BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

# SUSITNA HYDROELECTRIC PROJECT

VOLUME 5

# DRAFT

## EXHIBIT C

## EXHIBIT D

## APPENDIX D1

HARZA-EBASCO
SUSITNA JOINT VENTURE

Alaska Power Authority

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

# SUSITNA HYDROELECTRIC PROJECT
# DRAFT LICENSE APPLICATION

## VOLUME 5

## EXHIBIT C
## PROPOSED CONSTRUCTION SCHEDULE

## EXHIBIT D
## PROJECT COSTS AND FINANCING

## APPENDIX D1
## FUELS PRICING



November 1985

# NOTICE

A NOTATIONAL SYSTEM HAS BEEN USED
TO DENOTE DIFFERENCES BETWEEN THIS AMENDED LICENSE APPLICATION
AND
THE LICENSE APPLICATION AS ACCEPTED FOR FILING BY FERC
ON JULY 29, 1983

This system consists of placing one of the following notations beside each text heading:

(o) No change was made in this section, it remains the same as was presented in the July 29, 1983 License Application

(*) Only minor changes, largely of an editorial nature, have been made

(**) Major changes have been made in this section

(***) This is an entirely new section which did not appear in the July 29, 1983 License Application

# VOLUME COMPARISON

VOLUME NUMBER COMPARISON

LICENSE APPLICATION AMENDMENT VS. JULY 29, 1983 LICENSE APPLICATION

| EXHIBIT | CHAPTER | DESCRIPTION | AMENDMENT VOLUME NO. | JULY 29, 1983 APPLICATION VOLUME NO. |
|---|---|---|---|---|
| A | Entire | Project Description | 1 | 1 |
| B | Entire | Project Operation and Resource Utilization | 2 | 2 & 2A |
| | App. B1 | MAP Model Documentation Report | 3 | 2B |
| | App. B2 | RED Model Documentation Report | 4 | 2C |
| | App. B3 | RED Model Update | 4 | -- |
| C | Entire | Proposed Construction Schedule | 5 | 1 |
| D | Entire | Project Costs and Financing | 5 | 1 |
| | App. D1 | Fuels Pricing | 5 | 1 |
| E | 1 | General Description of Locale | 6 | 5A |
| | 2 | Water Use and Quality | 6 | 5A |
| | Tables<br>Figures | | 7 | 5A<br>5B |
| | Figures | | 8 | 5B |
| | 3 | Fish, Wildlife and Botanical Resources (Sect. 1 and 2) | 9 | 6A<br>6B |
| | | Fish, Wildlife and Botanical Resources (Sect. 3) | 10 | 6A<br>6B |
| | | Fish, Wildlife and Botanical Resources (Sect. 4, 5, 6, & 7) | 11 | 6A<br>6B |
| | 4 | Historic & Archaeological Resources | 12 | 7 |
| | 5 | Socioeconomic Impacts | 12 | 7 |
| | 6 | Geological and Soil Resources | 12 | 7 |
| | 7 | Recreational Resources | 13 | 8 |
| | 8 | Aesthetic Resources | 13 | 8 |
| | 9 | Land Use | 13 | 8 |
| | 10 | Alternative Locations, Designs and Energy Sources | 14 | 9 |
| | 11 | Agency Consultation | 14 | 10A<br>10B |
| F | Entire | Project Design Plates | 15 | 3 |
| F | Entire | Supporting Design Report | 16 | -- |
| G | Entire | Project Limits and Land Ownership Plates | 17 | 4 |

# SUMMARY TABLE OF CONTENTS

SUSITNA HYDROELECTRIC PROJECT
LICENSE APPLICATION

SUMMARY TABLE OF CONTENTS

EXHIBIT A
PROJECT DESCRIPTION

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT A
## PROJECT DESCRIPTION

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT A
PROJECT DESCRIPTION

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT B
## PROJECT OPERATION AND RESOURCE UTILIZATION

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT B - APPENDIX B1

MAN-IN-THE-ARCTIC PROGRAM (MAP)
TECHNICAL DOCUMENTATION REPORT
STAGE MODEL (VERSION A85.1)
REGIONALIZATION MODEL (VERSION A84.CD)
SCENARIO GENERATOR

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT B - APPENDIX B2
RAILBELT ELECTRICITY DEMAND (RED) MODEL
TECHNICAL DOCUMENTATION REPORT (1983 VERSION)

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT B - APPENDIX B3
RAILBELT ELECTRICITY DEMAND (RED) MODEL
CHANGES MADE JULY 1983 TO AUGUST 1985

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT C
PROPOSED CONSTRUCTION SCHEDULE

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT D
PROJECT COSTS AND FINANCING

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT D
PROJECT COSTS AND FINANCING

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT D - APPENDIX D1
FUELS PRICING

Title | Page No.

## EXHIBIT E - CHAPTER 1
## GENERAL DESCRIPTION OF THE LOCALE

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 2
WATER USE AND QUALITY

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT E - CHAPTER 2
## WATER USE AND QUALITY

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 3
FISH, WILDLIFE, AND BOTANICAL RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 3
FISH, WILDLIFE, AND BOTANICAL RESOURCES

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT E - CHAPTER 4
## HISTORIC AND ARCHEOLOGICAL RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 5
SOCIOECONOMIC IMPACTS

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT E - CHAPTER 5
## SOCIOECONOMIC IMPACTS

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 6
GEOLOGICAL AND SOIL RESOURCES

## SUMMARY TABLE OF CONTENTS (cont'd)

## EXHIBIT E - CHAPTER 7
## RECREATIONAL RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 7
RECREATIONAL RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 8
AESTHETIC RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 8
AESTHETIC RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 8
AESTHETIC RESOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 9
LAND USE

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 10
ALTERNATIVE LOCATIONS, DESIGNS, AND ENERGY SOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 10
ALTERNATIVE LOCATIONS, DESIGNS, AND ENERGY SOURCES

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT E - CHAPTER 11
AGENCY CONSULTATION

## EXHIBIT F
## SUPPORTING DESIGN REPORT (PRELIMINARY)

SUMMARY TABLE OF CONTENTS (cont'd)

EXHIBIT F
SUPPORTING DESIGN REPORT (PRELIMINARY)

# C - PROPOSED CONSTRUCTION SCHEDULE
# D - PROJECT COSTS AND FINANCING
# AND
# D1 - FUELS PRICING

# C - PROPOSED CONSTRUCTION SCHEDULE

SUSITNA HYDROELECTRIC PROJECT
LICENSE APPLICATION

EXHIBIT C
PROPOSED CONSTRUCTION SCHEDULE

TABLE OF CONTENTS

EXHIBIT C
PROPOSED CONSTRUCTION SCHEDULE

TABLE OF CONTENTS (cont'd)

## EXHIBIT C
## PROPOSED CONSTRUCTION SCHEDULE

## LIST OF FIGURES

# EXHIBIT C
# PROPOSED CONSTRUCTION SCHEDULE

This section describes the construction schedules prepared for Watana Stages I and III and Devil Canyon Stage II to meet the on-line power requirements of 1999, 2005 and 2012, respectively. Schedules for the development of both Watana and Devil Canyon are shown on Figures C.1, C.2, and C.3. The main elements of the project have been shown on these schedules, as well as some key interrelationships. For purposes of planning, it has been assumed that the FERC license will be awarded by January 1, 1990.

For all stages the period for construction of the dams and their appurtenances is critical. A study of the front end requirements for Watana Stage I concluded that initial construction access work would have to commence as soon as possible and be completed in the shortest possible time to permit accomplishment of support facilities to meet field exploration requirements for design.

## 1 - WATANA STAGE I SCHEDULE (**)

Commencement of construction:

- o Main access road - March 1990
- o Main site facilities - April 1990
- o Diversion - May 1994

Completion of construction:

- o Four units ready - July 1999

Commencement of commercial operations:

- o Four units - July 1999

The Watana Stage I schedule was developed to meet two overall project constraints:

- o FERC license would be issued by January 1, 1990; and
- o Four units would be on-line by July 1, 1999.

The critical path of activities to meet the overall constraints was determined to be through site access, site facilities, geotechnical programs, diversion and main dam construction. In general, construction activities leading up to diversion in 1994 are on a normal schedule whereas the remaining activities are on an accelerated schedule.

1.1 - Access (*)

Initial road access to the site is required by October 1987. Certain equipment will be transported overland during the preceding winter months so that an airfield can be constructed during the summer of 1990. This effort to complete initial access is required to mobilize labor, equipment, and materials for the field explorations and the orderly construction of site facilities and diversion works.

1.2 - Site Facilities (**)

Site facilities must be developed in a very short time to support the main construction activities. A camp to house approximately 750 workers must be constructed during the first twelve months. Site construction roads and contractors' work areas have to be started. An aggregate processing plant and concrete batching plant must be operational to start diversion tunnel concrete work by October 1993. Construction transmission lines must be completed by 1991 to supply power for camp and construction activities.

1.3 - Diversion (**)

Construction of diversion facilities, the first major activity, should start in the spring of 1992 after completion of access roads to the portal areas. Excavation of the portals and tunnels requires a concentrated effort to allow completion of the tunnels for river diversion by May 1994. The upstream diversion dike must be placed to divert river flows in May 1994. The cofferdams are scheduled for completion before December 1994 to avoid overtopping during the following spring.

1.4 - Dam Embankment (**)

The progress of work on the dam is critical throughout the period 1995 through 1998. Mobilization of equipment and start of site work must begin in 1994. Excavation of the right abutment as well as river alluvium under the dam core begins after diversion and installation of the cofferdams in 1994. During 1995 and 1996, dewatering, excavation and foundation treatment must be completed in the riverbed area and a substantial start made on placing fill. The construction schedule is based on the following program:

| Year | Fill Elevation October 15 (feet) | Reservoir Elevation (feet) |
|---|---|---|
| 1994 | -- | -- |
| 1995 | 1,506 | -- |
| 1996 | 1,725 | -- |
| 1997 | 1,835 | -- |
| 1998 | 2,025 | 1,920 |

The program for fill placing has been based on an average six- month season. It has been developed based on high utilization of construction equipment which is required to handle and process the necessary fill materials.

### 1.5 - Spillway and Intakes (**)

These structures have been scheduled for completion in consonance with embankment construction to meet the requirement to handle flows. In general, excavation for the spillway is on the critical path and must begin so that excavated rock can be placed in the dam embankment as soon as it is excavated.

### 1.6 - Powerhouse and Other Underground Works (**)

The four units are scheduled to be on line by 1999. Excavation for the access tunnel into the powerhouse complex has been scheduled to start in late 1994. Concrete begins late in 1996 with start of installation of major mechanical and electrical work in 1997. In general, the underground works have been scheduled to level resource demands as much as possible.

### 1.7 - Relict Channel (**)

Construction of underground seepage remedial measures (downstream adit toe drain) will be installed during 1998 and 1999 if impoundment reservoir level effects indicate the need.

### 1.8 - Transmission Lines/Switchyards (*)

Construction of the main transmission lines and switchyards has been scheduled to begin in 1995 and to be completed before commissioning of the first unit.

### 1.9 - General (**)

The Watana schedule for Stage I requires that extensive planning and commitments for exploration programs be made during 1986 to permit this type work to progress on schedule during 1987 and 1988.

## 2 - DEVIL CANYON STAGE II SCHEDULE (**)

Commencement of construction:

- o Main Access - April 1995
- o Site Facilities - June 1996
- o River Diversion - May 1999

Completion of construction:

- o Four units - October 2005

Commencement of commercial operations:

- o Four units - October 2005

The Devil Canyon schedule was developed to meet the on-line power requirement of all four units in 2005. The critical path of activities was determined to follow through site facilities, diversion and main dam construction.

### 2.1 - Access (**)

It has been assumed that site access built to Watana will exist at the start of construction. A road will be constructed connecting the Devil Canyon site to the Watana access road including a high level bridge over the Susitna River downstream of the Devil Canyon Dam. At the same time, a railroad spur will be constructed to permit railroad access to the south bank of the Susitna near Devil Canyon. These activities will be completed by mid-1997.

### 2.2 - Site Facilities (**)

Camp facilities should be started in 1996. Site roads and power transmission work could also be started at this time.

### 2.3 - Diversion (*)

Excavation and concreting of the single diversion tunnel should begin in 1994. River diversion and cofferdam construction will take place to permit start of dam construction in 1999.

### 2.4 - Arch Dam (**)

The construction of the arch dam will be the most critical construction activity from start of excavation in 1999 until topping out in 2004. The concrete program has been based on an average eight-month placing season for 4-1/2 years. The work has been scheduled so that a fairly constant work effort may be maintained during this period to make best use of equipment and manpower.

2.5 - Spillway and Intake (*)

The spillway and intake are scheduled for completion by the end of 2003 to permit reservoir filling the next year.

2.6 - Powerhouse and Other Underground Works (o)

Excavation of access into the powerhouse cavern is scheduled to begin in 2000. Concrete begins in 2001 with start of installation of major mechanical and electrical work in 2003.

2.7 - Transmission Lines/Switchyards (*)

The additional transmission facilities needed for Devil Canyon have been scheduled for completion by the time the first unit is ready for commissioning in 2004.

2.8 - General (*)

The development of site facilities at Devil Canyon begins gradually in 1996 with a rapid acceleration in 1997 through 1999. Within a short period of time, construction will begin on the major structures. This rapid development is dependent on the provision of support site facilities which should be completed in advance of the main construction work.

## 3 - WATANA STAGE III SCHEDULE (***)

Commencement of construction:

- o Access road - Provided in Stage I
- o Site facilities - Provided in Stage I
- o Dam construction - June 2006

Completion of construction:

- o Two units - October 2012

Commencement of commercial operations:

- o Six units - October 2012

### 3.1 - Access (***)

Access during Stage III construction will be provided by facilities constructed and utilized during Stages I and II.

### 3.2 - Site Facilities (***)

Site facilities developed to support the main construction activities for Stage I will be utilized during Stage III.

### 3.3 - Dam Embankment (***)

The progress of work on the dam is critical throughout the period 2006 through 2011. Mobilization of equipment and start of site work must begin early in 2006.

| Year | Fill Elevation October 15 (feet) | Reservoir Elevation (feet) |
|---|---|---|
| 2007 | 1,550 | -- |
| 2008 | 1,850 | -- |
| 2009 | 2,000 | -- |
| 2010 | 2,100 | -- |
| 2011 | 2,210 | -- |
| 2012 | -- | 2,065 |

The program for fill placement has been based on an average six-month season. It has been based on high utilization of construction equipment which is required to handle and process the necessary fill materials.

3.4 - Spillway and Intakes (***)

These Stage III structures have been scheduled to begin construction in 2008 and continue in consonance with embankment construction to meet the requirement to handle flows. Construction of the spillway ogee concrete work will be accomplished during the years 2010 and 2011. The gates will be reinstalled in the latter part of year 2011 and early 2012.

3.5 - Powerhouse and Other Underground Works (***)

All six units are scheduled to be on line by 2012. Concrete placement begins in the spring of 2008 with start of installation of major mechanical and electrical work in 2009.

3.6 - Relict Channel (***)

Construction of underground seepage remedial measures (cutoff wall) will be installed during 2011 and 2012 if impoundment reservoir level effects indicate the need.

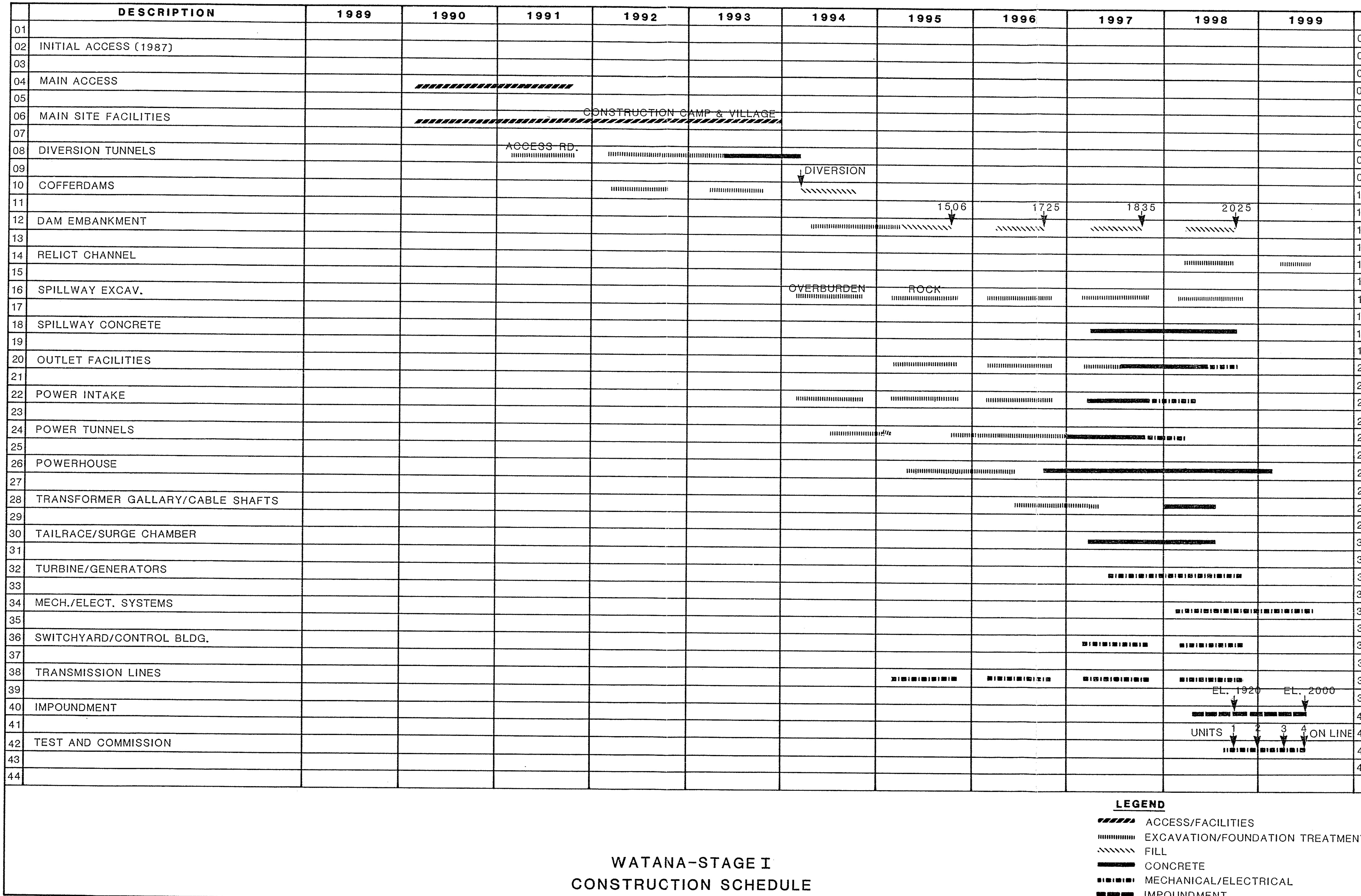
3.7 - Transmission Lines/Switchyards (***)

Construction of the transmission lines and switchyards for use in Stage III will begin in 2009 and be complete in 2011.

3.8 - General (***)

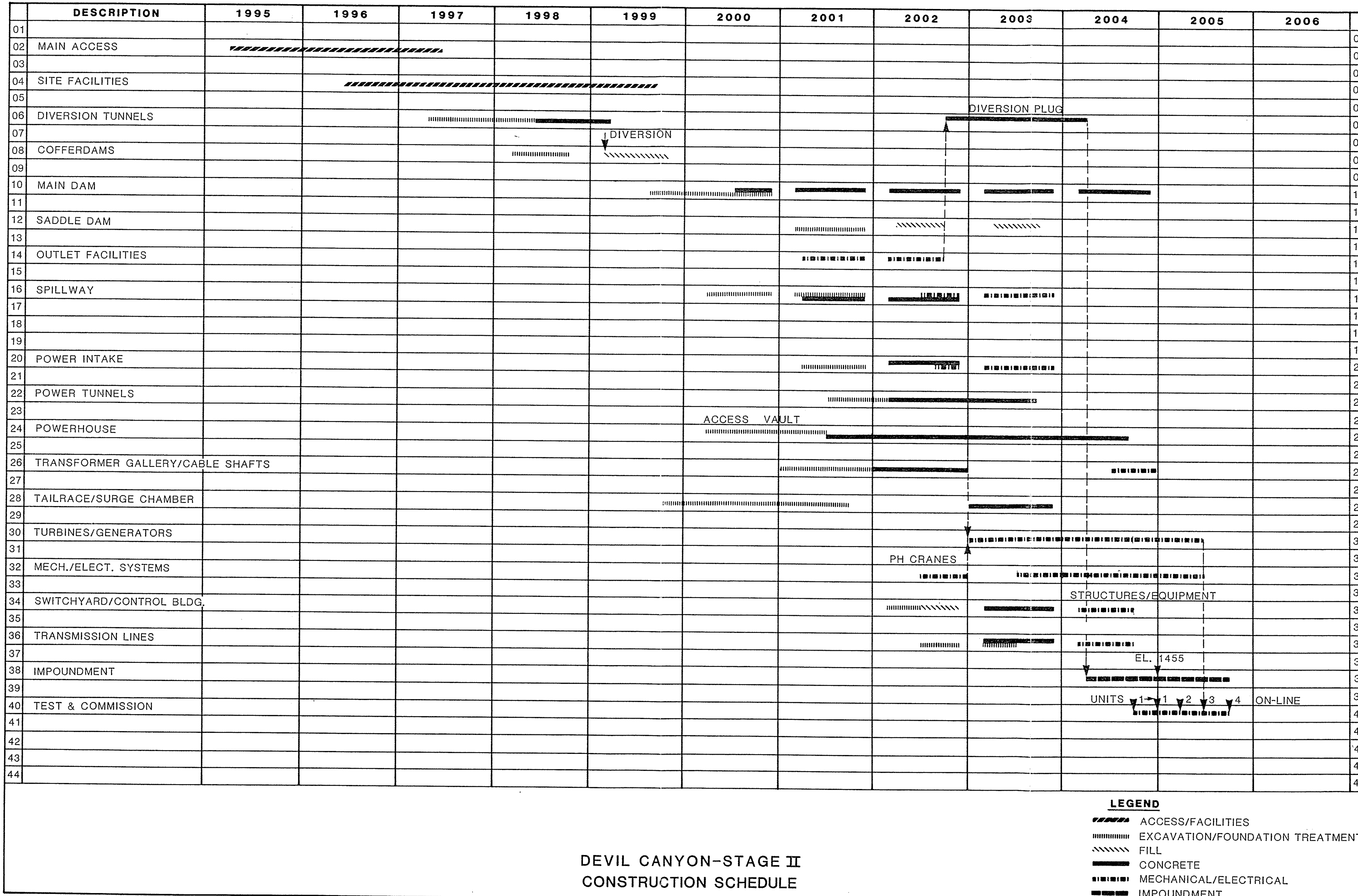
The Watana schedule requires that extensive engineering investigations be made during 2003 to permit this geotechnical work to progress on schedule from 2004 through 2005.

# FIGURES



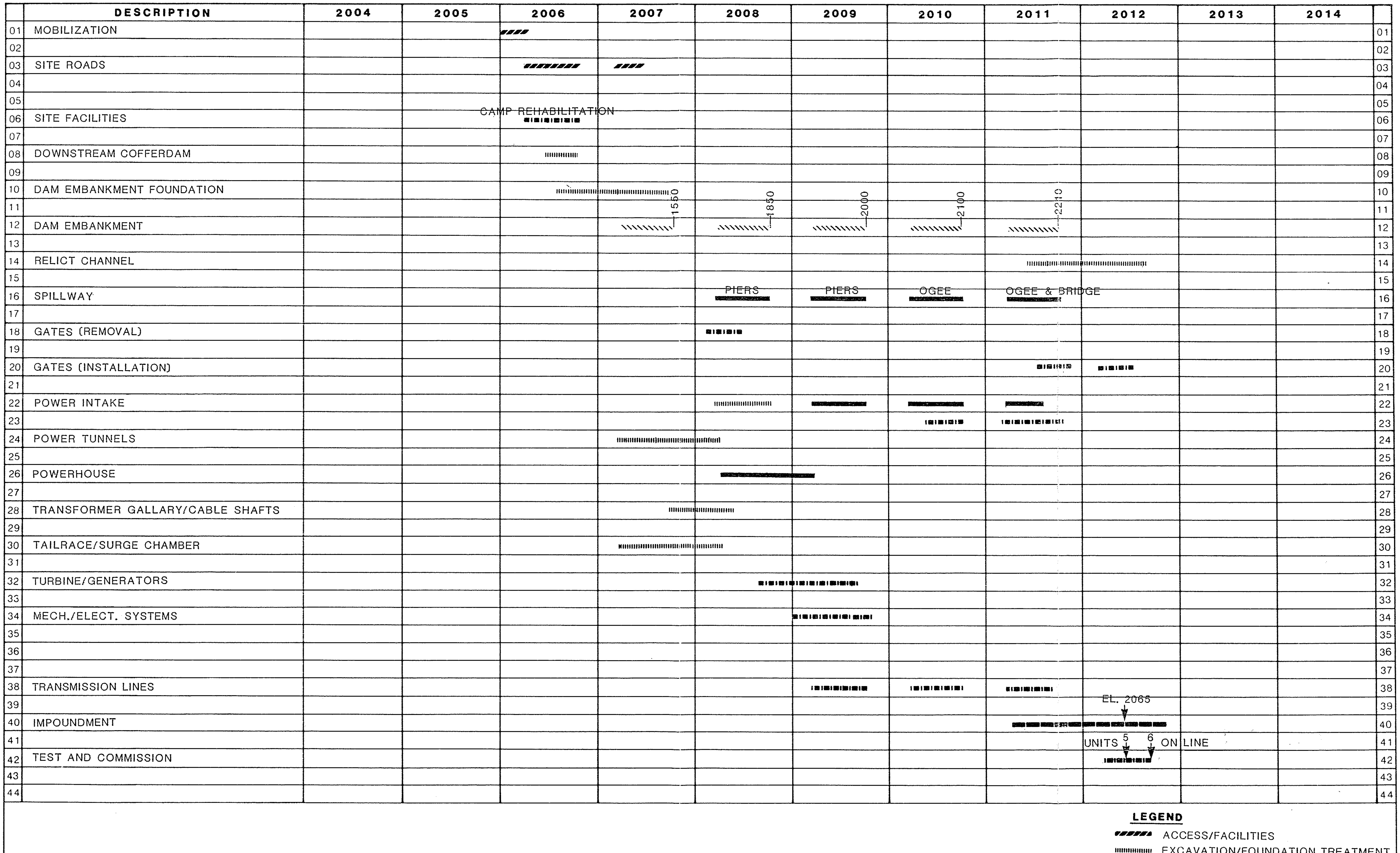

WATANA-STAGE I
CONSTRUCTION SCHEDULE

FIGURE C.1




DEVIL CANYON-STAGE II
CONSTRUCTION SCHEDULE

FIGURE C.2




WATANA-STAGE III
CONSTRUCTION SCHEDULE

FIGURE C.3

# D - PROJECT COSTS AND FINANCING

SUSITNA HYDROELECTRIC PROJECT
LICENSE APPLICATION

EXHIBIT D
PROJECT COSTS AND FINANCING

TABLE OF CONTENTS

TABLE OF CONTENTS (cont'd)

TABLE OF CONTENTS (cont'd)

EXHIBIT D
PROJECT COSTS AND FINANCING

TABLE OF CONTENTS (cont'd)

EXHIBIT D
PROJECT COSTS AND FINANCING

TABLE OF CONTENTS (cont'd)

**EXHIBIT D**
**PROJECT COSTS AND FINANCING**

## LIST OF TABLES

LIST OF TABLES (cont'd)

LIST OF TABLES (cont'd)

LIST OF TABLES (cont'd)

EXHIBIT D
PROJECT COSTS AND FINANCING

## LIST OF FIGURES

# EXHIBIT D
# PROJECT COSTS AND FINANCING

This exhibit presents the estimated project cost for the Susitna Hydroelectric Project, development of alternative system generation expansion plans and their evaluation to assess the economic feasibility of the Susitna Project, 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 Stages I and III and Devil Canyon Stage II 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 Susitna project is summarized in Table D.1.1.1. A more detailed breakdown of cost for each development is presented in Tables D.1.1.2, D.1.1.3 and D.1.1.4.

