SUSITNA HYDROELECTRIC PROJECT

FERC LICENSE APPLICATION

EXHIBIT D

FIRST DRAFT

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ALASKA POWER AUTHORITY

EXHIBIT D - PROJECT COSTS AND FINANCING

TABLE OF CONTENTS

EXHIBIT D - TABLE OF CONTENTS (Continued)

EXHIBIT D - TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF FIGURES

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:

Group	Description
Production Plant	Costs for structures, equipment, and facilities necessary to produce power.
Transmission Plant	Costs for structures, equipment, and facilities necessary to transmit power from the sites to load centers.
General Plant	Costs for equipment and facilities required for the operation and maintenance of the production and transmission plant.
Indirect Costs	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

(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 contractors will work an average of two 9-hour shifts per day, 6 days per week, with an expected range as follows:

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

These assumptions provide 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. Fuel and oil prices have also been included 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, adjusted for Alaskan conditions.

(d) Seasonal Influences on Productivity

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 therefore 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 $149 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, based on this procedure, is approximately $9 million. These costs have been assumed to be covered by 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

  . 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 aspects 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

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 (Account 72).

1.4 - 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.

1.5 - Escalation

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.

1.6 - 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 Figures D.1 through D.3. The manpower loading requirements (5) were developed from cash flow projections. These curves were used as the basis for camp loading and associated socioeconomic impact studies.

1.7 - 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.

1.8 - 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 $____________.

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.5 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.

Table D.6 provides a reconstruction of the annual cost of power for 2003 in both 1982 and 2003 price levels. An underlying 7 percent inflation rate has been assumed.

It is expected that the State of Alaska will introduce financial measures which will have the affect of reducing the cost of Susitna energy thus enabling its long term economic advantages to be realized without excessively high early year costs to consumers.

3 - MARKET VALUE OF PROJECT POWER

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.8. The service areas of these utilities are shown in Figure D.5 and the generating plants serving the region are listed in Table D.9.

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

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.

It will be necessary 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 will be constrained by both cost (as defined by Alaska Senate Bill 25) 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 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 low cost energy.

3.4 - Market Price for Watana Output 1995-2001

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

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.

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 increasing total savings to the system from Susitna with no associated increase in costs.

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

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, an attractive basis exists, particularly in the long term, for the Railbelt utilities to derive benefit from the Project.

4 - EVALUATION OF ALTERNATIVE ENERGY PLAN

4.1 - General

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 generation 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 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 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.10 summarizes the total generating capacity within the Railbelt system in 1980, based on information provided by Railbelt utilities and other sources. Table D.11 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.12.

(b) Retirement Schedule

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.12 lists the retirement dates for each of the current generating units based on the above retirement policy.

(c) Schedule of Additions

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 90 and 135 MW of installed capacity and would produce an annual average energy of 350 Gwn. 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. 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

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.13, 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.13.

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

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.14 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

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.

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

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-fired combined-cycle;

- Gas-fired gas turbine; and

- Diesel.

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 fuel 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.15.

(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.15.

(ii) Fuel Costs

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.15.

(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.11). 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 growth 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.15.

(e) Diesel Power Generation

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.15.

(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.15.

(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.

Thus, it should be recognized that the production costs modeled represent only a portion of ultimate consumer costs and in effect are only a portion, albeit major, of total costs.

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

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 Fired Unit (MW)
1993		1 x 200 (Beluga Coal)
1994		1 x 200 (Beluga Coal)
1996		1 x 200 (Nenana/Healy Coal)
1997	1 x 70	
1998	1 x 70	
2001	1 x 70	
2003	1 x 70	
2004	1 x 70	
2005	2 x 70	
2006	1 x 70	
2007		1 x 200 (Beluga Coal)
2009	1 x 70	
Total	630	800

(c) System as of 2010

Coal-fired steam:	813 MW
Natural gas GT:	746 MW
Oil GT:	0 MW
Diesel:	6 MW
Natural gas CC:	317 MW
Hydropower:	155 MW
Total (accounting for retirements and additions)	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 Project 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

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 (confidence 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 solely 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 short-term 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 real 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 socially-desirable 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.16, 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 throughout 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

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* (1 + the nominal rate) = (1 + the real rate) x (1 + 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).

- 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 markets.

. Domestic Market Prices

Table D.17 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.17 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 opportunity 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

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. $/ton) (25). This is 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).

- Survey of Forecasts

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

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* 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.18 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.

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

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* 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.18 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.18 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.19. 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 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 period 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

- Pattern 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.20. 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 (inflation-adjusted) 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 (inflation-inclusive) 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.

. <u>Zero Growth in Long-term Costs</u>

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.

. <u>Loss of Load Probabilities</u>

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

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* $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) Sensitivity Analysis

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;

- Base period fuel price;

- Real escalation in capital costs, O&M costs, and fuel prices;

- System reliability;

- Chackachamna; and

- Susitna Project delay.

Tables D.22 to D.29 depict the results of the sensitivity analysis. In particular, Table D.29 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 multivariate 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 Costs</u>

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 an associated probability of .018. The single comparison 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 supported 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

[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 power 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 Susitna 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

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.30. 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 planning 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_x) 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) Coal Gasifier - Combined-Cycle Plants

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_x, SO_x 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, CO_2 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

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 economc 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 consideation 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 CO_2 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-center 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 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) Conventional Hydroelectric Plants

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 favorable 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 prototype 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 several 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 power 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.31.

(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:

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

where:

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

In turn:

$$PWCP = \sum_{i=1}^{n} \frac{TAC_i}{EPP_i} * \frac{1}{(1+d)^i}$$

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.

Levelized Cost of Power (mills/kWh)

	Low Economic Scenario		Medium Economic Scenario		High Economic Scenario	
	1981-2010	1981-2050	1981-2010	1981-2050	1981-2010	1981-2050
Plan 1A	58	65	58	64	60	66
Plan 1B	58	63	58	59	58	60
Plan 2A	58	66	59	66	58	66
Plan 2B	57	61	58	61	57	69
Plan 3	58	67	59	65	62	68
Plan 4	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 plans 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

- 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 1B: 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 senstivity 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

- 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 combined-cycle 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.

- 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.

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

5 - CONSEQUENCES OF LICENSE DENIAL

5.1 - Cost of License Denial

The forecast energy demand for the Railbelt through the year 2010 can be met without constructing the Watana-Devil Canyon hydroelectric project. 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. Further, there is a 0.5 probability that this net benefit will be exceeded, and only a 0.36 probability that the net benefit will fall below $0.5 billion.

Therefore, the consequences of license denial will be the probable costs mentioned above.

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

6.1 - Financial Evaluation

(a) Forecast Financial Parameters

The financial, economic, and engineering estimates used in the financial analysis are summarized in Table D.7. 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 tax-liable 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 tax-liable 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.

(b) 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 specific measures are taken 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.

(c) Basic Financial Options

A range of financing options compatible with the conditions laid down in Senate Bill 25 have been considered as a means of meeting the inflationary financing deficit. The options basically consist of a range of appropriations by the State of Alaska with the balance of the project financing made up by either 35-year tax-exempt revenue bonds or by a combination of General Obligation (G.O.) bonds and 35-year revenue bonds, with the G.O. bonds refinanced into revenue bonds at the earliest opportunity. Throughout central estimates of capital costs, revenues, etc., are used.

(i) 100 Percent State Appropriation of Total Capital Cost ($5.1 billion in 1982 dollars)

This conforms to the possible outcome of Senate Bill 25 and represents the simplest financing option. It could take the form of the State of Alaska appropriating funds to meet capital costs as incurred over the 15-year construction schedule detailed in Table D.33.

On the basis of the present wholesale energy rate setting requirement incorporated in Senate Bill 25, the Power Authority would, however, not be able to charge more than the actual costs incurred. Given that in this case the only costs would be the very small year-to-year operating costs, this option would involve the output from Susitna being supplied at only a fraction of the price of electricity from the best thermal option.

(ii) State Appropriation of $3 Billion (in 1982 dollars) with Residual Bond Financing

The outcome for this option is summarized in Figure D.22 and Table D.34. It would still enable Susitna energy to be produced at a price 46 percent less than that of the best thermal option. It would also enable the project to be completed with only $0.9 billion (in 1982 dollars) of revenue bonds or G.O. bonds over the period 1991-93. The Devil Canyon stage could then be completed with a further $2.3 billion (in 1982 dollars) of revenue bonds over the period 1994 to 2002.

This level of appropriation would enable Susitna energy prices to be held virtually constant at their initial level for nearly a decade. A temporary "step-up" in price of Susitna output to the cost of the electricity from the best thermal option would be required when Devil Canyon was completed on the basis of its 100 percent revenue bond financing. Thereafter, however, the cost of the Susitna energy would again stabilize and give ever-increasing savings compared with cost of the best thermal option.

(iii) "Minimum" State Appropriation of $2.3 Billion (in 1982 dollars) with Residual Bond Financing

The "minimum" state appropriation is taken as the minimum amount required to meet a debt service cover of 1.25 on the residual debt financing by revenue bonds and makes Susitna's wholesale energy price competitive with the best thermal option in its first normal cost year (1994). This level of appropriation would require \$1.7 billion (in 1982 dollars) of bond financing in 1990-93 and a further \$2.1 billion (in 1982 dollars) over the period 1994 to 2002 to complete Devil Canyon (see Figure D.23 and Table D.35).

These levels of state appropriation would all therefore eliminate Susitna's "inflationary financing deficit".

(d) Issues Arising from the Basic Financing Options

(i) Need for Financial Restructuring

Irrespective of Susitna being chosen as the best means of meeting the Railbelt energy needs, significant financial restructuring of some Railbelt utilities will be required to enable them to offer adequate financial security in their power contracts and debt financing to meet generation expansion. It is assumed that this restructuring will take place.

(ii) Tax-exempt Bond Financing

In the \$2.3 billion state appropriation case interest cost, on the basis of tax-exempt financing, accounts for 90 percent of the unit price of Susitna output in 1994. Failure to obtain tax-exempt bond financing would increase these interest costs by approximately one-quarter. Ensuring tax-exempt status for the Susitna bond issues is therefore of fundamental importance to the economics of the project under these options.

This issue has been extensively reviewed by tax advisers and consultants and it has been concluded that at the stage at which bond financing is required in the early 1990s, tax-exempt financing should be possible in compliance with Section 103 of the IRS code.

(iii) Options for Residual Financing

Tables D.36 and D.37 set out the estimated requirements for bond financing with state appropriations of \$3 billion and \$2.3 billion respectively. Several options available to meet these financing needs are summarized below.

- Revenue Bonds with a Completion Guarantee
  A completion guarantee must be assumed to be a precondition of bond financing at the Watana stage (up to 1993).

A State of Alaska guarantee of project completion would probably enable all residual financing to be met by revenue bonds. (The completion guarantee may of necessity have to take the form of a G.O. bond authorization of an amount to be determined prior to the timing of the issuance of revenue bonds).

- Guaranteed Revenue Bonds with Post-Completion Refinancing

If the revenue bonds were guaranteed by the State of Alaska they could be issued without the provision of a completion guarantee.

- G.O. Bonds with Post-Completion Refinancing

G.O. Bonds on the "full faith and credit" of the State of Alaska are effectively identical to guaranteed revenue bonds and would also avoid the necessity of a completion guarantee.

In this case, as with that of guaranteed revenue bonds, the burden on the credit of the state could be minimized by making the bonds subject to "call" after a few years (when project viability was established) and refinancing into non-guaranteed revenue bonds.

(iv) Refinancing Watana and the Financing of Devil Canyon

Early refinancing of any guaranteed or G.O. bonds used to finance Watana, and the ongoing financing of Devil Canyon entirely by revenue bonds is taken to be an important financing objective. The main factor determining the date at which such refinancing will be possible is the magnitude of the initial state appropriation.

The basic conclusion from the analysis is that, with a state appropriation of $2.3 billion (in 1982 dollars), there is a very high degree of certainty that refinancing into non-guaranteed revenue bonds could occur within a few years of project completion.

(v) Importance of Adequate State Appropriation

The principal effect of appropriations significantly less than $2.3 billion would be a possible need for additional guaranteed or G.O. bond financing for Devil Canyon. This is because the impact of lesser appropriations would (as illustrated in Figure D.24) give rise to inadequate earnings coverage in the early years of Watana, and subsequently Devil Canyon, so that the raising of revenue bonds requiring such cover would have to be delayed. In addition, such inadequate funding would force the Susitna price to "track" the cost of energy from the best thermal option until adequate revenue had been built up to allow such refinancing.

(vi) Impact on State Credit Rating of Guaranteed or G.O. Bond Financing

The impact on state credit rating of guaranteed or G.O. bond financing of the order of $1.7 billion in the $2.3 billion (both in 1982 dollars) state appropriation case has been assessed by the Alaska Power Authority's investment banking and financial advisers First Boston Corporation and First Southwest Company. They have concurred in the following statement.

> "We are only able to render a conditional estimate of the possible impact on the credit of the State of Alaska as a result of the contemplated general obligation bond financing of $1.7 billion for the Watana stage of the Susitna hydroelectric project. Alaska's presently favorable ratings are greatly influenced by it's low debt to assessed value ratio which helps to overcome the unusually high per capita debt statistics. Given the dramatic growth of assessed valuation and the fact that interest expense through start-up of Watana is to be capitalized from bond proceeds the envisaged financing should not significantly impair the credit of the state. Even if the State of Alaska's general obligation bond rating were reduced one full letter grade, the cost in terms of interest rates on future bond issues would likely be in the approximate range of 1/4 percent to 1/2 percent per annum."

(e) Financing Options Under Senate Bill 646 and House Bill 655

As proposed these bills would permit financing of approved energy developments by state funding to be repaid at the rate of 3 percent per annum with an "uplift" reflecting past inflation.

(i) 100 Percent State Appropriation

The outcome in this case is illustrated in Figure D.25 and would differ from that covered by the outright appropriation (c) (i) above in that the resulting charge for Susitna energy to cover the repayment of state funding would be 81 mills/kWh in 1994 compared with 19 mills/kWh in the (c) (i) case.

(ii) "Minimum" State Appropriation of $3 Billion (in 1982 dollars)

The outcome of a state appropriation of $3 billion (in 1982 dollars) is shown in Figure D.26. This also would differ from the $3 billion outright appropriation dealt with in (c) (ii) in representing the minimum compatible with residual financing by revenue bonds, since the increasing payments to the state create an earnings cover shortfall in 2003. It would also result in a consequent higher charge for Susitna energy. In this case it would be 120 mills/kWh in 1994 compared with 80 mills/kWh under (c) (ii).

In both (i) and (ii) Susitna energy would still be produced at a price competitive with the best thermal option. These scenarios would also be compatible (subject to certain legislative requirements) with residual financing by revenue bonds.

(f) Future Development and Resolution of Uncertainties

Prior to the decision to proceed with actual construction of Susitna, several significant uncertainties affecting the project will have been reduced. Demand forecasts will be more certain and the impact of the electrical intertie between Anchorage and Fairbanks will be known. Fuel cost trends and energy prices from alternative generation sources will be more precisely known. More advanced engineering work and definition of the basis for construction contracts will have firmed up requirements for capital funds. In addition, the passage of time will have allowed better definition of the level of state appropriation required and the ability of the state to provide the necessary financial support.

The development of the institutional structure of the Railbelt utilities by this date should also permit power contracts and legislative proposals to be drawn up which would equitably share these then more clearly delineated risks between the utilities, the Power Authority and the State of Alaska. The key requirements for state guarantees and financing could then be more precisely defined in an appropriately limited form which would be acceptable to the state and adequate for project financing.

(g) Conclusion

The principal conclusion of the financial evaluation is that with a state appropriation of not less than $2.3 billion (in 1982 dollars) and consent for guaranteed or G.O. bond financing of $1.7 billion (in 1982 dollars), Susitna would be financially viable. It would also be able to market its output at an initial price competitive with the most efficient thermal option and produce substantial long-term savings compared with this option.

The evaluation, however, stressed the importance of establishing the project on a strong financial basis that would enable it to secure conversion of the guaranteed or G.O. bonds issued for the construction of Watana into non-guaranteed revenue bonds and obtain a highly competitive rate of interest. These objectives (together with the marketing of the Watana output in 1994 and a price 46 percent below that of the most efficient thermal option), could be secured by state appropriation of $3.0 billion (in 1982 dollars).

It should also be noted that the cost benefit analysis shows that full recovery long-term of any state appropriation would be possible with a better than 10 percent rate of return. Meeting the Susitna "inflationary financing deficit" by such appropriations can therefore be considered as a separate issue from subsidization of electricity prices by foregoing recovery of all or part of the state appropriation designed to meet this deficit.

6.2 - Financial Risk

The financial risks considered are those arising to the State of Alaska and to Alaskan consumers. The analysis of these risks is restricted to the period up to 2001 covering the completion of Watana and its first eight years of operation.

(a) Pre-completion Risk

The major pre-completion risk is simply the risk that the project will not be completed. The possibility of this arising owing to natural hazard has a negligibly small probability of occurrence, based on the risk analysis described in Reference 31.

The risk of non-completion owing to capital overrun is also assessed to have negligible probability. This is on the grounds that the project only involves well-established technology, has been extensively evaluated by Acres and wholly independent consultants and shown by formal probability analysis to have only a 27 to 20 percent probability of any real capital overrun.

(b) Post-completion Risks

(i) The Generation of Post-completion Risks

A probabilistic financial model was developed taking into account the probability distributions of the major engineering and financial variables on which the financial outcome for Susitna depends. This model, the basic parameters of which are given in Table D.38, was then used to consider in detail critical specific and aggregative risks posed by the project.

(ii) Specific Risks

- Specific Risk I; Risk of Bond Requirement Overrun (Figure D.27)

  Extensive analysis was undertaken to assess the probability that the bond financing requirements would overrun the forecast values as a result of capital costs, inflation, interest rates, etc., being less favorable than forecast. In the $2.3 billion state appropriation case it was found that the probability of the bond financing requirement exceeding the forecast of $1.7 billion (in 1982 dollars) by more than 50 percent was only 0.12. There is also a significant probability (0.71) that the bond financing requirements will be less than the forecast $1.7 billion.

- Specific Risk II; Inadequate Debt Service Cover (Figure D.28)

  Adverse impact on state credit rating might occur if the project failed to earn adequate debt service and cover and consequently conversion into non-guaranteed revenue bonds was delayed. The analysis showed that in the $2.3 billion state appropriation case:

  . The probability of forecast coverage being less than adequate (1.25 coverage) in 1994 (first normal year of Watana) is 0.22.

  Given that the probability of coverage shortfall diminishes with time (due to increased cost of alternative fuels), the risk of delayed conversion due to inadequate cover is minimal.

- Specific Risk III; Early Year Non-viability (Figure D.29

  The measure of financial non-viability in the early years is taken as the ratio of Watana's unit cost to the costs of the best thermal option in Watana's third year (1996). (For comparability excess debt service cover was excluded.) If this ratio is less than forecast it would reflect "non-viability" in the sense of the project not realizing its forecast savings in these important early years. This analysis indicates that in the $2.3 billion appropriation case there is only a 0.29 chance of the Susitna costs exceeding their forecast value (51 percent of the best thermal).

(iii) The Aggregate Risk

While specific risks of the type considered above are of importance basic concern must center on the aggregate risk. In long-term economics this is measured by the risk attaching to the rate of return. For the purpose of the financial risk, however, it is taken as represented by accumulative net operating earnings at the end of the first eight years of operation of Watana. Since this statistic is net of interest and debt repayment, it effectively subsumes all the risks involved in capital expenditure, inflation, interest rates, revenue, etc., deviating from their forecast values. This statistic was also adjusted to allow the pricing up of Watana energy to the cost of the best thermal option so that the statistic reflects the "upside" risk as well as the "downside."

On this basis in the $2.3 billion state appropriation case the statistic (see Figure D.30) was found to have only a 0.27 chance of being below forecast level of $0.8 billion (in 1982 dollars) by more than $0.2 billion. There is also a 0.73 probability of the statistic exceeding $0.8 billion and thus creating greater savings for the Alaskan comsumer.

(c) Conclusions

The analysis shows the exposure of the project, either to critical specific risks or to aggregative risk, at the Watana stage is relatively limited. The qualification attaching to this analysis is that the estimates and probabilities used are free from any systematic biases. The structure of the plan of the overall plan of study for Susitna and analysis of its alternatives has, however, been specifically designed to take every reasonable precaution against this possibility by seeking extensive independent verification of the key variables by Batelle and Ebasco operating wholly as independent consultants.

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TABLE D.1: SUMMARY OF COST ESTIMATE

Category	Watana	Devil Canyon	Total
	January 1982 Dollars $ X 10^6		
Production Plant	$1,986	$ 835	$2,821
Transmission Plant	391	91	482
General Plant	5	5	10
Indirect	378	188	566
Subtotal	$2,760	$ 1,119	$3,879
Contingency 17.5%	482	196	678
Total Construction	$3,242	$ 1,315	$4,557
Overhead Construction	405	165	570
TOTAL PROJECT	$3,647	$1,480	$5,127

ACRES

ESTIMATE SUMMARY

TABLE D.2

WATANA

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00
FILE NUMBER: P5700.14.09
SHEET 1 OF 5
BY JRP DATE 2/82
CHKD DATE

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	PRODUCTION PLANT						
330	Land & Land Rights				$ 51		
331	Powerplant Structures & Improvements				73		
332	Reservoir, Dams & Waterways				1,532		
333	Waterwheels, Turbines & Generators				65		
334	Accessory Electrical Equipment				21		
335	Miscellaneous Powerplant Equipment (Mechanical)				14		
336	Roads & Railroads				230		
	TOTAL PRODUCTION PLANT					$ 1,986	

ACRES

ESTIMATE SUMMARY

TABLE D.2

WATANA

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00

FILE NUMBER: P5700.14.09

SHEET 2 OF 5

BY: JRP DATE: 2/82

CHKD: DATE:

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT ($x 10^6$)	TOTALS ($x 10^6$)	REMARKS
	TOTAL BROUGHT FORWARD					$ 1,986	
	TRANSMISSION PLANT						
350	Land & Land Rights				$ 8		
352	Substation & Switching Station Structures & Improvements				12		
353	Substation & Switching Station Equipment				129		
354	Steel Towers & Fixtures				130		
356	Overhead Conductors & Devices				99		
359	Roads & Trails				13		
	TOTAL TRANSMISSION PLANT					$ 391	
						$ 2,377	

ESTIMATE SUMMARY

TABLE D.2

WATANA

ACRES

CLIENT: ALASKA POWER AUTHORITY

TYPE OF ESTIMATE: Feasibility

PROJECT: SUSITNA HYDROELECTRIC PROJECT

APPROVED BY: JDL

JOB NUMBER: P5700.00
FILE NUMBER: P5700.14.09
SHEET 3 OF 5
BY: JRP DATE: 2/82
CHKD: DATE:

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD					$ 2,382	
	INDIRECT COSTS						
61	Temporary Construction Facilities				$ -		See Note
62	Construction Equipment				-		See Note
63	Camp & Commissary				378		
64	Labor Expense				-		
65	Superintendence				-		See Note
66	Insurance				-		See Note
69	Fees				-		See Note
	Note: Costs under accounts 61, 62, 64, 65, 66, and 69 are included in the appropriate direct costs listed above.						
	TOTAL INDIRECT COSTS					$ 378	
						$ 2,760	

87.02.03. Form 134A.

ACRES

ESTIMATE SUMMARY

TABLE D.2

WATANA

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00

FILE NUMBER: P5700.14.09

SHEET 4 OF 5

BY: JRP DATE: 2/82

CHKD: DATE:

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					($\times 10^6$)	($\times 10^6$)	
	TOTAL BROUGHT FORWARD (Construction Costs)					$ 2,760	
	Contingency 17.5%					482	
	TOTAL CONSTRUCTION COSTS					$ 3,242	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)						
71	Engineering/ Administration				$ 405		
72	Legal Expenses				-		Included in 71
75	Taxes				-		Not applicable
76	Administrative & General Expenses				-		Included in 71
77	Interest				-		Not included
80	Earnings/Expenses During Construction				-		Not included
	Total Overhead					405	
	TOTAL PROJECT COST					$ 3,647	

ACRES

ESTIMATE SUMMARY

TABLE D.2

WATANA

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00

FILE NUMBER: P5700.14.09

SHEET 5 OF 5

BY: JRP DATE: 2/82

CHKD: DATE:

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD					$ 2,377	
	GENERAL PLANT						
389	Land & Land Rights				$ -		Included under 330
390	Structures & Improvements				-		Included under 331
391	Office Furniture/Equipment						Included under 399
392	Transportation Equipment						" "
393	Stores Equipment						" "
394	Tools Shop & Garage Equipment						" "
395	Laboratory Equipment						" "
396	Power-Operated Equipment						" "
397	Communications Equipment						" "
398	Miscellaneous Equipment						" "
399	Other Tangible Property				5		
	TOTAL GENERAL PLANT					$ 5	
						$ 2,382	

ESTIMATE SUMMARY

TABLE D.3

DEVIL CANYON

ACRES

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00
FILE NUMBER: P5700.14.09
SHEET 1 OF 5
BY: JRP DATE: 2/82
CHKD: DATE:

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	PRODUCTION PLANT						
330	Land & Land Rights				$ 22		
331	Powerplant Structures & Improvements				71		
332	Reservoir, Dams & Waterways				635		
333	Waterwheels, Turbines & Generators				42		
334	Accessory Electrical Equipment				14		
335	Miscellaneous Powerplant Equipment (Mechanical)				12		
336	Roads & Railroads				39		
	TOTAL PRODUCTION PLANT					$ 835	

