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

DRAFT FINAL

REPORT

FEASIBILITY LEVEL ASSESSMENT

APPENDICES

EBASCO

EBASCO SERVICES INCORPORATED

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ALASKA POWER AUTHORITY

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APPENDIX A

APPENDIX A

REPORT
ON
EXISTING DATA AND ASSUMPTIONS

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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. 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.

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.

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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2. Acres American, Inc., 1982. "Susitna Hydroelectric Project - Feasibility Report - Volume I, Engineering and Economic Aspects, Sections 9-19, Final Draft". Alaska Power Authority. Anchorage, Alaska.

3. State of Alaska, Dept. of Environmental Conservation, 1982. 1 set containing:
    1. Waste discharge permit application form
    2. Copies of current waste discharge permits for
        a. domestic wastewater to lands or waters of the state
        b. wastewater from a desalination plant
        c. discharge of drill muds and cuttings onto sea ice
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ADDENDUM B

LIST OF C''NTACTS

NORTH SLOPE GAS FEASIBILITY STUDY

LIST OF CONTACTS

Name	Organization/Agency	Reason for Contact
Ben Ball	ARCO-Alaska	Gas composition at Central Compressor Plant.
Bob Crosky	ARCO, Vice President Alaska Affairs	Gas use and facilities tour.
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 Norgaerd	ARCO-Alaska, President	Facilities tour.
Brad Spencer	ARCO (Pasadena)	Weight & size restrictions for barged modules to North Slope.
Archie Walker	ARCO-Alaska	Foundation design practi.e-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.

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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.

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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 statitistics, 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.
Ror 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.
Ean 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.

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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	Royal 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.

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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.

Locale1/	Temp2/ °F	Gas Turbine Capacity Change	Steam Turbine3/ 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.

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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.

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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 Anchorage 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.

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.

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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).

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).

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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	[illegible]	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.

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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	9[illegible]5	1041	1066
2006	1641	1720	1746	604	10[illegible]7	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.

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)			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	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	1[illegible]	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

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TABLE B5-5

NEW CAPACITY ADDITIONS - LOW 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	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) 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	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

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TABLE B5-9

NEW CAPACITY ADDITIONS - MEDIUM LOAD FORECAST

KENAI

	Required New Capacity At Peak Demand (MW)			Actual New Capacity (MW)	
Year	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	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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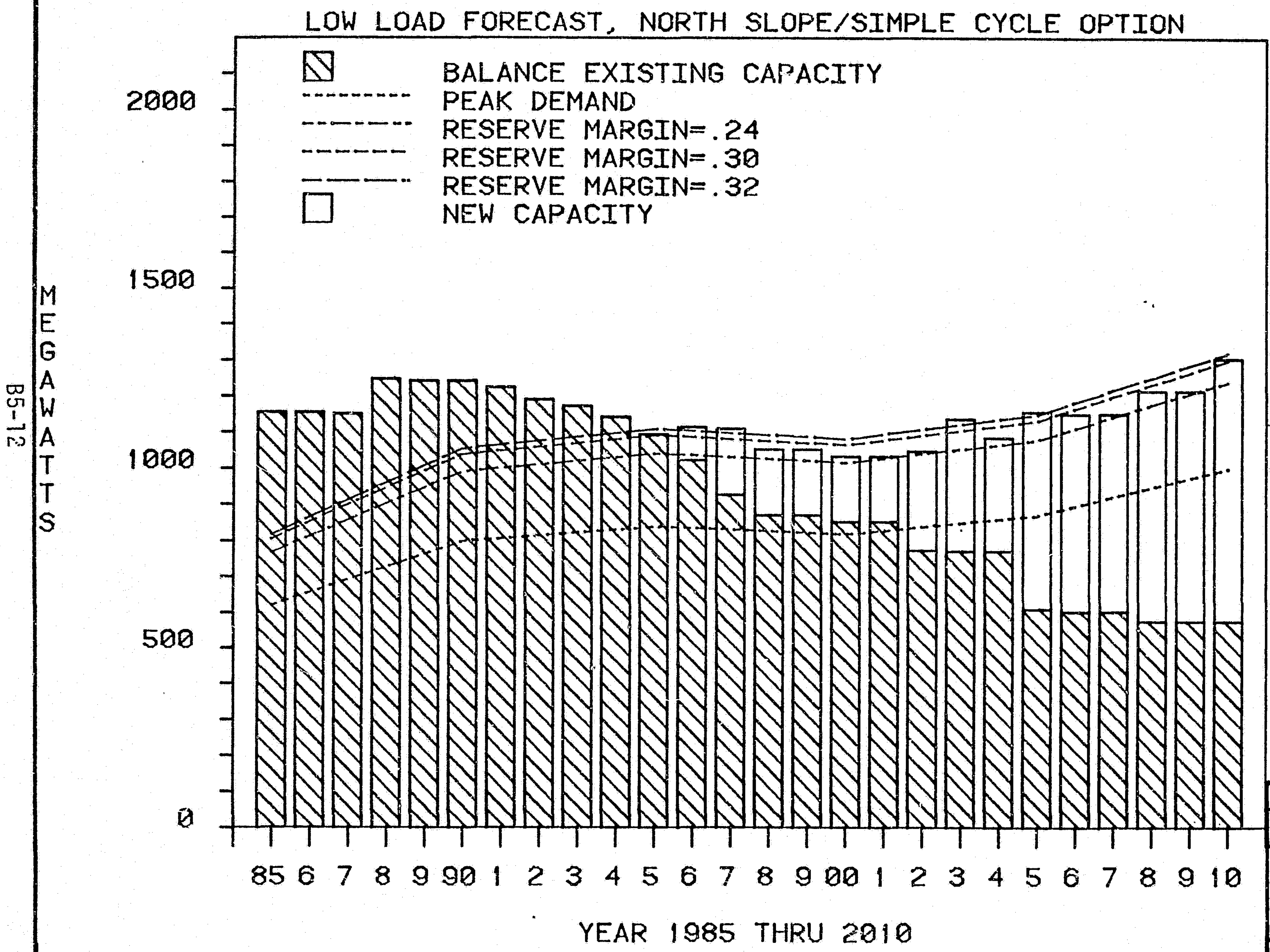


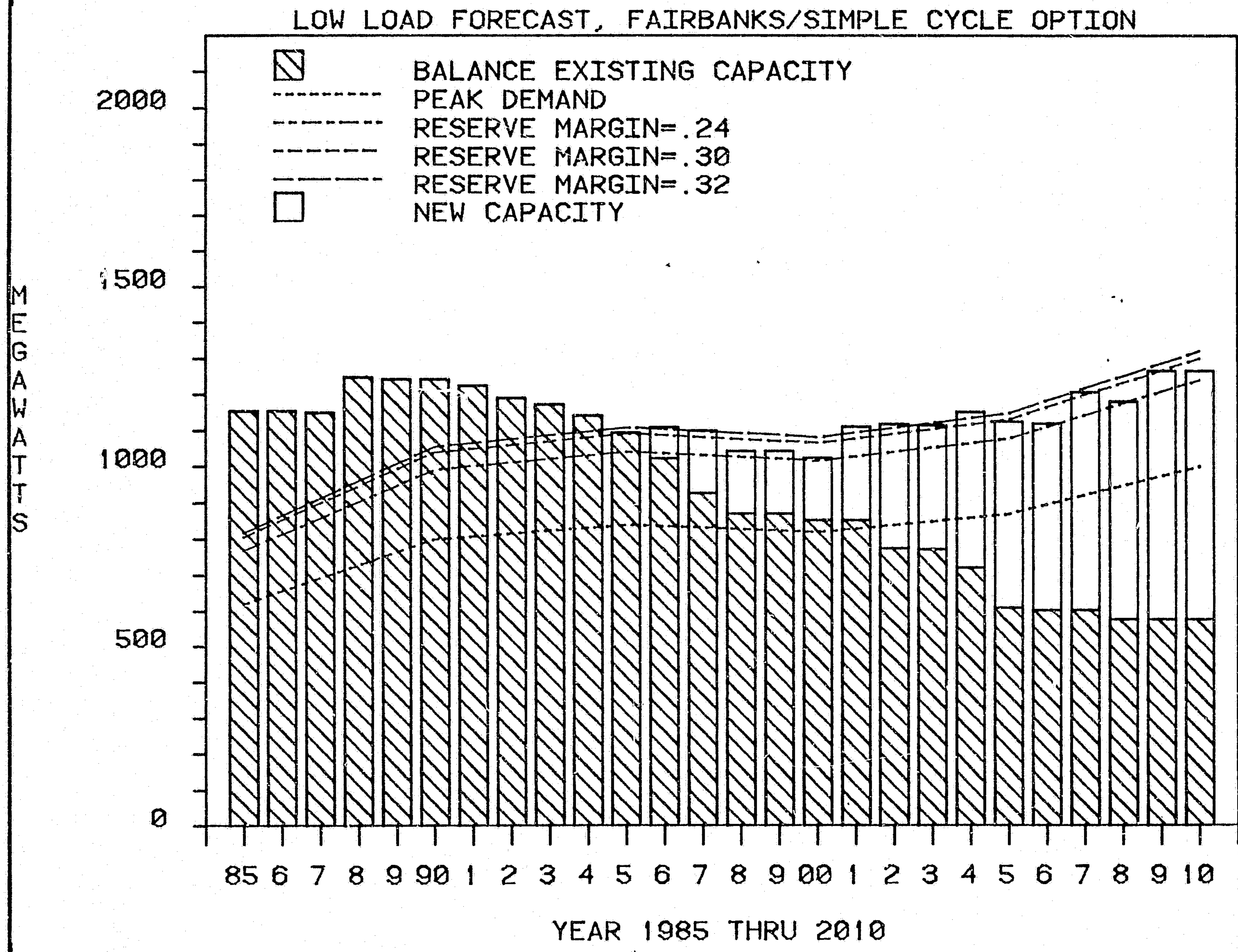
ALASKA POWER AUTHORITY

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



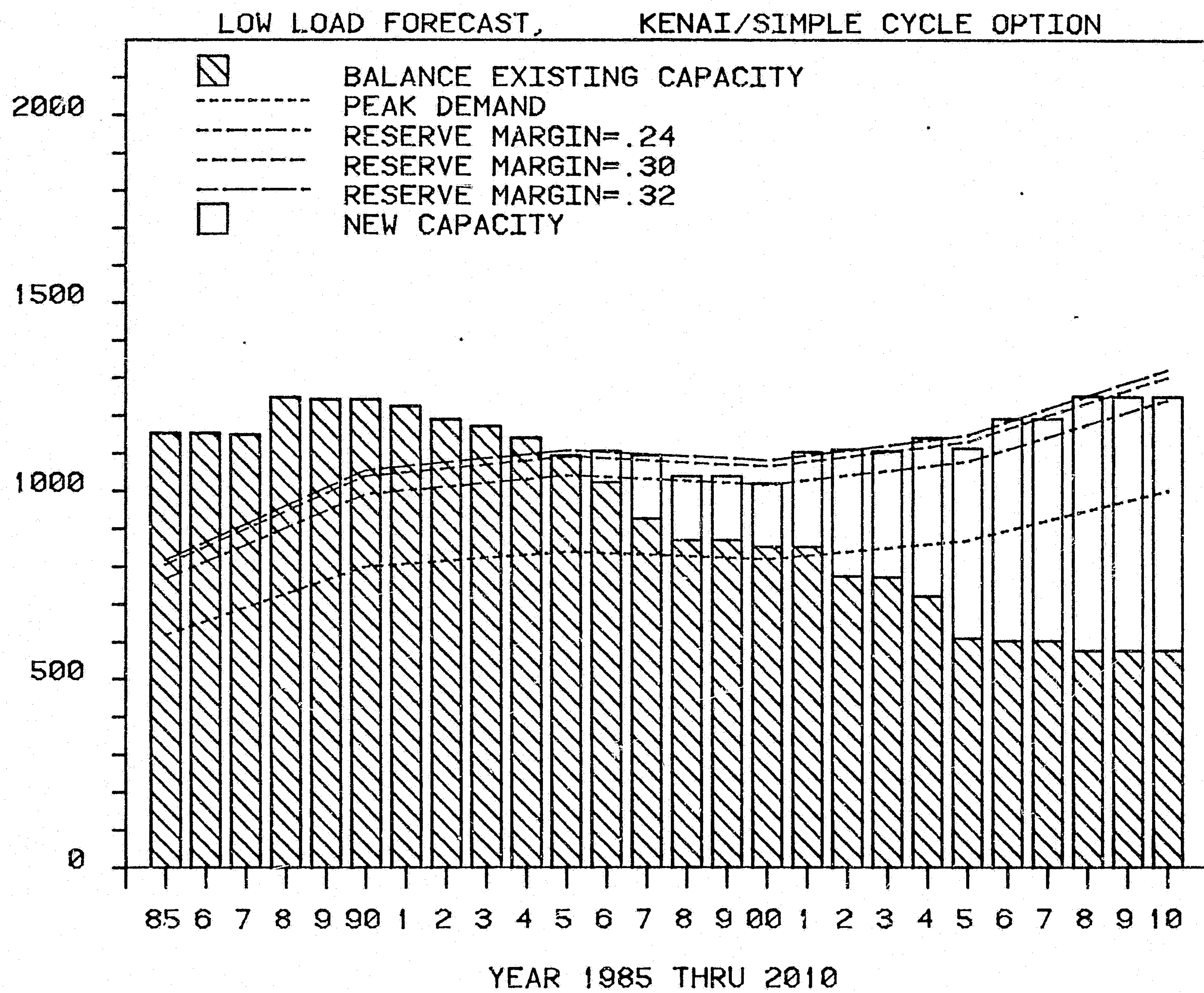
ALASKA POWER AUTHORITY

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



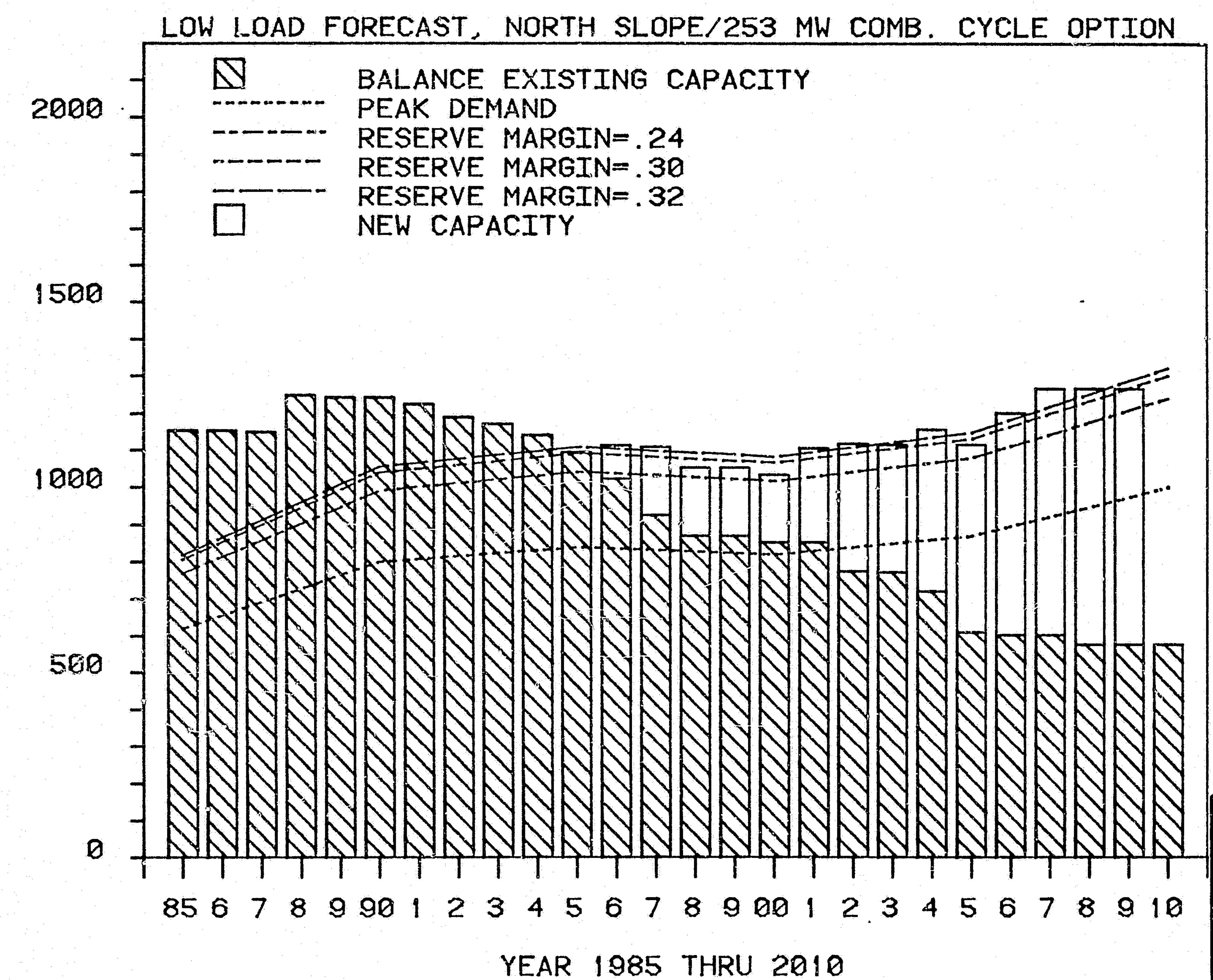
ALASKA POWER AUTHORITY

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



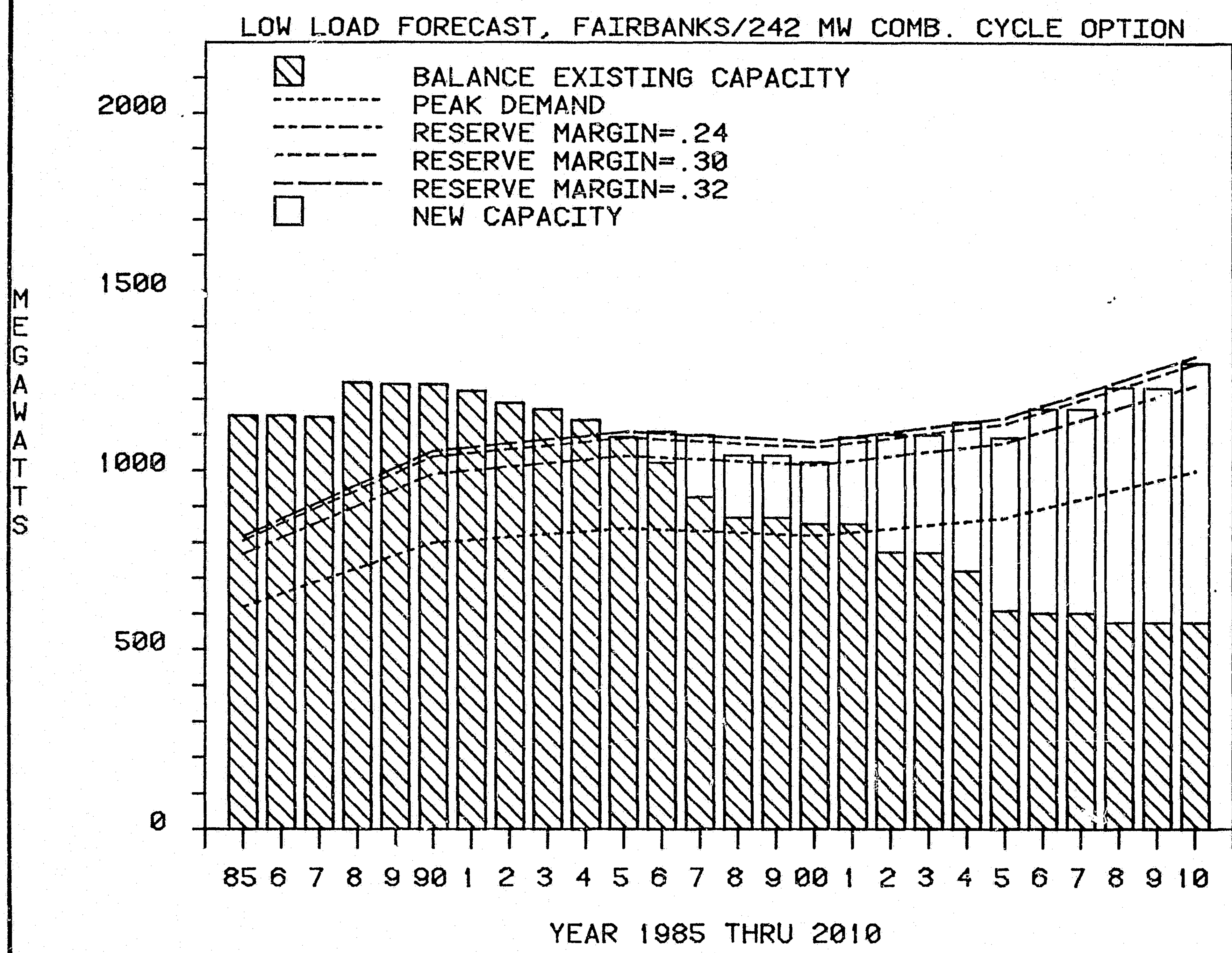
ALASKA POWER AUTHORITY

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



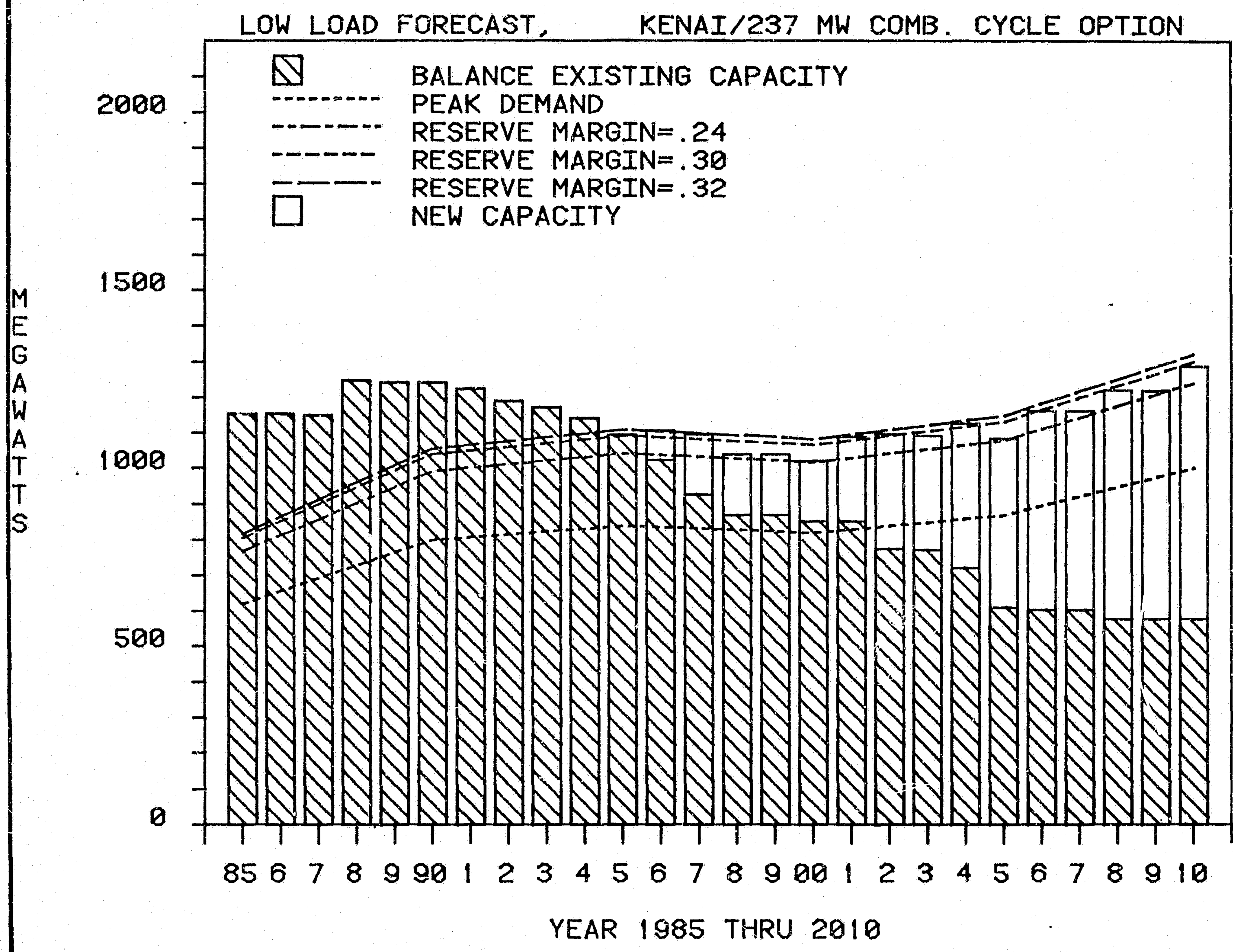
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Low Load Forecast, with Generating Facilities at Fairbanks.

FIGURE B5-5

EBASCO SERVICES INCORPORATED



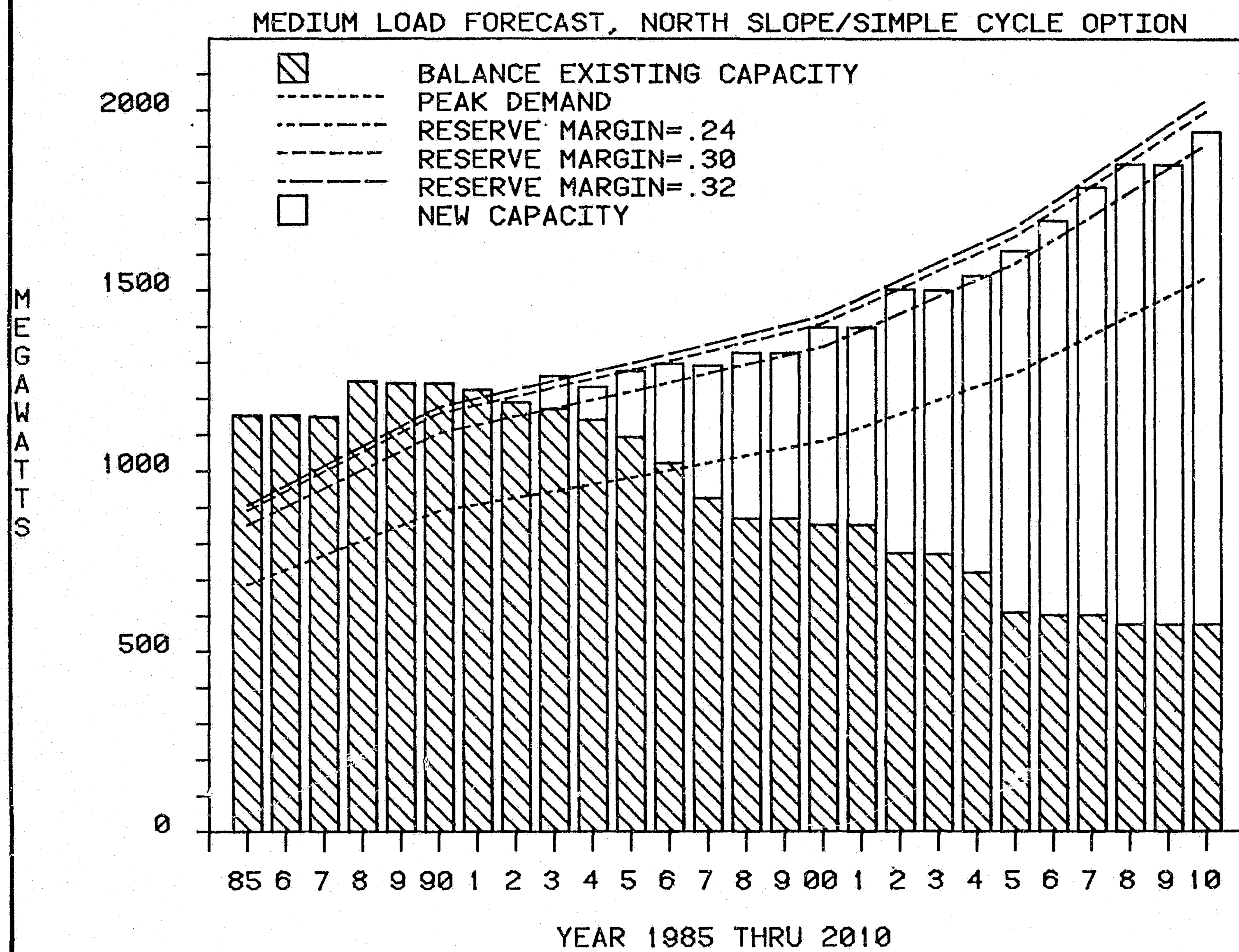
ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

Plot of System Requirements and Capacities for Combined Cycle Technology, Low Load Forecast, with Generating Facilities at Kenai.