### 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 construction costs were developed for the project in January 1982 dollars and later adjusted to January 1985.

#### 1.1.1 - Code of Accounts (**)

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

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, such as camps, catering and off-site transportation of workers. 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:

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

### 1.1.2 - Approach to Cost Estimating (o)

The estimating process used generally included the following steps:

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

### 1.1.3 - 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 were developed from an analysis of costs for recent projects performed in the Alaska environment.

It has been assumed that most contractors will work an average of two 10-hour shifts per day, six days per week. During periods of severe compression of construction activities, it has been assumed that work will be on two 12-hour shifts, seven days per week.

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

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. Equipment operating costs were estimated from industry source data, with appropriate modifications for the remote nature and extreme climatic environment of the site and duration of the project. Alaskan labor rates were used for equipment maintenance and repair. Fuel and oil prices have been based upon FOB site prices.

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

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

### 1.1.4 - 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 above-ground activities will either stop or be curtailed during 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:

- o Watana earth and rockfill dam - 6-month season
- o Devil Canyon arch dam - 8-month season.

Other above-ground 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 (Roberts 1976) 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 six to ten 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°F to 20°F, with snowfall of 10 inches per month.

### 1.1.5 - Construction Methods (*)

The construction methods assumed for development of the estimate and construction schedule are generally considered 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.

### 1.1.6 - Quantity Takeoffs (**)

Detailed quantity takeoffs were produced from the engineering drawings using methods normal to the industry.

### 1.1.7 - 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;
- Yard cranes and floats;

- Utilities including electrical power, heat, water, and compressed air;
- Small tools;
- Safety program and equipment;
- Contractor financing;
- Bonds and securities;
- Insurance;
- Taxes;
- Permits;
- Head office overhead; and
- Profit.

In developing contractor's 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. These have been addressed in both the economic and financial studies.
- 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.
- 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 the 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 $303.5 million and have been summarized in Table D.1.2.1. These costs include direct and indirect costs, engineering, administration, and contingencies.

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:

- o Raptor nesting platforms;
- o Salt licks;
- o Habitat management for moose; and
- o Slough enhancement.

A detailed discussion of the mitigation programs required for the project is included in Exhibit E along with tables listing detailed costs. The costs of these programs including contingency have been estimated as follows and listed under project indirects in the capital cost estimate.

| | | |
|---|---|---|
| Stage I Watana | $187.8 | million (approximately) |
| Stage II Devil Canyon | 35.4 | million (approximately) |
| Stage III Watana | 80.3 | million (approximately) |

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:

- o Archeological studies;
- o Fisheries and wildlife studies;
- o Right-of-way studies; and
- o Socioeconomic planning studies.

The costs for the above work have been included under project overheads and have been estimated at approximately $20 million.

### 1.3 - Engineering and Administration Costs (*)

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

- o Account 71
  - . Engineering and Project Management

- Construction Management
- Procurement

o <u>Account 76</u>

- 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 discussed in the following sections.

### 1.3.1 - Engineering and Project Management Costs (*)

These costs include allowances for:

- Feasibility studies, including preliminary designs, site surveys, 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 Applicant regarding all aspects of the project;
- Preliminary and detailed design;
- Plans and specifications for construction;
- 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.

1.3.2 - Construction Management Costs (*)

Construction management costs have been assumed to include:

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

1.3.3 - Procurement Costs (*)

Procurement costs have been assumed to include:

- o Establishment of project procurement procedures;
- o Preparation of non-technical procurement documents;
- o Solicitation and review of bids for construction services, support services, permanent equipment, and other items required to complete the project;
- o Cost administration and control for procurement contracts; and
- o Quality assurance services during fabrication or manufacture of equipment and other purchased items.

### 1.3.4 - Owner's Costs (*)

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

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

## 1.4 - Operation, Maintenance and Replacement Costs (**)

The estimated operation, maintenance, and replacement costs, at January 1985 price level, account for the personnel, materials, and facilities required to operate and maintain the dam and reservoir along with the generating plant and associated transmission facilities. Also included are costs to maintain structures and equipment in changing project conditions to insure dam safety at all times. A detailed breakdown of the operation, maintenance and replacement cost estimate and staffing requirements is shown in Table D.1.4.1. The following cost estimates cover the various periods of the project life:

- o Watana Stage I, $11.5 million/year;
- o Devil Canyon Stage II, $12.8 million/year;
- o Watana Stage III, $12.8 million/year; and
- o Mature project operation and maintenance cost, $11.5 million/year.

The operating plan provides powerhouse operators on duty at all times at Watana Stage I for the initial period of trials and operation. This level of attention provides adequate monitoring and supervision until all aspects of the power facility operation are proven reliable. A similar schedule would apply to the early years of operation at Devil Canyon Stage II and Watana Stage III. The operation transition from manual to computer control would be gradual and would depend upon the satisfactory functioning of the communication system, computers at each power plant, and training of the resident staff as emergency operators, should communications be interrupted. In a similar fashion, the maintenance needs in the new power plants will be greater initially to correct malfunctions as they are discovered.

Also included in the personnel shown in Table D.1.4.1 are staff required for two visitor centers, one located at each damsite. A resource management staff would be responsible for regulating use of the project's public facilities and use of lands managed by the project. This management of resources would include monitoring and enforcement of regulations but also include providing information and guidance for users.

An O&M staff would provide all necessary services for the operation and maintenance of the dam. Also included are personnel to operate town facilities and provide for essential health and safety needs of town residents. The staff would also provide warehouse and some maintenance personnel.

In addition to the personnel and equipment required to implement normal operation and maintenance, there are specific allowances for a sinking fund to provide for equipment machinery replacement, helicopter operations, and for snow clearing and maintenance of the dam, reservoir and access roads. Allowances have also been made for environmental mitigation services as well as a contingency for unforeseen costs.

## 1.5 - Allowance for Funds Used During Construction (AFDC) (**)

AFDC can be a significant element of project cost given the lengthy construction periods required for construction of the three stages of the project. Provisions for AFDC at appropriate rates of interest are made in the economic and financial analyses included in this Exhibit.

### 1.5.1 - AFDC for Economic Analysis (*)

Interest and escalation were calculated as a percent of the total capital costs of the project at the start of construction. The method used for calculating the effects of interest and escalation during construction is documented in "A Method for Estimating Escalation and Interest During Construction" (Phung 1978).

An S-shaped symmetric cash flow was adopted where:

$$1 + f_{co} = (1 + X)^{B} \left[\frac{[(1 + f)^{B} - 1]}{B \ln (1 + f)}\right] \left[1 - \frac{1}{\left[1 + \frac{2\pi}{B \ln (1 + f)}\right]^{2}}\right]$$

where

$1 + f_{co}$ = Total cost upon commercial service expressed as a multiplier of construction cost.

$$1 + f = \frac{1 + y}{1 + x}$$

x = effective interest rate
y = escalation rate
B = construction period

The value of the variables used in the AFDC computations are as follows:

- o the effective interest rate is equal to the discount rate, 3.5 percent, and
- o the escalation rate is zero percent.

The Watana Stage I, Devil Canyon Stage II, and Watana Stage III construction periods were taken from Exhibit C as 8 years, 9 years, and 6 years, respectively.

The resultant total project cost was then calculated for use in the OGP-6 economic studies.

#### 1.5.2 - AFDC for Financial Analysis (***)

For the financial analysis, interest and escalation were calculated as a percent of annual capital expenditure. Details of the calculation procedure are presented in Section 4 of this Exhibit.

### 1.6 - Escalation (**)

All construction costs presented in this Exhibit are at January 1985 levels and consequently include no allowance for future cost escalation. Thus, these costs would not be representative of actual 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 as discussed in Section 1.5.1 for the economic analyses and Section 1.5.2 for the financial analyses.

### 1.7 - Cash Flow (**)

The cash flow requirements for construction of the Susitna Hydroelectic Project are an essential input to financial planning studies. The basis for the cash flows are the construction cost estimates in January 1985 dollars and the construction schedules presented in Exhibit C.

The cash flow estimates were computed on an annual basis and do not include adjustments for advanced payments for mobilization or for holdbacks on construction contracts. The results are presented in Table D.1.7.1.

## 1.8 - Contingency (*)

Following prevailing norms such as those used by the COE (1980), an overall contingency allowance of approximately 15 percent of construction costs has been included in the cost estimates. Contingencies have been assessed for each account and range from 10 to 20 percent. The contingency is estimated to include cost increases which may occur in the detailed engineering phase of the project after more comprehensive site investigations and final designs have been completed and after the requirements of various concerned agencies have been satisfied. The contingency estimate also includes allowances for inherent uncertainties in costs of labor, equipment and materials, and for unforeseen conditions which may be encountered during construction. Escalation in costs due to inflation is not included. No allowance has been included for costs associated with significant delays in project implementation.

## 1.9 - Previously Constructed Project Facilities (*)

An electrical intertie between the major load centers of Fairbanks and Anchorage has been constructed by the Applicant. The line connects transmission systems at Willow in the south and Healy in the north. The intertie has been built to the same standards as those proposed for the Susitna Hydroelectric Project transmission lines. The line will be energized initially at 138 kV and will operate at 345 kV after the Watana Stage I is complete.

The cost for the completed intertie was $122 million. This cost is not included in the Susitna project cost estimates.

## 2 - EVALUATION OF ALTERNATIVE EXPANSION PLANS (***)

### 2.1 - General (***)

The Applicant's studies indicate that electric demand growth over the next 25 years coupled with the retirement of a considerable portion of the existing generation system will require the addition of new generating capacity. The Susitna hydroelectric project constitutes a major potential contributor to that additional capacity. This Section describes the development of system generation expansion plans and their evaluation in order to assess the economic feasibility of the Susitna Project.

The system expansion studies are performed using the Optimized Generation Planning (OGP) computer program and result in system expansion plans With and Without the Susitna Hydroelectric Project. The costs of these two expansion plans are then compared to determine the economic viability of the With-Susitna plan.

During the pre-license phase of Susitna project planning, two studies proceeded in parallel which addressed alternatives to generating power in the Alaska Railbelt. These studies are the Susitna Hydroelectric Project Feasibility Study (Acres 1982), and the Railbelt Electric Power Alternatives Study (Battelle 1982). Information from these earlier studies was used to support analyses in this Exhibit.

In this Section, information required for generation planning is presented for the hydroelectric (i.e. Susitna and Non-Susitna hydroelectric) and thermal generation options. The analysis relies on fuel prices for thermal alternatives, developed in Exhibit D, Appendix D1 and forecasts of electrical demand generated from the APR/MAP/RED model sequence discussed in Exhibit B, Chapter 5, Section 4.

### 2.2 - Hydroelectric Alternatives (***)

Numerous studies of hydroelectric potential in Alaska have been undertaken. These date back to 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. Significant identified hydroelectric potential is located in the Railbelt region, including several sites in the Susitna River Basin.

Drawing from the above studies, Acres American developed and evaluated Susitna and Non-Susitna basin hydroelectric alternatives. This series of studies was based on cost data and load forecasts prepared and updated over the period 1979 through 1982. During this period several study interactions were made to eliminate candidate hydroelectric alternatives and the resulting development plans are the most attractive alternatives.

### 2.2.1 - Susitna Basin Hydroelectric Developments (***)

The analysis of alternative sites for Susitna basin hydroelectric development is discussed in Exhibit B, Chapter 1. The plan formulation and selection methodology outlined in Exhibit B, Chapter 1 is summarized below.

#### (a) Selection Process (***)

Step 1 in the plan formulation and selection process was to define the overall objective of selecting the optimum expansion plan incorporating Susitna basin hydroelectric developments. In Step 2 of the process, all feasible sites were identified for inclusion in the subsequent screening process. The screening process (Step 3) eliminated those sites that did not meet the screening criteria and yielded candidates which could be refined and included in the formulation of Railbelt generation plans (Step 4).

#### (b) Selected Sites (***)

The results of the site screening process indicated that further Susitna basin development planning should incorporate a combination of several major dams and powerhouses located at one or more of the following sites on the Susitna River:

- Devil Canyon;
- High Devil Canyon;
- Watana;
- Susitna III; and
- Vee Canyon.

One-on-one comparisons of combinations of the above sites identified plans with Watana/Devil Canyon and High Devil Canyon/Vee as most economic. Further refinements to the project layouts and costs of these plans and systemwide generation expansion analyses resulted in selection of the Watana/Devil Canyon plan. Subsequent studies by the Applicant described in Exhibit B, Chapter 2, concluded that there would be advantages derived from modifying the Watana/Devil Canyon plan to provide for construction in three stages.

(c) Three-Stage Susitna Development Plan (***)

The three stage Susitna plan is as follows: first, construction and operation of a facility at the Watana site with a dam crest at elevation 2025 feet; second, completion and operation of the Devil Canyon facility with a dam crest at elevation of 1463 feet; and third, further elevation of the dam at the Watana facility to an elevation of 2205 feet.

The capital and operation, maintenance and replacement costs for the three-stage Susitna Hydroelectric Project are discussed in Section 1 - Estimates of Costs. Capital costs are shown in Tables D.1.1.1 through D.1.1.4. Operation, maintenance, and replacement costs are shown in Table D.1.4.1.

The operation of the three staged Susitna project is designed to meet system energy demand requirements along with minimum instream flow requirements. Project operation details are provided in Exhibit B, Section 3, and a summary follows.

Monthly estimates of project power and energy production are based on monthly reservoir simulation performed with a multiple reservoir operation model. The estimated energy generated is first compared to the system energy demand and if the energy produced is greater than that which the system can absorb the energy production is reduced by decreasing the discharge through the powerhouse. The resulting powerhouse discharge is compared to the minimum monthly flow requirements at Gold Creek to ensure that the project releases adequate flows for environmental purposes (Flow Regime E-VI).

The Watana - Stage I development initially operates on base load to maintain nearly uniform discharge from the powerplant. When Devil Canyon begins operation, Watana operates on load-following while Devil Canyon operates on base load. Watana-Stage III operation is essentially identical to Watana-Stage I and Devil Canyon Stage II operation. Table D.2.2.1 provides the power and energy production of the three stage project based on this operation plan.

2.2.2 - Non-Susitna Basin Hydroelectric Developments (***)

Selection of non-Susitna Basin hydroelectric plans involved a step-wise application of progressively more stringent criteria that eliminated candidate sites based on unfavorable economic and environmental characteristics. The details of this process are presented in the Susitna Development Selection Report (Acres 1981). A flow diagram of this process is shown in Figure D.2.2.1. Through this process, 10 of an original 91 sites were selected for detailed development and cost estimates. Of these, three sites - Chakachamna, Snow and Keetna - were proposed by the Applicant as the primary sites to be examined in alternative scenarios, and compared to the optimum development on the Susitna River. In the Draft Environmental Impact Statement (DEIS) prepared on the original License Application (FERC 1984), the FERC Staff identified a combination of five specific hydroelectric sites - Johnson site (210 MW) on the Tanana River, Browne site (100 MW) on the Nenana River, Keetna site (100 MW) on the Talkeetna River, Snow site (100 MW) near Kenai Lake, and the Chakachamna site (300 MW) on Chakachamna Lake - to partially fulfill the energy needs of the Railbelt. The five sites are shown on Figure D.2.2.2.

For the purposes of this application, the five recommended sites were re-examined in greater detail by the Applicant from engineering, economic, and environmental perspectives. Results of the evaluation are presented in Exhibit E, Chapter 10, and in "Alaska Power Authority Comments on the Federal Energy Regulatory Commission Draft Environmental Impact Statement of May 1984", Volume 4, Appendix II - Evaluation of Non-Susitna Hydroelectric Alternatives (APA 1984).

The overall conclusion of the re-examination, is that, based on the engineering, economic, and environmental characteristics of the non-Susitna hydro alternatives, they are not viable options and are unfavorable when compared to the proposed project.

## 2.3 - Thermal Alternatives (***)

A majority of the generating capability in the Railbelt is currently thermal, principally natural gas-fired combustion turbines with some coal-fired steam, oil-fired combustion turbine and diesel installations. Several alternative technologies exist that could be used to generate electricity for the Railbelt, either as substitutes for, or as complements to the Susitna Project. In Sections 2.4 and 2.5, the results of the analyses undertaken to define the most appropriate Without-Susitna generation plan for comparison with the With-Susitna generation plan are presented.

The overall objective established was the selection of an optimum Without-Susitna generation plan. Primary consideration was given to gas and coal electric generating 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 Railbelt Alternatives Study (Battelle 1982). As a result of this study, these unconventional resources were concluded to be infeasible for reasons of reliability, economy, insufficient capacity, or technical inadequacy.

Using coal and gas as fuels, three types of units were selected for evaluation by the OGP computer program. These units are the natural gas fired options of simple cycle combustion turbines (SCCT) and combined cycle combustion turbines (CCCT) and the coal-fired option of a conventional steam-electric generating station (HE 1985).

Table D.2.3.1 summarizes the capacity, generation, capital cost, operation and maintenance cost, and heat rate data of the three available alternatives. These are the data that are input to OGP. Following is a description of each of the options.

## 2.4 - Natural Gas-Fired Options (***)

### 2.4.1 - Natural Gas Availablility and Price (***)

Both the availability and pricing of natural gas as fuel for electric generation are addressed in detail in Appendix D1, Chapter 3. A summary follows.

Estimates of Cook Inlet natural gas quantities include 4.5 trillion cubic feet (TCF) of proven reserves and 3.4 TCF of estimated undiscovered resources. Therefore, 8 TCF of natural gas are assumed available for all future uses of Cook Inlet natural gas. Additionally, the North Slope contains at least 36 TCF of reserves. In the case of Cook Inlet natural gas, infrastructure exists to move the gas to the Railbelt market, however, no such infrastructure (e.g., a pipeline) is in place for North Slope gas. Consequently only Cook Inlet gas is considered available for the purposes of this analysis.

Because only Cook Inlet gas can be planned on, there are uncertainties regarding its long-term availability to fuel baseload power generation. The Applicant's analyses of competing demands throughout the planning period demonstrate a need for more natural gas than exists in the field. For long-tern planning purposes it has been assumed that Cook Inlet gas supplies will not be allowed to support baseload generation expansion after 1999. Therefore, in the system analyses gas-fired system additions after 1999 will be limited to 1,500 hours of operation.

The natural gas fuel prices developed in Appendix D1 are a function of world oil price and the technique for price estimation is netback methodology. Natural gas prices for the SHCA and Composite oil price forecasts which also include utility delivery charges are shown in Table D.2.4.1.

2.4.2 - Simple Cycle Combustion Turbine Power Plant (***)

In support of the Without-Susitna plan, a complete simple cycle plant conceptual design and the appropriate engineering, environmental, capital cost, and operating parameters were developed.

(a) Plant Description (***)

The Simple Cycle Combustion Turbine (SCCT) plant will consist of three large-frame, industrial-type gas-fired combustion turbine generators rated by the manufacturer at a nominal ISO[1/] rating of 80 MW each. The gross plant output will be 269 MW reflecting 3 units operating with ambient temperatures corrected to 30°F and with water injection (which increases output). The plant will have a net operating range from 26 MW (30 percent load for a single unit) to 262 MW (full load net at 30°F) which includes correction for plant auxiliary loads. The plant will require approximately a five-acre site. For purposes of this Application, it was assumed that any such plants will be located at existing, partially-developed sites.

The plant's major and auxiliary systems include the natural gas fuel system, water injection system, lubrication system, starting and cool down system, inlet and exhaust system, waste control system, and fire protection system.

(b) Combustion Turbine and Auxiliaries (***)

Each combustion turbine is an axial flow, multistaged compressor and power turbine on a common shaft directly coupled to the electric generator. The unit can be started, synchronized, and loaded in about one-half hour under normal conditions. The fuel system will be capable of utilizing natural gas, mixed gas, or liquid petroleum distillate for fuel.

Each gas turbine generator is a packaged unit and as such includes all auxiliary equipment. The package will include

---

1/ ISO - International Standards Organization, standard conditions of 59°F and atmospheric pressure at sea level.

the turbine and generator with exciter, complete controls, turbine auxiliary equipment, switchgear, transformers and motor control centers.

(c) Plant Auxiliary Loads (***)

The SCCT plant ratings are net values assuming an overall plant auxiliary load of 2.5 percent. The plant auxiliary loads consist of the combustion turbine auxiliary requirements and the plant loads. The combustion turbine loads are approximately one percent of the gross SCCT output and include the lube oil heaters and pumps, the cooling fans, water injection pumps, enclosure heaters, and cooling water pumps. The fixed plant load, estimated at 4,000 kW, includes lighting, service water pumps, HVAC equipment, water treatment pumps, and maintenance equipment.

The net output from the plant consisting of three SCCT units, varies from 308 MW at -23°F to 227 MW at 71°F. The plant has a design heat rate of 10,900 Btu/kWh based on the plant design operating condition at an ambient temperature of 30°F and the Lower Heating Value (LHV) of the natural gas. This corresponds to a heat rate of 12,000 Btu/kWh based on the Higher Heating Value (HHV) of the fuel.

(d) Plant Operating Parameters (***)

The performance of the 240 MW ISO rated SCCT plant is affected by plant elevation and ambient air temperature. Gas turbines are volumetric mass flow devices and cold, dense air increases the mass flow through the machines, which, with increased firing, increases the plant output and reduces the heat rate. The SCCT operating parameters are shown below.

SCCT PLANT OPERATING PARAMETERS

| | |
|---|---|
| Fuel Consumption (Full Load) | 3,135 X $10^6$ Btu/hr |
| Gross Generating Capacity (at 30°F) | 268,800 kW |
| Station Auxiliary Loads | 6,700 kW |
| Net Generation (Nominal Capacity) | 262,000 kW |
| Gross Station Heat Rate (Full Load) | 11,700 Btu/kWh |
| Net Station Heat Rate (Full Load) | 12,000 Btu/kWh |
| Net Station Heat Rate (30% Load) | 18,000 Btu/kWh |

The plant operating parameters are based on the average expected conditions of 30°F and approximately sea level atmospheric pressure. The temperature variation together with water injection increase output and account for the plant capacity and efficiency variance from ISO rating.

(e) Environmental Assessment (***)

Construction and operation of natural gas fired combustion turbines creates environmental concern in four areas. These are Air Quality, Water Quality, Noise Pollution, and Land Use Impacts. There concerns are addressed in detail in Exhibit E, Chapter 10, Section 4.

(f) Capital Costs (***)

The capital cost for the complete, 3 unit, SCCT plant is based on two separate estimates for single SCCT units. One estimate is for a new unit at an existing but not fully developed site and the second estimate is for a new unit add-on at a fully developed, existing site. The three unit plant estimate consists of one unit corresponding to the first estimate and two add-on units.

This plant configuration was selected as providing a feasible base-load alternative to the 200 MW coal plant for selection by OGP and for its flexibility in allowing the addition of single SCCT units for satifying intermittent or peak load requirements.

The estimates are based on a scope that includes facilities and systems required for self sustaining units. The estimates were prepared in 1983 dollars and escalated to 1985 dollars using Ebasco's Composite Index of Direct Cost for Electric Generating Plants (escalation factor 1.0394). The Composite Index is based on historical data and reflects annual changes in cost of materials, equipment, and labor rates.

Tables D.2.4.2 and D.2.4.3 present a summary of the detailed estimates for the SCCT initial unit and extension unit. Table D.2.4.4 presents the capital cost summary for the SCCT plant consisting of three units including other related plant costs. All costs are presented in 1985 dollars.

(g) Operation and Maintenance Costs (***)

Operation and Maintenance (O&M) costs were developed from three sources:

1) Railbelt Utility Data;

2) Lower 48 States Utility Data; and

3) Independent Data.

Through utility contacts, data was accumulated for similar operations and modified for the specific plant and site. The independent data was developed from vendor equipment information, operational parameters, data files, and engineering judgment.

The O&M costs were segregated into two components, fixed, and variable categories. The fixed costs are those which are independent of the level of plant operation, provided the plant is maintained in operational condition. Fixed costs are measured in dollars per kilowatt ($/kW) based on net plant capacity. Variable costs are those which occur only if the plant generates electricity. They vary directly with the amount of electricity produced and are measured in dollars per megawatt-hour ($/MWh) based on annual plant generation. A summary of the O&M costs are presented in Table D.2.4.5. These costs include fixed costs and variable costs and exclude fuel costs.

The O&M costs were developed in 1982 dollars and were escalated to 1985 dollars using the GNP Implicit Price Deflator (escalation factor 1.1046). All costs in Table D.2.4.5 are in 1985 dollars.

(h) Heat Rate (***)

The net output at the three unit SCCT station is 262,100 kW (262 MW nominal capacity) at full load. The corresponding heat rate is 12,000 Btu/kWh, HHV. This is a direct meassure of the amount of heat energy input to the combustor as natural gas that is required to produce one kilowatt-hour of electricity. The resulting net thermal efficiency is 28.5 percent.

As the operating load decreases, the SCCT efficiency decreases and net station heat rate increases. At the low load end of approximately 30 percent load a SCCT of the type and size considered here will have a heat rate of approximately 18,000 Btu/kWh and an operating efficiency of approximately 19 percent.

(i) Fuel Costs (***)

Estimated fuel costs for the combustion turbine are calculated by the OGP program based on the delivered fuel price, the annual energy generated and the station heat rate. Fuel prices are addressed in Appendix D1.

### 2.4.3 - Combined Cycle Combustion Turbine Power Plant (***)

The second gas-fired thermal alternative conceptual design developed for this analysis is a complete combined cycle plant. Development included the necessary engineering, environmental, capital cost, and operating parameters.

(a) Plant Description (***)

The Combined Cycle Combustion Turbine (CCCT) power plant incorporates two large-frame industrial-type natural gas fired simple cycle combustion turbine generator sets each exhausting into a waste Heat Recovery Steam Generator (HRSG) to generate high pressure steam for the steam turbine generator set. The plant's major equipment consists of the following:

- Two combustion turbine generators rated at 80 MW, ISO;
- Two heat recovery steam generators;
- One steam turbine generator rated at 59 MW;
- Air-cooled condenser; and
- Feedwater system.

The plant will have a gross output of approximately 237 MW. The capacity in excess of the ISO based capacity of 219 MW is due to increased efficiency of operation at the design generating temperature of 30°F and to increased efficiency realized due to injection of water into the two SCCT combustors. The net station capacity after deducting auxiliary loads is approximately 230 MW at full load and 69 MW at the minimum recommended load of approximately 30 percent. Alternatively, a single SCCT can be operated independently down to 26 MW at 30 percent load.

The plant will require a five-acre site and will be located at an existing, partially-developed site.

(b) Combustion Turbine (***)

The two natural gas-fired combustion turbines with attendant equipment will be identical to those described for the SCCT plant. The combustion turbine performance is slightly dertated due to the increase in exhaust pressure associated with the HRSG.

(c) Heat Recovery Steam Generator (***)

The heat recovery steam generators are considered part of the steam plant but would be housed with the gas fired combustion turbines in a common building.

Each heat recovery steam generator package will include the following:

- o Ductwork from combustion turbine to the steam generator;
- o Bypass damper and bypass stack; and
- o Steam generator exhaust stack.

Each HRSG will generate 258,000 pounds of steam per hour at 900 psig and 955°F when supplied with 250°F feedwater and 2,417,000 pounds per hour of exhaust gas at 973°F.

The HRSGs are designed for continuous operation and include an evaporative section, a superheat section, and an economizer. All steam generator controls will be located in a common area in the central control room.

