USE OF NORTH SLOPE GAS FOR HEAT AND ELECTRICITY IN THE RAILBELT

FINAL REPORT

FEASIBILITY LEVEL ASSESSMENT

EBASCO

EBASCO SERVICES INCORPORATED

SEPTEMBER 1983

ALASKA POWER AUTHORITY

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EBASCO SERVICES INCORPORATED

SEPTEMBER 1983

ALASKA POWER AUTHORITY

MEMORANDUM

State of Alaska

TO: Readers

DATE: August 29, 1983

FILE NO:

TELEPHONE NO:

FROM: Robert A. Mohn
Director of
Engineering

SUBJECT: USE OF NORTH SLOPE GAS FOR HEAT AND ELECTRICITY IN THE RAILBELT

I am pleased to present this report prepared for the Alaska Power Authority by Ebasco Services, Incorporated. The purpose of this study is limited, and care should be taken not to draw unfounded conclusions.

It is a feasibility assessment of certain technical aspects of North Slope gas utilization in the Railbelt. The study examines the engineering and environmental feasibility of three alternative approaches for generating and transmitting electrical energy. For each approach, the preferred type of power generation technology, gas transport facility, and electrical transmission system is identified. Based on representative electrical energy demand scenarios, a representative scale and conceptual design is presented for each of the various facilities. The costs for construction of the facilities are estimated at a reconnaissance level. To provide a sound basis for the cost estimates, realistic physical settings are identified for each facility. Siting and environmental constraints are discussed.

The study does not purport to offer a complete power development plan or to offer insight into the economic or environmental tradeoffs of North Slope gas utilization in relation to other Railbelt power generation options. On the other hand, this report does provide a sound engineering, environmental and cost basis for undertaking more comprehensive power generation planning and analysis, where North Slope gas utilization might be one part of an integrated power development plan.

The Power Authority's review of Ebasco's work has led to a difference of opinion on the selected electrical transmission line tower design and, therefore, on its construction cost. The Authority's view of the matter is discussed in the attached memorandum. The differences are a matter of professional judgement and resolution will require a more detailed level of analysis.

Attachment: As Stated

9986/065

MEMORANDUM

State of Alaska

TO: Project File

DATE: August 26, 1983

Sun by 8-29-83 70th 920

FILE NO:

Thru: Robert A. Mohn
Project Manager

TELEPHONE NO:

FROM: Remy G. Williams RW
Cost Estimator

SUBJECT: North Slope Gas Study, Cost Estimates Draft Final Report by Ebasco, January 1983

This study included project scoping, preliminary siting, conceptual design and cost estimates for three alternative scenarios for the utilization of North Slope natural gas to generate electricity for use in the Railbelt Region. The three scenarios are based on generating facilities located on the North Slope, at Fairbanks, and on the Kenai Peninsula and the study is based on medium and low load growth forecasts. The conceptual estimates prepared by EBASCO can be grouped into three categories; 1) generating facilities, 2) natural gas transmission and distribution facilities and 3) electrical transmission facilities. After reviewing the cost of estimates, it is my opinion that the cost estimates for the generating facilities and natural gas transmission facilities are conservative, but reasonable and satisfactory for this level of study. However, in my opinion, EBASCO's transmission facility cost estimates are overly conservative (too high) and I cannot support them.

In order to try to resolve differences, I requested and received estimating backup data from EBASCO, and on May 16, 1983, Mike Yerkes of our staff and Art Lee of Diversified Engineers and Constructors, Inc. 1/ met with the EBASCO staff at Bellevue, Washington. The EBASCO cost estimates are high, because, in my opinion, they are based on a very conservative transmission line tower design and because EBASCO used very conservative cost assumptions. EBASCO still maintains their design assumptions and cost estimates are reasonable.

After meeting with EBASCO, I instructed Diversified Engineers to prepare a conceptual tower design and, based on that design, prepare an independent cost estimate for the North Slope to Fairbanks Transmission System - Medium Load Forecast. Attachment 1 is a summary of the Diversified cost estimate. A copy of Diversified's detailed cost estimate and tower design analysis is in the project file. (The Diversified conceptual tower design was reviewed and considered satisfactory by Mr. Yerkes). To make the Diversified estimate comparable to the EBASCO estimate, I adjusted the costs for Land and Land Rights and added a 20 percent contingency (see Attachment 2). The adjusted Divesified estimate is $1,680,118,000. This compares to the EBASCO estimate of $2,370,827,000 (Table 2-6). In my opinion, the Diversified estimate is the more reasonable.

Based on the Diversified estimate and on Power Authority bid experience on the Anchorage-Fairbanks Intertie, I prepared cost estimate summaries for the remaining transmission schemes. The summaries are shown on Attachment 3 thru 7. In my opinion these estimates should be used in lieu of the EBASCO estimates.

1/ Diversified Engineers and Constructors, Inc., is under contract to the Alaska Power Authority to provide independent cost estimating services on an as-needed basis.

DIVERSIFIED ENGINEERS & CONSTRUCTORS, INC.

COST & ESTIMATE SUMMARY

North Slope to Fairbanks Transmission Line
Medium Load Forecast
May 26, 1983

Item	Description	Amount
1.	Switching Stations	$ 86,190,302
2.	Substations	140,399,826
3.	Energy Management System	5,786,116
4.	Steel Towers & Fixtures	891,777,010
5.	Conductors & Devices	36,238,112
6.	Clearing	143,253,589
	Subtotal	$1,303,644,955
7.	Land & Land Right	18,000,000
8.	Engineering & Construction	60,452,966
	Total Construction Cost	$1,382,097,921

9854/037

ATTACHMENT 1

ALASKA POWER AUTHORITY

7/18/83
R. Williams

COST SUMMARY

North Slope to Fairbanks Transmission System
North Slope Power Generator - Medium Load Forecast
(January '82 Dollars)

Item	Description	Amount
1.	Switching Stations	$86,190,302
2.	Substations	140,399,826
3.	Energy Management System	5,786,116
4.	Steel Towers & Fixture	891,777,010
5.	Conductors & Devices	36,238,112
6.	Clearing	143,253,589
	Subtotal	$1,303,644,955
7.	Land & Land Right	36,000,000
8.	Engineering & Construction Management	60,452,966
	Subtotal	$1,400,097,921
	Contingency 20%	280,019,584
	Total Construction Cost	$1,680,117,505
	Rounded	$1,680,118,000

ATTACHMENT 2

ALASKA POWER AUTHORITY

7/18/83
R. Williams

COST SUMMARY

Fairbanks to Anchorage Transmission System
North Slope Power Generation - Medium Load Forecast
(January '82 Dollars)

This estimate is based on Power Authority experience on the Anchorage - Fairbanks Intertie.

820 mile x $750,000/mile	=	$615,000,000
Contingencies 20%		123,000,000
Total Construction Cost		$738,000,000

Note - This estimate is also for:
Fairbanks to Anchorage Transmission System
Fairbanks Power Generation - Medium Load Forecast

9860/053

ATTACHMENT 3

ALASKA POWER AUTHORITY

7/19/83
R. Williams

COST SUMMARY

North Slope to Fairbanks Transmission System
North Slope Power Generation - Low Load Forecast

(January '82 Dollars)

Item	Description	Amount
1.	Switching Stations	$57,000,000
2.	Substations	87,000,000
3.	Energy Management System	5,786,116
4.	Steel Towers & Fixtures	891,777,010
5.	Conductors & Devices	36,238,112
6.	Clearing	143,253,589
	Subtotal	1,221,054,827
7.	Land & Land Rights	36,000,000
8.	Engineering & Construction Management	60,452,966
	Subtotal	1,317,507,793
	Contingency 20%	263,501,558
	Total Construction Cost	$1,581,009,351
	Rounded	$1,581,009,000

9860/053

ATTACHMENT 4

ALASKA POWER AUTHORITY

7/19/83
R. Williams

COST SUMMARY

Fairbanks to Anchorage Transmission System
North Slope Power Generation - Low Load Forecast
(January '82 Dollars)

This estimate is based on Power Authority experience on the Anchorage - Fairbanks Intertie

490 miles x $750,000/mile =	$367,500,000
Contingencies 20%	73,500,000
Total Construction Cost	$441,000,000

Note - This estimate is also for:

Fairbanks to Anchorage Transmission System
Fairbanks Power Generator - Low Load Forecast

9860/053

ATTACHMENT 5

ALASKA POWER AUTHORITY

7/19/83 Rev 8/25/83
R. Williams

COST SUMMARY

Kenai to Anchorage Transmission System
Kenai Area Power Generation - Medium Load Forecast
Submarine Cable Crossing Alternative
(January '82 Dollars)

Item	Description	Amount
1.	Switching Stations	--
2.	Substations	$120,000,000
3.	Energy Management System	5,000,000
4.	Steel Towers & Fixtures	151,200,000
5.	Conductors & Devices	7,200,000
6.	Clearing	36,000,000
7.	Submarine Cable & Devices	104,080,000
	Subtotal	$423,480,000
8.	Land & Land RIghts	7,200,000
9.	Engineering & Construction Management	25,409,000
	Subtotal	$469,089,000
	Contingency 20%	91,218,000
	Total Construction Cost	$547,307,000

9860/053

ATTACHMENT 6

ALASKA POWER AUTHORITY

7/19/83 Rev. 8/25/83
R. Williams

COST SUMMARY

Kenai to Anchorage Transmission System
Kenai Area Power Generation - Low Load Forecast
Submarine Cable Crossing Alternative
(January '82 Dollars)

This estimate is equal to the medium forecast estimate less $40,000,000 for reduced substation cost.

	$547,307,000
	- 40,000,000
Total Construction Cost	$507,307,000

ATTACHMENT 7

USE OF NORTH SLOPE GAS FOR
HEAT AND ELECTRICITY IN THE RAILBELT

FINAL REPORT

FEASIBILITY LEVEL

ASSESSMENT

EBASCO SERVICES INCORPORATED

with

FRANK MOOLIN & ASSOCIATES

and

ALASKA ECONOMICS INCORPORATED

SEPTEMBER 1983

2999A

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SUMMARY

1.0 SUMMARY

1.1 PURPOSE

The purpose of this study is to examine the technical and environmental feasibility of several alternatives for the utilization of North Slope natural gas to generate electricity for use in the Railbelt region, and to develop feasibility level cost estimates for each alternative. The alternatives are grouped into three scenarios based on selected generating locations, and the study is based on the medium and low growth forecasts of Railbelt electrical needs provided by previous studies. One scenario also provides for the development of a residential and commercial natural gas distribution system in Fairbanks.

Previous reports developed for this feasibility assessment have detailed the existing data and assumptions to be used in developing the scenarios, the technical and economic bases for establishing power generating technologies, and the factors to be considered in facility siting and corridor selection. Potential environmental effects are detailed in this report. The previous reports are appended to this report for completeness.

1.2 STUDY APPROACH

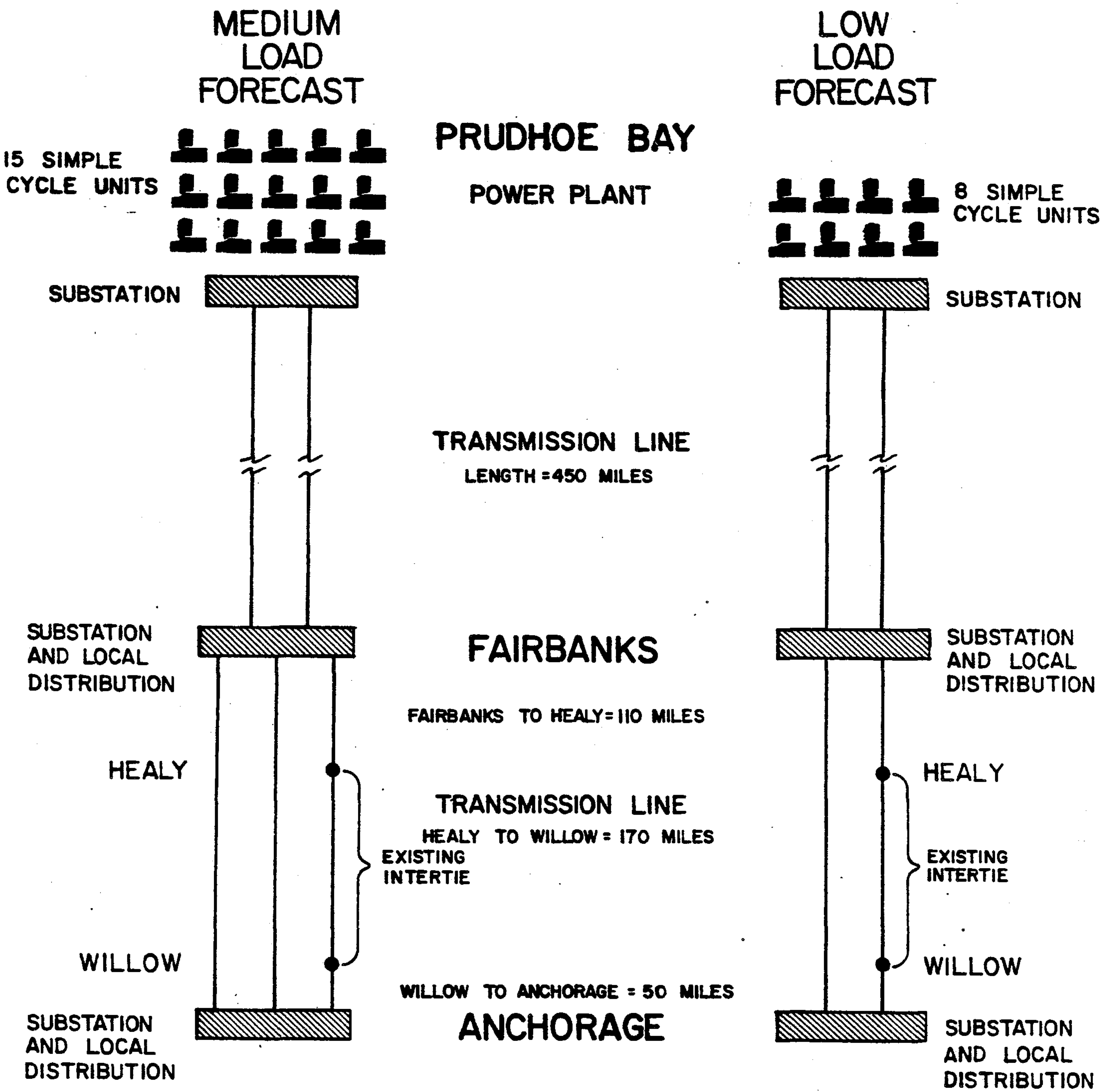
An initial survey of the electrical demand growth forecasts and the availability and characteristics of North Slope gas provided a basis for establishing candidate power generating technologies. Meetings and discussions with knowledgeable officials and industry representatives were held to focus the study on factors unique to each region, and factors unique to North Slope natural gas. Candidate generating sites and routing corridors (both electrical and natural gas) were evaluated. Forecasts of potential natural gas demand in Fairbanks and details for a gas distribution system were prepared.

Much of the above was completed prior to performing cost estimating tasks. While this study uses assumptions consistent with previous studies of other electrical generating scenarios for the Railbelt, cost estimating tasks have not included fuel cost derivation nor the development of cost of power values. Comparisons with alternative electric generating scenarios are therefore outside the scope of this study. Such comparisons can be considered as a logical extension of these studies which may be performed by the Alaska Power Authority.

1.3 SCOPE

The scope of the study was defined by the Alaska Power Authority to consist of three distinct scenarios. Each scenario was evaluated for its feasibility to meet the medium and low load forecasts of recent previous studies which examined the electrical demand requirements of the Railbelt Region. The first scenario is characterized by the generation of electricity on the North Slope using simple cycle combustion turbines fired by untreated natural gas. A major, new transmission line system would be required from the North Slope to Fairbanks, with substantial improvements to the transmission system connecting Fairbanks and Anchorage. Figure 1-1 is a depiction of the North Slope scenario showing the major differences between the medium and low load cases. The medium load forecast requires 15 units with a total capacity of almost 1400 megawatts (MW), two 500 kilovolt (kV) circuits from the North Slope to Fairbanks, and three 345 kV circuits from Fairbanks to Anchorage. The low load forecast can be met with 8 units (700 MW), two 500 kV circuits from the North Slope to Fairbanks, and two 345 kV circuits from Fairbanks to Anchorage. The present worth of costs of the medium load forecast is $3.8 billion versus $2.7 billion for the low load forecast. Both costs are in 1982 dollars and do not include fuel costs.

The second scenario consists of two distinct parts: a generating facility in the Fairbanks area and a gas distribution system in Fairbanks. Transmission of the gas to Fairbanks from the North Slope would require construction of a high pressure gas pipeline, although



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

NORTH SLOPE SCENARIO

FIGURE 1-1

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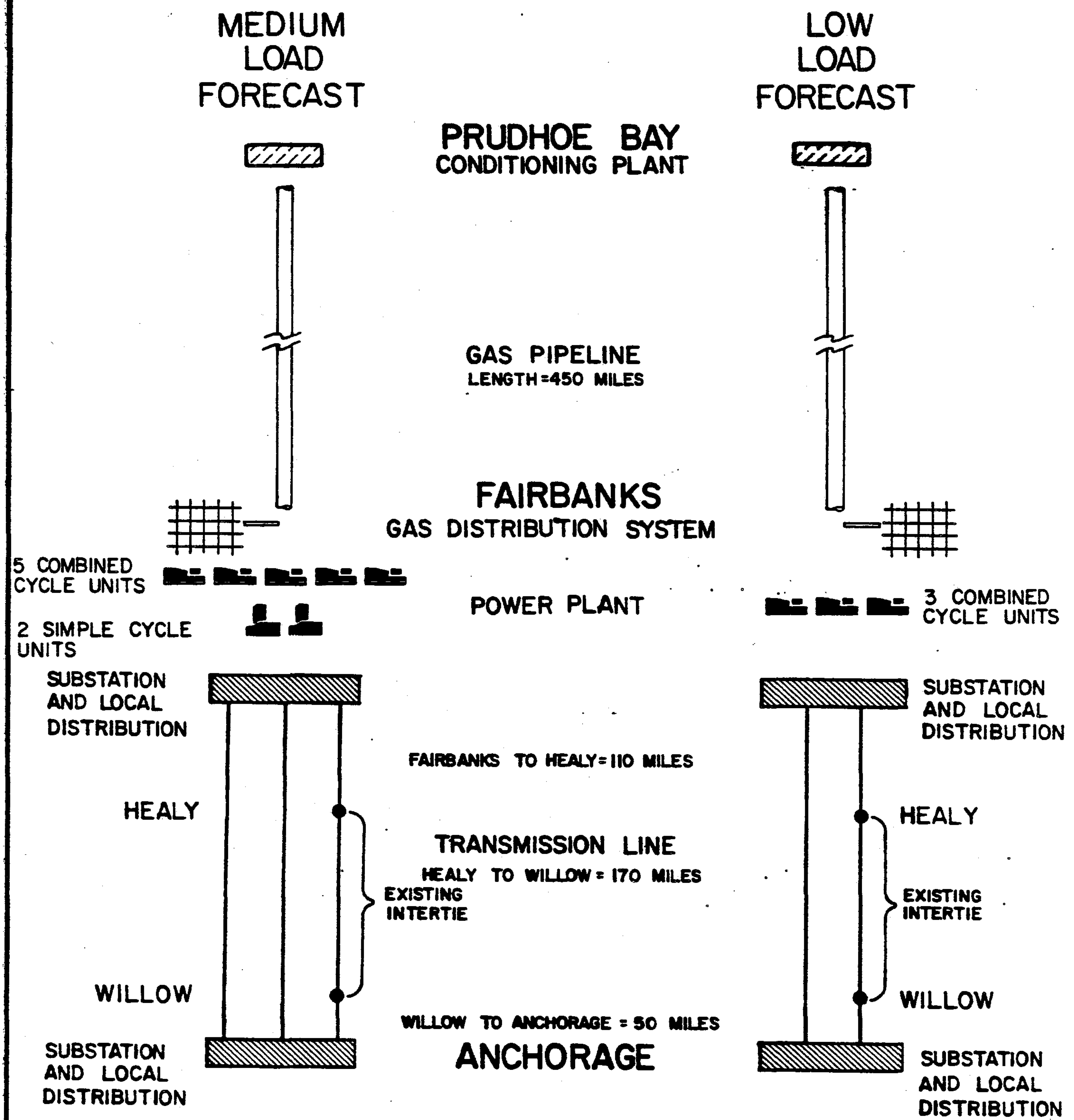
the size of the pipeline would be somewhat smaller than that proposed for the Alaska Natural Gas Transportation System (ANGTS). Electrical power generation near Fairbanks would use combined cycle plants consisting of gas fired combustion turbines, waste heat recovery boilers and steam turbines. A gas conditioning facility would be required on the North Slope.

The Fairbanks generating scenario is depicted in Figure 1-2 which shows that five combined cycle and two simple cycle units are required to meet the year 2010 medium load forecast (1400 MW). The low load forecast (700 MW) requires three combined cycle units. The Fairbanks generating scenario requires a 22 inch diameter gas pipeline from the North Slope to Fairbanks and includes a natural gas distribution system to meet residential and commercial heating needs. Three 345 kV transmission circuits from Fairbanks to Anchorage are required for the medium forecast and two for the low load forecast. Present worth of costs of the electrical generating scenarios, excluding fuel costs, in 1982 dollars is $5.4 billion (medium forecast) or $3.6 billion (low forecast). The present worth of costs for the Fairbanks gas distribution system is $0.9 billion for the medium load forecast and $1.1 billion for the low load forecast.

The third scenario is contingent on the construction of a major natural gas pipline from the North Slope to tidewater on the Kenai Peninsula. Delays in the construction of ANGTS have renewed interest in such an all-Alaska pipeline. This system is described in the Governor's Economic Committee on North Slope Natural Gas Report (1983) entitled "Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas." The Kenai electric generating scenario incorporates the anticipated energy demand from this system's tidewater facilities into the Railbelt's demand forecasts. Fuel for the power plant will be derived from a blend of waste gas from the conditioning facilities and sales gas. A major transmission line would also be required from near tidewater to the load center in Anchorage. The existing transmission



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

FAIRBANKS SCENARIO

FIGURE I-2

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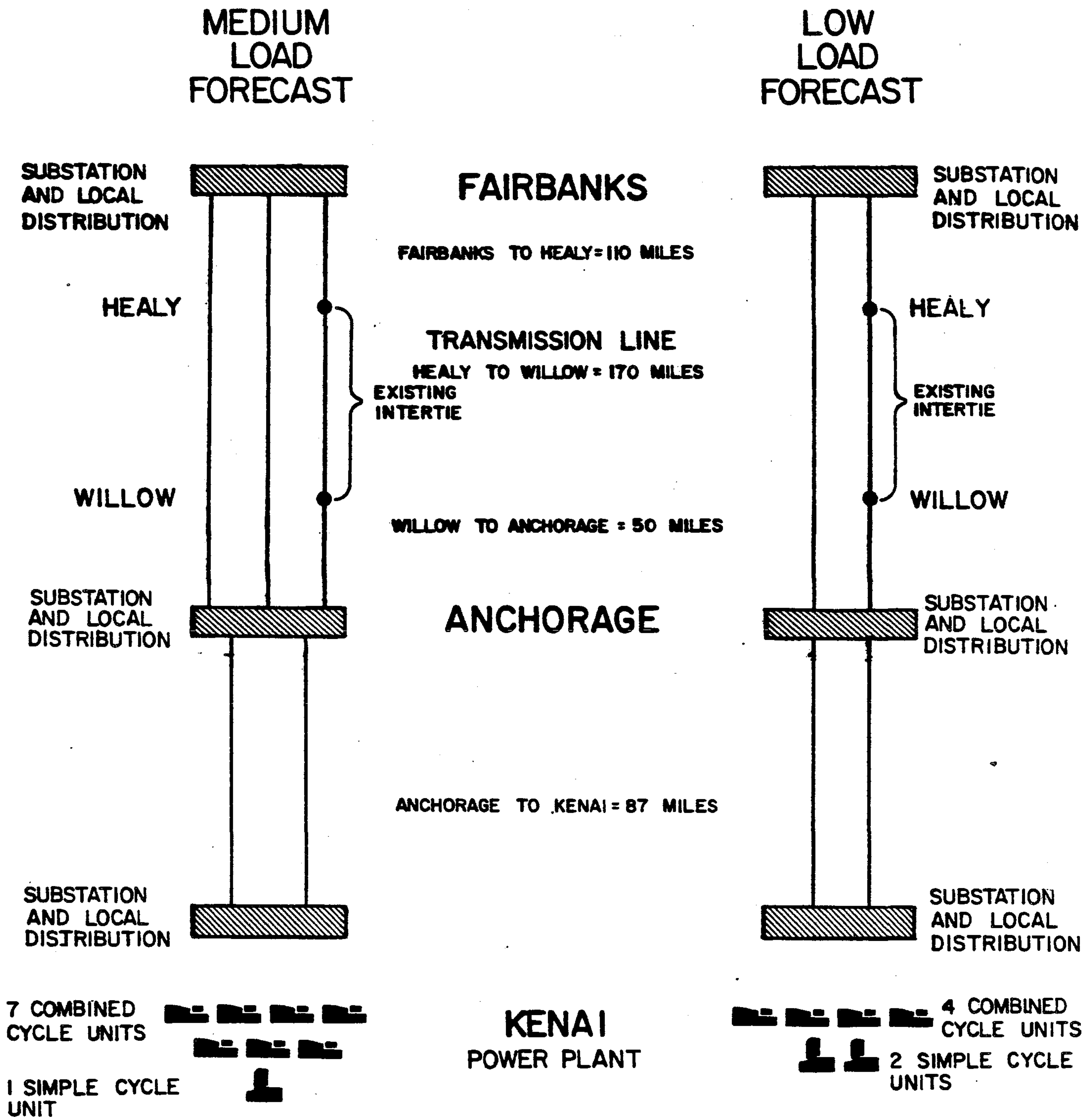
line from Anchorage to Fairbanks would have to be up-graded to handle the generating capacity.

The Kenai scenario (Figure 1-3) includes seven combined cycle units and one simple cycle unit to meet the energy demand in 2010 for the medium load forecast, and four combined cycle units and two simple cycle units for the low load forecast. In order to provide a highly reliable electric transmission system from Anchorage to Fairbanks, two parallel 345 kV circuits are required, even though a single circuit would be adequate in the low load forecast. Underwater cable crossing of Turnagain Arm is cost effective, with two 500 kV circuits from Kenai to Anchorage. Cost estimates (excluding the pipeline and gas processing facilities as well as fuel costs) result in a present worth of costs for the medium load forecast of $2.0 billion, and $1.7 billion for the low load forecast (in 1982 dollars).

1.4 RESULTS

This work has resulted in the development of several scenarios for meeting the electrical generating needs of the Railbelt region using North Slope natural gas for fuel. Each scenario has been refined to establish schedules of generating capacity additions consistent with medium and low load forecasts through the year 2010. Chapter 2 and Chapter 3 detail the North Slope Power Generation scenario for the medium and low forecasts, respectively. Chapter 4 and Chapter 5 detail the Fairbanks scenario, while Chapter 6 and Chapter 7 describe the Kenai Power Generation scenario.

Engineering and cost evaluations of technologies capable of using natural gas to generate electricity provide a consensus for the use of gas fired combustion turbines. For the Fairbanks and Kenai scenarios, the turbines are exhausted through waste heat recovery boilers to power steam turbines.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

KENAI SCENARIO

FIGURE 1-3

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All of the scenarios will require substantial construction of electric transmission lines. A power plant on the North Slope separates the generation and load centers by almost 900 miles, requiring special transmission system design considerations to obtain a stable and reliable system. Generation near Kenai, on the other hand, requires a 500 kV underwater crossing of Turnagain Arm.

Socioeconomic and environmental effects of generating significant amounts of electricity are substantial in both the construction and operation of the system. However, no effect would appear to preclude any of the scenarios. Both air and water pollution control measures associated with gas fired combustion turbines are generally modest compared to other technologies.

Cost estimates are provided for each forecast of all three scenarios. Because each scenario is distinctly different, except for providing the required electricity, cost comparisons should not be the sole factor in evaluating the desirability of any scenario. However, within the scope of this study, Kenai generation shows the least cost because it does not factor in the cost of the Trans Alaska Gas System and its associated processes. The Fairbanks scenario is the most costly because it includes a 450 mile natural gas pipeline, and a gas conditioning facility on the North Slope. The North Slope scenario is in the middle of the cost range and is characterized by the high capital cost of constructing high voltage transmission lines to Fairbanks.

SCENARIO I
NORTH SLOPE POWER GENERATION
MEDIUM LOAD

2.0 NORTH SLOPE POWER GENERATION

MEDIUM LOAD FORECAST

The first scenario, under the medium load forecast, centers on a major electric generating station on the North Slope at Prudhoe Bay, near the source of natural gas used to fuel the station. By the year 2010, the station would consist of 15 simple cycle combustion turbines capable of generating almost 1400 megawatts (MW) of power to serve the Railbelt. North Slope power generation does not require the construction of major gas pipelines, but does require construction of 500 kilovolt (kV) electric transmission lines from the North Slope to Fairbanks and additional transmission lines of 345 kV from Fairbanks to Anchorage. Detailed analysis of the transmission system shows that a stable and reliable system can be designed despite the generation and major load centers being over 800 miles apart. The total construction costs for the system described are $4.2 billion, with total annual operation and maintenance costs of $1.1 billion. The present worth of these costs excluding fuel costs is $3.8 billion as of 1982. Environmental and socioeconomic effects of this scenario are substantial, but none have been identified which would preclude the project.

2.1 POWER PLANT

The power generation technology selected for the North Slope scenario employs simple cycle combustion turbines utilizing 91 MW baseload, combustion turbine generators. The criteria and parameters which resulted in this selection are discussed in the Report on Systems Planning Studies (Appendix B).

2.1.1 General

Development of a North Slope site for the required generating units, construction and maintenance facilities, worker housing, and access facilities will be a major undertaking. In addition to continuously expanding facilities for maintenance and operation, there will be permanent construction facilities and a semi-permanent construction staff.

The scenario for utilizing simple cycle gas turbine-generators to generate power at the North Slope requires fifteen 91 MW (nominal) units for satisfying load demand under the medium load forecast. The units would be added in increments beginning in 1993. On the average, slightly less than one unit per year is required through the end of the study period in 2010. Incremental and total required new generation capacity for this scenario are summarized in Table 2-1.

The functional parts of the plant will consist of a gas supply system(s), the turbine-generators, various auxiliary and support systems, a central control facility, switchyards, and the northern terminus of the transmission line.

A single simple cycle unit will require approximately a 90 ft x 150 ft enclosure as shown in Figure 2-1. It is planned that the units be installed side by side as shown in Figure 2-2 up to the maximum of 15 units required for the medium load forecast. The site will include the 138 kV switchyard behind the units and a 500 kV transmission line termination centered on the planned maximum plant site. A 300 ft wide buffer area surrounding the site is planned, yielding a maximum total site acreage of 90 acres.

2.1.2 Combustion Turbine Equipment

The combustion turbine plant design envisioned is based on using currently available gas turbine units, rated by one manufacturer at approximately 77 MW each. Various other manufacturers' turbines of similar size could be used to satisfy the requirement of this study, but it must be pointed out that the specific plant output and various specific design parameters may be expected to change accordingly.

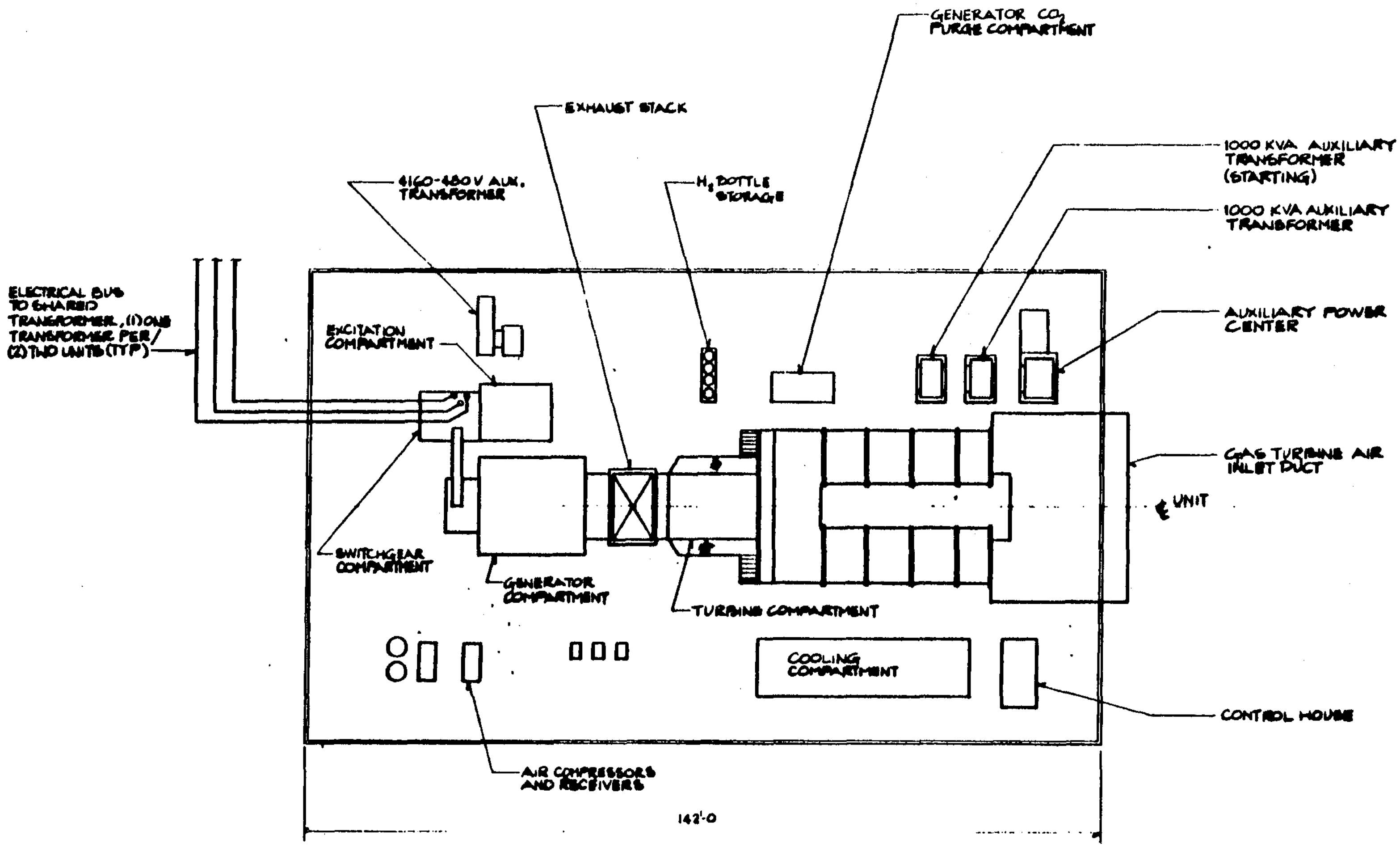
TABLE 2-1

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST

Year	New Capacity (MW) (Increment/Total)	Gas Required (MMSCFY)1/ 2/
1990	0/0	0.
1991	0/0	0.
1992	0/0	0.
1993	91/91	6,574.6
1994	0/0	6,574.6
1995	91/182	13,149.1
1996	91/273	19,778.7
1997	91/364	26,287.3
1998	91/455	32,861.9
1999	0/455	32,861.9
2000	91/546	39,546.7
2001	0/546	39,436.4
2002	182/728	52,585.6
2003	0/728	52,585.6
2004	91/819	59,325.0
2005	182/1001	63,546.9
2006	91/1092	66,548.2
2007	91/1183	69,538.7
2008	91/1274	72,540.2
2009	0/1274	75,530.6
2010	91/1365	78,532.0

1/ MMSCFY = million standard cubic feet per year.

2/ Values as calculated are shown for purposes of reproducibility only and do not imply accuracy beyond the 100 MMSCFY level.



PLAN - 77 MW NOMINAL RATING/SIMPLE CYCLE PLANT

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

SIMPLE CYCLE GAS TURBINE
GENERAL ARRANGEMENT

FIGURE 2-1

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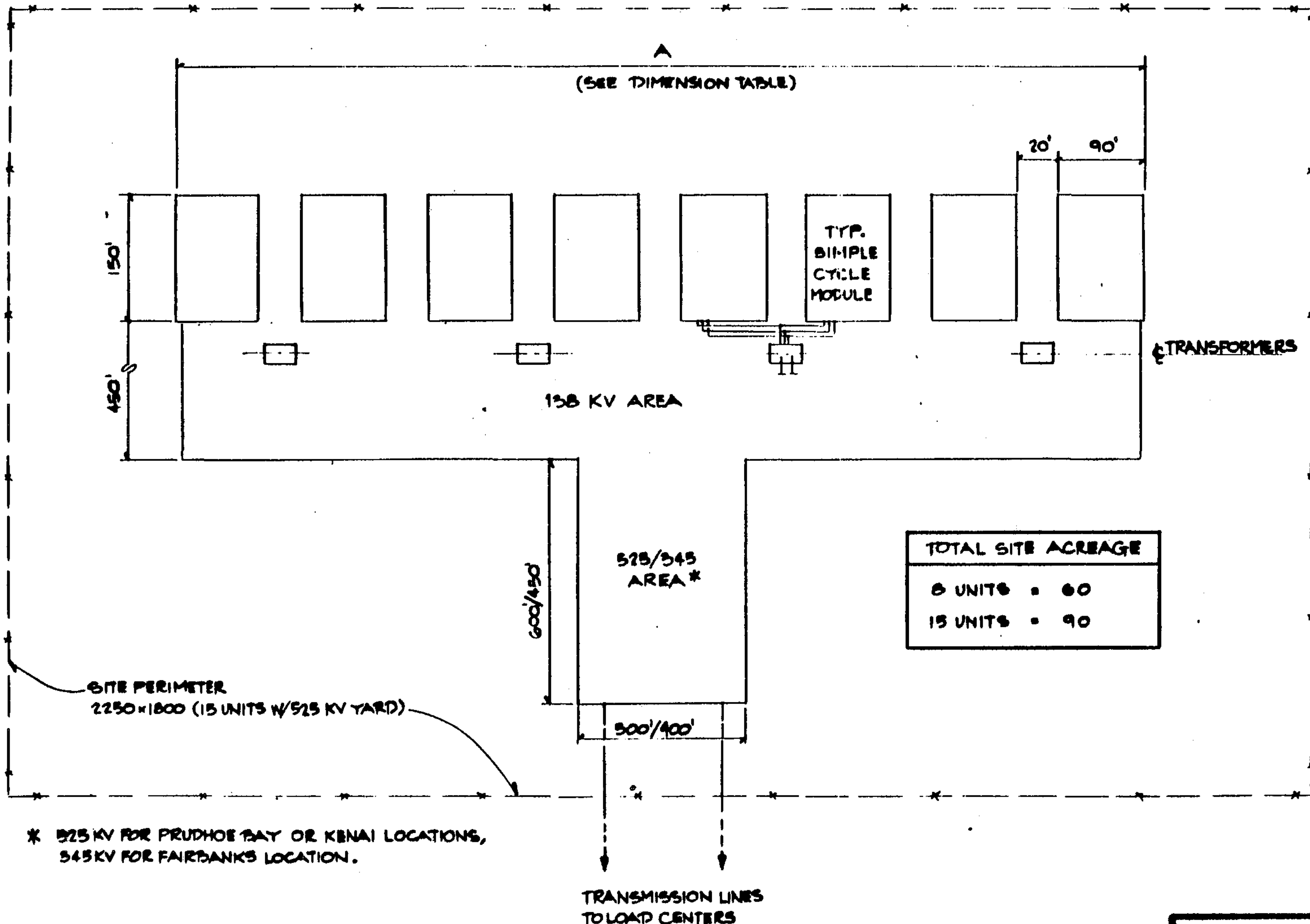

* 525 KV FOR PRUDHOE BAY OR KENAI LOCATIONS, 345 KV FOR FAIRBANKS LOCATION.

DIMENSION 'A'	NO. OF COMPLETE SIMPLE CYCLE UNITS
90	1
310	3
530	5
750	7
970	9
1190	11
1410	13
1630	15

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

SIMPLE CYCLE GAS TURBINE
SITE PLAN
NORTH SLOPE

FIGURE 2-2

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At International Standards Organization (ISO) referenced conditions (59°F and sea level) plant performance will consist of a net unit output of 77 MW. The ISO heat rate of the units will be approximately 11,900 Btu/kWh (higher heating value [HHV]). For the actual conditions existing at the North Slope (average annual temperature of 9°F and sea level) the rating of the turbines is approximately 91 MW and the heat rate is 11,500 Btu/kWh (HHV).

Each combustion turbine is a large frame industrial type with an axial flow multi-staged compressor and power turbine on a common shaft. The combustion turbine is directly coupled to an electric generator, and can be started, synchronized, and loaded in about one half hour under normal conditions.

The gas turbine generators are "packaged" units and as such include all auxiliary equipment. The package generally includes:

(1) 13.8 kV switchgear which houses the generator grounding transformer, and generator air circuit breaker.

(2) Nonsegregated phase (iso-phase) bus work which runs from the generator to the main transformer.

(3) A master control panel for overall operation and monitoring.

(4) A transformer (13.8/4.16 kV) sized to support the ancillary load (estimated to be 2 megavolt-amperes [MVA]).

(5) A 4.16 kV switchgear with air circuit breakers for other loads (e.g. 800 horse power [HP] cranking motor). The largest load (gas compressor) is fed from the plant common 4.16 kV switchgear.

(6) Electrical protection equipment.

Each combustion turbine generator package also includes an inlet air filtration system, fuel system, lubricating oil cooling system, and various minor subsystems as required, furnished by the manufacturer.

The design parameters for each combustion turbine with generator are presented in Table 2-2. Inlet air preheating using a heat exchanger will also be necessary.

2.1.3 Fuel Supply

Annual fuel requirements for power generation at the North Slope will be 6.5 BCFY (billion cubic feet per year) in 1993 and grow to 78 BCFY by 2010 for the medium growth forecast. Maximum potential firing rate for the medium load growth scenario will be 2.5 x 10^5 SCFM (standard cubic feet per minute) in the year 2010.

Fuel requirements on a year by year basis will vary with installed generating capacity and are shown in Table 2-1. These gas demands were generated based on an average annualized unit heat rate of 11,500 Btu/kWh (HHV) for the simple cycle gas turbines at average ambient conditions.

The HHV of the fuel gas is assumed to be 1046 Btu/SCF (lower heating value [LHV] 942 Btu/SCF). These values reflect the fact that no gas conditioning facilities will be required for the North Slope scenario.

The gas supply system will consist of piping from one or more of the existing North Slope natural gas gathering centers, a pressure reduction station and an in-plant distribution system. The supply and distribution system will be designed for maximum flexibility to operate any configuration of the available gas turbines. The pressure reduction system will be required to assure a constant gas supply pressure at 250 psig.

2.1.4 Substation

The circuit diagram of the power plant substation is shown in Figure 2-3. Two generators will be connected to the two primary windings of the 250 MVA 13.8/138 kV transformers. The bus arrangement will use a breaker and a half scheme unless reliability considerations

TABLE 2-2

COMBUSTION TURBINE WITH GENERATOR DESIGN PARAMETERS
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST

Turbine Type:1/ Simple-cycle, single-shaft, three bearing.

Generator Type: Hydrogen-cooled unit rated 130 MVA at 13.8 kV, with 30 psig hydrogen pressure at 10°C.

Performance: (Each Turbine - at ISO Conditions)

Heat Rate (LHV)	10,700 Btu/kWh
Heat Rate (HHV)	11,500 Btu/kWh
Air Flow	609 lbs/sec
Turbine Exhaust Temp	995°F
Turbine Inlet Temp	1985°F
Inlet Pressure Drop	3.5 in. water
Exhaust Pressure Drop	0.5 in. water
Overall Dimensions	38 ft. wide by 118 ft. long by 32 ft. high

Combustion Turbine Features:

Accessories include starting motor, motor control center for all base-mounted motors, lubrication system, hydraulic control system.

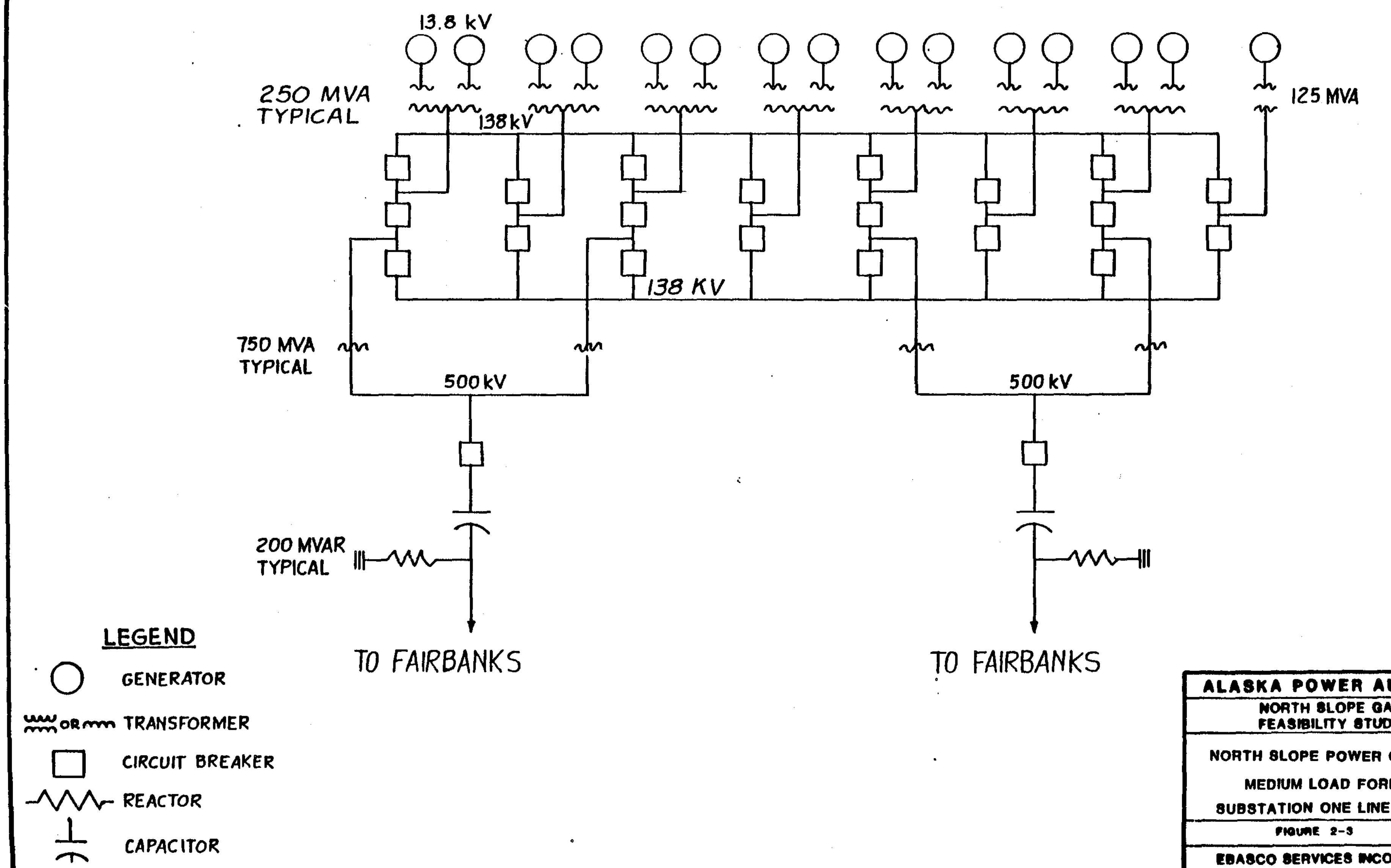
Excitation compartment complete with static excitation equipment.

Switchgear compartment complete with generator breaker, potential and current transformers, disconnect link for auxiliary feeder, and a power takeoff.

Fuel system capable of utilizing natural gas, mixed gas fuel, or liquid fuel.

Fire protection system (low pressure CO_2).

1/ Based on General Electric Model MS7001.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION

MEDIUM LOAD FORECAST

SUBSTATION ONE LINE SCHEMATIC

FIGURE 2-3

EBASCO SERVICES INCORPORATED

mandate otherwise. Two 750 MVA 138/525 kV autotransformers will supply each of the transmission line circuits. Each of the transmission lines will have a circuit breaker. On the line side of the circuit breakers will be the series capacitors and the shunt reactors. This arrangement has the advantage of being flexible as far as operation is concerned, and can be expanded easily. The system's flexibility is demonstrated in Figure 2-4, which shows the initial development associated with the installation of the first generator. There are seemingly more circuit breakers than necessary in this initial circuit; their purpose is to facilitate future expansion work.

The grounding mat of the switchyard is connected to four insulated 1000 kCM[1/] cables which terminate in a grounding rod system driven into the sea floor. The ground mat is also connected to the two counterpoises[2/] which run under the entire length of the transmission line.

2.1.5 Power Plant Support System Descriptions

The auxiliary systems described in this section represent generally the minimum necessary to operate a simple cycle combustion turbine facility. These systems include water supply, waste management, fire protection, electrical, and lubricating oil systems.

Plant makeup water will be derived from an assumed existing lake of at least 150 acres to supply the needs of two water systems: a potable water system for the plant and the camp, and a service water system. The potable water system will be designed to supply water for the maximum crew on hand through completion of the final unit. Service water will be provided to all units for maintenance, construction uses

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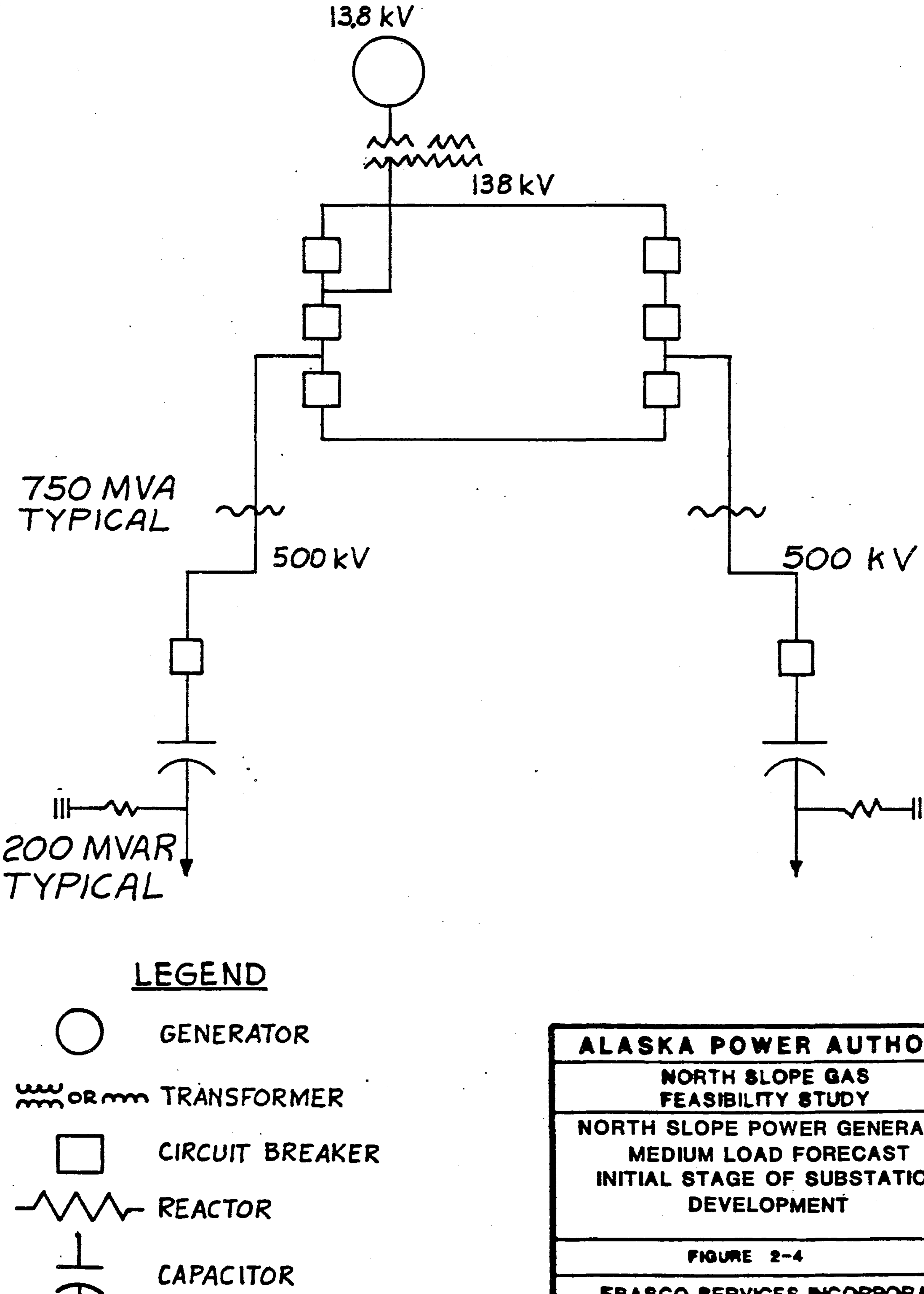
1/ kCM stands for thousands of circular mils, a measure of the cross-section of a cable.

2/ Counterpoises are buried grounding cables, running under transmission lines, which are necessary in areas with poorly conducting soils.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS
FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION
MEDIUM LOAD FORECAST
INITIAL STAGE OF SUBSTATION
DEVELOPMENT

FIGURE 2-4

EBASCO SERVICES INCORPORATED

and area cleaning. A water injection system should not be required for NO_x control on the North Slope (see Section 2.4.1 for further explanation).

Waste control systems for the plant will consist of control and processing through oil/water separation treatment of all floor drainage from operation and maintenance areas. This treated effluent and domestic wastes will be transported to an existing sanitary waste treatment facility. Because the natural gas supply is low in sulfur content, no sulfur dioxide (SO_2) emissions control will be required.

Due to the climatic conditions existing during most of the year, fire protection will be based on standard halon systems rather than water systems. Automatic halon systems will be installed for high risk areas, and manual systems will be used for low risk areas. Also, each system selected shall be compatible with any of the specific hazards it is intended to combat.

A system for storing both clean and dirty lubricating oil shall be included. The system will include a central storage area and portable units capable of transporting, replacing, and/or cleaning the lubricating oil in an operating gas turbine.

2.1.6 Construction and Site Services

The construction and operation of a simple cycle power plant will require a number of related services to support all work activities at the site. These site services will include the following for the North Slope power plant:

(1) Access

(2) Construction Water Supply

(3) Construction Transmission Lines

(4) Construction Camp

Access

Gravel roads with a 5 foot minimum gravel base will be required to connect the plant site with the existing road network at the North Slope. It is expected that no more than 2 miles of new road construction will be required.

It is anticipated that all personnel travel will be by air with pre-arranged commercial charter carriers to Deadhorse Airport. All perishable goods, mail, and rush-cargo, will be flown in. Equipment for construction will be flown in only under extraordinary circumstances.

The site will use the existing marine landing facilities during the six week "thaw" period to receive all major equipment and supplies. A fenced interim storage area will be provided. The Dalton Highway (Haul Road) from Fairbanks will be utilized for smaller shipments to the site.

Construction Water Supply

A complete water supply, storage and distribution system will be installed. Due to the nature of the site, a heated and insulated one-million gallon water storage tank will be incorporated into the camp's design, with one-half of this storage capacity dedicated to fire protection needs. The water supply will be derived from an existing lake.

Construction Transmission Lines

Power requirements during the construction phase will be supplied by constructing a 69 kV transmission line tapped from the area's existing transmission system.

Construction Camp Facilities

A 200 (maximum) bed labor camp will be provided unless an existing camp can be utilized. All personnel housed in this camp will be on single status. Provisions will be made to accommodate a work force of both men and women by providing separate facilities.

The 200 bed camp will accommodate the maximum required workforce for those years when two turbines will need to be installed and started up at the same time. For other years, a workforce of 50 to 100 (maximum) is anticipated. This camp will also be used to house operating personnel.

2.1.7 Operation and Maintenance

Plant Life

Each gas turbine will have a 30 year life expectancy. It is expected that the gas turbine units will be overhauled in accordance with manufacturer's suggestions and good operating practice for the life of the units.

Heat Rate of Units

Unit heat rates for the plants will vary, depending on ambient conditions at the sites. It is common practice for gas turbine manufacturers to quote heat rates in terms of the lower heating value (LHV) of the fuel. However, since fuel is purchased based on higher heating values (HHV), HHV figures are used in the balance of this report. The site specific HHV heat rate is 11,500 Btu/kWh. ISO conditions give a heat rate of 10,700 Btu/kWh (LHV) for base load operation.

Scheduled and Forced Outage Rate

It is expected that the forced outage rate will be about 8 percent. Operational experience on other plants indicates higher forced outages in the first few years, but this is attributed to operational adjustments required for a new plant. It is expected that a slight increase in forced outages will occur as the plant ages.

Scheduled outages will be an additional 7 percent based on two periods of regular semi-annual maintenance requiring shut down and one 5 week period every three years for overhaul.

Operating Workforce

The number of personnel required to operate a plant of this type can vary widely, depending on plant utilization and system operating practices. Based on Electrical Power Research Institute Operational Development Group study figures, and considering the severity of climate and operational failure, an on-duty operation and maintenance workforce of 10 persons will be required starting in 1993, when one unit is operating. This will grow as units are added until an on-duty force of approximately 50 persons will be required for the 15 units operating in 2010. Assuming a 12 hour shift and a 7-day-on, 7-day-off work schedule, the total required workforce will vary from 40 to 200 personnel.

2.1.8 Site Opportunities and Constraints

Climate is the single most important site characteristic affecting design at the North Slope. As previously mentioned, the 77 MW rating of the turbine is based on ISO conditions with an ambient temperature of 59°F. As the ambient temperature decreases, the capacity of these units increases. At 0°F, the rated capacity of these units is 122 percent of the capacity at 59°F, or approximately 94 MW. The heat rate decreases as the temperature decreases, and at 0°F is 97.5 percent of that at 59°F, or approximately 11,600 Btu/kWh (HHV). Clearly a cold climate site such as the North Slope offers some operational performance advantages. This is especially true since the cold weather also produces the annual peak loads for the Railbelt area. The average annual temperature at the North Slope site is 9°F resulting in an average annual unit capacity and heat rate of 91 MW and 11,500 Btu/kWh (HHV), respectively.

The remoteness of the site combined with the climatic conditions present the most significant problems to construction of this scenario. The short construction season and the cost of construction at the North Slope generally dictate that as much prefabrication as possible be performed prior to shipping units to the site. In addition the arrival of shipments via barge will be delayed until mid-summer when the Arctic coast becomes free of ice. This further shortens the construction season for shipped materials and may require storage over winter for completion of construction the following summer.

2.2 TRANSMISSION SYSTEM

2.2.1 Overview of the System

For reasons of reliability, two parallel circuits have been considered. The design criteria used in the study are presented in Table 2-3. Additional details regarding system design and alternatives are presented in Appendix D. The 450-mile length of the proposed transmission system between the North Slope and Fairbanks will be interrupted by two intermediate switching stations, one at Galbraith Lake and one at Prospect Camp; this will establish three almost exactly equal 150-mile-long segments.

The two circuits will originate in the Prudhoe Bay/Deadhorse area of the North Slope. Each circuit will be supplied by two 750 MVA transformers, protected by one circuit breaker and compensated with a series capacitor bank and shunt reactor. The two circuits will be

TABLE 2-3

TRANSMISSION LINE DESIGN CRITERIA
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST

Temperature range:	-60°F to +86°F
Wind loads:1/	25 lbs per sq. ft above the Arctic Circle and 8 lbs/sq. ft. below it; 2.3 lbs/sq. ft. at +86°F
Ice on conductor:	1.5" radial thickness with 8 lbs/sq. ft. wind load at 32°F
Snow on ground:	36" north of the Arctic Circle and 24" south of it
Clearance to ground:	minimum 38 feet with snow on the ground
Tension in conductors:	maximum 50% of rated tensile strength
Gradient on conductor surface:2/	maximum 18 kV per centimeter

1/ 25.0 lbs per square foot corresponds to 100 mph wind
8.0 lbs per square foot corresponds to 55 mph wind
2.5 lbs per square foot corresponds to 30 mph wind

2/ To reduce corona losses and mitigate radio and television interference located on opposite sides of the road for the first 60 miles, to Pump Station 2. South of the 60 mile mark, the line may not necessarily be located on the two sides of the road.

The first switching station will be at Galbraith Lake approximately 150 miles south of Prudhoe Bay. Immediately south of the switching station is a 30-mile portion of the route where the suitable terrain narrows, possibly requiring the two circuits to be placed on single towers. In the Atigun Pass area the slopes of the mountainside are not overly rugged and the two circuits could be constructed a few hundred feet up the slopes from the roadway. The Atigun Pass section is about 5 miles long and reaches an elevation of approximately 5,000 feet, the highest point of the transmission system.

The second switching station will be located at Prospect Camp. It will be identical to the one at Galbraith Lake. The line will cross the Yukon River near the Yukon River Bridge, and will terminate in the Fairbanks area.

2.2.2 Voltage Selection

Three voltage levels were investigated in detail: 500 kV AC, 765 kV AC, and $\pm$350 kV DC (see Appendix D). Each of these are capable of transmitting the required power from the North Slope to Fairbanks. A comparative cost study has been made using the methodology and cost figures supplied by Commonwealth Associates (1978). The study indicated that all three versions are within $\pm$10% as far as capital investment is concerned, which is within the expected range of accuracy of these types of calculations. Therefore, all three can be considered to be equal with respect to capital cost. The 500 kV alternative was chosen for detailed cost estimating because this version represents the most conventional approach and would likely have the best reliability.

2.2.3 Towers

Tubular steel H-frame towers will be utilized for the line; their average height will be 90 feet and the average span will be 1000 feet. There will be one dead end tower at approximately every 10 miles, or in other terms 2% of the towers will be dead end.[1/]

Special consideration has been given to the crossing of the Yukon River, about 1000 feet downstream from the highway bridge. The required span will be approximately 3000 feet. At the selected location the right (north) bank of the river is a flat, low floodplain, but an approximately 300-foot hill rises at the left (south) bank making the design of the crossing easier. The span will be between two lattice type dead end towers, one approximately 120 feet tall at the north shore and the other approximately 100 feet tall on the top of the hill at the south end of the span. This arrangement should pose no greater hazard to waterborne traffic than does the bridge.

2.2.4 Conductors

Bundled conductors will be used for the line with two conductors per bundle at 18 inches apart. Except for the Yukon River crossing, Chukar conductor, a 1780 kCM ACSR[2/] conductor with a rated strength of 51,000 lbs and an outside diameter of 1.6 inches, should be used. With a 1000-foot average span, the maximum sag will be 42 feet, which, with a 95 foot tall tower, will provide adequate clearance to ground. In satisfying all appropriate design criteria, the conductors will be oversized with respect to current carrying capacity, consequently, one circuit will be capable of carrying almost twice the required medium forecast power. The line will be provided with spacer dampers.

1/ A dead end tower is capable of withstanding a conductor break, preventing structural failure of the transmission system from proceeding beyond a dead end tower.

2/ ACSR - aluminum conductor, steel reinforced.

For the Yukon River crossing a special conductor with an ultimate strength of 235,500 lbs may have to be ordered, such as 61x5 strand Alumoweld from the Copperweld Company. With the recommended towers, minimum clearance to high water will be 70 feet during the summer and 45 feet in the winter. Construction of the span will be done during the winter months when ice cover permits working over the river bed. Special vibration studies must precede actual design and vibration recording instruments must be installed after erection.

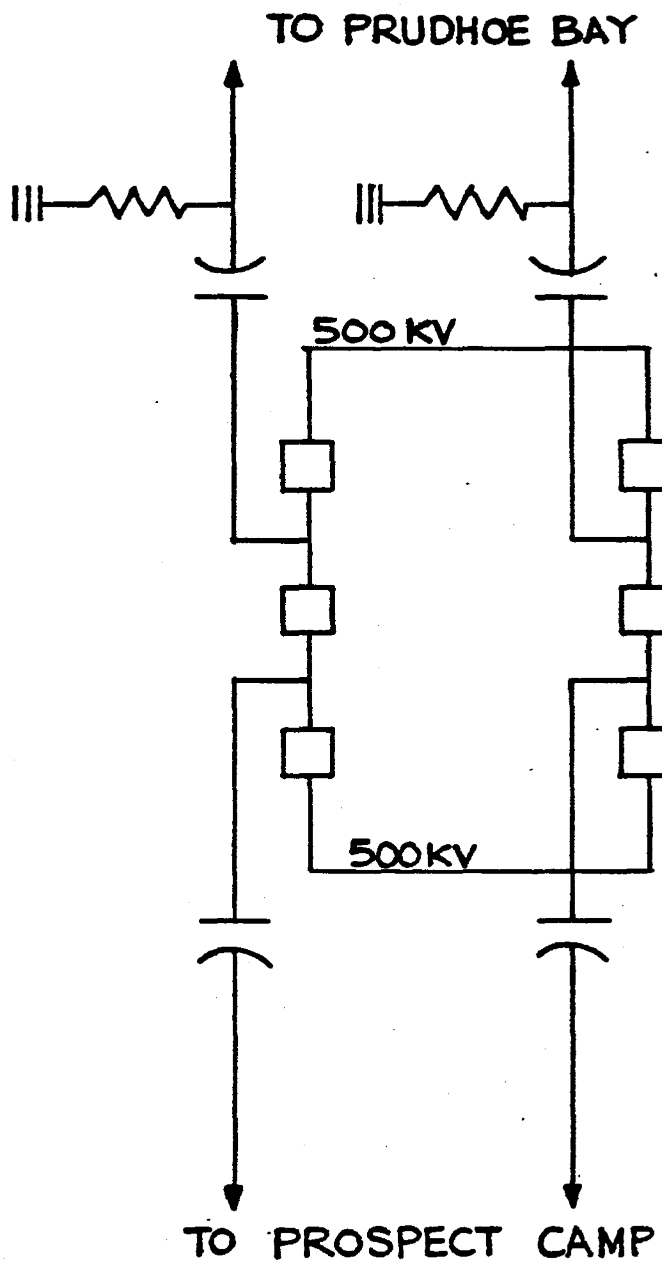
2.2.5 Insulators

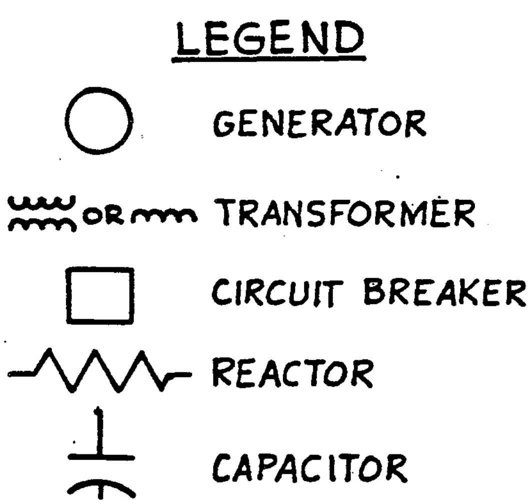
Suspension insulators, such as type 5-3/4" x 10" x 50 K lb, will be used. Two strings in a V configuration will hold the conductor bundle. Normally, 25 insulators are in each string.

For the first 60 miles from Prudhoe Bay fog type insulators will be installed and the number of insulators in the strings will be increased by two over that provided for the remainder of the route. Also, fixed insulator washing installations will be provided at each tower, based on the experience that Sohio has operating 69 kV lines at the North Slope. A tank truck equipped with pumps, hoses and other equipment will perform the annual washing in the fall.

2.2.6 Switching Stations

The two switching stations at Galbraith Lake and at Prospect Camp will divide each of the line circuits into three, almost equal, 150 mile long segments. The circuit schematic can be seen in Figure 2-5. The arrangement is conventional. The intermediate switching stations will make it possible to switch a shorter segment out of the system in case of a fault of a circuit, instead of the entire line length; this will improve the stability, hence the reliability, of the power system.





ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
NORTH SLOPE POWER GENERATION MEDIUM LOAD FORECAST TYPICAL TWO LINE SWITCHING STATION SCHEMATIC
FIGURE 2-5
EBASCO SERVICES INCORPORATED

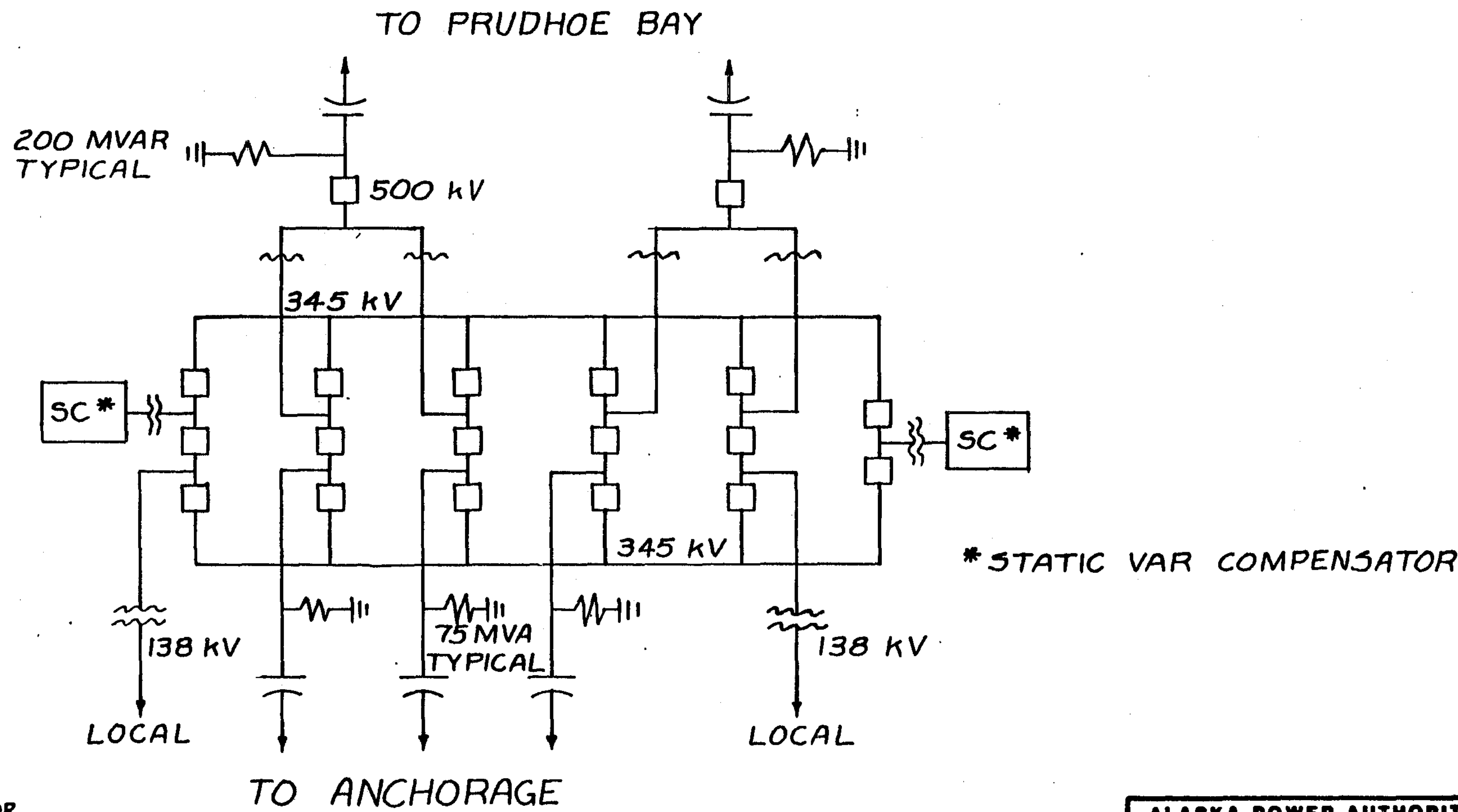
2.2.7 Fairbanks Substation

The Fairbanks substation one line schematic is shown in Figure 2-6. Two 500 kV line circuits, originating at Prudhoe Bay, will be connected to the substation, through either one 1500 MVA or two 750 MVA 345/525 kV transformers. Three 345 kV circuits will leave the substation in the direction of Anchorage. Two transformers will provide power for local area loads. The bus will be at 345 kV. The schematic shows two static VAR compensators connected to the bus through dedicated transformers. These static compensators will not necessarily be located where shown in Figure 2-6; their connections to the system are described in detail in Appendix D. The circuitry will use breaker and a half or double breaker arrangements. The substation will be designed so that the loss of one line, transformer, circuit breaker or compensator allows uninterrupted operation at full power.

2.2.8 Construction

Five camps will be used to house the work force; each camp will serve about a 90-mile section of the line for most of the construction period. The number of people will vary between 41 and 155 per camp, including the camp crew. The one exception is the period of building the gravel pads, when a total of 2400 people will have to be housed during the first summer of construction, which may require the opening of additional camps.

A 100' x 100' gravel pad must be constructed to serve as the base of each tower, and every 18 miles 300'x 1200' pads will serve as marshalling yards. Fifteen crews, with the aid of helicopters, can erect the towers during a six month work period. The last operation will be the stringing, which can be done by 5 crews, each with helicopter assistance. The switchyards will be constructed during the time that the line is stringed.



LEGEND

GENERATOR

TRANSFORMER

CIRCUIT BREAKER

REACTOR

CAPACITOR

ALASKA POWER AUTHORITY

NORTH SLOPE GAS
FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION
MEDIUM LOAD FORECAST
FAIRBANKS SUBSTATION SCHEMATIC

FIGURE 2-6

EBASCO SERVICES INCORPORATED

Pad building will take place in one summer using two 10-hour shifts. All other operations, except for surveying, will each take six months to perform and will be scheduled for fall and spring when the soil is frozen, but when enough daylight is available to work at least one 8-hour shift.

2.2.9 Operation and Maintenance

The least reliable equipment will be the series capacitors. The cost of a series compensated 500 kV line is about the same as that of an uncompensated 765 kV line. The 765 kV alternative should be investigated in more detail during detailed design of the line. The trade-offs of not having series capacitors are wider rights-of-way, increased problems due to contamination near Prudhoe Bay and increased difficulties to construct the two circuits through Atigun Pass.

2.2.10 Communications

To provide adequate communications, a microwave system will be installed. The North Slope-Fairbanks line will require 16 repeater stations. Five channels will be required, at least, one for supervisory voice communication, one for data transmission, one for relaying, one for service communication (below 4 kHz) and for alarm (above 4kHz), and one spare channel. Each repeater station will have a radio transceiver to maintain voice communication between vehicles and the dispatcher, using the service voice channel.

In addition, each transmission line circuit segment will be provided with a line carrier, mainly to provide redundancy for vital transfer trip functions.

Though this project assumed a dedicated microwave system, the project proponent may consider leasing microwave channels from ALASCOM. Several options, including direct satellite link, may be cost effective.

2.2.11 Siting Opportunities and Constraints

An inspection of the route indicated that most of the route should not cause significant construction problems. However, three areas are of some concern. The first 60 miles of the line south from the North Slope is a tundra area; civil engineering design and construction methods will have to be carefully investigated. Second, the grounding problems posed by frozen soil require that a bare copper conductor, called a counterpoise, be buried under each circuit along the entire length of the transmission line and be connected to the ground mats of all the substations and switching stations. Third, crossing Atigun Pass, as mentioned earlier, will require careful design; here the counterpoises may have to be routed farther from the circuits or be carried on the towers.

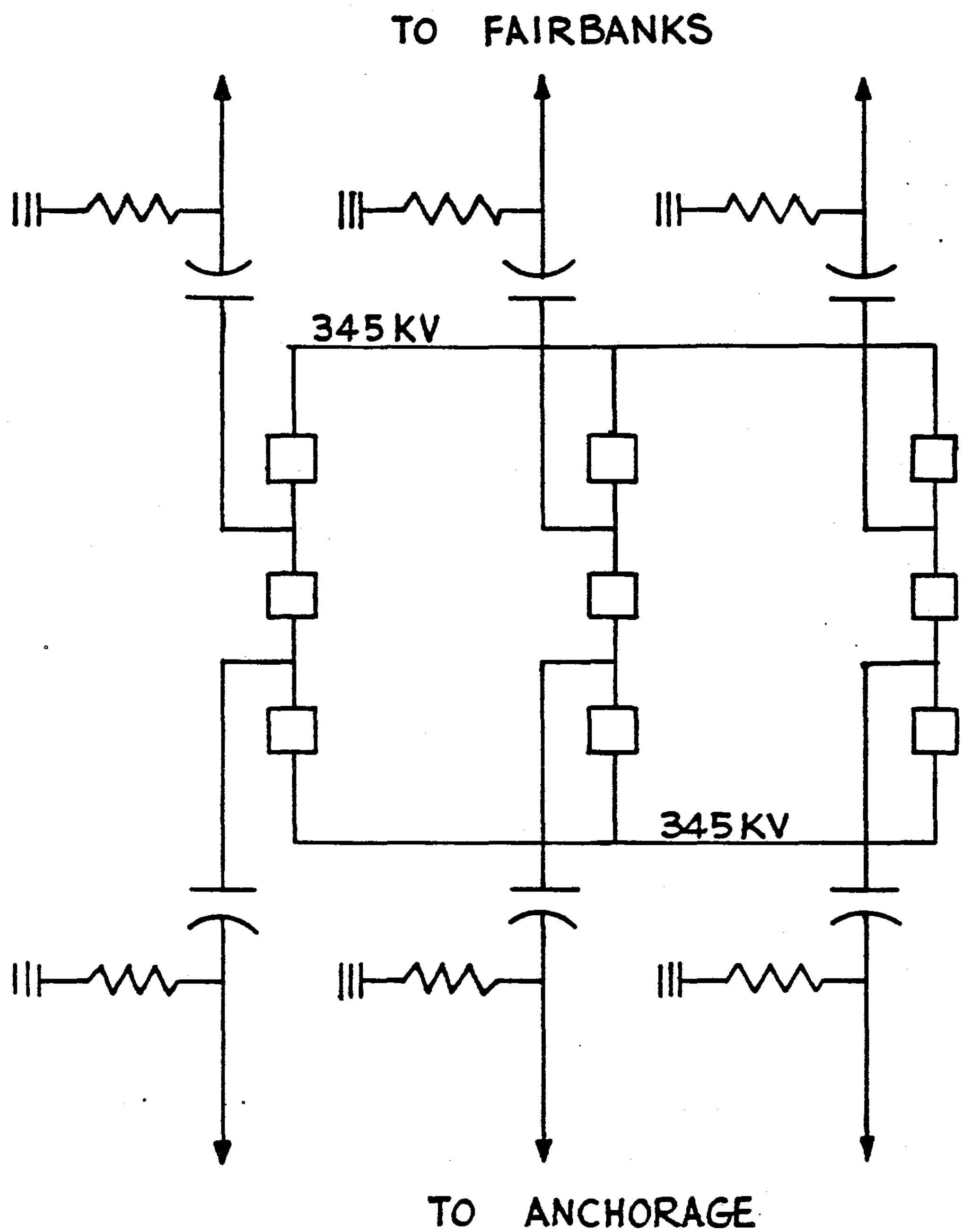
2.2.12 Fairbanks to Anchorage Line

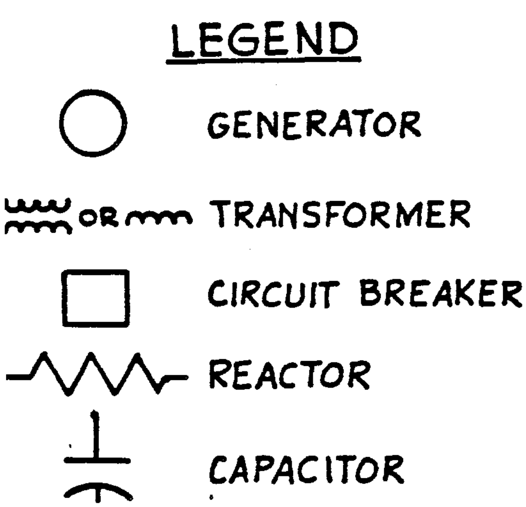
System studies performed by Ebasco (see Appendix D) indicate that 345 kV is a suitable voltage for this transmission line. This voltage is compatible with the 345 kV Intertie under construction. Therefore, two new 345 kV lines will be built and the Intertie will be extended fully between Fairbanks and Anchorage.

At the time of writing this report, the detailed design of the Intertie is available. Based on this information, the designs of the Intertie extension and the two new lines are assumed to be the same as the Commonwealth Associates (1981) design. The only additions will be the intermediate switching station, shown in Figure 2-7, the series capacitors and the shunt reactors.

2.2.13 Anchorage Substation

The Anchorage substation will be the termination of the three 345 kV line circuits. The substation bus will be 138 kV, as can be seen in Figure 2-8. All other details will be similar to that described for the Fairbanks substation (Section 2.2.7).





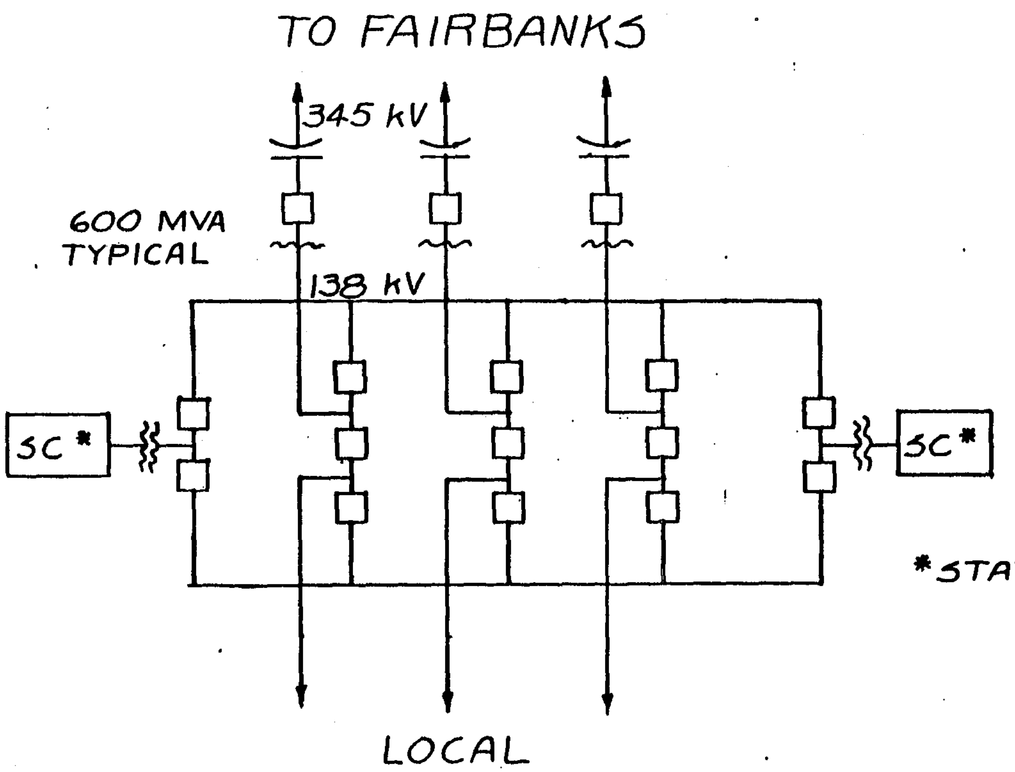
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION MEDIUM LOAD FORECAST TYPICAL THREE LINE SWITCHING STATION SCHEMATIC

FIGURE 2-7

EBASCO SERVICES INCORPORATED



*STATIC VAR COMPENSATOR

LEGEND

GENERATOR

TRANSFORMER

CIRCUIT BREAKER

REACTOR

CAPACITOR

ALASKA POWER AUTHORITY

NORTH SLOPE GAS
FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION

MEDIUM LOAD FORECAST
ANCHORAGE SUBSTATION SCHEMATIC

FIGURE 2-8

EBASCO SERVICES INCORPORATED

2.3 COST ESTIMATES

2.3.1 Construction Costs

2.3.1.1 Power Plant

To support the derivation of total systems costs which are presented in Section 2.3.4, feasibility level investment costs were developed for the major bid line items common to a 77 MW (ISO conditions) natural gas fired simple cycle combustion turbine and a 220 MW (ISO conditions) natural gas fired combined cycle plant. These costs are presented in Tables 2-4 and 2-5. The costs represent the total investment for the first unit to be developed at the site. Additional simple cycle units will have an estimated investment cost of $53,560,000 while additional combined cycle units will have an estimated investment cost of $218,820,000. The cost differential for additional units is due to significant reductions in line items 1 and 15, improvements to Site and Off-Site Facilities, and reductions in Indirect Construction Cost and Engineering and Construction Management.

For the North Slope power generation scenario only simple cycle unit costs have been used in the total system cost analysis (Section 2.3.4). Combined cycle costs were developed to support the cost sensitivity analysis performed in conjunction with the system planning studies (Appendix B).

2.3.1.2 North Slope to Fairbanks Transmission Line

Transmission line feasibility level investment cost estimates for the North Slope to Fairbanks connection are presented in Table 2-6. These estimates are based on two 500 kV lines of 1400 MW capacity with series compensation, and two intermediate switching stations.

TABLE 2-4

FEASIBILITY LEVEL INVESTMENT COSTS
77 MW SIMPLE CYCLE COMBUSTION TURBINE
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1. Improvements to Site	385	4,800	5,185
2. Earthwork and Piling	605	1,710	2,315
3. Circulating Water System	0	0	0
4. Concrete	25	450	475
5. Structural Steel Lifting Equipment, Stacks	675	1,230	1,905
6. Buildings	4,625	1,710	6,335
7. Turbine Generator	11,200	2,700	13,900
8. Steam Generator and Accessories	0	0	0
9. Other Mechanical Equipment	460	985	1,445
10. Piping	200	2,100	2,300
11. Insulation and Lagging	30	450	480
12. Instrumentation	100	300	400
13. Electrical Equipment	1,500	10,800	12,300
14. Painting	5	90	95
15. Off-Site Facilities[2]	500	9,000	9,500
SUBTOTAL	$20,310	$36,325	$56,635
Freight Increment			1,015
TOTAL DIRECT CONSTRUCTION COST			$57,650
Indirect Construction Cost			3,505
SUBTOTAL FOR CONTINGENCIES			61,155
Contingencies (15%)			9,175
TOTAL SPECIFIC CONSTRUCTION COST			70,330
Engineering and Construction Management			2,300
TOTAL CONSTRUCTION COST			$72,630

1/ The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

2/ Costs for construction camp and construction workforce travel included in Construction Labor category.

TABLE 2-5

FEASIBILITY LEVEL INVESTMENT COSTS
220 MW COMBINED CYCLE PLANT
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

	Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1.	Improvements to Site	385	4,800	5,185
2.	Earthwork and Piling	1,860	5,460	7,320
3.	Circulating Water System	0	0	0
4.	Concrete	100	2,160	2,260
5.	Structural Steel Lifting Equipment, Stacks	900	2,400	3,300
6.	Buildings	12,575	4,560	17,135
7.	Turbine Generator	30,300	10,500	40,800
8.	Steam Generator and Accessories	9,600	18,000	27,600
9.	Other Mechanical Equipment	5,625	11,705	17,330
10.	Piping	1,470	12,000	13,470
11.	Insulation and Lagging	290	2,880	3,170
12.	Instrumentation	1,700	1,200	2,900
13.	Electrical Equipment	4,500	36,000	40,500
14.	Painting	25	360	385
15.	Off-Site Facilities[2/]	500	9,000	9,500
	SUBTOTAL	$69,830	$121,025	$190,855
	Freight Increment			3,490
	TOTAL DIRECT CONSTRUCTION COST			$194,345
	Indirect Construction Cost			8,760
	SUBTOTAL FOR CONTINGENCIES			203,105
	Contingencies (15%)			30,465
	TOTAL SPECIFIC CONSTRUCTION COST			233,570
	Engineering and Construction Management			7,000
	TOTAL CONSTRUCTION COST			$240,570

1/ The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

2/ Costs for construction camp and construction workforce travel included in Construction Labor category.

TABLE 2-6

FEASIBILITY LEVEL INVESTMENT COSTS
NORTH SLOPE TO FAIRBANKS TRANSMISSION SYSTEM
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Material ($1000)	Construction[2/] Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	33,335	26,100	59,435
Substations	58,655	44,941	103,596
Energy Management System	12,900	12,000	24,900
Steel Towers and Fixtures	822,212	873,012	1,695,224
Conductors and Devices	63,962	149,760	213,722
Clearing	0	85,200	85,200
SUBTOTAL	$991,064	$1,191,013	$2,182,077
Land and Land Rights[3/]			36,000
Engineering and Construction Management			152,750
TOTAL CONSTRUCTION COST			$2,370,827

1/ The investment costs reflect two 500 kV lines, 1400 MW capacity with series compensation and two intermediate switching stations. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Construction camp facilities and services are included in the Construction Labor cost category.

3/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

2.3.1.3 Fairbanks to Anchorage Transmission Line

Transmission line feasibility level investment cost estimates for the Fairbanks to Anchorage connection are presented in Table 2-7. These estimates are based on two new 345 kV lines, with shunt and series compensation and an intermediate switching station. The investment cost estimates also reflect upgrading from 138 kV to 345 kV of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid.

2.3.2 Operation and Maintenance Costs

2.3.2.1 Power Plant

The power plant operation and maintenance (O&M) costs were derived to support the system planning studies (Appendix B). They reflect a review of figures from previous Railbelt studies, operation of other utilities, and salary requirements and expendable materials. The O&M costs for this scenario are estimated to be $0.0063 per kilowatt hour (6.3 mils/kWh).

2.3.2.2 Transmission Line Systems

Annual operation and maintenance costs (January, 1982 dollars) have been developed for the scenario's required transmission line facilities and total $35 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially, and increase with time.

2.3.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

TABLE 2-7

FEASIBILITY LEVEL INVESTMENT COSTS
FAIRBANKS TO ANCHORAGE TRANSMISSION SYSTEM
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Station	14,112	12,445	26,557
Substations	62,308	41,716	104,024
Energy Management Systems	12,300	10,960	23,260
Steel Towers and Fixtures	216,495	305,085	521,580
Conductors and Devices	33,678	78,361	112,039
Clearing	0	83,144	83,144
SUBTOTAL	$338,893	$531,711	$870,604
Land and Land Rights[2/]	0	0	27,600
Engineering and Construction Management			60,950
TOTAL CONSTRUCTION COST			$959,154

1/ The investment costs reflect two new 345 kV lines, 1400 MW capacity with shunt and series compensation and an intermediate switching station, and upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid to 345 kV.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

2.3.4 Total Systems Costs

The total system for the North Slope scenario, medium load forecast, consists of simple cycle gas turbines and an extensive transmission line system. No gas conditioning facilities or pipeline are required. Total annual systems costs reflect the relative simplicity of this system.

The methodology and assumptions utilized to derive the systems' costs which are presented below have been previously described in the Report on Systems Planning Studies (Appendix B). This methodology is consistent with previous studies of electric generating scenarios for the Railbelt, specifically Acres American, Inc. (1981), Susitna Hydroelectric Project Feasibility Report and Battelle (1982), Railbelt Electric Power Alternatives Study. The period of the analysis was assumed to be 1982 through 2010.

Annual capital costs for the system are presented in Table 2-8. Annual non-fuel operation and maintenance (O&M) costs are presented in Table 2-9. Total annual systems costs are then summarized in Table 2-10.

For scenario comparisons, the present worth of total annual costs for the North Slope medium load forecast has been calculated. Assuming a 3 percent discount rate and excluding fuel costs, the 1982 present worth of costs is $3.7 billion. The values are in 1982 dollars.

2.4. ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

Development of a gas fired simple cycle combustion turbine facility at the North Slope and transmission facilities to bring the energy to the Railbelt region will engender a variety of significant environmental effects. Precise quantification of environmental impacts will require more detailed site-specific analysis. However, most major potential

TABLE 2-8

TOTAL ANNUAL CAPITAL EXPENDITURES
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)1/

Calendar Year	Electricity Generation2/ Unit A	Unit B	Transmission Line	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	0.	0.	1,803.30	1,803.3
1990	0.	0.	418.45	418.5
1991	19.07 3/	0.	823.50	842.6
1992	53.56	0.	334.76	388.3
1993	0.	0.	0.	0.
1994	53.56	0.	0.	53.6
1995	53.56	0.	0.	53.6
1996	53.56	0.	0.	53.6
1997	53.56	0.	0.	53.6
1998	0.	0.	0.	0.
1999	53.56	0.	0.	53.6
2000	0.	0.	0.	0.
2001	53.56	53.56	0.	107.1
2002	0.	0.	0.	0.
2003	53.56	0.	0.	53.6
2004	53.56	53.56	0.	107.1
2005	53.56	0.	0.	53.6
2006	53.56	0.	0.	53.6
2007	53.56	0.	0.	53.6
2008	0.	0.	0.	0.
2009	53.56	0.	0.	53.6
2010	0.	0.	0.	0.
Total	$715.	$107.	$3,380.	$4,202.

1/ Values as calculated are shown for purposes of reproducibility only, and should not be taken to imply the indicated accuracy of significant figures.

2/ Unit A refers to first unit built in a given year and Unit B to the second unit built.

3/ Construction of campsite and site preparation for all units.

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TABLE 2-9

TOTAL ANNUAL NON-FUEL O&M COSTS
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generation	Transmission System	Total
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	0.	0.	0.
1991	0.	0.	0.
1992	0.	0.	0.
1993	3.767	35.0	38.8
1994	3.767	35.0	38.8
1995	7.535	35.0	42.5
1996	11.334	35.0	46.3
1997	15.063	35.0	50.1
1998	18.831	35.0	53.8
1999	18.831	35.0	53.8
2000	22.661	35.0	57.7
2001	22.598	35.0	57.6
2002	30.133	35.0	65.1
2003	30.133	35.0	65.1
2004	33.995	35.0	69.0
2005	36.414	35.0	71.4
2006	38.134	35.0	73.1
2007	39.848	35.0	74.8
2008	41.567	35.0	76.6
2009	43.281	35.0	78.3
2010	45.001	35.0	80.0
Total	$463.	$630.	$1,093.

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TABLE 2-10

TOTAL ANNUAL SYSTEMS COST
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	1,803.3	0.	1,803.3
1990	418.5	0.	418.5
1991	842.6	0.	842.6
1992	388.3	0.	388.3
1993	0.	38.8	38.8
1994	53.6	38.8	92.4
1995	53.6	42.5	96.1
1996	53.6	46.3	99.9
1997	53.6	50.1	103.7
1998	0.	53.8	53.8
1999	53.6	53.8	107.4
2000	0.	57.7	57.7
2001	107.1	57.6	164.7
2002	0.	65.1	65.1
2003	53.6	65.1	118.7
2004	107.1	69.0	176.1
2005	53.6	71.4	125.0
2006	53.6	73.1	126.7
2007	53.6	74.8	128.4
2008	0.	76.6	76.6
2009	53.6	78.3	131.9
2010	0.	80.0	80.0
Total	$4,202.	$1,093.	$5,295.
Present Worth @ 3%	$3,156.	$600.	$3,757.

environmental concerns related to this scenario have been identified, and may be categorized as follows:

(1) Air Resource Effects

(2) Water Resource Effects

(3) Aquatic Ecosystem Effects

(4) Terrestrial Ecosystem Effects

(5) Socioeconomic Effects

Each of these subject areas is discussed in the following subsections. Power plant characteristics related to each of these subject areas is summarized in Table 2-11.

2.4.1 Air Resource Effects

Development of the North Slope generating facility may be governed in large part by air quality considerations. The federal Clean Air Act and the Alaska rules for air quality control require the generating facility to meet both atmospheric emission and ambient air quality standards. Emission standards are defined in terms of New Source Performance Standards (NSPS) and Best Available Control Technology (BACT). NSPS apply generically to combustion turbines, and set a ceiling of emission levels that cannot be exceeded. Because gas fired power plants are relatively clean, NSPS levels do not pose a constraint to the development of this generating facility. BACT requirements are determined on a case-by-case basis, taking into account energy, environmental, and economic impacts, but are never less stringent than NSPS.

The Prevention of Significant Deterioration (PSD) program protects relatively clean areas from undergoing substantial degradation through ambient air quality standards. The PSD increments for particulate and sulfur dioxide have not been exhausted on the North Slope, and

TABLE 2-11

ENVIRONMENT RELATED FACILITY CHARACTERISTICS
SIMPLE CYCLE COMBUSTION TURBINES
NORTH SLOPE POWER GENERATION - MEDIUM LOAD FORECAST

Air Environment	
Emissions	
Particulate Matter	Below standards
Sulfur Dioxide	Below standards
Nitrogen Oxides	Emissions variable within standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	Maximum structure height of 50 feet
Water Environment	
Plant Water Requirements	50 Gallons per Minute (GPM)
Plant Discharge Quantity, Including Sanitary Waste and Floor Drains	Less than 50 GPM
Land Environment	
Land Requirements	
Plant and Switchyard	90 acres
Construction Camp	5 acres
Socioeconomic Environment	
Construction Workforce	Approximately 200 personnel at peak construction (power plant only)
Operating Workforce	Approximately 200 personnel employed in the year 2010 (power plant only)

therefore do not constrain development. PSD increments for nitrogen oxides, the major pollutant from combustion turbines, have not been established. However, general PSD requirements dictate that Best Available Control Technology be used to reduce nitrogen emission levels.

In the case of combustion turbines, BACT usually consists of using water or steam injection techniques to control emission levels by reducing combustion temperatures. Unfortunately, water or steam injection in the Prudhoe Bay area causes undesirable levels of ice fog. Furthermore, water or steam injection requires fresh water supplies that are generally not economically available on the North Slope. For these reasons, air quality regulatory agencies have not defined BACT for the North Slope to include using water or steam injection to control nitrogen oxides. Imposition of the requirement for water or steam injection would add substantial costs and significantly decrease the relative feasibility of this scenario. For the purposes of this study it is assumed that water injection for NO_x control would not be required.

Even with no water injection requirement, air quality regulations would not be likely to hamper installation of a gas fired power plant in the Prudhoe Bay area. However, a judicious siting effort would still be necessary to avoid compounding any air pollution problems from existing facilities.

The construction of two 500 kV transmission lines between the North Slope and Fairbanks would result in temporary air quality impacts. The use of heavy equipment and other construction vehicles would generate fugutive dust and exhaust emissions. Slash burning of material to clear the right-of-way would produce emissions. The impacts from these construction-related activities are expected to be small because the emissions would be widely dispersed and occur in unpopulated or sparsely populated areas.

The long term impacts from operation of the transmission lines are expected to be negligible. The transmission lines would generate small amounts of ozone which would be undetectable at ground levels and would not cause problems with nearby vegetation.

The air quality impacts of constructing the transmission lines from Fairbanks to Anchorage would result from activities similar to those mentioned above. The impacts are expected to be of approximately the same magnitude, although the amount of slash material to be burned would be greater within this corridor and would be within proximity to more populated areas.

The long term impacts from transmission line operations would be similar to those of the Prudhoe Bay-Fairbanks transmission line corridor.

2.4.2 Water Resource Effects

The principal effects of the proposed generating facility on the water resources of the Prudhoe Bay area include consumptive withdrawals from freshwater sources (existing lakes) for potable supplies and miscellaneous uses such as equipment wash-down. Because the generating station will require minor volumes of water and will be served by existing waste treatment facilities in the area, water resources effects associated with these uses will not be significant.

For the medium load forecast, the site must have access to approximately 50 gpm. This water will be taken from a nearby freshwater lake of sufficient size so that the lake level and hydrologic balance is not significantly affected.

Transmission line construction between the North Slope and Fairbanks may impact the quality of surface water resources through erosion caused by land disturbance, but has little or no impact on water supplies. Erosion control, especially in steep terrain or areas of susceptible soils, will be a major requirement imposed by permits issued for right-of-way clearing and construction of the transmission and related facilities, such as access roads. For example, the Bureau of Land Management (BLM) land use plan for the Prudhoe Bay-Fairbanks Utility Corridor (BLM 1980) within which the transmission facilities would be routed, specifically requires protection of stream banks and lake shores by restricting activities to prevent loss of riparian vegetation.

Construction activities of the transmission lines between Fairbanks and Anchorage would result in temporary impacts. The transmission lines would cross several large rivers and numerous creeks, resulting in temporary stream siltation, bank erosion, and the potential for accidental spillage of lubricating oils and other chemicals into the watercourses. Construction equipment working along streambanks or crossing smaller streams could cause direct siltation of the watercourse or cause indirect stream bank erosion and siltation through the removal of vegetation and disturbance of permafrost. The effects of siltation could alter stream channels, fill ponds, or damage aquatic flora or fauna.

Significant effects on watercourses may be prevented by keeping construction activities out of channels and away from stream banks. Measures that could be taken to avoid impacts include a set back of 200 feet from watercourses for transmission structures as well as establishment of a buffer strip along major watercourses to minimize disturbance of vegetation and soils by construction equipment. In cases where watercourses must be crossed by construction equipment, such crossings could be conducted either during cold periods when the stream is frozen or in a manner to limit pollution or siltation. The use of helicopters to erect the towers will help to minimize overall construction impacts, since ground access requirements will be minimized.

2.4.3 Aquatic Ecosystem Effects

The major aquatic ecosystems of the North Slope area include the marine environment of the Beaufort Sea, the freshwater environments of the Sag and Put Rivers and their tributaries, and estuarine habitats at the rivers' mouths. Shallow lakes in the area do not support fish because of complete freezing in the wintertime. Deeper lakes may contain resident species such as stickleback, but in general, knowledge of these lakes is presently limited. In the rivers and estuaries, two groups of fish are considered important: river fish such as the grayling, and anadromous fish such as the the Arctic char and cisco. The anadromous species descend local rivers at ice-breakup to feed in the shallow littoral and sublittoral zone of the Beaufort Sea. They ascend these rivers in the autumn and overwinter in deep pools. These fish do not appear to undertake extensive migrations up the Sag or Put Rivers.

These fishery resources could be affected by construction and operation of a water supply intake, pipeline and access road construction, gravel mining in rivers which could affect overwintering and general habitat quality of the fish, and the need to cross larger river channels which could interfere with fish passage. The latter item may require the use of special culverts to maintain migratory routes. Each of these potential effects would be analyzed on a site-specific basis, and detailed impact avoidance or mitigation measures developed.

Aquatic ecosystems within the transmission line corridor will also require protection during project construction. Between the North Slope and Fairbanks, the transmission lines may cross as many as 150 waterbodies which are utilized by fish for migration, rearing, spawning, and/or wintering. Siting should avoid or minimize impact to spawning areas in approximately 35 waterbodies and to wintering areas in approximately 15 waterbodies. Information regarding specific waterbodies of concern is presented in Appendix C, "Report on Facility Siting and Corridor Selection."

Counterpoise (ground cable) construction may require excavation in streambeds; this activity must be carefully planned (both spatially and temporally) and monitored in accordance with individual permit requirements. Conditions vary along the corridor, so that environmental protection stipulations imposed by the regulatory agencies will tend to be site-specific.

The transmission line corridor between Fairbanks and Anchorage makes as many as 100 crossings of rivers and streams and comes within one mile of numerous lakes and ponds. All of these waterbodies are important habitat for endemic and anadromous fisheries. Impacts to fisheries such as increased runoff and sedimentation could occur through clearing of the right-of-way and crossing of watercourses by construction equipment. The introduction of silt into streams can delay hatching, reduce hatching success, prevent swimup, and produce weaker fry. Siltation also reduces the benthic food organisms by filling in available intergravel habitat.

The potential adverse impacts can be reduced or eliminated through construction scheduling. Construction of the transmission lines during the winter would minimize erosion since the snow protects low vegetative cover that stabilizes soils. Ice bridges could be used by construction equipment for crossing spawning areas, where possible. Otherwise, where equipment would move through watercourses, construction could occur during periods when there are no eggs or fry in the gravel.

2.4.4 Terrestrial Ecosystem Effects

The North Slope area and specifically the river delta areas provide a variety of habitats that are important to a diversity of plants and animals. Project related impacts which require special consideration include: (1) direct habitat elimination through the construction of project facilities, access roads, and gravel borrow areas; (2) indirect habitat elimination resulting from access roads which impede drainage or which generate significant traffic related dust; and (3) restrictions to large mammal movements, especially caribou.

Construction of the powerplant, switchyard, construction camp and related access roads will disturb approximately 65 acres of land. All construction equipment should be restricted to areas covered with a gravel pad. Tundra adjacent to the generating facility should not be disturbed.

Because the generating facility will be located within the Prudhoe Bay industrial complex, terrestrial habitat impacts engendered by this project will be an added increment to those which have already occurred as a result of oil field development. Final siting efforts should include evaluation of the factors listed above, and will be the mechanism through which highly significant terrestrial impacts can be avoided, particularly the indirect impacts and migratory blockages. The direct impacts of habitat removal due to facility construction are generally unavoidable, but can be minimized through careful site planning and construction management.

Construction of the transmission line facilities will require vegetative clearing in forested areas. Clearing should be restricted to the following categories of vegetation:

(1) Trees and brush which may fall into a structure, guy, or conductor

(2) Trees and brush into which a conductor may blow during high winds.

(3) Trees and brush within 25 feet of a conductor, and trees within 110 feet of the line centerline.

(4) Trees or brush that may interfere with the assembly and erection of a structure.

Between the North Slope and Fairbanks, much of the area south of Nutirwik Creek will require clearing of trees within the right-of-way. Because two lines will be built and trees within 110 feet of the line will be cleared, the total width of cleared vegetation will be 440 feet. Over the length of the line, approximately 7000 acres will be cleared.

The transmission line corridor passes through a wide variety of terrestrial ecosystems, and is adjacent to several major federal land areas which have been protected, in part, for their wildlife values. The Bureau of Land Management (BLM) land use plan for the Utility Corridor (BLM 1980) has identified several areas as containing critical wildlife habitat. Specific management restrictions have not as yet been formulated; however, measures may be required for a number of areas. Details regarding these areas are given in Appendix C.

The land use plan also specifically requires protection of raptor habitat and critical nesting areas. Protection of crucial raptor habitats preserves the integrity of raptor populations and maintains predator-prey relationships.

Facilities and long term habitat alterations are prohibited within one mile of peregrine falcon nest sites unless specifically authorized by the U.S. Fish and Wildlife Service, because of the endangered species status of the peregrine falcon.

As the transmission line corridor generally avoids known nesting areas, the restriction may only apply to material sites. Information regarding specific raptor nesting areas and siting restrictions are presented in Appendix C.

It is unlikely that the transmission line would be sited in or near important Dall sheep habitat. A primary concern is aircraft traffic over critical wintering, lambing, and movement areas. Moose winter browse habitat in the Atigun and Sag River valleys is limited to areas of tall riparian willow. Habitat has already been eliminated by the construction of Trans Alaska Pipeline System (TAPS) and further destruction of this habitat should be avoided or minimized. The willow stand along Oksrukuyik Creek, in particular, should not be disturbed.

System design must allow free passage for caribou, but these animals should not be a major consideration in siting. Carnivore/human interaction is a major concern in facilities design and in construction and operations methods, but not in siting considerations.

Line routing and tower siting should avoid or minimize disturbance of the treeline white spruce stand at the head of the Dietrich Valley, which has been nominated for Ecology Reserve status.

For the Fairbanks to Anchorage transmission line approximately 80 percent of the corridor is located in forested areas (Commonwealth Associates, 1982). Assuming two additional lines are built and the Intertie is extended, a total of about 8700 acres will be cleared. The principal impacts associated with clearing a right-of-way and construction of the transmission line are the alteration of existing habitats and subsequent disruption of wildlife species that use those habitats and disturbance to indigenous fauna and bird populations.

Most big game species would relocate during the construction of the transmission lines. The construction schedule should be flexible so as to avoid construction near calving and denning sites. The moose, which adapts to many different habitat types, would establish a subclimax community in the cleared right-of-way. The distribution of caribou is limited along the transmission line corridor but those that do occur in the vicinity of the right-of-way would be displaced. The caribou, however, generally utilize habitats with low vegetative cover, resulting in little alteration of caribou habitat.

Grizzly and black bears would relocate to avoid construction activity along the right-of-way, except where construction occurs near a den site during winter dormancy. Construction activity near denning areas should be avoided from October 1 through April 30. The alteration of habitats could temporarily affect bear use of the right-of-way but this impact is expected to be relatively short-term.

Wolves within the vicinity of the right-of-way would also be displaced during construction of the transmission line. While these impacts would be temporary, long term impacts would occur to the wolf if their principal prey species, such as caribou, sheep, and moose were adversely affected.

Dall sheep occur only at the northern end of the transmission line corridor and would be impacted only minimally by construction activities. The use of helicopters to construct the lines in the Moody and Montana Creek drainages could severely disturb sheep in the vicinity of Sugarloaf Mountain.

The impact to the regional populations of any of the small game species is expected to be negligible. Small game species are expected to relocate during construction activities and re-invade the right-of-way once construction is over.

In heavily forested areas along the corridor, the right-of-way clearing could provide an improved habitat for most of the small game species that utilize subclimax communities.

Migratory waterfowl are susceptible to disturbance from construction activities from mid-April to the end of September when they are nesting and brood rearing. Construction activities should be restricted from May through August in areas with active trumpeter swan nesting territories. Collisions with transmission lines, guywires, and overhead groundwires are another potential impact. To date, however, the levels of avian mortality from line collision have not been biologically significant (Beaulaurier et al. 1982).

Furbearers are not expected to be greatly affected by construction activities except during the initial right-of-way clearing. Most furbearers will either adapt to the presence of the cleared right-of-way or undergo short term impacts. The maintenance of a shrub community in the right-of-way will reduce the loss of individuals.

The impacts on nongame mammals and birds are expected to be insignificant. Some small mammals and nongame birds would undergo population shifts during construction activities but populations are expected to recover within one to two reproductive seasons. Raptors may lose some habitat as a result of clearing. Benefits of a cleared right-of-way could occur as some raptors could find that it provides hunting habitat or hunting perches not previously available.

2.4.5 Socioeconomic and Land Use Effects

Potential socioeconomic and land use effects of the North Slope scenario include both temporary impacts related to the influx of workers and permanent land use impacts.

Since the generating plant would be located within the Prudhoe Bay/Deadhorse industrial complex, the in-migrating work force would not significantly affect the social and economic structure of the region. The work force requirements are small in comparison to the existing size of the transient work force in the Prudhoe Bay region. For 5 months of each year during the period 1993 through 2010 a maximum of 200 employees will be needed to assemble the prefabricated units of the plant. Housing facilities would be provided for the employees at the adjacent construction camp. During off-work periods, the majority of the employees would spend time outside of the borough. The operations work force is expected to be approximately 150 and will reside in the labor camp. The spending of wages earned by the employees within the North Slope Borough is expected to be minimal due to the transience of the work force.

The use of land for an electrical generating plant would be compatible with the land uses of the industrial enclave. The Coastal Zone Management Program for the North Slope Borough has delineated zones of preferred development. Permanent facilities are allowed in the industrial development zone, consisting of the existing Prudhoe Bay/Deadhorse complex and the Pipeline/Haul Road Utility corridor (North Slope Borough 1978). The generating plant would be located within the preferred development zone.

Within the Prudhoe Bay/Deadhorse complex, the plant would be located to minimize interferences with existing or planned facilities, including buildings, pipelines, roads, and transmission lines. Land ownership and lease agreements will limit the land available for the electrical generating facility.

Socioeconomic and land use impacts related to construction and operation of transmission facilities between Prudhoe Bay and Fairbanks will be strictly controlled as a result of the guidelines and constraints for development within the designated utility corridor. Construction employees would be housed either at the pump stations or the permanent camp facilities constructed for the trans-Alaska oil pipeline. Construction activities would be consistent with the land use criteria developed by the BLM. The BLM has prepared land use plans for the utility corridor between Sagwon Bluffs and Washington Creek. Road and highway crossings would be minimized, and areas of existing or planned mineral development would be avoided.

Construction facilities would be sited at carefully selected locations in the vicinity of Livengood Camp, Yukon Crossing, Five Mile Camp, Prospect, Coldfoot, Chandalar, and Pump Station #3. Existing facilities such as work pads, highways, access roads, airports, material sites and communications would be used to the maximum extent possible.

The schedule for constructing the transmission lines is approximately 3 years with activities occurring mainly during the autumn and spring of each year. A peak work force of 2400 employees would be required during the first year of construction when the pads would be built, and in subsequent years the total work force would be substantially reduced to approximately 500 in the second year, 600 in the third year, and 670 in the final year. It is expected that these workers will be hired from the Anchorage and Fairbanks union hiring halls.

Development of additional transmission facilities between Fairbanks and Anchorage would engender potentially more significant socioeconomic and land use impacts, since this segment is more populated and subject to future land use development. Temporary campsites would be provided to house the work crews at locations accessible by the Parks Highway or the Alaska Railroad. The work force requirements would be lower for this corridor because pads would not need to be constructed. The schedule for constructing the transmission lines is approximately 22 months. A peak work force of approximately 520 employees would be required during the last 6 months and the average work force would be approximately 300. It is assumed that the project would utilize the labor pools of Fairbanks and Anchorage.

Impacts to local communities would be minimized through careful siting of the temporary work camps. It is expected that the work camps would be self-contained in order to keep to a minimum interaction between the construction workers and the local residents. The project is expected to have minor primary economic benefits since few, if any, residents would be employed on the project.

Land use impacts could include encroachment of the project on residential areas as well as preclude future residential development land available for homesteading. The most significant potential impact would be the crossing of recreation lands and the subsequent effects on recreation and aesthetic values these lands are meant to preserve.

The potential aesthetic impacts of the proposed new and additional transmission facilities are significant. The cumulative effects of these facilities and previous linear developments (e.g., TAPS) could result in significant degradation of the aesthetic character of pristine wilderness landscapes. The visibility of the transmission lines from existing travel routes (Dalton Highway, Parks Highway, etc.) will vary depending on distance, topography and intervening vegetation. Special care would be taken in selecting final route alignments in proximity to areas of special visual significance, such as national parks, or high visual sensitivity, such as areas within the viewing range of motorists on the Parks Highway. In locations where visual impacts cannot be avoided through careful routing or tower spotting, mitigating measures, such as the use of non-reflective paint or vegetative screening, can be employed.

