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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 Alaska utilities, the Anchorage Daily News and the Fairbanks News-Miner, the National Electric Contractors Association, and the Alaska Conservation Society all strongly supported 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. One recent review of the project's political history concluded that Alaska's obsession with the grandiose and unrealistic Rampart proposal 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 new look at development of the Upper Susitna. In 1974, the Alaska Power Administration had completed 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 1975 studies. In the same year, Congress authorized spending of $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 in May 1977, when the Office of Management and Budget (OMB) blocked the expenditure, insisting instead on supplementary geological, engineering, and economic studies. The Corps issued its supplemental feasibility report in February 1979; OMB subsequently approved the report, and in the Summer of 1979 the Corps forwarded it to Congress, which now has it under consideration.

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

In 1973, 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) to be built about five miles upstream from the Devil Canyon site recommended by the Bureau of Reclamation and the Corps of Engineers, and subsequent smaller dams downstream (Olson) and upstream (Vee and Denali). 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 may 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. The Authority received its initial staff and funding in 1978.

Senator Gravel's funding proposal.

In 1976, the Susitna development did not seem to be moving very rapidly on the federal level. At the same time, it appeared to Alaska's Senator Mike Gravel that the time was quickly running out on the practice of appropriating vast amounts of federal money for river-development projects whose benefits were wholly local, and particularly for one that would direct a large proportion of total federal appropriations 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.

> 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 the conditional authorization of the Phase I work in the Water Resources Development Act of 1976 incorporated his philosophy to the extent that it provided for a cooperative federal-state effort in making detailed feasibility studies of the project, and required the state to reimburse the federal government for any Phase I expenditures made by the Corps of Engineers 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 begin a series of feasibility analyses and design studies that would ultimately cost $29.6 million.

The Acres study.

In this context the Alaska Power Authority treated the Corps equally with three private consulting firms as competitors for the Phase I effort. In November, 1979, the Authority contracted for the studies with a 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 will begin in January, 1980. and continue for about 30 months. There is no guarantee that the engineering, environmental, and economic findings will be favorable, but even the most positive conclusion would only begin a state and federal permitting process that would take at least three more years before construction could begin.

CHAPTER II 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.

In 1977, the Alaska legislature 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 division was disbanded in the Summer of 1979, the House Power Alternatives Study Committee, composed of Representatives Brian Rogers and Hugh Malone, was established to oversee this appropriation. (The Committee funded the present report with a part of the $200,000.)

The Alaska Power Authority subsequently augmented the legislative appropriation with $30,000 for a study (by the Institute of Social and Economic Research) on end uses of energy in Alaska. The study committee's final report is to be submitted to the legislature by April 15, 1980.

CHAPTER II: THE ACRES PLAN OF STUDY

Introduction

In February 1980, Acres American, Inc., published its Susitna Hydroelectric Project Plan of Study, based upon a preliminary plan that Acres submitted to the Alaska Power Authority in September 1979, as part of Acres' response to the Power Authority's June 1979 request for Susitna study proposals. 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.

The Alaska House of Representatives' Power Alternatives Study Committee commissioned this report partly in response to the Power Authority's request that interested parties continue to review the Acres Study Plan, in the interest of improving it further. After examining the February 1980 document, we believe that the plan still needs major changes before it can remotely be considered as the basis for an informed State decision on the Susitna project. This chapter briefly summarizes the Study Plan, identifies those shortcomings of the plan which we are competent to address, and proposes amendments to both its emphasis and the sequence of its study tasks.

General Description.

The $25 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. ($135,000)

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 relies upon a series of "Power Studies", to be completed 11 months into the overall study, as the documentation upon which the Power Authority is to justify its go or no-go decision. The Power Alternatives Study Report will contain:

> "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 develop the hydropower potential of the Susitna River. Unfortunately, this phase seems to be both the worst thought-out part of the Acres plan, and the worst funded, accounting for only 1.2 percent of the total study budget ($359,200).

The gravest defect in the power study phase is, moreover, one that can not be remedied simply by providing more funds or a more sophisticated work plan for some of its study subtasks but is, rather, a fault that demands an overhaul of the organization and scheduling of the study project as a whole. Under the current plan of study, the decision regarding Susitna's viability will not be based on either its economic or financial feasibility.

The power study phase does not provide for any cost, scheduling, or contingency analyses concerning the Susitna project itself, as a basis for evaluating alternative generation strategies. The study plan does not begin making even preliminary cost and scheduling estimates for the project until the 73rd week --- five weeks after the go/no-go decision --- 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 an the project's financibility only after the Power Authority had made a decision to proceed.

Cost and risk comparisons for alternative methods of electric generation (to Susitna) will be examined in the power alternatives study prior to the go/no-go decision, but all these studies of alternatives will be "developed for each technology (cost/unit energy) based on . . . existing studies." The sources explicitly referenced are 1976 documents, while the work tasks dedicated to 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 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."

<u>ISER's demand scenarios</u>. This report does not review or criticize the scope or methodology of the ISER study, because of our own continuing professional relationship with ISER, and because both Acres and the House Committee have explicitly assigned that task to other contractors. It is important, however, to recognize one crucial limitation of the "scenario" approach to demand projection used by ISER and most other forecasters.

In the words of the Acres Plan of Study, "the scenario method implies a consistent description of a system's evolution by fixing, through exogenous assumptions, the evolution of the scenario components: those variables characteristic of the system." More simply stated, the scenario method uses an economic model to produce results that are <u>consistent</u> 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 say nothing, and most forecasting technicians are unwilling to express strong opinions, about the <u>truth or even the likelihood</u> of those assumptions.

Using the scenario method, therefore, ISER will surely present several forecasts of future electricity demand, some of which will seem to argue in favor, and others against building the Susitna project, but will decline to say which (if any) the Power Authority ought to use in planning electrical generating facilities for the Railbelt. If a rational decision is ever to be made, however, somebody ultimately must (1) make an implicit or explicit judgment which scenarios are the most plausible descriptions of Alaska's future, and (2) prepare for the various ways in which that judgment might be 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 its forecasts if they are not already there. Our more serious concern is that the Study Plan does not even mention the need to deal systematically with <u>any</u> kind of uncertainty or risk (demand forecasting errors, delay or non-completion risks, construction cost overruns, uncertainties regarding the availability of alternative fuels, and interest rates and other financial risks) in choosing among different strategies for providing electricity to the Railbelt.