(d) Steam Turbine Generator (***)

The steam generated by the HRSGs will be conveyed to a single steam turbine generator set. The steam turbine generator will be a tandem compound, multistage condensing unit, with one extraction for feedwater heating, and will be mounted on a pedestal with a top exhaust going to the air-cooled condenser. The steam turbine generator set will be furnished complete with lubricating oil and electrohydraulic control system, gland seal system, and cooling and sealing equipment. Other associated equipment includes feedwater pumps, condensate pumps, vacuum pumps, deaerator, instrument and service air compressors, motor control centers, and control room.

(e) Plant Auxiliary Load (***)

The CCCT plant has an assumed overall plant auxiliary load of approximately three percent of the plant rating. The auxiliary loads fall into three categories:

- o Combustion turbine auxiliary power and control;
- o Steam cycle loads; and
- o Plant loads.

The combustion turbine auxiliary loads are approximately one percent of the CCCT plant output. The steam cycle auxiliary loads are estimated at four percent of the steam turbine generator output and consist of boiler feed pumps, condensate pumps, cooling tower fans, and water treatment equipment. The balance of plant load is estimated at 3,300 kW including plant lighting, heating and cooling, air compressors, and maintenance equipment.

(f) Plant Operating Parameters (***)

The CCCT plant performance is affected by site conditions similar to the SCCT plant. At ambient temperatures below design conditions, the CCCT plant output increases. Lower ambient temperatures improve performance of the air-cooled condenser, and increase mass flow through the combustion turbines which in turn increases steam generation in the HRSG, resulting in increased electric generation. The CCCT plant operating parameters are given below.

CCCT PLANT OPERATING PARAMETERS

| | |
|---|---|
| Fuel Consumption (Full Load) | 2,110 X $10^6$ Btu/hr |
| Gross Generating Capacity (at 30°F) | 237,300 kW |
| Station Auxiliary Loads | 7,400 kW |
| Net Generation (Nominal Capacity) | 230,000 kW |
| Gross Station Heat Rate (Full Load) | 8,900 Btu/kWh |
| Net Station Heat Rate (Full Load) | 9,200 Btu/kWh |
| Net Station Heat Rate (30% Load) | 12,600 Btu/kWh |

The plant operating parameters are based on average expected site conditions of 30°F and approximately sea level atmospheric pressure.

(g) Environmental Assessment (***)

Construction and operation of the combined cycle plant will create four areas of environmental concern. There are Air Quality, Water Quality, Noise Pollution, and Land Use Impacts. There concerns are addressed in Exhibit E, Chapter 10, Section 4.

(h) Capital Costs (***)

The capital costs for the CCCT plant were based on a single estimate for a three-unit combined cycle natural gas-fired plant.

The estimate was based on a scope that includes facilities and systems required for a self-sustaining plant. The estimate was prepared in 1983 dollars and escalated to 1985 dollars using Ebasco's Composite Index of Direct Cost for Electric Generating Plants (Escalation factor of 1.0394). The Composite Index is based on historical data and reflects annual changes in cost of materials, equipment, and labor rates.

Table D.2.4.6 presents a summary of the detailed estimate for the combined cycle power plant. Table D.2.4.7 presents the capital cost summary for the combined cycle power plant including other related plant costs. All costs are in 1985 dollars.

(i) Operation and Maintenance Costs (***)

Operation and Maintenance (O&M) costs were developed from three sources:

- o Rainbelt Utility Data;
- o Lower 48 States Utility Data; and
- o Independent Data.

Through utility contacts, data was accumulated for similar operations and modified for the specific plant and site. The independent data was developed from vendor equipment information, operational parameters, data files, and engineering judgment.

The O&M costs were segregated into two components, fixed costs and variable costs. A summary of the O&M costs are presented in Table D.2.4.8. These costs include variable costs, and exclude fuel costs.

The O&M costs were developed in 1982 dollars and were escalated to 1985 dollars using the GNP Implicit Price Deflator (escalation factor 1.1046). All costs in Table D.2.4.8 are in 1985 dollars.

(j) Heat Rates (***)

The combined cycle plant when operating at full load has a net output of 229,700 kW (230 MW nominal capacity) and a net station heat rate at 9,200 Btu/kWh. The resulting net thermal efficiency is 37 percent.

Like the SCCT, the combined cycle plant also decreases in efficiency as load decreases, but not to as great an extent. At minimum load of approximately 30 percent, with only one SCCT fired and the steam turbine at part load, the net station heat rate increases to 12,600 Btu/kWh and the net efficiency drops to approximately 27 percent.

(k) Fuel Costs (***)

Estimated fuel costs are determined by the OGP program based on the fuel price, energy generated and the station heat rate. Fuel prices are addressed in Appendix D1.

## 2.5 - Coal-Fired Options (***)

### 2.5.1 - Coal Availability and Price (***)

Alaskan coal availability and pricing for electric generation in the Railbelt is addressed in Appendix D1, Chapter 4. A summary follows.

Two major coal fields are available for fuel supply to the coal-fired thermal alternative. These are the Nenana field, which is currently mined for fuel and export, and the Beluga field which is currently in the permitting stage of development for export and potential power generation. Both fields are large enough to meet all foreseeable export and domestic requirements for the planning period.

The estimated recoverable reserves in the Nenana field are 457 million tons. The present mining capacity is about 2 million tons per year. The addition of a coal-fired plant (400 MW) in the Nenana area would require mining capacity expansion to approximately 4 million tons per year.

The recoverable reserves at Beluga are estimated in the billions of tons. The combination of export market needs and potential domestic use for electric generation would result in production of about 8 to 12 million tons per year per mine.

The prices of Alaskan coals are a function of primary market served, method of coal transport, and pricing methodology. The Nenana field coal is primarily assumed to serve domestic markets. However, the coal must be shipped to the town of Nenana if the coal is to be burned in an environmentally acceptable plant. Costs of Nenana coal have been calculated on a production basis.

The main potential for the Beluga field is to serve the export market. Domestically the field operation can serve mine mouth coal-fired power plants. The Beluga pricing methodology is netback pricing based on a supply/demand analysis of the Pacific

Rim market under both the SHCA and Composit oil price forecasts. Estimated prices of Nenana and Beluga coal are shown in Table D.2.5.1.

### 2.5.2 - Coal-Fired Power Plants (***)

For the coal-fired alterntive a conventional steam electric central generating station conceptual design was developed. The design includes the engineering, capital cost, environmental, and operating parameters necessary to develop the plant.

#### (a) Plant Description (***)

The basic building block for the Coal Fired Power Plant alternative is a single 200 MW (net) coal fired steam-electric generating unit. A complete plant will consist of two 200 MW generating units. The plant may be sited in either the Beluga or Nenana areas of Alaska. The major difference between the two plant conceptual designs is coal at Beluga will be received by truck and coal at Nenana will be received by rail. The area of either plant site is approximately 110 acres. The generating station will be centrally located on the site and will consist of the following major structures:

- Boiler house;
- Turbine building; and
- AQCS and stack.

Other buildings and facilities include:

- Administration building;
- Maintenance building;
- Warehouse;
- Parking area;
- Switchyard;
- Transmission line connection;
- Cooling tower;
- Coal receiving, processing, storage, and retrieval area; and
- Wastewater treatment facility.

(b) Steam Generator (***)

The steam generator will produce 1.46 x $10^6$ lbs/hr of steam at 2,520 psig and 1,005°F when combusting 135 tons/hr of coal. Coal is metered by gravimetric feeders to five (5) pulverizers, any four (4) of which can distribute coal to the burners to maintain Maximum Continuous Rating (MCR) of the boiler. The coals to be burned at a Beluga or Nenana site are similar: both are a low sulfur subbituminous Type C coal with relatively high ash and moisture content.

The calculated efficiency of the boiler for these plants using a coal analysis representative of either plant is about 84 percent. This is slightly lower than for many coal-fired plants, but it reflects the relatively low heating value and high moisture and ash content of the fuels being burned.

(c) Turbine-Generator Operating Parameters (***)

At a full load of 1.46 x $10^6$ lb/hr of main steam to the turbine, the generator output is 217,640 kW. The turbine is a tandem compound flow design with two intermediate pressure extraction points, four low pressure extraction points and an extraction between the intermediate and low pressure turbine piping in the crossover. The generator's power factor is 0.85 operating with a 45 psig hydrogen cooling system and two inches Hg absolute back pressure. The generator rating is 260,000 kW.

(d) Plant Auxiliary Loads (***)

The power plant will consume approximately 8 percent of the electricity generated when operating at full load. The components of the total estimated auxiliary load are listed below:

| Load Description | kW |
|---|---|
| Steam Generator including ID and FD Fans | 4,000 |
| Turbine Generator | 420 |
| Coal Handling System | 2,500 |
| Ash Handling System | 800 |
| Boiler Feed Pumps | 3,100 |
| Miscellaneous Pumps | 3,000 |
| Makeup Demineralizer | 200 |
| Condensate Polishing | 200 |
| Wastewater Treatment System | 275 |

| Load Description | kW |
|---|---|
| Cranes & Lifting Equipment | 275 |
| Turbine & Boiler Bldg. HVAC | 2,600 |
| Total Plant Auxiliary Loads | 17,370 kW |

(e) Plant Operating Parameters (***)

The performance of the station is not significantly affected by elevation or ambient air temperature. The station operating parameters are as follows:

STEAM PLANT OPERATING PARAMETERS

| | | |
|---|---|---|
| Fuel Consumption (Full Load) | 135 | tons/hr |
| Combustion Air Flow | $1.6 \times 10^6$ | ACFM at 350°F |
| Steam Generated/Pressure/ | 1,460,000 | lbs/hr |
| Temperature | 2,520 | psia/1005°F |
| Reheat Steam Flow | 1,270,996 | lbs/hr |
| Flue Gas Volume | $1.6 \times 10^6$ | ACFM |
| Lime Consumption | 1900 | lbs/hr |
| Particulate Collection Efficiency | 99.95% | |
| Turbine Throttle Steam Flow | 1,456,128 | lbs/hr |
| Turbine Exhaust | $1,395 \times 10^6$ | lbs/hr |
| Waste Heat Rejected | $1 \times 10^9$ | Btu/hr |
| Circulating Water Flow, at 90°F | 87,900 | GPM |
| Gross Generating Capacity | 217,600 | kW |
| Station Auxiliary Loads | 17,400 | kW |
| Net Generation (Nominal Capacity) | 200,000 | kW |
| Gross Turbine Heat Rate (Full Load) | 7,890 | Btu/kWh |
| Net Station Heat Rate (Full Load) | 10,300 | Btu/kWh |
| Net Station Heat Rate (40% Load) | 11,800 | Btu/kWh |

(f) Environmental Assessment (***)

Construction and Operation of the coal-fired power plants will result in potential environmental impact in five areas. These are Air Quality, Water Quality, Solid Waste Disposal, Noise Pollution, and Land Use Impact. These impacts are addressed in Exhibit E, Chapter 10, Section 4.

(g) Capital Costs (***)

The capital costs for the coal-fired power plant alternative were based on four separate estimates for 200 MW power plants at the Beluga and Nenana sites as follows:

- o Beluga Initial Unit;
- o Beluga Extension Unit;

- o Nenana Initial Unit; and

- o Nenana Extension Unit.

The estimates were prepared in 1983 dollars and escalated to 1985 dollars using Ebasco's composite Index of Direct Costs for Electric Generating Plants (escalation factor of 1.0394). The Composite Index is based on historical data and reflects annual changes in cost of materials, equipment and labor rates.

Tables D.2.5.2 and D.2.5.3 present a summary of the detailed estimates for the Beluga 200 MW initial unit and the Beluga 200 MW extension unit. Table D.2.5.4 presents the Capital Cost Summary for the Beluga coal-fired power plant including other related plant costs.

Tables D.2.5.5 and D.2.5.6 present a summary of the detailed estimates for the Nenana 200 MW initial unit and the Nenana 200 MW extension unit. Table D.2.5.7 presents the capital cost summary for the Nenana coal-fired power plant including other related plant costs.

All costs are in 1985 dollars.

(h) Operation and Maintenance Costs (***)

Operation and maintenance (O & M) costs were developed from two sources:

- o Railbelt Utility Data; and

- o Independent Data.

Through utility contacts, data was accumulated for similar operations and modified for the specific plants and sites. The independent data was developed from vendor equipment information, operational parameters, data files, and engineering judgment.

The operation and maintenance costs were segregated into two components, fixed costs and variable costs. The fixed costs are those which are independent of the level of plant operation, provided the plant is maintained in operational condition. Fixed costs are measured in dollars per kilowatt ($/kW) based on net plant capacity. Variable costs are those which occur only if the plant generates electricity and vary directly with the electricity produced. Variable costs are measured in dollars per megawatt hour ($/MWh) based on assumed annual plant generation.

A summary of the O&M costs are presented in Table D.2.5.8. These costs include fixed costs and variable costs, and exclude fuel costs.

The O&M costs were developed in 1982 dollars and were escalated to 1985 dollars using the GNP Implicit Price Deflator (escalation factor of 1.1046). All costs in Table D.2.5.8 are in 1985 dollars.

(i) Heat Rate (***)

The net output of the station will be 200,270 kW at full load after allowing for auxiliary loads. The turbine will have a gross heat rate of 7,890 Btu/kWh at full load. This is a direct measure of the amount of heat energy as steam required to produce a kilowatt hour at the generator bus. The net station heat rate is calculated based on the turbine heat rate and boiler efficiency after subtraction of the auxiliary load to obtain the net output of the unit at full load. The net station heat rate is 10,300 Btu/kWh for both a Nenana plant and a Beluga plant. The resulting net thermal efficiency is 33 percent.

(j) Fuel Costs (***)

Estimated annual fuel costs for the coal plants are termined by the OGP program based on the delivered fuel price, the energy generated, and the station heat rate. Fuel prices are addressed in Appendix D1.

## 2.6 - The Existing Railbelt System (***)

### 2.6.1 - System Description (***)

The two major load centers of the Railbelt region are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. These two load centers comprise the interconnected Railbelt market. The Glennallen-Valdez load center is not planned to be interconnected with the Railbelt nor to be served by the Susitna Project.

The existing transmission system of the Anchorage-Cook Inlet area extends north to Willow and consists of a network of 115-kV, 138-kV, and 230-kV lines with interconnection to Palmer. The Fairbanks-Tanana Valley system extends south to Cantwell over a 138-kV line. The Anchorage-Fairbanks Intertie, completed by the Applicant in 1985, connects Willow and Healy and operates at 138-kV. However, it is designed for 345-kV operation.

(a) Anchorage-Cook Inlet Area (***)

The Anchorage-Cook Inlet area has the following major electric utilities and power producers:

- o Municipal Utilities;
  - Municipality of Anchorage-Municipal Light & Power Department (AMLP)
  - Seward Electric System (SES)
- o Rural Electrification Administration Cooperative (REA);
  - Chugach Electric Association, Inc. (CEA)
  - Homer Electric Association, Inc. (HEA)
  - Matanuska Electric Association, Inc. (MEA)
- o Federal Power Marketing Agency; and
  - Alaska Power Administration (APAd)
- o Military Installations.
  - Elmendorf Air Force Base
  - Fort Richardson

AMLP and CEA are the two principal utilities serving the Anchorage-Cook Inlet area. AMLP and CEA are intertied and have established rate schedules which contain capacity charges and flat energy changes for certain commitments.

All of these organizations, with the exception of MEA, have electrical generating facilities. MEA buys its power from CEA. HEA and SES have relatively small generating facilities that are used for standby operation. They also purchase from CEA. The rate structures and tariffs for wholesale and retail electric power contracts are discussed in detail in Exhibit B, Chapter 5, Section 2.

The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 92 percent of the total capacity is provided by gas-fired units. The remainder is provided by hydroelectric units and oil-fired diesel units. Table D.2.6.1 presents the total generating capacity of the Anchorage-Cook Inlet utilities and military installations.

(b) Fairbanks-Tanana Valley Area (***)

The Fairbanks-Tanana Valley area is currently served by the following utilities and power producers:

- o Municipal Utility;
  - Fairbanks Municipal Utilities System (FMUS)
- o Rural Electrification Administration; Cooperative (REA)
  - Golden Valley Electric Association, Inc. (GVEA)
- o Military Installations; and
  - Eielson Air Force Base
  - Fort Greeley
  - Fort Wainwright
- o University of Alaska, Fairbanks.

GVEA and FMUS own and operate generation, transmission, and distribution facilities. The University and military bases maintain their own generation and distribution facilities. GVEA and FMUS are interconnected and exchange economy energy. In addition, Fort Wainwright is interconnected with GVEA and FMUS and provides both utilities with economy energy. Rate structures and tariffs for retail electric power sales from GVEA and FMUS are discussed in Exhibit B, Chapter 5, Section 2.

A large portion of the total installed capacity consists of oil-fired combustion turbines (58 percent) and coal-fired steam turbines (31 percent). The remaining capacity is provided by diesel units. Table D.2.6.2 presents the total generating capacity of the Fairbanks-Tanana Valley area utilities, military installations and the University.

2.6.2 - Total Present System (***)

The total Railbelt installed capacity is 1145 MW, excluding installations not available for public service at the University and military bases. The 1145 MW consist of 1098 MW of thermal generation fired by oil, gas, or coal, plus 47 MW from the Eklutna and Cooper Lake hydroelectric plants. Average and firm monthly energy estimates for the Eklutna and Cooper Lake hydroelectric projects are shown in Table D.2.6.3.

Tables D.2.6.4 and D.2.6.5 summarize equipment operation periods, generating capacity and operation characteristics including heat rates, operation and maintenance costs and outage rates. These data are based upon the Applicant's evaluation of information provided by the Railbelt utilities.

The unit capacities and heat rates were developed using power output versus inlet temperature curves, equipment heat rate curves, and fuel consumption versus power output curves.

The operation and maintenance costs are the result of review of historical plant accounting records. The utility records were assembled and analyzed based on a consistent breakdown of fixed and variable cost items. The planned and forced outage rates reflect established maintenance schedules and experienced outage data.

Retirement policy for the existing generating units was provided by the Railbelt utilities and reflects present age of the equipment, projected maintenance programs, anticipated hours of operation, and industry standards. The retirement schedule of existing Railbelt generating equipment is shown in Table D.2.6.6. For purposes of the economic evaluation, the Applicant has assumed the following lifetimes for new generation equipment:

| Equipment | Life in Years |
|---|---|
| Coal-Fired Steam Turbines: | 35 |
| Gas-Fired Combustion Turbines: | 25 |
| Oil-Fired Diesel Units: | 20 |
| Gas-Fired Combined-Cycle Turbines: | 30 |
| Hydroelectric Projects: | 50 |

## 2.7 - Generation Expansion Before 1996 (***)

The short-term generation plan is based on expansion studies with the Applicant's load forecast and evaluation of utility information for generation planned in the period 1985 through 1995. Table D.2.7.1 presents the year-by-year capacity additions and planned retirements. Table D.2.7.2 summaries on-line dates, operation costs, and characteristics of each unit.

Railbelt utility additions include 132 MW of gas-fired generation, and 7.5 MW of diesel standby generation. HEA and MEA are cooperating on the addition of a 45 MW combustion turbine which will be online in the fall of 1985. Both CEA and AMLP are planning the addition of 87 MW combustion turbines. However, based on the Applicant's load forecast only one combustion turbine is required in the period 1985 through 1995. Therefore an 87 MW combustion turbine has been scheduled on-line in 1992. SES plans include the addition of 2.5 MW of diesel standy capacity in 1985 and 1986 and an additional 2.5 MW in 1990.

The Applicant confirmed the economic feasibility of the Bradley Lake project and submitted an application for license to the FERC in March 1984. The Applicant and Railbelt utilities are currently negotiating power sales contracts for Bradley Lake power and energy.

The Project is located near Kachemak Bay at the southern end of the Kenai Peninsula. Project features include a 125-foot concrete-faced rock fill dam, and a 19,000-foot-long power tunnel which will divert water from Bradley Lake to an above-ground powerhouse at tidewater. The project will have 90 megawatts of installed capacity and average annual energy generation will be about 367 GWh. The estimated average and firm monthly energy generation for the Bradley Lake project are shown in Table D.2.6.3. A 20-mile, 115-kilovolt transmission line will connect the project to the existing Kenai Peninsula system.

## 2.8 - Formulation of Expansion Plans Beginning in 1996 (***)

### 2.8.1 - Methodology (***)

Capacity expansion studies undertaken for the Susitna Project serve three major functions: (1) reliability (or reserve) evaluation; (2) electricity production simulation; and, (3) capacity expansion optimization. Expansion optimization analyses provide a systematic means of evaluating the timing, type, and system costs of new power facilities, thus permitting analysis of the relative costs of different but equivalent means of meeting projected electrical demand.

The Optimized Generation Plan (OGP) model was used to develop expansion plans for the Railbelt. The details of the OGP program and its relationship with other computer models used in the power market forecast are described in Exhibit B, Chapter 5, Section 3. Section 5.3 discusses the variables used in all the models to assure that they are consistent throughout the planning process.

In developing an optimal capacity expansion plan, the program considers the load forecast and system operation criteria to determine the need for additional future capacity within the specified degree of reliability. Then the program considers the existing and committed units (planned and under construction) available to the system and the operating characteristics of these units. The program optimizes the amount and installation date of needed additional capacity as load increases over time.

In addition to a number of sensitivity cases described in Section 2.11 of this Exhibit, two companion cases were developed for the present analysis that rely on alternative oil price forecasts. The Sherman H. Clark Associates (SHCA) forecast and the Composite forecast, both of which are described in Appendix D1, Chapter 2. Generation expansion plans and related costs are presented for each case in the following discussion.

The next five sections briefly review Railbelt load forecasts and the elements of the OGP program, then the expansion planning analysis period is described.

### 2.8.2 - Load Forecast (***)

The electric demand forecasts from Exhibit B, Chapter 5, Section 4 are shown in Tables D.2.8.1 and D.2.8.2, respectively.

The RED Model forecasts of peak power demand and energy requirements are computed at the customer or point-of-use level. The generation required to supply the customer loads at the point of generation exceeds the load by bulk transmission, distribution, and unaccounted losses.

Estimates of bulk transmission capacity and energy losses between utility sub-stations were prepared using load flow over the high voltage transmission line configuration presented in this Application. The estimates of distribution system capacity losses were based on available cable sizes, line lengths, and line voltages for the distribution system in the Anchorage area. The energy losses at the distribution system level were estimated by comparing utility net generation and sales figures included in Alaska Electric Power Statistics, prepared by the Alaska Power Administration.

In addition, the load forecasts were extended from 2010 to 2025 using the average annual growth for the period 2000 to 2010 for use in the OGP model studies.

### 2.8.3 - Reliability Evaluation (***)

The Loss of Load Probability (LOLP) method is used in the OGP program to determine when additional capacity is needed. The LOLP approach recognizes that forced outages of generating units would cause a deficiency in the capacity available to meet the system load unless adequate capacity had been installed. The evaluation of generation reserve by probability techniques has been used for many years by utilities and the traditionally adopted value of LOLP has been about one day in ten years. Evaluation of expansion plans resulting from different LOLP levels indicated that the expansion plans and associated system costs of the With- and Without-Susitna plans are not significantly affected across the range investigated. For these studies, the Applicant has selected a LOLP of one day in ten years. System reliability criteria are further discussed in Exhibit B, Chapter 4, Section 1.

Spinning thermal reserve equal to the largest unit on line is included within the reserve margin for all alternative expansion plans. Spinning reserve is available capacity which can quickly be brought into full production to off-set any forced shut-down of operating units. The costs associated with this spinning reserve are included in all plans.

2.8.4 - Hydro Scheduling (***)

In the OGP simulation, the power and energy potential and timing of hydroelectric units are provided as input around which thermal units are added. The estimates of average monthly energy generation, which are limited by system demand, are input to OGP and are also used to define Susitna capacity as input to OGP. When the Watana Stage I development comes on-line, environmental constraints limit plant operation to base load maintaining nearly uniform discharge from the powerhouse. This effectively limits the Watana project dispatch to a constant 24-hour capacity level. The power capability input into OGP is then computed as the estimated average monthly energy generated, divided by the number of hours in the month.

When Devil Canyon Stage II comes on-line, the Watana Stage I project will follow load, regulate frequency and voltage, provide spinning reserve, and react to system needs under all normal and emergency conditions. This operation will result in powerhouse discharge fluctuations which will be regulated by the Devil Canyon reservoir. The load-following power output from Watana can equal the capability of the turbines, which is a function of Watana reservoir elevation. The monthly capability of the Watana Stage I turbines is input to OGP. The Devil Canyon Stage II power output used in OGP is computed as described above for Watana Stage I operating as a base load plant. Devil Canyon is operated as a base load plant maintaining nearly uniform discharge from the powerhouse.

The power and energy estimates of both facilities are increased when Watana Stage III comes on-line to reflect increased operating head and greater river regulation. The OGP inputs are revised based on the approach outlined for Stage II. Table D.2.2.1 provides estimates of power and energy production as input to OGP.

2.8.5 - Thermal Unit Commitment (***)

After deducting hydroelectric plant output, including Eklutna, Cooper and Bradley Lake, and thermal unit maintenance, the remaining loads are served by the existing thermal units available to the system. The units are added to the system to minimize operating costs, which consist of fuel costs and variable operating and maintenance (O&M) costs for each unit. Fixed O&M costs do not affect the order in which existing units are committed. The unit operation logic determines how many units will be on-line each hour and which units are selected, with the least expensive increment being added first.

2.8.6 - OGP Optimization Procedure (***)

For each year under study, OGP evaluates system reliability to determine the need for installing additional generating capacity. If the capacity is sufficient to maintain the desired LOLP of one day in ten years, the program calculates the annual production and investment costs and proceeds to the next year.

If additional capacity is needed, OGP adds units from the list of suitable additions until the given reliability level is met. Among the issues considered in determining suitability is the size of a potential unit relative to the size of system load and cost. For a combination of units the program calculates annual costs for a 25-year look-ahead period and selects the most economical installation. The capital and O&M costs and operating characteristics of the thermal units available for addition to the system are summarized on Table D.2.8.3. Summaries of fuel prices are shown in Tables D.2.4.1 and D.2.5.1.

2.8.7 - Generation Expansion (***)

The objective of the expansion planning study was to determine if the proposed Susitna Hydroelectric Project will produce energy at lower total cost than its competing alternative. The period of analysis for the evaluation consists of two periods. The first period covers the years of expansion of the system and ends in the year 2025. This period defines the alternative system developments to be compared. The annual costs are further extended for a second period which extends until the hydroelectric project has reached its service life.

The economic analysis of hydroelectric developments may be based on a period of 100 years. Dam and reservoir facilities normally have lives of at least 100 years, however, power facilities including the powerhouse and generating equipment will have shorter lives. If a period of analysis is used that exceeds the life of power facilities, interim replacement costs must be computed to provide for the cost of replacing units of property having a shorter life than the period of analysis. For the expansion planning analysis the Applicant has selected a period of analysis of 50 years for the Susitna Project. This 50-year period is assumed to end in 2054 or 50 years after the operation of the Devil Canyon project which is the middle stage of the three-stage development. The Applicant's estimate of operation and maintenance costs provides for overhaul of turbines and generators after 30 years of service.

Using the Optimized Generation Planning (OGP) program, alternative expansion plans were developed for the period from January 1996 to December 2025 to establish the least-cost system for that period with and without the Susitna Project. In the With-Susitna case, it was assumed that Watana-Stage I would start operation in 1999, Devil Canyon Stage II would be on line in 2005 and Watana-Stage III would be completed in 2012. In the Without-Susitna alternative plan, coal-fired and gas-fired thermal generation are added to the existing units.

The costs for each expansion plan include the annualized capital costs of any plants and transmission facilities added during the period and fuel and O&M costs of the generating units. Costs common to all the alternatives, such as investment costs of facilities in service prior to 1996, and administrative and customer service costs of the utilities, are excluded.

The long-term system costs (2026-2054) are estimated by extending the 2025 annual costs, with no load growth and fuel prices adjusted for real fuel price escalation, for the 29-year period. All costs are then converted to a 1985 present worth and the With-Susitna and Without-Susitna expansion plans are compared on the basis of the 1985 present worth of costs from the 1996 to 2054 time frame.

