Volume I

FINAL REPORT

Alaskan Electric Power

An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region

March 1978

For
Alaska Division of Energy and Power Development, Department of Commerce and Economic Development; and the Alaska Power Authority

Battelle
Pacific Northwest Laboratories

LEGAL NOTICE

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Development; and the Alaska Power Authority

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March 1978

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PREFACE AND ACKNOWLEDGEMENTS

This report presents the findings of an analysis conducted for the Division of Energy and Power Development of the Department of Commerce and Economic Development, and the Alaska Power Authority.

The analysis has benefitted strongly from contributions supplied by a number of people throughout the State and from the "lower 48". In particular, we would like to acknowledge the following organizations and people:

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Effective power system planning is not a "one-shot" effort. Rather it must be a continuous process as the system evolves. Thus the findings presented here must be treated largely as a starting point for future integrated system planning for the Railbelt. In that light, the authors hope that the work reported herein proves of value to the State of Alaska's power systems planners and decision makers. We would welcome comments, questions, and criticisms.

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1.0

Alaskan Electric Power

An Analysis of Future Requirements and Supply Alternatives

For the Railbelt Region

Prepared for the

Division of Energy and Power Development
Department of Commerce and Economic Development

and the

Alaska Power Authority

by

Battelle

Pacific Northwest Laboratories

December 1977

1.0 INTRODUCTION

The purpose of this report is threefold:

1. To provide an integrated analysis of alternatives for meeting the electric power requirements anticipated for the Railbelt Region of Alaska, the primary objective being to minimize the cost of power to the consumers.[a] The timespan for the analysis verges into the next century.

2. Provide a background of reference information for Alaskan policy makers and planners as well as the general public. Since the cost of power is expected to increase in the future for a variety of reasons, it is essential that all parties understand the causes in advance and how they may be influenced by the different options available for power generation.

   Certain of the physical and economics data presented in this report differ from previously published information. We have attempted to up-date all information to a common basis for comparison, and where possible, have provided documentation tracing back to the original data.

(a) For the purposes of this study, the Railbelt Region is defined as the Cook Inlet Region including the Kenai Peninsula and Anchorage, the Matanuska and Susitna Valleys, and the Fairbanks-North Star Borough.

3. To identify the economic and State and Federal policy considerations and and uncertainties that influence power system planning and indicate the sensitivity of power costs to these variables.

The Alaskan Railbelt region presents some unique attributes for consideration in future power system planning. The region currently consumes 83% of the State's electric power and even the lower estimates of electric load growth (9% per annum) for the region are significantly above the national average.

The State and particularly this region is a difficult one in which to forecast loadgrowths. This difficulty results from the nature of the economic activity base being influenced by external forces such as oil and gas developments and transportation systems with their cyclical tendency. Also since the economic base is still not large, the injection of a competitively scaled industry such as a major petroleum refinery or electrochemical industry can significantly perturb a forecast.

A major shift in the Alaskan Railbelt future power generating mode appears inevitable. The Cook Inlet regions capacity is presently dominated by combustion turbines fired by currently low cost natural gas; the Fairbanks-North Star Burrough by a mix of coal-fired steam turbine generation and oil-fired combustion turbines. The oil and gas based modes of generation however are highly exposed to inflationary pressures , external market forces, and Federal regulatory intervention.

The Railbelt region however does have a number of options open in the future. These include:

- Continued use of oil and gas (which have higher valued alternative end uses and thus may be subject to excise tax) in existing plants.
- Increased coal based thermal generation both in the interior based on the Healy Coal Field and in the Cook Inlet Region based on several coal fields including the very large reserves in the Beluga region.
- Development of the very significant hydroelectric potential including the Upper Susitna River, Braldey Lake, Chakachamna, Woodchopper, and

Wood Canyon. For a variety of reasons (including scale, costs, and environmental considerations), the Upper Susitna, Bradley Lake, and Chakachamna Projects are of more immediate interest as a means of establishing relatively inflation proof blocks of capacity. The other hydroelectric projects may well be considered prior to 2020.

- A transmission intertie between the Cook Inlet and Fairbanks load centers is of obvious interest as a means of increasing reliability or alternatively reducing additional generating capacity needed for reliability. Marketing of power from Upper Susitna projects will be dependent upon such an intertie.

Federal and, to a lesser degree, State policies are major considerations. The Federal Clean Air Act and its 1977 Amendments, particularly the provisions for "best available control technology" (BACT) regardless of coal sulfur content (Alaska's coals are very low in sulfur), may result in higher capital and operating costs of generation. The "prevention of significant deterioration" (PSD) provisions in the same act also affect costs and limit the amount of thermal generating capacity that can be installed at any one location.

Federal energy policy may have even a more profound influence and detrimental impact on power costs in Alaska. Various provisions in proposed legislation include 1) prohibitions against certain fuel uses, 2) tax disincentives on certain fuel uses, 3) minimum federal electric utility rate setting standards, 4) requirements for increased interties, 5) regulation of intrastate natural gas prices, 6) deregulation of new natural gas, and 7) tax incentives for fuel conversion and conservation. Because of certain unique aspects of Alaska's fuel situation, the economic impacts may be disproportionately greater here than in the rest of the nation. In any event the avowed State policy of minimizing energy costs to the consumer is counter to the effect of the national administration's policy. On a per capita basis, Alaska's power needs are however greater than the national average.

Electric power generation by whatever means is a very capital intensive activity. Different forms of generation however have different levels of exposure to inflation and escalation and cost comparisons on a straight

$/kw of installed capacity can be misleading. Thus a higher cost per kilowatt hydroelectric project has this exposure largely limited to the time period during planning and construction. On the other hand, a fossil fueled plant, though initially less costly, faces rising fuel costs as well as operating and maintenance costs in the future. Regardless of these factors, all generation options are faced with long lead times from decision to proceed to commercial operating date.

Power system planning for the future, regardless of circumstances, cannot be a one-shot affair: influences on future loads may change, regulatory considerations are in flux, and new information of importance arrives monthly. Thus, the following report must only be regarded as a first step toward integrated planning for the Railbelt region. A sustained planning effort is much needed.

2.0

2.0 EXECUTIVE SUMMARY AND RECOMMENDATIONS

This report has been prepared for the Alaska State Department of Commerce and Economic Development, Division of Energy and Power Development and the Alaska Power Authority by Battelle Memorial Institute, Pacific Northwest Laboratories. The primary objective has been to examine possible future electric power requirements and resources for the Railbelt Region to the year 2000 and to identify means of achieving the lowest cost of power to the consumers given constraints of timing, resources availability, and law. Highlights of our findings are as follows:

2.1 ELECTRIC POWER REQUIREMENTS (See Chapters 4.0 and 8.0)

- Electricity consumption in the Railbelt Region during 1976 was approximately 1.85 billion kWh.
- There are a wide range of forecasted or projected Railbelt power requirements. Elimination of low probability scenarios narrows the range considerably but as shown below, the range remains fairly wide.

Year	Annual Consumption[a]	Compound Annual Growth Rate(%)
1974	1.6 B kWh	
1980	2.6 to 3.4 B kWh	8.4 to 13.4 (1974-1980)
1990	8.5 to 10.8 B kWh	9.6 to 15.3 (1980-1990)
2000	16.0 to 22.5 B kWh	4.0 to 10.2 (1990-2000)

- Because of this wide range, the consequences of overbuilding or underbuilding should be considered. If overbuilding occurs, security is increased because the likelihood of service interruption and curtailments are reduced, but idle capacity increases the cost of electricity. Underbuilding avoids the problem of idle capacity, thus reducing the cost of electricity, but security is reduced because the risk of curtailment or interruption is increased.

(a) Includes uses by utility and industrial customers likely to be part of an intertied system. Excludes national defense and non-intertied users.

- For a Combined Railbelt Region (transmission intertie between Anchorage and Fairbanks), between 1950 MW and 3230 MW of new generating resources may be required between 1977-78 and the turn of the century.
- For the "Fairbanks" load center operating separately, between 237 and 737 MW of new generating resources may be required over the same time period.
- For the "Southern" load center operating separately, between 2250 MW and 3790 MW of new generating resources may be required.
- The Alaska Railbelt power system is strongly winter peaking. Power requirements at peak are approximately twice as high as the annual average requirement.

2.2 EXISTING AND NEAR-TERM PLANS FOR GENERATING RESOURCES (See Chapter 5.0)

- Near-term plans by Railbelt utilities for generating resources additions extend through 1986.
- The "Southern" load center has a currently installed capacity (exclusive of military and industrial resources) of approximately 566 MW, the majority of which is based on natural gas fired combustion turbines (∿512 MW).
- The "Fairbanks" load center has a currently installed capacity (exclusive of military resources) of approximately 295 MW, the majority of which is based on oil fired combustion turbines (∿209 MW).
- Thus the total net generating capacity of the Railbelt Region (exclusive of small communities along the Railbelt, industrial generation, and military resources, totals approximately 861 MW. Military and industrial resources add an additional 126 MW.
- Planned additions to the "Fairbanks" load center to 1983 will bring installed capacity to 587 MW assuming no retirements. Of the planned new resources, 130 MW is a coal fired steam turbine, the remainder oil fired combustion turbines.

- Planned additions to the "Southern" load center to 1986 will bring installed capacity to ∿1446 MW. Of the planned new resources, 400 MW are of coal fired steam turbines, the remainder are gas fired combustion turbines or additions of regenerative or combined cycle units.

- A significant fraction of the "Fairbanks" and "Southern" area capacity additions may be questioned under the pending National Energy Policy. These include in "Fairbanks", the 70-100 MW North Pole #3 (1981) and in "Southern", the 336 MW of new (gas) combustion turbine units. To be allowable under the national policy they may need to be shown necessary for peaking. Since they represent significant fractions of the installed capacity, such a justification may be difficult. Contingency planning is recommended as other alternatives (addition of combined cycle operation to other units) may exist. (See Section 8.5)

2.3 VIABILITY OF HYDROELECTRIC OPTIONS (See Appendix B)

- The Alaskan Railbelt Region has numerous hydroelectric power potentials. The Upper Susitna River is particularly blessed with adequate water supplies and sites suitable for the construction of dams and reservoirs for the generation of hydroelectric power. Full confirmation of physical site adequacy must await more detailed geologic exploration and site foundation information. Although preliminary examinations are favorable in most cases, the Upper Susitna River basin lies in an area of frequent earthquakes of major character and project safety demands a complete site analysis followed by a conservative project design. The environmental impacts of most of the project potentials are believed to be minor in nature although additional data is required for full analysis.

- On this basis, any consideration of measures to provide electric power for the Railbelt Area must include evaluation of hydroelectric power options. Of the many hydropower options available, as discussed in Appendix B, the following systems appear to be the most viable, subject to confirmation of site adequacy. The

Denali project could ultimately be added to each system if the site is found adequate for development.

a. Watana (High) and Devil Canyon
b. Devil Canyon, Watana (Low) and Vee
c. Susitna I, Olson and Vee

- The high Watana-Devil Canyon system, recommended in the Dec. 1975 Corps of Engineers Interim Feasibility Report, will provide the best development at the lowest unit cost. The recommended Watana project would be a record 810 ft. high earth and rock fill embankment dam. Because of the seismic hazard, complete site analysis and careful design must be assured. The recommended Devil Canyon project is proposed as a concrete thin arch dam which could be questioned for this high seismic risk area. Since a perfect site is not available for the thin arch, a concrete gravity structure or rock embankment dam may be preferable at essentially the same cost or a gravity arch dam at some increase in cost.
- The Devil Canyon - Low Watana and Vee system, subject to the above reservations regarding the type of dam at Devil Canyon, provides a viable system potential avoiding extreme height at Watana and also the large initial capital investment of the preceding plan because of high Watana. It would provide essentially the same power capabilities but at a higher ultimate cost.
- The Susitna I, Olson and Vee system would also provide essentially the same power capability as Watana-Devil Canyon but at substantially greater cost. Less is known about these project sites than the others hence it would be preferable to assign this system a third priority against the possibility that Watana or Devil Canyon sites prove defective upon detailed study.
- A brief comparison of the three systems is given below on the basis of an ultimate development in each case including the Denali project storage of 3.8 million acre-feet.

	A* Watana-Devil Canyon	B* Devil Canyon-Watana-Vee	C* Susitna I-Olson-Vee
Usable Storage	12.7 million Acre feet	7.7 million Acre feet	8.7 million Acre feet
Dependable Capacity	1550 MW	1430 MW	1350 MW
Average Annual Energy	6.9 billion KW-hr	6.9 billion KW-hr	6.5 billion KW-hr
Construction Cost (including transmission)	$2.27 billion	$2.58 billion	$3.12 billion

* Includes Denali in each case to compare possible ultimate systems.

- Dam safety is of concern not only to the design engineers but also to the public for their acceptance. Although an overly conservative concept may result in higher than necessary power costs, it must be recognized that delays in gaining public acceptance can be equally costly in terms of having to provide interim generating resources or just from escalation during this period required to gain acceptance. Thus a more conservative and apparently more costly concept may prove the best option.

2.4 CAPITAL AND OPERATING COSTS OF GENERATING CAPACITY (See Chapter 6.0)

- A 200 MW coal steam turbine generating plant located in the Anchorage area is estimated to cost $1120/KW not including flue gas desulfurization (FGD) and $1280 including FGD. The same plant would cost $1220/KW if built in the Beluga area without FGD and $1400/KW with FGD. If built in the Healy/Nenana area these plants would cost $1470/KW and $1710/KW respectively (January 1, 1977 dollars).

- A 100 MW oil or gas combined cycle generating plant is estimated to cost $300/KW in the Anchorage area and $380/KW in the Fairbanks area (Jaunary 1, 1977 dollars).
- The combination of Watana and Devil Canyon dams including transmission facilities to the Fairbanks and Anchorage load centers are estimated to cost about $1.8 billion ($1,147/KW) (January 1, 1977 dollars).
- Both residual fuel oil and new natural gas is estimated to cost about $2.50 per MMBTU during the 1985-2000 time period (January 1, 1977 dollars).
- Beluga coal is estimated to cost $0.85 per MMBTU at the mine mouth and $1.00 per MMBTU at the coast (January 1, 1977 dollars).
- Healy coal is estimated to cost $0.70 per MMBTU F.O.B. Healy. Railroad transportation would increase the cost to $0.90 per MMBTU delivered to Nenana and $1.10 per MMBTU delivered to Anchorage (January 1, 1977 dollars).

2.5 FINANCING CONSIDERATIONS (See Chapter 9.0)

- Current Railbelt electric power generation, transmission and distribution if financed and operated by cooperative associations in part financed through the Rural Electric Administration, by munitipal utilities, and a small fraction by the Alaska Power Administration of the U.S. Department of Energy.
- Future additions to the Railbelt power supply system can include the above entities or financing through the recently established Alaska Power Authority (APA), a State entity.
- The APA can directly finance (through revenue bonds) generation and transmission projects, can loan funds to existing entities, can guarantee power purchase through contracts with generators, and can finance the capital investment for coal (or other) resource development.

- Battelle suggests the APA should endeavor to measure and account for the opportunity cost of alternative uses of state funds in the cost of power produced and distributed by the Authority.
- APA financing should in the long run lower the cost of borrowing by 0.2 to 0.4 percentage points as compared to other financing alternatives.
- For capital intensive projects such as coal-steam turbine power generation, APA financing reduces busbar power costs 9-15% compared to REA financing. For combined cycle combustion turbines, the reduction is about 2%.

2.6 RAILBELT SYSTEM ALTERNATIVES AND COSTS (See Chapter 8.0)

2.6.1 Power Costs

- Hydroelectric power options (Upper Susitna, for example) typically produce power delivered to Anchorage and Fairbanks at costs 1/3 to 3/4 the cost of coal-steam turbines or combined cycle units regardless of inflation rates.
- Hydroelectric power from the Upper Susitna is not expected to be available until 1991.
- Bradley Lake (70 MW) and Chakachamna (366 MW) both have power costs less than thermal generation power costs. Chakachamna project costs are in doubt, however.
- Over the long run and for new units, power costs at the "Southern" load center are near a trade-off (±5%) between coal fired Beluga, coal (Healy) fired Anchorage area, and oil or gas fired combined cycle systems.
- For the Fairbanks region, oil or gas fired combined cycle units produce power at lower cost than coal-steam located at either Healy or Nenana if flue gas desulfurization (FGP) is required. The situation reverses is FGD is not required.
- The cost of power resulting from a requirement for FGD will increase the cost of power 11 to 16%.

- Economics of scale for coal fired plants level off fairly rapidly after 200 MW.
- The possible requirements for off-stream cooling and Alaska's climatic conditions may require wet (summer)/dry (winter) cooling for heat rejection for coal fired plants. A wet/dry system not only increases capital costs, it also reduces the plant heat rate. The net result is about a 7% increase in power cost. An EPA Section 316 variance for on stream, or cooling pond operation is obviously worth pursuing.
- Costs of power from coal fired plants are sensitive to cost impact parameters in the following order (See Page 8.11).
  1) Fuel cost escalation (not inflation) rate
  2) Plant heat rate (BTU/KWhr) and unit fuel costs
  3) Plant utilization factor (PUF)
  4) Capital cost
  5) Construction escalation rate.
- Costs of power from hydroelectric plants are most sensitive to:
  1) Capital costs
  2) Construction escalation rate (later plants).
  3) Plant utilization factor (PUF).
  4) Financing discount rate.
- Costs of maintaining reserve generating capacity (See Page 8.19) are understandably less with combustion turbines than with coal-steam plants. For the former, the costs are minimal; for the latter, not large but still substantial.

2.6.2 Matching Forecasted Requirements With Planned and Potential Resources (See Chapter 8.0).

- The Railbelt Region is not presently intertied between the "Fairbanks" and "Southern" load centers. Based on the analyses to follow there may be economic justification to do so by the mid to late 1980's.

- The "Fairbanks" load center currently has a strong surplus of generating capacity to meet peak loads. Based on low and high forecasts for 1977-1978, the area has gross resources (less losses) of approximately twice the estimated area peak loads.
- Current utility plans for capacity additions (237 MW by 1983) in the Fairbanks area appear more than ample for the probable maximum load growth until the early 1990's. The utilities hope to be able to avoid the currently planned installation of the 70-100 MW_e North Pole -3 combustion turbine and proceed with the Healy -2 coal fired plant.
- The "Southern" load center, based on the probable low range of load forecasts, will require an additional 400 MW of capacity by about 1988-89 over and above current plans.
- For the probable high range of load forecasts, the "Southern" load center is in a deficit situation now on peak after allowing a 20% reliability reserve margin and 10% for losses. If the requirements at peak follow the high forecast, a total of 800 MW of new (not currently scheduled) capacity will be required by 1988-89.
- At the probable maximum load forecast, the "Southern" load center could absorb all Watana and Devil Canyon hydropower by 1999-2000 and in addition require 1600 MW of thermal capacity beyond that planned.
- For a combined Railbelt (transmission intertie) system under conditions of probable low load forecasts, an additional 200 MW of thermal capacity will be needed by 1989-90 and power from a fully developed Watana can be marketed by the year 2000.
- For the probable high load forecast, the combined system will require 800 MW of thermal capacity by 1990-91, and the power from a fully developed Upper Susitna System (Watana plus Devil Canyon) can be marketed by 1999-2000. Upper Susitna hydropower will be needed about as fast as it can be brought on-line.

- Operation of separate load centers vs a combined intertied system will require several hundred more megawatts of generating capacity.

2.7 INSTITUTIONAL CONSIDERATIONS (See Chapter 10.0)

2.7.1 Federal Environmental Policy and Regulations

- Numerous federal environmental policies and regulations will impact the timing, siting, design, costs, and operation of power generation facilities both thermal and hydroelectric. The major acts include the National Environmental Policy Act, the Clean Air Act Amendments of 1977, the Federal Water Pollution Control Act Amendments of 1972, the Fish and Wildlife Coordination Act, and the Surface Mining and Control and Reclamation Act of 1977.

- In addition, the multiplicity of permit and approval processes at both the federal and state level is a source of duplication in information preparation, case presentation, and decisional processes, and can result in delay and multiple litigation. Because of these general institutional and process factors, it is recommended that the Alaska Power Authority

  1) prepare a critical path for the entire licensing process applicable to any proposed power project and the associated fuel type alternatives early in its planning,
  2) consider requesting federal license coordination through the Federal Regional Council, Region X,
  3) consider as alternatives to the present state multiple permit licensing process either the legislative enactment of a one-stop state or an executive coordination of the present state licensing system for bulk energy facilities to yield timely and final decision actions by the State, and,
  4) an early specification of the proposal concept and all of its reasonable alternatives.

  Because of lead times and financial commitments early in project development, project planning to assure environmental law compliance should be begun early. Time periods for permit approvals and litigation should be recognized when projecting generating resource availability.

- Federal licenses will be required for any major bulk energy facility located in the State of Alaska. Consequently, the mandatory provisions of the National Environmental Policy Act (NEPA) requiring environmental documentation for the proposal and the mandatory consultation required under the Fish and Wildlife Coordination Act should be planned for early in project development. The Authority should take steps to assure early NEPA compliance. Each federal agency normally has adopted its own regulations to implement the National Environmental Policy Act. The Authority should review and consolidate all NEPA regulations of federal agencies involved in any action for a proposed power project to identify the scope of studies necessary to prepare appropriate and complete documentation.
- It is extremely important to define the proposal objective in its narrowest sense and to identify all reasonable alternatives for accomplishing that proposal. Any and all alternatives that are reasonably related to accomplishing the project's objective should be identified and analyzed. Alternatives should include but not be limited to, the alternatives of no added power, power purchase, alternative sites, power rating and fuel type, and alternative configurations.
- The Alaska Power Authority should consider initiating contact with officials in the Fish & Wildlife Service early in project planning to identify concerns that agency may have as a result of project impacts upon water courses, fish and wildlife. Early consultation is desirable to permit the designing of mitigating conditions into the project.

Water

- Cooling water discharges from a power project must comply with national effluent limitations which control the amount of pollutants permitted to be discharged from the project. Liquid discharges also must comply with provisions of the State of Alaska's water quality standards, which standards include a non-degradation clause applicable where the ambient water quality is better than the water quality standards. These specific limitations upon a discharge reflect the fact that the "zero discharge" goal in the Federal Water Pollution Control Act Amendments of 1972 does not mean that there shall be no discharges but rather than stringent limits will be applied to control pollutants in a discharge. The Authority in this initial planning stage should assume no variances from the requirements when evaluating costs.

- Basic federal limits on new plants are standards of performance which have been defined by the Environmental Protection Agency. The regulations should be reviewed for cost implications in project planning and revisions to them by EPA should be monitored. The Standards of Performance require, where practicable, no discharge of a pollutant. Studies should be planned to identify whether there is an adequate legal and factual basis for finding that it is or is not practical to impose a no discharge standard upon some pollutants.
- Standards of Performance for new power plants essentially require <u>cooling towers</u> as a means of reducing the thermal discharge loads of a receiving water body. There is in effect a variance provision in the Federal Water Pollution Control Act Amendments of 1972, that being Section 316(a); but reliance upon its provisions to avoid a cooling tower requirement in Alaska may be imprudent when evaluating costs now in light of the Environmental Protection Agency, Region X's announced policy of opposition to once-through cooling for any new plant. Since, operation of conventional wet cooling towers in Alaska may present technical problems, the approximately 7% increase in power cost resulting from the need for wet/dry cooling must be recognized.
- EPA's regulations do not permit the use of <u>cooling lakes</u> for new plants. This regulation has been successfully challenged in Court; however, the revised regulations have not yet been promulgated. New coastal plants must use sea water cooling towers. The Authority

should determine the economic and technical feasibility of cooling lake alternatives and if appropriate, seek federal regulatory changes.

- Cooling water intake structures for a steam electric power plant are subject to a generic mandate that their design, location, capacity and operation must minimize adverse environmental impact. No specific federal agency has been given the statutory authority to implement this provision. The Authority should review the Development Document prepared by the Environmental Protection Agency which details the factors relevant to a determination as to whether a cooling water intake structure will have a minimum adverse environmental impact.

- Coal mining operations are also subject to effluent limitations that have been promulgated by the Environmental Protection Agency. These limitations should be reviewed in conjunction with the requirements of the Surface Mining & Reclamation Act of 1977 and state water quality standards to determine the allowable parameters and costs for liquid discharges from coal mining operations.

- Limitations upon water discharges can be made more stringent than the federal government by the State of Alaska. This can be done through issuance of its own discharge permit, through the state certification under Section 401 of the Federal Water Pollution Control Act Amendments of 1972, or requesting the imposition of more stringent conditions to achieve or maintain water quality conditions through Section 302 of the Act. Consultation with State personnel should be initiated to identify typical conditions. Similarly a review should be made of conditions in National Pollutant Discharge Elimination System (NPDES) permits issued by EPA, Region X, for steam electric power plants.

- The federal government has classified various water areas and made them subject to special statutory protection. One example is the Wild and Scenic River Bill which prohibits the issuance of any Federal

Power Commission (now Federal Energy Regulatory Commission) license for a project in a designated Wild and Scenic River area. Because of the probable expansion of Wild and Scenic River designations in Alaska under the announced policy of the Carter Administration (which is considering a study designation for the Susitna River) and the probable legislation to resolve the "D-2" Alaska Native Claims Settlement Act issue. The Authority should review potential additions to the Wild and Scenic Rivers Act for restriction of alternative sites.

- About 40% of the nation's wetlands lie within the State of Alaska. There is a statutory prohibition against filling or destruction of wetlands. A recently promulgated Executive Order by the President restricts any federal agency's financial support for projects located in the wetlands area unless no practical alternatives exist. The Authority should review all potential sites for impact upon wetland areas and a determination as to whether any practical alternative exists. Estuaries are also protected and a review should be made to determine if any are in the area where a project will be located since mitigating conditions are required in these areas.
- Hydroelectric facilities utilizing our nation's waters cannot be sited in a National Park without Congressional authorization. Emerging mitigating conditions applicable to hydroelectric facilities include the setting aside of alternative lands for recreational facilities, provision for fish passage and avoidance of nitrogen supersaturation, and upstream releases to moderate impacts upon a river's thermal regime. The Authority should review conditions included in Federal Power Commission (now the U.S. Department of Energy, Federal Energy Regulatory Commission) licenses to identify mitigating conditions that may be required if a hydroelectric facility is pursued.
- If the Corps of Engineers were to construct a hydroelectric facility, arguably a permit is not required by it from the Federal Energy Regulatory Commission (FERC). However, FERC can study the proposed project to determine what is a fair value for the power. If the Corps is to develop a project which the Authority has an interest in, efforts should be made to assure that appropriate consulting processes with FERC are effected in a timely fashion.

Air

- The Clean Air Act Amendments of 1977 are basically directed to prevention and control of air pollution at its source. The states are primarily responsible for the implementation and enforcement of the law's objective. While there is no "zero discharge" standard in the Clean Air Act as there is in the Water Pollution Control Act, there is a nondeterioration provision and a requirement of improving air quality to meet national standards.

- Standards relating to emissions from a coal, oil, or gas fired plant, are based upon National Ambient Air Quality Standards, hazardous standards, the Prevention of Significant Deterioration (PSD) of ambient air quality requirements, and the Standards of Performance would require continuous emission reduction at the point of discharge. For any proposed project in the State of Alaska, not only should these standards be reviewed, but also the site should be examined to determine if it is in a nonattainment area, near federal Class I lands, or near areas that would be reclassified to Class I, and if the site is subject to more stringent incremental limits upon emissions under the Prevention of Significant Deterioration (PSD) rules. Designation of Nonattainment areas for carbon monoxide in Fairbanks and Anchorage and total suspended particulates in urban areas are possible and should be accounted for in project planning. If a project is located in a nonattainment area, a plant's licenseability is questionable unless progress can be made towards achieving the national standard which is violated in the area when the new source is present by use of the lowest available emission rate. One way of achieving this under the EPA regulations is to "offset" the increased discharges from the proposed power project by closing down other sources in the nonattainment area. EPA may extend the offset policy to plants located near but not within nonattainment areas. The State of Alaska may wish to consider in its air quality control strategies such an offset policy to assure the availability of a site for a power project in the future. Limits upon benzine and radiation (radan, etc.) from coal fired plants should also be anticipated.

- Application of the Act's best available control technology (BACT) requirement should be considered to mean scrubbers for SO_2 and electrostatic precipitators for particulate emissions. Because the Standards of Performance require a percentage reduction in flue gas emissions, pretreatment of coal will not result in any credit that would otherwise reduce the technological system requirements for coal project. The Authority should evaluate the cost differentials as a function of fuel type for all applicable standards and area classifications.

- The State can set more stringent Standards of Performance and consultation with the appropriate state agency should be pursued to monitor such efforts. The State of Alaska may wish to consider reserving certain emission increments under the Prevention of Significant Deterioration requirements or national ambient air quality standards for future power projects,

- The Prevention of Significant Deterioration (PSD) regulations basically require that the existing air quality cannot be deteriorated as a result of the project's emissions. Depending upon a land area's classification under the regulations, the incremental release of pollutants becomes increasingly stringent. The most stringent increments apply in Class I areas which in Railbelt Alaska at the present time only encompasses the Mt. McKinley Park area. Even though a plant may be located in the Class II area, if it is close enough to a Class I area that it impacts its air quality, the Class II site could be restricted. While no automatic buffer is required around the Class I areas, the coldness of Alaskan air and the need to use cooling towers could cause a problem restricting sites within sixty to one hundred miles of a Class I area. The Alaskan limitation upon ice fog conditions should also be reviewed because of its impact on cooling tower operations. The Healy area is particularly exposed to the implications PSD regulations.

- The Clean Air Act mandates a preconstruction review and permit by the State of Alaska. To support issuance of such a permit, studies involving ambient air quality monitoring data and the impacts of growth resulting from the availability of the project must be studied.

The Authority should initiate such studies well in advance of a permit application and coordinate these studies with work to satisfy NEPA's requirements.

- Tall stacks have been used to disperse pollutants in a larger air shed so that emission levels are diluted. Stack heights are constrained under the Clean Air Act to what constitutes good engineering practice. As an initial reference point, stack heights in excess of 2-1/2 times the plant height are prohibited. Restriction upon stack heights when a plant is located in a hilly terrain area can reduce the otherwise planned for plant output.

Coastal Zone

- Alaska has not prepared a Coastal Zone Management Plan. The policies and components of such a plan could be foreseen by review of the Federal/State Land Use Planning Commission's work. The Authority should review its work. The Federal Coastal Zone Management Act requires in any state plan, explicit consideration be given to the regional interest when local decisions affect or control energy facility siting. The plan must also include a process to avoid duplication in the plant approval. The State of Alaska should study and determine if a coordinated or one-stop energy facility state licensing process is desirable. The State of Alaska should also consider whether it intends to prepare a Coastal Zone Management Plan and on what time-table. The Authority should monitor these activities to determine probable impacts upon possible coastal zone sites.

- The Department of Interior can make grants to the State of Alaska to develop its Coastal Zone Management Plan. Once such a plan has been developed and approved, grants are also available to minimize the impacts of energy facilities located within the coastal zone. This could provide a source of funding to the Authority to minimize the otherwise costly aspects of mitigating measures for coastal zone plants.

Land

- The large federal land holdings in the State of Alaska will significantly impact site availability and conditions. Depending upon the land classification, different restrictions on plant sites and power line routes can result. The Authority should classify and identify the restrictions arising from various federal land classifications in plant site or line route areas.

- Wildlife Refugee lands can be used for power lines if they are compatible with the purpose of the refugee. Rights-of-way are permitted through National Forest lands, but are limited to 100 feet in width and are for a limited term. In Wilderness Preservation areas, power lines and power project are permitted if it is in the national interest and the President approves them. This wilderness preservation category will be expanded in Alaska as a result of the "D-2" land legislation currently before Congress. In National Parks, rights-of-way for transmission lines are permitted if consistent with park purposes. The Authority should consult early in project planning with the local federal land managers for lands that may lie within or be impacted by a power project, transmission line routing or their alternatives.

- Land areas encompassed with these land classifications will be expanded as a result of the D-2 land issue legislation presently before Congress pursuant to the Alaska Native Settlement Claim Act. This D-2 legislation should be monitored since Congress could reclassify some of the designated lands as Class I under the Clean Air Act and thus, reduce allowable emission increments. They should consider requesting an exemption in lands classified under the D-2 legislation so that power plants or lines would be permitted in the newly identified areas notwithstanding the resulting federal land classification.

- The Surface Mining & Reclamation Act which affects coal mining was passed last August. Two provisions directly relate to Alaska. The Secretary of Interior can modify the applicability of the Act to land if mined one year before the Act's effective date in August of 1977.

The Secretary can also modify the requirements for new coal mining sites for special Alaska conditions. The provisions of the Act and special Alaska physical and topographic conditions in the area of probable coal mines should be reviewed with specific modification proposals made to the Secretary.

- The federal government controls coal mining operations until the state adopts and the federal government approves the state permit implementation program. The State of Alaska should consider expeditious response to this federal mandate and seek approval for such a plan in light of the potential Beluga field opening.

Flora and Fauna

- Gold and Bald Eagles cannot be taken. As the term "take" is defined, it includes any molesting or disturbing of these birds. Consequently, surveys of probable power sites should be made and appropriate steps taken to avoid such a defined taking. The definition of "take" for marine mammals includes harassment. A similar approach should be taken for these mammals as suggested for eagles.

2.7.2 Federal Energy Policy and Regulations

- The Energy Supply and Conservation Act gives the President the authority to reduce energy demand through implementation of conservation plans and to increase fossil fuel supply. States are authorized to develop conservation plans. The pending legislation on the National Energy Plan as passed by the House of Representatives (HR 8444, Rep. Ashley), gives the federal government the authority to establish the conservation plan for a state if the state does not develop its own. The administrator is also given the authority to establish energy conservation goals for Alaska. The State of Alaska and as appropriate, the Alaska Power Authority, could consider developing an energy conservation plan tailored to its specific perception of the measures feasible and reasonable for Alaska.

- The Energy Supply and Environmental Coordination Act can restrict fuel type selection by prohibition orders relating to oil and gas. The proposed National Energy Policy legislation as reflected in HR 8444 would strengthen this by prohibiting the use of oil or gas for any new power project. While temporary exemptions may be available for a period of up to five years if an operator can sustain the burden of proof, there is no permanent exemption except for cogeneration facilities when the benefits of that facility are not available unless the operator can demonstrate that oil and gas must be used. Only the State of Hawaii is exempted under HR 8444 from the prohibition against burning oil or gas in new plants. The Alaska Power Authority could consider efforts to extend this exemption to the State of Alaska because of its geographic and power supply isolation and locally available oil and gas supplies.

- The future course of HR 8444 which is the House of Representatives' legislation implementing the Administration's National Energy Policy is uncertain. The economic penalties contained in HR 8444 should be used in the present economic analysis since it is anticipated to be more conservative than the Senate version or the expected conference legislation. Under HR 8444, hydroelectric expansions at existing sites are favored by virtue of provisions allowing 50% cost grants and no charge for nonconsumptive use of the water. While coal is not directly taxed, it will undoubtedly have increased costs as a result of the provisions of the Surface Mining & Reclamation Act. The tax on oil for utilities under HR 8444 after 1985 is $1.50/bbl. Natural gas will be taxed after 1985 on the basis of $0.75/million Btu's adjusted for inflation and subject to a price cap based upon the Btu Equivalency Price for residual fuel oil. These tax penalties should be included in the analysis of fuel selection studies until the law is passed and more definitive information is available regarding the tax implications of the proposed National Energy Policy.
- Alaska does not have an explicit energy policy, however, one can be inferred, that being to provide the power desired at a minimum cost. This policy conflicts with national goals for conservation and could be subject to litigation because of the Alaska constitutional provision regarding the allocation of resources for maximum public

benefits. The Authority should seek revision in its authorizing legislation to substitute the words "reasonable power cost" for "minimum power costs."

2.7.3 State Statutes and Regulations

- The Alaska Constitution requires that the state's natural resources be allocated consistent with the maximum public interest. Even assuming that a power project is in the public interest, allocation of natural resources to it cannot relieve involved state agencies from considering the impacts and conditions to mitigate those impacts associated with such a project. The Authority should monitor permit actions by other state agencies to determine the type of mitigating conditions that may be required of it in developing a power project. As previously discussed, the Authority should participate in the development of an energy conservation plan and give appropriate consideration to it in its power planning forecasting methodology. The Authority should also revise its authorizing language to delete the decision making criteria of "minimum power costs."

- Water issues emerging in the State of Alaska include those dealing with supply which relate to the use of cooling towers since they are a consumptive use of water, with water quality which relate to a power project because of the nondegradation requirement in the water quality standards, with protection of in-stream values which relate to a power project by the requirements for possible minimum flows which would restrict water withdrawals and the protection of fish habitat and passage. The Authority should examine the water supply and quality parameters for any affected reach of a probable project and its alternatives.

- Even though the federal government requires a National Pollutant Discharge Elimination System (NPDES) Permit, the State of Alaska also requires a waste discharge permit. The State can substitute the federal permit for the state one if it desires. The principal state requirement in the water quality area involves the water quality standards which can vary with stream classification. The Authority should survey both the ambient water quality conditions as well as the water quality standards for any affected reach of water to determine discharge limitations. In addition, the Authority should review with the Department of Environmental Conservation its policy in implementing the mixing zone for a project's discharge since the water quality standards do not apply inside the limited area of a mixing zone. Depending upon the size of a permitted mixing zone for a particular water body, operational restrictions can be placed upon the quantity of water discharged and the design of the discharge structure.

- The State of Alaska should review the need for clarification of state law as it relates to reserving water rights for future power projects.
- The Authority should comprehensively examine mitigation conditions possibly required to protect ambient water quality and the aquatic biota residing in any area affected by a discharge. Consideration should also be given to the impact of the low ambient temperatures upon cooling tower operations and efficiency. Control costs for runoff from coal storage piles and mining fields should be estimated. Particular attention should be given to fish passage and impact upon river thermal regime if a hydroelectric facility is pursued. The consumptive use of water for cooling tower operations should be technically analyzed in comparison with the nonconsumptive use for cooling lakes. If cooling lakes are technologically and economically feasible, appropriate efforts should be made to assure, through federal regulations, their availability for a project.
- The presence of stagnant air conditions in the Fairbanks and Nenana areas cannot necessarily be solved by increasing stack height as a result of restrictions on stack height under the Clean Air Act Amendments of 1972. State air quality standards for suspended particulates are more stringent than the National Ambient Air Quality Standards and the impact of this upon electrostatic precipitator costs should be reviewed. Since Alaska has an ice fog limitation regulation which is particularly relevant to cooling tower operations, economic and technological analysis of alternatives, particularly cooling lakes, should be made.

The recommendations and studies by the Federal/State Land Use Planning Commission should be reviewed and efforts made to assure the appropriate availability of possible coastal sites.

- While Alaska land can be leased generally for use for a power project or its transmission lines, consideration should be given to monitoring the type of conditions that would be imposed to mitigate the impact of such facilities located on leased land. A power project will be subject to local zoning and building codes if located within an appropriate area. Considerations should be given to state legislation exempting a bulk energy facility from local building codes. Consideration should also be given to a possible withdrawal of local zoning control over bulk energy facilities in the event that a power plant site which is otherwise needed is zoned out by local authorities.

2.7.4 Alaska Power Authority Operations

- Planning now to assure the timely and reliable availability of power is needed by the Authority. Without an analysis of environmental law requirements, forecasting the scope and timing application studies and accounting for the costs of site-dependent conditions is uncertain. This situation could interfere then with the objective of providing low cost power. However, the Authority should review and seek legislative change of this standard and substitute the term "reasonable power costs", to avoid a conflict with other constitutional and statutory provisions and possible challenges by project opponents. See Alas. Stat. 44.56.010 (a) (3)
- Planning for a power project's need cannot be based upon extrapolation from past usage patterns. The Supreme Court in Oregon recently caused a significant delay in a nuclear power plant's schedule by remanding the licensing agency's decision for it to separate the finding of "need" for a project from the perceived "demand" for a project. Emerging trends and legislative efforts to promote conservation can significantly perturb historical demand patterns.

- Project delay when large capital amounts have been commited to a project can significantly increase the project costs. Delay when little capital is committed, can be acceptable. The Authority in its power project planning should take all steps to avoid later delay by early review and evaluation of the applicability of all environmental laws to site selection, project power rating, fuel sites, and alternative configurations. A critical path of studies for licensing actions should be done and compared with decisions related to financing and technical feasibility.
- Alaska has as a state a role recognized by the federal government in energy planning, particularly conservation. The Authority has a key role in the planning and supply of power. Detailed examination of all the applicable environmental laws and probable conditions influencing the costs of a project or restrictions on site availabilitiy should be pursued to assure adequate planning when pursuing timely, reliable availability of power for Alaska. A mechanism for joint power planning by APA and the utilities should be established.

3.0

3.0 SCOPE OF EFFORT

In attempting to fulfill the purposes of this study we have:

1. Reviewed all available electric power load forecasts or projections and documented their assumptions and reasons for differences.
2. Summarized current Alaskan Railbelt generating utility plans for capacity additions. Individual utility plans understandably extend into the future to the next addition to generating capacity.
3. Analyzed the capital costs of power generation and transmission options. These cost analyses included capacity scale factors, environmental control costs, and the affects of inflation, escalation and interest during construction on the various cost components. The latter ultimately enter into calculation of the cost of power to the consumer. Since the most up to date and statistically sound data are based on "lower 48" experience, we have also investigated the question of the "Alaska factor", i.e., the factor reflecting the higher costs of material, onsite construction, and operating and maintenance. Due to differences in total cost makeup for different types of plants and Alaskan locations, we have analyzed these cost components separately.
4. Reviewed data and prior available estimates of present and future fuel costs for the thermal generation options. This is an area of considerable uncertainty due to possible changes in Federal policy, terms and conditions of long term fuel supply contracts, potential new additions to fossil fuel reserves through discovery, and micro and macro market economic conditions. Aware of these factors, we have also applied natural resource economic theory in attempting to arrive at an "educated guess" of future fuel cost trends. Recognizing that (a) future fuel costs are an extemely important element in fossil fueled generation decisions and (b) that the above uncertainties exist, we have elected to treat future fuel costs parametrically, i.e., work primarily with the "educated guess" but also develop an understanding of the sensitivity that power costs have to a rational range of possible fossil fuel costs.

   The effect on power costs of the Alaska Power Authority entering into coal mining financing is also evaluated.

5. Analyzed the options available for financing capital investments in the power generation alternatives including continued financing through the Rural Electrification Act, municipal bond financing, and the Alaska Power Authority under variable equity positions.

6. Attempted to estimate the impacts on the power planning process of current and pending federal and State environmental and energy policy, statutes, regulations and court interpretations. At the Federal level, this area is a "moving target". Some sembalance of policy stability has been established in the environmental area (e.g., the Clean Air Act Amendments of 1977) but the consequences of the divergent Administration, House, and Senate positions on energy policy are unclear until an Act is finally signed. Due to the State's unique fuels situation, Alaskan options and power costs are quite sensitive to Federal policy.

7. Provided a computer program (ECOST2) for calculating the present worth levelized cost of power at the busbar over project lifetime. The program has been employed in parametric calculations with the following variables:

   - Plant type: hydro, coal/steam, gas turbine (simple, regenerative and combined cycles), combustion turbine (simple and combined cycles)
   - Plant commercial operating date
   - Plant location
   - Time required for construction
   - Capital costs in January 1977 dollars
   - Cost of capital (financing method)
   - Construction cost inflation and escalation rates
   - Fuel cost (inflated and escalated)
   - General inflation rate (Consumer Price Index)
   - Heat rates
   - Plant factor (variable over plant life)

8. Based on the above findings, prepared alternative schedules of capacity additions by size and type as constrained by policies and regulations and construction period requirements.

9. Analyzed the power cost sensitivity to over or undershoot errors in future demand estimation.

4.0

4.0 PEAK LOAD AND ENERGY REQUIREMENT FORECASTS

4.1 INTRODUCTION AND SUMMARY OF CONCLUSIONS

This chapter reviews several recent forecasts of electricity consumption and peak loads for the Railbelt area. In each case, assumptions and methodologies are briefly summarized and results presented in tabular and graphical form.[a] Next, the various forecasts are compared and a most likely range is suggested. Finally, the tradeoff between cost and security of electrical supply, and its relationship to forecasted consumption, is discussed.

The principal findings of this chapter are:

1. There is a very wide range in forecasted future Railbelt area electricity consumption.
2. That range remains quite wide even after eliminating low probability scenarios. The most likely range of total Railbelt annual consumption (utility and nonutility industrial) that would be part of an intertied system is indicated in Table 4.1 below.

TABLE 4.1. Range of Railbelt Annual Consumption (Includes use by utility and industrial customers likely to be part of an intertied system. Excludes national defense and non-intertied users.)

Year	Annual Consumption	Compound Annual Growth Rate
1974	1.6 B kWh	
1980	2.6 to 3.4 B kWh	8.4 to 13.4 (1974-1980)
1990	8.5 to 10.8 B kWh	9.6 to 15.3 (1980-1990)
2000	16.0 to 22.5 B kWh	4.0 to 10.2 (1990-2000)

   Total annual consumption and peak load forecasts are shown in Figures 4.1 and 4.2.

3. Because of this wide range, the consequences of overbuilding or underbuilding should be considered. If overbuilding occurs, security is increased because the likelihood of service interruption and curtailments are reduced, but idle capacity increases the cost of electricity. Underbuilding avoids the problem of idle capacity, thus reducing the cost of electricity, but security is reduced because the risk of interruption and curtailment is increased. The tradeoff

[a] In the interest of expositional clarity, graphical presentation of some information has been omitted from the main text. However, because these graphs may be of interest to some readers, they have been included in Appendix A.

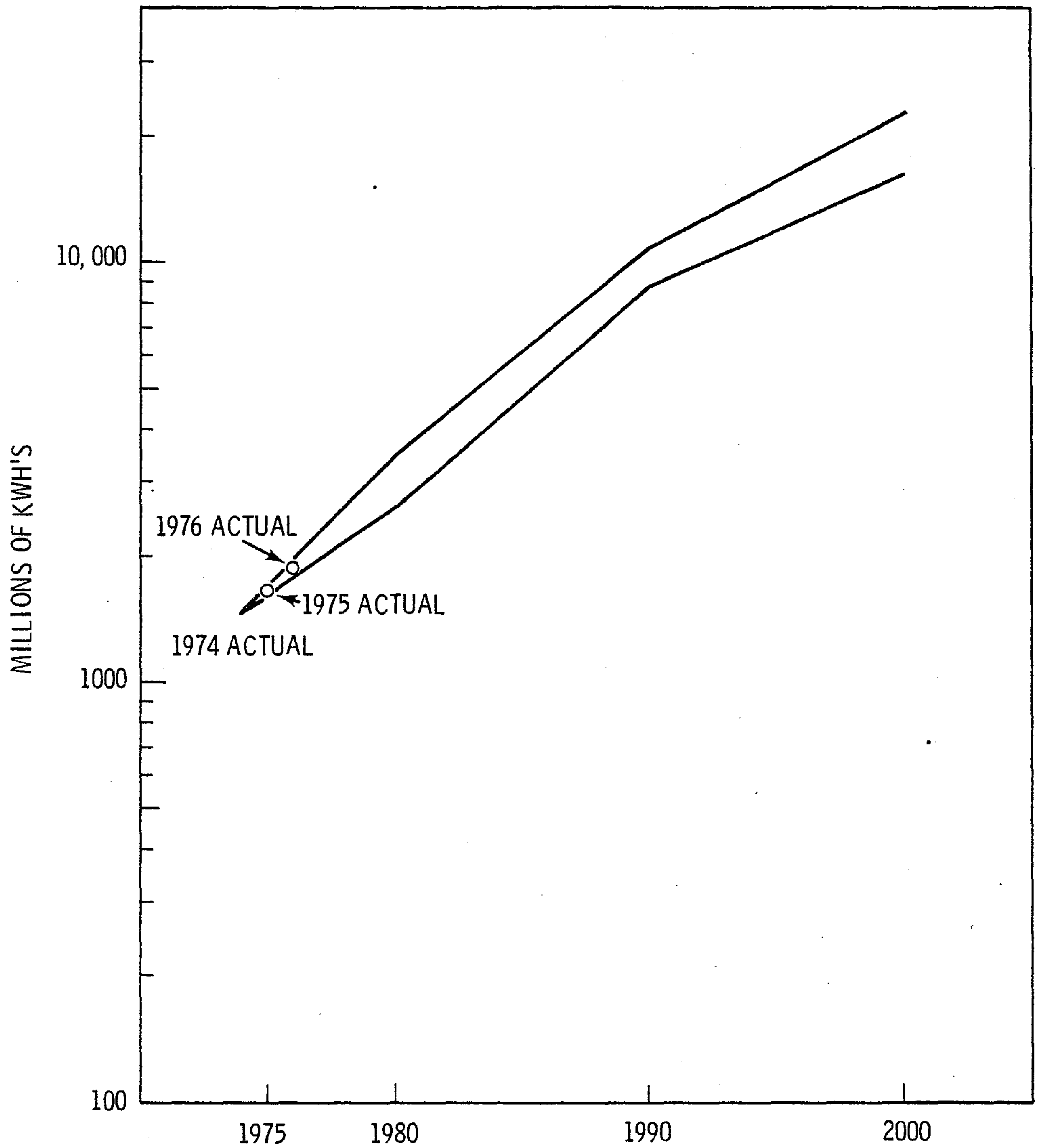

FIGURE 4.1. Most Likely Range of Utility and Industrial Annual Consumption; Intertied Railbelt Area

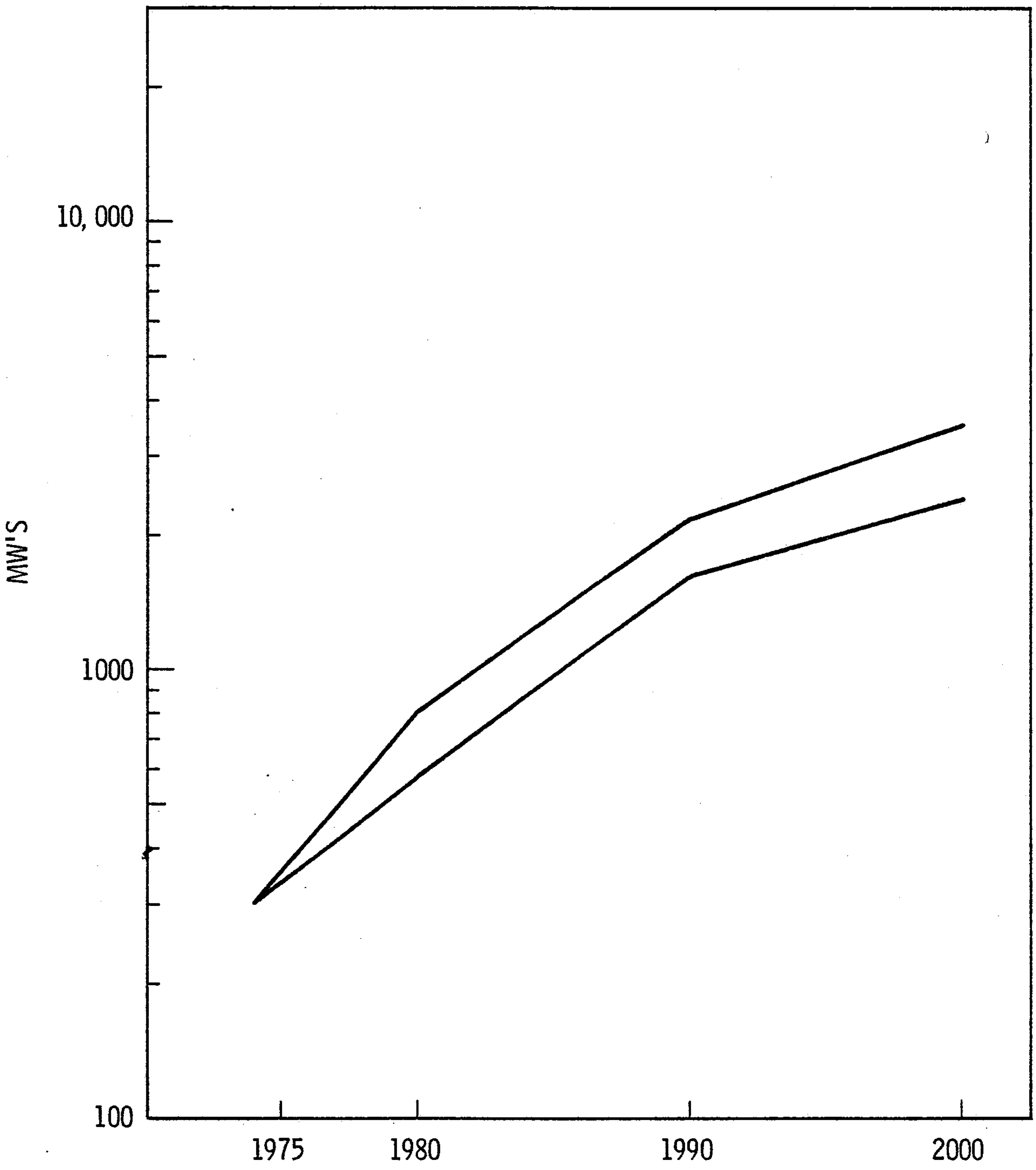

FIGURE 4.2. Most Likely Range of Utility and Industrial Peak Load; Intertied Railbelt Area

between electricity cost and security will be examined more fully in Section 8.0 where estimates will be made of cost increases resulting from increases in the reserve factor.

The following section reviews several recent studies of future electricity consumption. Two points should be made about these studies. The first is that none of the forecasts takes explicit, quantitative account of future prices of electricity. This is an important omission since it seems certain that prices will rise significantly in the future. In addition, since most studies have estimated long run price elasticities of demand[a] for electricity falling between 1.0 and 2.0,[1] the effect of these price increases is likely to be significant.

According to a University of Alaska study, discussed in the following section,[2] lack of data prevents adequate estimation of price elasticity of Alaskan electricity demand. Accordingly, the authors attempted to bound the impact of price on electricity use by incorporating assumptions about likely levels of electricity's market share and average electricity consumption per customer. This approach, while not as rigorous as might be desired, does provide an indication of the sensitivity of consumption to future price changes of the magnitude likely to be observed. The other studies reviewed below gave little apparent consideration to the effect of prices on future consumption. As will be pointed out below, however, there appears to be reasonably good agreement between these forecasts and the University of Alaska forecast.

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[a] Price elasticity of demand is a measure of the responsiveness of the quantity of a good demanded to changes in the price of that good after allowing for the effects of other factors (e.g., income). A price elasticity of 1.0 indicates that a 10% increase in price would, in the long run, result in a 10% reduction in quantity demanded assuming no change in other influencing variables. The fact that other variables are not in fact constant means that the 10% reduction in quantity demanded may never actually be observed. For example, if income increases, the positive effect on quantity demanded may outweigh the negative effect of the price increase. What may actually be observed under such circumstances is an increase in consumption which is less than it would have been if price had not increased.

The second point that should be made concerning the forecasts reviewed in the next section is that the peak load estimates presented there are not the same as the levels of capacity required to generate forecasted amounts of annual energy. The reason for this discrepancy is that reserve factors and system losses must be included in the analysis in order to take account of downtime for required maintenance and forced outages. These will be discussed more fully in Section 8.0.

4.2 SUMMARY OF RECENT LOAD FORECASTS

4.2.1 Electric Power in Alaska, 1976-1995

This report, published in August 1976, was prepared by the Institute for Social and Economic Research (ISER) of the University of Alaska for the House Finance Committee.(2) One of the forecasts contained in the report was used in a later study by Retherford Associates of the impact of natural gas transport systems on electric power supply.(3)

The ISER study forecasts electric utility sales and peak loads under a range of assumptions about Alaskan economic development and about the intensity of electricity use in the state. Forecasts are made for the state as a whole and for seven regions. The three regions encompassing the Railbelt are shown in Figure 4.3. The economic development assumptions are based on petroleum scenarios which were quantified by use of the Man in the Arctic Program (MAP) econometric model of the Alaskan economy developed at ISER. The petroleum scenarios are summarized below.

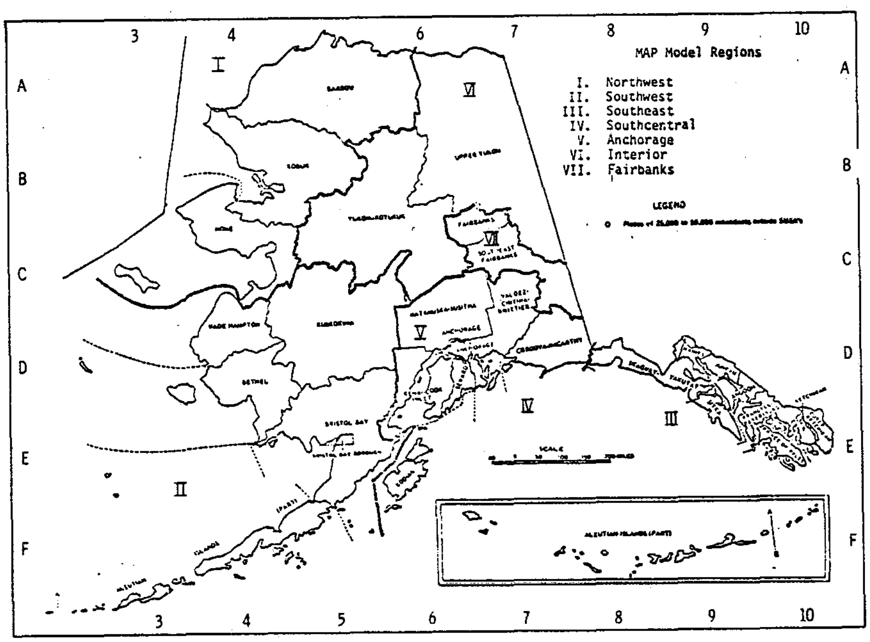

FIGURE 4.3. Alaska Census Divisions and Selected Places

Limited Petroleum Developments

Development envisioned under this scenario leads to total petroleum production rates of 2 M bbl/day in 1980 and 3.6 M bbl/day by 1990. A gas pipeline is constructed from Prudhoe Bay through Canada. An LNG plant is constructed for Gulf of Alaska natural gas.

Accelerated Development

In addition to the development envisioned under the Limited Development scenario, National Petroleum Reserve-A is developed and a second oil pipeline is built. Oil production reaches 2 M bbl/day by 1980 and 7.3 M bbl/day by 1990.

Maximum Development

Development occurs consistent with Project Independence and accelerated Federal Outer Continental Shelf (OCS) leasing. In addition to development assumed under the Accelerated Development scenario, an oil and a gas pipeline are built to transport oil and gas from western Alaska. Petroleum production reaches 2 M bbl/day by 1980 and 10 M bbl/day by 1990.

Of the three scenarios, the Limited Development assumption is thought to be the most likely at the present time.[a] Economic and demographic forecasts generated by the MAP model based on the Limited Development scenario are summarized in Table 4.2.

TABLE 4.2. State Economic and Demographic Forecasts Based on Limited Petroleum Development Scenario

Year	Population (1000's)	Employment (1000's)	Real Wage & Salary Income (M of 1974 $)
1980	456.9	219.7	1506.9
1985	547.9	265.4	1970.0
1990	641.3	312.7	2506.2
1995	750.7	367.9	3188.0

SOURCE: Electric Power in Alaska, 1976-1995

(a) Personal communication with Scott Goldsmith of the Institute for Social and Economic Research.

In addition to the petroleum based economic scenarios described above, a range of intensity of electricity use cases were distinguished. Each case consisted of an assumption about average use per customer and an assumption about the number of customers. The product of use per customer and number of customers is defined as the intensity of use. The purpose of distinguishing among the several cases was to bound the effects of variations in utility service area, geography, and economic variables, such as income and electricity prices, on electricity consumption. These cases are summarized below.

Residential Sector

Growth as Usual. Growth in average electricity use per customer is determined by the historical relationship between use per customer, and real wages and salaries. Growth in the number of customers is determined by its historical relationship to population and real wages and salaries.[a] The level (in real terms) and relative structure of energy prices are implicitly assumed to move as they have in the past. Appliance stocks per customer are assumed to increase at historical rates.

Moderate Electrification. Electricity use per customer is assumed to continue to increase. Average consumption of existing homes remains constant. New homes are all-electric with the exception that electric space heating saturation remains at current levels. A ceiling (3% above present levels) on the ratio of new hookups to population growth is assumed. This scenario is consistent with the assumption that prices are moderately favorable to electricity use.

Low Electrification. The ratio of hookups to population growth is the same as under the moderate electrification scenario. Electricity use per customer increases in similar fashion to the moderate scenario. The only difference is that major appliances (space heaters, water heaters and stoves) are limited to present saturation levels while all other appliances are all-electric. This scenario is consistent with the assumption that electricity prices remain competitive with alternative fuels.

[a] Wages and salaries adjusted for inflation.

No Growth. Both use per customer and the ratio of new hookups to population growth are constrained to current levels. This scenario is consistent with the assumption that energy price movements adversely affect electricity use.

Commercial/Industrial Sector

Growth as Usual. Growth in use per customer and number of customers is consistent with their historical relationships to employment and income.

Minimum Electrification. Growth in the number of customers is constrained to the ratio between number of customers and population growth observed in 1974. Use per customer grows at the rate observed for the nation as a whole during the period 1962 to 1972, 5.8%/year.

Other Sector

This is a small sector consisting primarily of public buildings, street lighting, and electricity use by utilities. It is assumed to grow in historical proportion to growth in population or employment.

The above assumptions regarding economic development and intensity of use can be combined in several ways. Of these, four combinations of intensity of use assumptions were selected for inclusion in the ISER report. Each combination is comprised of two forecasts, one based on limited development and one based on accelerated development. The four sets of assumptions are summarized below. Forecasts associated with each case are presented in Tables 4.3 and 4.4 for the three regions which encompass the Railbelt area. Although these regions include utility loads that will not be part of an intertied system, little error is expected to result since a very high percentage of population and economic activity is concentrated in areas that will be intertied.

Case 1. Growth as usual assumptions for both residential and commercial/industrial sectors.

Case 2. Moderate electrification assumed for residential sector, growth as usual for commercial/industrial.

Case 3. Low electrification for residential, minimum electrification for commercial/industrial.

Case 4. No growth for residential sector, minimum electrification for commercial/industrial.

TABLE 4.3. Utility Sales: Anchorage, South Central, Fairbanks Regions
(Millions of kWh)

	Case 1		Case 2		Case 3		Case 4	
Year	Limited Development	Accelerated Development	Limited Development	Accelerated Development	Limited Development	Accelerated Development	Limited Development	Accelerated Development
ANCHORAGE								
1974 (Actual)	867	867	867	867	867	867	867	867
1980	2,124	2,286	2,012	2,147	1,664	1,723	1,529	1,580
1985	3,734	4,822	3,245	4,076	2,550	2,924	2,347	2,679
1990	7,326	8,637	5,096	6,749	3,910	4,628	3,625	4,273
1995	10,633	15,350	7,982	11,514	6,071	7,416	5,679	6,918
FAIRBANKS								
1974 (Actual)	319	319	319	319	319	319	319	319
1980	631	658	598	616	485	495	446	455
1985	1,032	1,244	833	950	650	727	602	669
1990	1,534	1,891	1,090	1,256	861	977	803	907
1995	2,247	2,834	1,410	1,640	1,157	1,334	1,088	1,250
SOUTH CENTRAL								
1974 (Actual)	282	282	282	282	282	282	282	282
1980	762	933	717	849	563	612	503	544
1985	1,302	1,701	1,131	1,432	835	966	748	857
1990	1,659	2,178	1,390	1,774	1,087	1,267	987	1,142
1995	2,114	2,791	1,716	2,205	1,436	1,686	1,323	1,545
TOTAL								
1974 (Actual)	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
1980	3,517	3,877	3,327	3,612	2,712	2,830	2,478	2,579
1985	6,068	7,767	5,209	6,458	4,035	4,617	3,697	4,205
1990	9,519	12,706	7,576	9,779	5,858	6,872	5,415	6,322
1995	14,994	20,975	11,108	14,999	8,664	10,440	8,090	9,712

SOURCE: Electric Power in Alaska, 1976-1995.