<u>Forecasts of peak loads and load duration curves</u>. The amount of generating capacity a region requires in a given year stems directly from two needs: (1) to meet the highest anticipated peak load for the year, and (2) sufficient reserve capacity to serve unanticipated peaks and to allow for scheduled and unscheduled equipment outages. Estimates of total annual requirements for electrical energy, however, reveal very little about this need for generating capacity.

Total demand and peak demand are both functions of population, per capita income, climate, the regional industrial mix, and the like, but <u>the ratio between them</u> also varies powerfully with each of these factors, and moreover, can be powerfully influenced by utilities' rate structures, and by various "load management" measures. T [illegible] Study Plan contemplates that Woodward-Clyde will deri [illegible] eak load [illegible]recasts and load duration curves from ISER [illegible] jections of annual demand for electrical energy, on the [illegible] ent (and wholly unwarranted) assumption that peak loa[illegible] and load patterns are are a relatively simple function of total demand.

Total demand can be always be derived from a load duration curve, but the opposite is never possible. In order to produce a load duration curve and a peak demand forecast, Woodward-Clyde will have to duplicate everything ISER did --- and much more --- for each of ISER's scenarios. But the 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 that amount.

Peak responsibility pricing and load management. Peak loads can be reduced, and the efficiency of base-load generating capacity enhanced, by means of peak-responsibility pricing and other techniques of load management; and load management strategies are also a potenti substitute for reserve generating capacity. While these approaches 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 in some cases put off the need for new investment in generating capacity for several years. U.S. law, moreover, now requires federal and state regulatory commissions to consider implementing both peak-responsibility pricing and load management strategies.

In our view, any serious forecast of peak loads or the future need for generating capacity must give serious attention to the potential impact of peak responsibility pricing and other load-management techniques. The Acres Study Plan, however, does not mention them anywhere.

Selection of new generating facilities.

Acres plans to use a mathematical model that combines the ISER and Woodward-Clyde demand forecasts and the capital and operating costs for various power alternatives (still seemingly without any cost information on the Susitna project, however), in order "to 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 defective information inputs Acres intends to process. In the context of the current study plan, therefore, the model's output will be rubbish: it will be of no use whatsoever in making an informed decision on Susitna. It is therefore as appropriate as it is surprising that Acres plans to spend only one-tenth of one percent of the project budget ($30,000) for a systematic comparison of generation alternatives.

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 as 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 with the Alaska Power Administration.

The fact is that there has never yet been a utility project as large as the Sustita project financed entirely, or even 75 percent, with non-recourse debt. Gas and electric companies have consistently failed in such attempts, even for projects of proved design in familiar environments, facing guaranteed markets. In recent years a substantial number of conventionally-financed 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 regulatory hurdles, and it is not suprising that financial institutions have been reluctant to buy bonds whose only security is project revenue.

Rightly or wrongly, lenders are bound to perceive the Susitna project as bearing 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 considered methods of project financing for the Susitna project, inflation has severely damaged the bond markets; and unless general 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.

These considerations suggest that that it may be 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, especially when comparing Susitna's cost with those of its alternatives.

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; its service area and those of its wholesale electricity customers encompass the region in which most of the future growth of population and power demand in Alaska is likely to occur. It is not yet clear whether or not Susitna power would be the lowest-cost alternative for Chugach customers but it is almost certain that Susitna power will not be marketable or financially feasible and that, as a result of underutilization, it would not be the lowest-cost alternative for anybody without Chugach and its customers.

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.

Although the study's Subtask 11 is titled "Marketing and Financing", the plan contains no explicit discussion of power marketing, and we can not be sure exactly what the consultants have in mind when they use the term. (The section on financing and marketing does explictly discuss means of generating "the necessary degree of infectious enthusiasm which is an essential ingredient for even a determined team to succeed." Thus, it is conceivable that the authors are not referring to selling electricity at all, but only to selling the project.)

Study findings and credibility.

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 Administration have already decided that Susitna is in fact the best generation alternative for the Railbelt, and that the project should go ahead.

The current study plan's treatment of economic, financial, and institutional issues is consistently superficial, and nowhere does it 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. Acres seem to treat these issues (if at all) only as afterthoughts or window-dressing.

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 go/no-go decision is affirmative cannot help but be a powerful incentive for the study team to arrive at a favorable conclusion.

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 will not make the project any easier to sell. If the project is not sound, we ought to find out earlier rather than later. Thus, the current Study Plan requires a major overhaul.

Summary of recommendations.

1. Total and peak loads, and load duration curves, must be derived by one study team, in a single effort, and must take into account the potential impact of peak-responsibility pricing and load management on the need for peak generating capacity. A credible effort of this sort 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 according to the current studies should be as thorough and reliable as those for Susitna itself. At least $150,000 and six months would be necessary.

4. 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.

5. 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 assumptions 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.

6. 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 its results should 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.

7. The results of the decision model should be "run backward" through the process that led to those results. That is, those strategies 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) $950,000.

8. 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 less than one-fourth the original studies, or $250,000.

CHAPTER III: OVERVIEW OF THE ELECTRIC POWER INDUSTRY

Electric power industry functions.

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

Utilities may also own generating plants (fossil-fuel, hydro, nuclear, etc.), alone or jointly with other utilities, or they may purchase electricity from other utilities, federal power projects, or other entities. Some utilities are wholly self-sufficient, but most utilities buy and/or sell electricity; some are net buyers (buy more than they sell) and others are net sellers at wholesale.

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

Non-utility generation; Cogeneration. Institutions and industrial plants often produce electricity to meet their own requirements at lower cost than they could purchase power from a utility, or to supplement or backstop utility-supplied power. Where power generation is incidental to, or a co-product of other activities, such as raising steam for space heating or industrial processes, it is called cogeneration.

In Alaska's Railbelt, the chief non-utility power producers are military installations, the University of Alaska at Fairbanks, and petroleum-related installations on the Kenai peninsula.

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 (One utility can 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 (The loads of different utilities peak at different times of the day or the year; thus interconnection can reduce their joint need for high-cost peaking generation capacity); and

(3) to meet emergencies (Interconnection reduces the utilities' joint need for reserve generating capacity).