FIGURE B5-6

EBASCO SERVICES INCORPORATED



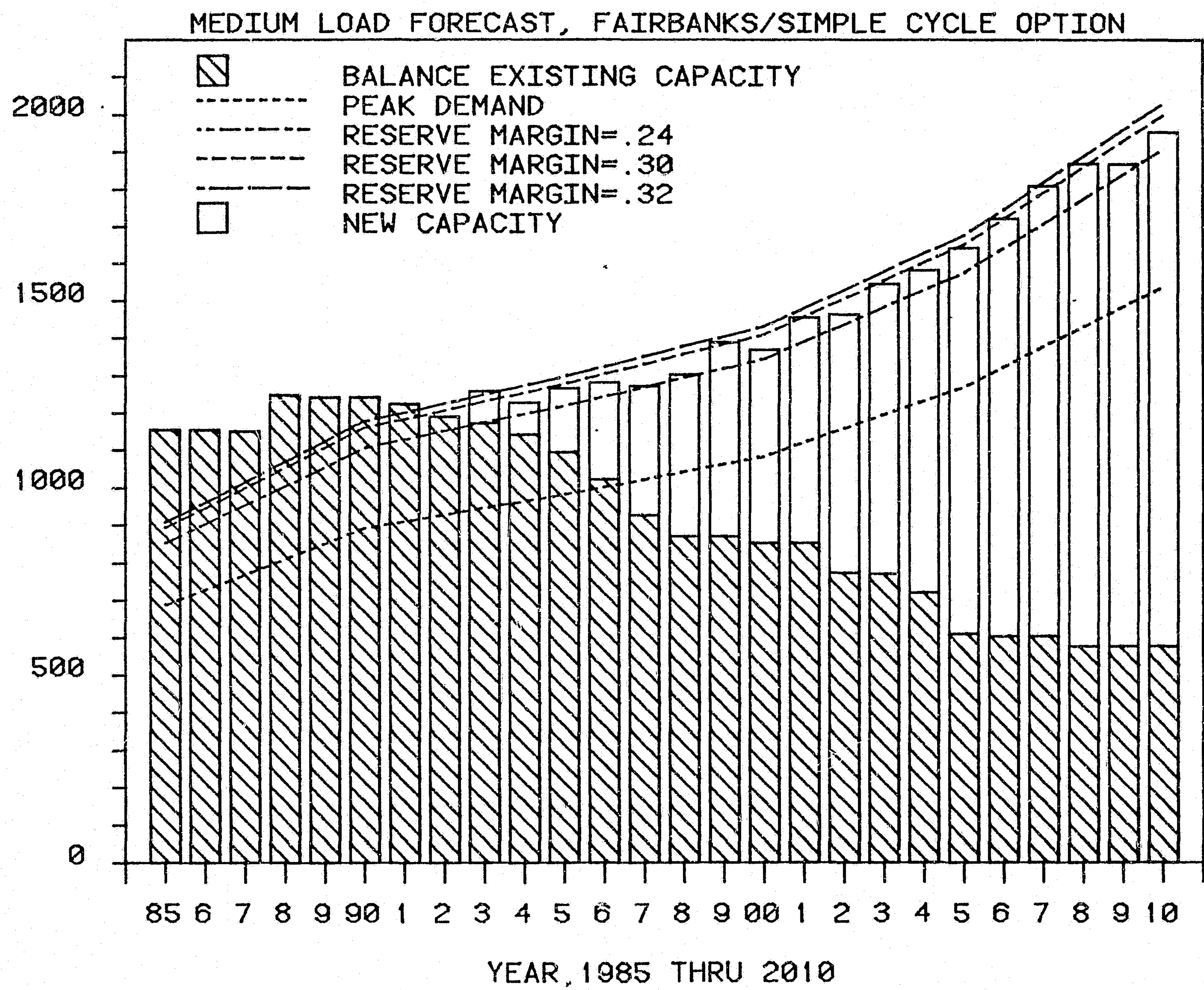
ALASKA POWER AUTHORITY

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



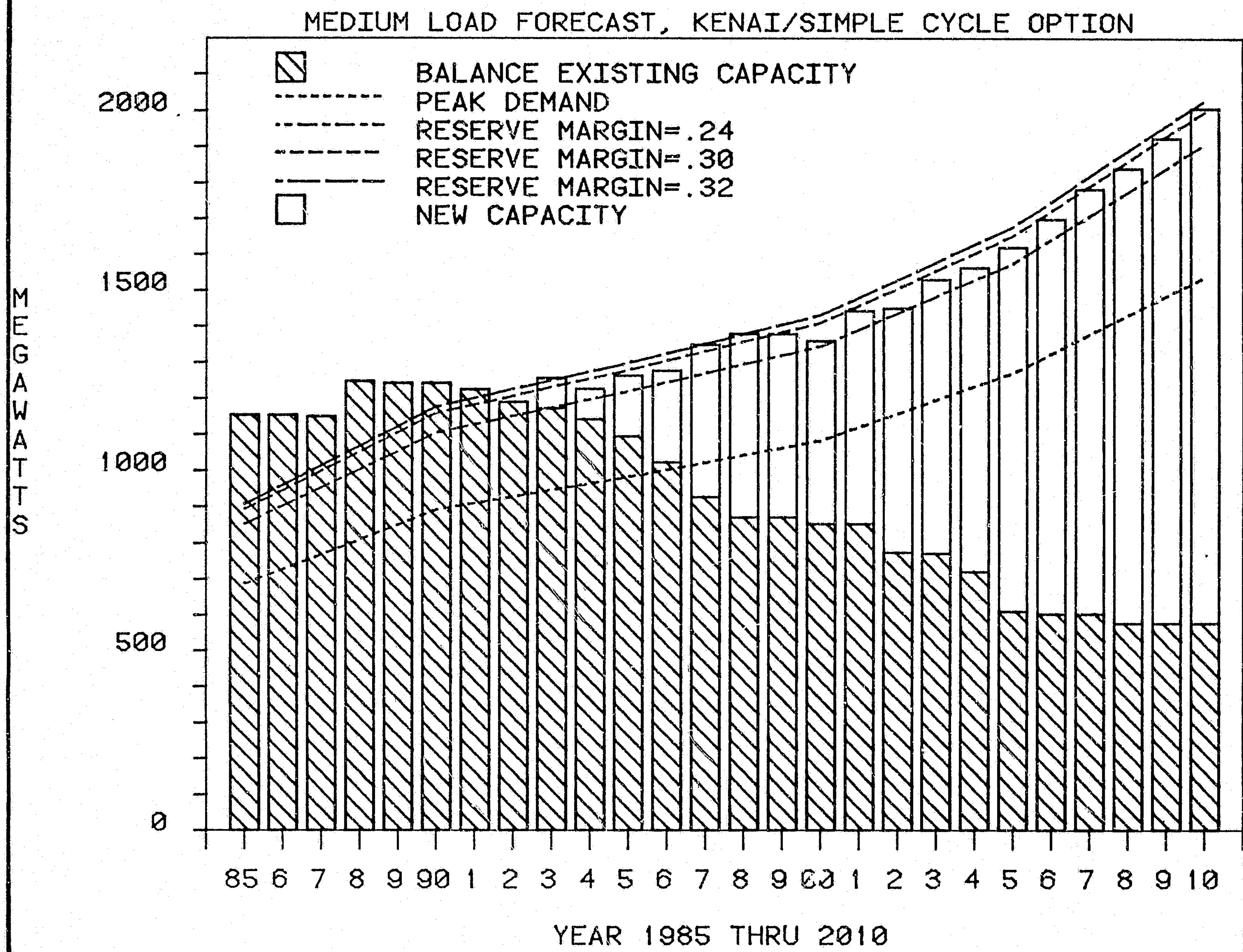
ALASKA POWER AUTHORITY

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

EBASCO SERVICES INCORPORATED



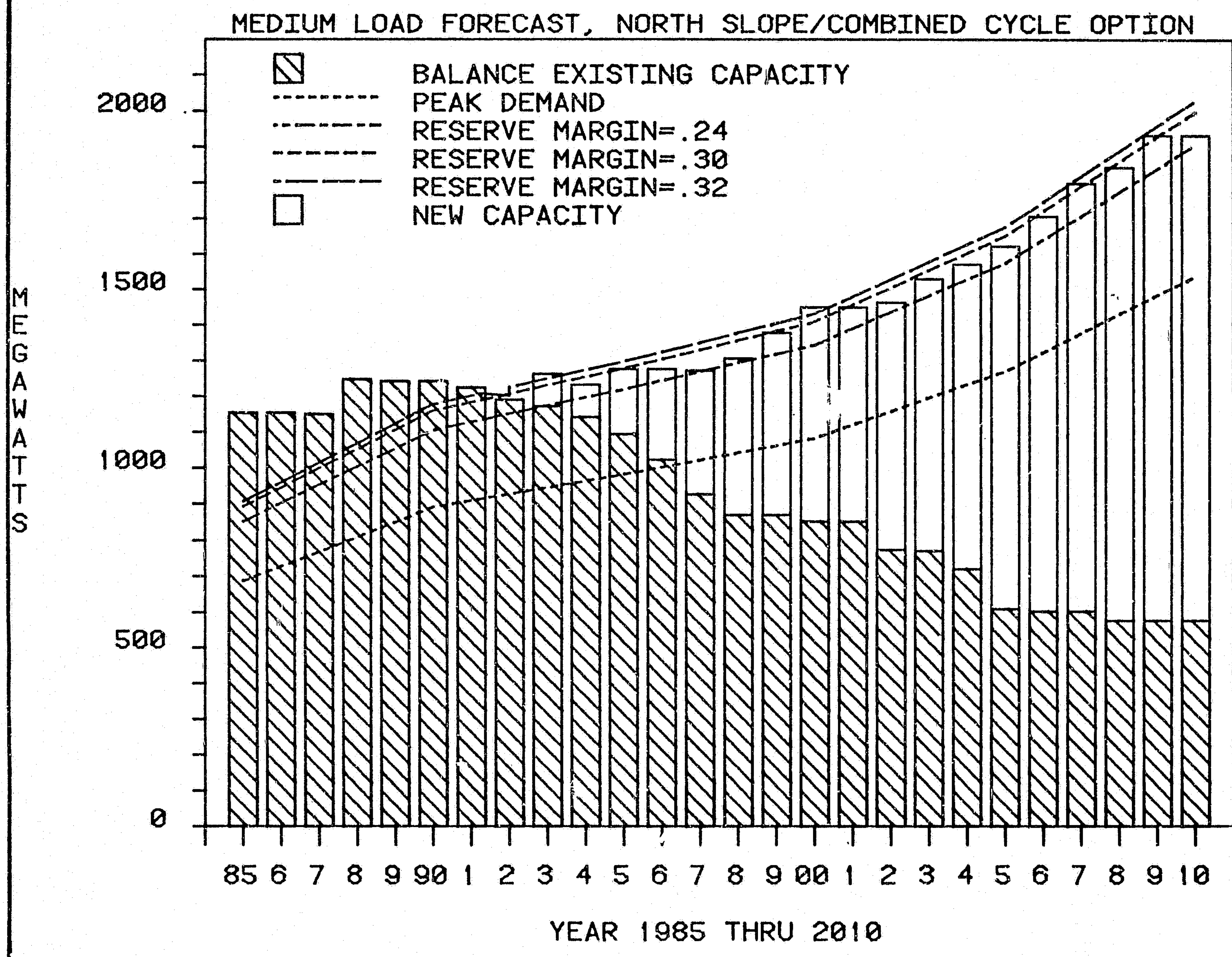
ALASKA POWER AUTHORITY

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



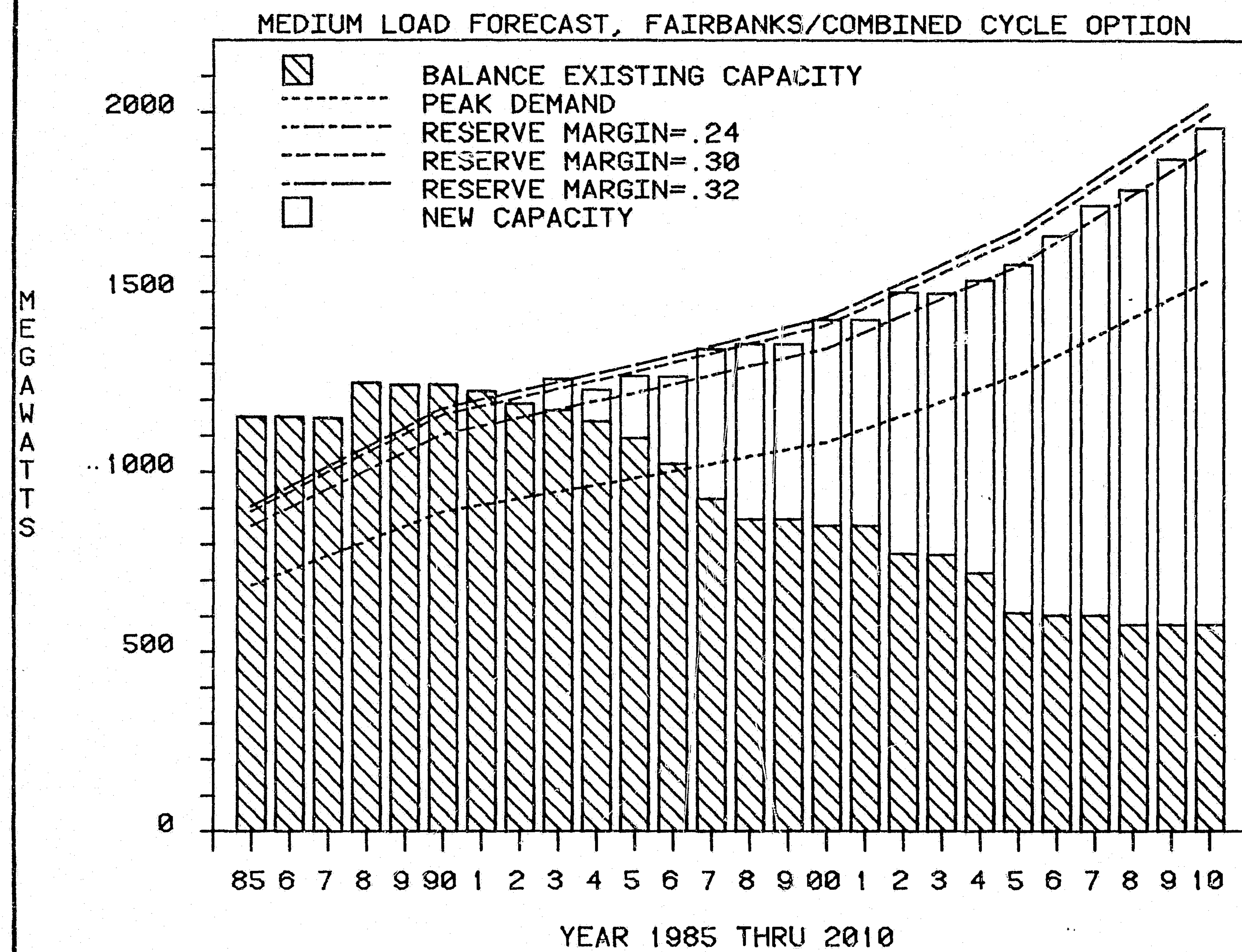
ALASKA POWER AUTHORITY

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



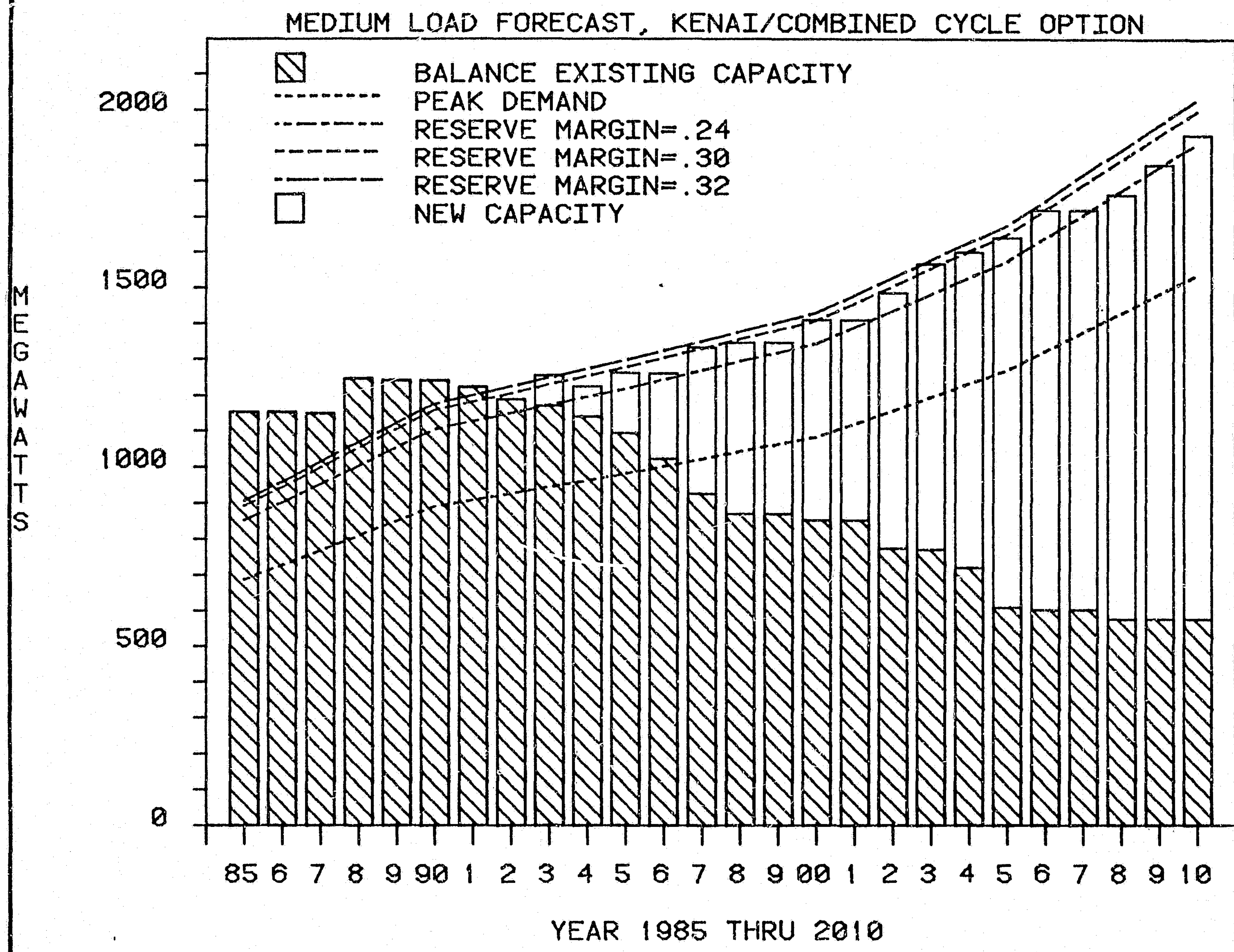
ALASKA POWER AUTHORITY

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

EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

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.

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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.

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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

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Edison Electric Institute. 1981. Combustion Turbine Operational Practices Guidebook. EPRI Operating Development Group. Edison Electric Institute. Washington, D.C.

R.W. Beck and Associates, Inc. 1982. Kenai Peninsula Power Supply and Transmission Study. Alaska Power Authority. Anchorage, Alaska (June 1982).

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.

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^3x10^6
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

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

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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

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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

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

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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	25.392	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

ELECTRICITY PROJECT YEAR	YEAR	PRODUCED (GWH)	EXPENDITURE ($x10^6)	CAPITAL EXPENDITURE ($x10^6)	O&M 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 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.

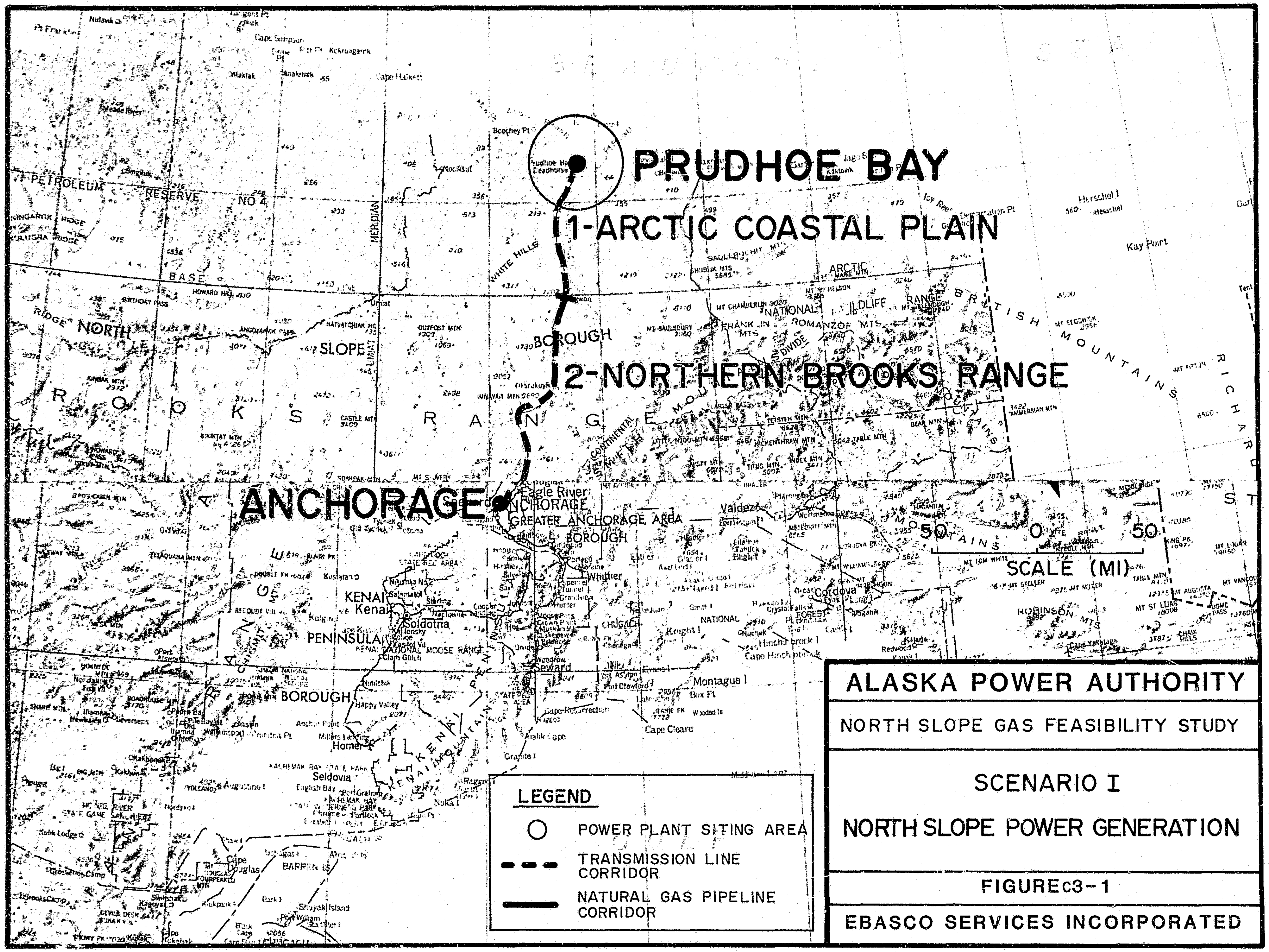
C3.0 SCENARIO I - NORTH SLOPE POWER GENERATION

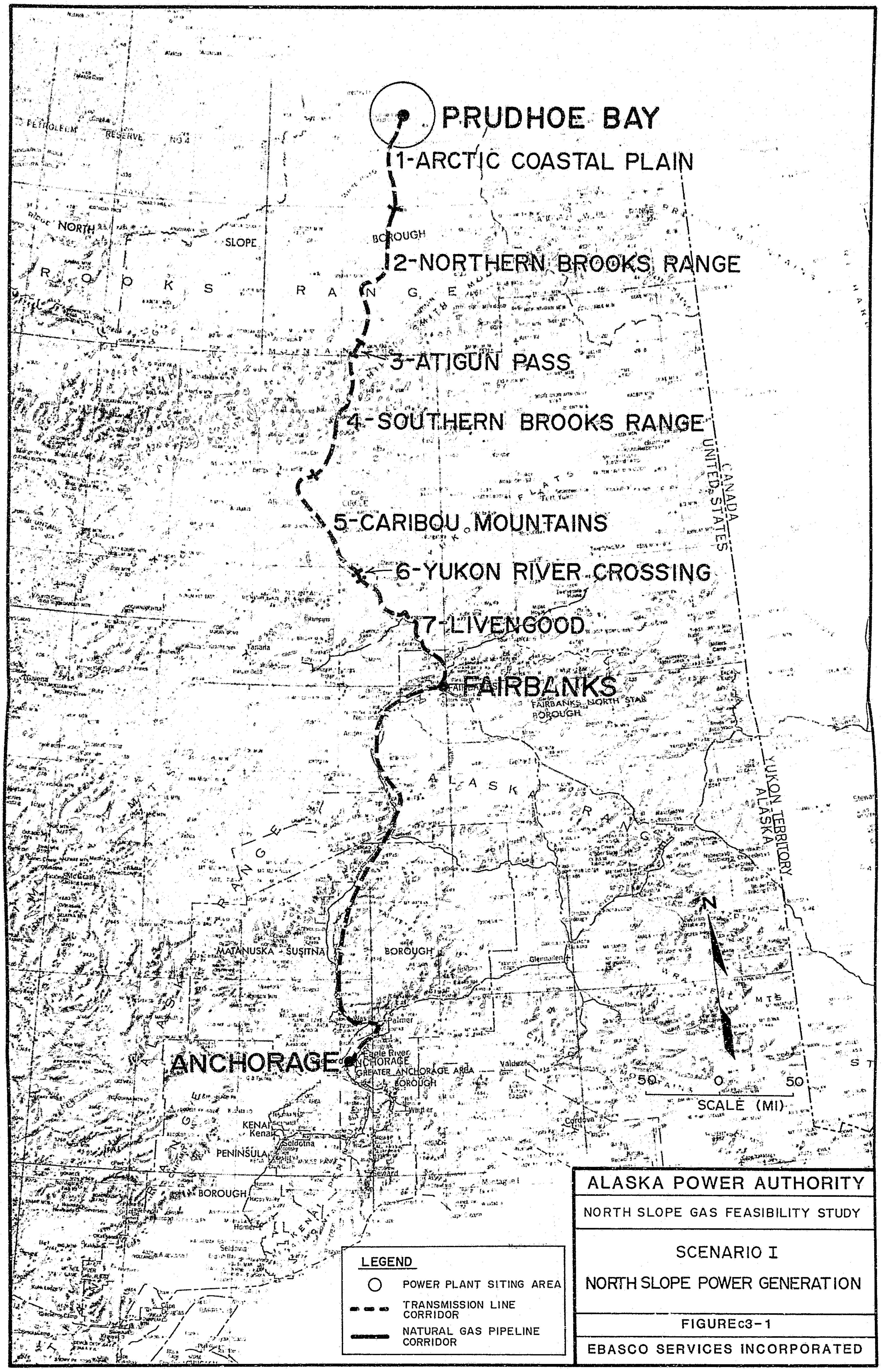
The North Slope scenario consists of electrical generation at the North Slope, with electrical transmission to Fairbanks via a new transmission line, and transmission from Fairbanks to Anchorage via an upgraded Anchorage-Fairbanks Intertie. This scenario is illustrated in Figure C3-1.

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.


PRUDHOE BAY
1-ARCTIC COASTAL PLAIN
2-NORTHERN BROOKS RANGE
ANCHORAGE
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 C3-1
EBASCO SERVICES INCORPORATED



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

SCENARIO I

NORTH SLOPE POWER GENERATION

FIGURE C3-1

EBASCO SERVICES INCORPORATED

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:

- Maximize use of existing facilities such as work pads, highway, access roads, airports, material sites, and communications.
- Minimize crossing roads and highways.
- 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 RAPTORS[1/]

Species	Sensitive Time Period	Protection Criteria				
		Aerial Activity[2/]	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 March[3/]- 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 St tion 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.

<u>Physical Setting</u>

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 2,000 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

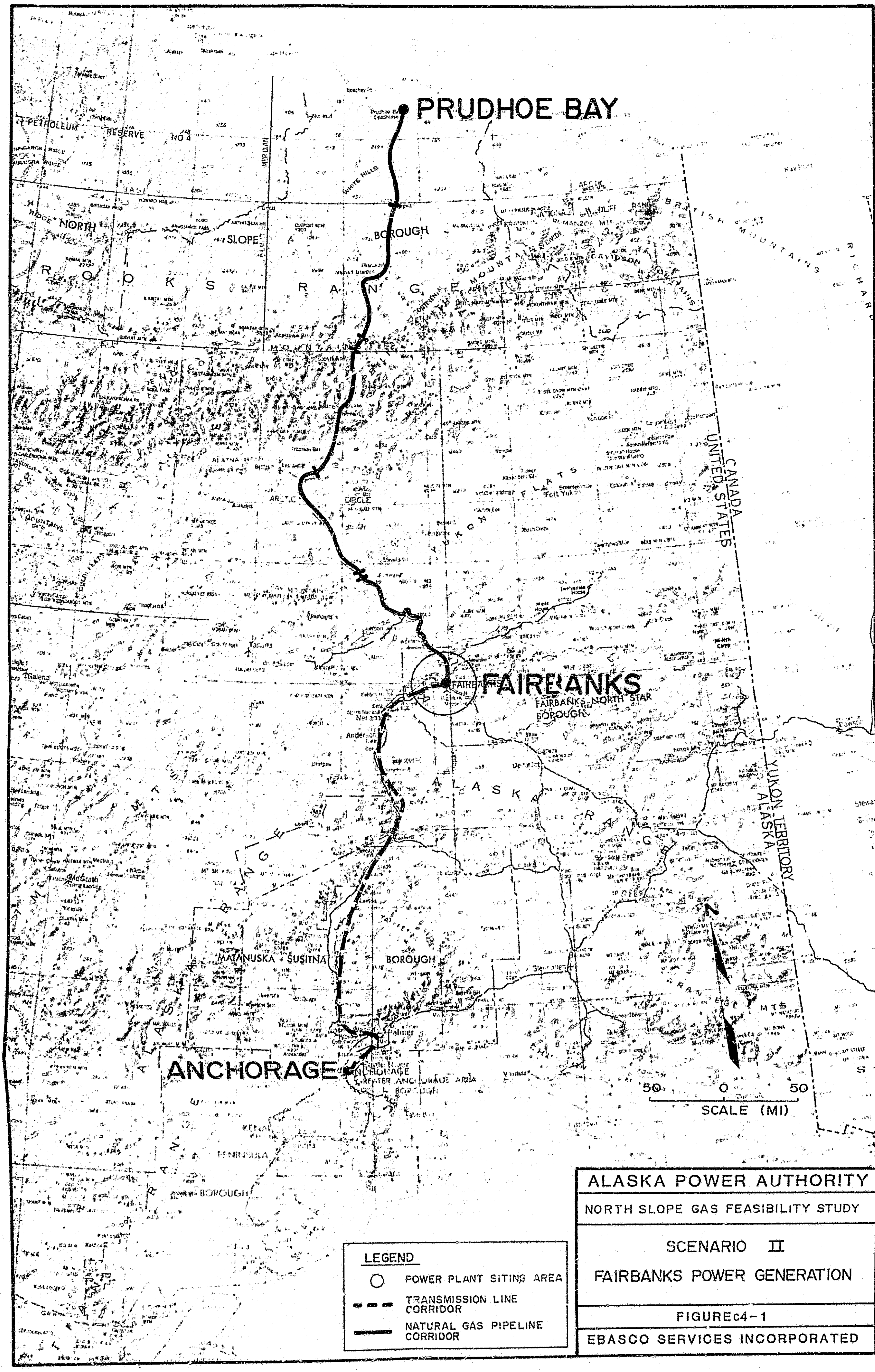
An overall description of the Fairbanks region, followed by power plant siting criteria, a discussion of candidate siting areas, and the generic site description is provided in this section.