TABLE 4.4. Utility Peak Load: Anchorage, South Central, and Fairbanks Regions (MW's)

Year	Case 1 Limited Development	Case 1 Accelerated Development	Case 2 Limited Development	Case 2 Accelerated Development	Case 3 Limited Development	Case 3 Accelerated Development	Case 4 Limited Development	Case 4 Accelerated Development
ANCHORAGE (Load Factor = .55; System Losses = 10.4%)								
1974 (Actual)	198.6	198.6	198.6	198.6	198.6	198.6	198.6	198.6
1980	486.4	523.5	460.7	491.7	381.1	394.6	350.1	361.8
1985	855.1	1104.2	743.1	933.4	584.0	669.6	537.5	613.5
1990	1448.7	1977.9	1167.0	1545.5	895.4	1059.8	830.1	978.5
1995	2435.0	3515.2	1827.9	2554.3	1390.3	1698.3	1300.5	1584.2
FAIRBANKS (Load Factor = .53; System Losses = 11.0%)								
1974 (Actual)	76.2	76.2	76.2	76.2	76.2	76.2	76.2	76.2
1980	150.8	157.3	142.9	147.2	115.9	118.3	106.6	108.7
1985	246.6	297.3	199.1	227.1	155.4	173.8	143.9	159.9
1990	366.6	451.9	260.5	300.2	205.8	233.5	191.9	216.8
1995	537.0	677.3	337.0	392.0	276.5	318.8	260.0	298.8
SOUTH CENTRAL (Load Factor = .56; System Losses = 7.4%)								
1974 (Actual)	61.8	61.8	61.8	61.8	61.8	61.8	61.8	61.8
1980	166.9	204.3	157.0	185.9	123.3	134.0	110.2	119.1
1985	285.1	372.5	247.7	313.6	182.9	211.6	163.8	187.7
1990	363.3	477.0	304.4	388.5	238.1	277.5	216.2	250.1
1995	463.0	611.2	375.8	482.9	314.5	369.2	289.7	338.4
TOTAL								
1974 (Actual)	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6
1980	804.2	885.1	760.6	824.8	620.3	646.9	566.9	589.6
1985	1386.8	1774.0	1189.9	1474.1	922.3	1055.0	845.2	961.1
1990	2178.6	2906.8	1731.9	2234.2	1339.3	1570.8	1238.2	1445.4
1995	3435.0	4803.7	2540.7	3429.2	1981.3	2386.3	1850.2	2221.4

SOURCE: Electric Power in Alaska, 1976-1995.

As can be seen in Table 4.3, the four cases described above result in a very wide range of forecasts, 8090 versus 20,975 M kWh by 1995 for the three regions. Peak load, shown in Table 4.4, ranges between 1,850 and 4,804 MW. Economic theory, recent historical developments, and simple tests of reasonableness suggest that this range may be narrowed by disregarding the Accelerated Petroleum Development and the Growth as Usual assumptions. This would have the effect of eliminating Case 1 altogether, and constraining Cases 2, 3, and 4 to the Limited Development end of their respective ranges.

The Growth as Usual intensity of use assumption must be questioned because of its implicit assumption that the level and relative structure of real energy prices will behave in the future as they have in the past. (Real energy prices declined through the early seventies.)

It seems certain that the real price of electricity will rise with the prices of capital, labor, and especially fuels used to produce electricity. In addition, several studies,(1) including that performed by the ISER study team using Alaskan data,(2) have found that the price elasticity of electricity demand is on the order of 1.0 to 2.0.(1) This indicates that electricity consumption growth will be dampened as the real price of electricity continues to increase. In addition, as the authors of the ISER report point out, the growth as usual assumptions lead to unrealistic projections:

> For example, average consumption in Fairbanks is projected to increase to 40,000 kWh annually by 1990. This is equivalent to an all-electric home for each additional household in Fairbanks with all presently existing households switching to electric heat. Growth in the number of customers also exceeds reasonable limits in some cases. In 1990, for example, 396 residential hookups are projected for every 1,000 population in Fairbanks. Both these results are consistent with historic growth trends but do not seem reasonable based upon present use levels and hookups as a percentage of population. (2)

The Accelerated Petroleum Development scenario is subject to question because the current slow pace of development is inconsistent with an assumed 1990 production rate of 7.3 M bbl/day. In order to achieve this rate of production, it was assumed that nine lease sales for the Outer Continental

Shelf would take place before 1979. Although two lease sales have been held recently, it appears extremely unlikely that the assumed nine sales will have taken place by the end of next year.

For these reasons, the Limited Development forecasts from Cases 2 and 4 are used in Figure 4.4 to bound expected utility sales for the Railbelt area.

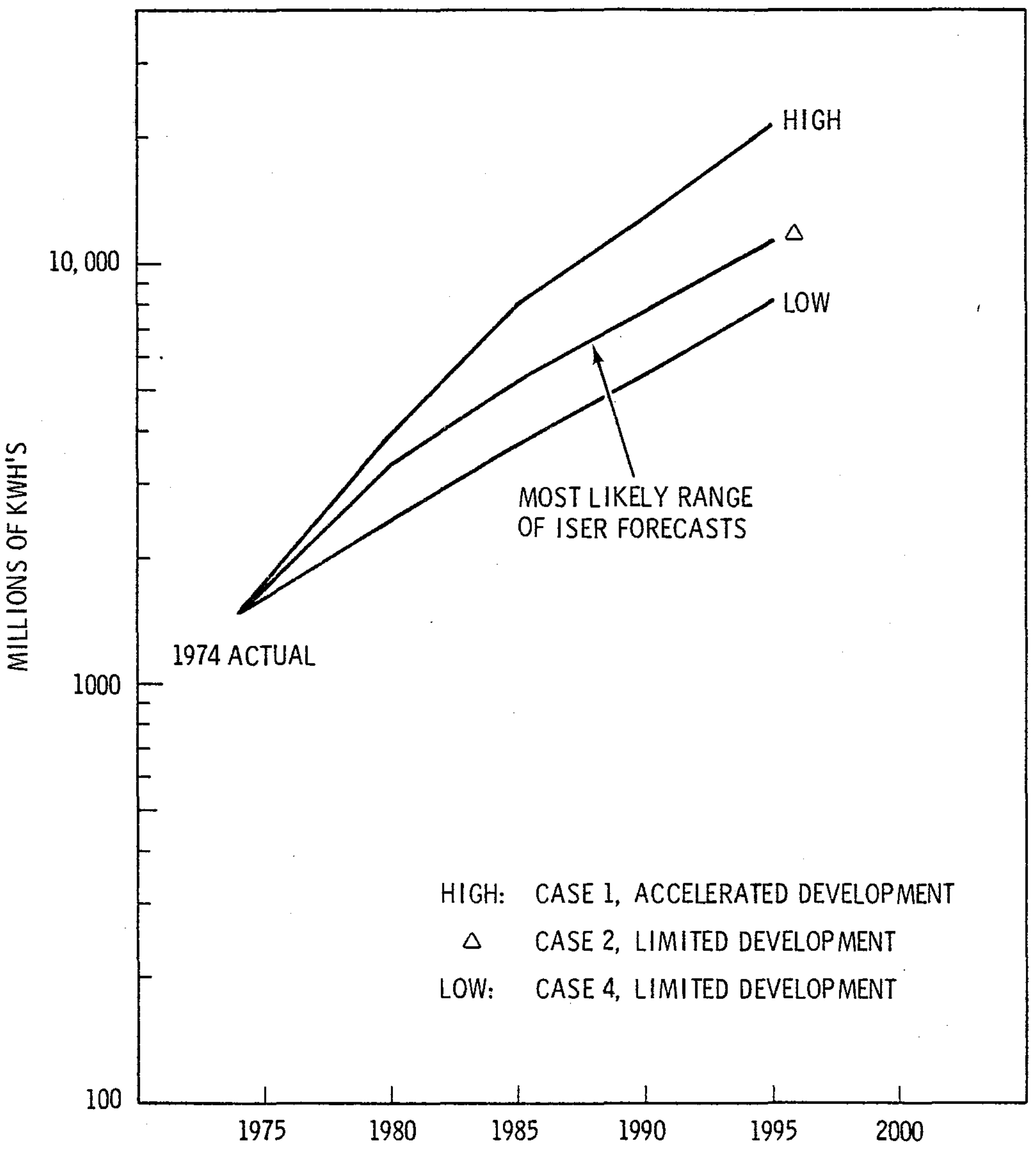

FIGURE 4.4. ISER Study, Utility Sales; Anchorage South Central, Fairbanks Regions

4.2.2 Report of the Technical Advisory Committee on Economic Analysis and Load Projections

This report,[4] published in 1974, was prepared for the Federal Power Commission as part of the Alaska Power Survey. It contains projections of utility, industrial and military consumption and peak loads for each of six regions and for the state as a whole through the year 2000. The two regions encompassing the Railbelt are shown in Figure 4.5.[a] These projections form the basis for those appearing in three subsequent studies. First, most of the estimates contained in the Technical Advisory Committee report also appear in the 1976 Alaska Power Survey.[5] Second, the estimates for the South Central and Yukon regions serve as the basis for the Railbelt area load estimates contained in the marketability analysis for the upper Susitna project[6] prepared by the Alaska Power Administration (APA). The marketability analysis report was published as Appendix 1, Part 2 of the Susitna Interim Feasibility Report,[7] prepared by the Corps of Engineers. Third, the Bradley Lake Project Power Market Study[8] prepared by the APA relies heavily on the Susitna project marketability analysis, and, therefore, on the Advisory Committee report.

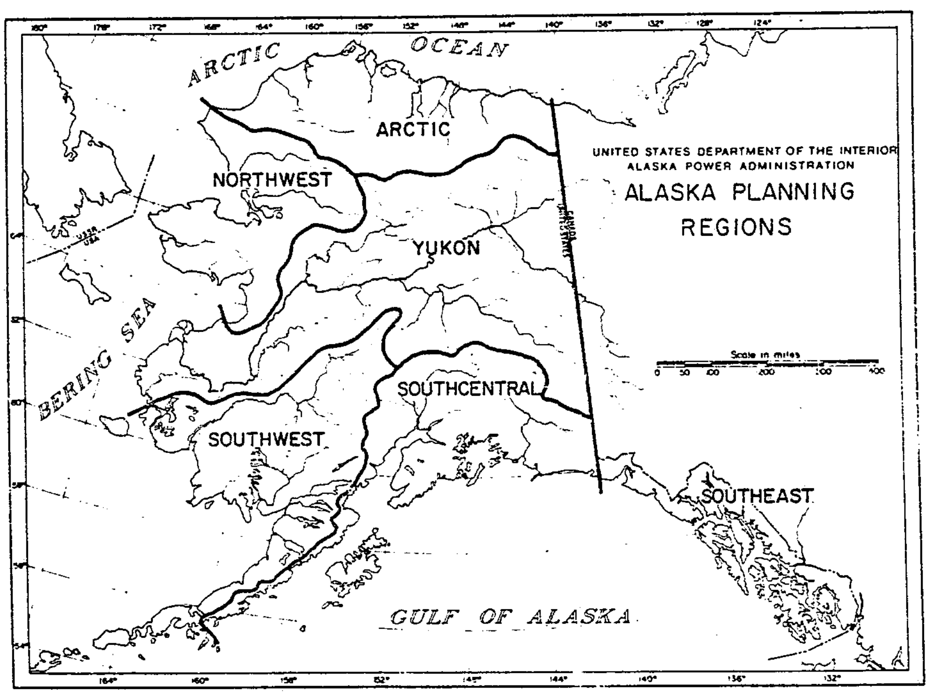

FIGURE 4.5. MAP Regions

(a) Note that the MAP regions shown in Figure 4.3 are somewhat different than the Planning Regions shown in Figure 4.5. This difference is not expected to affect the comparability of the two forecasts since the population and economic activity centers included under each scheme are basically the same.

Three projections are made in the report - a high range, a low range, and a likely mid-range. Assumptions underlying each are presented below.

- High range: "significant" energy and mineral development.
- Low range: slackening of development after completion of the Alyeska pipeline.
- Likely mid-range: a "reasonably conservative" forecast.

The only quantitatively specified economic or demographic assumptions appear[a] to be the "planning range" of population growth shown in Table 4.5.

TABLE 4.5. State Population, 1000's

	1960	1970	1980	1990	2000
Census	226	302			
Likely Future					
Lower Estimates			350	400	450
3% Growth			410	550	740
Higher Estimates			450	600	800+

SOURCE: Technical Advisory Committee Report on Economic Analysis and Load Projections

Projections are made through year 2000 at 10-year intervals beginning in 1980. 1980 utility loads for the likely mid-range projection were computed as the summation of individual utility projections. The higher and lower ranges were then set at 20% above and below the likely mid-range. Declining growth rates were assumed to prevail during the decades of the 1980's and 1990's as shown in Table 4.6. This decline resulted from the assumption that energy use would become more efficient and that energy conservation would increase.[b]

National defense consumption was assumed to grow at an annual average rate of 1.7% per year. Industrial consumption projections were based on a 1973 study conducted by E. O. Bracken at the Alaska Department of Commerce and Economic

[a] The utility load projections in the report "...generally reflects the planning range for future Alaska population..."

[b] Presumably the term conservation as used here includes reductions in use brought about by price increases.

TABLE 4.6 Assumed Annual Growth Rates

Estimate	1972-1980 (%)	1980-1990 (%)	1990-2000 (%)
Higher Range	14.8	9	8
Likely Mid-Range	12.3	7	6
Lower Range	9.8	6	4

SOURCE: Technical Advisory Committee Report on Economic Analysis and Load Projections

Development (DCED).[9] The DCED study, "...included review and estimates of power requirements for Alaska's fishery, forest products, petroleum, natural gas, coal and other mineral industries, all premised on significant identified resource potentials and power needs for similar developments elsewhere."

The DCED projections were adapted for use in the Advisory Committee report by:

1. Adjusting for the portion of industrial consumption that would be served by utilities (fish processing and support services for other industrial development).
2. Adjusting for minimum lead times required to develop the resources required.
3. Adjusting petroleum and petrochemical consumption downward to reflect the fact that most crude oil and natural gas would be exported for refinement and other processing elsewhere.

Projected utility and industrial consumption for the Yukon and South Central regions is presented in Tables 4.7 and 4.8. National defense projections are not included since it is assumed that for security reasons, military installations will rely on their own generating systems for power. It can be seen in Tables 4.7 and 4.8 that the low and high projections bound a very wide range (8.2 to 20 billion kWh for year 2000 utility loads). This is especially true for industrial consumption in the South Central region where a 2.5 M kW nuclear enrichment plant is assumed to be on line by 1990. This results in a range of 2.3 to 29.6 billion kWh in year 2000.

TABLE 4.7. Utility Loads: Yukon and South Central Regions (Millions of kWh, MW)(a)

Year	High Range		Likely Mid-Range		Low Range	
	Annual Energy	Peak Load	Annual Energy	Peak Load	Annual Energy	Peak Load
			YUKON			
1975 (Actual)	432	112	432	112	432	112
1980	870	200	780	180	680	160
1990	2,020	460	1,500	340	1,200	270
2000	4,230	970	2,610	600	1,730	390
			SOUTH CENTRAL			
1975 (Actual)	1,497	396	1,497	396	1,497	396
1980	2,990	680	2,670	610	2,340	530
1990	7,190	1,640	5,350	1,220	4,290	980
2000	15,740	3,590	9,710	2,220	6,430	1,470
			TOTAL			
1975 (Actual)	1,929	508	1,929	508	1,929	508
1980	3,860	880	3,450	790	3,020	690
1990	9,210	2,100	6,850	1,560	5,490	1,250
2000	19,970	4,560	12,320	2,820	8,160	1,860

(a) 50% load factor assumed. System losses not accounted for.

SOURCE: Alaska Power Survey, 1976.

TABLE 4.8. Industrial Loads: Yukon and South Central Regions (Millions of kWh, MW[a])

Year	High Range Annual Energy	High Range Peak Load	Likely Mid-Range Annual Energy	Likely Mid-Range Peak Load	Low Range Annual Energy	Low Range Peak Load
			YUKON			
1972 (Actual)	-[b]	-	-	-	-	-
1980	490	70	280	40	210	30
1990	1,680	240	490	70	280	40
2000	2,450	350	1,680	240	490	70
			SOUTH CENTRAL			
1972 (Actual)	254	58	254	58	254	58
1980	1,820	260	910	130	490	70
1990	23,340	3,330	1,820	260	910	130
2000	24,810	3,540	5,330	760	1,820	260
			TOTAL			
1972 (Actual)	-	-	-	-	-	-
1980	2,310	330	1,190	170	700	100
1990	25,020	3,570	2,310	330	1,190	170
2000	29,570	3,890	7,010	1,000	2,310	330

(a) 80% load factor assumed. System losses not accounted for.

(b) No data available.

SOURCE: A Report of the Technical Advisory Committee on Economic Analysis and Load Projections.

The information presented in the Advisory Committee report does not allow one to narrow this range by determining which load centers would be part of a Railbelt intertied system and which would not. Such an analysis was performed, however, as part of the marketability analysis[6] for the Upper Susitna project described previously. Specifically, utility and potential industrial consumption for remote areas were eliminated so that the projection would reflect only loads likely to be served by an interconnected Railbelt system. The results are presented in Tables 4.9 and 4.10 and Figures 4.6 and 4.7. A breakdown of total industrial peak load by specific development is contained in Table 4.11.

In addition to the general narrowing of the range between the High and Low projections, the principal effect of elimination of remote areas was on industrial consumption in the Fairbanks area, virtually all of which was eliminated. This resulted from the fact that most of the potential industrial development in the region consists of mining developments that would be remote from the Fairbanks area and, therefore, not likely to be linked to a Railbelt system.

In order to provide updated estimates and to choose a most likely case from among those described above, BNW conducted its own analysis of future industrial loads. The following assumptions were used to modify the Susitna study estimates shown in Table 4.11.

1. In addition to gradual expansion of existing refinery capacity, a new 150,000 b/d plant will be built by 1983 to handle royalty oil.
2. An aluminum smelter with capacity of 300,000 tons/year will be on line by 1985.
3. It is assumed that a nuclear fuel enrichment plant will not be built.
4. It is assumed that industrial development in the interior region will not be part of an intertied Railbelt system.

The only other difference besides those described above is our peak load estimate for the new LNG plant. We consider 17 MW's to be the most likely case. For the remaining loads, we have selected either the mid-range or low range cases from the Susitna study as most likely. Results are shown in Table 4.12 and Figure 4.7.

TABLE 4.9. Utility Loads: Fairbanks and Anchorage Areas (Millions of kWh's, MW's[a])

Year	High Range		Likely Mid-Range		Low Range	
	Annual Energy	Peak Load	Annual Energy	Peak Load	Annual Energy	Peak Load
			FAIRBANKS			
1974 (Actual)	330	83	330	83	330	83
1980	700	160	660	150	610	140
1990	1,660	380	1,270	290	1,050	240
2000	3,500	800	2,230	510	1,530	350
			ANCHORAGE			
1974 (Actual)	1,305	284	1,305	284	1,305	284
1980	2,850	650	2,580	590	2,410	550
1990	6,880	1,570	5,210	1,190	4,420	1,010
2000	15,020	3,430	9,420	2,150	6,570	1,500
			TOTAL			
1974 (Actual)	1,635	367	1,635	367	1,635	367
1980	3,550	810	3,240	740	3,020	690
1990	8,540	1,950	6,480	1,480	5,470	1,250
2000	18,520	4,230	11,650	2,660	8,100	1,850

(a) 50% Load factor assumed. System losses not accounted for.

SOURCE: Upper Susitna River Hydroelectric Studies, Report on Markets for Project Power.

TABLE 4.10. Industrial Loads: Fairbanks and Anchorage Areas (Millions of kWh's, MW(a))

Year	High Range		Likely Mid-Range		Low Range	
	Annual Energy	Peak Load	Annual Energy	Peak Load	Annual Energy	Peak Load
			FAIRBANKS			
1974 (Actual)	--( )	--( )	--	--	--	--
1980	--	--	--	--	--	--
1990	--	--	--	--	--	--
2000	--	--	--	--	--	--
			ANCHORAGE			
1974 (Actual)	45	10	45	10	45	10
1980	710	100	350	50	140	20
1990	20,390	2,910	710	100	350	50
2000	20,460	2,920	2,870	410	710	100
			TOTAL			
1974 (Actual)	45	10	45	10	45	10
1980	710	100	350	50	140	20
1990	20,390	2,910	710	100	350	50
2000	20,460	2,920	2,870	410	710	100

(a) 80% load factor assumed. System losses not accounted for.

(b) Less than 0.07 million kW hrs at 80% load factor.

(c) Less than 10 MW's.

SOURCE: Upper Susitna River Hydroelectric Studies, Report on Markets for Project Power

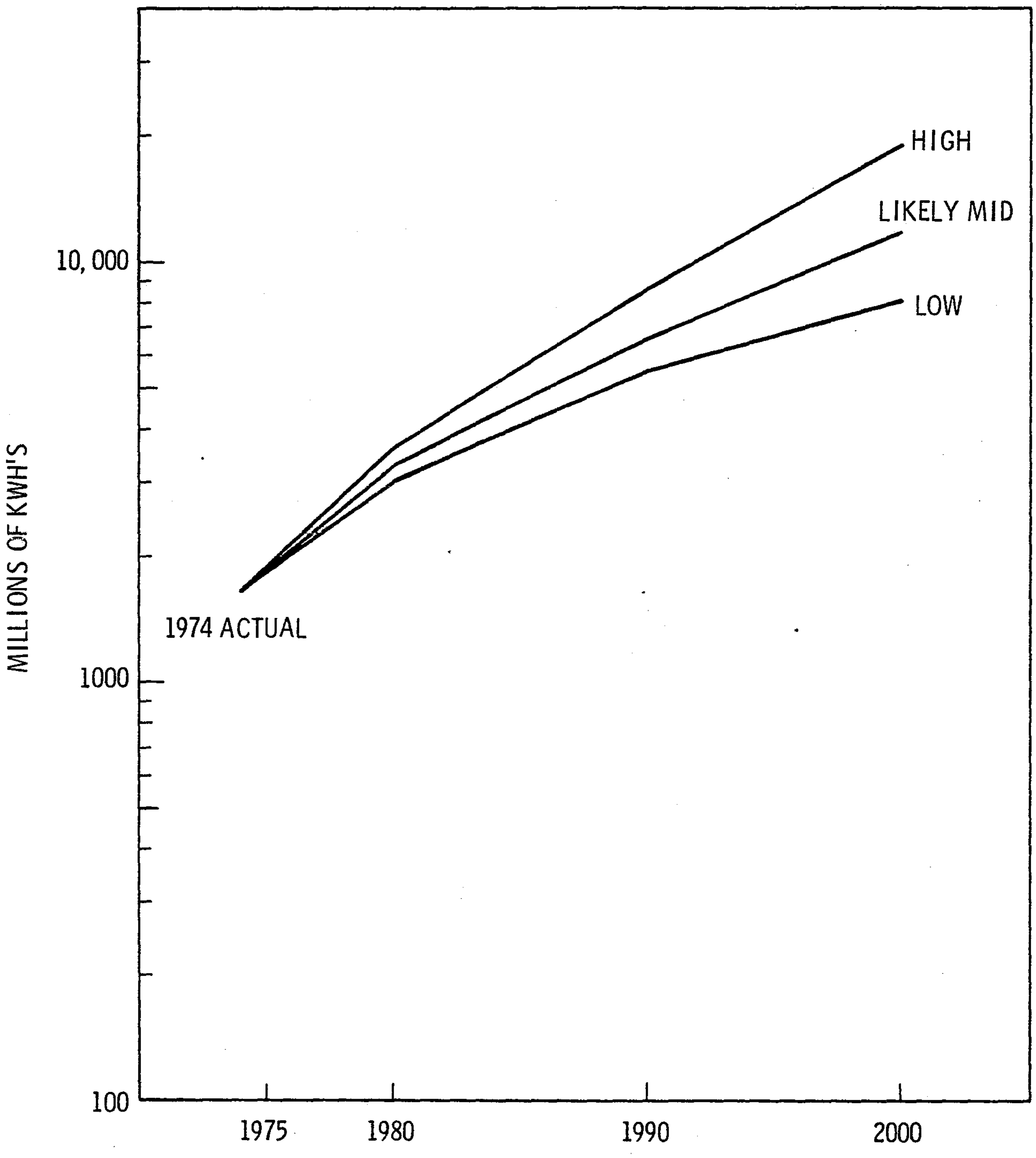

FIGURE 4.6. Utility Annual Load; Railbelt Intertied Area

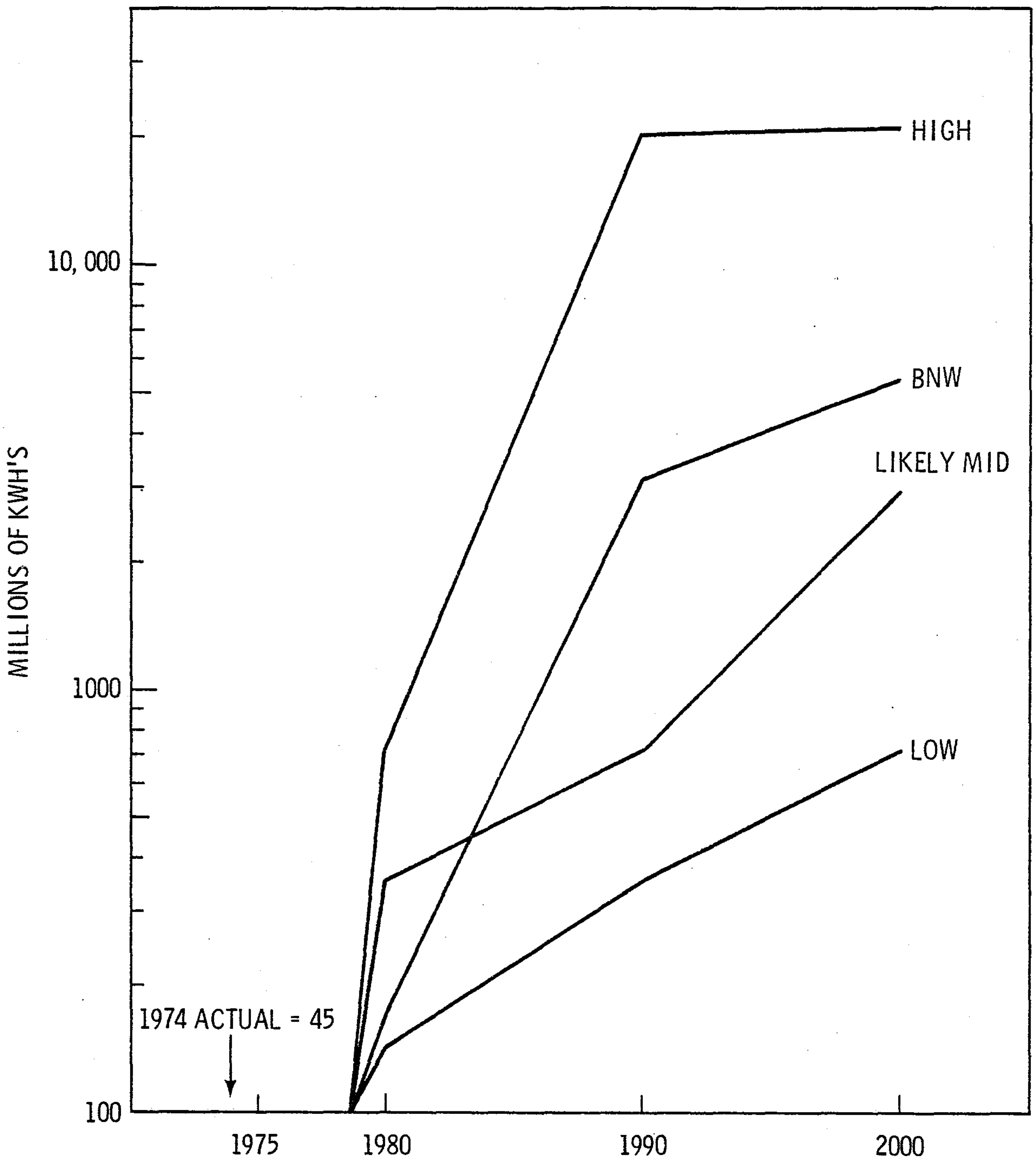

FIGURE 4.7. Industrial Consumption; Anchorage Area

TABLE 4.11. Industrial Peak Loads by Specific Developments

Rate of Development	Industrial Capacity in MW								
	Low Range			Mid Range			High Range		
Year	1980	1990	2000	1980	1990	2000	1980	1990	2000
Anchorage Area: Kenai Peninsula:									
Chemical Plant[1]	11	11	11	12	14	16	13	16	20
LNG Plant[1]	.4	.4	.4	.4	.5	.6	.5	.6	.7
New Plant		10	10	10	10	10	10	10	10
Refinery[1]	2.2	2.2	2.2	2.2	3	4	3	4	5
Timber[1]	2	3	5	3	5	5	5	5	5
Other Vicinities:									
Coal Gasification			10		10	250	10	250	250
Mining and Mineral Processing		5	25	5	25	50	25	50	50
Nuclear Fuel Enrichment								2500	2500
Timber		5	7	5	7	7	7	7	7
New City		17	30	10	30	70	30	70	70
TOTAL (rounded)	20	50	100	50	100	410	100	2910	2920
Fairbanks Area[2]									

Source: Upper Susitna River Hydroelectric Studies, Report on Markets for Project Power.

1 Existing Installations

2 Timber processing and oil refinery loads totaled less than 10 MW.

TABLE 4.12. Industrial Loads by Specific Developments; Anchorage/South Central Area (Peak Load in MW's, Annual Consumption in Millions of kWh)

Type of Load	Year					
	1980	1982	1983	1985	1990	2000
Existing Facilities:						
Chemical Plant	12.0	12.0	12.0	12.0	14.0	16.0
LNG Plant	.4	.4	.4	.4	.5	.6
Refinery	2.2	2.2	2.2	2.2	2.2	2.2
Timber	2.0	2.0	2.0	2.0	3.0	5.0
New Facilities:						
LNG Plant	-	17.0	17.0	17.0	17.0	17.0
Refinery	-	-	15.5	15.5	15.5	15.5
Aluminum Smelter	-	-	-	280.0	280.0	280.0
Coal Gasification Plant	-	-	-	-	10.0	250.0
Mining and Mineral Processing Plants	5.0	5.0	5.0	5.0	25.0	50.0
Timber	-	-	-	-	5.0	7.0
New City	-	-	-	-	17.0	30.0
Total Peak Load	21.6	38.6	54.1	334.1	389.2	673.3
Total Annual Consumption[a]	170.0	304.0	427.0	2634.0	3068.0	5308.0

(a) Assumes 90% Load Factor

The most recent of the studies based on the Advisory Committee report is the Bradley Lake Project Power Market Analysis[8] prepared by the Alaska Power Administration. In this study the APA reviews Railbelt load projections contained in the Upper Susitna Project market analysis in light of additional data for 1975 and 1976. Their conclusion was that the original projections remain valid.

4.2.3 Interior Alaska Energy Analysis Team (IAEAT) Study

This study,[10] completed in June 1977, was conducted by a special advisory team at the request of the Governor. It projects electricity consumption and peak load for the Golden Valley Electric Association (GVEA) and the Fairbanks Municipal Utilities System (FMUS).

These two utilities serve the greater Fairbanks - North Star Borrough area. Accordingly, forecasts of their combined loads may be compared with those made in the ISER study for the Fairbanks region and in the studies based on the Technical Advisory Committee report (particularly the marketability analysis for the Upper Susitna project) for the Yukon region.

The IAEAT study extrapolates the 1970-76 compound growth rates of annual energy and peak load through 1998 to generate a high case. A medium case is generated by assuming that the growth rate of per capita consumption declines to 4% from the 1970 to 1976 rate of 5%. Population was assumed to grow at 4%. A low case assumes that per capita consumption growth declines to 3% and population growth is 1.5%. The results are shown in Table 4.13.

TABLE 4.13. Utility Loads: GVEA and FMUS Areas

	Annual Energy Consumption (Millions of kWh)		
Year	High	Medium	Low
1976 (Actual)	425	425	425
1980	700	600	530
1990	2,250	1,300	825
1998	5,800	2,450	1,200
		Peak Load[a] (MW)	
1976 (Actual)	108	108	108
1980	168	145	130
1990	500	330	205
1998	1,220	630	290

[a] Load factor 46%. System losses not accounted for.

SOURCE: Interior Alaska Energy Analysis Team Report

4.2.4 Power System Study for Chugach Electric Association (CEA)

This study was prepared in March 1976 for the Chugach Electric Association (CEA) (Anchorage) by Tippett and Gee.[11] It projects electricity consumption in the CEA service area through 1984 by taking 1979 and 1984 loads, as contained in a 1975 power requirements study conducted by the Rural Electrification Association[12] (REA), and interpolating between the actual 1974 and projected 1979 values and between the projected 1979 and 1984 values. The REA estimates for 1979 and 1984 were based on extrapolation of recent historical trends with modifications based on unspecified anticipated industrial expansion.

Although CEA does not account for all sales in the Anchorage area, it does account for 70% to 80%. Accordingly, the growth rates implied in the CEA power system study may be compared with those implied in the ISER study and in the Upper Susitna marketability study for the Anchorage area.

Projected consumption and peak loads for the CEA service area are shown below in Table 4.14.

TABLE 4.14. Utility Loads; CEA Area

Year	Annual Consumption (Millions of kWh)	Growth Rate (Ave. Annual)	Peak Load[a] (MW's)	Growth Rate (Ave. Annual)
1974 (Actual)	708		148.9	
1975	921		200	
1977	1,214		258	
1979	1,600		334	
1981	2,085		434	
1984	3,100	15.9%	643	15.8%

[a] Load factor .55. System losses 6.3%.

SOURCE: 1976 Power System Study, Chugach Electric Association.

4.3 COMPARISON OF FORECASTS

The preceding review indicated a wide range of forecasted utility and industrial consumption. In this section, the various projections will be compared and a most likely range of future consumption suggested. The criteria for selecting this range consisted of agreement among the forecasts reviewed and judgment concerning appropriateness of methodology and assumptions.

Of the group of projections based on the report of the Technical Advisory Committee on Economic Analysis and Load Projections (TAC), the most appropriate for the Railbelt area is the Upper Susitna Project marketability analysis. The results of that analysis are similar to the other forecasts based on the TAC report. However, in the Susitna study, utility and industrial consumption that would not be part of a Railbelt intertied system were subtracted from regionwide totals.

The University of Alaska (ISER) study, although it did not forecast new industrial consumption that had not previously been served by utilities (as did the Susitna study) integrated quantitatively specified assumptions about petroleum development, aggregate income, population, saturation levels, and average usage per customer in a comprehensive analysis of future utility consumption.

In Figures 4.8 and 4.9, the ISER and Susitna Study forecasts for the Anchorage/South Central and Fairbanks area are compared. In the case of Anchorage/South Central, the Susitna study mid-range forecast falls largely within the range between ISER forecasts 2 and 4 for the Limited Petroleum Development[a] scenario, the most probable of the ISER cases. Also shown in Figure 4.8 is the Chugach Electric Association (CEA) service area forecast. It lies below the other forecasts because, as was pointed out earlier, a smaller service area is involved. Comparison of growth rates, rather than actual levels, reveals that the 16% average annual rate of the CEA projection is in closest agreement with ISER Case 1. Since both are primarily extrapolations, this agreement was to be expected. However, because of the problems with extrapolation of past trends in electricity consumption discussed earlier (e.g., the prospect of rising electricity prices), we attach a low probability to both the CEA and ISER Case 1 forecasts. The most likely range of utility consumption for the Anchorage/South Central area thus lies between ISER Cases 2 and 4. After 1995, the range between the Susitna study mid and high cases seems most likely.

(a)Recall that this development scenario leads to production of 3.6 mb/d by 1990, a gas pipeline from Prudhoe Bay through Canada, and an LNG plant.

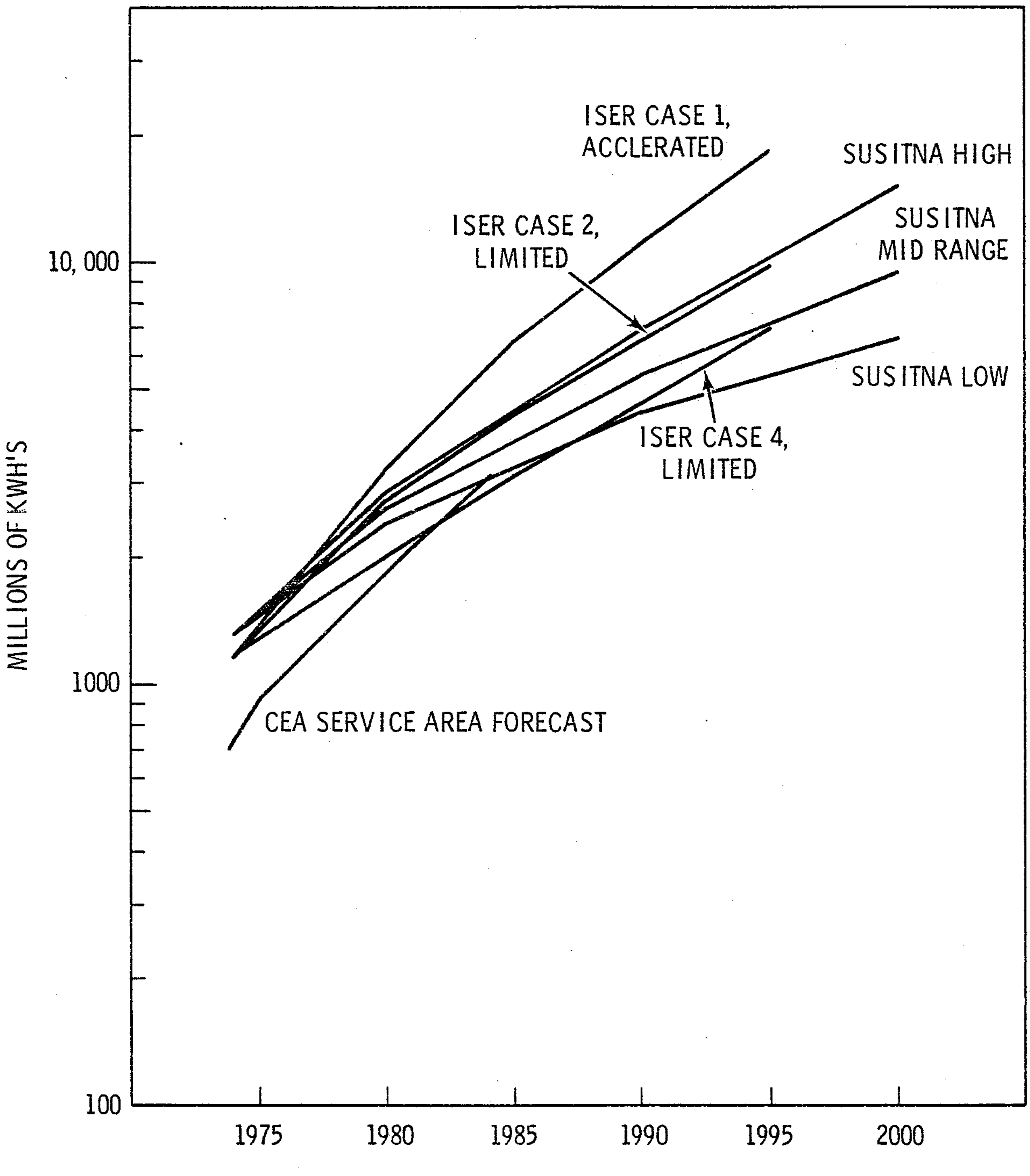

FIGURE 4.8. ISER and Susitna Studies Utility Forecasts; Anchorage and South Central Area Annual Consumption

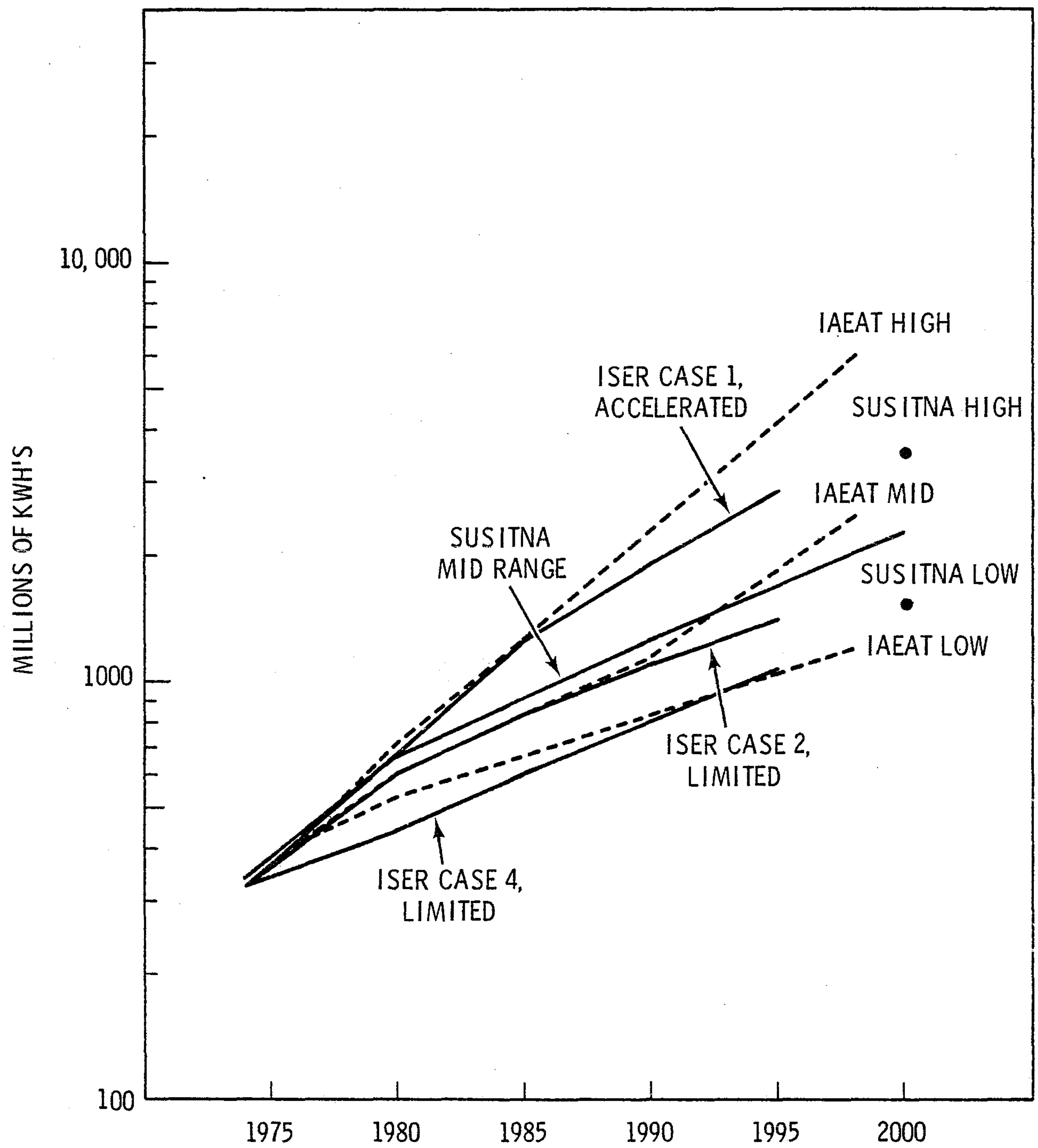

FIGURE 4.9. ISER and Susitna Studies Utility Forecasts; Fairbanks Area Annual Consumption

In the case of Fairbanks, the Susitna mid-range is slightly above, but still in good agreement with ISER Case 2. The IAEAT study projections are also plotted in Figure 4.9. The mid case is similar to both ISER Case 2 and the Susitna study mid case through about 1993. After that time, some disagreement is observed. The IAEAT low case is consistent with ISER Case 4. The most likely range for the Fairbanks area is thus bounded by the Susitna and IAEAT mid cases at the top and ISER Case 4 at the bottom. The most likely range of consumption for the Railbelt area as a whole, calculated as the sum of Anchorage/South Central and Fairbanks likely ranges, is shown in Figure 4.10.

New industrial consumption that is expected to be served from an intertied Railbelt system was forecasted in the Susitna market study. This forecast was updated and modified by BNW to generate a most likely forecast. As was pointed out earlier, virtually all of this forecasted load will be in the Anchorage/South Central area; industrial development in the interior region is expected to consist largely of self-supplied mining operations in remote areas. In Figures 4.1 and 4.2 industrial loads are added to the probable range of utility loads for the Railbelt area. It can be seen that the range of estimated future total consumption is very wide even after having reduced considerably the range of utility consumption. When the BNW most likely case for industrial development is assumed, the range of total Railbelt consumption varies from about 16 to about 22.5 billion kWh in year 2000. This translates into peak loads of from 2400 to 3500 MW as shown in Figure 4.2.

4.4 TRADEOFF BETWEEN SECURITY AND COST

The wide range of forecasted consumption and generation capacity discussed above emphasizes the importance of the tradeoff between security of supply and cost of electricity. If capacity is expanded sufficiently to allow consumption growth at the high end of the forecasted range, the chances of desired peak consumption exceeding generating capacity are reduced (security is increased). The price of electricity under such a policy, however, would be high. The principal reason for this is the high cost of constructing and operating new plants. In addition, it is likely that actual consumption

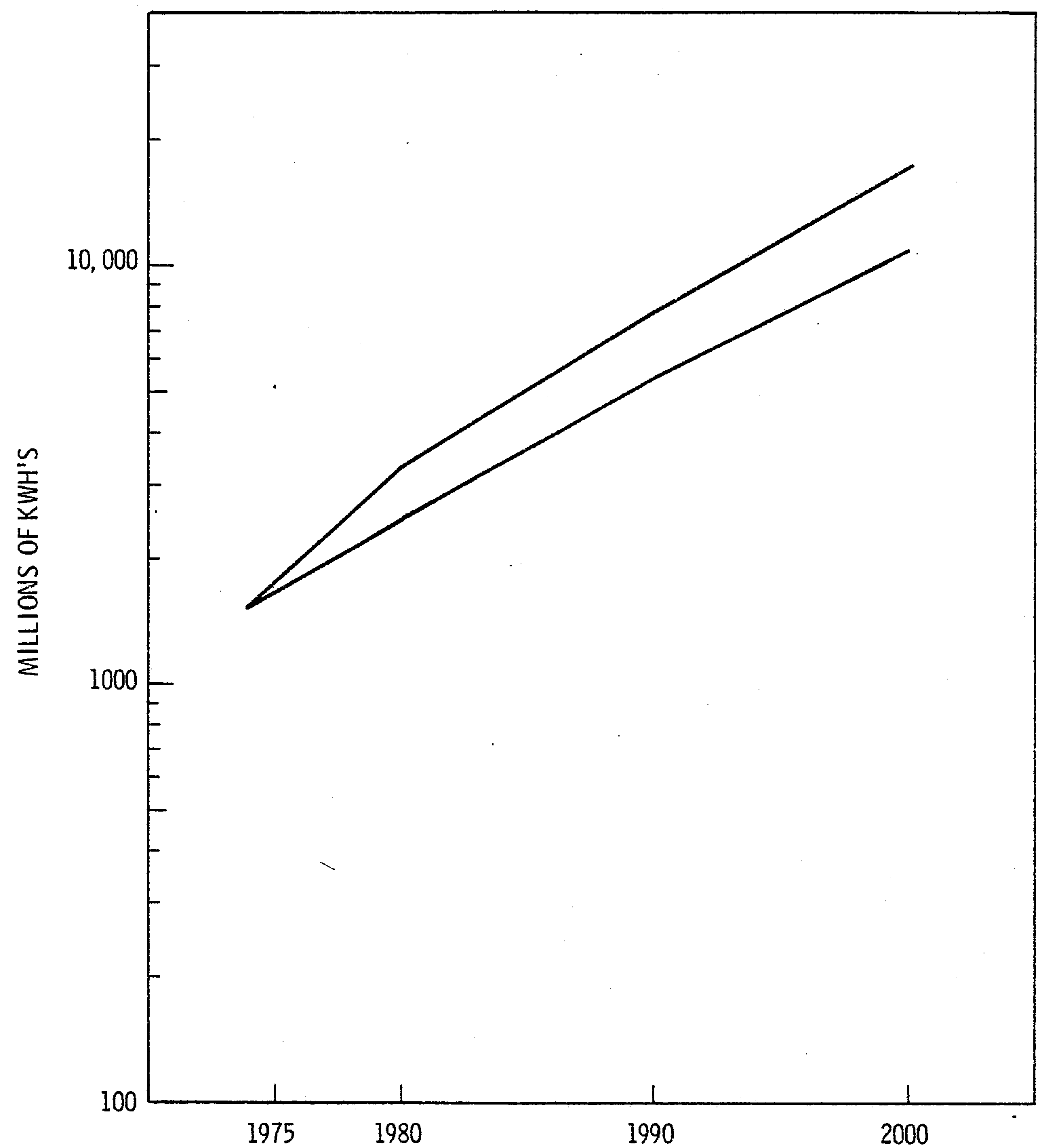

FIGURE 4.10. Most Likely Range of Utility Consumption; Railbelt Intertie Area

would fall short of planned consumption with the result that idle capacity would push electricity prices still higher.[a] If, on the other hand, capacity is expanded by only enough to allow low consumption growth, cost is low but security is also reduced. This situation is depicted in Figure 4.11 as an upward sloping line.

In selecting the preferred mix of security and cost, the benefits of security must be considered. These consist of the avoidance of expected[b] losses in the form of discomfort, inconvenience, and foregone production resulting from nonavailability or interruption of service. They are depicted in Figure 4.11 as decreasing with the level of security since the incremental avoidance of loss resulting from successive increments to security declines. The preferred security/cost mix is determined by the point at which the benefits from additional security just equal the cost of additional security [point (c,s)]. If capacity is expanded further, the additional cost outweighs the value of the resulting increase in security. Similarly, if capacity is reduced (expands more slowly), the value of additional security resulting from a higher rate of expansion outweighs the additional costs.

Consideration of the benefits of service security is beyond the scope of this study. However, the relationship between security (as measured by reserve factor) and the cost of electricity in Alaska will be addressed in quantitative fashion in Section 8.0.

(a) This result is based on the implicit assumption that the policy of average cost pricing remains in effect.

(b) Expected loss is defined here as the probability of disruption times the cost of disruption.

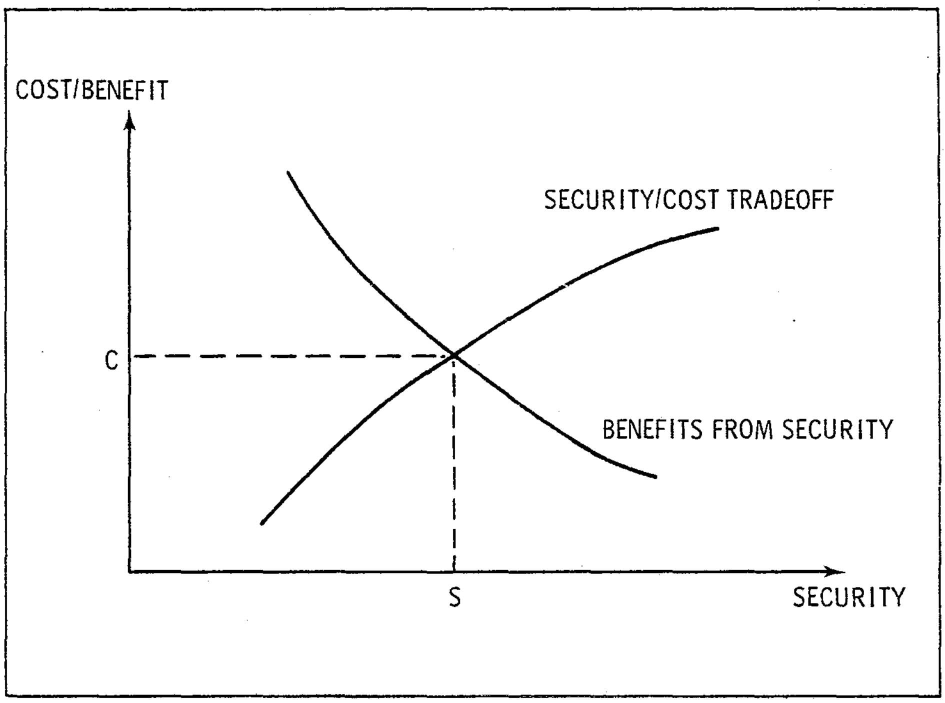

FIGURE 4.11

Relationship Between Security of Supply and Costs

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2. University of Alaska, Institute for Social and Economic Research, Electric Power in Alaska, 1976-1995, August 1976.

3. Robert R. Retherford Associates, North Slope Natural Gas Transport Systems and Their Potential Impact on Electric Power Supply and Uses in Alaska, March 1977.

4. U.S. Department of the Interior, Alaska Power Administration, A Report of the Technical Advisory Committee on Economic Analysis and Load Projections, 1974.

5. Federal Power Commission, The 1976 Alaska Power Survey, Vol. 1, 1976.

6. U.S. Department of the Interior, Alaska Power Administration, Upper Susitna River Hydroelectric Studies, Report on Markets for Project Power, December 1975.

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12. Rural Electrification Association, Power Requirements Study for Chugach Electric Association, May 1975.

5.0

5.0 EXISTING AND PLANNED GENERATING RESOURCES

This chapter contains a compilation of the historical and existing generating capacities in the Fairbanks and Anchorage/Cook Inlet/Kenai regions. In addition, the near term (to 1984) planned resources for the combined Railbelt system are listed. The combined Railbet system is derived by summing together the planned resources for the two subareas. This data forms the starting point for the load/resource anaylsis done in Chapter 8. Historical generating capacities for utility, intertied national defense, and intertied industrial plants are presented for 1972. In all cases only intertied national defense and industrial capacities are included. Generating capacities for the Railbelt utilities for 1975, 1976 and 1977 are presented. National defense and industrial loads are included in the totals for 1975-84 but are not updated beyond the 1972 data.

5.1 ANCHORAGE/COOK INLET/KENAI REGION

5.1.1 Existing Resources

The generating capacities for the Anchorage/Cook Inlet/Kenai region utilities as of mid-1977 are presented in Table 5.1.

5.1.2 Planned Additions

The planned additions by Chugach Electric Association (CEA) and Anchorage Municipal Light and Power (AML&P) through 1984 are shown in Table 5.2. The combined generating capacities for the Alaska Power Administration, the Homer Electric Association, Seward Electric System, and the Matanuska Electric Association, Inc. are assumed to remain constant during the period from 1976-1984 with CEA and AML&P being the major generating utilities.

5.1.3 Historical, Existing, and Planned Capacities

The historical (1972, 1975 and 1976), existing (1977), and planned (through 1984) generating capacities for the Anchorage/Cook Inlet/Kenai region are presented in Table 5.3. The yearly totals are shown graphically in Figure 5.1.

TABLE 5.1. Existing (mid-1977) Generating Capacities for Anchorage/Cook Inlet/Kenai Area Utilities

Unit Reference/ Name	Year of Installation	Location	Type of Generation	Capacity (kw)
ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)				
Diesel	-	Anchorage	Diesel	2,200
Unit 1	-	"	S.C.C.T.*	15,130
Unit 2	-	"	S.C.C.T.	15,130
Unit 3	-	"	S.C.C.T.	18,650
Unit 4	-	"	S.C.C.T.	31,700
Unit 5	-	"	S.C.C.T.	36,000
			Subtotal	121,100[a]
CHUGACH ELECTRIC ASSOCIATION (CEA)				
Beluga				
Unit 1	-	Beluga	S.C.C.T.	33,000
Unit 2	-	"	S.C.C.T.	
Unit 3	-	"	R.C.C.T.*	54,600
Unit 4	-	"	S.C.C.T.	9,300
Unit 5	-	"	R.C.C.T.	65,000
Unit 6	-	"	S.C.C.T.	67,810
Unit 7	1977	"	S.C.C.T.	68,000
Bernice Lake				
Unit 1	-	Bernice Lake	S.C.C.T.	8,370
Unit 2	-	"	S.C.C.T.	17,860
Cooper Lake	-	Cooper Lake	Hydro	16,500
International				
Unit 1	-		S.C.C.T.	30,510
Unit 2	-		S.C.C.T.	
Unit 3	-		S.C.C.T.	18,140
Knik Arm				
Combined	-	-	S.T.*	10,000
			Subtotal	399,590
MATANUSKA ELECTRIC ASSOCIATION (MEA)				
Talkeetna	-	Talkeetna	Diesel	600[b]

TABLE 5.1. Continued

Unit Reference/ Name	Year of Installation	Location	Type of Generation	Capacity (kw)
		HOMER ELECTRIC ASSOCIATION (HEA)		
English Bay	-	English Bay	Diesel	100
Homer & Kenai Combined	-	Homer	Diesel	300(c)
Homer Combined	-	Homer	S.C.C.T.	7,000(d)
Port Graham Combined	-	Port Graham	Diesel	200
Seldovia Combined	-		Diesel	1,500
			Subtotal	9,100
		SEWARD ELECTRIC SYSTEM (SES)		
Seward Combined	-	Seward	Diesel	5,500(b)
		ALASKA POWER ADMINISTRATION (APA)		
Eklutna	-	Eklutna	Hydro	30,000
			TOTAL	565,890

* S.C.C.T.- Simple Cycle Combustion Turbine
R.C.C.T.- Regenerative Cycle Combustion Turbine
S.T. - Steam Turbine
C.C. - Combined Cycle

(a) Capacities for individual units are from sources 1 & 2. These sum to 118,810 kW. Total shown is shown from source 2.
(b) Standby
(c) Leased to CEA.
(d) Leased to HEA by Golden Valley Electric Association for 1977-1979.

SOURCES:

1. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.

2. Alaska Electric Power Statistics 1960-1976, Alaska Power Administration, pp. 15-17, July 1977.

3. 1976 Power System Study, Chugach Electric Association, Inc., Tippett and Gee, Dallas, TX, p. 7, March 1976.

TABLE 5.2. Planned Additions for Anchorage - Cook Inlet - Kenai Area Utilities (1978 - 1984)

Unit Reference/ Name	Year of Installation	Location	Type of Generation	Capacity (kW)
		ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)		
Unit 6	1978	-	C.C.	16,500[a]
Unit 7	1979	-	S.C.C.T.	65,000[b]
Unit 6	"	-	C.C.	16,500[c]
		CHUGACH ELECTRIC ASSOCIATION (CEA)		
Beluga #8	1978	Beluga	C.C.	32,200[d]
Bernice Lake #3	"	Bernice Lake	S.C.C.T.	18,000
Beluga #9	1979	Beluga	C.C.	32,200[e]
X-1	1980	-	S.C.C.T.	100,000
Bernice Lake #4	1981	Bernice Lake	S.C.C.T.	18,000
X-2	1982	-	S.C.C.T.	100,000
Bernice Lake #5	1984	Bernice Lake	S.C.C.T.	18,000
Coal-1	"	-	S.T.	400,000

(a) Unit #6 is a steam unit addition which uses the exhaust heat from Unit #5.

(b) Unit #7 is a simple cycle combustion turbine unit which also supplies exhaust heat to Unit #6.

(c) This increase reflects the increase in capacity resulting from the addition of Unit #7.

(d) Beluga #8 is a steam unit addition to Beluga #6 (converts these to a 100 MW combined cycle unit).

(e) Beluga #9 is a steam unit addition to Beluga #7 (converts these to a 100 MW combined cycle unit).

SOURCES

1. 1976 Power System Study, Chugach Electric Association, Inc., Tippett & Gee, Dallas, Texas, pp. 7 & 25, March 1976.

2. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.

TABLE 5.3. Anchorage/Cook Inlet/Kenai Region Historical, Existing, and Planned Installed Nameplate Capacity

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 KW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine	1972 Gross Generation Million KWH	Fuels	Remarks
1972									
Utility Systems									
Anchorage (AML&P)	1972	88.6		2.2	86.4		273.9	Gas, oil standby	
Beluga, Anchorage, Bernice Lake, Cooper Lake (CEA)	1972	212.6	15.0		183.1	14.5	476.8	Gas	
Eklutna (APA)	1972	30.0	30.0				164.0	Oil	
Homer (HEA)	1971	2.4		2.4				Oil	
Kenai (HEA)	1969	6.2(a)		6.2(a)				Oil	
Seldovia (HEA)	1971	1.6		1.6			2.8	Oil	
Seward (SL&P)	1972	3.0(a)		3.0(a)			0.1	Oil	
Talkeetna (MEA)	1973	0.6(a)		0.6(a)					
Subtotal, Utilities		345.0	45.0	16.0	269.5	14.5			
National Defense Systems									
Elmendorf (USAF)	1972	33.6		2.1(a)		31.5	122.9	Gas	
Fort Richardson (Army)	1972	25.2		7.2(a)		18.0	43.6	Gas	
Subtotal, Nat'l Defense		58.8		9.3		49.5			
Industrial Systems									
Kenai Collier Plant	1972	9.7		9.7			45.3	Natural Gas	
Kenai LNG	1972	0.4(a)		0.4(a)				Oil	
Kenai Tesoro Refinery	1972	2.3			2.3		NA	Gas	
Subtotal, Indus. Systems		12.4		10.1	2.3				
TOTAL		416.2	45.0	35.4	271.8	64.0			

TABLE 5.3. (continued)

Location and Utility Symbol	Date of Data	Utility Installed Nameplate Capacity - 1,000 KW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine	1975 Generation Million KWH	Fuels	Remarks
1975									
Utility Systems									
Anchorage (AML&P)	1975	121.1		2.2	118.9		385.5		
Beluga, Anchorage, Bernice Lake, Cooper Lake (CEA)	1975	257.5	15.0		228.0	14.5	888.8		
Eklutna (APA)	1975	30.0	30.0				135.1		
Homer (HEA)	1975	2.4		2.4(a)			Incl.	Oil	
Kenai (HEA)	1975	3.7		3.7(a)			Incl.	Oil	
Seldovia (HEA)	1975	1.6		1.6			3.1	Oil	
Seward (SES)	1975	3.0		3.0(a)			3.2	Oil	
Talkeetna (MEA)	1975	.0		0.6(a)			.0		
Subtotal, Utilities		419.3	45.0	13.5	346.9	14.5	1,415.7		
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5			
Subtotal, Indus. Systems	1972	12.4		10.1	2.3				
TOTAL		490.5	45.0	32.9	349.2	64.0			
1976									
Utility Systems									
(AML&P)	1976	121.10		2.20	118.90		444.90	Gas	
(CEA)	1976	345.50	15.00		316.00	14.50	1,054.50	Gas	
(APA)	1976	30.00	30.00				118.00		
English Bay (HEA)	1976	0.10		0.10			0.10	Oil	
Homer & Kenai (HEA)	1976	0.30		0.30(a)			0.00	Oil	
Port Graham (HEA)	1976	0.20		0.20			0.30	Oil	
Seldovia (HEA)	1976	1.50		1.50			0.07	Oil	
Seward (SES)	1976	5.50		5.50(a)			1.50	Oil	
Talkeetna (MEA)	1976	0.60		0.60(a)			0.00		
Subtotal, Utilities	1976	504.80	45.00	10.40	434.90	14.50	1,619.40		
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5			
Subtotal, Indus. Sys	1972	12.4		10.1	2.3				
TOTAL		576.0	45.00	29.8	437.2	64.0			

TABLE 5.3. (continued)

	Date of Data	Total	Hydro	Diesel	Combustion Turbine	Steam Turbine	Gross Generation 106 KWH	Dominant Fuel	Remarks
1977									
Utility Systems									
AML&P	11/77	121.1		2.2	118.9			Gas	
CEA	11/77	399.6	16.5		373.2	10.0		Gas	Reflects 7.5% derating on all C.T. units Addition of Beluga #7
Others	1976	45.2	30.0	8.2[a]	7.0[b]			Oil	
Subtotal, Utilities		565.9	46.5	10.4	499.0	10.0		Gas	
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		637.1	46.5	29.8	501.3	59.5		Gas	
1978									
Utility Systems									
AML&P	11/77	137.6		2.2	135.4			Gas	Addition of unit #6
CEA	11/77	449.8	16.5		423.3	10.0		Gas	Addition of Bernice Lake #3 & Beluga #8
Others	1976	45.2	30.0	8.2[a]	7.0[b]			Oil	
Subtotal, Utilities		632.6	46.5	10.4	565.7	10.0		Gas	
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		703.8	46.5	29.8	568.0	59.5		Gas	

TABLE 5.3. (continued)

	Date of Data	Total	Hydro	Diesel	Combustion Turbine	Steam Turbine	Gross Generation 10^6 KWH	Dominant Fuel	Remarks
1979									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	Addition of unit #7 & upgrading of #6
CEA	11/77	482.0	16.5		455.5	10.0		Gas	Addition of Beluga #9
Others	1976	38.2	30.0	8.2 (a)				Oil	
Subtotal, Utilities		739.3	46.5	10.4	672.4	10.0		Gas	
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		810.5	46.5	29.8	674.7	59.5		Gas	
1980									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	
CEA	11/77	582.0	16.5		555.5	10.0		Gas	Addition of X-1 (100 MW C.T.S.C.)
Others	1976	38.2	30.0	8.2(a)				Oil	
Subtotal, Utilities		839.3	46.5	10.4	772.4	10.0		Gas	
Subtotal, Nat'l Defense	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		910.5	46.5	29.8	774.7	59.5		Gas	

TABLE 5.3. (continued)

	Date of Data	Total	Hydro	Diesel	Combustion Turbine	Steam Turbine	Gross Generation 10^6 kWh	Fuel	Remarks
1981									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	
CEA	11/77	600.0	16.5		573.5	10.0		Gas	Addition of Bernice Lake #4 (18 MW C.T.S.C.
Others	1976	38.2	30.0	8.2(a)				Oil	
Subtotal, Utilities		857.3	46.5	10.4	790.4	10.0		Gas	
Subtotal, Nat'l Def.	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		928.5	46.5	29.8	792.7	59.5		Gas	
1982									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	
CEA	11/77	700.0	16.5		673.5	10.0		Gas	Addition of X-2 (100 MW C.T.S.C.)
Others	1976	38.2	30.0	8.2(a)					
Subtotal, Utilities		957.3	46.5	10.4	890.4	10.0		Gas	
Subtotal, Nat'l Def.	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		1028.5	46.5	29.8	892.7	59.5		Gas	

	Date of Data	Total	Hydro	Diesel	Combustion Turbine	Steam Turbine	Gross Generation 10^6 Kwh	Fuel	Remarks
1983									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	
CEA	11/77	700.0	16.5		637.5	10.0		Gas	
Others	1976	38.2	30.0	8.2				Oil	
Subtotal, Utilities		957.3	46.5	10.4	890.4	10.0		Gas	
Subtotal, Nat'l Def.	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal, Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		1028.5	46.5	29.8	892.7	59.5		Gas	
1984									
Utility Systems									
AML&P	11/77	219.1		2.2	216.9			Gas	
CEA	11/77	1118.0	16.5		691.5	410.0		Gas	Addition of Bernice Lake #5 (18 MW C.T.S.C. Addition of coal -1 (400 MW S.T.)
Others	1976	38.2	30.0	8.2				Oil	
Subtotal, Utilities		1375.3	46.5	10.4	908.4	410.0		Gas	
Subtotal, Nat'l Def.	1972	58.8		9.3		49.5	166.5	Gas	
Subtotal Ind. Sys.	1972	12.4		10.1	2.3		45.3	Gas	
TOTAL		1446.5	46.5	29.8	910.7	459.5		Gas	

(a) Standby

(b) This total includes two 3500 kW simple cycle combustion turbine units leased to Homer Electric Association by Golden Valley Electric Association.