In the Anchorage area, the generating capacity of the two major utilities, Chugach Electric Association and Anchorage Municipal Light and Power, are interconnected at the Eklutna substation, but these two utilities do not im practice manage their facilities jointly in order to minimize costs or reduce the need for reserve generating capacity. In the Fairbanks area, however, the intertie composed of Golden Valley Electric Association, the Fairbanks municipal utility, the University of Alaska, and the two military bases, does actually function as a local power pool.

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 the 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), the Federal Energy Regulatory Commission (FERC) regulates their wholesale rates and service.

Cooperatives. Rural electrification (REA) cooperatives (or coops) are subscriber-owned utilities, governed by a board of directors elected by the ratepayer-members. Most coops outside of Alaska are distribution utilities for small towns and rural areas, and buy their power from private utilities or federal projects. Coops, 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 coops, 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 coops 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 from the Rural Electrification Administration (REA) at 2 and 5 percent.

REA will also guarantee the ordinary bonds or electric cooperatives, most of which they sell to the Federal Financing Bank at rates one to two percentage points below market rates for private utility bonds, and 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 are distributors to 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 city utilities. In Alaska's Railbelt, there are municipal utilities in Anchorage, Fairbanks and Seward, and the first two, while interconnected with other utilities, generate all or most of the power they sell.

State- or county-chartered public utility districts and state or provincial power or hydro authorities (such as the Alaska Power Authority) are also regarded as municipals.

A municipal utility may be a city, county, or state agency whose accounts are consolidated with the general government accounts, and whose management serves under the direction of the general political authorities (like the Anchorage and Fairbanks municipal utilities). Alternatively, it 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).

In some states, the retail business of municipal utilities is regulated by the state utility commission, and in others it is unregulated. The APUC regulates municipal utility rates and terms of service in Alaska only (1) outside the limits of the municipality, (2) where they compete with other utilities in the same service area (e.g., CEA and the Anchorage municipal utility), or (3) in their sales to other regulated utilities.

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

As agencies of government, municipal utilities are generally exempt from federal, state, and local taxes. The legislation that established the Alaska Power Authority, however, explicitly allows it to make payments in lieu of local property taxes, but does not state who (the local government or the Authority) decides 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. Most financing of municipal power projects is with revenue bonds, for whose interest and amortization the utility pledges only its own income. In some cases, however, general obligation bonds are issued, under which the full faith and credit of the municpality or state is committed to servicing the debt.

Federal power. Outside of the Tennessee Valley Authority (TVA) (a special case of little relevance to Alaska), 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 operates two projects --- Snettisham near Juneau and Eklutna near Anchorage.

Each federal power project must be approved by Congress several times during its planning, design and construction. The inevitable cost overruns create a need for further rounds of Congressional deliberation, authorization and appropriation. As a result, projects sometimes require decades from their conception to commencement of operation.

FERC reviews rates charged by federal power projects; these rates are supposed to cover operating costs, provide for depreciation, pay interest, and repay principal to the U.S. Treasury on the funds invested. Congress typically stipulates the interest rate for each project in the specific legislation authorizing it. In most cases, interest rates on federal projects have embodied a large subsidy element, because at any particular time they have been only a fraction of the rates paid on U.S. Treasury bonds.

Regulation of the electric power industry.

The distribution of electricity is a natural monopoly, in that the economic cost of service (sometimes called resource cost --- the value of labor, materials, and capital actually consumed) tends to be lowest when only one firm serves each market area. Thus, the public is not necessarily better off when there are competing firms, but unregulated private monopolies tend to charge excessive prices for insufficent service..

There are two general ways to deal with this dilemma: public utility regulation and government enterprise. The United States and the state of Alaska use both approaches in dealing with the electric power industry. In either case, public authorities have to deal with three broad types of decision:

*** franchising (sometimes certification or licensing) --- designation of an entity to operate in a given service area;

*** certification (sometimes licensing or permitting) of new facilities; 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. The term regulation is often reserved, however, to 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. The utility itself may have complete discretion over its own rates (perhaps within some statutory guideline), or rates may be made or reviewed by the general political authorities (e.g., the city council) or regulated by a state public utility commission or the Federal Energy Regulatory Commission (FERC).

Rate regulation. The various forms of utility organization use significantly different accounting concepts, and different regulatory commissions and government agencies define and measure the several elements of utility cost somewhat differently. Nevertheless, the basic principles of utility ratemaking are essentially the same for regulated private utilities and government enterprises. Rates are generally designed 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;

- *** amortization (repayment) of debt;

- *** depreciation (to the extent not covered by amortization of debt);

- *** taxes (if any); and

- *** a fair and reasonable return (or a competitive return) to the owners' equity investment.

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.

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 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 sales 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 make a difference, however. Thus far, anyway, FPC and FERC have not tried to assert jurisdiction over wholesale electricity sales by 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 interstate commerce.

FERC might use this authority to restrict shipment of Prudhoe Bay natural gas for use as electric utility fuel 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. The Act provides several grounds on which ERA may waive the prohibition.

Other licensing, permitting, and regulatory agencies. The appendix to this report 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 with respect to the responsibilities of the agencies listed.

CHAPTER IV: PLANNING FOR NEW GENERATING CAPACITY

This chapter considers the decision to install new electrical generating capacity from four 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 are intricately tangled with one another. For example, utilities and government power agencies project their need to install new generating capacity on the basis of the expected future demand for electricity. But these same entities have a powerful influence on future demand, because their decisions whether and what kind of new generating capacity to install, and how to allocate its cost among different categories of consumers and uses, determine the future electricity prices that will in turn determine how much electricity each category of consumer will use.

To put the point a bit more broadly, utilities and government agencies can legitimately combine demand forecasting, facilities planning, organization and financing, management, and marketing in ways that promote greater electricity demand and thereby maximize the need for new capacity, or in ways that foster electricity conservation and thus minimize 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.

This purpose of this chapter is not to provide support for one approach or the other, but in passing we shall point out some of the assumptions on which they differ.

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 (a) the area's population growth, (b) its per-capita demand for electricity in residential, commercial, and small industrial uses, and (c) 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 (d) 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 (e) a large degree of uncertainty, and compare the consequences of underbuilding with those of overbuilding.

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 really very 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.

Electricity consumption per capita. Electricity consumption tends to increase with real incomes per capita; it tends to decrease with rises in the real (constant-dollar) price of electricity; and it tends to increase as the prices of competing energy forms rise.

