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INTRODUCTION TO ELECTRIC POWER SUPPLY PLANNING

WITH SPECIAL ATTENTION TO ALASKA'S RAILBELT REGION AND THE PROPOSED SUSITNA RIVER HYDROELECTRIC PROJECT

Prepared for the Alaska State Legislature

May 9, 1980

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PREFACE

This report was prepared under contracts between the Power Alternatives Study Committee of the Alaska House of Representatives and Arlon R. Tussing and Associates, Inc. It combines summary papers on three issue areas the committee asked the consultants to address:

1. The history of the Susitna hydroelectric proposal; a description of the existing electric utilities in Alaska's Railbelt; and an explanation of how the Susitna project would fit into the existing system;

2. The major issues of electric power supply planning, with a special emphasis on the issues the legislature should examine if it is asked to authorize and fund the Susitna project; and

3. A review of Acres American, Inc.'s plan for its $30 million feasiblity study of the Susitna project, and recommendations (if any) for improving the study plan.

Chapter 1, "Overview of the Electric Power Industry," was written by Arlon R. Tussing (Anchorage and Seattle). Barbara F. Morse (Seattle) researched and wrote the appendices to chapter 1, "Existing Railbelt Utilities" and "Federal and State Agencies Having Jurisdiction over New Electrical Generating and Transmission Facilities in Alaska." Tussing and Lois S. Kramer (Juneau) wrote Chapter 2, "Planning for New Generating Capacity."

Chapter 3, "History of the Susitna Hydroelectric Project," was written by Morse, and Chapter 4, reviewing "The Acres Plan of Study" was written by Tussing and Kramer. Comments on the review draft of this report, by Eric P. Yould, executive director of the Alaska Power Authority, are appended to Chapter 4.

Connie C. Barlow (Juneau and Santa Fe) reviewed the entire report and made many substantive and editorial improvements; final editing was by Tussing, who accepts full responsibility for any errors or omissions.

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CHAPTER I: OVERVIEW OF THE ELECTRIC POWER INDUSTRY

Electric utilities.

Generation, transmission, distribution. The electric power business has three main branches: generation, transmission, and distribution. "Electric utilities" are first of all retail power distributors; as such they invariably own and operate local low-voltage lines, transformers, and switching facilities that deliver electricity to retail customers in their respective service areas.

Most utilites also own generating plants (fossil-fuel, hydro, nuclear, etc.), alone or jointly with other utilities, but some purchase their power at wholesale from other utilities, federal power projects, or other entities. Some utilities are wholly self-sufficient, but most of them buy some of the power they distribute, and/or sell some of the power they generate to other utilities.

Utilities may own the high-voltage transmission lines connecting the generating plants with their distribution systems, or they may depend on other utilities or governmental entities to "wheel" power for them.

Railbelt utilities. There are six electric utilities and one federal power project in Alaska's Railbelt. Anchorage-based Chugach Electric Association (CEA), the area's largest, is a net seller of power at wholesale. Fairbanks-centered Golden Valley Electric Association (GVEA), Anchorage Municipal Light and Power (AML&P), and the Fairbanks Municipal Utility System (FMUS) are nearly self-sufficient, while Matanuska Electric Association (MEA), the Seward Electric System (SES), and Homer Electric Association (HEA) are net buyers, mainly from CEA. The federal Alaska Power Administration operates the Eklutna hydroelectric project, and sells power to AML&P and MEA. [See the appendix to this chapter, "Existing Railbelt Utilities.]

Non-utility generation; cogeneration.

Institutions and industrial plants often produce their own electricity because they can generate it more cheaply than they could buy it from a utility, or because they need to supplement or backstop utility-supplied power. In some instances, utilities buy or exchange surplus electricity generated by non-utility power producers. In Alaska's Railbelt, the chief non-utility power producers are military installations, the University of Alaska at Fairbanks, and petroleum-related installations in Cook Inlet or on the Kenai peninsula.

Power generation that is incidental to, or a co-product of, other activities such as raising steam for space heating or industrial processes is called "cogeneration."

Interconnection and power pools.

Transmission lines owned by electric utilities and other entities are typically interconnected into regional power pools or grids that allow the utilities and non-utility power producers to lend, exchange, or sell power to one another. Interconnection helps ---

(1) to minimize joint costs, by allowing one utility to shut down a high-cost generating unit when another utility has surplus power available at lower cost;

(2) to level daily and seasonal load peaks: Where the loads of different utilities peak at different times times of the day or the year, interconnection can reduce their overall requirements for high-cost peak generation capacity; and

(3) to meet emergencies: Interconnection reduces each utility's individual need for reserve generating capacity).

In the Anchorage area, the generating capacity of CEA and AML&P are interconnected at the Eklutna substation, but these two utilities have yet not found it necessary or practical to manage their facilities jointly in order to minimize generating costs or to reduce the need for capacity. In the Fairbanks area, however, the intertie composed of GVEA, FMUS, the University of Alaska, and the two military bases, does actually function as a local power pool.

Utility customers: residential, commercial, and industrial.

For ratemaking and statistical purposes, electricity consumers are usually classified into at least three groups: residential, commercial, and industrial. Electric consumption by institutions and government is usually treated as part of the commercial sector, but is sometimes counted separately.

Residential consumers are individual households, including those apartment dwellers who are individually metered by the utility.

Commercial consumers include stores, office buildings, hotels, service establishments, and (usually) schools, hospitals, and other institutions, government buildings and street lights, and centrally-metered apartment houses.

Industrial consumers include manufacturing plants, resource extraction and processing facilities, and the like. Electric service to the industrial sector is either "firm" or "interruptible." The utility is obliged to provide service to its firm industrial customers to the limit of its capacity at all times, but in times of peak demand or equipment failure, it may shut off its interruptible customers, who pay lower rates, in order to assure reliable service to its residential, commercial and firm industrial customers.

Methods of organizing and financing electric power supply.

The chief forms of business organization in the electric power industry are private utilities, cooperatives, municipal utilities, and federal agencies.

Private utilities. Private or "investor-owned" electric utilities account for about three-fourths of the electricity sold in the United States, but their role is insignificant in Alaska and none currently exists in the Railbelt area.

A private utility is an ordinary business corporation governed by a board of directors responsible to its shareholders, who are typically individuals, other businesses, and financial institutions (insurance companies, pension funds, etc.). Its earnings are taxable, and it has no power to issue tax-exempt bonds.

Most private utilities do business only in a single state and have local operational management, but many are controlled by multi-state utility holding companies that make major construction and financing decisions. State public utility commissions or public service commissions like the Alaska Public Utilities Commission (APUC) typically regulate retail rates and terms of service for private utilities, while in most cases (but not in Alaska, where there are no interstate connections), the Federal Energy Regulatory Commission (FERC) regulates their wholesale rates and service.

Cooperatives. Rural electrification (REA) cooperatives (or co-ops) are subscriber-owned utilities, governed by a board of directors elected by its ratepayer-members. Most co-ops outside of Alaska are distribution utilities for small towns and rural areas, and buy their power from private utilities or federal projects. Co-ops, however, currently generate more than half of the electricity sold in Alaska's Railbelt. Anchorage-based Chugach Electric Association (CEA), with about 75,000 subscribers, is the largest electric utility in Alaska.

CEA sells electricity to two other co-ops, Matanuska Electric Association (MEA) and Homer Electric Association (HEA). Golden Valley Electric Association (GVEA), the state's second largest utility, serves the Fairbanks area, the upper Tanana valley, and the Nenana-Healy-McKinley Park area.

The retail business of electric co-ops, like that of the investor-owned utilities, is regulated by state utility commissions, including APUC, and their interstate wholesale business is regulated by FERC. As private enterprises, electric cooperatives do not have the power to issue tax-exempt securities, but they can borrow at 2 or 5 percent from the Rural Electrification Administration (REA), a federal government entity. REA will also guarantee the bonds of electric cooperatives, most of which are sold to the Federal Financing Bank at rates one to two percentage points below market rates for private utility bonds.

Cooperatives can borrow from the National Rural Utility Cooperative Financing Corporation at rates slightly below those of the private market.

Municipal utilities. The term municipal utility refers to any utility operated by a subdivision or agency of a state or province. In North America, most municipal utilities distribute power in a single community, and most of them are relatively small. The municipals do, however, include some large-city systems with substantial generating capacity, such as the Los Angeles and Seattle utilities. In Alaska's Railbelt, municipal utilities serve Fairbanks, Seward, and part of Anchorage.

The municipals include a variety of government-owned entities. In addition to city systems, the term is used to cover state- and county-chartered public utility districts, and state and provincial power or hydro authorities, including the Alaska Power Authority.

The management and accounts of some municipal utilities are merged with those of their parent city, county, or state government, as in the case of the Anchorage and Fairbanks municipal utilities. Alternatively, the utility may be an autonomous government-owned corporation with an independent board of directors and a wholly separate budget, and with the power to make its own construction and borrowing decisions (like the British Columbia Hydro Authority), or something in-between (like the Alaska Power Authority).

The retail business of municipal utilities is regulated by the state utility commission in some states, while in others it is left unregulated, on the ground that local elections give the consumers a better remedy for unsatisfactory service or excessive rates. In Alaska, the public utilities commission regulates municipal utility rates and terms of service only (1) outside the limits of the municipality (where the direct political remedy is absent), (2) where the utility competes with another utility in the same service area (e.g., CEA and AML&P), or (3) where the municipal utility wholesales power to a utility that is subject to APUC jurisdiction.

The Alaska Power Authority is exempt from APUC regulation, but the APUC may regulate the purchase and resale of Authority-generated electricity by the utilities that are under its jurisdiction.

As agencies of government, municipal utilities are generally exempt from federal, state, and local taxes. The state legislation establishing the Alaska Power Authority, however, explicitly allows it to make payments in lieu of local property taxes, but the law is not clear whether the local government or the Authority is to decide whether or not such payments will actually be made.

The Internal Revenue Code allows municipal utilities that engage in the retail distribution of electricity to issue tax-exempt securities, but it is not clear whether tax-exempt bonding would be available for a wholesale power project like the proposed Susitna facility. Tax-exempt revenue bonds are the most common source of funds for municipal power projects. Unlike general obligation bonds, for which the "full faith and credit" of the municpality or state is committed to servicing the debt, revenue bonds are a form of "non-recourse" debt, in which the lenders can call only on the revenues of the project itself, and not on the revenues or assets of the parent government.

Federal power. Outside of the Tennessee Valley Authority (TVA), federal power in the United States is generated in hydroelectric projects built by the Army Corps of Engineers or the Interior Department's Bureau of Reclamation. The Bureau of Reclamation or a regional subdivision of the Department of Energy (like the Bonneville Power Administration in the Pacific Northwest or the Alaska Power Administration) operates the facilities and markets the power. The Alaska Power Administration currently operates two projects --- Snettisham near Juneau and Eklutna near Anchorage.

Each federal power project must be acted upon several times by Congress during its planning, design, and construction. Congress first authorizes funds for planning and then --- in a separate action --- appropriates them. After that, Congress may or may not authorize construction and appropriate the funds called for in the initial construction budget. Project designs are often modified, and cost overruns are almost inevitable, creating a need for further rounds of Congressional deliberation. As a result, decades may pass between a project's initial conception and its operational start-up.

Federal law requires FERC to review rates charged by federal power projects, in order to ascertain that those rates correspond to the project's operating costs, including an allowance for depreciation and payment of interest to the U.S. Treasury on the federal funds invested in the project.

Congress typically stipulates the interest rate for each project in the specific legislation authorizing its construction. In most cases, interest rates on federal power projects --- and thus the rates for power they generate --- have embodied a federal subsidy. The interest rates, in other words, have tended to be substantially less than the current yields on U.S. Treasury bonds at the time they were authorized; more importantly in the view of most economists, the rates have been far less than the rates private investors would have had to pay for capital under otherwise similar terms.

Regulation of the electric power industry.

The distribution of electricity is often characterized as a "natural monopoly;" that is, an industry, in which the economic cost of service (sometimes called "resource cost" --- the value of labor, materials, and capital that go into the service) tends to be lowest when only one firm serves each market area. For an industry with this characteristic, competition would promote unnecessary duplication of facilities and consequently higher consumer costs. Without competition, however, there is little to spur a profit-seeking firm to pass the technical benefits of natural monopoly through to its consumers; economic theory and historical experience both suggest that unregulated private monopolies tend to charge excessive prices, and to deliver inadequate service.

There are two general ways of dealing with this dilemma: public utility regulation and government enterprise. In either case, public authorities face three broad types of decisions:

*** franchising (sometimes called "certification" or "licensing") --- authorizing a particular entity to operate in a given service area;

*** certification of new facilities (sometimes called "licensing" or "permitting"); and

*** ratemaking --- setting or approving charges to customers.

Regardless of the type of utility involved, construction of new facilities typically requires approval from several federal, state, and local agencies with respect to safety, environmental and other concerns. For utilities, however, the term "regulation" is often reserved for decisions regarding the three economic issues just listed.

For municipal utilities and other government enterprises, the franchising decision is made when the city council, state legislature, or Congress authorizes the utility or agency's establishment or expansion, while the budget approval process serves the function of certifying new projects. Some government-owned utilities have complete discretion over the rates they charge consumers (perhaps within some statutory guideline); the rates of others are set or reviewed by the general political authorities (e.g., the city council) or regulated by a state public utility commission or FERC.

Rate regulation. The several forms of utility organization use significantly different accounting concepts; likewise the ways in which government regulators define and measure the elements of utility cost vary from state to state and between levels of government. Nevertheless, the basic principles of utility ratemaking are essentially the same for regulated private utilities and government enterprises. Rates are generally designed to produce just enough revenue to cover the utility's "cost of service", which is composed of ---

*** operating costs, such as the costs of fuel, labor, materials, and purchased services;

*** interest on debt;

*** <u>amortization</u> (repayment) of debt;

*** <u>depreciation</u> (to the extent not covered by amortization of debt);

*** <u>taxes</u> (if any); and

*** <u>a fair and reasonable return</u> (or a <u>competitive return</u>) to the owners' equity investment.

<u>Rate structures</u>.

The principle that a utility's revenues should be just sufficient to cover its total costs (including a "fair and reasonable" return to investment in the case of a private firm) does not necessarily dictate the utility's "rate structure" --- the allocation of those costs among its customers and types of service. A utility's rate schedule or "tariff" normally provides different rates for different classes of service and, within each class, according to the amount of electricity the customer consumes.

<u>Promotional rates</u>. Utilities and regulatory bodies in North America have tended to favor "declining-block" or promotional rate structures, in which ---

1. Those customers whose electricity demand is least sensitive to prices, like households and small businesses, pay the highest rates, and those whose demand is more sensitive, heavy industry for example, pay lower rates;

2. Consumers within any service class who consume more electricity pay lower prices, as under "all-electric" residential rates, for example; and

3. Each class of consumers pays the same price for expensive peak-period power as for cheaper off-peak service.

One intended effect of such rate structures is to encourage the growth of power demand. They thereby accomodate the desire of utility managements to expand their organizations and, until the 1970's at least, this rate design strategy was supported by a widespread belief that electrical generation was a "declining-cost" industry in which load growth could result in lower rates for all classes of consumers.

The declining-cost rationale for promotional rate design includes the following elements:

Economies of scale in generation. Larger thermal (fossil and nuclear) generating plants cost less per kilowatt of capacity, and are more fuel-efficient. Thus, the larger a utility's total demand the greater the opportunity it has to use the largest, most economical plants.

Technical advance. Newer plants cost less per kilowatt of capacity, and are more fuel-efficient, so that the more rapidly a utility's demand grows, the newer its plant is on the average, and the lower its average cost of generation.

Economies of scale in distribution, administration, and billing. The more electricity each customer demands, the lower will be the unit cost (the cost per kilowatt-hour) of distribution, administration, and billing.

Load factors. Industrial demand for electricity fluctuates less over the the course of the year than residential or commercial demand, and the residential and commercial use of electricity for space-heating, water-heating and air-conditioning fluctuates less over the course of the day than do the residential and commercial uses (cooking, lighting, appliances, etc.) Lower rates for industrial consumers and for all-electric residential and commercial service, therefore, result in higher system load factors, and result in lower costs of service for everybody.

<u>Value of service</u>. Rates need to be lower for large industrial and commercial customers than for households and small businesses, because the former might find it profitable to generate their own power or switch from electricity to other forms of energy.

Some of these arguments are more valid than others; some of them are valid for some utility systems and not for others; and some of them have become distinctly unfashionable in recent years. Today most systems seem to face <u>increasing</u>, not decreasing, long-run generating costs. It is not clear that effective economies of scale exist for thermal plants beyond a capacity of about 500 megawatts, and the fact that a large plant can generate electricity more cheaply than a small one does not necessarily mean that greater system demand means lower costs, if it requires building of a greater number of plants. Moreover, while the energy efficiency of new generating plants improved constantly until the late 1960's, technical advance on this front now seems to have halted.

Most importantly, however, increased siting and construction costs, additional outlays for safety and environmental protection, higher interest rates, and licensing delays have made capital costs for new generating plants of all kinds --- and thus the cost of electricity from them --- far higher than at existing plants.

Increasing demand for electricity now clearly means higher rates in most parts of the United States, and more rapid increases in demand mean even higher rates. The difference between the cost of power from existing plants and new ones is most acute in regions like the Pacific Northwest that have been blessed with low-cost hydroelectric energy, but where incremental demand must be served by expensive nuclear or coal-fired steam plants.

Inverted rate structures. The phenomenon of long-run rising costs for electric power, coupled with greater public concern over adverse environmental, health, and safety impacts of all types of power plants, and the high price of fossil fuels, has created a national interest in designing utility rate structures that encourage conservation and restrain the growth of demand. This approach, in contrast to the customary promotional rate design, includes some or all of the following features:

1. The most price-sensitive customers pay rates that are at least as high (if not higher than) other customers, in order to encourage those who have the greatest ability to conserve power to do so.

2. Each class of customers faces an inverted or "ascending-block" rate structure, under which all customers share some of the low-cost power from old facilities, but in which increases in consumption are billed on the basis of "long-run marginal cost" (or "incremental cost") --- the full cost of power from the utility's most expensive source.