#### 2.8.8 - Transmission System Expansion (***)

Transmission system expansion costs for the With-Susitna expansion have been estimated and included as part of the Project, as discussed in Exhibit B, Chapter 2, Section 7.

Transmission system expansion needs associated with Without-Susitna expansion plans are added as a separate items to the alternatives and are discussed in Section 2.9.2 of this Exhibit.

### 2.9 - Selection of Expansion Plans (***)

Two forecasts are analyzed in OGP to demonstrate their effects on future generation expansion plans and the economic attractiveness of the Susitna Hydroelectric Project. In the analysis it is assumed that all Railbelt utilities will be interconnected and will share reserves as of 1996. A discussion of the selected plans and their capacity additions follows.

2.9.1 - With-Susitna Expansion Plan (***)

Table D.2.9.1 shows the yearly additions for the With-Susitna expansion plan based on the SHCA forecast. As shown in Table D.2.9.1, two combustion turbines (174 MW) are required to meet system reserve criteria during the period between Watana-Stage I and Devil Canyon-Stage II. In addition, one combustion turbine (87 MW) is required between Devil Canyon-Stage II and Watana-Stage III.

Following Watana-Stage III operation, about 350 MW of additional combustion turbines will be required to replace retired units and to meet the load demand and reserve criteria through 2025.

Two adjustments to the power and energy capabilities of the Susitna Project are implemented in 2009 and 2019. The adjustments reflect increased project power and energy as a result of system load growth.

Table D.2.9.1 also shows the yearly additions for the With-Susitna expansion plan based on the Composite forecast. Inspection of Table D.2.9.1 indicates that the alternative electric demand forecast has had very little impact on the system additions. This is due primarily to the similarity in the forecasted demands of the SHCA and Composite forecasts.

Table D.2.9.2 summarizes OGP output for the SHCA and Composite forecasts based on the With-Susitna alternatives related to Susitna dependable capacity and usable energy. The dependable capacity is defined as the Susitna project's capacity which is dispatched to carry system load at the time of peak, taking into account unit operating characteristics, hydrologic conditions, and resulting estimates of unit capability. Usable energy is the energy dispatched in the system when compared to the energy made available for dispatch in the OGP input data.

As can be seen from Table D.2.9.2 (Page 1 of 2), with the SHCA forecast the base-load capacity of the Watana Stage I development has been absorbed in the system. About 94 percent of energy available is usable in 1999, increasing to 97 percent in 2004.

With the addition of Devil Canyon Stage II in 2005 the capacity and energy available for dispatch increases. In addition, the project's capability is adjusted to reflect growth in demand in 2009. The dependable capacity and energy absorbed increases as system growth in peak load and energy requirements occurs. This increase also reflects the upward capability adjustments. Dependable capacity increases from 775 MW to 805 MW, which is the total capacity available. The usable energy increases from 4,230 GWh to 4,740 GWh in 2011.

In 2012 the Watana dam is raised and corresponding increments in capacity and energy are available due to increased head, addition of two units in the Watana powerhouse, and better regulation of Susitna River flows. Also, project capability is adjusted upward in 2019 due to growth in demand. During the period 2012 to 2025, dependable capacity increases 28 percent and usable energy increases 30 percent. The 2025 dependable capacity of about 1,220 MW is about 310 MW less than the available capacity, therefore, this level of capacity could be considered available for spinning reserve. The three-stage Susitna hydroelectric project's maximum average annual energy generation which corresponds to unlimited system demand is 6,900 GWh. It is projected that this level of energy generation would be absorbed in about 2027.

Review of Table D.2.9.2 (page 2 of 2), which summarizes the dependable capacity and usable energy for the Composite forecast, shows nearly identical utilization of the Susitna project's power and energy for the period 1999 through 2025 as with the SHCA forecast.

### 2.9.2 - Without-Susitna Expansion Plan (***)

#### (a) System Expansion Plans (***)

Table D.2.9.3 shows the Without-Susitna alternative plans for the SHCA and Composite forecasts. These plans were developed by the OGP process of comparing the economic advantages of various generation mixes including combined cycle, combustion turbine and coal-fired alternatives. Gas-fired system additions after 1999 are limited to 1500 hours of operation because projected gas supply and demand projections exceed resource estimates.

As the SHCA forecast OGP analysis is initiated, the existing Railbelt capacity is sufficient to meet the projected load growth and maintain reliability criteria through the middle to late 1990's. In 1999, coal-fired plants are added near the Beluga coal field. Additional coal-fired plants are added in 2004 and 2006 in the Nenana area of the northern Railbelt. Subsequent coal-fired power plants are sited near the Beluga field. Combustion turbines are brought on-line for peaking service, reliability requirements, and to replace combustion turbines added in earlier years.

Table D.2.9.3 also shows the yearly additions for the Without-Susitna expansion plan based on the Composite forecast. Capacity additions in the early years of this plan are essentially identical to the SHCA expansion plan. The coal-fired plant locations follow the same pattern as discussed in the SHCA plan. However, the Composite forecast expansion plan has one less coal-fired powerplant than the SHCA plan. The combustion turbines added in later years perform peaking service, meet reliability requirements and replace combustion turbines added in earlier years.

After allowance for the retirement of existing units and additions of new capacity in the period 1996 through 2025 the generation system mix (MW) as of 2025 for the SHCA and Composite forecasts can be summarized as follows:

| | SHCA Forecast | Composite Forecast |
|---|---|---|
| Coal-Fired Steam | 1,400 | 1,200 |
| Gas-Fired Combustion Turbine | 544 | 611 |
| Gas-Fired Combined Cycle | -- | -- |
| Hydroelectric | 137 | 137 |
| Total | 2,061 | 1,948 |

(b) Transmission System Expansion (***)

Electric system studies were carried out to establish transmission requirements associated with the Without-Susitna expansion plan. The object was to develop a system configuration which would be consistent with the Susitna transmission planning criteria. The guidelines concerning power transfer capability, stability, system performance limits,and thermal overloads for the Susitna Project are outlind in Exhibit B, Section 2.7.

Studies were made for both the SHCA and Composite forecasts and corresponding expansion plans. A system one line diagram, showing the transmission line configurations is shown on Figure D.2.9.1. The ultimate development shown applies to the Without-Susitna alternative for both forecasts, although there are variations in timing of transmission system additions between the two alternatives.

The system consists of 230-kV lines north of Nenana and south of Willow. Between Nenana and Willow, the 218-mile long section would be operated at 345 kV. The 345-kV section would consist of the existing Intertie operated at 345-kV and a new 345-kV circuit constructed parallel to the Intertie in 1999.

The system takes full advantage of the existing 138-kV and 230-kV submarine cables crossing Knik Arm. An additional 230-kV cable crossing was planned.

Load flow calculations were performed for selected stages of development. Figure D.2.9.2 shows a load flow diagram for approximate peak load conditions in the year 2025.

The load flow calculation verified acceptable voltage ranges and line loadings and established the ratings for transformers, reactors, and dynamic var compensators. 230-kV submarine cables have compensating shunt reactors at both ends.

Line energization studies using load flow calculations indicated that, during energization of the largest line section, namely, the 218-mile Willow to Nenana line, the volatage would not exceed 1.1 per unit at the open end.

In general, the load flows demonstrated that the transmission system would be capable of handling the full range of steady state conditions.

A cost estimate was prepared for the SHCA and Composite transmission line plans. The estimates are presented in Tables D.2.9.4 and D.2.9.5. The estimates cover the major transmission system developments expected to occur to the year 2025. For the coal-fired capacity additions at Beluga and Nenana, the cost of the powerplant substation and connections to the major transmission system are included with the powerplant estimate. For these costs, see Tables D.2.5.2 through D.2.5.7

Table D.2.5.2 shows the breakdown of transmission line and substation costs for the initial Beluga unit and the extension unit of the first 2-unit plant to be built at a Beluga site. It was determined that installing a transmission line with the initial unit which would be capable of handling the output of two units is not economically justified. Each 200-MW unit would, therefore, include a 230-kV transmission line installed along a common right-of-way. The second two-unit Beluga plant assumes costs identical to the first two-unit plant. That is, a new right-of-way, or expansion of the existing right-of-way, will be necessary for the additional transmission lines. Each 230 kV transmission line would be approximately 48 miles long.

Tables D.2.5.5 and D.2.5.6 present the total capital costs of plant, substations and transmission lines for the two

Nenana units. Two 230-kV transmission circuits would be required. Each circuit would be approximately 10 miles long.

For the simple-cycle and combined-cycle gas-fired additions, the siting criteria and transmission system costs are based on the following three assumptions: (1) Maximum of one plant with three combustion turbines or two combustion turbines and one steam turbine generator. Existing generating sites would be used, (2) At least two transmission lines are required from the generating site to an existing substation, and (3) High voltage transmission connections would be 115 or 138 kV.

The costs for the transmission lines in Tables D.2.9.4 and D.2.9.5 are based on the following unit costs:

| Voltage | Conductor Size | Material and Labor $ per Mile |
|---|---|---|
| 345 kV | 2 x 954 kcmil | $ 415,350 |
| 230 kV | 1 x 1272 kcmil | $ 340,800 |
| 138 kV | 556.6 kcmil | $ 181,050 |
| 115 kV | 556.5 kcmil | $ 106,500 |

These cost estimates are at 1985 price levels, and include material and labor. The estimates include right-of-way cost, engineering, construction management and Owner's overhead. A contingency allowance of 15 percent is included for material and labor. Tables D.2.9.4 and D.2.9.5 include additional information about line additions and reinforcements such as: line terminal name, voltage level, length in miles, conductor size, and line termination station costs. Line compensation such as shunt reactors, and static var compensation, is included with the line termination and substation costs.

The cost estimates also include the cost of a Railbelt energy management system which is included in the transmission system for the With-Susitna expansion plan.

### 2.9.3 - Comparison of Expansion Plans (***)

Figures D.2.9.3 through D.2.9.6 compare the contribution of energy production between the With-Susitna plan and Without-Susitna plan for each forecast. As shown by these exhibits, the Railbelt system generation will continue to be dominated by gas- and oil-fired generation over the next 10 to 15 years. By 1999 a very large share of the gas- and oil-fired generation can be replaced with Susitna in operation. Otherwise, coal-fired generation becomes more significant in the SHCA and Composite expansion plans, respectively.

## 2.10 - Economic Feasibility (***)

This section provides a discussion of the key economic parameters used in the study and develops the net economic benefits and benefit-cost ratio of the Susitna Hydroelectric Project.

First, economic principles and parameters relevant to the economic analysis are discussed. Then the annual and cumulative present worth of system costs of expansion plans resulting from the SHCA and Composite forecasts are developed for the With-and Without-Susitna expansion plans. Next, the net economic benefits and benefit-cost ratio of the Susitna Project are determined. Finally, sensitivity analyses were performed.

### 2.10.1 - Economic Principles and Parameters (***)

#### (a) Economic Principles (***)

The economic analysis compares the costs of alternatives during the planning period 1996-2054. Throughout the analysis, all costs and prices are expressed in real terms using January 1985 dollars.

The With-Susitna and Without-Susitna alternative expansion plans, discussed in detail in Section 2.9 above, are utilized here to assess the economic benefits of the Susitna Project. Net benefits are based on the difference between the costs of the Without-Susitna alternative and the With-Susitna alternative. For the Susitna Project to be considered economically feasible, net benefits must be positive and the benefit/cost ratio must be greater than one. The benefit/cost (B/C) ratio is determined using the following formula:

$$B / C = \frac{\text{Total Present Worth of System Expansion Plan Without-Susitna}}{\text{Total Present Worth of System Expansion Plan With-Susitna}}$$

Costs for each expansion alternative include three main items: capital, fuel, and operation and maintenance (O&M) costs. Capital costs include construction costs and interest on funds used during construction assuming 100 percent debt financing for all facilities. The method used for estimating interest on funds during construction is discussed in Section 1.5 of this Exhibit. Fuel costs for the coal or gas consumed annually in the thermal plants are adjusted to account for real fuel price escalation, O&M costs also are expended each year.

To determine the benefit/cost ratio and net benefits, all costs (or benefits) must be adjusted to a comparable present worth. Costs are adjusted to their present worth by discounting, which gives costs in earlier years more weight than costs in later years. The total present worth of each expansion plan was obtained by calculating the present worth of each future annual cost.

Table D.2.10.1 summarizes the principal economic parameters that were used in the economic analysis. The economic life of each generating plant type used in the economic analysis is based on 25 years for combustion turbines, 30 years for combined cycle, 35 years for steam turbines, and 50 years for hydroelectric plants.

The annual fixed carrying charge on the investment in generating facilities varies with estimated service life of the facilities. The three major elements included in this analysis are cost of money, amortization, and insurance payments. Taxes are not applicable since the applicant is a public agency. Interim replacement are included in operation and maintenance costs.

The fixed charge rates are expressed on a levelized basis over the economic life of the equipment. When applied to the plant investment costs they yield annual revenue requirements for capital recovery, which includes interest and principal, and insurance preminums to protect against losses and damage to facilities. The cost of money which is equated with the discount rate is discussed in the next section.

(b) Real Discount Rate (***)

The selection of a real discount rate for the Susitna economic analysis has been based on the anticipated real cost of project financing in accordance with regulations adopted by the Applicant.[1/] A major survey (Corey 1982) conducted in 1977 established that, in electricity and gas industries 94 percent of all investor-owned utilities, 100 percent of all cooperatives, and 71 percent of all government agencies used discount rates as determined by the

---

1/ AAC 94.055(c)(5) and 3 AAC 94.060(c)(5) require the adoption of a discount rate for project evaluation that represents "the estimated long-term real cost of money."

cost of finance methodology with only minor technical variations. The same methodology has long been advanced by the Electric Power Research Institute (EPRI 1982). In concept, the efficiency of a power system is enhanced if projects are undertaken that produce net economic benefit when evaluated with a discount rate determined in this manner. An expectation of benefit so derived is equivalent to a demonstration that a project's expected rate of return exceeds the cost of project financing.

As discussed in Section 4.0 of this Exhibit, it is intended that the full cost of project construction be financed through the issuance of tax-exempt revenue bonds. Consequently, determination of the real discount rate has been based on the real interest rate anticipated for such bonds issued during the course of project construction.

The real interest rate is equal to the inflation-adjusted rate of return over the life of the bond. For example, to estimate the real interest rate for 20-year bonds to be issued five years from now, it is necessary to forecast the nominal interest rate for bonds to be issued at that time and to forecast the inflation rate for the 20-year period following the date of issuance. To support estimation of a real interest rate for Susitna financing, forecasts of nominal interest rates and inflation rates produced by Data Resources, Inc., Wharton Econometrics Forecasting Associates, and Chase Econometrics were obtained during the spring of 1985.

It was necessary to adjust these forecasts in two ways in order to generate appropriate estimates of real interest rates:

1) The forecasts cover the 10-year period from 1985 to 1994. Since inflation forecasts are required over a longer term in order to make the necessary calculations, they were extended for an additional 20 years based on the average of the last 5 years of each forecast.

2) The nominal interest rate forecasts that were obtained are for long-term U.S. Treasury bonds. Analysis of long-term Treasury bond yields and Grade A tax-exempt yields between 1945 and 1984 indicates that the former has exceeded the latter by an average factor of 1.12 over the last 40 years. This factor was, therefore, applied to the Treasury bond interest rate forecasts in order to arrive at consistent forecasts of Grade A tax-exempt nominal interest rates.

Given this conversion of Treasury bond rates to tax-exempt rates, the averages of the three 10-year forecasts are shown below:

| Year | Inflation Rate Forecast* | Nominal Interest Rate Forecast ** |
|---|---|---|
| 1985 | 3.7 | 10.1 |
| 1986 | 4.3 | 9.8 |
| 1987 | 4.7 | 10.1 |
| 1988 | 5.3 | 10.3 |
| 1989 | 4.9 | 9.8 |
| 1990 | 5.2 | 9.4 |
| 1991 | 5.0 | 8.7 |
| 1992 | 4.9 | 8.2 |
| 1993 | 5.2 | 8.1 |
| 1994 | 5.3 | 8.0 |

*Percent change in U.S. Consumer Price Index.

**Long-term Grade A tax-exempt securities.

The real interest rates of long-term grade A tax-exempt securites implied by these forecasts are as follows:

| Year | Real Interest Rate Forecast |
|---|---|
| 1985 | 5.0 |
| 1986 | 4.6 |
| 1987 | 4.8 |
| 1988 | 4.9 |
| 1989 | 4.4 |
| 1990 | 4.1 |
| 1991 | 3.4 |
| 1992 | 2.9 |
| 1993 | 2.8 |
| 1994 | 2.8 |

An example of the manner in which the real interest rates are calculated is presented in Table D.2.10.2.

In addition to these forecasts, the historical pattern of real interest rates was examined to provide a more complete context for discount rate determination. Again, the analysis focused on U.S. Treasury issues over the last 40 years. In order to construct a series of real interest rates that extends to the present, it is necessary to examine a range of maturities. Real rates on 15-year maturities can be computed only for bonds issued prior to 1971, since bonds issued at a later date have not yet matured and, therefore, the actual rate of inflation throughout the term of the issue is not yet known. Real rates on 10-year maturities were therefore examined for the years 1971 through 1975, 3- to 5-year maturities for 1976 through 1981, and 3-month maturities thereafter. The results of the analyses are presented in Table D.2.10.3. Though these are essentially risk-free securities (in contrast to Grade A municipals), it is striking that real interest rates on these issues have been low or negative until the beginning of the 1980s.

Conclusions from the foregoing analysis can be summarized as follows:

- o Real interest rates currently appear to be in the vicinity of 5 percent;

- o During most of the last 40 years, real interest rates have been well below 3 percent; and

- o The average forecast described herein anticipates that real rates on Grade A tax-exempt securities will fall back below 3 percent by the early 1990s; i.e., prior to the time during which Susitna financing would take place.

No attempt has been made to formulate a precise forecast of real interest rates for long-term debt issued during the years of Susitna construction. However, based on the analysis above, it is reasonable to conclude that such rates will most likely be well below the levels apparent today, and that a 3.5 percent real rate represents a conservative judgment of the extent to which they will decline. A real discount rate of 3.5 percent has therefore been adopted, which is consistent in magnitude with the selected financial parameters of a 5.5 percent inflation rate and a 9 percent nominal interest rate.

### 2.10.2 - Analysis of Net Economic Benefits (***)

The comparison of the With and Without-Susitna plans is based on an assessment of the annual system costs and present worth of costs for the period 1996 to 2054, using the load forecast, fuel prices, fuel price escalation rates, and capital costs associated with the SHCA and Composite forecasts.

Table D.2.10.4 shows the computation of the total present worth of the With- and Without-Susitna expansion plans. During the 1996 to 2025 study period, the 1985 present worth costs for the Susitna plans are $3.5 and $3.4 billion for the SHCA and Composite forecasts, respectively. The annual production costs in 2025 are $423.3 and $315.8 million. The present worth of these costs, which reflect real fuel cost escalation for a period extending to the end of the planning period are $2.0 and $1.4 billion. The resulting total present worth in 1985 dollars of the With-Susitna plans are $5.5 and $4.8 billion for the SHCA and Composite forecasts, respectively.

The Without-Susitna expansion plans for the SHCA and Composite forecasts have 1985 costs of $4.6 and $4.5 billion for the 1996 to 2025 period, with 2025 annual costs of $604.0 and $553.4 million. The total long-term costs (2026-2054) have a present worth of $3.1 and 2.7 billion for the SHCA and Composite forecasts. The resulting total present worth in 1985 dollars of the Without-Susitna plans are $7.7 and $7.2 billion for the SHCA and Composite forecasts, respectively.

The Susitna Project has net benefits of $2.2 and 2.3 billion and benefit/cost ratios of 1.40 and 1.48 for the SHCA and Composite forecasts, respectively. Therefore, the Susitna Project is economically justified under both forecasts.

## 2.11 - Sensitivity Analysis (***)

Sensitivity analyses were carried out to identify the impact of a change in assumptions on the resulting net benefits and benefit-cost ratios of the Susitna Project. The analyses were directed at the following variables:

- Oil Price Forecast;
- Discount Rate;
- Construction Cost for Watana Stage I;
- Real Escalation of Coal Price;
- Natural Gas Availability for Baseload Generation; and
- Combined Sensitivity Case.

### 2.11.1 - World Oil Price Forecast (***)

World oil price forecasts influence the load forecast, natural gas prices, and economics of the With- and Without-Susitna alternative; therefore, a third oil price forecast was analyzed.

This forecast is the Wharton forecast which is discussed in Appendix D1. The Wharton forecast exhibits oil prices lower than either the SHCA or Composite forecasts.

Table D.2.11.1 summarizes the load forecasts based on the three (SHCA, Composite, and Wharton) oil price forecasts. The natural gas prices used in the analysis are presented in Appendix D1. Table D.2.11.2 shows the calculation of the net benefits and benefit-cost ratio of the Susitna project. Net benefits of $1.7 billion and a benefit-cost ratio of 1.34 demonstrate that the project is economically attractive under the Wharton forecast.

### 2.11.2 - Discount Rate (***)

The the Susitna Project's margin of feasibility was tested by computing the change in net benefits and benefit-cost ratio at a discount rate of 4.5 percent. Table D.2.11.3 summarizes the results of the analysis which show the Susitna Project remains attractive under the higher discount rate.

### 2.11.3 - Construction Cost for Watana Stage I (***)

The estimated construction cost of Watana-Stage I is $2.68 billion (January 1985 prices). If the construction cost of Watana-Stage I were to increase by 15 percent or to $3.08 billion, the net benefits of the Susitna project would be about $2.0 billion and the benefit-cost ratios would be 1.32 and 1.39 respectively for the SHCA and Composite forecasts, as shown in Table D.2.11.4.

### 2.11.4 - Real Escalation of Coal Price (***)

The sensitivity of the analysis to coal price escalation was tested using January 1985 coal prices of $1.30 and $1.42/MMBtu for Beluga coal at mine-mouth for the SHCA and Composite forecasts, respectively, and $1.84/MMBtu for Nenana coal delivered. A scenario of zero real escalation on the price of coal for the entire period from 1985 through 2054 was analyzed, and the results are presented in Table D.2.11.5. For the Sherman Clark and Composite forecasts, net benefit of the Susitna project would be $0.9 billion and $1.3 billion respectively, with benefit-cost ratio of 1.16 and 1.28.

### 2.11.5 - Natural Gas Availability for Baseload Generation (***)

The Applicant's analysis of natural gas supply and demand projections over the course of the planning period demonstrate that the demand for Cook Inlet gas exceeds the total estimated resource. For planning purposes the Applicant assumed that gas supplies would not be allowed to support baseload generation expansion after 1999. Therefore, in the system expansion planning analyses, gas-fired generation additions were designated as peaking facilities and limited to 1500 hours of operation after 1999. The sensitivity of the gas-fired generation was tested by allowing unlimited gas-fired operation for SHCA and Composite forecasts.

The unlimited gas expansion plans exhibited similar mixes of coal- and gas-fired plants when compared to the limited gas plans. This demonstrates that the economically preferred fuel for baseload generation is coal and that based on price considerations natural gas is the appropriate choice for peaking facilities. Table D.2.11.6 shows the calculation of the net benefits and benefit-cost ratios of the Susitna Project for the unlimited gas analysis. For the SHCA and Composite forecasts, net benefits would be $2.2 billion and $2.3 billion, respectively, with benefit-cost ratio of 1.41 and 1.48.

#### 2.11.6 - Combined Sensitivity Case (***)

In Sections 2.11.1, 2.11.4 and 2.11.5 above, the influences of world oil price, real coal price escalation, and gas availability for baseload generation on Susitna project economics were tested. In the combined sensitivity case the Wharton oil price forecast, real coal price escalation and gas availability influences were reanalyzed together with natural gas prices based on the Enstar gas pricing methodology.

The Enstar methodlogy establishes the well head price of Cook Inlet gas in relation to the world oil price, as described in Appendix D1. Table D.2.11.7 summarizes the results of the combined effects of the variables and shows that the Susitna Project remains attractive with net benefits of $0.8 billion and a benefit-cost ratio of 1.15.

### 2.12 - Conclusions (***)

Although stated in various terms throughout this Exhibit, the conclusion of the OGP analysis of Railbelt expansion plans is that the Susitna Project would have a benefit/cost ratio (greater than 1.0 over the planning period of 1996-2054. Therefore, the Applicant concludes that the three-stage Susitna Hydroelectric Project is the economically preferred alternative for meeting the Railbelt electric demand.

## 3 - CONSEQUENCES OF LICENSE DENIAL (***)

### 3.1 - Statement and Evaluation of the Consequences of License Denial (***)

The enabling legislation for the Alaska Power Authority establishes that "it is declared to be the policy of the state, in the interest of promoting the general welfare of the people of the state and public purposes, to reduce consumer power costs and otherwise encourage the long-term economic growth of the state, including the development of its natural resources through the establishment of power projects."

On the basis of extensive study, diligently pursued over a period of years, the Alaska Power Authority has found the Susitna Hydroelectric Project to be the least-cost means of meeting the power needs of the Railbelt for well into the 21st Century. The costs of Susitna power will be substantially fixed; these costs will be lower than those from alternative hydro projects and also alternative thermal projects under any credible scenario for the future cost of fuels. If the Commission denies the License to build Susitna, it will foreclose for the citizens of the Railbelt the least-cost opportunity of meeting their electricity needs.

The assured energy supply which Susitna represents will foster long-term economic growth in the state. If the Commission disapproves Susitna, electric utilities in the Railbelt area will have to participate in a series of shorter horizon measures for power generation; the reduced certainty of energy supply and the reduced certainty of the cost thereof, will be less condusive to long-term economic growth than a Susitna-based generation system.

In economic terms, the effect of the Commission's denying the License would be to cause the Railbelt power consumers to forego the net benefits of Susitna compared to the cost of the next-most attractive alternative. The present value of these net benefits will amount to approximately $2.3 billion in 1985 dollars with either of the two principal oil price forecasts presented herein. The environmental costs of denying the License are also substantial in view of the environmental impacts associated with the alternatives. These impacts are described in more detail in Exhibit E, Chapter 10, Section 4 of this Application.

### 3.2 - Future Use of the Dam Sites if the License is Denied (***)

The dam sites have no present economic purpose. It is expected that, in the absence of construction of the dams, the present situation would continue.

# 4 - FINANCING (***)

## 4.1 - General Approach and Procedures (***)

The financial analysis of the Susitna project utilizes the economic analysis described in Section 2.10 of this Exhibit and recasts it in nominal terms using the parameters set forth in Table D.4.1.1. Estimated bond requirements are derived based on assumed cash flows. Based on the bond requirements, annual debt service is obtained, which, along with other operating costs, determines the total annual revenues required.

Rate stabilization will be used to reduce retail costs during the initial years of operation of the With-Susitna plan to a level equal to the cost of the Without-Susitna alternative. Rate stabilization funds are assumed to be provided by State contributions. Once Susitna energy costs become less than the energy cost of the Without-Susitna alternative, the difference between the costs of the two plans becomes a regional benefit due to the lower and more stable cost of energy from the With-Susitna plan. The levelizing of front-end costs associated with the Susitna project through the device of rate stabilization payments enhances market confidence in the ability of the Railbelt customer rate base to support the debt servicing requirements of the project's financing.

## 4.2 - Financing Plan (***)

### 4.2.1 - Tax-exempt Revenue Bonds (***)

The construction costs of Susitna are anticipated to be funded through the issuance of tax-exempt revenue bonds. The bonds will be secured by revenues from the sale of Susitna power.

Bond requirements are estimated using a bond issuance computer program using the cash flow shown in Table D.4.2.1 and the financial parameters set forth earlier. It is anticipated that cost incurred prior to the issuance of the FERC license will be funded through continuing State appropriations. Such costs incurred after June 30, 1985 are assumed to be reimbursed to the State from bond proceeds. Interest is capitalized through the entire construction period.