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 belongs under this heading.

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 Decade at the earliest, when the economic expansion and construction boom driven by development of Prudhoe Bay oil and gas will have played themselves out. Thus, 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 potential 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 only highly speculative, but are bound to be controversial. Much 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 <u>some</u> 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. 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 <u>free</u> energy in Alaska would offset the plant's construction cost handicap.

In almost every case, energy-intensive industries are also capital-intensive industries; and we know of only two --- uranium enrichment and basic aluminum --- for which energy costs in the form of electricity normally exceed 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. The U.S. market for new light-water reactors had virtually disappeared even before the Three Mile Island incident, and the prospect that an enrichment facility would be installed in Alaska in this Century is almost nil. It is probably safe, therefore, to say that basic aluminum is the only industry that might 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, labor, and other costs.

It would therefore be prudent for power supply planners to include new energy-intensive industries in the forecasts they use to determine whether or not the Susitna project is feasible <u>if and only if</u> the new industrial facility is made an integral part of the development plan by the industrial firm's willingness to sign a minimum-bill <u>take or pay</u> contract to purchase a definite part of the plant's capacity.

Load characteristics.

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.

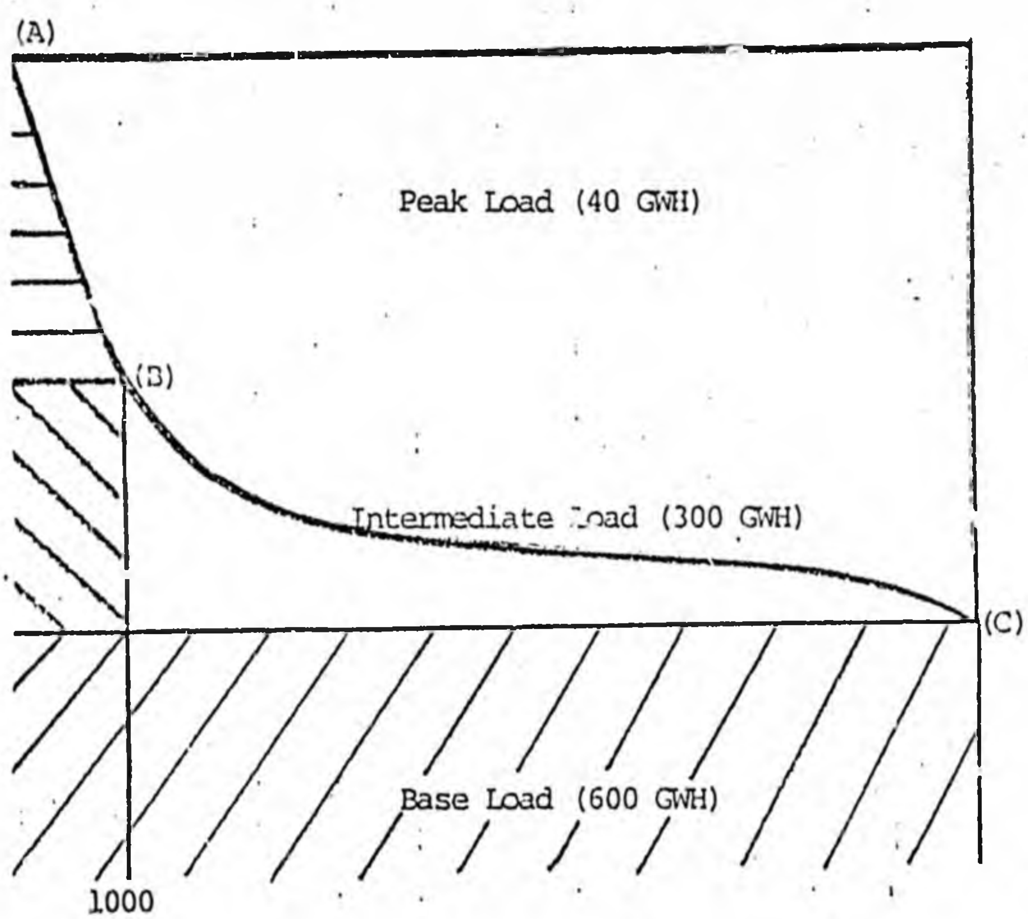
The load characteristics of a given system can be described by means of an annual load duration curve, which represents the number of hours in each year that consumers demand a given amount of electricity. Figure 1 shows such a curve for a hypothetical power supply system with a peak demand of 250 MW,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

Base loads. The horizontal axis of Figure 1 measures the number of hours in a the year's total of 8760 hours [365 days X 24 hours]. The vertical axis measures electrical consumption in MW. Thus, point c shows that demand never falls below 75 MW; this level of demand is called the base load, and the annual base load demand is 660 GWH [8760 hours X 75 MW].

Peak loads. For a small part of the year consumption greatly exceeds the annual average. A load exceeding some specified level is called a peak load. In Figure 1, levels of consumption more than 150 MW --- twice the base load --- are regarded as peak loads. Point a shows the annual peak, 250 MW, and point b shows that consumption is 150 MW or more for 1000 hours during the year. (This 1000 hour total may

Figure I

HYPOTHETICAL LOAD DURATION CURVE



be made up of 100 separate periods of 10 hours average duration on 100 separate days.) The total peak load demand during 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 1 the total annual intermediate load is 300 GWH.

The generating capacity of a power supply system must be able to deliver both the highest peak load and the total amount of power expected over 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 demensions of demand:

*** the peak load, which is measured in

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

*** the annual load, 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).

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 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.

The peak loads are exceedingly costly in terms of capacity. In figure 1, the peak load accounts for only 4 percent of total electricity sales, but requires 40 percent of the system's capacity. The intermediate load accounts for 30 percent of total sales and 30 percent of capacity, and the base load accounts for 60 percent of total sales and only 30 percent of capacity. Thus, each KWH of peak load power may require <u>20 times</u> 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 operating 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>. Regardless of the combination of generating equipment a power supply system chooses, peak load power is still exceedingly expensive in terms of capacity. As the system's total demand grows, the need to serve peak loads accounts for a very large part projected investment needs. Thus, a strategy capable of <u>increasing system load factors</u> might significantly reduce capital needs and the average cost of electricity.

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. Recent demand forecasts and proposed planning strategies for the Railbelt all seem to assume that load factors, and thus the efficiency with which new facilities are utilized, will remain at their present low levels.