3. Rates differ according to the season or the time of day, in order to encourage consumers to shift their power demand away from peak periods; such "peak-responsibility" pricing both reduces the current demand for expensive peaking power, and reduces the need for new generating capacity to serve peak period loads.

Regulatory authorities.

The Alaska Public Utilities Commission. The Alaska Public Utilities Commission (APUC) has jurisdiction over service areas, licensing of new facilities, and both retail and wholesale rates and terms of service for all Alaska private utilities, including cooperatives.

As we stated previously, the APUC also has authority to regulate municipal utilities ---

*** where they compete with another utility in the same service area; (Chugach Electric Association and the Anchorage Municipal Utility, for example, have overlapping service areas.)

*** where they operate outside municipal limits; and

*** in their wholesale electricity sales to regulated (i.e., non-municipal) utilities. (This authority has apparently never been exercised.)

The APUC has no direct jurisdiction over the Alaska Power Authority (state) or the Alaska Power Administration (federal), but it may approve or disapprove electricity purchase contracts that Alaska regulated utilities propose to sign with either agency.

The Federal Energy Regulatory Commission. The Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission (FPC), is an independent agency housed in the U.S. Department of Energy. FERC jurisdiction includes:

Licensing of all power facilities (1) on navigable rivers, and (2) on federal lands. Any Susitna power project will therefore need a license from FERC, because the upper Susitna is a navigable river for purposes of the Federal Power Act. The damsites and their surroundings are now on federal lands, but by the time any license could be granted, they will have been conveyed to the Cook Inlet regional corporation under the Alaska Native Claims Settlement Act.

Review of rates and terms of service on wholesale electricity transactions in interstate commerce. The federal courts have repeatedly upheld FPC claims of jurisdiction over wholesale electricity sales in the Lower 48, even within a single state, on the theory that almost all commerce is at least indirectly interstate commerce. Alaska's geographical isolation and the absence of electrical interties with other states may or may not make a difference; but thus far, FPC and FERC have not tried to assert jurisdiction over wholesale electricity transactions among Alaska utilities.

Review of rates and terms of service for electricity sold by federal power projects --- including the Alaska Power Administration's Snettisham and Eklutna hydroelectric projects.

Transportation of natural gas for resale in inter-state commerce. FERC might conceivably use its authority over interstate gas transportation to restrict shipment of Prudhoe Bay natural gas through the Alaska Highway gas pipeline for electric utilities in Alaska. The federal courts have upheld FPC prohibitions of shipment of gas on an interstate pipeline even within a single state and even for direct sale (that is, not a sale for resale), for an "inferior" purpose --- electric utility boiler fuel.

The Economic Regulatory Administration. The Economic Regulatory Commission (ERA) of the U.S. Department of Energy administers the Powerplant and Industrial Fuels Act of 1978 (PIFUA), which generally prohibits use of oil or natural gas as fuel for new electrical generating plants, and discourages its use in existing plants. The Act provides several grounds on which ERA may waive the prohibition.

Other licensing, permitting, and regulatory agencies. An appendix to this chapter lists other state and federal agencies with licensing, permitting, or other regulatory or supervisory authority over new electrical generating plants and associated transmission lines. This list is not complete, however, either with respect to the agencies involved or to their responsibilities.

APPENDIX A: EXISTING RAILBELT UTILITIES

Excluding the military bases, the University of Alaska and the private industrial installations on the Kenai Peninsula, the majority of Alaskans receive their electric power from eight major utility systems located throughout the Railbelt region. Of the utilities, three are municipally owned and operated, one is a federal power project, and four are rural electric cooperatives:

Cooperatives:	
CEA	Chugach Electric Association, Inc.
GVEA	Golden Valley Electric Association, Inc.
MEA	Matanuska Electric Association, Inc.
HEA	Homer Electric Association, Inc.
Municipals:	
AML&P	Anchorage Municipal Light and Power
FMUS	Fairbanks Municipal Utility System
SES	Seward Electric System
Federal project:	
APA-E	Alaska Power Administration-Eklutna

The Copper Valley Electric Association, Inc.(CVEA), and the region from Valdez to Glenallen served by this utility are not expected to become part of an interconnected Railbelt unless and until the Susitna Dam becomes a reality. We have, therefore, excluded it from this review.

As of December 1979, CEA estimated the number of its customers at 50,000 retail and 24,000 wholesale accounts making it the largest utility in the state. Peak demand reached 310 MW in 1979, with a recent annual growth rate of about 12 percent. The retail service area of CEA encompasses the Greater Anchorage Municipality, the City of Whittier and the Eastern Kenai Peninsula, while the utility supplies wholesale power to the City of Seward, the Homer Electric Association service area, and the Matanuska Valley.

Aside from being the largest electric utility in Alaska, Chugach Electric currently supplies its customers with the some of the least expensive power in the country. Natural gas prices in Anchorage are less than those in other states; hence, wholesale generation costs of operating natural gas turbines are now at a minimum and are being passed along to customers of the cooperative.

How much for how long? It is both an enviable and difficult position in which CEA now finds itself. The National Energy Act of 1978 technically prohibits the use of natural gas in future powerplant facilities and encourages utilities to convert to coal-fired generation. At the same time, exemptions can be granted under special conditions. It is logical for Chugach to seek these exemptions, either temporarily or permanently, in the hope of retaining the low-priced natural gas generation for as long as possible. What is difficult for both the utility and others to determine is exactly how long a time that will be.

Lobbying and legal efforts may be used to retain access to the gas at least for the short term. What is not clear is whether conversions to coal, small hydro, or other alternative technologies could be made later in a relatively short period of time to serve the mid-term growth needs of CEA's service area, if prohibitions on use of natural gas are enforced.

Let us assume, however, that the short-term needs are satisfied by natural gas and that CEA attempts to meet its mid-term needs by coal or another alternative, the question remains as to the amount of power needed for the long-term. Should Chugach enter into a take-or-pay contract that guarantee the utility's willingness to rely on Susitna-generated power in the next decade? Will the growth of demand make Susitna an economic power source for the Railbelt, or might a series of smaller generation projects fulfill the area's power needs at the same or even lower cost? It is the examination of questions such as these on which CEA must base its future actions; and one must keep in mind that Chugach is probably the key to a yes or no determination on Susitna's financial feasibility, and therefore, to the ultimate fate of the project itself.

On the Kenai Peninsula, power outages are frequent in severe winters, but they usually stem from transmission and distribution failure rather than inadequate generating capacity. While abundant power from a major hydroelectric project would seem to be a general boon, the cost of tapping into that power would still have to be borne by the customers of the smaller cooperatives, thus making individual billings higher during the time those tie-in services are being amortized. This, combined with the amortization of the capital costs of the Susitna Dam itself, might make any of several energy alternatives more attractive to Kenai residents. A smaller hydro project such as the one being considered at Bradley Lake may be more in scale with the size and demands of this area of the Railbelt.

Currently, only the Seward Electric System is engaging in new construction, the majority of which is aimed at upgrading transmission and tie-in facilities for wholesale power purchased from CEA Both SES and HEA (Homer) purchase the bulk of their present generation from CEA. During winter outages, each utility relies on minimal back-up systems. HEA has generators on lease from Golden Valley Electric Association in Fairbanks; these leases expire in the near future.

For non-emergency power supplies, SES and HEA remain under long-term purchase contracts with Chugach until the turn of the century — effectively locking them into costs and budgets tied to the decisions Chugach makes as to its own future course. If Chugach decides not to participate in a take-or-pay contract for Susitna, these smaller cooperatives may be hard-pressed to keep up with generation needs of their customers given a development spurt in the Anchorage area. On the other hand, if Chugach does guarantee their purchase of Susitna-generated power, initial expenses will be passed to wholesale and retail customers alike. For the Kenai Peninsula, electricity is likely to become more expensive whatever the source.

The service area of Matanuska Valley Electric Association, Inc. (MEA) is immediately adjacent to the proposed Susitna dams. Proximity to the source might make Susitna power here somewhat less expensive than in the outlying regions of the Railbelt. Anticipation of new industry, new construction jobs, and general Susitna-related growth make the project very appealing to many residents of this region. In light of a current economic slump in the Valley, a large project is more attractive to local business and political leaders than the suggested alternative of several scattered hydroelectric or thermal projects, as the developmental benefits of the former would be more concentrated in the Mat-Su area.

The Northern Railbelt is served by the Golden Valley Electric (GVEA) Association, Inc., and the Fairbanks Municipal Utility System (FMUS). GVEA operates in part of the city of Fairbanks, the Upper Tanana valley, and the Nenana valley as far south as the McKinley Park resort, and the FMUS is confined to the Fairbanks urban core. GVEA, like MEA, is also suffering a post-pipeline depresssion. Anticipation of gas pipeline construction has been keeping some investors interested in the area, but according to one utility executive, there were "some 1300 to 1400 idle services [inactive hookups] in Fairbanks" in December 1979. Something is desperately needed to revitalize business, and some (but not all) local leaders see the possibility that higher electric bills would be necessary to finance new generating plants as insignificant when weighed beside the positive impact new contstruction activity would have on the economy of the area.

GVEA's short and mid-term expansion plans include tapping of waste heat from Alyeska pump stations and extension of transmission lines further South along to Summit the Alaska Railroad and Parks Highway, and some new tie-ins expected north of Fairbanks. While no new generating plants are currently being considered planned, and plans to use coal from Healy were cancelled due to the cost of compliance with Environmental Protection Administration (EPA) clean air standards, more effective utililization of waste heat and effective conservation efforts are anticipated and are being encouraged in order to meet the immediate and near-future demand. Establishment of an intertie with the rest of the Railbelt, which is now under active consideration, might make GVEA more favorable to the Susitna hydroelectric proposal.

FMUS, serving the Fairbanks city core as an arm of the municipal government, is perhaps the most vulnerable to the boom/bust cycle of all Railbelt utilities. Rapid growth, as during TAPS construction, causes overuse of electricity as construction workers and others crowd the town. Yet long-range or even mid- to short-range generation plans cannot be made on the basis of these relatively short bursts of activity. Money for new and expensive facilities must come from the local tax base, whether it be sales, or residential and industrial property. These tax sources are constantly fluctuating, making planning all the more complicated. For now, no new money is going into utility expansion; and as is the case with GVEA, conservation and more efficient use of existing facilities are expected to suffice for the foreseeable future.

The Alaska Power Administration-Eklutna, and its principal customer, Anchorage Municipal Light and Power, would be less affected by construction of a Susitna Dam than the other utilities mentioned here. No expansion is now planned for Eklutna, and APA-E could deliver unused power to the military installations in the area if Susitna power displaced it from its present utility markets.

AML&P operates in a limited service area (partially overlapping that of CEA) within the Anchorage municipality; this area is already fully urbanized, so that its electricity demand may be relatively insensitive to further growth in the region as a whole. As in the case of FMUS in the north, AML&P plans its expansion budget around the service area's tax base, which is currently in a period of slow growth. Past projections of demand have been scaled down from a high growth rate in the mid-teens to a current 12 percent figure. Installation of two gas turbines in the early 1980's, as currently planned, should keep this utility well on track for meeting its 1989 capacity goal of 225 MW. As in the case of CEA, the effect of federal legislation on future natural gas supplies to AML&P remains to be seen.

EXISTING UTILITY PLANT AND ORGANIZATION: ANCHORAGE -- COOK INLET

UTILITY	SERVICE AREA	CUSTOMERS	TYPE OF UTILITY	PRESENT AND PLANNED GENERATING EQUIPMENT	PEAK LOAD	DEMAND FORECASTS
CHUGACH ELECTRIC ASSOCIATION, INC. (CEA)	Greater Anchorage, Eastern Kenai Peninsula, Whittier	50,000 retail, 24,000 wholesale (via MEA, HEA) (1979)	REA coop since 1948	Five generation plants, 13 gas turbines, 2 hydro turbines (Cooper Lake). Present base capacity (including 9.0 MW purchase from Eklutna) 403 MW. New gas turbine will add 60 MW in 1980 ; 5 gas turbines to be retired in 1985. Interconnections: MEA, HEA, SES, Eklutna	310 MW peak (Dec 1979)	1985: 856 MW (1976 study) New study in 1980 will probably lower forecast
ANCHORAGE MUNICIPAL LIGHT & POWER (AML&P)	Anchorage municipality within and specific locations outside old city limits	16,378 retail 4,756 street lights Merrill Field (1979)	Municipal utility owned by Muncipality of Anchorage	Six gas turbines, 5 simple; one waste heat. One gas turbine scheduled for installation 1980, one more in 1982-83. Interconnectionm: Emergency 20 MW connectiom to Elmendorf	107 MW peak (Sep 1979) 109 MW peak (1978)	1989: 225 MW
MATANUSKA ELECTRIC ASSOCIATION, INC. (MEA)	Matanuska-Susitna Borough including Palmer, Eagle River, Talkeetna	13,000 retail (1979)	REA coop since 1941	93 percent of power purchased from CEA; 7 percent from Eklutna. 600 KW standby diesel generator at Talkeetna. Interconnection: CEA	63 MW peak (Feb 1979) 13 MW 1970 11 MW 1969	1989: 225 MW (does not include new capital)

EXISTING UTILITY PLANT AND ORGANIZATION: ANCHORAGE -- COOK INLET (CONTINUED)

UTILITY	SERVICE AREA	CUSTOMERS	TYPE OF UTILITY	PRESENT AND PLANNED GENERATING EQUIPMENT	PEAK LOAD	DEMAND FORECASTS
HOMER ELECTRIC ASSOCIATION (HEA)	Western Kenai Peninsula, Port Graham, Seldovia, Homer, Soldotna	10,422 retail (1979)	REA coop	Four diesel and two simple gas turbines, 9.3 MW. Balance purchased from CEA. Interconnection: CEA	55 MW peak Dec 1979 184 million KWH (1977)	1989: 100 MW 1982: 502 mil KWH (annual) 1989: 967 mil KWH (annual)
SEWARD ELECTRIC SYSTEM (SES)	City of Seward to mile 24, Seward Highway	1,319 retail (1979)	Municipal utility owned by city of Seward	All power purchased from CEA. Interconnection: CEA	5 MW average daily peak (1979)	
ALASKA POWER ADMINISTRATION-EKLUTNA	not applicable	CEA, MEA	Federal hydropower project	2 hydro turbines, 30 MW	not available	not applicable

EXISTING UTILITY PLANT AND ORGANIZATION: FAIRBANKS -- TANANA VALLEY

UTILITY	SERVICE AREA	CUSTOMERS	TYPE OF UTILITY	PRESENT AND PLANNED GENERATING EQUIPMENT	PEAK LOAD	DEMAND FORECASTS
GOLDEN VALLEY ELECTRIC ASSOCIATION INC (GVEA)	Fairbanks North Star Borough, including part of Fairbanks city; North Pole, Ester, Delta Junction, Healy, Clear, Anderson, Cantwell, Rex, McKinley Park, Ft. Wainwright, Eilson AFB. Will extend to Summit	15,000 retail	REA coop	Coal-fired steam turbine (Healy) 25 MW; Six oil-fired gas turbines 179 MW; 10 diesel 22 MW --- Total 226 MW Interconnections: FMUS, Fort Wainwright, Eilson AFB, U. of A.	850 KHW/mo/ customer (1979)	1983: 900 KWH/mo/ customer 1988: 1000/ kwh/mo/ customer
FAIRBANKS MUNICIPAL UTILITY SYSTEM (FMUS)	Fairbanks city limits	5,615 retail (1979)	Municipal utility owned by city of Fairbanks	Four steam turbines 8 MW Two oil-fired gas turbines 32 MW; three diesel 8 MW --- Total 68 MW Interties: GVEA, U of A	28.7 MW (1979)	n.a.

APPENDIX B: FEDERAL AGENCIES HAVING JURISDICTION OVER NEW ELECTRICAL GENERATING AND TRANSMISSION FACILITIES IN ALASKA

AGENCY	PERMIT OR JURISDICTION
DEPARTMENT OF ENERGY (DOE)	
Federal Energy Regulatory Commission (FERC)	Licenses power facilities on navigable waters and on federal lands.
	Regulates wholesale electric rates and service in interstate commerce
	Reviews electric rates on federal power projects.
	Regulates natural gas sales and transmission in interstate commerce.
Economic Regulatory Administration (ERA)	Administers PIFUA, grants exceptions allowing new geneating facilities to burn oil or gas.
	Establishes and administers price ceilings, entitlements treatment, and allocation of petroleum, including electric utility fuel. This authority reverts to standby emergency power only on October 1, 1981.
Alaska Power Administration (APA)	Constructs and operates federal power projects in Alaska,. as authorized by Congress.
DEPARTMENT OF THE INTERIOR (DOI)	
Office of the Secretary	Administers overall policy.
Geological Survey (USGS)	Advises on geological, seismic, geotechnic, and hydrological criteria and design.
Fish & Wildlife Service (FWS)	Protection of fish, wildlife, and migratory birds; anadromous fish; endangered species.

FEDERAL AGENCIES HAVING JURISDICTION OVER NEW ELECTRICAL GENERATING AND TRANSMISSION FACILITIES IN ALASKA (CONTINUED)

AGENCY	PERMIT OR JURISDICTION
DEPARTMENT OF THE INTERIOR (DOI) (CONTINUED)	
Bureau of Land Management (BLM)	Grants rights-of way for electrical transmission lines across public lands.
National Park Service (NPS)	Supports BLM and USFS in protecting archeological and palentological remains under Antiquities Act.
Bureau of Indian Affairs	Advises Alaska Native organizations on lands, employmwent, etc.
Mining and Safety Enforcement Administration (MESA)	Approves gravel removal from federal lands.
DEPARTMENT OF AGRICULTURE	
Forest Service (USFS)	Grants rights-of-way, permits for use and occupancy in national forests.
DEPARTMENT OF THE ARMY	
Corps of Engineers (COE)	Issues permits for construction in and affecting navigable waters as designated by COE; floodplains management. Builds hydroelectric and other river basin developments as authorized by Congress.
DEPARTMENT OF LABOR	
Occupational Safety and Health Administration (OHSA)	Establishes and enforces safety and health standards for workers.
DEPARTMENT OF TRANSPORTATION	
Federal Aviation Administration (FAA)	Reviews construction affecting airspace use, control and safety.
DEPARTMENT OF THE TREASURY	
Bureau of Alcohol, Tobacco & Firearms	Issues permits for use and storage of explosives (if not overseen by OSHA or Alaska Department of Labor)

FEDERAL AGENCIES HAVING JURISDICTION OVER NEW ELECTRICAL GENERATING AND TRANSMISSION FACILITIES IN ALASKA (CONTINUED)

AGENCY	PERMIT OR JURISDICTION
DEPARTMENT OF COMMERCE National Oceanic and Atmospheric Administration	Coordinates and/or advises on administration of Coastal Zone Management Act (CZM), particularly with reference to protection of anadromous fish.
ENVIRONMENTAL PROTECTION ADMINISTRATION (EPA)	Administers air and water quality standards. Grants permits for discharge into navigable waters. Grants exemption from noise control standards.
COUNCIL ON ENVIRONMENTAL QUALITY (CEQ)	Advises DOI, DOE, COE, EPA, et al, and the President on environmental issues.

