REASSESSMENT REPORT

ON

UPPER SUSITNA RIVER

HYDROELECTRIC DEVELOPMENT

FOR

THE STATE OF ALASKA

September 1974

HENRY J. KAISER COMPANY

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ACKNOWLEDGMENTS

In preparing this report, the Henry J. Kaiser Company project team has been given invaluable assistance by the staff of the Office of the Governor, the Departments of Economic Development, Labor and Natural Resources, as well as the electrical utilities and municipal agencies of the Anchorage-Cook Inlet and Fairbanks Areas. The Federal Power Commission, Alaska Power Administration, and the Alaska District of the U. S. Army Corps of Engineers, and the Alaska Chapter, Associated General Contractors of America, Inc. have also generously extended their cooperation. In addition, many private firms and individual Alaskans were interviewed in the course of this study. The Henry J. Kaiser Company would like to express sincere gratitude for this support.

I. INTRODUCTION

A. GENERAL

The hydroelectric development potential of the upper Susitna River has long been recognized. Investigation of the river was begun by the U. S. Bureau of Reclamation (U. S. B. R.) in 1950, and by 1953 an ultimate development plan was formulated. The initial proposed development recommended by these and subsequent studies was the Devil Canyon Project. The U. S. B. R. feasibility report for this project was completed in May 1960 and endorsed by the State of Alaska in June of 1961. The Alaska Power Administration "Devil Canyon Status Report" of May 1974 contained minor modifications to the original designs and presented a cost estimate updated to January 1974.

B. THE DEVIL CANYON PROJECT

The Devil Canyon Project report proposed construction of a concrete arch dam in Devil Canyon and a low earth-rockfill dam at Denali as the first step in the Susitna River's development. A power plant was proposed for the Devil Canyon site only because heavy drawdown of Denali reservoir would make power generation there uneconomical. The project's transmission system would supply electricity to substations in Anchorage, Fairbanks, and the proposed site of the new state capitol.

As visualized by U. S. B. R., the ultimate development of the upper Susitna River would also include dams and power installations at Watana and Vee Canyon at some later date. Further detailed studies were recommended by U. S. B. R. to confirm the economic feasibility of the ultimate development plan indicated.

C. AN ALTERNATIVE CONCEPT TO DEVIL CANYON PROJECT

In 1973, the Henry J. Kaiser Company prepared a preliminary analysis of the hydroelectric development potential of the upper Susitna River. At that time it was considered that growth of regional power markets and rising cost of fossil fuels could now make it feasible to begin the long-delayed hydroelectric development of the river. It was also anticipated that if the river were capable of producing sufficiently economical power, a major energy-intensive industry could be attracted to utilize any long-term surplus.

Following evaluation of the Devil Canyon Project as planned by U. S. B. R., the Henry J. Kaiser Company outlined an alternate and potentially more economical development concept.

This alternate concept visualizes a single dam and powerhouse installation near Devil Canyon in lieu of the two-dam, single powerhouse scheme recommended by the U. S. B. R. This concept would eliminate, at least from the initial development, the Denali dam and reservoir, which appear to present unresolved technical, economic, and environmental problems. Early in 1974, this alternate concept was presented to the State of Alaska, along with a proposal to undertake a small preliminary study. The study, as proposed, was to include preparation of a conceptual design, order of magnitude cost estimate, and a preliminary feasibility report for an alternate hydroelectric project on the upper Susitna River.

On June 4, 1974, the State of Alaska contracted with Henry J. Kaiser Company for performance of the services set forth in the proposal.

This report presents the results of Kaiser's study. In this study, the project concept recommended by Kaiser for initial development of the Susitna River is identified as Susitna I. Future projects to utilize the ultimate development potential of the river are identified as Susitna II and Susitna III.

II. SUMMARY AND CONCLUSIONS

A. REASSESSMENT AND ALTERNATE CONCEPT

This study has reassessed the U. S. Bureau of Reclamation (U. S. B. R.) scheme for development of the hydroelectric potential of the upper Susitna River and presents an alternate concept for its initial and ultimate development.

The U. S. B. R. scheme consists of a concrete arch dam and a power plant at Devil Canyon and an earth-rockfill dam at Denali as the first step in the Susitna River's development. Ultimate development would include dams and power installations at Watana and Vee Canyons. These facilities would effect full regulation of the river and provide a total installed capacity of 1, 372, 000 kilowatts with firm annual energy production of 7, 000 million kilowatt-hours. The installed capacity of the Devil Canyon plant would be 600, 000 kilowatts and the firm annual energy production would be 2, 900 million kilowatt-hours. The construction cost for the first step, based on January 1974 prices was estimated to be $597, 100, 000. With $84, 900, 000 of interest during construction, the estimated total project investment cost was $682, 000, 000.

The Kaiser concept includes three projects, designated Susitna I, II, and III, which would be located as shown in Section VII, Figure VII-1. The initial project, Susitna I, which is the main focus of this report, would consist of a hydroelectric development at a location about five miles upstream from Devil Canyon. The power plant would have an installed capacity of 700, 000 kilowatts and a firm annual energy production of 3, 372 million kilowatt-hours. As in the Devil Canyon's scheme, the Susitna I project transmission system would deliver power to the Anchorage-Cook Inlet and Fairbanks Areas. Subsequent stages of development would include Susitna II, a dam and run-of-river power plant located below Portage Creek, with an installed capacity of 163, 000 kilowatts and an annual energy production of 785 million kilowatt-hours. Susitna III would consist of a dam and power plant located approximately at the headwater limit of the Susitna I reservoir. Susitna III would have an installed capacity of 445, 000 kilowatts and an annual energy production of 1, 840 million kilowatt-hours.

The construction cost of Susitna I was estimated at $525,720,000 based on June 1, 1974 price levels. Including interest during construction of $77,000,000, the estimated total project investment costs would be $602,720,000. On the basis of the schedule shown in Section VIII, Figure VIII-1, with engineering starting in early 1975 and main construction starting in 1977, the estimated total project investment costs would be $638,100,000.

The overall alternate development concept would have a total installed capacity of 1,308,000 kilowatts and a total annual energy production of 6,309 million kilowatt-hours. These totals are slightly less than the figures presented for the U.S.B.R. development scheme, and the reduction is directly attributed to avoiding development of the Denali Reservoir which may have an unfavorable environmental impact.

Economic comparisons of Susitna I with alternative thermal development and the Devil Canyon-Denali scheme indicate that Susitna I is the most attractive alternative.

The findings of this report are summarized on the following pages.

B. ELECTRICAL LOAD GROWTH FORECASTS AND SYSTEM BALANCE

Load growth forecasts through 1990 have been prepared for major Anchorage-Cook Inlet and Fairbanks Area utilities, resulting in the following conclusions on the region's energy consumption and peak load.

	Anchorage-Cook Inlet		Fairbanks		Total	
Year	Net Energy million kwh	Peak Load thousand kw	Net Energy million kwh	Peak Load thousand kw	Net Energy million kwh	Peak Load thousand kw
Actual						
1968	559	125	161	43	720	168
1973	1,090	213	318	73	1,408	286
Forecast						
1975	1,400	271	410	87	1,810	358
1980	2,740	513	803	164	3,543	677
1985	5,080	928	1,354	266	6,434	1,194
1990	9,420	1,721	2,281	434	11,701	2,155

Existing system expansion plans for the Anchorage-Cook Inlet Area are capable of satisfying this forecast through mid-1979. Prior to mid-1981, the earliest date at which Susitna I could be commissioned, it would be necessary to add approximately 84,000 kilowatts of new capacity to serve this area. Existing expansion plans for the Fairbanks Area should satisfy load growth requirements until mid-1982.

The power system balance indicates that if Susitna I were commissioned in mid-1981, its 700,000 kilowatt capacity would be fully absorbed by the systems normal load growth through early 1986.

Power and energy forecasts by area and the overall power system balance are illustrated in Figure II-1.

C. HYDROELECTRIC POWER CAPACITY OF SUSITNA I

Hydrologic studies based on 23 years of recorded river flow at Gold Creek indicated an estimated flow at the Susitna I site as follows:

Annual Flow in Acre-Feet

Minimum	Average	Maximum
3,772,000	6,639,000	7,795,000

The minimum annual flow was recorded in 1969 and was not taken into account in the Alaska Power Administration's "Devil Canyon Status Report," 1974.

Reservoir operation studies for the 23-year period of record and hydrologic studies indicated that 3,372 million kilowatt-hours of energy could be produced at least 97% of the time.

Because Susitna I will be part of a larger system including substantial thermal capacity, the system as a whole could be operated to meet overall demand in a dry year, such as 1969, despite a reduction in Susitna I energy production. Accordingly, the project's firm annual energy capability has been established at 3,372 million kilowatt-hours for an installed capacity of 700,000 kilowatts at 55% plant factor. On the average, 500 million kilowatt-hours of secondary energy can be produced per year.

D. CONCEPTUAL ENGINEERING STUDIES

These studies used U. S. Geological Survey maps to identify sites potentially favorable for locations of dams and impoundment of large reservoirs. River runoff records from the U. S. G. S. Gold Creek and Cantwell stations, and climatological data from a number of weather stations in the region were used to assess the water resource of the river. All of these data were combined to evaluate several alternate concepts of project scope and layout. The geologic and engineering reconnaissance survey made early in the study confirmed the superiority of the terrain of the selected site over several alternate sites. It revealed the occurrence at the site of a granitic-type bedrock eminently suitable for project location and use in dam construction, and identified important geologic features which were significant in selecting the layout and location of main project features. The reconnaissance also provided preliminary information on the availability of other construction materials.

Estimates of cost were based on conceptual designs, site characteristics, and most recent information on costs of labor, equipment, and materials, all related to the project site.

E. PRINCIPAL PROJECT FEATURES

Type of dam	Concrete face rockfill
Crest elevation, feet (m. s. l.)	1,755
Crest length, feet	3,050
Height of dam, feet	800 - approximately
Reservoir maximum normal capacity, acre-feet	5,760,000
Reservoir area, acres	24,200
Power plant type	Underground
Installed capacity - kilowatts	700,000
Units	4 @ 175,000 Kw, Francis type
Average gross head, feet	702
Range in gross head, feet	758-518
Annual plant factor, percent	55
Annual firm energy, kilowatt-hours	3,372 million
Annual average energy, kilowatt-hours	3,872 million
Transmission line, rating kilovolts	230
Length to Anchorage, miles double circuit	139
Length to Fairbanks, miles single circuit	214

F. ESTIMATED SUSITNA I PROJECT COST

The estimated construction and equipment costs for the project, based on June 1, 1974 price levels, are summarized below:

Hydroelectric Plant	
Site access, reservoir clearing, and diversion tunnels	$ 47,185,000
Dam and spillway	263,690,000
Power plant and related facilities	129,570,000
Living quarters and general property	2,880,000
Subtotal	$443,325,000
Transmission System	82,395,000
Total construction costs	$525,720,000
Interest during construction	77,000,000
Total Estimated Project Investment	$602,720,000

The above estimate includes contingency and engineering costs but does not include escalation to the date of award of the construction and equipment supply contracts.

G. FINANCIAL EVALUATION AND ECONOMIC ANALYSIS

A pro forma income statement has been prepared for Susitna I in order to determine whether the project's cost, construction schedule, and revenue base are consistent with a practical financing plan. The results of this analysis indicate that the project would be capable of making regular interest payments beginning in January 1982, six months after startup, and that regular sinking fund installments could begin in the fourth quarter of 1985.

The project would produce power valued at an average 14.5 mills per kilowatt-hour at the service area step-down substation. Allowing for differences in load factor and especially the incremental cost of transmission, Susitna I power would cost 13.5 mills per kilowatt-hour in Anchorage and 17.5 mills per kilowatt-hour in Fairbanks.

For comparison with Susitna I costs, it is estimated that power generated by new thermal capacity commissioned in 1981 would be approximately 15.9 mills in the Anchorage-Cook Inlet Area, and approximately 18.6 - 21.0 mills in the Fairbanks Area. It has also been estimated that Susitna I power cost would be approximately 75% that of the U.S.B.R. Devil Canyon project.

H. CONCLUSIONS AND RECOMMENDATIONS

The summary presented above indicates that the Susitna I project provides an economical means of meeting the service area electrical load growth requirements of the 1980's.

The generation of first power in 1981 is contingent upon the completion early in 1976 of the definitive designs and cost estimates required to firm-up project feasibility and provide a sound basis for project financing measures. This requires that engineering be started early in 1975 so that the prerequisite site mapping and detailed geologic investigations can be carried out as early as possible in 1975.

Application for preliminary licensing by the Federal Power Commission should be made before the end of 1974. Environmental studies should be started as early as possible so that environmental questions can be resolved without causing delay to project implementation.

The key steps in the implementation of the project and generation of first power in 1981 are as follows:

- Establishment of Power Authority.

  It is recommended that the State of Alaska establish an autonomous development authority to undertake the Susitna Project. Such an agency would have as its immediate responsibility the financing and management of this project; however, its role later could be expanded to include similar developments in other parts of Alaska.

Initially, the operations of such an authority probably must be funded by the state government. However, as the authority develops into a revenue-producing agency, it is considered desirable that it become fully self-sufficient.

- Application for Preliminary Licensing by the Federal Power Commission.

- Environmental Studies.

- Land Acquisition.

Most land in the upper Susitna Basin, particularly in the area of Susitna I is both withdrawn as a Federal powersite and also earmarked for selection by native regional corporations under the Alaska Native Claims Settlement Act (ANCSA). It is not clear whether either of these designated uses establishes a peremptory claim to use of the land.

It is considered that the State of Alaska may require Susitna Basin lands either by arranging for assignment of the Federal powersite withdrawal, or by negotiating for NACSA selection of eligible lands, with subsequent lease or sale to the State or its power authority.

- Engineering.

This will include the following main items:

- Mapping of project site area
- Detailed investigations of site geology including drilling and investigation of construction materials
- Development of definitive designs
- Preparation of definitive cost estimate and application for full licensing by the Federal Power Commission

- Preparation of specifications and contracts for construction and for supply and installation of major equipment

- Recommendations for awards of construction and supply contracts

- Engineering and management of construction

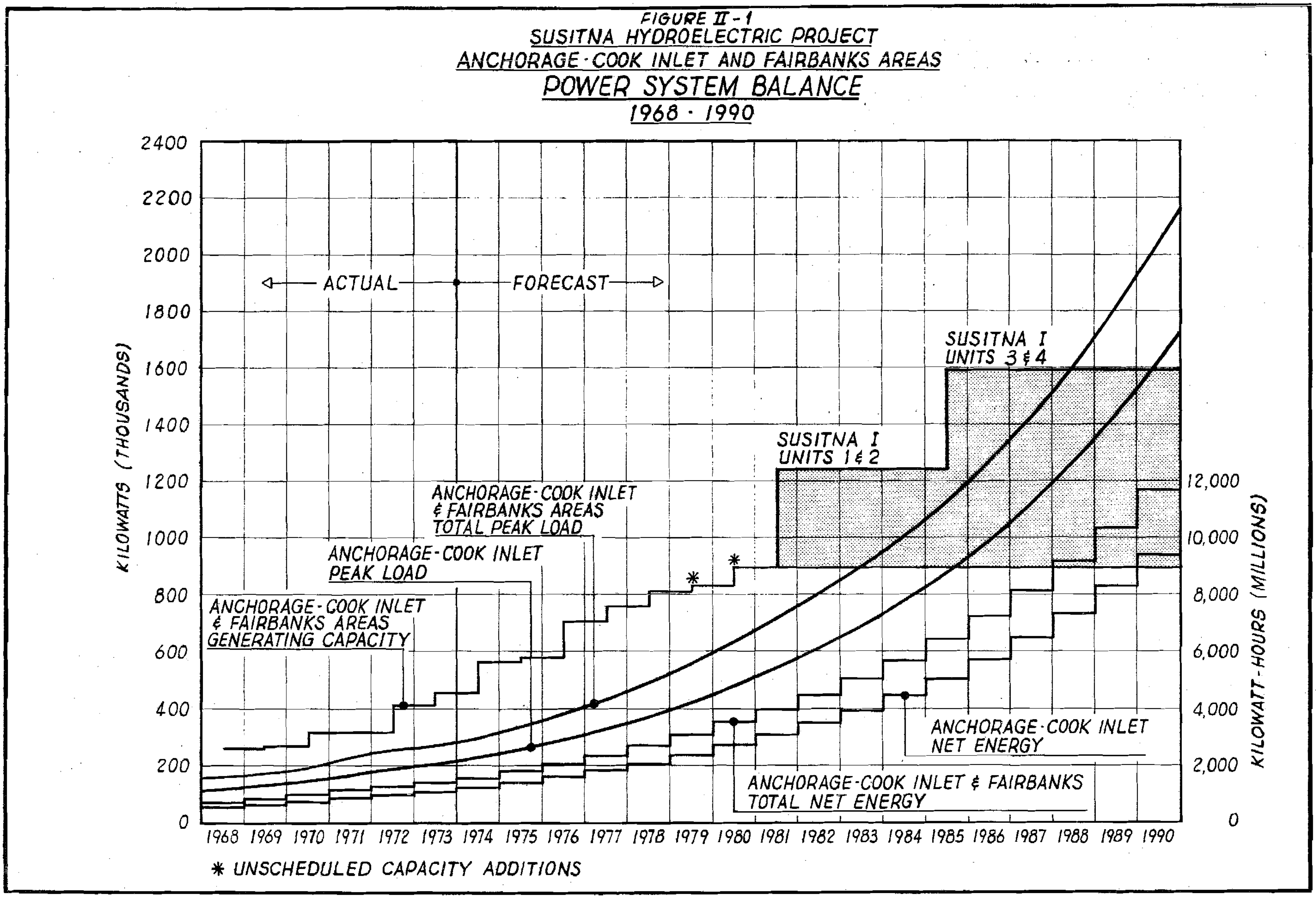


FIGURE II - 1
SUSITNA HYDROELECTRIC PROJECT
ANCHORAGE - COOK INLET AND FAIRBANKS AREAS
POWER SYSTEM BALANCE
1968 - 1990
ACTUAL
FORECAST
SUSITNA I UNITS 3 & 4
SUSITNA I UNITS 1 & 2
ANCHORAGE - COOK INLET & FAIRBANKS AREAS TOTAL PEAK LOAD
ANCHORAGE - COOK INLET PEAK LOAD
ANCHORAGE - COOK INLET & FAIRBANKS AREAS GENERATING CAPACITY
ANCHORAGE - COOK INLET NET ENERGY
ANCHORAGE - COOK INLET & FAIRBANKS TOTAL NET ENERGY
KILOWATTS (THOUSANDS)
KILOWATT - HOURS (MILLIONS)
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2,000
4,000
6,000
8,000
10,000
12,000
1968 1969 1970 1971 1972 1973 1974 1975 1976 1977 1978 1979 1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990
* UNSCHEDULED CAPACITY ADDITIONS

III. POWER AND ENERGY FORECASTS

A. METHODOLOGY

The methodology used in forecasting Susitna I project power and energy demands is as follows:

- A primary service region was selected for the project.
- Population and employment of the service region were forecast to 1990.
- Growth of regional utilities' electrical energy sales was forecast based on its historical relationship with population and employment; nonutility industrial and U. S. military energy consumption were also evaluated.
- Power system generation and peak loads were projected in terms of recorded system operating parameters for regional utilities.
- Power and energy demands on Susitna I were projected in terms of the regional demand-capacity balance in the 1980s.

B. SERVICE REGION

The primary service region selected as a forecasting base for project power sales consists of the U. S. Census Divisions of Anchorage, Kenai-Cook Inlet, Matanuska-Susitna, and Seward--designated the "Anchorage-Cook Inlet Area;" and Fairbanks--designated the "Fairbanks Area."

The criteria for this selection are as follows:

1. Service to Population

Based on the 1970 U.S. Census, and subsequent estimates by the State of Alaska Department of Labor, the Anchorage-Cook Inlet Area today comprises approximately 90% of the population of Alaska's South Central Region, one of the state's five major geographical subdivisions, and it includes approximately 50% of the population of the state as a whole. The Fairbanks Area comprises approximately 80% of the population of the Interior Region and 15% of the state as a whole.

Together, the Anchorage-Cook Inlet and Fairbanks Areas make up 65% of Alaska's total population. Through 1990, it is anticipated that the growth rates of these areas will be higher than that of the state as a whole.

On the basis of this selected service region, it is believed that the project can convey benefits to a sufficiently large and broadly distributed population base to justify its sponsorship by the State of Alaska.

2. Transmission Economy

The Susitna I project site is located approximately 139 transmission miles north of the Anchorage-Cook Inlet Area and 214 transmission miles south of Fairbanks. It is projected that transmission to both of these areas would follow the present routes of the Anchorage-Fairbanks Highway, and/or of the Alaska Railroad. Roughly 90% of the Anchorage-Cook Inlet Area population is located adjacent to this main transmission route, while the remaining 10% is interconnected by transmission systems of area utility systems. Approximately 100% of Fairbanks Area population is located adjacent to the terminus of the northern transmission section. As a result, the extension of service to both of these areas offers a reasonable concentration of electrical load in terms of the length of transmission required.

In addition to the Anchorage-Cook Inlet and Fairbanks Areas, a small additional population is now located in the Susitna-Chulitna and Nenana valleys adjacent to the proposed transmission mainline. It is expected that this population will increase rapidly due to ease of access via the new Anchorage-Fairbanks Highway. The proposed new location of the Alaska state capitol is also in this area. Therefore, the practical service region of the project has a substantial capability of expansion along its transmission mainline.

Areas which have been excluded from the service region in this report fall into two categories. The first of these includes remote areas which, for the foreseeable future, are not expected to have sufficient population and electrical load to make extended transmission of Susitna-generated power competitive with local generation, even where the latter is very costly. The second category includes two areas which now have small population bases, but which could warrant extended transmission in the future. The first of these areas is the middle Tanana valley, including the community of Big Delta. It is probable that this area will be connected by Fairbanks Area utilities prior to completion of initial development of the Susitna River power. The second area is the eastern perimeter of Prince William Sound, including Valdez and Cordova. This is expected to be one of Alaska's fastest growing population centers in the late 1970s and 1980s due to the construction of the Alyeska Pipeline, the probable construction of a natural gas pipeline from the North Slope, and subsequent development of refining and petrochemical industries at the pipeline termini. This area has been excluded from the service region in this report for the following reasons. First, serving it would require an additional transmission system nearly as long as the mainline; this would add substantially to the delivered cost of Susitna power in this area. Second, this area is expected to have relatively inexpensive sources of fuel for local power generation, which, due to transmission cost of Susitna power, could easily be more competitive. Third, although this area's population should increase several times from its present base, inclusion of the related electrical load in this report would not affect the economic feasibility of the initial Susitna project.

C. POPULATION AND EMPLOYMENT FORECASTS

1. Forecasting Guidelines

To forecast growth of population and employment in the Anchorage-Cook Inlet and Fairbanks Areas through 1990, two sets of statewide and regional forecasts have been used. These were prepared by the State of Alaska Department of Labor, Research and Analysis Section (ADL) and by the National Bank of Alaska, Economics Department (NBA). Other population and employment forecasts have also been consulted, particularly those prepared recently for Alyeska Pipeline Service Company, Inc., and the University of Alaska, Institute of Social, Economic and Government Research. In addition, reference has been made to forecasts cited in the drafts of the Alaska Power Administration's Alaska Power Survey, 1974. The ADL and NBA forecasts are summarized in Tables III-1 and III-2.