Measures do exist, however, that can significantly increase load factors, thereby improving the efficiency with which installed generating capacity is operated and economizing on the need for new capacity, thereby reducing average costs per KWH. These measures, which include (1) interconnection, (2) interruptible electricity sales, (3) central-station load management, and (3) peak responsibility pricing, 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, in the past, used forecasts of demand and load as the major determinents of required plant size. However, there are a number of other considerations important when 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. We also ought to be concerned with uncertainties and consider how flexible a system is to changes in anticipated demand, for example, or the prices and availability of fuel.

Facilities planning involves looking at the entire supply system --- including its present and anticipated load factors, use of existing equipment and the management of reserve capacity --- and for that reason, facilities planning is quite site-specific. One factor that complicates any evaluation of the Susitna project is the fact that the existing generating plants and distribution system are owned and operated by several different utilities and thus, how to optimize use of existing plant facilities in order to supply the Railbelt is an important question still to be resolved.

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 it is operating or not. They include costs for purchase and development of a site, equipment and assembly, materials, engineering, overhead and contingencies, and interest. Fixed costs are generally spread over the operating life of a facility and, if they are very large, they will significantly affect the cost of electricity. As a working index of how important fixed costs are to the cost of electricity, they are often expressed in dollars per installed kilowatt 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 electricity. Table 1 also suggests that initial capital costs for diesel generators are considerably less than the capital costs 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. 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 or over $5.3 million on fuel. If fuel is a large portion of total costs (fixed and operating), the cost of electricity from that particular facility will be very sensitive to the price of fuel.

Heat Rate. Heat rate is a measure of 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. The heat rate for a given facility 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 price of individual fuels, heat rates determine the relative fuel costs for a unit of electricity.

Table 2 illustrates the different 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, are less efficient in converting natural gas energy into electricity than diesel generators are in converting distillate fuel oil. In Alaska, however, the greater efficiency of the diesel engine is more than offset by its higher price for fuel.

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 tne 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 types of turbines, each designed for different capacities and fuel efficiencies. Smaller simple-cycle units can be purchased like diesel units ready-made from the manufacturer; larger regenerative or combined-cycle units may take two years to build 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 fuel-efficient and can have 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 ability to respond quickly to rapid (and uneven) demand growth, and the exceptionally low price of natural gas in the Anchroage 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. As Figure 2 suggests, for a limited number of hours, the

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

cost per kilowatt hour for electricity produced by gas turbines is, and probably will remain, inexpensive relative to other types of generation. However, as the load factor increases, unit costs climb rather rapidly making gas turbines most attractive for 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 at least ten times as costly as the utilities' current supplies.

For almost a decade, FPC and 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 tried to interpret it very strictly.

Since 1977, when the law was enacted, however, the national outlook for natural gas supply has improved radically, and unless ERA interprets PIFUA quite 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 the new facilities, as well as for their existing plants.

Federal policies, 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 fied by Beluga coal.

Steam Turbine Generating Units. Conventional steam plants consist of a fuel-fired boiler for generating steam which drives a steam 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 means to generate electric power. Plants can be fired by oil, gas, natural gas liquids, coal or nuclear fuel and, except for the smallest units, are always custom designed with <u>long lead times</u> 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. In Figure 3, uranium and coal seem to be the least expensive fuels for steam generation.in Alaska. 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 cost, siting problems, and potential 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 will 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).

<u>Hydroelectric generating units</u>. Hydroelectric facilities create electricity from falling water and are considered among the most <u>reliable</u> types of generating equipment. Minimum maintenance requirements and the virtual absence of fuel costs make these facilities very cheap to <u>operate</u>. <u>Initial capital costs are usually very high</u>, however, with investment per KW of total capacity greater than fossil fuel-fired installations. Transmission of hydropower from remote generating sites to the load centers is 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

Hydroelectric energy conversion efficiency is the ratio between electric energy delivered out of the plant and the maximum theoretical energy of falling water. The ratio is typically 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 costs are high, variable costs play a relatively small role in the unit cost of electricity: fixed costs tend to be a large proportion of total costs for steam and hydroelectric plants. At the other end of the hierarchy, gas turbine and diesel plants have relatively low initial costs and high variable costs for fuel and maintenance.

This cost hierarchy is the main consideration in power supply and management strategies. Where fixed costs are large and must be recovered whether electricity is generated or not, it makes sense to operate a plant as much as possible. From the perspective of minimizing unit costs, a plant operating for most hours of the year spreads fixed costs over a large number of kilowatt hours. If such a plant operates only half the time, however, its unit cost for electricity will nearly double.

Where variable costs are a larger percentage of total costs, on the other hand, unit costs are more sensitive to the price of fuel. Thus, a gas turbine is relatively expensive to operate as a base-load supply, but as fuel and labor are its major costs, this type of plant is comparatively inexpensive to hold in reserve for peak loads or emergencies.

