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SUSITNA HYDROELECTRIC PROJECT

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DRAFT

FERC LICENSE APPLICATION

EXHIBIT D

PROJECT COSTS AND FINANCING

NOVEMBER 1982

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Prepared by:

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ALASKA POWER AUTHORITY

EXHIBIT D - PROJECT COSTS AND FINANCING

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EXHIBIT D - PROJECT COSTS AND FINANCING

This exhibit presents the estimated project cost for the Susitna Hydroelectric Project, the market value of project power and a financing plan for the project. Alternative sources of power which were studied are also presented.

1 - ESTIMATES OF COST

This section presents estimates of capital and operating costs for the Susitna Hydroelectric Project, comprising the Watana and Devil Canyon developments and associated transmission and access facilities. The costs of design features and facilities incorporated into the project to mitigate environmental impacts during construction and operation are identified. Cash flow schedules, outlining capital requirements during planning, construction, and start-up are presented. The approach to the derivation of the capital and operating costs estimates is described.

The total cost of the Watana and Devil Canyon projects is summarized in Table D.1. A more detailed breakdown of cost for each development is presented in Tables D.2 and D.3.

1.1 - Construction Costs

This section describes the process used for derivation of construction costs and discusses the Code of Accounts established, the basis for the estimates and the various assumptions made in arriving at the estimates. For general consistency with planning studies, all costs developed for the project are in January, 1982 dollars.

(a) Code of Accounts

Estimates of construction costs were developed using the FERC format as outlined in the Federal Code of Regulations, Title 18 (1).

The estimates have been subdivided into the following main cost groupings:

1-1

Group

Production Plant

Transmission Plant

General Plant

Indirect Costs

Description

Costs for structures; equipment, and facilities necessary to produce power.

Costs for structures, equipment, and facilities necessary to transmit power from the sites to load centers.

Costs for equipment and facilities required for the operation and maintenance of the production and transmission plant.

Costs that are common to a number of construction activities. For this estimate only camps have been identified in this group. The estimate for camps includes electric power costs. Other indirect costs have been included in the costs under production, transmission, and general plant costs.

Overhead Construction Costs

Costs for engineering and administration.

Further subdivision within these groupings was made on the basis of the various types of work involved, as typically shown in the following example:

- Group:	Production Plant
- Account 332:	Reservoir, Dam, and Waterways
- Main Structure 332.3:	Main Dam .
- Element 332.31:	Main Dam Structure
- Work Item 332.311:	Excavation
- Type of Work:	Rock

The detailed schedule of costs using this breakdown is presented in Reference 5.

(b) Approach to Cost Estimating

The estimating process used generally included the following steps:

- Collection and assembly of detailed cost data for labor, material, and equipment as well as information on productivity, climatic conditions, and other related items;
- Review of engineering drawings and technical information with regard to construction methodology and feasibility;
- Production of detailed quantity takeoffs from drawings in accordance with the previously developed Code of Accounts and item listing;
- Determination of direct unit costs for each major type of work by development of labor, material, and equipment requirements; development of other costs by use of estimating guides, quotations from vendors, and other information as appropriate;
- Development of construction indirect costs by review of labor, material, equipment, supporting facilities, and overheads; and
- Development of construction camp size and support requirements from the labor demand generated by the construction direct and indirect costs.

(c) Cost Data

Cost information was obtained from standard estimating sources, from sources in Alaska, from quotes by major equipment suppliers and vendors, and from representative recent hydroelectric projects. Labor and equipment costs for 1982 were developed from a number of sources (2,3) and from an analysis of costs for recent projects performed in the Alaska environment.

It has been assumed that most contractors will work an average of two 10-hour shifts per day, 6 days per week. Due to the severe compression of construction activities in 1985-86, it has been assumed that most work in this period will be on two 12-hour shifts, 7 days per week.

Mechanical/Electrical Work	8-hour	shifts
Formwork/Concrete Work	9-hour	shifts
Excavation/Fill Work	10-hour	shifts

The 10-hour work shift assumption provides for high utilization of construction equipment and reasonable levels of overtime earnings to attract workers. The two-shift basis generally achieves the most economical balance between labor and camp costs.

Construction equipment costs were obtained from vendors on an FOB Anchorage basis with an appropriate allowance included for transportation to site. A representative list of construction equipment required for the project was assembled as a basis for the estimate. It has been assumed that most equipment would be fully depreciated over the life of the project. For some activities such as construction of the Watana main dam, an allowance for major overhaul was included rather than fleet replacement. Equipment operating costs were estimated from industry source data, with appropriate modifications for the remote nature and extreme climatic environment of the site. Alaskan labor rates were used for equipment maintenance and repair. Fuel and oil prices have been based upon FOB site prices.

Information for permanent mechanical and electrical equipment was obtained from vendors and manufacturers who provided guideline costs on major power plant equipment.

The costs of materials required for site construction were estimated on the basis of suppliers' quotations with allowances for shipping to site.

(d) Seasonal Influences on Productivity ---

Service Station

A review of climatic conditions together with an analysis of experience in Alaska and in Northern Canada on large construction projects was undertaken to determine the average duration for various key activities. It has been projected that most aboveground activities will either stop or be curtailed during the period of December and January because of the extreme cold weather and the associated lower productivity. For the main dam construction activities, the following seasons have been used:

- Watana dam fill - 6-month season; and

- Devil Canyon arch dam - 8-month season.

Other aboveground activities are assumed to extend up to 11 months depending on the type of work and the criticality of the schedule. Underground activities are generally not affected by climate and should continue throughout the year.

Studies by others (4) have indicated a 60 percent or greater decrease in efficiency in construction operations under adverse winter conditions. Therefore, it is expected that most contractors would attempt to schedule outside work over a period of between 6 to 10 months.

Studies performed as part of this work program indicate that the general construction activity at the Susitna damsite during the months of April through September would be comparable with that in the northern sections of the western United States. Rainfall in the general region of the site is moderate between mid-April and mid-October, ranging from a low of 0.75 inches precipitation in April to a high of 5.33 inches in August. Temperatures in this period range from 33°F to 66°F for a twenty-year average. In the five-month period from November through March the temperature ranges from 9.4°F to 20.3°F, with snowfall of 10 inches per month.

(e) Construction Methods

The construction methods assumed for development of the estimate and construction schedule are generally considered as normal to the industry, in line with the available level of technical information. A conservative approach has been taken in those areas where more detailed information will be developed during subsequent investigation and engineering programs. For example, normal drilling, blasting, and mucking methods have been assumed for all underground excavation. Conventional equipment has also been considered for major fill and concrete work.

(f) Quantity Takeoffs

Detailed quantity takeoffs were produced from the engineering drawings using methods normal to the industry. The quantities developed are listed in the detailed summary estimates in Appendix C to the Susitna Hydroelectric Feasibility Report (5).

(g) Indirect Construction Costs

Indirect construction costs were estimated in detail for the civil construction activities. A more general evaluation was used for the mechanical and electrical work.

Indirect costs included the following:

- Mobilization;
- Technical and supervisory personnel above the level of trades foremen;
- All vehicle costs for supervisory personnel;
- Fixed offices, mobile offices, workshops, storage facilities, and laydown areas, including all services;
- General transportation for workmen on site and off site;
- Yard cranes and floats;
- Utilities including electrical power, heat, water, and compressed air;
- Small tools;
- Safety program and equipment;
- Financing;

- Bonds and securities;
- Insurance;
- Taxes;

- Permits;
- Head office overhead;
- Contingency allowance; and
- Profit.

In developing contractors indirect costs, the following assumptions have been made:

- Mobilization costs have generally been spread over construction items:
- No escalation allowances have been made, and 'herefore any risks associated with escalation are not included;
- Financing of progress payments has been estimated for 45 days, the average time between expenditure and reimbursement;
- Holdback would be limited to a nominal amount;
- Project all-risk insurance has been estimated as a contractor's indirect cost for this estimate, but it is expected that this insurance would be carried by the owner; and
- Contract packaging would provide for the supply of major materials to contractors at site at cost. These include fuel, electric power, cement, and reinforcing steel.

1.2 - Mitigation Costs

The project arrangement includes a number of features designed to mitigate potential impacts on the natural environment and on residents and communities in the vicinity of the project. In addition, a number of measures are planned during construction of the project to reduce similar impacts caused by construction activities. These measures and facilities represent additional costs to the project than would otherwise be required for safe and efficient operation of a hydroelectric development. These mitigation costs have been estimated at \$153 million and have been summarized in Table D.4. In addition, the costs of full reservoir clearing at both sites has been estimated at \$85 million. Although full clearing is considered good engineering practice, it is not essential to the operation of the power facilities. These costs include direct and indirect costs, engineering, administration, and contingencies.

[NOTE: This section will be revised to be made exact after the completion of mitigation planning.]

A number of mitigation costs are associated with facilities, improvements or other programs not directly related to the project or located outside the project boundaries. These would include the following items:

- Caribou barriers;
- Fish channels;
- Fish hatcheries;
- Stream improvements;
- Salt licks;

- Recreational facilities;
- Habitat management for moose;
- Fish stocking program in reservoirs; and
- Land acquistion cost for recreation.

It is anticipated that some of these features or programs will not be required during or after construction of the project. In this regard a probability factor has been assigned to each of the above items, and the estimated cost of each reduced accordingly. The estimated cost of these measures has been covered in the construction contingency.

A number of studies and programs will be required to monitor the impacts of the project on the environment and to develop and record various data during project construction and operation. These include:

- Archaeological studies;

- Fisheries and wildlife studies;

- Right-of-way studies; and

- Socioeconomic planning studies.

The costs for the above work have been included in the owner's costs under project overheads.

1.3 - Engineering and Administration Costs

Engineering has been subdivided into the following accounts for the purposes of the cost estimates:

- Account 71

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- . Engineering and Project Management
- . Construction Management
- . Procurement

- Account 76

. Owner's Costs

The total cost of engineering and administrative activities has been estimated at 12.5 percent of the total construction costs, including contingencies. A detailed breakdown of these costs is dependent on the organizational structure established to undertake design and management of the project, as well as more definitive data relating to the scope and nature of the various project components. However, the main elements of cost included are as follows:

(a) Engineering and Project Management Costs

These costs include allowances for:

- Feasibility studies, including site surveys and investigations and logistics support;
- Preparation of the license application to the FERC;
- Technical and administrative input for other federal, state and local permit and license applications;
- Overall coordination and administration of engineering, construction management, and procurement activities;
- Overall planning, coordination, and monitoring activities related to cost and schedule of the project;
- Coordination with and reporting to the Power Authority regarding all asperts of the project;
- Preliminary and detailed design;
- Technical input to procurement of construction services, support services, and equipment;

- Monitoring of construction to ensure conformance to design requirements;
- Preparation of start-up and acceptance test procedures; and
- Preparation of project operating and maintenance manuals.

(b) Construction Management Costs

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Construction management costs have been assumed to include:

- Initial planning and scheduling and establishment of project procedures and organization;
- Coordination of onsite contractors and construction management activities;
- Administration of onsite contractors to ensure harmony of trades, compliance with applicable regulations, and maintenance of adequate site security and safety requirements;
- Development, coordination, and monitoring of construction schedules;
- Construction cost control;
- Material, equipment and drawing control;
- Inspection of construction and survey control;
- Measurement for payment;
- Start-up and acceptance tests for equipment and systems;
- Compilation of as-constructed records; and

- Final acceptance.

(c) Procurement Costs

Procurement costs have been assumed to include:

- Establishment of project procurement procedures;
- Preparation of non-technical procurement documents;
- Solicitation and review of bids for construction services, support services, permanent equipment, and other items required to complete the project;
- Cost administration and control for procurement contracts; and

- Quality assurance services during fabrication or manufacture of equipment and other purchased items.

(d) Owner's Costs

Owner's costs have been assumed to include the following:

- Administration and coordination of project management and engineering organizations;
- Coordination with other state, local, and federal agencies and groups having jurisdiction or interest in the project;
- Coordination with interested public groups and individuals;
- Reporting to legislature and the public on the progress of the project; and

- Legal costs

1.4 - Operation, Maintenance and Replacement Costs

The facilities and procedures for operation and maintenance of the project are described in Section 15 of the Susitna Hydroelectric Project Feasibility Report, Volume 1. Assumptions for the size and extent of these facilities have been made on the basis of experience at large hydroelectric developments in northern climats. The annual costs for operation and maintenance for the Watana development have been estimated at \$10 million. When Devil Canyon is brought on line these costs increase to \$15.2 million per annum. Interim replacement costs have been estimated at .3 percent per annum of the capital cost.

The breakdown in Table D.5 is provided in support of the allowance used in the finance/economic analysis of the Susitna Hydroelectric Project. It is based on an operating plan involving full staffing of power plant and permanent town site support personnel. A total of 105 will be employed for Watana with another 25 to be added when Devil Canyon comes on-line. This manpower level will provide manned supervisory staff on a 24-hour, 3 shift basis, with maintenance crews to handle all but major overhauls. A nominal allowance has been made for major maintenance work which would utilize contracted labor. It is unlikely that major overhauls will be necessary in the first 10 years of project operation. In earlier years, this allowance is a prudent provision for unexpected start-up costs over and above those covered by warranty.

Allowance for contracted services also covers helicopter operations and access road snow-clearing and maintenance.

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Allowances have also been made for environmental mitigation as well as a contigency for unforseen costs.

Estimates for Susitna have been based on original estimates and actual experience at Churchill Falls. It should be realized that alternative operating plans are possible which would eliminate the need for permanent town site facilities and rely on more remote supervisory systems and/or operations/maintenance crews transported to the plant on a rotating shift basis. Cost implications of these alternatives have not yet been examined.

1.5 - Allowance for Funds Used During Construction

At current high levels of interest rates in the financial marketplace, AFDC will amount to a significant element of financing cost for the lengthy periods required for construction of the Watana and Devil Canyon projects. However, in economic evaluations of the Susitna project the low real rates of interest assumed would have a much reduced impact on assumed project development costs. Furthermore, direct state involvement in financing of the Susitna project will also have a significant impact on the amount, if any, of AFDC. For purposes of the feasibility study, therefore, the conventional practice of calculating AFDC as a separate line item for inclusion as part of project construction cost has not been followed. Provisions for AFDC at appropriate rates of interest are made in the economic and financial analyses included in this Exhibit.

1.6 - Escalation

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All costs presented in this Exhibit are at January 1982 levels, and consequently include no allowance for future cost escalation. Thus, these costs would not be truly representative of construction and procurement bid prices. This is because provision must be made in such bids for continuing escalation of costs, and the extent and variation of escalation which might take place over the lengthy construction periods involved. Economic and financial evaluations take full account of such escalation at appropriate rates. These rates are shown in Table D.9.

1.7 - Cash Flow and Manpower Loading Requirements

The cash flow requirements for construction of Watana and Devil Canyon are an essential input to economic and financial planning studies. The bases for the cash flow are the construction cost estimates in January 1982 dollars and the construction schedules presented in Exhibit C, with no provision being made as such for escalation. The cash flow estimates were computed on an annual basis and do not include adjustments for advanced payments for mobilization or for holdbacks on construction contracts. The results are presented in Table D.6 and Figures D.1 through D.3. The manpower loading requirements were

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developed from cash flow projections. These curves were used as the bas's for camp loading and associated socioeconomic impact studies.

1.8 - Contingency

A contingency allowance of 17.5 percent of construction costs has been included in the cost estimates. The contingency is estimated to include cost increases which may occur in the detailed engineering phase of the project after more comprehensive site investigations and final designs have been completed and after the requirements of various concerned agencies have been satisfied. The contingency estimate also includes allowances for inherent uncertainties in costs of labor, equipment and materials, and for unforeseen conditions which may be encountered during construction. Escalation in costs due to inflation is not included. No allowance has been included for costs associated with significant delays in project implementation.

1.9 – Previously Constructed Project Facilities

An electrical intertie between the major load centers of Fairbanks and Anchorage is currently under construction. The line will connect existing transmission systems at Willow in the south and Healy in the north. The intertie is being built to the same standards as those proposed for the Susitna project transmission lines and will become part of the licensed project. The line will be energized initially at 138 kV in 1984 and will operate at 345 kV after the Watana phase of the Susitna project is complete.

The current estimate for the completed intertie is \$130.8 million. This cost is not included in the cost estimates of this section.

1.10 – EBASCO Check Estimate

An independent chck estimate was undertaken by EBASCO Services Incorporated. The estimate was based on engineering drawings, technical information and quantities prepared by Acres. Major quantity items were checked. The EBASCO check estimated capital cost was approximately 7 percent above the Acres estimate.

A meeting was held with APA, EBASCO and Acres to review differences in the estimates. It was generally possible to reconcile the differences and it was concluded that no major changes were required in the Feasibility Report estimate.



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2 - ESTIMATED ANNUAL PROJECT COSTS

As a two-stage (Watana and Devil Canyon) development with varying levels of energy output and the assumption of ongoing inflation (at 7 percent per annum), the real cost of Susitna power will be continually varying. As a consequence, no simple single value real cost of power can be used.

Table D.7 gives the projected year-by-year projection energy levels on the first line and the second, the year-by-year unit cost of power in 1982 dollars. Costs are based on power sales at cost assuming 100 percent debt finance at 10 percent interest. This is seen to result in a real cost of power of 128 mills in 1994 (first 'normal' year of Watana) falling to 72.76 mills in 2003 (the first 'normal' year of Watana and Devil Canyon). The real cost of power would then fall progressively for the whole remaining life.

The Cost of Power given in Table D.8 is designed to reflect as fully as possible the economic cost of pwoer for purposes of broad comparison with alternative power options. It is, therefore, based on the capacity cost which would arise if the project were 100 percent debt financed at market rates of interest. It does not reflect the price at which power will be charged into the system. This, on the financing plan shown in Section 6 is given on RL 521 of Table D.36.



3 - MARKET VALUE OF PROJECT POWER

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This section presents an assessment of the market in the Railbelt region for the energy and capacity of the Susitna development. A range of rates at which this power could be priced is presented together with a proposed basis for contracting for the supply of Susitna energy.

3.1 - The Railbelt Power System

Susitna capacity and energy will be delivered to the "Railbelt Region Interconnected System" which will result from the linkage of the Anchorage and Fairbanks systems by an intertie to be completed in the mid-1980s.

The Railbelt region covers the Anchorage-Cook Inlet area, the Fairbanks-Tanana Valley area, and the Glennallen-Valdez area (Figure D.4). The utilities, military installations and universities within this region which own electric generating facilities are listed in Table D.10. The service areas of these utilities are shown in Figure D.5 and the generating plants serving the region are listed in Table D.11.

The Railbelt region is currently served by nine major utility systems; five are rural electric cooperatives, three are municipally owned and operated, and one is a federal wholesaler. The relative mix of electric generating technologies and types of fuel used by the Railbelt utilities in 1980 is summarized in Figure D.6.

In 1980, the Anchorage-Cook Inlet area had 81 percent, the Fairbanks-Tanana Valley area 17 percent, and the Glennallen-Valdez area 2 percent of the total energy sales in the Railbelt region.

Due to the pending construction of the Willow to Healy transmission line, the Anchorage and Fairbanks power systems will be intertied before the Susitna Project comes into operation. The proposed intertie will allow a capacity transfer of up to 70 MW in either direction. The proposed plan of interconnection envisages initial operation at 138 kV with subsequent uprating to 345 kV allowing the line to be integrated into the Susitna transmission facilities.

3.2 - Regional Electric Power Demand and Supply

A review of the socioeconomic scenarios upon which forecasts of electric power demand were based is presented in Exhibit B of this

application. The forecasts used here are in the mid-range levels made by Battelle Northwest in December 1981. The results of studies presented in Exhibit B call for Watana to come into operation in 1993 and to deliver a full year's energy generation in 1994. Devil Canyon will come into operation in 2002 and deliver a full year's energy in 2003. Energy demand in the Railbelt region and the deliveries from Susitna are shown in Figure D.7.

3.3 - Market and Price for Watana Output in 1994

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It has been assumed that Watana energy will be supplied at a single wholesale rate on a free market basis. This requires, in effect, that Susitna energy be priced so that it is attractive even to utilities with the lowest cost alternative source of energy. On this basis it is estimated that for the initially marketable 3315 GWh of energy generated by Watana in 1994 to be attractive, a price of 145 mills per kWh in 1994 dollars is required. Justification for this price is illustrated in Figure D.8. Note that the assumption is made that the only capital costs which would be avoided in the early 1990s would be those due to the alternative addition of new coal-fired generating plants (i.e., the 2 x 200 MW coal-fired Beluga station). The Susitna energy price of 145 mills/kWh suggested here matches closely the value determined from generation planning analysis in the financial evaluation.

The financing considerations under which it would be appropriate for Watana energy to be sold at approximately 145 mills per kWh price are considered in Section 6 of this Exhibit; however, it should be noted that some of the energy which would be displaced by Watana's production would have been generated at a lower cost than 145 mills, and utilities might wish to delay accepting it at this price until the escalating cost of natural gas or other fuels made it more attractive. A number of approaches to the resolution of this problem can be postulated, including pre-contract arrangements.

The Power Authority will seek to contract with Railbelt Utilities for the purchase of Susitna capacity and energy on a basis appropriate to support financing of the project.

Pricing policies for Susitna output, as defined by the Alaska legislature, will be constrained by both cost and by the price of energy from the best alternative option. These options are discussed in Section 4 of this Exhibit.

Marketing Susitna's output within these twin costraints would ensure that all state financial support for Susitna flowed through to consumers and under no circumstances would prices to consumers be higher than they would have been under the best alternative option. In addition, consumers would also obtain the long-term economic benefits of Susitna's stable cost of energy.

3.4 - Market Price for Watana Output 1995-2001

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After its initial entry into the system in 1994, the price and market for the total 3387 GWh of Watana output is consistently upheld over the years to 2001 by the projected 20 percent increase in total demand over this period as projected in Exhibit B forecasts.

There would, as a result, be a 70 percent increase in cost savings compared with the best thermal generating alternative: the increasing cost per unit of output from a system without Susitna is illustrated in Figure D.9.

The addition of the Susitna project will add a large generating resource in the system in 1993, displacing a significant amount of the existing generating resources in the system. The project will provide about 70 percent of total energy demand. The displaced units will be used as reserve capacity and to meet growing load until the Devil Canyon project comes on line. This effect is illustrated on Figure D.7.

3.5 - Market and Price for Watana and Devil Canyon Output in 2003

A diagramatic analysis of the total cost savings which the combined Watana and Devil Canyon output will confer on the system compared with the alternative thermal option in the year 2003 is shown in Figure D.10. These total savings are divided by the energy contributed by Susitna to indicate a price of 250 mills per kWh as the maximum price which can be charged for Susitna output.

Only about 90 percent of the total Susitna energy output will be absorbed by the system in 2002; the balance of the output will be progressively absorbed over the following decade. This will provide additional total savings to the system with Susitna since no other resources will be needed.

After the Devil Canyon project comes on line, the Susitna project will provide 90 percent of the energy demand. The excess Susitna power occurs in the summer while additional energy from other resources is required in the winter. The generating resources displaced are units nearing retirement and will be used as reserve capacity., This effect is shown on Figure D.7.

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3.6 - Potential Impact of State Appropriations

In the preceding paragraphs the maximum price at which Susitna energy could be sold has been identified. Sale of the energy at these prices will depend upon the magnitude of any proposed state appropriation designed to reduce the cost of Susitna energy in the earlier years. At significantly lower prices it is likely that the total system demand will be higher than assumed. This, combined with a state appropriation to reduce the energy cost of Watana energy, would make it correspondingly easier to market the output from the Susitna development; however, as the preceding analysis shows, a viable and strengthening market exists for the energy from the development that would make it possible to price the output up to the cost of the best thermal alternative.

3.7 - Conclusions

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Based on the assessment of the market for power and energy output from the Susitna Hydroelectric Project, it has been concluded that with the appropriate level of state appropriation and with pricing policy as defined in Alaska State Laws, a viable basis exists for the Susitna power to be absorbed by the Railbelt utilities.



4 - EVALUATION OF ALTERNATIVE ENERGY PLANS

4.1 - General

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This section describes the process of assembling the information necessary to carry out the systemwide generation planning studies necessary for assessment of economic feasibility of the Susitna Project. Included is a discussion of the existing system characteristics, the planned Anchorage-Fairbanks intertie, and details of various generating options including hydroelectric and thermal. Performance and cost information required for the generation planning studies is presented for the hydroelectric and thermal options considered.

The approach taken in economically evaluating the Susitna project involved the development of long term generation plans for the Railbelt electrical supply-system with-and without the proposed project. In order to compare the with and without plans, the cost of the plans were compared on a present worth basis. A generation planning model which simulated the operation of the system annually was used to project the annual generation costs.

During the pre-license phase of the Susitna project planning, two studies proceeded in parallel which addressed the alternatives in generating power in the Alaska Railbelt. These studies are the Susitna Hydroelectric Project Feasibility Study done by Acres American Incorporated for the Alaska Power Authority and the Railbelt Electric Power Alternatives Study done by Battelle Pacific Northwest Laboratories for the Office of the Governor, State of Alaska.

One objective of the Susitna Feasibility was to determine the feasibility of the proposed project. The economic evaluations done during study found the project to be feasible as documented in this exhibit. The independent study done by Battelle focused on the feasibility of all possible generating and conservation alternatives.

Although the studies were independent, several key factors were consistent. Both studies used the approach of comparing costs by using generation planning simulation models. Thus, selected alternatives were put into a plan context and their economic performance compared by comparing costs of the plans. Additionally, parameters such as costs for fuel and capital costs and escalation were consistent between the two studies.

The following presentation focuses primarily on the Susitna Feasibility study process and findings. A separate section provides the findings of the Battelle Study, which generally agree with the feasibility study findings.

4.2 - Existing System Characteristics

(a) System Description

The two major load centers of the Railbelt region are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area (see Figure D.11), which, at present, operate independently. The existing transmission system between Anchorage and Willow consists of a network of 115 kV and 138 kV lines with interconnection to Palmer. Fairbanks is primarily served by a 138 kV line from the 28 MW coal-fired plant at Healy. Communities between Willow and Healy are served by local distribution.

