Power Project Development and Financing in Alaska

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PREPARED FOR

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES RESEARCH AGENCY

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ACKNOWLEDGMENTS

We would like to acknowledge the contribution of Mr. Jack Kreinheder of the Alaska State Legislature, House of Representatives Research Agency who served as Study Manager on this project. Mr. Kreinheder's cooperation and assistance was invaluable in our work.

We would also like to extend our thanks and acknowledge the assistance received from a number of people associated with Alaska power supply. In the course of our work we had extensive discussions with the staff of the Alaska Power Authority, their bond counsel, financial advisors and underwriters. We also wish to acknowledge the time given us by management and staffs of the Division of Energy and Power Development, the Department of Commerce and Economic Development, the Alaska Public Utilities Commission, the Office of Management and Budget, The Division of Policy Development and Planning, and the staff of the Alaska State Legislature. Our discussions with a number of the State's utilities in the Railbelt area and the Alaska Village Cooperative as well as the Alaska Rural Electric Cooperative Associative were also very helpful. We would also like to acknowlege the assistance provided by the Alaska Power Administration and the Rural Electrification Administration.

PREFACE

This report on power project development and financing was authorized by the Governing Committee of the House Research Agency, composed of the Speaker of the House, the Minority Leader, and the ranking House member of the Legislative Council. The purpose of the report is to provide legislators and others with a central source of information on the State's power development activities, and to identify alternative approaches for consideration.

The report focuses primarily on the activities of the Alaska Power Authority, although the report also addresses the Division of Energy and Power Development, the Alaska Public Utilities Commission, and other agencies. The consultant was not asked to provide specific recommendations, but rather was directed to review several aspects of power development and, where appropriate, suggest alternatives for consideration.

The Alaska Legislature has enacted legislation modifying the power development program in each of the last several years. Major changes in the project development process, rate structures, and other areas were made by SB 25 in 1981 and HB 9 in 1982. This session, the legislature is considering several bills relating to the construction and financing of the Susitna hydroelectric project and may consider action to resolve the power rate problem facing the Tyee project.

Power development is a complex field involving questions of economics, engineering, State and debt financing, rate design, and other technical and policy aspects. It is hoped that this report will provide legislators and others with a useful reference source in evaluating power development approaches and legislation.

This study was conducted under a contract of $53,000 by the firm of RMI Pacific Northwest, of Portland, Oregon. This firm was selected through a competitive bid procedure conducted by the House Research Agency. We were specifically requested to obtain the services of a consultant with extensive electric utility and power development experience. Harrison Call, Jr., the principal consultant for the study, has worked in the utility industry for over 20 years and most recently was chief economist for the Los Angeles Department of Water and Power, which has 1.2 million power customers.

The contract manager for this study was Jack Kreinheder of the House Research Agency staff. Any questions concerning the report should be directed to him. In addition, the Agency is available to provide further information on power development upon request.

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SECTION I

INTRODUCTION AND SUMMARY

As was anticipated, the work involved in this study presented a challenging assignment. The scope of the study covered essentially all of the activities involved in Alaska's Power Project Development Program. In addition, a number of related issues have been addressed.

One of the most challenging aspects of the work was the fact that we were dealing with what might best be termed a "moving train". During the course of the work a number of important elements of the Program were under review and, in some cases, actually revised by the Alaska Power Authority and other agencies. To the extent possible we have recognized these changes but there are undoubtedly some instances where we have not been able to do this.

Our work was undertaken within the framework of six separate tasks. These were:

- Alaska Power Supply
- Development Program of Alaska's Power Project
- Wholesale Power Rate Structure
- State Funding Alternatives for Power Projects
- Debt Financing Alternatives for Power Projects
- Alternatives for Disposition of Projects Upon Completion

This section of the report provides a summary of the results of our work. To accomodate the reader with limited time, this material provides only our major observations and alternatives to present practices and procedures. The balance of the report provides a detailed discussion of the work under each of the tasks listed above.

ALASKA POWER SUPPLY

A number of organizations are involved in energy research, development and management activities directly and indirectly related to power supply in Alaska. Nearly every agency or department of state, local and federal government is involved to some degree in energy related pursuits, although these are not all related to power supply. Section 2 of the report provides an overview of the institutions and legislative directives relating to Alaska power supply.

General Observations

Our general observations of institutions and legislative directives relating to Alaska power supply are as follows:

- Legislative directives relating to Alaska power supply have evolved over a period from the early 1960's. Significant changes have been made, almost on an annual basis, beginning in the mid 1970's.
- The key agencies involved in Alaska power supply, in addition to the State's utilities are:
  - Alaska Public Utilities Commission (APUC)
  - Division of Energy and Power Development of the Department of Commerce and Economic Development (DEPD)
  - Alaska Power Authority (Authority)
- Other agencies and the Legislature itself are involved in the funding of power supply facilities independent of the Energy Program for Alaska and there exists a multitude of programs relating to electrical energy under several agencies.
- There are important areas of Alaska power supply development where there is overlapping responsibility. Particular examples of this are in the areas of planning, conservation, and renewable resources.

Alternatives for Consideration

It may be time to stabilize existing responsibilities and programs to allow a maturing process in activities related to power supply. However, consideration might be given to some consolidation of similar programs and clearer definitions of responsibility to take advantage of the expertise and experience of particular agencies. The objective of such an effort would be to minimize overlap and duplicative responsibilities and programs.

An example of an alternative to accomplish this would be centralizing responsibilities, at the State level, for power supply activities with the APUC, the DEPD, and the Authority. The APUC might well be given the added responsibility for review and coordination of utility service area forecasts. The DEPD might assume full responsibility for the planning, assessment, and implementation of conservation programs and for the continuing assessment of renewable and alternative energy options. The Authority then, would be responsible for power suppy planning, reconnaissance studies, feasibility studies, and project financing and development. These activities would utilize the work of the APUC on load forecasting, as well as the work of the DEPD on conservation and renewable resources.

ALASKA POWER PROJECT DEVELOPMENT PROGRAM

The work involved in our review and assessment of the Alaska Power Supply Development Program was the primary focus of the study. The scope of this work included:

- Power supply planning
- Reconnaissance and feasibility studies leading to project selection
- Project authorization process

General Observations

The following are general observations with respect to the power supply development program:

- The Authority has inherited a variety of studies and data relating to all aspects of power supply as well as individual projects that were in one stage or another of development. The power supply planning process is an evolving one and, although the Authority has and continues to implement improvements, it is not yet mature.

- Power supply planning areas have not been well defined beyond the Railbelt region.

- Load forecasting has been undertaken by individual utilities as well as several State agencies. However, the credibility of load forecasts continues to be questioned and there has not been an integration of load forecasting and power supply planning. The DEPD's Long Term Energy Plan includes a section relating to electrical energy, but it does not constitute a power supply plan, even at the State level. For the most part, power supply plans for individual areas of the State have not been developed and periodically updated.

° The Authority has made significant improvements in their approach to and the methodology utilized in reconnaissance studies. However, with the introduction of a more disciplined power supply planning process additional improvements in the reconnaissance level studies are required. The Authority has also made significant improvements in their approach to feasibility studies. The Office of Management and Budget (OMB) has provided a number of recommendations for improvements in the feasibility study process in addition to their oversight and review role of completed feasibility studies. However, there continues to be areas where further improvements in the feasibility study phase of power supply development can be made.

° As the feasibility study provides an assessment of "economic feasibility", the financial plan does essentially the same thing with respect to "financial feasibility". The Authority's work with their financial advisors and bond counsel towards the end of developing overall financial policies has laid a good foundation for the development of financial plans This will be an important element in the decision process for future projects.

° The project authorization process is unique in that the Legislature is, in effect, the final decision maker, with the concurrence of the Governor. This occurs because of the significant financial participation of the State in power project financing. The statutory restrictions which limit the power of one legislature to commit a future legislature, and the fact that the budgetary process deals only with a single year while power projects involve a commitment over an extended period of design and construction are complicating factors.

Alternatives for Consideration

It is emphasized that the power supply development process in Alaska is evolving and that the Authority, with input from the OMB and others, has made significant improvements in the several elements of that process. However, we believe that additional improvements can and should be considered.

In this regard, alternatives offered for consideration are summarized below:

- The Authority, in consultation with other agencies including DEPD, APUC, and OMB, might define power supply planning areas consisting of population centers which are presently interconnected or which might be interconnected by transmission lines in the future. These areas would be in addition to individual communities, primarily located in bush areas, which would have to be dealt with on an individual basis for power supply planning.

- A formal assignment of responsibility for review and coordination of utility load forecasts and the development of independent load forecasts for power supply planning areas as well as individual communities and villages might be made. This responsibility could rest with the Authority or with DEPD, but serious consideration should be given to adding this responsibility to those of the APUC. A number of reasons for this should be considered, including the fact that load forecasts are an important part of other APUC responsibilities, not the least of which is their rate proceedings.

- Once initial load forecasts were developed for the various power supply planning areas, as well as individual communities and villages, a procedure might be developed that would provide for periodic review and updating.

- With defined power supply planning areas and compatible load forecasts, the credibility of which would be enhanced as a result of a formalized process discussed above, accurate power supply requirements can be determined.

- The reconnaissance level studies might then be focused on providing a pool of resources for further study that would be available to meet identified needs in the various areas of the State. Periodically, the reconnaissance level studies would be updated to reflect technological advancements in alternative and renewable resource technologies as well as changes in other factors.

- Consideration should be given to incorporating other economic evaluation methodologies, in addition to present value life cycle cost analysis, in the assessment of economic feasibility of alternative projects. It is suggested that a comparison of the busbar costs of power from alternative projects might be developed both on a constant and current dollar basis. This methodology facilitates development of sensitivity analyses with respect to the several variables and assumptions involved in economic analysis.

- OMB should continue its oversight role in the review of all aspects of the power supply planning and project evaluation process. The Authority and OMB should cooperate in the development of documentation for decision makers which describes the entire power supply planning process as well as requests for project authorization. This documentation should be periodically updated and reviewed with the appropriate committees of the Legislature and other State agencies.

WHOLESALE POWER RATE STRUCTURE

The Authority's wholesale power rate structure is based on very explicit rate directives provided by the Legislature. There has been a continuing evolution of legislative directives relating to the Authority's rates beginning with the initial legislation that created it.

General Observations

During the 1982 session, the Governor and Legislature undertook a comprehensive review of the Authority's rate structure. Bills reflecting the Governor's position, as well as a House committee position, were considered and rejected. A compromise, HB 9, was ultimately passed and signed by the Governor.

The changes in legislative direction concerning the Authority's rate structure provided by HB 9 were significant. In place of the uniform or "postage stamp" rate previously in effect, a project-specific rate was established. HB 9 provided that there would be some levelizing of the debt service costs between projects subject to a cap.

The predominate feeling on the part of those directly involved in the Authority's financing is that it is important that legislative direction relating to rates be stabilized. However, there are, relatively minor "housekeeping" and clarifying changes that will be suggested to the Legislature this year.

Equally as important as the rates established by the Authority is the language of power sales contracts covering the output of the Authority's several projects. Our review of the most current draft power sales contracts indicates that they are consistent with the directives provided by HB 9 and that they do provide for adjustment of rates in the face of unforeseen circumstances, for example, abnormally low water conditions.

Alternatives for Consideration

Unless the language of HB 9 is interpreted to be broad enough to allow for inclusion of all project costs in the revenue requirement as well as for the inclusion of debt service coverage, then we would suggest that serious consideration be given to a legislative remedy. Also, we believe that consideration should be given to establishing rates for non-firm energy and for capacity in addition to the present single wholesale power rate.

With respect to power sales contracts, consideration needs to be given to the timing of the execution of those contracts. Contracts will have to be executed prior to the Authority's undertaking of any revenue bond financing. However, the Legislature may wish to establish that power sales contracts be executed prior to major appropriations for design and construction of projects.

STATE FUNDING

The State of Alaska's direct participation in the funding of the costs of construction of power projects is not only unique among other states, but has been the key to electrification of bush areas and the construction of hydro projects that will enhance service to the more populated areas of the State.

General Observations

Legislative appropriations for power project development have been made under several programs involving both the Authority and other State agencies. The major programs under which appropriations have been made include:

- Alaska Power Authority
  - Power Development Fund
  - Power Project Loan Fund
  - Rural Electrification Revolving Loan Fund
  - Legislative Grants for Power Development Projects
- Department of Administration
  - Electric Power Grants
- Department of Community and Regional Affairs
  - Legislative Grants for Bush Village Electrification

After the 1982 session of the Legislature, the House Research Agency was requested to develop an approach involving a dedicated energy fund as an alternative to the present State funding practices. The proposal developed in response to this request was to would provide a whole new set of jurisdictions centered on energy management areas to assure that projects funded would have the support of the areas that they would serve.

Alternatives for Consideration

Our consideration of alternatives to present State funding practices focused on the proposal discussed above.

- The State's commitment to partially fund power projects is a basic policy decision. Likewise, a commitment to create a dedicated fund with earmarked revenues is also a basic policy decision.

- The dedicated fund alternative has certain advantages in terms of financial planning, primarily because it would provide assurance that funds would be available for power project financing and it would establish a formula to determine the amount of State participation.

- The proposal for the dedicated fund would involve the formation of local energy management areas with their own boards and would provide for voter approval of projects. An alternative to this would be to provide legislative direction to the Authority for increased consultation, and perhaps an approval requirement, of already established local and regional governmental agencies. Submission to the voters for approval might be difficult because of the complexity of the decisions.

- Any alternative for State funding that would provide a basis for the level of that funding as opposed to the present practice of addressing the question on a project by project basis and leaving uncertainty as to whether or not more funds can be obtained from the State, would enhance the Authority's ability to negotiate power sales contracts prior to construction of the projects. Also, multiyear appropriations for individual projects is another alternative for consideration.

DEBT FINANCING ALTERNATIVES

One of the more compelling reasons, if not the primary reason, for the formation of the Authority was to provide an entity that would have the statutory authority and the practical capability to undertake major financings for power projects. Although the scope of the Authority's responsibilities in this regard has changed since its creation in 1976, power project financing remains among the Authority's primary responsibilities.

General Observations

The Authority has successfully undertaken interim financing associated with power projects under construction. It has not yet, however, undertaken any long term revenue bond financing of these projects. The latter is imminent, and the Authority in consultation with its investment bankers, financial consultants, and bond counsel has been finalizing a financing program during the period of our work. We have had the opportunity to review the progress of this work with the Authority and its consultants.

Our general observations with respect to the Authority's debt financing are as follows:

- The Authority's interim financing policies and practices are consistent with those generally utilized by publicly owned utilities and have successfully provided funds for construction financing.

- The Authority's work with consultants and bond counsel in developing a financing program represents a prudent business approach.

- It is important that the Legislature and other agencies of State government involved work with the Authority to formalize its financing program and to provide any required statutory amendments. The timely completion of such a cooperative effort will enhance the ability of the Authority to successfully undertake the required long term financing.

- It is important that any required modification in the Authority's rate directives to implement a financing program be adopted. Particularly, if it is determined that the existing statutes do not provide for inclusion of debt service coverage and the operation of funds to which those amounts would flow, legislative remedies must be developed in a timely manner.

DISPOSITION OF POWER PROJECTS

The questions addressed under this subject pertain both to ownership and operation of the Authority's projects upon completion.

Our discussions with the Authority's bond counsel and investment bankers indicate that there is very little flexibility with regard to the question of ownership. If the Authority undertakes debt financing for a particular project, title to that project will have to be vested in the Authority. It is suggested that any further questions on this subject should be directed to the Authority's bond counsel or the Attorney General.

With respect to the operation of completed projects, there is considerably more flexibility. Financing considerations dictate that assurance be provided that the projects will be operated and maintained by an agency that is competent to do this work. Therefore, any arrangement for operation and maintenance may have to be disclosed at the time of financing. Again, this question needs to be addresssed by the Authority's financial advisors and bond counsel.

Alternatives that should be considered with respect to operation and maintenance of completed projects include the following:

- The Authority could operate and maintain all projects that they finance.
- Projects could be operated by the local utility serving the area where the project is located under a contractual arrangement. (This has been done with the Solomon Gulch Project.)
- Even as the Authority contracts for the operation and maintenance of one or more of its projects, certain economies of scale can be achieved if the Authority would maintain responsibility for, for example, training of plant operators, major overhauls, maintenance of spare parts and other activities of this nature.

A number of power generation facilities have been constructed throughout the State with funds appropriated by the Legislature or obtained from State agencies other than the Authority. An alternative for operation of these projects that we believe should be considered would be a requirement, as a condition of providing funds, that arrangements be made for operation and maintenance of the generation facility. For example, the Alaska Village Electric Cooperative might be able to efficiently fulfill this function within their service area.

SECTION 2

ALASKA POWER SUPPLY

INTRODUCTION

A number of organizations are involved in energy research, development, and management activities directly and indirectly related to power supply in Alaska. Nearly every agency or department of State, local, and the federal government is involved to some degree in energy related pursuits. This section of the report will provide an overview of the institutions and legislative direction relating to Alaska power supply.

There are several Federal Agencies operating in Alaska whose energy activities influence the lives and livelihoods of Alaskans. The most active of these is the Alaska Power Administration of the U.S. Department of Energy.

The agencies, activities, and programs within the Alaska State government are also analyzed and discussed in some detail in this section. The agencies which will receive the most in-depth discussion are the Division of Budget and Management and the Division of Policy Development and Planning in the Office of the Governor; and the Alaska Public Utilities Commission, the Alaska Power Authority, and the Division of Energy and Power Development of the Department of Commerce and Economic Development. These are the key State organizations involved in energy activities in Alaska.

Power supply planning in Alaska differs from the lower 48 states in that a State agency under the control of the Legislature and Governor (the Authority) serves as the wholesale power marketing agent for power from State owned facilities. Alaska has invested substantial sums in the development of power projects. Therefore, the State has a vested interest in all phases of power supply by reason of both its overall energy policy concerns and its participation in power project financing.

Finally, one further point warrants mention; public agencies, utilities, private enterprise, and special interest groups are all involved in Alaska Power Supply. As a result, no entity has a monopoly on power and energy within Alaska. In fact, energy activities within Alaska are incredibly diversified, ranging from economic assistance for high cost power or fuel to research, development and demonstration programs for power supplies.

As a result, there is considerable duplication of effort in Alaska. The State organizational structure in particular is characterized by overlapping responsibilities and confusing lines of authority. State energy policy has not always been consistent either, and this has hindered the development of a coordinated energy plan. This problem has grown with the size and wealth of the State. The majority of Alaska energy programs did not exist five years ago, therefore, the transition has not been smooth and coordinated in all cases. In the interest of charting this evolution, the following presents a discussion of several of the key agencies charged with developing Alaska's energy future. A list of Alaska utilities is also provided in Appendix 2-A.

Federal Agencies

There are several Federal Agencies operating in Alaska whose activities are of direct concern to Alaskans. A summary outline of these agencies is provided below, and a complete list of these agencies and their specific programs is provided in Appendix 2-B.

Federal Agencies

Department of Energy
Alaska Power Administration
Alaska District Corps of Engineers
Internal Revenue Service
Farmers Home Administration
U.S. Forest Service
U.S. Department of Agriculture
U.S. Department of Housing and Urban Development

State Agencies

As can be seen from the figure below, nearly every office and department within the Alaska State organization is involved in energy related activities. Some are more active than others, and these will receive more attention in our report as warranted. A comprehensive list of all energy related agencies and their respective programs is provided in Appendix 2-B.

Alaska Organization and Administration of Departments

Conducts Specific Energy Related Activities	Office or Department	Important Energy Activity Detailed in Report
X	Office of the Governor	X
X	Department of Administration	X
	Department of Law	
X	Department of Revenue	
	Department of Education	
X	Department of Health and Social Services	
X	Department of Natural Resources	X
X	Department of Commerce and Economic Development	X
X	Department of Transportation and Public Facilities	
X	Department of Community and Regional Affairs	
	Department of Public Safety	
X	Department of Military Affairs	
X	Department of Fish and Game	
	Department of Labor	
X	Department of Environmental Conservation	

This section of the report contains a brief description of several of the key federal and State organizations involved in evergy planning, development, and management activities in Alaska. Those chosen were selected on the basis of compatibility and relevance to report goals. Their responsibilities, programs, and organization are chronicled. This is also accompanied by a brief survey of their status in the recent past. The order of presentation is as follows: a federal agency is discussed first, followed by the Office of the Governor, and concludes with an account of relevant State agencies within the Department of Commerce and Economic Development.

ALASKA POWER ADMINISTRATION

The Alaska Power Administration (APA), a federal power agency, was established in 1967 as a unit of the Department of the Interior and became a branch under the Department of Energy on October 1, 1977. The APA headquarters are in Juneau, Alaska, and they report to the Assistant Secretary of Energy for Resource Applications.

The APA operates, maintains, and markets power for Alaska's two Federal hydroelectric projects - the 47,160 kw Snettisham Project near Juneau, and the 30,000 kw Eklutna Project near Anchorage. The agency is also involved in transmission studies and studies of future water and power potential. Through cooperation with the Corps of Engineers, the State of Alaska and other entities, the agency's activities encompass economic and financial analysis, environmental evaluations, estimates of future energy demand, and engineering and cost studies.

The APA is divided into three major divisions that report to an administrator who, in turn, reports to the Assistant Secretary of Conservation and Renewable Energy. These three divisions are: the Planning Division, the Power Division, and the Administrative Division.

In recent years, the APA has placed high priority on implementing President Carter's Solar Pricing Program, which instructed Federal Power Marketing Administrations to increase their conservation efforts and renewable resources development. They responded by increasing the rate of utilization of Snettisham power, expanding the peaking capability of the Eklutna Project, and by committing funds to exercise renewable resource options and implement conservation programs.

OFFICE OF THE GOVERNOR

Two divisions in the Office of the Governor have been involved in Power Project Development. This is in addition to the continuing involvement of the Governor and members of his staff in all aspects of the program.

Division of Budget and Management

The primary function of the Division of Budget and Management (DBM) is the review of budget and program activities of all Alaska State agencies. DBM has had significant involvement in Alaska's Power Project Development Program through its review of the Authority's budget and of their reconnaissance and feasibility studies. Not only does DBM review these studies for the Legislature and Governor, but DBM staff has worked closely with Authority staff in developing methodology and improving the general quality of the work.

Although there has been controversy at times between DBM and the Authority, it is our observation that DBM's involvement has been positive and that the Authority's management and staff have carefully considered suggestions offerred by DBM's staff.

Division of Policy Development and Planning

The Division of Policy Development and Planning (DPDP) is the primary policy analysis organization of the State. Their primary involvement in the Power Project Development Program relates to the Railbelt area. To assure objectivity in the analysis of alternatives to the Susitna Project, DPDP undertook these studies. The work was actually done by consultants, but supervised by DPDP.

THE DEPARTMENT OF COMMERCE AND ECONOMIC DEVELOPMENT

The Department of Commerce was established as a State agency in 1959 (Ch 64 SLA 1959). It was renamed the Department of Commerce and Economic Development (DCED) in 1976 to more accurately reflect its activities. The DCED's principal energy related responsibilities and duties include:

- Administering State programs which relate to commerce, enforcing the laws relevant to those programs, and adopting regulations consistent with those laws
- Registering corporations and collecting their franchise taxes
- Enforcing the State laws which regulate public utilities and other public service enterprises
- Conducting studies, entering into contracts, and making surveys which relate to the economic development of the State and, when appropriate, analysing, assembling, and dispersing the findings obtained
- Collecting raw data from businesses, individuals, and other organizations which will aid the Department in formulating economic impact information
- Formulating a continuous program for basic economic development, and establishing and activating programs which will achieve balanced economic development
- Advising the Governor on economic development policy matters and administering the economic development programs of the State
- Reviewing annual reports and programs of State agencies, and preparing an annual report on the economic status of the State

The DCED's power development role is complimented by several divisions, offices, commissions, and public corporations over which it has varying degrees of administrative control. This accountability ranges from subordinate organizations within the DCED, to public corporations of the State within the DCED but which have a legal existence independent of and separate from the State.

In the latter case, the exercise by the corporation of the powers granted to it is considered an essential function of the State, and the role of the DCED is limited to that of a supervisory body.

An overview of the organization of the DCED is furnished below. A more detailed summary of the divisions within the DCED and their respective energy related programs and activities is provided in Exhibit 2-1 on the following page.

<u>Department of Commerce and Economic Development</u>

Division of Energy and Power Development

Division of Business Loans

Office of Mineral Development

Office of Special Industrial Development

Alaska Royalty Oil and Gas Development Board

<u>Quasi-Independent Entities</u>

Alaska Public Utilities Commission

Alaska Power Authority

Alaska Renewable Resources Corporation

Summary of
Department of Commerce and Economic Development Divisions
and their Energy-Related Programs and Activities

Division of Energy and Power Development

- Residential Energy Conservation Program
- Low-Income Weatherization
- Energy Planning (Long-Term Energy Plan)
- Energy Field Offices and Education Program
- Energy Research, Development and Demonstration Projects
- Appropriate Technology Small Grants Program
- REAA Grants Program
- Institutional Buildings Grants Program
- Residential Building Lighting and Termal Standards

Division of Business Loans

- Alternative Technology Revolving Loan Fund
- Bulk Fuel Revolving Loan Fund
- Residential Energy Conservation Loan Fund

Office of Mineral Development

Office of Special Industrial Development

Alaska Royalty Oil and Gas Development Board

Quasi-Independent Entities

Alaska Public Utilities Commission

Alaska Power Authority

- Reconnaissance, Feasibility Studies
- Power Project Loan Fund
- Power Cost Assistance Fund
- Rural Electrification Revolving Loan Fund
- Power Development Fund
- Legislative Grants for Power Development

Alaska Renewable Resources Corporation

- Alaska Renewable Resources Development Fund
- Alaska Renewable Resources Investment Fund
- Alaska Renewable Resources Permanent Fund

Division of Energy and Power Development

The Division of Energy and Power Development's (DEPD) goal is to assure that Alaska's energy needs are met as efficiently as possible. Its prime concern is in the development, management, and efficient use of the State's energy resources. Conservation and a commitment to reducing the State's dependence on fossil fuel generation are two additional concerns of the DEPD.

The DEPD was created in 1960 (Ch 135 SLA 1960) as part of the Department of Commerce. It was not funded until 1974 and has been amended twice--in 1976 to reflect the changes made in the Department of Commerce's name, and in 1980 to require certain energy conservation functions.

Its specific duties as required by statute are:

- Study the State's water, fossil fuel, and other power resources and collect and disseminate information relating to them
- Study existing and potential uses and markets for electric power and energy; promote and encourage the development of major markets
- Encourage and assist rural electrification, energy efficiency programs, and the development of power grids, power pools, and solar energy
- Prepare a State Long Term Energy Plan; adopt thermal and lighting energy standards for non-public buildings; and establish a training and certification program for energy auditors
- Cooperate with federal, state, and local agencies as well as private companies interested in the development and use of Alaska's energy and other natural resources
- Coordinate and represent the State's interest in securing federal participation in the development and financing of large-scale, low-cost power projects
- Make grants to school districts and regional educational areas for planning, developing, and implementing energy efficient standards for rural educational facilities
- Supply State grants to match any grants made by the Department of Energy under the Appropriate Technology Small Grants Program

The DEPD carries out its activities through six programs: Energy Administration, Energy Assessment and Programs, Energy Engineering, Conservation, Information Services, and Education and Field Offices.

Energy Administration

This section assimilates energy policy decisions and provides the DEPD with planning and management directives as well as support facilities. The Energy Administration Section is supported by three groups: accounting, grants administration, and clerical.

Energy Assessment and Programs

This section's functions include: long term energy planning, resource development planning, in-state energy supply and demand forecasting, and energy policy and planning activities. Some specific planning activities which this section undertakes are:

- Alaska Long Term Energy Plan
- Assessment of Energy Technologies
- Energy Emergency Contingency Plan
- Energy Conservation Evaluation
- Alaska Energy, Resource Development, and Economic Future Study

Energy Engineering

A technical appraisal of energy issues is the major assignment for employees within this section. They are responsible for the operation of the DEPD's research development and demonstration projects. The projects themselves are concentrated in the following areas:

- Wind
- Peat
- Geothermal

- Biomass/Wood
- Energy Use and Transformation
- Miscellaneous Technologies
- Alaska Energy Center Projects
(transferred to the DEPD from the Alaska Energy)

Energy Conservation

Alaska's residential energy conservation programs are the primary responsibility of this section. Three of its activities include:

- Residential Energy Audits
- Low-Income Weatherization Program
- Energy Conservation Grants and Refunds

Information Services

The Public Information Sector collects, prepares, and disseminates timely energy information to the public. It publishes a quarterly newsletter and an Energy Resource Handbook. It also produces radio and television programs and serves as the public relations arm. The section also provides a liason with the Legislature and analyzes energy related legislative developments.

Field Offices and Education

Through its field offices the DEPD establishes contact with most areas of Alaska. It accomplishes this goal through five vehicles:

- Anchorage-Southcentral Field Office/Energy Information Clearinghouse
- Juneau-Southeast Field Office
- Fairbanks-Interior Field Office
- Education Programs
- Technical Reference Library

ALASKA PUBLIC UTILITIES COMMISSION

The Alaska Public Utilities Commissionn (APUC) was created in 1959 (Ch 199 SLA 159) within the Department of Commerce (renamed the Department of Commerce and Economic Development in 1976). It consists of five members who are appointed by the Governor and confirmed by the Legislature, and whose terms of office are six years.

Among the general powers and duties of the APUC are:

- Regulation of every public utility engaged or proposing to engage in the utility business inside the State except for municipal utilities
- Jurisdiction includes the following types of utility services: electric, gas, steam, water
- Investigations of the rules, regulations, rates, classifications, services, and facilities of public utilities
- Shall hold rate hearings and approve rates
- Shall ensure that public utilities charge rates that are just, fair, and reasonable
- Shall prescribe the system of accounts and require public utilities to file reports and other information and data
- Shall regulate the service and monitor the safety of operations of public utilities
- Shall develop PURPA Regulations
- Appear personally or by counsel and represent the interests and welfare of the State

The APUC also is required to publish and submit to the Legislature an annual report reviewing its work in the previous year, plus an outline of the Commission's program for the development and regulation of public utility services in the forthcoming year.

In addition, the APUC requires each public utility to provide it with a a complete tariff showing the rates charged to all classes of customers. It further stipulates that rates shall be just and reasonable, and non-discriminatory or preferential. If the APUC determines that a utility's rates do not conform to these criteria, it is empowered to determine its own estimate of a just and reasonable rate and can establish it by order.

No public utility may operate within Alaska without first having obtained from the APUC a certificate declaring that public convenience and necessity require or will require the service. If two or more public utilities are competing to provide identical service to the same area and this competition is not in the public interest, the APUC is authorized to take appropriate action to eliminate the competition or any undesirable duplication of facilities. Furthermore, those utilities receiving certificates must furnish and maintain adequate, efficient, and safe service and facilities. The service provided also must be reasonably continuous and without unreasonable interruption or delay. In the event a utility fails to conform to any of these provisions, the APUC may order an investigation, formal hearing, or a review of the utility's license privilege.

ALASKA POWER AUTHORITY

The Alaska Power Authority (Authority) is a public corporation made up of a seven member Board of Directors who are appointed by the Governor and confirmed by the Legislature. It was created in 1976 (Ch 278 SLA 1976), but it was not actually funded and staffed until 1978. A staff of 32 conducts the day-to-day business of the Authority from offices in Anchorage.

"The role of the Authority is to identify, evaluate, and develop electrical power production facilities utilizing the most appropriate technology from among those that are commercially available (except nuclear generation)."1/ The Authority is authorized to conduct reconnaissance and feasibility studies; issue bonds; design, construct and operate projects; and enter into contracts for power sales. The extent of their involvement in any power project depends on local needs and preferences, project specifics, and State budget priorities. Power project facilities can be studied, financed, constructed and owned by the Authority, but in some cases their involvement is confined to financing alone, or just to the early phases of project investigation, evaluation, and/or development.

The creation of the Authority was necessary due to the peculiarities of long term energy planning in general, and the geography and energy needs of the State of Alaska specifically. The Legislature recognized this situation as early as 1960 when they laid the groundwork for an agency whose primary responsibility would be electrical power development--the DEPD in the Department of Commerce. A State power development plan was required by the original 1960 legislation, but the first plan was not produced until 1980.

In 1976 the Legislature reached a concensus on Alaska's energy development and long term economic growth policies. The 1976 Legislature passed a Legislative Finding and Policy Section in Article 1 of the Alaska Power Authority Bill (Ch 278 SLA 1976) which stated:

> (a) The Legislature finds, determines and declares that
>
> (1) there exist numerous potential hydroelectric and fossil fuel generating sites in the State;
>
> (2) the establishment of power projects at these sites is necessary to supply power at the lowest reasonable cost to the State's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumer of the State, as well as to supply existing or future industrial needs; (HB 442 1978)
>
> (3) the achievement of the goals of lowest reasonable consumer power costs and beneficial long-term economic growth and of establishing, operating and developing power projects in the State will be accelerated and facilitated by the creation of an instrumentality of the State with powers to construct, acquire, finance, and operate power projects (HB 442 1978)
>
> (b) It is declared to be the policy of the State, in the interests of promoting the general welfare of all the people of the State, and public purposes, to reduce consumer power costs and otherwise to encourage the long-term economic growth of the State, including the development of its natural resources, through the establishment of power projects by creating the public

corporation with powers, duties, and functions as provided in this chapter. 2/

In order to achieve the goals of its policy, the State found that hydroelectric projects should be considered the most desirable new resource option. Hydroelectric projects appeared to ensure the State of a supply of long term, stable priced and secure electrical power.3/

However, it was discovered that financing constraints often argue against the construction of the most cost effective project. The problem arises because high, front-end construction costs (which are sensitive to inflation) cause wholesale power rates to be much higher than other alternatives in the early years of project life. The problem is also compounded by the sheer magnitude of the financing which must be secured to even conduct the preliminary investigations, let alone the actual construction. This set of circumstances makes it very difficult for a single utility or an association of utilities to embark on such a project even if it were proven feasible.

Hence, it was decided that the situation required State intervention. Other agencies could carry out reconnaissance, feasibility, design and construction activities, but a public corporation would be the perfect vehicle for achieving the State's purposes in this instance. By its status as a public corporation the Authority could sell bonds, subject to IRS regulations, whose interest to bondholders would be tax free. This feature would lower the cost of debt capital. When combined with existing State financing instruments, Alaska would have a more diversified pool of financing alternatives whose combined cost of borrowed capital was much lower and whose investor attraction was much greater.

With this in mind, the electric power development function was transferred from the DEPD and became the primary responsibility of the Authority in 1976. It was set up as a public corporation of the State in the DCED, but with separate and independent legal existence. The Authority and the DEPD do collaborate, however. For example, they both work together in formulating the State of Alaska Long Term Energy Plan and its annual revision.

Among the specific powers the Authority was granted by Chapter 83, "The Omnibus Energy Bill," are:

- To acquire, whether by construction, purchase, gift or lease, and to improve, equip, operate, and maintain power projects

- To issue bonds to carry out any of its corporate purposes and powers . . . and to deposit and invest its funds subject to agreements with bondholders

- To sell, lease as lessor or lessee, exchange, donate, convey or encumber in any manner . . . real or personal property owned by it, or in which it has an interest . . .