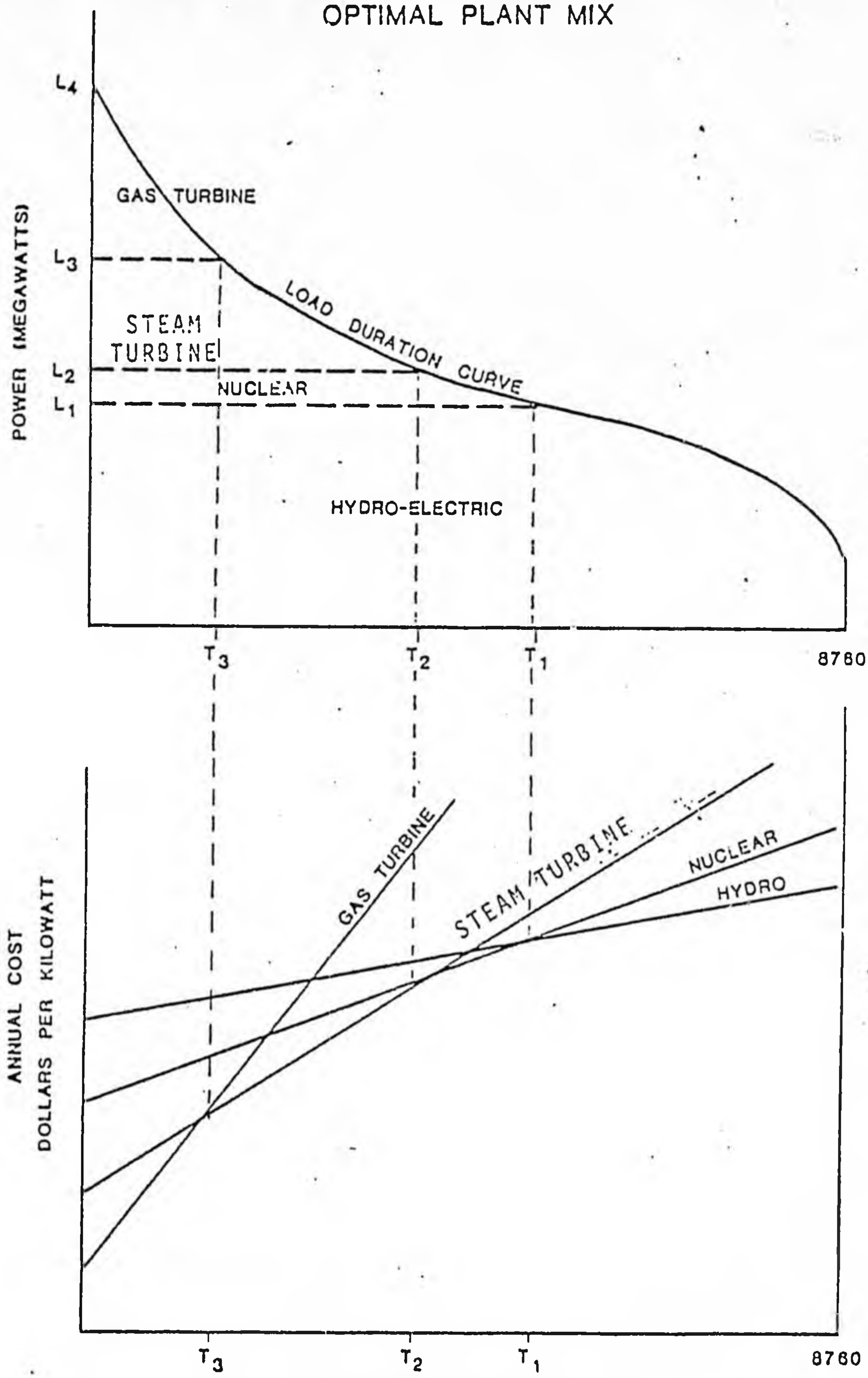
Plant mix. The cost hierarchy among generating technologies, plus the load duration curve, determines what mix of facilities would provide the lowest cost electricity for base, intermediate, and peak load situations, and thus, for the entire system.

The top graph in figure 2 is a load duration curve that describes the variation in a hypothetical utility's load during a year. At the bottom of the figure 4 are curves representing annual costs (in dollars per kilowatt of capacity) for four types of generating technology. The initial point for each line on the cost axis reflects the capital cost of a given type of technology and the slope reflects operating costs over time (including fuel).

In this example, the four cost curves indicate that hydroelectric generation is the least-cost way to satisfy any load that will persist at least T_1 hours. For any load whose annual duration is less than T_2 and more than T_1 hours, nuclear facilities would have the lowest unit cost. In a similar manner, load blocks can be assigned to steam and combustion turbines. The assignment of load blocks to different generating technologies shows the optimum amount of generating capacity for each: L_1 kilowatts of hydroelectric, L_2-L_1 kilowatts of nuclear, and so on.

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, and provide sufficient reserve capacity to meet unanticipated demand, and scheduled and unscheduled equipment outages. Each utility or region has a unique hierarchy, and the available generation technologies are not always arrayed on load duration curves as suggested in Figure 4. Some hydroelectric projects, for example, are most suitable for use as base-load supply, and others are more valuable for peak

Figure 2
OPTIMAL PLANT MIX



HOURS PER YEAR

loads, depending upon their individual combination of annual stream flow, storage capacity, and installed generating capacity.

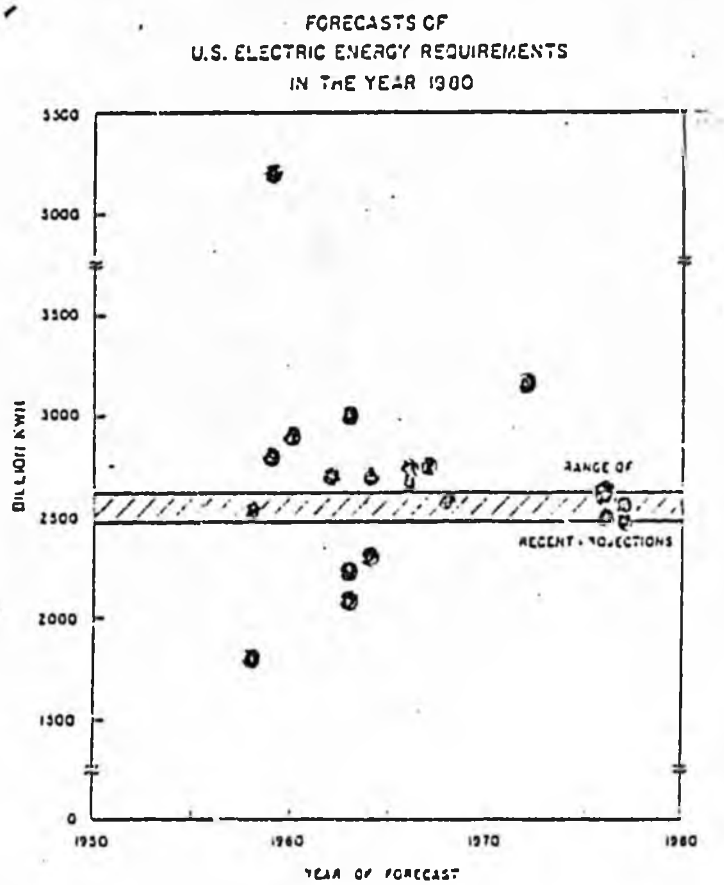
The functional role of an existing plant may also change over time. An older fossil-fired plant may be shifted from base-load to peaking service, and ultimately retained only as back-up, if operating costs are lower on newer parts of the system. A older hydropower facility may likewise be shifted from base-load to peaking service if the cost per KWH of additional generating capacity installed at an existing dam is less than the combined capital and operating cost per KWH of a new thermal plant. In either case, the aim is to minimize system-wide unit costs for electricity.