There are currently nine electric utilities (including the Alaska Power Administration) providing power and energy to the Railbelt system. Table D.12 summarizes the total generating capacity within the Railbelt system in 1980, based on information provided by Railbelt utilities and other sources. Table D.13 presents the resulting detailed listing of units currently operating in the Railbelt, information on their performance characteristics, and their online and projected retirement dates for generation planning purposes. The total Railbelt installed capacity of 984 MW as of 1980 consists of two hydroelectric plants totaling 46 MW plus 938 MW of thermal generation units fired by oil, gas, or coal, as summarized in Table D.14.

(b) Retirement Schedule

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In order to establish a retirement policy for the existing generating units, several sources were consulted, including the Power Authority's draft feasibility study guidelines, FERC guidelines, the Battelle Railbelt Alternatives Study, and historical records. Utilities, particularly those in the Fairbanks area, were also consulted. Based on these sources, the following retirement periods of operation were adopted for use in this analysis:

- Large Coal-Fired Steam Turbines (> 100 MW):	30 years
- Small Coal-Fired Steam Turbines (< 100 MW):	35 years
- Oil-Fired Gas Turbines:	20 years
- Natural Gas-Fired Gas Turbines:	30 years
- Diesels:	30 years
- Combined Cycle Units:	30 years
- Conventional Hydro:	50 years

Table D.14 lists the retirement dates for each of the current generating units based on the above retirement policy.

(c) Schedule of Additions

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Six new projects were expected to be added to the Railbelt system prior to 1990. The Chugach Electric Association is in the process of adding gas-fired combined-cycle capacity in Anchorage at a plant called Beluga No. 8. When complete, the total plant capacity will be 178 MW, but the plant will encompass existing Units 6 and 7. Chugach added a 26.4 MW gas turbine rehabilitation at Bernice Lake No. 4 in August 1982.

The Corps of Engineers is currently in the post-authorization planning phase for the Bradley Lake hydroelectric project located on the Kenai Peninsula. The project would include between 60 and 135 MW of installed capacity and would produce an average annual energy of 350 Gwh. For analysis purposes, the project is assumed to come on line in 1988.

Three other units are also scheduled or have been added to the system since 1980. Anchorage Municipal Light and Power Department is planning to add a 90 MW gas turbine in 1983-84 called AMLPD No. 8. Copper Valley Electric Association is operating the new 12 MW Solomon Gulch Hydroelectric Project which is owned by the Alaska Power Authority. Finally, the 7 MW Grant Lake Hydroelectric Project is undergoing planning for addition to the system in 1988 by the Alaska Power Authority.

4.3 - Fairbanks - Anchorage Intertie

Engineering studies have been undertaken for construction of an intertie between the Anchorage and Fairbanks systems. As presently envisaged, this connection will involve a 345-kV transmission line between Willow and Healy scheduled for completion in 1984. The line will initially be operated at 138 kV with the capability for expansion as the loads grow in the load centers.

Based on these evaluations, it was concluded that an interconnected system should be assumed for the generation planning studies, and that the basic intertie facilities would be common to all generation scenarios considered.

Costs of additional transmission facilities were added to the scenarios as necessary for each unit added. In the "with Susitna" scenarios, the costs of adding circuits to the intertie corridor were added to the Susitna project cost. For the non-Susitna units, transmission costs were added as follows:

- No costs were added for combined-cycle or gas-turbine units, since they were assumed to have sufficient siting flexibility to be placed near the major transmission works;
- A multiple coal-fired unit development in the Beluga fields was estimated to have a transmission system with equal security to that planned for Susitna, costing \$220 million. This system would take power from the bus back to the existing load center; and
- A single coal-fired unit development in the Nenana area using coal mined in the Healy fields would require a transmission system costing \$117 million dollars.

With the addition of a unit in the Fairbanks area in the 1990s, no additions to the 345 kV line were considered necessary. Thus, no other transmission changes were made to the non-Susitna plans.

4.4 - Hydroelectric Alternatives

Numerous studies of hydroelectric potential in Alaska have been undertaken. These date as far back as 1947 and were performed by various agencies including the then Federal Power Commission, the Corps of Engineers, the U.S. Bureau of Reclamation, the U.S. Geological Survey, and the State of Alaska. A significant amount of the identified potential is located in the Railbelt region, including several sites in the Susitna River Basin.

(a) Selection Process

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The application of the five-step methodology (Figure D.12) for selection of non-Susitna plans which incorporate hydroelectric developments is summarized in this section. The analysis was completed in early 1981 and is based on January 1981 cost figures; all other parameters are contained in the Development Selection Report (6). Step 1 of this process essentially established the overall objective of the exercise as the selection of an optimum Railbelt generation plan which incorporated the proposed non-Susitna hydroelectric developments for comparison with other plans.

Under Step 2 of the selection process, all feasible candidate sites were identified for inclusion in the subsequent screening exercise. A total of 91 potential sites were obtained from inventories of potential sites published in the COE National

Hydropower Study and the Power Administration report "Hydroelectric Alternatives for the Alaska Railbelt."

The screening of sites under Step 3 required a total of four successive iterations to reduce the number of alternatives to a manageable short list. The overall objective of this process was defined as the selection of approximately 10 sites for consideration in plan formulation, essentially on the basis of published data on the sites and appropriately defined criteria. Figure D.13 shows 49 of the sites which remained after the two initial screens.

In Step 4 of the plan selection process, the ten sites shortlisted under Step 3 were further refined as a basis for formulation of Railbelt generation plans. Engineering sketch-type layouts were produced for each of the sites, and quantities and capital costs were evaluated. These costs, listed in Table D.15, incorporate a 20 percent allowance for contingencies and 10 percent for engineering and owner's administration. A total of five plans were formulated incorporating various combinations of these sites as input into the Step 5 evaluations.

Power and energy values for each of the developments were reevaluated in Step 5 utilizing monthly streamflow and a computer reservoir simulation model. The results of these calculations are summarized in Table D.15.

The essential objective of Step 5 was established as the derivation of the optimum plan for the future Railbelt generation incorporating non-Susitna hydro generation as well as required thermal generation.

(b) Selected Sites

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The selected potential non-Susitna Basin hydro developments were ranked in terms of their economic cost of energy. They were then introduced into the all-thermal generating scenario during the generation planning analyses, in groups of two or three. The most economic schemes were introduced first and were followed by the less economic schemes. The methods of analysis are the same as those discussed in Section 4.5 (f).

The results of these analyses, completed in early 1981, are summarized in Table D.16 and illustrate that a minimum total system cost can be achieved by the introduction of the Chakachamna, Keetna, and Snow projects (See also Figure D.14). Note that further studies of the Chakachamna project were initiated in mid-1981 by Bechtel for the Alaska Power Authority.

(c) Lake Chakachamna

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Bechtel Civil and Minerals studied the feasibility of developing the power potential of Lake Chakachamna. The lake is on the west side of Cook Inlet 85 miles west of Anchorage. Its water surface lies at about elevation 1140 feet.

Two basic alternatives have been identified to harness the hydraulic head for the generation of electrical energy. One is via the valley of the Chakachatna River. This river runs out of the easterly end of the lake and descents to about elevation 400 feet where the river leaves the confines of the valley and spills out onto a broad alluvial flood plain. A maximum hydrostatic head of about 740 feet could be developed via this alternative.

The other alternative is for development by diversion of the lake outflow to the valley of the McArthur River which lies to the southeast of the lake outlet. A maximum hydrostatic head of about 960 feet could be harnessed by this diversion.

(i) Project Layout

The Bechtel study evaluated the merits of developing the power potential by diversion of water southeasterly to the McArthur river via a tunnel about 10-miles long, or easterly down the Chakachatna valley either by a tunnel about 12-miles long or by a dam and tunnel development. In the Chakachatna valley, few sites, adverse foundation conditions, the need for a large capacity spillway and the nearby presence of an active volcano made it evident that the feasibility of constructing a dam there would be problematical. The main thrust of the initial study was therefore directed toward the tunnel alternatives.

Two alignments were studied for the McArthur tunnel. The first considered the shortest distance that gave no opportunity for an additional point of access during construction via an intermediate adit. The second alignment was about a mile longer, but gave an additional point of access, thus reducing the lengths of headings and also the time required for construction of the tunnel. Cost comparisons nevertheless favored the shorter 10-mile 25-foot diameter tunnel.

The second alignment running more or less parallel to the Chakachatna River in the right (southerly) wall of the valley afforded two opportunities for intermediate access adits. These, plus the upstream and downstream portals would allow construction to proceed simultaneously in 6 headings and reduce the construction time by 18 months from that required for the McArthur tunnel. If all the controlled water were used for power generation, the McArthur powerhouse could support 400 MW installed capacity, and produce average annual firm energy of 1753 GWh. The effects of making a provisional reservation of approximately 19 percent of the average annual inflow to the lake for instream flow requirements in the Chakachatna River were found to reduce the economic tunnel diameter to 23 feet. The installed capacity in the powerhouse would then be reduced to 330 MW and the average annual firm energy to 1446 MW.

For the Chakachatna powerhouse, diversion of all the controlled water for power generation would support an installed capacity of 300 MW with an average annual firm energy generation of 1314 GWh. Provisional reservation of approximately 0.8 percent of the average annual inflow to the lake for instream flow requirements in the Chakachatna River was regarded as having negligible effect on the installed capacity and average annual firm energy because that reduction is within the accuracy of the Bechtel study.

(ii) Technical Evaluation and Discussion

Several alternative methods of developing the project have been identified and reviewed. Based on the analyses performed, the more viable alternatives have been identified by Bechtel for further study.

- Chakachatna Dam Alternative

The construction of a dam in the Chakachatna River canyon approximately 6 miles downstream from the lake outlet, does not appear to be a reasonable alternative. While the site is topographically suitable, the foundation conditions in the river valley and left abutment are poor. Furthermore, its environmental impact specifically on the fisheries resource will be significant although provision of fish passage facilities could mitigate this impact to a certain extent.

- McArthur Tunnel Alternatives A and B

Diversion of flow from Chakachamna Lake to the McArthur valley to develop a head of approximately 900 feet has been identified as the most advantageous with respect to energy production and cost.

The geologic conditions for the various project facilities including intake, power tunnel, and powerhouse appear to be favorable based on a 1981 field reconnaissance. No

insurmountable engineering problems appear to exist in development of the project.

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Alternative A, in which essentially all stored water would be diverted form Chakachamna Lake for power production purposes could deliver 1664 GWh of firm energy per year to Anchorage and provide 400 MW of peaking capacity. However, since the flow of the Chakachatna River below the lake outlet would be adversely affected, the existing anadromous fishery resource which uses the river to gain entry to the lake and its tributaries for spawning, would be lost. In addition, the fish which spawn in the lower Chakachatna River would also be impacted due to the much reduced river flow. For this reason, Alternative B has been developed, with essentially the same project arrangement except that approximately 19 percent of the average annual flow into Chakachamna Lake would be released into the Chakachatna River below the lake outlet to maintain the fishery resource. Because of the smaller flow available for power production, the installed capacity of the project would be reduced to 330 MW and the firm energy delivered to Anchorage would be 1374 GWh per year. Obviously, the long term environmental impacts of the project in this Alternative B are significantly reduced in comparison to Alternative A, since the river flow is maintained, albeit at a reduced amount. Estimated project costs for Alternatives A and B are \$1.5 billion and \$1.45 billion respectively.

- Chakachatna Tunnel Alternatives C and D

An alternative to the development of this hydroelectric resource by diversion of flows from Chakachamna Lake to the McArthur River is by constructing a tunnel thorugh the right wall of the Chakachatna valley and locating the powerhouse near the downstream end of the valley. The general layout of the project would be similar to that of Alternatives A and B for a slightly longer power tunnel.

The geologic conditions for the various project features including intake, power tunnel, and powerhouse appear to be favorable and very similar to those of Alternatives A and B. Similarly, no insurmountable engineering problems appear to exist in development of the project.

Alternative C, in which essentially all stored water is diverted from Chakachamna Lake for power production, could deliver 1248 GWh of firm energy per year to Anchorage and provide 300 MW of peaking capability. While the riverflow
in the Chakachatna River below the powerhouse at the end of the canyon will not be substantially affected, the fact that no releases are provided into the river at the lake outlet will cause a substantial impact on the anadromous fish which normally enter the lake and pass through it to the upstream tributaries. Alternative D was therefore proposed in which a release of 30 cfs is maintained at the lake outlet to facilitate fish passage thorugh the canyon section into the lake. In either of Alternatives C or D the environmental impact would be limited to the Chakachatna River as opposed to Alternatives A and B in which both the Chakachatna and McArthur Rivers would be affected. Since the instream flow release for Alternative D is less than 1 percent of the total available flow, the power production of Alternative D can be regarded as being the same as those of Alternative C (300 MW peaking capability, 1248 GWh of firm energy delivered to Anchorage). Estimated project costs for Alternatives C and D are \$1.6 billion and \$1.65 billion respectively.

4.5 - Thermal Options - Development Selection

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As discussed earlier in this section, the major portion of generating capability in the Railbelt is currently thermal; principally natural gas with some coal- and oil-fired installations. There is no doubt that the future electric energy demand in the Railbelt could be satisfied by an all-thermal generation mix. In the following paragraphs, an outline is presented of the analysis undertaken in the feasibility study to determine an appropriate all-thermal generation scenario for comparison with the Susitna hydroelectric scenario.

(a) Assessment of Thermal Alternatives

The overall objective established for this selection process was the selection of an optimum all-thermal Railbelt generation plan for comparison with other plans (Figure D.15).

Primary consideration was given to gas, coal, and oil-fired generation sources which are the most readily developable alternatives in the Railbelt from the standpoint of technical and economic feasibility. The broader perspectives of other alternative resources such as peat, refuse, geothermal, wind and solar and the relevant environmental, social, and other issues involved were addressed in the Battelle alternatives study (32). As such, a screening process was therefore considered unnecessary in this study, and emphasis was placed on selection of unit sizes appropriate for inclusion in the generation planning exercise.

For analysis purposes the following types of thermal power generation units were considered:

- Coal-fired steam;
- Gas-fireu combined-cycle;
- Gas-fired gas turbine; and
- Diesel.

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The following paragraphs present the thermal options used in developing the present without Susitna plan.

(b) Coal-Fired Steam

A coal-fired steam plant is one in which steam is generated by a coal-fired boiler and used to drive a steam-turbine generator. Cooling of these units is accomplished by steam condensation in cooling towers or by direct water cooling.

Aside from the military power plant at Fort Wainwright and the self supplied generation at the University of Alaska, there are currently two coal-fired steam plants in operation in the Railbelt. These plants are small in comparison with new units under consideration in the lower 48 states and in Alaska.

(i) Capital Costs

A detailed cost study was done by Ebasco Services Incorporated as part of Battelle's alternative study. The report found that it was feasible to establish a plant at either the undeveloped Beluga field or near Nenana, using Healy field coal. The study produced costs and operating characteristics for both plants. All new coal units were estimated to have an average heat rate of 10,000 Btu/kWh and involve an average construction period of five to six years. Capital costs and operating parameters are defined for coal and other thermal generating plants in Table D.15.

It was found that, rather than develop solely at one field in the non-Susitna case, development would be likely to take place in both fields. Thus, one unit would be developed near Nenana to service the Fairbanks load center, with other units placed in the Beluga fields. To satisfy the national New Performance Standards, the capital costs incorporate provision for installation of flue gas desulfurization for sulphur control, highly efficient combustion technology for control of nitrogen acids, and baghouses for particulate removal.

(ii) Fuel Costs

Fuel costs based on long-term opportunity values were set at \$1.43/MMBtu for Beluga field coal and \$1.75/MMBtu for Healy coal to be used at Nenana. Real escalation on these values was estimated as follows:

	1982-2000	2001-2010
	•	
Beluga/Coal	2.6%	1.2%
Healy Coal at Nenana	2.3%	1.1%

Details of the fue! cost information are included in Reference 31 of this report.

(iii) Other Performance Characteristics

Annual operation and maintenance costs and representative forced outage rates are shown in Table D.17.

(c) Combined Cycle

A combined cycle plant is one in which electricity is generated partly in a gas turbine and partly in a steam turbine cycle. Combined cycle plants achieve higher efficiencies than conventional gas turbines. There are two combined cycle plants in Alaska at present. One is operational and the other is under construction. The plant under construction is the Beluga No. 8 unit owned by Chugach Electric Association (CEA). It is a 42-MW steam turbine, which will be added to the system in late 1982, and utilize heat from currently operating gas turbine units, Beluga Nos. 6 and 7.

(i) Capital Costs

A new combined cycle plant unit size of 200-MW capacity was considered to be representative of future additions to generating capability in the Anchorage area. This is based on economic sizing for plants in the lower 48 states and projected load increases in the Railbelt. A heat rate of 8,000 Btu/kWh was adopted based on the alternative study completed by Battelle.

The capital cost was estimated using the Battelle study basis and is listed in Table D.17.

(ii) Fuel Costs

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The combined cycle facilities would burn only gas with a domestic market value of \$3.00 per MM Btu was chosen to reflect the equitable value of gas in Anchorage, assuming development of the export market. Currently, the local incremental gas market price is about one-third of this amount due to the relatively light local demands and limited facilities for export.

Using an approach similar to that used for coal costs, a real annual growth rate in gas costs of 2.5 percent (1982-2000) and 2 percent (2000-2040) was used in the analysis.

(iii) Other Performance Characteristics

Annual operation and maintenance costs, along with a representative forced outage rate, are given in Table D.17.

(d) Gas-Turbine

Gas turbines burn natural gas or oil in units similar to jet engines which are coupled to electric generators. These also require an appropriate water cooling arrangement.

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at present. There are 470 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 168 MW of oil-fired gas turbines supplying the Fairbanks area (see Table D.13). Their low initial cost, simplicity of construction and operation, and relatively short implementation lead time have made them attractive as a Railbelt generating alternative. The extremely low-cost contract gas in the Anchorage area also has made this type of generating facility cost-effective for the Anchorage load center.

(i) Capital Costs

A unit size of 75 MW was considered to be representative of a modern gas turbine plant addition in the Railbelt region. However, the possibility of installing gas turbine units at Beluga was not considered, since the Beluga development is at this time primarily being considered for coal.

Gas turbine plants can be built over a two-year construction period and have an average heat rate of approximately 10,000 Btu/kWh. The capital costs were again taken from the Battelle alternatives study.

(ii) Fuel Costs

Gas turbine units can be operated on oil as well as natural gas. The opportunity value and market cost for oil are considered to be equal, at \$6.50 per million Btu. The real annual y owth rates in oil costs used were 2 percent for 1982-2000 and 1 percent for 2000-2040.

(iii) Other Performance Characteristics

Annual operation and maintenance costs and forced outage rates are shown in Table D.17.

(e) Diesel Power Generation

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Most diesel plants in the Railbelt today are on standby status or are operated only for peak load service. Nearly all the continuous duty units were retired in the past several years because of high fuel prices. About 65 MW of diesel plant capacity is currently available.

(i) Capital Costs

The high cost of diesel fuel and low capital cost makes new diesel plants most effective for emergency use or in remote areas where small loads exist. A unit size of 10 MW was selected as appropriate for this type of facility. The capital cost was derived from the same source as given in Table D.17.

(ii) Fuel Costs

Diesel fuel costs and growth rates are the same as oil costs for gas turbines.

(iii) Other Performance Characteristics

Annual operation and maintenance and the forced outage rate are given in Table D.17.

(f) Plan Formulation and Evaluation

The four candidate unit types and sizes were used to formulate plans for meeting future Railbelt power generation requirements. The objective of this exercise was defined as the formulation of appropriate plans for meeting the projected Railbelt demand on the basis of economic preferences.

Economic evaluation of any Susitna Basin development plan requires that the impact of the plan on the cost of energy to the Railbelt area consumer be assessed on a systemwide basis. Since the consumer is supplied by a large number of different generating sources, it is necessary to determine the total Railbelt system cost in each case to compare the various Susitna Basin development options.

The primary tool used for system costs was the mathematical model developed by the Electricity Utility Systems Engineering Department of the General Electric Company. The model is commonly known as OGP5 or Optimized Generation Planning Model, Version 5. The following information is paraphrased from GE literature on the program.

The OGP5 program was developed over ten years to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis. OGP5 will automatically develop optimum generation expansion patterns in terms of economics, reliability and operation. Many utilities use OGP5 to study load management, unit size, capital and fuel costs, energy storage, forced outage rates, and forecast uncertainty.

The OGP5 program requires an extensive system of specific data to perform its planning function. In developing an optimal plan, the program considers the existing and committed units (planned and under construction) available to the system and the characteristics of these units including age, heat rate, size and outage rates as the base generation plan. The program then considers the given load forecast and operation criteria to determine the need for additional system capacity based on given reliability criteria. This determines "how much" capacity to add and "when" it should be installed. If a need exists during any monthly iteration, the program will consider additions from a list of alternatives and select the available unit best fitting the system needs. Unit selection is made by computing production costs for the system for each alternative included and comparing the results.

The unit resulting in the lowest system production costs is selected and added to the system. Finally, an investment cost analysis of the capital costs is completed to answer the question of "what kind" of generation to add to the system.

The model is then further used to compare alternative plans for meeting variable electrical demands, based on system reliability and production costs for the study period.

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The use of the output from the generation planning model is in Section 4.6(a).

4.6 - Without Susitna Plan

In order to analyze the economics of developing the Susitna project, it was necessary to analyze the costs of meeting the projected Alaska Railbelt load forecast with and without the project. Thus, a plan using the identified components was developed.

Using the OGP5 system model, a base case "without Susitna" plan was structured based on middle range projections. The base case input to the model included:

- Battelle's middle range load forecast (Exhibit B);
- Fuel cost as specified;
- Coal-fired steam and gas-fired combined-cycle and combustion turbine units as future additions to the system;
- Costs and characteristics of future additions as specified;
- The existing system as specified and scheduled commitments listed in Table D.12;
- Middle range fuel escalation as specified;
- Economic parameters of three percent interest and zero percent general inflation;
- Real escalation on operation and maintenance and capital costs at a rate of 1.8 percent to 1992 and 2 percent thereafter; and
- Generation system reliability set to a loss of load probability of one day in ten years. This is a probabilistic measure of the inability of the generating system to meet projected load. One day in ten years is a value generally accepted in the industry for planning generation systems.

The model was initially to be operated for a period from 1982-2000. It was found that, under the medium load forecast, the critical period for capacity addition to the system would be in the winter of 1992-1993.

Until that time, the existing system, given the additions of the planned intertie and the planned units, appear to be sufficient to meet Railbelt demands. Given this information, the period of plan development using the model was set as 1993-2010.

The following was established as the non-Susitna Railbelt base plan (see Figure D.16):

(a) System as of January 1993

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Coal-fired steam:	59 MW
Natural gas GT:	452 MW
Oil GT:	140 MW
Diesel:	67 MW
Natural gas CC:	317 MW
Hydropower:	155 MW

Total (including committed conditions): 1190 MW

(b) System Additions

	Year	Gas Fired Gas Turbine (MW)		Coal Fi	red Unit MW)		
	1993 1994 1996 1997 1998 2001 2003 2004 2005 2006 2007 2009	1 x 70 1 x 70 1 x 70 1 x 70 1 x 70 1 x 70 2 x 70 1 x 70 1 x 70 1 x 70		1 x 200 1 x 200 1 x 200 1 x 200	(Beluga (Beluga (Nenana/	Coal) Coal) /Healy C	02])
	Total	630		800			
(c)	System as of 20	10					
	Coal-fired stea Natural gas GT: Oil GT: Diesel: Natural gas CC: Hydropower:	m :	813 MW 746 MW 0 MW 6 MW 317 MW 155 MW				
	Total (accounti retirements a	ng for nd add(tions)	2037 MW				

There is one particularly important assumption underlying the plan. The costs associated with the Beluga development are based on the opening of that coal field for commercial development. That development is not a certainty now and is somewhat beyond the control of the state, since the rights are in the hands of private interests. Even if the seam is mined for export, there will be environmental problems to overcome. The greatest problem will be the availability of cooling water for the units. The problem could be solved in the "worst" case by using the sea water from Cook Inlet as cooling water; however, this solution would add significantly to project costs.

Two alternatives which Battelle included in their base plan which have not been included in this plan are the Chakachamna and Allison Creek hydroelectric plants. The Chakachamna plant is currently the subject of a feasibility study by the Power Authority. The current plan would develop a 330 MW plant at a cost of \$1.45 billion at January, 1982 price levels. The plant would produce nearly 1500 GWh on an average annual basis.

Due to some current questions regarding the feasibility of the Chakachamna plant, it has not been included in the non-Susitna plan. It has been checked, however, in the sensitivity analysis presented later in this section.

The Allison Creek Hydroelectric Troject was included on the non-Susitna base plan by Battelle. It has not been included in this base plan due to its high costs (\$125/MWh in 1981 dollars).

The thermal plan described above has been selected as representative of the generation scenario that would be pursued in the absence of Susitna. The selection has been confirmed by the Battelle results which show an almost identical plan to be the lowest cost of any non-Susitna plan.

4.7 - Economic Evaluation

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This section provides a discussion of the key economic parameters used in the study and develops the net economic benefits stemming from the Susitna Hydroelectric Project. Section 4.7 (a) deals with those economic principles relevant to the analysis of net economic benefits and develops inflation and discount rates and the Alaskan opportunity values (shadow prices) of oil, natural gas and coal. In particular the analysis is focused on the longer-term prospects for coal markets and prices. This follows from the evaluation that, in the absence of Susitna, the next best thermal generation plan would rely on exploitation of Alaskan coal. The future coal price is therefore considered in detail to provide rigorous estimates of prices in the most likely alternative markets and hence the market price of coal at the mine-head within the state.

Section 4.7 (c) presents the net economic benefits of the proposed hydroelectric power investments compared with this thermal alternative. These are measured in terms of present valued differences between benefits and costs. Recognizing that even the most careful estimates will be surrounded by a degree of uncertainty, the benefit-cost assessments are also carried out in a probabilistic framework as shown in Section 4.8. The analysis therefore provides both a most likely estimate of net economic benefits accruing to the state and a range of net economic benefits that can be expected with a likelihood _onfidence level) of 95 percent or more.