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 C4-1

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.

C5.0 SCENARIO III - KENAI POWER GENERATION

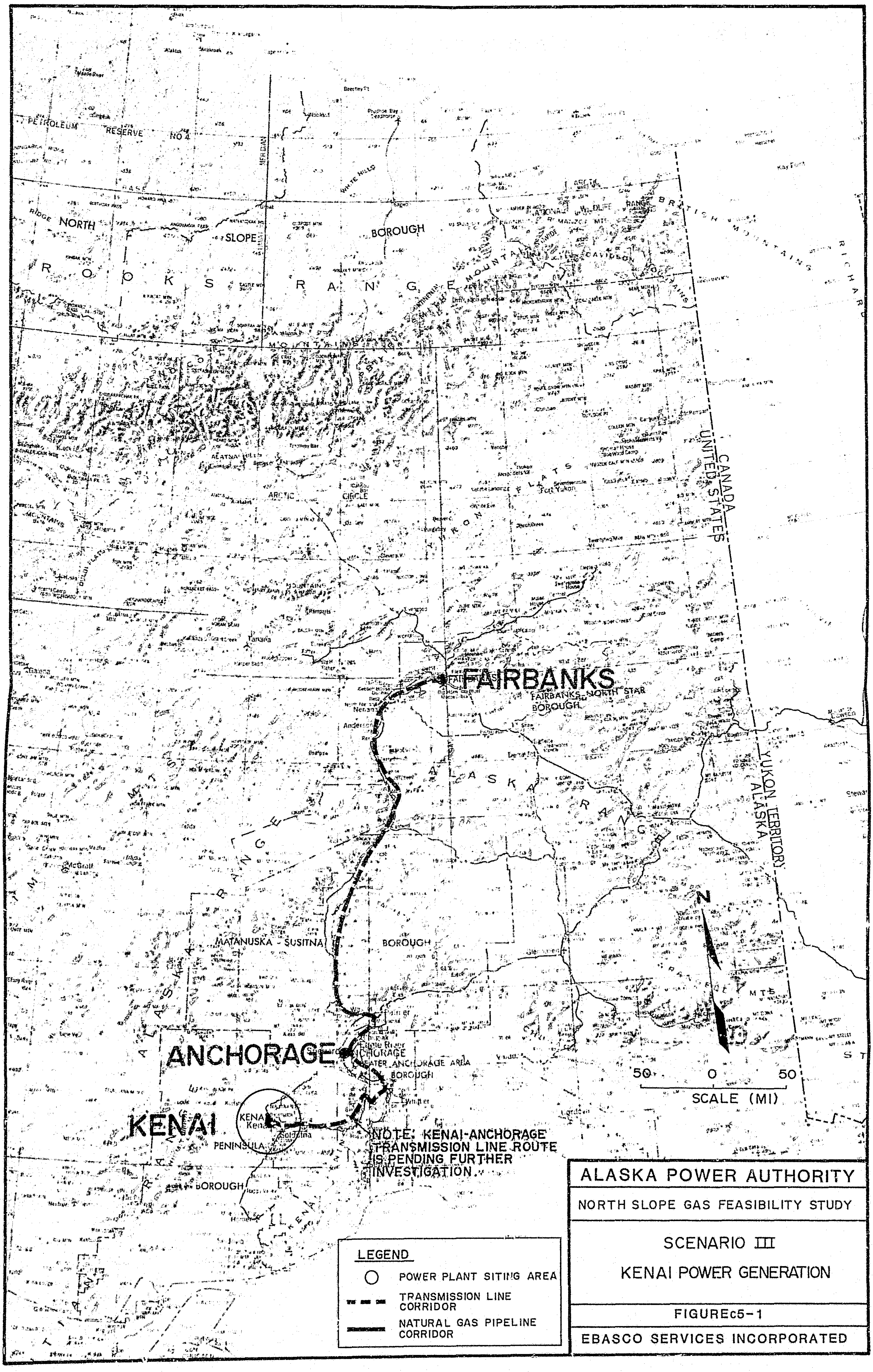
The Kenai Power Generation scenario (Figure C5-1) is predicated on the development of a large diameter natural gas pipeline from Prudhoe Bay to a tidewater location near Kenai or Nikiski. This all-Alaska pipeline is being studied by others. Several assumptions regarding this facility are used in this 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.



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

SCENARIO III

KENAI POWER GENERATION

FIGURE c5-1

EBASCO SERVICES INCORPORATED

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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APPENDIX D

APPENDIX D

REPORT

ON

TRANSMISSION SYSTEM DESIGN

JANUARY, 1983

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2560B

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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 that 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 the rest of the generators connected to the system will be less than 50% of the single big 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 part 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 the 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 simulator 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
$\pm$ 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	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 ±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 satisfy also 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-section of the two bundles is 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 be preferably less but not to exceed 100 feet, and preferably be less.

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. Therefore, 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 ±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 load 700 MW per bipole and 2000 A in case of an emergency 1400 MW per bipole. 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.

In the figures which appear in Section D8.0 at the end of this Appendix, the following symbols are used:

- G - generation
- E - equivalent of the local area system
- GL - Galbraith Lake (150 south of the North Slope)
- OM - Prospect Camp (150 north of Fairbanks)
- FB - Fairbanks
- HE - Healy
- DC - Devil's Canyon
- MP - Midpoint

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, Devil's Canyon, which makes the segments approximately 190 miles from Fairbanks to Devil's Canyon and 140 miles from Devil's Canyon 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 the line is quite acceptable.

Opening of the Devil's Canyon end of the Fairbanks-Devil's Canyon 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 Devil's Canyon line segment open at Devil's Canyon 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 Devil's Canyon, 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 Devil's Canyon 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 Devil's Canyon 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-Devil's Canyon line. It is shown in Figure D-15 and appears to have approximately the same severity as an outage at the Devil's Canyon 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 Devil's Canyon-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 Devil's Canyon.

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 North 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 Devil's Canyon 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 ± 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 DOE. Although these figures are based on lower 48 costs, their relative value was used to do a cursory comparison. The results were within ± 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

Prudhoe Bay to Fairbanks

Medium Forecast

(1) 765 kV, two circuits
(2) 500 kV, two circuits with series compensation
(3) ± 350 kV DC, two bipoles[1/]

Lower Forecast

(4) 500 kV, two circuits
(5) 345 kV, two circuits with series compensation
(6) ± 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.

2560B

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.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(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	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	FT
1	1.3440	0.0000	1.3440	200.00	2.55	0.00	399.59
2	1.3440	2.7123	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	10124	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	13865	16000*	16272	50.85
4	86	0.00	2.30	.00	34.17	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	34.17	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.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(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	WH	WR	LOW POINT(FT)		ADD.L	UNSTR.L
	LB/FT	LB/FT	LB/FT	HORIZ.	VERT.	FT	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	3031	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.	RED.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	6.3725	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 01/08/82

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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	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.	ICE	WIND	K	SAG	TENSIONS(LB)			% RTS
	F	IN	PSF		FT	HORIZ	AVG	UP.SUP	(3)
1	-60	0.00	0.00	.00	30.22	7192	7210	7249	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	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	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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	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) 23500 LB (2) AT -60 DEG.F, 0.00 IN ICE, 25.00 PSF WIND, K=0.00
C) 23500 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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	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. F	ICE IN	WIND PSF	K	SAG FT	TENSIONS(LB) HORIZ	AVG	UP.SUP	% RTS (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 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	500.00	30.03	0.00	1001.81
2	2.0750	3.3375	3.9300	500.00	32.67	0.00	1001.81
3	7.8635	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	1511.53
2	2.0750	3.3375	3.9300	750.00	85.45	0.00	1511.55
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

G - generation

E - equivalent of the local area system

GL - Galbraith Lake (150 south of the North Slope)

OM - Prospect Camp (150 north of Fairbanks)

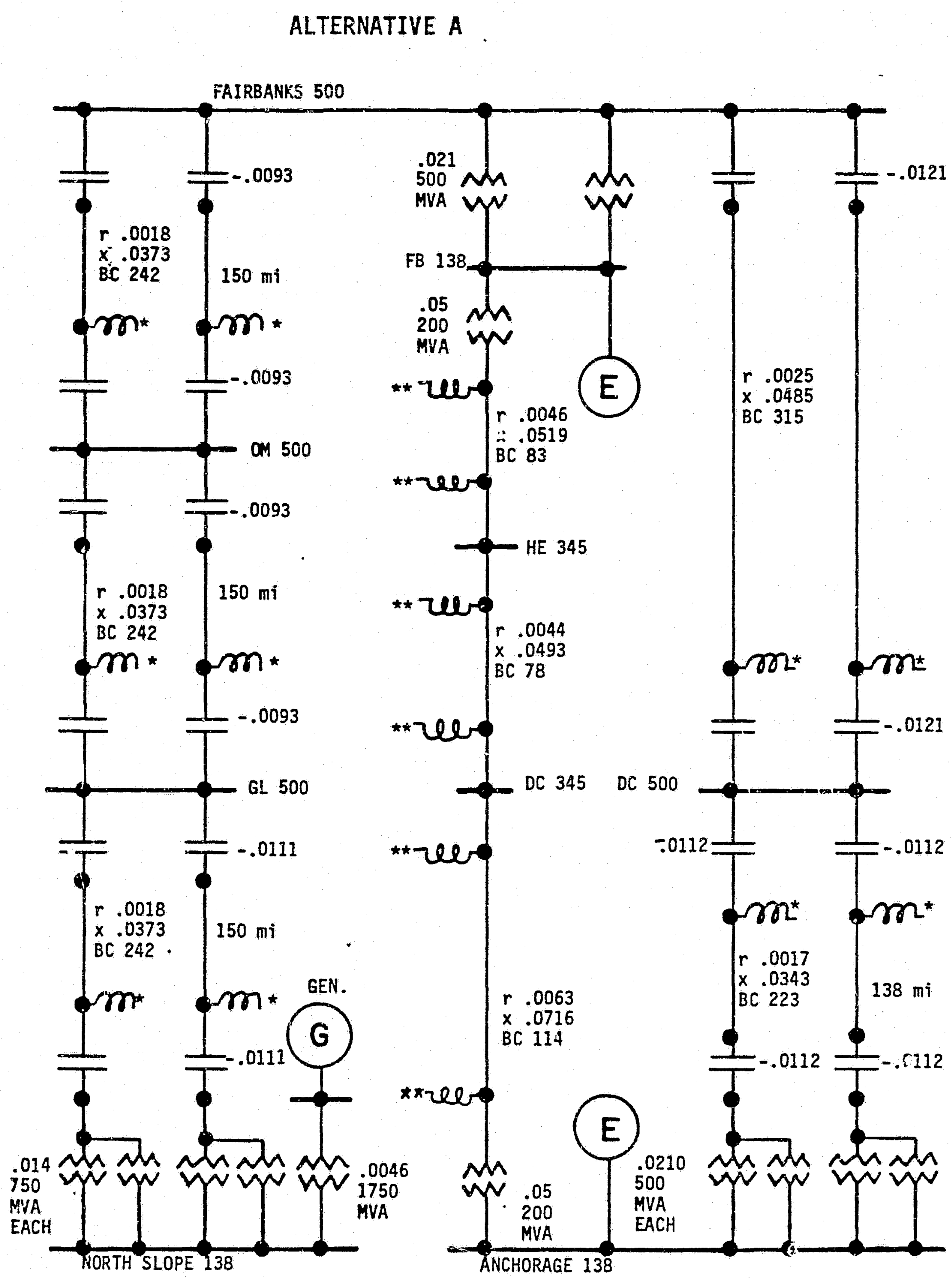
FB - Fairbanks

HE - Healy

DC - Devil's Canyon

MP - Midpoint

All impedances shown in the figures are on 100 MVA base.



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

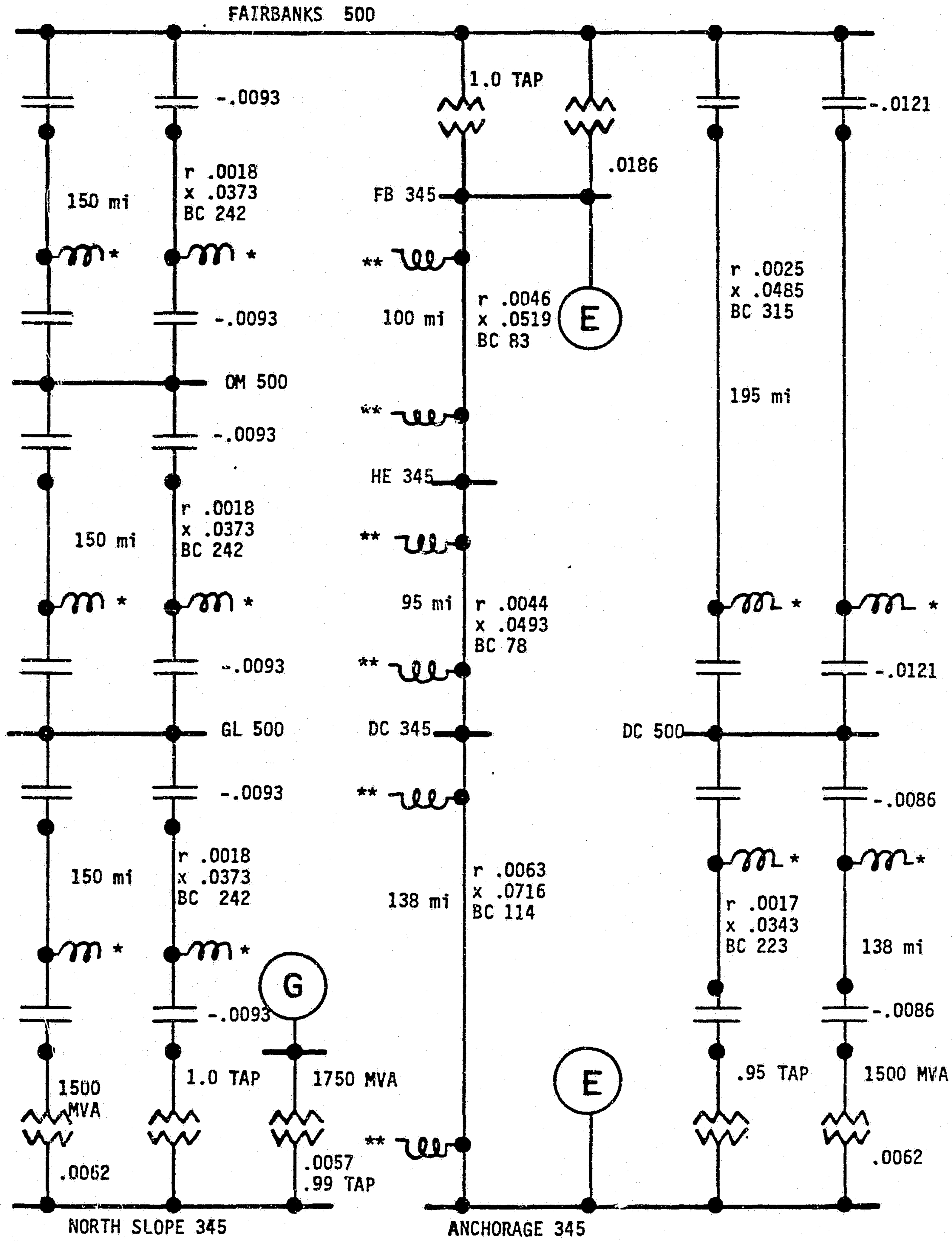
ONE LINE SCHEMATIC WITH IMPEDANCES

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

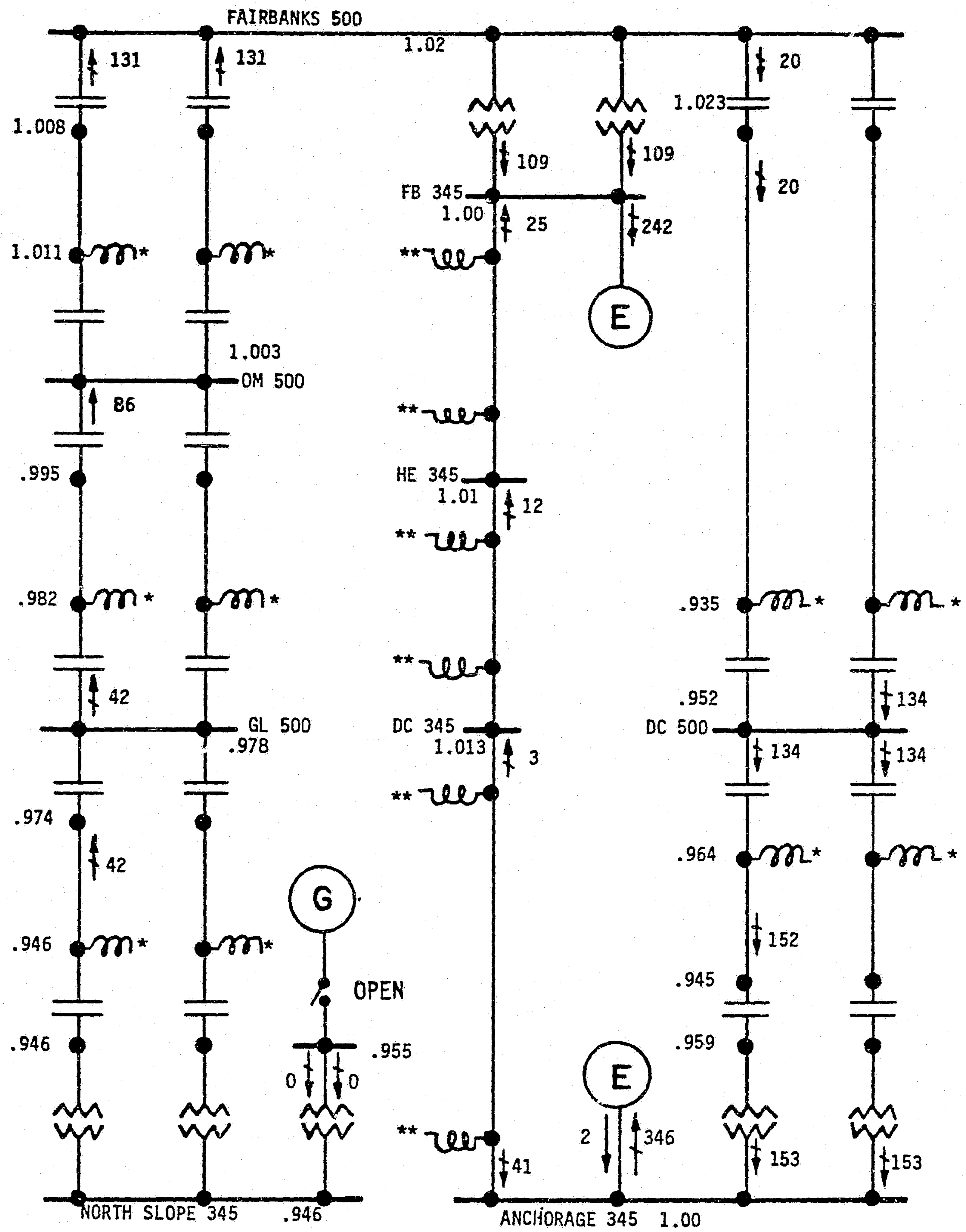
ONE LINE SCHEMATIC WITH IMPEDANCES

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

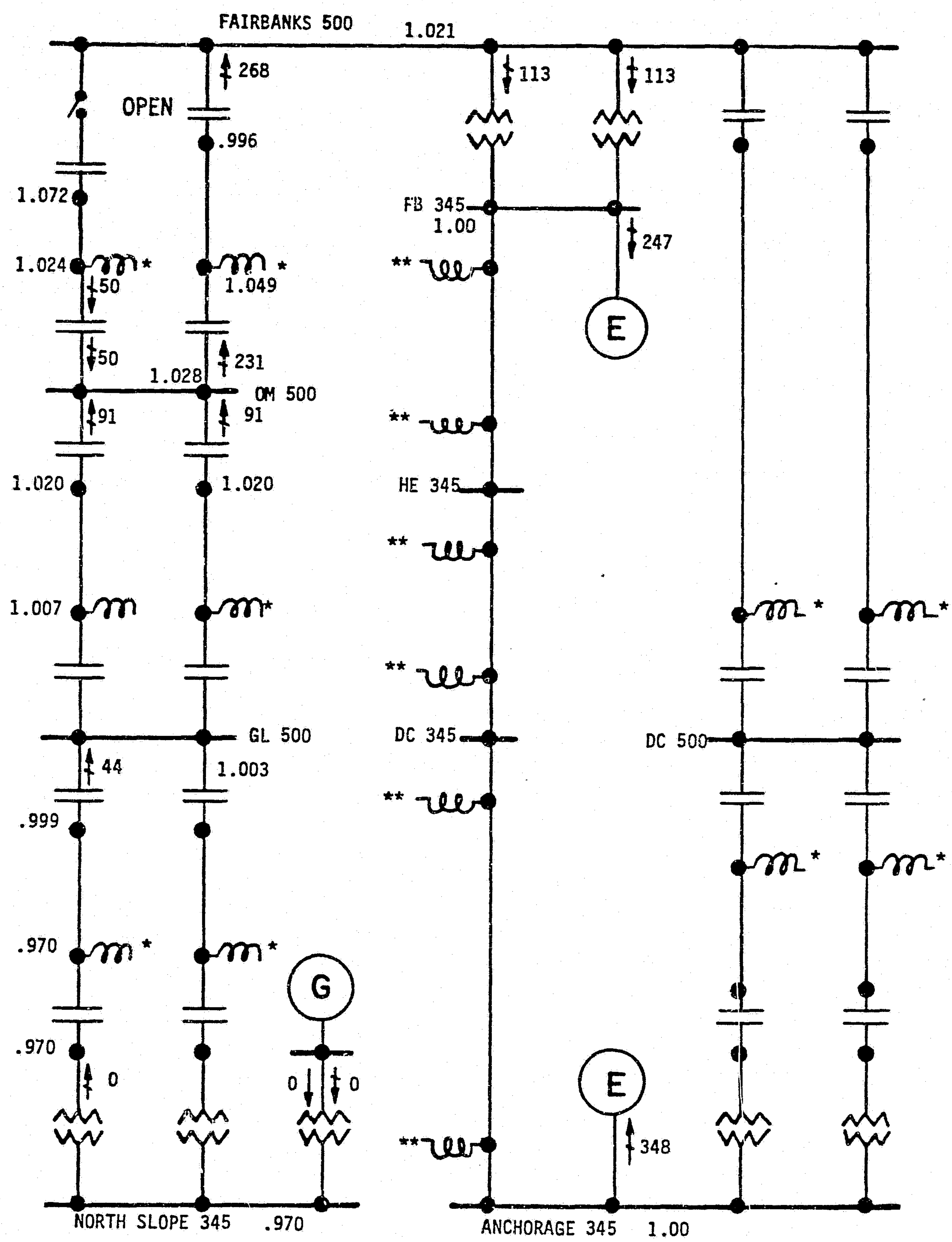
NORTH SLOPE GAS FEASIBILITY STUDY

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

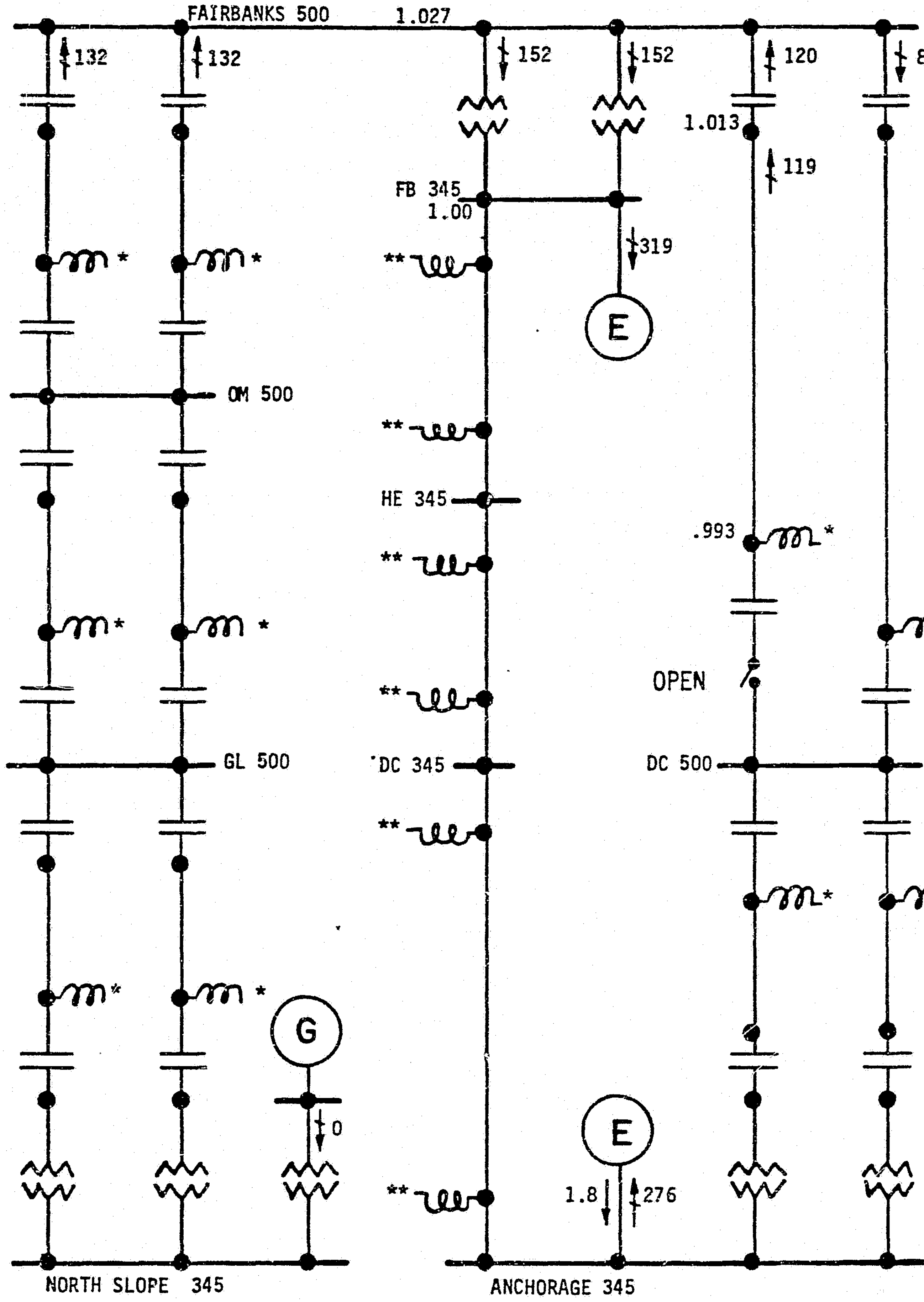
LOAD FLOW

No generation at Prudhoe Bay. One line segment open north of Fairbanks.