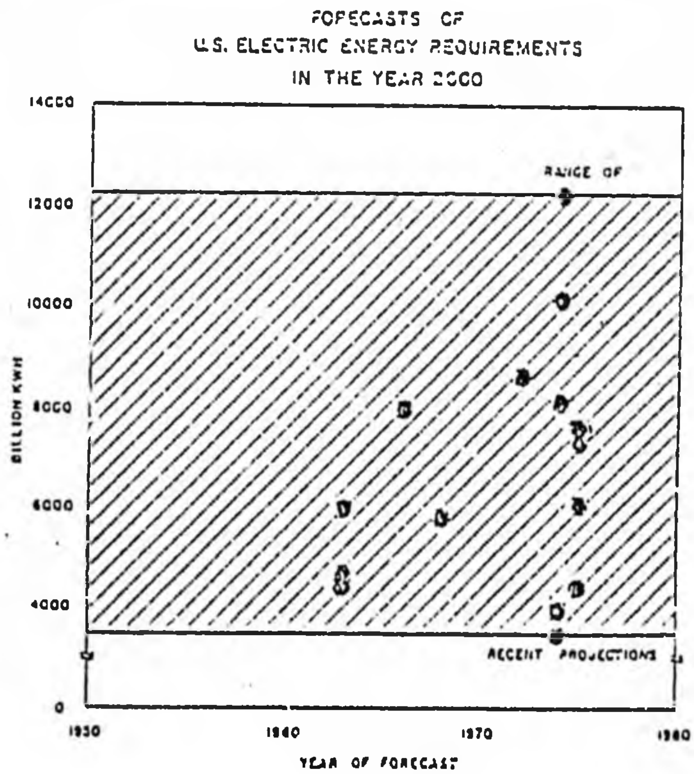
Dealing with Uncertainty. In hindsight, it would certainly be possible to reconstruct the rationale for choosing one technology or plant mix over another, but the future is quite uncertain.

Demand forecasts are notorously inaccurate, especially for Alaska where major development projects continue to have an uneven and often unanticipated effect on demand. Even without big surprises, 20 year forecasts are bound to be speculative. Figure 3 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 is astonishingly wide.

Figure 3

Long Range Forecasts of U.S. Electric Energy Requirements





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 most large utilities have voluntarily postponed or curtailed their building programs.

During the 1960's, forecasters in Alaska consistently underestimated the demand growth that would occur in the Railbelt during the 1970's, because they (understandibly) failed to anticipate the economic stimulus of TAPS construction and Prudhoe Bay oil revenues. It appears, 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 have indicated earlier in this paper, current forecasts of Railbelt demand in 1990 and 2000 are also more likely to be too high than too low.

[illegible] 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 more to complete than originally planned, and cost overruns of 100 to 500 percent were not unusual. A mere six month delay in commencement of service can increase the final capital cost --- and thus the unit cost of electricity --- of a project financed with a construction loan at 13 per cent interest by as much as 6 percent.

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 seemed feasible on the basis of its original engineering cost estimate and planned completion date sometimes turns out to be uneconomic on the basis of a more realistic schedule and cost estimate.

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

In planning for an uncertain future, therefore, we must be aware of the consequences of both overbuilding and underbuilding. The costs of excess capacity will consist largely of fixed charges on investment in plant, resulting in higher per 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 or 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 operating costs for the old installation exceed the new plant's full cost per unit of electricity generated --- 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.

Reserve requirements and load management.

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 cosntruction.

In Europe and Asia, however, where both capital and operating costs have been considerably higher than in the United States, [illegible] and utility managers have given much more attention to conservation --- both of capital and of fuel --- as a goal of ratemaking and system management 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 required 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.

While conditions vary widely among countries and power systems, these figures suggest that domestic utilities might be able to get by 20 to 30 percent less capacity than their current forecasts and policies would indicate.

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, electrical generation seemed to have major economies of scale, and newer plants tended to be cheaper and more efficient than older ones.

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, and (3) reduction of planned reserve ratios.

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

- o conservation of energy supplied by electric utilities;
- o efficient use of existing generation facilities and resources; and,
- o 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.

<u>Reserve generating capacity</u>. 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 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

Source: Alaska Power Administration.

The reserve margins that Railbelt utilities carried, even at the peak of the TAPS construction boom were thus considerably higher 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 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 1977 peak. The additional useful capacity thus 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 is 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. For example, Louis Roddis Jr., former vice chairman of Consolidated Edison, has estimated that U.S. utilities could save as much as $20 billion in investments by over a ten year period by cutting generation reserve margins by up to eight per cent: half this cut would cause little change in customer service perception [Electrical Week, February 3, 1975].

One reason for this new skepticism about traditional reliability standards is of course the rising cost of new plants, and the difficulty of siting and licensing them, but it also stems from a growing recognition that the great majority of the 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 day in ten years while the utilities, the 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; economize on the higher operating costs of existing intermediate and peak capacity; and 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 shed off less essential loads during peak demand hours or system emergencies, by means of a signal sent 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 has 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, before 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.

Organization and financing.

Principles of finance. 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, strciter environmental and safety standards, inflation, and the cost of capital have all conspired to drive up the original cost of electrical generating plants.

Economies of scale dictate large projects, but their sheer size increases the investment risk. In recent years, other economic circumstances, such as the unanticipated fall-off in demand growth, rapidly and unpredicatbly 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 overcome or minimize these risks, lenders invariably require one, and usually both of the following assurances:

> 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

> 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.

These requirements are normally met by the borrower's equity in the venture. The more equity there is in the borrower'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.

Most firms have 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. Even for the top 50 utility companies, 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 conventional 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 economic unit, in most cases a single company (or the parent company of a project subsidairy) or governmental entity.

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, at a lower interest rate than conventional bonds, and cooperatives ar 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 of to cover their debt service (principal and interest payments) obligations. (Municipal utilities and governmental power authorities generally do not calculate a "profit" entry in their books, or pay dividends at all. They may nevertheless accumulate surplus earnings and depreciation 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:

Projects are getting bigger. In most places, new base-load generating facilities are designed to carry greater loads and to take advantage of economies of scale. With 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, delay, or non-completion.