- To perform reconaissance studies, feasibility studies, and engineering and design with respect to power projects

- To enter into contracts or agreements with respect to the exercise of any of its powers (with the United States or any person), and do all things necessary and convenient to carry out its corporate purpose and exercise the powers granted in AS 44.83.010-44.83.510 4/

In addition to those mentioned above, the Authority has specific powers which relate to the financing methods that it can recommend to the Legislature. To accomplish its mission of assisting utilities and others with the development and operation of power projects by providing loans and grants; issuing bonds; and preparing feasibility, reconnaissance, plans of finance, and engineering and design studies, the Authority can recomend to the Legislature:

- The issuance of general obligation bonds of the State to finance the construction of a power project if the Authority first determines that the project cannot be financed by revenue bonds of the Authority at reasonable rates of interest;

- The pledge of the credit of the State to guarantee repayment of all or any portion of revenue bonds issued to assist in construction of power projects;

- An appropriation from the General Fund

  - For debt service on bonds or other project purposes; or

  - To reduce the amount of debt financing for the project;

- An appropriation to the Power Project Fund for a power project;
- An appropriation of a part of the income of the Renewable Resources Investment Fund for a power project;
- Development of a project under financing arrangements with other entities using leveraged leases or other financing methods.
- An appropriation for a power project acquired or constructed under the Energy Program for Alaska.5/

The existence of two potential sources of funds for development of renewable energy projects--the Authority and the State of Alaska--expands the range of financing alternatives. The financing arrangements available to parties within Alaska are:

- Alaska Power Authority Revenue Bonds
- State General Obligation Bonds
- Revenue Bonds with State Guarantee
- State General Fund Appropriation
  - Debt Service Payment
  - Reduction of Bondable Costs
- State General Fund (Equity Investment)
- Non-State Assistance
  - Federal (REA & FFB)
  - CFC
- Leveraged Leases
  - Other Third Party Financing Methods

The purpose of the State assistance in whatever form is to lower the cost of borrowed capital for the development of projects and the cost of energy to consumers. The latter factor is especially critical when the project is a capital intensive project, and the greatest benefits to the consumer are realized in the early years of project operation.6/ However, under current legislation where debt service costs must be incorporated into wholesale power rates, the objective of reducing initial consumer power costs for hydro projects is not always fulfilled to the maximum extent possible due to the considerable markup in rates which these financing costs impose. Debt financing (under current legislation) will not necessarily provide the consumer with inexpensive power or "an early break" when a substantial amount of the project cost is financed through debt and an equally substantial amount of debt service costs are incurred early in the project's life.

Specific Programs

To carry out its power development role the Authority administers four specific programs: the Power Project Loan Fund, the Power Cost Assistance Program, the Rural Electrification Revolving Loan Fund, and the Energy Program for Alaska (which has a Power Development Fund). These programs were established at different times and amended, renamed, and their functions revised as the Legislature built a comprehensive energy plan. When the Authority was first created it only administered one program. Today there are four specific programs which compliment its power development role. A chronological history of the Authority and the DCED, showing the changes in their structure and programs, is presented in Exhibit 2-2. From this chart it is apparent how much these agencies have grown and changed over time.

In addition to its specific programs, the Authority also has general authority to promote power development. For example, the Authority can issue bonds outside of the Energy Program for Alaska. It can also provide loans to individual utilities from funds which are appropriated to the Authority generally, as opposed to those which are conditionally dedicated by the Legislature to specific programs. These options, combined with the other four programs, give the Authority considerable flexibility in power development.

A SUMMARY, BY YEAR, OF SELECTIVE CHANGES IN THE DEPARTMENT OF COMMERCE AND ECONOMIC DEVELOPMENT

1959 - 1981

1959

Department of Commerce and Economic Development Established

- Alaska Public Utilities Commission Established

1960

Department of Commerce and Economic Development

- Alaska Public Utilities Commission
- Division of Energy and Power Development Established (Funded in 1974)

1976

Department of Commerce and Economic Development

- Alaska Public Utilities Commission
- Division of Energy and Power Development
- Alaska Power Authority Established (Funded in 1978)
  - Power Project Revolving Fund Established

1978

Department of Commerce and Economic Development

- Alaska Public Utilities Commission
- Division of Energy and Power Development
  - Long-Term Energy Plan Required
- Alaska Power Authority
  - Power Project Fund (Renamed)

1980

Department of Commerce and Economic Development

- Alaska Public Utilities Commission
- Division of Energy and Power Development
  - Long-Term Energy Plan
- Alaska Power Authority
  - Power Project Loan Fund (Renamed)
  - Power Production Cost Assistance Fund Established

1981

Department of Commerce and Economic Development

- Alaska Public Utilities Commission
- Division of Energy and Power Development
  - Long-Term Energy Plan
- Alaska Power Authority
  - Power Project Loan Fund
  - Power Cost Assistance Program (Renamed)
  - Rural Electrification Revolving Loan Fund Established
  - Energy Program for Alaska Established
    - Power Development Fund Established

Power Project Loan Fund

The Power Project Loan Fund was formerly known as the Power Project Revolving Fund. It was established in the original legislation (Ch 278 SLA 1976) that created the Authority. Its purpose was to loan funds to cities, boroughs, and others; to conduct necessary studies; and construct power projects. The statutes governing this program were amended in 1978 and in 1980. The most significant changes made concerned the source of funds for the program (Ch 83 SLA 1980 provided that the fund include only money apopropriated by the Legislature and would not include interest earned on the loans as it had previously), and the authorized uses for loans from the fund (Ch 156 SLA 1978 expanded and explained these in greater detail).

The present statute declares that the Power Project Loan Fund is established to provide loans to electric utilities, regional electric authorities, municipalities, cities, boroughs, regional and village corporations, village councils, and non-profit marketing cooperatives; or borrowers who allow the above entities to operate a project under third party or leveraged lease financing arrangements.

To be eligible for assistance, potential recipients must meet and follow certain standards, procedures, and criteria as determined by the Authority, and they must prove that they need the loan to cover the costs of various non-nuclear expenses. Valid expenses include: reconnaissance studies, feasibility studies, license and permit applications, preconstruction engineering, design of power projects, construction, equipping, modifying, improving, and expanding power production facilities and transmission and distribution facilities. In fact, loans can be used to pay most costs except those of debt service, bond defeasance costs, or operation and maintenance costs. In addition, to receive a loan, the applicant must "demonstrate to the Authority that the financing arrangement for the power project will reduce project financing costs below costs of comparable public power projects."7/

Loans for power projects from the fund carry an interest rate which is not less than five percent, nor greater than the average weekly yield of municipal bonds for the 12 months preceding the date of the loan. The term of the loan may not exceed 50 years. Loans of 25 years or less for diesel generation, and 35 years or less for hydroelectric projects are common.

Power Project Loan funds are distinct from any other money or funds of the Authority and include only money appropriated by the Legislature. Loan repayments and interest earned on the loans outstanding from the fund are deposited in the State General Fund.8/ As of August 4, 1981, the Legislature had appropriated a total principal amount of $25,070,000 plus interest.

Power Cost Assistance Program

In 1980, the Power Production Cost Assistance Program was established to provide a State subsidy to high-cost residential power. Thereafter, the 1981 Legislature retitled it the Power Cost Assistance Program and the qualifications and level of assistance were changed.

The program has a fund which is administered by the Authority as a fund distinct from other funds, and it is composed of money appropriated for the purpose of providing power cost assistance to eligible electric utilities. The 1980 Legislature established the program with a total funding of $2,621,000 . For the fiscal year ending June 30, 1981, program expenses were $2,287,735. Fifteen utilities received Power Production Cost Assistance during 1981. The program is funded through FY 1982.

The APUC determines utility power costs and eligibility, and it determines the amount of State assistance per kilowatt-hour sales for individual utilities. The Authority disburses the funds to eligible utilities based on the recommendations of the Commission and statements of sales to eligible customers submitted by eligible utilities.

An electric utility can receive power cost assistance for sales of power to local community facilities. The subsidy is calculated in the aggregate for each community served by the qualified utility. It is based on actual consumption of not more than 55 kilowatt-hours per month for each resident and not more than 600 kilowatt-hours per month sold to each customer other than local community facilities. Power cost assistance payments are used to reduce the cost of all power sold to local community facilities, in the aggregate, to the extent of 55 kilowatt-hours per month per resident of the community, and to reduce the cost of the first 600 kilowatt-hours per customer per month for all other classes served by the utility. The amount of relief per kilowatt-hour provided to the utility as determined by the Commission may not exceed the average rate per eligible kilowatt-hour sold, or 95 percent of the power cost, whichever is less. In addition, to receive assistance, a utility's power costs must be greater than 12 cents per kilowatt-hour and less than 45 cents per kilowatt-hour (the base level of support for FY 1983 will increase one cent per kilowatt-hour from 12 cents to 13 cents, plus one cent per kilowatt-hour for each fiscal year thereafter). An eligible utility may not be denied the benefits of this program because complete cost information is not available. Needy utilities are assisted by the Commission so that they may supply the information the APUC considers necessary to comply with the program requirements. Therefore, power cost assistance can be determined even for utilities with no historical kilowatt-hour sales data.

A utility whose customers receive benefits from this program must specify in each billing period for which a State subsidy is received: the rate without power cost assistance, the amount of power cost assistance per kilowatt-hour sold, and the rate charged to the customer (which is the difference between the two amounts).

To be entitled to receive power cost assistance, each electric utility must:

- Maintain accurate records that contain the information necessary to comply with program requirements.
- Report monthly to the Authority in the time and form which the Authority requests.

- Use metering equipment which measures individual customer power consumption and the utility's overall fuel consumption.
- Meet customer consumption restrictions discussed previously.
- Provide its customers with a notice, continuing information stipulated by the Authority, which describes the power costs with and without the program and the amount of State aid.
- Cooperate with the appropriate State agencies.
- Be willing to eliminate unnecessary or duplicative operating expenses as requested by the APUC.

The legislation, in a separate section, included specific provisions and conditions under which the amount of power cost assistance could be adjusted by the APUC. A section was also included so that utilities who are not regulated by the APUC could receive power cost assistance. Their requirements are almost identical to those of utilities which are regulated by the APUC.

Rural Electrification Revolving Loan Fund

The Rural Electrification Revolving Loan Fund was established in the Authority by SB 25 (Ch 118 SLA 1981) for the purpose of assisting electric utilities in extending new electric service into unserved areas of the State. The fund consists of appropriations made to the fund, and interest and principal payments on loans made from the fund.

Loans from the fund are made only to electric utilities certified by the APUC and must be approved by the Authority and recommended by a loan advisory committee made up of local residents of the area to be served by the applicant.

Loans are made at two percent interest with interest charges recovered through appropriate retail rate increases. Principal is repaid as future service connections are added to the extension.

When the Authority receives an application for a loan, it appoints a local advisory committee to consider the request. To receive a favorable recommendation from the group, the applicant must show that the proposed extension will provide immediate service for at least three customers and that its installation will generate sufficient revenues to repay the loan within 10 years.

Energy Program for Alaska

SB 25 (Ch 118 SLA 1981) established the Energy Program for Alaska (Energy Program) in the Authority. The Energy Program was created to facilitate the financing and construction of non-nuclear power projects through direct State appropriations. It was also intended to provide a mechanism for pooling the costs of debt financed projects. Funds for the Energy Program were provided by a newly created Power Development Fund that was supplied with State appropriations, plus any revenues collected from power sales which were not required by law to be deposited in the General Fund.9/ The Authority is authorized to acquire or construct power projects with money from the Power Development Fund.

Resources expended from the Power Development Fund are considered as State investments or grants. This contrasts with the status of the monies allocated from the Power Project Loan Fund because they are classified as loans which must be repaid.

Monies from the fund can be used for reconnaissance and feasibility studies and project finance plans; project design, licensing and construction costs; the defeasance of bonds or the payment of debt service on loans or bonds issued for power projects; and the costs of operating and maintaining power projects. However, "money in the fund can be used only for a power project that provides the lowest reasonable power cost to utility customers in the market area for the estimated life of the power project."10/

A power project can be acquired or constructed as a part of the Energy Program only if the project is submitted to, and approved by, the Legislature.11/ To be approved, a proposed project must complete and pass the following steps:

- Reconnaissance study
- Review of the reconnaissance study by the Division of Budget and Management
- Feasibility Study and Finance Plan
- Review of feasibility studies and plans of finance by the Division of Budget and Management
- Submission to the Legislature (by the Authority)

If the project is approved, the Legislature passes a new law authorizing the expense of funds. The proceeds from the appropriation are invested by the Department of Revenue, and money from the fund is provided to the Authority only after a project cost is incurred.

Power projects that are acquired or constructed as part of the Energy Program may be:

- Owned by the State and administered by the Authority.
- Owned by the State, but operated by a qualified utility through a contract or lease entered into by the Authority and the qualified utility (the Authority is guided by specific regulations which detail the procedure for selecting the "qualified utility" when there is more than one wholesale power customer to be served directly by the power project).
- Leased under reasonable terms and conditions to an applicant utility when that party is the only wholesale power customer to be served directly by the project (the Authority must enter into a contract or lease with the applicant unless they are determined to be incapable of operating the power project).

When the Authority allows a project to be operated by another party, it must review and approve the annual budget for the operation and maintenance of the power project. It must also assure that the facility is being operated efficiently and in a manner that is consistent with national standards for the power production industry.

As a wholesale power marketing agency, the Authority sells energy from its projects. A utility that desires to purchase energy produced from Authority projects must agree with the Authority to:

- Give preference in the retail sale of power to all classes of consumers except industrial consumers.
- Charge industrial consumers a rate that is greater than the wholesale power rate, but that is less than the rate charged residential consumers.

The Authority establishes a wholesale power rate structure for sales of power to its customers at the busbar of the power project. Under current State law (HB 9), each power project acquired or constructed under the Energy Program has its own wholesale power rate. The costs which the Authority uses to determine the revenue requirements which the operation of the project must produce are:

- Operation, maintenance, and equipment replacement costs of the power project
- The power project's proportionate share of debt service on State loans and bonds for all power projects in the Energy Program for Alaska (with a share limit or "cap")
- Safety inspections and investigations of the power project by the Authority

The Authority transmits all the money it receives to the Commissioner of Revenue for deposit in the State General Fund except money it has pledged to secure bonds in accordance with contracts with bondholders.

Lastly, the Energy Program legislation included provisions concerning energy conservation. The Authority is directed to ensure that cost-effective energy conservation measures are implemented by the communities which receive benefits from the Energy Program.

APPENDIX 2-A

ALASKA UTILITIES

Alaska Electric Light and Power Company (Juneau)
AMFAC Foods, Inc. (Sand Point on Popov Island)
Anchorage Municipal Light and Power
Alaska Power Administration-Eklutna (Anchorage)
Alaska Power Administration-Snettisham (Juneau)
Aniak Power Company
Alaska Power & Telephone Company (Craig, Hydaburg, Skagway, Tok, Dot Lake)
Alaska Village Electric Cooperative, Inc. (48 villages)
Arctic Utilities, Inc. (Deadhorse)
Barrow Utilities & Electric Cooperative, Inc.
Bethel Utilities Corporation, Inc.
Bettles Light & Power, Inc.
Circle Electric
Chugach Electric Association Inc. (Anchorage Area)
Cordova Electric Cooperative, Inc.
City of Manokotak
City of Unalaska
Chistochina Trading Post
Copper Valley Electric Association, Inc. (Glennallen, Valdez)
Dot Lake Electric, Inc.
Fairbanks Municipal Utilities System
Fort Yukon Utilities
Glacier Highway Electric Association, Inc. (Juneau Area)
Golden Valley Electric Association, Inc. (Fairbanks Area)
Homer Electric Association, Inc. (Kenai Peninsula)
Haines Light and Power Co., Inc.
Hughes (Esther J. James)
Iliamna-Newhalen Electric Cooperative, Inc. (I-N, Nondalton)
Kodiak Electric Association Inc.
Klukwan Electric Utility
Kotzebue Electric Association, Inc.
Ketchikan Public Utilities
M&D Enterprises (Galena)
Matanuska Electric Association, Inc. (Eagle River, Palmer-Talkeetna Area)
Manley Utility Co., Inc. (Manley Hot Springs)
Metlakatla Power and Light
McGrath Light & Power
Napakiak Corporation
Naknek Electric Association, Inc.
Nushagak Electric Cooperative, Inc. (Dillingham)
Nikolski Power & Light Co.
Nome Light and Power Utilities
Northern Power & Engineering Corporation, Inc. (Cold Bay)
Northway Power & Light, Inc.
No. Slope Borough Power & Light System (Atkasook, Kaktovik, Wainwright, Point Hope, Point Lay, Nuiqsut, Anaktuvuk Pass)
Paxson Lodge, Inc.
Petersburg Municipal Power and Light
Pelican Utility Company
Sitka Electric Department
Seward Electric System
Semlon Supply (Lake Minchumina)
Teller Power Company
Tlingit-Haida Regional Electrical Authority (Angoon, Hoonah, Kake, Kasaan, Klawock)
Tanana Power Company
Unalakleet Valley Electric Cooperative
Wrangell Municipal Light and Power
Weisner Trading Co.
Yakutat Power, Inc.

APPENDIX 2-B

SUMMARY OF ENERGY PROGRAMS WITHIN ALASKA

Federal Agencies

- Department of Energy

  Activities:

  - State energy production and use data
  - Federal/State energy programs
    - Energy Extension Service Program
    - Low Income Weatherization Program
    - Institutional Buildings Program

- Alaska Power Administration

  Activities:

  - Power Supply Studies & Project Operation

- Alaska District Corps of Engineers

  Activities:

  - Inventories
  - Reconnaissance Studies
  - Feasibility Studies

- Internal Revenue Service

  - Residential Energy Tax Credit
  - Business Energy Tax Credit

- U.S. Department of Agriculture

  - Solar Grain Drying Loans

- Farmers' Home Administration

  - Home Improvement Repair Loans and Grants

- U.S. Forest Service

  - Wood Energy Program

State of Alaska

- Legislature

  - Division of Legislative Finance
  - Division of Legislative Audit

- Office of the Governor

  Programs and Activities:

  - Fuel Emergency Fund
  - Coal Policy Task Force

  - Division of Budget and Management
  - Division of Policy Development and Planning
  - Special Assistants to the Governor

State Agencies

- Division of Energy and Power Development (DCED)

  Programs and Activities:

  - Residential Energy Conservation Program
  - Low-Income Weatherization (w/DOE)
  - Energy Research, Development and Demonstration Projects
  - Institutional Buildings Grants Program
  - Residential Building Lighting and Thermal Standards
  - REAA Grants Program
  - Appropriate Technology Small Grants Program
  - Energy Field Offices and Education Program
  - Energy Planning (Long-Term Energy Plan)

- Division of Business Loans (DCED)

  - Alternative Technology Revolving Loan Fund
  - Bulk Fuel Revolving Loan Fund
  - Residential Energy Conservation Loan Fund

- Alaska Power Authority (DCED)
  - Reconnaissance and Feasibility Studies
  - Power Project Loan Fund
  - Power Cost Assistance Fund
  - Rural Electrification Revolving Loan Fund
  - Energy Program for Alaska (Power Development Fund)
  - Legislative Grants for Power Development
- Alaska Public Utilities Commission (DCED)
- Department of Natural Resources
- Department of Administration
  - Alaska Energy Center
  - Alaska Council on Science and Technlogy
  - Northern Technology Grants Program
- Department of Community and Regional Affairs
  - Bulk Fuel Storage Grant Program
  - Legislative Grants for Rural Village Electrification
  - Coastal Energy Impact Program
- Department of Transportation and Public Facilities

  Activities:
  - Energy Audits of State Buildings
  - Energy Planning
  - Energy Projects
- Department of Health and Social Services
  - Energy Assistance Program
- Department of Military Affairs
  - Emergency Resonse Program
- Office of Mineral Development (DCED)
- Office of Special Industrial Development (DCED)
- Alaska Royalty Oil/Gas Development Advisory Board (DCED)
- Department of Environmental Conservation
  - Waste Oil Utilization (funded by EPA)
  - Oil Pollution Control
  - Management and Technical Assistance Program
- Alaska Oil and Gas Conservation Commission
- Alaska Renewable Resources Corporation (DCED)
  - Alaska Renewable Renewable Resources Development Fund
  - Alaska Renewable Resources Investment Fund
  - Alaska Renewable Resources Permanent Fund
- University of Alaska
- Department of Fish and Game
  - Oil Spill Response Team
  - Habitat Protection
  - Pipeline Surveillance Program
- Department of Revenue
  - Investment of State Energy Money
  - Business Energy Conservation Tax Credit
- Alaska Gas Pipeline Financing Authority

Private Non-Profit Activities

- Rural Community Action Program
  - Rural Weatherization Program
  - Fuel Loan Program

SECTION 3

REVIEW AND ASSESSMENT OF ALASKA'S POWER PROJECT DEVELOPMENT PROGRAM

INTRODUCTION

The power supply planning process in Alaska has been evolving rapidly since the creation of the Alaska Power Authority. Changes in the process have been imposed legislatively and internally, and the changing economic parameters which affect any power supply planning process seem even more extreme in Alaska than in the lower 48 states. The power supply planning process which precedes the selection of a specific power project or set of projects for development represents a series of decisions which take place over several years. Therefore, the problems identified with a specific project development may be based on decisions born from a power supply planning method or criteria which is no longer used. In many cases in power supply planning, the decision making criteria and methodologies vary significantly over time, but the implementation of the plans resulting from past decisions live on based on the momentum provided from the previous decisions.

The following analysis of the power supply planning process attempts to address this issue in light of the ever changing power supply planning environment experienced in Alaska. While there are some alternative approaches which would improve the power supply planning process in Alaska, much of the controversy surrounding such planning decisions is the result of decisions and commitments made in recent years from planning work conducted several years ago. This analysis attempts to differentiate between past planning problems which manifest themselves in current power supply plan implementation controversy, any ongoing planning activities which could benefit from revision to avoid future planning, and implementation problems.

Since the Authority procedures have been changing substantially, even as this report has been prepared, some of what could be considered criticisms of the process may no longer apply to current or proposed planning procedure and policy. One of the objectives of this evaluation is to identify current problems which resulted from past planning methods which have been abandoned by the Authority for new procedures.

POWER SUPPLY PLANNING

Power supply planning is best thought of as a "process" as opposed to a single task. The product of this process is "A Power Supply Plan" spanning a period of time into the future. The length of this period is a function of a number of factors, including the lead time required for generation additions, but most often covers ten to twenty years.

Once a power supply plan has been developed, it must be periodically updated. In other words, the process is a dynamic one. It is not that a new power supply plan is periodically published, but rather that it is periodically updated and extended into the future.

The process used to develop a power supply plan at any level of complexity, whether it is for an individual village, an urban utility system, an interconnected utility grid or a geographic region involves a series of interrelated evaluations and analyses which ultimately lead to the development of power projects to meet the electrical loads of the planning area.

In this section of the report, the planning process and methods used in Alaska to identify power supply needs and to select projects for inclusion in a power supply plan are identified and evaluated. The objective of this evaluation is to identify the strengths and weaknesses of current power supply planning efforts and to compare these practices with alternative approaches. To provide a background for evaluating the current planning process, a description of the generic steps included in any power supply planning process is provided. The current practices of power supply planning in Alaska are summarized, using examples of the planning which has preceded the current development of some specific power projects in Alaska.

This review of planning activities and the decision making process focuses on the difficulties encountered by the Alaska Power Authority, electric utilities, the State Legislature, and other participants in the process. The review includes a description of alternative methods for power supply planning which could be considered to remedy the current power supply planning problems. When applicable, effort has been made to differentiate between planning considerations in the Railbelt region as compared to other areas of the State.

General Steps in Power Supply Planning

Although the complexity of the process may vary depending upon the size and diversity of the utility system or geographic area involved, there is a general progression of analyses which should occur in developing and updating a power supply plan. The following describes a "typical" power supply planning process as a basis for the evaluation of the power supply planning process in Alaska. The process generally requires:

- Identifying the study area to be included in the power supply plan
- Projecting the future electrical power requirements
- Establishing policies and criteria as a basis for selection of alternative energy resources and technologies to consider for meeting the projected electrical power requirements
- Evaluating the relative availability and desirability of alternative power resources, and identifying specific resource alternatives for which detailed feasibility studies will be undertaken
- Conducting a detailed feasibility analysis for projects found promising at the reconaissance level stage
- Selection of preferred projects from among the projects found feasible for authorization for development to meet projected needs
- Securing final approval for the supply plan and individual project development

This process is shown graphically in Exhibit 3-1. The following briefly describes the general types of activities and considerations which comprise each major step of a power supply planning process.

Definition of Study Area

The first step in the power supply planning process is to define the study area. The definition of a study area includes geographic, demographic, and utility system considerations. Depending upon the scope of the planning process, the study area can be a single utility system, a group of interconnected utility systems, or a geographic area which includes separate utility systems which potentially could be interconnected with expansion of the transmission system. The extent to which currently independent utility systems are considered in a study area is dependent upon the transmission distance between the system, their current size and prospects for future growth, and the relative cost of power among the systems.

The selection of the study area to be included in a power supply plan is critical for forecasting of electrical load requirements. Furthermore, since the cost of power can differ significantly between utility systems, the economic basis for evaluating alternative power resources is dependent upon the systems to be served by generation resources in the power supply plan.

Load Forecasting

Prior to determining which power projects should be evaluated and implemented, the anticipated electrical loads of the selected study area must be projected. A variety of forecasting methods can be used to project power requirements. The complexity of the forecasting tools used to project power requirements depends upon the complexity of the system and the level of accuracy required. The level of detail which should be considered depends on the availability of energy use, demographic and economic data for the study area. Because of data

GENERALIZED POWER SUPPLY PLANNING PROCESS

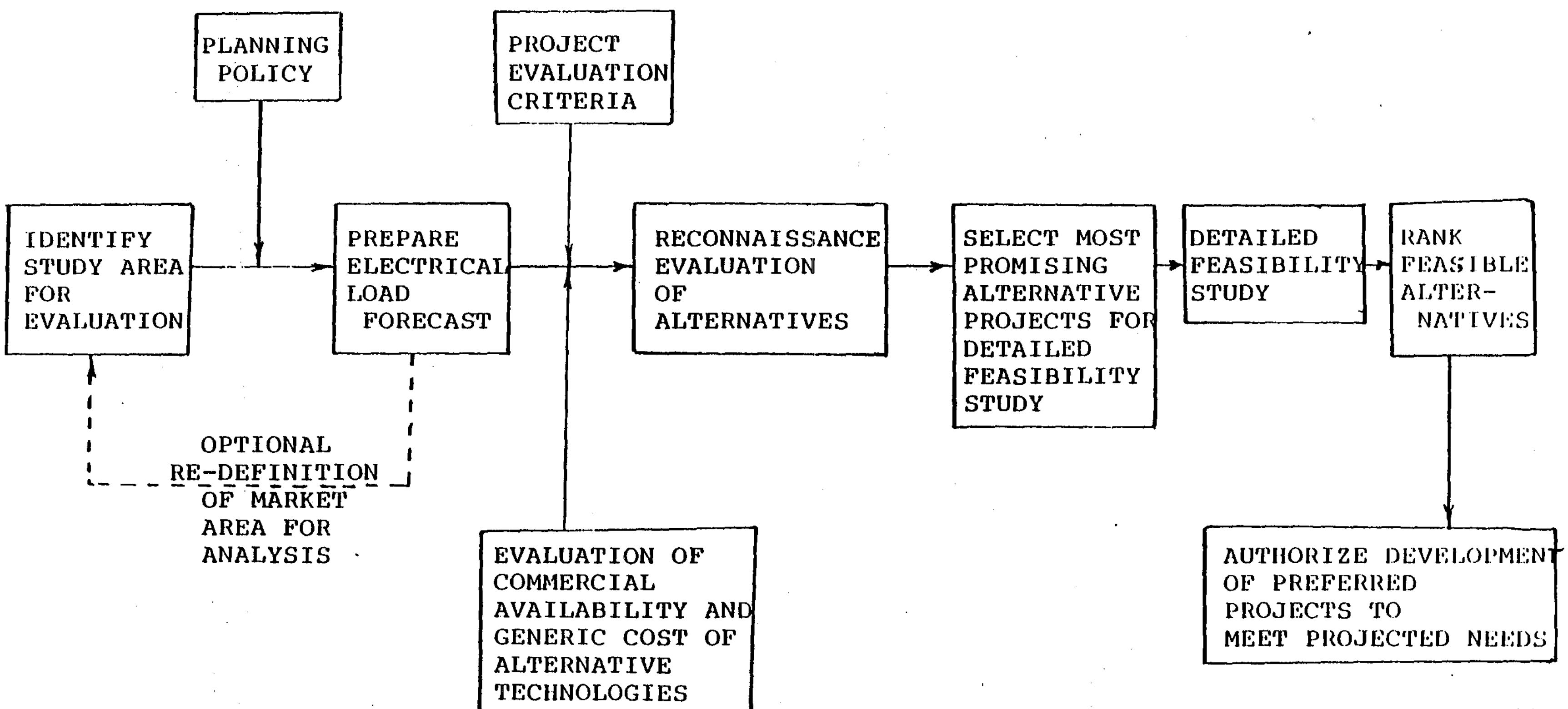


EXHIBIT 3-1

limitations and practical considerations, the rigor of load forecasting for the Railbelt utilities is likely to exceed that used for the bush communities and less developed Alaska.

Once developed, load forecasts are used to establish the amount of electrical capacity and energy required for the study area over the planning period. These total projected electrical capacity and energy requirements are then compared to the amount of capacity and energy which can be provided by existing power resources over the planning period. It is against this projection of aggregate power and energy requirements that the need for new power facilities is evaluated. The extent to which existing power plants are to be retired, whether due to age, policy considerations or economic obsolescence, directly impacts the estimated need for additional power resources.

Policy and Criteria for Power Supply Planning

A key element to power supply planning is establishing policies and criteria for selection of alternative energy resources, technologies and specific projects for inclusion in a supply plan. Such policies and criteria can also impact load forecasting. For example, the cost of power from power supply alternatives will impact load projections due to pricing effects on demand for power.

The type of policies and criteria which most affect the decisions on the facilities to be included in a supply plan evaluation are (1) the degree of preference for specific types of projects such as renewable energy resource projects, (2) power cost limitations (short and long term) placed on alternatives, (3) environmental constraints, (4) the economic criteria used to compare alternatives, (5) financial limitations, and (6) the availability and location of resources. All of these factors are considered either explicitly or implicitly in the selection of resources for consideration in the supply plan and during the selection of specific projects for authorization for development.

Review of Energy Resource Alternatives

After adopting a load forecast and establishing a set of policies and criteria for power supply planning, the selection of the alternative types of power supply projects and identification of specific projects for inclusion in the supply plan can begin. The general steps for this portion of the evaluation include:

Generic Assessment

A generic assessment is conducted to identify preferred commercially available technologies and physically available energy resources in the planning area which could be developed within the planning period under consideration. Such an evaluation includes a generic (as opposed to site specific) evaluation of the cost of power from a "typical" project using the various technologies or fuels, status of commercial operation of such projects, environmental considerations, and general availability of the required resources in the study area.

Reconnaissance-Level Study

A reconnaissance-level study to identify the potential for development of the preferred generic types of power projects believed to be available in the planning area is then undertaken to narrow the options for supply alternatives to those with the best prospects for feasibility. The product of this analysis is the identification of specific projects which appear worthy of more detailed evaluation.

Ranking of Alternatives

The ranking of alternatives which are found to be promising in the reconnaissance level studies establishes a basis for determining which projects should be studied in more detail.

Detailed Feasibility Assessment of Alternatives

Detailed feasibility studies are performed to further evaluate the promising projects identified during the reconnaissance study. The purpose of these studies is to determine which of the prospective projects meet the evaluation criteria and deserve to be considered for inclusion in the supply plan. The feasibility study results are then used to make a final ranking of projects. This evaluation of projects considers the anticipated schedule for development, method of financing, and the proposed market for power from the project.

Selection of Projects for Recommendation for Development

After ranking those projects found preferable and feasible within the policies and evaluation criteria established, the "pool" of feasible projects is evaluated in terms of their ability to operate as an augmentation to the existing utility system to determine which "mix" of projects results in the most favorable supply plan. In the case of evaluating small village energy supply options, this evaluation is often reduced to comparing one or more hydroelectric or cogeneration (waste heat recovery) project alternatives with continued or expanded diesel generating projects. Those projects with the best combined characteristics are then tentatively selected through a screening process to develop an integrated plan for implementation of projects over a designated period. Alternative or "second best" projects or groups of projects are also identified.

If the power supply plan is for a sufficiently large study area that several projects will be required to meet the projected power resource requirements over a 10 to 20 year planning period, the list of preferred projects will usually include some projects for near term development and other promising projects for later implementation to meet longer term needs.

Authorization for Design and Construction

Although a list of preferred projects in an integrated plan has been developed, this does not necessarily infer commitment. The preferred projects with the earliest dates of implementation are reviewed in more detail based on financing plans and updated economic constraints. If this review confirms the relative economic priority of the most promising projects, a recommendation is made for licensing/permitting and final design. Assuming no "fatal flaws" are uncovered during final design, each project is reviewed after design is completed for construction authorization, assuming project financing can be arranged. A final economic evaluation is conducted and once authorized, the project proceeds to bid and construction.

Updating Power Supply Plans

The power supply plan must be reviewed periodically to ensure that projects scheduled for implementation late in the planning period remain feasible and preferred over the alternatives. This process involves updating load forecasts and re-evaluating the feasibility of projects previously identified for deferred development to meet longer term forecasted needs. In addition, in the interim, periodic re-evaluation of the availability of additional alternatives can be conducted to update the list of preferred projects.

CRITIQUE OF ALASKA POWER SUPPLY PLANNING METHODS

Based on the steps outlined above, the following is a review of the methods which have been or are currently used in power supply planning at the State level in Alaska. A general observation, which is a recurring finding in the review, is that the planning conducted in Alaska at the State level has been more "project" oriented and not utility system or planning area oriented. There are other contributing factors, but this "project-by-project" evaluation and approval can be linked to a number of the past weaknesses in the power supply planning process.

On many of the projects which are in the more advanced stages of project planning, the evaluation of alternatives has been largely limited to a comparison of one or more projects to the "preferred alternative" after questions have been raised regarding the feasibility of the preferred project. Many of these projects, such as Lake Tyee, Bradley Lake, or, more notably, Susitna, are projects for which substantial analysis had been conducted by the Corps of Engineers, the U.S. Department of Energy, or others in a project-specific analysis, not as part of an integrated power supply plan. The planning momentum created by such previous analyses tends to establish these projects as the "base case" in an analysis of any alternatives. This fosters a continued project-oriented planning approach for the market area served by the project. To a large extent this situation is unavoidable.

Many of the recent planning and evaluation efforts undertaken by the Authority where past studies have not created a designated "preferred project" have been more power supply plan oriented rather than project oriented. Mention is made of some of the problems which have surfaced with the project-oriented approach on some of the long-standing projects referred to herein in an attempt to identify the source of some of the controversy surrounding these projects. These examples also serve to identify some of the positive steps the Authority is taking in recent planning efforts and to include some advantages of alternative approaches which could be considered by the Authority.

The following describes the strengths and weaknesses of the current practices for each of the major stages in the planning process, and identifies some alternative approaches for consideration. Where possible, this discussion attempts to differentiate between past planning activities and recent changes in planning approaches by the Authority.

Power Supply Planning Areas

The extended Railbelt Region has been recognized as a power supply planning area. The Authority and the Alaska Power Administration have also looked at other areas of the State in terms of power supply planning. However, a more formalized power supply planning process requires the definition of other areas in the State for planning purposes.

The primary criteria for designation or definition of a power supply planning area is either existing interconnections or indications that interconnections might at some time in the future be feasible. We have discussed this with Authority staff and at our request they have indicated that the following areas might very well be designated as power supply planning areas:

- Southeast Alaska including Ketchikan, Wrangell, Petersburg, Juneau, and Skagway, as well as Prince of Wales Island and Sitka
- South Central Alaska which would generally encompass the area presently known as the extended Railbelt
- Barrow-Atkasuk-Wainwright
- Kotzebue-Lower Kobuk Region
- Seward Peninsula
- Bristol Bay-Bethel
- Kodiak Island

Designation of these or other areas as power supply planning areas would not reflect a commitment for the construction of interties. Rather, it would provide a framework where the construction of interties would be evaluated periodically as alternatives to construction of small generation facilities to serve individual loads within the area.

Other areas of the State, particularly the bush villages, would have to be dealt with on an individual basis as is the current practice.