FIGURE D-4

EBASCO SERVICES INCORPORATED

CASE AA3



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

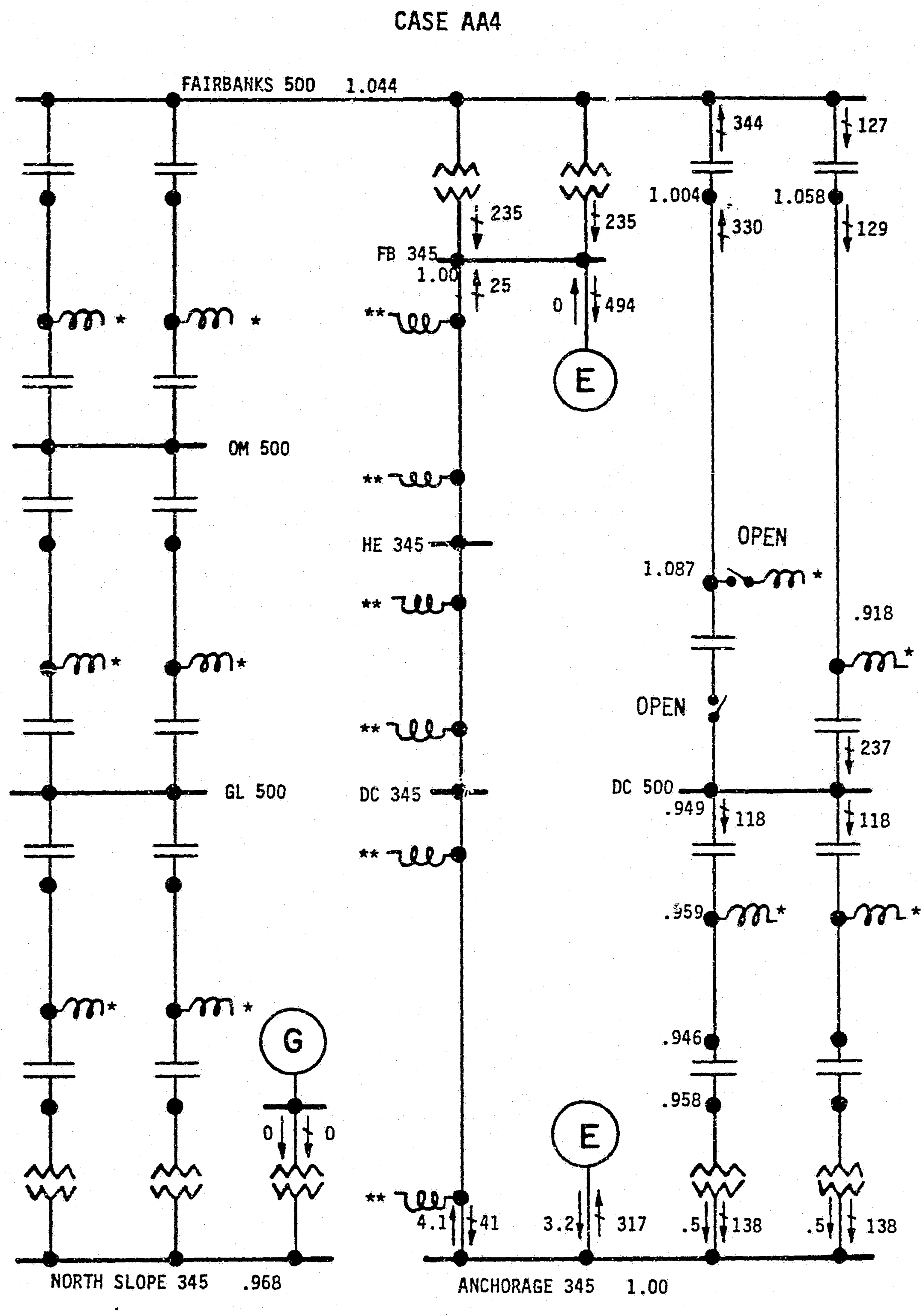
ALASKA POWER AUTHORITY

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



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

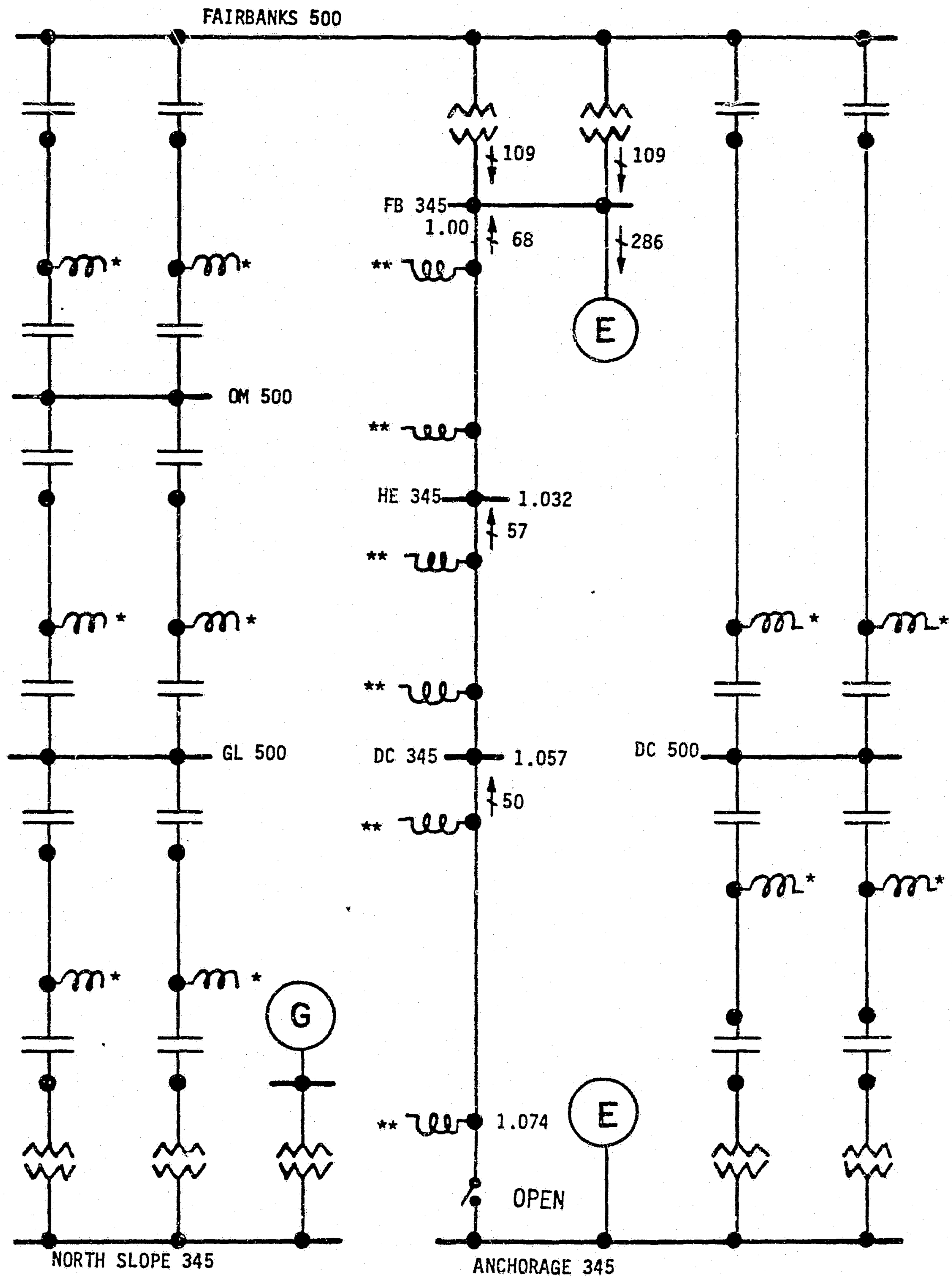
LOAD FLOW

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

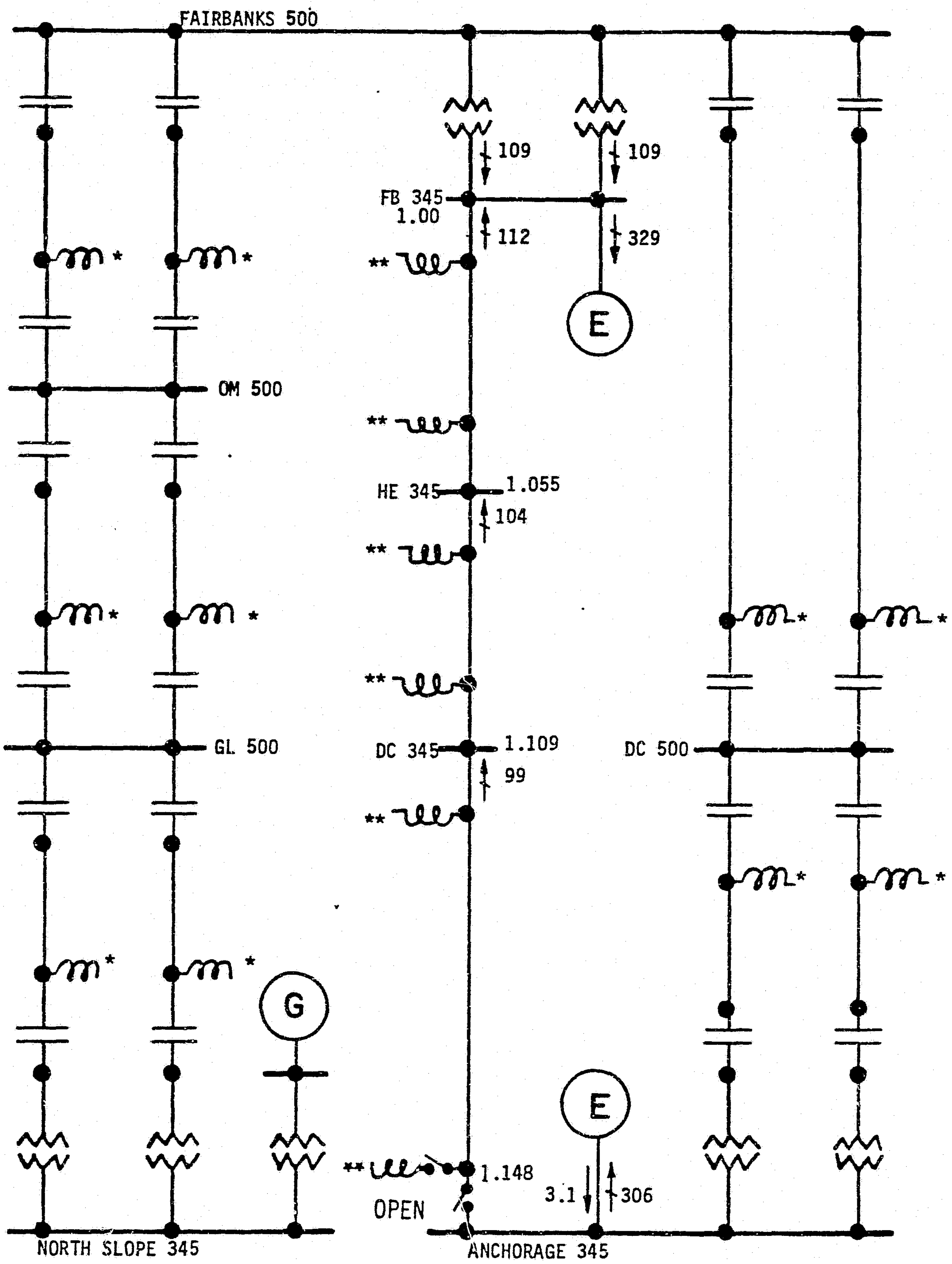
LOAD FLOW

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

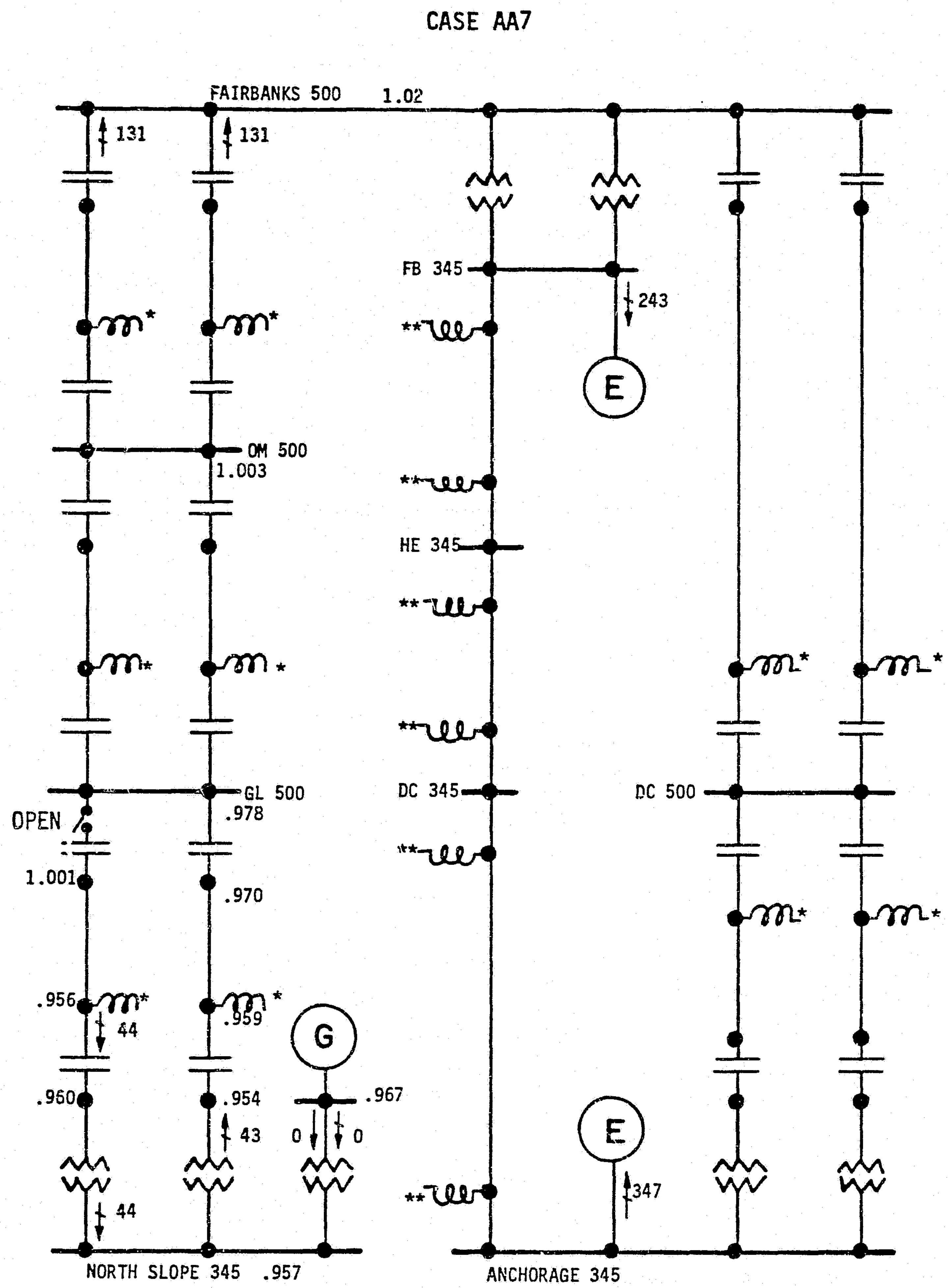
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. The 345 kV intertie opened at Anchorage, less one reactor.

FIGURE D-8

EBASCO SERVICES INCORPORATED



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

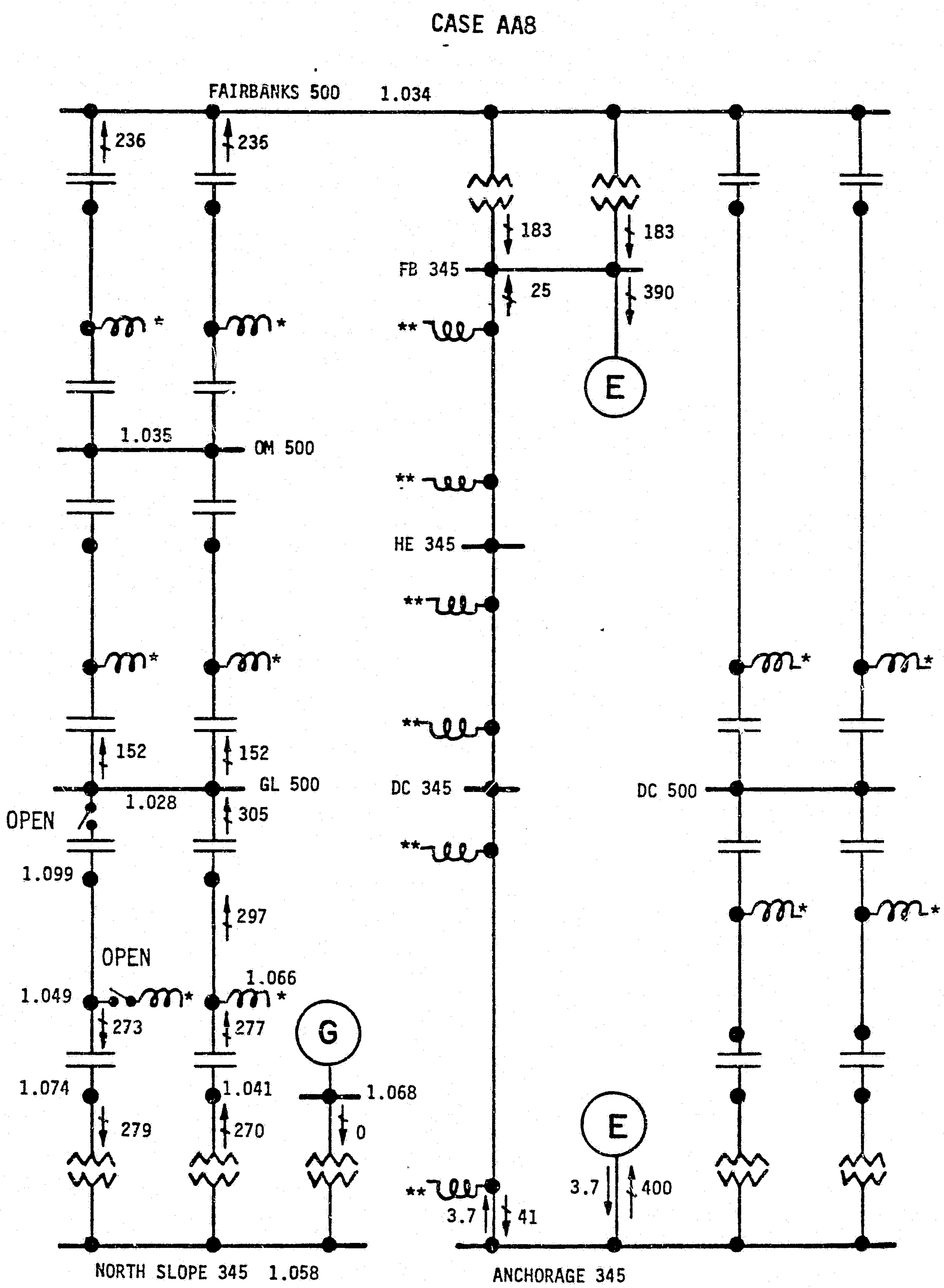
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

No generation at Prudhoe Bay. One line segment 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

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

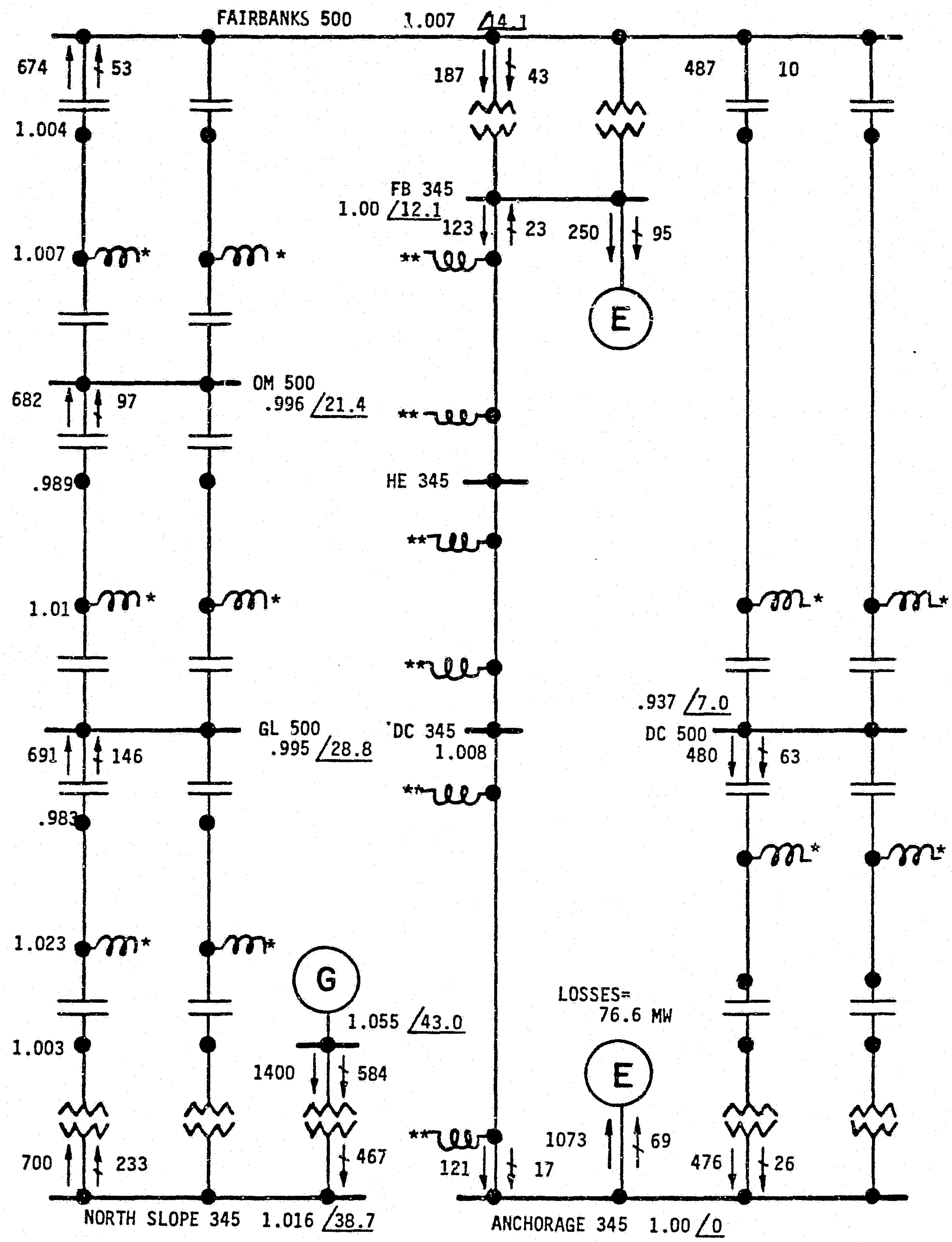
LOAD FLOW

No generation at Prudhoe Bay. One line segment opened north of Galbraith Lake, less one reactor.