SCENARIO I
NORTH SLOPE POWER GENERATION
LOW LOAD

3.0 NORTH SLOPE POWER GENERATION

LOW LOAD FORECAST

The North Slope power generation scenario, under the low load forecast, is conceptually the same as the medium growth case, except that units are phased in at a slower rate. By the year 2010, eight simple cycle combustion turbine units are required to produce 728 MW. The electric transmission system requires two 500 kV lines; however, series capacitors are not required to ensure system stability. Total system cost is estimated to be $3.3 billion, with annual operation and maintenance costs of $0.7 billion. The present worth of these costs excluding fuel costs is $2.7 billion as of 1982. Environmental effects of the project are substantial, but would not preclude construction.

Information presented in this section is designed to highlight only those conditions which are significantly different from those of the medium load forecast presented in Chapter 2.

3.1 POWER PLANT

This scenario requires eight 91 MW simple cycle gas turbines to satisfy the low load forecasted demand. The first of these will go on line in 1996 and the eighth in 2010. Additions are summarized in Table 3-1 and scenario details are addressed in Appendix B. Annual fuel requirements for power generation will start at 6.60 BCFY in 1996 and grow to 47.2 BCFY in 2010. The maximum potential firing rate in 2010 will be approximately 1.33 x 10^5 SCFM. Fuel requirements on an annual basis are also shown in Table 3-1.

With the exception of the substation, all details of individual plant items are identical to those described for the medium load case in Section 2.1. The substation for this scenario differs from the medium forecast design (Figure 2-3) in that there are no series capacitors

TABLE 3-1

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST

Year	New Capacity (MW) (Increment/Total)	Gas Required[1/] (MMSCFY)
1990	0/0	0
1991	0/0	0
1992	0/0	0
1993	0/0	0
1994	0/0	0
1995	0/0	0
1996	91/91	6,596.6
1997	91/182	13,149.1
1998	0/182	13,149.1
1999	0/182	13,149.1
2000	0/182	13,182.1
2001	0/182	13,149.1
2002	91/273	19,723.7
2003	91/364	26,287.3
2004	0/364	26,364.2
2005	182/546	39,216.5
2006	0/546	39,436.4
2007	0/546	39,436.4
2008	91/637	44,284.9
2009	0/637	45,736.1
2010	91/728	47,187.4

[1/] Values as calculated are shown for reproducibility only, and do not imply accuracy beyond the 100 MMSCFY level.

installed and the facility is smaller in size. The circuit diagram is shown in Figure 3-1. Only four 13.8/138 kV generator transformers are needed, and each transmission line circuit is supplied by only one 750 MVA 138/500 kV transformer. The initial installation is essentially the same as in Figure 2-4 except that the series capacitors are not required.

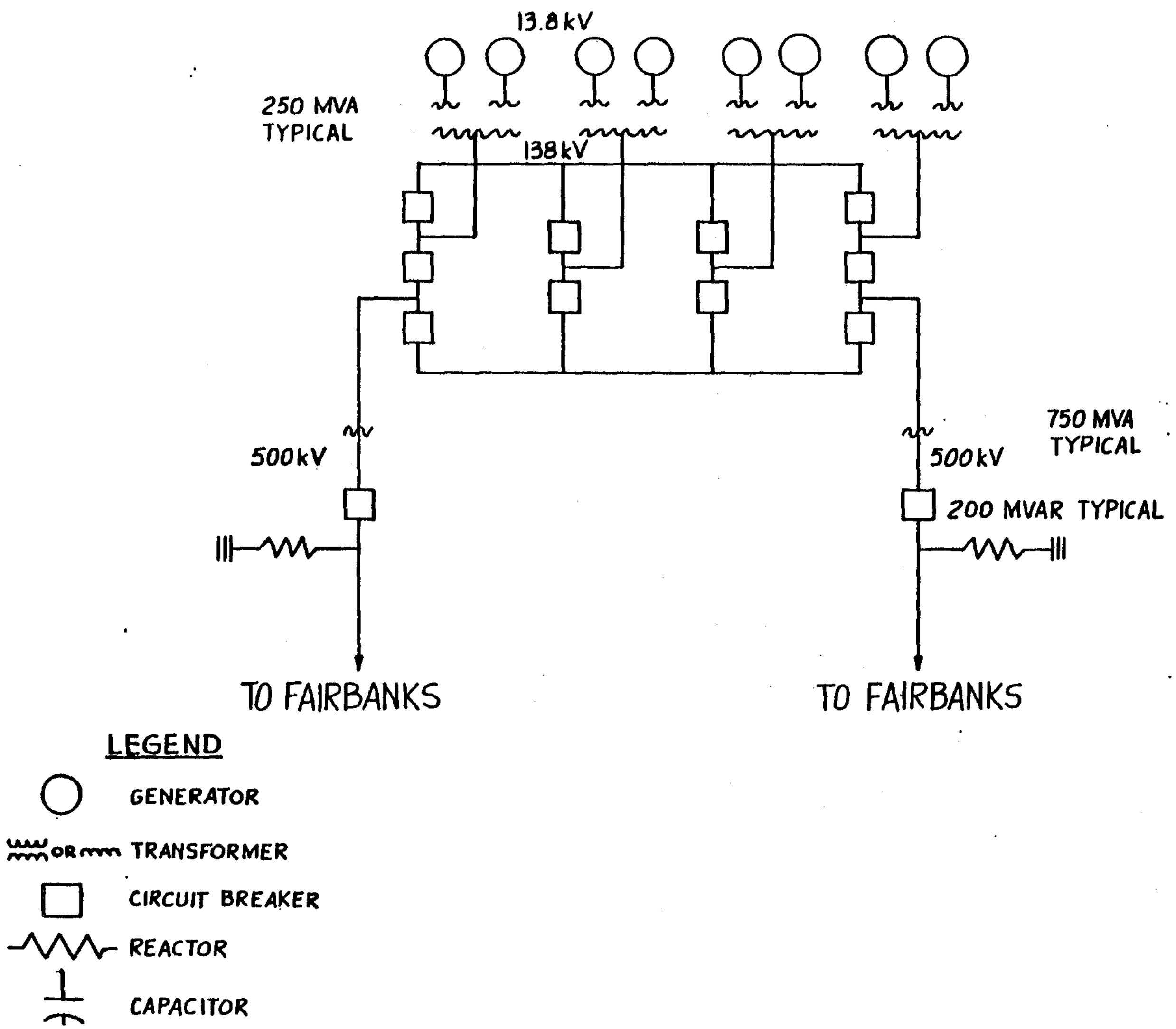
Personnel required for operation and maintenance will be less for this scenario than for the medium load forecast. Ten on-duty personnel will be required in 1996 for the first unit. This number will increase to approximately 35 on-duty personnel when 8 units are operating in 2010. The total two-shift, full year, work force would therefore range from 40 to 140 for the study period.

3.2 TRANSMISSION SYSTEM

The North Slope to Fairbanks, and the Fairbanks to Anchorage transmission systems for the low load forecast scenario do not differ significantly from the medium forecast designs. A voltage of 500 kV is cost effective for the line between the North Slope and Fairbanks; however, for this case, series capacitors will not be needed. For the Fairbanks-Anchorage section, two 345 kV lines with series compensation are sufficient. That is, one new 345 kV line will be constructed and the Healy-Fairbanks and the Willow-Anchorage segments of the existing intertie will be upgraded from 138 kV to 345 kV.

The number and sizes of the intermediate switching stations remain unchanged. There are two such stations on the 500 kV line (without any series capacitors), at Galbraith Lake and at Prospect Camp. There is only one switching station on the 345 kV line from Fairbanks to Anchorage, but in this case it has to be at the midpoint of the line, i.e., some 30 miles north of the Devil's Canyon switchyard of the medium forecast scenario.

The substation at Fairbanks and Anchorage are slightly scaled down from those described in Section 2.3 and Figures 2-5 and 2-6.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

NORTH SLOPE POWER GENERATION

LOW LOAD FORECAST

SUBSTATION ONE LINE SCHEMATIC

FIGURE 3 - 1

EBASCO SERVICES INCORPORATED

3.3 COST ESTIMATES

3.3.1 Construction Costs

The capital cost of each simple cycle gas turbine is the same as that presented in Section 2.3 for the medium load forecast.

The feasibility study investment costs of the transmission line systems are presented in Table 3-2 and 3-3. Table 3-2 presents the estimates for two 500 kV, 700 MW capacity lines without series compensation, and two intermediate switching stations. Table 3-3 contains the estimates for one new 345 kV line, 700 MW capacity, with series compensation and an intermediate switching station, and the required upgrading of the Willow-Anchorage and Healy-Fairbanks transmission lines.

3.3.2 Operation and Maintenance Costs

Power plant operation and maintenance (O&M) costs are the same for both the medium and low load forecasts, 6.3 mils/kWh. Transmission line O&M costs are estimated to be $30 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially and will increase with time.

3.3.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

3.3.4 Total Systems Costs

The total system for the North Slope low load forecast, like the North Slope medium growth forecast, consists only of simple cycle combustion turbines and a transmission line system.

TABLE 3-2

FEASIBILITY LEVEL INVESTMENT COSTS
NORTH SLOPE TO FAIRBANKS TRANSMISSION SYSTEM
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST
(January, 1982 Dollars)

Description1/	Material ($1000)	Construction Labor 2/ ($1000)	Total Direct Cost ($1000)
Switching Stations	20,440	19,253	39,693
Substations	35,518	28,694	64,212
Energy Management System	12,900	12,000	24,900
Steel Towers and Fixtures	822,212	873,012	1,695,224
Conductors and Devices	63,962	149,760	213,452
Clearing	--	85,200	85,200
SUBTOTAL	$954,762	$1,167,919	$2,122,681
Land and Land Rights3/			36,000
Engineering and Construction Management			148,600
TOTAL CONSTRUCTION COST			$2,307,281

1/ The investment costs reflect two 500 kV lines, 700 MW capacity without series compensation and two intermediate switching stations. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Construction camp facilities and services are subsumed in the Construction Labor cost category.

3/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

TABLE 3-3

FEASIBILITY LEVEL INVESTMENT COSTS
FAIRBANKS TO ANCHORAGE TRANSMISSION SYSTEM
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST
(January, 1982 Dollars)

Description 1/	Material ($1000)	Construction 2/ Labor ($1000)	Total Direct Cost ($1000)
Switching Station	8,857	8,414	17,271
Substation and Switching Station	32,958	30,872	63,830
Energy Management Systems	12,300	10,960	23,260
Steel Towers and Fixtures	129,214	182,083	311,291
Conductors and Devices	20,049	53,183	73,232
Clearing	--	41,572	41,572
SUBTOTAL	$203,378	$327,084	$530,456
Land and Land Rights 2/			14,400
Engineering and Construction Management			37,130
TOTAL CONSTRUCTION COST			$581,986

1/ The investment costs reflect one new 345 kV line, 700 MW capacity without series compensation and an intermediate switching station, and upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the Intertie to 345 kV.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

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The methodology and assumptions utilized to derive the systems' costs which are presented below have been previously described in the Report on Systems Planning Studies (Appendix B). This methodology is consistent with previous studies of electric generating scenarios for the Railbelt, specifically the Acres American, Inc. (1981), Susitna Hydroelectric Project Feasibility Report and Battelle (1982), Railbelt Electric Power Alternatives Study. The period of the analysis was assumed to be 1982 through 2010.

The annual capital expenditures are presented in Table 3-4. Annual non-fuel O&M costs are presented in Table 3-5. The summary of all annual costs in presented in Table 3-6. The 1982 present worth of costs for this scenario (in 1982 dollars) is $2.7 billion, exclusive of fuel costs.

3.4 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The power plant for the low load forecast will consist of 8 simple cycle units, in contrast to 15 units for the medium load forecast. Most environmental impacts will therefore be correspondingly smaller than the medium load forecast. Environment related power plant characteristics are summarized in Table 3-7.

Air emissions will be approximately one-half the medium growth value and will not pose constraining air quality problems. Approximately 25 gpm of fresh water will be pumped from a nearby lake to provide equipment wash-down and potable water supplies. Wastewater discharges will be less than 25 gpm and will be discharged to the existing facilities in the area.

Aquatic resources, as for the medium load forecast, will not be significantly affected. Plant acreage, including the construction camp and switchyard, will be approximately 65 acres, as compared to 95 acres for the medium load forecast. Terrestrial impacts, such as tundra disturbance and habitat elimination, are correspondingly less.

TABLE 3-4

TOTAL ANNUAL CAPITAL EXPENDITURES
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)1/

Calendar Year	Electricity Generated2/ Unit A	Unit B	Transmission Line	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	0.	0.	0.	0.
1990	0.	0.	0.	0.
1991	0.	0.	0.	0.
1992	0.	0.	1,540.1	1,540.1
1993	0.	0.	358.0	358.0
1994	19.07 3/	0.	704.6	723.7
1995	53.56	0.	286.4	340.0
1996	53.56	0.	0.	53.6
1997	0.	0.	0.	0.
1998	0.	0.	0.	0.
1999	0.	0.	0.	0.
2000	0.	0.	0.	0.
2001	53.56	0.	0.	53.6
2002	53.56	0.	0.	53.6
2003	0.	0.	0.	0.
2004	53.56	53.56	0.	107.1
2005	0.	0.	0.	0.
2006	0.	0.	0.	0.
2007	53.56	0.	0.	53.6
2008	0.	0.	0.	0.
2009	53.56	0.	0.	53.6
2010	0.	0.	0.	0.
TOTAL	$394.	$54.	$2,889.	$3,337.

1/ Values as calculated are shown for purposes of reproducibility only, and should not be taken to imply the indicated accuracy of significant figures.

2/ Unit A refers to the first unit built in a given year and Unit B to the second unit built.

3/ Construction of camp site and site preparation for all units.

TABLE 3-5

TOTAL ANNUAL NONFUEL OPERATION AND MAINTENANCE COSTS
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars))

Calendar Year	Electricity Generated	Transmission Line	Total
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	0.	0.	0.
1991	0.	0.	0.
1992	0.	0.	0.
1993	0.	0.	0.
1994	0.	0.	0.
1995	0.	0.	0.
1996	3.8	30.0	33.8
1997	7.5	30.0	37.5
1998	7.5	30.0	37.5
1999	7.5	30.0	37.5
2000	7.5	30.0	37.5
2001	7.5	30.0	37.5
2002	11.3	30.0	41.3
2003	15.1	30.0	45.1
2004	15.1	30.0	45.1
2005	22.6	30.0	52.6
2006	22.6	30.0	52.6
2007	22.6	30.0	52.6
2008	25.4	30.0	55.4
2009	26.2	30.0	56.2
2010	27.0	30.0	57.0
TOTAL	$229.	$450.	$679.

TABLE 3-6

TOTAL ANNUAL COSTS
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars))

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	0.	0.	0.
1991	0.	0.	0.
1992	1,540.1	0.	1,540.1
1993	358.0	0.	358.0
1994	723.7	0.	723.7
1995	340.0	0.	340.0
1996	53.6	33.8	87.4
1997	0.	37.5	37.5
1998	0.	37.5	37.5
1999	0.	37.5	37.5
2000	0.	37.5	37.5
2001	53.6	37.5	91.1
2002	53.6	41.3	94.9
2003	0.	45.1	45.1
2004	107.1	45.1	152.2
2005	0.	52.6	52.6
2006	0.	52.6	52.6
2007	53.6	52.6	106.2
2008	0.	55.4	55.4
2009	53.6	56.2	109.8
2010	0.	57.0	57.0
Total	$3,337.	$679.	$4,016.
Present Worth @ 3%	$2,345.	$360.	$2,705.

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TABLE 3-7

ENVIRONMENT RELATED POWER PLANT CHARACTERISTICS
NORTH SLOPE POWER GENERATION - LOW LOAD FORECAST

Air Environment	
Emissions	
Particulate Matter	Below standards
Sulfur Dioxide	Below standards
Nitrogen Oxides	Emissions variable within standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	Maximum structure height of 50 feet
Water Environment	
Plant Water Requirements	25 GPM
Plant Discharge Quantity Including Sanitary Waste and Floor Drains	Less than 25 GPM
Land Environment	
Land Requirements	
Plant and Switchyard	60 acres
Construction Camp	5 acres
Socioeconomic Environment	
Construction Workforce	Approximately 115 personnel at peak construction
Operating Workforce	Approximately 140 personnel

Impacts associated with the transmission line from the North Slope to Fairbanks are identical to those discussed for the medium load forecast (Section 2.4). From Fairbanks to Anchorage only one line in addition to the Intertie will be necessary, in contrast to two new lines for the medium load forecast. Cleared acreage within the right-of-way will be approximately 5200 acres, as compared to 8700 acres for the medium load forecast. Impacts associated with vegetative clearing, including erosion, sedimentation, and habitat disturbance, are correspondingly less than those discussed in Section 2.4.

Construction of the project according to the low demand forecast would result in a smaller work force than under the medium demand forecast as well as a shorter work schedule. The construction work force is forecasted to be 115 employees, or a 40 percent reduction over the 200 employees forecasted for the medium growth scenario. The operations work force is predicted to be 140 persons, which is 70 percent of the work force requirements of the medium growth forecast.

Operation of the first generation unit would begin in 1996 compared to 1993 under the medium growth forecast. For five months of each of seven years during the period 1996-2010 a prefabricated unit of the plant would be assembled. During off-work periods, the majority of the employees would spend time outside of the North Slope Borough. The spending wages earned by the employees within the borough is expected to be minimal due to the transience of the workforce.

Despite the differences in work force requirements and schedule between the low and medium growth forecasts, the socioeconomic impacts would be expected to be similar. The relatively low level of impact can be attributed to the location of the generating plant within the Prudhoe Bay/Deadhorse industrial complex, which is isolated from communities.

The work force requirements and schedule for construction of the transmission lines is almost identical to that of the medium forecast scenario, and, therefore, socioeconomic impacts will be essentially the same as those discussed in Section 2.4.

SCENARIO II
FAIRBANKS POWER GENERATION
MEDIUM LOAD

4.0 FAIRBANKS POWER GENERATION

MEDIUM LOAD FORECAST

Fairbanks power generation, under the medium load forecast, requires a gas conditioning plant on the North Slope, a medium diameter pipeline to the Fairbanks area, an electric generating station at the pipeline terminus, and electrical transmission capacity between Fairbanks and Anchorage. The North Slope gas conditioning plant will remove carbon dioxide (12% by volume of the raw gas) and natural gas liquids. Initial and final peak delivery volumes are anticipated to be 230 MMSCFD and 407 MMSCFD, respectively, using a 22 inch diameter pipeline operating at 1260 pounds per square inch of pressure. The pipeline will be buried. Initially, three gas compressor stations along the pipeline route will be required, increasing to 10 by the year 2010.

The electric generating station necessary to produce almost 1400 MW of capacity in 2010 will consist of 5 combined cycle units, each consisting of two gas fired combustion turbines paired with two waste heat recovery boilers and one steam turbine generator, and 2 simple cycle gas turbines, which can be paired with waste heat recovery boilers to form a sixth combined cycle unit after 2010. Transmission lines to carry the power to the load center in Anchorage will require two additional (total of 3) 345 kV lines from Fairbanks to Anchorage.

This scenario also includes the construction of a natural gas distribution system in Fairbanks to serve residential and commercial space and water heating needs. Forecasting a fuel demand which replaces existing fuels is speculative, but highest demand (including growth) is based on 100 percent penetration of the potential market. In Fairbanks, in 2010, this is estimated to be as much as 63 MMSCFD.

Costs for shared facilities have been apportioned between the electric generating facility and the residential/commercial gas distribution system. Given this apportionment, construction of the gas conditioning facilities, gas pipeline, power generating facilities and transmission systems, is estimated to cost $6.5 billion. Total annual operation and maintenance costs are estimated to be $0.8 billion. The present worth of these costs excluding fuel costs is $5.4 billion. Construction costs for the Fairbanks gas distribution system serving residential/commercial markets total $1.2 billion, with total annual operation and maintenance costs totalling $86 million. The present worth of costs for this system consisting of a portion of the pipeline and gas conditioning facilities, plus the distribution network itself, is $0.9 billion.

4.1 NORTH SLOPE TO FAIRBANKS NATURAL GAS PIPELINE

The design of the gas pipeline and the gas conditioning facilities proceeded on the basis of preliminary gas demand calculations (detailed in Appendix A). Subsequent refinement of total peak demand for the Fairbanks scenario based on domestic gas distribution and electric usage (detailed in Appendix E and Appendix B, respectively) did not require design changes in the pipeline but resulted in small differences in gas demands in the sections that follow. The pipeline gas demands are as follows:

Pipeline Design (Preliminary Demand)	Medium Load Forecast (MMSCFD)
Power Generation	
Annual Average Demand	186
Daily Peak Demand	307
Residential/Commercial	
Annual Average Demand	27
Daily Peak Demand	76
Totals	
Annual Average Demand	213
Daily Peak Demand	383

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The refined values on which the Fairbanks gas distribution system and the electric generating unit additions depend are as follows:

Utility Systems Design (Refined Demand)	Medium Load Forecast (MMSCFD)
Power Generation Peak Daily Demand	271
Residential/Commercial Peak Daily Demand	63
Totals Peak Daily Demand	334

The refined gas demand is about 50 MMSCFD less than the preliminary value, an amount insufficient to necessitate pipeline design changes.

4.1.1 Gas Conditioning Plant

Gas to be transmitted through the pipeline will first be conditioned on the North Slope. The conditioning facility will receive the gas from the production fields, treat it, and compress it to 1260 psig and a temperature of 25 to 30°F. Initial design delivery volume will be 230 MMSCFD; however, the plant will be capable of expansion to 407 MMSCFD as future demand increases. These values are based on total Fairbanks gas demand, compressor station requirements and a pipeline availability of 96.5 percent. The gas delivery and quality specifications are presented in Table 4-1.

The process assumed for carbon dioxide removal is Allied Chemical's SELEXOL physical solvent process, the same process selected for use with ANGTS. A mechanical refrigeration process will control hydrocarbon dewpoint. Water dewpoint control will be accomplished in the dehydration equipment located in the existing Prudhoe Bay Unit gas/crude oil separation sites called Gathering Centers and Flow Stations. The hydrogen sulfide content of the feed gas is very low. It was therefore assumed that no process equipment will be required for either water dewpoint control or hydrogen sulfide removal.

TABLE 4-1

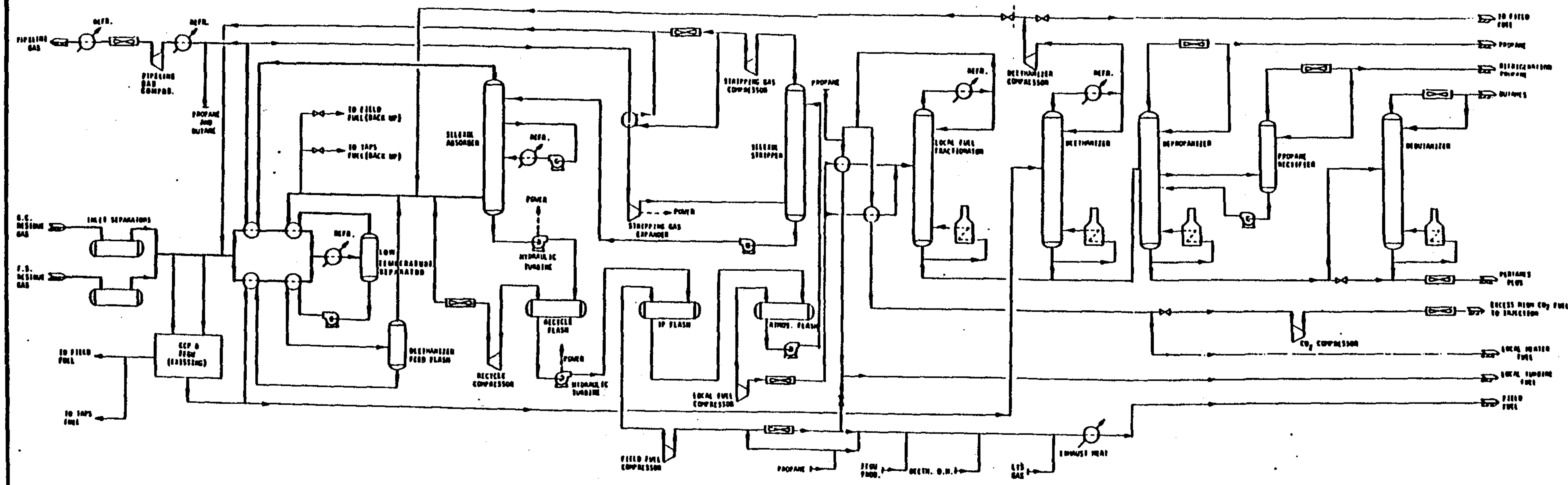
GAS DELIVERY AND QUALITY SPECIFICATIONS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Parameter	Specifications
Initial Delivery Volume	230 MMSCFD
Ultimate Delivery Volume	407 MMSCFD
Delivery Pressure	1260 psig
Delivery Temperature	25-30°F
Carbon Dioxide Content (max.)	2.0 volume %
Hydrogen Sulfide Content (max.)	1.0 grain/100 SCF
Hydrocarbon Dewpoint (max.)	-10°F @ 1000 psia
Water Dewpoint (max.)	-25°F @ 1000 psia

A simplified process flow diagram illustrates the basic process flow of the conditioning facilities (Figure 4-1). Two trains will be installed, one for continuous operation and the other as a spare. Feed gas, originating from the gas/crude separators, will be compressed in the Gathering Centers and Flow Stations and flow to the inlet separation unit. The inlet gas streams will be metered, and any solids or free liquids in the gas will be removed at this point. The feed gas will flow first to the natural gas liquids (NGL) extraction section for hydrocarbon dewpoint control. The gas will then flow to the SELEXOL section where the carbon dioxide is removed. The conditioned gas will then go to the gas compressors where it will be boosted to pipeline pressure, then refrigerated for transmission. SELEXOL solvent characteristically absorbs, along with the carbon dioxide, a significant quantity of hydrocarbons, particularly the heavier hydrocarbons. During the regeneration of the SELEXOL solvent, both the carbon dioxide and hydrocarbons are flashed from the solvent, producing a low Btu gas. The gas will be utilized within the facility to offset some of the energy requirements.

The hydrocarbon liquids from the NGL Extraction and SELEXOL flash gas will be separated in the fractionation unit into propane, butanes, and pentanes-plus products to facilitate disposal. Some propane will be used for heating value control of certain fuel streams. The remaining propane will be injected into the pipeline gas. The butanes will be either injected into the pipeline gas up to hydrocarbon dewpoint limits or into the crude oil delivered to the Trans Alaskan Pipeline System (TAPS) as is presently accomplished at the existing central compression facility for gas reinjection. The pentanes-plus will be injected into the same crude oil stream.

The facilities will require approximately 175,000 total installed horsepower including motors, power recovery units and gas turbines. The bulk of this horsepower will be developed by 9 operating gas turbines with 6 spare gas turbines. The major auxiliary systems will include refrigeration, offsite and general utilities, and power generation facilities.



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NORTH SLOPE GAS FEASIBILITY STUDY

GAS CONDITIONING FACILITY

FIGURE 4-1

EBASCO SERVICES INCORPORATED

The remoteness and severe environmental conditions at the North Slope impose limitations on both the process and mechanical design of the facilities. All equipment will therefore be housed in totally enclosed modules. Modules, with contained equipment, will be fabricated prior to shipment to the North Slope. They will be sea-lifted to the North Slope by ocean-going barges. At Prudhoe Bay they will be offloaded by crawler transporters or rubber-tired vehicles and moved to their pile supports on graveled sites.

A critical timing factor in any construction program at Prudhoe Bay is the limited time period during which the sea lanes are passable. Major plant components can only be delivered via ocean-going barges during the short (4-6 weeks) period each year when the sea lanes are not blocked by ice. Failure to deliver any critical major component during the scheduled period could effectively delay full-capacity startup by one full year.

4.1.2 Pipeline

4.1.2.1 Pipeline and Route

Gas to be transported will be provided to the pipeline from the gas conditioning plant. Pipeline quality gas will be a hydrocarbon mixture with approximately 88 percent methane, and a gross higher heating value of approximately 1100 Btu/SCF. The pipeline will be designed and operated to maintain the soil around the buried sections of the pipeline in a frozen state. The operating temperature of the gas in the pipeline will be between 0°F and 32°F under normal conditions. However, during transient periods, the gas in the line may exceed 32°F or may go down to as low as -5°F for short periods of time.

The proposed pipeline route originates in the Prudhoe Bay area in northern Alaska (refer to Appendix C). The pipeline will connect to the gas conditioning plant at the metering station, designated Milepost 0. The pipeline route, which assumes the ANGTS right-of-way, follows TAPS in a southerly direction to about Milepost 274 near Prospect Creek. The pipeline route then follows TAPS in a southeasterly direction to about Milepost 480, the assumed location of the power plant metering station. A tap will be provided at Milepost 455 near Fox to supply gas to Fairbanks for residential and commercial uses.

The pipeline will cross 15 major streams requiring special construction considerations, such as heavy wall pipe, continuous concrete coating or set-on concrete weights. At the Yukon River an existing aerial crossing will be used.

There will be 20 uncased road crossings, 27 road crossings with 28 inch casings, and 8 road crossings with 36 inch casings. The pipeline will cross TAPS at 21 locations, the TAPS fuel gas line at 13 locations, and other pipelines at 3 locations.

The basic assumption that this pipeline will follow the ANGTS right-of-way is a major one. Pipeline design and subsequently cost could be greatly affected if this right-of-way could not be used. Significant areas of concern would include the narrow Atigun Pass area and the Yukon River crossing.

4.1.2.2 Pipeline Design

The pipeline design pressure will be 1260 psig, based on current proven technology for resistance to crack propogation at low temperatures. The pipeline has been designed for the daily peak flow required to satisfy the gas demand associated with the medium forecast assuming a pipeline availability of 96.5 percent. The following flowrates were used for the hydraulic design of the pipeline:

Annual Average Flow (MMSCFD)	213/0.965 = 220
Daily Peak Flow (MMSCFD)	383/0.965 = 397

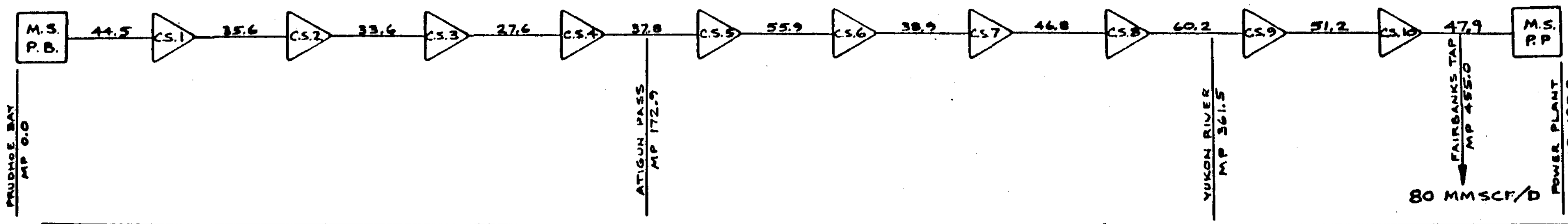
Initial annual average daily capacity of the pipeline will be 127 MMSCFD with a peak daily load of 227 MMSCFD during extreme cold weather periods.

The peak daily flowrate will require a pipeline outside diameter of 22 inches. The pipe shall be API 5LX or API 5LS Grade X70 with a minimum wall thickness of 0.275 inches for the majority of the length. At road crossings, bridges, and within public road right-of-ways, the minimum wall thickness will be 0.330 inches. These thicknesses are based on the entire pipeline being located in a Class 1 location as defined in CFR 49, Part 192.

The peak daily flowrate requires 10 compressor stations of approximately 3400 HP each. The average daily flowrate will require the operation of only 3 compressor stations, Stations 2, 4 and 7. The compressor stations are at the locations selected by ANGTS and use the same numbering system. The delivery pressure to the power plant will be 1038 psig. Figure 4-2 summarizes this flowrate condition. Compressor station fuel consumption will be approximately 1 MMSCFD per operating station.

A total of 28 mainline block valve assemblies will be provided at a nominal spacing of 20 miles including the initial compressor sites where the mainline valves will be installed in the station bypass loop. Seven of the 28 block valves will be installed at the additional station sites to facilitate system expansion. Pig launchers and receivers will be installed at the compressor and metering stations.

The pipe will be installed in a buried mode, using the proposed ANGTS construction techniques. Pipe ditches will be selected from several basic types, based on site-specific conditions. Special ditch configurations will be required to provide for the mitigation of frost heave effects in areas having frost-susceptible soils.



TOTAL 480 MILES, 22" O.D. PIPELINE, WALL THICKNESS = 0.275 INCH MINIMUM

	STATION DESIGNATION	M.S. PRUDHOE BAY	C.S. 1	C.S. 2	C.S. 3	C.S. 4	C.S. 5	C.S. 6	C.S. 7	C.S. 8	C.S. 9	C.S. 10	M.S. POWER PLANT
STATION	MILEPOST (MILES)	0.0	44.5	80.1	113.7	141.3	179.1	235.0	273.9	320.7	380.9	432.1	480.0
	ELEVATION (FEET)	21	362	825	1525	3050	3158	1220	1315	1730	880	1520	500
	STATION INLET VOLUME (MMSCF/D)	407	407	406	405	404	403	402	401	400	399	398	318
	TOTAL FUEL (MMSCF/D)	—	1	1	1	1	1	1	1	1	1	1	—
	STATION OUTLET VOLUME (MMSCF/D)	407	406	405	404	403	402	401	400	399	398	397	318
	STATION SUCTION PRESSURE (PSIG)	1260	1047	1063	1057	1031	1063	1124	1095	1039	1028	971	1038
	STATION DISCHARGE PRESSURE (PSIG)	1260	1245	1245	1245	1230	1230	1260	1260	1230	1230	1145	—
COMPRESSION	COMPRESSOR SUCTION PRESSURE (PSIG)	—	1031	1047	1041	1015	1047	1108	1079	1023	1012	955	—
	COMPRESSOR DISCHARGE PRESSURE (PSIG)	—	1259	1259	1259	1244	1244	1274	1274	1244	1244	1159	—
	COMPRESSION RATIO	—	1.218	1.200	1.206	1.222	1.186	1.148	1.178	1.213	1.226	1.210	—
	HORSEPOWER REQUIRED	—	3400	3150	3200	3400	2900	2300	2750	3200	3250	3400	—

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

HYDRAULIC SUMMARY
MEDIUM FORECAST
PEAK DAILY FLOW

FIGURE 4-2

EBASCO SERVICES INCORPORATED

Pipeline corrosion control will be provided by a combination of external coating and a cathodic protection system that will be compatible with the sacrificial zinc anode system used on the adjacent TAPS pipeline. The pipeline will be hydrostatically tested to 1.25 times the maximum allowable operating pressure.

4.1.3 Compressor and Metering Stations

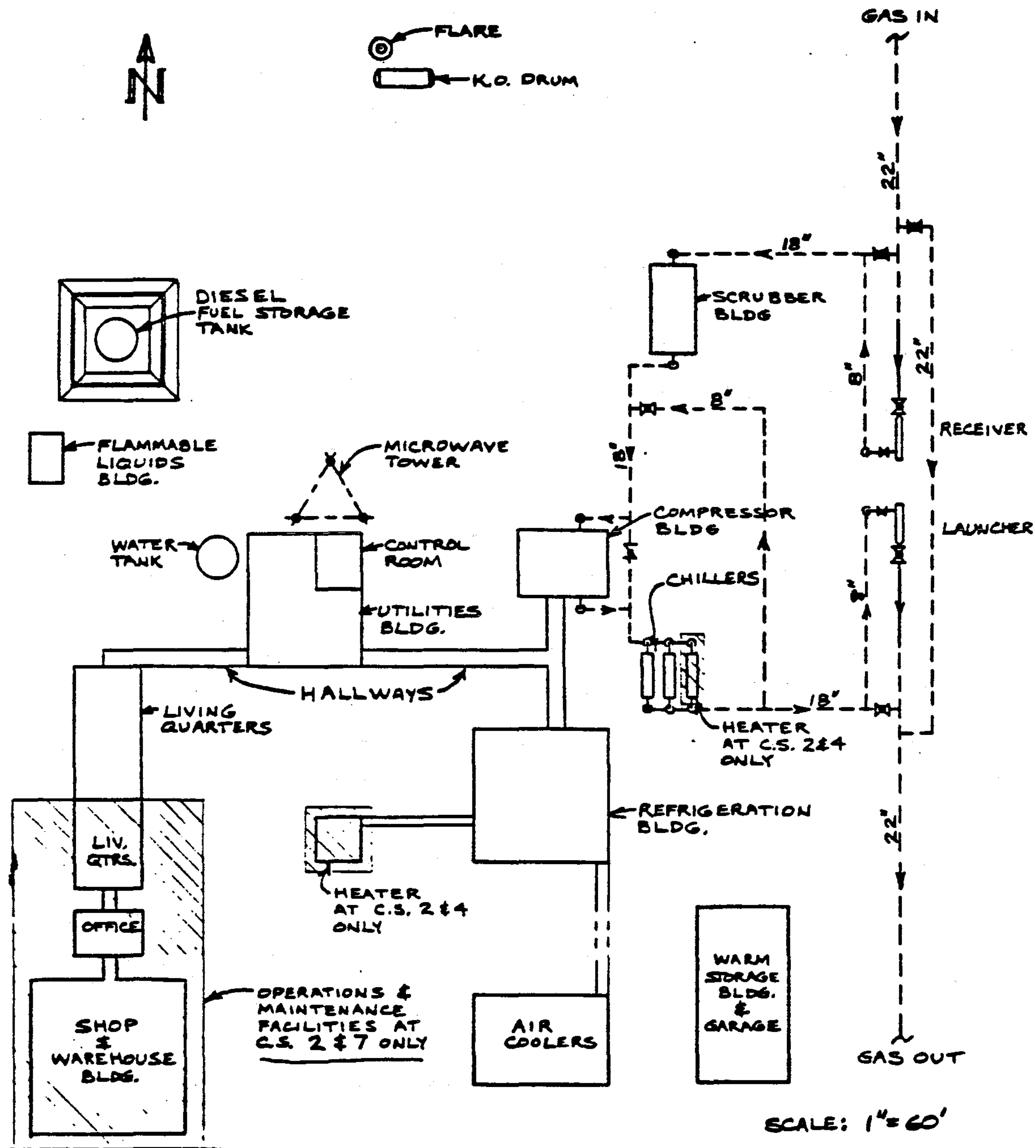
Two metering stations will be provided. One will measure the quantity of gas supplied to the pipeline from the gas conditioning plant at the North Slope, and the other will measure the gas delivered to the power plant just south of Fairbanks. Details of the compressor and metering stations design are provided in the Figures 4-3 and 4-4.

Each compressor station site will require about 10 acres, and the metering stations about 1.5 acres of land. Compressor stations will include buildings for the compressors, refrigeration equipment, utilities and control room, flammable liquids storage, warm storage and garage, a gas scrubber unit, living quarters and interconnecting hallways. Additional living quarters, office, and shop and warehouse building will be included at compressor stations 2 and 7.

Two refrigeration units will be provided at every compressor station to maintain the pipeline gas temperature. Gas heaters will be provided at compressor stations 2 and 4 to assure that gas temperatures will be maintained above the hydrocarbon dewpoint of the mixture under all operating conditions. Pipeline gas will be used to power the drivers for the gas compressors, refrigerant compressors and electric generators. Compressor station and metering station design and equipment are summarized in Tables 4-2 through 4-10.

4.1.4 Supervisory Control System

A supervisory control system will be provided to operate the pipeline system, perform related system balancing, and coordinate functions with the gas conditioning plant at the North Slope and the Fairbanks power plant.



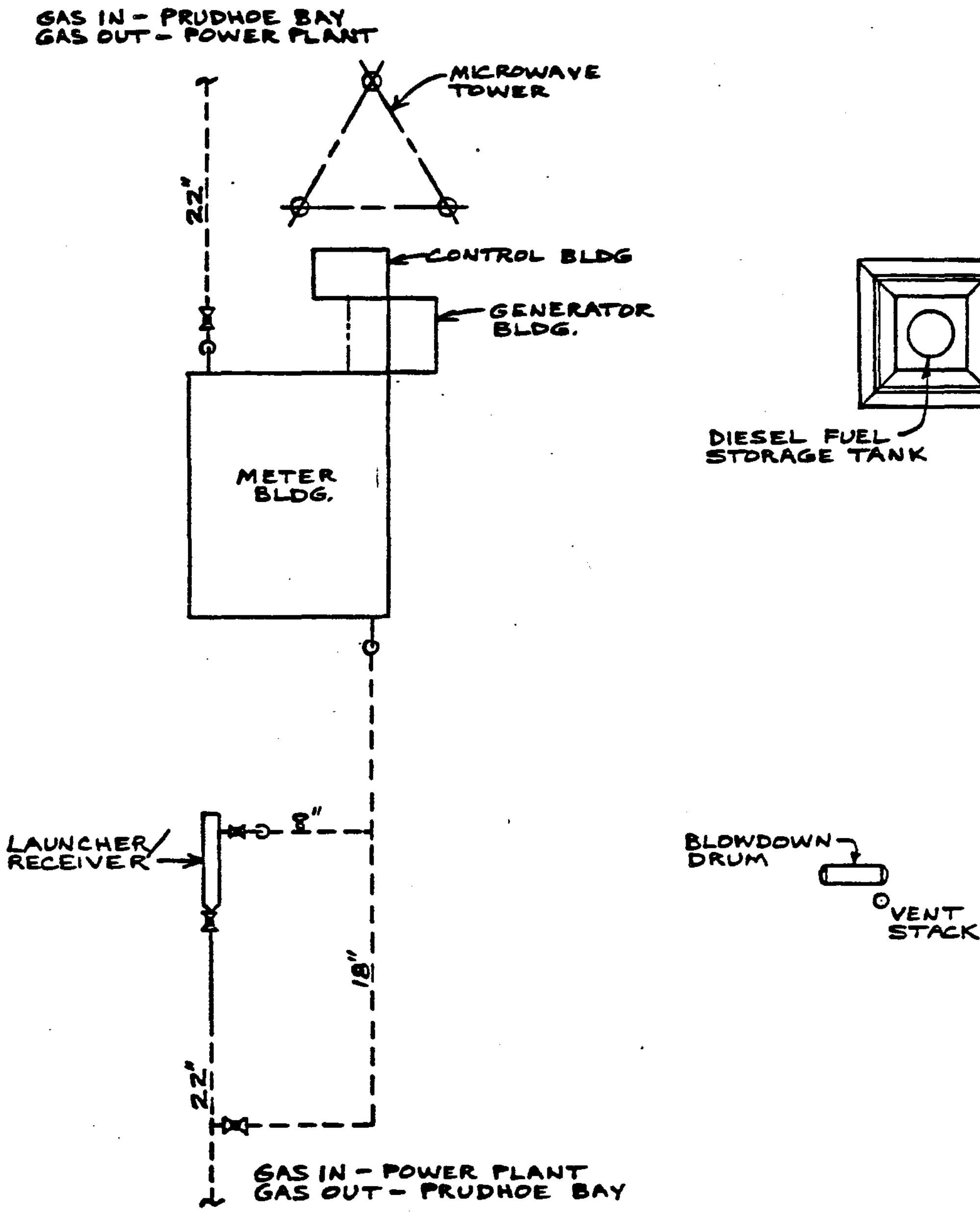
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

TYPICAL COMPRESSOR STATION LAYOUT

FIGURE 4-3

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

TYPICAL METERING STATION LAYOUT

FIGURE 4-4

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TABLE 4-2

COMPRESSOR STATION PIPE DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Major piping - 1280 psig design pressure

a.	22" O.D. x 0.406" wall API 5LX, GR. X70 pipe
b.	18" O.D. x 0.750" wall ASTM A333, GR. 6 pipe
c.	16" O.D. x 0.656" wall ASTM A333, GR. 6 pipe
d.	12" XS ASTM A333, GR. 6 pipe
e.	10" XS ASTM A333, GR. 6 pipe
f.	8" STD. WT. ASTM A333, GR. 6 pipe

NOTE: API 5LX piping to have additional specifications for -50°F Charpy Impact requirements and chemical requirements for improved weldability.

TABLE 4-3

CIVIL DESIGN DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

---

a. All buildings and heated components will be elevated on steel pile foundations above a gravel pad to allow free air circulation under the structures. The pile embedment will be adequate to prevent frost jacking of the structures. Non-heated facilities will be supported by a granular fill and sand pad.

b. Snow loads will be 60 psf

c. Earthquake design will be Zone 3

d. Wind loads will be:

30 psf	30' height
40 psf	30'-50' height
50 psf	50'-100' height
60 psf	100' height

e. Ambient temperature range -70°F to +80°F

f. Structural steel - inside heated structures, will use normal steel materials. Outside heated structures, will use suitable low temperature steels.

g. The diesel fuel storage tank will be placed over an impermeable liner covering the entire diked area.

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TABLE 4-4

BUILDING DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

a. All buildings will be pre-engineered insulated-panel metal structures, suitable for their intended use.

b. Buildings suitable for truck transportation through size or modularization will be prefabricated.

c. Hazardous materials storage buildings will be mechanically ventilated. Ventilation rates will be four air changes per hour for normal ventilation and 15 air changes per hour for emergency conditions.

d. The sizes of buildings will be as follows:

Scrubber bldg.	20' x 40' x 24' eave height
Compressor bldg.	30' x 40' x 20' eave height
Refrigeration bldg.	60' x 60' x 30' eave height
Warm Storage bldg.	40' x 80' x 20' eave height
Utilities bldg.	50' x 60' x 16' eave height
Living quarters (except C.S. 2 & 7)	30' x 60' x 16' eave height
Flammable Liquids Bldg.	15' x 20' x 10' eave height
Living quarters (C.S. 2 & 7)	30' x 100' x 16' eave height
Office (C.S. 2 & 7)	20' x 30' x 8' eave height
Shop and Warehouse (C.S. 2 & 7)	70' x 70' x 20' eave height
Hallways	6'-8' wide x 10' eave height
Meter bldg.	40' x 50' x 20' eave height
Generator bldg.	10' x 15' x 10' eave height
Control bldg.	10' x 15' x 10' eave height

TABLE 4-5

COMPRESSOR AND GAS SCRUBBER DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Main Compressors - 1 each per compressor station

a. Compressor - 1280 psig min. design pressure
   1.23 pressure ratio
   6000 ft. adiabatic head
   2750 ACFM

b. Gas Turbine Driver - 3800 ISO Horsepower
   gas fueled

c. Typical Equipment - Solar Centaur Gas Turbine Natural Gas Compressor Set with a C-304 Single Stage Compressor, or equal.

Gas Scrubber - (1) each per station

a. Designed to remove 99.5% of all solid and liquid particles 1 micron and larger.

b. Design flowrates will range from 130 to 400 MMSCFD.

c. Typical Equipment - Peco Robinson filter and liquid-gas separator, Model 75H-56-FG372, or equal.

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TABLE 4-6

REFRIGERATION SYSTEM AND GAS HEATER DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Refrigeration System

a. Refrigeration system will be a compression/expansion type using Freon gas and a gas turbine driver for the refrigerant compressors.

b. Chillers will be shell and tube with natural gas in the tubes at 1280 psig and Freon in the shell.

c. Condensers will be air cooled with multiple electric driven fans.

d. Required capacity will be 2200 HP.

e. The system will be comprised of two parallel 50% refrigeration trains to meet the total required capacity.

f. Typical Equipment - Two (2) 1100 HP refrigeration trains using Solar Saturn Gas Turbine Compressor Sets, or equal.

Gas Heater - One (1) each at Compressor Stations 2 and 4 only

a. Designed to add 5,000,000 Btu/hr to heat the pipeline gas during low flow winter conditions.

b. Equipment will be a gas fired heater and utilize a water/glycol solution to heat the gas in a shell and tube heat exchanger.

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TABLE 4-7

COMPRESSOR STATION
ELECTRICAL SYSTEM AND CONTROL SYSTEM DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Electrical System

a. Each station will be self-sufficient in electric power with its own power generation and distribution system.

b. Power will be 480 V., 3 phase, 60 Hz.

c. Main generators will be two (2) 800 KW continuous duty dual-fueled gas turbine driven generator sets, one will normally supply the station load and one will be standby.

d. Emergency (lifeline) generator will be one (1) 200 KW diesel engine driven generator connected to the essential services bus.

e. The emergency generator will be located in the warm storage building or another location remote from the main generators in the utilities building.

f. Typical Equipment:
Main generators - Solar Saturn GSC-1200, or equivalent
Emergency generator - Caterpiller 3406 TA, or equivalent

Control System

a. Each station will have a control system designed for completely remote and unattended operation.

b. The station Central Control Unit (CCU) will be linked by communications to the Operations Control Center (OCC).

c. Each individual piece of station equipment will have its individual control system which in turn will be controlled by the CCU which is the master controller.

d. The OCC input to the CCU will primarily be start/stop commands and setpoint changes.

e. The OCC will have sufficient information transmitted to it to allow for full compressor station control.

TABLE 4-8

MISCELLANEOUS COMPRESSOR STATION SYSTEMS' DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

---

a. Blowdown and Flare System will be sized for 100,000 lb/hr. of saturated light hydrocarbon gases and liquid storage capacity of 10,000 gallons.

b. Nitrogen Purge System - for purging.

c. Instrument and Utility Air System - Instrument air to be clean and dry for operating pneumatic control system components. Utility air for power tools and maintenance.

d. Fuel Gas Conditioning - Gas for station fuel requirements will be filtered, heated, reduced in pressure, and distributed at 500 psig.

e. Diesel Fuel - A diesel fuel storage and back-up fuel system will be provided for electric power generation and heating. The tank size will be 40,000 gallons to provide 14 days of capacity.

f. Fire Protection - Station fire protection will be provided by a Halon 1301 extinguishing system with a water/foam back-up system.

g. Water System - A single 40,000 gallon water tank will provide a source of water for potable uses as well as for the back-up water/foam fire system. The fire pump will be diesel driven. The potable water will be filtered, chlorinated, and distributed.

h. Sewage System - Sewage will be collected by a vacuum collection system. Final disposal will be through a septic system or a lagoon as site conditions warrant. Lagoon disposal will require secondary treatment and chlorination.

i. Heating System - The station will be heated by a water/glycol system utilizing waste heat from the station turbine generators. A combustion boiler unit will be provided as back-up to the waste heat system.

j. Cathodic Protection - A cathodic protection system will be provided to protect all buried piping, tank bottoms, and other structures in contact with the soil. The station will be electrically insulated by isolation flanges where the pipeline enters and leaves the compressor station property.

TABLE 4-9

METERS AND METERING STATION ELECTRICAL AND CONTROL SYSTEMS DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Meters

a. Each metering station will have 3 parallel meters with provisions for future addition of a fourth meter.

b. Meters will be concentric orifice plate with differential pressure transmitters.

c. Meter runs will be 12 inch diameter by 30' long.

Electrical System

a. Both metering stations will be powered by an outside commercial power source.

b. A 50 kW diesel-powered back-up generator will automatically come on line during a power failure.

Control System

a. Designed for remote and unattended operation.

b. Gas flow will be computed by a microprocessor-based flow computer with 100% redundancy.

c. The flow computer will be linked to the OCC by telecommunications.

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TABLE 4-10

MISCELLANEOUS METERING STATION SYSTEMS' DETAILS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

---

a. Blowdown drum and vent stack system.

b. Nitrogen purge system.

c. Diesel Fuel - A diesel fuel storage system will be provided for electric power generation.

d. Fire Protection - Fire protection will be provided by a Halon 1301 extinguishing system with a water/foam back-up system.

e. Heating System - Heating and ventilating will be by means of redundant gas-fired furnaces and warm air duct systems.

f. Cathodic Protection - A cathodic protection system will be provided to protect all buried piping, tank bottoms, and other structures in contact with the soil. The station will be electrically isolated by isolation flanges where the pipeline enters and leaves the compressor station property.

The supervisory control system master station will be located near the Fairbanks power plant at the operations control center (OCC). A communication system will provide the voice and data intertie to each compressor and metering station from the OCC. Each station will include a control system that will interface through the communication link to the OCC.

The OCC in Fairbanks will include the dispatcher console, which will provide the monitoring and control equipment necessary for centralized operation of the pipeline.

4.1.5 Communications System

The communications system will include voice and data transmission systems, the mobile radio system, and record communications. A basic communication system will be installed during the construction phase to provide voice and data links among the pipeline and compressor station camps, and the Fairbanks construction headquarters.

Mobile radio equipment will be provided to permit communication by field construction teams through a network of repeater stations to the camps, stations and other facilities. This basic communication system will later be modified to provide the operational communications system. This operational system will support the supervisory control system. Data communications will also be provided.

4.1.6 Operation and Maintenance Facilities

Operation and maintenance (O&M) facilities will be located at three sites along the pipeline: Compressor Stations 2 and 7, and the Fairbanks operations headquarters. Each O&M facility will include the following:

(1) Warehouse for storing project spare parts inventory.
(2) Maintenance shop, including maintenance equipment.
(3) District office.
(4) Living quarters for the O&M personnel.

The Fairbanks operations headquarters near the power plant will also house the OCC, the related supervisory control equipment, required power supplies and the communications system equipment.

Stations 2 and 7 will serve as shop and warehouse with both living quarters and maintenance facilities. The other stations will have small living quarters attached. It is anticipated that a staff of 5 to 6 will serve at each compressor station except stations 2 and 7, which will have a total of 16 each, including 6 maintenance personnel. This would then require a total staff of 80 for the medium load forecast peak demand (10 stations).

4.1.7 Construction and Site Support Services

Temporary facilities will include those facilities required to support the construction phase activities. These facilities will include the Fairbanks construction headquarters, the pipeline and compressor station construction camps, airfields, access roads, material (borrow) sites and disposal sites.

Thirteen pipeline construction camps will be provided along the route, including one located at the Fairbanks construction headquarters site. These camps will be capable of accommodating between 250 to 1,300 persons, depending on location and planned use.

The camps, once completed, will be turned over to contractors for operation. The twelve camps along the pipeline will be renovated generally in place using equipment and modules obtained mostly from the existing TAPS camps. Three compressor station construction camps will be provided by relocating and renovating equipment and modules available from eight existing TAPS pump station camps.

Airfields will consist of certain existing commercial airfields, as well as renovated private airfields previously built in support of TAPS. Material (borrow) sites are available along the pipeline route to provide construction materials, as well as areas to dispose of construction spoil. Maximum haul distances should be kept under 5 miles.

A pipe yard at Fairbanks will be provided to receive mainline pipe, store, externally coat, double-joint (weld) and insulate pipe as required. Access roads will be provided as needed to allow access to stations, borrow sites, pipeline spreads and related facilities.

4.2 POWER PLANT

The Report on System Planning Studies (Appendix B) concluded that combined cycle power plants are the most technically feasible and economical choice for satifying demand when generating electrical power at a Fairbanks site. The individual combined cycle plants will consist of two gas turbines, each with a heat recovery steam generator and one steam turbine for a total of three turbine-generator sets.

4.2.1 General

The Fairbanks site will contain all required generating units, construction and maintenance facilities, various auxiliary and support systems, a central control facility and switchyards. This power generation scenario calls for five 242 MW combined cycle and two 86 MW simple cycle units to satisfy the demand for energy in the year 2010. The first unit, a simple cycle gas turbine, is required in 1993 and in subsequent years either gas turbines or steam turbines are added. Incremental and total required new generation capacity for this scenario are summarized in Table 4-11.

A single combined cycle unit will require an area with outside dimensions of 300 feet by 440 feet. The arrangement of the three turbine-generator sets, the air cooled condenser and auxiliary equipment is shown in Figures 4-5 and 4-6. The site plan shown in Figure 4-7 illustrates the planned installation method (side by side) for up to six units with switchyards. This arrangement will require a total area of approximately 150 acres.

TABLE 4-11

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Year	New Capacity (MW) (Increment/Total)	Gas Required[1/] (MMSCF)
1990	0/0	0.
1991	0/0	0.
1992	0/0	0.
1993	86/86	6,265.8
1994	0/86	6,265.8
1995	86/172	12,531.6
1996	70/242	12,633.1
1997	172/414	25,132.7
1998	70/484	25,202.9
1999	0/484	25,202.9
2000	86/570	31,551.3
2001	0/570	31,467.3
2002	156/726	37,804.3
2003	0/726	37,804.3
2004	86/812	44,188.1
2005	156/968	45,809.0
2006	86/1050	49,535.1
2007	86/1140	53,145.7
2008	70/1210	52,292.0
2009	86/1296	55,892.6
2010	86/1382	59,424.8

1/ Values as calculated are shown for reproducibility only, and do not imply accuracy beyond the 100 MMSCF level.

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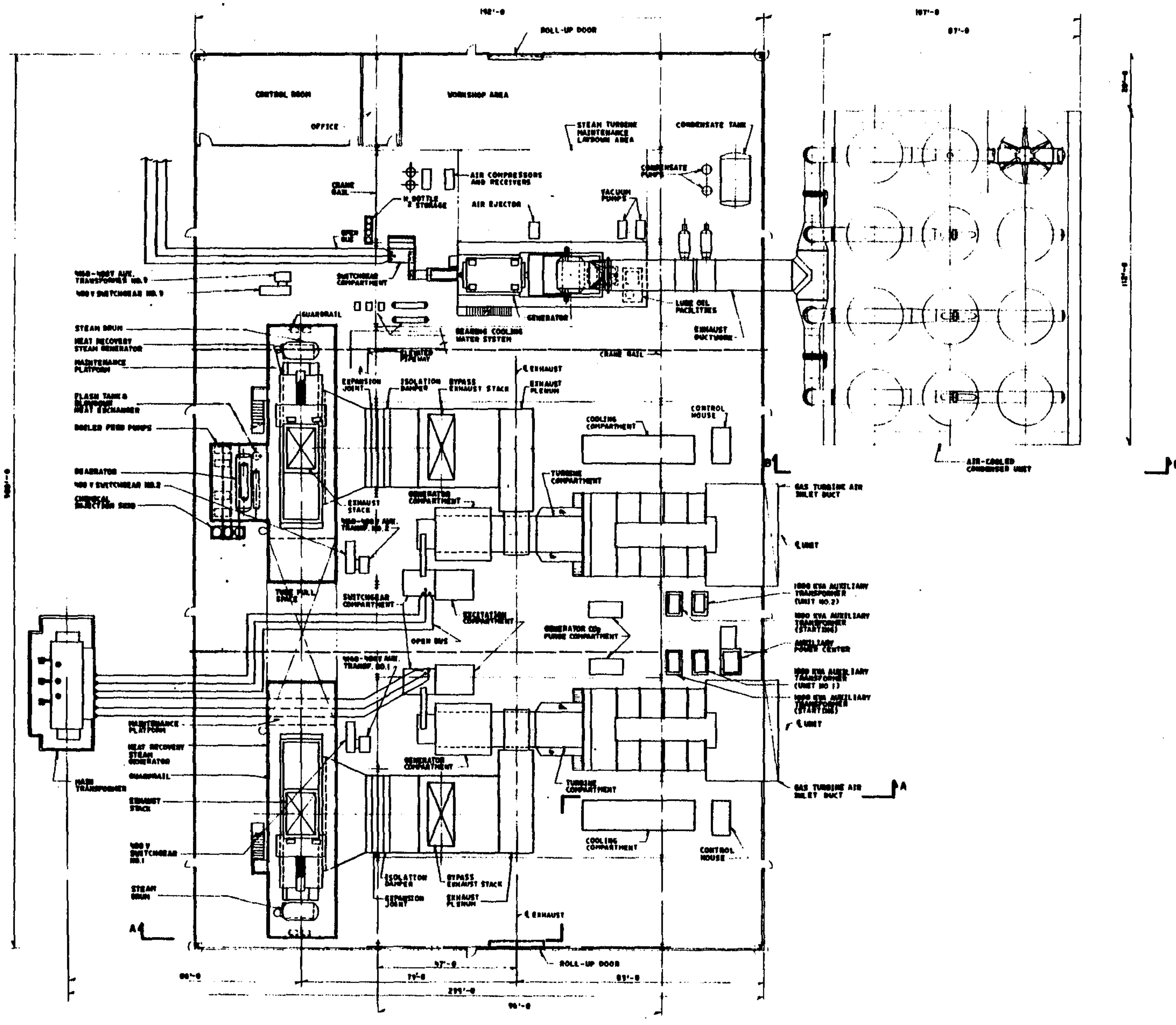

PLAN - 220 MW NOMINAL RATING/COMBINED CYCLE PLANT

NOTES:
1- THE COMBINED CYCLE PLANT ARRANGEMENT SHOWN IS BASED ON ADDITION OF STEAM TURBINE EQUIPMENT TO A TWO-UNIT SIMPLE CYCLE GAS TURBINE PLANT.

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

COMBINED CYCLE PLANT
GENERAL ARRANGEMENT
PLAN VIEW

FIGURE 4-5

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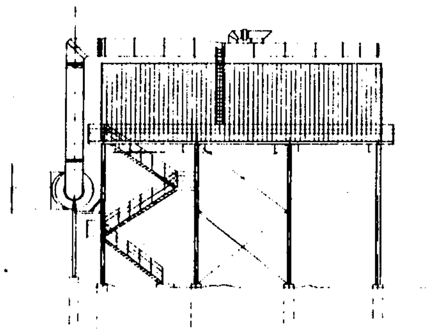
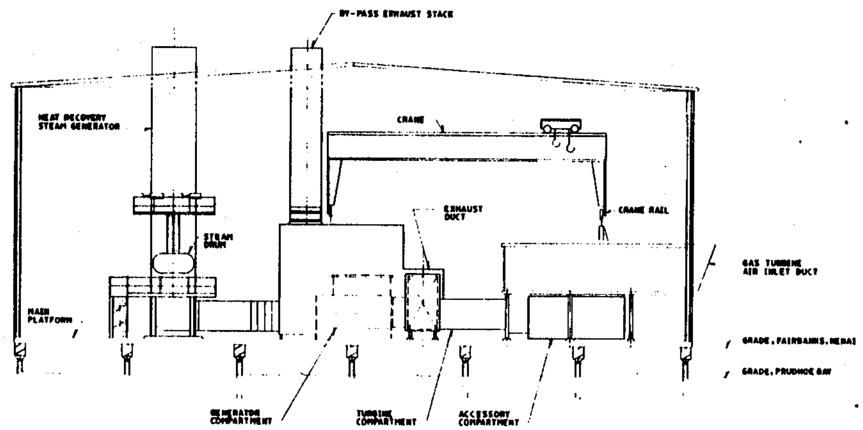


SECTION - B



SECTION - A

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NORTH SLOPE GAS FEASIBILITY STUDY

COMBINED CYCLE PLANT
GENERAL ARRANGEMENT

ELEVATIONS

FIGURE 4-6

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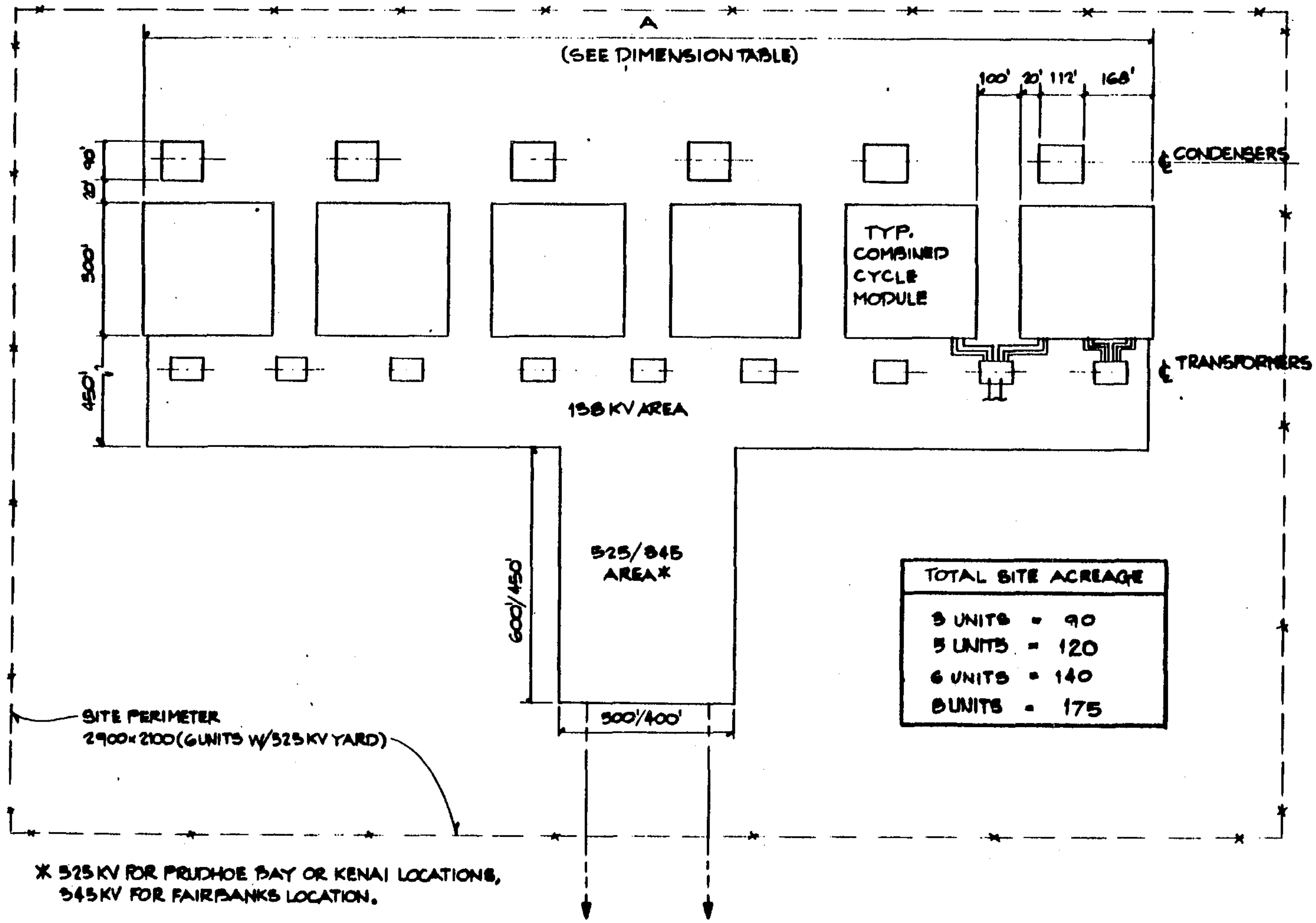

TOTAL SITE ACREAGE	
3 UNITS	= 90
5 UNITS	= 120
6 UNITS	= 140
8 UNITS	= 175

DIMENSION 'A'	NO. OF COMPLETE COMB. CYCLE UNITS
300	1
700	2
1100	3
1500	4
1900	5
2300	6
2700	7
3100	8

* 525KV FOR PRUDHOE BAY OR KENAI LOCATIONS, 345KV FOR FAIRBANKS LOCATION.

* ASSUME MAXIMUM DIMENSION FOR SWITCHYARD

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NORTH SLOPE GAS FEASIBILITY STUDY

COMBINED CYCLE PLANT
SITE PLAN
FAIRBANKS AND KENAI

FIGURE 4-7

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The functional parts of the plant will be similar to those described in Section 2.0 for the gas turbine portion of the plant. The steam cycle will require the addition of heat recovery steam generators, steam and auxiliary system piping, a steam turbine generator, condenser, condensate polishing, water quality control systems, and an increase in the quantity of water used.

4.2.2 Combustion Turbine Equipment

All combustion turbine equipment will be identical to that described in Section 2.1.

4.2.3 Steam Plant

The heat recovery steam generators (HRSG) are considered part of the steam plant although physically the steam generators will be housed together with the gas turbines in a large common building.

Each heat recovery steam generator package, one at each gas turbine exhaust, will include the steam generator complete with ductwork from the combustion turbine to the steam generator, a bypass damper and bypass stack, and a steam generator exhaust stack. The steam generators will have a steam outlet pressure of 850 psig at 950°F. Each steam generator is designed to produce one half of the plant's normal flow for steam when supplied with feedwater at a temperature of 250°F. The heat recovery steam generators are designed for continuous operation. All steam generator controls will be located in a common area in the central control room.

During start-up and other load conditions, the bypass damper may be operated to provide operational flexibility. By opening the bypass damper and closing the louvered dampers, the combustion turbine exhaust is routed to the stack and does not reach the steam generator. Design parameters for the heat recovery steam generators are shown in Table 4-12. The flow diagram and anticipated heat balance for a single combined cycle unit is presented in Figure 4-8.

TABLE 4-12

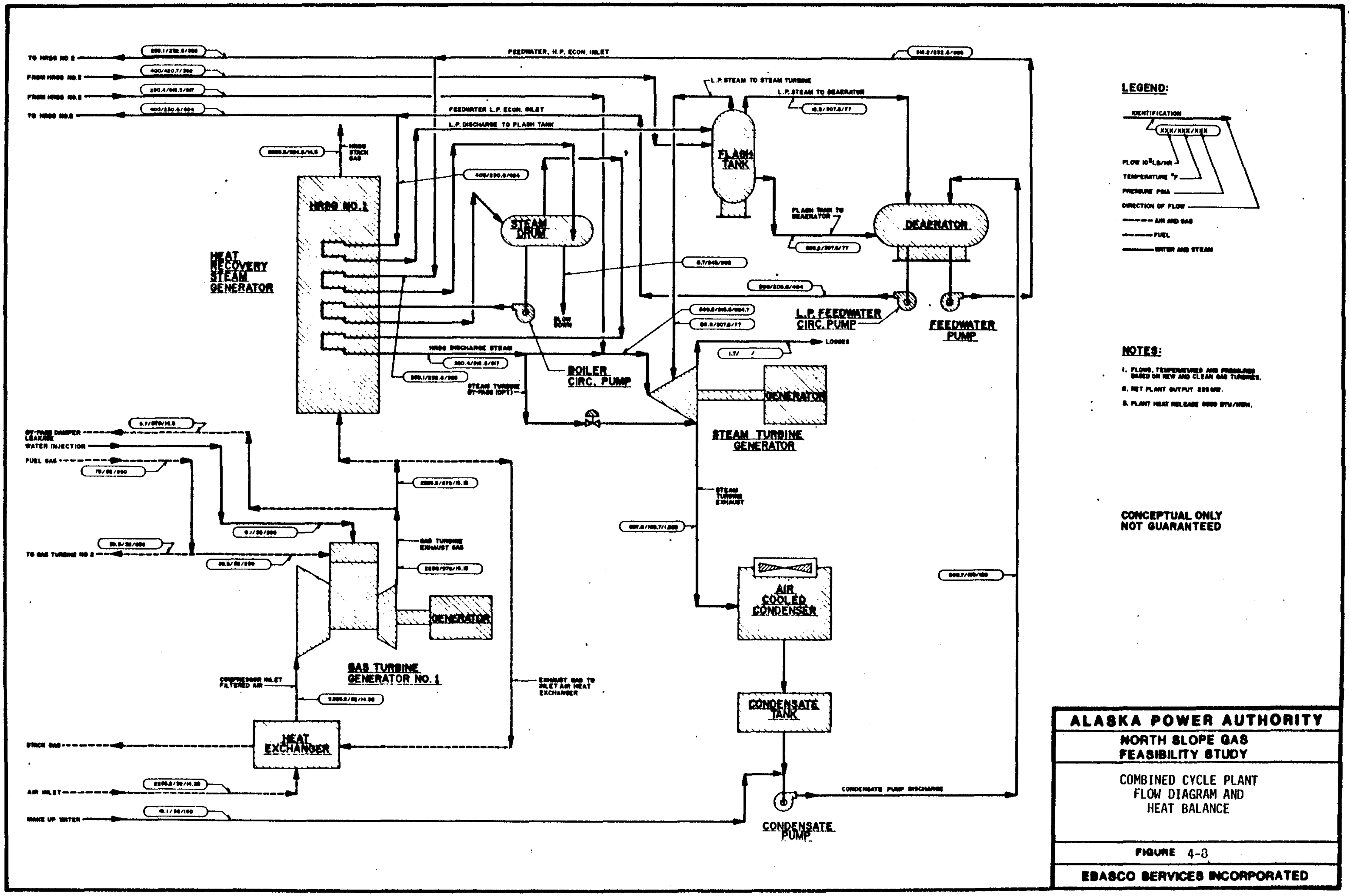
HEAT RECOVERY STEAM GENERATOR DESIGN PARAMETERS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Two Required Per Unit)

Type:	Watertube, forced circulation	
Performance:	(Each Steam Generator)	
	Main Steam	
	Outlet Condition	850 psig, 950°F
	Quantity	250,400 lbs/hr

Steam production under normal operation will be achieved with an exhaust gas flow through the boiler of 2,286,000 lbs/hr at 970° F. Feedwater will be supplied to the HRSG at 250°F from the feedwater heater.

Heat Recovery Steam Generator Features

Feedwater Heater
Economizer
Evaporator Section with Steam Drum
Superheater Section
Economizer
Evaporator Section with Steam Drum
Exhaust Gas Bypass Dampers with Separate Stack



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NORTH SLOPE GAS FEASIBILITY STUDY

COMBINED CYCLE PLANT FLOW DIAGRAM AND HEAT BALANCE

FIGURE 4-8

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The generator is rated 72 MW. The unit auxiliary transformer is a three winding 15 MVA, 13.8/4.16/4.16 kV. The two secondary windings supply 4.16 kV buses 3A and 3B. The step-up transformer is rated 50 MVA, 18/138 kV.

The main steam produced in the heat recovery steam generators will be conveyed to a common turbine generator set. The turbine generator will be a tandem compound, multistage condensing unit, mounted on a pedestal with a top exhaust going to the air cooled condenser. Design parameters for the turbine generator are shown on Table 4-13. The turbine generator set will be furnished complete with lubricating oil and electrohydraulic control systems as well as the gland seal system, and the generator cooling and sealing equipment.

In addition to the combustion generators, steam generators and steam turbine, the building will also contain the feedwater pumps, condensate pumps, vacuum pumps, deaerator, instrument and service air compressors, motor control centers, control room, and diesel generator (see Figure 4-5). The diesel generator will be sized for black start-up service.

Heat will be rejected from the steam turbine cycle at the outside mounted air-cooled condenser where air flowing across cooling fins absorbs heat from the exhaust system. The condensate from the condenser will then flow to the condensate storage tank where it will be pumped back into the cycle.

Fuel requirements for this scenario will start at approximately 6.27 BCFY in 1993, when the first gas turbine starts delivering power, and increase to 59.43 BCFY in the year 2010. The maximum anticipated gas consumption rate, in the year 2010, with 1382 MW of capacity in operation, is 1.88×10^5 SCFM. Detailed annual gas use figures are presented in Table 4-11.

TABLE 4-13

STEAM TURBINE GENERATOR UNIT DESIGN PARAMETERS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(One Required Per Unit)

Turbine Type:	Multistage, straight condensing, top exhaust	
Generator Type:	Hydrogen-cooled unit rated 72 MW at 13.8 kV with 30 psig hydrogen pressure at 10°C	
Performance:	Base Rating	72 MW
	Steam Inlet Pressure	850 psig
	Steam Inlet Temperature	950°F
	Exhaust Pressure	2" to 4" Hg
	Exhaust Temperature	108°F
	Speed	3600 RPM
Steam Turbine Generator Features:	Common base mounted with direct-drive couplings. Accessories include multiple inlet control valves, electric hydraulic control system, lubricating oil system with all pumps and heat exchangers for cooling water hook-up, gland steam system and generator cooling. Excitation compartment complete with static excitation equipment. Switchgear compartment complete with generator and breaker potential transformers.	

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4.2.4 Substation

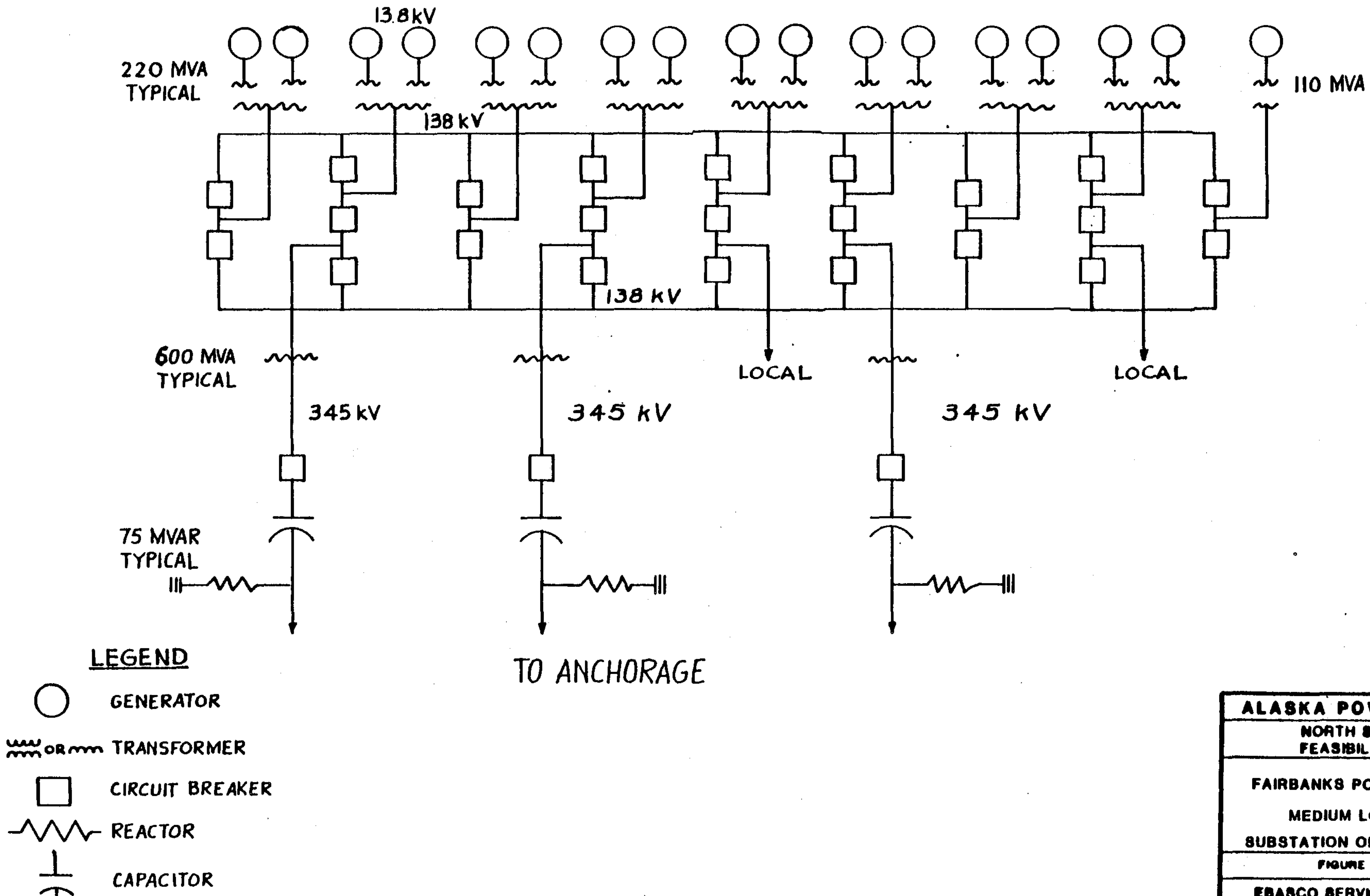
The circuit diagram of the powerplant substation is shown in Figure 4-9. It is quite similar to the North Slope substation (Figure 2-3). Two generators will be connected to the two primary windings of the 250 MVA 13.8/138 kV transformers, and the last generator to a 125 MVA two winding transformer. The bus arrangement will use a breaker and a half scheme unless reliability considerations mandate otherwise. One 600 MVA 138/345 kV transformer will supply each of the transmission line circuits. Each of the transmission lines will have a circuit breaker. On the line side of the circuit breakers are the series capacitors and the shunt reactors. This arrangement has the advantage of being flexible as far as operation is concerned and can be expanded easily.

4.2.5 Other Systems

In addition to the potable and service water system described in Section 2.1, this plant will require make-up water for the steam cycle. To purify the make-up water a demineralizing system will be required.

Blowdown from the HRSGs and waste from the demineralizer and the condensate polisher represent additional waste handling capacity requirements over and above that previously discussed (Section 2.1). These waste streams will require treatment, in accordance with regulation, prior to discharge.

Other systems such as fire protection or lubricating oil will not change in scope or capacity to any significant degree from those presented in Section 2.1.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

FAIRBANKS POWER GENERATION

MEDIUM LOAD FORECAST

SUBSTATION ONE LINE SCHEMATIC

FIGURE 4-9

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4.2.6 Construction and Site Support Services

The construction of this power plant in the Fairbanks area will require the following services:

(1) Access Roads
(2) Construction Water Supply
(3) Construction Power Supply

All new roads will be of similar design to existing public roads in the Railbelt. The roads will be paved, and will meet all code design requirements for the maximum loads expected.

A complete water supply similar to that described in Section 2.1 will be provided, except the source of water will be wells. The construction power supply will be a 12.47 kV line run from existing facilities.

Since a permanent construction force will be utilized through the period of the study, it is assumed that the local area can supply living accommodations for the work force. The number of workers necessary for construction of the power station will vary over the total period of the project from a low of 50 to a high of approximately 200. Construction facilities required are: utility services; temporary construction office; temporary and permanent access roads; temporary enclosed and open laydown storage facilities; temporary office and shop spaces for various subcontractors; settling basins to collect construction area storm runoff; and permanent perimeter fencing and security facilities.

4.2.7 Operation and Maintenance

<u>Plant Life</u>

Each unit will have a 30 year life expectancy, which is based on the life of the gas turbine units. It is expected that the gas turbine units will be overhauled a number of times throughout the life of the units during scheduled or unscheduled outages.

Heat Rate of Units

The facility's heat rate will vary, depending on the number of gas turbines and heat recovery units operating at a given time. Ideally, with only combined cycle units in operation, a heat rate of 8290 Btu/kWh (HHV, ambient conditions) can be realized.

Scheduled and Forced Outage Rate

It is expected that the forced outage rate will be about 8 percent. Operational experience on other plants indicates higher forced outages in the first few years, but this is attributed to operational adjustments required for a new plant. It is expected that a slight increase in forced outages will occur as the plant ages. Scheduled outages for annual maintenance and periodic overhaul are expected to be approximately 5 percent.

Operating Workforce

The combined cycle power plant will require a continuously increasing staff over the study period. The staff will start at approximately 10 on-duty personnel when the first gas turbine begins operation and will increase to approximately 80 on-duty personnel in the year 2010.

4.2.8 Site Opportunities and Constraints

Fairbanks represents the nearest location to which North Slope gas can be transported to and have the resulting generation of electrical energy be fed directly into an existing portion of the Railbelt electric transmission network. Transportation of heavy equipment to the site does not represent technical problems; however, the location will require expensive overland transport from the port facilities at Anchorage.

4.3 TRANSMISSION SYSTEM

The power to be transmitted from Fairbanks to Anchorage equals the power generated less the Fairbanks area load. This amount is the same as the North Slope generation scenario, except for the line losses between the North Slope and Fairbanks, which are not significant when compared to the power generated. Therefore, the conditions for the Fairbanks to Anchorage transmission line are almost exactly identical for both cases and consist of two new 345 kV lines, and an upgrade of the Willow-Anchorage and Healy-Fairbanks segments of the Intertie from 138 kV to 345 kV (Refer to Section 2.2).

4.4 FAIRBANKS GAS DISTRIBUTION SYSTEM

4.4.1 Fairbanks Residential/Commercial Gas Demand Forecasts

The following paragraphs are a summary of the study performed by Alaska Economics Incorporated to forecast residential and commercial gas demand in Fairbanks. The text of this report appears in Appendix E.

The potential residential and commercial demand for natural gas in the Fairbanks area is dependent on the price competitiveness of natural gas with respect to No. 2 distillate fuel oil and propane in heating and water heating markets, and its price competitiveness with propane and electricity in cooking applications. The potential demand of natural gas as a cooking fuel is estimated to be less than 5.0 percent of the total potential demand for natural gas even if the gas were to fully displace bottled propane in commercial cooking applications.

The forecasts of potential gas demand have been made conditional on the gas achieving discrete percentages of the total market for heating and cooking energy (10 percent, 25 percent, 40 percent, and 100 percent displacement of fuel oil and propane in heating and of propane in cooking). The size of the total market to which these percentages have been applied has, in turn, been projected to grow at a 1.43 percent annual average rate from 1981 for the low growth forecast, and at a 2.30

percent annual average rate for the medium growth forecast. These growth rates are the rates of Fairbanks population growth implied, respectively, by Battelle's (1982) low forecast of the demand for electricity in the Railbelt area, and Acres American's (1981) medium forecast of Railbelt electricity demand.

The prices at which residential and commercial users would have a minimum financial incentive to convert from fuel oil to natural gas for heating purposes have been derived. These "consumer breakeven" prices are based upon the assumption that the maximum discounted payback period for consumers is 5 years. At the 1982 price of No. 2 distillate, $1.22 per gallon, the calculated consumer breakeven prices are $9.58 per MCF for residential heating and $9.94 per MCF for commercial heating. These prices will rise annually at approximately the real (inflation free) rate of increase of fossil fuel prices in general. If this rate is the 2.0 percent real rate assumed by Battelle (1982) and Acres (1981), by the year 2010 the breakeven prices in (1982 dollars) will have reached $16.68 per MCF (residential) and $17.31 per MCF (commercial).

The presence of calculated breakeven prices is necessary for the forecasting of natural gas demand. However, breakeven price data and price elasticity data are insufficient for such a forecast in this case. These price and elasticity data are insufficient because the situation involves a new product (natural gas) competing with an existing product (e.g., distillate oil, propane). Additional factors influence consumer demand including:.(1) consumer perceptions of the two products; (2) consumer inertia; (3) initial and/or unusual incentives offered by suppliers of the competing fuels based upon their calculated present worth of achieving certain market shares; and (4) other less defined factors. Because of these unquantified factors, conditional demand estimates have been forecast; and these are based upon price analysis alone.

If natural gas is priced below the consumer breakeven level, users will have an increased financial incentive to shift from fuel oil. For every 10¢ by which the price of gas falls below the breakeven level, residential users will realize approximately $81.00 (1982 dollars) in additional savings over the estimated cost of conversion. It might be expected that extensive inroads against fuel oil will begin to be made if gas is priced sufficiently below breakeven so as to cover conversion costs and to achieve a significant level of savings (measured as the excess of the present value of annual cash savings over conversion costs).

It must be recognized that the producers and suppliers of fuel oil are likely to respond to the intrusion of natural gas by either lowering the price of No. 2 distillate or by offering other incentives. While the intensity of reaction by oil suppliers cannot be forecast, it can be assumed that suppliers are capable of at least offsetting the price advantage that natural gas has traditionally enjoyed based on its reputation as a "clean" fuel. Therefore, the above calculation of consumer breakeven prices correctly ignores the fact that many consumers might be willing to pay a premium for such natural gas properties.

The conditioned demand projections derived are presented in detail in Appendix E and are summarized below for the medium growth projection.

	DELIVERED GAS, BCF PER YEAR	
	1985	2010
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.527	0.931
25% of Market	1.319	2.328
40% of Market	2.110	3.726
100% of Market	5.274	9.314

These values represent the annual demand for delivered gas conditional upon the percentage of market penetration indicated, where the total market, defined in terms of effective MMBtu's[1/] is set equal to 100

1/ Effective MMBtu's (million Btu's) are delivered MMBtu's adjusted for the fuel burning efficiency of heating units and cooking units. For example, if oil burners are 65 percent efficient, one delivered MMBtu equals 0.65 effective MMBtus.

percent of commercial and residential heating energy requirements plus 29 percent of residential cooking energy requirements. The delivered gas demand values were calculated based upon different thermal efficiencies for oil and gas fired units.

The demand for gas would not be constantly distributed throughout the year. Based on an appraisal of normal monthly heating degree days in Fairbanks, and an assumed indoor temperature setting of 65° Fahrenheit, approximately 16.6 percent of annual Fairbanks heating energy is consumed in January, the peak month for demand.1/ Although cooking energy requirements may be more evenly spread across the year, the relatively small size of cooking demand, less than 5.0 percent of the total, suggests rather strongly that an apportionment of total demand according to the conductive heat transfer formula will yield a good estimate of peak monthly demand. Use of this method implies the following peak monthly demand (January) for natural gas in Fairbanks for the medium growth projection.

	DELIVERED GAS, BCF PER PEAK MONTH	
	January 1985	January 2010
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.087	0.155
25% of Market	0.219	0.386
40% of Market	0.350	0.619
100% of Market	0.875	1.546

Peak daily demand during the month of January can reasonably be estimated as 0.0322 (1/31) of the monthly demand times a factor that allows for extremes of cold. Between 1961 and 1982, the highest number of January heating degree days recorded in Fairbanks was 3002 (in January 1971). The January average was 2384. The ratio of the two

1/ Heat loss is proportional to the indoor-outdoor temperature differential and inversely proportional to the insulation factor. At an indoor temperature setting of 65° Fahrenheit, relative monthly heating degree days is the appropriate measure of relative monthly heat loss.

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(1.26) when multiplied by 0.0322 yields an appropriate measure of peak daily demand when their product is in turn multiplied by peak monthly demand. Thus, peak daily demand equals 0.0406 times peak monthly demand. The daily peaks are given in the following table for the medium growth projection:

	DELIVERED GAS, BCF, PEAK DAILY	
	January 1985	January 2010
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.004	0.006
25% of Market	0.009	0.016
40% of Market	0.014	0.025
100% of Market	0.036	0.063

Peak hourly demand, defined as 0.0417 (1/24) times peak daily demand is quite small. For example, in the maximal case of 2.30 percent growth and 100 percent market penetration, the peak hourly demand is only 0.0026 BCF, or 2,600 MCF.

Finally, expansion of the Fairbanks steam district heating system could reduce the demand for natural gas below the estimates presented above. On the assumption that the district heating system supplies only commercial and government users, the implied reduction is at most 15.0 percent of the estimates given above, since commercial use of gas is projected to be at most 15.0 percent of total demand.

4.4.2 Fairbanks Gas Distribution System

The Fairbanks natural gas transmission and distribution system will be designed in conformance with Part 5, Alaska Public Utilities Commission, Chapter 48, Practice and Procedures; Federal Safety Standards for Transportation of Natural Gas and Other Gas by Pipeline, 49 CFR Part 192, Latest Revision; and the American National Standard Code for Gas Transmission and Distribution Piping Systems, B 31.8, Latest Edition.

The overall system network will consist of a transmission lateral from a metering station near Fox to a City Gate Station with a minimum inlet pressure to the gate station of 250 psig, a 125 psig high pressure system to distribute gas to district regulators, and a 60 psig maximum distribution system to carry gas to individual customer services. Generally, the rural facilities will be considered in Location Class 3, and those in the urban areas in Location Class 4.

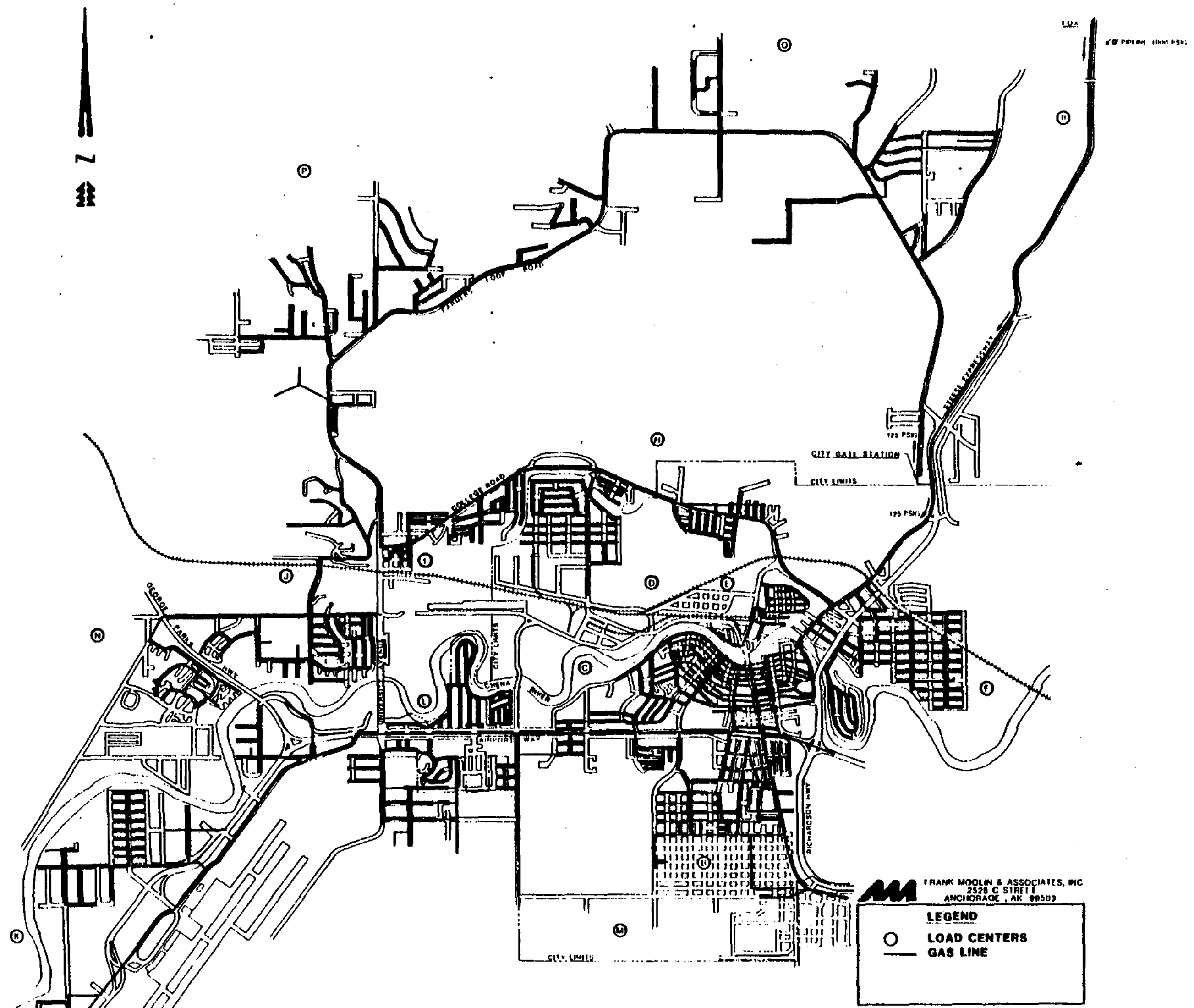
4.4.2.1 Gas Transmission Line

The gas transmission line will connect to the 22-inch pipeline near Fox (Figure 4-10). The line will be in public right-of-way, adjacent to the traveled roadway. The line will follow the Steese Highway to the intersection of Farmers Loop Road to the City Gate Station. This is approximately 12 miles of transmission line.

As load develops north of the Chena Hot Spring Road along the Steese Highway and McGrath Road, a secondary tap and gate station might be considered at the intersection of Chena Hot Spring Road and the Steese Highway for service to this northern load, and as a backfeed to the McGrath and Farmers Loop Road facilities.

The transmission line will operate at the main pipeline pressure of approximately 1,000 psig at the take-off point and have a design pressure of 1,260 psig. The gas flow will be metered at the take-off point.

The transmission line has been designed to provide peak hour coverage for commercial and residential customers in the year 2010. At this point, depending on actual growth and the location of additional supply sources, the transmission line may have to be supplemented. The 2010 peak hour projections were used to determine the range of transmission line sizes required.



NOTES.
1 HIGH PRESSURE DISTRIBUTION FROM CITY GATE STATION AT 125 PSIG
2 LOW PRESSURE DISTRIBUTION FROM LOAD CENTER AT 60 PSIG
3 LOAD CENTERS (A), (G), AND (I) FOR FUTURE USE

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

CITY OF FAIRBANKS GAS DISTRIBUTION

FIGURE 4-10

EBASCO SERVICES INCORPORATED

4.4.2.2 City Gate Station

The City Gate Station will be designed for an incoming gas pressure of 1,260 psig. The normal incoming operating pressure could drop as low as 250 psig during the medium forecast peak daily flowrates. The outlet pressure will be 125 psig. Gas heating equipment may be required to prevent the gas temperature from dropping below -20° F.

The vicinity of the intersection of Farmers Loop Road and the old Steese Highway appears to be a suitable location for the City Gate Station. No specific inquiries were made as to availability and cost of vacant land in the area. The station will be above ground and can be accommodated on an average city lot.

United States Geological Survey (USGS) maps indicate that this is a permafrost area. One test bore in the immediate area indicates that permafrost begins at a depth of 19 feet. Further analysis will have to be made to determine soil and foundation conditions before any land commitments are made.

Gas metering, conditioning, pressure reduction and flow control are the basic functions that will take place at the gate station. It is anticipated that the meter runs, control valves, odorization equipment and instrumentation devices will be indoors. A single story concrete block or insulated corrugated metal building approximately 20' x 50' would fulfill the requirement.

Gas purity is a major concern to distribution companies and specifications are incorporated into gas purchase contracts. The North Slope gas conditioning facility, however, will produce a pipeline gas that meets typical specifications for domestic and commercial natural gas. It is therefore assumed that the only gas processing required at the gate station will be particulate and liquids removal carried over from the North Slope to Fairbanks pipeline after primary processing has been accomplished.

Suspended solids and liquids will be removed prior to pressure reduction by means of a conventional scrubber, and liquid resulting from the condensation phenomena accompanying pressure reduction will be removed by liquid knockout drip pots.

A gas odorization system will be part of the gate station facilities. The system will be designed to maintain a relatively constant rate of odorization with varying gas volumes. A liquid injection system based upon gas volume measurement is anticipated. The odorization rate will be in the range of 0.25 to 1.00 pounds odorant per million cubic feet of gas.

Pressure reduction from 1,000 psig inlet pressure to 125 psig station outlet pressure will be accomplished at the gate station. Conventional pressure reducing valve(s) with pilots and bypasses will be used. The outlet of the gate station (inlet to high pressure system) will also be provided with overpressure protection. An atmospheric relief sized to relieve at the maximum allowable operating pressure plus 10 percent or series monitor regulation will be considered.

Metering and gas flow control will take place at parallel meter runs. Station flow will be remotely controlled by the gas dispatcher from the headquarters office. Remote control telemetering will allow the station to be normally unmanned.

4.4.2.3 High Pressure System

The high pressure system will operate at an inlet pressure of 125 psig from the City Gate Station. It is expected to traverse public rights-of-way adjacent to traveled roads as shown on the conceptual grid map (Figure 4-10). Laterals will branch off to load centers where pressure reduction and overpressure protection will be provided at district regulating stations. From these regulator stations, gas will be distributed to the individual 60 psig networks.

Individual high pressure mains are sized based upon peak hour load center estimates using the Spitzglass high pressure formula. The sizes and footages of the high pressure mains based upon the preliminary network analysis are listed below. The high pressure system will be standard wall API 5L GR.B steel pipe as required.

HIGH PRESSURE SYSTEM MAINS

Size	Length - Feet
8"	6,000
10"	15,000
12"	---
14"	27,375
18"	7,500

4.4.2.4 District Regulators

District regulator stations will be located at the inlet to 60 psig distribution networks as shown on Figure 4-10. These fifteen (15) stations will be designed to reduce the inlet pressure to 60 psig, and to provide overpressure protection for the distribution system. The method of overpressure protection (e.g., atmospheric relief, monitor regulators, etc.) will be determined during final design.

The type of construction and location of district regulator stations will also be determined during final design. The options of underground vault versus aboveground station construction must be reviewed with respect to considerations of the availability of public right-of-way, private easement, soil and groundwater characteristics, equipment operating capabilities and safety.

4.4.2.5 Distribution Systems

The distribution systems as shown on Figure 4-10 will deliver maximum 60 psig and minimum 15 psig gas to individual customer services. The lines will be polyethylene pipe, PE 3408 per ASTM D 2513. The pipe will be SDR 11 for Class 4 locations and SDR 13.5 for Class 3 locations. The smoother inside surface of plastic pipe allows the same sizes as steel pipe to handle the higher flowrates. Individual lines will be sized using the Spitzglass formula. In general, distribution lines will be 2" as standard. Larger size lines will be the exception. Distribution lines will be valved to comply with code requirements and good operating practices.

The distribution lines will be laid in public rights-of-way at a depth of three feet to the top of the main. The lines will be laid on the opposite side of the road from existing or proposed water mains. The estimated footages by size of distribution mains are tabulated below.

SCHEDULE OF DISTRIBUTION MAINS

Size	Length - Feet
2"	450,000
4"	78,000
6"	87,000
8"	2,250
12"	1,500

4.4.2.6 Residential Services

Services will be sized to deliver gas for maximum estimated demand of approximately 225 cubic feet per hour (CF/HR).

Residential temperature compensated meters sized for this demand load must also satisfy the following specifications:

Maximum pressure drop	- 0.5" Water Column (W.C.)
Gas temperature	- 30° F
Inlet pressure	- 7" W.C.
Ambient air temperature	- -70° F

Residential regulators sized to deliver the demand load at an inlet pressure range 15 to 60 psig and an outlet pressure of 6" to 7" W.C. will be specified for residential customers as standard.

Residential services will be standardized as welded and wrapped steel. The meter and regulator will, when desirable, be in the basement. The service will have a curb cock where the meter and regulator is indoors.

If a service meter/regulator set cannot be placed indoors, consideration will be given to enclosing them in a metal or wooden, insulated and heated enclosure. In this case, a curb cock may not be required. The service head will be designed to allow for flexibility of movement due to frost heave and settlement.

Services will be sized for a 1.5 to 3 psig maximum allowable pressure drop for inlet pressures of 15 psig minimum to 60 psig maximum.

Assuming an average service length of 100 feet (allowing for equivalent length for fittings), and a 15 psig inlet pressure and a maximum 1.5 psig pressure drop, a 1/2" steel service has the capacity of 395 CF/HR at a specific gravity of 0.65 and a temperature of 30° F. This is in excess of the 225 CF/HR estimated maximum residential demand, and the allowable pressure drop is not exceeded. Therefore, a system standard of 1/2" service size will be used for the average residential customer.

4.4.2.7 Commercial/Industrial Services

Commercial/industrial services will be designed and constructed following the same general procedures as for residential services. However, no attempt is made to standardize on size. Rather, each service will be sized to meet its special load requirements. In addition, it is highly possible that some commercial/industrial customers may be better served from a 125 psig main. In these cases, the requirement of dual regulation or other secondary overpressure protection will be provided in the service design.

4.4.2.8 Headquarters Building

The headquarters building will contain office space for the gas dispatch and operating personnel. It will also include telemetry for controlling gas flow at the City Gas Station. Building size will be approximately 25' x 50' single story, constructed of concrete block or insulated corrugated metal suitable for climatic conditions in Fairbanks, Alaska.

4.4.2.9 Cold Temperature Design and Environmental Factors

The Fairbanks gas distribution facilities will be designed to meet or exceed the most stringent applicable minimum construction and safety standards. However, there are technical considerations which are not now specifically covered by code which must be investigated in great detail and solutions developed prior to final site selection and completion of detailed design. In addition, there are environmental considerations which must be investigated and addressed more fully during the design phase of the project. Among these are:

1. Permafrost and Frost Heave
2. Field (hydrostatic) Testing
3. Cold Temperature Operation of System Components
4. River and Stream Crossings
5. Ice Fog

<u>Permafrost and Frost Heave</u>

United States Geological Survey data for the area of the gas distribution system has been reviewed. This review indicates that the distribution system will traverse three generalized units of subsurface conditions. These are the Tanana-Chena River Flood Plain, the Upland Hills, and the Creek Valley Bottom formations.

The Tanana-Chena River Flood Plain consists of alternating layers of alluvial silt, sand and gravel. The top silt layers ranges from 1 to 15 feet thick. Permafrost is discontinuous and randomly located and ranges in depth to the top from 2 to 4 feet in older parts of the flood plain, and to 25 to 40 feet in cleared areas. Where frozen, silt has a low to moderate ice content in the form of thin seams. The silt will develop some subsidence when thawed, and may undergo intense seasonal frost heave. The portion of the distribution system "in town" is generally in the flood plain formation.

Adjacent to the flood plain are gently rolling bedrock hills covered by from 3 to 200 feet of windblown silt (loess). The Upland Hills are generally free of permafrost although perennially frozen silt does occur along the base of most hills. Portions of the transmission lateral along the Steese Highway traverse this formation, as do portions of the distribution system along Farmers Loop Road.

The valley bottoms of the upland contain silt accumulations that are perennially frozen and have high ice content. The depth to permafrost is from 1-1/2 to 3 feet on lower slopes and valley bottoms, from 5 to 20 feet near contact with the unfrozen silt zone, and from 10 to 25 feet in cleared areas.

The seasonal frost layer is from 1-1/2 to 3 feet thick. Seasonal frost action is intense, and there is great subsidence when permafrost thaws. Sections of the transmission lateral along the Steese Highway as well as part of the distribution system along Farmers Loop Road cross this formation. In addition, the proposed location of the City Gate Station is within the limits of the Creek Valley Bottom formation.

The relation made between the distribution system and area geology above is based upon subsurface formation areas generally described on USGS Quadrangle Maps. Local variations may occur, particularly near the interface between formations. Therefore, a detailed analysis of soil conditions along the proposed right-of-way will be necessary to determine where and to what extent frost susceptible soil and/or permafrost exist.

Final facilities location and design must be based upon flowing gas temperatures within the system and subsurface soil survey and analysis. Systems operating temperatures, at one extreme, may cause thermal degradation of permafrost, and at the other extreme frost heave may be the problem. In either case, specialized design may be necessary to assure that the integrity of the system and/or the environment are not jeopardized.

Field (Hydrostatic) Testing

The detailed design phase of the project will result in final determination of the pipe specifications for the project. These will be based upon the balance of service performance expectations and the economics of purchase and installation. At that time, the final code and permit requirements with respect to testing will be more exactly known.

Hydrostatic testing will require that procedures and specifications address testing at ambient air temperatures below 32° F., and dewatering and "drying" of pipe lines after testing. In addition, cold temperature testing will require a review of brittle fracture mechanics for the specified pipe material.

As generally designed now, the 60 psig distribution system would be pneumatically tested to 100 psig. The 125 psig high pressure system would be hydrostatically tested to 175 psig. The transmission lateral would be tested hydrostatically to 1.4 times the maximum operating pressure.

System Component Operation

The effects of subarctic temperatures and the temperature of flowing gas will require particular attention and perhaps specialized design to assure long, trouble free operation of the system. Among the areas where special effort may be required are:

<u>Gas Meters</u>: Diaphragm materials with acceptable lower operating temperature limit to -70° F. must be provided. Potential condensate problems must be analyzed.

<u>Shut Off Valve</u>: Lubricant freeze up potentials must be investigated. Valve box and operating nut accessibility in frozen snow and ice must be reviewed.

Pipe Material: Effects of stress at cold temperature must be considered. Stresses resulting from cold temperature must be considered in design.

Regulators: Effects of cold temperature and condensate freeze up on diaphragm and valve discs must be studied.

River and Stream Crossings

The conceptual system layout indicates that there are nine river and creek pipeline crossings. They are:

Jessela Creek at Farmers Loop Road;
Isabella Creek at Farmers Loop Road;
Pearl Creek at Farmers Loop Road;
Chena River at N. Hall Street;
Noyes Slough at Illinois Street;
Noyes Slough at Alder Avenue;
Deadman Slough at Geist Road;
Deadman Slough at Loftus Road, and
Deadman Slough at Fairbanks Street.

It is anticipated that the major crossings can be made using existing bridges. These will require close interface with highway officials and engineers. Specialized design for support, thermal movement, installation procedures, and protective coating may be necessary.

Those crossings for which a bridge crossing is not possible will require that stream flows, bed movement and scour, and potential fishery impacts be analyzed, and that appropriate design and construction procedures be developed accordingly.

Ice Fog

Ice fog is a serious and complex problem which is still being studied. Many solutions have been suggested to reduce the occurrence of ice fog. The principal focus has been on reducing water vapor emissions from the generation of heat and power. It is understood that as the quantity of water vapor released to this atmosphere is reduced, the temperature at which ice fog forms will decrease away from zero, thus decreasing the frequency of occurrence. Any design of a gas distribution system in

Fairbanks must include appropriate measures to reduce water vapor released to the atmosphere.

4.5 COST ESTIMATES

4.5.1 Capital Costs

4.5.1.1 North Slope to Fairbanks Natural Gas Pipeline

Feasibility level investment cost estimates have been prepared for the systems and facilities which comprise the North Slope to Fairbanks natural gas pipeline. These estimates are presented in Table 4-14.

4.5.1.2 Power Plant

To support the derivation of total systems costs which are presented in Section 4.5.4, feasibility level investment costs were developed for the major bid lines items common to a 77 MW (ISO conditions) natural gas fired simple cycle combustion turbine and a 220 MW (ISO conditions) natural gas fired combined cycle plant. These costs are presented in Tables 4-15 and 4-16. The costs represent the total investment for the first unit to be developed at the site. Additional simple cycle units will have an estimated investment cost of $33,900,000 while additional combined cycle units will have an estimated investment cost of $127,430,000. The cost differential for additional units is due to significant reductions in line items 1 and 15, improvements to Site and Off-Site Facilities, and reductions in Indirect Construction Cost and Engineering and Construction Management.

4.5.1.3 Transmission Line Systems

Transmission line feasibility level investment cost estimates for the Fairbanks to Anchorage connection are presented in Table 4-17. These estimates are based on two new 345 kV lines, in parallel, 1400 MW capacity, with series compensation and an intermediate switching

TABLE 4-14

FEASIBILITY LEVEL INVESTMENT COSTS
NORTH SLOPE TO FAIRBANKS NATURAL GAS PIPELINE
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description 1/	Materials ($1000)	Construction Labor 2/ ($1000)	Total Direct Cost ($1000)
22 in O.D. Gas Pipeline	480,000	4,100,000	4,580,000
Compressor Stations - 10 ea	96,800	83,400	180,200
Metering Stations - 2 ea	2,800	6,000	8,800
Valve Stations - 28 ea	2,500	3,800	6,300
Engineering & Construction Management			286,500
SUBTOTAL	$582,100	$4,193,200	$5,061,800
Gas Conditioning Facility 3/			780,000
TOTAL CONSTRUCTION COST			$5,841,800

1/ A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes and land and land rights expenses have not been included.

2/ Construction camp facilities and services are subsummed in the Construction Labor cost category.

3/ Factored pricing basis which includes engineering and construction management costs.

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TABLE 4-15

FEASIBILITY LEVEL INVESTMENT COSTS
77 MW SIMPLE CYCLE COMBUSTION TURBINE
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Materials ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1. Improvements to Site	405	1,240	1,645
2. Earthwork and Piling	195	345	540
3. Circulating Water System	0	0	0
4. Concrete	475	2,145	2,620
5. Structural Steel Lifting Equipment, Stacks	1,725	1,370	3,095
6. Buildings	750	1,440	2,190
7. Turbine Generator	11,100	650	11,750
8. Steam Generator and Accessories	0	0	0
9. Other Mechanical Equipment	460	235	695
10. Piping	205	510	715
11. Insulation and Lagging	30	110	140
12. Instrumentation	100	70	170
13. Electrical Equipment	1,510	2,590	4,100
14. Painting	70	250	320
15. Off-Site Facilities	300	1,080	1,380
SUBTOTAL	$17,325	$12,035	$29,360
Freight Increment			865
TOTAL DIRECT CONSTRUCTION COST			$30,225
Indirect Construction Costs			1,665
SUBTOTAL FOR CONTINGENCIES			31,890
Contingencies (15%)			4,790
TOTAL SPECIFIC CONSTRUCTION COST			36,680
Engineering and Construction Management			2,200
TOTAL CONSTRUCTION COST			$38,880

1/ The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

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TABLE 4-16

FEASIBILITY LEVEL INVESTMENT COSTS
220 MW COMBINED CYCLE PLANT
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1. Improvements to Site	425	1,295	1,720
2. Earthwork and Piling	570	1,050	1,620
3. Circulating Water System	0	0	0
4. Concrete	1,485	6,730	8,215
5. Structural Steel Lifting Equipment, Stacks	3,800	3,530	7,330
6. Buildings	1,800	3,600	5,400
7. Turbine Generator	30,100	2,520	32,620
8. Steam Generator and Accessories	9,600	4,320	13,920
9. Other Mechanical Equipment	6,735	3,425	10,160
10. Piping	1,500	2,910	4,410
11. Insulation and Lagging	290	690	980
12. Instrumentation	1,700	290	1,990
13. Electrical Equipment	4,550	8,640	13,190
14. Painting	200	720	920
15. Off-Site Facilities	300	1,080	1,380
SUBTOTAL	$63,055	$40,800	$103,855
Freight Increment			3,155
TOTAL DIRECT CONSTRUCTION COST			$107,010
Indirect Construction Costs			4,235
SUBTOTAL FOR CONTINGENCIES			111,245
Contingencies (15%)			16,685
TOTAL SPECIFIC CONSTRUCTION COST			127,930
Engineering and Construction Management			6,800
TOTAL CONSTRUCTION COST			$134,730

1/ The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

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TABLE 4-17

FEASIBILITY LEVEL INVESTMENT COSTS
FAIRBANKS TO ANCHORAGE TRANSMISSION SYSTEM
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description1/	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	14,112	12,445	26,557
Substations	62,308	41,716	104,024
Energy Management Systems	12,300	10,960	23,260
Steel Towers and Fixtures	216,495	305,085	521,580
Conductors and Devices	33,678	78,361	112,039
Clearing	---	83,144	83,144
SUBTOTAL	$388,893	$531,711	$870,604
Land and Land Rights2/			27,600
Engineering and Construction Management			60,950
TOTAL CONSTRUCTION COST			$959,154

1/ The investment costs reflect two new 345 kV lines, 1400 MW capacity, with series compensation and an intermediate switching station and upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid to 345 kV.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

station. The investment cost estimates also reflect upgrading from 138 kV to 345 kV of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid.