Traditional sources of direct and third-party guaranteed loans to Alaska utilities are drying up. Most cooperatives in Alaska have financed their expansior 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.

Rapid facilities expansion in the 1970's created unprecedented debt ratios and inadequate debt service coverage rates. Rapid expansion during the TAPS construction boom aggravated the already high debt ratios of REA cooperatives in the Railbelt. Despite their exceptionally low interest ratesrThe utilities appear to be facing increasing difficulty servicing their existing long-term debt.

As a general rule REA expects its borrowers to have an interest coverage ratio of at least 1.5. Table 5 shows that the utilities' debt ratios have tended to increase, and their interest coverage to fall, to levels that may preclude large debt issues in the future, at least without very large 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. 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.

The cost of money is increasing, and fixed-rate utility bonds may be unsaleable at any price 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 disorganmized bond market. Recent rates in municipal bond sales have been at 8 to 9 percent or higher, and the outlook may be for double-digit rates on municipals before the end of 1980. 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 any combination of existing utilities. Instead, the Alaska Power Authority is considering an alternative method.

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 to meet these payments.

Project financing 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 firmaly as the sponsors would have assumed them in a conventional financing. There are essentially two methods of securing debt <u>without recourse</u> against the sponsors as such --- guarantees from consumers, and guarantees from government or other third parties.

The first approach relies on revenues from project customers, secured by <u>all-events</u>, <u>minimum-bill</u>, <u>take-or-pay</u> contracts, whereby the wholesale customers (Alaska utilities) bind themselves to pay the costs of operation and maintenance, interest and the scheduled repayment of principal --- <u>however high those charges may be, and whether or not the service or product is actually delivered</u>. 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, <u>in advance of construction</u>, obliging them 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, whether or not consumers actually need or want the power, whether electricity is actually delivered or not, and 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 forms 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 no chance whatsover that private lenders will accept 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.

There are only two parties capable of securing the construction debt of a large project-financed generating plant in Alaska: once again they are 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, and 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 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 is likely to double or triple the average cost of electricity to Chugach Electric Association customers over the entire period of ten years or more before they 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), but we believe that the public acceptablility of such an arrangement is virtually nil.

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:

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

The (CVEA) Copper Valley Electric Association, Inc., and the region from Valdez to Glenallen served by this utility is not expected to become part of the interconnected Railbelt until such time as construction of the Susitna Dam becomes a reality, and is, therefore, excluded from this discussion.

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, certain 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.

The delay of lobbying and legal efforts that may be used to retain access to the gas could serve to maintain the status quo for the short run. What is not clear is whether conversions to coal, small hydro, or other alternative technologies could be made then 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 long-term development. Should Chugach Electric Association enter into a take-or-pay contract to guarantee their willingness to sell Susitna-generated power in the next decade?

Can the growth of demand make Susitna an economic power source for the railbelt, or can a series of smaller generation projects meet the demand at the same or less cost for both the utility and its customers? It is the examination of questions such as these on which Chugach Electric Association is basing its future actions. 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 than of 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 the 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 Chugach Electric. 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. SES and HEA remain under long-term contracts to purchase power from Chugach until the turn of the Century, locking them into costs and budgets that will depend on 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 going to become more expensive whatever the source.

The Matanuska Valley Electric Association, Inc. service area is located immediately adjacent to the proposed Susitna dams. Distance from the generation source might make power here somewhat less expensive than in the further extremes 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, high initial costs seem less significant, if the long-range picture would be brighter. One large project is more appealing to local business and political leaders than the suggested alternative of several smaller hydroelectric 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 Association, Inc. and the Fairbanks Municipal Utility System. GVEA, as MEA, has again felt the effects of the "bust" end of the cycle. Anticipation of gas pipeline construction project has been keeping some investors interested in the area, but according to one utility executive, there were in December 1979 "some 1300 to 1400 idle services in Fairbanks at the moment." Expansion is needed here to revitalize business, and the costs of guaranteeing electric service to new industries or employed residents seem, to some, almost insignificant when weighed against the positive impact new activity would have on the economy and stability of the area.

GVEA's short and mid-term expansion plans are progressing both along the "pipeline corridor" (tapping of waste heat from Alyeska pump stations) and extension of transmission lines down the Railbelt (soon to extend from Fairbanks to Summit), with individual tie-ins occurring north of Fairbanks on occasion. While no new generating plants are planned, and plans to use coal from Healy were cancelled due to the cost of compliance with Environmental Protection Agency clean air standards, conversions to waste heat facilities and effective conservation efforts are anticipated and are being encouraged in order to meet the immediate and near future demand. Implementation of plans for a completed Railbelt intertie, also now under consideration, might alter GVEA'S reading of the need for a Susitna Dam project, if wheeling and reserve spinning capacities were more available through an intertied system.

FMUS, serving the Fairbanks urban area as an arm of the municipal government, is perhaps the most influenced by 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-rarge 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 bases, whether they be sales, residential or industrial. These tax sources are in a constant state of fluctuation making planning all the more complicated. For now, no new money is going into utility expansion, and as is the case for GVEA conservation and conversion of existing facilities is anticipated to meet future needs.

The Alaska Power Administration-Eklutna, and the Anchorage Municipal Light and Power services in the Southern Railbelt would be less affected by construction of a Susitna Dam than the other utilities mentioned here. APA-E could sell unused power to the military installations in the area if Susitna power were in competition with it in Anchorage. AML&P is serving a specific service area whose growth might be only minimally affected by construction of a major hydroelectric or gasline project. There is no current expansion planned for Eklutna, and, as with its counterpart in the north, the municipal utility servicing Anchorage plans its expansion budget around the the service area's tax base, which is currently reflecting 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 should keep this utility well on track for meeting its 1989 capacity goal of 225 MW. As with Chugach Electric, effects of the National Energy Act on future plans remain 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 197? 184 million KWH (1977)	1989: 100 1982: 502 KWH (annu 1989: 967 KWH (annu
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 appli

EXISTING UTILITY PLANT AND ORGANIZATION: FAIRBANKS — TANANA VALLEY

UTILITY	SERVICE AREA	CUSTOMERS	TYPE OF UTILITY	PRESENT AND PLANNED GENERATING EQUIPMENT	PEAK LOAD	DEMAND FORECAST
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: 90 KWH/mo/ custome 1988: 10 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.