SOURCES FOR TABLES 5.3 AND 5.6

1972: 1974 Alaska Power Survey, Report of the Technical Advisory Committee - Resources and Electric Power Generation, Appendix A. Alaska Power Administration, May 1974.

1975: Alaska Electric Power Statistics 1960-1975. Alaska Power Administration, pp. 15-18, July 1976.

1976: Alaska Electric Power Statistics 1960-1975. Alaska Power Administration, pp. 15-17, July 1977.

1977-80: Electric Power in Alaska, 1976-1995. ISER, University of Alaska, pp. 5.2-7.4, August 1976.

1977-83: Interior Alaska Energy Analysis Team. Final Report, June 1977.

1977-84: 1976 Power System Study, Chugach Electric Association, Inc. Tippett and Gee, Dallas, TX, pp. 7, 25, March 1976.

1977-84: Various Utility Managers, Private Communications, October 1977.

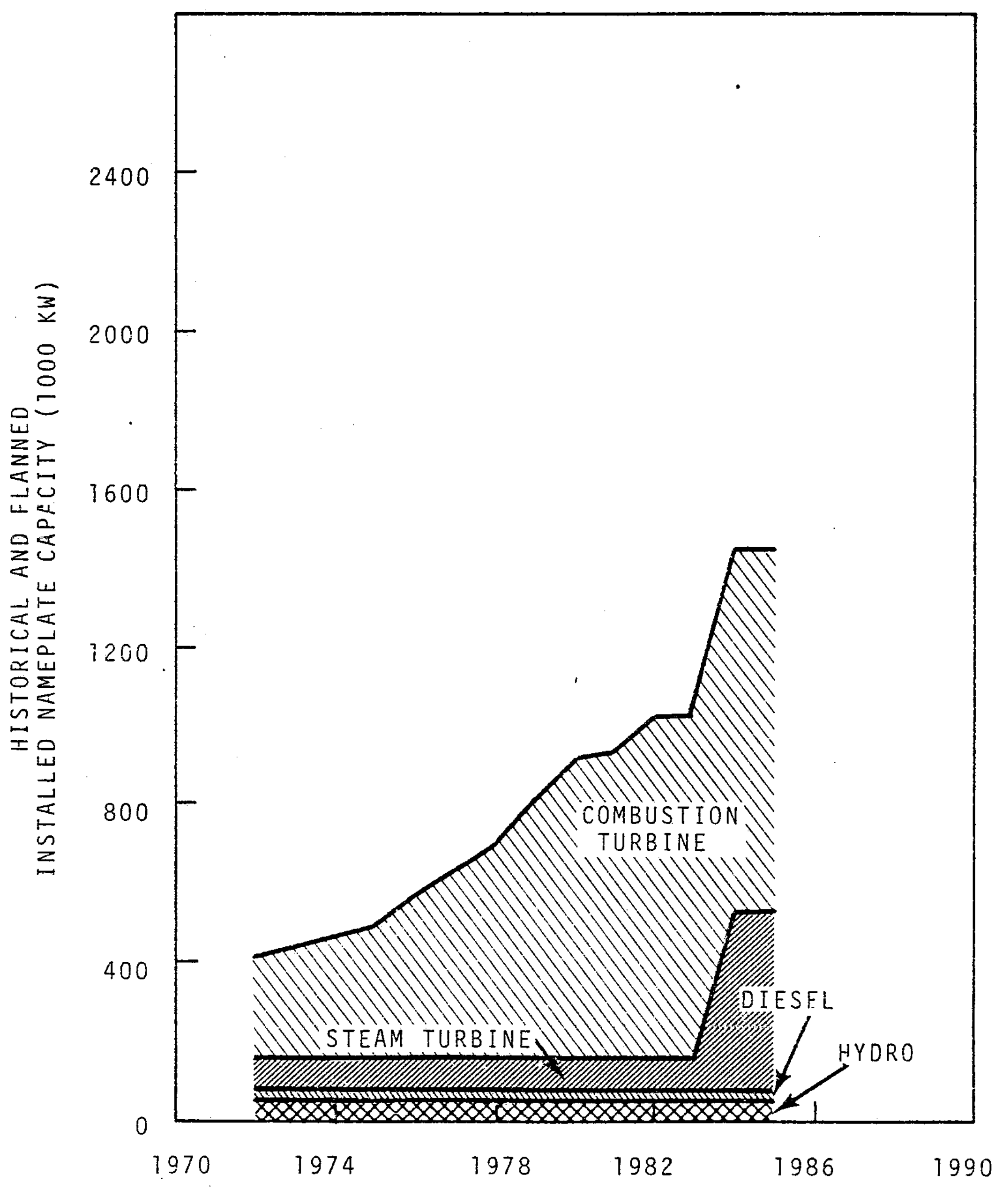

FIGURE 5.1. Historical and Planned Nameplate Capacity Anchorage/Cook Inlet/Kenai Area 1972-1984

5.2 FAIRBANKS REGION

5.2.1 Existing Resources

The generating capacities for the Fairbanks region utilities as of mid-1977 are shown in Table 5.4.

TABLE 5.4. Existing (Mid-1977) Generating Capacities for Fairbanks Region Utilities

Unit Reference Name	Year of Installation	Location	Type of Generation	Capacity (kW)
FAIRBANKS MUNICIPAL UTILITIES SYSTEM (FMV)				
Chena 2	1952	Fairbanks	S.T.	2,000
Chena 3	1952	Fairbanks	S.T.	1,500
Chena 1	1954	Fairbanks	S.T.	5,000
Chena 4	1963	Fairbanks	S.C.C.T.	5,350
Diesel 1	1967	Fairbanks	Diesel	2,665
Diesel 2	1968	Fairbanks	Diesel	2,665
Diesel 3	1968	Fairbanks	Diesel	2,665
Chena 5	1970	Fairbanks	S.T.	20,000
Chena 6	1976	Fairbanks	S.C.C.T.	23,500
			Subtotal	65,345
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)				
	1961,1964 and 1970	Fairbanks	Diesel	24,000
Healy #1	1967	Healy	S.T.	25,000
	1971,1972	Fairbanks	S.C.C.T.	40,000
	1975	Fairbanks	S.C.C.T.	7,000(a)
	1975	Delta	Diesel	500
North Pole #1	1976	North Pole	S.C.C.T.	70,000
North Pole #2	1977	North Pole	S.C.C.T.	70,000
			Subtotal	229,500
			TOTAL	294,845

(a) These units are leased to the Homer Electric Association for 1977-1979. They are not included in total here.

SOURCE: Interior Alaska Energy Analysis Team, Final Report, June 1977.

5.2.2 Planned Additions

The planned additions for the Fairbanks area through 1983 are shown in Table 5.5.

TABLE 5.5. Planned Additions for Fairbanks Area Utilities (1978-1984)

Unit Reference Name	Year of Installation	Location	Type of Generation	Capacity (kW)
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)				
North Pole #3	1981	North Pole	S.C.C.T.	70,000
Healy #2	1982	Healy	S.T.	130,000

SOURCE: Interior Alaska Energy Analysis Team, Final Report, June 1977.

5.2.3 Historical, Existing, and Planned Capacities

The historical, existing, and planned generating capacities for the Fairbanks area are listed in Table 5.6 and the total are shown plotted in Figure 5.2.

5.3 COMBINED RAILBELT REGION HISTORICAL AND EXISTING RESOURCES AND PLANNED ADDITIONS

The historical, existing, and planned additions for the combined Railbelt Region are shown in Table 5.7. The data for the combined system are derived by summing the totals from the two subregions. These data are shown graphically in Figure 5.3.

TABLE 5.6. Fairbanks Region Historical, Existing, and Planned Installed Nameplate Capacity

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 KW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine	1972 Gross Generation Million KWH	Fuels	Remarks
1972									
Utility Systems									
Fairbanks Municipal (FMU)	1972	43.8		8.3	7.0	28.5	107.8		
Golden Valley (GVEA)	1972	84.0		23.9	35.1	25.0	211.0		
Subtotal, Utilities		127.8		32.2	42.1	53.5	318.8	Oil,Coal	
National Defense Systems									
Eilson AFB (USAF)	1972	20.0		5.0		15.0	58.5	Coal,Oil	
Fort Greeley (Army)	1972	8.3		6.3		2.0	14.3	Oil	
Fort Wainwright (Army)	1972	27.0		3.5		23.5	50.1	Coal,Oil	
Subtotal, Nat'l Defense		55.3		14.8		40.5	122.9		
TOTAL		183.1		47.0	42.1	94.0	441.7		
1975									
Utility Systems									
(FMU)	1975	43.7		8.2	7.0	28.5	137.2		
(GVEA)	1975	89.8		23.9	40.9	25.0	286.9		
Subtotal, Utilities		133.5		32.1	47.9	53.5	424.1	Oil,Coal	
Subtotal, Nat'l Defense	1972	55.3		14.8	-	40.5	122.9		
TOTAL		186.8		46.9	47.9	94.0	547.0	Oil,Coal	

TABLE 5.6 (Continued)

Location and Utility Symbol	Date of Data	Utility Installed Nameplate Capacity -- MW Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine	1976 Generation Million KWH	Fuels	Remarks
1976									
Utility Systems									
(FMU)	1976	67.7		8.2	31.0	28.5	139.0		
(GVEA)	1976	154.5		23.9	105.6	25.0	321.0		
Subtotal, Utilities		222.2		32.1	136.6	53.5	459.9	Oil,Coal	
Subtotal, Nat'l Defense	1972	53.3		14.8	-	40.5	122.9		
TOTAL		275.5		46.9	136.60	94.0	582.8	Oil,Coal	
1977									
Utility Systems									
FMU	11/77	65.3		8.0	28.8	28.5	-	Coal,Oil	
GVEA	11/77	229.5		24.5	180.0(b)	25.0	-	Coal,Oil	Addition of North Pole, #2 (65 MW R.C.C.T)
Subtotal, Utilities	11/77	294.8		32.5	208.8	53.5		Coal,Oil	
Subtotal, Nat'l Defense	1972	55.3		14.8	-	40.5	-	Coal,Oil	
TOTAL		350.1		47.3	208.8	94.0	-	Coal,Oil	
1978									
Utility Systems									
FMU	11/77	65.3		8.0	28.8	28.5	-	Coal,Oil	
GVEA	11/77	229.5		24.5	180.0(b)	25.0	-	Coal,Oil	
Subtotal, Utilities	11/77	294.8		32.5	208.8	53.5		Coal,Oil	
Subtotal, Nat'l Defense	1972	55.3		14.8	-	40.5		Coal,Oil	
TOTAL		350.1		47.3	208.8	94.0		Coal,Oil	

TABLE 5.6. (continued)

Location and Utility Symbol	Date of Data	Utility Installed Nameplate Capacity -- MW Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine	1976 Generation Million KWH	Fuels	Remarks
1979									
Utility Systems									
FMU	11/77	65.3		8.0	28.8(b)	28.5	-	Coal,Oil	
GVEA	11/77	229.5		24.5	180.0	25.5	-	Coal,Oil	
Subtotal, Utilities	11/77	294.8		32.5	208.8	53.5	-	Coal,Oil	
Subtotal, Nat'l Defense	1972	55.3		14.8	-	40.5	-	Coal,Oil	
TOTAL		350.1		47.3	208.8	94.0	-	Coal,Oil	

Location and Utility Symbol	Date of Data	Installed Generating Capacity -- 1000 KW Total	Hydro	Diesel	Gas Turbine	Steam Turbine	Gross Generation 10^6 KWH	Fuels	Remarks
1980									
Utility Systems									
FMU	11/77	65.3		8.0	28.8	28.5	-	Coal,Oil	
GVEA	11/77	236.5		24.5	187.0	25.0	-	Coal,Oil	
Subtotal, Utilities	11/77	301.8		32.5	215.8	53.5	-	Coal,Oil	
Subtotal, Nat'l Defense	1972	55.3		14.8	-	40.5	-	Coal,Oil	
TOTAL		357.1		47.3	215.8	94.0	-	Coal,Oil	

TABLE 5.6. (continued)

Location and Utility Symbol	Date of Data	Installed Generating Capacity -- 1000 KW Total	Hydro	Diesel	Gas Turbine	Steam Turbine	Gross Generation 10^6 KWH	Fuels	Remarks
1981									
Utility Systems									
FMU	11/77	65.3		8.0	28.8	28.5	-	Coal,Oil	
GVEA	11/77	336.5		24.5	287.0	25.0	-	Coal,Oil	Addition of
Subtotal, Utilities		401.8		32.5	315.8	53.5	-	Coal,Oil	North Pole
Subtotal, Nat'l									#3 (100 MW
Defense	1972	55.3		14.8	-	40.5	-	Coal,Oil	R.C.C.T.)
TOTAL		457.1		47.3	315.8	94.0	-	Coal,Oil	
1982									
(No Change)									
1983									
Utility Systems									
FMU	11/77	95.1		8.0	28.8	58.5	-	Coal,Oil	Addition of
GVEA	11/77	336.5		24.5	287.0	125.0	-	Coal,Oil	Heavy #2 (130
Subtotal, Utilities		531.8		32.5	315.8	183.5			MW S.T. -
Subtotal, Nat'l									30 MW - FMU &
Defense		55.3		14.8	-	40.5	-	Coal,Oil	100 MW - GVEA)
TOTAL		587.1		47.3	315.8	224.0			

(a) Standby

(b) This total does not include two 3500 kW combustion turbines leased to Homer Electric Association for 1977-1978.

SOURCES: See Table 5.3

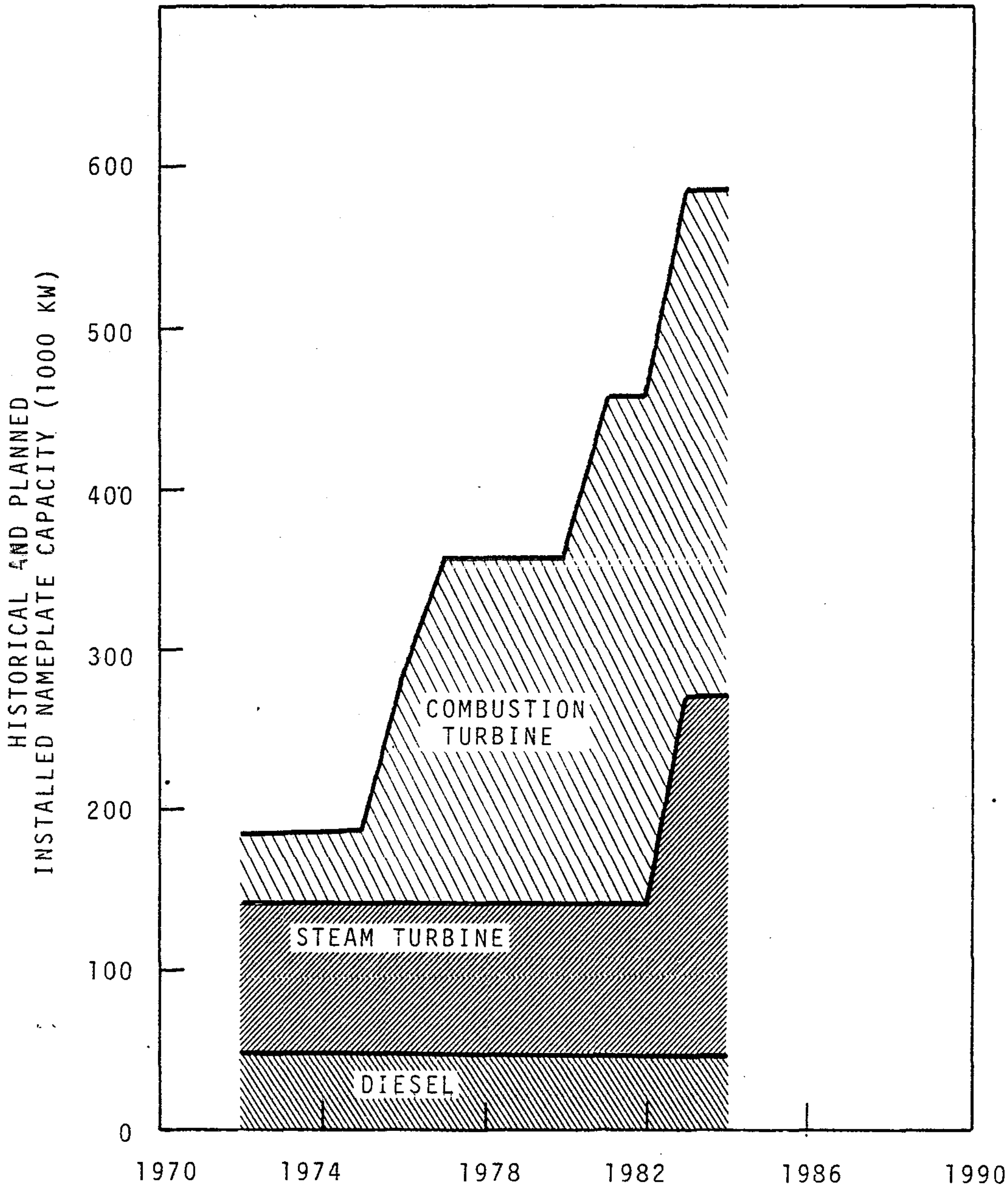

FIGURE 5.2. Historical and Planned Nameplate Capacity Fairbanks Area 1972-1983

TABLE 5.7 Combined Railbelt Historical, Existing, and Planned Installed Capacity

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 kW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
1972						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1972	345.0	45.0	16.0	269.5	14.5
Fairbanks	1972	127.8	-	32.2	42.1	53.5
Subtotal, Utilities		472.8	45.0	48.2	311.6	68.0
National Defense						
Anchorage/Cook Inlet/Kenai	1972	58.8	-	9.3	-	49.5
Fairbanks	1972	55.3	-	14.8	-	40.5
Subtotal, Nat'l Defense		114.1	-	24.1	-	90.0
Industrial Systems						
Anchorage/Cook Inlet/Kenai	1972	12.4	-	10.1	2.3	-
TOTAL		599.3	45.0	82.4	313.9	158.0
1975						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1975	419.3	45.0	13.5	346.9	14.5
Fairbanks	1975	133.5	-	32.1	47.9	53.5
Subtotal, Utilities		552.8	45.0	45.6	394.8	68.0
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		679.3	45.0	79.8	397.1	158.0

TABLE 5.7 (Continued)

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 kW Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
1976						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1976	504.8	45.0	10.4	434.9	14.50
Fairbanks	1976	222.2	-	32.1	136.6	53.5
Subtotal, Utilities		727.0	45.0	42.5	571.5	68.0
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		853.5	45.0	76.7	573.8	158.0
1977						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	565.9	46.5	10.4	499.0	10.0
Fairbanks	1977	294.8	-	32.5	208.8	53.5
Subtotal, Utilities		860.7	46.5	42.9	707.8	63.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		987.2	46.5	77.1	710.1	153.5

TABLE 5.7 (Continued)

Location and Utility Symbol	Date of Data	Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
		Installed Generating Capacity - 1000 kW				
1978						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	632.6	46.5	10.4	565.7	10.0
Fairbanks	1977	294.8	-	32.5	208.8	53.5
Subtotal, Utilities		927.4	46.5	42.9	774.5	63.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Defense	1972	12.4	-	10.1	2.3	-
TOTAL		1053.9	46.5	77.1	776.8	153.5
1979						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	739.3	46.5	10.4	672.4	10.0
Fairbanks	1977	301.8	-	32.5	215.8	53.5
Subtotal, Utilities		1041.1	46.5	42.9	888.2	63.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		1167.6	46.5	77.1	890.5	153.5

TABLE 5.7 (Continued)

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 kW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
1980						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	839.3	46.5	10.4	772.4	10.0
Fairbanks	1977	301.8	-	32.5	215.8	53.5
Subtotal, Utilities		1141.1	46.5	42.9	988.2	63.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		1267.6	46.5	77.1	990.5	153.5
1981						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	857.3	46.5	10.4	790.4	10.0
Fairbanks	1977	401.8	-	32.5	315.8	53.5
Subtotal, Utilities		1259.1	46.5	42.9	1106.2	63.5
National Defense						
Subtotal, Nat'l Defense		114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		1385.6	46.5	77.1	1108.5	153.5

TABLE 5.7 (Continued)

Location and Utility Symbol	Date of Data	Installed Generating Capacity - 1000 kW: Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
1982						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	957.3	46.5	10.4	890.4	10.0
Fairbanks	1977	401.8	-	32.5	315.8	53.5
Subtotal, Utilities		1359.1	46.5	42.9	1206.2	63.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		1485.6	46.5	77.1	1208.5	153.5
1983						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	957.3	46.5	10.4	890.4	10.0
Fairbanks	1977	531.8	-	32.5	315.8	183.5
Subtotal, Utilities		1489.1	46.5	42.9	1206.2	193.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		1615.6	46.5	77.1	1208.5	283.5

TABLE 5.7 (Continued

Location and Utility Symbol	Date of Data	Total	Hydro	Diesel (IC)	Gas Turbine	Steam Turbine
		Installed Generating Capacity - 1000 kW				
1984						
Utility Systems						
Anchorage/Cook Inlet/Kenai	1977	1375.3	46.5	10.4	908.4	410.0
Fairbanks	1977	531.8	-	32.5	315.8	183.5
Subtotal, Utilities		1907.1	46.5	42.9	1224.2	593.5
National Defense						
Subtotal, Nat'l Defense	1972	114.1	-	24.1	-	90.0
Industrial Systems						
Subtotal, Industrial Systems	1972	12.4	-	10.1	2.3	-
TOTAL		2033.6	46.5	77.1	1226.5	683.5

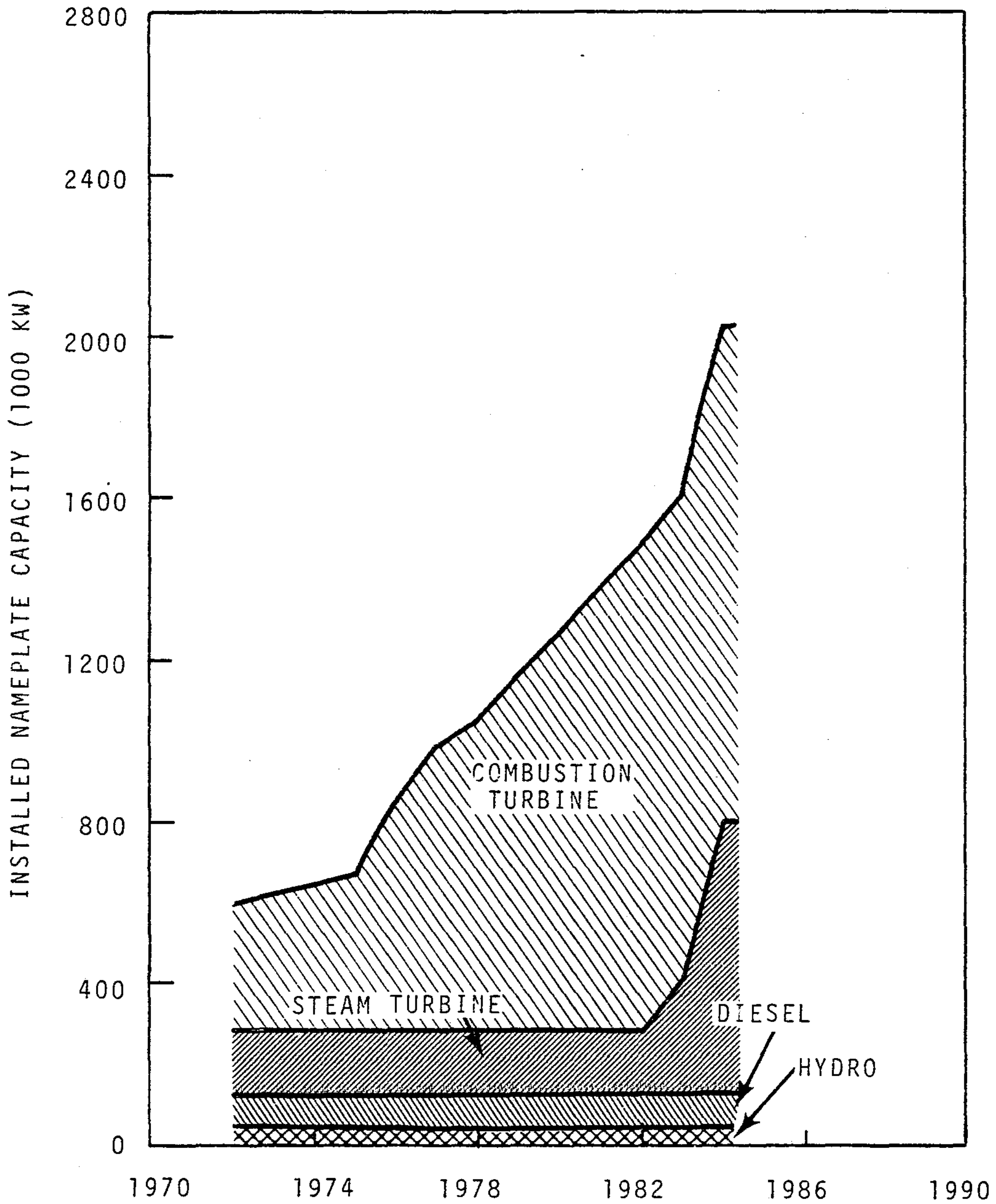

FIGURE 5.3. Historical and Existing Resources and Planned Additions for the Combined Railbelt System (1972-1984)

6.0

6.0 CAPITAL AND OPERATING COSTS OF GENERATING CAPACITY

6.1 CAPITAL COST ESTIMATES

Several methods can be used to estimate the capital cost of electrical generating plants. Each method has a different level of uncertainty or "error band" associated with it. As would be expected, the less the uncertainty associated with an estimate, the more time and money required to prepare it. Several factors contribute to the uncertainty of an estimate; rapidly escalating equipment, site materials, and labor costs and changing requirements for environmental protection are perhaps the most important at the present time. The cost estimates presented in this report should not be viewed as firm estimates, but as the best estimates available considering the scope of the study.

The most accurate estimating procedure is to obtain a firm bid for the installed equipment from a supplier. This procedure can be quite expensive, however, since it usually requires site specific studies and binding commitments from subcontractors. As a result, this method is typically not used unless there are definite plans to purchase the equipment.

Perhaps the next most accurate method of estimating the capital cost of a facility is to get an estimate (nonfirm) by a supplier. In most cases with large and expensive equipment, suppliers are reluctant to give such estimates because the total costs are highly dependent on site-specific factors which require a working knowledge of local conditions. In some cases, suppliers with recent experience in the area can give relatively accurate short term estimates. Neither this, nor the previous estimating method were used in the estimates presented in this report.

6.1.1 Recent Experience

Another relatively accurate estimating procedure is to estimate the costs of the proposed facilities based on data from recent purchases of similar equipment of the same size located in a similar location. This technique is applicable in Alaska for combustion turbine equipment since there is recent Alaskan experience in the construction and operation of all types of combustion turbine generating systems.

Railbelt utilities have recently purchased simple cycle, regenerative cycle, and combined cycle combustion turbine facilities. Alaskan utilities also have recent experience with small hydroelectric facilities.

In the absence of recent local experience with units of similar capacity, it is necessary to estimate the costs of facilities using data for facilities built during different time periods, at different locations, and of different capacities. There has been no Alaskan experience with fossil fuel-fired steam turbine plants in the 100 to 400 MW range. The only Alaskan experiences with coal steam turbine generating facilities are the Healy I plant (Golden Valley Electric Association) which is rated at 20 MW and came on-line in 1968 and the Chena V plant (Fairbanks Municipal Utilities System) which is also rated at 20 MW and came on-line in 1971.

6.1.2 Inflation and Escalation Effects

To estimate the capital cost of a generating plant, given the capital cost of a similar plant built in a prior year, allowance must be made for the effects of inflation and escalation.

The comparitively long lead times from initiation to commercial operation of electric power generation and transmission plants makes them highly sensitive to inflationary effects. Lead times, including planning, site selection, licensing, and construction typically run 2 to 3 years for combustion turbines, 6 to 10 years (9 typical) for coal-fired power plants[1] depending on size and 9 to 15 years for hydroelectric plants.[2] Furthermore, the inflationary pressures have been aggravated by high demand and supply sector bottlenecks which have lead to an escalation of electric plant costs at a rate in excess of the overall inflation rate. The following paragraphs analyze past escalation and inflation effects and develop a rational basis for judging their likely future impacts.

During the past decade, general plant and particularly power plant construction costs have been subject to severe inflation.[3] Rossi, et al., for example, estimated that over an initial operating date span of 10 years from 1976-1978 to 1986-1988 operation date, power plant investment requirements will have multiplied by a factor of more than five (17.5% per year).[4]

A significant part of this inflation and escalation impact arises due to statutory requirements, largely environmental, or the delays and costs created by federal, state and sometimes local licensing procedures. Rossi thus estimated (in 1976) station capital costs for three 800 MW coal-fired units at $1036/kW for 1986-1988 operation.

Figures 6.1, 6.2, and 6.3 summarize historical construction cost trends for fossil-fired (coal and gas turbine) plants, hydroelectric plants, and transmission systems respectively for the Pacific Region as published by the Handy Whitman Index.[5]

Since 1930, coal-fired plant costs have increased (Figure 6.1) on the average of 4.8% per annum. However, during the past decade inflation, plus escalation, has averaged about 9.8% per annum. Gas turbine experience is somewhat shorter (since 1964) and the average escalation rate has been about 5.6%, but since 1964 has run at 16.8%. The latter rate probably reflects the effects of shop capacity limitations that may not prevail long into the future. Figure 6.1 also presents a plot of the general inflation rates as represented by the GNP deflation.

Hydropower plants (Figure 6.2) have seen similar escalation rate experience -- 5.0% since 1930, 9.9% since 1970 and there is similar experience with transmission plants (Figure 6.3).

The Handy Whitman Index is derived in such a manner that the cost indices are for physically identical units regardless of time. Therefore, they do not reflect changes in technology or added costs resulting from increased lead times or statutorily imposed environmental controls such as off-stream cooling and atmospheric emission controls. The data reported by Rossi, et al., do, however, reflect such costs as shown in Table 6.1. Hence, the far higher apparent escalation rate.

Since this analysis is directed toward comparison of alternative future plants that are either in the planning stage or are as yet unscheduled, it is essential to develop some rational basis for estimating future

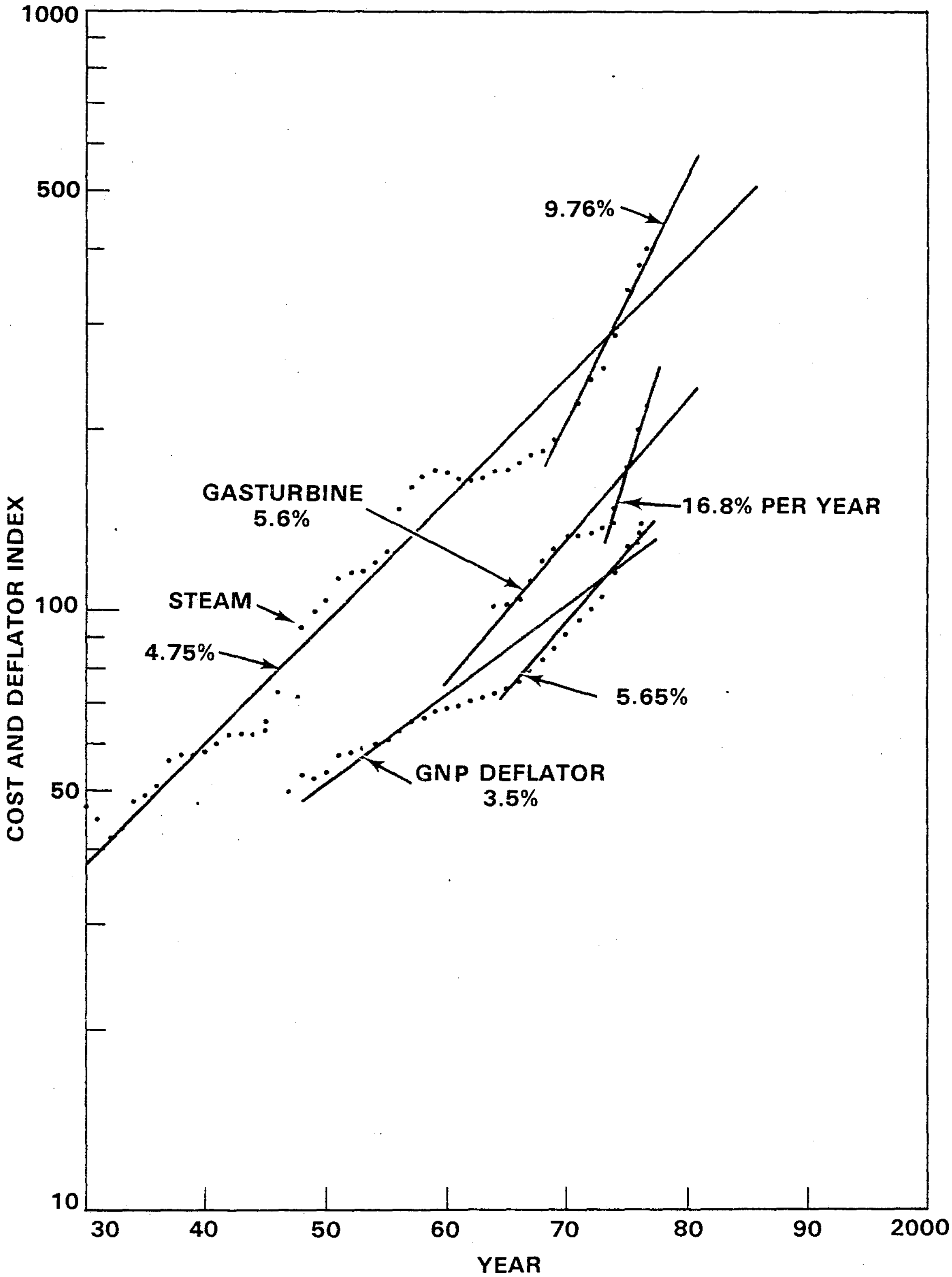

FIGURE 6.1. GNP Deflator and Thermal Power Plant Construction Cost Trends (Pacific Region)

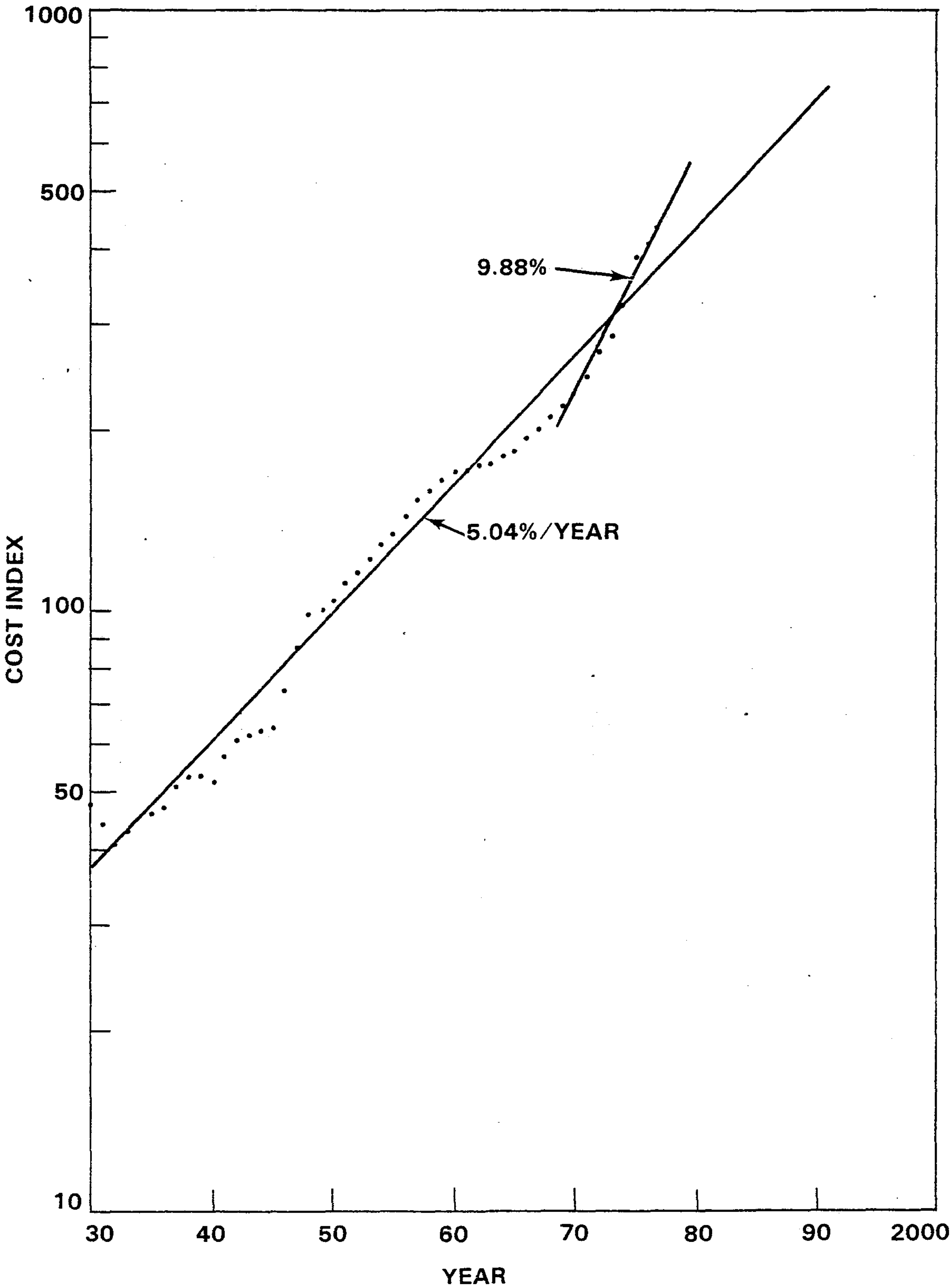

FIGURE 6.2. Hydroelectric Power Plant Cost Trends (Pacific Region)

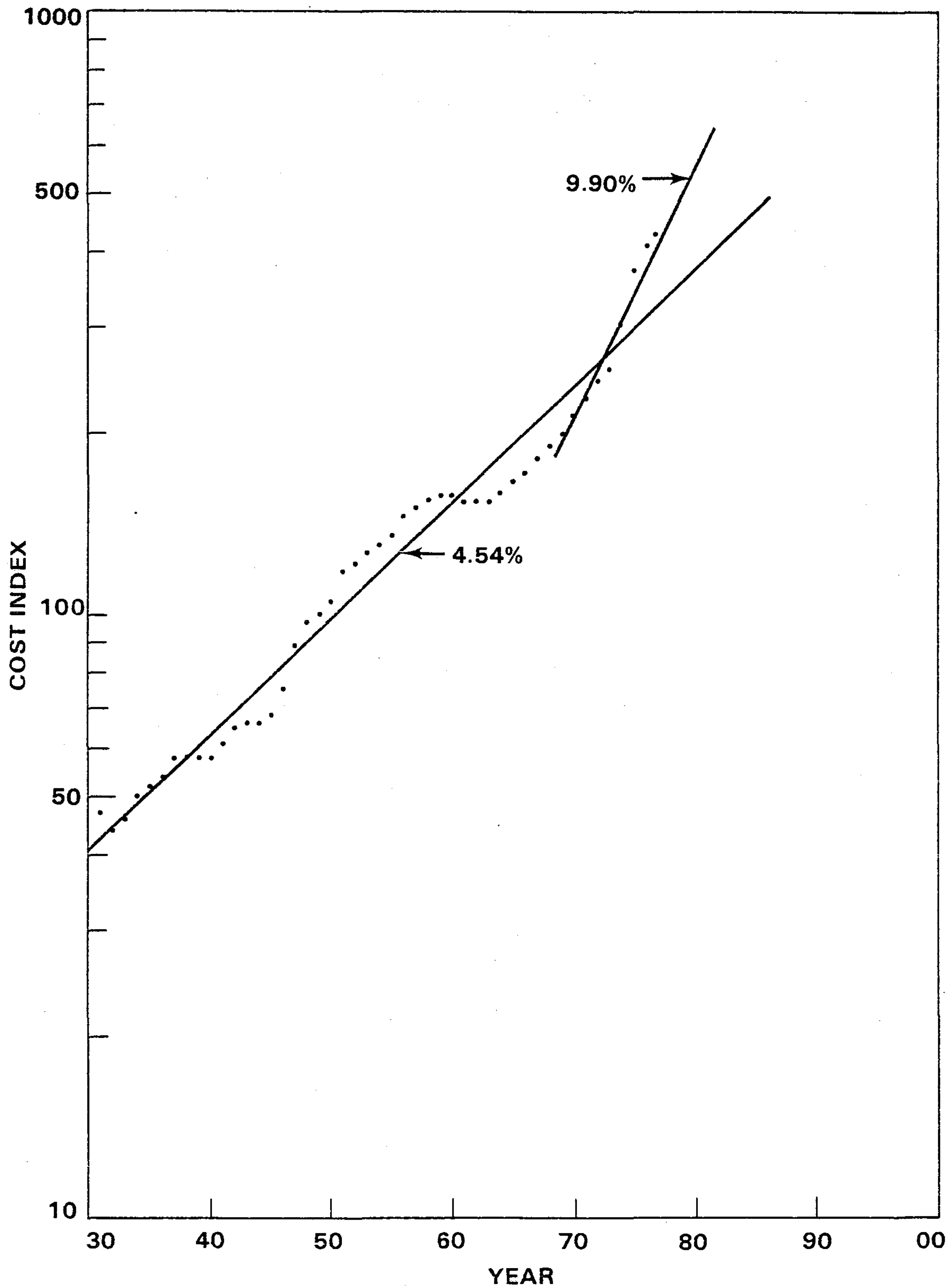

FIGURE 6.3. Cost Trends of Electric Utility Construction Pacific Region Total Transmission Plant

TABLE 6.1. Post 1969 Environmental Requirements - Coal-Fired Plants

	1969	1976	Δ$/KW
Cooling Water	Open Cycle	Cooling Tower	25
Stack Emissions	Electrostatic Collector -95%	Electrostatic Collector -99+%	47
	--	SO_2 Scrubber	130
	Unlined Ash Pond	Lined Ash Pond	3
	--	NO_x	6
	600 Ft. Stack	800 Ft. Stack	3
Increased Generating Capacity	--	High Auxilliary Load	13
Liquid Waste	Multiple Discharge, Oil Separation Only	Complete Waste Management System, Single Discharge or Rinse	8
Noise	No Special Provision	Noise Attenuation	8
Licensing	Single Application	Environmental Report, Review by Federal & State Agencies, Hearings	3
Construction	No Environmental Provisions	Protection of Environment During Construction	3
Contingency	--	--	15
IDC	--	Longer Schedule	20
Other			26
	Total		327

inflation and other escalation rates and their probable range. Future plant (fossil-fired or hydroelectric) costs can be thought as of as composed of: (1) a base cost in a reference year; (2) inflation related to the implicit GNP deflator; (3) an escalator for construction projects; and (4) escalation resulting from statutorily imposed added costs. Also, different types of plants have different degrees of exposure to these factors.

Rossie et al.,[4] suggests that capital cost escalation adders (in recent years largely due to environmental requirements), as illustrated in Table 6.1, may have run their course and that in the future escalation will continue at a more normal rate. However, for thermal plants and hardware in general, limitations in plant capacity will remain higher over the foreseeable future as utilities attempt to catch up.

Table 6.2 summarizes several construction cost indices and compares them by difference to the general rate of inflation. The major conclusion to be drawn is that capital cost increase rates for electric power plants are generally 2 to 3 percentage points higher than the general inflation rate as measured by the GNP deflator. This differential has been sustained since 1950 and, if anything, appears to have accelarated over the past decade.

The above data are, of course, derived from experience in the "lower 48" Pacific Region and hence, are not truly representative of the costs to be expected in Alaska. Compared to "lower 48" costs, the proportion of total plant costs due to onsite construction is expected to be considerably higher in Alaska. Therefore, we have chosen the higher range of the estimates as 2.5% above the GNP deflator as a reasonable value for estimating purposes. This selection may slightly underrate costs for hydropower systems where the major costs occur in Alaska and over-rate costs of thermal plants where a substantial expenditure is made in "lower 48" shop fabrication.

In Alaska, recent experience by the Corps of Engineers has seen an even more pronounced rate of inflation. For example, the estimate for the Devil Canyon/Watana Upper Susitna projects capital costs (exclusive of interest during construction) has increased from $1.52 billion in January 1975 to $2.1 billion in September 1977.[6] This is equivalent to an annual rate of 12.5% which occurred during a period when the State was experiencing a generally high level of construction activity. Thus, the rate is probably anomalous. Forthcoming construction of the North Slope gas line may contribute to another period of relatively high escalation at least into the mid-1980's.

TABLE 6.2. Comparison in Growth in Construction Cost Indices with General Inflation Rates

Index	Annual Growth Rates 1950-1975	Annual Growth Rates 1965-1975	Apparent Construction Escalators [Index - IPC] 1950-1975	Apparent Construction Escalators [Index - IPC] 1965-1975
Implicit Price Deflator(IPC)[a]	3.46	5.65	0	0
Wage Rate of Constructive Trades[b]	4.9	8.3	1.4	2.6
Construction Index[c]	7.7	9.3	4.2	3.6
Fossil Steam Electric[d]	4.7	7.2	1.1	1.6
Hydroelectric Plants[d]	5.4	7.6	1.9	2.0
		Average	2.2	2.4

(a) Implicit Price Deflator (Total), U.S. Dept. of Commerce, "Business Statistics" 1976.

(b) U.S. Bureau of Labor Statistics

(c) Engineering News Record

(d) Handy-Whitman Index - Pacific.

In this report, the cost trends of electric utility construction drawn from the Handy-Whitman Index for the Pacific Region (lower 48) is used to account for differences in dates of construction in Alaska.[5] The Handy-Whitman Index is defined as:

> A percentage ratio between the cost of an item at any slated time and the cost of that item at a base period, or:

$$\text{Index Number} = \frac{\text{Cost at Stated Time}}{\text{Cost at Base Period}} \times 100$$ [5,p.viii]

Due to the considerable uncertainty of calculations on capital and power costs for future plants we must treat inflation parametrically recognizing the potential range. Economic comparison (life cycle or present worth levelizing of incomes and expenditures basis) for power generation and transmission system alternatives necessarily takes into account the capital cost of capacity additions based on their power-on-line or commercial operating date. The capital cost at that date includes direct and indirect expenditures and interest and escalation during construction (IDC). These costs are paid at different times prior to operation and an exact analysis must take into account the point in time when the costs are incurred and inflate these to the operating date over the appropriate period. (See Section 7.4).

6.1.3 Alaska Factor

To estimate the cost of a generating facility given, the capital cost of a similar plant previously built at a different location, a location adjustment factor may be used. Conditions that influence the construction cost of facilities differ among various regions. The differences may be due to such things as the relative availability of transportation facilities, labor costs, climate, and distance from equipment suppliers. In many cases, these factors combine to influence costs in a consistent manner which allows a location adjustment factor to be used. As with the Handy-Whitman Index, this number is expressed at the ratio between the construction cost of an item at a proposed location and the construction cost of that item at a base location; i.e.,

$$\text{Location Adjustment Factor} = \frac{\text{Cost at Proposed Location}}{\text{Cost at Base Location}}$$

Such a location adjustment factor may be used to estimate the cost of a facility in Alaska given the cost of a similar facility in the lower 48.

Because of the large and diverse nature of Alaska, the "Alaska factor" must be defined for a specific location in the state. The base location in the lower 48 should also be specified although it is not as critical as in Alaska. A number of Alaska factors are listed in Table 6.3.

The Alaska factor can be refined slightly by using different factors to escalate labor and materials. The total cost of the completed project is weighted based on the relative amount of labor and materials used. Labor and material adjustment factors were developed by the Alaska Power Administration (APA), for the Interim Feasibility Study on the Upper Susitna River Hydroelectric Study.[7] The labor adjustment factor was 1.9 and the materials adjustment factor was 1.1. These numbers are based on Oregon and Washington data and a remote job site in Alaska (approximately 100 miles north of Anchorage). These estimates are also presented in Table 6.3.

Using the APA estimates and assuming that 30% of the total cost is labor (typical estimate for 200 MWe plant in the lower 48), an overall factor of 1.34 is computed.

$$\text{Overall Factor} = .3 \times 1.9 + .7 \times 1.1 = 1.34$$

This figure appears to be generally lower than the other factors shown in Table 1. There are two possible reasons for this:

1. The factor of 1.1 for materials assumes that the cost of transportation including loading and unloading from the Pacific Northwest to the Railbelt is \$2.37/100 lbs. A more recent estimate for materials typical of power plant is \$8.00/100 lbs.[8] Using this estimate, the materials factor becomes 1.27 (round to 1.25).

   Using this modified estimate and again assuming that 30% of the total cost is labor, an overall factor of 1.45 is indicated.

TABLE 6.3. Alaskan Construction Cost Location Adjustment Factors

FROM \ TO	Pacific Coast	Anchorage	Beluga	Healy	Fairbanks	Barrow	Railbelt
Washington, D.C.	1.06[a]	1.7[b]	2.75[b]	2.42[b]	-	-	-
Pacific Coast	-	-	-	-	-	-	1.1 - Materials[c] 1.9 - Labor
Lower 48 (General)	-	1.35[d]	-	-	-	-	-
Anchorage	-	-	-	-	1.2[e]	2.8[e]	-
Derived for Pacific Northwest	-	1.65	2.70	2.35	2.0		
Battelle Estimates		1.65	1.80	2.20			

[a] Based on Handy-Whitman Index for North Atlantic Region and Pacific Region. January 1, 1977 price levels - total plant all steam generation.

[b] Letter from Charles A. Debelius, Colonel, Corps of Engineers to M. Frank Thomas, Regional Engineer, Federal Power Commission, 5 May 1975. Based on heavy construction with labor being 50% of the total cost.

[c] Upper Susitna River Basin, Interim Feasibility Report, Appendix 1, Part 2. U.S. Army Corps of Engineers, p. H-57, December 12, 1975. Upper value is for materials, lower value is for labor.

[d] Electric Power In Alaska, 1976-1995. ISER, University of Alaska, p. G.1.1, August 1976. (Letter from Thomas R. Stahr to A. Tussing, May 10, 1976.)

[e] Electric Power In Alaska, 1976-1995. ISER, University of Alaska, p. G.2.1, August 1976.

$$\text{Overall Factor} = .3 \times 1.9 + .7 \times 1.25 = 1.45$$

2. Because of the lack of infrastructure in Alaska, the relative amount of labor required to build a plant would be greater than in the lower 48. Assuming that the cost proportions of labor and materials are each 50%, an overall factor of 1.58 is computed.

$$\text{Overall Factor} = .5 \times 1.9 + .5 \times 1.25 = 1.58$$

Based on this analysis, it appears that an Alaska factor of 1.5 to 1.6 is justified for estimating the cost of a plant in the Anchorage area given the cost of a plant in the Pacific Northwest. Previous work done by Battelle for the state of Alaska indicates that a multiplier of 1.5 would be appropriate for a chemical plant using modular construction to minimize site labor.[9]

Based on this discussion, it appears that the Alaska factor used by the Corps of Engineers but adjusted for the Pacific Northwest (1.65) would be reasonable for a 200 MWe coal-fired steam turbine generating plant located in the Anchorage area.

Construction costs at Beluga should be higher than costs in the Anchorage area. The estimate prepared by the Corps of Engineers (2.75) appears to be higher than recent estimates of construction costs in the Beluga area would suggest, however. There are some cost trade-offs which support this viewpoint.

Land should cost much less in the Beluga area for example. Also if much of the power plant were modularized and pre-built in Seattle even large modules could be barged to the Beluga beaches where barges could be beached (using the 25 to 30 ft tides) and unloaded without the need of a barge harbor construction. Such modules could not be built if the Anchorage City dock were to be used.

Housing for labor would be an added cost item at Beluga. The plant site would be only 50 to 70 air miles from Anchorage and a weekly rotation of crews would be possible. Fuel for equipment and daily supplies could come by landing craft type barges from Anchorage or Nikiski.

Based on this reasoning an Alaska construction cost factor of 1.80 is used for the Beluga area.

Power plant construction in the Healy area could not take advantage of the modular construction opportunities available at Beluga although labor costs might be lower. A construction cost factor of 2.2 is used for the Healy area.

These derived estimates are shown in Table 6.3 and are used in this report. Since there is a great deal of uncertainty associated with these estimates, the results of this analysis as presented in Section 8.0 contain sensitivity tests which show how the results of the analysis are altered given estimating factor changes.

6.1.4 Capacity Scaling Factor

The most recent experience with fossil fired power plants is generally associated with units in the 500 to 1000 MW range. Since in the near term such sizes may be inappropriate to the Railbelt capacity needs, extrapolation to smaller units is necessary (200 MWe is used in this study). To estimate the cost of a generating plant (or any piece of equipment) when there are no cost data available for a plant of similar size, an exponential scaling procedure may be used. Under this procedure, given the cost of a unit at one capacity, the cost of a similar unit can be computed by using an exponential scaling factor. In equation form:

$$\text{Cost of Plant A} = \text{Cost of Plant B} \left(\frac{\text{Capacity of Plant A}}{\text{Capacity of Plant B}}\right)^{\text{Scaling Factor}}$$

Caution must be used when using this procedure.

> In general, the cost-capacity concept should not be used beyond a tenfold range of capacity, and care must be taken to make certain the two pieces of equipment are similar with regard to type of construction, materials of construction, temperature and pressure operating range, and other pertinent variables.(10, p. 108)

In the following analysis 1,000 MW plants are used as a base to estimate the cost of 100 to 200 MW units. An exponential scaling factor of 0.85 is used in the 200-1000 MW range and 0.60 is used in the 100-200 MW range. Figure 6.4 illustrates the consequences of plant size on capital cost.

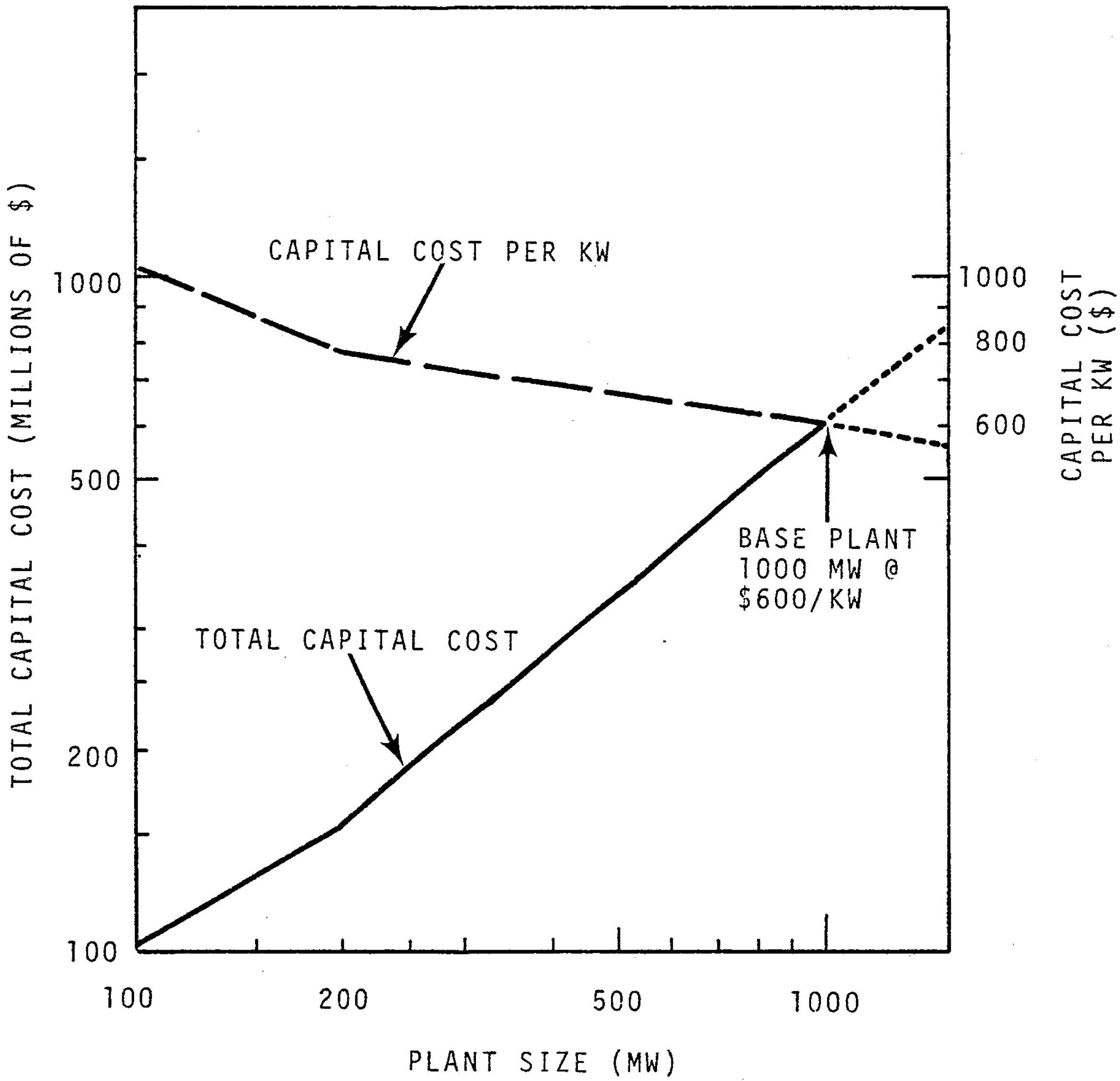

FIGURE 6.4. Effect of Plant Size on Capital Costs Assuming a 0.85 Exponential Scaling Factor in the 200-1000 MW Range and 0.60 in the 100-200 MW Range

6.1.5 Combustion Turbine Plant Capital Costs

The estimates used in this report for combustion turbine equipment are largely based on recent Alaskan experience. Capital cost estimates for combustion turbine equipment are present in Tables 6.4 through 6.7. Cost estimates for simple and regenerative cycle combustion turbine units are presented although the costs of power production from them are not analyzed.

TABLE 6.4: Comparative Capital and Operating Costs of Simple Cycle Combustion Turbine Generating Facilities -- Cook Inlet

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 8-3	450	75	--	--	120	1/75	156	--	--	--	--	--
(2) pp. G.5.5	25	25	Gas	15,000	217	75[b]	282	338	17[c]	114[d]	--	20
(2) pp. G.5.6	50	50	Gas	15,000	210	75[b]	273	512	32[c]	221[d]	--	20
(5) pp. 82,91	20	20	Gas	15,000	135	1/73	210	(h)	(e)	(f)	(g)	20
(5) pp. 82,91	35	35	Gas	13,500	135	1/73	210	(h)	(e)	(f)	(g)	20

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Gas Turbogenerators) for the Pacific Region (Lower 48).

(b) Price level date assumed to be 1/75.

(c) Annual insurance costs are assumed to be 0.3% of plant capital costs.

(d) Annual taxes are assumed to be 2.1% of gross receipts net of taxes.

(e) Annual insurance costs are assumed to be 0.25% of plant capital cost for private, municipal and other public non-Federal, and REA financing. No annual insurance costs are included for Federal financing.

(f) Annual taxes (in lieu of and miscellaneous Federal) are assumed to be 0.75% of the plant capital cost for municipal and other public non-Federal and REA financing. Annual Federal, State and local taxes are set at 5.89% of plant cost for private financing options. No Federal taxes are assessed for Federally financed projects.

(g) Annual interim replacement costs are assumed to be 0.35% of plant capital costs.

(h) Annual operations and maintenance costs are estimated to be $6.60/KW as of 1/73. Using the Anchorage CPI, this is equivalent to $9.40/KW as of 1/77.

TABLE 6.5: Comparative Capital and Operating Costs of Regenerative Cycle Combustion Turbine Generating Facilities -- Cook Inlet

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KW)	Capital Cost (Bus Bar) ($/KW)	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 8-3	450	75	--	--	140	1/75	182	--	--	--	--	--
(2) pp. G.6.3	25	25	Gas	10,000	268	75[b]	348	338	20[c]	141[d]	--	20
(2) pp. G-6.4	50	50	Gas	10,000	259	75[b]	337	512	39[c]	272[d]	--	20
(5) pp. 82,91	50	50	Gas	12,000	167	1/73	259	(h)	(e)	(f)	(g)	20
(5) pp. 82,91	500	50	Gas	12,000	150	1/73	233	(h)	(e)	(f)	(g)	20

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Gas Turbogenerators) for the Pacific Region (Lower 48).

(b) Price level date assumed to be 1/75.

(c) Annual insurance costs are assumed to be 0.3% of plant capital costs.

(d) Annual taxes are assumed to be 2.1% of gross receipts net of taxes.

(e) Annual insurance costs are assumed to be 0.25% of plant capital cost for private, municipal and other public non-Federal, and REA financing. No annual insurance costs are included for Federal financing.

(f) Annual taxes (in lieu of and miscellaneous Federal) are assumed to be 0.75% of the plant capital cost for municipal and other public non-Federal and REA financing. Annual Federal, State, and local taxes are set at 5.98% of plant cost for private financing options. No Federal taxes are assessed for Federally financed projects.

(g) Annual interim replacement costs are assumed to be 0.35% of plant capital costs.

(h) Annual operations and maintenance costs are estimated to be $6.60/KW as of 1/73. Using the Anchorage CPI this is equavalent to $9.40/KW as of 1/77.

TABLE 6.6: Comparative Capital and Operating Costs of Combined Cycle Generating Facilities -- Cook Inlet

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 8-3	450	112.5	--	--	235	1/75	280	--	--	--	--	--
(1) pp. 8-8	-	-	--	--	285	1/76	305	--	--	(b)	--	30
(6)	112.5	112.5	Gas	8500	320	1/77	320	--	--	--	--	--
(6)	112.5	112.5	Gas	8200	320	1/77	320	--	--	--	--	--

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Total Plant - All Steam Generation) for the Pacific Region (Lower 48).

(b) The composite rate for taxes is assumed to be 0.94%.

TABLE 6.7: Comparative Capital and Operating Costs of Regenerative Cycle Combustion Turbine Facilities -- Interior

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 8-8	--	--	--	--	260	1/76	278	--	--	--[b]	--	--
(7)	140	70	Oil #2	--	350	1/77	--	--	--	--	--	--

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Gas Turbogenerators) for the Pacific Region (Lower 48).