4.5.1.4 Gas Distribution System

Feasibility level investment cost estimates (January, 1982 dollars) have been prepared for the systems and facilities which comprise the Fairbanks gas distribution system. The results of the analyses are given below. A 15 percent contingency has been assumed for the entire project and has been distributed between each cost category. Sales/use taxes and land rights have not been included.

	Materials ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Gas Distribution System	$11,500	$48,200	$59,700
Engineering and Construction Management			3,582
TOTAL CONSTRUCTION COST			$63,282

4.5.2 Operation and Maintenance Costs

4.5.2.1 Gas Pipeline and Conditioning Facility

Annual operation and maintenance costs (January, 1982 dollars) for the gas conditioning facilities are estimated to be as follows:

ITEM	ANNUAL COSTS ($1000)
Salaries	$2,480
Maintenance Costs (Parts and Expendables)	3,750
TOTAL	$6,230

Annual operation and maintenance costs (January, 1982 dollars) for the gas compressor stations and pipeline maintenance activities are estimated to be as follows:

ITEM		ANNUAL COSTS ($1000)
Salaries		$ 4,400
Maintenance Costs (Parts, Expendables, Other)		5,850
	Total	$10,250

4.5.2.2 Power Plant

operation and maintenance costs for the combined cycle facility at Fairbanks are estimated to be $0.0040/ kWh. These are based on discussions with operating plant personnel, history of similar units, Electric Power Research Institute data, published data and other studies performed.

4.5.2.3 Transmission Line Systems

Annual operation and maintenance costs (January 1982 dollars) have been developed for the scenario's required transmission line facilities and total $12 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially, and will increase with time.

4.5.2.4 Gas Distribution System

Annual operation and maintenance costs (January 1982 dollars) for the Fairbanks gas distribution system are estimated to be as follows:

ITEM		ANNUAL COSTS ($1000)
Salaries		$1,290
Maintenance Costs (Parts, Consumables, Other)		500
	Total	$1,790

4.5.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

4.5.4 Total Systems Costs

4.5.4.1 Cost Allocation Methodology

For purposes of total system cost comparisons, natural gas pipeline and conditioning plant costs from the North Slope to Fairbanks must be allocated between electricity generation applications and residential/commercial customer applications. In this way the non-electric system costs can be removed from the total cost comparison associated with electricity supply. Two types of costs must be allocated: (1) capital investment costs; and (2) annual costs, including operation and maintenance (O&M) costs and fuel costs (e.g., for pipeline compressor stations).

Capital cost allocation is based upon the peak demand for natural gas, and consequently the capacity requirements of the line. In this allocation it is useful to make the conservative assumption that both peak loads may occur simultaneously. Given that assumption, the following formulas can be used to allocate capital costs:

$$P_E/(P_E + P_R) = O_I \qquad (1)$$
$$O_I\ (I_{GC} + I_p) = ESCC \qquad (2)$$

Where

- P_E = peak natural gas demand for electricity generation
- P_R = peak natural gas demand for residential and commercial uses
- O_I = the proportion of investment costs charged to electricity generation
- I_{GC} = capital investment in the conditioning plant
- I_p = capital investment in the pipeline
- ESCC = electric service related capital charges

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The second formula arrives at the specific dollar value for allocation purposes. It can be applied either to I_{GC} or I_p separately when capital costs must be disaggregated by component, or as shown for the total capital burden. Neither formula is applied to investments that are specific to one user community (e.g. the residential gas distribution system), as those investment costs must be borne totally by the appropriate users.

Annual costs are allocated on an energy basis rather than on a capacity basis. Those costs are allocated by the following formula:

$$SC_A = SC_{O\&M} + SC_F \qquad (3)$$

$$EC_E/(EC_E + EC_R) = O_A \qquad (4)$$

$$O_A \times SC_A = ESAC \qquad (5)$$

Where:

SC_A	=	total shared annual charges
$SC_{O\&M}$	=	shared O&M costs
SC_F	=	shared fuel costs
EC_E	=	annual natural gas consumption for electricity generation
EC_R	=	annual natural gas consumption by residential and commercial users
O_A	=	the proportion of annual costs charged to electricity generation
ESAC	=	electrical service related annual costs

Again, disaggregation may be accomplished for O&M or fuel costs; and this is accomplished by multiplying the O_A term by either $SC_{O\&M}$ or SC_F. Again, only shared costs are considered, and user community-specific costs are not considered.

Given these formulae, costs may be disaggregated. Costs may be allocated to residential and commercial users by substituting $(1-O_I)$ for O_I and $(1-O_A)$ for O_A. Precise comparison of the electrical generation options can now be accomplished.

4.5.4.2 Power Generation System Costs

The Fairbanks medium load growth scenario is far more complex than the Prudhoe Bay medium load growth scenario in that it includes: (1) a gas conditioning facility, (2) a natural gas pipeline, (3) power generation facilities, and (4) transmission line facilities.

Further, the conditioning plant and pipeline facilities serve both electricity and residential/commercial markets. As a consequence, the capital, operating and maintenance, and fuel costs associated with the conditioning facility and pipeline must be apportioned to the respective user communities.

The method for apportionment has been previously described (see Section 4.5.4.1). On this basis 0_I and 0_A values are calculated (0 refers to the fraction of costs apportioned to the electricity segment of the natural gas market). 0_I, the capital cost apportionment term, is calculated as follows for the medium load forecast:

Residential/Commercial Peak Daily Flow (2010)	=	63 MMSCFD
Electricity Generation Peak Daily Flow (2010)	=	271 MMSCFD
Total Peak Daily Flow	=	334 MMSCFD
0_I	=	0.82

0_A, the annual costs apportionment term, varies over time for the medium load forecast. Values for 0_A are presented in Table 4-18.

Given the apportionment terms, the annual systems costs for the electricity generation system can be presented. The annual capital expenditures are shown in Table 4-19. The annual non-fuel O&M costs are shown in Table 4-20. The summary of total systems costs is presented in Table 4-21. The period of the analysis was assumed to be 1982 through 2010.

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TABLE 4-18

O_A VALUES[1/]

FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Calendar Year	Residential Demand (BCFY)	Electrical Demand (BCFY)	Total Demand (BCFY)	O_A
1982	0.	0.	0.	NA[2/]
1983	0.	0.	0.	NA
1984	0.	0.	0.	NA
1985	0.	0.	0.	NA
1986	0.	0.	0.	NA
1987	0.	0.	0.	NA
1988	0.	0.	0.	NA
1989	0.	0.	0.	NA
1990	0.	0.	0.	NA
1991	0.	0.	0.	NA
1992	0.	0.	0.	NA
1993	1.219	6.266	7.485	0.84
1994	2.494	6.266	8.760	0.72
1995	3.827	12.532	16.359	0.77
1996	5.220	12.633	17.853	0.71
1997	6.676	25.133	31.809	0.79
1998	6.829	25.203	32.032	0.79
1999	6.986	25.203	32.189	0.78
2000	7.147	31.551	38.698	0.82
2001	7.311	31.467	38.778	0.81
2002	7.479	37.804	45.283	0.83
2003	7.651	37.804	45.455	0.83
2004	7.827	44.188	52.015	0.85
2005	8.008	45.809	53.817	0.85
2006	8.192	49.535	57.727	0.86
2007	8.380	53.146	61.526	0.86
2008	8.573	52.292	60.865	0.86
2009	8.770	55.893	64.663	0.86
2010	8.971	59.425	68.396	0.87

1/ Values as calculated are shown for purposes of reproducibility only, and do not imply accuracy beyond 100 MMSCFD.

2/ NA - Not applicable

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TABLE 4-19

TOTAL ANNUAL CAPITAL EXPENDITURES
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated[1] Unit A	Unit B	Transmission Line	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.	0.	0.
1983	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.
1988	0.	0.	514.2	0.	0.	514.2
1989	0.	0.	118.1	1,383.6	0.	1,501.7
1990	0.	0.	232.4	1,383.6	319.8	1,935.8
1991	9.91[2]	0.	94.5	1,383.6	319.8	1,807.8
1992	33.90	0.	0.	0.	0.	33.9
1993	0.	0.	0.	0.	0.	0.
1994	33.90	0.	0.	0.	0.	33.9
1995	56.97	0.	0.	0.	0.	57.0
1996	33.90	33.90	0.	0.	0.	67.8
1997	56.97	0.	0.	0.	0.	57.0
1998	0.	0.	0.	0.	0.	0.
1999	33.90	0.	0.	0.	0.	33.9
2000	0.	0.	0.	0.	0.	0.
2001	33.90	56.97	0.	0.	0.	90.0
2002	0.	0.	0.	0.	0.	0.
2003	33.90	0.	0.	0.	0.	33.9
2004	33.90	56.97	0.	0.	0.	90.9
2005	33.90	0.	0.	0.	0.	33.9
2006	33.90	0.	0.	0.	0.	33.9
2007	56.97	0.	0.	0.	0.	57.0
2008	33.90	0.	0.	0.	0.	33.9
2009	33.90	0.	0.	0.	0.	33.9
2010	0.	0.	0.	0.	0.	0.
Total	$554.	$148.	$959.	$4,151.	$640.	$6,451.

1/ Unit B denotes a second unit erected in any give year.

2/ Includes all site preparation activities for multiple unit site.

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TABLE 4-20

TOTAL ANNUAL NON-FUEL OPERATING AND MAINTENANCE COSTS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated	Transmission Line	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.	0.
1983	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	0.
1989	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	0.
1991	0.	0.	0.	0.	0.
1992	0.	0.	0.	0.	0.
1993	2.260	12.0	8.61	5.23	28.1
1994	2.260	12.0	7.38	4.49	26.1
1995	4.520	12.0	7.89	4.80	29.2
1996	6.376	12.0	7.28	4.42	30.1
1997	10.880	12.0	8.10	4.92	35.9
1998	12.720	12.0	8.10	4.92	37.7
1999	12.720	12.0	8.00	4.86	37.6
2000	15.020	12.0	8.41	5.11	40.5
2001	14.980	12.0	8.30	5.05	40.3
2002	19.080	12.0	8.51	5.17	44.8
2003	19.080	12.0	8.51	5.17	44.8
2004	21.396	12.0	8.71	5.30	47.4
2005	23.120	12.0	8.71	5.30	49.1
2006	24.212	12.0	8.82	5.36	50.4
2007	25.300	12.0	8.82	5.36	51.5
2008	26.392	12.0	8.82	5.36	52.6
2009	27.480	12.0	8.82	5.36	53.7
2010	28.572	12.0	8.92	5.42	54.9
Total	$296.	$216.	$151.	$92.	$755.

TABLE 4-21

TOTAL ANNUAL COSTS
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	514.2	0.	514.2
1989	1,501.7	0.	1,501.7
1990	1,935.8	0.	1,935.8
1991	1,807.8	0.	1,807.8
1992	33.9	0.	33.90
1993	0.	28.1	28.14
1994	33.9	26.1	60.04
1995	57.0	29.2	86.29
1996	67.8	30.1	97.94
1997	57.0	35.9	92.94
1998	0.	37.7	37.77
1999	33.9	37.6	71.57
2000	0.	40.5	40.54
2001	90.9	40.3	131.24
2002	0.	44.8	44.81
2003	33.9	44.8	78.72
2004	90.9	47.4	138.30
2005	33.9	49.1	83.03
2006	33.9	50.4	84.39
2007	57.0	51.5	85.43
2008	33.9	52.6	86.54
2009	33.9	53.7	87.63
2010	0.	54.9	54.90
Total	$6,451.	$755.	$7,206.
Present Worth @ 3%	$4,965.	$415.	$5,380.

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For comparison purposes, the 1982 present worth of power generating costs has been calculated, assuming a real discount rate of 3 percent and excluding fuel costs. The present worth of costs, expressed in 1982 dollars, is $5.4 billion.

4.5.4.3 Gas Distribution System Costs

The costs attributable to the gas distribution system are those costs not associated with electricity generation. The capital costs include a portion of the gas conditioning plant, a portion of the pipeline, and the Fairbanks residential/commercial gas distribution itself. Operation and maintenance costs, and internal fuel requirements, must be treated in a like manner.

In Section 4.5.4.2 the values for 0_I and 0_A were presented. Allocation of costs to the gas distribution system require the presentation of $(1-0)_I$ and $(1-0)_A$ values; and these are presented in Table 4-22. These are required because, by definition, 1-0 defines the portion of costs associated with joint investments attributed to non-electric purposes.

Given such values, the annualized expenditures associated with the natural gas distribution system can be calculated. These are summarized in Tables 4-23 through 4-25. The present worth of all costs associated with the distribution system, as of 1982, is $0.9 billion (January, 1982 dollars), excluding fuel costs. The period of the analysis was assumed to be 1982 through 2010.

4.6 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

Environmental effects associated with the Fairbanks power generation scenario will be similar in many respects to those of the North Slope scenario. Because the pipeline from the North Slope to Fairbanks will be buried and chilled, it will result in different environmental effects and will require different types of mitigation than would a

TABLE 4-22

APPORTIONMENT VALUES FOR THE GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Term	Year	Value
$(1-0)_I$	NA[1/]	0.18
$(1-0)_A$	1982-1992	NA
	1993	0.16
	1994	0.28
	1995	0.23
	1996	0.29
	1997	0.21
	1998	0.21
	1999	0.22
	2000	0.18
	2001	0.19
	2002	0.17
	2003	0.17
	2004	0.15
	2005	0.15
	2006	0.14
	2007	0.14
	2008	0.14
	2009	0.14
	2010	0.13

1/ NA - Not applicable

TABLE 4-23

TOTAL ANNUAL CAPITAL EXPENDITURES FOR THE GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Gas Distribution System	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	12.66	303.7	0.	316.4
1990	12.66	303.7	70.2	386.6
1991	12.66	303.7	70.2	386.6
1992	12.66	0.	0.	12.7
1993	12.66	0.	0.	12.7
1994	0.	0.	0.	0.
1995	0.	0.	0.	0.
1996	0.	0.	0.	0.
1997	0.	0.	0.	0.
1998	0.	0.	0.	0.
1999	0.	0.	0.	0.
2000	0.	0.	0.	0.
2001	0.	0.	0.	0.
2002	0.	0.	0.	0.
2003	0.	0.	0.	0.
2004	0.	0.	0.	0.
2005	0.	0.	0.	0.
2006	0.	0.	0.	0.
2007	0.	0.	0.	0.
2008	0.	0.	0.	0.
2009	0.	0.	0.	0.
2010	0.	0.	0.	0.
Total	$63.	$911.	$140.	$1,115.

TABLE 4-24

TOTAL ANNUAL NON-FUEL OPERATING AND MAINTENANCE COSTS
FOR THE GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Gas Distribution System	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	0.	0.	0.	0.
1990	0.	0.	0.	0.
1991	0.	0.	0.	0.
1992	0.	0.	0.	0.
1993	1.8	1.7	1.0	4.5
1994	1.8	3.0	1.7	6.5
1995	1.8	2.4	1.4	5.6
1996	1.8	3.0	1.8	6.6
1997	1.8	2.2	1.3	5.3
1998	1.8	2.2	1.3	5.3
1999	1.8	2.3	1.4	5.5
2000	1.8	1.8	1.1	4.7
2001	1.8	1.9	1.2	4.9
2002	1.8	1.7	1.1	4.6
2003	1.8	1.7	1.1	4.6
2004	1.8	1.5	0.9	4.2
2005	1.8	1.5	0.9	4.2
2006	1.8	1.4	0.9	4.2
2007	1.8	1.4	0.9	4.2
2008	1.8	1.4	0.9	4.2
2009	1.8	1.4	0.9	4.2
2010	1.8	1.3	0.8	3.9
Total	$32.	$34.	$20.	$86.

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TABLE 4-25

ANNUAL SYSTEMS COST SUMMARY, GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O&M Costs	Total Expenditures
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	316.4	0.	316.4
1990	386.6	0.	386.6
1991	386.6	0.	386.6
1992	12.7	0.	12.7
1993	12.7	4.5	17.2
1994	0.	6.5	6.5
1995	0.	5.6	5.6
1996	0.	6.6	6.6
1997	0.	5.3	5.3
1998	0.	5.3	5.3
1999	0.	5.5	5.5
2000	0.	4.7	4.7
2001	0.	4.9	4.9
2002	0.	4.6	4.6
2003	0.	4.6	4.6
2004	0.	4.2	4.2
2005	0.	4.2	4.2
2006	0.	4.2	4.2
2007	0.	4.2	4.2
2008	0.	4.2	4.2
2009	0.	4.2	4.2
2010	0.	3.9	3.9
Total	$1,115.	$86.	$1,201.
Present Worth @ 3%	$877.	$51.	$928.

transmission line through the same area. As in the North Slope scenario, power plant emissions will be a significant consideration because of existing air quality problems in the Fairbanks area. Environmental impacts caused by the transmission line from Fairbanks to Anchorage will be identical to those discussed for the North Slope scenario, Sections 2.5 and 3.5, and are not repeated here. Power plant characteristics related to environmental effects are summarized in Table 4-26.

4.6.1 Air Resource Effects

Meteorological conditions in the Fairbanks area play a very important role in determining the ambient air quality levels in the area. Analyses of the Fairbanks urban "heat island" have shown that winds are generally light in the winter and that wind directions change dramatically in the vertical direction during the wintertime. During the winter months, the air near the ground is relatively cold, compared to the air aloft. This reduces mixing of the air in the vertical direction, and when combined with relatively light winds, often leads to periods of air stagnation.

In large part due to the winter stagnation conditions, the Fairbanks area is currently designated as a non-attainment area for carbon monoxide (CO). Emissions of CO are largely due to automobiles. The State Department of Environmental Conservation and the Fairbanks North Star Borough Air Pollution Control Agency are implementing a plan to reduce the ambient CO mainly through the use of vehicle emission or traffic control techniques. In addition, relatively high levels of nitrogen oxides have recently been monitored in the Fairbanks area. Only an annual average nitrogen dioxide standard exists, but the short term measurements of nitrogen oxides are as high as in major urban areas such as Los Angeles.

The installation and permitting of a major fuel-burning facility, such as a power plant, will require a careful analysis of the impact of its

TABLE 4-26

ENVIRONMENT RELATED POWER PLANT CHARACTERISTICS
COMBINED CYCLE POWER PLANT
FAIRBANKS POWER GENERATION - MEDIUM LOAD FORECAST

Air Environment	
Emissions	
Particulate Matter	Below Standards
Sulfur Dioxide	Below Standards
Nitrogen Oxides	Emissions variable within standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	Maximum structure height of 50 feet
Water Environment	
Plant Water Requirements	200 GPM
Plant Discharge Quantity including treated sanitary waste, floor drains, boiler blowdown and demineralizer wastes	Less than 200 GPM
Land Environment	
Land Requirements	
Plant	140 acres
Socioeconomic Environment	
Construction Workforce	Approximately 200 personnel at peak construction
Operating Workforce	Approximately 150 employed personnel

emissions on ambient air quality. Because Fairbanks is a non-attainment area, the operators of such a facility must demonstrate that they will reduce, or offset, impacts of the power plant by reducing emission levels of CO at other sources. Emissions of CO from a natural gas fired power plant are relatively low, and any displacement of the burning of other fuels, such as coal or oil, will likely lead to improved air quality. This arises from the clean burning nature of natural gas and from the fact that emissions from a major facility will be injected higher in the atmosphere (due to plume buoyancy) than the displaced emissions. During the very stagnant conditions in midwinter, the plume from a power plant will likely remain well aloft with little mixing to the surface layers. The complex urban heat island and associated wind pattern will require a great deal of in-depth modeling and analysis to determine air quality impacts in terms that will withstand regulatory scrutiny.

A large combustion turbine power plant must meet the existing New Source Performance Standards and Best Available Control Technology. The nitrogen oxides limits will be the most constraining atmospheric pollutant. The operation of the power plant will also consume a portion of the allowable deterioration in air quality for nitrogen oxides. While it is possible that the power plant could be sited near Fairbanks, its installation would constrain other development efforts which also might consume a portion of the air quality increment. The nature, magnitude, and duration of emission plumes must be studied as well as the potential for beneficial impacts due to reduced combustion at other sources within the area.

The Fairbanks area is also subjected to extended periods of wintertime ice fog, and the Alaska Department of Environmental Conservation will require the impact of any water vapor plumes to be carefully assessed. A combustion turbine power plant which uses water or steam injection techniques would have an adverse impact on the ice fog and icing deposition nearby. For the purposes of this study, it is assumed that Best Available Control Technology would be defined to not include water or steam injection.

Construction of the gas pipeline from the North Slope to Fairbanks will result in fugitive dust and exhaust emissions from construction vehicles. These air quality impacts will be temporary and located in very sparsely populated areas, and will therefore be insignificant.

Ten compressor stations will be located along the pipeline route, each producing relatively low levels of emissions. The impacts of these facilities will most likely not cause exceedances of the Alaska Ambient Air Quality Standards and will not be required to meet the Prevention of Significant Deterioration Increments. The emissions will not impact any air quality sensitive areas.

4.6.2 Water Resource Effects

The gas fired combined cycle power plant described in Section 4.2 will use approximately 200 gpm of fresh water for boiler make-up, potable supplies, and miscellaneous uses such as equipment wash-down. Because ample groundwater exists in the Fairbanks area and because the water requirements are not particularly large, impacts on water supplies in the area will not be significant.

Power plant wastes will consist of wash-down water (for cleaning of equipment), sanitary wastes, boiler blowdown, and demineralizer regenerant wastes. The wash-down water will be treated for oil and suspended solids removal. Sanitary wastes will be passed through a sanitary wastewater treatment facility, and demineralizer wastes will be treated for pH control. No treatment should be required for boiler blowdown. The resultant wastewater stream, up to 200 gpm, will meet all applicable effluent guidelines and will be discharged to a local water body with sufficient assimilating capacity.

The gas pipeline from the North Slope to Fairbanks will cross 15 major streams and rivers, including the Yukon River, and could potentially impact numerous additional small streams and drainages. The pipeline will be buried for its entire length; vegetation will be disturbed within a 50 ft wide strip. Without careful siting and construction practices, erosion from exposed areas could cause sedimentation problems in nearby water bodies.

To control soil loss and subsequent sedimentation effects, several mitigation practices should be used during pipeline construction. Existing work pads, highways, access roads, airports, material sites, and disposal sites should be used whenever possible to minimize vegetation disturbance. Pipeline rights-of-way and access roads should avoid steep slopes and unstable soils. Hand clearing could be used in areas where the use of heavy equipment would cause unacceptable levels of soil erosion. A 50-foot buffer strip of undisturbed land could be maintained between the pipeline and streams, lakes, and wetlands wherever possible. Construction equipment should not be operated in water bodies except where necessary. Where high levels of sediment are expected from construction activity, settling basins should be constructed and maintained. All disturbed areas should be left in a stabilized condition through the use of revegetation and water bars; culverts and bridges should be removed, and slopes should be restored to approximately their original contour.

A significant problem with the operation of a chilled, buried pipeline is the formation of aufeis. Aufeis is an ice structure formed by water overflowing onto a surface and freezing, with subsequent layers formed by repeated overflow. Chilled pipe in streams can cause the stream to freeze to the bottom in the vicinity of the pipe, creating aufeis over the blockage. A chilled pipe through unfrozen ground can also form a frost bulb several times larger than the pipe diameter. This frozen area can block subsurface flow, forcing water to the surface and causing aufeis. Road cuts can also expose subsurface flow channels, causing aufeis build-up over the roadway. The potential for aufeis and possible effects will require detailed considerations for all construction areas.

All stream crossing facilities should be designed to withstand the Pipeline Design Flood as defined for the ANGTS system. Streams should be stabilized and returned to their original configuration, gradient, substrate, velocity, and surface flow. Water supplies for compressor or meter stations should not be taken from fish spawning beds, fish rearing areas, overwintering areas or waters that directly replenish those areas during critical periods.

The Yukon River crossing will utilize an existing bridge. The Yukon River will therefore not be significantly affected by the pipeline.

4.6.3 Aquatic Ecosystem Effects

The Fairbanks power plant will not cause significant impacts to the aquatic resources. The water supply for the power plant will be obtained from groundwater, and therefore will not affect surface waterbodies. Discharges from the plant will be treated to meet effluent guidelines before being released, so that fish habitat should not be significantly affected. Discharge quantities will be relatively low, less than 200 gpm.

The pipeline from the North Slope to Fairbanks will cross numerous rivers and creeks, including the Yukon River. Aquatic resource impacts will include all those discussed for the North Slope scenario (Section 2.5.3), and additional impacts caused by the chilled pipeline crossing waterbodies. Several mitigation measures, in addition to those already discussed, should be implemented to protect the fish habitat affected by pipeline construction and operation. Stream crossings should be constructed such that fish passage is not blocked and flow velocity does not exceed the maximum allowable flow velocity for the fish species in a given stream. If these criteria cannot be met, a bridge should be installed.

Chilled pipes in streams should not cause: a) lower stream temperatures so as to alter biological regime of stream; b) slow spring breakup and delay of fish migration; or c) early fall freeze-up which would affect fish migration. In addition, the temperature of surface or subsurface water should not be changed significantly by the pipeline system or by any construction-related activities.

All mitigation measures designed to reduce sedimentation of water bodies (discussed in the Section 4.6.2) will protect fish spawning, rearing and overwintering areas.

For the purpose of making recommendations regarding timing of ANGTS construction activities, the pipeline corridor was divided into three large geographical regions: Region I, Beaufort Sea to the Continental Divide of the Brooks Range; Region II, Continental Divide of the Brooks Range to the Yukon River; and Region III, Yukon River to Fairbanks. In association with the ANGTS development, the following broad temporal guidelines were developed for recommendation for each gasline corridor region based on fish use habitat (Schmidt et al 1981). These would also be applicable to a smaller diameter pipeline.

Region I Region II Region III	1 May-20 July 15 April-15 July 1 April-15 July (early breakup streams) 15 April-15 July (late breakup streams)	A critical period for most streams due to the occurrence of major spring migrations and spring spawning (primarily grayling).
Region I Region II Region III	20 July-25 August 15 July-25 August 15 July-1 September	A sensitive period. Fry of spring spawning species have emerged and major fall emigrations have not yet begun. Fish are mobile at this time and can move to avoid or reduce effects of disturbance.
Region I Region II Region III	25 August-1 October (small streams) 25 August-15 October (large streams) 25 August-1 October (small streams) 25 August-15 October (large streams) 1 September-1 November	A critical period for all streams. Fish must emigrate from streams that do not provide winter habitat prior to freeze-up. Major upstream migrations and spawning of fall spawning species occurs in streams that provide over-wintering habitat.

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Region I	1 October-1 May (small streams) 15 October-1 May (large streams)	A preferred period for construction in many streams that do not provide winter habitat. These streams generally are dry or freeze to the bottom during winter. This is a critical period for fish overwintering in springs, large rivers, and lakes.
Region II	15 October-15 April (small streams) 1 November-15 April (large streams)	
Region III	1 November-1 April (early breakup streams) 1 November-15 April (late breakup streams)	

4.6.4 Terrestrial Ecosystem Effects

The Fairbanks power plant will affect terrestrial resources primarily through habitat disturbance. As discussed in the Report on Facility Siting and Corridor Selection (Appendix C), potential power plant sites in the Fairbanks area are located in developed or previously disturbed areas. The potential for adversely affecting terrestrial habitats is therefore not considered to be significant.

Construction of the gas pipeline from the North Slope to Fairbanks will require total clearing of a 50-foot right-of-way for the length of the gasline. In addition, ten 10-acre compressor stations, two 1.5 acre metering stations and a gas conditioning facility (15 acres) will be constructed. Construction activities will disrupt terrestrial animals near the corridor during the 3-year construction period. The pipeline alignment will avoid the peregrine falcon nest sites near the Franklin and Sagwon Bluffs, but other raptors may restrict construction schedules (refer to Appendix C). Special construction measures may be necessary in the areas delineated by the BLM land use plan, as discussed for the North Slope scenario. Construction activities, especially aircraft traffic, could disturb Dall sheep habitat in critical wintering, lambing and movement areas. These construction-related impacts would be less than 3 years in duration.

Long term terrestrial impacts will result primarily from habitat elimination. Important moose browsing habitat, such as the willow stand along Oksrukuyik Creek, should be preserved. The treeline white spruce stand at the head of Dietrich Valley, which has been nominated for Ecology Reserve status, should be avoided. The pipeline design should allow for free passage of caribou and other large animals.

4.6.5 Socioeconomic and Land Use Effects

The potential socioeconomic and land use effects of locating an electrical generating facility in the vicinity of Fairbanks includes the temporary impacts related to the influx of workers and permanent land use impacts.

The size of the construction work force for the generating facility is expected to be approximately 200 persons. These generation units will be constructed during the summer for about 4-5 months.

Since the project could draw on the large labor pool of Fairbanks, it can be expected that the majority of workers will be hired locally. Economic benefits to the region will not be significant as employment on the project will be temporary. Any in-migrating work force will have to seek temporary housing on their own since housing will not be provided at the project site. The extent of the impacts on the local housing supply will depend on the vacancy rate for the summer of each year of construction.

As discussed in the Report on Facility Siting and Corridor Selection (Appendix C), development of a generating facility on the outskirts of the Fairbanks area should not engender significant land use conflicts, since the focus of the final site selection activities will be on areas which are presently used for industrial development. However, the long-term staged development of a major electric generating complex will certainly be a determinant of future land uses in the local area.

Construction activities at the generating plant site will generate additional worker and construction vehicle traffic loads on the local road system. However, disruptions to existing traffic patterns can be minimized through site selection by utilizing major highways and arterials to the maximum extent possible and by developing a local access plan and schedule. Depending on the site selected, new access requirements will be planned in recognition of local traffic requirements.

For construction of the gas pipeline in the North Slope-Fairbanks corridor, employees will be housed either at the pump stations or the permanent camp facilities that were constructed for the trans-Alaska oil pipeline. Construction activities will be consistent with the BLM land use criteria as discussed in Section 2.5.5.

The potential socioeconomic and land use impacts of the transmission facilities between Fairbanks and Anchorage included in this scenario are identical to those discussed in Section 2.5.5 for the North Slope scenario, with the addition of transmission facilities from the Fairbanks generating site to the power grid. Again, assuming the site is located on the outskirts of Fairbanks to the southeast, transmission interconnections can probably expand on existing GVEA rights-of-way with minimal additional impacts to existing land uses. However, future land use patterns will be signficantly affected by the presence of the three parallel 345 kV transmission lines.

SCENARIO II
FAIRBANKS POWER GENERATION
LOW LOAD

5.0 FAIRBANKS POWER GENERATION

LOW LOAD FORECAST

The Fairbanks generation scenario, under the low load forecast, requires all of the major systems of the medium growth forecast except that fewer compression stations are required to transport the gas and fewer units are required to generate electricity. The Fairbanks area electrical generating station will require 3 combined cycle plants, each consisting of two gas fired combustion turbines paired with two waste heat recovery boilers, and a steam turbine generator for a station capacity of 726 MW in 2010. Units will be phased-in by bringing each combustion turbine on-line individually, followed by the waste heat recovery boilers and steam turbine generator. Between Fairbanks and Anchorage, one new 345 kV transmission line and upgrading of the Healy-Fairbanks and Willow-Anchorage segments of the existing line will be required. The Fairbanks residential/commercial, gas system peak demand at 100 percent penetration of potential market is 49 MMSCFD.

Construction of the gas conditioning facilities, gas pipeline, power generating facilities and transmission systems, is estimated to cost $4.9 billion. Total annual operation and maintenance costs are estimated to be $0.4 billion. The present worth of costs excluding fuel costs is $3.6 billion. Construction costs of the Fairbanks gas distribution system serving residential/commercial markers total $1.6 billion, with total annual operation and maintenance costs totalling $41 million. The present worth of costs for this system, consisting of a portion of the pipeline and gas conditioning facilities, plus the distribution network itself, is $1.1 billion.

5.1 NORTH SLOPE TO FAIRBANKS NATURAL GAS PIPELINE

As explained in Section 4.1, pipeline design proceeded on the basis of preliminary gas demand calculations. Because the refined demand values did not warrant design changes, certain of the gas demand calculations differ in the low load forecast as follows:

Pipeline Design (Preliminary Demand)	Low Load Forecast (MMSCFD)
Power Generation	
Annual Average Demand	108
Peak Daily Demand	179
Residential/Commercial	
Annual Average Demand	14
Peak Daily Demand	40
Total	
Annual Average Demand	122
Peak Daily Demand	219

After refined demand values were available, the results were:

Utility System Design (Refined Demand)	Low Load Forecast (MMSCFD)
Power Generation	
Peak Daily Demand	130
Residential/Commercial	
Peak Daily Demand	49
Total	
Peak Daily Demand	179

For the low load forecast, the refined demand was 40 MMSCFD less than the preliminary calculation.

5.1.1 Gas Conditioning Plant

The gas conditioning facility required for the low growth scenario will utilize the SELEXOL physical solvent process, as described in Section 4.1.1. The design flowrate will be 230 MMSCFD based on the daily peak load anticipated for this growth forecast, a pipeline availability of 96.5 percent and compressor station demands. All other details and specifications will be as described in Section 4.1.1.

5.1.2 Pipeline

Similar to the medium forecast design, the pipeline will have an outside diameter of 22 inches and will follow the same route, the ANGTS right-of-way. Details regarding pipeline design and route are presented in Section 4.1.2.

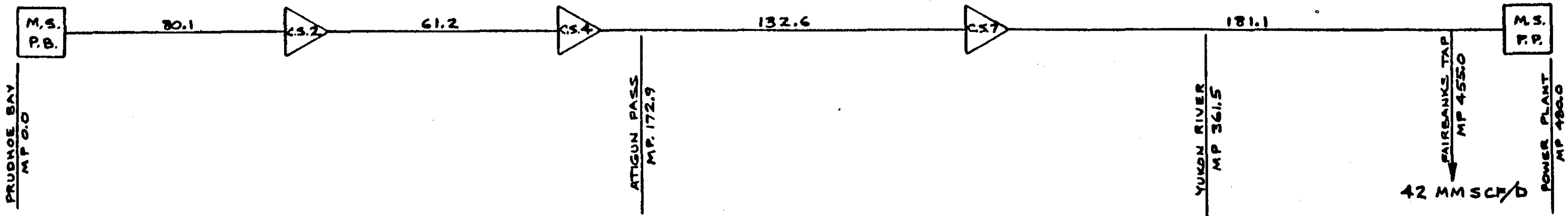
The peak daily flowrate, however, requires only three compressor stations, which will be located at Stations 2, 4 and 7 when using the ANGTS numbering system. The flow conditions anticipated for the demand scenario are presented in Figure 5-1. The design of the compressor stations is indentical to that presented for the medium load forecast. All other required systems, facilities and support services will also be the same as those presented in Section 4.1.2.

5.2 POWER PLANT

The scenario for power generation at a Fairbanks site, under the low load forecast requires three combined cycle plants to satisfy the anticipated demand in the year 2010. The schedule for unit addition which resulted from the analyses presented in the Report on System Planning Studies (Appendix B) is shown in Table 5-1.

The details of plant design and operation are identical to those described for the medium load case in Section 4.2. Only where there are variances due to the decreased number of units are specific items addressed below.

Total operations and maintenance personnel will be less for this scenario than the medium load case. Ten on duty operations and maintenance personnel will be required per shift in 1996 when the first gas turbine begins operation. In the year 2010 when three complete units are operating, 60 on duty personnel will be required per shift. The plant site will be approximately 90 acres in size and will include all three units, two switchyards, and a 300 foot buffer zone around the plant.



TOTAL 480 MILES, 22" O.D. PIPELINE, WALL THICKNESS = 0.275 INCH MINIMUM

	STATION DESIGNATION	M.S. PRUDHOE BAY	C.S. 1	C.S. 2	C.S. 3	C.S. 4	C.S. 5	C.S. 6	C.S. 7	C.S. 8	C.S. 9	C.S. 10	M.S. POWER PLANT
STATION	MILEPOST (MILES)	0.0		80.1		141.3			273.9				480.0
	ELEVATION (FEET)	21		825		3050			1315				500
	STATION INLET VOLUME (MMSCF/D)	230		230		229			228				185
	TOTAL FUEL (MMSCF/D)	—		1		1			1				—
	STATION OUTLET VOLUME (MMSCF/D)	230		229		228			227				185
	STATION SUCTION PRESSURE (PSIG)	1260		1101		1036			1114				1041
	STATION DISCHARGE PRESSURE (PSIG)	1260		1260		1185			1260				—
COMPRESSION	COMPRESSOR SUCTION PRESSURE (PSIG)	—		1097		1032			1110				—
	COMPRESSOR DISCHARGE PRESSURE (PSIG)	—		1264		1189			1264				—
	COMPRESSION RATIO	—		1.150		1.150			1.137				—
	HORSEPOWER REQUIRED	—		1450		1470			1320				—

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

HYDRAULIC SUMMARY
LOW FORECAST
PEAK DAILY FLOW

FIGURE 5-1

EBASCO SERVICES INCORPORATED

TABLE 5-1

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS FAIRBANKS POWER GENERATION - LOW LOAD FORECAST[1/]

Year	Combined Cycle (MW) (Increment/Total)	Gas Required (MMSCFD)
1990	0/0	0.
1991	0/0	0.
1992	0/0	0.
1993	0/0	0.
1994	0/0	0.
1995	0/0	0.
1996	86/86	5,957.6
1997	86/172	11,873.2
1998	0/172	11,873.2
1999	0/172	11,873.2
2000	0/172	11,904.7
2001	70/242	11,939.4
2002	86/328	17,876.4
2003	0/328	17,876.4
2004	86/414	23,873.6
2005	70/484	23,873.8
2006	86/570	29,814.1
2007	0/570	29,814.1
2008	86/656	33,413.4
2009	0/656	34,508.4
2010	70/726	32,228.9

1/ Values as calculated are shown for purposes of reproducibility only, and do not imply accuracy beyond the 100 MMSCFD level.

Annual fuel requirements for power generation will grow from 5.96 BCFY in 1996 to 32.23 BCFY in 2010. The maximum potential firing rate in the year 2010, based on a heat rate of 8280 Btu/kWh, will be approximately 9×10^4 SCFM. Annual fuel requirements for the study period are also shown in Table 5-1.

5.3 TRANSMISSION SYSTEM

5.3.1 Fairbanks to Anchorage

This transmission system uses two 345 kV lines as described in Section 3.2. Other details are similar, including series compensation.

5.4 FAIRBANKS GAS DISTRIBUTION SYSTEM

5.4.1 Fairbanks Residential/Commercial Gas Demand Forecasts

A study has been performed by Alaska Economics Incorporated to forecast residential and commercial gas demand in Fairbanks. A summary of the study's methodology and the results of the medium growth projection appear in Section 4.4.1. The text of the study appears in Appendix E. Table 5-2 presents the study's results for the low growth forecast. These forecasts have been made conditional on the gas achieving the discrete percentages of the total market for heating and cooking energy applications shown in Table 5-2. The size of the total market to which these percentages have been applied has been projected to grow at a 1.43 percent annual average rate, the low growth forecast, beginning in 1981. This rate is the implied population growth rate for Fairbanks as derived in Battelle's (1982) low forecast of the demand for electricity in the Railbelt area.

5.4.2 Fairbanks Gas Distribution System

The gas distribution system has been designed to supply Fairbanks a low growth demand value of 5.2 BCFY. The differences in flowrates and service areas between the medium and low growth scenarios affect the

TABLE 5-2

FAIRBANKS RESIDENTIAL/COMMERCIAL GAS DEMAND
FAIRBANKS POWER GENERATION - LOW GROWTH FORECAST[1]

	Delivered Gas, BCF Per Year	
	1985	2010
Market growth at 1.43 Percent		
10% of Market	0.510	0.727
20% of Market	1.275	1.818
40% of Market	2.039	2.908
100% of Market	5.098	7.720
	Delivered Gas, BCF Per Peak Month	
	1985	2010
10% of Market	0.085	0.121
20% of Market	0.212	0.302
40% of Market	0.338	0.483
100% of Market	0.846	1.207
	Delivered Gas, BCF Peak Daily	
	1985	2010
10% of Market	0.003	0.005
20% of Market	0.009	0.012
40% of Market	0.014	0.020
100% of Market	0.034	0.049

[1]Refer to Appendix E for details.

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size and lengths of the high pressure and distribution system mains. The sizes and footages of the high pressure mains and the distribution mains required for the low growth forecast are presented below. All other system and piping details are the same as the medium growth forecast which is described in Section 4.4.2.

High Pressure System Mains

Size (Inches)	Length (Feet)
8	6,000
10	15,000
12	27,375
14	7,500

Schedule of Distribution Mains

Size (Inches)	Length (Feet)
2	450,000
4	78,000
6	90,750

5.5 COST ESTIMATES

5.5.1 Capital Costs

5.5.1.1 North Slope to Fairbanks Gas Pipeline

Feasibility level investment cost estimates have been prepared for the systems and facilities which comprise the North Slope to Fairbanks natural gas pipeline. These estimates are presented in Table 5-3.

5.5.1.2 Power Plant

The capital cost of simple cycle combustion turbines and combined cycle facilities are the same as that presented in Section 4.5 for the medium load forecast.

TABLE 5-3

FEASIBILITY LEVEL INVESTMENT COSTS
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Description 1/	Materials ($1000)	Construction Labor 2/ ($1000)	Total Direct Costs ($1000)
22 in O.D. Gas Pipeline	480,000	4,100,000	4,580,000
Compressor Stations - 3 ea	30,300	25,300	55,600
Metering Stations - 2 ea	2,800	6,000	8,800
Valve Stations - 28 ea	2,500	3,800	6,300
Engineering & Construction Management			279,000
SUBTOTAL	$515,600	$4,135,100	$4,929,700
Gas Conditioning Facility 3/			538,300
TOTAL			$5,468,000

1/ A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes and land and land rights expenses have not been included.

2/ Construction camp facilities and services are subsumed in the Construction Labor cost category.

3/ Factored pricing basis which includes engineering and construction management.

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5.5.1.3 Transmission Line Systems

Feasibility level investment cost estimates have been prepared for all required transmission line systems. The results of this analysis are presented in Table 5-4. The estimate is of one new 345 kV line, 700 MW capacity, with series compensation and an intermediate switching station, and the required upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid.

5.5.1.4 Gas Distribution System

Feasibility level and investment cost estimates (January, 1982 dollars) have been prepared for the systems and facilities which comprise the Fairbanks gas distribution system. The results of the analysis are presented below. A 15 percent contingency has been assumed for the entire project and has been distributed between each cost category. Sales/use taxes and land and land rights have not been included.

	Materials ($1000)	Construction Labor ($1000)	Total Direct Costs ($1000)
Gas Distribution System	$11,300	$45,200	$56,500
Engineering and Construction Management			3,390
Total Construction Costs			$59,890

5.5.2 Operation and Maintenance Costs

5.5.2.1 Gas Pipeline and Conditioning Facility

Annual operation and maintenance costs (January, 1982 dollars) for the gas conditioning facilities are estimated to be as follows:

Item	Annual Costs ($1000)
Salaries	$1,390
Maintenance Costs (Parts and Expendables)	2,100
Total	$3,490

TABLE 5-4

FEASIBILITY LEVEL INVESTMENT COSTS
FAIRBANKS TO ANCHORAGE TRANSMISSION SYSTEM
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Description1/	Materials ($1000)	Construction Labor ($1000)	Total Direct Costs ($1000)
Switching Stations	8,857	8,414	17,271
Substations	32,958	30,872	63,830
Energy Management Systems	12,300	10,960	23,260
Steel Towers and Fixtures	129,214	182,083	311,291
Conductors and Devices	20,049	53,183	73,232
Clearing	--	41,572	41,572
SUBTOTAL	$203,378	$327,084	$530,456
Land and Land Rights2/			14,400
Engineering and Construction Management			37,130
TOTAL			$581,986

1/ The investment costs one new 345 kV line, 700 MW capacity with series compensation and an intermediate switching station, and reflect upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the existing grid to 345 kV.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

Annual operation and maintenance cost (January, 1982 dollars) for the gas compressor stations and pipeline maintenance activities are estimated to be as follows:

Item	Annual Costs ($1000)
Salaries	$2,090
Maintenance Costs (Parts and Expendables)	1,750
Total	$3,840

5.5.2.2 Power Plant

Operation and maintenance costs for the combined cycle facility at Fairbanks are estimated to be $0.0040/kWh. These are based on discussions with operating plant personnel, history of similar units, EPRI published data and other studies.

5.5.2.3 Transmission Line Systems

Annual operation and maintenance costs (January, 1982 dollars) have been developed for the scenario's required transmission line facilities and total $8 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially, and increase with time.

5.5.2.4 Gas Distribution System

Annual operation and maintenance costs (January, 1982 dollars) for the Fairbanks gas distribution system are estimated to be as follows:

Item	Annual Costs ($1000)
Salaries	$680
Maintenance Costs (Parts and Expendables)	270
Total	$950

5.5.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

5.5.4 Total Systems Costs

5.5.4.1 Cost Allocation Methodology

The methodology that was developed and presented in Section 4.4.4.1 is equally applicable to the low growth scenario.

5.5.4.2 Total System Costs

Like the Fairbanks medium load growth scenario, the Fairbanks low load growth scenario involves a complex series of investments in a gas conditioning facility, a natural gas pipeline, power generation facilities, and transmission lines. Also, like the previous Fairbanks scenario, the costs of the the gas conditioning facility and pipeline must be apportioned according to the formulae presented in Section 4.5.4.1. After that apportionment, total annual system costs can be calculated.

The formulae for conditioning facility and pipeline cost apportionment are the same regardless of growth; however, the resulting 0_I and 0_A values are quite different between the low and medium growth scenarios. For the low load forecast the 0_I value is as follows:

Residential/Commercial Peak Daily Flow (2010)	=	49 MMSCFD
Electrical Generation Peak Daily Flow (2010)	=	130 MMSCFD
Total Peak Daily Flow (2010)	=	179 MMSCFD
0_I	=	0.73

The O_A values for the Fairbanks low load forecast are presented in Table 5-5. Significant to note is the fact that in the low load forecast case, the residential/commercial customers must assume a higher share of the capital and annual cost burdens of the gas conditioning and pipeline facilities.

Given the joint systems cost apportionment, the total annual electrical systems costs can be calculated. Total annual capital costs are presented in Table 5-6. Total annual O&M costs are presented in Table 5-7. Total annual costs are then summarized in Table 5-8. The period of the analysis was assumed to be 1982 through 2010.

The present worth of costs has been calculated for comparison purposes. The present worth of costs as of 1982, assuming a discount rate of 3 percent, is $3.6 billion (1982 dollars) exclusive of fuel costs.

5.5.4.3 Gas Distribution System Costs

The costs attributable to the gas distribution system serving residential and commercial customers include a portion of the gas conditioning plant, a portion of the pipeline, and all of those costs associated with the distribution system within Fairbanks. Again, the apportionment method discussed in Section 4.5.4.1 is an essential precursor to the calculation of final total system costs.

Gas distribution costs depend upon calculating $1-O_I$ and $1-O_A$ values. These are presented in Table 5-9. Again, it is clear that the non-electric customers must assume a larger portion of the capital and operating expenses in the low load growth scenario as compared to the medium load growth scenario.

Given those apportionment values, the total systems costs for the gas distribution system can be calculated. Capital and O&M are presented in Tables 5-10 and 5-11. Total annual systems costs are summarized in Table 5-12. The present worth of these costs of 1982, assuming a real discount rate of 3 percent, is $1.1 billion, exclusive of any fuel costs.

TABLE 5-5

O_A VALUES
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST

Calendar Year	Residential Demand (BCFY)	Electrical Demand (BCFY)	Total Demand (BCFY)	O_A
1982	0.	0.	0.	NA[1/]
1983	0.	0.	0.	NA
1984	0.	0.	0.	NA
1985	0.	0.	0.	NA
1986	0.	0.	0.	NA
1987	0.	0.	0.	NA
1988	0.	0.	0.	NA
1989	0.	0.	0.	NA
1990	0.	0.	0.	NA
1991	0.	0.	0.	NA
1992	0.	0.	0.	NA
1993	0.	0.	0.	NA
1994	0.	0.	0.	NA
1995	0.	0.	0.	N/A
1996	1.266	5.958	7.224	0.82
1997	2.568	11.873	14.441	0.82
1998	3.906	11.873	15.779	0.75
1999	5.283	11.873	17.156	0.69
2000	6.698	11.905	18.603	0.64
2001	6.794	11.939	18.913	0.63
2002	6.891	17.876	24.767	0.72
2003	6.990	17.876	24.866	0.72
2004	7.090	23.874	30.964	0.77
2005	7.191	23.874	31.065	0.77
2006	7.294	29.814	37.108	0.80
2007	7.398	29.814	37.212	0.80
2008	7.504	33.413	40.917	0.82
2009	7.611	34.508	42.119	0.82
2010	7.720	32.229	39.949	0.81

1/ NA - Not applicable

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TABLE 5-6

ANNUAL CAPITAL EXPENDITURES
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated[1/] Unit A	Unit B	Transmission Line	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.	0.	0.
1983	0.	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	0.	0.
1989	0.	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	0.	0.
1991	0.	0.	0.	0.	0.	0.
1992	0.	0.	311.3	0.	0.	311.3
1993	0.	0.	71.8	1,199.6	0.	1,271.4
1994	9.96[2/]	0.	141.4	1,199.6	196.5	1,547.5
1995	33.90	0.	57.5	1,999.6	196.5	1,487.5
1996	33.90	0.	0.	0.	0.	33.9
1997	0.	0.	0.	0.	0.	0.
1998	0.	0.	0.	0.	0.	0.
1999	0.	0.	0.	0.	0.	0.
2000	56.97	0.	0.	0.	0.	57.0
2001	33.90	0.	0.	0.	0.	33.9
2002	0.	0.	0.	0.	0.	0.
2003	33.90	0.	0.	0.	0.	33.9
2004	56.97	0.	0.	0.	0.	57.0
2005	33.90	0.	0.	0.	0.	33.9
2006	0.	0.	0.	0.	0.	0.
2007	33.90	0.	0.	0.	0.	33.9
2008	0.	0.	0.	0.	0.	0.
2009	0.	0.	0.	0.	0.	0.
2010	0.	0.	0.	0.	0.	0.
Total	$327.	0.	$582.	$3,599.	$393.	$4,901.

1/ Unit A refers to first unit built in a given year and Unit B to second unit built.

2/ Includes site preparation activities for multiple unit site.

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TABLE 5-7

ANNUAL NON-FUEL OPERATION AND MAINTENANCE COSTS
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated	Transmission Line	Pipeline	Gas Conditioning Plant	Total
1982	0.	0.	0.	0.	0.
1983	0.	0.	0.	0.	0.
1984	0.	0.	0.	0.	0.
1985	0.	0.	0.	0.	0.
1986	0.	0.	0.	0.	0.
1987	0.	0.	0.	0.	0.
1988	0.	0.	0.	0.	0.
1989	0.	0.	0.	0.	0.
1990	0.	0.	0.	0.	0.
1991	0.	0.	0.	0.	0.
1992	0.	0.	0.	0.	0.
1993	0.	0.	0.	0.	0.
1994	0.	0.	0.	0.	0.
1995	0.	0.	0.	0.	0.
1996	2.268	8.00	3.15	2.86	16.3
1997	4.520	8.00	3.15	2.86	18.5
1998	4.520	8.00	2.88	2.62	18.0
1999	4.520	8.00	2.65	2.41	17.6
2000	4.520	8.00	2.46	2.23	17.2
2001	6.360	8.00	2.42	2.20	19.0
2002	8.620	8.00	2.76	2.51	21.9
2003	8.620	8.00	2.76	2.51	21.9
2004	10.908	8.00	3.00	2.69	24.6
2005	12.720	8.00	3.00	2.69	26.4
2006	14.980	8.00	3.07	2.79	28.8
2007	14.980	8.00	3.07	2.79	28.8
2008	16.112	8.00	3.15	2.86	30.1
2009	16.640	8.00	3.15	2.86	30.7
2010	17.168	8.00	3.11	2.83	31.1
Total	$147.	$120.	$44.	$40.	$351.

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TABLE 5-8

TOTAL ANNUAL COSTS
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	0.	0.	0.
1991	0.	0.	0.
1992	311.3	0.	311.3
1993	1,271.4	0.	1,271.4
1994	1,547.5	0.	1,547.5
1995	1,487.5	0.	1,487.5
1996	33.9	16.3	50.2
1997	0.	18.5	18.5
1998	0.	18.0	18.0
1999	0.	17.6	17.6
2000	57.0	17.2	74.2
2001	33.9	19.0	52.9
2002	0.	21.9	21.9
2003	33.9	21.9	55.8
2004	57.0	24.6	81.6
2005	33.9	26.4	60.3
2006	0.	28.8	28.8
2007	33.9	28.8	62.7
2008	0.	30.1	30.1
2009	0.	30.7	30.7
2010	0.	31.1	31.1
Total	$4,901.	$351.	$5,252.
Present Worth @ 3%	$3,405.	$185.	$3,590.

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TABLE 5-9

APPORTIONMENT VALUES FOR THE GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST

Term	Year	Value
$(1-0)_I$	NA	0.27
$(1-0)_A$	1983-1995	NA
	1996	0.18
	1997	0.18
	1998	0.25
	1999	0.31
	2000	0.36
	2001	0.37
	2002	0.28
	2003	0.28
	2004	0.23
	2005	0.23
	2006	0.20
	2007	0.20
	2008	0.18
	2009	0.18
	2010	0.19

TABLE 5-10

CAPITAL COSTS ASSOCIATED WITH THE DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Gas Conditioning Plant	Pipeline	Distribution System	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	0.	0.	0.	0.
1990	0.	0.	0.	0.
1991	0.	0.	0.	0.
1992	0.	0.	0.	0.
1993	0.	443.7	12.0	455.7
1994	72.6	443.7	12.0	528.3
1995	72.6	443.7	12.0	528.3
1996	0.	0.	12.0	12.0
1997	0.	0.	12.0	12.0
1998	0.	0.	0.	0.
1999	0.	0.	0.	0.
2000	0.	0.	0.	0.
2001	0.	0.	0.	0.
2002	0.	0.	0.	0.
2003	0.	0.	0.	0.
2004	0.	0.	0.	0.
2005	0.	0.	0.	0.
2006	0.	0.	0.	0.
2007	0.	0.	0.	0.
2008	0.	0.	0.	0.
2009	0.	0.	0.	0.
2010	0.	0.	0.	0.
Total	$145.	$1,331.	$60.	$1,536.

TABLE 5-11

OPERATION AND MAINTENANCE COSTS
ASSOCIATED WITH THE DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Gas Conditioning Plant	Pipeline	Distribution System	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	0.	0.
1987	0.	0.	0.	0.
1988	0.	0.	0.	0.
1989	0.	0.	0.	0.
1990	0.	0.	0.	0.
1991	0.	0.	0.	0.
1992	0.	0.	0.	0.
1993	0.	0.	0.	0.
1994	0.	0.	0.	0.
1995	0.	0.	0.	0.
1996	0.63	0.69	0.95	2.3
1997	0.63	0.69	0.95	2.3
1998	0.87	0.96	0.95	2.8
1999	1.08	1.19	0.95	3.2
2000	1.26	1.38	0.95	3.6
2001	1.29	1.42	0.95	3.7
2002	0.98	1.08	0.95	3.0
2003	0.98	1.08	0.95	3.0
2004	0.80	0.88	0.95	2.6
2005	0.80	0.88	0.95	2.6
2006	0.70	0.77	0.95	2.4
2007	0.70	0.77	0.95	2.4
2008	0.63	0.69	0.95	2.3
2009	0.63	0.69	0.95	2.3
2010	0.66	0.73	0.95	2.3
Total	$13.	$14.	$14.	$41.

TABLE 5-12

ANNUAL SYSTEMS COST SUMMARY FOR THE GAS DISTRIBUTION SYSTEM
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Cost	O & M Cost	Total Cost
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	0.	0.	0.
1991	0.	0.	0.
1992	0.	0.	0.
1993	455.7	0.	455.7
1994	528.3	0.	528.3
1995	528.3	0.	528.3
1996	12.0	2.3	14.3
1997	12.0	2.3	14.3
1998	0.	2.8	2.8
1999	0.	3.2	3.2
2000	0.	3.6	3.6
2001	0.	3.7	3.7
2002	0.	3.0	3.0
2003	0.	3.0	3.0
2004	0.	2.6	2.6
2005	0.	2.6	2.6
2006	0.	2.4	2.4
2007	0.	2.4	2.4
2008	0.	2.3	2.3
2009	0.	2.3	2.3
2010	0.	2.3	2.3
Total	$1,536.	$41.	$1,577.
Present Worth at 3%	$1,075.	$22.	$1,097.

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5.6 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The Fairbanks power plant for the low load forecast will consist of three combined cycle units in contrast to five combined cycle and two simple cycle units for the medium load forecast. Power plant characteristics are summarized in Table 5-13.

It is assumed that water or steam injection would not be required for NO_x control because of associated ice fog problems. Air emissions will be reduced by approximately one-half from the medium load forecast, and will meet all applicable air quality standards. Groundwater will provide approximately 100 gpm for equipment wash-down, potable supplies, and boiler make-up water. This relatively small amount of water will not affect groundwater supplies in the area. Wastewater discharges will be less than 100 gpm and will be treated to meet effluent guidelines.

Aquatic resources, as for the medium load forecast, will not be significantly affected. Plant acreage will be approximately 90 acres, as compared to 140 acres for the medium load forecast. Terrestrial impacts on vegetation and habitat elimination are correspondingly reduced.

Pipeline-related impacts are identical to those discussed for the Fairbanks scenario medium load forecast, Section 4.5. Impacts associated with the transmission line from Fairbanks to Anchorage are identical to those discussed in Section 3.5 for the North Slope scenario, low load forecast. Socioeconomic impacts are expected to be similar to those for the medium demand scenario.

Socioeconomic impacts, as for the medium load forecast, are not expected to be significant. The majority of workers will be hired locally. Any in-migrating workforce will have to seek temporary housing on their own but this number is expected to be low.

TABLE 5-13

ENVIRONMENT RELATED POWER PLANT CHARACTERISTICS
COMBINED CYCLE POWER PLANT
FAIRBANKS POWER GENERATION - LOW LOAD FORECAST

<u>Air Environment</u>	
Emissions	
Particulate Matter	Below standards
Sulfur Dioxide	Below standards
Nitrogen Oxides	Emissions variable within standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	Maximum structure height of 50 feet
<u>Water Environment</u>	
Plant Water Requirements	100 GPM
Plant Discharge Quantity, including treated sanitary waste, floor drains, boiler blow-down and demineralizer wastes	Less than 100 GPM
<u>Land Environment</u>	
Land Requirements	
Plant and Switchyard	90 acres
<u>Socioeconomic Environment</u>	
Construction Workforce	Approximately 100 personnel at peak construction
Operating Workforce	Approximately 50 personnel

SCENARIO III
KENAI POWER GENERATION
MEDIUM LOAD

6.0 KENAI AREA POWER GENERATION

MEDIUM LOAD FORECAST

The development of power generation facilities in the Kenai area which will utilize North Slope natural gas is dependent on the construction of a major, high pressure gas pipeline from the North Slope to a tidewater location near Kenai. The details concerning this pipeline and the attendant tidewater gas conditioning and liquefaction facilities are presented in The Governor's Economic Committee (1983) report entitled "Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas."

The gas conditioning and liquefaction facilities associated with the Trans Alaska Gas System (TAGS) will have numerous power loads, many of which cannot be satisfied by any source except electricity. These loads will include lighting, certain types of heating, ventilation and air conditioning systems, pumps, various process coolers and compressors, controls, tools, and any shaft horsepower requirements that are intermittant, such as some refrigeration applications, or too small to be economical for a combustion turbine. Based on the electrical demand values required for the ANGTS gas conditioning facility and discussions with gas liquefaction process equipment vendors, the total peak electrical demand of these tidewater processing facilities has been estimated to be approximately 300 MW. This value is only an approximation; the actual demand requirements will be dependent upon the type of liquefaction facility selected for design (e.g. compressor/expander system, cascade refrigerant system), and specific design decisions regarding various process power sources made during detailed engineering. To ensure that the Kenai power generation scenario presents a realistic development approach and that the entire Railbelt utility system can support such a major contingency of demand, the anticipated electrical requirements of these processing facilities have been included in the electrical demand analysis. As TAGS will be developed in phases, the total electrical demand of the facilities has been proportioned, based on the flow rates anticipated during each phase.

This scenario, then, centers on a major electric generating station in the Kenai area near the terminus of the TAGS pipeline. By the year 2010, the station would consist of 7 combined cycle units and 1 simple cycle gas turbine to satisfy the medium energy demand forecast for the Railbelt and the additional power requirements of the TAGS gas conditioning and liquefaction facilities, a total of 1743 MW. The fuel for the power plant will be a blend of waste gas from the TAGS gas conditioning facilities and TAGS sales gas. A major electrical transmission system from the Kenai generating station to Anchorage is required. The Kenai to Anchorage lines would be operated at 500 kV and employ an underwater crossing of Turnagain Arm. To ensure system reliability, both the 500 kV lines from Kenai to Anchorage and the 345 kV lines from Anchorage to Fairbanks would consist of two parallel lines. A residential/commercial gas distribution system for Fairbanks is not an integral part of this scenario, although it is not precluded as an adjunct to TAGS. The total construction cost of this scenario is $2.1 billion, with total operation and maintenance costs of $0.8 billion per year. The present worth of these costs excluding fuel costs is $2.0 billion.

The Kenai development scenario described above represents a revised scheme from that originally envisioned. The original scenario anticipated the use of gas conditioning facility waste gas only to fuel the electric generating station. Investigation of this alternative, however, determined that the amount of waste gas available (approximately 430 MMSCFD) would only result in approximately 350 MW of electrical power. As this amount would probably be totally consumed within the TAGS gas processing facilities, it was decided to supplement the waste gas with TAGS sales gas to satisfy the electrical demands of the Railbelt and the TAGS facilities.

6.1 POWER PLANT

6.1.1 General

The power generation technology selected for the Kenai locale is combined cycle utilizing 237 MW baseloaded plants (refer to Appendix B). The plants are identical in configuration with those described in Section 4.2. The difference in capacity rating is due to the slightly higher average annual temperature encountered in the Kenai locale.

Facilities required for the site and the site arrangement will be the same as that described in Section 4.2. Equipment arrangement will be as previously shown in Figures 4-1 and 4-2 and the site arrangement as shown in Figure 4-3. A total of 7 complete combined cycle plants plus 1 simple cycle gas turbine will be required to satisfy the demand for energy in the year 2010. The land area required for this development will be approximately 175 acres. The schedule for addition of these facilities is shown on Table 6-1 along with the total of new capacity on a yearly basis.

The functional parts of the power plant will include all the systems described in Section 4.2. Additionally, a system for gas quality monitoring will be necessary. The fuel to be utilized will be a blend of waste gas and sales gas from the gas conditioning plant (see Section 6.1.4 Fuel Supply).

6.1.2 Combustion Turbine Equipment

The combustion turbines will be identical to those described previously except for one operating detail. The gas burner nozzle in the combustion chamber is typically designed to operate at a specific fuel heat value plus or minus 10 percent. A nozzle purchased to burn 400 Btu/ft^3 fuel will be useful to 440 Btu/ft^3. In order to burn higher Btu content gas, a different nozzle would need to be installed. Several nozzles for a range of potential fuels should be inventoried for each turbine.

TABLE 6-1

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST

Year	New Capacity (MW) (Increment/Total)	Gas Required (MMSCFY)1/ Waste Gas	Sales Gas
1989	84/84	12,451.6	3,625.4
1990	84/168	24,903.3	7,250.7
1991	0/168	24,903.3	7,250.7
1992	237/405	49,864.6	14,518.3
1993	0/405	49,864.6	14,518.3
1994	69/474	49,924.1	14,535.7
1995	84/558	62,372.7	18,160.2
1996	84/642	74,827.0	21,689.7
1997	153/795	87,336.2	25,428.4
1998	84/879	99,786.8	29,053.5
1999	0/879	99,786.8	29,053.5
2000	69/948	99,848.2	29,071.4
2001	0/948	99,848.2	29,071.4
2002	168/1116	124,745.6	36,320.0
2003	0/1116	124,745.6	36,320.0
2004	69/1185	124,810.1	36,339.3
2005	168/1353	141,620.7	41,234.4
2006	69/1422	139,175.5	40,522.0
2007	84/1506	146,795.8	42,740.2
2008	153/1659	147,913.1	43,066.1
2009	84/1743	155,253.6	45,203.9
2010	0/1743	156,950.0	46,994.3

1/ Values as calculated are shown for reproducibility only, and do not imply accuracy beyond a 100 MMSCFD level.

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6.1.3 Steam Plant

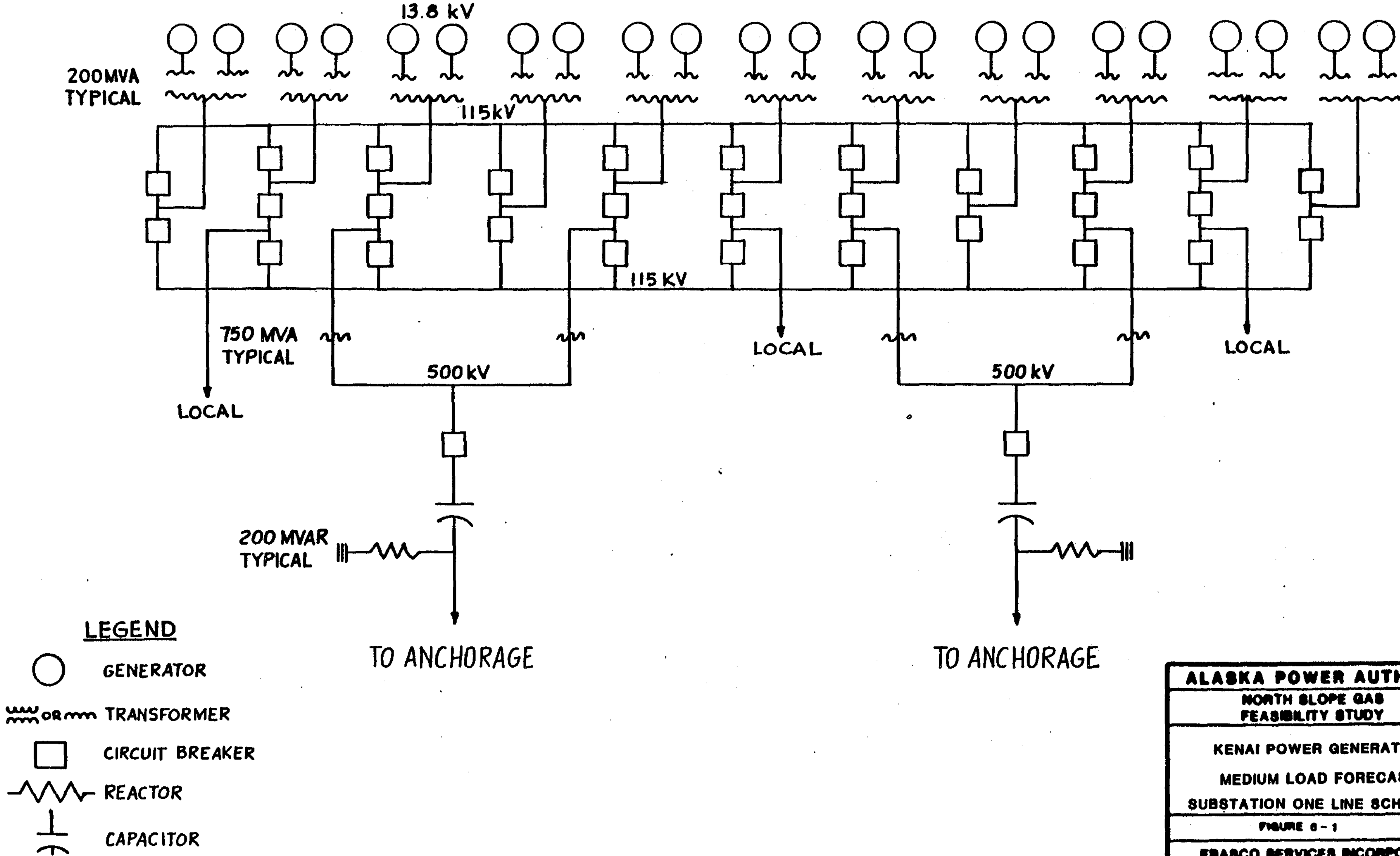
The effect of burning a low Btu content fuel on the heat recovery steam generator (HRSG) will be negligible. Since the gas turbines are controlled at a constant gas temperature, the response of the system to a higher flow of noncombustibles in the waste stream will be to reduce the amount of excess air while maintaining gas temperature and mass flow constant. Therefore, no changes to the HRSG or the balance of the steam cycle from that described in Section 4.2 is expected.

6.1.4 Fuel Supply

Depending upon the gas conditioning facility design chosen, a waste gas stream comprised mainly of carbon dioxide and heavier hydrocarbons may be generated. It has been previously estimated (refer to Appendices A and B) that a waste gas stream of approximately 430 MMSCFD with a higher heating value of 195 Btu/ft^3 could result. While it is possible to directly burn this waste gas in combustion turbines, it will require expensive redesign of the turbines, and increased equipment supply costs. Since the waste stream alone could not supply enough energy to satisfy demand through the year 2010, it was decided to blend the waste gas with sales gas to achieve a minimum heating value of 400 Btu/ft^3 (HHV). Tnis resultant heating value does not require combustion turbine modifications. The required amounts of both waste and sales gas are shown in Table 6-1.

6.1.5 Electrical Equipment and Substation

The electrical equipment, including the generators, will essentially be the same as that described for the North Slope and Fairbanks medium forecast scenarios (Sections 2.1 and 4.2). Major differences involve the number of units installed, their actual ratings, and the bus voltage. Figure 6-1 presents a simplified one line diagram of the substation. There will be 22 generators feeding the 11 transformers, each rated 200 MVA 13.8/115 kV. For this alternative 115 kV bus



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

KENAI POWER GENERATION
MEDIUM LOAD FORECAST
SUBSTATION ONE LINE SCHEMATIC

FIGURE 6 - 1

EBASCO SERVICES INCORPORATED

voltage was chosen to be compatible with the existing 115 kV Chugach Electric Association line in the area. Three circuits will provide power for local area loads. The outgoing voltage will be 500 kV with the two lines, each supplied by two 750 MVA transformers. The lines will terminate in Anchorage. Whenever possible, a breaker and a half configuration will be used.

6.1.6 Other Systems

Depending on interpretation of regulations governing the application of Best Available Control Technology (BACT), it may be necessary to add an NO_x control system to the gas turbines at the Kenai location. All other systems will be identical to those described for the Fairbanks medium load growth forecast (Section 4.2).

The NO_x control system will consist of either steam or water injection directly into the combustion chamber. This is used to control the gas temperature, keeping it below the range of high NO_x formation.

6.2 TRANSMISSION SYSTEMS

6.2.1 Kenai to Anchorage Line

6.2.1.1 Overview of the System

To transmit medium forecast power from Kenai to Anchorage, a 500 kV transmission alternative was developed and found to be a cost effective voltage. Two routes were investigated in detail: a 150 mile long land based route around Turnagain Arm, crossing the mountains west of Girwood to Anchorage; and an underwater cable crossing of Turnagain Arm. The latter route was chosen as the better alternative. A brief description of the line is presented below.

The line, with its two circuits on separate towers, will originate at the Kenai generating plant substation and will run eastward to approximately Sterling. The two circuits will then run towards the northeast and follow an existing pipeline right-of-way. The overland route on the Kenai peninsula will be 65 miles in length and will terminate at Gull Rock. From this point 4 mile-long cables will carry the power underwater to the north shore of Turnagain Arm to a location marked Isle 29, which is less than a half-mile northwest of McHugh Creek. The remaining overhead line segment will parallel the Seward-Anchorage highway for about 25 miles before reaching the substation at Anchorage.

This routing is made possible by recent advancements in cable technology developed by Pirelli of Italy and Standard Telefon O.G. Kabel Fabrik A/S of Norway, which are about to install, for the British Columbia Hydro and Power Authority, two 500 kV circuits, each consisting of three single phase cables between the British Columbia mainland and Vancouver Island. The Turnagain Arm crossing will consist of 7 cables: 3 for each circuit and 1 spare.

The system is similar to the one presented for the North Slope to Fairbanks connection, except there will be no intermediate switching stations and there will be a cable crossing. The design of the overhead section of the line will be identical to the North Slope-Fairbanks connection described in Section 2.3 and Appendix D, except that guyed type transmission towers will be used for this line and only 3 repeater stations will be required for communication purposes.

6.2.1.2 Alternatives

Several alternative transmission corridors between Kenai and Anchorage were considered in order to select a reasonable route for cost estimating purposes. Factors considered were general engineering and environmental constraints. Of the many potential routes, two were investigated in detail. A land based route was assumed to follow the existing Chugach Electric Association (CEA) right-of-way, which generally follows the Sterling and Seward Highways, and which traverses the eastern end of Turnagain Arm. However, closer examination of that route in light of the major transmission facility requirements disclosed the following severe constraints:

(1) The existing transmission lines between Portage and Indian Creek are co-located with the Seward Highway and the Alaska Railroad on a narrow bench between Turnagain Arm and the Chugach Mountains. The bench is at the base of a uniformly steep slope which rises to above 3500 feet in elevation. The proposed transmission facilities could not reasonably be accommodated within or adjacent to the existing rights-of-way. One option for avoiding this area would be to traverse the Chugach Mountains between Portage and Anchorage. This would, however, involve crossing difficult terrain, much of which is included in the Chugach State Park.

(2) The existing CEA right-of-way parallels the Sterling Highway for most of its length. In the vicinity of Bear Mountain, designated wilderness areas within the Kenai National Wildlife Refuge are within close proximity of the highway. Development of transmission facilities of the magnitude required by this scenario would engender severe aesthetic impacts to travelers along this scenic highway, and possibly infringe on wilderness land use values.

As a consequence of these severe routing constraints, this study focused on a transmission line corridor which utilizes a Turnagain Arm crossing from Gull Rock to McHugh Creek. The total length of this preferred corridor route is 94 miles, as compared to the 150 mile route which would be required for a completely overland route around the eastern end of Turnagain Arm.

6.2.2 Anchorage Substation

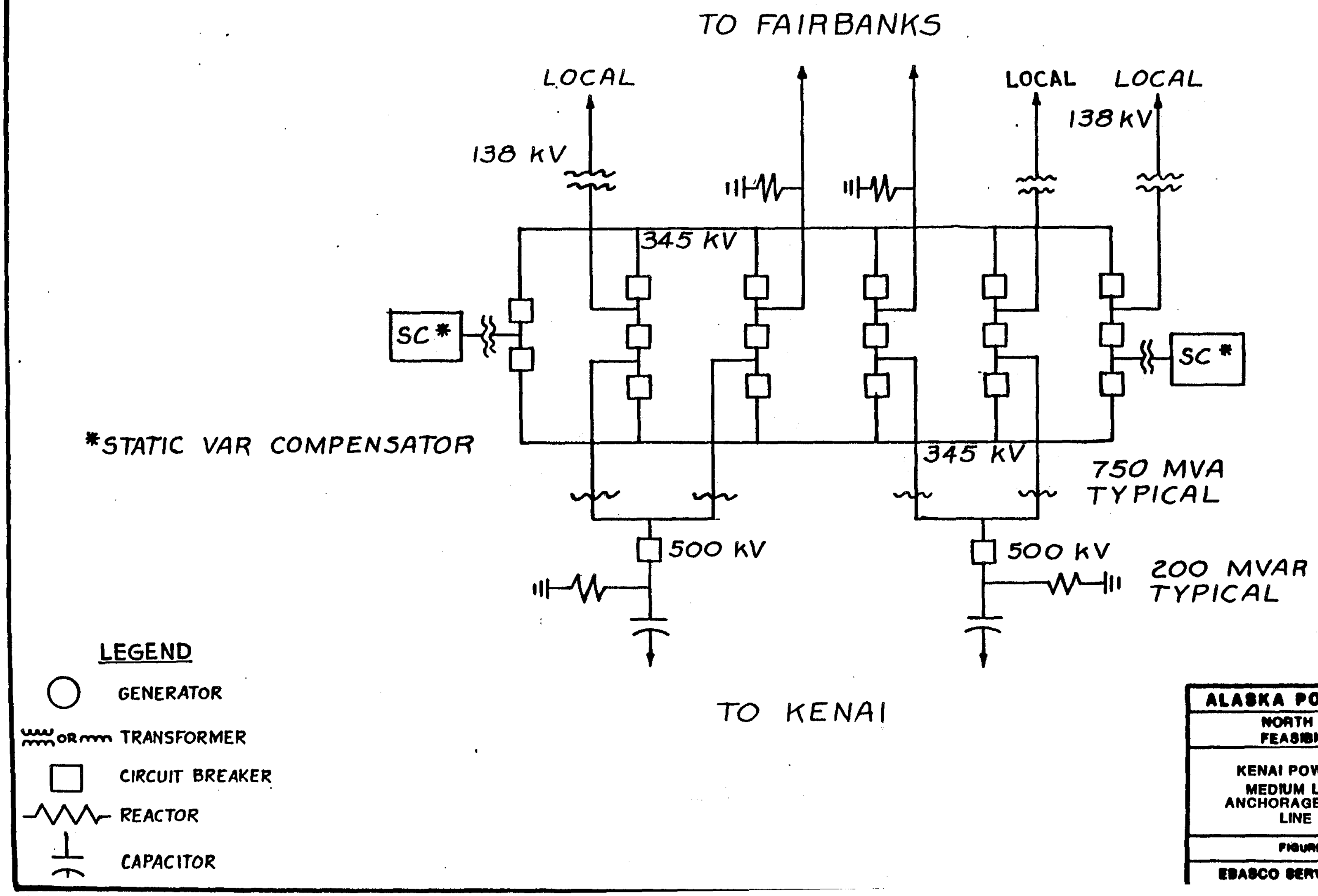
The planned Anchorage substation is shown in Figure 6-2. The two 500 kV lines will terminate in two 750 MVA 345/525 kV transformers. The bus will feed the area transmission system using 138/345 kV transformers. From the bus two 345 kV lines will connect to Fairbanks. These lines will have shunt reactors but no series capacitors connected to them.

6.2.3 Anchorage to Fairbanks Line

This line must carry about half the amount of power that the Fairbanks to Anchorage lines have to carry under previously discussed low growth forecast conditions (Section 3.2). Therefore, one 345 kV line would be adequate as far as power carrying capability and system performance is concerned. However, the reliability of electric power transmission over a single line is very poor, making two lines in parallel a minimum requirement. With two lines, neither series compensation nor an intermediate switching station is required at 345 kV. Therefore, in this scenario, the 345 kV intertie will be fully extended and a second line will be built between Anchorage and Fairbanks using the Gilbert Commonwealth (1981) design.

6.2.4 Fairbanks Substation

The Fairbanks substation will be the terminus of the two 345 kV lines. It will be a conventionally designed 345/138 kV substation using a breaker and a half scheme to supply the two 138/345 kV transformers that will provide power locally.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

KENAI POWER GENERATION
MEDIUM LOAD FORECAST
ANCHORAGE SUBSTATION ONE
LINE SCHEMATIC

FIGURE 6-2

EBASCO SERVICES INCORPORATED

6.3 COST ESTIMATES

6.3.1 Construction Costs

6.3.1.1 Power Plant

To support the derivation of total systems costs which is presented in Section 6.3.4, feasibility level investment costs were developed for the major bid lines items common to a 77 MW (ISO conditions) natural gas fired simple cycle combustion turbine and a 220 MW (ISO conditions) natural gas fired combined cycle plant. These costs are presented in Tables 6-2 and 6-3. The costs represent the total investment for the first unit to be developed at the site. Additional simple cycle units will have an estimated investment cost of $35,680,000 while additional combined cycle units will have an estimated investment cost of $128,060,000. The unit cost differential for addition units is due to significant reductions in line items 1 and 15, improvements to Site and Off-Site Facilities, and reductions in Indirect Construction Cost and Engineering and Construction Management.

6.3.1.2 Kenai to Anchorage Transmission Line

Transmission line feasibility level investment cost estimates for the submarine cable crossing alternative are presented in Table 6-4. These estimates are based on two 500 kV lines of 1400 MW capacity with series compensation. A feasibility level investment cost estimate has also been prepared for the land based route which traverses the eastern end of Turnagain Arm. These estimates are presented in Table 6-5. As the submarine cable crossing alternative is preferred, only this estimate has been used in the derivation of total systems costs (Section 6.3.4).

TABLE 6-2
FEASIBILITY LEVEL INVESTMENT COSTS
77 MW SIMPLE CYCLE PLANT
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1. Improvements to Site	475	1,410	1,885
2. Earthwork and Piling	75	500	575
3. Circulating Water System	0	0	0
4. Concrete	475	2,145	4,505
5. Structural Steel Lifting Equipment, Stacks	1,725	1,370	3,095
6. Buildings	750	1,440	2,190
7. Turbine Generator	11,400	685	12,085
8. Steam Generator and Accessories	0	0	0
9. Other Mechanical Equipment	955	530	1,485
10. Piping	265	590	855
11. Insulation and Lagging	35	135	170
12. Instrumentation	100	70	170
13. Electrical Equipment	1,535	2,665	4,200
14. Painting	70	250	320
15. Off-Site Facilities	300	1,080	1,380
SUBTOTAL	$18,160	$12,870	$31,030
Freight Increment			910
TOTAL DIRECT CONSTRUCTION COST			$31,940
Indirect Construction Costs			1,780
SUBTOTAL FOR CONTINGENCIES			33,720
Contingencies (15%)			5,060
TOTAL SPECIFIC CONSTRUCTION COST			38,780
Engineering and Construction Management			2,200
TOTAL CONSTRUCTION COST			$40,980

1/ The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

TABLE 6-3
FEASIBILITY LEVEL INVESTMENT COSTS
220 MW COMBINED CYCLE PLANT
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
1. Improvements to Site	490	1,440	1,930
2. Earthwork and Piling	220	1,520	1,740
3. Circulating Water System	0	0	0
4. Concrete	1,485	6,730	8,215
5. Structural Steel Lifting Equipment, Stacks	3,800	3,530	7,330
6. Buildings	1,800	3,600	5,400
7. Turbine Generator	30,700	2,590	33,290
8. Steam Generator and Accessories	9,600	4,320	13,920
9. Other Mechanical Equipment	6,230	3,120	9,350
10. Piping	1,630	3,055	4,685
11. Insulation and Lagging	295	720	1,015
12. Instrumentation	1,700	290	1,990
13. Electrical Equipment	4,600	8,785	13,385
14. Painting	200	720	920
15. Off-Site Facilities	300	1,080	1,380
SUBTOTAL	$63,050	$41,500	$104,550
Freight Increment			3,150
TOTAL DIRECT CONSTRUCTION COST			$107,700
Indirect Construction Costs			4,310
SUBTOTAL FOR CONTINGENCIES			112,010
Contingencies (15%)			16,800
TOTAL SPECIFIC CONSTRUCTION COST			128,810
Engineering and Construction Management			6,800
TOTAL CONSTRUCTION COST			$135,610

[1/] The following items are not addressed in the plant investment pricing: laboratory equipment, switchyard and transmission facilities, spare parts, land or land rights, and sales/use taxes.

TABLE 6-4

FEASIBILITY LEVEL INVESTMENT COSTS
SUBMARINE CABLE CROSSING ALTERNATIVE
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description[1]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	--	--	--
Substations	63,073	43,729	106,802
Energy Management System	11,400	9,400	20,800
Steel Towers and Fixtures	112,370	130,909	243,279
O.H. Conductors and Devices	12,726	29,919	42,645
Submarine Cable and Devices	77,900	52,200	130,100
Clearing	--	4,164	4,164
SUBTOTAL	277,469	270,321	547,790
Land and Land Rights[2]			7,200
Engineering and Construction Management			38,290
TOTAL CONSTRUCTION COST			$593,280

1/ The investment costs reflect two 500 kV lines, 1400 MW capacity with series compensation. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

TABLE 6-5

FEASIBILITY LEVEL INVESTMENT COSTS
LAND BASED ROUTE ALTERNATIVE
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description1/	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	0	0	0
Substations	51,262	35,540	86,802
Energy Management System	11,400	9,400	20,800
Steel Towers and Fixtures	265,066	281,477	546,543
Conductors and Devices	20,522	48,248	68,770
Clearing	0	6,720	6,720
SUBTOTAL	348,250	381,385	729,635
Land and Land Rights2/			11,600
Engineering and Construction Management			51,100
TOTAL CONSTRUCTION COST			$792,335

1/ The investment costs reflect two 500 kV lines, 1400 MW capacity with series compensation. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

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6.3.1.3 Anchorage to Fairbanks Transmission Line

Feasibility level investment cost estimates have been prepared for the Anchorage-Fairbanks connection. These estimates which are presented in Table 6-6 are based on one new 345 kV line without series compensation and an intermediate switching station. The estimates also reflect upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the present Intertie.

6.3.2 Operation and Maintenance Costs

6.3.2.1 Power Plant

The power plant operation and maintenance (O&M) costs were derived to support the system planning studies (Appendix B). They reflect a review of figures from previous Railbelt studies, operation of other utilities, and salary requirements and expendable materials. The O&M costs for this scenario are estimated to be $0.0040/kWh.

6.3.2.2 Transmission Line Systems

Annual operation and maintenance costs (January, 1982 dollars) have been developed for the scenario's required transmission line facilities and total $12 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially, and will increase with time.

6.3.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

TABLE 6-6

FEASIBILITY LEVEL INVESTMENT COSTS
ANCHORAGE TO FAIRBANKS TRANSMISSION SYSTEM
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(January, 1982 Dollars)

Description1/	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	--	--	--
Substations	38,531	32,100	70,631
Energy Management System	12,300	10,960	23,260
Steel Towers and Fixtures	129,214	182,091	311,305
Conductors and Devices	20,049	53,183	73,232
Clearing	--	41,572	41,572
SUBTOTAL	200,094	319,906	520,000
Land and Land Rights2/			14,400
Engineering and Construction Management			36,400
TOTAL CONSTRUCTION COST			$570,800

1/ The investment costs reflect one new 345 kV line without series compensation or an intermediate switching station, and the upgrading of the Willow-Anchorage and Healy-Fairbanks segments of the Intertie to 345 kV.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

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6.3.4 Total Systems Costs

Total systems costs for Kenai reflect a very different situation than the North Slope or Fairbanks scenarios. The Kenai medium growth scenario recognizes that a pipeline and gas conditioning facility are required; however, these capital investments are external to the electricity generation system per se. The costs of the pipeline and the gas conditioning facility should be reflected in the purchase price of the natural gas rather than in the capital or O&M outlays.

The methodology and assumptions utilized to derive the systems costs which are presented below have been previously described in the Report on Systems Planning Studies (Appendix B). This methodology is consistent with previous studies of electric generating scenarios for the Railbelt, specifically Acres American, Inc. (1981), Susitna Hydroelectric Project Feasibility Report and Battelle (1982), Railbelt Electric Power Alternative Study. The period of the analysis was assumed to be 1982 through 2010.

The total systems costs for the Kenai medium growth scenario have been calculated. Annual capital outlays are presented in Table 6-7. Annual O&M costs are presented in Table 6-8. Total annual costs are summarized in Table 6-9. The present worth of these costs, exclusive of fuel costs, is $2.0 billion as of 1982, assuming a discount rate of 3 percent and a value base of 1982 dollars.

6.4 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The Kenai power plant and transmission line to Anchorage and Fairbanks will have many environmental effects similar to those discussed for the North Slope and Fairbanks scenarios. The environmental and socioeconomic considerations associated with the transmission line from Anchorage to Fairbanks will be identical to those discussed in Section 3.5, the North Slope Scenario (low load forecast), and therefore will not be repeated here. Power plant characteristics related to environmental impacts are summarized in Table 6-10.

TABLE 6-7

ANNUAL CAPITAL EXPENDITURES
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated 1/ Unit A	Unit B	Transmission Line	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	621.2	621.2
1986	0. 2/	0.	142.8	142.8
1987	10.6	0.	282.2	292.8
1988	35.68	0.	114.9	150.6
1989	35.68	0.	0.	35.7
1990	0.	0.	0.	0.
1991	53.65	71.36	0.	125.0
1992	0.	0.	0.	0.
1993	53.65	0.	0.	53.7
1994	35.68	0.	0.	35.7
1995	35.68	0.	0.	35.7
1996	53.65	35.68	0.	89.3
1997	35.68	0.	0.	35.7
1998	0.	0.	0.	0.
1999	53.65	0.	0.	53.7
2000	0.	0.	0.	0.
2001	35.68	35.68	0.	71.4
2002	0.	0.	0.	0.
2003	53.65	0.	0.	53.7
2004	35.68	35.68	0.	71.4
2005	53.65	0.	0.	53.7
2006	35.68	0.	0.	35.7
2007	35.68	53.65	0.	89.3
2008	35.68	0.	0.	35.7
2009	0.	0.	0.	0.
2010	0.	0.	0.	0.
Total	$689.	$232.	$1,161.	$2,083.

1/ Unit A refers to first unit built in a given year and Unit B to second unit built.

2/ Includes site preparation activities for multiple unit site.

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TABLE 6-8

ANNUAL NON-FUEL OPERATION AND MAINTENANCE COSTS
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated	Transmission Line	Total
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	2.21	12.0	14.21
1990	4.42	12.0	16.42
1991	4.42	12.0	16.42
1992	10.64	12.0	22.64
1993	10.64	12.0	22.64
1994	12.46	12.0	24.46
1995	14.66	12.0	26.66
1996	16.87	12.0	28.87
1997	20.89	12.0	32.89
1998	23.10	12.0	35.10
1999	23.10	12.0	35.10
2000	24.91	12.0	36.91
2001	24.91	12.0	36.91
2002	29.33	12.0	41.33
2003	29.33	12.0	41.33
2004	31.14	12.0	43.14
2005	33.64	12.0	45.64
2006	34.72	12.0	46.72
2007	35.81	12.0	47.81
2008	36.90	12.0	48.90
2009	37.99	12.0	49.99
2010	39.08	12.0	51.08
Total	$501.	$264.	$765.

TABLE 6-9

TOTAL ANNUAL COSTS
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	621.2	0.	621.2
1986	142.8	0.	142.8
1987	292.8	0.	292.8
1988	150.6	0.	150.6
1989	35.7	14.21	49.91
1990	0.	16.42	16.42
1991	125.0	16.42	141.42
1992	0.	22.64	22.64
1993	53.7	22.64	76.34
1994	35.7	24.46	60.16
1995	35.7	26.66	62.36
1996	89.3	28.87	118.17
1997	35.7	32.89	68.59
1998	0.	35.10	35.10
1999	53.7	35.10	88.80
2000	0.	36.91	36.91
2001	71.4	36.91	108.31
2002	0.	41.33	41.33
2003	53.7	41.33	95.03
2004	71.4	43.14	114.54
2005	53.7	45.64	99.34
2006	35.7	46.72	82.42
2007	89.3	47.81	137.11
2008	35.7	48.90	84.60
2009	0.	49.99	49.99
2010	0.	51.08	51.08
Total	$2,083.	$765.	$2,848.
Present Worth @ 3%	$1,612.	$436.	$2,048.

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TABLE 6-10

ENVIRONMENT RELATED POWER PLANT CHARACTERISTICS
NATURAL GAS COMBINED CYCLE
KENAI AREA POWER GENERATION - MEDIUM LOAD FORECAST

Air Environment	
Emissions	
Particulate Matter	Below standards
Sulfur Dioxide	Below standards
Nitrogen Oxides	Emissions variable within standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	maximum structure height of 50 feet
Water Environment	
Plant Water Requirements	
Water Injection	800 GPM
Other Requirements	200 GPM
Plant Discharge Requirements	
Demineralizer	40 GPM
Steam Generators	70 GPM
Treated Sanitary Waste	15 GPM
Floor Drains	25 GPM
Land Environment	
Land Requirements	175 acres
Socioeconomic Environment	
Construction Workforce	Approximately 200 personnel at peak construction
Operating Workforce	Approximately 150 employed personnel

6.4.1 Air Resource Effects

As is typical of many exposed coastal locations, the air quality and meteorological conditions are generally favorable to the development of facilities such as power plants. It is not likely that an intense "marine layer", which may restrict dispersion of pollutants, develops in this area. The air quality attains the applicable ambient standards, but the locale is burdened with several existing petroleum refinery emissions. A new natural gas fired power plant could probably be sited in the area with the use of appropriate emissions controls including water or steam injection to reduce nitrogen oxides emissions. The impact of water vapor emissions on the formation of fog must also be considered. The power plant must be carefully sited in order to avoid adding to the air quality impacts of the existing facilities.

Construction of the transmission line from Kenai to Anchorage will result in temporary air quality impacts. Heavy equipment and construction vehicles will cause fugitive dust and exhaust emissions, and slash burning will cause particulate emissions. As discussed in Section 2.5, these emissions would occur rarely and would be widely dispersed, generally in unpopulated areas. Long term impacts would be negligible.

6.4.2 Water Resource Effects

As in the Fairbanks scenario, water resource effects will be minimal. Groundwater will supply up to 1000 gpm for water or steam injection (for control of nitrogen oxides emissions), boiler make-up, potable supplies and miscellaneous uses. Wastewater discharges will consist of boiler blowdown, demineralizer regenerant wastes and sanitary wastes, each treated within the plant to meet the appropriate effluent guidelines. Because water used for water or steam injection is consumed rather than recycled, wastewater quantities will be less than 200 gpm.

The transmission line from Kenai to Anchorage would cross the streams and creeks listed below.

Soldatna Creek	Moose River
Mystery Creek	Chickaloon River
Big Indian Creek	Little Indian Creek
Potter Creek	Furrow Creek
Campbell Creek	Chester Creek
Ship Creek	

The water quality of these streams should not be directly affected if towers will be set back from the streambank at least 200 feet, and construction activities stay out of stream channels. Indirect impacts on the waterbodies, however, will result from construction activity in the small drainageways that feed the main channel, primarily from removal of vegetation (causing higher erosion rates), equipment crossings of small drainages, and access road construction. Because helicopter construction will be used along most of the route, the use of heavy equipment, vegetation removal, and access road construction should be minimal.

The transmission line will cross Turnagain Arm from Gull Rock to the mouth of McHugh Creek via seven buried submarine cables. Construction phase impacts will consist of increased turbidity from the cable installation, and construction activity near the shore on both shorelines. Operation phase impacts will primarily be the potential for cable rupture and subsequent cable oil contamination of Turnagain Arm. The cable will be designed to have a very low probability of rupture over the life of the project. A synthetic cable oil, dodecobenzene, should be used for cable insulation. If this oil accidentally leaks, it will rise to the surface and quickly evaporate when exposed to air. This oil is used specifically to minimize environmental effects associated with a cable rupture.

6.4.3 Aquatic Ecosystem Effects

Because groundwater will provide the power plant's water supply, and wastewater discharges will be low, the power plant in Kenai will not significantly affect aquatic resources.

Soldatna Creek and Moose River flow into the Kenai River System, a major river for anadromous fish habitat. Sodatna Creek provides spawning and rearing habitat for silver salmon, and Moose River contains king, silver, and sockeye salmon (U.S. Army Corps of Engineers 1978). Sedimentation of these water bodies, as discussed in the previous section, could affect spawning and rearing habitat in these streams. Because helicopter construction will be used for most of the route, however, sedimentation effects would be relatively minor.

Impacts to freshwater aquatic resources will be mitigated primarily through the control of sedimentation of waterbodies, keeping construction equipment out of streambeds and wetlands, and avoiding areas of high biological value. These mitigation measures are discussed in greater detail in Section 2.5.3 for the North Slope scenario.

Crossing Turnagain Arm with underwater cables poses additional environmental hazards. Turnagain Arm is an environmentally sensitive area in the general vicinity of the project that contains marine mammals, including harbor seals, sea lions and beluga whales (U.S. Department of Commerce 1979). Salmon are present in some of the small streams that enter this area (Alaska Department of Fish and Game 1978).

Installation of buried, submarine cables will temporarily disrupt the sea floor along the cable route and increase turbidity and suspended solids in the vicinity of the crossing. Tidal currents could carry suspended sediment beyond the immediate crossing site. Special construction techniques should be used to minimize disturbance of the substrate. Installation should take place when biological activity is at its lowest point in the yearly cycle.

An accidental rupture of a cable would leak cable oil into the aquatic environment. As discussed in the previous section, the cable oil used, dodecobenzene, was chosen because it evaporates when exposed to air, thereby minimizing environmental impacts.

The cables may operate at a temperature level above ambient conditions. Because the cables will be buried six to ten feet, only the substrate temperature and not water temperature would be elevated (Bonneville Power Administration 1981).

6.4.4 Terrestrial Ecosystem Effects

Because the Kenai power plant will be located in an area already extensively developed, little habitat degradation will occur. The area disturbed for power plant construction, approximately 140 acres, will not significantly affect terrestrial resources in the area.

The transmission route passes through an area of caribou habitat northeast of Kenai (University of Alaska 1974). Little alteration of caribou habitat will result from construction of the transmission line because the animal utilizes cover types that require little if any clearing.

Much of the route between Kenai and Anchorage is within moose rangeland. However, because moose utilize many different habitat types, they will be the least adversely affected by habitat alterations (Spencer and Chatelain 1953). Where the proposed route crosses heavily forested areas, moose will benefit from additional clearing of the right-of-way and the subsequent establishment of a subclimax community (Leopold and Darling 1953). The route does not cross Dall sheep or mountain goat habitat.

The transmission line corridor passes near Chickaloon Flats and Potter Marsh on Turnagain Arm, both key waterfowl areas. Various puddle ducks, geese and sandhill cranes feed and rest during seasonal migration periods in these areas. The shoreline of Turnagain Arm is also used by seals and sea lions. The transmission line would not directly affect this wildlife habitat.

Construction of the submarine cable could slightly affect terrestrial habitat indirectly by increasing turbidity of Turnagain Arm and thereby affecting food sources. This would be a temporary effect during the construction phase only.

The transmission corridor passes through several vegetation types. Between Kenai and Sterling, the vegetation is primarily bottomland spruce-poplar forest. As the corridor extends northeasterly towards Turnagain Arm, the vegetation becomes upland spruce-hardwood forest and, on the foothills of the Kenai Mountains, coastal western hemlock-Sitka spruce forest. North of Turnagain Arm, the vegetation is primarily bottomland spruce-poplar forest (University of Alaska 1974).

Transmission line construction will necessitate clearing a 220-foot wide corridor in all forested areas. Over the length of the corridor, it is assumed that a total of 550 acres would be cleared within the right-of-way.

6.4.5 Socioeconomic and Land Use Effects

The socioeconomic effects of locating a gas conditioning facility and electrical generating plant depends primarily on the size of the in-migrating work force. Land use impacts are not expected to occur as these facilities are compatible with the heavily industrialized development that dominates the Kenai-Nikiski area.

The size of the construction work force for the generating facility is expected to be approximately 175 persons. The construction schedule would require that a unit be constructed every year during the period 1993-2010, with the exception of 1994 and 1999, when no new units would be required. The duration and time of the construction period would be 4 to 5 months in the summer.

The extent to which local people would be hired would depend on the match of skills required for the project to those skills of the available labor force. Labor union policies would also influence the extent of local hires on the project. The in-migrating work force would have to seek temporary housing on their own since housing would not be provided at the project site. The magnitude of the impacts on the local housing supply would depend on the vacancy rate for the summer of each year a unit was constructed.

The project is expected to have little effect on the unemployment rate since employment on the project would be seasonal. In addition, these job openings would be competitive with other employment opportunities in seasonal industries such as construction and fisheries.

The operations work force is expected to be approximately 100. The magnitude of potential impacts depends on the availability of local labor to meet the work force requirements. If the majority of the employees migrate to the Kenai-Nikiski region, the demand for housing could exceed the supply.

Construction of the transmission lines between Kenai and Anchorage is expected to take 22 months. The peak work force is estimated at 221 persons during the last 6 months and average construction work force is expected to be approximately 163 workers. It is assumed that workers would be hired from the labor pools of Kenai and Anchorage.

SCENARIO III
KENAI POWER GENERATION
LOW LOAD

7.0 KENAI AREA POWER GENERATION

LOW LOAD FORECAST

The Kenai area power generation scenario, under the low load forecast, is also depedent upon the development of TAGS. The anticipated electrical requirements associated with TAGS gas conditioning and liquefaction facilities have also been included in the electrical demand analysis. The development scheme will consist of 4 combined cycle plants and 2 simple cycle combustion turbines conditioning facility. Fuel for the power plant will be a blend of waste gas and sales gas. A reliable electrical transmission system will require parallel lines from the Kenai area to Anchorage (at 500 kV and underwater across Turnagain Arm) and from Anchorage to Fairbanks (at 345 kV). A residential/commercial gas distribution system is not a part of the scenario. Construction costs for this scenario are $1.7 billion, with total operation and maintenance costs of $0.6 billion. The present worth of these costs excluding fuel costs is $1.7 billion.

The information in this section is intended to include only those conditions which are significantly different from those for the medium load forecast presented in Section 6.0.

7.1 POWER PLANT

This scenario will require four complete combined cycle plants, each capable of generating 237 MW and two simple cycle combustion turbines, to satisfy the low load forecast demand for energy in the year 2010. The first gas turbine unit will go on line in 1990. The scheduled additions are summarized in Table 7-1 and details are addressed in Appendix B. Fuel requirements for this scenario are also shown in Table 7-1.

TABLE 7-1

NEW CAPACITY ADDITIONS AND FUEL REQUIREMENTS
KENAI AREA POWER GENERATION - LOW LOAD FORECAST

Year	New Capacity (MW) (Increment/Total)	Gas Requirements (MMSCFD)[1/] Waste Gas	Sales Gas
1990	84/84	12,451.6	3,625.4
1991	0/84	12,451.6	3,625.4
1992	153/237	24,962.1	7,267.8
1993	0/237	24,962.1	7,267.8
1994	84/321	37,413.5	10,893.2
1995	84/405	49,864.6	14,518.3
1996	0/405	49,864.6	14,518.3
1997	153/558	62,372.7	18,160.2
1998	0/558	62,372.7	18,160.2
1999	0/558	62,372.7	18,160.2
2000	0/558	62,372.7	18,160.2
2001	84/642	74,827.0	21,689.7
2002	69/711	74,886.2	21,803.5
2003	0/711	74,886.2	21,803.5
2004	84/795	87,336.2	25,428.4
2005	84/879	99,786.8	29,053.5
2006	69/948	99,848.2	29,071.4
2007	0/948	99,848.2	29,071.4
2008	84/1032	110,241.2	32,097.3
2009	0/1032	95,864.8	27,911.6
2010	84/1116	117,735.7	34,279.4

1/ Values as calculated are shown for reproducibility only, and do not imply accuracy beyond a 100 MMSCFD level.

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Facilities required for the site and the site arrangement will be the same as that described in Section 4.2. Equipment arrangement will be as previously shown in Figures 4-1 and 4-2 and the site arrangement as shown in Figure 4-3. The land area required for this development will be approximately 120 acres.

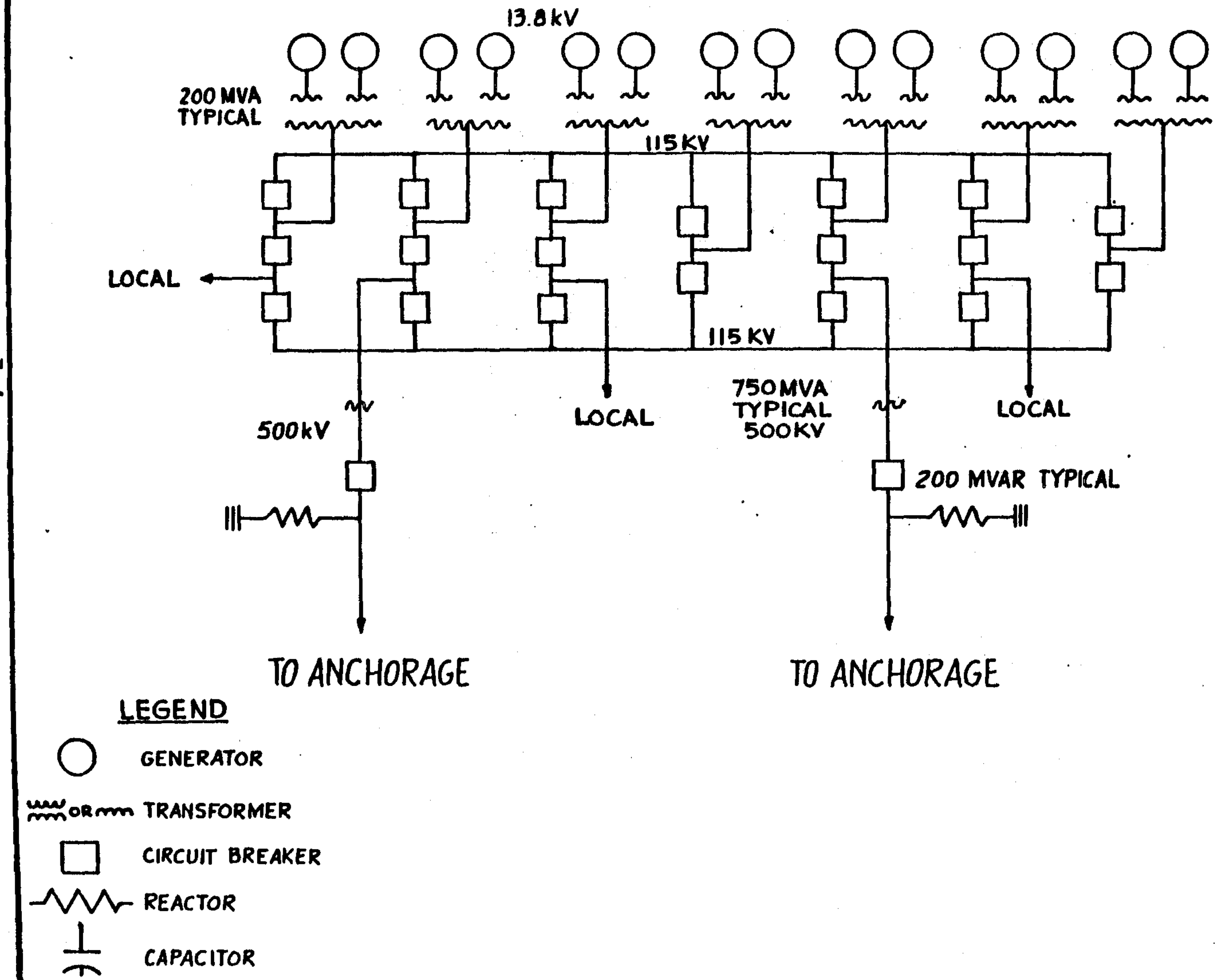
The one line schematic of the low forecast generation plant substation is shown in Figure 7-1. It is essentially a scaled down version of Figure 6-1. The number of generators is reduced to 14 and only one transformer will supply each of the 500 kV lines, which will be without series compensation.

7.2 TRANSMISSION SYSTEM

The Kenai-Anchorage transmission system will be similar to the medium forecast design including the utilization of 7 cables: 3 for each circuit and 1 spare (Section 6.2). Series compensation is not required, however, because the power transmitted to Anchorage in this low forecast case will be much reduced from that of the medium forecast.

Installing a reduced number of cables under Turnagain Arm was investigated but was not considered feasible because it is unlikely that the required switchyards could be located at the two terminations due to the lack of suitable land. During the system studies performed for this project, the possibility of transmitting the power on two 230 kV circuits, with one intermediate switching station, was also considered. Complete investigation of this system would have required detailed studies far beyond the scope of this project. However, such an alternative should be investigated during detailed engineering.

At the substation in Anchorage the 500 kV voltage will be transformed to 345 kV for transmittal to Fairbanks and to supply local Anchorage loads. The one line diagram would be similar to that presented in Figure 6-2, except that there will only be two 750 kVA transformers at the substation and the 500 kV lines will not be series compensated. The Fairbanks substation will terminate the two 345 kV circuits and supply, via transformers, the local area load at 138 kV.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS
FEASIBILITY STUDY

KENAI POWER GENERATION
LOW LOAD FORECAST
SUBSTATION ONE LINE SCHEMATIC

FIGURE 7-1

EBASCO SERVICES INCORPORATED

7.3 COST ESTIMATES

7.3.1 Construction Costs

7.3.1.1 Power Plant

The capital cost of simple cycle combustion turbines and combined cycle facilities are the same as that presented in Section 6.3 for the medium load forecast.

7.3.1.2 Transmission Line Systems

Feasibility level investment cost estimates for the submarine cable crossing alternative for the Kenai-Anchorage line are presented in Table 7-2. These estimates are based on two 500 kV lines of 700 MW capacity without series compensation. A feasibility level investment cost estimate has also been prepared for the land based route which traverses the eastern end of Turnagain Arm. These estimates are presented in Table 7-3. As the submarine cable crossing alternative is preferred, only this estimate has been used in the derivation of total systems costs (Section 7.3.4).

The construction costs associated with the Anchorage-Fairbanks line are the same for both the medium and low growth forecasts. These costs were previously presented in Table 6-6.

7.3.2 Operation and Maintenance Costs

Power plant operation and maintenance (O&M) costs are the same for both the medium and low load forecasts, $0.0040/kWh. Transmission line O&M costs are estimated to be $12 million per year. These costs should be viewed as an annual average over the life of the system. Actual O&M costs should be less initially and will increase with time.

TABLE 7-2

FEASIBILITY LEVEL INVESTMENT COSTS
SUBMARINE CABLE CROSSING ALTERNATIVE
KENAI AREA POWER GENERATION - LOW LOAD FORECAST
(January 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	--	--	--
Substations	41,620	30,885	72,505
Energy Management System	11,400	9,400	20,800
Steel Towers and Fixtures	112,370	130,909	243,279
O.H. Conductors and Devices	12,726	29,919	42,645
Submarine Cable and Devices	77,900	52,200	130,100
Clearing	--	4,164	4,164
SUBTOTAL	256,016	257,477	513,493
Land and Land Rights[2/]			7,200
Engineering and Construction Management			35,950
TOTAL CONSTRUCTION COST			$556,643

1/ The investment costs reflect two 500 kV lines, 700 MW capacity with no series compensation. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

TABLE 7-3

FEASIBILITY LEVEL INVESTMENT COSTS
LAND BASED ROUTE ALTERNATIVE
KENAI AREA POWER GENERATION - LOW LOAD FORECAST
(January 1982 Dollars)

Description[1/]	Material ($1000)	Construction Labor ($1000)	Total Direct Cost ($1000)
Switching Stations	--	--	--
Substations	30,140	22,366	52,506
Energy Management System	11,400	9,400	20,800
Steel Towers and Fixtures	265,066	281,477	546,543
Conductors and Devices	20,522	48,248	68,770
Clearing	--	6,720	6,720
SUBTOTAL	327,128	368,211	695,339
Land and Land Rights[2/]			11,600
Engineering and Construction Management			48,700
TOTAL CONSTRUCTION COST			$755,639

1/ The investment costs reflect two 500 kV lines, 700 MW capacity with no series compensation. A 15 percent contingency has been assumed for the entire project and has been distributed among each of the cost categories shown. Sales/use taxes have not been included.

2/ Assumes a cost of $40,000 per mile (Acres American Inc. 1981).

7.3.3 Fuel Costs

For the economic analyses which follow fuel costs were treated as zero. This approach permits fuel cost and fuel price escalation to be treated separately; and makes possible subsequent sensitivity analyses of the Present Worth of Costs for this scenario based upon a range of fuel cost and cost escalation assumptions.

7.3.4 Total Systems Costs

Total systems costs for the Kenai low load growth scenario are constructed in a manner identical to that used for the Kenai medium load growth scenario, except for the number of power plants installed and operated.

The methodology and assumptions utilized to derive the systems costs which are presented below have been previously described in the Report on Systems Planning Studies (Appendix B). This methodology is consistent with previous studies of electric generating scenarios for the Railbelt, specifically Acres American, Inc. (1981), Susitna Hydroelectric Project Feasibilty Report and Battelle (1982), Railbelt Electric Power Alternatives Study. The period of the analysis was assumed to be 1982 through 2010.

Annual capital expenditures are presented in Table 7-4. Annual O&M costs are presented in Table 7-5. The summary of all annual costs is presented in Table 7-6. For comparison purposes the 1982 present worth of costs, assuming a discount rate of 3 percent and excluding fuel costs, is $1.7 billion (1982 dollars).

7.4 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The Kenai power plant for the low load forecast will consist of three combined cycle units, in contrast to the five combined cycle and two simple cycle units for the medium load forecast. Power plant characteristics related to environmental resources are summarized in Table 7-7.

TABLE 7-4

ANNUAL CAPITAL EXPENDITURES
KENAI AREA POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated Unit A	Unit B	Transmission Line	Total
1982	0.	0.	0.	0.
1983	0.	0.	0.	0.
1984	0.	0.	0.	0.
1985	0.	0.	0.	0.
1986	0.	0.	603.2	603.2
1987	0.	0.	138.6	138.6
1988	10.60	0.	274.0	284.6
1989	35.68	0.	111.6	147.3
1990	0.	0.	0.	0.
1991	35.68	53.65	0.	89.33
1992	0.	0.	0.	0.
1993	35.68	0.	0.	35.7
1994	35.68	0.	0.	35.7
1995	0.	0.	0.	0.
1996	53.65	35.68	0.	89.3
1997	0.	0.	0.	0.
1998	0.	0.	0.	0.
1999	0.	0.	0.	0.
2000	35.68	0.	0.	35.7
2001	53.65	0.	0.	53.7
2002	0.	0.	0.	0.
2003	35.68	0.	0.	35.7
2004	35.68	0.	0.	35.7
2005	53.65	0.	0.	53.7
2006	0.	0.	0.	0.
2007	35.68	0.	0.	35.7
2008	0.	0.	0.	0.
2009	35.68	0.	0.	35.7
2010	0.	0.	0.	0.
Total	$405.	$89.	$1,128.	$1,710.