TABLE III-1

FORECASTS OF ALASKA'S TOTAL POPULATION

	Alaska Department of Labor (ADL)	National Bank of Alaska (NBA)
1974	357,200	361,300
1975	386,600	406,900
1976	-	433,200
1977	-	446,100
1978	-	461,000
1979	-	473,700
1980	448,400	479,900

Sources: Annual Population and Employment Projections 1961-1980, Alaska Department of Labor, Research and Analysis Section
National Bank of Alaska, Economics Department

TABLE III-2

ALASKA CIVILIAN EMPLOYMENT FORECASTS 1975 AND 1980

Industry	Alaska Department of Labor (ADL) 1975		1980		Annual Rate of Change	
Construction		18,000		12,000		-5.9
Mining		3,000		6,400		16.3
Distributive and Service		59,100		77,600		5.6
Government		46,400		56,900		4.2
Federal	17,500		18,000		.6	
State-Local	28,900		38,900		6.2	
Manufacturing		10,500		13,500		5.2
Other		14,200		16,200		2.7
TOTAL[1]		151,200		182,600		3.9

Industry	National Bank of Alaska (NBA) 1975		1980		Annual Rate of Change	
Construction		18,100		14,100		-4.1
Mining		3,000		5,500		12.9
Distributive and Service		65,000		83,000		5.1
Government		49,900		62,500		4.6
Federal	17,400		17,900		.6	
State-Local	32,500		44,600		6.5	
Manufacturing		13,500		12,100		-2.0
Other		14,300		16,300		2.7
TOTAL		160,000		193,500		3.9

[1] Totals may not add due to rounding.

Source: See Table III-1.

The ADL and NBA forecasts extend to 1980. Both forecasts have been based on polynomial regression analysis of historical trends, with estimates of the impacts of Alyeska Pipeline construction beginning in 1974. Both forecasts anticipate sustained growth of population and employment following the peak impacts of Alyeska Pipeline's construction in the late 1970s. This growth will be based on activity in mining, and other industrial sectors, as well as public, commercial, and residential construction. In addition to private sector growth, the NBA forecast has noted that the State of Alaska will receive net royalties and severance taxes of as much as $900 million per year from first-stage North Slope oil and gas production; these revenues are expected to stimulate increased investment and employment in state and local government.

The ADL and NBA population forecasts differ principally with respect to growth between mid-1974 and mid-1975. During this period, ADL forecasts an increase of 29,400 persons compared to the NBA forecast of 45,600. Beyond this, for the period 1975 through 1980, ADL projects a population gain of 16.0% with an annual compound growth rate of 3.0%. For the same period, the NBA forecasts an overall population increase of 17.9%, with a corresponding annual growth rate of 3.3%.

Key differences between the ADL and NBA employment forecasts are as follows:

(a) Compared to ADL, NBA forecasts that Alyeska Pipeline construction will have greater impact on employment in distribution and services, and in state government.

(b) NBA forecasts a smaller drop in construction activity in the late 1970s than does ADL, with less strength in mining and manufacturing.

(c) NBA forecasts a larger total employment gain from 1975 to 1980 than does ADL.

Both forecasts indicate that approximately 90% of Alaska's new employment in the last half of the 1970s will be in the distributive and service sectors, and in state government.

Kaiser's judgment is that both the ADL and NBA forecasts have been conservative in their evaluation of industrial impacts on Alaska's economy resulting from further development of the petroleum industry in the late 1970s, particularly relating to gas pipeline impact and development of the manufacturing sector. Further, it has been impossible for the forecasters to consider the magnitude of possible impacts from major expansion of the oil industry in southern Cook Inlet, the Gulf of Alaska, and possibly other areas. Such developments are probable and will justify substantially greater forecasting optimism when their size can be determined.

For this analysis, the higher NBA forecast has been selected as the basis for estimates of population and employment growth through 1980. In order to relate the NBA statewide forecast to the Susitna project service region, Kaiser has estimated the probable Southcentral and Interior regional components of this forecast, based on ADL data. The result revises the NBA's statewide figures to a regional base consistent with the historical distribution recorded by ADL.

2. Forecasts to 1980 and 1990

The record of growth in Southcentral and Interior Alaska's population and employment from 1961 through 1973 is indicated in Table III-3, along with forecasts to 1980 by ADL and by Kaiser based on the NBA statewide data as noted above.

Kaiser's forecast to 1990 is also shown in Table III-3. In the absence of authoritative guidelines, trends in population and employment to 1990 are based primarily on a statistical extrapolation of the historical record from 1961 through 1973, and of the revised NBA forecast through 1980. The annual growth rates forecast for the 1980s are somewhat less than those experienced in the past decade and those expected in the remainder of the 1970s. This reflects the substantially greater population and economic base to be achieved by 1980 and the associated probability that even very large industrial development projects will have a smaller percentage impact on growth than the Alyeska Pipeline has at the present time. Even with this limitation, the forecast annual volume of growth is on the average substantially larger than for the years prior to 1980.

TABLE III-3

RECORD AND FORECAST OF
TOTAL POPULATION AND CIVILIAN EMPLOYMENT
SOUTHCENTRAL AND INTERIOR REGIONS
1961-1990

Year	Southcentral Population	Southcentral Employment	Interior Population	Interior Employment
1961	115,900	35,400	48,100	12,300
1962	119,100	36,600	49,850	12,950
1963	122,400	37,850	51,650	13,550
1964	123,800	40,300	50,700	13,850
1965	132,600	44,700	50,500	14,850
1966	136,550	46,700	50,850	15,100
1967	140,200	49,500	51,050	15,000
1968	146,100	50,950	50,950	15,400
1969	151,800	54,900	52,500	16,950
1970	164,900	59,100	56,500	17,600
1971	174,600	62,950	55,000	18,350
1972	183,000	66,800	56,400	19,100
1973	188,700	71,100	56,300	19,300
FORECAST				
1975 ADL	223,100	84,800	66,500	26,500
Kaiser[1]	236,000	90,000	70,000	28,000
1980 ADL	265,000	104,000	70,000	28,000
Kaiser[1]	284,000	111,000	75,000	30,000
1990 Kaiser	415,000	162,000	128,000	51,000

[1] Based on NBA statewide forecasts.

Sources: 1961-1971, State of Alaska, Department of Economic Development, Alaska Statistical Review, 1972
1972-1973, State of Alaska, Department of Labor, Annual Population and Employment Projections, 1961-1980, and unpublished data.

In Kaiser's judgment, this forecast is warranted and probably conservative due to the following factors:

(a) Alaska's production of crude petroleum natural gas and other minerals, particularly coal, limestone, and iron ore, is expected to increase substantially in the 1980s, both as a result of new petroleum production in the North Slope and other areas, and the increasingly short supply and high world prices of mineral ores, which will encourage development of known Alaskan deposits of these materials. Growth in distribution, services, and government similar to that of the 1970s is expected to accompany expansion of these extractive industries.

(b) Alaska's manufacturing sector is expected to develop substantially in the 1980s, particularly if North Slope natural gas, or gas from offshore sources, becomes available on the Gulf coast. Alaska is in an excellent position to exploit domestic and foreign export markets for gas-derivative petrochemical products and, also, to apply its relatively low-cost natural gas as fuel to facilitate cement manufacturing, coal beneficiation, and direct reduction of iron and other ores. At present, both U.S. West Coast and Far Eastern markets for these products are heavily dependent on imports from the eastern U.S. and other sources. As a result, Alaska's remoteness and high labor cost, which typically have deterred local manufacturing, are expected to be outweighed both by availability of resources and the advantages of shipping them as semifinished products from near the source of the raw material. Development of these industries, which are relatively capital and labor-intensive compared with crude oil production, should be accompanied by a high rate of activity in distribution, service, and construction sectors.

(c) Alaska's expected revenues from oil and gas royalties, and its outright ownership of royalties in kind, make the state uniquely capable of controlling and encouraging local industrial development and of providing the community facilities and services necessary to mitigate impacts of population and industrial growth. As a result, it is expected that the State of Alaska itself will be capable both of promoting and assimilating a high rate of growth in the 1980s.

D. ENERGY CONSUMPTION FORECASTS

The selected Susitna project service region, consisting of Anchorage-Cook Inlet and Fairbanks Areas, comprises all but a small part of the population and employment of Alaska's Southcentral and Interior Regions, as noted above. Therefore, the growth trends forecast for the Southcentral and Interior Regions as a whole have been taken as representative of the service region.

At the present time, the Anchorage-Cook Inlet and Fairbanks Areas are served by the following utilities:

Anchorage-Cook Inlet Area

* Chugach Electric Association, Inc.
* Anchorage Municipal Light and Power Department
Homer Electric Association, Inc.
Matanuska Electric Association, Inc.
Seward Light and Power Department

Fairbanks Area

* Golden Valley Electric Association, Inc.
* Fairbanks Municipal Utilities System

Of these seven utilities, four, indicated by asterisk (*), have regularly operating generating capacity. In the Anchorage-Cook Inlet Area, Chugach Electric and Anchorage Municipal Light and Power deliver power to the other smaller systems, along with the Alaska Power Administration, which supplies the systems in this area from its Eklutna hydroelectric plant.

Records of these utilities for the period 1961 through 1973, compiled by the Federal Power Commission and the Alaska Power Administration, have been used as the basis for forecasting electrical energy sales in the Susitna service region. Two categories of electrical load were established for forecasting, following the most consistent division of the recorded data: residential and an aggregation of commercial-industrial and other uses. Other uses include sales to public buildings and street lighting, which together comprise about 5% of total consumption.

1. Residential Energy Sales

To forecast residential energy consumption in the Anchorage-Cook Inlet Area, a correlation was established between population of the Southcentral Region and the number and energy consumption of individual customers in the Anchorage-Cook Inlet Area. In this analysis, the data for 1961 through 1973, shown in Table III-5, were first translated into logarithms. Using a computer, a regression analysis was then prepared, taking the change in number of residential customers as the dependent variable and population as the independent variable. The following formula was derived:

$$\text{Log } R = \text{Log } a + b(\text{Log } P)$$

where: R = number of residential customers
a = intercept on Y axis
b = factor describing slope of growth line
P = population

The result was as follows:

$$\text{Log } R = -4.11281 + 1.66711(\text{Log } P)$$

For the Fairbanks Area, no reliable formula could be obtained by computer to forecast the number of residential customers. Population changes occurring in the Interior Region, possibly because of shifts in military personnel, were not immediately reflected in comparable changes in number of residential customers. For Fairbanks, however, a relationship was noted between average annual population growth from 1961 through 1973 and the average annual growth in numbers of residential customers for the same period. Growth factors derived from this relationship were then applied to the population forecast to estimate energy consumption.

Using these data the following forecasts were made for energy sales per customer in both areas through 1980:

Energy Sales per Residential Customer

	Anchorage-Cook Inlet (kwh)	Fairbanks
1961	5,130	3,590
1968	6,480	4,880
1970	7,830	8,820
1973	9,280	11,000
	---------- Forecast ----------	
1980	13,000	14,000

These forecasts of per-customer residential energy sales reflect the following considerations:

(a) The average annual increase per capita income in Alaska between 1974 and 1980 will exceed the average annual gain of 5.7% recorded between 1959 and 1971 and will stimulate further increases in energy consumption per residential customer.

(b) A decline in the price of residential energy sales has undoubtedly stimulated consumption in both the Anchorage-Cook Inlet and Fairbanks Areas, but this trend probably will not continue in the last half of the 1970s. It is expected that rising costs, particularly of fuels, will lead to leveling and possibly increases in energy charges.

(c) The Fairbanks Area, with its colder climate and its sharply increasing use of electricity for home heating, will continue to outpace Anchorage in consumption of energy per residential customer.

2. Commercial-Industrial Energy Sales

Commercial-industrial energy sales for both the Anchorage-Cook Inlet and Fairbanks Areas were forecast by identifying a correlation between total civilian employment and numbers of customers. Again using a computer program, the following formulas were derived:

For Anchorage: Log 0 = -.446306 + .8777366(Log E)
For Fairbanks: Log 0 = -2.47902 + 1.35334(Log E)

where: 0 = the number of nonresidential customers
E = total civilian employment

Forecasts of the number of commercial-industrial and other customers were next applied to separate forecasts for sales of energy per customer through 1980, as indicated in the following table:

Energy Sales per Commercial-Industrial Customer

	Anchorage-Cook Inlet (kwh)	Fairbanks
1961	29,730	31,970
1965	46,270	38,000
1970	64,860	62,510
1973	80,390	76,190
	------------- Forecast	-------------
1980	148,000	118,000

In forecasting sales of energy per commercial-industrial customer, the following factors were considered:

(a) Employment increases in distributive and service industries and state government will be accompanied by growth in the average size of commercial and industrial establishments and government office buildings.

(b) The cost of commercial-industrial energy, which fell sharply between 1961 and 1973, will tend to level, or possibly rise, as generation and distribution costs are affected by inflation.

(c) In the Anchorage-Cook Inlet Area, energy consumption per commercial-industrial customer increased at an average annual rate of 8.6% from 1961 through 1973, and is forecast to increase at 9.1% from 1973 to 1980.

(d) In the Fairbanks Area, growth in energy consumption per commercial-industrial customer averaged 7.5% annually from 1961 through 1973, and is expected to increase at 6.4% annually from 1973 through 1980.

Tables III-4 and III-5 summarize records and forecasts of energy consumption by residential and commercial-industrial service categories for the years 1961 and 1980.

3. Nonutility Industrial and Military Energy Sales

Alaska Power Administration data indicate that today approximately 17% of Alaska's total electricity generation is by nonutility industrial plants, and that 22% is by U.S. military installations.

Nonutility industrial generation is more or less evenly divided between the timber industry of Southeast Alaska and the petroleum industry of Cook Inlet and the North Slope. The timber industry utilizes wood scrap with a residual oil supplement for much of its fuel, primarily to generate process steam; most of this industry's electric power is then produced from a combination of fresh steam and recycled process heat. In general, this type of industrial power generation would not be replaced by utility sources even if they were available, and would not contribute demand to a project like Susitna I. The oil industry generates its own power in locations which either do not have established utilities, such as the North Slope, or which are inaccessible to utility distribution, such as the production platforms of Cook Inlet. Again, this market is not capable of being serviced from utility sources and would not enter into Susitna's demand base.

Past trends in utility load growth in Southcentral Alaska have indicated that new industrial loads which local utilities can reach will be connected. This has been true of the Kenai oil refining and petrochemical industries, which are served by Homer Electric Assn., Inc., and also of portions of the Alyeska Pipeline, which may be served by Golden Valley Electric Assn., Inc. In Kaiser's judgment, the forecast trends in industrial growth for the Anchorage-Cook Inlet and Fairbanks Areas give reasonable weight to prospective new industrial loads.

TABLE III-4

ENERGY SALES TO RESIDENTIAL AND COMMERCIAL-INDUSTRIAL CUSTOMERS IN THE ANCHORAGE-COOK INLET AREA 1961-1973

	Residential Customers		
	Energy Sales (million kwh)	Number of Customers	Energy Sales Per Customer (kwh)
1961	108.9	21,225	5,130
1962	121.3	22,177	5,470
1963	129.4	23,443	5,520
1964	146.7	24,813	5,910
1965	169.5	26,164	6,480
1966	190.0	27,278	6,960
1967	204.2	28,690	7,120
1968	227.6	31,617	7,180
1969	256.4	34,428	7,450
1970	302.4	38,589	7,830
1971	362.0	41,765	8,670
1972	416.3	46,983	8,860
1973	452.8	48,880	9,280
FORECAST			
1980	1,135	87,300	13,000

	Commercial-Industrial Customers		
	Energy Sales (million kwh)	Number of Customers	Energy Sales Per Customer (kwh)
1961	108.5	3,650	29,730
1962	125.7	3,776	33,280
1963	142.0	3,850	36,890
1964	153.0	3,904	39,190
1965	185.9	4,017	46,270
1966	209.8	4,220	49,710
1967	239.7	4,391	54,590
1968	270.9	4,773	56,740
1969	304.3	5,011	60,720
1970	353.4	5,449	64,860
1971	409.4	5,812	70,450
1972	481.1	6,498	74,080
1973	546.7	6,800	80,390
FORECAST			
1980	1,425	9,600	148,000

Sources: 1961-1967 Alaska Power Administration, "Statistics of Major Utilities in the Railbelt Area."
1968-1973 Federal Power Commission, "Power System Statements." Cugach Electric Assn., Inc., Anchorage Municipal Light and Power Dept., Homer Electric Assn., Inc., Matanuska Electric Assn., Inc., Seward Light and Power Dept., Alaska Power Administration, Eklutna Plant, Golden Valley Electric Assn., Inc., Fairbanks Municipal Utilities System.

TABLE III-5

ENERGY SALES TO RESIDENTIAL AND COMMERCIAL-INDUSTRIAL CUSTOMERS IN THE FAIRBANKS AREA 1961-1973

	Residential Customers		
	Energy Sales (million kwh)	Number of Customers	Energy Sales Per Customer (kwh)
1961	23.8	6,636	3,590
1962	27.5	7,013	3,920
1963	29.5	7,875	3,750
1964	29.9	7,957	3,760
1965	39.3	8,055	4,880
1966	46.7	8,094	5,770
1967	51.1	8,467	6,030
1968	62.5	8,903	7,020
1969	75.2	9,442	7,960
1970	90.7	10,289	8,820
1971	109.2	10,876	10,040
1972	121.0	11,281	10,720
1973	132.0	12,000	11,000
FORECAST			
1980	307	21,900	14,000

	Commercial-Industrial Customers		
	Energy Sales (million kwh)	Number of Customers	Energy Sales Per Customer (kwh)
1961	34.8	1,090	31,970
1962	39.1	1,167	33,500
1963	43.2	1,333	32,420
1964	54.6	1,382	39,530
1965	54.0	1,421	38,000
1966	58.0	1,531	37,850
1967	63.5	1,533	41,400
1968	81.8	1,595	51,290
1969	89.5	1,781	50,230
1970	117.2	1,874	62,510
1971	132.4	1,904	69,510
1972	138.9	1,987	69,880
1973	160.0	2,100	76,190
FORECAST			
1980	440	3,700	118,000

Source: See Table III-4.

If new electric power supplies became available at sufficiently low cost to induce large energy-intensive industries to locate in Alaska, it could then become necessary to provide for a nonutility industrial load sector in forecasting. However, it is evident that the Susitna I project will have neither the prerequisite low cost nor long-term capacity surplus to do this.

It also appears inappropriate to include U. S. military loads in the forecasts for Susitna. In the past, Alaskan military bases have been largely self-sustaining. Although in some cases inter-ties have been set up with local utilities, these have not drawn or delivered significant net amounts of energy. Because the U. S. military establishment in Alaska is now declining, a trend which probably will continue in future, it appears that existing military power plants should be adequate for future needs.

4. Total Energy Sales

Through 1980, total energy sales in the Anchorage-Cook Inlet Area are forecast to increase at an average annual rate of 14.4%. For the Fairbanks Area, annual growth is forecast at an average 14.4%.

For 1990, the growth trend for total energy sales has been forecast based on the overall trend from 1961 through 1980. For the Anchorage-Cook Inlet Area, the average annual rate of growth from 1980 through 1990 is expected to be approximately 13%. For Fairbanks it is forecast at 11%. In both cases, these rates are less than the trend forecast through the latter part of the 1970s.

Table III-6 summarizes the record of total energy sales in Anchorage-Cook Inlet and Fairbanks Areas from 1961 through 1973, with Kaiser's forecasts through 1980 and 1990.

For reference, these forecast data may be compared with forecasts of individual utilities in the Anchorage-Cook Inlet and Fairbanks Areas, and the Alaska Power Administration as compiled in Appendix Tables 1, 2 and 3.

E. GENERATION AND PEAK LOADS

Projections have been made of power system generation or net energy input and peak loads associated with the above forecasts.

TABLE III-6

RECORD AND FORECAST OF
TOTAL ENERGY SALES
ANCHORAGE-COOK INLET AND FAIRBANKS AREAS
1961-1990

Record	Anchorage-Cook Inlet	Fairbanks	Total
	(million kwh)		
1961	217.4	58.7	276.1
1962	246.9	66.6	313.5
1963	271.4	72.7	344.1
1964	299.7	84.6	384.3
1965	355.4	93.3	448.7
1966	399.8	104.6	504.4
1967	444.0	114.5	558.5
1968	510.6	141.5	652.1
1969	577.9	170.3	748.2
1970	673.6	211.4	885.0
1971	785.1	250.7	1,035.8
1972	892.4	259.8	1,152.2
1973	996.3	291.0	1,287.3
FORECAST			
1980	2,560	747	3,307
1990	8,800	2,121	10,921

Source: See Table III-4.

For this purpose, Federal Power Commission data on operations of Anchorage-Cook Inlet and Fairbanks utilities have been compiled and analyzed for the period 1968 through 1973. To compute net energy input, distribution losses for both areas were projected at a long-term average rate of 7%. This rate is lower than the average recorded losses of all but one utility from 1968 through 1973; however, a downtrend in losses is observable, and the higher rates experienced by some utilities in recent years are considered to reflect long-distance transmission losses, equipment and operating problems, and recording errors, which either would not be present in the future, or would not apply to energy received from Susitna. Additional transmission losses for Susitna itself are estimated in the Power System Balance section, below.

To compute peak load resulting from forecast net energy requirements, system load factors were examined also over the period 1968 through 1973. In both the Anchorage-Cook Inlet and Fairbanks Areas, there has been a trend toward higher system load factors. This trend has been extrapolated through the forecast period, with an arbitrary limit set at 62.5% for the Anchorage-Cook Inlet Area system, and 60.0% for the Fairbanks Area system. These load factors would be relatively high for systems of comparable size in other areas; however, it is recognized that Alaskan winter energy consumption provides a much more continuous load than typical in other areas. Although the system load factors may eventually exceed these set limits, it is considered more conservative to underestimate them for planning purposes, thereby allowing for a margin of peaking capacity.

Operating statements of the four generating utilities and the Alaska Power Administration do not indicate any significant diversity of peak loads during the 1968-1973 period.

Table III-7 summarizes energy sales and recorded and forecast net energy for system, and peak load, as well as system load factors for the years 1968 through 1990.