FIGURE D-10

EBASCO SERVICES INCORPORATED

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

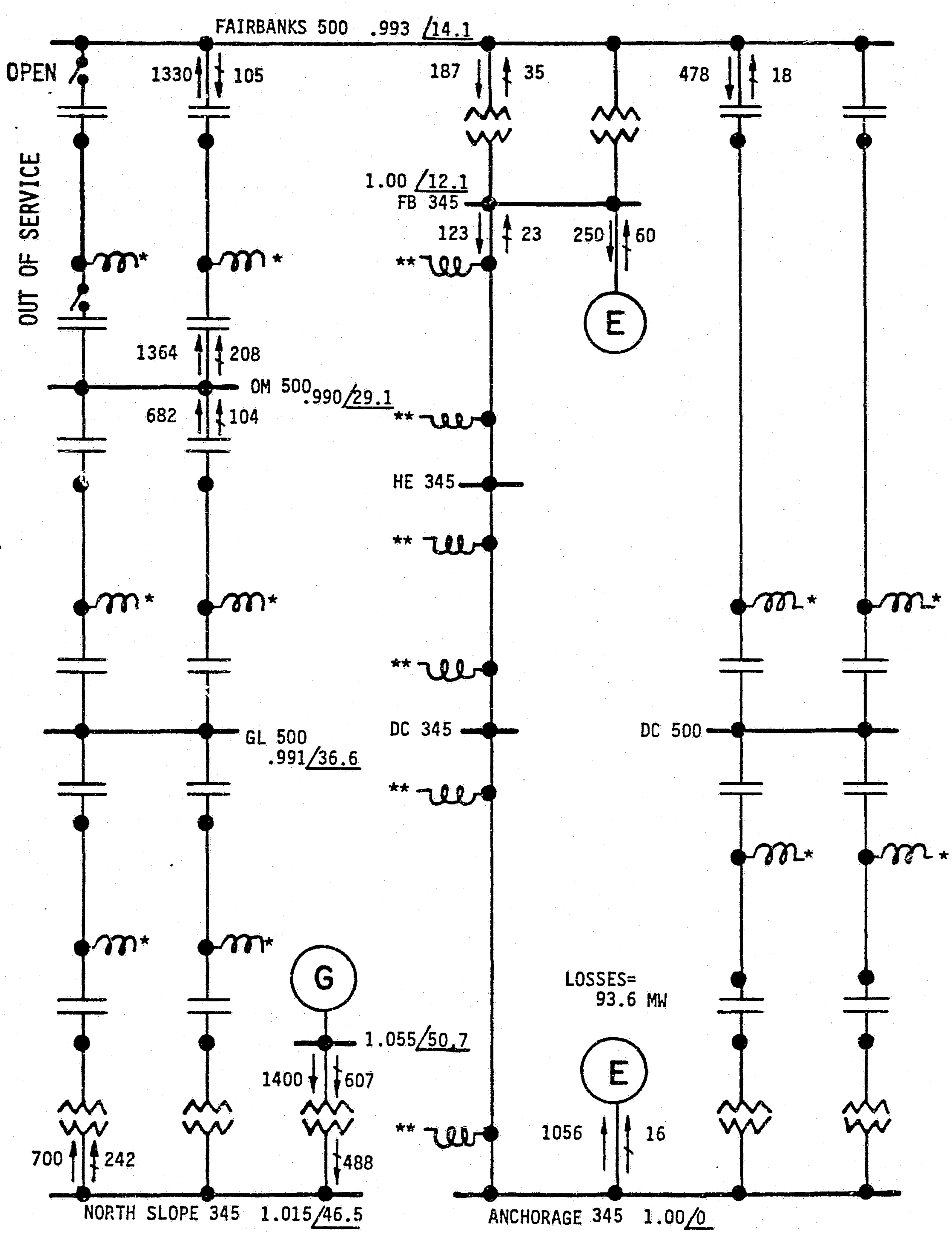
LOAD FLOW

1400 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-11

EBASCO SERVICES INCORPORATED

CASE AA10



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

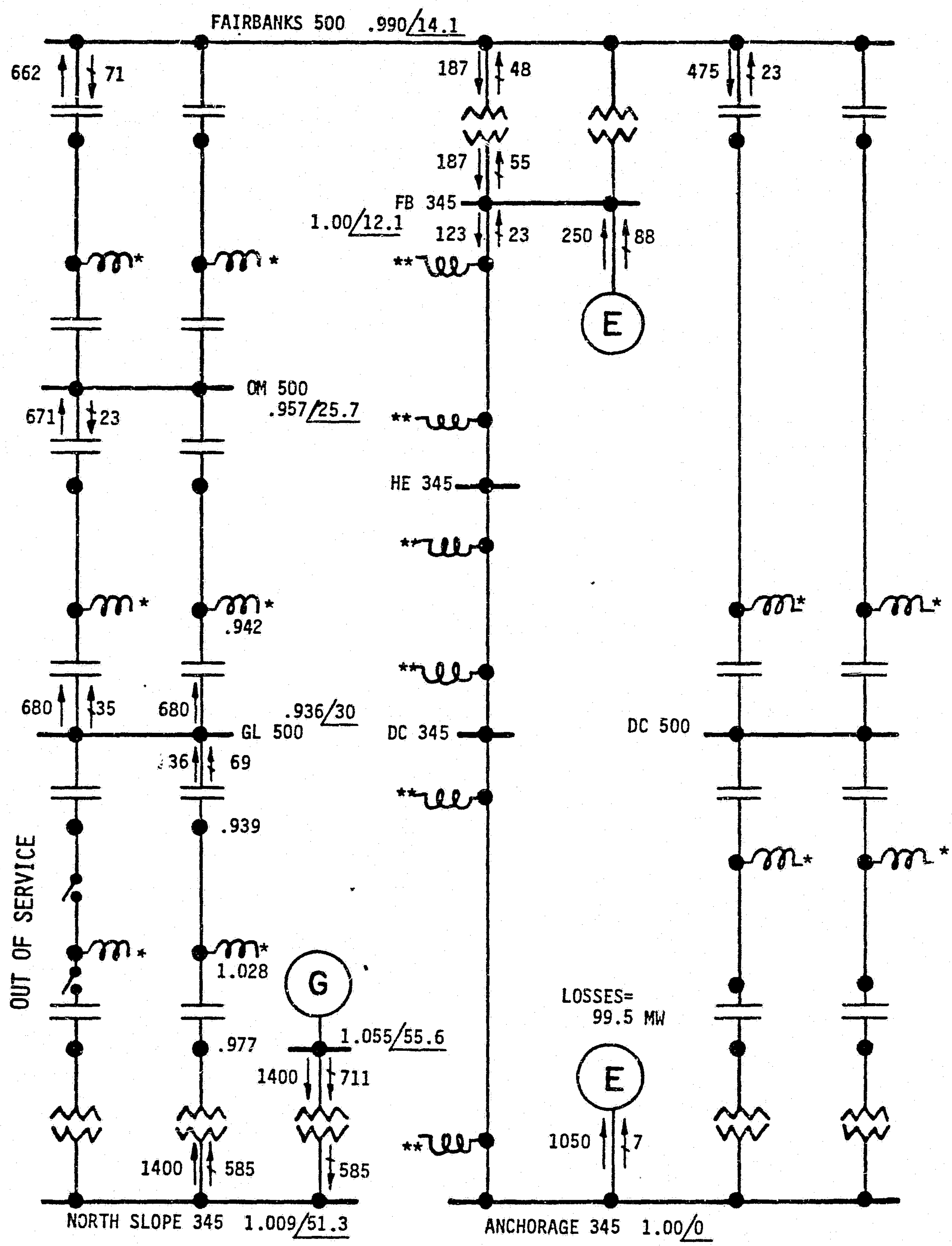
LOAD FLOW

1400 MW generation at Prudhoe Bay. One line segment out of service north of Fairbanks.

FIGURE D-12

EBASCO SERVICES INCORPORATED

CASE AA11



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

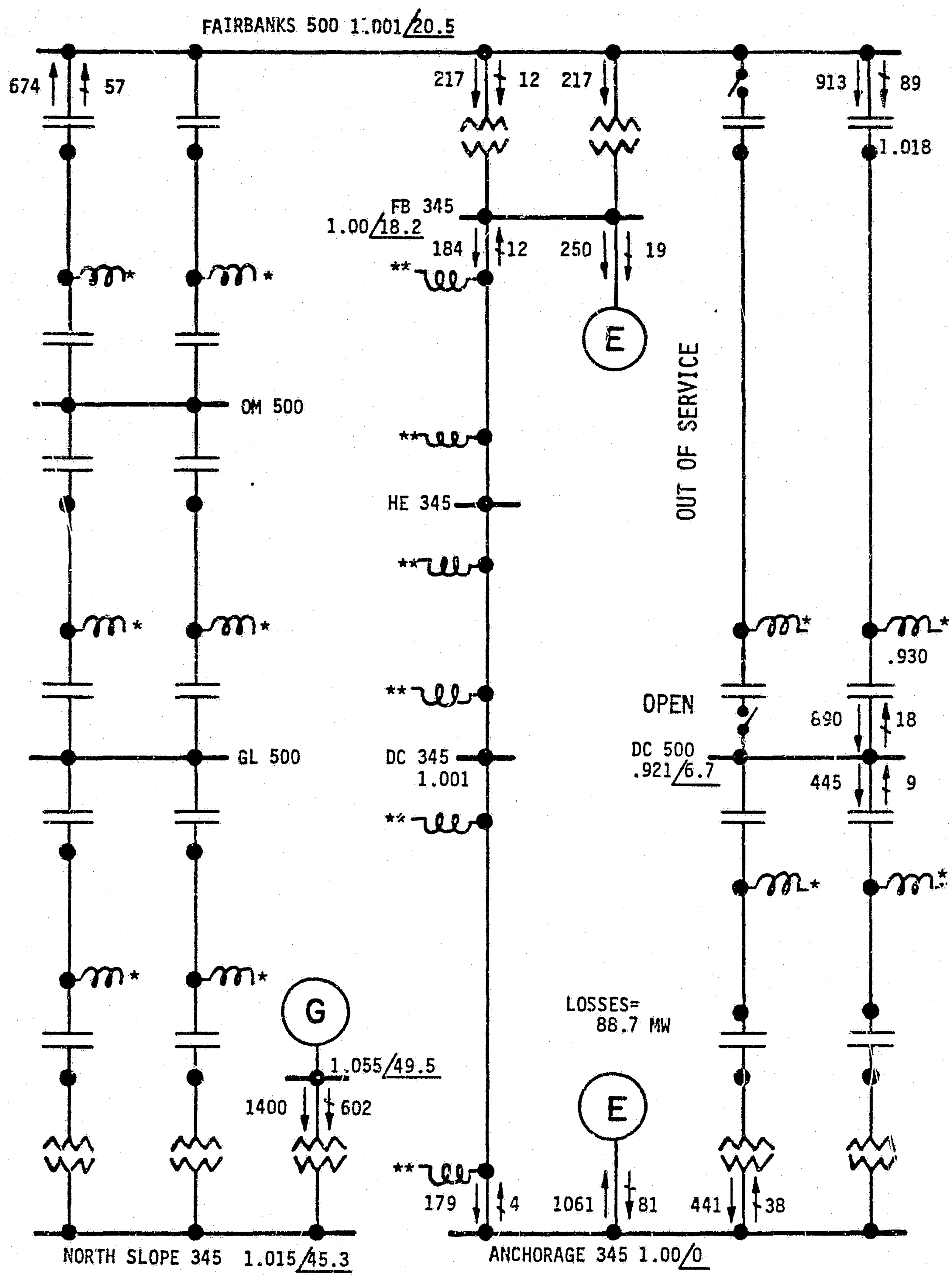
LOAD FLOW

1400 MW generation at Prudhoe Bay. One line segment out of service south of Prudhoe Bay.

FIGURE D-13

EBASCO SERVICES INCORPORATED

CASE AA12



Notes

* 200 MVAR
** 35 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

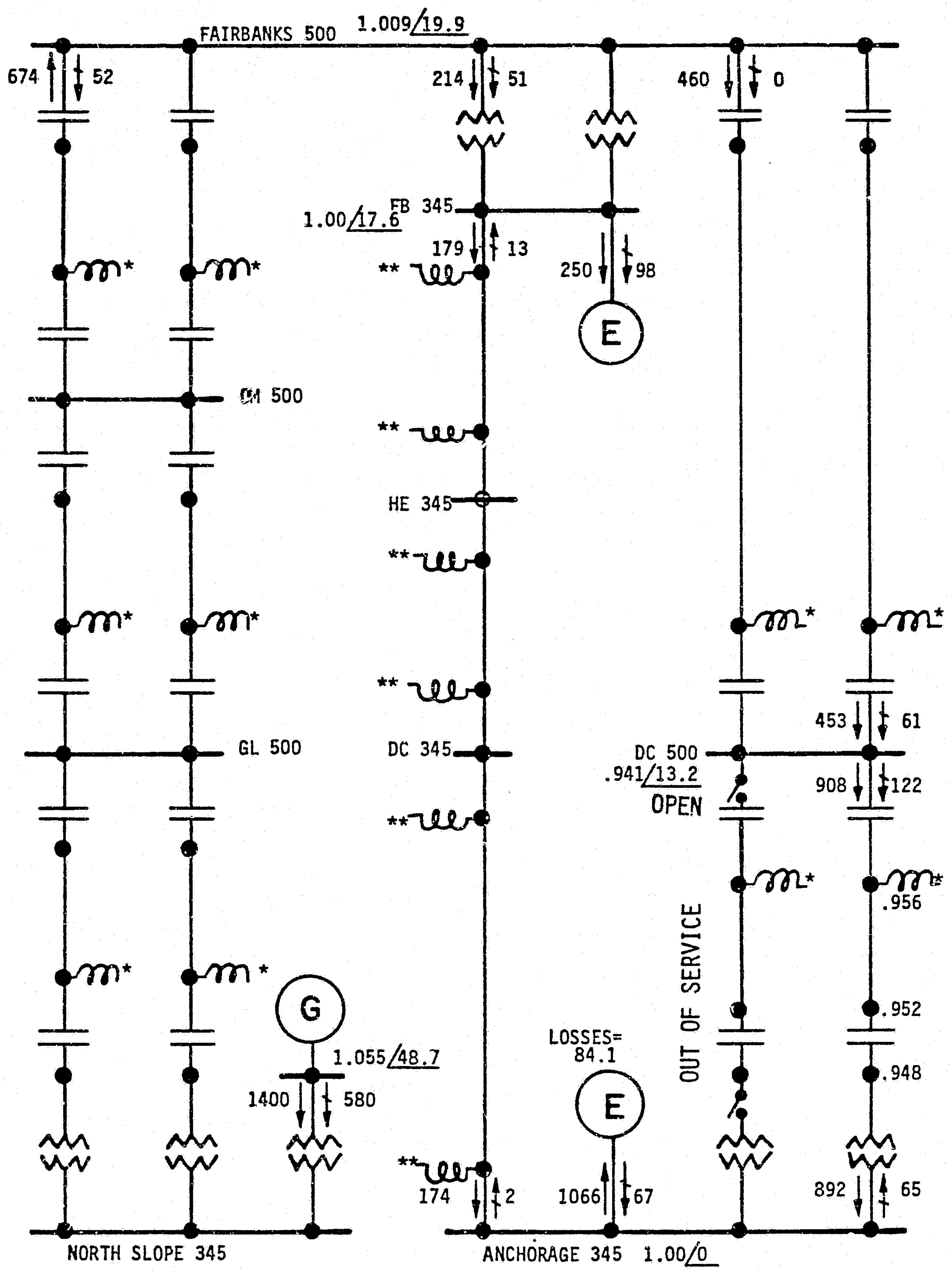
LOAD FLOW

1400 MW generation at Prudhoe Bay. One 500 kV line segment out of service south of Fairbanks.

FIGURE D-14

EBASCO SERVICES INCORPORATED

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

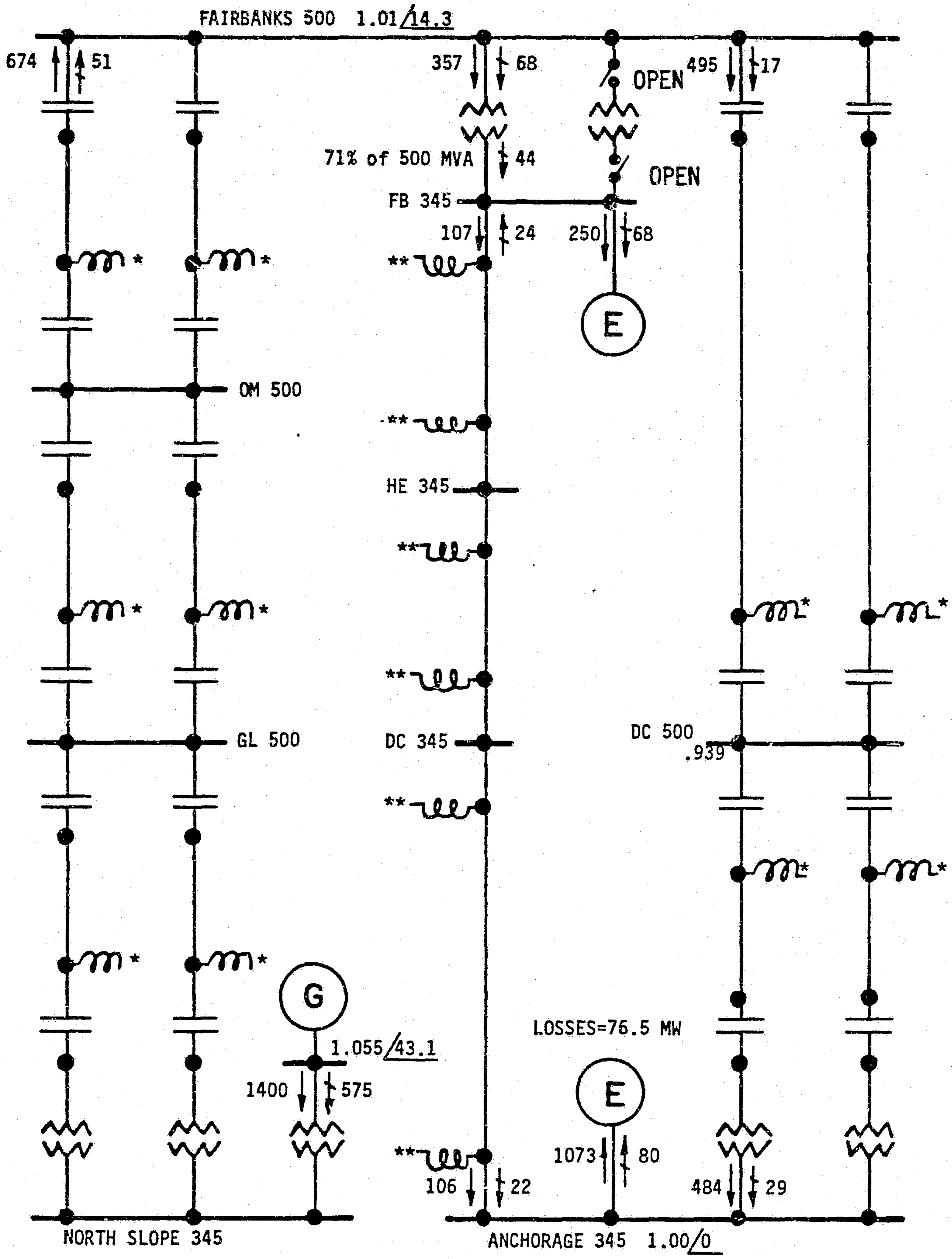
LOAD FLOW

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

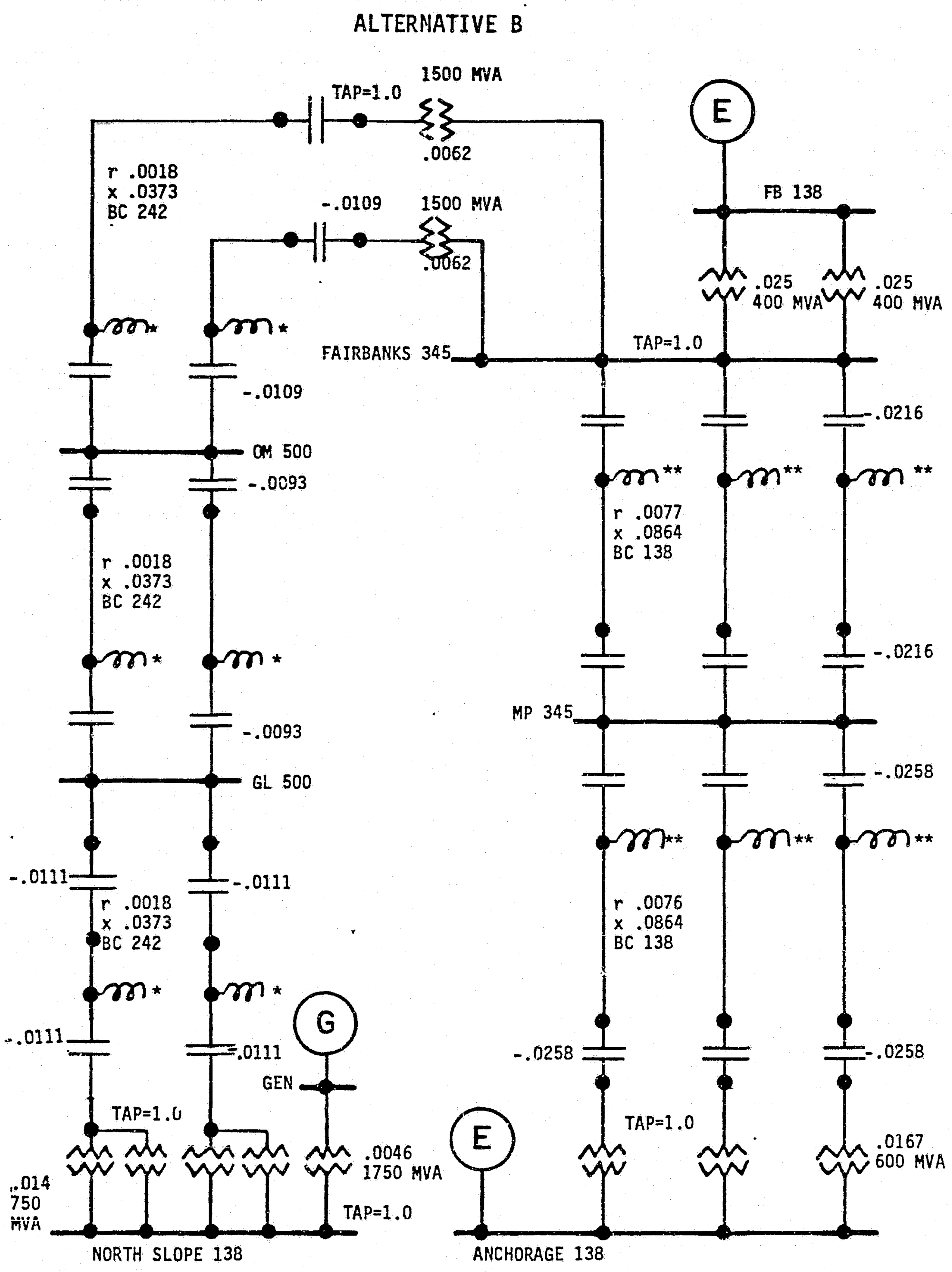
NORTH SLOPE GAS FEASIBILITY STUDY

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



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

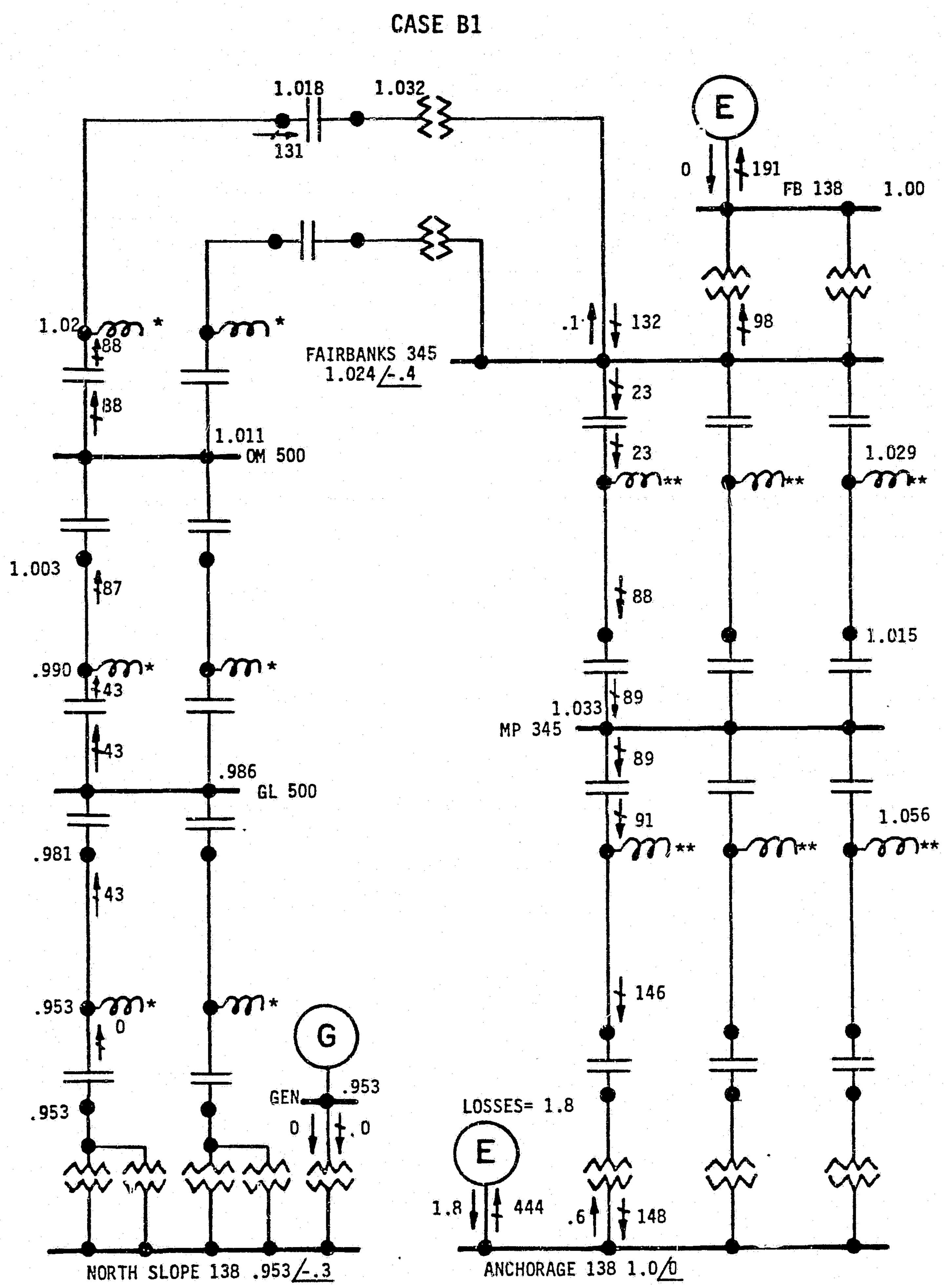
NORTH SLOPE GAS FEASIBILITY STUDY

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



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

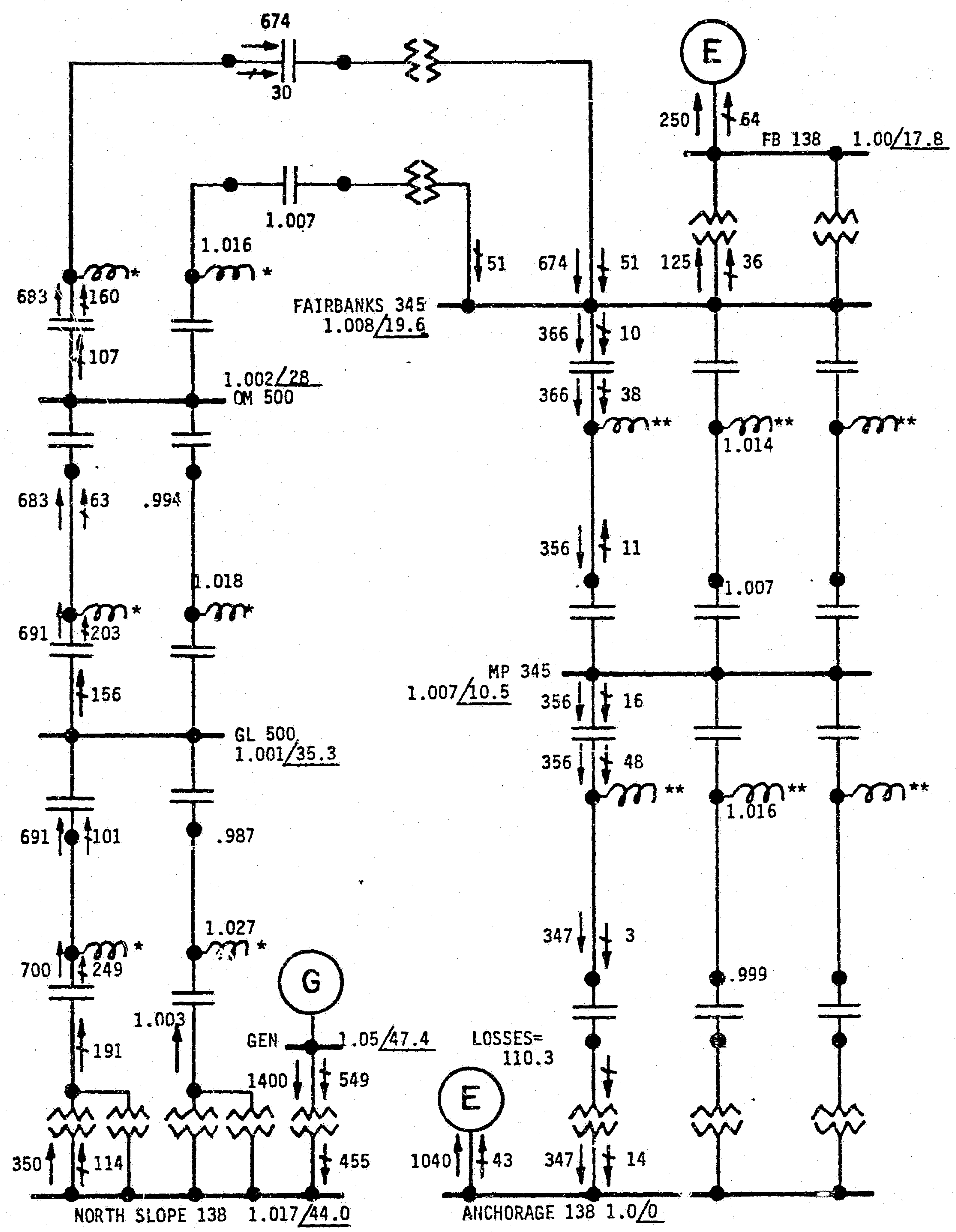
LOAD FLOW

No generation at Prudhoe Bay. Normal system configuration.

FIGURE D-18

EBASCO SERVICES INCORPORATED

CASE B2



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

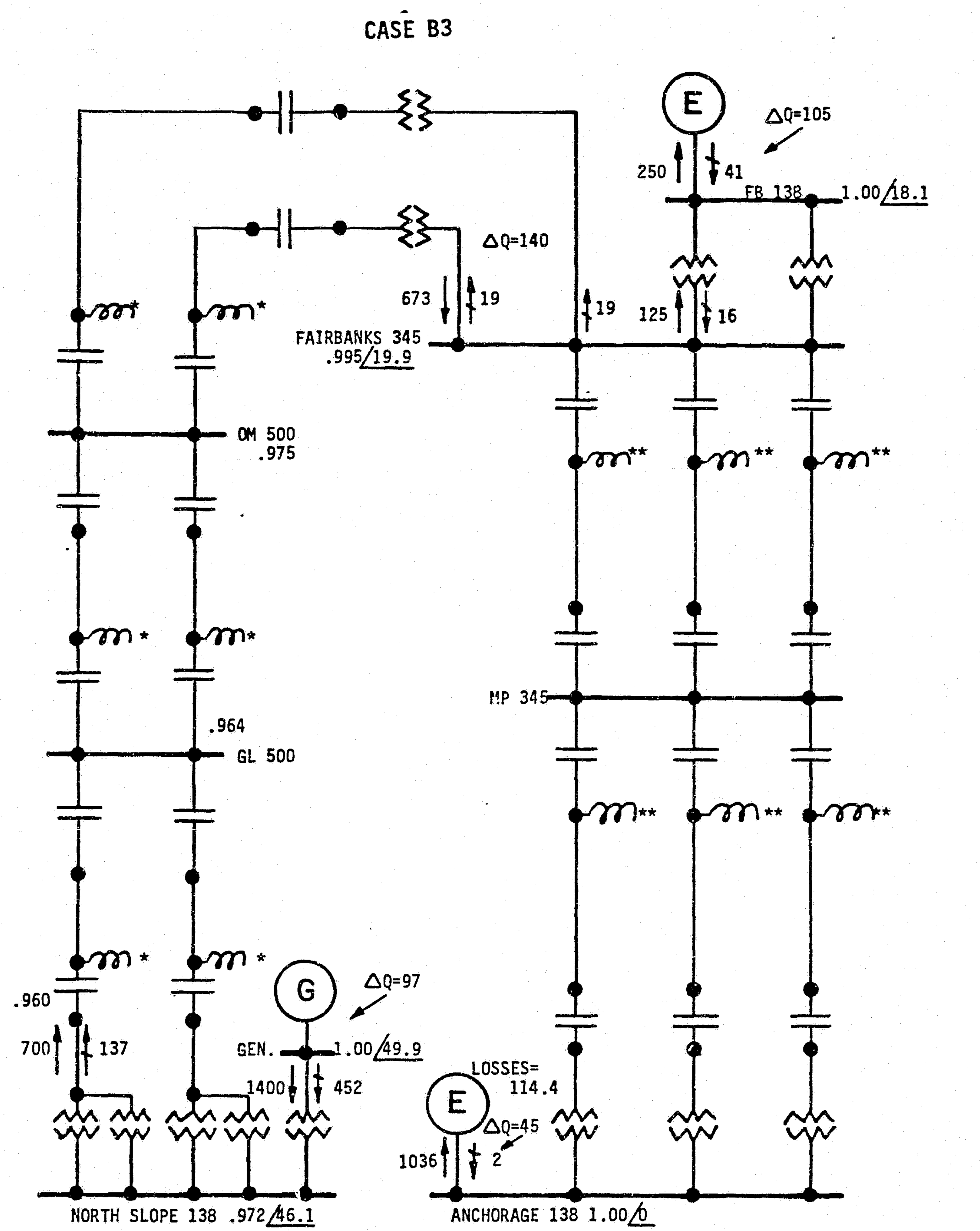
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