(a) Economic Principles and Parameters

(i) Economic Principles - Concept of Net Economic Benefits

A necessary condition for maximizing the increase in state income and economic growth is the selection of public or private investments with the highest present valued net benefits to the state. In the context of Alaskan electric power investments, the net benefits are defined as the difference between the costs of optimal Susitna-inclusive and Susitna-exclusive (all thermal) generation plans.

The energy costs of power generation are initially measured in terms of opportunity values or shadow prices which may differ from accounting or market prices currently prevailing in the state. The concept and use of opportunity values is fundamental to the optimal allocation of scarce resources. Energy investment decisions should not be made sclely on the basis of accounting prices in the state if the international value of traded energy commodities such as coal and gas diverge from local market prices.

The choice of a time horizon is also crucial. If a shortterm planning period is selected, the investment rankings and choices will differ markedly from those obtained through a long-term perspective. In other words, the benefit-cost analysis would point to different generation expansion plans depending on the selected planning period. A short-run optimization of state income would, at best, allow only a moderate growth in fixed capital investment; at worst, it would lead to underinvestment in not only the energy sector but also in other infrastructure facilities such as roads, airports, hospitals, schools, and communications. It therefore follows that the Susitna Project, like other Alaskan investments, should be appraised on the basis of long-run optimization, where the long-run is defined as the expected economic life of the facility. For hydroelectric projects, this service life is typically 50 years or more. The costs of a Susitna-inclusive generation plan have therefore been compared with the costs of the next-best alternative which is the all-thermal generation plan and assessed over a planning period extending from 1982 to 2040, using internally consistent sets of economic scenarios and appropriate opportunity values of Alaskan energy.

Throughout the analysis, all costs and prices are expressed in real (inflation-adjusted) terms using January 1982 dollars. Hence, the results of the economic calculations are not sensitive to modified assumptions concerning the rates of general price inflation. In contrast, the financial and market analyses conducted in nominal (inflation-inclusive) terms will be influenced by the rate of general price inflation from 1982 to 2051.

(ii) Price Inflation and Discount Rates

- General Price Inflation

Despite the fact that price levels are generally higher in Alaska than in the Lower 48, there is little difference in the comparative rates of price changes; i.e., price inflation. Between 1970 and 1978, for example, the U.S. and Anchorage consumer price indexes rose at annual rates of 6.9 and 7.1 percent, respectively. From 1977 to 1978, the differential was even smaller: the consumer prices increased by 8.8 percent and 8.7 percent in the U.S. and Anchorage (7).

Forecasts of Alaskan prices extend only to 1986 (8). These indicate an average rate of increase of 8.7 percent from 1980 to 1986. For the longer period between 1986 and 2010, it is assumed that Alaskan prices will escalate at the overall U.S. rate, or at 5 to 7 percent compounded annually. The average annual rate of price inflation is therefore about 7 percent between 1982 and 2010. Since this is consistent with long-term forecasts of the CPI advanced by leading economic consulting organizations, 7 percent has been adopted as the study value (9,10).

- Discount Rates

Discount rates are required to compare and aggregate cash flows occurring in different time periods of the planning

horizon. In essence, the discount rate is a weighting factor reflecting that a dollar received tomorrow is worth less than a dollar received today. This holds even in an inflation-free economy as long as the productivity of capital is positive. In other words, the value of a dollar received in the future must be deflated to reflect its earning power foregone by not receiving it today. The use of discount rates extends to both rea! dollar (economic) and escalated dollar (financial) evaluations, with corresponding inflation-adjusted (real) and inflation-inclusive (nominal) values.

. Real Discount and Interest Rates

Several approaches have been suggested for estimating the real discount rate applicable to public projects (or to private projects from the public perspective). Three common alternatives include:

- .. the social opportunity cost (SOC) rate;
- .. the social time preference (STP) rate; and
- .. the government's real borrowing rate or the real cost of debt capital (11, 12, 13).

The SOC rate measures the real social return (before taxes and subsidies) that capital funds could earn in alternative investments. If, for example, the marginal capital investment in Alaska has an estimated social yield of X percent, the Susitna Hydroelectric Project should be appraised using the X percent measure of "foregone returns" or opportunity costs. A shortcoming for this concept is the difficulty inherent in determining the nature and yields of the foregone investments.

The STP rate measures society's preferences for allocating resources between investment and consumption. This approach is also fraught with practical measurement difficulties since a wide range of STP rates may be inferred from market interest rates and sociallydesirable rates of investment.

A sub-set of STP rates used in project evaluations is the owner's real cost of borrowing; that is, the real cost of debt capital. This industrial or government borrowing rate may be readily measured and provides a starting point for determining project-specific discount rates. For example, long-term industrial bond rates have averaged about 2 to 3 percent in the U.S. in real (inflation-adjusted) terms (9,14). Forecasts of real interest rates show average values of about 3 percent and 2 percent in the periods of 1985 to 1990 and 1990 to 2000, respectively. The U.S. Nuclear Regulatory Commission has also analyzed the choice of discount rates for investment appraisal in the electric utility industry and has recommended a 3 percent real rate (30). Therefore, a real rate of 3 percent has been adopted as the base case discount and interest rate for the period 1982 to 2040.

. Nominal Discount and Interest Rates

The nominal discount and interest rates are derived from the real values and the anticipated rate of general price inflation. Given a 3 percent real discount rate and a 7 percent rate of price inflation, the nominal discount rate is determined as 10.2 percent or about 10 percent*.

(iii) Oil and Gas Prices

- Oil Prices

In the base period (January 1982), the Alaskan 1982 dollar price of No. 2 fuel oil is estimated at \$6.50/ MMBtu.

Long-term trends in oil prices will be influenced by events that are economic, political and technological in nature, and are therefore estimated within a probabilistic framework.

As shown in Table D.18, the base case (most likely escalation rate) is estimated to be 2 percent to 2000 and 1 percent from 2000 to 2040. To be consistent with Battelle forecasts, a 2 percent rate was used chroughout the OGP planning period 1982 to 2010 and 0 percent thereafter. In other scenarios the growth rates were estimated at 0 percent from 1982-2051 (low growth); and at 4 percent to 2000, and 2 percent beyond 2000 (high growth). These projections are also consistent with

* $(1 + \text{the nominal rate}) = (1 + \text{the real rate}) \times (1 + \text{the inflation})$ rate) = 1.03 x 1.07, or 1.102 those recently advanced by such organizations as DRI (15), World Bank (16), U.S. DOE (17), and Canadian National Energy Board (18).

A September 1982 review of major forecasts for oil price trends reaffirms the Battelle projection. Projections from seven sources indicated ten forecasts which varied from a low trend projection of -0.5 to a high of 5.3 percent. Seven of the ten trend forecasts were within a band of +1.7 to +3.4 percent.

- Gas Prices

Alaskan gas prices have been forecast using both export opportunity values (netting back CIF prices from Japan to Cook Inlet) and domestic market prices as likely to be faced in the future by Alaskan electric utilities. The generation planning analysis used market prices as estimated by Battelle, since there are indications that Cook Inlet reserves may remain insufficient to serve new export …arkets.

. Domestic Market Prices

Table D.19 depicts the low, medium and high domestic market prices used in the generation planning analysis. In the medium (most likely) case, prices escalate at real rates of 2.5 percent from 1982 to 2000 and 2 percent beyond 2000. In the low case, there is zero escalation and in the high case, gas prices grow at 4 percent 1982 to 2000 and 2 percent beyond 2000.

. Export Opportunity Values

Table D.19 also shows the current and projected opportunity value of Cook Inlet gas in a scenario where the Japanese export market for LNG continues to be the alternative to domestic demand. From a base period plant gate price of \$4.69 MMBtu (CIF Japan), low, medium and high price escalation rates have been estimated for the intervals 1982 to 2000 and 2000 to 2040. The cost of liquefaction and shipping (assumed to be constant in real terms) was subtracted from the escalated CIF prices to derive the Cook Inlet plant-gate prices and their growth rates. These Alaskan opportunity values are projected to escalate at 2.7 percent and 1.2 percent in the medium (most likely) case. Note that the export of ortunity values consistently exceed the domestic prices. In the year 2000, for example, the opportunity value is nearly double the domestic price estimated by Battelle.

(iv) Coal Prices

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The shadow price or opportunity value of Beluga and Healy coal is the delivered price in alternative markets less the cost of transportation to those markets. The most likely alternative demand for thermal coal is the East Asian market, principally Japan, South Korea, and Taiwan. The development of 60-year forecasts of coal prices in these markets is conditional on the procurement policies of the importing nations. These factors, in turn, are influenced to a large extent by the price movements of crude oil.

- Historical Trends

Examination of historical coal price trends reveals that FOB and CIF prices have escalated at annual real rates of 1.5 percent to 6.3 percent as shown below:

- . Coal prices (bituminous, export unit value, FOB U.S. ports) grew at real annual rates of 1.5 percent (1950 to 1979) and 2.8 percent (1972 to 1979) (17).
- . In Alaska, the price of thermal coal sold to the GVEA utility advanced at real rates of 2.2 percent (1965 to 1978) and 2.3 percent (1970 to 1978).
- . In Japan, the average CIF prices of steam coal experienced real escalation rates of 6.3 percent per year in the period 1977 to 1981 (26,27). This represents an increase in the average price from approximately \$35.22 per metric ton (mt) in 1977 to about \$76.63/mt in 1981.

As shown below, export prices of coal are highly correlated with oil prices, and an analysis of production costs has not predicted accurately the level of coal prices. Even if the production cost forecast itself is accurate, it will establish a minimum coal price, rather than the market clearing price set by both supply and demand conditions.

- . In real terms export prices of U.S. coal showed a 94 percent and 92 percent correlation with oil prices (1950 to 1979 and 1972 to 1979).*
- Supply function (production cost) analysis has estimated Canadian coal at a price of \$23.70 (1980 U.S. \$/ton) for S.E. British Columbia (B.C.) coking coal, FOB Roberts Bank, B.C., Canada (24,29). In fact, Kaiser Resources (now B.C. Coal Ltd.) has signed agree-

* Analysis is based on data from the World Bank.

ments with Japan at an FOB Price of about \$47.50 (1980 U.S. 100 percent more than the price estimate based on production costs.

- . The same comparison for Canadian B.C. thermal coal indicates that the expected price of \$55.00 (1981 Canadian \$) per MT (2200 pounds) or about \$37.00 (1980 U.S. \$) per ton would be 60 percent above estimates founded on production costs (24,25,29).
- . In longer-term coal export contracts, there has been provision for reviewing the base price (regardless of escalation clauses) if significant developments occur in pricing or markets. That is, prices may respond to market conditions even before the expiration of the contract.*
- . Energy-importing nations in Asia, especially Japan, have a stated policy of diversified procurement for their coal supplies. They will not buy only from the lowest-cost supplier (as would be the case in a perfectly competitive model of coal trade) but instead will pay a risk premium to ensure security of supply (24, 29).

- <u>Survey of Forecasts</u>

Data Resources Incorporated is projecting an average annual real growth rate of 2.6 percent for U.S. coal prices in the period 1981 to 2000 (9). The World Bank has forecast that the real price of steam coal would advance at approximately the same rate as oil prices (3 percent/a) in the period 1980 to 1990 (16). Canadian Resourcecon Limited has recently forecast growth rates of 2 percent to 4 percent (1980 to 2010) for subbituminous and bituminous steam coal (28).

- Opportunity Value of Alaskan Coal

. Delivered Prices, CIF Japan

Based on these considerations, the shadow price of coal (CIF price in Japan) was forecast using conditional

* This clause forms part of the recently concluded agreement between Denison Mines and Teck Corporation and Japanese steel makers. probabilities given low, medium, and high oil price scenarios. Table D.20 depicts the estimated coal price growth rates and their associated probabilities, given the three sets of oil prices. Combining these probabilities with those attached to the oil price cases yields the following coal price scenarios, CIF Japan.

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Scenario	Probability	Real Price Growth		
Medium (most likely)	49 percent	2 percent (1982-2000) 1 percent (2000-2040)		
Low	24 percent	0 percent (1982-2040)		
High	27 percent	4 percent (1982-2000) 2 percent (2000-2040)		

The 1982 base period price was initially estimated using the data from the Battelle Beluga Market Study (24). Based on this study, a sample of 1980 spot prices (averaging \$1.66/MMBtu) was escalated to January 1982 to provide a starting value of \$1.95/MMBtu in January 1982 dollars.*

As more recent and more complete coal import price statistics became available, this method of estimating was found to give a significant underestimate of actual CIF prices. By late 1981, Japan's average import price of steam coal reached \$2.96/MMBtu.** An important sensitivity case was therefore developed reflecting these updated actual CIF prices. The updated base period value of \$2.96 was reduced by 10 percent to \$2.66 to recognize the price discount dictated by quality differentials between Alaskan coal and other

^{*} The escalation factor was 1.03 x 1.14, where 3 percent is the forecast real growth in prices (mid-1980 to January 1982) at an annual rate of 2 percent, and 14 percent is the 18-month increase if the CPI is used to convert from mid-1980 dollars to January 1982 dollars.

^{**} As reported by Coal Week International in October 1981, the average CIF value of steam coal was \$75.50 per MT. At an average heat value of 11,500 Btu/lb, this is equivalent to \$2.96/MMBtu.

sources of Japanese coal imports, as estimated by Battelle (24).

. Opportunity Values in Alaska

.. Base Case - Battelle-based CIF Prices, No Export Potential for Healy Coal

Transportation costs of \$0.52/MMBtu were subtracted from the initially estimated CIF price of \$1.95 to determine the opportunity value of Beluga coal at Anchorage. In January 1982 dollars, this base period net-back price is therefore \$1.43. In subsequent years, the opportunity value is derived as the difference between the escalated CIF price and the transport cost (estimated to be constant in real terms). The real growth rate in these FOB prices is determined residually from the forecast opportunity values. In the medium (most likely) case, the Beluga opportunity values escalate at annual rates of 2.6 percent and 1.2 percent during the intervals 1982 to 2000 and 2000 to 2040, respectively.

For Healy coal, it was estimated that the base period price of \$1.75/MMBtu (at Healy) would also escalate at 2.6 percent (to 2000) and 1.2 percent (2000 to 2040). Adding the escalated cost of transportation from Healy to Nenana results in a January 1982 price of \$1.75/MMBtu.* In subsequent years, the cost of transportation (of which 30 percent is represented by fuel cost which escalates at 2 percent) is added to the Healy price, resulting in Nenana prices that grow at real rates of 2.3 percent (1982 to 2000) and 1.1 percent (2000 to 2040). Table D.20 summarizes the real escalation rates applicable to Nenana and Beluga coal in the low, medium, and high price scenarios.

.. Sensitivity Case - Updated CIF Prices, Export Potential for Healy Coal

The updated CIF price of steam coal (\$2.66/MMBtu after adjusting for quality differentials) was reduced by shipping costs from Healy and Beluga to Japan to yield Alaskan opportunity values. In

* Transportation costs are based on Battelle (18,23).

January 1982, prices were \$2.08 and \$1.74 at Anchorage and Nenana, respectively. The differences between escalated CIF prices and shipping costs result in FOB prices that have real growth rates of 2.5 percent and 1.2 percent for Beluga coal and 2.7 percent and 1.2 percent for Healy coal (at Nenana). Table D.20 shows escalation rates for the opportunity value of Alaskan coal in the low, medium, and high price scenarios, using updated base period values.

(v) Generation Planning Analysis - Base Case Study Values

Based on the considerations presented in (i) through (iv) above, a consistent set of fuel prices was assembled for the base case probabilistic generation planning (OGP5) analysis, as shown in Table D.21. The study values include probabilities for the low, medium and high fuel price scenarios. The probabilities are common for the three fuels (oil, gas and coal) within each scenario in order to keep the number of generation planning runs to manageable size. In the case of the natural gas prices, domestic market prices were selected for the base case analysis with the export opportunity values used in sensitivity runs. The base period value of \$3 was derived by deflating the 1996 Battelle prices to 1982 by 2.5 percent per year. Coal prices were also selected from the base case using Battelle's 1980 sample of prices as the starting point, with the updated CIF prices of coal reserved for sensitivity runs. Oil prices have been escalated by 2 percent (1982 to 2040).

(b) Analysis of Net Economic Benefits

(i) Modeling Approach

(•)

Using the economic parameters discussed in the previous section and data relating to the electrical energy generation alternatives available for the Railbelt, an analysis was made comparing the costs of electrical energy production with and without the Susitna project. The primary tool for the analysis was a generation planning model (OGP5) which simulates production costs over a planning period extending from 1982 to 2010.

The method of comparing the "with" and "without" Susitna alternative generation scenarios is based on the long-term present worth (PW) or total system costs. The planning model determines the total production costs of alternative plans on a year-by-year basis. These total costs for the

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period of modeling include all costs of fuel and operation and maintenance (O&M) for all generating units included as part of the system, and the annualized investment costs of any generating and system transmission plants added during the period of 1993 to 2010. Factors which contribute to the ultimate consumer cost of power but which are not included as input to this model are investment costs for all generation plants in service prior to 1993 investment, cost of the transmission and distribution facilities already in service, and administrative costs of utilities. These costs are common to all scenarios and therefore have been omitted from the study.

In order to aggregate and compare costs on a significantly long-term basis, annual costs have been aggregated for the period of 1993 to 2051. Costs have been computed as the sum of two components and converted to a 1982 PW. The first component is the 1982 PW of cost output from the first 18 years of model simulation from 1993 to 2010. The second component is the estimated PW of long-term system costs from 2011 to 2051.

For an assumed set of economic parameters on a particular generation alternative, the first element of the PW value represents the amount of cash (not including those costs noted above) needed in 1982 to meet electrical production needs in the Railbelt for the period 1993 to 2010. The second element of the aggregated PW value is the long-term (2011 to 2051) PW estimate of production costs. In considering the value to the system of the addition of a hydroelectric power plant which has a useful life of approximately 50 years, the shorter study pericd would be inadequate. A hydroelectric plant added in 1993 or 2002 would accrue PW benefits for only 17 or 9 years, respectively, using an investment horizon that extends to 2010. However, to model the system for an additional 40 years it would be necessary to develop future load forecasts and generation alternatives which are beyond the realm of any prudent projections. For this reason, it has been assumed that the production costs for the final study year (2010) would simply reoccur for an additional 41 years, and the PW of these was added to the 18-year PW (1995 to 2010) to establish the long-term cost differences between alternative methods of power generation.

(ii) Base Case Analysis

- Pactern of Investments "With" and "Without" Susitna

The base case comparison of the "with" and "without" Susitna plans is based on an assessment of the PW production costs for the period 1993 to 2051, using mid-range values for the energy demand and load forecast, fuel prices, fuel price escalation rates, capital costs, and capital cost escalation rates.

The with-Susitna plan calls for 680 MW of generating capacity at Watana to be available to the system in 1993. Although the project may come on-line in stages during that year, for modeling purposes full-load generating capability is assumed to be available for the entire year. The second stage of Susitna, the Devil Canyon project, is scheduled to come on-line in 2002. The optimum timing for the addition of Devil Canyon was tested for earlier and later dates. Addition in the year 2002 was found to result in the lowest long-term cost. Devil Canyon will have 600 MW of installed capacity.

The without-Susitna plan is discussed in Section 4.5. It includes three 200 MW coal-fired plants added at Beluga in 1993, 1994, and 2007. A 200 MW unit is added at Nenana in 1996 and nine 70 MW gas-fired combustion turbines (GTs) would be added during the 1997 to 2010 period.

- Base Case Net Economic Benefits

The economic comparison of these plans is shown in Table D.22. During the 1993 to 2010 study period, the 1982 PW cost for the Susitna plan is \$3.119 billion. The annual production cost in 2010 is \$0.385 billion. The PW of this level cost, which remains virtually constant for a period extending to the end of the life of the Devil Canyon plant (2051), is \$3.943 billion. The resulting total cost of the with-Susitna plan is \$7.06 billion in 1982 dollars, presently valued to 1982.

The non-Susitna plan (Section 4.5) which was modeled has a 1982 PW cost of \$3.213 billion for the 1993 to 2010 periods with a 2010 annual cost of \$0.491 billion. The total long-term cost has a PW of \$8.24 billion. Therefore, the net economic benefit of adopting the Susitna plan is \$1.18 billion. In other words, the present valued cost difference between the Susitna plan and the expansion plan based on thermal plant addition is \$1.18 billion in 1982 dollars. This is equivalent to a 1982 per capita net economic benefit of \$2,700 per capita for the 1982 population of the State of Alaska. Expressed in 1993 dollars (at the on-line date of Watana), the net benefits would have a levelized value of \$2.48 billion.*

It is noted that the magnitude of net economic benefits (\$1.18 billion) is not particularly sensitive to alternative assumptions concerning the overall rate of price inflation as measured by the Consumer Price Index. The analysis has been carried out in real (inflationadjusted) terms. Therefore, the present valued cost savings will remain close to \$1.18 billion regardless of CPI movements, as long as the real (inflation-adjusted) discount and interest rates are maintained at 3 percent.

The Susitna project's internal rate of return (IRR), i.e., the real (inflation-adjusted) discount rate at which the with-Susitna plan has zero net economic benefits, or the discount rate at which the costs of the with-Susitna and the alternative plans have equal costs, has also been determined. The IRR is about 4.1 percent in real terms, and 11.4 percent in nominal (inflationinclusive) terms. Therefore, the investment in Susitna would significantly exceed the 5 percent nominal rate of return "test" proposed by the State of Alaska in cases where state appropriations may be involved.**

It is emphasized that these net economic benefits and the rate of return stemming from the Susitna project are inherently conservative estimates due to several assumptions made in the OGP5 analysis.

. Zero Growth in Long-term Costs

From 2010 to 2051, the OGP5 analysis assumed constant annual production costs in both the Susitna and non-Susitna plans. This has the effect of excluding real escalation in fuel prices and the capital costs of thermal plant replacements, and thereby understating the long-term PW costs of thermal generation plans.

. Loss of Load Probabilities

The loss of load probability in the non-Susitna plan is calculated at 0.099 in the year 2010. This means that

* \$1.18 billion times 2.105, where 2.105 is the general price inflation index for the period 1982 to 1993.

** See State of Alaska's SB-25, Section 44.83.670.

the system in 2010 is on the verge of adding an additional plant, and would do so in 2011. These costs are however, not included in the analysis, which is cut off at 2010. On the other hand, the Susitna plan has a loss of load probability of 0.025, and may not require additional capacity for several years beyond 2010.

. Long-term Energy From Susitna

Some of the Susitna energy output (about 350 GWh) is still not used by 2010. This energy output would be available to meet future increases in projected demand in the summer months. No benefit is attributed to this energy in the analysis.

. Equal Environmental Costs

The generation planning analysis has implicitly assumed equal environmental costs for both the Susitna and the non-Susitna plans. To the extent that the thermal generation expansion plan is expected to carry greater environmental costs than the Susitna plan, the economic cost savings from the Susitna project are understated. It is conceivable that these so-called negative externalities from coal-fired electricity generation will have been mitigated by 1993 and beyond as a result of the enactment of new environmental legislation.

(iii) <u>Sensitivity Analysis</u>

Rather than rely on a single point comparison to assess the net benefit of the Susitna project, a sensitivity analysis was carried out to identify the impact of modified assumptions on the results. The analysis was directed at the following variables:

- Load forecast;

- Real interest and discount rate;
- Construction period;
- Period of analysis;
- Capital costs;
 - . Susitna
 - . Thermal alternatives

- O&M costs;

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- Base period fuel price;
- Real escalation in capital costs, O&M costs, and fuel prices;
- System reliability;

- Chackachanina; and

- Susitna Project delay.

Tables D.24 to D.31 depict the results of the sensitivity analysis. In particular, Table D.31 summarizes the net economic benefits of the Susitna Project associated with each sensitivity test. The net benefits have been compared using indexes relative to the base case value (\$1.176 billion) which is set to 100.

The greatest variability in results occurs in sensitivity tests pertaining to fuel escalation rates, discount rates, and base period coal prices. For example, a scenario with high fuel price escalation results in net benefits that have a value of 253 relative to the base case. In other words, the high case provides 253 percent of the base case net benefits. In general, the Susitna plan maintains its positive net benefits over a reasonably wide range of values assigned to the key variables.

A multivariate analysis in the form of probability trees has been undertaken to test the joint effects of varying several assumptions in combination rather than individually. This probabilistic analysis reported in Section 4.7 provides a range of expected net economic benefits and probability distributions that identify the chances of exceeding particular values of net benefits at given levels of confidence.

4.8 - Probability Assessment

(a) Multivariate Sensitivity Analysis

The feasibility study of the Susitna Hydroelectric Project included an economic analysis based on a comparison of generation system production costs with and without the proposed project using a computerized model of the Railbelt generation system. In order to carry out this analysis, numerous projections and forecasts of future conditions were made. These forecasts of uncertain conditions include future electrical demand, costs, and escalation. In order to address these uncertain conditions, a sensitivity analysis on key factors was carried out. This analysis focused on the variance of each of a number of forecast conditions and determined the impact of variance on the economic feasibility of the project. Each factor was varied singularly with all other variables held constant to determine clearly its importance.

The purpose of this multivariable analysis was to select the most critical and sensitive variables in the economic analysis and to test the economic feasibility of the Susitna Project in each possible combination of the selected variables.

While a number of variables were identified and tested in the single variable sensitivity analysis for the Susitna economic feasibility study, the variables which were chosen for the multi-variate sensitivity analysis represent the key issues such as load forecasts, capital cost of alternatives, fuel escalation and Susitna capital cost.

The methodology for the multivariate analysis was implemented by constructing probability trees of future conditions for the Alaska Railbelt electrical system, with and without the Susitna Project. Each branching of the tree represents three values for a given variable. These were assigned a high, medium, and low value as well as a corresponding probability of occurrence. The three values represent the expected range and mid-point for a given variable. In some cases, the mid-point represents the most likely value which would be expected to occur. End limbs of the probability tree represent scenarios of mixed variable conditions and a probability of occurrence of the scenario.