F. POWER SYSTEM BALANCE

A power system balance has been prepared for the Anchorage-Cook Inlet and Fairbanks Areas for the comparative base period 1968 through 1973 and subsequently through 1990, as shown in Table III-8. Capacity expansion plans for existing systems have also been compiled for the years 1974 through 1980; these are shown in Table III-9

TABLE III-7

ENERGY SALES, NET ENERGY FOR SYSTEM, AND PEAK LOAD
ANCHORAGE-COOK INLET AND FAIRBANKS AREAS
1968-1990

	Anchorage-Cook Inlet				Fairbanks				Total			
	Energy Sales (million kwh)	Net Energy (million kwh)	Peak Load[1] (thousand kw)	Load Factor %	Energy Sales (million kwh)	Net Energy (million kwh)	Peak Load (thousand kw)	Load Factor %	Energy Sales (million kwh)	Net Energy (million kwh)	Peak Load (thousand kw)	Load Factor %
Actual[2]												
1968	510.6	559.4	125.0	51.0	141.5	160.8	42.7	42.9	652.1	720.2	167.7	49.0
1969	577.9	631.4	132.4	54.4	170.3	190.3	45.6	47.6	748.2	821.7	178.0	52.7
1970	673.6	739.8	153.5	55.0	211.4	235.9	57.1	47.1	885.0	975.7	210.6	52.9
1971	785.1	873.2	178.3	55.9	250.7	279.3	65.1	49.0	1,035.8	1,152.5	243.4	54.1
1972	892.4	979.3	196.4	56.9	259.8	302.5	66.0	53.3	1,152.2	1,281.8	262.4	55.8
1973	996.3	1,089.8	213.0	58.4	291.0	318.4	72.5	50.1	1,287.2	1,408.3	285.5	56.3
Forecast												
1974	1,140	1,220[3]	238[4]	58.5	333	358[3]	76[4]	53.8	1,473	1,578	314	57.4
1975	1,305	1,400	271	59.0	381	410	87	53.8	1,686	1,810	358	57.7
1976	1,493	1,600	307	59.4	436	469	98	54.6	1,929	2,069	405	58.3
1977	1,709	1,830	349	59.8	498	535	111	55.0	2,207	2,365	460	58.7
1978	1,955	2,090	396	60.2	570	613	127	55.1	2,525	2,703	523	58.9
1979	2,237	2,390	450	60.6	652	701	144	55.6	2,889	3,091	594	59.4
1980	2,560	2,740	513	61.0	747	803	164	55.9	3,307	3,543	677	59.7
1981	2,896	3,100	576	61.4	829	891	180	56.5	3,725	3,991	756	60.3
1982	3,277	3,510	648	61.8	920	989	199	56.7	4,197	4,499	847	60.6
1983	3,708	3,970	729	62.2	1,022	1,099	219	57.3	4,730	5,069	948	61.0
1984	4,195	4,490	820	62.5	1,134	1,219	242	57.5	5,329	5,709	1,062	61.4
1985	4,746	5,080	928	62.5	1,259	1,354	266	58.1	6,005	6,434	1,194	61.5
1986	5,370	5,750	1,050	62.5	1,397	1,502	293	58.5	6,767	7,252	1,343	61.6
1987	6,076	6,500	1,187	62.5	1,551	1,668	323	58.9	7,627	8,168	1,510	61.7
1988	6,874	7,360	1,344	62.5	1,721	1,851	356	59.3	8,595	9,211	1,700	61.8
1989	7,777	8,320	1,520	62.5	1,911	2,055	393	59.7	9,688	10,375	1,913	61.8
1990	8,800	9,420	1,721	62.5	2,121	2,281	434	60.0	10,921	11,701	2,155	61.8

[1] Based on recorded peak loads of Chugach Electric Assn., Inc., Anchorage Municipal Light and Power Dept, Golden Valley Electric Assn., Inc. and Fairbanks Municipal Utilities System; individual years adjusted 1-6% for Alaska Power Administration sales to Matanuska Electric Assn., Inc. and other minor generation.

[2] Federal Power Commission, "Power System Statements," 1968-73 for utilities indicated in Table III-4.

[3] Computed from energy sales, assuming distribution losses at 7%.

[4] Computed from net energy, based on load factors shown.

TABLE III-8

POWER SYSTEM BALANCE
ANCHORAGE-COOK INLET AND FAIRBANKS AREAS
1968-1990

Data as of year end (thousand kw)

	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
Anchorage-Cook Inlet Area																							
Peak Load	125.0	132.4	153.5	178.3	196.4	213.0	238	271	307	349	396	450	513	576	648	729	820	928	1,050	1,187	1,344	1,520	1,721
Existing and planned dependable capacity	189.1	192.6	210.9	230.9	284.6	325.6	429	444	497	552	552	552	552	552	552	552	552	552	552	552	552	552	552
(less) system reserves	(51.0)	(51.3)	(48.0)	(48.0)	(64.1)	(99.5)	(108)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)	(123)
Assured capacity	138.1	141.3	162.9	182.9	220.5	226.1	321	321	374	429	429	429	429	429	429	429	429	429	429	429	429	429	429
Original balance	13.1	8.9	9.4	4.6	24.1	13.1	83	50	67	80	33	(21)	(84)	(147)	(219)	(300)	(391)	(499)	(621)	(758)	(915)	(1,091)	(1,292)
New dependable Capacity:																							
Other than Susitna I	-	-	-	-	-	-	-	-	-	-	-	21	84	84	84	84	84	84	154	350	569	780	1,021
Susitna I	-	-	-	-	-	-	-	-	-	-	-	-	-	66	149	263	364	500	583	550	518	518	518
(less) Susitna I losses	-	-	-	-	-	-	-	-	-	-	-	-	-	(3)	(7)	(11)	(16)	(22)	(29)	(28)	(26)	(26)	(26)
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	63	142	252	348	478	554	522	492	492	492
(less) adjusted reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(7)	(36)	(41)	(63)	(87)	(114)	(146)	(181)	(221)
Adjusted balance	13.1	8.9	9.4	4.6	24.1	13.1	83	50	67	80	33	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-
Fairbanks Area																							
Peak Load	42.7	45.6	57.1	65.1	66.0	72.5	76	87	98	111	127	144	164	180	199	219	242	266	293	323	356	393	434
Existing and planned dependable capacity	70.8	76.1	104.3	112.8	130.8	130.8	131	131	131	184	184	184	237	237	237	237	237	237	237	237	237	237	237
(less) system reserves	(28.5)	(11.2)	(32.3)	(32.3)	(33.7)	(33.7)	(34)	(34)	(34)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)	(53)
Assured capacity	42.3	64.9	72.0	80.5	97.1	97.1	97	97	97	131	131	131	184	184	184	184	184	184	184	184	184	184	184
Original balance	(0.4)	19.3	14.9	15.4	31.1	24.6	21	10	(1)	20	4	(13)	20	4	(15)	(35)	(58)	(82)	(109)	(139)	(172)	(209)	(250)
New dependable Capacity:																							
Other than Susitna I	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	12	21	66	113
Susitna I	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16	38	62	88	117	150	182	182	182
(less) Susitna I losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	(3)	(4)	(6)	(8)	(11)	(13)	(13)	(13)
Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	35	58	82	109	139	169	169	169
(less) adjusted reserves	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(6)	(12)	(18)	(26)	(32)
Adjusted balance	(0.4)	19.3	14.9	15.4	31.1	24.6	21	10	(1)	20	4	(13)	20	4	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-	-0-

TABLE III-9

PROJECTED INSTALLATION OF NEW GENERATING CAPACITY ANCHORAGE-COOK INLET AND FAIRBANKS AREAS

	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
	Data as of year end (thousand kw)																
Anchorage-Cook Inlet Area																	
Planned capacity:																	
Beluga 4 & 5	70.0	-	70.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Anchorage 8, 9 & 10	40.0	15.0	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other capacity (not sized)	-	-	-	-	-	-	-	-	-	-	-	-	70	196	219	211	241
Fairbanks Area																	
Planned capacity:																	
North Pole 1	-	-	-	53.0	-	-	-	-	-	-	-	-	-	-	-	-	-
Healy 2	-	-	-	-	-	-	53.0	-	-	-	-	-	-	-	-	-	-
Other capacity (not sized)	-	-	-	-	-	-	-	-	-	-	-	-	6	6	9	45	47
Susitna I:																	
Units 1 & 2	-	-	-	-	-	-	-	350.0	-	-	-	-	-	-	-	-	-
Units 3 & 4	-	-	-	-	-	-	-	-	-	-	-	350.0	-	-	-	-	-

along with the projected commissioning schedule for Susitna and other capacity requirements to occur before and after the Susitna project.

1. Criteria

In preparing the power system balance, Federal Power Commission data[1] on existing systems' dependable capacity and reserves were compiled for the comparative base period 1968 through 1973. Generally, during this period, system reserves were relatively high as a percentage of peak load due to the fact that each of four utility systems maintained a reserve more or less equal to its largest unit, plus some minor standby capacity. Over the period 1974 through 1990, system reserves for both the Anchorage-Cook Inlet and Fairbanks Areas have been projected at 20% of peak load, or the size of the largest generator unit in the system, whichever is greater; in general the 20% ratio is the governing factor. Compared to previous reserve ratios in the region, the projected reserve levels are relatively low and may have the effect of very slightly understating demand for the Susitna project.

During its first four years of operation, from late 1981 through 1985, the Susitna project will add a substantial capacity surplus to the system. This will make it unnecessary to add capacity during this period for the purpose of increasing system reserves. Beginning in 1986, it is assumed that additional reserves will be installed at other locations.

Susitna transmission losses of peak power have been estimated at 5% of Anchorage-Cook Inlet peak demand on Susitna and 7% of Fairbanks peak demand. The resulting overall energy loss is estimated at 1.25%. Losses for other remote plants in the system, such as Beluga, Healy, and North Pole, which are nearer their respective load centers are estimated at 3% of peak demand.

2. System Capacity Requirements

For the Anchorage-Cook Inlet Area the power system balance indicates minor capacity surpluses throughout the period of record and through the end of 1978. From 1979 until the projected commissioning of the Susitna I project, the Anchorage-Cook Inlet Area probably would require about 84,000 kilowatts of new assured capacity in addition to expansions planned at the present time.

[1] Federal Power Commission, "Power System Statements," 1968-1973, for utilities indicated in Table III-4.

Since 1969, the Fairbanks Area has had proportionally greater capacity surpluses than Anchorage-Cook Inlet; however, present system development plans indicate a less adequate margin over demand through 1978. A small but significant capacity deficit is indicated for the Fairbanks Area in 1979, but the installation of new capacity in 1980, as now planned, should be capable of restoring a surplus through late 1982.

Commissioning of Susitna is projected for October 1, 1981, at which time 4 x 175,000 kilowatt turbine-generator units would be ready for service as shown in Table III-9. Capacity of the Susitna project is assumed to be allocated according to immediate demand in the Anchorage-Cook Inlet and Fairbanks Areas until it is fully utilized. The resulting shares would correspond to the relative peak loads of the two areas; Anchorage-Cook Inlet would receive 74% and Fairbanks would receive 26%.

As indicated in Table III-10, 98% of the 700,000 kilowatt peak capacity of Susitna I would be required as assured capacity by the end of 1986, approximately five years after commissioning, with 100% utilization in the following year. From 1986 through 1990, the Anchorage-Cook Inlet Area would require an additional 927,000 kilowatts of new assured capacity, while the Fairbanks Area would require 113,000 kilowatts during the same period.

3. Susitna I Generation

It is not considered necessary to prepare a complete system energy balance in order to estimate consumption of Susitna I energy. In general, past installation of thermal capacity for peaking has provided the system with a substantial excess energy capability, because the system load factor, which in 1973 averaged approximately 56%, is less than the optimal plant factor for most fuel-fired plants. As a result, the Susitna project has been designed to a 55% plant factor, on the basis of which energy output of the system's thermal capacity may be increased to a more optimal 65% plant factor by 1988. In each year of operation, the Susitna project is assumed to supply new peak demand as indicated in the system balance, with corresponding primary generation computed at its design plant factor. During the years 1981 through 1986,

TABLE III-10

CAPACITY AND SALES PROJECTION

		Peak Demand				Net Energy Sales	
Year	Dependable Capacity	Anchorage Cook Inlet[1]	Fairbanks[2]	Total	Net Energy Capability[3]	Primary	Surplus
	(thousand kw)				(million kwh)		
1981	330	63	-	63	1,515	158	1,357
1982	330	135	15	150	3,030	733	2,297
1983	330	216	35	251	3,030	1,265	1,765
1984	330	307	58	365	3,030	1,832	1,198
1985	661	415	82	497	3,180	2,498	682
1986	661	537	109	646	3,330	3,263	67
1987	661	522	139	661	3,330	3,330	-
1988	661	492	169	661	3,330	3,330	-

1 Losses excluded @5%

2 Losses excluded @7%

3 Losses excluded @ (average) 1.25%

when Susitna has surplus energy capability, it is assumed that it will be operated at 100% of its continuous energy capability and that surplus energy will be sold in the system at a reduced rate to replace use of fuel by the system's thermal plants.

Estimated Susitna energy deliveries are shown in Table III-10, and provide the basis for Susitna project revenue estimates.

IV. HYDROLOGY

A. STUDY INFORMATION

Hydrologic studies were based on mean monthly river discharges recorded at U. S. Geological Survey gaging stations and precipitation records of climatological stations as described below:

River Gaging Stations	Years of Record	
Susitna River		
Gold Creek	Oct 1949 - Sept 1972	(23)
Cantwell	May 1961 - Sept 1972	(11)
Denali	June 1957 - Sept 1966	(10)
	and July 1968 - Sept 1972	(5)
Maclaren River		
Paxson	June 1958 - Sept 1972	(13)

Climatological Stations and Elevation - ft		Years of Precipitation Records
Big Delta	1,268	30
Gulkana	1,570	31
McKinley Park	2,070	43
Snowshoe Lake	2,410	11
Summit	2,401	32
Talkeetna	345	43
Gracious House	2,550	3 (some records missing)
Trims Camp	2,405	16

B. PAST STUDIES

Hydrologic studies and subsequent power generation studies for the Devil Canyon project were based on runoff records of the Susitna River at Gold Creek Station for the 10-year period from October 1949 through September 1959. Use was made of runoff data from the Denali Station which began operation in May 1957 and the Denali data were extended to cover the 1949-1959 period by correlation with the runoff data from the Gold Creek Station. The runoff data for the Devil Canyon site were derived by a straight-line relationship between drainage areas and incremental runoff.

The Devil Canyon Status Report of May 1974 made use of the same data described above without further study of hydrologic data for years later than 1959.

C. UPDATED STUDIES AT GOLD CREEK

Hydrologic data for the years 1950 to 1972 were gathered by the Henry J. Kaiser Company early in 1974.

Examination of the data for the Gold Creek Station revealed the occurrence in 1969 of a new low in annual runoff at this station. The main information resulting from examination of the 23-year runoff record at the Gold Creek Station is summarized as follows:

	1950-1959 Record	1950-1972 Record
Average Annual Runoff, acre-feet	7,139,500	7,131,000
Minimum Annual Runoff, acre-feet (year)	5,815,000 (1950)	4,052,000 (1969)
Ratio of Minimum to Average	81%	57%

In the 23-year record, the 1970 inflow was second lowest at 5,496,000 acre-feet and the 1950 inflow was third lowest. Only three of the 23 years have a runoff of less than 6,500,000 acre-feet.

D. RUNOFF AT PROPOSED DAMSITE

Damsite B as proposed by the Henry J. Kaiser Company for the location of Susitna I is on the Susitna River between two gaging stations. The upstream station, called Cantwell, is near Vee Canyon and the downstream gaging station is near Gold Creek. Records for the station near Gold Creek are available for the 23 water years 1950-1972 (see Appendix Table 4), and records for Cantwell station are available for eleven water years 1962-1972 (see Appendix Table 5). The 11 years of joint records were used to compute monthly coefficients to adjust the Gold Creek flows to the proposed damsite. With this set of coefficients and the Gold Creek runoff records, 23 years of records of monthly runoff were computed for Damsite B. In Appendix Table 6 these estimated flows at the damsite are presented in acre-feet per month.

The evaluation of these coefficients utilized the ratio between the average monthly discharge for the 11 years of overlapping Gold Creek and Cantwell records and the ratio between the drainage areas of the damsite and the two gaging stations.

The formula used to compute the monthly coefficient is as follows:

$$K = \left[(1.0 - \frac{Q_2}{Q_1}) \times \left(\frac{A_D - A_2}{A_1 - A_2}\right)\right] + \left[\frac{Q_2}{Q_1}\right]$$

The coefficient is used as shown below:

$$Q_{Damsite} = Q_1 \times K = \left[(Q_1 - Q_2) \times \left(\frac{A_D - A_2}{A_1 - A_2}\right)\right] + \left[Q_2\right]$$

where:

Q = Average monthly discharge for 11 water-years (1962-1972)
Q_1 = Average monthly discharge for the gaging station at Gold Creek
Q_2 = Average monthly discharge for the gaging station at Cantwell
A_D = Drainage area in square miles for the damsite
A_1 = Drainage area in square miles for gaging station at Gold Creek
A_2 = Drainage area in square miles for gaging station at Cantwell

The coefficient will be obviously higher during the summer months due to the glacier runoff and snow melt coming from the high elevations and due to the high summer precipitation. (For monthly coefficients, see Figure IV-1 at the end of this chapter.)

In order to simplify the calculations and because the discharge during seven months is only approximately 12% of the total annual discharge, an average annual coefficient for the year was computed from the average monthly distribution of runoff and the monthly coefficients.

E. IMPACT OF NEW DATA

From examination of the hydrologic data for the years from 1950 to 1972 inclusive, it was evident that the two successive dry years of 1969 and 1970 would have a significant impact upon the results of studies based on hydrologic information prior to 1969.

In order to assess the impact of these dry years, the probabilities of annual discharge volume at the proposed damsite were calculated. The probabilities of annual discharge equalling or exceeding a recorded event were calculated by use of the following equation:

$$\text{Probability} \geq \frac{m}{n+1}$$

where m = rank
n = number of recorded events = 23

TABLE IV-1

PROBABILITIES OF ANNUAL DISCHARGE AT THE PROPOSED DAMSITE ON THE SUSITNA RIVER

Water Year	Discharge (acre-feet in thousands)	Rank	Probability
1962	7795.81	1	4.2
1956	7735.52	2	8.3
1967	7562.10	3	12.5
1963	7463.43	4	16.7
1972	7341.14	5	20.8
1961	7287.11	6	25.0
1959	7117.53	7	29.2
1957	6999.25	8	33.3
1955	6912.20	9	37.5
1971	6910.11	10	41.7
1965	6852.54	11	45.8
1953	6801.32	12	50.0
1968	6616.17	13	54.2
1964	6607.06	14	58.3
1960	6549.25	15	62.5
1954	6525.52	16	66.7
1952	6438.94	17	70.8
1958	6386.99	18	75.0
1966	6356.97	19	79.2
1951	6138.25	20	83.3
1950	5413.57	21	87.5
1970	5116.38	22	91.7
1969	3772.32	23	95.8

Table IV-1 indicates that the minimum annual discharge at the proposed damsite, calculated to be 3,772,320 acre-feet, would be equalled or surpassed nearly 96% of the time.

To further evaluate the frequency of extremely low river runoff, the overall basin runoff for years of record at Gold Creek was studied with respect to measured annual precipitation in the region. The annual precipitation records for three stations which coincided with the Gold Creek station record period were examined. These stations were Gulkana to the southeast, Talkeetna to the southwest, and Summit to the northwest. The Denali station records were not sufficiently complete for use in this analysis.

Precipitation data from the three stations were used to relate the frequency of occurrence of ranges of precipitation depth to the frequency of occurrence of the same ranges of overall basin runoff depth as measured at Gold Creek. The results are shown in Table IV-2, below.

TABLE IV-2

FREQUENCY OF OCCURRENCE

Depth, Inches	Overall Basin Runoff at Gold Creek	Precipitation		
		Talkeetna	Summit	Gulkana
5-10			1	10
10-15	1*	1	2	13
15-20	2**	1	13	
20-25	18	4	5	
25-30	2	9	2	
30-35		7		
35-40		0		
40-45		1		
	23	23	23	23

*1969
**1950, 1970

In the year of lowest runoff at Gold Creek--1969--the precipitation was also the lowest recorded at all three stations; in addition, it was the lowest of 43 years of records at the Talkeetna station. The uniform distribution of the annual depths of rainfall at Gulkana is closely related to the continental climate in this area.

F. LONG RANGE HYDROLOGIC STUDIES

Preliminary computations of discharge on the Susitna River by regression analysis on climatological data and by Stochastic Hydrology indicate that the frequency of extremely low annual runoff events will be less than indicated by the shorter term historical records.

1. Gold Creek Station--Regression Analysis Computations

The discharge records at the Gold Creek Station for 23 years were used to extend the discharge records to 30 years by regression analysis using river runoff and precipitation records.

The best prediction of one dependent variable can be obtained from another independent variable or variables by determining mathematical models of correlative association of two or more variables. The models are called regression functions.

Several conditions which precluded the development of an optimal multiple correlation model are as follows:

- Insufficient numbers and/or location of rain gage stations in and around the drainage basin to give representative basin precipitation records,
- Lack of useful temperature records, and
- Short duration of all records.

The results of the regression analysis conducted indicate, however, that there is sufficient precision to extend the recorded occurrence of low annual runoff.

The developed regression equation for calculating annual runoff at Gold Creek gave a multiple correlation coefficient of 0.8434.

The regression equation developed in this study is based on 23 years of annual discharge at Gold Creek and on 22 years of precipitation records at Talkeetna and Gulkana.

The Talkeetna station is almost entirely dominated by maritime influences, where the Gulkana station represents continental climatic conditions in the South of the Alaska Range. Based on numerous correlation calculations among eight climatological stations in the North and the South of the Alaska Range, it was established that precipitation records in the South of the Alaska Range are much more representative of climatic conditions in the Susitna River Basin.

The annual records for the water years were taken in order to eliminate the influences of winter storage and snow melt.

Volume changes of the glaciers, temperature fluctuations, as well as precipitation in the previous year, are expressed partially in the equation by the discharge of the previous water year.

The equation for the annual runoff at the Gold Creek Gaging Station is:

$$\log Q_1 = 3.52958 + 0.358166 \times \log P_1^1 + 0.314512 \times \log P_1^2 + 0.362557 \times \log Q_0$$

$$\log Q_2 = 3.52958 + 0.358166 \times \log P_2^1 + 0.314512 \times \log P_2^2 + 0.362557 \times \log Q_1$$

$$\log Q_n = 3.52958 + 0.358166 \times \log P_n^1 + 0.314512 \times \log P_n^2 + 0.362557 \times \log Q_{n-1}$$

where:

Q_n = Discharge in acre-feet of water year n at the Gold Creek Station.

Q_{n-1} = Discharge in acre-feet of the previous water year n-1 at the Gold Creek Station. The average of the 1950-1972 records (Q_0 = 7,131,000 acre-feet) was assumed for the first year.

P_n^1 = Annual precipitation at Talkeetna in inches for the water year n, and,

P_n^2 = Annual precipitation at Gulkana in inches for the water year n.

Using climatological data for the water years 1943-1949, the annual runoff at Gold Creek and at the proposed damsite were calculated. The annual runoff for both stations is as follows:

Annual Discharge in 1,000 acre-feet for the Water Year

Station	1943	1944	1945	1946	1947	1948	1949
Susitna River at Gold Creek	7956	8258	9133	7941	9046	7844	8065
Susitna River at the Proposed Site B	7407	7689	8503	7393	8422	7302	7508

As a consequence of the above-mentioned results, the frequency of the extremely low annual runoff in 1969 will be 3.2% instead of 4.2% (see Figure IV-2). The studies extend the period of hydrologic records from 23 to 30 years and the extremely low flow of 1969 would occur once in 30 years.

The regression equation predicts an average annual runoff from 1950 to 1972 at Gold Creek of 7,133,313 acre-feet, which is 0.03% higher than the average annual recorded runoff of 7,131,000 acre-feet. The average annual estimated runoff at Gold Creek for the extended period of 1943-1972--7,410,260 acre-feet as derived by the equation-- is 4% higher than the measured average annual recorded runoff for the historical period of 1950-1972--7,131,000 acre-feet.

With 43 years of precipitation records at the Talkeetna rain station, an extension for computing additional 13 years would have been possible. Since there are no other records available for the Gulkana Station, any further regression analysis must be based either on one or more new favorable variables, or on a different regression function which expresses better the relation between Gold Creek discharge and Talkeetna precipitation.

In order to assess further the reliability of the extremely low annual runoff predictions, it is expected that additional detailed evaluations of regression analysis functional relations between runoff and climatological data would be made in the next stage of the work. These studies could provide estimates of the accuracy of the confidence interval of the predicted stream flows.