Load Forecasting - Railbelt Region

The level of complexity of forecasting requirements and availability of data for accurate forecasting differs significantly between the Railbelt Region, Southeast Alaska, and the bush communities. The review of the forecasting of electrical loads in the Railbelt Region is discussed separately from forecasting for the bush communities and Southeast Alaska.

Current Practices - Forecasting for the Railbelt

The most extensive effort to date to forecast electrical loads in the Railbelt Region is that which was recently completed as part of the Railbelt Alternative Study. This effort can be characterized as a "top-down" type of forecast where aggregate regional economic and demographic factors were considered in an energy end-use prediction model to forecast total subregional and aggregate regional electrical demands. One of the major weaknesses of the forecast is that it is not built on forecasts of the anticipated load growth for each of the respective utilities.12/

Due to the lack of an agreed upon Railbelt area forecast, the Authority is in the position of having to reevaluate the potential alternative demand scenarios in the evaluation of each potential power supply project in the region--most notably the Susitna Project.

Assessment of the Railbelt Forecasting Process

The forecasting work being conducted for the Division of Energy and Power Development is not structured for use in power supply planning. It appears that regional data is being aggregated without consideration for (or at least without presenting) the individual projected loads of each utility in the region. This makes involvement, critique, and utilization of the forecast by the individual utilities difficult. This generally precludes taking advantage of each utility's knowledge of their own system trends and operating characteristics in judging the reasonableness of the forecast.

Additional uncertainty has been added to the forecasting process by the past treatment of the Anchorage-Fairbanks intertie as a variable.13/ The previous lack of a decision on this interconnection has caused great uncertainty about near-term interconnected demand for the region. This policy-related issue is addressed in more detail later.

The forecasting effort in the Railbelt has diverted efforts to conduct forecasting in a manner which would be more compatible with power supply planning needs. Due to the major funding commitment to the Railbelt Analysis forecast and the expectations of that effort, other major forecasting efforts to support the Authority's power supply planning were not undertaken.

The Division of Energy and Power Development is required to prepare a long term energy plan, of which load forecasting is a part. Preparing a totally new forecast for the entire State of Alaska annually is nearly impossible. Insufficient time exists for evaluating changing economic conditions, policies, and demographics to allow for evaluation, presentation of preliminary results and constructive, participative critique by the parties involved.

Forecasting for the Long Term Energy Plan under-emphasizes forecast assumptions and results for the near-term, 5-10 years. This reduces the ability to review short term forecasts. Periodic review of forecast accuracy is an important element in any long term forecasting program.

Alternative Approaches to Railbelt Forecasting

Any renewed effort to prepare a forecast for the Railbelt utility systems will be out of phase with much of the project specific evaluation procedures and authorization decisions currently before the State Legislature. However, decisions regarding system interties, financing of Susitna and other projects, project operation and dispatching, and other major power supply planning decisions which remain unresolved are dependent upon load forecasts which provide sufficient electrical load and load characteristics data to enable such planning to occur. The following identifies some alternative approaches and considerations for preparing such forecasts:

- The Railbelt Alternative Study included an analysis of a set of consistent economic assumptions for application to the total market area of the Railbelt study area. However, there has been disagreement as to whether the range of alternative demand forecast scenarios has encompassed the full range of potential demand scenarios. In addition, as presented in the Railbelt Study report, the forecasting assumptions utilized do not appear to address differing demand and energy end-use assumptions between the major utility areas in the Railbelt areas in a manner which allows each utility area to provide a planning critique of the validity of those assumptions in its service area. This information may be available, and may be incorporated in the model, but the forecasting results do not appear to be presented in a manner which allows individual utility review and critique.

- The assumptions on the extent of interconnection between the various systems could be established in advance. The Anchorage-Fairbanks intertie is now considered to be a planned project, eliminating one variable from the forecast assumptions which complicated some of the earlier planning efforts.

- The forecast period could be separated into short, medium, and long term forecasts (as an example, 5, 10 and 20-year planning periods). Planning and forecasting assumptions could consider the relative uncertainty of knowledge of the factors which influence energy costs and demand over these different planning periods. This is particularly useful if near and intermediate term power costs are used as one parameter in deciding among power supply alternatives. The forecasting effort currently undertaken by the Authority could be easily adjusted to develop forecasting assumptions which coincide with near, medium, and long term planning periods.

- Individual utility system service areas could be evaluated separately prior to and after aggregation of load forecasts into forecasts of interconected systems. This would allow identifying load implications of specific utility service area economic development scenarios, such as new industrial projects under consideration, in much the same manner as has typically been done for some of the isolated systems in southwest and southeast Alaska. Regional aggregate forecasts can still be generated while providing utility system or sub-area specific projections which enable critical review and use by the individual utilities. If individual utility service area loads and resources are not addressed in the demand forecasts, future rate setting and power allocation must treat the entire Railbelt as a homogeneous utility service area. Since most of the Railbelt utilities have existing resources of their own which differ in average energy cost by utility, the impact of one or more regional projects on average cost of energy to each utility will differ. It is unclear how an aggregated analysis of Railbelt regional demand can address this issue.

- Seasonal and time of day load diversity could be addressed on an aggregate and individual utility basis to allow for more specific evaluation of rate making and power marketing alternatives.

- A base forecast could be established and updated on a periodic basis (such as every two or three years) to provide an evolving planning tool for use in power supply planning. More frequent changes could be made on an exception basis in the event of major revisions in planning assumptions, but annual revisions on a regular basis make planning complicated.

Load Forecasting - Outside the Railbelt Area

Forecasting for bush communities and other Alaska communities, such as native settlements or communities which exist primarily due to industrial operations (fish canneries or lumber mills, for example), presents different problems from Railbelt system forecasting. Energy end use patterns, demographics, and price elasticity, among other factors, are clearly substantially different for bush communities as compared to the Railbelt. The availability of historic and current data regarding parameters which impact energy use and demand can preclude the use of sophisticated econometric forecast models. The following describes some of the strengths and weaknesses with the manner in which the Authority has addressed these problems.

Current Practice - Forecasting Outside the Railbelt Area

The constraints associated with forecasting for the bush communities and the lack of data on which to base forecasts have generally been acknowledged in the forecasting efforts conducted to date for these power market areas. Forecasts for bush communities are often criticized simultaneously by reviewers as being too high and as too low by local citizens with a more optimistic outlook on local economic growth.

Strengths of Current Forecasting Outside the Railbelt Area

Strengths of the current practice include the following:

- Current and past forecasting efforts for these communities have recognized the constraints to accurate forecasting. Where possible, local utility operators appear to have been relied upon for input concerning historic and projected energy use patterns. Attention has focused on industrial or commercial development which can greatly influence demand.

- The effects of the Power Cost Assistance Program applicable to many of these areas and the potential for future conversion to electric heat has been addressed at least qualitatively, if not quantitatively, in preliminary demand forecasts conducted as part of village reconnaissance studies.

- Interconnection opportunities have also been more regularly addressed in recent studies of bush communities. In some instances, significant changes in industrial/commercial or government facility operations occur during the course of project planning. This can require reconsideration of interconnection alternatives at untimely points in the power supply planning process for a specific community or region. The Authority has shown willingness to incorporate such changes in their planning process (see discussion of Appendix 3-C regarding reconsideration of adding Thorne Bay to an interconnected system for the Black Bear Project on Prince of Wales Island). More recent planning efforts have focused more extensively on interconnection alternatives and "market area" analyses in bush community studies (such as in the July 1982 Bristol Bay Regional Power Plan Detailed Feasibility Analysis).

Weaknesses of Current Forecasting Outside the Railbelt Area

The major weakness in the forecasting effort in the bush communities and Southeast Alaska is the manner in which the forecast is used in planning. Examples include:

- Forecast ranges continue to be a large variable in the power supply planning process beyond the stage where a final project has been selected for implementation. The forecast is not consistently used as a basis for establishing a reasonable range of electric needs.

Instead, a project is often selected when alternative forecasted power needs predict a potentially wide range. Perhaps more importantly, the range of alternative forecasts used at reaconnaissance level or even detailed feasibility assessments does not always encompass more conservative demand levels considered more likely by some reviewers, or higher demand levels considered likely (or hopeful) by local citizens of the communities. To the extent that the potential range of energy demand addressed in Authority studies does not cover lower or upper limits considered possible by reviewers, basic questions regarding the preferability of a selected supply plan may create unwarranted controversy during later project planning activities. Consideration (and perhaps early but well justified dismissal) of lower or higher ranges of energy demand projections at the early planning stages could help reduce untimely requests for consideration of alternative demand scenarios by project reviewers at the project authorization phase.

- Two major policy issues--the long term use of the Power Cost Assistance Program and the conversion to electric heating can greatly impact forecasted electric demand. Policy decisions on whether to plan for these programs were not resolved before forecasts were developed. As an example, forecasts with and without conversion of electric heating often continue to be addressed as equally viable alternatives well into the stage of alternative project selection and even project authorizations. The analysis of the Old Harbor project on Kodiak and the Silver Lake Project in Cordova are examples of the former and the Tyee Lake Project analysis is an example of the latter. The result is that the range of alternative forecasted demand can be so high that the value of the forecast in power supply planning is questionable.

- A related problem exists in forecasting for those areas where interconnection of currently independent communities is a possibility. Forecasts can vary substantially depending upon the planning area considered in a study. In several cases, a specific project has been selected for development, and authorization decisions are being based on project feasibility with and without interconnection of various neighboring interconnected loads. The forecasted load associated with the alternative planning areas can differ substantially, causing wide variations in estimated average annual energy costs from hydroelectric projects. The December 1981 Statement of Findings and Conclusions analysis of the Tyee Lake project is an example of this situation. Analyses for the Black Bear Project on Prince Wales Island is another. The Bristol Bay study mentioned above is a good example of the approach to evaluating bush community alternative market areas prior to selection of specific projects for development.

Alternative Approaches to Forecasting
Outside of the Railbelt Area

As in the Railbelt area, many of the project development decisions have already been made despite some of the problems with the manner in which forecasting has been used in the power supply planning process. In those situations where planning has not progressed to this stage, or reconsideration has been requested by the Legislature, the following provides some alternative approaches:

- Alternative market areas can be evaluated early in the forecasting process using reconnaissance level interconnection cost estimates to determine the likelihood of including communities in an interconnected system. Alternative forecasts using different market area assumptions, where applicable, can be developed and used to screen power supply alternatives at the reconnaissance level stage.

- Studies conducted by and for the Authority have generally incorporated alternative and most likely energy demand scenarios at an early stage in the planning process. Public input has also been solicited as part of the preliminary demand forecasting conducted during reconnaissance studies for bush communities. However, if the preliminary evaluation of the feasibility of a specific alternative energy resource or project available in the market area is particularly sensitive to load growth assumptions, the effect of alternative demand forecasts could be evaluated at the reconnaissance level stage. The purpose of such an evaluation would be to see if a change in market area definition or a demand sensitive policy implementation (e.g., power cost assistance or electric heat conversion) would result in a different ranking of all alternatives. This level of evaluation would not be necessary in all cases. To the extent that bush communities in a study area have a possibility for interconnection, or there are factors which could substantially alter power demands in an area, these alternatives should be addressed at the reconnaissance level stage.14/ This is discussed in more detail later.

Power Supply Planning Policy and Evaluation Criteria

An important element of power supply planning and the evaluation of alternatives to meet identified needs is the policy direction that provides a basis for the planning work and for the evaluations in the reconnaissance and feasibility study phases. The portions of the legislation creating the Authority and establishing the Energy Program for Alaska set forth certain goals or objectives established by the Legislature. One area that we believe deserves additional policy consideration relates to the utilization of fossil fuels, particularly oil and natural gas, as boiler fuel. Utilities within the State, in many cases, have no alternative but the construction of diesel generating units. However, in some areas of the State, particularly the Railbelt Region, utilities continue to construct natural gas-fired units. We believe that the Legislature should address itself to the question of establishing a policy in this area. If, in fact, the State establishes to minimize or eliminate where possible the use of these fossil fuels for boiler fuel, the importance of developing large hydroelectric projects would be emphasized.

As in the case of power supply plans, the policy directions provided, for both the overall guidance of the power supply planning process and with respect to the methodology utilized in that process, must also be periodically reviewed and updated. In this regard, the responsibility for monitoring the overall policy area might be assigned to DEPD with the charge that they would periodically report to the Legislature with recommendations for any indicated changes. Likewise, the Division of Budget and Management might be charged with the responsibility of periodically reviewing analytical methods utilized in feasibility studies and the development of financial plans to provide the Legislature with recommendations for policy direction in these areas. In the development of policies for the guidance of power supply planning and development it must be recognized that because of the diversity between the various areas of the State it may be that some policies have to be promulgated on an area specific basis as opposed to a statewide basis.

Current Policy and Evaluation Criteria

Prior to evaluating alternative power technologies and specific power supply projects, the planning objectives and the criteria used to evaluate projects must be established. These policies and criteria are reflected in the Authority's project evaluation procedure to some extent, since this procedure is used to select projects for development. Simply stated, the Authority's goals in power supply development are to:

(1) Maximize net power project economic benefits tempered by environmental, socioeconomic and public preference constraints, and

(2) Intervene in financial markets to permit "worthy" projects which may not be capable of being financed using traditional financing methods to be developed free of the traditional financing constraints.

To implement these objectives, the primary criteria used to approve projects for development is a life cycle cost analysis comparing the present value of project costs over the project life to the present value of the costs of a base case thermal alternative. The planning period for evaluating the life cycle present value of project costs is also established as a period equal to the life of the project with the longest commerical life of those under consideration. Since most Railbelt and Southeast Alaska projects under consideration for implementation are hydroelectric projects and the alternatives are oil- and gas-fired or coal-fired plants, the 50 year life of the hydroelectric project is usually used as the period over which the present value analysis is made.

A 50-year present value analysis to compare projects using fuel which escalates in price with projects with no fuel costs will often favor the project which does not use fuel if sufficiently high levels of prolonged real escalation of fuel costs are used in the analysis. The Authority has utilized fuel escalation sensitivity analyses in their final feasibility studies. The use of the analyses by the Authority in the final decision process is unclear, however.

For example, in the Tyee project analysis, the Authority's Statement of Findings and Recommendations (12/2/81 Update) analyzed project scenarios using zero, 2.6 percent and 3.5 percent real fuel cost escalation. The report mentions that if fuel escalation rates are significantly lower than the annual 2.6 percent real escalation rate for a twenty-year period, the Tyee project is economically inferior to continuing diesel generation.

The analysis of lower fuel cost escalation has been performed and conclusions drawn, but it is unclear how this risk of lower future diesel generation costs is factored into the decision making process. At issue may be the presentation of the results of the analyses and not a question as to whether the analyses were performed.

The strong focus by the Authority on the 50-year present value life cycle cost analysis as the critical criteria for determining project feasibility de-emphasizes the risk that actual fuel cost escalation rates may not meet the expectations of the "most likely cost projection" (even though the analyses generally include an evaluation of that risk). If the present value analysis shows the existing thermal case to be preferable to, for example, a hydroelectric alternative, even when moderate or high fuel escalation rates are utilized, the Authority has appropriately eliminated the hydroelectric project from further evaluation. There are several examples of such findings by the Authority.

The risk of over-estimating fuel cost escalation using a 50-year present value analysis (where costs are held constant after 20 years) as a decision criteria becomes an issue when the 50-year benefit/cost ratio of the hydroelectric project to the base case thermal alternative is near unity, using a fuel escalation scenario which assumes substantial continued real fuel cost escalation. This is often (but certainly not always) the situation when a hydroelectric project is determined to be feasible in Authority studies. This is also usually the situation in which there is controversy regarding the advisability of proceeding with development of the hydroelectric project.

In a situation such as this, the true cost of power from the hydroelectric project is generally projected to substantially exceed power costs from the thermal base case alternative for several years of operation. This cost of power comparison is now being included in Authority studies. However, it is not clear that past decisions to develop a project with, for example, a benefit cost ratio of 1.15 assuming 2 to 3 percent real oil escalation for 20 years has given full consideration to the risk that the preferred project would continue to have power costs in excess of the base case thermal alternatives if the real rate of final cost escalation were, for example, 1 to 1.5 percent annually during the same period.

Recent studies by the Authority appear to be addressing this issue in re-analyses of feasibility studies to consider this risk and the risks of overestimating power demands where the results using the present value life cycle cost criteria alone do not provide a conclusive test of feasibility. However, there does not yet appear to be an agreed upon "standard" procedure or criteria to augment the present value cost method when that method proves to be of limited value as a single decision criteria.

The uncertainty of price elasticity impacts on energy demand caused by the State subsidy program complicates project evaluation in areas where a subsidy is used. The uncertainty caused by such subsidy is inversed if the subsidy encourages conversion from heating with fuel oil to electric space heating. This issue is treated as a variable in some project specific evaluations. When reviewing the feasibility of hydroelectric projects outside of the Railbelt area, the extent to which the study area population converts from fuel oil heating to electric heating can be one of the largest variables in predicting average energy costs from a hydroelectric project as compared to thermal generation sources.

Alternative Approaches to Establishing Policy and Evaluation Criteria

The use of the present value life cycle cost as the primary evaluation criteria for power supply planning is, in itself, a major policy decision. As discussed above, where the present value cost of the selected alternative plan or project is vastly superior to the base case thermal alternative, this criteria may be a reasonable decision criteria. Even projects with substantially lower present value life cycle cost often result in high near to intermediate term power costs relative to thermal generation. Using present value life cycle cost as the sole economic test assumes that it is an established and accepted policy that the substantial financial resources of the State of Alaska should be used to help alleviate the "market shock" of near term hydroelectric project power costs, through subsidy or savings.

Where the difference between present value costs of alternative projects is small, if a hydroelectric or other renewable energy project (or set of projects) is selected over the base case thermal alternatives, there is an inferred policy behind such a decision. The inferred policy is that the desirability of using renewable resources and protecting against incurring the penalty of high escalation of fuel costs is worth the risk that the future fuel costs are lower than those assumed in the scenarios used as the basis for a decision to develop the hydroelectric or other renewable resource project. If this is not a current or desired policy of the State, another form of economic evaluation criteria (such as the criteria described in the discussion of reconnaissance studies later in this report) could either replace or augment the present value life cycle cost criteria.

The Authority has struggled with this issue on projects where the present value cost of what has come to be the preferred alternative is not clearly economically superior under the full range of reasonably possible projected fuel costs. (The decisions in such situations are further complicated when relative present value life cycle costs of alternative projects or plans are highly sensitive to alternative demand forecasts.) This has been a decision-making problem on projects such as Lake Tyee, Black Bear, to some extent on Bradley Lake, and, on a much larger scale, for the Susitna Project.

Due to the controversy regarding decisions on these projects, the Authority has been appropriately conducting additional analyses of these projects to consider alternative fuel cost and demand assumptions. Nominal cost of power analyses have also been added to the "inflation free" analyses used in the standard Authority procedure. The Authority's exhibited willingness to be flexible and use different economic evaluation methods and criteria as needed shows a practical approach to the decision making process. These alternative evaluation procedures which have been used by the Authority on a case-by-case basis may ultimately lead to revising, or at least augmenting the present value life cycle cost evaluation method and decision criteria in the Authority's standard procedure.

Discussions of the reconnaissance and detailed feasibility study stages of the power supply planning process (in later sections of the report) include descriptions of some alternative evaluation methods and criteria which could be considered by the Authority for use in augmenting the present value life cycle cost procedure.

Examples of other policy decisions which could reduce the variables in power supply planning in general and project evaluation in particular could include:

- A policy on the acceptability of displacing fossil fuel sources for space heating with electric heating from renewable resources. It is a reasonable policy to encourage the conversion from fossil fuel-fired space heating to electric heating supplied from power plants using renewable energy resources if the electrical power from renewable sources can be provided on a cost effective basis. The issue becomes complicated in the instance where (1) conversion to electric heating in a market area is necessary for a hydroelectric project to have a significantly lower present value life cycle cost over thermal alternatives, and (2) substantial State subsidy is needed to make the power from such a project marketable for several years of project operation. This appears to be a policy issue faced on several projects.

- A requirement to evaluate the integration of independent utility systems as a prerequisite to evaluation of specific power projects within a given utility system. This appears to be an evolving, if not a formally adopted policy utilized in recent studies conducted for the Authority (the Bristol Bay Regional Power Plan and the Bethel Area Power Plan feasibility assessments are examples of a major effort to consider the impacts of potential interconnection options in evaluating the economic feasibility power supply plan alternatives).

- A preference for achievable conservation and implementation of conservation projects prior to commitment to power supply projects.

Each of these policy topics could be addressed on a geographically specific basis, a utility system basis, or a statewide basis. As an example, a decision could be made that natural gas or oil will only be used in the Railbelt if there are no other alternative sources, but that such a provision need not apply to other areas of the State. The advantage of establishing specific policies is to reduce extensive re-evaluation of the issue on a project-by-project basis.

The alternative criteria which can be used to evaluate supply plans and analyze the feasibility of specific project alternatives is another planning consideration which can be established in advance of power supply planning to be consistent with established policies. These alternative evaluation approaches are discussed in the section of the report on feasibility assessment.

Reconnaissance Evaluation

Recognizing that the power supply process addresses both the "demand side" with the load forecasting functions and the "supply side" with the resource development functions, the reconnaissance evaluation is really the first step on the supply side. The load forecast, together with a balancing of loads against existing resources, indicates a potential need. The reconnaissance evaluation is the first effort to identify alternatives to meet that need. Once completed, reconnaissance evaluations for individual villages or communities or for all or portions of power supply planning areas must, as with the total power supply plan, be periodically updated.

The product of the reconnaisance study is a prioritized pool of alternative projects to meet identified needs within the power supply planning area. The reconnaissance study results are the initial input to the feasibility study.

Current Practice

The methods and approaches used by the Authority, or which were used by others in the past, to identify projects currently under development by the Authority vary significantly. The hydroelectric projects in advanced stages of development today (design or construction) were generally those identified in the U.S. Army Corps of Engineers statewide reconnaissance study or other previous efforts to identify potential hydroelectric sites. This effort was not part of a power supply planning process. Its purpose was to identify specific projects. The availability of this work effort undoubtedly helped contribute to what has previously been a project-oriented power supply planning process in Alaska.

In the past, due, at least in part, to this hydroelectric project data base, many of the reconnaissance level studies have focused on the feasibility of a specific project as the basis for evaluating other alternatives early in the study. Criticism has been received at the State and local level in some cases that insufficient consideration of alternative planning concepts (such as interconnection or potentially lower or higher demand forecasts) were considered as part of the study.15/

This project-oriented approach is less prevalent in more recent Authority studies. The Bristol Bay Regional Power Plan study is an example. Although this study is more detailed than a reconnaissance study, the "Interim Feasibility Assessment" (Phase I of the Study) is much like an extensive regional reconnaissance analysis. As with studies of other market areas, this study did focus on the relative desirability of a single project, in this case the Tazimina Hydroelectric Project, as compared to a variety of alternative projects. The Tazimina Project was identified as a preferred project for the region in early studies of alternative hydroelectric projects. It is therefore appropriate that one of the main objectives of the updated studies be to compare alternatives to this project. One of the strongest features of the Bristol Bay study is that it has considered a variety of alternatives and combinations of alternative power supply resource to the Tazimina Project before a major financial commitment was made to develop that project. As a result, a wide range of alternatives are being analyzed in a systematic planning approach to consider regional market area needs. This study appears to be a good model which the Authority can use in future analyses.

A large number of reconnaissance level analyses are being conducted under the Village Energy Reconnaissance Program by the Authority. This program includes evaluation of both direct thermal application of energy and electric energy demand and supply. It is about one-half completed with approximately 60 villages with populations in excess of 50 persons scheduled for reconnaissance study next year. While considerable analysis will be done as part of this proposed effort, the majority of the areas in which significant electrical capacity is potentially needed have already received some level of reconnaissance study.

As mentioned above, the procedures which are being used in the recent Bristol Bay and Bethel Area studies represent substantial improvements in the overall power supply planning approach. To the extent that this approach is incorporated at the outset of future reconnaissance studies, many of the previous problems encountered in the planning process will be reduced. Therefore, the primary focus of this review of the reconnaissance level phase of power supply planning is to identify some of the weaknesses in past reconnaissance studies as a source of some of the difficulties currently experienced in decisions on authorizing projects for design and construction. These past problems are contrasted with some of the recent improvements in the Authority's approach to supply planning in an attempt to distinguish between residual problems from past practices and suggestions for alternative evaluation methods to augment the improved process now being used by the Authority.

A significant aspect of the Authority's reconnaissance study methodology is the use of the present value life cycle cost analysis to evaluate alternative projects and select projects for detailed feasibility analysis. This practice, which is the Authority's method of meeting a legislative mandate to apply a consistent evaluation procedure, is used throughout the feasibility study and authorization phases of project evaluation. The significance of using this economic evaluation criteria at the reconnaissance level stage is described below. Since the use of reconnaissance level studies has differed between the Railbelt and other areas, these differences are described where appropriate.

Strengths of Past and Current Practices In Reconnaissance Studies

The Village Energy Reconnaissance Program includes most of the appropriate considerations for such studies. The concept of reviewing village interconnection potential and evaluating ranges of demand forecasts are incorporated in the studies to some degree. Of the studies and study summaries reviewed, the studies recognize that there is likely to be some impact on power demand in communities where the Power Cost Assistance Program has been implemented. Presumably due to the limits of the budgets of such studies, the reports understandably treat this issue qualitatively.

The Authority's efforts to maintain consistency between the reconaissance studies are also appropriate. This allows for consistent comparison of projects.

The Authority's work in securing local input to such studies is also a strength.

Weaknesses of Past Practices in Reconnaissance Studies

A review of the procedures used and issues surrounding reconnaissance level studies performed by the Authority require a comparison of past practices with more recent approaches used by the Authority. A further distinction must be made between studies conducted for the Railbelt and those conducted for bush communities.

The problems with reconnaissance analyses in the Railbelt are primarily a function of the timing of the analyses of alternatives relative to the advanced stage of planning for the Susitna Project. The Battelle study of the Railbelt Alternatives is an extensive effort to evaluate alternative power supply resources in the Railbelt area. A study this extensive can be approached from several directions utilizing a variety of techniques. Some alternative approaches to conducting such an analysis are discussed in Appendix 3-B.

Regardless of the approach taken in such an analysis, however, a major constraint to using the results of this study is its timing. From a planning perspective, the analysis at a reconnaissance level of any single project or group of projects as alternatives to Susitna faces the problem of exceedingly disproportionate data bases upon which to make a comparison. The Susitna Project enjoys the benefit of years of environmental, engineering, and economic study. To compare preliminary analyses of alternatives at a reconnaissance level creates a natural planning and evaluation bias towards the more extensively evaluated project.

This observation is not a criticism of the Authority nor any of the organizations involved in the study and evaluation of Railbelt power supply plans, it is simply a recognition of the existing planning environment. The result of this situation is that it is difficult to offer alternative approaches to the evaluation of Railbelt power supply options which would provide study results that would receive serious consideration as feasible alternatives to Susitna.

In the reconnaissance evaluation of bush communities, the problem of identifying service areas and preparing a more complete list of alternatives for consideration is less complex than in the Railbelt. Power Supply "systems" in the bush are simpler and have fewer available alternatives than Railbelt utility systems. However, the lack of a well established data base for estimating energy use and little previous analysis of available energy resources can make it difficult to accurately evaluate energy needs and available alternatives. (This is the primary reason the reconnaissance-level study is needed.) In reviewing some of the completed reconnaissance studies, the possibility of regional power projects supplying power to more than one village or community is possibly being discounted too early in the process. Since much of the regional or sub-regional power demand picture is not known until <u>after</u> the reconnaissance-level studies are done, it is difficult to make judgments on the ability to develop sub-regional systems to supply power to a group of the smaller villages until after the reconnaissance-level studies are completed. This problem and some of the recent Authority approaches to it are described under the discussion of alternative approaches.

Since economic events (such as commercial facility developments or closings) can significantly impact energy demand at a village, it may be prudent for the reconnaissance studies to give special consideration to energy supply projects which appear technically feasible. Past reconnaissance studies have noted that future increases in demand beyond the projections used in the study could make some of the larger projects (usually hydroelectric) feasible. Some preliminary quantitative analysis of the rates of growth or power demand levels necessary for the alternative project to be economically superior would aid in identifying when a future reevaluation of alternatives might be justified.

A problem common to all reconnaissance studies is the State's policy of using present value life cycle cost as the sole economic criteria for evaluating and comparing alternatives. The present value cost method is used by the Authority to screen and rank alternatives at the reconnaissance study phase. If reconnaissance level study estimates of the present value life cycle cost of a project vary greatly from the cost of alternative projects, this finding may be sufficient to recommend one alternative over another for detailed evaluation. However, it is difficult to confidently select between projects whose present value life cycle cost over a fifty year period are relatively similar. The potential drawback to this evaluation approach as a sole criteria is discussed in more detail in the section pertaining to detailed feasibility studies.

Alternative Reconnaissance Study Approaches

One change which could be considered is to broaden the objectives of the studies. This could be accomplished by incorporating phased studies. First, an evaluation aimed at identifying alternative and most likely study or service areas for interconnection could be conducted. In the case of isolated villages the need for such evaluation would obviously be limited. This first reconnaissance-level study could focus primarily on existing energy use patterns and demand projections and availability of alternative energy resources in the study area. Although it is appropriate to identify and evaluate specific project alternatives at this stage, the primary focus of this first phase of analysis would be as a "screen" to rank those villages or groups of villages where additional analysis of alternatives is warranted. This focus would provide budget planning guidance for the Authority in establishing future study priorities.

The Bristol Bay and Bethel area regional power plan approach is a good example of the types of follow-up study that would follow the reconnaissance level studies described above. In these studies, the results of earlier reconnaissance studies were reviewed to identify potential regional and sub-regional development plans, and additional project concepts were identified and evaluated in more detail. A similar approach could be applied to the results of the reconnaissance studies which have been completed (although there is not likely to be other bush areas with regional development potential as extensive as the Bristol Bay or Bethel areas).

The future village reconnaissance studies to be conducted for the Authority could be structured to be followed by an overview which compares the results of individual studies to identify the potential for a regional or sub-regional approach, or to rank the villages for more detailed analyses based on the results of the reconnaissance level studies. Although the Authority's procedures do not reflect this specific approach, the Bristol Bay and Bethel studies indicate that the Authority is moving in this direction. It may be appropriate to formally recognize this approach in the Authority's procedures.

This second phase of the reconnaissance study would use one or more load growth scenarios, based on alternative forecasts, alternative interconection concepts, or a combination of both to evaluate power supply alternatives. However, an administrative problem can arise with this phased approach. Unless the Authority conducts the preliminary analysis itself, the budget for the total reconnaissance level study is not accurately known until the first phase, as described above, is completed and the scope of the remainder of the study is known. This could be overcome by budgeting slightly more for the studies than is currently done and withholding a reserve for augmenting budgets.

In several of the reconnaissance level studies, renewable resource projects are identified as technically feasible, but economically infeasible due to insufficient energy demand in the projections utilized. Since bush village energy demands can increase substantially with the addition of a commercial facility in the area, it may be appropriate in some cases to conduct preliminary sensitivity analyses to identify the energy demand level that might be needed to make such alternatives economically superior. A review of the results of reconnaissance level studies would then be made periodically to determine whether an update is warranted. The results of the sensitivity studies could be used to rank the villages in terms of priority for future re-evaluation. For example, a village where energy demand must triple before alternatives to diesel generation become economically superior would have a lower priority for re-analysis than a village in which a fifty percent increase would make alternatives potentially economically superior. This type of analysis would also help eliminate some of the criticism by local citizens that demand projections used to evaluate alternatives are not as optimistically high as they would hope for. If energy demands increase at rates which would justify considering alternatives preferred by the local community, the Authority could then consider such options.

Still another alternative is to augment the present value life cycle cost evaluation method with other economic evaluation criteria, including nominal cost of power analysis,16/ using shorter periods for the present value life cycle analysis, and using savings to capital investment ratios.17/ Although nominal cost of power analyses are now being included in Authority studies, it is not clear how the results of these analyses are factored into the decision making process. This is discussed in more detail below, with respect to detailed feasibility studies.

Feasibility Assessment

This section addresses the process of using the results of reconnaissance level studies to select projects for detailed feasibility analysis. Since the analysis of the feasibility of individual projects leads to selection among alternatives for project development (where alternatives have been identified), this ranking and selection is an important part of the power planning process.

Selection of Projects for Feasibility Assessment and Ranking of Alternatives

Prior to reviewing the current practices in feasibility assessment, it is important to note that many of the completed feasibility studies which have been used by the Authority have either been "inherited" from other organizations or are studies which were conducted for the Authority based on the results of reconnaissance level studies which were conducted by other organizations.18/ Therefore, some of the problems identified are associated with parties who are no longer directly responsible for the continued power supply planning process in Alaska. Furthermore, studies such as those for Bristol Bay and the Bethel area have shown a significant improvement in scope and approach as compared to past studies.

Current Practice in Selecting Projects for Feasibility Assessment

The Railbelt Alternatives Study is the closest effort to a reconnaissance level study which has been conducted for the Railbelt area. In terms of scope and depth of analysis, the study was much more extensive than a regional initial reconnaissance study. However, due to the timing of its completion, several detailed feasibility studies for specific projects in the Railbelt were completed before the Railbelt Alternative Study was completed, or even started. Because of this there was not a framework for evaluating the results of the project-specific feasibility studies which had been completed in a manner which allowed comparison of the study results when they were conducted. The Railbelt Alternative Study may now form the basis for detailed evaluation of specific projects and groups of projects. However, the level of detailed analysis of new projects relative to the Susitna project is likely to remain a problem for a comparative evaluation.

The use of reconnaissance studies in the bush and Southeast Alaska has varied depending primarily upon how long ago the reconnaissance level studies were conducted. Projects which are in advanced stages of development (Lake Tyee, Terror Lake and

Swan Lake, for example) had feasibility studies which were either conducted by other agencies or were based on reconnaissance level studies which were conducted to identify alternatives to those projects after the projects had already been identified as "preferred." This is similar to the approach which has been used for Susitna, discussed above.

The Authority is currently selecting feasibility studies based on more extensive and consistent reconnaissance level studies in bush locations. The general approach taken in the past appeared to be to select a single preferred project with the lowest present value life cycle cost as identified in the reconnaissance level, where a clear economic preference was indicated in a study. However, in many of the studies, the present value life cycle cost evaluation method has not identified substantial economic differences between the alternatives evaluated at the reconnaissance level. The Authority has, therefore, recently moved towards a two-stage feasibility assessment following the conduct of the reconnaissance level studies. The Bristol Bay, Bethel area, Kotzebue, and Cordova studies are examples of this approach.

Strengths of the Current Process for Selection of Projects for Feasibility Analysis

The strengths of the current process for selecting feasibility studies from reconnaissance results are the attempt to make such reconnaissance studies consistent, to the extent possible, and to conduct them concurrently to allow for comparison of results. The recent efforts to standardize the reconnaissance study approach should improve the ability of the Authority to set priorities for authorizing feasibility studies of promising projects in the bush communities.

The "two stage" feasibility assessment to consider alternatives identified in reconnaissance studies before determining which projects are to be considered preferred alternatives for detailed feasibility analysis is a major improvement in the planning process.

Weaknesses of Past and Current Process for Selection of Projects for Feasibility Analysis

From the description of the process used to select projects for feasibility assessment in the past, several weaknesses can be identified:

- The lack of a reconnaissance level review of Railbelt alternatives until recently has resulted in piecemeal evaluation of the alternatives. The feasibility studies which have been conducted for each alternative are therefore not likely to be as useful for selecting alternatives for development as they would be had the studies been conducted following area-wide reconnaissance studies before the extensive studies of Susitna were performed.