(b) The composite rate for taxes is assumed to be 0.94%.

SOURCES FOR TABLES 6.4-6.9

1. The 1976 Alaska Power Survey, Federal Power Commission, Volume 1.

2. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, Anchorage, AK, August 1976.

3. J. J. Jacobsen, Derived from EPRI data for 500 MWe plant in Lower 48. Includes .85 exponential scaling factor and 1.65 Alaska construction factor.

4. Bradley Lake Project Power Market Analysis, Review Draft, Alaska Power Administration, August 1977.

5. The 1974 Alaska Power Survey, Technical Advisory Committee, Report on Resources and Electric Power Generation, APA, 1974.

6. George Hanley, Federal Power Commission, San Francisco, CA. Personal communication, September 15, 1977.

7. A. W. Baker, Golden Valley Electric Association, Fairbanks, AK. Personal communication, September 16, 1977.

8. J. J. Jacobsen, Derived from WPPSS data for 1000 MWe plant in Bellingham, WA burning Beluga coal. Includes .85 exponential scaling factor and a 1.65 Alaska construction factor.

6.1.6 Coal-Fired Steam Turbine Capital Cost

Capital costs for a 200 MWe steam turbine (both coal and oil-fired) are estimated using two alternative base cases:

1. A recent Washington Public Power Supply System (WPPSS) estimate for a 1000 MWe coal-fired plant burning Beluga coal sited near Bellingham, Washington.
2. A recent Electric Power Research Institute (EPRI) report of coal-fired steam turbine generating plants in the 500-1000 MWe range located in the western United States.

Washington Public Power Supply System Evaluation

WPPSS recently completed a study to evaluate the cost of producing electricity from 1000 MW coal-fired steam turbine units at various locations in the Pacific Northwest.[11] One of the alternatives evaluated in this study is a plant located in Bellingham, WA, burning coal from the Beluga field.

The study estimates the following costs in July 1976 dollars:

- with FGD - $588.7 million ($588.7/kw)
- without FGD - $512.6 million ($512.6/kw)

These estimates do not include either interest or escalation during construction. Including interest during construction and assuming a 7% interest rate increases the costs by 15-16%. Adjusting these figures to January 1977 dollars using the Hardy-Whitman Index gives:

- with FGD - $611.2 million ($611.2/kw)
- without FGD - $532.2 million ($532.2/kw)

Scaling these plants to 200 MW units using a 0.85 exponential scaling factor yields:

- with FGD - $155.6 million ($778.0/kw)
- without FGD - $135.5 million ($677.5/kw)

As explained above, to estimate the cost of these plants in Alaska the appropriate Alaska Factor, is used. The Alaska Facotrs used here are, Anchorage, 1.65; Beluga, 1.80; and Healy or Nenana 2.20.

Anchorage

- with FGD - $256.7 million ($1,283.5/kw)
- without FGD - $223.6 million ($1,117.8/kw)

Beluga

- with FGD - $280.1 million ($1,400.4/kw)
- without FGD - $243.9 million ($1,219.5/kw)

Healy/Nenana

- with FGD - $342.3 million ($1,711.6/kw)
- without FGD - $298.1 million ($1,468.5/kw)

Electric Power Research Institute Evaluation

The following capital cost estimates are contained in a recent EPRI report.[12] The estimates reflect July 1, 1976, price levels. They are for two 500 MW units (1000 MW total). Interest during construction has been subtracted out of the estimates.

Plant Reference #	Region	Emission Standards	Total Cost (millions of $) 2-500 MW net with FGD	w/o FGD
3	Western U.S.	EPA (NSPS)	761.1	660.8

Source: (12, pp.8-5)

The current Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) allow SO_2 emissions of 1.2 pounds per million Btu fired which translates to 0.6 weight percent sulfur in the coal. Both Beluga and Healy coals are estimated to have 0.2% sulfur and hence are termed "compliance coals". This means that under the NSPS no flue gas desulfurization (FGD) would be required. However, the latest provisions of the Clean Air Act require the "best available control technology" (BACT) for all plants regardless of sulfur content. For this reason cases both with and without FGD are evaluated. (Chapter 10 provides a more complete discussion of the implications of the Clean Air Amendments.)

In the report it is assumed that 54% of the total cost of the two 500 MW units is spent on the first unit (pp.8-4). Using this reasoning, the cost of a 500 MW plant corresponding to those shown above would be as follows:

- with FGD - $410.9 million ($821.8/kw)
- without FGD - $365.6 million ($731.2/kw)

As discussed above, an exponential scaling factor of 0.85 is used to estimate the cost of units down to 200 MW. For 200 MW plants this gives:

- with FGD - $188.6 million ($942.9/kw)
- without FGD - $167.8 million ($839.0/kw)

Escalating these cost figures from July 1, 1976, dollars to January 1, 1977, dollars using the Handy-Whitman Index gives the following:

- with FGD - $196.2 million ($981.0/kw)
- without FGD - $174.5 million ($872.5/kw)

Applying the Alaska location adjustment factors give the following results:

Anchorage (1.65)

- with FGD - $323.7 million ($1,618.6/kw)
- without FGD - $287.9 million ($1,439.6/kw)

Beluga (1.80)

- with FGD - $353.2 million ($1,765.8/kw)
- without FGD - $314.1 million ($1,570.5/kw)

Healy/Nenana (2.20)

- with FGD - $431.6 million ($2,158.2/kw)
- without FGD - $383.9 million ($1,919.5/kw)

These estimates derived from WPPSS and EPRI data are listed in Tables 6.8 and 6.9 along with other estimates of steam turbine generating facility costs.

TABLE 6.8: Comparative Capital and Operating Costs of Steam Turbine Generating Facilities -- Cook Inlet

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)[i]	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 83	450	150	Coal	-	585	1/75	696	--	--	--	--	--
(2) pp. G.7.6	66	66	Coal	11,500	509	75[b]	606	810	100[c]	705[d]	--	40
(2) pp. G.7.7	200	--	Coal	9,500	494	75[b]	588	1,279	296[c]	2,073[d]	--	40
(2) pp. G.7.8	300	--	Coal	9,500	480	75[b]	571	1,791	428[c]	2,995[d]	--	40
(2) pp. G.9.6	66	66	Oil	11,500	427	75[b]	508	680	85[c]	733[d]	--	40
(2) pp. G.9.7	200	--	Oil	9,500	414	75[b]	493	1,074	249[c]	1,742[d]	--	40
(2) pp. G.9.8	300	--	Oil	9,500	403	75[b]	480	1,504	363[c]	2,540[d]	--	40
(1) pp. 8-8	--	--	Coal	-	655	1/76	703	—	--	(j)	--	35
(4) pp. 37-38	450	150	Coal	10,000	585[s]	1/75	696[s]	—	(e)	(e)	(e)	35

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Total Plant - All Steam Generation) for the Pacific Region (Lower 48).

(b) Price level date assumed to be 1/1/75.

(c) Annual insurance costs are assumed to be 0.3% of plant capital costs.

(d) Annual taxes are assumed to be 2.1% of gross receipts net of taxes.

TABLE 6.8. (continued)

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)	Price Level Date	Capital Cost as of 1/77 (Bus Bar)[a] ($/KW)	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(5) pp. 82,102	100	100	Coal	10,000	496	1/73	814	(k)	(f)	(g)	(h)	35
(5) pp. 82,102	200	100	Coal	10,000	456	1/73	748	(k)	(f)	(g)	(h)	35
(5) pp. 82,102	500	250	Coal	10,000	373	1/73	612	(k)	(f)	(g)	(h)	35
(5) pp. 82,102	1,000	500	Coal	10,000	313	1/73	514	(k)	(f)	(g)	(h)	35
(3) EPRI-Anch.	200	200	Coal	--	1439.6	1/77	--	--	--	--	--	--
(3) EPRI-Anch.	200	200	Coal	10,102	1618.6(s)	1/77	--	--	--	--	--	--
(3) EPRI-Beluga	200	200	Coal	--	1570.5	1/77	--	--	--	--	--	--
(3) EPRI-Beluga	200	200	Coal	10,102	1765.8(s)	1/77	--	--	--	--	--	--
(8) WPPSS-Anch.	200	200	Coal	9,277	1117.8	1/77	--	--	--	--	--	--
(8) WPPSS-Anch.	200	200	Coal	9,782	1283.5(s)	1/77	--	--	--	--	--	--
(8) WPPSS-Beluga	200	200	Coal	9,277	1219.5	1/77	--	--	--	--	--	--
(8) WPPSS-Beluga	200	200	Coal	9,732	1400.4(s)	1/77	--	--	--	--	--	--

(e) Annual fixed charges of 8.77% for public, non-Federal financing is assumed. This includes cost of money, depreciation, interim replacements, insurance, and payments in lieu of taxes.

(f) Annual insurance costs are assumed to be 0.25% of plant capital cost for private, municipal and other public non-Federal, and REA financing. No annual insurance costs are included for Federal financing.

(g) Annual taxes (in lieu of and miscellaneous Federal) are assumed to be 0.75% of the plant capital cost for municipal and other public non-Federal and REA financing. Annual Federal, State, and local taxes are set at 5.89% of plant cost for private financing options. No Federal taxes are assessed for Federally financed projects.

(h) Annual interim replacement costs are assumed to be 0.35% of plant capital costs.

(i) Coal plant costs are assumed to not include flue gas desulfurization unless noted by (s).

(j) The composite rate for taxes is assumed to be 0.94%.

(k) O&M costs are assumed to be $9.00/KW/YR for 100 MW, $5.70/KW/YR for 200 MW, $4.50/KW/YR for 500 MW, and $4.40/KW/YR for 1000 MW as of 1/73. Using the Anchorage CPI this is equavalent to $12.80/KW/Yr for 100 MW, $8.12/KW/YR for 200 MW, $6/41/KW/YR for 500 MW, and $6.26/KW/YR for 1000 MW as of 1/77.

TABLE 6.9. Comparative Capital and Operating Costs of Steam Turbine Generating Facilities -- Interior

Reference	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost (Bus Bar) ($/KW)[c]	Price Level Date	Capital Cost as of 1/77 (Bus Bar) ($/KW)[a]	O&M Costs ($1000/YR)	Insurance Costs ($1000/YR)	Taxes (or payments in lieu of) ($1000/YR)	Interim Replacement ($1000/YR)	Operating Life (Years)
(1) pp. 8-3	150	75	Coal	-	640	1/75	761	-	-	-	-	-
(1) pp. 8-8	-	-	Coal	-	715	1/76	765	-	-	-[b]	-	-
(3) EPRI-Healy/ Nenana	200	200	Coal	-	$1919.5	1/77	-	-	-	-	-	-
(3) EPRI-Healy/ Nenana	200	200	Coal	10,102	$2158.2[s]	1/77	-	-	-	-	-	-
(8) WPPSS-Healy/ Nenana	200	200	Coal	9,277	$1468.5	1/77	-	-	-	-	-	-
(8) WPPSS-Healy/ Nenana	200	200	Coal	9,782	$1711.6[s]	1/77	-	-	-	-	-	-

(a) Investment costs presented in this column are updated using the Handy-Whitman Index (Total Plant - All Steam Electric) for the Pacific Region (Lower 48).

(b) The composite tax rate is assumed to be 0.70%.

(c) Coal plant costs are assumed not to include flue gas desulfurization unless noted by (s).

6.1.7 Hydroelectric Plant Capital Costs[a]

A number of hydroelectric plant opportunities exist in or nearby the Railbelt region. These include the several proposals for development of the Upper Susitna River, The Bradley Lake Project on the lower Kenai Pennisula, the Chackachamna Project on the western side of Cook Inlet, and the Wood Chopper Concept on the Yukon River, and the Wood Canyon Concept on the Copper River. None of these potential projects have progressed to the point of final design and several have only received reconnaissance level examination. The estimates of capital costs are therefore subject to revision in the future and in some instances probably substantially. The Upper Susitna and Bradley Lake concepts are of maximum current interest. The other concepts have or may have substantial environmental questions associated with them.

A number of studies have been made since 1948 of alternative concepts for development of the hydropower potential of the Upper Susitna River since 1948.[13] In 1952, the U.S. Bureau of Reclamation described a plan that would ultimately include 12 major dams, have a powerplant capacity of 1,250 MW and provide firm annual energy of 6.18 billion kWh.[14] In 1961, the Bureau of Reclamation recommended the proposed Devil Canyon Project which would consist of two major dams with power generation at Devil Canyon and a Devali storage dam. Ultimately the system would be expanded to a four dam with a firm annual energy of 7.0 billion kWh.[15] The Alaska Power Administration updated the 1961 report in 1974 preparing new cost estimates and a brief analysis of the power market.[16] Also in 1974, the Henry J. Kaiser Company prepared a report for the state of Alaska suggested a first-stage Upper Susitna River development with a "Devil Canyon High" dam (referred to as Susitna I in this report) located five miles upstream from the USBR Devil Canyon damsite.[17] Susitna I would have a capacity of 600 MW and annual energy of 2.6 and 3.35 billion kWh, firm and average respectively. Ultimate development (4 dams) would have a capacity of 1.347 MW and 5.9 and 6.52 billion kWh.

(a) See also Appendix B.

The Alaska District, U.S. Army Corps of Engineers in 1975, prepared an "Interim Feasibility Report" analyzing and updating previous studies of alternatives, providing an environmental assessment, cost estimates and a marketability analysis.[18] The Corps recommended that a two dam system (at Watana and Devil Canyon) be developed that would capture about 96 percent of the basin hydroelectric potential with a dependable capacity of 1,568 MW and firm and average annual energy of 6.1 and 6.90 billion kWh, respectively. The cost of the project was estimated at $1.52 billion (mid-1975 dollars) including a transmission system intertie of the Railbelt.

More recently the Corps Alaska District proposed a plan of study for the state of Alaska based on the Watana/Devil Canyon concept.[6] In this report the Corps notes that inflation and escalation has increased project cost to $2.2 billion.

Harza Engineers have recently prepared summary evaluations of staged development of the Upper Susitna (Watana, Watana/Devil Canyon, Watana/Devil Canyon/Devali/Vee) with the primary interest to lay out a plan with project increments sized at a level suitable for state financing.[19] Unfortunately, no construction cost estimates are available.

A summary of several of the Upper Susitna hydropower concepts considered in this study is presented in Table 6.10. A more complete discussion of the nature of the hydroelectric alternatives, their viability and some of the uncertainties involved in their feasibility is presented in Appendix B. Cost estimates[17] are based largely on Corps of Engineers data in January 1975 dollars escalated to January 1977 at a 10 percent per annum rate (see Section 6.1.7). The Corps estimate for the Railbelt transmission intertie has also been adjusted downward reflecting consultants opinion that an overly conservative dual right of way is not justified over the entire length of the route. Thus, these estimates are slightly different from previously published data.

TABLE 6.10. Railbelt Hydropower Alternatives

Concept	River Mile	Type	Structural Height (FT)	Normal Pool Elev. (FT)	Reservoir Area (Acres)	Miles of River Inundated	Installed Capacity (MW)	Annual Annual Energy (KWh-10^9)	Project Cost ($-$10^6$)	Capital Cost ($/KW)	Operation, Maintenance & Replacement Costs ($/KW/YR)
Watana (USCE)	165	Earthfill	810	2200	43,000	54	686	3.5	1,318	1,921	1.63
Watana & Devil Canyon (USCE)	165	Earthfill	810	2200	43,000	54	776	3.5	1,318	--	--
	134	Conc. Thin Arch	635	1450	7,550	28	792	3.4	682	--	--
					51,000	82	1,568	6.9	2,000	1,275	1.79
Bradley Lake (USCE, APA)	-	Concrete Gravity	100	1170	2,000	Existing Lake	70	0.32	160	2,286	9.28
Chakachamna (USBR, 1962)	-	Tunnel	-	1127	15,250	Existing Lake	366	1.6	804	2,196	5.12
Wood Canyon (USBR-Copper R.)	84.7	Concrete Gravity	615	900	NA	48	3,600	NA	3,524	882	NA
Wood Chopper (Yukon River)	1153	Earthfill	380	1030	415,000	NA	2,440	NA	3,200	1,398	NA

Other Interior/South Central Hydroelectric Alternatives

Included in this category are the Bradley Lake Project, the Chakachamna concept for a tunnel and power plant and the more remote (and larger) Wood Canyon (Copper River) and Woodchopper (Yukon) concepts. Of these alternatives, only Bradley Lake has received sufficient study to have estimated cost data of quality comparable to the Upper Susitna concepts. The Bradley Lake Project was actually authorized by the Congress in 1962 but no appropriations have since been made.[20]

Data for Chackachamna are next lowest in quality being somewhat dated (1962).[21] The Chackachamna project area may be included in the proposed Lake Clark National Park.

Data for the Wood Canyon and Woodchopper project concepts are the least firm and at best are educated guesses. Both concepts are physically more remote from the Railbelt, may be sited in areas proposed for inclusion in the National Park System, are very large (2,100 to 3,600 MW) and will require new, long distance transmission systems. In any event, these projects will be of serious interest probably only after 2000.

6.2 OPERATING COST ESTIMATES

The costs of operating a generating plant (excluding fuel costs) can be classified in a number of ways. In this analysis the following classification scheme is used.

6.2.1 Operating, Maintenance, Interim Replacement Costs and Heat Rate

Operating and Maintenance Costs

This category includes both fixed and variable operating and maintenance costs. Specific costs covered in this category include: staff, fees, administration, supplies, and ash disposal. If the unit includes flue gas desulfurization, limestone and slurry disposal are also included. In the case of hydroelectric cost estimates this category is referred to as "operating, maintenance and replacement" and includes interim replacement. For fossil fuel plants interim replacement costs are considered independently (see below).

Insurance Costs

Insurance costs include the annual cost of fire, storm, vandalism, public liability, and property damange insurance.

Taxes

Taxes include all Federal, state, and local tax payments. Since all the utilities in the Railbelt area are publically owned they do not pay taxes directly, but rather make payments in lieu of taxes.

Interim Replacement Costs

Interim replacement costs includes those items included in the plant with life spans less than the adopted overall facility service life.

Heat Rate

The heat rate is the ratio of the BTU's going into the plant as fuel to the kWh's of electricity produced by the plant. The heat rates used in this analysis represent average heat rates over the life of the plant and as a result are higher than the heat rates at design load.

Operating and maintenance costs, insurance costs, taxes (or payments in lieu of), interim replacement costs and heat rates for the various generating options are presented in Tables 6.4 through 6.9.

6.2.2 Present and Future Fuel Costs

Fossil fuel available in Railbelt Alaska for future electric power generation (absent federal prohibitions on use) include natural gas (Cook Inlet region and Fairbanks via the North Slope pipelines), coal (Cook Inlet and Interior sources), distillate and potentially residual fuels from refining operations either existing (Kenai and North Pole) or a future plant based on North Slope royalty oil. Over the long term, other fuel sources may be developed within and near off-shore the State and not too distant from the Railbelt.

An understanding of future fuel costs is essential to the evaluation of any thermal generation option. Thus, before attempting to arrive at a "best guess" or a "reasonable range" of expected fuel costs it is worthwhile to review estimates made by prior workers, make adjustments based on new information and then apply some economic theory.

The future costs of utility fuels in Alaska will be determined by a number of factors that have different weights depending on the fuel type:

1. The world energy market is largely controlled by the Organization of Petroleum Exporting Companies (OPEC).
2. The marginal cost of production plus the appropriate taxes, royalties, and return on investment.
3. The general rate of inflation.
4. The nature and extent of federal price controls and taxes.
5. Transportation tariffs.
6. Terms and conditions of long-term contracts for natural gas.
7. The market rate of interest.
8. The extent to which Alaskan fuels can participate in the domestic and world markets through fixed transportation systems.

Different fuels (coal, gas and oil) costs can be expected to respond to the above factors in different manners and hence are discussed separately below.

Fuel Oil

As a practical matter the world oil market and hence, to a degree, the world BTU market, is controlled by the OPEC cartel. The OPEC pricing strategy appears to be based on their perception of the marginal costs of production of their nearest competitor. This policy is intended to maximize their long-term profits. Early 1977 domestic refinery acquisition cost of foreign crude was \$14.10 per bbl (\$2.43 per MMBTU) vs \$9.20 bbl (\$1.59 per MMBTU) for domestic crude.

Although oil fired generation capacity additions are not expected to play a major future role in the Railbelt, other fuel costs are becoming increasingly linked to fuel oil prices. Thus, some understanding of oil prices is essential to assess prices of other fuels, particularly natural gas.

In the future OPEC's most probably strategy (assuming the cartel can be sustained and no other super-giant oil fields are found or alternative lower cost technologies are developed) will be to escalate its prices paralleling the market rate of interest occurring in its western world market area. The market rate of interest sets the basis from which OPEC can measure its opportunity cost and escalates at approximately 3 percentage points higher than the general inflation rate as measured by the GNP deflator. Thus for a general 5% per annum inflation rate, the OPEC oil price increase rate would be expected to be about 8% per annum.

Alaska, being a major oil producing region, competes in the same market with OPEC. Thus, the intrastate crude oil price will reflect the difference between the landed market price of the dominating imported crudes in the "lower 48" less the transportation costs from various points in Alaska.

Figure 6.5 summarizes some past data and several estimates of future utility fuel oil prices in the Railbelt region. These estimates are presented primarily to illustrate the divergency of opinion that can and does exist. Even ignoring the FPC (1976 Alaska Power Survey) estimated price curve (which seems unjustifiably low on all counts) a considerable spread still remains. Curves (1) and (3) estimated by the Institute for Social and Economic Research (ISER) for distillate and residual fuels are based on their assumption that fuel costs will track a general inflation rate of 6% per annum after 1980. Forecasts by the Interior Alaska Energy Advisory Team (IAEAT) for 1980, 1985 appear low based on recent experience and the influences affecting inflation and escalation.

The effective price of fuel oil to utilities may also be subject to federal excise tax if the House of Representatives version of the National Energy Act goes into effect. (See Section 10.2 of this report). No excise taxes are applied until calendar year 1983 but in that year and thereafter, utilities (Tier 3) will be taxed at a rate of \$1.50/bbl or in BTU equivalent, \$0.26 per MMBTU. This tax rate in addition to the base fuel cost, is also subject to inflation pegged to the GNP deflator.

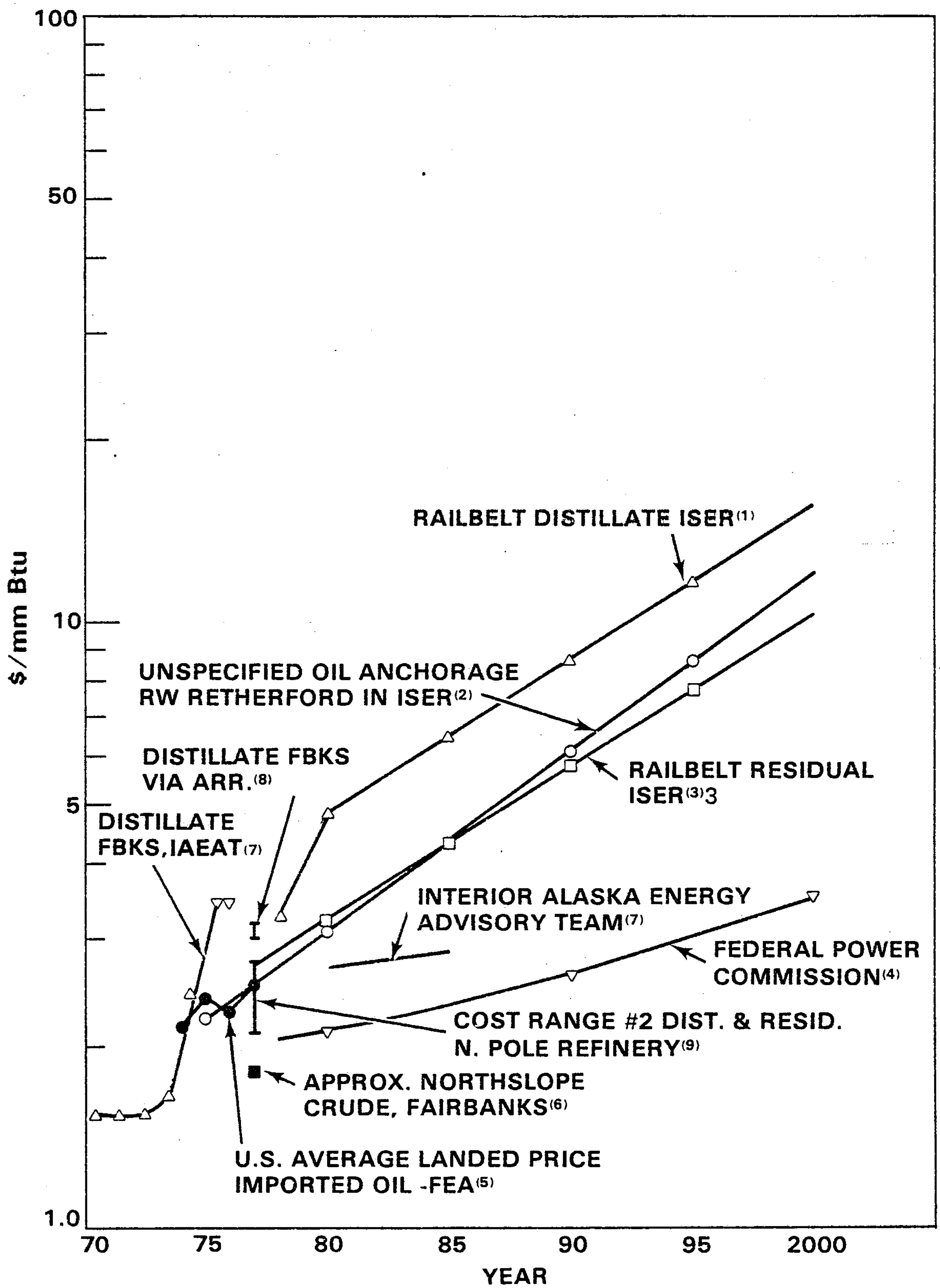

FIGURE 6.5. Estimates of Future Oil Prices

Footnotes for Figure 6.5

Curve No.

1. Railbelt distillate, Institute of Social & Economic Research, "Electric Power in Alaska, 1976-1995," August 1976, Pages 7-24, 25. Six percent per annum inflation and escalation assumed after 1979.

2. Unspecified oil at Anchorage. Estimate by R. W. Retherford reported by ISER, pages 7-11, 25. 7.3% per annum apparent inflation escalation rate.

3. Railbelt Residual, ISER, pages 7-25, 6% per annum inflation and escalation assumed.

4. Railbelt unspecified oil in "1976 Alaska Power Survey, Vol. 1, pages 8-9, Federal Power Administration.

5. U.S. Landed Price, average foreign imported crude, Federal Energy Administration Monthly Energy Review, September 1977.

6. Prudhoe Bay Crude at North Pole, Battelle Estimate, September 1977 based on Oil & Gas Journal, September 5, 1977, page 56, 50% of Pipeline Tariff applicable.

7. Distillate oil Fairbanks, Interior Alaska Energy Advisory Team, June 17, 1977.

8. Distillate, Fairbanks via Alaska Railroad, Date from GVEA, FMUS, October 1977.

9. Range of Cost for #2 Distillage and Residual FOB North Pole Refinery, Data from GVEA, FMUS, October 1977.

Natural Gas

Compared to fuel oil, natural gas represents a completely different and even more complex situation. Figure 6.6 illustrates some estimates of future gas prices under differing long-term contracts for old gas, marketability situations, and potential regulatory conditions. Again, the illustration demonstrates the wide ranges of possible outcomes under varying assumptions.

Due to the necessary investments in transmission and transportation systems, natural gas prices usually involve long-term (20-30 year) contracts often with clauses covering take-or-pay, escalation, rollover, and adjustments for alternative future takers, etc. An example of this latter situation is illustrated by the Chugach Electric Association contract with the producers at the Beluga Field, curves No. 9 and No. 10 in Figure 6.6. Under conditions without the Pacific Alaska LNG (PALNG) proposed system, Chugach's contract calls for gas prices to follow the latter curve. If however PALNG initiates operations in 1982, the contract formula terms result in Chugach's costs to follow curve No. 9 assuming that the provisions for old gas under new contracts in the Administration's National Energy Act (passed by the House as H.R.-8444) prevail and a 5% per annum inflation rate is sustained. (Curve No. 3). In effect, a 4 to 5 fold increase in fuel costs can come about as a result of shifts in the marketability and the contract provisions.

In addition to the above factors, future natural gas prices are subject to considerable regulatory uncertainty. Assuming that new transportation systems will allow Alaskan gas access to the domestic market, a number of possible outcomes can occur under new contracts for <u>old</u> gas or for <u>new</u> gas. Under the current Federal Energy Regulatory Commission (formerly the FPC) ruling 770A, new gas can be priced at the well head according to Curve No. 5. However, the present Administration and the House (H.R.-8444) propose that new gas follow a formula pricing based upon the average refinery crude oil acquisition cost which in early 1977 was approximately $1.98/mm BTU.

Assuming inflation plus escalation at a rate of 8% per annum, the <u>new</u> gas could be priced at the well head as high as the levels shown by Curve No. 1.

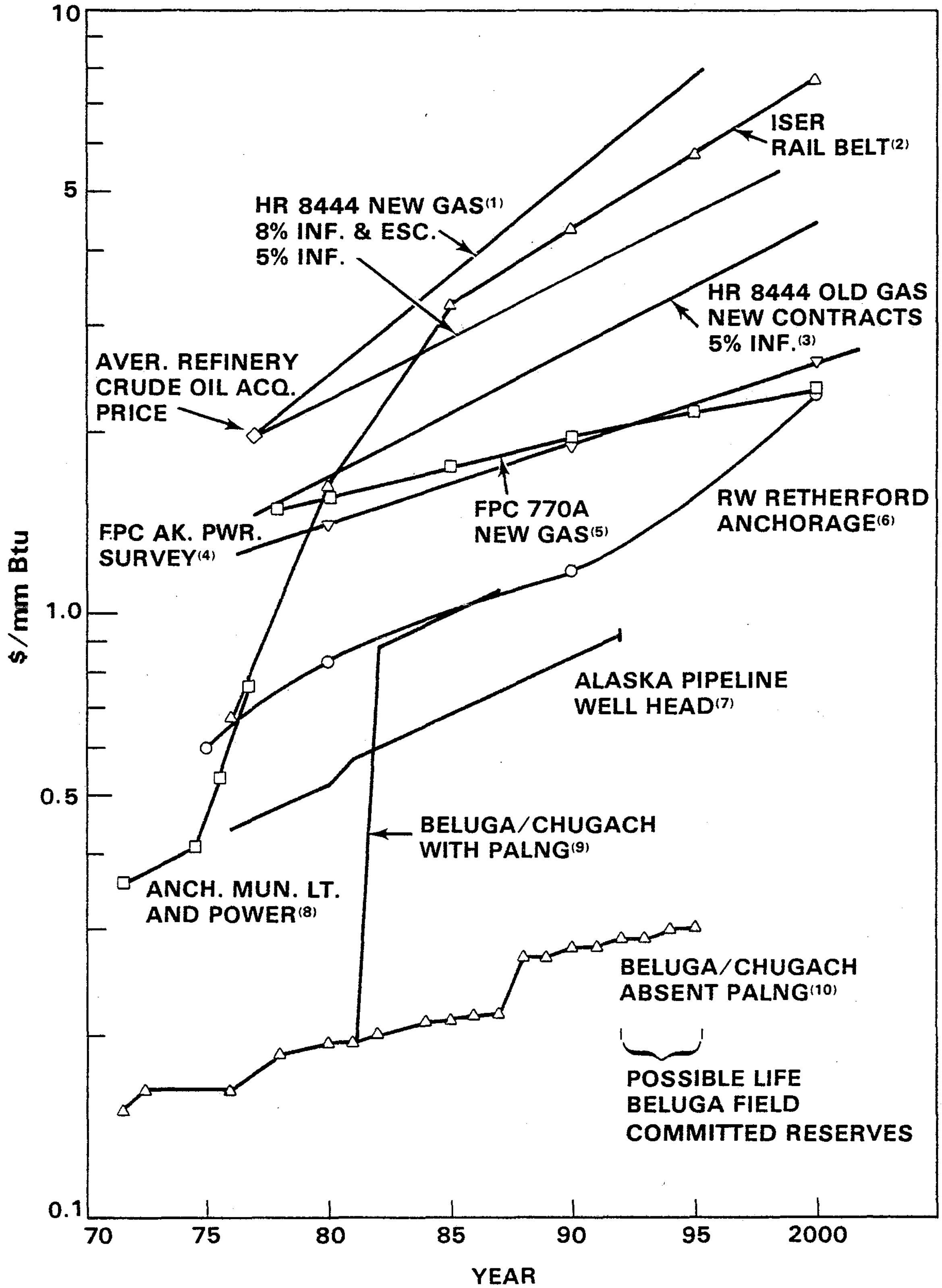

FIGURE 6.6. Estimates of Future Natural Gas Prices

Footnotes for Figure 6.6

Curve No.

1. Proposed National Energy Act. H.R. 8444 - New Gas at well head. 5 and 8% inflation plus escalation assumed in refinery average crude oil acquisition cost from January 1977. This price is at the well head and does not include federal excise taxes on utility use on transmission cost to the plant.
2. Railbelt gas, Institute for Social and Economic Research.
3. Proposed National Energy Act H.R. 8444 - Old gas at well head at 5% inflation rate.
4. "1976" Alaska Power Survey", Federal Power Commission estimate.
5. FPC ruling 770A well head price.
6. R. W. Retherford estimate appearing in ISER report "Electric Power in Alaska, 1976-1995. August 1976, pages 7-25.
7. Contract Provisions. Alaska Pipeline Co. Well head cost.
8. Anchorage Municipal Light and Power cost.
9. Beluga Field Producers Price Assuming Pacific Alaska LNG Commercial Operating Date is 1982.
10. Same as 9 but without PALNG.

For old gas (i.e., presently producing fields) under new contracts or rollover contracts, the well head price might be expected to track Curve No. 3 assuming a 5% general inflation rate and no escalation.

The question of natural gas prices is probably moot in considering new generating capacity as it is very likely that pending federal legislation (even with provisions of possible variences under appeals) will make new gas fired plants out of the question excepting for possible peaking facilities. However, existing facilities may continue to employ natural gas (for base and intermediate loads, and later for peaking) and it is instructive to assess the probable price trend under H.R.8444.

Under the House of Representatives concept of the Natural Energy Act (discussed in Section 10.2) excise taxes may be imposed on the business user of oil and natural gas (see H.R.8444 Sec. 4991-4994). The proposed act, among other things, links the price of natural gas to electric utilities (Tier 3 classification) to the regional price of residual fuel oil on a BTU equivalency basis. When the price of natural gas is less than the average residual fuel BTU price (based on 6.2 MMBUT/BBL) a tax is to be imposed according to the following schedule.

Year	Tax - $/MMBTU
1979	None
1980	None
1981	None
1982	None
1983	$0.55
1984	0.65
1985 or thereafter	0.75

A cap on a Tier 3 taxible use of natural gas is proposed to be set such that the tax associated with such use will not cause the cost to exceed the BTU equivalency price for residual fuel oil. Provisions for inflation (not escalation) is given in 1981 and there after.

For the purposes of the analysis in this report it is assumed that any future natural gas-based generating capacity would in any event have to be fueled with new gas and would be subject to the H.R. 8444 well head price regulation and excise tax provisions. The net effect is that natural gas, at least after 1983, is at a stand-off vis-a-vis residual fuel oil on a $/BTU basis. There may well be variances between now and the mid 1980's that result in a somewhat lower net price for Cook Inlet natural gas but the consequences are almost immaterial for long range Railbelt power planning.

Coal

Coal prices in Alaska appear much more predictable due to the absence of regulation and the currently limited influence of marketability factors.

Two sources of coal supply for the Railbelt region are most pertinent to this analysis:

1. The Healy Coal Field currently being mined by the Usibelli Coal Co. at about 700,000 tons/year with plans for expansion to 1.5 million tons per year. This mine currently supplies the Golden Valley Electric Association (GVEA) plant located at Healy and the Fairbanks Municipal Utility System in Fairbanks.

2. A potential future coal source is the Beluga Field in the Cook Inlet region. The latter field is known to contain very substantial reserves but the new mine development required will be costly due to lack of transportation facilities and mine supporting infrastructure.

Figure 6.7 summarizes various previous forecasts of coal prices in the Railbelt region. The Healy Coal Field is the obvious supplier for future Interior generation based on coal. Recent cost of coal delivered by truck to the GVEA Healy Plant is $0.70/MMBTU and by rail at Fairbanks, $1.05/MMBTU. Although the Healy site may be able to expand to perhaps 200 MW capacity, its location 4.5 miles from Mt. McKinley National Park may restrict further development due to air quality considerations. Thus further coal fired expansion in the upper Railbelt most probably will necessitate plant location in the Nenana area along the rail line. In this case, additional costs above mine mouth costs, will be incurred including tipple costs (approximately $0.11 per MMBTU currently) and Alaska Railroad tariffs. The latter may be reduced if unit trains were to be employed.

The Usibelli Coal Mine, Inc. has indicated that they expect their prices to rise at about 7% per annum. This pricing schedule appears reasonable if if is assumed that a 5% per annum general inflation rate continues and a 2 percentage point markup escalation is appropriate for the resource owner. Early 1977 mine mouth coal costs were $0.60/MMBTU. Therefore, assuming mine mouth and tipple costs increase at 7% per annum and that rail transportation costs have an 80% exposure to general inflation (i.e., 4% per annum) coal costs appropriate for the Fairbanks-North Star Borrough load center should follow the curve shown in Figure 6.7.

The Healy area could also serve the Cook Inlet region via the Alaska Railroad. Tariffs for Healy coal delivered by rail at Anchorage and Partage as provided by the Alaska Railroad are summarized in Table 6.11 as a function of annual tonnage and car ownership.[25] A 200 MW plant operating at an 0.65 plant factor will require about 650,000 tons/year. Under conditions of carrier owned cars, the tariff at this rate would be about $0.38 per MMBTU. For a power station with a total of 400 MWe, unit train operation would be appropriate and the tariff would be reduced to ea. $0.30 per MMBTU. Railroad tariffs have an inflation and escalation exposure of about 80%.

For the purpose of this analysis we have assumed that the tariff would be about $0.30 per MMBTU resulting in Healy-Anchorage curve as shown in Figure 6.7.

The Beluga/Susitna coal field is an obvious source of supply for coal fired generation. The reserves are very large and capable of supporting a world scale mine for export and mine mouth power generation. The coal is subbituminous (Rank C) and of relatively low heating value ($\sim$7100 BTU/lb) at run-of-mine but quite low in sulfur (0.15% typical). Coal preparation including washing and drying could raise the heating value to 9,000 BTU/lb. Some of the coal will be of too low a quality for export but would nevertheless be suitable for mine mouth power generation

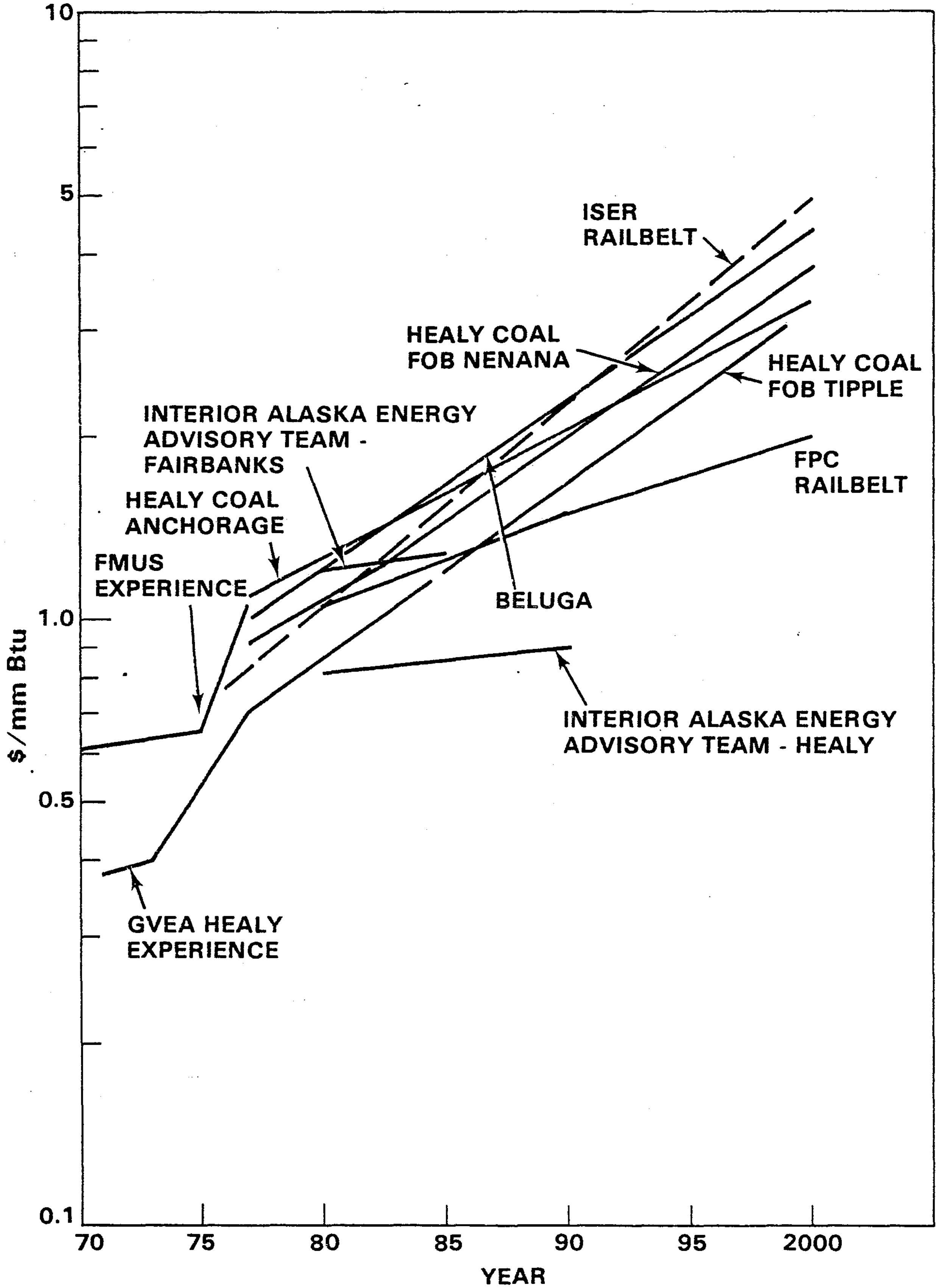

FIGURE 6.7. Estimates of Future Coal Prices

TABLE 6.11: Alaska Railroad Tariffs-Healy Origin[a]

	ANCHORAGE				PORTAGE			
	Shipper Owned Cars		Carrier Owned Cars		Shipper Owned Cars		Carrier Owned Cars	
Annual Tonnage	$/Ton	$MMBTU	$/Ton	$/MMBTU	$/Ton	$/MMBTU	$/Ton	$/MMBTU
200,000 to 500,000	-	-	7.67	0.441	-	-	7.73	0.444
1,000,000	4.21	0.242	5.51	0.317	4.71	0.271	6.01	0.345
1,500,000	4.20	0.241	5.18	0.298	4.70	0.270	5.68	0.326
2,000,000	4.10	0.236	5.00	0.287	4.59	0.264	5.49	0.316

(a) Conversion to $/MMBTU based on 8700 BTU/# coal quality.

Placer Amex Inc., holder of the larger leases has recently conducted considerable exploration to prove out the reserve. They are of the opinion that a 6MMTPY for export mine would be required to support the front end capital investment necessary for such a frontier area operation, in particular for the harbor and loading facilities. Under private financing conditions the estimated coal price F.O.B. mine would be in the range of $0.85 to $1.00/ MM BTU ($12 to 14/ton).

The 6MMTPY economic mining scale would support about 2,000 MW of generating capacity, a scale which suggests that mining for export or for other industrial development in combination with on-site use would be required at least initially for Beluga based generation. If coal were used to provide all process heat requirements for a 150,000 BBL/day oil refinery, this load alone would require about 2 MMTPY.

The beluga field is well positioned as a site for a power plant. Chugach Electric Association already has a transmission corridor in place from its station near Tyonek. This corridor could be up-rated to 350-500 kv at a lower cost than required for a totally new system.

A major mine and export facility at Beluga will be capital intensive. Placer Amex Inc. has estimated that a capital investment approaching $300 million will be required or about $50 per annual ton. A major distinction has to be made between:

A) Coal mined for export:

Because of infrastructure and in particular high harbor costs, minimum scale of operations has to be about 6MMTPY. The initial capital cost estimate for such a major mine would be in excess of $250 million with additional major mining equipment and townsite additions required within a few years of start up as the coal stripping ratio increases. Coal cost would be ∿$1.25/MM BTU F.O.B. ships.

B) Coal mined for local use:

Meaning a power plant at the mine or on the shore of Cook Inlet.

1. Initial capital costs would be much less; on the order of \$25 to \$30 million, with substantial additional expenditures in subsequent years, because of increasing stripping ratios and growing production requirements to meet area load growth, which will necessitate expansion of the mine.
2. Coal would be ∿\$0.85 and \$1.00/MM BTU F.O.B. mine and on the shores of Cook Inlet, respectively.
3. Initial capital costs for a major 6MMTPY mine for local power production would again be high, approaching \$200 million because of early acquisition of large scale mining equipment and a more elaborate townsite for the larger work force.

In Figure 6.7, Beluga coal costs are presented assuming a five percent inflation rate and a three percent escalation rate.

Recent information suggests that a Beluga mining operation sufficient to support ∿400 MW of generating capacity could take place at the "Three Mile" site nearby the existing Beluga station and deliver coal at about \$0.80/MMBTU in todays dollars. Shallow reserves are limited however and significant development is not expected.

Other alternative Railbelt coal supply regions include the Matanuska and Kenai fields. The Matomuska field is 50-70 miles Northeast of Anchorage and the valley is served by a branch line of the Alaska Railroad.[a] The beds of the Matanuska Valley vary in thickness and the seams are separated by shale and sandstone layers. Reserves are estimated at only 100 million tons. Coal quality is excellent however, being bituminous in rank with a heating value in excess of 11,000 BTU/lb and a sulfur content of 0.6 percent or less.

Because of the limited proven reserves and difficult underground mining situation in the Matanuska Valley, no further consideration is given to this area as a coal source.

(a) The tracks have been removed past Palmer but the roadbed still exists.

The Kenai field (~300 million tons, 7,700 BTU/lb, 0.1-0.4% sulfur) also suffers from having seams six feet or less in thickness. In addition, the beds are lenticular, making continuous mining of a seam impossible over large areas.

Summary of Railbelt Fuel Cost Assumptions

From the above discussion, it is obvious that forecasts of future Railbelt utility fuel costs are subject to considerable uncertainty. Nevertheless, given the assumptions regarding the world BTU market and the National Energy Policy (NEP), at least some rational judgements can be made. Even if the Administration's NEP is not enacted and some more moderate approach is taken on fuel costs, the consequences to Alaska in two of effecting intermediate to long term planning are not great. Short term (10 years) consequence can, however, be larger.

Therefore, for the purposes of the analysis presented in this report, Railbelt fuel prices will be used as presented in Figure 6.8. Note that these future fuel prices are predicted upon a market rate of interest at zero inflation rate, i.e., 3% annum. The effects of inflation are taken into account in final power cost computations as outlined in Sections 7.2 and 7.4.

6.3 SUMMARY OF CAPITAL AND OPERATING COST ESTIMATES FOR FOSSIL FUEL FIRED GENERATING OPTIONS

The capital and operating costs used in this analysis for fossil fuel fired generating options are derived from the information presented in Tables 6.6, 6.8 and 6.9. These costs are summarized in Tables 6.12 and 6.13. As mentioned earlier simple and regenerative cycle combustion turbine power production costs are not evaluated in this report and data for them are not included in Tables 6.12 and 6.13.

The coal-fired steam turbine estimates are based upon the numbers derived from the WPPSS study. These estimates are consistently lower than the numbers derived from the EPRI data and therefore may be conservative.

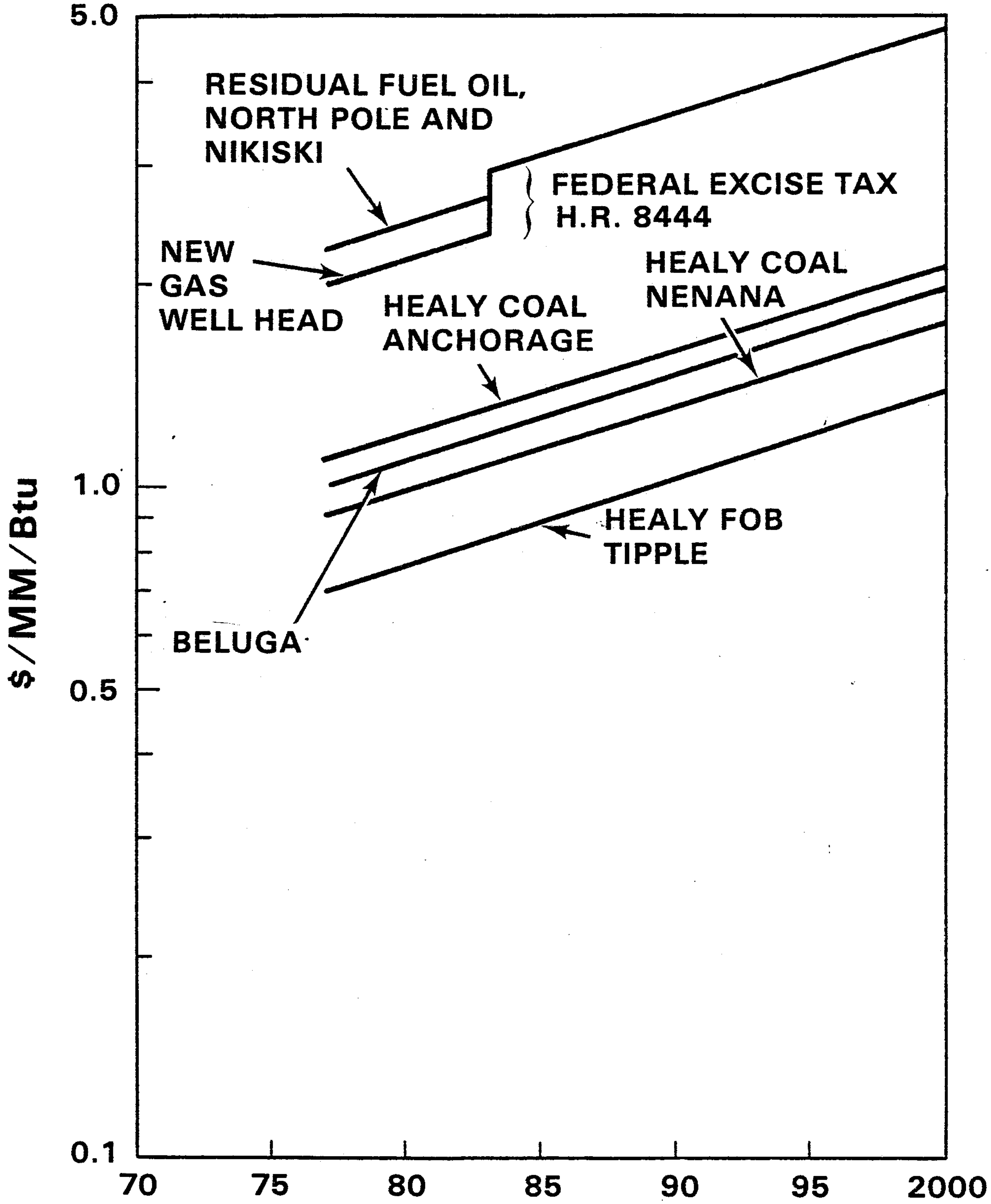

FIGURE 6.8. Summary of Probable Fuel Costs Zero Inflation Rate

TABLE 6.12. Capital and Operating Costs of Fossil Fuel Generating Facilities -- Cook Inlet

Plant Type (Location)	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost as of 1/77 (Bus Bar) ($/KW)	O&M Costs ($/KW/YR)	Insurance Costs (% of Plant Capital Costs)	Taxes (or payments in lieu of) (% of Plant Capital Costs)	Interim Replacement (% of Plant Capital Costs)	Operating Life (Years)
Steam Turbine (Anchorage)	200	200	Coal	10,000.	1120	8.1	.25	.75	.35	35
Steam Turbine (Anchorage)	200	200	Coal	10,500.	1280(s)	10.5	.25	.75	.35	35
Steam Turbine (Beluga)	200	200	Coal	10,000	1220	10.1	.25	.75	.35	35
Steam Turbine (Beluga)	200	200	Coal	10,500.	1400(s)	13.2	.25	.75	.35	35
C. T. Combined Cycle	100	100	Gas	9,000.	300	9.4	.25	.75	.35	30
C. T. Combined Cycle	100	100	Oil	8,700.	300	9.4	.25	.75	.35	30

(s) Includes flue gas desulfurization

TABLE 6.13. Capital and Operating Costs of Fossil Fuel Generating Facilities -- Interior

Plant Type (Location)	Size of Plant (MW)	Size of Units (MW)	Fuel	Heat Rate (Btu/KWh)	Capital Cost as of 1/77 (Bus Bar) ($/KW)	O&M Costs ($/KW/YR)	Insurance Costs (% of Plant Capital Costs)	Taxes (or payments in lieu of) (% of Plant Capital Costs)	Interim Replacement (% of Plant Capital Costs)	Operating Life (Years)
Steam Turbine (Healy/Nenana)	200	200	Coal	10,000	1470	8.1	.25	.75	.35	35
Steam Turbine (Healy/Nenana)	200	200	Coal	10,500	1710(s)	10.5	.25	.75	.35	35
C. T. Combined Cycle	100	100	Gas	9,000	380	9.4	.25	.75	.35	30
C. T. Combined Cycle	100	100	Oil	8,700	380	9.4	.25	.75	.35	30

(s) Includes flue gas desulfurization.

The addition of flue gas desulfurization equipment is assumed to raise the heat rate of the coal-fired units from 10,000 to 10,500 BTU/kWh. The heat rates for the combined cycle units are raised slightly (~500 BTU/kWh) to more accurately represent average heat rates over the lifetime of the plants.

Operating and maintenance (O&M) costs for both steam turbine and combustion turbine units are drawn from the 1974 Alaska Power Survey.[22; pp. 95-102] These costs, when expressed in January 1, 1977, dollars, appear reasonable for combustion turbines and steam turbine plants without flue gas desulfurization (FGD). The installation of FGD increases the O&M costs of a coal-fired steam turbine by about 30%.[23, pp. 29] As with capital costs the O&M costs are sensitive to geographical location. The O&M costs for steam turbine equipment at Beluga are increased by 25% over the estimates for the Anchorage Cook Inlet area.

Insurance costs are evaluated at 0.25% of gross plant investiment annually.[22; pp. 82] Payments in lieu of taxes are estimated to be .75% of gross plant investment annually.[22; pp. 82] Interim replacement costs for fossil fuel fired plants are estimated to be .35% of total plant investment annually.[22; pp.80)

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7.0

7.0 METHOD FOR SELECTING THE LEAST COST GENERATING OPTIONS

7.1 INTRODUCTION

This chapter describes the methodology used to evaluate power costs of the alternative electrical generating options available in the Railbelt. The first section explains the use of the levelized cost of power criterion in the selection of the generating alternatives which produce power at the lowest cost. The second section briefly discusses the factors which determine the cost of power. The third section describes the computational method used to compute the cost of electricity in any single year. These costs of power produced during each year of a plant's lifetime are used to compute the levelized cost of power. The next section introduces ECOST2, a computer model which incorporates the methodology described in this chapter.

In a study of this nature, a consistent analysis procedure utilizing a unified general economic scenario is of utmost importance. The last section of this chapter presents the economic scenarios which are used in the calculation of the cost of power.

7.2 LEVELIZED COST OF POWER AS THE CRITERION

In this report the levelized cost is used as the criterion to select the lowest cost power generation alternative. The relationship between the annual cost of power at the bus bar from a power plant and the levelized cost of power from that power plant over its lifetime is shown graphically in Figure 7.1.

The annual plant capital expenses are fixed by the initial financing and are typically constant over the life of the plant. Operation and maintenance and fuel costs typically increase over time as affected by inflation and real fuel price increases, however. As a result, the annual cost of power progressively increases over time.

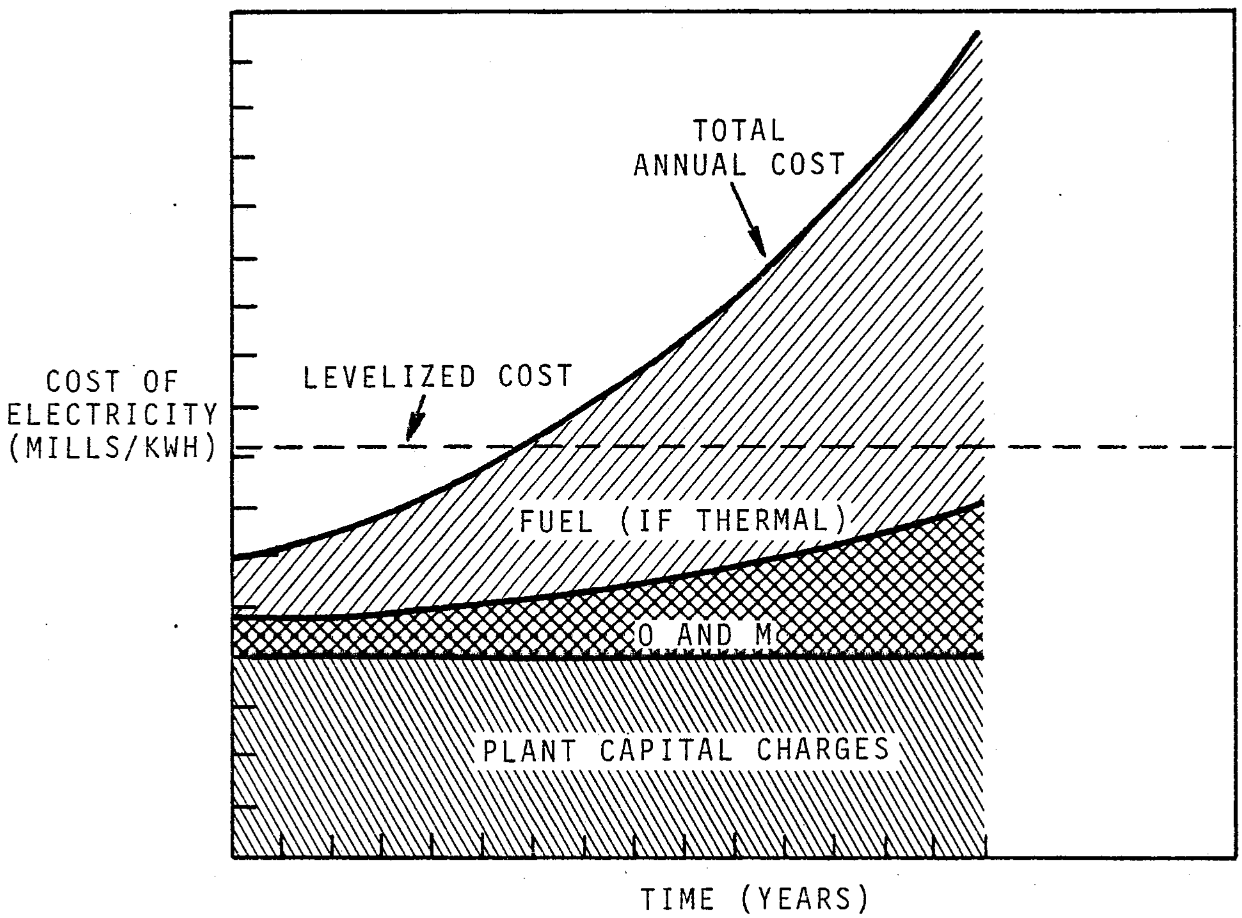

FIGURE 7.1. Annual Cost of Power and Total Levelized Cost

The levelized cost of power is computed using the present worth of the annual costs of power produced over the lifetime of a plant. In equation form:

$$\text{Levelized Cost of Power} = \text{PWCP} * \text{CRF} \tag{6.1}$$

where:

PWCP = Present worth of the cost of power

CRF = Capital Recovery Factor -- the factor by which a present sum is multiplied to find a future series that is equivalent to the present sum (annuity) at a specified discount rate and plant lifetime.(1, p. 26)

In turn:

$$\text{PWCP} = \sum_{i=1}^{n} \frac{\text{TAC}_i}{\text{EPP}_i} * \frac{1}{(1+r)^i} \tag{6.2}$$

where:

TAC_i = Total annual costs in year i ($)

EPP_i = Electrical power produced in year i (KWh)

r = Discount rate (fraction)

n = Plant lifetime (years)

The discount rate used in equations 6.1 and 6.2 corresponds to the societal discount rate rather than the financing discount rate. A societal discount rate of 6.4% is used in this study. (For a discussion of the present worth process and the various discount rates see Chapter 9.)

Figure 7.2 illustrates the use of the levelized cost of power to select the alternative with the lower levelized cost. Alternative A represents a plant with a low capital cost but with relatively high operation and maintenance and fuel costs. Alternative B represents a plant with a higher capital cost but with relatively low operation and maintenance and fuel costs. Without use of a present worth analysis the selection of the lower cost alternative would be unclear. Initially alternative A would look more attractive while alternative B would look more attractive in later years. Using the levelized costs, however, it is clear that alternative B is the lower cost alternative over the lifetime of the plants.

It is important to realize that the levelized cost of power from the generating options may be different relative to each other for different

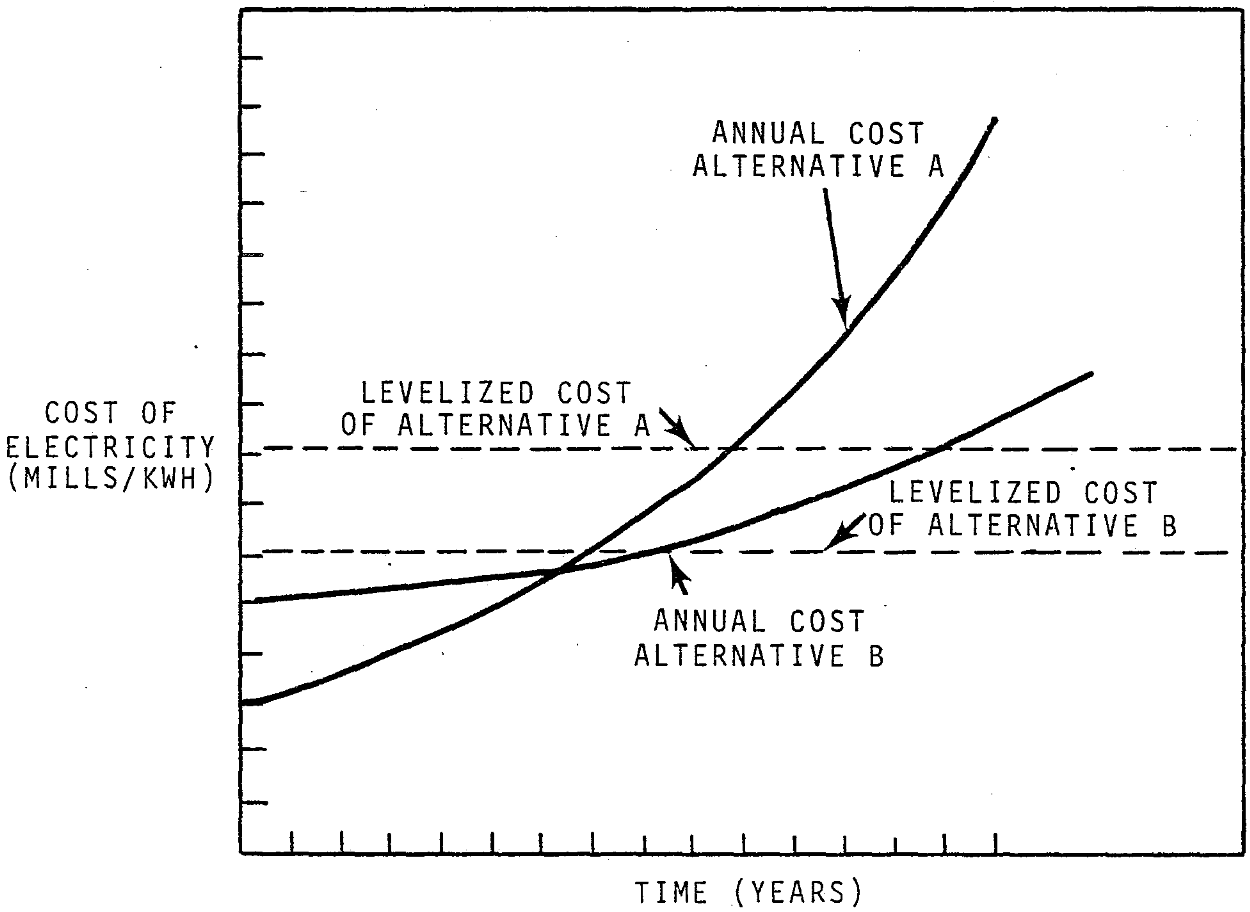

FIGURE 7.2. Use of Levelized Cost to Select Lowest Life Cycle Cost Alternative

rates of general inflation. For example, power produced by alternative plant A with its higher operation and maintenance and fuel costs will be influenced more by the rate of inflation than alternative plant B. If there was no inflation, all the annual costs (and hence the levelized cost) of alternative A would be lower than the annual costs (and levelized cost) of alternative B. On the other hand, if the rate of inflation were even higher, the levelized cost of alternative A would increase faster than the levelized cost of alternative B. For this reason, judgments about the future rate of inflation may have to be made before the lowest cost of power generating alternative can be selected.