ESTIMATE SUMMARY

TABLE D.3

DEVIL CANYON

ACRES

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00
FILE NUMBER: P5700.14.09
SHEET 2 OF 5
BY JRP DATE 2/82
CHKD DATE

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD					$ 835	
	TRANSMISSION PLANT						
350	Land & Land Rights				$ –		Included in Watana Estimate
352	Substation & Switching Station Structures & Improvements				7		
353	Substation & Switching Station Equipment				21		
354	Steel Towers & Fixtures				29		
356	Overhead Conductors & Devices				34		
359	Roads & Trails				–		Included in Watana Estimate
	TOTAL TRANSMISSION PLANT					$ 91	
						$ 926	

ACRES

ESTIMATE SUMMARY

TABLE D.3

DEVIL CANYON

CLIENT ALASKA POWER AUTHORITY

PROJECT SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE Feasibility

APPROVED BY JDL

JOB NUMBER P5700.00

FILE NUMBER P5700.14.09

SHEET 3 OF 5

BY JRP DATE 2782

CHKD DATE

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD					$ 926	
	GENERAL PLANT						
389	Land & Land Rights				$		Included under 330
390	Structures & Improvements						Included under 331
391	Office Furniture/Equipment						Included under 399
392	Transportation Equipment						" "
393	Stores Equipment						" "
394	Tools Shop & Garage Equipment						" "
395	Laboratory Equipment						" "
396	Power Operated Equipment						" "
397	Communications Equipment						" "
398	Miscellaneous Equipment						" "
399	Other Tangible Property				5		
	TOTAL GENERAL PLANT					$ 5	
						$ 931	

87.02.03. Form 134A

ACRES

ESTIMATE SUMMARY

TABLE D.3

DEVIL CANYON

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00

FILE NUMBER: P5700.14.09

SHEET 4 OF 5

BY JRP DATE 2/82

CHKD DATE

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD					$ 931	
	INDIRECT COSTS						
61	Temporary Construction Facilities				$ -		See Note
62	Construction Equipment				-		See Note
63	Camp & Commissary				188		
64	Labor Expense				-		See Note
65	Superintendence				-		See Note
66	Insurance				-		See Note
69	Fees				-		See Note
	Note: Costs under accounts 61, 62, 64, 65, 66, and 69 are included in the appropriate direct costs listed above.						
	TOTAL INDIRECT COSTS					$ 188	
						$ 1,119	

ACRES

ESTIMATE SUMMARY

TABLE D.3

DEVIL CANYON

CLIENT: ALASKA POWER AUTHORITY

PROJECT: SUSITNA HYDROELECTRIC PROJECT

TYPE OF ESTIMATE: Feasibility

APPROVED BY: JDL

JOB NUMBER: P5700.00

FILE NUMBER: P5700.14.09

SHEET 5 OF 5

BY JRP DATE 2/82

CHKD DATE

No.	DESCRIPTION	QUANTITY	UNIT	COST/UNIT	AMOUNT	TOTALS	REMARKS
					(x 10^6)	(x 10^6)	
	TOTAL BROUGHT FORWARD (Construction Costs)					$ 1,119	
	Contingency 17.5%					196	
	TOTAL CONSTRUCTION COSTS					1,315	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)						
71	Engineering				$ 165		
72	Legal Expenses				-		Included in 71
75	Taxes				-		Not Applicable
76	Administrative & General Expenses				-		Included in 71
77	Interest				-		Not Included
80	Earnings/Expenses During Construction				-		Not Included
	Total Overhead Costs					165	
	TOTAL PROJECT COST					$ 1,480	

57.02.03. Form 134A

TABLE D.4: MITIGATION MEASURES - SUMMARY OF COSTS INCORPORATED IN CONSTRUCTION COST ESTIMATES

COSTS INCORPORATED IN CONSTRUCTION ESTIMATES	WATANA $\$ \times 10^3$	DEVIL CANYON $\$ \times 10^3$	
Outlet Facilities			
Main Dam at Devil Canyon		14,610	
Tunnel Spillway at Watana	47,050		
Restoration of Borrow Area D	1,617	NA	
Restoration of Borrow Area F	551	NA	
Restoration of Camp and Village	2,260	990	
Restoration of Construction Sites	4,050	2,016	
Fencing around Camp	350	217	
Fencing around Garbage Disposal Area	125	125	
Multilevel Intake Structure	18,400	NA	
Camp Facilities Associated with trying to Keep Workers out of Local Communities	10,156	9,000	
Restoration of Haul Roads	756	505	
SUBTOTAL	85,315	27,463	
Contingency 17.5%	14,930	4,806	
TOTAL CONSTRUCTION	100,245	32,269	
Engineering 12.5%	12,530	4,034	
TOTAL PROJECT	112,775	36,303	149,078

DATA9H WATANA-DC (ON LINE 1993-2002)-NO FUND-NO STATE CONTR.-INFLATION 7%-INTEREST 10%-CAPITAL COST $5.117 BN 20-JAN-82

CASH FLOW SUMMARY
===($MILLION)====

		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73	ENERGY GWH	3387	3387	3397	3387	3387	3387	3387	5721	5844	5968
521	REAL PRICE-MILLS	119.63	112.91	105.53	99.59	93.98	87.83	82.87	47.60	79.11	72.76
466	INFLATION INDEX	249.23	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
399	PRICE-MILLS	298.22	301.17	301.17	304.13	307.08	307.08	310.03	190.54	338.83	333.47
	-----INCOME-----------------										
210	REVENUE	1010.0	1020.0	1020.0	1030.0	1040.0	1040.0	1050.0	1090.0	1980.0	1990.0
170	LESS OPERATING COSTS	24.9	26.7	28.5	30.5	32.7	35.0	37.4	72.0	77.9	84.0
213	OPERATING INCOME	985.1	993.3	991.5	999.5	1007.3	1005.0	1012.6	1018.0	1902.2	1906.0
240	LESS INTEREST EXPENSE	923.6	920.5	917.0	913.2	908.8	904.0	898.7	892.8	1710.9	1710.2
527	NET EARNINGS FROM OPERS	61.5	72.8	74.5	86.3	98.5	101.1	113.9	125.2	191.3	195.9
214	INTEREST EARNED ON FUNDS	4.9	5.2	5.6	6.0	6.4	6.9	7.3	7.9	15.1	16.3
434	INTEREST ON CASH DEFICIT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.6
	-----CASH SOURCE AND USE----										
445	CASH INCOME	66.4	78.0	80.1	92.3	104.9	107.9	121.2	133.0	206.4	212.9
446	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	391.7	445.5	415.7	1178.2	1441.1	1617.9	1485.9	1098.8	101.9	15.6
447	TOTAL SOURCES OF FUNDS	458.1	523.6	495.8	1270.5	1546.0	1725.8	1607.1	1231.8	308.3	228.4
320	LESS CAPITAL EXPENDITURE	417.4	477.9	446.9	1215.8	1486.0	1661.1	1535.1	1077.8	90.9	99.2
448	LESS WORCAP AND FUNDS	3.7	4.9	4.2	5.5	5.8	5.1	6.5	81.9	101.9	14.9
260	LESS DEBT REPAYMENTS	37.0	40.7	44.8	49.2	54.2	59.6	65.5	72.1	109.5	120.4
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1	-6.1
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1	-6.1
	-----BALANCE SHEET----------										
225	RESERVE AND CONT. FUND	52.3	56.0	59.9	64.1	68.6	73.4	78.6	151.3	163.3	176.3
221	DEBT SERVICE RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
454	OTHER CASH SURPLUS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1	0.0
523	TOTAL FUNDS	52.3	56.0	59.9	64.1	68.6	73.4	78.6	151.3	169.4	176.3
371	OTHER WORKING CAPITAL	104.7	106.0	106.3	107.6	108.9	109.2	110.6	119.8	209.7	211.6
370	CUM. CAPITAL EXPENDITURE	10140.9	10618.9	11065.7	12281.5	13767.5	15428.6	16963.6	18041.4	18132.3	18231.5
463	CAPITAL EMPLOYED	10298.0	10780.9	11231.9	12453.2	13945.0	15611.2	17152.8	18312.5	18511.4	18519.4
461	STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462	RETAINED EARNINGS	485.7	563.7	643.8	736.1	841.0	948.9	1070.1	1203.2	1409.8	1622.4
280	DEBT OUTSTANDING	9812.3	10217.2	10588.1	11717.1	13104.1	14662.4	16087.7	17109.4	17101.8	16997.0
382	DEBT SERVICE COVER-CASH	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.99	0.95	1.00
383	DEBT SERVICE COVER-INCOME	1.03	1.04	1.04	1.04	1.05	1.05	1.06	1.06	1.05	1.05
511	DEBT SERVICE COVER-BEF TFR	1.03	1.04	1.04	1.05	1.05	1.05	1.06	1.06	1.05	1.05
512	DEBT SERVICE COVER-AFT TFR	1.03	1.04	1.04	1.05	1.05	1.05	1.06	1.06	1.05	1.05

NO FUND – NO STATE CONTRIBUTION SCENARIO
7% INFLATION, 10% INTEREST

TABLE D.5

ACRES

DATA9H WATANA-DC (ON LINE 1993-2002)-NO FUND-NO STATE CONTR.-INFLATION 7%-INTEREST 10%-CAPITAL COST $5.117 BN 20-JAN-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.18	128.01
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
399 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	109.25	298.22
-----INCOME-----										
210 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	370.0	1010.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.8	23.3
213 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.2	986.7
240 LESS INTEREST EXPENSE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	920.2
527 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.2	66.5
214 INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6
434 INTEREST ON CASH DEFICIT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----CASH SOURCE AND USE-----										
445 CASH INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.2	71.1
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	403.7	513.0	571.4	648.4	1152.0	1879.2	1763.8	1369.6	901.0	289.2
447 TOTAL SOURCES OF FUNDS	403.7	513.0	571.4	648.4	1152.0	1879.2	1763.8	1369.6	1249.2	360.2
320 LESS CAPITAL EXPENDITURE	403.7	513.0	571.4	648.4	1152.0	1879.2	1763.8	1369.6	1163.2	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.0	67.4
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
450 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.7	48.9
221 DEBT SERVICE RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
454 OTHER CASH SURPLUS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
523 TOTAL FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.7	48.9
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.3	104.5
370 CUM. CAPITAL EXPENDITURE	403.7	916.8	1488.1	2136.5	3288.5	5167.7	6931.5	8301.1	9464.3	9723.5
465 CAPITAL EMPLOYED	403.7	916.8	1488.1	2136.5	3288.5	5167.7	6931.5	8301.1	9550.3	9876.9
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.2	419.3
280 DEBT OUTSTANDING	403.7	916.8	1488.1	2136.5	3288.5	5167.7	6931.5	8301.1	9202.1	9457.6
382 DEBT SERVICE COVER-CASH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.94
383 DEBT SERVICE COVER-INCOME	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04
511 DEBT SERVICE COVER-BEF TFR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04
512 DEBT SERVICE COVER-AFT TFR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.04

NO FUND — NO STATE CONTRIBUTION SCENARIO
7% INFLATION, 10% INTEREST

Sheet 1 of 2

TABLE D.5

ACRES

TABLE D.6: SUSITNA COST OF POWER

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

		$'s Per Net Kilowatt	
		Actual $'s	1982 $'s
Total Plant Investment (RL 370 + 73) Inc. I.D.C.		3103	724
I. Fixed Charges	Percent		
(a) Cost of Money	10.00		
(b) Depreciation (10% 50 yr S.P.)	.09		
(c) Insurance	.10		
(d) Taxes	.00		
1. Federal Income	0.00		
2. Federal Miscellaneous	0.00		
3. State & Local	0.00		
	10.19		
		316.17	73.81
II. Fixed Operating Costs			
(a) Operation & Maintenance (RL 213 & 73)		14.40	3.13
(b) Administrative & General Experience (35% of (a))		4.69	1.10
Total Annual Capacity Costs		334.26	78.04

Notes:
(1) RL = Reference Line on far left of Table 5 printout
(2) Working Capital carying charge is omitted as 80% covered by earnings from Reserve & Contingency Fund (RL 225).
(3) Cost in 1982 $'s is derived by deflating Actual $ cost by the inflation index (RL 466) to reflect the economic cost to consumers over the 50-yr. assumed life of the facility. It therefore diverges from the year to year financial cost of power dependent on the specific debt amortization and financing plan embodied in the assumed financing scenario. As noted in pages to it is expected that the State of Alaska will finance a mahor part of the investment and substantially reduce the financial cost of power very substantially below that of RL 399 of Attachment A.

TABLE D.7: FORECAST FINANCIAL PARAMETERS

	Watana	Devil Canyon	Total
Project Completion - Year	1993	2002	
Energy Level - 1993			3 387 GWh
- 2002			5 223 "
- 2010			6 616 "
Costs in January 1982 Dollars			
Capital Costs	$ 3.647 billion	$1.470 billion	$ 5.117 billion
Operating Costs - per annum	$10.0 million	$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	100 percent of Operating Costs 100 percent of Provision for Capital Renewals
Interest Rate	10 percent per annum
Debt Repayment Period	35 years
Inflation Rate	7 percent per annum
Real Rate of Increase in Operating Costs	
- 1982 to 1987	1.7 percent per annum
- 1988 on	2.0 percent per annum
Real Rate of Increase in Capital Costs	
- 1982 to 1985	1.1 percent per annum
- 1986 to 1992	1.0 percent per annum
- 1993 on	2.0 percent per 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
Matanuska Electric Association	0.9	Diesel	Non-Exempt	*	–	268.0
Homer Electric Association	2.6	Diesel	Non-Exempt	*	–	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]	221.3	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					2577.1

[1]Pooling Arrangements in Force

TABLE D.8 – RAILBELT UTILITIES PROVIDING MARKET POTENTIAL

ACRES

PLANT LIST

PLANT No.	NAME OF PLANT	UTILITY	TYPE OF OWNERSHIP
2	Anchorage No. 1	Anchorage Municipal Light and Power	Municipal
3	Anchorage	Anchorage Municipal Light and Power	Municipal
6	Eklutna	Alaska Power Administration	Federal
7	Chena	Fairbanks Municipal Utilities System	Municipal
10	Knik Arm	Chugach Electric Association, Inc.	Cooperative
22	Elmendorf-West	United States Air Force	Federal
23	Fairbanks	Golden Valley Electric Association, Inc.	Cooperative
32	Cooper Lake	Chugach Electric Association, Inc.	Cooperative
34	Elmendorf-East	United States Air Force	Federal
35	Ft. Richardson	United States Army	Federal
36	Ft. Wainright	United States Air Force	Federal
37	Eilson	United States Air Force	Federal
38	Ft. Greeley	United States Army	Federal
47	Bernice Lake	Chugach Electric Association, Inc.	Cooperative
55	International Station	Chugach Electric Association, Inc.	Cooperative
58	Healy	Golden Valley Electric Association, Inc.	Cooperative
59	Beluga	Chugach Electric Association, Inc.	Cooperative
75	Clear AFB	United States Air Force	Federal
80	Collier-Kenai	Collier-Kenai	Municipal
81	Eyak	Cordova Public Utilities	Municipal
82	North Pole	Golden Valley Electric Association, Inc.	Cooperative
83	Valdez	Golden Valley Electric Association, Inc.	Cooperative
84	Glennallen	Golden Valley Electric Association, Inc.	Cooperative

TABLE D.9 – LIST OF GENERATING PLANTS SUPPLYING RAILBELT REGION

ACRES

TABLE D.10: TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM

Abbreviations	Railbelt Utility	Installed Capacity[1]
AMLPD	Anchorage Municipal Light & Power Department	221.6
CEA	Chugach Electric Association	395.1
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
CVEA	Copper Valley Electric Association	19.6
MEA	Matanuska Electric Association	0.9
HEA	Homer Electric Association	2.6
SES	Seward Electric System	5.5
APAd	Alaska Power Administration	30.0
U of A	University of Alaska	18.6
TOTAL		984.0

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

TABLE D.11: GENERATING UNITS WITHIN THE RAILBELT - 1980

Railbelt Utility	Station Name	Unit No.	Unit Type	Installation Year	Heat Rate (Btu/kWh)	Installed Capacity (MW)	Fuel Type	Retirement Year
Anchorage Municipal Light & Power Department (AMLPD)	AMLPD	1	GT	1962	14,000	16.3	NG	1992
	AMLPD	2	GT	1964	14,000	16.3	NG	1994
	AMLPD	3	GT	1968	14,000	18.0	NG	1998
	AMLPD	4	GT	1972	12,000	32.0	NG	2002
	G.M. Sullivan	5,6,7	CC	1979	8,500	139.0	NG	2011
Chugach Electric Association (CEA)	Beluga	1	GT	1968	15,000	16.1	NG	1998
	Beluga	2	GT	1968	15,000	16.1	NG	1998
	Beluga	3	GT	1973	10,000	53.0	NG	2003
	Beluga	5	GT	1975	15,000	58.0	NG	2005
	Beluga	6	GT	1976	15,000	68.0	NG	2012
	Beluga	7	GT	1977	15,000	68.0	NG	2012
	Bernice Lake	1	GT	1963	23,440	8.6	NG	1993
		2	GT	1972	23,440	18.9	NG	2002
		3	GT	1978	23,440	26.4	NG	2008
	International Station	1	GT	1964	40,000	14.0	NG	1994
		2	GT	1965	--*	14.0	NG	1995
		3	GT	1970	--*	18.0	NG	2000
	Copper Lake	1	HY	1961	--*	16.0	--	2011
Golden Valley Electric Association (GVEA)	Healy	1	ST	1967	11,808	25.0	Coal	2002
		2	IC	1967	[illegible] 000	2.8	Oil	1997
	North Pole	1	GT	1976	1[illegible]00	65.0	Oil	1996
		2	GT	1977	13,500	65.0	Oil	1997
	Zehander	1	GT	1971	14,500	18.4	Oil	1991
		2	GT	1972	14,500	17.4	Oil	1992
		3	GT	1975	14,900	3.5	Oil	1995
		4	GT	1975	14,900	3.5	Oil	1995
		5	IC	1965	14,000	3.5	Oil	1995
		6	IC	1965	14,000	3.5	Oil	1995
		7	IC	1965	14,000	3.5	Oil	1995
		8	IC	1965	14,000	3.5	Oil	1995
		9	IC	1965	14,000	3.5	Oil	1995
		10	IC	1965	14,000	3.5	Oil	1995
Fairbanks Municipal Utility System (FMUS)	Chena	1	ST	1954	14,000	5.0	Coal	1989
		2	ST	1952	14,000	2.5	Coal	1987
		3	ST	1952	14,000	1.5	Coal	1987
		4	GT	1963	16,500	7.0	Oil	1993
		5	ST	1970	14,500	21.0	Coal	2005
		6	GT	1976	12,490	23.1	Oil	1997
	FMUS	1	IC	1967	11,000	2.8	Oil	1997
		2	IC	1968	11,000	2.8	Oil	1998
		3	IC	1968	11,000	2.8	Oil	1998

TABLE D.11 (Continued)

Railbelt Utility	Station Name	Unit No.	Unit Type	Installation Year	Heat Rate (Btu/kWh)	Installed Capacity (MW)	Fuel Type	Retirement Year
Homer Electric Association (HEA)	Homer							
	Kenai	1	IC	1979	15,000	0.9	Oil	2009
	Pt. Graham	1	IC	1971	15,000	0.2	Oil	2001
	Seldovia	1	IC	1952	15,000	0.3	Oil	1982
		2	IC	1964	15,000	0.6	Oil	1994
		3	IC	1970	15,000	0.6	Oil	2000
University of Alaska (U of A)	University	1	ST	1980	12,000	1.5	Coal	2015
	University	2	ST	1980	12,000	1.5	Coal	2015
	University	3	ST	1980	12,000	10.0	Coal	2015
	University	1	IC	1980	10,500	2.8	Oil	2011
	University	2	IC	1980	10,500	2.8	Oil	2011
Copper Valley Electric Association (CVEA)	CVEA	1-3	IC	1963	10,500	1.2	Oil	1993
	CVEA	4-5	IC	1966	10,500	2.4	Oil	1996
	CVEA	6-7	IC	1976	10,500	5.2	Oil	2006
	CVEA	1-3	IC	1967	10,500	1.8	Oil	1997
	CVEA	4	IC	1972	10,500	1.9	Oil	2002
	CVEA	5	IC	1975	10,500	1.0	Oil	2005
	CVEA	6	IC	1975	10,500	2.6	Oil	2005
	CVEA	7	GT	1976	14,000	3.5	Oil	1996
Matanuska Elec. Association (MEA)	Talkeetna	1	IC	1967	15,000	0.9	Oil	1997
Seward Electric System (SES)	SES	1	IC	1965	15,000	1.5	Oil	1995
		2	IC	1965	15,000	1.5	Oil	1995
		3	IC	1965	15,000	2.5	Oil	1995
Alaska Power Administration (APAd)	Eklutna	-	HY	1955	--	30.0	--	2005
TOTAL						984.0		

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.

TABLE D.12: SCHEDULE OF PLANNED UTILITY ADDITIONS (1980-1988)

Utility	Unit	Type	MW	Year	Avg. Energy (GWh)
CVEA	Solomon Gulch	HY	12	1981	55
CEA	Bernice Lake #4	GT	26.4	1982	--
AMLPD	AMLPD #8	GT	90.0	1982	--
CEA	Beluga #6,7,8	CC	42*	1982	--
COE	Bradley Lake	Hydro	90.0	1988	--
APA	Grant Lake	Hydro	7.0	1988	33
TOTAL			267.4		

* 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.13: OPERATING AND ECONOMIC PARAMETERS FOR SELECTED HYDROELECTRIC PLANTS

No.	Site	River	Max. Gross Head (ft)	Installed Capacity (MW)	Average Annual Energy (Gwh)	Plant Factor (%)	(1981 $) Capital Cost[1] ($$10^6$)	Economic[2] Cost of Energy ($/1000 Kwh)
1	Snow	Snow	690	50	220	50	255	45
2	Bruskasna	Nenana	235	30	140	53	238	113
3	Keetna	Talkeetna	330	100	395	45	463	73
4	Cache	Talkeetna	310	50	220	51	564	100
5	Browne	Nenana	195	100	410	47	625	59
6	Talkeetna-2	Talkeetna	350	50	215	50	500	90
7	Hicks	Matanuska	275	60	245	46	529	84
8	Chakachamna[3]	Chakachatna	945	500	1925	44	1480	30
9	Allison	Allison Creek	1270	8	33	47	54	125
10	Strandline Lake	Beluga	810	20	85	49	126	115

Notes:

(1) Including engineering and owner's administrative costs but excluding AFDC.
(2) Including IDC, Insurance, Amortization, and Operation and Maintenance Costs.
(3) 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.

TABLE D.14: RESULTS OF ECONOMIC ANALYSES OF ALTERNATIVE GENERATION SCENARIOS

Generation Scenario Type	Generation Scenario Description	Load Forecast	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010: Thermal Coal	Thermal Gas	Thermal Oil	Hydro	Total System Installed Capacity in 2010 (MW)	Total System Present Worth Cost ($ 10^6)
All Thermal	No Renewals	Medium	LME1	900	801	50	144	1895	8130
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500)[1]-1993 Keetna (100)-1997	Medium	L7W1	600	576	70	744	1990	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	Medium	LXF1	700	426	30	822	1978	7041
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Snow (50), Cache (50), Allison Creek (8), Talkeetna-2 (50), Strandline (20)-2002	Medium	L403	500	576	30	922	2028	7088

Notes:

(1) Installed capacity.

TABLE D.15: SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS/1982$

Parameter	200 MW	Combined Cycle 200 MW	Gas Turbine 70 MW	Diesel 10 MW
Heat Rate (Btu/kWh)	10,000	8,000	12,200	11,500
Earliest Availability	1989	1980	1984	1980
O&M Costs				
Fixed O&M ($/yr/kW)	16.83	7.25	2.7	0.55
Variable O&M (&/MWH)	0.6	1.69	4.8	5.38
Outages				
Planned Outages (%)	8	7	3.2	1
Forced Outages (%)	5.7	8	8	5
Construction Period (yrs)	6	2	1	1
Startup Time (yrs)	6	4	4	1
Unit Capital Cost ($/kW)[1]				
Railbelt	-	1,075	627	856
Beluga	2,061	-	-	-
Nenana	2,107	-	-	-
Unit Capital Cost ($/kW)[2]				
Railbelt	2,242	1,107	636	869
Beluga	-	-	-	-
Nenana	2,309	-	-	-

Notes:

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

TABLE D.16: REAL (INFLATION-ADJUSTED) ANNUAL GROWTH IN OIL PRICES

	Growth Rates (Percent) 1982-2000	Growth Rates (Percent) 2000-2040	Probability
Low Case	0	0	0.3
Medium (most likely case)	2.0	1.0	0.5
High Case	4.0	2.0	0.2

Base Period
(January 1982)

Price of No. 2 Fuel Oil - $6.50/MMBtu.