Annual revenue bond requirements in nominal dollars, and their application, are shown in Table D.4.2.2. Constant dollar bond requirements are also shown. Thus in real terms (1985 dollars), the annual bonding requirements average about $415 million although the amounts shown would shift from year to year depending on interest rate conditions. The Applicant anticipates securing tax-exempt status for Susitna financing through implementation of direct billing, which is discussed in the following section.

### 4.2.2 - Direct Billing (***)

Alaska Senate Bill 290 and House Bill 389 introduced in the last session of the Legislature will amend the Alaska Power Authority's enabling statute to permit the Applicant to charge direct service charges for the purchase of power generated by means of facilities owned or financed by the Applicant, to retain power customers. The proposed legislation also provides that the Applicant may enter into one or more agency agreements with a distributor of power relating to the billing and collection of these service charges.

This proposed legislation is advanced to provide a possible means of tax-exempt financing of the Susitna Project. Section 103(b) of the Internal Revenue Code restricts the use of tax-exempt bonds for financing power projects which are secured by payments to be made under Power Sales Agreements with non-governmental entities, which include rural electric associations, such as Chugach Electric Association (CEA). The restriction applies when the project is located within more than two political subdivisions and more than 25 percent of output is sold under a power sales agreement to an entity like CEA. Unless other means are found, these restrictions would seem to preclude tax-exempt status if the power output of the Susitna Project were to be sold to Railbelt utilities pursuant to conventional power sales agreements. The direct billing procedure under agency agreements envisioned by the aforementioned legislation is designed to provide such an alternative means, although confirmation from the Internal Revenue Service will perhaps be necessary before financing of the project on this basis could proceed.

The Applicant has met with the Railbelt utilities on an ongoing basis for the past year to negotiate agency agreements. Representatives of the utilities have expressed an interest in considering a plan that would permit the Applicant to bill the consumer directly with the utilities acting as the "agent" in the billing process in order to achieve tax-exempt status for the project. Negotiations for these agency agreements are expected to be concluded in early 1986.

### 4.2.3 - Legislative Status of Alaska Power Authority and Susitna Project (***)

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

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

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

- Minimize market area electric power costs;
- Minimize adverse environmental and social impacts while enhancing environmental values to the extent possible; and
- Safeguard both life and property.

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

Two pieces of legislation are required for the current finance plan. First, further legislative action is required to assure adequate funding of rate stabilization payment obligations to be undertaken by the state. Second, as previously discussed, legislation will be required to provide for direct billing for the project so as to secure tax-exempt status for project financing. Appropriate legislation to accomplish both objectives was introduced into the 1985 legislative session and held over for consideration in the 1986 session. It is anticipated that this legislation will be acted upon during the next session.

## 4.3 - Annual Costs (***)

As stated previously, construction of Susitna is anticipated to be funded through the issuance of tax-exempt revenue bonds. The average annual cost of energy from the Susitna Project itself has been estimated for the years 1999 through 2024 and is set forth in Table D.4.3.1. Costs include debt amortization and other operating costs and take into account the anticipated on-line date of each phase. Annual costs per unit of Susitna Project energy are shown in both nominal and real dollars.

## 4.4 - Market Value of Power (***)

The Susitna project is schedule to begin generating power for the Railbelt in 1999. At that time, the project will meet growing electric demand, replace retiring units, and displace capacity having more expensive operating costs.

The market value of Susitna power is based on an assessment of the cost of power to the Railbelt system had Susitna not been built. The least-cost Without-Susitna expansion plan is based on a combination of coal and gas-fired units, and the capital and operating costs of the alternative system have been established in a manner similar to that of Susitna.

Table D.4.4.1 shows that without rate stabilization the costs of the With-Susitna plan in the early years are higher than those incurred under the alternative Without-Susitna expansion plan. In order to facilitate the maximum use of Susitna and reduce the use of natural gas for electrical generation, Susitna power is anticipated to be priced such that the Susitna system is no higher in cost than the alternative system. Therefore, rate stabilization will be used in the early years. The actual amount will vary depending on the outcome of contract negotiations with the utilities.

## 4.5 - Rate Stabilization (***)

Due to the capital intensiveness of Susitna, the cost of energy from the With-Susitna system is higher in the short term than the least-cost Without-Susitna System (See Figure D.4.5.1). In order to eliminate the higher initial costs of Susitna, rate stabilization has been included in the finance plan.

The rate stabilization fund will be provided through State contributions and sized such that with interest earnings the fund will be sufficient to offset annual costs in the early years of operation to a level that would have been experienced with the least-cost thermal alternative. Interest earnings are anticipated to commence accruing to the fund in fiscal year 1987. Table D.4.5.1 depicts the required State contribution for rate stabilization, interest earnings, and annual payments from the fund given the bond requirements developed above and other system costs With- and Without-Susitna. With interest earnings, the required State contribution for rate stabilization is about $220 million for the SHCA and Composite forecasts.

## 4.6 - Sensitivity Analyses (***)

The Applicant recognizes that the actual level of fuel prices, power requirements and other parameters may differ from that assumed. An important variable is the world oil price forecast.

Oil price effects on fuel prices are discussed in Exhibit D, Appendix D1. The impact of oil prices on power requirements is discussed in Exhibit B, Section 5.4. Should oil prices follow the Wharton forecast which exhibits oil prices lower than either the SHCA and Composite forecasts, the required state contribution would be about $710 million.

In the combined sensitivity case (Section 2.11.6) the Wharton oil price forecast was further analyzed. In this analysis real coal price escalation and gas availability assumptions were relaxed and natural gas prices were based on Enstar gas pricing methodology. Under these assumptions the required state contribution would be $850 million.

## 5 - REFERENCES


Acres American, Inc. December 1981. Susitna Hydroelectric Project Development Selection Report. Prepared for the Alaska Power Authority.

Acres American, Inc. 1982. Susitna Hydroelectric Project, Feasibility Report. Design Development Studies. Final Draft. Prepared for the Alaska Power Authority.

Alaska Power Administration. 1984. Alaska Electric power Statistics (1960-1983). Ninth Edition. U.S. Department of Energy. Sept.

Alaska Power Authority. 1984. Comments on the Federal Regulatory Commission Draft Environmental Impact Statement of May 1984. Vol. 4, Appendix II - Evaluation of Non-Susitna Hydroelectric Alternatives. Susitna Hydroelectric Project, FERC Project No. 7114.

Battelle Pacific Northwest Laboratories. 1982. Railbelt Electric Power Alternatives Study. Vol. VI: Existing Generating Facilities and Planned Additions for the Railbelt Region of Alaska.

Caterpillar Tractor Co. 1981. Caterpillar Performance Handbook. Peoria, Illinois. October, 1981.

Code of Federal Regulations. 1982. Title 18, Conservation of Power and Water Resources, Parts 1 and 2. Government Printing Office, Washington, D.C.

Corey, G.D. 1982. Plant Decision Making in the Electrical Power Industry. In: Lind et al. (eds.), Discounting for Time and Risk in Energy Policy. Washington, D.C.

Department of the Air Force. 1985. Letter from H. Bargar, Chief Energy Engineer, Department of the Air Force, to W. Dyok, Harza/Ebasco Susitna Joint Venture, January 1985.

Department of the Army. 1985. Letter from H. Froehle, Director of Engineering and Housing, Corps of Engineers to W. Larson, Harza/Ebasco Susitna Joint Venture, January 31, 1985.

Electric Power Research Institute. 1982. Technical Assessment Guide. Special Report. Technical Evaluation Group, EPRI Planning and Evaluation Division. P-2410-SR. Palo Alto, California.

Federal Energy Regulatory Commission. 1984. Susitna Hydroelectric Project draft Environment Impact Statement. FERC No. 7114. Volume 6: Appendices L and M.

Harza-Ebasco Susitna Joint Venture. 1985. Definition and Costs of Thermal Power Alternatives to Susitna. Final Report. Prepared for Alaska Power Authority, Anchorage, Alaska.

Phung, D.L. 1978. A Method for Estimating Escalation and Interest During Construction. Institute for Energy Analysis, Oak Ridge Associated Universities. April, 1978.

Roberts, W.S. 1976. Regionalized Feasibility Study of Cold Weather Earthwork. Cold Regions Research and Engineering Laboratory, Special Report 76-2. July, 1976.

State of Alaska. 1982. Alaska Agreements of Wages and Benefits for Construction Trades. In effect January 1982.

U.S. Army Corps of Engineers. 1980. Cost Estimates - Planning and Design. Engineering Manual 1110-2-1301. July 31, 1980.

# TABLES

TABLE D.1.1.1: SUMMARY OF SUSITNA COST ESTIMATE

| | JANUARY 1985 DOLLARS $ X $10^6$ | | | |
|---|---|---|---|---|
| CATEGORY | WATANA (SI) | DEVIL CANYON (SII) | WATANA (SIII) | TOTAL |
| Production Plant | $ 1,422 | $ 990 | $ 852 | $ 3,264 |
| Transmission Plant | 460 | 64 | 135 | 659 |
| General Plant | 5 | 6 | 1 | 12 |
| Indirect | 349 | 180 | 184 | 713 |
| Total Construction | $ 2,236 | $ 1,240 | $ 1,172 | $4,648 |
| Overhead Construction | 446 | 154 | 147 | 747 |
| TOTAL PROJECT CONSTRUCTION COST | $ 2,682 | $ 1,394 | $ 1,319 | $ 5,395 |
| **Economic Analysis (0 percent inflation, 3.5 percent interest)** | | | | |
| Escalation | --- | --- | --- | --- |
| AFDC | 399 | 236 | 146 | 781 |
| TOTAL PROJECT COST | $ 3,081 | $ 1,630 | $ 1,465 | $ 6,176 |
| **Financial Analysis (5.5 percent inflation, 9.0 percent interest)** | | | | |
| Escalation | 1,863 | 1,935 | 3,544 | 7,342 |
| AFDC | 1,879 | 1,576 | 1,351 | 4,806 |
| TOTAL PROJECT COST | $ 6,424 | $ 4,905 | $ 6,214 | $17,543 |

TABLE D.1.1.2: COST ESTIMATE SUMMARY - WATANA STAGE I (Page 1 of 5)

JANUARY 1985 PRICE LEVEL

| Line Number | Description | Amount ( x $10^6$) | Totals ( x $10^6$) | Remarks |
|---|---|---|---|---|
| | PRODUCTION PLANT | | | |
| 330 | Land & Land Rights | $ 34 | | |
| 331 | Powerplant Structures & Improvements | 78 | | |
| 332 | Reservoir, Dams & Waterways | 857 | | |
| 333 | Waterwheels, Turbines & Generators | 47 | | |
| 334 | Accessory Electrical Equipment | 15 | | |
| 335 | Miscellaneous Powerplant Equipment (Mechanical) | 12 | | |
| 336 | Roads & Railroads | 197 | | |
| | Subtotal | $1,240 | | |
| | Contingency | 182 | | |
| | TOTAL PRODUCTION PLANT | | $1,422 | |

TABLE D.1.1.2: (Page 2 of 5)

| Line Number | Description | Amount ( x $10^6$) | Totals ( x $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $1,422 | |
| | TRANSMISSION PLANT | | | |
| 350 | Land & Land Rights | $ 6.6 | | |
| 352 | Substation & Switching Sta. Structures & Improvements | 4.8 | | |
| 353 | Substation & Switching Sta. Equipment | 98.5 | | |
| 354 | Steel Towers & Fixtures | 171.0 | | |
| 356 | Overhead Conductors & Devices | 126.1 | | |
| 359 | Roads & Trails | 6.0 | | |
| | Subtotal | $ 413.0 | | |
| | Contingency | 47.0 | | |
| | TOTAL TRANSMISSION PLANT | | $ 460.0 | |
| | Page Total | | $1,882.0 | |

TABLE D.1.1.2: (Page 3 of 5)

| Line Number | Description | Amount ( x $10^6$) | Totals ( x $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $1,882 | |
| | 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 | -- | | Included under 399 |
| 393 | Stores Equipment | -- | | Included under 399 |
| 394 | Tools Shop & Garage Equip. | -- | | Included under 399 |
| 395 | Laboratory Equipment | -- | | Included under 399 |
| 396 | Power-Operated Equipment | -- | | Included under 399 |
| 397 | Communications Equipment | -- | | Included under 399 |
| 398 | Miscellaneous Equipment | -- | | Included under 399 |
| 399 | Other Tangible Property | 4 | | Included under 399 |
| | Subtotal | $ 4 | | |
| | Contingency | 1 | | |
| | TOTAL GENERAL PLANT | | $ 5 | |
| | Page Total | | $1,887 | |

TABLE D.1.1.2: (Page 4 of 5)

| Line Number | Description | Amount ( x $10^6$) | Totals ( x $10^6$) | Remarks |
| --- | --- | --- | --- | --- |
| | TOTAL BROUGHT FORWARD | | $1,887 | |
| | INDIRECT COSTS | | | |
| 61 | Temporary Construction Facilities | $ --- | | See Note |
| 62 | Construction Equipment | --- | | See Note |
| 63 | Camp & Commissary | 274 | | |
| 64 | Labor Expense | --- | | See Note |
| 65 | Superintendence | --- | | See Note |
| 66 | Insurance | --- | | See Note |
| 68 | Mitigation | 30 | | |
| 69 | Fees | --- | | See Note |
| | Subtotal | $ 304 | | |
| | Contingency | 45 | | |
| | TOTAL INDIRECT COSTS | | $ 349 | |
| | Page Total | | $ 2,236 | |

Note: Costs under Accounts 61, 62, 64, 65, 66 and 69 are included in the appropriate direct costs listed above.

TABLE D.1.1.2: (Page 5 of 5)

| Line Number | Description | Amount ( x $10^6$) | Totals ( x $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $2,236 | |
| | OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS) | | | |
| 71 | Engineering/Administration and Environmental Monitoring | $ 446 | | |
| 72 | Legal Expenses | --- | | Included in 71 |
| 75 | Taxes | --- | | Not Applicable |
| 76 | Administrative and General Expenses | --- | | Included in 71 |
| 77 | Interest | --- | | Not Included |
| 80 | Earnings/Expenses during Construction | | | Not Included |
| | TOTAL OVERHEAD | | $ 446 | |
| | TOTAL PROJECT COSTS - January 1985 Price Level | | $ 2,682 | |

TABLE D.1.1.3: COST ESTIMATE SUMMARY - WATANA Stage III 

JANUARY 1985 PRICE LEVEL

| Line Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | PRODUCTION PLANT | | | |
| 330 | Land & Land Rights | $ 20 | | |
| 331 | Powerpland Structures & Improvements | 22 | | |
| 332 | Reservoir, Dams & Waterways | 615 | | |
| 333 | Waterwheels, Turbines & Generators | 23 | | |
| 334 | Accessory Electrical Equip. | 5 | | |
| 335 | Misscellaneous Powerplant Equipment (Mechanical) | 5 | | |
| 336 | Roads & Railroads | 53 | | |
| | Subtotal | $ 743 | | |
| | Contingency | 109 | | |
| | TOTAL PRODUCTION PLANT | | $ 852 | |

TABLE D.1.1.3 (Page 2 of 5)

| Line Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $ 852 | |
| | TRANSMISSION PLANT | | | |
| 350 | Land & Land Right | $ 1.1 | | |
| 352 | Substation & Switching Station Structures & Improvements | 3.2 | | |
| 353 | Substation & Switching Sta. Equipment | 33.8 | | |
| 354 | Steel Towers & Fixtures | 38.7 | | |
| 356 | Overhead Conductors & Devices | 42.8 | | |
| 359 | Roads & Trails | 1.5 | | |
| | Subtotal | $ 121.1 | | |
| | Contingency | 13.9 | | |
| | TOTAL TRANSMISSION PLANT | | $ 135.0 | |
| | Page Total | | $ 987.0 | |

TABLE D.1.1.3 (Page 3 of 5)

| Line Number | Description | Amounts ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $ 987 | |
| | GENERAL PLANT | | | |
| 389 | Land & Land Right | --- | | Included under 330 |
| 390 | Structures & Improvements | --- | | Included under 331 |
| 391 | Office Furniture/Equipment | --- | | Included under 399 |
| 392 | Transportation Equipment | --- | | Included under 399 |
| 393 | Stores Equipment | --- | | Included under 399 |
| 394 | Tools, Shop, & Garage Equip. | --- | | Included under 399 |
| 395 | Laboratory Equipment | --- | | Included under 399 |
| 396 | Power-Operated Equipment | --- | | Included under 399 |
| 397 | Communications Equipment | --- | | Included under 399 |
| 398 | Miscellaneous Equipment | --- | | Included under 399 |
| 399 | Other Tangible Property | 1 | | Included under 399 |
| | Subtotal | 1 | | |
| | Contingency | 0 | | |
| | TOTAL GENERAL PLANT | | $ 1 | |
| | Page Total | | $ 988 | |

TABLE D.1.1.3 (Page 4 of 5)

| Line Number | Description | Amounts ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $ 988 | |
| | INDIRECT COSTS | | | |
| 61 | Temporary Construction Facilities | $ --- | | See Note |
| 62 | Construction Equipment | --- | | See Note |
| 63 | Camp & Commissary | 156 | | |
| 64 | Labor Expense | --- | | See Note |
| 65 | Superintendence | --- | | See Note |
| 66 | Insurance | --- | | See Note |
| 68 | Mitigation | 4 | | |
| 69 | Fees | --- | | See Note |
| | Note: Costs under Accounts 61, 62, 64, 65, 66 and 69 are included in the appropriate direct costs listed above. | | | |
| | Subtotal | $ 160 | | |
| | Contingency | 24 | | |
| | TOTAL INDIRECT COSTS ................... | | $ 184 | |
| | Page Total | | $1,172 | |

TABLES D.1.1.3 (Page 5 of 5)

| Line Number | Description | Amounts ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | <u>TOTAL BROUGHT FORWARD</u> | | $ 1,172 | |
| | <u>OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)</u> | | | |
| 71 | Engineering/Administration and Environmental Monitoring | $ 147 | | |
| 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 | | $ 147 | |
| | TOTAL PROJECT COSTS - January 1985 Price Level | | $ 1,319 | |

TABLE D.1.1.4: COST ESTIMATE SUMMARY - DEVIL CANYON STAGE II 

JANUARY 1985 PRICE LEVEL

| LINE Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | PRODUCTION PLANT | | | |
| 330 | Land & Land Rights | $ 23 | | |
| 331 | Powerplant Structures & Improvements | 75 | | |
| 332 | Reservoir, Dams & Waterways | 572 | | |
| 333 | Waterwheels, Turbines & Generators | 42 | | |
| 334 | Accessory Electrical Equip. | 17 | | |
| 335 | Miscellaneous Powerplant Equipment (Mechanical) | 12 | | |
| 336 | Roads & Railroads | 122 | | |
| | Subtotal | $ 863 | | |
| | Contingency | 127 | | |
| | TOTAL PRODUCTION PLANT | | $ 990 | |

TABLE D.1.1.4 (Page 2 of 5)

| Line Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | <u>TOTAL BROUGHT FORWARD</u> | | $ 990 | |
| | <u>TRANSMISSION PLANT</u> | | | |
| 350 | Land & Land Rights | $ 0.2 | | |
| 352 | Substation & Switching Sta. Structures & Improvements | 10.2 | | |
| 353 | Substation & Switching Sta. Equipment | 37.8 | | |
| 354 | Steel Towers & Fixtures | 5.2 | | |
| 356 | Overhead Conductors & Devices | 2.3 | | |
| 359 | Roads & Trails | $ 0.4 | | |
| | Subtotal | $ 56.1 | | |
| | Contingency | 7.9 | | |
| | TOTAL TRANSMISSION PLANT | | $ 64.0 | |
| | Page Total | | $ 1,054 | |

TABLE D.1.1.4 (Page 3 of 5)

| Line Number | Description | | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | | $ 1,054 | |
| | 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 | | --- | | Included under 399 |
| 393 | Stores Equipment | | --- | | Included under 399 |
| 394 | Tools, Shop, & Garage Equip. | | --- | | Included under 399 |
| 395 | Laboratory Equipment | | --- | | Included under 399 |
| 396 | Power-Operated Equipment | | --- | | Included under 399 |
| 397 | Communications Equipment | | --- | | Included under 399 |
| 398 | Miscellaneous Equipment | | --- | | Included under 399 |
| 399 | Other Tangible Property | | 5 | | |
| | Subtotal | $ | 5 | | |
| | Contingency | | 1 | | |
| | TOTAL GENERAL PLANT | | | $ 6 | |
| | Page Total | | | $ 1,060 | |

TABLE D.1.1.4 (Page 4 of 5)

| Line Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL BROUGHT FORWARD | | $ 1,060 | |
| | INDIRECT COSTS | | | |
| 61 | Temporary Construction Facilities | $ --- | | See Note |
| 62 | Construction Equipment | --- | | See Note |
| 63 | Camp & Commissary | 153 | | |
| 64 | Labor Expense | --- | | See Note |
| 65 | Superintendence | --- | | See Note |
| 66 | Insurance | --- | | See Note |
| 68 | Mitigation | 4 | | |
| 69 | Fees | --- | | See Note |
| | Note: Costs under accounts 61, 62, 64, 65, 66 and 69 are included in the appropriate direct costs listed above. | | | |
| | Subtotal | 157 | | |
| | Contingency | 23 | | |
| | TOTAL INDIRECT COSTS | | $ 180 | |
| | Page Total | | $ 1,240 | |

TABLE D.1.1.4 (Page 5 of 5)

| Line Number | Description | Amount ( X $10^6$) | Totals ( X $10^6$) | Remarks |
|---|---|---|---|---|
| | TOTAL CONSTRUCTION COSTS BROUGHT FORWARD | | $ 1,240 | |
| | <u>OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)</u> | | | |
| 71 | Engineering/Administration and Environmental Monitoring | $ 154 | | |
| 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 | | $ 154 | |
| | TOTAL PROJECT COSTS - January 1985 Price Level | | $ 1,394 | |

TABLE D.1.2.1: SUMMARY OF MITIGATION COSTS INCORPORATED IN CONSTRUCTION COST ESTIMATES



JANUARY 1985 PRICE LEVEL

| | COSTS INCORPORATED IN CONSTRUCTION ESTIMATES | STAGE I WATANA $ X $10^3$ | STAGE II DEVIL CANYON $ X $10^3$ | STAGE III WATANA $ X $10^3$ | Remarks |
|---|---|---|---|---|---|
| 1. | Outlet Facilities | $ 59,000 | $ 12,100 | $ 19,000 | |
| 2. | Restoration of Borrow Area D | ----- | ----- | | Included in 5 |
| 3. | Restoration of Borrow Area F | ----- | ----- | | Included in 5 |
| 4. | Restoration of Camp and Village | 640 | 640 | 625 | |
| 5. | Restoration of Construction Sites | 11,500 | 1,500 | 10,000 | |
| 6. | Fencing around Camp | 300 | 300 | 380 | |
| 7. | Fencing around Garbage Disposal Area | ----- | ----- | ----- | Included in 6 |
| 8. | Multilevel Intake Structure | 19,100 | N.A. | 18,900 | |
| | Page Total | $ 90,540 | $ 14,540 | $ 48,905 | |

TABLE D.1.2.1 (Page 2 of 3)

| | COSTS INCORPORATED IN CONSTRUCTION ESTIMATES | STAGE I WATANA $ X $10^3$ | STAGE II DEVIL CANYON $ X $10^3$ | STAGE III WATANA $ X $10^3$ | Remarks |
|---|---|---|---|---|---|
| | Total Brought Forward | $ 90,540 | $ 14,540 | $ 48,905 | |
| 9. | Worker Amenities | 12,300 | 8,100 | 7,400 | |
| 10. | Restoration of Haul Roads | ------ | ------ | ------ | |
| 11. | Slough Modifications | 1,400 | ------ | ------ | |
| 12. | Habitat Management on Mitigation Lands | 1,370 | ------ | ------ | |
| 13. | Raptor Compensation | 440 | ------ | ------ | |
| 14. | Cultural Resource Mitigation | 7,500 | 800 | 2,400 | |
| 15. | Long Term Environmental Monitoring During Stage I Construction | 9,800 | ------ | ------ | |
| 16. | Development of Permanent Recreation Facilities and Visitor Center | 610 | 705 | 1,800 | |
| 17. | Impoundment Modifications | 1,100 | ------ | ------ | |
| 18. | Other Wildlife Monitoring | 1,200 | ------ | ------ | |
| | Page Total | $126,260 | $ 24,145 | $ 60,505 | |

TABLE D.1.2.1 (Page 3 of 3)

| | COSTS INCORPORATED IN CONSTRUCTION ESTIMATES | STAGE I WATANA $\$ \times 10^3$ | STAGE II DEVIL CANYON $\$ \times 10^3$ | STAGE III WATANA $\$ \times 10^3$ | Remarks |
|---|---|---|---|---|---|
| | Total Brought Forward | $126,260 | $ 24,145 | $ 60,505 | |
| 19. | Community Infra-structure | 4,667 | 2,712 | 342 | |
| 20. | Worker Transportation | 11,000 | ------ | ------ | |
| 21. | Aesthetics | 500 | ------ | ------ | |
| | SUBTOTAL | $142,427 | $ 26,857 | $ 60,847 | |
| | Contingency | 20,913 | 3,943 | 8,934 | |
| | TOTAL CONSTRUCTION | 163,340 | 30,800 | 69,781 | |
| | ENGINEERING & ADMINISTRATION | 24,501 | 4,620 | 10,467 | |
| | TOTAL PROJECT.......... | $187,841 | $ 35,420 | $ 80,248 | $303,509 |

TABLE D.1.4.1: SUSITNA HYDROELECTRIC PROJECT ANNUAL OPERATION, MAINTENANCE AND REPLACEMENT COSTS

COST ESTIMATE
(thousand 1985$)

| Period | Watana Stage I 1999-2004 | | | Devil Canyon Stage II 2005-2011 | | | | | Watana - Stage III 2012-2016 | | | | | Mature Stage 2017- beyon | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Stage I Immature | | | Stage II Immature | | | Mature Stage I Watana | Susitna Project | Stage III Immature | | | Mature Stages I & II | Susitna Project | | | |
| Cost Estimate | Labor | Material | Total | Labor | Material | Total | Total | Total | Labor | Material | Total | Total | Total | Labor | Material | Total |
| Power Transmission, Plant & Admin. | 3480 | 1050 | 4530 | 660 | 530 | 1190 | 3650 | 4840 | 660 | 530 | 1190 | 3650 | 4840 | 3290 | 1050 | 4340 |
| Contracted Services | -- | 1200 | 1200 | -- | 510 | 510 | 1200 | 1710 | 00 | 510 | 510 | 1200 | 1710 | -- | 1200 | 1200 |
| Townsite Operations | 660 | 880 | 1540 | 420 | 200 | 620 | 1180 | 1800 | 420 | 200 | 620 | 1180 | 1800 | 780 | 880 | 1660 |
| Resource Management, Visitor Center | 1250 | 150 | 1400 | -- | -- | -- | 1400 | 1400 | -- | -- | -- | 1400 | 1400 | 1250 | 150 | 1400 |
| Environmental Mitigation Svcs. | -- | 1350 | 1350 | -- | -- | -- | 1350 | 1350 | -- | -- | -- | 1350 | 1350 | -- | 1350 | 1350 |
| Subtotal | 5390 | 4530 | 10020 | 1080 | 1240 | 2320 | 8780 | 11100 | 1080 | 1240 | 2320 | 8780 | 11100 | 5320 | 4630 | 9950 |
| Contingency (±) | 800 | 680 | 1480 | 150 | 190 | 340 | 1310 | 1650 | 150 | 190 | 340 | 1310 | 1650 | 800 | 700 | 1500 |
| TOTAL | 6190 | 5310 | 11500 | 1230 | 1430 | 2660 | 10090 | 12750 | 1230 | 1430 | 2660 | 10090 | 12750 | 6120 | 5330 | 11450 |

TABLE D.1.4.1 (Page 2 of 2)