7.3 FACTORS EFFECTING THE COST OF POWER

7.3.1 Capital Costs

The capital costs represents the total cost of constructing a generating facility. The cost figures used in this analysis do not include interest or escalation during construction. The effects of interest and escalation during construction are computed and added to the cost figures automatically by ECOST2 to give the total investment cost of a project. It is assumed that the investment costs are repaid in equal annual payments (annuity) over the payback period of the plant. It is also assumed that the annual depreciation costs are computed in accordance with straight-line depreciation accounting principles. Thus, in any one year the cost of capital recovery for a particular facility would include the annual depreciation cost plus the cost of money rate applied to the net drpreciated investment.

As mentioned above, the capital cost estimates used are in terms of constant January 1, 1977 dollars.

7.3.2 Heat Rate

As mentioned earlier in Chapter 6 the heat rate is the ratio of the Btu's going into the plant as fuel to the KWh's of electricity produced by the plant. The heat rate is assumed to remain constant for all plant utilization factors over the lifetime of the plant.

7.3.3 Operation and Maintenance Costs

The operation and maintenance (O&M) costs ($/KW/Year) include the administrative and general expenses, but not the interim replacement costs. O&M costs are assumed to be constant for all plant utilization factors. All estimates are expressed in terms of January 1, 1977 dollars. They are escalated at a rate equal to the rate of general inflation (see Section 6.1).

7.3.4 Financing Discount Rate

The financing discount rate represents the cost of capital to a utility. The financing discount rates are derived and discussed in Chapter 9.0.

7.3.5 Facility Construction Time

Generating facilities require time to construct and be put into operation. The construction and preoperation period (called facility construction time here) can range from a year or less for a small combustion turbine plant to as long as 10 years for a major hydroelectric facility.

The following facility construction times are for fossil fuel generating options used in this analysis.

- Combined cycle units - 2 years
- 200 MW coal steam turbine units - 5 years
- 400 MW coal steam turbine units - 5 years
- 800 MW coal steam turbine units - 6 years

The facility construction times for hydroelectric projects are developed on a case by case basis.

7.3.6 Interest and Escalation During Construction

During the facility construction time various activities take place, such as purchasing of equipment, construction by the labor force, testing, etc. The construction schedule includes a payout schedule that specifies the times during the construction period that specific equipment, materials, and labor are purchased. In other words, the payout schedule is an estimate of how the base construction costs are dispersed as a function of time.

During the construction period the prices for materials and equipment escalate. In addition, interest must be paid on the escalated cost of the materials and equipment until the plant comes on line and begins to provide an income stream to repay the costs. As shown in Figure 7.3 both escalation during construction (EDC) and interest during construction (IDC) add to the total cost of the plant. These costs must be included in the total cost of the project since they are included in the amount of capital required to finance the plant.

The cost of a plant, not including IDC and EDC, is defined in this report as the base or capital cost. The cost of a plant, including IDC and EDC is referred to as the total investment cost.

The dates that must be considered are the base year, i.e., the year that charges begin to accrue against the project (in most cases early site selection and environmental analyses are not charged against the project); the date when construction is completed; and the date when commercial operation begins. For simplicity in this analysis, the date when construction is completed is assumed to coincide with the date of commercial operation.

In this analysis, the payout schedule is assumed to be a symmetric S-shaped curve similar to that shown in Figure 7.3, unless specified otherwise.

7.3.7 Payback Period

The length of time over which the plant is financed is the payback period. This assumed to be equal to the plant lifetime except for hydroprojects where a 50 year payback period is assumed vs. at least a 100 year plant lifetime.

7.3.8 Insurance Costs

Annual insurance costs are assumed to be a constant fraction of the investment cost of the plant.

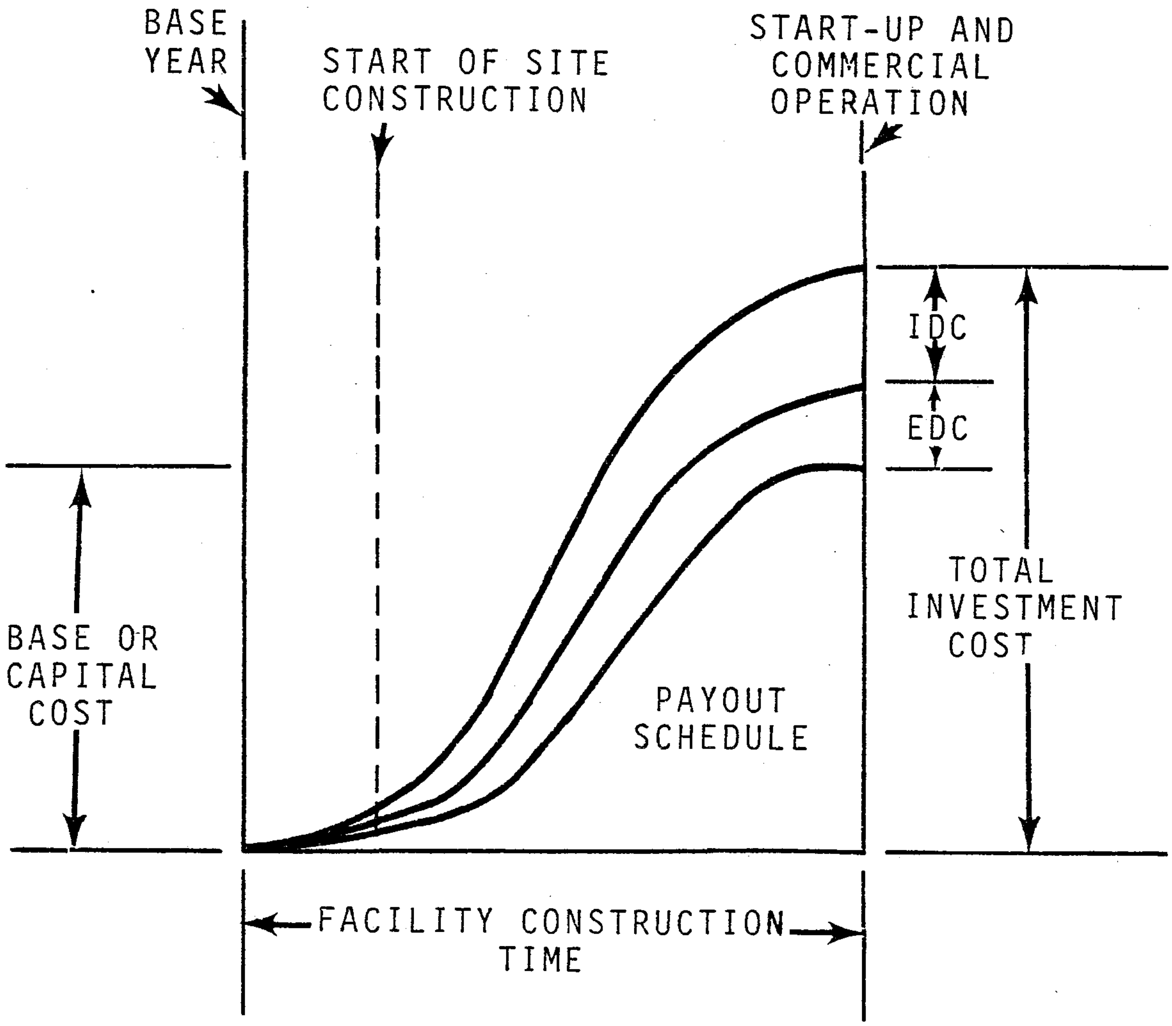

FIGURE 7.3. Cumulative Capital Requirements During Construction

7.3.9 Tax Costs

The annual tax payments (or payments in lieu of taxes) are assumed to be a constant fraction of the investment cost of the plant.

7.3.10 Interim Replacement Costs

The annual interim replacement costs are also assumed to be a constant fraction of the plant investment costs. Interim replacement costs are included with the operating and maintenance costs for hydro-projects.

7.3.11 Annual Plant Utilization Factor

The plant utilization factor (PUF) is the ratio of the actual power production during a year to the theoretical maximum if the plant was to run 8760 hours at 100% capacity during the year.

The annual plant utilization factor is highly variable depending upon many factors (i.e., forced outage rate, cost of power from alternative sources, and power production requirements). Because of this, it is necessary to explicitly consider the effects of the PUF on the cost of power over the lifetime of a plant. The PUF's used as base cases in this report are shown in Figure 7.4 for various types of thermal generating facilities. For the hydroelectric cases, average annual energy is used and the PUF is assumed constant over the facility lifetime.

7.3.12 Unit Fuel Costs

Estimates of the unit cost of various types of fossil fuels in the Railbelt area are presented in Section 6.2.2.

7.3.13 General Inflation Rate

Because of the uncertainty involved in estimating the future rate of inflation, three alternative cases are evaluated. A constant dollar case (0% inflation), a 4% inflation case, and a 7% inflation case are presented.

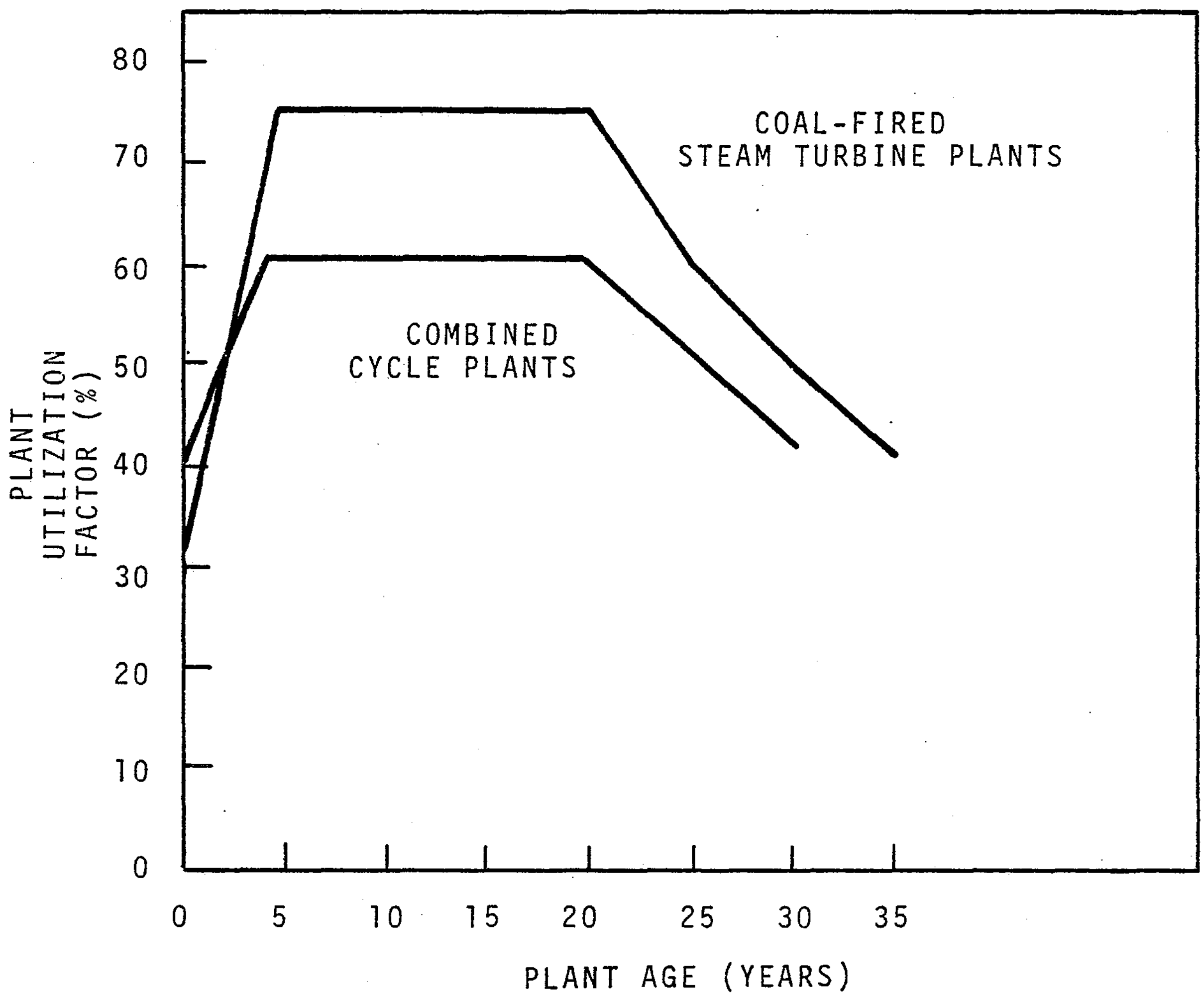

FIGURE 7.4. Plant Utilization Factor versus Plant Age

7.3.14 Construction Escalation Rate

As explained in Section 6.1.7, historically construction costs have increased about 2.5% faster than the rate of general inflation. In this analysis construction costs are assumed to escalate 2.5% faster than the rate of general inflation.

7.3.15 Fuel Escalation Rate

Economic theory suggests that fuel costs will escalate over the long term at a rate equal to the cost of capital. The fuel escalation rate is set equal to the real cost of money plus the general inflation rate.

7.4 COMPUTATIONAL METHOD

The key to the computation of the cost of power is the assumption that the cost of power in any one year is set to exactly cover all costs. In equation form:

$$EPC_i = \frac{TAC_i}{EPPRO_i * 1000}$$

where:

EPC_i = Electrical power costs in year i (mills/KWh)

TAC_i = Total annual costs of production in year i (\$/Year)

$EPPRO_i$ - Electrical power production in year i (MMKWh/Year)[a]

The electrical power production is computed thus:

$$EPPRO_i = (ICAP * PUF_i * HPY)/1000$$

(a) Parameters with the subscript i are assumed to vary each year over the lifetime of the plant. Parameters without the subscript are assumed to be constant over the lifetime of the plant.

Unless otherwise noted, all costs dealt with in this report represent bus bar costs of production (i.e., transmission and distribution costs are not included).

where:

$ICAP$ = Installed capacity (MW)

PUF_i = Plant utilization factor in year i (fraction)

HPY = Hours per year (8760 hours/year)

The total annual costs (TAC) are composed of two elements: variable costs and fixed costs. In equation form:

$$TAC_i = VARC_i + FIXC_i$$

where:

$VARC_i$ = Variable costs in year i ($/Year)

$FIXC_i$ = Fixed costs in year i ($/Year)

The variable costs consist only of the fuel costs.

$$VARC_i = FUELC_i$$

where:

$FUELC_i$ = Fuel costs in year i ($/Year)

In turn, fuel costs are computed:

$$FUELC_i = HEATR * EPPRO_i * UFUELC_i$$

where:

$HEATR$ = Heat rate (Btu/KWh)

$EPPRO_i$ = Electrical power production in year i (MMKWh)

$UFUELC_i$ = Unit fuel costs in year i ($/MMBtu)

The fixed costs consist of five factors. These factors can be written in the following equation form:

$$FIXC_i = INTAM + INTRE + TAXES + IC + OMC_i$$

where:

$INTAM$ = Interest and amortization (capital recovery) charges ($/Year)

$INTRE$ = Interim replacement ($/Year)

$TAXES$ = Annual taxes ($/Year)

IC = Annual insurance costs ($/Year)

OMC_i = Operations and maintenance costs in year i ($/Year)

The interest and amortization charges (INTAM) represent the annual debt service payments.

As mentioned above, it is assumed that the annual depreciation costs are computed in accordance with straight-line depreciation accounting principles. Under these assumptions the annual cost of capital recovery can be computed by applying the sinking fund depreciation plus the cost-of-money rate to the total investment.[2, p.79] In equation form:

$$INTAM = TINVC * IR + SFDF * TINVC$$

where:

$TINVC$ = Total investment costs ($)

IR = Financing discount rate (fraction)

$SFDF$ = Sinking fund deposit factor

However, since:

$$SFDF + IR = CRF$$

where:

CRF = Capital recovery factor (fraction)

this equation can be rewritten as:

$$INTAM = CRF * TINVC$$

The capital recovery factor is used to compute a future series of equal end-of-year payments that will just recover a present sum p over n periods with compound interest (IR). It is computed thus:[1, p.26]

$$CRF = \frac{IR(1 + IR)^{PBP}}{(1 + IT)^{PBP} - 1}$$

where:

PBP = Payback period (years)

The interim replacement costs are assumed to be a constant fraction of the investment cost.

INTRE = INTRER * TINVC

where:

INTRER = Interim replacement rate (fraction)

The annual taxes (or payments in lieu of taxes) are also assumed to be a fraction of the investment cost.

TAXES = TAXR * TINVC

where:

TAXR = Tax rate (fraction)

The annual insurance costs are assumed to be a fraction of the investment cost.

IC = INSR * TINVC

where:

INSR = Insurance rate (fraction)

The operation and maintenance (O&M) costs per KW of installed capacity are entered directly. They are assumed to be constant for all plant utilization factors. O&M costs include administrative and general expenses but, as indicated above, do not include interim replacement costs.

The fixed charge rate (FIXCR) is the sum of the capital recovery factor, the interim replacement rate, the tax rate, and the insurance rate. It is computed for reference.

FIXCR = CRF + INTRE + TAXR + INSR

7.5 ELECTRICITY COST MODEL (ECOST2)

The methodology described in this chapter is incorporated into a model called ECOST2. ECOST2 is used to forecast the levelized cost of electricity from the alternative generating schemes during the period from 1980 to 2000. ECOST2 is a computer model and as a result has several attractive features for use as a forecasting tool. Two of the most useful features, for the purpose of this report, are:

1) It quickly reveals the effects of parameter changes on the cost of power, and
2) Through the use of sensitivity analysis parameters that maximally affect cost behavior are revealed for further investigation.

The results of the ECOST2 analyses are presented in Section 8.0 and Appendix D. A listing of the computer code is given in Appendix C.

7.6 ECONOMIC SCENARIOS

This study compares the cost of producing electricity from a variety of fossil fuel and hydroelectric generating facilities. Because these facilities use different types of fuels, are more or less capital intensive, are built during different periods of time, and may be financed under different discount rates, care must be taken to insure that the cost of power computed for all options are evaluated on a consistent basis. For example, the capital, operating, and fuel price estimates are all expressed in January 1, 1977 dollars in the analyses.

In addition, a set of three internally consistent economic scenarios are used in the calculation of the capital, operating, and fuel costs. These costs determine the cost of power and hence are the bases for the comparison of the generating alternatives. The scenarios consist of a 0% (constant dollar) rate of general inflation case, a 4% rate of general inflation case, and a 7% rate of general inflation case. The rate of general inflation is defined here as the rate of change of the gross national product deflator. The general inflation rate, financing discount rates, construction escalation rates, and fuel escalation rates are consistent within any one scenario. These scenarios are listed in Table 7.1.

TABLE 7.1. Discount and Escalation Rates for 0% (Constant Dollar), 4%, and 7% Rates of General Inflation

General Inflation	Construction Escalation[a] Plus Inflation	Fuel Escalation[b] Plus Inflation	Financing Discount Rates: Alaska Power Authority (Aa)[c]	Financing Discount Rates: Alaska Municipality (A/Baa)[d]	Financing Discount Rates: REA
0	2.5	3.0	2.8	3.1	4.5
4	6.5	7.0	6.8	7.1	8.5
7	9.5	10.0	9.8	10.1	11.5

(a) Construction escalation is equal to the rate of general inflation plus 2.5%.

(b) Fuel escalation is equal to the risk free rate of return (assumed to be 3%) plus the rate of general inflation.

(c) The Alaska Power Authority is assumed to have an Aa bond rating.

(d) The smaller Alaska municipalities (Anchorage and Fairbanks) are assumed to have a bond rating 2 points below the Alaska Power Authority (A/Baa).

Each of these factors are derived and discussed elsewhere in this report; construction escalation in Section 6.1.7, fuel escalation in Section 6.2.2, and the financing discount rates in Section 9.0.

REFERENCES, SECTION 7.0

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8.0

8.0 LOAD/RESOURCE ANALYSES

8.1 INTRODUCTION

Previous sections of this report (and Section 9.0 to follow) have addressed the possible and probable electric power load growths for the Railbelt region, the near term (to 1984) plans by the utilities for capacity additions, and the economic factors and other constraints involved in the various power generation options.

There are four purposes of this chapter:

1. To present estimates for the cost of electricity obtained using the methodology described in Chapter 7 and the estimates for the various cost components discussed in Chapter 6.
2. To present the results of analyses done to test the sensitivity of the cost of power to changes in the various cost components.
3. To use the information developed in Parts 1-2 above to match the alternative supply options and demand forecasts to minimize the bus bar cost of power under the alternative demand forecasts.
4. To present a set of general conclusions regarding the load/resource analysis undertaken in this chapter.

8.2 SUMMARY OF ESTIMATES OF COST COMPONENTS

The most reasonable estimates for the components that contribute to the cost of power discussed in other sections of this report are used to compute the cost of power for a set of generation alternatives. These components include:

- capital and operating costs
- fuel costs
- interest and escalation rates.

The capital and operating costs for both fossil fuel and hydroelectric generating plants were discussed in Chapter 6.0. The capital and operating costs for fossil fuel generating options to be used in this analysis were presented for the Anchorage/Cook Inlet/Kenai region and the Fairbanks region in Tables 6.13 and 6.14, respectively. The hydroelectric capital and operating costs to be used were presented in Tables 6.10 and 6.11.

The fuel costs were also discussed in Chapter 6.0. The best estimates of the fuel costs were summarized in Figure 6.8.

The interest and escalation rates corresponding to each of the three inflation rate scenarios were presented in Table 7.1.

8.3 LEVELIZED COSTS FOR SELECTED GENERATING OPTIONS

8.3.1 Description of Selected Options and Summary of Costs

The levelized cost of power for 28 fossil fuel and 4 hydroelectric generating options available to the Railbelt are presented and analyzed in this section.

Four types of generating units were analyzed: 1) 100, 200, and 400 MW coal steam turbines, 2) 100 MW gas combined cycle units, 3) 100 MW oil combined cycle units, and 4) various hydroelectric options. Costs of power were calculated for coal fired steam turbine plants located at Beluga, Anchorage, Healy, and Nenana. Coal was assumed to be supplied from the Beluga area reserves (Threemile or Capps Fields) to Beluga plants and from Healy via the Alaska Railroad to the other locations. Alaska Power Authority (APA), REA, and municipal plant financing options were examined. Fuel supply financing was assumed to be private throughout. Coal plants were evaluated with and without flue gas desulfurization (FGD).

Costs of power were evaluated for oil-combined cycle units located in the Cook Inlet and Fairbanks (North Pole) area. The fuel for these plants is assumed to come from refineries in the same areas. As with coal fired plants APA, REA, and municipal financing options were examined.

Gas combined cycle units were also assumed to be located either in Cook Inlet or North Pole area. Fuel for units in the Cook Inlet area were assumed to obtain fuel from the Cook Inlet area while those located at North Pole were assumed to obtain gas from the proposed ALCAN gas pipeline. All three financing options were again evaluated.

Four hydroelectric projects were examined: 1) Bradley Lake, 2) Chakachamna, 3) Watana only (Upper Susitna), and 4) Watana plus Devil Canyon (Upper Susitna --proposed by Corps of Engineers). Data for these options were based upon Corps of Engineers cost estimates.

The costs are summarized in Tables 8.1, 8.2, and 8.3 for the 0%, 4%, and 7% inflation scenario, respectively. Costs are presented for plants coming on line in 1980, 85, 90, 95, and 2000. Appendix D provides details of the cost estimates and all assumptions used in their derivation.

8.3.2 Analysis of Results

Many issues can be analyzed by examining the data presented in Tables 8.1, 8.2, and 8.3. Several of these are discussed in this section.

Lowest Cost of Power to the Railbelt

Hydroelectric options typically produce power at about 1/2 to 3/4 the cost of coal steam turbines and combined cycle units. These results are true for all three inflation rates. It is important to keep in mind that the estimates upon which the hydroelectric costs are based are the results of preliminary studies only. As further site studies such as the Plan of Study for Upper Susitna Hydro Power are undertaken the capital costs may increase.[1] The capital costs of the Upper Susitna hydroelectric options would have to approximately double to eliminate the cost of power advantage that exists using present data. The costs presented for the Watana and Watana plus Devil Canyon include the cost of transmission to the Fairbanks and Anchorage load centers.

The hydroelectric options have relatively long planning and construction lead times. For example, it is estimated the Watana or Watana plus Devil Canyon will not be available until at least 1991. Bradley Lake and Chakachamna

TABLE 8.1. Levelized Cost of Power for Railbelt Generating Options 0% Inflation Rate

Case Number	Generation Type	Location	Fuel Source	Plant Financing	F.G.D.	Power on Line Date 1980	1985	1990	1995	2000
1	Coal Steam Turbine	Beluga	Beluga	APA		Case Deleted				
2						Case Deleted				
3					Yes	38.60	43.76	49.67	56.44	64.20
4					No	34.67	39.38	44.78	50.97	58.07
5						Case Deleted				
6						Case Deleted				
7					Yes	43.52	49.33	55.97	63.58	72.28
8					No	38.97	44.24	50.28	57.19	65.10
9						Case Deleted				
10						Case Deleted				
11		Anchorage	Healy		Yes	38.03	43.23	49.21	56.06	63.92
12					No	34.45	39.23	44.71	51.01	58.24
13				REA	Yes	42.53	48.33	54.97	62.58	71.30
14					No	38.39	43.69	49.76	56.72	64.69
15				Municipal	Yes	38.77	44.07	50.15	57.13	65.13
16					No	35.10	39.96	45.54	51.95	59.30
17	(400 MW)			APA	Yes	36.44	41.41	47.12	53.67	61.19
18	(100 MW)				Yes	44.08	50.02	56.82	64.61	73.52
19	Gas Combined Cycle	Cook Inlet	Cook Inlet		NA	39.10	45.99	52.86	60.80	70.00
20				REA	NA	39.99	46.99	54.00	62.09	71.45
21				Municipal	NA	39.25	46.16	53.05	61.02	70.24
22	Oil Combined Cycle			APA	NA	38.50	44.69	51.35	59.05	67.97
23				REA	NA	39.38	45.69	52.49	60.34	69.42
24				Municipal	NA	38.64	44.85	51.54	59.27	68.21
25	Coal Steam Turbine	Healy	Healy	REA/Munic.	Yes	42.11	47.67	54.01	61.24	69.50
26					No	37.07	42.02	47.67	54.12	61.48
27		Nenana			Yes	45.59	51.70	58.68	66.66	75.78
28					No	40.39	45.86	52.12	59.28	67.46
29				APA	Yes	40.78	46.26	52.53	59.70	67.90
30					No	36.25	41.19	46.83	53.30	60.69
31	Oil Combined Cycle	North Pole	TAPS	REA/Munic.	NA	40.56	47.02	53.99	62.04	71.34
32				APA	NA	39.66	46.00	52.83	60.73	69.87
33	Gas Combined Cycle		ALCAN	REA/Munic.	NA	41.16	48.32	55.50	63.79	73.37
34				APA	NA	40.26	47.30	54.34	62.48	71.89
40	Hydro	Bradley Lake	NA		NA	27.03	30.31	34.03	38.23	42.98
41		Chakachamna			NA	26.13	29.42	33.13	37.33	42.08
42		Watana			NA	19.18	21.65	24.46	27.63	31.22
43		Watana + Devil Canyon			NA	15.05	16.98	19.15	21.62	24.41

TABLE 8.2. Levelized Cost of Power for Railbelt Generating Options 4% Inflation Rate

Case Number	Generation Type	Location	Fuel Source	Plant Financing	F.G.D.	Power on Line Date 1980	1985	1990	1995	2000
1	Coal Steam Turbine	Beluga	Beluga	APA			Case Deleted			
2							Case Deleted			
3					Yes	71.35	98.08	134.98	185.95	256.41
4					No	64.37	88.65	122.20	168.61	232.83
5							Case Deleted			
6							Case Deleted			
7					Yes	78.26	107.54	147.95	203.72	280.75
8					No	70.39	96.90	133.50	184.09	254.04
9							Case Deleted			
10							Case Deleted			
11		Anchorage	Healy		Yes	70.89	97.73	134.84	186.20	257.34
12					No	64.49	89.03	123.02	170.10	235.37
13				REA	Yes	77.21	106.38	146.69	202.45	279.59
14					No	70.02	96.60	133.39	184.31	254.84
15				Municipal	Yes	71.96	99.18	136.83	188.94	261.08
16					No	65.42	90.30	124.76	172.49	238.64
17	(400 MW)			APA	Yes	68.20	93.98	129.65	179.02	247.40
18	(100 MW)				Yes	81.23	111.75	153.89	212.12	292.60
19	Gas Combined Cycle	Cook Inlet	Cook Inlet		NA	72.71	102.66	142.89	199.01	277.36
20				REA	NA	73.93	104.33	145.17	202.14	281.65
21				Municipal	NA	72.92	102.95	143.28	199.55	278.10
22	Oil Combined Cycle			APA	NA	71.21	99.71	138.74	193.20	269.21
23				REA	NA	72.43	101.38	141.03	196.33	273.50
24				Municipal	NA	71.42	99.99	139.13	193.73	269.94
25	Coal Steam Turbine	Healy	Healy	REA/Munic.	Yes	74.23	101.86	139.89	192.26	264.43
26					No	65.65	90.20	124.04	170.68	235.01
27		Nenana			Yes	81.31	111.78	153.80	211.78	291.81
28					No	72.39	99.65	137.29	189.27	261.08
29				APA	Yes	74.53	102.50	141.08	194.35	267.93
30					No	66.56	91.67	126.36	174.29	240.56
31	Oil Combined Cycle	North Pole	TAPS	REA/Munic.	NA	74.36	104.02	144.64	201.28	280.29
32				APA	NA	73.12	102.32	142.31	198.09	275.91
33	Gas Combined Cycle		ALCAN	REA/Munic.	NA	75.85	106.97	148.79	207.10	288.44
34				APA	NA	74.61	105.27	146.46	203.90	284.06
40	Hydro	Bradley Lake	NA		NA	52.66	71.49	97.13	132.08	179.76
41		Chakachamna			NA	50.76	69.16	94.30	128.63	175.54
42		Watana			NA	37.13	50.77	69.43	94.97	129.93
43		Watana + Devil Canyon			NA	29.17	39.84	54.42	74.36	101.63

TABLE 8.3. Levelized Cost of Power for Railbelt Generating Options
7% Inflation Rate

Case Number	Generation Type	Location	Fuel Source	Plant Financing	F.G.D.	Power on Line Date 1980	1985	1990	1995	2000
1	Coal Steam Turbine	Beluga	Beluga	APA		Case Deleted				
2						Case Deleted				
3					Yes	116.25	183.80	290.93	460.96	731.03
4					No	105.41	166.97	264.74	420.13	667.24
5						Case Deleted				
6						Case Deleted				
7					Yes	124.58	196.92	311.58	493.47	782.20
8					No	112.67	178.40	282.74	448.45	711.84
9						Case Deleted				
10						Case Deleted				
11		Anchorage	Healy		Yes	116.77	185.13	293.80	466.65	741.74
12					No	106.74	169.49	269.36	428.38	681.74
13				REA	Yes	124.38	197.13	312.68	496.37	788.53
14					No	113.40	179.99	285.88	454.39	722.68
15				Municipal	Yes	118.06	187.17	297.01	471.70	749.69
16					No	107.87	171.28	272.17	432.80	688.70
17	(400 MW)			APA	Yes	113.07	179.22	284.35	451.57	717.74
18	(100 MW)				Yes	131.56	208.17	329.72	522.69	829.27
19	Gas Combined Cycle	Cook Inlet	Cook Inlet		NA	120.99	195.35	312.40	499.93	800.51
20				REA	NA	122.44	197.63	316.00	505.59	809.42
21				Municipal	NA	121.24	195.74	313.02	500.90	802.04
22	Oil Combined Cycle			APA	NA	118.12	189.62	303.17	485.07	776.57
23				REA	NA	119.57	191.90	306.77	490.73	785.48
24				Municipal	NA	118.37	190.01	303.79	486.04	778.11
25	Coal Steam Turbine	Healy	Healy	REA/Munic.	Yes	114.35	180.44	284.96	450.41	712.43
26					No	101.73	160.75	254.22	402.32	637.15
27		Nenana			Yes	127.34	201.35	318.64	504.64	799.78
28					No	114.09	180.66	286.29	453.98	720.34
29				APA	Yes	119.14	188.45	298.34	472.68	749.46
30					No	107.05	169.57	268.83	426.50	677.08
31	Oil Combined Cycle	North Pole	TAPS	REA/Munic.	NA	122.24	196.10	313.38	501.13	801.86
32				APA	NA	120.75	193.76	309.70	495.34	792.74
33	Gas Combined Cycle		ALCAN	REA/Munic.	NA	125.11	201.83	322.60	515.99	825.79
34				APA	NA	123.62	199.49	318.93	510.20	816.68
40	Hydro	Bradley Lake	NA		NA	80.32	124.88	194.42	303.00	472.71
41		Chakachamna			NA	76.39	119.37	186.66	292.09	457.37
42		Watana			NA	55.19	86.64	136.05	213.69	335.72
43		Watana + Devil Canyon			NA	43.55	68.25	107.00	167.84	263.35

also have long lead times. At the present time there are no plans to intertie the Fairbanks and Anchorage load centers until construction of the Upper Susitna projects. For these reasons both the Fairbanks and Anchorage areas will have to add new thermal capacity before any of the hydroelectric options evaluated here could come on line if they are to meet the forecasted load growth as noted in Section 8.5. The cost of power produced by the various fossil fuel generating options for the Anchorage and Fairbanks areas are discussed below.

Lowest Cost of Power to the Anchorage Region(1980-1990 Power on Line Date)

To compare the costs of power for the Anchorage area an assumption must be made about the costs of transmission from Beluga to Anchorage. These transmission costs were estimated to be 2.5 mills in 1975 dollars.[2] Using the Handy-Whitman index this is equivalent to about 3.9 mills in January 1, 1977 dollars. This estimate is used in this comparison.

Assuming that FGD is required coal steam turbine units located at Anchorage and combined cycle units located on Cook Inlet produce power delivered to Anchorage 5-9% cheaper than coal steam turbine units located at Beluga. If FGD is not required the cost of power from the coal steam turbine units becomes cheaper than power from the combined cycle units.

Lowest Cost of Power to the Fairbanks Region (1980-1990 Power on Line Date)

As was the case with the Anchorage region, assumptions must be made about the costs of transmission from Healy and Nenana to Fairbanks. It is assumed that transmission costs increase the cost of power by 3.0 mills from Healy to Fairbanks and 1.5 mills from Nenana to Fairbanks.

Assuming that FGD is required, the oil and gas combined cycle units located at North Pole produce power at a lower cost to the Fairbanks market than coal steam turbine units located at either Healy or Nenana. Assuming the FGD is not required the coal steam turbine units product the cheapest power for the Fairbanks market.

Effects of Flue Gas Desulfurization on Cost of Power

The addition of FGD adds approximately 10-11% to the bus bar cost of electricity.

APA versus REA Financing

APA financing reduces the bus bar cost of electricity by 9-15% compared to REA financing for coal steam turbine plants. For combined cycle units APA financing reduces the bus bar cost of electricity by about 2% compared to REA financing.

Cost of Power versus Plant Size

The costs of power for a 100 MW (Case 18), a 200 MW (Case 11), a 400 MW (Case 17), and a 800 MW (not presented) coal steam turbine generating plant are shown in Figure 8.1.

Effects of Wet/Dry Cooling on Cost of Power

It is assumed that the coal steam turbine generating options would use mechanical draft cooling towers. It is possible that steam turbine units would require wet/dry cooling in the Fairbanks area to reduce ice fog. The effects of wet/dry cooling on the cost of power was determined by increasing the capital cost of a 200 MW unit located at Nenana (Case 27) by 15.38 million dollars and increasing the heat rate to 12,000 BTU/kWh. Under these assumptions the cost of power was increased from 84.58 mills/kWh to 91.06 mills/kWh (4% inflation rate, 1980 power on line date).

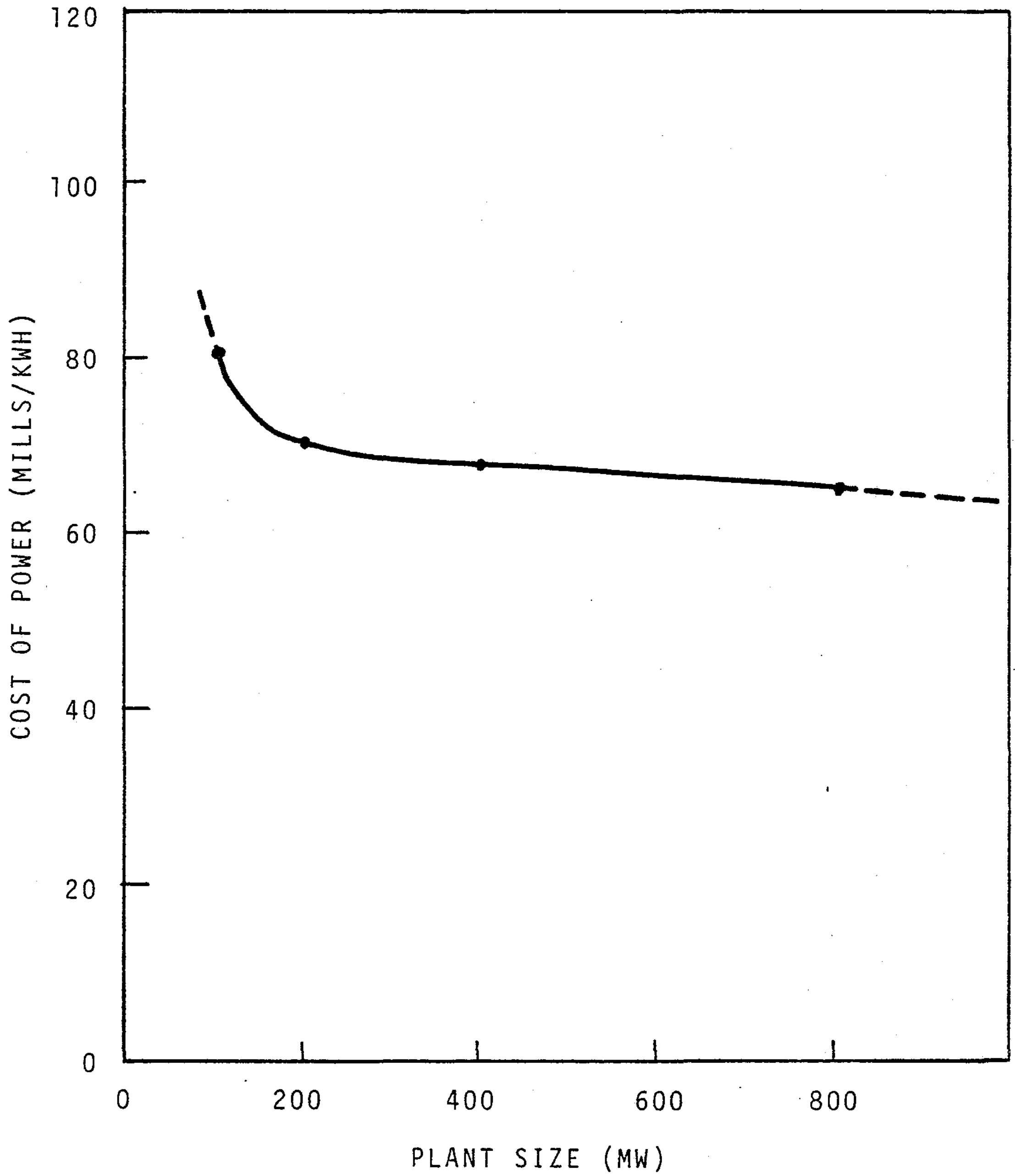

FIGURE 8.1. Bus Bar Cost of Power Versus Plant Size for Coal Steam Turbine Plants with FGD in the Anchorage Area

8.4 SENSITIVITY ANALYSIS

8.4.1 Sensitivity of ECOST2 Results to Changes in Input Parameters

In any parametric analysis such as is presented in Section 8.3 it is important to know which input parameters have the most effect on the results, i.e., which input parameters are the results most sensitive to. This information serves as a guide to the analyst pointing out those parameters which maximally affect the results. Additional research can then be focused on those parameters to insure their accuracy. This information is also useful to the reader since it allows he or she to focus attention on the derivation or source of the parameters which the model is most sensitive to.

To test the sensitivity of ECOST2 to the input parameters, each parameter was varied between a value 10% higher than the base case and a value 10% lower than the base case (20% total change). The percentage change in the levelized cost of power for the years 1980 and 2000 were then calculated from these model runs. These percentage changes are presented for three cases in Table 8.4, 8.5, and 8.6. Table 8.4 corresponds to a coal steam turbine unit located in the Anchorage area (Case 11). Table 8.5 corresponds to a gas combined cycle unit located in the Cook Inlet area (Case 19). Table 8.6 presents the results for the Watana hydroelectric project (Case 42). In each case the relative change in the levelized cost of power caused by a 20% change in the input parameter for 1980 and 2000 power on line dates are entered in the first two columns. The parameters that the model is most sensitive to are ranked in Column 3.

The data presented in Table 8.4 indicates that the results presented for Case 11 (and for the other coal steam turbine plants also) are most sensitive to the fuel escalation rate. The results are also relatively sensitive to the unit fuel cost, heat rate, and plant utilization factor.

The data presented in Table 8.5 points out that the results for the oil and gas combined cycle cases are also most sensitive to the fuel escalation rate. Again the results are also sensitive to the heat rate and unit fuel costs.

TABLE 8.4. Sensitivity of Levelized Cost of Power to 20% Change in Input Parameters - Coal Steam Turbine - (Case 11)

Input Parameter	Sensitivity (% Change) Power on Line Date 1980	2000	Relative Sensitivity
Capital cost	8.1	8.5	4
Heat rate	11.0	11.8	2
Operating and maintenance cost	1.1	0.7	
Financing discount rate	6.9	6.7	6
Facility construction time(a)	0.1	0.1	
Payback period(b)	6.4	6.4	7
Insurance rate	0.2	0.2	
Tax rate	0.7	0.7	
Interim replacement rate	0.3	0.3	
Plant utilization factor	10.0	9.3	3
Unit fuel cost	11.0	11.8	2
General inflation rate	0.7	0.96	
Construction escalation rate	0.3	10.7	5
Fuel escalation rate	15.1	34.4	1

(a) Facility construction time is considered an integer in the analysis. It was varied between 4 and 6 years (50% change).
(b) The sensitivity of ECOST2 to changes in the payback period was tested separately since the present formulation constrains the payback period to 5 year increments.

As shown in Table 8.6 the results for the hydroelectric cases are most sensitive to the capital cost estimates, construction escalation rate, financing discount rate, and plant utilization factor.

8.4.2 Special Sensitivity Analyses

This section points out some additional concepts and parameters which have a relatively strong impact on the analysis presented in this chapter.

TABLE 8.5. Sensitivity of Levelized Cost of Power to 20% Change in Input Parameters - Gas Combined Cycle - (Case 19)

Input Parameter	Sensitivity (% Change) Power on Line Date 1980	2000	Relative Sensitivity
Capital cost	2.0	1.8	
Heat rate	18.6	19.3	3
Operating and maintenance cost	1.0	0.6	
Financing discount rate	1.3	1.2	
Facility construction time[(a)]	0.0	0.0	
Payback period[(b)]	6.4	6.4	4
Insurance rate	0.0	0.0	
Tax rate	0.2	0.2	
Interim replacement rate	0.1	0.1	
Plant utilization factor	3.0	2.4	
Unit fuel cost	18.9	19.6	2
General inflation rate	0.6	0.7	
Construction escalation rate	0.2	2.5	
Fuel escalation rate	22.5	54.8	1

(a) Facility construction time is considered an integer in the analysis. It was varied between 1 and 3 years (200% change).
(b) The sensitivity of ECOSTZ to changes in the payback period was tested separately since the present formulation constrains the payback period to 5 year increments.

Effects of Plant Utilization Factor on the Relative Costs of Power from Steam Turbine and Combined Cycle Units

The cost of power produced by a generating plant varies inversely with the plant utilization factor (PUF), i.e., the higher the PUF the lower the costs and the lower the PUF the higher the costs. The exact relationship between the cost of power and the PUF is determined by, among other things, the relative importance of variable costs (such as fuel charges) and fixed costs (such as plant capital costs) to the total cost of power. The fixed costs must be paid whether a plant is operating or not while variable costs accrue only when a plant is operating.

TABLE 8.6. Sensitivity of Levelized Cost of Power to 20% Change in Input Parameters - Hydroelectric - (Case 42)

Input Parameter	Sensitivity (% Change) Power on Line Date 1980	2000	Relative Sensitivity
Capital costs	21.8	21.9	1
Operating and maintenance costs	0.3	0.2	
Financing discount rate	21.1	21.2	4
Facility construction time[a]	0.3	0.3	
Payback period	2.4	2.4	
Insurance rate	0.2	0.2	
Tax rate	1.9	1.9	
Plant utilization factor	23.1	23.1	3
General inflation rate	0.3	0.4	
Construction escalation rate	0.0	27.3	2

(a) Facility construction time is considered an interger in the analysis. It was varied between 5 and 7 years (40% change).

Plant capital costs contribute a greater portion of the total cost of power for coal steam turbine plants than for combined cycle plants. Fuel costs largely determine the cost of power from a combined cycle plant. The effects these differences have on the relative annual cost of power for steam turbine and combined cycle plants is shown in Figure 8.2. The annual cost of power from the steam turbine increases much more rapidly as the PUF decreases than does the annual cost of power from the combined cycle plant.

These differences have a significant impact on the decision as to which type of capacity to build. If the capacity is to be used for base load (high plant utilization) steam turbine units are more attractive relative to combined cycle units than if the new capacity will be used to meet intermediate or peak loads (low plant utilization). Steam turbine units must be operated at a relatively high PUF to keep the costs of the power produced down. Combined cycle units on the other hand can be operated over a wider range of PUFs without such a significant increase in the cost of power. For these

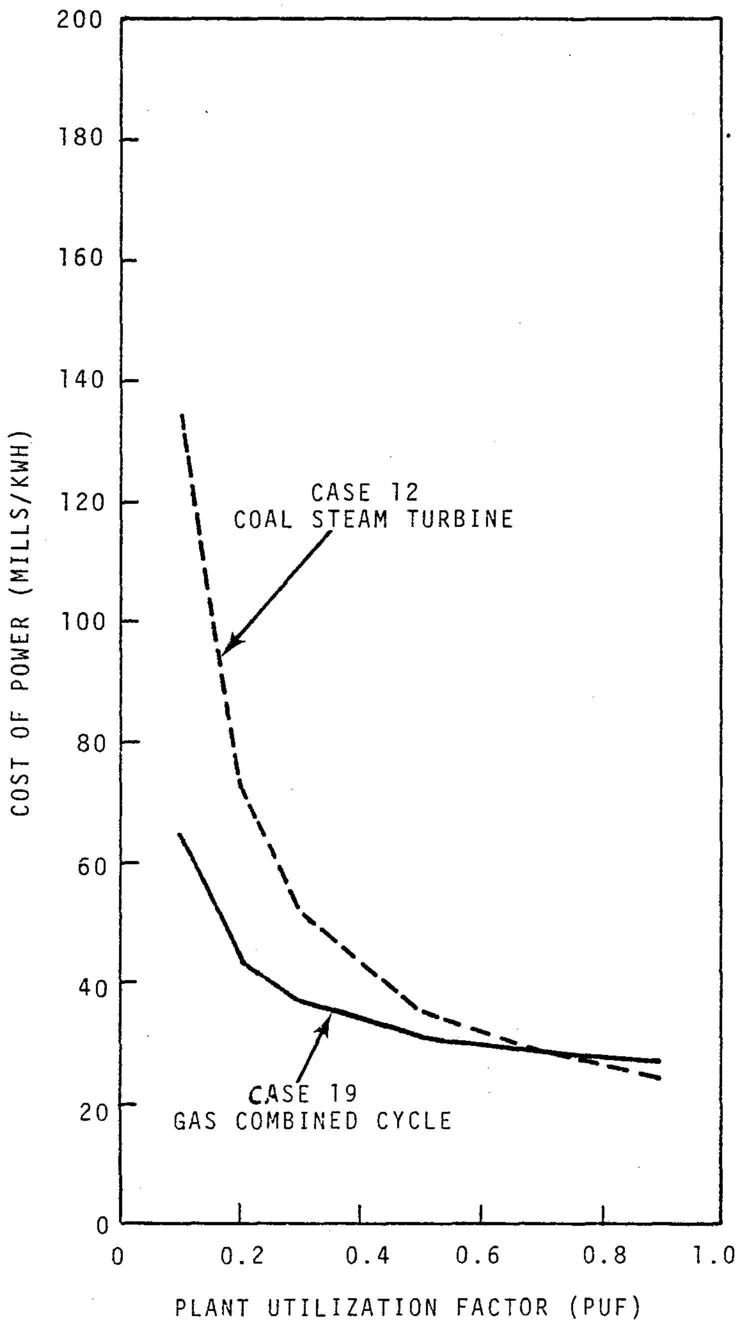

FIGURE 8.2. Annual Cost of Power Versus Plant Utilization Coal Steam Turbine and Gas Combined Cycle

same reasons the cost of power from hydroelectric generating facilities is even more strongly affected by changes in the PUF than either steam turbine or combined cycle capacity. This result is also evident in the results of the sensitivity test presented in the previous section.

To illustrate the effects on the levelized cost of power an additional set of sensitivity tests were done. The plant utilization factors for a coal steam turbine unit (Case 11), a combined cycle plant (Case 19), and a hydroelectric plant (Case 42) were varied as shown in Figures 8.3, 8.4, and 8.5, respectively.

The PUFs for the coal steam turbine and the combined cycle units were arbitrarily set to be higher and lower than the base case. The trial PUF for the hydroelectric case roughly corresponds to a situation where the three units at Watana are brought on line over a 10-yr period. This situation occurs in Section 8.5 for the low load growth case. The results of these runs for a 1980 power on line data are presented in Table 8.7.

As expected there is a relatively large change in the cost of power for the coal steam turbine and the hydroelectric cases. The change in cost is especially large in the hydroelectric case since the reduction in power production occurs early in the plant lifetime and the present worth analysis employed in the levelizing procedure causes power costs occurring early in the plant lifetime to be weighted more heavily than later costs.

TABLE 8.7. Changes in Levelized Cost of Power Due to Changes in Plant Utilization Factor

Life-Cycle Plant Utilization Factor	Steam Turbine (Case 11)	Gas Combined Cycle (Case 19)	Hydro (Case 42)
Low	74.47	75.20	51.42
Base	70.89	72.71	37.13
High	62.28	71.03	--

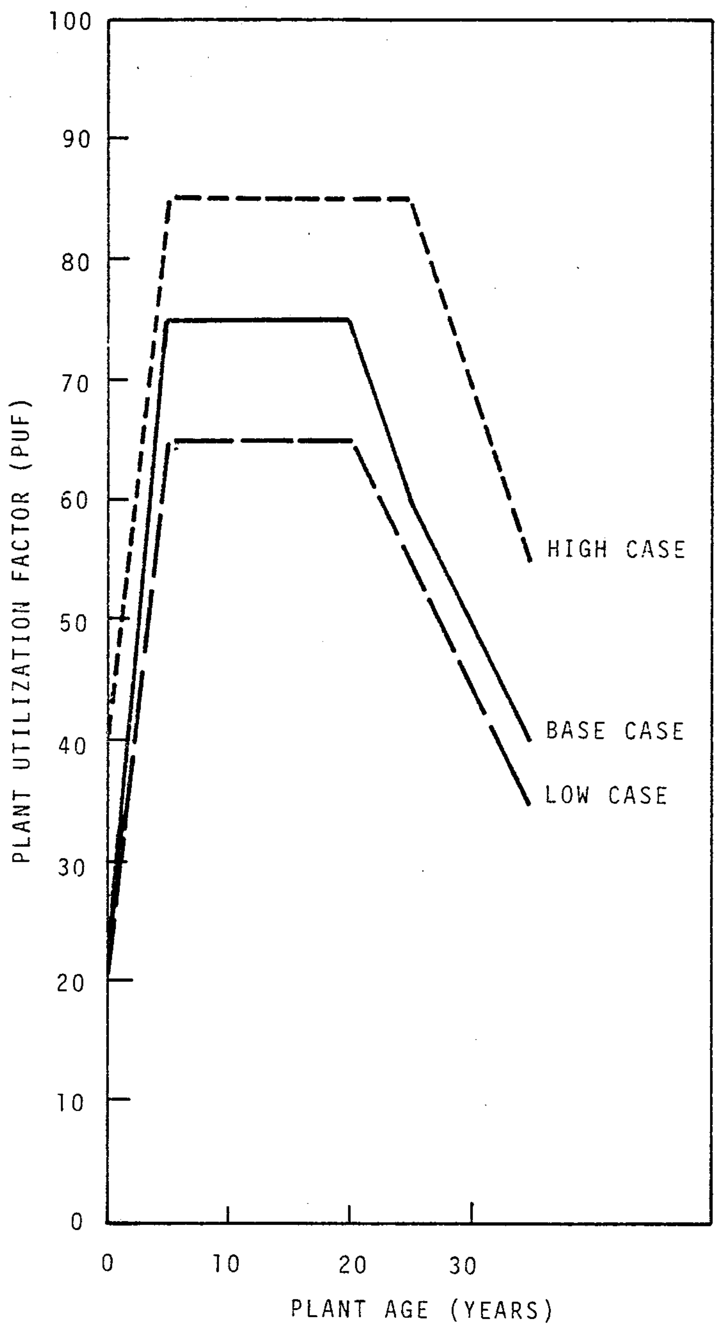

FIGURE 8.3. Alternative Plant Utilization Factors for Coal Steam Turbine Generating Units (Case 11)

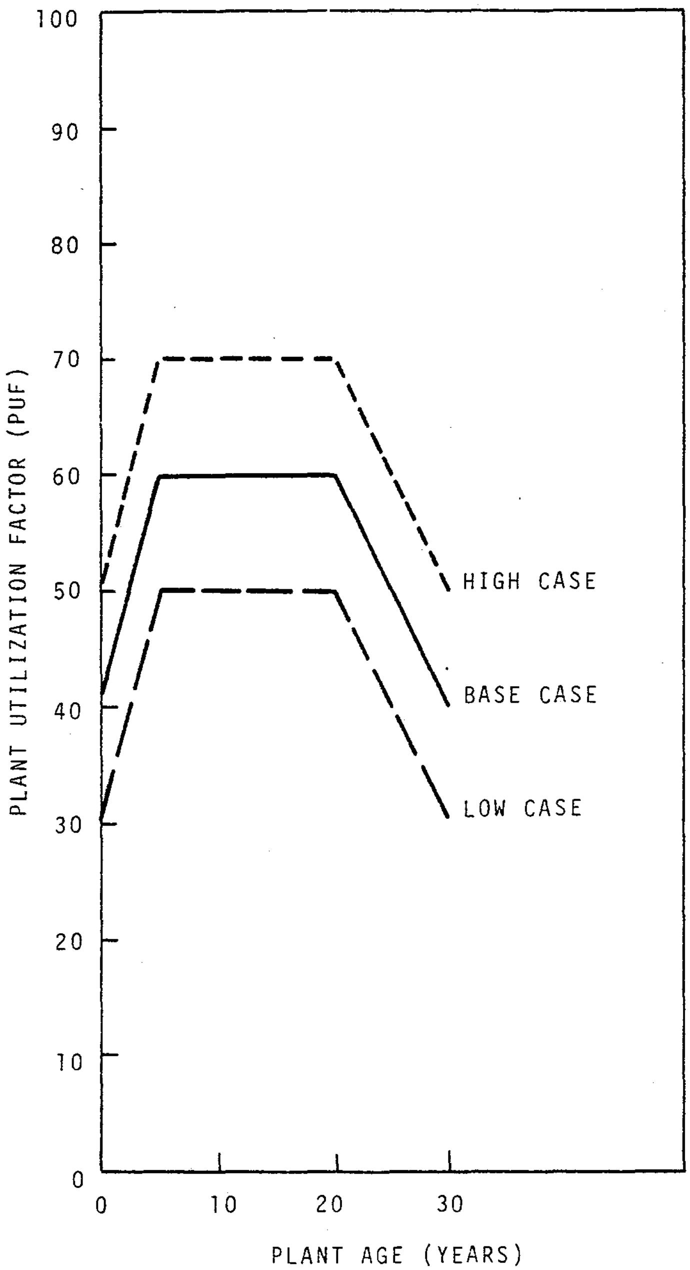

FIGURE 8.4. Alternative Plant Utilization Factors for Gas Combined Cycle Generating Units (Case 19)

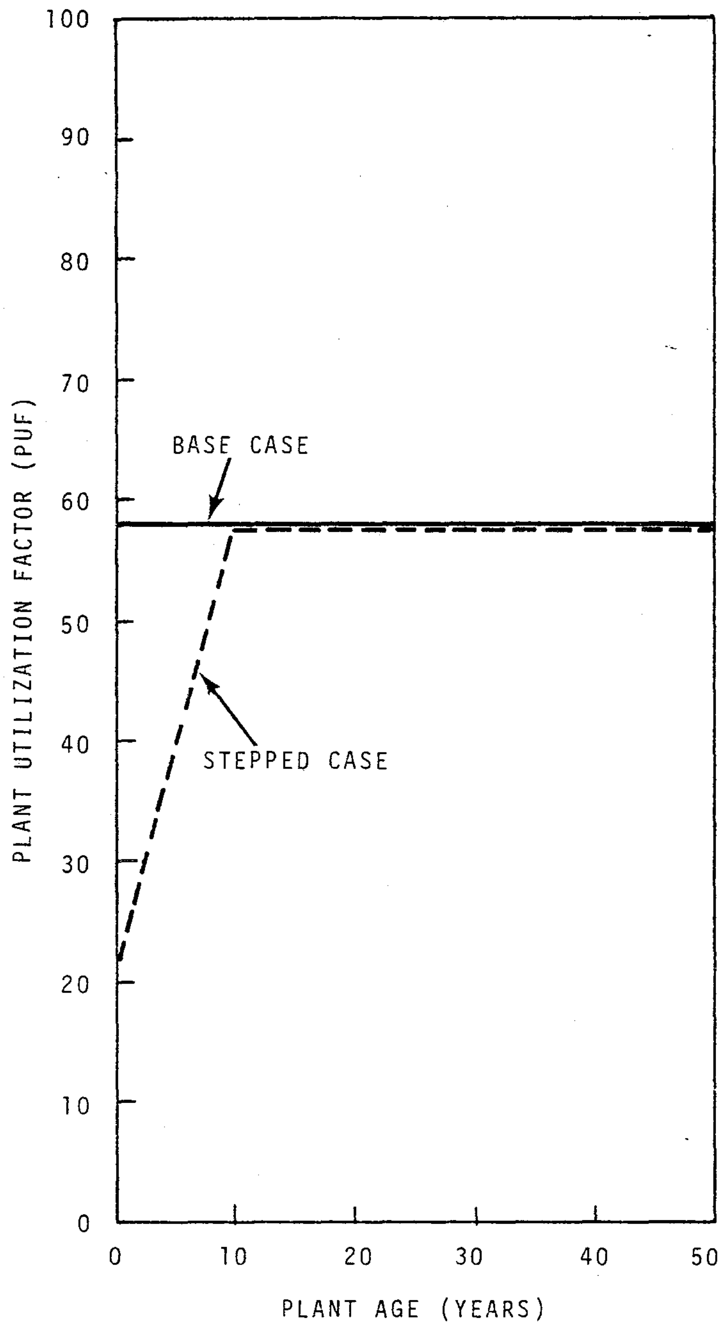

FIGURE 8.5. Alternative Plant Utilization Factors for Watana Hydroelectric Generating Plant

Relationship Between Reserve Capacity and the Cost of Power

As discussed earlier in Section 4.4 there is a tradeoff between security of supply and the cost of power. Security of supply is measured here in terms of reserve capacity. A larger reserve capacity makes it less likely that a generating system will not be able to meet peak power demands. On the other hand, this additional capacity must be paid for through increased power costs. The purpose of this section is to establish a relationship between security (as measured by reserve capacity) and the bus bar cost of electricity.

As shown in Figure 4.11 this curve will be an upward sloping line. However, the exact relationship depends upon the mix of generating capacity available. In this section two cases are evaluated; a case where the entire generating system is composed of coal steam turbine units (while this is unlikely it provides an interesting contrast) and a case where the entire generating system is composed of combined cycle units. (The steam turbine case was done using data for Case 11 and the combined cycle case used data for Case 19). The results of the analysis is shown in Figure 8.6.

In most cases utilities attempt to maintain reserve capacities in the 10 to 20% range. Increasing the reserve capacity from 10 to 20% increases the cost of power by about 4% for the coal steam turbine case and by about 1.4% for the combined cycle case. Increasing the reserve capacity from 10 to 30% increases the cost of power by about 11% for the coal steam turbine case and by about 3% for the combined cycle case.

As mentioned earlier in Section 4.4 the determination of the benefits of service security is beyond the scope of this study. However, the relationships presented in this section provide estimates of the costs of power as a function of reserve capacity which provides a basis for a more complete analysis.

Sensitivity of Cost of Power to Changes in the Social Discount Rate

As discussed in Section 9.2 the rate of which future expenditures are discounted can be critical to the choice of projects. A social discount rate is used when computing the levelized cost of power over the lifetime of the

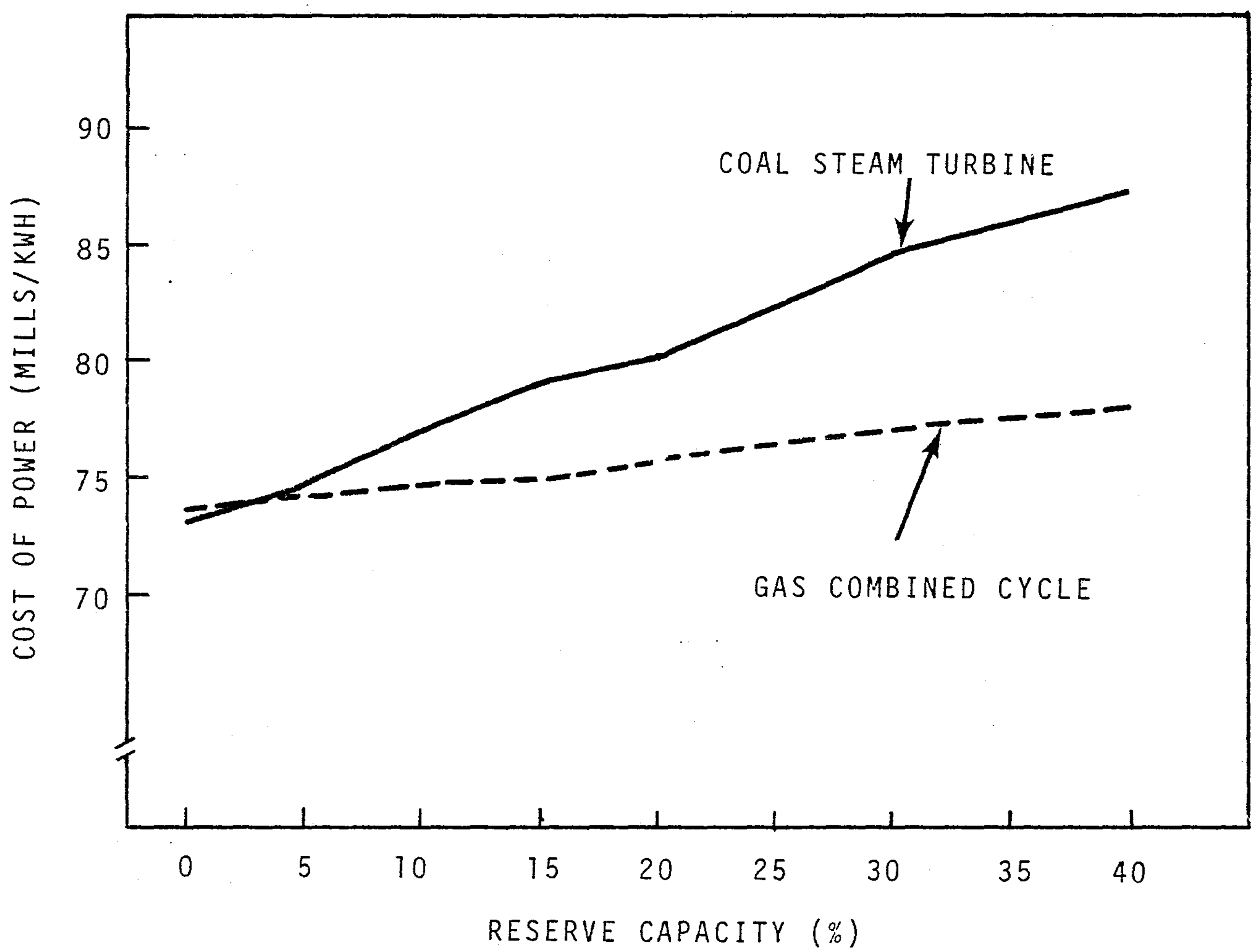

FIGURE 8.6. Cost of Power Versus Reserve Capacity

plant given the total annual costs and annual power production (see Section 7.2). The purpose of this section is to estimate the sensitivity of the cost of power to changes in the social discount rate.