TABLE D.17: DOMESTIC MARKET PRICES AND EXPORT OPPORTUNITY VALUES OF NATURAL GAS

	Domestic Market Price[1]			Export Opportunity Value		
	Low	Medium	High	Low	Medium	High
Probability of Occurrence	N.A.	N.A.	N.A.	27%	46%	27%
Base Period Value	-	$3.00/MMBtu	-	-	$4.65/MMBtu[2]	-
Real Escalation CIF Price, Japan[3]						
1982 - 2000	-	N.A.	-	0%	2%	4%
2000 - 2040	-		-	0%	1%	2%
Real Escalation Alaska Price[4]						
1982 - 2000	0%	2.5%	5.0%	0%	2.7%	5.2%
2000 - 2040	0%	2.0%	2.0%	0%	1.2%	2.2%

---

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.18: SUMMARY OF COAL OPPORTUNITY VALUES

	Base Period (Jan. 1982) Value ($/MMBtu)	Annual Real Growth Rate 1980 - 2000 (%)	Annual Real Growth Rate 2000 - 2040 (%)	Probability of Occurrence %
Base Case				
Battelle Base Period CIF Price				
Medium Scenario				
- CIF Japan	1.95	2.0	1.0	49
- FOB Beluga	1.43	2.6	1.2	49
- Nenana	1.75	2.3	1.1	49
Low Scenario				
- CIF Japan	1.95	0	0	24
- FOB Beluga	1.43	0	0	24
- Nenana	1.75	0.1	0.1	24
High Scenario				
- CIF Japan	1.95	4.0	2.0	27
- FOB Beluga	1.43	5.0	2.2	27
- Nenana	1.75	4.5	1.9	27
Sensitivity Case				
Updated Base Period CIF Price[1]				
Medium Scenario				
- CIF Japan	2.66	2.0	1.0	49
- FOB Beluga	2.08	2.5	1.2	49
- FOB Nenana	1.74	2.7	1.2	49
Low Scenario				
- CIF Japan	2.66	0	0	24
- FOB Beluga	2.08	0	0	24
- FOB Nenana	1.74	-0.2	-0.1	24
High Scenario				
- CIF Japan	2.66	4.0	2.0	27
- FOB Beluga	2.08	4.8	2.2	27
- FOB Nenana	1.74	5.3	2.3	27

1 Assuming a 10 percent discount for Alaskan coal due to quality differentials, and export potential for Healy coal.

TABLE D.19: SUMMARY OF FUEL PRICES USED IN THE OGP5 PROBABILITY TREE ANALYSIS

	Fuel Price Scenario		
	Low	Medium	High
Probability of occurrence	25%	50%	25%
Base period January 1982 prices			
(1982$/MMBtu)			
Fuel Oil	6.50	6.50	6.50
Natural Gas	3.00	3.00	3.00
Coal			
- Beluga	1.43	1.43	1.43
- Nenana	1.75	1.75	1.75
Real escalation rates per year[1] (percent)			
Fuel Oil			
- 1982 - 2000	0	2.0	4.0
- 2000 - 2040	0	2.0	2.0
Natural Gas			
- 1982 - 2000	0	2.5	5.0
- 2000 - 2040	0	2.0	2.0
Beluga Coal			
- 1982 - 2000	0	2.6	5.0
- 2000 - 2040	0	1.2	2.2
Nenana Coal			
- 1982 - 2000	0.1	2.3	4.5
- 2000 - 2040	0.1	1.1	1.9

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

TABLE D.20: ECONOMIC ANALYSIS
SUSITNA PROJECT - BASE PLAN

Plan	ID	Components	1982 Present Worth of System Costs $ x 10^6: 1993-2010	2010	Estimated 2011-2051	1993-2051
Non Susitna	A	600 MW Coal-Beluga	3,213	491	5,025	8,238
		200 MW Coal-Nenana				
		630 MW GT				
Susitna	C	680 MW Watana	3,119	385	3,943	7,062
		600 MW Devil Canyon				
		180 MW GT				-
Net Economic Benefit of Susitna Plan			-	-	-	1,176

TABLE D.21: SUMMARY OF LOAD FORECASTS
USED FOR SENSITIVITY ANALYSIS

	Medium		Low		High	
	MW	GWh	MW	GWh	MW	GWh
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.22: LOAD FORECAST SENSITIVITY ANALYSIS

Plan	ID	Components	1982 Present Worth of System Costs ($ x 10^6) 1993-2010	2010	Estimated 2011-2051	1993-2051	Net Economic Benefit
Non-Susitna with Low Forecast	K_1	400 MW Coal-Beluga 200 MW Coal-Nenana 560 MW GT	2,640	404	4,238	6,878	-
Susitna with Low Forecast	K_2	680 MW Watana (1995) 600 MW Devil Canyon (2004)	2,882	360	3,768	6,650	228
Non-Susitna with High Forecast	J_1	800 MW Coal-Beluga 200 MW Coal-Nenana 700 MW GT 430 MW Pre-1993	4,176	700	6,683	10,8591[1]	-
Susitna with High Forecast	J_2	680 MW Watana (1993) 600 MW Devil Canyon (1997) 350 MW GT 430 MW Pre-1993	3,867	564	5,380	9,2471[1]	1,612

[1] From 1993 to 2040

TABLE D.23: DISCOUNT RATE SENSITIVITY ANALYSIS

Plan	ID	Real Discount Rate (Percent)	1982 Present Worth of System Costs ($ x 10^6) 1993-2010	2010	Estimated 2011-2051	1993-2051	Net Economic Benefit
Non-Susitna	Q_1	2	3,701	465	7,766	11,167	-
Susitna	Q_2	2	3,156	323	5,394	8,550	2,617
Non-Susitna	A	3	3,213	491	5,025	8,328	-
Susitna	C	3	3,119	385	3,943	7,062	1,176
Non-Susitna	S_1	4	2,791	517	3,444	6,235	-
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.24: CAPITAL COST SENSITIVITY ANALYSIS

Plan	ID	1993-2010	2010	Estimated 2011-2051	1993-2051	Net Economic Benefit
		1982 Present Worth of System Costs ($ x 10^6)				
Non-Susitna Capital Costs Up 20 Percent						
Non-Susitna	G	3,460	528	5,398	8,858	-
Susitna	C[1]	3,119	385	3,943	7,062	1,976
Non-Susitna Capital Costs Down 10 Percent						
Non-Susitna	G	3,084	472	4,831	7,915	-
Susitna	C[1]	3,119	385	3,943	7,062	853
Susitna Capital Costs Less Contingency						
Non-Susitna	A	3,213	491	5,025	8,238	-
Susitna	X_2	2,710	336	3,441	6,151	2,087
Susitna Capital Costs Plus Doubled Contingency						
Non-Susitna	A	3,213	491	5,025	8,238	-
Susitna	Y_2	3,529	434	4,445	7,974	264

[1] 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 10^6. Beyond 2010, this effect was not included.

TABLE D.25: SENSITIVITY ANALYSIS - UPDATED BASE PLAN (JANUARY 1982) COAL PRICES

	Base Period Beluga Coal Price (1982 $/MMBtu)	Costs of Non-Susitna Plan	Costs of Susitna Plan	Net Economic Benefits
		1982 Present Worth of System Costs ($ x 10^6)		
Base Case	1.43	8,238	7,062	1,176
Sensitivity (Updated) Case	2.08	9,030	7,062	1,968

TABLE D.26: SENSITIVITY ANALYSIS - REAL COST ESCALATION

Plan	ID	1993-2010	1982 Present Worth of System Costs ($ X 10^6) 2010	Estimated 2011-2051	1993-2051	Net Benefit
Zero-Escalation in Capital and O&M Costs						
• Non-Susitna	O_1	2,838	422	4,319	7,157	-
• Susitna	O_2	2,525	299	3,060	5,585	1,572
Escalation in Capital Costs and O&M (Battelle)[1]						
• Non-Susitna	X_1	3,142	477	4,881	8,023	-
• Susitna	X_2	2,988	366	3,745	6,737	1,286
Double Escalation Capital and O&M Costs						
• Non-Susitna	P_1	3,650	602	6,161	9,811	-
• Susitna	P_2	3,881	503	5,148	9,029	782
Zero-Escalation in Fuel Prices						
• Non-Susitna	V_1	2,233	335	3,427	5,660	-
• Susitna	V_2	3,002	365	3,736	6,738	(1,078)
High Escalation in Fuel Prices						
• Non-Susitna	W_1	4,063	643	6,574	10,367	-
• Susitna	W_2	3,267	403	4,121	7,388	2,979

[1]Capital and O&M costs assumed to escalate at 1.4 percent 1982 to 2010

TABLE D.27: SENSITIVITY ANALYSIS - NON-SUSITNA PLAN WITH CHAKACHAMNA

Plan	ID	Components	1993 2010	1982 Present Worth of System Costs ($ X 10^6) 2010	Estimated 2011-2051	1993-2051	Net Benefit
• 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	-
• Susitna	C	680 MW Watana 600 MW Devil Canyon 180 MW GT	3,119	385	3,943	7,062	837

TABLE D.28: SENSITIVITY ANALYSIS - SUSITNA PROJECT DELAY

	ID	$ x 10^6 1982 Present Worth of System Costs	$ x 10^6 Net Economic Benefit
Susitna Base Case	C	7,062	1,176
One-year delay for Watana (1994)	C3	7,105	1,133
One-year delay for Devil Caryon (2003)	C4	7,165	1,134
One-year delay for Watana and Devil Canyon (1994, 2003)	C5	7,230	1,138

TABLE D.29: SUMMARY OF SENSITIVITY ANALYSIS INDEXES OF NET ECONOMIC BENEFITS

	Index Values
BASE CASE ($1,176 MILLION)	100
Fuel Escalation	
- High	253[1]
- Low	-92[2]
Discount Rates	
- High-High (5%)	-44
- High (4%)	9
- Low (2%)	223
Susitna Capital Cost	
- High	23
- Low	178
Load Forecast	
- High	137
- Low	19
Non-Susitna (Thermal) Capital Costs	
- High	168
- Low	73
Capital and O&M Cost Escalation	
- High	67
- Intermediate (Battelle)	109
- Low	134
Chakachamna (included in Non-Susitna Plan)	71
Updated Base Coal Price	167
Planned Delay in Susitna Project	
- One-year delay, Watana	96
- One-year delay, Watana and Devil Canyon	96
- Two-year delay, Watana and Devil Canyon	97

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

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

TABLE D.30: BATTELLE ALTERNATIVE STUDY

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

TABLE D.30 (Contd)

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

(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.

TABLE D.31: BATTELLE ALTERNATIVES STUDY

Alternative	Capacity[(a)] (MW)	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	-	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	4669	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	-
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

(a) Configuration in parentheses used in analysis of Railbelt electric energy plus taken from earlier estimates (Alaska Power Authority 1980)
(b) A heat 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 energy plans.
(d) Configuration selected in preliminary feasibility study (Bechtel Civil and Minerals 1981)
(e) Configuration selected in Railbelt alternatives study (Ebasco 1982b)

TABLE D.32: Summary of Electrical Energy Alternatives Included as Future Additions in Electric Energy Plans

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

(a) Plan 1: Base Case
- A. Without Upper Susitna
- B. With Upper Susitna

Plan 2: High conservation and use of renewables
- A. Without Upper Susitna
- B. With Upper Susitna

Plan 3: Increase Use of Coal

Plan 4: Increase Use of Natural gas

DATA10K WATANA-DC (ON LINE 1993-2002). INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY ($MILLION)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.65	7.98
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.77	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.94	18.59
-----INCOME-----										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	63.0
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	33.6
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
-----CASH SOURCE AND USE-----										
543 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	229.7
145 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549 TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	431.1	276.9
320 LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	676.4	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6860.1
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6698.9	6975.8
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6267.8	6600.9	6830.6
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.5
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
51[illegible] DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

Sheet 1 of 3

TABLE D.33

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)- INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	8.24	8.38	8.74	8.88	9.04	9.17	9.30	7.66	8.84	8.68
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
523 PRICE-MILLS	20.55	22.36	24.93	27.13	29.53	32.06	34.79	30.64	37.86	39.80
-----INCOME-----------------										
516 REVENUE	69.6	75.7	84.4	91.9	100.0	108.6	117.8	160.0	204.9	223.1
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	37.6	40.8	46.3	50.2	54.6	59.0	63.7	69.0	105.5	114.6
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	36.3
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
548 NET EARNINGS FROM OPERS	32.2	35.1	38.3	41.8	45.6	49.8	54.4	59.3	90.9	99.2
-----CASH SOURCE AND USE----										
544 CASH INCOME FROM OPERS	32.2	35.1	38.3	41.8	45.6	49.8	54.4	59.3	90.9	99.2
446 STATE CONTRIBUTION	363.1	382.1	303.8	1028.3	1177.5	1204.8	913.1	303.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	403.4	446.5	353.3	1082.4	1233.7	1265.1	979.8	490.3	115.6	142.0
320 LESS CAPITAL EXPENDITURE	395.3	417.2	342.1	1070.1	1223.2	1254.6	967.5	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
760 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
227 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7255.4	7672.6	8014.7	9084.8	10308.0	11562.6	12530.1	12892.5	12983.3	13082.5
465 CAPITAL EMPLOYED	7379.2	7325.7	8179.0	9261.4	10495.1	11760.2	12740.0	13230.3	13345.9	13487.9
461 STATE CONTRIBUTION	7193.7	7575.8	7879.6	8907.9	10085.4	11290.3	12203.4	12506.4	12506.4	12506.4
462 RETAINED EARNINGS	61.6	96.8	135.1	176.9	222.6	272.4	326.7	386.1	477.0	576.1
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

TABLE D.33

ACRES

DATALOK WATANA-DC (ON LINE 1993-2002) INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
71 NERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521 REAL PRICE-MILLS	8.18	8.27	8.33	8.24	8.30	8.35	8.48	8.57	8.67	0.00
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520 PRICE-MILLS	40.12	43.39	46.75	49.49	53.35	57.45	62.39	67.48	73.02	0.00
-----INCOME-----------------										
515 REVENUE	244.4	266.7	292.1	320.3	349.1	380.1	414.1	449.4	487.9	4530.0
179 LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517 OPERATING INCOME	126.0	137.4	151.1	166.3	181.1	196.7	214.0	231.0	249.5	2328.0
214 ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
553 LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	746.6
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
545 NET EARNINGS FROM OPERS	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	1993.8
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	1993.8
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12506.4
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549 TOTAL SOURCES OF FUNDS	144.7	169.4	188.2	186.5	199.4	219.6	220.6	240.8	262.8	15319.9
320 LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	14500.2
443 LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371 OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	13190.7	13308.9	13437.8	13578.5	13732.1	13899.7	14082.6	14282.3	14500.2	14500.2
465 CAPITAL EMPLOYED	13632.6	13801.9	13990.2	14176.7	14376.1	14595.7	14816.3	15057.1	15319.9	15319.9
461 STATE CONTRIBUTION	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4	12506.4
462 RETAINED EARNINGS	684.4	802.5	931.4	1072.1	1225.7	1393.3	1576.3	1775.9	1993.8	1993.8
555 DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Sheet 3 of 3

100% STATE APPROPRIATION OF TOTAL CAPITAL COST ($5.1 BILLION IN 1982 DOLLARS)

TABLE D.33

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.74	34.38
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	64.76	80.08
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	219.3	271.2
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	192.4	241.9
21 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
559 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.0	183.4
549 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	54.3
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	54.3
446 STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	1[illegible]0.4	462.4	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	784.7	754.9	294.6	211.6
248 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
547 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	403.7	472.7	479.7	499.5	938.3	1550.4	1247.1	754.9	333.1	259.2
448 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.8
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6679.4	6938.6
465 CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5591.4	6346.3	6777.4	7054.3
461 STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	4344.3	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	92.8
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	0.0	784.7	1539.5	1834.2	2039.0
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	371.0	135.3	90.8
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	412.6	783.6	918.9	1009.7
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.25	1.25

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

Sheet 1 of 3

TABLE D.34

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$3.0 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
(\$MILLION)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	32.59	30.81	29.37	27.83	26.39	25.04	23.79	58.55	55.54	50.49
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	31.25	82.18	83.81	84.97	86.24	87.54	89.00	234.36	237.89	231.37
-----INCOME-----										
516 REVENUE	275.2	278.3	283.8	287.8	292.1	296.5	301.4	1224.0	1287.8	1296.7
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	243.1	243.4	245.7	246.2	246.6	246.9	247.3	1132.9	1188.4	1188.2
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
559 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	20.0	21.9	34.7	36.3
391 LESS INTEREST ON LONG TERM DEBT	182.7	182.0	181.2	130.3	179.3	178.2	177.0	883.4	895.7	891.5
548 NET EARNINGS FROM OPERS	55.0	55.7	56.6	57.5	58.4	59.5	60.7	239.0	277.2	281.4
-----CASH SOURCE AND USE-----										
548 CASH INCOME FROM OPERS	55.0	55.7	56.6	57.5	58.4	59.5	60.7	239.0	277.2	281.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	368.9	427.7	395.4	1163.0	1432.3	1604.7	1473.5	137.8	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	432.0	512.8	463.1	1232.7	1501.3	1674.7	1546.5	504.8	301.9	324.3
320 LESS CAPITAL EXPENDITURE	416.4	475.3	442.9	1210.5	1479.8	1654.5	1527.9	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260 LESS DEBT REPAYMENTS	7.4	8.2	9.0	9.9	10.9	12.0	13.2	14.5	42.6	46.8
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	-2.3	-6.8	0.0	143.7	135.4
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	2.3	6.8	0.0	-9.1	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	134.6	135.4
-----BALANCE SHEET-----										
225 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.[illegible]
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7355.0	7830.3	8273.2	9483.7	10963.5	12618.0	14145.9	14508.2	14599.1	14698.3
465 CAPITAL EMPLOYED	7478.8	7983.4	8437.5	9660.3	11150.6	12815.6	14355.8	14846.1	14961.7	15103.7
461 STATE CONTRIBUTION	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7	4806.7
462 RETAINED EARNINGS	147.8	203.5	260.1	317.5	376.0	435.5	496.2	735.2	877.8	1023.8
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	199.8	219.0	346.9	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	2400.5	2820.0	3206.4	4359.4	5780.8	7373.5	8833.8	8957.1	8914.6	8867.7
542 ANNUAL DEBT DRAWDOWN $1982	148.0	160.4	138.5	380.8	438.3	459.0	393.9	34.4	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	1157.7	1318.0	1456.6	1837.4	2275.7	2734.7	3128.6	3163.0	3163.0	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

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

Sheet 2 of 3

TABLE D.34

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

		1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73	ENERGY GWH	0	0	0	0	0	0	0	0	3387	3387
521	REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.85	58.76
466	INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520	PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	110.73	136.90
	-----INCOME-----------------										
516	REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	375.0	463.6
170	LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.9	29.3
517	OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	348.1	434.3
214	ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
550	LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.8
391	LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	303.1	331.9
548	NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	98.3
	-----CASH SOURCE AND USE----										
548	CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	98.3
446	STATE CONTRIBUTION	403.7	472.7	479.7	499.5	938.3	738.4	0.0	0.0	0.0	0.0
143	LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	812.0	1328.3	890.4	288.1	173.2
248	WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
549	TOTAL SOURCES OF FUNDS	403.7	472.7	479.7	499.5	938.3	1550.4	1328.3	890.4	431.1	289.2
320	LESS CAPITAL EXPENDITURE	403.7	472.7	479.7	499.5	938.3	1550.4	1328.3	890.4	333.1	259.2
448	LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	17.7
260	LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.2
141	CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249	SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444	CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	-----BALANCE SHEET-----------										
225	RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.5	61.6
371	OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.5	54.1
454	CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370	CUM. CAPITAL EXPENDITURE	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5672.6	6563.0	6896.1	7155.3
465	CAPITAL EMPLOYED	403.7	876.4	1356.1	1855.6	2794.0	4344.3	5672.6	6563.0	6994.1	7271.0
461	STATE CONTRIBUTION	403.7	876.4	1356.1	1855.6	2794.0	3532.4	3532.4	3532.4	3532.4	3532.4
462	RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0	143.3
555	DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	98.0	115.7
554	DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	812.0	2140.2	3030.7	3318.7	3479.6
542	ANNUAL DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	456.8	698.4	437.6	132.3	74.3
543	CUM. DEBT DRAWWDOWN $1982	0.0	0.0	0.0	0.0	0.0	456.8	1155.3	1592.9	1725.2	1799.5
519	DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.15	1.25

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

Sheet 1 of 3

TABLE D.35

ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN 23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	TOTAL
73 ENERGY GWH	6092	6147	6250	6472	6544	6616	6638	6660	6682	104826
521 REAL PRICE-MILLS	48.42	45.23	41.99	38.32	35.80	33.46	31.55	29.75	28.07	0.00
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	0.00
520 PRICE-MILLS	237.42	237.31	235.75	230.18	230.09	230.15	232.21	234.23	236.49	0.00
-----INCOME-----------------										
516 REVENUE	1446.3	1458.6	1473.3	1489.6	1505.6	1522.6	1541.3	1559.8	1580.1	21929.6
170 LESS OPERATING COSTS	118.4	129.2	141.0	153.9	168.0	183.4	200.1	218.4	238.4	2202.0
517 OPERATING INCOME	1327.8	1329.4	1332.3	1335.7	1337.6	1339.2	1341.2	1341.4	1341.7	19727.6
214 ADD INTEREST EARNED ON FUNDS	22.8	24.9	27.1	29.6	32.3	35.3	38.5	42.0	45.9	412.4
559 LESS INTEREST ON SHORT TERM DEBT	40.5	44.2	49.3	55.2	59.8	64.4	69.6	73.4	77.5	746.6
391 LESS INTEREST ON LONG TERM DEBT	982.8	976.3	969.1	961.2	952.5	943.0	932.5	920.9	908.2	14428.0
543 NET EARNINGS FROM OPERS	327.3	333.8	341.0	348.9	357.5	367.1	377.6	389.2	401.9	4965.4
-----CASH SOURCE AND USE----										
548 CASH INCOME FROM OPERS	327.3	333.8	341.0	348.9	357.5	367.1	377.6	389.2	401.9	4965.4
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3532.4
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10107.8
248 WORCAP DEBT DRAWDOWNS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
549 TOTAL SOURCES OF FUNDS	363.7	385.0	400.2	394.7	403.4	419.0	415.3	430.3	446.8	19425.3
320 LESS CAPITAL EXPENDITURE	108.2	118.1	128.9	140.7	153.6	167.6	182.9	199.7	217.9	16200.7
448 LESS WORCAP AND FUNDS	36.4	51.3	59.3	45.8	45.9	52.0	37.7	41.2	44.9	819.7
260 LESS DEBT REPAYMENTS	65.2	71.8	78.9	86.8	95.5	105.1	115.6	127.1	139.9	1165.5
141 CASH SURPLUS(DEFICIT)	153.8	143.9	133.1	121.3	108.4	94.4	79.1	62.4	44.1	1239.3
247 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	153.8	143.9	133.1	121.3	108.4	94.4	79.1	62.4	44.1	1239.3
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	248.7	271.4	296.2	323.3	352.8	385.1	420.3	458.7	500.6	500.6
371 OTHER WORKING CAPITAL	193.2	221.7	256.2	274.9	291.2	310.9	313.4	316.2	319.2	319.2
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14891.3	15009.4	15138.3	15279.0	15432.6	15600.2	15783.2	15982.8	16200.7	16200.7
465 CAPITAL EMPLOYED	15333.1	15502.5	15690.7	15877.2	16076.6	16296.2	16516.8	16757.6	17020.5	17020.5
461 STATE CONTRIBUTION	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4
462 RETAINED EARNINGS	1595.9	1785.8	1993.7	2221.2	2470.3	2743.0	3041.5	3368.3	3726.1	3726.1
555 DEBT OUTSTANDING-SHORT TERM	441.8	493.1	552.4	598.2	644.0	696.0	733.7	774.8	819.7	819.7
554 DEBT OUTSTANDING-LONG TERM	9763.0	9691.2	9612.3	9525.4	9429.9	9324.8	9209.2	9082.1	8942.2	8942.2
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3827.2
543 CUM. DEBT DRAWDOWN $1982	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2	3827.2
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.35 ACRES

DATA10K WATANA-DC (ON LINE 1993-2002)-$2.3 BN ($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAP COST $5.117 BN   23-FEB-82

CASH FLOW SUMMARY
===($MILLION)====

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3387	3387	3387	3387	3387	3387	3387	5223	5414	5605
521 REAL PRICE-MILLS	55.38	52.11	49.27	46.43	43.78	41.29	38.96	63.57	59.90	55.83
466 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	138.06	139.00	140.63	141.79	143.06	144.36	145.75	254.47	256.58	255.86
-----INCOME-----------------										
516 REVENUE	467.6	470.8	476.3	480.2	484.5	488.9	493.6	1329.0	1389.0	1434.0
170 LESS OPERATING COSTS	32.0	35.0	38.1	41.6	45.4	49.6	54.1	91.1	99.4	108.5
517 OPERATING INCOME	435.6	435.8	438.1	438.6	439.1	439.3	439.5	1237.9	1289.6	1325.5
214 ADD INTEREST EARNED ON FUNDS	6.2	6.7	7.3	8.0	8.7	9.5	10.4	11.4	19.1	20.9
550 LESS INTEREST ON SHORT TERM DEBT	11.6	12.4	15.3	16.4	17.7	18.7	19.8	21.0	33.8	36.3
391 LESS INTEREST ON LONG TERM DEBT	330.6	329.3	327.8	326.2	324.4	322.4	320.3	982.5	994.1	988.8
548 NET EARNINGS FROM OPERS	99.5	100.8	102.3	104.0	105.8	107.7	109.9	245.8	280.8	321.3
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	99.5	100.8	102.3	104.0	105.8	107.7	109.9	245.8	280.8	321.3
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	326.5	381.2	344.2	1106.6	1370.3	1538.8	1405.6	142.8	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
549 TOTAL SOURCES OF FUNDS	434.2	511.3	457.7	1222.8	1486.6	1657.0	1527.8	516.5	305.5	364.2
320 LESS CAPITAL EXPENDITURE	412.6	467.2	430.2	1192.7	1456.3	1624.8	1491.6	362.3	90.9	99.2
448 LESS WORCAP AND FUNDS	8.1	29.3	11.2	12.2	10.6	10.4	12.3	128.0	24.7	42.8
260 LESS DEBT REPAYMENTS	13.5	14.8	16.3	17.9	19.7	21.7	23.9	26.2	53.9	59.3
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.0	162.8
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	136.0	162.8
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	67.2	73.4	80.1	87.4	95.4	104.1	113.7	191.3	208.8	227.8
371 OTHER WORKING CAPITAL	56.6	79.7	84.2	89.1	91.7	93.4	96.2	146.6	153.8	177.6
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	7567.9	8035.1	8465.3	9657.9	11114.2	12739.1	14230.7	14593.0	14683.8	14783.0
465 CAPITAL EMPLOYED	7691.7	8188.2	8629.6	9834.5	11301.4	12936.6	14440.5	14930.8	15046.4	15188.4
461 STATE CONTRIBUTION	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4	3532.4
462 RETAINED EARNINGS	242.8	343.7	446.0	550.0	655.7	763.4	873.3	1119.1	1263.9	1422.4
555 DEBT OUTSTANDING-SHORT TERM	123.9	153.1	164.3	176.6	187.1	197.6	209.9	337.8	362.6	405.4
554 DEBT OUTSTANDING-LONG TERM	3792.7	4159.0	4486.9	5575.6	6926.2	8443.3	9825.0	9941.5	9887.6	9828.2
542 ANNUAL DEBT DRAWDOWN $1982	131.0	142.9	120.6	362.4	419.4	440.1	375.7	35.7	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	1930.5	2073.4	2194.0	2556.3	2975.7	3415.8	3791.5	3827.2	3827.2	3827.2
513 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.22	1.22	1.25