The OGP5 production cost model was then used to determine the PW (in 1982 dollars) of the long-term cost of the electric generation related to each variable. The PW of the long-term costs for each "with" and "without" Susitna scenario in terms of cumulative probability of occurrence were determined and plotted. Net benefits of the project have also been calculated and analyzed in a probabilistic manner.

Figures D.17 and D.18 present the non-Susitna and Susitna probability trees with resultant long-term costs.

(b) <u>Comparison of Long-term</u> Costs

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Figure D.19 presents the two histograms of long-term costs for the "with" and "without" Susitna cases plotted on the same axes. From these plots it is seen that the non-Susitna plan costs could be

expected to be significantly less than the Susitna plan costs for about 6 percent of the time, approximately equal to the Susitna costs 16 percent of the time, and significantly greater for 78 percent of the time.

A comparison of the expected value of long-term costs of the "with" and "without" Susitna cases yields an expected value net benefit of \$1.45 billion. This value represents the difference between the non-Susitna LTC of \$8.48 billion and the Susitna LTC of \$7.03 billion.

(c) Net Benefit Comparison

A second method of comparing the "with" and "without" Susitna probability trees is by making a direct comparison of similar scenarios and calculating the net benefit which applies. As in the case of the individual tree cases, the net benefits were ranked from low to high and plotted against cumulative probability. This graph has been represented as a single line due to the number of points on the curve. It, however, would be most accurately portrayed as a histogram in the manner of Figure D.19. The net benefits vary from a negative \$2.92 billion with an associated probability of .0015 to a high of \$4.80 billion with the highest probability of occurrence of .108 has a net benefit of \$2.09 billion.

Figure D.20 plots the net benefit with the cross-over between the "with" and "without" Susitna costs occurring at about 23 percent. This is consistent with the previous comparison and with the expected value net benefit calculated by this method of \$1.45 billion.

(d) Sensitivity of Results to Probabilities

In assigning the probabilities of occurrence for each set of variables, a number of subjective assumptions were made. An exception was the Susitna capital cost probability distribution which was supported by a probabilistic risk assessment of construction cost. The probabilities for load forecast of 0.2, 0.6 and 0.2 for the low, medium and high cases respectively, reflect the analysis by Battelle and the probability of exceedence of approximately 10 percent for the high level of demand.

Capital costs for alternative generation modes estimated in the Battelle study reflect a 0.20, 0.60 and 0.20 distribution, again within a range of a 90 percent chance of exceedence of the low and 10 percent exceedence of the high level.

The single variable to which the results are most sensitive is the rate of real fuel escalation adopted. (This conclusion is sup-

ported by the single variable analysis as well.) The distribution of probabilities was 0.25, 0.50 and 0.25 for low, medium and high fuel cost escalation scenarios. A case can be made for the argument that some of the combined events, for example high fuel cost escalation, load and capital cost are not (as our results assume) independent of each other. High fuel prices, it may be argued, would result in lower load and increased capital cost. It is probable, however, that the greater revenues consequent on higher fuel prices would result in greater economic activity in Alaska thus increasing demand for energy. This and other considerations led to the conclusion that the results would be relatively insensitive to probable ranges of interdependence.

4.9 - Battelle Railbelt Alternatives Study

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[Note to Power Authority - This section will be revised upon receipt of the final (and extensively revised) Battelle reports.]

The Office of the Governor, State of Alaska, Division of Policy Development and Planning and the Governor's Policy Review Committee contracted with Battelle, Pacific Northwest Laboratories to investigate potential strategies for future electric nower development in the Railbelt region of Alaska. This section presents a summary of final results of the Railbelt Electric Power Alternatives Study.

The overall approach taken on this study involved five major tasks or activities that lead to the results of the project, a comparative evaluation of electric energy plans for the Railbelt. The five tasks conducted as part of the study evaluated the following aspects of electrical power planning:

- fuel supply and price analysis
- electrical demand forecasts
- generation and conservation alternatives evaluation
- development of electric energy themes or "futures" available to the Railbelt .
- systems integration/evaluation of electric energy plans.

Note that while each of the tasks contributed data and information to the final results of the project, they also developed important results that are of interest independent of the final results of this project.

The first task evaluated the price and availability of fuels that either directly could be used as fuels for electrical generation or indirectly could compete with electricity in end-use applications. such as space or water heating. The second task, electrical demand forecasts, was required for two reasons. The amount of electricity demanded determines both the size of generating units that can be included in the system and the number of generating units or the total generating capacity required. The forecast used from this study in the Susitra feasibility study is presented in Exhibit B.

The third task's purpose was to identify electric power generation and conservation alternatives potentially applicable to the Railbelt region and to examine their feasibility, considering several factors. These factors include cost of power, environmental and socioeconomic effects, and public acceptance. Alternatives appearing to be best suited for future application to the region were then subjected to additional in-depth study and were incorporated into one or more of the electric energy plans.

The fourth task, the development of electric energy themes or plans, presents possible electric energy "futures" for the Railbelt. These plans were developed both to encompass the full range of viable alternatives available to the region and to provide a direct comparison of those futures currently receiving the greatest interest within the Railbelt. A plan is defined by a set of electrical generation and conservation alternatives sufficient to meet the peak demand and annual energy requirements over the time horizon of the study. The time horizon of the study is from 1981-2050 time period. The set of alternatives used in each plan was drawn from the alternatives selected for further study in the analysis of alternatives task.

As the name implies, the purpose of the fifth task, the system integration/comparative analysis task, was to integrate the results of the other tasks and to produce a comparative evaluation of the electric energy plans. This comparative evaluation basically is a description of the implications and impacts of each electric energy plan. The major criteria used to evaluate and compare the plans are cost of power, environmental and socioeconomic impacts, as well as the susceptibility of the plan to future uncertainty in assumptions and parameter estimates.

This summary focuses on the third, fourth and fifth tasks: alternatives evaluation, plan development and plan comparison.

(a) Alternatives Evaluation

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The Battelle study reviewed a much wider range of generating alternatives than the Susitna feasibility study. The following text summarizes the process followed and results of selecting technologies for developing energy plans.

Selecting generating alternatives for the Railbelt electric energy plans proceeded in three stages. First, a broad set of candidate technologies was identified, constrained only by the availability of the technology for commercial service prior to year 2000. After a study was prepared on the candidate technologies, they were evaluated based on several technical, economic, environmental and institutional considerations. Using the results of that study, a subset of more promising technologies subsequently was identified. Finally, prototypical generating facilities (specific sites in the case of hydropower) were identified for further development of the data required to support the analysis of electric energy plans.

A wide variety of energy resources capable of being applied to the generation of electricity is found in the Railbelt. Resources currently used include coal, natural gas, petroleum-derived liquids and hydropower. Energy resources currently not being used but which could be developed for producing electric power within the planning period of this study include peat, wind power, solar energy, municipal refuse-derived fuels, and wood waste. Light water reactor fuel is manufactured in the "lower 48" states and could be readily supplied to the Railbelt, if desired. Candidate electric generating technologies using these resources and most likely to be available for commercial order prior to year 2000 are listed in Table D.32. The 37 generation technologies and combinations of fuel conversion - generation technologies shown in the table comprised the candidate set of technologies selected for additional study. Further discussion of the selection process and technologies rejected from consideration at this stage are provided in Reference 33.

Selection of generation alternatives was based on the followinng considerations:

- the availability and cost of energy resources;

- the likely effects of minimum plant size and operational characteristics on system operation;
- the economic performance of the various technologies as reflected in estimated busbar power costs;
- public acceptance, both as reflected in the framework of electric energy plans within which the selection was conducted and as impacting specific technologies; and

- ongoing Railbelt electric power p'anning activities.

From this analysis, described morefully in Reference 33, 13 generating technologies were selected for possible inclusion in the Railbelt electric power plans. For each nonhydro technology, a prototypical plant was defined to facilitate further development of the needed information. For the hydro technologies, promising sites were selected for further study. These prototypical plants and sites consistute the generating alternatives selected for consideration in the Railbelt electric energy plans. In the following paragraphs, each of the 13 preferred technologies is briefly described, along with some of the principal reasons for its selection. Also described are the prototypical plants and hydro sites selected for further study.

(i) Coal-Fired Steam-Electric Plants

Coal-fired steam-electric generation was selected for consideration in Railbelt electric energy plans because it is a commercially mature and economical technology that potentially is capable of supplying all of the Railbelt's base-load electric power needs for the indefinite future. An abundance of coal in the Railbelt should be mineable at costs allowing electricity production to be economically competitive with all but the most favorable alternatives throughout the planning period. The extremely low sulfur content of Railbelt coal and the availability of commercially tested oxides of sulpher (SO_y) and particulate control devices will facilitate control of these emissions to levels mandated by the Clean Air Act. Principal concerns of this technology are environmental impacts of coal mining, possible ambient air-quality effects of residual SO_x , oxides of nitrogen (NO_x) and particulate emissions, long-term atmospheric buildup of CO_{2} (common to all combustion-based technologies) and the long term susceptibility of busbar power costs to inflation.

Two prototypical facilities were chosen for in-depth study: in the Beluga area a 200-MW plant that uses coal mined from the Chutna Field, and at Nenana a plant of similar capacity that uses coal delivered from the Nenan field at Healy by Alaska Railroad. The results of the prototypical study are documented in Reference 34.

(ii) <u>Coal Gasifier - Combined-Cycle Plants</u>

These plants consist of coal gasifiers producing a synthetic gas that is burned in combustion turbines that drive electric generators. Heat-recovery boilers use turbine exhaust heat to raise steam to drive a steam turbine-generator.

These plants, when commercially available, should allow continued use of Alaskan coal resources at costs comparable to conventional coal steam-electric plants, while providing enviromental and operational advantages compared to conventional plants. Environmental advantages include less waste-heat rejection and water consumption per unit of output due to higher plant eficiency. Better control of NO_{v} , SO_{v} and particulate emission is also afforded. From an operational standpoint, these plants offer a potential for load-following operation, broadening their application to intermediate loading duty. (However, much of the existing Railbelt capacity most likely will be available for intermediate and peak loading during the planning period.) Because of superior plant efficiencies, coal gasified - combined-cycle plants should be somewhat less susceptible to inflation fuel cost than conventional steam-electric plants. Principal concerns relative to these plants include land disturbance resulting from mining of coal, CO₂ production, and uncertainties in plant performance and capital cost due to the current state of technology development.

A prototypical plant was selected for in-depth analysis. This 200 MW plant is located in the Beluga area and uses coal mined from the Chuitna Field. The plant would use oxygen-blown gasifiers of Shell design, producing a medium Btu synthesis gas for combustion turbine firing. The plant would be capable of load-following operation. The results of the study of the prototypical plant are described in Reference 35.

(iii) Natural Gas Combustion Turbines

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Although of relatively low efficiency, natural gas combustion turbines serve well as peaking units in a system dominated by steam-electric plants. The short construction lead times characteristic of these units also offer opportunities to meet unexpected or temporary increases in demand. Except for production of CO_2 , and potential local noise problems, these units produce minimal environmental impact. The principal econome concern is the sensitivity of these plants to escalating fuel costs.

Because the costs and performance of combustion turbines are relatively well understood, and because a major component of future Railbelt capacity additions most likely would not consist of combustion turbines, no prototype was selected for in-depth study.

(iv) Natural-Gas - Combined-Cycle Plants

Natural gas - combined-cycle plants were selected for consideration because of the current availability of low-

cost natural gas in the Cook Inlet area and the likely future availability of North Slope supplies in the Railbelt (although at prices higher than those currently experienced). Combined-cycle plants are the most economical and environmentally benign method currently available to generate electric power using natural gas. The principal economic concern is the sensitivity of busbar power costs to the possible substantial rise in natural gas costs. The principal environmetnal concern is CO₂ production and possible local noise problems.

A nominal 200 MW prototypical plant was selected for further study. The plant is located in the Beluga area and uses Cook Inlet natural gas. The results of the analysis of this prototype are documented in Reference 35.

(v) Natural Gas Fuel-Cell Stations

These plants would consist of a fuel conditioner to convert natural gas to hydrogen and CO_2 , phosphoric acid fuel cells to produce dc power by electrolytic oxidation of hydrogen, a power conditioner to convert the dc power output of the fuel cells to ac power. Fuel-cell stations most likely would be relatively small and sited near load centers.

Natural gas fuel-cell stations were considered in the Railbelt electric energy plans primarily because of the apparent peaking duty advantages they may offer over combustion turbines for systems relying upon coal or natural-gas fired base and intermediate load units. Plant efficiencies most likely will be far superior to combustion turbines and relatively unaffected by partial power operation. Capital investment cost most likely will be comparable to that of combustion turbines. These cost and performance characteristics should lead to significant reduction in busbar power costs, and greater protection from escalation of natural gas prices compared to combustion turbines. Construction lead time should be comparable to those of combustion turbines. Because environmental effects most likely will be limited to CO_2 production, load-cunter siting will be possible and transmision losses and costs consequently will be reduced. No prototypical plant was selected for further study.

(vi) Natural-Gas - Fuel-Cell - Combined-Cycle

These plants would consist of a fuel conditioner that converts natural gas to hydrogen and carbon dioxide, molten carbonate fuel cells that produce dc power by electrolytic cost natural gas in the Cook Inlet area and the likely future availability of North Slope supplies in the Railbelt (although at price. higher than those currently experienced). Combined-cycle plants are the most economical and environmentally benign method currently available to generate electric power using natural gas. The principal economic concern is the sensitivity of busbar power costs to the possible substantial rise in natural gas costs. The principal environmetnal concern is CO₂ production and possible local noise problems.

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(vi) Natural-Gas - Fuel-Cell - Combined-Cycle

These plants would consist of a fuel conditioner that converts natural gas to hydrogen and carbon dioxide, molten carbonate fuel cells that produce dc power by electrolytic

oxidation of hydrogen, and heat recovery boilers that use waste heat from the fuel cells to raise steam for driving a steam turbine-generator. A power conditioner converts the dc fuel cell power to ac power for distribution. If they attain commercial maturity as envisioned, fuel-cell combined-cycle plants should demonstrate a substantial improvement in efficiency over conventional, combustion turbine-combined-cycle plants. Although the potential capital costs of these plants currently are not well know, the reduction in fuel consumption promised by the forecasted heat rate of these plants would result in a baseload plant less sensitive to inflating fuel costs and less consumptive of limited fuel supplies than conventional combined-cycle plants. An added advantage is the likely absence of significant environmental impact. Operationally, these plants appear to be less flexible than conventional combined-cycle plants and will be limited to baseload operation.

Because of the early stages of development of these plants, additional study within the scope of this project was believed to yield little additional useful information. Consequently, no prototypical plant was selected for study.

(vii) <u>Conventional Hydroelectric Plants</u>

Substantial hydro resources are present in the Railbelt region. Much of this could be developed with conventional (approximately 15 MW installed capacity or larger) hydroelectric plants. The data and alternatives considered were the same as those discussed in Section 3 of this exhibit.

(viii) Small-Scale Hydroelectric Plants

Small-scale hydroelectric plants include facilities having rated capacity of 0.1 MW to 15 MW. Several small-scale hydro sites have been identified in the Railbelt and two currently undeveloped sites (Allison and Grant Lake) have been subject to recent feasibility studies. Although typically not as economically favorable as conventional hydro because of higher capital costs, small-scale hydro affords similar long-term protection from escalation of costs.

Two small-scale hydroelectric projects were selected for consideration in Railbelt electric energy plans: the Allison Hydroelectric Project at Allison Lake near Valdez and the Grant Lake Hydroelectric Project at Grant Lake north of Seward. These two projects appear to have relatively favorable economics compared with other small hydroelectric sites, and relatively minor environmental impact.

(ix) Microhydroelectric Systems

Microhydroelectric systems are hydroelectric installations rated at 100 kW or less. They typically consist of a water-intake structure, a penstock, and turbine-generator. Reservors often are not provided and the units operate on run-of-the-stream.

Microhydroelectric systems were chosen for analysis because of public interest in these systems, their renewable character and potentially modest, environmental impact. Concrete information on power production costs typical of these facilities were not available when the preferred technologies were selected. Further analysis indicated, however, that few michrohydroelectric reservoirs could be developed for less than 80 mills/kWh and even at considerably higher rates, the contribution of this resource would likely be minor. Because of the very limited potential of this technology in the Railbelt, it was subsequently dropped from consideration. However, installations at certain sites, for example residences or other facilities remote from distribution systems, may be justified.

(x) Large Wind Energy Conversion Systems

Large wind energy conversion systems consist of machines of 100 kW capacity and greater. These systems typically would be installed in clusters in areas of tavorable wind resource and would be operated as central generating units. Operation is in the fuel-saving mode because of the intermittent nature of the wind resource.

Large wind energy conversion systems were selected for consideration in Railbelt electric nergy plants for several reasons. Several areas of excellent wind resource have been identfied in the Railbelt, notably in the Isabell Pass area of the Alaska Range, and in coastal locations. The winds of these areas are strongest during fall, winter and spring months, coinciding with the winter-peaking electric load of the Railbelt. Furthermore, developing hydroelectric projects in the Railbelt would prove complementary to wind energy systems. Surplus wind-generated electricity could be readily "stored" by reducing hydro generation. Hydro operation could be used to rapidly pick up load during periods of wind insufficiency. Wind machines could provide additional energy, whereas excess installed hydro capacity could provide capacity credit. Finally, wind systems have few adverse environmental effects with the exception of their visual presence and appear to have widespread public support.

A prototypical large wind energy conversion system was selected for further study. The prototype consisted of a wind farm located in the Isabell Pass area and was comprised of ten 2.5 MW rated capacity, Boeing MOD-2, horizontal axis wind turbines. The results of the protocype studied are provided in Reference 36.

(xi) Small Wind Energy Conversion Systems

Small wind energy conversion systems are small wind turbines of either horizontal or vertical axis, design rated at less than 100 kW capacity. Machines of this size would generally be dispersed in individual households and in commercial establishments.

Small wind energy conversion systems were selected for consideraton in Railbelt electric energy plans for soveral reasons. Within the Railbelt, selected areas have been identified as having superior wind resource potential. Another reason for selection is because the resource is renewable. Finally, power produced by these systems appeared to possibly be marginally economically competitive with generating facilities currently operating in the Railbelt. However, these machines operate in a fuel-saver mode because of the intermittent nature of the wind resource, and because their economic performance can be analyzed only by comparing the busbar power cost of these machines to the energy cost of power they could displace.

Data for further analysis of small wind energy conversion systems were taken from the technology profiles. Further analysis of this alternative indicated that 20 MW of installed capacity producing approximately 40 GWh of electric energy possible could be economically developed at 80 mill marginal power costs, under the highly unlikely assumption of full penetration of the available market (households). Furthermore, in this analysis these machines were give parity with firm generating alternatives for cost of power comparisons. Because the potential contribution of this alternative is relatively minor even under the rather liberal assumptions of this analysis, the potential energy production of small wind energy conversion systems
was not included in the analysis of Railbelt electric energy plans.

(xii) Tidal Power

Tidal power plants typically consist of a "tidal barrage" extending across a bay or inlet that has substantial tidal fluctuations. The barrage contains sluice gates to admit water behind the barrage on the incoming tide, and turbine-generator units to generate power on the outgoing tide. Tidal power is intermittent, available, and requires a power system with equivalent amount of installed capacity capable to cycling in complement to the output of the tidal plant. Hydro capacity is especially suited for this purpose. Alternatively, energy storage facilities (pumped hydro, compressed air, storage batteries) can be used to regulate the power output of the tidal facility.

Tidal power was selected for consideration in Railbelt electric energy plans because of the substantial Cook Inlet tidal resource, because of the renewable character of this energy resource and because of the substantial interest in the resource, as evidenced by the first-phase assessment of Cook Inlet tidal power development.

Estimated production costs of unretimed tidal powe. facility would be competitive with principal alternative sources of power, such as coal-fired power plants, if all power production could be used effectively. The costs would not be competitive, however, unless a specialized industry were established to absorb the predictable, but cyclic output of the plant. Alternatively, only the portion of the power output that could be absorbed by the Railbelt power system could be used. The cost of this energy would be extremely high relative to other power-producing options because only a fraction of the "raw" energy production could be used. An additional alternative would be to construct a retiming facility, probably a pumped storage plant. Due to the increased capital costs and power losses inherent in this option, busbar power costs would still be substantially greater than for nontidal generating alternatives. For these reasons, the Cook Inlet tidal power alternative was not considered further in the analysis of Railbelt electric energy plans.

(xiii) Refuse-Derived Fuel Steam Electric Plants

These plants consist of boilers, fired by the combustible fraction of municipal refuse, that produce steam for the

operation of a steam turbine-generator. Rated capacities typically are small due to the difficulties of transporting and storing refuse, a relatively low energy density fuel. Supplemental firing by fossil fuel may be required to compensate for seasonal variation in refuse production.

Enough municipal refuse appears to be available in the Anchorage and Fairbanks areas to support small refuse-derived fuel-fired steam-electric plants if supplemental firing (using coal) were provided to compensate for seasonal fluctuations in refuse availability. The cost of power from such a facility appears to be reasonably competitive, although this competitiveness depends upon receipt of refuse-derived fuel at little or no cost. Advantages presented by disposal of municipal refuse by combustion may outweigh the somewhat higher power costs of such a facility compared to coal-fired plants. The principal concerns relative to this type of plant relate to potential reliability, atmospheric emission, and odor problems.

Cost and performance characteristics of these alternatives are summarized in Table D.33.

(b) Energy Plans

Four electric energy plans were developed using different combinations of these generation and conservation options. Each plan represents a possible electric energy future for the Railbelt. The plans were selected to encompass the full range of viable alternatives available to the Railbelt.

Plan 1: Base Case

A. Without Upper Susitna

B. With Upper Susitna

Plan 2: High Conservation and Use of Renewable Resources A. Without Upper Susitna B. With Upper Susitna

Plan 3: Increased Use of Coal

Plan 4: Increased Use of Natural Gas

The list of alternatives used in developing each of the above plans is in Table D.32. Battelle has used a generation planning model derived from the EPRI Over/Under Capacity Model to construct the plans and calculate annual energy costs. To compare the costs of power for the various plans, Battelle used the concept of a levelized cost of power. The levelized cost of power is computed by estimating a single level annual payment, which would be equivalent to the present worth, given assumptions about the time value of money.

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

Levelized Cost of Power = PWCP
$$\star \frac{d(1+d)^{i}}{(1+d)^{i}-1}$$

where:

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PWCP = Present worth of the cost of power d = Real discount rate i = year - 1981 (base year)

In turn:

$$PWCP = \sum_{i=1}^{n} \frac{TAC}{EPP_{i}} \frac{1}{(1+d)^{i}}$$

where:

 $TAC_{i} = total annual costs in year i ($)$

 $EPP_{i} = electrical power produced in year i (kWh)$

n = time horizon (years)

Formal forecasts of power costs were not made by Battelle beyond 2010, however, this difference in power costs between with and without Susitna plans can be expected to increse over the service life of the Upper Susitna project. This difference is expected to be maintained because the other plans are relatively more reliant on fossil fuel, which is expected to continue to escalate in price.

To recognize this longer term behavior of power costs, the levelized costs of power were computed for two different time horizons (1981-2010 and 1981-2050) throughout the Battelle analysis. The shorter time horizon was picked to correspond to the time horizon of the study. However, since the study evaluates the Upper Susitna project, which has an economic lifetime of 50 years (and an even longer expected service lifetime), the longer time is also used to correspond to the economic lifetime of the project. The levelized costs of power for the 1981-2050 time period are computed assuming that no change will occur in the annual cost of power over the 2010-2050 time horizon. Whereas this assumption understates the relative advantages of the plans that include the Upper Susitna project, it does indicate advantages of these plans over the project lifetime. The levelized costs of power for the six plans over the two periods of analysis are presented below.

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			Levelized	Cost of I	Power (mill	s/kWh)	
		Low		Medi	um	, Higl	1 .
		Econor	nic	Econor	nic	Econor	nic
		Scenar	rio	Scenar	rio	Scenar	rio
		1981-	1981-	1981 -	1981-	1981 -	1981-
		2010	2050	2010	2050	2010	2050
lan 1	LA	58	65	58	64	60	66
Plan 1	LB	58	63	58	59	58	60
nan 🖥	?A	58	65	59	66	58	66
Plan 2	2B	57	61	58	61	57	69
Plan 3	3	58	67	59	65	62	68
Plan 4	1	57	64	59	66	61	68

For the medium economic scenario, essentially no difference exists in the levelized cost of power among the varius electric energy plans over the 1981-2010 time period. Over the longer time horizon the costs of power for the plans including the Upper Susitna project (Plans 1B and 2B) are lower than for the other plans.

For the low economic scenario, again little difference exists in the levelized costs of power over the 1981-2010 time horizon. The advantages of the plans including the Upper susitna project are smaller than for the medium economic scenario.

In the case of the high economic scenario, relatively little difference exists in the costs of power over the shorter time period, although the plan's including the Upper Susitna project have slightly lower power costs. Over the longer time period, the plans including the Upper Susitna project have significantly lower power costs. The plans heavily reliant on fossil fuels, Plans 1A, 3, and 4, have relatively high power costs in the high economic scenario. In general, the longer the time period and the higher the demand, the more attractive are plans containing the Upper Susitna project.

Based upon the evaluation of the socioeconomic and environmental effects of the plans and sensitivity analyses of factors affecting

the plans, the following conclusions are drawn for the various electric energy plans.

(i) Plan 1A: Base Case Without Upper Susitna

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- The levelized costs of power for this plan are relatively stable among the various sensitivity tests.
 Generally, it is neither the highest nor the lowest cost plan.
- Significant potential impacts on air quality, land use, and susceptibility to inflation due to fossil fuel use are possible.
- Incremental coal mining and reclamation activities will occur due to expanded coal use in the Beluga and Healy areas.
- The development of a coal export mine at Beluga to supply coal to generating plants located there is uncertain.
- The costs and environmental impacts of the Chakachamna hydroelectric project are uncertain.
- (ii) Plan 18: Base Case With Upper Susitna
 - Except for cases assuming higher than estimated capital costs for the Upper Susitna project, this plan provides relatively low power costs over the 1981-2010 time period. The plan provides either the lowest or nearly the lowest cost of power in all sensitivity tests over the extended time period.
 - Electric power needs can be met without significant impacts to air quality, visibility, health and safety and other environmental sectors. However, improper river flow control may be detrimental to fish production.
 - Relatively good information is available on capital cost and environmental impacts of the Upper Susitna Project.
 - The plan is resistant to inflation once the project is constructed.
 - Significant boom/bust, land-use effects and high capital costs are associated with the construction of the Upper Susitna project.