1400 MW generation at Prudhoe Bay. Normal system configuration. Generator bus voltage 1.05 p.u.

FIGURE D-19

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

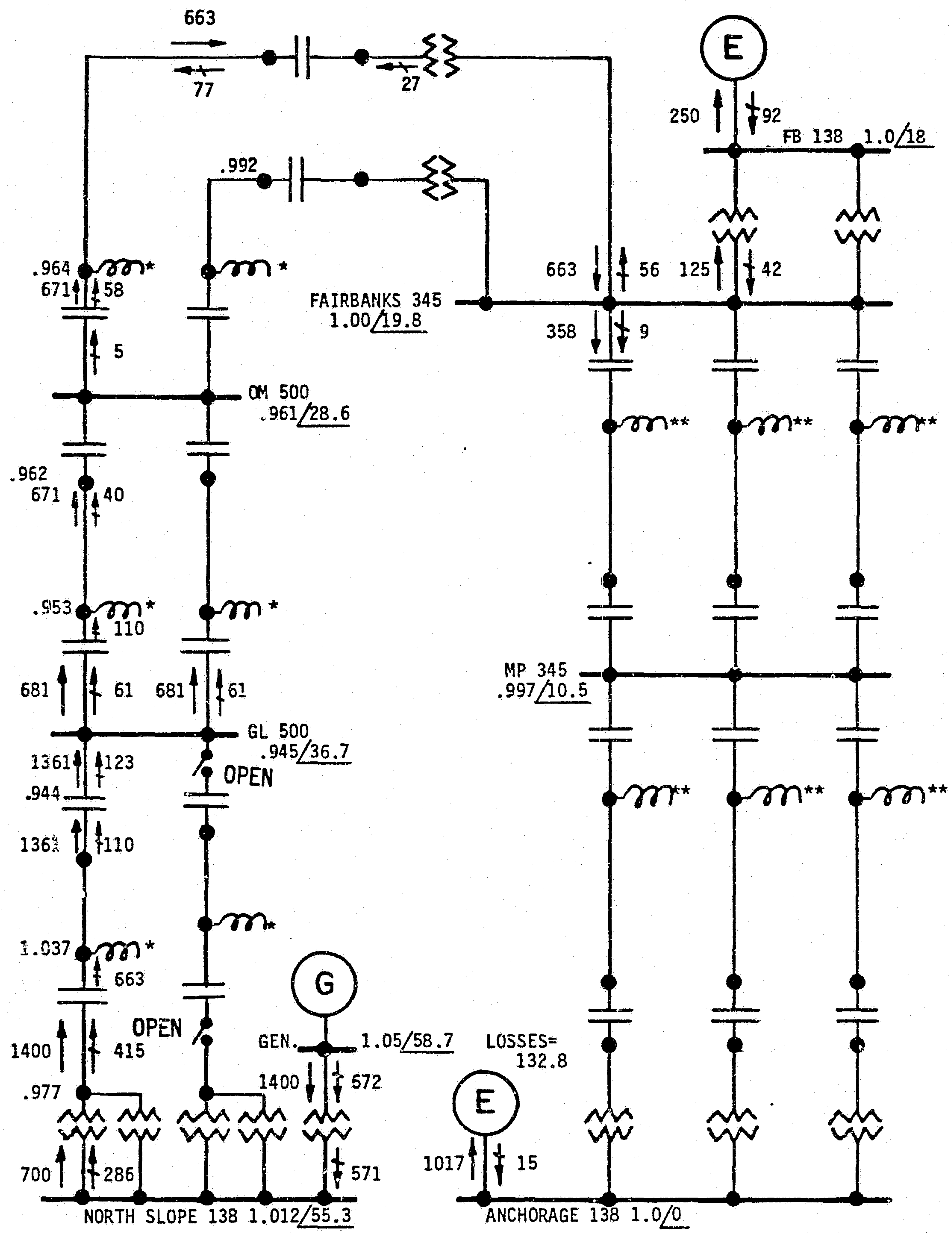
LOAD FLOW

1400 MW generation at Prudhoe Bay. Normal system configuration. Generator bus voltage 1.00 p.u.

FIGURE D-20

EBASCO SERVICES INCORPORATED

CASE B4



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

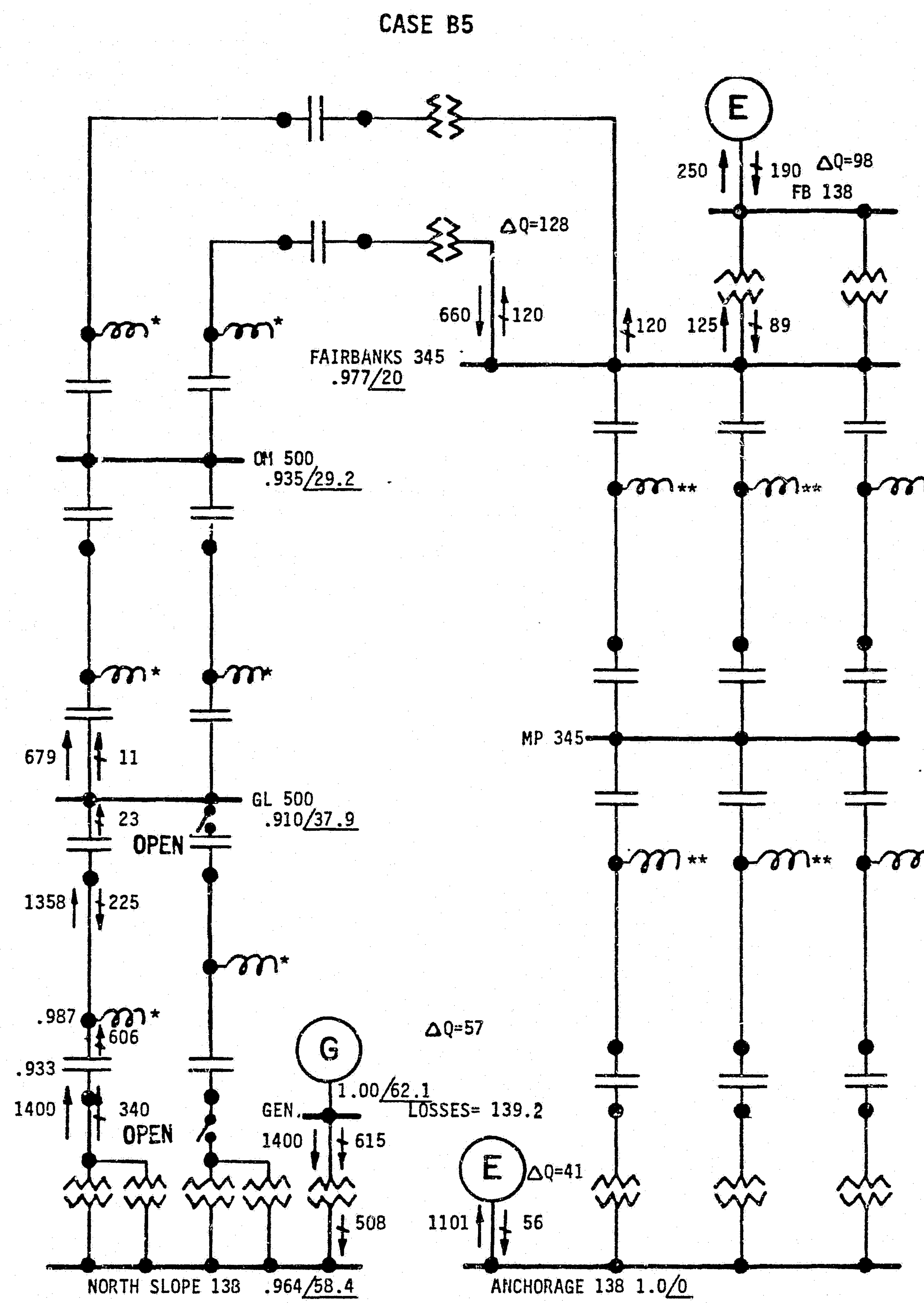
NORTH SLOPE GAS FEASIBILITY STUDY

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



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

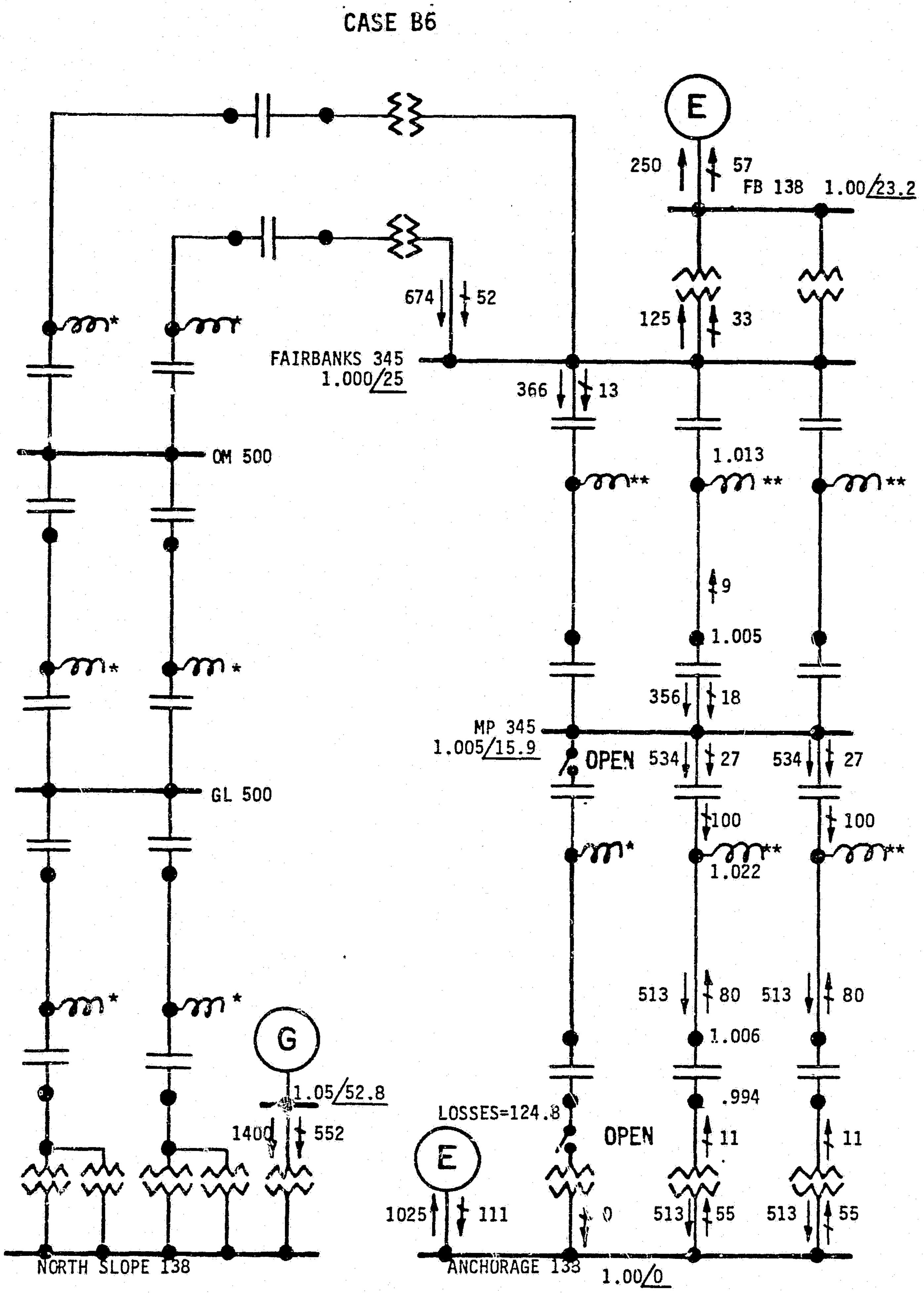
NORTH SLOPE GAS FEASIBILITY STUDY

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



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

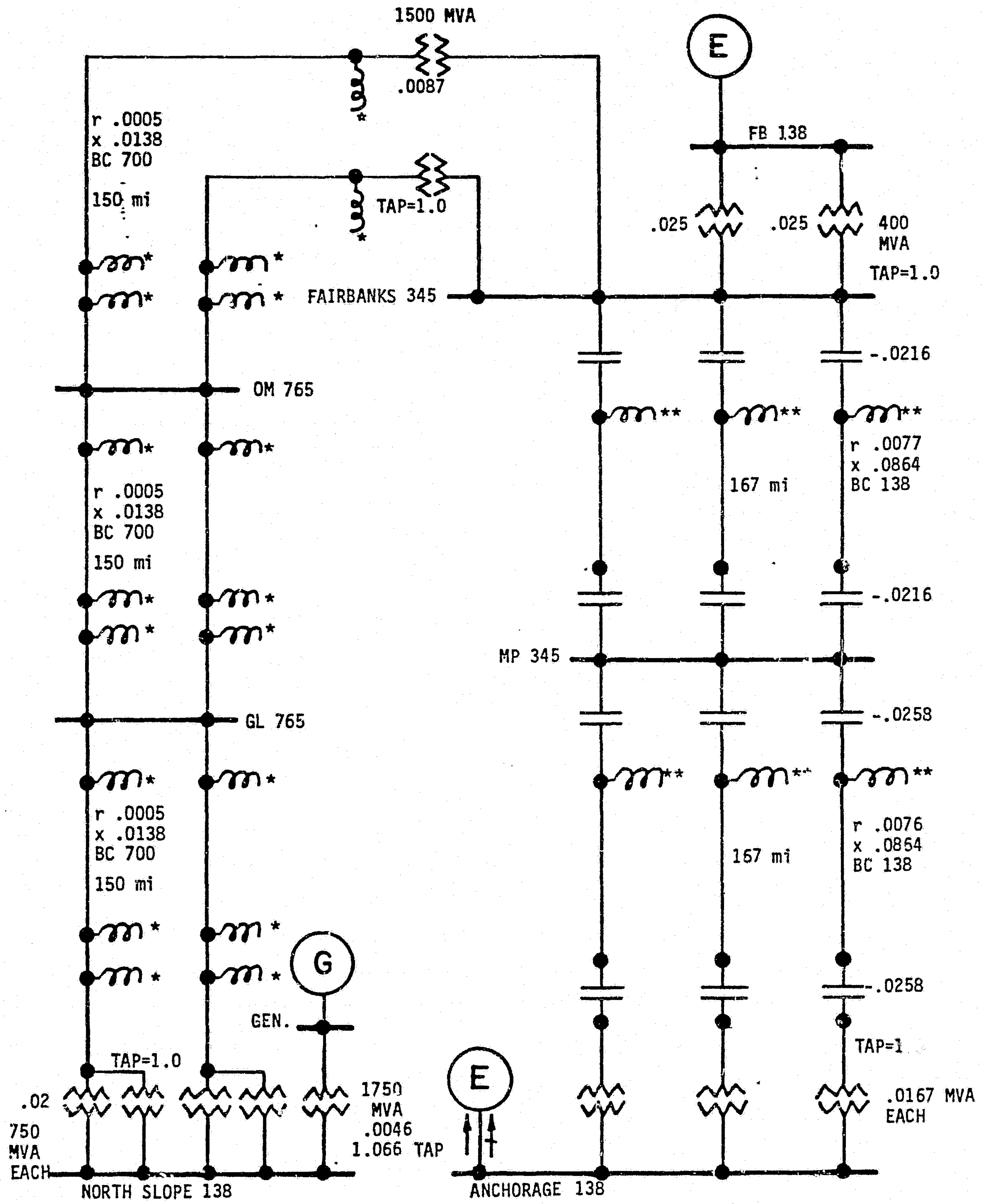
LOAD FLOW

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

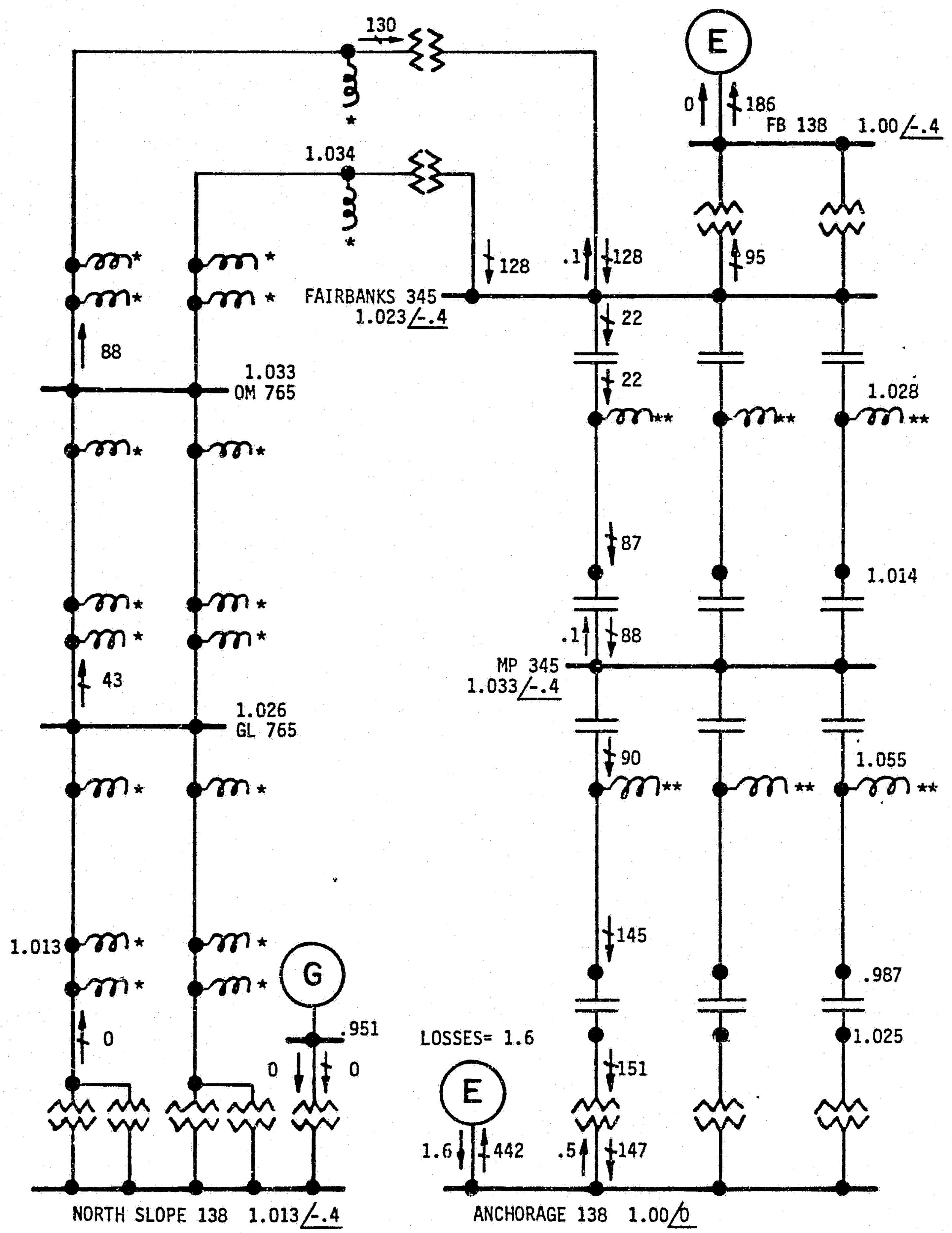
ONE LINE SCHEMATIC WITH IMPEDANCES

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

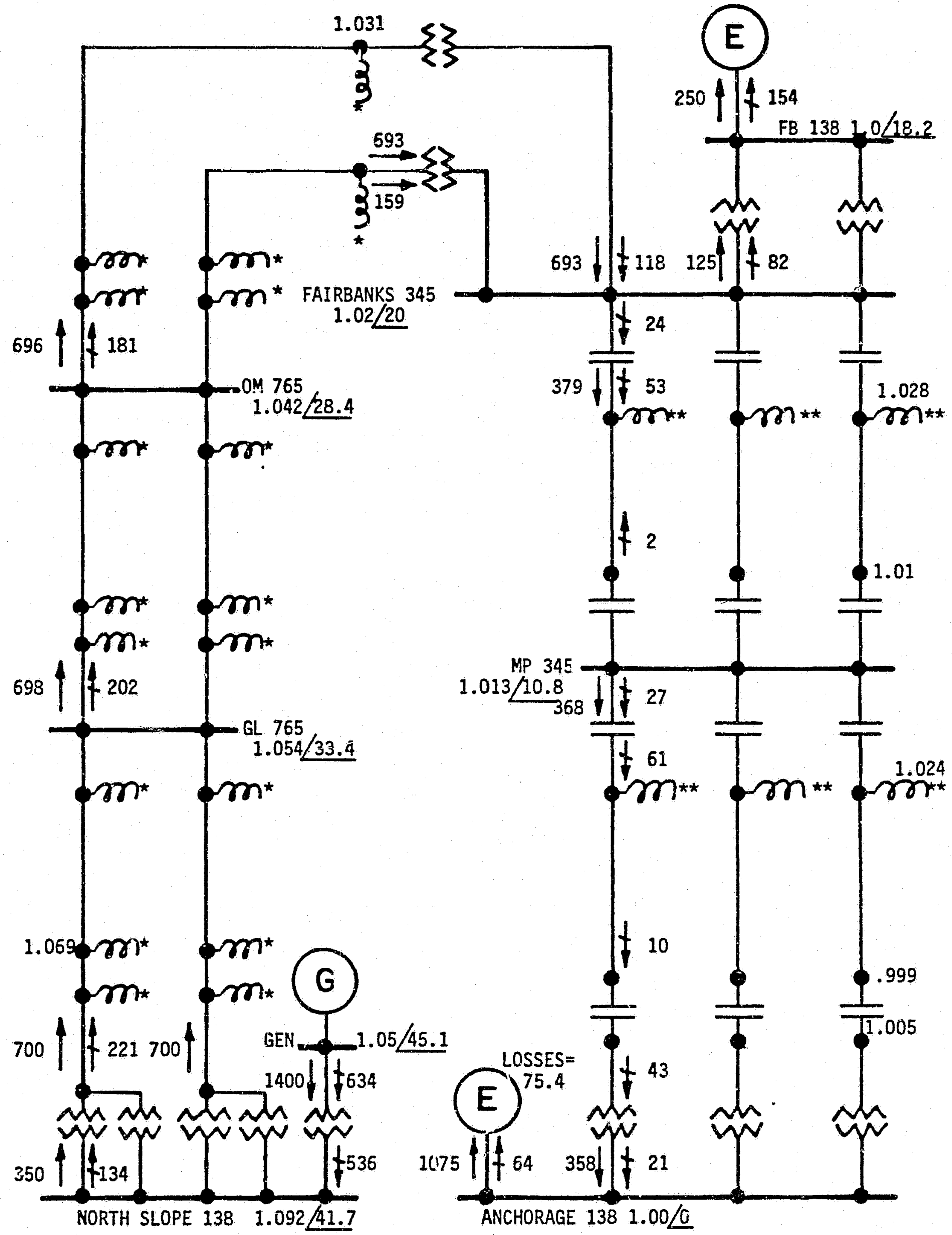
LOAD FLOW

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

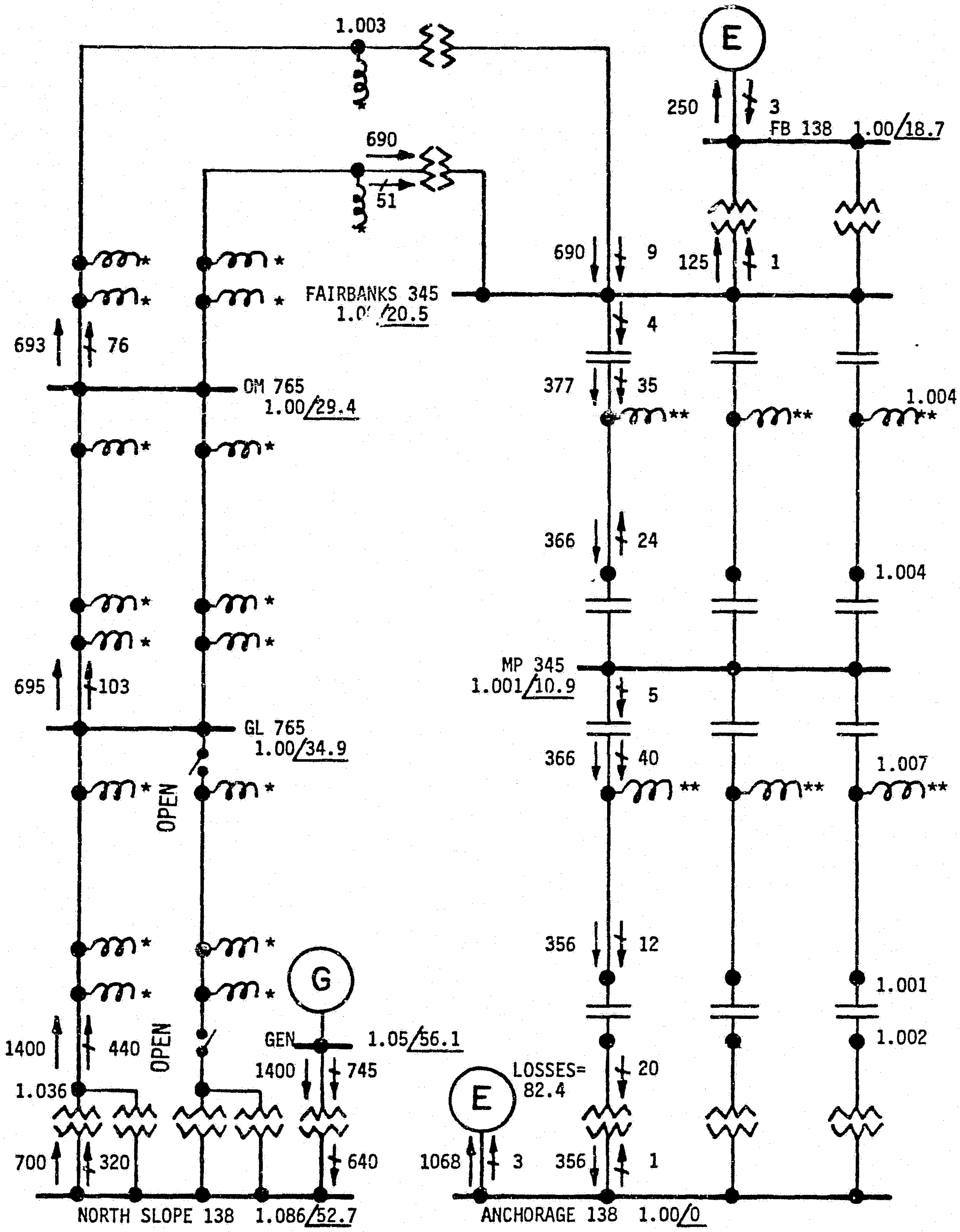
LOAD FLOW

1400 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-26

EBASCO SERVICES INCORPORATED

CASE C3



Notes

* 200 MVAR
** 75 MVAR
50 Percent series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

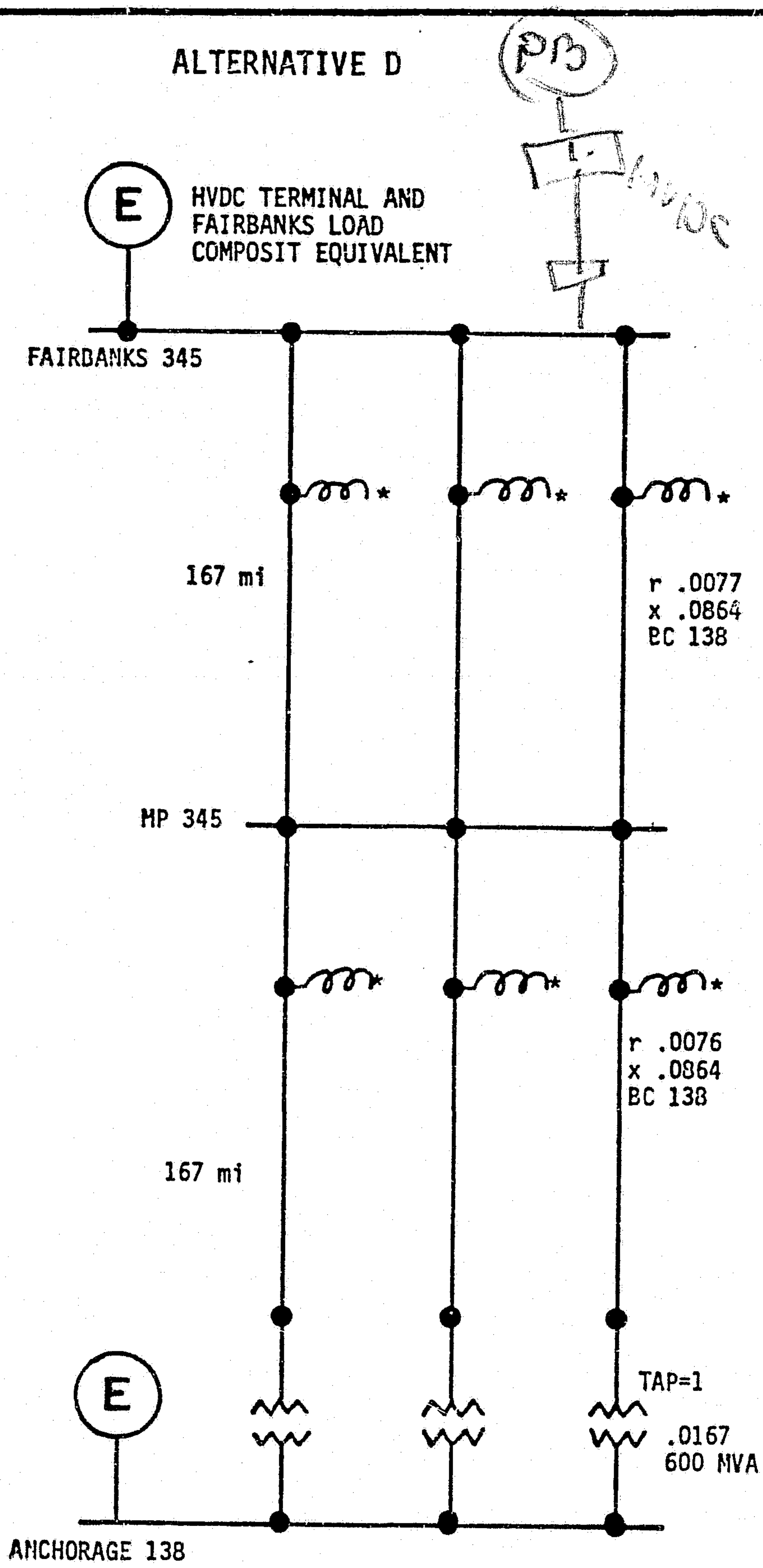
LOAD FLOW

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

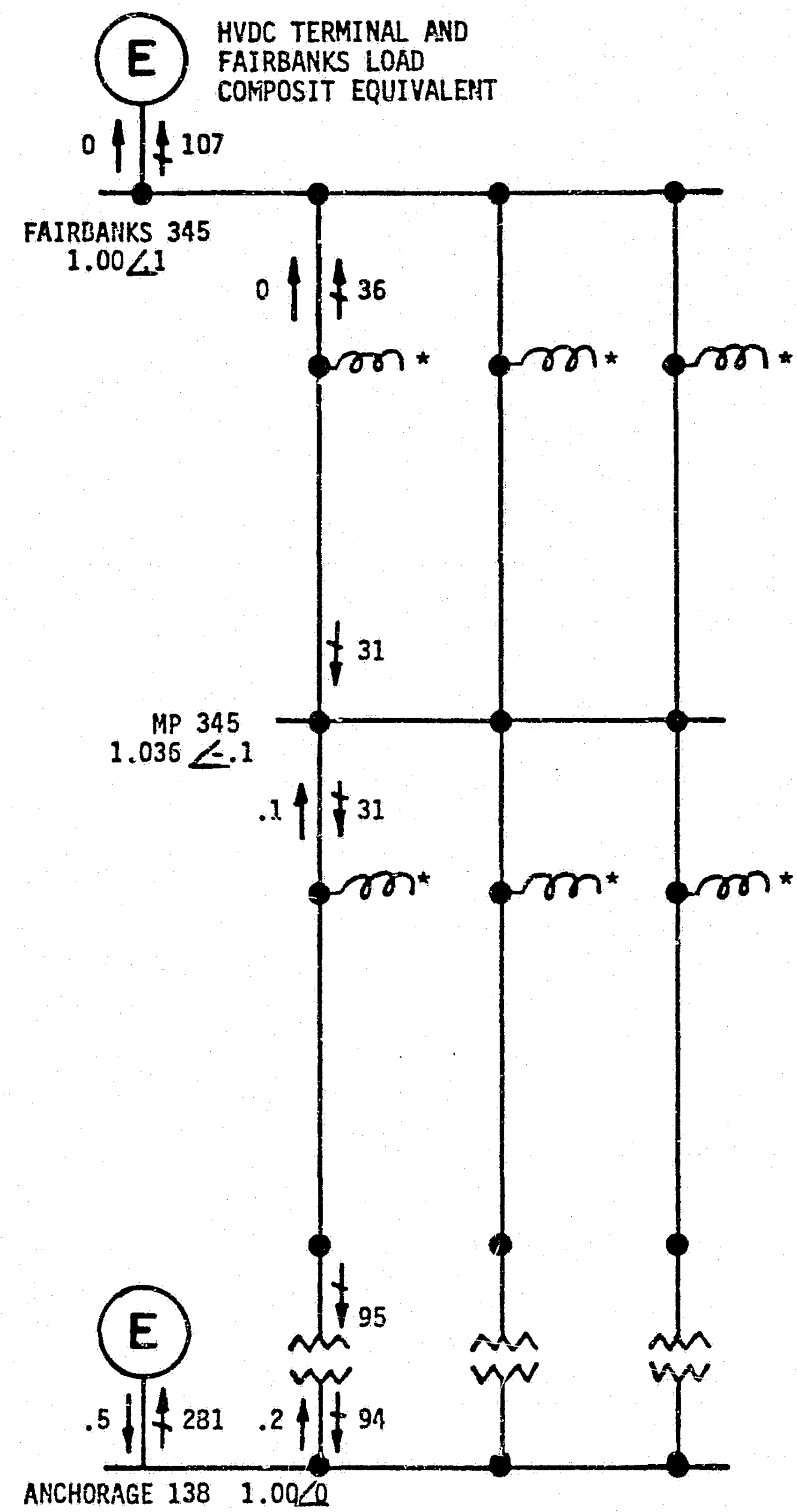


Notes

* 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

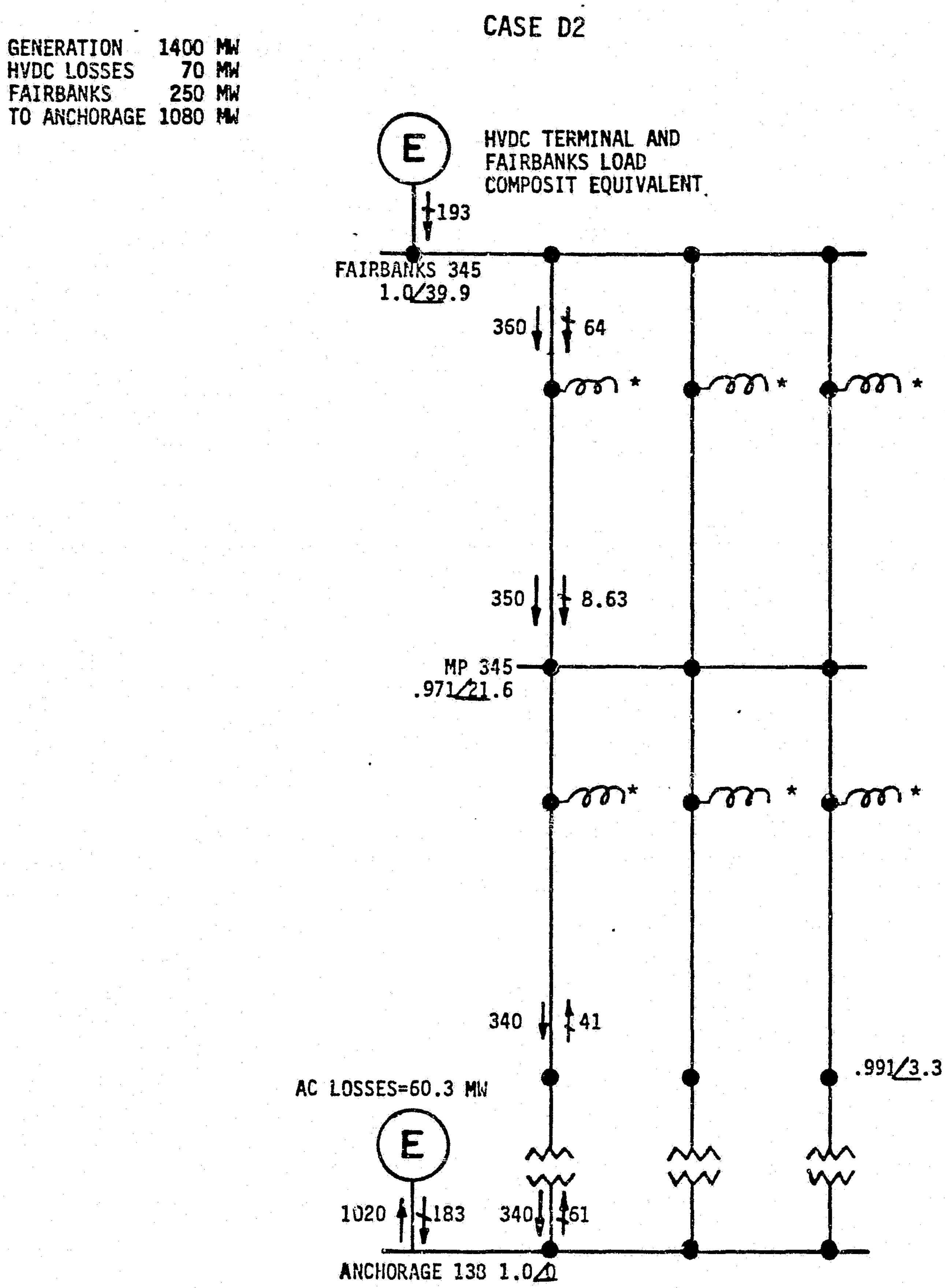
NORTH SLOPE GAS
FEASIBILITY STUDY

LOAD FLOW

No power transfer between Fairbanks and Anchorage. Normal system configuration.