- The reliance on the lowest present value life cycle cost for project evaluation in the reconnaissance level studies leads to a bias towards selecting only one project for detailed feasibility assessment when one project is identified as being capable of meeting the study area demand. This precludes the comparison of what could be economically preferable projects which were ranked close to the "preferred alternative" at the reconnaissance level. If any of the major assumptions change, project ranking can shift dramatically. Using a single criteria heightens the risk of selecting an inferior project. The "two stage" feasibility study process the Authority is moving towards may alleviate the problems of inadequate data availability at the reconnaissance level stage. This should provide for a more extensive analysis of alternatives before planning work focuses on one preferred alternative.

Alternative Approaches to Selecting Projects for Feasibility Assessment

Alternative approaches to selecting projects for feasibility analysis include the following:

- Where more than one alternative evaluated in the reconnaissance study appears potentially feasible, more than one project can be evaluated in the detailed feasibility study to provide a more complete basis for the selection of a project for development. It appears that the Authority evaluation process is moving in this direction. If so, the formal procedures should be updated to reflect this change.

- If a reconnaissance study has been completed, but questions regarding alternative interconnection or load growth scenarios remain, an augmentation of the reconnaissance study to identify other potential alternative projects for detailed analysis can be undertaken before detailed feasibility studies begin, either separately or as an initial phase of the feasibility study.

- Economic evaluation methods, in addition to, or in lieu of present value life cycle cost, could be used to evaluate projects at the reconnaissance level stage (see discussion in the following section).

Economic Evaluation Procedures in Feasibility Assessments

The objective of the Authority's detailed feasibility assessment is to compare one or more alternative power supply projects (or power supply plans) to a base case plan to form the basis for a final recommendation for development of one or more projects. The present value life cycle cost analysis is the analytical method and decision making criteria used by the Authority in these assessments. The following describes the strengths and weaknesses of this methodology and offers some alternatives for consideration to augment this evaluation concept.

Current Economic Evaluation Practice

After a specific project has been selected for detailed feasibility assessment, the Authority utilizes a standard procedure which it has adopted to perform project evaluation. This evaluation procedure is aimed at providing consistency between feasibility studies. The approach used is basically a more detailed version of the reconnaissance level evaluation, only focused on a fewer number of projects and in greater detail. The project or projects evaluated in the detailed feasibility study are compared to a base case which is generally a thermal power plant or system.

The current dollar "overnight" capital and operation and maintenance costs of the base case plan and alternatives are estimated in a traditional manner.19/ The Authority then uses an "inflation free" method to estimate installed capital costs and future annual project costs in today's dollars with an assumed real escalation rate for capital costs, fuel costs, and operation and maintenance costs. These annual costs are estimated over a period equal to the longest economic life of the projects under consideration with no escalation of costs after twenty years. As an example, if a study uses a plan with a hydroelectric project with a fifty year life planned for construction ten years into the planning period, the Authority would use a sixty year evaluation period to estimate present value life cycle costs. Where the present value life cycle cost of an alternative project or plan is significantly lower than the other alternatives, this lowest present value cost alternative is usually recommended for development.

The Authority has found that in comparing capital intensive projects such as hydroelectric projects with diesel generators or other thermal alternatives, the high initial energy costs associated with the hydroelectric projects result in financing complexities due to the high initial energy costs. Recently, consideration has been given to the impact on project economics of delaying the development of hydroelectric projects as a variable in feasibility studies. The purpose of this approach is to determine whether delaying implementation of a project will yield a lower present value cost for the project, as compared to the base case alternatives. This "timing" analysis has been of particular interest to the Authority in situations where the difference in present value costs between alternatives is not large.

Strengths of Current Economic Evalation Procedure in FeasibiityStudies

The main strengths of the current feasibility assessment economic evaluation methods are:

- The effort to use a consistent methodology and economic criteria. This is particularly important when the State must assist in the financing of several projects of various sizes, project lives, schedules for implementation and geographic location.

- The recent efforts to consider different implementation schedules for projects when evaluating project feasibility.

Weaknesses of the Current Practice

The weaknesses of the current economic evaluation methods used in the Authority's feasibility study procedure pertain to the reliance of a present value cost method on long term assumptions regarding real fuel cost escalation and forecasted demand. While the Authority appears to utilize alternative economic assumptions in its present value cost analyses, it is not clear how these alternative assumptions are utilizd in the decision making process. The following identifies some of the weaknesses of the past practices of utilizing the results of the present value life cycle cost analysis method:

- The Authority has regularly included a range of real fuel cost escalation rates as a sensitivity analysis in feasibility assessments. Most final feasibility studies performed for the Authority include zero real fuel escalation in addition to average rates of approximately 2 to 3 percent annual real escalation. The Authority also adopts a "most likely" average fuel cost escalation which is constant over a twenty year period of analysis. Although analyses are conducted using lower fuel escalation rates, and these results are presented in final feasibility studies and the Authority's Statements of Findings and Recommendations, it appears that the final recommendations have previously been based on the adopted "most likely" fuel cost escalation scenario. In FY 1982, the Authority adopted an average annual real fuel cost escalation scenario of 2.6 percent/year for 20 year studies. The result of using this high of a real escalation rate when expressed in nominal dollar terms (estimated future costs including estimates for the general rate of inflation) is shown in the Tyee Lake sample evaluation in Appendix 3-A (see Exhibit 3-2 in the Appendix). If lower rates of fuel cost escalation are being used in the decision making process, the presentation of the findings and recommendations have not clearly indicated how the results of analysis using the lower escalation rates were considered.

- The use of present value life cycle cost as the sole economic criteria for determining project feasibility de-emphasizes the near to intermediate term energy cost increases associated with capital intensive hydroelectric projects, as compared to the thermal base case. The use of a 50-year evaluation period for present value analysis for hydroelectric projects can create a very misleading perspective of the attractiveness of a project. The

Authority has incorporated nominal cost of power estimates in their studies, but it is unclear how this analysis is utilized in the decision making process. As an example, the diesel generation nominal power cost curve shown in Exhibit 3-2 in Appendix 3-A would tend to suggest that there would be some response to energy demand on behalf of the consumer, or fuel supply substitution which could impact such long term escalation before the nominal fuel cost values in the later years of the forecast were incurred. It is not clear that the effective nominal power costs are considered in establishing the real escalation rate which is used as the basis for the present value life cycle cost analysis. More emphasis on the near to intermediate term power costs appears warranted. Appendix 3-A addresses this problem with a quantitative example comparing alternative methods of evaluating project economics.

- The public can be misled by power cost estimates expressed in constant dollars. The State is proposing to subsidize project costs and the total magnitude of such a subsidization program can be misunderstood when base year, inflation-free cost estimates are used for estimating project feasibility. Nominal dollar estimates would provide an additional perspective of the size and timing of State expenditures. The Authority is providing this information in more recent studies, which should help focus more attention on the power marketability issue.

Alternative Approaches to Feasibility Assessment

As alternatives to the current procedure for feasibility assessment, the following strategies for structuring feasibility assessment could be utilized to better meet power supply planning requirements:

- The selection of the fuel cost escalation rate, in most cases, is the most significant decision that the Authority must make in conducting a present value life cycle cost analysis. Since the present value cost of oil or gas fired generation is so sensitive to fuel cost escalation, the Authority may want to consider incorporating an explicit analysis of alternative fuel cost escalation rates on a project-specific basis which considers the cost of power including an estimate of general inflation. The efforts of the Authority to eliminate the vagaries of the general rate of inflation in their future cost analyses is understandable. However, when the "most likely" scenarios used in past studies for the Authority are reviewed in nominal power cost terms for a specific project, lower rates of real escalation could be seen as being likely as well. Although additional economic evaluation scenarios can be viewed as "information overload", once the feasibility study has narrowed down the reasonable alternative scenarios to a manageable number some additional fuel cost escalation sensitivity analysis could be performed. In cases where controversy regarding the recommendation to develop a project has been encountered, the Authority has conducted sensitivity analyses. One approach to this sensitivity analysis, once a tentative "preferred" project or plan has been identified, is to determine the real fuel escalation which corresponds with a 1.0 benefit cost ratio. The decision-making can then focus on the perceived risk that fuel cost escalation will be less than that "break-even" rate over the period of analysis.

- In addition to the use of a 50-year project life for a present value life cycle cost, a shorter term analysis, for example 20 years, could be used to evaluate the near and intermediate term cost of the project alternatives. Such analysis could also be undertaken using nominal dollar costs, including estimated inflation rates, to present the best estimate of the costs of the alternatives. This could be estimated in addition to the "inflation free estimate." Appendix 3-A provides a comparison of the 50-year present value cost method to a 20-year analysis. The purpose of the 20-year analysis is to determine <u>when</u> the benefit from a project which has a lower fifty year present value life cycle cost is expected to occur. This approach takes a "snapshot" view of twenty years of operation, disregarding the salvage value of the equipment at the end of that period. (This method also disregards the remaining debt service payments due in the case of a hydroelectric project financed with long term debt, on the basis that the project would continue operating at a "profit" after twenty years, in any event). This analysis provides an indication as to how dependent a "preferred" project (using a 50-year analysis) is upon the cost savings which occur after the 20-year planning period in order to obtain the estimated total value of the 50-year present value cost savings.

- The calculation of the present value savings per dollar of capital investment anticipated to be obtained from a project over a period of time, such as during its commercial life, provides a measure to assess the relative cost-effectiveness of alternative projects. Appendix 3-A provides a sample calculation of the savings per incremental dollar of capital expenditure for the Tyee hydroelectric project as compared to continued use of diesel generation to provide an indication of the application of this evaluation method.

- Another method of evaluating near-term project economics is to incorporate the cumulative present value break even cost of the alternatives in the analysis. By including this evaluation, the decision maker would know how many years it would take (on a present value basis) for, as an example, a hydroelectric project to recover the higher cost of power in the early years of operation due to the savings anticipated after thermal power costs exceed the hydroelectric project power costs.

Selection, Development, and Authorization

After feasibility studies are complete, the project or projects found to be feasible and desirable for development must proceed through the authorization process. This section addresses the phase of the power supply planning process which combines the review of feasibility study results with consideration of project financing alternatives to make a decision on project authorization.

Current Practice of Project Selection

The authorization process for power development in Alaska involves a multi-tiered review process. It originates with a staff recommendation to the Authority's Board of Directors and culminates with the enactment of law authorizing the power project and approving its construction cost. The ultimate decision-making authority for most major projects resides with the State Legislature and its decision is based on recommendations from the Division of Budget and Management in the Office of the Governor and from the Authority's Board of Directors. To review the authorization process it is appropriate to first review the steps which proposed projects must complete before the Board recommends them for budget authorization. Although reconnaissance and feasibility studies must pass through authorization processes of their own, the focus of this next section is on the process used to authorize projects to proceed beyond the feasibility stage.

Feasibility Study and Finance Plan

A reconnaissance study for a proposed power project is considered approved if it has not been disapproved by the

Division of Budget and Management within 30 days of submission. Once approved, the Authority must complete a feasibility study and plan of finance for each proposed project if they want to proceed to the next phase of the authorization process.

A feasibility study is used "to assess the technical, economic, and environmental aspects of a power project or program identified in a reconnaissance study so that the Authority may decide whether to apply for licenses or permits, or invest in detailed engineering and design."20/ A feasibility study must include detailed information concerning the proposed project, a statement of all assumptions which affect the feasibility of the project, a comparative analysis of all reasonable alternatives to construction of the project, and information based on engineering and design work which meets the requirements for submission to the Federal Energy Regulatory Commission of a license application.

The purpose of the plan of finance is "to present various alternatives available to finance the power project and to identify the most appropriate means to achieve the lowest cost electric power for consumers while minimizing the amount of State assistance required."21/ It must include recommendations of the most appropriate means to finance a project. These means include, but are not limited to, the following: revenue bonds, general obligation bonds, revenue bonds of the Authority with partial or full guarantee of the State, an appropriation or loan from the General Fund, financing arrangements with other entities using leveraged leases or other financing methods, assistance from any federal agency, a loan from the Power Project Fund or the Renewable Resources Investment Fund, or any combination of the financing arrangements listed above.

When any State assistance is necessary for a project to meet financial feasibility criteria, an estimate of the minimum amount of financial assistance required by the project from the State must be included in the plan of finance. This assistance must be stated in terms of estimated present value.

The techniques applied in determining the information required, and the standard criteria and measures for comparative analysis of alternative financing arrangements are adopted in regulations which are developed jointly by the Authority and the Division of Budget and Management. As a result, plans of finance and feasibility studies should be relatively consistent between projects, at least in format, and readily understood by all parties.

Review by Division of Budget and Management

When these two documents are completed, they are forwarded to the Division of Budget and Management (DBM) in the Office of the Governor for review for compliance with the provisions noted above (condensed from AS 44.83.181 (b)-(d)). The DBM can obtain an independent evaluation from another source of the feasibility study and plan of finance at this stage if they feel it is warranted to comply with the provisions mentioned previously.

When the DBM has completed its review of both reports, it submits a report to the Governor which includes a financial analysis that evaluates the project's proposed bond resolutions or other financial plans or arrangements, and their impact on the total direct and indirect indebtedness of the State. The report includes a recommendation to the Governor and Legislature for approval or disapproval of the proposed project, again based on compliance with the requirements of AS 44.83.181 (b)-(d). This report must be completed and submitted not later than 60 days after having been received by the DBM.

Authority Process for Recommendation of Projects

Upon completion of a draft feasibility study and plan of finance for a project, the Authority distributes both for a period of 60 days for review by staff, other agencies, and the public. The Authority Board of Directors secures an independent cost estimate for the project from its consulting engineer. The findings of the consulting engineer and the staff, combined with any agency or public input are presented in a briefing to the Board and are addressed one by one in the final feasibility report. This briefing includes a review of project costs, technical feasibility, environmental impacts, financing options, and public and agency preferences. From this review the Board decides whether to seek required permits and licenses and initiate design (subject to legislative authorization of the project). The Board has the authority to approve all permit acquisitions, initiate project design and award design contracts, once legislative authorization and appropriation of funds have been obtained.

The Executive Director prepares a "Statement of Findings and Recommendations" and submits it, along with the feasibility report and finance plan to the Governor, the Legislature, and the DBM. The DBM reviews the feasibility report and plan of finance and transmits independent recommendations to the Legislature and the Governor.

It is important to note that under the present written procedures, the Authority's decision to recommend a project for licensing and design can be considered as a recommendation to prepare for construction assuming that upon completion of licensing and design the project remains technically, economically, and environmentally feasible. Thus, approval by the Legislature for design and licensing could be an authorization to develop the project, with certain final review requirements as described in the next section. The Authority has, however, considered legislative authorization as approval to conduct project design only. The Legislature's decision on appropriation of funds for construction after design is complete is considered by the Authority to be the final authorization to construct a project.

Submission to the Legislature

The Legislature, for any proposed power project, will have in its possession at this stage reports and documents from the Alaska Power Authority and the Division of Budget and

Management in the Office of the Governor. The Legislature's materials and their sources are:

- Alaska Power Authority
  - Statement of Findings and Recommendations
  - Feasibility Studies
  - Plans of Finance
- Division of Budget and Management
  - Recommendations concerning the project
  - Analysis of Authority Feasibility Studies
  - Analysis of Authority Plans of Finance

In fact, all three players in the process, the Governor, the Legislature, and the DBM receive these six reports which analyze the proposed project from different perspectives. The different viewpoints should provide sufficient data to make an informed decision. The problem lies in sorting through the information and determining the most appropriate analysis upon which to base a decision.

The project authorization process is treated as a component of the total annual State budget review and authorization. To receive authorization for projects, the Authority compiles the results of feasibility studies which have been completed in sufficient time to be considered in the annual State budget process.

To present its recommended projects to the Legislature, the Authority separates the State into three geographic planning regions - the Railbelt, the Bush, and Southeast Alaska. For each region, the regional power supply issues are described and the recommended power development program efforts from reconnaissance study through construction authorization are briefly presented. In support of recommendations for project licensing, design,and construction, the Authority presents a brief background on the alternatives considered, and the results of the feasibility analysis on the basis of the present value life cycle cost estimate.

The Legislature reviews the projects presented by the Authority and considers the individual projects and the total request. The fact that the authorization decision is made by the Legislature is a significant factor in comparing Alaska's power supply planning process to the process typically used for a utility service area. In addition to consideration of the merits of individual projects, the power development program budget must be considered in light of other State budget priorities.

The Legislature considers and must approve all proposed new projects except those that are exempt under AS 44.83.187.22/ The Authority may proceed with the engineering and design work necessary to meet the requirements for submission to FERC of a license application, but may proceed no further toward project completion until the Legislature approves the proposed new project. Approval of a proposed new project comes only by the Legislature enacting a law that authorizes the project and approves its construction cost.

Recently there was a proposal to adopt a method to expedite the process from project design to construction. The procedure provided for the Authority to obtain a final cost estimate from a source independent of the firm which conducted the project design and is qualified to make such an estimate. The objective of this independent review would be to determine whether the expected project costs exceed the authorized budget by more than 7.5 percent, adjusted for inflation. If the costs are within this margin, the Board would be provided with an update of project feasibility and a recommended plan of finance.

Under this plan, if the final cost estimate exceeds the authorized budget, adjusted for inflation, by more than 7.5 percent, the feasibility report would be revised to determine if the project is still feasible. If the Board feels that the project is feasible, it would submit the revised feasibility study and the independent cost estimate to the Legislature for reauthorization. Any project which is returned for reconsideration would not be constructed unless the Legislature reauthorizes it by enacting law for that purpose.

The Authority has not adopted this procedure and has recommended that it not be adopted. The Authority has not operated under the assumption that authorization for design infers approval to construct a project. Therefore, the Authority makes recommendations to the Legislature for appropriations for construction on each project to be developed. If, based on the review of final design cost estimates, the project feasibility is questionable, the Authority would recommend an updated feasibility analysis prior to requesting authorization for construction from the Legislature. Even after Legislative authorization and appropriation of funds from the Legislature, the Board often awaits receipt of major construction contract bids before giving final approval for the project. Final approval often takes the form of an initial construction contract award. The Board has the authority to approve by resolution any indebtedness for an authorized project for which an appropriation has been approved by the Legislature.

Weaknesses of the Current Practice in Project Authorization

Many of the difficulties currently experienced in the project authorization process are attributable to the very nature of a legislative approval process. For instance, due to the unconventional body which performs power supply decisions, Alaska's power supply planning process has experienced difficulties such as: State funding uncertainties which lead to financing plan uncertainties, and untimely yearly budget review periods relative to project study completion dates which can preclude project development until the next annual budget review occurs. Limitations to the amount of time that the Legislature can devote to power supply planning issues, and the transitory nature of the tenure of elected positions are also inherent weaknesses in the decision making for Alaska's power supply planning. The evolving nature of State policy on financial assistance for power development has also hampered the authorization process.

At present, the State is in the process of developing a plan for determining how to utilize State funding to assist in project financing. Therefore, the Legislature must currently consider the authorization of power projects based on tenuous State funding, with a final financing plan to be confirmed at a later date. The financing plan which is finally adopted can substantially impact the present value life cycle cost for the proposed alternative relative to the base case thermal plan or other alternatives. This uncertainty has complicated decisions by the Authority to recommend projects for authorization and for legislative action.

One problem with the current practice is that the State Legislature reviews only those projects for which studies have been approved. Often there are time frame differences which preclude some projects from consideration in the State's yearly budget authorization. Important projects which stand alone or complement an energy grid can be closed out from the annual authorization "window" because of technical delays or minor deficiencies which delay agency approval at lower levels of the process. In these instances, invaluable supplementary information which would enhance decision making at the authorization phase can be precluded from consideration. This contributes to the project-by-project approach to power supply planning in Alaska, especially if only those projects which are included in that fiscal year's budget proposal are considered.

Another weakness inherent in the current procedure is that previous efforts and experiences in the planning activities are not given sufficient exposure to today's decision making bodies. This reduces the extent to which the decision makers can learn from others' past efforts. For instance, the presentation of the process used to recommend the proposed projects, including the alternatives considered and discussed, is an important input to the decision making process. With the project-by-project approach which is inherent in a legislative budget review, the role that an individual project has in the study area is not easily understood. Where a proposed project meets a portion of the needs of the study area it is difficult for a decision to be made on that project absent some analysis of other alternatives currently under evaluation to augment the project. This places a burden on the Authority to document past planning assumptions and decisions in an attempt to maintain a consistent planning process.

All this seems to suggest a more comprehensive presentation process at higher levels of the authorization process. More complete, and painstakingly detailed proposals would surely improve the amount of information on alternatives and their respective feasibilities within a regional power development scheme. But this solution would not be without its costs. There is the potential for information overload on parties whose time is definitely finite. In a normal utility setting these decisions are made by full-time managers, specialized in their field. For legislators who make the final decision, these issues are but one of many issues they face in a hectic schedule. Their lack of experience in power development, together with rapid turnover (as compared to a career utility manager) makes the approval of projects that much more difficult for them than for their counterparts in the utility industry. Although they have professional staffs and support facilities, none-the-less, these weaknesses are inherent in the system.

Another factor which creates difficulties for the process is that it is very difficult for the Legislature to reach a concensus on development priorities for proposed projects. Often there is a natural tencency for legislators to want projects in their districts to receive priority. Likewise, their colleagues may be hesitant to agree to particular bills for fear that funds will be unavailable later for projects in their districts. Of course, this is not the rule, but it is a factor which has hindered statewide development priorities.

Alternative Approaches to Project Authorization

Because the Authority is a State agency and the State of Alaska has made a significant financial commitment, through the budget process, for power project development, the project approval process is somewhat different than for projects in other areas of the country. In effect, there is not a single decision to proceed with the project that is required, but rather that decision and then annually a formal decision appropriating funds for construction. This is complicated by restrictions on the commitment by one legislature of a future legislature.

An alternative that might be considered, in this regard, would be to bifurcate the approval process generally as follows:

- At the point in time that a project is identified, studies have been completed, and a decision has been made at the staff level to seek Authority Board of Directors and legislative approval, documentation should be developed which is focused on the decision makers involved. This documentation would be supported by the bulk of studies underlying the staff's decision, but would serve as a summary that periodically would be updated for the use of those who must finally approve the project.

- This documentation would be submitted with other authorization documents as a package. An important element of this document would be a cash flow forecast both in constant and current dollars for the proposed project. This cash flow forecast, segregated by source of funds (bond proceeds or legislative appropriations), would reflect the estimate of the annual appropriations that would be required.

Under such an approach, the first decision required would be whether or not to proceed with the project. Following this, the Legislature would have to address the question of appropriations annually. The "decision documents" should be periodically updated, not only at the time that annual appropriations are required, but, equally as important, when certain milestones were reached. These would be identified in the request for approval of the project . These milestones would include completion of engineering design with engineered cost estimates, receipt of bids for construction, and other events that trigger decisions.

APPENDIX 3-A

CASE ANALYSIS
TYEE LAKE HYDROELECTRIC PROJECT

Introduction

As discussed in Section 3, the 50-year present value cost evaluation method (present value analysis) is used by the Authority to evaluate the feasibility of hydroelectric projects. This method of evaluation provides one perspective of project feasibility. This appendix provides a sample evaluation of the Tyee Lake Project (Tyee) to compare a 50-year present value analysis with a similar analysis considering only the first 20 years of operation and a cost estimate in nominal dollars for both Tyee and the base case. In addition, as a method to evaluate the economic return on the capital investment in the project, the present value of the anticipated savings from the project, as compared to the base case, is estimated on the basis of savings per incremental dollar of capital investment.

This example shows the advantage in using more than one method of evaluation to assess feasibility. The alternative methods described in the examples provide a means for determining whether the long-term cost savings indicated in a 50-year present value analysis appear sufficiently attractive to warrant State funding.

Some simplifying assumptions were used to conduct this analysis, therefore, the absolute value of project energy costs and present value costs should not be considered as estimates for comparison with the results of previous studies. No effort has been made in this example to conduct analyses using different escalation rates or to perform any sensitivity analyses, as might be conducted in a complete analysis. The purpose of this sample analysis is to illustrate the potential value of augmenting the

50-year present value life cycle cost method of economic evaluation with other criteria.

Background

An analysis of the Tyee Project was completed for the Authority in December of 1981. The purpose of the Tyee Lake Hydroelectric Project Findings and Recommendations (Tyee Report) was to provide justification for an appropriation of funds for construction of the project. In keeping with the Authority's standard economic evaluation procedure, the report compares the present value cost of energy from Tyee to the alternative cost of energy from diesel generation over the same period. Diesel and existing hydroelectric generation currently serve the communities of Wrangell and Petersburg, and it was assumed that the diesel generation would be displaced by Tyee. The analysis presented here is based on the assumptions of the Tyee Report. The assumptions and methods used to estimate the comparative costs of Tyee with the base case are described in Attachment 1.

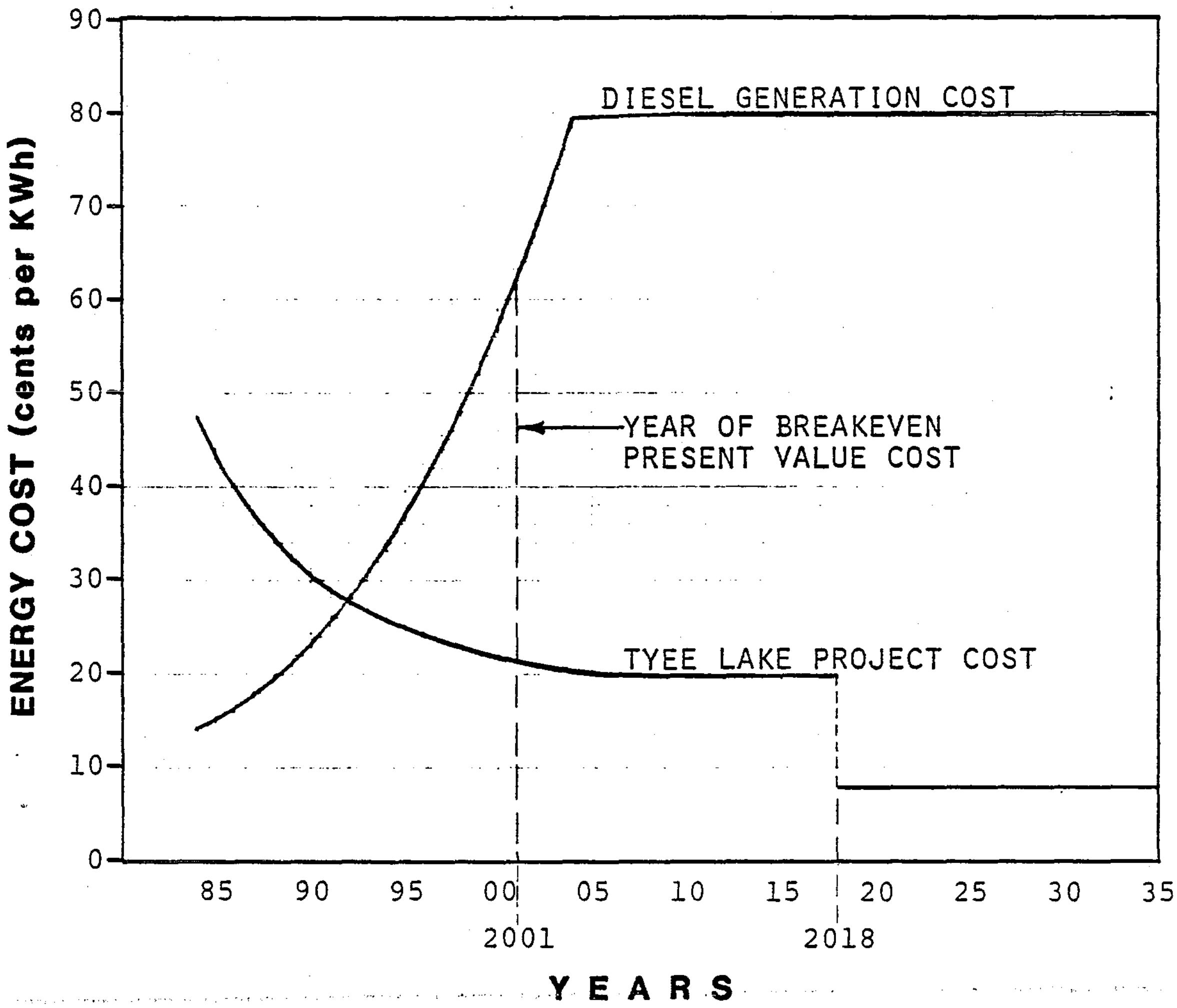
Comparison of Alternative Economic Evaluation Methods

Nominal Dollar Cost of Energy

The cost of energy per kwh for Tyee and the base case in nominal dollars is shown in Exhibit 3-2. The results of comparing Tyee with continued use of diesel generators with waste heat recovery is shown in Exhibit 3-3.

Using the criteria of the present value analysis over the expected 50-year economic life of Tyee, the project appears significantly superior to the base case, with a present value cost of approximately $160 million compared to approximately $330 million for diesel generation, based on the assumptions used in the Tyee Report. However, viewing the unit energy cost in the near and intermediate term, as shown on Exhibit 3-2, indicates the dependence of this long-term cost savings on the continued high escalation of diesel fuel costs. As shown, on a present value basis, the losses

COMPARISON OF TYEE LAKE HYDROELECTRIC PROJECT COST OF ENERGY TO DIESEL GENERATION



NOTES:
1) No inflation or load growth is assumed after 2003.
2) Tyee debt service is based on 10% financing over 35 years. The cost of energy drops in 2018 when debt is fully amortized.
3) In the year 2001 the cumulative present value of the cost of diesel generation surpasses the cost of Tyee.

SAMPLE ECONOMIC COMPARISON OF TYEE LAKE HYDROELECTRIC PROJECT AND DIESEL GENERATION

Year	Adjusted 1/ Energy Sales (MWH)	Tyee Lake Project Cost 2/ Total Cost ($x1000)	Unit Cost (¢/kWh)	Diesel Generation Costs 3/ Total Cost ($x1000)	Unit Cost (¢/kWh)
1984	27,616	12,961	46.9	3,914	14.2
1985	30,372	13,091	43.1	4,617	15.2
1990	46,471	13,890	29.9	11,280	24.3
1995	60,091	15,010	25.0	23,647	39.4
2000	75,636	16,581	21.9	44,595	59.0
2005	90,921	18,282	20.1	72,301	79.5
2015	90,921	18,282	20.1	72,782	80.0
2025	90,921	7,175	7.9	72,348	79.6
2033	90,921	7,175	7.9	72,348	79.6

Present Value of Cost over 20 years:

Diesel Generation	$132,583,000
Tyee Lake	$120,812,000

Present Value of Cost over 50 years:

Diesel Generation	$330,293,000
Tyee Lake	$158,841,000

1/ This is the projected annual demand for energy to be purchased from the project. The project produces more energy than is projected to be required in the area for several years of operation. No growth of energy demand is assumed after 20 years of operation.

2/ Although Tyee operating costs escalate with inflation, load growth increases are adequate to cause unit energy costs to decline continuously. A large drop in cost occurs after 2018 when debt service is paid off.

3/ Cost of diesel generation increases steadily until 2003, after which inflation and real escalation are assumed to be 0. The total cost fluctuates slightly after 2003 as capacity is retired and replaced at slightly different costs.

in the early years of project operation under these assumptions would be recovered from long-run project savings in approximately the year 2001, 17 years after project has commenced commercial operation (based on the assumptions used in the Tyee Report). Average annual energy costs from Tyee are estimated to be equal to diesel energy costs in approximately 1992.

Shorter Term Evaluation of Present Value Costs

A major criticism of 50-year present value analysis is the uncertainty of long-term costs and lack of knowledge of the future availability of other lower cost technologies not currently commercially available. Another method for evaluation would be to compare the first 20 years of operation of Lake Tyee to the base case. Project capital costs are still amortized over 35 years in this example. The analysis merely takes a 20 year "snap-shot" of project costs to compare the present value costs with the base case for the first 20 years of operation. Twenty years is used as a period over which greater forecasting accuracy is achievable compared to the virtual uncertainty of forecasting between 20 to 50 years in the future (The Authority has recognized the long term uncertainty in their analyses by stopping all cost and price escalation for values after 20 years. This analysis ignores both the salvage value of the equipment and remaining debt service payments after 20 years on the presumption that the hydroelectric project would remain operating after 20 years as an economic alternative to thermal generation).

As shown in Exhibit 3-3, the 20 year present value cost of Tyee is marginally less than the diesel base case. Thus the large economic advantage of the Tyee project indicated in the 50 year analysis is achieved after the first 20 years of operation.

This type of information would be helpful in determining whether a project appears sufficiently attractive in the long-term to warrant State subsidizing or restructuring debt service payments to make near term power costs competitive. The presentation of energy costs in nominal dollars also helps identify the likely amount of the subsidy that would be required.

Savings to Investment Ratio

Although a review of annual power costs over the project life and shorter term evaluation of present value project costs provide an additional perspective on project economics, neither method of viewing costs is well suited as a basis for comparing the relative attractiveness of different projects. One method of evaluating several projects, either within a region or statewide, is to compare the projected savings of the alternatives over a base case cost on the basis of savings per incremental dollar of capital investment. Power projects of different size, location and service area can be evaluated, compared, and a prioritization established based on the expected return in savings per dollar of capital investment.

This concept is not necessarily one which is commonly used by electric utilities. The marketability of power from a project relative to available alternatives, and the "melded" system cost of power by the addition of a new resource are more conventional methods to determine project feasibility in a typical eleactric utility system. However, with the broad range of existing power costs, and the limitations on available alternatives in many regions and communities, the savings per dollar of capital investment is an evaluation method deserving of consideration by the Authority.23/

As an example of this approach to evaluation, the estimated savings per dollar of capital investment was calculated for Tyee for the first 20 years of operation and for 50 years of operation as compared to continued diesel generation. Exhibit 3-4 presents this calculation for the 20 and 50-year present value savings. To conduct this analysis, the present value capital cost of Tyee is compared to the present value capital cost of the additional diesel generating capacity which would otherwise be added over the period of analysis. To evaluate the savings per incremental dollar of capital investment for Tyee, the difference between the present value capital costs is divided by the present value savings expected from Tyee.

SAMPLE CALCULATION OF SAVINGS TO INVESTMENT RATIO TYEE LAKE HYDROELECTRIC PROJECT

20 Year Savings To Investment Ratio 1/

Present Value Cost Over 20 Years

Diesel Generation	$132,583,000 2/
Tyee Lake	120,812,000
Savings	11,771,000

Present Value Capital Costs

Tyee Lake	$103,700,000 3/
Diesel Generation	20,464,000 4/
Incremental Present Value Cost of Tyee compared to Diesel Generation	$83,236,000

Savings/Incremental Capital Investment =
11,771,000/83,236,000 = 0.141
= $0.141 savings per dollar of capital investment

50 Year Savings To Investment Ratio

Present Value Cost Over 50 Years

Diesel Generation	$330,293,000
Tyee Lake	158,841,000
Savings	171,452,000

Savings/Incremental Capital Investment =
$171,452,000/83,236,000 = 2.06

= $2.06 savings per dollar of capital investment

1/ First 20 years of Tyee Lake project operation.

2/ From Exhibit 3-3.

3/ Capital cost estimate without interest during construction, emergency and replacement reserves, bonds, fees or other capitalized project financing costs.

4/ See assumptions in Attachment 1 for calculation of present value of diesel generation capacity costs.

Based on the comparative costs between the diesel base case and Tyee, Tyee is estimated to have a present value savings of approximately $0.141 per incremental dollar of capital investment over the first 20 years of operation. Over the 50 year operation of Tyee it is estimated to have a present value savings of $2.32 per incremental dollar of capital investment.

These values can be compared to the savings per dollar of capital investment of any other project for purposes of establishing a region-wide or statewide economic priority of development on the basis of economic return on the State's investment.

ASSUMPTIONS FOR TYEE PROJECT ECONOMIC ANALYSIS

The following is a description of the assumptions used to prepare alternative economic analyses of Tyee as compared to continued diesel generation.