MANPOWER ESTIMATE

| Manpower | Watana Stage I 1999-2004 | | Devil Canyon Stage II 2005-2011 | | | Watana - Stage III 2012-2016 | | | Mature Stage 2017- beyond | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Stage I Watana | Central Dispatch | Stage II Devil Canyon | Stage I Watana | Central Dispatch | Stage III Watana | Susitna Stages I & II | Central Dispatch | Project Site | Central Dispatch |
| Power Transmission | | | | | | | | | | |
| Superintendent | 1 | - | - | - | 1 | - | - | 1 | - | 1 |
| Assistant | - | 1 | 1 | 1 | - | 1 | 1 | - | 1 | - |
| Line Crew | - | 5 | - | - | 5 | - | - | 5 | - | 5 |
| Plant | | | | | | | | | | |
| Chief | 1 | - | - | - | 1 | - | - | 1 | - | 1 |
| Shift Operators | 20 | - | 7 | - | 13 | 7 | - | 13 | 5 | 13 |
| Plant Maintenance | 25 | 1 | 8 | 17 | 1 | 8 | 17 | 1 | 20 | 1 |
| Resource Management | | | | | | | | | | |
| Manager | 1 | - | - | 1 | - | - | 1 | - | 1 | - |
| Rangers | 2 | - | - | 2 | - | - | 2 | - | 2 | - |
| Resource Specialists | 10 | - | - | 10 | - | - | 10 | - | 10 | - |
| Visitor Center | | | | | | | | | | |
| Manager | 1 | - | - | 1 | - | - | 1 | - | 1 | - |
| Stage | 4 | - | - | 4 | - | - | 4 | - | 4 | - |
| Administration | | | | | | | | | | |
| Chief | 1 | - | - | - | 1 | - | - | 1 | 1 | 1 |
| Clerk/typist | 3 | - | 2 | 1 | 3 | 2 | 1 | 3 | 2 | 3 |
| Townsite | | | | | | | | | | |
| Management, Security, Fire Protection, Warehouse | 11 | - | 7 | 5 | - | 7 | 5 | - | 13 | - |
| Subtotal | 80 | 7 | 25 | 42 | 25 | 25 | 42 | 25 | 60 | 25 |
| TOTAL | 87 | | | 92 | | | 92 | | 85 | |

TABLE D.1.7.1: CUMULATIVE AND ANNUAL CASH FLOW SUSITNA STAGES I, II, III 

January 1985 Dollars - In Millions

| Year End | Annual Cash Flow St I Watana | St II Devil Canyon | St III Watana | Combined | Cumulative Cash Flow St I Watana | St II Devil Canyon | St III Watana | Combined |
|---|---|---|---|---|---|---|---|---|
| 1985 | 134.2 | --- | --- | 134.2 * | 134.2 | --- | --- | 134.2 |
| 1986 | 25.8 | --- | --- | 25.8 * | 160.0 | --- | --- | 160.0 |
| 1987 | 28.5 | --- | --- | 28.5 * | 188.5 | --- | --- | 188.5 |
| 1988 | 32.6 | --- | --- | 32.6 * | 221.1 | --- | --- | 221.1 |
| 1989 | 51.5 | --- | --- | 51.5 * | 272.6 | --- | --- | 272.6 |
| 1990 | 67.8 | --- | --- | 67.8 | 340.4 | --- | --- | 340.4 |
| 1991 | 186.5 | --- | --- | 186.5 | 526.9 | --- | --- | 526.9 |
| 1992 | 326.1 | --- | --- | 326.1 | 853.0 | --- | --- | 853.0 |
| 1993 | 170.1 | --- | --- | 170.1 | 1023.1 | --- | --- | 1023.1 |
| 1994 | 205.4 | --- | --- | 205.4 | 1,228.5 | --- | --- | 1,228.5 |
| 1995 | 253.5 | 46.7 | --- | 300.2 | 1,482.0 | 46.7 | --- | 1,538.7 |
| 1996 | 355.1 | 47.7 | --- | 402.8 | 1,837.1 | 94.4 | --- | 1,931.5 |
| 1997 | 491.0 | 75.7 | --- | 566.7 | 2,328.1 | 170.1 | --- | 2,498.2 |
| 1998 | 325.0 | 127.7 | --- | 452.7 | 2,653.1 | 297.8 | --- | 2,950.9 |
| 1999 | 28.9 | 137.0 | --- | 165.9 | 2,682.0 | 434.8 | --- | 3,116.8 |

TABLE D.1.7.1 (Page 2 of 2)

| Year End | Annual Cash Flow St I Watana | St II Devil Canyon | St III Watana | Combined | Cummulative Cash Flow St I Watana | St II Devil Canyon | St III Watana | Combined |
|---|---|---|---|---|---|---|---|---|
| 2000 | --- | 149.4 | --- | 149.4 | 2,682.0 | 584.2 | --- | 3,266.2 |
| 2001 | --- | 243.7 | --- | 243.7 | 2,682.0 | 827.9 | --- | 3,509.9 |
| 2002 | --- | 211.8 | --- | 211.8 | 2,682.0 | 1,039.7 | --- | 3,721.7 |
| 2003 | --- | 218.7 | --- | 218.7 | 2,682.0 | 1,258.4 | --- | 3,940.4 |
| 2004 | --- | 114.0 | --- | 114.0 | 2,682.0 | 1,372.4 | --- | 4,054.4 |
| 2005 | --- | 21.6 | --- | 21.6 | 2,682.0 | 1,394.0 | --- | 4,076.0 |
| 2006 | --- | --- | 147.8 | 147.8 | 2,682.0 | 1,394.0 | 147.8 | 4,223.8 |
| 2007 | --- | --- | 203.8 | 203.8 | 2,682.0 | 1,394.0 | 351.6 | 4,427.6 |
| 2008 | --- | --- | 197.2 | 197.2 | 2,682.0 | 1,394.0 | 548.8 | 4,624.8 |
| 2009 | --- | --- | 286.0 | 286.0 | 2,682.0 | 1,394.0 | 834.8 | 4,910.8 |
| 2010 | --- | --- | 271.9 | 271.9 | 2,682.0 | 1,394.0 | 1,106.7 | 5,182.7 |
| 2011 | --- | --- | 135.3 | 135.3 | 2,682.0 | 1,394.0 | 1,242.0 | 5,318.0 |
| 2012 | --- | --- | 77.0 | 77.0 | 2,682.0 | 1,394.0 | 1,319.0 | 5,395.0 |

* Estimated costs related to engineering, administration and environmental studies expected to be incurred prior to issuance of FERC license and prior to beginning of construction.

TABLE D.2.2.1: SUSITNA POWER AND ENERGY PRODUCTION 

| MONTH | STAGE I | | | STAGE II | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | WATANA | | | WATANA | | | DEVIL CANYON | | |
| | Capa-bility 1/ (MW) | Average Energy (GWh) | Firm Energy 2/ (GWh) | Capa-bility 3/ (MW) | Average Energy (GWh) | Firm Energy 2/ (GWh) | Capa-bility 1/ (MW) | Average Energy (GWh) | Firm Energy 2/ (GWh) |
| Jan | 297 | 221 | 212 | 417 | 223 | 210 | 388 | 288 | 267 |
| Feb | 193 | 130 | 124 | 379 | 170 | 161 | 349 | 234 | 219 |
| Mar | 204 | 152 | 147 | 340 | 169 | 166 | 337 | 250 | 242 |
| Apr | 150 | 108 | 103 | 299 | 142 | 142 | 320 | 230 | 230 |
| May | 267 | 199 | 199 | 298 | 113 | 113 | 315 | 234 | 234 |
| Jun | 365 | 263 | 171 | 374 | 91 | 91 | 322 | 231 | 226 |
| Jul | 356 | 265 | 164 | 462 | 132 | 124 | 267 | 198 | 198 |
| Aug | 358 | 266 | 179 | 496 | 159 | 159 | 242 | 180 | 180 |
| Sep | 371 | 267 | 216 | 503 | 172 | 168 | 266 | 191 | 191 |
| Oct | 192 | 143 | 130 | 500 | 182 | 150 | 303 | 225 | 184 |
| Nov | 235 | 169 | 101 | 483 | 203 | 183 | 338 | 243 | 216 |
| Dec | 276 | 205 | 187 | 454 | 220 | 203 | 364 | 271 | 246 |
| Total | | 2388 | 1933 | | 1976 | 1870 | | 2775 | 2623 |

1/ Corresponds to monthly plant capacity output that produces the total estimated monthly energy available.

2/ Firm energy is referred to as reliability energy in OGP and is used in reliability calculations.

3/ Corresponds to four unit capability and is based on monthly net head and turbine efficiency.

TABLE D.2.2.1 (Page 2 of 2)

| MONTH | STAGE III | | | | | |
|---|---|---|---|---|---|---|
| | WATANA | | | DEVIL CANYON | | |
| | Capability[1/] (MW) | Average Energy (GWh) | Firm Energy[2/] (GWh) | Capability[3/] (MW) | Average Energy (GWh) | Firm Energy (GWh) |
| Jan | 1068 | 377 | 349 | 462 | 344 | 326 |
| Feb | 1032 | 297 | 269 | 411 | 276 | 260 |
| Mar | 997 | 309 | 286 | 392 | 292 | 282 |
| Apr | 963 | 254 | 167 | 350 | 252 | 171 |
| May | 958 | 222 | 215 | 360 | 268 | 268 |
| Jun | 1010 | 179 | 179 | 381 | 274 | 274 |
| Jul | 1083 | 203 | 203 | 355 | 264 | 264 |
| Aug | 1136 | 220 | 220 | 333 | 248 | 248 |
| Sep | 1159 | 259 | 233 | 308 | 222 | 222 |
| Oct | 1156 | 314 | 200 | 376 | 280 | 157 |
| Nov | 1135 | 336 | 220 | 418 | 301 | 177 |
| Dec | 1105 | 365 | 289 | 442 | 329 | 268 |
| TOTAL | | 3335 | 2830 | | 3350 | 2917 |

1/ Corresponds to six unit capability and is based on monthly net head and turbine efficiency.

2/ Firm energy is referred to as reliability energy in OGP and is used in reliability calcuations.

3/ Corresponds to monthly plant capacity output that produces the total estimated monthly energy available.

TABLE D.2.3.1: SUSITNA HYDROELECTRIC PROJECT THERMAL ALTERNATIVES DATA SUMMARY



| | Coal-Fired Steam-Electric | Gas-Fired Simple-Cycle Combustion Turbine | Gas-Fired Combined Cycle |
|---|---|---|---|
| <u>Capital Data</u> | | | |
| Gross Capacity Per Unit | 217 MW | 80,000 kW at ISO<br>89,600 kW at 30°F | CT 79,600 kW at ISO<br>ST 59,125 kW at ISO<br>Two CTs at 89,100 kW each; One ST at 59,100 kW, all at 30°F |
| Units Per Plant | Two, one initially with second at later date | Three, one initially with second and third at later dates. | One 3-unit group as described above. |
| Total Gross Capacity at 30°F | 217 MW - first unit<br>434 MW - two unit | 268,800 kW | 237,300 kW |
| Auxiliary Loads | 17 MW per unit | Each CT unit = 896 kW<br>Station Loads for A/C, Lighting, etc = 4,000 kW<br>Total Aux. = 6,688 | Each CT unit = 891 kW<br>Each ST unit = 2,365 kW<br>Station Loads for A/C, Lighting, etc = 3,300<br>Total Aux. = 7,447 |
| Net Capacity at 30°F | 200 MW - one unit<br>400 MW - two unit | 262,112 kW | 229,853 kW |
| Nominal Plant Capacity | 400 MW | 262 MW | 230 MW |

TABLE D.2.3.1 (Page 2 of 3)

| | Coal-Fired Steam-Electric | | Gas-Fired Simple-Cycle Combustion Turbine | Gas-Fired Combined Cycle |
|---|---|---|---|---|
| Capital Cost Data (thousand 1985$) | | | | |
| | Beluga | Nenana | | |
| Unit Direct Capital Cost | | | | |
| Initial | 593,640 | 639,713 | 38,672 | 146,138 |
| First Extension | 385,386 | 399,706 | 30,537 | N/A |
| Second Extension | N/A | N/A | 30,537 | N/A |
| Total | 979,026 | 1,039,419 | 99,746 | |
| Other Costs | | | | |
| Town Site | 18,333 | N/A | N/A | N/A |
| Owner's Cost | 24,476 | 25,985 | 997 | 2,192 |
| Startup, Parts and Tools | 11,044 | 11,044 | 499 | 1,096 |
| Machinery and Equipment | 2,209 | 2,209 | N/A | N/A |
| Land | 2,209 | 2,209 | N/A | N/A |
| Subtotal | 58,271 | 41,447 | 1,496 | 3,288 |
| Total Project Cost | 1,037,297 | 1,080,866 | 101,242 | 149,426 |
| Unit Cost $/kW | 2,593 | 2,702 | 386 | 650 |
| Nominal Capacity - MW | 400 | 400 | 262 | 230 |
| Operating and Maintenance Cost Data | | | | |
| Net Generation at Capacity Factor of 0.80 | 2,804,000 MWh (400 MW) | 2,804,000 MWh (400 MW) | 1,836,000 MWh | 1,612,000 MWh |

TABLE D.2.3.1 (Page 3 of 3)

| | Coal-Fired Steam-Electric | Gas-Fired Simple-Cycle Combustion Turbine | Gas-Fired Combined Cycle |
|---|---|---|---|
| Operating and Maintenance Cost Data (Cont'd) (thousand 1985 $) | | | |
| Total Fixed O&M Costs | 24,566 (400 MW) | 2,295 | 3,049 |
| Total Variable O&M Costs 1/ | 12,044 (400 MW) | 1,071 | 1,070 |
| Total Annual O&M Costs | 36,610 (400 MW) | 3,366 | 4,119 |
| Annual Nonfuel, Unit Production Costs - $/MWh | 13.06 | 1.83 | 2.57 |
| Fixed O&M Unit Costs - $/KW/yr | 61.42 | 8.76 | 13.26 |
| Variable O&M Unit Costs - $/MWh | 4.30 | 0.58 | 0.66 |
| Heat Rate Data | | | |
| Fuel Used (HHV) | 4,109.6 x $10^6$ Btu/hr | 1045.0 x $10^6$ Btu/hr/unit Total = 3135 x $10^6$ Btu/hr | 2110.0 x $10^6$ Btu/hr |
| Nominal Capacity | 400 MW | 262 MW | 230 MW |
| Net Station Heat Rate | 10,300 Btu/kWh | 12,000 Btu/kWh | 9200 Btu/kWh |

1/ Capital costs for repairs and maintenance are included in variable O&M costs on an annual basis. These costs, as an annual percentage of the complete plant total project costs, are approximately 0.4% for the Beluga and Nenana coal plants, 0.8% for the three-unit simple cycle plant, and 0.5% for the combined cycle plant.

TABLE D.2.4.1: NATURAL GAS FUEL PRICES
(1985 $)

| Year | SHCA Forecast | | Composite Forecast | |
|---|---|---|---|---|
| | Oil ($/bbl) | Gas 1/ ($/MMBtu) | Oil ($/bbl) | Gas 1/ ($/MMBtu) |
| 1985 | 28.10 | 2.13 | 27.10 | 1.98 |
| 1990 | 27.70 | 2.08 | 26.50 | 1.90 |
| 1995 | 33.70 | 2.80 | 31.80 | 2.65 |
| 2000 | 41.00 | 3.95 | 38.10 | 3.53 |
| 2010 | 61.50 | 6.83 | 51.30 | 5.37 |
| 2020 | 85.00 | 10.15 | 68.90 | 7.85 |
| 2030 | 96.00 | 11.70 | 75.00 | 8.70 |
| 2040 | 106.00 | 13.12 | 75.00 | 8.70 |
| 2050 | 117.00 | 14.67 | 75.00 | 8.70 |

1/ Includes 0.40$/MMBtu charge for natural gas delivery.

TABLE D.2.4.2: CAPITAL COST ESTIMATE SIMPLE CYCLE COMBUSTION TURBINE, INITIAL UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installation | Total |
|---|---|---|---|---|
| 1. | Improvements to Site | 305 | 834 | 1,139 |
| 2. | Earthwork and Piling | 98 | 597 | 695 |
| 4. | Concrete | 238 | 806 | 1,044 |
| 5. | Strct stl/lft Equipment | 1,306 | 782 | 2,088 |
| 6. | Buildings | 695 | 1,095 | 1,790 |
| 7. | Turbine Generator | 12,812 | 706 | 13,518 |
| 10. | Other Mechan Equip | 646 | 359 | 1,005 |
| 12. | Piping | 271 | 523 | 794 |
| 13. | Insulation | 38 | 96 | 134 |
| 14. | Instrumentation | 103 | 62 | 165 |
| 15. | Electrical Equipment | 1,560 | 1,276 | 2,836 |
| 16. | Painting | 47 | 171 | 218 |
| 17. | Off-Site Facilities | 310 | 1,714 | 2,024 |
| 71. | Indirect Const Cost | 0 | 4,478 | 4,478 |
| 72. | Professional Services | 0 | 2,181 | 2,181 |
| 300. | Total Cost w/o Cont | 18,429 | 15,680 | 34,109 |
| 100. | Contingency | 2,211 | 2,352 | 4,563 |
| 99. | Total Project Cost | $20,640 | $18,032 | $38,672 |

TABLE D.2.4.3: CAPITAL COST ESTIMATE SIMPLE CYCLE COMBUSTION TURBINE, EXTENSION UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installation | Total |
|---|---|---|---|---|
| 2. | Earthwork and Piling | 98 | 597 | 695 |
| 4. | Concrete | 238 | 806 | 1,044 |
| 5. | Strct stl/lft Equipment | 1,306 | 782 | 2,088 |
| 6. | Buildings | 695 | 1,095 | 1,790 |
| 7. | Turbine Generator | 12,812 | 706 | 13,518 |
| 10. | Other Mechan Equip | 646 | 359 | 1,005 |
| 12. | Piping | 271 | 523 | 794 |
| 13. | Insulation | 38 | 96 | 134 |
| 14. | Instrumentation | 103 | 62 | 165 |
| 15. | Electrical Equipment | 1,560 | 624 | 2,184 |
| 16. | Painting | 47 | 171 | 218 |
| 71. | Indirect Const Cost | 0 | 2,078 | 2,078 |
| 72. | Professional Services | 0 | 1,306 | 1,306 |
| 300. | Total Cost w/o Cont | 17,814 | 10,585 | 27,019 |
| 100. | Contingency | 2,138 | 1,380 | 3,518 |
| 99. | Total Project Cost | $19,952 | $10,585 | $30,537 |

TABLE D.2.4.4: CAPITAL COST SUMMARY SIMPLE CYCLE COMBUSTION TURBINE POWER PLANT THREE UNITS (thousand 1985 $)

| | |
|---|---|
| Direct Project Costs | |
| Unit 1 Estimate, Table D.2.4.2 | 38,672 |
| Unit 2 Estimate, Table D.2.4.3 | 30,537 |
| Unit 3 Estimate, Table D.2.4.3 | 30,537 |
| Subtotal | 99,746 |
| Items Not Included in Estimate | |
| Owners Cost (at 1% of Direct Project) | 997 |
| Startup, Spare Parts, and Special Tools (0.5% of Direct Project) | 499 |
| Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture (Equipment Already Exists) | |
| Land (Installed at Existing Site) | |
| Subtotal | 1,496 |
| Project Total Cost | 100,242 |
| Average Cost per kW - $/kW For 3 unit, 262 MW plant | 386 |

TABLE D.2.4.5: SUMMARY OF O&M COSTS 262 MW SIMPLE CYCLE COMBUSTION TURBINE POWER PLANT (1985 $)

| | Total Cost (thousand $) | Unit Cost |
|---|---|---|
| Fixed Costs | | |
| Staff | 2,295 | \$8.76/kW/yr 1/ |
| Variable | | |
| Consumable Materials | | |
| Water Treatment | 45 | |
| Lubrications | 85 | |
| Inlet Air Filtration | 53 | |
| Turbine Exhaust | 50 | |
| Waste Disposal | 48 | |
| Overall and Repair | 790 | |
| Total Variable Cost | 1,071 | \$ 0.58/MWh 2/ |
| Total Non-fuel Costs | 3,366 | \$12.85/kW/yr 1/ |
| | | \$ 1.83/MWh 2/ |

1/ Based on net plant unit capacity of 262,000 kW.

2/ Based on annual plant generation of 1,836,000 MWh at the assumed design capacity factor of 80 percent.

TABLE D.2.4.6: CAPITAL COST ESTIMATE COMBINED CYCLE POWER PLANT (thousand 1985 $)

| Account Number | Description | Materials | Installation | Total |
|---|---|---|---|---|
| 1. | Improvements to Site | 434 | 1,288 | 1,722 |
| 2. | Earthwork and Piling | 649 | 1,394 | 2,043 |
| 4. | Concrete | 1,633 | 5,584 | 7,217 |
| 5. | Strct stl/lft Equipment | 4,179 | 3,263 | 7,442 |
| 6. | Buildings | 1,956 | 2,985 | 4,941 |
| 7. | Turbine Generator | 34,861 | 2,249 | 37,110 |
| 8. | Stm Generator & Access | 14,268 | 3,913 | 18,181 |
| 10. | Other Mechan. Equip | 6,849 | 2,785 | 9,634 |
| 12. | Piping | 2,009 | 2,533 | 4,542 |
| 13. | Insulation | 352 | 789 | 1,141 |
| 14. | Instrumentation | 2,869 | 248 | 2,117 |
| 15. | Electrical Equipment | 5,057 | 6,916 | 11,973 |
| 16. | Painting | 220 | 692 | 912 |
| 17. | Off-Site Facilities | 330 | 1,714 | 2,044 |
| 71. | Indirect Const Cost | 0 | 10,567 | 10,567 |
| 72. | Professional Services | 0 | 7,439 | 7,439 |
| 300. | Total Cost w/o Cont | 74,666 | 54,359 | 129,025 |
| 100. | Contingency | 8,960 | 8,153 | 17,113 |
| 99. | Total Project Cost | $ 83,626 | $ 62,512 | $ 146,138 |

TABLE D.2.4.7: CAPITAL COST SUMMARY COMBINED CYCLE POWER PLANT (thousand 1985 $)

| | |
|---|---|
| Direct Project Costs | |
| Table D.2.4.6 | 146,138 |
| Items Not Included in Estimate | |
| Owners Cost (at 1-1/2% of Direct Project) | 2,192 |
| Startup, Spare Parts, and Special Tools (at 0.75% of Direct Project) | 1,096 |
| Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture (Equipment Already Exists) | 0 |
| Land (Installed at Existing Site) | 0 |
| Subtotal | 3,288 |
| Project Total Cost | 149,426 |
| Average Cost per kW - $/kW For 230 MW Plant | 650 |

TABLE D.2.4.8: SUMMARY OF O&M COST 230 MW COMBINED CYCLE POWER PLANT (1985 $)

| | Total Cost (thousand $) | Unit Cost |
|---|---|---|
| Fixed Costs | | |
| Staff | 3,049 | $13.26/kw/yr1/ |
| Variable Costs | | |
| Consumable Materials | | |
| Lime | 45 | |
| Water Treatment | 68 | |
| Vehicles | 35 | |
| Lubricants | 33 | |
| Waste Disposal | 85 | |
| Overhaul and Repair | 804 | |
| Total Variable Costs | 1,070 | $ 0.66/MWh2/ |
| Total Non-fuel Costs | 4,119 | $17.91/kw/yr1 |
| | | $ 2.56/MWh2/ |

1/ Based net plant capacity of 230,000 kw.

2/ Based on plant annual generation of 1,612,000 MWh at assumed capacity factor of 80 percent.

TABLE D.2.5.1: NENANA AND BELUGA COAL FUEL PRICES (1985 $)

| Year | Nenana Delivered ($/MMBtu) | Beluga Minemouth SHCA Forecast ($/MMBtu) | Beluga Minemouth Composite Forecast ($/MMBtu) |
|---|---|---|---|
| 1985 | 1.84 | 1.32 | 1.42 |
| 1990 | 1.99 | 1.45 | 1.54 |
| 1995 | 2.14 | 1.60 | 1.65 |
| 2000 | 2.31 | 1.78 | 1.78 |
| 2010 | 2.69 | 2.13 | 2.19 |
| 2020 | 3.13 | 2.55 | 2.57 |
| 2030 | 3.64 | 3.30 | 3.08 |
| 2040 | 4.24 | 4.10 | 3.22 |
| 2050 | 4.94 | 5.12 | 3.74 |

TABLE D.2.5.2: CAPITAL COST ESTIMATE BELUGA 200 MW COAL-FIRED POWER PLANT INITIAL UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installations | Total |
|---|---|---|---|---|
| 1. | Improvements to site | 1,212 | 2,958 | 4,170 |
| 2. | Earthwork and piling | 15,158 | 19,840 | 34,998 |
| 3. | Circ water system | 4,074 | 4,290 | 8,364 |
| 4. | Concrete | 3,850 | 16,958 | 20,808 |
| 5. | Strct stl/lft eqp | 10,909 | 17,051 | 27,960 |
| 6. | Buildings | 6,016 | 12,646 | 18,662 |
| 7. | Turbine generator | 16,777 | 2,726 | 19,503 |
| 8. | Stm gner and access | 24,552 | 19,335 | 43,887 |
| 9. | AQCS | 30,842 | 24,355 | 55,197 |
| 10. | Other mechan equip | 15,063 | 5,305 | 20,368 |
| 11. | Coal and ash hndl equip | 13,650 | 9,677 | 23,327 |
| 12. | Piping | 10,104 | 18,545 | 28,649 |
| 13. | Insulation | 593 | 6,445 | 7,038 |
| 14. | Instrumentation | 6,650 | 580 | 7,230 |
| 15. | Electrical Equipment | 21,483 | 37,411 | 58,894 |
| 16. | Painting | 159 | 2,117 | 2,276 |
| 17. | Off-site facilities | 6,169 | 7,602 | 13,771 |
| 18. | Waterfront facility | 1,932 | 6,086 | 8,018 |
| 19. | Substantion/t-line | 13,381 | 10,352 | 23,733 |
| 71. | Indirect const cost | 0 | 42,891 | 41,891 |
| 72. | Professional services | 0 | 55,907 | 55,907 |
| 300. | Total cost w/o cont | 202,574 | 322,077 | 524,651 |
| 100. | Contingency | 23,093 | 45,896 | 68,989 |
| 99. | Total project cost | $225,667 | $367,973 | $593,640 |

TABLE D.2.5.3: CAPITAL COST ESTIMATE BELUGA 200 MW COAL-FIRED POWER PLANT EXTENSION UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installations | Total |
|---|---|---|---|---|
| 1. | Improvements to site | 174 | 158 | 332 |
| 2. | Earthwork and piling | 7,656 | 6,438 | 14,094 |
| 3. | Circ water system | 3,822 | 3,828 | 7,650 |
| 4. | Concrete | 2,613 | 10,856 | 13,469 |
| 5. | Strct stl/lft eqp | 8,493 | 11,000 | 19,493 |
| 6. | Buildings | 3,263 | 6,068 | 9,331 |
| 7. | Turbine generator | 16,138 | 2,734 | 18,872 |
| 8. | Stm gner and access | 23,616 | 20,239 | 43,855 |
| 9. | AQCS | 21,887 | 19,147 | 41,034 |
| 10. | Other mechan equip | 10,288 | 3,931 | 14,219 |
| 11. | Coal and ash hndl equip | 3,513 | 2,202 | 5,715 |
| 12. | Piping | 9,223 | 16,789 | 26,012 |
| 13. | Insulation | 571 | 6,429 | 7,000 |
| 14. | Instrumentation | 6,396 | 558 | 6,954 |
| 15. | Electrical Equipment | 18,499 | 26,876 | 45,375 |
| 16. | Painting | 132 | 2,039 | 2,171 |
| 17. | Off-site facilities | 561 | 3,039 | 3,600 |
| 19. | Substantion/t-line | 11,284 | 7,312 | 18,596 |
| 71. | Indirect const cost | 0 | 27,159 | 27,159 |
| 72. | Professional services | 0 | 14,052 | 14,05 |
| 300. | Total cost w/o cont | 148,129 | 190,854 | 338,983 |
| 100. | Contingency | 17,775 | 28,628 | 46,403 |
| 99. | Total project cost | $165,904 | $219,482 | $385,386 |