ALASKA STATE AGENCIES HAVING JURISDICTION OVER NEW ELECTRICAL GENERATING AND TRANSMISSION FACILITIES

DEPARTMENT OF COMMERCE & ECONOMIC DEVELOPMENT	
Division of Energy & Power Development	Forecasts electricity demand; plans facilities.
Alaska Power Authority (APA)	Review and approve construction plans; oversee design, construction, acquisition, financing, and operation of hydroelectric and other power generation projects; lend money to utilities.
Alaska Public Utilities Commission (APUC)	Grants and amends authority to operate generation and transmission facilities. Oversees rates, classifications, practices, services, and facilities of utility companies.

CHAPTER II: PLANNING FOR NEW GENERATING CAPACITY

This chapter considers the decision to install new electrical generating capacity from the four most important vantage points:

1. Demand forecasting. How much new central-station electrical generating capacity will the Railbelt require over the next ten to twenty years?

2. Facilities planning. What combination of generating and transmission facilities will provide this capacity at lowest cost?

3. Organization and financing. What organizational and financial arrangements will provide this capacity most efficiently?

4. Marketing. How should the fixed and operating costs of the new and old facilities be allocated among different user groups?

Promotion vs. conservation. Despite the seemingly distinct headings, these four issues cannot be completely isolated from one another. For example, utilities and government power agencies determine their need to install new generating capacity on the basis of expected future electrical demand. But these same entities have a powerful influence on future demand, because their own decisions on whether and what kind of new generating capacity to install and how to allocate costs among different categories of consumers and uses, directly affect future electricity prices. Prices are, in turn, one of the most important influences on the amount of electricity each category of consumer uses.

Utilities and government agencies, therefore, cannot avoid molding the future, at least in part. They can, in fact, use their power over demand forecasting, facilities planning, organization and financing, and marketing in a manner to accomplish chosen goals, for example promoting greater electricity demand and thereby maximizing the need for new capacity, or fostering electricity conservation and thus minimizing the need for new capacity.

Electric utilities, both private and public, understandably tend to favor the first strategy, which was almost unchallenged in the United States until the 1970's. In the Lower 48, the promotional approach to electric power planning has recently lost much of its support outside the utility industry itself, but it still has many enthusiastic backers in Alaska.

Demand forecasting.

The amount of new electrical generating capacity needed in the Railbelt depends, of course, on the increase in total demand for electricity, which reflects the area's population growth, its per-capita demand for electricity in residential, commercial, and small industrial uses, and the electrical requirements of new energy-intensive basic industries.

The kind of generating equipment that will meet this demand growth most efficiently will depend upon the load characteristics of demand --- its daily and seasonal variations --- as well as on the technical characteristics of the various kinds of generating equipment, the kind and capacity of existing facilities, and on the rate of demand growth.

Finally, because large-scale power projects take many years to plan, design, build, and put into reliable full-capacity operation, their justification typically depends upon forecasts of demand ten or twenty years or even further into the future. Projections of electricity consumption are notoriously inaccurate, no matter how sophisticated their methodology, even for much shorter periods. Power facility planners must therefore take into account a large degree of uncertainty, and compare the consequences of underbuilding with those of overbuilding.

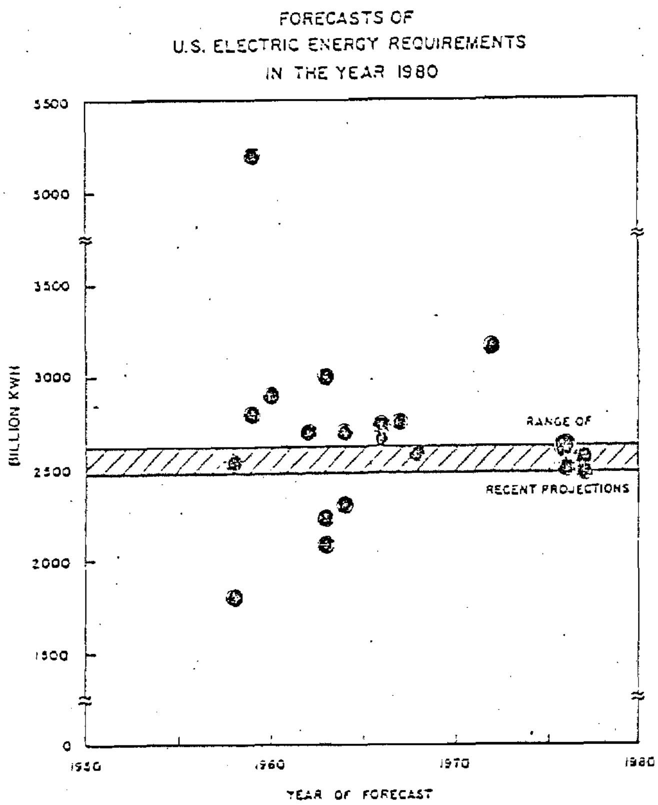
Even without big surprises, 20 year forecasts are bound to be speculative. Figure 1 compares the forecasts of authoritative government and industry groups, made between 1960 and 1970 regarding U.S. electric energy requirements in 1980, and the forecasts made between 1970 and 1980 for the year 2000. Power system planners must anticipate requirements at least that far in advance, but the range of their judgments has been astonishingly wide.

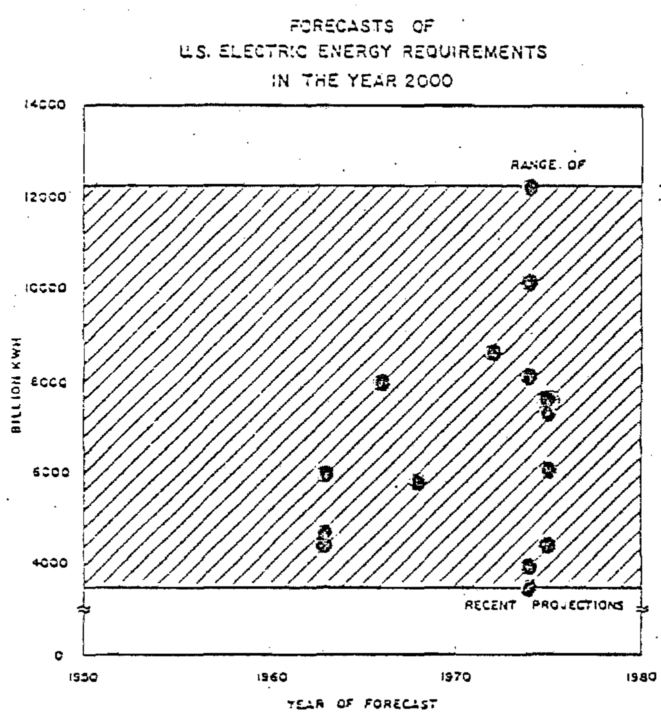
Most government and industry forecasters in the 1960's and early 1970's essentially extrapolated the high rates of electrical load growth that had prevailed since World War II. Until very recently they took very little account of the "price-elasticity of demand for" electricity --- that is, the responsiveness of power loads to higher electric rates. As a result, most regional and national forecasts in the Lower 48 greatly overestimated the growth of demand, and many large utilities have now voluntarily postponed or curtailed the building programs that they had predicated on these forecasts.

During the 1960's, forecasters in Alaska, on the other hand, consistently underestimated the demand growth that would occur in the Railbelt during the 1970's, because they had no way of anticipating the economic stimulus of TAPS construction and Prudhoe Bay oil revenues. It appears,

Figure 1

Long Range Forecasts of U.S. Electric Energy Requirements





however, that 1980 power demand will turn out to be considerably lower than the lowest forecasts for that year in either the Alaska Power Administration's 1974 study or ISER's 1976 report. As we indicate elsewhere in this paper, current forecasts of Railbelt demand in 1990 and 2000 are also more likely to be too high than too low.

Population and real income. The most powerful influences on electricity demand are population and per-capita real income. Projections of rapid demand growth for the Railbelt rest mainly upon the assumption that its population and economy will continue to boom at annual rates like those of the 1970's.

Economic boom in the 1980's. The most likely prospect is indeed that rapid economic growth will resume in 1980 or 1981, fueled by the spending of Prudhoe Bay (and perhaps other) oil and gas revenues. Major construction projects, including the Alaska Highway gas pipeline and possibly the Alpetco refinery, one or more petrochemical plants, or the Susitna hydroelectric project, are likely to give the boom added force during the mid-1980's.

The Railbelt's long-term economic outlook, however, is dominated by the manner and rate at which the state government spends its oil and gas income. Over the ten-to-twenty year span that is relevant for planning new electrical generating facilities, nothing else is nearly as important. Without extremely large new petroleum discoveries on state lands, the coming boom will have run its course by the late 1980's or early 1990's at the latest.

Decline in the 1990's? No other basic industry or combination of industries is now in sight to replace the state's Prudhoe Bay petroleum revenues or otherwise to support even Alaska's 1979 levels of population, employment, and per-capita income, much less the levels that will be reached by the mid-1980's. As a result, Alaska's population, and thus the residential and commercial demand for electricity, will probably peak and then begin a long-term decline some time before the end of the 20th Century.

The authors have presented the grounds for this assessment in considerable detail elsewhere. In this report, however, what matters most is not whether the "boomers" or "doomers" will ultimately be vindicated, but the need for power planners to consider more than one development scenario and the costs and risks their chosen strategy will impose in the event that actual electricity demand turns out to be much less, or much more, than their projections.

Electricity consumption per capita. Per capita electricity consumption tends to increase if per capita real incomes or the relative prices of competing fuels go up; and it tends to fall if the real (constant-dollar) price of electricity rises.

Together with population, therefore, per-capita real income, electricity prices, and the prices and availability of alternative fuels will be the chief influences on the residential, commercial, and institutional demand for electricity in the Railbelt. The effect various deliberate conservation measures would have on electricty demand also must be taken into account.

Per capita income. In the past, higher levels of real family income have consistently resulted in greater residential and commercial use of electricity, as people moved into larger houses, used more lights and electrical appliances, and demanded more and better commercial and public services that use electricity --- generously lit and outfitted stores, offices, schools, and the like.

Since World War II, however, the most income-sensitive part of electricity demand nationally has been air-conditioning --- an application of little relevance in Alaska. Except for air-conditioning, most households in the Railbelt now have most of the heavy energy-using appliances that characterize the American lifestyle, so that income-driven increases in per-capita electricity demand may have about run their course --- at least in the residential and commercial sectors.

Electricity prices. Higher electricity prices discourage elecricity consumption generally; they also make voluntary conservation measures more attractive economically, and mandatory conservation measures more acceptable. They also encourage owners and builders of homes and commercial buildings to install solar heating and cooling equipment, and industry to rely more on co-generation.

Higher electricity prices outside of Alaska will likely restrain the future growth of per-capita electricity consumption in the Railbelt, even if real costs for power there do not increase at all, as Alaskans adopt the more energy-efficient appliances and construction techniques developed in response to Lower 48 conditions, or mandated nationwide by federal regulations.

Fuel substitution. During the 1980's, energy conservation will almost certainly more than offset any tendency of higher personal incomes to increase electricity consumption. Thus, per-capita demand in the Railbelt is likely to grow only to the extent that higher prices or unavailability of heating oil and natural gas may induce households, businesses, and public institutions to use more electricity for space heating, water heating, cooking, and the like.

Competition between electricity and fossil fuels for the home and commercial space-heating market has its greatest impact at the time owners or developers choose the equipment to go into new buildings. Conversion of existing structures takes place only where very substantial differences exist in the price or supply reliability of alternative fuels; even in these cases, conversion tends to be gradual and incomplete.

For this reason, the timing of new power projects may be crucial. If Susitna power could be made available in the early 1980's, for example, and if it were significantly cheaper than natural gas as a fuel for space-heating, most of the structures built in the Railbelt during the next decade would be electrically-heated.

No power is likely to come on line from any new low-cost source, however, until the end of the 'eighties at the earliest, when the economic expansion and construction boom driven by development of Prudhoe Bay oil and gas will have played themselves out. By then, a new power source may face a large existing stock of residential and commercial structures already committed to oil or gas, and little or no opportunity to provide heating for newly-built structures.

In any event, a realistic forecast of residential and commercial demand for electricity in the Railbelt must carefully consider the area's natural gas price and supply outlook, including the question whether gas distribution systems are likely to be established in the Matanuska-Susitna and Fairbanks areas.

Electricity consumption by new energy-intensive industry. Forecasting the growth of large-scale industrial demand for electricity is particularly tricky in a relatively small market like the Alaska Railbelt, where one plant could account for a very large fraction of total electricity consumption. While projections of residential, commercial, and small industrial use of electricity can normally rely on forecasts of broad economic indicators like population, employment, or personal income, a realistic estimate of the demand for electricity by large energy-intensive firms has to be approached on a plant-by-plant basis.

The demand for electricity by large-scale energy-intensive industrial plants is even more sensitive to power costs and to the relative prices of different energy sources than are residential, commercial, and small industrial demand. Heavy industry's choice among sources of energy is also more affected by government regulation, which currently tries to discourage industry from using oil and gas, even where they are plentiful.

Unfortunately, the plants whose potential electrical requirements need to be analyzed do not yet exist, and in most cases are purely speculative. Forecasters of electric power demand thus have to make assumptions about the economic prospects of various industries in Alaska --- about the likelihood, timing, and location of actual investments --- as well as about the technical characteristics of each kind of facility and about prices and the other factors that will influence their choice of energy inputs.

Does cheap power attract industry? Forecasts of large-scale industrial demand for electricity in Alaska are therefore not just highly speculative, but are bound to be controversial. Some of the push to build large electrical generating facilities comes from Alaskans who hope and assume --- almost as a matter of faith --- that abundant or cheap electrical power will attract energy-intensive industries like aluminum or other primary metals refining. Ironically, some of the opposition to the same projects comes from people who fear heavy industrialization, but share the boomers' faith, for example, that construction of the Susitna dams will guarantee establishment of an aluminum refining industry in Alaska.

The cost of electric power, like the cost of any input to production, will surely have some effect on Alaska's attractiveness as a location for heavy industrial investments, but there will be few instances in which it will be decisive. One illustration should put the issue into perspective: Suppose that a given plant costs 1.6 times as much to build in Alaska as in the Lower 48, Europe, or East Asia --- a not unrealistic figure. Energy costs faced by such a plant outside of Alaska would therefore have to equal at least 60 percent of its fixed capital costs (depreciation, interest, and required return on equity) before even free energy in Alaska would offset the plant's construction cost handicap.

In almost every case, however, energy-intensive industries are also capital-intensive industries. We know of only two (uranium enrichment and basic aluminum) for which energy costs in the form of electricity normally exceed even 10 percent of total costs, or 20 percent of fixed costs.

It is worth noting that a uranium enrichment plant accounted for more than half of the Railbelt's industrial power consumption in the Alaska Power Administration's 1974 forecasts for 1990 and 2000. Since then, the U.S. market for new light-water reactors has virtually disappeared --- a trend that was apparent even before the Three Mile Island incident --- and the prospect that an enrichment facility would be installed in Alaska in this Century is therefore almost nil. It is probably safe, therefore, to regard basic aluminum as the only energy-intensive industry that might ever plausibly be attracted to Alaska by the prospect of abundant or relatively cheap power as such.

The potential for attracting aluminum refiners to Alaska is a legitimate consideration in estimating the probable benefits (and costs) of a project like the Susitna dams. But many factors beside the availability and cost of electricity influence an aluminum producer's decision whether, where, and when to build a new plant, including the world supply-and-demand outlook for aluminum and for other primary metals, the particular company's existing capacity and market position, the type and source of ore available and the cost of shipping it to the proposed location, and local construction and labor costs.

It is therefore prudent for power supply planners to include new energy-intensive industries in forecasts used to ascertain the Susitna project's feasibilty if and only if the new industrial facility is made an integral part of the development plan by means of a minimum-bill "take-or-pay" contract between the industrial firm and the Power Authority for a definite part of the plant's generating capacity.

Interruptible sales contracts. The desire to attract energy-intensive industry may not be a realistic basis for building new large-scale generating plants in the Railbelt, but the prospect of marketing off-peak or surplus power to industries already located or planning to locate in the area is an important consideration in determining the feasibility of a large power project like Susitna.

One possible example is the sale of interruptible power for pump- or compressor-stations on TAPS or the Alaska Highway gas pipeline (ANGTS). Petroleum refineries and petrochemical plants may offer another market for interruptible power, as a substitute for the oil, natural gas, liquefied petroleum gases (LPG's) that the plants would otherwise use as boiler and process fuel, or to generate hydrogen.

It is not likely that electricity from Susitna or any new generating facility would be competitive with oil or gas as pump-station or refinery fuel, if these industries had to pay the same price per kilowatt-hour as other electricity consumers --- a price designed to cover each kilowatt-hour's proportional share of the project's fixed capital costs, as well as its operating or "variable" costs.

Once a generating plant's capital costs have already been sunk, however, the added variable cost incurred in generating and selling more hydropower is virtually nil, up to the plant's full year-round capacity. Likewise, the added variable cost incurred in generating more power at (say) a coal-fired steam plant is little more than the cost of the additional fuel it consumes, up to the point at which the plant is running at full capacity all the time.