$2.3 BILLION (1982 DOLLARS) MINIMUM STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.35 ACRES

TABLE D.36: FINANCING REQUIREMENTS - $ BILLION

For $3.0 billion State Appropriation Scenario

	Interest Rate 10% Inflation Rate 7% Actual	1982 Purchasing Power
	$ billion	
1985 State Appropriation	0.4	0.3
86 "	0.5	0.4
87 "	0.5	0.3
88 "	0.5	0.3
89 "	0.9	0.6
90 "	0.5	0.9
91 "	1.5	0.2
Total State Appropriation	4.8	3.0
1990 Guaranteed or G.O Bonds	-	-
1 " "	0.8	0.4
2 " "	0.7	0.4
3 " "	0.3	0.1
Total Watana Bonds	1.8	0.9
1994 Revenue Bonds	0.2	0.1
5 " "	0.4	0.1
6 " "	0.4	0.2
7 " "	0.4	0.1
8 " "	1.2	0.4
9 " "	1.4	0.4
2000 " "	1.6	0.5
1 " "	1.5	0.4
2 " "	0.1	0.1
Total Devil Canyon Bonds	7.2	2.3
Total Susitna Bonds	9.0	3.2

TABLE D.37: FINANCING REQUIREMENTS - $ BILLION

For $2.3 billion State Appropriation Scenario

	Interest Rate 10% Inflation Rate 7%	
	Actual	1982 Purchasing Power
	$ billion	
1985 State Appropriation	0.4	0.3
86 "	0.5	0.4
87 "	0.5	0.3
88 "	0.5	0.3
89 "	0.9	0.6
90 "	0.7	0.4
Total State Appropriation	3.5	2.3
1990 Guaranteed or G.O Bonds	0.8	0.5
1 " "	1.3	0.7
2 " "	0.9	0.4
3 " "	0.3	0.1
Total Watana Bonds	3.3	1.7
1994 Revenue Bonds	0.2	0.1
5 " "	0.3	0.1
6 " "	0.4	0.2
7 " "	0.3	0.1
8 " "	1.1	0.4
9 " "	1.4	0.4
2000 " "	1.5	0.4
1 " "	1.4	0.4
2 " "	0.2	-
Total Devil Canyon Bonds	6.8	2.1
Total Susitna Bonds	10.1	3.8

BASIC PARAMETERS OF RISK GENERATION MODEL

	COAL PRICE ESCALATION (% REAL)		
	0	2.6 to 2000 1.2 thereafter	5.0 to 2000 2.2 thereafter
PROBABILITY	.25	.50	.25

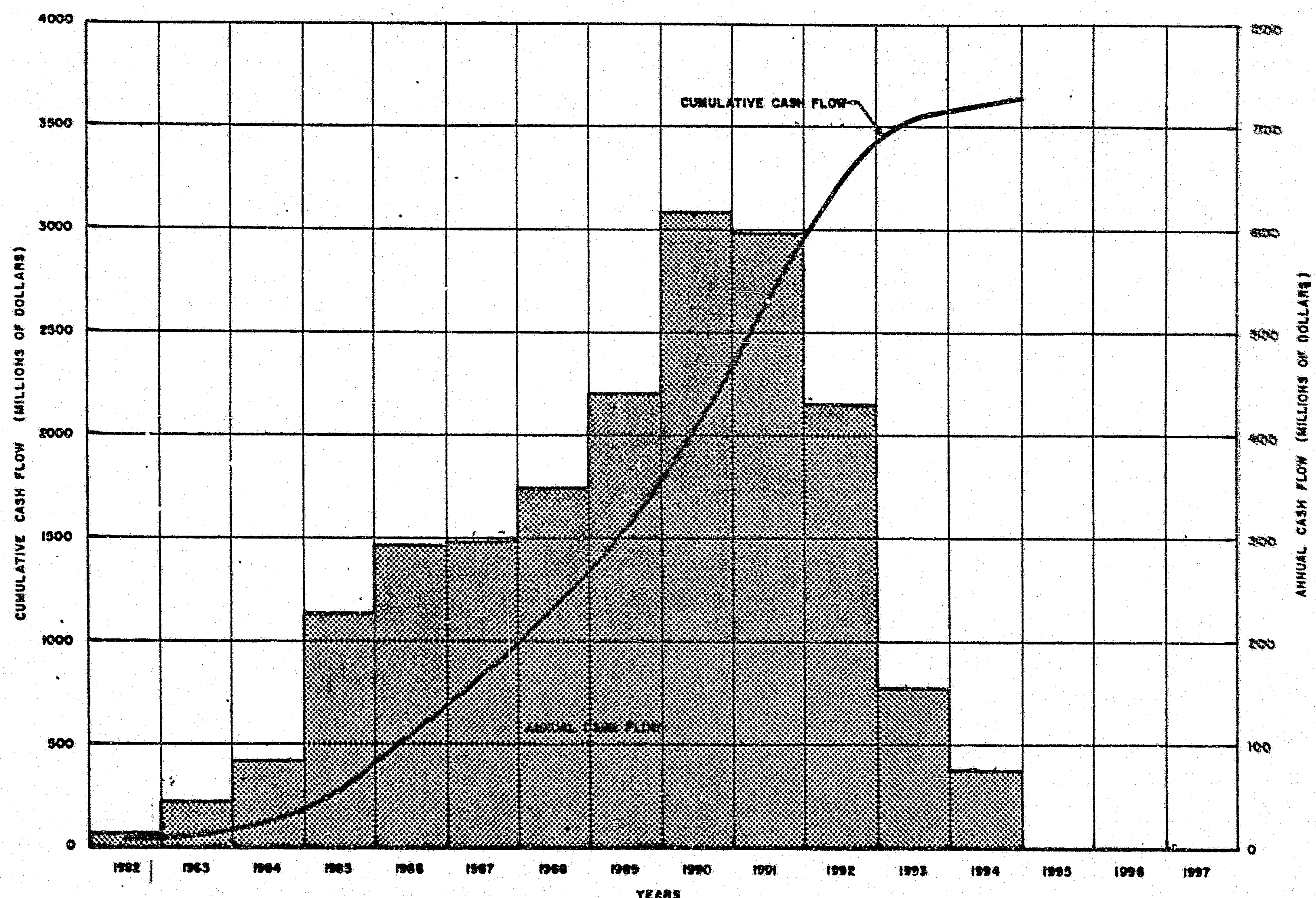
	INTEREST RATES %			
	5 – 7	7 – 9	9 – 11	11 – 13
PROBABILITY	.10	.32	.43	.15

	INFLATION RATE DIFFERENCE FROM INTEREST RATE		
	– 2%	– 3%	– 4%
PROBABILITY	.33	.34	.33

	CAPITAL COSTS (REAL 1982 $billion)			
	Below 3.1	Below 3.6	Below 4.3	Below 5.1
PROBABILITY	.46	.73	.90	1.00

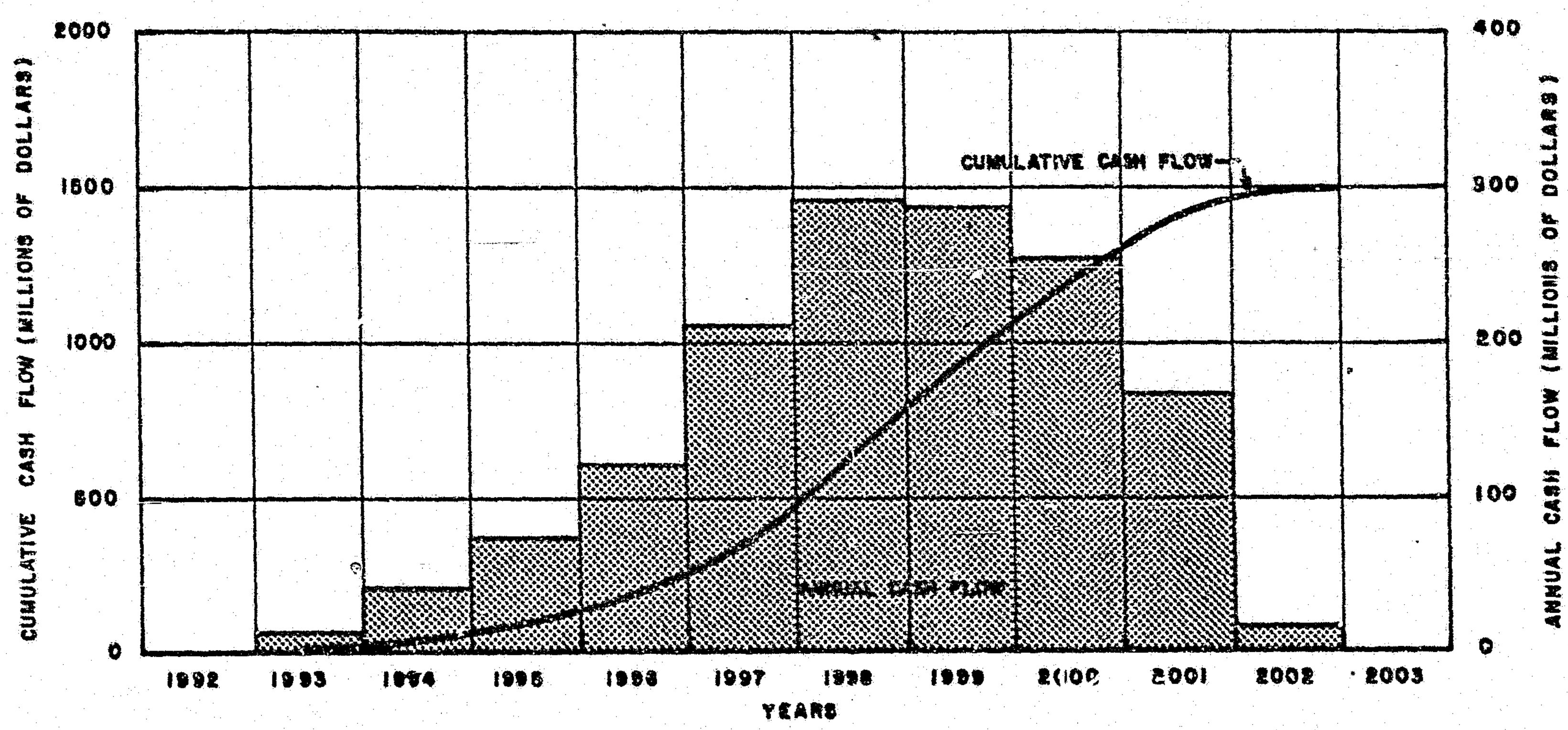
TABLE D.38

ACRES



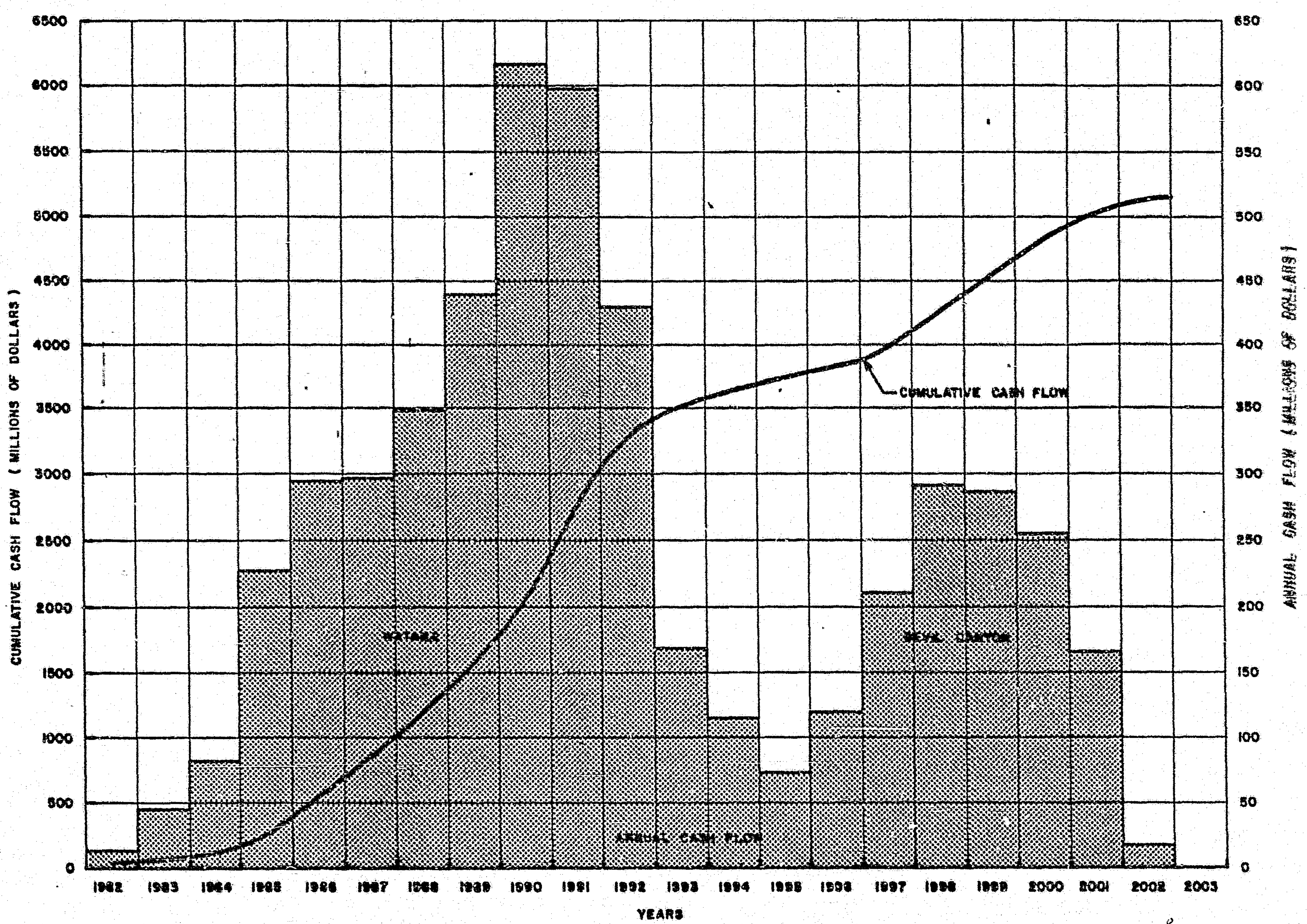
WATANA DEVELOPMENT
CUMULATIVE AND ANNUAL CASH FLOW
JANUARY, 1982 DOLLARS

FIGURE. D. 1



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

FIGURE D.2



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

FIGURE D.3

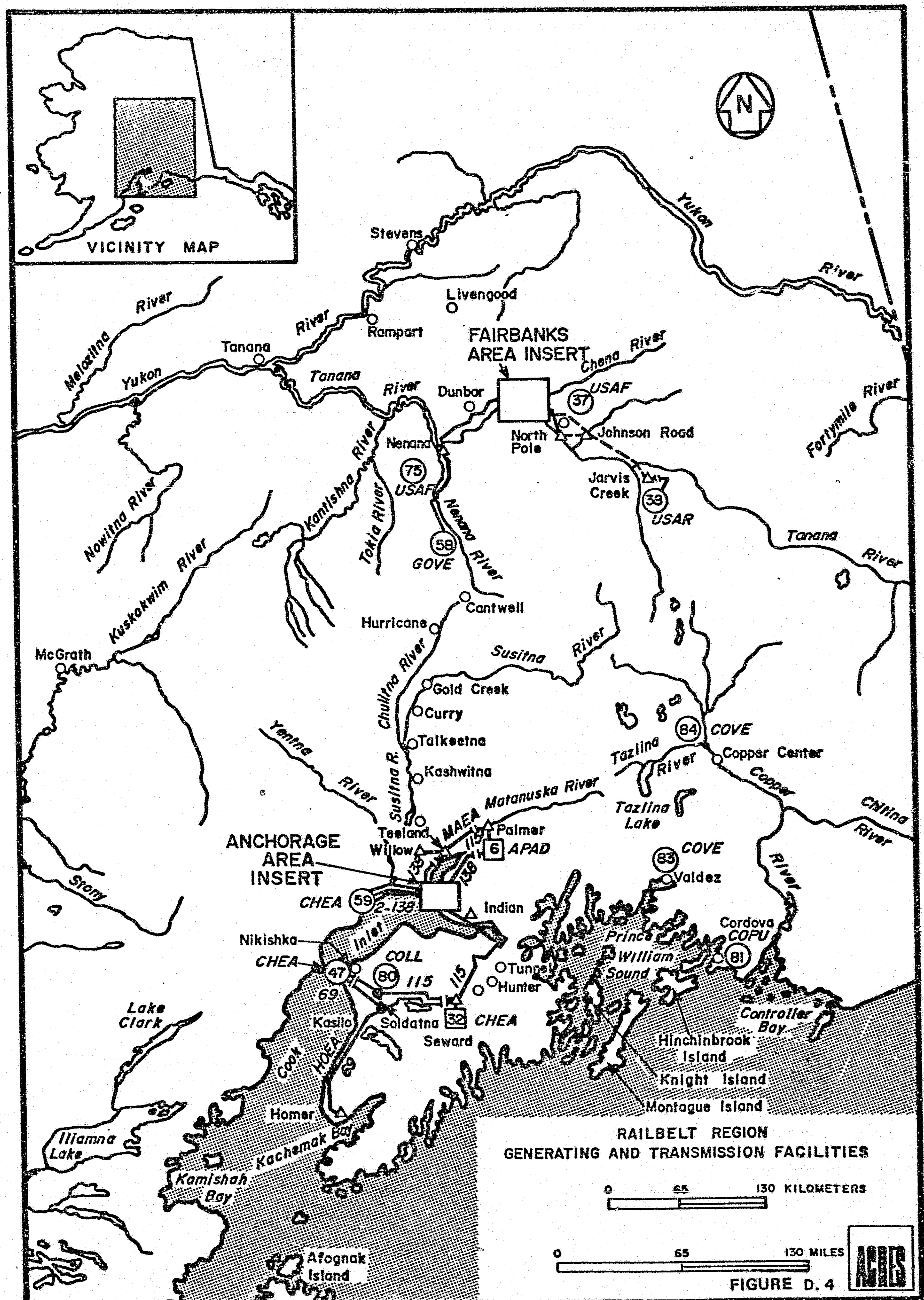

VICINITY MAP
Stevens
Livengood
Rampart
Tanana
FAIRBANKS
AREA INSERT
Yukon
River
Melozitna
River
Tanana
River
Chena River
USAF
37
Dunbar
North
Pole
Johnson Road
Nenana
75
USAF
Jarvis
Creek
38
USAR
Fortymile River
Tanana
River
Nowitna River
Kantishna River
Toklat River
Nenana River
58
GOVE
Kuskokwim River
Cantwell
Hurricane
McGrath
Chulitna River
Susitna River
Gold Creek
Curry
Talkeetna
Kashwitna
Yentna
River
Susitna R.
84
COVE
Tazlina
River
Copper Center
Copper
Matanuska River
Tazlina
Lake
Chitina
River
Teeland
Willow
MAEA
Palmer
6
APAD
ANCHORAGE
AREA
INSERT
83
COVE
Valdez
Stony
CHEA
59
2-138
Indian
Cordova
COPU
81
Nikishka
Inlet
COLL
CHEA
47
80
115
Tunnel
Hunter
Prince
William
Sound
69
Kasilo
Soldatna
32
CHEA
Seward
Controller
Bay
Lake
Clark
HOEA
Cook
Hinchinbrook
Island
Knight Island
Montague Island
Homer
Iliamna
Lake
Kachemak Bay
Kamishak
Bay
Afognak
Island
RAILBELT REGION
GENERATING AND TRANSMISSION FACILITIES
0
65
130 KILOMETERS
0
65
130 MILES
ACRES

FIGURE D. 4

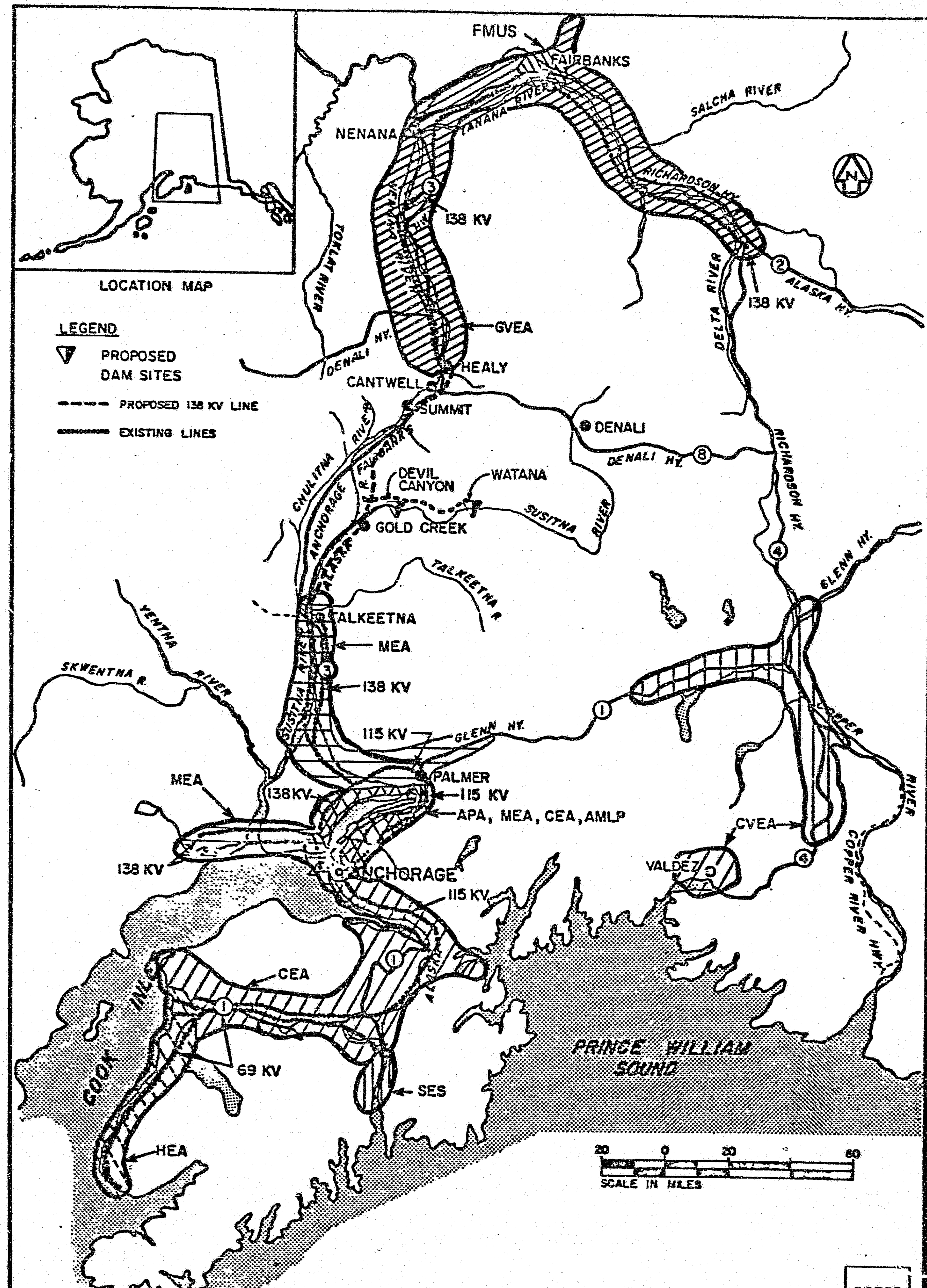
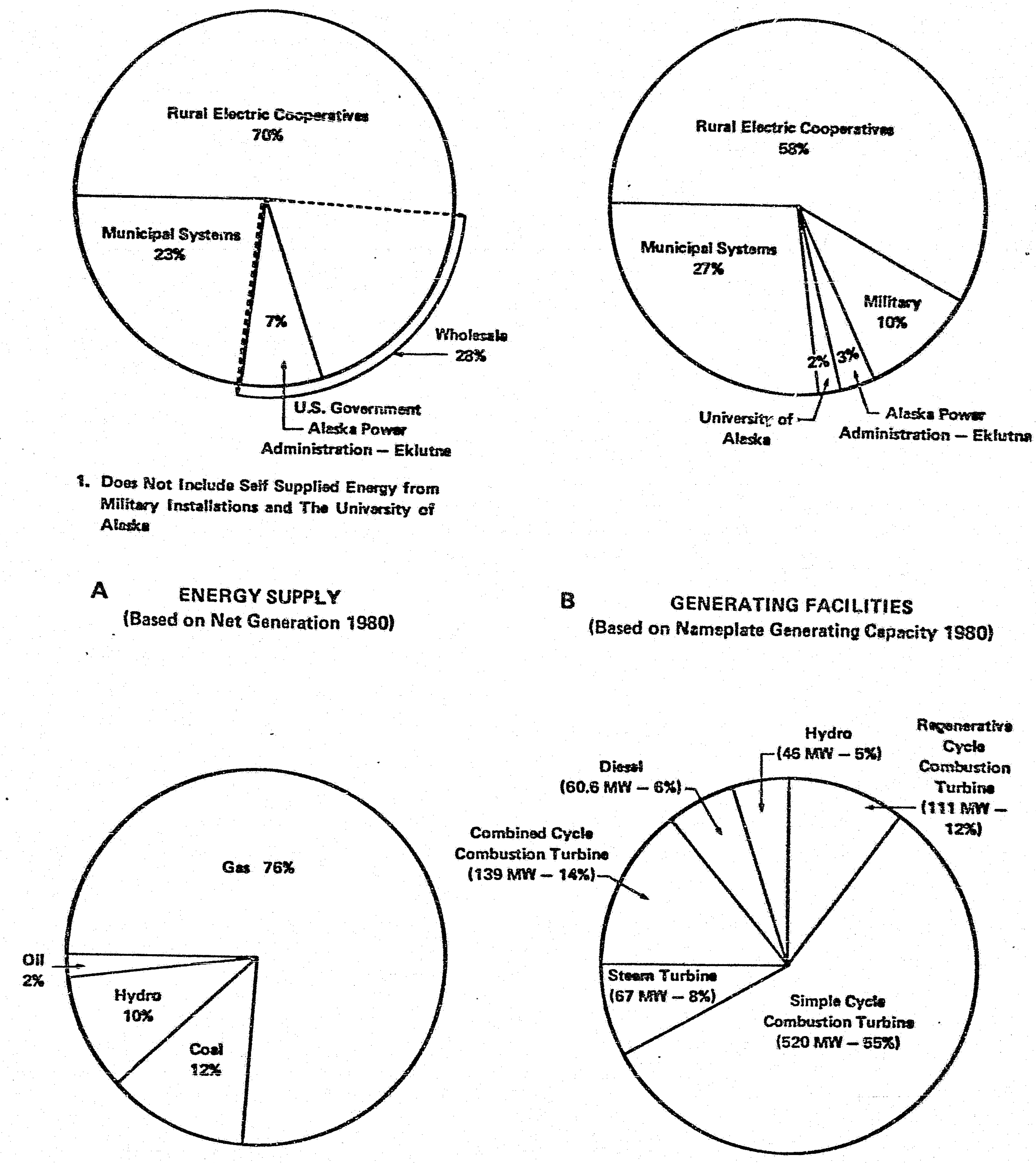