TABLE D.2.5.4: CAPITAL COST SUMMARY BELUGA COAL-FIRED POWER PLANT TWO UNITS (thousand 1985 $)

| | |
|---|---|
| Direct Project Costs | |
| Unit 1 Estimate, Table D.2.5.2 | 593,640 |
| Unit 2 Estimate, Table D.2.5.3 | 385,386 |
| Subtotal | 979,026 |
| Items Not Included in Estimate | |
| Town Site Cost | 18,333 |
| Owners Cost (at 2-1/2% of Direct Project) | 24,476 |
| Startup, Spare parts, and Special Tools | 11,044 |
| Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture | 2,209 |
| Land (200 acres at $10,920 per acre) | 2,209 |
| Subtotal | 58,271 |
| Project Total Cost | 1,037,297 |
| Average Cost per kW - $/kW | 2,593 |

TABLE D.2.5.5: CAPITAL COST ESTIMATE NENANA 200 MW COAL-FIRED POWER PLANT INITIAL UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installations | Total |
|---|---|---|---|---|
| 1. | Improvements to site | 2,565 | 5,824 | 8,399 |
| 2. | Earthwork and piling | 17,133 | 25,217 | 42,350 |
| 3. | Circ water system | 3,930 | 4,331 | 8,261 |
| 4. | Concrete | 6,522 | 24,428 | 30,950 |
| 5. | Strct stl/lft eqp | 11,322 | 18,819 | 30,141 |
| 6. | Buildings | 5,974 | 13,295 | 19,269 |
| 7. | Turbine generator | 16,097 | 2,754 | 18,851 |
| 8. | Stm gner and access | 23,557 | 19,528 | 43,085 |
| 9. | AQCS | 30,779 | 24,989 | 55,768 |
| 10. | Other mechan equip | 14,675 | 5,544 | 20,219 |
| 11. | Coal and ash hndl equip | 16,390 | 10,845 | 27,235 |
| 12. | Piping | 9,765 | 20,362 | 30,127 |
| 13. | Insulation | 827 | 7,609 | 8,436 |
| 14. | Instrumentation | 6,380 | 586 | 6,966 |
| 15. | Electrical Equipment | 24,652 | 39,171 | 63,823 |
| 16. | Painting | 165 | 2,302 | 2,467 |
| 17. | Off-site facilities | 7,339 | 13,698 | 21,037 |
| 19. | Substantion/t-line | 7,956 | 2,832 | 10,788 |
| 71. | Indirect const cost | 0 | 55,575 | 55,575 |
| 72. | Professional services | 0 | 57,911 | 57,911 |
| 300. | Total cost w/o cont | 206,028 | 355,620 | 561,648 |
| 100. | Contingency | 24,723 | 53,342 | 78,065 |
| 99. | Total project cost | $230,751 | $408,962 | $639,713 |

TABLE D.2.5.6: CAPITAL COST ESTIMATE NENANA 200 MW COAL-FIRED POWER PLANT EXTENSION UNIT (thousand 1985 $)

| Account Number | Description | Materials | Installations | Total |
|---|---|---|---|---|
| 1. | Improvements to site | 226 | 235 | 461 |
| 2. | Earthwork and piling | 8,283 | 8,289 | 16,572 |
| 3. | Circ water system | 3,854 | 4,259 | 8,113 |
| 4. | Concrete | 3,636 | 12,703 | 16,339 |
| 5. | Strct stl/lft eqp | 8,485 | 11,950 | 20,435 |
| 6. | Buildings | 3,397 | 6,412 | 9,809 |
| 7. | Turbine generator | 16,376 | 2,753 | 19,139 |
| 8. | Stm gner and access | 23,970 | 19,527 | 43,497 |
| 9. | AQCS | 21,833 | 19,755 | 41,588 |
| 10. | Other mechan equip | 9,863 | 3,916 | 13,779 |
| 11. | Coal and ash hndl equip | 3,612 | 2,913 | 6,525 |
| 12. | Piping | 9,838 | 17,907 | 27,745 |
| 13. | Insulation | 820 | 6,653 | 7,473 |
| 14. | Instrumentation | 6,380 | 586 | 6,966 |
| 15. | Electrical Equipment | 19,463 | 34,187 | 53,650 |
| 16. | Painting | 157 | 2,201 | 2,358 |
| 17. | Off-site facilities | 601 | 2,598 | 3,199 |
| 19. | Substantion/t-line | 1,736 | 1,416 | 3,152 |
| 71. | Indirect const cost | 0 | 33,968 | 33,968 |
| 72. | Professional services | 0 | 16,531 | 16,531 |
| 300. | Total cost w/o cont | 142,530 | 208,759 | 351,289 |
| 100. | Contingency | 17,104 | 31,313 | 48,417 |
| 99. | Total project cost | $159,634 | $240,072 | $399,706 |

TABLE D.2.5.7: CAPITAL COST SUMMARY NENANA COAL-FIRED POWER PLANT TWO UNITS (thousand 1985 $)

| | |
|---|---|
| Direct Project Costs | |
| Unit 1 Estimate, Table D.2.5.5 | 639,713 |
| Unit 2 Estimate, Table D.2.5.6 | 399,706 |
| Subtotal | 1,039,419 |
| Items Not Included in Estimate | |
| Owners Cost (at 2-1/2% of Direct Project) | 25,985 |
| Startup, Spare parts, and Special Tools | 11,044 |
| Maintenance Shop Machinery, Laboratory Equipment, and Office Furniture | 2,209 |
| Land (200 acres at $10,920 per acre) | 2,209 |
| Subtotal | 41,447 |
| Project Total Cost | 1,080,866 |
| Average Cost per kW - $/kW | 2,702 |

TABLE D.2.5.8: COAL-FIRED POWER PLANT SUMMARY OF O&M COSTS (1985 $)

| | 200 MW Plant Cost (thousand $) | 400 MW Plant Cost (thousand $) | Unit Cost |
|---|---|---|---|
| Fixed Costs | | | |
| Staff | 12,283 | 24,566 | $61.42/kw/yr |
| Variable Costs | | | |
| Consumable Materials | | | |
| Lime | 1,260 | 2,520 | |
| Water Treatment | 743 | 1,486 | |
| Vehicles | 102 | 204 | |
| Lubricants | 55 | 110 | |
| Waste Disposal | 1,814 | 3,628 | |
| Overhaul and Repair | 2,058 1/ | 4,116 | |
| Total Variable Costs | 6,032 | 12,064 | $ 4.30/MWh 2/ |
| Total Non-fuel Costs | 18,315 | 36,630 | $91.58/kw/yr |
| | | | $13.06/MWh 2/ |

1/ Capital replacement costs for repairs and maintenance are included in this figure. There costs, on an annual basis, are approximately 0.4% of the complete Plant total Project costs.

2/ Based on 200 MW plant annual generation of 1,402,000 MWh at the design capacity factor of 80 percent.

TABLE D.2.6.1: INSTALLED CAPACITY OF ANCHORAGE-COOK INLET AREA-DEC. 1984 (in megawatts)

| | HYDRO | OIL | NATURAL GAS | | |
|---|---|---|---|---|---|
| | Hydro | Diesel | Combustion Turbine | Steam Turbine | Total |
| **Utilities**1/ | | | | | |
| Alaska Power Administration | 30.0 | 0 | 0 | 0 | 30.0 |
| Anchorage Municipal Light and Power | 0 | 0 | 329.9 | 0 | 329.9 |
| Chugach Electric Associaton | 17.4 | 0 | 490.4 | 0 | 507.8 |
| Homer Electric Association | 0 | 2.1 | 0 | 0 | 2.1 |
| Matanuska Electric Association | 0 | 0 | 0 | 0 | 0 |
| Seward Electric Association | 0 | 5.5 | 0 | 0 | 5.5 |
| Total | 47.4 | 7.6 | 820.3 | 0 | 875.3 |
| **Military Installations**2/ | | | | | |
| Elmendorf AFB | 0 | 2.1 | 0 | 31.5 | 33.6 |
| Fort Richardson | 0 | 7.2 | 0 | 18.0 | 25.2 |
| Subtotal | 0 | 9.3 | 0 | 49.5 | 58.8 |
| **Industrial Installations**3/ | | | | | |
| Industry | 0 | 9.6 | 16.0 | 0 | 25.6 |
| TOTAL | 47.4 | 26.5 | 836.3 | 49.5 | 959.7 |

1/ Data based on Applicant's evaluation of information provided by the Railbelt Utilities.

2/ Source: Departments of Army and Air Force, January 1985.

3/ Source: Battelle (1982) and Alaska Power Administration (1983); updated by Harza-Ebasco Susitna Joint Venture, 1983. Figures are for 1981, latest year that data was available.

TABLE D.2.6.2: INSTALLED CAPACITY OF THE FAIRBANKS-TANANA VALLEY AREA-DEC. 1984 (in megawatts)

| | HYDRO | OIL | | COAL | |
|---|---|---|---|---|---|
| | Hydro | Diesel | Combustion Turbine | Steam Turbine | Total |
| Utilities[1] | | | | | |
| Fairbanks Municipal Utility System | 0 | 8.4 | 32.2 | 28.6 | 69.2 |
| Golden Valley Electric Association | 0 | 17.3 | 157.8 | 25.0 | 200.1 |
| University of Alaska | 0 | 0 | 0 | 13.0 | 13.0 |
| Subtotal | 0 | 25.7 | 190.0 | 66.6 | 282.3 |
| Military Installations[2] | | | | | |
| Eielson AFB | 0 | 0 | 0 | 15.0 | 15.0 |
| Fort Greeley | 0 | 5.5 | 0 | 0 | 5.5 |
| Fort Wainwright | 0 | 0 | 0 | 22.0 | 22.0 |
| Subtotal | 0 | 5.5 | 0 | 37.0 | 42.5 |
| Industrial Installations[3] | | | | | |
| Industry | 0 | 2.8 | 0 | 0 | 2.8 |
| TOTAL | 0 | 34.0 | 190.0 | 103.6 | 327.6 |

1/ Data based on Applicant's evaluation of information provided by the Railbelt Utilities.

2/ Source: Departments of Army and Air Force, January 1985.

3/ Source: Battelle (1982) and Alaska Power Administration (1983); updated by Harza-Ebasco Susitna Joint Venture, 1983. Figures are for 1981, latest year that data was available.

TABLE D.2.6.3: EXISTING AND PLANNED RAILBELT HYDROELECTRIC GENERATION

| | Average Energy (GWh) | | | | | Firm Energy (GWh) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Existing Plants | | | Proposed Plant | | Existing Plants | | | Proposed Plant | |
| Month | Eklutna 1/ | Cooper Lake 1/ | Sub-Total | Bradley Lake 2/ | Total | Eklutna | Cooper Lake | Sub-Total | Bradley Lake 2/ | Total |
| Jan | 14 | 4 | 18 | 41 | 59 | 13 | 4 | 17 | 41 | 58 |
| Feb | 12 | 3 | 15 | 39 | 54 | 12 | 3 | 15 | 39 | 54 |
| Mar | 12 | 3 | 15 | 31 | 46 | 9 | 3 | 12 | 31 | 43 |
| Apr | 10 | 3 | 13 | 26 | 39 | 10 | 3 | 13 | 26 | 39 |
| May | 12 | 3 | 15 | 20 | 35 | 11 | 3 | 14 | 20 | 34 |
| Jun | 12 | 3 | 15 | 13 | 28 | 8 | 2 | 10 | 13 | 23 |
| Jul | 13 | 4 | 17 | 17 | 34 | 9 | 3 | 12 | 13 | 25 |
| Aug | 14 | 4 | 18 | 27 | 45 | 8 | 2 | 10 | 13 | 23 |
| Sep | 13 | 3 | 16 | 39 | 55 | 9 | 3 | 12 | 14 | 26 |
| Oct | 14 | 4 | 18 | 34 | 52 | 9 | 3 | 12 | 29 | 41 |
| Nov | 14 | 4 | 18 | 39 | 57 | 8 | 2 | 10 | 39 | 49 |
| Dec | 14 | 4 | 18 | 41 | 59 | 12 | 3 | 15 | 41 | 56 |
| Total | 154 | 42 | 196 | 367 | 563 | 118 | 34 | 152 | 319 | 471 |

1/ Source: Acres (1982).

2/ Scheduled on-line in 1990.

TABLE D.2.6.4: ANCHORAGE-COOK INLET AREA EXISTING PLANT DATA, DEC. 1984 

| Unit Name | Operation Period Online Date | Operation Period Retire Date | Generating Capacity 30°F | Heat Rate @ Gen. Capacity | O&M Costs (1985 $) Fixed | O&M Costs (1985 $) Variable | Outage Rates Planned Outage | Outage Rates Forced Outage |
|---|---|---|---|---|---|---|---|---|
| | | | (MW) | (Btu/kWh) | ($/kW/yr) | ($/MWh) | (%time) | (%time) |
| | | | **Alaska Power Administration** | | | | | |
| Eklutna | 1955 | 2055 | 30.0 | - | - | 19.0 | - | - |
| | | | **Anchorage Municipal Light and Power** | | | | | |
| AMLPCT#1 | 1962 | 1990 | 16.2 | 15,329 | 10.12 | 5.67 | 12.0 | 5.0 |
| AMLPCT#2 | 1964 | 1990 | 16.2 | 15,329 | 10.12 | 5.67 | 9.7 | 5.0 |
| AMLPCT#3 | 1968 | 1991 | 19.9 | 14,089 | 10.12 | 5.67 | 12.3 | 5.0 |
| AMLPCT#4 | 1972 | 1992 | 33.8 | 13,901 | 10.12 | 5.67 | 13.5 | 5.0 |
| AM CC#56 | 1979 | 1999 | 47.5 | 10,570 | 12.79 | 0.92 | 11.0 | 5.0 |
| AM CC#76 | 1979 | 1999 | 109.3 | 9,365 | 12.79 | 0.92 | 11.0 | 5.0 |
| AMLPCT#8 | 1984 | 2009 | 87.0 | 12,000 | 12.79 | 0.92 | 14.8 | 5.0 |
| Total AMLP Capacity | | | 329.9 | | | | | |

TABLE D.2.6.4 (Page 2 of 3)

| Unit Name | Operation Period Online Date | Retire Date | Generating Capacity 30°F | Heat Rate @ Gen. Capacity | O&M Costs (1985 $) Fixed | Variable | Outage Rates Planned Outage | Forced Outage |
|---|---|---|---|---|---|---|---|---|
| | | | (MW) | (Btu/kWh) | ($/kW/yr) | ($/MWh) | (%time) | (%time) |
| | | | Chugach Electric Association | | | | | |
| BEL CT#1 | 1968 | 1994 | 16.1 | 16,100 | 11.21 | 1.40 | 10.3 | 5.0 |
| BEL CT#2 | 1968 | 1994 | 16.1 | 16,100 | 11.21 | 1.40 | 9.0 | 5.0 |
| BEL CT#3 | 1972 | 1999 | 49.5 | 12,800 | 11.21 | 1.40 | 12.8 | 5.0 |
| BEL CT#4 | 1976 | 1996 | 10.0 | 17,500 | 11.21 | 1.40 | 11.5 | 5.0 |
| BEL CT#5 | 1975 | 1999 | 67.3 | 12,400 | 11.21 | 1.40 | 12.8 | 5.0 |
| BEL CC#68 | 1976 | 2007 | 100.6 | 9,600 | 11.21 | 1.40 | 11.5 | 6.0 |
| BEL CC#78 | 1976 | 2007 | 100.6 | 9,600 | 11.21 | 1.40 | 11.5 | 6.0 |
| BERNCT#1 | 1963 | 1988 | 8.9 | 17,300 | 10.03 | 2.19 | 9.0 | 5.0 |
| BERNCT#2 | 1971 | 1997 | 18.4 | 14,500 | 10.03 | 2.19 | 9.0 | 5.0 |
| BERNCT#3 | 1978 | 2004 | 27.2 | 13,700 | 10.03 | 2.19 | 10.3 | 5.0 |
| BERNCT#4 | 1981 | 2004 | 27.2 | 13,700 | 10.03 | 2.19 | 12.8 | 5.0 |
| INT CT#1 | 1965 | 1996 | 14.3 | 18,000 | 19.39 | 13.47 | 7.7 | 5.0 |
| INT CT#2 | 1968 | 1996 | 14.3 | 18,000 | 19.39 | 13.47 | 7.7 | 5.0 |
| INT CT#3 | 1970 | 1996 | 19.9 | 14,500 | 19.39 | 13.47 | 15.4 | 5.0 |
| COOPER | 1960 | 2055 | 17.4 | - | - | 7.4 | - | - |
| Total CEA Capacity | | | 507.8 | | | | | |

TABLE D.2.6.4 (Page 3 of 3)

| Unit Name | Operation Period Online Date | Operation Period Retire Date | Generating Capacity @ 30°F | Heat Rate @ Gen. Capacity | O&M Costs (1985 $) Fixed | O&M Costs (1985 $) Variable | Outage Rates Planned Outage | Outage Rates Forced Outage |
|---|---|---|---|---|---|---|---|---|
| | | | (MW) | (Btu/kWh) | ($/kW/yr) | ($/MWh) | (%time) | (%time) |
| | | | Homer Electric Association | | | | | |
| SELDIC#1 | 1952 | 1990 | 0.3 | 14,998 | 2.81 | 38.80 | 4.0 | 5.0 |
| SELDIC#2 | 1964 | 1994 | 0.6 | 12,006 | 2.81 | 38 80 | 4.0 | 5.0 |
| SELDIC#3 | 1970 | 2000 | 0.6 | 12,006 | 2.81 | 38.80 | 4.0 | 5.0 |
| SELDIC#4 | 1982 | 2012 | 0.6 | 12,006 | 2.81 | 38.80 | 4.0 | 5.0 |
| Total HEA Capacity | | | 2.1 | | | | | |
| | | | Seward Electric System | | | | | |
| SES IC#1 | 1965 | 1990 | 1.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| SES IC#2 | 1965 | 1990 | 1.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| SES IC#3 | 1965 | 1995 | 2.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| Total SES Capacity | | | 5.5 | | | | | |

TABLE D.2.6.5: FAIRBANKS-TANANA VALLEY AREA EXISTING PLANT DATA, DEC. 1984

| Unit Name | Operation Period Online Date | Operation Period Retire Date | Generating Capacity @ 30°F | Heat Rate @ Gen. Capacity | O&M Costs (1985 $) Fixed | O&M Costs (1985 $) Variable | Outage Rates Planned Outage | Outage Rates Forced Outage |
|---|---|---|---|---|---|---|---|---|
| | | | (MW) | (Btu/kWh) | ($/kW/yr) | ($/MWh) | (%time) | (%time) |
| | | | **Fairbanks Municipal Utility System** | | | | | |
| CHENST#1 | 1954 | 2000 | 5.1 | 15,968 | 51.12 | 1.22 | 6.0 | 6.0 |
| CHENST#2 | 1952 | 2000 | 2.0 | 18,049 | 51.12 | 1.22 | 6.0 | 6.0 |
| CHENST#3 | 1952 | 2000 | 1.5 | 18,091 | 51.12 | 1.22 | 6.0 | 6.0 |
| CHENST#4 | 1963 | 1985 | 6.1 | 12,894 | 8.76 1/ | 0.58 1/ | 3.0 | 8.0 |
| CHENST#5 | 1970 | 2005 | 20.0 | 14,236 | 73.57 | 0.64 | 6.0 | 6.0 |
| CHENST#6 | 1976 | 2006 | 26.1 | 12,733 | 8.76 1/ | 0.58 1/ | 3.0 | 8.0 |
| FMUSIC#1 | 1967 | 1992 | 2.8 | 12,128 | 0.87 | 22.82 | 2.0 | 5.0 |
| FMUSIC#2 | 1968 | 1992 | 2.8 | 12,128 | 0.87 | 22.82 | 2.0 | 5.0 |
| FMUSIC#3 | 1969 | 1992 | 2.8 | 12,128 | 0.87 | 22.82 | 2.0 | 5.0 |
| Total FMUS Capacity | | | 69.2 | | | | | |
| | | | **Golden Valley Electric Association** | | | | | |
| HEALST#1 | 1967 | 2002 | 25.0 | 12,750 | 69.96 | 4.11 | 7.0 | 1.8 |
| HEALIC#2 | 1967 | 1997 | 2.6 | 11,210 | 0.59 | 5.72 | 20.0 | 1.0 |
| NOPOCT#1 | 1976 | 2006 | 60.9 | 9,500 | 7.42 | 1.43 | 15.0 | 1.0 |
| NOPOCT#2 | 1977 | 2007 | 60.9 | 9,500 | 7.42 | 1.43 | 15.0 | 1.0 |
| ZEN CT#1 | 1971 | 2001 | 18.0 | 14,869 | 8.79 | 0.59 | 15.0 | 1.0 |
| ZEN CT#2 | 1972 | 2002 | 18.0 | 14,869 | 8.79 | 0.59 | 15.0 | 1.0 |
| DSL IC#1 | 1961 | 1991 | 1.9 | 11,209 | 0.59 | 5.72 | 20.0 | 5.0 |
| DSL IC#2 | 1961 | 1991 | 1.9 | 11,209 | 0.59 | 5.72 | 20.0 | 5.0 |
| DSL IC#3 | 1961 | 1991 | 1.9 | 11,209 | 0.59 | 5.72 | 20.0 | 5.0 |
| DSL IC#5 | 1970 | 2000 | 2.6 | 11,210 | 0.59 | 5.72 | 20.0 | 5.0 |
| DSL IC#6 | 1970 | 2000 | 2.6 | 11,210 | 0.59 | 5.72 | 20.0 | 5.0 |
| UAF IC#7 | 1970 | 1996 | 1.9 | 11,209 | 0.59 | 5.72 | 20.0 | 5.0 |
| UAF IC#8 | 1970 | 1996 | 1.9 | 11,209 | 0.59 | 5.72 | 20.0 | 5.0 |
| Total GVEA Capacity | | | 200.1 | | | | | |

1/ Applicant's estimate of O&M costs used.

## TABLE D.2.6.6: RAILBELT EXISTING EQUIPMENT RETIREMENT SCHEDULE

| | AMLP | | CEA | | HEA | | SES | | FMUS | | GVEA | | TOTAL RAILBELT | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Capacity Retired (MW) | Unit Name 1/ | Capacity Retired (MW) | Unit Name | Capacity Retired (MW) | Unit Name | Capacity Retired (MW) | Unit Name | Capacity Retired (MW) | Unit Name | Capacity Retired (MW) | Unit Name | Annual Capacity Retired (MW) | Cumulative Capacity Retired (MW) | Year |
| 1985 | | | | | | | | | 6.1 | CHENCT #4 | | | 6.1 | 6.1 | 1985 |
| 1986 | | | | | | | | | | | | | | 6.1 | 1986 |
| 1987 | | | | | | | | | | | | | | 6.1 | 1987 |
| 1988 | | | 8.9 | BERNCT #1 | | | | | | | | | 8.9 | 15.0 | 1988 |
| 1989 | | | | | | | | | | | | | | 15.0 | 1989 |
| 1990 | 32.4 | AMLPCT #1&2 | | | 0.3 | SELDIC #1 | 3.0 | SESIC #1&2 | | | | | 35.7 | 50.7 | 1990 |
| 1991 | 19.9 | AMLPCT #3 | | | | | | | | | 5.7 | DSLIC #1,2,&3 | 25.6 | 76.3 | 1991 |
| 1992 | 33.8 | AMLPCT #4 | | | | | | | 8.4 | FMUSIC #1,2,&3 | | | 42.2 | 118.5 | 1992 |
| 1993 | | | | | | | | | | | | | | 118.5 | 1993 |
| 1994 | | | 32.2 | BELCT #1&2 | 0.6 | SELDIC #2 | | | | | | | 32.8 | 151.3 | 1994 |
| 1995 | | | | | | | 2.5 | SESIC #3 | | | | | 2.5 | 153.8 | 1995 |
| 1996 | | | 58.5 | BELCT #4, INTCT #1,2,&3 | | | | | | | 3.8 | UAFIC #7&8 | 62.3 | 216.1 | 1996 |
| 1997 | | | 18.4 | BERNCT #2 | | | | | | | 2.6 | HEALIC #2 | 21.0 | 237.1 | 1997 |
| 1998 | | | | | | | | | | | | | | 237.1 | 1998 |
| 1999 | 156.8 | AMCC #56&76 | 116.8 | BELCT #3&5 | | | | | | | | | 273.6 | 510.7 | 1999 |
| 2000 | | | | | 0.6 | SELDIC #3 | | | 8.6 | CHENST #1,2,&3 | 5.2 | DSLIC #5&6 | 14.4 | 525.1 | 2000 |
| 2001 | | | | | | | | | | | 18.0 | ZENCT #1 | 18.0 | 543.1 | 2001 |
| 2002 | | | | | | | | | | | 43.0 | HEALST #1 ZENCT #2 | 43.0 | 586.1 | 2002 |
| 2003 | | | | | | | | | | | | | | 586.1 | 2003 |
| 2004 | | | 54.4 | BERNCT #3&4 | | | | | | | | | 54.4 | 640.5 | 2004 |
| 2005 | | | | | | | | | 20.0 | CHENST #5 | | | 20.0 | 660.5 | 2005 |
| 2006 | | | | | | | | | 26.1 | CHENCT #6 | 60.9 | NOPOCT #1 | 87.0 | 747.5 | 2006 |
| 2007 | | | 201.2 | BELCC #68&78 | | | | | | | 60.9 | NOPOCT #2 | 262.1 | 1009.6 | 2007 |
| 2008 | | | | | | | | | | | | | | 1009.6 | 2008 |
| 2009 | 87.0 | AMLPCT #8 | | | | | | | | | | | 87.0 | 1096.6 | 2009 |
| 2010 | | | | | | | | | | | | | | 1096.6 | 2010 |
| 2011 | | | | | | | | | | | | | | 1096.6 | 2011 |
| 2012 | | | | | 0.6 | SELDIC #4 | | | | | | | 0.6 | 1097.2 | 2012 |
| Total | 329.9 | | 490.4 | | 2.1 | | 5.5 | | 69.2 | | 200.1 | | 1097.2 | | |
| | | | | | | | | | | Not Retired: | | Eklutna | 30.0 | | |
| | | | | | | | | | | | | Cooper | 17.4 | | |
| | | | | | | | | | | Total Online: | | | 1144.6 | | |

1/ Key to plant types:
- CC: Gas-fired combined cycle
- CT: Combustion turbine
- H: Hydroelectric
- IC: Oil-fired internal combustion (diesel)
- ST: Coal-fired steam turbine

TABLE D.2.7.1: RAILBELT SYSTEM ADDITIONS AND RETIREMENTS 1985-1995

| Year | Coal | Combustion Turbine | Diesel | Hydroelectric | Total Additions | Total Retirements | Total Capability |
|---|---|---|---|---|---|---|---|
| 1985 | | 45 | 2.5 | | 47.5 | 6.1 | 1186 |
| 1986 | | | 2.5 | | 2.5 | 0.0 | 1188 |
| 1987 | | | | | | 0.0 | 1188 |
| 1988 | | | | | | 8.9 | 1179 |
| 1989 | | | | | | 0.0 | 1179 |
| 1990 | | | 2.5 | 90 | 92.5 | 35.7 | 1237 |
| 1991 | | | | | | 25.6 | 1210 |
| 1992 | | 87 | | | 87 | 42.2 | 1255 |
| 1993 | | | | | | 0.0 | 1255 |
| 1994 | | | | | | 32.8 | 1222 |
| 1995 | | | | | | 2.5 | 1220 |
| TOTALS | | 132 | 7.5 | 90 | 229.5 | 153.8 | |

TABLE D.2.7.2: RAILBELT SYSTEM ADDITIONS 1985-1995, PLANT DATA

| Unit Name | Company | Operation Period Online Date | Operation Period Retire Date | Generating Capacity @ 30°F (MW) | Heat Rate @ Gen. Capacity (Btu/kWh) | O&M Costs (1985 $) Fixed ($/kW/yr) | O&M Costs (1985 $) Variable ($/MWh) | Outage Rates Planned Outage (%time) | Outage Rates Forced Outage (%time) |
|---|---|---|---|---|---|---|---|---|---|
| GTK CT#1 | HEA/MEA | 1985 | 2010 | 45.0 | 12,785 | 11.21 | 1.40 | 9.0 | 5.0 |
| SES IC#4 | SES | 1985 | 2006 | 2.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| SES IC#5 | SES | 1986 | 2006 | 2.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| SES IC#6 | SES | 1990 | 2010 | 2.5 | 15,000 | 0.59 | 5.72 | 1.0 | 5.0 |
| BRAD LK | APA | 1990 | 2055 | 90.0 | --- | -- | -- | - | - |
| AMLPCT#9 | AMLP | 1992 | 2016 | 87.0 | 12,000 | 12.79 | 0.92 | 14.8 | 5.0 |

TABLE D.2.8.1: SHCA LOAD FORECAST

| Year | System Sales | | Net Generation[1] | |
|---|---|---|---|---|
| | Peak Demand | Energy | Peak Demand | Energy |
| | (MW) | (GWh) | (MW) | (GWh) |
| 1985 | 632 | 3322 | 702 | 3691 |
| 1986 | 642 | 3372 | 713 | 3747 |
| 1987 | 651 | 3423 | 724 | 3803 |
| 1988 | 661 | 3474 | 735 | 3861 |
| 1989 | 671 | 3527 | 746 | 3919 |
| 1990 | 681 | 3580 | 757 | 3976 |
| 1991 | 692 | 3639 | 769 | 4043 |
| 1992 | 704 | 3699 | 782 | 4110 |
| 1993 | 715 | 3760 | 795 | 4178 |
| 1994 | 727 | 3822 | 808 | 4247 |
| 1995 | 739 | 3885 | 821 | 4317 |
| 1996 | 743 | 3907 | 826 | 4341 |
| 1997 | 748 | 3930 | 831 | 4366 |
| 1998 | 752 | 3952 | 836 | 4392 |
| 1999 | 756 | 3975 | 840 | 4417 |
| 2000 | 761 | 3998 | 845 | 4442 |
| 2001 | 772 | 4059 | 858 | 4510 |
| 2002 | 784 | 4122 | 871 | 4579 |
| 2003 | 796 | 4185 | 885 | 4650 |
| 2004 | 808 | 4249 | 898 | 4721 |
| 2005 | 821 | 4314 | 912 | 4793 |
| 2006 | 843 | 4431 | 937 | 4923 |
| 2007 | 866 | 4551 | 962 | 5056 |
| 2008 | 889 | 4674 | 988 | 5193 |
| 2009 | 913 | 4800 | 1015 | 5333 |
| 2010 | 936 | 4930 | 1042[2] | 5478[2] |
| 2011 | | | 1064 | 5594 |
| 2012 | | | 1087 | 5712 |
| 2013 | | | 1110 | 5833 |
| 2014 | | | 1133 | 5957 |
| 2015 | | | 1157 | 6083 |
| 2016 | | | 1182 | 6212 |
| 2017 | | | 1207 | 6343 |
| 2018 | | | 1232 | 6478 |
| 2019 | | | 1258 | 6615 |
| 2020 | | | 1285 | 6755 |
| 2021 | | | 1312 | 6898 |
| 2022 | | | 1340 | 7044 |
| 2023 | | | 1369 | 7193 |
| 2024 | | | 1398 | 7345 |
| 2025 | | | 1427 | 7501 |

1/ Includes 10 percent for transmission and distribution losses.