In such an instance, the variable cost of the additional power used by pipelines or refineries might well be less than the value of the oil or gas it would displace. If so, the Alaska Power Authority might be able to set a price for interruptible off-peak or surplus power that allowed the pipeline companies or refineries to reduce the cost of energy needed to run their facilities and which, at the same time, contributed something toward the generating plant's fixed costs and thereby permitted all consumers to receive lower rates than they would in the absence of the interruptible contracts. [In technical terms, the required price is one greater than short-term marginal costs and less than long-term average costs.]

Load characteristics.

The generating capacity of a power supply system must be able to deliver both (1) the highest peak load and (2) the total amount of electrical energy demanded during the year (with an adequate reserve to cope with equipment failures or unexpectedly high demand). For this reason, load forecasts are generally stated in terms of two dimensions of demand:

*** peak loads, which are measured in

kilowatts . . . (KW = 10^3 watts),
megawats . . . (MW = 10^6 watts), or
gigawatts . . . (GW = 10^9 watts); and

*** total annual consumption, which is measured in

kilowatt-hours (KWH = 10^3 watt-hours),
megawatt-hours (MWH = 10^6 watt-hours), or
gigawatt-hours (GWH = 10^9 watt-hours).

Electricity consumption in a given service area will have large daily, weekly, and seasonal fluctuations. The daily peak is typically in the late afternoon or early evening; loads tend to be greater on weekdays than on Saturdays, and lightest on Sundays and holidays. In warm climates the annual peak is usually in the summer when air conditioners are operating; in cold climates, including Alaska's, demand usually peaks in the winter.

The load characteristics of a given system can be described by means of an "annual load duration curve," which represents the number of hours in each year that consumers demand a given amount of electricity. Figure 2 shows such a curve for a hypothetical power supply system with a peak demand of 250 MW, and total annual consumption of 1,000 GWH.

Base loads. The horizontal axis of Figure 2 measures the number of hours in the year's total of 8760 hours [365 days X 24 hours]. The vertical axis measures electrical consumption in MW. Point c shows that in this case, the load never falls below 75 MW; this level of consumption is called the "base load," and the annual base load consumption is therefore 660 GWH [8760 hours X 75 MW].

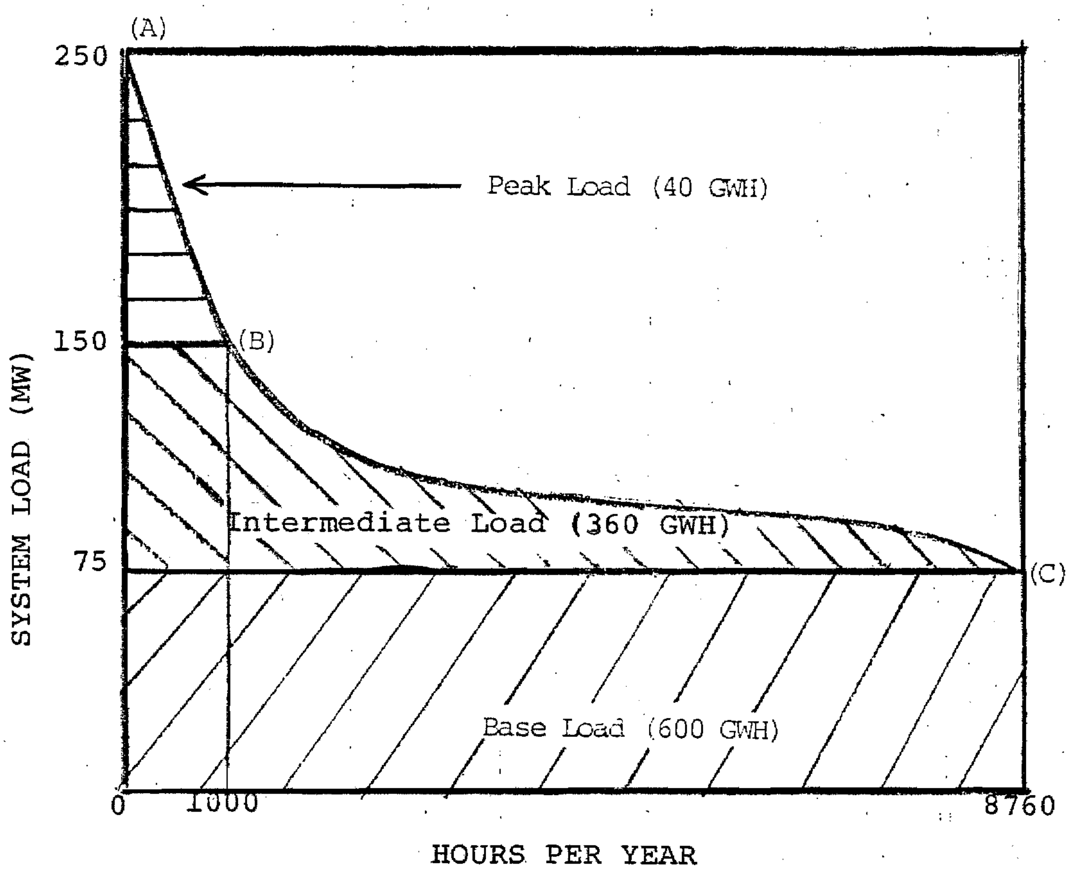
Peak loads. For a small part of the year consumption greatly exceeds the base load. A load exceeding some specified level is called a "peak load." In Figure 2, levels of consumption more than 150 MW --- twice the base load --- are regarded as peak loads. Point a shows the annual peak --- the highest level of consumption encountered during the entire year --- as 250 MW, and point b shows that consumption is 150 MW or more for 1000 hours during the year. The total peak load consumption over the year is 40 GWH.

Intermediate loads. Consumption that exceeds the base load [75 MW] but is less than the lower boundary of the peak load [150 MW] is referred to as an "intermediate load." In Figure 2 the total annual intermediate load consumption during the year is 360 GWH.

System load factors. The peak load and the total annual load can be combined into a single measure that indicates the greatest efficiency with which a power supply

FIGURE 2

HYPOTHETICAL LOAD DURATION CURVE



system could use its generating capacity. The system's load factor is its average consumption, expressed as a percentage of peak consumption. In the hypothetical power supply system of Figure 1, the average annual load is 114 MW [1,000 GWH ÷ 8760 hours], and peak consumption is 250 MW. Thus its load factor is 46 percent. The average load factor for the utilities of Alaska's Railbelt is currently around 50 percent.

Low load factors are exceedingly costly in terms of the fixed capital that must be invested in generating capacity. In figure 2, the peak load accounts for only 4 percent of total annual consumption [40 out of 1000 GWH] but requires 40 percent of the system's capacity [75 out of 250 MW]. The intermediate load accounts for 36 percent of total annual consumption [360 GWH] and 30 percent of capacity [75 MW], while the base load accounts for 60 percent of total consumption [600 GWH] and only 30 percent of capacity [75 MW]. Thus, each KWH of peak load power delivered requires the utility to have 20 times as much fixed capital as a KWH of base load power.

The preceding figures exaggerate the disparity between peak load and average generating costs per KWH, because the kind of generating equipment that can produce the lowest-cost power when it operates every hour of every day is likely to be different from the equipment that produces the lowest-cost peaking power. Knowledge of a system's expected load characteristics is therefore necessary for deciding what combination of generating facilities will be most economical for meeting future electricity demand. We explore this issue later in the present chapter.

<u>Alternatives to peaking power</u>. Even if a utility installs the ideal combination of generating equipment for

serving its individual combination of peak-, intermediate-, and base-load consumption, peak-load power is still exceedingly expensive in terms of capacity. Unless something causes a system's load factor to improve as its loads expand, the need to serve peak loads will account for a very large part of its investment in new generating capacity. Thus, strategies capable of increasing system load factors might significantly reduce both the average cost of electricity to the utility's customers and the need to build new generating plants.

In the United States, however, forecasts of electricity demand have traditionally accepted a system's load duration curve as given, and the normal inclination of utility and power agency planners is to design and build new facilities to serve the projected peaks. [The current feasibility study for the Susitna project, by Acres American, Inc. under contract to the Alaska Power Authority, does plan to forecast both total consumption and load duration curves for the Railbelt. Chapter IV of this report, however, points out some serious shortcomings in this aspect of the study plan.]

Measures do exist for significantly increasing load factors, thereby improving the efficiency with which installed generating capacity is operated, and (assuming that total annual consumption remains unchanged) economizing on the need for new capacity. These effects, in turn, can be expected to reduce average costs per KWH. Such measures include (1) interconnection, (2) interruptible electricity sales, (3) central-station load management, and (3) peak responsibility pricing, which are described later in this chapter.

Facilities Planning.

Even given some idea of the amount of electricity needed and the load characteristics of that demand, we are still faced with the problem of choosing a combination of generating and transmission facilities that will provide electricity at lowest cost. Facilities planners have traditionally used forecasts of demand and load as the major determinents of required plant size. However, there are a number of other issues that are important in thinking about how to expand an electrical supply system. Capital and fuel costs for new power facilities are obviously important factors as are system requirements for reliability. Another important consideration that has so far received inadequate attention in the public discussion of Railbelt supply is the impact of uncertainty about future demand, construction costs, fuel prices, and the like, and a system's need for flexibility to cope with the unexpected.

Facilities planning involves looking at the entire supply system --- including its present and anticipated load factors, use of existing equipment and management of reserve capacity --- and for that reason, each utility and each region faces its own unique set of facility planning problems. One factor that complicates any evaluation of the Susitna project is the fact that the existing generating plants and distribution system for the area Susitna would serve are owned and operated by several different utilities. Determining where and to what extent Susitna would fit in requires some assumptions about how the rest of the power supply system will function --- an issue that is clouded by the separation of jurisdiction among several utilities.

Planning for power development in the Railbelt as a whole must take into account the potential uses of existing facilities owned by the utilities as well as any new facilities that may be owned and operated by the Alaska Power Authority. The legislation that established the Authority placed this responsibility in the Department of Commerce and Economic Development, but thus far [early 1980] the department does not even have the funding or the staff to begin work on a credible power development plan.

Cost concepts. Several concepts frequently used in describing the costs of a particular generation facility or system supply plan are worth mentioning at the outset.

Fixed Costs. Fixed costs are costs incurred by a facility regardless of whether or not it is actually operating. They include the initial outlays for purchase and development of a site, equipment and its assembly, materials, engineering, overhead and contingencies, and interest. Fixed costs are generally spread over the entire operating life of a facility; if they are very large, they will significantly affect the cost of electricity. A working index of how important fixed costs are to the cost of electricity generated by a particular facility is the ratio of fixed cost in dollars to its installed capacity in kilowatts, or "installed cost." Table 1 compares (1976) installed costs for a variety of generating equipment.

Table 1 tells us that for each kind of generating facility (with the possible exception of hydroelectric, where fixed costs per unit of capacity vary enormously from one site to another), the larger the generating unit, the smaller the installed cost per unit of capacity. Table 1 also suggests that initial capital costs per kilowatt for diesel generators tend to be considerably less than for steam turbines or hydroelectric plants.

Table 1
Installed Cost Estimates for Typical Generating Units*

Unit	Size (MW)	$/KW Installed
Diesel Generator	0.1	680
	3.0	412
Gas Turbine (Simple)	.8	526
	10.0	322
	50.0	210
Steam Turbine (Coal Fired)	.3	1346
	10.0	891
	200.0	494
Steam Turbine (Gas Fired)	.3	1130
	10.0	749
	200.0	415
Hydroelectric	5.0	1557
	30.0	1032
	125.0	1748
Nuclear	1000.0	1000+

* The installed costs are taken from estimates for Alaska, made by the Institute of Social and Economic Research in 1976 and should be considered only as examples.

Operating costs. Operating costs, or "variable costs" as they are sometimes called, refer to expenses incurred to operate, maintain and insure a particular facility once it is built. With the exception of nuclear and hydroelectric plants where fuel is relatively cheap, fuel is the number one operating cost if a plant is operating near full capacity. For example, in 1978, Anchorage Municipal Light and Power spent 85 per cent of its operation and maintenance budget on fuel. If fuel comprises a large portion of total costs (fixed and operating), the cost of electricity from that particular facility will, of course, be very sensitive to the price of fuel.

Heat rate. Heat rate is a measure of the energy-efficiency of a given generating facility, stated as the amount of heat energy in BTU that a specific fuel must provide in order to produce one KWH of electrical energy. (Thus, the more energy-efficient the facility, the lower is its heat rate.) The heat rate for a given generating plant depends not only the type of fuel, but also on the type of generating unit, the characteristics of the particular plant, and its operating schedule. Together with the prices of individual fuels, therefore, heat rates determine the relative fuel costs for a unit of electricity.

Table 2 illustrates heat rates for different kinds of generating units. One plant's greater energy-efficiency in converting fossil fuel to electricity may be balanced against a higher price for the fuel it requires. Combustion turbines, for example, convert natural gas energy into electricity less efficiently than diesel generators convert distillate fuel oil. In Alaska, however, the greater efficiency of the diesel engine is more than offset by the higher price of distillate fuel oil.

Table 2
Heat Rates and Relative Fuel Costs for Electrical Generation

Plant	Heat Rate (MBTU/KWH)	Fuel Price (¢/MMBTU)	Fuel Cost (Mills/KWH)
Steam turbine — coal fired	10	90	9.0
Combustion turbine, open cycle — gas fired	16	60	9.6
Combustion turbine, regenerative cycle — gas fired	14	60	8.4
Combustion turbine — distillate oil fired	17	221	37.6
Combustion turbine — residual oil fired	18	180	32.6
Diesel — distillate oil fired	11	221	24.3

Source: Estimates for Alaska made by ISER in 1976.

Electrical generating technologies.

In practical terms, it makes sense to talk about four basic types of generating technologies that could be used to augment generating capacity in the Railbelt.

Diesel Electric Generating Units. Diesel generating units are diesel-type internal combustion engines directly connected to an alternating generator. The units are built as a complete assembly and marketed by major manufacturers as an "on-the-shelf" item. If properly installed and maintained, they are fairly reliable both for base loads and for emergency on-line systems. Larger units (500 KW or greater) can approach fuel efficiencies of 13 kwh/gallon or a heat rate of 10,800 btu/kwh, which is competitive with the larger steam plants. However, smaller units (75 to 250 KW diesels) may have efficiencies as low as 7 kwh/gallon or 20,000 btu/kwh.

Diesel generators have low fixed costs relative to other fossil-fuel-fired generating units, but they need a high-priced fuel. As a result, the price of distillate fuel oil is the single most important factor determining the cost of electricity generated by diesel plants.

Combustion (or gas) turbine generating units. Gas turbines are installations in which either gas or oil is fired in a turbine that drives a generator. There are a variety of turbine types, each designed for different capacities and fuel efficiencies. Like diesel units, small simple-cycle turbines can be purchased ready-made from the manufacturer; larger regenerative or combined-cycle units may take two years to build on-site and another year to bring on line.

Heat rates for simple-cycle gas turbines range from 12,000 to 16,000 btu/kwh, depending on their size. Regenerative-cycle gas turbines are more costly but more fuel-efficient, with heat rates between 9,500 and 13,500 btu/kwh.

In the Railbelt, gas-fired turbines are the predominant type of electrical generating unit, carrying about 70 per cent of the total load in 1977. (See Table 3.) The popularity of gas turbines in Alaska reflects their ease of installation and consequent ability to respond quickly to rapid (and uneven) demand growth, as well as the exceptionally low price of natural gas in the Anchorage area (where it constitutes the cheapest utility fuel in the United States).

Because of rising gas prices, gas turbines may prove too expensive in the future for base-load power generation. For a limited number of hours, the cost per kilowatt hour

Table 3
Railbelt Electrical Generating Capacity --- 1977

	Installed Capacity --- Megawatts				
	Hydro	Diesel	Gas Turbine	Steam Turbine	TOTAL
Anchorage-Cook Inlet					
Utilities	45.0	9.8	435.1	14.5	504.5
Military		9.2		40.5	49.7
Industrial		10.2	14.8		25.0
Subtotal	45.0	29.3	449.9	55.0	579.2
Fairbanks-Tanana Valley					
Utilities		32.1	203.1	53.5	288.8
Military		14.0		63.0	77.0
Subtotal		46.1	203.1	116.5	365.8
TOTAL	45.0	75.4	653.0	161.5	945.0

for electricity produced by gas turbines is, and probably will remain, inexpensive relative to other types of generation. But, as the load factor increases, unit costs do not fall rapidly, as they do for coal-fired, nuclear, or hydroelectric plants. For this reason the greatest appeal of gas turbines is for use in limited peak load situations.

Nevertheless, the low capital costs of gas-fired power are an especially welcome feature in a period of double-digit interest rates and disorganized bond markets, and gas-based generating strategies are by far the most flexible in the face of uncertain future demand growth. For these reasons, the installation of new gas turbines is one of the most attractive options for Alaska utilities, even for base-load generation. This is likely to remain the case despite the prospect that prices for new gas supplies (whether from Cook Inlet or the North Slope) will be about ten times as costly as the utilities' current supplies.

Federal restrictions on use of natural gas. For almost a decade, FPC (FERC) and most state utility commissions have discouraged the use of natural gas as electric utility fuel. More importantly, the Power Plant and Industrial Fuels Use Act (PIFUA) prohibits the use of gas in new generating facilities, with certain exceptions. The Economic Regulatory Administration of the Department of Energy (ERA), which administers PIFUA, has thus far tended to interpret the Act strictly.

Since the law was enacted in 1978, however, the national outlook for natural gas supply has improved radically, and unless ERA interprets PIFUA liberally, Congress will almost certainly amend or repeal it. If Railbelt utilities conclude that gas turbines remain the least-cost or most prudent source of additional power, we do not believe that federal regulators will prevent them from obtaining as much gas as they need for new facilities, as well as for their existing plants.