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TABLE 7-5

ANNUAL NON-FUEL OPERATION AND MAINTENANCE COSTS
KENAI AREA POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Electricity Generated	Transmission Line	Total
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	0.	0.	0.
1987	0.	0.	0.
1988	0.	0.	0.
1989	0.	0.	0.
1990	2.21	12.0	14.21
1991	2.21	12.0	14.21
1992	6.23	12.0	18.23
1993	6.23	12.0	18.23
1994	8.44	12.0	20.44
1995	10.64	12.0	22.64
1996	10.64	12.0	22.64
1997	14.66	12.0	26.66
1998	14.66	12.0	26.66
1999	14.66	12.0	26.66
2000	14.66	12.0	26.66
2001	16.87	12.0	28.87
2002	18.68	12.0	30.68
2003	18.68	12.0	30.68
2004	20.89	12.0	32.89
2005	23.10	12.0	35.10
2006	24.91	12.0	36.91
2007	24.91	12.0	36.91
2008	26.62	12.0	38.62
2009	23.15	12.0	35.15
2010	27.68	12.0	39.68
Total	$331.	$252.	$583.

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TABLE 7-6

TOTAL ANNUAL COSTS
KENAI AREA POWER GENERATION - LOW LOAD FORECAST
(Millions of January, 1982 Dollars)

Calendar Year	Capital Expenditures	O & M Costs	Total Expenditures
1982	0.	0.	0.
1983	0.	0.	0.
1984	0.	0.	0.
1985	0.	0.	0.
1986	603.2	0.	603.2
1987	138.6	0.	138.6
1988	284.6	0.	284.6
1989	147.3	0.	147.3
1990	0.	14.21	14.21
1991	89.3	14.21	103.51
1992	0.	18.23	18.23
1993	35.7	18.23	53.93
1994	35.7	20.44	56.14
1995	0.	22.64	22.64
1996	89.3	22.64	111.92
1997	0.	26.66	26.66
1998	0.	26.66	26.66
1999	0.	26.66	26.66
2000	35.7	26.66	62.36
2001	53.7	28.87	82.57
2002	0.	30.68	30.68
2003	35.7	30.68	66.38
2004	35.7	32.89	68.59
2005	53.7	35.10	88.80
2006	0.	36.91	36.91
2007	35.7	36.91	72.61
2008	0.	38.62	38.62
2009	35.7	35.15	70.85
2010	0.	39.68	39.68
Total	$1,710.	$583.	$2,292.
Present Worth @ 3%	$1,342.	$331.	$1,673.

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TABLE 7-7

ENVIRONMENT RELATED POWER PLANT CHARACTERISTICS
COMBINED CYCLE POWER PLANT
KENAI AREA POWER GENERATION - LOW LOAD FORECAST

Air Environment	
Emissions	
Particulate Matter	Below standards
Sulfur Dioxide	Below standards
Nitrogen Oxides	Emissions variable without standards - dry control techniques would be used to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions. This value calculated based upon new source performance standards, facility heat rate, and unit size.
Physical Effects	Maximum structure height of 50 feet
Water Environment	
Plant Water Requirements	500 GPM
Plant Discharge Quantities	100 GPM
Wastewater Holding Basin including treated sanitary waste, floor drains, boiler blow-down, and demineralizer wastes	
Land Environment	
Land Requirements	
Plant and Switchyard	120 acres
Socioeconomic Environment	
Construction Workforce	Approximately 200 personnel at peak construction
Operating Workforce	Approximately 130 personnel

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Approximately 500 gpm of fresh water will be supplied by groundwater for water or steam injection (for NO_x control), equipment wash-down, boiler make-up water, and potable supplies. This amount of water will not significantly affect groundwater supplies in the area. Wastewater discharges will be less than 100 gpm and will be treated to meet effluent guidelines.

Aquatic resources, as for the medium load forecast, will not be significantly affected. Plant acreage will be approximately 120 acres as compared to 175 acres for the medium load forecast. Terrestrial impacts are correspondingly reduced.

Impacts associated with the transmission line from Kenai to Anchorage and on to Fairbanks are identical to those discussed in Section 6.4 for the medium load forecast.

Socioeconomic impacts are expected to be similar to those for the medium load forecast. They would be less significant for the low load forecast. The in-migrating work force, which would have to seek temporary housing on their own, would be smaller than for the medium growth forecast, and thus would cause fewer demands on local housing and public services.

COMPARISON OF SCENARIOS

8.0 COMPARISON OF SCENARIOS

The three development scenarios have a common purpose of meeting the electrical generating needs of the Railbelt region using North Slope gas as a fuel source. However, the electric generating schemes and auxiliary systems vary widely among the scenarios making comparison of their relative merits complex. Table 8-1 is a side-by-side comparison of some of the important features of the three scenarios for both medium and low load forecasts. Each power plant meets the respective electricity demand forecast for the Railbelt. The Kenai plants also include the anticipated electrical requirements of the TAGS gas conditioning and liquefaction facilities. Simple cycle units are the recommended technology for electric generators on the North Slope, but combined cycle is more appropriate for the other two scenarios. The environmental and socioeconomic effects of all development scenarios are substantial, but none have been identified which would preclude any project. All scenarios are technically feasible from an engineering point of view.

The ultimate feasibility of each development scenario described herein will depend upon a comparison of power costs between these scenarios and alternative electric generating technologies. Such comparisons are outside Ebasco's scope of work, but can be considered as a logical extension of these studies which may be performed by the Alaska Power Authority.

TABLE 8-1

COMPARISON OF SCENARIOS

Factor	Power Plant Location and Demand Forecast					
	North Slope		Fairbanks		Kenai	
	Medium	Low	Medium	Low	Medium	Low
Power Plant Capacity (MW)	1365	728	1383	726	1743	1116
Required Units (Simple Cycle/Combined Cycle)	15/0	8/0	2/5	0/3	1/7	2/4
Plant Site Acreage	90	60	140	90	175	120
North Slope to Fairbanks Transmission Lines (500 kV)	2	2	NA 1/	NA	NA	NA
Fairbanks to Anchorage Transmission Lines (345 kV)	3	2	3	2	2	2
Kenai to Anchorage Transmission Lines (500 kV)	NA	NA	NA	NA	2	2
North Slope to Fairbanks Pipeline Compressor Stations	NA	NA	10	3	NA	NA
POWER GENERATION (1982 $ Billion)						
Capital Investment	4.2	3.3	6.5	4.9	2.1	1.7
Total O&M	1.1	0.7	0.8	0.4	0.8	0.6
Present Worth	3.8	2.7	5.4	3.6	2.0	1.7
DISTRIBUTION SYSTEM (1982 $ Billion)						
Capital Investment	NA	NA	1.2	1.6	NA	NA
Total O&M	NA	NA	0.09	0.04	NA	NA
Present Worth	NA	NA	0.9	1.1	NA	NA

1/ NA - Not applicable

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9.0 REFERENCES

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APPENDIX A

APPENDIX A

REPORT
ON
EXISTING DATA AND ASSUMPTIONS

NOVEMBER 1982

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SUMMARY

Ebasco prepared this report to identify existing data and various assumptions concerning the composition and availability of North Slope gas and potential constraints to its use for meeting future energy needs in the Railbelt. The report plays an essential role in the ongoing feasibility level assessment by establishing a common data base from which to proceed. The report discusses the physical composition of North Slope gas, the quantity and availability of the gas, and various engineering and economic factors. An extended bibliography and a list of persons contacted to compile the data and assumptions are appended.

A1.0 INTRODUCTION

This report is the first of a series in developing a feasibility level assessment regarding the use of North Slope natural gas for power generation in the Railbelt and for residential/commercial heating uses in Fairbanks. Use of North Slope natural gas to meet these needs has not been fully assessed by previous studies because it has been presumed that all North Slope gas would be dedicated to the Alaska Natural Gas Transportation System (ANGTS). Alternative evaluations for ANGTS were based on transportation and utilization of the gas outside of the Railbelt market area. It now appears that ANGTS will be substantially delayed and that the gas may be available for Railbelt utilization.

The overall study of which this report is a part is charged with developing the conceptual design with subsequent cost estimates and environmental impact assessments of three energy development scenarios for two energy demand forecasts: the medium demand forecast presented in the final draft Susitna Hydroelectric Project Feasibility Report[1] and the low demand forecast presented in Battelle Pacific Northwest Laboratories' Evaluation of Railbelt Electric Energy Plans - Comment Draft.[23] The scenarios included:

1) Electrical generation at the North Slope with attendant electrical transmission to Fairbanks and on to Anchorage;

2) Electrical generation at the terminus of a high pressure natural gas pipeline to tidewater fueled by the "waste" gas byproduct of a gas conditioning facility, with necessary electrical transmission to Anchorage and Fairbanks; and,

3) Transportation of North Slope gas via a small diameter pipeline to Fairbanks, with electrical generation at Fairbanks, electrical transmission to Anchorage, and gas distribution for residential/commercial use at Fairbanks.

All three scenarios require an analysis of the energy demand forecasts to determine optimum facility staging and capacity requirements, and an analysis of facility and corridor siting constraints and/or opportunities. These latter two topics are the subject of other project reports.

Ebasco has prepared this report to identify existing data and various study assumptions which concern the composition and availability of North Slope gas and potential constraints to its use. In addition, several engineering and economic assumptions fundamental to the other aspects of the study are presented. The report is based on a review of the literature as well as numerous discussions with knowledgeable agency and industry representatives.

This report plays an essential role in the feasibility level assessment by establishing study assumptions so that all disciplines formulating the technical details of the three scenarios will have a common data base from which to proceed. A common data base will also facilitate comparisons among the scenarios.

The structure of this report begins with a short background chapter (Chapter A2.0), which serves to establish an historical perspective to the various studies that are referenced. Following this background, is a discussion of the physical composition and characteristics of North Slope gas (Chapter A3.0). Gas supply and availability (Chapter A4.0) are reviewed and summarized. Engineering (Chapter A5.0) and economic (Chapter A6.0) assumptions are provided to establish an early, common data base for the scenarios. Chapter A7.0 is reserved for issues of concern to utilization of North Slope natural gas to meet the future energy needs of the Railbelt. Following these chapters is an addendum of literature on North Slope natural gas and Railbelt energy needs, and an addendum listing Ebasco's contacts with agency and industrial personnel.

A2.0 BACKGROUND

The natural gas reserves on the North Slope have been the subject of numerous studies and reports since their discovery. Since development on the North Slope began, various proposals to build a pipeline to carry the gas to markets in the lower 48 states have been formulated. As a result of the proposals, an extensive literature of economic, technical, and environmental studies that evaluate the alternatives to each proposal has been accumulating. Many of these studies have been reviewed to assemble the data contained in this report and are listed in the Addendum.* Ebasco presents a background to the literature survey by summarizing some of the most useful studies in chronological order in this chapter.

"The Final Environmental Impact Statement for the Alaska Natural Gas Transportation Systems" is representative of studies in support of the initial attempts to develop North Slope natural gas.[29] This statement by the Federal Power Commission, which analyzes two separate proposals and numerous alternatives for pipeline systems, was issued in April 1976 and is of principal interest for historical purposes. The document established a preferred pipeline route from Prudhoe Bay to Fairbanks and then through Canada to the lower 48 states.

A second study of interest is "Analysis of Prudhoe Bay Royalty Natural Gas Demand and the Proposed Prudhoe Bay Royalty Natural Gas Sale," dated January 1977.[34] While the analysis is out of date and should be used for informational purposes only, the report covers many of the issues which are relevant to the present study. In particular, it discusses the royalty share (12.5 percent) of the produced gas, the expected gas production rate, and natural gas demand and demand growth.

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* Reference numbers refer to the bibliography in the Addendum of this Appendix. The bibliography also contains documents not referenced in this report.

Studies by electric power planning agencies during the early years of development of the Prudhoe Bay field is typified by the report, "North Slope Natural Gas Transport Systems and their Potential Impact on Electric Power Supplies and Uses in Alaska".[36] This report by R.W. Retherford Associates for the Alaska Power Administration updated various analyses presented in the previously cited Federal Power Commission EIS concerning the impacts of a natural gas pipeline on Alaskan electric power generation. This study is also out of date but of interest because of its negative conclusions on the economics of using natural gas for electrical generation. The study concludes that electricity from other sources should be used to power the gas pipeline.

In March of 1977, the Alaska Department of Commerce and Economic Development issued a report written by the staff of Battelle Pacific Northwest Laboratories entitled, "Alaskan North Slope Royalty Natural Gas - An Analysis of Needs and Opportunities for In-State Use".[22] This report concludes that North Slope natural gas had no potential for electrical generation since other less expensive fuels were available. Like many of the studies prior to 1980, it assumed the timely completion of a major gas pipeline carrying all of the available gas to markets outside of Alaska.

In November 1977, President Carter designated the Alaska Highway Pipeline Project (Alcan) for construction based on the provisions of the Alaska Gas Transportation Act of 1976. The Alcan proposal is the project which is now referred to as the Alaska Natural Gas Transportation System (ANGTS). Typical of the several informative reports commissioned by the Alaska legislature concerning the ANGTS project is the report by K. Brown and C. Barlow, "An Overview of Natural Gas and Pipeline Issues," dated June 1978.[24] The document provides insight to the issues regarding development of North Slope gas. While this study is a critique of the Alcan project, it raises issues on possible licensing and development constraints and the effects of wellhead price on the economic viability of the project.

In September 1978, the Ralph M. Parsons Company produced a report entitled, "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska".[35] The importance of this document is in its specification of the composition of North Slope gas and the conditioning needed to produce a pipeline quality gas for ANGTS. The study presumes a major pipeline but many of the specifications are applicable to the present feasibility level assessment.

The State of Alaska Department of Natural Resources issued a report by C. Barlow of Arlon R. Tussing & Associates in March 1980 which presents a highly informative technical discussion of the characteristics of North Slope gas, written for the layman.[21] Titled "Natural Gas Conditioning and Pipeline Design," the report is particularly useful in explaining the effects of carbon dioxide and permafrost on pipeline design for the delivery of North Slope gas.

Among the later documents which are important to the present study context is, "Alaska-Historical Oil and Gas Consumption," a report written by Battelle and issued by the State of Alaska Department of Natural Resources in January 1982 as a statutory requirement to the Alaska legislature.[37] The report provides a basis for projecting the amount of gas required for the analyses in this feasibility level study.

A study representative of the current economic issues which arise concerning North Slope gas utilization is a report by Kidder, Peabody, and Company, "Report to the Governor's Task Force on State of Alaska Participation in Financing the Alaskan Segment of the Alaska Natural Gas Transportation System".[31] This report is dated March 1982 and explores alternatives the state could use to help finance the Alaska Natural Gas Transportation System segment in Alaska. Likewise, a recent report titled, "Alaska Natural Gas Development: An Economic Assessment of Marine Systems," is representative of alternatives to ANGTS for moving North Slope natural gas to markets outside Alaska.[30]

Several studies to utilize North Slope gas are currently being conducted in addition to this feasibility level assessment. Booz, Allen & Hamilton, Inc. is performing a study for the Alaska Department of Natural Resources to screen a wide range of transport and use options (including ANGTS), and to analyze economic and environmental aspects resulting in a general ranking of promising options. Brown and Root, Inc. is performing a study for the Governor's Economic Committee on Alaska Natural Gas which focuses on a gas pipeline to a tidewater conditioning plant in the Kenai/Nikiski area. The study is also investigating various marketing options for the gas. Use of the waste gas stream from this conditioning plant is the basis of the Kenai generation scenario in Ebasco's assessment.

The U.S. General Accounting Office recently contracted for another study with Parsons, Brinkerhoff, Quade and Douglas, Inc. to generate a financial report on engineering costs associated with transporting Alaska natural gas to markets in the lower 48 states.

A3.0 GAS COMPOSITION

A determination of the physical composition of North Slope natural gas is essential to evaluate the economics of its utilization under alternative scenarios. The trade-offs among gas conditioning, gas transportation, and gas utilization alternatives depend on the types and quantities of chemical compounds present in the natural gas. In particular, North Slope natural gas is characterized as "sweet and wet" (generally desirable factors), but is relatively high in carbon dioxide (undesirable factor).[21]

Several studies and sources of data on chemical composition of North Slope natural gas are available.[21,35] The data are in substantial agreement to support a preliminary feasibility level analysis. Variation among the data sources may be attributable to the fact that North Slope natural gas can be obtained from the top of the Sadlerochit formation (the gas cap) or from the lower lying oil as a dissolved gaseous constituent.

Ebasco, based on consultation with industry and government personnel, will use the natural gas composition shown in Table A3-1 as the common data base for each scenario. The Ralph M. Parsons Company assembled these data in September 1978 to support a study for sales gas conditioning facilities at Prudhoe Bay.[35] The Parsons' study, in support of a major all-Alaska pipeline proposal, embodies several gas composition assumptions appropriate for the three Railbelt scenarios considered in Ebasco's study.

The single most significant factor in the composition of North Slope natural gas which influences the economics of its utilization is the relatively high carbon dioxide content. Table A3-1 shows that over 12 percent (by volume) of the gas is carbon dioxide, a combustion product gas which is a generally undesirable constituent. Carbon dioxide removal

TABLE A3-1

NORTH SLOPE NATURAL GAS COMPOSITION

Constituent	Volume Percent
H_2S	0.0008
CO_2	12.63
N_2	0.47
Methane	74.17
Ethane	6.47
Propane	3.48
Butanes	1.66
Pentanes-plus	1.22
	100.00
Raw Gas Heating Value	1046 Btu/ft^3

is required to produce a high quality pipeline gas. The gas represents an added transportation cost if conditioning facilities are not on the North Slope. Carbon dioxide may also promote pipeline corrosion through the formation of carbonic acid and must be removed if natural gas is to be stored as liquid natural gas (LNG). (Carbon dioxide does allow a pipeline to carry greater quantities of heavy hydrocarbons, but the net benefit is rather small.)

The sulfur content of North Slope natural gas is low and treatment is not required prior to pipeline transmission.[35] Sulfur is an undesirable constituent of natural gas which can increase treatment costs considerably, contribute to air pollution, and promote pipeline corrosion. The low sulfur content is denoted by the gas being termed "sweet".

The relatively high proportion of natural gas liquids (NGL) compared to methane is a desirable characteristic if natural gas is used as a petrochemical feed stock.[21,24] Natural gas liquids are present in North Slope gas because it is derived from an oil reservoir. The heavier hydrocarbons (ethane, propane, and butane) which make up the natural gas liquids are not desirable for domestic utility use where "dry gas" is favored. The "wet" gas can be conditioned to remove the heavier hydrocarbons.

The composition of the waste gas stream associated with the Kenai electrical generation scenario arises from the assumption that gas conditioning will be employed at the tidewater terminus rather than on the North Slope. In the absence of a specific gas conditioning process design, Ebasco derived a theoretical maximum gas composition based on a stipulated waste gas heating value of 300 Btu/SCF. This analysis shows that an unrealistic quantity of raw gas hydrocarbons is necessary to achieve this heating value. Based on a brief analysis of available gas conditioning processes, the waste gas stream could have an approximate heating value of 175 to 195 Btu/SCF. An exact composition of the waste gas stream cannot be specified at this time, but it will be high in heavier hydrocarbons and carbon dioxide.

A4.0 GAS SUPPLY AND AVAILABILITY

Gas supply refers to the physical quantity of natural gas present in the Prudhoe Bay field. Gas availability refers to physical and institutional constraints on gas production. Most estimates of the total volume of gas are in the range of 30 to 40 trillion cubic feet (TCF) for the known reserves in the Sadlerochit formation, of which some 25 to 30 trillion cubic feet are recoverable.[21,22,28,34] To place these quantities in perspective, the North Slope contains 10 percent of the known U.S. natural gas reserves and could supply 5 percent of the present demand in the lower 48 states for 30 years.

For purposes of this study, Ebasco will use a quantity of 26 TCF as an estimate of the recoverable reserves of North Slope gas. This is consistent with the 1977 Battelle report on North Slope royalty gas.[22] This quantity refers only to the Sadlerochit formation gas, for which the State of Alaska royalty share is 12.5 percent of production.

Production of Prudhoe Bay natural gas will be at a rate to maximize recovery of oil in the formation. At present, some 2 billion cubic feet (BCF) of gas are brought to the surface with the oil each day. All but a few percent are injected back into the gas cap in order to maintain reservoir pressures and maximize oil recovery. The State of Alaska Oil and Gas Conservation Committee establishes the operating methods through pool rules, an administrative rule making procedure. Conservation Order No. 145 (June 1, 1977) provides for annual average offtake rates of 1.5 million barrels per day for oil and 2.7 BCF per day for gas. The pool rule production rate is consistent with other published production capabilities for the Prudhoe Bay field and therefore will be used by Ebasco. A production rate of 2.7 BCF per day is assumed to yield 2.0 BCF per day of conditioned gas.[21]

"Production" is a term which must be carefully defined in context once a significant quantity of Prudhoe Bay gas can be utilized. According to the Prudhoe Bay Lease Agreements, the State of Alaska royalty share (12.5

percent) applies to gas that is "produced, saved, sold or used off said land", and does not include gas utilized to operate the oil field and gas injected to maintain reservoir pressure. The only gas now being produced is the 60 million cubic feet per day sold to Alyeska to operate four of the Trans-Alaska Pipeline System (TAPS) pump stations. If North Slope gas is to be utilized solely for the scenarios considered in this study, the project proponent would have to enter into discussions with the producers to negotiate for the sale of the gas.

Of the approximately 2.0 BCF per day of conditioned gas available for use, the Railbelt low and medium future electricity needs could only absorb on the average 0.11 BCF per day and 0.19 BCF per day, respectively. The Alaskan royalty share alone (12.5 percent) would generally be sufficient to meet both growth forecasts.

The waste gas stream associated with the Kenai electrical generating scenario is incapable of meeting the needs of even the low forecast. The amount of available gas is approximately 430 x 10^6 SCF/day, with a heating value of 175 to 195 Btu/SCF. This is only about 50 percent of the required energy to meet the electrical needs in the low growth case. The waste gas stream must, therefore, be supplemented with appropriate quantities of sales gas to meet energy needs.

A5.0 ENGINEERING ASSUMPTIONS

Several engineering assumptions have been made to facilitate development of the electrical generation scenarios. These include using the medium load and energy demand forecasts presented in the final draft Susitna Hydroelectric Project Feasibility Report (Table 5.7)[1] and the low load and energy demand forecasts presented in Battelle Pacific Northwest Laboratories' Evaluation of Railbelt Electric Energy Plans - Comment Draft (Executive Summary, Page iv).[23] It should be noted that the latter forecasts are lower than the low range forecasts given in the Susitna Feasibility Report. These particular forecasts are being used at the request of the Alaska Power Authority to ensure comparability with previous Railbelt electric energy analyses. It is also expected that these forecasts will bracket a revised medium range forecast which is currently being prepared by Battelle Pacific Northwest Laboratories using their existing RED model and based on revised economic forecasts currently being prepared by the University of Alaska Institute of Social and Economic Research.

Preliminary estimates of the amount of gas to meet power generation needs are being based on the use of a conversion (heat) rate of approximately 10,000 Btu/kWh and a sales gas heating value of approximately 1,000 Btu/SCF. These values, when applied to the low electrical demand forecast result in an annual average usage in the year 2010 of 39.4 BCF. Similarly, the medium electrical demand forecast results in an annual usage in the year 2010 of 67.9 BCF for electrical generation. These annual average values as well as required peaking values and preliminary Fairbanks residential/ commercial usage estimates are presented in Table A5-1. The assumptions utilized to generate Fairbanks gas demand are presented in Chapter A6.0 The preliminary gas demand estimates presented in Table A5-1 are presently being utilized for North Slope to Fairbanks small diameter gas pipeline design and the Fairbanks gas distribution system design. When final estimates of gas demand are generated appropriate refinements in gas pipeline and distribution system design will be made.

TABLE A5-1

PRELIMINARY GAS REQUIREMENTS FOR POWER GENERATION AND FAIRBANKS RESIDENTIAL/COMMERCIAL USE IN THE YEAR 2010

USE	LOW LOAD FORECAST	MEDIUM LOAD FORECAST
POWER GENERATION		
Maximum Requirements* (SCFM x 10^5)	1.2	2.1
Average Requirements** (SCFM x 10^5)	0.75	1.3
Average Annual Requirements (BCFY)	39.4	67.9
RESIDENTIAL/COMMERCIAL USE***		
Average Annual Requirements (BCFY)	5.3	10.1
TOTAL AVERAGE ANNUAL REQUIREMENTS (BCFY)	44.7	78.0

* Natural gas firing rate at peak demand based upon the following required new gas fired generating capacity in the year 2010: 741 MW for low load forecast and 1278 MW for medium load forecast.

** Natural gas firing rate associated with total annual energy requirements: required new gas fired energy requirements in the year 2010 are 3937 GWh for low load forecast and 6788 GWh for medium load forecast.

*** Values represent "Extreme of Reasonable". Refer to Chapter A6.0 for discussion.

All three scenarios involve power plant facilities. The diversity of the Alaskan environment requires each location to have different facility design conditions. A North Slope facility must be built on steel piles using modular construction in the manner of the existing Prudhoe Bay facilities. Zone 1 earthquake design criteria will apply. For both Fairbanks and Kenai, conventional construction methods for Zone 3 earthquakes are applicable, although Fairbanks also requires consideration of greater temperature extremes. Air cooled condensers will be used for steam cycles in order to avoid large cooling water flows and problems associated with cooling water such as availability limitations and intake icing. In many places in Alaska, evaporative cooling water can also be a significant source of ice fog.

Engineering assumptions applicable to construction of a natural gas pipeline to serve Fairbanks begin with the original ANGTS route using a minimum separation of 200 feet with TAPS. This distance is commensurate with that specified in the U.S. Department of the Interior grant of right-of-way for ANGTS.[43] Ebasco assumes the use of buried line which requires the gas to be kept cooled to maintain the permafrost. An initial line pressure of 1260 psig will be used in sizing the pipeline. Because of the high carbon dioxide content of North Slope gas, the Fairbanks scenario will include gas treatment for CO_2 removal at Prudhoe Bay. The number of compressor stations has not been determined yet, but will be established using standard computer programs.

Associated with the small diameter line to Fairbanks is a domestic gas distribution system. Minimum inlet pressure will be 350 psig at gas regulators, 125 psig in the high pressure system to district regulators, and 60 psig in the distribution system to customers. Distribution lines will be laid in public rights-of-way at a depth of 3 feet using standard 2 inch lines.

For the purpose of sizing the transmission lines from Prudhoe Bay to Fairbanks and from Kenai to Anchorage, preliminary estimates of required new generating capacity were made. These estimates, which accounted for plant retirements, planned additions and energy demand forecasts, resulted in required capacities for the year 2010 of approximately 700 MW for the low demand forecast and 1400 MW for the medium demand forecast. Required additions to and upgrading of the Anchorage-Fairbanks Intertie were designed to distribute capacity and ensure stability, and not to optimize the entire Railbelt transmission system. Therefore, it was assumed that 80 percent of the power that either arrives at Fairbanks from Prudhoe Bay or is generated in the Fairbanks area, depending upon the development scenario, is transmitted to Anchorage. Similarly, for the Kenai scenario it was assumed that 20 percent of the power arriving in Anchorage is transmitted to Fairbanks. The 4 to 1 split assumed is based on the ratio of total utility sales in the Railbelt during 1980.[1/]

For the Prudhoe Bay generation scenario, the transmission line from the North Slope to Fairbanks carries 100 percent of the generating capacity through adverse environmental conditions. The contamination, due to salt, dust, and moisture is severe from Prudhoe Bay to approximately 60 miles inland, requiring washing of insulators at the switchyard and on that portion of the line to prevent flashover. Several combinations of wind, temperature, and ice loading will be evaluated to determine conductor design. Table A5-2 summarizes conductor loading conditions for the Prudhoe Bay-Fairbanks transmission line. The stream crossing design for the Yukon River requires special investigation. A DC alternative will also be analyzed. With one AC line segment or one of the DC poles out of service, the Prudhoe Bay-Fairbanks-Anchorage system will remain stable in the steady-state at normal peak continuous loading.

The Fairbanks-Anchorage lines (330 miles) carry 80 percent of the capacity for the Prudhoe Bay and Fairbanks generation scenarios, but only 20 percent for the Kenai scenario. The Fairbanks-Anchorage Intertie which is presently under construction (170 miles at 345 kV AC) will be

TABLE A5-2
TRANSMISSION LINE CONDUCTOR LOADINGS

CONDUCTOR LOADINGS FOR PRUDHOE BAY - FAIRBANKS TRANSMISSION LINE*

Temperature (°F)	Ice Thickness (radial inches)	Wind Pressure (lb/sq ft)	Corresponding Wind Speed (miles per hour)
-60	none	25	100
32	1.5	8	60
86	none	2.3	30

CONDUCTOR LOADINGS FOR FAIRBANKS - ANCHORAGE TRANSMISSION LINES

Temperature (°F)	Ice Thickness (radial inches)	Wind Pressure (lb/sq ft)	Corresponding Wind Speed (miles per hour)
-60	none	25	100
32	0.75	8	60
86	none	2.3	30

CONDUCTOR LOADINGS FOR KENAI - ANCHORAGE TRANSMISSION LINE

Temperature (°F)	Ice Thickness (radial inches)	Wind Pressure (lb/sq ft)	Corresponding Wind Speed (miles per hour)
-40	none	25	100
32	0.75	8	60
90	none	2.3	30

* All conductor loadings derived from published literature, evaluations of environmental conditions, discussions with utility operations personnel, and engineering judgement.

fully extended (to 330 miles) in each scenario, and additional lines will be considered, as required, to carry the projected loads. Only AC operation will be considered. Conductor loading conditions for these scenarios are also given in Table A5-2.

The Kenai generation scenario assumes construction of a Kenai-Anchorage Intertie which would carry 100 percent of the load for about 150 miles. Environmental conditions are moderate for this line including mild contamination. Table A5-2 summarizes expected conductor loadings.

Design parameters for the AC switchyard at the generating station and intermediate switching stations will assume breaker and a half bus arrangement.

A6.0 ECONOMIC ASSUMPTIONS FOR FAIRBANKS NATURAL GAS DEMAND

Preliminary residential and commercial gas demand has been estimated for Fairbanks so that the North Slope natural gas pipeline and the Fairbanks natural gas distribution system conceptual design could proceed. Numerous assumptions were made in order to develop the preliminary forecast of natural gas demand.

Based upon an inventory of current fuel prices in Fairbanks (Table A6-1) and a subsequent economic evaluation, the primary assumption is that natural gas will be used exclusively for space and water heating; and that it will compete directly with #2 distillate oil which is currently used in most residential and commercial installations. It is assumed that natural gas will not compete with coal, wood, or electricity for either price or application reasons.

Given the age of the building stock in Fairbanks, it is assumed that oil fired equipment operates at a thermal efficiency of 60%, and that gas-fired units will have a thermal efficiency of 74%. The cost of conversion from oil to natural gas is assumed to be $600/unit, based upon contacts with local oil dealers. There are about 23,000 residences in Fairbanks to be heated. Average #2 distillate consumption is 1,500 gal/yr, at a higher heating value of 138,100 Btu/gal. Natural gas for distribution is assumed to have a higher heating value of 1,000 Btu/ft^3.

The commercial demand for natural gas is based upon an assumed consumption rate of 160,000 Btu/ft^2. A commercial building inventory of 3.22 million ft^2 of space exists in Fairbanks.

Given these assumptions, preliminary demand forecasts have been made. They will be used, subsequently, in engineering analyses.

TABLE A6-1

INVENTORY OF FUEL PRICES IN FAIRBANKS

Fuel/Energy Type	1981 Fuel Price In Fairbanks	Equivalent 1981 Price - Efficiency Adjusted ($/million Btu)
#2 distillate	$1.23/gal	$14.84
Residential Coal (Healy)	$61/ton	$ 5.36
Wood (split and delivered)	$100/cord	$ 9.83
Residential electricity (GVEA)*	$0.1051/kWh	$30.70
Residential electricity (FMUS)**	$0.0906/kWh	$26.55
Commercial electricity (GVEA)	$0.0922/kWh	$27.01
Commercial electricity	$0.0770/kWh	$22.56

* Golden Valley Electric Association.

** Fairbanks Municipal Utilities System.

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The preliminary forecasts assume growth rates of 2% and 4.3%, per year, in heating system demand.[1,23] At a 2%/yr growth rate, the maximum demand in the year 2010 will be 8.4 BCF, or 8.4 trillion Btu. At a 4.3%/yr growth rate, the upper limit of demand in 2010 is 15.9 BCF of natural gas, or 15.9 trillion Btu.

The extreme of reasonable value, used for subsequent engineering design studies (capacity planning) is based upon replacing 63.3% of the #2 distillate demand in the year 2010. In this case the projections are as follows:

Growth Scenario	Natural Gas Demand (BCF)	Natural Gas Demand (trillion Btu)
Low (2%/yr)	5.3	5.3
Medium (4.3%/yr)	10.1	10.1

These projections are based upon an initial break-even price between natural gas and oil of $10.14/thousand cubic feet (MCF) for residential applications, and $10.54/MCF for commercial applications (1981 prices). After an assumed competitive response to natural gas by the North Pole Refinery, these break-even prices may drop to $9.07/MCF for residential users and $9.43/MCF for commercial users (also 1981 prices).

These preliminary demand estimates will be expanded upon, and refined, for the final report. Such refinement will be based upon additional data now being developed.

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A7.0 OTHER CONSIDERATIONS

A7.1 POWERPLANT AND INDUSTRIAL FUEL USE ACT

A new gas or oil fired electric generating facility using North Slope natural gas will be subject to the provisions of the Power Plant and Industrial Fuel Use Act of 1978 (FUA). Pursuant to section 201 of the FUA, oil and/or natural gas may not be used as a primary energy source in a new electric power plant unless special permission is obtained. Special permission is granted by the Economic Regulatory Administration (ERA) within the Department of Energy (DOE) in the form of an exemption from the FUA prohibition of the use of natural gas. A statutory exemption for Alaskan utilities was recently (December 30, 1982) signed into law by President Reagan as part of the fiscal 1983 Department of the Interior Appropriations Bill (H.B. 7356). The exemption, however, does not apply to any new electric power plant which would use natural gas produced from the Prudhoe Bay unit.

Prior to this exemption, a very thorough analysis of the Act and potential exemptions applicable to Alaskan utilities were provided as an appendix to a report submitted to the Legislative Affairs Agency of the Alaska State Legislature by G. Erickson.[28] The analysis concluded that:

> It appears there do exist grounds under which any of the utilities along the Railbelt might qualify for a permanent exemption from the requirement of the Act to use coal or other alternate fuel. Such grounds might include (a) lack of alternate fuel supply for the first 10 years of the useful life of the facility; (b) lack of alternate fuel at a cost which does not substantially exceed the cost of imported oil; (c) site limitations (this seems less likely); (d) inability to comply with applicable environmental requirements, and (e) inability to use alternative fuel because of a State or local requirement.

It should be cautioned that this analysis has no legal implications and that a final decision regarding an exemption will not be known until an application is submitted to the ERA. For the purposes of this study, however, the FUA is not considered prohibitive of development of new electric power plants using Prudhoe Bay unit natural gas.

A7.2 COST OF NATURAL GAS

Cost of North Slope gas at the point of use is fundamental to scenario planning and the ultimate determinant of project viability. The constraints, technical and institutional, to determining a reliable cost have prevented, in large part, the implementation of all previous proposals to use North Slope gas, and no definitive cost can be presented here. However, upper limits to the wellhead cost of North Slope gas can be established through comparison to alternative fuel costs by subtracting engineering estimates of gas upgrading and transmission (including distribution) system costs. Essentially all costs incurred between the well and the consumer must be so accounted for. Thus, by "backing out" the wellhead cost as a remainder, it can be determined whether gas can compete with alternative fuels.

It has been determined, by Alaska Economics, Inc., that natural gas will compete almost exclusively with #2 distillate oil. The reasons, and price comparisons, are discussed in Chapter A6.0 of this report. Presently, #2 oil costs $14.84 per million Btu (efficiency adjusted) in Fairbanks. In the simplest case, any combination of gas wellhead cost plus upgrading and transportation cost (including distribution cost) plus system conversion costs that is significantly less than $14.84 per million Btu (net heat delivered to the house) means gas can compete with oil in Fairbanks. Ebasco's approach will be to determine all conditioning, transportation and system costs to allow the wellhead cost of North Slope gas to be derived. The desired result of this calculation is to obtain a value which indicates that for any given the cost, North Slope gas will be either competitive or non-competitive (in price) with alternative fuels. The only basis for estimating the cost of North Slope gas at this time is the cost for gas used to operate the Trans-Alaska Pipeline System stations. The delivered cost varies somewhat in time, but is about $1.86 per million Btu.

Facility costs and derived wellhead values will also provide information essential in the development of any comparative power costs between alternative generation technologies. Such comparisons are outside Ebasco's scope of work, but can be considered as a logical extension which may be performed by the Alaska Power Authority.

ADDENDUM A

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Peter Christensen	Brown & Root, Inc.	Governor's Economic Committee on Alaska Natural Gas study, "waste" gas composition, "waste" gas volumes, location of all-Alaska pipeline route and conditioning plant.
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ADDENDUM B

LIST OF CONTACTS

NORTH SLOPE GAS FEASIBILITY STUDY

LIST OF CONTACTS

Name	Organization/Agency	Reason for Contact
Ben Ball	ARCO-Alaska	Gas composition at Central Compressor Plant.
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Loren Douglas	ARCO-Alaska	ARCO's electrical system.
William Friar	ARCO-Alaska	General North Slope information, facilities tour.
Darrell Jordan	ARCO-Alaska	Foundation design practice-North Slope.
Mary Jane Little	ARCO-Alaska, Administrative Supervisor	General North Slope information, facilities tour.
Jim Moreland	ARCO-Alaska	ARCO's electrical system.
Paul Norgaard	ARCO-Alaska, President	Facilities tour.
Brad Spencer	ARCO (Pasadena)	Weight & size restrictions for barged modules to North Slope.
Archie Walker	ARCO-Alaska	Foundation design practice-North Slope.
Richard Blumer	SOHIO	SOHIO's North Slope electrical system and power plant design.
Charles Elder	SOHIO, Vice President Alaska Affairs	Gas use and plant tour.
Richard Lipinski	SOHIO, Manager Construction Support	North Slope construction and operation considerations.
Paul Martin	SOHIO, Vice President Operations	Gas use and plant tour.
Larry Colp	Fairbanks Municipal Utilities System	Fairbanks' electrical system and climatological data.
Alan Martin	Fairbanks Municipal Utilities System	Fairbanks' electrical system and climatological data.

LIST OF CONTACTS (Continued)

Name	Organization/Agency	Reason for Contact
George Ott	Fairbanks Municipal Utilities System, Public Services Director	General information. Chena plant design.
William Perry	Fairbanks Municipal Utility System, General Manager	Power requirements and plant tour.
Gary Rice	Fairbanks Municipal Utilities System	General Civil Information. Chena Plant Design.
Keith Sworts	Fairbanks Municipal Utilities Systems	General utility statistics - fuel consumption by type; steam and electric baseload data, rate structure, expansion plans. Chena plant design, facility tour.
Harold Alexander	Alyeska Pipeline Co.	General information, facility tour.
Frank Fisher	Alyeska, Alaska Manager, ANGTS Relations	Proximity to TAPS, right-of-way constraints.
Jim Harley	Alyeska, Technical Manager, ANGTS Relations	Proximity to TAPS, right-of-way constraints.
Eldon Johnson	Alyeska Pipeline Co.	Climatological data.
Joe Pitman	Aleyska, Pump Station 1	Pump station operation.
John Ratterman	Alyeska, Manager Public Affairs	General information, facility tour.
Andrew Smart	Alyeska, Corrosion Engineer	Effect of HVDC on TAPS.
Jim Weiss	Artic Environmental Information Data Center	Climatological data.
Bela Gevay	Private Consultant	Prudhoe Bay electr. network data
Bonnie Rappaport	MAPCO (Parent of North Pole Refinery)	Current fuel oil prices, Residential Btu requirements.

LIST OF CONTACTS (Continued)

Name	Organization/Agency	Reason for Contact
Staples Brown	University of Alaska Plant Engineer	Energy needs.
Gerald England	University of Alaska (Fairbanks) Power Plant Operator	Power plant statistics, fuel consumption by type; number and area of buildings served for both steam and electricity peak and baseload data and expansion plans.
George Gordan	College Utilities General Manager	Potential gas use.
Dr. James Malosh	University of Alaska (Fairbanks) Director Dept. of Transportation Fuel Cell Study	Potential fuel cell use in Fairbanks.
Robert Sieforts	University of Alaska (Fairbanks) Cooperative Extension Agency - Energy Specialist	Appliance stock and saturation data.
Bill Allen	Mayor, North Star Borough	Electricity and gas use.
Dave Braden	Assessor, North Star Borough	Gas and electricity use and land values.
Scott Burgess	Director of Planning North Star Borough	Gas and electricity use.
John Carlson	Former Mayor, North Star Borough	Gas use.
Richard Van Orman	Deputy Director of Planning North Star Borough	Gas distribution right-of-way.
Cary Brewster	Ft. Wainwright Facility Engineer	Energy needs.
Craig Helmuth	Energy Specialist - Community Resource Center, Fairbanks	Annual energy reports, energy balance report, fuel source & end use statistics.
John Weaver	City of Fairbanks, Right-of-Way Agent	Right-of-way corridor.

LIST OF CONTACTS (Continued)

Name	Organization/Agency	Reason for Contact
Major Terry Lane	Elmendorf AFB	Federal building fuel use in Fairbanks.
Jan Brewer	Residential Energy Audit Program	Energy audit data base, Fairbanks.
John Varadi	Shawanigan Engineering	Prudhoe Bay electrical network data.
Wally Droz	City Manager, Fairbanks	Gas distribution system.
Len McLean	Pacific Alaska LNG Alaska Affairs Manager	Status of LNG plant, gas development plans, gas prices.
Tim Wallace	Doyan, Inc., President	Gas distribution.
A.W. Baker	Golden Valley Electric Association	North Pole and Fairbanks plant design, tour.
Ron Hansen	Golden Valley Electric Association	General utility statistics - fuel consumption by type; steam and electric baseload data, rate structure, expansion plans.
Eric Haemer	Chugach Electric Association, Inc. Division Manager-Systems Planning	Beluga Power Plant design, tour.
Dan Lindsey	Chugach Electric Association, Inc.	Beluga Power Plant design, tour.
W. McKinney	G.E.A., San Diego	Air-cooled condenser design information.
Mark Allisson	General Electric Co. Seattle, Washington	Gas turbine data.
Bruce Pasternak	Booz-Allen & Hamilton, Inc. Vice President, Energy and Environmental Division	To discuss DNR North Slope gas study, coordinate study efforts.
Ben Schlesinger	Booz-Allen & Hamilton, Inc. Principal	To discuss DNR study, coordinate study efforts.
Kathy Thomas	Booz-Allen & Hamilton, Inc.	To discuss DNR study, coordinate study efforts.

LIST OF CONTACTS (Continued)

Name	Organization/Agency	Reason for Contact
R. Maynard	State of Alaska, Attorney General	Constraints on use of North Slope gas.
B. Herman	Attorney General's Office, Supervising Attorney	Constraints on use of North Slope gas.
Alvin G. Ott	State of Alaska Department of Natural Resources, State Pipeline Coordinator	Status of ANGTS, SPCO Library, right-of-way constraints.
Ed Park	State of Alaska, Department of Natural Resources.	Gas production.
Ronald Ripple	State of Alaska, Department of Natural Resources, Budget & Management	To discuss DNR study, coordinate study efforts.
Mark Wittow	State of Alaska, Department of Natural Resources, Special Assistant to the Commissioner	Gas composition, availability, constraints and prices.
L. Smith	State of Alaska, Department of Natural Resources, Oil & Gas Conservation Commission, Commissioner	Determine gas supplies, constraints, availability.
H. Kugler	State of Alaska, Department of Natural Resources, Oil & Gas Conservation Commission, Commissioner	Determine gas supplies, constraints, availability.
C.V. Chatsworth	State of Alaska, Department of Natural Resources, Oil & Gas Conservation Commission, Commissioner	Determine gas supplies, constraints, availability.
Chuck Logsdon	State of Alaska, Department of Revenue, Petroleum Revenue Division	Gas revenues, production.
Vince Wright	State of Alaska, Department of Revenue	Gas revenues.

LIST OF CONTACTS (Continued)

Name	Organization/Agency	Reason for Contact
R.H. Dempsey	Alaska Interior Resources Company, Vice President	Methanol Plant plans for Fairbanks, gas and electricity use.
Mead Treadwell	Governor's Economic Committee on Alaska Natural Gas, Executive Director	Governor's Economic Committee on Alaska Natural Gas study, "waste" gas composition, "waste" gas volumes, location of all-Alaska pipeline route and conditioning plant.
Peter Christensen	Brown & Root, Inc.	Governor's Economic Committee on Alaska Natural Gas study, "waste" gas composition, "waste" gas volumes, location of all-Alaska pipeline route and conditioning plant.
Don Hale	Brown & Root, Inc. Manager Pipeline Engineering Department	Governor's Economic Committee on Alaska Natural Gas study, "waste" gas composition, "waste" gas volumes, location of all-Alaska pipeline route and conditioning plant.
Don Wold	Royalty Oil and Gas Advisory Board	Governor's Economic Committee on Alaska Natural Gas study, "waste" gas composition, "waste" gas volumes, location of all-Alaska pipeline route and conditioning plant.

APPENDIX B

APPENDIX B

REPORT

ON

SYSTEM PLANNING STUDIES

DECEMBER 1982

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SUMMARY

Ebasco prepared this report to identify from both an economic and technical viewpoint, the power generating technology and scale which best satisfy the requirements associated with Railbelt electric capacity demand forecasts. The report also identifies on a preliminary basis the year of installation of each new generating unit to be added to the system through the year 2010.

As discussed herein, a 220 MW (ISO conditions) combined cycle plant size is considered optimum for development for the Fairbanks and Kenai scenarios for reasons of flexibility, economics, and number of units to be installed. In the case of the North Slope, simple cycle combustion turbines are preferred. Each 220 MW combined cycle plant is comprised of two 77 MW gas turbines and a 66 MW steam turbine. Simple cycle units are 77 MW gas turbines. These capacities are at ISO conditions, as discussed within the text; actual capacities are higher at specific locations due to temperature differentials. The staging plan recommended for each location and technology is summarized below:

	LOW LOAD FORECAST			MEDIUM LOAD FORECAST		
YEAR	NORTH SLOPE	FAIRBANKS	KENAI	NORTH SLOPE	FAIRBANKS	KENAI
1993	0/0	0/0	0/0	91/91	86/86	84/84
1994	0/0	0/0	0/0	0/0	0/0	0/84
1995	0/0	0/0	0/0	91/182	86/172	84/168
1996	91/91	86/86	84/84	91/273	70/242	69/237
1997	91/182	86/172	84/168	91/364	172/414	168/405
1998	0/182	0/172	0/168	91/455	70/484	69/474
1999	0/182	0/172	0/168	0/455	0/484	0/474
2000	0/182	0/172	0/168	91/546	86/510	84/558
2001	0/182	70/242	69/237	0/546	0/570	0/558
2002	91/223	86/328	84/321	182/728	156/726	153/711
2003	91/364	0/328	0/321	0/728	0/726	84/795
2004	0/364	86/414	84/405	91/819	86/812	84/879
2005	182/546	70/484	69/474	182/1001	156/968	153/1032
2006	0/546	86/570	84/558	91/1092	86/1050	84/1116
2007	0/546	0/570	0/558	91/1183	86/1140	0/1116
2008	91/637	86/656	84/642	91/1274	70/1210	69/1185
2009	0/637	0/656	0/642	0/1274	86/1296	84/1269
2010	91/728	70/726	69/711	91/1365	86/1382	84/1353

B1.0 INTRODUCTION

The use of North Slope natural gas, or any other fossil fuel, for generating power to meet the demand for electrical energy in the Railbelt region requires careful system planning to optimize the addition of new generation capacity. Capacity additions must be sized and scheduled to meet increased demand for energy, replace older units as they are retired, and provide a system reserve margin that assures an uninterrupted power supply.

This system planning study utilizes data from the Acres American Inc. (1981) and Ballelle Pacific Northwest Laboratories (1982) studies to determine demand levels for energy, an acceptable range for Railbelt system reserve margins, and the capacity deficits that must be satisfied with new electrical generation. This capacity deficit forecast is then used to develop various scenarios for addition of new capacity from one of the available technologies capable of utilizing North Slope natural gas.

Planning for the growth of the system requires selection of a type or types of technology to be used for the new generation capability. Selection of the optimum technology(s) is a function of the fuel type and cost, technology efficiency, required capacity additions, capital and operating and maintenance costs, and licensing and construction times. The purpose of this system planning study is to evaluate and recommend, from both an economic and a technical viewpoint, the technology(s) and scale which best satisfy capacity, reliability and least cost criteria. Further, the study recommends on a preliminary basis the year of installation of each new generating unit to be added to the system through the year 2010.

This System Planning Report is the second of a series in developing a feasibility level assessment regarding the use of North Slope natural gas for power generation in the Railbelt and for residential/commercial heating uses in Fairbanks, and as such provides required data necessary for the completion of the overall feasibility study. The results of this analysis assure that the feasibility study analyzes scenarios which meet the needs of the Railbelt region. The specific outputs which will be used to complete the balance of the feasibility study are selection of the optimum power generating technology and unit size, and proper timing of unit addition to maintain reserve margins, thus providing the bases for facility design, siting, cost estimating, and environmental assessment.

B2.0 METHODOLOGY

B2.1 TECHNOLOGY REVIEW

It was determined that there are three applicable technologies that could be used to generate electricity by using North Slope gas. These are simple cycle gas turbines, combined cycle installations (gas turbines with heat recovery boilers and steam turbines), and gas fired boilers with steam turbines. Each technology was reviewed to determined the state-of-the-art, efficiency, size, availability, constructability, and conceptual design criteria. This review data was then evaluated in light of the three locations considered in the feasibility study, (i.e., the North Slope, the Fairbanks area, and the Kenai area) to determine technology applicability. Finally, advantages, disadvantages and potential problems associated with each technology in each location were determined and evaluated.

B2.2 DERIVATION OF NEW CAPACITY REQUIREMENTS

Data from two sources were used to develop the new capacity requirements for the Railbelt region. Reserve margins and low load growth forecasts for the region were derived from Battelle's Evaluation of Railbelt Electric Energy Plans - Comment Draft (Battelle 1982). Medium load growth forecasts, planned power plant additions for the immediate future, and the retirement schedule for existing Railbelt generating capacity were obtained from the final draft Susitna Hydroelectric Project Feasibility Report (Acres American Inc. 1981).

The reserve margins and load forecasts were used to establish maximum required capacities for each year through the year 2010. Existing capacity plus planned additions and retirements were used to establish the balance of existing capacity for each year. These two derived data sets were then used to establish the required new capacity for each year.

B2.3 APPLICATION OF TECHNOLOGIES TO REQUIREMENTS

The results of the technology review provided the data necessary to project the units of new generation capacity required to satisfy electrical demand. The size of units for addition were selected based on least capital cost and the range of unit sizes which satisfied the new capacity requirements without greatly exceeding maximum reserve requirements. These unit sizes were then applied to create scenarios for new generating capacity. Of the three technologies previously mentioned (simple cycle, combined cycle and gas boiler) two were found to be acceptable for application in this study. Those two are simple cycle and combined cycle gas turbines. The direct fired gas boiler/steam turbine was judged to be non-competitive due to high capital costs which are not offset by any significant advantage in either heat rates or operating and maintenance costs. Operating costs advantages which might be realized with this technology in very large plants are not available in the unit size range (150-350 MW) being considered here.

The two remaining technologies with the two different load growth forecasts result in four basic scenarios. It is then necessary to consider the effect of ambient conditions on capacity and efficiency at each of the three potential scenario locations. The primary factor affecting operation is temperature. After reviewing the effects of the average annual temperature on capacity and efficiency at each location, it was decided that the locales must be considered separately. The following table shows the effect of temperature on capacity and efficiency.

Locale[1]	Temp[2] °F	Gas Turbine Capacity Change	Steam Turbine[3] Capacity Change	Heat Consumption Change
North Slope	9°	+18.2%	+3.5%	+14.6%
Fairbanks	26°	+12.0%	+2.2%	+9.6%
Kenai	33°	+9.5%	+1.7%	+7.5%

1/ Changes are based on International Standards Organization (ISO) conditions for base loaded units, which are 59° F and sea level.
2/ Average annual temperature.
3/ Applies to steam turbines as part of combined cycle only.

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These three sets of conditions combined with the four basic scenarios result in 12 locale specific scenarios for evaluation and comparison. As input for economic evaluation, the total energy (GWh) generated for each scenario in each year was also developed.

B2.4 ECONOMIC EVALUATION

Developed scenarios were analyzed to determine which resulted in the lowest overall cost on the basis of present worth of costs. In order to perform this analysis it was necessary to develop capital, operating and maintenance, and fuel costs for each technology and to calculate the total energy generated in each year for each scenario. The economic model yielded the total cost of each scenario in 1982 dollars.

B3.0 TECHNOLOGY REVIEW

Three mature and proven technologies were reviewed for application to the Railbelt. They are Simple Cycle Gas Turbines, Combined Cycle Systems (Gas Turbine with Heat Recovery Boilers and Steam Turbines), and Gas Fired Boilers with Steam Turbines.

It is common industrial practice to quote heat rates for oil and gas fired simple cycle turbines as a function of the lower heating value of the fuel. However, fuel is purchased by higher heating value, and other technologies' heat rates are in terms of higher heating values. In this report heat rates quoted and used for analysis are based on higher heating values. Where applicable, lower heating value heat rates are given in parentheses.

B3.1 SIMPLE CYCLE TECHNOLOGY

Simple cycle gas turbines are available from several vendors in a variety of sizes. Review of the designs, lead times for licensing and construction, and constructability of the gas turbines led to the conclusion that they would be applicable to all three potential locations considered in the feasibility study. Heat rates for these units vary from 11,800 to 13,000 Btu/kWh (10,600-11,700 Btu/kWh-LHV).

Pre-constructed simple cycle units for the North Slope can be shipped by barge from a lower 48 port for installation at the slope. Existing piling and support methods at the slope are adequate for units up to 100 MW, the largest commercially available unit size. Handling capabilities for 2400 ton units already exist at the North Slope and are sufficient for this option. The units would be moved into place on crawlers, leveled on pre-placed steel and concrete pilings, and connected to the gas supply and electrical systems. Several gas fired simple cycle units of this type are already in operation at the North Slope.

A Fairbanks area location for gas turbines would allow "in place" construction on typical spread footings or pilings. There are many existing combustion turbine units in operation in the Fairbanks area using distillate fuel.

The Kenai area option for simple cycle differs from that for Fairbanks only in the quality of the fuel. The waste stream fuel to be used here is expected to have a very low heating value (approximately 175- 195 Btu/ft^3) and high CO_2 content. Gas turbines can be modified for firing on fuel with heating values as low as approximately 150 Btu/ft^3. Such firing requires modification of the combustion chamber, valving and piping, and requires that the units be started up on higher Btu fuel such as distillate or natural gas. An additional problem is that the high CO_2 content of North Slope gas results in a conditioning facility waste gas that will be difficult to burn due to the quenching effect that CO_2 has in the combustion chamber. This problem can be overcome by blending higher Btu content gas during startup and less than full load operation, and through modifications to hardware, similar to those for the low Btu problem.

The total energy available in the waste stream is insufficient to meet the energy needs of the Railbelt. It is, therefore, necessary to supplement the waste stream with some of the sales gas which will be the main product of the conditioning facility.

B3.2 COMBINED CYCLE TECHNOLOGY

Combined cycle technology has matured in the past 10 to 15 years. Typically larger gas turbines (50 MW and greater) are used for combined cycle plants in order to supply enough waste heat for an economically designed heat recovery boiler. Also, two or more heat recovery boilers are used to drive one steam turbine. The range of heat rates for operating combined cycle plant is 8,350 to 9,200 Btu/kWh (7550-8300 Btu/kWh-LHV). For the steam cycle, the site environments considered in this study strongly favor the use of air cooled condensers. Air cooled condensers have been built for combined cycle plants and for steam boiler plants as large as 350 MW, and have been operated under applicable ambient conditions. An air cooled condenser is presently operating in the Beluga area for the steam cycle of a 179 MW combined cycle plant.

Combined cycle plants for the North Slope will be pre-constructed in three subunits for assembly at the slope in a manner similar to that described for simple cycle units. A plant would consist of two gas turbine units with heat recovery steam generators, one steam turbine-generator set with attendant equipment, and one air cooled condenser. The heaviest unit to be handled is the steam turbine-generator module that weighs approximately 2300 tons. Constructability could be a problem since the three modular units and the field-erected condenser would require assembly during the short North Slope construction season. It is felt, however, that careful planning of logistics and manpower can make this feasible.

Combined cycle plants in the 150 MW range have been built within the Railbelt region. Only one problem other than typical siting and environmental questions is anticipated for either of the two southerly locations. That problem is the low heating value and high CO_2 content of the conditioning facility waste gas which will also effect the design of the gas turbines for the combined cycle units. Further, this gas quality may also effect the size and efficiency of the heat recovery boilers and the steam cycle.

B3.3 GAS FIRED BOILERS

The direct fired steam boiler with steam turbine-generator is the most widely used technology of the three being considered. Identical in concept and general design features with coal fired plants, gas fired boilers are most efficient and economical in larger units. For this reason the technology was considered in 200 MW and larger sizes.

At the North Slope, the short construction period and physical size of the boiler present severe problems for erection of a gas fired boiler unit. Physically handling a pre-assembled boiler on crawlers is not practical, especially when one considers the difficulty of maintaining the integrity of the pressure parts and the casing. Another problem is the physical size of the turbine-generator set. A 200 MW steam turbine-generator pre-assembled on foundations far exceeds the North Slope handling capacity of 2400 tons. Finally, the short construction season of the North Slope does not allow erection at the site. An alternative which may be viable, however, is to pre-erect the entire unit on barges, move the barges to the North Slope and permanently anchor or beach them in shallow water. Three barges would be necessary, one for the boiler, one for the turbine-generator, and one for the air cooled condenser and auxiliaries.

Construction of gas fired boilers within the Railbelt (e.g., at Fairbanks and Kenai) does not present the severe problems seen at the North Slope and could be accomplished in the same manner as the other technical alternatives. As with the other alternatives, the waste gas option presents problems. The low heating value of the gas will result in much larger furnace volumes and lower efficiencies.

Gas fired steam turbine generation systems have higher capital costs (approximately 50 percent higher) on a $/kW installed basis and higher heat rates (9,500-11,000 Btu/kWh) than combined cycle units. As a consequence, it would not be advantageous to install them in any of the considered locations, in that there would be a capital cost and fuel cost disadvantage. Operating cost advantages which might be realized with this technology in very large plants are not available in the required unit size range. For these reasons gas fired boilers were eliminated from further study.

B4.0 ASSUMPTIONS AND INPUT DATA

B4.1 TECHNICAL ASSUMPTIONS AND DATA

The plant heat rates used in this study result from a review of existing plants and data supplied by equipment vendors. As mentioned, simple cycle gas turbines have heat rates which vary from 11,800 to 13,000 Btu/kWh (10,600-11,700 Btu/kWh-LHV). The simple cycle capacities and heat rates used are listed in Table B4-1.

The range of heat rates for operating combined cycle plants is 8350 to 9200 Btu/kWh (7,550-8,300 Btu/kWh LHV) while available technology for new plants claim heat rates as low as 8200 Btu/kWh for a 225 MW (net) plant. The heat rates assumed in this study are shown in Table B4-1.

Fuel costs for coal, oil, and gas fired plants in the Railbelt region were investigated. At present coal generally varies from $2.10 per million Btu for a mine mouth location to as much as $4.50 per million Btu when remote from its source. Based upon discussions with utilities in the Railbelt region, distillate prices for utilities are presently in a range of $5.03 to $5.60 per million Btu. This price is also sensitive to location and is higher at remote locations. A current export market price for natural gas is $5.50 per million Btu, while the Battelle (1982) "Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans" cites an anticipated Fairbanks price of $5.92 per million Btu for North Slope gas. There are existing contracts for sale of natural gas in the Cook Inlet area at prices under $1.00 per million Btu. Due to these low prices and the relatively high prices of alternate fuels, it was decided to utilize a range of gas prices thus providing a sensitivity analysis for technology selection as a function of fuel price. The fuel prices that were used were $0.00, $1.50, $2.50, $3.50, and $5.50 per million Btu.

TABLE B4-1

CAPACITIES AND HEAT RATES FOR SIMPLE AND COMBINED CYCLE UNITS

SIMPLE CYCLE GAS TURBINES

Locale	Ambient Temperature 1/	Capacity (MW)	Heat Rate (Btu/kWh) 2/
North Slope	9°	91	11,500
Fairbanks	26°	86	11,600
Kenai	33°	84	11,650

COMBINED CYCLE UNITS

Locale	Ambient Temperature 1/	Capacity (MW)	Heat Rate (Btu/kWh) 2/
North Slope	9°F	253	8,320
Fairbanks	26°F	242	8,290
Kenai	33°F	237	8,280

1/ Average annual temperature.
2/ Based on higher heating value.

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Ebasco reviewed the operating and maintenance (O&M) costs used in the Railbelt Electric Power Alternatives Study (Battelle 1981) for applicability to this analysis. After comparing these to current manufacturer's maintenance recommendations, other utility O&M costs and to Edison Electric Institute's (1981) Guides for Operating Practice, it was decided that the Battelle figures remained adequate for application to the Railbelt region scenario in this study. For the North Slope option, higher wages, shorter work seasons, and adverse working conditions resulted in revised higher O&M costs. All O&M costs are listed below:

Locale	Simple Cycle Units (mils/kWh)	Combined Cycle Units (mils/kWh)
North Slope	6.3	5.5
Fairbanks or Kenai	4.6	4.0

Capital costs for each new technology were also developed. The costs are in 1982 dollars/kWh for the unit sizes used in each technology. These costs were derived after reviewing costs of past and current similar projects in both Alaska and the lower 48 states. It should also be noted that these costs refer only to the power generation facilities and do not include costs associated with transmission lines or fuel supply facilities. These costs are shown in Table B4-2.

In order to develop the number of gigawatt-hours generated for each scenario, it was necessary to make several assumptions. First, it was assumed that the new units would operate at an average capacity factor of 0.75. Secondly, it was assumed that all existing hydro power would be base loaded and operated at a capacity factor of approximately 0.50 (Acres American Inc. 1981). It was also assumed that the new gas fired

TABLE B4-2

ASSUMED CAPITAL COSTS[1/]

Region	Technology	Capital Cost (1982 $/kW installed) First Plant	Capital Cost (1982 $/kW installed) Subsequent Plant
North Slope	Simple Cycle	798	589
	Combined Cycle	951	865
Fairbanks	Simple Cycle	452	394
	Combined Cycle	557	527
Kenai	Simple Cycle	488	415
	Combined Cycle	572	540

1/ Adjusted for capacities at specific locations.

units would replace older existing units for base load and that the older units would become part of the reserve margin until they are retired. Finally, all new gas fired capacity was assumed to generate energy up to the lower of either their limit at 0.75 capacity factor, or to the total required energy in each year after deducting the hydro supplied energy. The 0.75 capacity factor was selected as a conservative estimate for individual gas turbine or combined cycle units. The system capacity factor will be significantly lower.

B4.2 ECONOMIC ASSUMPTIONS AND INPUT DATA

In performing the economic evaluation of the alternate development scenarios, economic factors utilized in the Railbelt Electric Power Alternatives Study (Battelle 1982) were employed. These are summarized in Table B4-3. The period of analysis was assumed to be 1983 through 2010. The useful life of the combustion turbines and heat recovery steam generators (waste heat boilers) was assumed to be 30 years. The inflation rate was assumed to be 0 percent. Capital costs were assumed to escalate at the rate of inflation. Operating and maintenance costs, similarly, were assumed to escalate at the rate of inflation. Fuel costs were assumed to escalate at a rate varying from 0 to 3 percent greater than inflation, in 1% increments. The discount rate was assumed to be 3 percent.

These standard factors were developed in order to make different economic studies comparable. In some cases additional comment is warranted. Inflation, for example, is taken at 0% in order to convert all analyses into "real" dollars. Capital costs are assumed to escalate at the rate of inflation, as this trend has existed for the last few years and has been documented by the Power Authority. Fossil fuel costs (typically oil) are escalated at a rate higher than inflation.

TABLE B4-3

ECONOMIC ASSUMPTIONS

Item	Assumptions
Period of Analysis	1983-2010
Life of Boilers, Combustion Turbines, and Heat Recovery Steam Generators	30 yrs
Salvage Value, All Cases	$0
Fuel Costs	$0 to $5.50/million Btu (1982)
Inflation Rate	0%
Capital Cost Escalation Rate	0% (Real)
Fuel Cost Escalation Rate	0% to 3% (Real)
O&M Escalation Rate	0% (Real)
Discount Rate	3.0% (Real)

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In addition, no salvage values were taken despite the fact that some projected generating units only had a project life of 1 to 2 years within the period of analysis. The elimination of salvage values (or values of unutilized capital) from the analysis was made for two reasons: 1) it was assumed that if differentials in annual costs occurred between technologies following the year 2010, they would accentuate trends emerging within the period of analysis; and 2) it was recognized that the influence of discounting, even at 3 percent, would make any apparent differences after the year 2010 small (e.g., one dollar, discounted at 3 percent from 1982 to the year 2010, is only worth $0.44).

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B5.0 RESULTS

B5.1 SYSTEM CAPACITY REVIEW

The capacity retirement schedule, planned additions, and resulting balance of existing capacity are listed in Table B5-1 along with the peak demand for both the low and medium forecasts. The total required capacity for each reserve margin, the balance of existing capacity, and the resulting requirements for new capacity are listed in Tables B5-2 and B5-3 for the low and medium load forecasts, respectively. The very large reserve margins which exist at present are the result of the isolated nature of the region's utilities, wherein each small community maintains a reserve capacity of 50-150% or more, and of the transition that the region is going through from small local plants to larger central generating stations. The retirement schedule is controlled by a single input, the operating life of the existing plants.

B5.2 SELECTION OF UNIT SIZES

The size range of units selected for the technologies was governed by two items. The first was capital costs. Where there were significant capital cost variance over the size range, the range was restricted to the lower cost end. The second is the range of reserve margins within which the Railbelt system will operate. Previous studies have used a loss of load probability (LOLP) of one day in ten years as the basis for design (Acres American Inc. 1981). The Battelle system evaluation studies initially determined that this LOLP results in a range of reserve margins of 24 to 32 percent (Battelle 1982). For all future system evaluation studies, Battelle utilized an average reserve margin of 30 percent. Also, the Battelle report states that the cost of power is nearly constant within this range of reserve margins. This system planning report employs the reserve margin range determined by Battelle (1982). Unit sizes for the two technologies have been evaluated based upon these reserve margins and other factors.

TABLE B5-1
EXISTING CAPACITY, PLANNED ADDITIONS, UNIT RETIREMENT SCHEDULE AND PEAK DEMANDS

Year	Existing Capacity (MW)	Planned* Additions (MW)	Unit** Retirements (MW)	Peak Demand*** Low Load Forecast	Peak Demand*** Medium Load Forecast
1982	1154.1	158.4	0.3	560	603
1983	1154.1	-	-	580	631
1984	1154.1	-	-	600	659
1985	1154.1	-	-	620	687
1986	1154.1	-	-	656	728
1987	1050.1	-	4.0	692	769
1988	1247.1	97	-	728	810
1989	1242.1	-	5.0	764	851
1990	1242.1	-	-	800	892
1991	1223.7	-	18.4	808	910
1992	1190.0	-	33.7	816	928
1993	1173.2	-	16.8	824	947
1994	1142.3	-	30.9	832	965
1995	1094.8	-	47.5	840	983
1996	1023.9	-	70.9	836	1003
1997	927.5	-	96.4	832	1023
1998	871.7	-	55.8	828	1044
1999	871.7	-	-	824	1064
2000	853.1	-	18.6	820	1084
2001	852.9	-	0.2	830	1121
2002	775.1	-	77.8	840	1158
2003	722.1	-	53.0	850	1196
2004	722.1	-	-	860	1233
2005	609.5	-	112.6	870	1270
2006	604.3	-	5.2	896	1323
2007	604.3	-	-	922	1377
2008	577.9	-	26.4	948	1430
2009	577.0	-	0.9	974	1484
2010	577.0	-	-	1000	1537

* Derived from Table 6.3 of Susitna Feasibility Report (Acres American Inc. 1981). The 1988 additions consist of Bradley Lake (90 MW) and Grant Lake (7MW). More recent Alaska Power Authority plans envision a Bradley Lake Project with 135 MW of total installed capacity and eliminate the Grant Lake Project (R.W. Beck and Associates 1982).

** Derived from Table 6.2 of Susitna Feasibility Report (Acres American Inc. 1981).

*** Low load forecast derived from summary table (page iv) in Battelle (1982); medium growth forecasts derived from Table 5.7 of Susitna Feasibility Study (Acres American Inc. 1981).

TABLE B5-2

CAPACITY REQUIREMENTS AT PLANNING RESERVE MARGINS
LOW LOAD FORECAST

Year	Total Required Capacity (MW)*			Balance Existing Capacity (MW)	Required New Capacity (MW)		
	24% RSRV	30% RSRV	32% RSRV		24% RSRV	30% RSRV	32% RSRV
1990	992	1040	1056	1242	0	0	0
1991	1002	1050	1067	1224	0	0	0
1992	1012	1061	1077	1190	0	0	0
1993	1022	1071	1088	1173	0	0	0
1994	1032	1082	1098	1142	0	0	0
1995	1042	1092	1109	1095	0	0	14
1996	1037	1087	1104	1024	13	63	80
1997	1032	1082	1098	928	104	154	170
1998	1027	1076	1093	872	155	204	221
1999	1022	1071	1088	872	150	199	216
2000	1017	1066	1082	853	164	213	229
2001	1029	1079	1096	853	176	226	243
2002	1042	1092	1109	775	267	317	334
2003	1054	1105	1122	772	282	333	350
2004	1066	1118	1135	722	344	396	413
2005	1079	1131	1148	610	469	521	538
2006	1111	1165	1183	604	507	561	579
2007	1143	1199	1217	604	539	595	613
2008	1176	1232	1251	578	598	654	673
2009	1208	1266	1286	577	631	689	709
2010	1240	1300	1320	577	663	723	743

*The values represent peak demand plus the designated reserve margin.

TABLE B5-3

CAPACITY REQUIREMENTS AT PLANNING RESERVE MARGINS
MEDIUM LOAD FORECAST

Year	Total Required Capacity (MW)*			Balance Existing Capacity (MW)	Required New Capacity (MW)		
	24% RSRV	30% RSRV	32% RSRV		24% RSRV	30% RSRV	32% RSRV
1990	1106	1160	1177	1242	0	0	0
1991	1128	1183	1201	1224	0	0	0
1992	1151	1206	1225	1190	0	16	0
1993	1174	1231	1250	1173	1	58	77
1194	1197	1255	1274	1142	55	113	132
1995	1219	1278	1298	1095	124	183	203
1996	1244	1304	1324	1024	220	280	300
1997	1269	1330	1350	928	341	402	422
1998	1295	1357	1378	872	423	485	506
1999	1319	1383	1404	872	447	511	532
2000	1344	1409	1431	853	491	556	578
2001	1390	1457	1480	853	537	604	627
2002	1436	1505	1529	775	661	730	754
2003	1483	1555	1579	772	711	783	807
2004	1529	1603	1628	722	807	881	906
2005	1575	1651	1676	610	965	1041	1066
2006	1641	1720	1746	604	1037	1116	1142
2007	1707	1790	1818	604	1103	1186	1214
2008	1773	1859	1888	578	1195	1281	1310
2009	1840	1929	1959	577	1263	1352	1382
2110	1906	1998	2029	577	1329	1421	1452

*The values represent peak demand plus the designated reserve margin.

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A gas turbine of 77 MW capacity (ISO conditions, baseload) was chosen based on minimizing the number of plants and satisfying the new capacity requirements range. Combined cycle unit increments are very suitable to this study with gas turbine units of 50 to 100 MW being available and steam cycles from 40 to 80 MW available for heat recovery. Total combined cycle unit sizes of 220 MW (ISO conditions, baseload) total were selected. This includes two 77 MW gas turbine units and a 66 MW steam turbine unit. This size unit was selected for economy of scale reasons and the fact that it closely matches the required capacity additions.

B5.3 NEW CAPACITY REQUIREMENTS

The requirements for new capacity and proposed additions are listed in Tables B5-4 through B-9 and are a function of the previously discussed system characteristics and available unit sizes. Units were added as appropriate to maintain the total capacity needed within the required range. Twelve different tabulated scenarios resulted from this analysis with three locations having two technological and two load forecast possibilities.

Possible variation in load growth for the region has been taken into account by performing all analysis for both the low and medium load growth forecasts. This provides a wide range for study since the total new capacity required in 2010 under the medium forecast is approximately twice that for the low load forecast.

The new generating units to be added for each technology under each load growth forecast are shown in Figures B5-1 through B5-12. In applying the technologies, it was demonstrated that simple cycle unit additions most closely followed the targeted total capacity corresponding to the 30 percent reserve margin. Combined cycle systems could be added within the target range, but were less flexible in following capacity addition requirements than simple cycle combustion turbines.

TABLE B5-4

NEW CAPACITY ADDITIONS - LOW LOAD FORECAST

NORTH SLOPE

Year	Required New Capacity At Peak Demand (MW) 24% RSRV	30% RSRV	32% RSRV	Actual New Capacity (MW) Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	0	0	0/0	0/0
1993	0	0	0	0/0	0/0
1994	0	0	0	0/0	0/0
1995	0	0	14	0/0	0/0
1996	13	63	80	91/91	91/91
1997	104	154	170	91/182	91/182
1998	155	204	221	0/182	0/182
1999	150	199	216	0/182	0/182
2000	164	213	229	0/182	0/182
2001	176	226	243	0/182	71/253
2002	267	317	334	91/273	91/944
2003	282	333	350	91/364	0/344
2004	344	396	413	0/364	91/435
2005	469	521	538	182/546	71/506
2006	507	561	579	0/546	91/597
2007	539	595	613	0/546	0/597
2008	598	654	673	91/637	91/688
2009	631	689	709	0/637	0/688
2010	663	723	743	91/728	0/688

TABLE B5-5

NEW CAPACITY ADDITIONS - LOW LOAD FORECAST

FAIRBANKS

Year	Required New Capacity At Peak Demand (MW) 24% RSRV	30% RSRV	32% RSRV	Actual New Capacity (MW) Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	0	0	0/0	0/0
1993	0	0	0	0/0	0/0
1994	0	0	0	0/0	0/0
1995	0	0	14	0/0	0/0
1996	13	63	80	86/86	86/86
1997	104	154	170	86/172	86/172
1998	155	204	221	0/172	0/172
1999	150	199	216	0/172	0/172
2000	164	213	229	0/172	0/172
2001	176	226	243	86/758	70/242
2002	267	317	334	86/344	86/328
2003	282	333	350	0/344	0/328
2004	344	396	413	86/430	86/414
2005	469	521	538	86/516	70/484
2006	507	561	579	0/516	86/570
2007	539	595	613	86/602	0/570
2008	598	654	673	0/602	86/656
2009	631	689	709	86/688	0/656
2010	663	723	743	0/688	70/726

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TABLE B5-6

NEW CAPACITY ADDITIONS - LOW LOAD FORECAST

KENAI

Year	Required New Capacity At Peak Demand (MW) 24% RSRV	30% RSRV	32% RSRV	Actual New Capacity (MW) Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	0	0	0/0	0/0
1993	0	0	0	0/0	0/0
1994	0	0	0	0/0	0/0
1995	0	0	14	0/0	0/0
1996	13	63	80	84/84	84/84
1997	104	154	170	84/168	84/168
1998	155	204	221	0/168	0/168
1999	150	199	216	0/168	0/168
2000	164	213	229	0/168	0/168
2001	176	226	243	84/252	69/237
2002	267	317	334	84/336	84/321
2003	282	333	350	0/336	0/321
2004	344	396	413	84/420	84/405
2005	469	521	538	84/504	69/474
2006	507	561	579	84/588	84/588
2007	539	595	613	0/588	0/588
2008	598	654	673	84/672	84/642
2009	631	689	709	0/672	0/672
2010	663	723	743	0/672	69/711

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TABLE B5-7

NEW CAPACITY ADDITIONS - MEDIUM LOAD FORECAST

NORTH SLOPE

Year	Required New Capacity At Peak Demand (MW) 24% RSRV	30% RSRV	32% RSRV	Actual New Capacity (MW) Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	16	35	0/0	0/0
1993	1	58	77	91/91	91/91
1994	55	113	132	0/0	0/91
1995	124	183	203	91/182	91/182
1996	1220	280	300	91/273	71/253
1997	341	402	422	91/364	91/344
1998	423	485	506	91/455	91/435
1999	447	511	532	0/455	71/506
2000	491	556	578	91/546	91/597
2001	537	604	627	0/546	0/597
2002	661	730	754	182/728	91/688
2003	711	783	807	0/728	71/759
2004	807	881	906	91/819	91/850
2005	965	1041	1066	182/1001	162/1012
2006	1037	1116	1142	91/1092	91/1103
2007	1103	1186	1214	91/1183	91/1194
2008	1195	1281	1310	91/1274	71/1265
2009	1263	1352	1382	0/1274	91/1356
2010	1329	1421	1452	91/1365	0/1356

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TABLE B5-8

NEW CAPACITY ADDITIONS - MEDIUM LOAD FORECAST

FAIRBANKS

Year	Required New Capacity At Peak Demand (MW)			Actual New Capacity (MW)	
	24% RSRV	30% RSRV	32% RSRV	Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	16	35	0/0	0/0
1993	1	58	77	86/86	86/86
1994	55	113	132	0/0	0/86
1995	124	183	203	86/172	86/172
1996	1220	280	300	86/258	70/242
1997	341	402	422	86/344	172/414
1998	423	485	506	86/430	70/484
1999	447	511	532	86/516	0/484
2000	491	556	578	0/516	86/570
2001	537	604	627	86/602	0/570
2002	661	730	754	86/688	156/726
2003	711	783	807	86/774	0/726
2004	807	881	906	86/860	86/812
2005	965	1041	1066	172/1032	156/968
2006	1037	1116	1142	86/1118	86/1050
2007	1103	1186	1214	86/1204	86/1140
2008	1195	1281	1310	86/1290	70/1210
2009	1263	1352	1382	0/1290	86/1296
2010	1329	1421	1452	86/1376	0/1382

TABLE B5-9

NEW CAPACITY ADDITIONS - MEDIUM LOAD FORECAST

KENAI

Year	Required New Capacity At Peak Demand (MW) 24% RSRV	30% RSRV	32% RSRV	Actual New Capacity (MW) Simple Cycle (Increment/ Total)	Combined Cycle (Increment/ Total)
1990	0	0	0	0/0	0/0
1991	0	0	0	0/0	0/0
1992	0	16	35	0/0	0/0
1993	1	58	77	84/84	84/84
1994	55	113	132	0/0	0/84
1995	124	183	203	84/168	84/168
1996	1220	280	300	84/252	69/237
1997	341	402	422	16/420	168/405
1998	423	485	506	84/504	60/474
1999	447	511	532	0/504	0/474
2000	491	556	578	0/504	84/558
2001	537	604	627	84/588	0/588
2002	661	730	754	84/672	153/711
2003	711	783	807	84/756	84/795
2004	807	881	906	84/840	84/879
2005	965	1041	1066	168/1008	153/1032
2006	1037	1116	1142	84/1092	84/1116
2007	1103	1186	1214	84/1176	0/1116
2008	1195	1281	1310	84/1260	69/1185
2009	1263	1352	1382	84/1344	84/1269
2010	1329	1421	1452	84/1428	84/1353

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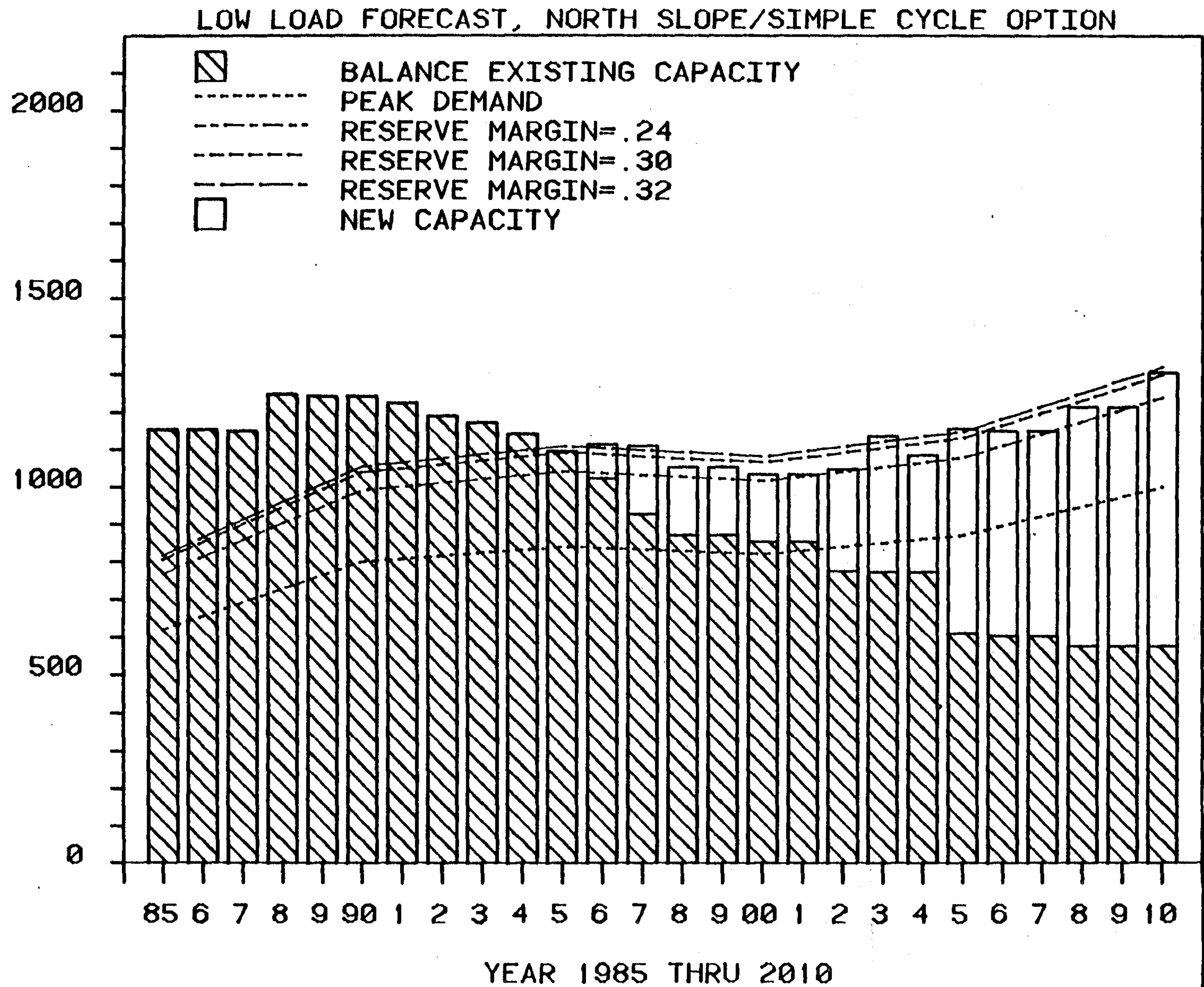
B5-12



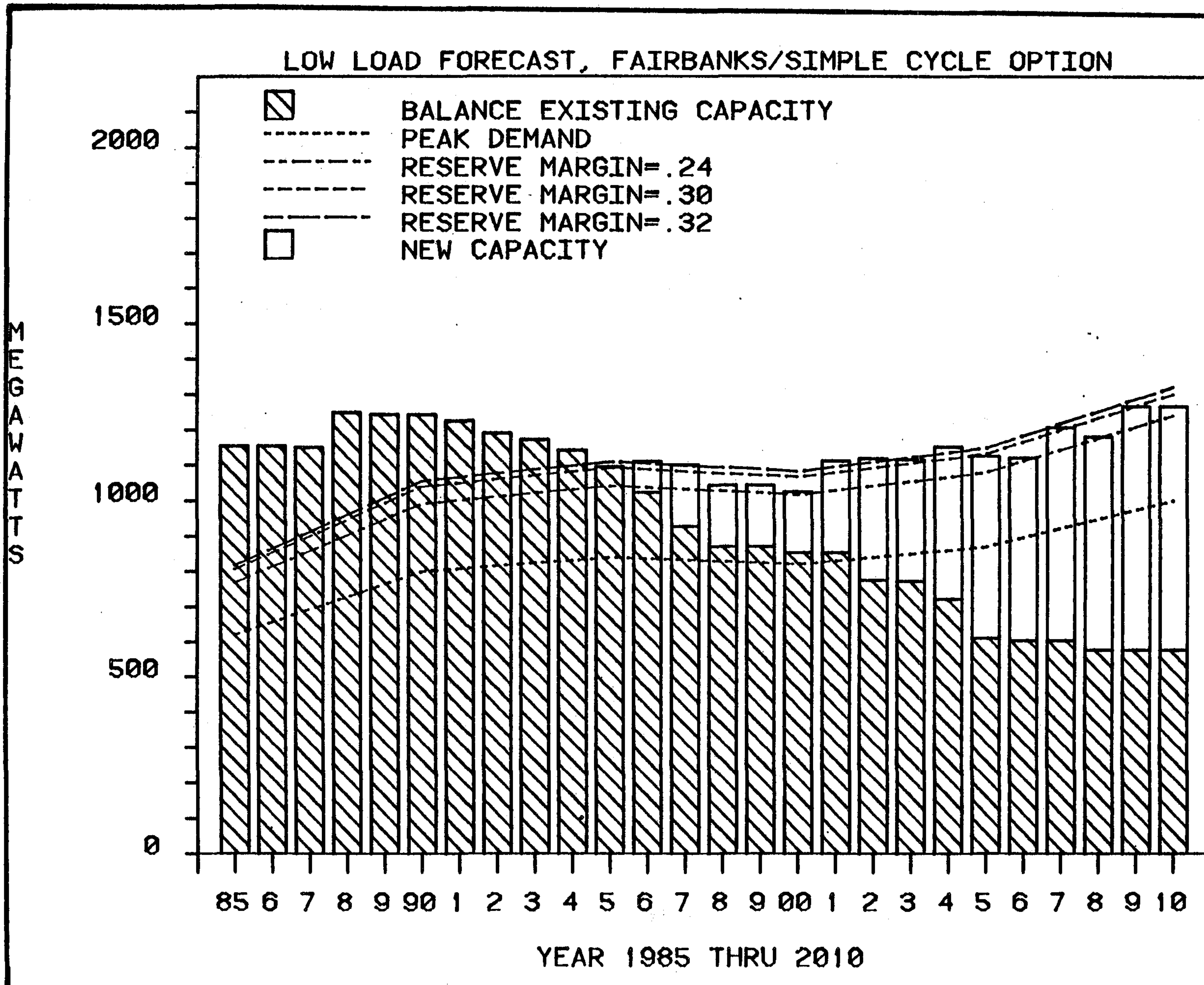
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technolgy, Low Load Forecast, with Generating Facilities at the North Slope.

FIGURE B5-1

EBASCO SERVICES INCORPORATED



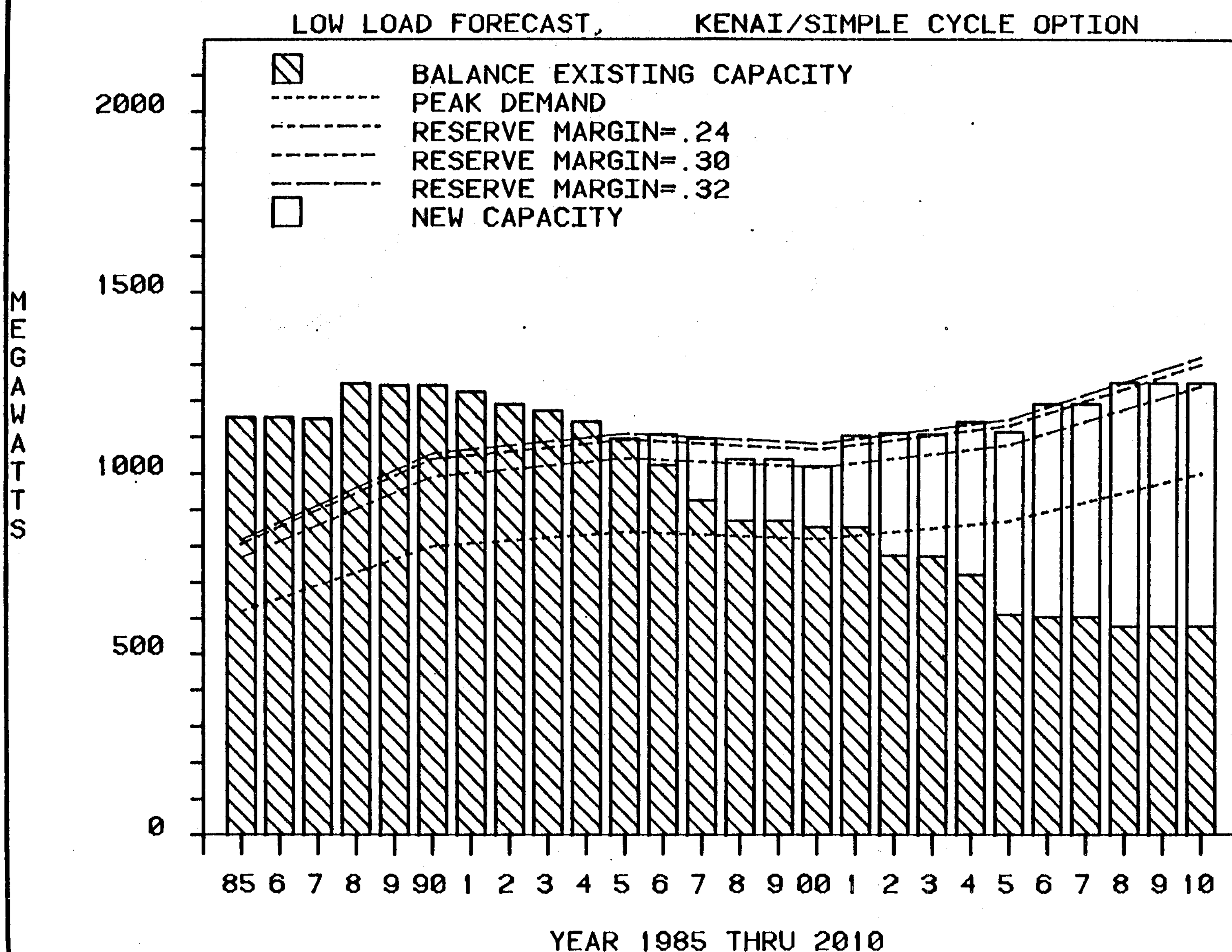
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technology, Low Load Forecast, with Generating Facilities at Fairbanks.

FIGURE B5-2

EBASCO SERVICES INCORPORATED



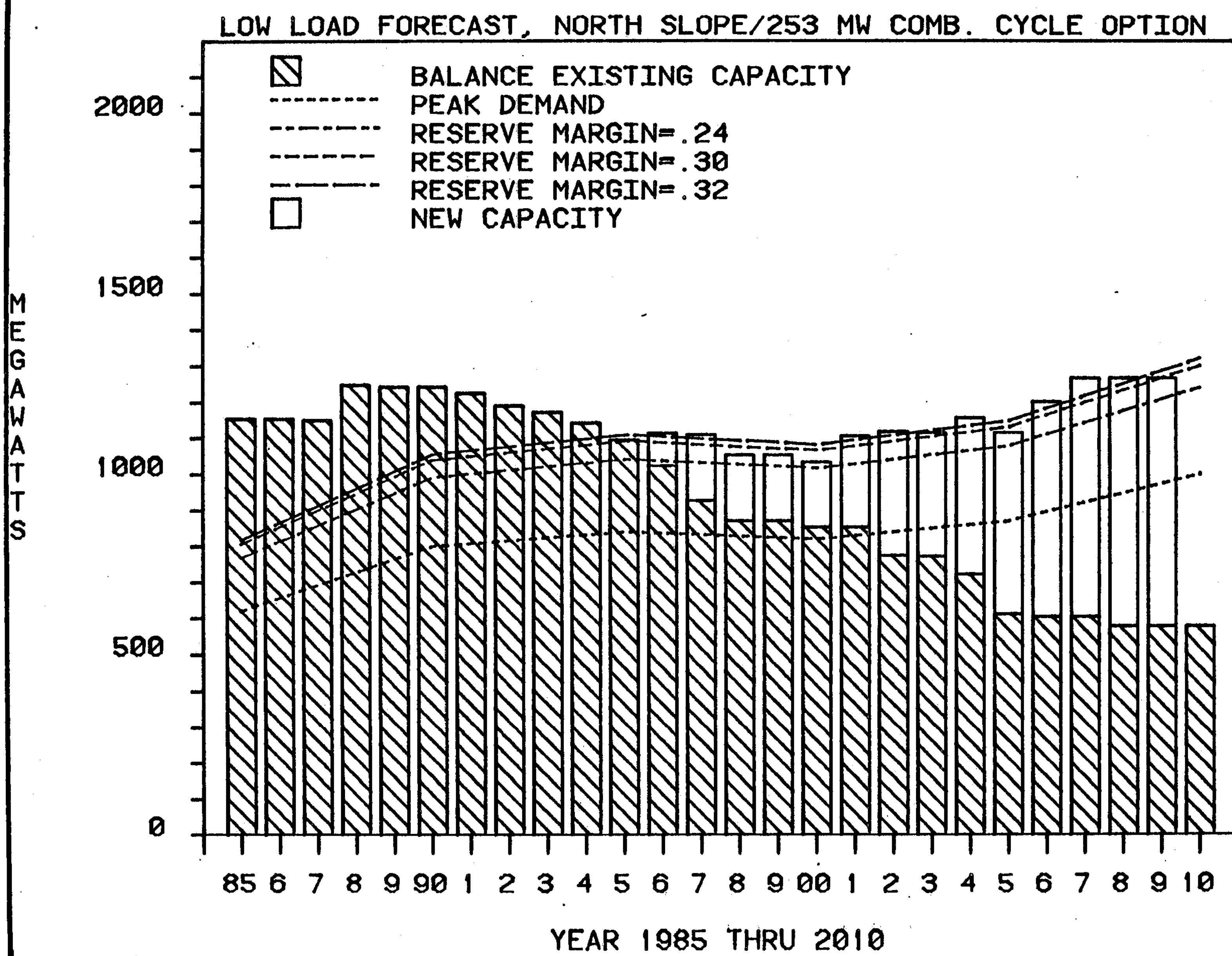
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technology, Low Load Forecast, with Generating Facilities at Kenai.

FIGURE B5-3

EBASCO SERVICES INCORPORATED



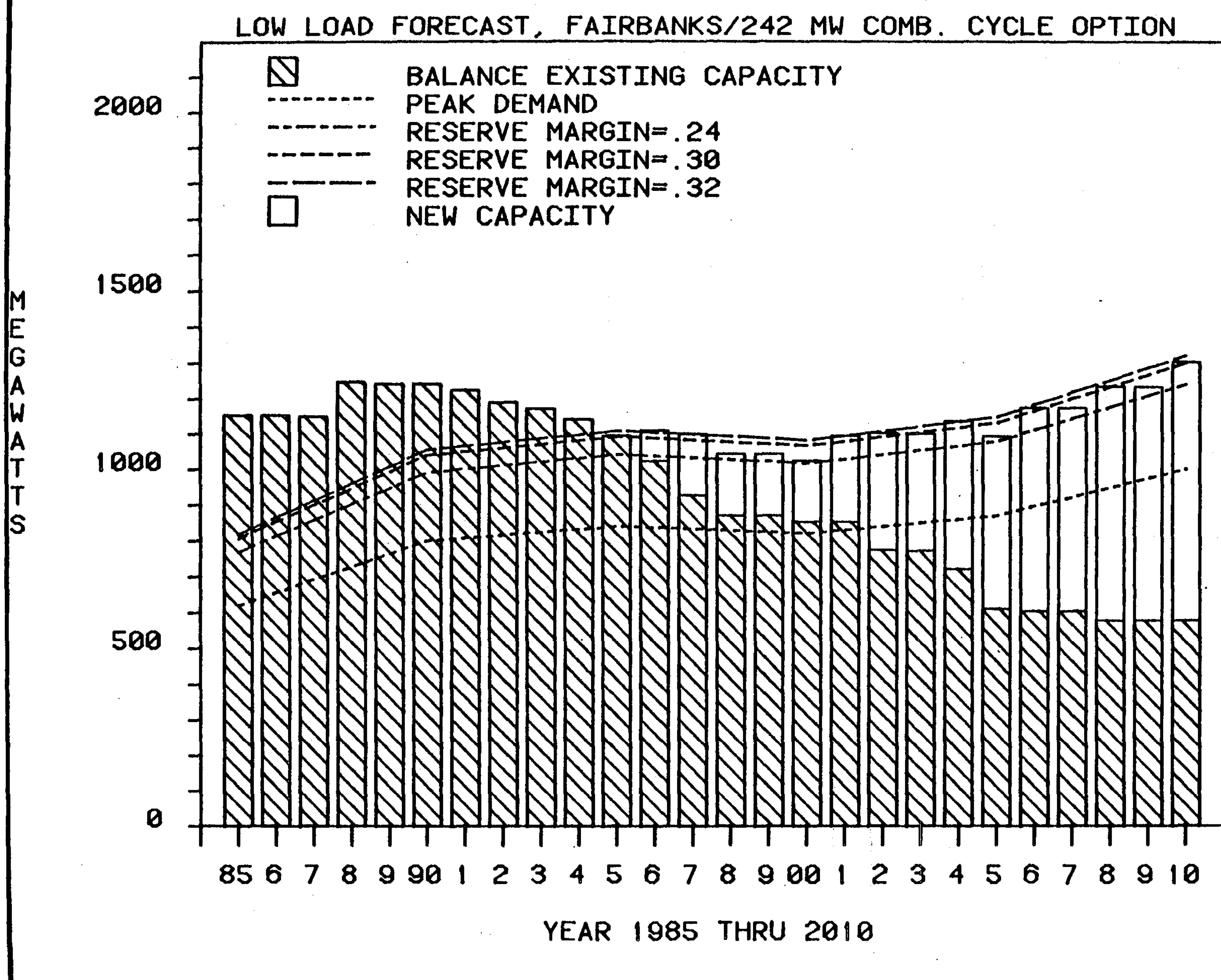
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Low Load Forecast, with Generating Facilities at the North Slope.

FIGURE B5-4

EBASCO SERVICES INCORPORATED



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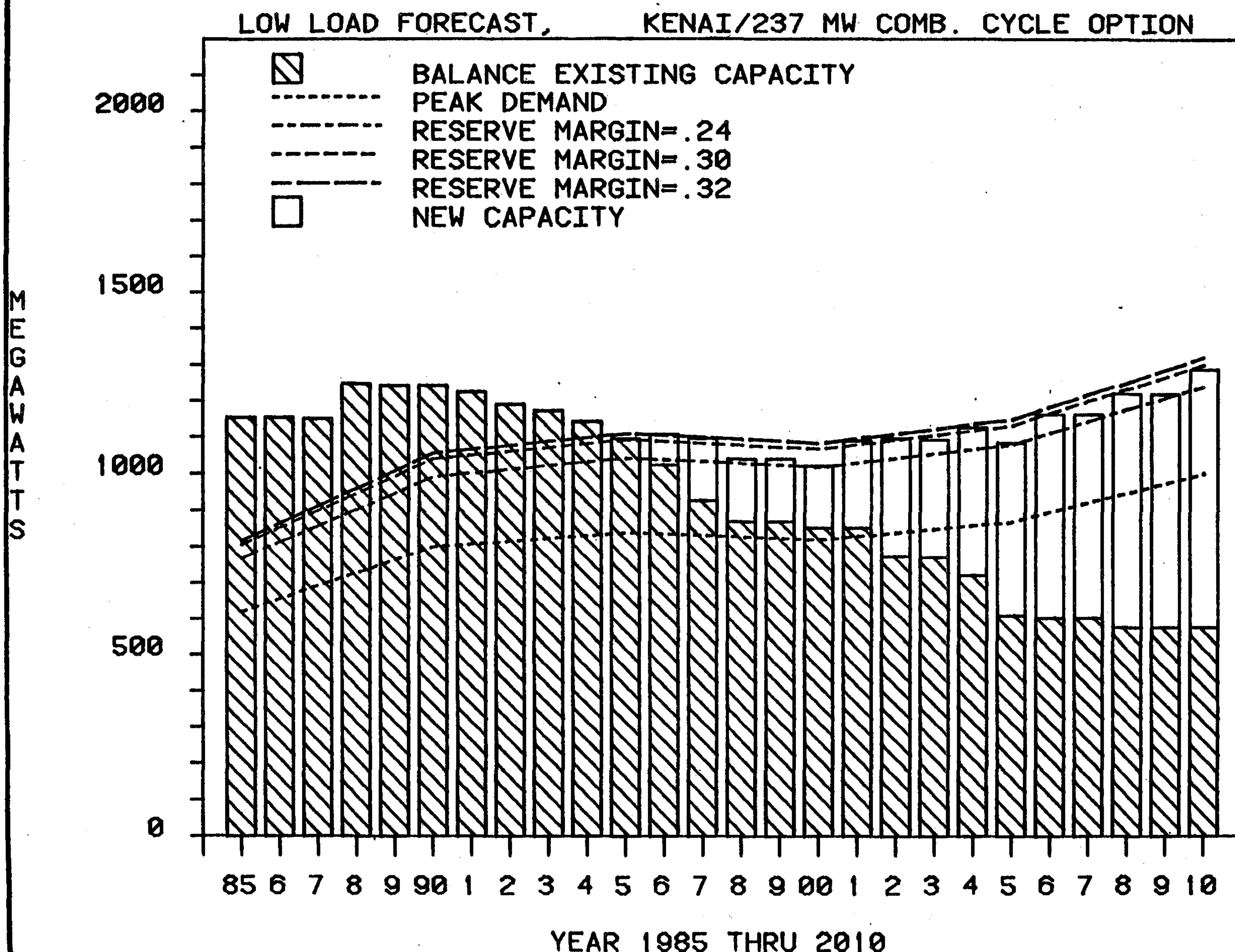
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Low Load Forecast, with Generating Facilities at Fairbanks.

FIGURE B5-5

EBASCO SERVICES INCORPORATED



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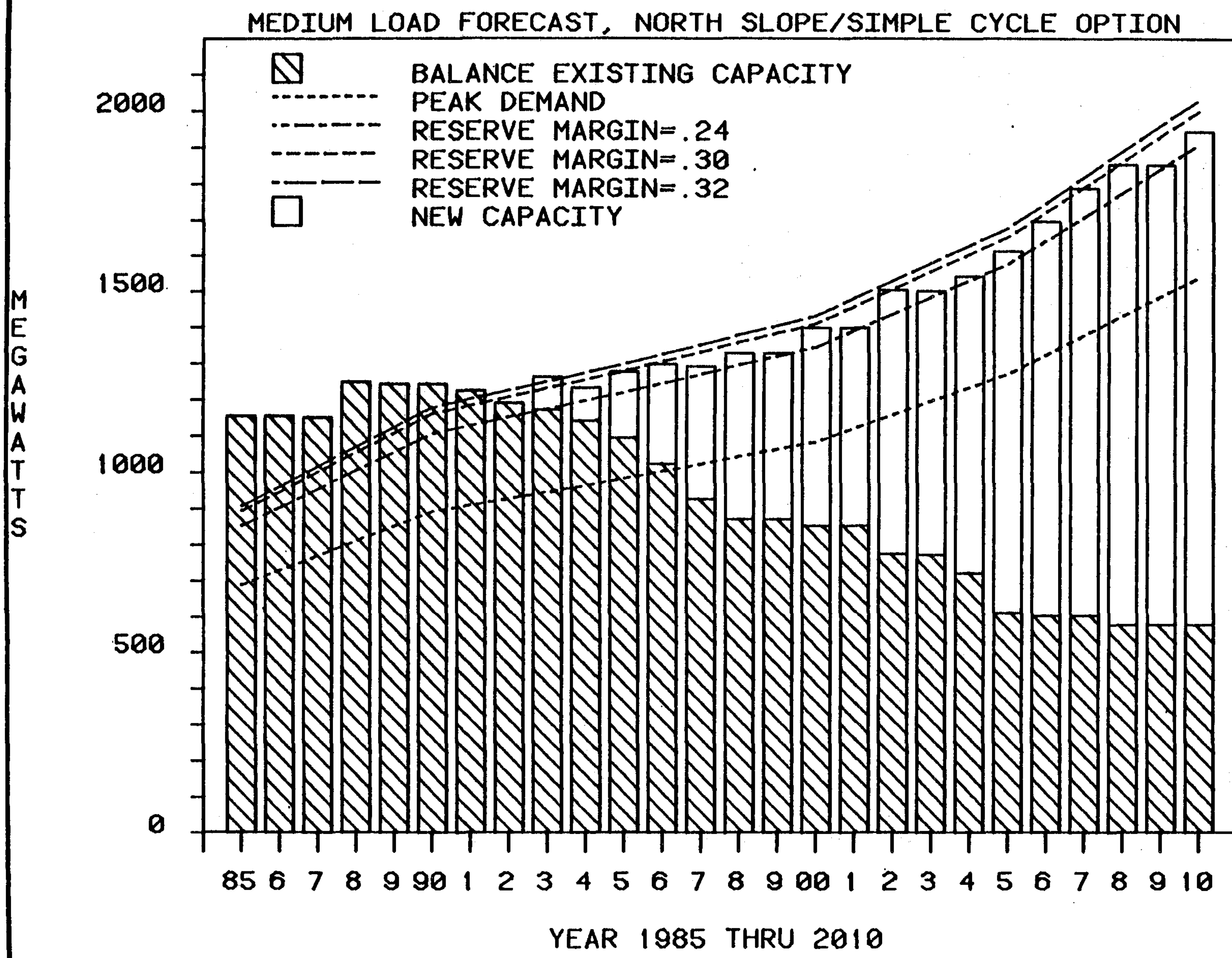
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Low Load Forecast, with Generating Facilities at Kenai.

FIGURE B5-6

EBASCO SERVICES INCORPORATED



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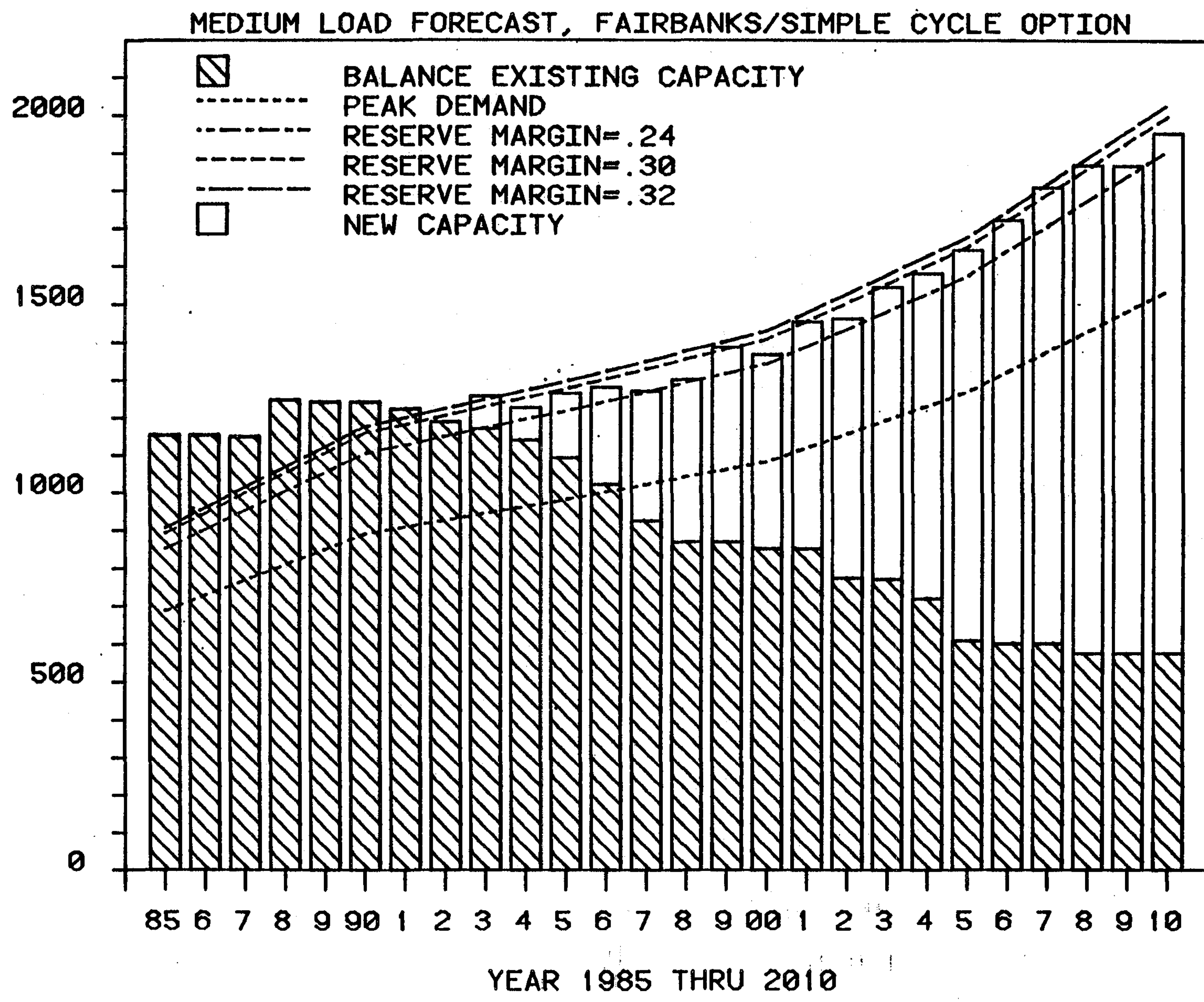
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technology, Medium Load Forecast, with Generating Facilities at the North Slope.

FIGURE B5-7

EBASCO SERVICES INCORPORATED



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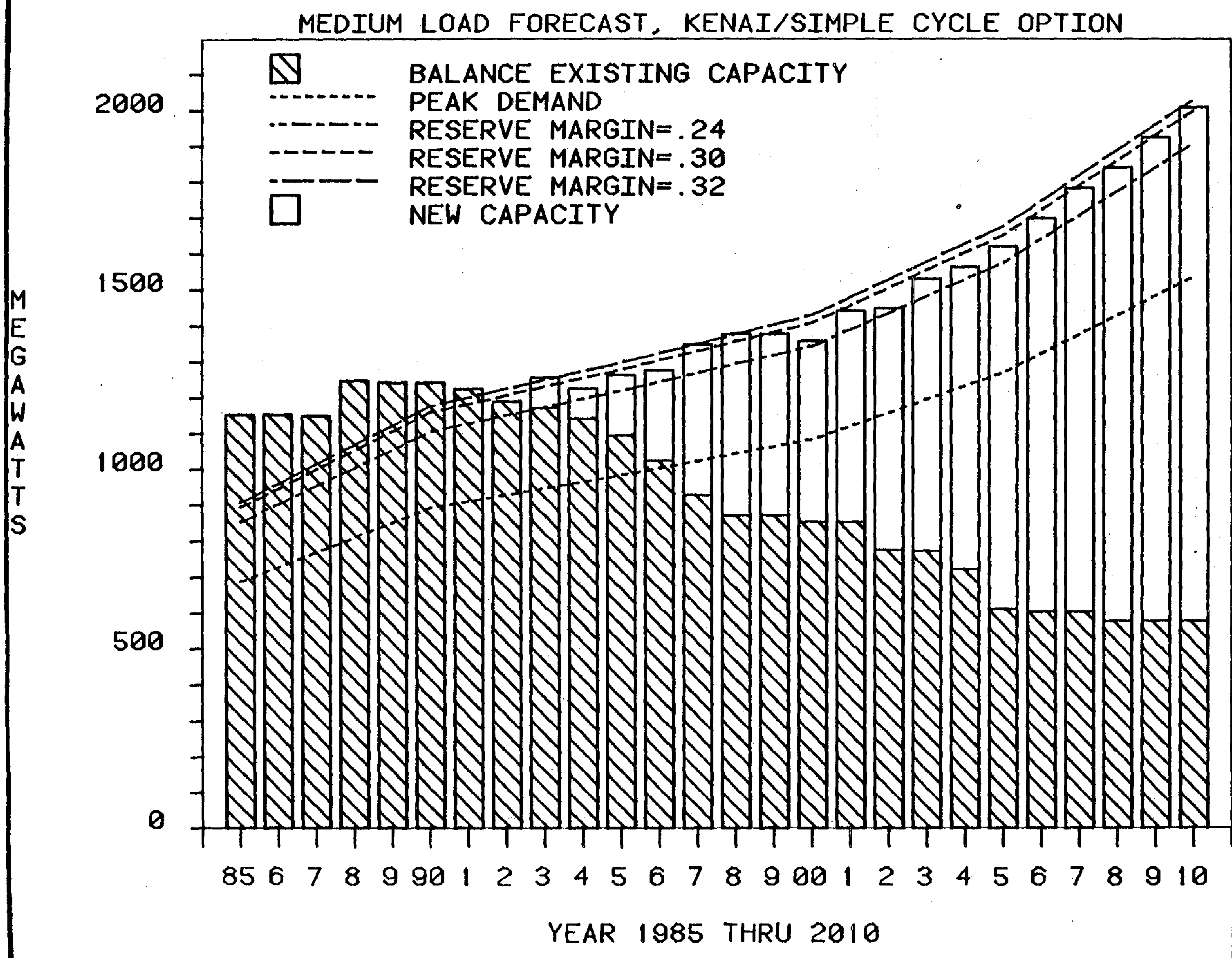
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technology, Medium Load Forecast, with Generating Facilities at Fairbanks.