Method of Calculating Project Costs

In the Tyee report, the economic analysis of the Tyee project was performed assuming four different electrical energy demand growth scenarios and several financing plans. In this analysis, a single load growth scenario (Case C from the Tyee Report) was chosen. This forecast is the "expected scenario" from the Definite Project Report.24/ In the analysis conductd for this example, the entire capital cost of Tyee is assumed to be financed at 10 percent over 35 years, while the cost of additional diesel generation capacity is assumed to be financed at 10 percent over 20 years (for each increment of capacity addition).

The inflation estimate of seven percent per year from the Tyee Report was applied to show how the cost of energy from each alternative changes over time. The middle fuel escalation scenario from the Tyee Report assumes that fuel escalates at 2.6 percent above the rate of inflation and was applied in this analysis. No load growth, inflation, or real escalation in fuel was assumed after the twentieth year of analysis, consistent with the Tyee Report assumptions.

The cost of the diesel generation alternative in this analysis was calculated by the same method used in the Tyee Report. First, the diesel capacity required under Case C to augment existing hydroelectric and diesel generation capacity was estimated. The annual debt service for diesel capacity was then estimated over the 50 year study period, assuming 20 year lives for diesel generators and that investments in diesel capacity are made in every fifth year to meet the projected load growth for the next five years. The cost of fuel and operation and maintenance were estimated consistent with the assumptions of the Tyee Report, except that inflation was added.

The Tyee Report anticipates that some of the waste heat from diesel generation can be used to heat buildings in Petersburg, thereby displacing fuel oil. The fuel savings from waste heat utilization was credited against the cost of diesel generation in the Tyee Report for Load Cases A and B. For use in this sample analysis, this fuel savings value was estimated for Load Case C using the same procedure as was used in the Tyee Report for Cases A and B. The annual capital charge, fuel expense, operation and maintenance and waste heat fuel savings were then combined to calculate the net annual cost of the diesel generation alternative to Tyee.

The total capital requirement for development of Tyee and the O & M, insurance and repair and replacement expense were calculated in the same manner as in the Tyee Report. The annual cost for diesel generation and for Tyee were then discounted to establish a present value and summed over 20 years and over 50 years. A summary of specific assumptions made in this analysis are as follows:

Assumptions

General:

- All assumptions are consistent with the Tyee Report
- Inflation rate of seven percent
- Interest rate for financing of ten percent (three percent real escalation above seven percent assumed inflation rate)

Electrical Energy Demand Forecasts:

- Based on Load Case C.
- No load growth after 2003 (the 20th year of analysis).

Diesel Generation:

- Capacity

- No capital cost is assumed for existing capacity.

- Capacity retirements are scheduled consistent with the Tyee Report.

- Investment in new diesel generation capacity is made at five year intervals.

- Costs and Financing

  - Investments before 2003 are made at ten percent interest and at three percent thereafter over 20 years (inflation of seven percent is removed from cost projections after 20 years).

  - Capital cost is $730/kw in 1981 and is escalated at the inflation rate.

  - Operation and maintenance expense is 2.2 cents/kWh in 1981 and is escalated at the inflation rate.

  - Diesel fuel cost is $1.10/gallon in 1981 and is escalated at a 2.6 percent real rate.

- Operation

  - Capacity factors assumed are consistent with the Tyee Report.

  - Each gallon of fuel is assumed to generate 12.6 kWh.

  - Diesel generation capacity is assumed to have a 20 year life.

- Petersburg Waste Heat Utilization Credit

  - While total electrical load growth is given for each case in the Tyee Report, Petersburg's share is given only for Cases A and B. That share under Case C is estimated in this analysis by assuming that the relationship under Case B between Petersburg's load growth and total load growth is constant.

  - The waste heat utilization efficiency assumed in the Tyee Report is applied in this analysis.

  - The waste heat utilization capital cost and system life assumed in the Tyee Report are used here. The capital cost is escalated with inflation.

  - The operation and maintenance expense assumed in the Tyee Report is applied here, adjusted for inflation.

Tyee Lake Hydroelectric Project

- The total completed construction cost in 1984 dollars used in the analysis is $103,700,000.

- The project is assumed to be fully financed with tax exempt revenue bonds at ten percent over 35 years.

- Total Capital Requirements, the Reserve Fund, Financing Expense, Insurance Expense, Administration and General Expense, Emergency Maintenance and Replacement, and Earnings on Reserve Fund are calculated in the same manner as in the Tyee Report.

Calculation of Diesel Generation Present Value Capital Costs

- Diesel capacity capital outlays are (in thousand dollars) estimated as follows:

1990	$ 6,643
1995	17,973
2000	14,784
2010	17,127
2015	33,043
2020	19,376
2030	17,127

- To develop present value capital costs consistent with the Authority's assumption of zero inflation after 20 years, all costs incurred in the first 20 years are discounted at ten percent and after 20 years at three percent (ten percent financing rate less seven percent inflation).

APPENDIX 3-B

ALTERNATIVE METHOD OF ANALYZING REGIONAL POWER SUPPLY ALTERNATIVES

Introduction

The selection of power supply projects for design and construction by the Authority and the State Legislature has, in most cases in the past, been based on the present value cost of a single project as compared to the cost of supplying an equivalent amount of energy from a thermal base case. Evaluating a single project as an alternative to thermal capacity may be suitable when one project meets all of the incremental power supply needs of a system. Generally, however, such an approach is limited to small utility systems. In the case where energy requirements in a service area exceed the generation capabilities of a single project, or where several small projects are alternatives to a single larger project, this method of separately comparing individual projects to the same base case makes the comparison of the various alternative projects difficult. The recent completion of an analysis of alternative power supply plans in the Railbelt provides the Authority with a planning tool which represents a major step towards analysis of a power supply system rather than evaluating the relative merits of an existing thermal system and a specific power project.

The following presents some considerations for augmenting the Railbelt power system analyses which have been conducted to date with regard to (a) the selection of alternative power supply plans for evaluation, and (b) comparison of alternative supply plans.

Current Methods of Evaluating Railbelt Power Project Alternatives

The extent of evaluation of alternative power supply plans to serve the Railbelt Region has basically been the alternatives considered explicity in the Susitna Project feasibility study, and the Railbelt Electric Power Alternatives Study (Railbelt Study).

The Railbelt Study used a sophisticated generation planning model. The specific assumptions and methods used in that model were not evaluated in detail for purposes of this review. The method in which the model was applied and the results presented are evaluated in a general manner for purposes of identifying some alternative ways of applying such a model.

The Susitna study of alternatives displayed a present value analysis of the Susitna Project alternatives, the "all thermal" base case which includes coal and gas turbine additions to existing thermal capacity, and the thermal base case with the Chakachamna Hydroelectric project in lieu of Susitna.

The Railbelt Study reviewed several different plans which are then summarized as follows and shown on Exhibit 3-5.25/

- Plan 1A - Base Case without Susitna
  - Non-thermal alternatives in this plan include Chakachamna, Allison, and Grant Lake hydroelectric (approximately 345 MW of additional hydroelectric capacity).
- Plan 1B - Base Case with Susitna
  - This plan deletes Chakachamna, Grant Lake, and Allison hydroelectric projects and adds Susitna.
- Plan 2A - High Conservation and Use of Renewable Resources
  - This plan assumes lower energy demand due to conservation, with a total of approximately 630 MW of new hydroelectric capacity without Susitna, a large wind energy conversion system, and solar and wood fired space and hot water heating.

SUMMARY OF ELECTRICAL ENERGY ALTERNATIVES INCLUDED AS FUTURE ADDITIONS IN ELECTRIC ENERGY PLANS

	Electric Energy Plan[a]					
BASE LOAD ALTERNATIVES	1A	1B	2A	2B	3	4
Coal Steam Electric	X	X	X	X	X	
Refuse-Derived Fuel Steam Electric			X	X		
CYCLING ALTERNATIVES						
Coal Gasifier - Combined-Cycle					X	
Natural Gas - Fuel Cell-Stations						X
Natural Gas - Combined-Cycle	X	X	X	X		X
Natural Gas - Combustion Turbine	X	X	X	X	X	X
Natural Gas - Fuel-Cell Combined-Cycle						X
Bradley Lake Hydroelectric	X	X	X	X	X	X
Grant Lake Hydroelectric	X		X			
Lake Chakachamna Hydroelectric	X		X			
Upper Susitna Hydroelectric		X		X		
Allison Hydroelectric	X		X			
Browne Hydroelectric			X			
Keetna Hydroelectric			X			
Snow Hydroelectric			X			
Strandline Lake Hydroelectric			X			
FUEL SAVER (INTERMITTENT) ALTERNATIVES						
Large Wind Energy Conversion System			X	X		
ELECTRIC ENERGY SUBSTITUTES						
Passive Solar Space Heating			X	X		
Active Solar Hot Water Heating			X	X		
Wood-Fired Space Heating			X	X		
ELECTRIC ENERGY CONSERVATION						
Building Conservation			X	X		

(a) Plan 1: Base Case
A. Without Upper Susitna
B. With Upper Susitna
Plan 2: High conservation and use of renewables
A. Without Upper Susitna
B. With Upper Susitna
Plan 3: Increase Use of Coal
Plan 4: Increase Use of Natural gas

- Plan 2B - High Conservation and Use of Renewable Resources with Susitna
  - Same plan as 2A, except Susitna replaces all other new hydroelectric projects (other than Bradley Lake).
- Plan 3 - Increased Use of Coal
  - No new hydroelectric projects other than Bradley Lake are included in this plan nor any other new renewable energy resource projects.

Annual average energy costs in 1982 dollars and levelized energy costs were used to compare the plans in the Railbelt Study.26/ By comparison, the present value life cycle cost method was used to evaluate alternatives in the Susitna Feasibility Study. Of the two analyses, the methods used in the Railbelt Study most nearly approximate a system analysis approach which considers different power supply plans. In the Railbelt Study, several combinations of potential projects were compared to develop an estimated system cost of power for each plan. However, the Railbelt Study analysis did not compare the different sets of power project alternatives against the same demand forecasts. The selection of alternative power supply plans assumed that hydroelectric projects other than Susitna or Chakachamna would only be developed under the high energy conservation scenario used in evaluating plans 2A and 2B. Alternative power supply plans 2A and 2B assumed a lower energy demand than Plans 1A and 1B.

Alternatives for Augmenting the Analysis of Power Supply Plans

The Railbelt Alternatives Study has compared various combinations of alternative power supply projects with and without Susitna. The average cost of power for the Railbelt was analyzed for each alternative power supply plan. As discussed above, however, the comparison of alternative supply plans which are presented in the study did not assume the same levels of demand in each case. By assuming that the more extensive list of hydroelectric project alternatives to Susitna in Plan 2A would only be developed under the scenario assuming high conservation implementation (hence lower demand) and maximum use of renewable resources, there has not been a true comparison of the entire list of potential hydroelectric projects to the "with Susitna" scenario.

The Plan 1A power supply resources (the "without Susitna" plan) excludes approximately 283 MW of hydroelectric capacity which is included in the Plan 2A resources (this is the combined capacity of the Browne, Keetna, Snow, and Strandline projects, using the capacity estimates provided in Table 4.2 of the Railbelt Electric Power Alternatives Study Feb. 1982 Comment Draft). Including the 283 MW of additional hydroelectric capacity from these projects in Plan 1A to compare with Plan 1B using the same level of demand forecast for both plans would appear to be a more useful method to compare an alternative plan to a "with Susitna" plan. This approach would allow the comparison of a combination of as many smaller hydroelectric projects as are potentially available to match (to the extent possible) the capacity and energy which would otherwise be met by Susitna, using the same energy demand forecast in each case.

The Authority could also consider varying from its established standard of utilizing a base case analysis method for reviewing alternative projects in the Railbelt study area. In evaluating the generation additions to meet future energy requirements which exceed total existing and committed project energy production, a base case approach does not necessarily have to be taken. Each set of alternative additions to the existing and committed system can be evaluated on an equal basis. Although, if a plan was previously selected as a preferred or most likely plan, it could be selected as a base case for purposes of comparing alternatives. The application of a generation planning model does not require this, however.

APPENDIX 3-C

REVIEW OF POWER MARKET AREA ANALYSIS

Introduction

One of the basic problems which has been encountered in past reconnaissance and feasibility assessments of many of the power projects to serve communities in the bush and Southeast Alaska has been the limited evaluation of alternative definitions of the service or market area. Examples where this problem has been apparent are the reconnaissance study of the Kake-Petersburg Transmission Intertie and the reconnaissance study of power supply alternatives for the bush community of Galena. In both of these analyses, considerable uncertainty as to project feasibility has been encountered due to questions regarding the area and the corresponding electrical demand to be served by the projects being studied. One of the sources of this problem has been the project-oriented approach to reconnaissance and feasibility studies. By focusing early in the evaluation process on the feasibility of specific projects, consideration of the power supply system as a whole can be under-emphasized.

In addition to the above projects, the Black Bear project is used as an example where, despite earlier consideration of interconnection alternatives, there has been a need to reconsider the possibility of including additional villages in the system to be served by the project. It is important to note that in recent studies such as the Bristol Bay and Bethel area regional power plans, the Authority has taken more of a power systems and market area approach by considering regional and sub-regional possibilities for interconnection to serve several villages from "central" projects. Adoption of this approach as a standard evaluation procedure, where it is warranted, should reduce some of the problems described herein.

This appendix provides a brief description of three studies which have been conducted for the Authority. These studies are presented as examples of some of the problems which have been encountered in the power supply planning process both when interconnection prospects are not evaluated extensively early in the process and when conditions durng the planning process change prior to project construction (the latter situation was encountered in the Black Bear Project). Alternative planning approaches which could minimize such problems are described for each study as examples. It is important to note that on the Black Bear hydroelectric project and the Kake-Peteresburg Intertie project additional analyses appear to be either underway or planned to address some of these issues. The purpose of these brief case studies is to present examples of how early recognition of the need to fully evaluate alternative power market areas would increase the efficiency of the power supply planning effort, and how uncertainties regarding the market area to be served can complicate the project authorization process.

Kake-Petersburg Transmission Intertie

The community of Kake is a city of 570 people on Kupreanof Island in Southeastern Alaska. A reconnaissance-level report was completed in January 1981 on the potential for constructing a 24.9 kV transmission intertie between Kake and Petersburg for power from the Tyee Lake hydroelectric project. The two sources of power for Kake are the Tlingit-Haida Regional Electric Authority (THREA) and diesel generation at Kake Cold Storage which generates for their own use. The 1981 energy generation was 1,525 MWh for THREA and 501 MWh for Kake Cold Storage. Recently installed capacity is 1,600 kw at THREA and 975 kw at Kake Cold Storage.

A forecast including Kake Cold Storage requirements was prepared for the study. However, in conducting the present value life cycle cost analysis (present value analysis) for alternative projects, the analysis assumed that Kake Cold Storage will continue to self-generate, although Kake Cold Storage has requested to puprchase power from THREA.

The reconnaissance study provided present value analysis results for four alternatives, as follows, excluding the Cold Storage generation costs.

Plan	Present Value Cost
Base Case - Diesel Generation	$13,900,000
Kake-Peteresburg Intertie	14,700,000
Cathedral Falls Hydro	14,900,000
Wood Fired Generation	17,200,000

Although alternative economic analysis methods may indicate otherwise, based on present value analyses the first three alternatives are nearly of equal economic desirability. The addition of the Cold Storage electrical demands to the system to be served by the intertie would increase the total load served by approximately one-third. Adding approximately one-third to the electrical demand to be served by either the Cathedral Falls project or the intertie would likely provide substantially different relative present value estimates.

An additional local concern with the study was the demand forecast. Annual load growth estimates of approximately two percent were adopted as a most likely forecast. Local opinion indicated that a higher rate of growth was hoped for, if not likely, based on economic growth and development in the area. Since the cost of a transmission intertie is nearly all fixed capital cost, the cost per kwh for the intertie project as compared to diesel generation is highly sensitive to the size load served. Early consideration of all loads potentially served by the project and a range of load growth rates would have provided a more complete review of the range of comparative economics between the alternatives.

The accommodation of local opinion regarding load growth in selecting alternative power supply plan scenarios can be a budget concern. Often local opinion regarding high demand growth possibilities is founded more on desire than probability of such growth occurring. The extent to which the Authority evaluates higher demand projections will influence the cost of reconnaissance and feasibility studies. However, if analyses using higher energy demand levels do not change the relative economics of project alternatives studied, then later local questions or criticisms that a preferred alternative was foreclosed due to a "low" demand assumption can be avoided. If such early consideration avoids a later reevaluation, the net result can be a savings in time and expense.

A study of the intertie is currently being augmented by the Authority to address these alternative considerations to form a basis for decision. Incorporating such considerations at the outset would save substantial planning time and expense.

Black Bear Hydroelectric Project

The Black Bear hydroelectric project on Prince of Wales Island west of Ketchikan is a 6,000 kw project for which a detailed feasibility study was conducted in 1981. A FERC license for the project was filed in early 1981 and approximately $2.4 million has previously been appropriated for feasibility, licensing, and design in 1981 and 1982.

The project as proposed was planned to serve the utilities in the villages of Craig, Klawock, and Hydaburg. Recently, requests have been made to also interconnect the project to serve Thorne Bay, Hollis, and a new U.S. Forest Service camp proposed at Polk Inlet on the island. As with most hydroelectric projects under development in Alaska, the near-term energy costs of the Black Bear project may have to be subsidized or debt service payments restructured to market the power. The extent of such subsidy or other financing assistance will be highly sensitive to the electrical loads served by the project. Since the Black Bear project is projected to be capable of providing more energy than the villages of Craig, Klawock, and Hydaburg are expected to require in the early years, the addition of other communities to the system served by the project could significantly impact project revenue, and therefore affect the amount of state financial assistance required.

The potential for including Thorne Bay and Hollis was considered preliminarily in the previous studies conducted for the

Black Bear project. At that time, the costs of interconnection were considered to be in excess of the benefits gained from increasing the load growth served by the project. Recent changes in population growth at Thorne Bay due to federal land transfers has changed the conditions from those existing when the studies were previously conducted. The Authority currently plans to review the feasibility of interconnecting Thorne Bay and Polk Inlet in early 1983.

The impact of adding Thorne Bay and Polk Inlet to the area served by the project is unknown. It is possible, however, that the addition could impact overall project economics such that the financing arrangements (the amount of State funding needed to make the project power marketable in the early years of operation) may differ depending upon whether these loads are served by the project. The impact of such revisions to planning assumptions must be considered as part of the final authorization process and as part of the selection of a financing plan if the changes significantly impact project economics.

Galena Reconnaisance Study

As part of the Authority's Village Energy Reconnaissance Program, a reconnaissance-level analysis of electrical and thermal energy demands and supply alternatives was conducted for the Village of Galena. This study is another example of the importance of considering opportunities for interconnection early in power supply planning.

Galena is a village with a population of approximately 805 people located on the Yukon River about 270 air miles west of Fairbanks. Electrical energy is provided by a private utility company with a total diesel electrical capacity of 635 kw. The U.S. Air Force Base at Galena supplies its own electric power from four diesel units with a total capacity of 2,000 kw. Peak demand for the private utility system is 300 kw and the Air Force Base peak demand is approximately 970 kw. Based on 1980 annual energy use data, the private system produced 1,000 MWh of energy for the village and the Air Force produced approximately 6,000 MWh of electrical energy for the base.

Summary of Study Results

The Galena reconnaissance study of electric power supply alternatives was based on a forecast of the village energy needs only. The Air Force Base requirements were assumed to be constant, but were not included in the total demand estimates used to evaluate alternative power supply projects for the village.27/ The peak power demand and the annual energy requirements of the village are projected to increase from approximately 300 kw to 850 kw and 1,100 MWh/yr to 3,000 MWh/yr, respectively, between 1982 and 2001 in the reconnaissance study .

The study estimated the present value life cycle cost of the following three alternative power supply plans to meet the Galena electrical power requirements during the period from 1982 through 2041.

Base Case

This plan is the continued use of a diesel-based central utility system with waste heat recovery to meet some local thermal energy requirements.

Alternative Plan A - Kalakaket Hydroelectric Project

This alternative involves developing a run-of-the-river hydroelectric project on Kalakaket Creek. The capacity of the project is not stated in the report, but its annual energy generation is estimated at 1,729 MWh. The plant would not operate from November through April due to "glaciering" of the river. Therefore the same diesel capacity additions projected for the base case are assumed to be required in this case to meet the winter peak demands and the winter energy requirements.

The hydroelectric project would produce more energy than than the village could utilize when it operates. The study therefore assumed any excess energy could be marketed to the Air Force Base.

Alternative B - Melozitna Hydroelectric Project

This alternative involves constructing a 20 MW or larger hydroelectric project on the Melozitna River to serve Galena and five other villages in the region. There was strong local preference for evaluation of such a project. To evaluate this project, the regional potential power requirements, including the Air Force Base at Galena, were projected. To compare the cost of this plan for Galena relative to the base case plan the total project costs were prorated on the basis of Galena's share of energy from the project.

The annual total power cost and power cost per kwh were estimated for each alternative and the present value life cycle cost of each alternative was calculated, producing the following results:

Alternative	60 year Present Value Life Cycle Cost
Base Case - Diesel Generation	$20,220,000
Alternative A - Kalakaket Hydro.	$22,463,000
Alternative B - Melozitna Hydro.	$46,263,000

Based on this analysis, the base case diesel generation with waste heat recovery was selected as the most economic alternative. The study indicated, however, that additional evaluation of the regional Melozitna project might be warranted. It was recommended that such a study focus on a more detailed analysis of regional power needs, the configuration and cost of the Melozitna Project and transmission interconnection opportunities and costs.

Alternative Planning Considerations

Preliminary consideration was given in the study to interconnecting the Galena Air Force Base utility system (2000 kw capacity with a 970 kw peak load) with the private utility's system which serves Galena (635 kw system with a 300 kw peak load). This option was dismissed without any quantitative analysis due to uncertainties over the issues associated with power sale or exchange arrangements between a federally owned system and the privately owned system.

The evaluation of potential savings from interconnecting existing systems to share excess capacity, defer new capacity, and share in fuel efficiency gains is an alternative which can be evaluated in a reconnaisance study regardless of the availability of preferred renewable resource projects. In the case of Galena, the Air Force Base operates larger diesel generators than those serving Galena. To the extent the larger plants can be operated nearer to their rated capacity, it is likely that fuel efficiency would increase, as compared to operating the base's plants at lower output and operating the smaller private utility's equipment at partial output.

Perhaps a more significant consideration is that the combined capacity of the Air Force Base plant and the private utility's system is 2,635 kw and the combined peak demand (assuming the peaks for both systems would be simultaneous) is currently 1270 kw. If the back-up generators from the local school and other private generators were added, the excess reserve capacity is even greater. Combining these generating facilities into an interconnected system would likely defer capacity additions for several years.

As a specific example, the proposed expansion plan described in the report calls for a new 440 kw unit to be added in 1986 at a 1981 cost of $352,000. Interconnection might result in elimination or substantial deferment of this requirement. The costs of interconnection, the operating characteristics of the two utilities, the fuel efficiency of the respective power plants and the respective load growth of the Base and the Village would have to be evaluated to determine the relative economics of this option as compared to continued isolated operation of the two systems.

The purpose of this review is to emphasize that if the power supply planning process is oriented towards evaluating and developing new generation projects, then lower cost modifications to existing systems to increase operating efficiency through interconnection may be overlooked. Furthermore, if such options are not evaluated early in the process--at the reconaissance level--it is likely that the concept will not receive attention later, even when no other options are found to be superior to continuation of the status quo.

It should be noted that the opportunities for interconnection of electrical loads which are currently isolated are not necessarily widespread in Alaska. Small villages in isolated areas have few opportunities for interconnection. Furthermore, it is common for bush communities to be reluctant to accept the idea of interconnection to a "central utility system" since the solitude of bush community living is one of the factors which draws people to the bush. Therefore, in many cases, the issue of interconnection options may be academic. However, for communities where power costs are of vital concern, and where local economic growth is considered a desirable (if not achievable) goal, the prospects for interconnection should not be discounted without explicit consideration of such alternatives.

Where interconnection opportunities have been preliminarily evaluated and dropped during reconnaissance studies, it would be helpful to fully document the assumptions used to make such a recommendation to allow for future reference if conditions change or the issue is raised during the authorization process. The Authority's recent efforts to reevaluate interconnection opportunities in situations such as the Black Bear project appear to be steps in this direction.

SECTION 4

REVIEW AND ASSESSMENT OF WHOLESALE POWER RATE STRUCTURE

INTRODUCTION

This section of the report provides the results of our work under Task 4.0. This work addressed issues and alternatives relating to the efficiency and equity of the present rate structure. Our approach to this work utilized the present rate structure provided under HB 9 as a base case. Our evaluation of the present rate structure, as well as the previous rate structure provided under SB 25, was made on the basis of the following criteria:

- Efficiency in providing a stable flow of revenues sufficient to cover costs over a relevant range of variations in load
- Consistency with conservation goals
- Consistency with policy goals other than conservation
- Equity in the distribution of costs
- Equity in the distribution of benefits of State funding

In addition we have considered the potential impact of the HB 9 rate structure on the Authority's financing as well as the more general question of financing considerations in establishing the wholesale power rate structure.

GENERAL PRINCIPLES FOR WHOLESALE POWER RATES

The bulk of the general literature on the subject of electric utility rates is dedicated to retail rates for sales to the ultimate consumer as opposed to wholesale rates. Rates established by the Authority pursuant to the rate directives provided by the Alaska Legislature are not, in themselves, utilized in the billing of ultimate or retail customers. Rather, the Authority's rates form the basis of billings to its utility customers. The cost of power purchased by those utility customers becomes one component of the total cost which must be recovered through retail rates.

For the most part, wholesale rates of electrical utilities are under the jurisdiction of the Federal Energy Regulatory Commission (FERC), a federal agency. The notable exceptions to this are the rates of publicly owned utilities or public agencies which market the power at wholesale. Statutory rate directives governing wholesale rates under the FERC jurisdiction are provided primarily by the Federal Power Act (16 U.S.C. 791 et seq.).

The basic principles governing the establishment of rates and charges subject to the FERC jurisdiction are as follows:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful. (16 U.S.C 824d(a))

> No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service. (16 U.S.C. 824 d(b))

The two most important rate directives provided by the Federal Power Act which have generally guided the FERC's review of wholesale power and wheeling rates are, therefore, that they be based on the cost of providing service and that they be non-discriminatory.

Over the years, the Federal Government, through the U. S. Army Corps of Engineers (Corps) and the Bureau of Reclamation of the Department of Interior (Bureau) have constructed a number of hydroelectric generating facilities. For the most part, these have been part of multipurpose projects primarily constructed for flood control, reclamation and irrigation purposes. Power from these projects is marketed by federal power marketing agencies (FPMA) within the Department of Energy.

Rate directives governing the establishment of rates for the sale of federal power which is surplus to the requirements of the projects from which it is generated have been provided by Congress both in statutes relating to the projects and in those creating Bonneville Power Administration, the largest of the FPMA.

The language of these rate directives generally provides for the disposition of federal power in such a manner as to encourage the most widespread use at the lowest possible rates to consumers consistent with sound business principles. The other most common language in the several statutes provides that rate schedules shall be drawn having regard to the recovery of cost of producing and transmitting electric energy, including the amortization of the capital investment allocated to power over a reasonable period of years.

Although the words of the Federal Power Act which govern wholesale rates of utilities regulated by the FERC are slightly different than those of the statutes that provide rate directives for the disposition of federal power, they both mandate that rates should be based on cost.

It is noted that the general rate directive language of the statutes relating to the Authority is very similar to that contained in the federal statutes. Neither SB 25 nor HB 9 changed the language that provided "the Authority . . . shall sell the power or cause the power to be sold at the lowest reasonable prices which cover the full cost of the electricity or service . . ." (AS 44.83.090). In plain language, this provides a cost based rate standard.

Although, as previously discussed, most of the literature on the subject of rates pertains to retail rates, several principles certainly have application to wholesale rates. Bonbright in his Principles of Public Utility Rates, sets forth eight criteria of a "desirable rate structure". These are:

- The related, "practical" attributes of simplicity, understandability, public acceptability and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirements.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to customers.
- Fairness of the specific rates and the apportionment of total costs of service among the different customers.
- Avoidance of undue discrimination in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service and in the control of the relative use of alternative types of service (on-peak versus off-peak).

In addition to the considerations of equity and cost recovery, it has always been recognized that utility rates must be developed on a basis that is consistent with established public policy. This is particularly true in the case of rates for a publicly owned utility.

In any consideration of utility rates, it is important to draw a distinction between rate level and rate structure. Rate level is governed by the total revenue requirement of the utility. This is the amount that must be raised or in the case of regulated utilities, the amount that is allowed to be raised, from rates. Rate structure, on the other hand, relates to the distribution of the revenue requirement between customer classes and individual customers within the same customer class. These are important policy considerations that must be addressed in rate directives provided by Legislatures.

EVOLUTION OF AUTHORITY WHOLESALE POWER RATES

Although not actually funded and staffed until 1978, the Authority was created in 1976 (SCS CSHB 779 Ch 278 SLA 1976) for the purpose of acquiring, financing, constructing and operating hydroelectric and fossil fuel generating projects.

Initial Rate Directives

HB 779 created the Authority in 1976. Included in its powers was authorization to enter into contracts for sale of power. The authorizing legislation established individual power rates for each project whose rate would provide power at the lowest possible price while covering the full cost of generation, capital and operation and maintenance charges, plus a fair cost of transmission.28/ Thus, each contract for the sale, transmission and distribution of power from a particular project was unique in that it was determined by factors specific to that project. Rates which were fixed initially in the contract could be "adjusted from time to time on the basis of true cost data."

Contracts to sell power were subject to review by the Alaska Public Utilities Comission (APUC) and this led to some confusion regarding rate setting jurisdiction.

1978 Amendments

The question of rate setting jurisdiction was settled by legislation enacted in 1978 (SCS CSHB 442 Ch 156 SLA 1978). This bill established that the Authority would not be subject to the jurisdiction of the APUC, and that the Authority likewise would have no jurisdiction over the services or rates of any public utility within the domain of the APUC.

In addition, the 1978 legislation modified the requirements concerning power sales contracts. It mandated that the Authority provide a method by which municipal electric, rural electric, cooperative electric, or private electric utilities and regional electric authorities could secure a reasonable share of power generated by a power project, or any interest in a project. Furthermore, it stated that "power shall . . . be sold at the lowest reasonable prices which cover the full cost of the electricity or services." 29/

SB 25 Amendments

In 1981 the Legislature made significant changes in statutes governing the Authority (FCCSSB 25 CH 118 SLA 1981). SB 25 created the Energy Program for Alaska (Energy Program) and made significant changes in the wholesale power rate structure for projects which were included in that program. Individual power rates for each project were replaced with a single wholesale power rate. This applied to all projects which were acquired or constructed as part of the Energy Program and funded by appropriations from the Power Development Fund.

The rate, applicable at the busbar of the power project, was to be computed by the Authority annually and was to equal the rate estimated to produce revenue that would be sufficient to pay operation, maintenance, and equipment replacement costs; plus debt service; plus monitoring expenses incurred on all of its power projects. It also specified the terms and conditions of power sales leases.

The rate language provided certain consequences if the legislature did not appropriate at least $5 billion to the Power Development Fund by 1986. (This provision has become known as the "Susitna Blackmail Clause" because it did not specifically require the Legislature to appropriate funds, which would be unconstitutional, but it did specify what would happen if it did not.) If this was not done, the ensuing wholesale rate, beginning in 1986, was to be: the greater of 10 percent of the amount the Authority had invested in the power projects or the rate estimated as necessary to produce revenue sufficient to cover project costs as described above. Lastly, this bill stipulated that the Legislature may, by law, annul or change the Authority's wholesale power rate for sales of power.

1982 Proposed Changes

Early in 1982, two bills to amend SB 25 were introduced. HB 655 was introduced in January at the request of the Governor. In March, the Resources Committee offered a substitute bill (CSHB 758). Both contained language which would have altered wholesale power rate structure in Alaska. The following description of the 1982 proposed changes is presented in a summary form which highlights key aspects of these bills. A more technical account is provided in Appendix 4-A.

HB 655 proposed to change the statewide wholesale power rate, provide an adjustment mechanism when miscalculations were discovered, create a new fund for the Authority, and utilize an alternative formula for determining the return to the State on its investment.

Under HB 655 the single statewide wholesale power rate would have been replaced and each project would have had its own rate. The wholesale power rate would have been calculated based on project costs identical to those of SB 25, except that rates could have been influenced by loan repayment obligations for those projects that used the Power Project Emergency Maintenance Fund (which this bill would have created).

Furthermore, this bill would have removed the "Susitna Blackmail Clause" entirely. It proposed a method whereby the State would have been repaid the entire initial investment in equal installments through yearly rate increases over a 33 1/3 year period with each period's principal adjusted for inflation. The amount repaid to the State would have been escalated by a factor of 1.0 plus the rate of inflation (calculated as the average rate of inflation over the preceding 33 years). This procedure would have resulted in the State being repaid its investment in dollars of equal purchasing power. This bill differed from SB 25 in that it would have required repayment of the State's investment.

CSHB 758 (HB 758) concentrated its rate reform proposals on three major areas: rate structures; the relationship, and procedures for the Authority and the APUC; and the method by which the return to the State would have been calculated.

Like HB 655, HB 758 would have required that a separate wholesale power rate be established for each power project. Both bills would have included the same components for calculating the wholesale power rate, except where the return to the State was concerned.

The area which this legislation dealt with was the method and timing of repayment to the State of its capital investment in power projects under the Energy Program. Like HB 655, this bill would have deleted the "Susitna Blackmail Clause" and provided a repayment schedule for money contributed by the State. However, under this proposal, the repayment period would have been 33 1/3 years or a period equal to 3/4 of the life of the project, whichever was less.

HB 758 would have calculated the inflation rate differently and applied it to more items than HB 655. This bill would have directed the Authority to consider inflation over two different time horizons, near and long term, and to use the lesser of the two in insure that the value, in terms of "purchasing power" of the State's capital outlay was preserved over the repayment period.

This bill also attempted to compensate for inflation's effect on the wholesale power rate over time. The inflation rate applicable would have been calculated as outlined previously and the yearly payment adjusted accordingly. However, this bill also would have escalated the wholesale power rate itself once every ten years, to "catch up" in a sense.

One unique provision of HB 758 was that it would have provided a consumer rate structure consisting of at least three rates. The utility would have been expected to implement an "inverted" rate schedule at the retail level, with the lowest rate being an "equity rate". This change in rate structures would have necessitated the APUC's intervention in the rate setting process so that they could hold public hearings before rates were changed.

Finally, both HB 655 and HB 758, like SB 25, would have allowed the Legislature to annul or change the wholesale power rate by law.

HB 9 Amendments

CCSHB 9 (CH 133 SLA 1982), which evolved as a compromise to HB 655 and HB 758 was enacted in May 1982, and had a significant effect on wholesale power rate structure. The major areas changed by this legislation were in the type of wholesale rate, and in the debt service share of each project.

HB 9 replaced the single wholesale power rate established in SB 25 with an individual rate for each project to be based on O & M and inspection costs, plus the individual project's proportionate share of the debt service on State bonds and loans for all power projects in the Energy Program. The wholesale power rate was to be computed annually by the Authority, but it could be calculated more frequently if necessary.

Under this bill, transmission interties are also allowed to have individual rate structures. This provision was included to prevent high-priced interties from pricing themselves out of use in higher priced utility service areas. This bill also included a clause which made allowances for interties that cease to function as separate projects. If the Authority determined that an intertie had effectively become a part of another power project, its special status as an intertie with its own rate would be terminated.

Unlike HB 655 or HB 758, HB 9 maintained the provisions of the "Susitna Blackmail Clause" described earlier. What it did add, however, was a clause whereby the debt service on State loans and bonds for all projects in the Energy Program is allocated to each power project on the basis of its "proportionate share" of that debt service. The proportionate share is equal to the State's investment in the particular power project divided by the State's investment in all power projects in the Energy Program for Alaska and multiplied by the debt service on State loans and bonds for all power projects in the program. The basic intent was to spread the State investment for power projects more equitably among projects. This arrangement appeared to be more equitable than totally separate rate structures because the formula accounted for project size and construction efficiency in that it considered the total cost of each project relative to the total cost of the power system when allocating debt service shares.