2. Gold Creek Station--Stochastic Hydrology Computations

These calculations were made to extend the discharge records at Gold Creek. They made use of the computer program No. 723-X6-L2340 which was prepared in the Hydrologic Engineering Center, U. S. Army Corps of Engineers at Davis, California. This program analyzed monthly stream flows at interrelated gaging stations on the Susitna River to determine their various statistical characteristics and generated a sequence of hypothetical stream flows of the desired length having those characteristics.

In order to get complete records over 23 years for all the gaging stations, missing stream flows for the stations at Denali, Maclaren, and Cantwell were first constituted, utilizing all available monthly discharge records of the Susitna River gaging stations--Denali, Maclaren River, Cantwell, and Gold Creek. To obtain the missing values, a regression equation in terms of normal standard variables was computed by selecting required coefficients from the complete correlation matrix for that month and solving by the Crout method.

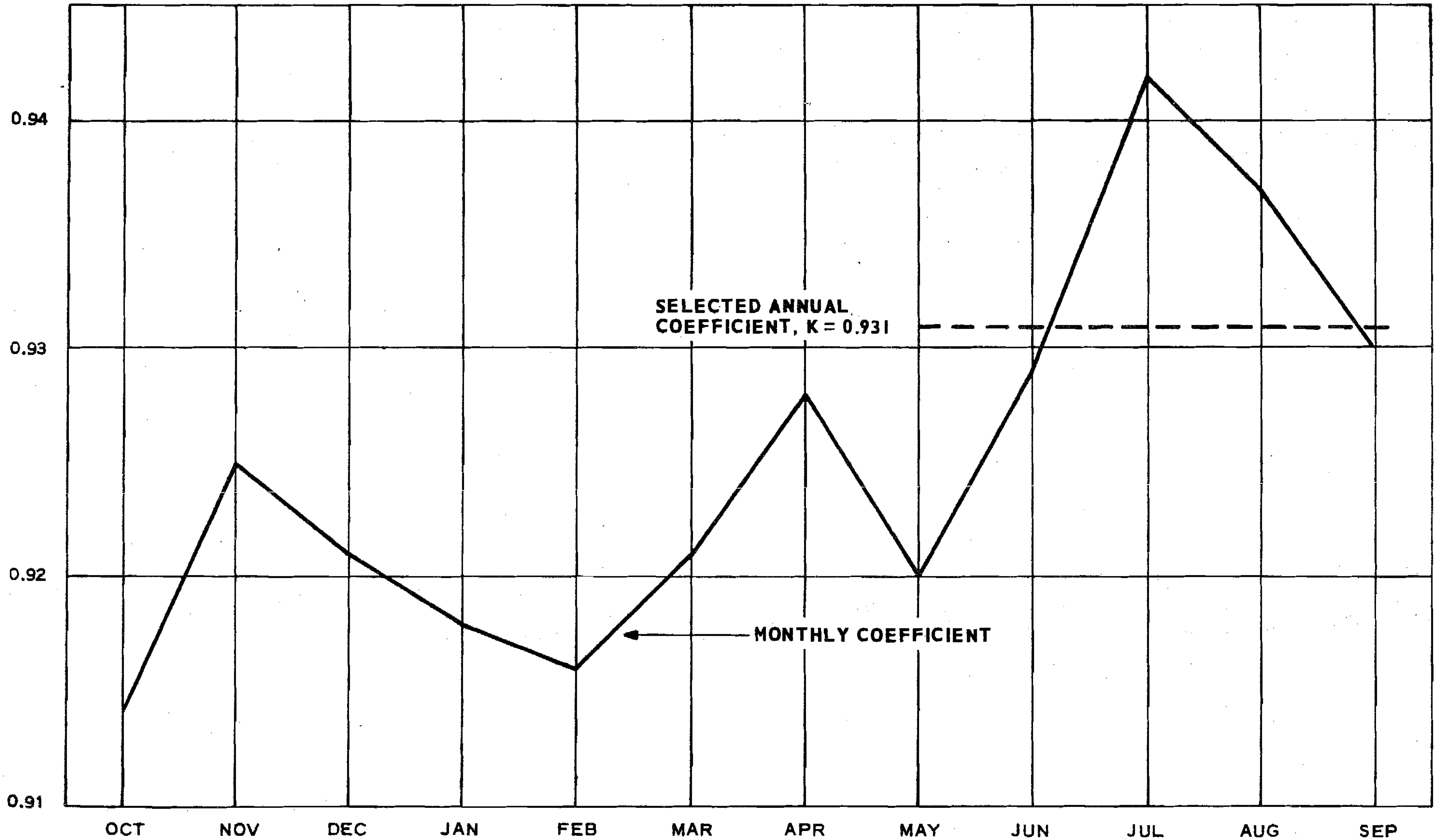
Next, 77 years of hypothetical stream flows at Gold Creek were generated. The multiple correlation regression equation developed in reconstituting the historical stream flows was solved simultaneously on a step-by-step basis. A Stochastic random variable term was added to the solution process. The 23 years of historical records at Gold Creek station and the 77 years of generated flows provide 100 years of usable monthly discharge records.

The results show that there are only two years in the range of 4. 5 to 5. 0 million acre-feet annual discharge (the minimum recorded annual discharge was 4, 052 million acre-feet). The maximum historical annual discharge of 8, 373 million acre-feet is exceeded by four events. Although these results do not give the same accuracy as the regression analysis, the probability of a year as dry as 1969 would still be quite low, statistically. Independent factors such as very low precipitation over the whole basin and low temperatures almost everywhere in the basin have to occur simultaneously to give such a low flow year. As the probability of these two events individually is quite small, the probability of their occurring simultaneously is exceptionally small. Therefore, the results seem to be understandable for the magnitude of the basin investigated; however, further detailed investigation by Stochastic Hydrology methods will improve the degree of obtained accuracy.

From these studies it would appear that the frequency of occurrence of the extremely dry year of 1969 would be even lower than one year in thirty.

FIGURE IV-1

COEFFICIENTS RELATING SUSITNA RIVER RUNOFF AT GOLD CREEK TO RUNOFF AT SITE B



V. TOPOGRAPHY AND GEOLOGY

A. INTRODUCTION

In order to make a preliminary assessment of the technical feasibility of constructing the Susitna I hydroelectric project at the selected Site B, a geologic reconnaissance of that site and other areas of interest was made in late June 1974. The prime objectives of this reconnaissance were to identify the type of rock, assess its general condition, and to assess any features of terrain and geologic structure which would affect location, design and construction of the project. In addition, it was necessary to assess the availability of construction materials, and of materials suitable for use as concrete aggregates.

The reconnaissance was made in a fixed wing aircraft for general overall observations supplemented by use of a helicopter to provide access for on-the-ground observations.

B. TOPOGRAPHY

The topography at the selected site conforms generally with the one inch to the mile maps prepared by the United States Geological Survey. The canyon is generally V-shaped. The average slope of the north abutment is about 45^{o} for the first 500 feet above the river; above this the slopes flatten to about 25^{o} up to a height of 1,000 feet above the river. The south abutment slopes upward at an angle of 45^{o} for the first 200 feet above the river; for the next 800 feet the slope averages about 25^{o}. In the steepest part of the canyon, rock walls on each side rise almost vertically for several hundred feet above the river level. At the higher elevations on both sides of the river the terrain becomes more rounded. While the north abutment of the canyon is covered with dense forest extending to the uplands, the forest on the south abutment thins several hundred feet above the river to patches and islands of trees, and the uplands have very little tree cover.

C. GENERAL GEOLOGY

1. Glacial Deposits

The site area has been extensively glaciated and is mantled with glacial and nonglacial deposits. The glacial materials consist primarily of moraines and eskers composed of erratic lenses and layers of sand, rounded to angular gravel and cobbles, boulders, silt and considerable rock flour. Some older glacial deposits exhibit considerable weathering evidenced by iron stains and chemical alteration.

Material size ranges from rock flour to boulders three feet in diameter, with a high percentage of material larger than four inches in diameter. Because of the high content of rock flour, and with the exception of occasional granular pockets or stringers of sand, the moraines should be impervious.

2. <u>Talus and Swamp Deposits</u>

The nonglacial materials are primarily talus, outwash, and swamp deposits. Talus material, unsorted, angular to subangular, occurs generally on the south abutment area and also near the base of gullies and cliffs on both sides of the canyon. It is almost entirely granitic in composition and is derived from adjacent outcrops. The blocks range in size from a few inches to 15 feet in maximum dimension. Deposits on the upper bench areas probably do not exceed 10 feet in thickness; however, on the steep slopes of both abutments they average about 20 feet in thickness and locally may be as much as 40 feet in thickness.

Swamp and muskeg deposits occur on benches on the south abutment in areas of poor drainage. The deposits are composed of moss and low shrubs mixed with fine sand, gravel, and silt. These deposits generally are less than three feet thick and are underlain by moraine and outwash.

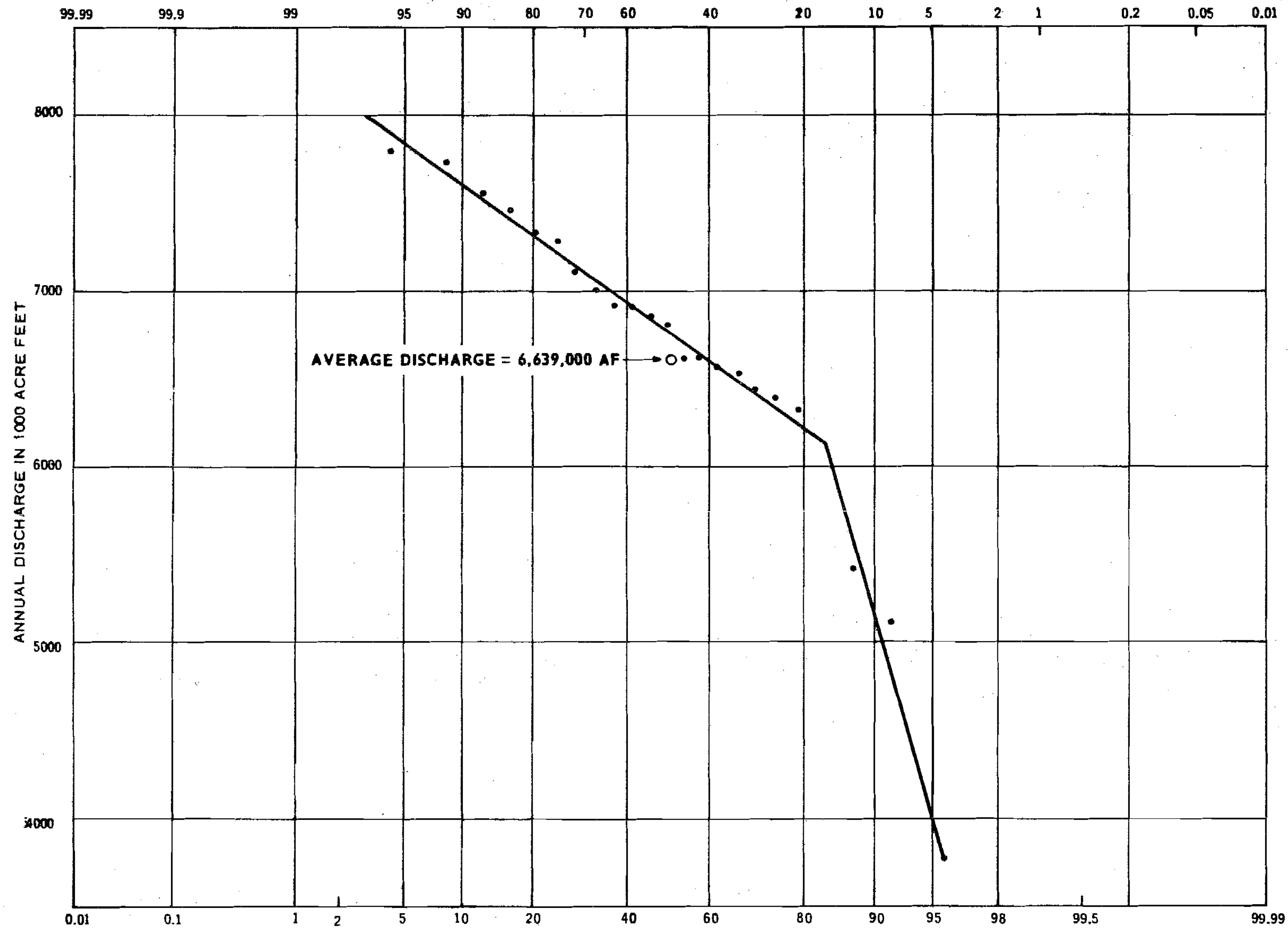
3. <u>River Terraces and Gravel Bars</u>

River-deposited terraces and gravel bars occur several miles upstream of the damsite. They are composed of coarse to fine sand, subrounded to rounded gravel and boulders observed to five feet in diameter. The terrace gravels on the river floor extend to about 60 feet above the river level with an unknown thickness below river level. The rock composition of the materials varies from phyllite to granite to basalt.

FIGURE IV-2

PROBABILITY DISTRIBUTION OF ANNUAL DISCHARGE AT THE PROPOSED DAMSITE B ON SUSITNA RIVER BASED ON RUNOFF RECORDS FOR GOLD CREEK STATION AND CANTWELL STATION

(REF TABLE V-3).



4. Bedrock

The bedrock on the site, as observed in massive outcrops on both sides of the river is a fine-grained granitic rock composed mainly of quartz, feldspar, biotite, and hornblende. Well-developed sets of regional joints occur in the damsite area. The major joint set has a strike that is almost perpendicular to the river channel; it averages about N 25^{o} W but varies from due north to N 45^{o} W. The dip averages 80^{o} east but varies from 65^{o} east to vertical.

Two prominent and well-developed shear or fault zones occur on the north abutment, but are obscured by overburden on the left abutment. These two zones have caused the formation of near-vertical V-shaped gullies; they appear to have a general strike of N 25^{o} W and a dip ranging from 80^{o} NE to vertical. These two fault or shear zones are located upstream of the proposed dam, on the north abutment; on the south abutment they may intersect the proposed diversion tunnels near their entrances. In that area on the south abutment, however, a diabase-like intrusion is exposed, and it appears that this under-material has deflected the course of the river at this point. From aerial and ground reconnaissance and air photo interpretation there does not appear to be any faulting or rock structure dislocation paralleling the river.

The steep escarpment faces in the river canyon have resulted in large blocks 15 to 20 feet high distinctly separated from adjacent bedrock on the north abutment. No conspicuous faults or displacement features were noted in the south abutment escarpment area adjacent to the river. There appears to be no appreciable depth of weathered rock on either abutment.

D. ENGINEERING GEOLOGY

Aerial reconnaissance supplemented by a study of existing geological data indicates that the reservoir basin will be tight at the selected site for Susitna I.

1. North Abutment

The most obvious features of the north abutment are the two well-developed shear or fault zones.

The sheared rock is not well healed, and intensive fracturing with open crevices is common. It was not possible to estimate a lateral or vertical displacement in the fault zone. As noted above, fissures 15 to 20 feet deep were observed in the steep escarpment faces near the river.

The upstream toe of the dam is located several hundred feet downstream of the nearest shear zone. While further geologic investigation is required, the occurrence of the shear zones would appear unlikely to affect the stability or performance of a rockfill dam. The occurrence of fissures in the bedrock foundation of a rockfill dam are significant only to watertightness of the foundation which will be remedied as necessary by the customary foundation treatment techniques.

2. South Abutment

There is no observable evidence that the two shear zones of the north abutment extend to the south. If these zones do continue on the south abutment, they might intersect the upstream ends of the diversion tunnels but this occurrence would present no major construction problems. The rock structure of the escarpment face at the river shows no conspicuous faults or displacement features and joint faces are well healed. The diabase intrusion at the bend upstream of the dam is an extremely competent, fine-grained dark grey rock mass; it displays a uniform set of joint planes dipping about 5 to 10° southeast.

This abutment will require more excavation to remove deposits of soft overburden and to remove or spread talus materials. The bedrock appears to be tight, and no particular problems are anticipated in cut-off curtain grouting.

3. The Riverbed

Due to the depth and velocity of river flow, no observation of riverbed was possible. The depth of boulders and gravel above bedrock may range from 30 to 60 feet. Although it will be necessary to excavate through to bedrock where the impervious membrane of the dam meets the riverbed, the main body of the rockfill dam can be founded on the compact river gravel-boulder mass.

4. Spillway

The spillway will be located on the south abutment of the dam and nominal grouting may be anticipated under the crest structure. The unlined and stepped discharge channel will be excavated in massive granite which is expected to be highly resistant to erosion by spillway releases.

5. Underground Powerhouse and Tunnels

The restricted topography and favorable geological conditions indicate the desirability of an underground powerhouse in the south abutment. The competency of the granite bedrock indicates the possibility of excavating an underground chamber and various tunnels with a minimum of support. Deep drilling, of course, will be required to fully outline the problems which may arise during construction of the powerhouse chamber and the various tunnels.

Because the powerhouse will be located below the dam impoundment level, extensive grouting may be necessary to prevent water inflows through joint and fracture systems.

6. Construction Materials

The granitic bedrock materials are adjudged to be well suited for the construction of a rockfill dam and would also be suitable for use in the manufacture of concrete aggregates. The occurrence of natural sands and gravels appears to be limited to small river terraces and gravel bars located upstream of the damsite. These deposits are composed of fine to coarse sand, subrounded to rounded gravel and cobbles, and boulders ranging up to five feet in diameter. The rock materials include greywacke, phyllite, granite, and basalt. A terrace deposit ranging in height to 60 feet above river level is located about 3-1/2 miles upstream of the site.

Glacial deposits at elevations ranging upward from the 2,000-foot contour are comprised largely of a silty rock flour with inclusions of generally angular rock fragments. These areas are generally barren except for a thin muskeg cover. The silty rock flour appears to be suitable for use as impervious material and similar glacial till has been used for that purpose in other northern areas. From on-site observations, the exploitation of moderate quantities of impervious materials appears to be economically feasible.

7. Permafrost

Permafrost may be encountered in access road construction and the exploitation of borrow materials. It will be encountered in transmission line construction.

VI. POWER STUDIES

A. INTRODUCTION

For the Kaiser proposal on the Susitna project, a preliminary evaluation of the power capability of the river was made, using hydrologic data contained in the U. S. Bureau of Reclamation (U. S. B. R.) "Devil Canyon Project Report," of May 1960. These data covered the period from October 1949 to September 1959. After submission of the Kaiser proposal, hydrologic data for the full 23-year period from October 1949 to September 1972 became available, and these data were used for the power studies described herein.

U. S. Geological Survey topographic maps were used to prepare reservoir area capacity curves and to estimate tailwater elevations at the selected project site, in conjunction with topographic data furnished by the Alaska Power Administration.

The monthly energy and peak load requirements upon which the power studies were based, were taken as percentages of total annual energy generation and annual peak load respectively. These percentages are the same as used in the U. S. B. R. Devil Canyon report and are as follows:

Month	Monthly Load Distribution (% of annual total)	Monthly Peak Load (% of annual peak)
January	9.3	89
February	8.1	87
March	8.3	81
April	7.7	71
May	7.6	67
June	7.2	63
July	7.4	68
August	7.7	71
September	8.0	81
October	8.9	89
November	9.4	94
December	10.4	100

For these studies an average hydraulic efficiency of 82% was used on gross head. On the basis of the preliminary layout of the project, the operational range of the project, and the operational range of the reservoir, this efficiency is considered to be reasonable.

The result of this initial assessment indicates that the economic maximum normal level of the reservoir is 1,750 feet elevation. A more detailed study should be made when improved data on topography, hydrology, and geology become available. As in the U. S. B. R. Devil Canyon report, reservoir evaporation was considered to be negligible.

B. OPERATION STUDIES

Initial operation studies were made to ascertain the firm continuous power which could be generated over all 23 years of hydrologic records. Under this criterion, firm continuous power was found to be 325,000 kw, with corresponding annual energy generation of 2,837 million kwh; this was governed by the extremely low water year of 1969.

If hydroelectric power from the Susitna River was the sole input to a power system, its nominal continuous power would necessarily be limited to the lowest predictable dry year inflow. However, Susitna power will be integrated into a system comprised of natural gas and coal-fired thermal generating plants, as well as other hydroelectric plants. This system is considered to have sufficient energy capability to meet system requirements in a low water year by operating on a higher than average plant factor. Therefore, analyses were made to develop criteria whereby the Susitna reservoir could be operated to produce a higher level of continuous power in normal years with a curtailed output in an isolated extremely dry year. On the basis of the 23 years of water records, two reservoir rule curves were established, as shown in Figure VI-1, at the end of this chapter.

When the reservoir level is on or above the upper rule curve, actual power generation should equal or exceed normal firm continuous power; that is, secondary power may be generated. When the reservoir level is between the upper and lower rule curves, power generation should be equal to normal firm continuous power. When the reservoir level is below the lower rule curve, power generation must be curtailed below the normal firm continuous level to allow the reservoir to recover the upper rule curve.

Power studies carried out on the basis of the two reservoir operating rule curves resulted in firm continuous power of 385,000 kw for the period from October 1949 to May 1969, and also from December 1970 to September 1972. For the dry year cycle, between June 1969 and November 1970, firm continuous power was 250,000 kw. The studies also indicated that the higher level could be increased to 390,000 kw, with a corresponding dry cycle level of 210,000 kw. As noted in the hydrologic studies, Chapter IV, the probability of occurrence of the 1969 low water year is less than one in thirty; therefore, energy output of the Susitna project would be curtailed less than 3% of the time.

To substantiate whether the higher continuous power figure could be used for system planning, an analysis was made of the projected power system balance for the Anchorage-Cook Inlet and Fairbanks areas. As shown in Table VI-1, a dry year occurring in 1985 would impose the most stringent operating conditions on thermal units of the system. The annual average load factor for thermal units in a 1985 dry year would be 82.9%; re-regulation of the Susitna reservoir could prevent monthly load factors from exceeding this level. It is believed that it would be feasible for the thermal units in the system to maintain this level of operation in an isolated dry year. Beyond 1985, addition of other assured thermal capacity would reduce the system thermal load factor to be maintained in a dry year.

The conclusion of this analysis is that the project can be based on firm continuous power of 385,000 kw, with corresponding firm annual generation of 3,372 million kwh. Using a plant factor of 55%, the resulting Susitna I installed capacity is 700,000 kw.

Reservoir operation rule curves are presented on Figure VI-1. This drawing also shows inflow, outflow, and elevation, and average monthly power generation when the reservoir is operated to these rule curves for the 23-year period of record. Typical yearly load curves are also shown for normal years and for an extremely dry year.

Table VI-2 presents a summary of annual operating data for the 23-year period of runoff records.