(iii) Plan 2A: High Conservation and Use of Renewable Resources Without Upper Susitna

- This plan has slightly higher power costs in most cases. The costs are high mainly because of the plan's reliance on relatively high capital cost generating alternatives (hydroelectric, refuse-derived fuel, and wind).
- Reduced air infiltration associated with building conservation may present health and safety hazards from indoor air pollution. The exact relationship between building conservation and indoor air pollution has not be established.
- The capital costs of alternate hydroelectric projects are uncertain.
- This plan assumes that a state conservation grant program exists.
- (iv) Plan 2B: High Conservation and Use of Renewable Resources With Upper Susitna
 - This plan has much the same costs and impacts as Plan
 1B. This similarity is expected since they both include the Upper Susitna project.
 - The health and safety aspects of the indoor air quality of conservation activities are unknown.
 - As with 2A, this plan assumes an extensive state conservation grant program.
- (v) Plan 3: Increased Use of Coal

- This plan produces relatively high costs of power over the 1981-2050 time period. The plan is more attractive in the case with lower fuel price escalation rates.
- Significant potential problems are possible in air quality, water quality, visual impacts, and land-use and inflation effects.
- Constraints due to nondegradation air-qualty regulations are possible.
- Incremental coal mining and reclamation activities will occur due to expanded coal use in the Beluga and Healy area.

- The development of a coal export mine at Beluga is uncertain.

(vi) Plan 4: Increased Use of Natural Gas

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- This plan behaves very similarly to Plan 3. It provides the lowest cost of power over the 1981-2010 time period in the case of lower fuel price escalation rates and in the case of reduced demand beyond 1995. It is one of the higher cost alternatives over the extended time horizon.
- This plan has little impact on all sectors of the environment. No major problems are associated with jobs, boom/bust effects, or land use.
- Due to high technology of fuel cells and gas combinedcycle units susbstantial spending will occur outside the state.
- Inflation effects are significant because power production is directly tied to the price of natural gas.
- Existing reserves of natural gas in the Cook Inlet area will not be adequate to support expanded gas-fired generation beyond 1990-1995. The discovery of additional reserves is uncertain.

As indicated by this discussion, much uncertainty remains regarding all key alternatives to the Upper Susitna project. Coal, natural gas and hydroelectric projects are the primary alternatives to the Upper Susitna project. Whereas uncertainties do remain regarding the Upper Susitna project, more is known about the costs and impacts of the Upper Susitna project than any of the alternatives. The following uncertainties are associated with the alternatives:

 Coal-based generation at Beluga depends upon the development of a large-scale export mine. Such a mine is based upon Pacific Rim steam coal market development. While this market is expanding development of Beluga coal resources is uncertain.

- Current reserves of natural gas in the Cook Inlet area are not expected to be adequate for generation beyond 1990-1995. The availability of additional reserves by that time is uncertain. - The development of a coal export mine at Beluga is uncertain.

(vi) Plan 4: Increased Use of Natural Gas

- This plan behaves very similarly to Plan 3. It provides the lowest cost of power over the 1981-2010 time period in the case of lower fuel price escalation rates and in the case of reduced demand beyond 1995. It is one of the higher cost alternatives over the extended time horizon.
- This plan has little impact on all sectors of the environment. No major problems are associated with jobs, boom/bust effects, or land use.
- Due to high technology of fuel cells and gas combinedcycle units susbstantial spending will occur outside the state.
- Inflation effects are significant because power production is directly tied to the price of natural gas.
- Existing reserves of natural gas in the Cook Inlet area will not be adequate to support expanded gas-fired generation beyond 1990-1995. The discovery of additional reserves is uncertain.

As indicated by this discussion, much uncertainty remains regarding all key alternatives to the Upper Susitna project. Coal, natural gas and hydroelectric projects are the primary alternatives to the Upper Susitna project. Whereas uncertainties do remain regarding the Upper Susitna project, more is known about the costs and impacts of the Upper Susitna project than any of the alternatives. The followirg uncertainties are associated with the alternatives:

- Coal-based generation at Beluga depends upon the development of a large-scale export mine. Such a mine is based upon Pacific Rim steam coal market development. While this market is expanding development of Beluga coal resources is uncertain.
- Current reserves of natural gas in the Cook Inlet area are not expected to be adequate for generation beyond 1990-1995. The availability of additional reserves by that time is uncertain.

- Gas-based generation in Fairbanks depends upon the availability of natural gas from the North Slope in the Fairbanks area either via the Alaska Natural Gas Transportation System (ANGTS) or another system.
- The capital costs and environmental impacts of alternative hydroelectric projects are based upon reconnaissance studies and as a result have a high degree of uncertainty associated with them.

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- The relationship between building conservation and indoor air pollution has not been established.

5 - CONSEQUENCES OF LICENSE DENIAL

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5 - CONSEQUENCES OF LICENSE DENIAL

5.1 - Cost of License Denial

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The forecast energy demand for the Railbelt through the year 2010 can be met without constructing the Watana-Devil Canyon hydroelectric project provided that other, albeit more costly, alternatives are developed. The best alternative generating system is outlined in Section 4.5 of this Exhibit. However, the economic comparison described in Section 4.7 concludes that the Susitna project will yield an expected present valued net benefit of \$1.45 billion. The economic consequences of license denial will be the probable costs mentioned above.

The State of Alaska energy program is based on a policy of using revenues generated by non-renewable resources to finance the development of renewable resources. The Susitna project is a cornerstone of that program. Denial of the license will require furher mid-term use of non-renewable resources.

The Susitna project makes a significant contribution to the energy independance of both the State and the nation. Generation of power by a renewable resource in the State allows for export of renewable resources to the lower 48 states. Denial of the license will negate this effort.

The most likely alternative to Susitna is subject to a great deal of cost risk since less study has been done in investigating the alternatives. License denial will force the State into pursuing a less certain program in meeting power needs.

5.2 - Future Use of Damsites if License is Denied

There are no present plans for an alternative use of the Watana and Devil Canyon damsites. In the absence of the hydroelectric project, they would remain in their present state.



6 - FINANCING

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6.1 - Forecast Financial Parameters

The financial, economic, and engineering estimates used in the financial analysis are summarized in Table D.9. The interest rates and forecast rates of inflation (in the Consumer Price Index - CPI) are of special importance. They have been based on the forecast inflation rates and the forecast of interest rates on industrial bonds as given by Data Resources Incorporated (9), and conform to a range of other authoritative forecasts. To allow for the factors which have brought about a narrowing of the differential between tax exempt and taxable securities, it has been assumed that any tax exempt financing would be at a rate of 80 percent rather than the historical 75 percent or so of the taxable interest rate. This identifies the forecast interest rates in the financing periods from 1985 in successive five-year periods as being of the order of 8.6 percent, 7.8 percent, and 7 percent. The accompanying rate of inflation would be about 7 percent. In view of the uncertainty attaching to such forecasts and in the interest of conservatism, the financial projections which follow have been based upon the assumption of a 10 percent rate of interest for tax-exempt bonds and an ongoing inflation rate of 7 percent.

6.2 - Inflationary Financing Deficit

The basic financing problem of Susitna is the magnitude of its "inflationary financing deficits". Under inflationary conditions these deficits (early year losses) are an inherent characteristic of almost all debt financed, long life, capital intensive projects (see Figure D.21). As such, they are entirely compatible (as in the Susitna case) with a project showing a good economic rate of return. However, unless additional state equity is included to meet this "inflationary financing deficit" the project may be unable to proceed without imposing a substantial and possibly unacceptable burden of high early-year costs on consumers.

6.3 - Legislative Status of Alaska Power Authority and Susitna Project

The Alaska Power Authority is a public corporation of the State in the Department of Commerce and Economic Development but with separate and independent legal existence.

The Authority was created with all general powers necessary to finance, construct and operate power production and transmission facilities throughout the State. The Authority is not regulated by the Alaska Public Unitilities Commission, but is subject to the Executive Budget Act of the State and must identify projects for development in accordance with the project selection process outlined within Alaska Statues. The Authority must receive legislative authorization prior to proceeding with the issuance of bonds for the financing of construction of any project which involves the appropriation of State Funds or a project which exceeds 1.5 megawatts of installed capacity.

The Alaska State Legislature has specifically addressed the Susitna Project in legislation (Statute 44.83.300 Susitna River Hydroelectric Project). The legislation states that the purpose of the project is to generate, transmit and distribute electric power in a manner which will:

- (1) Minimize market area electrical power costs;
- (2) Minimize adverse environmental and social impacts while enhancing environmental values to the extent possible; and
- (3) Safeguard both life and property.

Section 44.83.36 Project Financing states that "the Susitna River Hydroelectric Project shall be financed by general fund appropriations, general obligation bonds, revenue bonds, or other plans of finance as approved by the legislature."

6.4 - Financing Plan

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The financing of the Susitna Project is expected to be accomplished by a combination of direct State of Alaska appropriations and revenue bonds issued by the Power Authority. It is expected that project costs for Watana through early 1991 (estimated at \$3.0 billion in 1982 dollars) will be funded from such state appropriations. Thereafter completion of Watana is then expected to be financed by issuance of approximately \$.9 billion (1982 dollars) of revenue bonds. On the assumption of 7 percent annual inflation from 1982 to the end of construction, the \$.9 billion in 1982 dollars will have a then current money value of approximately \$1.8 million as detailed in Table D.35. These annual par amounts do not exceed the Authority's estimated annual addition debt capacity for the period 1991 to 1995.

The Revenue bonds are expected to be secured by project power sales contracts, other available revenues, and by a Capital Reserve Fund (funded by a State appropriation equal to a maximum annual debt service) and backed by the "moral obligation" of the State of Alaska. At the issuance of the first revenue bonds for Watana, expenditures of State appropriations are expected to have funded sufficient construction progress so that subsequent construction risks will be relatively small.

The completion of the Susitna project by the building of Devil Canyon is expected to be financed on the same basis requiring (as detailed in Table D.33) the issuance of approximately \$2.2 billion of revenue bonds (in 1982 dollars) over the years 1994 to 2202. Summary financial statements based on the assumption of 7 percent inflation and bond financing at a 10 percent interest rate and other estimates in accordance with the above economic analysis are given in Tables D.36 and D.7.

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A material factor will be securing tax exempt status for the Revenue bonds. This issue has been extensively reviewed by the Power Authority's financial advisors and it has been concluded that it would be reasonable to assume that by the operative date the relevant requirements of Section 103 of the IRS code would be met. On this assumption the 7 percent inflation and 10 percent interest rates used in the analysis are consistent with authoritative estimates of Data Resources (U.S. Review July 1982) forecasting a CPI rate of inflation 1982-1991 of approximately 7 percent and interest rates of AA Utility Bonds (non exempt) of 11.43 percent in 1991 dropping to 10.02 percent in 1995.

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	Jan	uary 1982 Dollars \$	x 10 ⁶
Category	Watana	Devil Canyon	Total
Production Plant	\$2,293	\$ 1,069	\$3,362
Transmission Plant	456	105	561
General Plant	5	5	10
Indirect	429	212_	641
Total Construction	\$3, 183	\$ 1,391	\$4,574
Overhead Construction	398	174	572
TOTAL PROJECT	\$3, 581	\$1,565	\$5, 146

TABLE D. 1: SUMMARY OF COST ESTIMATE

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	CLIENT ALASKA POWER AUTHO	RY жity	TABLE D.: WATANA	2	TYPE OF ESTIMATE	Feasibility	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 1 OF 5
	PROJECT HUROELECT	IRIC PROJECT	*******	ang ang kang sang sang ang kang sang sang sang sang sang sang sang s	APPROVED BY	JDL	BY DATE DATE
No.	DESCRIPTION	QUANTITY	UNIT	COST/	AMOUNT	TOTALS	REMARKS
	PRODUCTION PLANT				(x 10 ⁶)	(x 10 ⁶)	
330 331	Land & Land Rights				• \$ 51		
332	Reservoir, Dams & Waterways	• • • • • • • • • • • • • • • • •			1, 547		
333 · 334	Waterwheels, Turbines & Generators Accessory Electrical Equipment	• • • • • • • • • • • • • • • • • • • •	• • • • • • • • • • • •		• 66 • 21		
335 336	Miscellaneous Powerplant Equipment Roads & Rallroads	(Mechanical)	••••••••		14		
	Subtotal		• • • • • • • • • •		1,987		
	TOTAL PRODUCTION PLANT	• • • • • • • • • • • • • • • • • • •	•••••	•••••	306	\$ 2,293	
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	CLIENT ALASKA POWER AUTH	RY TRIC PROJECT	TABLE D. WATANA	2	TYPE OF ESTIMATE	Feasibility JDL	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 2 OF 5 BY DATE
· • No.	DESCRIPTION	QUANTITY	UNIT			TOTALS	CHKD DATE
					6	6	
					(× 10°)	(x 10°)	
	TOTAL BROUGHT FORWARD					\$ 2,293	
	TRANSMISSION PLANT						
350	Land & Land Rights				\$ 8		
352	Substation & Switching Station Str	uctures & Improveme	nts		12		
353	Substation & Switching Station Equ	Ipment			. 131		
354	Steel Towers & Fixtures				131		
356	Overhead Conductors & Devices				100		
359	Roads & Trails				13		
	Subtotal				395		
	Cóntigency				61		
	TOTAL TRANSMISSION PLANT	• • • • • • • • • • • • • • • • •				456	
			•				
			•				
			•			\$ 2,749	

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	CLIENT ALASKA FOWER AUTH	ORITY .	WATANA	•	TYPE OF ESTIMATE	Feasibility	FILE NUMBER P5700.14.09 SHEET 3 OF 5
	PROJECTSUSITNA HYDROELEC	TRIC PROJECT	<u>Constitutive program and a state</u>		APPROVED BY	JDL	BY DATE CHKD DATE
0.	DESCRIPTION	QUANTITY	UNIT	COST/	AMOUNT	TOTALS	REMARKS
	TOTAL BROUGHT FORWARD			1	(x 10 ⁶)	(x 10 ⁶) \$ 2,749	
	GENERAL PLANT		ţ				Included under 330
9 D	Structures & Improvements	• • • • • • • • • • • • • • • • • • •		• • • • • • • • • •			Included under 331
1 2	Office Furniture/Equipment Transportation Equipment						Included under 399 10 11
4	Stores Equipment Tools Shop & Garage Equipment	• • • • • • • • • • • • • • • • • • •	• • • • • • • • • • •	••••			
5	Laboratory Equipment Power-Operated Equipment	• • • • • • • • • • • • • • • • • • • •	• • • • • • • • • • •	• • • • • • • • • •			
7 8	Communications Equipment Miscellaneous Equipment		• • • • • • • • • • •	•••••			17 17 17 17 17 17 17 17 17 17 17 17 17 1
9	Other Tangible Property TOTAL GENERAL PLANT	· · · · · · · · · · · · · · · · · · ·			5	\$ 5	

JOB NUMBER P5700.00 ESTIMATE SUMMARY TABLE D.2 FILE NUMBER P5700.14.09 WATANA TYPE OF ESTIMATE Feasibility SHEET 4 5 ALASKA POWER AUTHORITY OF CLIENT BY_ DATE SUSITNA HYDROELECTRIC PROJECT JDL APPROVED BY TRE 2782 PROJECT DATE CHKD COST/ UNIT DESCRIPTION QUANTITY UNIT AMOUNT REMARKS No. TOTALS (x 10⁶) $(x 10^{6})$ TOTAL BROUGHT FORWARD 2,754 \$ INDIRECT COSTS See Note 61 Temporary Construction Facilities Construction Equipment See Note 62 Camp & Commissary 373 63 Labor Expense 64 Super Intendence See Note 65 See Note 66 See Note 69 Note: Costs under accounts 61, 62, 64, 65, 66, and 69 are included in the appropriate direct costs listed above. Subtotal 373 Configency 56 TOTAL INDIRECT COSTS 429 * 3,183 \$ TOTAL CONSTRUCTION COSTS

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	CLIENT ALASKA POWER AUTHO PROJECT SUSITNA HYDROELEC	RY RITY TRIC PROJECT	TABLE D.2 WATANA		TYPE OF ESTIMATE	Feasibility JDL	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 5 OF 5 BY DATE JRP DATE CHKD DATE
No.	DESCRIPTION	QUANTITY	UNIT	COST/	AMOUNT	TOTALS	REMARKS
	TOTAL CONSTRUCTION COSTS BROUGHT	FORWARD		• • • • • •	(x 10 ⁶)	(× 10 ⁶) \$ 3,183	
71 72	Engineering/ Administration			•••••	• \$ 398 • -		Included in 71
75 76	Taxes Administrative & General Expenses	•••••••		• • • • • • • •			Not applicable Included in 71
80	Earnings/Expenses During Construc	tion			•		Not included
	Total Overhead	• • • • • • • • • • • • • • • • • • •			• • • • • • • • • • • • • • • • • • •	398 \$3,581	
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	CLIENT ALASKA POWER AUTHOR PROJECT	RITY RIC PROJECT	TABLE D. DEVIL CAN	3 IYON T	YPE OF ESTIMATE	Feasibility JDL	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 1 OF 5 BY DATE JRP DATE CHKD DATE
No.	DESCRIPTION	QUANTITY	UNIT	COST/	AMOUNT	TOTALS	REMARKS
330 331 332 333 334	PRODUCTION PLANT Land & Land Rights Powerplant Structures & improvemen Reservoir, Dams & Waterways Waterwheels, Turbines & Generators Accessory Electrical Equipment	ts		•••••••••	(x 10 ⁶) \$ 22 72 646 42 . 14	(× 10 ⁶)	
335 336	Miscellaneous Powerplant Equipment Roads & Rallroads	(Mechan Ical) ****		•••••	12 119		
	Subtotal Contingency	••••••	• • • • • • • • • •	•••••••••	927 142	\$ 1,069	

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P5700.00 TABLE D.3 JOB NUMBER ESTIMATE SUMMARY FILE NUMBER P5700.14.09 DEVIL CANYON ALASKA POWER AUTHORITY Feasibility OF TYPE OF ESTIMATE SHEET CLIENT DATE BY JDL APPROVED BY SUSITNA HYDROELECTRIC PROJECT PROJECT DATE CHKD COST / REMARKS AMOUNT TOTALS DESCRIPTION QUANTITY UNIT No. ÷. (x 10⁶) $(x 10^{6})$ 1,069 TOTAL BROUGHT FORWARD S TRANSMISSION PLANT Included in Watana Estimate ' 350 Land & Land Rights \$

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21

29

34

91

14

5

105

1,174

Substation & Switching Station Structures & Improvements

Substation & Switching Station Equipment

Overhead Conductors & Devices

Roads & Trails

Subtotal

Contingency

Steel Towers & Fixtures

TOTAL TRANSMISSION PLANT

352

353

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356

359

Included in Watana Estimate

	CLIENT ALASKA POWER AUT	ARY	TABLE D. DEVIL CAN	3 IYON	TYPE OF ESTIMAT	E Feasibility	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 3 OF 5
	PROJECT SUSITNA HYDROELE	CTRIC PROJECT	tion and a second s		APEROVED BY	JDL	BY DATE CHKD DATE
No.	DESCRIPTION	. QUANTITY	UNIT	COST/ UNIT	AMOUNT	TOTALS	REMARKS
	TOTAL BROUGHT FORWARD				(x 10 ⁵)	(x 10 ⁶) \$ 1,174	
89	Land & Land Right's	* • • • • • • • • • • • • • • • • • • •	, • • • • 0 • • • • •		\$		Included under 330
91	Structures & Improvements	· • • • • • • • • • • • • • • • • • • •	• • • • • • • • • • •	•••••			Included under 331 Included under 399
92	Transportation · Equipment						
94	Tools Shop & Garage Equipment Laboratory Equipment						 It is a final state of the stat
96	Power Operated Equipment	• • • • • • • • • • • • • • • • • • •					
98	Miscellaneous Equipment	· • • • • • • • • • • • • • • • • • • •		••••			10 - 10 - 10 - 10 - 10 - 10 - 10 - 10 -
•	TOTAL GENERAL PLANT	• • • • • • • • • • • • • • • • • • •	• • • • • • • • • • •			\$ 5	

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	ESTIMATE SUMMA CLIENT ALASKA POWER AUTH PROJECT SUSITNA HYDROELED	HORITY	DEVIL CANY	DN 7	TYPE OF ESTIMATE	Feasibility	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09 SHEET 4 OF 5 BY
No.	DESCRIPTION	QUANTITY	UNIT	COST/	AMOUNT	TOTALS	REMARKS
	TOTAL BROUGHT FORWARD		• • • • • • • • • •		(x 10 ⁶)	(x 10 ⁶) \$ 1,179	
51	Temporary Construction Facilitie Construction Equipment	S			\$		See Note See Note
53 54 55	Camp & Commissary Labor Expense Superintendence	• • • • • • • • • • • • • • • • • • • •	•••••	• • • • • • • • • •	164 		See Note See Note
56 59	Insurance	67 64 65 66 and	60				See Note See Note
	are included in the appro listed above.	priate direct costs	•••••		184	an an an ang an	
	Contigency TOTAL INDIRECT COSTS	••••••••			28	\$ 212	

CLIENT Addata Power AUTRATITY TYPE OF ESTIMATE Tests Diff. SHEET S OF S PROJECT SUBITIVA HYDROELEGTRIC PROJECT APPROVED BY JOL BY DATE CHKD DATE </th <th>CLIENT AUSKA HOMER AUHRAUITY TYPE OF ESTIMATE TestIJI/I/T SHEET O OF PROJECT SUITNA HYDROELECTRIC FROJECT APPROVED BY JDL SY DATE No. DESCRIPTION QUANTITY UNIT DOTT AMOUNT TOTALS REMARKS No. DESCRIPTION QUANTITY UNIT DOTT AMOUNT TOTALS REMARKS 1 TOTAL CONSTRUCTION COSTS (PROJECT INDIRECTS) </th> <th></th> <th>ESTIMATE SUMMA</th> <th>NRY ·</th> <th>TABLE D</th> <th>.3 Nyon</th> <th></th> <th>C</th> <th>JOB NUMBER P5700.00 FILE NUMBER P5700.14.09</th>	CLIENT AUSKA HOMER AUHRAUITY TYPE OF ESTIMATE TestIJI/I/T SHEET O OF PROJECT SUITNA HYDROELECTRIC FROJECT APPROVED BY JDL SY DATE No. DESCRIPTION QUANTITY UNIT DOTT AMOUNT TOTALS REMARKS No. DESCRIPTION QUANTITY UNIT DOTT AMOUNT TOTALS REMARKS 1 TOTAL CONSTRUCTION COSTS (PROJECT INDIRECTS)		ESTIMATE SUMMA	NRY ·	TABLE D	.3 Nyon		C	JOB NUMBER P5700.00 FILE NUMBER P5700.14.09
No. DESCRIPTION QUANTITY UNIT COST/UNIT AMOUNT TOTALS REMARKS TOTAL CONSTRUCTION COSTS BROUGHT FORMARD (** 10 ⁶) (** 10 ⁶) 1,391 1,391 OVERMEND CONSTRUCTION COSTS (PROJECT INDIRECTS) 5 174 1 1 71 Engineering - - Included in 71 72 Legal Expenses - - Not Applicable 76 Administrative & General Expenses - - Included in 71 77 Interest - Not Included Not Included 80 Earnings/Expenses During Construction - 174 74 Total Overhead Costs - 174 75 Total Overhead Costs - 174	No. DESCRIPTION QUANTITY UNIT COST/ UNIT AMOUNT TOTALS REMARKS TOTAL CONSTRUCTION COSTS EROUGHT FORMARD (x 10 ⁶) (x 10 ⁶) 1,391 1,391 OVERHEAD CONSTRUCTION COSTS EROUGHT FORMARD - - 1 1 1,391 71 Englage Expenses - - - - Not Applicable 75 Taxes - - - Not Applicable - 76 Administrative & General Expenses - - - Not Applicable 80 Earnings/Expenses During Construction - - 174 - 70TAL ROJECT COST - - 174 - -		CLIENT ALASKA FOWER AUTH PROJECT SUSITNA HYDROELED	TRIC PROJECT		T A	PPROVED BY	JDL	SHEET 5 OF 5 BY
71 Englneering (x 10 ⁶) (x 10 ⁶) 72 Legal Expenses 1,391 75 Taxes - Included in 71 76 Administrative & General Expenses - Not Applicable 70 Interest - Not Included 80 Earnings/Expenses During Construction - Not Included 71 Interest - Not Included 70 Total Overheed Costs 174 - 71 Total Overheed Costs 174 - 75 - 174 - - 76 Administrative & General Expenses - - Not Applicable 77 Interest - - Not Included - 80 Earnings/Expenses During Construction - - - - - 78 Total Overheed Costs -	TOTAL CONSTRUCTION COSTS BROUGHT FORWARD (x 10 ⁶) OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS) 1,391 71 Engineering - 72 Legal Expenses - 73 Taxes - 74 - Not Applicable 75 Taxes - 76 Administrative & General Expenses - 77 Inforest - 78 Earnings/Expenses During Construction - 77 Inforest - 78 Earnings/Expenses During Construction - 79 Total Overhead Costs - 70 Inforest - 71 Inforest - 72 Legal Expenses During Construction - 74 Total Overhead Costs - 75 1,565 - -	No.	DESCRIPTION	QUANTITY	UNIT	COST/ UNIT	AMOUNT	TOTALS	REMARKS
OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS) Find Inserting	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS) Engineering Yest Legal Expenses Taxes Administrative & General Expenses Administrative & General Expenses Total Overhead Costs Total Overhead Costs Total Overhead Costs Total PROJECT COST		TOTAL CONSTRUCTION COSTS BROUGHT	FORWARD			(* 105)	(x 10 ⁶)	
72 Legal Expenses	72 Legal Expenses	71	OVERHEAD CONSTRUCTION COSTS (PRO	JECT INDIRECTS)			\$ 174		
76 Administrative & General Expenses - Included in 71 77 Interest Not included 80 Earnings/Expenses During Construction - Not included 76 Total Overhead Costs 174 174 5 1,565 - - 174	76 Administrative & General Expenses Included in 71 77 Interest Not included 80 Earnings/Expenses During Construction - Not included 77 Total Overhead Costs 174 174 5 1,565 1,565 1,565	72 75	Legal Expenses		• • • • • • • • • • •				Included in 71 Not Applicable
80 Earnings/Expenses During Construction Not Included Total Overhead Costs 174 TOTAL PROJECT COST \$ 1,565	80 Earnings/Expenses During Construction Included Not Included Total Overhead Costs 174 174 TOTAL PROJECT COST \$ 1,565	76 .77	Administrative & General Expense Interest	5	• • • • • • • • • •	•••••			Included In 71 Not Included
TOTAL FROJECT COST	TOTAL FROJECT COST	80	Earnings/Expenses During Constru Total Overhead Costs	c ion	••••	•••••		174	Not Included +
			TOTAL PROJECT COST	•••		• • • • • • • • •		<u>\$ 1,565</u>	
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COSTS INCORPORATED IN CONSTRUCTION ESTIMATES	WATANA \$ X 10	DEVIL CANYON
Outlet Facilities		
Main Dam at Devil Canyon Tunnel Spillway at Watana	47,100	14, 600
Restoration of Borrow Area D	1,600	NA
Restoration of Borrow Area F	600	NA
Restoration of Camp and Village	2, 300	1,000
Restoration of Construction Sites	4, 100	2,000
Fencing around Camp	400	200
Fencing around Garbage Disposal Area	100	100
Multilevel Intake Structure	18, 400	NA
Camp Facilities Associated with trying to Keep Workers out of Local Communities	10, 200	9,000
Restoration of Haul Roads	800	500
SUBTOTAL	85, 600	27,400
Contingency 20%	17,100	5,500
TOTAL CONSTRUCTION	102, 700	32, 900
Engineering 12 5%	12,800	4,100
TOTAL PROJECT	115, 500	37,000