FIGURE D.5 – SERVICE AREAS OF RAILBELT UTILITIES



1. Does Not Include Self Supplied Energy from Military Installations and The University of Alaska

A ENERGY SUPPLY
(Based on Net Generation 1980)

B GENERATING FACILITIES
(Based on Nameplate Generating Capacity 1980)

1. Does Not Include Generation by Military Installations and The University of Alaska

C NET GENERATION BY TYPES OF FUEL
(Based on Net Generation 1980)

D RELATIVE MIX OF ELECTRICAL GENERATING TECHNOLOGY – RAILBELT UTILITIES – 1980

FIGURE D.6

ACRES

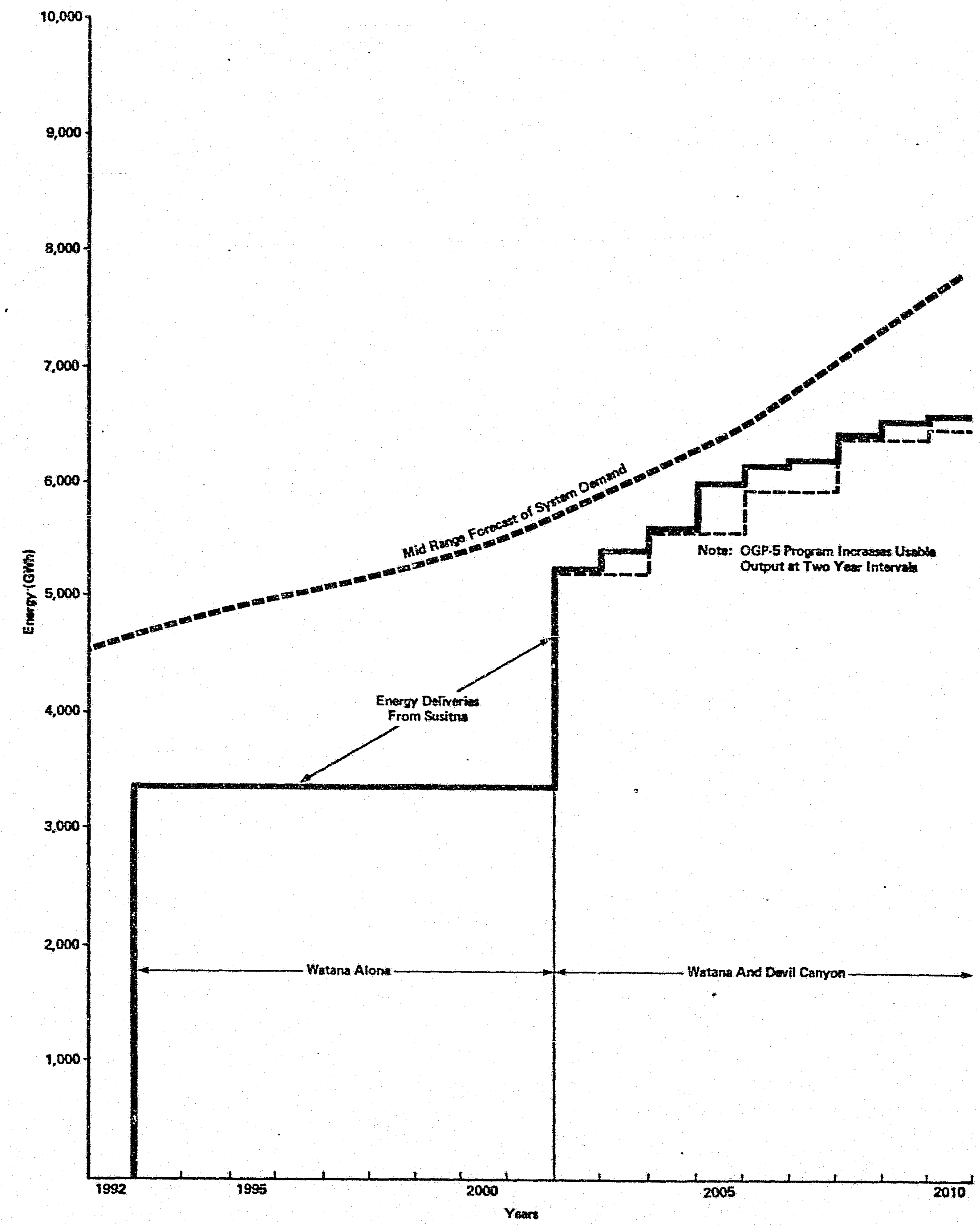


FIGURE D.7 — ENERGY DEMAND AND DELIVERIES FROM SUSITNA

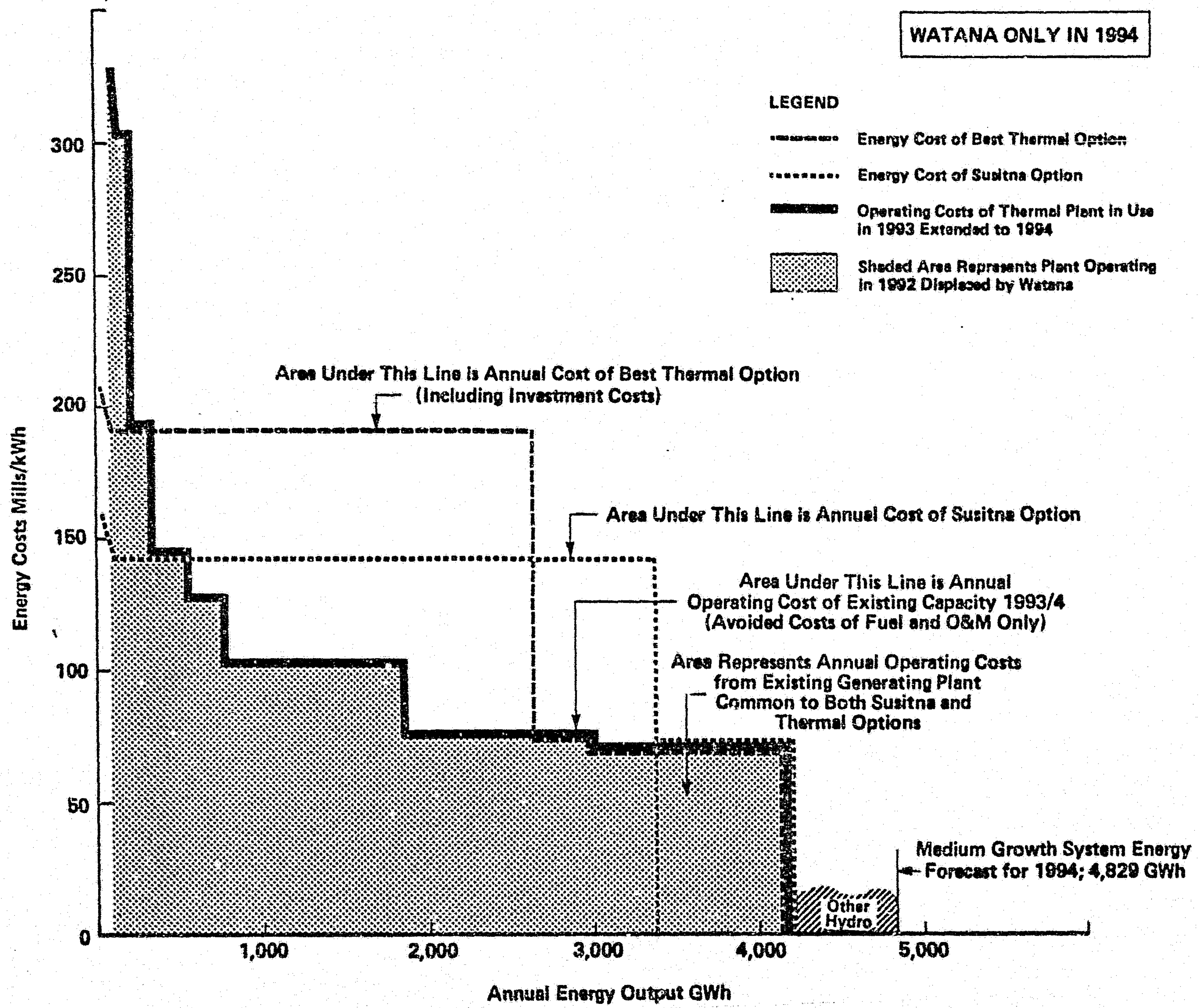


FIGURE D.8 — ENERGY PRICING COMPAR[illegible]ONS — 1994

ACRES

Rev. 1

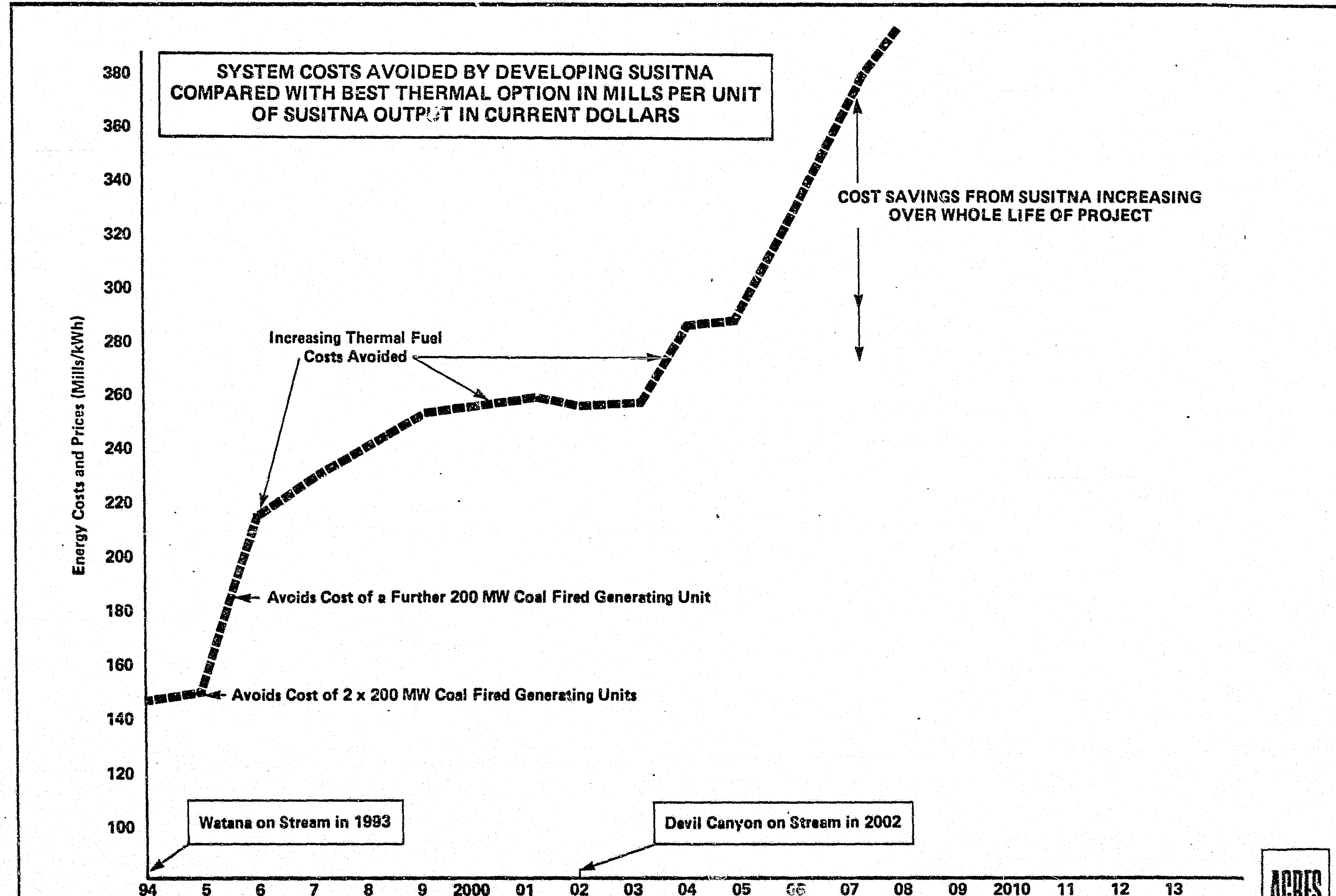


FIGURE D.9 – SYSTEM COSTS AVOIDED BY DEVELOPING SUSITNA

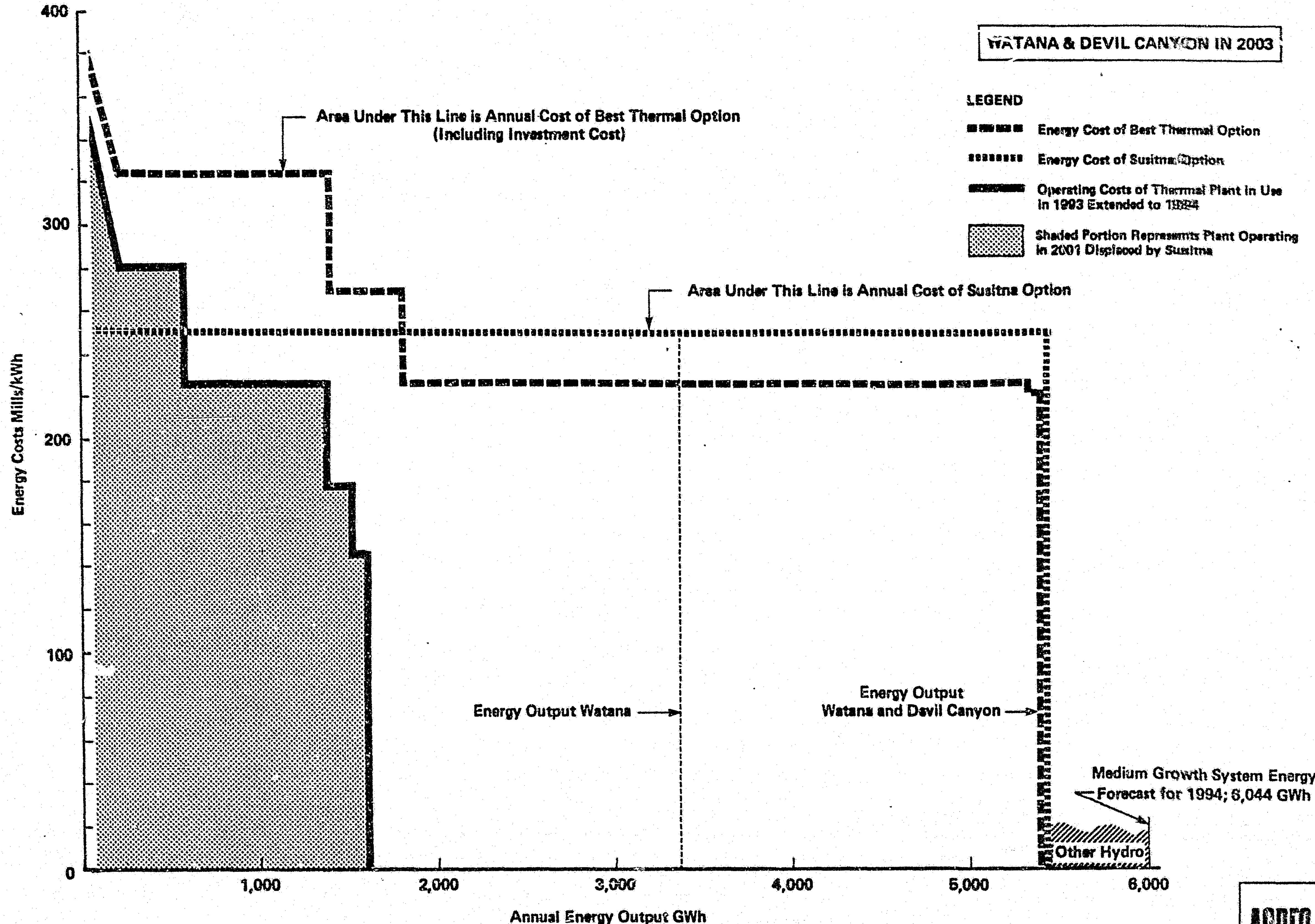
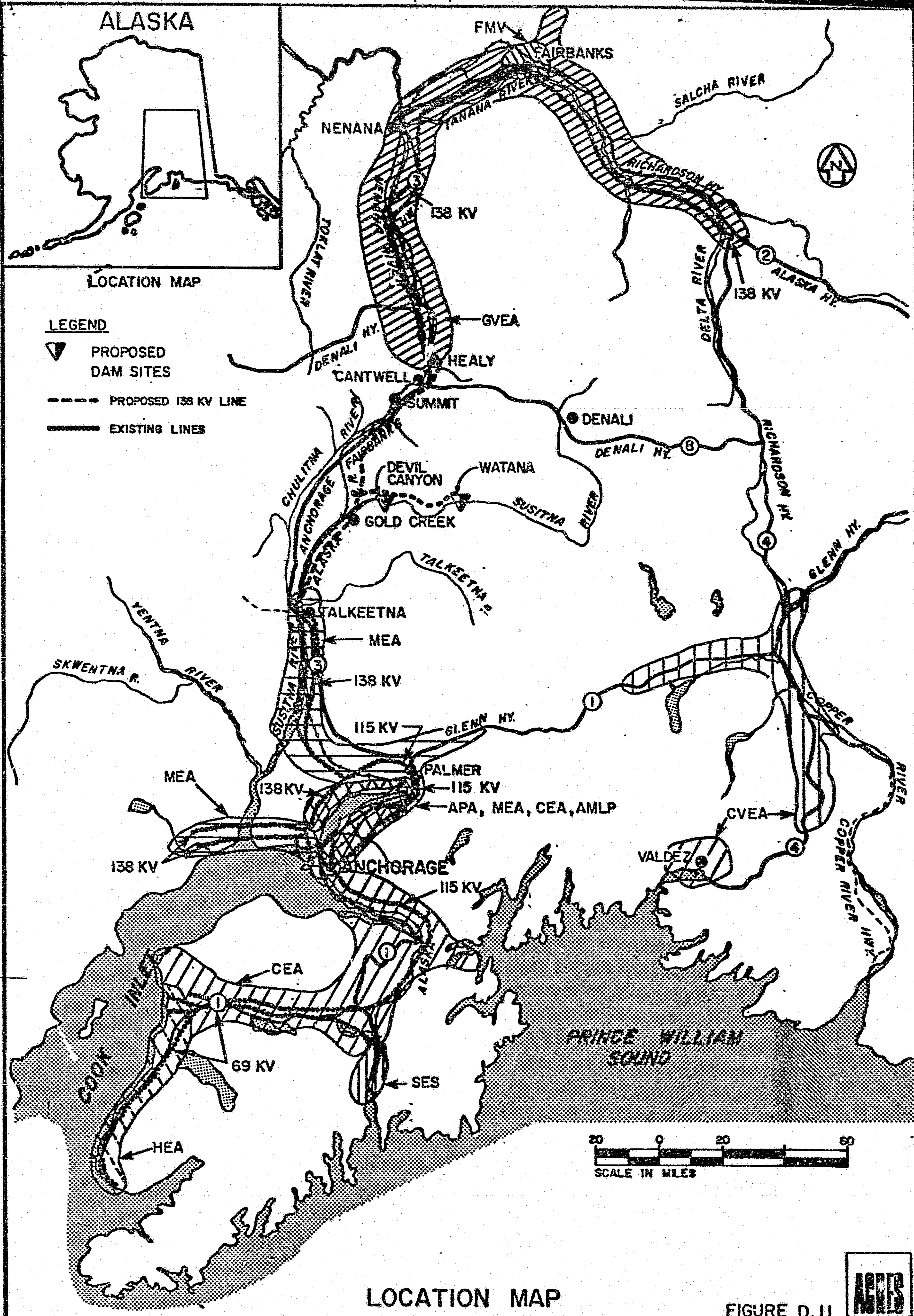


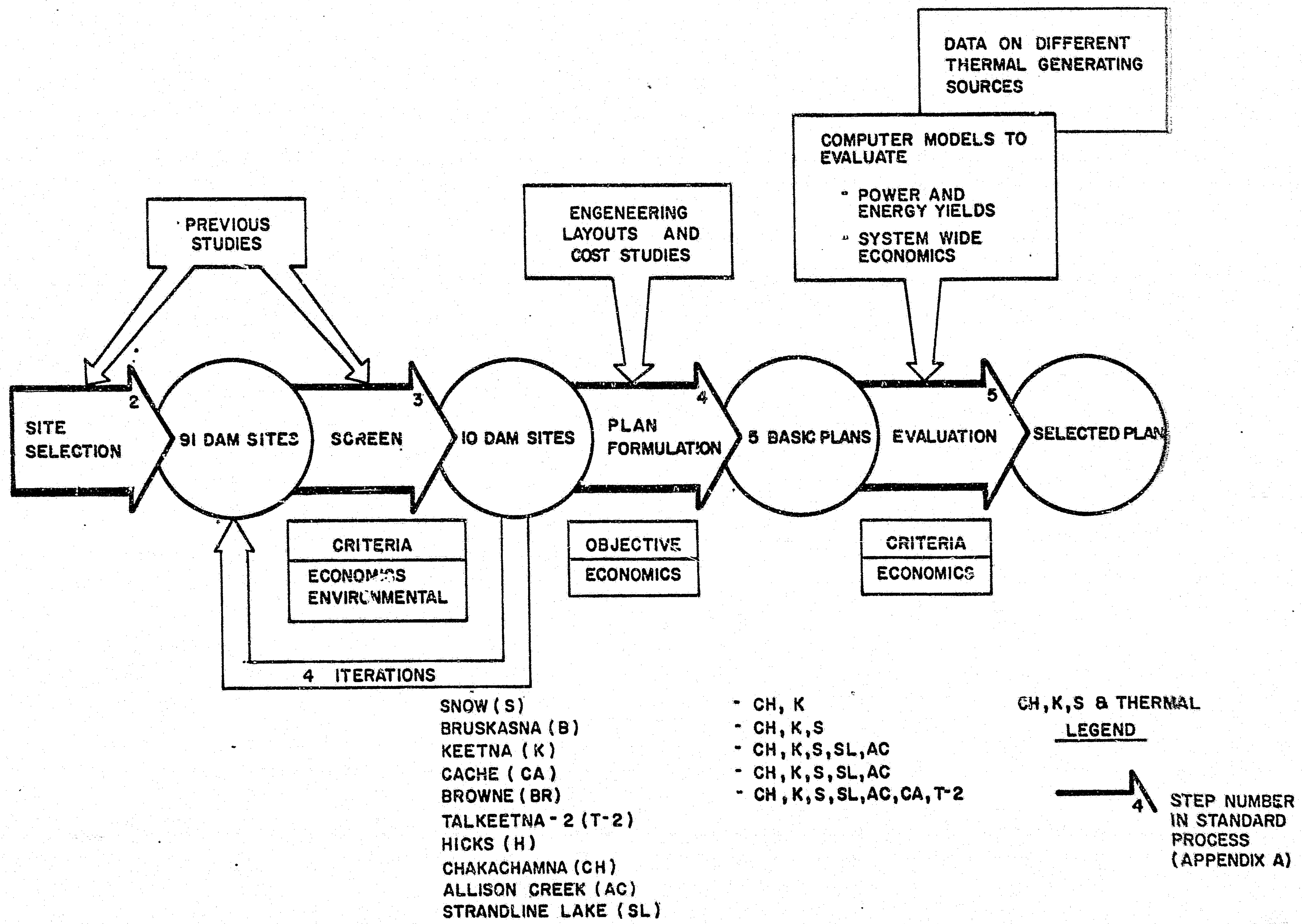
FIGURE D.10 – ENERGY PRICING COMPARISONS – 2003