C. COMPARISON WITH THE U.S.B.R. DEVIL CANYON PROJECT

The power and energy capability of the U.S.B.R. Devil Canyon project, as described in the 1960 and 1974 Project Reports, was based

TABLE VI-1

SUMMARY OF THERMAL LOAD FACTORS UNDER NORMAL AND DRY YEAR CONDITIONS

Year	Net Energy for System	Susitna Generation Normal (million kwh)	Susitna Generation Dry Year (million kwh)	Thermal Generation Normal (million kwh)	Thermal Generation Dry Year (million kwh)	Assured Thermal Capacity (thousand kw)	Thermal Load Factor Normal %	Thermal Load Factor Dry Year %
1980	3,543	-	-	3,543	-	697	59.6	-
1981	3,991	158	-	3,833	-	697	63.8	-
1982	4,499	733	-	3,716	-	697	60.9	-
1983	5,069	1,265	-	3,804	-	697	62.3	-
1984	5,709	1,832	-	3,877	-	697	63.5	-
1985	6,434	2,498	2,190	3,936	4,244	697	64.5	69.5
1986	7,252	3,263	2,190	3,989	5,062	697	65.3	82.9
1987	8,168	3,330	2,190	4,838	5,978	849	65.1	80.4
1988	9,211	3,330	2,190	5,881	7,021	1,039	64.6	77.1
1989	10,375	3,330	2,190	7,045	8,185	1,252	64.2	74.6
1990	11,701	3,330	2,190	8,371	9,511	1,484	64.4	73.2

TABLE VI-2

ANNUAL SUMMARY
RESERVOIR AND POWER OPERATION

Year Ending Sept. 30	Inflow	Release for Power	Spill	Reservoir Content End of Year	Firm Energy	Secondary Energy	Total Energy
	1,000 acre-feet				(million kwh)		
1949/50	5,414	5,722	-	5,364	3,373	-	3,373
50/51	6,138	6,016	-	5,486	3,373	-	3,373
51/52	6,439	6,253	-	5,673	3,373	292	3,665
52/53	6,801	6,801	-	5,673	3,373	740	4,113
53/54	6,526	6,463	63	5,673	3,373	499	3,872
54/55	6,912	6,867	45	5,673	3,373	752	4,125
55/56	7,736	7,140	596	5,673	3,373	921	4,294
56/57	6,999	6,811	188	5,673	3,373	742	4,115
57/58	6,387	6,431	-	5,629	3,373	537	3,910
58/59	7,118	6,652	422	5,673	3,373	597	3,970
59/60	6,549	6,322	227	5,673	3,373	438	3,811
60/61	7,287	7,268	19	5,673	3,373	1,049	4,422
61/62	7,796	7,584	212	5,673	3,373	1,220	4,593
62/63	7,463	6,978	485	5,673	3,373	858	4,231
63/64	6,607	6,607	-	5,673	3,373	565	3,938
64/65	6,853	6,690	163	5,673	3,373	636	4,009
65/66	6,357	6,357	-	5,673	3,373	448	3,821
66/67	7,562	7,052	510	5,673	3,373	846	4,219
67/68	6,616	6,616	-	5,673	3,373	621	3,994
68/69	3,772	5,416	-	4,030	3,084	-	3,084
69/70	5,116	4,184	-	4,962	2,205	-	2,205
70/71	6,910	6,198	-	5,673	3,373	138	3,511
71/72	7,341	7,341	-	5,673	3,376	1,055	4,428
Mean	6,639	6,512	127		3,309	563	3,872

on the hydrologic record for the years from October 1949 to September 1959, and the low water year of 1950. From the analysis above, it is believed that reassessment of the power capability of the Devil Canyon project using the full 23 years of runoff records would significantly reduce this project's power capability if the dry year were considered to govern. Of course, this project would also become part of the same system with the probable result that its normal firm continuous power capability would be only slightly reduced from the level shown, and that thermal generation could be used to supplement its dry year generation.

The Devil Canyon project and Susitna I may be compared as follows:

	Devil Canyon	Susitna I
Continuous power	330,000 kw	385,000 kw
Load factor	55%	55%
Installed capacity	600,000 kw	700,000 kw
Annual energy	2,900 million kwh	3,372 million kwh

The peak power and energy generation of Susitna I is 16.6% greater than that of the Devil Canyon project.

VII. CONCEPTUAL PROJECT STUDIES

A. INTRODUCTION

The project concept originally advanced by the Henry J. Kaiser Company as an alternative to the U. S. B. R. Devil Canyon Project, consisted of a single high dam located near Devil Canyon with a power plant located at or near the dam. This concept was aimed at the formation of a reservoir in a location where the water released from the reservoir could be used directly for power generation. This concept would eliminate Denali dam and reservoir from the first stage of river resources development at least and at the same time significantly reduce the effect of first stage river development upon the natural environment.

In the initial studies an alternative concept was considered. This secondary concept was comprised of a dam and power plant several miles upstream of Devil Creek, shown as Site D, combined with a dam and power plant just downstream of Portage Creek, shown as Site A on Figure VII-1, at the end of this chapter.

Comparative studies of these two concepts which included evaluation of power potential, increased length of access, and transmission facilities indicated that the original concept of a single project installation was the more favorable. Consideration was given in each case to location of the power plant further downstream; however, the gain in head from fall in the river was not sufficient to justify location of the power plant beyond the immediate vicinity of the dam.

B. SELECTED PROJECT CONCEPT

1. General

The main features of the selected project concept designated as Susitna I are a dam approximately 800 feet high, a spillway controlled by three tainter gates, a power intake and tunnels which carry water to generating units in an underground powerhouse, a switchyard and a transmission system which supplies electric power to the Anchorage-Cook Inlet and Fairbanks areas. The location of the project is shown on Figure VII-1 and the layout of the main project features is shown on Figure VII-2.

2. The Dam

Consideration was given to three general types of dams; namely, concrete arch, concrete gravity and, compacted rockfill. All three types have been built in other locations to heights exceeding that of the dam required for the project concept. While concrete arch dams are usually well suited for V-shaped canyons, the spread of the V at Site B was considered too wide for an arch dam. The cost of a concrete gravity dam, considering especially the limited availability of naturally occurring sands and gravels, was not competitive with the cost of a rockfill dam.

Two types of compacted rockfill dam were considered, the sloping core type and the concrete face type. The main structural element of the sloping core type dam is the downstream rockfill zone. This is overlain by the impervious earth core which is protected by several layers of sand and gravel filters at the upstream and downstream faces of the core. The core and filter zones are overlain by upstream rockfill which provides structural stability for the impervious earth zone. The principle of the vertical core type of dam is similar. Core-type dams of similar height range include Mica Dam in British Columbia which is 800 feet high; Oroville Dam in California, 774 feet high; Chivor Dam in Colombia which will be 727 feet high when completed in 1975. Nurek Dam, now under construction in Russia, will be about 1,040 feet high when completed. The sole structural element of the concrete face type of rockfill dam is a single rockfill zone. This zone is similar in size and performs the same function as the downstream rockfill zone in the inclined core type rockfill dam. The dam is made impervious by a reinforced concrete face which varies in thickness from top to bottom of the dam. The concrete face is underlain by and bonded to a zone of graded rock-fill limited to maximum rock size of six inches. Existing major dams of this type include Exchequer Dam in California and Anchicay Dam in Colombia, both 500 feet high. The proposed Areia Dam now being designed by a Kaiser affiliate in Brazil will be 520 feet high and the proposed Yacambu Dam in Venezuela will be 540 feet high.

A concrete face type of rockfill dam has been tentatively selected for use in the conceptual project. Recent progress in improvement of concrete face dams due to increased knowledge and major improvements in rockfill design favors the use of such dams to heights greater than presently established. The dam proposed in this concept has been modified by use of a conventional impervious earth core overlain by an upstream rockfill zone in the lower 300 feet. This earth core and rockfill is placed over the lower 300 feet of concrete face and the lower part of the dam thus has two distinct impervious barriers. The height of concrete face constituting a single impervious barrier is about 500 feet, the same as Exchequer and Anchicay dams. The typical dam section and profile are shown on Figure VII-3.

The modified concrete face rockfill dam has been tentatively selected over the conventional core type rockfill dam for the following reasons:

(a) Availability of Materials

The core type of dam requires a much larger volume of impervious earth than the selected type. It also requires sands and gravels for protective filter zones. Field reconnaissance indicated that the volumes of these materials readily available for economic dam construction is relatively limited. It is anticipated that filter materials would have to be produced by crushing rock.

(b) Volume of Dam

The volume of the core type of dam would be 30 to 40% greater than the concrete face dam and could require as much as two years longer to complete.

(c) Climate

Frequent rainfall and low temperatures during the seven to eight month dam construction season would inhibit placement of the impervious earth core which requires careful moisture control.

(d) Diversion and power tunnels would be longer with the core type of dam.

As noted, the selection of the concrete face type of dam as modified is tentative. More field exploration for materials and more detailed study and analysis are required before final selection of rockfill dam type can be made.

3. Spillway

The spillway will be located on the south abutment of the dam as shown on Figure VII-2. The main elements of the spillway are the approach channel, the control structure, and the discharge channel.

The concrete control structure will be provided with three 40-foot wide by 45-foot high tainter gates. The control structure will be designed to pass the design flood with a reservoir surcharge of five feet. The design flood, which will have a peak inflow of 213,000 cubic feet per second and a fifteen-day volume of 2,460,000 acre-feet, was established in the Devil Canyon Status Report of May 1970.

The spillway discharge channel will be paved and lined with concrete walls for a distance of about 100 feet downstream of the control structure. The remainder of the channel will be unlined. Downstream of the initial sloping section, the spillway discharge channel will be excavated in a series of 50-foot high steps down to river level as shown on Figure VII-3. With this arrangement, much of the energy of the spilled water will be dissipated by the time the water reaches the river. The discharge channel will be located well away from other project features, and final release will be in the direction of river flow. The fine-grained granite bedrock will be well suited for the cascade type of flow which has been successfully used in other projects. Rock derived from excavation of the spillway will be used in construction of the dam.

4. Power Features

a. Intake

The intake structure will be located upstream of the dam on the south abutment. It consists of two intake units, each servicing two generating units in the powerhouse. Each intake unit will be equipped with a semicircular steel trashrack and an hydraulically operated fixed wheelgate. Two concrete-lined tunnels will convey water to the powerhouse area where each tunnel will bifurcate into two steel-lined tunnels which will deliver water to the turbines.

b. Powerhouse

An underground powerhouse has been tentatively selected for the project, and it is located under the dam on the south abutment as shown on Figure VII-2. The tailrace tunnels will discharge into the diversion tunnels.

The tentative selection is based on the apparently favorable rock structure of the south abutment, and consideration of the very steep and narrow canyon at river level as well as the severe winter climate.

The total installed generating capacity will be 700,000 kilowatts, and tentative selection has been made of four 175,000 kilowatt generating units.

The 241,000-horsepower Francis turbines will be equipped with electrohydraulic governors and each turbine will be provided with a butterfly valve at the entrance to the scroll case. The generators will be rated at 194,000 kva, 13.8 kv with a power factor at 0.90 and will be equipped with static excitation. They will be capable of operating at an overload capacity of 15%. The generators will be coupled with six single phase transformers each rated at 75,000 kva, 13.8-230 kv. High tension cables will be carried in a tunnel from the powerhouse to the switchyard.

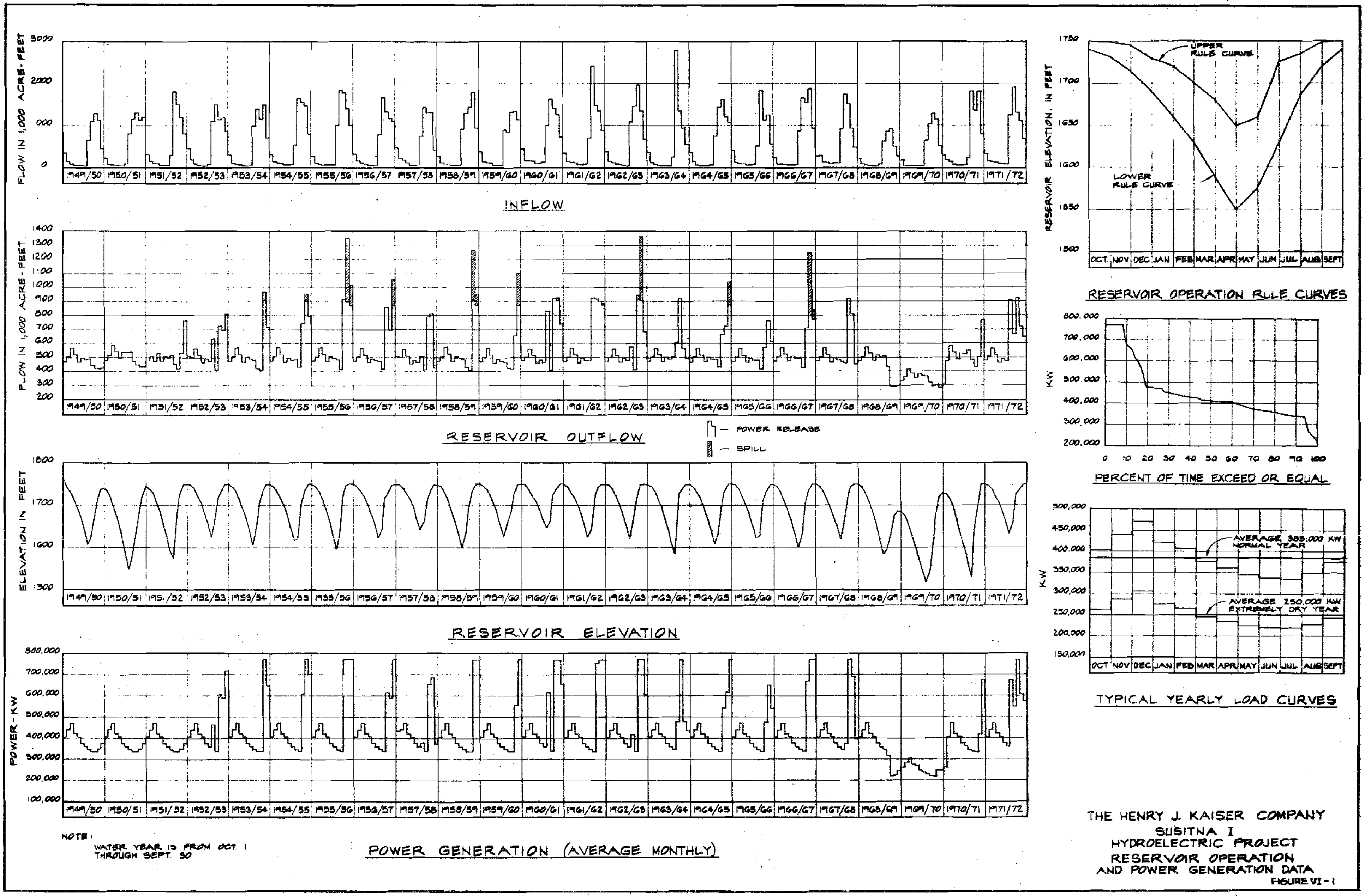
Major powerhouse equipment will be installed and serviced by twin 350-ton capacity bridge cranes.

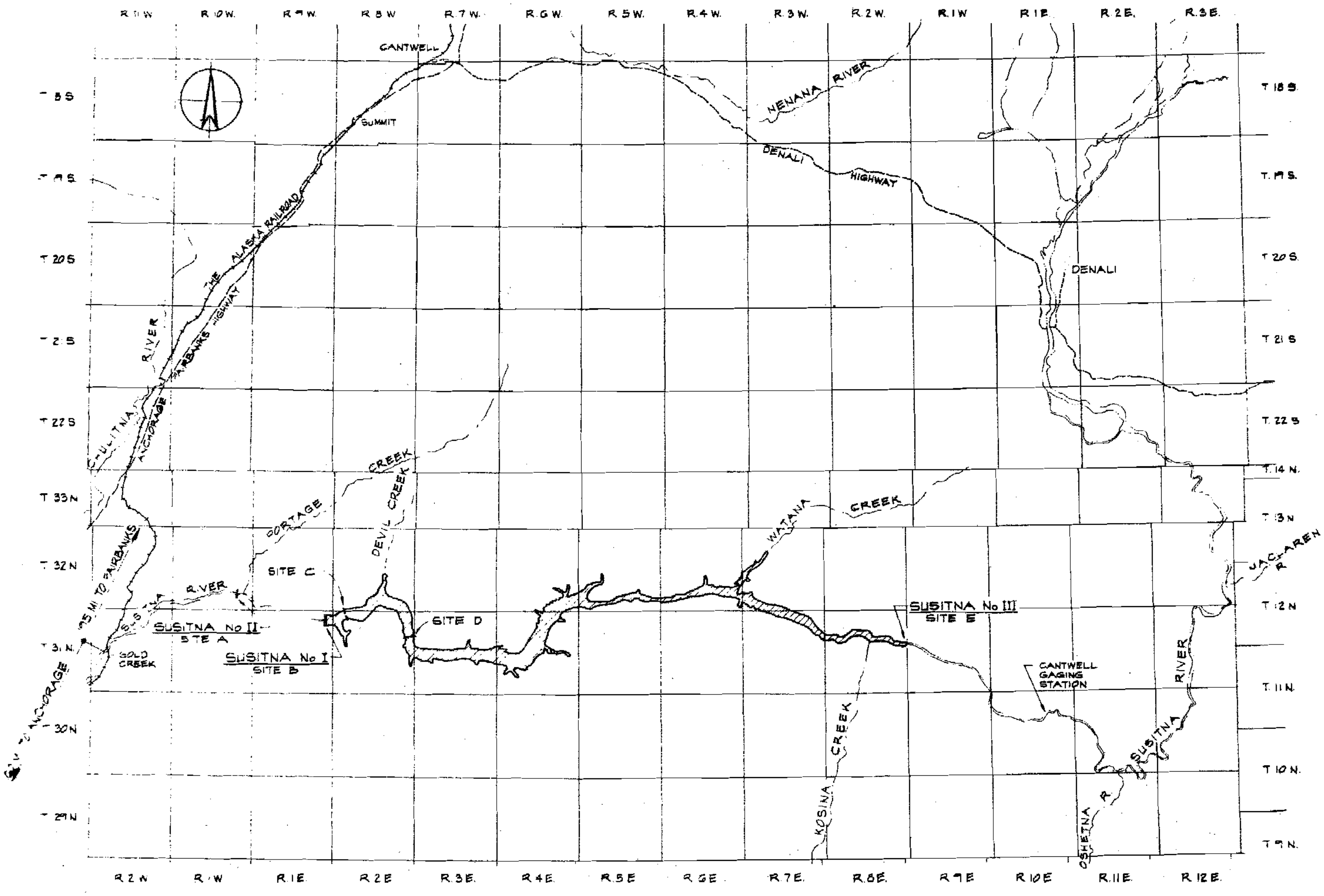
5. Transmission System

The transmission system consists of a single circuit 230 kv line to Fairbanks, a double circuit 230 kv line to Anchorage, and substations at both of these line terminals.

6. Sedimentation

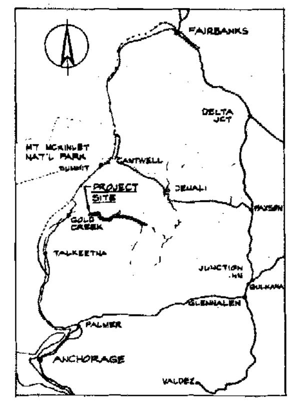
In studies carried out by the Bureau of Reclamation in 1963, it was estimated that without upstream storage, sediment inflow to the Devil Canyon area would amount to 593,000 acre-feet in 100 years. The reservoir visualized for the Susitna I project has a total capacity of the order of 5,670,000 acre-feet, and the effect of one hundred years of sedimentation would be of no consequence.


INFLOW
FLOW IN 1,000 ACRE-FEET
RESERVOIR OUTFLOW
POWER RELEASE
SPILL
RESERVOIR ELEVATION
ELEVATION IN FEET
POWER GENERATION (AVERAGE MONTHLY)
POWER - KW
NOTE: WATER YEAR IS FROM OCT. 1 THROUGH SEPT. 30
RESERVOIR ELEVATION, IN FEET
UPPER RULE CURVE
LOWER RULE CURVE
OCT. NOV DEC JAN FEB MAR APR MAY JUN JUL AUG SEPT
RESERVOIR OPERATION RULE CURVES
KW
PERCENT OF TIME EXCEED OR EQUAL
AVERAGE 385,000 KW NORMAL YEAR
AVERAGE 250,000 KW EXTREMELY DRY YEAR
TYPICAL YEARLY LOAD CURVES
THE HENRY J. KAISER COMPANY
SUSITNA I
HYDROELECTRIC PROJECT
RESERVOIR OPERATION
AND POWER GENERATION DATA
FIGURE VI - 1