TABLE D. 4: MITIGATION MEASURES - SUMMARY OF COSTS INCORPORATED

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TABLE D. 5: SUMMARY OF OPERATING AND MAINTENANCE COSTS

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	_(1	WATANA 000's Omit	ted)	(\$	DEVIL CANYON (\$ 0001s Omitted)			
	Labor	Expense Items	Subtotal	Labor	Expense <u>ltems</u>	<u>Subtotal</u>		
Power & Transmission Operation/ Maintenance	5330	990	6320	1920	500	2420		
Contracted Services	-	900	900		480	480		
Permanent Townsite Operations	540	340	880	120	80	200		
Allowance for Environmental Mitigation		1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 - 1990 -	1000			1000		
Contignecy			900			500		
Additional Allowance from 2002 to Replace Community Facilities			400			200		
Total Operating and Maintenance Expenditure Estimate Power Development and Transmission Facilities		WATANA	10,400	DEVIL	CANYON	4,800		

TABLE D. 6 - SUSITNA HYDROELECTRIC PROJECT

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Watana and Devil Canyon Cumulative and Annual Cash Flow

	ANNUA	L CASH FLOW		CUMULA	TIVE CASH FLOW (TO END	OF YEAR
YEAR	WATANA	DEVIL CANYON	COMBINED	WATANA	DEVIL CANYON	COMBINED
1981	27.6		27.6	27.6		27.6
82	12.9		12,9	40.4		40.5
83	28.7		28.7	69.2		622
84	48.5		48 5	117.7		117, 7
85	198.6		198.6	316.3		316.3
86	282. 7		282.7	599.0		599.0
87	294 1		294 1	893 1		893 1
88	367.4		367, 4	1260. 5		1260. 5
89	436.5		436 5	1697.0		1693 0
90	624 9		624 9	2321. 9		2321, 9
91	606 2	4,9	61 1, 1	2928 1	4,9	2933 0
92	427. 2	48.1	475.3	3355, 3	53.0	3408 1
93	152.5	68,9	221.4	3507.8	121.9	3629.7
94	73.4	64. 6	138.0	3581. 2	186, 5	376% 7
95		65.2	65.2		251.7	3832.9
96		115.8	115.8		367, 5	3948.7
97		204 2	204.2		571.7	4152, 9
98		295. 1	295. 1		866. 8	4448.0
99		281.0	281.0		1147.8	4729.0
2000		242.8	242.8		1390, 6	4971. 8
2001		156 7	156.7		154 7. 3	5128 5
2002		17.7	17.7		1565. 0	51 46 2
TOTAL	3581.2	1565.0	5146.2			

JANUARY 1982 DOLLARS - IN MILLIONS

*** DA1 ***	**************************************	******** E FUNDS~1 ****	NFLATION	77-INTERE	********** ST 10%-C/	ATC	******** • 1 1 7 BN *******	*******	******	*********** 8-N *******	******** 10V-82 *********
		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
				CA	SH FLOW						
7 52 46 52	3 ENERGY GWH 1 REAL PRICE-MILLS 6 INFLATION INDEX 3 PRICE-MILLS	0 0.00 126.72 0.00	0 0.00 135.59 0.00	0 0.00 145.08 0.00	0°00 155°24 0°00	0 0.00 166.10 0.00	0 177.73 0.00	0 0.00 190.17 0.00	0 203.48 0.00	3387 116-22 217-73 253-04	3387 122-06 232-97 284-37
51 17	6 REVENUE O LESS UPERATING COSTS	0.0	0.0 U.U		0.0		0.0		0 • 0 0 • 0	857.0 26.9	963•1 29•3
51 21 55 39	7 DPERATING INCOME 4 ADD INTEREST EARNED ON FUNDS 0 LESS INTEREST ON SHURT TERM DEBT 1 LESS INTEREST ON LONG TERM DEBT	0 • 0 0 • 0 0 • 0 0 • 0 5 • 0								830.1 0.0 0.0 830.1	933+8 5+6 14+6 863+4
54	8 NET EARNINGS FROM DPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	61.4
54 44 14 24	9 CASH INCOME FROM OPERS 5 CASH INCOME FROM OPERS 5 STATE CONTRIBUTION 3 LONG TERM DEBT DRAWDOWNS 9 WORCAP DEBT DRAWDOWNS	0.0 0.0 403.7 0.0	0+0 U+0 513+0 0+0	0.0 0.0 571.4 0.0	0 • 0 U • 0 6 4 8 • 4 0 • U	0.0 0.0 1152.0 0.0	0.0 0.0 1879.2 0.0	0.0 0.0 1763.8 0.0	0.0 0.0 1369.6 0.0	0.0 0.0 333.1 146.2	61.4 0.0 229.7 16.1
54	V TOTAL SOURCES OF FUNDS	403.7	513.0	571.4	648.4	1152.0	1879.2	1763.8	1369.6	479.3	307.2
37,44	O LESS CAPITAL EXPENDITURE B LESS HORCAP AND FUNDS O LESS DEBT REPAYMENTS 5 LESS PAYMENT TO STATE	403.7 0.0 0.0 0.0	513.0 0.0 0.0 0.0	571.4 0.0 0.0 0.0	648•4 0•0 0•0 0•0	1152.0 0.0 0.0 0.0	1879.2 0.0 0.0 0.0 0.0	1763.8 0.0 0.0 0.0	1369•6 0•0 0•0 0•0	333.1 146.2 0.0 0.0	259°2 16°1 31°9 0°0
14 24 44	1 SASH SURPLUS(DEFICIT) 9 SHORT TERM DEBT 4 SASH RECOVERED			0 • 0 0 • 1 0 • 0							0 • 0 0 • 0 0 • 0
22 37 45 37	5 RESERVE AND CONT. FUND 1 JTHER WORKING CAPITAL 4 CASH SURPLUS RETAINED 0 CUM. CAPITAL EXPENDITURE	0 • 0 0 • 0 2 • 0 4 0 3 • 7	0.0 0.0 0.0 916.8	0.0 0.0 0.0 1488.1	0.0 U.U 0.U 2136.5	0.0 0.0 0.0 3288.5	0 • 0 0 • 0 0 • 0 5167 • 7	0.0 0.0 0.0 6931.5	0.0 0.0 0.0 8301.1	56.5 89.7 0.0 8634.2	61.6 100.7 0.0 8893.4
46	5 CAPITAL EMPLOYED	403.7 *=====	916.8	1488.1	2136.5	3288.5	5167.7	6931.5	8301.1	8780.4	9055.7
46 46 55	1 STATE CONTRIBUTION 2 RETAINED EARNINGS 5 DEBT DUTSTANDING-SHORT TERM 4 DEBT DUTSTANDING-LONG TERM	0•0 0•0 0•0 403•7	0 • 0 0 • 0 0 • 0 916 • 8	0.0 0.0 0.9 1488.1	0 • 0 0 • U 0 • U 2136 • 5	0.0 0.0 0.0 3288.5	0.0 0.0 0.0 5167.7	0.0 0:0 0.0 6931.5	0 • 0 0 • 0 0 • 0 8 3 0 1 • 1	0.0 0.0 146.2 8634.2	0.0 61.4 162.3 8832.0
54 54 51	2 ANNUAL DEBT URAHWJOWN \$1982 3 Cum. DEBT DRAWWDOWN \$1982 9 JEBT SERVICE COVER	318.6 313.6 0.00	378•4 697•0 0•00	373•8 1090•8 0•00	417.6 1508.4 0.00	693.5 2201.9 0.00	1057•3 3259•2 0•00	927.5 4186.7 0.00	673•0 4859•8 0•00	153.0 5012.7 1.00	98.6 5111.3 1.03

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NO STATE CONTRIBUTION SCENARIO

7% INFLATION AND 10% INTEREST

Sheet 1 of 3

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>*******************************	******** E FUNDS-' ******	********* INFLATION *******	********* 72-1NTER ******	\$74474444 ST 102-C \$7444444	********* APCUST \$5 ********	v******** •117 BN *******	************ *******	***********	1-6 1-6 1:000000000000000000000000000000000000	******** *0V-82 ******
	1995	1996	1997	1998	1 999	2000	2001	2002	2003	2004
			C	ASH FLOW S						
73 ENERGY GWH 521 REAL PRICE-MILLS 465 INFLATION INDEX 520 PRICE-MILLS	3387 114.84 249.28 280.26	3387 107.99 266.73 288.03	3387 101.60 285.40 289.95	3387 95.65 305.38 292.08	3387 90.08 326.75 294.35	3387 84.90 349.62 296.83	3387 80.08 374.10 299.58	5223 84.91 400.29 339.87	5414 81.12 428.31 347.44	5605 73.95 458.29 338.92
516 REVENUE 170 LESS OPERATING COSTS	969.5 32.0	975.5 35.0	982.0 38.1	989.2 41.6	996.9	1005.3	1014.6	1775.0 91.1	1880.9	1899.5 108.5
517 OPERATING INCOME 214 ADD INTEREST EARNED ON FUNDS 550 LESS INTEREST ON SHURT TERM DEBT 391 LESS INTEREST ON LONG TERM DEBT	937.5 u=2 10=2 360=2	940-5 6-7 16-9 856-7	, 943.9 7.3 17.6 852.9	947.6 8.0 18.4 845.6	951.5 8.7 19.3 844.0	955•7 9*5 20•2 538•5	960.5 10.4 21.2 833.2	1683.9 11.4 22.3 1545.3	1781.5 19.1 38.3 1568.7	1791.0 20.9 41.2 1558.5
549 NET EARNINGS FROM DPERS	67.2	73.6	80.7	80.5	97.0	106.2	116.5	12707	193.6	212.2
CASH SOURCE AND USE 548 CASH INCOME FROM OPERS 446 STATE CONTRIBUTION 143 LONG TERM DEBT DRAHDOWNS 248 AURCAP DEBT DRAHDOWNS	67.2 0.0 386.1 6.7	73.6 0.0 443.7 7.2	80.7 0.0 409.7 7.8	88.5 0.0 1175.2 8.6	97.0 0.0 1441.9 9.3	106.2 0.0 1613.4 10.2	116.5 0.0 1483.1 11.1	127.7 0.0 302.9 159.2	193.6 0.0 0.0 29.3	212.2 0.0 0.0 22.3
549 TOTAL SOURCES OF FUNDS	459.9	524+5	498.2	1272.3	1548.2	1729.8	1610.7	589.8	223.0	234.5
320 LESS CAPITAL EXPENDITURE 448 LESS MORCAP AND FUNDS 200 LESS DEBT REPAYMENTS 395 LESS PAYMENT TO STATE	418•2 6•7 35•0 0•0	478•8 7•2 38•5 0•0	448.0 7.8 42.4 0.0	1217.1 8.6 46.6 0.0	1487.6 9.3 51.3 0.0	1663.3 10.2 56.4 0.0	1537.5 11.1 0.0	362.3 159.2 68.3 0.0	90.9 29.3 102.7 0.0	99•2 22•3 113•0 0•0
141 CASH SURPLUS(DEFICIT) 249 SHORT TERM DEBT 444 CASH RECOVERED		0.0 0.0 0.0		0.0 0.0 0.0	0.0 0.0 0.0			0.0 0.0 0.0		
225 RESERVE AND CONT. FUND 371 JTHER HORKING CAPITAL 454 CASH SURPLUS RETAINED 370 CUM. CAPITAL EXPENDITURE 465 CAPITAL EMPLOYED	67.2 101.8 0.0 9311.6 9480.6	73.4 102.8 0.0 9790.4 9966.6	80.1 103.9 0.0 10238.5 10422.5	87.4 105.2 0.0 11455.5 ==================================	95.4 106.5 0.0 12943.1 13145.0	104.1 108.0 0.0 14606.4 14818.5	113.7 109.6 0.0 16143.6 16367.1	191.3 191.2 0.0 16506.2	208.8 203.0 0.0 16597.0 17008.8	227.8 206.2 0.0 16696.2 17130.3
461 STATE CONTRIBUTION 462 RETAINED EARNINGS 555 DEET DUTSTANDING-SHORT TERM 554 DEBT DUTSTANDING-LONG TERM	0.0 128.5 169.0 9183.0	0.0 202.2 176.3 9588.2	0.0 282.9 184.1 9955.5	0.0 371.4 192.7 11084.0	0.0 468.4 202.0 12474.6	0.0 574.6 212.2 14031.6	0.0 691.1 223.4 15452.6	0.0 818.7 382.6 15687.3	0.0 1012.4 411.9 15584.5	0.0 1224.6 434.1 15471.5
542 ANNUAL DEBT DRAWWDOWN \$1982 543 Jum. Debt Drawwdown \$1982 519 Debt Service Cover	154.9 5266.2 1.04	166.3 5432.5 1.04	143.6 5576.1 1.04	384 • 8 5960 • 9 1 • 05	441.3 6402.2 1.05	461.5 6863.7 1.06	396.4 7260.1 1.06	75.7 7335.8 1.04	0.0 7335.8 1.05	0.0 7335.8 1.06

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TABLE D.7

30000000000000000000000000000000000000	******** 2 FUNDS-1 ******	********* NFLATION ********	********* 72-INTERI ******	2040000000 ST 102~C/ 204000000	ACCOST \$5	********** •117 dN ********	**** ** *****	**********	x0\$\$\$\$\$\$\$\$ j-1 \$\$\$\$\$\$\$\$\$	********* 10V-02 ********
	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
			C/	SH FLOW S	UMHARY		•			
73 ENERGY GWH 521 REAL PRICE-MILLS 466 INFLATION INDEX 520 PRICE-MILLS	6092 64.24 490.37 314.99	5147 60.15 524.69 315.59	6250 55.94 561.42 314.07	6472 51.13 600.72 307.16	6544 47.92 642.77 507.98	6616 44.95 637.77 309.15	6638 42.54 735.91 313.04	6660 40.30 787.42 317.35	6682 38-23 842-54 322-11	104826 0.00 0.00 0.00
515 REVENJE 170 LESS OPERATING COSTS	1918.8 118.4	1939.8 129.2	1962.8 141.0	1987.8 153.9	2015.3	2045.2 183.4	2077.9 200.1	2113.4 218.4	2152.2 238.4	32521.6 2202.0
517 DPERATING INCOME 214 ADD INTEREST EARNED ON FUNDS 550 LESS INTEREST UN SHORT TERM DEBT 341 LESS INTEREST ON LONG TERM DEBT	1800.4 22.8 43.4 1547.2	1810.6 24.9 45.8 1534.7	1821.8 27.1 48.5 1521.0	1833.9 29.6 51.4 1506.0	1847.3 32.3 54.5 1489.5	1861.8 35.3 58.0 1471.3	1877.7 38.5 61.7 1451.2	1 d95 . 0 42 . 0 65 . 8 1 42 7 . 2	1913.8 45.9 70.3 1405.0	30319.0 412.4 745.6 25655.5
543 NET EARNINGS FROM OPERS	232.0	254.9	279.4	306 • 1	335.6	367.9	403.2	442.0	434.4	4330e8
548 CASH INCOME FROM OPERS 548 CASH INCOME FROM OPERS 546 STATE CUNTRIZUTION 143 LJNG TERM DEBT DRAWDOWNS 249 HORCAP DEBT DRAWDOWNS	232.6 0.0 0.0 24.2	254.9 0.0 0.0 26.5	279.6 0.0 0.0 28.9	306.1 0.0 0.0 31.5	335*6 0•0 040 34•4	367:9 0.0 0.0 37:5	403.2 0.0 0.0 41.0	442.0 0.0 0.0 44.7	484.4 0.0 0.0 48.8	4330.8 0.0 16119.9 751.5
549 TUTAL SOURCES OF FUNDS	256.9	281.3	308.2	337.6	370.1	405.4	444.2	486.7	533.2	21202.3
320 LESS CAPITAL EXPENDITURE 448 LESS AJRCAP AND FUNDS 260 LESS DEBT REPAYMENTS 395 LESS PAYMENT TO STATE	108.2 24.2 124.3 0.0	118 • 1 26 • 5 136 • 7 0 • 0	128.9 28.9 150.4 0.0	140.7 31.5 165.5 U.0	153.6 34.4 182.0 0.0	167.6 37.5 200.2 0.0	182.9 41.0 220.2 0.0	199•7 44•7 242•3 U=0	217.9 48.8 266.5 0.0	18113.9 751.6 2336.5 0.0
141 CASH_SURPLUS(DEFICIT) 247 SHORT TERM DEBT 444 CASH RECOVERED		0 • 0 0 • 0 0 • 0	0.0 0.0 0.0	-0.1 0.1 0.0	0•1 -0•1 0•0	0.1 0.0 0.1	0)1 0.0 0.1			0 • 3 0 • 0 0 • 3
225 RESERVE AND CONT. FUND 371 OTHER WURKING CAPITAL 454 CASH SURPLUS RETAINED 370 CUM. CAPITAL EXPENDITURE	248.7 209.6 0.0 16804.4	271.4 213.4 0.0 16922.6	296.2 217.4 0.0 17051.5	323.3 221.9 0.0 17192.2	352.8 226.7 0.0 17345.8	385.1 232.0 0.0 17513.4	420.3 237.8 0.0 17695.3	458.7 244.1 0.0 17896.0	500.6 251.0 0.0 18113.9	500 • 6 251 • 0 0 • 0 18113 • 9
465 CAPITAL EMPLOYED	17262.7	17407+3	17565.1	17737.3	17925.3	10130.5	18354.4	18598.8	18865.5	18865.5
461 STATE CONTRIBUTION 462 RETAINED EARNINGS 555 DEBT DUTSTANDING-SHORT TERM 554 DEBT DUTSTANDING-LONG TERM	0.0 1457.2 458.3 15347.2	0.0 1712.1 484.8 15210.5	0.0 1991.5 513.6 15060.0	0.0 2297.6 545.2 14894.6	0.0 2633.2 579.5 14712.6	3001.0 617.1 14512.4	0.0 3404.2 658.1 14292.1	0.0 3846.1 702.8 14049.9	0.0 4330.5 751.6 13783.4	0.0 4330.5 751.6 13783.4
542 ANNUAL DEBT DRAHWDOWN \$1982 543 JUM, DEBT DRAHWDOWN \$1982 519 DEBT SERVICE COVER	0.0 7335.8 1.06	0.0 7335.8 1.07	0.0 7335.8 1.08	0.0 7335.6 1.03	7335.8 1.09	0.0 7335.d 1.10	0.0 7335.8 1.11	0.0 7335.8 1.12	0.0 7335.8 1.13	7335.8 7335.8 0.00

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INO STATE CONTRIBUTION SCENARIO

7% INFLATION AND 10% INTEREST

Sheet 3 of 3

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TABLE D.7

TABLE D. 8: SUSITNA COST OF POWER

First full year of Watana & Devil Canyon - 2003 (See Table 5 for Detail)

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		J'S Per Net Kilowatt					
		Actual \$'s	1982 \$'s				
Total Plant Investment							
Inc. I. D. C (RL 370 + 466)			2392				
1. Fixed Charges	Percent						
(a) Cost of Money	10.00						
(b) Depreclation							
(10% 50 yr S.F.)	• 09						
(c) Insurance	. 10						
(d) Taxes	. 00						
1. Federal Income	0.00						
2. Federal			teen station ‡roin dig. Line and an article				
Miscellaneous	0,00						
3. State & Local	0.00						
	10.19						
			243. 74				
a de la companya de La companya de la comp							
II. Fixed Operating Costs							
(a) Operation & Mainten	ance						
including administr	ativa						
and general expense	(RL170)		14.33				
Total Annual Capacity Costs			258.07 ³				
NOTES: (1) KL = Reference L	Ine on far	left of printout					
(2) Cost in 1952 \$1e	le dontro	d throughout by set					

- (2) Cost in 1982 \$'s is derived throughout by deflating Actual dollar costs by the inflation index (RL 466).
- (3) At the 38 percent plant factor in 2003 this gives a cost of power of 77.5 mills kWh in 2003 (in 1982 dollars). the cost of 81.12 mills kWh in Table 2 results from the more detailed cost analysis of that table and in particular allowance for renewals. This data reflects the economic cost of power in 2003. The charge to consumers for this power will be determined by the level of state appropriation and the specifics of the financing plan. For the plan given in the text the charge to consumers is as shown in RL 521 of Table 1 at 55.54 mills in 2003.
TABLE D. 9: FORECAST FINANCIAL PARAMETERS

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	Watana	Dev 11 Canyon	Total			
Project Completion - Year	1993	2002				
Energy Level - 1993 - 2002 - 2010			3 387 GWh 5 223 m 6 616 m			
Costs in January 1982 Dollars						
Capital Costs	\$ 3.647 billion	\$1. 470 b111 ion	\$ 5. 117 byllion			
Operating Costs - per annum	\$10.0 m11110n	\$5.42 million	\$15.42 million			
Provision for Capital Renewals - per annum (0.3 percent of Capital Costs)	\$10.94	\$4. 41	\$15.35			
Operating Working Capital		15 percent of Operating Costs 10 percent of Revenue				
Reserve and Contingency Fund		100 percent of 100 percent of Renewals	Operating Costs Provision for Capital			
Interest Rate		10 percent per	annum			
Dobt Repayment Period		35 years				
Inflation Rate		7 percent per annum				
Real Rate of Increase in Operatin - 1982 to 1987 - 1988 on	ng Costs	1.7 percent pe 2.0 percent pe	r annum r annum			
Real Rate of Increase in Capital - 1982 to 1985 - 1986 to 1992 - 1993 on	Costs	1. 1 percent pe 1. 0 percent pe 2. 0 percent pe	r annum r annum r annum			

UTILITY	Generating Capacity 1981 MW at 0°F Rating	Predominant Type of Generation	Tax Status Re: IRS Section 103	Purchases Wholesale Electrical Energy	Provides Wholesale Supply	Utility Annual Energy Demand 1980 GWh
IN ANCHORAGE-COOK INLET AREA						
Anchorage Municipal Light and Power	221.6	SCCT	Exempt	#		585.8
Chugach Electric Association	395.1	SCCT	Non-Exempt		• • • • • • • • • • • • • • • • • • •	941.3
Natanuska Electric Association	0.9	Diesel	Non-Exempt			268.0
Homer Electric Association	2.6	Diesel	Non-Exempt	*	energia Antonio de la composición de la Composición de la composición de la comp	284.8
Seward Electric System	5.5	Diesel	Non-Exempt		-	26.4
Alaska Power Administration	30.0	Hydro	Non-Exempt		*	— —
National Defense	58.8	ST	Non-Exempt	—		_
Industrial — Kenai	25.0	SCCT	Non-Exempt			
IN FAIRBANKS TANANA VALLEY						
Fairbanks Municipal Utility System ¹	68.5	ST/Diesel	Exempt	-		116.7
Golden Valley Electric Association ¹	221.6	SCCT/Diesel	Non-Exempt	-		316.7
University of Alaska	18.6	ST	Non-Exempt	-	_	
National Defense ¹	46.5	ST	Non-Exempt	-		
IN GLENALLEN/VALDEZ AREA						
Copper Valley Electric Association	19.6	SCCT	Non-Exempt		-	37.4
TOTAL	1114.3		Anglane tanan unakan makan ny tingnaka aki	In an an	. Ang a	2577.1

1Pooling Arrangements in Force

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. TABLE D.10 - RAILBELT UTILITIES PROVIDING MARKET POTENTIAL



PLANT LIST

PLANT Nc. NAME OF PLANT 2 Anchorage No. 1 3 Anchorage 6 Eklutna 7 Chena 10 Knik Arm 22 Elmendorf-West 23 **Fairbanks** 32 Cooper Lake 34 Elmendorf-East 35 Ft. Richardson 36 Ft. Wainright Eilson 37 38 Ft. Greeley 47 **Bernice Lake** 55 **International Station** 58 Healy 59 Beluga 75 **Clear AFB** 80 Collier-Kenai 81 Eyak 82 North Pole 83 Valdez 84 Glennallen

UTILITY

Anchorage Municipal Light and Power Anchorage Municipal Light and Power Alaska Power Administration Fairbanks Municipal Utilities System Chugach Electric Association, Inc. **United States Air Force** Golden Valley Electric Association, Inc. Chugach Electric Association, Inc. United States Air Force **United States Army** United States Air Force United States Air Force United States Army Chugach Electric Association, Inc. Chugach Electric Association, Inc. Golden Valley Electric Association, Inc. Chugach Electric Association, Inc. United States Air Force Collier-Kenai **Cordova Public Utilities** Golden Valley Electric Association, Inc. Golden Valley Electric Association, Inc. Golden Valley Electric Association, Inc.