FIGURE B5-8



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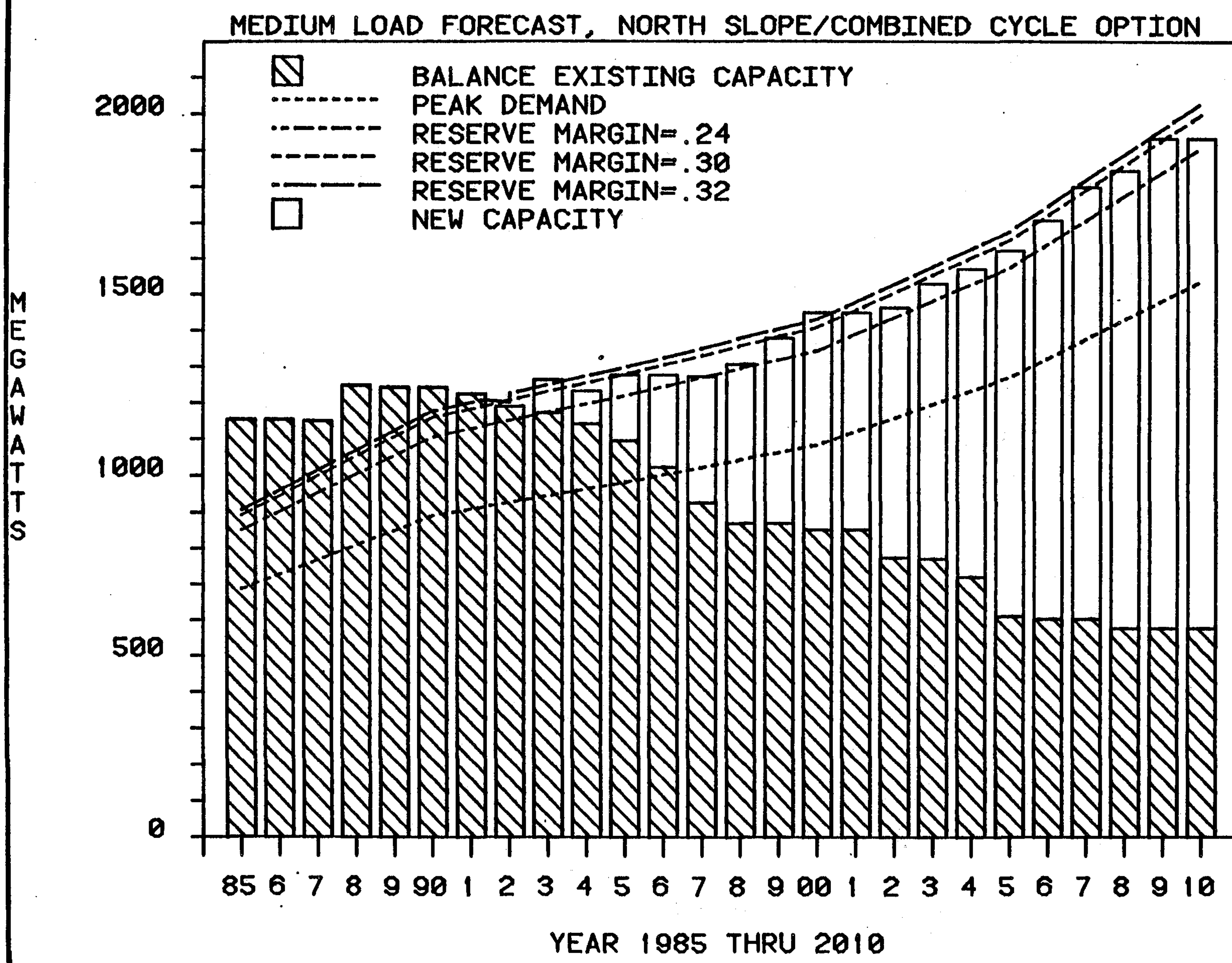
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Simple Cycle Technology, Medium Load Forecast, with Generating Facilities at Kenai.

FIGURE B5-9

EBASCO SERVICES INCORPORATED



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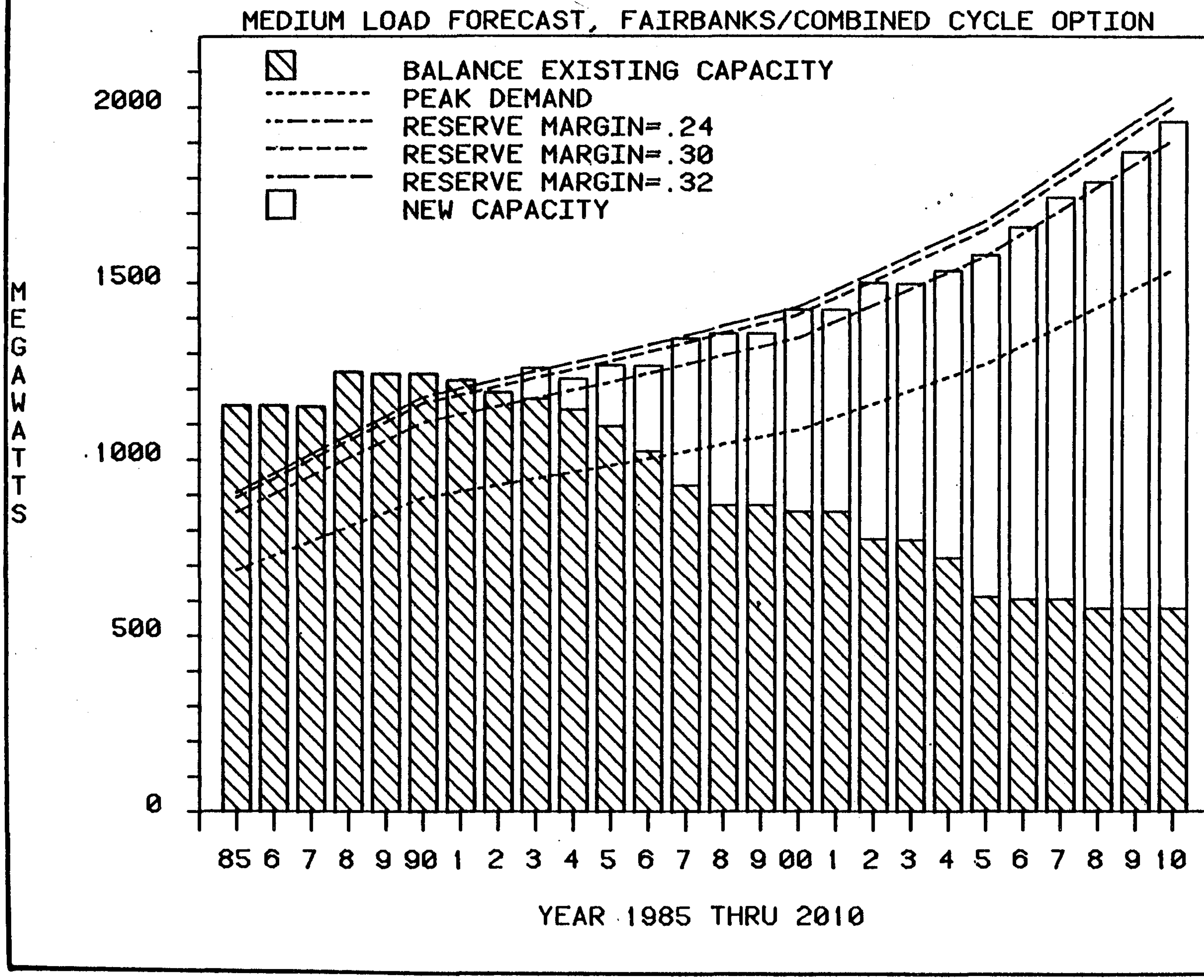
NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Medium Load Forecast, with Generating Facilities at the North Slope.

FIGURE B5-10

EBASCO SERVICES INCORPORATED



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NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacitities for Combined Cycle Technology, Medium Load Forecast, with Generating Facilities at Fairbanks.

FIGURE B5-11

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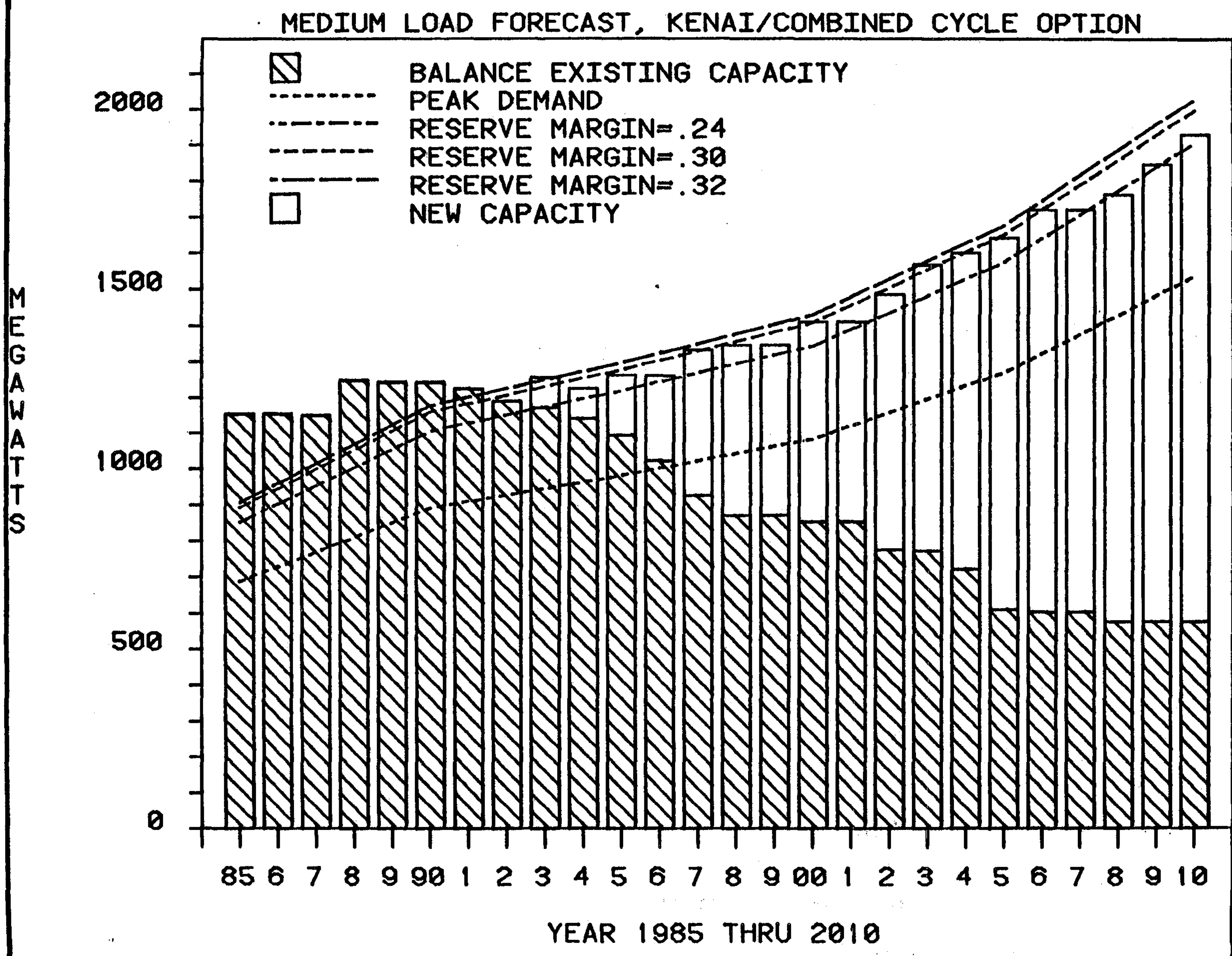

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NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Medium Load Forecast, with Generating Facilities at Kenai.

FIGURE B5-12

EBASCO SERVICES INCORPORATED

A resultant factor of this unit sizing and staging for each technology is that no two scenarios for new capacity result in the same amount of total energy being supplied. This is also considered in the economic analysis.

As will be discussed below, the simple and combined cycles costs are nearly identical for low cost fuels at the North Slope. The simplicity of operation and maintenance, combined with much lower freshwater requirements result then in selection of simple cycle technology for the North Slope scenarios.

The combined cycle alternative results in the least cost option for Fairbanks and Kenai and will be applied exclusively to meet the capacity requirements as shown in Tables B5-4 through B5-9 and Figures B5-1 through B5-12. As previously mentioned, other sizes of combined cycle plants are available. The alternatives are smaller gas turbines and heat recovery boilers, and a combination of three or more heat recovery boilers with one steam turbine. There are, however, no cost advantages to be gained by either of these choices while a great deal of flexibility is lost. The total number of plants would also increase significantly if smaller plants were used.

B5.4 ECONOMIC ANALYSIS AND RESULTS

Given the assumptions presented in Section B4.0, and the technologies available, the systems analysis was made by applying the accepted Alaska Power Authority model for calculation of the Present Worth of Costs for the alternative options. All costs were considered for each system; that is, the analysis included capital costs, operating and maintenance costs, and fuel costs. These costs were accounted for in the year they occurred. As a consequence, all capital costs were taken in the year of installation and did not include interest during construction.

This data when input to the model generated a total cost stream per year for each scenario. This cost stream was then discounted back to 1982 at a rate of 3.0 percent. The discounted values, for each scenario, were summed to achieve the present worth of costs for each scenario. The present worth of costs for each scenario were then used to compare different scenarios. The cost analyses made by employing Alaska Power Authority economic analyses techniques were compared on the basis of total present worth of costs for each scenario.

The results of the economic analysis of alternative technologies and load growths are shown in Tables B5-10 through B5-13. These results demonstrate that the combined cycle technology exhibits both the lowest present worth of costs except in cases where natural gas costs were less than $1.50/million Btu. The results reflect the fact that the combined cycle power plant has the lowest heat rate and a modest installed capital cost, particularly in the size range considered in this study.

TABLE B5-10

PRESENT WORTH OF COSTS FOR NATURAL GAS FIRED GENERATION

AS A FUNCTION OF LOAD GROWTH, LOCATION, TECHNOLOGY, AND FUEL PRICE

AT A 0 PERCENT FUEL PRICE ESCALATION

(VALUES IN 1982$ x 10^9)

LOAD GROWTH FORECAST	LOCATION	TECHNOLOGY	FUEL PRICE ($ x 10^6 Btu) 0	1.50	2.00	2.50	3.50	5.50
Low	North Slope	Simple Cycle	0.360	0.678	0.784	0.890	1.103	1.527
		Combined Cycle	0.420	0.692	0.783	0.874	1.056	1.419
	Fairbanks	Simple Cycle	0.239	0.568	0.677	0.787	1.006	1.444
		Combined Cycle	0.256	0.517	0.605	0.692	0.866	1.215
	Kenai	Simple Cycle	0.248	0.577	0.687	0.797	1.017	1.457
		Combined Cycle	0.284	0.542	0.628	0.713	0.885	1.229
Medium	North Slope	Simple Cycle	0.707	1.370	1.591	1.812	2.255	3.319
		Combined Cycle	0.875	1.387	1.558	1.728	2.069	2.751
	Fairbanks	Simple Cycle	0.486	1.157	1.381	1.604	2.052	2.946
		Combined Cycle	0.556	1.061	1.229	1.398	1.735	2.408
	Kenai	Simple Cycle	0.505	1.184	1.410	1.636	2.088	2.993
		Combined Cycle	0.562	1.072	1.242	1.413	1.753	2.433

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TABLE B5-11
PRESENT WORTH OF COSTS FOR NATURAL GAS FIRED GENERATION
AS A FUNCTION OF LOAD GROWTH, LOCATION, TECHNOLOGY, AND FUEL PRICE
AT A 1 PERCENT FUEL PRICE ESCALATION
(VALUES IN 1982$ x 10^9)

LOAD GROWTH FORECAST	LOCATION	TECHNOLOGY	FUEL PRICE ($ x 10^6 Btu) 0	1.50	2.00	2.50	3.50	5.50
Low	North Slope	Simple Cycle	0.360	0.759	0.892	1.026	1.292	1.825
		Combined Cycle	0.420	0.761	0.874	0.988	1.125	1.669
	Fairbanks	Simple Cycle	0.239	0.651	0.789	0.926	1.201	1.751
		Combined Cycle	0.256	0.583	0.692	0.801	1.019	1.456
	Kenai	Simple Cycle	0.248	0.662	0.800	0.938	1.213	1.765
		Combined Cycle	0.284	0.606	0.714	0.821	1.036	1.467
Medium	North Slope	Simple Cycle	0.707	1.530	1.805	2.079	2.628	3.726
		Combined Cycle	0.875	1.509	1.720	1.932	2.354	3.119
	Fairbanks	Simple Cycle	0.486	1.319	1.600	1.875	2.430	3.541
		Combined Cycle	0.556	1.182	1.390	1.599	2.016	2.851
	Kenai	Simple Cycle	0.505	1.347	1.628	1.908	2.469	3.592
		Combined Cycle	0.562	1.195	1.405	1.616	2.038	2.881

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TABLE B5-12

PRESENT WORTH OF COSTS FOR NATURAL GAS FIRED GENERATION
AS A FUNCTION OF LOAD GROWTH, LOCATION, TECHNOLOGY, AND FUEL PRICE
AT A 2 PERCENT FUEL PRICE ESCALATION
(VALUES IN 1982$ x 10^9)

LOAD GROWTH FORECAST	LOCATION	TECHNOLOGY	FUEL PRICE ($ x 10^6 Btu) 0	1.50	2.00	2.50	3.50	5.50
Low	North Slope	Simple Cycle	0.360	0.861	1.028	1.195	1.529	2.197
		Combined Cycle	0.420	0.846	0.988	1.130	1.413	1.980
	Fairbanks	Simple Cycle	0.239	0.756	0.928	1.101	1.445	2.135
		Combined Cycle	0.256	0.665	0.801	0.938	1.210	1.756
	Kenai	Simple Cycle	0.248	0.767	0.940	1.113	1.459	2.151
		Combined Cycle	0.284	0.687	0.822	0.956	1.225	1.763
Medium	North Slope	Simple Cycle	0.707	1.748	2.088	2.429	3.110	4.472
		Combined Cycle	0.875	1.660	1.922	2.184	2.707	3.753
	Fairbanks	Simple Cycle	0.486	1.520	1.865	2.210	2.899	4.278
		Combined Cycle	0.556	1.331	1.590	1.848	2.365	3.399
	Kenai	Simple Cycle	0.505	1.549	1.897	2.245	2.942	4.334
		Combined Cycle	0.562	1.346	1.607	1.869	2.391	3.436

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TABLE B5-13
PRESENT WORTH OF COSTS FOR NATURAL GAS FIRED GENERATION
AS A FUNCTION OF LOAD GROWTH, LOCATION, TECHNOLOGY, AND FUEL PRICE
AT A 3 PERCENT FUEL PRICE ESCALATION
(VALUES IN 1982$ x 10^9)

LOAD GROWTH FORECAST	LOCATION	TECHNOLOGY	FUEL PRICE ($ x 10^6 Btu) 0	1.50	2.00	2.50	3.50	5.50
Low	North Slope	Simple Cycle	0.360	0.988	1.197	1.406	1.825	2.662
		Combined Cycle	0.420	0.952	1.129	1.306	1.661	2.369
	Fairbanks	Simple Cycle	0.239	0.887	1.103	1.318	1.750	2.614
		Combined Cycle	0.256	0.767	0.937	1.108	1.448	2.130
	Kenai	Simple Cycle	0.248	0.898	1.115	1.332	1.766	2.633
		Combined Cycle	0.284	0.788	0.956	1.124	1.460	2.132
Medium	North Slope	Simple Cycle	0.707	1.994	2.416	2.838	3.683	5.373
		Combined Cycle	0.875	1.847	2.171	2.495	3.143	4.439
	Fairbanks	Simple Cycle	0.486	1.769	2.197	2.625	3.480	5.191
		Combined Cycle	0.556	1.516	1.836	2.157	2.797	4.077
	Kenai	Simple Cycle	0.505	1.800	2.232	2.663	3.527	5.253
		Combined Cycle	0.562	1.533	1.857	2.181	2.828	4.123

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B6.0 CONCLUSIONS AND RECOMMENDATIONS

B6.1 ECONOMIC CONCLUSION

The economic data as portrayed in Tables B5-10 through B5-13, and particularly those in B5-12 (2% fuel price escalation rate) clearly illustrate that for fuel costs greater than about $\$1.50/10^6$ Btu for both medium and low growth forecasts at all three locations, the combined cycle technology has a clear economic edge, but less so at the North Slope. Combined cycle is capital cost effective, and has a slightly lower operating and maintenance factor than the simple cycle option. It has the highest thermal efficiency of any of the technologies considered. For these reasons, there is ample justification for selecting the combined cycle technology as the method for future power generation, should natural gas be available in the quantities required. Higher fuel costs favor this technology even more.

B6.2 TECHNICAL CONCLUSION

There are several technical factors favoring the selection of the combined cycle option: a 220 MW plant (ISO conditions, baseload) consisting of two 77 MW independently operated gas turbines and one 66 MW steam turbine generator offers virtually the same flexibility in construction, timing, operation, and maintenance that the simple cycle gas turbine offers; at the same time it achieves a heat rate far better than the simple cycle units.

At the North Slope location, for the range of fuel costs expected ($\$1.00$ to $\$2.00/10^6$ Btu), the combined cycle option enjoys a very slight margin in present worth costs versus simple cycle units. However, to be weighed against this are the added complexities of operating boilers on the North Slope with attendant water supply, water treatment, water chemistry control and other more specialized maintenance requirements of the higher temperature steam cycles. In addition, spare parts requirements increase due to the addition of the steam turbine cycle and attendant waste heat boilers, duct work, dampers, and other equipment.

Thus, for the North Slope, the technical advantages of the simple cycle unit outweigh the slight economic edge of the combined cycle. At Fairbanks and Kenai, the advantages of the combined cycle unit, where fuel prices are higher, clearly show combined cycle units being favored, especially since operation of these units is more favorable due to the availability of trained operators familiar with similar units and fossil fired boilers and steam turbines. In addition, the standard construction methods used in these areas more readily lend themselves to combined cycle plants, whereas the North Slope requires modular or non-standard methods.

B6.3 RECOMMENDATION

Since both the technical evaluation and economic analysis favor use of combined cycle plants for utilizing North Slope gas to generate electricity, this technology is recommended for the Fairbanks and Kenai locations. For the North Slope, the range of fuel costs anticipated do not outweigh the additional complexities of construction and operation of the combined cycle unit, and the use of simple cycle units is recommended.

As discussed previously, simple cycle plants are considered optimum at the North Slope for reasons of operation flexibility and cost. The low load forecast results in eight 77 MW (ISO conditions) simple cycle units at the the North Slope site, for the medium load forecast this would be fifteen units, as shown in Tables B5-4 and B5-7.

For Fairbanks and Kenai, for low load forecast, three 220 MW (ISO conditions) combined cycle systems would be installed for the low load forecast and 5 2/3 combined cycle systems for the medium load forecast by the year 2010, as shown in Tables B5-5, B5-6, B5-8 and B5-9.

B7.0 REFERENCES

Acres American, Inc. 1981. Susitna Hydroelectric Project - Feasibility Report - Volume I, Engineering and Economic Aspects, Final Draft. Alaska Power Authority. Anchorage, Alaska.

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Edison Electric Institute. 1981. Combustion Turbine Operational Practices Guidebook. EPRI Operating Development Group. Edison Electric Institute. Washington, D.C.

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT

ADDENDUM 1

Supplemental information for the economic analysis is contained in two sets of tables included in this addendum. Each set contains 12 separate tables. The first set shows energy requirements and gas requirements for each of the twelve scenarios in each year of the study period. The second set of tables is a summary of generation and economic data input to the model for analysis of each scenario in each year.

ENERGY USE AND GAS REQUIREMENTS TABLES

This set of tables utilizes the low and medium load forecasts and the energy available from hydro sources to determine the net energy required from thermal sources. The energy available from the new plants utilizing North Slope gas is then calculated. It is then assumed that use of the new gas units will be preferential and actual utilization of those plants is listed based on their supplying as much as possible (up to a capacity factor of 0.75) of the net required. The last column then lists millions of cubic feet of North Slope gas required to generate the energy utilized.

There are twelve tables, six for each load forecast, within those six, three for each technology, for the two technologies. All tables cover every year of the study period. The North Slope locale tables assume utilization of untreated gas at 1046 Btu/ft^3 (HHV). The Fairbanks scenario assume treated gas at 1104 Btu/ft^3 (HHV) and the Kenai assumes utilization of a gas treatment plant waste stream of up to 200 x 10^6 ft^3/day at 195 Btu/ft^3(HHV). For the waste stream utilization blending with sales gas to acheive a usable gas of 400 Btu/ft^3 (HHV) is assumed. This allows purchase of turbines with no modification from those burning pure sales gas.

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ELECTRICITY PRODUCED, COSTS AND HEAT RATES

The four data items listed in this table, electricity produced in gigawatt hour, capital expenditure, operating and maintenance (O & M) expenditures and system heat rates, all for each year operation, are the inputs for economic analysis generated by engineering design and estimating.

The project year is listed to indicate the discount period for each cost item. The electricity produced combined with annual heat rates and fuel prices yield annual fuel costs.

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 1

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

NORTH SLOPE LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2550	254	2296			
81	2646	254	2392			
82	2742	254	2488			
83	2838	254	2584			
84	2934	254	2680			
85	3030	254	2776			
86	3194	254	2940			
87	3358	254	3104			
88	3522	648	2874			
89	3686	648	3038			
90	3850	648	3202			
91	3892	648	3244			
92	3934	648	3286			
93	3976	648	3328			
94	4018	648	3370			
95	4060	648	3412			
96	4046	648	3398	600	600	6,596.6
97	4032	648	3384	1196	1196	13,149.1
98	4018	648	3370	1196	1196	13,149.1
99	4004	648	3356	1196	1196	13,149.1
2000	3990	648	3342	1199	1199	13,182.1
01	4048	648	3400	1196	1196	13,149.1
02	4106	648	3458	1794	1794	19,723.7
03	4164	648	3516	2391	2391	26,287.3
04	4222	648	3574	2398	2398	26,364.2
05	4280	648	3632	3587	3567	39,216.5
06	4412	648	3764	3587	3587	39,436.4
07	4544	648	3896	3587	3587	39,436.4
08	4676	648	4028	4197	4028	44,284.9
09	3808	648	4160	4185	4160	45,736.1
10	4940	648	4292	4783	4292	47,187.4

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 2

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

FAIRBANKS LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2550	254	2296			
81	2646	254	2392			
82	2742	254	2488			
83	2838	254	2584			
84	2934	254	2680			
85	3030	254	2776			
86	3194	254	2940			
87	3358	254	3104			
88	3522	648	2874			
89	3686	648	3038			
90	3850	648	3202			
91	3892	648	3244			
92	3934	648	3286			
93	3976	648	3328			
94	4018	648	3370			
95	4060	648	3412			
96	4046	648	3398	567	567	6,288.0
97	4032	648	3384	1130	1130	12,531.6
98	4018	648	3370	1130	1130	12,531.6
99	4004	648	3356	1130	1130	12,531.6
2000	3990	648	3342	1133	1133	12,564.9
01	4048	648	3400	1695	1695	18,797.3
02	4106	648	3458	2260	2260	25,063.1
03	4164	648	3516	2260	2260	25,063.1
04	4222	648	3574	2833	2833	31,417.6
05	4280	648	3632	3390	3390	37,594.7
06	4412	648	3764	3390	3390	37,594.7
07	4544	648	3896	3955	3896	43,206.1
08	4676	648	4028	3966	3966	43,982.4
09	3808	648	4160	4520	4160	46,133.8
10	4940	648	4292	4520	4292	47,597.7

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 3

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

KENAI LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$	
						WASTE GAS	SALES GAS
1980	2550	254	2296				
81	2646	254	2392				
82	2742	254	2488				
83	2838	254	2584				
84	2934	254	2680				
85	3030	254	2776				
86	3194	254	2940				
87	3358	254	3104				
88	3522	648	2874				
89	3686	648	3038				
90	3850	648	3202				
91	3892	648	3244				
92	3934	648	3286				
93	3976	648	3328				
94	4018	648	3370				
95	4060	648	3412				
96	4046	648	3398	553	553	12,474.2	3,631.9
97	4032	648	3384	1104	1104	24,903.3	7,250.7
98	4018	648	3370	1104	1104	24,903.3	7,250.7
99	4004	648	3356	1104	1104	24,903.3	7,250.7
2000	3990	648	3342	1107	1107	24,970.9	7,270.4
01	4048	648	3400	1656	1656	37,354.9	10,876.1
02	4106	648	3458	2208	2208	49,806.5	14,501.5
03	4164	648	3516	2208	2208	49,806.5	14,501.5
04	4222	648	3574	2767	2767	62,416.1	18,172.8
05	4280	648	3632	3311	3311	74,687.3	21,745.6
06	4412	648	3764	3863	3764	84,905.7	24,720.8
07	4544	648	3896	3863	3863	87,138.9	25,371.0
08	4676	648	4028	4427	4028	90,860.9	26,454.6
09	3808	648	4160	4415	4160	93,838.4	27,321.8
10	4940	648	4292	4415	4292	96,816.0	28,188.5

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 4

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

NORTH SLOPE LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2550	254	2296			
81	2646	254	2392			
82	2742	254	2488			
83	2838	254	2584			
84	2934	254	2680			
85	3030	254	2776			
86	3194	254	2940			
87	3358	254	3104			
88	3522	648	2874			
89	3686	648	3038			
90	3850	648	3202			
91	3892	648	3244			
92	3934	648	3286			
93	3976	648	3328			
94	4018	648	3370			
95	4060	648	3412			
96	4046	648	3398	600	600	6,596.6
97	4032	648	3384	1196	1196	13,149.1
98	4018	648	3370	1196	1196	13,149.1
99	4004	648	3356	1196	1196	13,149.1
2000	3990	648	3342	1199	1199	13,182.1
01	4048	648	3400	1662	1662	13,219.7
02	4106	648	3458	2260	2260	19,793.4
03	4164	648	3516	2260	2260	19,793.4
04	4222	648	3574	2866	2866	26,440.6
05	4280	648	3632	3324	3324	26,439.5
06	4412	648	3764	3922	3764	31,684.5
07	4544	648	3896	3922	3896	32,795.7
08	4676	648	4028	4533	4028	35,277.7
09	3808	648	4160	4520	4160	36,433.8
10	4940	648	4292	4520	4292	37,589.9

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 5

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

FAIRBANKS LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2550	254	2296			
81	2646	254	2392			
82	2742	254	2488			
83	2838	254	2584			
84	2934	254	2680			
85	3030	254	2776			
86	3194	254	2940			
87	3358	254	3104			
88	3522	648	2874			
89	3686	648	3038			
90	3850	648	3202			
91	3892	648	3244			
92	3934	648	3286			
93	3976	648	3328			
94	4018	648	3370			
95	4060	648	3412			
96	4046	648	3398	567	567	5,957.6
97	4032	648	3384	1130	1130	11,873.2
98	4018	648	3370	1130	1130	11,873.2
99	4004	648	3356	1130	1130	11,873.2
2000	3990	648	3342	1133	1133	11,904.7
01	4048	648	3400	1590	1590	11,939.4
02	4106	648	3458	2155	2155	17,876.4
03	4164	648	3516	2155	2155	17,876.4
04	4222	648	3574	2727	2727	23,873.6
05	4280	648	3632	3180	3180	23,873.8
06	4412	648	3764	3745	3745	29,814.1
07	4544	648	3896	3745	3745	29,814.1
08	4676	648	4028	4322	4028	33,413.4
09	3808	648	4160	4310	4160	34,508.4
10	4940	648	4292	4770	4292	32,228.9

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 6

TOTAL ENERGY USE AND GAS REQUIREMENTS

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

KENAI LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$	
						WASTE GAS	SALES GAS
1980	2550	254	2296				
81	2646	254	2392				
82	2742	254	2488				
83	2838	254	2584				
84	2934	254	2680				
85	3030	254	2776				
86	3194	254	2940				
87	3358	254	3104				
88	3522	648	2874				
89	3686	648	3038				
90	3850	648	3202				
91	3892	648	3244				
92	3934	648	3286				
93	3976	648	3328				
94	4018	648	3370				
95	4060	648	3412				
96	4046	648	3398	553	553	12,474.2	3,631.9
97	4032	648	3384	1104	1104	24,903.3	7,250.7
98	4018	648	3370	1104	1104	24,903.3	7,250.7
99	4004	648	3356	1104	1104	24,903.3	7,250.7
2000	3990	648	3342	1107	1107	24,970.9	7,270.4
01	4048	648	3400	1557	1557	24,962.1	7,267.8
02	4106	648	3458	2109	2109	37,413.5	10,893.2
03	4164	648	3516	2109	2109	37,413.5	10,893.2
04	4222	648	3574	2668	2668	49,995.7	14,556.5
05	4280	648	3632	3114	3114	50,527.1	14,711.2
06	4412	648	3764	3666	3666	62,372.7	18,160.2
07	4544	648	3896	3666	3666	62,372.7	18,160.2
08	4676	648	4028	4229	4028	71,456.4	20,804.9
09	3808	648	4160	4218	4160	73,798.1	21,486.7
10	4940	648	4292	4671	4292	68,810.0	20,034.4

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 7

TOTAL ENERGY USE AND GAS REQUIREMENTS

MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION

NORTH SLOPE LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2785	254	2531			
81	2893	254	2639			
82	3028	254	2774			
83	3162	254	2908			
84	3296	254	3042			
85	3431	254	3177			
86	3636	254	3382			
87	3841	254	3587			
88	4046	648	3398			
89	4251	648	3603			
90	4456	648	3808			
91	4549	648	3901			
92	4642	648	3994			
93	4738	648	4088	598	598	6,574.6
94	4829	648	4181	598	598	6,574.6
95	4922	648	4274	1196	1196	13,149.1
96	5031	648	4383	1799	1799	19,778.7
97	5141	648	4493	2391	2391	26,287.3
98	5250	648	4602	2989	2989	32,861.9
99	5360	648	4712	2989	2989	32,861.9
2000	5469	648	4821	3597	3597	39,546.7
01	5661	648	5013	3587	3587	39,436.4
02	5853	648	5205	4783	4783	52,585.6
03	6044	648	5396	4783	4783	52,585.6
04	6236	648	5588	5396	5396	59,325.0
05	6428	648	5780	6577	5780	63,546.9
06	6701	648	6053	7174	6053	66,548.2
07	6973	648	6325	7772	6325	69,538.7
08	7246	648	6598	8393	6598	72,540.2
09	7518	648	6870	8370	6870	75,530.6
10	7791	648	7143	8968	7143	78,532.0

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NORTH SLOPE GAS FEASIBILITY STUDY
SYSTEM PLANNING REPORT - ADDENDUM 1
TABLE 8
TOTAL ENERGY USE AND GAS REQUIREMENTS
MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION
FAIRBANKS LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2785	254	2531			
81	2893	254	2639			
82	3028	254	2774			
83	3162	254	2908			
84	3296	254	3042			
85	3431	254	3177			
86	3636	254	3382			
87	3841	254	3587			
88	4046	648	3398			
89	4251	648	3603			
90	4456	648	3808			
91	4549	648	3901			
92	4642	648	3994			
93	4738	648	4088	565	565	5,936.6
94	4829	648	4181	565	565	5,936.6
95	4922	648	4274	1130	1130	11,837.2
96	5031	648	4383	1700	1700	17,862.3
97	5141	648	4493	2260	2260	23,746.4
98	5250	648	4602	2825	2825	29,683.0
99	5360	648	4712	3390	3390	35,619.6
2000	5469	648	4821	3399	3399	35,714.1
01	5661	648	5013	3955	3955	41,556.2
02	5853	648	5205	4520	4520	47,492.8
03	6044	648	5396	5085	5085	53,429.4
04	6236	648	5588	5666	5588	58,714.5
05	6428	648	5780	6780	5780	60,731.9
06	6701	648	6053	7345	6053	63,600.4
07	6973	648	6325	7910	6325	66,458.3
08	7246	648	6598	8499	6598	69,326.8
09	7518	648	6870	8475	6870	72,184.7
10	7791	648	7143	9040	7143	75,053.3

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 9

TOTAL ENERGY USE AND GAS REQUIREMENTS

MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION

KENAI LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$	
						WASTE GAS	SALES GAS
1980	2785	254	2531				
81	2893	254	2639				
82	3028	254	2774				
83	3162	254	2908				
84	3296	254	3042				
85	3431	254	3177				
86	3636	254	3382				
87	3841	254	3587				
88	4046	648	3398				
89	4251	648	3603				
90	4456	648	3808				
91	4549	648	3901				
92	4642	648	3994				
93	4738	648	4088	552	552	12,451.6	3,625.4
94	4829	648	4181	552	552	12,451.6	3,625.4
95	4922	648	4274	1104	1104	24,903.3	7,250.7
96	5031	648	4383	1660	1660	37,445.1	10,902.4
97	5141	648	4493	2759	2759	62,235.6	18,120.2
98	5250	648	4602	3311	3311	74,687.3	21,745.6
99	5360	648	4712	3311	3311	74,687.3	21,745.6
2000	5469	648	4821	3320	3320	74,890.3	21,804.7
01	5661	648	5013	3863	3863	87,138.9	25,371.0
02	5853	648	5205	4415	4415	99,590.5	28,996.3
03	6044	648	5396	4967	4967	112,042.2	32,621.7
04	6236	648	5588	5534	5534	124,832.2	36,345.6
05	6428	648	5780	6623	5780	130,381.2	37,961.2
06	6701	648	6053	7188	6053	136,539.4	39,754.2
07	6973	648	6325	7739	6325	142,675.0	41,540.6
08	7246	648	6598	8314	6598	148,833.1	43,333.6
09	7518	648	6870	8843	6870	154,968.7	45,120.0
10	7791	648	7143	9395	7143	159,950.0	47,339.4

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 10

TOTAL ENERGY USE AND GAS REQUIREMENTS

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

NORTH SLOPE LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2785	254	2531			
81	2893	254	2639			
82	3028	254	2774			
83	3162	254	2908			
84	3296	254	3042			
85	3431	254	3177			
86	3636	254	3382			
87	3841	254	3587			
88	4046	648	3398			
89	4251	648	3603			
90	4456	648	3808			
91	4549	648	3901			
92	4642	648	3994			
93	4738	648	4088	598	598	6,574.6
94	4829	648	4181	598	598	6,574.6
95	4922	648	4274	1196	1196	13,149.1
96	5031	648	4383	1667	1667	13,259.5
97	5141	648	4493	2260	2260	19,793.4
98	5250	648	4602	2858	2858	26,366.8
99	5360	648	4712	3324	3324	26,439.5
2000	5469	648	4821	3933	3933	33,107.1
01	5661	648	5013	3922	3922	33,014.5
02	5853	648	5205	4520	4520	39,586.7
03	6044	648	5396	4987	4987	39,667.2
04	6236	648	5588	5600	5588	46,263.9
05	6428	648	5780	6649	5780	45,974.8
06	6701	648	6053	7247	6053	49,662.4
07	6973	648	6325	7845	6325	53,242.5
08	7246	648	6598	8334	6598	52,481.2
09	7518	648	6870	8909	6870	56,043.7
10	7791	648	7143	8909	7143	58,270.1

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 11

TOTAL ENERGY USE AND GAS REQUIREMENTS

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

FAIRBANKS LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$
1980	2785	254	2531			
81	2893	254	2639			
82	3028	254	2774			
83	3162	254	2908			
84	3296	254	3042			
85	3431	254	3177			
86	3636	254	3382			
87	3841	254	3587			
88	4046	648	3398			
89	4251	648	3603			
90	4456	648	3808			
91	4549	648	3901			
92	4642	648	3994			
93	4738	648	4088	565	565	6,265.8
94	4829	648	4181	565	565	6,265.8
95	4922	648	4274	1130	1130	12,531.6
96	5031	648	4383	1594	1594	12,633.1
97	5141	648	4493	2720	2720	25,132.7
98	5250	648	4602	3180	3180	25,202.9
99	5360	648	4712	3180	3180	25,202.9
2000	5469	648	4821	3755	3755	31,551.3
01	5661	648	5013	3745	3745	31,467.3
02	5853	648	5205	4770	4770	37,804.3
03	6044	648	5396	4770	4770	37,804.3
04	6236	648	5588	5349	5349	44,188.1
05	6428	648	5780	6360	5780	45,809.0
06	6701	648	6053	6925	6053	49,535.1
07	6973	648	6325	7490	6325	53,145.7
08	7246	648	6598	7971	6598	52,292.0
09	7518	648	6870	8515	6870	55,892.6
10	7791	648	7143	9080	7143	59,424.8

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 12

TOTAL ENERGY USE AND GAS REQUIREMENTS

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

KENAI LOCALE

YEAR	LOAD GWH	HYDRO GWH	NET GWH	AVAILABLE NSG-GWH	UTILIZED NSG-GWH	GAS REQ'D $FT^3 x 10^6$	
						WASTE GAS	SALES GAS
1980	2785	254	2531				
81	2893	254	2639				
82	3028	254	2774				
83	3162	254	2908				
84	3296	254	3042				
85	3431	254	3177				
86	3636	254	3382				
87	3841	254	3587				
88	4046	648	3398				
89	4251	648	3603				
90	4456	648	3808				
91	4549	648	3901				
92	4642	648	3994				
93	4738	648	4088	552	552	12,451.6	3,625.4
94	4829	648	4181	552	552	12,451.6	3,625.4
95	4922	648	4274	1104	1104	24,903.3	7,250.7
96	5031	648	4383	1561	1561	25,026.2	7,286.5
97	5141	648	4493	2661	2661	49,864.6	14,518.3
98	5250	648	4602	3114	3114	49,924.1	14,535.7
99	5360	648	4712	3114	3114	49,924.1	14,535.7
2000	5469	648	4821	3676	3676	62,542.8	18,209.7
01	5661	648	5013	3666	3666	62,372.7	18,160.2
02	5853	648	5205	4671	4671	74,886.2	21,803.5
03	6044	648	5396	5223	5223	87,336.2	25,428.4
04	6236	648	5588	5791	5588	96,555.6	28,112.7
05	6428	648	5780	6780	5780	95,732.3	27,873.0
06	6701	648	6053	7332	6053	102,984.7	29,984.6
07	6973	648	6325	7332	6325	107,612.5	31,332.0
08	7246	648	6598	7807	6598	105,780.1	30,798.5
09	7518	648	6870	8337	6870	113,107.2	32,931.8
10	7791	648	7143	8889	7143	120,298.9	35,025.7

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 13

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

NORTH SLOPE LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		72.63		
14	96	600	53.56	3.780	11,500
15	97	1,196	-0-	7.535	11,500
16	98	1,196	-0-	7.535	11,500
17	99	1,196	-0-	7.535	11,500
18	2000	1,196	-0-	7.535	11,500
19	01	1,196	53.56	7.535	11,500
20	02	1,794	53.56	11.302	11,500
21	03	2,391	-0-	15.063	11,500
22	04	2,398	107.12	15.107	11,500
23	05	3,587	-0-	22.598	11,500
24	06	3,587	-0-	22.598	11,500
25	07	3,587	53.56	22.598	11,500
26	08	4,028	-0-	25.376	11,500
27	09	4,160	53.56	26.208	11,500
28	10	4,292	-0-	27.040	11,500

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 14

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

FAIRBANKS LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		38.88		
14	96	567	33.90	2.608	11,600
15	97	1,130	-0-	5.198	11,600
16	98	1,130	-0-	5.198	11,600
17	99	1,130	-0-	5.198	11,600
18	2000	1,130	33.90	5.198	11,600
19	01	1,695	33.90	7.797	11,600
20	02	2,260	-0-	10.396	11,600
21	03	2,260	33.90	10.396	11,600
22	04	2,833	33.90	13.032	11,600
23	05	3,390	-0-	15.594	11,600
24	06	3,390	33.90	15.594	11,600
25	07	3,896	-0-	17.922	11,600
26	08	3,966	33.90	18.244	11,600
27	09	4,160	-0-	19.136	11,600
28	10	4,292	-0-	19.743	11,600

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 15

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, SIMPLE CYCLE GENERATION

KENAI LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		40.98		
14	96	553	35.68	2.544	11,650
15	97	1,104	-0-	5.078	11,650
16	98	1,104	-0-	5.078	11,650
17	99	1,104	-0-	5.078	11,650
18	2000	1,104	35.68	5.078	11,650
19	01	1,656	35.68	7.618	11,650
20	02	2,208	-0-	10.157	11,650
21	03	2,208	35.68	10.157	11,650
22	04	2,767	35.68	12.728	11,650
23	05	3,311	35.68	15.231	11,650
24	06	3,764	-0-	17.314	11,650
25	07	3,863	35.68	17.770	11,650
26	08	4,028	-0-	18.529	11,650
27	09	4,160	-0-	19.136	11,650
28	10	4,292	-0-	19.743	11,650

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 16

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

NORTH SLOPE LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		91.70		
14	96	600	53.56	3.300	11,500
15	97	1,196	-0-	6.578	11,500
16	98	1,196	-0-	6.578	11,500
17	99	1,196	-0-	6.578	11,500
18	2000	1,196	95.31	6.578	11,500
19	01	1,662	53.56	9.141	8,320
20	02	2,260	-0-	12.430	9,161
21	03	2,260	53.36	12.430	9,161
22	04	2,866	111.70	15.763	9,650
23	05	3,324	53.36	18.282	8,320
24	06	3,764	-0-	20.702	8,805
25	07	3,896	53.56	21.428	8,305
26	08	4,028	-0-	22.154	9.161
27	09	4,160	-0-	22.880	9,161
28	10	4,292	-0-	23.606	9,161

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 17

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

FAIRBANKS LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		43.86		
14	96	567	33.90	2.268	11,600
15	97	1,130	-0-	4.520	11,600
16	98	1,130	-0-	4.520	11,600
17	99	1,130	-0-	4.520	11,600
18	2000	1,130	56.97	4.520	11,600
19	01	1,590	33.90	6.360	8,290
20	02	2,155	-0-	8.620	9,158
21	03	2,155	33.90	8.620	9,158
22	04	2,727	59.63	10.908	9,665
23	05	3,180	33.90	12.720	8,290
24	06	3,745	-0-	14.980	8,789
25	07	3,745	33.90	14.980	8,789
26	08	4,028	-0-	16.112	9,158
27	09	4,160	-0-	16.640	9,158
28	10	4,292	-0-	17.168	8,290

NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 18

LOADS, COSTS AND HEAT RATES

LOW LOAD FORECAST, COMBINED CYCLE GENERATION

KENAI LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE (x10^6$)	O&M EXPENDITURE (x10^6$)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92				
11	93				
12	94				
13	95		46.28		
14	96	553	35.98	2.212	11,650
15	97	1,104	-0-	4.416	11,650
16	98	1,104	-0-	4.416	11,650
17	99	1,104	-0-	4.416	11,650
18	2000	1,104	53.65	4.416	11,650
19	01	1,557	35.68	6.228	8,280
20	02	2,109	-0-	8.436	9,162
21	03	2,109	35.68	8.436	9,162
22	04	2,668	56.70	10.672	9,678
23	05	3,114	35.68	12.456	8,280
24	06	3,666	-0-	14.664	8,787
25	07	3,666	35.68	14.664	8,787
26	08	4,028	-0-	16.112	9,162
27	09	4,160	56.70	16.640	9,162
28	10	4,292	-0-	17.168	8,280

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 19

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION

NORTH SLOPE LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		72.63		
11	93	598	-0-	3.767	11,500
12	94	598	53.56	3.767	11,500
13	95	1,196	53.56	7.535	11,500
14	96	1,799	53.56	11.334	11,500
15	97	2,391	53.56	15.063	11,500
16	98	2,989	-0-	18.831	11,500
17	99	2,989	53.56	18.831	11,500
18	2000	3,587	-0-	22.661	11,500
19	01	3,587	107.12	22.598	11,500
20	02	4,783	-0-	30.133	11,500
21	03	4,783	53.56	30.133	11,500
22	04	5,396	107.12	33.995	11,500
23	05	5,780	53.56	36.414	11,500
24	06	6,053	53.56	38.134	11,500
25	07	6,325	53.56	39.848	11,500
26	08	6,598	-0-	41.567	11,500
27	09	6,870	53.56	43.281	11,500
28	10	7,143	-0-	45.001	11,500

NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 20

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION

FAIRBANKS LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		38.88		
11	93	565	-0-	2.599	11,600
12	94	565	33.90	2.599	11,600
13	95	1,130	33.90	5.198	11,600
14	96	1,700	33.90	7.820	11,600
15	97	2,260	33.90	10.396	11,600
16	98	2,825	33.90	12.995	11,600
17	99	3,390	-0-	15.594	11,600
18	2000	3,390	33.90	15.594	11,600
19	01	3,955	33.90	18.193	11,600
20	02	4,520	33.90	20.792	11,600
21	03	5,085	33.90	23.391	11,600
22	04	5,588	67.80	25.705	11,600
23	05	5,780	33.90	26.588	11,600
24	06	6,053	33.90	27.844	11,600
25	07	6,325	33.90	29.095	11,600
26	08	6,598	-0-	30.351	11,600
27	09	6,870	33.90	31.602	11,600
28	10	7,143	-0-	32.858	11,600

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 21

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, SIMPLE CYCLE GENERATION

KENAI LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		40.98		
11	93	552	-0-	2.539	11,650
12	94	552	35.68	2.539	11,650
13	95	1,104	71.36	5.078	11,650
14	96	1,660	35.68	7.636	11,650
15	97	2,759	-0-	12.691	11,650
16	98	3,311	-0-	15.230	11,650
17	99	3,311	35.68	15.230	11,650
18	2000	3,311	35.68	15.230	11,650
19	01	3,863	35.68	17.770	11,650
20	02	4,415	35.68	20.309	11,650
21	03	4,967	71.36	22.848	11,650
22	04	5,534	35.68	25.455	11,650
23	05	5,769	35.68	26.535	11,650
24	06	6,053	35.68	27.844	11,650
25	07	6,325	35.68	29.095	11,650
26	08	6,598	35.68	30.351	11,650
27	09	6,870	35.68	31.602	11,650
28	10	7,143	-0-	32.858	11,650

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 22

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

NORTH SLOPE LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE (x10^6$)	O&M EXPENDITURE (x10^6$)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		91.76		
11	93	598	-0-	3.289	11,500
12	94	598	53.56	3.289	11,500
13	95	1,196	95.31	6.578	11,500
14	96	1,667	53.56	9.169	8,320
15	97	2,260	53.56	12,340	9,161
16	98	2,858	111.70	15.719	9,650
17	99	3,324	53.56	18.282	8,320
18	2000	3,933	-0-	21.632	8,805
19	01	3,922	53.56	21.571	8,805
20	02	4,520	111.70	24.860	9,161
21	03	4,987	53.56	27.429	8,320
22	04	5,588	165.26	30.734	8,660
23	05	5,780	53.56	31.790	8,320
24	06	6,053	53.56	33.292	8,582
25	07	6,325	111.70	34.788	8,805
26	08	6,598	53.56	36.289	8,320
27	09	6,870	-0-	37.785	8,533
28	10	7,143	-0-	39.287	8,533

NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 23

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

FAIRBANKS LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE (x10^6$)	O&M EXPENDITURE (x10^6$)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		43.86		
11	93	565	-0-	2.260	11,600
12	94	565	33.90	2.260	11,600
13	95	1,130	56.97	4.520	11,600
14	96	1,594	67.80	6,376	8,290
15	97	2,720	59.63	10.880	9,665
16	98	3,180	-0-	12.720	8,290
17	99	3,180	33.90	12.720	8,290
18	2000	3,755	-0-	15.020	8,789
19	01	3,745	93.53	14.980	8,789
20	02	4,770	-0-	19.080	8,290
21	03	4,770	33.90	19.080	8,290
22	04	5,349	93.53	21.396	8,641
23	05	5,780	33.90	23.120	8,290
24	06	6,053	33.90	24.212	8,560
25	07	6,325	59.63	25.300	8,789
26	08	6,598	33.90	26.392	8,290
27	09	6,870	33.90	27.480	8,510
28	10	7,143	-0-	28.572	8,702

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NORTH SLOPE GAS FEASIBILITY STUDY

SYSTEM PLANNING REPORT - ADDENDUM 1

TABLE 24

LOADS, COSTS AND HEAT RATES

MEDIUM LOAD FORECAST, COMBINED CYCLE GENERATION

KENAI LOCALE

PROJECT YEAR	YEAR	ELECTRICITY PRODUCED (GWH)	CAPITAL EXPENDITURE ($x10^6)	O&M EXPENDITURE ($x10^6)	HEAT RATE (BTU/KWH)
	1980				
	81				
0	82				
1	83				
2	84				
3	85				
4	86				
5	87				
6	88				
7	89				
8	90				
9	91				
10	92		46.28		
11	93	552	-0-	2.208	11,650
12	94	552	35.68	2.208	11,650
13	95	1,104	53.65	4.415	11,650
14	96	1,561	71.36	6.244	8,280
15	97	2,661	56.70	10.644	9,678
16	98	3,114	-0-	12.456	8,280
17	99	3,114	35.68	12.456	8,280
18	2000	3,676	-0-	14.704	8,787
19	01	3,666	92.38	14.664	8,787
20	02	4,671	35.68	18.684	8,280
21	03	5,223	35.68	20.892	8,636
22	04	5,588	92.38	22.352	8,924
23	05	5,780	35.68	23,120	8,554
24	06	6,053	-0-	24.212	8,787
25	07	6,325	56.70	25.300	8,787
26	08	6,598	35.68	26.392	8,280
27	09	6,870	35.68	27.480	8,503
28	10	7,143	-0-	28.572	8,698

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APPENDIX C

APPENDIX C

REPORT ON
FACILITY SITING AND CORRIDOR SELECTION

EBASCO SERVICES, INCORPORATED

JANUARY 1983

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C1.0 INTRODUCTION

The North Slope gas feasibility level assessment will result in a series of four reports. This report on facility siting and corridor selection is the third of that series. The complete series of reports is as follows:

1. Report on Existing Data and Assumptions
2. Report on System Planning Studies
3. Report on Facility Siting and Corridor Selection
4. Feasibility Assessment Report (draft and final)

This overall study is focused on three alternative development scenarios for power generation and gas and electrical transportation systems to move the energy from its source to points of consumption:

- o Electrical generation at the North Slope, with electrical transmission to Fairbanks via a new transmission line, and on to Anchorage via an upgraded Anchorage-Fairbanks Intertie;
- o Transport of North Slope natural gas via a small diameter pipeline to Fairbanks, with electrical generation at Fairbanks and similar upgrading of the Intertie for transmission to Anchorage;
- o Electrical generation at the terminus of a high-pressure natural gas pipeline to tidewater (Kenai-Nikiski area of the Kenai Peninsula), fueled by a waste component of the gas stream, with necessary electrical transmission to Anchorage and Fairbanks.

These are hereafter referred to as Scenario I: North Slope Power Generation; Scenario II: Fairbanks Power Generation; and Scenario III: Kenai Power Generation, respectively.

Following this introductory chapter, Chapter C2 details the siting process used in this study. Chapters C3, C4, and C5 provide complete siting descriptions for each respective scenario. Maps of the scenarios are provided in each of those chapters.

C2.0 FACILITY SITING AND CORRIDOR SELECTION PROCESS

C2.1 OBJECTIVES

Preliminary siting of the facilities included within each development scenario was accomplished at a level of detail commensurate with the conceptual design requirements of this feasibility level assessment. The objective of this study component is to provide a realistic physical setting for engineering, economic and environmental evaluations of the power generating, gas transport, and electric transmission facilities included within each of the three scenarios under consideration, rather than to identify specific sites or routes. The siting process has emphasized those considerations most critical to facility cost. In addition, siting opportunities and/or constraints associated with each of the candidate areas and corridors are identified.

The general areas considered for siting the generating facilities and routing the gas transportation and transmission facilities are identified in Section C2.3 below. These areas were used to develop generic site and route descriptions for each scenario. It is expected that further planning studies will be required in order to select actual sites and precise routes.

C2.2 SITING FACTORS

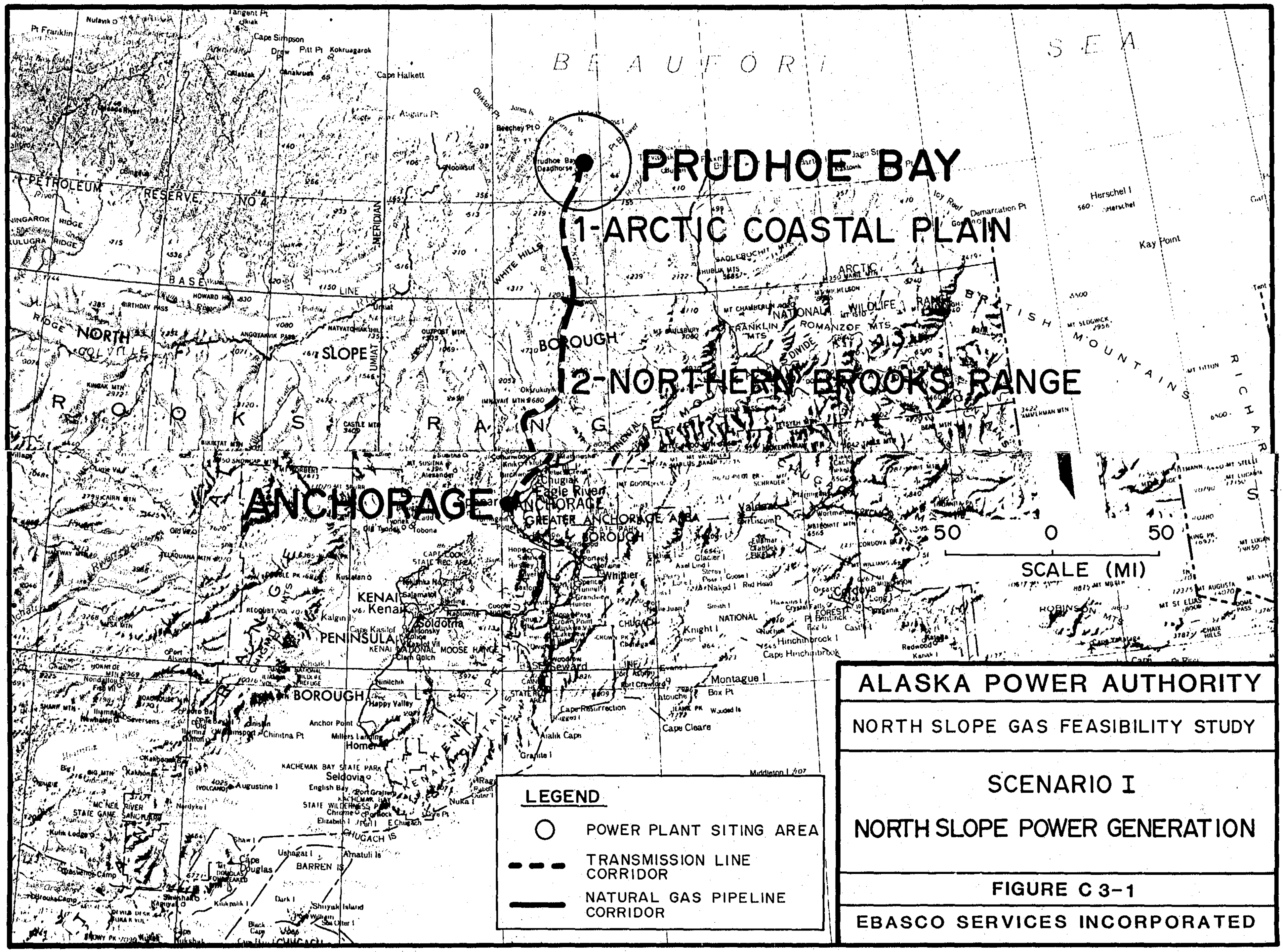
Because the objectives of this study are oriented to the requirements of conceptual engineering and cost estimating, and not toward the selection of specific sites or rights-of-way, the siting factors developed for the study's purposes are limited in number and are broad in scope. Establishment of suitable factors was an interactive process in which siting considerations important to each scenario/region were identified by the study participants, in parallel with the development of preliminary information regarding unit sizing and generation/transmission concepts. For example, based on the region's climatic extremes, it was evident early in the study process that the study would focus on air-cooled (dry) condenser systems for combined- cycle plants. Therefore, unlike most traditional power plant siting studies, the availability of substantial volumes of water for condenser cooling purposes would not be a significant siting criterion.

For each scenario (as discussed in succeeding chapters), relevant factors were developed for land status and use, geotechnical, engineering and environmental considerations. In general, the considerations were developed to ensure that 1) significant site-related factors were not overlooked in each scenario, 2) descriptions of the physical settings for further evaluations of the generating and transmission facilities would be focused on factors which are significant engineering and/or cost concerns and 3) "fatal-flaw" environmental constraints would not prohibit development.

C2.3 IDENTIFICATION AND EVALUATION OF CANDIDATE AREAS

The regions encompassed by each generation scenario are large and can pose significant constraints to industrial development. It was necessary to substantially narrow the geographic focus of the siting activities early in the study process, so that study resources could be allocated to the development of a realistic physical setting for the subsequent assessments, rather than to a search for specific sites or routes which offer the greatest development potential. The following paragraphs describe the basis for this "narrowing of focus," first for the generating facilities siting evaluations, and then for the transmission and pipeline corridor delineations.

The potential siting area for a generating facility for Scenario I - North Slope Power Generation - encompasses a vast region from the Beaufort Sea to the foothills of the Brooks Range. Primarily because of the existing support infrastructure, including road and electrical transmission systems and centralized waste treatment facilities, the generating site evaluation was confined to locations reasonably close to the Prudhoe Bay/Deadhorse development complex. Close proximity minimizes


BEAUFORT SEA
PRUDHOE BAY
1-ARCTIC COASTAL PLAIN
2-NORTHERN BROOKS RANGE
NORTH SLOPE BOROUGH
BROOKS RANGE
ANCHORAGE
GREATER ANCHORAGE AREA BOROUGH
KENAI PENINSULA BOROUGH
50 0 50
SCALE (MI)
LEGEND
POWER PLANT SITING AREA
TRANSMISSION LINE CORRIDOR
NATURAL GAS PIPELINE CORRIDOR
ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
SCENARIO I
NORTH SLOPE POWER GENERATION
FIGURE C 3-1
EBASCO SERVICES INCORPORATED

haul distances from the existing barge unloading facilities, and minimizes new road construction. The Prudhoe Bay area is relatively uniform with respect to the occurrence of permafrost, small surface lakes, topography, and climate. Actual site selection would consider the following factors: 1) minimizing interferences with existing land uses and facilities such as the pipelines comprising the gathering system; 2) optimizing the use of the supporting infrastructure, particularly roads; and 3) avoiding locations of significant environmental value, such as snow goose nesting areas. For these reasons, a generic site description encompassing significant factors likely to be encountered in most specific locations within the Prudhoe Bay area was developed.

Scenario II - Fairbanks Power Generation - is the most complex from a siting perspective with topograpic, land use, and air quality/ meteorologic conditions exhibiting significant variation within the area. This variation makes it difficult to define a homogeneous siting area. For purposes of this study, preliminary evaluations considered an approximate 50-mile radius centered on Fairbanks. Fairbanks is located at the northern edge of the broad Tanana River Valley. Extensive low, flat areas occur to the south and east, while the terrain rises significantly just to the north and west of the city. Most of the area south and east of Fairbanks is occupied by military reservations (Ft. Wainwright and Eielson Air Force Base); these designated land uses have concentrated some industrial expansion from the city into a narrow corridor along the Richardson Highway, particularly at or near the community of North Pole. This area would be potentially suitable for the generating facility site. Industrial development north and west of Fairbanks is limited by the steepening terrain and by federal land holdings. The southern boundary of the White Mountains National Recreation Area is about 25 miles north of Fairbanks. Suitable topography and access indicates that industrial development could be accommodated to the southwest, toward Nenana, but that is in the opposite direction from the TAPS Corridor, which passes to the east of Fairbanks. For these reasons, the geographic focus of this study was narrowed to include Fairbanks itself and nearby areas suggested by local utility representatives. Specific candidate siting areas are discussed in Chapter C4, along with a discussion of the climatic peculiarities of the Fairbanks area which may influence the siting of new generating facilities. The generic site description developed for Scenario II is based on conditions likely to be encountered within a short distance (10-15 miles) southeast of Fairbanks. This is not to imply that generating facilities could not be sited elsewhere in the Fairbanks region, but rather to provide a reasonable and realistic basis for the subsequent engineering investigations.

Scenario III - Kenai Area Power Generation - encompasses a much smaller area than the previous scenarios. This area is the assumed terminus of an all-Alaska large diameter natural gas pipeline. The communities of Kenai, Salamatof and Nikiski comprise a linear residential, commercial, and industrial development area, linked together by the North Kenai Road, along the west side of the Kenai Peninsula. The area occupies a relatively narrow strip between the Kenai National Wildlife Refuge and Cook Inlet. Within this well-defined area, physical and environmental characteristics are relatively uniform. The area is relatively flat, varying from 100 to about 150 feet in elevation, with spruce bogs and small lakes predominating. The principal siting consideration is the existing industrial infrastructure, which consists of petrochemical refineries and supporting facilities, a gas-fired generating station and transmission system operated by Chugach Electric Association, and one major road. For this scenario, a "narrowing of focus" was not necessary for development of a generic site description.

The geographic focus of the transmission corridor evaluations under each scenario was determined by the existence of established utility corridors or routes. The established Utility Corridor was used as the basis of the gas pipeline and electric transmission routing evaluations between Prudhoe Bay and Fairbanks. The Utility Corridor is defined by the Bureau of Land Management (BLM 1980) as a strip of land 336 miles in length from Washington Creek (28 miles north of Fairbanks) to Sagwon Bluffs (60 miles south of Prudhoe Bay). It varies in width from 12 to 24 miles and contains about 3.6 million acres. The Corridor was withdrawn and designated as a utility and transportation corridor by Public Land Order 5150 in 1971. For the purposes of this study, the Utility Corridor (and extensions to Prudhoe Bay and Fairbanks at either end) was divided into seven segments, each exhibiting relatively uniform characteristics for pipeline and transmission line routing.

Electric transmission between Fairbanks and Anchorage was assumed to involve three geographic segments:

- the Anchorage-Fairbanks Intertie, now under construction between Willow and Healy;
- existing Golden Valley Electric Association transmission rights-of-way between Healy and Fairbanks; and
- existing Chugach Electric Association transmission rights-of-way between Willow and Anchorage.

The routing evaluations focused on upgrade requirements in each segment rather than on alternative routes. Electric transmission between Kenai and Anchorage was likewise assumed to be via the existing Chugach Electric Association rights-of-way; these would also require substantial upgrading and possible re-routing in selected areas. One such area is the right-of-way alongside the highway which traverses the north shoreline of Turnagain Arm. The very limited area available between the shoreline and steep cliff in this segment may preclude upgrading the existing transmission line. Routing alternatives to avoid this severe constraint include a submarine cable crossing Turnagain Arm. These alternatives are discussed in greater detail in Chapter C5.

C2.4 DEVELOPMENT OF GENERIC SITE AND ROUTE DESCRIPTIONS

The methods described above were used to develop generic site and route descriptions upon which the subsequent feasibility assessments are based. For each generation and transmission scenario, a generalized site and corridor description was developed by the study team. Important parameters included access (in relation to the overall area), size and surface characteristics, water resources, soils and foundations, and environmental conditions.

Gas transportation and electric transmission facility routes are described on the basis of relatively homogeneous spatial segments, such as the Arctic Coastal Plain. Significant routing considerations specific to individual segments are given special attention in the generic route descriptions.

C3.0 SCENARIO I - NORTH SLOPE POWER GENERATION

The North Slope scenario consists of electrical generation at the North Slope, with electrical transmission to Fairbanks via a new transmission line, and transmission from Fairbanks to Anchorage via an upgraded Anchorage-Fairbanks Intertie. This scenario is illustrated in Figure C3-1.

C3.1 GENERATING FACILITY SITE EVALUATIONS

The previous report issued in this series, "Report on System Planning Studies," concluded that the best generating plant design for the North Slope is either a series of 220 MW combined cycle units consisting of two 77 MW gas turbine units and a 66 MW steam turbine, or a series of 77 MW simple cycle gas turbines alone, depending on fuel price. Three combined cycle units with one simple cycle unit or nine simple cycle units alone would be required for the low load forecast, while six combined cycle units with one simple cycle unit or eighteen simple cycle units alone would be required for the medium load forecast. In evaluating potential sites for the generating facilities, the plant size corresponding to the medium load forecast for both the combined cycle and simple cycle alternatives was used, under the assumption that any site appropriate for the larger development scenario would be more than adequate for the other alternatives.

The purpose of the generating facility site evaluations was to provide realistic site characteristics for engineering, economic, and environmental evaluations; not to identify a specific site. The geographic focus of the North Slope site selection process was the existing Prudhoe Bay/Deadhorse development complex, because of the existing support infrastructure. An overview of the Prudhoe Bay region is given below, followed by siting criteria and the generic site description.

C3.1.1 Description of Region - the Prudhoe Bay/Deadhorse Area

The Prudhoe Bay area is located at the northernmost reaches of the North Slope in flat, treeless, lake-filled tundra that extends from the foothills of the Brooks Range to the Arctic Ocean. It is an industrial enclave eight to ten miles inland from the coast near the mouth of the Sagavanirktok (Sag) and Putuligayuk (Put) Rivers. The Prudhoe Bay industrial area consists of numerous facilities to support oil recovery, processing and transportation, and a number of work camps housing construction and operations personnel. The Deadhorse airport is located in the southeastern section of the industrial area.

Physical Setting

The Prudhoe Bay area is located in the Arctic Coastal Plain, a subdivision of the Interior Plains physiographic province. The Arctic Coastal Plain topography consists of a smooth plain that rises from the Arctic Ocean to a maximum altitude of 600 feet at its southern border (Wahrhaftig 1965). Since the area is poorly drained, numerous marshes form in the summer. The land area is underlain by continuous permafrost approximately 2,000 feet thick which thaws a short distance below the surface in summer. Common permafrost landforms include ice-wedge polygons, braided streams, oriented thaw lakes, and pingos (University of Alaska 1978b).

The Prudhoe Bay area is beset with harsh weather conditions. The seasonal variation is dramatic due to the high latitude, where daylight lasts continuously during the summer and the sun remains below the horizon for 56 days in midwinter. The prevailing winds are east-northeast year-round with an average speed of 11 mph. Periods of stagnation are very rare. Fog is a regular occurrence at Prudhoe Bay, particularly during the summer months. Temperature ranges are large with measured annual extremes of -60°F and +75°F. The ground is covered with snow a major portion of the year but precipitation is less than 7 inches per year (University of Alaska 1978a).

Social Profile

Prudhoe Bay/Deadhorse is the largest community in the North Slope Borough with a transient population of approximately 6000. The second largest community is Barrow, the economic center of the North Slope Borough, located 110 miles northwest of Prudhoe Bay. As an industrial enclave, Prudhoe Bay is geographically isolated from communities on the North Slope and does not depend on the North Slope Borough for provision of services.

Travel in the region is primarily by air carrier, although nonperishable goods and bulky items are shipped by barge during the navigable season, generally a six-week period during August and the first half of September. The only major road is the Dalton Highway (Haul Road) which links Prudhoe Bay to Fairbanks.

The Inupiat, or northern Eskimos, are the indigenous people of the North Slope. The region is characterized by a dual economy of wage employment and subsistence that allows many of the Inupiat to continue cultural traditions using modern technology. In general, unemployment is a serious problem among the permanent residents. Both economic and cultural pressures have intensified the need for continued access to subsistence resources. The Inupiat are oriented both to the sea and interior regions for resources to maintain a subsistence lifestyle. Bowhead whale, seal, and caribou provide the bulk of subsistence needs for the Inupiat; waterfowl, furbearers, and fish are relied on to a lesser degree.

C3.1.2 Siting Considerations

Development of siting criteria focused on major factors that could affect the cost and design of the generating facility. Siting criteria for the North Slope scenario were developed under the assumption that the plant would be located in the Prudhoe Bay/Deadhorse industrial area, and would consist of six 220 MW combined cycle units and one 77 MW simple cycle unit, or eighteen simple cycle units.

C3.1.2.1 Land Status and Use Considerations

The Coastal Zone Management Program for the North Slope Borough has delineated zones of preferred development. Permanent facilities are allowed in the industrial development zone, consisting of the existing Prudhoe Bay/Deadhorse complex and the Pipeline/Haul Road Utility corridor (North Slope Borough 1978).

Within the Prudhoe Bay/Deadhorse complex, land use criteria consist of minimizing interferences with existing or planned facilities, including buildings, pipelines, roads, and transmission lines. Land ownership and lease agreements will also limit the land available for the electrical generating facility.

C3.1.2.2 Geotechnical Considerations

Due to the uniformity of foundation conditions at the North Slope (i.e., a thin active zone overlying permafrost), the major geotechnical consideration is developing a foundation scheme that would not cause permafrost degradation. The entire area is in seismic zone one, so seismic risk is not a significant siting criteria within the Prudhoe Bay area.

C3.1.2.3 Engineering Considerations

The site must be sufficiently large to house the generating units, a switchyard, and a construction and operations camp (should existing facilities be inadequate) for approximately 400 workers (approximately 70 acres). The site should be fairly level and adequate drainage must be provided.

The site should be in close proximity to the barge unloading facilities to minimize the cost of transporting equipment and should be close to existing electrical transmission lines, access roads, and gravel borrow areas to minimize cost and minimize land disturbance.

The site should have access to the existing sewage and solid waste disposal facilities. It should be possible to route a natural gas pipeline from the gas source (the compressor facility) to the site.

Combined cycle units require water for boiler feedwater makeup requirements, potable demand and other minor miscellaneous uses such as equipment wash down. Depending upon ambient air quality, a water or steam injection system may be required to limit the emissions of oxides of nitrogen (NO_x). In this system demineralized water is injected directly into the combustors limiting the peak flame temperature which in turn limits the formation of NO_x. Typical water injection rates for each unit at base load are about 50 gallons per minute (gpm) for gas fuel.

For the medium load forecast and both the combined cycle and simple cycle alternatives, the site must have access to approximately 900-1000 gpm of water if water injection for NO_x control is required. If water injection is not required, the combined cycle alternative will require approximately 200 gpm while the simple cycle alternative will require about 50 gpm.

C3.1.2.4 Environmental Considerations

The major environmental considerations for siting a generating facility in Prudhoe Bay relate to air quality, aquatic, and terrestrial ecology.

Air Quality

Air quality concerns play a signficant role in the siting of thermal power plants anywhere in the United States, and Alaska is no exception. The facility will be required to meet atmospheric emission standards and to demonstrate compliance with ambient air quality standards. Two sets of emission standards exist. These are the New Source Performance Standards (NSPS), which apply generically to combustion turbines; and the Best Available Control Technology (BACT), which is the best control system which can be affordably used on the plant's emissions. The Prudhoe Bay area is currently undergoing an intensive development of its oil resources. This development is having an impact on the air quality of the region. The Clean Air Act Amendments of 1977 establish allowable increments of degradation of air quality. These amendments, called the "Prevention of Significant Deterioration" (PSD) program, protect the air quality of relatively clean areas from undergoing substantial degradation. However, the allowable PSD increments for particulates and sulfur dioxide in the Purdhoe Bay area have not been used up. In addition PSD increments for nitrogen oxides, the major pollutant from combustion turbines have not been established. Therefore, it is unlikely that the installation of a gas-fired power plant in Prudhoe Bay would be hampered by air quality regulations, if a judicious siting effort is undertaken to prevent the compounding of any air pollution problems from existing facilities.

For combustion turbines, the PSD requirements would normally dictate the use of water or steam injection techniques to reduce the emission of nitrogen oxides to a level which meets the definition of Best Available Control Technology. The use of water injection measures will lead to the formation of ice fog in the Prudhoe Bay area and will also require the availability of an adequate supply of suitable fresh water. These additional requirements pose a substantial threat to the installation of combustion turbines, which use water injection control, in the Arctic environment. In the recent past, agencies with review authority over the installation of the combustion turbines have granted a waiver from the use of water or steam injection in the Prudhoe Bay area. It will also be necessary in the specific case being examined to obtain a waiver from these same requirements before the planned combustion turbines can be installed. The use of air cooled condensers or dry cooling towers is also required in order to eliminate the formation of ice fog and its associated hazards (primarily the reduction of visibility for road traffic).

Aquatic Ecology

Two groups of fish utilize the freshwater resources of the Prudhoe Bay area and would thus require consideration during the detailed site selection process: river fish such as the grayling, and anadromous fish such as the Arctic char and cisco. The anadromous species descend local rivers at ice-breakup to feed in the shallow littoral and sublittoral zone of the Beaufort Sea. They ascend these rivers in the autumn and overwinter in deep pools. These fish do not appear to undertake extensive migrations up the Sag or Put Rivers. Potential development-related impacts on fish which would require consideration include: pipeline and access road construction, and gravel mining in rivers which could affect overwintering and general habitat quality of the fish; and the need to cross larger river channels which could interfere with fish passage. The latter item may require the use of special culverts to maintain migratory routes.

Terrestrial Ecology

The Prudhoe Bay area and specifically the river delta areas provide a variety of habitats that are important to a diversity of plants and animals. The varied features of estuarine and river delta shorelines, sand dunes and dry, moist, wet, and aquatic tundra provide conditions for many types of vegetation that in turn provide breeding, feeding, nesting, and staging areas for many birds and mammals. A prime concern relative to the effects of any major development on the North Slope is the effect of vegetation change on important wildlife habitat. In addition, the ecological value of wetland vegetation has been nationally recognized, and these areas have been granted special regulatory status under Section 404 of the Clean Water Act of 1977. Project related impacts which would require special consideration during a detailed siting study include: 1) direct habitat elimination through the construction of project facilities, access roads, and gravel borrow areas; 2) indirect habitat elimination resulting from access roads which impede drainage or which generate significant traffic related dust; and 3) restrictions to large mammal movements, especially caribou.

C3.1.3 Generic Site Description

It is assumed that one or more locations could be found that would fit the generic description given below. The descriptions are of physical characteristics as they are assumed to exist, and emphasizes factors that may significantly affect cost or engineering design.

C3.1.3.1 Location and Access

The electrical generating facility site is located within the industrial enclave of Prudhoe Bay/Deadhorse, in the general vicinity of the existing SOHIO-operated powerplant, approximately five miles from the Beaufort Sea shoreline. This general location does not involve extensive transport distances for equipment received at the barge unloading facilities, and is also accessible for material transported by air or via the Haul Road. The area is served by existing roads, transmission lines, and waste treatment and disposal facilities, minimizing the cost for developing these facilities.

C3.1.3.2 Size and Surface Characteristics

The power plant site is approximately 65 acres in size, including the power plant housing and switchyard. An additional five acres will be used for the construction camp, operations personnel housing, and related facilities. The construction camp site is located adjacent to the generating facility site.

The power plant site is on a nearly level slope, although final grading will be achieved by shaping the gravel mat that will underlie the structure.

C3.1.3.3 Water Source

The power plant site is located adjacent to a lake of approximately 600 acres. The lake will be dredged to an appropriate depth to provide adequate storage volumes. The lake will provide the water needed for boiler feedwater requirements, potable, and other miscellaneous uses, but will not provide sufficient quantities for water or steam injection associated with NO_x control. If water injection is required, a suitable fresh water source would have to be developed.

C3.1.3.4 Soils and Foundations

The existing soil profile consists of an active zone approximately 1.5 feet thick overlying permafrost. The permafrost in this area is about 2000 feet thick.

Because maintenance of the permafrost is the primary geotechnical consideration in building a generating facility on the North Slope, foundation design will ensure permafrost integrity. A five foot thick engineered gravel mat will be placed directly over the tundra. Power plant modules will be set on 2-foot diameter steel pipe piles having a wall thickness of one inch. The pipe piles will be placed in 30 to 35-foot deep pre-augered holes, and backfilled with a sand-water slurry. A 90-day freezeback period will be required prior to loading any piling. Piling will extend above the ground surface six to eight feet, resulting in a total pile length of 36 to 43 feet. This foundation design will prevent any thawing of the permafrost from the generating facility.

C3.2 TRANSMISSION FACILITY ROUTING EVALUATIONS

The North Slope scenario involves transmitting electricity generated at the North Slope to Fairbanks and on to Anchorage. Discussion of the transmission route is divided into two sections, Prudhoe Bay to Fairbanks, within the utility corridor, and Fairbanks to Anchorage, via the Intertie now under construction. This scenario assumes that 100 percent of the generated electricity would be transmitted to Fairbanks, and approximately 80 percent transmitted on to Anchorage.

C3.2.1 Prudhoe Bay to Fairbanks

C3.2.1.1 Description of the Region

The designated utility corridor extending from Prudhoe Bay to Fairbanks consists of a strip of land about 425 miles long and from 12 to 24 miles wide. The portion of the corridor from Sagwon Bluffs, 60 miles south of Prudhoe Bay, to Washington Creek (28 miles north of Fairbanks) was designated as a utility transportation corridor by Public Land Order (PLO) 5150 in 1971. This PLO also designated an inner corridor, extending the entire length and varying in width from three to 20 miles.

The trans-Alaska oil pipeline (TAPS) occupies a 54-foot right-of-way within the corridor. Related pipeline facilities such as pump stations, material sites, and access roads are located along the corridor's length. The Dalton Highway (Haul Road) completed in 1974 to serve pipeline construction needs, is a 28-foot wide, all-weather, gravel highway within a 200-foot right-of-way granted to the State of Alaska. It extends from the Elliott Highway to Prudhoe Bay. North of the Yukon River the highway is closed to the public except during June, July and August, when it is open as far as Dietrich Camp.

Physical Setting

The physiographic provinces along the corridor are the Arctic Coastal Plain, Arctic Foothills, Arctic Mountains, and Northern Plateaus Provinces. The Arctic Coastal Plain is a wet tundra and mosaic of small lakes that extends from Prudhoe Bay to a maximum altitude of 600 feet. To the south, the Arctic Foothills consists of rolling plateaus and low linear mountains. The central and eastern Brooks Range and the Ambler-Chandalar ridge and lowland section comprise the Arctic Mountains Province. The Brooks Range is a series of rugged glaciated ridges that rise to summits of 7,000 to 8,000 feet in altitude in the northern part and 4,000 to 6,000 feet in the southern part. Small cirque and valley glaciers and lakes are common features.

The Northern Plateaus Province includes the region south of the Brooks Range and is characterized by even-topped ridges. These mountains descend to the Yukon Flats characterized by gently sloping outwash fans and nearly flat floodplains. Continuing south, the corridor extends into the rolling uplands of the Yukon and Tanana valleys.

Five major federal land designations are located adjacent to or near the corridor. Immediately to the west of the corridor in the Brooks Range is Gates of the Arctic National Park. To the east is the Arctic National Wildlife Refuge. Further south are the Yukon Flats National Wildlife Refuge and the Kanuti National Wildlife Refuge. To the south of the designated utility corridor is the White Mountains National Recreation Area.

The climate along the corridor can be divided into two zones. The Arctic zone extends from the Arctic Ocean to the Brooks Range and the Continental zone, which is the predominant zone of Alaska, covers the area from the Brooks Range to Fairbanks. Annual precipitation ranges from less than 5 inches in some Arctic areas to 20 inches in the Interior.

The corridor parallels major north-south rivers including the Sagavanirktok, Atigun, Dietrich, and Koyukuk Rivers. South of the Brooks Range, river valleys are primarily in an east-west orientation and the corridor crosses numerous streams.

North of the Brooks Range, in the foothills and coastal plain, the vegetation consists mainly of moist tundra composed of dwarf shrubs, sedges, cotton grass tussocks, mosses, and lichens with some high brush occurring in the floodplains. Alpine tundra, consisting of dwarf birch, willow, and low heath shrubs, and barren ground are found in the Brooks Range. Upland spruce-hardwood forest occurs south of the Brooks Range along riverine systems. Treeless tundra occurs above 2,000 feet. In the Yukon and Tanana Rivers region the vegetative cover is predominantly bottomland spruce and hardwood forests.

Social Profile

There are few signs of human inhabitance along the Prudhoe Bay-Fairbanks corridor. The villages of Livengood and Wiseman, and a number of small mining operations near the Wiseman area, are located near the Haul Road. TAPS pump stations with transient personnel are located at Pump Station 2, Slope Mountain (Pump Station 3), Galbraith Lake (Pump Station 4), Prospect (Pump Station 5) and the Yukon River (Pump Station 6). Department of Transportation camps are located at Slope Mountain, Chandalar, Dietrich, Coldfoot, Prospect and seven miles north of the Yukon River. Some of these camps have worker dependents and a school is located at the Yukon River camp. Commercial service establishments (i.e., truck stops) are located at Coldfoot and the Yukon River.

C3.2.1.2 Routing Considerations

Trans-Alaskan Pipeline System Restrictions

One of the most important siting criteria for the transmission line is to protect the integrity of the existing TAPS line and to avoid interference with pipeline operations. However, the present study assumes that no "fatal flaws" to the routing of either a transmission line (Scenario I) or a gas pipeline (Scenario II) would be imposed by the presence of the TAPS line. This assumption is based on the fact that a major additional linear facility (the ANGTS line) within the Utility Corridor has been licensed. While it is reasonable to expect that either transmission or new pipeline facilities could be routed within the corridor, such routing would not be done without numerous local complications imposed by physical and environmental constraints, including the presence of the TAPS line.

Specific TAPS restrictions would be negotiated during the detailed siting procedure. However, the following general critiera would be applicable:

- Minimize crossing the trans-Alaskan pipeline. Each crossing of the TAPS line poses a risk to the pipeline's integrity. Crossing of the line should only take place where required by topography, right-of-way, or other restrictions.

- Locate the transmission line at least 200 feet from the existing oil pipeline whenever possible. This was the minimum separation agreed upon for the ANGTS line, and it can be assumed that a similar separation would be required for the transmission line.

- Locate the transmission line downslope of TAPS and the haul road when feasible. This would prevent any ground slumping or deposition of eroded materials from affecting the TAPS line.

Utility Corridor Considerations

The Bureau of Land Management (BLM) has prepared land use plans for the Utility Corridor between Sagwon Bluffs and Washington Creek. These plans provide for a minimum of interference among alternate land uses, preservation of the environment, and appropriate use of the natural resources within the corridor. The land use plans contain specific programs for intensive land uses (such as pipelines, airports, and roads), mineral development, forest products use, rangeland, watershed protection, wildlife protection, and recreation. Specific components of the land use plan that relate directly to transmission line construction are summarized below (BLM 1980).

- Consolidate all permanent facilities except pump and compressor facilities at carefully selected nodes in the vicinities of Livengood Camp, Yukon Crossing-Five Mile Camp, Prospect, Coldfoot, Chandalar, and Pump Station #3 area.

- Take appropriate action to safeguard against damages to the pipeline and any new pipelines and related facilities.

- Protect stream banks and lakeshores by restricting activities to prevent loss of streamside vegetation.

- Restrict development of land within the floodplains of rivers to avoid loss of property by floodwaters.

- Protect raptor habitat and critical nesting areas. The Endangered Species Act mandates protection of threatened and endangered wildlife species. Protection of crucial raptor habitats preserves the integrity of raptor populations and maintains predator-prey relationships.

- Protect fish overwintering habitat. The critical overwintering areas have been mapped by BLM. Sufficient water levels should be maintained to meet the needs of overwintering fish. Conditions vary at each site, so stipulations should vary at each site to mitigate or prevent adverse alterations in fish habitat.

The land use plan has identified several areas as containing critical wildlife habitat. Specific management restrictions have not as yet been formulated; however, measures may be required for the following areas at the time of transmission line construction:

A. The Galbraith Lake-Toolik Lake-Atigun Canyon area.

B. The Sukakpak-Wiehl Mountain area.
   - Because of critical wildlife habitat, rare plants, historical, and archaeological sites and scenic values within the Corridor, all of vital national interest, special management is needed to focus properly on these two areas.

C. The Joe Creek-Chandalar Shelf area.
   - This area has a concentration of mineral licks, nesting raptor sites, and a Dall sheep lambing area.

D. The bluffs along the Yukon River.

E. Sagwon Bluffs.

- These areas have been identified as peregrine falcon habitat.

F. The Jim River and Prospect Creek areas.

- This has the highest quality year-long habitat for salmon in the Corridor. Proposed development and mining endanger this habitat. Also, these areas have high archaeological values.

G. The Bonanza Creek area.

- Just below Bonanza Creek is an important salmon fry overwintering area. Springs originating here are the main source of wintertime water flow.

H. The Ivishak River, Lupine River, Accomplishment Creek, Ribdon River area.

- These are important char overwintering areas.

I. The Kanuti and Sagavanirktok River areas.

J. The Wickersham Dome Area.

- These areas have been identified as caribou winter range.

In addition to the BLM land use plans, general land use criteria include:

o Maximize use of existing facilities such as work pads, highway, access roads, airports, material sites, and communications.

o Minimize crossing roads and highways.

o Avoid areas of existing or planned mineral development.

Engineering Considerations

The design of the transmission line from Prudhoe Bay to Fairbanks faces special challenges. This line must be able to serve the Railbelt with a substantial amount of power by the year 2010 and will provide for greater than 50 percent of the state's total available capacity at that time. A sudden loss of more than half, or almost three quarters of the power at the low or the medium load forecast, respectively, would cause serious interruptions in the Railbelt's electricity supply. In order to prevent this from happening, the line must be designed such that potential outages will be kept to a minimum, and that the loss of a single line segment will not jeopardize system operation even during peak loading.

The minimum condition to achieve this objective is to build two transmission lines (i.e., to have two circuits on separate towers). This is obviously a major cost consideration, and will be treated in detail in the subsequent Feasibility Assessment Report. The width of the right-of-way (ROW) of these 500 kV circuits is assumed to be 300 feet each or 600 feet total if they run side by side. This is somewhat more than the ROW used in the lower 48 (220 and 440 feet) but the rugged conditions require heavier structures and therefore wider ROWs. In general, two circuits would be routed side by side over the entire length with local exceptions. In the Atigun Pass area, for example, separate route alignments would be necessary.

The alternating current transmission line with its two circuits would be sectionalized by installing two switchyards at about 1/3 and 2/3 of the way along the line, or approximately 150 miles apart. With the substations at the two ends of the line, switching can be accomplished at four locations: Prudhoe Bay, Galbraith Lake (Pump Station 4), Prospect Camp (Pump Station 5) and Fairbanks. Should a failure occur at any of the line sections, a 150 mile stretch of one circuit has to be disconnected. During such a time period, one of the circuits would carry the power over the 150 mile long section, while for the rest of the line, both circuits would carry power. The circuits would be designed to carry the full load without any damage.

As transmission line grounding poses severe problems in many areas, including Prudhoe Bay, a continuous conductor wire, called contrepoise, would be carried along the entire length of each circuit, buried underground. This will assure proper behavior of the line during switching operations.

Access from the Haul Road to the transmission line right-of-way would be provided at suitable locations along the entire route. Construction personnel would utilize the existing camp facilities developed for TAPS.

Geotechnical Considerations

Geotechnical criteria consist of avoiding steep slopes, unstable soils, bedrock slide areas, and active fault zones. In some segments of the corridor, however, adverse geotechnical conditions cannot be avoided. In these cases, tower foundations would be designed to accommodate unfavorable subsurface conditions. Soil types within the corridor consist of marine sediments, floodplain gravels, alluvial fan and slopewash deposits, residual soil over bedrock and aeolian deposits. Continuous and discontinuous permafrost is also present.

Environmental Considerations

There are numerous environmental considerations that must be taken into account during detailed siting efforts and design engineering for a Prudhoe Bay to Fairbanks transmission line. These considerations have been derived from numerous environmental studies performed in conjunction with the evaluation of the TAPS line and in support of the ANGTS project. Some of the major considerations are discussed below.

Facilities and long term habitat alterations are prohibited within one mile of peregrine falcon nest sites unless specifically authorized by the U.S. Fish and Wildlife Service, because of the endangered species status of the peregrine falcon. Along the utility corridor six nests are located along Franklin Bluffs, and Sagwon Bluffs, and one nest on Slope Mountain. As a transmission line or gasline alignment along or west of the Dalton Highway would avoid the Franklin Bluffs and Sagwon Bluffs locations, the restriction may apply primarily to material sites.

Other raptors which may influence routing and siting include golden eagles (at least 42 nests between the Yukon River and Slope Mountain), rough legged hawk (24 nest locations between Slope Mountain and Prudhoe Bay), and gyrfalcons (5 nest locations between the Yukon River and Atigun Pass, 11 nest locations from Atigun Pass to the end of Sagwon Bluffs). Siting restrictions for these raptors which were applicable to ANGTS are presented in Table C3-1.

It is unlikely that the transmission line would be sited in or near important Dall sheep habitat. A primary concern is aircraft traffic over critical wintering, lambing, and movement areas. Moose winter browse habitat in the Atigun and Sag River valleys is limited to areas of tall riparian willow. Habitat has already been eliminated by the construction of TAPS and further destruction of this habitat should be avoided or minimized. The willow stand along Oksrukuyik Creek, in particular, should not be disturbed.

System design must allow free passage for caribou, but these animals should not be a major consideration in siting. Carnivore/human interaction is a major concern in facilities design and in construction and operations methods, but not in siting considerations.

Major impacts to fish would be from contrepoise construction. Between Fairbanks and Prudhoe Bay, the transmission line may cross as many as 150 waterbodies which are utilized by fish for migration, rearing, spawning, and/or wintering. Siting should avoid or minimize impact to spawning areas in approximately 35 waterbodies and to wintering areas in approximately 15 waterbodies. Important spawning waterbodies include large to middle sized rivers and streams such as the Chatanika River; Kanuti River, Fish Creek, Bonanza Creek, Prospect Creek, Jim River, and Koyukuk River and adjacent sloughs, Dietrich River and associated side channels and sloughs and the Kuparuk River, and also such small streams as Mary Angel Creek. Waterbodies that include important fish overwintering areas include Fish Creek, Bonanza Creek, the Jim River, the Koyukuk River, and the Dietrich River and associated springs and sloughs.

TABLE C3-1

STATE OF ALASKA TEMPORAL AND SPATIAL PROTECTION CRITERIA FOR NESTING RAPTORS1/

Species	Sensitive Time Period	Protection Criteria				
		Aerial Activity2/	Minor Ground Activity	Major Ground Activity	Facility Siting	Habitat Disturbance
Peregrine falcon	15 April - 31 August	1 mi h or 1500 ft v	1 mi	2 mi	2 mi	2 mi
Gyrfalcon	15 February- 15 August	1/4 mi h or 1000 ft v	1/4 mi	1/4 mi	1/2 mi	-
Golden eagle	15 April- 31 August	1/2 mi h or 1000 ft v	1/4 mi	1/2 mi	1/2 mi	-
Rough-legged hawk	15 April- 31 August	1/4 mi h or 1000 ft v	1/4 mi	1/4 mi	1/2 mi	--
Bald eagle	15 March3/- 15 August	1/4 mi h or 1000 ft v	1/8 mi	1/4 mi	1/2 mi	1/8 mi
Osprey	15 March- 15 August	1/4 mi h or 1000 ft v	1/8 mi	1/4 mi	1/2 mi	1/8 mi

1/ Extracted from 'Sensitive wildlife areas of the Northwest Alaskan gas pipeline corridor', C.E. Behlke, State Pipeline Coordinator, letter to E.A. Kuhn, NWA, 15 July 1980 and presented in Roseneau et al. 1981.

2/ h = horizontal; v = vertical.

3/ 1 March for areas between mileposts 472 and 573 (Tanana River from near North Pole to near Gerstle River).

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Identified overwintering areas such as Schroeder's Spring on the Dietrich River should be avoided altogether. Another very important area to be avoided is the wetland between Pump Station 4 and the Dalton Highway, and important rearing areas for fish in the Atigun Valley.

Line routing and tower siting should avoid or minimize disturbance of the treeline white spruce stand at the head of the Dietrich Valley, which has been nominated for Ecology Reserve status.

Transmission line construction may cause increased erosion rates in disturbed areas. This impact can be minimized by routing the line so that existing access roads can be used as much as possible. In addition, steep slopes and highly erodible soils should be avoided wherever possible.

Water quality impacts, primarily increased suspended solids concentrations, are closely related to erosion effects. In addition to the soil erosion considerations discussed above, the line should be routed so that a buffer strip of vegetation can be maintained between the disturbed areas and all water bodies.

C3.2.1.3 Generic Route Description

Because the topography and climate vary dramatically between Prudhoe Bay and Anchorage, the transmission line route has been divided into seven segments, as shown in Figure C3-1. Within each segment, the engineering design of the transmission line and tower foundations would be generally uniform. A brief summary description of each segment is given below, with emphasis given to topographic and climatic factors that affect transmission line costs.

Segment 1 - Arctic Coastal Plain (Prudhoe Bay to Pump Station 2)

The first segment encompasses the route from the Prudhoe Bay oil fields to Pump Station 2 of the pipeline. It is a 60 mile long segment, consisting of flat tundra with numerous lakes and ponds. The soil is mainly coarse alluvium and is underlain with continuous permafrost. Near the coast, arctic sand, picked up by moist, salty winds would contaminate the insulators in the late summer and/or early fall; this requires annual washing of the insulators.

The temperatures in this segment range from -60 to 86°F, with an average annual snowfall of 35 inches. Wind speeds can be up to 100 miles per hour. Ice thickness on transmission lines can reach 1.5 inches radially.

Segment 2 - Northern Brooks Range (Pump Station 2 to Galbraith Lake)

The second segment is approximately 95 miles long and gently rises from 500 feet above sea level to 3000 feet. No serious contamination problems are anticipated here because of the distance from the Beaufort Sea and because dust is generated only on the roads. The soil is alluvial deposits, floodplain gravel and slopewash deposits; it is in the zone of discontinuous permafrost. One of two intermediate switching stations would be located at the end of this segment, at Galbraith Lake,. The area is in the vicinity of Pump Station 4 and is easily accessible by road or air all year round.

Temperatures range from -60° to 90°F, and winds reach 100 miles per hour. Snowfall averages 63 inches annually, with a maximum of approximately 48 inches on the ground at any time. Maximum ice loading on the proposed line would be 1.5 inches radial thickness.

Segment 3 - Atigun Pass (Galbraith Lake to Nutirwik Creek)

The Atigun Pass segment of the line is only 30 miles long. For most of this length the road and the TAPS pipeline would be between the two circuits. Should any ROW be reserved for future pipelines or other structures, this should be specified in advance in order to avoid future conflicts. For about a 5-mile stretch at the pass itself at 3,000 feet above sea level, the circuits would be routed on the mountainsides. Suitably designed transmission towers can be erected on the slopes of

Atigun Pass. Far more difficult terrains have been successfully crossed with electric transmission lines elsewhere in the United States and abroad. Avalanches, however, are a major consideration. Another potential problem is that the contrepoises cannot be lowered into the rock soil, in which case two alternatives are available. The contrepoises can be either continued on the top of the towers as ground (aerial, sky) wires or they can be routed a few hundred feet away from the circuits close to the road and pipeline with tie connections to as many towers as possible.

The temperatures in this area range from -60° to 90°F. Average annual snowfall is approximately 63 inches, with roughly 48 inches maximum snow depth on the ground. Ice loading can reach 1.5 radial inches, and dust contamination would occur from the haul road. Wind speeds reach 120 miles per hour.

Segment 4 - Southern Brooks Range (Nutirwik Creek to Jim River)

From Atigun Pass to the Jim River the line would gradually descend from 3000 feet to 1000 feet in elevation. In this 90-mile section, extensive geotechnical surveying is necessary to identify a route which provides suitable soil for transmission tower footings. Being south of the Continental Divide and having only the road as a dust source, no serious contamination problems are expected in this segment.

Temperatures range from -75° to 90°F, with approximately 150 inches of snowfall per year. Maximum snow depth is about 110 inches. Wind speeds reach 90 mph.

Segment 5 - Caribou Mountain (Jim River to Yukon River)

The fifth segment runs between the Jim and Yukon Rivers and is 75 miles long. It is characterized by rolling hills and some flat terrain with an average elevation of approximately 1000 feet. Construction and operation of the line would be less demanding here than many of the other segments. The Prospect Camp/Airport area (about 25 miles south of the Jim River) is a good location for one of the intermediate switching stations. This site is next to Pump Station 5 and a DOT camp and therefore, has year-round access.

Temperatures range from -80 to 95°F, with 100 inches annual snowfall and 75 inches maximum snow depth. Wind speeds reach 80 mph. Dust contamination occurs from the road.

Segment 6 - Yukon River Crossing

The Yukon River crossing was identified as a separate segment, because of the dissimilar engineering problems it involves. The line would cross the river west (downstream) of the highway bridge. The bridge is approximately 2100 feet long and carries the TAPS line on its upriver side. The span of the line, located several hundred feet downriver of the bridge, is estimated to be approximately 2500 feet long. The span would originate on the flat area on the north (right) bank of the river. It would terminate on top of a hill on the left bank, at some 300 feet in elevation above the river. The hill provides the necessary height required for such a long span and eliminates the use of unusually large, heavy, expensive and unsightly transmission towers. With a 100 foot tower on the North Bank and a less than 200 ft tower on the South bank, on the top of the hill, the profile of the conductors would be almost exactly a half catenary curve, with the lowest point at the north end. The line therefore, would not create an obstruction to river traffic.

Temperatures range from -80 to 95°F. Average annual snowfall is 66 inches with a maximum snow depth of 50 inches. Wind speeds reach 70 mph.

Segment 7 - Livengood (Yukon River to Fairbanks Area)

The last segment of the transmission line runs to the Fairbanks area, the site of the final substation. The line would be routed among rolling hills. For approximately one mile the grade is in excess of 30 percent, the steepest grade along the entire route. The soil is residual soil over bedrock with aeolian and silt deposits down-slope. The soil of the smaller valleys consists of ice-rich silts to a depth of over 100 feet, and the larger streams have unfrozen floodplain gravels and sand.

Temperatures range from -70 to 98°F, with an average annual snowfall of 66 inches and maximum snow depth of about 50 inches. Wind speeds reach 70 mph. Dust or other contamination problems can be serious near construction sites or other disturbed areas.

C3.2.2 Fairbanks-Anchorage

C3.2.2.1 Description of the Region

The Anchorage-Fairbanks corridor encompasses these two economic centers and the major portion of the State's population. The transmission intertie would parallel the Alaska Railroad as well as the Parks Highway, which is the major transportation link between the two major cities. The area falls within three jurisdictions, the Anchorage Area Borough, the Fairbanks North Star Borough, and Matanuska-Susitna Borough. The Denali National Park, adjacent to and west of the Parks Highway, has national as well as international importance and attracts thousands of visitors each summer.

Physical Setting

The topography of the area is dominated by the north to south river valleys of the Susitna, Talkeetna, Chulitna, and Nenana Rivers, and the Alaska Range to the west and north. The transmission line corridor falls within the valley floor of these rivers. The highest point along the corridor is 2,300 feet at Broad Pass, which marks a watershed divide. The physiography of the region is widely varied. The corridor crosses four physiographic subdivisions that belong to the Pacific Mountain System division. The Cook Inlet- Susitna Lowland, a glaciated lowland less than 500 feet above sea level, covers the area from Anchorage to Talkeetna. This subdivision contains most of Alaska's developed agricultural land and is almost ice-free except for sporadic permafrost present in the northern part. The Broad Pass Depression is 1,000 to 2,500 feet in altitude, a trough having a glaciated floor that covers the area between Talkeetna and Healy. To the north, the central and eastern Alaska Range consists of rugged glaciated ridges broken at intervals by cross-drainages or low passes. The Northern Alaska Range Foothills includes the area between Healy and Fairbanks and is characterized by flat-topped east-trending ridges separated by rolling lowlands. The transmission corridor is situated in the glaciated valleys of this subdivision.

The region falls within the northern extension of the North American boreal forest which is characterized by interior forests of willow, spruce, and alder in the southern two-thirds and open woodland, shrubs, and tundra in the northern one-third. The vegetation cover supports big game species of moose, caribou, brown and black bear, small game, migratory game birds, furbearer, raptors, and other nongame mammals and birds. The Susitna River Basin and portions of the Nenana River Basin are important spawning grounds for anadromous salmon and common river species.

Social Profile

The region is dominated by two population centers, Anchorage to the south and Fairbanks to the north. Small population centers are located in Wasilla, Palmer, Houston, Talkeetna, Willow, Cantwell, and Healy with the remaining population scattered along the Parks Highway and the Alaska Railroad. Cantwell, Montana Creek, and Caswell are native villages within the corridor. The 1980 estimated population for the region was approximately 247,000 with over 70 percent of that population based in Anchorage.

Although Anchorage and Fairbanks are major centers with diversified economic bases, the economy of the region between the two cities is largely undeveloped. No significant additions to the project area's economic base has occurred during the past decade except for the expansion of commercial activity along the Parks Highway and the expansion of coal mining activities in Healy. Some major development projects proposed for the region could dramatically impact the demographic and employment outlook.

Outside of the Anchorage and Fairbanks labor markets, job opportunities are limited mostly to construction labor and tourist and recreation-oriented services. As a result, the labor force along the corridor is highly mobile in search of work and the unemployment rates are chronically high with wide seasonal swings.

C3.2.2.2 Routing Considerations

Route Descriptions

An existing transmission line corridor connects Fairbanks to Anchorage and is essentially divided into three segments. From Fairbanks to Healy, a 138 kV transmission line is operated by Golden Valley Electric Association. This 110-mile segment parallels the Fairbanks-Anchorage Highway for its entire length.

From Healy to Willow, the Intertie now under construction will consist of a 345 kV line that will be initially operated at 138 kV. This line will extend for 170 miles with a right-of-way width of 400 feet (Commonwealth Associates 1982).

The Intertie corridor passes through the Montana and Moody Creek drainages between Healy and Windy Pass, and is routed along the eastern portion of Broad Pass. The route then passes east of Chulitna Butte and crosses the Susitna River near Indian River, paralleling the Alaska Railroad until just north of Deadhorse Creek. The route crosses the Talkeetna River near Bartlett Hills, five miles east of Talkeetna, and proceeds south and west to near the village of Montana. The route parallels the Matanuska Electric Association right-of-way for the last 19 miles into the Willow Substation.

Between Willow and Anchorage, an existing 115 kV line passes along the eastern side of Knik Arm. In addition, a 138 kV line extends from Teeland, seven miles south of Wasilla, to Anchorage, along the western side of Knik Arm. As part of the Intertie construction, the Teeland substation will be connected to the Willow-Anchorage line with a 5.5 mile new 138 kV segment. The remainder of the 30-mile line from Teeland to Willow will then be converted to 138 kV.

Applicability of the Intertie Route

The transmission corridor selected for the Intertie balances concerns for environmental resources, public interests, economics and reliability. During route selection, substantial input was incorporated from both the public and private sector, including the Railbelt communities through the Public Participation Program, the resource management agencies through informal meetings and formal presentations and the participating Alaskan Utilities through the Technical Review Committee (Commonwealth Associates 1982). Based on this methodical siting process, the designated Intertie route was assumed to be the most appropriate for the present study's purposes.

The Intertie route was chosen specifically to minimize engineering and geotechnical complications, land use interferences and environmental consequences. The route avoids most of the local communities along the Parks Highway and Alaska Railroad. The route includes no crossing of the Denali National Park and Preserve, one crossing of the Denali State Park, no crossings of the Parks Highway, and only two crossings of the Alaska Railroad.

In addition to siting considerations, special measures are being implemented during the construction phase to further minimize environmental consequences. Several of these mitigating measures, as presented in the Environmental Assessment of the Intertie (Commonwealth Associates 1982), are summarized below.

In the very steep areas, soils will likely be cleared by hand to avoid excessive soil erosion. Soils susceptible to severe erosion or creep will be avoided.

The transmission line will unavoidably cross several large rivers and numerous creeks. However, all towers will be set back from water bodies at least 200 feet where possible. A buffer strip will be established along major watercourses to minimize siltation of streams. Equipment crossings of streams will take place when the stream is frozen, whenever possible.

Because trumpeter swans are very susceptible to human disturbance, construction activity will be restricted from May through August in areas with active trumpeter swan nesting territories.

The route avoids all known bald and golden eagle nests. Peregrine falcons are not known to utilize the project area except as migrants.

Because even a single equipment pass can cause serious permafrost degradation (Brown 1976), construction in permafrost areas will be completed when the ground is frozen. Construction in muskeg-bog soils will also be completed when the ground is frozen.

Fisheries resources will be protected by minimizing erosion and the subsequent siltation of water bodies. At stream crossings where equipment will move directly through the water, the crossings will be made during periods when there are no eggs or fry in the gravel. Generally, this will be a period in June and July after the rainbow trout and Dolly Varden fry have developed through swim-up and before the Pacific salmon start to spawn. Activities will be closely coordinated with the Alaska Department of Fish and Game. Construction activity will avoid small lakes and beaver ponds that are important nursery habitat for local and anadromous fish communities.

The Moody Creek-Montana Creek portion of the line will be constructed by helicopter. In other areas, existing roads and trails will be used as much as possible.

Upgrade Considerations

Satisfying the forecasted electrical energy demands within the Railbelt will require upgrading of each transmission line segment between Fairbanks and Anchorage including the Intertie. For all development scenarios evaluated in this study the existing 138 kV lines connecting Healy to Fairbanks and Willow to Anchorage will have to be upgraded to 345 kV essentially through line replacement. The Intertie would then be operated at 345 kV. One or two additional 345 kV lines are also required, extending the entire length of the corridor. In addition, various other electrical equipment changes including a switching station may be required, depending upon the developed scenario. Each aspect of the required upgrade is presently under study and will be specified in the Feasibility Assessment Report. It is realized that incremental environmental impacts will accrue due to line upgrading activities and these will also be discussed in the Feasibility Report. Because transmission line upgrading will utilize existing corridors, engineering and/or environmental considerations which could significantly affect system design or preclude development are not envisioned at the present time. It should be noted that substantial upgrading of the Anchorage-Fairbanks Intertie, on the order of that described above, will be required for any major energy development alternative to serve increased Railbelt power demands.

C4.0 SCENARIO II - FAIRBANKS POWER GENERATION

The Fairbanks scenario (Figure C4-1) consists of a small diameter gas pipeline from Prudhoe Bay to Fairbanks, a gas distribution system within Fairbanks, an electrical generating facility in the Fairbanks vicinity, and transmission of 80 percent of the energy produced to Anchorage. Each of these components is discussed below.

C4.1 GENERATING FACILITY SITE EVALUATIONS

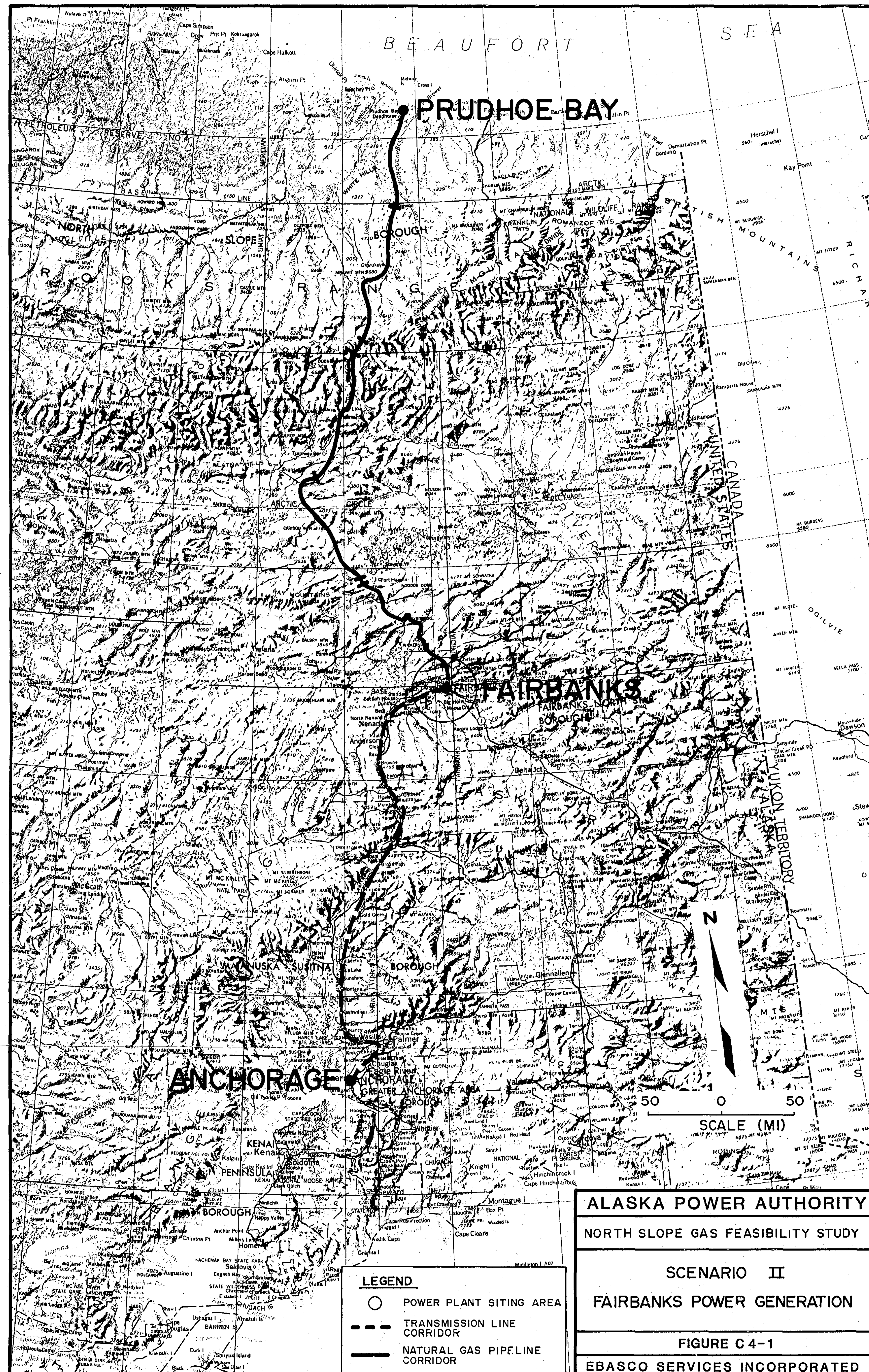
An overall description of the Fairbanks region, followed by power plant siting criteria, a discussion of candidate siting areas, and the generic site description is provided in this section.