SITE LOCATION PLAN

0 5 10 20 MILES



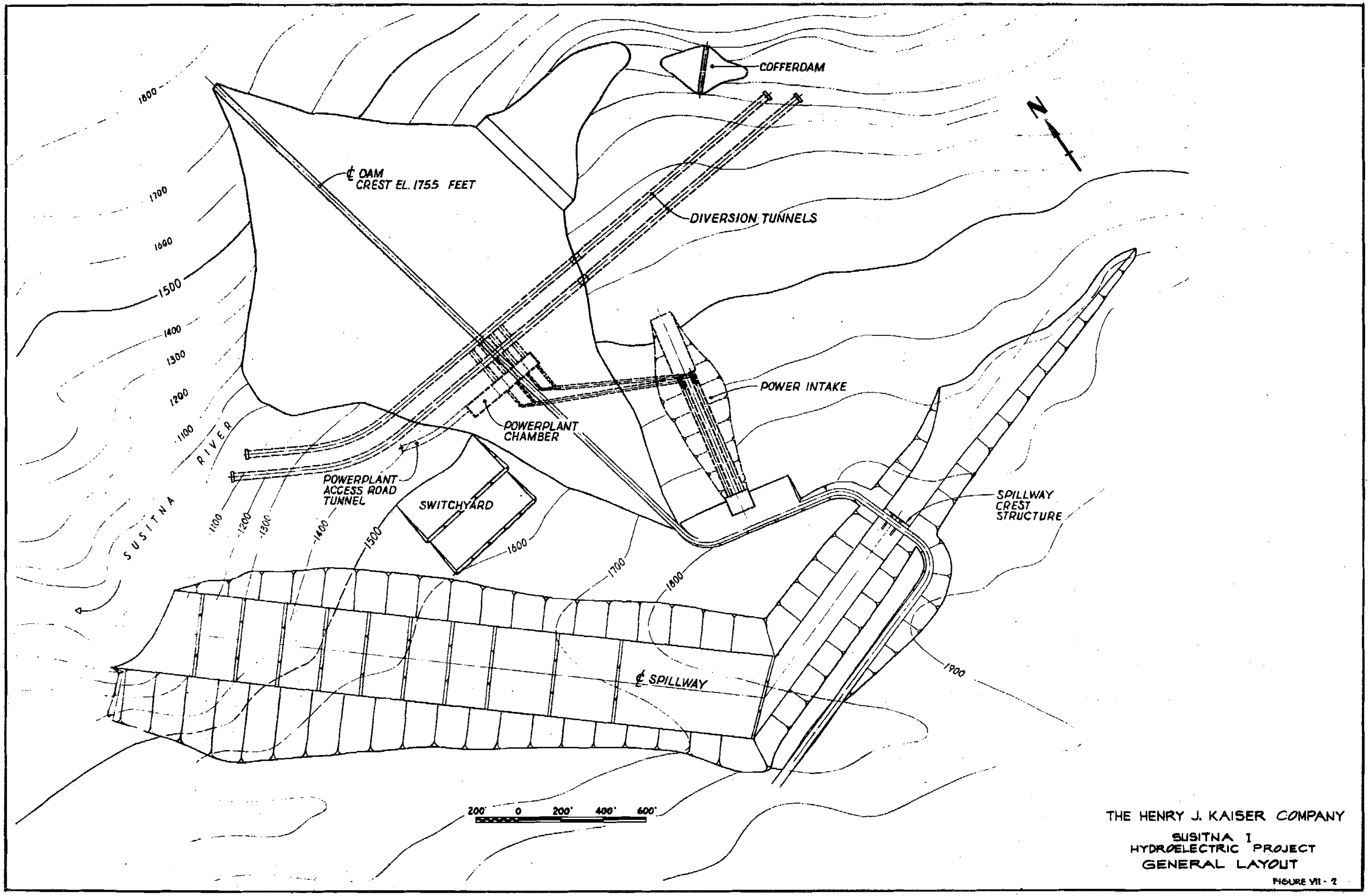
VICINITY PLAN

0 10 50 100 MILES

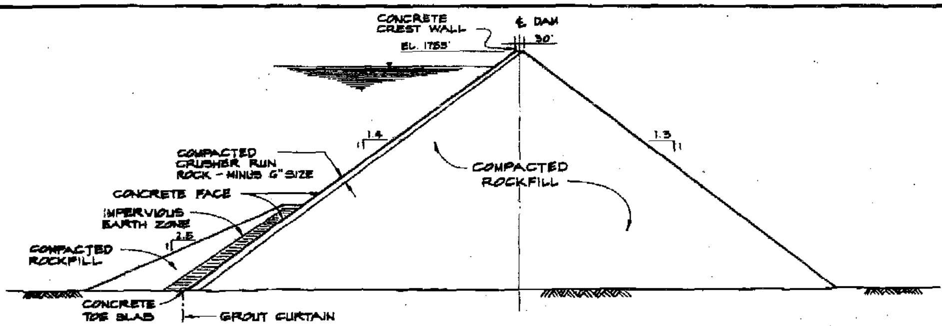
THE HENRY J. KAISER COMPANY

SUSITNA I
HYDROELECTRIC PROJECT
SITE LOCATION PLAN

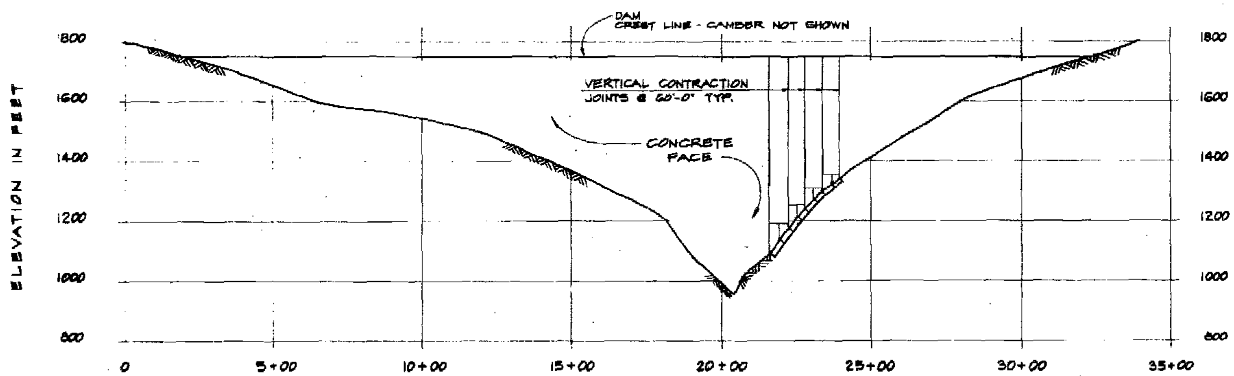
FIGURE VII-1



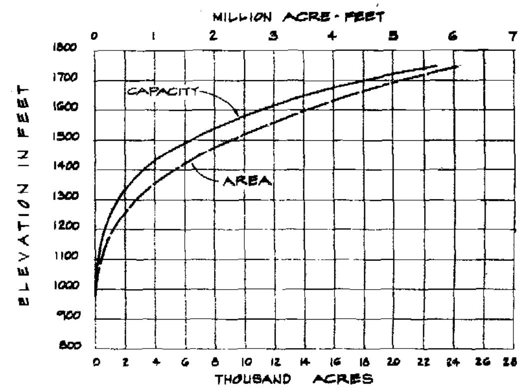
THE HENRY J. KAISER COMPANY
SUSITNA I
HYDROELECTRIC PROJECT
GENERAL LAYOUT
FIGURE VII - 2



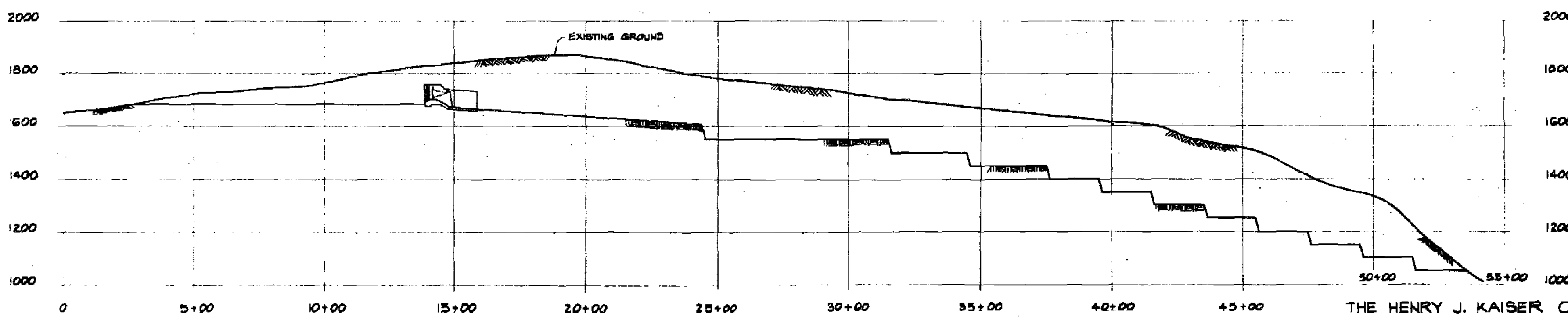
TYPICAL DAM SECTION
SCALE: 1" = 200'-0"



UPSTREAM ELEVATION OF DAM
SCALE: 1" = 200' HORIZONTAL & VERTICAL



RESERVOIR AREA - CAPACITY CURVE



SPILLWAY ℄ PROFILE
SCALE: 1" = 200' HORIZONTAL & VERTICAL

THE HENRY J. KAISER COMPANY
SUSITNA I
HYDROELECTRIC PROJECT
SECTIONS

FIGURE VII - 3

VIII. COST ESTIMATE AND CONSTRUCTION PLAN

A. SUMMARY

The estimated cost of Susitna I, by project features, is shown in Table VIII-1. This estimate was based on June 1, 1974 cost levels for major equipment items, materials, and civil construction of the project. Included in the estimate are provisions for escalation of prices during the construction period. Also included are allowances for engineering design, supervision of construction, administration of contracts, contingencies, and interest during construction.

The total estimated cost for the project at completion of construction, excluding interest during construction, is $525.72 million. Assuming an interest rate of 6%, interest capitalized during construction would total $77.0 million, the resulting total investment in the project would be $602.72 million, as detailed on Table VIII-1.

The estimated cost for supply, transportation, and installation of major items of permanent equipment was based on information supplied by equipment manufacturers. The estimated cost for construction of main project features was based on analysis of the construction methods which would be used. Analyses were made of construction plant and equipment requirements, along with labor force, and materials and supplies; costs were built up in the manner required for actual bid preparation. All costs were based on latest material prices applied to Alaskan conditions and recent Alaskan trade and craft labor rates. The transmission system cost estimate was based on available data, including recent experience, on the cost of constructing high voltage transmission lines in Alaska.

B. CONSTRUCTION PLAN

1. Climate

The climate of central Alaska is the factor which most affects the timing and certain costs of project construction. In the past years the heavy construction season in similar climates has been generally limited to the six months from April to September inclusive. Specialized techniques developed in the construction of similar projects in winter climates have, however, enabled extension of the construction season from mid-March to mid-November.

TABLE VIII-1

SUMMARY OF CAPITAL COST ESTIMATE[1]
(June 1974 Costs)

Hydroelectric Plant	
Site Access, reservoir clearing, and diversion tunnels	$ 47,185,000
Dam and spillway	263,690,000
Power plant and related facilities	129,570,000
Living quarters and general property	2,880,000
	$443,325,000
Transmission System	$ 82,395,000
Total construction costs	$525,720,000
Interest during construction	$ 77,000,000
TOTAL CAPITAL INVESTMENT	$602,720,000

[1] The above costs include contingency and engineering costs but do not include escalation to the date of award of the construction and equipment contracts.

Freezing temperatures at the extremes of this construction season would have relatively little effect on excavation of rock and placement of rock in the dam, particularly considering the low precipitation in the area in those months. Certain underground operations can continue on a year-around basis, once well established, and some above-ground concreting can be carried out in sub-zero temperatures.

2. Access

In order to expedite the start of project construction and economically reduce the overall length of the construction period, it is proposed to start work on the access road one year before the award of main construction contracts. The road would be scheduled to provide reasonably good access for the first stage of construction at the site and would be later improved for the movement of major construction equipment and materials. It is assumed that the road would commence at Gold Creek, and during the early years of the project, project supplies and equipment would be carried to that point via the Alaska Railroad. Later the road would be extended to the Anchorage-Fairbanks Highway to facilitate routine access.

3. Diversion

Two tunnels have been tentatively selected for diversion of the river from its normal channel. Cofferdams will be placed upstream and downstream of the dam, and the downstream cofferdam will be incorporated in the toe of the dam. In the first stage of dam construction, rockfill will be placed to the full length of the dam in the riverbed. To provide for the possible occurrence of a major flood flow in the first diversion season, the downstream toe of the rockfill will be reinforced with a network of steel wire mesh and welded steel reinforcing bars. In the event that major flooding causes overtopping of the initial low dam portion, the toe reinforcement, used in other similar projects, will prevent damage to the rockfill. The following season the dam will be raised high enough to route major river floods through the diversion tunnels. After closure, the diversion tunnels will be used as part of the powerhouse tailrace.

4. Major Excavation and Dam Fill

The largest construction operation will consist of the excavation of rock and its subsequent placement in the dam. Rock for the dam will be derived partly from excavation required for construction of the spillway, intake, powerhouse, and switchyard. It will also be taken from one or more quarries that will be established in the reservoir area near the dam. The use of several major sources of rock will permit more efficient use of excavation equipment and will minimize the congestion of traffic transporting rock from source to the dam. Major excavation will be planned so that rock can be placed in the dam at or near the level from which it is excavated.

5. Underground Construction

The scale of underground construction required for Susitna I is comparable to projects of similar size and scope in many parts of the world. Once initial access to underground works is achieved, no unusual problems are anticipated, either in construction or in the installation of permanent equipment.

6. Transmission System

While the transmission lines will traverse some difficult terrain and permafrost will be encountered, no unusual construction problems are foreseen at this time.

C. CONSTRUCTION SCHEDULE

A tentative schedule has been prepared for the implementation of the project, and is shown on Figure VIII-1. It is estimated that first power can be generated about six-and-one-half years after commencement of work on the project.

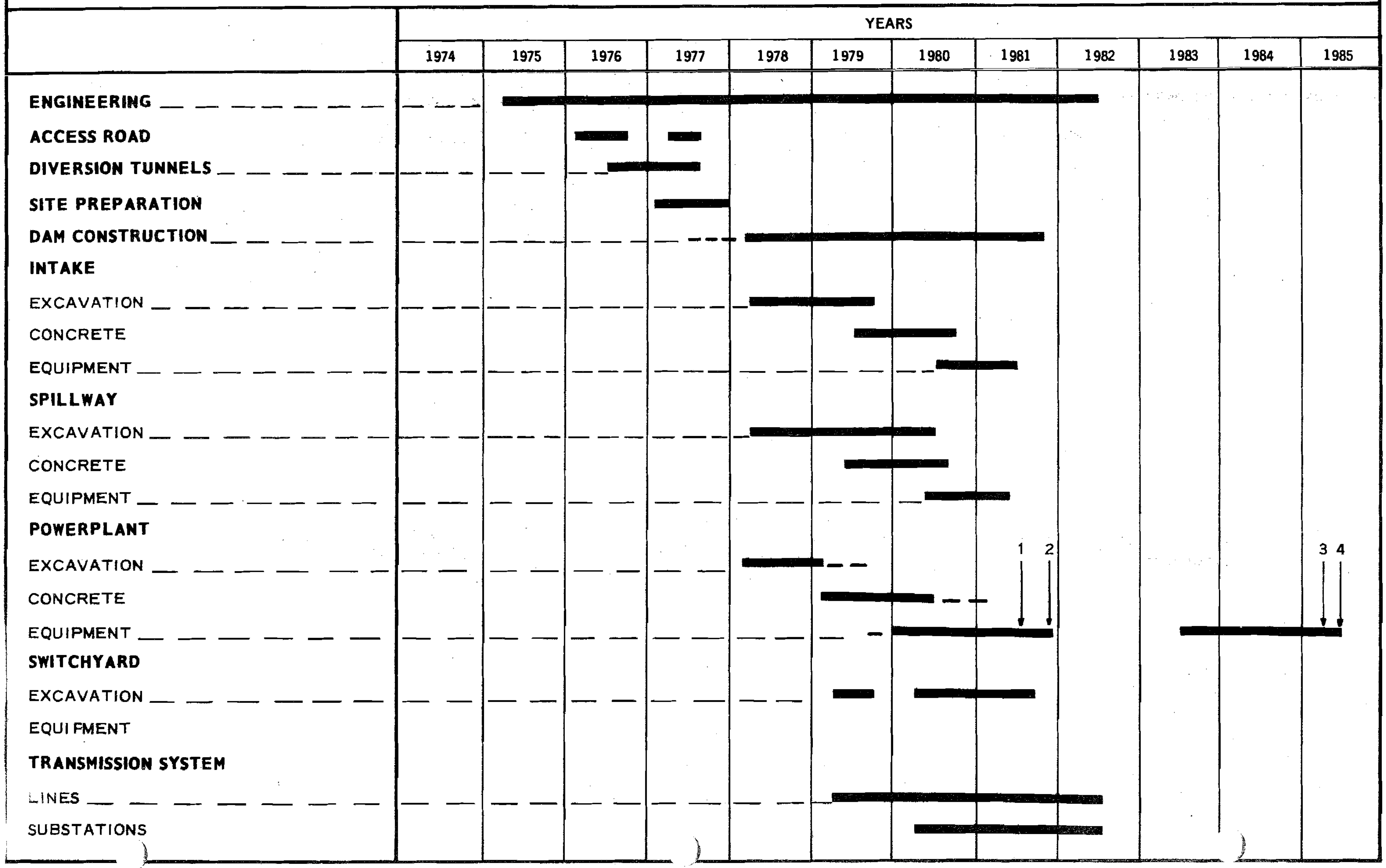
About two-and-one-half years will be required for the completion of preconstruction engineering. This will include site mapping, detailed geologic investigations and the preparation of designs, specifications and documents for construction and equipment supply contracts. Documentation required for project licensing by the Federal Power Commission will be prepared in the early stages of engineering work.

Construction of the access road is scheduled to commence about one year after the start of engineering and work on the diversion tunnels is scheduled to start six months later. The contract for construction of the main project features is scheduled for award about two years after the start of engineering, and contracts for the supply of major items of permanent equipment would be awarded during the following six-month period. Transmission system engineering and construction would be phased to provide for the transmission of power to the Anchorage area upon generation of first power, and to the Fairbanks area one year later, as required by present electrical load growth forecasts.

FIGURE VIII-1

SUSITNA I

TENTATIVE CONSTRUCTION SCHEDULE



IX. FINANCIAL EVALUATION AND ECONOMIC ANALYSIS

A. INTRODUCTION

The financial and economic evaluations have been based on the tentative construction schedule shown on Figure VIII-1. The schedule visualizes the commencement of detailed engineering in early 1975, the commissioning of the first two generating units in 1981 and second two in 1985, in accordance with the projected load growth of the areas to be served by the project.

B. FINANCIAL EVALUATION

1. Method

A pro forma income statement has been prepared for Susitna I in order to determine whether the project's schedule, costs, and revenues are consistent with a practical financing method.

This analysis takes into account total costs estimated for the project, along with projections of revenues to accrue from sales of primary and surplus energy.

The pro forma income statement is presented as Table IX-1.

2. Financing Plan

It is believed that if the Susitna project were undertaken by the State of Alaska, a state issue of tax-exempt revenue bonds would be the most practical method of financing the major part of its cost. It is considered possible that leveraged lease financing could be used for major equipment items, comprising 10 to 20% of total cost, reducing the magnitude of the revenue bond issue by a corresponding amount. The use of these financing methods would require that the project be capable of obtaining firm commitments for revenue power sales to its utility customers, and possibly that the project's financial obligations also be guaranteed by the State of Alaska.

In order to make best use of the term of the revenue bond issue, it is assumed that bonds would be sold approximately six months prior to project commissioning, although bond market conditions

TABLE IX-1

PRO FORMA INCOME STATEMENT AND SOURCES AND APPLICATIONS OF FUNDS

Thousands of Dollars ($000), except as noted

	Total	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987-2015	
Revenues															
Primary Energy Sales															
kwh (thousands)		-	-	-	-	-	-	158,000	733,000	1,265,000	1,832,000	2,498,000	3,263,000	3,330,000	
Revenue @ $.01447		-	-	-	-	-	-	2,286	10,607	18,305	26,509	36,146	47,216	48,174	
Surplus Energy Sales															
kwh (thousands)		-	-	-	-	-	-	1,357,000	2,297,000	1,765,000	1,198,000	682,000	67,000	-	
Revenue @ $.0082								11,127	18,835	14,473	9,824	5,592	549	-	
Total Revenues		-	-	-	-	-	-	13,413	29,442	32,778	36,333	41,738	47,765	48,174	
Annual Costs															
Operating Costs @ .00205		-	-	-	-	-	-	310	740	760	780	1,050	1,308	1,308	
Interest Payments @ .06		-	-	-	-	-	-		35,213	36,614	37,451	38,066	38,288	38,288	
Depreciation @ .01		-	-	-	-	-	-	2,855	6,028	6,176	6,307	6,344	6,381	6,381	
Total Annual Costs		-	-	-	-	-	-	3,165	41,981	43,550	44,538	45,460	45,977	45,977	
NET INCOME		-	-	-	-	-	-	10,248	(12,539)	(10,772)	(8,205)	(3,722)	1,788	2,197	
Sources of Funds															
Net Income		-	-	-	-	-	-	10,248	(12,539)	(10,772)	(8,206)	(3,722)	1,788	2,197	
Depreciation		-	-	-	-	-	-	2,855	6,028	6,176	6,307	6,344	6,381	6,381	
Debt															
Bond Proceeds or Notes	561,100	1,600	17,400	69,000	75,700	109,600	128,800	91,800	31,900	14,800	13,100	7,400	-	-	
Capitalized Interest	77,000	50	620	3,250	7,780	13,800	21,790	29,710	-	-	-	-	-	-	
Total	638,100	1,650	18,020	72,250	83,480	123,400	150,590	134,613	25,389	10,204	11,201	10,022	8,169	8,578	
Applications for Funds															
Construction Program	561,100	1,600	17,400	69,000	75,700	109,600	128,800	91,800	31,900	14,800	13,100	7,400	-	-	
Interest During Construction	77,000	50	620	3,250	7,780	13,800	21,790	29,710	-	-	-	-	-	-	
Subtotal	638,100	1,650	18,020	72,250	83,480	123,400	150,590	121,510	31,900	14,800	13,100	7,400	-	-	
Sinking Fund @ .0126		-	-	-	-	-	-	-	-	-	-	2,042	8,040	8,040	
Total		1,650	18,020	72,250	83,480	123,400	150,590	121,510	31,900	14,800	13,100	9,442	8,040	8,040	
NET CASH SURPLUS															
(DEFICIT)		-0-	-0-	-0-	-0-	-0-	-0-	13,103	(6,511)	(4,596)	(1,898)	580	129	538	
Cumulative		-	-	-	-	-	-	13,103	6,592	1,996	98	678	807	1,345	16,409

might indicate a different date. In the interim, it is assumed that bond anticipation notes would be issued to finance construction, following the issuance of a Federal Power Commission license for the project.

Prior to federal licensing of the project, it would be necessary to provide a source of interim funding sufficient for prerequisite engineering and environmental studies. Although preliminary commitments to purchase the project's power may be obtained from prospective utility customers prior to this initial funding, it is recognized that an element of uncertainty would remain which would prevent use of revenue bonding at this early stage. This uncertainty involves the possibility that in-depth site investigations, definitive cost estimates, complete environmental reports, or unforeseen conditions could indicate that the project was not capable of being carried forward. As a result, it is believed that State of Alaska general obligation bonds would be the most practical method of financing these initial project expenditures. These bonds would later be refunded by the project's revenue bond issue when the project could adequately guarantee its financial obligations.

3. Terms of Financing

The following outline of terms of financing has been used:

Revenue bond financing as percent of total capital investment	80-100%
Interest rate or gross yield, for revenue bonds, general obligation bonds, and anticipation notes	6%
Sale of revenue bond issue	First quarter 1981
Term and type of revenue bond issue	30 year sinking fund; 5 years grace
First payment of interest	First quarter 1982
First sinking fund payment	Fourth quarter 1985

If leveraged lease financing were used, it is expected that its terms would be similar to those for the revenue bond issue, except that the rate of interest should be 0.5% to 0.75% lower. It is possible that the lessor would provide advance funding to replace use of anticipation notes for the portion of project cost to be covered by the leveraged lease contract.

4. Pro Forma Income Statement Parameters

a. Analysis Period

The pro forma income statement covers each unique year of project operation from 1975 through 1987. Following 1987, individual year's data are assumed to be identical, throughout a financial period extending through 2015, when bonded indebtedness is fully amortized.

b. Operating Costs

Operation, maintenance, and administrative costs are charged as 0.15% of total capital investment for the hydroelectric plant and 0.5% for the transmission system, averaging 0.205% for the project as a whole. Operating costs are reduced to 60% of normal from mid-1981 through mid-1985, prior to installation of Units 3 and 4.

c. Interest

Interest during construction is computed semiannually assuming that the mean point of each year's capital expenditures is at mid-year. Following project commissioning, interest is computed as a constant annual charge accompanying sinking fund repayment of debt.

d. Depreciation

Depreciation is listed as a noncash charge based on 100-year service life.

e. External Cash Flow and Secondary Financing

No cash flow other than revenues from energy sales is applied to cover the cash obligations of the project.

f. Surplus

Under the revenue base selected for the project, a net cash surplus is generated equal to 0.1% of total capital investment in the hydroelectric plant beginning in 1987. Surpluses averaging approximately 50% of this level are generated in 1984, 1985 and 1986.

Applicable fixed and variable annual charges are summarized in Table IX-2.

g. Revenues

Revenues are computed from the schedule of primary energy required by the system, plus surplus energy available from Susitna I during its early years of operation. Primary energy is charged at 14.47 mills per kilowatt hour, the average energy charge computed for the complete project. Surplus energy is assumed to be salable at 8.2 mills per kilowatt hour, the projected least cost of fuel in the Anchorage-Cook Inlet Area. In this analysis, no allowance has been made for the difference in Anchorage-Cook Inlet and Fairbanks Area rates, which could slightly affect some years' revenues.

5. Conclusions

This analysis indicates that the proposed construction program for Susitna I and related estimates of costs and revenues are consistent with a practical method of financing the project and repaying its indebtedness.