"To prevent power rates for some projects (primarily Swan Lake and Lake Tyee) from escalating to excessive levels under this rate structure, a limit or cap was placed on the debt service share for projects underway before the effective date of HB 9. The level of the cap increases by four percent per year to account for the increased utilization (power sales) of the power projects."30/

As explained in the Letter of Intent on Conference CS for HB 9 (Senate Journal, May 31, 1982):

> Subsection (h) of section 16 provides for the phasing-in of a project's payment of its proportionate share of all power project debt service. The Legislature intends, in establishing this "cap" formula, that the weighted average share of debt service be computed by dividing the total annual debt service of all projects in the energy program for Alaska by the total annual electricity sales. An eligible project's share is then annually raised by 4% above the average until it reaches its actual share under the system described in (g), at which point the "cap" for that project terminates. Thus, in FY 1984, no eligible project would pay more than 104% of the average share; in FY 1985, no eligible project would pay more than 108% of the average share; and so forth. The "cap" assures that the allocation of debt service among projects does not place an undue burden on those projects which were begun under the previous hydro financing system. Further, it is the Legislature's intent that the difference between an eligible project's share of the total debt service and the amount paid under the "cap" shall be made up by the shares paid by all other projects in the energy program for Alaska for which debt service is not limited under the "cap."31/

Finally, HB 9 provided that the Legislature may annul or change a wholesale power rate by law, but that if the Authority has entered into an agreement with bondholders to maintain or increase the rate, then that rate will remain in effect.

ANALYSIS OF AUTHORITY RATE DIRECTIVES

We have developed a comparative analysis of the significant provisions of, and actual rates that would be in effect under, the rate directives provided by SB 25, HB 655, HB 758, and HB 9.

Comparison of Rate Directive Provisions

A summary comparison of the rate directives under the above noted legislative bills is provided in Exhibit 4-1 on the following page.

Rate Form

SB 25 provided a "postage stamp" or uniform rate that would be calculated on the basis of the total costs and sales related to all Authority projects. Under HB 9, this was changed to a project specific rate. Both HB 655 and HB 758 would have provided project specific rates. Under HB 9, however, there is a limited equalization of debt service between projects which introduces a "flavor" of a uniform rate for all projects.

We understand that the change from the postage stamp rate to a project specific rate was influenced, at least in part, by the Legislature's concern that cost overruns on projects and relatively low utilization of the output would adversely affect the rates from previously constructed projects. In effect, this change was intended to provide an economic incentive with respect to both the capital cost of projects and project utilization.

Frequency of Calculation

All of the legislative directives have provided for annual calculation of rates from the Authority's projects. HB 9 did, however, add a provision that would allow recalculation of rates more frequently than annually, as may be necessary.

So long as the sale of energy from the projects is a relatively small portion of the potential average generation, revenue shortfalls should not be a problem. Once project sales and project generation capacity are more nearly equal, there may be situations, in dry years, when revenue shortfalls might occur. One solution to this problem would be an adjustment in rates once water conditions had been determined. There are, however, other approaches to this problem which are discussed later in this section of the report.

EXHIBIT 4-1

SUMMARY COMPARISON OF PROVISIONS OF ALASKA POWER AUTHORITY RATE DIRECTIVES

	SB 25	HB 655	HB 758	HB9
Rate Form				
Postage Stamp	X			
Project Specific		X	X	X
Frequency of Calculation				
Annually	X	X	X	X
"As May Be Necessary"				X
Rate Components				
O & M, Replacement, and Inspection Costs	X	X	X	X
Debt Service	X	X	X	X
Repayment of State Investment		X	X	
Procedure to Compensate for Rate Estimation Errors from Previous Year		X	X	
Power Project Emergency Maintenance Loans		X	X	
Separate Rates for Interties				X
Legislative Prerogatives				
Can Annul or Change Rate Without Restriction	X	X	X	
Constrained by Contracts with Bondholders				X
Other				
"Susitna Blackmail Clause"	X			X
Inflation Adjustments for:				
Wholesale Power Rate			X	
Repayment of State Investment		X	X	
Tiered Retail Power Rates			X	

Rate Components

The various components or categories of costs that make up the Authority's revenue requirement under the several legislative bills are discussed below.

O and M, Replacement and Inspection Costs

As would be expected, all of the legislation relating to the Authority's rates provides for recovery of these costs. A broad interpretation of O and M costs would indicate that they would also include that portion of the Authority's administrative and general costs that are applicable to operation of projects as opposed to planning and project development. This will become more of a factor as projects are completed and become operational. With respect to replacement costs, again a broad interpretation would indicate that a "formula" contribution to a renewal and replacement fund might be included in this component of revenue requirement. This point is discussed further later in this section of the report.

Debt Service

Again, all of the legislative bills provided for recovery of annual debt service which includes principal payments on outstanding Authority debt (as opposed to State grants for construction). However, the rate directives are silent on the question of any coverage of debt service that might be included. AS 44.83.425 does contain a definition of debt service that provides for "cash flow necessary to secure bonds." To the extent that debt service coverage is deemed "necessary" in bond covenants, this definition does not preclude the use or need of funds for debt service coverage. However, the absence of a specific directive creates some ambiguity. This point is also discussed later in this section of the report and in more detail in Section 6 under Authority financing.

It should be noted that total debt service is included as an Authority revenue requirement under HB 9, but a provision is made for a proportional allocation of debt service to individual projects with a cap. This has been discussed in some detail previously.

<u>Repayment of State Investment</u>

Only HB 655 and HB 758 had provisions whereby the State's investment in the form of grants in power projects would be repaid. Neither SB 25 nor HB 9 had such provisions, but they did include the so-called "Sustina Blackmail Clause". If the clause was "triggered", rates might exceed the level required for operation and maintenance costs and debt service. No specific language was added specifying that those "excess funds" would flow back to the State as a repayment of their investment, but it was assumed that those revenues would be deposited in the General Fund. This is discussed in greater detail under the "Susitna Blackmail Clause", in the "Other Rate Directives" section following.

<u>Procedure to Compensate for Rate Estimation Errors</u>

Again, HB 655 and HB 758 provided a procedure to compensate for rate estimation errors from the previous year. No such provision was provided in either SB 25 or HB 9.

<u>Power Project Emergency Maintenance Fund Loans</u>

HB 655 and HB 758 provided a mechanism for the loan of funds required for emergency maintenance. The "Power Project Emergency Maintenance Fund" was to consist of money appropriated by the Legislature. (This subject is discussed in connection with interim replacements later in this section of the report.) No similar provision is explicitly provided under HB 9 nor was it provided under SB 25. However, the Authority is able to obtain loans from independent sources to cover emergency situations under the "Powers of the Authority" provisions (AS 44.83.080 (8) and (14)) of current legislation.32/

Separate Rates for Interties

HB 9 specifically provides that a separate rate, distinct from the rate for any power project, can be established for interties. We have concluded that what the Legislature had in mind, specifically, was the Anchorage-Fairbanks intertie. We believe that such a provision is very appropriate in that transactions beyond the delivery of power generated from projects developed by the Authority will take place on interties. Establishing a specific rate for wheeling service on the intertie will facilitate such transactions.

Legislative Prerogatives

Under SB 25, HB 655, and HB 758 the Legislature reserved unto itself the prerogative of annulling or changing a rate established by the Authority without any restriction. Under HB 9, although this authority continues, the Legislature recognized that it would have to be constrained by any covenants or contracts with bondholders made in connection with the issuance of Authority revenue bonds or other debt instruments.

Other Rate Directives

Other rate directives provided by these four pieces of legislation are discussed below.

"Susitna Blackmail Clause"

As previously discussed, SB 25 and HB 9 both contain provisions that would increase the rates to all projects if at least $5 billion is not appropriated to the Power Development Fund by 1986. In such an event, the level of rates from the Authority's other projects would be set at a minimum of at least 10% of the total investment of the State in those projects. In both cases, the legislation was silent on the disposition of any surplus funds that might be generated from a higher rate calculated on the basis of 10% of the investment in projects. However, it seems realistic to assume that the excess funds (those above O & M and debt service costs) received would be deposited to the General Fund. Constitutional prohibitions against dedicated funds ensure that receipts not otherwise pledged (this provision applies to bondholder trust funds and power sales receipts) are returned to the General Fund. Furthermore, to deposit power sales receipts which are in excess of bondholder covenants in the Power Development Fund requires an appropriation from the Legislature.

Inflation Adjustments

HB 758 specifically provided for escalation of the wholesale power rate on the basis of inflation. HB 655 and HB 758 provided for escalation of repayment to the State to assure that the dollars returned to the State would have the same purchasing power as those invested originally in the power projects.

Tiered Retail Power Rates

HB 758 provided that, as a condition of obtaining power from Authority projects, utilities would be required to put into place a tiered or inverted retail power rate. This provision was not, however, contained in any of the other legislation. We would observe that the Alaska Public Utilities Commission, which has jurisdiction over the retail rates of most utilities in the State, also operates under the control of the Legislature. If the Legislature wishes to implement such a policy, it could be done more directly through the statutes it enacts with the APUC.

COMPARISON OF RATES UNDER AUTHORITY RATE DIRECTIVES

We have calculated rates for four major projects presently under construction under the rate directives provided by SB 25, HB 655, HB 758, and HB 9 for the years 1985 and 1990. The results of this work are shown on Exhibit 4-2 on the following page. In order that this comparison could be made on a "apples and apples" basis, it has been necessary to make certain simplifying assumptions. These assumptions are summarized on Exhibit 4-3.

For the most part, the data shown on Exhibit 4-3 has been obtained from the Authority's budget documents. We have, however, made one adjustment which relates to providing 10% coverage on debt service. The subject of debt service coverage is discussed in some detail in Section 6 of the report covering Authority financing.

The rate comparisons have been developed on the basis of four cases:

- Case A - Individual rates for each of the four projects on the basis that no other projects existed.
- Case B - Rates for Solomon and Terror
- Case C - Rates for Solomon, Swan, and Terror
- Case D - Rates for Solomon, Swan, Terror, and Tyee

SB 25 Rates

SB 25 provided a postage stamp or uniform rate for all of the Authority's projects. Under Case A the individual rate that would be applicable to each project has been calculated and can serve as a basis of the impact of the uniform rate on the individual rates for each of the projects. It will be noted that under Case A the SB 25 and HB 9 rates are identical.

The remaining rates shown for SB 25 increase successively under Cases B, C, and D as additional projects are added. The 1990 rate which would result from the provisions of the "Susitna Blackmail Clause" is also shown on Exhibit 4-2 under "Susitna Rate 1990."

EXHIBIT 4-2

COMPARISON OF RATES UNDER ALASKA POWER AUTHORITY RATE DIRECTIVES
(cents per KWh)

	SB 25			HB 655/758		HB 9 w/o cap		HB 9 w/cap				
			"Susitna Rate"							"Susitna Rate"	Based on Avg. Generation	
	1985	1990	1990	1985	1990	1985	1990	1985	1990	1990	1985	1990
CASE A												
Solomon	3.10	4.34	12.93	7.37	9.80	3.10	4.34	3.10	4.34	12.93	2.36	3.31
Swan	17.93	15.08	22.79	27.08	24.24	17.93	15.08	17.93	15.08	22.79	6.72	7.20
Terror	18.67	16.18	19.48	26.28	24.40	18.66	16.18	18.66	16.18	19.48	11.79	12.07
Tyee	26.47	18.45	24.09	37.53	27.67	26.47	18.45	26.47	18.45	24.09	6.05	6.45
CASE B												
Solomon	13.73	12.84	17.63	7.37	9.80	10.91	12.15	13.02	12.15	12.93	8.69	9.25
Terror	13.73	12.84	17.63	26.28	24.40	15.03	13.11	14.05	13.11	19.48	9.34	9.78
CASE C												
Solomon	14.56	13.32	18.76	7.37	9.80	10.58	11.82	12.70	11.82	12.93	8.60	8.99
Swan	14.56	13.32	18.76	27.08	24.24	20.02	16.71	16.73	16.71	22.79	8.12	7.99
Terror	14.56	13.32	18.76	26.28	24.40	14.43	12.60	14.64	12.60	19.48	8.52	9.40
CASE D												
Solomon	16.45	14.35	19.83	7.37	9.80	10.64	11.88	13.02	11.88	12.93	8.93	9.11
Swan	16.45	14.35	19.83	27.08	24.24	20.18	16.84	18.38	16.84	22.79	8.26	8.12
Terror	16.45	14.35	19.83	26.28	24.40	14.56	12.70	16.29	12.70	19.48	7.76	9.35
Tyee	16.45	14.35	19.83	37.53	27.67	25.85	18.04	19.51	18.04	24.09	6.62	6.36

EXHIBIT 4-3

SUMMARY OF ASSUMPTIONS FOR RATE COMPARISONS

	PROJECT			
	Solomon	Swan	Terror	Tyee
Date of Completion (FY)	1982	1983	1985	1984
Installed Capacity (KW)	12,000	22,000	20,000	20,000
Average Annual Generation (MWh)	53,872	85,400	139,700	133,000
Capital Cost ($000)				
Debt Financing	0	35,000	115,000	50,000
State Grants	53,000	58,000	88,000	62,000
Total	53,000	93,000	203,000	112,000
Proportional Debt Share Under HB9 ($000)	3,093	5,429	11,850	6,538
33-year Average Rate of Inflation	5%	5%	5%	5%
Annual Costs ($000)				
Operation and Maintenance				
1985	1,270	1,028	990	1,320
1990	1,781	1,442	1,388	1,851
Debt Service				
Actual	0	4,281	14,066	6,116
Coverage	0	428	1,407	612
Total	0	4,709	15,473	6,728
Projected Sales (MWh)				
1985	41,000	32,000	88,200	30,400
1990	41,000	40,800	104,200	46,500

HB 655/758 Rates

The rates under HB 655 and 758 are identical in the first 10 years of project operation. If rates had been calculated for a year in the second decade of project life, they would have been higher under HB 758 because of the escalation provisions of the rate directives provided by that legislation (HB 758 escalates the wholesale power rate <u>and</u> the debt service by the appropriate factor).

As will be noted, the rates do not vary for the individual projects under the four cases. This is because both of these pieces of legislation provided for a project specific rate that would not have been impacted by the level of costs of any other project.

HB 9 Rates

HB 9 rates were calculated, on the basis of sales forecasts contained in Exhibit 4-3, both with and without the effect of the cap provisions provided by this legislation. We have also calculated a 1990 rate reflecting the provisions of "Susitna Blackmail Clause" (see "Susitna Rate" in table). In addition, we have calculated rates under HB 9 reflecting the effect of the cap provision based on full utilization of average generation for both 1985 and 1990.

Looking first at 1985, it will be noted that the operation of the cap provision results in increases in the rates for both Solomon and Terror, but decreases for Swan and Tyee. In 1990, however, the cap has no effect. The reason for this is that by 1990, sales on the all of the projects except Solomon have increased at a rate that exceeds the escalation rate assumed for operation and maintenance expenses.

With respect to the "Susitna Blackmail Clause", in 1990, based on sales projections, all of the projects would have higher rates if this provision becomes operational.

When the rates are calculated on the basis of average generation or of full utilization of project output, the effect is rather dramatic. Under Cases B, C, and D, rates fall below 10 cents per kwh for each of the projects in both 1985 and 1990. This highlights the importance of full utilization or a level of utilization that approaches the capacity of hydroelectric projects as soon as possible after their completion.

EVALUATION OF THE AUTHORITY'S RATE STRUCTURE

As previously discussed, we have evaluated the Authority's rate structure on the basis of four criteria:

- Efficiency in providing a stable flow of revenue sufficient to cover costs over a relevant range of variations in load
- Consistency with conservation goals
- Consistency with policy goals other than conservation
- Equity in the distribution of costs
- Equity in the distribution of benefits of State funding

The results of this evaluation are discussed below.

Revenue Stability

In developing any utility's rate structure, a major concern must be the efficiency of rates in providing a stable flow of revenue sufficient to cover costs over a relevant range of variations in load. This is more commonly referred to as "revenue stability".

The problem of revenue stability is of particular concern in the structuring of rates primarily involving hydroelectric generation. First, almost all costs associated with hydroelectric generation are fixed. That is, the annual revenue requirement associated with a hydroelectric generating facility does not vary in any significant amount on the basis of the number of kilowatt hours generated. This, coupled with the fact that the level of stream flows, and therefore the potential generation, is a function of the amount of rainfall or snowfall that occur during the course of the year, provides a potentially serious revenue stability problem. If the output of hydroelectric projects are fully sold or committed and such sales or commitments are based on average stream flow conditions there will be a revenue shortfall during dry years.

There are a number of ways that this potential revenue shortfall can be mitigated. The most effective might be to establish rates on the basis of installed capacity, as opposed to energy, and structure the charge such that purchasers pay on the basis of entitlement to capacity at a fixed rate per kw (as opposed to kwh). Although it would be possible to design a rate to be charged on a per kwh basis which would cover the dry year contingency, a more effective approach is to deal with this potential problem contractually. This is the approach that the Authority has used.

Our comments with respect to rate stability pertain both to the HB 9 and SB 25 rate structures. In the setting of rates, it is necessary to project both costs and the level of production from a particular project, which is a function of the amount of water that will be available in the case of hydroelectric projects. If actual conditions vary from the projections and assumptions, either a revenue shortfall or excess revenue might result. The concern for revenue stability relates to the former. The most volatile factor relating to revenue stability is the amount of water available, which is beyond the control of the Authority or any other rate setting body. As indicated above, the Authority has chosen to deal with this problem contractually.

In the Authority's power sales contracts a mechanism is provided for adjustment of rates from particular projects based on the availability of water. It is our observation that this mechanism will provide a vehicle to assure adequate revenues in dry years. This would be true under either the HB 9 or the SB 25 rate structures and is the most efficient way to deal with this problem.

Conservation Considerations

The primary conservation concern with respect to rates is that rates not be subsidized to the point that cost effective conservation programs are not feasible. In other words, whether or not customers will undertake conservation depends on whether or not that conservation will be cost effective. With full knowledge, if the customer can save more in the electric bill than he spends on the conservation feature, a rational choice would be to implement the conservation feature. If rates are subsidized, there is a bias against some conservation programs.

We have previously discussed initiation of a more concentrated effort in the area of conservation, which would yield value in terms of the level of cost effectiveness for various conservation programs. This information will serve as a benchmark against which to measure whether or not it is prudent to subsidize electric rates to a level that might preclude the implementation of conservation, which would be in the best interest of the State and the utility's ratepayers. Even lacking this data, however, the level of rates that are projected for the several projects in which the Authority is involved, as well as the level of rates paid by ratepayers even after the effect of the Power Cost Assistance Program, is such that this will probably not be a consideration.

The concern for consistency between rates and conservation is one that is more directly applicable in the case of retail rates. These are the rates that the customer pays and are therefore the rates that influence the customer's decision.

Policy and Equity Considerations

Because of the fact that the Authority's rates are set on the basis of the rate directives provided by the Legislature, which are very specific with respect to the distribution of costs and benefits, the Authority's rates are not only consistent with policy, but are a vehicle for direct implementation of policy. There is some difference in the distribution of costs and benefits between the rate structure provided under SB 25 and that under HB 9. In the case of SB 25, a single rate would have been established for all projects. In other words, the costs of all projects would be totalled and the projected sales of those projects utilized to calculate a common or "postage-stamp" rate that would be applicable for all sales. The effect of this would be an equal distribution of the costs of projects, as well as the benefits of State funding contributions to those projects, and to all customers that would be served power generated from Authority projects.

HB 9 made a very significant change in this approach in that it mandated that each individual project would bear the annual operation and maintenance costs associated with it as well as the associated debt service. It did provide, however, that there would be a limited leveling of debt service subject to a cap whereby projects that had relatively high debt service costs would receive some subsidation from those with relatively low debt service costs. This reflects a modification of policy with respect to the distribution of benefits of State funding.

ALTERNATIVES FOR LEGISLATIVE DIRECTIVES GOVERNING THE AUTHORITY'S RATE STRUCTURE

As previously outlined, the Federal Government has, for the most part, preempted State regulation of wholesale power rates leaving to the states the regulation of retail rates for the sale of electricity within their own boundaires. Therefore, Alaska is somewhat unique in that the Authority is a State agency which markets power at wholesale, but which is under the control of the Legislature and Governor. Further, the State has invested substantial sums in the development of power projects, most recently under the Energy Program for Alaska.

Primarily for these reasons, the State's interest in the Authority's wholesale rate structure goes beyond the conventional concern that rates be established on a just and reasonable, or cost basis. The State, has a vested interest in all phases of power supply by reason of both its overall energy policy concerns and its participation in power project financing.

Rate Structure and Rate Level

As previously discussed, it is important to draw a distinction between rate structure and rate level. Rate level is governed by the total revenue requirement of the utility. This is the amount that must be raised, or in the case of regulated utilities the amount that is allowed to be raised from rates. Rate structure, on the other hand, relates to distribution of the revenue requirement between customer classes and individual customers within the same customer class. These are important policy considerations that must be addressed in the Authority's rate directives provided by the Legislature.

Rate Structure Considerations

In the case of the Authority, rate structure relates to the distribution of revenue requirement or costs between projects. Given the Legislature's directive under HB 9 that each project should bear its own operation and maintenance costs, the question becomes one of how debt service, explicitly, and the benefits of the State funding for project construction, implicitly, are distributed.

Present Rate Structure Directives

We believe that the requirement that each project bear its own operaton and maintenance cost is proper. This is entirely consistent with the body of statutory directives relating to rates at the federal and state level generally. To do anything else would be a clear subsidy from one set of ratepayers to another set of ratepayers.

With respect to the distribution of debt service and the benefits of State funding, this is clearly a policy question. From our review of legislation that has been both considered and enacted, it is obvious that the Legislature has devoted a great deal of time to this question.

Additional Rate Structure Considerations

We believe that the legislation that has been considered and that which has been adopted in recent years has provided an exploration of a wide range of alternatives with respect to the structuring of rates. There are, however, two additional areas that we believe should be considered.

The HB 9 wholesale power rate for each project is based on energy. In other words, it is a rate per kwh of energy delivered from a project. To put this in context, it must be realized that there are three rather distinct "products" that are produced from a hydroelectric generating facility:

- Firm energy
- Nonfirm energy
- Capacity

The wholesale power rate is designed on the basis of firm energy available from a project. HB 9 implicitly provides, however, that the rate be applied to both firm and nonfirm energy produced from a project. There is no provision in the HB 9 rate for a capacity component or for a separate wholesale capacity rate.

In most years there will be some amount of nonfirm or secondary energy available from Authority projects. This is energy that is in excess of that produced on a firm basis, based on historic water conditions. Under HB 9 this energy would have to be sold at the same rate as firm energy, although it is generally recognized that nonfirm energy is not the same quality of product as firm energy. This is the case because it is only sold on an "as, if and when available basis". In contrast, firm energy is, in effect, guaranteed to be available.

Under the HB 9 rate it is implicitly assumed that capacity follows energy in the sense that all energy sold from a project would be sold with the same capacity factor. Particularly in the Railbelt, different utilities may have different requirements for capacity and energy. In some cases there may even be a requirement or a market for capacity alone, without energy.

We believe that consideration should be given to providing a mechanism to allow for the sale of nonfirm or secondary energy and, perhaps, even firm energy that is surplus to the needs of all purchasers from a particular project. This would be sold at a rate less than the wholesale power rate. The market for this energy would most likely be fuel displacement. That is, utilities with transmission access to a project might purchase nonfirm energy, as it was available, to displace thermal generation. It is not uncommon that such transactions take place on some form of a "share of savings basis". In some cases the savings are split on a 50/50 basis between the buying and selling utilities; in other cases the selling utility takes a larger percentage, as high as 80 to 90% of the fuel savings. The advantage of this approach would be that additional revenues would be generated during times when the full output of a particular project could not be utilized by those utilities which had entered into power sales contracts with the Authority. This additional revenue would serve to reduce the level of the wholesale power rate paid by firm energy purchasers.

Likewise, we believe that consideration should be given to providing a mechanism to establish a capacity rate. Such a rate could be developed in one of several ways. For example, the basic wholesale power rate could be structured with separate capacity and energy components. Under this rate form, utilities would pay the Authority based on a combination of the maximum rate of delivery or capacity they utilized and the total amount of energy that they would take. Alternatively, a capacity rate could be developed that would be utilized for the sale of capacity only. That is, the wholesale power rate would continue to operate as envisioned by HB 9, but the capacity rate would be applied for transactions involving only capacity. For example, any surplus capacity, above that which would be sold under the wholesale power rate with energy, would be sold at the capacity rate.

Rate Level Considerations

Because the Authority sets its own rates without review by any regulatory body and because it plans to undertake a significant amount of revenue bond financing, it is important that it be provided with definitive directives as to the level of its rates.

Present Rate Level Directives

The Legislature has provided directives with respect to the level of the Authority's rates in all of the statutes under which the Authority has operated. This is discussed under the heading, "Evolution of Authority Wholesale Power Rates", earlier in this section of the report. The rate directives provided under HB 9 specifically set forth the components of the Authority's revenue requirment to be recovered through its wholesale power rates.

With respect to the Authority's total revenue required for all projects, these are:

- Operation and maintenance expenses
- Inspection costs
- Debt service on outstanding State bonds and loans.

The present statutory directives with respect to the level of rates, therefore, provide the Authority with revenues sufficient to meet the "ordinary" annual costs of all of its projects. There is, however, no explicit provision for setting the revenue requirement at a level sufficient to cover "extraordinary" costs, nor is there an explicit provision for the provision of any coverage on debt service.

Additional Revenue Requirement Considerations

A utility generally will include in its revenue requirements certain components beyond "ordinary" annual costs. These include:

- The balance of the Authority's administrative and general expenses which are not capitalized
- Depreciation

- An amount to provide funding for certain reserves
- An amount to provide some level of debt service coverage required in excess of the amounts included for depreciation

As the Authority undertakes operation of completed projects, either with its own personnel or under contract with local utilities, some portion of its administrative and general costs will be related to these projects. This will be different than in the past when its entire effort was devoted to planning and project development. As this evolves, it may be found appropriate to include these costs in rates. A broad definition of what comprises operation and maintenance costs would allow such a policy without additional legislation.

Under conventional utility accounting practices, interest on outstanding debt is considered an expense. The recovery of the capital cost of a project is generally accomplished, in the case of publicly owned utilities, through the inclusion of a depreciation cost component in the revenue requirement. However, this is a "non-cash" expense and it "flows through" to the balance available for debt service. Therefore, it is an amount that is included in the revenue requirement that is available for the principal component of debt service and debt service coverage. The latter is discussed below.

Because of the Authority's intended utilization of revenue bond financing with its attendant requirement for the production of accounting statements on an enterprise basis, a depreciation cost component will probably have to be included in the revenue requirement, or at least displayed in financial statements. It is emphasized, however, that this will not impact the level of rates in that the principal component of debt service must be recovered and there will have to be some debt service coverage included in the revenue requirement.

It is common for utilities to include in their revenue requirements funding for the creation and maintenance of certain reserve accounts. In the case of Authority, some of these requirements have been met through legislative appropriation. However, one reserve fund that is directly related to individual projects is that for renewals and replacements. In the ordinary operation of a project from year to year, certain pieces of equipment and apparatus require major maintenance or even replacement before the project reaches the end of its useful life. However, these expenditures do not necessarily flow smoothly from year to year. Creation of a renewal and replacement fund assures the availability of adequate funds to meet these requirements as they occur. If this fund is provided from the revenues of individual projects, then the costs are born by the beneficiaries of those projects.

We believe that a broad interpretation of the operation and maintenance expense category would allow the inclusion of an amount, each year, to maintain a renewal and replacement fund. Our experience indicates that utilities with substantial hydroelectric generation have utilized a formula that is based on providing 1/20 of the balances in the capital accounts covering equipment (FERC accounts 333-turbine generator, 330-accessory electrical equipment, 335-miscellaneous power equipment, and 353-electrical station equipment).

If such a practice were adopted, the amounts in the renewal and replacement fund would be restricted for use in repair and replacement expenditures above normal maintenance costs related to the particular project for which the fund is established. The Authority may find, however, that all of the projects would benefit if it would pool the renewal and replacement funds to assure that adequate funds were available in the early years. A separate accounting could be kept to maintain the balances of the individual projects in the pooled fund.

We have previously discussed the subject of debt service coverage and additional discussion is provided in Section 5. All utilities that utilize revenue bond financing covenant to provide some amount of revenue above the absolute amount required for debt service. As is discussed elsewhere, there is every indication that this will be required for the Authority and therefore it can be expected that the revenue requirement will have to reflect this.

In discussions with Authority staff and consultants, the opinion has been expressed that the language of HB 9, with respect to debt service, would allow such a practice. Arguably however, it might be appropriate for the Legislature to explicitly set forth the Authority's responsibility to provide debt service coverage.

POWER SALES CONTRACTS

Earlier in this section and elsewhere in this report we have made reference to, or discussed, power sales contracts. We have had the opportunity to review both those power sales contracts that have been executed and drafts of power sales contracts that are currently being negotiated. With respect to the latter, we have provided detailed comments to the Authority's Counsel on the latest draft. A copy of these has been sent to the Study Manager.

An important issue is the timing of execution of power sales contracts. Almost without exception, power sales contracts covering projects in the lower 48 states are executed before any financing is undertaken. Generally, this would coincide with the determination of project feasibility and the initiation of project design.

It is our observation that there is reluctance on the part of utilities to execute power sales contracts for several reasons. Uncertainty as to what the cost of power from the project will be, both initially and over the long run, is one of their main concerns. The concern for the initial cost of power relates, at least in part, to uncertainty as to the total amount the Legislature will appropriate for the particular project. Over the longer run, there is concern that projects subsequently approved might increase power costs because of the debt service provisions of HB 9.

As a practical matter, power sales contracts will probably have to be executed before the Authority could undertake any long term financing utilizing revenue bonds. However, the Legislature may wish to consider the alternative of requiring power sales contracts to be in place before any significant State appropriations are made for design or construction of a project.

These subjects are discussed elsewhere in the report, but are set out separately here to assure that the importance of this issue is highlighted.

APPENDIX 4-A

1982 Proposed Changes In Rate Statutes

Early in 1982, two bills to amend SB 25 were introduced. HB 655 was introduced in January at the request of the Governor. In March, the Resources Committee offered a substitute bill (CSHB 758). Both contained language which would have altered wholesale power rate structure in Alaska.

HB 655 proposed to change the statewide wholesale power rate, provide an adjustment mechanism when miscalculations were discovered, create a new fund for the Authority, and utilize an alternative formula for determining the return to the State on its investment.

Under HB 655 the single statewide wholesale power rate would have been replaced and each project would have had its own rate. The Authority would have established, by regulation, a method for applying a wholesale power rate to various types of power projects. By regulation, the Authority would have also been required to establish a procedure for the adjustment of individual wholesale power rates to compensate for overestimates or underestimates in a previous year of program receipts or in the return due to the State from its investment in the power project.

Except for these regulated adjustments, the wholesale power rate would have been computed annually and set to provide receipts sufficient to pay operation, maintenance, and equipment replacement costs; including any repayments for loans from the Power Project Emergency Maintenance Fund (which this bill would have established in the Authority to bridge gaps when other appropriations were not available or were insufficient to cover these non-capital costs). Debt service on bonds issued and safety inspection and investigative costs would also have been components of the calculation.

Furthermore, this bill would have removed the so-called "Susitna Blackmail Clause" entirely. It proposed a method whereby the State would have been repaid the entire initial investment in equal installments through yearly rate increases over a 33 1/3 year period with each period's principal adjusted for inflation. This procedure would have resulted in the State being repaid its investment in dollars of equal purchasing power.

For the first year in which a wholesale power rate would have been in effect, the Authority would have determined the amount to be returned to the State by multiplying the State's investment in the power project by a factor of 0.03. For each subsequent year, the amount to be returned to the State would have been escalated by a factor of 1.0 plus the rate of inflation (calculated in the year the wholesale power rate was initially established and equal to the average of the preceding 33-year's rate of inflation based on the Federal Consumer Price Index). Every ten years the Authority would have recalculated the applicable escalation rate (for the 33-year period preceding the recalculation) and would have used it for the next 10-year period.

After 33 1/3 years, the amount to be returned to the State would have been zero, unless other State investments in that particular power project were made after the wholesale power rate was initially established. In that case, the additional return due to the State would have been determined separately in the manner described above. This amount would have been treated as an additional debt service cost for the project.

CSHB 758 (HB 758) concentrated its rate reform on three major areas: rate structures; the relationship between, and procedures for, the Authority and the APUC; and the method by which the return to the State would have been calculated.

Like HB 655, HB 758 would have required that a separate wholesale power rate be established for each power project. Both bills included the same components for calculating the wholesale power rate (including loans from the Power Project Emergency Maintenance Fund which would have been retained), except where the return to the State was concerned.

One provision which set HB 758 apart was that it would have provided for a consumer rate structure consisting of at least three rates. The utility would have designated the lowest rate as the "equity rate", and that would be the rate charged for the first 250 kilowatt hours of power used during a monthly billing period. In addition, the utility would have specified successively higher ranges of power usage to which successively higher charges would have applied. This would have provided what is commonly referred to as an "inverted" or "tiered" rate at the retail level.

This bill also would have changed the relationship between the individual utilities, the Authority, and the APUC. For example, utilities buying power from the Authority would have had to agree to incorporate tiered rate structures into their retail pricing schemes. In addition, before an affected utility could establish or amend their rate structure under the new requirements of this bill, the APUC would have had to conduct a public hearing within the utility's service area to explain the proposed action and its effect on rates.

Even though enactment of this bill would have complicated the working relationships between the parties involved, nothing in HB 758 would have affected the authority of the APUC under existing statutes (AS 42.05.361-42.05.441).

The third major area which this legislation would have dealt with was the method and timing of repayment to the State of its capital investment in power projects under the Energy Program. Like HB 655, this bill would have deleted the "Susitna Blackmail Clause" and provided a repayment schedule for money contributed by the State. However, under this proposal, the repayment period would have been 33 1/3 years or a period equal to 3/4 of the life of the project (as determined by the Authority), whichever was less. In other words, the typical thermal generating facility with a 30 to 35 year useful life would have repaid the State's investment over 22 1/2 to 26 1/4 years, while a hydro facility would have been allowed a maximum of 33 1/3 years.

Also, HB 758 would have calculated the inflation rate differently, and applied it to more items than HB 655. For the first year in which a wholesale power rate was to have been in effect, the Authority would have determined the amount to be returned to the State by dividing the State's investment in the power project by the appropriate repayment period. This calculation would have provided an equal payment stream to the State, but the first payment would not have been adjusted for inflation.

Initially, the inflation rate would have been calculated as the 33-year average of the Federal Consumer Price Index. This escalation factor (plus 1.0) would have been used in payback years two through nine and it would have been multiplied by the amount determined in the preceding year to establish that period's return to the State. Every ten years, the inflation rate would have been recalculated, and it is in this calculation that the two bills would have differed. HB 755 called for the Authority to calculate the average rate of inflation for the preceding 33-year and 10-year periods and to use whichever was less (plus 1.0) as the escalation factor (HB 655 would have used only the 33-year average). Thereafter, new escalation factors would have been used to preserve the State's repayment in constant dollars. This process would have continued until the final installment was paid, at which time the return due to the State would have been zero. (Additional State investment repayments due for funding received after the original wholesale power rate was established would have been treated the same as in HB 655.)

As described above, this bill would have directed the Authority to consider inflation over two different time horizons, near and long term, and to use the lesser of the two to ensure that the value, in terms of "purchasing power" of the State's capital outlay was preserved when being repaid over an extended period. (Note that the effect of inflation on cash flows during construction and up to completion was not accounted for in this formula because the wholesale power rate and the amount due the State were not calculated until the year that the project went on line.)