C4.1.1 Description of the Region

Fairbanks is the regional commercial center of interior Alaska. The communities surrounding Fairbanks (e.g., Fox, North Pole) are located to the north, west, and southeast along the major transportation corridors. Fairbanks and these neighboring communities comprise the Fairbanks North Star Borough.

Physical Setting

Fairbanks is located in a broad floodplain near the confluence of the Chena and Tanana Rivers. Two vegetation types are located in the region. The lowland spruce-hardwood forest is an interior forest of evergreen and deciduous trees dominated by black spruce which sometimes occurs in pure stands. The bottomland spruce-poplar forest, located adjacent to the Tanana River, is a tall, relatively dense, interior forest primarily of white spruce. The vegetation cover supports big game species of black and grizzly bear, moose, small game, migratory game birds, furbearers, raptors, and other nongame mammals and birds. The Tanana River is an important spawning ground for anadromous salmon, arctic grayling, and whitefish.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

SCENARIO II

FAIRBANKS POWER GENERATION

FIGURE C 4-1

EBASCO SERVICES INCORPORATED

In the winter, stagnant conditions occur often, with very light winds and a strong temperature inversion in the vertical direction. These conditions bring about persistent air stagnation with ice fog and high levels of carbon monoxide. Ice fog, formed through the concentration of pollutants from automobiles, power plants, and domestic heating, settles in the bowl-like depression in Fairbanks during these stagnant conditions. Annual temperatures are extreme and range from a mean minimum of -24°F in January to a mean maximum of 75°F in July. Extremes can range from -60°F to over 90°F. The annual average precipitation in Fairbanks is 11 inches, which includes roughly 70 inches of snow.

Social Profile

The 1980 population for the Fairbanks North Star Borough was approximately 54,000. Data on non-agricultural wage and salary employment indicates that in the Fairbanks area government is the largest economic sector followed by trade and transportation, communications, and utilities. Tourism is a major factor in the trade sector and this activity has grown in the last few years. Since 1979, the average annual unemployment rate has exceeded 10 percent (Alaska Department of Labor 1981).

C4.1.2 Siting Considerations

Siting a generating facility in the Fairbanks area is more complex than on the North Slope, because of the diversity in topography and population patterns. Preliminary siting efforts have concentrated on areas of industrial development with space for expansion that are already served by utility facilities and have adequate transportation access.

C4.1.2.1 Land Status and Use Considerations

Land use criteria for power plant siting in the Fairbanks area are:

1) Compatibility with existing land uses. The Fairbanks area is bordered on the east and south by large military reservations. It is assumed that siting a power plant on these reservations would be precluded. While there are industrial areas within the city's immediate vicinity, sufficient space does not appear to be available for major new electrical generating facilities. Power plant siting on the outskirts of Fairbanks must take into account compatibility with specific land ownership and uses, such as new residential developments, the University of Alaska campus, and the Fairbanks Airport and its zone of influence. Preferably, the site would be located within or adjacent to an existing industrialized area, isolated from residential and commercial population centers. Ideally, the potential generating facility site will be zoned for industrial development.

2) Adequate existing transportation system. Because the generating facility will involve a large number of construction and operating personnel, the surrounding road network will experience a significant increase in use. The development of new roads or highways to provide site development access to as yet undeveloped portions of the Fairbanks area is assumed to be undesirable, both from a cost standpoint and because new transportation facilities should be part of a comprehensive, rather than project-specific, planning process. Therefore it is assumed that the plant site must be located within a reasonably short distance of existing major roads or highways.

3) Compatibility with adjacent utility corridors. The location of the gas pipeline and electrical transmission lines to and from the plant must not interfere with existing utility corridors. However, it would be advantageous to locate new generating facilities to optimize the use of existing pipeline and transmission line rights-of-way, and to minimize, to the extent possible, the acquisition of new rights-of-way.

These land status and land use considerations suggest that the vicinity of North Pole, east of Fairbanks along the Alaska Highway, should be examined in more detail. Candidate siting areas are discussed in Section C4.1.3.

C4.1.2.2 Geotechnical Considerations

In selecting the location of the power generating facility, the major geotechnical criteria are:

1) Foundation soils with good bearing capacity and limited settlement potential.

2) Suitable site drainage.

3) Primarily non-frost susceptible foundation materials.

4) Foundation soils generally free of permafrost or permafrost with low ice content.

These criteria are common to any industrial facility. In addition, given the imposed loads, the criteria allow the foundation design to consist of a concrete mat on a grade, with or without an engineered gravel pad.

C4.1.2.3 Engineering Considerations

In general, the power plant should be sited in relatively flat terrain, to minimize the amount of required grading and excavation. It will also minimize the potential for adverse environmental impacts due to erosion and transport of suspended solids to nearby waterways. The plant should also be sited above the 100-year floodplain of any major surface water resource in the area to avoid flooding.

An area's seismic activity can also be an important site differentiating factor, with preference given to those sites located in regions of low activity. In the Fairbanks area, however, all potential site locations fall within regions of high seismic activity (Zone 3). While this will not preclude development nor differentiate between the sites, it will increase construction costs as more material will be required to insure plant foundation stability. The location and extent of all faults within the general Fairbanks area should be studied during the actual site selection process, as the plant should not be sited in close proximity to fault lines.

Siting a power plant in close proximity to existing roads, railroads, and transmission lines minimizes the cost associated with these required connection links. Existing electrical power will be necessary during the initial construction phase. Railroads will be used to transport large equipment as close to the site as possible, and trucks for the remaining distance. The site must have access to approximately 200 gpm of fresh water. This assumes that water injection for nitrogen oxides control will not be required, in order to avoid severe ice fogging.

C4.1.2.4 Environmental Considerations

Air Quality

Meteorological conditions in Fairbanks play a very important role in determining the ambient air quality levels in the area. Analyses of the Fairbanks urban "heat island" have shown that winds are generally light in the winter and that wind directions change dramatically in the vertical direction during the wintertime. During the winter months, the air near the ground is relatively cold, compared to the air aloft. This reduces mixing of the air in the vertical direction, and when combined with relatively light winds, often leads to periods of air stagnation.

In large part due to the winter stagnation conditions, the Fairbanks area is currently designated as a non-attainment area for carbon monoxide (CO). Emissions of CO are largely due to automobiles. The State Department of Environmental Conservation and the Fairbanks North Star

Borough Air Pollution Control Agency are implementing a plan to reduce the ambient CO mainly through the use of vehicle emission or traffic control techniques. In addition, relatively high levels of nitrogen oxides have recently been monitored in the Fairbanks area. Only an annual average nitrogen dioxide standard exists, but the short term measurements of nitrogen oxides are as high as in major urban areas such as Los Angeles.

The installation and permitting of a major fuel-burning facility, such as a power plant, will require a careful analysis of the impact of its emissions on ambient air quality. The operators of such a facility must demonstrate that they will reduce, or offset, impacts of the power plant by reducing emission levels of CO at other sources.

The protection of air quality in Fairbanks and its associated regulatory framework will pose a significant concern for the siting of a major power plant. However, these concerns will not preclude the development of at least some form of a natural gas fired power plant. Emissions of CO from this fuel source are relatively low, and any displacement of the burning of other fuels, such as coal or oil, will likely lead to improved air quality. This arises from the clean-burning nature of natural gas and from the fact that emissions from a major facility will be injected higher in the atmosphere (due to plume buoyancy) than the displaced emissions. During the very stagnant conditons in midwinter, the plume from a power plant will likely remain well aloft with little mixing to the surface layers. The complex urban heat island and associated wind pattern will require a great deal of in-depth modeling and analysis to determine air quality impacts in terms that will withstand regulatory scrutiny.

A large combustion turbine power plant must meet the existing New Source Performance Standards and Best Available Control Technology. The nitrogen oxides limits will be the most constraining atmospheric pollutant. The operation of the power plant will also consume a portion of the allowable deterioration in air quality for nitrogen oxides. While it is possible that the power plant could be sited near Fairbanks, its installation would constrain other development efforts which also might consume a portion of the air quality increment.

The Fairbanks area is also subjected to extended periods of wintertime ice fog, and the Alaska Department of Environmental Conservation will require the impact of any water vapor plumes to be carefully assessed. A combustion turbine power plant which uses water or steam injection techniques would have an adverse impact on the ice fog and icing deposition nearby. The nature, magnitude, and duration of plumes must be studied as well as the potential for beneficial impacts due to reduced combustion at other sources within the area. The combustion turbine facility would have to use water or steam injection techniques to meet the standards of Best Available Control Technology. The requirements for water injection will be waived if and when it is determined that the subsequent formation of ice fog will cause a traffic hazard (40 CFR 60.332).

Other Environmental Considerations

If more detailed siting analyses were to be conducted for Scenario II, the land use and air quality concerns previously discussed would provide the only significant screening criteria to discriminate among alternative areas. At a more localized scale, there could be significant ecological or cultural resources affected, but judicious siting and project planning could avoid or mitigate such impacts. In this scenario, air quality and land use concerns will override other environmental concerns because the siting effort would focus on previously disturbed areas or areas of low biological significance.

C4.1.3 Candidate Siting Areas

Three general areas in the Fairbanks vicinity have been identified by local GVEA and Fairbanks Municipal Utility personnel as possible locations for an electrical generating facility: 1) near the Chena Power

Plant in Fairbanks; 2) in the North Pole area approximately 14 miles southeast of Fairbanks, and 3) in the Fox area, approximately 9 miles north of Fairbanks. In addition, there may be additional potential generating facility sites in the Fairbanks region that have not yet been identified. Each of the identified areas is described below in order to provide a frame of reference for the subsequent description of the generic site.

C4.1.3.1 Chena Power Plant Area

The Chena power plant is located in downtown Fairbanks. The plant is located on floodplain gravel, adjacent to the Chena River. The area is nearly fully developed; expansion of the plant would be restricted by lack of available space.

C4.1.3.2 North Pole Power Plant Area

North Pole, Alaska is located 14 miles southeast of Fairbanks, on the Richardson Highway, near the Tanana River. The town of North Pole has a population of 470, although 6,000 people live in the municipal area.

Golden Valley Electrical Association (GVEA) operates a 130 MW power plant outside of North Pole. Sufficient space exists for expansion of the plant. The topography in this area is generally flat, with little forest vegetation and sparse ground cover.

C4.1.3.3 Fox Area

The town of Fox is located approximately nine miles north of Fairbanks. The area consists of extensive dredge tailings remaining from past gold mining operations in the Goldstream Creek Valley. The valley floor is generally flat, and is about 300 feet higher in elevation than Fairbanks.

C4.1.4. Generic Site Description

C4.1.4.1 Location and Access

The generating site is assumed to be located within several miles of Fairbanks, along a major transportation route. The area is served by existing electrical transmission lines, so that electricity will be available during the construction phase. A railroad spur extends to within several miles of the site; transportation of equipment over the remaining distance will be handled by truck. The small diameter pipeline route from Washington Creek (the southern end of the Utility Corridor from Prudhoe Bay) is over relatively gentle terrain and does not cross any major population centers, rivers, or other constraining features.

C4.1.4.2 Size and Surface Characteristics

The power plant site is approximately 65 acres in size. Because no construction camp will be used at the Fairbanks site, no additional acreage will be needed during the construction phase.

The terrain in the vicinity of the site is flat to gently rolling. Very little vegetation is present because much of the area is already disturbed by existing or previous development.

C4.1.4.3 Water Source

The water supply for plant operations will be provided by wells, and treated to bring the quality up to the necessary standards. The water table in the area is within 20 feet of the surface.

C4.1.4.4 Soils and Foundations

The generic site soils can be described as river floodplain sands and gravels with low ground ice content overlaid by approximately 5 feet of silt with low to moderate ice content. The site is free of permafrost.

A generic foundation design can be described as a 2 to 4-foot thick concrete mat overlying a 5-foot thick gravel pad. The overburden silts will be excavated and spoiled.

C4.2 GAS PIPELINE ROUTING EVALUATIONS

A major component of the Fairbanks scenario is the construction of a small diameter gas pipeline from Prudhoe Bay to Fairbanks. The pipeline would have a 22-inch outside diameter with a maximum operating pressure of 1260 psig. The pipeline would have ten compressor stations for the medium load forecast, and three for the low load forecast. The pipeline would be buried for its entire length, and would have an operating temperature between 0 and 32°F. At the Yukon River the existing aerial crossing would be used. The pipeline would be routed within the Utility Corridor described in Section C3.2.1.1.

C4.2.1 Routing Considerations

C4.2.1.1 Trans-Alaskan Pipeline System and Utility Corridor Restrictions

Development restrictions imposed by TAPS and the Bureau of Land Management regarding transmission line construction from the North Slope to Fairbanks, discussed in Section C3.2.1.2, would also be applicable to the construction of the gas pipeline.

C4.2.1.2 Engineering and Geotechnical Considerations

Within the designated Utility Corridor, certain natural hazards exist which must be identified and considered during pipeline design. Such things as potential land slides, snow avalanche areas, earthquake faults, and erosion areas cause a threat to the pipeline integrity. Thus, their location and potential magnitude is of primary concern. Additionally, the construction of a workpad and the interaction of the pipe with the soil thermal regime and local hydrological conditions can significantly alter normal terrain stability. Liquefaction, ice damming, aufeising, flooding, and thaw degradation are but a few concerns which must be addressed.

Two major considerations of primary importance to a safe design are the mitigation or prevention of frost heave and thaw settlement. Both these phenomena pose a hazard to a gas line by changing the delicate thermal balance in certain soil conditions along the route. A significant effort has been put into understanding these phenomena by Alyeska and Northwest Alaskan Pipeline Company (NWA), but additional research will be required to understand the specific interaction of any new design configuration or construction mode.

Another potential problem concerns additional rights-of-way for future pipelines or other structures in the Atigun Pass area. This region is extremely narrow with little ground space available for pipeline development. Should other rights-of-way be envisioned they should be specified in advance so that the least costly alternative for all routes can be achieved.

Some specific engineering criteria that must be considered during pipeline design include:

1) Minimize cross drainage blockage.
2) Avoid thaw unstable slopes as much as possible.
3) Minimize traversing areas with frost susceptible soil.
4) Minimize the haul distance for construction materials.
5) Provide year-round, all-weather access to the proposed pipeline.
6) Maximize route cost effectiveness.
7) Prevent degradation of the permafrost.

C4.2.1.5 Environmental Considerations

The environmental considerations discussed in Section C3.2.1.2 regarding transmission line construction from the North Slope to Fairbanks are generally applicable to the gas pipeline system. Additional considerations specific to the gas pipeline include:

1. Fish passage must not be blocked and flow velocity must not exceed the maximum allowable flow velocity for the fish species on a given stream. If these criteria cannot be met, a bridge must be installed.
2. Stream crossings must be able to withstand the pipeline design flood as determined for each stream.
3. Chilled pipes in streams should not cause: a) lower stream temperature so as to alter biological regime of stream; b) slow spring breakup and delay of fish migration; c) early fall freeze-up which would affect fish migration.
4. Chilled pipe in streams should not aggravate or initiate aufeis buildup, if possible.
5. The original configuration, gradient, substrate, velocity, and surface flow of streams should not be altered.
6. For fish, construction scheduling should avoid in-stream construction during critical sensitivity periods and be miniminal in moderate periods.
7. Disturbance of wetlands should be minimized.
8. The temperature of natural surface or groundwater should not be changed significantly by the pipeline system or by any construction-related activities.

C4.2.2 Applicability of the ANGTS Route

The Alaska Natural Gas Transportation System (ANGTS) route is located within the Utility Corridor, set aside under Public Law Order 5150 in 1971. The Alaska Natural Gas Transportation Act (1976) and the Presidential Decision (1977), routed the 48-inch diameter pipeline within this corridor, including its infrastructure of roads, material sites, and ancillary development. The corridor, from Washington Creek north to about 60 miles south of Prudhoe Bay, is managed by the Bureau of Land

Management under a land use plan centered around nodal development. Construction on State lands on the North Slope is further regulated through North Slope Borough ordinances. In addition, private property owners, native corporation lands, holders of sub-surface mineral rights, and Alyeska had numerous stipulations that had to be resolved.

During the evolution of the gas pipeline routing, environmental, socioeconomic, and land use decisions dictated gasline locale. The selection process took several years while Northwest Alaskan Pipeline Company (NWA) developed the resources and environmental data base to be used for route selection and design criteria. NWA reviewed existing trans-Alaska oil pipeline and State highway construction data, resource agency files, and implemented biological, physical, and civil field programs to further delineate constraints.

The information provided by NWA was reviewed by State and Federal agency representatives through the State Office of Pipeline Coordinator and the Office of the Federal Inspector -- a 'one window' coordinated effort where government resource and NWA personnel developed acceptable mitigation measures to be incorporated in ANTGS route selection, project design activities, and construction stipulations.

Through the processes described above, NMA minimized the crossings of the trans-Alaska oil pipeline, the Alyeska gasline (Prudhoe Bay to Pump Station 4), and the Dalton Highway. The environmental and non-technical programs conducted since the environmental impact report (1976) have provided information that altered the route to mitigate gasline impact on sensitive areas (e.g., a white spruce stand on the Dietrich River was avoided). The gasline alignment has been reviewed in detail and the general route approved by resource agency personnel. It has also been reviewed by the public during the public participation program developed by NWA.

Based on the synopsis provided here, which is supported by years of field research by NWA, Alyeska, and resource agencies, it is reasonable to base the present study on the assumption that the ANGTS route is a viable pipeline route for the transportation of gas from the North Slope to the Fairbanks area.

C4.3 GAS DISTRIBUTION SYSTEM FOR FAIRBANKS

As indicated at the beginning of Chapter C4, Scenario II includes the development of a gas distribution system within Fairbanks. It is generally assumed that siting of this system would necessarily conform to good engineering practice in municipal environments. Specific engineering considerations related to facility location decisions are discussed in the following paragraphs.

The overall system network would consist of a transmission lateral from a metering station at the main pipeline near Fox to one or several city gate stations. The metering station would be located where the gas pipeline crosses the Steese Highway about 2 miles northeast of Fox. From there a transmission line would run into Fairbanks in public rights-of-way adjacent to traveled roadways, to the city gate station(s).

The type of construction and location of district regulator stations will be determined during final design. The options of underground vault versus aboveground station construction must be reviewed with respect to considerations of the availablility of public right-of-way, private easement, soil and groundwater characteristics, equipment operating capabilities and safety.

The distribution lines would be laid in public rights-of-way at a depth of three feet to the top of the main. The lines would occupy the opposite side of the road from existing or proposed water mains.

C4.4 TRANSMISSION FACILITY ROUTING EVALUATION

The Fairbanks to Anchorage transmission line routing requirements for this scenario are the same as those for the North Slope power generation scenario. The regional description, engineering and environmental considerations, and route description presented in Section C3.2.2 of this report are also applicable to this scenario.

C5.0 SCENARIO III - KENAI POWER GENERATION

The Kenai Power Generation scenario (Figure C5-1) is predicated on the development of a large diameter natural gas pipeline from Prudhoe Bay to a tidewater location near Kenai or Nikiski. This all-Alaska pipeline is being studied by others. Several assumptions regarding this facility are used in this report. A conditioning facility would be located at the tidewater site to remove impurities (mainly carbon dioxide) from the gas and liquefy the gas for transhipment to appropriate markets. The waste gas from this conditioning facility would be used to fuel the power generating facility discussed in this study. Because the waste gas could only produce a small amount of electrical power, it would be supplemented by sales gas from the pipeline to satisfy the requirements of both load forecasts. Electricity generated at this plant would be transmitted to Anchorage where 80 percent of the capacity would be used, by constructing new transmission lines. The remaining 20 percent capacity would be transmitted on to Fairbanks, via the upgraded Intertie.

C5.1 GENERATING FACILITY SITE EVALUATIONS

Siting for the Kenai scenario focused on the coastal area between Kenai and Nikiski. This section gives an overview of the region, siting considerations, and the generic site description.

C5.1.1 Description of the Region

The Kenai-Nikiski area is on the western border of the Kenai Peninsula. Kenai is situated on the Sterling Highway at the mouth of the Kenai River. A corridor of industrial and rural residential development is situated along the North Kenai Road, which extends about 20 miles north of Kenai. The communities of Salamatof and Nikiski are included within this area. Major onshore facilities are located in Nikiski, including refineries, an ammonia urea manufacturing plant, and natural gas liquefaction facility.

Physical Setting

The Kenai-Nikiski area ranges in elevation from 100 to 150 feet above sea level. The shoreline on Cook Inlet is an abrupt, steep bluff. Much of the surface is marshes or muskeg bogs interspersed among numerous small lakes. Subsurface drainage ranges from good to poor, depending on the nature of underlying sediments and topography. Vegetation ranges from sedge-grass-moss cover on the wettest sites to mature stands of white spruce, white birch, aspen and cottonwood on the drier sites (Karlstrom 1958).

Meteorological conditions in the area are generally favorable for the development of facilities such as power plants. The site is in an exposed coastal setting with generally moderate winds and good atmospheric dispersion conditions. Fog develops often in the area during the winter months, but is relatively rare during the spring and summer months. Temperature extremes can range from -30°F to 80°F in the site area but the average winter temperature is 13°F while the average summer temperature is 54°F.

Social Profile

Kenai is the largest economic center on the Kenai Peninsula. The 1980 populations at Kenai and Nikiski were 4,324 and 1,109, respectively. The three largest economic sectors for the Kenai-Cook Inlet census subarea are manufacturing, government, and wholesale and retail trade, in that order. Unemployment is high due to the seasonality of construction and commercial fishing and averaged 13 percent in 1981 (Alaska Department of Labor 1982).

C5.1.2 Siting Considerations

C5.1.2.1 Land Status and Use Considerations

Because the Kenai-Nikiski area is already extensively industrialized, compatibility with existing land uses will not pose serious problems.

Detailed facility siting analyses for this scenario should address potential effects on locally significant land uses such as the Captain Cook Recreation Area at the north end of the North Kenai Road; existing and future rural residential developments; flight operations of the Kenai Municipal Airport; and the numerous pipeline rights-of-way serving the area's refineries. New generating facilities might be sited to take advantage of the existing Bernice Lake Generating Station operated by the Chugach Electric Association.

C5.1.2.2 Geotechnical Considerations

In selecting the location for a generating facility, the key geotechnical criteria are foundation soils with good bearing capacity and limited settlement potential, and suitable site drainage. These conditions are prevalent just north of Kenai adjacent to the North Kenai Road, where terrace and alluvial plain silts, sands and gravels predominate. These terrace and alluvial deposits are of glacio-lacustrine and glacio-fluvial origin. The topography is flat to undulating.

C5.1.2.3 Engineering Considerations

General engineering considerations presented for both the North Slope and Fairbanks power generating scenarios (Sections 3.1.2.3 and 4.1.2.3) are also applicable to the Kenai area.

All potential site locations in the Kenai area fall within regions of high seismic activity (Zone 3). While this will not preclude development, it will increase construction costs as more material will be required to insure plant foundation stability. The site must also have access to approximately 1000 gpm of water because water or steam injection for the control of nitrogen oxides will likely be required.

C5.1.2.4 Environmental Considerations

Air Quality

As is typical of many exposed coastal locations, the air quality and meteorological conditions are generally favorable to the development of facilities such as power plants. It is not likely that an intense "marine layer", which may restrict dispersion of pollutants, develops in this area. The air quality attains the applicable ambient standards, but the locale is burdened with several existing petroleum refinery emissions. A new natural gas-fired power plant could probably be sited in the area with the use of appropriate emissions controls including water or steam injection to reduce nitrogen oxides emission. The impact of water vapor emissions on the formation of fog must also be considered. The power plant must be carefully sited in order to avoid adding to the air quality impacts of the existing facilities.

Other Environmental Considerations

The Kenai-Nikiski industrial corridor, by virtue of its past development, is generally not an ecologically important land area. The Kenai National Wildlife Refuge, a few miles to the east, is a major environmental resource which provides habitat protection for both resident and migratory wildlife. However, there are other local environmental concerns which must be considered in siting additional power generating facilities in the area. Effects on local residential developments, recreational facilities and tourism must be addressed on a site-specific basis, but probably would not preclude site development in this rural industrial area.

C5.1.3 Generic Site Description

C5.1.3.1 Location and Access

Because the generating facility will be using waste gas and sales gas from a gas conditioning facility, the plants will be located in close proximity to each other. The generic site is in the general Kenai-Nikiski area within a few miles of the coast. The area is served by existing electrical transmission lines and access roads.

C5.1.3.2 Size and Surface Characteristics

The power plant site is approximately 65 acres in size. No construction camp will be used at the site because sufficient local housing appears to be available.

The terrain in the site vicinity is flat to gently rolling. Vegetation consists generally of sparse stands of shallow-rooted trees with local patches of denser forest and shrub.

C5.1.3.3 Water Source

Groundwater will be used for all plant water needs. The water will be treated to reach the quality needed for make-up water. Groundwater is generally available in the Nikiski area, so that water supply will not pose a significant constraint to development.

C5.1.3.4 Soils and Foundations

Generic site topography and soils consist of flat to undulating topography and well-drained granular materials (i.e., sands and gravel). The foundation will consist of a concrete mat 2 to 4 feet thick on grade. Other than clearing and grubbing, and perhaps some minor grading, no other foundation work will be required.

C5.2 TRANSMISSION FACILITY ROUTING EVALUATIONS

All of the electricity generated at the Kenai/Nikiski site would be transmitted to Anchorage via new transmission lines. Eighty percent of the generated capacity would be used in Anchorage; the remaining 20 percent would be transmitted on to Fairbanks via the upgraded Intertie. The Kenai-Anchorage corridor is discussed first below, followed by the Anchorage-Fairbanks corridor.

C5.2.1 Kenai-Anchorage Corridor

C5.2.1.1 Description of the Corridor

The transmission corridor between Kenai and Anchorage is maintained by the Chugach Electric Association (CEA). The corridor generally parallels the Sterling Highway across the Kenai Peninsula to the upper end of Turnagain Arm at Portage. It is located on a narrow bench along the highway traversing the north shore of Turnagain Arm as far west as Indian Creek, where it turns north to traverse Powerline Pass in the Chugach Mountains. The corridor then descends to the northwest into Anchorage.

Physical Setting

The corridor lies within the Coastal Trough and Pacific Border Ranges physiographic provinces. That portion of the corridor which lies north of Turnagain Arm is within the Cook Inlet-Susitna Lowland subdivision of the Coastal Trough province. This is a glaciated lowland containing areas of ground moraine and stagnant ice topography, drumlin fields, eskers and outwash plains. The lowland is generally less than 500 feet above sea level. That portion of the corridor to the south of Turnagain Arm lies within the Kenai-Chugach Mountains subdivision of the Coastal Trough province. The Kenai Mountain range has been heavily glaciated and is characterized by rock-basin lakes, U-shaped valleys, and incised ravines. The Kenai Lowlands extend west of the mountains and are drained by the Kenai River (Wahrhaftig 1965).

The Kenai River system is a major physiographic feature of the region. The Kenai River and its tributaries are important spawning grounds for king, sockeye, and silver salmon. The vegetation of the Kenai River watershed lies in a transition zone between the Pacific rainforest biome and the Arctic-alpine biome. Vegetation types within this zone include the coastal western hemlock-Sitka spruce forest, upland spruce-hardwoods, lowland spruce-hardwoods, high brush, muskeg, and tundra. These habitat types support an abundance and variety of bird and mammal populations (U.S. Army Corps of Engineers 1978).

The climate of the study corridor varies with changes in the topography and relationship to the Kenai Mountain range. The climate, in general, is not as wet as that characteristic of the maritime climatic region and is not as extreme as the continental climate of interior Alaska. Annual precipitation ranges from 15 inches in Anchorage to 23 inches along the western coast of the Kenai Peninsula. Temperatures in Kenai average 13° F in winter and 54° F in summer (U.S. Army Corps of Engineers 1978).

Social Profile

The study corridor falls within the jurisdiction of the Kenai Peninsula Borough. In 1980 the population of the borough was 25,282 with Soldotna and Kenai the major communities within the corridor. The area around Kenai, Soldotna, and Sterling has undergone rapid subdivision. Increased tourism and recreational activity have contributed to the growth in Soldotna and, to a lesser extent, in Sterling. Growth in population and employment has been influenced strongly by growth in the hydrocarbon industry. As a result of petroleum and natural gas activity, the peninsula has experienced extensive development, including pipelines, marine terminals, refineries and other processing facilities. The food and kindred products industry is important to the regional economy, particularly with regard to fish processing. Unemployment is currently and historically has been high, due in part to seasonal variations in the labor market.

The study corridor falls with the Chugach National Forest, administered by the U.S. Forest Service, and the Kenai National Moose Range, administered by the U.S. Fish and Wildlife Service. These areas offer numerous recreational opportunities to residents of the peninsula as well as of Anchorage.

C5.2.1.2 Existing Transmission Facilities

Chugach Electric Association, Inc. presently operates a 115 kV line from Anchorage to Soldotna and Nikiski (Bernice Lake), via Portage and Quartz Creek, and a 69 kV line between Quartz Creek and Soldotna which continues to Homer. These transmission lines cannot be considered as part of the system evaluated in this feasibility study because their load carrying capacity is a small fraction of the considered electrical requirements. The established rights-of-way associated with these lines have been considered to the maximum extent possible, however.

Engineering Considerations

Because of the relatively short distance there is no need for intermediate switching stations between Kenai and Anchorage, even in the medium forecast scenario. The two circuits of the transmission line require a 440 foot wide right-of-way or two 220 foot wide corridors. Should less than 440 feet be available for the entire length, the two circuits may be routed for short distances on single towers, though this would lower the availabilty of the system.

Environmental Considerations

Several environmental protection factors should be taken into account in planning and design of an expanded right-of-way and, in certain areas, for new rights-of-way.

To minimize soil erosion, steep slopes and highly erodible soils should be avoided where possible. Existing access roads should be used at all possible locations. New access roads should incorporate adequate drainage systems to minimize erosion of the road surface.

The selected route should minimize the number of additional stream crossings. Where stream crossings are unavoidable, the towers should be set back a minimum distance from streambanks and a buffer strip of vegetation should be retained along water bodies to minimize siltation of streams. Equipment should cross streams using well-designed bridges that protect the stream bank.

The present route passes through a small area of caribou habitat near Kenai (University of Alaska 1974). Little alteration of caribou habitat will result from construction of the transmission line because the animal utilizes cover types that require little if any clearing. The route also passes adjacent to Dall Sheep and Mountain Goat range between Cooper Landing and Saxton, but does not extend into the rangeland at any location. Much of the route between Kenai and Cooper Landing is within Moose fall and winter rangeland. However, because the moose utilizes many different habitat types, it will be the least adversely affected by habitat alterations (Spencer and Chatelain 1953). Where the proposed route crosses heavily forested areas, the moose will benefit from additional clearing of the right-of-way and the subsequent establishment of a subclimax community (Leopold and Darling 1953).

Fisheries resources can be protected by closely coordinating construction activity with the Alaska Department of Fish and Game. Equipment should not cross streams without bridges when eggs or fry are in the streambed.

C5.2.1.4 Route Description

Two 500 kV circuits are required for both the medium and low electrical demand forecasts. No intermediate switching stations are required but series compensation is required for the medium load forecast.

The line would originate at the powerhouse in the Kenai area. Routed in an easterly direction, it would parallel the 115 kV Chugach line. It would follow the Kenai River Valley, the north shore of Kenai Lake, and would turn northeast along Quartz Creek. At the East Fork of the Bend River it would make a sharp turn, and follow the river until the Granite Creek Valley. The line would then follow the Seward Highway around Turnagain Arm to Girdwood.

The section between Girdwood and Rainbow Creek is the most difficult as far as engineering is concerned. In this report it is asumed that the line would be located on the mountain side, which slopes to 1000 feet in elevation with an average grade in excess of 50 percent and then, between 1000 and 2000 feet at a 20 percent slope. From Rainbow Creek to Anchorage the area is flat and sufficiently wide to accommodate the line.

In order to avoid the Girdwood to Rainbow Creek section, other route alternatives will be investigated. All alternatives would carry the power using a Turnagain Arm crossing with undersea cables from Windy Point to Bird Creek. From the Bird Creek Cable termination three alternative routings will be investigated: 1) traversing Bird Creek Pass into the valley of the North Fork of Ship Creek; 2) crossing from Girdwood to Penguin Creek over the mountains and following Bird Creek Pass as outlined above; and 3) following Penguin Creek across the mountains at an elevation of less than 3000 feet into Bird Creek and then following the existing Chugach line through Powerline Pass to Anchorage.

C5.2.2 Anchorage-Fairbanks Corridor

The Fairbanks to Anchorage transmission line routing requirements for this scenario are the same as those for the North Slope and Fairbanks power generation scenarios. The regional description, engineering and environmental considerations, and route description presented in Section C3.2.2 of this report are also applicable to Scenario III.

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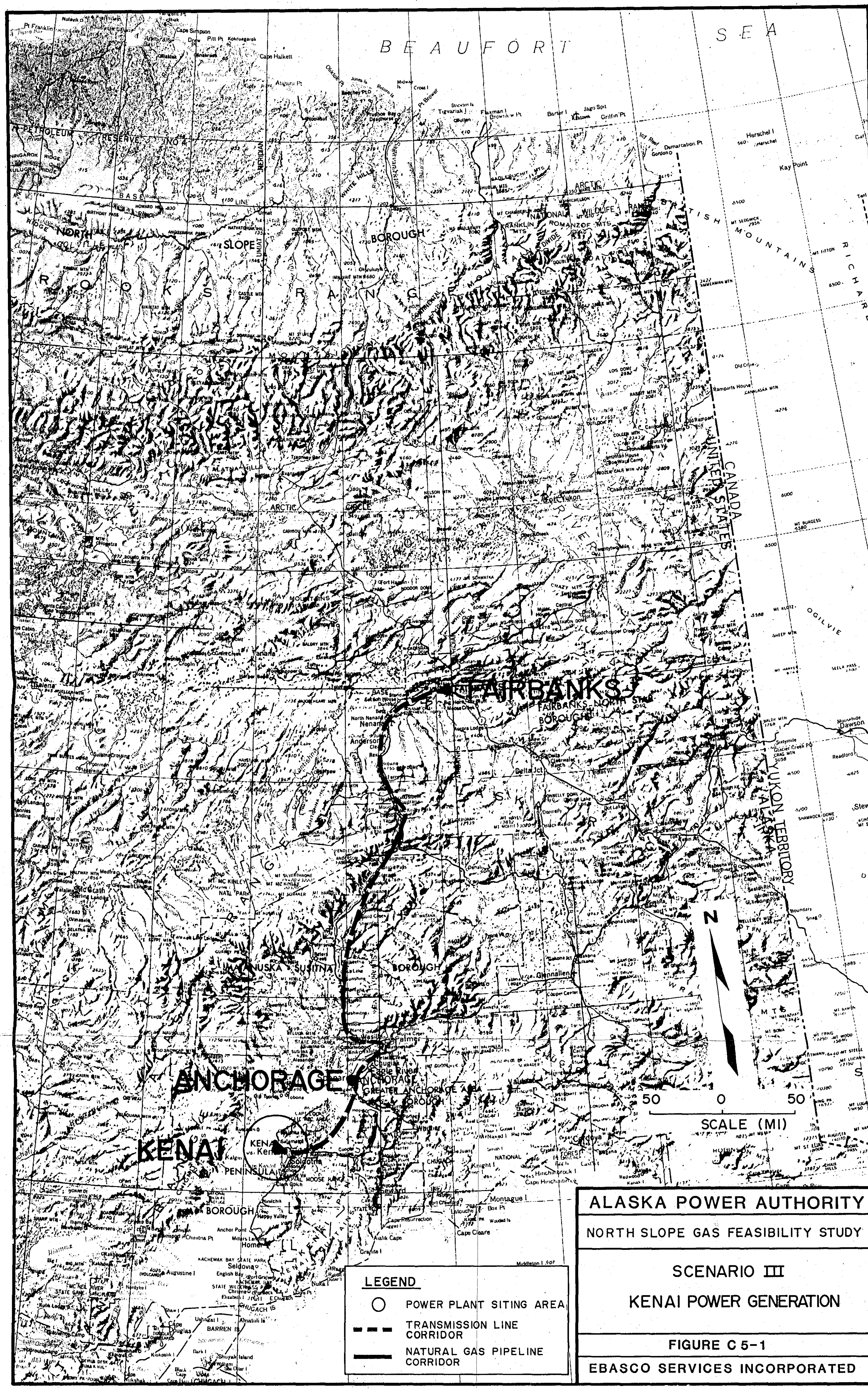
BEAUFORT SEA
FAIRBANKS
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N
50 0 50
SCALE (MI)
LEGEND
POWER PLANT SITING AREA
TRANSMISSION LINE CORRIDOR
NATURAL GAS PIPELINE CORRIDOR
ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
SCENARIO III
KENAI POWER GENERATION
FIGURE C 5-1
EBASCO SERVICES INCORPORATED

APPENDIX D

APPENDIX D

REPORT

ON

TRANSMISSION SYSTEM DESIGN

JANUARY 1983

2560B

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2560B

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LIST OF FIGURES (continued)

D1.0 INTRODUCTION

In the descriptions that follow, the North Slope-Fairbanks-Anchorage system, medium load forecast level, is used as a model. However, many of the findings are directly applicable to the Fairbanks and Kenai generation scenarios and to the low load forecast cases.

An important aspect of this design study is that the load carrying capacity of the lines is not the limiting factor of this transmission system. Rather, the critical factor is the stability of the system, and the system was designed around this factor. The North Slope medium forecast scenario concentrates the bulk of Alaska's generation at one location, from which the greatest part of the power has to be transmitted over a long (almost 800 miles) line to the bulk of the load at Anchorage. By the time the system is fully developed, all other power generation stations connected to the system will be less than 50% of the single large power station located at Prudhoe Bay and most of them will be even further than 800 miles away from it. Therefore, in addition to the criteria listed in Section 2.3, performance considerations and criteria had to be introduced into the design process. In the following pages, these additional considerations/criteria are also described.

Sections D2.0 through D4.0 deal with the hardware aspects of the transmission system and Section D5 summarizes the findings of the system design. Section D6 presents conclusions from the preceding studies. Section D7.0 presents the results of the sag and tension calculations and section D8.0 contains all Appendix D figures.

D2.0 FACILITIES AT NORTH SLOPE

D2.1 SUBSTATION

D2.1.1 One-Line Diagram

The line diagram for the North Slope Substation is shown in Figure 2-3.[1/] There are 15 generators in the fully developed plan, with each two connected, through 15kV iso-phase buses, to one 250/125/125 MVA, 138/13.8/13.8 kV three-winding transformer, except one generator which is connected to a two-winding 125 MVA transformer. Each generator can be synchronized to the 345 kV bus through its 13.8 kV circuit breaker installed inside the plant. Four 450/600/750 MVA OA/OAF/OAF, 138/525 (or 765) kV step-up transformers, two connected in parallel, feed the two transmission line circuits heading south to Fairbanks. The 138 kV bus, whenever reliability considerations permit, uses breaker-and-a-half arrangements. The series capacitors and the shunt reactors are on the line side of the 500 (or 765) kV circuit breakers protecting the lines. The arrangement enables the buswork of the substation to be expanded gradually, as can be seen from Figure 2-4, in which the first stage of development is displayed.

D2.1.2 Auxiliary Power Source

An auxiliary 69 kV tie line should be negotiated with SOHIO to avoid installing additional diesel generators for black start. The tie and 13.8 kV distribution will be developed as each plant is built.

1/ Figures 2-3 and 2-4 are in the main text.

D2.2 SPECIAL PROBLEMS PERTAINING TO THE NORTH SLOPE

D2.2.1 Contamination Mitigation in the North Slope

The 138 kV and 525 kV switchyard and 60 miles of transmission lines are exposed to heavy pollution. The main source of contamination is dirt picked up off the arctic desert (tundra) by wind mixed with salt from the Beaufort Sea, even when frozen, and, to a lesser extent, calcium chloride spread on the roads as a dust supressor (Ruef 1981). Based on local research performed by the SOHIO Company, effective washing of insulators on their 69 kV and 13.8 kV lines is necessary to prevent flashovers.

Experience with hot-line washing of insulators in substations in other areas with voltages above 230 kV demonstrated that the risk of using mobile washing installations in high voltage substations is too high, even in more temperate climates with higher temperatures and lower winds. Therefore, it is planned that a fully automated, fixed hot-line washing installation will be adopted for the substation, and a fixed installation with mobile operation of the water pumps will be used for the towers along the first 60 miles.

The fully automated fixed installation at the Prudhoe Bay substation consists of two high pressure pumps, a demineralized water tank filled with water from the water treatment plant of the power plants, fixed washing nozzles around each substation insulator, and controls which automatically start the washing of insulators when the test insulator accumulates a given amount of pollutant.

The insulators on the transmission line are equipped with fixed nozzles connected to a pipe that is brought down to the bottoms of the towers. A truck equipped with a stainless steel water tank and a pump with a head and flow sufficient to spray the insulators is used. A hose and an operator will be lifted from the haul road to the pads at the towers. The operator attaches the hose to the pipe at the tower and washes the insulators. Special measures (such as blowing the water out with compressed air) are taken after completing the washing of the insulators to prevent freezing the water inside the fixed pipes of the washing installations.

The cost of hot-line washing of insulators is relatively high but is the only way to maintain the reliability of a transmission system on the North Slope. The cost estimate, based on Ebasco's experience in designing and installing such installations, includes a hot-line washing installation.

D2.2.2 Grounding

The permafrost is an important obstacle in obtaining a low resistance grounding mat. In the Prudhoe Bay area the grounding mat of the Dalton substation will be designed as follows:

A copper mat will be installed in trenches under the gravel inside the switchyard perimeter. From this mat four 1000 kCM insulated copper cables will be installed in trenches to the sea shore (about 6 miles north).

Four electrodes, each fifty feet long, will be driven into the bottom of the sea near the shore, connected together, and connected to the four cables. The vertical electrodes will be in the sea sufficiently deep enough to avoid damages caused by movement of the ice. The distance between the electrodes will be about 100 feet.

Both transmission line circuits will require counterpoises along the entire length to Fairbanks. Both counterpoises will be connected to the substation mat.

D3.0 NORTH SLOPE TO ANCHORAGE TRANSMISSION SYSTEM DESIGN

D3.1 GENERAL

The transmission line routing from North Slope to Fairbanks follows the Alaska pipeline (TAPS line) and the Haul Road (officially called Dalton Highway) for approximately 450 miles. The route includes the crossing of Atigun Pass and the Yukon River. The portion from Fairbanks to Anchorage follows the ROW selected for the 345 kV Intertie (Commonwealth Associates, Inc. 1981).

The basic design criteria for this transmission line considers the special climatic conditions, such as low temperature, heavy winds and ice formation, as well as permafrost on most of the ROW.

The reliability of transmission requires a minimum of two lines to be built for any alternative. Each line (in the cae of two parallel lines) or two lines (in the case of three parallel lines) should be able to carry the entire design power, in order to provide uninterrupted service in the event one of the line segments is tripped.

D3.2 DESIGN CONSIDERATIONS

The transmission system is designed using the following basic design criteria.

D3.2.1 Meteorological and Climatic Conditions

For the North Slope-Fairbanks Portion of the transmission system, the following conditions were assumed:

Temperature range:	-60°F to +86°F.
Wind loads:	25 lbs per sq. ft north of the Arctic Circle and 8 lbs/sq. ft. below it; 2.3 lbs/sq. ft. at +86°F.

Ice on conductor:	1.5" radial thickness with 8 lbs/sq. ft. wind load at 32°F.
Compact snow on ground:	36" north of the Arctic Circle and 24" south of it.
Tension in conductors:	maximum 50% of rated tensile strength.
Gradient on conductor surface:	maximum 18 kV RMS per centimeter.

The above are values used in the overall design of the transmission lines. In certain areas, like Atigun Pass, special conditions exist and, therefore, different criteria would have to be established as part of a detailed engineering process.

D3.2.2 Mitigation of Contamination

Except for the portion from Prudhoe Bay to Pump Station #2, the line is in a non-polluted atmosphere. However, in the first 60 miles the line is exposed to heavy pollution in the periods between September and January, when the northeast winds coat the insulators with a black conducting film. For this portion of the transmission line the insulation requires long leakage distance, and is provided with fixed insulator washing nozzles.

D3.2.3 Transmission Voltages

Two AC voltage levels were investigated for each of the two load levels. For the medium forecast load 500 kV and 765 kV AC transmissions were compared. For the low forecast level 500 kV and 345 kV AC transmissions were analyzed. HVDC transmission was also considered as an alternative for both forecast scenarios.

D3.2.4 Conductors and Bundle Types

The conductors investigated are listed in Table D-1.

D3.2.5 Clearances

Line clearances should permit safe operation in all climatic conditions. Clearance to ground will be increased 36 or 24 inches above minimum to account for the snow on the ground and clearances required for maximum sag under ice conditions and are shown in Table D-2.

D3.2.6 Insulators

The insulators considered are listed in Table D-3.

For 60 miles from Prudhoe Bay to Pump Station #2, high leakage distance (fog type) insulators are used and the number of insulators is increased by two in each string.

D3.2.7 Safety Factors and Strength Requirements of Support Structures

The overload capacity factors (OCF) applied for the structures and the foundations are shown in Tables D-4 and D-5.

D3.2.8 Lightning Protection and Grounding

The Prudhoe Bay-Fairbanks portion of the system will not be equipped with shield wires because the isokeraunic level (average number of thunder-days per year) is very low. However, one 4/0 AWG copper conductor counterpoise will be planned beneath each line. The counterpoise is connected to each tower and buried at least one foot under ground level. At the substations and switching stations the counterpoise will be connected to the ground mats.

The Fairbanks-Anchorage portion will be equipped with shield wires.

TABLE D-1

CONDUCTORS CONSIDERED

Voltage kV	Conductor Code Word	Conductor Type	Conductor KCM	Conductors per bundle
345 AC	Cardinal	ACSR	954	2
500 AC	Chukar	ACSR	1781	2
500 AC	Bunting	ACSR	1193	3
765 AC	Martin	ACSR	1351	4
± 350 DC	Special 2" diameter	ACSR	2839	1

TABLE D-2

CLEARANCES REQUIRED

	Minimum Clearance in Feet		
Voltage kV	To Ground	Phase to Phase or Pole to Pole	Phase to Tower
345 AC	35	26	8
500 AC	38	35	10
765 AC	45	45	18
±350 DC	35	38	8

TABLE D-3

INSULATORS CONSIDERED

Voltage	Size and Strength	Strings per Phase	Insulators per String Suspension	Insulators per String Strain
345 AC	5-3/4" x 10" x 50 K lb	1[1/]	18	20
345 AC	5-3/4" x 10" x 50 K lb	2 in V[2/]	18	20
500 AC	5-3/4" x 10" x 50 K lb	2 in V	25	26
765 AC	6-3/4" x 11" x 50 K lb	4 in V	28	29
±350 DC	6-3/4" x 11" x 50 K lb	2 in V	28	28

1/ Outside phases
2/ Center phase

TABLE D-4

TOWER OVERLOAD CAPACITY FACTORS (OFCs)

Load	NESC OCF[1/]
Vertical strength	1.50
Transverse strength	
Wind load	2.50
Wire tension load at angles	1.65
Longitudinal strength	
At crossings	
In general	1.10
At dead ends	1.65
Elsewhere	
In general	1.00
At dead ends	1.65

[1/] For heavy ice loading the OFC is 1.10.

TABLE D-5

OVERLOAD CAPACITY FACTORS (OFCs) OF GUYS OF GUYED TOWERS

Load	NESC OCF[1/]
Transverse strength	
Wind load	2.67
Wire tension load	1.50
Longitudinal strength	
In general	1.00
At dead ends	1.50

[1/] For heavy ice loading the OFS is 1.10.

D3.2.9 Distance Between Parallel Lines, Route and Pipeline

The transmission lines will follow the Prudhoe Bay-Fairbanks Highway and the TAPS line as closely as possible. Except at the substations and switching stations, the distance between center lines of the two parallel lines is such that failure of one line will not affect operation of the other. For the 525 kV, 345 kV and $\pm$350 kV DC alternatives the lines are 200 feet apart. For the 765 kV alternative, the lines are 300 feet apart. Distances to the highway and pipeline will be designed to minimize electromagnetic induction into the pipeline during line to ground faults and to maintain the level of electrostatic field below harmful values at the edge of the right-of-way as shown in Table D-6. The admissible induced short circuit current under the line is limited to a maximum of 5 mA RMS as recommended by the NESC.

D3.2.10 Corona Criteria for Conductor Size

The minimum corona onset voltages of the selected conductor bundle are 1.25 times the rated line to ground voltage as follows:

249 kV for 345 kV lines
379 kV for 525 kV lines
552 kV for 765 kV lines

D3.2.11 Radio and Television Interference: RI and TVI

The noise level at 230 feet from the center line of the line at ground level is less than that allowable for low residential density areas.

TABLE D-6

ELECTROSTATIC FIELD INTENSITY LIMITS
AT 1 METER ABOVE GROUND

Location	kV/Meter
Public road	7
Private road	11.0
All other terrain	11.8
At the edge of the line's ROW	1.6

D4.0 TRANSMISSION DESIGN (HARDWARE)

D4.1 GENERAL

The following alternatives were investigated in detail for the Prudhoe Bay generating scenarios.

For the medium forecast generation alternative:

Two 500 kV transmission line circuits from Prudhoe Bay to Anchorage and the existing 345 kV Intertie line from Anchorage to Fairbanks fully extended and operating in parallel with the 500 kV lines.

Two 765 kV line circuits from Prudhoe Bay to Fairbanks and two new 345 kV line circuits from Fairbanks to Anchorage with the existing 345 kV Intertie in operation as above.

Two $\pm$350 kV DC line bipoles from Prudhoe Bay to Fairbanks and two new 345 kV line circuits from Fairbanks to Anchorage with the existing 345 kV Intertie in operation as above.

For the low forecast generation alternative:

Two 500 kV transmission lines from Prudhoe Bay to Fairbanks and two 345 kV lines (the extended Intertie and a new line) from Fairbanks to Anchorage.

Two 345 kV transmission lines from Prudhoe Bay to Anchorage.

The five above alternatives were investigated to select a feasible solution for economic comparison with the other generation scenarios.

D4.2 DESIGN DATA OF THE 500 kV TRANSMISSION LINES

A cursory investigation of the 500 kV alternatives was performed to select the most cost effective design for the transmission line.

D4.2.1 Conductor Selection

D4.2.1.1 Current Carrying Criteria

The maximum load of the medium forecast transmission is considered to be 1400 MW. Assuming a 0.93 power factor, the line should be able to carry 1500 MVA or 1730 A per phase. This current has to be carried by a single circuit during emergencies. A bundle of two Chukar conductors and a bundle of three Bunting conductors are compared in Table D-7, from which it can be seen that the current carrying capacity is not a limiting factor for the conductor selection.

D4.2.1.2 Acceptable Conductor Gradient

The noise level of the line depends on the electrical gradient. The size and the number of conductors in the bundle as well as the clearances determine the maximum gradient. For a bundle of two Chukar conductors the allowable gradient is 18 kV RMS/cm while for three Bunting conductors the allowable gradient is 18.8 kV RMS/cm. With these values the noise level will stay within allowable limits at 230 feet from the centerline of the line.

Maintaining the gradient on the conductor surface under 18 kV rms/cm will also satisfy the RIV and corona loss requirements for the line. Using the curves of conductor surface gradients given in the EPRI Transmission Line Reference Book (EPRI 1982), the surface gradients for 550 kV class are 17 kV/cm for three Bunting and 18 kV/cm for two Chukar conductors.

TABLE D-7

AMPACITIES

Conductor Type	Current Carrying Capacity[1/] Amperes		Required Capacity Amperes
	1 Conductor	Bundle	
2 x Chukar	1460	2920	1730
3 x Bunting	1160	3480	1730

1/ At 75° conductor temperature, 25°C ambient temperature and 2 ft/sec wind velocity.

Both conductors are acceptable for the proposed 500 kV transmission. The equivalent cross-sections of the two bundles are 2x1781 = 3562 KCM for the Chukar conductor compared to 3x1993 = 3579 KCM for the Bunting conductor. Consequently, the resistances are practically the same and the losses will also be nearly the same.

D4.2.1.3 Mechanical Design Selection of Conductor, Towers and the Ruling Span

The selection of long spans results in high towers. Selection of lower towers on the other hand leads to shorter spans but larger number of towers. Length of span and height of average tower is established from preliminary sag and tension calculations. The following assumptions were made:

Average tower height to the lowest crossarm should not exceed 100 feet.

Low number of piles per tower for foundations and guys.

Easy shipping of towers to site.

Reduced manpower for construction on site.

The sag and tension calculations for Bunting and Chukar conductors are shown in Section D7.0 of this Appendix. The calculations were performed for six ruling spans: 1500, 1200, 1000, 800, 600 and 400 feet. The limiting condition for all spans is the 1.5" radial ice load with 8 lb/sq ft wind pressure. In order to maintain the towers under 100 feet heights, with 13.5 feet long insulator and 38 feet clearance to ground, the maximum sag must be under 48.5 feet. The maximum sag for 1000 foot spans with two Chukar conductors is 41.7 feet while with three Bunting conductors the sag is 56.7 feet. The ruling span of the line is taken as 1000 feet. The average height of tower, for the

Chukar, results in 41.7 + 13.5 + 38 = 93.2 feet or approximately 95 feet; this compares to 108 feet tower height to lowest crossarm if Bunting conductors are used. Phase conductors are required to be equipped with spacer dampers.

It is assumed for cost estimates that one dead end or angle tower is installed every 10 miles, or roughly 2% of the towers. For the 30 mile section at Atigun Pass the number of dead end and angle towers is increased to 8%.

In order to provide work areas for the towers and maintenance areas, 100' x 100' gravel pads are built at each tower site between Prudhoe Bay and Fairbanks. In addition, 300' x 1200' gravel marshalling yards are built every 18 miles along the Haul Road to permit helicopter work.

D4.2.1.4 River Crossings

River crossings along the selected route, except for the Yukon River crossing, do not raise special problems. The Yukon River will be crossed downstream of the highway bridge. In this area the south shore is approximately 300 feet above the water level. A special span of 3,000 feet with two dead end towers and high strength Alumoweld conductors is anticipated to permit overhead crossing.

The minimum clearance to high water level is 70 feet for +86°F ambient temperature and no wind. At this stage no attempt of optimization of tower heights or exact location of towers was made. The main problem is the special conductor that has to be manufactured to obtain the lowest possible sag under maximum load. The worst loading condition is during the winter when the conductors are covered with ice. However, during this period the river is frozen and no barges or boats can pass under the line. Therefore the minimum clearance to ice level with ice load on conductors is only 45 feet.

The two dead end towers are of lattice type. Installation of conductors is assumed during the winter when the river is frozen. Special foundations will be used to avoid movement in the soil due to pressure and temperature variation at surface. Automatic equipment to monitor conductor vibration and settling of towers will be necessary. Alternatives with two low dead-end and one high tangent tower may result in lower cost; however, for the feasibility level of estimating the alternative with two high dead end towers is on the conservative side. The height of the towers depends on the maximum sag of the conductor. A bundle of two special 61 x 5 strand Alumoweld conductors with an ultimate strength of 235,500 lb., manufactured on special order by Copperweld, is able to carry the maximum current of 1000 A per conductor. The maximum sag of the conductor for a 3000 foot span with 1.5" radial ice load and 8 lb/sq. ft. wind pressure is approximately 105 feet. As a result, the required tower heights are 100 feet on the northern shore and 70 feet on the southern shore.

D4.3 DESIGN DATA OF THE 765 kV TRANSMISSION LINE

Following the same procedures as for the 500 kV line, the maximum current per phase is 1195 A. A bundle of four Martin (1351 KCM ACSR) conductors is able to carry 5000 A. The surface gradient for 800 kV class conductors from Figure 5.4.34 of the EPRI Transmission Line Reference Book (EPRI 1982) for a bundle of four Martin conductors is 17.5 kV/cm. The allowable level for this conductor is 18 kV/cm.

The sag and tension calculation for six ruling spans are given at the end of this Appendix. The limiting condition for this conductor is the 1.5" radial ice load with 8 lb/sq. ft. wind pressure. The most recent design of 765 kV James Bay #3 line in Canada uses guyed towers for special medium design load district and self supporting lattice type towers for the special heavy load district. However, Niagara Mohawk Power Company used an H-frame design for their 765 kV line in 1974. For the reasons of easy shipment and installation as well as simple foundation of the tubular steel towers, it is assumed that the 765 kV line is also built on H-frame tubular steel towers. The sag and tension calculations show that for a 1200 foot span the maximum sag is 61.07 feet. With this sag the height of the average tower results H = 61.07 + 19.0 + 45 = 125.07 feet. With 1000 foot span the maximum sag is only 42.28 feet and the total height would be 106.28 feet. The 17% decrease in tower height cannot compensate for the 20% increase in the number of towers. The 1200 foot span is more economical. Therefore, a 125 foot high tubular steel H tower is selected for the 765 kV line. It is assumed for cost estimating purposes that one dead end or angle tower is installed each 10 miles or 2.27% of the towers are dead end types. For the Atigun Pass portion (30 miles) the number of dead end and angle towers is increased to 8%.

River crossings along the selected route, except the Yukon crossing, do not raise special problems. The Yukon River will be crossed, similar to the 500 kV alternative, near the highway bridge. The same special Alumoweld conductor will be used as for the 500 kV line, only instead of two conductors, a four conductor bundle will be used for each phase. The dead end tower on the northern shore will be about 120 feet high, and on the southern shore the tower will be 100 feet high.

D4.4 DESIGN DATA OF THE $\pm$350 kV BIPOLAR DC TRANSMISSION LINE

The HVDC transmission uses two bipolar circuits. The selection of one large conductor instead of a two conductor bundle reduces the ice load on the line and the total cost of the line. For cost estimating purposes it is assumed that the line will have a 1000 foot ruling span with 90 foot high towers. The selected 2839 KCM conductor is able to carry the normal 1000 A (700 MW) per bipole and 2000 A (1400 MW) per bipole in case of an emergency. The conductor is similar to that used for the Square Butte DC transmission line.

The towers will be of the guyed tubular steel type with a single pole, except for the dead end towers which will be guyed A frames.

The DC system is designed to not resort to ground return during any conditions. This was necessary to avoid corrosion of the pipeline due to stray currents. Grounding of the line is similar to the AC lines using counterpoise along the ROW. Special attention must be given to the grounding electrodes on both ends of the transmission. Tests of stray current magnitude along the transmission must be performed before line commissioning.

D4.5 DESIGN DATA OF THE 345 kV TRANSMISSION LINES

The 345 kV lines were based on the design developed by Commonwealth Associates for the Anchorage-Fairbanks Intertie under construction .

D4.6 SUBSTATIONS AND SWITCHING STATIONS

Several switching stations are required to insure reliable operation of the transmission in all AC alternatives. The switching stations must be able to isolate a fault on any segment of the transmission lines without affecting the operation of the rest of the system. The switching stations are built with a breaker and half scheme. The reliability of the system can be improved if double circuit breaker arrangements are adopted for the switching stations, because this prevents the loss of two line segments for a common breaker failure. The one-line diagram of a typical switching station is shown on Figure 2-5.

D4.6.1 Fairbanks Substation

The substation in Fairbanks is an intermediate point for the transmission system, but it is also handling the power used in the area. A one-line diagram is shown on Figure 2-6 for the preferred transmission system.

D4.6.2 Anchorage Substation

The one line diagram is shown on Figure 2-8 for the preferred transmission system.

D4.6.3 Series and Parallel Compensation

Series and Parallel compensation is installed in several locations. Each series compensation bank is built on insulating platforms for the corresponding voltage and is equipped with full protective systems.

D4.7 COMMUNICATION SYSTEM

In order to provide reliable service, a microwave link is proposed. The number of repeater stations assumed is the same number ALASCOM has between Prudhoe Bay and Fairbanks. Information received from them, Alyeska Pipeline, and other sources form the basis of Section 2.2.10. To provide redundancy for vital functions, a carrier system is also planned.

D5.0 SYSTEM DESIGN (LOAD FLOW STUDIES)

D5.1 GENERAL

This series of alternatives is concerned with how the Prudhoe Bay, medium forecast scenario would be integrated into the Fairbanks-Anchorage system. Many alternatives were investigated, however, this report contains only those alternatives which proved to be viable.

It was assumed that the electrical angular displacement between any two buses should never exceed 45°. This is a rather generous allowance, which assumes that voltage regulation at those terminal buses will be sufficient to hold flat voltage schedules. Another criterion that was used for transmission systems extending from North Slope to Anchorage was that the electrical displacement between the extreme ends of the system should not exceed 60°. This is an attempt to limit the amount of shunt compensation which would be required at Fairbanks and could possibly be relaxed if extraordinary amounts of regulation were present at Fairbanks.

It should be recognized that all of these angular criteria are merely rough approximations. In case of detailed engineering design, the chosen alternatives must be verified by transient stability studies. In those cases performance will depend upon the nature of the testing criteria, the duration of the faults, and the nature of the remedial action, to determine what angular displacements are acceptable across the system.

In adding shunt compensation to the system a philosophy had to be developed. It was assumed in this case that the dynamic compensation requirements at Fairbanks and Anchorage would best be met by static compensation of an inductive nature. It was therefore attempted to leave enough line charging uncompensated on the lines so that all losses during the worst outages would be supplied from the lines without requiring a positive (capacitive) output from the VAR compensators at Fairbanks and Anchorage. In the unloaded condition or the zero generation cases, Anchorage and Fairbanks are forced to absorb rather large amounts of reactive power. These may not be completely absorbed by the VAR compensating devices, but may also be assisted by switched shunt reactors. Although it was not always possible, there was an attempt to limit the magnitude of the capacitive output of the compensators at Fairbanks and Anchorage.

In determining the location of the VAR compensators at Fairbanks and Anchorage, a compensator should not be lost at the same time as a critical line would be lost. This necessitates double breaker or breaker and a half switching at the various stations, and also the separation of the compensators from the step down transformers at Anchorage. To do otherwise in Anchorage would result in a common mode failure potential for a transformer outage, which would remove both a line and a static compensator from service simultaneously. At Fairbanks the static compensators may be located on the tertiaries of the step down transformers since the switching on the EHV bus at Fairbanks is such that a transformer and a line will not be lost for a common contingency. However, these details are not shown in the one line schematics presented in the main body of this report.

D5.2 PERFORMANCE STUDIES

D5.2.1 Alternatives A and AA - 1400 MW Generation at Prudhoe Bay, Two 500 kV Lines from Prudhoe Bay to Anchorage and the 345 kV Intertie In Parallel Between Fairbanks and Anchorage

Alternative A was one of the first alternatives considered. It is shown in Figure D-1. This alternative consists of two 500 kV circuits from Prudhoe Bay to Fairbanks and two 500 kV circuits from Fairbanks to Anchorage. The latter two circuits would operate in parallel with a 345 kV Intertie under construction[1/] which is presumed to be extended to both Fairbanks and Anchorage.

The 500 kV circuits are sectionalized at two places between the North Slope and Fairbanks so that the primary HV segments are approximately 150 miles in length. Between Fairbanks and Anchorage there is one intermediate station which would be located ideally at the mid-point of the system. However, for Alternative A, it is assumed to be located at, or near, Gold Creek, which makes the segments approximately 190 miles from Fairbanks to Gold Creek and 140 miles from Gold Creek to Anchorage.

Alternative A uses 50 percent series compensation for the 500 kV system in all of its segments, including terminal transformers. In each of the six segments between the North Slope and Fairbanks and four segments between Fairbanks and Anchorage a 200 MVAR shunt reactor has been provided to compensate the line charging of the system.

There are two transformers rated at 750 MVA at Prudhoe Bay for each circuit, stepping up the voltage from 138 to 500 kV. A 1500 MVA

1/ Construction of the 345 kV line is to begin in the spring of 1983 with completion expected by the fall of 1984.

transformer cannot be used on one circuit because it would provide excessively high current duties on 138 kV switchgear, but two banks in parallel on each of the two circuits provide acceptable circuit breaker and bus duties. The same configuration is maintained in Anchorage. However, the transformers there are sized 500 MVA each because of the lower loadings expected at that point. Transformation is also provided at Fairbanks from 500 to 138 kV to serve the local loads at Fairbanks and to connect to the Intertie, which would consist of 500 to 138 kV and 138 to 345 kV transformation. The transformation at Fairbanks provides double transformation between the 500 kV and the 345 kV systems. However, this is believed to be less expensive than providing direct transformation from 500 to 345 kV. The 345 kV circuit, when operating in parallel with the two 500 kV circuits, does not provide significant support, so it is not a critical support element in the system.

The transformers at Fairbanks are sized at 500 MVA each, even though the load at Fairbanks is expected to be only about 250 MW. The extra transformer capacity is provided both to allow for through-flows through the 345 kV system and to allow use of the transformers at Fairbanks for connection of a static VAR system or synchronous condensers on their tertiaries.

The system of Alternative A was not directly tested for load flow. However, a similar system, Alternative AA, was tested and is shown in Figure D-2. The difference between Alternative A and AA is that in Alternative AA switching at North Slope and Anchorage was assumed to be at 345 kV rather than 138 kV, but it turned out to be more expensive than Alternative A. However, performances of these two alternatives are quite similar.

Figure D-3 shows Case AA1, where there is no generation at North Slope and the system is unloaded; this, therefore, represents an extreme case where the line charging of the transmission system has to be absorbed by the static compensators at Fairbanks and Anchorage. The reactive power absorbed is shown on the Fairbanks and Anchorage 345 kV buses. In Alternative A they would be on the 138 kV bus or on the tertiaries of the 500 to 138 kV transformers. The difference is rather insignificant in the overall picture. Case AA1 shows that the system north of Fairbanks produces about 262 MVAR of excess line charging and the location of the shunt reactor and the series capacitors have been arranged so that the voltage at North Slope is at the bottom end of its possible range. This allows for a maximum voltage rise in the event there are reactor failures or circuit outages. The voltage at North Slope for this configuration is approximately 95% of normal, whereas the voltage at Fairbanks is 102%. The locations of the shunt reactors between Fairbanks and North Slope have been arranged in such a manner that it produces the lowest possible voltage at North Slope. This is ideal from the point of view of energizing the system from Fairbanks. However, the arrangement may have to be modified if the system is to be energized initially from the North Slope end. The kind of modification expected might be to relocate the shunt reactors from the northern ends of their segments to the southern ends in one or more of the sections, which would tend to develop a more-balanced voltage profile along the lines. The configuration shown in Alternative AA, however, is that which would give the lowest possible voltages on the 500 kV system north of Fairbanks for contingencies involving outages of reactors or segments when the system is only connected to Fairbanks. For the circuits of the system south of Fairbanks, reactive compensation is not particularly critical, since both Fairbanks and Anchorage are asssumed to have substantial voltage regulating capabilities. In this case, Fairbanks is required to absorb 242 MVAR of line charging and Anchorage is forced to absorb 346 MVAR of line charging. This balance can be changed by modification of transformer taps at Anchorage. However, as shown in Figure D-3, this system is designed so that Anchorage absorbs the maximum amount of reactive power at no load, but it will be lightly loaded when full power is being delivered . This is more compatible with the use of static compensators with inductive capabilities than with synchronous condensers.

The compensation of the 345 kV Intertie between Fairbanks and Anchorage is not known exactly at this point; it is assumed that six 35 MVAR reactors are on the line. The six reactors, shown in a later case, appear to give a reasonable amount of compensation and should not have any significant effect on the conclusions regarding the remainder of the 500 kV system.

The system was tested at no generation to insure that it has enough strength for energization and failures of components. Case AA2, Figure D-4, for instance, shows a case where, at Fairbanks, a circuit breaker on one of the 500 kV lines to the north would be open. The intent was to see how high the voltage at the Fairbanks end of the transmission line would go. In this case it goes up to 107% of normal voltage, which is certainly well within the capabilities of the equipment installed. The outage of this segment interrupts the major reactive power flow and one could expect that the voltages at the far end of the system would also rise. In this case they went up to only 97% from their system normal value of 94.6%. This is a relatively insignificant voltage rise at the North Slope and the voltage rise at the Fairbanks end of tne line is quite acceptable.

Opening of the Gold Creek end of the Fairbanks-Gold Creek Line segment is shown as Case AA3 in Figure D-5. This being the longest segment, it is believed to be a possible critical case for voltage rise. However, all voltages are acceptable. The series capacitors at Fairbanks tend to keep the voltage levels down because of the reactive flow from the line to Fairbanks through the series capacitors.

Case AA4 in Figure D-6 shows a double contingency, with a Fairbanks to Gold Creek line segment open at Gold Creek and the shunt reactor located on the line removed. The voltage increased in this case to approximately 109% of normal. This is still acceptable.

An outage designed to test the suitability of the shunt compensation of the 345 kV intertie is Case AA5, shown in Figure D-7. This case represents a condition where the breaker at the Anchorage end is open. The voltage rose to 107% which is considered to be acceptable. However the amount of compensation is not sufficiently great that the loss of a reactor in addition to the open ended line could be tolerated. This is shown in case AA6, Figure D-8, where the voltage level reaches 115%. It can be concluded, therefore, that the amount of shunt compensation on the 345 kV system as modelled was reasonable although it could undergo some fine tuning.

Case AA7, shown in Figure D-9, is another test to determine the adequacy of the shunt compensation of the system and the location of the shunt reactors. It shows an outage of the line from North Slope to the first intermediate station which in this case is termed GL 500. The voltage rise at both North Slope and the GL 500 end of the open ended line is reasonable.

Case AA8, Figure D-10, takes the preceding outage one contigency level further by removing the shunt reactor on the open ended line. In this case the voltage reached 110% which, again, should be acceptable. If a modification were made to allow the system to be energized initially from the North Slope end, the initial voltages at North Slope would be higher than the 95% shown in Figure D-3. In that case a higher amount of shunt compensation might be required to keep voltages down to the 110% shown in Case AA8. The additional compensation could be installed in the intermediate switching station, rather than on the line and could be viewed as switched spare reactors.

Case AA9, shown in Figure D-11, deals with 1400 MW generation at the North Slope. It is assumed that the power is divided between Fairbanks and Anchorage with Fairbanks getting 250 MW and Anchorage getting the remainder less losses. In Case AA9 the full load line losses are approxmately 77 MW or roughly 5% of the total power generated. Case AA9 shows electrical angular displacements between the generation at North Slope and Anchorage of 43 degrees. This appears to be acceptable provided that there is a substantial voltage support in Fairbanks which is assumed for this case. In Case AA9 the North Slope generation voltage schedule has been assumed to be 10% higher than the voltage scheduled with no generation in service. This 10% swing on the generator bus tends to maximize the reactive power output of the North Slope generation and to minimize the swing required by the voltage regulation at Fairbanks and Anchorage. In this case Anchorage absorbs only 69 MVAR and Fairbanks absorbs 95 MVAR. With 1400 MW generation both Fairbanks and Anchorage are lightly loaded with reactive power because the generation is required to put out the most reactive power. Voltages across the system are all quite reasonable, with the possible exception of the intermediate switching station at Gold Creek, which is down to about 94% and may require some shifting of the shunt reactor locations to bring that up.

Figure D-12 shows Case AA10 which represents one of the critical outages of the system with one line segment north of Fairbanks out of service. The most significant factor to note is the electrical angle across the system which increased from the 43 degrees of Case AA9 to 50.7 degrees. Though this seems to be a rather wide angular swing, it is tolerable considering the voltage support provided at Fairbanks. Voltages along the 500 kV system are all acceptable. The reactive power swing at Fairbanks is also reasonable; it is now a positive 60 MVAR instead of a negative 95 MVAR as it is in Case AA9. This is an acceptable outage case.

Case AA11, shown in Figure D-13, appears to be slightly more severe that the previous case. The loss of a line segment between the North Slope and the first intermediate switching station causes a slightly higher impedance increase on the system. The electrical angle across the system is now 55.6 degrees, rather than the 50.7 degrees of Case AA10. This, therefore, is probably the most severe outage to the system. Even in this case, however, voltages are quite acceptable across the system. The voltages at the intermediate stations are down around 94 to 96%, but that is tolerable. The reactive output at North

Slope is on the order of 90% power factor, which would tend to determine the reactive rating of the generators. The reactive output at Fairbanks is also moderate with 88 MVAR, and Anchorage essentially floats. So the original intention to have Anchorage absorbing on the order of 350 MVAR appears to be well designed.

In Case AA12 of Figure D-14 the outage of the Fairbanks Gold Creek line segment is modelled. This case was run to see if it would compete in severity with the outage of the line segment between the North Slope and the first switching station. This contingency turns out to be less severe because the electrical angle across the system is 49.5 degrees which is less than the 55.6 degrees of Case AA11. Therefore it is of no concern if Gold Creek is selected rather than a point exactly halfway between Fairbanks and Anchorage. This case also demonstrates the potential magnitude of throughflow on the 345 kV Intertie. In this case the intertie carries only 184 MW between Fairbanks and Anchorage. The 500 kV line segment remaining in service with its 50 percent series compensation is much more significant as it carries 930 MW. Therefore, whether or not the 345 kV intertie is in service is not a prime consideration with this alternative. The loadings on the transformers at Fairbanks are also quite acceptable, being only on the order of 217 MVA per bank. Therefore, the bank size of 500 MVA is more than adequate to handle the through flow. It could probably even handle an outage of one of the transformers at Fairbanks in addition to this line outage, and still stay within the 500 MVA rating. Case AA12 represents a condition which produces the highest reactive output requirement in Anchorage, in this case 81 MVAR.

Case AA13 deals with an outage of the Anchorage-Gold Creek line. It is shown in Figure D-15 and appears to have approximately the same severity as an outage at the Gold Creek-Fairbanks line, even though it is shorter, because in this case the impedance of the step down transformers is included with the line which is equivalent to an increase in the length of the line. The electrical angle across the system, however, is only 48.7 degrees and therefore the situation is not as severe as an outage of any of the segments between the North Slope and Fairbanks.

Case AA14 again is designed to test the effects of throughflows on the 345 kV system and is shown in Figure D-16. In this case, an outage of one of the transformers at Fairbanks would load the remaining transformer to 71% of its 500 MVA rating, indicating that the 500 MVA rating is reasonable for these transformers.

Referring back to Case AA12, the increase in loading on the 345 kV intertie for an outage on the Gold Creek-Fairbanks 500 line was on the order of 60 MW. If this increase of 60 MW is added to Case AA14, the loading on the remaining bank would just be over 400 MW. This demonstrates again that the sizing of the banks at 500 MVA is sufficient to withstand the loss of even one bank and one line between Fairbanks and Gold Creek.

The previous case studies show that the Intertie's presence or absence does not appear to have a major impact on loadings across the system. As a result, this alternative is overbuilt. Therefore subsequent alternatives attempted to use weaker system configurations between Fairbanks and Anchorage, such as two new 345 kV circuits, instead of the two 500 kV circuits, in addition to the Intertie under construction.

D5.2.2 Alternative B - 1400 MW Generation at Prudhoe Bay, Two 500 kV Lines Between Prudhoe Bay and Fairbanks and Three 345 kV Lines Between Fairbanks and Anchorage

The basic configuration of Alternative B is shown in Figure D-17. This alternative differs from Alternative A in that three 345 kV circuits between Fairbanks are substituted for the one 345 kV and two 500 kV circuits of Alternative A. Alternative B therefore has switching at Fairbanks at the 345 kV level and requires transformation at Fairbanks to step up to the 500 kV level used for the lines north of Fairbanks. It also incorporates 345 to 138 kV transformation at Fairbanks purely to serve the local area loads and to incorporate the reactive power compensation of the system required at Fairbanks. Also shown is 345 to 138 kV transformation at Anchorage. Therefore, 138 kV is present at the Nortn Slope, Fairbanks, and Anchorage.

The 345 kV lines are 50 percent series compensated. The 50 percent includes the impedance of the step down transformers when they are part of the line switching, similarly to the previous alternative. The shunt compensation of Alternative B on the 500 kV portion is identical to that of Alternative A. The 345 kV lines, however, require less shunt compensation since they produce less line charging. In this case it is assumed that each of the six line segments between Fairbanks and Anchorage have one 75 MVAR shunt reactor attached to it.

The transformers in Alternative B are sized at 1500 MVA, or two 750 MVA, on each of the circuits from the North Slope to Fairbanks. Two 400 MVA transformers step down the voltage to 138 kV. The 400 MVA size is selected because, in the absence of any through-flow problems, the transformers are used to serve the local load. The three transformers at Anchorage are sized at 600 MVA each, to allow 1200 MVA capability remain even after the outage of one circuit. This is essentially the same capability that remained in Alternative A with the loss of one 500 kV circuit between Fairbanks and Anchorage.

The intermediate switching station between Fairbanks and Anchorage is assumed to be approximately half way between the two cities, since a 190 mile long 345 kV line segment, which would result from a Gold Creek location, might not be acceptable for this configuration.

Case B1 of Figure D-18 is a no generation case with no outages. The attempt here is to duplicate the voltage profile of earlier alternatives, so the voltages are approximately 95% at the North Slope and about 102% at Fairbanks. It was also attempted to absorb as much reactive power as possible at Anchorage and to minimize the absorption at Fairbanks. It turned out to be a success by 444 MVAR being absorbed at Anchorage and 191 MVAR at Fairbanks. Voltages all across the system are satisfactory.

Case B2 shows 1400 MW generation at North Slope. Conditions between North Slope and Fairbanks are quite similar to those in Alternative A. Between Fairbanks and Anchorage power flows are evenly distributed on the three 345 kV lines since they are now equally series compensated. Voltages along the system are also acceptable. The reactive absorption as in the previous cases, is low, being down to 43 MVAR at Anchorage and 64 MVAR at Fairbanks. The angular difference across the system is 47.4 degrees, compared to 43 degrees in Alternative AA. Therefore, the electrical conditions are quite similar to those of Alternative AA. This case is shown in Figure D-19.

Figure D-20 is labeled Case B3 and was run to show the effect of changing the voltage schedule at the North Slope generator bus. In this case the voltage was raised only 5% over the no load case, instead of 10% as in Case B2. That reduced the reactive output of the North Slope generation by 97 MVAR. However, in doing so the reactive output at Fairbanks had to increase by 105 MVAR and reactive output at Anchorage increased by 45 MVAR. Therefore, it is highly desirable to hold the highest possible operating voltage and the peak-to-off-peak voltage differential at the North Slope to minimize the dynamic reactive power requirements of other parts of the system.

Case B4 (Figure D-21) is quite similar to Case AA11 of Alternative AA. In either case it is an outage of the line from the North Slope to the first intermediate switching station. In this case the electrical displacement across the system is 58.7 degrees instead of 55.6. This alternative, therefore, has only a slightly higher transfer impedance between the North Slope and Anchorage than Alternative AA. The loading on the one remaining circuit between the North Slope and the first intermediate station is approximately 15 per unit current. Therefore, all the facilities on each of the 500 kV circuits were sized at 1500 MVA.

Case B5 was investigated to measure once more the sensitivity of the system to changes in voltage at Prudhoe Bay. In this case, as is shown in Figure D-22, lowering the voltage by 5% during the outage reduced the reactive output of the generator by only 57 MVAR, but Fairbanks and Anchorage must increase their outputs by 98 MVAR and 41 MVAR, respectively. So again, this demonstrates that the voltage should be held as high as possible at the North Slope, even during outage conditions.

Figure D-23 shows Case B6 which represents an outage of one of the three 345 kV circuits from the midpoint switching station to Anchorage. The electrical displacement across the system is only 52.8 degrees this time. Therefore, it is significantly less severe than an outage of one of the 500 kV circuits in Figure D-15. Loadings on the remaining two circuits in parallel are on the order of 520 MVA, therefore they are within the 600 MVA capabilities that were assumed for the transformers at the ends of the lines. Voltages are quite acceptable. The reactive output requirement at Anchorage is 111 MVAR, which is as high as it becomes for any contingency.

D5.2.3 Alternative C - 1400 MW Generation at Prudhoe Bay, Two 765 kV Lines Between Prudhoe Bay and Fairbanks and Three 345 kV Lines Between Fairbanks and Anchorage

Alternative C differs from Alternative B in that 765 kV is used north of Fairbanks. It is displayed in Figure D-24. Instead of having two 500 kV series compensated circuits in parallel, it has two 765 kV circuits without series compensation. The impedances are on the same order of magnitude as those on the lower voltage circuits. One major difference, though, is that the line charging of the 765 kV circuits is substantially higher than that of the 500 kV circuits. In Alternative C a very high degree of shunt compensation is required. In this case

660 MVAR of shunt reactors are placed at each 150 mile segment of the 765 kV line. The line charging from each of these segments is approximately 700 MVAR. Therefore the 660 MVAR represents about 94% shunt compensation of the lines. Changes in net reactive output could prove to be a problem if the frequency of the system should deviate significantly from 60 Hertz. Other than the higher voltage, the circuiting is identical to that of Alternative B. The transformers at the North Slope remain at 750 MVA, each having two paralleled on each circuit in the same manner as they were in the 500 kV alternative, and the transformers at Fairbanks on the lines to the north also remain at 1500 MVA.

The shunt reactors have been located to lower the voltage as much as possible at the North Slope. The shunt reactor compensation requirements are large, and it is impossible to supply all the shunt reactive requirements of the line segments in one location with excessive open end voltages. Therefore, three 220 MVAR reactors are connected to each line segment, with two of them being located at the northern ends and one at the southern ends, to attempt a voltage decrease from Fairbanks as the lines go north.

One of the great advantages of this alternative, in addition to reduced losses, is that it does not require series compensation on the 765 kV lines. This could be important in view of the long maintenance times, high maintenance cost and relatively low reliability record of such series capacitors. Therefore, at detailed feasibility-engineering studies this alternative has to be considered.

Alternative C, Case C1 (Figure D-25) is a no generation case comparable to Case B1 of Alternative B. The net line charging output of the circuitry north of Fairbanks is approximately 260 MVAR as it was in Case B1. However, the absence of the series capacitor compensation in the line makes it difficult to obtain the same voltage profile that was obtainable in Alternative B. In this case the voltage at North Slope can be brought down only to 1.013 per unit with the distribution of the shunt reactors as shown. Alternatives with series capacitors could give more flexibility to obtain the desired voltage profile by adjusting the location of the series capacitor compensation. Other than this the voltage profiles across the system are quite similar to those of Alternative B.

Case C2 (Figure D-26) shows 1400 MW generation at the North Slope. The voltage level at the generator bus was raised by 10% as it was in previous cases. However, this appears to result in excessively high voltages on both the 765 kV system and on the 138 kV bus at Prudhoe Bay. Therefore, the 765 kV alternative may be more difficult to optimize in terms of producing maximum reactive output at the North Slope. The voltage levels on the 138 kV bus are relatively easy to clear up by changing the taps on the generator step up banks and the 765/138 kV banks. However, the voltage level of 1.069 on the 765 kV line is probably excessive unless transformers with higher rated voltages are purchased. Therefore it may not be possible to raise the voltage 10% from no load to full load with the 765 kV alternative unless some further optimization of the shunt reactor locations can be made. The electrical angular displacement across the system is approximately 45 degrees which is again comparable to the other alternatives that have been looked at so far. The reactive loading at Anchorage is low, as it was in the other alternatives; at Fairbanks approximately 154 MVAR would have to be absorbed. Line losses are only 75 MW, which is 35 lower than Alternative B.

Case C3, in Figure D-27, shows an outage of the 765 kV circuit between the North Slope and the first intermediate station. As in Alternative B the electrical angle across the system is in the mid 50 degree range, in this case 56.1 degrees. Therefore, it performs in quite a similar fashion to that of the 500 kV system. For this case one should note that the reactive output of Fairbanks and Anchorage is essentially zero. This indicates that shunt compensation levels on the lines are appropriate, if the North Slope voltage level can be maintained.

D5.2.4 Alternative D - 1400 MW Generation at Prudhoe Bay, Two Bipolar ± 350 kV DC Lines Between Prudhoe Bay and Fairbanks and Three 345 kV Lines Between Fairbanks and Anchorage

Alternative D is designed to carry 1400 MW from the North Slope to Fairbanks using HVDC transmission. The inverter station, at Fairbanks, converts DC to AC. From Fairbanks to Anchorage the transmission is at 345 kV AC. The DC performance and an AC performance of the system can be treated separately in the given configuration. The following sections first describe the DC portion of the system followed by that of the AC system portion.

D5.2.4.1 Description of the System

The system schematic is shown in Figure D-28.

A primary design criteria for the DC system is system reliability. It was concluded that a system of two bipoles would provide performance comparable to that of two AC circuits.

There are other compelling reasons why the two bipole arrangement is better for the Prudhoe Bay to Anchorage transmission rather than a system which has one bipole and is in monopolar operating mode during a contingency. The main reason is to avoid potential problems with ground return current flow in the TAPS line. In case of two bipoles each one can be carefully balanced to assure that no DC current flows in the ground. If only a monopolar DC line remains after an outage, the full DC return current would have to flow in the ground. That current would be twice the operating current for the required power level. Currents always try to find the path of least resistance and the pipeline provides an excellent means to provide a good path between Prudhoe Bay and Fairbanks. Such currents would have destructive effects on the pipeline and its operation.

The voltage to be selected for the DC system is a variable which can be changed to meet a minimum cost criterion. Our calculations indicate that a voltage level of approximately $\pm$350 kV on each bipole and designed to carry normally 700 MW on each bipole is close to optimum, and was, therefore, used in this development. The reliability criterion applied was that either bipole should be able to carry the entire 1400 MW. This, plus the influence of normal line loss considerations, determine the approximate conductor size to be used on each bipole.

Sizing the converter poles at each terminal is an independent decision. In this case it is assumed that each of the four poles would have a converter with 33% of full load capability. Thus one of the four converters could be lost and still maintain full power transfer. It can be assumed that the valves have 10% emergency capability, which can be used in the event of a converter outage. Thus each pole is rated at 467 MW in an emergency, so that three of them would have a total rating of 1400 MW in normal operation. This results in a converter normal rating of 425 MW per pole, which was used for pricing purposes.

These ratings apply to the converter/rectifier terminal at the North Slope. The voltage and power ratings of the converter poles at the inverter terminal at Fairbanks are slightly lower because line losses, normally amounting to some 6%, are dissipated in the DC transmission system. The ratings of the converters at Fairbanks are assumed to be 400 MW normal and 440 MW emergency per converter pole, thus allowing up to 1200 MW to be inverted during one converter pole outage at Fairbanks. Because higher than normal line losses occur during such a contingency, the rectifier terminal and generator capabilities would limit rather than the inverter.

A major design consideration for the inverter is providing adequate short circuit levels to enable commutation of the inverters. This is a major problem for the DC alternative, since much of the generation in

Fairbanks and Anchorage will be decommissioned by the time the Prudhoe Bay generation is operating. For this case it is assumed that the system would be very weak in the absence of local generation and it is necessary therefore to add a large amount of synchronous condenser capacity at Fairbanks to supply an adequate short circuit level. It is generally regarded that a short circuit level approximately 2 1/2 times the DC power inverted is the minimum acceptable level of system strength. At Fairbanks it is assumed that with much of the generation shut down the short circuit level might be as low as 200 MVAR on the system without augmentation by condensers. Therefore, the additional short circuit level required was on the order of 3125 MVAR. This would be supplied by synchronous condensers, which are assumed to have transient impedances of 40% on their own base and connected to the system with transformers having 5% impedances, also on their own base. Thus each MVA of condenser would be able to supply 1/0.45 or 2.22 MVA of short circuit capacity. To raise the system capacity by 3125 MVAR would therefore require 3125/2.22 or 1406 MVAR of synchronous condensers, or approximately the same capacity as the inverter terminal is required to convert.

To connect the 1400 MVAR of synchronous condensers to the system, each of the converter poles could conveniently have two converter transformers (about 250 MVA each) associated with it, therefore there are 8 converter transformers available for connecting the synchronous condensers. If all 8 transformers have condensers on them, each of the condensers would have to be rated at approximately 234 MVAR to tolerate the outage of two condensers and still maintain adequate short circuit levels. The 234 MVAR rating for the condensers is excessive in light of the fact that the largest hydrogen-cooled condensers in the world are 250 MVAR and gave unsatisfactory performance on the AEP system. Also, the 234 MVAR rating would significantly influence converter transformer sizing.

It should be noted that the assumption of the outage of two condensers out of 8 amounts to a 25% outage rate. Hydro-Quebec concluded that a

30% reserve of condensers is needed on their system to meet an acceptable level of availability. To counteract both the large number of condensers and the poor availability, a second iteration on the condensers was attempted. In this case, the tertiaries of the two 345/138 kV transformers are also used to connect the condensers. This allows 10 condensers to be in service and, planning for an outage of two, allowed a rating of 176 MVAR per condenser to be used. This is a more satisfactory arrangement. Alternatively, a rating of 195 MVAR each would allow the loss of three condensers. Such refinements must also depend upon more accurate determination of condenser impedances and short circuit contributions from other sources.

Although the synchronous condenser capacity installed at Fairbanks must be on the order of 1750 MVA, the reactive power requirements of the converters themselves is on the order of 800 MVAR, with about half of that provided by filters. Thus there is a substantial reactive power capability in excess of that required by the converters at Fairbanks which becomes available to control voltages on the AC system south of Fairbanks.

The description is as follows.

The AC system south of Fairbanks consists of three 345 kV circuits with one intermediate switching station. Because the transient stability problems of this system are substantially less severe than that of the other completely AC transmission system, series compensation is not necessary for this portion of the system. The transmission requirements are those of a power plant located at Fairbanks shipping power to Anchorage. Therefore, a larger angular displacement can be allowed between Fairbanks and Anchorage.

The AC line south of Fairbanks is compensated by shunt reactors in the same way as Alternative 8 using 75 MVAR reactors on each of the six line sectors. A description of the DC system operation is rather trivial, hence the analysis shown in the following figures concentrates on the AC system.

D5.2.4.2 Performance Studies

Figure D-29 displays case D1 showing the AC system with no power transfer between Anchorage and Fairbanks. It represents either zero generation at the North Slope or no more generation than is consumed by the load of the Fairbanks area. The excess line charging of the AC system is absorbed at Fairbanks and Anchorage. Fairbanks absorbs 107 MVAR and Anchorage absorbs 281 MVAR. It is assumed that Anchorage has three static compensator systems. Each of the three static VAR systems in Anchorage is sized at -100 to +200 MVAR. This represents the addition of one static compensator system more than has been used in Alternatives A, B and C. It also reflects the fact that series compensation is not used in the AC portion of the transmission system and, therefore, the changes in reactive line losses are greater during outages and during load swings.

This approach of using more dynamic shunt compensation and no series compensation was a natural outgrowth of the presence of the enormous amount of reactive capacity available at Fairbanks. Therefore, this approach appears to be more economical than to continue to use series compensation.

Case D2 shows full load generation at Prudhoe Bay (Figure D-30), which would result in approximately 1330 MW being inverted at Fairbanks. This amount of power, less the Fairbanks load, is shipped from Fairbanks to Anchorage (1080 MW). Voltage levels on the 345 kV system are acceptable; however, Anchorage is forced to output 133 MVAR to sustain its voltage level. It should be noted that the reactive power swing from no load to full load at Anchorage is 464 MVAR. This, again, is an indication of the effect of the omission of series capacitors and indicates the approximate range of the dynamic reactive power source required at Anchorage.

Case D3, in Figure D-31, shows an outage of one of the three circuits between Anchorage and the mid-point switching station. It is the most severe outage of the AC system which can affect this alternative. It increases the reactive power requirements at Anchorage from 183 to 405 MVAR. This outage again shows the large increase in reactive power losses caused because of the omission of series compensation. The 405 MVAR output of the condensor represents an increase of 686 MVAR over the output of the same compensation system at no load. Also, the electrical angular displacement across the system is increased to a considerable 53° by this outage. However, when the DC power is fully controlled, as it is in this alternative, transient stability concerns on the AC system are substantially less important than they are in conventional power systems, therefore a larger angular displacement can be allowed in steady state.

Case D4, in Figure D-32, shows the effect of raising the voltage level at Fairbanks by 5% at full load, as compared to the zero generation case. The net effect of this is the reduction of the reactive power output of the static compensation system at Anchorage by 109 MVAR.

Case D5 (Figure D-33) shows the effect of a 5% voltage increase at Fairbanks for the same contingency that was discussed as Case D3. In this case the reactive power output at Anchorage is reduced from 405 MVAR to 298 MVAR, corresponding to a change of 107 MVAR. This appears to be a desirable operating procedure because it reduces the magnitude of the reactive power requirements at Anchorage. It also has a beneficial impact on the angular displacement across the system, because the displacement is now only 50° instead of 53°. Raising the voltage schedule at Fairbanks by 5% increases the reactive demands on the synchronous condensers at Fairbanks. In this case the AC system lines require 332 MVAR. The demands of the converter terminals are on the order of 800 MVAR, however, approximately half of that would be supplied by the filters. Therefore, the total condenser loading at Fairbanks for this case would be 732 MVAR plus whatever reactive demand is present in the Fairbanks area. Since the condensers have a rating in excess of 1700 MVAR, there is no need in this alternative to correct the power factor of the load of Fairbanks.

D5.2.5 Alternative E - 700 MW Generation at Prudhoe Bay, Two 345 kV Lines from Prudhoe Bay to Anchorage

Alternative E provides transmission for 700 MW of generation at the North Slope. The system, as shown in Figure D-34, consists of two 345 kV circuits north of Fairbanks with two intermediate switching stations. The 345 kV circuits, including their terminating transformers, are 50% series compensated. The system south of Fairbanks also has two 345 kV circuits with one intermediate switching station. It, too, is given 50% series compensation. Shunt compensation is also provided on each of the circuits. The 150 mile long segments north of Fairbanks have 100 MVAR shunt reactors and the 165 mile segments south of Fairbanks have 75 MVAR shunt reactors. In this alternative, it is assumed to have dynamic reactive power regulation at both Fairbanks and Anchorage. At each station it is assumed that there are two devices with -100MVAR to +100MVAR ranges. For light load conditions this range would have to be supplemented by additional switched reactors at each station and at the other intermediate stations.

Case E1 shows the system energized with no generation at the North Slope Figure D-35. With the shunt reactors located at the northern ends of all the circuits, a voltage level of about 94% is obtained at the North Slope, which appears to be satisfactory. The excess line charging is absorbed at Fairbanks and Anchorage, with Fairbanks taking 119 MVAR and Anchorage taking 277 MVAR.

Figure D-36 shows case E2 which represents a no generation case, with the line between Fairbanks and the first intermediate station north of Fairbanks open at the Fairbanks end. Voltage levels on the open-ended circuit are acceptable.

Case E3 goes further by one more contingency level. It removes the shunt reactor from the line as well as open-ending it at Fairbanks

(Figure D-37). The voltage reaches a level of 111% at the Fairbanks open end of the line; the North Slope voltage level has risen to only 102%, both are acceptable.

Case E4 represents Alternative E with 700 MW of generation at the North Slope. Full load losses on the lines are 67.3 MW. The voltage schedule at the North Slope has been raised by 10% from the zero generation case as can be seen on Figure D-38. Voltage profiles across the system are all near unity and are acceptable. Line charging has been consumed to a great extent by the line losses. This is also indicated by the loading of the reactive power sources at Fairbanks and Anchorage which are required to absorb only 48 and 113 MVAR, respectively.

Case E5 shows the worst outage for this alternative (Figure D-39), namely the loss of one line segment between Prudhoe Bay and the first intermediate station. Line losses increase to 85.7 MW and voltage at the first intermediate station drops to 95%. In other respects, the system performs quite acceptably, the electrical displacement across the system is 52° which, again, though on the high side, is still acceptable.

D5.2.6 Alternative F - 700 MW Generation at Prudhoe Bay, Two 500 kV Lines Between Prudhoe Bay and Fairbanks and Two 345 kV Lines Between Fairbanks and Anchorage

Alternative F also provides a transmission system for 700 MW of generation at the North Slope. The system shown in Figure D-40 consists of two 500 kV circuits with two intermediate switching stations, but without series compensation, between Prudhoe Bay and Fairbanks. South of Fairbanks it is the same as Alternative E, with two 345 kV circuits, one intermediate switching station, and 50% series compensation of the lines and corresponding terminating transformers. Reactive shunt compensation is provided on the circuits north of Fairbanks in the amount of 200 MVAR for each of the circuits. South of

Fairbanks the same 75 MVAR shunt reactors are provided on the 345 kV circuits. Only the 345 kV lines are series compensated. At Fairbanks two static VAR systems with ranges of $\pm$100 MVAR are provided and the same is provided at Anchorage. At Fairbanks the reactive devices may be located on the tertiaries of the 400 MVA transformers. At Anchorage the reactive devices are located on the 138 kV bus to avoid their loss if an outage of the 345 to 138 kV transformers occurs.

Alternative F at zero generation is shown in Case F1 (Figure D-41). The voltage profile across the system from Fairbanks to North Slope is reasonably flat. The same is true for the profile between Fairbanks and Anchorage. The excess line charging is absorbed at Fairbanks and Anchorage with Fairbanks taking 216 MVAR and Anchorage taking 303 MVAR. These amounts can be changed by varying the tap settings on the transformers at Anchorage.

Case F2 shows 700 MW of generation at the North Slope. The voltage schedule on the generation has been increased only 5% because of the already high no-load voltage as can be seen on Figure D-42. Losses are 35.7 MW on the lines. The voltage profiles are all acceptable across the system. The reactive power absorbed at Fairbanks and Anchorage has been reduced to 123 MVAR and 121 MVAR, respectively. The electrical angular displacement across the system is 45.4°, which is acceptable.

Case F3 (Figure D-43) shows an outage of one of the circuits between the North Slope and the first intermediate switching station. It results in a 60° electrical angle across the system and 45° electrical displacement between Fairbanks and North Slope. This can be regarded as the upper limit. It should be noted that the reactive power demand at Fairbanks dropped to a level where Fairbanks absorbs only 10 MVAR. This confirms that the initial loadings at Fairbanks are acceptable while coping with this outage.

Case F4 represents an outage of the line from Anchorage to the midpoint switching station as shown in Figure D-44. Since the lines at this point in the system are shorter than those north of Fairbanks and are more lightly loaded, this is not as critical a contingency as an outage of one of the circuits north of Fairbanks. This can be seen by observing that the electrical angular displacement is only 53° rather than 60° which was the case for an outage north of Fairbanks.

D6.0 CONCLUSIONS

With all the prefeasibility level design completed, a preliminary cost estimate was made based on figures published by the Department of Energy. Although these figures are based on lower 48 costs, their relative value was used to do a cursory comparison. The results were within $\pm$ 10% dollar range for both the medium forecast and the low forecast scenarios. This meant that within the accuracy of the level of this study the costs of each of the alternatives described in this Appendix is about the same. This meant that the following 15 transmission lines are about equivalent within their respective groups.

Prudhoe Bay Generation

Pruanoe Bay to Fairbanks

Medium Forecast

(1) 765 kV, two circuits
(2) 500 kV, two circuits with series compensation
(3) $\pm$ 350 kV DC, two bipoles[1/]

Low Forecast

(4) 500 kV, two circuits
(5) 345 kV, two circuits with series compensation
(6) $\pm$ 350 kV, two bipoles[1/]

1/ The two HVDC versions may differ in current and/or voltage ratings.

Fairbanks Generation

Fairbanks to Anchorage

Medium Forecast

(7) 500 kV, two circuits and with or without the 345 kV Intertie

(8) 345 kV, three circuits with series compensation

Low Forecast

(9) 345 kV, two circuits with series compensation

Kenai Generation

Kenai to Anchorage

Medium Forecast

(10) 500 kV, two circuits with some series compensation
(11) 345 kV, two circuits with series compensation
(12) 345 kV, three circuits

Low Forecast

(13) 500 kV, two circuits
(14) 345 kV, with series compensation

Anchorage to Fairbanks

Both Medium and Low Forecasts

(15) 345 kV, two circuits without an intermediate switching station

It was much simpler to design the transmission system for the Kenai generation scenarios than to do it for the Prudhoe Bay scenarios. The reason: Kenai is much closer to Anchorage, the main bulk of load, than is Prudhoe Bay. With the many studies made for the other scenarios completed, the Kenai alternatives, with a 150 mile transmission distance,[1/] needed only few computer runs.

As the costs of the versions within a group are nearly the same, the final versions were selected in such a manner as to minimize the work required for the detailed cost estimating. Ultimately, the following seven versions were chosen for final evaluation: (2), (4), (8), (9), (10), (13), and (15).

1/ Initially, a 150 mile long route was selected around Turnagain Arm. In the final round, an even shorter, 90 mile route, with undersea cable crossing, was selected. This final version should perform even better.

D7.0 SAG AND TENSION CALCULATIONS

This section contains the computer generated sag and tension calculations using Bunting and Chukar conductors. Calculations were performed for six ruling spans: 1500, 1200, 1000, 800, 600 and 400 feet. Towers were limited to 100 foot heights, with 13.5 foot long insulators and 38 foot clearance to ground, thus limiting maximum sag to 48.5 feet. Conductor loadings were specified as follows:

Special NESC Heavy

-60°F	No ice	0 lb/sq ft wind pressure
-60°F	No ice	25 lb/sq ft wind pressure
32°F	1.5" radial ice	8 lb/sq ft wind pressure
86°F	No ice	2.3 lb/sq ft wind pressure

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 400.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	2.55	10559	10560*	10562	33.01
2	-60	0.00	25.00	.00	4.67	12954	12959	12969	40.53
3	32	1.50	8.00	.00	9.81	14625	14648	14695	45.92
4	86	0.00	2.30	.00	7.87	3476	3480	3487	10.90

(1) HORIZONTAL TENSION *LIMIT A) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	200.00	2.55	0.00	399.59
2	1.3440	2.7125	3.0272	200.00	4.67	0.00	399.59
3	6.5725	2.8680	7.1710	200.00	9.81	0.00	400.02
4	1.3440	0.2495	1.3670	200.00	7.87	0.00	400.26

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 600.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	10.80	5605	5609	5619	17.56
2	-60	0.00	25.00	.00	13.48	10110	10126	10151	31.72
3	32	1.50	8.00	.00	20.26	15952	16000*	16097	50.30
4	86	0.00	2.30	.00	17.70	3479	3487	3503	10.95

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	300.00	10.80	0.00	600.16
2	1.3440	2.7125	3.0272	300.00	13.48	0.00	600.16
3	6.5725	2.8680	7.1710	300.00	20.26	0.00	600.79
4	1.3440	0.2495	1.3670	300.00	17.70	0.00	601.17

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 800.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	27.18	3962	3974	3998	12.49
2	-60	0.00	25.00	.00	29.18	8313	8342	8401	26.25
3	32	1.50	8.00	.00	36.15	15914	16000*	16173	50.54
4	86	0.00	2.30	.00	33.58	3264	3280	3310	10.34

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	400.00	27.18	0.00	802.12
2	1.3440	2.7125	3.0272	400.00	29.18	0.00	802.12
3	6.5725	2.8680	7.1710	400.00	36.15	0.00	802.97
4	1.3440	0.2495	1.3670	400.00	33.58	0.00	803.46

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1000.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	48.04	3508	3529	3572	11.16
2	-60	0.00	25.00	.00	49.77	7629	7679	7779	24.31
3	32	1.50	8.00	.00	56.74	15865	16000*	16272	50.85
4	86	0.00	2.30	.00	54.17	3167	3191	3241	10.13

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	500.00	48.04	0.00	1005.75
2	1.3440	2.7125	3.0272	500.00	49.77	0.00	1005.75
3	6.5725	2.8680	7.1710	500.00	56.74	0.00	1006.81
4	1.3440	0.2495	1.3670	500.00	54.17	0.00	1007.44

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1200.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	73.60	3303	3336	3402	10.63
2	-60	0.00	25.00	.00	75.20	7284	7360	7511	23.47
3	32	1.50	8.00	.00	82.18	15804	16000*	16393	51.23
4	86	0.00	2.30	.00	79.60	3109	3145	3218	10.06

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	600.00	73.60	0.00	1211.52
2	1.3440	2.7125	3.0272	600.00	75.20	0.00	1211.52
3	6.5725	2.8680	7.1710	600.00	82.18	0.00	1212.81
4	1.3440	0.2495	1.3670	600.00	79.60	0.00	1213.56

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1192.5 KCMIL ACSR 45/7 "BUNTING" DIAMETER: 1.3020 IN
WEIGHT: 1.3440 LB/FT, AREA: 1.00100 SQIN RTS: 32000 LB
MOD.OF ELAST: 9350000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1500.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 10560 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 16000 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 16000 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	121.29	3143	3198	3306	10.33
2	-60	0.00	25.00	.00	122.79	6995	7118	7366	23.02
3	32	1.50	8.00	.00	129.80	15691	16000*	16622	51.94
4	86	0.00	2.30	.00	127.20	3051	3109	3225	10.08

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.3440	0.0000	1.3440	750.00	121.29	0.00	1525.32
2	1.3440	2.7125	3.0272	750.00	122.79	0.00	1525.32
3	6.5725	2.8680	7.1710	750.00	129.80	0.00	1526.93
4	1.3440	0.2495	1.3670	750.00	127.20	0.00	1527.88

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 400.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	2.27	15278	15279*	15282	33.01
2	-60	0.00	25.00	.00	3.96	17387	17391	17400	37.58
3	32	1.50	8.00	.00	8.78	17718	17741	17786	38.41
4	86	0.00	2.30	.00	7.00	5026	5030	5038	10.88

(1) HORIZONTAL TENSION *LIMIT A) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.7370	0.0000	1.7370	200.00	2.27	0.00	399.53
2	1.7370	2.9667	3.4378	200.00	3.96	0.00	399.53
3	7.1932	2.9493	7.7743	200.00	8.78	0.00	399.93
4	1.7370	0.2729	1.7583	200.00	7.00	0.00	400.16

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 600.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	5.12	15276	15279*	15285	33.01
2	-60	0.00	25.00	.00	8.18	18918	18928	18946	40.92
3	32	1.50	8.00	.00	15.55	22512	22552	22633	48.88
4	86	0.00	2.30	.00	11.95	6626	6633	6647	14.36

(1) HORIZONTAL TENSION *LIMIT A) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	1.7370	0.0000	1.7370	300.00	5.12	0.00	599.36
2	1.7370	2.9667	3.4378	300.00	8.18	0.00	599.36
3	7.1932	2.9493	7.7743	300.00	15.55	0.00	599.95
4	1.7370	0.2729	1.7583	300.00	11.95	0.00	600.30

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 800.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	14.70	9456	9464	9481	20.48
2	-60	0.00	25.00	.00	18.16	15156	15177	15218	32.87
3	32	1.50	8.00	.00	26.99	23080	23150*	23290	50.30
4	86	0.00	2.30	.00	23.01	6119	6133	6160	13.30

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	1.7370	0.0000	1.7370	400.00	14.70	0.00	800.09
2	1.7370	2.9667	3.4378	400.00	18.16	0.00	800.09
3	7.1932	2.9493	7.7743	400.00	26.99	0.00	800.89
4	1.7370	0.2729	1.7583	400.00	23.01	0.00	801.36

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 1000.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	30.22	7192	7210	7245	15.65
2	-60	0.00	25.00	.00	33.10	13003	13041	13117	28.33
3	32	1.50	8.00	.00	42.28	23041	23150*	23369	50.47
4	86	0.00	2.30	.00	38.27	5755	5777	5822	12.57

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	1.7370	0.0000	1.7370	500.00	30.22	0.00	1001.83
2	1.7370	2.9667	3.4378	500.00	33.10	0.00	1001.83
3	7.1932	2.9493	7.7743	500.00	42.28	0.00	1002.83
4	1.7370	0.2729	1.7583	500.00	38.27	0.00	1003.42

EBASCO SERVICES INC. - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 1200.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	49.28	6359	6388	6445	13.92
2	-60	0.00	25.00	.00	51.80	11976	12035	12154	26.25
3	32	1.50	8.00	.00	61.07	22992	23150*	23467	50.68
4	86	0.00	2.30	.00	57.05	5565	5598	5665	12.24

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	1.7370	0.0000	1.7370	600.00	49.28	0.00	1204.74
2	1.7370	2.9667	3.4378	600.00	51.80	0.00	1204.74
3	7.1932	2.9493	7.7743	600.00	61.07	0.00	1205.94
4	1.7370	0.2729	1.7583	600.00	57.05	0.00	1206.64

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1351.5 KCMIL ACSR 54/19 "MARTIN" DIAMETER: 1.4240 IN
WEIGHT: 1.7370 LB/FT, AREA: 1.19600 SQIN RTS: 46300 LB
MOD.OF ELAST: 10110000 PSI, TEMP.COEFF: 0.0000108 /DEG.F

SPAN= 1500.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 15279 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 23150 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23150 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG(4)	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	84.40	5813	5861	5959	12.87
2	-60	0.00	25.00	.00	86.67	11206	11305	11504	24.85
3	32	1.50	8.00	.00	95.99	22902	23150*	23648	51.08
4	86	0.00	2.30	.00	91.95	5405	5459	5567	12.02

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	1.7370	0.0000	1.7370	750.00	84.40	0.00	1511.86
2	1.7370	2.9667	3.4378	750.00	86.67	0.00	1511.86
3	7.1932	2.9493	7.7743	750.00	95.99	0.00	1513.36
4	1.7370	0.2729	1.7583	750.00	91.95	0.00	1514.24

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 400.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	2.47	16828	16830*	16833	33.01
2	-60	0.00	25.00	.00	4.06	19367	19372	19382	38.00
3	32	1.50	8.00	.00	8.88	19031	19055	19105	37.46
4	86	0.00	2.30	.00	7.76	5410	5415	5426	10.64

(1) HORIZONTAL TENSION *LIMIT A) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	2.0750	0.0000	2.0750	200.00	2.47	0.00	399.58
2	2.0750	3.3375	3.9300	200.00	4.06	0.00	399.58
3	7.8633	3.0680	8.4407	200.00	8.88	0.00	400.00
4	2.0750	0.3071	2.0976	200.00	7.76	0.00	400.25

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 600.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	5.55	16826	16830*	16838	33.02
2	-60	0.00	25.00	.00	8.38	21105	21116	21138	41.45
3	32	1.50	8.00	.00	15.61	24351	24395	24483	48.01
4	86	0.00	2.30	.00	13.02	7252	7261	7279	14.27

(1) HORIZONTAL TENSION *LIMIT A) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	2.0750	0.0000	2.0750	300.00	5.55	0.00	599.45
2	2.0750	3.3375	3.9300	300.00	8.38	0.00	599.45
3	7.8633	3.0680	8.4407	300.00	15.61	0.00	600.08
4	2.0750	0.3071	2.0976	300.00	13.02	0.00	600.46

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 800.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	14.77	11242	11252	11272	22.10
2	-60	0.00	25.00	.00	17.94	17540	17563	17610	34.53
3	32	1.50	8.00	.00	26.60	25425	25500*	25650	50.29
4	86	0.00	2.30	.00	23.56	7130	7146	7179	14.08

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	2.0750	0.0000	2.0750	400.00	14.77	0.00	800.11
2	2.0750	3.3375	3.9300	400.00	17.94	0.00	800.11
3	7.8633	3.0680	8.4407	400.00	26.60	0.00	800.96
4	2.0750	0.3071	2.0976	400.00	23.56	0.00	801.46

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1000.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	30.03	8647	8668	8709	17.08
2	-60	0.00	25.00	.00	32.67	15058	15100	15186	29.78
3	32	1.50	8.00	.00	41.66	25383	25500*	25735	50.46
4	86	0.00	2.30	.00	38.59	6808	6835	6889	13.51

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	2.0750	0.0000	2.0750	500.00	30.03	0.00	1001.81
2	2.0750	3.3375	3.9300	500.00	32.67	0.00	1001.81
3	7.8633	3.0680	8.4407	500.00	41.66	0.00	1002.87
4	2.0750	0.3071	2.0976	500.00	38.59	0.00	1003.49

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1200.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	48.78	7674	7708	7775	15.25
2	-60	0.00	25.00	.00	51.10	13877	13944	14077	27.60
3	32	1.50	8.00	.00	60.18	25331	25500*	25839	50.66
4	86	0.00	2.30	.00	57.08	6634	6674	6754	13.24

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	2.0750	0.0000	2.0750	600.00	48.78	0.00	1204.64
2	2.0750	3.3375	3.9300	600.00	51.10	0.00	1204.64
3	7.8633	3.0680	8.4407	600.00	60.18	0.00	1205.91
4	2.0750	0.3071	2.0976	600.00	57.08	0.00	1206.66

EBASCO SERVICES INC - SAG & TENSION W/FIXED MODULUS

ALASKA POWER AUTHORITY 11/08/82

CABLE: 1780 KCMIL ACSR 84/19 "CHUKAR" DIAMETER: 1.6020 IN
WEIGHT: 2.0750 LB/FT, AREA: 1.51300 SQIN RTS: 51000 LB
MOD.OF ELAST: 9690000 PSI, TEMP.COEFF: 0.0000115 /DEG.F

SPAN= 1500.00 FT DIFF. IN ELEV.= 0.00 FT

LIMITING CONDITION(S):
A) 16830 LB (2) AT -60 DEG.F, 0.00 IN ICE, 0.00 PSF WIND, K=0.00
B) 25500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 25500 LB (2) AT 32 DEG.F, 1.50 IN ICE, 8.00 PSF WIND, K=0.00

NO.	TEMP. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (3)
1	-60	0.00	0.00	.00	83.35	7030	7088	7203	14.12
2	-60	0.00	25.00	.00	85.45	12991	13103	13327	26.13
3	32	1.50	8.00	.00	94.57	25235	25500*	26033	51.04
4	86	0.00	2.30	.00	91.45	6483	6546	6674	13.09

(1) HORIZONTAL TENSION *LIMIT C) IS GOVERNING
(2) EFFECTIVE AVERAGE TENSION
(3) UPPER SUPPORT TENSION
(4) TANGENT SAG

NO.	WV LB/FT	WH LB/FT	WR LB/FT	LOW POINT(FT) HORIZ.	VERT.	ADD.L FT	UNSTR.L FT
1	2.0750	0.0000	2.0750	750.00	83.35	0.00	1511.35
2	2.0750	3.3375	3.9300	750.00	85.45	0.00	1511.35
3	7.8633	3.0680	8.4407	750.00	94.57	0.00	1513.15
4	2.0750	0.3071	2.0976	750.00	91.45	0.00	1514.09

D8.0 FIGURES

TABLE D-8

LETTER SYMBOLS

BC - line charging MVAR at 1.0 per unit voltage

G - generation

E - equivalent of the local area system

GL - Galbraith Lake (150 miles south of the North Slope)

OM - Prospect Camp (150 miles north of Fairbanks)

FB - Fairbanks

HE - Healy

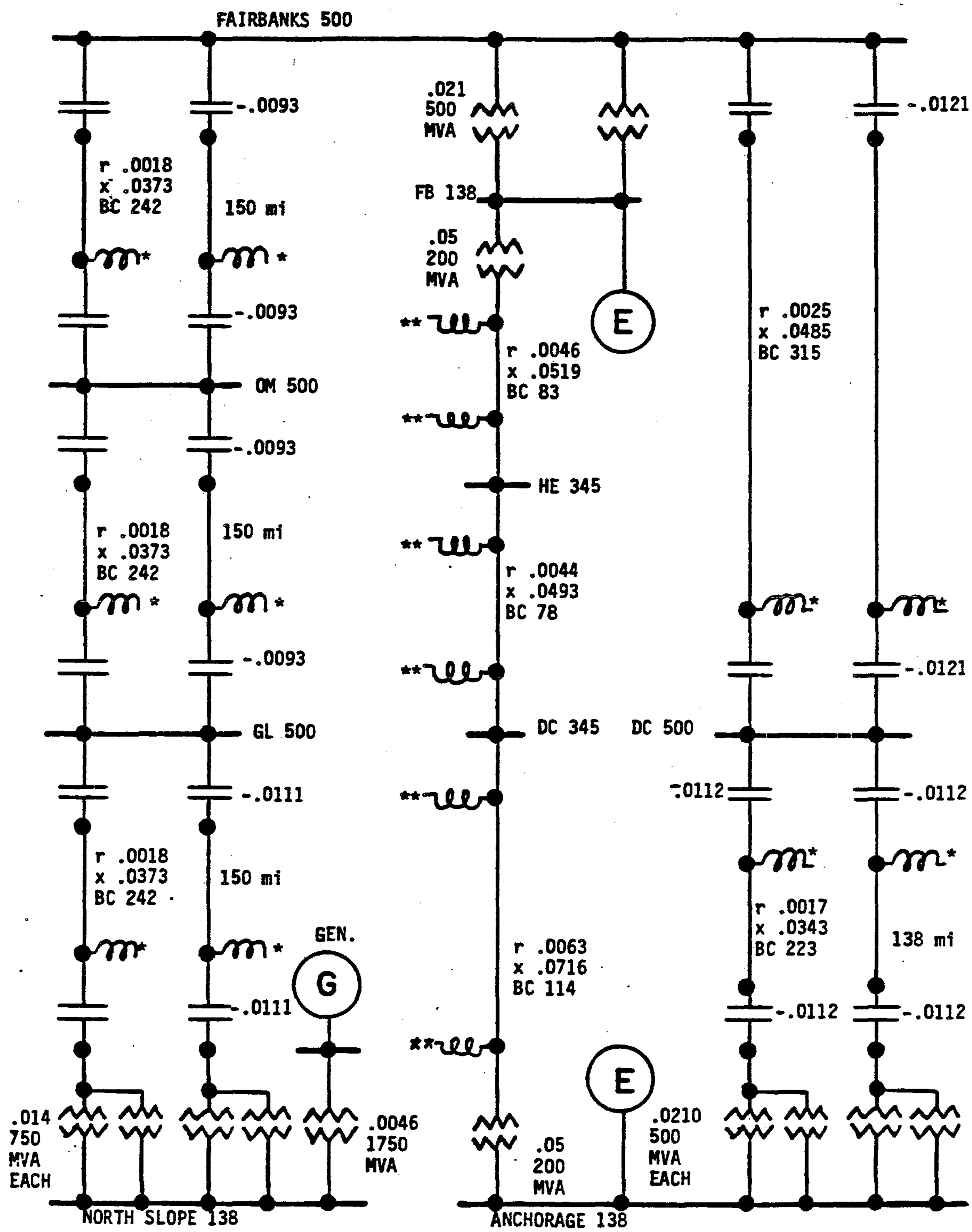
DC - Gold Creek

MP - Midpoint

R - resistance in per unit on a 100 MVA base

X - reactance in per unit on a 100 MVA base

ALTERNATIVE A



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

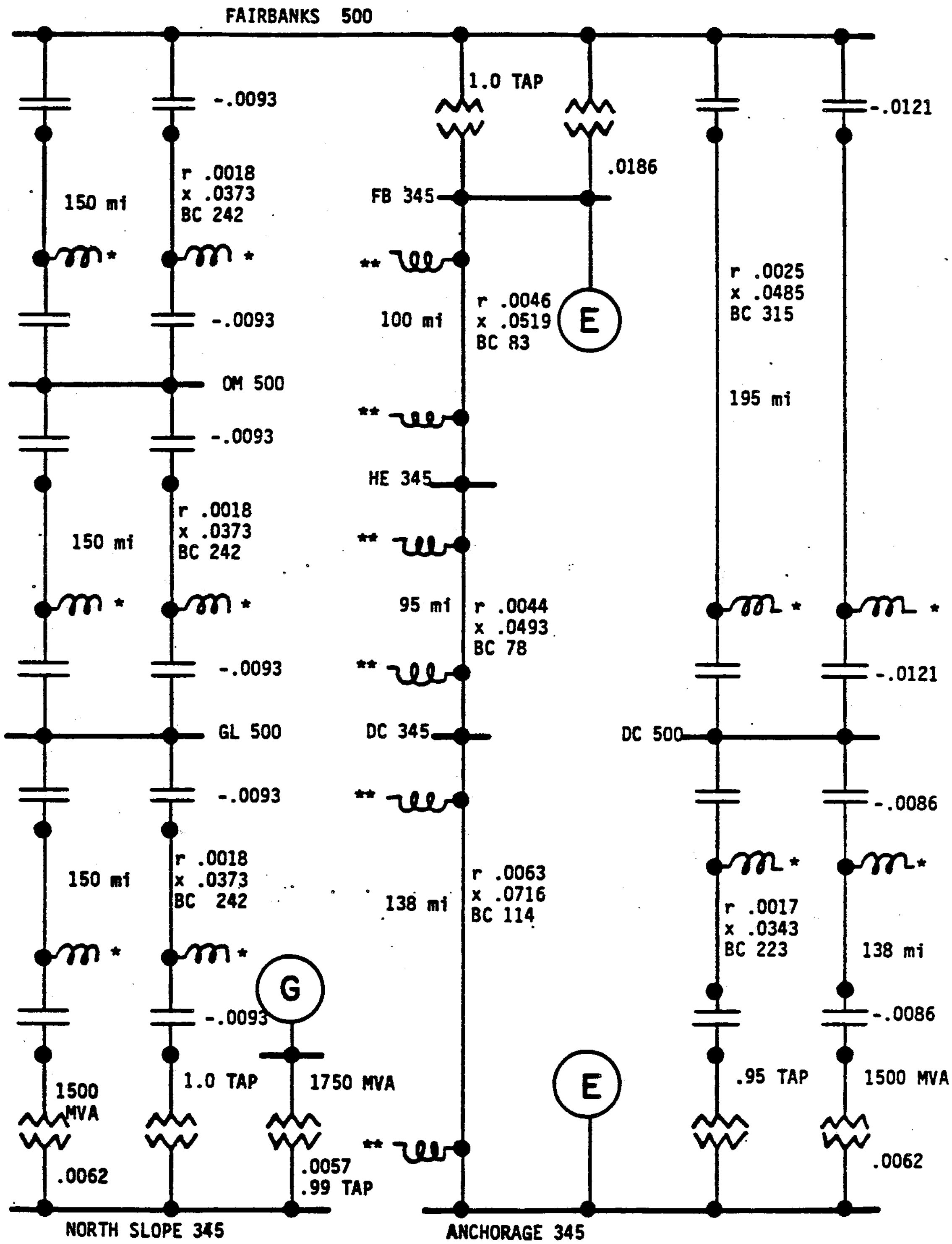
ONE LINE SCHEMATIC WITH IMPEDANCES

1400 MW capacity at Prudhoe Bay;
500 kV transmission system;
345 kV intertie in parallel between
Fairbanks and Anchorage;
intermediate 138 kV bus at Fairbanks

FIGURE D-1

EBASCO SERVICES INCORPORATED

ALTERNATIVE AA



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

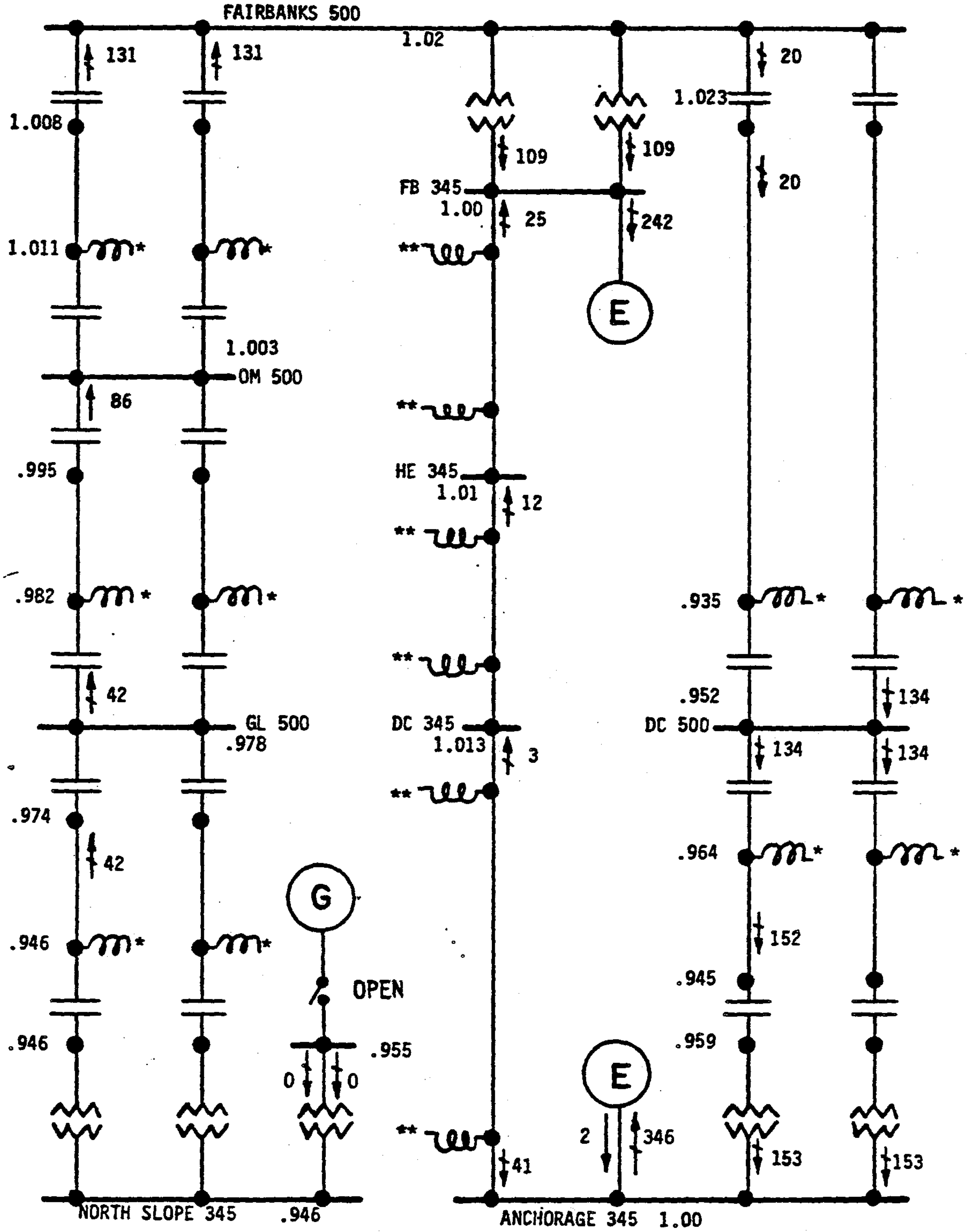
ONE LINE SCHEMATIC WITH IMPEDANCES

1400 MW capacity at Prudhoe Bay; 500 kV transmission system; 345 kV intertie in parallel between Fairbanks and Anchorage; no intermediate transformation at Fairbanks.