ACRES



LOCATION MAP

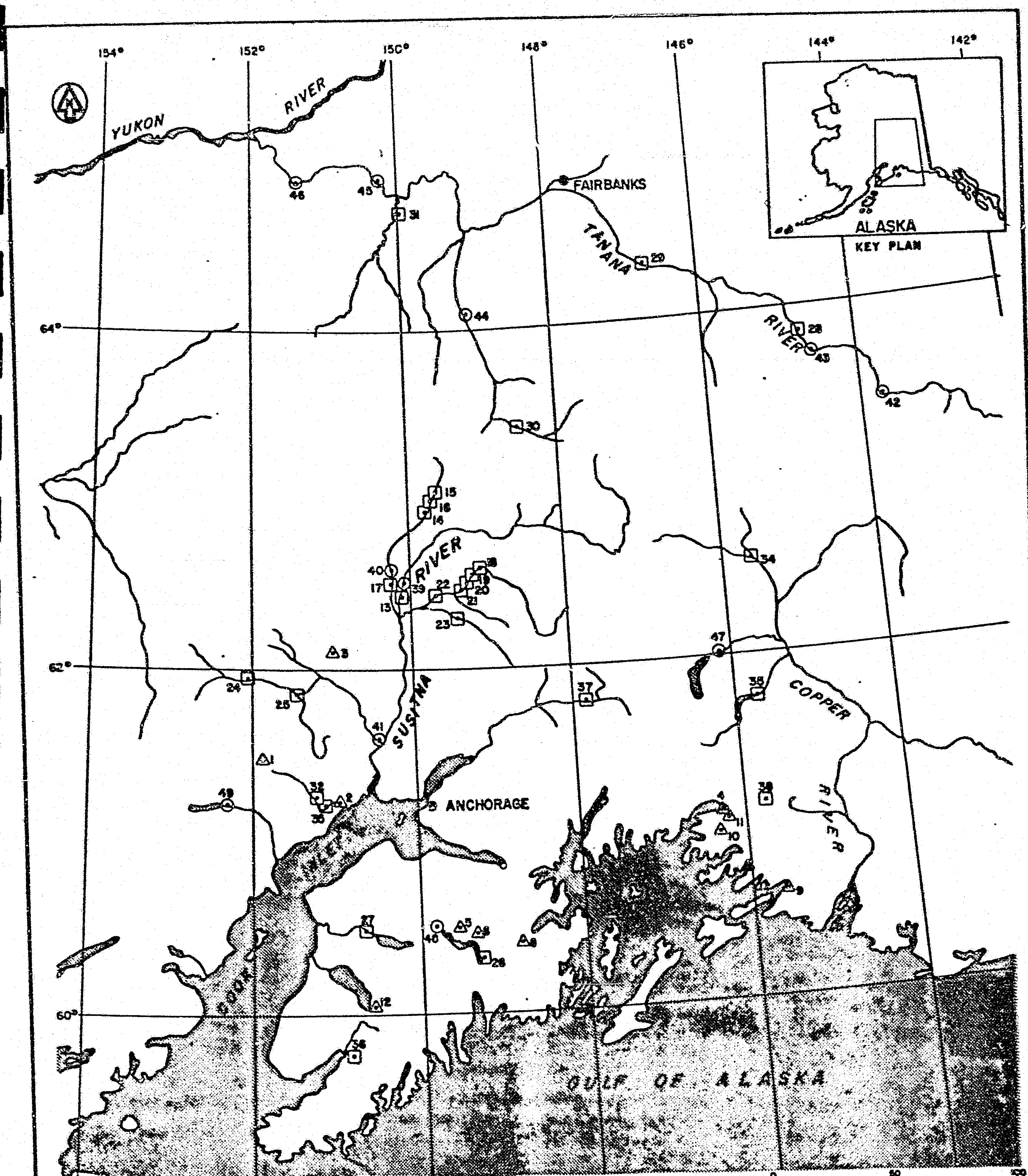
FIGURE D.11



FORMULATION OF PLANS INCORPORATING NON-SUSITNA HYDRO GENERATION

FIGURE D.12

ACRES



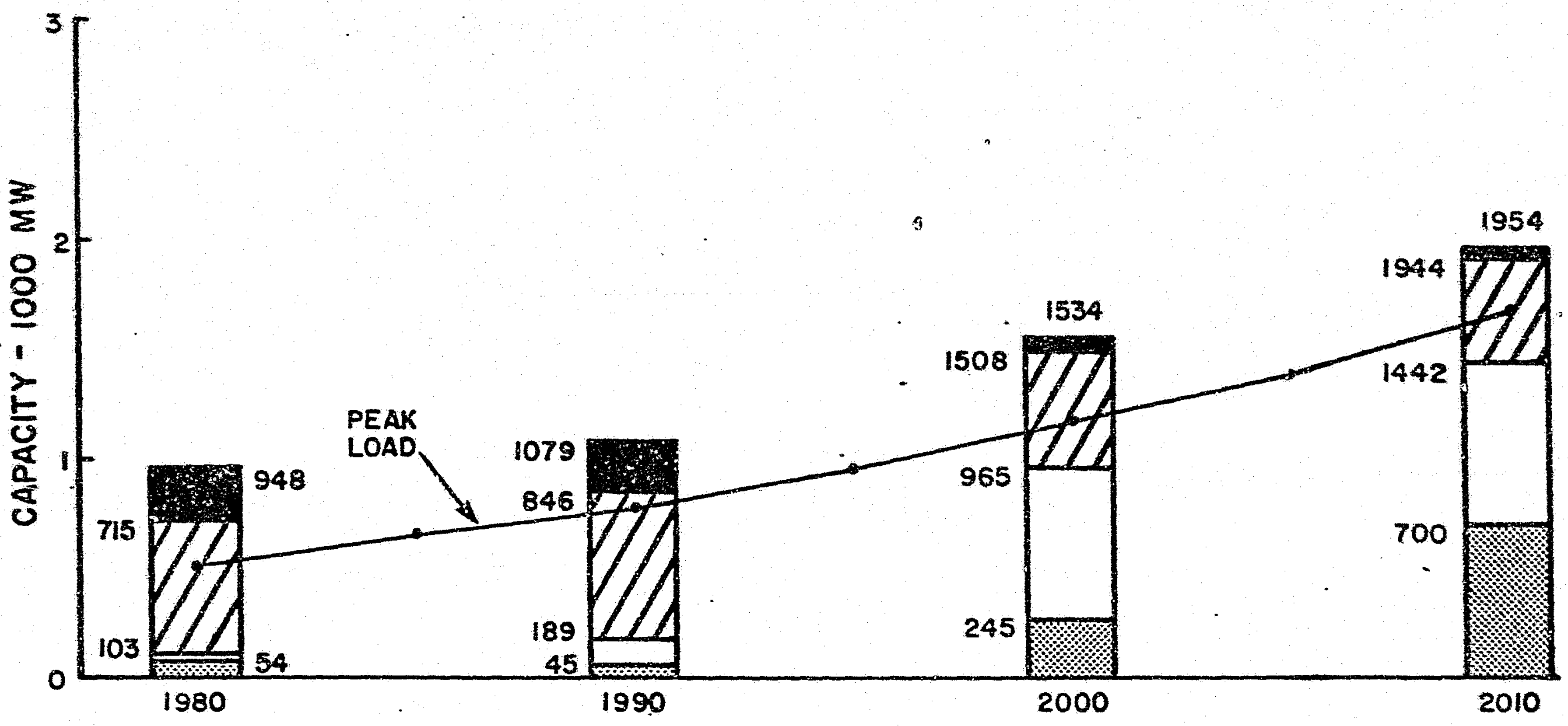
ALASKA RAILBELT REGION

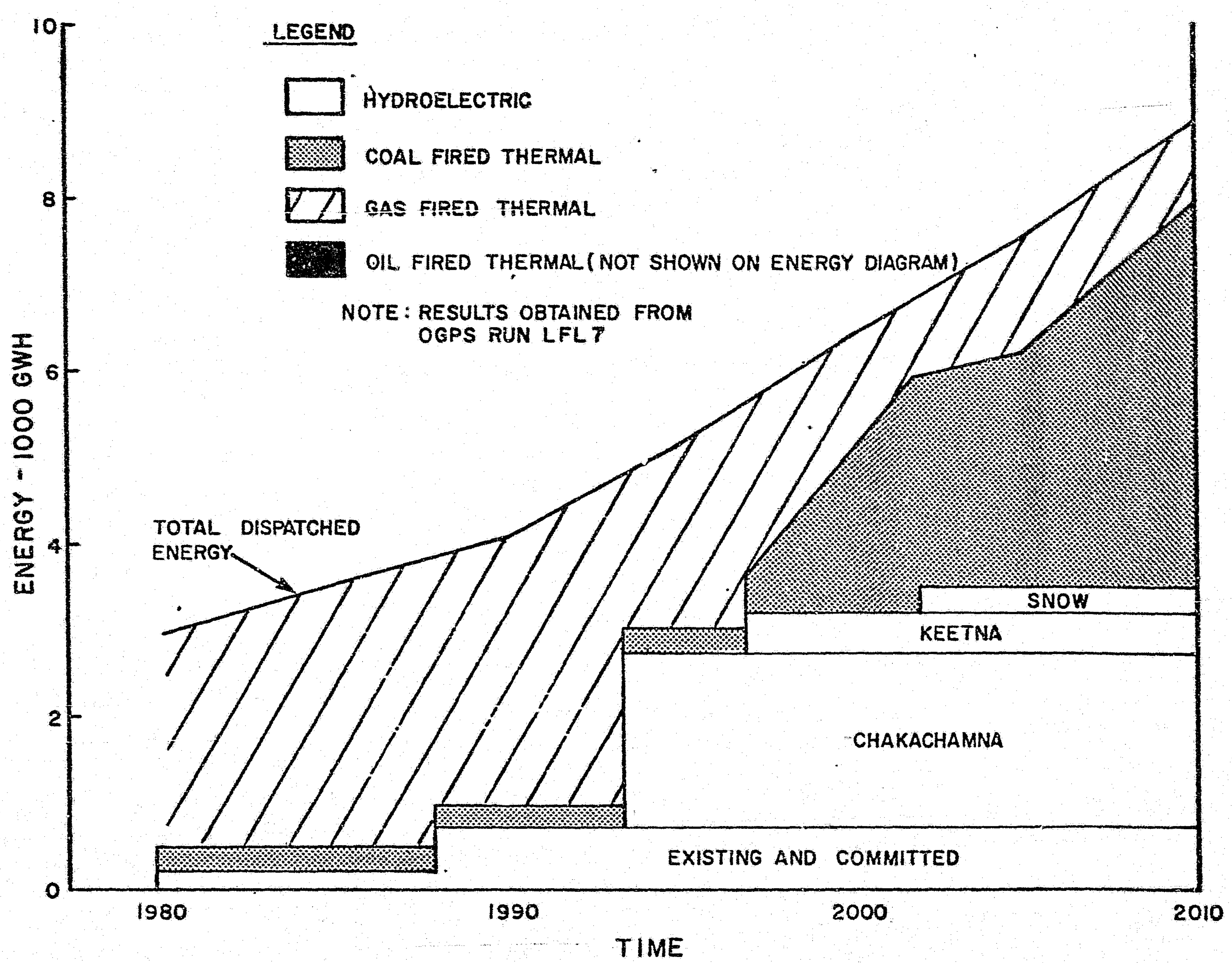
SCALE - MILES
1 INCH EQUALS APPROXIMATELY 40 MILES

0 - 25 MW		25-100 MW		25-100 MW		> 100 MW	
1.	STRANDLINE L.	13.	WHISKERS	26.	SNOW	39.	LANE
2.	LOWER BELUGA	14.	COAL	27.	KENAI LOWER	40.	TOKICHITNA
3.	LOWER LAKE CR.	15.	CHULITNA	28.	GERSTLE	41.	YENTNA
4.	ALLISON CR.	16.	OHIO	29.	TANANA R.	42.	CATHEDRAL BLUFFS
5.	CRESCENT LAKE 2	17.	LOWER CHULITNA	30.	BRUSKASHA	43.	JOHNSON
6.	GRANT LAKE	18.	CACHE	31.	KANTISHNA R.	44.	BROWNE
7.	McCLURE BAY	19.	GREENSTONE	32.	UPPER BELUGA	45.	JUNCTION IS.
8.	UPPER NELLIE JUAN	20.	TALKEETNA 2	33.	COFFEE	46.	VACHON IS.
9.	POWER CREEK	21.	GRANITE GORGE	34.	GULKANA R.	47.	TAZILNA
10.	SILVER LAKE	22.	KEETNA	35.	KLUTINA	48.	KENAI LAKE
11.	SOLOMON GULCH	23.	SHEEP CREEK	36.	BRADLEY LAKE	49.	CHAKACHAMNA
12.	TUSTUMENA	24.	SKWENTNA	37.	HICK'S SITE		
		25.	TALACHULITNA	38.	LOWE		

SELECTED ALTERNATIVE HYDROELECTRIC SITES

FIGURE D.13

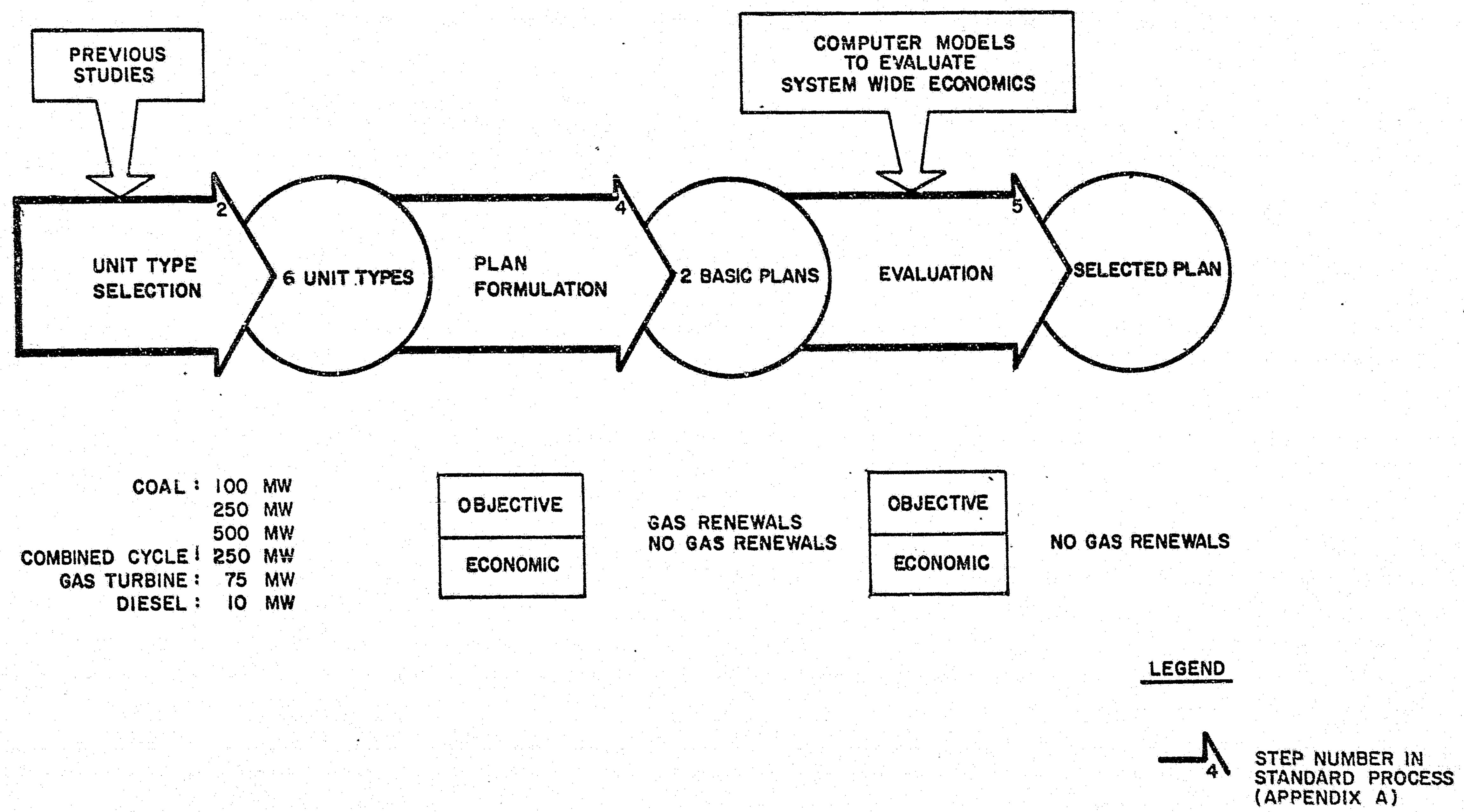




GENERATION SCENARIO INCORPORATING THERMAL AND ALTERNATIVE HYDROPOWER DEVELOPMENTS - MEDIUM LOAD FORECAST -

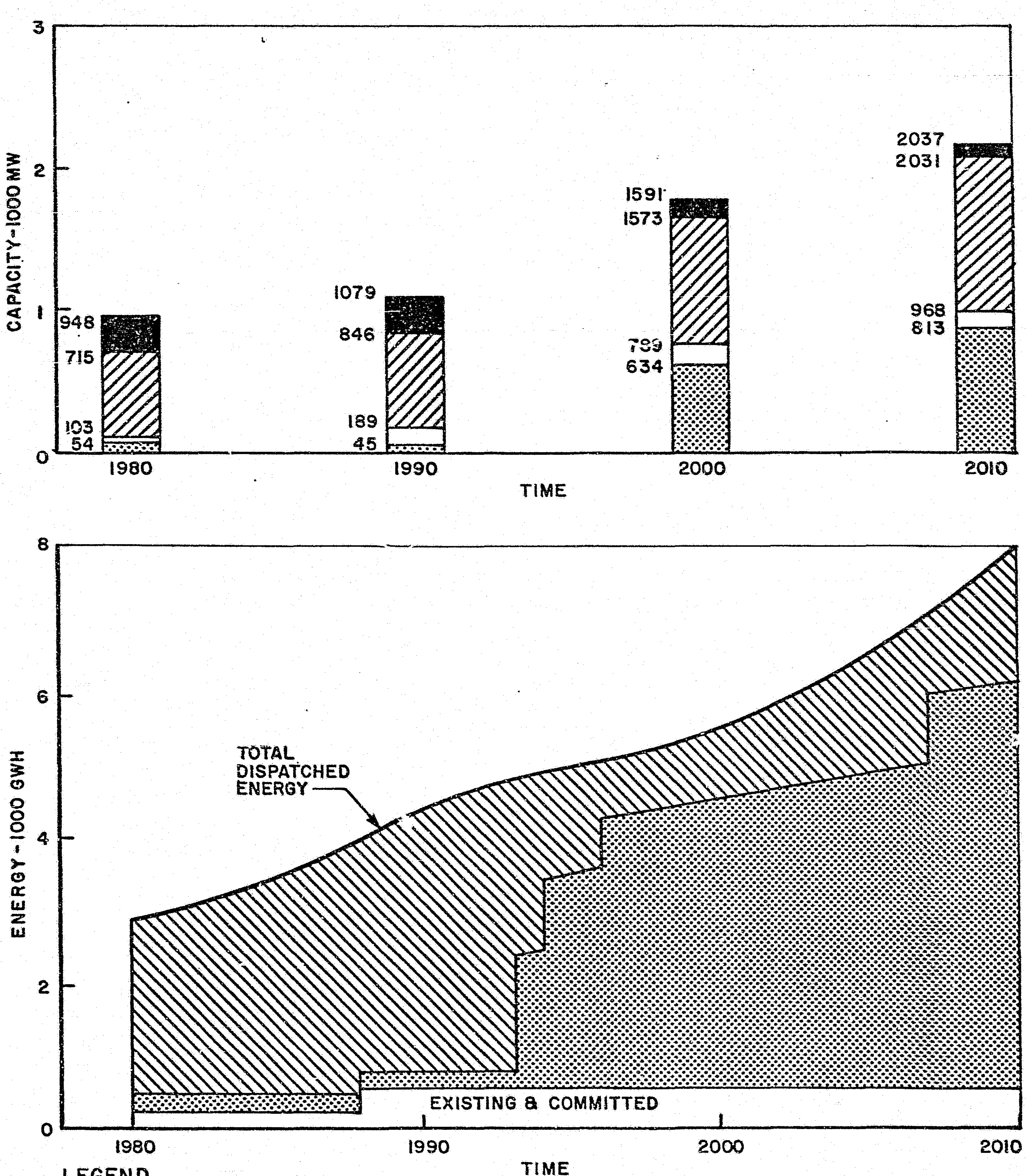
FIGURE D.14

ACRES



FORMULATION OF PLANS INCORPORATING ALL-THERMAL GENERATION

FIGURE D.15

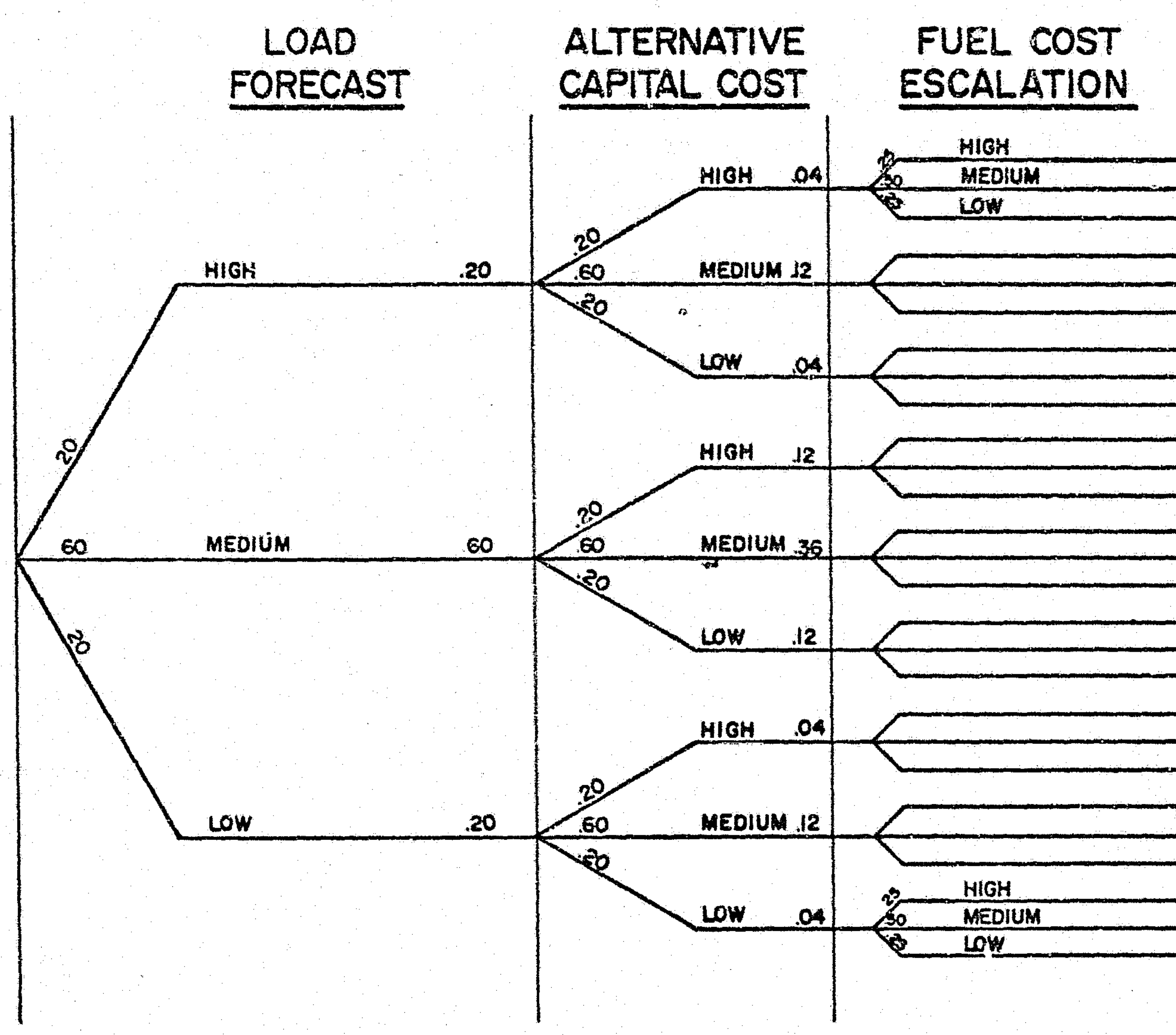


LEGEND

- HYDROELECTRIC
- COAL FIRED THERMAL
- GAS FIRED THERMAL
- OIL FIRED THERMAL (NOT SHOWN ON ENERGY DIAGRAM)