This bill also attempted to compensate for inflation's effect on the wholesale power rate over time. Specifically, "Every 10 years after the initial establishment of a wholesale power rate, the Authority shall calculate the average rate of inflation for the preceding 33-year period and increase the wholesale power rate by a percentage equal to the increase in the average rate of inflation for the preceding 33 years or the preceding 10 years, whichever is less." (section 44.83.398(f))

Both HB 655 and HB 758, like SB 25, would have allowed the Legislature to annul or change the wholesale power rate by law.

SECTION 5

REVIEW AND ASSESSMENT OF STATE FUNDING OF POWER PROJECTS

INTRODUCTION

The State of Alaska's direct participation in the funding of the costs of construction of power projects is not only unique among other states but has been the key to electrification of bush areas and the construction of hydro and other projects that will enhance service to the more populated areas of the State. State funding has been undertaken on a project-by-project basis, based on the availability of funds and project cost considerations.

Legislative appropriations for power project development have been made under several programs involving both the Authority and other State agencies. The major programs under which appropriations have been made include:

- Alaska Power Authority
  - Power Development Fund
  - Power Project Loan Fund
  - Rural Electrification Revolving Loan Fund
  - Legislative Grants for Power Development Projects
- Department of Administration
  - Electric Power Grants
- Department of Community and Regional Affairs
  - Legislative Grants for Bush Village Electrification

These programs are reviewed in Section 2 of the report. Because of the relative magnitude of the various programs, only the Power Development Fund is discussed further in this section.

ENERGY PROGRAM FOR ALASKA

Funding for projects included in the Energy Program for Alaska (Energy Program) has, since 1981, been provided through appropriations by the Legislature to the Power Development Fund. These appropriations provide funds for construction of projects identified through reconnaissance and feasibility studies and approved by the Legislature. Funds provided by the Legislature as loans, prior to iniation of the Energy Program, have been replaced by grants for those project involved in the Energy Program.

At the time the Energy Program was enacted, it was envisioned that the State might undertake total funding of power projects from oil and gas revenues. With the stabilization of oil prices and the resulting reduction in State revenue projections, this approach is no longer considered feasible. Therefore, projects included in the Energy Program, as a practical matter, will have to be funded from a combination of State revenue, under the Energy Program, and the proceeds of interim financing which will be replaced with long-term debt upon completion of the projects.

PROPOSED ENERGY RESOURCE FUND

After the 1982 session of the Legislature, the House Research Agency was requested to develop an approach involving a dedicated Energy Fund as an alternative to present State funding practices. A copy of their October 4, 1982 response to this request is included as Appendix 5-A. The major elements of the Energy Fund, as proposed, are summarized below.

- The Energy Fund will receive at least 25 percent of the State's royalty revenues for a fifteen year period, beginning in FY 86, the earliest full fiscal year in which the program would be in effect. This would amount to over $3.1 billion (1982 dollars) or approximately $7,856 per current resident. At the end of the fifteen-year period, the contribution rate into the Fund would be cut in half, in order to meet the objective of providing funds to keep pace only with population growth. The contribution rate and the duration of the initial period of full funding are subject to revision as revenue forecasts and cost estimates for the major projects change.

- The Fund would be housed in the Department of Commerce and Economic Development and administered by a six-member board. The Commissioner of Revenue would be responsible for investing the Fund.

- As deposits and interest earnings flow into the Fund, they would be allocated and would accrue to the accounts of energy management areas, on the basis of each area's population (computed for Municipal Revenue Sharing) for the previous year. The per capita distribution of funds would be adjusted for construction cost differentials in the different areas of the State. No area would be allowed to accrue its share of the Fund more quickly than another area.

- An energy management area could draw upon its account to construct an energy facility which would reduce the area's dependence on fossil fuels imported from outside the area <u>and</u> which had been approved by both the Energy Fund board of trustees and the area's voters.

- Local service area boards would operate these facilities, or could contract with the Alaska Power Authority for these services. The Alaska Power Authority would retain responsibility for reconnaissance and feasibility studies and project construction.

- In adition to financing construction of energy projects, Energy Fund entitlements could also be used to meet debt service on bonds issued by the area.

- First and second class boroughs would automatically become energy management areas, and their governments would become energy management boards. In areas outside these boroughs, the Commissioner of Community and Regional Affairs would designate area boundaries and elections would be held for each area's board.

- Two or more areas may jointly propose a project to the Fund's board for approval. For projects involving significant economies of scale, the board would be able to mandate a joint project involving two or more areas.

Discussion of Proposed Energy Resource Fund

The House Research Agency response identifies and discusses a number of issues relating to the proposal (Appendix 5-A, pages 3 - 9). It is suggested that this material be reviewed since it is not repeated here. Our discussion of the proposal is intended to supplement their work.

The decision of the State to directly participate in the funding of the costs of construction of power projects reflected a very basic and certainly a major policy decision. The proposal to establish a dedicated fund with earmarked revenues is likewise a major policy decision.

Clearly, there are public policy arguments against both a commitment of State funds to power plant development and the taking of the "next step", creation of a dedicated fund with earmarked revenues. We assume that these arguments will be presented and duly considered. Our discussion of the Proposal takes the decision for State participation in the funding of power projects as a given and focuses on the advantages and disadvantages of the Proposal for a dedicated energy fund with respect to its impact on the original State funding decision.

The Proposal embodies the creation of a dedicated energy fund, earmarking of revenues, and establishment of a multitiered structure to administer the dedicated fund, a methodology for allocation of funds, and a procedure for approval of projects in which funds would be invested. In effect, it provides a "stand alone system" for power projects that utilize State funding. The following comments are directed to these major features of the Proposal.

Dedicated Fund

The providing of a dedicated fund with earmarked revenues that would accrue balances over time would have some distinct advantages in the financing of power projects. One of the problems with the current method of State funding is the requirement that appropriations be made on an annual basis. This introduces uncertainty as to the continuation of appropriations and the ultimate total level of State participation in a particular project. A dedicated fund, assuming it was structured in a way that removed the prohibition against multiyear commitments, would provide for the allocation of a certain amount of money to a particular project which could be drawn down on the basis of that project's cash flow.

The advantages of this would be that any required debt financing could be scheduled with more certainty and that financing could be made on the basis of the committed State funds which would enhance marketability. Equally as important, with a known level of State funding for a particular project the cost of power from that project could more accurately be estimated. This would facilitate execution of power sales contracts.

We have no basis for comment on the adequacy of the level of the fund. It is noted that the Railbelt share would be approximately 50% of the requirements for Susitna financing through 1998 (1982 dollars). If the level of funding provided by the Proposal was determined to be inadequate at some future time, the State could supplement the amount either by increasing the percentage of royalty revenue earmarked to the fund, or by appropriations from other sources of revenue.

Administrative Structure

The Proposal envisions a statewide governing board as well as local boards for the individual energy management areas. In the case of first and second class boroughs, the existing government would serve as the energy management board.

The House Research Agency's analysis recognized this, both with respect to the exclusion of the executive and legislative branches and the participation of Authority in projects that might be constructed from the Energy Fund. Consideration should be given to whether or not the local input and independent control functions of the structure in the Proposal could be achieved within the existing governmental structure of the State. This might be accomplished through requirements for concurrence by local governmental entities with proposed projects and even a requirement that an advisory election be held within the service area of the project.

This alternative would leave with the Legislature and Governor the final decision on the expenditure of State funds for power projects. The Authority, then, would continue its work on reconnaissance and feasibility studies as well as the financing and construction of projects that were approved. The change here would be whatever requirements were imposed with respect to expressions of approval of projects from the areas that they would serve.

One other point, in this regard, is that the Proposal ignores the existence of utilities that serve the various areas of the State. If the Proposal is pursued, there will have to be some consideration given to how the utilities who will have to distribute power from projects constructed from the fund will fit into the program.

Allocation of Funds

The Proposal anticipates the allocation of funds to the several energy management areas would be made on the basis of population. Unfortunately, it is easier to criticize this aspect of the Proposal than it is to propose alternatives.

The House Research Agency has pointed out potential problems with this method of allocation. We agree that those they cite are, in fact, concerns. If a decision were made to stay within the existing administrative structure, consideration should also be given to not initially specifying how funds will be allocated. As time passes and the actual need for additional generating capacity becomes clearer and as projects are proposed to meet these needs more enlightened decisions can be made with respect to the most appropriate way to make the allocations from the fund. It might be found that continuation of the Power Cost Assistance Program in some more remote areas of the State would be a more efficient way to provide benefits to those areas than would additional capital investments from State sources of revenue. This is not to suggest that if after due consideration with full recognition of the shortcomings of an allocation on the basis of population that a decision might be made to proceed on this basis.

One other point with respect to the allocation of funds relates to their utilization to meet annual debt service costs. Since the greatest portion of debt service in early years is the interest component, the application of these funds for this purpose would not constitute an investment in power production facilities.

OTHER ALTERNATIVES

In discussions relating to State funding it is clear that a number of alternatives have been considered. It has been our observation that the benefits of State participation in power project financing would be enhanced if the level of participation in a particular project could be determined other than on an annual basis. This would facilitate development of financial plans and, more importantly, facilitate execution of power sales contracts at an earlier date. One alternative that would accomplish this would be to initiate multiyear appropriations.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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APPENDIX 5-A

October 4, 1982

MEMORANDUM

TO: Representative Eric Sutcliffe

FROM: Anne DeVries and Jack Kreinheder
Research Staff

RE: Proposed Energy Resource Fund -- Revised Draft
Research Request 82-156

You asked that the Agency develop your concept for an energy resource fund into a workable program which would finance energy projects on a statewide basis. You indicated that the fund should meet the following criteria:

- it should provide equity, measured by expenditures per capita, in State funding for energy projects;
- it should be sufficiently large to accommodate the State's expected contribution to all currently planned hydroelectric projects; and
- it should only finance projects which have received the approval of voters in the area served.

We have taken your initial framework and expanded it into the suggested legislation found in Attachments A and B. Within the body of this memorandum, we briefly outline the program and discuss potential issues which surround such a fund. During the course of our work, it became apparent that there are a number of factors on which we require further guidance from you; these are discussed in the text and in footnotes to the legislation.

To compile the suggested language, we have drawn from existing statutes regarding the Permanent Fund and the Alaska Coastal Management Program. In addition, the following individuals reviewed, at some stage, a draft of this proposed legislation: McKie Campbell, aide to Senator Gilman, regarding local government considerations; Milt Barker, Legislative Finance, on financial issues; Ron Lorenson, Deputy Attorney General, regarding the general concept and language; and Dick Bradley, Legal Services, also concerning language. Their comments have been incorporated in the legislation or noted in the text. As you indicate where changes are needed, we will work with Mr. Bradley in drafting revised language.

Outline of the Proposed Energy Fund

- The Energy Fund will receive at least 25 percent of the State's royalty revenues for a fifteen year period, beginning in FY 86, the earliest full fiscal year in which the program would be in effect. This would amount to over $3.1 billion (1982 dollars)[1] or approximately $7,856 per current resident. At the end of the fifteen-year period, the contribution rate into the Fund would be cut in half, in order to meet your objective of providing funds to keep pace only with population growth. The contribution rate and the duration of the initial period of full funding are subject to revision as revenue forecasts and cost estimates for the major projects change.[2]

- The Fund would be housed in the Department of Commerce and Economic Development and administered by a six-member board. The Commissioner of Revenue would be responsible for investing the Fund.

- As deposits and interest earnings flow into the Fund, they would be allocated and would accrue to the accounts of energy management areas, on the basis of each area's population (computed for Municipal Revenue Sharing) for the previous year. The per capita distribution of funds would be adjusted for construction cost differentials in the different areas of the state. No area would be allowed to accrue its share of the Fund more quickly than another area.

- An energy management area could draw upon its account to construct an energy facility which would reduce the area's dependence on fossil fuels imported from outside the area <u>and</u> which had been approved by both the Energy Fund board of trustees and the area's voters.

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[1]While this approach only approximately achieves your goal of depositing $7,500 per person over a period of time, it is simpler to legislate and administer.

[2]Current oil and gas royalty projections terminate in 1998, which would be only thirteen years after the start of this program. For the thirteen-year period 1986 through 1998, 25 percent of expected oil and gas royalties total $3,142.28 million (1982 dollars).

- Local service area boards would operate these facilities, or could contract with the Alaska Power Authority[3] for these services. The Alaska Power Authority would retain responsibility for reconnaissance and feasibility studies and project construction.

- In addition to financing construction of energy projects, Energy Fund entitlements could also be used to meet debt service on bonds issued by the area.

- First and second class boroughs would automatically become energy management areas, and their governments would become energy management boards. In areas outside these boroughs, the Commissioner of Community and Regional Affairs would designate area boundaries and elections would be held for each area's board.

- Two or more areas may jointly propose a project to the Fund's board for approval. For projects involving significant economies of scale, the board would be able to mandate a joint project involving two or more areas.

Issues

This approach to financing energy projects raises a number of philosophical and practical questions. Each of these questions is briefly discussed below.

- Why do energy investments warrant the commitment associated with dedicated revenues when other important State functions, such as education, do not?

This is probably the most important philosophical issue surrounding this program, or any program calling for dedicated funds.

While energy investments may be an important State activity, it is not clear why such investments should not be forced to compete with other demands on the State treasury, particularly when greatly reduced revenues are projected for the future. As Attachment C shows, unrestricted general fund revenues in 1998 may only be approximately 27 percent of current revenues, in real terms. Under those circumstances,

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[3]Your original outline did not indicate how the activities of the Fund related to those of the Alaska Power Authority. Later in this memorandum, we discuss a number of options for different levels of APA involvement.

the State's priorities may be expected to change, so that in the future energy may or may not seem as such an important investment as it does today.

- Why should money for energy investments be provided on a per capita basis, with no consideration of the need for an energy project, and no adjustment for differences in project scale.

From an apolitical public policy perspective, it is not clear why energy projects should be funded on a per capita basis. Not all areas of the state may be able to absorb the funds allocated to them, particularly in western and northern Alaska where alternatives to diesel generation are limited. On the other hand, projects in rural areas will tend to be smaller and have higher costs per unit of energy produced. Although this revised draft incorporates an adjustment in the distribution of funds to account for construction cost differences in various areas of the state, such an index would not reflect the higher relative costs of smaller projects.

The construction cost adjustment included in this revised draft would increase the per capita amounts for high cost areas of the state and reduce the per capita amounts for areas with relatively low construction costs. In practice, this would mean more funds (on a per capita basis) for rural areas and less for urban areas, thus raising the potential for divisiveness on this issue.

- Is it wise to exclude both the Executive and Legislative branches from any role in the distribution and use of this amount of money?

Neither the Executive nor Legislative Branch is involved in the process of spending these funds. This could be viewed as a benefit or a drawback of the program depending on one's perspective and is certainly an issue which may be raised.

- Should local governments be formed in rural areas to administer this program?

You suggested that this program be administered by local service areas. The creation of yet another set of boundaries in rural areas for the delivery of services raises the question of whether it is time to establish more local regional governments. Some individuals will resent the imposition of an Energy Management Area structure in order to receive their per capita grants, while others might argue that fully functional regional governments should be formed to administer these grant monies.

- How should feasibility studies be funded?

In your outline, you indicated that Fund money was to be used for the design and construction of projects which already have been determined feasible. Consequently, we assumed that you did not want fund money to be used for feasibility studies, and have included that provision in the proposed legislation.

Given the high cost of some feasibility studies, it seems that some areas could easily consume large amounts in the study stage without ever benefiting from new energy sources.

There are at least three alternative ways that areas could secure funding for feasibility analyses: local revenues could be used; special State appropriations could be sought, a means of involving the Executive and Legislature; or, the Energy Fund board could distribute grant money, which had been appropriated to the Fund in a lump sum, to local areas for the purpose of analyzing project feasibility.

- What is the desired relationship between the Fund and the Alaska Power Authority?

In your outline, there was no indication of how the relationship between the Energy Fund and the Alaska Power Authority was to be structured. In the original draft of August 9, we established a separate entity where the APA's role would be limited to its contractual relationships with energy management areas regarding the completion of feasibility studies, and the design, construction and operation of facilities.

In this revised draft, the APA would retain responsibility for reconnaissance and feasibility studies and project construction. The area boards would be responsible for working with the public and the local utilities to ensure that their concerns were reflected in the project evaluation and selection process. Based on the reconnaissance studies, the area board would recommend the project or projects for which feasibility studies would be conducted by the APA. Those projects which are feasible would then be recommended by the area board to the state board, placed on the ballot, and constructed by the APA if approved by the voters.

Currently, projects constructed by the APA are subjected to a two-step approval process. The Division of Budget and Management in the Governor's Office approves feasibility plans and financial plans prior to submission to the legislature. Under this revised draft, we have retained the review of reconnaissance and feasibility studies by the Division of Budget and Management, but have not included a requirement for legislative approval in accordance with our interpretation of your outline. As mentioned earlier, legislative approval is one of the major issues to be considered.

If the Energy Fund is established apart from the APA, and assuming that the money contributed to the Energy Fund represents the bulk of the State's commitment to energy project financing for the foreseeable future, the APA's role in shaping State energy policy would be greatly reduced. Even if the Fund were incorporated into APA, provisions for equity in per capita financing and voter approval would constrain the policy latitude of the Authority.

There are at least four ways in which the APA could be affiliated with the Energy Fund:

1) areas could be required to use the APA for feasibility, design, construction and management services, for projects initiated within the area (as in this revised draft).

2) the APA could be made responsible for projects of a certain type and size.

3) the APA could recommend projects to the area board and present them to the area board and the fund board. Essentially, the APA would be staff to each board. It would then have the responsibility for designing, constructing and maintaining the project.

4) the APA could recommend, own and operate these facilities. The activities of the APA would only be subject to voter approval in the area served, as no separate legislation would be required for these facilities. The fund board would take the place of the Division of Budget and Management.

These alternatives would permit the APA varying degrees of influence over the selection and construction of energy projects.

- Who owns the energy projects financed by the Fund?

In the suggested legislation, we have assumed that each energy management area will own the facilities it builds. This seems appropriate, particularly if the area were issuing bonds for the project. An alternative to this approach is State ownership and operation, through the APA or the Department of Transportation and Public Facilities.

- How should the economic feasibility of projects be determined?

We are assuming that these funds will be provided as grants to local areas, and that no return on equity or interest would be repaid to the State. Consequently, it seems that the only criteria for economic feasibility is that local rates cover the costs of maintaining and operating the facilities. Under the proposed legislation, Fund monies may not be used to pay maintenance and operating costs.

- Will this financing plan be adequate to meet the needs, both in total amounts and timing of revenues, of large-scale hydroelectric projects, in particular--Susitna?

Table I, below, shows the: 1) amount of money which would be deposited into the Energy Fund, assuming 25 percent of current Department of Revenue royalty projections; 2) share which would be received by energy management areas throughout the Railbelt; and 3) estimates of the financing requirements of Susitna construction.

Table I
Estimates of Energy Fund Deposits & Susitna Financing Requirements
(All 1982 dollars)

	Energy Fund	Railbelt Share (70%)	Susitna Requirements
1982	-	-	-
1983	-	-	-
1984	-	-	85.00
1985	-	-	230.00
1986	303.47	212.43	296.00
1987	334.62	234.23	298.00
1988	340.74	238.52	349.00
1989	352.71	246.90	442.00
1990	316.05	221.24	615.00
1991	265.51	185.86	597.00
1992	239.47	167.63	435.00
1993	211.40	147.98	170.00
1994	190.35	133.25	115.00
1995	160.55	112.39	75.00
1996	147.11	102.98	120.00
1997	142.37	99.66	210.00
1998	137.93	96.55	295.00
Total	$3142.28	$2199.62	$4332.00

Sources: Timing of Susitna financing requirements by House Research Agency, J. Kreinheder. For Energy Fund Deposits, please see Attachment C.

As noted in the proposed legislation, the earliest full year for the fund to be in operation is FY 86.

Whether or not this flow of funds is adequate for Susitna construction depends upon a number of other assumptions, including the amount and timing of expected bond financing. That determination would require a more detailed financial analysis.

One reviewer suggested that using a per capita distribution approach may damage the chances of funding Susitna. If voters in the Municipality of Anchorage know that it is assured of over $1.5 billion (1982 dollars) during the next fifteen years for energy projects, they may be more interested in alternatives such as tidal power and coal development. In addition to providing power, these projects may offer other advantages, such as being the catalyst for Beluga coal export development.

Even if the Fund board forced the Railbelt to jointly propose the Susitna project, Anchorage residents could vote down such a proposal. Similar factors may also affect Fairbanks.

- How are the activities of energy management boards in the unorganized borough regulated to insure proper use of funds, etc.

If the program is established apart from the APA, it would seem desirable to institute some form of controls over the local boards, to insure the proper use of funds, etc., and avoid the abuses experienced on some Regional Education Attendance Area boards. At this point, this program only requires financial accountability through annual audits.

- What about those areas where there are no feasible alternatives to imported fuels for either electricity or space heat and which have exhausted their conservation possibilities--would they be able to subsidize diesel imports?

The proposed program does not provide for an area which can generate no approvable projects. If exceptions are to be made, some wording of the constitutional amendment probably has to be changed. The program also does not provide for an area which is not interested in submitting projects; money would simply accrue to its account until such time as it was interested in making energy investments.

After you have had a chance to review this memorandum and the attachments, please let us discuss what changes you would like to see in the proposed legislation.

AHD/JK/sj

cc: Representative Don Clocksin

Attachment A: Proposed Wording for the Constitutional Amendment
Attachment B: Proposed Wording for Necessary Legislation
Attachment C: Projected Royalties and Energy Fund Deposits

Table 1
Estimates of Contributions to the Energy Fund and Unrestricted
Based on June 1982 Department of Revenue Royalty Projections
(Millions of 1982 Dollars)

	Real O&G Royalties[a]	Real O&G Prod Tax[a]	Less Perm. Fund[b]	Petro Prod. Contribution to Unres. GF	Sub-Total Unresricted General Fund[c]	Est. Total Unrestricted General Fund
1982	$1,538.98	$1,602.74	$384.75	$2,756.98	$4,114.90	$4,114.90
1983	1,186.87	1,212.05	296.72	2,102.20	3,137.61	3,137.61
1984	1,113.13	1,137.27	278.28	1,972.12	2 943.46	2,943.46
1985	1,091.76	1,085.42	272.94	1,904.24	2,842.15	2,842.15
1986	1,213.86	1,196.81	303.47	2,107.21	3,145.09	2,841.62
1987	1,338.46	1,305.81	334.62	2,309.66	3,447.25	3,112.63
1988	1,362.95	1,143.77	340.74	2,165.98	3,232.81	2,892.07
1989	1,410.83	1,184.17	352.71	2,242.29	3,346.70	2,993.99
1990	1,264.18	982.18	316.05	1,930.32	2,881.07	2,565.02
1991	1,062.02	799.73	265.51	1,596.25	2,382.46	2,116.95
1992	957.86	730.39	239.47	1,448.79	2,162.37	1,922.90
1993	845.61	581.03	211.40	1,215.24	1,813.79	1,602.39
1994	761.41	503.56	190.35	1,074.62	1,603.91	1,413.56
1995	642.21	416.98	160.55	898.64	1,341.25	1,180.70
1996	588.45	347.47	147.11	788.81	1,177.33	1,030.22
1997	569.47	338.04	142.37	765.14	1,142.00	999.63
1998	551.73	323.43	137.93	737.23	1,100.34	962.41
Total	$17,499.78	$14,890.85	$4,374.97	$28,015.72	41,814.49	$37,439.52

[a] Oil and gas production tax receipts and royalties: Department of Revenue, computer run dated 7/16/82. Projections were in nominal dollars; converted to real dollars for this table using inflation factor provided by Department of Revenue. Between 1982 and 1998, an inflation rate of 7.67 percent per year was assumed.

[b] Permanent Fund contribution: assumed to be 25 percent of royalties. The actual rate will be higher in some of these years due to the increased contribution rate legislated for newer leases.

[c] Unrestricted General Fund revenues before Energy Fund deposit. In FY 82, oil and gas production taxes and royalties after deducting the Permanent Fund deposit, represented about two-thirds of unrestricted General Fund revenues. This percentage was applied to each year to approximate the total unrestricted revenues before the Energy Fund deposit. This may be an optimistic assumption; the Department of Revenue shows that oil and gas production taxes and royalties less the P.F. deposit, are projected to account for 73 percent and 74 percent of unrestricted General Fund revenues in FY 83 and FY 84. If one of these higher figures had been assumed, the total unrestricted general fund revenues shown in column x would be lower. Note: A projection of total unrestricted general fund revenues for this period was not available from the Department of Revenue.

[d] Susitna financing requirements. Annual expenditures for Susitna construction in FY 82 dollars, Jack Kreinheder,

SECTION 6

REVIEW AND ASSESSMENT OF DEBT FINANCING FOR POWER PROJECTS

INTRODUCTION

One of the compelling reasons, if not the primary reason, for the formation of the Authority was to provide an entity that would have the statutory authority and practical capability to undertake major financings for power projects. Although the scope of the Authority's responsibilities, in this regard, has changed from its creation in 1976, power project financing remains among the Authority's primary responsibilities.

This section of the report provides the results of our review and assessment of debt financing under Task 6. This review covered both present and planned practices with respect to interim and long term debt financing.

During the period that we were involved in the work under Task 6, a working group which included Authority staff and the Authority's bond counsel, financial advisor, and lead underwriters were involved in a comprehensive review of long term debt financing alternatives. Through the cooperation of the Authority and members of the working group, we have been able to review the progress of their work as well as provide comments to them.

On October 11, 1982, the Authority's Executive Director transmitted to the board a "Plan of Finance for Alaska Power Authority Projects" which was developed by the working group. We have included in this section of the report a summary of our assessment of the content of this document.

STATUTORY DIRECTIVES RELATED TO DEBT FINANCING

The Authority's statutory directives relating to financing are provided in Chapter 83, Article 3 of Alaska Statutes (44.83.100 - 44.83.160). The significant provisions of these sections are summarized below.

Bonds of the Authority

The Authority is authorized to borrow money as one of its general powers. This authority includes, but is not limited to, the issuance of bonds on which the principal and interest are payable: exclusivley from the income and receipts, or other money derived from the project, or designated projects (whether or not they are financed in whole or in part with the proceeds of the bonds); from its income and receipts or other assets generally, or a designated part or parts of them; from one or more revenue-producing contracts including a contract providing for the security of the bonds.33/

Bond issues are authorized by a resolution of the Authority. The specifics of resolutions are left to the Authority's discretion, with one limitation--that no bond may mature more than 50 years from the date of its issue. Other than this, a resolution of the Authority may provide: the date of issue and term to maturity; the form, denomination, rate of interest, medium of payment, and the places and terms of redemption. The Authority also determines the time or times of offerings, the price or prices, and the method of sale--public or private.

A special provision applies to bonds for power projects under the Energy Program for Alaska. The Authority can borrow money by issuing its bonds if appropriations to the Power Development Fund are insufficient to cover the total cost of acquiring or constructing the power project, and the cost of financing (the bond's interest rate) is less than any other alternative available. Principal and interest are paid from money derived from the sale of power from the financed power projects.

Trust Indentures and Trust Agreements

The Authority has the discretion to determine the form of security for each bond issue. Security may consist of a trust indenture or trust agreement between the Authority and a corporate trustee, or it can be obtained through a secured loan agreement or other instrument. A third alternataive is to pass a resolution which grants specific powers to a corporate trustee.

A trust agreement must also contain a covenant by the Authority that it will at all times maintain charges, fees, or rates that are sufficient to meet its obligations and that a wholesale power contract between the Authority and another party for the sale, transmission, or distribution of power shall establish charges sufficient to pay: the costs of operation and maintenance of the project; the principal and interest on bonds issued under the trust agreement; a debt service coverage amount (the size necessary to market its bonds is determined by the Authority); for renewals, replacements and improvements of the project; for the maintenance of a reserve as required by the terms of the trust agreement.34/

To secure issues of its bonds the Authority establishes one or more special funds, called "capital reserve funds". These funds are established if the Authority determines that they will enhance the marketability of its bonds. Proceeds from the sale of its bonds, or any other money supplied to the Authority for the same purpose as those proceeds, are paid into a capital reserve fund. All money held in the fund must be used for bond payment and/or redemption.

Income or interest earned by a capital reserve fund may be transferred to other accounts or funds by the Authority. However, the amount transferred must not reduce the amount within the fund below the capital reserve fund requirement (which is established by a resolution of the Authority). This same rule applies when the Authority wishes to issue additional bonds secured by such a capital reserve fund.

General Financial Provisions

The statute specifies that a pledge made with respect to bonds is valid and binding from the time the pledge is made. Furthermore, bonds issued by a public corporation do not constitute an indebtedness or other liability of the State of Alaska or of a political subdivision of the State. Any claims are payable solely from the income and receipts or other funds or property of the Authority. However, the State does pledge that it "will not limit or alter the rights and powers vested in the Authority by this chapter to fulfill the terms of a contract made by the Authority . . . until the bonds . . . and all costs and expenses in connection with an action or proceeding by or on behalf of holders, are fully met and discharged.35/

One final point which must be recognized is that these bond agreements and trust indenture provisions must be read in context with the provisions of the Energy Program for Alaska. The language presented here may not be strictly applicable in instances where project debt service is pooled among several power projects. This is important to note because a debt financed project will not necessarily be responsible for all of its debt service, since HB 9 provides for a limited equalization of debt service between projects.

INTERIM DEBT FINANCING

The interim financing of power project construction is a common practice in the industry. Under typical interim financing arrangements, a debt instrument is issued for a term up to a short period after completion of construction or some date certain to provide construction funds required in excess of those provided as an equity investment. This interim financing is then "taken out" or paid from the proceeds of long term debt or a combination of long term debt and additional equity investment.

Authority Interim Debt Financing Program

The Authority has utilized interim debt financing in connection with three of the four major hydroelectric projects presently under construction (Solomon Gulch was financed entirely from appropriations by the Legislature). The $200 million proceeds of these tax exempt issues have supplemented funds appropriated by the Legislature for construction of those projects.

Swan Lake Project Interim Debt Financing

In May of 1981 the Authority issued $35 million of series 1981 General Obligation Bonds for a term of three years. These bonds were purchased by a consortium of banks under terms of an agreement that provided for semi-annual interest payments at an interest rated pegged at 65 percent of the Morgan Guarantee Trust Company prime rate, not to exceed 13 percent. The agreements further provided that if the calculated rate were below the ceiling it would be adjusted to compensate the lenders for interest that would have been paid in prior periods had there been no ceiling.

Under these agreements, the proceeds of the bond sale were loaned by the Authority to the City of Ketchikan for construction of Swan Lake. The bonds were secured by the general obligation of the Authority and by all proceeds of any refunding bonds as well as the agreements between the Authority and the City of Ketchikan. The loan to the City of Ketchikan was secured by proceeds of any Ketchikan public utility refunding bonds, certain revenues and amounts in the utility's revenue fund, and all moneys in the Swan Lake Construction Fund. The agreement with the City provided identical terms with respect to other matters and the same interest provisions as did the Authority's bonds and its agreements with the purchasers of those bonds.

The Swan Lake project interim financing was somewhat atypical for several reasons. First, the Authority was obtaining interim financing for a project that it did not own. Also, the Authority utilized a general obligation bond as the financing vehicle and these bonds were sold at a variable rate pegged to the prime rate with a cap.

The maturity of the bonds issued by the Authority for the Swan Lake project is the earliest of the interim financing undertaken to date. These, therefore, will be the first interim financing debt instruments that will be refunded through the issuance of long term debt, assuming that the legislature does not appropriate sufficient funds to meet this obligation.

Tyee and Terror Lake Projects Interim Debt Financing

In providing interim debt financing for the Tyee and Terror Lake projects, the Authority issued Variable Rate Demand Notes (notes) supported by bank letters of credit. This is typical of the interim financing arrangements for power projects in other parts of the country.

Interim financing for the portion of the Tyee costs in excess of State appropriations was undertaken in January of 1982 with the issuance of $50 million of notes. Terror Lake interim financing was completed in May, 1982, with the issuance of $115 million of notes. The notes are general obligations of the Authority, payable from:

- Amounts on deposit and interest earnings under the Authority's note resolution.
- Drawings under the letters of credit issued by banks.
- The proceeds of long term bonds of the Authority issued for permanently funding the costs of Tyee and Terror Lake projects.

The issuance of notes did not involve a pledge of the faith and credit nor the taxing power of the State of Alaska or any political subdivision.

The variable rate interest on the notes is pegged at 1/4 of 1 percent above the "Tax Exempt Note Rate" (TENR). This is an index which reflects the current bid-side yields on short term tax exempt securities (U.S. Government guaranteed housing project notes, other high quality municipal notes and tax exempt commercial paper). This rate is announced on a weekly basis by the Bankers Trust Company. This interest rate arrangement brings the interest rate paid by the Authority very close (within 1/4 of 1 percent) to the highest grade tax exempt short term securities.

Authority Interim Debt Financing Policy

On October 11, 1982, the Authority's Executive Director transmitted a financing policy statement to the Authority's board. A copy of this communication, which was the Authority's response to the request in the legislative letter of intent filed with HB 9, is included as Appendix 6-A. This policy statement provided the following guidelines:

- Permanent financing for the project can be obtained when interim financing matures.
- The interim financing matures no sooner than six months after the expected date of project completion.
- Short term rates offer an interest cost savings over long term financing.
- At least 75 percent of the project cost is under contract when the interim financing is authorized.
- Where possible, the interim financing combined with the available resources should fully fund the remaining cost of the project, plus an adequate contingency.

Assessment of the Authority's Interim Debt Financing Program and Policy

The use of interim debt financing has to be an important part of the Authority's overall financing program as well as specific financing plans for individual projects. We are in general agreement with both the approach used by the Authority in its interim financing to date and the advantages of an interim financing program as set forth in Appendix 6-A.

Authority Interim Debt Financing Program

As outlined above, the Authority's initial interim debt financing involved issuance of short term general obligation bonds in connection with the Swan Lake project. When this financing was undertaken, the Authority, in effect, acted as an intermediary between the City of Ketchikan and the capital market. The interest rate charged on the general obligation bonds reflected what was then a short term rate for tax exempt borrowers. Therefore, although the use of general obligation bonds for interim financing is not common practice, the results were successful.

In the interim financing for the Tyee and Terror Lake projects, the Authority moved to a more conventional interim financing arrangement with the issuance of variable rate notes. The Tyee interim financing involved the sale of variable rate notes which were supported by a letter of credit from Bankers Trust Company. Subsequent interim financing for Terror Lake was made on the same basis but the banks supporting the financing through letters of credit were expanded to include First Interstate Bank of California and Mellon Bank. This reflected a continuing maturity of the Authority's interim financing program.

The ultimate test of the validity of the Authority's interim financing program is, of course, market acceptance of the securities involved and the interest rate that must be paid. One evidence of the success of the Tyee and Terror Lake interim financings was the fact that the financing was successful and rated by Moody's as "MIG 1", which is their highest rating for short term securities. Another is that the pegging of the interest rate to the TENR has brought the Authority's interest cost into the range of interest paid on the highest quality tax exempt short term financings.

Authority Interim Debt Financing Policy

The Executive Director's communication, which is included as Appendix 6-A, in our view, presents a concise analysis of the benefits of interim financing as well as the policy guidelines for its use. As we have stated, we believe that interim financing has to be an important part of the Authority's overall financing program. We are therefore supportive of the policy set forth in this document.

There are really only two areas of risk associated with utilizing interim financing for construction. The first is that at the time long term debt is issued to "take out" the interim financing, market conditions might be worse than they were at the time interim financing was undertaken. This would mean that the Authority might pay a higher rate of interest for the long term debt than they would have had they issued long term debt initially. In the extreme, the Authority might find the market condition such that it was unable to finance on a long term basis the amounts involved in the interim financing.