C. ECONOMIC ANALYSIS

1. Cost of Susitna I Power by Service Area

Using the project financing and operating cost criteria outlined above, the average cost of net energy delivered by Susitna I is computed at 14.47 mills per kilowatt-hour, including 12.13 mills per kilowatt-hour for generation and 2.34 mills for transmission, as shown in Table IX-3. This average cost is not equally allocable to the Anchorage-Cook Inlet and Fairbanks service areas because of two factors. First, the Anchorage-Cook Inlet Area is expected to draw Susitna I energy on a slightly higher load

TABLE IX-2

SUMMARY OF FIXED AND VARIABLE ANNUAL CHARGES

Hydroelectric Plant	
Interest @ 6%	0.0600
Sinking Fund @ 30 years	0.0126
Subtotal	0.0726
Operation, Maintenance, and Administration	0.0015
Subtotal	0.0741
Surplus	0.0010
Total	0.0751
Transmission System	
Interest @ 6%	0.0600
Sinking Fund @ 30 years	0.0126
Subtotal	0.0726
Operation, Maintenance, and Administration	0.0050
Total	0.0776

TABLE IX-3

COMPUTATION OF COST TO POWER AND ALLOCATION BY SERVICE AREA

	Total	Anchorage-Cook Inlet		Fairbanks	
	Total $000	%	Amount $000	%	Amount $000
Hydroelectric Plant					
Power @ 50%	268,950	74	199,023	26	69,927
Energy @ 50%	268,950	76	204,402	24	64,548
Total	537,900		403,425		134,475
Annual charge @ .0751	40,396		30,297		10,099
Energy sales, million kwh	3,330		2,538		792
Cost in mills/kwh	12.13		11.93		12.75
Transmission System	100,200	52	52,104	48	48,096
Annual charge @ .0776	7,776		4,044		3,732
Energy sales, million kwh	3,330		2,538		792
Cost in mills/kwh	2.34		1.59		4.71
TOTAL PROJECT	638,100		455,529		182,571
Annual charges	48,172		34,341		13,831
Cost in mills/kwh	14.47		13.53		17.46

factor than Fairbanks. To account for the value of this, project costs have been attributed to power and energy on a 50-50 division, and then allocated to the two service areas based on demand. The resulting Anchorage-Cook Inlet revenue base at the power plant is 11.93 mills, while the Fairbanks base is 12.75 mills. Second, the costs of transmission to Anchorage-Cook Inlet and Fairbanks are nearly equal, although the Anchorage-Cook Inlet Area draws about three times as much energy from Susitna I. The allocation of transmission costs produces a charge of 1.59 mills per kilowatt-hour for Anchorage-Cook Inlet, and 4.71 mills per kilowatt-hour for Fairbanks. The resulting total cost of Susitna I power at Anchorage would be 13.53 mills per kilowatt hour, while the corresponding total for Fairbanks would be 17.46 mills.

2. Cost of Thermal Power in the Anchorage-Cook Inlet and Fairbanks Areas

The present average cost of power generated by Anchorage-Cook Inlet and Fairbanks Area utilities has been estimated based on data from Federal Power Commission and utility sources.[1] Cost items included are operation and maintenance of generating plants and long-distance transmission, fuel cost, and allowances for depreciation and administrative costs.

For Anchorage-Cook Inlet Area utilities, the resulting average cost of energy generated in 1973 is estimated at 8.9 to 9.2 mills per kilowatt-hour. Of this total cost, fuel alone averages about 40%. The corresponding fuel prices range from a low of approximately 16¢ per million Btu for natural gas at Beluga, to a high of approximately 38¢ per million Btu for natural gas delivered to Anchorage. In 1974, the cost of natural gas delivered to Anchorage was increased to 41¢ per million Btu. In the last half of the 1970's, it is expected that costs of Cook Inlet gas will continue to escalate, reflecting the value of the gas in export markets. It is also considered probable that uniform Federal Power Commission price regulation and usage restrictions will be applied to Alaskan natural gas when a substantial level of exports to the lower 48 states develops. At the present time, expansion plans for Anchorage-Cook Inlet Area utilities rely solely on gas-fired capacity.

[1] Federal Power Commission, "Statement of Income for Year," and "Electric Operation and Maintenance Expenses," 1973, Chugach Electric Assn., Inc., Anchorage Municipal Light & Power; Golden Valley Electric Assn., Inc., Annual Report, 1973

For Fairbanks, there is a wide spread between the 1973 costs of the two area utilities; therefore the lower of the two systems' average costs is taken as indicative. This was approximately 20.5 mills per kilowatt-hour. Of this, the fuel cost component was approximately 20%. The principal fuel used for power generation in the Fairbanks Area is Healy coal, for which the most indicative price is the present contract for mine-mouth delivery at Healy. In 1973, this contract was 40¢ per million Btu; however, this value has now been increased to 47¢ per million Btu, with provision for escalation following U.S. government indices to 1989. Fairbanks utilities are planning to take power from a crude or residual oil-fired gas turbine plant to be set up at a proposed refinery at North Pole, beginning in 1977, followed by the possible addition of coal-fired capacity at Healy in 1980.

A key factor in determining the value of power in the Anchorage-Cook Inlet and Fairbanks Areas in the early 1980s is the expected market value of Alaska's petroleum products on the U.S. West Coast. Recent data from petroleum industry sources indicate an expected long-term average price of $8 to $10 per barrel of crude oil, with a similar value for residual fuel oil. This corresponds to a residual oil heating value of approximately $1.25 to $1.60 per million Btu. It is probable that the cost of fuel products refined in Alaska will roughly equal West Coast prices less the equivalent of freight charges on crude oil. On this basis, the outlook for residual oil prices in the Anchorage-Cook Inlet and Fairbanks Areas in the early 1980s is approximately $7.50 to $9.50 per barrel, or about $1.20 to $1.50 per million Btu. This estimate in effect assumes that today's fuel price levels will still be current in the early 1980s.

For natural gas, the West Coast market value in the early 1980s is also expected to be in the range of $1.25 to $1.50 per million Btu. In the case of gas, the cost of liquefaction and shipping from Alaska would be approximately 50¢ per million Btu, resulting in a market value in Alaska of about 75¢ to $1.00 per million Btu. This estimate is also consistent with El Paso Natural Gas Company's estimated transmission toll of approximately 65¢ per thousand cubic feet (1,000 cubic feet = 1 million Btu), from the North Slope to Gravina Bay, plus wellhead prices of 10¢ to 35¢ per thousand cubic feet. It is considered probable that Cook Inlet natural gas prices will escalate to approximately this level. If the El Paso line is constructed, the Fairbanks Area may also be supplied with natural gas. However, due to the smaller volume in the Fairbanks Area and the need to install line taps and distribution facilities at relatively high unit cost, it is estimated that gas will cost about $1.00 per million Btu in Fairbanks.

If new sources of oil and gas are brought into production in South Cook Inlet or the Gulf of Alaska, it is expected that their production costs will be in the range of these prices, due to the cost of new field development in the last half of the 1970s.

It is possible that coal will be among Alaska's cheaper fuels in the 1980s. Under a current contract with a Fairbanks utility, Healy coal is now available at 47¢ per million Btu, subject to an escalation agreement which could increase this price to approximately 73¢ per million Btu by 1981 and to $1.00 per million Btu by 1986. On the other hand, a California firm is now exploring a coal deposit near Beluga; very tentatively, this deposit is thought to be capable of producing at a mine-mouth cost of about 25¢ per million Btu, but only in very large quantities. It is also considered possible that the existing coal mines at Jonesville could resume production at a cost of 50¢ to 75¢ per million Btu. A major deterrent to use of coal as fuel will continue to be the capital and operating costs of coal-fired steam power plants, which are much higher than those of oil- and gas-fired plants. In addition, it is probable that environmental regulations on coal mining and mine reclaiming practices could substantially increase the selling price of coal from today's estimated levels.

In addition to these fuel cost indicators, it is estimated that capital costs of fossil-fueled power plant and equipment, and operating costs other than fuel, will escalate at an average of about 6% per year through the early 1980s.

With regard to possible alternate power sources other than hydro, it is not expected that nuclear power will be competitive in Alaska in the 1980s due to the size of Alaskan power markets, the rapidly escalating cost of nuclear plant and equipment, and potentially serious thermal pollution problems in the Alaskan climate. While Alaska may have attractive geothermal resources, it is believed that several years of preliminary exploration, testing, and research are required before these can be regarded as a practical alternate power source.

As a result of these cost indicators, estimates of power cost have been prepared for new thermal generating systems commissioned in 1981; these are indicated in Tables IX-4 and IX-5. These estimates are considered roughly comparable to present power system costs and also to Susitna project power costs estimated for this report. These estimates include allowances for transmission of thermal power from remote sites such as Beluga, Healy, and North Pole. It is expected that most future thermal capacity added to the Alaskan systems will be installed at such locations both to save the cost of transporting fuel and to minimize thermal pollution in urban areas.

The Anchorage-Cook Inlet Area is expected to have natural gas available for fuel at approximately 75¢ per million Btu, provided that federal regulation does not restrict use of gas as utility fuel. On this basis, the most economical method of thermal generation in this area in the early 1980s is expected to be combined cycle gas turbine base loading with open cycle peaking. The cost of generation produced by new plants of this type in the early 1980s is expected to be 15.9 mills per kilowatt-hour, as shown in Table IX-2.

In the Fairbanks Area, it is considered possible that the El Paso transmission line will make natural gas available at approximately $1.00 per million Btu. Alternatively a spur from the Alaska-Arctic Gas Co. line also could make gas available in Fairbanks, although probably at higher cost. Provided that gas is available at $1.00 per million Btu, gas turbine capacity similar to that used in the Anchorage-Cook Inlet Area may be used in Fairbanks in the early 1980s with a resulting power cost of approximately 18.6 mills per kilowatt-hour. If gas is not available in Fairbanks, a combination of coal-fired steam base loading and oil-fired open cycle gas turbine peaking probably will be most economical, at a cost of 21.0 mills per kilowatt-hour. The Fairbanks Area is expected to experience a smaller percentage increase in costs than Anchorage because of sharp declines in costs of system overhead and reserves as its relatively small base expands.

3. Comparison of Susitna I and Devil Canyon Project Costs

Estimated cost of Susitna I has been compared with that of the Devil Canyon project based on data presented in the Alaska Power Administration, "Devil Canyon Status Report," May 1974. For

TABLE IX-4

COST OF GAS TURBINE POWER
EARLY 1980s
Combined Cycle: 50-75 thousand kw

	Gas-Fired	Residual Oil-Fired
	(Costs escalated to 1981 @ 6-1/2%)	
Capital Cost, $/kw Continuous[1]		
Gas Turbine Unit 70% @ 180	124	
Steam Turbine Unit 30% @ 470	141	
Average Cost/Base kw	265	
Allowance for Peaking Capacity, gas turbine only @ 61.8% lf: 180 x .6	108	
Subtotal	372	409[2]
Allowance for Transmission	150	150
Total	522	559
Annual Capital Charges, $/kw/hr		
6% - 20 years = .0872	45.52	48.74
Cost to Power, mills/kwh @ 8,760 kwh/yr	5.2	5.6
Operation, Maintenance and Administrative Costs, Fixed and Variable	2.5	2.5
Fuel Cost		
Gas @ 75¢/million Btu x 10,900 Btu/kwh[3]	8.2	-
Residual Oil @ $1.20/million Btu x 10,900 Btu/kwh	-	13.1
TOTAL, mills/kwh	15.9[4]	21.2
Gas @ $1/million Btu	18.6[5]	-

[1]Based on 1974 costs as follows: gas turbine $125/kw, waste heat boiler and steam turbine $350/kw; transmission $115,000/mi., including substations.

[2]Residual oil-fired gas turbine plant estimated approximately 10% higher than gas fired.

[3]Assumes combined cycle base loading at 10,000 Btu/kwh, with open cycle peaking at 14,500 Btu/kwh.

[4]Probable least cost in Anchorage-Cook Inlet Area.

[5]Probable least cost in Fairbanks, assuming availability of natural gas.

TABLE IX-5

COST OF COAL-FIRED STEAM POWER WITH GAS TURBINE PEAKING EARLY 1980s

(Costs escalated to 1981 @ 6-1/2%)

Capital Cost, $/kw Continuous[1]	
Steam Plant	600
Gas Turbine Plant 180 x .6	108
Subtotal	708
Allowance for Transmission	150
Total	858
Annual Capital Charges, $/kw/yr	
6% - 20 years = .0872	74.82
Cost to Power, mills/kwh @ 8,760 kwh/yr	8.5
Operating, Maintenance and Administrative Costs, Fixed and Variable	3.5
Fuel Cost	
Coal @ 80% x 25¢/million Btu x 9,000 Btu/kwh	1.8
Gas @ 20% x $1.00/million Btu x 14,500 Btu/kwh	2.9
TOTAL, mills/kwh	16.7
Coal @ 50¢/million Btu	18.5
Coal @ 75¢/million Btu	20.3
Alternate Oil-Fired Peaking	
Capital Cost Adjustment	
Gas Turbine Plant 108 x .1 x .0872 ÷ 8,760	.1
Fuel Cost	
Residual Oil @ 20% x 1.20/million Btu x 14,500 Btu/kwh	3.5
TOTAL, mills/kwh	17.4
Coal @ 50¢/million Btu	19.2
Coal @ 75¢/million Btu	21.0[2]

[1]Based on 1974 costs as follows: coal-fired steam plant $450/kw; gas turbine $125/kwh; transmission $115,000/mi., including substations.
[2]Probable least cost in Fairbanks if natural gas is not available.

LOCATION SUSITNA RIVER DAMSITE B

___1/4, ___1/4, Sec.___T___R___, ___B&M

RUNOFF OF Susitna River Basin

APPENDIX TABLE 6 (Cont)

STREAM FLOW SUMMARY

ACTIVITY

SOURCE OF RECORD Generated: $\frac{Q_{GC} \times 0.931}{1,000}$

UNIT acre-feet AREA 5760 Sq Miles

SEASON	OCT.	NOV.	DEC.	JAN.	FEB.	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	TOTAL
1970	178.85	67.31	49.59	47.18	39.71	44.41	59.84	651.51	1032.48	1296.88	1143.27	505.35	5116.38
1971	302.67	188.71	131.09	82.54	53.55	54.38	59.92	214.41	1824.76	1371.36	1826.62	800.10	6910.11
1972	334.69	171.40	143.65	128.20	108.56	104.37	94.78	1253.13	1907.62	1303.40	1104.17	687.17	7341.14
Average	330.49	139.29	102.88	84.10	63.84	62.47	74.78	768.58	1574.76	1391.60	1278.95	767.41	6639.00
% Annual	5.0	2.1	1.5	1.3	1.0	0.9	1.1	11.6	23.7	21.0	19.3	11.5	100%

LOCATION SUSITNA RIVER DAMSITE B

____1/4, ____1/4, Sec. ____ T ____ R ____, ____ B&M

RUNOFF OF Susitna River Basin

APPENDIX TABLE 6

STREAM FLOW SUMMARY

ACTIVITY ____

SOURCE OF RECORD Generated: Q_{GC} x 0.931

UNIT 1,000 acre-feet AREA 5760 Sq Miles

SEASON	OCT.	NOV.	DEC.	JAN.	FEB.	MAR	APR.	MAY	JUNE	JULY	AUG	SEPT.	TOTAL
1950	362.62	143.10	82.36	58.81	40.72	41.57	48.20	658.96	1085.55	1294.09	1137.68	459.91	5413.57
1951	220.28	72.02	62.97	54.96	42.40	42.36	89.56	806.53	1151.65	1292.23	1126.51	1176.78	6138.25
1952	318.87	152.03	108.74	91.59	53.55	50.38	50.96	310.21	1793.11	1510.08	1197.27	802.15	6438.94
1953	469.50	193.74	97.29	62.97	42.40	46.94	89.47	1103.23	1513.81	1156.30	1179.58	846.09	6801.32
1954	320.73	116.38	85.87	74.42	51.71	44.65	68.42	989.65	1398.36	1165.61	1494.25	715.47	6525.52
1955	307.42	152.87	117.12	102.69	72.39	62.97	66.47	533.46	1654.39	1577.11	1473.77	791.54	6912.20
1956	283.40	105.30	74.42	56.10	51.95	53.81	52.63	1011.07	1847.10	1780.07	1403.95	1015.72	7735.52
1957	332.37	168.98	122.61	97.29	77.56	68.70	66.47	787.44	1671.14	1334.12	1175.85	1096.72	6999.25
1958	470.06	219.06	186.85	112.47	67.59	65.74	84.94	738.19	1423.50	1309.92	1290.37	418.30	6386.99
1959	275.39	119.08	86.60	82.92	67.59	56.10	69.25	915.17	1292.23	1430.95	1784.73	937.52	7117.53
1960	375.38	157.90	125.96	105.67	77.74	68.51	72.02	903.35	860.52	1315.50	1350.88	1135.82	6549.25
1961	446.14	166.18	154.17	140.30	90.67	103.62	146.82	994.31	1632.04	1406.74	1265.23	740.89	7287.11
1962	338.70	149.61	120.19	108.74	77.56	80.14	94.22	720.69	2397.32	1480.29	1348.09	880.26	7795.81
1963	384.88	155.11	114.51	91.59	77.56	57.25	45.98	1089.27	1440.26	1969.06	1355.54	682.42	7463.43
1964	369.14	124.66	85.49	60.01	51.75	40.82	41.27	246.53	2802.31	1313.64	941.24	530.20	6607.06
1965	360.11	155.11	69.30	54.96	44.47	51.52	75.35	743.40	1424.43	1593.87	1208.44	1071.58	6852.54
1966	412.43	115.91	93.38	80.14	67.22	74.42	98.31	552.18	1825.69	1136.75	1249.40	651.14	6356.97
1967	238.34	88.64	85.87	85.87	72.39	68.70	64.63	886.22	1634.84	1534.29	1867.59	934.72	7562.10
1968	280.51	130.34	117.59	113.40	101.76	108.74	105.86	926.07	1747.49	1512.87	983.14	488.40	6616.17
1969	218.79	90.30	50.51	41.46	37.40	46.72	83.65	632.34	858.85	921.78	508.33	282.19	3772.32

LOCATION SUSITNA RIVER, CANTWELL

____1/4, ____1/4, Sec. ____T____R____, ____B&M

ACTIVITY ____

SOURCE OF RECORD USGS

RUNOFF OF SUSITNA RIVER BASIN

UNIT 1,000 acre-feet AREA 4140 Sq Miles

APPENDIX TABLE 5

STREAM FLOW SUMMARY

SEASON	OCT.	NOV.	DEC.	JAN.	FEB.	MAR	APR	MAY	JUNE	JULY	AUG	SEPT.	TOTAL
1962	226.60	119.00	98.38	86.08	61.09	61.49	77.36	611.90	1822.00	1433.00	1105.00	626.60	6328.00
1963	266.00	130.90	86.08	61.49	47.21	46.73	42.84	697.20	892.60	1401.00	1118.00	546.60	5337.00
1964	236.60	77.36	53.95	39.59	33.70	26.38	27.67	172.60	2060.00	1048.00	707.50	318.50	4802.00
1965	192.70	113.70	56.65	46.73	37.77	43.62	65.26	542.20	977.90	1128.00	826.40	768.10	4799.00
1966	191.60	59.50	46.12	43.04	36.10	39.97	52.07	269.80	1101.00	751.10	779.50	388.10	3757.70
1967	142.80	46.41	44.27	41.81	35.54	34.43	30.55	581.20	1168.00	1038.00	1180.00	611.50	4954.00
1968	189.60	88.66	81.92	75.77	69.02	73.79	72.79	569.90	1160.00	1075.00	672.40	321.90	4451.00
1969	148.00	63.27	37.98	31.24	26.94	33.70	59.40	459.40	733.50	830.60	405.70	200.90	3031.00
1970	100.70	48.50	33.40	26.86	23.64	28.48	52.76	466.10	589.70	854.70	757.80	310.10	3293.00
1971	132.50	91.04	64.46	44.93	27.95	28.88	31.46	117.70	1307.00	1115.00	1396.00	583.10	4940.00
1972	249.50	122.00	84.30	65.65	53.04	54.15	52.11	596.00	1190.00	1026.00	960.60	560.70	5014.00
Average	188.78	87.30	62.50	51.20	41.09	42.88	51.30	462.18	1181.97	1063.67	900.81	476.01	4609.70
% Annual	4.1	1.9	1.4	1.1	0.9	0.9	1.1	10.0	25.6	23.1	19.6	10.3	100%

LOCATION SUSITNA RIVER, GOLD CREEK

___1/4, ___1/4, Sec.___T___R___, ___B&M

RUNOFF OF SUSITNA RIVER BASIN

APPENDIX TABLE 4 (Cont)

STREAM FLOW SUMMARY

ACTIVITY

SOURCE OF RECORD USGS

UNIT 1,000 acre-feet AREA 6160 Sq Miles

SEASON	OCT.	NOV.	DEC.	JAN.	FEB.	MAR	APR.	MAY	JUNE	JULY	AUG	SEPT.	TOTAL
1970	192.10	72.30	53.26	50.68	42.65	47.70	64.27	699.80	1109.00	1393.00	1228.00	542.80	5496.00
1971	325.10	202.70	140.80	88.66	57.52	58.41	64.36	230.30	1960.00	1473.00	1962.00	829.40	7421.00
1972	359.50	184.10	154.30	137.70	116.60	112.10	101.80	1346.00	2049.00	1400.00	1186.00	738.10	7885.00
Average 1950-59	360.97	154.95	110.08	85.31	60.99	57.27	73.73	843.60	1593.00	1487.70	1424.70	887.18	7139.50
% Annual 1950-59	5.1	2.2	1.5	1.2	0.9	0.8	1.0	11.8	22.3	20.8	20.0	12.4	100%
Average 1960-72	350.38	145.52	110.82	94.20	74.39	74.66	86.15	810.82	1767.22	1500.16	1334.54	775.86	7125.00
% Annual 1960-72	4.9	2.0	1.6	1.3	1.0	1.1	1.2	11.4	24.8	21.1	18.7	10.9	100%
Average 1962-72	333.86	140.33	103.62	87.31	71.47	71.43	80.44	772.95	1845.14	1507.10	1321.73	733.67	7069.00
% Annual 1962-72	4.7	2.0	1.5	1.2	1.0	1.0	1.2	10.9	26.1	21.3	18.7	10.4	100%
Average 1950-72	354.98	149.62	110.50	90.33	68.56	67.10	80.75	825.07	1691.47	1494.74	1373.74	824.29	7131.00
% Annual 1950-72	5.0	2.1	1.5	1.3	1.0	0.9	1.1	11.6	23.7	21.0	19.3	11.5	100%

LOCATION SUSITNA RIVER, GOLD CREEK

____1/4, ____1/4, Sec. ____ T____ R____, ____ B&M

RUNOFF OF Susitna River Basin

APPENDIX TABLE 4

STREAM FLOW SUMMARY

ACTIVITY ____

SOURCE OF RECORD USGS

UNIT 1,000 acre-feet AREA 6160 Sq Miles

SEASON	OCT.	NOV.	DEC.	JAN.	FEB.	MAR.	APR.	MAY	JUNE	JULY	AUG.	SEPT.	TOTAL
1950	389.50	153.70	88.46	63.17	43.74	44.65	51.77	707.80	1166.00	1390.00	1222.00	494.00	5815.00
1951	236.60	77.36	67.64	59.03	45.54	45.50	96.20	866.30	1237.00	1388.00	1210.00	1264.00	6593.00
1952	342.50	163.30	116.80	98.38	57.52	54.11	54.74	333.20	1926.00	1622.00	1286.00	861.60	6917.00
1953	504.30	208.10	104.50	67.64	45.54	50.42	96.10	1185.00	1626.00	1242.00	1267.00	908.80	7305.00
1954	344.50	125.00	92.23	79.93	55.54	47.96	73.49	1063.00	1502.00	1252.00	1605.00	768.50	7009.00
1955	330.20	164.20	125.80	110.30	77.75	67.64	71.40	573.00	1777.00	1694.00	1583.00	850.20	7424.00
1956	304.40	113.10	79.93	60.26	55.80	57.80	56.53	1086.00	1984.00	1912.00	1508.00	1091.00	8309.00
1957	357.00	181.50	131.70	104.50	83.31	73.79	71.40	845.80	1795.00	1433.00	1263.00	1178.00	7518.00
1958	504.90	235.30	200.70	120.80	72.60	70.61	91.24	792.90	1529.00	1407.00	1386.00	449.30	6860.00
1959	295.80	127.90	93.02	89.06	72.60	60.26	74.38	983.00	1388.00	1537.00	1917.00	1007.00	7645.00
1960	403.20	169.60	135.30	113.50	83.50	73.59	77.36	970.30	924.30	1413.00	1451.00	1220.00	7035.00
1961	479.20	178.50	165.60	150.70	97.39	111.30	157.70	1068.00	1753.00	1511.00	1359.00	795.80	7827.00
1962	363.80	160.70	129.10	116.80	83.31	86.08	101.20	774.10	2575.00	1590.00	1448.00	945.50	8374.00
1963	413.40	166.60	123.00	98.38	83.31	61.49	49.39	1170.00	1547.00	2115.00	1456.00	733.00	8017.00
1964	396.50	133.90	91.83	64.46	55.58	43.85	44.33	264.80	3010.00	1411.00	1011.00	569.50	7097.00
1965	386.80	166.60	74.44	59.03	47.76	55.34	80.93	798.50	1530.00	1712.00	1298.00	1151.00	7362.00
1966	443.00	124.50	100.30	86.08	72.20	79.93	105.60	593.10	1961.00	1221.00	1342.00	699.40	6829.00
1967	256.00	95.21	92.23	92.23	77.75	73.79	69.42	951.90	1756.00	1648.00	2006.00	1004.00	8122.00
1968	301.30	140.00	126.30	121.80	109.30	116.80	113.70	994.70	1877.00	1625.00	1056.00	524.60	7106.00
1969	235.00	96.99	54.25	44.53	40.17	50.18	89.85	679.20	922.50	990.10	546.00	303.10	4052.00

this purpose, Devil Canyon cost data based on January 1974 prices have been escalated by 6% to a level comparable with the June 1974 estimating base used for Susitna I. The value of interest during construction has also been adjusted to represent the differing interest rates used under each set of criteria. As shown in Table IX-6, Susitna I project costs in mills per kilowatt-hour of energy sold equal 75.4% of the comparable costs for Devil Canyon.