As implied by the term "discount rate" a discount rate has the effect of discounting future costs or benefits at a certain rate. A higher discount rate will have the effect of discounting future costs more than a lower discount rate. Because of this, using a higher discount rate will have the effect of lowering the levelized cost of power since future costs are discounted at a higher rate. For the same reason changing the social discount rate will have a greater effect on the cost of power from generating plants with annual costs that increase more rapidly over time than for plants with annual costs that increase less rapidly over time. Based on this reasoning the levelized cost of power from coal steam turbine facilities should be more sensitive to changes in the social discount rate than hydroelectric generating facilities.

A social discount rate of 0.064% is used in this analysis. To test the sensitivity of the cost of power to changes in the social discount rate additional ECOST2 model runs were made. Alternate social discount rates of 0.050 and 0.075 were inserted into the model. The results of these runs are shown in Table 8.8. As expected the cost of power from coal steam turbine generating facilities (Case 11) are effected more than the cost of power from a hydroelectric facility (Case 42).

Changing the social discount rate from 0.064% to 0.050% or 0.075% represents a 20% variation. For Case 11 this 20% change results in a 2.5% to 4.0% change in the cost of power. For Case 42 this change results in a 0.1% to 0.2% change in the cost of power.

Based on this analysis it can be concluded that the results of the cost of power computations are relatively insensitive to changes in social discount rate compared to other model parameters listed earlier in Section 8.4.1.

8.5 DESCRIPTION OF LOAD RESOURCE ANALYSES

This section undertakes the matching of future power requirements (loads) with existing, already planned, and potential future generation resources as yet unscheduled. Since the Railbelt region is not presently interconnected

TABLE 8.8. Sensitivity of Cost of Power to Changes in the Social Discount Rate (4% Inflation Assumed)

Social Discount Rate	Case 11 Cost of Power	Case 11 % Change	Case 42 Cost of Power	Case 42 % Change
0.050	73.72		37.20	
		3.99		0.2
0.064	70.89		37.13	
		2.58		0.1
0.075	69.06		37.09	

and may not be so for a number of years, it is necessary to address both the two separate load centers (Fairbanks-North Star Borough, and Cook Inlet) separately and a combined or transmission intertied system that may be appropriate at some time in the future. One of the benefits of an intertied system is the reduction of the amount of total installed generating capacity necessary to maintain a desired degree of reliability of supply. A correlative benefit may be reduced energy costs to the consumer as plants may operate at higher load factors.

Load/resource matching, as well as taking into account load growth and existing or planned resources, must recognize the nature of the generation resources. For example, the National Defense (military) resources at both Anchorage and Fairbanks are interconnected with the utility systems primarily for reliability reasons and not necessarily for supplying average annual energy needs. Thus the National Defense resources reasonably can be included in net resources available for peak load reliability consideration but not for average annual energy. Industrial self-generation is small and may be interconnected to a minor degree but is not considered as a factor in the reserve margin required by the future utility systems.

Both the Anchorage/Cook Inlet and Fairbanks load centers are strongly winter peaking to the extent that system load factors run at about 50%. As a consequence, if adequate resources are available to meet forecasted peak loads, average annual energy requirements can be met. These load-resource analyses are therefore based on loads at peak.

The general approach to analysis is to summarize existing and planned gross resources for each year, adjust them downward for a reliability margin and for system transmission losses to arrive at net resources. If these net resources exceed the critical period peak load for the year being analyzed, plant additions are not called up and the analysis proceeds to the next year critical period and is repeated. At some point, the net resources will not meet the forecasted peak loads and additional capacity must be added in the previous year. The selection of the size of capacity to be added requires a detailed analysis that is beyond the scope of this study. Larger units benefit from economies of scale but if too large, may necessitate upward adjustment of reserve requirements. Site-specific factors would come into play in such a detailed analysis.

The reserve capacity margin desired (to be deducted from gross resources) varies with system configuration. For purposes of these analyses, we have assumed 20% of peak load or the largest single unit, whichever value is larger, for the separate load centers and 15% or largest single unit for an intertied system. This reduction in reserve margin is based on a presumption of some benefits accruing from increased load diversity and a more detailed analysis should be made prior to adopting it. Also, if and when Upper Susitna hydropower comes on-line with a twined transmission intertie and Susitna power becomes more dominant in the system, (i.e., in excess of ~400 MW) a more detailed analysis should be performed to evaluate the impacts of transmission system reliability.

System losses must also be deducted from gross resources at peak. We have assumed losses at 10% of peak load for separated load centers and 5% for a larger intertied system where fuller compensation may be applied. This is not a conservative assumption and should receive a more detailed analysis as system planning progresses.

The following sections address load-resource matching for the Fairbanks, Cook Inlet, and combined load centers. Separate load centers are carried through the planning time horizon (2000) as a means of assessing the consequences of not developing Upper Susitna hydropower or the intertie, i.e, how much thermal generating resources might be needed if Upper Susitna development does not proceed.

The tracking of the potential future capacity addition steps versus the utility planned addition steps with the forecasted peak load growth curves is an indication of the degree of conservatism used in these analyses, i.e., we have used minimum plant addition scenarios. The utilities also carry an additional subjective reserve in their plans recognizing that plant slippages may occur.

We have also not factored in any plant retirements. Obviously good system management would utilize all available resources in a manner to achieve minimum net power cost. As soon as lower cost hydro or thermalpower becomes available, more costly to operate plants would be put on standby reserve and ultimately retired from service completely. Such analyses are beyond the scope of this work as detailed knowledge of each plant's history and operating performance would be necessary. Such analyses should be incorporated into the next phase of system planning.

Also in these analyses, we have not considered the Bradley Lake (70 MW) or the Chakachamna (366 MW) hydroelectric options and have instead centered on the Upper Susitna projects as reasonable "bogies." Chackachamna (based on information available) might afford reasonable cost power. However, the data is probably less than "reconnaissance grade" and substantial escalation might result. Uncertainty is also introduced by the proposal for Lake Clark National Park.

Bradley Lake would be a small and relatively expensive addition (but less costly than thermal) relative to the expected load growth rates. It should not be dismissed however as it obviously would strengthen the reliability of the southern end of the Railbelt region system. Additional study is warranted.

8.5.1 Fairbanks-North Star Borough Load-Resource Analysis

Tables 8.9 and 8.10 summarize load-resource computations for the above region. Area loads are based on the Susitna study midrange case and ISER Case 4 (limited) peaks (see Table 4.4 and 4.9, page 4.10 and 4.19) with a constant 45 MW National Security load added. The results of the analysis is also plotted in Figure 8.7.

Assuming no retirements of existing capacity, the utilities hope to be able to avoid installation of the North Pole -3 unit through conservation measures. This path would make the Healy-2 unit the next addition with power costs possibly lower than would be the case for North Pole-3. Also, a reserve margin of 20% for the Fairbanks area may be insufficient as the consequences of a significant outage be could be more severe than in more temperate climates.

AREA: Fairbanks/No. Star Borough. CASE: Probable Low. Figures are in Annual Peak in Megawatts.[a]

CRITICAL PERIOD	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
Requirements																							
Area Peak Loads[g]	140	146	153	160	167	175	182	190	200	210	219	225	235	247	258	270	280	292	305	320	335	350	364
Resources[b]																							
Existing																							
Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Steam/Elec.	94	94	94	94	94	94	94	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224	224
Comb. Turbine	137	209	209	216	216	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316	316
Diesel	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
TOTAL EXISTING	276	350	350	357	357	457	457	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587
Planned Addn.	65	-	7[e]	-	100[d]	-	130[f]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	350	350	357	357	457	457	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587	587
Reserve Req.(c)	70	70	70	70	100	100	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Losses @ 10%	14	15	15	16	17	18	18	19	20	21	22	23	24	25	26	27	28	29	30	32	34	35	36
Net Resources	266	265	272	271	340	339	439	438	437	436	435	434	433	432	431	430	429	428	427	425	423	422	421
Surplus (Deficit)	126	119	119	113	173	167	257	248	237	226	216	209	193	185	173	160	149	136	122	105	88	72	57
TOTAL RESOURCES	226	265	272	271	340	339	439	438	437	436	435	434	433	432	431	430	429	428	427	425	423	422	421
SURPLUS (DEFICIT)	126	119	119	111	173	164	257	248	237	226	216	209	193	185	173	160	149	136	122	105	88	72	57

(a)Values may not add due to rounding.
(b)Resources available for peak include National Defense resources but not industrial.
(c)Reserve requirements on peak valued at largest single unit or 20% of load whichever is higher.
(d)Addition of North Pole #3 - 100 MW R.C.C.T.
(e)7 MW Combustion turbine returned from on loan to HMUS.
(f)Healy #2 @ 130 MW on line 1983.
(g)National Defense peak load assumed to be 45 MW and constant.
(h)Losses taken at 10% of peak load.

TABLE 8.9. Load-Resource Analysis - Fairbanks/ N.S. Borough - Low

AREA: Fairbanks/No. Star Borough. CASE: Probable High. Figures are in Annual Peak in Megawatts.[a]

CRITICAL PERIOD	77-78	78-79	79-80	80-81	81-82	82-83	33-84	84-85	85-86	86-87	87-88
Requirements											
Area Peak Loads	164	180	195	210	223	237	252	267	280	295	309
Resources[b]											
Existing											
Hydro	-	-	-	-	-	-	-	-	-	-	-
Steam/Elec.	94	94	94	94	94	94	94	224	224	224	224
Comb. Turbine	137	209	209	216	216	316	316	316	316	316	316
Diesel	47	47	47	47	47	47	47	47	47	47	47
TOTAL EXISTING	276	350	350	357	357	457	457	457	457	457	457
Planned Addn.	65	-	7[e]	-	100[d]	-	130[f]	-	-	-	-
Gross Resources	350	350	357	357	457	457	587	587	587	587	587
Reserve Req.(c)	70	70	70	70	100	100	130	130	130	130	130
Losses @ 10% (h)	16	18	20	21	22	24	25	27	28	30	31
Net Resources	264	262	267	266	335	333	432	430	429	427	426
Surplus (Deficit)	110	82	72	56	112	96	180	163	149	132	117
Potential Future Resources											
Plant A	-	-	-	-	-	-	-	-	-	-	-
Plant B	-	-	-	-	-	-	-	-	-	-	-
Plant C	-	-	-	-	-	-	-	-	-	-	-
Plant D	-	-	-	-	-	-	-	-	-	-	-
Reserve Adjust.											
TOTAL RESOURCES	264	262	267	266	335	333	432	430	429	427	426
SURPLUS (DEFICIT)	110	82	72	56	112	96	180	163	149	132	117

CRITICAL PERIOD	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-200
Requirements												
Area Peak Loads	323	342	360	380	405	430	465	500	545	600	675	800
Resources[b]												
Existing												
Hydro	-	-	-	-	-	-	-	-	-	-	-	-
Steam/Elec.	224	224	224	224	224	224	224	224	224	224	224	224
Comb. Turbine	316	316	316	316	316	316	316	316	316	316	316	316
Diesel	47	47	47	47	47	47	47	47	47	47	47	47
TOTAL EXISTING	457	457	457	457	457	457	457	457	457	457	457	457
Planned Addn.	-	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	587	587	587	587	587	587	587	587	587	587	587	587
Reserve Req.(c)	130	130	130	130	130	130	130	130	130	130	135	160
Losses @ 10% (h)	32	34	36	38	40	43	47	50	55	60	68	80
Net Resources	425	423	421	419	417	414	410	407	402	397	384	347
Surplus (Deficit)	102	81	61	39	12	(16)	(55)	(93)	(143)	(203)	(291)	(453)
Potential Future Resources												
Plant A	-	-	-	-	-	100	100	100	100	100	100	100
Plant B	-	-	-	-	-	-	-	-	100	100	100	100
Plant C	-	-	-	-	-	-	-	-	-	100	100	100
Plant D	-	-	-	-	-	-	-	-	-	-	-	200
Reserve Adjust.												40
TOTAL RESOURCES	425	423	421	419	417	514	510	507	602	697	684	807
SURPLUS (DEFICIT)	102	81	61	39	12	84	45	7	57	97	9	7

(a)Values may not add due to rounding.
(b)Resources available for peak include National Defense resources.
(c)Reserve requirements on peak valued at largest single unit or 20% of load whichever is higher.
(d)Addition of North Pole #3 - 100 MW R.C.C.T.
(e)7MW Combustion turbine returned from on loan to HMUS.
(f)Healy #2 @ 130 MW on line 1983.
(g)See Appendix A, Figure A-5. National Defense peak load assumed to be 45 MW and constant.
(h)Losses taken at 10% of peak load.
(i)Adjustment for largest single unit in system.

TABLE 8.10. Load-Resource Analysis - Fairbanks/ N.S. Borough - High

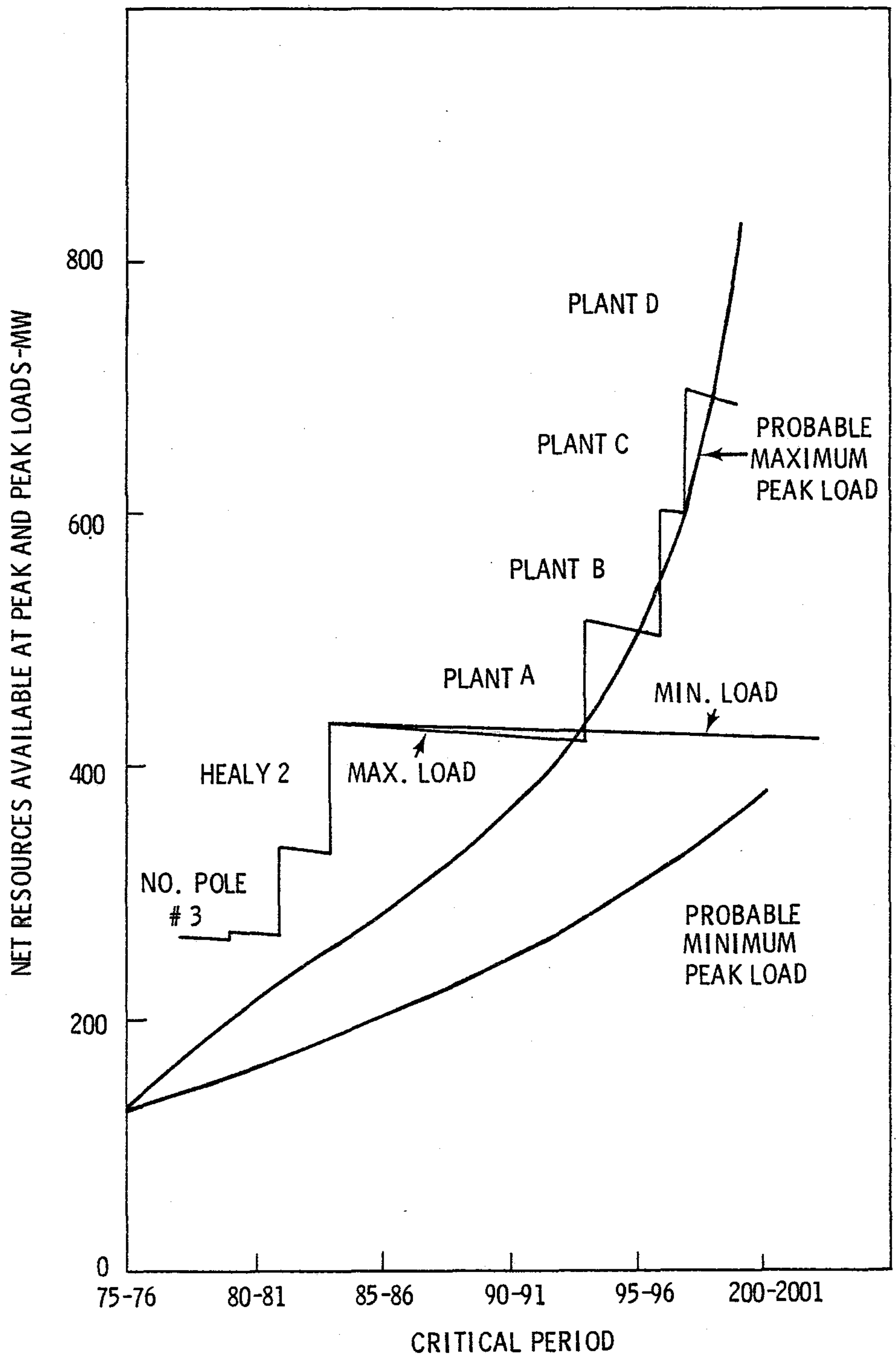

FIGURE 8.7. Load-Resource Analysis, Fairbanks-North Star Borough

The North Pole Unit #3 combustion turbine at 70 to 100 MW scheduled for 1981 may not however be qualifiable under the National Energy Policy unless it can be shown as needed for peaking service. If it is not certifiable, the Healy-2 unit as scheduled could take up the slack. Alternatively FMUS's Chena-6 (23.5 MW) and GVEA's Fairbanks and North Pole Units 1 and 2 (total 180 MW) could be upgraded to combined cycle operation and stay within the law. Further analysis is warranted.

In summary, the Fairbanks-North Star Borough region could hold capacity addition commitments for a few years and possibly make it through without North Pole 3 to the availability of Healy-2 and Upper Susitna power. Combined cycle or otherwise upgrading of existing capacity is another option that could be explored.

8.5.2 Anchorage/Cook Inlet/Kenai Region

Tables 8.11 through 8.12 summarize the peak load resource computations for the above region for low and high range forecasts respectively. The results are also plotted in Figure 8.8 through 8.9 for low and high range forecasts respectively. National Security loads are included based on 50 MW peak. Industrial resources and loads are not included. Loads are based on ISER Cases 2L and 4L adjusted to the Railbelt region.

Under the "probable minimum" forecast case (Table 8.11), and assuming utility plans are met, the region will not enter a deficit situation until 1988-89. At which time some thermal capacity (∿400 MW) will be needed assuming Upper Susitna hydropower is not available at that time. After 1991, Watana-1 is called up in 1992 (assuming the Fairbanks area does not require a share) on through to two Devil Canyon units before the turn of the century. If the Upper Susitna projects do not proceed, about 1000 MW of additional thermal capacity will be necessary by the turn of the century.

Under the "probable maximum" forecast case (Table 8.12 and Figure 8.9) and again assuming current plans are met, the region is in a deficit situation now and will continue to be so through the 1984 planning horizon of the utilities. After that, the situation will worsen rapidly unless new plants are brought on-line.

AREA: Anchorage/Cook Inlet. CASE: Probable Minimum. Figures are in Annual Peak in Megawatts.[a]

CRITICAL PERIOD	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88
Requirements											
Area Peak Loads	425	460	495	540	580	630	680	730	790	860	925
Resources[b]											
Existing											
Hydro	47	47	47	47	47	47	47	47	47	47	47
Steam/Elec.	60	60	60	60	60	60	60	60	460	460	460
Comb. Turbine	438	499	565	672	771	789	889	889	907	907	907
Diesel	20	20	20	20	20	20	20	20	20	20	20
TOTAL EXISTING	564	625	691	799	898	916	1016	1016	1434	1434	1434
Planned Addn.	61	66	107	99	18	100	-	418[d]	-	-	-
Gross Resources	625	691	799	898	916	1016	1016	1434	1434	1434	1434
Reserve Req.(c)	85	92	99	108	116	126	136	400	400	400	400
Losses @ 10%	43	46	50	54	58	63	68	73	79	86	93
Net Resources	497	553	650	736	742	827	812	961	955	948	941
Surplus (Deficit)	72	93	155	196	162	197	132	231	165	88	16
Potential Future Resources											
Plant A	-	-	-	-	-	-	-	-	-	-	-
Watana 1	-	-	-	-	-	-	-	-	-	-	-
Watana 2	-	-	-	-	-	-	-	-	-	-	-
Watana 3	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 1	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 2	-	-	-	-	-	-	-	-	-	-	-
TOTAL RESOURCES	497	553	650	736	742	827	812	961	955	948	941
SURPLUS (DEFICIT)	72	93	155	196	162	197	132	231	165	88	16

CRITICAL PERIOD	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
Requirements												
Area Peak Loads	1000	1090	1180	1270	1380	1490	1620	1750	1850	1960	2050	2150
Resources[b]												
Existing												
Hydro	47	47	47	47	47	47	47	47	47	47	47	47
Steam/Elec.	460	460	460	460	460	460	460	460	460	460	460	460
Comb. Turbine	907	907	907	907	907	907	907	907	907	907	907	907
Diesel	20	20	20	20	20	20	20	20	20	20	20	20
TOTAL EXISTING	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434
Planned Addn.	-	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434
Reserve Req.(c)	400	400	400	400	400	400	400	400	400	400	410	430
Losses @ 10%	100	109	118	127	138	149	162	175	185	196	205	215
Net Resources	934	925	916	907	896	885	872	859	849	838	819	789
Surplus (Deficit)	(66)	(165)	(264)	(363)	(484)	(605)	(748)	(891)	(1001)	(1122)	(1231)	(1361)
Potential Future Resources												
Plant A	400	400	400	400	400	400	400	400	400	400	400	400
Watana 1	-	-	-	-	235	235	235	235	235	235	235	235
Watana 2	-	-	-	-	-	-	235	235	235	235	235	235
Watana 3	-	-	-	-	-	-	-	235	235	235	235	235
Devil Canyon 1	-	-	-	-	-	-	-	-	-	170	170	170
Devil Canyon 2	-	-	-	-	-	-	-	-	-	-	-	170
TOTAL RESOURCES	1334	1325	1316	1307	1531	1520	1742	1964	1954	2113	2094	2234
SURPLUS (DEFICIT)	334	235	136	37	151	30	122	214	104	153	40	84

(a)Figures may not add due to rounding.
(b)Resources available for peak include National Defense resources but not industrial.
(c)Reserve requirements on peak valued at largest single unit or 20% of load whichever is higher.
(d)CEA 400 MW "Coal-1".

TABLE 8.11. Load-Resource Analysis - Anchorage/Cook Inlet - Low

AREA: Anchorage/Cook Inlet. CASE: Probable Maximum. Figures are in Annual Peak in Megawatts.[a]

	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88	88-89
Requirements												
Area Peak Loads	505	575	640	710	760	850	930	1020	1110	1200	1300	1410
Resources[b]												
Existing												
Hydro	47	47	47	47	47	47	47	47	47	47	47	47
Steam/Elec.	60	60	60	60	60	60	60	60	460	460	460	460
Comb. Turbine	438	499	565	672	771	789	889	889	907	907	907	907
Diesel	20	20	20	20	20	20	20	20	20	20	20	20
TOTAL EXISTING	564	625	691	799	898	916	1016	1016	1434	1434	1434	1434
Planned Addn.	61	66	107	99	18	100	-	418(d)	-	-	-	-
Gross Resources	625	691	799	898	916	1016	1016	1434	1434	1434	1434	1434
Reserve Req.(c)	101	115	128	142	152	170	186	400	400	400	400	400
Losses @ 10%	51	58	64	71	76	85	93	102	111	120	130	141
Net Resources	473	518	607	685	688	761	737	932	923	914	904	893
Surplus (Deficit)	(32)	(57)	(33)	(25)	(72)	(89)	(193)	(88)	(187)	(286)	(396)	(517)
Potential Future Resources												
Plant A	-	-	-	-	-	-	400	400	400	400	400	400
Plant B	-	-	-	-	-	-	-	-	-	-	-	400
Watana 1	-	-	-	-	-	-	-	-	-	-	-	-
Watana 2	-	-	-	-	-	-	-	-	-	-	-	-
Watana 3	-	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 1	-	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 2	-	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 3	-	-	-	-	-	-	-	-	-	-	-	-
Devil Canyon 4	-	-	-	-	-	-	-	-	-	-	-	-
Plant C	-	-	-	-	-	-	-	-	-	-	-	-
Plant D	-	-	-	-	-	-	-	-	-	-	-	-
Reserve Adjust.							214					
TOTAL RESOURCES	473	518	607	685	688	761	923	1332	1323	1314	1304	1693
SURPLUS DEFICIT	(32)	(57)	(33)	(25)	(72)	(89)	(7)	312	213	114	4	283

	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
Requirements											
Area Peak Loads	1530	1650	1790	1930	2070	2230	2400	2600	2800	3010	3260
Resources[b]											
Existing											
Hydro	47	47	47	47	47	47	47	47	47	47	47
Steam/Elec.	460	460	460	460	460	460	460	460	460	460	460
Comb. Turbine	907	907	907	907	907	907	907	907	907	907	907
Diesel	20	20	20	20	20	20	20	20	20	20	20
TOTAL EXISTING	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434
Planned Addn.	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434	1434
Reserve Req.(c)	400	400	400	400	414	446	480	520	560	602	652
Losses @ 10%	153	165	179	193	207	223	240	260	280	301	326
Net Resources	881	870	855	841	813	765	714	654	594	531	456
Surplus (Deficit)	(649)	(780)	(935)	(1089)	(1257)	(1465)	(1686)	(1946)	(2206)	(2479)	(2804)
Potential Future Resources											
Plant A	400	400	400	400	400	400	400	400	400	400	400
Plant B	400	400	400	400	400	400	400	400	400	400	400
Watana 1	-	-	235	235	235	235	235	235	235	235	235
Watana 2	-	-	-	235	235	235	235	235	235	235	235
Watana 3	-	-	-	-	-	235	235	235	235	235	235
Devil Canyon 1	-	-	-	-	-	-	170	170	170	170	170
Devil Canyon 2	-	-	-	-	-	-	170	170	170	170	170
Devil Canyon 3	-	-	-	-	-	-	-	170	170	170	170
Devil Canyon 4	-	-	-	-	-	-	-	-	170	170	170
Plant C	-	-	-	-	-	-	-	-	400	400	400
Plant D	-	-	-	-	-	-	-	-	-	-	400
Reserve Adjust.											
TOTAL RESOURCES	1681	1670	1890	2111	2083	2270	2559	2669	3179	3116	3441
SURPLUS DEFICIT	151	20	100	181	13	40	152	69	379	106	181

(a) Figures may not add due to rounding.
(b) Resources available for peak include National Defense resources but not industrial.
(c) Reserve requirements on peak valued at largest single unit or 20% of load whichever is higher.
(d) CEA 400 MW "Coal-1".

TABLE 8.12. Load-Resource Analysis - Anchorage/ Cook Inlet - High

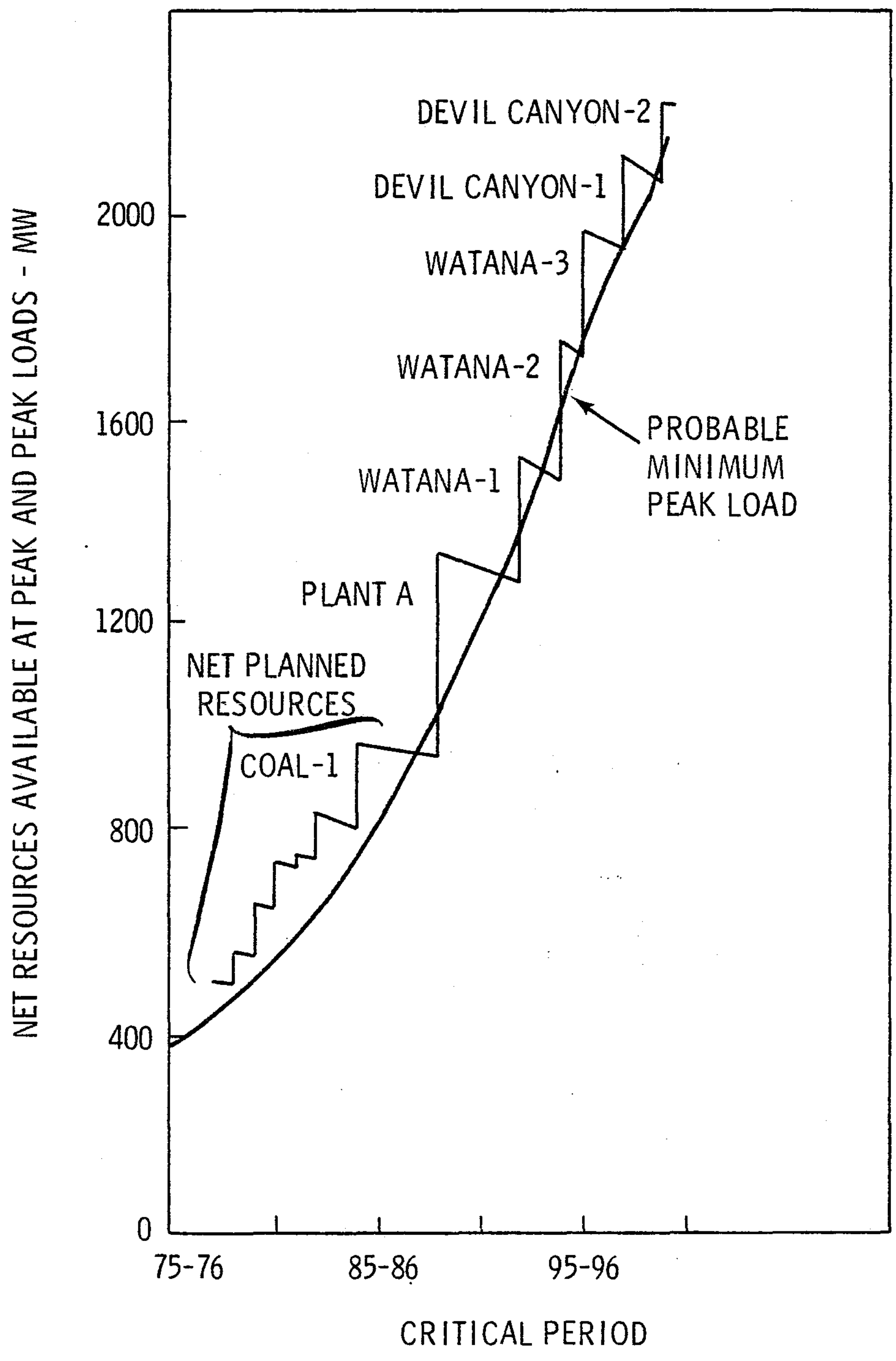

FIGURE 8.8. Load-Resource Analysis, Anchorage/Cook Inlet/Kenai - Probable Minimum Load.

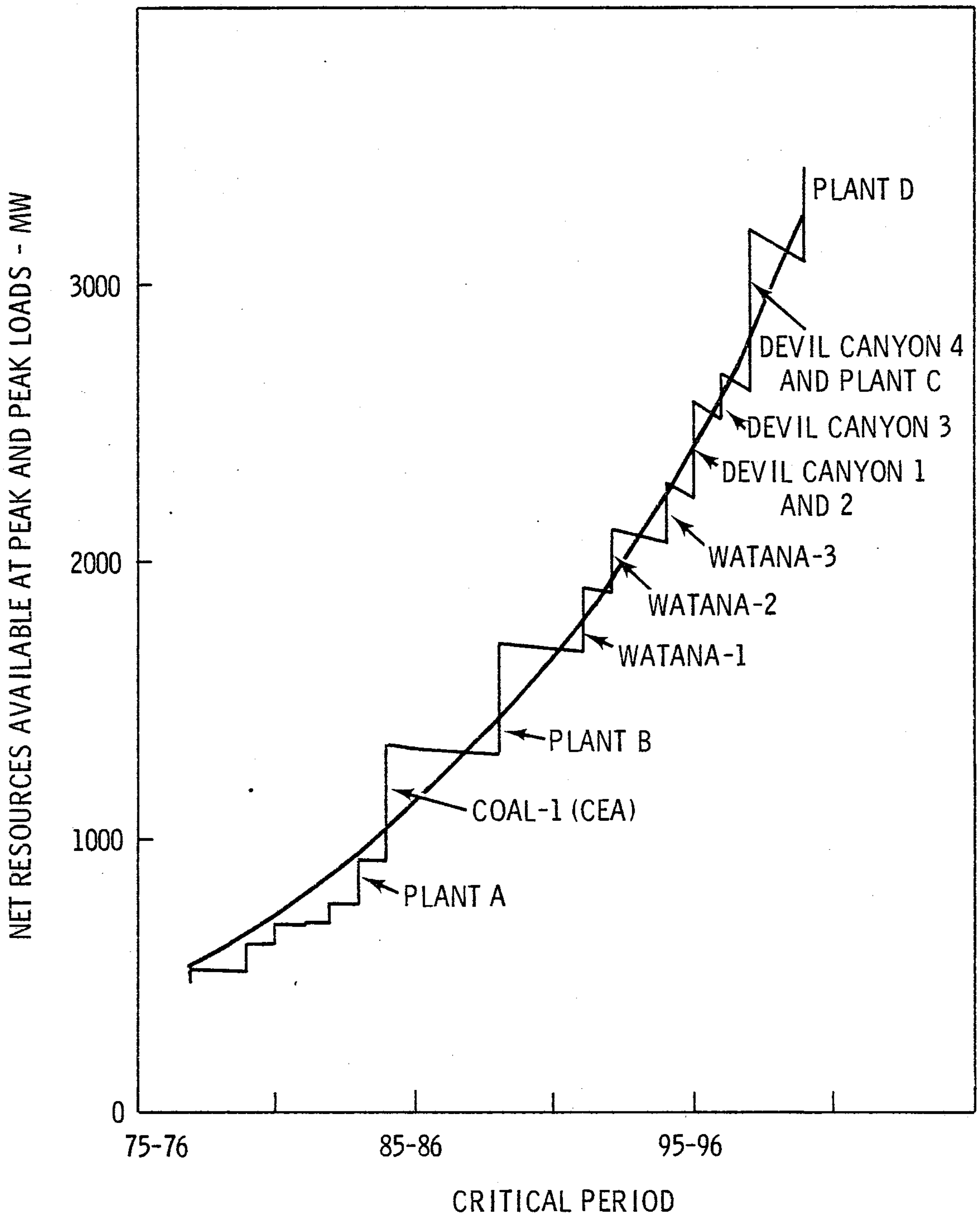

FIGURE 8.9. Load Resource Analysis, Anchorage/Cook Inlet/Kenai - Probable Maximum Load

Between now and 1985-85 when CEA's Coal-1 is scheduled,[a] considerable additional combustion turbine capacity is planned by AML&P and CEA. (See Table 5.2, Page 5.6). Of this added capacity, 80.9 MW (AML&P Unit-6, CEA, Beluga 8, and Beluga 9) represent upgrading of heat rates for existing units and are therefore arguably allowable under the National Energy Policy (see Section 10.0).

However, 335.5 MW represent new combustion units and their viability under the National Energy Policy may be in question unless they can be justified as peaking units, (AML&P Unit-7, Unit-6; CEA Bernice Lake #3, X-1, Bernice Lake #4, X-2, Bernice Lake #5). Since these are a substantial contribution to the system capacity (∿80% of the probable 1977-78 peak loads) not all may necessarily be allowable under the peaking unit provisions of the National Policy.

Between now and 1990, the only reasonably scaled alternative clearly fitting within National policy and given the likely lead time for siting, approvals, and construction (total ∿six yr), the earliest new plant could meet the 1983-84 critical period <u>if started now</u>.

Under this "probable maximum" scenario thermal additions, beyond those planned, total 1600 MW by the turn of the century <u>if</u> Upper Susitna hydropower is available. If the latter does not proceed, an additional 1385 MW of thermal capacity will be required. Unfortunately 400 of these MWs are called for only a few years prior to hydropower availability.

Again under a "probable maximum" scenario, the reliability of the south end of the Railbelt is hard pressed. Thus load growths should be monitored carefully and the development of a contingency plan for rapid upgrading of existing plant heat rates is recommended to the extent allowable.

8.5.3. <u>Combined Railbelt System</u>

Tables 8.13 and 8.14 summarize load-resource computations for the combined system for "probable minimum" and "probable maximum" peak load forecasts respectively. The results are also plotted in Figure 8.10.

(a) Note added in proof: CEA's plans now call for coal fired plant additions of 200 MW each in 1985 and 1986

AREA: Railbelt Combined. CASE: Probable Minimum. Figures are in Annual Peak in Megawatts.[a]

CRITICAL PERIOD	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
Requirements																							
Area Peak Loads	445	495	560	610	680	750	830	930	1020	1140	1270	1400	1550	1670	1740	1800	1880	1950	2050	2110	2200	2290	2380
Resources[b]																							
Existing																							
Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Steam/Elec.	154	154	154	154	154	154	154	284	684	684	684	684	684	684	684	684	684	684	684	684	684	684	684
Comb. Turbine	564	564	700	767	880	1980	1098	1198	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206
Diesel	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
TOTAL EXISTING	842	975	1042	1156	1257	1374	1474	1604	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
Planned Addn.	133	67	114	100	118	100	130[d]	418[e]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	975	1042	1156	1256	1374	1474	1604	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2020	2022	2022	2022
Reserve Req.(c)	67	74	84	92	102	113	125	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Losses @ 5%	22	25	28	31	34	38	42	47	51	57	64	70	78	84	87	90	94	98	103	106	110	115	119
Net Resources	886	943	1044	1133	1238	1323	1437	1575	1571	1565	1558	1552	1544	1538	1535	1532	1528	1524	1519	1516	1512	1507	1503
Surplus (Deficit)	441	448	484	523	558	573	607	645	551	425	288	152	(6)	(132)	(210)	(268)	(352)	(426)	(531)	(594)	(688)	(783)	(877)
Potential Future Resources																							
Plant A	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200
Watana 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235	235	235	235	235	235	235
Watana 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235	235	235
Watana 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235
TOTAL RESOURCES	886	943	1044	1133	1238	1323	1437	1575	1571	1565	1558	1552	1744	1738	1970	1967	1963	1959	2189	2186	2417	2412	2408
SURPLUS (DEFICIT)	441	448	484	523	558	573	607	645	551	425	288	152	194	68	230	167	83	9	139	76	217	122	28

(a)Values may not add due to rounding.
(b)Resources available for peak include National Defense resources but not industrial.
(c)Reserve requirements on peak valued at largest single unit or 15% of load whichever is higher.
(d)Healy #2 unit addition.
(e)Includes 400 MW of coal-fired steam electric added by CEA (Coal 1).
(f)See Figure 4.2 - low curve.

TABLE 8.13. Load-Resource Analysis - Combined - Low

AREA: Railbelt Combined. CASE: Probable Maximum Figures are in Annual Peak in Megawatts.[a]

CRITICAL PERIOD	77-78	78-79	79-80	80-81	81-82	82-83	83-84	84-85	85-86	86-87	87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-2000
Requirements																							
Area Peak Loads	540	640	750	840	930	1020	1130	1250	1390	1520	1700	1880	2080	2220	2330	2450	2580	2680	2820	2970	3100	3260	3400
Resources[b]																							
Existing																							
Hydro	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Steam/Elec.	154	154	154	154	154	154	154	284	684	684	684	684	684	684	684	684	684	684	684	684	684	684	684
Comb. Turbine	564	700	767	880	1980	1098	1198	1198	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206	1206
Diesel	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
TOTAL EXISTING	842	975	1042	1156	1256	1374	1474	1604	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
Planned Addn.	133	67	114	100	118	100	130[d]	418[e]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gross Resources	975	1042	1156	1256	1374	1474	1604	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
Reserve Req.[c]	81	96	113	126	140	153	170	400	400	400	400	400	400	400	400	400	400	402	423	446	465	489	510
Losses @ 5%	27	32	38	42	47	51	57	63	70	76	85	94	104	111	117	123	129	134	141	149	155	163	170
Net Resources	867	914	1005	1088	1187	1270	1377	1559	1552	1546	1537	1528	1518	1511	1505	1499	1493	1486	1458	1427	1402	1370	1342
Surplus (Deficit)	327	274	225	248	257	250	247	309	162	26	(163)	(352)	(562)	(709)	(825)	951	(1087)	(1194)	(1362	(1543)	(1698)	(1890)	(2058)
Potential Future Resources																							
Plant A	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200	200
Plant B	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200	200
Plant C	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200	200
Plant D	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200	200	200	200	200	200	200	200	200
Watana 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235	235	235	235	235	235	235
Watana 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235	235	235	235	235
Watana 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	235	235	235	235	235
Devil Canyon 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170	170	170	170
Devil Canyon 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170	170	170
Devil Canyon 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	170	170
Devil Canyon 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-	-	170
TOTAL RESOURCES	867	914	1005	1088	1187	1270	1377	1559	1552	1546	1737	1928	2118	2311	2540	2534	2763	2756	2963	3102	3247	3385	3527
SURPLUS (DEFICIT)	327	274	225	248	257	250	247	309	162	26	37	48	38	91	210	84	183	76	143	132	147	125	127

(a)Values may not add due to rounding.
(b)Resources available for peak include National Defense resources but not Industrial.
(c)Reserve requirements on peak valued at largest single unit or 15% of load whichever is higher.
(d)Healy #2 unit addition.
(e)Includes 400 MW of coal-fired steam electric added by CEA (Coal 1).
(f)See Figure 4.2 - high curve.

TABLE 8.14. Load-Resource Analysis - Combined - High

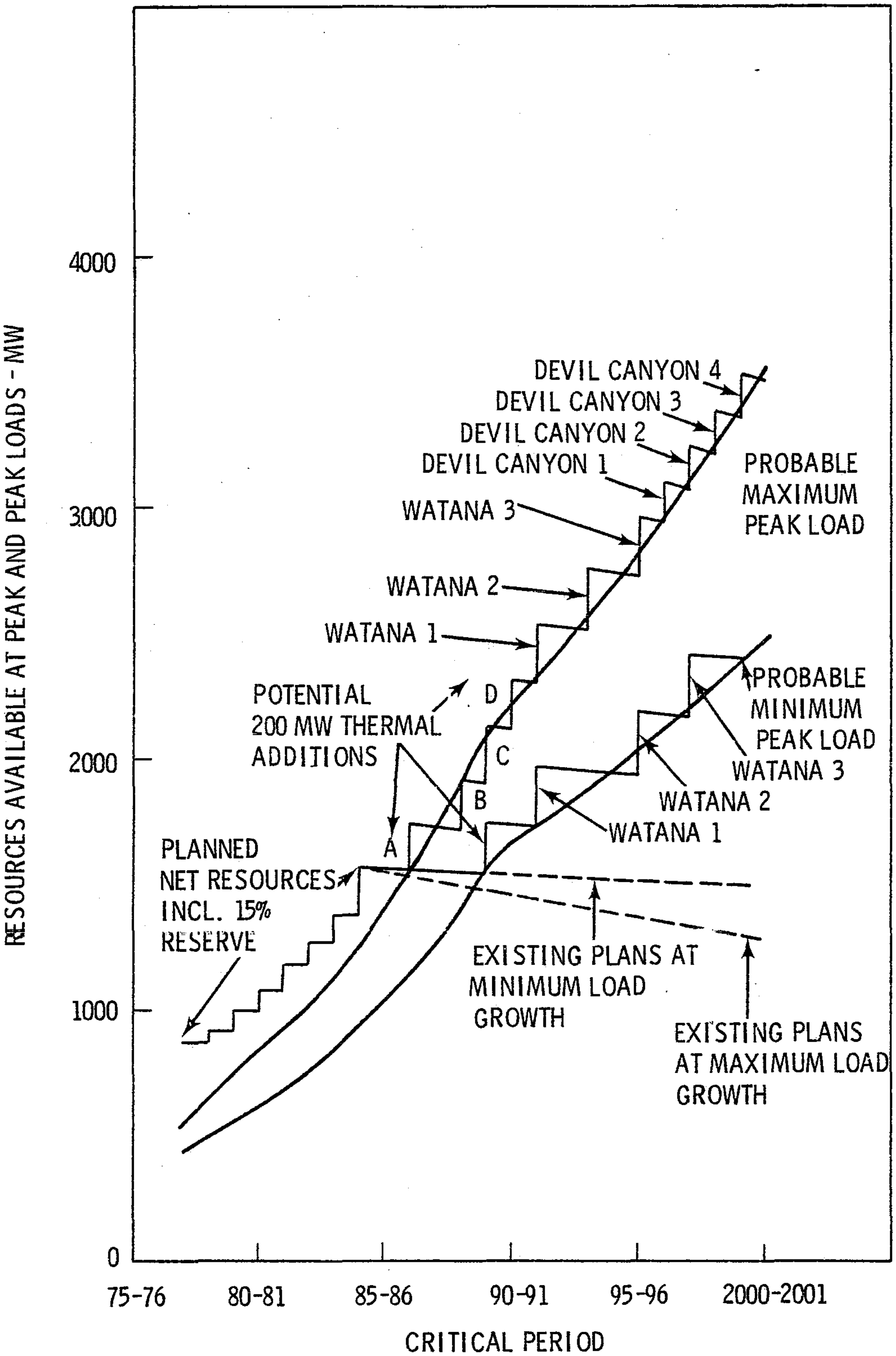

FIGURE 8.10. Load-Resource Analysis Combined Railbelt Region

The basis for the low and high load forecasts and resources is Figure 4.2 (page 4.3) with adjustments for National Defense loads and resources. Provision is also given for industrial loads we have postulated (see Figure 4.7, page 4.22). To that extent, the combined system estimate departs from the previous cases for separated load centers.

It is recognized that the load centers are not currently planned for interconnection until or if Upper Susitna hydropower could be in place (1991). However, given the apparent relative weakness of the southern Railbelt vs-a-vs the interior an earlier intertie could be beneficial and avoid the construction of at least one thermal unit. Further analysis is warranted for this as a possibility between 1987 and 1989 or even earlier. Under the "probable minimum" peak load growth scenario 200 MW of additional thermal capacity are needed by 1989 (assuring intertie by that date) and only the Watana site need be developed by 1999.

Under the "probable maximum" scenario 800 MW of additional thermal capacity are required over current plans prior to Upper Susitna hydropower availability for the 1991-92 critical period. With Upper Susitna development, the Watana and Devil Canyon units could meet loads to the turn of the century. If the Upper Susitna hydropower is not developed, approximately 1400 MW of additional thermal capacity will be required at peak for the combined region.

The authors recognize that, under the load growth conditions forecasted, when a hydroproject is placed on line a system wide power production plan may very likely call for all possible capacity from the hydro project as the first step rather than staged turbine installations. Nevertheless we have staged hydrocapacity additions as necessary to meet peak.

8.5.4 Comparison of Intertied Versus Separate Systems

With the development of the Upper Susitna hydropower, interconnection of the Railbelt is extremely logical for a number of reasons previously stated. However, it is instructive to compare the generating resource requirements (capacity) developed in the previous Sections 8.5.1-8.5.3 to estimate the net Railbelt region benefits from combined operations.

Under a scenario without intertie the peak generating resource forecasts (MW) are as follows for low and high forecasted requirements:

	1990-91 Low	1990-91 High	1995-96 Low	1995-96 High	1999-2000 Low	1999-2000 High
Fairbanks	425	430	425	510	420	810
South End	1310	1675	1965	2560	2220	3440
Total	1735	2105	2390	3070	2640	4250
Combined System	1690	2320	2190	2960	2400	3508
Net Benefit from Combined System	45	(215)	200	110	240	732

The above table suggests that the intertie benefits in terms of reducing capacity additions are quite substantial. The apparent negative net benefit in 1990-91 high is a result of our assumption that a combined system could and would support a very significant industrial load prior to 1990-91. Without that load, intertie benefits would be markedly more positive for this and succeeding years, i.e., the non-intertied values assume no assumption of industrial loads.

REFERENCES

1. Upper Susitna Hydro Power - A Plan of Study, Alaska District, U.S. Army Corps of Engineers, September 1977.

2. Upper Susitna River Basin, Interim Feasibility Report, Appendix 1, Part 2, U.S. Army Corps of Engineers, pp. 667, December 12, 1975.

9.0

9.0 ANALYSIS OF FINANCING CONSIDERATIONS AND ALTERNATIVES

9.1 SCOPE AND SUMMARY

Since a number of financing options are available for near and long term capacity additions, the following paragraphs address the cost of capital and associated financing issues and alternatives. The discussion shall begin with a general overview of the subject, the significance of the cost of capital and how it is determined. This will include the cost of state funds and the revolving fund established by virtue of the Alaska Power Authority Act of 1976. Then specific issues effecting the cost of financing the Alaska Power Authority (APA) are considered, including interest rates on state and local bonds, the impact of inflation and the "market sensitivity" of state and local bond issues. The final section will examine the relative cost of capital to the APA as compared to small municipal, rural electric cooperatives and will review alternative means of reducing the cost of capital.

In order to determine the cost of capital, it was necessary to first estimate the opportunity cost of public funds. That rate was found to be 6.4%. This figure was reduced as a common discount throughout the analysis and the cost of direct investment in power facilities. It was determined by a weighted average of the return on private investment and the time preference of the consumer. Under current institutional arrangements, it was found that the Alaska Power Authority financing was the least cost alternative. Also, the State of Alaska has other options available to it to reduce the cost of capital to utilities in the State.

9.2 DETERMINATION OF THE COST OF CAPITAL

9.2.1 An Overview of the Issue

In the economic evaluation of publicly-owned investments, the determination of the cost of capital has been an issue of considerable controversy within the economic literature.[1,2] For this reason, the subject has been included in this planning report. However, our discussion will only provide a broad overview of the subject and will be geared primarily to the practical application of the concepts.

Within economics, the common principle in determining the cost of a resource, whether it is borrowed capital or a person's labor, is the "opportunity cost" of alternative uses of the resource. That is, the cost of obtaining something is the value of what must be given up in order to obtain it. When considering the cost of capital, we think in terms of money or liquid capital and the price is expressed as an interest rate or rate of return. The opportunity costs of a $1000 investment in project A, which returns 7% is the 8% return on a $1000 investment in project B, and vice versa. The opportunity cost of an investment is the highest return on an alternative investment with comparable risk. Thus, project B would be preferred as the least cost alternative. When the amount of funds available for investment is constrained only by the capital market's willingness to supply, the decision rule for accepting projects can be simplified from the above pairwise comparision of alternatives. Projects are economically acceptable if their rate of return exceeds the cost of acquiring the capital from the intermediate markets because they are providing a net benefit to society.

The influence of the cost of capital on the overall cost of the project can be assessed by several methods.[a] In the case of selecting the type

[a] Only the method used in this analysis is discussed in the text. A brief comment on another method might be useful. In the past, the "internal rate of return" has been a frequently used method for evaluating investment projects. A project's internal rate of return is determined by finding a discount rate which equates a stream of benefits with the stream of costs. This method had the initial attraction that it does not require an _a priori_ specification of the costs of capital. However, there are several problems with the methodology. For example, there may be more than one discount rate which equates the benefit and costs. This will occur when the cash flow becomes negative at any point during the project - such as the expenses of closing a coal mine at a mine-mouth power plant. Also, the method will not consistently rank mutually exclusive projects. That is, a project which has a higher internal rate of return may have a smaller present value of some range of discount rates. The conditions for which the internal rate of return calculation will produce an unabiguous ranking of alternatives are: 1) cash flows remain positive after once becoming positive, 2) projects are mutually exclusive, and 3) the scale of the projects are fixed. A complete review of these arguments are given in Herfindahl and Kneese.(1)

of power plant, the choice of investment project is determined by the least cost alternative which produces the same benefits. However, the alternatives may have different cost streams over time. For example, hydropower plants very high initial investments but low operating costs as compared fossil fuel plants which have moderate "front end" expenditures but high operating costs. The integration of the cost of capital into the analysis by discounting (or present worthing) the expenditures will determine the overall least cost project.

The process of discounting expenditures explicitly recognizes the opportunity cost of the funds. Above, we established that the market cost of capital to the enterprise was equivalent to the opportunity cost of the funds. Suppose the opportunity costs were 10% per annum, then one dollar will be worth \$1.10 in one year. But, the process can be viewed in reverse. If you were to receive or pay \$1.10 one year from today and your opportunity cost was again 10%, the discounted value today is \$1.00. If the time frame extends over one year, the present discounted value can be determined iteratively. The calculation for the present value of any amount (x) for any time (t) with an opportunity cost of money (r) can be generalized to:

$$P.V.\ (x) = \frac{x}{(1+r)^t} \tag{1}$$

Perhaps a more concrete example will demonstrate the significance of the present value calculation to problem of selecting power plants. We shall examine a simple case of two investments, with equal benefits and economic lives of three years, further suppose the opportunity cost of capital is 10%. The cost of the projects is given in nominal dollars in Table 1. Project A requires a lower expenditure of nominal dollars \$90 as compared to \$100 for Project B. However, project A has a large initial outlay while expenditures for B are low in the early years and increase in the later years. The "life cycle" costs of project B is lower than project A after the opportunity cost of money is taken into account. Therefore, after taking into account the cost of capital, project B is preferred.

TABLE 9.1. Comparison of Nominal and Present Value Costs

Expenditures in Nominal Terms

Project	Year 0	1	2	3	Total
A	60	10	10	10	90
B	10	20	30	40	100

Present Value of Expenditures

Project	Year 0	1	2	3	Total
A	60	9.09	8.26	7.51	84.86
B	10	18.18	24.79	30.05	83.03

The concept of cost used in this analysis to evaluate alternative types of generating facilities expands upon present value of the life cycle costs. The objective is to find the least cost alternative for the planning horizon, as defined by the average cost per unit of output. To do this in a fashion that accounts for the opportunity cost of money, the average cost per kWh was calculated for each year of the plant's operation. Then, the present value of each annual cost was calculated and summed. To place this amount in the context of the traditional average annual cost per kWh, an annuity (A_i) was determined whose present value was equal to present value of the sum of the annual cost per kWh, where the subscript i represents the ith type plant.

$$P.V.\ (A_i) = \Sigma \frac{\left(\frac{C_{it}}{Q_{it}}\right)}{(1+r)^t} \qquad (2)$$

The rate at which future expenditures are discounted is critical to the choice of projects as illustrated by the simple example. Therefore, it is very important that the discount rates used reflect the true social opportunity cost of capital. This is especially the case in evaluating publically funded projects which produce private (saleable) goods. A political determined discount rate set below the opportunity cost of capital will result in a fundamental shift in resources toward the public sector without an overall improvement in social well being.

9.2.2 Choice of a Discount Rate

In a world free from market imperfections there would be no problem in determining the appropriate discount rate. The capital market would equate the supply and demand for long term capital and the resulting market rate of interest which simultaneously represented the social opportunity cost of capital and time preference of consumption. The distortions in the capital market are the results of personal and corporate income taxes, government regulation of interest rates and imperfect information. As a consequence, the social time preference represented by the after tax return on private savings is substantially less than the opportunity cost of investment determined by the pre-tax return on private investment.

Perhaps the greatest distortion in capital market is introduced by the income tax system. The tax creates a discrepancy between the social returns (pre-tax) and the after tax private which is further aggravated by the double taxation of corporate dividends. A 50% tax rate will double the social returns relative to the private returns. Additional distortions are created by "friction" in the capital market. Transaction costs of assessing the risks of projects are high and subject to economies of scale. This results in greater levels of uncertainty and an increase in the discrepancy between an individual's borrowing and lending rates of interest.

The prevailing wisdom today suggests that the appropriate method for reconciling these differences is by taking a weighted average of the rate-of-time preference and the opportunity cost of capital. This might at first seem to be an arbitrary means of resolving the dilemna. However, some economic justification for specific weighting factors can be developed. Any expenditure by a governmental unit will displace both private consumption and investment. The opportunity cost of capital for the public expenditure can be measured by the cost of the source of the funds. Over the long run approximately 80% of the aggregate income is devoted to consumption and 20% is invested. These proportions become the relative weights for the opportunity cost of capital for state funds. This factor is used as the discount rate throughout the study. It represents the cost funds contributed by the general revenues of the state or reserves built up by the APA.

The overall cost of capital to the APA can now be measured by taking a weighted average of the cost of borrowed capital and the costs of state funds. The cost of capital is explicitly stated below

$$R_p = (1-m)R_b + m(dR_c + (1-d)R_i) \qquad (3)$$

where

R_p = cost of capital to the APA
R_b = interest rate on APA bonds
R_c = private time preference of consumption
R_i = rate of return on private investment (pre-tax)
m&d = weighting factors.

In this case, m is the proportion of state funds invested in the APA projects or the reserve margin on the bonds and d is ratio of aggregate consumption to aggregate private income. It is expected that the reserve margin (m) will be approximately 10% which is a fairly standard level of state investment.

9.2.3 Discussion of Coverage Ratios

Occasionally there is some confusion over the relationship between coverage ratios and the cost of capital. Therefore, a brief discussion here should clear the air. Coverage ratios are requirements placed on the bond issues in terms of minimum operating income requirements relative to their interest obligations. The cost of capital is determined by the opportunity cost of funds invested in the project and independent of the coverage requirement per se. To reiterate the discussion in 9.2.2, the cost of capital depends upon the capital structure (borrowed capital versus direct investment) and their respective costs.

Suppose initially an agency borrows 100% of the capital for a project and the coverage ratio is in excess of the debt service requirement. If the requirements of the credits dictate that the surplus is accumulated as reserves, the costs will change. The cost of capital in this case will be altered not by the interest coverage but by the change in the capital structure resulting from the increase in reserves. When the issuer is free (terms of the creditor) to use the excess operating income as they choose, then it is not a cost of the service. When there are reserves in the capital structure, then operating income must be sufficient to meet not only the debt service requirements, but also the opportunity cost of the reserves analogous to the profits in the private sector.

9.3 FINANCING COSTS OF THE ALASKA POWER AUTHORITY

9.3.1 Interest Rates on Municipal Bonds

In Section 9.2.2 it was shown that cost of borrowed funds would be the primary determinant of the Authority's cost of capital as it is heavily weighted in the capital structure. The trend of interest rates in recent years is shown in Figure 9.1. In the post-War period, this has been a time of relative unsettled financial markets beginning with the disintermediation of 1967 and continuing through the near bankruptcy of New York City. Several patterns emerge from the analysis of the recent past. These will be discussed immediately below and in the following sections.

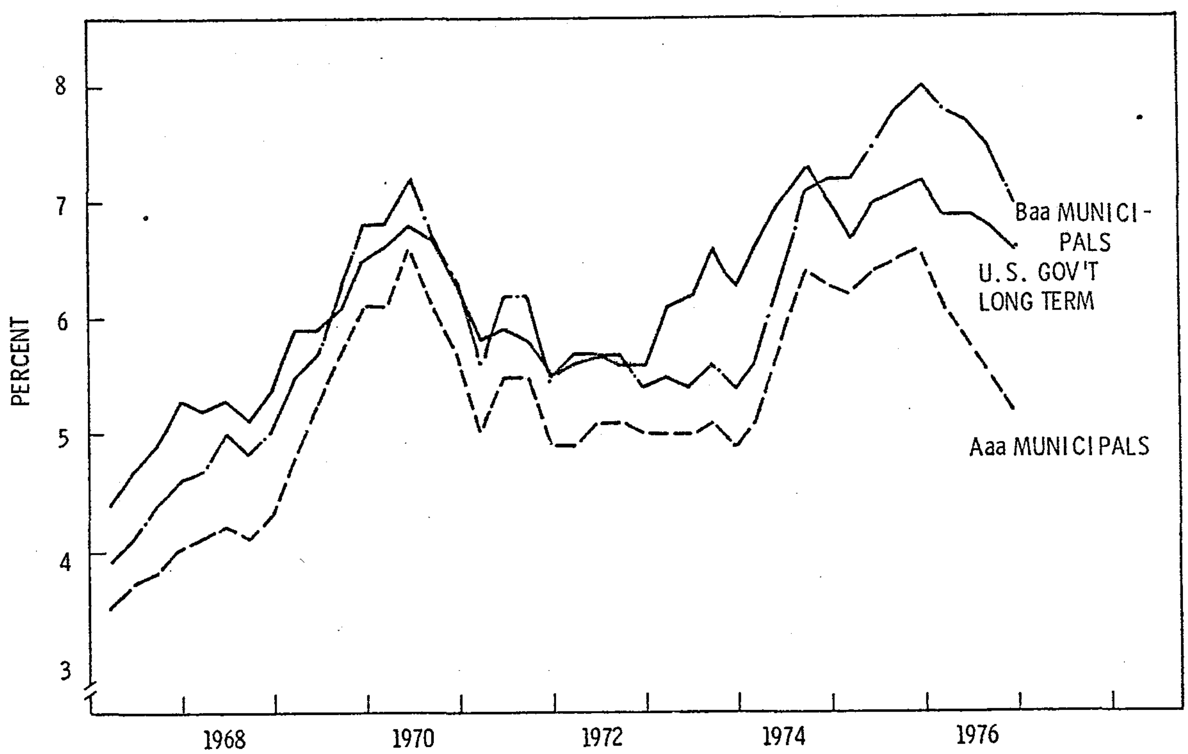

FIGURE 9.1. Interest Rates on Long Term Bonds

First it should be noted that the coupon rate of top grade municipal bonds fall significantly below that of the long term U.S. Government securities which would have to be considered the closest thing to a risk free security. This is due to the tax-exempt status of the interest from state and local government bonds. We have estimated that after incorporating the risk differences and the tax subsidy that Aaa municipal bonds can be issued with a coupon 0.8% below the yield on long term federal government securities. For addition, Baa municipals would be expected to yield 0.6% more than the Aaa municipal bonds. Both of the interest rate differentials are subject to fluctuation and will be discussed in Section 9.3.3.

Our methodology for estimating the cost of capital in this report has been to assume the risk free rate of interest to be constant and then peg the other rates to the risk-free return. There has been considerable discussion of the riskless rate of interest and it is generally assumed to about 3%. Table 9.2 gives the borrowing costs and overall cost of capital for two ratings of municipals and typical REA. The cost of capital was determined by equation (3).

TABLE 9.2. Cost of Capital

Institution	Bond Interest (%)	Cost of Capital (%)
Municipal		
Aaa	2.2	2.6
Baa	2.8	3.2
Rural Electric Association	3.75	4.5

9.3.2 Nominal Versus Real Rate of Interest

Another trend observable in Figure 9.1 is the increase in all interest rates shown from the beginning of the period until late in 1975. This period is characterized by a relatively high rate of inflation. There has been a long established relationship between the level of interest rates and changes in the price level.[4]

In the process of investing (saving) an individual is foregoing current consumption for greater consumption in the future - the return of principal plus some interest. If during the interim the general price level changes, then real consumption or purchasing power is altered. If prices increase, then the investor's real return has been reduced. Therefore, a rational consumer will try to anticipate changes in price levels and adjust his interest requirements such that the purchasing power of his capital is preserved and an appropriate increase is future consumption realized.

The prevailing market rate of interest (nominal) is composed of two components, the real rate of interest and the expected rate of change in the purchasing power of a dollar. In Figure 9.2, we see that in 1975 to 1976, the expected long term rate of inflation was approximately 4.0% given our hypothesized value of real rate of interest (3%). The expected rate of inflation will not necessarily equal the current change in prices, as it appears to be formed over long periods of time. Expected price changes can never be measured exactly, but there are several competing models for estimated expected prices.(5) Those, however, are beyond the scope of this discussion. For the purposes of the cost analysis in this report, we have compared three scenarios based upon different expected rates of inflation (0, 4 and 7%).

9.3.3 Municipal Bond Market Characteristics

Three groups of investors have traditionally dominated the market for state and local securities. Those are individuals, commercial banks and insurance companies. For each of these groups the tax avoidance aspect of the interest income is a prime consideration. For individuals in high marginal income tax brackets, a tax free 6% coupon is comparable to fairly high taxable rates of return before income taxes are considered. The institutional investors in the municipal market are corporate entities again with marginal tax rates of approximately 50%.