TYPE OF OWNERSHIP

Municipal Municipal Federal Municipal Cooperative Federal Cooperative Cooperative Federal Federal Federal Federal Federal Cooperative Cooperative Cooperative Cooperative Federal Municipal Municipal Cooperative Cooperative Cooperative

TABLE D.11 - LIST OF GENERATING PLANTS SUPPLYING RAILBELT REGION



TABLE D. 12: TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM

Abbreviations	Railbelt Utility	Installed Capacity ¹
AMLPD	Anchorage Municipal Light & Power Department	2216
CEA	Chugach Electric Association	395 1
GVEA	Golden Valley Electric Association	221.6
FMLS	Fairbanks Municipal Utility System	68 5
CVEA	Copper Valley Electric Association	19.6
MEA	Matanuska Electric Association	0.9
HEA	Homer Electric Association	26
SES	Seward Electric System	5 .5
APAd	Alaska Power Administration	• 30.0
U of A	University of Alaska	18.6
TOTAL		984.0

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(1) Installed capacity as of 1980 at 0°F
 (2) Excludes National Defense Installed capacity of 46.5 MW

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Raitbelt	Station	Unit	Uh It	Instal lation	Heat Rate	Instal lod		
Utility	Name	No.	Type	Year	(Btu/kWh)	Capacity (MW)	Fuel Tune	Dotting and Mary
			,£,		(Capacity (cm)	I dot i ype	Net IL ellent Teat
Anchorage Municipal	AMLPD	1	GT	1962	14.000	16.3	NG	1002
Light & Power	AMLPD	2	GI	1964	14,000	163	NG	1004
Department	AMLPD	3	GT	1968	14 000	18.0	NC	1994
	AMLPD	4	GT	1972	12 000	72.0	NO NO	1998
(AMLPD)	G.M. Sullivan	5.6.7	ČĊ.	1070	P 500	130.0	NG NC	2002
		-, -, .		3.27.2	0, 200	1350	ING	2011
Chugach	Bel uga	1	GI	1968	15.000	16.1	NG	1009
Electric	Beluna	2	GI	1968	15 000	16.1	NG	1000
Association (CEA)	Beluga	3	GT	1975	10,000	53.0	NC NC	1950
	Beluga	5	្រោ	1975	15,000	59 0	NO NO	2005
	Baluna	6		1075	15,000	20 0	NG	2005
	Bolugo	7	OT OT	1970	15,000	68.0	NG	2012
	Port los loka	1	GI	19/1	12,000	68.0	NG	2012
	Derifice Lake		GI	1965	25,440	8.6	NG	1993
			GI	1972	23, 440	18, 9	NG	2002
		2	GI	1978	23,440	26.4	NG	2008
	International							
	Station	1	CT .	1064	40 000	14.0	NO	
	orarion	2	CT .	1045	40,000	14.0	NG	1994
		<u>z</u>	OT	1909	A means M	14.0	NG	1995
		•	er	1970		18, 0	NG	2000
	Copper Lake	, 1	HY	1961	۲۰۰۰ ۲ ۰۰۰ ۲۰۰۰ ۲۰۰۰	16.0		2011
Golden Valley	Heal v	· · 1 · · · ·	ST	1967	11 80.9	25.0	01	0.000
Electric		2	ic	1067	14,000	2.3.0	Loal	2002
Association	North Pole	- <u>+</u>	CT CT	1076	17,000	48	UII	1997
(GVFA)	ior in 1018	2		1770	15,000	02.0	011	1996
	7-bender.	4	GI	1977	15,500	65.0	011	1997
	zandinal		GI	1971	14, 50(8	18.4	011	1991
	an a	2	GI	1972	14,500	17.4	011	1992
		2	GI	1975	14,900	3.5	011	1995
		4	GT	1975	14,900	3.5	011	1995
•		5	IC IC	1965	14,000	3.5	011	1995
		6	IC	1965	14.000	3.5	011	1005
		7	IC	1965	14,000	3.5	011	1995
		8	IC	1965	14,000	3,5	011	1005
		9	IC	1965	14 000	35		1995
		10	IC	1965	14.000	35	011	1992
							~11	1959
Fairbanks	Cheria	- 1	ST	1954	14,000	5.0	Coai	1989
Mun ici pal		2	ST	1952	14.000	25	Coal	1087
Utility		3	ST	1952	14.000	15	Coal	1207
System (FMUS)		4	GT	1963	16 500	76		1907
		5	ST	1970	14 500	21 0	MII 01	1995
		6	<u>द</u> ा	1076	12 400		Loai	2005
	EMIS	1		1067	12,450	4.3 F	VII	1997
		2	10	1007	11,000	40	UII	1997
		<u> </u>		1900	11,000	48	011	1998
		- - - -	10	1708	11.000	2.8	OTI	1998

TABLE D. 13: GENERATING INTE WITHIN THE RAILBELT - 1980

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TABLE D. 13 (Continued)

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Ralloelt	Stat Ion	Unit	Unit	Instal lation	Heat Rate	Installed		
Utility	Name	No.	Туре	Year	(Btu/kWh)	Capacity (MW)	Fuel Type	RetIrement Year
Honer Electric	Homer							
Association	Kenal	- 1	IC	1979	15,000	0.9	011	2009
(HEA)	Pt. Graham	1	IC	1971	15.000	0.2	011	2001
	Sel dov la	1	IC	1952	15,000	0.3	011	1982
		2	IC	1964	15.000	0.6	GII	1994
		3	IC	1970	15,000	0.6	011	2000
University of	University	1	ST	1980	12.000	1.5	Coal	2015
Alaska (1) of A)	University	2	ST	1980	12,000	1.5	Coal	2015
	Iniversity	3	ST	1980	12,000	10.0	Coal	2015
	University	1	ic	1980	10, 500	2.8	011	2011
	University	2	IC	1980	10,500	2.3	oii	2011
Copper Valley	CYEA	1-3	IC	1963	10, 500	1. 2	011	1993
Electric	CVEA	4-5	IC	1966	10,500	2.4	011	1996
Association (CVEA)	CVEA	6-7	IC	1976	10, 500	5.2	011	2006
	CVEA	1-3	IC	1967	10,500	1.8	011	1997
	CVEA	4	ic	1972	10, 500	1.9	011	2002
	CVFA	5	ic	1975	10,500	1.0	011	2005
	CVFA	5	ic	1975	10,500	2.6	011	2005
	CVEA	7	GT	1976	14,000	35	011	1996
Matanuska Elec. Association (MEA)	Tal keetna	1	IC	1967	15,000	Q. 9	011	1997
Saward Electric	SES	1	IC	1965	15,000	1. 5	011	1995
System (SES)		2	IC	1965	15,000	1,5	011	1995
		3	IC	1965	15,000	2,5	011	1995
Alaska Power Administration (APAd)	Ekl utna	-	ΗΥ	1955		30.0		2005
TOTAL						984.0		

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Notes:

GT = Gas turbine CC = Combined cycle HY = Conventional hydro IC = internal combustion ST = Steam turbine NG = Natural gas NA = Not available

*This value judged to be unrealistic for large range planning and therefore is adjusted to 15,000 for generation planning studies.

Utility	Unit	Туре	MW	Year	Avg. Energy (GWh)
CVEA	Solomon Gulch	HY	12	1981	55
CEA	Sernice Lake #4	GT	26.4	1982	
AMLPD	AMLPD #8	GT	90. 0	1982	
CEA	Beiuga ∦6, 7, 8	CC	42*	1982	
COE	Bradley Lake	Hydro	90, 0	1988	
APA	Grant Lake	Hydro	7.0	1988	33
TOTAL			267.4		

TABLE D. 14: SCHEDULE OF PLANNED UTILITY ADDITIONS (1980-1988)

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* New Unit No. 8 will encompass Units 6 and 7, each rated at 68 MW. Total new station capacity will be 178 MW.

TABLE D. 15: OPERATING AND ECONOMIC PARAMETERS FOR SELECTED HYDROELECTRIC PLANTS

No.	Site	R i ver	Max. Gross Head (ft)	installed Capacity (MW)	Average Annual Energy (Gwh)	Plant Factor (%)	(1981 \$) Capital Cost (\$10 [°])	Economic ² Cost of Energy (\$/1000 Kwh)
1	Snow	Snow	690	50	220	50	255	45
2	Bruskasna	Nenana	235	30	140	53	238	113
3	Keetna	Tal keetna	330	100	395	45	463	73
4	Cache	Tal keetna	310	50	220	51	564	100
5	Browne	Nenana	195	100	410	47	625	59
6	Tal keetna-2	Tal keetna	350	50	215	50	500	90
7	Hicks	Matanuska	275	60	245	46	529	84
8	Chakachamna	Chakachatha	94.5	500	1925	44	1 480	30
9	Allison	Allison Creek	1270	8	33	47	54	125
10	Strand Ine							
	Laka	Bel uga	810	20	85	49	126	115

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Notes:

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Including engineering and owner's administrative costs but excluding AFDC.
 Including IDC, insurance, Amortization, and Operation and Maintenance Costs.
 An indepedent study by Bechtel has proposed an installed capacity of 330 MW, 1500 GWh annually at a cost of \$1,405 million (1982 dollars), including AFDC.

Generation	Scenar lo			Ins1	ailed Ca Cate	apacity (M gory in 20	W) by 10	lotal Sistem	Total System
Турс	Description	Load Forecast	Id-No	Thermal	~~~~		Hydro	Capacity in	Cost -
All Thermal	No Renewals	Medium	LME 1	900	Gas	011 50		2010 (MW)	(\$10 ⁶)
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500) ¹ -1993 Keetna (100)-1997	Med lum	L7W 1	600	576	70	744	1895 1990	8130 7080
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1997 Snow (50)-2002	Medium	LFL7	700	501	10	894	2005	7040
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-1998	Medium	LWP7	500	576	60	822	1958	7064
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-2002	Med jum	LXF 1	700	426	30	822	1978	704 i
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1995 Snow (50), Cache (50), Allison Creek (8), Talkeetna-2 (50), Strandline (20)-2002	Mədium	L403	500	576	30	922	2028	7088

TABLE D. 16: RESULTS OF ECONOMIC ANALYSES OF ALTERNATIVE GENERATION SCENARIOS

Notes:

1997 A.

(1) Installed capacity.

TABLE D. 17: SUMMARY	OF THERMAL G	ENERATING RESOL	RCE PLANT PAR	AMETERS /10
Parameter Heat Rate (Btu/kWh) Earliest Availability O&M Costs	<u>200 Mw</u> 10,000 1989	Comb in ed Cycle 200 MW 8,000 1980	Gas Turbine 70 MW 12,200 1984	Diesei 10 MW 11,500 1980
Fixed O&M (\$/yr/kw) Variable O&M (&/MWH) Outages	16, 83 0, 6	7.25 1.69	2.7 4.8	0.55 5.38
Planned Outages (%) Forced Outages (%)	8 5.7	7 8	32 8	1 5
Construction Period (yrs) Startup Time (yrs)	6 6	2 4	1	1
<u>Unit Capital Cost (\$/kW)</u> ¹ Rallbelt Beluga Nenana	2,061 2,107	1, 075 - -	527 	856 -
Jnit Capital Cost (\$/kW) ²				i ter 🖷 e 1997 - El Constantino 1997 - El Constantino
la i i bei † Jei uga Jenana	2, 242 2, 309	1, 107	636 -	869 ⁻

Notes:

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As estimated by Battelle/Ebasco without AFDC.
 Including IDC at 0 pecent escalation and 3 percent interest, assuming an S-shaped expenditure curve.
 Excludes transmission.

n an	Growth Rates	(Percent)	
	1982-2000	2000-2040	Probability
Low Case	0	0	0.3
Medlum (most likely case)	20	1.0	0.5 /
High Case	4.0	2.0	0.2

TABLE D. 18: REAL (INFLATION-ADJUSTED) ANNUAL GROWTH IN OIL PRICES

Base Period

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(January 1982)

Price of No. 2 Fuel OII - \$6. 50/MMBtu.

Probability of	Dome Low	stic Market i <u>Medium</u>	Price ¹ High	Expe	ort Opportuni Medium	ty Value High
Occurrence	N.A.	N.A.	N.A.	27%	45%	27%
Base Period Value	-	\$3. 00/MMBtu	-		\$4. 65/MMBtu ²	
Real Escalation CIF Price, Japan						
1982 - 2000		N. A.	-	0%	2%	49
2000 - 2040	eq.		-	0%	15	2%
Real Escalation Alaska Price						
1982 - 2000	0%	2.5%	5.0%	0%	2, 7%	5.74
2000 - 2040	0%	2 0%	2 0%	0\$	1.2%	2 2%

TABLE D. 19: DOMESTIC MARKET FRICES AND EXPORT OPPORTUNITY VALUES OF NATURAL GAS

¹ OGP5 analysis used domestic market prices with zero escalation beyond 2010, (Source: Battelle)

² Based on CIF price in Japan (\$6,75) less estimated cost of liquefaction and shipping (\$2,10). (Source: 19, 20, 21).

³ Source: (9), (22).

⁴ Alaska opportunity value escalates more rapidly than CIF prices as liquefaction and shipping costs are estimated to remain constant in real terms.

TABLE D. 20: SUMMARY OF COAL OPPORTUNITY VALUES

	Base Per lod	Annual Real	Growth Rate	Probability	
	(Jan. 1982) Value (\$/MMB†u)	1980 - 2090 (\$)	2000 - 2040	of Occurrence	
Base Case					
Batteile Base Period CIF Price					
Medium Scenario					
- CIF Japan - FOB Beluga - Nenana	1. 95 1. 43 1. 75	2.0 2.6 2.3	1. 0 1. 2 1. 1	49 49 49	
Low Scenario					
-CIF Japan -FOB Beluga -Nenana	1.95 1.43 1.75	0 0 0 1	0 0	24 24	
High Scenario				4	
-CIF Japan -FOB Beluga -Nenana	1. 95 1. 43 1. 75	4.0 5.0 4.5	2.0 2.2 1.0	27 27	
Sensitivity Case			10 2	21	
Updated Base Period CIF Price ¹					
Medium Scenario					
-CIF Japan -FOB Beluga -FOB Nenana	2.66 2.08 1.74	2.0 2.5 2.7	1.0 1.2	49 49	
Low Scenario			I● 	49	
-CIF Japan -FOB Beluga -FOB Nenana	2,66 2,08 1,74	0 0 -0, 2	0 0 -0 1	24 24	
High Scenario				4	
- CIF Japan - FOB Beluga - FOB Nenana	2. 66 2. 08 1. 74	4.0 4.8 × 3	20 22 23	27 27 27	

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Assum'ng a 10 percent discount for Alaskan coal due to quality differen-tials, and export potential for Healy coal.

		Fuel Price Scenario	
	Low	Med i um	High
Probability of occurrence	25%	50\$	25%
Base period January 1982 prices			
(1982\$/MMB+u)			
Fuel OII	6, 50	6, 50	6.50
Natural Gas	3.00	3.00	3.00
Coal - Belvga - Nenana	1. 4.3 1. 75	1. 43 1. 75	1. 43 1. 75
Real escalation rates per year (percent)			
Fuel 011 - 1982 - 2000 - 2000 - 2040	0	2.0 2.0	4.0 2.0
Natural Gas - 1982 - 2000 - 2000 - 2040	0 0	2, 5 2, 0	50
Beluga Coel - 1982 - 2000 - 2000 - 2040	0 0	26	5.0
Venana Coal - 1982 - 2000 - 2000 - 2040	Q. 1 Q. 1	23 11	4.5 1.9

TABLE D. 21: SUMMARY OF FUEL PRICES USED IN THE OGP5 PROBABILITY TREE AMALYSIS

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Beyond 2010, the OGP analysis has used zero real escalation in all cases.

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TABLE D. 22: ECONOMIC ANALYSIS SUSITNA PROJECT - BASE PLAN

		1982 Pr	esent' Ka \$	rth of System x 10 ⁵	Costs
<u>Plan</u>	<u>Cemponents</u>	1993- 2010	2010	Estimated 2011-2051	199 3- 2051
Non Susitna A	600 MW Coal-Beluga	3, 213	491	5, 025	8, 238
	200 MM Coal-Nenana				
	630 MW GT			•	
Susitna C	680 MW Watana	3, 119	385	3, 943	7,062
	600 MW Devil Canyon				
	180 Mw GT				-
Not Foonante Ronafit					

Net Economic Benefit of Susitna Plan

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TABLE D. 23: SUMMARY OF LOAD FORECASTS USED FOR SENSITIVITY ANALYSIS

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	Me	ed i unr	Lo	W	High		
	MW	GWh	MW	GWh	MW	G₩h	
1990	892	4,456	802	3, 999	1,098	5, 703	
2000	1,084	5, 469	921	4, 641	1,439	7, 457	
2010	1, 537	7,791	1,245	6,303	2, 165	11,435	

TABLE D. 24: LOAD FORECAST SENSITIVITY ANALYSIS

			1982	Present	Worth of Syst	em Costs (\$	x 10 ⁰)
<u>Plan</u>	<u>1D</u>	<u>Components</u>	1993- 2010	2010	Estimated 2011-2051	1993- 2051	Net Economic Benefit
Non-Susitna	к1	400 MW Coal-Balluga	2,640	404	4, 238	6, 878	
Low Forecast		200 MW Coal-Nenana 560 MW GT					
Susitna with	К2	680 MW Watana (1995)	2, 882	360	3, 768	6, 650	228
Low Forecast		600 MW Davil Canyon (2004)					
Non-Susitna with	J ₁	800 MW Coal-Beluga	4, 176	700	6, 683	10, 8591 ¹	
High Forecast		200 MW Coal-Nenana 700 MW GT 430 MW Pre-1993					
Sus i tna with	J2	680 MW Watana (1993)	3, 867	564	5, 380	9, 2471 ¹	1, 612
High Forecast		600 MW Devil Canyon (1997) 350 MW GT 430 MW Pre-1993					

1 From 1993 to 2040

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TABLE D. 25: DISCOUNT RATE SENSITIVITY ANALYSIS

	ID	Real Discourt Pate					
Plan	10	(Percent)	1993- 2010	2010	Estimated 2011-2051	1993 - 2051	Net Economic Benefit
Non-Susitna	Q1	2	3, 701	465	7, 766	11, 167	evia
Susitna	Q2	2	3, 156	323	5, 394	8, 550	2,617
Non-Sust ma	A	3	3,213	491	5, 025	8, 328	
Sustma	C	3	3, 119	385	3, 943	7, 052	1, 176
Non-Sus I tha	s ₁	4	2, 791	517	3, 444	6, 235	a an
SusItna	s ₂	4.	3, 080	457	3,046	6, 126	109
Non-Susitna	P ₁	5	2, 468	550	2,478	4, 946	
Susitna	P ₂	5	3, 032	539	2, 426	5, 459	(513)

TABLE D. 26: CAPITAL COST SENSITIVITY ANALYSIS

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		1982 Pr	resent Wo	orth of Syster	n Costs (10^{6}
Plan		1993- 2010	2010	Estimated 2011-2051	1993- 2051	Net Economic Benefit
Non-Susitma Capital Costs Up 20 Percent						
Non-Sus I tna	G	3, 460	528	5, 398	8, 858	, sa
Susitna	c ¹	3, 119	385	3, 943	7,062	1, 976
Non-Susitna Capital Costs Down 10 Percent						
Non-Sus I tha	G	3, 084	472	4, 831	7, 91 5	-
Sus I tha	c ¹	3, 119	385	3, 943	7,062	853
Susitna Capital Costs Less Contingency						
Non-Sus I tha	Α	3, 213	491	5, 025	8, 238	an an an Arrange An Arrange Arrange
Susttna	X ₂	2, 710	336	3, 441	6, 151	2, 087
Susitna Capital Costs Plus Doubled Contingency						
Non-Sus I tha	A	3, 213	491	5, 025	8, 238	ан сайтан 1910 — Албан 1910 — Албан
Susima	Y ₂	3, 529	434	4, 445	7, 974	264

An adjustment calculation was made regarding the \pm capital costs of the 3GT units added in 2007-2010 since the difference was less than \$10 x 10°. Beyond 2010, this effect was not included.

TABLE D. 27: SENSITIVITY ANALYSIS - UPDATED BASE PLAN (JANUARY 1982) COAL PRICES

	Bear	1982 Present Wort	h of System Cos	ts (\$ x 10 ⁶)
	Period Beluga Coal Price (1982 \$/MMBtu)	Costs of Non-Susitna Plan	Costs of Susitna Pian	Net Econamic Benefits
Base Case	1₀ 43	8,238	7,062	1, 176
SensItivity (Updated) Case	2, 08	9, 030	7,062	1, 968

			1982 P	resent Worth (\$ X 1	of Sys	tem Costs
Plan	<u> ID </u>	1993- 2010	2010	Estimated 2011-2051	1993- 2051	Net Benefit
Zero-Escalation in Capital and O&M Costs						
• Non-Susitna • Susitna	01 02	2, 838 2, 525	422 299	4, 319 3, 060	7, 157 5, 585	1,572
Escalation in Capital Costs and O&M (Battelle	<u>)</u> 1					
• Non-Susitna • Susitna	X ₁ X ₂	3, 142 2, 988	477 366	4, 881 3, 745	8, 023 6, 737	1,286
Double Escalation Capital and O&M Costs						
• Non-Susitna • Susitna	P ₁ P ₂	3, 650 3, 881	602 503	6, 161 5, 148	9, 81 1 9, 029	782
Zero-Escalation In Fuel Prices						
• Non-Susitna • Susitna	$v_1 \\ v_2$	2, 233 3, 002	335 365	3, 427 3, 736	5, 660 6, 738	(1,078)
High Escalation In Fuel Prices						
• Non-Susitna • Susitna	W1 W2	4, 063 3, 267	643 403	6, 574 4, 121	10, 367 7, 388	2, 979

TABLE D. 28: SENSITIVITY ANALYSIS - REAL COST ESCALATION

¹Capital and O&M cests assumed to escalate at 1.4 percent 1982 to 2010

TABLE D. 29: SENSITIVITY ANALYSIS - NON-SUSITNA

DEAN. HET	L OUN VAOUA LAUA		
	I UNANAUNAMWA		

				_	1982 Pr	esent Worth (\$ X 10	gf Syst	em Costs
	Plan	<u>ID</u>	Components	1993 2010	2010	Estimated 2011-2051	1993- 2051	Nət Benef It
•	Non-Susitna with Chakachamna	B	330 MW Chakachamna 400 MW Coal-Beluga 200 MW Coal-Nenana 440 MW GT	2, 038	475	4 , 861	7, 899	
•	Sus I tna	C	680 MW Watana 600 MW Devil Canyon 180 MW GT	3, 119	385	3, 943	7,062	337

TABLE	D. 7/0:	SENSITIVITY ANALYSIS -	
		SUSITNA PROJECT DELAY	

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	<u>ID</u>	\$ x 10 ⁶ 1982 Present Worth of System Costs	\$ x 10 ⁶ Net Economic Benefit
Susitna Base Case	С	7, 962	1, 176
One-year delay for Watana (1994)	C3	7, 105	1, 133
One-year delay for Devil Caryon (2003)	¢4	7, 165	1, 134
One-year delay for Watana and Devil Canyon (1994, 2003)	С5	7,230	1,138

	Index Values
BASE CASE (\$1,176 MILLION)	100
Fael Escalation - High - Low	253 ¹ -92
Discount Rates - High-High (5%) - High (4%) - Low (2%)	-44 9 223
Susitna Capital Cost — High — Low	23 178
Load Forecast - High - Low	137 19
Non-Susitna (Thermal) Capital Costs - High - Low	168 73
Capital and Q&M Cost Escalation — High — Intermediate (Battelle) — Low	67 109 134
Chakachamna (Included In Non-Susitna Plan)	71
Updated Base Coal Price Planned Delay in Susitna	167
Project - One-vear delay, Watana	96
- One-year delay, Watana and Davil Canvon	°C GR
- Two-year delay: Pat©na and Devil Canyon	97

TABLE D. 31: SUMMARY OF SENSITIVITY ANALYSIS INDEXES OF NET ECONOMIC BENEFITS

¹ High fuel escalation case provides net benefits equal to 253 percent of the base value, $2.53 \times 1,176$, or 2,975.

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² Low fuel escalation case provides minus 92 percent of the base case net benefits, -, 92 x \$1,176, or -\$1,082.