TABLE IX-6

COMPARISON OF PROJECT COSTS
SUSITNA I V. DEVIL CANYON

	Federal Criteria[1]				Kaiser Criteria[2]	
	Susitna 1		Devil Canyon			
	Economic	Financial	Economic	Financial	Susitna 1	Devil Canyon
	thousands of dollars ($000), except as noted					
Total Capital Investment	649,300	633,300	742,000	722,900	638,100	729,000
Annual Capital Charges						
Rate	.0689	.0601	.0689	.0601	.0726	.0726
Amount	44,737	38,061	51,123	43,446	46,326	52,925
Annual Operating Costs						
Rate	.0015	.0015	.0015	.0015	.0029[3]	.0029
Amount	974	950	1,113	1,084	1,846	2,114
Total Annual Costs	45,711	39,011	52,236	44,530	48,172	55,039
Energy Sales, kwh (millions)	3,330	3,330	2,866	2,866	3,330	2,866
Cost in Mills/kwh	13.75	11.72	18.23	15.54	14.47	19.20
Susitna 1 % Devil Canyon	75.4	75.4			75.4	

[1]Federal criteria specify the following interest and amortization criteria:
Economic analysis, interest 6.875%, amortization 100 years.
Financial analysis, interest 5.625%, amortization 50 years.
[2]Kaiser criteria are interest 6%, amortization 30 years.
[3]Includes allowances for sinking fund and cash surplus.

X. ENERGY-INTENSIVE INDUSTRIES

Prior to the preparation of this report, it was believed that the addition of a large industrial energy user to the Anchorage-Cook Inlet or Fairbanks Areas would be necessary if Susitna I were to be developed on the largest and correspondingly most economical initial scale.

Accordingly, the Henry J. Kaiser Company obtained expressions of interest in purchasing Alaskan hydropower from Kaiser Aluminum & Chemical Corporation and other primary aluminum manufacturers. These firms were interested in obtaining approximately 300,000 continuous ~~kilowatts of power;~~ approximately 2,600 million kilowatt-hours per year, at an average cost of less than 10 mills per kilowatt-hour. If such a power source were made available in Alaska, it is probable that an aluminum reduction plant could be located in the state.

As this report materialized, three main factors became clear. First, it was evident that reasonable and conservative forecasts of utility load growth in the Anchorage-Cook Inlet and Fairbanks Areas would be substantially higher than previously anticipated. Second, the optimum or most economical capacity of Susitna I was determined to be 385,000 continuous kilowatts, instead of 450-500,000 as originally considered probable. Third, due to the substantial and probably non-recurring inflation of the first half of 1974, the cost base for Susitna I escalated to an unexpected high level.

As a result, it has been concluded that utility demand in the Anchorage-Cook Inlet and Fairbanks Areas is capable of providing a sufficient revenue base for Susitna I and that moreover, the full capacity of Susitna I can be utilized within five years of normal utility load growth. The estimated cost of Susitna I power is estimated to be less that that of alternative methods of utility generation in the early 1980's; however, it is higher than the ceiling which an aluminum manufacturer would consider at the present time.

XI. ENVIRONMENTAL CONSIDERATIONS

A. INTRODUCTION

The environmental impact of land inundation in the upper Susitna River Basin has been evaluated by a number of governmental agencies; namely, the Fish and Wildlife Service, the Bureau of Mines, the Bureau of Land Management in respect of forestry resources, and National Park Service, and the Corps of Engineers. Various of these reports are contained in the Devil Canyon report of 1960 and a further listing of reports and additional comments are made in the Devil Canyon Status Report of May 1974.

While some recommendations have been made in connection with further studies, it has been generally concluded that the reservoirs created by the construction of dams at Denali and Devil Canyon would have relatively small impact on the environment considering the size of the project. It has been recommended that the future Vee reservoir should not be any higher than conceived in the overall development plan lest it affect the sport fishing resource in the Tyone Basin.

B. CANYON SECTION OF THE RIVER

None of the available reports raise any serious questions on the environmental impact of lands to be flooded within the confines of the canyon stretch of the river which extends approximately to the mouth of the Oshetna River. The steep canyon walls encountered in much of this stretch of the river are not conducive to significant wildlife habitation and the loss of wildlife habitat in the canyon would be expected to be small. There is no evidence of anadromous fish in the canyon, due presumably to high water velocities, and at present sport fishing is virtually nonexistent. Improved accessibility with roads and reservoirs will result in increased hunting and fishing, but both will be mitigated to some extent by the fluctuation of reservoir levels. While reservoirs in the canyon will flood some forest lands, these areas are generally inaccessible without project development. There are no known mineral resources within the canyon section of the river.

C. DENALI AND VEE

The Denali reservoir, as projected in the Devil Canyon Status Report of 1974, would inundate an area of 54,000 acres and Vee, with a reservoir elevation of 2,355 feet would inundate an area of 17,000 acres. Inundation of these areas is not expected to adversely affect fishing.

The most significant impact of inundation of these areas would be the destruction of the moose habitat, largely in the Denali area, and the loss of rangelands for caribou. It is anticipated that the moose population of flooded areas must be relocated, as it is considered unlikely that the surrounding area can support the displaced animals. The loss of caribou rangeland is not considered significant; inundation of the land would not seriously affect movement of caribou to other areas. The effect of inundation on the habitat of certain other wildlife requires more investigation; however, waterfowl would appear to be little affected. Of the two areas, Denali and Vee, the most extreme impacts of inundation are at Denali, the necessity of which is largely eliminated by the alternate development scheme presented herein. Improved accessibility would increase game take in both areas. Mineral and forest resources in the area have not been fully evaluated, although it would appear that the loss of marketable timber through inundation would not be significant.

D. THE TRANSMISSION SYSTEMS

The most significant impact of the transmission system would be the appearance of towers and lines which would intrude on the natural scene. Wildlife would be little affected. However, detailed line routing studies will have to be made to minimize the impact of the transmission systems on both natural scenic beauty and wildlife.

E. SUMMARY

It is apparent that inundation of the canyon section of the river would have little effect upon the environment. The inundation of areas upstream of Vee and Denali would have greater but still moderate impacts. Any development which includes Denali will have to justify increased environmental impacts over development restricted to the canyon section, and development which can economically exclude Denali would be preferable.

The Kaiser concept of initial development of the hydroelectric potential of the upper Susitna River, first-stage project, designated as Susitna I, proposes a project which limits the inundation of land to about 24,000 acres in the canyon section of the river. By eliminating the Denali dam and reservoir, which alone would inundate 54,000 acres (61,550 acres with Devil Canyon), the impact upon the environment for first-stage development of the river resource is considerably reduced. The depth and cost of further detailed environmental studies for initial development would be reduced; approval for implementation of the project with due consideration for environmental impact would be more easily attained.

Development of the river upstream of Susitna I would provide for a reservoir inundating approximately the same area as would the Vee Canyon project proposed by the U.S.B.R. As noted, the impact on the environment by the Vee project reservoir would appear to be considerably less than the impact created by the Denali reservoir. While detailed studies would be required for the lands to be inundated by the reservoir in or near Vee Canyon, the overall impact of the Kaiser concept would be reduced to the extent that Denali reservoir is eliminated.

To accurately assess environmental impacts from development of the hydroelectric potential of the upper Susitna River, it will be necessary not only to review all presently available data, but also to complete such studies as may significantly influence final impact evaluations. Such studies would include benefits to recreation and assessment of impact on the environment of alternative means of generating electric power.

Full and open evaluation of the environmental impact of Susitna River development must be made in the earliest stages of project planning so that once committed, hydroelectric development can proceed without delay due to environmental problems.

XII. FUTURE DEVELOPMENT

A. INTRODUCTION

The Susitna I hydroelectric project recommended by the Henry J. Kaiser Company as the initial step in development of the upper Susitna River also allows for two future projects which may be designed to utilize the river's full hydroelectric potential. These projects are located both downstream and upstream of Susitna I, as outlined in this section.

B. DOWNSTREAM DEVELOPMENT: SUSITNA II

The degree of river regulation resulting from Susitna I would facilitate the economical construction of a run-of-the-river hydroelectric plant downstream. Approximately 110 feet of head could be developed by the construction of a low dam at the Devil Canyon site. Downstream of Portage Creek, three miles below Devil Canyon, approximately 155 feet of head can be developed, and the inflow from Portage Creek can be captured, adding approximately 4% to total runoff.

Either the Devil Canyon or Portage Creek site is technically suitable for hydroelectric project construction. The Portage Creek site would require a longer dam than the Devil Canyon site, but it enables construction of a more economical surface powerhouse and an easier overall construction program than would be possible within the narrow confines of Devil Canyon. The Portage Creek site is well suited for a rockfill dam, and the native greywacke would be an excellent construction material.

Construction of Susitna II would be simplified by the river control afforded by Susitna I, the primary site access road would have been built for Susitna I, and the project's power output could be carried by the Susitna I transmission system. If constructed on the Portage Creek site, Susitna II could generate an estimated 785 million kilowatt-hours of energy, and would have an installed capacity of 163,000 kilowatts, at a 55% plant factor. It is estimated that Susitna II would cost on the order of $500 to $600 per installed kilowatt, two-thirds or less the cost of Susitna I, including transmission. Additional studies are required to determine the general characteristics of Susitna II and its impact on overall system operation and cost of power.

C. UPSTREAM DEVELOPMENT: SUSITNA III

Susitna III could be located near the upstream end of the reservoir formed by Susitna I, in the canyon section between the Watana and Vee sites proposed by U. S. B. R. Detailed studies would be required to finalize location of Susitna III and to establish its most economical project size.

In concept, Susitna III would impound a reservoir somewhat larger than that visualized at Vee by U. S. B. R.; however, its maximum normal reservoir elevation would be 2, 355 feet, the same level indicated for the Vee project. The Susitna III dam would be approximately 600 feet high over the riverbed.

Assuming that the Susitna III would be operated in the same manner proposed for Susitna I, but as an independent facility, its installed capacity would be about 380, 000 kilowatts on an annual plant factor of 55%. Under these conditions, the annual energy output of Susitna III would be approximately 1, 840 million kilowatt-hours. However, preliminary study indicates that river regulation provided by Susitna III would increase the annual energy generated by Susitna I approximately 9%, from 3, 372 million kilowatt-hours to 3, 679 million kilowatt-hours; therefore the combined annual generation of Susitna I and Susitna III would total 5, 519 million kilowatt-hours.

It is expected that in practice, operation of the Susitna I and Susitna III reservoirs and power plants would be integrated for greater efficiency. Under such an integrated operation, with an overall annual load factor of 55%, the total installed capacity of the two sites would be 1, 145, 000 kilowatts. With 700, 000 kilowatts installed at Susitna I, the installed capacity at Susitna III would be 445, 000 kilowatts, and the annual plant factor at Susitna III would be 47. 2%. Further detailed studies would be necessary to determine the most efficient means of integrated operation, as well as the optimum installed capacity for Susitna III.

D. THE ULTIMATE DEVELOPMENT

Ultimate development of the three projects, Susitna I, II, and III, would provide total installed capacity of about 1, 308, 000 kilowatts, with annual energy generation of about 6, 309 million kilowatt-hours. Fully integrated operation of the three facilities could result in a still higher total capability; however, this requires further detailed study.

E. COMPARISON WITH THE U.S.B.R. SCHEME

The U.S.B.R. scheme for ultimate development of the upper Susitna River includes dams at Devil Canyon, Watana, Vee, and Denali, with power plants at the first three sites. Installed capacity under this scheme would be 1,372,000 kilowatts, and annual energy generation would be 7,000 million kilowatt-hours.

Both the U.S.B.R. scheme and Kaiser's alternate concept would require detailed study to justify subsequent stages of development and to establish the economic size of future projects. It is considered, however, that the Susitna I, II, and III projects, as proposed by Kaiser, are potentially more economical than the major projects at Devil Canyon, Watana, Vee, and Denali sites proposed by U.S.B.R.

The total installed capacity outlined by U.S.B.R. is approximately 5% greater than projected by Kaiser, while annual energy generation indicated by U.S.B.R. is 11% greater than Kaiser's. This is because the ultimate development outlined by Kaiser excludes Denali dam and reservoir for economic and environmental reasons.

If Denali were added to Kaiser's alternate concept, a relatively small dam and reservoir on that site could provide a sufficient increase in river regulation to raise the combined outputs of Susitna I, II, and III to equal the capability of the U.S.B.R. scheme. Alternatively, due to the storage provided by Susitna I, Kaiser's concept would allow the Denali project to be designed to release its stored water on a year-round basis, and a power plant could be installed at Denali, further increasing total energy generated by the alternate system. This is not possible under the U.S.B.R. scheme, in which the Denali reservoir provides most storage for the system as a whole; because of this, it must in most years be fully drawn down in an eight-month annual period of operation, and would not furnish sufficient average head to justify a power plant.

Although Kaiser's alternate concept tentatively excludes Denali, it would still be possible to develop this project following Susitna I, II, and III, pending more favorable conclusions on its technical and economic feasibility, and especially its environmental impacts.

APPENDIX TABLE 1

RECORDS AND FORECASTS OF ANCHORAGE-COOK INLET AND FAIRBANKS AREA UTILITIES 1968-1990

Year	CEA, HEA, MEA		AML&P		Total		GVEA		FMUS		Total	
	Net Energy (million kwh)	Peak Load (thousand kw)	Net Energy (million kwh)	Peak Load[1] (thousand kw)	Net Energy (million kwh)	Peak Load (thousand kw)	Net Energy (million kwh)	Peak Load (thousand kw)	Net Energy (million kwh)	Peak Load (thousand kw)	Net Energy (million kwh)	Peak Load (thousand kw)
1968	-	-	-	43	-	-	-	-	-	-	-	-
1969	-	-	-	48	-	-	-	-	-	-	-	-
1970	-	-	-	56	-	-	-	-	-	-	-	-
1971	-	-	-	64	-	-	-	-	-	-	-	-
1972	674.0	152.0	-	68	-	220	-	-	-	-	-	-
1973	789.7	175.1	-	73	-	248	221	49.4	95	20.3	316	69.7
1974	925.3	201.8	425	81	1,350	283	258	57.1	103	21.9	361	79.0
1975	1,084.1	232.4	455	91	1,539	323	302	66.2	110	23.7	412	89.9
1976	1,270.4	267.9	495	101	1,765	369	352	76.6	119	25.5	471	102.1
1977	1,488.6	308.8	545	113	2,034	422	412	88.7	128	27.6	540	116.3
1978	1,662.0	344.8	600	125	2,262	470	476	100.5	138	29.8	614	130.3
1979	1,865.5	385.0	655	138	2,521	523	527	111.8	149	32.1	676	143.9
1980	2,073.4	429.0	725	-	2,798	-	583	124.3	160	34.6	743	158.9
1981	2,316.3	479.9	800	-	3,116	-	646	138.2	173	37.2	819	175.4
1982	2,587.7	536.0	875	-	3,463	-	714	153.7	187	40.0	901	193.7
1983	-	-	965	-	-	-	793	170.9	199	43.1	992	214.0
1984	-	-	1,050	-	-	-	877	190.1	216	46.4	1,093	236.5
1985	-	-	1,175	-	-	-	970	211.4	233	49.9	1,203	261.3
1986	-	-	-	-	-	-	1,076	235.1	249	53.8	1,325	288.9
1987	-	-	-	-	-	-	1,192	261.4	267	57.8	1,459	319.2
1988	-	-	-	-	-	-	-	-	-	-	-	-
1989	-	-	-	-	-	-	-	-	-	-	-	-
1990	-	-	-	-	-	-	-	-	-	-	-	-

[1] Adjusted from fiscal to calendar years

Source: Chugach Electric Assn., Inc. (CEA), includes Homer Electric Assn., Inc. (HEA), and Matanuska Electric Assn., Inc. (MEA), Anchorage Municipal Light & Power Dept. (AML&P), Golden Valley Electric Assn., Inc. (GVEA), Fairbanks Municipal Utilities System (FMUS).

APPENDIX TABLE 2

ALASKA POWER ADMINISTRATION
"UTILITY LOAD ESTIMATE EXTENDED TO 1990"

	Generation 1972		Projected Requirements 1980		1990	
Location and Utility Symbol	Peak Demand (thousand kw)	Annual Generation (million kwh)	Peak Demand (thousand kw)	Annual Generation (million kwh)	Peak Demand (thousand kw)	Annual Generation (million kwh)
Southcentral[1]						
City of Anchorage (AML&P)	71.9	310.1	123.0	658.0	314.0	1,680.0
Chugach (CEA)	123.5	600.0	360.0	1,800.0	1,065.0	5,370.0
Include:						
Homer (HEA)	(16.5)	(85.1)	(36.5)	(190.0)	(90.0)	(490.0)
Kenai (HEA)	(4.7)	(22.1)	(7.9)	(37.6)	(14.9)	(71.1)
Seldovia-Port Graham (HEA)	(0.8)	(3.4)	(1.6)	(6.8)	(3.5)	(16.1)
Seward (SL&P)	Not Available		(5.2)	(27.9)	(8.0)	(45.0)
Tyonek	Not Available		(2.1)	(8.7)	(3.0)	(12.3)
Palmer-Talkeetna (MEA)	15.9	73.9	54.0	225.0	181.0	850.0
Subtotal, Anchorage-Cook Inlet Area	211.3	984.0	537.0	2,683.0	1,560.0	7,900.0
Cordova (CPU)[2]	1.3	5.8	2.3	10.1	4.6	20.2
Glennallen	1.2	5.4	3.2	14.0	5.2	22.8
Kodiak and Port Lions (Kd EA)	7.6	33.4	13.4	61.9	22.1	102.9
Old Harbor (AVEC)[2]	0.2	0.8	0.3	1.2	0.4	1.6
Valdez	1.5	6.4	4.2	18.3	6.9	30.0
Other Communities	0.5	1.2	0.7	1.8	1.1	2.9
Total, Southcentral Region	223.6	1,037.0	561.1	2,790.3	1,600.3	8,080.4
Interior[1]						
Fairbanks Area						
City of Fairbanks (FMU)	21.0	90.0	51.8	221.0	161.1	687.3
Golden Valley (GVEA)	45.9	211.0	131.0	610.0	379.0	1,790.0
Subtotal, Fairbanks Area	66.9	301.0	182.8	831.0	540.1	2,477.3
Fort Yukon (FYU)	0.4	0.7	0.7	1.8	1.2	2.9
Tok (AP&T)	0.8	2.9	1.2	4.3	2.0	7.0
Other Communities	1.2	2.1	2.1	5.4	3.6	8.7
Total, Interior Region	69.3	306.7	186.8	842.5	546.9	2,495.9

[1]Utility estimates from REA power requirements studies, and consultant's studies, generally through 1982, and extended to 1990 by APA at same growth rate.
[2]APA estimate based on 1972 generation and various growth assumptions.

Source: Alaska Power Administration, Alaska Power Survey, 1974.

APPENDIX TABLE 3

ALASKA POWER ADMINISTRATION
"STATEWIDE AND REGIONAL UTILITY LOAD ESTIMATES, 1972-2000"

Region	Actual Requirements 1972		Estimated Future Requirements 1980		1990		2000	
	Peak Demand (thousand kw)	Annual Energy (million kwh)	Peak Demand (thousand kw)	Annual Energy (million kwh)	Peak Demand (thousand kw)	Annual Energy (million kwh)	Peak Demand (thousand kw)	Annual Energy (million kwh)
			Higher Rate of Growth					
Southeast	52	229	140	600	310	1,360	640	2,820
Southcentral	224	1,037	680	2,990	1,640	7,190	3,590	15,740
Interior	69	307	200	870	460	2,020	970	4,230
Southwest, Northwest, Arctic, Combined	10	47	30	140	80	330	160	710
Total	355	1,620	1,050	4,600	2,490	10,900	5,360	23,500
			Likely Mid-Range Rate of Growth					
Southeast			120	530	230	1,010	400	1,740
Southcentral			610	2,670	1,220	5,350	2,220	9,710
Interior			180	780	340	1,500	600	2,610
Southwest, Northwest, Arctic, Combined			30	120	60	240	100	440
Total			940	4,100	1,850	8,100	3,320	14,500
			Lower Rate of Growth					
Southeast			110	470	180	810	260	1,150
Southcentral			530	2,340	980	4,290	1,470	6,430
Interior			160	680	270	1,200	390	1,730
Southwest, Northwest, Arctic, Combined			30	110	50	200	70	290
Total			830	3,600	1,480	6,500	2,190	9,600
			12% Growth Assumption					
Statewide Total				4,020		12,450		38,800

[1] Estimated future peak demand based on 50% annual load factor.

Source: Alaska Power Administration, Alaska Power Survey, 1974.