Federal policies, however, coupled with uncertainty about future gas prices, do contribute significant risks to any natural-gas-based generation strategy. It is not clear, however, whether these risks are greater than the engineering, cost, scheduling, marketing, and regulatory risks of strategies that depend upon Susitna hydropower or steam generating plants fired by Beluga coal.

Natural gas liquids as turbine fuel? Another possible fuel for combustion turbines in Alaska is natural gas liquids (NGL's) --- ethane, propane, butane, and pentanes-plus --- that will be separated from the crude oil and natural gas streams at Prudhoe Bay. State agencies and chemical producers are now looking at the possibility of shipping these liquids by means of a third pipeline (in addition to TAPS and ANGTS) from the North Slope to the Fairbanks or Cook Inlet areas, where they would be used as feedstocks for chemical manufacturing.

No reliable estimates yet exist on the cost of such a gas liquids pipeline or the delivered price of NGL's in the Railbelt area, but prices that are low enough to assure the feasibility of petrochemicals manufacturing may also be low enough to make NGL's competitive as a turbine fuel for electric utilities. Prudhoe Bay NGL's would constitute a reliable 20- to 25-year supply, with two conspicuous advantages over oil or gas as turbine fuel: (1) their prices could be fixed in advance for the life of the field, on the basis of the maximum price they would be allowed to receive under federal law as part of the natural gas stream in ANGTS, and (2) the largest component of the gas liquids (ethane) seems to be exempt from federal end-use controls on both oil and gas. Thus, NGL's are at least worthy of consideration for use as electric utility fuel.

<u>Methanol as turbine fuel</u>? Another potential source of energy for combustion turbines in the Railbelt is methanol. Several firms are now investigating the feasibility of producing fuel-grade methanol from Prudhoe Bay natural gas, from Beluga coal, or both. Credible cost estimates are not currently available but methanol, like NGL's, may conceivably turn out to be a clean utility fuel that is cheaper than oil and exempt from some of the regulatory risks of natural gas.

<u>Steam turbine generating units.</u> Conventional steam plants consist of a fuel-fired boiler for raising steam, which then drives a turbo-generator. Steam turbine generators, especially units built to handle large base loads (100

to 1000 MW), are considered the most reliable and fuel-efficient thermal generating equipment. Steam can of course be raised by oil, gas, natural gas liquids, coal or nuclear fuel. Except for the smallest units, the systems are always custom-designed, requiring long lead times for environmental assessment, fabrication and delivery of major equipment. As with gas turbines and diesel generators, the economics of steam plants are very sensitive to the price of fuel.

The 1976 ISER study found that uranium and coal would be the least expensive fuels for steam generation in Alaska in the long run. While nuclear power may be viable technically, the Alaska Power Administration and most of the utilities in the region have ruled it out because of its high initial fixed cost, siting problems, and probable public opposition.

Coal-fired plants remain a serious alternative as a source of additional power for the Railbelt, because of the nearby Beluga coal reserves. Although fuel costs would probably be low compared with those of oil or gas, initial cost for an enclosed plant with scrubbers would be extremely high: the Power Administration has estimated them at $372 million (1978 dollars) for a 200 MW plant ($1,860 per kilowatt installed), and $810 million for a 500 MW plant ($1,620 per kilowatt installed).

Hydroelectric generating units. Hydroelectric facilities create electricity from falling water and are considered among the most reliable types of generating equipment. Minimum maintenance requirements and the virtual absence of fuel costs make these facilities very cheap to operate. Initial capital costs are usually very high, however, with investment per KW of total capacity greater than fossil fuel-fired installations. Because the best hydro sites are usually at some distance from the load centers, transmission facilities are often a large portion of the initial cost. In Table 4 the 1978 cost estimates suggest that hydroelectric plants would be more expensive to build but cheaper to run than coal-fired steam turbine plants.

Table 4
Estimated Costs for Coal-Fired
Steam Plants and the Susitna Project

	Installed Cost		OM&R Cost	
	(mil.$)	($/KW)	(mil.$/ year)	($/KW/ year)
100 MW coal steam turbine	245.4	2,454	3.76	37.6
200 MW coal steam turbine	372.0	1,860	5.70	28.5
400 MW coal steam turbine	646.8	1,617	9.80	24.5
Watana dam (795 MW)	2,020.7	2,554	0.74	0.94
Transmission line	470.5			2.01
Devil Canyon dam (778 MW)	834.0	1,072	0.73	0.94
Total Susitna project	3,335.2	2,120	1.47	3.89

Source: Alaska Power Administration, October 1978

The efficiency of hydroelectric energy conversion is expressed as the ratio between electric energy delivered out of the plant and the maximum theoretical energy of the available volume of falling water. This ratio can reach about 90 per cent, compared to a maximum conversion efficiency of about 38 per cent in the best fossil-fueled plants.

Each hydroelectric site and each facility is unique, and thus the economics of hydroelectric plants are very sensitive to local conditions (e.g., topographic and hydrographic conditions, distance to load centers, etc.). Typically, hydroelectric facilities require long lead times for design and installation.

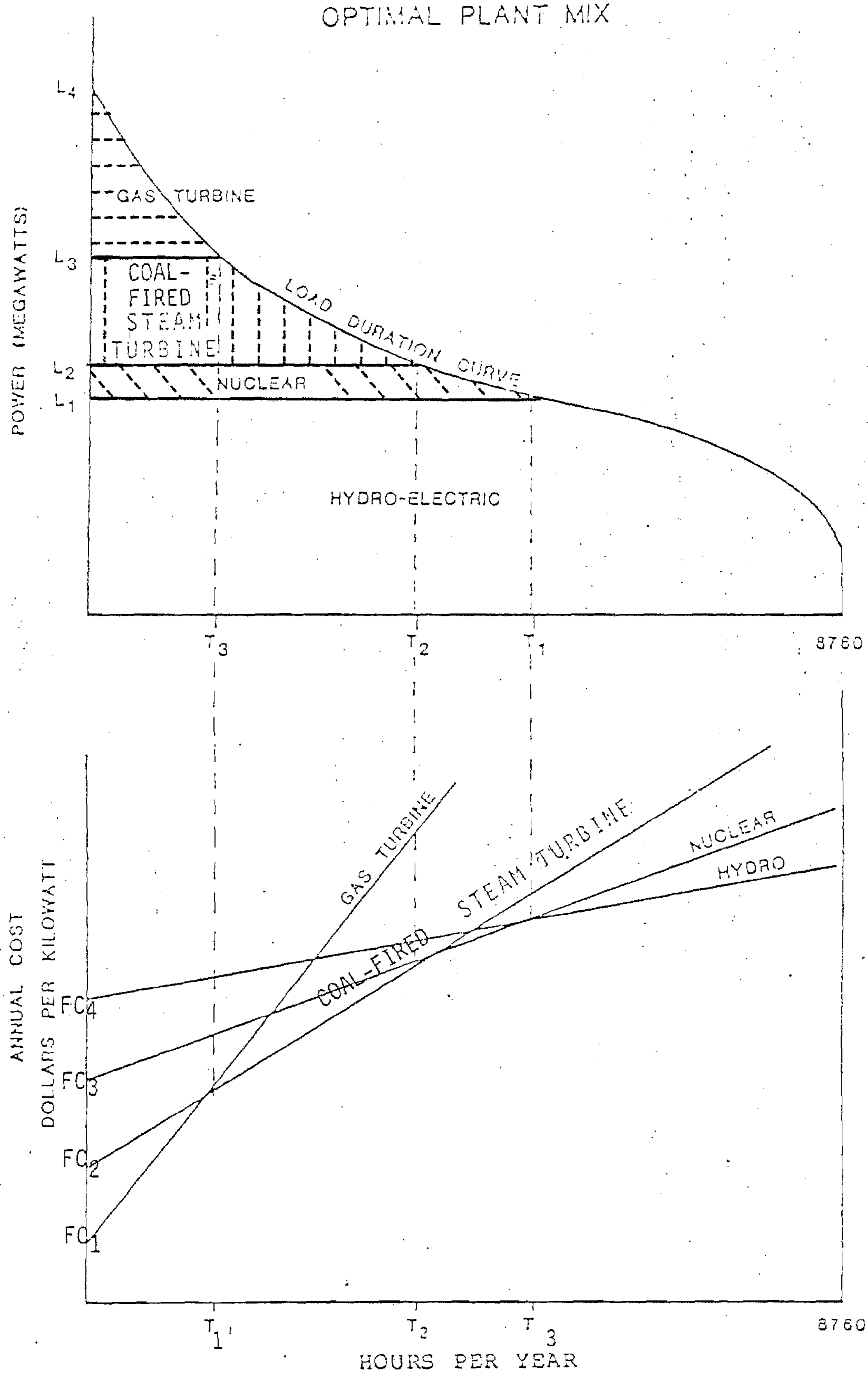
Cost hierarchy for electrical generation. As the previous discussion shows, the composition of generating costs depends upon the type of plant. When initial fixed costs are high, as in the case of steam and hydroelectric plants, operating costs play a relatively small role in the unit cost of electricity. At the other end of the hierarchy gas turbine and diesel plants have relatively low initial costs but high operating costs for fuel and maintenance.

This cost hierarchy is the main consideration in power supply and management strategies. For a hydro project where fixed costs are large and must be recovered whether electricity is generated or not, it is extremely important for demand to justify operating the plant as many hours as possible. A utility that relies on diesel or gas turbine generation, on the other hand, will not suffer disaster if some of its plants are forced to stand idle. This is the reason demand forecasts are so crucial in assessing the viability of the Susitna project.

Plant mix. The cost hierarchy among generating technologies, plus the load duration curve, determine what mix of facilities would provide the lowest cost electricity for base, intermediate, and peak load situations, and thus, for the entire system.

In figure 3, the top graph is a load duration curve similar to that of figure 2, depicting the number of hours in a year that hypothetical utility faces a given level of demand, from the peak load (L_4) down to the lowest load of the year. In the bottom graph the four curves each depict the annual costs (in dollars per kilowatt of capacity) for four types of generating technology. The point where each line originates on the vertical axis shows the fixed capital

Figure 3
OPTIMAL PLANT MIX



cost of a given type of technology, while the slope reflects hourly operating costs --- principally fuel.

As we have seen in earlier examples, initial fixed costs cost per kilowatt of capacity are lowest for gas turbines (FC_1), followed by the coal-fired steam turbine (FC_2), nuclear (FC_3), and hydro (FC_4). The hierarchy of fuel and other operating costs is just the opposite, however: the figure shows that gas turbine generating costs increase the most steeply, and hydropower costs the least, as the number of hours of operation increases.

In this example, the four cost curves indicate that gas turbine generation is the least-cost way to satisfy any load that will persist for no more than T_1 hours. For any load whose annual duration is more than T_1 and less than T_2 hours, a coal-fired steam plant would have the lowest unit cost. In a similar manner, the figure identifies those portions of demand for which nuclear and hydro would be the cheapest alternatives.

Returning to the upper graph, we can infer the least-cost mix of generating plant for the entire system: Hydro capacity should be L_1 MW, and should be operated continuously. Nuclear capacity should be L_2-L_1 MW (provided, of course, that this is a feasible scale for a nuclear plant) and should be operated T_3 hours per year. Coal-fired Plants should have a capacity of L_3-L_2 MW, and should be operated T_2 hours per year, while gas-turbine capacity should be L_4-L_3 MW, and operated only T_1 hours per year.

Use of existing equipment. When facilities planners choose a mix of technologies, they must match the system's load characteristics to both existing and proposed equipment in order to determine what kind of supply system will best serve base, intermediate, and peak loads, while providing sufficient reserve capacity to meet unanticipated demand, and scheduled and unscheduled equipment outages. Each utility or region has a unique cost hierarchy, and the cost of available generation technologies are not always ranked on the load duration curve in the same order as they appear in figure 3. Some hydroelectric projects, for example, are best suited for use as base-load supply, and others make more sense for meeting peak load requirements. The distinction depends on each facility's unique combination of annual stream flow, reservoir storage capacity, and installed generating capacity.

The most cost-effective role for an existing plant may also change through time. An older fossil-fired plant may be shifted from base-load to peaking service, and ultimately retained only as reserve capacity, if operating costs are lower on newer parts of the system. Changes in the relative costs for different generating technologies may likewise make it worthwhile to install additional generators at an existing hydro-electric project whose initial construction had to be justified by its low cost for base-load supply, in order to use its limited water supply to generate peak-load power.

Dealing with Uncertainty. With perfect foresight, it would be possible to choose the lowest-cost combination of plants for a given system with confidence, but the real world is full of surprises. We noted earlier that demand forecasts are notoriously inaccurate, especially in Alaska where major development projects continue to have an uneven and often unanticipated effect on demand.

There are other uncertainties as well. Large projects are more prone to cost overruns and delays in completion and operation than small, quickly constructed plants. Large ($1 billion and up) custom-engineered construction ventures in North America begun in the 1970's typically took three to five years longer to complete than originally planned, and cost overruns of 100 to 500 percent were not unusual.

The bigger the unit of construction, the more unique the design, the more novel the technology or environment, and the larger the number of governmental entities and permits and licenses involved, the greater the overruns and the longer the delays tend to be. A project that seems feasible on the basis of its original engineering cost estimate and planned completion date may easily turn out to be uneconomic on the basis of a more realistic schedule and cost estimate.

Choosing to build a series of small generation plants, say gas turbines, avoids most of the uncertainty about construction cost overruns and scheduling delays, but it invokes another unknown: the rate of fuel cost escalation. The latter was certainly one of the great surprises of the last decade.

In providing for an uncertain future, therefore, utility planners must be aware of the consequences of both overbuilding and underbuilding. The costs of excess capacity will consist largely of fixed charges on investment, resulting in higher unit costs of electricity and higher costs to consumers. Proponents of maximizing capacity tend to argue that the new capacity, with its greater thermal efficiency, can be expected to save on fuel costs. But a new fuel-efficient facility can be justified as a replacement for, or duplication of, an existing facility if and only if the old intallation's <u>operating costs</u> alone exceed the new plant's <u>total costs</u> per unit of electricity --- that is, its fixed and operating costs combined.

If capacity turns out to be inadequate, a power system usually has considerable latitude for using its existing generating capacity more intensively. Doing so is likely to require more high-priced fuel, however, and some reduction in system reliability. Utilities can also bring on line additional capacity in smaller --- if less efficient --- units as they are needed, and not run the risk of investing large amounts of capital for a demand that may not materialize.

<u>Reserve requirements and load management</u>.

The investment strategy of most electric utilities in the United States has historically been a passive response to growing demand. Each utility tried to construct, in advance of need, sufficient generating capacity to meet its forecasted total and peak load demands, plus an adequate reserve to cover unexpected peak loads and scheduled or unscheduled equipment outages. To the extent that rate design or marketing strategies were deliberately used to influence demand, they tended to be promotional --- aimed at stimulating demand and thus justifying new construction.

In Europe and Asia, however, where both capital and operating costs have been considerably higher than in the United States, planners and utility managers have given much more attention to conservation --- both of dollars invested and of fuel consumed. As a result, system load factors in some countries are as high as 65 to 75 percent, in contrast to a range of 45 to 60 percent in the United States. Also, reserve margins above forecasted peak loads have been reduced below 10 percent in some countries, while utilities in the United States tend to carry reserves of 20 to 30 percent.

The promotional policies of North American utility systems generally had the support of state and federal regulators and of the public at large, so long as utility fuel remained cheap, blueprints for massive new projects seemed to offer major economies of scale, and the technologies of newer plants surpassed the older ones in efficiency and operating costs.

Recently, however, the growing difficulty of siting and licensing new plants, higher construction costs and interest rates, and above all higher fuel costs, have finally created an interest among utility planners and regulators in promoting the more intensive use of existing generating capacity and reducing the need for new facilities, by means of (1) peak-responsibility pricing, (2) "load manangement" techniques, and (3) reduction of planned reserve ratios.

These initiatives were boosted in 1978 by Congressional passage of the Public Utility Regulatory Policies Act (PURPA), which is intended to encourage:

*** conservation of energy supplied by electric utilities;

*** efficient use of existing generation facilities and resources; and

*** equitable rates to electric consumers.

Among other things, PURPA requires FERC and the state utility commissions to consider peak-responsibility pricing and other rate-design measures intended to foster efficiency and energy conservation.

Reserve generating capacity. Electric power systems always carry some reserve capacity in excess of their forecasted peak demand. The excess capacity provides insurance against system failure, and is also available to meet unanticipated peak loads or future increases in base load demand.

Reserve capacity is usually measured in terms of a "reserve margin," which is the percentage of total capacity that is in excess of the anticipated annual peak load. In the two Railbelt load centers, 1977 reserve margins were as follows:

Place	(1) Peak Load (MW)	(2) Generating Capacity (MW)	(3) (2)-(1) Reserve Capacity (MW)	(4) (3)/(2) Reserve Margin (%)
Anchorage-Cook Inlet	464.4	691.1	226.7	32.8
Fairbanks-Tanana Valley	159.9	364.9	220.5	56.2
TOTAL	623.3	1,056.0	447.2	42.3

Source: Alaska Power Administration.

The reserve margins that Railbelt utilities carried, even at the peak of the TAPS construction boom, were thus considerably higher than the 20 to 25 percent sought by most Lower 48 utilities. This comparison does not necessarily mean that the Alaska margins were excessive, because they reflect in part the relatively small size of these systems, in which the shutdown of a single unit would make a very significant dent in total generating capacity. They do, however suggest that measures that reducing the required reserve margins could serve as a substitute for a large volume of new plant construction.

Suppose, for example, that the two load centers were interconnected into a single power pool, and that this pooling, plus load management and selective load-shedding strategies, permitted reserve margins to fall as low as 15 percent and yet preserved acceptable levels of reliability: The 1056 MW of area-wide generating capacity that existed in 1977 would then be able to serve a peak load of 898 MW [85 percent of 1056], an increase of 44 percent over the actual 1977 peak demand. The additional useful capacity that might thus be made available from the Railbelt's existing equipment would be equal to more than one-third of the projected capacity of the Susitna project's Watana dam.

System reliability is the extent to which power can be provided to customers without interruption and at an acceptable voltage and frequency. System planners have developed a number of statistical measures of reliability, which serve as their targets in determining each system's optimum reserve margin, taking into account uncertainty of load forecasts, size of generating units relative to total system size, need for preventive maintenance, and the reliability of individual units.