ALTERNATIVE GENERATION SCENARIO
BATTELLE MEDIUM LOAD FORECAST

FIGURE D.16 ACRES

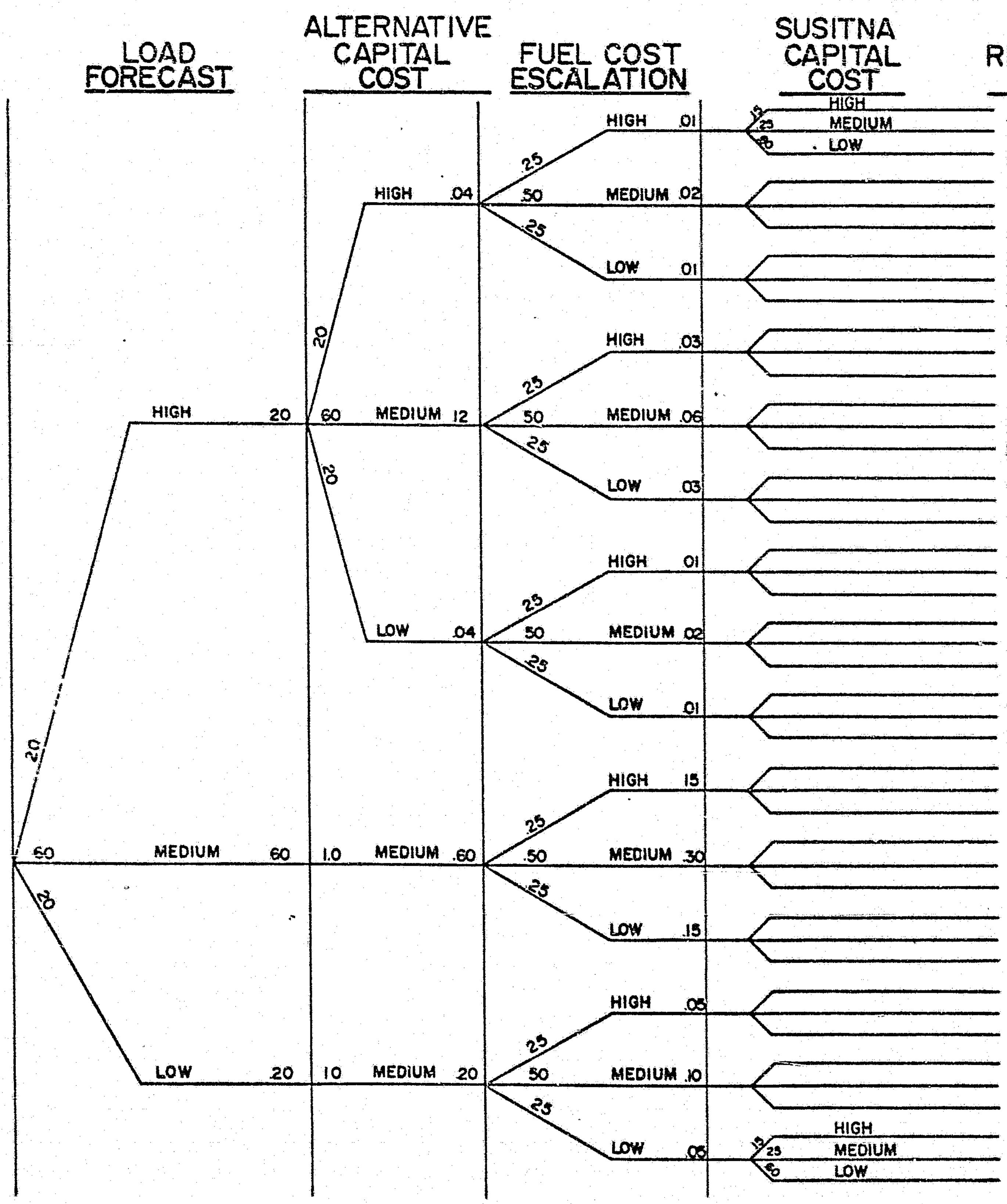


RESULT ID	PROBABILITY	LONG-TERM COST PRESENT WORTH
T01	.01	$15,088
T02	.02	11,669
T03	.01	7,624
T04	.03	14,194
T05	.06	10,859
T06	.03	7,313
T07	.01	13,742
T08	.02	10,503
T09	.01	7,184
T10	.03	11,272
T11	.06	8,858
T12	.03	5,991
T13	.09	10,637
T14	.18	8,238
T15	.09	5,661
T16	.03	10,321
T17	.06	7,915
T18	.03	5,489
T19	.01	9,253
T20	.02	7,460
T21	.01	4,856
T22	.03	8,746
T23	.06	6,878
T24	.03	4,590
T25	.01	8,492
T26	.02	6,101
T27	.01	4,412

$\Sigma = 1.00$

FIGURE D.17 – PROBABILITY TREE – SYSTEM WITH ALTERNATIVES TO SUSITNA

ACRES



RESULT ID	PROBABILITY	LONG-TERM COST PRESENT WORTH
S01	.0015	$11,684
S02	.0025	10,683
S03	.0060	9,784
S04	.0030	10,190
S05	.0050	9,290
S06	.0120	8,390
S07	.0015	8,951
S08	.0025	8,050
S09	.0060	7,151
S10	.0045	11,558
S11	.0075	10,658
S12	.0180	9,758
S13	.0090	10,147
S14	.0150	9,247
S15	.0360	8,347
S16	.0045	8,908
S17	.0075	8,008
S18	.0180	7,108
S19	.0015	11,414
S20	.0025	10,514
S21	.0060	9,614
S22	.0030	10,126
S23	.0050	9,221
S24	.0120	8,326
S25	.0015	8,886
S26	.0025	7,986
S27	.0060	7,081
S28	.0225	8,371
S29	.0375	7,388
S30	.0900	6,477
S31	.0450	7,974
S32	.0750	7,062
S33	.1800	6,161
S34	.0225	7,650
S35	.0375	6,738
S36	.0900	5,827
S37	.0075	7,884
S38	.0125	6,991
S39	.0300	6,097
S40	.0150	7,543
S41	.0250	6,650
S42	.0600	5,757
S43	.0075	7,331
S44	.0125	6,437
S45	.0300	5,543
	$\Sigma = 1.000$	

FIGURE D.18 — PROBABILITY TREE — SYSTEM WITH SUSITNA

ACRES

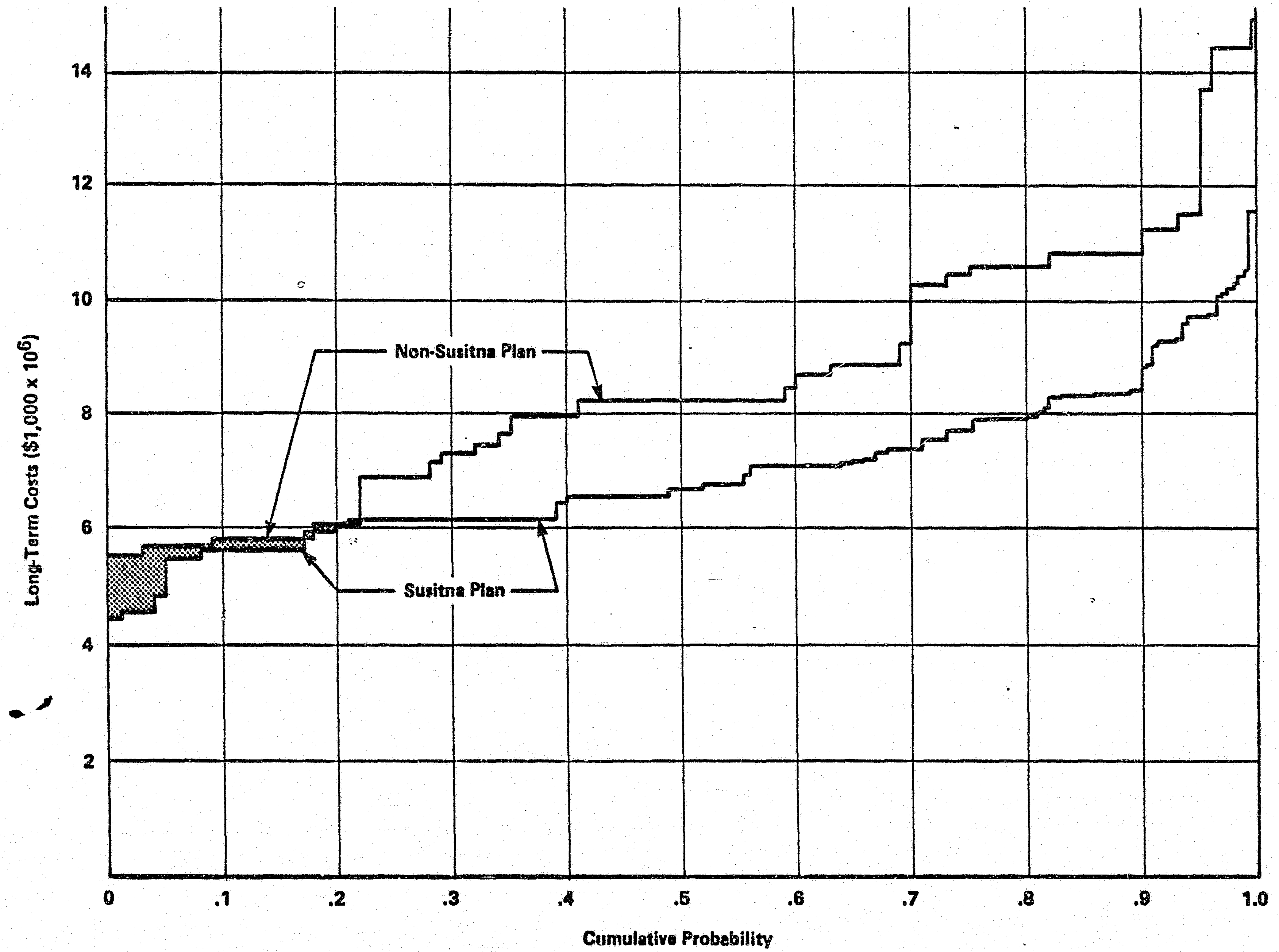


FIGURE D.19 — SUSITNA MULTIVARIATE SENSITIVITY ANALYSIS — LONG-TERM COSTS VS CUMULATIVE PROBABILITY

ACRES

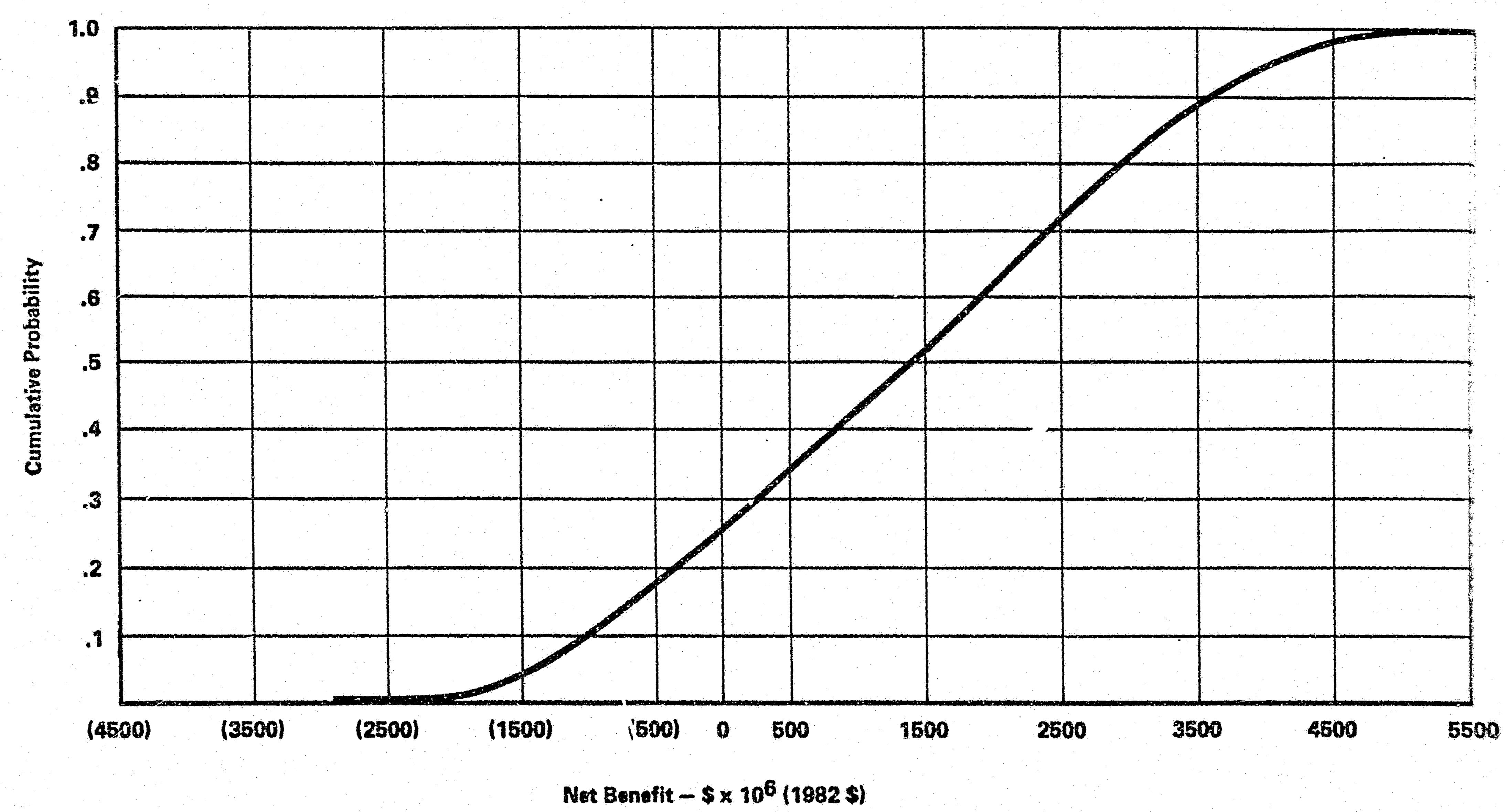


FIGURE D.20 – SUSITNA MULTIVARIATE SENSITIVITY ANALYSIS – CUMULATIVE PROBABILITY VS NET BENEFITS

ACRES

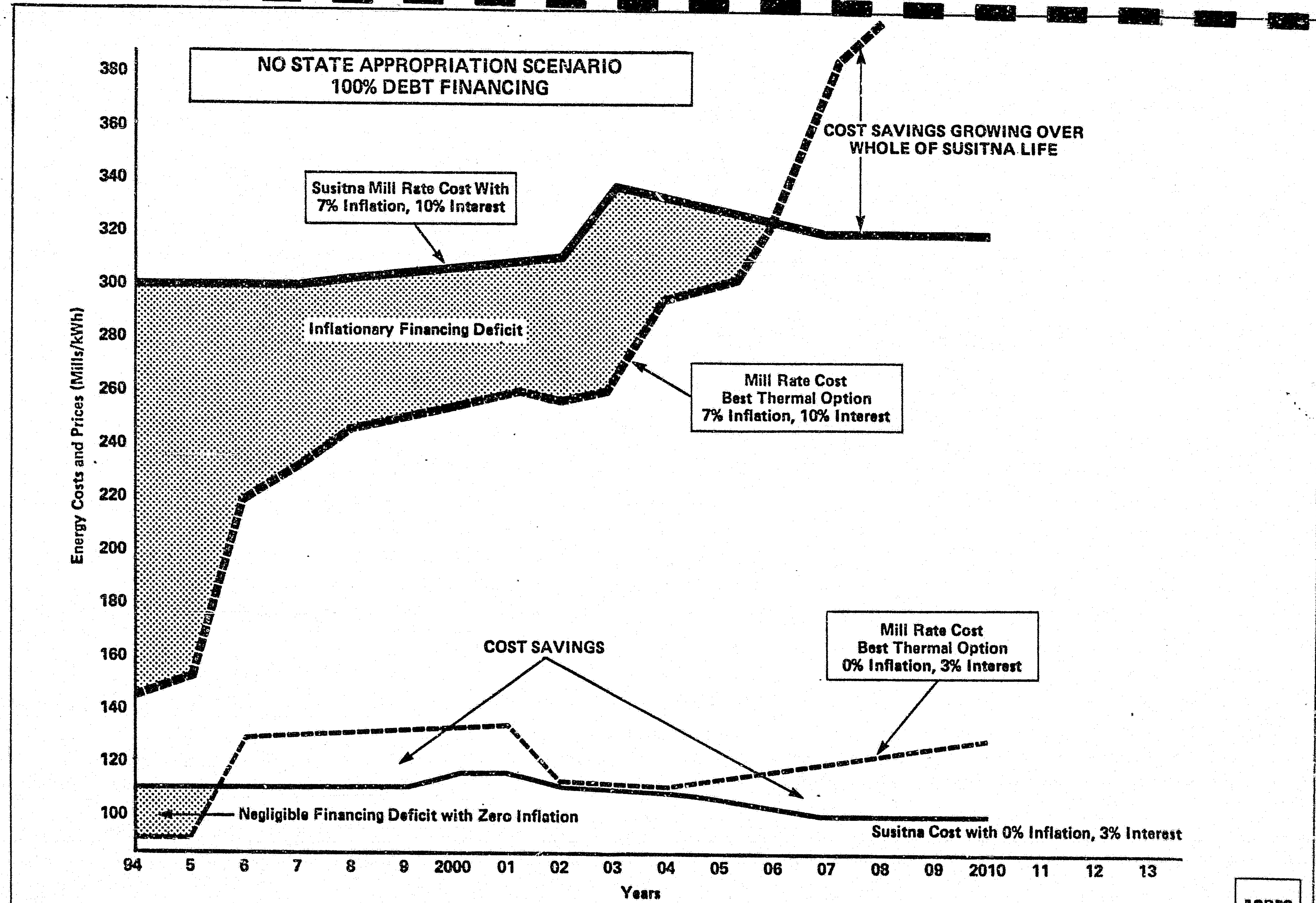


FIGURE D.21 – ENERGY COST COMPARISON – 100% DEBT FINANCING 0 AND 7% INFLATION

ACRES

Rev. 1

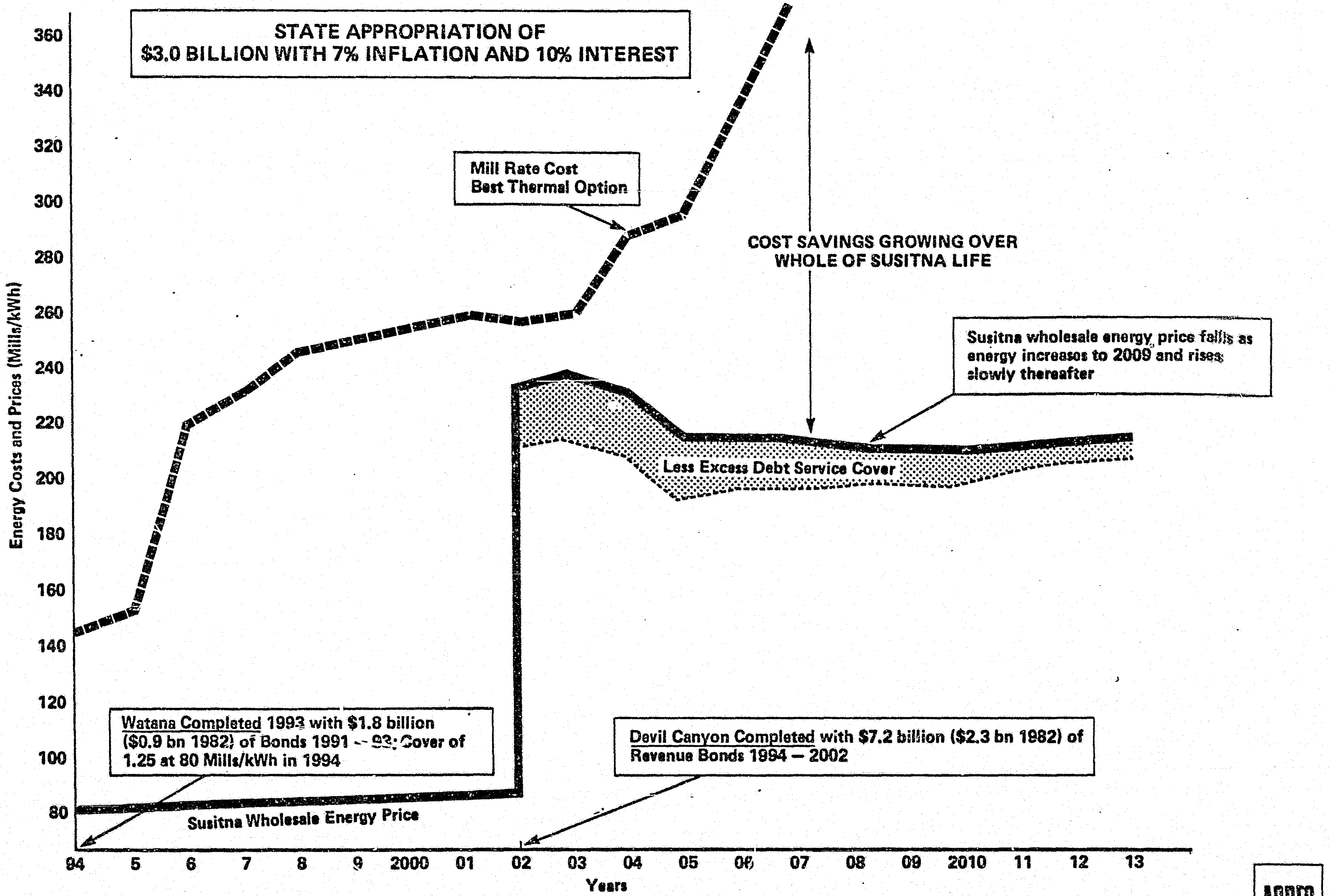


FIGURE D.22 – ENERGY COST COMPARISON – STATE APPROPRIATION $3 BILLION (1982 $)