Resource Base	Principal Sources for Railbelt	Fuel Conversion	Generation Technology	Typical Application	Availability for Commercial Order
Coal	Beluga Field, Cook Inlet	Crush	Direct-Fired Steam-Electric	Baseload	Currently Available
	nchana i iciu, iicaiy	Gasification	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell - Combined-Cycle	Base load Base load /Cyc ling Base load	1985-1990 1985-1990 1990-1995
		Liquefaction	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle	Baseload Baseload/Cycling Baseload/Cycling Baseload	1985-1990 1985-1990 1985-1990 1990-1995
Natural Gas	Cook Inlet North Slope	None	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Station Fuel-Cell - Combined-Cycle Combustion Turbine	Base load Base load/Cyc ling Base load/Cyc ling Base load Base load/Cyc ling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available
Petroleum	Cook Inlet North Slope	Refine to distillate and residual fractions	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell Stations Fuel-Cell - Combined-Cycle Combustion Turbine Diesel Electric	Base load Base load/Cyc ling Base load/Cyc ling Base load Base load/Cyc ling Base load/Cyc ling	Currently Available Currently Available 1985-1990 1990-1995 Currently Available Currently Available
Peat	Kenai Peninsula	None	Direct-Fired Steam-Electric	Baseload	Currently Available
	Lower Susitna Valley	Gasification	Direct-Fired Steam-Electric Combined Cycle Fuel-Cell - Combined-Cycle	Base load Base load /Cyc ling Base load	1990-2000 1990-2000 1990-2000
Municipal Refuse	Anchorage Fa irbank s	Sort & Classify	Direct-Fired Steam-Electric	Base load(a)	Currently Available
Wood Waste	Kena i Anchorage Nenana Fa irbank s	Hog	Direct-Fired Steam-Electric	Base load(a)	Currently Available

TABLE D. 32: BATTELLE ALTERNATIVE STUDY

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Resource Base	Principal Sources for Railbelt	Principal Sources Fuel Generation for Railbelt Conversion Technology		Typical Application	Availability for Commercial Order
Geothermal	Wrangell Mountains Chigmit Mountains		Hot Dry Rock-Steam-Electric Hydrothermal-Steam-Electric	Base I oad Base I oad	1990-2000 Currently Available
Hydroelectric	Kenai Mountains Alaska Range .		Conventional Hydroelectric Small-Scale Hydroelectric Microhydroelectric	Baseload/Cycling (b) Fuel Saver	Currently Available Currently Available Currently Available
Tidal Power	Cook Inlet		Tidal Electric Tidal Electric w/Retime	Fuel Saver Baseload/Cycling	Currently Available Currently Available
Wind	Isabell Pass Offshore Coastal		Large Wind Energy Systems Small Wind Energy Systems	Fuel Saver Fuel Saver	1985-1990 1985-1990
Solar	Throughout Region		Solar Photovoltaic Solar Thermal	Fuel Saver Fuel Saver	1985-1990 1995-2000
Uranium	Import	Enrichment & Fabrication	Light Water Reactors	Base load	Currently Available

TABLE D.32 (Contd)

(a) Supplemental firing (w/coal) would be required to support baseload operation due to cyclical fuel supply.
(b) May be baseload/cycling or fuel saver depending upon reservoir capacity.

Alternative	Capaçity (MW) (a)	Heat Rate Btu/kWh)	Availability (%)	Average Annual Energy (GWh)	Capital Cost (\$/kW)	Fixed O&M (\$/kW/yr)	Variable O&M (mills/kWh)
Coal Steam-Electric (Beluga)	200	10,000	87	-	2090	16.70	0.6
Coal Steam-Electric (Nenana)	200	10,000	87	• •	2150	16.70	0.6
Coal Gasifier-Combined Cycle	220	9,290	85	••••••••••••••••••••••••••••••••••••••	•	14.80	3.5
Natl. Gas Combustion Turbines	70	13,800 ^(b)	89	-	730	48	
Natl. Gas Combined Cycle	200	8,200 ^(c)	85	-	1050	7.30	1.7
Natl. Gas Fuel Cell Stations	25	9,200	91	1 <mark>.</mark>	890	42	
Natl. Gas Fuel Cell Comb. Cyc.	200	5,700	83	-	· •	50	•
Bradley Lake Hydroelectric	90	-	94	347	3190	9	
Chakachamna Hydroelec. (330 MW) ^(d)) 330		94	1570	3860	4	-
Chakachamna Hydroelec. (480 MW) ^(e)) ₄₈₀	-	94	1923	2100	4	-
Upper Susitna (Watana I)	680	-	94	3459	4659	5	-
Upper Susitna (Watana II)	340	-	94	•	168	5	-
Upper Susitna (Devil Canyon)	600	•	94	3334	2263	5	
Snow Electric	63	-	94	220	5850	7	
Keetna Hydroelectric	100	-	94	395	5480	5	•
Strandline Lake Hydroelec.	20(17)	-	94 •	85	7240	44	*•
Browne Hydroelectric	100(80)	•	94	430	4470	5	en son Son - en son
Allison Hydroelectic	8	-	94	37	4820	44	
Grant Lake Hydroelectric	7			-	2840	44	•
Isabell Pass Wind Farm	25		36	8	2490	3.70	3.3 -
Refuse-Derived Fuel Steam Electric (Anchorage)	50	14,000	N/A	· · · · · · · · · · · · · · · · · · ·	2980	140	15
Refuse-Derived Fuel Steam Electric (Fairbanks)	20	14,000	N/A	•	3320	. 140	15

TABLE D. 33: BATTELLE ALTERNATIVES STUDY

(a) Configuration in parentheses used in analysis of Railbelt electric energy plus taken from earlier estimates (Alaska Power Authority 1980)
(b) .. neat rate of 12,000 Btu/kWh was used in analysis of Railbelt electric energy plans. 13,000 Btu/kWh is probably more representative of partial load operation characteristic of peaking duty.
(c) An earlier estimate of 8500 Btu/kWh was used in the analysis of Railbelt electric electric energy plans.
(d) Configuration selected in preliminary feasibility study (Bechtel Civil and Minerals 1981)
(e) Configuration selected in Railbelt alternatives study (Ebasco 1982b)

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TABLE D.34: Summary of Electrical Energy Alternatives Included as Future Additions in Electric Energy Plans

		Electr	ic Ene	rgy P1	$an^{(a)}$	
BASE LOAD ALTERNATIVES	1	<u>1B</u>	<u>2A</u>	28	3	4
Coal Steam Electric Refuse-Derived Fuel Steam Electric	X	X	X X	X X	X	
CYCLING ALTERNATIVES						
Coal Gasifier - Combined-Cycle Natural Gas - Fuel Cell-Stations Natural Gas - Combined-Cycle Natural Gas - Combustion Turbine Natural Gas - Fuel-Cell Combined-Cycle Bradley Lake Hydroelectric Grant Lake Hydroelectric Lake Chakachamna Hydroelectric Upper Susitna Hydroelectric Allison Hydroelectric Keetna Hydroelectric Snow Hydroelectric Strandline Lake Hydroelectric	X X X X X X	X X X X	X X X X X X X X X X X	X X X X	X X X	X X X X X
FUEL SAVER (INTERMITTENT) ALTERNATIVES				•		
Large Wind Energy Conversion System			X	X		
ELECTRIC ENERGY SUBSTITUTES						
Passive Solar Space Heating Active Solar Hot Water Heating Wood-Fired Space Heating			X X X	X X X		
ELECTRIC ENERGY CONSERVATION						
Building Conservation			X	X		

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

TABLE D.35: FINANCING REQUI	REMENTS - \$	MILLION
FOR \$3.0 BILLION STATE APP	ROPRIATION	
	\$ Mi	llion
	Interest Inflatic	Rate 10% on Rate 7%
	Actual	1982 Purchasing Power
1985 State Appropriation 86 " 87 " 88 " 89 " 90 " 91 "	403.7 472.7 479.7 499.5 938.3 1550.4 462.4	318.6 348.2 330.9 321.8 564.9 872.3 243.3
Total State Appropriation	4806.7	3000.0
1990 Revenue Bonds 1 2 " 3 " Total Watana Bonds	784.7 754.9 294.6 1834.2	412.6 371.1 139.0 922.7
1994 Revenue Bonds 5 " 6 " 7 " 8 " 9 "	211.6 368.9 427.7 395.4 1163.0 1432.3	90.8 148.0 160.3 138.5 380.8 438.6
2000 " 1 " 2 , "	1604.7 1473.5 137.8	458.8 393.9 34.5
Total Devil Canyon Bonds	7214.9	2244.2
Total Susitna Bonds	9049.1	3156.9

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**************************************	\$******* \$3.0 BN(\$ *******	******** 1982) 57A *******	********* 1E FUNDS- ********	********* INFLATION ********	********** 73-INTER ********	0*000**** CEST 102-C ********	******** APCOST \$5 *******	********** •117 BN *********	\$\$\$\$\$\$\$\$\$ 23-F \$\$\$\$\$ \$\$	******** EB-82 *******
	1985	1986	1997	1988	1989	1990	1991	1992	1993	1994
			CA ==	SH FLOW S	UMMARY					
73 ENERGY GWH 521 REAL PRICE-MILLS 466 INFLATION INDEX 520 PRICE-MILLS	0 0.00 126.72 0.00	0.00 135.59 0.00	0 0.00 145.08 0.00	0 0.00 155.24 0.00	0.00 166.10 0.00	0.00 177.73 0.00	0.00 190.17 0.00	0.00 203.48 0.00	3387 29.74 217.73 64.76	3387 34•38 232•97 60•08
516 REVENUE 170 LESS OPERATING COSTS	0.0 0.0	0.0 0.0	0.0	0.0	0.0	0.0 0.0	0.0 0.0	0.0	219.3 26.9	271.2 29.3
517 JPERATING INCOME 21+ ADD INTEREST EARNED ON FUNDS 550 LESS INTEREST ON 'HORT TERM DEBT 391 LESS INTEREST ON LONG TERM DEBT			0.0 0.0 0.6 0.0						192.4 0.0 0.0 154.0	241.9 5.6 9.8 183.4
548 NET EARNINGS FROM DPERS	0.0	0.0	0.0	0.0	0.0	G.0	0.0	0.0	38.5	54.3
CASH SOURCE AND USE 548 CASH INCOME FROM CPERS 446 STATE CONTRIBUTION 143 LONG TERM DEBT DRAWDOWNS 244.WORCAP DEBT DRAWDOWNS	0.0 403.7 0.0 0.0	0.0 472.7 0.0 0.0	0.0 479.7 0.0 0.0	0.0 499.5 0.0 0.0	0.0 938.3 0.0 0.0	0.0 1550.4 0.0 0.0	0.0 462.4 784.7 0.0	0.0 0.0 754.9 0.0	38.5 0.0 294.6 98.0	54.3 0.0 211.6 17.7
54) TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	431.1	283.7
320 LESS CAPITAL EXPENDITURE 448 LESS WORCAP AND FUNDS 260 LESS DEBT REPAYMENTS	403.7 0.0 0.0	472.7 0.0 0.0	479.7 0.0 0.0	499.5 0.0 0.0	938.3 0.0 0.0	1550.4 0.0 0.0	1247.1 0.0 0.0	754.9 0.0 0.0	333.1 98.0 0.0	259•2 17•7 6•8
141 CASH SURPLUS(DEFICIT) 249 SHORT TERM DEBT 444 CASH RECOVERED	0.0 0.0 9.0	0.0 0.0 0.0	0.0 0.0 0.0	0.0 0.0 0.0	0.0		0.0 0.0 0.0			0 • 0 0 • 0 0 • 0
225 RESERVE AND CONT. FUND 371 DTHER WORKING CAPITAL 454 CASH SURPLUS RETAINED 370 CUM. CAPITAL EXPENDITURE	0.0 0.0 0.0 403.7	0.0 0.0 0.0 876.4	0.0 0.0 0.0 1356.1	0.0 C.0 0.0 1855.6	0.0 0.0 0.0 . 2794.0	0.0 0.0 0.0 4344.3	0.0 G.0 0.0 5591.4	0.0 0.9 0.0 6346.3	56.5 41.5 0.0 6679.4	61.6 54.1 0.0 6938.6
465 CAPITAL EMPLOYED	403.7	376.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6777.4	7054.3
461 STATE CONTRIBUTION 462 RETAINED EARNINGS 555 DEBT DUTSTANDING-SHORT TERM 554 DEBT DUTSTANDING-LONG TERM	403.7 0.0 0.0 0.0	876.4 0.0 0.0 0.0	1356.1 0.0 0.0 0.0	1855.6 0.2 0.0 0.0	2794,0 0.0 0.0 0.0	4344.3 0.0 0.0 0.0	4806.7 0.0 0.0 784.7	4806.7 0.0 0.0 1539.5	4806.7 3845 98.0 1834.2	4806.7 92.8 115.7 2039.0
542 ANNUAL DEBT DRAWWDOWN \$1982 543 CUM. DEBT DRAWWDOWN \$1982 519 DEBT SERVICE COVER		0.0 0.0 0.0 0.00	0.0 0.0 0.0	0.0 C.0 0.00	0.0 0.0 0.00	0 • 0 6 • 0 0 • 00	412.6 412.6 0.00	371.0, 783.6 0.00	135.3 918.9 1.25	90 • 8 1009 • 7 1 • 25

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\$3 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO 7% INFLATION AND 10% INTEREST

TABLE D.36

Sheet 1 of 3

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\$3 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO 7% INFLATION AND 10% INTEREST

Sheet 2 of 3

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CASH FLOW SUMMARY ===(\$MILLION) ==== 73 ENERGY GWH 521 REAL PRICE-MILLS 466 INFLATION INDEX 3387 5605 3387 3387 3387 3387 3387 3387 5223 5414 23.79 58.55 55.54 428-31 50.49 458.29 30.81 29.37 25.04 27.83 26.39 32-59 249-28 266.73 285.40 305.38 326.75 349.62 520 PRICE-MILLS 84.97 87.54 237.89 231.37 82.18 83.81 89.00 234.36 31.25 86.24 ----INCOME-----275.2 516 REVENUE 278.3 283.8 287.8 292.1 296.5 301.4 1224.0 1287.8 1296.7 170 LESS OPERATING COSTS 91.1 35.0 38.1 49.6 54.1 99.4 108.5 32.0 41.6 45.4 517 OPERATING INCOME 214 ADD INTEREST EARNED ON FUNDS 550 LESS INTEREST ON SHORT TERM DEBT 391 LESS INTEREST ON LONG TERM DEBT 245.7 1132.9 243.1 243.4 246.6 246.9 247-3 1188.4 1188.2 246.2 6.7 8.0 8.7 9.5 10.4 19.1 20.9 :6 • Z 20.0 11.6 18.7 21.9 34.7 36.3 12-4 15.3 16.4 17.7 182.7 182.0 191.2 130.3 179.3 178.2 883.4 895.7 891.5 59.5 548 NET EARNINGS FROM OPERS 55.0 55.7 57.5 58.4 239.0 277.2 281.4 56.6 60.7 548 CASH INCOME FROM OPERS 446 STATE CONTRIBUTION 58.4 69.7 0.0 239.0 277.2 281.4 57.5 59.5 55.7 55.0 56.6 0.0 0.0 0.0 C.O 0.0 143 LONG TERM DEBT DRAHDOWNS 1473.5 137.8 0.0 368.9 427.7 395.4 1163.0 1432.3 1604-7 0.0 24.7 42.8 128.0 243 WORCAP DEBT DRAWDOWNS 8.1 29.3 11.2 12.2 10.6 10.4 12.3 TOTAL SOURCES OF FUNDS 1546.5 504-8 301.9 324.3 549 1232.7 1501.3 1674.7 432.0 512.8 463.1 320 LESS CAPITAL EXPENDITURE 448 LESS HURCAP AND FUNDS 260 LESS DEBT REPAYMENTS 475.3 442.9 1210.5 1479.8 1654.5 1527.9 90.9 99.2 416.4 362.3 12.3 11.2 9.0 10.4 42.8 29.3 12.2 10.6 128.0 24.7 8.1 9.9 10.9 12.0 42.6 14.5 46.8 ويد تعد أحد 141 CASH SURPLUS(DEFICIT) 249 SHORT TERM DEBT 444 CASH RECOVERED -2.3 0.0 0.0 0.0 0.0 0.0 0.0 143.7 135.4 -6-8 0.0 0.0 0.0 0.0 0.0 -9-1 0.0 0.0 6.8 134.6 0.0 135.4 0.0 0.0 0.0 0.0 0.0 0.0 0.0 225 RESERVE AND CONT. FUND 371 OTHER HORKING CAPITAL 208.8 227.8 30.1 37.4 95.4 104-1 113.7 191.3 67.2 73.4 79.7 84.2 89.1 91.7 93.4 96.2 146.6 153.8 177.6 56.6 CASH SURPLUS RETAINED 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 0.0 14599.1 7355.0 8273.2 10963.5 14698.3 370 CUM. CAPITAL EXPENDITURE 7830.3 9483.7 12618.0 14145.9 14508-2 ------IXXXXXX ---------------*= = = = = = = = = = = = ----------***** 465 CAPITAL EMPLOYED 7478.8 7983.4 8437.5 9660.3 11150.6 12815.6 14355.8 14846-1 14961.7 15103.7 =zz=z=z= -----****** ======= z = : = = = = = ****** -----******** STATE CONTRIBUTION 4806.7 4806.7 4800.7 4806.7 4806.7 4800.7 4806.7 4806.7 4806.7 4306.7 RETAINED EARNINGS DEBT OUTSTANDING-SHORT TERM 203.5 240.1 14.3 462 317.5 376.0 435.5 496.2 735-2 877.8 1023.8 147.8 199.8 362.6 555 123.9 176.6 187.1 219.0 346.9 405.4 554 DEBT OUTSTANDING-LONG TERM 2400.5 2820.0 3236.4 4359.4 5780.8 7373.5 8833.8 8957-1 8914.6 8867 .7 542 ANNUAL DEBT DRAWNDOWN \$1982 543 CUM. DEBT DRAWNDOWN \$1982 393.9 0.0 380.8 459.0 148.0 100.4 .38.5 438.3 34.4 0.0 1157.7 1837.4 3163.0 3163.0 1318.0 1456.6 2275.7 2734.7 3128.6 3163.0 519 DEBT SERVICE COVER 1.25 1.25 1.25 1.25 1-25 1.25 1.25 1.25 1.25 1.25

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1998

1999

2001

2002

2000

2003

2004

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TABLE D.36

TA10K WATANA-DC (ON LINE 1993-2002)-	\$3.0 BN/S	1982) STA	TE FUNDS-	INFLATION	1 7%-INTER	EST 102-0	APCOST \$5	•117 BN	23-F 1900400000	EB-82
	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
			CA ==	SH FLOW S =(\$MILLIS	UMMARY					
21 REAL PRICE-MILLS 66 INFLATION INDEX 20 PRICE-MILLS	6092 43.82 490.37 214.89	6147 40.97 524.69 214.98	6250 38.08 561.42 213.79	34.79 600.72 208.98	32.53 642.77 209.12	30.45 687.77 209.41	28.74 735.91 211.54	6660 27.13 787.42 213.62	25.63 842.54 215.95	
16 REVENUE 70 LESS OPERATING COSTS	1309.0 118.4	1321.4 129.2	1336.1 141.0	1352.4 153.9	1368.4	1385.3 183.4	1404.1 200.1	1422.6 218.4	1442.9 238.4	18656.
17 OPERATING INCOME 14 ADD INTEREST EARNED ON FUNDS 50 LESS INTEREST ON SHORT TERM DEBT 91 LESS INTEREST ON LONG TERM DEBT	1190.6 22.8 40.5 886.8	1192.2 24.9 44.2 881.6	1195.0 27.1 49.3 876.0	1198.5 29.6 55.2 869.7	1200.4 32.3 59.8 862.9	1202.0 35.3 64.4 855.3	1204.0 38.5 69.6 847.0	1204•2 42•0 73•4 837•9	1204.5 45.9 77.5 827.9	16454. 412. 748. 12013.
48 NET EARNINGS FROM UPERS	286•1	291.2	296.9	303.1	310.0	317.5	325.8	335.0	345.0	4104.
CASH SOURCE AND USE 43 CASH INCOME FROM OPERS 46 STATE CUNTRIBUTION 43 LONG YERM CEBT DRAWDOWNS 43 WORCAP DEBT DRAWDOWNS	286.1 9.0 0.0 36.4	291-2 0.0 0.0 51-3	296.9 0.0 0.0 59.3	303.1 0.0 0.0 45.8	310.0 0.0 0.0 45.9	317.5 0.0 0.0 52.0	325.8 0.0 0.0 37.7	335.0 0.0 0.0 41.2	345.0 0.0 0.0 44.9	4104. 4806. 9049. 819.
47 TOTAL SOURCES OF FUNDS	322.5	342.5	356.2	349.0	355.9	369.5	363.6	376.1	389.9	18780.
20 LESS CAPITAL EXPENDITURE 43 LESS HORCAP AND FUNDS 60 LESS DEBT REPAYMENTS	108.2 36.4 51.5	118.1 51.3 56.7	128.9 59.3 62.3	140•7 45•8 68•6	153.6 45.9 75.4	167.6 52.0 83.0	182.9 37.7 91.3	199.7 41.2 100.4	217.9 44.9 110.4	16115. 819. 880.
41 CASH SURPLUS(DEFICIT) 49 SHORT TERM DEBT 44 CASH RECOVERED	125+3 0+0 126+3	116.4 0.0 116.4	105.6 0.0 105.6	93•9 0•0 93•9	81.0 0.0 81.0	67.0 0.0 67.0	51.6 0.0 51.6	34.9 0 34.9	16.7 0.0 16.7	963. 0. 963.
25 RESERVE AND CONT. FUND 71 OTHER HORKING CAPITAL 54 CASH SURPLUS RETAINED 70 CUM. CAPITAL EXPENDITURE	249.7 193.2 0.0 14306.5	271.4 221.7 0.0 14924.6	296.2 256.2 0.0 15053.6	323.3 274.9 0.0 15194.3	352.8 291.2 0.0 15347.9	385.1 310.9 0.0 15515.5	420.3 313.4 0.0 15698.4	458.7 316.2 0.0 15898.1	500.6 319.2 0.0 16116.0	500. 319. 0. 16116.
65 CAPITAL EMPLOYED	15248.3	15417.7	15605.9	15792.4	15971.9	16211.4	16432.1	16672.9	16935.7	16935.
61 STATE CONTRIBUTION 62 RETAINED EARNINGS 55 DEBT OUTSTANDING-SHORT TER ⁽) 54 DEBT OUTSTANDING-LUNG TERM	4806.7 1183.5 441.3 8816.2	4806 • 7 1358 • 3 493 • 1 8759 • 5	4806.7 1549.6 552.4 8697.2	4806.7 1758.9 598.2 3628.6	4806.7 1987.9 644.0 8553.2	4806.7 2238.5 696.0 8470.2	4806.7 2512.7 733.7 8378.9	4806.7 2812.8 774.8 8278.6	4806.7 3141.1 819.7 8168.1	4806. 3141. 819. 8168.
42 ANNUAL DEBT DRAWHDOWN \$1982 43 CUM. DEBT DRAWHDOWN \$1982 19 DEBT SERVICE COVER	9.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	0.0 3163.0 1.25	3163 • 3163 • 0 • 0

7% INFLATION AND 10% INTEREST

TABLE D.36

Sheet 3 of 3

CUMULATIVE CASH FLOW-(WILLIONS OF DOLLARS) ~~ ~**5**00 P ÷ CUMULATIVE CASH FLOW ANNUAL CASH FLOW YEARS

> WATANA DEVELOPMENT CUMULATIVE AND ANNUAL CASH FLOW JANUARY, 1982 DOLLARS



FIGURE D.I

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DEVIL CANYON DEVELOPMENT CUMULATIVE AND ANNUAL CASH FLOW JANUARY, 1982 DOLLARS

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400 SC, 00 300 õ 200 Ξ NO 14 НS 100 5 \mathbf{z} ÅN 0 FIGURE D.2

6500 6000 . 5500 5000 . ٠ 4500 DOLLARS) 4000 R - CUMULATIVE CASH FLOW MILLIONS 3500 . . - - - -3000 FLOW CASH 2500 CUMULATIVE 2000 WATANA DEVIL CANYON 1500 1000 500 ANNUAL CASH FLOW 0 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 YEARS

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SUSITNA HYDROELECTRIC PROJECT CUMULATIVE & ANNUAL CASH FLOW ENTIRE PROJECT JANUARY, 1982 DOLLARS

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FIGURE D.3









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3 - 1000 MW 1954 2 1944 1534 1508 1442 CAPACITY PEAK LOAD 1079 965 948 846 700 715 245 189 103 0 1980 1990 2000 2010 10 LEGENU NYDROELECTRIC COAL FIRED THERMAL 8 GAS FIRED THERMAL OIL FIRED THERMAL (NOT SHOWN ON ENERGY DIAGRAM) NOTE : RESULTS OBTAINED FROM OGPS RUN LFL7 GWH 6 - 1000 ENERGY TOTAL DISPATCHED ENERGY. SNOW KEETNA 2 -CHAKACHAMNA EXISTING AND COMMITTED 0 1980 1990 2000 2010 TIME GENERATION SCENARIO INCORPORATING THERMAL AND ALTERNATIVE HYDROPOWER DEVELOPMENTS - MEDIUM LOAD FORECAST -FIGURE D.14

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LOAD	ALTERNATIVE	FUEL COST	RESULT		LONG-TERM COST
FORECAST	CAPITAL COST	ESCALATION	<u></u>	PROBABILITY	PRESENT WORTH
	HIGH OA	HIGH	TOI	.01	\$15,058
		100	- T02	,02	11,569
		Z	- TO3	.01	7,624
NICH 20	TO MEDILIAA 12	. Januar and the second se	- TO4	<u> </u>	14,184
			- TO5	.08	10,859
	NO 1		TC6	.03	7,313
	1000	Junior and the second se	- T07	.01	13,742
	LDW .04		TOB	.02	10,503
			- 109	.61	7,184
				.03	11.272
N N	HIGH J2			.06	R.858
				.03	5.901
	30			.08	10 837
60 MEDIUM 60	GO MEDIUM 36			18	5.238
N	30	·	-1 +15	.09	8.661
\mathbf{N}			TIG	63	10.321
6	LOW .12] +/¥	.08	7.915
				.03	5,400
$\left\{ 1, 1, N_{1}^{2}, \dots, N_{n}^{2}, \dots, N_{n}^{n} \right\}$			- TI9	.01	9,253
	HIGH .04		- 120	.02	7,460
$1 \rightarrow \infty$			-1 121	.01	4,856
	20	·	- T22	.03	8,746
LOW 20	.60 MEDIUM .12	<u> </u>	T23	.06	6,878
	- Co		- T24	.03	4,590
		HIGH	T25	.01	8.492
	LOW .04	NEDIUM	- T26	.02	9.101
		Ve LOW	- T27	.01	4,412
				Σ = 1.00	

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 $\Sigma = 1.00$

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FIGURE D.I7- PROBABILITY TREE - SYSTEM WITH ALTERNATIVES TO SUSITNA

FIGURE D.I8- PROBABILITY TREE - SYSTEM WITH SUSITNA



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FIGURE D.20 - SUSITNA MULTIVARIATE SENSITIVITY ANALYSIS - CUMULATIVE PROBABILITY VS NET BENEFITS