FIGURE D-2

EBASCO SERVICES INCORPORATED

CASE AA1



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

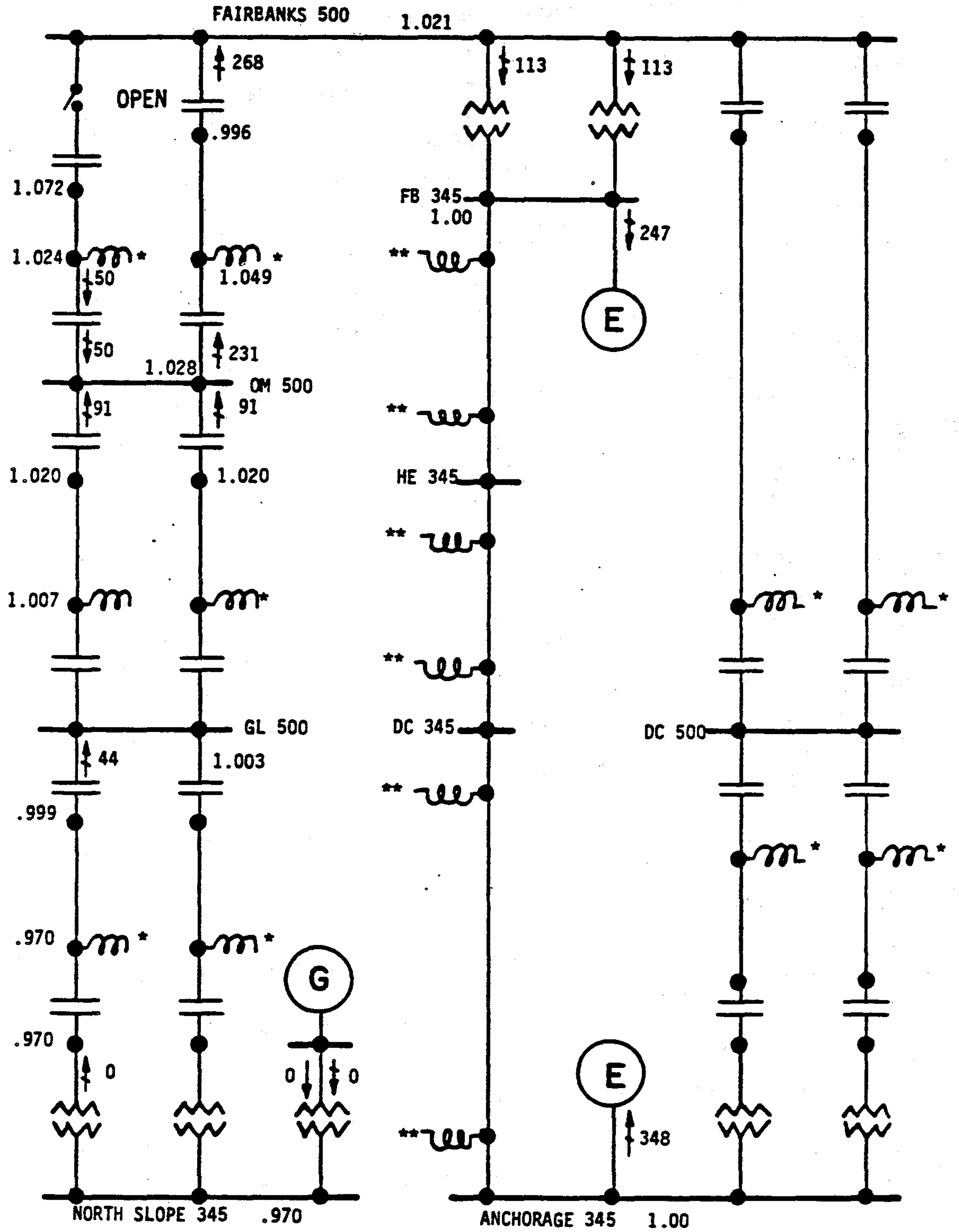
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW
No generation at Prudhoe Bay. Normal system configuration.

FIGURE D-3

EBASCO SERVICES INCORPORATED

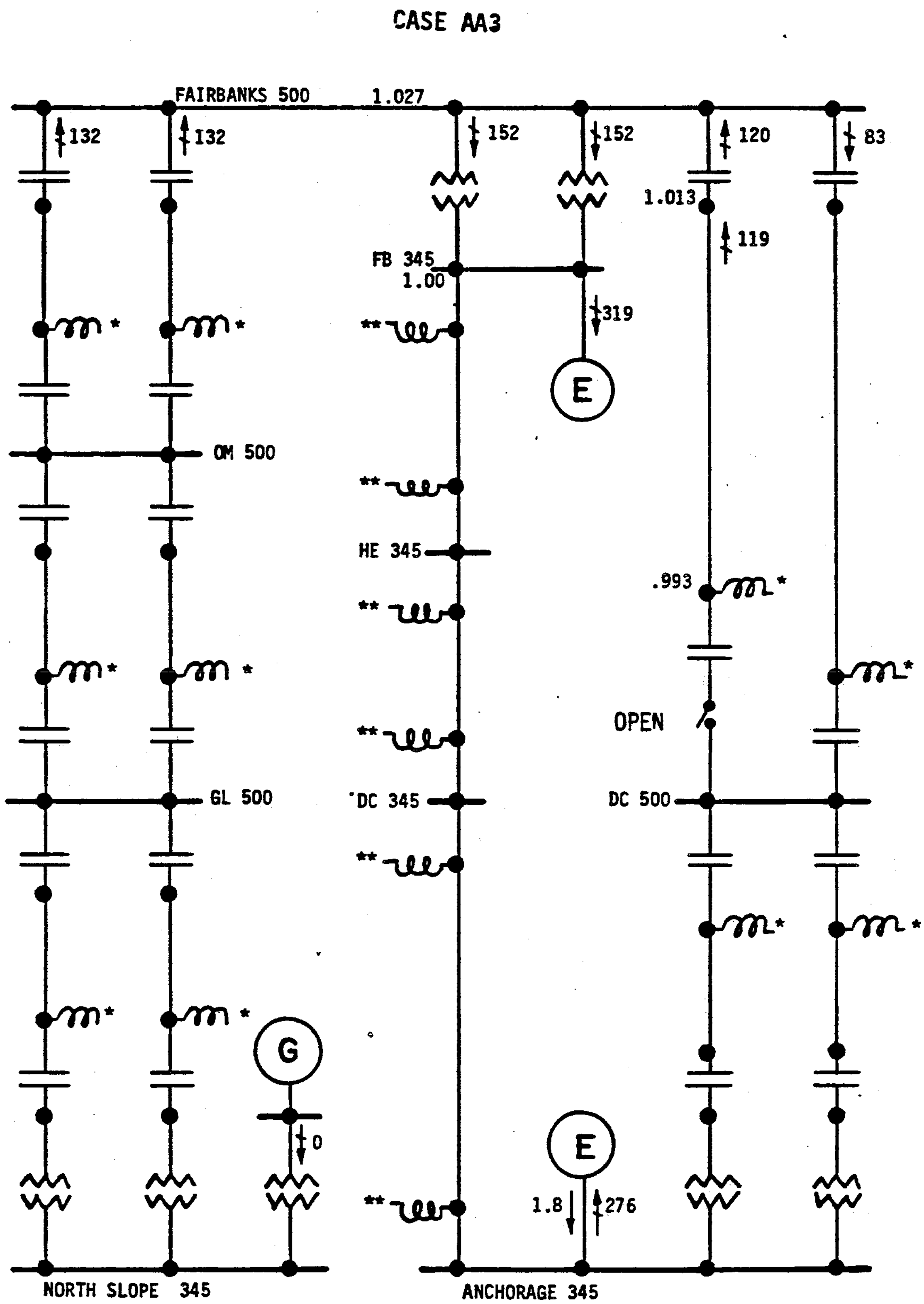
CASE AA2



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
LOAD FLOW No generation at Prudhoe Bay. One line segment open north of Fairbanks.
FIGURE D-4
EBASCO SERVICES INCORPORATED



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

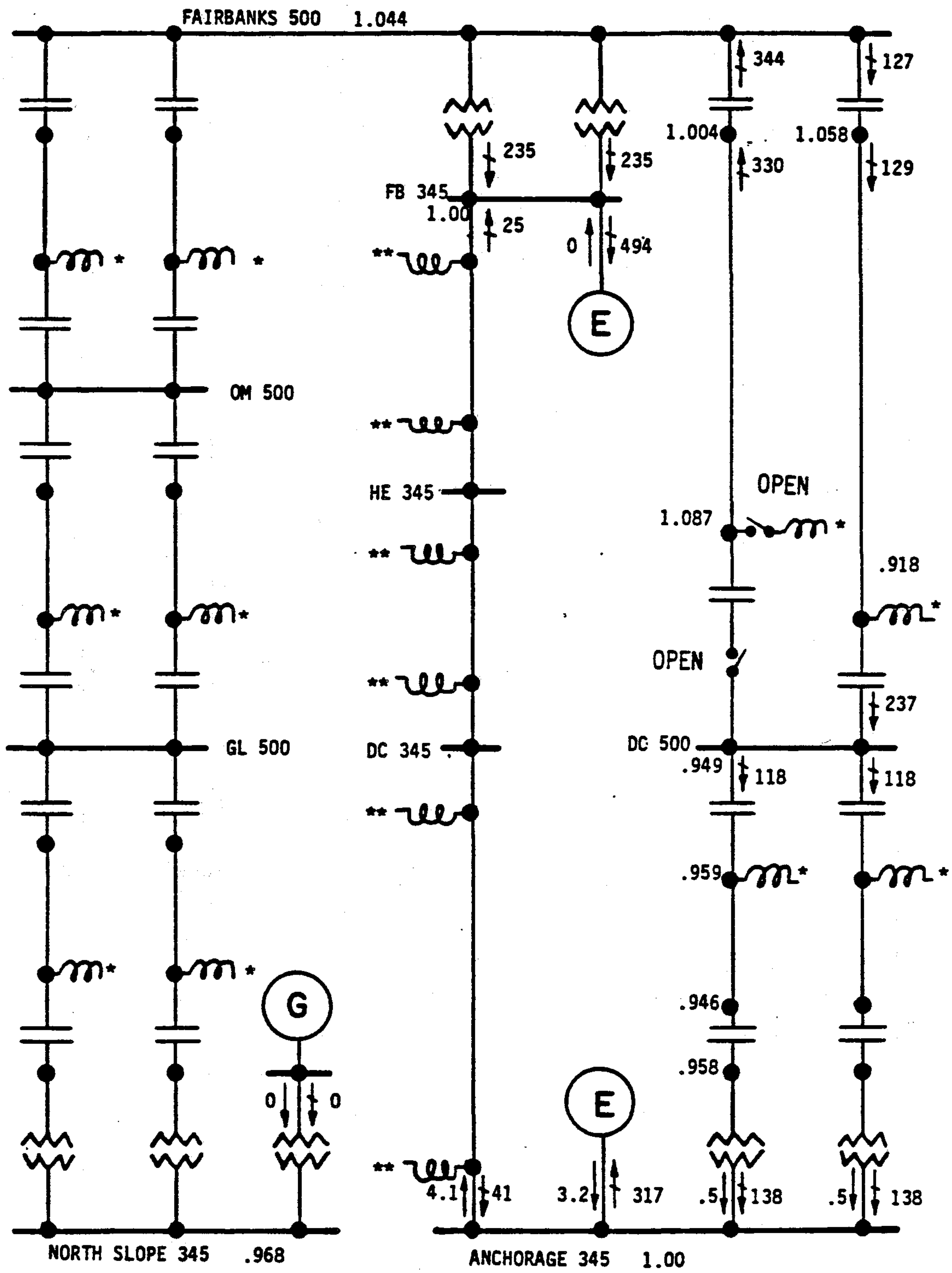
LOAD FLOW

No generation at Prudhoe Bay. One line segment open north of Devil's Canyon.

FIGURE D-5

EBASCO SERVICES INCORPORATED

CASE AA4

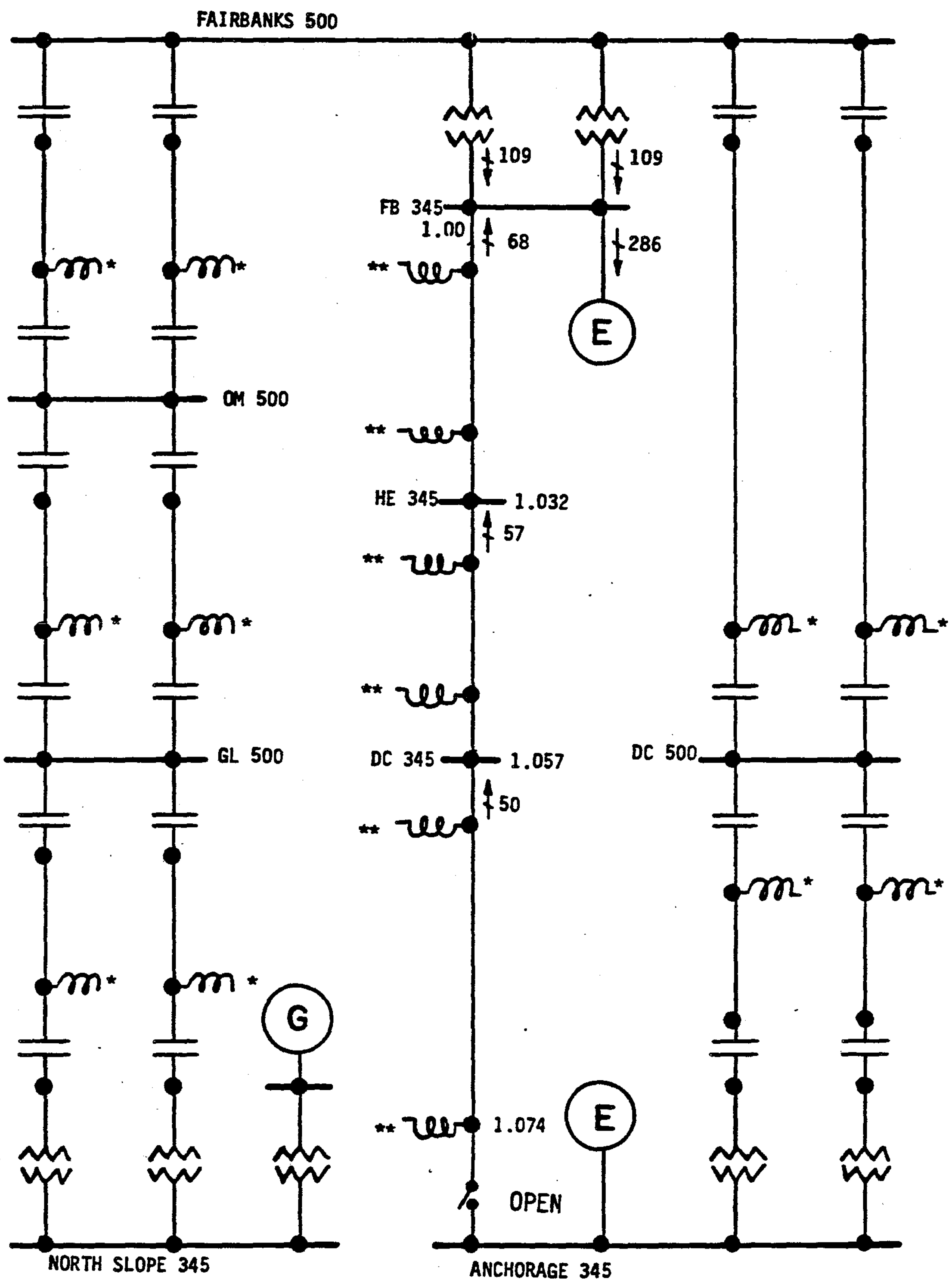


Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
LOAD FLOW No generation at Prudhoe Bay. One line segment open north of Devil's Canyon, less one reactor.
FIGURE D-6
EBASCO SERVICES INCORPORATED

CASE AA5



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

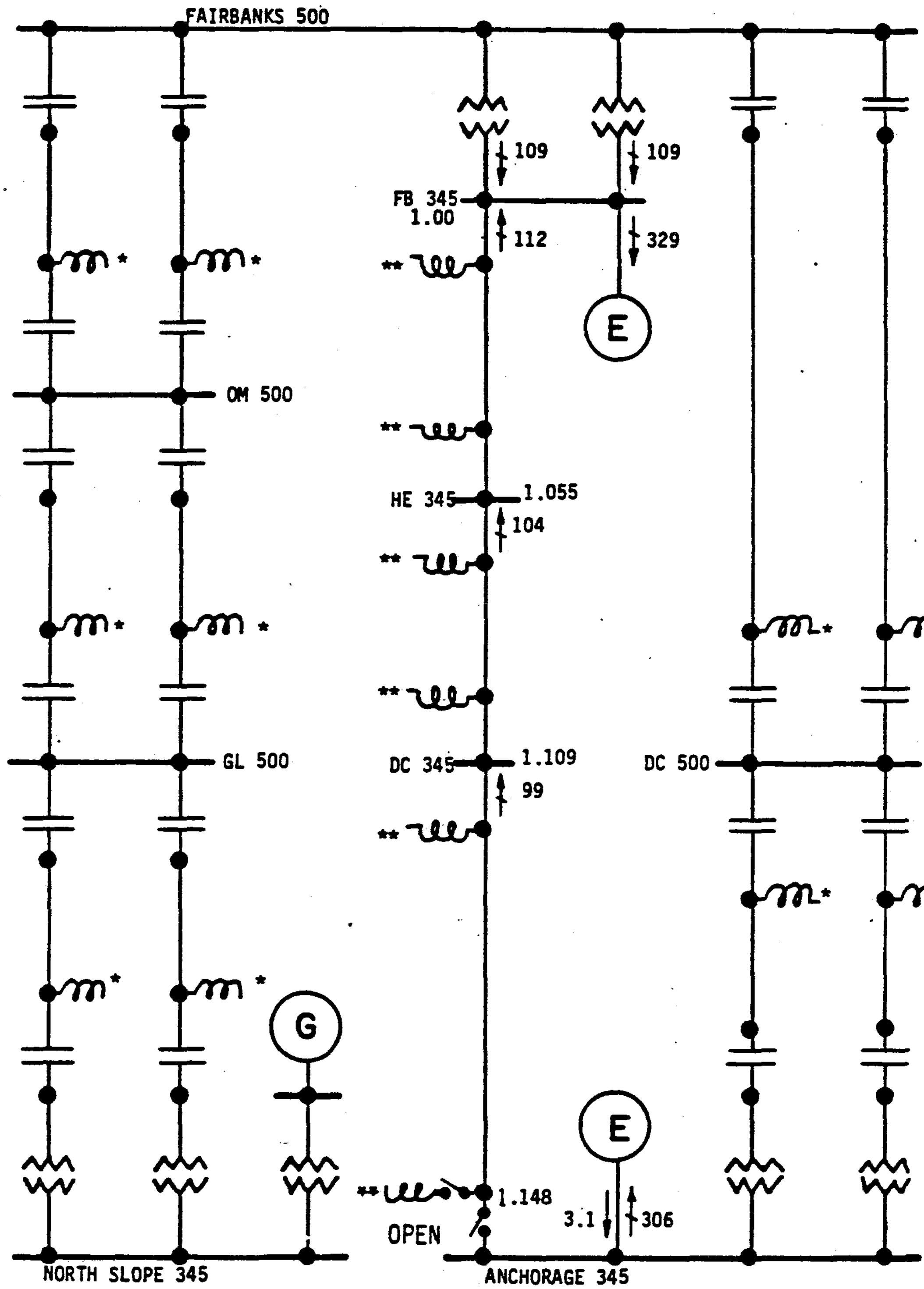
LOAD FLOW

No generation at Prudhoe Bay. The 345 kV intertie opened at Anchorage.

FIGURE D-7

EBASCO SERVICES INCORPORATED

CASE AA6



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

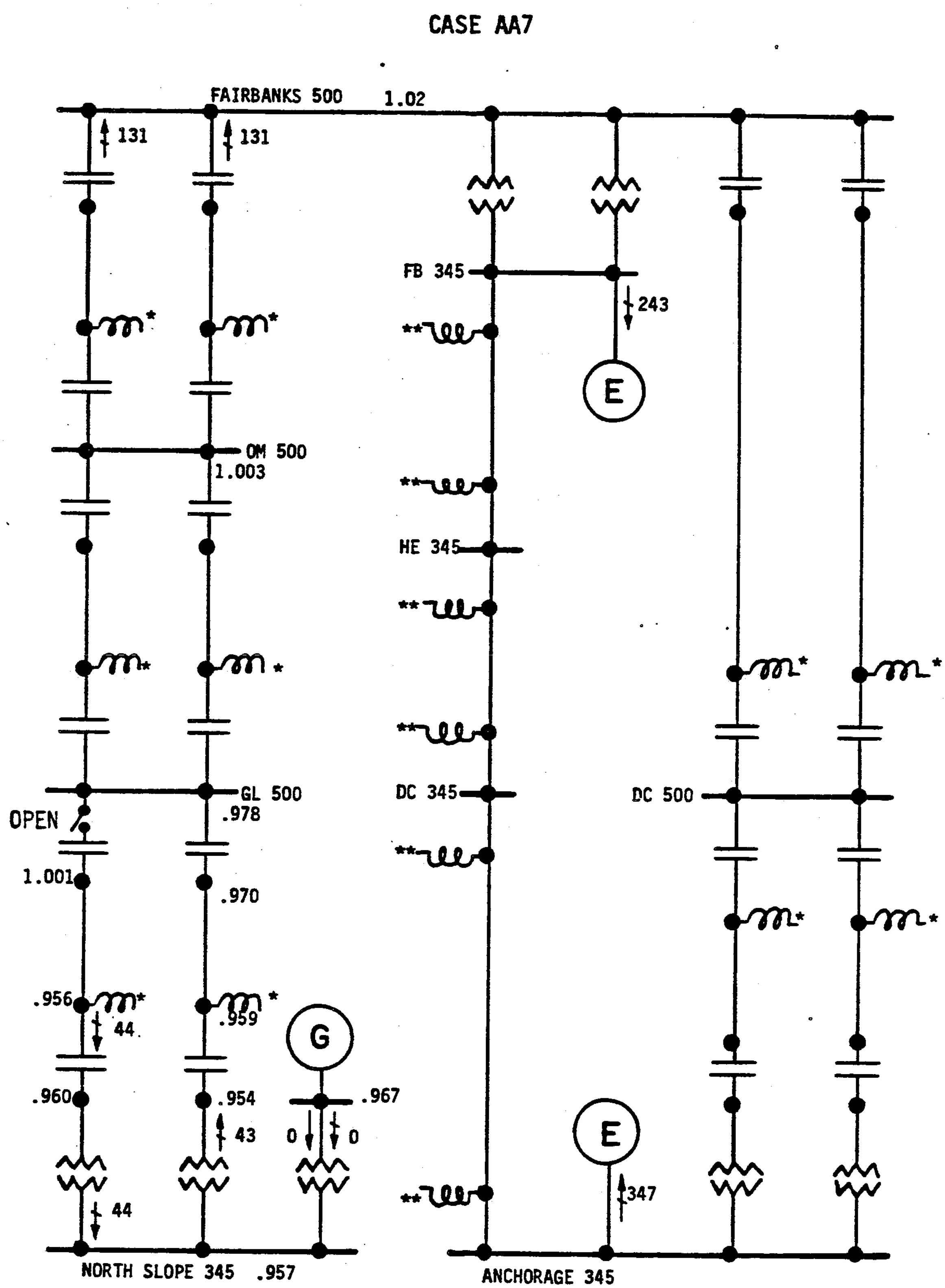
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. The 345 kV intertie opened at Anchorage, less one reactor.

FIGURE D-8

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. One line segment opened north of Galbraith Lake.

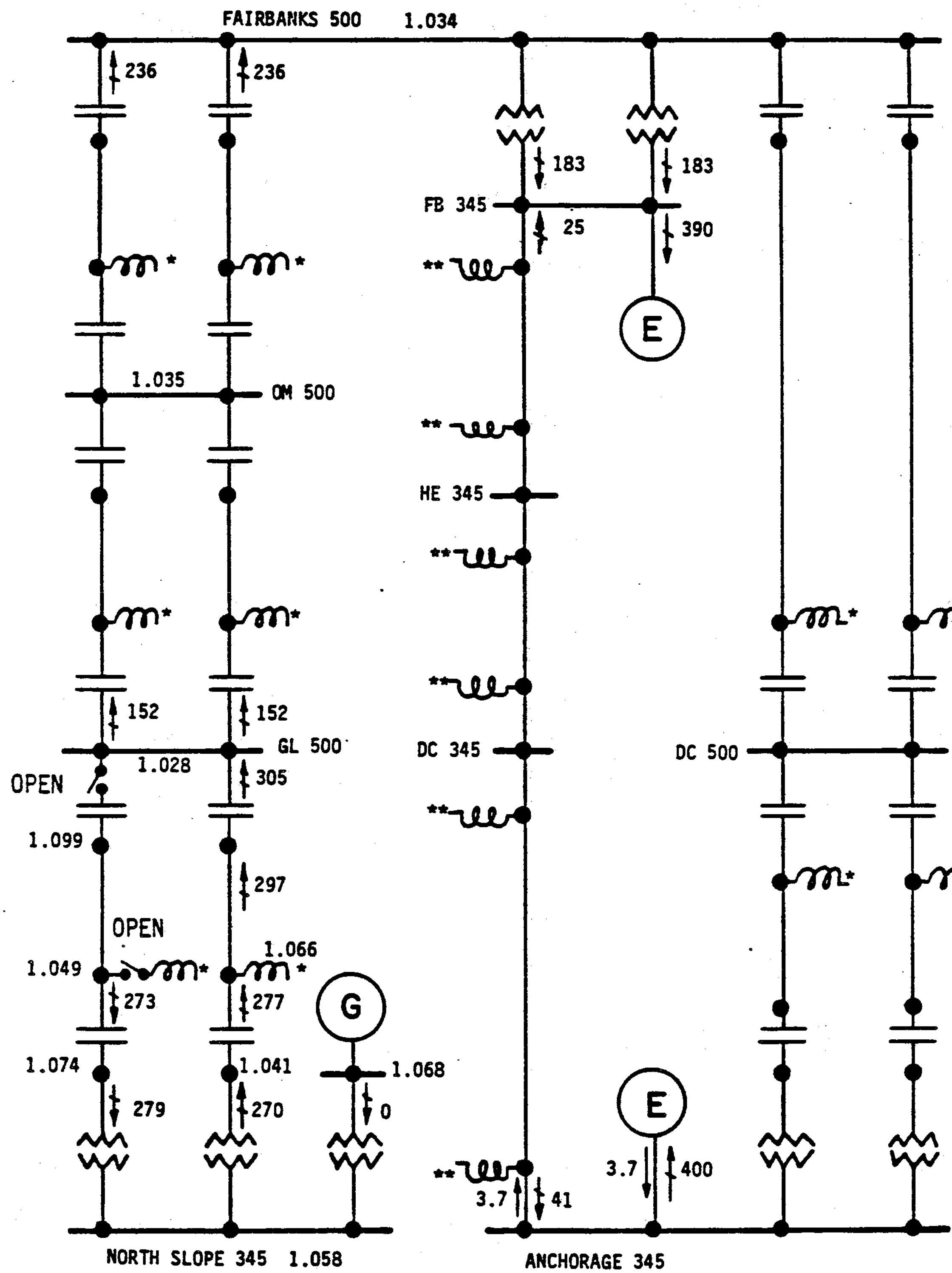
FIGURE D-9

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

CASE AA8



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. One line segment opened north of Galbraith Lake, less one reactor.

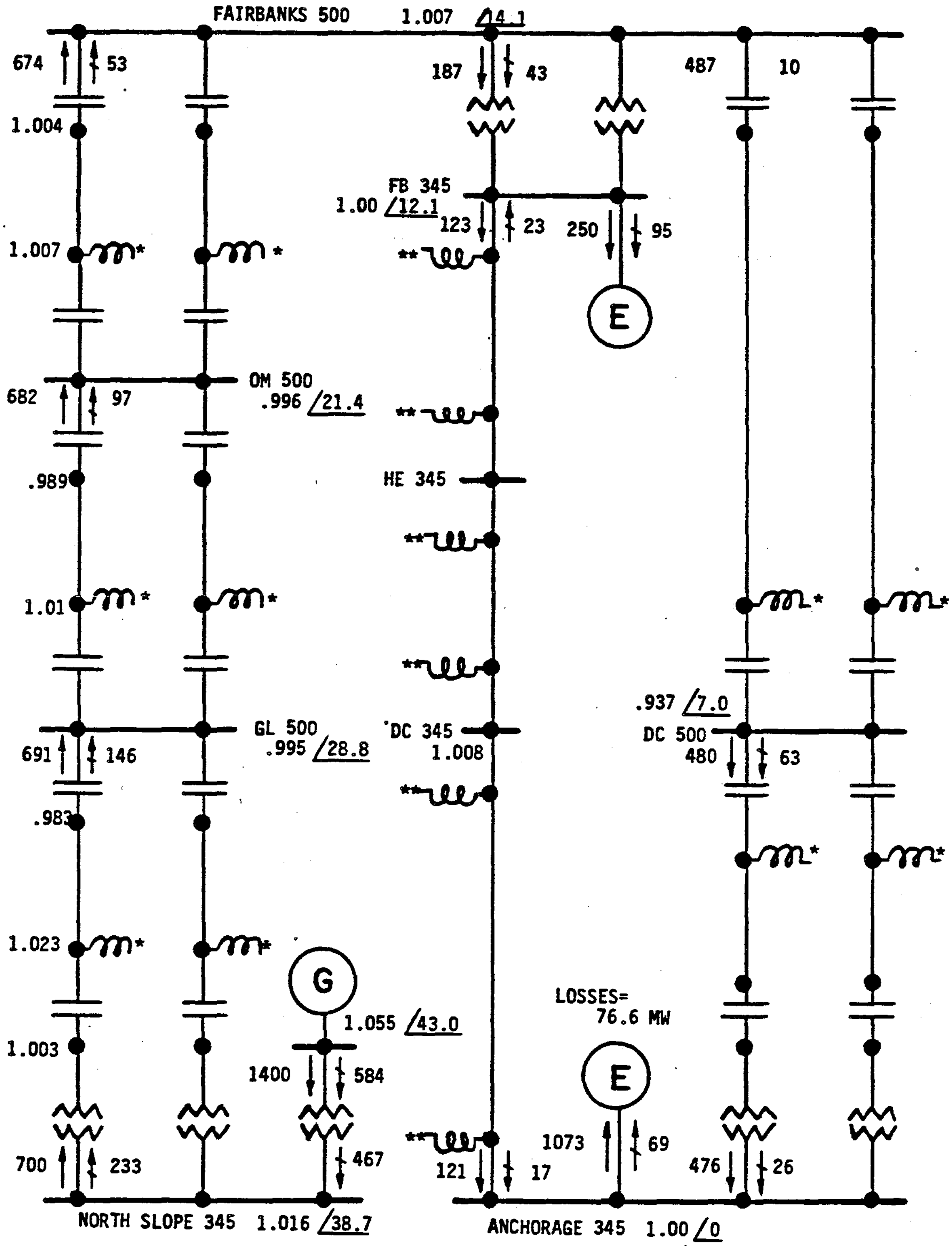
FIGURE D-10

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

CASE AA9



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

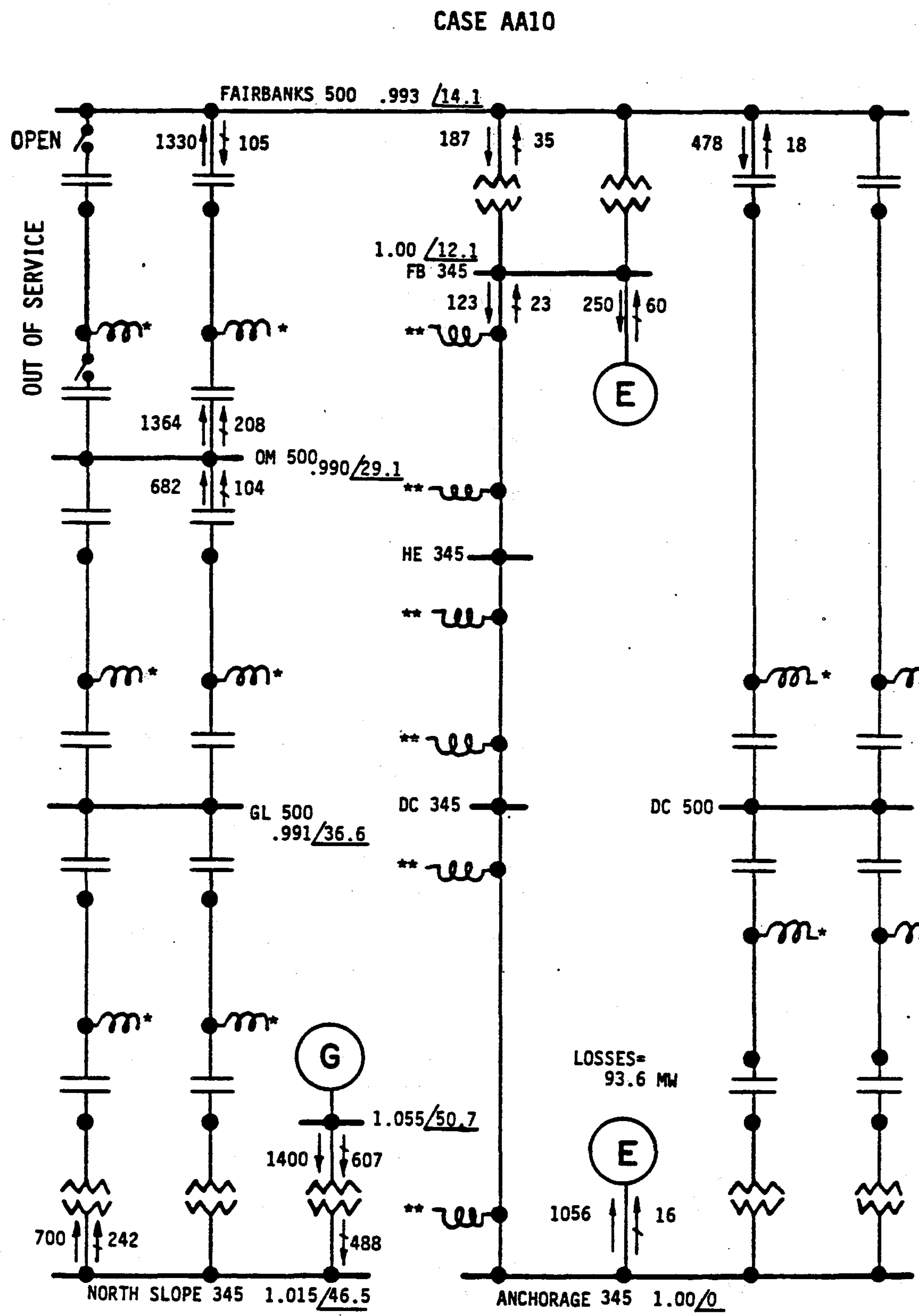
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-11

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

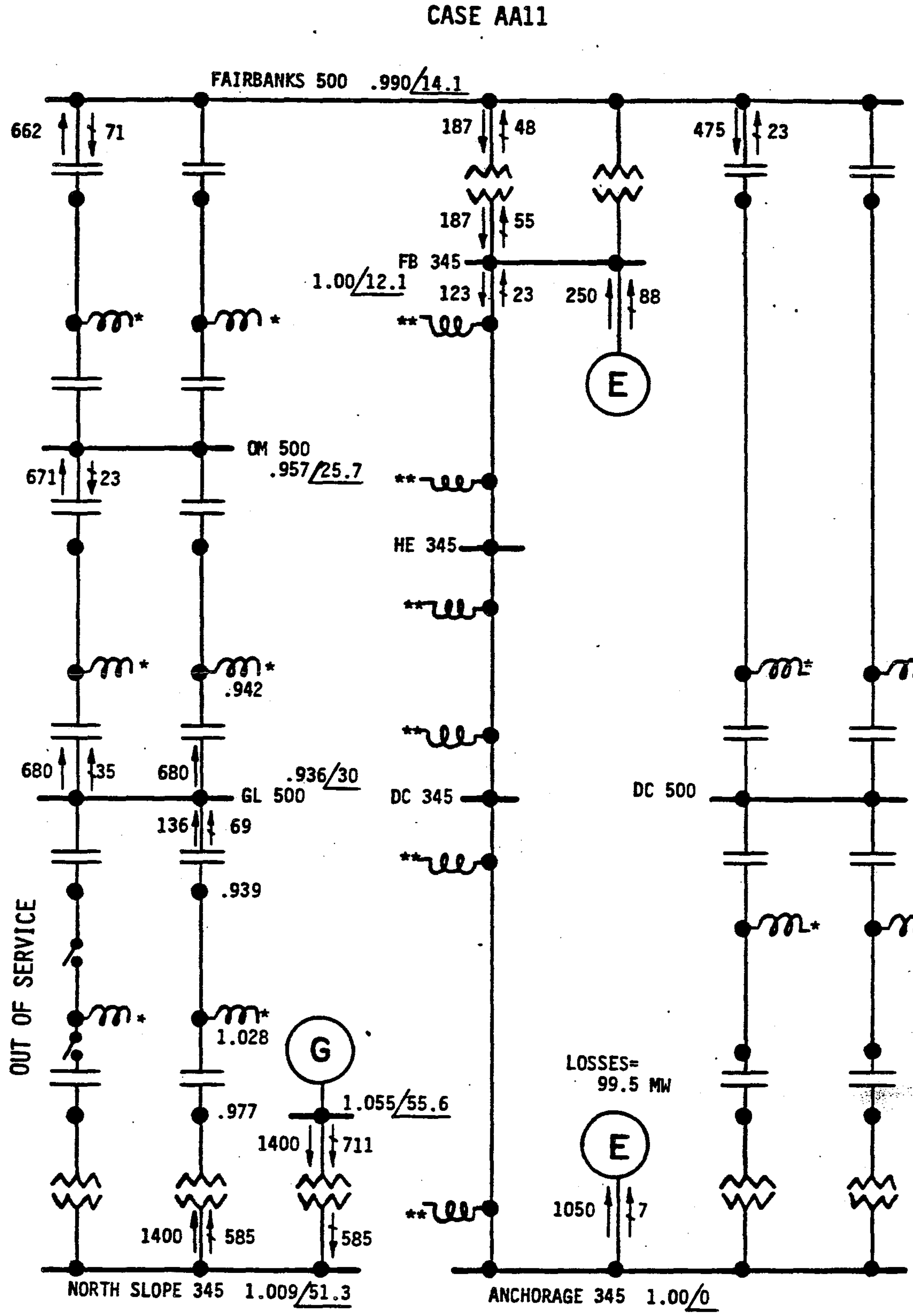
1400 MW generation at Prudhoe Bay. One line segment out of service north of Fairbanks.

FIGURE D-12

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

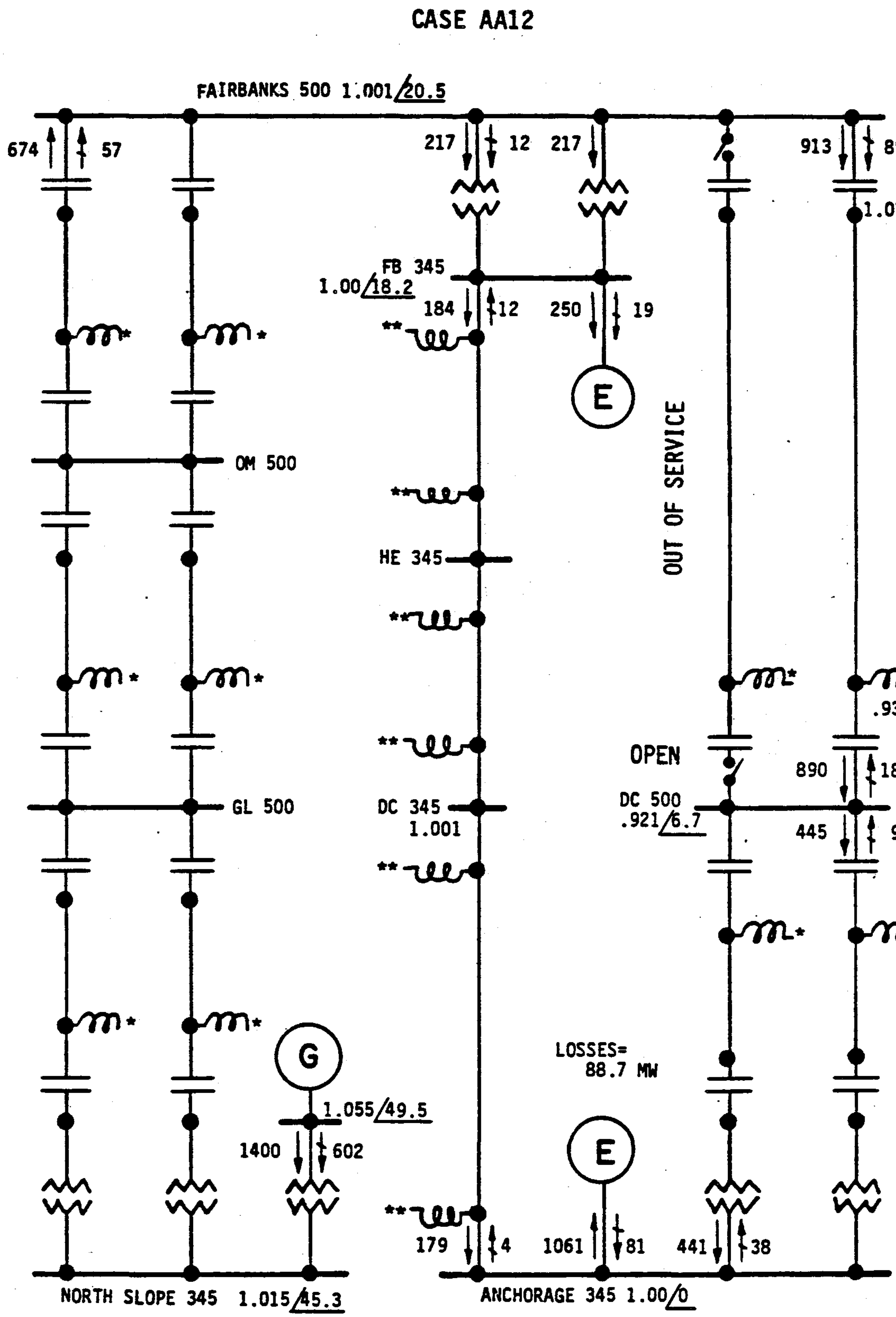
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay. One line segment out of service south of Prudhoe Bay.

FIGURE D-13

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay. One 500 kV line segment out of service south of Fairbanks.

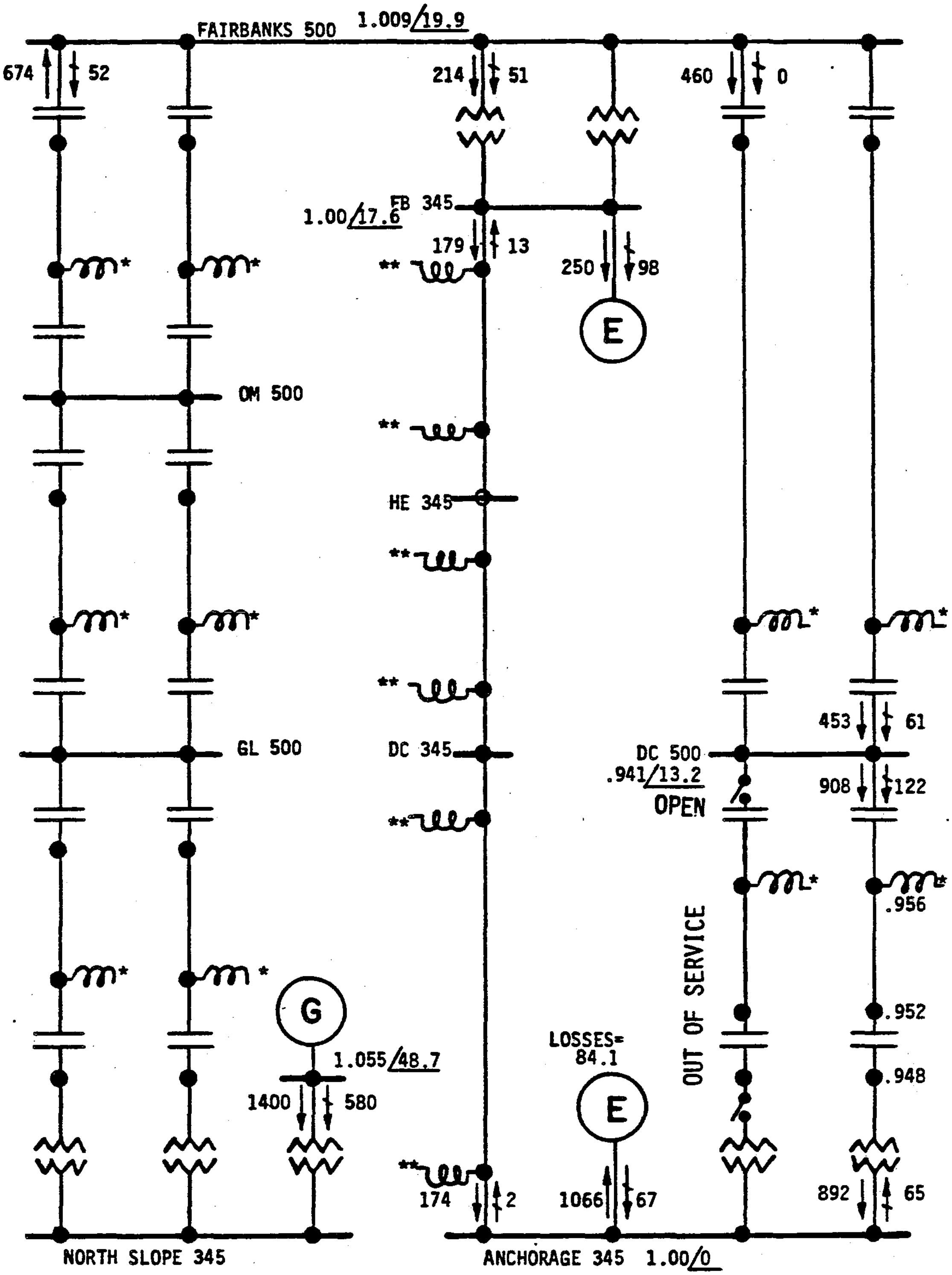
FIGURE D-14

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

CASE AA13



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

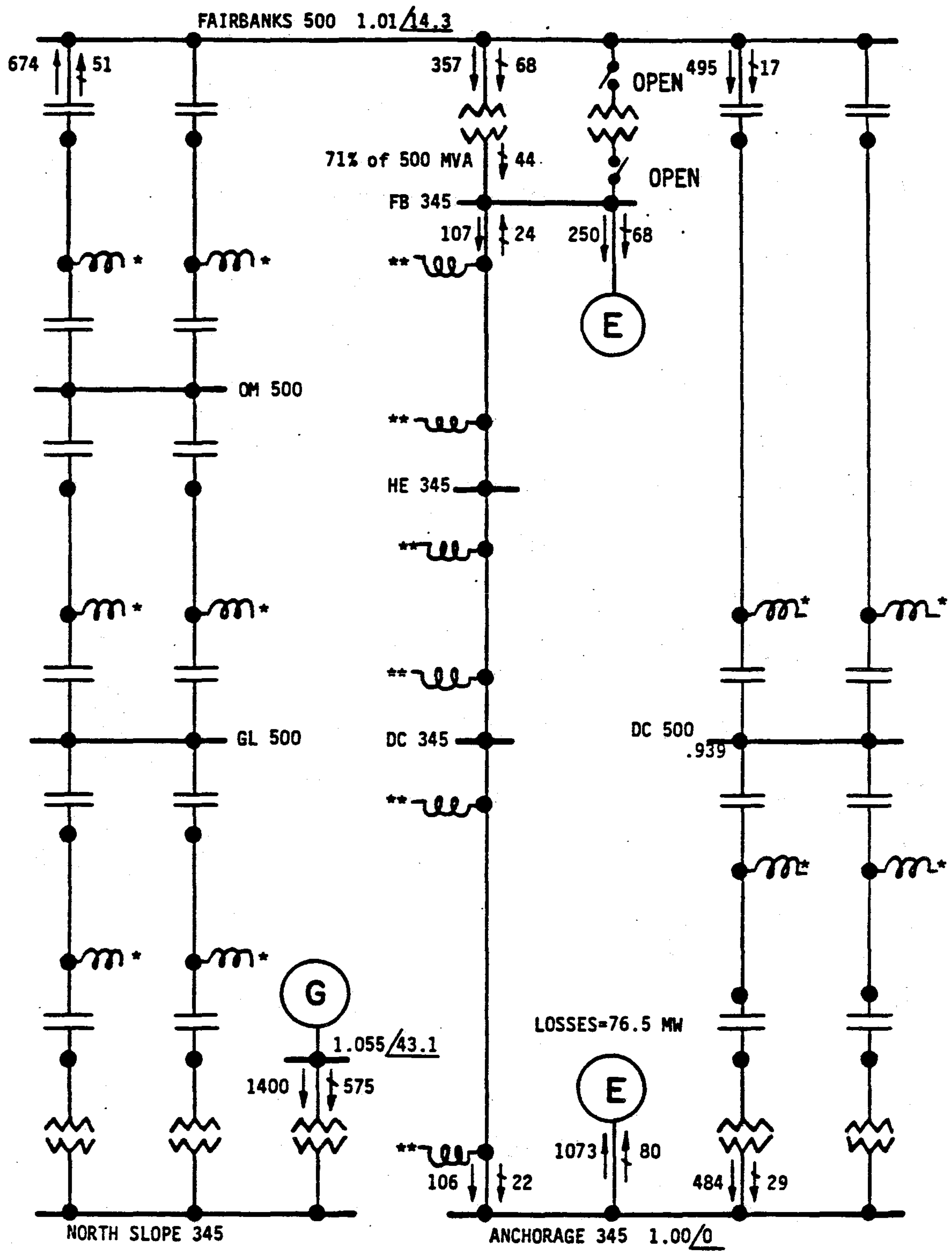
LOAD FLOW

1400 MW generation at Prudhoe Bay.
One 500 kV line segment of service north of Anchorage.

FIGURE D-15

EBASCO SERVICES INCORPORATED

CASE AA14



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

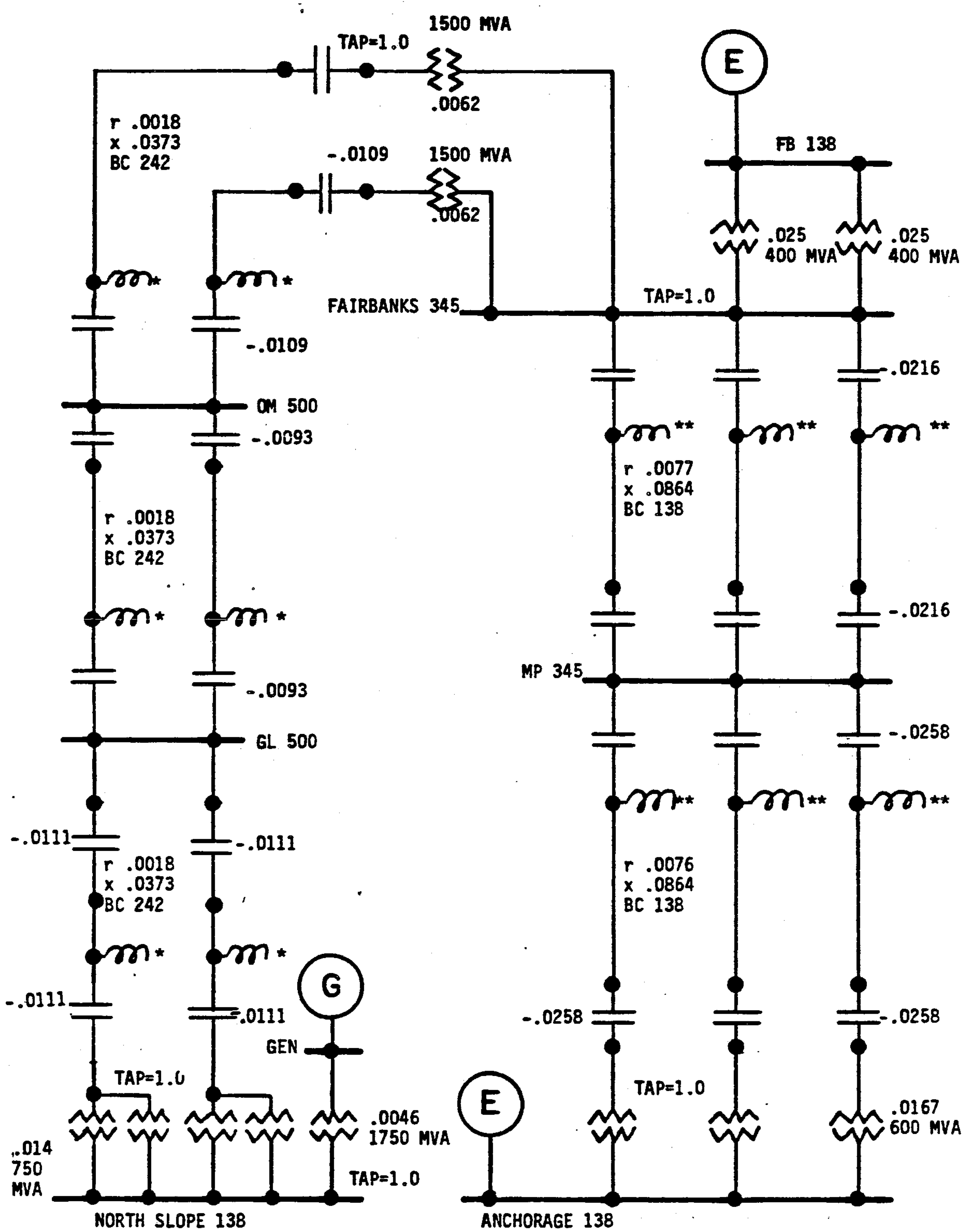
LOAD FLOW

1400 MW generation at Prudhoe Bay. One of the 500-345 kV transformers out of service at Fairbanks.

FIGURE D-16

EBASCO SERVICES INCORPORATED

ALTERNATIVE B



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

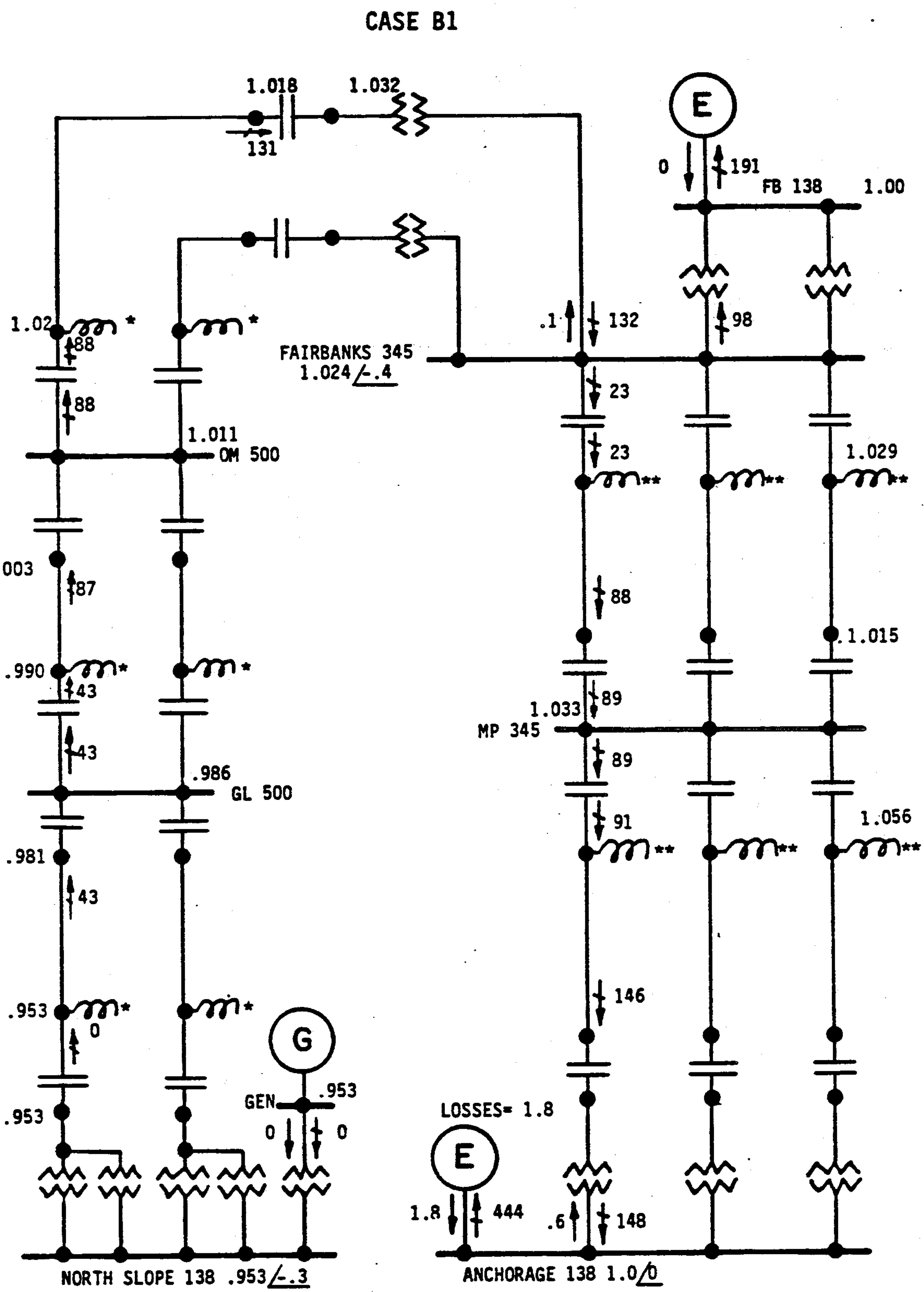
NORTH SLOPE GAS FEASIBILITY STUDY

ONE LINE SCHEMATIC WITH IMPEDANCES

1400 MW capacity at Prudhoe Bay; two 500 kV transmission line circuits between Prudhoe Bay and Fairbanks and three 345 kV transmission line circuits between Fairbanks and Anchorage.

FIGURE D-17

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

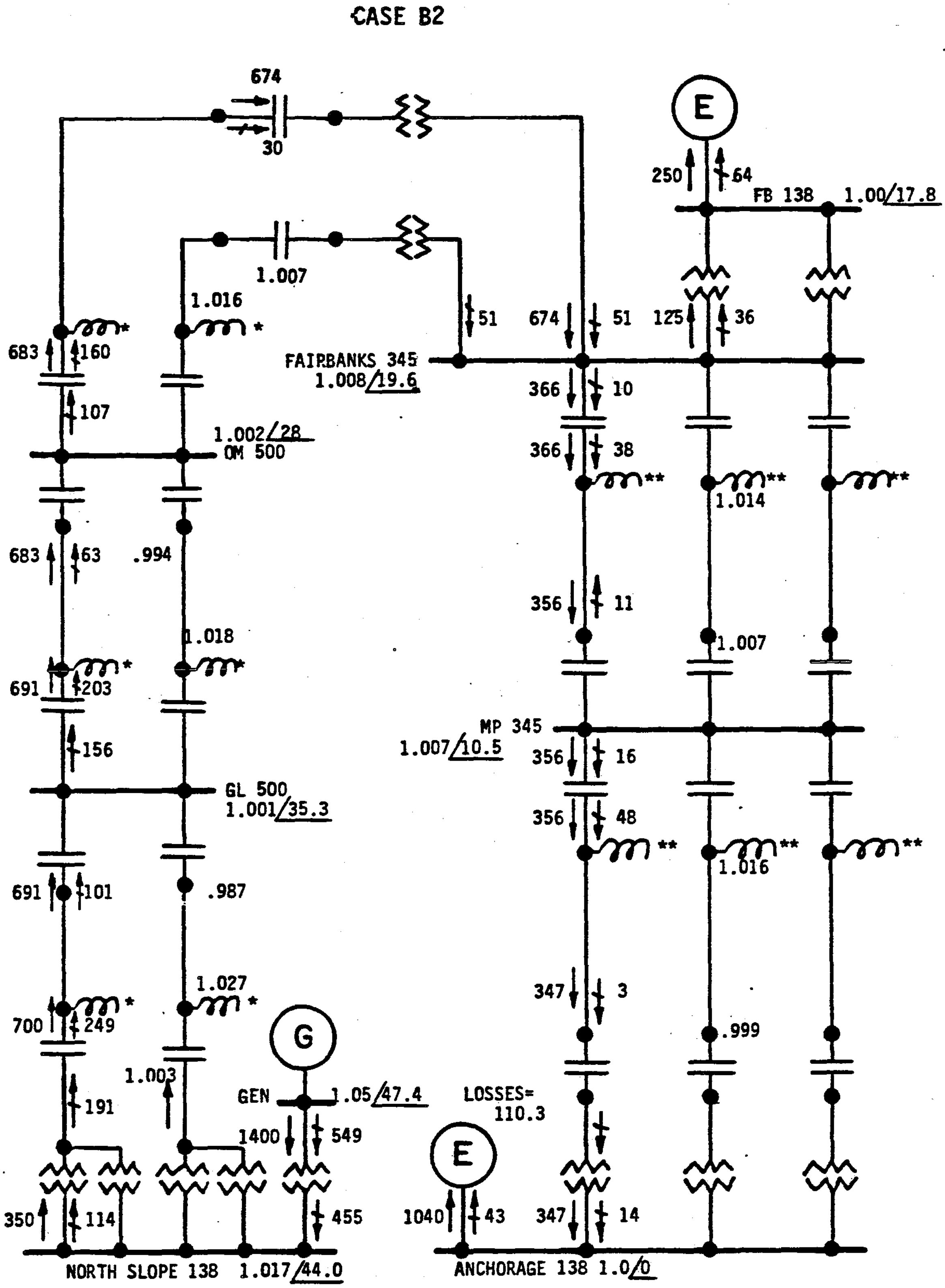
No generation at Prudhoe Bay. Normal system configuration.

FIGURE D-18

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensatio"
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

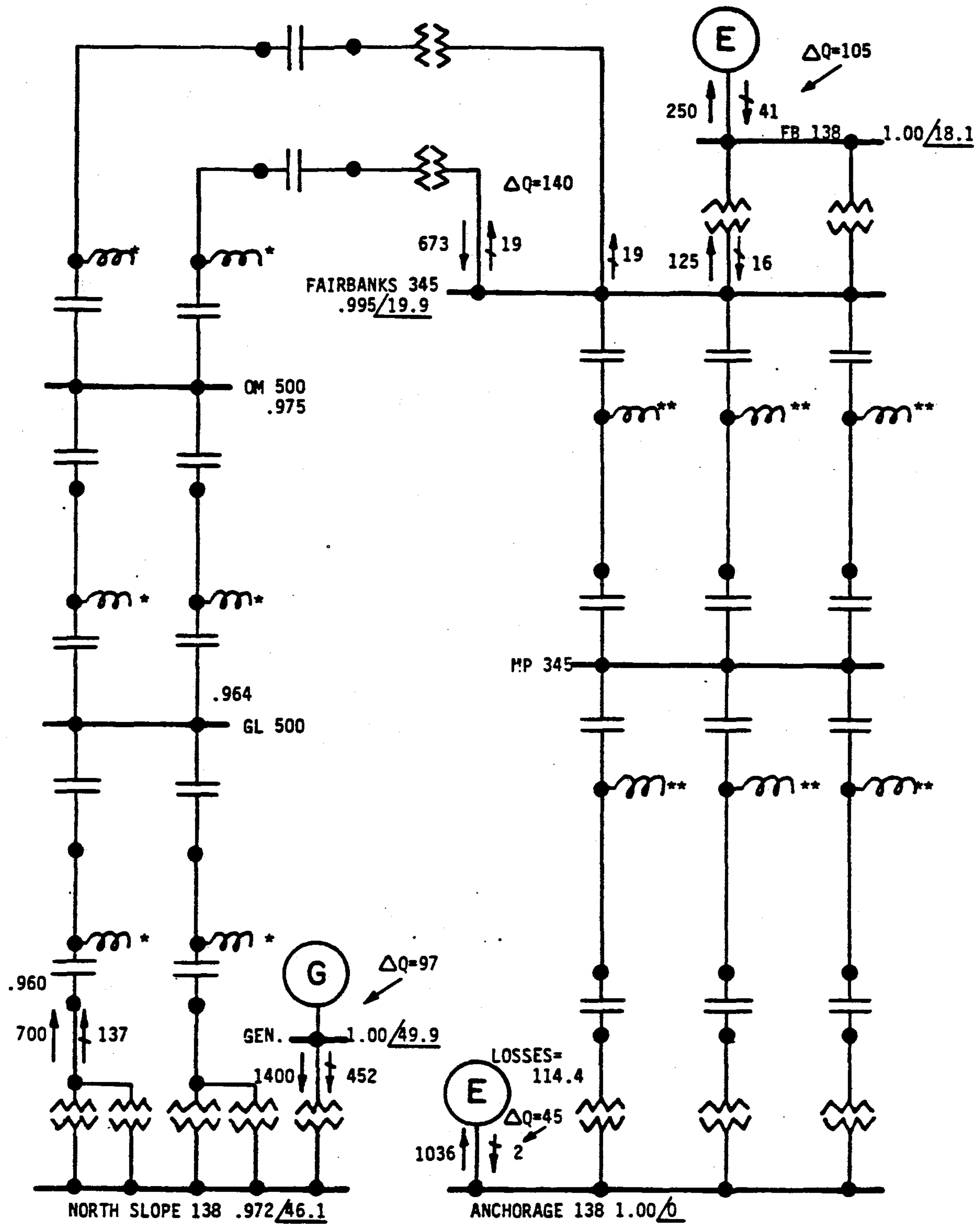
LOAD FLOW

1400 MW generation at Prudhoe Bay. Normal system configuration. Generator bus voltage 1.05 p.u.

FIGURE D-19

EBASCO SERVICES INCORPORATED

CASE B3



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay. Normal system configuration. Generator bus voltage 1.00 p.u.

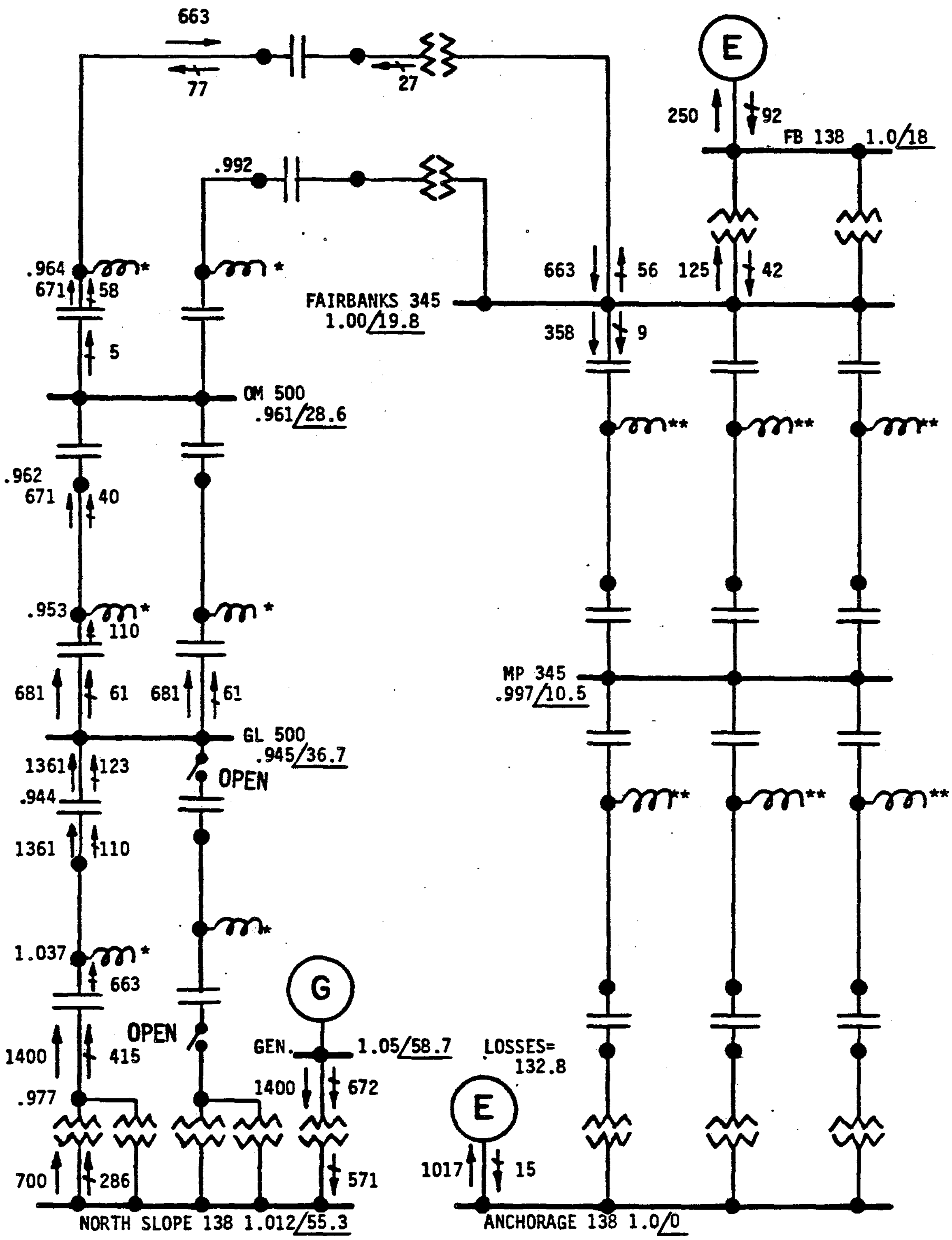
FIGURE D-20

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

CASE B4



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

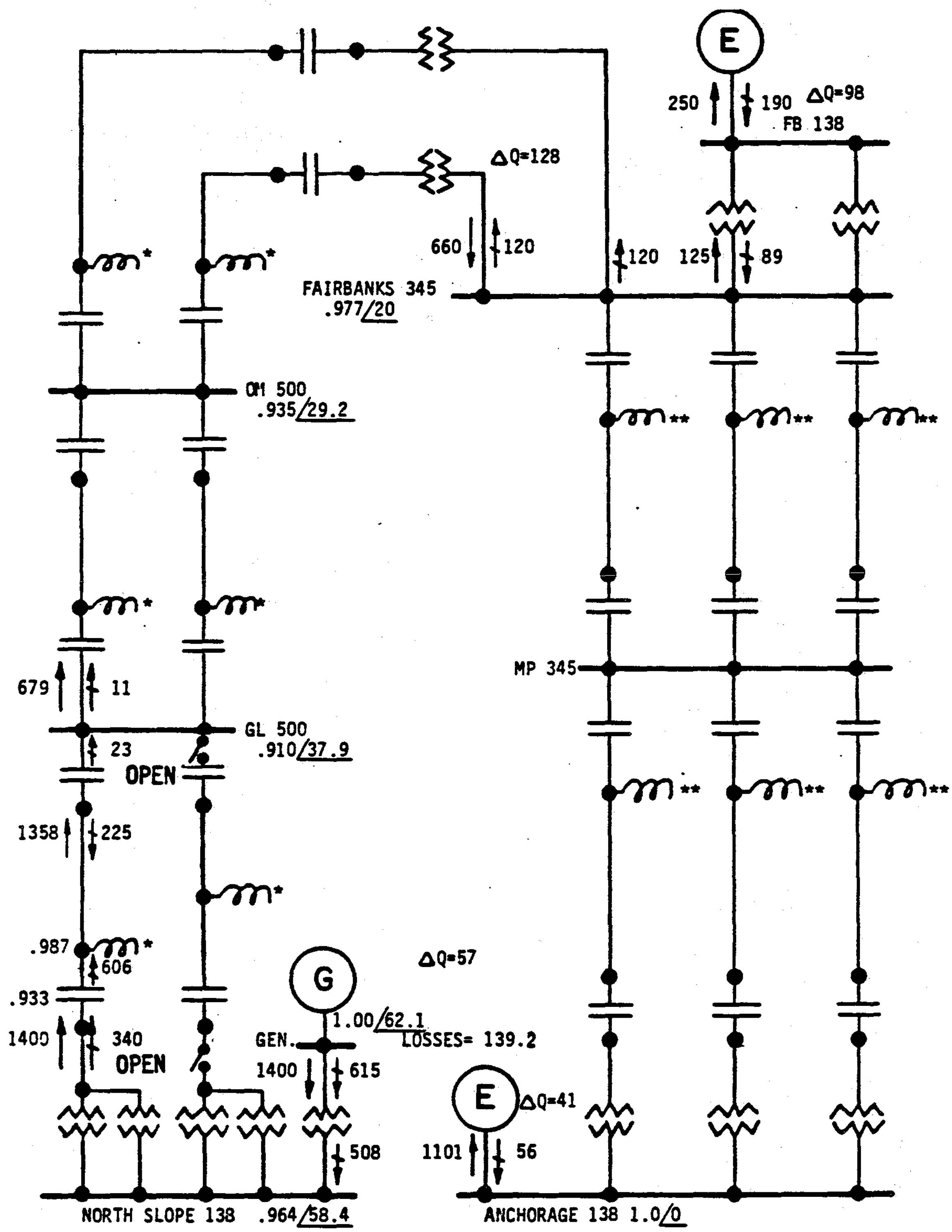
LOAD FLOW

1400 MW generation at Prudhoe Bay. One line segment out of service south of Prudhoe Bay. Generator bus voltage 1.05 p.u.

FIGURE D-21

EBASCO SERVICES INCORPORATED

CASE B5



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

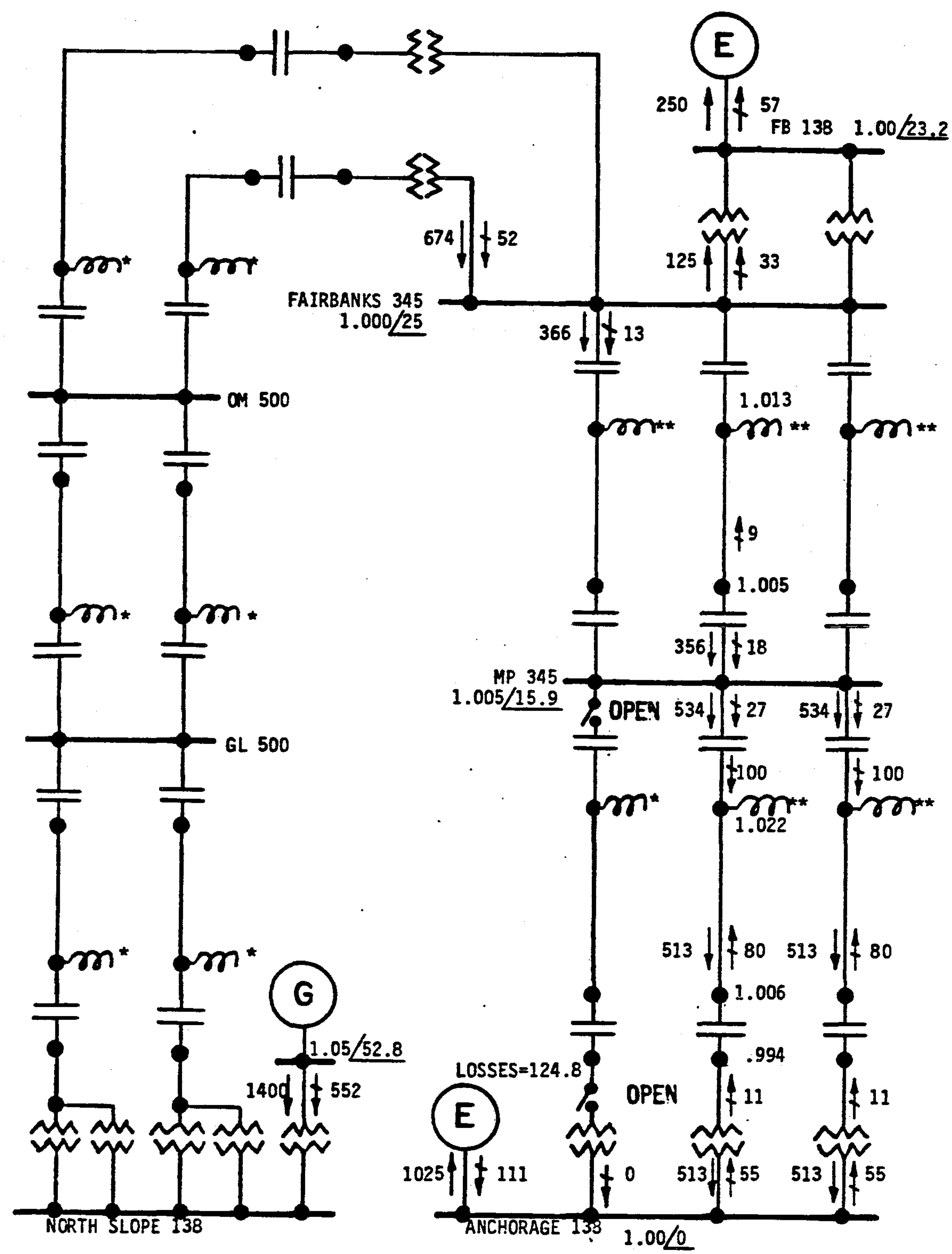
LOAD FLOW

1400 MW generation at Prudhoe Bay. One line segment out of service south of Prudhoe Bay. Generator bus voltage 1.00 p.u.

FIGURE D-22

EBASCO SERVICES INCORPORATED

CASE B6



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

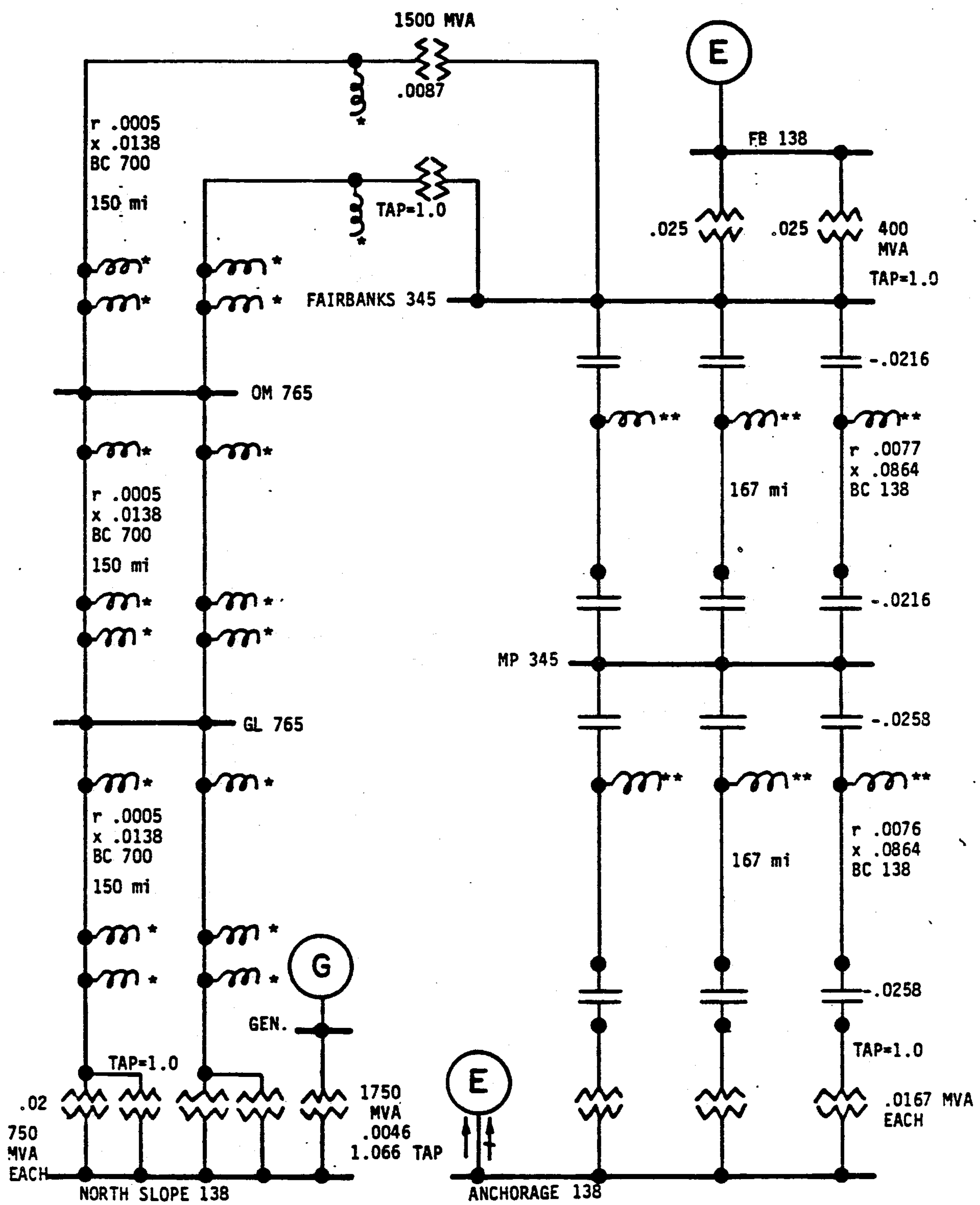
LOAD FLOW

1400 MW generation at Prudhoe Bay.
One line segment out of service
north of Anchorage.

FIGURE D-23

EBASCO SERVICES INCORPORATED

ALTERNATIVE C



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

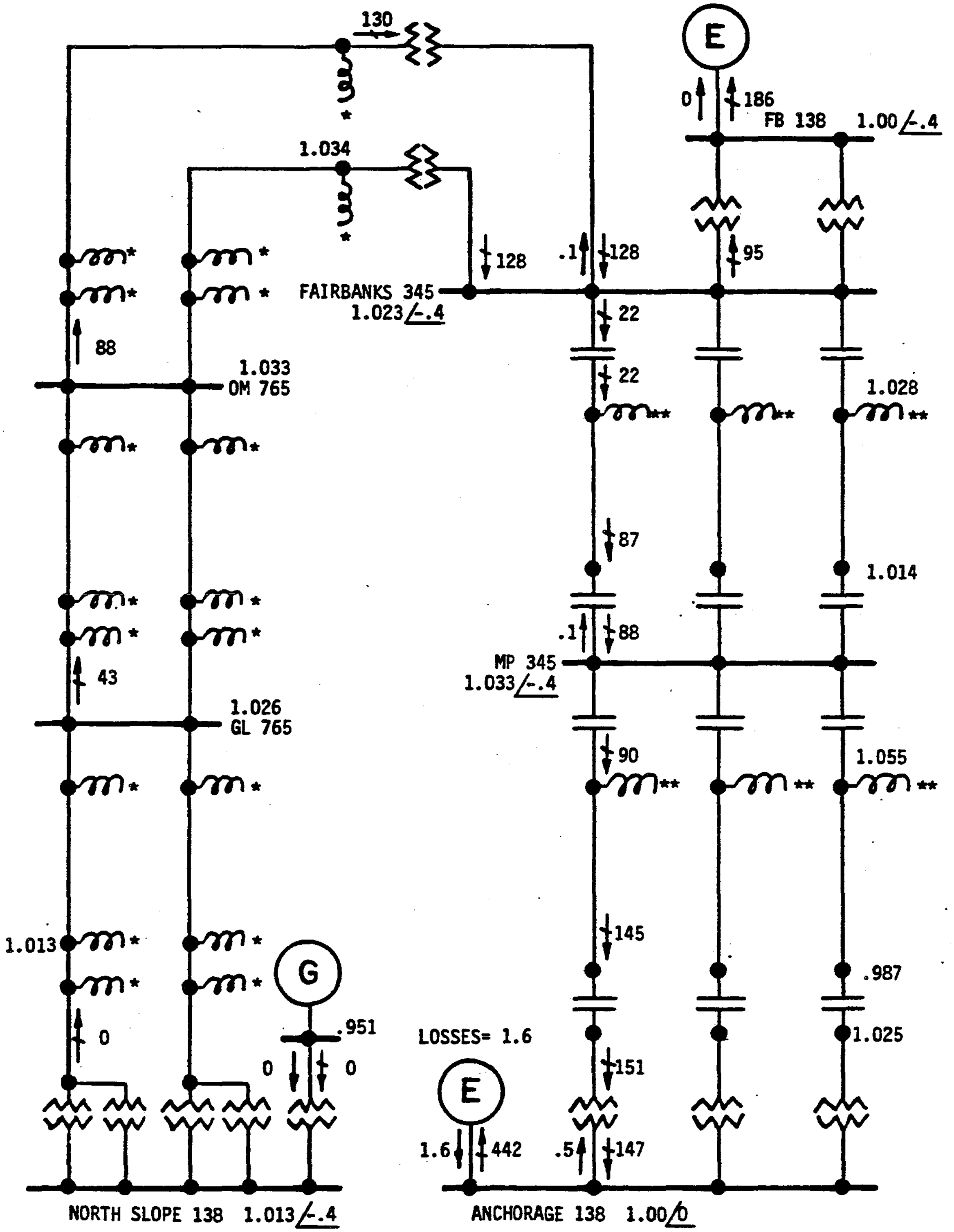
ONE LINE SCHEMATIC WITH IMPEDANCES

1400 MW capacity at Prudhoe Bay; two 765 kV transmission line circuits between Prudhoe Bay and Fairbanks and three 345 kV transmission line circuits between Fairbanks and Anchorage.

FIGURE D-24

EBASCO SERVICES INCORPORATED

CASE C1

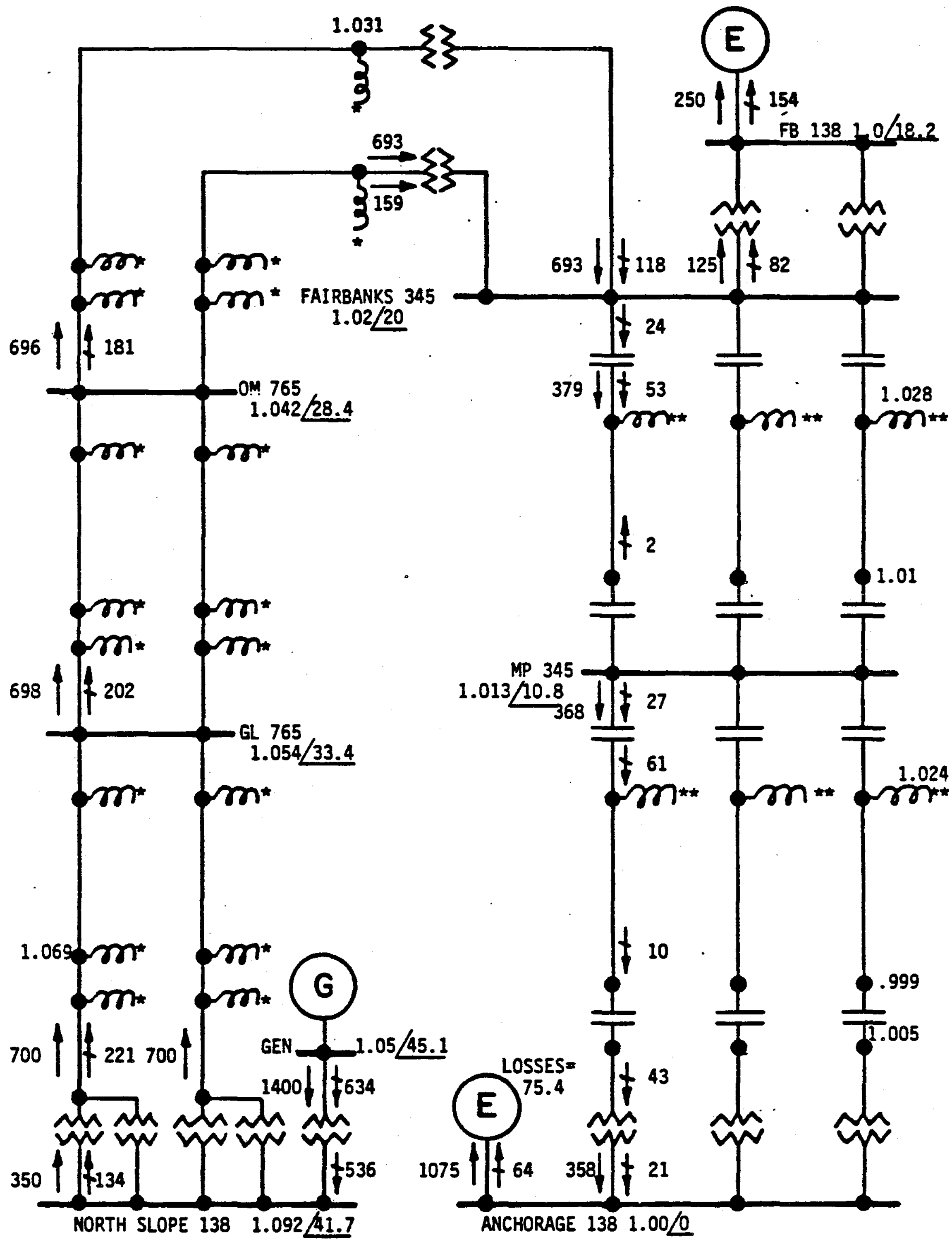


Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
LOAD FLOW No generation at Prudhoe Bay. Normal system configuration.
FIGURE D-25
EBASCO SERVICES INCORPORATED

CASE C2



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

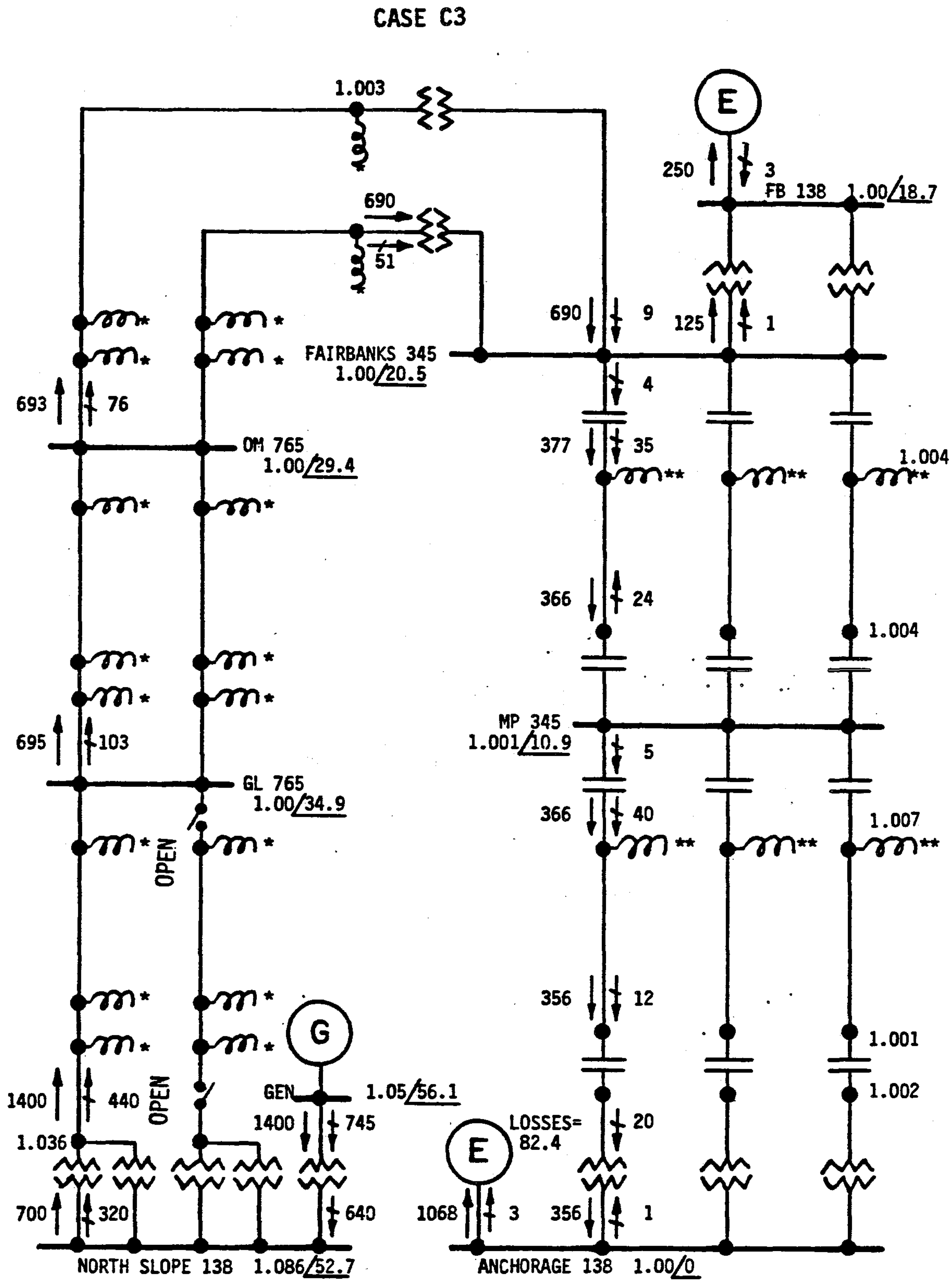
NORTH SLOPE GAS
FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-26

EBASCO SERVICES INCORPORATED



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

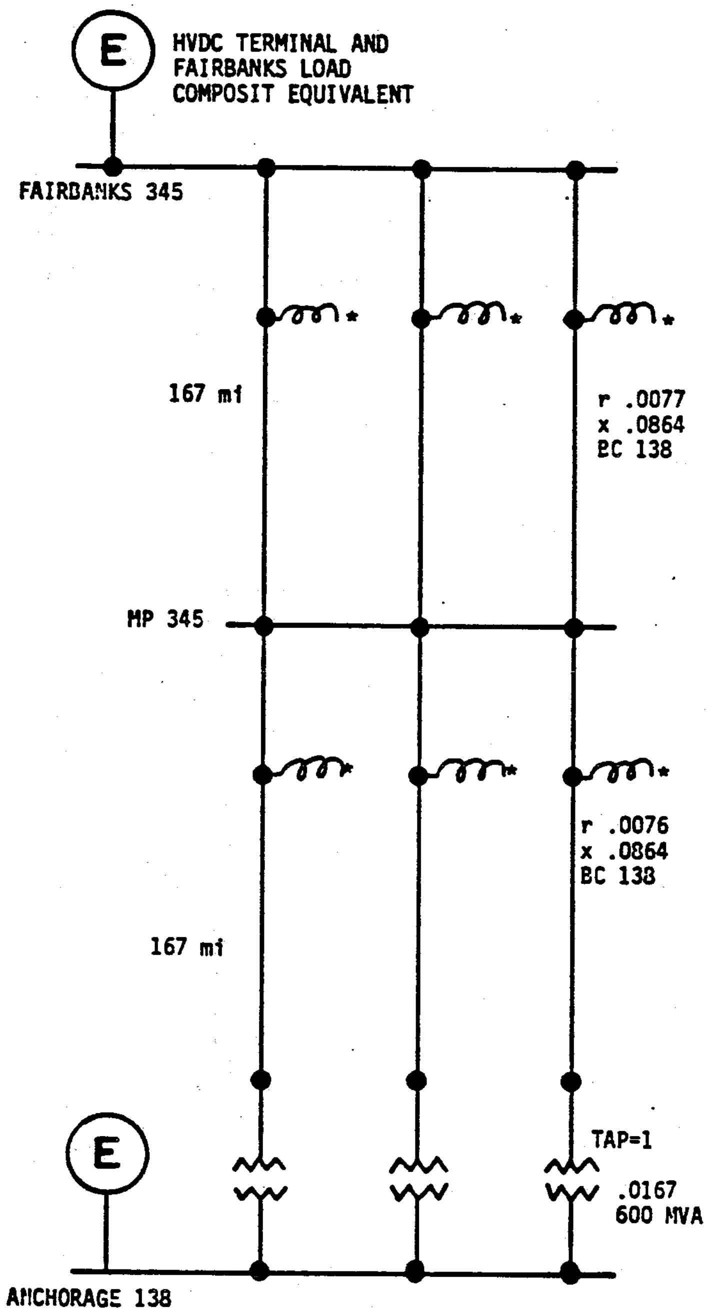
LOAD FLOW

1400 MW generation at Prudhoe Bay. One 765 kV line segment south of Prudhoe Bay out of service.

FIGURE D-27

EBASCO SERVICES INCORPORATED

ALTERNATIVE D



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

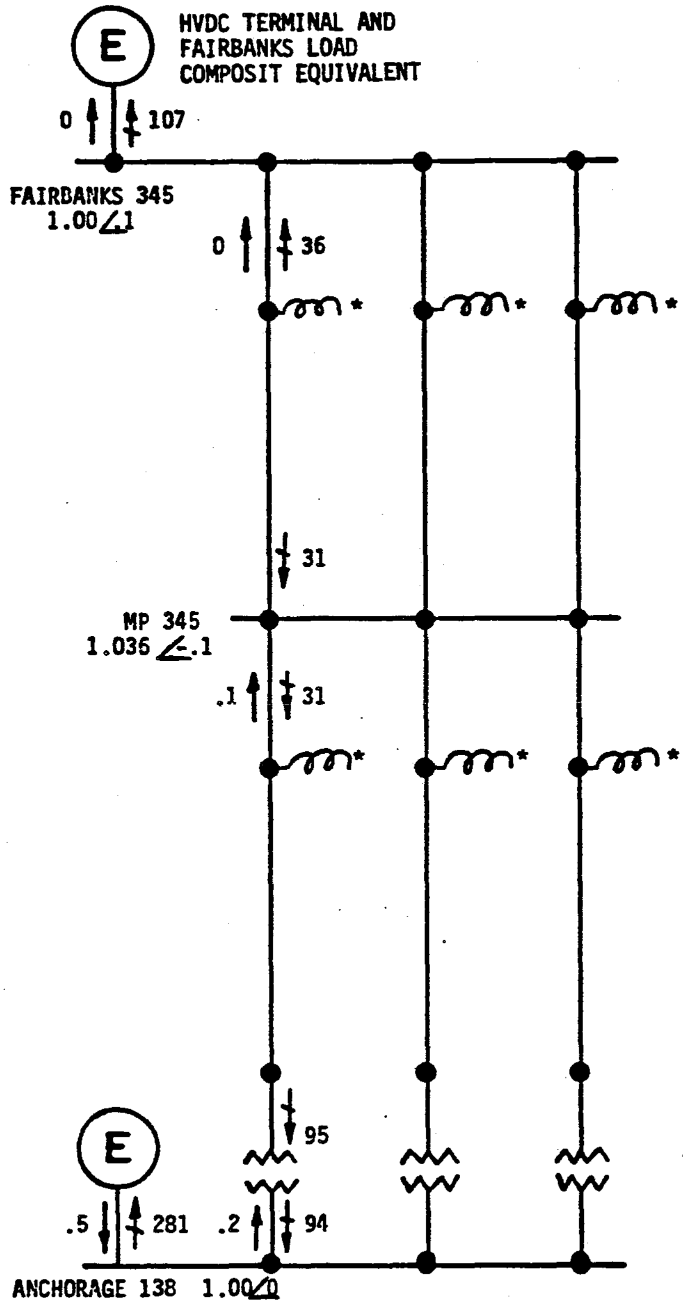
ONE LINE SCHEMATICS WITH IMPEDANCES

1400 MW generation at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks and three 345 kV transmission line circuits between Fairbanks and Anchorage.

FIGURE D-28

EBASCO SERVICES INCORPORATED

CASE D1



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

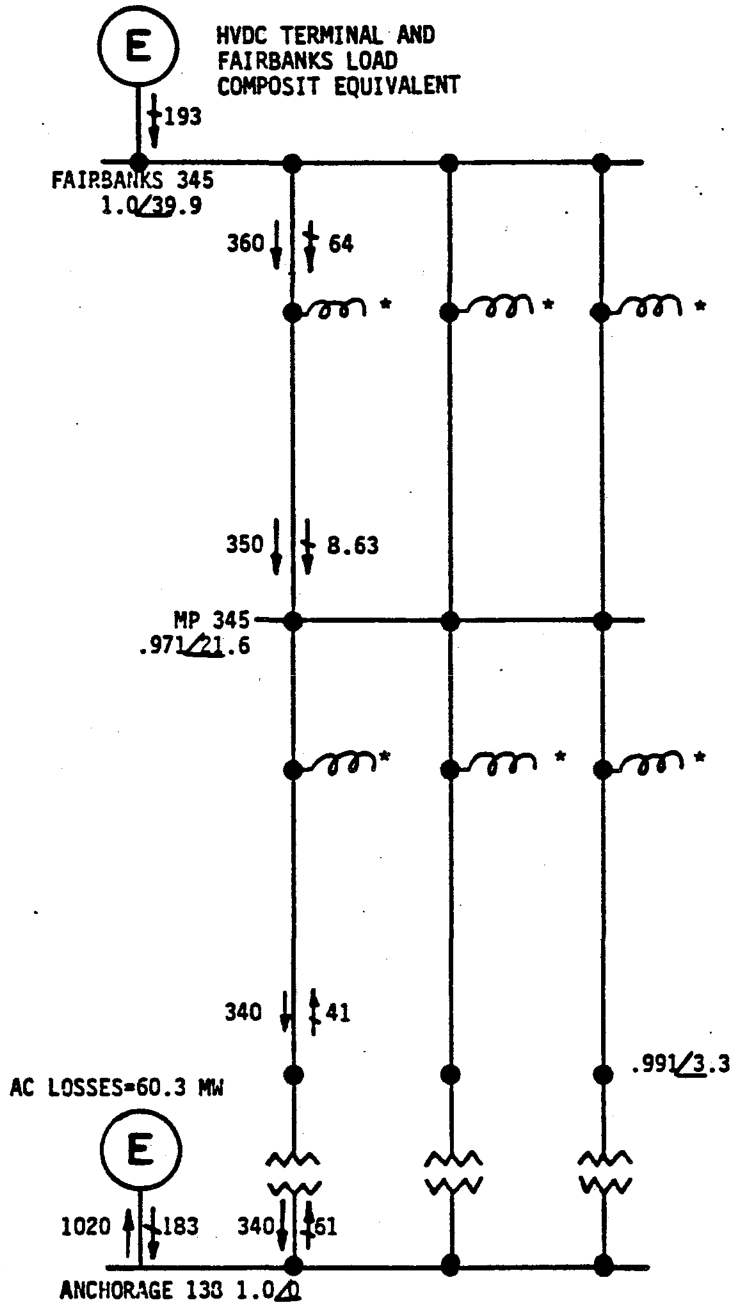
No power transfer between Fairbanks and Anchorage. Normal system configuration.