There is however, a remedy to this situation. In the event that the Authority is forced into the market for the issuance of long term debt during periods of very high interest rates, subsequently, the bonds issued could be refunded when the market returns to what would be considered a more "normal" level. In the event that the market, for whatever reason, would not accept long term debt issues, arrangements can be made to roll over the interim financing until market conditions improve.

The second area of risk is that a project might be terminated. If this were the case, the outstanding interim financing that had been expended would have to be paid off and it probably would not be possible to convert this to long term financing in any conventional way. This risk is not limited to interim financing but would be the same, and perhaps more complicated, if long term debt had been issued initially to finance construction. We do not consider either of these risks to be persuasive in an argument against utilization of interim debt financing.

One of the main advantages of interim financing is that it postpones going to the capital markets with a long term debt issue until projects are completed. Without exception, this will result in more favorable terms for the long term financing than if such financing was undertaken prior to completion of the projects. Initiating long term debt financing after completion of the projects means that the Authority can go to market with a completed operating project and power sales contracts in place, guaranteeing payment for the project output. In effect, the financing is made on the basis of a "going business" as opposed to a project in some stage of construction with the inherent uncertainties.

Authority Interim Financing Alternatives

The arrangements used for interim debt financing, as well as long term debt financing, are almost exclusively a function of market acceptability. These arrangements change over time as new approaches are introduced and ultimately accepted. For this reason it is absolutely crucial that the Authority continue to work closely with its financial advisors and lead underwriters as well as with its bond counsel. It is our observation that this has been the Authority's practice and we encourage its continuation.

One area that the Authority and its financial advisors may want to explore as time passes is the potential use of tax exempt commercial paper in conjunction with whatever form of interim financing might be used. Particularly, the issuance of tax exempt commercial paper in combination with variable rate notes might be useful in leveling cash flow from State appropriations. For example, if the flow of State appropriations for a given fiscal year did not "mesh" with the projected flow of expenditures based on those appropriations, short term commercial paper, supported by letters of credit from the Authority's bankers, could be used to assure the availability of funds required by the construction schedule.

LONG TERM DEBT FINANCING

To date, the Authority has not undertaken any long term debt financing. However, the maturity schedules of interim financing necessitate the Authority's entering the long term market sometime within the next year. As previously discussed, in anticipation of this the Authority staff and the Authority's bond counsel, financial advisor, and lead underwriters have undertaken a review of long term debt financing alternatives. The results of this work were summarized in the "Plan of Finance for Alaska Power Authority Projects" which was transmitted to the Board by the Authority's Executive Director on October 11, 1982.

We have included this document as Appendix 6-B. Our assessment of its content is summarized in this section of the report.

Assessment of "Plan of Finance for Alaska Power Authority Projects"

First, we do not consider this document to be a financing plan for a particular project. Rather, it represents a general statement of principles concerning long term debt financing that might be undertaken for several projects. We have covered the subject of a financing plan for specific projects elsewhere in this report and, therefore, our comments on the document included as Appendix 6-B are made in the context of the overall financing program in the Authority. These comments are made on a section by section basis.

Objectives

The objectives stated in the plan are not its substance. However, they are broad enough that they provide for a rational approach to debt financing. If, however, this document were to be redrafted, consideration might be given to relating objectives to statutory directives provided by the Legislature.

Summary

Our comments on the material provided in the summary are included under the several headings of the document. One point, however, relates to the proportion of debt to equity that might be maintained by the Authority. We would agree that bond marketing and rating considerations are important in determining some optimum level of debt to equity. But, for the Authority, in the final analysis, the level of equity provided is determined by the Legislature through its appropriations to individual projects constructed by the Authority.

Timing

As previously discussed, we are very supportive of the interim financing program undertaken by the Authority and the principles of future interim financing included in Appendix 6-A. With respect to the potential sales of long term debt prior to project completion our inclination is to defer to the advice of the Authority's financial advisor and lead underwriters. But, we would suggest that consideration be given, to the extent practicable, to the scheduling of maturities on interim financing to occur a few months after scheduled project completion in order that the long term debt issue would be made when the project was actually in operation. We do not believe that this approach would impact the level of capitalized interest which would continue until the project was completed no matter what the source of funds. Such an approach would totally remove any construction risk for those who might purchase the Authority's long term debt instruments.

Debt Instruments

We agree that the Authority should first look to the issuance of revenue bonds, as opposed to general obligation bonds. We would suggest that the scheduling of maturities on individual bond issues or on bond issues for a specific project not be set as a matter of policy. Market conditions, from time to time, may dictate that the maturities of a particular issue may be shorter than a 35 year period to take advantage of more favorable interest rates. The Authority's policy, therefore, might better provide that the total debt service for all outstanding indebtedness would be structured in such a way that it would approximate a levelized 35 year debt service.

Security

The security for the Authority's bonds as set forth in the policy is, for the most part, dictated by the Legislature's statutory directives relating to financing. The language of the policy does not clearly indicate that the bonds to be issued will be revenue bonds. There is a suggestion that the assets of the Authority might also be pledged as security for such bonds. If this be the case, the debt instrument would be something more than a revenue bond in that it would provide some type of mortgage on the Authority's assets. This point aside, we agree that the bonds issued by the Authority, except in special cases, should be supported by a pledge of their total revenues as opposed to the revenues of a particular project. This approach provides a broader security for the debt instrument which should result in more favorable interest rates.

The policy also provides that future bonds would be issued on a parity basis. That is, that the Authority proposes to covenant that it would not issue bonds in the future that would have a prior claim on the Authority's revenues pledged as security for previously issued bonds. We agree that this is a necessary requirement. We note that the Authority will reserve the right to issue bonds for a specific project separately from the system bonds and that the revenues from that project might be pledged solely to the benefit of that project's bondholders. Even if this were never done, the reservation of such a right is clearly necessary to preserve maximum flexibility in future financings.

Reserves

One of the most important areas of the policy relates to the reserves that will be provided in connection with the issuance of long term debt. Each of the reserves set forth in the policy are discussed below.

Debt Service Reserve

A debt service reserve is a necessary condition for the succesful marketing of revenue bonds. As an industry practice this reserve is set at a minimum, and most often at a level equal to the maximum annual debt service on outstanding bonds. For perspective, the debt service reserve on the basis of maximum annual debt service, assuming that the bonds issued will in total have level annual debt service, for the Swan, Terror, and Tyee projects will be approximately $25 million annually. This is the amount, therefore, that would have to be deposited into the debt service reserve by the time that the interim financing on these three projects is replaced by long term debt.

The working group has considered, and the Authority's plan at least hints, that the debt service would be funded through appropriations by the Legislature. This would mean that the Legislature would be required to appropriate approximately $25 million in addition to the approximately $260 million already appropriated for the four projects under construction (Solomon, Swan, Terror, and Tyee). This, clearly, is an alternative.

Another alternative, which we understand has been considered by the working group, would be to borrow the debt service reserve. This would mean the bond issue would have to include, among other things, approximately $25 million to fund the debt service reserve. This is not an uncommon practice in revenue bond financings for major projects. In fact, it is the most common approach.

The advantage of providing funds through appropriation for the debt service reserve is that another increment of "equity" would be provided by the State for these projects This would enhance the evaluation of the bonds by potential bond buyers as well as rating agencies. If additional amounts are borrowed to fund a debt service reserve, annual debt service payments will have to be made on these amounts. However, the debt service reserve is invested by the trustee, and if the interest earnings on the amounts invested approximate the interest to be paid, in effect, the money is obtained for "free". Generally speaking, it is possible to achieve a balance of interest earnings and interest cost on reserve accounts. However, there are times when this cannot be done and the interest required to be paid on the reserve accounts becomes a project cost. This would impact the level of rates required from each of the projects, although the impact would be relatively small when compared to the total revenue that has to be raised.

Regardless of how the debt service reserve is funded, consideration should be given to structuring the reserve in such a way that it is available for the debt service on any and all projects financed through the sale of parity bonds. In other words, we are suggesting that the debt service reserve not be segregated by bond issue, but rather that it be a "pooled" reserve. This approach would make it possible to utilize the reserve to pay more than one year's debt service on a particular project if that became necessary.

Operation and Maintenance Reserve

A reserve for operation and maintenance costs, beyond financing considerations, is generally considered to be "prudent business". This is particularly true in the case of hydroelectric systems where water flow variations might impact the level of revenues in a particular year.

The Authority's plan indicates that this reserve would be equivalent to six months of estimated systemwide operation and maintenance costs. Further, although the plan does not specifically address the question of funding, it appears that this reserve would also be funded by legislative appropriation. Again, an alternative would be to borrow the funds for this reserve.

With respect to the level of this reserve, six months would appear to be a minimum when measured against industry practice. It is not uncommon to provide an operation and maintenance reserve equal to one year's costs. However, an additional six months of reserves may not have to be provided initially. An alternative would be to provide the initial six months, either from bond proceeds or by appropriation, and then supplement this annually for a period of several years from the debt service coverage amount included in rates until the reserve becomes equal to one year's operation and maintenance costs.

Inflation's effect on the reserve balance must also be considered. Escalation of operation and maintenance costs will cause the reserve balance, although adequate in the previous period, to fall below the desired level in a future period. If the reserve is to be maintained at a constant level in real terms, an annual deposit will have to be made to cover inflation. Again, this could be handled from the debt service coverage component of rates. This is discussed further under the heading "Flow of Funds".

As discussed in the case of the debt service reserve, the operation and maintenance reserve should also be maintained on a pooled basis rather than earmarking portions of the reserve for specific projects.

Renewal and Replacement Fund

As with the operation and maintenance reserve, the renewal and replacement fund is established on the basis of financing and practical considerations. This reserve is intended to provide funds for the interim replacement of major pieces of mechanical and electrical equipment that can be expected to "wear out" before the project reaches the end of its useful life. We have previously discussed the renewal and replacement fund requirements in Section 4 of the report.

The Plan of Finance suggests that this fund would be established in an amount equal to 5 percent of the cost of projects included in the system. For the most part, the concern for renewal and replacement relates to equipment as opposed to structures, the latter being the most significant component of project cost. A more direct approach, therefore, is to peg the level of funding of the renewal and replacement fund to the cost of equipment as opposed to total project cost. The appropriate formula to establish the level of this fund is a matter of judgment and we would defer to the project design engineers as well as the Authority's operating staff on this question. However, our expreience indicates that utilities with substantial hydroelectric generation have utilized a formula that is based on providing 1/20 of the balances in the FERC capital accounts covering equipment annually.

Rate Covenant

The plan envisions that a rate covenant would be made providing that the Authority would maintain rates at a level sufficient to recover operation and maintenance costs, any required deposits to reserve funds, and at least 1.10 times average annual debt service on all outstanding system revenue bonds. Such a covenant is attractive in the marketing of bonds, and, as a practical matter, must be met if the Authority is to cover its obligations.

It is not uncommon for a covenant to be made with respect to the level of rates before additional bonds might be sold. For example, an additional bonds covenant might require that revenues would be sufficient to provide the rate components enumerated above including the debt service and coverage on the additional bonds. If this is the case it is also common that this test be made on the basis of an adjustment to reflect the additional revenue that will be derived from the project or projects for which the additional bonds are sold.

So long as the components of rates included in rate covenants are those that statutorily or as a matter of policy will be included in the calculation of the actual rates, then they can be made without imposing an additional burden on the Authority's ratepayers. Given the benefit of such covenants to debt financing, they are clearly advantageous.

Flow of Funds

The Plan of Finance provides that revenues be deposited as follows:

> First, to fund the operation and maintenance account to the extent required to pay operation and maintenance expenses of the system;
>
> Next, to the principal and interest account until equal to the next scheduled payment of interest and principal;
>
> Next, to restore, if necessary, the debt service reserve, the operation and maintenance reserve, and the renewal and replacement reserve to the required balances;
>
> Next, any remaining revenues would be deposited in the retained coverage account of the Authority to be used first to restore the deficiencies in the reserves, and then as equity contribution to the future projects authorized by the Legislature, and the revenues of which are pledged to the system revenues.

This concept introduces the generation of funds from rates to provide equity in future projects from revenues. These funds would be the balance of the 10 percent of annual debt service that would be provided in rates as debt service coverage.

With respect to debt service coverage, we concur that it is absolutely necessary that rates be set at a level to provide some coverage of the annual debt service if the Authority is to utilize revenue bond financing. Based on our experience, the 10 percent level proposed in the Plan should be considered a minimum. It may be found, over time, that there would be some benefit in providing a higher level of coverage even though the covenants would only require the 10 percent coverage that is included in the Plan.

Additional Parity Bonds and Permitted Indebtedness

The Plan sets forth four conditions that would have to be met before any additional parity bonds could be issued for improvements to existing projects or new projects that might be added to the system:

- New projects would not benefit from any legislatively mandated power rate limit.
- An independent nationally recognized consulting firm would provide a finding of technical and financial feasibility, including a finding that project revenues would be at least equal to annual operation and maintenance expense and 1.1 times maximum annual debt service for the additional debt required to construct the project.
- An independent, nationally recognized consulting engineering firm shall have concluded that the project is needed, technically and financially feasible, compatible with existing resources, and that under these requirements wholesale rates for all projects, except so-called "capped" rate projects, do not increase and may decline, depending on the initial year power sales of the added project.
- In the first full year following project completion, the ratio of additional annual debt service to total project cost cannot exceed the systemwide ratio of annual debt service to project costs.

One exception would be provided to these tests. This would permit the issuance of completion bonds having a par value no greater than 15 percent of the project cost for which they were issued.

These conditions for the issuance of additional bonds are, in our view, reasonable and generally consistent with similar provisions that will be found in bond resolutions of other agencies. The requirement for a finding that revenues from the project to be financed will be sufficient to cover operation and maintenance costs and debt service plus coverage is consistent with the rate covenants previously discussed.

OTHER CONSIDERATONS

In the Authority's financing of projects it faces a somewhat unique problem due to the fact that large areas of the State are served by rural electric cooperatives as opposed to municipal utilities. To the extent that the output of Authority projects is sold to these utilities there is a restriciton on the issuance of tax exempt bonds. Unless a particular project will qualify under other provisions of law for tax exempt financing, the Authority may be faced with the situation where some taxable debt instruments would have to be issued. This problem has been, and continues to be, considered by the Authority and its consultants.

ALASKA POWER AUTHORITY

APPENDIX 6-A

October 11, 1982

Mr. Charles Conway, Chairman
Alaska Power Authority
2481 Belmont Drive
Anchorage, Alaska 99503

Subject: Interim Financing for Alaska Power Authority Projects

Dear Chuck:

To date the Alaska Power Authority has issued interim financing having a total outstanding par amount of $200 million for the following projects:

Swan Lake	$ 35 million
Tyee Lake	50 million
Terror Lake	115 million

In each instance the interim financing was incurred in order to proceed with the award of contracts which would otherwise have exceeded the amount of funds on hand. It is expected that when due, the interim financing will be replaced with permanent financing in the form of long-term revenue bonds or additional direct State appropriations.

Interim financing offers advantages of cost and flexibility where the following circumstances apply:

1) Full funding at project costs is required to obtain the best bids and to avoid project completion delays.

2) The Legislature has evidenced a desire to consider additional direct funding for a project out of funds available in a subsequent fiscal year.

3) Short-term rates offer a significant cost savings at the time of issuance and market risks are hedged.

4) The Authority and its financial team have determined that it should defer long-term financing until market conditions are more favorable.

The use of interim financing need not constrain future debt issuance policies of the Authority, but purchasers or providers of credit facilities will want enforceable agreements regarding the Authority's intention to issue a long-term debt that is properly secured and, hence, marketable. In this regard, interim lenders normally expect that long-term financing will be secured by contracts for the sale of the power produced by the project being constructed. This expectation is not unreasonable, especially in view of the fact that it is standard industry practice to conclude such power sales agreements prior to award of contracts and initiation of construction.

Therefore, it is the policy of the Alaska Power Authority to use interim financing under the following guidelines:

1. Permanent financing for the project can be obtained when the interim financing matures.

2. The interim financing matures no sooner than six months after the expected date of project completion.

3. Short-term rates offer a substantial advantage over long-term financing and future market risk has been incorporated in this segment.

4. At least 75% of the project cost is under contract when the interim financing is authorized.

5. Where possible, the interim financing combined with the available resources should fully fund the remaining cost of the project, plus an adequate contingency.

This brief letter is the Authority's response to the request in the Letter of Intent filed with H.B.9 concerning interim financing.

Sincerely,

Eric P. Yould
Executive Director

ALASKA POWER AUTHORITY

APPENDIX 6-B

October 11, 1982

Mr. Charles Conway, Chairman
Alaska Power Authority
2481 Belmont
Anchorage, Alaska 99503

Subject: Plan of Finance

Dear Chuck:

The attached "Plan of Finance" sets forth a recommended financing structure that will meet the Alaska Power Authority's operational objectives while complying with both State and Federal legislation and regulatory constraints.

Sincerely,

E P Yould

Eric P. Yould
Executive Director

Attachment: As stated

PLAN OF FINANCE FOR ALASKA POWER AUTHORITY PROJECTS

Objective:

To establish a financial structure for the Alaska Power Authority which

1) Provides power to Alaskans at rates below the costs of alternative fossil fuel generation resources.

2) Assures an optional mix of direct State funding and externally raised debt financing.

3) Encourages local electric utilities to participate in the statewide power system and to assume a share of its costs.

4) Assures continuing access to the nation's capital markets for such amounts as are needed on terms and conditions favorable to the Authority and its power purchasers.

5) Affords flexibility to meet unforeseen circumstances affecting the Authority, the State and its economy.

Summary:

Projects of the Authority will be financed from a mix of tax-exempt debt, direct State appropriations or reinvestment of retained coverage. The tax-exempt bonds will be general obligations of the Authority to be repaid from the aggregate annual revenues of the Authority whether or not such revenues represent payments for power, investment income or other fees and charges.

For the system as a whole, the proportion of debt to equity will be determined by bond marketing requirements, rating agency consideration, the terms of agreements with bondholders and the terms of power sales agreements with participating utilities.

Systemwide revenues must at least equal 110 per cent of maximum annual debt service (except for certain obligations incurred in connection with interim financing), costs of system operation and maintenance and additional amounts as necessary to fund certain reserve funds.

The portion of required annual revenues to be derived from each project in the Statewide system is determined by application of the formula established in H.B.9 or a similar mechanism authorized by the Legislature and implemented by the Board of Directors of the Authority.

Timing: Absent special circumstances in the capital markets or the project construction schedule, it is expected that State appropriations will be spent first and that debt will not be incurred until project construction has proceeded sufficiently as to eliminate or reduce most of the uncertainties that might have generated substantial cost overruns or project delays. Such a financing schedule avoids unnecessary capitalized interest and allows external financing to be completed with little remaining construction risk.

Debt Instruments: While a variety of forms of interim or short-term financing may be used during construction of certain projects, it is assumed that most projects will be permanently financed with tax-exempt revenue bonds having a maturity of approximately 35 years.

Where other forms of permanent financing are used, it is expected that their cash flow requirements will approximate those of long-term tax-exempt bonds.

Security: The bonds would be issued as general obligations of the Authority payable from any unrestricted assets or revenues of the Authority. The principal assets of the Authority will be the projects built by the Authority and financed as part of the system, and its right to payments under power sales agreements entered into with the purchasers of power from projects in the system.

In addition, the bonds would be secured by amounts in a debt service reserve (equal to maximum annual debt service on all outstanding system bonds), an operation and maintenance reserve (equal to estimated systemwide operation and maintenance costs for 6 months), a renewal and replacement fund (equal to 5% of the cost of the projects in the System) and any amounts held in the Authority's retained coverage account. With the exception of the retained coverage account, these reserves would be initially funded from legislative appropriation and subsequently increased from the same source upon the issuance of additional bonds.

The debt service reserve fund would benefit from the moral obligation language contained in the Authority's authorizing statute.

The Authority would covenant to grant no special security or preferred standing to any bondholders or with respect to any system project through a pledge of revenues or other security device. However, projects outside the system could be financed through a pledge of their revenues solely for the benefit of that project's bondholders.

Rate Covenant & Flow of Funds:

Individual project rates would be set pursuant to the legislatively mandated formula, but the aggregate revenue derived would be covenanted to be at least equal to the sum of operation and maintenance, any required deposits to systemwide reserve funds (operation and maintenance, debt service, and renewal and replacement), and at least 1.10 times average annual debt service on all outstanding system revenue bonds.

As received, revenues would be deposited as follows:

First, to fund the operations and maintenance account to the extent required to pay operation and maintenance expenses of the System.

Next, to the principal and interest account until equal to the next scheduled payment of interest and principal;

Next, to restore, if necessary, the debt service reserve, the operation and maintenance reserve and the renewal and replacement reserve to their required balances;

Next, any remaining revenues would be deposited in the retained coverage account of the Authority to be used first to restore deficiencies in reserves, and then as equity contribution to future projects authorized by the Legislature, and the revenues of which are pledged as system revenues.

In the event revenues are insufficient to meet scheduled principal or interest payments, the Trustee would withdraw amounts as needed from the debt service reserve fund. The debt service reserve fund would benefit from the moral obligation provided by statute.

In addition, withdrawals from the debt service reserve fund would be immediately restored from amounts in the surplus account, the renewal and replacement reserve and the operating and maintenance reserve, respectively. The Authority may adjust rates as necessary, whether or not as provided by the wholesale power rate formula, to provide revenues sufficient to restore the debt service reserve fund, renewal and replacement reserve and operating and maintenance reserve by the end of the Authority's next fiscal year. Any subsequent revenues not required to meet operating and maintenance expense to pay debt service or to restore the debt service reserve fund shall be used first to restore the operating and maintenance fund, then the renewal and replacement fund, and then deposited to the retained coverage account.

Power Sales Contracts: The output of each project in the system would be sold pursuant to power sales agreements unique to that project. Within the system, the power from some projects would be sold under strict take-or-pay, "hell-or-high-water" contracts, others under requirement contracts, some as demand charges, some for firm energy, others for secondary. The appropriate arrangement would depend on IRS considerations, physical factors relating to interconnection and competing sources of power, and the composition of existing and projected demand in the market served by each project.

Power sales agreements would be concluded <u>prior</u> to initiating construction of any project.

Regardless of the exact form of agreement, each project would be expected to sell power at rates and in amounts sufficient to generate revenues equal to

1) Its proportionate share of debt service and coverage,

2) Its direct costs of operation and maintenance, and

3) Restore reserves.

In addition, the agreements and the covenants with bondholders would provide for a step-up in each project's wholesale power rate to temporarily absorb a systemwide revenue shortfall due to interruption of service or payment default at other projects in the system. Coverage on a systemwide basis would assure that interruption of service or default on one or two of the smaller projects could be absorbed within the system.

For certain purchasers there may be need to limit amounts of power self-generated or purchased from non-Authority sources.

Wholesale Cost of Power:

The allocation of systemwide debt service and associated costs has been the subject of repeated legislative deliberations. H.B.9, which currently governs this matter, provides for the allocation of systemwide debt service to each project in proportion to the ratio of that project's cost to total system cost. The wholesale cost of power for that project is then the sum of its share of annual debt service, its share of coverage and its direct operating costs divided by kilowatt-hours sold.

Attached as an appendix is a mathematical study of the affect on rates as new projects having different cost, capacity, debt/equity ratio and utilization rates are added to the system.

Additional Parity Bonds and Permitted Indebtedness::

Additional bonds could be issued to finance additions or improvements to projects already in the system, and to finance construction of new projects to be added to the system, provided that:

1) New projects did not benefit from any legislatively mandated power rate limit.

2) An independent, nationally recognized consulting engineering firm shall have concluded that the project is needed, technically and financially feasible, compatible with existing resources and that project revenues will be at least equal to annual operation and maintenance and 1.10 times maximum annual debt service for the additional debt required to construct the project.

3) In the first full year following project completion the ratio of additional annual debt service to total project cost cannot exceed the systemwide ratio of annual debt service to project cost as determined in 198__.

4) An independent, nationally recognized consulting engineering firm shall have concluded that the project is needed, technically and financially feasible, compatible with existing resources, and

that under these requirements wholesale rates for all projects, except so-called "capped" rate projects, do not increase and may decline, depending on the initial year power sales of the added project.

In addition, without regard to these tests, completion bonds having a par value no greater than 15% project cost may be issued.

Interim notes and other short-term indebtedness could be issued to temporarily finance construction costs of power projects. Such notes or other short-term indebtedness would be payable from moneys held in the retained coverage account and the proceeds of system bonds thereafter issued to permanently finance the project.

Ratings:

Rating analysis would begin with an evaluation of the financial and operating strength of the Authority and the power system it owns and operates. The system's strength would be its size, geographic and market diversity and the substantial equity contributions of the State. Ultimately, a rating of the system takes on the character of a rating of the principal centers of economic activity in Alaska. However, in the early years of the system's creation it will be vulnerable to a single project default, outage or failure to achieve projected power sales.

For this reason it will be essential to provide through legislative appropriation sufficient Authority reserves to absorb problems associated with one project without resorting to the moral obligation.

Having evaluated the economic strengths of the system and its revenues, the rating services will consider, among others, the following items:

1) Type of power sales contracts and the resulting allocation of project risks, marketing risks and risks of catastrophic loss.

2) Probability that projected load growth and project utilization will be realized.

3) Arrangements for project construction operation and maintenance and the experience and expertise of personnel involved.

4) Adequacy of reserves and rate revision powers to meet adverse operating experience.

Bond Marketing:

The combined security of the Authority's general obligation, its statewide power sales revenues, state-funded systemwide reserve funds and access to the State Legislature through the moral obligation feature gives an investor several layers of security and of a dollar magnitude sufficent to meet all but a systemwide crisis. In addition, the financial interconnection of projects while not equivalent to physical connection, provides the benefit of diversifying certain economic and geotechnic risks. At least in part, the focus of credit analysis is shifted away from individual utility systems and toward a statewide analysis of power needs, resources and state financial strength.

Investors will devote special attention to limitations on future projects that can be added to the debt of the system so that they are assured that uneconomic or infeasible projects will not be allowed to dilute bondholder security.

Allocation of Project Risk:

By its very nature, system financial structure will alter the allocation of project risk to include the power purchaser, the Authority and, contingently, the State of Alaska. Thus, the magnitude of resources available more nearly approaches the range of probable losses. In addition, the expertise of the Authority qualify it to better manage and control the project risks.

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SECTION 7

REVIEW AND ASSESSMENT OF ALTERNATIVES FOR DISPOSITION OF PROJECTS UPON COMPLETION

As projects developed and financed by the Authority are completed, the question of who shall own and operate them becomes timely. These questions have been raised from a number of quarters and they were included as part of the scope of work of the Study.

OWNERSHIP OF COMPLETED PROJECTS

Our discussions with the Authority's bond counsel and investment bankers indicate that there is little flexibility with regard to the question of ownership of completed projects. If the Authority undertakes debt financing for a particular project, title to that project will have to be vested with the Authority. It is suggested that any further questions on this subject should be directed to the Authority's bond counsel or the Attorney General.

This situation is not different from that found in the lower 48 states. In recent years there has been a definite trend away from the development and ownership of projects by individual utilities. Project development has, by and large, been undertaken either by a consortium of utilities acting jointly with one designated as a project manager, or by so-called joint action agencies. In the case of projects developed by a consortium of utilities, each of which contributes money to the project, the participating utilities own an undivided interest in the project in proportion to their financial participation. In the case of projects developed by joint action agencies, the situation is similar to that faced by the Authority. If the joint action agency issues debt to finance a project, it then must own the project.

PROJECT OPERATION AND MAINTENANCE

With respect to the operation and maintenance of completed projects, there is considerably more flexibility. Financing considerations dictate that assurance be provided that the projects will be operated and maintained by an agenacy that is competent to do this work. Therefore, any arrangement for operation and maintenance will have to be disclosed at the time of financing. Beyond this, however, the decision as to the entity that will operate and maintain projects developed and financed by the Authority is one that would be made on the basis of relative economics and political considerations.

General Utility Practice

Almost without exception, utilities operate those projects which they develop and finance. With the advent of projects that involve the participation of a number of utilities, the general practice has been that one of those utilities is designated as the project manager. Most commonly, this will be the utility that has the largest ownership share in the project or the utility in whose service area the project is located. An operating committee composed of representatives of each of the utilities that oversee the operations generally determines the operational arrangement for the projects.

For projects developed by joint action agencies--that is agencies formed primarily for the purpose of construction of power projects--there are two basic alternatives. If the agency is comprised of utilities that do not have their own major generation projects, or if the agency is developing a number of large projects, it is likely that the agency will develop a capability for project operation and will perform this function. In cases where one or more of the participating utilities in the joint action agency do operate their own generation it is not uncommon that one of these utilities will, under contractual arrangements, assume the role of the project manager and operator.

Alternatives for Operation and Maintenance of Authority Projects

There are three basic alternatives for operation and maintenance of projects developed and financed by the Authority:

- The Authority could operate and maintain one or more of the projects that they finance.
- One or more projects could be operated by local utilities serving the area where the project is located under a contractual arrangement with the Authority.
- One or more projects could be operated by local utilities, as described above, with the Authority maintaining certain responsibilities with respect to maintenance and overhaul work.

The operation and maintenance decision should be made on the basis of the economics involved, and, of course, political considerations. If a particular project is located within the service area of a utility that is already capably operating similar projects, then serious consideration should be given to a contractual relationship under which that utility would operate the Authority's project. If the project location is not as described above, then either the Authority or some other entity will have to develop operational staff at the project location. Here, the decision should be based on who can provide the most economical and efficient service. It should be noted that the Authority has contracted with the City of Ketchikan for the operation of the Swan Lake project. This is certainly consistent with the discussion above.

As the several projects that are now under construction are completed, the Authority may operate some projects itself with individual utilities operating others. To provide appropriate management control over projects that are operated by the Authority and to maintain a capability for oversight and inspection of projects operated by local utilities, the Authority is developing an operating staff. We believe that this effort reflects a prudent business approach given that a number of projects are near completion. Beyond the decision as to what entity will operate a particular project, consideration should be given to the potential savings of centralizing, with the Authority, certain responsibilities with respect to maintenance and overhaul work. The Authority may find that it is efficient to maintain a centralized inventory of certain parts. Also, it may be more efficient for the Authority to maintain a staff qualified to undertake heavy maintenance and overhaul work. This staff might consist of supervisory personnel that would be available to oversee work at all projects or, depending on the capability of individual utilities, it may be advantageous to actually maintain crews that could perform this work.

Operation and Maintenance of Other State Funded Projects

In the course of our work it was observed that a number of power generation facilities have been constructed throughout the State with funds appropriated by the Legislature or obtained from State agencies other than the Authority. We understand that, at least in some cases, long term arrangements are not always made for the operation and maintenance of these facilities.

It has been suggested that a procedure be established to assure that generation facilities constructed with State funds are properly operated and maintained so that the full benefits can be enjoyed by the people that they are intended to serve. We believe that consideration should be given to establishing a requirement, as a condition of providing funds, that the service area make arrangements for operation and maintenance before funds are actually provided. For example, the Alaska Village Electric Cooperative might be able to efficiently fulfill this function in the bush area. In other areas of the State, utilities could serve this function if the generation facility was sited in their service area.

NOTES

1/ *Alaska Power Authority 1981 Year-End Report* p.1

2/ State Statute SCS CSHB 779 amS, section 44.56.010(a)(1),(b)

3/ It had already been agreed that Alaska should gradually decrease its use of energy sources over which it had relatively little control with respect to supply and/or price. To accomplish this it was necessary to choose energy sources that were insulated to some extent from inflation, extreme competition, or from price pressure in other markets outside Alaska. In effect, this equates to a preference for hydroelectric, coal, and perhaps solar, wind, or wood.

4/ State Statute HCS CSSB 438(Finance)amH, section 44.83.080(5)-(10)

5/ State Statute HCS CSSB 438 (Finance)amH, section 44.83.080(16)

6/ A characteristic of hydroelectric power (a capital intensive project) is that it is often difficult to match the project's output to existing market area requirements. The project site characteristics often determine the scale of cost-effective development. In instances such as this, State intervention can allow the project to be built. The State can ensure that power rates remain within mandated guidelines until demand increases sufficiently to utilize the project's excess capacity.

7/ State Statute HCS CSSB 438 (Finance)amH, section 44.83.170(2)(c)

8/ If a reconnaissance or feasibility study, financed by a loan from the Power Project Fund, determines that the investigated project is not feasible, then the Legislature may forgive the repayment of the loan.

9/ This bill was passed at a time when State revenue projections were much higher than they are today. The State originally intended to pay for the construction of power projects entirely by cash.

10/ State Statute FCCSSB 25, section 44.83.384(b)(2)

11/ SB 25 also added two specific criteria that a candidate must meet in order to receive money from the Power Project Fund: The Authority must determine that the project is economically feasible, and, after construction, the operation of the power project must be able to provide revenue sufficient to return annually to the State five percent of the amount that the Authority has spent from the fund. No return to the State was actually required, but the latter provision was intended to serve as a type of market test for projects.

12/ The time frame within which the forecast was to be prepared and the guidelines under which it was conducted made such utility involvement difficult, if not impossible, to achieve in a meaningful way.

13/ As of this writing this interconnection appears essentially assured of proceeding.

14/ The general approach used in the Bristol Bay Regional Power Plan Detailed Feasibility Analysis, as described in the July 1982 Interim Feasibility Assessment prepared for the Authority, appears to provide a reasonable model for the type of market area analysis which could be incorporated at the reconnaissance study stage, perhaps in less detail.

15/ Examples are Tyee Lake, Black Bear, and Old Harbor.

16/ A nominal dollar energy cost projection is an estimate of future energy costs including estimated inflation. This represents an estimate of what the costs are expected to be in the year that they are incurred.

17/ A method of evaluating the savings in power cost for each dollar of capital investment in a project.

18/ Most notably, the Corps of Engineers and the U.S. Department of Energy.

19/ An overnight capital cost is an estimate, in today's dollars, of what it would cost to construct a project today, ignoring the anticipated escalation of the capital cost which would occur over the actual period required for project planning and construction.

20/ Article 3 AAC 94.060 Alaska Power Authority, Register 81, April 1982.

21/ Article 3 AAC 94.065, Alaska Power Authority, Register 81, April 1982.

22/ The provisions described would apply only to proposed new projects which will generate more than 1.5 megawatts of power and which require an appropriation from a State fund or are based on a plan of finance which requires a pledge of the credit of the State. These provisions would also apply to a project which will generate more than 25 megawatts of power and whose cost of construction will require the issuance of Authority revenue bonds. Finally, these provisions would apply to electrical transmission or distribution facilities which cost more than $3,000,000 to construct, or to additions or modifications which cost more than $1,000,000.

23/ The State of California, as an example, has adopted a similar method for ranking and selecting energy conservation equipment and conservation programs for implementation at State facilities.

24/ U.S. Army Corps of Engineers Report.

25/ All cases assume the Bradley Lake Hydroelectric Project (90 MW) is built.

26/ A levelized cost is an annual average energy cost, which, if paid at a fixed rate over the period of analysis, would yield the same total present value cost of energy.

27/ Except for the analysis of regional energy demands for the larger Melozitna project, described later in this section.

28/ State Statute SCS CSHB 779 amS, section 44.56.090

29/ State Statute SCS CSHB 442, section 44.56.090(a)

30/ "Legislative History of Alaska Power Department Statutes 1960-1982", House Research Agency (9/28/82), p.5

31/ Senate Journal, May 31, 1982, p.1638

32/ Under 44.83.080 (8) and (14), the Authority has the following powers:

> (8) to accept gifts, grants, or loans from, and enter into contracts or other transactions regarding them, with any person;
>
> (14) to enter into contracts of agreements with respect to the exercise of any of its powers, and do all things necessary or convenient to carry out its corporate purposes and exercise the powers granted in AS 44.83.010-44.83.510;

33/ State Statute HCS CSSB 438(Finance)amH, section 44.83.100(8)

34/ State Statute HCS CSSB 438(Finance)amH, section 44.83.110(b)

35/ State Statute HCS CSSB 438(Finance)amH, section 44.83.140

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