A growing number of analysts believe that the prevailing reliability standards are unnecessarily strict, and require wasteful excess capacity. One reason for this new skepticism about traditional reliability standards is of course the soaring cost of new plants, and the difficulties of obtaining site approval and licenses. But it also stems from a growing recognition that the great majority of power interruptions that electric customers actually experience result from distribution system failures, rather than generating plant outages. It makes little sense to provide a generation "loss of load probablity" (LOLP) of one incident in ten years while the utilities offer (and regulatory authorities and consumers are willing to put up with), say, an average of one outage per year arising from a failure of transmission lines, substations, or distribution lines.

Load Management. Utilities in the United States are belatedly finding it attractive to reduce reliability target levels and devise peak-responsibility pricing or load management schemes. Load management permits a utility to make more intensive use of its low-cost base-load generating capacity; to economize on the higher operating costs of existing intermediate and peak capacity; and to reduce the amount of new construction required to serve intermediate and peak loads and to maintain reserve margins.

Load management techniques include:

1. Establishment of power pools or interties with other utilities, in order to take advantage of peaks occuring at different hours or times of the year and to share reserve generating capacity.

2. Installation of time switches to shut off less essential heavy-load appliances and industrial equipment during peak demand hours.

3. Installation of remote-control switches that permit the utility to shut off less essential loads during peak demand hours or system emergencies, by means of a signal sent by radio, telephone, or through the power line.

4. Design of peak-responsibility rate structures, under which consumers are billed for peak period power at its relatively high cost to the system and for off-peak power at the much lower cost of base-load generation, creating an incentive for consumers themselves to reduce peak-hour demand.

5. Sale of off-peak or surplus power to industry at low interruptible rates.

Only pooling (#1) and interruptible sales (#5) are commonplace in the United States today, and the latter is actually a device for increasing off-peak loads rather than for reducing peak demand. In the past, the cost of installing time-switches, remote control load-shedding equipment, and time-of-day metering was a major obstacle to implementation of load management strategies in the United States --- or so the utilities argued. The appearance of the $10 microprocessor (the chip at the heart of pocket calculators and mini-computers) has now swept away any substance this objection may have had in the past.

In the future, environmental and consumer spokesmen at licensing and rate hearings; federal and state regulators, and the utilities' bankers and investors will all demand that utility planners fully exlore the potential of using rate design and load-management strategies to reduce capital and operating costs, <u>before</u> they raise rates or build expensive new plants. Thus far, the question is practically unheard-of in Alaska, but we are confident that --- sooner or later --- it will be a prominent issue in debate over the Susitna project, and rightly so.

<u>Organization and financing</u>.

<u>Principles of finance</u>. When utilities must replace equipment or build new capacity, they are concerned, from a financial standpoint, with two questions: how to raise the necessary capital and who will assume the risk. These questions are major ones, for advances in technology, stricter environmental and safety standards, inflation, and the cost of capital have all conspired to drive up the original cost of electrical generating plants.

While large projects offer certain benefits with respect to economies of scale, their sheer size also increases the investment risk. In recent years, other economic circumstances, such as an unanticipated fall-off in demand growth, rapidly and unpredictably rising fuel prices, changes in laws and regulations, equipment and technology failures, cost overruns, and delays in plant construction, have also aggravated the uncertainty of actual completion and final costs for large projects.

To avoid or minimize these risks, lenders invariably require one, and usually both, of the following assurances:

(1) The project's anticipated cash flow from operations must be sufficient to make all scheduled payments of principal and interest on time, and with a substantial margin ("coverage") to spare; and

(2) The borrower or a creditworthy third party must pledge sufficient collateral or unrelated income to pay of the entire loan plus accumulated interest, even if the particular project should fail altogether.

The first requirement is normally met by the borrower's equity in the venture. The more equity there is in the project's "capital structure," the less likely it is that revenues will fail to cover operating expenses and debt service. Conversely, the more leveraged a firm's capital structure --- that is, the higher the percentage of debt --- the greater the danger that, for some reason, revenues will not be adequate.

The second assurance is usually carried on the strength of the borrower's total assets and the soundness of its overall capital structure. Most firms maintain a capital structure about evenly divided between equity and debt. The 1978 debt of the top 50 manufacturing companies in the Fortune 500, for example, was 51 percent of their total assets. Utilities can safely carry higher debt ratios than unregulated industries because, while regulation does limit profit rates, a utility's monopoly status gives lenders confidence that it will be able to cover its costs, including debt service charges, under almost any circumstance. Even for Fortune's top 50 utility companies, however, debt was only 62 percent of total assets, and among the utilities, there were just two that had "debt ratios" exceeding 75 percent.

Conventional balance-sheet financing. Traditionally, private and municipal utilities alike have raised capital and assumed the risk of building and operating new generating facilities through "balance-sheet financing". That is, all debt capital contributed to the project is secured not only by the assets of and the cash flow from that project, but by the entire income and assets of the sponsoring company or government agency.

Capital for conventional balance-sheet financing is usually raised by selling securities (stocks and bonds) to the public --- individuals, banks, mutual funds, pension funds, and insurance companies. Municipal utilities usually sell tax-exempt bonds, thus obtaining a lower interest rate than conventional bonds, and cooperatives are able to borrow from the Rural Electrification Administration (REA).

The surplus earnings that a utility retains from its operations, and depreciation allowances on existing facilities, are also sources of capital. Generally, private utilities do not pay out all their net earnings in dividends to shareholders, but rather retain a portion for reinvestment or as a reserve to cover their debt service (principal and interest payments) obligations, should future cash flow fall short of expectations. (Municipal utilities and governmental power authorities generally do not calculate a "profit" entry in their books, or pay dividends to their governmental owners at all. They may nevertheless accumulate surplus cash from earnings and depreciation allowances for reinvestment or debt service coverage.)

Most utility expansions, including all projects we are aware of in Alaska (other than federal power projects) have been financed conventionally on the utility's balance-sheet. Several factors, however, are undermining the ability of individual utilities to finance large projects conventionally, particularly in Alaska:

1. Projects are getting bigger. In most places, new base-load generating facilities are designed to carry greater loads and thereby take advantage of economies of scale. However, with the attendant high initial fixed costs, compounded by long construction and shake-down schedules, the assets and markets of a single utility may not be able to cover construction and operating costs, or bear the risks of cost-overruns, delays, and non-completion.

2. Traditional sources of direct and third-party guaranteed loans to Alaska utilities are drying up. Most cooperatives in Alaska have financed their expansion heretofore with two- and five-percent REA revolving loans. Payments of principal and interest on earlier REA loans are the chief source of new loan money. Because the demand for these loans is increasing, while the original appropriation

into the revolving fund is limited, this source of capital will be depleted within the next five- to ten-year period unless Congress injects additional money.

3. Rapid facilities expansion in the 1970's aggravated the already high debt ratios of REA cooperatives in the Railbelt. Despite their exceptionally low interest rates, the utilities appear to be facing increasing difficulty in servicing their existing long-term debt.

As a general rule REA expects its borrowers to have an "interest coverage ratio" --- the ratio between revenues less operating expenses and interest payment obligations --- of at least 1.5. Table 5 shows that the utilities' debt ratios have tended to increase, with a corresponding drop in interest coverage down to levels that may preclude large debt issues in the future, at least without very dramatic and unpopular rate increases.

Table 5

Debt and Interest Coverage Ratios for Railbelt REA Cooperatives

Utility	Debt Ratio		Interest Coverage	
	1973	1977	1973	1977
Matanuska Electric Association	87.0	93.7	2.76	1.03
Homer Electric Association	88.5	87.7	2.07	1.51
Golden Valley Electric Association	92.1	95.9	2.07	1.61
Chugach Electric Association	90.9	94.7	1.52	.93

Thus far, the Alaska regional office of REA has managed successfully to meet the utilities' demand for low interest capital. But if the cooperatives must turn to other sources, such as the Federal Financing Bank or the National Rural Electrical Cooperative Financing Corporation, they will face not only higher interest rates, but the need to reduce their debt ratios and increase their interest coverage.

4. The cost of money is increasing. With soaring interest rates, utilities that need to raise capital will have to pay dearly for that money --- if, indeed they can obtain it at all in a disorganized bond market. Recent rates in municipal bond sales have been at 8 to 9 percent or higher, and higher interest rates may require more than proportional increases in electricity prices, because of the need for higher absolute levels of interest coverage --- in addition to the rate increases dictated by higher fuel and construction costs.

Alternative financing strategies: Project financing. The circumstances we have described probably make conventional balance-sheet financing of a project as large as Susitna infeasible for any existing Alaska utility or even any combination of existing utilities. Instead, the Alaska Power Authority is considering an alternative method: "project financing."

The essence of project financing is creation of a new business entity in charge of the project for which the sponsoring companies or government bears no liability. The new entry has virtually no assets outside of the project itself; hence prospective lenders must be assured that some other creditworthy party will meet the tab for principal and interest payments in the event that the project does not generate sufficient revenues.

Project financing --- if attainable --- carries two advantages for sponsoring utilities: (1) the debt ratio can be comparatively high (70 to 100 percent), and (2) the debt is secured by means other than placing the assets of the parent companies (or the full faith and credit of the governmental sponsor) on the line. It virtually absolves the sponsoring companies from carrying any business risks beyond contributed equity capital, if any. Moreover, because the debt does not appear on the sponsors' balance sheet, they can use project financing to sidestep provisions in their existing debt obligations that would otherwise limit their ability to incur further debt.

Project financing is not, however, a means of shifting construction, operating, or marketing risks to the lenders. All such risks must be assumed by some other party or parties at least as firmly as the sponsors would have assumed them in a conventional financing. There are essentially two methods of securing debt without recourse against the sponsors --- guarantees from consumers, and guarantees from governments or other third parties.

The first approach relies on revenues from project customers, secured by "all-events", "minimum-bill", "take-or-pay" contracts, whereby the wholesale customers (Alaska utilities) bind themselves to pay the costs of operation and maintenance, interest and the scheduled repayment of principal --- however high those charges may be, and whether or not the service or product is actually delivered. There are three preconditions for this kind of project financing:

1. Distribution utilities must be willing to sign all-events, minimum-bill, take-or-pay contracts, in advance of construction, obligating themselves to pay all of the project's debt service and operating costs, however high those costs might be.

2. The Alaska Public Utilities Commission (APUC) must have the legal authority, and use that authority, to assure in advance that those contract obligations will be "perfectly tracked" into the bills of the final electricity consumers, no matter how great the charges may be.

3. Lenders must be confident, despite these contractual and legal assurances, that an adequate market exists for the power, and that the bills paid by final consumers will in fact be enough to meet the utilities' contractual obligations to the project entity (along with their other obligations).

These conditions are not implausible, but they are exceedingly demanding. If they can not be met, a non-recourse (revenue bond) project financing will be impossible, and capital can be raised for plant construction only by means of general obligation bonds or some other form of state loan guarantee, or by direct governmental financing.

Construction financing. Take-or-pay contracts do not normally take effect until projects are complete and operating. There is little chance that private lenders will agree to assume the risk that a major Alaska power project will not be completed, will be completed only after an extended delay or, if completed, will not work properly. Thus, while the three assurances described above might attract financing of post-construction long-term debt, it will be far more difficult to find lenders who are willing to carry the project over its construction period.

There are only two parties capable of securing the construction debt of a large project-financed generating plant in Alaska: final consumers and the state government. The preconditions for consumer guarantees of construction debt are even more demanding, and considerably less probable of achievement, than those for securing long-term debt by means of take-or-pay contracts:

1. The utilities that contract to buy power from the project entity must agree to pay interest and to begin repaying the principal on all funds used for "construction work in progress" (CWIP) during the entire construction period. This arrangement is in contrast to the more conventional one in which all pre-operational costs, incuding interest on construction debt (the "allowance for funds used during construction" [AFUDC]) are "capitalized," with all charges to customers postponed until the facility begins operating.

2. The APUC must have the authority, and must use that authority, to assure that these pre-operational charges are perfectly tracked into final consumer bills, despite the fact that consumers might not receive any electricity from the project for ten or more years (if ever).

3. Lenders must be confident, despite these contractual and legal assurances, that the existing market for electricity in the Railbelt can bear the additional charges, and that the bills paid by final consumers will in fact be enough to meet the utilities' contractual obligations to the project entity in addition to their other obligations.

We have not rigorously calculated the expected impact of this method of financing on consumer electric bills, but in the case of the Susitna project it would likely double or triple the average cost of electricity to Chugach Electric

Association customers over the entire period of ten years or more before they even began to receive Susitna power. Consumer bills after the facility went on line would be correspondingly lower because much of the project's capital cost would already have been paid. This attraction, however, probably would not be sufficient to override the consumer outcry against taking on huge price increases now.

The implication of the foregoing is that construction of the Susitna project, or any generating facility of comparable size in Alaska, is unlikely to be financed without some kind of government loan guarantee or direct government investment.

CHAPTER III: HISTORY OF THE SUSITNA PROPOSAL

During the first half of the Twentieth Century, hydroelectric generation (with its high reliability and its freedom from recurring fuel costs) was the preferred source of electricity wherever suitable damsites existed. One of the chief missions of the Interior Department's Bureau of Reclamation was to identify potential hydropower sites, particularly on the Western federal lands.

Origins of the Susitna project.

Alaska's rivers were included in the federal site identification program, but they were too remote from the continent's population centers to draw much attention during the federal dam-building programs of the 1930's. Major developments, instead, centered on the Tennessee, Columbia, Colorado and other Lower 48 river systems. Federal interest in Alaska's hydropower potential was almost nonexistent until the late 1940's.

> [In 1950,] the Department of the Interior provided $150,000 to be used by the Bureau of Reclamation to update its Alaskan investigations of 1948. The results of these studies were to be used as a basis for legislation authorizing the development of the territory's water resources.
>
> In its final report, published in 1952, the Bureau of Reclamation identified a large number of possible hydroelectric power sites throughout Alaska. The Bureau pointed out that, among all the potential rivers, the Susitna River was the most strategically located of all Alaska streams because of its proximity to Anchorage and Fairbanks and the connecting railbelt. [Naske & Hunt, 1978]

The Bureau of Reclamation report identified three Susitna River damsites as having special potential --- Vee, 17 miles below the mouth of the tributary Tyone River; Watana, 36 miles downstream; and Devil Canyon, 28 miles further downstream. In view of the still-limited demand for electricity in the region, however, Congress only authorized construction of a smaller dam closer to the Anchorage load center: the Eklutna project, which was completed in 1955.

Bureau of Reclamation interest in the Susitna continued nevertheless, with release of a feasibility study in 1960 that favored a two-dam project at Devil Canyon and Denal; a site between Vee and Watana, about 10 miles below the Susitna River Bridge on the Denali Highway. In 1961, the Interior Department recommended Congressional authorization of this project with transmission lines to move Susitna power to both Fairbanks and Anchorage.

The Army Engineers' Rampart proposal.

About the same time, however, a rival project promoted by the Army Corps of Engineers and the Alaska Congressional delegation began to draw off much of the political support for Susitna development both within Alaska and in Congress. Advocates of the gigantic Rampart Dam on the Yukon River successfully persuaded Congress to defer action on the Susitna concept until studies of Rampart were completed.

Although Governor Egan, two major Railbelt utilities, the Anchorage Daily News and the Fairbanks News-Miner, the Alaska Chapter of the National Electric Contractors Association, and the Alaska Conservation Society all preferred the Susitna development, the Corps of Engineers and Senator Ernest Gruening captured the public's interest for the much more dramatic Rampart project throughout the mid-sixties. A recent review of Rampart's political history by Klaus Naske and William Hunt [1978] concluded that obsession with the grandiose and unrealistic Rampart scheme delayed serious consideration of the Susitna by more than a decade.

A 1967 report by the Interior Department effectively eliminated Rampart as a contender, finding that the project was neither economically nor environmentally sound. Instead, Interior recommended creation of a power pool that would interconnect the Cook Inlet and Interior Alaska load centers, and construction of new gas-fired plants in the Cook Inlet area and a mine-mouth coal-fired plant at Healy. For the longer-term it recommended further consideration of hydroelectric projects on the Susitna River and at Bradley Lake near the head of Kachemak Bay.

By the time that Interior issued its report, two organizational changes had occurred that affected the outlook for the Susitna project. First, the Army and Interior Departments, responding to Congressional annoyance about their competitive posture on river-development schemes, agreed to end their rivalry. The lead in hydropower policy and research was to be located in the Bureau of Reclamation (Interior), while design and construction responsibilities went to the Corps of Engineers (Army).

Creation of the Alaska Power Administration.

Subsequently, in 1967, the Interior Department withdrew the Bureau of Reclamation from Alaska entirely, and transferred its duties to the Alaska Power Administration (now part of the Department of Energy, and not to be confused with the state's Alaska Power Authority). The new agency is charged with forecasting electricity demand, and planning water resource development and electrical transmission facilities. The Administration also operates and markets power from the existing Eklutna hydroelectric installation near Anchorage and the Snettisham project near Juneau.

New federal interest in Susitna.

In 1972, the U.S. Senate Public Works Committee, of which Alaska's Mike Gravel was a member, passed a resolution requesting the appropriate federal agencies to assess the electricity needs of Alaska's railbelt area, and to take a fresh look at development of the Upper Susitna. In 1974, the Alaska Power Administration responded with an update of the Bureau of Reclamation's 1961 report and again recommended construction of a two-dam system, using the Denali and Devil Canyon sites.

In 1976 the Corps proposed to proceed with Phase I of the project's engineering and design on the basis of the 1974 studies. That year, Congress authorized $25 million for the Phase I effort, conditional upon "notification to Congress of the approval of the Chief of Engineers." All the required procedures for this approval had been completed by May 1977, when the office of Budget and Management (OMB) blocked the expenditure, insisting instead on supplementary geological, engineering, and economic studies. The Corps issued its supplemental report in February 1979; OMB approved it, and in the summer of 1979 the Corps forwarded it to Congress, where it is still under consideration.

State initiatives: The Kaiser proposal and establishment of the Alaska Power Authority.