Although banks and insurance companies have major portfolios of municipal securities, these are not their primary investment opportunity. Commercial banking is focussed upon short term loans directly to businesses while insurance companies have broadly diversified portfolios in corporate stock and bonds. The individuals investing in state and local bonds have sufficient

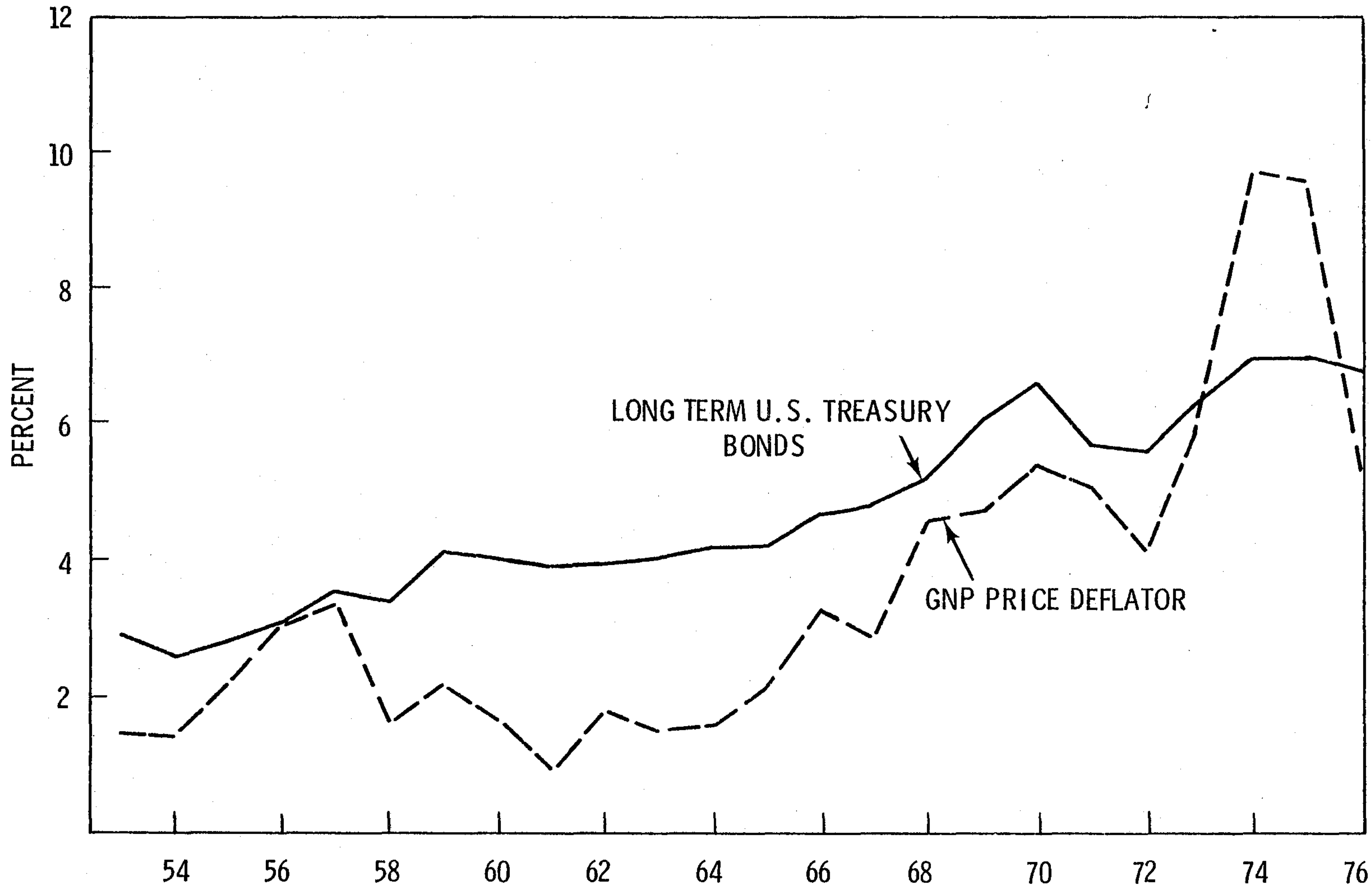

FIGURE 9.2. Comparison of Interest Costs and Inflation Rates

amounts of capital that a wide variety of investment opportunities are open to them. The implication of this is that the market for municipal bonds can be sensitive to cyclical changes in the business cycle and financial markets.

This point is demonstrated by reviewing the historical trends of interest rates. In the mid-1960's, Aaa rated municipal bonds typically sold with coupon a full percentage point below long term U.S. government bonds. During the tight credit period of 1969 through 1971, the spread between these securities, as shown in Figure 9.1, range between .1 and .2 percentage points. The impact is even greater on the lower grade securities. State and local bonds rated at Baa were yielding less than federal government bonds throughout the 1960's. During the 1970's when, in general, there have been more unsettled conditions, Baa bonds have sold with yield equal or exceding U.S. government issues with the one exception of 1973.[a] While financing with municipal bonds has some inherent interest rate risk, the higher grade of securities are less sensitive to overall market changes.

9.3.4 Proposed Changes in the Federal Tax Laws

In recent years, the tax exempt status of municipal securities has been questioned by some policy makers. The federal income tax exemption currently provides a borrowing cost subsidy to state and local governments in the range of 35% to 50%. If this advantage were lost, it would increase the cost of municipals relative to the REA's. One proposal of the current administrator is the issuance of municipal taxable securities with federal government giving a 35% interest subsidy back to the municipality. This could mostly offset the increase in borrowing costs incurred by local borrowing authorities. The second proposal would make interest income from state and local securities subject to the minimum income tax requirement. The loss of the tax-exempt status of these securities to individuals would dry-up a source of capital to the municipalities and raise their cost of borrowing.

Neither of these two measures is seen to have enough political support to be inacted in the face very strong opposition. Even if some tax is imposed on interest from state and local securities, it is doubtful if the relative

[a] In 1975 and 1976, part of the relative increase in Baa borrowing costs was the result of the uncertainty created by New York financial troubles.

cost advantage of prime municipal credit would be disrupted. Therefore, proposed changes in the tax should not weigh heavily in choice of a financing mechanism.

9.4 RELATIVE COST OF CAPITAL FOR THE APA

9.4.1 Cost of Capital Comparison

Earlier in this Section, the differences in the cost of capital to alternative utility organizations were noted (Table 9.2). It would be useful to elaborate further on these comparisons. The cost of capital estimates vary by differing hypothesized values for the cost of borrowed funds and the capital structure of the utility.

Municipal enterprises have the lowest borrowing cost and the lowest overall cost of capital. As has been discussed above, the advantage of municipal financing is its tax-exempt status. This financing option has a second advantage which is the large amount of leverage (debt to total asset ratio) accepted by municipal bond investors. In this report it was assumed that a municipal utility could finance 90% of its capital requirements by long term debt. From the financing perspective, the particular institutional arrangement of state and/or local government which can obtain the highest possible credit rating would be preferred.

Based upon the experience of the last ten years, it was assumed that each increase in bond rating would reduce the interest cost of a municipal bond 0.2 percentage points. In the last few years, it would have been an even greater savings. Even though bond ratings are given in discrete intervals, the actual quality of a security is evaluated on a continuous scale. It was assumed for the purpose of making cost calculations, that the Alaska Power Authority would borrow funds at a rate of 0.3% lower than independent utilities. Cost advantages of the State Authority are determined by the relative size of future projects, the economics of scale and national financial markets, and diversification of power contracts.

The cost of capital to REA is influenced by higher borrowing costs and a smaller amount of leverage. At first the cost borrowing to an REA is difficult to assess given the number of options. The Rural Electrification Administration can, at its discretion, loan money at 2% and at 5%. However, these loans are for small amounts and not generally available for generating facilities. Therefore, the cost of borrowing for the projects currently being analyzed was assumed to be at a rate available through the Federal Financing Bank. These rates are slightly higher than rates on direct U.S. Treasury borrowing. Also, the proportion of debt in the REA capital structure was assumed to be at the recommended maximum of 70%. This results in an overall cost of capital in real terms of 4.5%, significantly higher than the cost of state and local financing.

9.4.2 Alternative State Roles

There have been several alternative methods suggested in addition to the traditional means of utility financing in Alaska. It has recently been suggested that the Alaska Permanent Fund (APF) loan money directly to the local power companies. Another means is to use the Revolving Fund established by the Alaska Power Authority Act to serve as a financing intermediary loaning funds to the local utilities. A third suggestion is for the APA to guarantee the purchase of all the power produced from future generating facilities. Each method has some interesting attributes and will be discussed below.

The use of the APF financing electric utility development has appealing characteristics. However, the Funds efficient utilization is a very complex problem. Based upon the principal that the cost of capital of public funds is determined by the opportunity cost of the fund at their source (i.e., private consumption or investment), the APF are very costly funds. This is because the royalties are taken directly from business profits which traditionally have a high reinvestment rate. Thus, the heavy weight given private return on investment would increase the opportunity cost of capital. However, from the prespective of the State, the potential returns are likely to be greater than the direct return from the investment in electric facilities.

The overall return would depend upon the increased economic development induced by expanded electrical systems, the multiplier effects from increased investment, and the prevailing tax structure. In addition, there would be several nonmarket effects from economic growth such as favorable changes in income distribution. The quantification of the total return is beyond the scope of this analysis and would require additional evaluation.

On an interim basis, the APF could be used to develop the credit position of the Alaska Power Authority. There are significant economies in a large scale national bond distribution network yet it will be a few years before the financing requirement of the Alaska utilities will become large. In this situation, the APF could provide intermediate term financing for power facilities. Then at some future point, permanent financing could be obtained directly through the bond markets. This would add significantly to the financing flexibility of the APA as it could time the issue of long term debt with favorable periods in the cycle of the securities market. Recently private electric utilities have moved in this direction using intermediate term (7 to 8 years) credit instruments to finance the construction of generating plants.

The second method mentioned above was the Revolving Fund of the APA. The primary characteristics of this option are that it utilizes the large scale financing capability to the power utilities in Alaska but it does not require an additional layer of management for generating and transmission facilities. The present utilities have established good credit ratings. However, centralized financing through the APA offers the electric customers in the State opportunity for real economic savings from risk reduction.

The APA is in a position to decrease the investment risk in Alaska power facilities via two channels. First, the APA, by simultaneously lending to several different areas across the State, is able to diversify its investments. This will reduce the overall risk unless the economic well being of power companies in each area are perfectly correlated. Second, the APA will have better information on the credit worthiness of projects and obtain the information at a lower cost than the typical investor. This again will reduce the risk and therefore, cost of capital for financing the generation facilities.

The third option listed above was the purchase guarantee by APA. This would put the APA into the position of wheeler of electric power to the wholesale customers in state and would be dependent of Railbelt intertie. This is a nonfinancing option but it would have strong ramification for the cost of capital for generating facilities. The guarantee to purchase all the power produced by a plant is equivalent to the APA guarantee of the economic integraty of the power plant. This should reduce cost of capital to the individual companies owning and operating the generating facilities. The Bonneville Power Administration has made similar arrangements with the utilities in the Pacific Northwest. The disadvantage of the last options is that the scale of some efficient generating facilities may exceed the capability of any single company to operate.

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10.0

10.0 INSTITUTIONAL CONSIDERATIONS

Power project development by the Alaska Power Authority is subject to a variety of federal and state laws which relate to the physical environment. A total analysis of these laws applied to specific fuel types, plant locations and line routings is needed to evaluate plant cost and schedule impacts. The best available judgments as to cost and schedule constraints on a project should be available before significant capital commitments are made. For once large amounts of capital are at stake, any delay can be costly. This section in a preliminary way identifies the range of environmental laws and their probable impacts upon a power project decisional process. Consequently, this section's objective is to make available to the Alaska Power Authority's decisionmakers and personnel a body of information that will aid the timely, economical and reliable availability of needed power supplies.

Future Railbelt power supplies may be derived from coal, oil, natural gas or hydroelectric sources. The environmental laws relating to fuel type, site location and line routings are discussed. Laws relating to the fuel cycle are not within the study scope except for the recently enacted federal statute dealing with coal mining operations.

10.1 LEGISLATIVE ASPECTS OF ENERGY NEED AND FUEL SELECTION

10.1.1 Alaska's Perception of "Need" for Power

The United States has looked to Alaska to satisfy its energy resource needs. North Slope oil during the 1970's will provide approximately 2 million barrels per day of oil, and about 4.5 million cubic feet of natural gas per day at full capacity. In the 1980's, a significant offshore oil and gas exploration effort as well as probable development at the Beluga Coal Fields can be anticipated.

But Alaska has energy needs itself. The real problem in energy is for Alaska to meet its instate needs from a variety of alternatives responsive to local conditions. This causes a demand for increased reliable sources of energy. Planning is required now to assure the timely and reliable availability of power.

Coal fired plants take six years or so to plan and construct; hydro-electric facilities take nine to eleven years, and each requires large capital investment decisions early in project development.

Critical to the planning process is distinguishing between the "need" for power and the "demand" for power. In the past, most power planning projections for future demands evolved from historical patterns of usage. This usually assumed that "need" and "demand" were equivalent terms. This reliance upon the "demand" for power is continued in the provisions of the Alaska Hydroelectric Power Development Act. See 42 U.S.C. 1962 d-14a(1). A recently decided case in Oregon examines exactly this proposition. The State of Oregon's Energy Facility Siting Council determined that power from the Pebble Springs nuclear power project was "needed". The basis for the finding was challenged in Marbet v. Portland General Electric Company and the Energy Facility Siting Council, 277 Or. 381, 561 P.2d 154 (1977).

The Marbet case reviewed Oregon's certification of a site for two nuclear fuel power reactors. One issue was whether the Council failed to establish standards required by its siting statute before reaching its decision to certify the site. The Court found that those rules that had been adopted were mostly information requirements and not criteria governing decision making. While the Council in the Court's opinion was not required to adopt a standard on need for power under the governing statute, the Court indicated that it was not clear whether the Council had equated "need" with "demand". Since the Council had no standard that "demand" would be equated with "need", the Court ordered a remand.

The Marbet case is relevant to the Alaska Power Authority's decision to pursue a project. (See Alas. Stat. 44.56.010(a) (2), .010(a) (3) and .070). For example, if the Authority perceived demand in excess of the near term needs, power costs may exceed the criteria of achieving lower power costs because of reduced revenues.

Presently, the Authority under its governing statute must take actions to "lower consumer power costs". See Alas. Stat. 44.56.010(a) (3). This standard could be the basis for attacking a plant decision if "need" is less than "demand". Additionally, this standard could cause a conflict with responsibilities by other state agencies when they have trustee duties for allocation of resources.

Consequently, the

> Authority should seek revision of the standard in Alas. Stat. 44.56.010(a) (3) so that it reads "reasonable power costs".

This standard would preserve the normal decision making discretion of the Authority and would still permit it to consider power costs.

The argument on need or demand for power also involves the examination of environmental impacts associated with the proposal and its alternative of "no-action" under the National Environmental Policy Act ("NEPA": 42 USC 4321, et seq.)

> Power planning by the Alaska Power Authority should utilize state-of-the-art forecasting methodologies to distinguish the "need: and "demand" for power. See particularly Alas. Stat. 44.56.010(a) (3). Emphasis should be placed on forecasting instead of projecting power demands.

10.1.2 Environmental Laws Impact Today's Decisions

The planning to timely implement a power project by the Alaska Power Authority should account for legal constraints in the environmental area. Suffice to say energy development impacts the environment. Citizens everywhere are using environmentally related laws to object to or delay a power project when their individual judgment is at odds with the utility governmental bodies. It is not sufficient to consider merely the temper of Alaskans as to the need for a project in determining the risk of litigation under the environmental laws. The recent impact of citizens from the "lower-48" involved in the development of the Trans-Alaska pipelines and the "D-2" land issue indicates that continuing concern could spawn litigation occasioning delay of a project. Since delay inevitably costs money when capital-intensive decisions have been made,

> the Alaska Power Authority should comprehensively account for the impact of environmental laws on the scheduling and development of a project. This analysis should account, to the extent possible, for the impact of compliance and litigation time periods upon the projected generating resource availability.

Such an analysis permits better economic evaluations because it takes account of the need to design conditions into a project to minimize probable environmental impacts. Laws are changing and their regulatory implementation varies with time. The fast changing debate involving the National Energy Plan presents the Alaska Power Authority with a moving target on fuel and site selection. However, it is important to set a reference point in time so that incremental changes in the laws, regulations or standards may be evaluated as to the impact of such a change upon projects.

10.1.3 Alaska as a State Has an Acknowledged Role In Energy

The states' role in energy development is a critical role and one which has been acknowledged by the federal government. As one example of this acknowledgement, reference is made to Section 402(a) (4) (Public Law 94-385, August 14, 1976) of the Energy Conservation and Production Act where Congress in treating energy conservation found:

> "The primary responsibility for the implementation of such major programs should be lodged with the government of the state; the diversity of conditions among the various states and regions of the nation is sufficiently great that a wholly federal administered program would not be as effective as one which is tailored to meet local requirements and to respond to local opportunities; . . ."

The Carter Administration's National Energy Plan affirms a vital state role. For example, proposed legislation passed by the House of Representatives to implement the Plan (See HR 8444, Rep. Ashley) looks to the states to develop residential energy conservation plans (See Section 103(c), HR 8444) and develop and implement minimum rate standards to promote conservation (See Section 511, HR 8444).

The states' role is not limited to conservation, but includes power supply. Alaska has recognized this for example in establishing the Alaska Power Authority. Alternatives for power supply available in the study area principally relate to oil and gas in Cook Inlet, the Susitna-Beluga and Coal Fields (where there is approximately 2.4 billion tons of sub-bitumininous coal) and hydroelectric potential on the Upper Susitna and other areas. Proven reserves of some 300 million barrels of crude oil and 8.3 trillion cubic feet of natural gas off Cook Inlet and a hydroelectric capacity potential of about 1,500 MW in the Upper Susitna may be available for selecting power projects. Environmental laws and regulations are critical to site and fuel-type selection and may be the source of project delay in the event of project opposition.

10.2 FEDERAL LAWS AFFECTING POWER DEVELOPMENT

10.2.1 Energy Conservation Laws

The thrust of the Energy Policy and Conservation Act (42 USC Section 6201, *et seq.*) is that the President has the authority to reduce demand for energy through the implementation of energy conservation plans and to increase the supply of fossil fuels in the United States. (42 USC Section 6201). The Act should be considered by the Alaska Power Authority when planning because the Act can affect power needs and fuel availability. See Section 10.1.1; see also Alas. Stat. 44.56.010(2).

Under the Act energy efficiency improvement goals for each specified type of consumer product are to be developed. (42 USC Section 6292). Sections 201 through 206 of the National Energy Policy Act (See HR 8444) amend some provisions of the Act, but basicially retain the approach and made the goals mandatory for product manufacturers.

> Implementation of such standards can affect the estimation of future power demands in the Railbelt area, and should be considered in any long-range forecasting effort.

The Energy Policy and Conservation Act also deals with state programs for energy conservation. In Part B of the Act (42 USC Section 6321, *et seq.*) Congress made a finding that state development and implementation of laws, policies, programs and procedures to conserve and improve efficiency in the use of energy" . . . will have an immediate and substantial effect in reducing the rate of growth of energy demand and in minimizing the adverse environmental impacts of increasing energy consumption." 42 USC Section 6321(a). Under the implementation scheme set up in Part B, it is the responsibility of the states to develop their own energy conservation plan. The plan is to be directed at achieving a goal of a 5% reduction in the amount of energy consumed in the year 1980 from that which is projected for that yeat at this time. 42 USC Section 6322(a). A state is not required to develop such a plan. The National Energy Policy Act (HR 8444) revised this voluntary approach in the Energy Policy & Conservation Act by giving the Federal Energy Administration (now part of the U.S. Department of Energy) Administrator stand-by authority to formulate a residential energy conservation plan applicable to utilities if the state ratemaking authority does nto develop an approved plan. See Section 106, HR 8444.

> The Alaska Power Authority should, if the HR 8444 provision on Residential Energy Conservation Plans is adopted, develop its own plan instead of being subjected to a federally issued plan.

The Administrator of the Federal Energy Administration (now part of the U.S. Department of Energy) also under the law has the authority to set an energy conservation goal for Alaska for 1980 and to set interim goals. 42 USC Section 6324. The Administrator is to specify the assumptions used in the determination of the forecasted energy consumption in each state taking into account population trends, economic growth and the affect of national energy conservation programs. 42 USC Section 6324.

> The Alaska Power Authority should monitor Department of Energy activities related to energy conservation goals for impact of energy forecasts.

10.2.2 Fuel Selection Legislation

Fuel Type Restrictions

Provisions in the Energy Supply and Environmental Coordination Act can have significant impact upon fuel selection for a power generation project. The Federal Energy Administrator (now in the U.S. Department of Energy) can prohibit any power plant from burning natural gas or petroleum products as its primary energy source. See 15 USC Section 92(a). This requirement may be imposed upon any installation in the early planning process other than a combustion turbine or combined cycle unit to require a steam electric plant to be designed and constructed to be capable of using coal as its primary energy source. An exception is when requiring the use of coal as the primary energy resource is likely to result in an impairment of reliability or adequacy of service, or if an adequate and reliable supply of coal is not expected to be available.

The Federal Energy Administration on May 9, 1977 announced that it was going to issue the agency's first orders under this Act to prohibit the use of oil and natural gas in existing industrial plants, and to ensure that new industrial plants are built to burn coal as their primary fuel. A notice of intention was applied to 24 existing plant sites in 17 states. The authority to issue such notices has been extended to December 31, 1978. 15 USC Section 792(f) (1). Further extensions are probable if the need is perceived to exist.

The House of Representatives in passing the National Energy Act on August 5, 1977 gave its approval to a major program to promote industrial and utility conversions from oil and natural gas to coal. The bill would require that no new electric power plant or major fuel burning installation shall use oil or natural gas as a primary energy source. See Section 613(a), (b), HR 8444, passed by the House, August 5, 1977). Temporary exemptions from this prohibition may be obtained for a limited period of up to five years. See Section 611(d), HR 8444. Exemptions could not take effect until a state's regulatory authority has approved the new power plant. See Section 611(h), HR 8444. Criteria related to obtaining such an exemption include the inability to arrange adequate and reliable supplies of coal or other fuels, an exemption that furthers the coal conversion program, or environmental constraints. See Section 611(d), HR 8444. Permanent exemptions from the prohibition against petroleum product use are available for peakload stations. Section 611(g), HR 8444. A peakload power plant is one whose generation in any 12 months does not exceed the plant's design capacity multipled by 1500 hours. Another limited exemption is available if the utility demonstrates that the economic and other benefits of cogeneration are unobtainable unless petroleum or natural gas are used in the proposed facility. See Section 616(1), HR 8444.

The prohibition applies to any new power plant unless it is located in Hawaii. See Section 604, HR 8444.

> The Alaska Power Authority in conjunction with appropriate Congressional offices should review whether an exemption from the oil and natural gas prohibition should be provided for Alaska.

Geographic and power supply isolation and locally available supplies of oil and natural gas may provide a factual basis for such a limited exemption from the Act.

When this study started, it was hoped that a more definitive reading of emerging national legislation would be possible. The continuing, uncertain and flexible nature of Congressional disputes on the Administration's National Energy Policy has not made this possible. Consequently,

> the Alaska Power Authority should monitor and attempt to appropriately influence provisions tailored to Alaska's unique situation to avoid the strangling economic impact of provisions more appropriate to the 48 contiguous states.

Fuel Cost Restrictions

The Carter Administration and the House of Representatives have basically relied upon tax penalties to force conversion to coal and to implement conservation measures. Press reprots indicate that the U.S. Senate is relying more upon tax breaks to achieve these goals. At the current time, it is virtually impossible to forecast economic penalties on Alaska Power Authority projects resulting from the National Energy Policy bill. Consequently, the study approach has been to assume that the worst case is represented by HR 8444 due to the differing philosophies of the House and Senate.

Hydroelectric facilities would cost less under HR 8444 because of the provision for expediting licensing of existing dam expansions and gratns of up to 50%. See Section 586, HR 8444. These incentives are only available for the expansion of existing hydroelectric facilities. HR 8444 also provides that small hydroelectric projects will not be charged for non-consumptive use of water in the project. See Section 586, HR 8444. These incentive provisions operate as an economic bias in favor of expanding existing hydroelectric facilities.

Coal is not taxed as a fuel source under the HR 8444. However, costs associated with coal mining and meeting air quality requirements operate as an offsetting balance when compared with hydro, oil and natural gas facilities. Under the Surface Mining and Reclamation Act (Sec. 402(a)) a $0.35/ton tax will be levied for surface mined coal.

HR 8444 establishes tax penalties on the use of oil and natural gas which are relevant to this study if such fuels could be used when the National Energy pOlicy Act finally is adopted. The Alaska Power Authority would have to pay an equalization tax on the use of oil or natural gas. See Section 2041, HR 8444. Since the Authority would use the fuels in facilities larger than 100 MW to produce electricity, the tax classification would be Tier 3. See Section 2041 (See Section 4993(a) (3) thereof), HR 8444. After 1985 the tax would be $1.50 per barrel. The natural gas tax is less amenable to dollar specification. After 1985 it is $0.75 per million BTU of taxable use, except that it is adjusted annually for inflation (See Section 2041 (Section 4991 (d) thereof), HR 8444 and is subject to a price cap (Section 2041 (Section 4991(c) thereof), HR 8444). The price cap is limited to the BTU Equivalency Price for residual fuel oil which involves further statutory definitions. In effect the limit reflects the average regional price for residual fuel oil. Credits against the tax are permitted for qualified energy investments. See Section 2051, HR 8444.

> The Alaska Power Authority should conservatively assume in its present calculations tax impacts based upon HR 8444. Development with appropriate Congrssional offices of specific, limited relief for Alaska should be pursued.

State Energy Policies

Alaska does not currently have an explicit overall energy policy. Glimmers of an ad-hoc policy can be discerned by examining the powers of two state agencies. The Department of Commerce and Economic Development has been directed to use the hydroelectric and other electric power resources of the State to make an abundant supply of electric power and energy available to the people of the State at the lowest possible rates compatible with sound business principals. In addition, the Alaska Power Authority was established so as to reduce consumer power costs and otherwise encourage the long-term economic growth of the State, including the development of its natural resources. These objectives appear to conflict with the thrust of the Carter Administration's National Energy Policy relating to power costs. See Section 511, HR 8444. Declining block rates and other aspects that can characterize conventional and historic rate regulation practices have been cast into doubt as a result of the House adoption of the Carter energy bill which calls for regulatory reform. However, these provisions of the bill will not likely be made mandatory for the states. Notwithstanding this, rate reform to promote conservation has been viewed as an integral tool in the effort to reduce power demands by increasing power costs.

> To avoid future litigation, consideration should be given to revising the Alaska Power Authority's authorizing legislation to require "reasonable rates" instead of "lowest possible rates".

Conservation

Conservation is indicated to be a keystone of the Carter energy plan. Indeed, at one point in the Plan it addresses the programs to be pursued to increase home insulation. See particularly Sections 103, 121, 122 and 161, HR 8444. Because of Alaska's relative small population but larger percentage of cold days per year, Congress should give serious consideration to revision of any financial allocations under the Carter plan to assist in Alaskan home insulation activities. Any successful efforts in this area can have a perturbing effect upon energy demand forecasts and the Authority should explicitely consider changes in historic use patterns when forecasting power needs.

These emerging laws brought forth under the Carter Administration's Energy Plan introduce a measureable note of uncertainty in evaluating the environmental law and economic impacts on Alaska power development.

> Continued efforts to review the progress of the federal energy policy legislation as it affects Alaska should be a priority item for the Alaska Power Authority.

10.3 MANDATORY FEDERAL ENVIRONMENTAL REVIEW PROCESSES

Power development does affect the environment. Federal actions within the meaning of the National Environmental Policy Act ("NEPA") will undoubtedly occur as the result of any energy development within the State of Alaska. For example, federal actions involve issuance of water discharge permits under the Federal Water Pollution Control Act Amendments of 1972 (Publ. L. 92-500) for liquid effluents from coal, oil and natural gas facilities, licensing from the Federal Power Commission for a hydroelectric development, permits from the Corps of Engineers for certain of these developments, and from various other federal agencies because of land leasing practices that may be applicable. Since intake structures for cooling water withdrawals or discharge facilities from a power plant will be required for projects, these permits will also require a consultation with the federal Fish & Wildlife Service under the terms of the Fish & Wildlife Coordination Act.

The two general review processes required by NEPA and the Fish & Wildlife Coordination Act may cause significant delay and litigation during the implementation of a project. The normal pattern for power projects has been and continues to be to wait for the federal government to initiate the required processes.

> It is strongly recommended that power development projects in Alaska identify a critical path for the permitting process and the Alaska Power Authority should make all reasonable efforts to schedule completion of the activities under the National Environmental Policy Act and the Fish & Wildlife Coordination Act as early as possible in the project development.
>
> Because of the large amounts of capital at stake, critical path charting of project licensing for each type of fuel development is recommended. The first federal permit that can be applied for should be identified so that efforts to comply with NEPA and the Fish & Wildlife Coordination Act can be completed early.

10.3.1 NEPA Procedures

Much can be done when a specific proposal has been formulated to expedite the processes required for compliance with NEPA. Because of the uncertain extent of information now available on specific projects, only a few aspects regarding NEPA can be worthwhile discussed at this point. The emphasis now should be to indicate planning efforts necessary to expedite the process in a reasonable fashion.

There is no Statute of Limitations which restricts challenges by an individual or a group against an action for failure to comply with the provisions of NEPA. In the event of a suite brought under NEPA, laches has been used as a defense. Laches is basically a defense that prevents someone from bringing litigation when they have unreasonably delayed bringing it and the party sued has changed his position in reliance on the lack of a suit. Laches has been a disfavored defense due to the overriding public policy considerations in NEPA. Two recent cases, however, have suggested specific fact patterns under which laches as a defense may be available. In one case, East Sixty-Third Street Association of E. Coleman, 9 ERC 1193 (DC, SNY; 1976), a citizens' group's three-year delay in filing suit over a federally-funded subway route in New York City, together with the Department of Transportation's good faith attempt to minimize project environmental impacts, warranted the Court's denial of a preliminary injunction blocking construction of the subway station. In another case, Save Our Wetlands v. Corps of Engineers, 9 ERC 2026 (CA, 5th Cir; 1977), the Sixth Circuit dismissed an environmental group's suit to enjoin a real estate development because the group inexcusably delayed in bringing the suit and the project was substantially completed.

> The laches defense suggests that all efforts should be made to identify, early in a project's development, when the first federal agency action subject to NEPA might be scheduled so as to cause any challenges to be brought early in the process.

Preparation of an Environmental Impact Statement ("EIS") for a federal agency's compliance with NEPA is often governed by specific regulations the agency has adopted. Though not explicit in NEPA, the normal rule is that once an EIS has been prepared, it need not be redone for each subsequent governmental action. One limit on this case law is that there can have been no significant change in the nature of the project or in the discovery of significant adverse impacts not adequately analyzed previously. See Save Our Invaluable Land v. Needham, 10 ERC 1593 (DC, Kan.: 1975) (EIS not obsolete merely due to passage of time.

> For any specific power project, the NEPA regulations for all involved federal agencies should be collated to identify as a matter of regulation and as a matter of practice what will be comprehensively required to satisfy NEPA.

The scope of matters that must be covered in an EIS has often bothered many planners because of some of the case decisions under NEPA. The concern has been over what type of alternatives must be considered. One case out of the United States Court of Appeals in the Ninth Circuit in late 1974 explicitely indicated that an Interior Department's EIS on a proposed dam was adequate since it considered all alternative "reasonably related to purposes of the project". See Trout Unlimited v. Morton, 7 ERC, 1329 (CA, 9th Cir.; 1974). In another case involving the Soil Conservation Service, the EIS was determined adequate since in the Court's opinion, it presented sufficient information for reasoned choice of alternatives. See Robertson v. Knebel, 10 ERC, 1097 (CA, 8th Cir.; 1977). The instruction in this type of case is that it is important to identify any and all alternatives that are reasonably related to accomplishing or affecting the purposes of the project, particularly those that may involve environmental impacts less than the proposed project.

> Early planning of alternative fuel type and site selection efforts should reflect a clear statement of project purpose and identification of reasonable alternatives.

In a recent Sixth Circuit case an EIS for a coal-fired project was found to be adequate. The case, Mason County Medical Association v. Knebel, 10 ERC 1801 (CA, 6th Cir.; 1977) is helpful in seeing what alternatives should be considered. The EIS examined alternatives relating to no additional power, purchased power from alternate sites, alternate generation and fuels, alternate ash and sludge disposal, alternate transmission line construction, voltage and towers. The Alaska Power Authority should use the instructions in cases like this when developing study plans for alternatives to be examined under NEPA.

The primary (i.e., effluent discharge impacts) and secondary (i.e., impacts from growth enables by project) impacts must be adequately discussed in the EIS. Project opponents will often argue that sufficient information is just not available and further action should be delayed pending completion of appropriate studies. But final answers to all questions are not necessarily required. For example, in a case decided recently by the Seventh Circuit, U.S. Court of Appeals, the Court held that the failure to resolve issues of possible viral and bacterial aeration in a proposed sewage treatment facility was not an inherent deficiency in the EIS. The EIS had recommended post construction monitoring of aeration impacts instead of further studies at that time. The Court indicated that this approach satisfied NEPA since the statement prepared by the Environmental Protection Agency contained an adequate analysis of the problem and the intended solution. Then, very importantly, the Court indicated that the present state of scientific knowledge does not permit full assessment of the issue absent monitoring. See City of De Plaines v. Metropolitan Sanitary District, 10 ERC, 1253 (CA, 7th Cir.; 1977). The instruction here is that, within the scope of the NEPA regulations for the various federal agencies that might be involved in the approval of a particular power development project for Alaska,

> the Alaska Power Authority should prepare a comprehensive outline of studies necessary to provide sufficient information upon which to draft the Environmental Impact Statement (EIS).

One useful tool in NEPA that can be used to reduce the cost of impact studies is found in various NEPA requirements. Under NEPA, the federal government has a continuing responsibility to use all practical means to improve and coordinate federal plans, functions, programs and resources. The federal government is also required to cooperate with state governments in a manner calculated to foster and promote the general welfare. See 43 USC Sections 4331 (a.b). These mandatory policy objectives of the Act can be read in conjunction with those procedural provisions of NEPA which make mandatory the federal government's making available to states advice and information useful in restoring, maintaining and enhancing the quality of the environment as well as initiating and utilizing ecological information in the planning and development of resource oriented projects. See 43 USC Sections 4332 (2) (G,H). The Alaska Power Authority might consider utilizing these provisions of NEPA to request federal agency consultation and advice in preparation of an EIS. This approach may also provide the opportunity of permitting early identification of the type of studies necessary to satisfy concerns of the involved agencies.

10.3.2 Fish & Wildlife Coordination

Whenever the waters of any stream or other body of water are proposed or authorized to be impounded, diverted, the channel deepened, or the stream or body of water otherwise controlled or modified for any purpose whatsoever, the Fish & Wildlife Coordination Act applies. It specifically requires that any federal agency involved in the issuance of a federal permit or license initiate consultation with the United States Department of Interior Fish & Wildlife Service before permit issuance. See 16 USC Section 662(a). The consultation is required for determining the project's possible damage to wildlife resources, the means and measures that should be adopted to prevent the loss of or damage to such wildlife resources, and to provide concurrently for the development and improvement of such resources. See 16 USC Section 622(b).

The risks of noncompliance with the Act are seen in a recent case, National Wildlife Federation v. Andrus, 10 ERC 1353 (DC, DC; 1977). In this case, the Department of Interior (DOI) failed to comply with the Fish & Wildlife Coordination Act for a power construction project. A preliminary injunction was issued stopping further power planning and construction until DOI obtained proper authorization and until it complied with provisions of NEPA and the Fish & Wildlife Coordination Act.

The Fish & Wildlife Coordination Act can be a stronger force in the future because of emphasis in the recent environmental message by President Carter to Congress on May 23, 1977. In that address, the President indicated, "My administration will ensure timely implementation of the mitigation features required by the Fish & Wildlife Coordination Act to make up such losses."

> The costs of mitigation measures should be accounted for in feasibility studies by the Authority.

Usually this consulation process is initiated late in a project's development, thereby minimizing the chances of negotiating for acceptable, but less costly, conditions because of project delay costs. It would be far more appropriate to have this consultation process early as part of the EIS development for a project so as to preclude such type of late arising conditions.

The consultative and coordination policies of NEPA discussed above should be used to realize early analysis here.

10.3.3 Licensing Coordination

No effective formal process exists to coordinate and implement a timely and final processing of all federal permits that might be required for a power project. The Carter Administration is now developing a Nuclear Regulatory Reform Act which provides for a determinative and non-duplicative state role on environmental aspects. It preserves the independent federal agency jurisdictions. There has been some discussion of broadening the concept to provide for integrated license and permit processing for coal plants. During the near term such licensing process reform is doubtful. Background information on the issue can be usefully obtained from two studies recently completed by the U.S. Nuclear Regulatory Commission; "Improving Regulatory Effectiveness in Federal'State Siting Actions," NUREG-0195, Office of State Programs, USNRC; (May, 1977) and "Success Factor Evaluation Panel," NUREG-0196, Joel Haggard (March, 1977).

> The Authority should, in planning any project, comprehensively identify all agencies, federal and state, with jurisdiction or consultation roles. The licensing process, timing and required studies should be charted for a critical path analysis. This information is critical in determining appropriate financial commitment timing to minimize the cost of delay. The State of Alaska should consider as an alternative to the present state multiple permit process a one-step state licensing system for bulk energy facilities or an executive coordination to yield a final state action.

10.4 WATER

Power plant discharges to surface waters contain materials and heat which are defined by federal law to be "pollutants". These discharges can affect the water quality characteristics of the receiving waters. This can have an impact upon aquatic biota and other characteristic uses. While a thermal pollutant is dissipative, some chemical pollutants are not. Consequently, the amount discharged and the receiving water volumes are important in assessing these material concentrations and their impacts. Depending upon the receiving water's daily or seasonal flow, consumptive water withdrawals for cooling tower operation can accentuate discharge impacts.

Impacts of water withdrawal and effluent discharges are primarily controlled at the federal level by the Federal Water Pollution Control Act Amendments of 1972 (33 USC 1251, et seq.; "FWPCA of 1972"). The scheme used is to prohibit all discharges unless a federal permit, called a National Pollutant Discharge Elimination System (NPDES) Permit, has been granted. The permits contain conditions which restrict what can be in the discharge, i.e., effluent limitations. These limitations normally are applied to the point of discharge. However, if internal control measures are normal practice within an industry, for example, steam electric power plants, EPA arguably has the authority to require in-plant controls. See American Paper Institute v. Train, 9 ERC 1065 (CA, DC; 1976). For new power projects, the effluent limitations of principal concern are set out as Standards of Performance in regulations for steam electric power plants.

Specific water related concerns also arise if projects are constructed adjacent to, or discharges are made into scenic and wild rivers, wetlands, or estuaries. Where projects require excavation in navigable waters, statutory provisions relating to dredged spoil disposal are important. These provisions can impact non-hydroelectric facility site selection because of costs for mitigating measures and permit condition compliance. Hydroelectric projects have unique water related problems, particularly as to fish passage and changes in river thermal regimes.

10.4.1 Federal Control

In 1965 the Water Pollution Control Act relied principally upon water quality standards to assure maintenance of water quality. Water quality standards were used to limit the maximum pollution level of a water body. Regulatory enforcement under this statutory approach was awkward and identification of specific violators was difficult to prove. The reason was the need to relate an individual discharge's impact to the resultant water quality of a larger receiving water body. The basic strategy and approach of the Act was revised in 1972 to prohibit all discharge of pollutants unless specific characteristics of the discharge are controlled.

Zero-Discharge Goal

Congress declared in the 1972 Amendments that the national goal is elimination of all pollutant discharges into navigable waters by 1985. 33 USC Section 1251 (a) (1). A recent public opinion survey noted that as many as 66% felt that the goal of zero-discharge should be reexamined. This was an increase from the 49% who felt the same in 1976. Court cases have also looked at the no-discharge of pollutant goal.

The "zero-discharge" goal does not mean that there can be no discharge made to a receiving water body. See Appalachian Power v. Train, 9 ERC 1033, 1046 (CA, 4th Cir.; 1976). In another case the regulations for the inorganic chemical industry were remanded to EPA for clarification so that the definition of "process waste water" in the context of the "no-discharge" standard would not apply to unavoidable leaks and spills. See DuPont v. Train, 8 ERC 1718, 1725 (CA, 4th Cir.; 1976). In the Appalachian Power v. Train, 9 ERC 1033, 1053-4 (CA, 4th Cir.; 1976) case, EPA's regulation requiring no-discharge of suspended solids from fly ash transport (See 40 CFR Sections 423.15(e), 423.25(e)) was challenged. Industry had contended that EPA failed to show that dry fly ash transport systems are available to all sources required to employ them. The Court agreed and remanded the regulations to EPA for purposes of explicating the basis for such a rule. New regulations have not yet been promulgated.

Disputes have also arisen on whether pollutants present in intake water have to be cleaned up prior to discharge. See Appalachian Power v. Train, supra at 1053-4. The 4th Circuit Court of Appeals agreed that EPA had no jurisdiction to require removal of pollutants that enter a plant through its intake stream. The 4th Circuit remedied the problem with EPA's regulations in 40 CFR Section 125.28(a) (2) by construing "treatment system" to mean those systems designed and used for the removal of process waste water pollutants. This gives a plant operator credit for all pollutants in the intake supply.

The 9th Circuit Court of Appeals (which has jurisdiction over federal cases arising out of Alaska) has accepted for review a case involving variances under the Act. In Louisiana-Pacific v. EPA, (9th Cir.; No 77-3322) the issue involves EPA's denial of variances where it is alleged that the best practicable technology effluent limitations will not imporve water quality. The House of Representatives is considering amendments to the FWPCA of 1972 to provide for waivers when the costs of best available technology controls are significantly greater than the marginal pollution reduction achieved. Senate conferences on the bill have so far rejected this approach.

> The Alaska Power Authority should base its planning for new power plants on satisfying application of best available control technology without a variance. If judicial or Congressional relief is granted, adjustments in project economics could then be made.

NPDES Permit

The basic scheme of the FWPCA of 1972 as related to liquid discharges is that a discharger must obtain a permit from the federal government. The permit is termed a National Pollutant Discharge Elimination System (NPDES) Permit. The NPDES permit incorporates effluent limitations which restrict the type and quantity of materials discharged in the cooling medium to the receiving water. Effluent limitations for new projects are basically established by the Standards of Performance. See USC Section 1316.

The states are not precluded from imposing conditions through the NPDES permit more stringent than the federal effluent limitations. See 33 USC Sections 1302, 1341. Other limitations of a general nature, i.e., monitoring, oil spill prevention, emergency operations, are included along with effluent limitations in an NPDES permit.

> The Alaska Power Authority should comprehensively review NPDES permits issued by EPA, Region X, in order to identify and evaluate the impact of such conditions upon plant feasibility.

10.4.2 Steam Electric Power Plants

Standards of Performance

In evaluating the effluent limitations that will be applicable to coal, oil or natural gas fired steam power plant in the Railbelt area, primary attention should be directed to the National Standards of Performance established pursuant to 33 USC Section 1316. A Standard of Performance is a standard for the control of the discharge of pollutants which reflects the greatest degree of effluent reduction which the EPA Administrator deems to be achievable through application fo the best available demonstrated control technology processes, operating methods or other alternatives, including <u>where practicable</u> a standard permitting no discharge of the pollutant. See 33 USC Section 1316(a) (1). The Standards of Performance apply to any new source; that is, any source for which construction has been commenced after the publication of proposed regulations prescribing the Standards of Performance. This has been done for steam electric power plants and are set out in 40 CFR, Part 423, Section 15. These standards place restrictions upon total suspended solids, oil and grease, copper, iron, free available chlorine and materials added for corrosion inhibition, including but not limited to zinc, chromium and phosphorus.

The Standards of Performance regulations do not provide for any variance as is the case with existing plants that are "fundamentally different" than the national basis considered by EPA in promulgating the regulations. The 4th Circuit considered this situation in <u>DuPont v. Train</u>, 8 ERC 1718 (CA, 4th Cir.; 1976). The court reviewed the effluent regulations for the inorganic chemical industries. The regulations were remanded to EPA for development of ". . . some limited escape mechanism for new sources." DuPont v. Train, <u>supra</u> at 1722. No similar holding has been made for steam electric power plants. If the Standards of Performance requirements impose severe economic penalties on a power project, legal analysis of relief on the basis of impracticality should be considered. See 33 USC Section 1316(a) (1).

For thermal discharges no discharge of heat from the main condensers is permitted. Heat may be discharged in blowdown from recirculated cooling water systems provided that the temperature from which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water prior to the addition of the makeup water. If cooling ponds are utilized, heat may be discharged from cooling ponds provided that the temperature at which the blowdown is discharged does not exceed at any time the lowest temperature of recirculated cooling water <u>prior</u> to the addition of the makeup water. See 40 CFR 423.15(1).

Cooling Towers -- General

The federal thermal effluent limitations in effect require a cooling tower instead of a once-through discharge facility. Consequently, significant added costs must be accounted for in project feasibility work. A limited variance provision does exist when the thermal effluent limitation is more stringent than necessary to protect the balanced indigineous population of fish, shellfish and wildlife. See USC Section 1316(a). "316-a" demonstrations have already resulted in two variances for existing plants operated by Golden Valley Electric (Fairbanks) and an Army plant in Anchorage. EPA Region X informal policy indicates that "317-a" determinations will be extremely difficult for new plants. Consequently, little practical relief from the cooling tower requirement may be available to the Alaska Power Authority.

The thermal regulations for new plants are significantly different than for existing plants in that existing plants may utilize a variety of cooling techniques, including cooling lakes. Compare 40 CFR Section 423.15(1) and Section 423.25(1). Industry and the State of Texas challenged this on the basis of being arbitrary and capricious in light of the resulting increase in water consumption. See Appalachian Power v. Train, supra at 1045. The Court agreed that cooling lakes should be available for use by new plants.. One factor which weighed heavily with the Court was the impact upon water availability in a local area resulting from the large consumptive use associated with cooling towers. See Appalachian Power v. Train, supra at 1047-1048. On remand, the Court indicated that EPA should consider a subcategorization of the industry by locality taking into account the availability of water for consumptive use.

> Review of water availability data in potential plant sites in Alaska should be considered by the Alaska Power Authority in determining whether to seek appropriate regulatory changes to permit use of cooling lakes instead of cooling towers.

Cooling Towers - Coastline Plants

EPA's regulations prohibit use of once-through cooling facilities at new power plants located along the nation's coastlines. See 40 CFE, Section 423.13(1), as amended by 40 Fed. Reg. 7095-96 (1975). EPA requires that sea-water be utilized in the towers. See 39 Fed. Reg. 36190 (1974). These regulations have been remanded. The 4th Circuit in Appalachian Power v. Train, supra, at 1049, required EPA to consider whether sea-water cooling towers are "currently available" and thus "demonstrated". No regulations have yet been resubmitted by EPA.

> The Authority should analyze the impact of such a requirement because of the potential air and water impacts resulting from salt water windage losses.

Area Runoff

Standards of Performance covering area runoff have been promugated by EPA. See 40 CFR Section 423.45. These regulations in part require that Total Suspended Solida in area runoff be limited to 50 mg/l. This condition directly affects the cost for site preparation. (NOTE: Alaska Water quality standard limitations upon turbidity are supplementary to and can be more restrictive than the EPA effluent limitations). These limitations are also applicable to fuel storage areas so cost differentials principally for coal should be recognized.

One issue that has arisen for the area runoff limitations is whether they apply to all site construction activity. EPA's Development Document which provides the basis for the regulations indicates that the limits do apply only to activity undertaken in the immediate vicinity of the plant site. See "Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category," p. 412, U.S. Environmental Protection Agency, EPA 440/1-74 029-a. However, EPA's regulations do not include this restriction. The regulations have been remanded for EPA clarification of the scope of their applicability. See Appalachian Power v. Train, supra at 1050.

Another issue involves the validity of the 50 mg/l limitation for Total Suspended Solids. The 4th Circuit in Appalachian Power v. Train, supra at 1052, remanded the regulation to EPA for establishing that the required control technology can reasonably be expected to achieve the required effluent reduction.

Under the area runoff limitations, a plant operator must have treatment facilities available to handle the runoff associated with the maximum

24 hours, once-in-ten-years rainfall event. If a greater rainfall event occurs, untreated discharges may be made under the federal regulations. However, the state's water quality standards would still apply to restrict the discharges.

Cooling Water Intakes

Section 316(b) of the FWPCA of 1972 requires that the location, design, construction and capacity of cooling water intake structures "reflect the best technology available for minimizing adverse environmental impact." 33 USC Section 1316(b). The statute does not require a permit or approval, but rather imposes the requirement as a general statutory matter. Since the Corps of Engineers is responsible for assuming 316(b) compliance. However, the U.S. Environmental Protection Agency has taken the position that it will make 316(b) decisions. As a practical matter, EPA input and control is practices through the Corps in a consultative role and through issuance of NPDES permits as part of agency policy.

EPA has published a report describing the best available technology for cooling water intakes.

> The report, "Development Document for Best Technology Available for the Location, Design, Construction and Capacity of Cooling Water Intake Structures for Minimizing Adverse Environmental Impact," EPA 440/1-76/015-a, dated May, 1976 should be reviewed and applied in the planning and evaluation of all power projects.

10.4.3 Coal Industry

EPA has promugated effluent limitations for various aspects of the coal industry. 40 CFS Section 434.10, et seq. The regulations have specific limitations for coal preparation plants and associated areas (40 CFR Section 434.20, et seq.), for acid or ferrogenous mine drainage (40 CFR Section 434.30, et seq.) and alkaline mine drainage (40 CFR Section 434.40). EPA just proposed Standards of Performance for "new source coal mines". See 42 FR 46932. The limits in these proposed regulations apply to any substantially new operation and should be reviewed by the Authority for cost impacts upon coal development. Many of the general issues discussed above for steam electric power plants are relevant here.

Coal mining effluent limitations apply to total iron, total manganese, total suspended solids and pH. Drainage which is not from an active mining area is not required to meet the limits so long as it is not commingled with untreated mine drainage. See 40 CFR Section 434.32(c). A variance from the effluent limitations, but not the Standards of Performance, is possible if an operator can establish that factors relating to equipment or facilities, the process used, or such other factors that are "fundamentally different" from those factors considered by EPA in developing the limitations.

10.4.4 Alaska Has A Determinative Role In NPDES Permits

Review of EPA's effluent limitations is not sufficient when assessing water discharge restrictions. Under the FWPCA of 1972, Alaska has three significant opportunities for imposing conditions more stringent than the federal limits.

Alaska has not requested EPA authority to issue NPDES permits under 33 USC Section 1342. Consequently, an operator is required to get both an NPDES permit from EPA pursuant to the FWPCA of 1972 and a waste discharge permit from Alaska pursuant to state law. Alaska law was recently amended to permit the state to use an NPDES permit in lieu of a separate state waste discharge permit. Alas. Stat. 46.03.110(e). Alaska through its state waste discharge permit process can impose conditions to protect water quality.

As a condition precedent to the issuance of any federal permit which involves a project for which water discharges will be made, a state must provide a "401" certification that the discharge will comply with water quality standards. 33 USC Section 1341(a). When issuing such a certification, effluent limitations upon which the state certification is based must be specified. 33 USC Section 1341(e). Consequently, Alaska can assure through the "401) certification that water quality standards, including the non-degradation clause, will be met.

Alaska can also request EPA to impose conditions more stringent than the applicable federal effluent limitations if necessary to protect fish and water quality. See 33 USC Section 1302. If this statutory procedure is used, the operator is entitled to a hearing and the socio-economic benefits and costs associated with the more stringent effluent limitations must be weighed by the EPA Administrator before imposing the more stringent limitations.

10.5 WATER ORIENTED RESTRICTIONS ON SITE AVAILABILITY

10.5.1 Wild and Scenic Rivers Act

The purpose of the Wild & Scenic Rivers Act is to provide protection to the immediate environment for certain designated rivers so that they will be protected for the benefit and enjoyment of present and future generations. These rivers are to be preserved in a free flowing condition. 16 USC Section 1278(a). Designating a river within the system thus eliminates the site from consideration for hydroelectric development. The Federal Energy Regulatory Commission, formerly the Federal Power Commission, is restricted from licensing the construction of any dam, water conduit, reservoir, powerhouse, transmission line or other project works under the Federal Power Act" . . . on or directly affecting any river . . ." which is designated in 16 USC Section 1274 or 1276(a).

No scenic and wild river presently designated by Congress is in Alaska. This may not always be the case. President Carter in his environmental message to Congress on May 23, 1977 proposed to designate as potential additions to the National Wild & Scenic River System the Delta River in Alaska. Under the Alaska Native Claims Settlement Act, 33 rivers and river segments totalling 2.45 million acres are being considered for addition to the system in Alaska.

The Carter Administration has proposed that the Susitna River be considered a study area for inclusion in the system. The Wild & Scenic Rivers Act does not prohibit the Federal Power Commission from licensing a proposed federal electric dam during the pendency of the state's request to the Interior Department that the river be included in the National Wild & Scenic Rivers System. North Carolina v. Federal Power Commission, 8 ERC 1917 (CA, DC; 1976). However, the timing of any proposed development on a river that might be affected in Alaska under the statute will be important in determining whether or not the restrictions of the Wild & Scenic Rivers Act applies.

The Alaska Power Authority should review the proposed ANSCA additions to the Scenic & Wild Rivers Act to determine if preferable power project sites would be eliminated.

A non-hydroelectric power plant can theoretically be sited above or below a Wild & Scenic River area so long as the activity will not invate the area or unreasonably diminish the scenic, recreational, and fish and wildlife values present in the area. 16 USC Section 1278(a).

The Secretary of the Interior or the Secretary of Agriculture, as the case may be, may grant easements and rights-of-way upon, over, under, across or through any component of the National Wild & Scenic Rivers System in accordance with the laws applicable to the National Park System or the National Forest System, respectively. However, conditions will be imposed upon the grant of such easements and rights- of-way as are related to the policy and purpose of the Wild & Scenic Rivers Act. See 16 USC Section 1284(g).

10.5.2 Marine Sanctuaries

Marine sanctuaries may be designated for the purpose of preserving and restoring such areas for conservation, recreational, ecological or aesthetic values. 16 USC Section 1432(a). Prior to designating a marine sanctuary lying within the territorial limits of any state, consultation and due consideration of the views of the responsible official of the state involved is required. The Governor of the state may certify that portion lying within the state as unacceptable in which case the designation of a marine sanctuary will not apply. See 16 USC Section 1432(b). Once a marine sanctuary has been identified, no permit, license or other authorization shall be valid unless the Secretary of Interior certifies that the permitted activity is consistent with the purposes of the Act and can be carried out within the regulations promugated under the Act. The Alaska Power Authority should monitor any efforts to designate marine sanctuaries in Alaska.

10.5.3 Wetland Areas

Wetlands have special protection in federal law. Congress has found that it is in the public interest to preserve, restore and improve the wetlands of the nation and thereby to conserve the surface waters. 16 USC Section 1301.

The Act authorizes the Secretary of Agriculture to enter into agreements for the conservation of water on specified farm, ranch and other wetlands identified in conservation plans, developed in cooperation with the Soil and Water Conservation District in which the lands are located. See USC Section 1302. If the Act is applicable to a potential power site, no filling or other destruction of the wetland character of such areas is permitted. See 16 USC Section 1303(2).

> The Alaska Power Authority should review important migratory, water fowl nesting and breeding areas and information from the Soil and Water Conservation District in areas of potential site location to determine if the Wetlands Act will restrict filling or destruction of wetlands.

The Carter Administration is expected to increase efforts to preserve wetland areas. This trend is important to Alaska where about 40% of our nation's wetlands exist. If the President's environmental message to Congress on May 23, 1977, he stated:

> "The important ecological function of coastal and inland wetlands is well known to natural scientists . . .
>
> We are losing wetlands at the rate of some 300,000 acres per year . . . . We now must protect against the cumulative effects of reducing our total wetlands acreage. For these reasons, I am proposing a concerted federal effort to protect our wetlands."

The definition of wetlands as established in the executive order means:

> ". . . those areas that are inundated by surface or ground water with the frequency to support under normal circumstances, does or would support a prevalence of vegetative or aquatic life that requires saturated or seasonally saturated soil conditions for growth and reproduction."

Steps to protect wetland areas proposed by President Carter (See Executive Order 11990, dated May 24, 1977) include provisions which direct that all agencies refrain from giving any financial support to proposed developments in wetlands unless the agency determines that no practical alternative sites exist. The U.S. Water Resources Council published guidelines on September 20, 1977 to help federal agencies comply with this Executive Order. See 42 FR 52590. This restriction is of immediate interest to Alaska because of the role specified for the Corps of Engineers under the Alaska Hydroelectric Power Development Act. 42 USC Section 1962d-14a. If applicable, this requirement to review alternative sites should be integrated with the appropriate NEPA-type studies.

In making the practical alternative finding required under the Wetlands Act, the head of the agency is to take into account economic, environmental and other pertinent factors. Factors to be considered in evaluating a proposal's effect upon the survival and quality of wetlands includes such things as water supply and quality; water recharge and discharge; pollution; flood storm hazards, sediment and erosion; maintenance of natural systems including conservation and long-term productivity of existing flora and fauna species and habitat diversity, hydrologic utility, fish, wildlife, timber and food, and other uses of wetlands in the public interest, including recreational, scientific and cultural values.

> Restrictions upon potential sites and the costs of mitigating measures for sites affecting wetlands should be considered by the Alaska Power Authority. If possible, sites in wetland areas should be avoided if there is any practical alternative.

10.5.4 Estuaries

Estuarian areas are also protected by federal law. Congress has found that many of the estuaries in the United States are of immediate and potential value to the present and future generations of America. Congress has provided a means for considering the need to protect, conserve and restore these estuaries in a manner that adequately and reasonably maintains the balance between the national need for such protection and the need to develop these estuaries to further the growth and the development of the nation. See 16 USC Section 1221, et seq. An estuary is defined in 13 USC Section 1254(n) (4) to include all or part of the mouth of a river or stream or other body of water having unimpaired natural connection with an open sea, and within which the sea water is measurably diluted with fresh water derived from land drainage.

> The Alaska Power Authority should determine whether potential sites are within an estuarine area protected by federal law to determine study efforts and costs associated with alternative sites.

10.5.5 Dredged Materials

Unregulated dumping of materials into ocean waters was found by Congress when adopting the FWPCA of 1972 to endanger the human health, welfare and amenities as well as the marine environment. See 33 USC Section 1401. Consequently, Congress acted to regulate the dumping of all types of materials (i.e., matter of any kind or description) into ocean waters. A permit is required for transporting the material. No permit shall be issued if the dumping of the material will violate applicable water quality standards.

No dredged material may be depostied without a permit issued by the Secretary of the Army under 33 USC Section 1414. Dumping can only occur in areas where it will not unreasonably degrade, or endanger human health, welfare or amenities or the marine environment, ecological systems or economic potentials. Permit conditions include the type of materials to be dumped, the amount of material authorized to be dumped, the location of the dumping, and "any special provisions deemed necessary" by the Administrator. See 33 USC Section 1414(a). The requirements of the Fish & Wildlife Coordination Act are applicable. See 33 USC Section 1414(3). This permit requirement is applicable to virtually all dredge or fill work in navigable waters although there is an active dispute over its applicability to inland tributaries. (See Generally 33 CFR 320 through 329) The Corps will not process a permit application concurrently with other required applications for federal, state or local permits. The Corps in a preamble to its regulations stated that if another required permit or certification is denied, it will not issue the permit. In effect, this puts the Corps in the continued position of being the last federal agency to act.

10.5.6 Hydroelectric Development

The recently enacted Department of Energy Organization Act in Section 301(b) transferred to the Department of Energy the functions of the Federal Power Commission, now called the Federal Energy Regulatory Commission ("FERC"). It is too early to tell if any substantive change in FPC policies will result from such transfer. The following analysis assumes that the basic provisions of the Federal Power Act will continue to apply in the near term to activities of the FPC replacement, The D.O.E. Federal Energy Regulatory Commission (FERC). However, one policy change expected would reflect the present Administration's favoring of expansion or augmentation of hydroelectric development at the site of existing dams instead of at new dam sites.

FERC issues licenses for the purpose of constructing, operating and maintaining dams, water conduits, reservoirs, power houses, transmission lines or other projects work necessary or convenient for the development and improvement of navigation, and for the development, transmission and utilization of power across, along, from or in any of the streams or other bodies of water over which Congress has juristiction under its authority to regulate commerce with foreign nations and among several states. See 16 USC Section 797(e). Any license which involves a project affecting the navigable capacity of any navigable waters of the United States shall be issued only after the plans affecting the navigation have been approved by the Chief of Engineers and the Secretary of Army. 16 USC Section 797(e). No license may be issued for the development, transmission or utilization of power within the limits as constituted on March 3, 1921 of any National Park or National Monument without the specific authorization of Congress. 16 USC Section 797a.

License conditions must by law require that the project be best adapted to a comprehensive plan for improving or developing a waterway and for other beneficial public uses including recreational purposes. In accordance with this particular condition, recent trends in Commission licensing disputes have involved the requirement to set aside lands for recreational activities within the project area. Other conditions not inconsistent with the provisions of the Federal Power Act can be imposed. 16 USC Section 803(g). Since the policies of the National Environmental Policy Act are supplementary to all existing statutory authorizations, this particular provision in the Federal Power Act arguably gives the Commission the authority and the duty to impose conditions upon the proposed development that are necessary for or related to the mitigation or elimination of adverse environmental impacts. These conditions would be identified and brought out in the appropriate environmental documents required for NEPA compliance. One type of such a condition that is just now emerging in certain licensing disputes before the Commission is the requirement for releases from the dam to maintain the downstream thermal regime of the water body and to protect fish life. The imposition of such a condition could reduce the seasonal or total power generated by a hydroelectric facility. Other conditions include the installation of fish passage devices and facility designs to mitigate the impacts of nitrogen supersaturation upon anadramous fish. The Alaska Power Authority should evaluate the impact of such conditions upon costs and capacity.

> A comprehensive survey should be made of existing and proposed conditions in current licensing activities of the Federal Energy Regulatory Commission to ascertain the nature of hidden costs associated with compliance for such type of conditions.

If an Alaskan hydroelectric project is constructed by the U.S. Corps of Engineers pursuant to the Alaska Hydroelectric Power Development Act, 42 USC Section 1962d-14a, a FERC license would not be required. However, this does not mean that FERC can be ignored. It has the authority to determine whether such a government dam can be advantageously used by the United States for its public purposes and what is a fair value for the power. See 16 USC Section 797(a). In addition; if FERC finds that any government dam (See definition in 16 USC 796(10)) can be advantageously used for public purposes in addition to navigation, no license can be issued until two years after the facts have been reported to Congress. See 16 USC 797(e). Further analysis of schedule and licensing aspects of a Corps of Engineers facility should be made by the Authority.

10.6 AIR

Power plants characteristically will discharge pollutants to the atmosphere. The pollutants include particulates, nitrous oxides, carbon monoxide and sulfur dioxide for all fossil-fueled plants, as well as radioactive materials and possibly benzene for coal plants and water droplets in the case of any cooling tower. Each pollutant discharge affects air quality in varying degrees depending upon ambient pollutant levels, meteorological conditions, and topography. The resultant air quality conditions may cause concern due to health, visibility and nearby land use impacts.

One of the purposes of the Clean Air Act is to prevent and control air pollution at its source. The Act specifies that this is the primary responsibility of state and local government. 42 USC Section 1857. The basic scheme of the Clean Air Act as amended in 1977 by Publ. L. 95-95 is dece deceptively simple, but quite complex in its application. Appendix E provides a schematic outline of the Clean Air Act as related to new projects. In summarizing the Act's scheme, references will be given to the Act's statutory sections not its United States Code citation.

Congressional findings and purposes for the Clean Air Act are set out in Section 101(a,b). There is no "zero-discharge" objective as is the case in the FWPCA of 1972 for liquid discharges. But one purpose of the Clean Air Act is to protect air and promote health and welfare. When Section 101(b)(1)'s purpose is combined with provisions dealing with the non-deterioration of ambient air conditions (See Sections 160, et seq.), the thrust of the Act is to permit air discharges only so long as further deterioration of the air does not result.