ACRES

Rev. 1

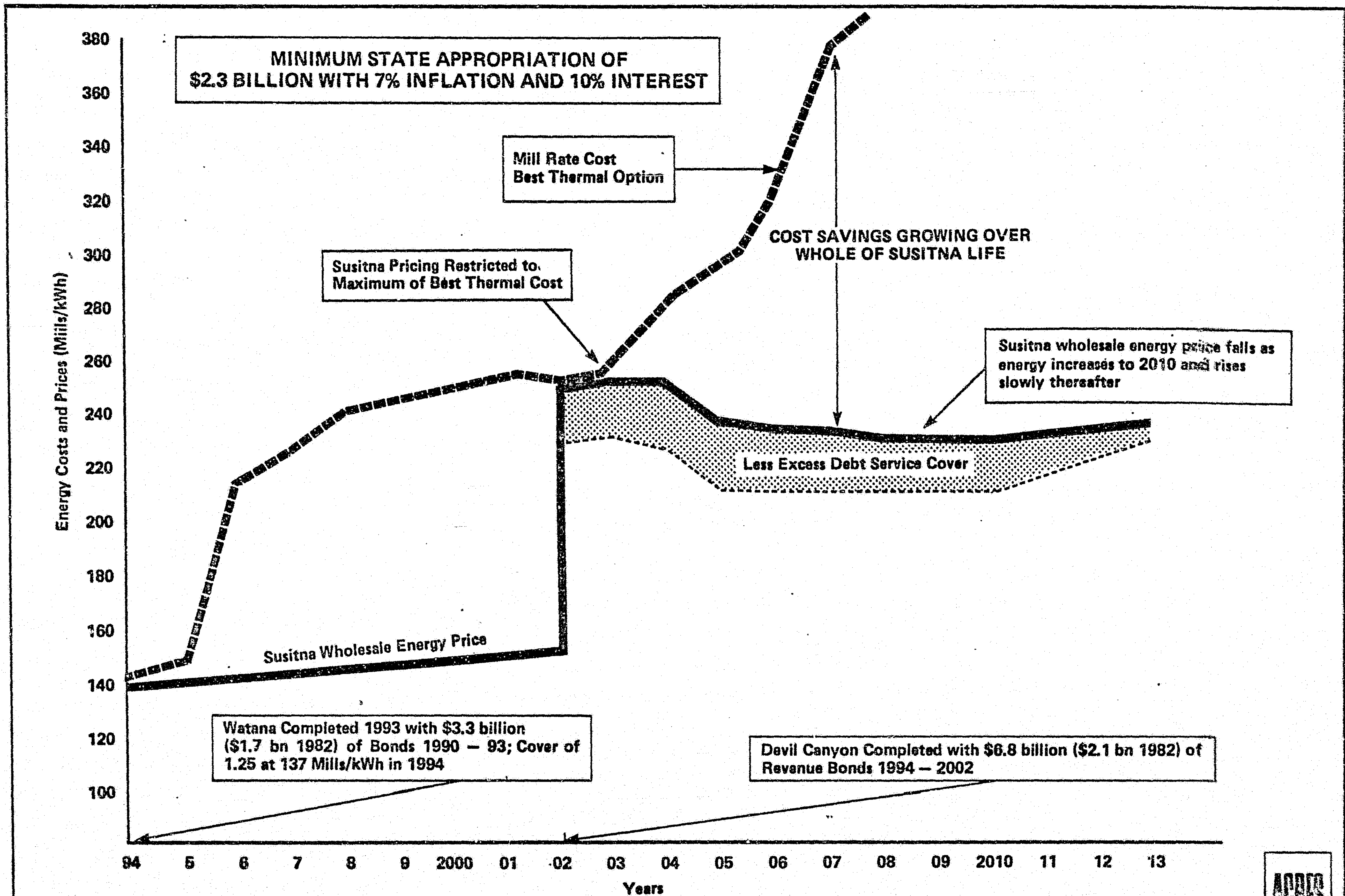


FIGURE D.23 — ENERGY COST COMPARISON $2.3 BILLION (1982 $) — MINIMUM STATE APPROPRIATION

Rev. 1

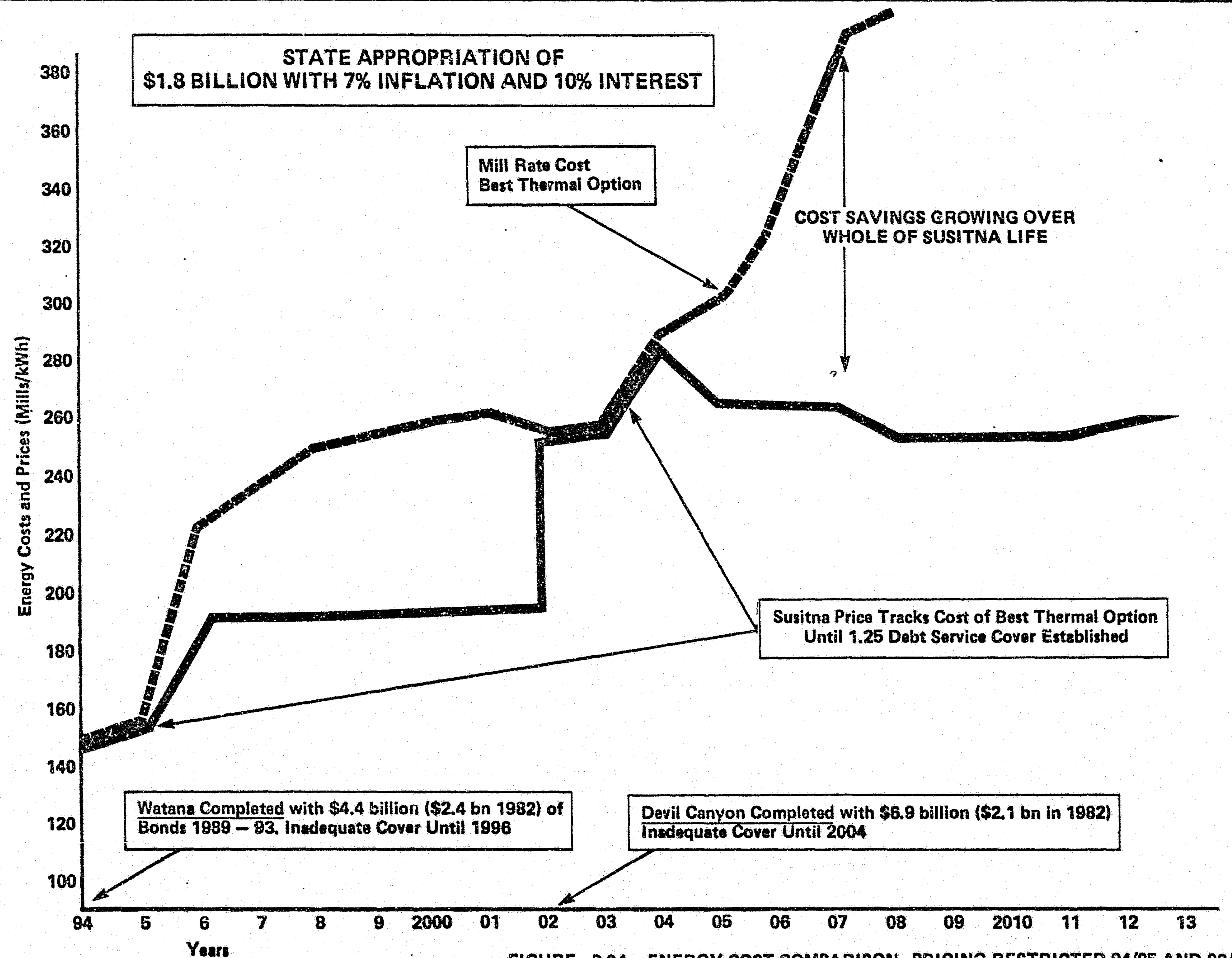


FIGURE D.24 – ENERGY COST COMPARISON – PRICING RESTRICTED 94/95 AND 03/04

ACRES

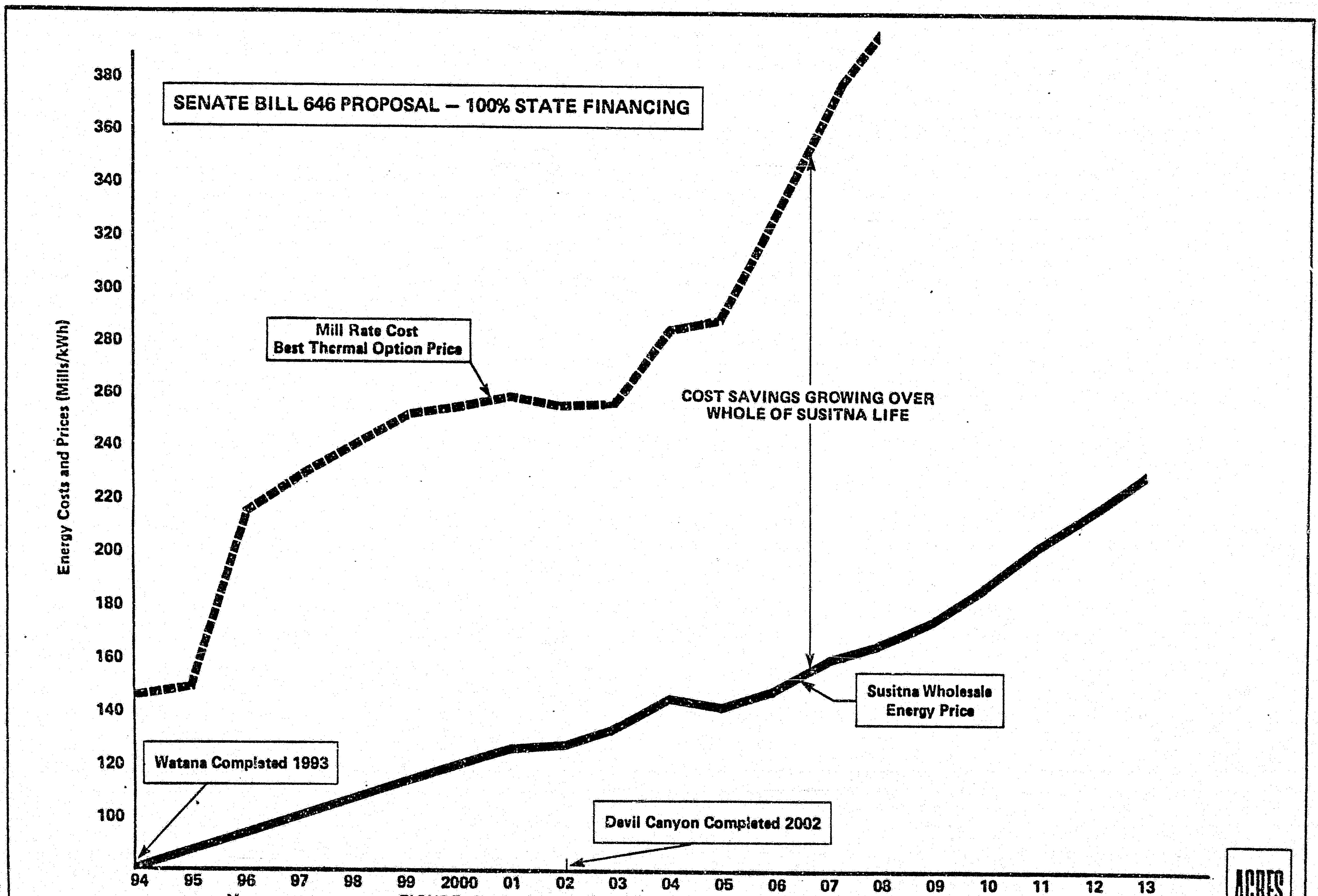


FIGURE D.25 — ENERGY COST COMPARISON MEETING SB 646 REQUIREMENTS WITH 100% FINANCING

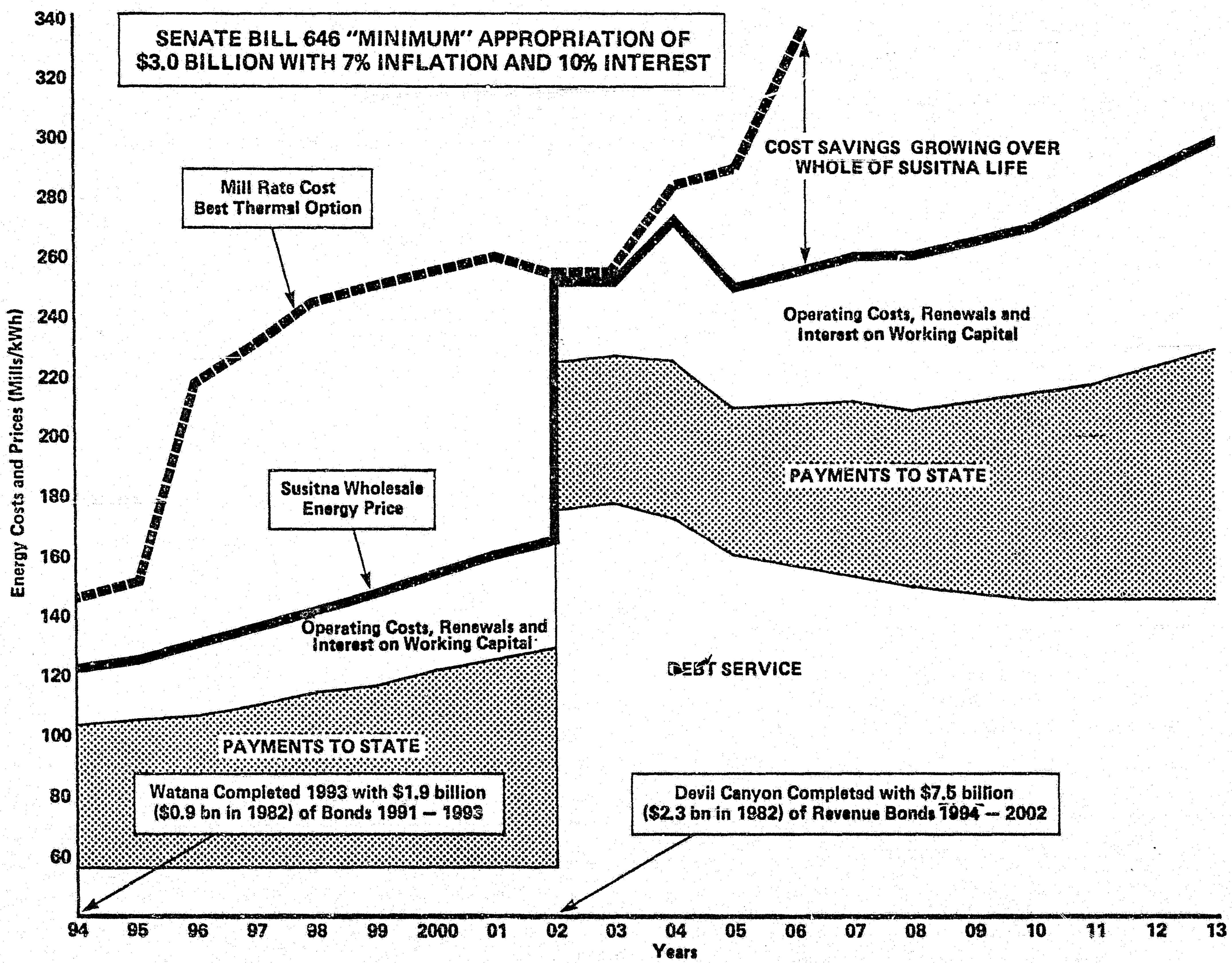


FIGURE D.26 – ENERGY COST COMPARISON MEETING SB 646 REQUIREMENTS WITH $3.0 BILLION APPROPRIATION

SPECIFIC FINANCING RISK III: EARLY YEAR NONVIABILITY

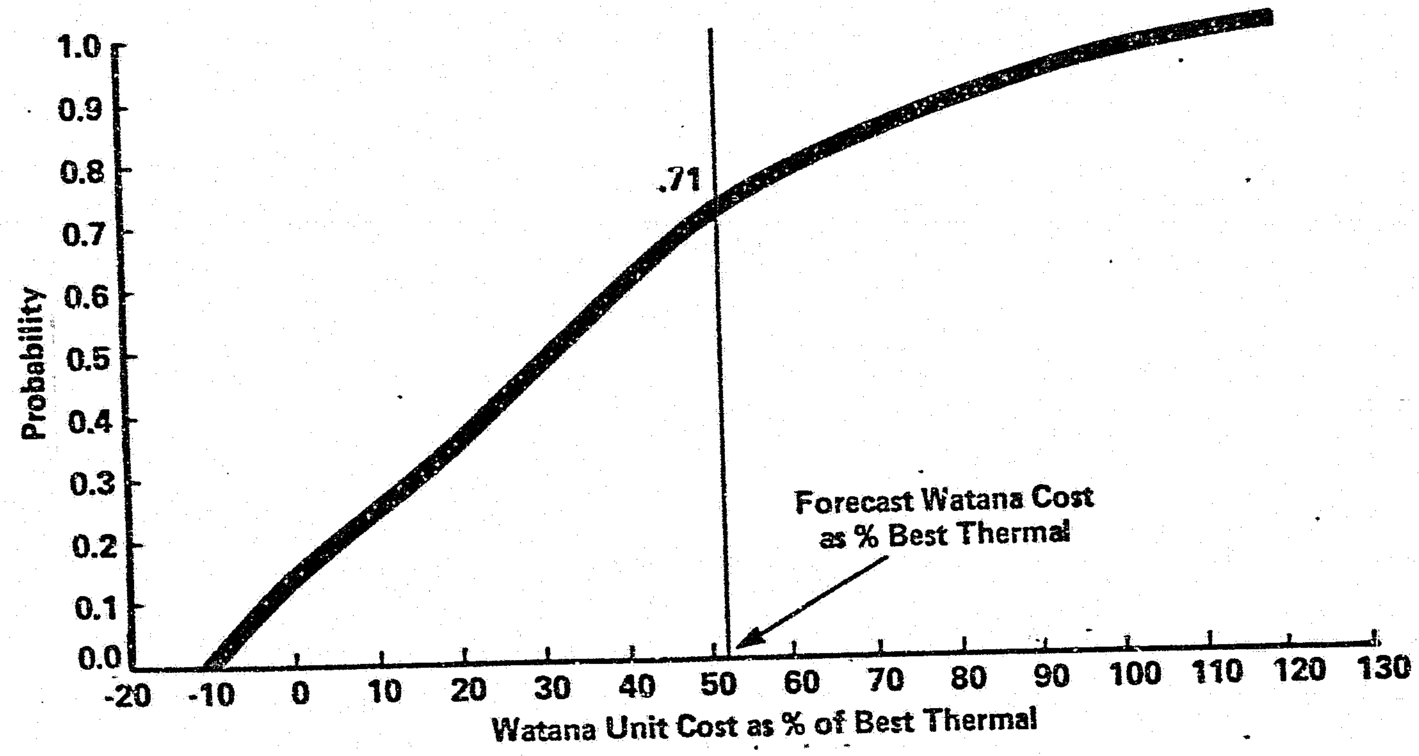


FIGURE D.27 – WATANA UNIT COSTS AS PERCENT OF BEST THERMAL OPTION IN 1996

AGGREGATE RISK: POTENTIAL NET OPERATING EARNINGS

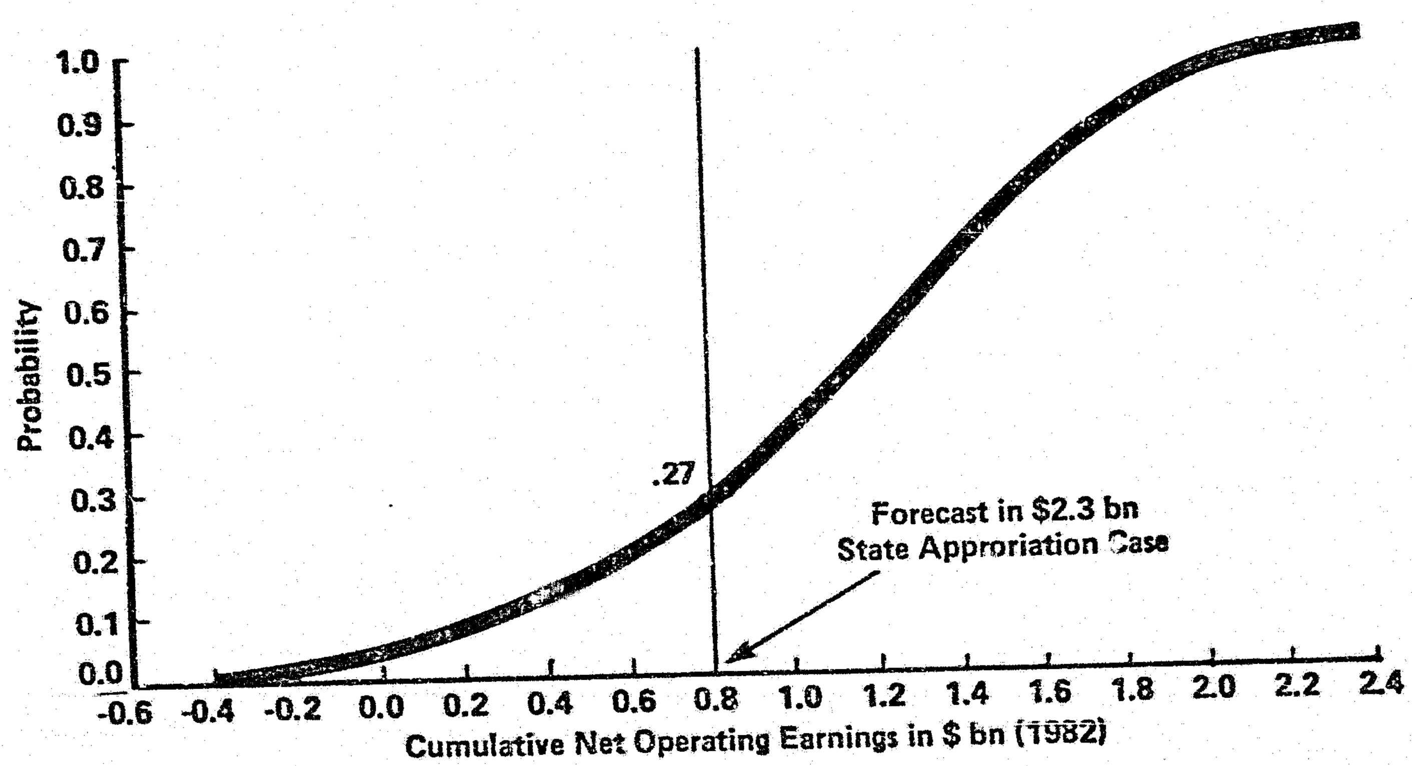


FIGURE D.28 – CUMULATIVE NET OPERATING EARNINGS BY 2000

ACRES

SPECIFIC RISK I: RISK OF BOND REQUIREMENT OVERRUN

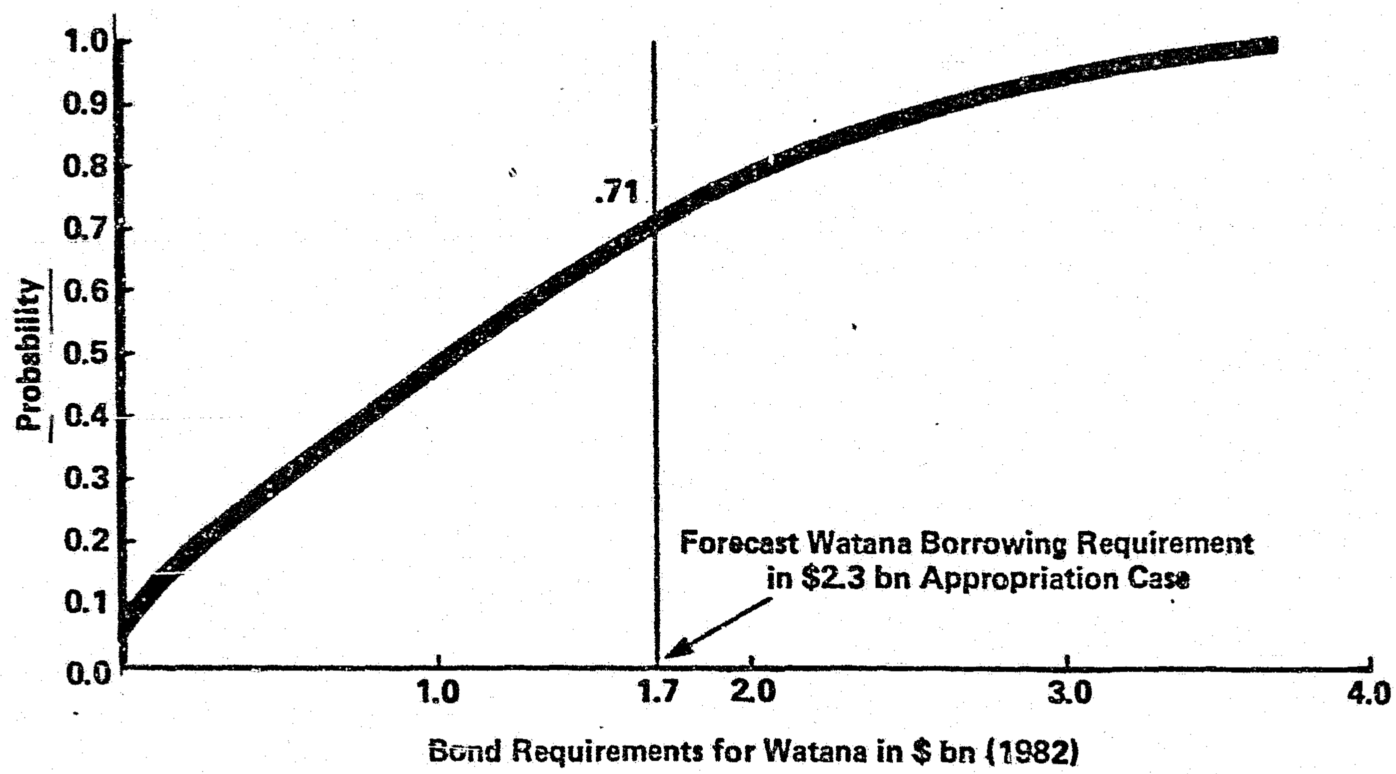


FIGURE D.29 – BOND FINANCING REQUIREMENTS

SPECIFIC RISK II: IMPAIRMENT OF STATE CREDIT

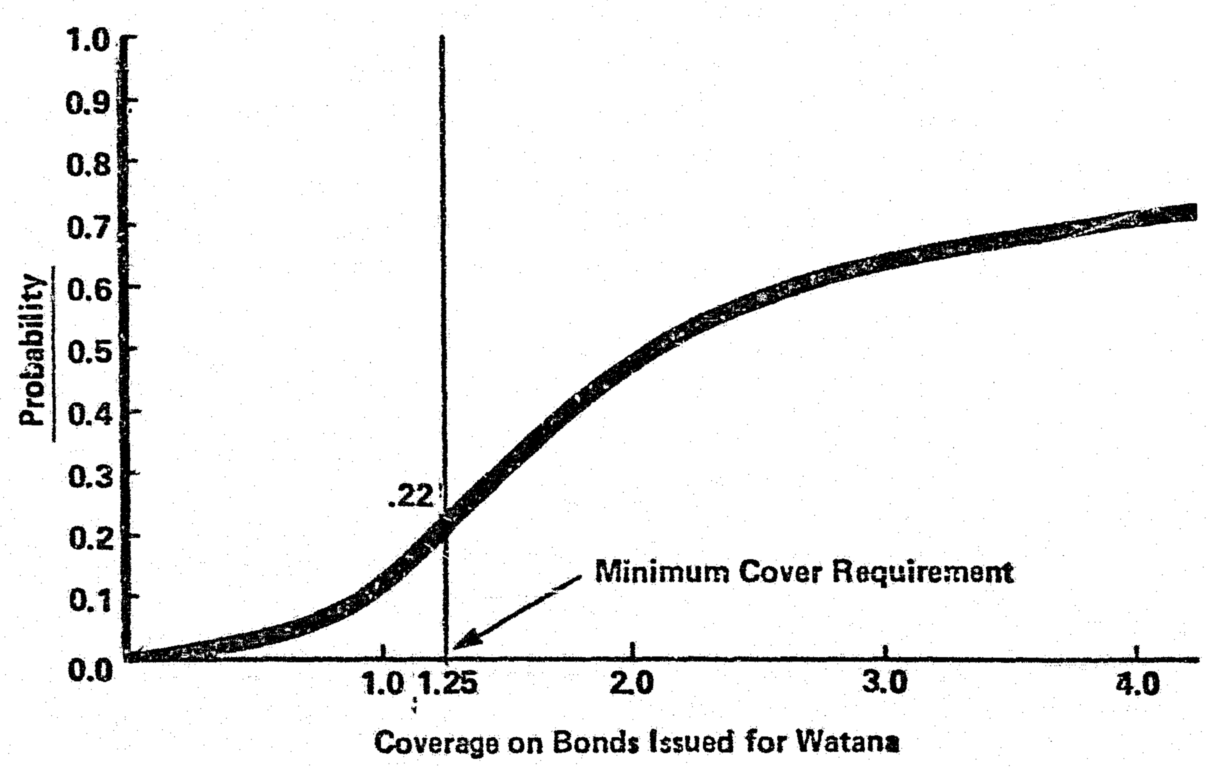


FIGURE D.30 – DEBT SERVICE COVER

ACRES