Meanwhile, the State of Alaska had begun to consider independent initiatives to advance Susitna hydropower development. The state contracted for an economic and engineering feasibility study with the Henry J. Kaiser Company, which was considering Alaska locations for a major aluminum refining plant. Kaiser's 1974 report proposed a wholly different construction strategy, composed of a higher dam (Susitna I) about five miles upstream from the Devil Canyon site recommended by the Bureau of Reclamation and the Corps of Engineers, with smaller dams downstream (Olson) and upstream (Vee and Denali), to be built later. This concept appears to have no active support today.

The 1976 session of the Alaska Legislature created the Alaska Power Authority (to be distinguished from the federal Alaska Power Administration) as a vehicle for direct state initiatives in the design, financing, construction and operation of a Susitna hydroelectric project or other electrical generating and transmission facilities in the state.

The Authority was empowered to conduct engineering, economic, and financial feasibility studies; finance power projects directly through issuance of revenue bonds; lend to existing utilities or regional power authorities through a power project revolving loan fund; and contract with producers for the purchase of electricity. While legislation creating the Authority was enacted in 1976, it did not get any staff or funding until 1978.

Senator Gravel's funding proposal.

In 1976, the Susitna development was not moving very rapidly on the federal level. Moreover, Alaska's Senator Mike Gravel was concerned that Congressional attitudes toward federal power were changing and that the time was quickly running out on the practice of appropriating vast amounts of money for river-development projects whose benefits were wholly local. The Susitna proposal was clearly in this category: It would require a large portion of total federal outlays for power development to an oil-rich state, for the benefit of as little as one-tenth of one percent of the nation's population --- and in the richest state in the nation, to boot.

> Senator Gravel argued the urgent need for a break with tradition. Alaska must rely upon another means of financing hydroelectric projects. The senator proposed that Congress appropriate monies to a revolving fund equal to the phase one or the advanced engineering and design portion of any one project. The sponsoring state agency, in this case the Alaska Power Authority, soon to be created by the state legislature, would issue bonds based on the proposed project to pay the Corps for the phase-one work.
>
> In the event that the proposed development was not feasible, the federal revolving fund monies would be used to pay off the state bonds. If, however, the proposed project proved to be feasible, the Alaska Power Authority would issue revenue bonds and contract for the work. Under the Gravel plan, the federal revolving fund would act solely as a guarantee for the phase-one costs incurred by the state sponsor. [Naske and Hunt, 1978]

Current investigations.

The Gravel proposal as such was not adopted by Congress, but Phase I work for Susitna was conditionally authorized in the Water Resources Development Act of 1976. The Act did incorporate Gravel's concept of a cooperative federal-state effort in detailed feasibility studies, and required the state to reimburse the federal outlay for Phase I if the project proved feasible.

As an alternative to executing a cooperative agreement with the Corps of Engineers, the state had the option of arranging for and financing its own studies. The creation of the Alaska Power Authority in 1976, combined with suspicions in Alaska that the federal government was both out of sympathy with Alaskan goals and unable to move with dispatch or competence, led the state legislature to appropriate

$8.17 million to the Authority in 1979 for a series of feasibility analyses and design studies that may ultimately cost more than $50 million.

The Acres study.

The Alaska Power Authority treated the Corps equally with three private consulting firms as competitors for the Phase I effort. In November 1979, nevertheless, the Power Authority contracted for the studies with a private group led by Acres American, Inc. of Buffalo, N.Y. and Columbia, Maryland. Acres' subcontractors include ---

*** R & M Consultants of Anchorage (geotechnical field studies);

*** Frank Moolin & Associates of Anchorage (construction management):

*** Terrestrial Environmental Specialists, Inc., of Phoenix & New York (environmental assessment);

*** Woodward-Clyde Consultants of Anchorage & San Francisco (seismic studies);

*** Salomon Brothers of New York (financial advisors); and

*** Cook Inlet Region, Inc., and Holmes and Narver, of Anchorage (logistical support).

Work began in January, 1980, and will continue for about 30 months. There is no guarantee that the engineering, environmental, and economic findings will be favorable. Further, even with the most positive study conclusions, the state and federal permitting process would take another three to five years before construction could begin.

Chapter IV of this report summarizes Acres' February 1980 Plan of Study, identifies some weaknesses in the Plan, and proposes some modifications to it.

The legislature's study of alternatives to Susitna, and this report.

In 1979, the Alaska legislature, fearing the attention and funding devoted to the Susitna project would obscure potential alternatives, which might be more economical or less environmentally disruptive, appropriated $200,000 to the Division of Legislative Research to "(1) analyze existing assumptions and findings concerning power needs and population growth projections of the Railbelt . . . [and] . . . (2) analyze energy supply alternatives, including Susitna . . ."

When the research division was disbanded in the Summer of 1979, the House of Representatives established a Power Alternatives Study Committee, composed of Representatives Brian Rogers and Hugh Malone, to oversee this appropriation. [The Committee funded the present report out of the $200,000 with a $25,000 contract to Arlon R. Tussing and Associates, Inc.]

The Alaska Power Authority subsequently augmented the legislative appropriation with $30,000 to increase the scope of a power market demand study for Acres by the Institute of Social and Economic Research, so that ISER might consider end uses of energy in Alaska.

CHAPTER IV: THE ACRES PLAN OF STUDY

Introduction

In February 1980, Acres American, Inc., published its Susitna Hydroelectric Project Plan of Study. This document is the refinement of a preliminary plan that Acres submitted to the Alaska Power Authority in September 1979, in the firm's original study proposal. Eric P. Yould, executive director of the Power Authority, introduced the Study Plan "to the public at large and all interested agencies and organizations," stating:

> 1. The fact that a feasibility study is to be undertaken does not necessarily mean that a hydroelectric project of any kind will ever be constructed on the Susitna River. It will provide the basis, however, upon which an informed decision can be made as to whether the State could or should proceed in the matter.
>
> 2. The publication of this plan does not permanently fix the manner in which the proposed work is to be accomplished. On the contrary, I regard it as a dynamic document which will, I hope, be steadily improved with your assistance. It has already undergone an important metamorphosis as a result of testimony and correspondence received during the past four months, and I have no doubt that further editions will be responsive to your suggestions and comments.

In line with the Power Authority's request, the Alaska House of Representatives' Power Alternatives Study Committee contracted with Arlon R. Tussing & Associates to review the Acres Study Plan, in order to propose further improvements. After examining the February 1980 document, the reviewers concluded that the plan needs serious changes in its emphasis and in the scheduling of its study tasks if it is to serve as the basis for informed decisions by the state. This chapter briefly summarizes the Study Plan, identifies those shortcomings in subject areas that we are competent to address, and proposes a number of amendments in the substance, funding level, and sequence of study tasks.

General description.

The $30 million Acres American, Inc., study plan is intended to establish the technical, economic and financial feasibility of the proposed Susitna hydroelectric project for meeting the future power needs of the Railbelt region, and to evaluate its environmental consequences. If the Alaska Power Authority determines that the venture is feasible, Acres and its subcontractors would prepare a license application for submission to the Federal Energy Regulatory Commission.

The study itself is scheduled to take 30 months and involves a multidisciplinary team of consulting firms:

*** Woodward-Clyde Consultants --- power studies and seismic analysis;

*** Salomon Brothers --- financing plan;

*** R & M Consultants --- hydrologic investigations;

*** Frank Moolin & Associates --- project and construction management;

*** Terrestrial Environmental Specialists --- environmental assessement; and

*** Cook Inlet Region, Inc., and Holmes and Narver --- logistical support.

The project team will undertake essentially thirteen tasks as follows, at a total cost of $29,604,249:

1. Power studies --- demand forecasts, generation alternatives, expansion sequence and plant mix, and impact assessment. ($359,200)

2. Survey and site facilities --- land tenure and jurisdictional analysis, field studies and surveys, aerial photography and mapping, and access roads. ($7,858,600)

3. Water resource studies --- development of stream flow data; reservoir operation; glacial movement, flooding, ice, sedimentation, etc. ($1,826,000)

4. Seismic studies --- seismic risk analysis, and development of seismic design criteria for dams, transmission lines and access roads. ($1,139,000)

5. Geotechnical exploration --- data collection and analysis for surface and subsurface geology and geotechnical conditions. ($3,620,500).

6. Design development --- development of preliminary engineering design and cost information for Watana and Devil Canyon damsites. ($1,769,000)

7 Environmental studies --- assessment of alternatives for power generation, access road and site facility locations and power transmission corridors; preparation of FERC license application exhibit. ($6,570,300)

8. Transmission --- selection of transmission route, preliminary engineering designs, and cost estimates. ($729,300)

9. Construction cost estimates and schedules --- cost estimate summaries and construction schedules suitable for the application to FERC; analysis of possible delays, changes and their effects on costs and schedules. ($185,000)

10. Licensing --- preparation and assembly of all necessary documentation for the application to FERC. ($293,500)

11. Marketing and financing --- examination of financial feasibility and development of a financing plan. ($383,100)

12. Public participation --- establishment of a public information office; conduct of public workshops and meetings; and preparation of information, materials, and action lists. ($383,000)

13. Administration --- project management. ($467,700)

Information for decision-making.

The Study Plan assumes that the Power Authority will base a choice between the Susitna project and one or more alternatives on the findings of a Power Alternatives Study Report to be completed 11 months into the overall study, containing ---

> "load forecasting for the Railbelt region;
>
> "selection of alternative energy and/or power generation scenarios;
>
> "evaluation of viable expansion sequence scenarios; and the
>
> "recommended expansion sequence."

This first phase of the study is thus its most vital element from the standpoint of deciding whether or not the state should concentrate its efforts on developing the hydropower potential of the Susitna River or pursue other alternatives in earnest. Unfortunately, this phase seems to be both the most superficially considered part of the Acres plan, and the least adequately funded, accounting for only 1.2 percent of the total study budget ($359,200).

The gravest defect in the current plan of study is the fact that neither Acres' findings nor the Power Authority's decision regarding Susitna's viability would be based on its economic or financial feasibility. This is not a fault that Acres or the Authority can remedy simply by providing more funds or a more sophisticated work plan for some of the study subtasks but is, rather, one that demands an overhaul of the organization and scheduling of the study as a whole.

As it now stands, the Acres plan proposes to choose among alternative generation strategies before making any cost, scheduling, or contingency analyses of the Susitna project itself. The contractors would not begin making even preliminary cost and scheduling estimates for the project until the 73rd week --- five weeks after all other alternatives have been rejected --- nor does it begin to consider "potential contingencies/risks and to evaluate their effects upon cost estimates and schedules" until the 115th week. The study plan, moreover, would begin considering the marketability of Susitna power and the project's financibility only after the Power Authority had made a decision to proceed.

The contractors would look at cost and risk comparisons for alternative methods of electric generation (to Susitna) in the power alternatives study prior to the go/no-go decision, but according to the plan information on even the alternatives would be "developed for each technology (cost/unit energy) based on . . . existing studies." [emphasis added] The sources that the plan explicitly references are 1976 documents, while the whole work tasks of analyzing alternative power generation strategies and determining the optimal plant mix account for only 4/1000 of the total project budget ($126,000). Even if this information on alternatives were adequate for making a choice among them, it is hard to see what use it would be in the absence of cost, scheduling, and risk estimates for the Susitna project itself.

Demand studies.

The "need" for Susitna power, its marketability, its cost to consumers, and the project's financibility all depend upon the total amount of electricity demanded by residential, commerical and institutional, and industrial consumers in the Railbelt. In order to choose the best combination (or indeed, even a workable combination) of generating facilities, power system planners need to know two dimensions of future demand: (1) the total demand for electrical energy, which is usually measured in megawatt-hours over the course of a year, and (2) the peak load, which is the highest number of megawatts demanded at any time during the year.

In the Acres plan, the Institute of Social and Economic Research of the University of Alaska (ISER) will prepare forecasts of total demand, while Woodward-Clyde Consultants are to produce peak power demands and load duration curves "in a manner which is consistent with the economic, social, political, and technical assumptions made by the ISER when developing their energy consumption forecasts."

ISER's demand scenarios. This report does not review or criticize the scope or methodology of the ISER study. It is important, however, to recognize one crucial limitation of the "scenario" approach to demand projection used by ISER and most other forecasters. The scenario method uses an economic model to produce results that are consistent with some set of assumptions about (say) future oil discoveries or petrochemical development in Alaska, world energy prices, federal regulations regarding the end-uses and pricing of natural gas, and the like. But the scenarios themselves will say nothing about the truth or even the likelihood of such assumptions, and most forecasting technicians hesitate to express strong opinions on their truth or likelihood.

Using the scenario method, therefore, ISER will surely present several forecasts of future electricity demand, some of which will seem to argue in favor of, and others against building the Susitna project, but Acres and the Power Authority will have to decide which, if any, of these forecasts they should take seriously in planning new electrical generating facilities for the Railbelt. If a rational decision is ever to be made, in other words, somebody ultimately must (1) make an implicit or explicit judgment which scenario describes Alaska's future most plausibly, and (2) be prepared for that judgment to turn out quite wrong.

In our judgment the most likely scenarios for the state's future are ones that no recent power demand forecast (including ISER's 1976 study) has even mentioned, let alone formally considered: scenarios in which no combination of existing and new basic industries can equal or replace government revenues from Prudhoe Bay oil and gas as a source of Alaska income and employment. In these scenarios, the inevitable decline in Prudhoe Bay production will mean that the Railbelt's business activity, employment, population --- and electricity demand --- will peak in the late 1980's or early 1990's, and fall sharply for at least several years.

We do not expect the Alaska Power Authority to agree with our judgment that this is the most probable course for Railbelt electricity demand, but it is vital for power planners in Alaska to recognize that it is a wholly plausible course, and to consider the implications for the State of a decision to build Susitna if power demand did actually begin to decline at just about the time the project was completed.

It would be a relatively simple matter for ISER to add one or more boom-and-bust scenarios to the demand forecasts if such scenarios are not already part of ISER's program. Our more serious concern is that the Study Plan does not seem to deal systematically with any kind of uncertainty or risk (demand forecasting errors, delay or non-completion risks, construction cost overruns, uncertainties regarding the availability of alternative fuels, or interest rates and other financial risks) in choosing among different strategies for providing electricity to the Railbelt.

Forecasts of peak loads and load duration curves. The amount of generating capacity a region requires in a given year stems directly from (1) the need to meet the highest anticipated peak load for the year, and (2) the need for sufficient reserve capacity to serve unanticipated peaks, while allowing for scheduled and unscheduled equipment outages. Estimates of total annual requirements for electrical energy by themselves reveal very little about the need for peaking and reserve generating capacity.

A utility's total energy demand and its peak demand are both functions of population, per capita income, climate, the regional industrial mix, and the like. Its load factor --- the ratio between the average annual demand for electrical energy and the annual peak load --- also depends on all of these variables, and moreover, can be powerfully influenced by the utility's rate structure, and by various "load management" measures. While the Study Plan discusses a number of arcane theoretical issues in the forecasting of load duration curves, the meager funding for this subtask implies that Woodward-Clyde must derive its peak load forecasts and load duration curves from ISER's projections of annual demand for electrical energy, on the apparent (and unwarranted) assumption that peak loads and load patterns are are a relatively simple function of total demand.

The total annual demand for electrical energy can always be derived from a load duration curve, but Woodward-Clyde will not be able to make forecasts of future load duration curves or peak loads consistent with ISER's assumptions without working from the original data and methodology for each of ISER's scenarios --- in other words, without repeating ISER's work and adding new analyses to it. But the Acres study plan provides only $43,700 for this effort. No credible forecast can be produced for this sum, and we do not believe that any credible firm would offer to produce one for this amount.

Peak-responsibility pricing and load management. Peak-responsibility pricing and other techniques of load management can reduce costly peak loads, enhance the operating efficiency of base-load generating capacity, and provide a partial substitute for reserve generating capacity. While these measures are relatively novel in the United States, European experience suggests that they can reduce the need for total generating capacity by 20 to 30 percent, and thereby postpone the need for new investment for several years.

Conceivably, peak-responsibility pricing and load management might eliminate any need in the forseeable future for new large-scale generating facilities to serve the Railbelt, and at the same time spare consumers large rate increases necessary to help finance new construction. Federal law now requires utilities and the federal and state agencies that regulate them to consider such measures, and the failure of the Susitna planning process to give them sufficient attention could, at the very least, jeopardize or delay the project's ultimate approval. The Acres plan does consider rate design and load management, under the heading of "non-hydro alternatives," but as with peak-load forecasting, their placement and funding level suggest that they are being treated only as an afterthought or parenthesis, rather than as central issues in assessing the need for new generating capacity.

Selection of new generating facilities.

Acres plans to combine the ISER and Woodward-Clyde demand forecasts with existing capital and operating cost estimates for various power alternatives (but not, apparently, for Susitna itself), by means of a mathematical model that will " . . . determine the total system costs of selected future Railbelt expansion sequences, both with and without incorporation of the Susitna Hydroelectric Project, and rank the preferred generation expansion scenarios . . ." according to the cost of electricity.

The program Acres has selected for choosing among the various generation strategies would combine " . . . system reliability evaluation, operations cost estimation, and investment cost estimation." Even the most sophisticated, state-of-the art planning model of this type would be wasted, however, on the incomplete or questionaable information inputs Acres intends to process. In the context of the current study plan, therefore, the model's output will be of little use to the state in making an informed decision on Susitna. The fact that Acres plans to spend only one-tenth of one percent of the project budget ($30,000) for the systematic comparison of generation alternatives is a dramatic signal of the contractor's lack of regard for the entire power alternatives study task.

Financial Feasibility.

As we pointed out earlier, the current Acres plan would begin to consider the marketability of Sustina power and the project's financial feasibility only after the Power Authority had made its decision whether or not to proceed. Even so, the plan's approach to financing is based upon two assumptions that are doubtful at best and which, in any case, warrant a close and early examination. The first is that the Susitna project can be financed by revenue bonds (preferably tax-exempt), and the second is that the electric utilities of the Railbelt will voluntarily enter into full-cost-of-service take-or-pay contracts for Susitna power with the Alaska Power Authority.