FIGURE D-29

EBASCO SERVICES INCORPORATED

CASE D2

GENERATION 1400 MW
HVDC LOSSES 70 MW
FAIRBANKS 250 MW
TO ANCHORAGE 1080 MW



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

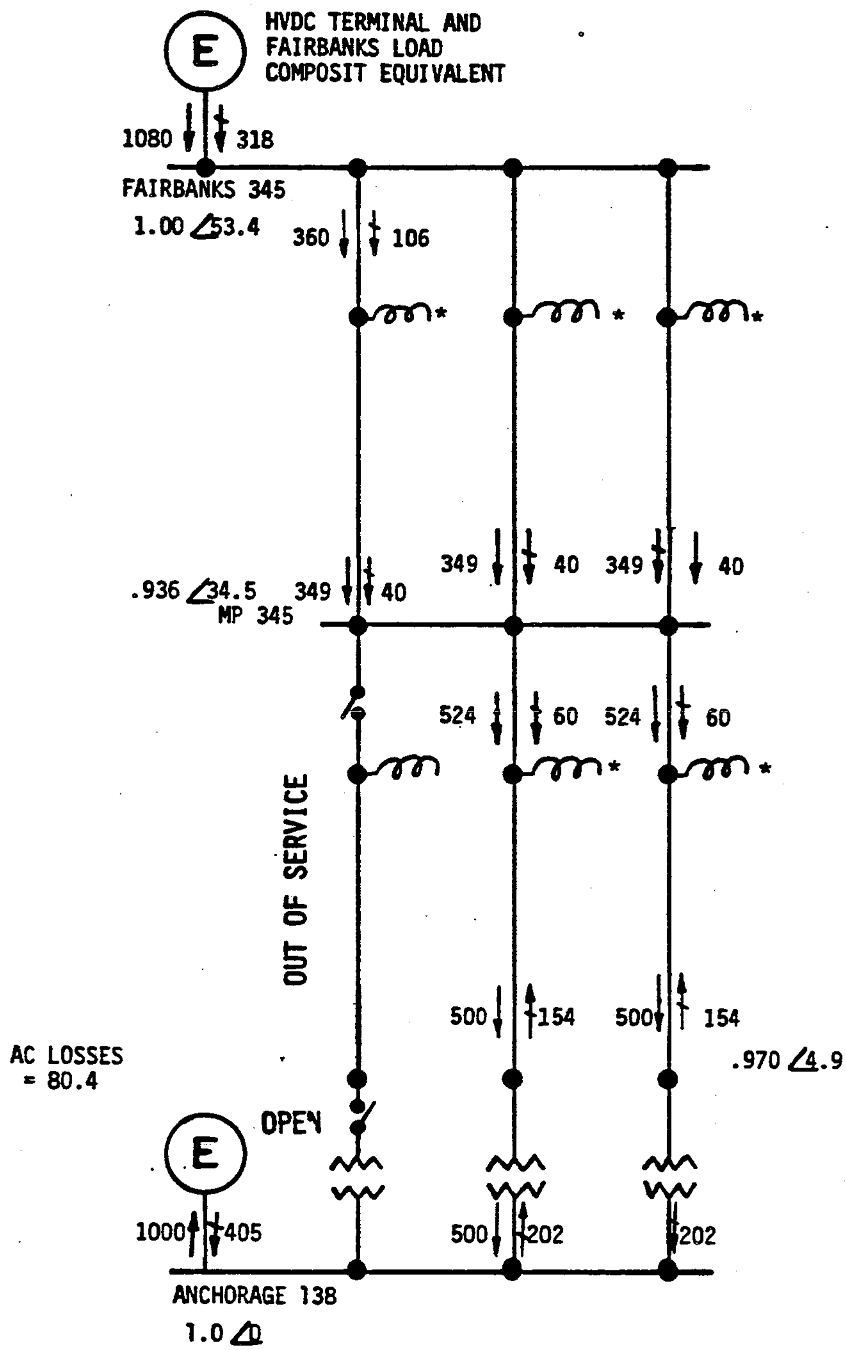
1400 MW capacity at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks. Normal system configuration.

FIGURE D-3C

EBASCO SERVICES INCORPORATED

CASE D3

GENERATION 1400 MW
HVDC LOSSES 70 MW
FAIRBANKS 250 MW
TO ANCHORAGE 1080 MW



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

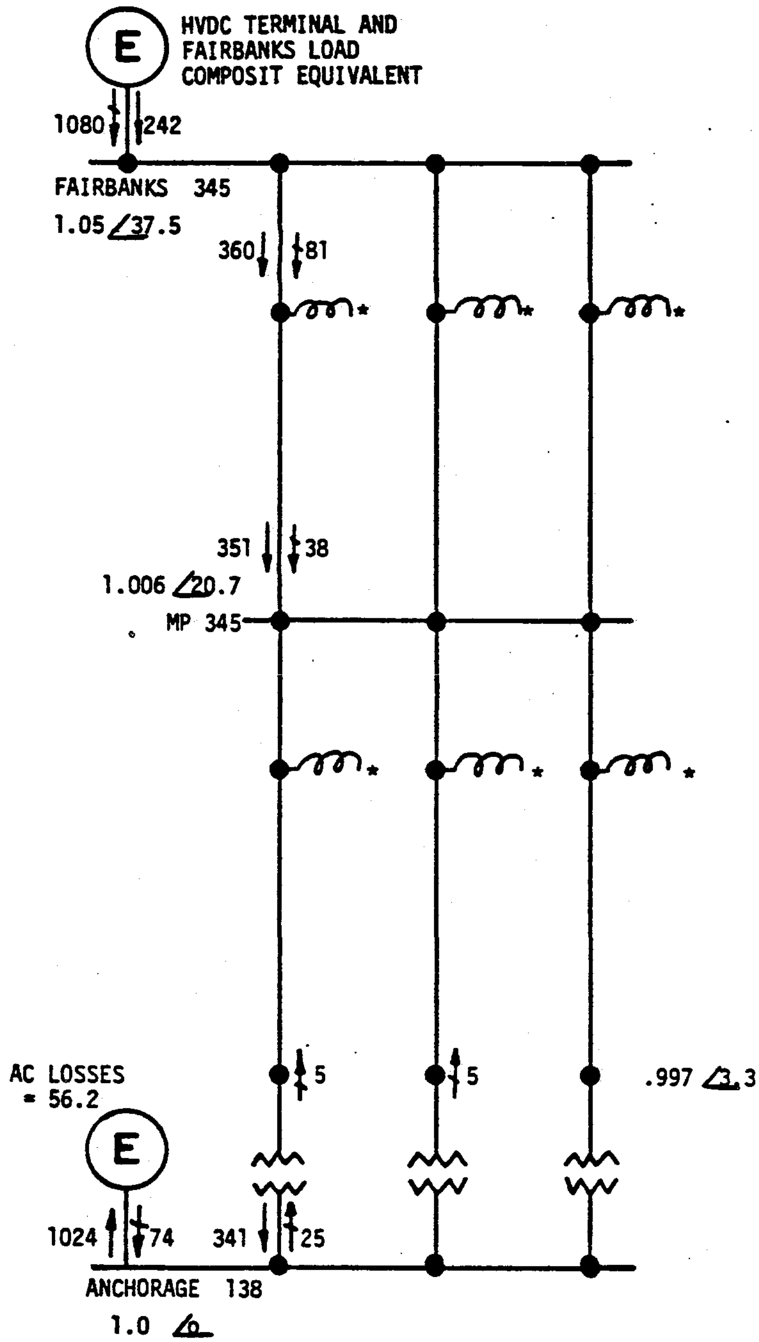
1400 MW generation at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks and one 345 kV line segment out of service north of Anchorage.

FIGURE D-31

EBASCO SERVICES INCORPORATED

ENERATION 1400 MW
IVDC LOSSES 70 MW
AIRBANKS 250 MW
O ANCHORAGE 1080 MW

CASE D4



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

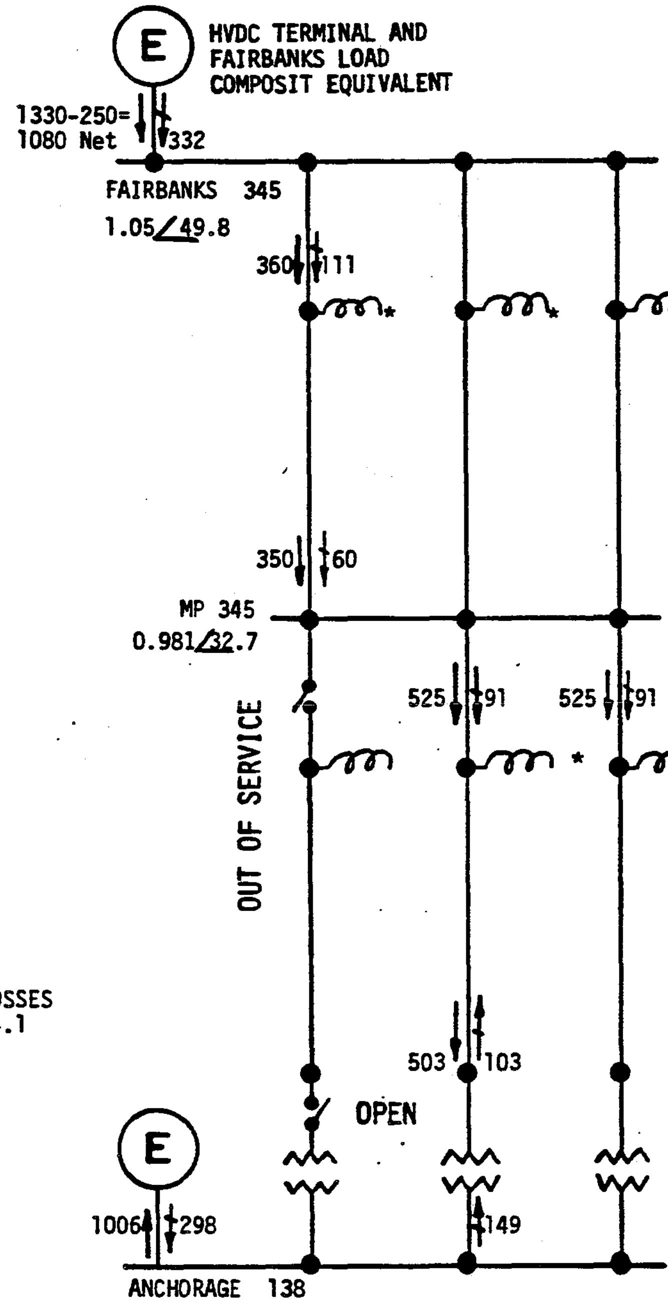
1400 MW generation at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks. Normal system configuration; voltage raised by 5% at Fairbanks.

FIGURE D-32

EBASCO SERVICES INCORPORATED

GENERATION 1400 MW
HVDC LOSSES 70 MW
FAIRBANKS 250 MW
TO ANCHORAGE 1080 MW

CASE D5



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

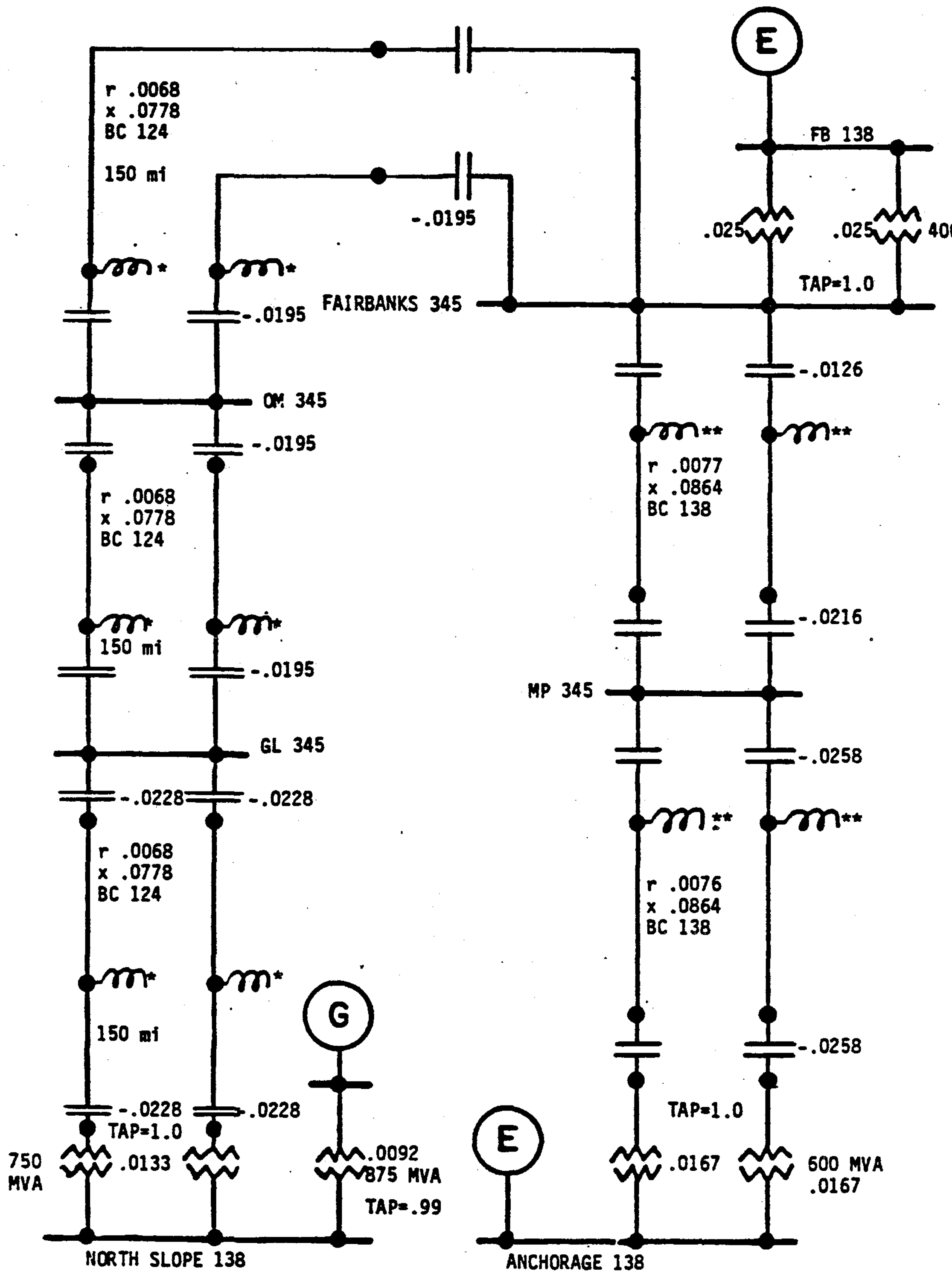
LOAD FLOW

1400 MW generation at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks. One 345 kV line segment out of service north of Anchorage; voltage raised by 5% at Fairbanks.

FIGURE D-33

EBASCO SERVICES INCORPORATED

ALTERNATIVE E



Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

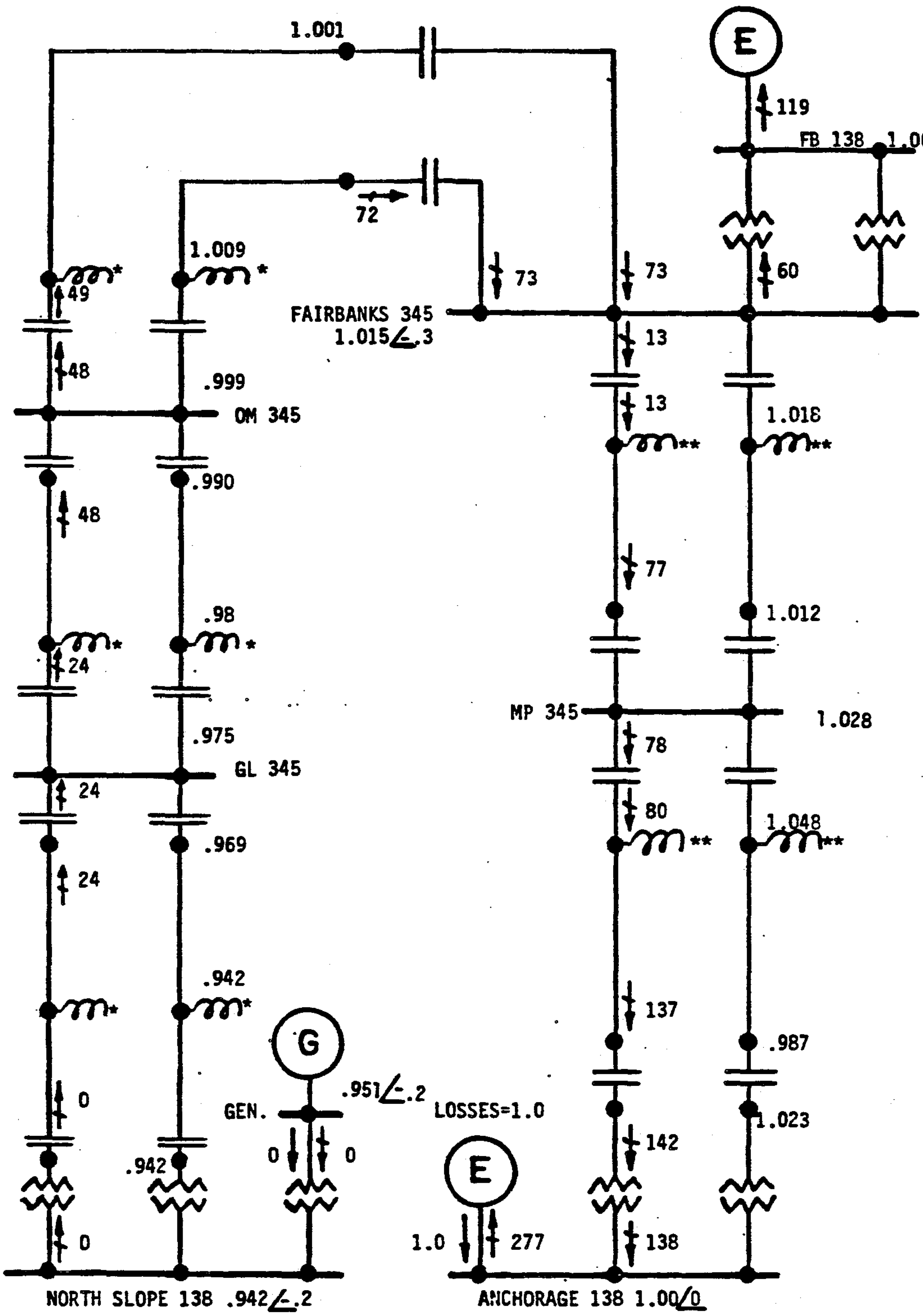
ONE LINE SCHEMATIC WITH IMPEDANCES

700 MW capacity at Prudhoe Bay; 345 kV transmission system with series compensation

FIGURE D-34

EBASCO SERVICES INCORPORATED

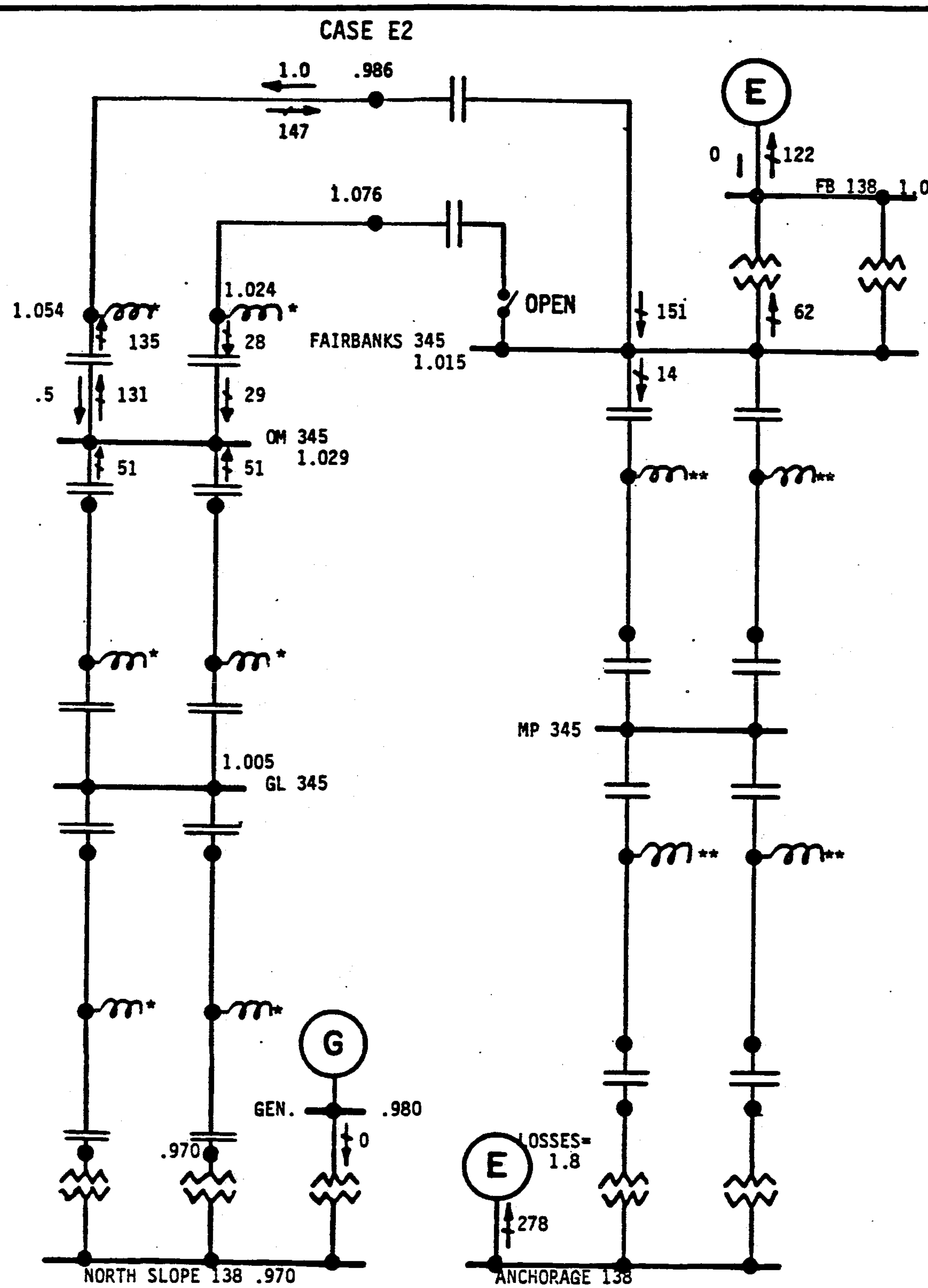
CASE E1



Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
LOAD FLOW No generation at Prudhoe Bay. Normal system configuration.
FIGURE D-35
EBASCO SERVICES INCORPORATED



Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

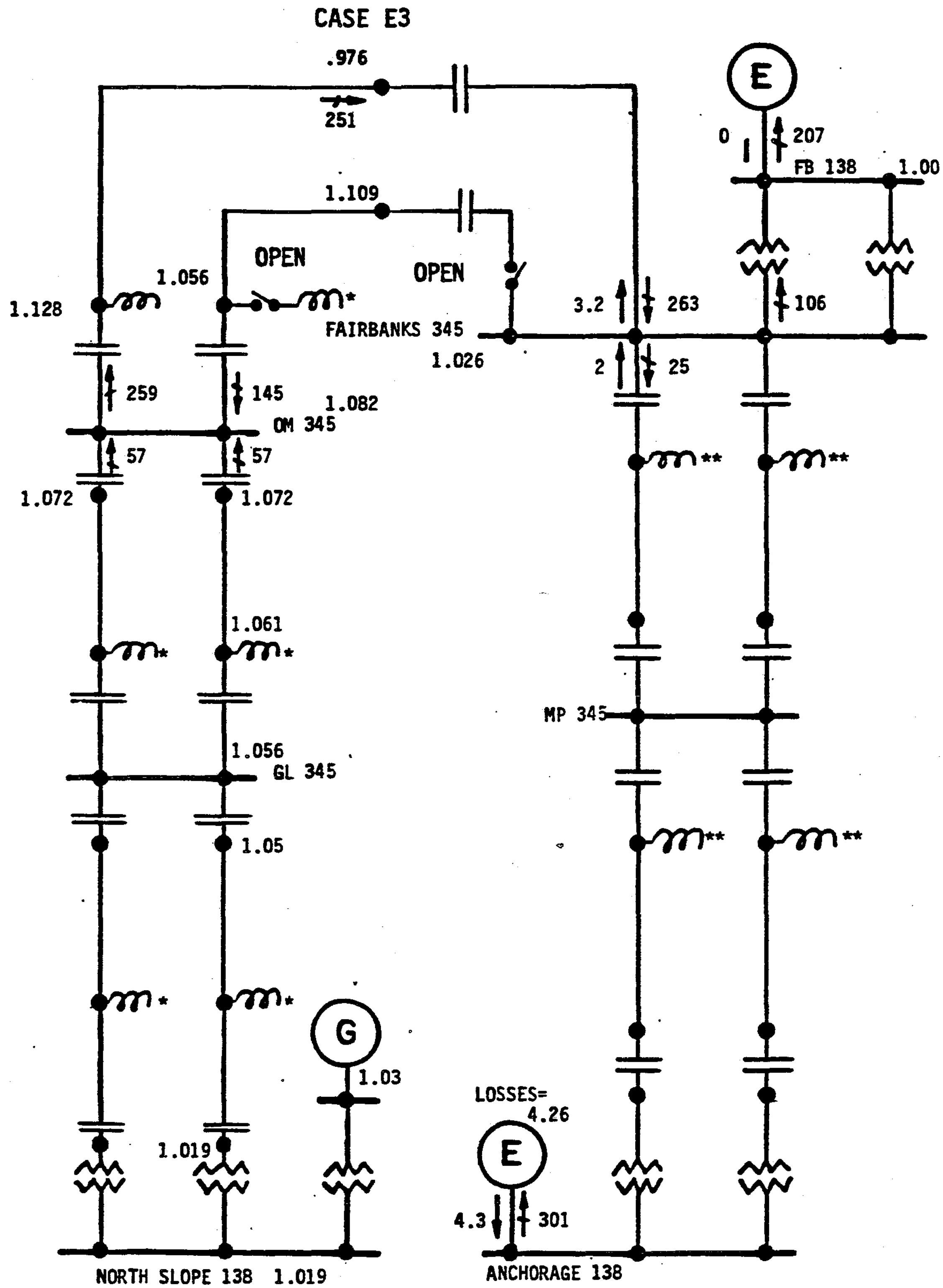
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. One line segment opened north of Fairbanks.

FIGURE D-36

EBASCO SERVICES INCORPORATED



Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

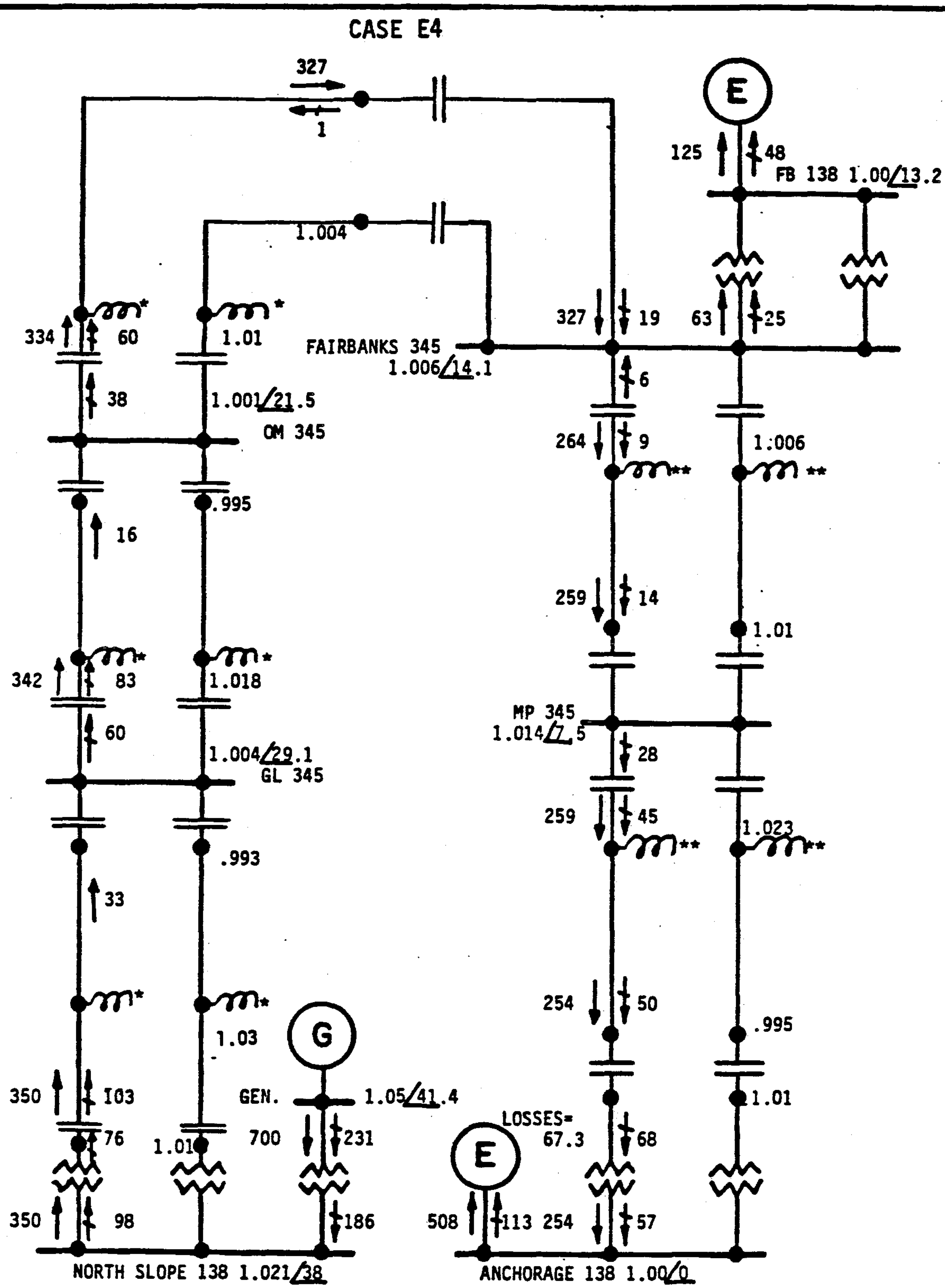
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. one line segment opened north or Fairbanks with the loss of an additional reactor.

FIGURE D-37

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

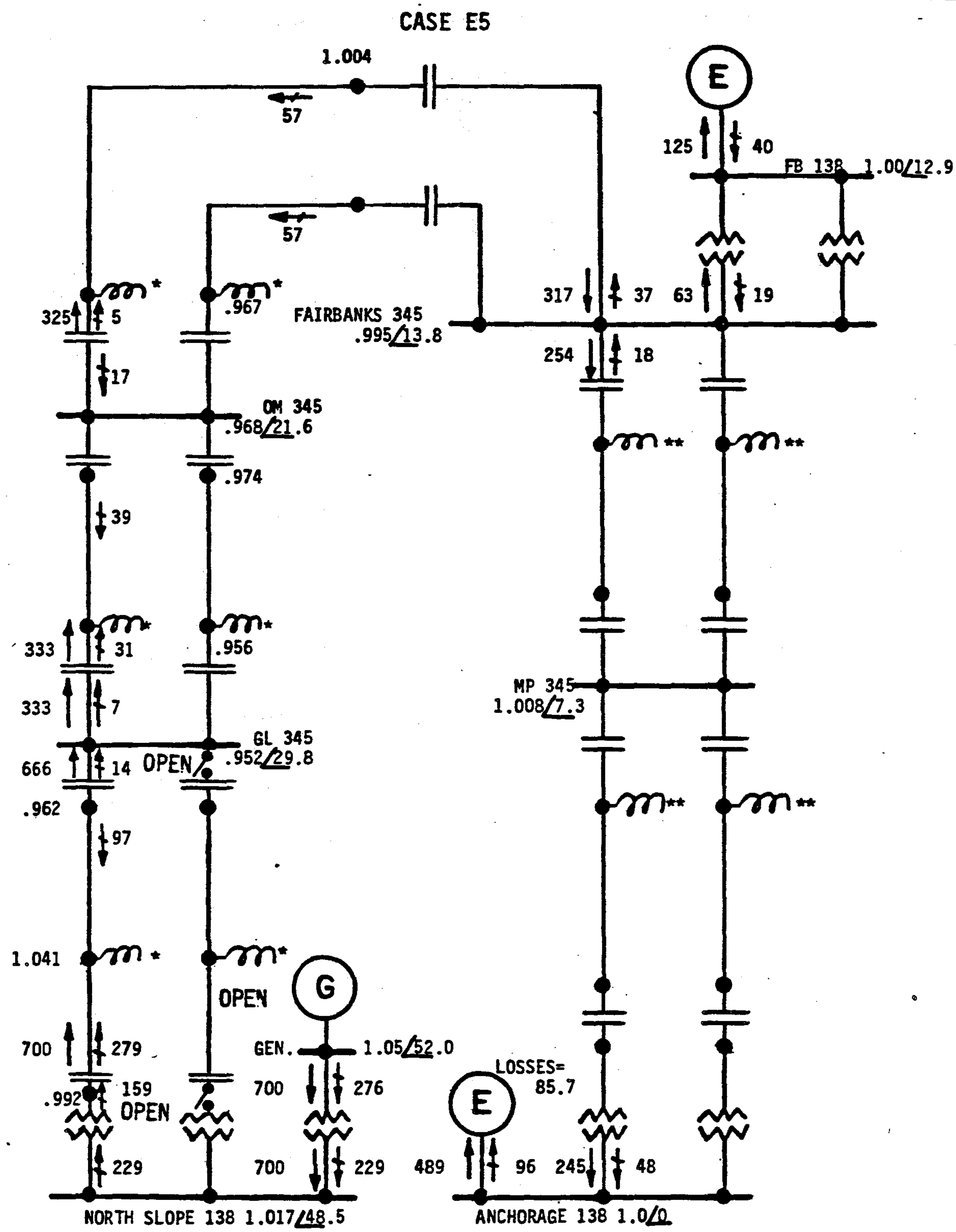
LOAD FLOW

700 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-38

Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

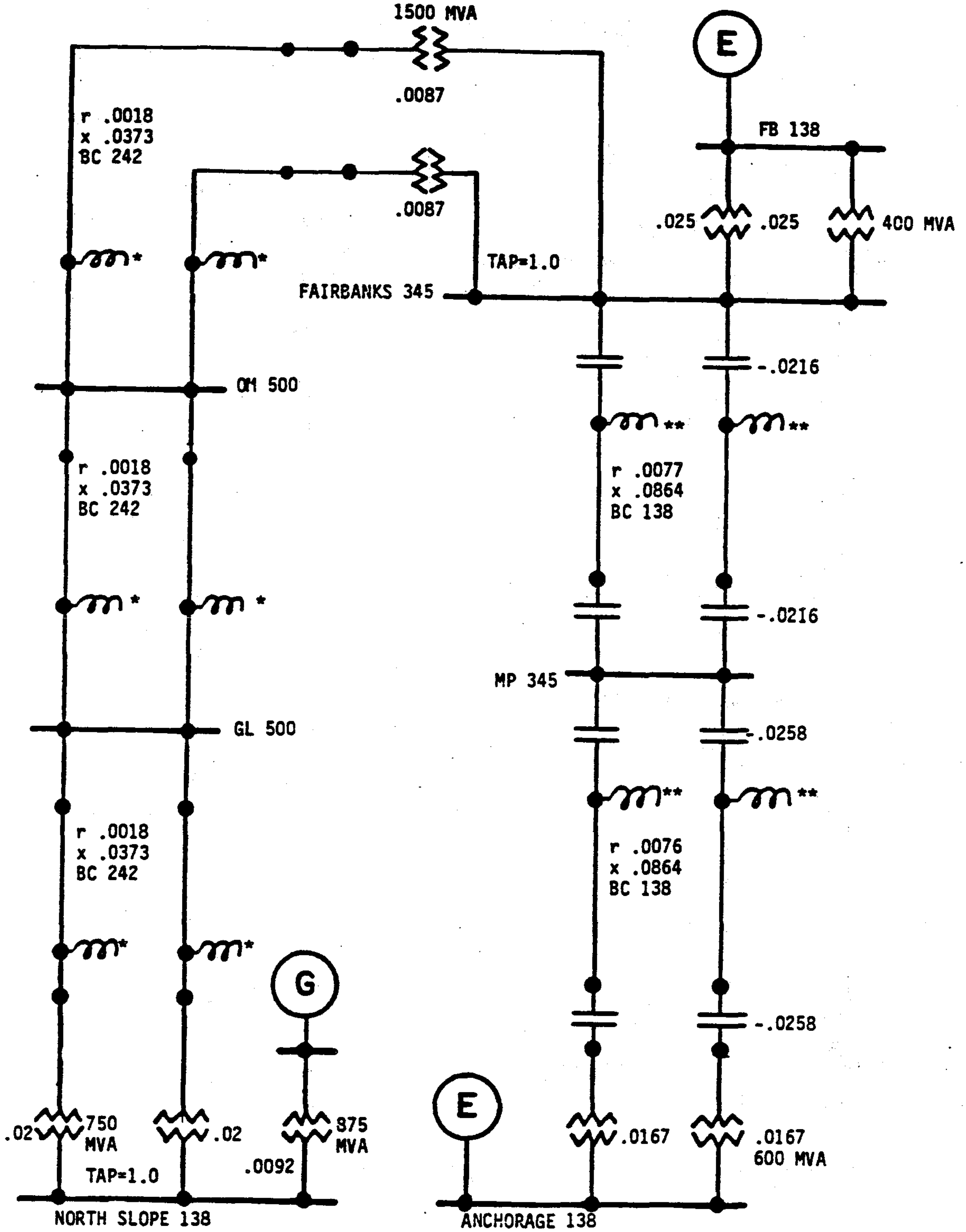


Notes

* 100 MVAR
** 75 MVAR
50% series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY
NORTH SLOPE GAS FEASIBILITY STUDY
LOAD FLOW 700 MW generation at Prudhoe Bay, one line segment out of service south of Prudhoe Bay.
FIGURE D-39
EBASCO SERVICES INCORPORATED

ALTERNATIVE F



Notes

* 200 MVAR
** 75 MVAR
50% series compensation at the 345 kV line only
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

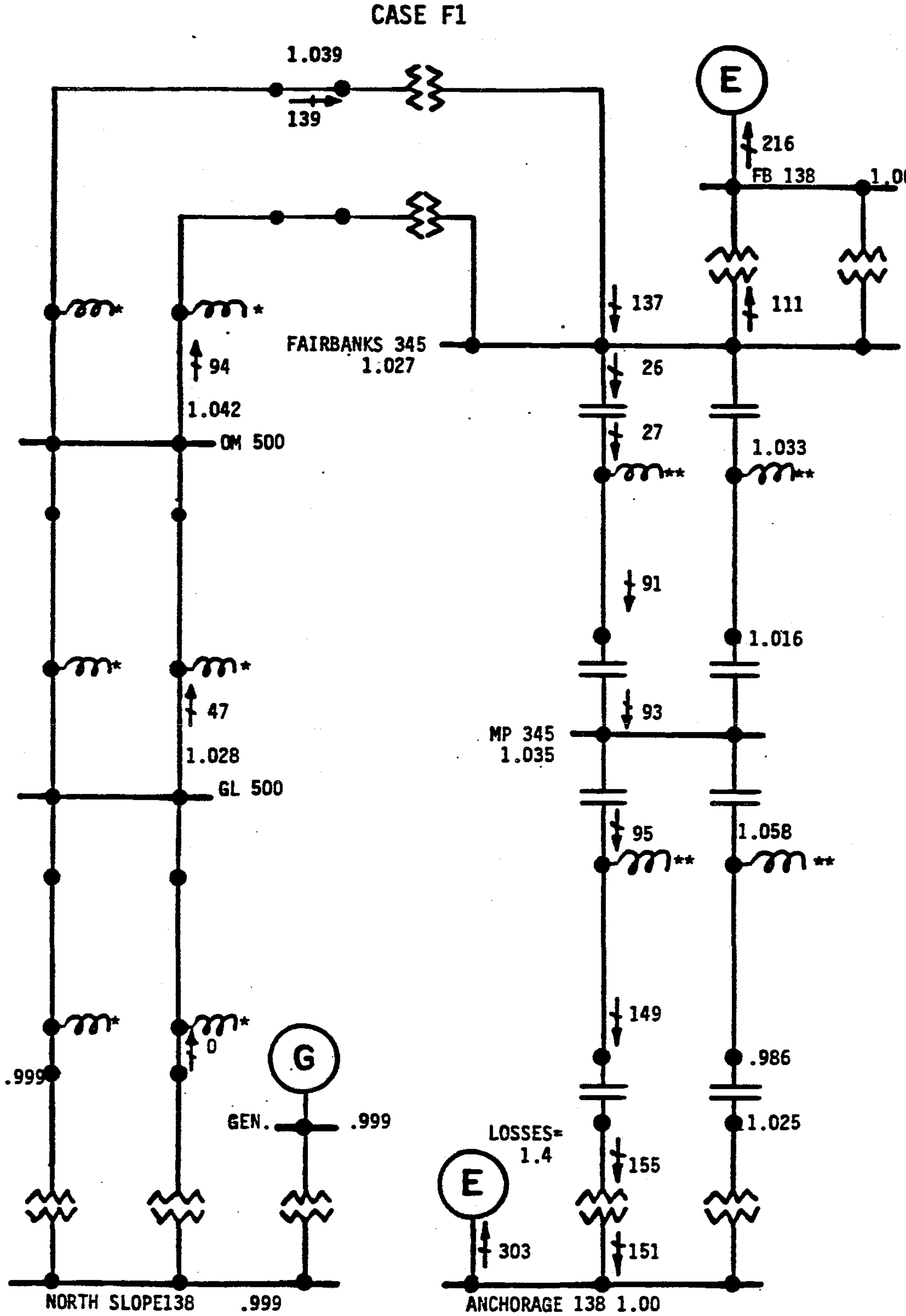
NORTH SLOPE GAS FEASIBILITY STUDY

ONE LINE SCHEMATIC WITH IMPEDANCES

700 MW capacity at Prudhoe Bay; 500 kV transmission between Prudhoe Bay and Fairbanks and 345 kV transmission with series compensation between Fairbanks and Anchorage.

FIGURE D-40

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

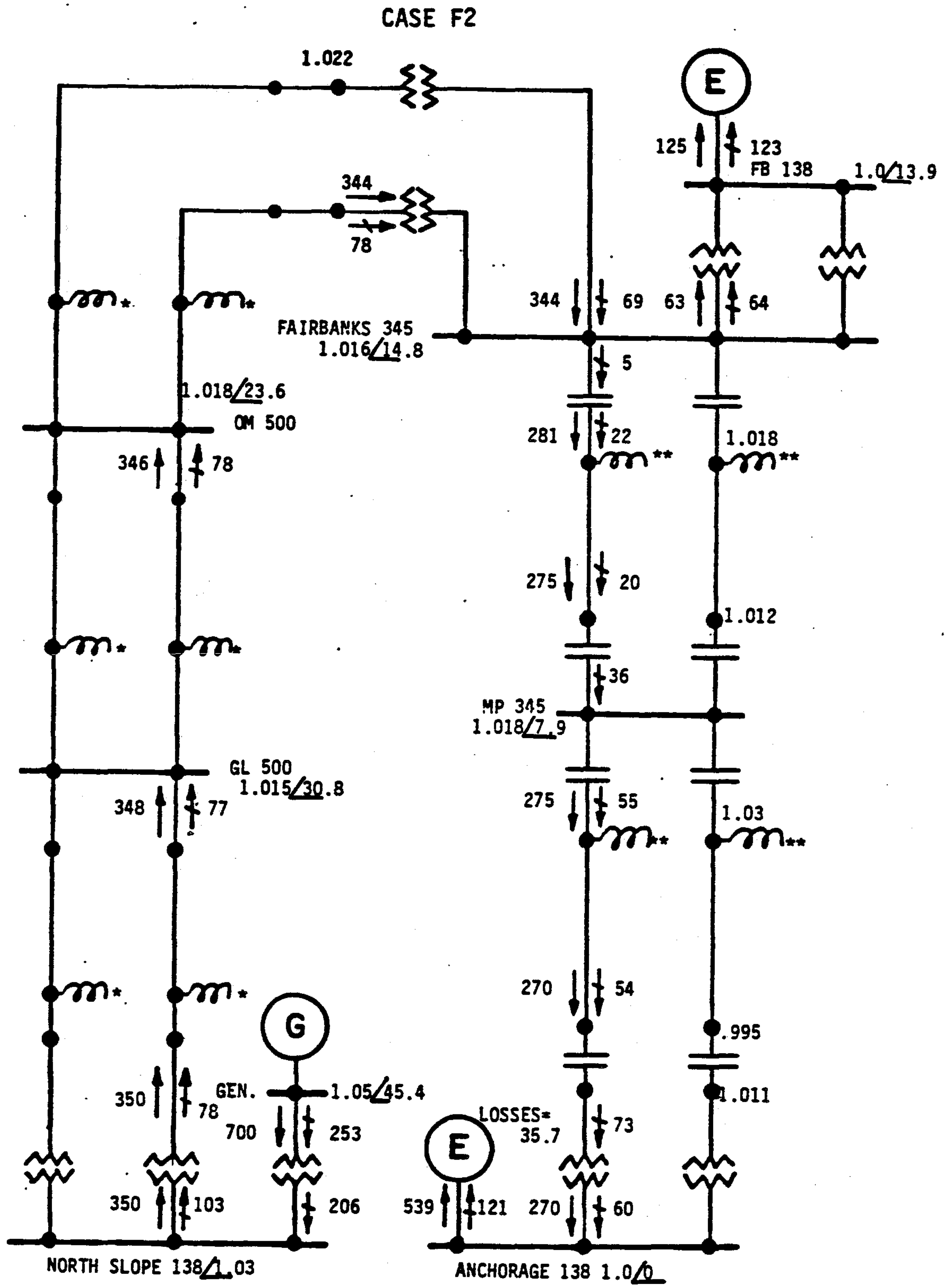
No generation at Prudhoe Bay, normal system configuration.

FIGURE D-41

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 75 MVAR
50% series compensation at the 345 kV line only
For letter symbols, see Table D-8



Notes

* 200 MVAR
** 75 MVAR
50% series compensation at the 345 kV line only
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

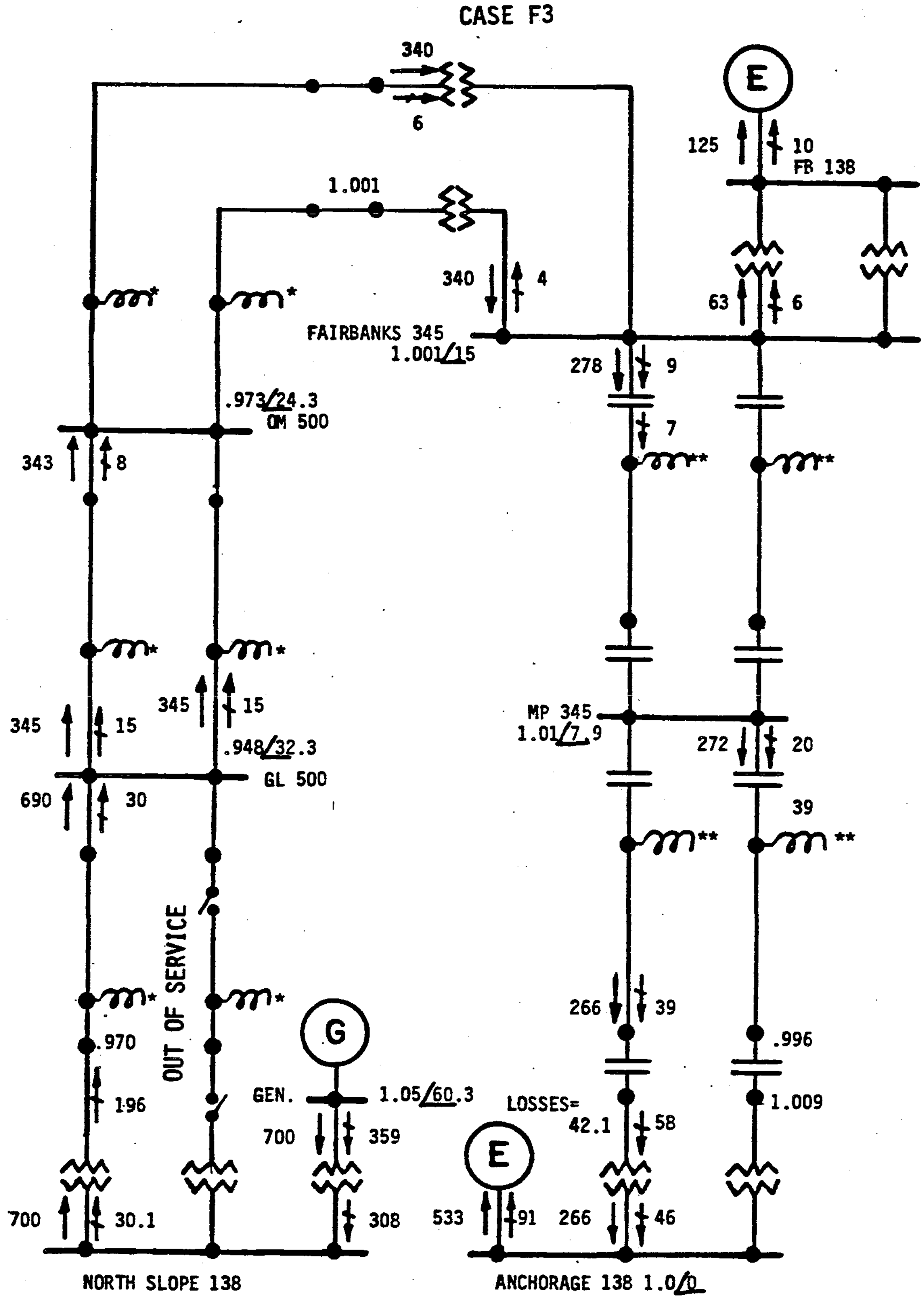
NORTH SLOPE GAS
FEASIBILITY STUDY

LOAD FLOW

700 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-42

EBASCO SERVICES INCORPORATED



Notes

* 200 MVAR
** 75 MVAR
50% series compensation at the 345 kV line only
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

700 MW generation at Prudhoe Bay, one line segment out of service south of Prudhoe Bay.

FIGURE D-43

EBASCO SERVICES INCORPORATED

D.9.0 REFERENCES

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Commonwealth Associates, 1978. Model for the Ready Definition and Approximate Comparison of Alternative High Voltage Transmission Systems. DOE/ET/5916-1.

APPENDIX E

APPENDIX E

FAIRBANKS RESIDENTIAL/COMMERCIAL

GAS DEMAND FORECASTS

JANUARY, 1983

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E1.0 FAIRBANKS RESIDENTIAL/COMMERCIAL GAS DEMAND FORECASTS

The potential residential and commercial demand for natural gas in the Fairbanks area is dependent on the price competitiveness of natural gas with respect to No. 2 distillate fuel oil and propane in space heating and water heating markets, and its price competitiveness with propane and electricity in cooking markets. The potential demand of natural gas as a cooking fuel is estimated to be less than 5.0 percent of the total potential demand for natural gas even if the gas were to fully displace bottled propane in commercial cooking applications.

The forecasts of potential gas demand have been made conditional on the gas achieving discrete percentages of the total market for heating and cooking energy (10 percent, 25 percent, 40 percent, and 100 percent displacement of fuel oil and propane in heating and of propane in cooking). The size of the total market to which these percentages have been applied has, in turn, been projected to grow at a 1.43 percent annual average rate from 1981 for the low growth forecast, and at a 2.30 percent annual average rate for the medium growth forecast. These growth rates are the rates of Fairbanks population growth implied, respectively, by Battelle's (1982) low forecast of the demand for electricity in the Railbelt area, and Acres American's (1981) medium forecast of Railbelt electricity demand.

The prices at which residential and commercial users would have a minimum financial incentive to convert from fuel oil to natural gas for heating purposes have been derived. These "consumer breakeven" prices are based upon the assumption that the maximum discounted payback period for consumers is 5 years. At the 1982 price of No. 2 distillate, $1.22 per gallon, the calculated consumer breakeven prices are $9.58 per MCF for residential heating and $9.94 per MCF for commercial heating. In real terms, these prices will rise annually at approximately the real (inflation free) rate of increase of fossil fuel prices in general. If this rate is the 2.0 percent real rate assumed by Battelle (1982) and Acres (1981), by the year 2010 the breakeven prices (in 1982 dollars) will have reached $16.68 per MCF (residential) and $17.31 per MCF (commercial).

The presence of calculated breakeven prices is necessary for the forecasting of natural gas demand. However, breakeven price data and price elasticity data are insufficient for such a forecast in this case. These price and elasticity data are insufficient because the situation involves a new product (natural gas) competing with an existing product (e.g., distillate oil, propane). Additional factors influence consumer demand including: 1) consumer perceptions of the two products; 2) consumer inertia; 3) initial and/or unusual incentives offered by suppliers of the competing fuels based upon their calculated present worth of achieving certain market shares; and 4) other less defined factors. Because of these unquantified factors, conditional demand estimates have been forecast; and these are based upon price analysis alone.

If natural gas is priced below the consumer breakeven level, users will have an increased financial incentive to shift from fuel oil. For every 10¢ by which the price of gas falls below the breakeven level, residential users will realize approximately $81.00 (in 1982 dollars) in additional savings (present value) over the estimated cost of conversion. If there is any significance to numbers like $500, one might expect extensive inroads against fuel oil to begin to be made if gas is priced below breakeven to cover conversion costs and to achieve this level of savings (measured as the excess of the present value of annual cash savings over conversion costs).

One must recognize that the producers and suppliers of fuel oil are likely to respond to the intrusion of natural gas by either lowering the price of No. 2 distillate or by offering other incentives. While the intensity of reaction by oil suppliers cannot be forecasted, it can be assumed that suppliers are capable of at least offsetting the price advantage that natural gas has traditionally enjoyed based on its reputation as a "clean" fuel. Therefore, the above calculation of consumer breakeven prices correctly ignores the fact that many consumers might be willing to pay a premium for such natural gas properties.

The conditional demand projections derived are summarized below.

	DELIVERED GAS, BCF PER YEAR 1985	2010
MARKET GROWTH @ 1.43 PERCENT		
10% of Market	0.510	0.727
25% of Market	1.275	1.818
40% of Market	2.039	2.908
100% of Market	5.098	7.720
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.527	0.931
25% of Market	1.319	2.328
40% of Market	2.110	3.726
100% of Market	5.274	9.314

These values represent the annual demand for delivered gas conditional upon the percentage of market penetration indicated, where the total market, defined in terms of effective MMBtu's[1/] is set equal to 100 percent of commercial and residential heating energy requirements plus 29 percent of residential cooking energy requirements. The delivered gas demand values were calculated based upon different thermal efficiencies for oil and gas fired units.

The demand for gas would not be constantly distributed throughout the year. Based on an appraisal of normal monthly heating degree days in Fairbanks, and an assumed indoor temperature setting of 65° Fahrenheit, approximately 16.6 percent of annual Fairbanks heating energy is

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1/ Effective MMBtu's are delivered MMBtu's adjusted for the fuel burning efficiency of heating units and cooking units. For example, if oil burners are 65 percent efficient, one delivered MMBtu equals 0.65 effective MMBtu's.

consumed in January, the peak month for demand.[1/] Although cooking energy requirements may be more evenly spread across the year, the relatively small size of cooking demand, less than 5.0 percent of the total, suggests rather strongly that an apportionment of total demand according to the conductive heat transfer formula will yield a good estimate of peak monthly demand. Use of this method implies the following peak monthly demand (January) for natural gas in Fairbanks.

	DELIVERED GAS, BCF PER PEAK MONTH	
	January 1985	January 2010
MARKET GROWTH @ 1.43 PERCENT		
10% of Market	0.085	0.121
25% of Market	0.212	0.302
40% of Market	0.338	0.483
100% of Market	0.846	1.207
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.087	0.155
25% of Market	0.219	0.386
40% of Market	0.350	0.619
100% of Market	0.875	1.546

Peak daily demand during the month of January can reasonably be estimated as 0.0322 (1/31) of the monthly demand times a factor that allows for extremes of cold. Between 1961 and 1982, the highest number of January heating degree days recorded in Fairbanks was 3002 (in January 1971). The January average was 2384. The ratio of the two (1.26) when multiplied by 0.0322 yields an appropriate measure of peak daily demand when their product is in turn multiplied by peak monthly demand. Thus, peak daily demand equals 0.0406 times peak monthly demand.

1/ Heat loss is proportional to the indoor-outdoor temperature differential and inversely proportional to the insulation factor. At an indoor temperature setting of 65° Fahrenheit, relative monthly heating degree days is the appropriate measure of relative monthly heat loss.

The daily peaks are given in the following text table.

	DELIVERED GAS, BCF, PEAK DAILY	
	January 1985	January 2010
MARKET GROWTH @ 1.43 PERCENT		
10% of Market	0.003	0.005
25% of Market	0.009	0.012
40% of Market	0.014	0.020
100% of Market	0.034	0.049
MARKET GROWTH @ 2.30 PERCENT		
10% of Market	0.004	0.006
25% of Market	0.009	0.016
40% of Market	0.014	0.025
100% of Market	0.036	0.063

Peak hourly demand, defined as 0.0417 (1/24) times peak daily demand is quite small. For example, in the maximal case of 2.30 percent growth and 100 percent market penetration, the peak hourly demand is only 0.0026 BCF, or 2,600 MCF.

Finally, it is useful to note that any expansion of the Fairbanks steam district heating system could reduce the demand for natural gas below the estimates given above. On the assumption that the district heating system supplies only commercial and government users, the implied reduction is at most 15.0 percent of the estimates given above, since commercial use of gas is projected to be at most 15.0 percent of total demand.

E1.1 BASE YEAR ENERGY CONSUMPTION

Table E-1 presents base year, 1981, residential and commercial energy consumption estimates for the Fairbanks area. The estimates represent "delivered" energy, that is gross energy volumes measured at the input to the various energy-using devices being powered. These estimates reflect the quantity of energy that must be produced and supplied to the marketplace.

For all Fairbanks residential and commercial users combined, the estimates show that fuel oil and propane supplied approximately 65 percent of the 1981 delivered energy used for space heating and water heating. Coal, wood, electricity, and steam supplied 1.8 percent, 20.5 percent, 8.0 percent, and 1.9 percent, respectively.

Because the appropriate end use surveys have never been made, residential use of propane in lighting and appliance applications in Fairbanks cannot be separately enumerated. Fairbanks consumers use propane for space heating, water heating, powering vehicles, and energizing lights and appliances.1/ Faced with this difficulty, it is assumed that propane accounts for 14.1 percent of the energy used for residential lights and appliances in Fairbanks. The resultant 1981 total residential consumption of energy for this end use, 258 billion Btu's, results in an implicit per capita consumption for lighting and appliances that is consistent with national averages.2/

1/ A survey detailed enough to yield more accurate estimates of consumption by fuel and end use in Fairbanks was beyond the scope of this work.

2/ Using a July 1, 1981 Fairbanks North Star population of 51,569 persons drawn from [3], estimated per capita consumption for lights and appliances comes to 5.0 MMBtu in 1981. The few national estimates we have seen place this figure between 5.0 and 5.5 MMBtu. See, for example [8], p. 75.

TABLE E-1

FAIRBANKS NORTH STAR BOROUGH
ESTIMATED 1981 ENERGY CONSUMPTION
DELIVERED ENERGY, SELECTED END USES

	Residential		Commercial	
	MMBtu'S	Units*	MMBtu'S	Units*
SPACE AND WATER HEATING				
Fuel Oil/Propane**	3,043,752	22.041	467,368	3.384
Coal	97,127	5,582	0	0
Wood	1,109,815	59,990	0	0
Electricity	322,071	94,366	108,974	31,929
Steam	***	***	101,263	104,395
Other	163,591			
TOTAL	4,736,356		677,605	
LIGHTS AND APPLICANCES				
Propane	36,334	0.402	75,073	0.830
Electricity	221,511	64,902	149,000	43,656
TOTAL	257,845		224,073	

* Fuel Oil and Propane -- Millions of Gallons
Coal -- Tons
Wood -- Cords
Electricity -- Megawatt Hours
Steam -- Thousands of Lbs. Per Year

** Conversion to units from MMBtu's at fuel oil rate

*** Less than 0.1% of residential total

Residential Space Heating and Water Heating: The estimates in Table E-1 were constructed in four steps:

Step 1: According to the Fairbanks North Star Borough Community Research Center, University of Alaska Extension, Engineer Axel Carlson has estimated that the statistically average residence in the Borough would use 1,500 gallons of No. 2 distillate fuel oil per year for space heating and water heating purposes if fuel oil were the fuel exclusively employed. Given that there were 22,751 occupied residences in the Borough on average during 1981,[1/] that oil furnaces have an efficiency of 65 percent, and that a delivered gallon of No. 2 distillate contains 0.138 MMBtu's, the implied total 1981 North Star Borough residential space heating requirement, measured in effective MMBtu's, is 3,070,000 MMBtu's.

Step 2 Based upon a survey conducted by the Interior Woodcutters Association, and cross-checked with two additional surveys (see the discussion below), it was assumed that in 1981 this total space heating market was distributed among the available fuels in the following manner: 63.8 percent, fuel oil and propane; 25.3 percent, wood; 9.6 percent, coal; and 1.3 percent, other.

1/ This is 5.97 percent more than the 21,469 units shown in the 1980 Census of Housing, the same percentage increase over the Census implied by the Borough's 1981 population estimate of 51,569 persons. (The Eielson Reservation Census subarea is excluded from these figures.) In effect it is assumed that the Census undercount (recognition of which would cause us to raise the number of estimated occupied residences) and the existence of vacant housing units (recognition of which would cause a reduction in the number of estimated occupied residences), cancel each other. The June 1981 Fairbanks Housing Survey conducted by the Federal Home Loan Bank of Seattle showed only an overall 3.3 percent vacancy rate for the area.

Step 3 Employing average equipment thermal efficiences of 65 percent for fuel oil heaters, 55 percent for woodstoves, 60 percent for coal burners, and 100 percent for electric heating units, estimates of delivered energy by fuel type for residential space and water heating were obtained. These are presented in Table E-1.

Step 4 At MMBtu conversion factors of: 0.138 MMBtu/gallon for fuel oil; 17.4 MMBtu/ton for coal; 18.5 MMBtu/cord for wood; and 0.0034 MMBtu/kWh for electricity, the MMBtu estimates of delivered energy by fuel type were converted into unit estimates, (also shown in Table E-1).1/

Commercial Space Heating and Water Heating: The 1978 Fairbanks Energy Inventory [5b] tabulated the number of businesses and the square footage of office space for each of eight commercial industries. For these eight industries, estimates of heating energy used were also provided. Initally, the list of industries appears incomplete with respect to all types of units encompassed by what would be defined as the "commercial" sector.2/ For purposes of ultimately determining the demand for natural gas in commercial heating, a comprehensive inventory of buildings is needed. This requirement is also considered in the 1978 Energy Inventory:

> "Data regarding numbers and types of businesses, as well as the commercial building specifications, are necessary for the initial analysis of the commercial sector. Such

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1/ These conversion factors are fairly standard but will differ dependent upon how one calculates them. In the case of coal and wood, the estimates of MMBtu/ton and MMBtu/cord are taken from [5a]. The estimate for wood is the mean for dry birch and dry spruce.

2/ The eight industries are: Hotels & Motels; Restaurants & Bars; Wholesale Trade; Retail Trade; Shopping Centers; Auto Sales & Service; Other Services; Entertainment.

raw data are available through a cooperative effort by the Borough Planning Department, the Borough Environmental Services Department, and the State Department of Transportation, based on Borough Assessor's records. The intent is to locate each building within the Fairbanks area in order to project new development, air quality, traffic, etc. Since these data also include the square footage of each building, it can be used for energy planning as well."

A diligent attempt was made to include all nongovernment, non-residential, nonmanufacturing buildings in the data base. Since the total number of businesses for which 1978 energy consumption was estimated totalled 1,823 and since the total number of nongovernment, nonmanufacturing Fairbanks North Star labor reporting units listed for the third calendar quarter of 1978 by the Alaska Department of Labor was only 1,210; it appears that the 1978 report was complete.[1/] For these reasons, the 1978 Fairbanks Energy Inventory estimates have been accepted as the best available estimates of commercial sector energy consumption at a point in time in Fairbanks.

The same report provided estimates of both delivered heating energy and effective heating energy used in the Fairbanks commercial sector in 1978 [5b, Table 25]. The total of 528,000 MMBtu of effective heating energy, when divided by the Borough square foot estimate of space, yielded an average for 1978 of 0.175 MMBtu of effective heating energy required per square foot of commercial office space.

The estimates of delivered energy used in 1981 shown in Table E-1 were then constructed in six steps.

1/ A "reporting unit" is a place of business at which at least one worker is a salaried employee. Multiple locations for a given firm count as multiple reporting units. Many buildings contain more than one labor reporting unit. On the other hand, some reporting units are housed in more than one building.

Step 1 Estimates of the total commercial square footage to be heated in 1981 were made for each of the eight industries covered by the FNSB in the year 1978. For each industry these were defined to equal 1978 square footage plus the estimated change in square footage between 1978 and 1981, where the change was based on the estimated percent change in the number of establishments reported by the Alaska Department of Labor for that industry.1/

Step 2 The 0.175 MMBtu per square foot of effective heating energy used was reduced by ten percent to allow for increased conservation and reduced temperature settings.2/

Step 3 A 1981 estimate of effective heating MMBtu's used in the commercial sector was constructed by multiplying the adjusted per square foot heating requirement by the estimate of total square feet to be heated. The result came to 514,000 MMBtu's.

Step 4 As discussed below, 59.1 percent of the 1981 commercial sector heating requirement (effective MMBtu's) was estimated to be satisfied by burning fuel oil, 21.2 percent by electricity, and 19.7 percent by steam district heating.

Step 5 Employing average heating efficiencies of 65 percent for fuel oil heaters and 100 percent for district steam heating and electric heating, the MMBtu requirement estimates of delivered energy were obtained, and they are shown in Table E-1.

1/ See [7]. The Department of Labor data are not as yet available for 1981. For all eight "industries" we defined the 1980-81 percent change to equal 2.0 percent.

2/ There are no good estimates of this effect in Fairbanks. However, given the large number of energy audits conducted there, failure to allow for at least some reduction in heating requirements per square foot since 1978 would likely be a more serious analytical error than an assumption of ten percent.

Step 6 At MMBtu conversion factors of: 0.138 MMBtu/gallon for fuel oil; 0.0034 MMBtu/kWh for electricity, and 0.970 MMBtu/thousand pounds for steam, the MMBtu estimates of delivered energy by fuel type were converted into unit estimates (also shown in Table E-1).

Lights and Appliances: According to data by the Alaska Power Administration and published in [4], total residential electricity sales by GVEA and FMUS in 1981 came to 159,000 megawatt hours.1/ The electricity consumption estimate of 65,000 MWh for residential lights and appliances is the 1981 residential sales total less our estimate of 94,400 MWh for heating.

The 43,700 MWh estimate of electricity consumed in the commercial sector for lights and appliances is the North Star Borough's published 1978 estimate plus an increment of 8.5 percent. The 8.5 percent increment is the 1978-1981 percent change in commercial sector square footage estimated above, in Step 1.

Direct estimates of the amount of propane used in the residential sector to fuel lights and appliances could not be obtained. Available national and Alaska estimates of the delivered energy used per capita to power residential lights and appliances suggest an average of between 5.0 and 5.5 MMBtu per person per year.2/ The estimate was set at the MMBtu level which brought Fairbanks total residential delivered energy use for lights and appliances to 5.0 MMBtu per person per year. The resultant 36,300 MMBtu's of propane energy (402,000 gallons), comes to 14.1 percent of the total residential delivered energy estimated to have been used in 1981 for lighting and appliance applications.

1/ GVEA - Golden Valley Electric Association, FMUS - Fairbanks Municipal Utility System.

2/ The Kake end use survey led to estimates of 5.4 MMBtu per capita for Kake. National estimates also are in this range, for example, [8], p. 75.

The estimate of commercial propane use is the Borough's 1978 estimate [5b, p. 45] with the value for cooking uses increased by the estimated 1978-1981 employment growth in the industrial category "eating and drinking places" (11.5 percent).1/

Estimating Fuel Shares: Heating: There have been three residential end use energy surveys conducted recently in the Fairbanks North Star Borough: (1) a 526 response survey conducted by the Interior Woodcutters Association [6], (2) a 616 response survey conducted by the Fairbanks Consumer Advocacy Committee and tabulated in [5d]; and (3) a 408 response survey conducted by Battelle Northwest as part of the Railbelt Electric Power Alternatives Study.

All three of these surveys were designed solely to estimate the percent of Fairbanks residences which used each of several fuels for primary and supplemental purposes.2/ None of the surveys attempted to measure total consumption of each fuel type by end use.

The similarity of the estimated percents using fuel oil is notable as shown in the text table.

PERCENT OF SURVEYED RESIDENCES
USING FUEL AS PRIMARY HEATING SOURCE
1981

	WOODCUTTERS	FCAC	BATTELLE3/
Fuel Oil	63.3	61.2	66.5
Wood	25.3	22.7	8.8
Electricity	7.8	9.6	15.2
Coal	1.3	1.8	3.0
Propane	0.5	1.3	4.0
Other	0.2	5.7	2.5

1/ The 1978-1980 published Alaska Department of Labor rate with an added 2.0 percent assumed for 1981. Alaska Department of Labor [7].

2/ The Battelle survey also requested information on fuels used to power lights and appliances.

3/ Weighted average of responses for space heating (85 percent weight) and water heating (15 percent weight).

Weighting each set of survey results by their relative number of responses yields the following estimates of percent of Borough residences using each fuel for primary heating: fuel oil (63.3 percent), wood (19.9 percent), electricity (10.5 percent), coal (1.9 percent), propane (1.2 percent), other (3.2 percent).

For purposes of this study, it was assumed that these percentages also represent the respective shares of the residential heating requirement (effective MMBtu's) satisfied by each fuel type.

No direct 1981 information is available for the commercial sector. The FNSB 1978 Energy Inventory [5b, Table 25] showed that commercial sector heating requirements were then supplied as follows: 59.1 percent, fuel oil; 21.2 percent, electricity; and 19.7 percent, steam. Since 1978 the average commercial price of electricity (¢/kWh) in Fairbanks has gone from 5.5¢/kWh to 8.5¢/kWh, while the price of fuel oil has risen from 55¢ to $1.22 per gallon.1/ Thus, the relative price of commercial electricity has declined by approximately 30 percent. In spite of this drop in relative price, electricity as a source of commercial heating energy remains over twice as costly per effective MMBtu as fuel oil in Fairbanks (Table E-2). The high 1981 relative price of electricity argues against there having been an increase in electricity's share of commercial heating between 1978 and 1981, despite the decline in relative electricity prices over that period. Further, since 1978 there has been an annual average 2.5 percent decline over this period in total electrical energy generated by GVEA and FMUS.2/ Faced with this evidence, and in the absence of direct data, the share of space heating and water heating energy requirements met by electricity has been held constant at the 21.2 percent estimated by the Fairbanks North Star Borough for 1978.

1/ Price quotes are taken from [5a].

2/ Alaska Power Administration [4].

TABLE E-2

FAIRBANKS NORTH STAR BOROUGH
ENERGY PARAMETERS USED IN THIS STUDY

Units	No. 2 Oil Gallons	Natural Gas MCF	Coal Tons	Wood Cords	Electricity kWh	Propane Gallons	Steam 1,000 lbs
MMBtu's/Unit	.138095	1.02	17.4	18.5	.003413	.090476	0.970
Heating Efficiency*	.65	.75	.60	.55	1.00	.70	1.00
Unit Prices** (1982)	1.22	--	62.50	96.25	.109	1.24	6.50
Prices Per Efficiency MMBtu	13.59	--	5.99	9.46	31.93	19.58	6.70

* Efficiency of wood burning predicated on FNSB estimates for airtight stoves.

** Price Source: "The Energy Report," August 1982, Fairbanks North Star Borough Community Research Center

No. 2 Oil - January 1982 through August 1982 monthly mean; August 1982 = $1.216
Coal - August 1982, wholesale price per ton, 2 tons delivered
Wood - August 1982, dry, split, delivered, mean of birch and spruce
Electricity - August 1982, 1,000 kWh, mean of GVEA and FMUS commercial and residential (rate with cost of power adjustment for GVEA)
Propane - July 1982
Steam - July 1982

According to Keith Swartz of the Fairbanks Municipal Utility System, 152.3 million pounds of steam were sent into the district heating system in 1981. Indications are that the 1981 steam sales to the commercial market are not significantly different from the steam sales to the commercial sector in 1978.[1/] The 1978 estimate for steam heat as a percent of the total commercial heating market, therefore, also has been held constant at 19.7 percent. The resultant 104.4 million pounds of delivered steam heat, allowing for line losses and other users, is consistent with the 1981 total FMUS production of 152.3 million.

Since fuel shares must sum to 1.0, retention of the 1978 electricity and steam shares of commercial heating requirements implies retention of the fuel oil share, 59.1 percent.

Relative Prices: Information on the various energy parameters used in this study (Btu content, heating efficiency), recent 1982 unit prices for each fuel as delivered and the equivalent prices per effective heating MMBtu for each fuel, is presented in Table E-2. The latter prices are defined as the unit prices divided by K, where K is defined as the product of the efficiency factor and the MMBtu's per unit. No natural gas prices are presented because natural gas is not now commercially available in Fairbanks.

Two points are worth noting.

(1) All fuels identified, except electricity, are fossil fuels. Electricity itself is 100 percent fossil fuel generated in Fairbanks (fuel oil and coal).

1/ Commercial consumption has accounted for over one-half of all the steam generated for heat by FMUS. Thus one would expect that significant changes in commercial consumption would appear as significant changes in total consumption. In 1978, FMUS received payment for 130 million pounds of steam. Allowing for transmission losses this figure is not greatly out of line with 1981's 152.3 million pounds of steam produced.

(2) Given the very high relative price of electricity as a heating fuel, and the fact noted above that its relative price was even higher four years ago, it seems reasonable to assume that residential and commercial users of electricity for space and water heating purposes are either ignorant of the price disadvantage they face, or have some other reason for preferring electricity as an energy source for heating.

The following analysis and the projection of the conditional demand for natural gas as a space heating and water heating energy source is based on the assumption that the demand for natural gas is determined by its price substitutability for fuel oil. The real price assumptions used by Battelle Northwest [2] and Acres American [1] assume for all real fossil fuel prices except coal to escalate at 2.0 percent per year, with coal prices escalating at 2.1 percent per year. Under these price escalation assumptions, 1982 relative prices remain essentially unchanged throughout the forecast period, with the exception of prices relative to electricity. However, even if real electricity prices are assumed to remain constant, fuel oil prices per effective MMBtu remain 26 percent lower than corresponding electricity prices in the year 2010.

E1.2 THE CONDITIONAL DEMAND FOR NATURAL GAS IN FAIRBANKS

At this time, the minimum required price for natural gas, delivered to residential and commercial users in Fairbanks, has not been determined. That price is a function of the wellhead price of gas, the cost of conditioning the gas, the cost of transporting it to Fairbanks, and the cost of distributing it within Fairbanks. It is based upon the ability of system owners to achieve an acceptable rate of return on their major capital investments. The purpose of this analysis, therefore, is to estimate the demand for gas, conditional upon price. These conditional gas demand forecasts are formulated under each of two sets of economic assumptions. The first set includes those assumptions buttressing Battelle Northwest's "low" electricity demand projection of

February 1982, while the second set includes those which buttress Acres American's 1982 "middle" projection.1/ With respect to the electricity demand components, both the Battelle "low" and the Acres' "middle" forecast are products of the Railbelt Electricity Demand model, developed by the University of Alaska for the Railbelt Electric Power Alternatives Study.

For the foreseeable future, the increasing demand for electrical items, such as new office equipment, electronic games, and electrical appliances, has apparently convinced Battelle and Acres to forecast an increasing per capita demand for electricity in Alaska's Railbelt. In contrast, it would be wholly inappropriate for us in this study to project an increasing per capita demand for fuel oil or natural gas. The relative price assumptions discussed the end of the proceeding chapter indicate that one could not reasonably project more than a small fraction of the demand for premium fuels to be for purposes other than space heating or water heating.2/

Rising fossil fuel prices have induced a reduction in effective heating energy requirements across the United States. Such conservation does not appear to have reached its technological limits. For this reason, this study does not simply adopt the rates of per capita increase in electricity consumption and apply them to natural gas demand. Instead this study derives the underlying Battelle and Acres rates of Fairbanks population growth and makes natural gas consumption projections a function of constant unit consumed/person values.

1/ See [1] and [2].

2/ The potential demand for gas in Fairbanks will be estimated from the point of view of its substitutability for other fuels in specific end uses. If natural gas were available in Fairbanks, it undoubtedly could fuel some decorative lights and be used as a cooking fuel in some kitchens. However, demand from these sources is likely to be either very small relative to the demand for gas as a heating fuel and unlikely to increase in per capital terms.

Approximating the Railbelt Model: The Battelle and Acres studies focused on the Railbelt as a whole. The Acres study, in particular, provided relatively little detail for Fairbanks. In order for this study to be confidently based on rates of Fairbanks population growth that are consistent with the Battelle and Acres rates of growth of Railbelt electricity demand, it was necessary to develop a mathematical bridge between the forecasted rate of growth of electricity demand in the Railbelt and the forecasted rate of Fairbanks population growth. The equations that accomplish this are given below. (All percent changes are thirty-year compound annual averages, t-statistics in parentheses.)

(1)
$$\text{Railbelt Pop. \% Change} \times 100 \text{ 1980-2010} = \underset{(-9.6)}{-.0192} + \underset{(14.2)}{.7237} * \text{Railbelt Electricity Demand \% Change} \times 100 \text{ 1980-2010}$$
$$R^2 = .9991 \qquad \text{Six Observations}$$

(2)
$$\text{Fairbanks Pop. \% Change} \times 100 \text{ 1980-2010} = \underset{(-7.6)}{-.0326} + \underset{(6.0)}{.9299} * \text{Railbelt Pop. \% Change} \times 100 \text{ 1980-2010}$$
$$R^2 = .9954 \qquad \text{Nine Observations}$$

The data bases to which these two equations were fit are the six sets of simulation results given on pages 3.8 and 3.13 of the Battelle report [2]; and the nine sets of simulation results given in appendix Table A3 through all of that report.[1/]

Because the R^2 values were very high, the results of this study are consistent with the earlier work.[2/] In particular, the rate of population growth (annual average) in Fairbanks that is consistent by this definition with the Battelle 2.2 percent rate of growth in

1/ Alaska Economics, Incorporated calculated the 30-year compound annual average percent changes from the published simulation results and then ran the indicated regressions.

2/ Although statistically significant, the constant terms in these two equations are quite small (2/100 of a percent and 3/100 of a percent). The implied elasticity of Railbelt electricity demand with respect to Railbelt population growth is (a) constant and (b) equal to 1.38. This statement was verified by running regression 1 in reverse. This analysis was performed even though the .999 R^2 and near zero intercept assured the result.

Railbelt electricity demand is 1.43 percent. When 2.2 is substituted into the right-hand side of the first equation above, and the result is substituted into the right-hand side of the second equation, the figure 1.43 is determined. Similarly, the rate of population growth in Fairbanks that is consistent with the 3.5 percent Acres rate of growth of Railbelt electricity demand is found to be 2.30 percent.

Framework for Analysis: The relative price analysis leads to the conclusion that the potential commercial and residential demand for natural gas in Fairbanks is limited to 1) use as a substitute for fuel oil in space heating and water heating; 2) use as a substitute for electricity and propane in cooking; and 3) some incidental uses. Accepting that the small quantity of gas that might be used to fire gas lamps can be ignored, the relative magnitude of the demand for cooking can be compared to the magnitude of demand for heating.

According to the U.S. Department of Energy, a modern gas cooking range for the home uses between 6 MMBtu's and 13 MMBtu's of fuel per year, depending on its efficiency. The same source records that in 1980, approximately 29 percent of U.S. households that had modern ranges used natural gas and the remaining 71 percent used electricity.[1/] With natural gas prices scheduled for complete decontrol, it is reasonable to conclude that the national average price of natural gas to residential and commercial users will rise relative to the price of electricity. If so, the present 29 percent market penetration nationally may be an upper limit for the foreseeable future, especially when one considers the growing attractiveness of combination electric range-microwave ovens.

1/ "Estimate of Average Annual Energy Consumption of Gas Appliances," Consumer Products Efficiency Branch, U.S. Department of Energy, also (same source) "Estimate of Average Annual Energy Consumption of Electric Appliances."

Unless the Fairbanks price of natural gas relative to electricity is unusually low, possibly much lower than it has been nationally, one would not expect gas ranges to account for more than 29 percent of the home cooking units in Fairbanks. The only change in this market relationship would result from a major innovation not yet made, or that a Fairbanks preference biased in favor of natural gas for nonprice reasons.[1/] The market penetration could be lower for natural gas than the estimated 29 percent. The Department of Energy's estimated 825 kWh consumption per year for a low efficiency conventional electric range in Fairbanks costs approximately $82.50 per year to operate today. Even if gas were free, the cash savings that could be achieved by switching from an electric range to a gas range would not be substantial.

The demand for gas as a commercial cooking fuel may be more price sensitive, because the commercial volume of cooking fuel required per user year is much greater than for home cooking. Based on the available data and conversations with commercial suppliers of equipment, it appears that propane is presently the preferred commercial cooking fuel in Fairbanks. The 1978 Borough survey, for example, estimated that 85 percent of the effective commercial cooking MMBtu's were supplied by propane.[2/] On the assumption that this percentage is correct, we define the maximum volume of natural gas that would be demanded for commercial cooking in Fairbanks to be equal to 85 percent of the projected demand for effective commercial cooking energy. Because this volume is quite small relative to the potential demand for gas in space heating and water heating (75,000 delivered MMBtu's for commercial cooking in 1981 compared to nearly 3.5 million MMBtu's for space and water heating) commercial cooking demand amounts

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1/ If the penetration percentage was 29 percent of the modern ranges, it would clearly be no larger as a precent of all home cooking units.

2/ See [5b].

to something approaching rounding error in these projections of the total demand for natural gas.1/

Finally, it should be noted that the total 1981 maximum potential demand for gas as a commercial and residential cooking fuel (delivered energy) amounts to 137,800 MMBtu's or approximately 135,000 MCF.2/ This is only 4.6 percent of the estimated 1981 maximum potential demand for gas as a heating fuel (approximately 3.1 BCF). Because this percentage is so low, it is clear that the potential of natural gas as a heating fuel is the critical factor in determining the overall demand in Fairbanks.

The Conditional Demand for Natural Gas: The 1981 maximum potential demand for natural gas is defined as the estimated volume of fuel oil and propane used in space heating, water heating and cooking measured in effective MMBtu's, and adjusted to delivered Btu's based upon efficiency correction.

Tables E-3 and E-4 present conditional forecasts of the demand for delivered gas in Fairbanks (a) if it is priced so as to penetrate 10 percent; (b) 25 percent; (c) 40 percent; and (d) 100 percent of the total heating and cooking fuel market; (i.e., 1981 combined fuel oil/propane share). Maximum potential demand for the low growth scenario in the year 1981+t is defined in Table E-3 as 1981 maximum

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1/ The 3 million MMBtu's is the sum of the 1981 commercial and the 1981 residential demand for fuel oil and propane for space and water heating, see Table E-1.

2/ We have added 75,073 (commercial) and 62,679 (residential). The residential estimate is the product of the 1981 number of occupied residences (22,751), the factor .29 representing gas cooking penetration, and an average 9.5 MMBtu per year gas usage per range. The 9.5 MMBtu consumption estimate is the mean of the Department of Energy's gas range estimate of 6-13 MMBtu per year.

TABLE E-3

FAIRBANKS NORTH STAR CONDITIONAL GAS DEMAND
POPULATION GROWTH AT 1.43%
(Delivered Energy)

	1985	1990	1995	2000	2005	2010
10% of Market						
Residential (MMBtu)	439512.8	471849.7	506565.8	543836.0	551612.9	626804.6
Commercial (MMBtu)	80488.0	86409.9	92767.4	99592.7	106920.2	114786.8
Sum (MMBTU)	520000.9	558259.6	599333.2	643428.7	690768.6	741591.4
Residential (MCF)	430894.9	462597.8	496633.1	533172.5	572400.4	614514.4
Commercial (MCF)	78909.8	84715.6	90948.5	97639.9	104823.7	112536.1
Sum (MCF)	509804.8	547313.3	587581.5	630812.5	677224.1	727050.4
25% of Market						
Residential (MMBtu)	1098782.1	1179624.3	1266414.4	1359590.0	1379032.1	1567011.6
Commercial (MMBtu)	201220.0	216024.7	231918.6	248981.8	267300.5	286966.9
Sum (MMBTU)	1300002.2	1395649.0	1498332.9	1608571.8	1726921.4	1853978.6
Residential (MCF)	1077237.4	1156494.4	1241582.7	1332931.4	1431000.9	1536285.9
Commercial (MCF)	197274.6	211788.9	227371.1	244099.8	262059.3	281340.1
Sum (MCF)	1274511.9	1368283.3	1468953.9	1577031.2	1693060.2	1817626.0
40% of Market						
Residential (MMBtu)	1758051.4	1887398.9	2026263.0	2175344.0	2206451.4	2507218.6
Commercial (MMBtu)	321952.1	345639.5	371069.7	398370.9	427680.8	459147.1
Sum (MMBTU)	2080003.4	2233038.3	2397332.7	2573714.9	2763074.3	2966365.7
Residential (MCF)	1723579.8	1850391.0	1986532.4	2132690.2	2289601.5	2458057.4
Commercial (MCF)	315639.3	338862.2	363793.8	390559.7	419294.9	450144.2
Sum (MCF)	2039219.1	2189253.3	2350326.2	2523249.9	2708896.4	2908201.7
1981 Fuel Oil/Propane Share of Market						
Residential (MMBtu)	2834857.8	3043430.7	3267349.1	3507742.2	3557902.9	4042890.0
Commercial (MMBtu)	475684.2	510682.3	548255.5	588593.0	631898.3	678389.9
Sum (MMBTU)	3310542.0	3554113.0	3815604.6	4096335.2	4397720.4	4721279.8
Residential (MCF)	2779272.4	2983755.6	3203283.4	3438962.9	3691982.4	3963617.6
Commercial (MCF)	466357.0	500669.0	537505.3	577052.0	619508.2	665088.1
Sum (MCF)	3245629.4	3484424.5	3740788.8	4016014.9	4311490.6	4628705.7

TABLE E-4

FAIRBANKS NORTH STAR CONDITIONAL GAS DEMAND
POPULATION GROWTH AT 2.30%
(Delivered Energy)

	1985	1990	1995	2000	2005	2010
10% of Market						
Residential (MMBtu)	454787.4	509549.7	570906.2	639650.7	654362.7	802969.9
Commercial (MMBtu)	83285.2	93313.9	104550.1	117139.3	131244.4	147047.9
Sum (MMBtu)	538072.6	602863.6	675456.3	756790.0	847917.4	950017.8
Residential (MCF)	445870.0	499558.6	559711.9	627108.6	702620.6	787225.4
Commercial (MCF)	81652.2	91484.2	102500.1	114842.4	128671.0	144164.6
Sum (MCF)	527522.2	591042.7	662212.0	741951.0	831291.6	931390.0
25% of Market						
Residential (MMBtu)	1136968.4	1273874.3	1427265.4	1599126.9	1635906.8	2007424.7
Commercial (MMBtu)	108213.1	233284.7	261375.2	292848.2	328111.0	367619.8
Sum (MMBtu)	1345181.6	1507159.0	1688640.7	1891975.1	2119793.6	2375044.5
Residential (MCF)	1114674.9	1248896.4	1399279.8	1567771.4	1756551.6	1968063.4
Commercial (MCF)	204130.5	228710.5	256250.2	287106.1	321677.4	360411.6
Sum (MCF)	1318805.4	1477606.9	1655530.1	1854877.5	2078229.0	2328475.0
40% of Market						
Residential (MMBtu)	1819149.5	2038198.9	2283624.7	2558603.0	2617450.8	3211879.5
Commercial (MMBtu)	333141.0	373255.5	418200.3	468557.1	524977.5	588191.7
Sum (MMBtu)	2152290.5	2411454.4	2701825.0	3027160.1	3391669.8	3800071.2
Residential (MCF)	1783479.9	1998234.2	2238847.7	2508434.3	2810482.6	3148901.4
Commercial (MCF)	326608.8	365936.8	410000.3	459369.7	514683.9	576658.5
Sum (MCF)	2110088.7	2364171.0	2548848.1	2967804.0	3325166.4	3725560.0
1981 Fuel Oil/Propane Share of Market						
Residential (MMBtu)	2933378.6	3286595.7	3682344.8	4125747.3	4220639.5	5179155.6
Commercial (MMBtu)	492215.8	551485.0	617891.0	692293.2	775654.3	869053.2
Sum (MMBtu)	3425594.4	3838080.7	4300235.8	4818040.5	5398195.5	6048208.9
Residential (MCF)	2875861.4	3222152.7	3610142.0	4044850.3	4531903.2	5077603.6
Commercial (MCF)	482564.5	540671.6	605775.5	678718.8	760445.4	852013.0
Sum (MCF)	3358425.9	3762824.3	4215917.5	4723569.1	5292348.6	5929616.5

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potential demand times the factor $(1.0143)^t$.[1/] Maximum demand, as presented in Table E-4 for the medium growth scenario, employs the factor $(1.023)^t$. The two annual average percentage rates of growth, 1.43 percent and 2.30 percent, are the rates of Fairbanks population growth discussed previously.[2]

Whether a reasonable forecast of the actual demand for gas in any single year should be set equal to zero, 10 percent of maximum, 25 percent of maximum, 40 percent of maximum, or 100 percent of maximum, is a function of the price set for gas relative to the price set for its primary competitor as a heating fuel, No. 2 distillate.[3/] This requires a comparison of the two prices on an efficiency adjusted, MMBtu basis, with an allowance for the cost of conversion of heating units from fuel oil to natural gas. In addition, one must also allow for any financial constraints that may prevent consumers from taking advantage of lower priced gas (should it indeed be lower priced), for any willingness to pay a premium for "clean" gas, and for the inevitable effect of inertia.

Based on the energy parameters presented in Table E-2, assuming different heating efficiencies, a $600 conversion cost, a 3.0 percent real discount rate and a required five year payback period (recovery of conversion costs), the 1982 delivered prices at which consumers would be financially indifferent between gas and No. 2 distillate as heating fuel are:

$9.58 per MCF	Residential
$9.94 per MCF	Commercial

given a delivered price of $1.22 per gallon for distillate.

1/ In turn, the 1981 maximum is defined by the combined share of fuel oil and propane.

2/ See the previous section.

3/ Since the cooking component is less than 5 percent of the total.

In other words, at these prices users would have no financial preference for one or the other fuel.[1/] At gas prices below these \$9.58-\$9.84/MCF, gas is economically attractive. Because the typical household in Fairbanks requires 135 MMBtu's of effective heating energy per year and the typical commercial establishment requires 264 MMBtu's per year,[2/] the typical commercial user would recover conversion costs more quickly than would the residential user for a given set of gas and distillate prices. Consequently, the "breakeven" price of natural gas for the representative commercial user is higher than it is for the representative household.[3/]

Because real fossil fuel prices are assumed to escalate at a 2.0 percent rate in the Battelle and Acres studies, the projected real consumer "breakeven" prices of gas also escalate at this rate. In any year, 1982+t, the constant dollar (1982 \$) consumer breakeven prices are (1982 \$/MCF):

$9.58*(1.02)^t$ Residential
$9.94*(1.02)^t$ Commercial

1/ The formula for this calculation is (ignoring conversion costs): breakeven price of gas = 1.22* (Btuga*Effga)/(Btufo*Efffo); where 1.22 is the price per gallon of fuel oil and where Btuga = MMBtu/MCF = 1.02, Btufo = MMBtu/gallon = .138, Effga = .75, Efffo = .65.

2/ The per residence figure is the Borough's/Alex Carlson's 1,502 gallons of fuel oil converted to MMBtu's and adjusted for 65 percent efficiency (that is 1502*.138*.65). The per establishment figure is the total effective 1981 MMBtu's required as calculated in Section 4.4.1.2 (514,000) divided by the estimated 1981 number of establishments (1,947).

3/ Conversion costs vary considerably. The \$600 estimate was obtained by Alaska Economics, Inc., as an average of three estimates kindly provided by different plumbing/heating firms.

These become (1982 $/MCF):

CONSUMER BREAKEVEN GAS PRICES*
(1982 $/MCF)

	1985	1990	1995	2000	2005	2010
Residential	10.17	11.23	12.40	13.69	15.11	16.68
Commercial	10.55	11.65	12.86	14.20	15.68	17.31

* 1982 $/MCF at which gas is estimated to breakeven with No. 2 distillate priced at 1982 $/gallon = $1.22*(1.02)^t$, where t is the number (year-1982). These prices allow for conversion costs of $\$600*(1.02)^t$. That is, they assume conversion costs escalate at a 2.0 percent real rate also. Breakeven prices would be slightly higher if conversion costs accelerate only at the rate of inflation.

<u>Lumpy Demand</u>: Virtually all of the published gas demand studies derive price and income demand elasticities by applying statistical methods of estimation to historical data bases. These studies employ nonzero gas sales over the entire period for which the data are available. No studies have been found that analyze the price and income responsiveness of gas demand over a transition period during which natural gas is at first unavailable, and then enters the marketplace. This renders previous empirical estimates of the price and income elasticities of gas demand unusable for our purposes. Were a gas service to be formed in Fairbanks, and a new equilibrium between gas and other fuels established, one could reasonably turn to previous analyses to obtain insights as to how the equilibrium shares of the market would change with changes in relative fuel prices and real income. The interest in this study lies in determining 1) the price at which gas become competitive; 2) in suggesting a reasonable upper limit to the quantity of gas that could be sold; and 3) in providing at least some guidance as to how much of a share gas would garner of the potential Fairbanks market if it were priced at different percentages below consumer breakeven levels. Tables E-3 and E-4, and the consumer breakeven prices presented above satisfy the first two of these interests. Of necessity, our discussion of the third will be somewhat limited and rather conjectural.

The introduction of a new product is almost always preceeded by a detailed marketing research effort. It almost always sparks some form of response from competitors (in this case, principally the producers and suppliers of fuel oil). Because the content and success of an initial natural gas advertising campaign, and the extent to which the competition would be prepared to lower prices or engage in counter-advertising cannot be predicted, a definitive estimate of the share of the market that gas might capture cannot be made.[1/] What can be presented are estimates of the 1982 present discounted value of the five-year annual savings that would accrue to commercial and residential users of gas for every 10¢ by which the price of gas falls below the consumer breakeven level, assuming fuel oil is the competition. The results are shown in Table E-5.

Reading from Table E-5, if residentially sold gas is priced approximately 62¢ per MCF below consumer breakeven, that is at $8.96 in 1982 assuming a $1.22 per gallon price of fuel oil, the typical residential user would realize a present value savings of $500 in excess of the estimated $600 conversion cost. If there is any marketing magic to round numbers like $500 and $1,000, it might be reasonable to expect that gas would achieve significant inroads against fuel oil if it were priced to save residential users $500 over the cost of conversion (say 10 percent of the total market), and might be expected to approach dominance (say, 40 percent of the total market) if the savings reached $1,000 in excess of conversion costs ($1.24 below breakeven or $8.34/MCF if fuel oil is $1.22 per gallon).

1/ For reasons of corporate security, Fairbanks producers and suppliers of fuel oil would be ill advised to identify and to quantify their potential competitive responses.

TABLE E-5

PRESENT VALUE ANNUAL SAVINGS IN EXCESS OF $600

Discount*	Residential	Commercial
.10	80.70	158.04
.20	161.40	316.08
.30	242.10	474.12
.40	322.80	632.16
.50	403.50	790.20
.60	484.20	948.24
.70	564.90	1106.28
.80	645.60	1264.32
.90	726.30	1422.36
1.00	807.00	1580.40
1.10	887.70	1738.44
1.20	968.40	1896.48
1.30	1049.10	2054.52
1.40	1129.80	2212.56
1.50	1210.50	2370.60
1.60	1291.20	2528.64
1.70	1371.90	2686.68
1.80	1452.60	2844.72
1.90	1533.30	3002.76
2.00	1614.00	3160.80
2.10	1694.70	3318.84
2.20	1775.40	3476.88
2.30	1856.10	3634.92
2.40	1936.80	3792.96
2.50	2017.50	3951.00
2.60	2098.20	4109.04
2.70	2178.90	4267.08
2.80	2259.60	4425.12
2.90	2340.30	4583.16
3.00	2421.00	4741.20

* The discount is the amount in dollars that natural gas is priced below the consumer breakeven price for gas.

These statements are, of course, speculative. Furthermore, one must expect some competitive response from fuel oil producers and suppliers. Nevertheless, one can reasonably conclude the following (all prices are 1982 prices).

1) Natural gas should be no higher priced than consumer breakeven if one expects it to have a viable market.

2) In all likelihood, gas would need to be priced <u>below</u> $9.00/MCF (1982 price) to obtain a significant market share, unless Fairbanks users have a strong preference for "clean" gas.1/

Similar statements substituting prices raised at approximately the same percent per year as competing fuels can be made for any year in the forecast period.2/

Returning to Tables E-3 and E-4 these statements can be translated into BCF quantity values. Assuming a price of fuel oil of $1.22/gallon in 1982,

3) If gas were priced at approximately $9.00/MCF (1982 price) and rose in price at the same rate as the price of competing fuels, and if this were to lead to gas garnering 10 percent of the total market, gas demand would be approximately 0.5 BCF in 1985, rising to 0.7 BCF in the year 2010 - Battelle "low"; or in the Acres "middle" case, 0.5 BCF in 1985 rising to 0.9 BCF in the year 2010.

1/ We implicitly assume in our breakeven calculations, that potential price reductions by fuel oil dealers are large enough to offset the price advantage gas enjoys as a "clean" fuel.

2/ We say "approximately" because the appropriate rate of escalation is slightly less than the rate of increase of competing fuel prices if conversion costs escalate more slowly than that rate.

4) If the gas price were to be set at approximately $8.34/MCF, and rose in price at the same rate as the price of competing fuels, and if this were to lead to gas obtaining 40 percent of the total market, gas demand would be approximately 2.0 BCF in 1985 rising to 2.9 BCF in the year 2010 (Battelle) or in the case of the Acres results, 2.1 BCF in 1985 rising to 3.7 BCF in the year 2010.

5) If gas were priced so as to completely displace fuel oil and propane as heating and cooking fuels, demand would be 1/

	DELIVERED BCF	
	1985	2010
Battelle low	3.2	4.6
Acres middle	3.4	5.9

Finally,

6) The total market (all fuels) if garnered by gas would amount to

	DELIVERED BCF	
	1985	2010
Battelle low	5.1	7.3
Acres middle	5.3	9.3

Monthly Peak vs. Total Annual Demand: In the absolute, and as a percentage of the annual total, monthly heating degree days in Fairbanks average: 2/

1/ As shares of the total market these would be 64.5 percent (residential heating/cooking) and 59.1 percent (commercial heating/cooking).

2/ National Oceanic and Atmospheric Administration.

	JAN	FEB	MARCH	APRIL	MAY	JUNE
Heating Degree Days	2384	1890	1720	1083	549	211
% of Total	16.6	13.2	12.0	7.6	3.8	1.5

	JULY	AUG	SEPT	OCT	NOV	DEC
Heating Degree Days	148	304	618	1234	1866	2337
% of Total	1.0	2.1	4.3	8.6	13.0	16.3

Heat loss per unit of time between a structure and the outside is directly proportional to the temperature differential and inversely proportional to the amount of insulation between the two. In a uniformly insulated structure, we have approximately:[1/]

$$\text{Heat Loss} = k^*(T_2-T_1)/L$$

where k is a thermal conductivity constant that declines as the structure's insulation increases;

T_1 is the mean daily outside temperature in degrees;

T_2 is the mean daily inside temperature in degrees;

L is the length of the path travelled by the heat.

Applying this formula one can approximate month to month consumption of heating energy by defining July requirements as a reference level and calculating relative heat loss from the formula above based on the percentage difference between the number of heating degree days in a given month and the number of July heating degree days.

1/ See Lunde, Peter J., Solar Thermal Engineering, (John Wiley and Sons, New York) 1980, pp. 18-19, or one of many similar texts.

This yields the percentages given above.

Applying these monthly fuel requirement percentages to our annual projections of natural gas demand we derive the monthly peak demands for methane (delivered MCF) shown in Table E-6.[1/]

Improved Efficiency: The results of this study are premised in part on average heating efficiencies of 65 percent for fuel oil burners and 75 pecent for gas burners. Improved efficiency can be achieved for both types of units. If heating efficiency improves, delivered energy requirements decline. If one wishes, one can multiply our forecasts of delivered MMBtu's by the factor (.75/Effga) to obtain an "adjusted" efficiency forecast, where Effga is some alternative estimate of gas heating efficiency.

1/ Cooking energy is spread in the same proportions as heating energy, a minor "error" given our estimate of cooking demand relative to the total (about 5%).

TABLE E-6

DELIVERED ENERGY, PEAK DEMAND MONTH
(MCF)

	January, 1985	January, 2010
Battelle "Low"		
10% of Market	117,255	167,222
25% of Market	293,138	418,054
40% of Market	469,020	668,886
1981 Fuel Oil/Propane Share	746,495	1,064,602
100% of Market	1,172,550	1,672,215
Acres "Middle"		
10% of Market	121,330	214,220
25% of Market	303,325	535,549
40% of Market	485,320	856,879
1981 Fuel Oil/Propane Share	772,438	1,363,812
100% of Market	1,213,300	2,142,198

E2.0 REFERENCES

[1] Alaska Power Authority, "Susitna Hydroelectric Project, Feasibility Report," Volume 1, 1982 (prepared by Acres American, Inc.).

[2] Battelle Pacific Northwest Laboratories, "Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans," February 1982 (prepared for the Alaska Office of the Governor).

[3] Community and Regional Affairs, Alaska Department of, Alaska Taxable 1981, (Division of Local Government Assistance).

[4] Energy, U.S. Department of, Alaska Power Administration, Alaska Electric Power Statistics, 1960-1981, 7th edition, August 1982.

[5] Fairbanks North Star Borough, Community Research Center:
   (a) The Energy Report, August 1982.
   (b) 1978 Fairbanks Energy Inventory, July 1979.
   (c) Community Research Quarterly, Summer 1982.
   (d) The Energy Report, June 1982.

[6] Interior Woodcutters Association, "Fuel Wood Utilization in The Fairbanks North Star Borough," report of a survey conducted November 1981 through January 1982.

[7] Labor, Alaska Department of, Statistical Quarterly, 1978:3 and 1980:3 (Research and Analysis Section).

[8] Resources for the Future, Energy in America's Future, (John Hopkins Press, Baltimore), 1979.

[9] Revenue, Alaska Department of, Petroleum Production Revenue Forecast, Quarterly Report September 1982 (Division of Petroleum Revenue).

APPENDIX F

APPENDIX F

OFFICE OF MANAGEMENT AND BUDGET

DRAFT REPORT COMMENTS

AND

ASSOCIATED RESPONSES

MEMORANDUM

State of Alaska

TO Robert Mohn
Alaska Power Authority
Anchorage

THRU: Gordon Harrison, Associate Director
Division of Strategic Planning

FROM: Ronald D. Ripple RB for RR
Division of Strategic Plannig
Office of Management and Budget

DATE: March 29, 1983

FILE NO.

TELEPHONE NO: 465-3573

SUBJECT: Ebasco Draft Final Report

The work performed thus far by Ebasco Services Inc. on the use of North Slope natural gas for Railbelt electrical and heating end-use adds significantly to the data bank on Railbelt alternatives and to alternative uses of North Slope natural gas. My review will address conceptual issues first and then technical issues.

<u>Conceptual</u>

While this report provides substantial amounts of new data and technical information, it does not constitute a feasibility level analysis of the North Slope natural gas alternative. A feasibility study generally includes a cost-of-power analysis, based on a plan of finance, and a comparison with alternatives. While the information provided is extensive, such comparisons are not and cannot be made. As such, the study more closely fits the definition of a reconnaissance level analysis.

Given the aforementioned, a second issue may be most appropriately addressed at the next stage of analysis. This study has as its focus an electric generation facility based on North Slope natural gas which is to supply the entire Railbelt electrical demand.

This concept follows the Susitna plan of completely displacing existing facilities based on Cook Inlet natural gas. The size of any element of the Railbelt supply network will depend on its relative competitiveness. There is no justification for assuming that any <u>one</u> supply source must be capable of delivering the entire load. In fact, it appears that a major drawback to Susitna is that it is too large and too inflexible. An optimal supply system will take into consideration the relative competitiveness of all supply sources and balance the size of each element on this basis. Cook Inlet natural gas is close to the primary load center, plentiful, and likely to very competitive with North Slope natural gas for Railbelt electricity. Therefore, it does not appear reasonable to eliminate Cook Inlet natural gas fired generation out-of-hand.

Technical

1. As discussed during our recent phone conversation, the transmission line costs appear excessively high. I understand that these costs are being reviewed and an independent estimate has been solicited.

2. The Alaska Power Authority economic parameters call for the use of a 3.5% real discount rate, not 3.0%.

3. The text implies that the cost figures have been discounted back to 1982. They have been discounted to 1983. While it is in fact 1983, for comparability, the 1982 figures would be useful, and the tables do not represent the text. The one year discounting differential makes about a 3% difference. This is well within the 15% contigency applied to most cost elements. However, the transmission lines, which account for the bulk of the costs in the North Slope generation alternative, have no contigency attached.

4. Given the unusual nature of the transmission line from the North Slope, i.e., the length, terrain and conditions, it would seem appropriate to attach a contigency factor to this element.

5. The handling of transmission line O & M is curious. First, the annual average cost is approximately 1% of the total construction cost. There is no justification provided for using the 1% factor. Second, it is noted that "Actual O & M costs should be less initially, and increase with

time." (p. 2-32). However, Ebasco uses a flat average annual cost. This has the tendency to increase the present value of costs relative to a stream of costs which increase over time.

6. Why was the 1260 psi pipeline scenario choosen? This follows the ANGTS design, but justification is not given. The TAGS design calls for an operating pressure of 1660 psi. In the TAGS report (p.13) it is noted that while the higher pressure line required thicker wall pipe the reduced diameter lead to less weight per mile in pipe. Presumably less steel will imply less cost. This should be looked into.

7. Chapter 4 values for natural gas consumption in 2010 for a combined cycle facility show a 20 Bcf/year savings over the simple cycle in Chapter 2. At an unescalated price of $1 per mcf the saving over the entire period is about $98 million, in 1982 dollars discounted at 3%. This is a substantial saving. Moreover, in non-discounted dollars, the savings in 2010 and beyond is $20 million annually. Why then is the simple cycle chosen for the North Slope?

8. The relative capital costs between locations seem out of line. Reference Table B4-2. Both the North Slope and the Kenai location can make use of barged, modular units which are constructed in the lower-48 at lower labor and materials cost. Fairbanks, on the other hand, cannot make use of modular construction. The materials must be shipped from the lower-48, transported overland and construction performed at the Fairbanks site. Given this difference, it is surprising that the Fairbanks facilities are the least costly, especially when compared to Kenai.

9. Errors in representation of natural gas prices still remain in Appendix B. Reference p.B4-1. The $5.50 export price is the Japan landed price, not an ex-Alaska price. Also, Battelle's $5.92 per MMBtu is for Fairbanks, not Anchorage.

Please feel free to contact me if you have any questions.

cc: Lennie Boston
George Matz

RESPONSES TO OFFICE OF MANAGEMENT AND BUDGET QUESTIONS

CONCEPTUAL

We concur that this study does not constitute a feasibility level analysis. The purpose of the study was to select the most appropriate types of facilities for utilization of North Slope gas, to optimize their scale and general configuration, and to estimate facility costs at a reconnaissance level. The system studies undertaken were designed to complement this purpose, not formulate a complete power supply system for the Railbelt. The facilities described in this study will be time phased and incorporated into comprehensive power supply plans in the course of other power planning activities. These other activities are not being limited to a single supply source and are not dismissing Cook Inlet natural gas.

TECHNICAL

1) Ebasco's transmission line cost estimates reflect the unique project setting and the system stability and reliability required. The line will represent the major electrical service for the entire state. Heavy duty towers (48 ton) and associated equipment were required based upon high wind loadings (up to 130 mph), extreme radial ice loadings (1.5 inches), and reliability requirements. These design specifications were confirmed based upon discussion with ARCO electrical engineers and their Prudhoe Bay experience (ARCO operates 75 miles of 13.8 kV lines in this arctic environment). Such specifications significantly increase costs. The environmental and topographical constraints in the Kenai to Anchorage transmission system required a submarine cable crossing near Turnagain Arm. This served to increase the line's cost. Several construction factors also raised costs, including the extreme remoteness of much of the routes, the very narrow time window for construction, and compressed construction schedules due to climatic conditions.

The Power Authority has solicited an independent cost estimate which will be reported as an addendum to this study.

2) Current Power Authority economic parameters do use a 3.5% real discount rate. A real discount rate of 3.0% was however previously utilized by Acres American Inc. in their Susitna Hydroelectric Project Feasibility Studies and by Battelle Pacific Northwest Laboratories in their Railbelt Electric Power Alternatives Study. The 3.0% rate was therefore utilized in this study to facilitate an economic comparison with these previous efforts.

3) Discounting back to a specified year is a matter of convention. Two conventions exist regarding whether the beginning or end of the year is used as the point of cash flow occurrence. We used the end of year convention. The statement of the problem implies a realization of the answer, and as noted, the difference (3%) is well below the contingency included in each cost estimate.

4) A 15% contingency is included in the transmission line cost estimates. It is factored into each bid line item cost. Please refer to the notes cited in each table.

5) Based on Ebasco's experience, the one percent value is suitable and appropriate for these transmission systems. It is derived from Ebasco's transmission line experience and an analysis of recent cost data supplied by several local Alaskan utilities. It should be noted that the effect on present value from the average annualization of transmission line O&M costs is insignificant.

6) ANGTS was chosen as the convention because it is the proven, licensed technology. The Trans Alaska Gas System proposes some unique design features which will have to be evaluated during detailed engineering.

7) Simple cycle is favored because of the added complexity of operating boilers on the North Slope with attendant water supply, water treatment, water chemistry control and other more specialized maintenance requirements of the higher temperature steam cycles. In addition, spare parts requirements increase due to the addition of the steam turbine cycle and other equipment. It was, thus, felt that the technical advantages of the simple cycle unit outweighs the slight economic edge of combined cycle. This decision is explained in Appendix B.

8) Factors such as water requirements and emissions standards (e.g., nitrogen oxides) cause variations in capital expenditures at different locations. A water supply and water injection system to control nitrogen oxides was assumed for the Kenai location. These systems were not included in the Fairbanks plant due to ice fog problems. Please refer to our discussion of air quality concerns in Chapters 4.0 and 6.0.

9) The discussion of natural gas prices presented in Appendix B (Page B4-1) briefly summarized our rationale for choosing the price range utilized in our sensitivity analysis, i.e., $0.00 through $5.50 per MMBTU. The sensitivity analysis was performed to support our recommendation of the most appropriate technology for each study location. There is no error in representation. The $5.50 cited is a direct quote from one of our contacts listed in Appendix A. If this price is the Japan landed price as suggested it makes little difference to the discussion. The Governor's Economic Committee report estimates LNG shipping costs at $1.00/MMBTU in 1988 dollars which would be $0.66 in 1982 dollars when using the Committee's reported economic parameters. Subtracting $0.66 from $5.50 yields $4.84. The $5.92 is for Fairbanks and not Anchorage. The text has been corrected on this point. To further justify our range and our recommendations, the following LNG costs are cited in the Governor's Economic Committee report (see pages 43, 44 and 45 of the Economics Section); calculated 1982 values are also presented for comparison.

4045A

	Total System LNG Tariffs South Alaska ($/MMBtu)	Phase 1 System LNG Tariffs South Alaska ($/MMBtu)
1988	$4.67 to $6.16	$5.94 to $7.91
1982	$3.11 to $4.10	$3.95 to $5.27

In addition it should be noted that the majority of North Slope gas which is reinjected has a negative wellhead price. The value (delivered cost) of the small amount sold to Alyeska varies somewhat in time but was about $1.86/MMBTU when the report was written.

In light of the above cited prices it could possibly be argued that the price range used in our sensitivity analyses should have been expanded to include negative values and values greater than $5.50. To do this, however, would not have increased the utility of the analysis as the combined cycle technology was always favored when natural gas prices were above about $1.50/MMBTU.