The states have primary responsibility for effecting the Congressional objectives (Section 101(a) (3)) so long as certain national standards and procedures are met. The basic procedural tool is the State Implementation Plan ("SIP"; Section 110). The SIP must provide that national standards for air quality are met. There are four basic types of standards. The first type involves national ambient primary and secondary air quality standards (Sections 108 and 109). These involve SO_2, particulate matter, carbon monoxide and photochemical oxidants (40 CFR Section 50), but will be extended to cover NO_x by August 8, 1978. Section 108(c). The second type involves hazardous pollutants, that is those pollutants for which there is no national standard but which can be anticipated to cause mortality or illness. Section 112(a) (1). The third type relates to areas which have an ambient condition better than the national standards. In these areas the limits are for the prevention of significant deterioration ("PSD") of the ambient air quality. Section 160, et seq. The fourth involves standards of performance, that is requirements for continuous emission reduction at the point of discharge. Section 302(1).

An Alaskan power plant is subject to these air pollutant limits in a variety of ways. The primary tool in evaluating the limits is the Alaska SIP. The present Alaskan SIP (See 40 CFR 52.71, 52.81, 52.95 and 52.96) has been approved by EPA except for principally the PSD provision. While most provisions of the Clean Air Act get brought together into the ambit of the SIP, separate highlighting of the SIP provisions is necessary for evaluating air quality costs. The first factor is to identify air quality regions principally for the purpose of determining whether air quality requirements are being met. (See Section 107). For areas in which they are not being met, the non-attainment requirements of Section 171 are applicable. The analysis is not complete, however, without review of the non-deterioration provisions of Section 160. Here the concern is for the air quality in the power plant's location and nearby lands that may be affected by discharges. Finally, a review of the requirements to obtain a construction permit set out in Section 165 is necessary.

Two short but important sections are in the 1977 amendments dealing with stack heights and radioactive releases. This can strongly influence coal plant economics and site suitability.

The following sections highlight details of this legislative scheme which may be important to Alaskan power plants. The Act basically operates to increase plant costs to control air pollutants and to restrict site availability. Tradeoffs between site location, plant size and technological controls are necessary elements of an adequate feasibility study. While no cases have been decided under the new amendments, cases arising under the previous Act will be discussed as appropriate.

10.6.1 Emission Limitations

National Ambient Standards

EPA has previously established national primary and secondary ambient air quality standards. Primary standards are to be set at levels to protect public health; secondary to protect public welfare. These are set out in 40 CFR 50. EPA is required by the Clean Air Act Amendments of 1977 to promulgate standards for NO_2 by August 7, 1978. EPA is currently reviewing the standards for photochemical oxidants and expects to promulgate them in February of 1978. The principal distinction between the primary and secondary standards is that the former must include a margin of safety. Another distinction is that primary standards must be achieved as expeditiously as possible (Section 110(a) (2) (A) (i), 110(e)), but secondary standards must be achieved in a reasonable time. (Section 110(a) (2) (A) (ii)). See Section 109(b) (1). The standards are enforced principally through the State's SIP since the SIP must include specification of emission limits to attain the standards. Section 110(a) (2) (B).

The 1977 amendments did not change the provision requiring that the national standards be met within three years after plan approval. Section 110(a) (2) (A). A two year extension is available under limited circumstances. See Section 110(e); See 42 USC, Section 1857c-5(e). Consequently, the decision in West Penn. Power v. Train, 9 ERC 1206 (CA, 3rd Cir.; 1976) appears to still stand. In that particular case decided on a procedural matter, the issue involved an extension for compliance on the grounds that it was economically and technologically infeasible for the power company to comply with the emission limitations established by the SIP. The petition for review was denied citing the case of Union Electric Company v. EPA, 8 ERC 2143 (U.S. Sup. Ct.; 1976) in which the Supreme Court held that:

> "Claims of economic or technological infeasibility may not be considered by the administrator in evaluating a state requirement that primary ambient air quality standards be met in the mandatory three years." (Note 11).

Standards of Performance

Under the old Clean Air Act, EPA had established Standards of Performance applicable to new fossil-fuel fired steam generators of greater than 250 million BTU/hr. See 40 CFR Section 60.40 et seq. The standards are currently in the process of revision. The Authority should monitor the proposed changes for purposes of suggesting appropriate changes. The present standards are the same for coal, oil and natural gas except as to the following: oil has an opacity standard of 40% for 2 min/hr while the rest do not; the SO_2 standard for coal is 1.2 lbs 110^6 BTU, 0.8 for oil and no standard for gas; and the NO_x standard for coal is 0.7 lbs/10^6 BTU, 0.3 for oil and 0.2 for natural gas. The standards are being revised by EPA and this effort should be monitored by the Authority. The new standards will be promulgated in about August of 1978. The standards require application of the best available control technology (BACT) for continuous emission reduction that have been adequately demonstrated. If the EPA Administrator finds that it is not feasible to prescribe a standard, he can promulgate requirements on design, equipment, work practice or operational standards. See Sections 111 (h) (1, 2).

The Clean Air Act Amendments of 1977 made a significant change in the Standards of Performance definition. The Standards of Performance with respect to any air pollutant emitted from a fossil fuel fired stationary source is a standard which has two parts. The first establishes allowable emission limitations for that source. The second, an significant change, requires the achievement of a percentage reduction in the emissions from such category of sources from the emissions which would have resulted from the use of fuels which are not subject to treatment prior to combustion. See Section 111(a) (1) (K). This second factor broadens the allowable emission limitation and can cause serious concern to the economic viability of a project because of the increased requirements for air pollutant treatment. The percentage reduction requirement applies to SO_2, particulates and nitrogenoxides. Some representatives of the fossil fuel-fired plant industry believe the percentage reduction should only apply to SO_2. While EPA has conceded the practical difficulties of applying the approach to particulates and nitrogen oxides, the law does not appear to allow an exemption. If the revised Standards of Performance will require percentage reductions in the range of 80% it may be possible to avoid the scrubber requirement. The Authority should carefully monitor changes in the standards.

The EPA Administrator has the authority to distinguish among classes, types, sizes within categories of new sources for a purpose of establishing such standards. See Section 111(p) (2).

> The Alaska Power Authority or other owner or operator would be reasonably advised to initiate efforts now to establish a case allowing the distinction among classes, types, or sizes of new sources of fuel plants in Alaska, which would take into account the specific problems there.

The problem with this effort is seen in similar activities under the FWPCA of 1972 where activities to establish regional differences were generally not successful because the primary objective of the Act was to provide uniform national standards. However, investigation of the sub-categorization approach, so long as there is a reasonable basis to distinguish plants in Alaska on other than purely locational criteria may be a worthwhile approach.

States are allowed to set standards more stringent than the federal requirements. The standards can be tightened in three ways by the Governor's request. They are (a) if the Governor shows new technology exists (Section 111(g) (4)), (b) if the standards are improperly developed (Section 111(g) (3)), or (c) if a hazardous pollutant is not included in the standards (Section 111(g) (5)).

A waiver of limited period (See Sections 111(k) (1) (D,E)) may be obtained if an operator can establish three items and the Governor concurs. This is not a waiver in the conventional sense of obtaining relief from an emission limit; but rather the authority to use control equipment not approved by EPA but which the operator thinks can do a better job. The elements of proof include a demonstration that the proposed system is not adequately demonstrated, that better reduction in terms of energy, economics or non-air factors can be realized, and there is no unreasonable risk. Section 111(k) (1) (A). If the waiver is granted special limits (Section 111(k) (2) (B)) and a compliance schedule is establsihed (Section 111(k) (2) (B)).

Hazardous Pollutants

Standards for certain hazardous pollutants have been set by EPA. See 40 CFR Section 61.01 et seq. Additional standards can be set if pollutants are identified by EPA to cause an anticipated mortality or illness.

Two candidates for control as hazardous pollutants relevant to coal fired plants are radionuclides and benzene. Both will probably be phased in over time but initial work should be done now to avoid excessive retrofit costs. Radionuclide emissions are of greater concern than benzene. A recent study by Oak Ridge National Laboratory for the U.S. Nuclear Regulatory Commission examined the environmental impacts of coal plants. One apparent surprise in the study involves the magnitude of possible radionuclide emissions.

> The cost of cyrogenic or alternative control equipment for radionuclide emissions should be accounted for in coal plant analysis by the Authority.

Benzene releases are possible but the nature and extent of the releases is much more uncertain than radionuclide releases. EPA is currently developing standards for benzene and they are expected sometime in June, 1978. The Authority should monitor these regulations for possible impact upon coal plant costs.

Unregulated Pollutants

The 1977 Clean Air Act Amendments require EPA to study the impact of radioactive pollutants, cadmium, arsenic and polycyclic organic material to see if they may be reasonably anticipated to endanger public health. Section 122(a). If so, Standards of Performance of national standards limiting their release will be established. This section is of most interest to coal fired plants due to the possible concern with sulfates and polycyclic organics when tall stacks are used.

10.6.2 Sensitive Areas

Plant siting is as equally critical to a generating plant as the control technology required in a plant once sited. Depending upon the site location, control costs can significantly increase. The principal factors related to a site are its location in a Non-Attainment area and/or in or close to areas protected by the Non-Deterioration provisions.

Non-Attainment Areas

Non-Attainment areas are those where the ambient condition is worse than national standards (Section 171 (2)). Non-Attainment areas can not be larger than Air Quality Control Regions but can be smaller if adequate information is available to justify the area designation. Special restrictions apply to new sources if located in a non-attainment area because of the Act's purpose of achieving national air quality standards. Basically if a plant is located in a Non-Attainment area, other sources must be cleaned up to allow the new emissions. These areas must be specially treated in the state's SIP.

For Non-Attainment areas, an inventory of all sources must be made and the additional emissions permitted are to be identified. Sections 172(b) (4,5). This information is used to determine whether a new source will permit progress to be made to attain national standards. Section 173 (1) (A).

If photochemical oxidants and CO limits cannot be achieved by December 31, 1982, an analysis of alternative sites and an evaluation of benefits and costs must be made before extension of compliance limits to December 31, 1987 is possible. Section 172 (11) (A), 172(a) (2). EPA currently appears to presume that all urban areas of greater than 200,000 population are in violation of the air quality standards for photochemical oxidants. This presumption places the burden upon Alaska when making Non-Attainment area designations to show attainment. Alaskan Non-Attainment areas are to be specified by December 5, 1977. It is possible that the Fairbanks and Anchorage areas will be designated as Non-Attainment areas for CO. Urban areas of Alaska may also be designated for Total Suspended Particulates and fugitive dust. No areas have yet been designated as Non-Attainment regions.

> The Authority should evaluate the impact of Non-Attainment area designations when made upon fuel type and site selection.

In Non-Attainment areas, all reasonably available control measures are required as expeditiously as possible. Section 172(b) (2).

In Non-Attainment areas, a permit will be issued only if progress towards national standards is made when the new source is present (Section 173(1) (A)) and the source yields the lowest achievable emission rates. Section 173 (2). New source of pollutants may not be constructed unless emissions from existing sources are reduced to more than offset the emissions from the proposed source. EPA had promulgated regulations before the 1977 amendments, commonly called the "Offset Provision," that permitted a tradeoff between phasing out or cleaning up existing sources and permitting new sources in non-attainment areas. See 41 Fed. Reg. 55524-30. These regulations are continued under the 1977 amendments (Section 129(a)), but can be expected to be revised. The 1977 amendments establish that the baseline for determining emission offsets will be those in effect at the time of application for a permit. Section 129(a) (1). The offset regulations may be extended to areas near Non-Attainment areas so the Authority should not ignore the policy merely because a site is not planned in a Non-Attainment area. The offset requirements may be waived by the EPA Administration. Section 129(a) (2). One condition for a waiver is that the state have a program which requires reduction in total allowable emissions prior to January 1, 1979 so as to result from the same level of emission if the offset were required. See Section 129(a) (2) (C).

The non-attainment provisions apply to major emitting facilities, defined in Section 169A (g) (7) which deals with PSD. In effect, a plant is subject to the requirements if it has the potential to emit 250 tons or more of any pollutant and is more than 250 million BTU/hr heat input. The potential for pollutant emission is calculated without respect to actual emission control. Such a plant must not only comply with the affect provisions but also allow "reasonable further progress". (See Section 171 (1)) towards attainment of national air standards. The plant must use as a minimum reasonability available Control Technology (RACT). The Authority should not rely upon use of RACT to satisfy the law since the plant must also employ the more stringent heat available control technology (BACT) required under the preconstruction permit provisions (See Section 165(a) (4)) and the best technological system of continuous emission reduction required under the Standards of Performance. (See Section 111(a) (1) (c)).

The State of Alaska may wish to request of EPA a waiver of the federal emissions offset policy. Under such a waiver, the state would be allowed to administer its own growth policy if it has programs which provide incremental emission reductions to assure attainment of national ambient air quality standards by 1982.

Non-Deterioration Areas

The basic issue with regard to non-deterioration areas (i.e., Prevention of Significant Deterioration, "PSD") is whether the new source will produce increases of total suspended particulates or SO_2 in excess of that permitted by law over a baseline. EPA has published rules and proposals to implement the new PSD provisions. See 42 FR 47459, 57471 and 57479.

The starting point then for non-deterioration areas is to determine how land has been classed, i.e., Class I, II or III under the Act. Most federal parks, including Mt. McKinley National Park, are designated as Class I. New federal parks would be Class II unless Congress designates tham as Class I. Every other area is Class II unless redesignated. The State has the responsibility to initiate redesignation. EPA can only object if procedural regulations are not followed. Areas can be classified as Class III if this will not result in the contribution to a pollutant concentration which exceeds the masimum in other areas. See Section 164(a) (2) (B).

The importance of area classifications is seen in the difference between the maximum allowable increases in concentration of SO_2 and particulate matter over baseline concentrations that vary with classification. For example, the three hour maximum SO_2 increment is 25 micrograms/m^3 in Class I areas, 512 in Class II and 700 in Class III.

EPA, after further study, can expand these limits to cover hydrocarbons, carbon monoxide, photochemical oxidants or NO_2, Section 166(a).

EPA recently promulgated regulations relating to the Non-Deterioration aspects of a state's SIP. These are set out in 42 Fed. Reg. 57471-57488. The Authority should review the proposal and provide appropriate comment.

In addition to the above quantitative limits, the maximum allowable concentration of any air pollutant in an area cannot exceed the lowest national standard for a pollutant. Section 163(b) (4).

Two credits against these absolute and incremental limits are allowed. The first is for temporary emissions or construction work. Section 163(c) (1) (C). The second is for concentrations coming from plants prohibited from burning gas or oil under the provisions of the Energy Supply and Environmental Coordination Act of 1974. See Section 163(c) (1) (A,B).

Class I areas under the non-deterioration provisions are specifically protected for visibility as well as SO_2 emissions. Section 169A(a) (1). After EPA develops appropriate regulations, the best available retrofit technology will be required (See Section 169A(g) (2)) unless the owner demonstrates that its project will not reasonably cause a significant visibility impairment. In Alaska's cold air, this provision could be of concern with the use of cooling towers.

The EPA required analysis for non-deterioration does not require the use of automatic or uniform buffer zones. Section 165(e) (3) (A). However, buffers are in effect required for avoiding significant impairment of visibility (Section 169A(c) (1)) or exceeding maximum allowable pollutant concentrations (Section 165(d) (2) (C)) in Class I areas. This may present a problem in connection with further capacity additions at Healy which is adjacent to McKinley National Park.

An example of this section's impact is seen in the case of the proposed Inter-mountain Power Project proposed at a site near two national parks in South Central Utah. The proposed site for a 3,000 megawatt coal fired plant is 9 miles from the Reef National Park and 50 miles from the Canyon Land National Park. The location has provoked fears that emissions from the plant could pollute the clean air over the park. The Secretary of Interior, Cecil Andrus, indicated recently that while he did not like the idea of a massive coal fired plant within 9 miles of a state park, there may be justification for locating the plant there if an acceptable alternative cannot be found.

Preconstruction Permit

All major emission sources (Section 169(1)) must be permitted by the state before construction. Section 165(a) (1). Past EPA practice required permits only in non-attainment areas; but the 1977 amendments change this practice. As conditions precedent to issuance of the permit, the owner must demonstrate that as a minimum, they are using the best available control technology. (Section 165(a) (4)). EPA has determined that this require scrubbers for SO_2 and electrostatic precipitations for particulates. However, the Standards of Performance ofr steam electric power plants will be revised and close attention should be given to the percentage requirements. If the percentage reduction is on the order of 80% it is possible that scrubbers may not be necessarily required when low sulfur coal is used. The owner must further demonstrate that there will be no violation of any ambient standard, of any Standard of Performance, or any increase over the ambient in excess of that specified in the non-deterioration provision (See Section 163(b)). Section 165(a) (3).

The application will be subject to analysis using ambient air quality monitored data (Section 165(e) (2)) obtained for a minimum of one prior year. The operator will have to assess the air quality impacts of growth due to the facility's existence. Section 165(a) (6). Depending upon a power plant's relationship to area growth, this could be a significant stumbling block in permit processing.

Two special problems arise depending upon land classification. For a plant located in a Class III area, EPA must approve the control technology used if there is no Standard of Performance for a pollutant and the plant's emissions will cause ambient levels in a nearby Class II area to be exceeded. Section 165(a) (8). For a plant near (i.e., 60 to 100 miles) a Class I federal area, the responsible federal official can file a notice alleging a potential adverse impact. If the federal official can demonstrate a violation of the non-deterioration limits will result in the Class I area, the permit will be denied. Section 165(d) (2) (C) (ii). If the owner can demonstrate that there will be no adverse impact upon the purposes of the Class I lands involved, then specific limits can be imposed (Section 165(d) (2) (C) (iv)) and a permit issues. These limits are the same as the Class II limits except for the three-hour maximum SO_2 (325 instead of 512 mg/m^3).

If a permit is denied because of air quality impacts in a Class I area, a variance procedure is available. The owner must demonstrate that there will be no adverse effect on the air quality related values of the affected Class I area. If the responsible federal official objects, the matter is resolved by the President. Special SO_2 limits, depending upon low or high terrain, are applicable if a variance is granted.

The Alaska Power Authority should actively monitor State activities to revise and develop air quality stratgies. One issue would involve how the state will allocate the non-deterioration increments to new sources. Another issue could involve whether the State would reserve part of the allowable increment for new coal fired plants. Both strategies should be analyzed.

The permit process for non-deterioration provisions can cause project delay if adequate studies are not available in a timely fashion. Sites for a plant within 60-100 miles of Class I federal areas like McKinley National Park should be closely analyzed in terms of the Section 165 requirements for SO_2 and visibility.

Air Quality and Coal Plants

The best available control technology requirement has been usually met by using low sulfur coal or pretreating the coal. These two alternatives are no longer available as a result of the definition of Standards of Performance which requires absolute emission limits as well as a percentage reduction in emissions from coal burnt in the project. Consequently, flue gas desulfurization systems (scrubbers) are the best available control technology now required for SO_2 emissions. There may be some relief from this depending upon EPA's revision to the applicable regulations. Scrubbers use about 4% of the plant output and occasion a sludge disposal problem.

> The Alaska Power Authority should make a detailed analysis of the technical, economic and legal requirements relevant to any proposed coal plant.

Another major concern for coal plants involves the release of radioactive materials. (See Section 10.6.1, Hazardous Pollutants, in this report.) Depending upon the coal source, it is probable that a conventional coal fired plant will release radiation in excess of that permitted by Appendix I for nuclear power plants. The problem may be centered on precipated fly ash which is estimated to contain about 70% of the radioactivity. Stack emissions are also a source of radionuclide emissions. The U.S. Nuclear Regulatory Commission just released a study done by Oak Ridge National Laboratory on coal plant environmental impacts. This study should be closely reviewed. While historically the federal government has preempted the jurisdiction over radionuclide emission, the Clean Air Act changed the situation as to radionuclide emissions to the atmosphere.

> The Alaska Power Authority should review the probable courses of state control over radionuclide emissions from coal plants. Cost estimates for coal plants should include radionuclide control systems.

10.6.3 Stack Heights

Stack heights are of special interest to coal-fired plants. See Section 123(a). Atmospheric loading through despersion techniques are not acceptable techniques for meeting air quality goals under the Clean Air Act. Limits on tall stacks and prohibitions against intermittent control systems for dispersion can not be considered when determining compliance with national air quality standards or PSD increments. However, the Act does permit some limited use of stacks.

The Act specifically provides that the degree of emission limitation required for the control of any air pollutant will not be affected in any manner by "so much of a stack height of any source as exceeds good engineering practice or any other dispersion technique." See Section 123(a). Good engineering practice ("GEP") will be determined in the future under regulations promulgated by the Administrator. Dispersion techniques as defined in the law include any intermittent or supplemental control of air pollutants bearing with atmospheric conditions. See Section 123(b). The Act does provide some indication of what good practice means. In Section 123(c) it indicates in effect that good practice is that height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source, as a result of that atmospheric downwash eddies and wakes that may be created by the source, nearby structures, or nearby terrain obstacles.

Of particular importance in Non-Attainment areas is the EPA policy on retroactive application of PSD rules for stack heights. EPA has taken the position that if any increment under PSD would have been violated had all esisting sources been limited to GEP stack height, no additional sources would be able to locate in the area. The Authority should review other plants in potential site areas in light of this policy.

This stack height limitation is particularly important with respect to the location of plants in valleys. The stack height is important because a taller stack permits more diffusion by emissions. Thus Class II increments in non-flat terrains can be minimized by taller stacks. This allows plant size to be increased. But the Act restricts stack height to less than 2.5 times the height of the source unless the owner demonstrates that the greater height is necessary. See Section 123(c).

> The Alaska Power Authority should consider terrain, stack height, power plant size and emission limits when studying alternative plant sites.

10.6.4 Energy Production Considerations

State Review for Oil or Gas Plants

Each state is required to review its SIP with respect to major fuel burning sources. Section 124(a). The purpose is to determine the extent to which compliance with the plan is dependent upon the use of oil or natural gas or non-local coal and the extent to which this dependent is inadequate. Section 124(a) (1-3). EPA is to review this state search and require revision to the SIP to account for prohibitions on oil or natural gas. This review by Alaska should be analyzed by the Authority.

Prohibition on Oil or Natural Gas

The FERC (formerly FEA) has authority to prohibit the burning of natural gas or oil (Section 2(a), PL 93-319: Energy Supply and Environmental Coordination Act of 1974). The order is not effective until EPA notifies NERC that the plant will be able to burn coal and comply with all applicable air pollution requirements without a compliance date extension.

EPA can suspend any emission limitation other than primary standards (Section 119(b) (1) (A) (ii)) if the plant has been prohibited from using oil or natural gas under Section 2(a) of the Energy Supply and Environmental Coordination Act. Section 119(c) (1) (A). Compliance date extensions are available until January 1, 1979 if the available coal cannot be burnt without the extension and primary standards will be complied with during the extension. Section 119 (c) (2). The plant will have to achieve the most stringent degree of emission reduction otherwise required under the SIP. Section 119(c) (2) (C).

10.6.5 Uncertainties for Alaska

Two principal uncertainties are present in evaluating the cost of the Air Quality Act's effect upon projects in Alaska. The first is associated with delay in the licensing process. The second is associated with the development of standards that depend in part upon the areas in which a plant is to be located.

> Licensing delay can be caused by such things as the failure to have one year of continuous ambient air quality monitoring or other meteorological data to support an application or failure to adequately consider growth resulting from

> generating plant availability. The Alaska Power Authority should prepare a study schedule for any proposed site and its alternatives at least two years before any application. This work should be coordinated with NEPA's procedures.
>
> The Authority should monitor the Department of Environmental Conservation's work on revision of the SIP.

Under the influence of the recent Air Quality Act amendments, the reclassification of Alaskan areas as Class III or Class I to remedy can have a measurable impact upon environmental control requirements. The extension of Class I areas can also inhibit site alternatives if a plant site in a Class II area affects air quality or visibility in the Class I areas. The development of standards for NO_2 and for radioactive materials can occasion the need for further treatment.

> Consultation with State personnel involved in air quality plans is a necessary prerequisite to avoiding significant impacts upon site availability and air control costs.

10.7 COASTAL ZONE AREAS

The probability of a power plant site or alternative being in the coastal zone of Alaska is fairly high. While the State is not required under federal law to have a coastal zone management program, its existence could significantly influence energy development since the Plan must provide a mechanism to assure that local regulations do not unreasonably restrict uses of regional benefit. Financial assistance is available to develop the program. Once an approved plan exists, Alaska could seek grants to mitigate losses resulting from a coastal zone energy activity.

10.7.1 Coastal Zone Management Act

Congress has found a national interest in the effective management, beneficial use, protection and development of the coastal zone. 16 USC Section 1451. With respect to energy, Congress noted:

> The national objective of attaining a greater degree of energy self sufficiency would be advanced by providing federal financial assistance to meet state and local needs resulting from new or expanded energy activity in or affecting the coastal zone.

16 USC Section 1451(i).

Under the Coastal Zone Management Act, the federal government provides funds to a state for the development of a management plan. At the present time, Alaska has not developed a Coastal Zone Management Plan. The development of such a plan by Alaska could have significant impacts upon energy development. The plan would cover coastal waters including those adjacent to the shorelines which contain a measurable quantity or percentage of sea water, including but not limited to sound, bays, lagoons, ponds and estuaries. See 16 USC Section 1453(2). The state plan would have to specify for these areas what constitutes permissible land water uses which have a direct and significant affect on the coastal zone, including but not lmiited to a process for anticipating and managing the impacts from such facilities. See 16 USC Section 1454(b) (2,8). The plan would be subject to federal review. Among the criteria for federal acceptance is a provision that the management program must provide for adequate consideration of the national interest involved in planning and siting of facilities which are necessary to meet requirements which are other than local in nature. 16 USC Section 1455(c) (8). The program must provide a method of ensuring that local land and water use regulations within the coastal zone do not unreasonably restrict or exclude land and water uses of regional benefit. 16 USC Section 1455(e).

> Alaska's development of a Coastal Zone Management plan would most likely involve legislation to assure that local governmental activities do not preclude a project which is in the national or regional interest.

10.7.2 Coastal Energy Impact Program

The Secretary of Interior is responsible for developing a coastal energy impact program. See 16 USC Section 1456(a). This program provides financial assistance to meet the needs of the state resulting from specified activities involving energy development. The provision may be worthwhile for handling potential water quality problems in the Chuitna River arising from the Beluga coal development.

The Secretary has the authority to make grants to any coastal state if he finds that it is being or likely to be significantly affected by the siting, construction, expansion or operation of new or expanded energy facilities.

> Investigation of this funding source by the State of Alaska may be appropriate to assist in developing a Coastal Zone Management Plan that would provide assistance to the development and establishment of new power facilities.

The Secretary is also authorized to make grants to enable it to prevent, reduce or ameliorate any unavoidable loss of any valuable environmental or recreational resource in the state's coastal zone if such loss results from coastal energy activity. 16 USC Section 1456a(b) (4). To qualify, a state must have an approved coastal zone management program. See 16 USC Section 1455.

> The Alaska Power Authority may wish to suggest that Alaska develop an approved Coastal Zone Management Plan so as to qualify for impact mitigation grants.

10.8 LAND

Because of the immense federal land holdings in Alaska, plant sites and line toures necessitate an identification of the type of federal land on which they are located. This is necessary to properly evaluate and cost out proposed and alternative sites. Obtaining rights-of-way where allowed by law involves actions which are subject to NEPA. Consequently, land rights-of-way permit applications could be useful in early initiation of the preparation of an EIS for a proposed power generation project.

Federal law restricts certain activities on federal lands depending upon the reason for which the land was set aside. A brief review of land use characteristics for various federal land types follows.

10.8.1 National Wildlife Refuges

National Wildlife Refuge System lands may be used for power line routes. 16 USC Section 668 dd. Easements in, over, across, upon, through or under any areas for purposes such as, but not necessarily limited to power lines, pipe lines and roads are permitted. The use must be compatible with the purpose for which the area is established.

10.8.2 National Forest Lands

The Secretary of Agriculture, in conformity with regulations that he has established, may permit the use and occupancy of National Forest lands in

Alaska for purposes of industrial use for periods not exceeding thirty years, and for areas not exceeding 80 acres. 16 USC Section 497a. However, such use must not be incompatible with the best use and management of the National Forests. The Secretary is also authorized to permit the use of rights-of-way through the National Forests for electrical plants, poles and lines for the generation and distribution of electrical power. See 16 USC Section 522. The rights-of-way shall not exceed 50 feet on each side of the marginal limits nor exceed 50 feet on each side of the center line of the pipes, electrical lines and poles. The permits may be issued only after a finding that the use is not incompatible with the public interest. Similar rights-of-way under 16 USC Section 523 are limited to 50 years.

10.8.3 National Wilderness Preservation Systems

A Wilderness Area is one which is untrammeled by man and where man himself is a visitor who does not remain. 16 USC Section 1131(c). Such areas are to be devoted to the public purposes of recreational, scenic, scientific, educational, conservation and historic uses. See 16 USC Section 1133(b). No commercial enterprise nor permanent road is permitted with a Wilderness Area except as is necessary to meet minimum requirements for administration of the area. See 16 USC Section 1133(c). However, reservoirs, power projects and transmission lines needed in the public interest are permitted by Presidential action. See 16 USC Section 1133(d) (4). Such use in a specific area must better serve the interests of the United States and the people thereof than will its denial. 16 USC Section 1133(d) (4).

Current Wilderness Areas in Alaska include the Forrester Island Wilderness, Hazy Island National Wildlife Refuge, St. Lazaria National Wildlife Refuge, Puxedini National Wildlife Refuge, Bering Sea National Wildlife Refuge, Chamisso National Wildlife Refuge, and Simeonof National Wildlife Refuge. 16 USC Section 1132. However, this listing may be considerably expanded when the "D-2" land issue is resolved. (See Section 10.8.5 of this report.)

10.8.4 National Parks, Military Parks, Monuments, and Seashores

Rights-of-way through National Parks, Military Parks, Monuments or Seashores are permitted for periods not to exceed fifty (50) years. They may be granted for purposes of establishing and maintaining electrical poles and lines for the transmission and distribution of electrical power to the extent of 200 feet on each side of the center line of such lines and poles. There must be a finding that such use is not incompatible with the public interest. See 16 USC Section 5. Rights-of-way are permitted through the public lands, forests and other reservations of the United States for electrical plants, poles and lines for the generation and distribution of electrical power. Reservoirs for power production are not permitted. Such rights-of-way are limited to 50 feet on each side of the marginal limits of the lines. 16 USC Section 79. Rights-of-way granted under 16 USC 79 and 522 are available in Mt. McKinley National Park if they are consistent with the park purposes. 16 USC Section 349.

10.8.5 Alaska Native Settlement Claim Act

The Alaska Native Settlement Claim Act authorized Alaskan villages and native corporations to take possession of certain lands. In the selection of those lands, prior land patents which had been issued for the surface or minerals are to be protected. See 43 USC Section 1611(g). The Cook Inlet Region, Inc. as a Native Corporation is entitled to land which might relate to a proposed power project. Early consultation with it is advised.

A significant amount of Alaska land can also be withdrawn by the federal government for classification as national parks, wildlife refuges, national forests and wildlife rivers. See 43 USC 1616(d) (2). This has been identified as the "D-2" land issue currently before Congress. Under the recent proposal announced by Interior Secretary Cecil Andrus, a total of about 92 million acres would be withdrawn by the federal government. This includes about 41.7 million acres for national parks, 45.1 million acres for wildlife refuges, 2.45 million acres for wild and scenic rivers, and about 2.5 million acres would be withdrawn for boundary adjustments to be added to the National Forests for multiple use. A Wilderness categorization is proposed for 30.2 million national park acres and 13.1 million wildlife refuge acres. Most of Admirality Island would be recommended as wilderness.

Review and monitoring of proposed withdrawals under the D-2 land issue will be important because of restrictions upon the use of such lands under other provisions previously discussed. Consideration should be given in Congressional resolution of the "D-2" land issue to a provision provision allowing power projects to utilize any land withdrawn so as to preclude denying site availability.

10.8.6 Surface Mining Control and Reclamation Act of 1977

President Carter signed the Surface Mining Control and Reclamation Act of 1977 (Pub. L. 95-87; "SMC&R Act") on August 3, 1977. Congress found in the Act, among other things, that coal mining operations contribute significantly to the energy requirements of our nation. However, many surface mining operations result in disturbances of surface areas that burden and adversely affect commerce and the public welfare. Consequently, Congress found there is a need to control coal mining and to establish appropriate standards to minimize damage to the environment and the productivity of the soil. Section 101(d), SMC&R Act.

The Act bans mine highwalls and requires the land to be restored to its approximate original contour in most cases. No mining in prime farmland is permitted unless the operator ahs the technological capacity to restore the area in a reasonable time. Even so, no material damage to water quantity or quality is permitted. Standards for an adequate reclamation plan are specified in the Act. If federal coal is mined, consent must be obtained from the surface landowner before mining is permitted. This provision could be important to Alaska because Village Corporation land selection under 43 USC Section 1613(a,b) provides for title only to the surface estate. However, the Village Corporation must consent to the exploration, development and removal of any subsurface estate minerals. 43 USC Section 1613(f).

Alaska Provisions

Two specific provisions in the SMC&R Act deal with Alaska. An indepth study by August 3, 1979 of surface coal mining conditions in the State of Alaska may be done to determine which, if any, of the provisions of the SMC&R Act should be modified with respect to surface coal mining operations in Alaska. Section 708, SMC&R Act. Until the study is completed, the Secretary is authorized to modify the applicability of any environmental protection provision of the SMC&R Act or any regulation issued pursuant thereto for any surface coal mining operation in Alaska but only if the operation was "mined during the year preceding enactment of this Act". Section 708(d), SMC&R Act. For new mines, the Secretary is authorized to issue interim regulations which reflect modifications for the environmental standards based upon the special physical, hydrological and climatic conditions in Alaska. The modifications must still protect the environment to an extent equivalent to those standards for non-Alaskan coal regions.

> A detailed technical review of the standards and the proposed modifications required for Alaska should be initiated at the earliest possible time to assist the Secretary in modifying coal mining standards for Alaska.

Section 716 of the SMC&R Act indicates that nothing in it diminishes the rights of any owner of coal in Alaska to conduct or authorize surface coal mining operations for coal which have been or hereafter will be conveyed out of federal ownership to the State of Alaska or pursuant to the Alaska Native Claim Settlement Act. However, Section 716 requires that surface coal mining operations for these lands meet the requirements of the Act. It is not certain whether this would affect the need to get the surface estate owner's consent prior to mining required by Section 510(b) (6) of the SMC&R Act.

Unsuitable Mining Areas

Certain areas may be designated as unsuitable for surface coal mining under the Act. Section 522, SMC&R Act. Such areas include those that (a) are incompatible with existing state or local land use plans or programs, (b) affect fragile or historic lands in which such operations could result in significant damage to important historical, cultural, scientific, and aesthetic values and natural systems, (c) affect renewable resource lands in which such operations could result in a substantial loss or reduction of long-range productivity of water supply (including aquifers and aquifer recharge areas) or food or food fibers, and (d) affect natural hazard lands in which such operations could substantially endanger life or property (such lands to include areas subject to frequent flooding and areas of unstable geology).

> A review of proposed Alaskan coal mining areas of interest to the Authority should be made with the unsuitable mining area criteria in mind to determine whether such proposed areas might be presumed or found to be unsuitable.

Federal Control of Surface Mining

The Federal Government may directly control surface coal mining even though states are given the primary responsibility under the Act. One way is if the surface mining operation is conducted on federal land. See Section 523(a), SMC&R Act. In this case, any SMC&R state adopted and approved standards will be imposed as a minimum. See Section 523(a), SMC&R Act. The SMC&R Act's and the federal lands program's (or an approved state program's requirements) are to be incorporated by reference into any permit which has been issued for federal lands. Section 523(b), SMC&R Act.

On non-federal lands, the federal government will control the operation of surface mining under Section 502(e) until a state program has been approved. The federal government will also regulate if a state fails to adopt a program or if the state program is not approved by the federal government. Section 504(a) (1-3), SMC&R Act. In such a case, the federal government shall have exclusive jurisdiction for the regulation and control of the surface coal mining and reclamation operations taking place on lands within the state not in compliance with this Act.

> Considering the opening of the Beluga Field, Alaska should act rapidly to gain state program approval if federal control is not desired. The Secretary's interim regulations (See 42 Fed. Reg. 44920, et seq.) should be reviewed to determine cost and process impacts.

The Alaska plan must fulfill the requirements of Sections 503(a) (107). The plan must establish a process for avoiding duplication in, and a process for coordinating, the review and issuance of permits for surface coal mining and reclamation operations with any other federal or state permit process applicable to the proposed operations. Section 503(6), SMC&R Act. Fulfilling this provision may provide a method to expedite the federal and state licensing processes otherwise applicable to a coal mining operation and require legislative changes to state laws involving air, water, land, flora, and fauna resources.

State Permit Requirement

Any new surface coal mining operation must obtain a permit from the state regulatory authority if the state has an approved plan. Permits that are issued cannot exceed five years. See Section 506(b), SMC&R Act. To minimize operator investment uncertainties, there is an automatic renewal unless operations are extended beyond that originally identified in the initial permit.

> The Alaska Power Authority if it would operate a coal mining project should attempt to seek a permit for the largest possible area when initially applying.

When submitting a permit application, the method and type of coal mining operation that is proposed as well as the engineeirng techniques and equipment proposed must be described. Identification of probable hydrologic consequences of the mining and reclamation operations "both on and off the mine site" are required. See Section 507(b) (11), SMC&R Act. Farm lands have a special importance under the Act and they must be identified and specific provisions provided for their protection. A Reclamation Plan is also required. See Section 507(b), SMC&R Act. The operator must assess, among other things, the probable cumulative impact of all anticipated mining in the area on the hydrologic balance specified in Section 507(b). See Section 510(b), SMC&R Act. This broadens the aspects of consideration for alternatives and environmental controls that would have to be considered pursuant to NEPA if another permit issued by the federal government would be required. This may suggest a preference for lands not located on federal properties.

Reclamation Plans

The requirements of a Reclamation Plan are specified in Section 508. One of the elements of the plan is that it must assure the quality of surface and ground water systems both on and off site against adverse affects due to mining and reclamation processes. See Section 508(a) (13) (A), SMC&R Act. The specific requirements of the Reclamation Plan should be reviewed to evaluate cost impacts.

Reclamation Fee

Under Section 402(a), operators of coal mining operations shall pay the Secretary of the Interior a reclamation fee of 35 cents per ton of coal produced by surface mining or 10% of the value of the coal at the mine whichever is less.

Permit Conditions

The broad nature of possible conditions imposed upon a permit under Section 515(b), SMC&R Act, are such that proper cost evaluation is largely site-dependent. For example, Section 515(b) (1) requires that the surface mining operation be conducted so as to maximize the utilization and conservation of the solid fuel resource so that reaffecting the land in the future through surface coal mining can be minimized. Uses which the land was capable of supporting prior to any mining, or high and better uses of which there is reasonable likelihood, must be restored. Section 515(b) (2), SMC&R Act. All surface areas including spil piles must be stabilized and protected. Section 515(b) (4), SMC&R Act. Steep slope areas, those with slopes greater than 20°, have special standards. See Section 515(d), SMC&R Act.

> The Alaska Power Authority should review the requirements in Section 515 of the SMC&R Act in detail for its probable impact upon the operation and restoration costs of a surface coal mine.

10.8.7 Solid Waste Disposal

The adequacy of the disposal techniques for solid waste used throughout our country has long been questioned. An objective of the Solid Waste Disposal Act Congress passed in 1976 was to define sanitary land fill requirements for disposal of solid waste and hazardous waste. Standards developed apply to all federal agencies. 42 USC Section 6964(a) (1). The standards also apply to any person using federal property for purposes of disposal of solid waste. 42 USC Section 6964(a) (3).

Solid waste disposal costs could be significant for coal plants. For example, a plant burning 3% sulfur coal will produce about one-quarter ton of waste for each ton of coal consumed. If federal land is used to dispose of scrubber wastes for coal plants, the cost of compliance with these standards should be evaluated. Such evaluation should consider balancing chemical treatment of wastes against untreated landfill protection costs because of leachate concerns.

10.9 FLORA AND FAUNA

Federal law prohibits the taking of any Bald or Golden Eagle. See 16 USC Section 668. "Taking" is defined in this statute to include any action to molest or disturb the animals. If any Bald or Golden Eagle might be within the area of a proposed facility's impact, particularly with respect to influence zones for noise or air pollutant emissions, special attention should be given to avoid any disturbance to the birds.

Seals and otters (16 USC Section 1151) and other marine mammals (16 USC Section 1632(13)) are protected by federal law. The definition of taking for seals and otters is "kill" which would render a plant operator less exposed to violation than in the case of eagles. However, taking of marine mammals includes any harrassment. An argument can be made that discharges from a power plant can harrass a marine mammal. Consideration of mitigating measures for coastal power plants should be made.

Congress has also established specific provisions dealing with endangered species. Endangered species, defined in 16 USC Section 1531, are those various species of fish, wildlife and plants rendered extinct or so depleted in numbers that they are in danger of, or threatened with, extinction, or those fish, wildlife and plants that are of aesthetic, ecological, historical, educational, recreational and scientific value. Presently identified endangered species are set out in 50 CFR 17.11 et seq. This list should be compared against flora and fauna surveys in a proposed project area.

All federal departments and agencies must seek to conserve endangered species and threatened species, and are required to utilize their authority in furtherance of the purposes of this Act. See 16 USC Section 1531(c). Such authority to further the protection purposes would include the denial of any permit to otherwise construct or operate a power project required under federal law. Since the taking of any endangered species is defined to include any harrassment or harm to the species, the cost of mitigating conditions to avoid any taking of such species could be important.

10.10 ALASKA ENVIRONMENTAL LAWS

Power development involves the use of natural resources in Alaska. The first touchstone for consideration of the impact of Alaska law is in its Constitution. Article VIII, Section 17, of the Constitution requires that laws and regulations governing the use and disposal of natural resources shall be applied uniformly. This would not prevent the establishment of different regulations for various types of fuel sources, so long as there is a reasonable classification supporting the difference. Sections 1 through 3 of Article VIII contain general provisions dealing with natural resources. Section 1 provides that the State's policy is to provide for maximum use of its natural resources, but such use shall be consistent with the public interest. Section 2 further indicates that the use of all natural resources shall be for the maximum benefit of the people. These provisions permit the argument that the allocation of certain natural resources for a power development is required if it is for the maximum benefit of the people. Section 3 reserves fish, wildlife and water of the State for the benefit of the people. However, surface and subsurface waters are subject to appropriation. Article 8, Section 3, State Constitution.

10.10.1 Energy

Alaska's energy policy must be inferred from existing law. In effect, the policy is to assure needed power at the lowest possible cost to the consumer. See for example Alas. Stat. 44.46.010(b).

> State policy reflected in the Authority's enabling statute should be revised to provide for "reasonable power costs" instead of "lower consumer/power costs".

While this statutory change would preserve Authority discretion on power costs and project approval, its decision would be less subject to attack. The attack, based upon conservation goals, could be argued from the Constitutional provisions dealing with allocation of natural resources, that is trading resource use now for lower power costs is not to the maximum interest of the state. (See particularly the discussion of the Marbet case in Section 10.1.1 of this report.)

10.10.2 Water

The State water policy is to conserve, improve and protect its natural resources. Alas Stat. 46.03.010(a). In furtherance of that responsibility, water resources are to be developed and managed to the end that the State may fulfill its responsibility as trustee of the environment for future and present generations. The responsibility as a trustee can be argued to impose a duty to deny allocation of resources for use by present generations for the benefit of, and reservation of the resources for future generations.

Emerging Water Issues

Pursuant to the Federal Water Resources Planning Act of 1965, the Alaska Water Study Committee was formed to initiate a statewide planning effort. That study is currently underway with some parts having been finished. With about seventy percent of the state population residing within the 300 mile radius of the City of Anchorage, and the adjacent areas having been intensively used for recreation and natural resource development, the Study Committee believes that long-range planning is needed for effective management and conservation of the existing water resources of the area and to prevent future problems arising from increased demand and limited supply, In the near term, plans will be provided for coordination of all water use activities in the State and to encourage desirable benefits for water use while discouraging over-development.

> The Committee"s water use coordination work could significantly affect power development because of the alrge consumptive withdrawals associated with cooling towers and non-consumptive use in coal mining. The Alaska Power Authority should maintain technical liaison with the Alaska Water Study Committee.

Hydroelectric reservoir evaporation in Alaska is quite low at the present time. However, as hydroelectric development occurs, this should be of increasing concern to local meteorological conditions. Development of hydroelectric facilities can modify downstream flow both with respect to quantity and quality.

The Study Committee has identified the following concerns to be accounted for in evaluating the water availability for proposed power projects. Probable sites should be identified so that water quality and quantity aspects of a site and its alternative can be properly and timely evaluated. If a site involves an area of natural beauty, the increased recreational use of the more accessible rivers, lakes and estuaries should be considered in site development. The expansion of wild and scenic rivers is something that must be realistically contemplated since some 42 Alaskan rivers have been selected for study for such designation.

Concern has been expressed for the larger rivers and river bottoms which provide avenues of migration from and to the sea. To provide free migration, the rivers should be clear of physical or chemical obstructions so that both resident and migrating fish may be able to pass. Concern with respect to discharge and intake locations will be relevant and must be considered in site selection studies. The timing of migration and passage of juvenile and adult salmonids should be considered.

Estuarine areas pose particular water related problems. Coastal areas, both fresh and saline, play an essential role in supplying primary food and nutrients to adjacent estuaries. At the present time, only a small fraction of Alaska wetlands have been altered by man, but with increasing development particularly with large-scale mines and/or power plants, concern over the State's wetlands will increase. Because of such things as the failure in 1974 and 1975 of salmon return which may have resulted in part from inhospitable natural conditions in major estuaries when young salmon migrated seaward in the spring, it can be reasonably anticipated that State agencies will be seriously concerned with respect to any plant location in an estuarian area.

The problem is not limited to coastal areas. Erosion of stream banks and sedimentation of streams is of serious concern because of possible fish habitat destruction. Rapid erosion and sedimentation action in larger rivers often produces shifting of bars and islands and impairs navigation. The fine textured sediments contained in Alaskan rivers provide absorbtive surfaces for chemical contaminants added to the rivers. All of these factors indicate concerns that should be examined specifically with respect to the discharges from proposed power plants.

Water quality problems are tending to emerge particularly in the Cook Inlet area. Part of the problem is the result of increases in population. Ground water sources in the Anchorage area and water supply problems in the Kenai Peninsula area, the increased demand for domestic and industrial water and the resulting waste water effluents from these operations may have an adverse effect on in-stream water quantity and quality resulting in degradation of the associated fish, water fowl and wildlife habitat. Concerns over the development of the Beluga Coal Field have already been identified due to the shallowness of nearby waters, the lack of part facilities and shoaling on that side of the inlet that may hamper shipping.

IN-stream flow needs also can be affected by power plant operation. A primary example involves the degradation of water quality as the result of either the reduction of flow due to withdrawals of water for cooling or from the discharges resulting after operation of the plant. Large withdrawals can increase the concentration of dissolved chemical constituents downstream from diversion. With a narrow range in temperature critical to salmon spawning habitat in streams and fish passage affected by the synergistic affects of disease and chamical constitutents of the discharge with temperature, concern over plant discharges and their effects upon fish and wildlife habitats can be expected to be of serious concern in Alaska.

While Alaskan statutes do not expressly protect in-stream flows for fish and wildlife uses, there seems to be constitutional basis from the provisions previously cited for such an approach. Arguably minimum in-stream flows could be established if the Department of Environmental Conservation can establish that such flows are necessary to assure water quality for protection of a stream's best usage. See Alas. Stat. 46.03.080. Maintenance of in-stream flow requirements for fish and wildlife in terms of portions of monthly flow has not been done. One can anticipate an increasing effort in this area in order to specifically evaluate the impact of a large power plant discharge upon the fish and game. Establishment of in-stream minimum flows could restrict a power project's operation or require cooling-water recycling.

Water Pollution Control

Any pollution or addition to the pollution of the waters of Alaska is prohibited. As with the National Pollutant Discharge Elimination System (NPDES) permit issued by the federal government (EPA, Region X), Alaska also has an industrial discharge permit provision. See Alas. Stat. 46.03.100. Under recent law, the state permit requirement can be waived and an NPDES permit used in lieu of its own waste discharge permit. Alas. Stat. 46.03.110(e).

Waste disposal permits generally require that the discharge cause no pollution. Pollution is inferred from the violation of any established water quality conditions. In the State discharge permit, the department may specify the terms and conditions under which waste material may be discharged. Alas. Stat. 46.03.110. These terms and conditions are to be interpreted in the sense that they should be directed to avoiding pollution and to otherwise carry out the policies of the Chapter. See Alas. Stat. 46.03.110(d). The conditions normally contemplated within the ambit of the State discharge permit are those conditions necessary to assure compliance with the applicable water quality standards.

The water quality standards vary with different classifications for water bodies. The Department of Environmental Conservation water quality standards and stream classifications are set out in Chapter 70, Title 18 of the Alaska Administrative Code.

> Applicable water quality standards for various power plant sites should be reviewed as necessary to evaluate control costs.

A significant provision of water quality standards is the general provision requiring that waters with quality better than established standards are to be maintained at that high quality. In other words, if the ambient water quality conditions are better than the limits established under the applicable State water quality standards, then the ambient conditions are substituted for the numbers there. See 18 AAC 70.010. The issue then arises whether a discharge can be made that results in some variation of the ambient conditions. Alaska permits a variance in the ambient standards if: "It has been affirmatively demonstrated to the department that a change is justifiable as a result of necessary economic or social development, and that change shall not preclude the present and anticipated uses of such waters."

To properly evaluate the economic differentials for various sites, review should be made of ambient water quality conditions as compared to the established water quality standards in the State regulations.

An essential difference exists between the application of water quality standards and effluent limitations in a discharge permit. The former, the water quality standards, is related to the water quality for a body of water that receives the discharge; while the latter, the effluent limitations, apply to the nature of a specific discharge at the point of discharge. A power plant might discharge materials which would violate the ambient water quality conditions at the point of discharge, but upon subsequent mixing in the larger volume of the receiving water fall within the prescribed standards. An accepted process for handling this situation exists in the State of Alaska's water quality procedures, that is, the definition of a mixing zone. See 18 AAC 70.030(3). The regulations specifically allow the use of a mixing zone, which is a limited area inside of which violations of the water quality criteria will not be found. The mixing zone must be of limited volume, not interfere with biological communities of important species to a degree which is damaging to the ecosystem, and not diminish other beneficial uses disproportionately. See 18 AAC 70.030(3).

A review of the procedures used by Alaska in determining the size and extent of mixing zones is important in determining the extent to which the design of the discharge can favor or disfavor a proposed site.

The issue of mixing zone size is critical to plant availability since with too small of a zone plant operations could be shut down during ambient low flow conditions when sufficient volumes of water are not available for mixing.

Review of the seasonal water flows past a possible diffuser location should be evaluated since this could have a significant impact upon the economics of a particulat site.

The State of Alaska may in effect require a power plant operator to comply with conditions more stringent than the federal effluent limitations. This can be done through Section 401 of the FWPCA of 1972 which requires a state certification as a condition precedent to the issuance of the NPDES permit. In the 401 certification the state must indicate that the proposed discharge will comply with the provisions of the applicable effluent limitations as well as water quality standards. To the extent that the state determines that conditions more stringent than the effluent limitations should be imposed, they have the opportunity to propose such conditions through Section 401 utilizing the process set out in Section 302 of the FWPCA of 1972.

<u>Water Rights</u>

Waters in Alaska are reserved to the people for their common use. Article VIII, Section 3, Alaska Constitution. But they shall be utilized for the maximum benefit of the people. Article VIII, Section 2, Alaska Constitution. All waters in the State of Alaska are subject to appropriation. Article VIII, Section 13, Alaska Constitution. The appropriation of water rights is within the jurisdiction of the Department of Natural Resources. See Alas. Stat. 46.15.010 generally. Under the Alaska statutes, the state generally provides that the right to water is based upon the date of filing of an application for appropriation. Alaska does not specifically provide that appropriations may be reserved for use at some time in the future. Alas. Stat. 46.15.110 does provide that a permit may include a time limit for the beginning of construction and the perfection of appropriation.

> The Alaska Power Authority should explore the procedures for making application for water rights to support proposed power project developments with a time limit for the permit reasonably similar to the expected time period within which the project may be brought on line. Legislative clarification of water rights reservation for power projects may be necessary.

A water permit will be issued if basically it is determined to be in the public's interest. Alas. Stat. 46.15.080 sets forth eight specific factors that the Commissioner of Natural Resources shall review in making such a determination. Since one of the factors relates to the effect upon fish and game resources,

> consideration should be given to the cost of mitigation measures for fish and game resources that may be required in particular streams as a result of the diversion of substantial quantities of water for cooling of a power project.

As a general matter, the operation of a cooling tower is dependent upon the intake temperature of the cooling water.

> Because of the relatively average low temperatures of Alaskan waters, this factor's impact upon design parameters, water use demands and the cost of a cooling tower should be considered.

Water Aspects of Coal Development

A principal distinction among fuel types for water quality impacts involves surface coal mining. Among the factors principally impacted by water use for surface coal mining are turbidity, color, suspended solids concentration, heavy metals concentration, dissolved oxygen, and dissolved organic concentration. In addition to the individual factors, the synergistic effect of these discharge characteristics on aquatic biota must be considered. Removal of an area's vegetative cover for surface coal mines can affect the thermal regime of the runoff and impact the water quality of the ambient streams.

> Economic evaluation of measures to mitigate coal mine runoff impacts should be considered in differentially evaluating the costs of fuel types.

The adverse impact to water quality can be minimized with available technology to meet both water quality standards and effluent limitations.

> The vosts of control measures to minimize adverse impacts to water quality in Alaska, particularly as required to meet the non-degradation clause in the Alaska water quality regulations, may be unknown but should be considered as an additional economic factor.

Water Aspects of Hydroelectric Development

Water quality impacts peculiar to hydroelectric development can be exposed by a quick review of the problems which have emerged recently with the major hydroelectric facilities located on the Columbia River. These include the nitrogen supersaturation impacts from dam spillage as well as the necessity to provide for fish passage. These two factors may be prominent for any hydroelectric development in Alaska due to dependence upon the fish resources as an inherent element of the economic activity base. By the storage and controlled release of waters behind a dam, the downstream thermal regime may be impacted with consequent impact upon fish migration and residence. The impact of the hydroelectric facility upon a river's thermal regime has not yet been prominent in FPC proceedings. It is probable that the Federal Energy Regulatory Commission in the future would consider, particularly at the urging of a state agency, the requirement that controlled releases be made to minimize the differential effect upon the stasonal thermal regime of the river. This could have an impact upon power availability and storage capacity for a hydroelectric facility and should be evaluated when determining project output.

Water Aspects of Cooling Tower Operation

Fossil fueled steam/electric generating facilities under the applicable effluent limitations promulgated by EPA are presumptively required to have a cooling tower. Supplementary cooling may be required in order to meet applicable water quality standards because of differential in outlet temperature from the cooling tower and the ambient receiving water conditions.

Cooling towers significantly increase consumptive use of water as compared to once-through cooling. Depending upon the stream by which a power facility in Alaska is located, the consumptive use question could become a rather significant one in state proceedings for a water appropriation. Presently, EPA effluent limitations do not permit uncontrolled discharges of cooling water to a manmade lake utilized as a cooling pond.

> Depending upon the economics and the advisability of pursuing a cooling pond approach as distinguished from a direct discharge to a receiving water body, consideration should be given by the Alaska Power Authority to efforts directed at EPA's adoption of regulations permitting use of cooling lakes.

10.10.3 Air

A major weather problem in the Fairbanks area is stagnant air caused by thermal inversions and the surrounding topography. Consequently, stack heights as a means of emitting pollutants above the inversion level are an important factor in evaluating the impact of Alaska air quality standards. See Section 10.6.3 herof. But stack heights are not an adequate answer due to restrictions in the Clean Air Act Amendments of 1977.

Alaska has established ambient air quality standards. See 18 AAC 50.020. Standards apply to suspended particulates, sulfur oxides, carbon monoxide, nitrogen dioxide and reduced sulfur compounds. Alaska's standard for suspended particulates is more stringent than the federal ambient air quality standards. Alaska does not presently have a standard for hydrocarbons as is the case with the federal standards.

Alaska also has a non-degradation regulation which could be interpreted, depending upon agency policy, the same as the Clean Air Act Non-Deterioration Policy. See 18 AAC 50.020. Alaska may impose emission control requirements to prevent, abate or control air pollution. The regulations may vary from area to area as appropriate. See Alas. Stat. 46.03.140. A permit is required for all fuel burning electric generating equipment of greater than 250 kilowatts capacity. 18 AAC 50.120(c).

> Air quality permit requirements and procedures may be changed as a result of the 1977 Clean Air Act Amendments so review with the Department of Environmental Conservation is advised.

A variance from applicable emission control regulations is possible. See Alas. Stat. 46.03.170. But such variances granted under State law will be controlled by the 1977 amendments to the Clean Air Act. Under present State law, a variance may not be granted unless there is no practical, known or available technology for the adequate prevention, abatement or control of the air pollution involved. The economic impacts of utilizing any practicable means known or available may impose costs upon a project as a result of the startup time associated with proving the existence of such material or equipment. The federal Clean Air Act does provide some limited relief in this matter. See Section 111(b), Clean Air Act Amendments of 1977.

A particularly important provision of the Alaska Air Quality standards which would relate to power project development is the ice fog limitation contained in 18 AAC 50.090. This provision basically allows the Department to impose such conditions as a result of granting a permit to reduce the water emissions in areas of potential ice fog. While no comparable standard exists in federal law, the requirements for visibility protection in federal Class I areas is analogous. See Section 169A, Clean Air Act Amendments of 1977.

Because of the requirement for cooling towers, the conditions necessary to eliminate or mitigate the drift from a cooling tower could cause important economic penalties. Site selection may eliminate ice fog problems and utilization of once-through cooling may be an alternative if otherwise permitted under federal law.

10.10.4 Coastal Zone

Coastal zone area sites are subject to requirements for public access. Alas. Stat. 38.05.127 is applicable on its face to any land to be acquired from the State which is adjacent to any body of water. This arguably includes the coastal zone areas. While the remainder of the statutory language in Section 38.05.127 appears directed towards rivers inland from the coastal area, considerations should be given to provision for free access to the public if a coastal site is pursued.

The principal Alaska statute relevant to the coastal zone involves the Federal/State Land Use Planning Commission of Alaska. Alas. Stat. 41.40.010 and .020. The Commission has the duty to investigate and study all aspects of the coastal environment, including but not limited to land use in the coastal zone, water and power development and any and all other social, economic and legal matters relative to the conservation and utilization of ocean resources. See Alas. Stat. 46.26.090. It is the purpose of this investigation to encourage and maintain a comprehensive, coordinated state plan for the orderly, long-range conservation and development of coastal resources, which will ensure their wise, multiple use in the total public interest. See Alas. Stat. 46.26.020. The obvious relationship between the Commission's duties and the provisions of the Coastal Zone Management Act (See Section 10.7 herein) are apparent. At the present time, Alaska has not developed a Coastal Zone Management Plan pursuant to the federal act and recommendations from the Federal/State Land Use Planning Commission for Alaska have not been finalized.

> Review and consideration on a constant liaison basis by the Alaska Power Authority with the Federal/State Land Use Planning Commission is important to ensure that recommendations from the Commission and development of a Coastal Zone Management Plan (if pursued by Alaska) will not restrict the availability of sites for potential use.

Such coastal site restrictions are readily apparent in the California Coastal Zone Management Plan for example. The economic impacts of such a plan are unable to be identified at this time.

10.10.5 Land

Land Acquisition

As a general matter, utilization of any land currently owned by the state of Alaska will involve either the acquisition of the property or of a right-of-way lease or permit from the State for the use of the property. Leasing of State lands is specifically authorized for pipelines under Alas. Stat. 38.05.020, for tide, submerged or shore lands in Alas. Stat. 38.35.020, and any lands owned in fee by the state. See Alas. Stat. 38.05.045. Tide, submerged or shore lands may not be sold, but may be leased from the State. See. Alas. Stat. 38.05.045 and .070.

Generally, appr-priate conditions may be put on land acquisition. Such conditions which may be considered are those determined to be "necessary and proper" to protect the interest of the State. See Alas. Stat. 38.05.085. Since the interest of the State includes the utilization of natural resources for the maximum benefit of its people, conditions arguably could be imposed to require mitigating measures such as public access and recreational facilities, fish passage, etc. Similar conditions are set forth in Alas. Stat. 38.05.035.

> The cost of land interest acquisition and conditions attached to it are site dependent and should be evaluated as such.

Land Use Planning

The principal factor in the area of land use planning which may affect the plans of the Alaska Power Authority are those that may be forthcoming from the Federal State Land Use Planning Commission for Alaska. As previously discussed, this could be particularly important for sites which are associated with the marine and coastal environment. See Alas. Stat. 41.40.010, et seq.

If a site is located within a borough, the project would be subject to the comprehensive plan and zoning requirements of that area. There appears to be no preemptive override of local zoning and project opponents could use these laws to restrict the availability of sites otherwise acceptable for power plants. If the State legislature were to consider that this might be an important problem in the future as a result of opposition to a particular site,

> consideration should be given to legislation which would permit, under certain controlled circumstances, the limited override of local zoning for energy facilities.

One example of such a type of legislation is contained in the Florida Power Plant Siting Act. Locating a public agency's power plant in a borough subjects it to compliance with applicable local building codes. To the extent that a facility constructed by the Alaska Power Authority is, in law, considered a public building, the provisions of Alas. Stat. 35.10.025 would apply.

> Consideration may be given to amending state law to exempt a power plant facility from the requirements of the local building codes.

Soil Conservation

The Commissioner of Natural Resources has the authority to develop comprehensive plans for the conservation of soil and control of soil erosion within a district. See Alas. Stat. 41.10.1100.

> Because of the impacts of site construction activities and surface coal mining, consideration should be given to cooperative arrangements with the Commissioner of Natural Resources to determine the appropriateness or applicability of any comprehensive plan developed which may impact upon the proposed plans for a project.

Historic Sites

Historic, prehistoric, prehistoric and archeological resources of Alaska are entitled to special protection under the provisions of Alas. Stat. 41.35.010, et seq. To the extent that a facility would be located on a site which affects such types of resources, the provision in Section 41.35.010 regarding their preservation during public construction may impact the costs and timetable of one site versus another. Site construction activities could be delayed until such time as the necessary investigation, recording and salvage of the site location remains have been concluded. See Alas. Stat. 41.35.070(c).

State Parks

Uses incompatible with a state park are prohibited or restricted as provided by regulations.

> A review of the state park use regulations, particularly for Captain Cook State Recreation Area (Alas. Stat. 41.20.150), should be made to determine any impact upon transmission line routing.

Solid Waste

Alaska's Administrative Code contains provisions applicable to solid waste management. A permit is required with respect to anyone operating an incinerator facility having a total rated capacity of more than 200 lbs. of solid waste per hour. In addition, the responsibility for solid waste management rests upon the industry where the solid waste is accumulated.

> The Alaska Power Authority would be required to the extent that it generates solid waste for disposal at a construction site to comply with the provisions of 18 AAC 60.050.

10.10.6 Flora and Fauna

The Department of Fish and Game administers the state program for the conservation and development of the state's commercial fisheries, sports fish, birds, game and fur bearing animals. See Alas. Stat. 44.39.020. The Board of Fisheries has the authority to set apart fish reserve areas, refuges and sanctuaries in the water of the State subject to the approval of the legislature.

State game refuges are identified in Alas. Stat. 16.20.030. Any activity within these areas require the Commissioner to review, approve and condition the plans and activities in the area with the proper protection to fish and game. See Alas. Stat. 16.20.060.

Any time a dam or other obstruction is to be built across a stream frequented by salmon or other fish, the owner must notify the Commissioner before construction begins. The owner may request the waters within the construction areas that are important for spawning and migration of anadromous fish. See Alas. Stat. 16.05.870. The Alaska Power Authority should informally pursue this approach long before construction is imminent so as to properly evaluate alternative sites and possible mitigating condition costs.

The Commissioner may require that a durable and efficient fish way and a device for efficient passage for downstream migrants be established. See Alas. Stat. 16.05.840. The plan must be approved before the proposed construction or use has begun. See Alas. Stat. 16.05.870. In addition, if such a fish way is considered inpracticable, the owner of the dam or obstruction may be required to compensate for the loss resulting from the dam. See Alas. Stat. 16.05.850. The Commissioner is authorized to specify various rivers, lakes and streams that are important for the spawning or migration of anadromous fish. Such a specification could impinge upon a site's acceptability because of water discharge concerns or blockage from dams.

Endangered species have protection under the State's law as well as under federal law. See Alas. Stat. 16.20.180. A person is prohibited from injuring any species or subspecies of fish or wildlife listed under these provisions. Consequently, consideration of the locality of species adjacent to a proposed site would be important in identifying the timing of construction activities to avoid any injury to the protected species.