In recent years, a substantial number of electrical generation projects (fossil-fueled and hydro, as well as nuclear) have foundered in mid-construction because of design faults, poor management, revised demand forecasts, or legal and regulatory hurdles. It is not surprising, therefore, that financial institutions are reluctant to buy bonds whose only security is project revenue. There has never actually been any utility venture as large as the Susitna project whose construction has been project-financed entirely, or even as much as 75 percent, with non-recourse debt (that is, with revenue bonds). While there have been many attempts at such financings, sponsors in each case have had to choose between pledging their "full faith and credit" (that is, by selling general obligation bonds), finding third-party guarantors, or abandoning the project. This has been the case even for projects of proved design in familiar environments, facing guaranteed markets.

Rightly or wrongly, lenders are bound to perceive the Susitna project as bearing even greater risks of non-completion, extended delays, cost overruns, or market deficiencies than the Lower-48 projects they have already declined to finance on a non-recourse basis. Moreover, since Salomon Brothers first reported to the state on possible methods of project financing for the Susitna proposal, inflation has severely damaged the bond markets; and unless economic conditions improve radically between now and the time a Susitna financial plan is completed, debt in the quantities it requires may be unavailable at any price, on any terms.

Thus, it is very likely that the state will be faced with the choice between financing Susitna with a direct appropriation, guaranteeing the project's bonds, or compelling Railbelt power consumers to begin paying for Susitna's enormous capital costs in their electric bills many years before they receive any power from the project. It is probably imprudent to count on selling revenue bonds as the principal means of financing Susitna and even more imprudent to assume that the costs or availability of financing will not influence the project's viability or merits. Although we are considering a facility project whose completion is at least ten years away, the feasibility of project financing may indeed be an important consideration in choosing a power supply strategy for the Railbelt.

Marketability.

The second assumption, concerning the utilities' willingness to enter into take-or-pay contracts, should not be taken as given. Railbelt utilities are not a single entity, and unless the legislature is willing to impose Susitna power on reluctant utilities and their customers, the Alaska Power Authority will have to negotiate individual contracts with each utility. Non-recourse financing, moreover, would require all-events contracts (compelling consumers to pay for Susitna whether or not they ever got Susitna power, and no matter how much it turned out to cost) prior to construction. Since Susitna power is likely to be more expensive than conventional Railbelt power generation, at least at the outset, the Power Authority could face a buyer's market, especially if gas prices remain relatively low or if Beluga coal development proves economically feasible.

Chugach Electric Association is by far the biggest electric utility in the Railbelt, and its service area together with the service areas of its wholesale customers encompasses the region in which most of the future growth of population and power demand in Alaska is likely to occur. Susitna power may or may not be the lowest-cost alternative for Chugach customers, but it is very likely that, absent Chugach and its customers, Susitna power will not be marketable or financially feasible and that, as a result of the project's underutilization, it would not be the lowest-cost alternative for <u>anybody</u>.

Chugach Electric Association has not thus far been an enthusiastic backer of the Susitna project, and its management is not now convinced that Susitna power is the lowest-cost or most practical way of serving its customers --- who are the owners of the utility and elect its management. Curiously, these realities have not yet been mentioned in any of the public literature on the feasibility of Susitna, and it is not alluded to even indirectly in the Acres plan of study.

<u>Study findings, incentives, and credibility</u>.

The Plan of Study does not explicitly presume that the Susitna project is feasible, and its introduction explicitly rejects any such presumption. The substance and sequence of work tasks, however, strongly imply that Acres and possibly the Power Authority have already decided that Susitna is in fact the best generation alternative for the Railbelt, and that the project should go ahead.

Clearly, the \$13.5 million already spent on the study at the time the power alternatives report is issued will create substantial momentum for the contractor and subcontractors to complete their work in progress. Even more importantly, the \$16.1 million remaining to be spent if and only if the initial go/no-go decision is affirmative cannot help but be a powerful incentive for the study team to arrive at a favorable conclusion.

The current study plan's treatment of economic, financial, and institutional issues is consistently inadequate, and it does not provide the funding necessary for timely and professionally competent demand forecasts, cost and risk analyses, or studies of marketing and rate design, reliability and load management, or financial feasibility.

The Acres plan apparently does not even intend that its cost, risk, and scheduling analyses, or its study of marketing and financing, be used for decision-making in Alaska. The place of these studies in the project schedule, and the language of the Plan itself, state implicitly and explicitly that the main or only reason for including the studies is the fact that FERC requires them as part of a power facility license application.

This strategy, if endorsed by the Power Authority, the governor, and the legislature, means that Alaska is willing to postpone any realistic and credible analysis of Susitna's feasibility to the FERC licensing proceeding, and to delegate the real go/no-go decision on Susitna to FERC and other federal agencies.

As it approaches construction, the Susitna project will become more rather than less controversial. It will arouse controversy within the state's utility industry, in the legislature, and among the public at large; before FERC, EPA, and other federal agencies involved in the licensing process, and possibly in the Congress; and it will be controversial at best in the financial community. If the project is indeed the best alternative for the Railbelt, an inadequate information-base or patently biased decision-making process at the state level will hinder rather than speed the federal review process, and it will not make ultimate approval any more likely. On the other hand, if the project is unsound, Alaskans ought to find out earlier rather than later, and in a study process that they control, rather than in adversary proceedings before federal regulatory bodies.

The established philosophy of Alaska's capital budgeting procedures is that planning, and particularly the projection of capital needs, can be objective and rational only if they are independent of the parties that have a material interest in construction. The legislation that established the Alaska Power Authority explicitly set out such a procedure, placing the responsibility for power facilities planning in the Department of Commerce and Economic Development, and requiring a thorough executive-branch review of any major power project the Power Authority proposes for legislative approval.

The current study plan and decision-making schedule for the Susitna project are quite inconsistent with this philosophy. The Division of Energy and Power Development in the Department of Commerce and Economic Development has apparently not yet attempted to assert the role the legislature contemplated for it, and the division's staff and funding have in any case been inadequate for that role. As a result, forecasting and planning responsibilities have fallen by default to the one party the legislature intended should <u>not</u> bear them --- the Power Authority. And the Power Authority has, through the Acres contract, delegated these responsibilities to a consultant group that has a compelling material interest in approval of the Susitna project.

Under the present plan, the Governor is scheduled to make his recommendation to the legislature in late 1980 whether to concentrate the state's effort on Susitna or on some other alternative. There is now a serious danger that the information available at that time will not be (or appear to be) objective, credible, or even wholly relevant to informed decision-making on this issue.

<u>Recommendations</u>.

We therefore recommend four major changes in the Study Plan and decision schedule:

A. <u>Decision date</u>. The initial go/no-go decision should be delayed until about the end of 1981. There is virtually no possibility that sufficient information will be available for an informed decision before that time. This recommendation does not mean that study tasks currently scheduled by Acres for 1981 should be postponed until the later decision date, but only that neither Susitna nor any of its plausible alternatives should be rejected before that date.

B. <u>Divorcement of forecasting and analysis from construction design and management</u>. The combination of demand forecasts and analyses of power alternatives into a facilities investment strategy should be directed by, and responsible to, someone other than Acres or the Power Authority.

The location and administration of these studies for bookkeeping purposes is not at issue, nor is the need for the contractors to coordinate their assumptions and methodology with Acres and its subcontractors. In the absence of an established power planning capability anywhere else in state government, timely attention to the issues identified in this report probably demands a continuity of effort that can be achieved only within the framework of the existing Acres contract, but the Plan should be restructured so that the analysis of generation alternatives, and the input to that analysis, is more independent of the Power Authority and Acres, both in fact and in appearance.

One way of achieving this independence might be for the Power Authority to contract (or Acres to subcontract) management of an expanded "power studies" phase to a consultant firm that has no other role in the study, and for that firm to be responsible for its assumptions, methodology, and results to an interdepartmental task force in the executive branch or to a joint executive-legislative task force, rather than to Acres or the Power Authority.

C. Scope and funding of power studies. The "power studies" phase of the Susitna feasiblity study needs to be expanded in scope and funding, at the same time as it is extended and made more independent of entities that have a material stake in the study outcome. The following recommendations for additional time and funding are little more than preliminary, intuitive estimates, but we offer them in order to indicate the shift in emphasis we believe is necessary to an adequate, objective study plan:

1. Total and peak loads, and load duration curves, must be derived in a single coordinated effort, and

must explicitly take into account the potential impact of peak-responsibility pricing and load management on the need for peak and reserve generating capacity. A credible effort would require at least $250,000 and one year.

2. Preliminary cost, risk, and scheduling analyses for alternative Susitna scenarios should be available as inputs to the decision on generating strategy. These preliminary analyses would cost at least $300,000, and require one year.

3. Cost, risk, and scheduling analyses for the most promising alternatives to Susitna identified at in the initial study phase should be as thorough and reliable as those for Susitna itself. At least $150,000 and six months would be necessary.

4. The potential of natural gas liquids and fuel-grade methanol as turbine or boiler fuel should be added to the list of generation alternatives to be studied. Initial consideration of these alternatives (at least sufficient to determine whether or not to reject them summarily) would cost about $30,000.

5. Preliminary marketing and financial analyses are necessary as inputs to the demand, cost, risk, and, scheduling studies, and to any practical decision regarding Susitna. The cost of these studies would probably be about $75,000 over six months.

6. A multidisciplinary panel of contractor, subcontractor, agency and outside experts should examine and reexamine the major assumptions used in the demand, cost, risk, scheduling, marketing, and financing studies. The views of these experts should be translated into probability distributions and systematically incorporated into the assump-

tions by means of "Delphi" or comparable methods. This process would cost on the order of $75,000, and run concurrently with the other studies mentioned here.

7. The program used to rank expansion strategies for Railbelt electrical generating capacity should take account of all of the information generated in the power studies, and should be operable within a "Monte Carlo" framework so that its results can be expressed in terms of probabilities. Operating a state-of-the-art power planning model with the information described here would cost at least $100,000.

8. The results of the decision model should be "run backward" through the process that led to those results. That is, those strategies that the model identifies as having the greatest expected net benefit, or having the greatest benefit in the most likely scenario, should be analyzed under other plausible assumptions in order to compare (say) the consequences of not building Susitna if it turned out to be "needed", with the consequences of building the facility if its power turned out to be unmarketable. The costs of this process are incorporated in the previous figures, which total (at minimum) $980,000.

9. Because circumstances and knowledge about the Susitna project and its alternatives will change substantially during the overall study period, all of the assumptions, methods, and results of the preliminary study phase should be reevaluated and updated before any construction actually takes place. This process is likely to cost about one-fourth the original studies, or $250,000.

D. Fallback strategy. It is likely that the Alaska Power Authority, the governor, and the legislature will choose Susitna hydropower over other Railbelt generating alternatives at each decision point in the present study schedule. The project may nevertheless fail to obtain a federal license, sales contracts with Railbelt utilities, or financing on terms that are acceptable to Railbelt consumers or Alaska voters. Even with a license, sales contracts, and financing commitments, actual construction or operation may be delayed indefinitely by regulatory indecision or litigation. For this reason, the state and the utilities of the Railbelt should always keep alive one or more fallback strategies that involve smaller fixed investments and shorter lead-times. The study of alternatives, in other words, should never be totally given up.

ALASKA POWER AUTHORITY

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May 2, 1980

Mr. Arlon R. Tussing
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Dear Mr. Tussing:

We have had the opportunity to examine your review draft entitled "Susitna Hydropower: A Review of the Issues" and appreciate the opportunity to offer our comments before your preparation of the final version. In this response we initially summarize the purpose of the Susitna Plan of Study (POS) and discuss its intended philosophy. This is followed by a discussion of some specific issues raised in your Report.

The Susitna Plan of Study is a dynamic document which has been and will continue to be modified and expanded as the concerns and needs of various agencies and the general public become known. There are obviously a number of courses of action which the Power Authority and the utilities might take over the next decade to meet the future electric power needs of the Railbelt Region. As presently conceived, the Susitna POS embodies but one of these courses of action. The scope of work will:

- establish the criteria by which the technical, economic, financial and environmental feasibility of the Susitna Project should be measured;

- assess whether Susitna or some other alternative future Railbelt generation expansion plan satisfies such criteria; and finally,

- if such criteria are satisfied, pursue the FERC licensing of the Project.

In other words, the study will establish whether the Susitna development is appropriate and if so, how best to proceed with that development.

The POS has since its inception undergone a continuing process of evolution in satisfying the overall objectives. At the same time, provision has been made for tapping the input of those concerned through reviews, public meetings and the action list. As a result, the scope and direction of the Susitna study may be changed at any time or the study even terminated, should the evidence indicate that some other course of action should be pursued instead.

Your Report constitutes probably the most detailed assessment yet made of the POS, and is welcomed as a positive contribution to the development of an acceptable course of action. By and large, it is well prepared, thoughtful, and well written, but a significant flaw is its preoccupation with making explicit judgements about the Project before all the evidence is in. Many of the comments may prove to be valid, but until studied, cannot be verified. More specific comments follow.

1. The Report seems to be based on a misunderstanding of the Go/No Go decision points. In the POS there are essentially three such decision points. During the proposed 30-month study period, each of these decision points relate to "continue-to-study" or "not-continue", rather than "build the project". We wholeheartedly agree with you that a project as large as Susitna requires extensive study and cost expenditures to fully determine whether it is the appropriate course of action. In our judgement and that of Acres, a 30-month period and at least a $30 million expenditure is necessary for a license application decision to be made which adequately considers all issues involved. Nevertheless, it would clearly not be cost effective to defer an obvious No-Go decision until the end of the 30-month period. The Power Authority has not only fiscal responsibility, but also cannot delay its power generation expansion planning activities for that long. The first Go/No Go decision in early 1981 will consequently be made on the basis of an initial comparison of alternatives essentially based on available information and considerable well-informed judgement.

   There is no question that, with the constraints imposed on data collection, load forecasting, alternative energy studies, etc., it will be difficult enough to make the decision whether or not to proceed with the study within one year; it would be entirely impractical and imprudent to make the much more profound decision regarding whether or not to build at that time, unless some overwhelming factor(s) intervene (either for or against).

2. Nowhere does the POS propose that "Woodward-Clyde will derive . . . load duration curves from ISER's projections". The first paragraph of Page 5-11 of the POS states that various recognized methodologies and their applicability will be studied for the problem at hand.

3. Contrary to the assertion that peak load pricing is not mentioned in the POS, Subtask 1.03 has load management activities as an integral part.

4. In response to your concern regarding the lack of some sort of probability assessment for ISER's scenarios, it should be noted that the ISER contract calls for an evaluation of " . . . the probability of each of the projections generated . . .".

5. Your Report presents a useful overview of the planned Susitna hydroelectric project in relation to likely future developments and economic trends in Alaska's Railbelt Region. In this regard, however, the Report seems biased towards a general scenario which sees preferential pricing of natural gas continuing into the next century and a resource-depletion-led slow-down in the mid 1990's. This bias strongly influences the arguments presented in relation to the marketability of Susitna power

and energy. Further, the Report seems to view Susitna hydroelectric development as a single project coming into operation all at once. In fact, the present proposal is for a two stage development phased to meet market area requirements, and we are pursuing studies to assess the possibility of more numerous smaller stages. While there is some support for the cautionary attitude regarding competitiveness of Beluga coal and other alternatives, the situation regarding these must certainly be taken at the time as "not proven". The level of relative competitiveness with Susitna hydroelectric power production will be only partially established one year from now when the decision is taken whether or not to proceed with the study (let alone the project).

The lack of support for Susitna development from the management of Chugach Electric is readily acknowledged, but Chugach can hardly be expected to commit itself to the Project in advance of completed feasibility studies. At the same time, it would be foolish to drop further consideration of Susitna because Chugach has not committed itself; to do so would be to accept a Catch-22 situation. Also overlooked in your assessment of marketability is the opportunity to provide power to industries which now produce their own power. Certain marketing arrangements are conceivable that would induce the purchase of Susitna power to the benefit of all Susitna power customers.

6. The content of Task 11 as proposed in the POS does not appear to be properly understood. You state with emphasis that "Susitna's viability will not be based on either its economic or financial feasibility". This is incorrect. Task 11 requires incisive studies and reports on:

   - "Possible Economic Limits to Project"
   - "Overrun Possibilities"
   - "Security of Project Capital and Structure"
   - "Evaluation of Alternative Markets of Susitna Output"
   - "Evaluation of Alternative Options for Meeting Railbelt Power Needs"

   All of these are to be completed before the third Go/No Go decision point and before a decision is made on submitting the license application.

7. It is fully realized that one of the problems to be faced with a capital intensive development such as a hydropower plant is that the cost of service <u>with</u> the project in the system is likely to exceed the cost of service <u>without</u> the project in the system for the first several years (probably 8-10). Particular attention will be necessary to find ways and means of alleviating the burden on Alaskan consumers in this century of costs of service which will benefit the next generation. This is a very major issue which will require review of a number of options and it should not be readily assumed that past practices will prevail.

In two places in your report, the burden imposed on consumers by the Construction Financing burden (AFUDC) is referred to. It is suggested that the consumers will pay in advance for electricity they may not receive for 10 years or, in your words, "if ever". Capitalization of AFUDC is yet another issue that will be exhaustively studied and treated in the marketing and financing tasks. It is quite improper to assert at this stage that "non-recourse financing would require all-events contracts (compelling consumers to pay for Susitna whether or not they ever got Susitna Power and no matter how much it turned out to cost) prior to construction". The statement is correct if the words in parenthesis are omitted; but the inference with the words left in is, to say the least, provocative and misleading. You may claim that under Alaska PUC rules this has occurred in the past on other arrangements between wholesaler and utility delivering to consumers, but it is a gross assumption that it is necessarily to be the approach for Susitna.

In closing, I want to reiterate my sincere appreciation for your helpful review of our Susitna Plan of Study. While I believe there were a number of inaccuracies or misunderstandings in the review draft, there were also a number of very worthwhile suggestions. A revised plan of study has already been prepared and presented to the Legislature and to the Administration for their consideration. If approved and funded, I think it will be extremely responsive to your recommendations.

Sincerely,

Eric P. Yould

Eric P. Yould
Executive Director