FIGURE D-29

EBASCO SERVICES INCORPORATED



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

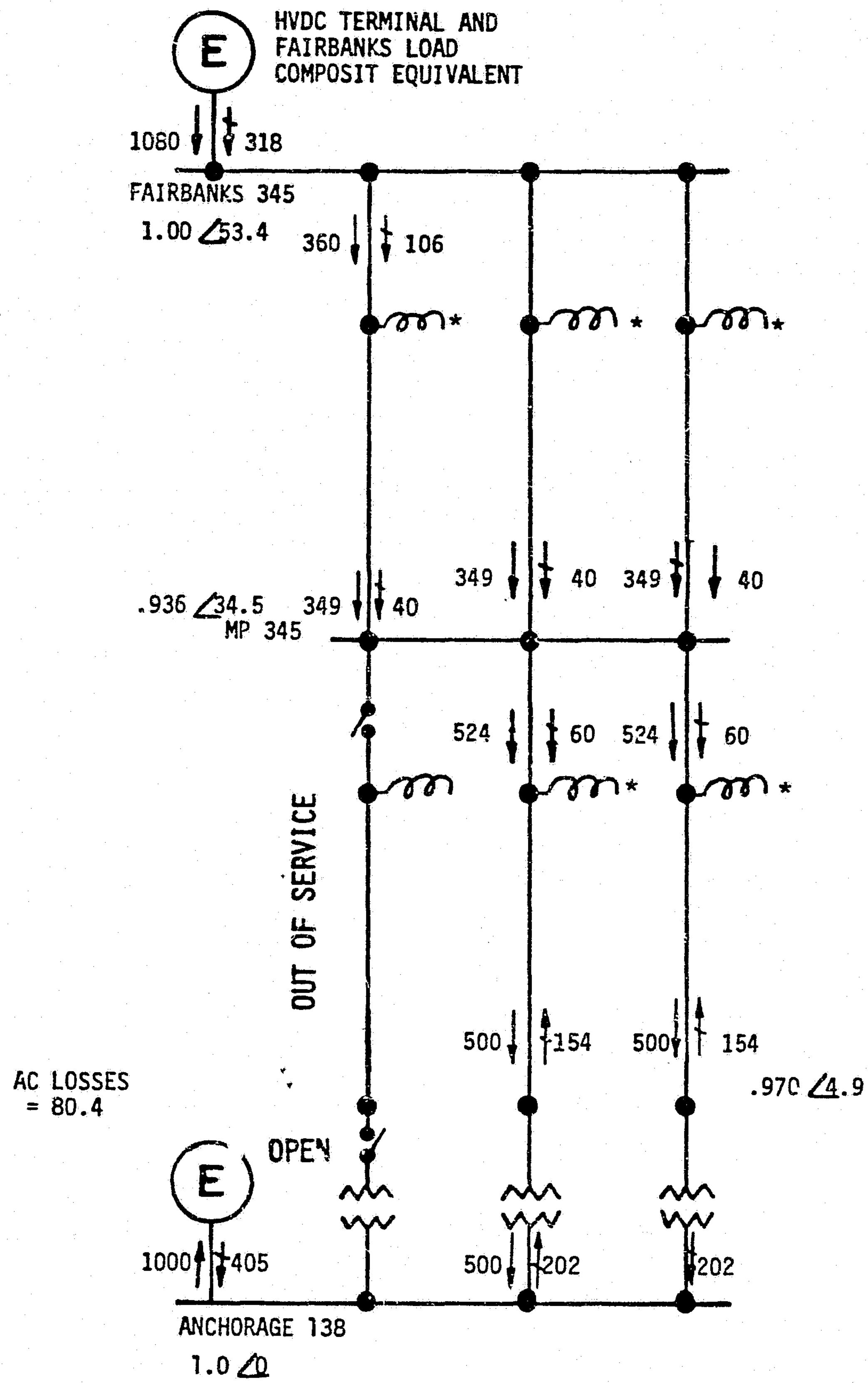
1400 MW capacity at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks. Normal system configuration.

FIGURE D-30

EBASCO SERVICES INCORPORATED

GENERATION 1400 MW
HVDC LOSSES 70 MW
FAIRBANKS 250 MW
TO ANCHORAGE 1080 MW

CASE D3



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

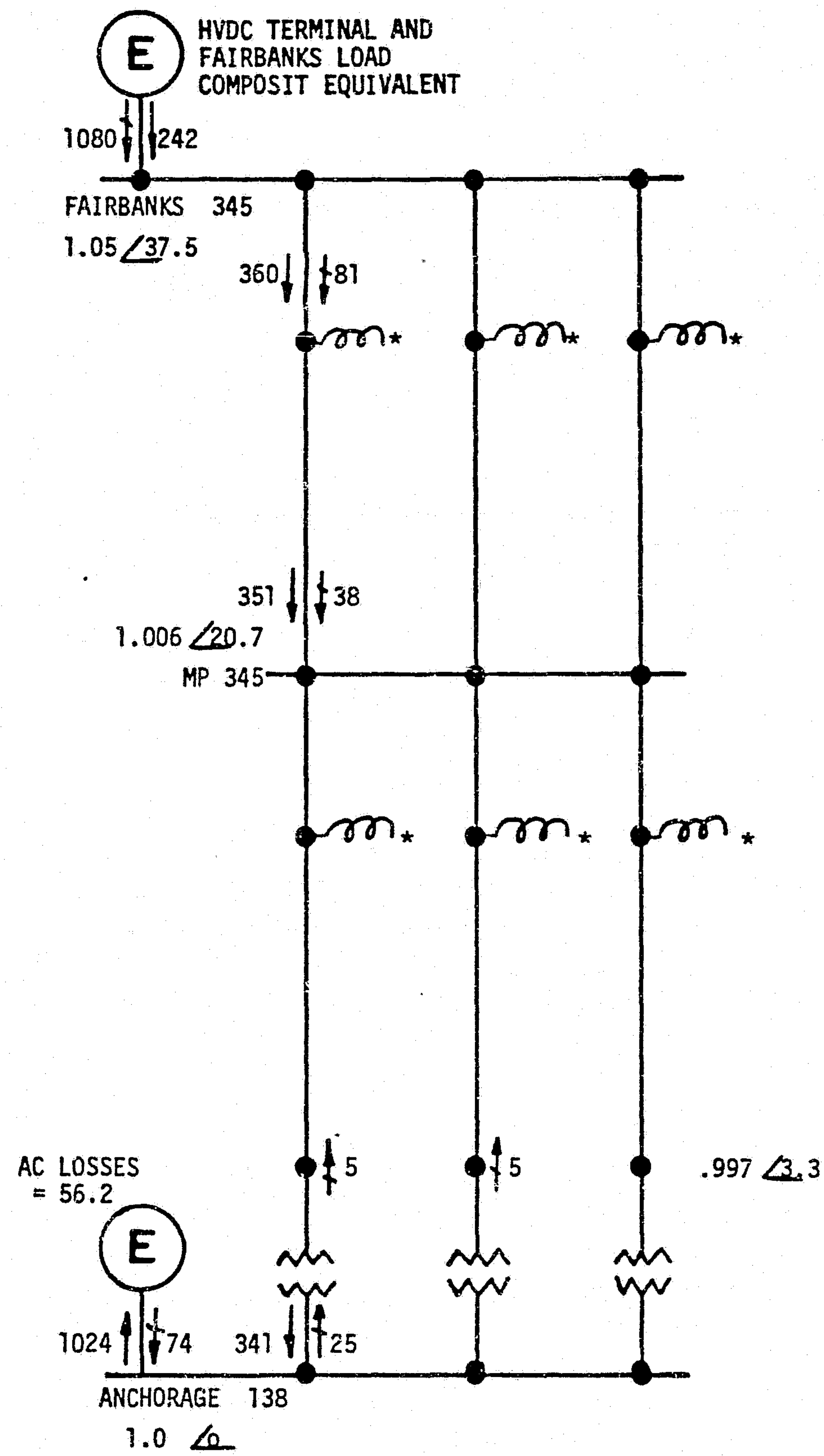
1400 MW generation at Prudhoe Bay; HVDC transmission between Prudhoe Bay and Fairbanks and one 345 kV line segment out of service north of Anchorage.

FIGURE D-31

EBASCO SERVICES INCORPORATED

GENERATION 1400 MW
HVDC LOSSES 70 MW
FAIRBANKS 250 MW
TO ANCHORAGE 1080 MW

CASE D4



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

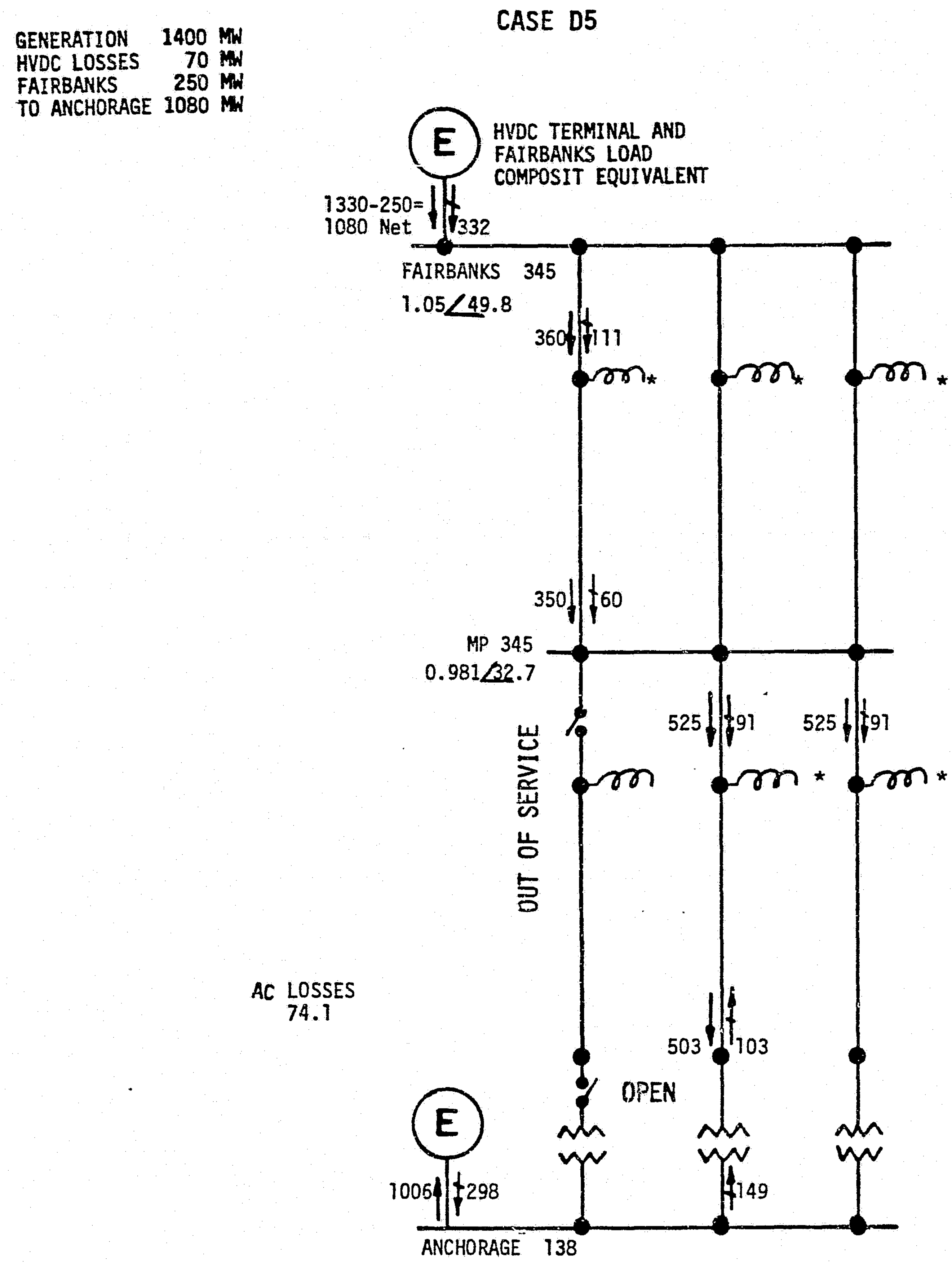
NORTH SLOPE GAS FEASIBILITY STUDY

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



Notes

* 75 MVAR
No series compensation
For letter symbols, see Table D-8

ALASKA POWER AUTHORITY

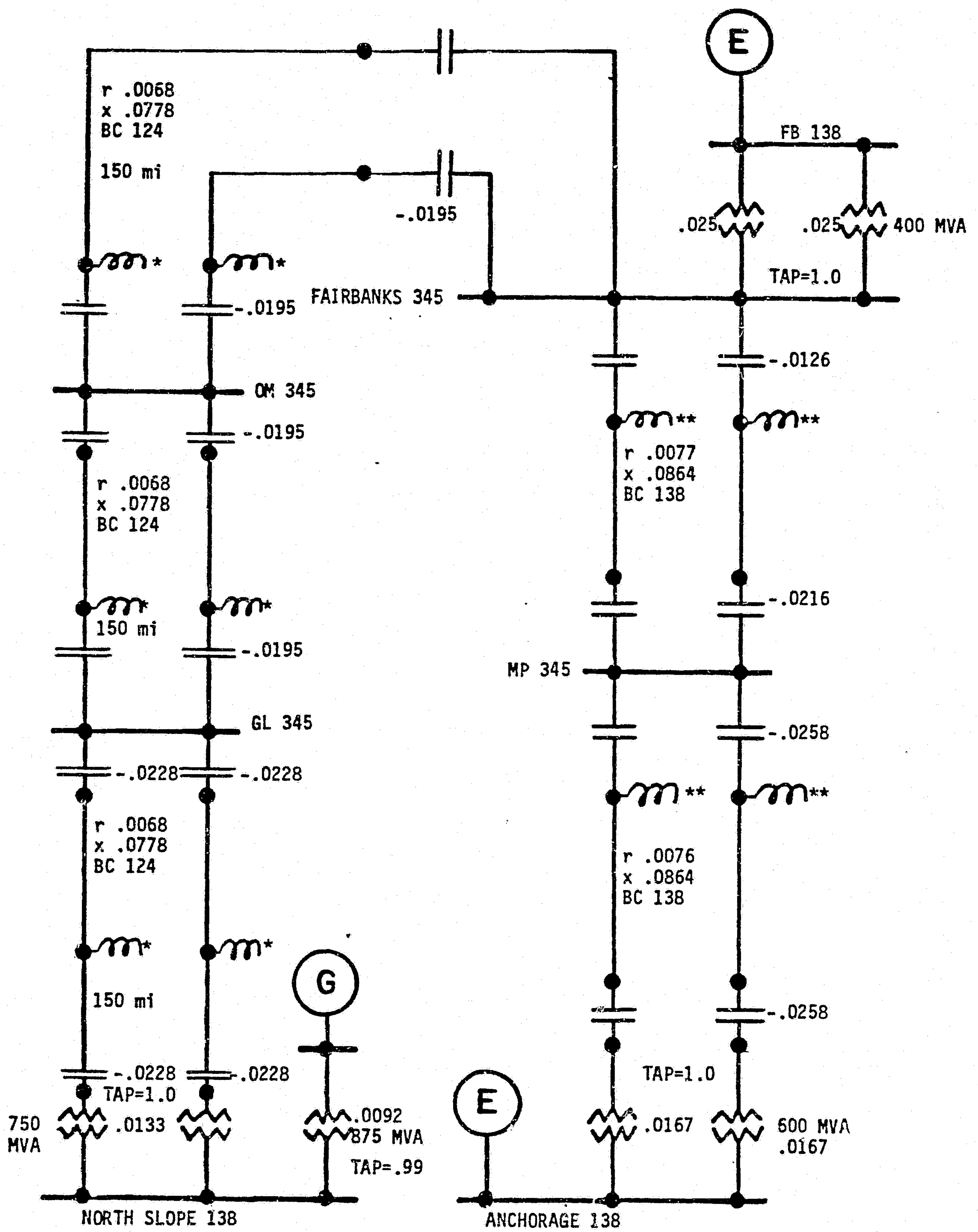
NORTH SLOPE GAS FEASIBILITY STUDY

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

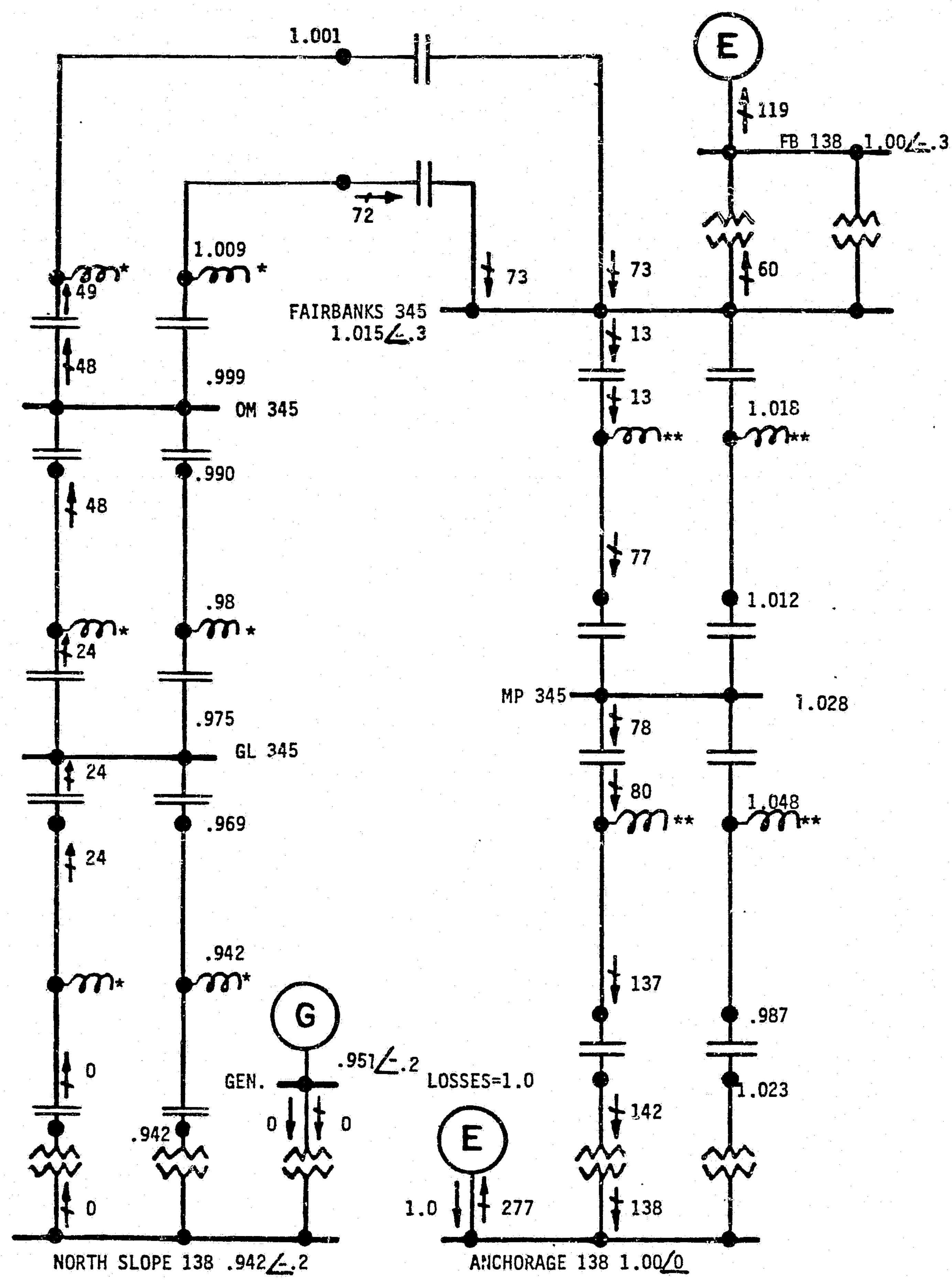
ONE LINE SCHEMATIC WITH IMPEDANCES

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

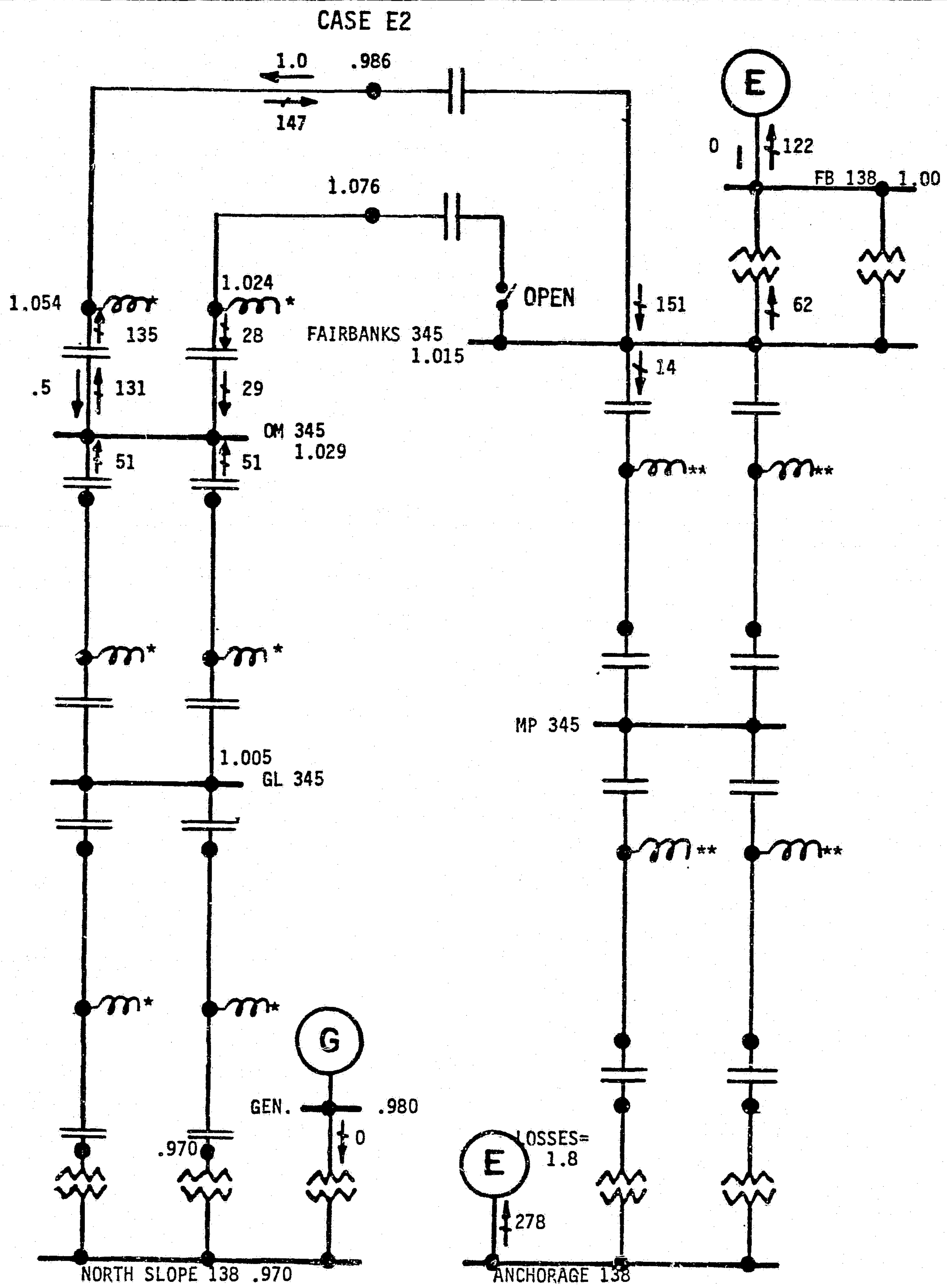
NORTH SLOPE GAS
FEASIBILITY STUDY

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

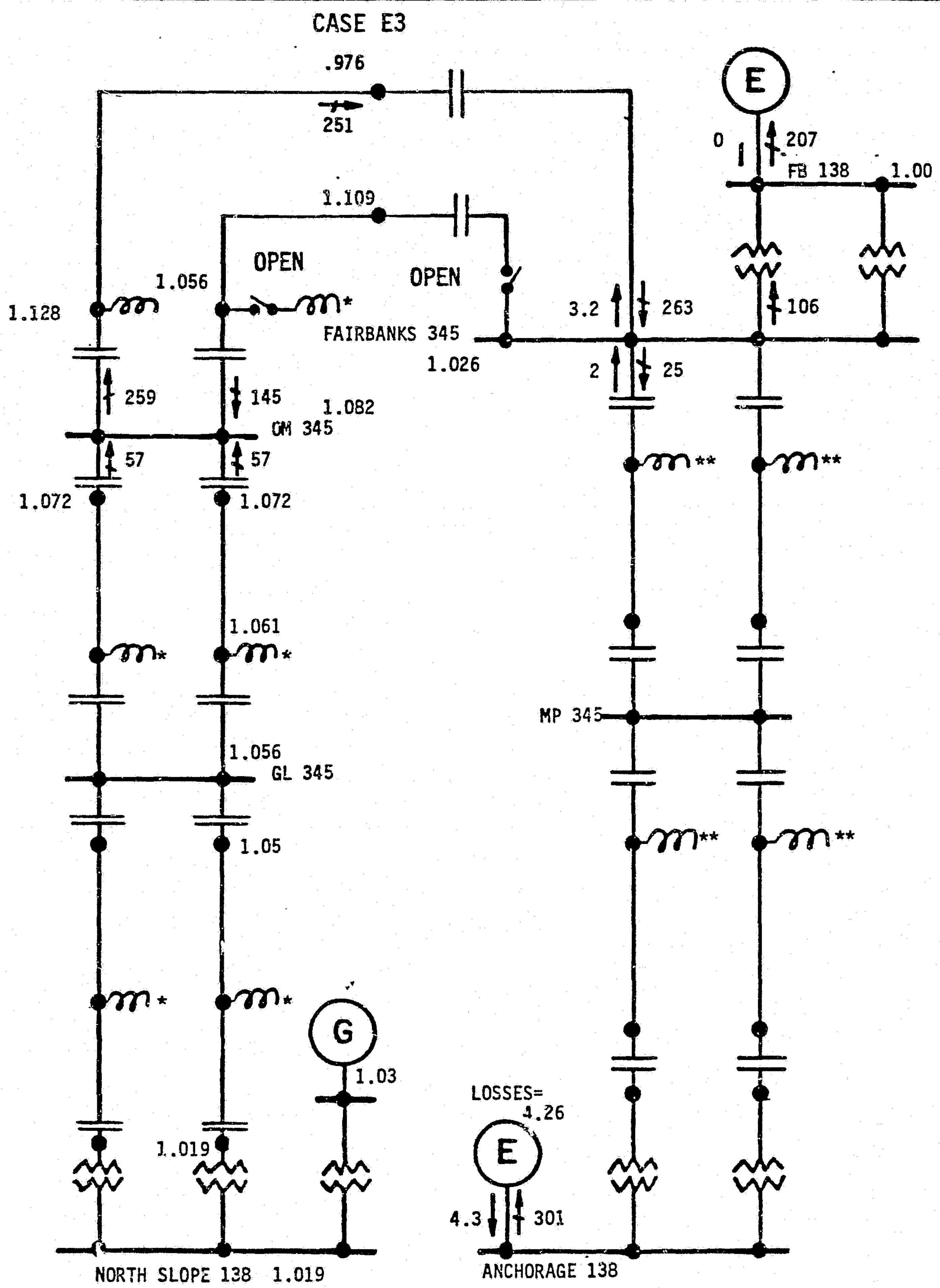
NORTH SLOPE GAS FEASIBILITY STUDY

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

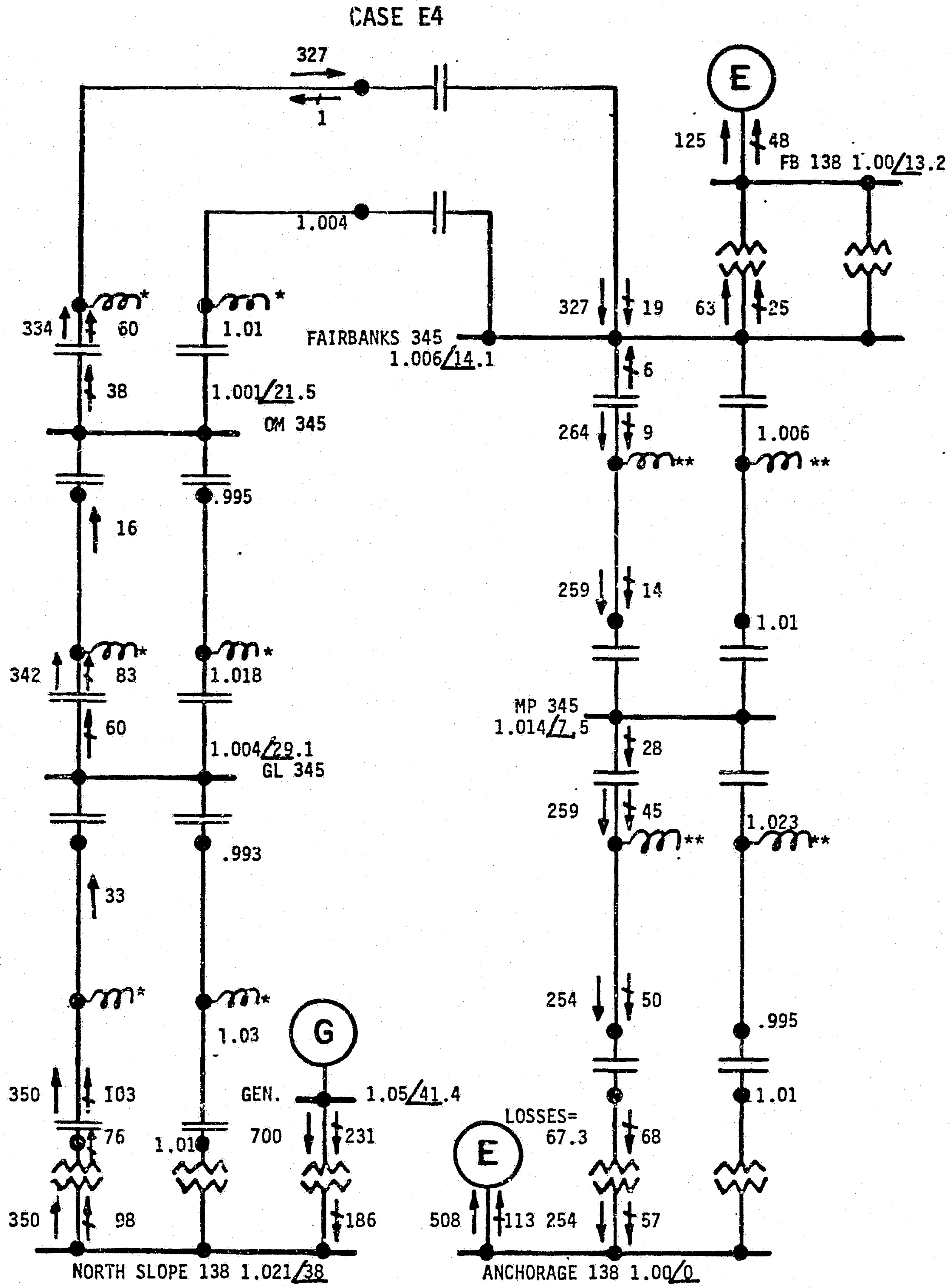
NORTH SLOPE GAS FEASIBILITY STUDY

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

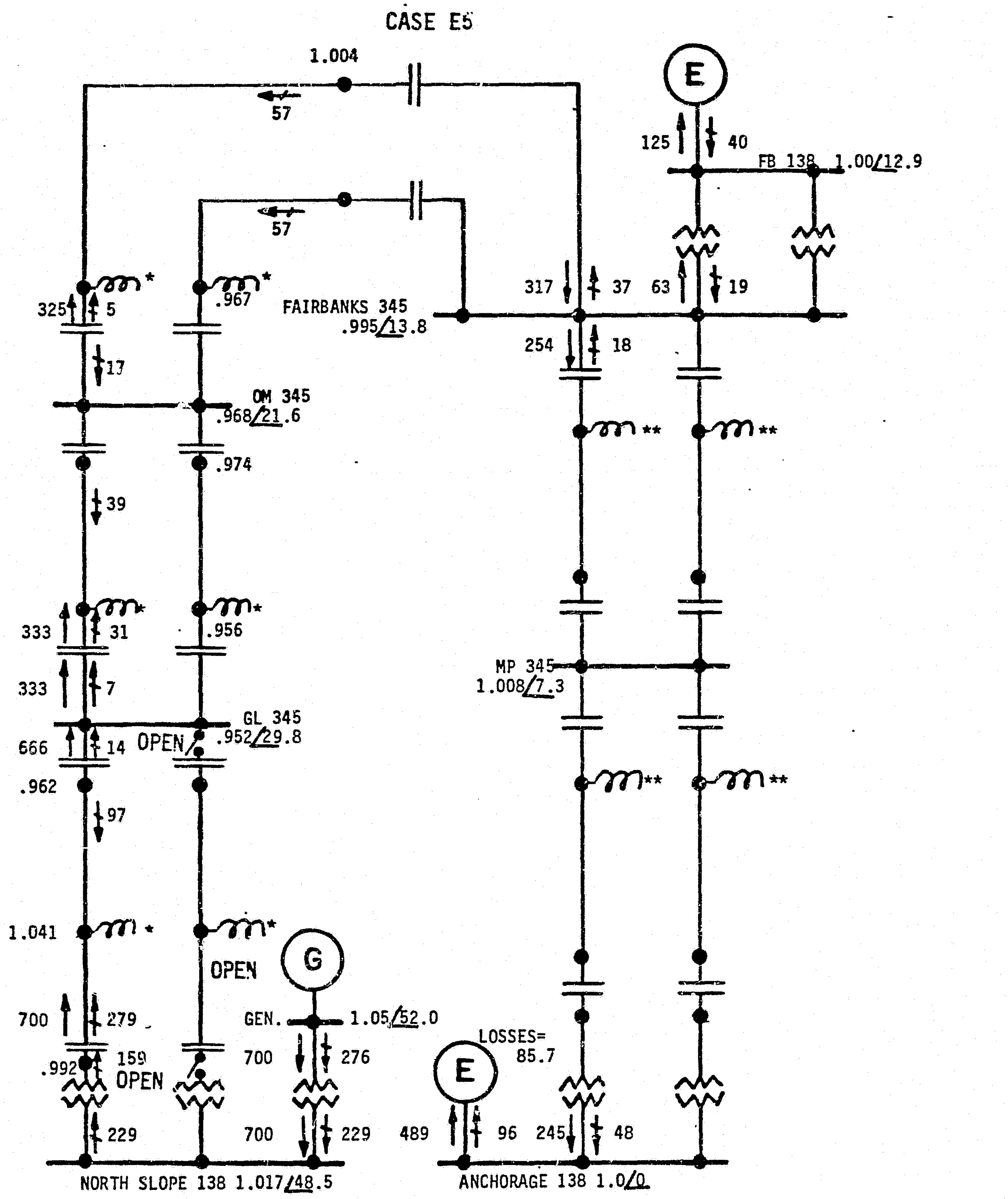
700 MW generation at Prudhoe Bay.
Normal system configuration.

FIGURE D-38

EBASCO SERVICES INCORPORATED

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

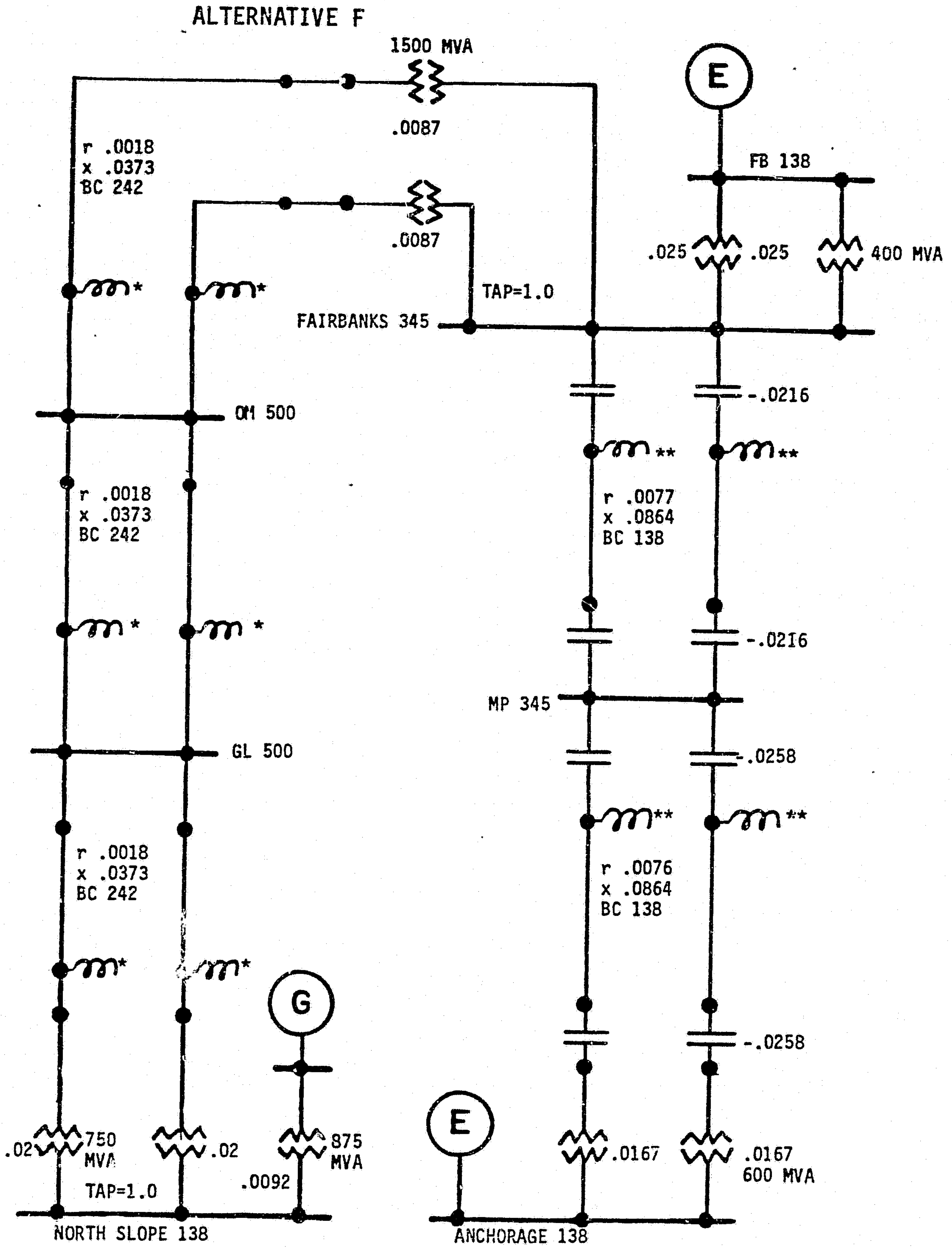
NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

700 MW generation at Prudhoe Bay, one line segment out of service south of Prudhoe Bay.

FIGURE D-39

EBASCO SERVICES INCORPORATED



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

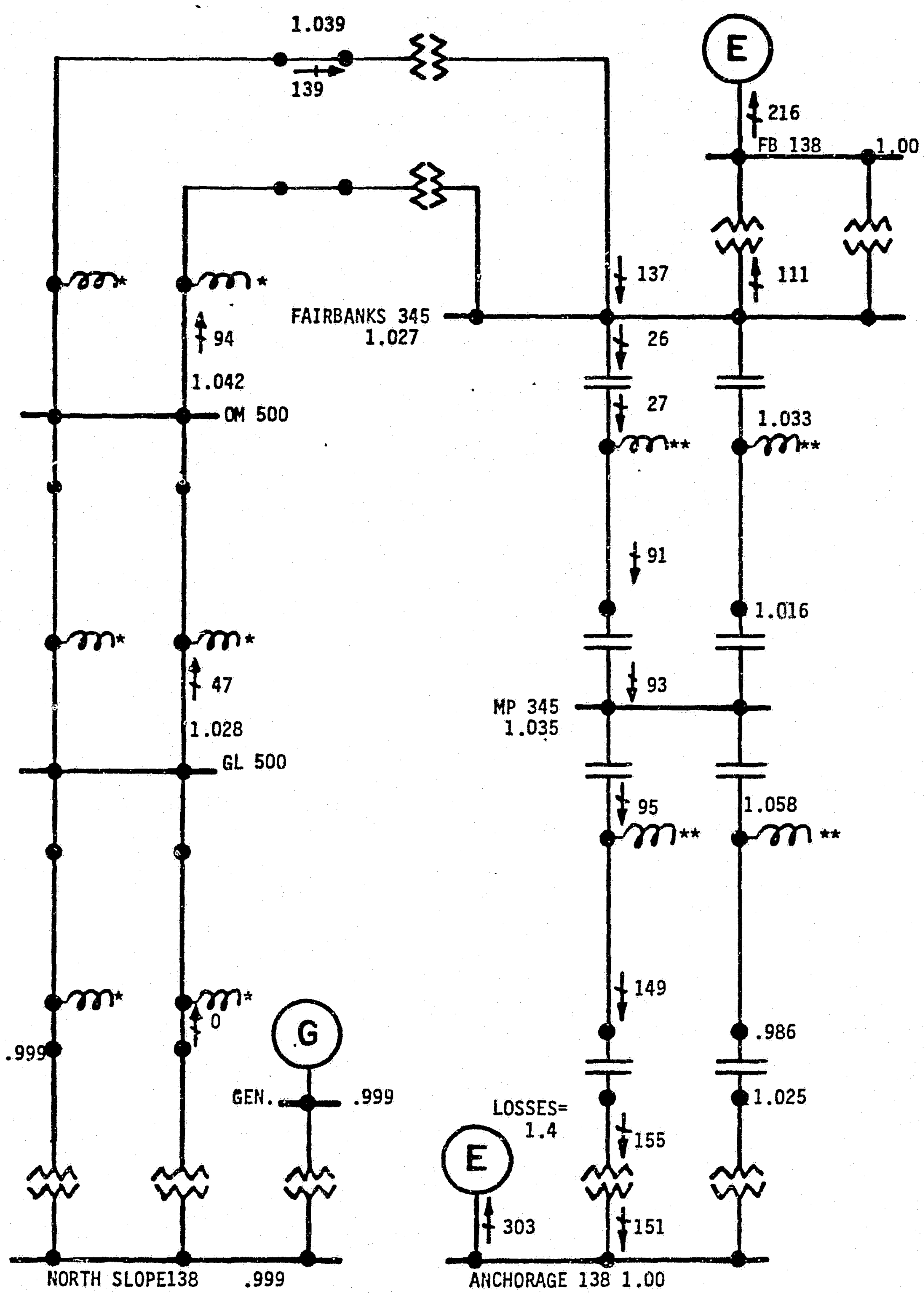
ONE LINE SCHEMATIC WITH IMPEDANCES

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

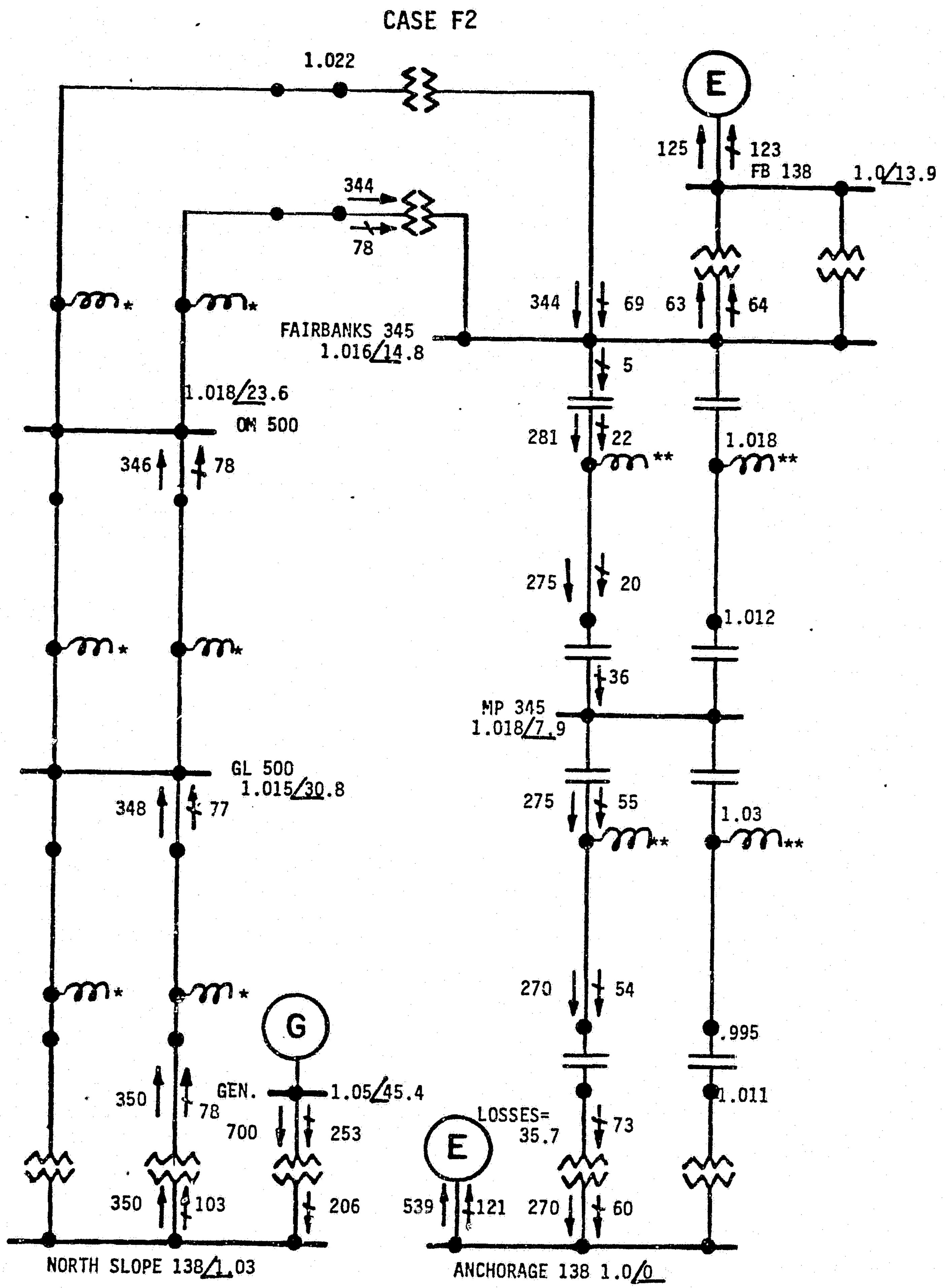
CASE F1



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 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

ALASKA POWER AUTHORITY

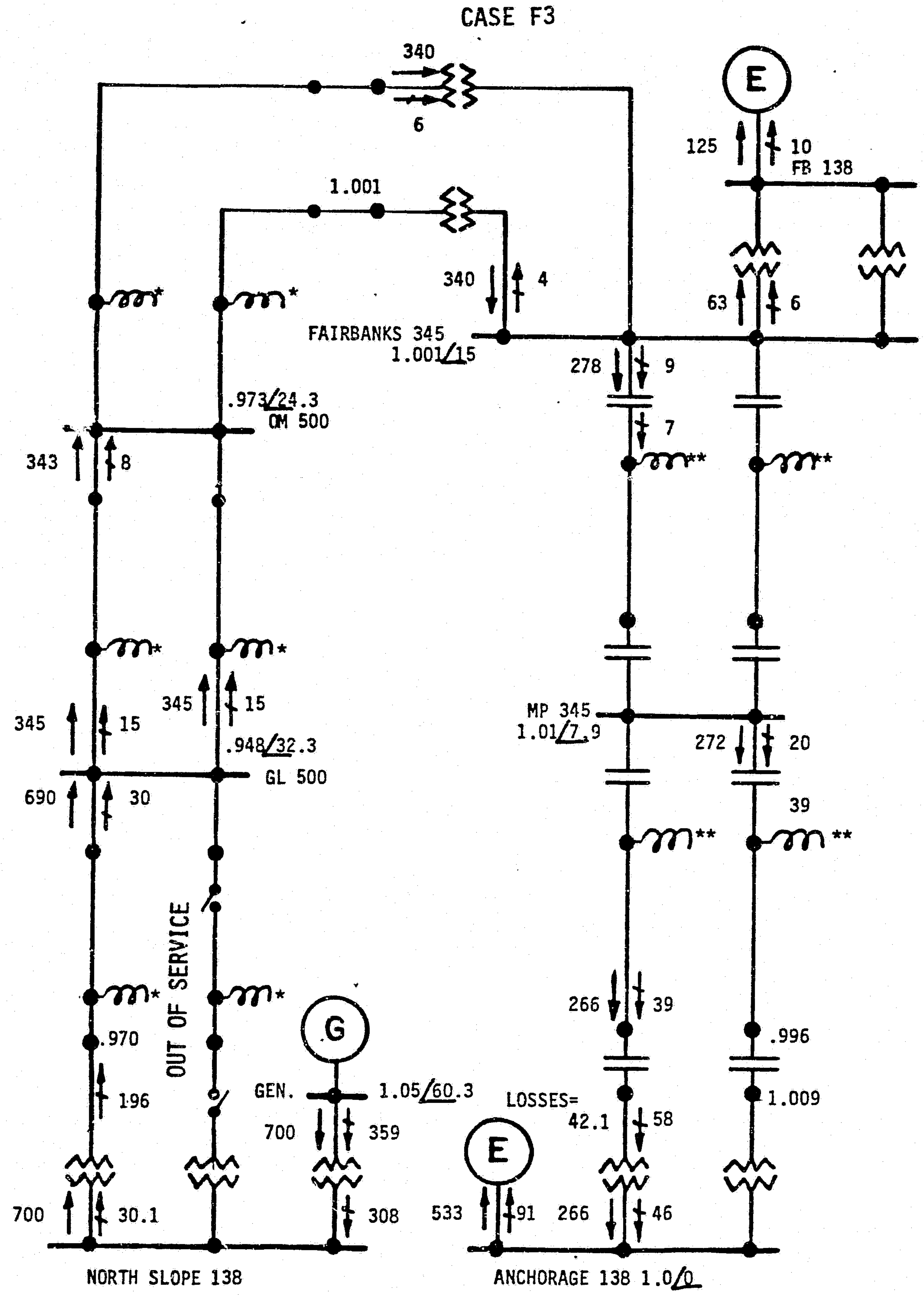
NORTH SLOPE GAS FEASIBILITY STUDY

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

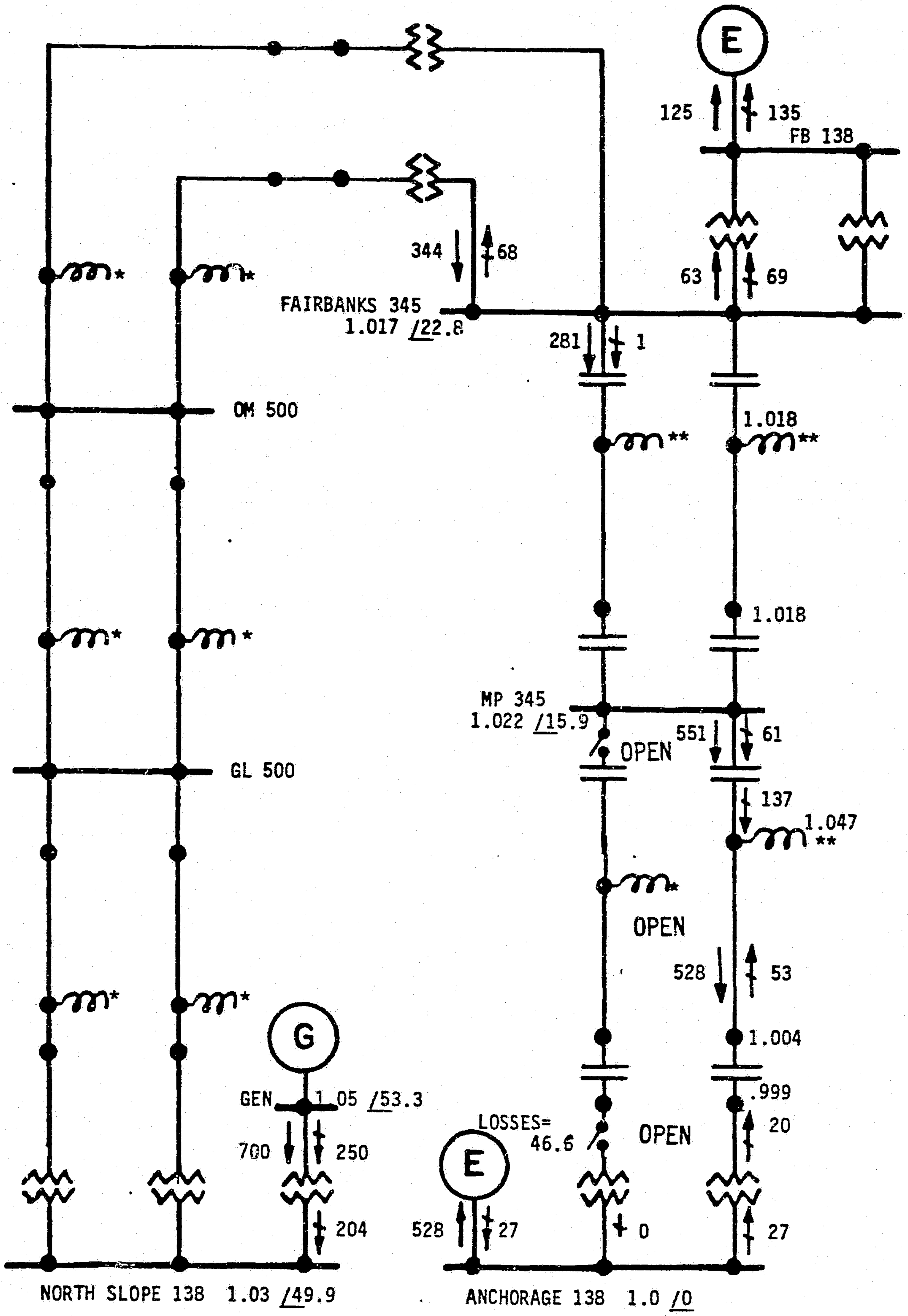
LOAD FLOW

700 MW generation at Prudhoe Bay, one line segment out of service south of Prudhoe Bay.

FIGURE D-43

EBASCO SERVICES INCORPORATED

CASE F4



ALASKA POWER AUTHORITY

NORTH SLOPE GAS FEASIBILITY STUDY

LOAD FLOW

700 MW generation at Prudhoe Bay, one line segment out of service north of Anchorage.

FIGURE D-44

EBASCO SERVICES INCORPORATED

Notes

* 200 MVAR
** 75 MVAR
50% series compensation at the 345 kV line only
For letter symbols, see Table D-8

D.9.0 REFERENCES

Ruef, D.M., 1981. Experiences with Contaminated Insulators Under Arctic Conditions. SOHIO Alaska Petroleum Company.

Commonwealth Associates, Inc., 1981. Anchorage-Fairbanks Transmission Intertie Route Selection Report.

Electric Power Research Institute (EPRI), 1982. Transmission Line Reference Book: 345 kV and Above; 2nd Ed.

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. 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 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 conditional demand projections derived are 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

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, prepared by the Fairbanks North Star Borough (FNSB) 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 suplied to the merketplace.

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, 278 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
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
MMBTUS/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

Residential Space Heating and Water Heating: The estimates in Table E-2 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.

TABLE E-2

FAIRBANKS NORTH-STAR CONDITIONAL GAS DEMAND
POPULATION GROWTH AT 1.43%
(Delivered Energy)

	1985	1990	1995	2000	2005	2010
<u>10% of Market</u>						
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
<u>25% of Market</u>						
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	149[illegible].9	1608571.8	1726921.4	1853978.6
Residential (MCF)	1077237.4	1156494.4	124[illegible].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
<u>40% of Market</u>						
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
<u>1981 Fuel Oil/Propane Share of Market</u>						
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

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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-3.

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.

TABLE E-3

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	2558503.0	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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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, nonresidential, 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-3 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-3.

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-3).

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. 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].

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-1. 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) Railbelt Pop. % Change x 100 1980-2010 = -.0192 + .7237* Railbelt Electricity Demand % Change x 100 1980-2010

(-9.6) (14.2)

R^2 = .9991 Six Observations

(2) Fairbanks Pop. % Change x 100 1980-2010 = -.0326 + .9299* Railbelt Pop. % Change x 100 1980-2010

(-7.6) (6.0)

R^2 = .9954 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

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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-2 and E-3 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-2 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-3.

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.

potential demand times the factor $(1.0143)^t$.[1/] Maximum demand, as presented in Table E-3 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 above in Table E-1, 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): breakdown 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.

Lumpy Demand: 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-2 and E-3, 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-4.

Reading from Table E-4, 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-4

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-2 and E-3 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-5.[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. As the attached information shows, 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

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. As the attached information shows, 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.

E2.0 REFERENCES

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[6] Interior Woodcutters Association, "Fuel Wood Utilization in The Fairbanks North Star Borough," report of a survey conducted November 1981 through January 1982.

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