2/ The load forecasts produced by the RED Model were extended from 2010 to 2025 using the average annual growth for the period 2000 to 2010.

TABLE D.2.8.2: COMPOSITE LOAD FORECAST

| Year | System Sales Peak Demand | System Sales Energy | Net Generation[1] Peak Demand | Net Generation[1] Energy |
|---|---|---|---|---|
| | (MW) | (GWh) | (MW) | (GWh) |
| 1985 | 632 | 3322 | 702 | 3691 |
| 1986 | 641 | 3369 | 712 | 3743 |
| 1987 | 650 | 3416 | 722 | 3796 |
| 1988 | 659 | 3465 | 732 | 3850 |
| 1989 | 668 | 3513 | 743 | 3904 |
| 1990 | 678 | 3563 | 753 | 3959 |
| 1991 | 691 | 3630 | 767 | 4033 |
| 1992 | 704 | 3698 | 782 | 4109 |
| 1993 | 717 | 3767 | 796 | 4186 |
| 1994 | 730 | 3838 | 811 | 4264 |
| 1995 | 744 | 3910 | 827 | 4344 |
| 1996 | 751 | 3948 | 835 | 4387 |
| 1997 | 758 | 3986 | 843 | 4429 |
| 1998 | 766 | 4025 | 851 | 4473 |
| 1999 | 773 | 4064 | 859 | 4516 |
| 2000 | 781 | 4104 | 868 | 4560 |
| 2001 | 789 | 4147 | 877 | 4608 |
| 2002 | 797 | 4191 | 886 | 4657 |
| 2003 | 806 | 4235 | 895 | 4706 |
| 2004 | 814 | 4280 | 905 | 4755 |
| 2005 | 823 | 4325 | 914 | 4806 |
| 2006 | 843 | 4432 | 937 | 4925 |
| 2007 | 864 | 4542 | 960 | 5047 |
| 2008 | 886 | 4655 | 984 | 5172 |
| 2009 | 908 | 4771 | 1008 | 5301 |
| 2010 | 930 | 4889 | 1034[2] | 5432[2] |
| 2011 | | | 1052 | 5528 |
| 2012 | | | 1070 | 5626 |
| 2013 | | | 1089 | 5725 |
| 2014 | | | 1108 | 5826 |
| 2015 | | | 1128 | 5929 |
| 2016 | | | 1148 | 6034 |
| 2017 | | | 1168 | 6140 |
| 2018 | | | 1189 | 6249 |
| 2019 | | | 1210 | 6359 |
| 2020 | | | 1231 | 6471 |
| 2021 | | | 1253 | 6586 |
| 2022 | | | 1275 | 6702 |
| 2023 | | | 1298 | 6820 |
| 2024 | | | 1321 | 6941 |
| 2025 | | | 1344 | 7063 |

1/ Includes 10 percent for transmission and distribution losses.

2/ The load forecasts produced by the RED Model were extended from 2010 to 2025 using the average annual growth for the period 2000 to 2010.

TABLE D.2.8.3: SUMMARY OF THERMAL GENERATING PLANT PARAMETERS (1985 $)

| Parameters | Coal 200 MW | Combined Cycle 230 MW1/ | Combustion Turbine 87 MW2/ |
|---|---|---|---|
| Heat Rate (Btu/kWh) | 10,300 | 9,200 | 12,000 |
| Earliest Availability | 1992 | 1988 | 1988 |
| O&M Costs | | | |
| Fixed O&M ($/kW/yr) | 61.42 | 13.26 | 8.76 |
| Variable O&M ($/MWh) | 4.30 | 0.66 | 0.58 |
| Outages | | | |
| Planned Outages (%) | 8 | 7 | 3.2 |
| Forced Outages (%) | 5.7 | 8 | 8 |
| Construction Period (yrs) | 6 | 2 | 1 |
| Startup Time (yrs) | 3 | 2 | 1 |
| Unit Construction Cost ($/kW) | | | |
| Beluga/Railbelt | 2,593 | 650 | 386 |
| Nenana | 2,702 | --- | --- |
| Unit Capital Cost ($/kW)3/ | | | |
| Beluga/Railbelt | 2,877 | 673 | 393 |
| Nenana | 2,998 | --- | --- |

1/ Gross output at 30° F is 237.3 MW and includes correction for water injection for NOx control. Net output of 230 MW includes correction for station auxiliary loads.

2/ Values reflect assembly of three units, gross output at 30°F is 268.8 MW and includes correction for water injection for NOx control. Net output of 262 MW (87.3 MW each) includes correction for station auxiliary loads.

3/ Includes AFDC at 3.5 percent interest assuming an S-shaped expenditure curve.

TABLE D.2.9.1: WITH-SUSITNA EXPANSION PLAN YEARLY MW ADDITIONS

| Year | SHCA Forecast | | | | | Composite Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Peak Demand | Coal | Combustion Turbine | Susitna[1] | Total[2] Capability | Peak Demand | Coal | Combustion Turbine | Susitna[1] | Total[2] Capability |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) | (MW) |
| 1996 | 826 | | | | 1158 | 835 | | | | 1158 |
| 1997 | 831 | | | | 1137 | 843 | | | | 1137 |
| 1998 | 836 | | | | 1137 | 851 | | | | 1137 |
| 1999 | 840 | | | 297 | 1160 | 859 | | | 297 | 1160 |
| 2000 | 845 | | | | 1146 | 868 | | | | 1146 |
| 2001 | 858 | | | | 1128 | 877 | | | | 1128 |
| 2002 | 871 | | 87 | | 1172 | 886 | | 87 | | 1172 |
| 2003 | 885 | | | | 1172 | 895 | | | | 1172 |
| 2004 | 898 | | 87 | | 1205 | 905 | | 87 | | 1205 |
| 2005 | 912 | | | 491 | 1674 | 914 | | | 491 | 1674 |
| 2006 | 937 | | | | 1584 | 937 | | | | 1584 |
| 2007 | 962 | | | | 1322 | 960 | | | | 1322 |
| 2008 | 988 | | | | 1322 | 984 | | | | 1322 |
| 2009 | 1015 | | | 17 | 1252 | 1008 | | | 17 | 1252 |
| 2010 | 1042 | | 87 | | 1292 | 1034 | | 87 | | 1292 |
| 2011 | 1064 | | | | 1292 | 1052 | | | | 1292 |
| 2012 | 1087 | | | 698 | 1989 | 1070 | | | 693 | 1984 |
| 2013 | 1110 | | | | 1989 | 1089 | | | | 1984 |
| 2014 | 1133 | | | | 1989 | 1108 | | | | 1984 |
| 2015 | 1157 | | | | 1989 | 1128 | | | | 1984 |
| 2016 | 1182 | | | | 1989 | 1148 | | | | 1984 |
| 2017 | 1207 | | 87 | | 1990 | 1168 | | 87 | | 1985 |
| 2018 | 1232 | | | | 1990 | 1189 | | | | 1985 |
| 2019 | 1258 | | 87 | 28 | 2105 | 1210 | | 87 | 33 | 2105 |
| 2020 | 1285 | | 87 | | 2192 | 1231 | | | | 2105 |
| 2021 | 1312 | | | | 2192 | 1253 | | | | 2105 |
| 2022 | 1340 | | | | 2192 | 1275 | | | | 2105 |
| 2023 | 1369 | | 87 | | 2279 | 1298 | | 87 | | 2192 |
| 2024 | 1398 | | | | 2279 | 1321 | | | | 2192 |
| 2025 | 1427 | | | | 2279 | 1344 | | | | 2192 |

1/ The three Susitna stages are Watana-Stage I (1999), Devil Canyon-Stage II (2005), and Watana-Stage III (2012).

2/ Includes existing generation plants less retirements

TABLE D.2.9.2: SUSITNA DEPENDABLE CAPACITY AND ENERGY 

| | SHCA Forecast | | | | | | |
|---|---|---|---|---|---|---|---|
| Year | Railbelt Peak | Thermal Capacity at Peak | Existing Hydro Capacity at Peak | Susitna Capacity at Peak | Susitna Capacity as Input to OGP-6 | Susitna Energy Absorbed | Susitna Energy as Input to OGP |
| | (MW) | (MW) | (MW) | (MW) | (MW) | (GWh) | (GWh) |
| 1996 | 826 | 689 | 137 | 0 | 0 | 0 | 0 |
| 1997 | 831 | 694 | 137 | 0 | 0 | 0 | 0 |
| 1998 | 836 | 699 | 137 | 0 | 0 | 0 | 0 |
| 1999 | 840 | 410 | 137 | 293 | 297 | 2238 | 2388 |
| 2000 | 845 | 415 | 137 | 293 | 297 | 2250 | 2388 |
| 2001 | 858 | 427 | 137 | 294 | 297 | 2269 | 2388 |
| 2002 | 871 | 440 | 137 | 294 | 297 | 2282 | 2388 |
| 2003 | 885 | 451 | 137 | 297 | 297 | 2295 | 2388 |
| 2004 | 898 | 464 | 137 | 297 | 297 | 2310 | 2388 |
| 2005 | 912 | 0 | 137 | 775 | 788 | 4230 | 4477 |
| 2006 | 937 | 12 | 137 | 788 | 788 | 4264 | 4477 |
| 2007 | 962 | 37 | 137 | 788 | 788 | 4298 | 4477 |
| 2008 | 988 | 63 | 137 | 788 | 788 | 4332 | 4477 |
| 2009 | 1015 | 75 | 137 | 803 | 805 | 4508 | 4751 |
| 2010 | 1042 | 100 | 137 | 805 | 805 | 4624 | 4751 |
| 2011 | 1064 | 122 | 137 | 805 | 805 | 4740 | 4751 |
| 2012 | 1087 | 0 | 137 | 950 | 1503 | 5149 | 5909 |
| 2013 | 1110 | 0 | 137 | 973 | 1503 | 5270 | 5909 |
| 2014 | 1133 | 0 | 137 | 996 | 1503 | 5394 | 5909 |
| 2015 | 1157 | 0 | 137 | 1020 | 1503 | 5520 | 5909 |
| 2016 | 1182 | 0 | 137 | 1045 | 1503 | 5649 | 5909 |
| 2017 | 1207 | 0 | 137 | 1070 | 1503 | 5779 | 5909 |
| 2018 | 1232 | 0 | 137 | 1095 | 1503 | 5914 | 5909 |
| 2019 | 1258 | 0 | 137 | 1121 | 1531 | 6052 | 6685 |
| 2020 | 1285 | 0 | 137 | 1148 | 1531 | 6192 | 6685 |
| 2021 | 1312 | 0 | 137 | 1175 | 1531 | 6305 | 6685 |
| 2022 | 1340 | 20 | 137 | 1183 | 1531 | 6441 | 6685 |
| 2023 | 1369 | 35 | 137 | 1197 | 1531 | 6591 | 6685 |
| 2024 | 1398 | 50 | 137 | 1211 | 1531 | 6638 | 6685 |
| 2025 | 1427 | 70 | 137 | 1220 | 1531 | 6685 | 6685 |

TABLE D.2.9.2 (Page 2 of 2)

| Year | Composite Forecast Railbelt Peak | Thermal Capacity at Peak | Existing Hydro Capacity at Peak | Susitna Capacity at Peak | Susitna Capacity as Input to OGP-6 | Susitna Energy Absorbed | Susitna Energy as Input to OGP |
|---|---|---|---|---|---|---|---|
| | (MW) | (MW) | (MW) | (MW) | (MW) | (GWh) | (GWh) |
| 1996 | 835 | 698 | 137 | 0 | 0 | 0 | 0 |
| 1997 | 843 | 706 | 137 | 0 | 0 | 0 | 0 |
| 1998 | 851 | 714 | 137 | 0 | 0 | 0 | 0 |
| 1999 | 859 | 430 | 137 | 292 | 297 | 2264 | 2388 |
| 2000 | 868 | 435 | 137 | 296 | 297 | 2277 | 2388 |
| 2001 | 877 | 443 | 137 | 297 | 297 | 2289 | 2388 |
| 2002 | 886 | 452 | 137 | 297 | 297 | 2301 | 2388 |
| 2003 | 895 | 461 | 137 | 297 | 297 | 2314 | 2388 |
| 2004 | 905 | 471 | 137 | 297 | 297 | 2327 | 2388 |
| 2005 | 914 | 0 | 137 | 777 | 788 | 4243 | 4477 |
| 2006 | 937 | 12 | 137 | 788 | 788 | 4273 | 4477 |
| 2007 | 960 | 35 | 137 | 788 | 788 | 4303 | 4477 |
| 2008 | 984 | 59 | 137 | 788 | 788 | 4334 | 4477 |
| 2009 | 1008 | 66 | 137 | 805 | 805 | 4488 | 4571 |
| 2010 | 1034 | 92 | 137 | 805 | 805 | 4619 | 4571 |
| 2011 | 1052 | 110 | 137 | 805 | 805 | 4715 | 4571 |
| 2012 | 1070 | 0 | 137 | 933 | 1498 | 5063 | 5761 |
| 2013 | 1089 | 0 | 137 | 952 | 1498 | 5162 | 5761 |
| 2014 | 1108 | 0 | 137 | 971 | 1498 | 5263 | 5761 |
| 2015 | 1128 | 0 | 137 | 991 | 1498 | 5365 | 5761 |
| 2016 | 1148 | 0 | 137 | 1011 | 1498 | 5471 | 5761 |
| 2017 | 1168 | 0 | 137 | 1031 | 1498 | 5577 | 5761 |
| 2018 | 1189 | 0 | 137 | 1052 | 1498 | 5683 | 5761 |
| 2019 | 1210 | 0 | 137 | 1073 | 1522 | 5796 | 6685 |
| 2020 | 1231 | 0 | 137 | 1094 | 1522 | 5908 | 6685 |
| 2021 | 1253 | 0 | 137 | 1116 | 1522 | 6023 | 6685 |
| 2022 | 1275 | 0 | 137 | 1138 | 1522 | 6139 | 6685 |
| 2023 | 1298 | 0 | 137 | 1161 | 1522 | 6257 | 6685 |
| 2024 | 1321 | 5 | 137 | 1179 | 1522 | 6341 | 6685 |
| 2025 | 1344 | 20 | 137 | 1187 | 1522 | 6461 | 6685 |

TABLE D.2.9.3: WITHOUT-SUSITNA EXPANSION PLAN YEARLY MW ADDITIONS

| | SHCA Forecast | | | | | Composite Forecast | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | Peak Demand (MW) | Coal[1] (MW) | Combustion Turbine (MW) | Combined Cycle (MW) | Total[2] Capability (MW) | Peak Demand (MW) | Coal[1] (MW) | Combustion Turbine (MW) | Combined Cycle (MW) | Total[2] Capability (MW) |
| 1996 | 826 | | | | 1158 | 835 | | | | 1158 |
| 1997 | 831 | | | | 1137 | 843 | | | | 1137 |
| 1998 | 836 | | | | 1137 | 851 | | | | 1137 |
| 1999 | 840 | 400 B | | | 1263 | 859 | 400 B | | | 1263 |
| 2000 | 845 | | 87 | | 1336 | 868 | | 87 | | 1336 |
| 2001 | 858 | | | | 1318 | 877 | | | | 1318 |
| 2002 | 871 | | | | 1275 | 886 | | | | 1275 |
| 2003 | 885 | | | | 1275 | 895 | | 87 | | 1363 |
| 2004 | 898 | 200 N | | | 1421 | 905 | | | | 1308 |
| 2005 | 912 | | | | 1398 | 914 | 200 N | | | 1486 |
| 2006 | 937 | 200 N | | | 1509 | 937 | | | | 1396 |
| 2007 | 962 | 200 B | 87 | | 1534 | 960 | 200 N | 174 | | 1509 |
| 2008 | 988 | | | | 1534 | 984 | | | | 1509 |
| 2009 | 1015 | | 174 | | 1622 | 1008 | | 87 | | 1509 |
| 2010 | 1042 | | | | 1574 | 1034 | 200 B | | | 1661 |
| 2011 | 1064 | | | | 1574 | 1052 | | | | 1661 |
| 2012 | 1087 | | 87 | | 1661 | 1070 | | | | 1661 |
| 2013 | 1110 | | | | 1661 | 1089 | | | | 1661 |
| 2014 | 1133 | | | | 1661 | 1108 | | | | 1661 |
| 2015 | 1157 | | 87 | | 1748 | 1128 | | | | 1661 |
| 2016 | 1182 | | | | 1748 | 1148 | | | | 1661 |
| 2017 | 1207 | | 87 | | 1748 | 1168 | | 174 | | 1748 |
| 2018 | 1232 | | | | 1748 | 1189 | | | | 1748 |
| 2019 | 1258 | 200 B | | | 1948 | 1210 | | | | 1748 |
| 2020 | 1285 | | | | 1948 | 1231 | | | | 1748 |
| 2021 | 1312 | | | | 1948 | 1253 | | 87 | | 1836 |
| 2022 | 1340 | | | | 1948 | 1275 | | | | 1836 |
| 2023 | 1369 | | | | 1948 | 1298 | | | | 1836 |
| 2024 | 1398 | | | | 1948 | 1321 | | | | 1836 |
| 2025 | 1427 | 200 B | | | 2061 | 1344 | 200 B | | | 1948 |

1/ B denotes Beluga coal-fired plant; N denotes Nenana coal-fired plant

2/ Includes existing generation plants less retirements

TABLE D.2.9.4: TRANSMISSION SYSTEM EXPANSION, WITHOUT-SUSITNA ALTERNATIVE, SHCA FORECAST



| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1/] | Total |
|---|---|---|---|---|---|---|---|---|
| 1996 | | | | 230 | Use existing line between Lorraine and Teeland. Termination at 230 kV Lorraine substation. | 1,590 | | |
| 1996 | | | | 230 | Use two existing lines between Pt. MacKenzie and Lorraine. Terminations at 230 kV Lorraine substation. | 3,180 | - | |
| 1996 | | | | 230 | Use existing line between Fossil Creek and Lorraine. Terminations at 230 kV Fossil Creek and Lorraine Substations (includes 2-25 MVAR 230 kV reactors). | 3,590 | - | |
| 1996 | | | | 230 | Use two existing lines between Fossil Creek and Station-2. Terminations at 230 kV Fossil Creek and Station-2 substations. | 3,490 | - | |
| 1996 | | | | 230 | Use two existing lines between Station-2 and University. Terminations at 230 kV Station-2 and University substations. | 5,640 | - | |
| 1996 | | 2-954 | 57 | 345 | Healy 345 kV substation to Nenana 230 kV substation (includes 2-30 MVAR 345 kV reactors). | 6,760 | 26,290 | |
| 1996 | | 1-1272 | 26 | 230 | Willow 230 kV substation to Teeland, with termination at Willow only. | 1,590 | 9,630 | |
| 1996 | | | | 230 | 230 kV Palmer substation power supply to existing 115 kV Palmer substation. | 2,510 | - | |
| 1996 | | | | 230 | 230 kV Fairbanks substation power supply to GVEA system. | 5,640 | - | |
| 1996 | | | | 345 | Use existing line from Gold Creek to Willow. Terminations at 345 kV Gold Creek and 230 kV Willow substations (Includes 2-30 MVAR 345 kV reactors). | 6,040 | - | |
| 1996 | | | | 345 | Use existing line from Gold Creek to Healy. Terminations at Gold Creek and Healy 345 kV substations (Includes 2-30 MVAR 345 kV reactors). | 5,790 | - | |
| 1996 | | 1-1272 | 60 | 230 | Nenana 230 kV substation to Fairbanks 230 kV substation | 9,540 | 22,220 | |
| 1996 | | 1-1272 | 50 | 230 | Palmer 230 kV substation to Fossil Creek 230 kV substation. | 3,180 | 18,510 | |

TABLE D.2.9.4 (Page 2 of 5) SHCA FORECAST

| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1/] | Total |
|---|---|---|---|---|---|---|---|---|
| 1996 | | | | 230 | Willow 230 kV substation to Palmer 230 kV substation (Includes a 300 MVA 230 kV phase shifting transformer). | 3,800 | 13,330 | |
| 1996 | | - | - | - | Energy Management System. | 11,540 | - | |
| | | | | | Subtotal 1996 | 73,880 | 89,980 | |
| | | | | | Contingency[2/] | 11,080 | 13,500 | |
| | | | | | Engineering, Administration and Owners Overhead[3/] | 12,740 | 15,520 | |
| | | | | | Total 1996 | 97,700 | 119,000 | 216,700 |
| 1999 | 2-200 MW-Beluga | - | 48 | 230 | 4/ | | | |
| 1999 | | 1-1272 | 7 | 230 | Station-2 230 kV substation to University 230 kV substation. | 3,180 | 2,590 | |
| 1999 | | 1-1272 | 6 | 230 | Fossil Creek 230 kV substation to Station-2 230 kV substation. | 2,460 | 2,220 | |
| 1999 | | 2-954 | 91 | 345 | Gold Creek 345 kV substation to Healy 345 kV substation (Includes 2-30 MVAR 345 kV reactors). | 5,790 | 41,980 | |
| 1999 | | 2-954 | 79 | 345 | Gold Creek 345 kV substation to Willow 230 kV substation (Includes 2-30 MVAR 345 kV reactors). | 6,920 | 36,440 | |
| 1999 | | 1-1272 | 41 | 230 | Willow 230 kV substation to Lorraine 230 kV substation. | 2,460 | 15,180 | |
| 1999 | | 2-954 | 57 | 345 | Healy 345 kV substation to Nenana 230 kV substation (Includes 2-30 MVAR 345 kV reactors). | 6,920 | 26,290 | |
| 1999 | | 1-1272 | 60 | 230 | Nenana 230 kV substation to Fairbanks 230 kV substation. | 2,460 | 22,220 | |
| 1999 | | - | - | 230 | 230 kV Palmer substation second transformer. | 2,510 | - | |
| 1999 | | 1-1272 | 14 | 230 | Lorraine 230 kV substation to Fossil Creek 230 kV substation (Includes 4 miles of submarine cable which has 2-25 MVAR 230 kV reactors). | 2,870 | 52,400 | |

TABLE D.2.9.4: (Page 3 of 5) SHCA FORECAST

| Year | Generation Capacity Added | Required/Substation Transmission Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1/] | Total |
|---|---|---|---|---|---|---|---|---|
| 1999 | | - | - | 230 | Addition of a phase shifting transformer at 230 kV Pt. MacKenzie substation. | 2,360 | | |
| 1999 | | - | - | - | Energy Management System. | 11,540 | | |
| | | | | | Subtotal 1999 | 49,470 | 199,320 | |
| | | | | | Contingency[2/] | 7,420 | 29,900 | |
| | | | | | Engineering, Administration and Owners Overhead[3/] | 8,530 | 34,380 | |
| | | | | | Total 1999 | 65,420 | 263,600 | 329,020 |
| 2000 | 87 MW | - | - | 115 | Connection of unit to existing 115 kV Station-2 substation. | 810 | | |
| | | | | | Subtotal 2000 | 810 | | |
| | | | | | Contingency[2/] | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead[3/] | 140 | | |
| | | | | | Total 2000 | 1,070 | | 1,070 |
| 2004 | 200 MW-Nenana | - | 10 | 230 | [4/]Two terminations of 230 kV line from Nenana Powerplant at 230 kV Nenana substation. | 1,740 | | |
| | | | | | Subtotal 2004 | 1,740 | | |
| | | | | | Contingency[2/] | 260 | | |
| | | | | | Engineering, Administration and Owners Overhead[3/] | 300 | | |
| | | | | | Total 2004 | 2,300 | | 2,300 |
| 2006 | 200 MW-Nenana | - | 10 | 230 | [4/] | | | |

TABLE D.2.9.4: (Page 4 of 5)

| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1] | Total |
|---|---|---|---|---|---|---|---|---|
| 2007 | 200 MW-Beluga | - | 48 | 230 | 4/ | | | |
| 2007 | 87 MW | - | - | 115 | Connection between Station-2 unit to existing 115 kV Station-2 substation. | 810 | | |
| | | | | | Subtotal 2007 | 810 | | |
| | | | | | Contingency[2] | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 140 | | |
| | | | | | Total 2007 | 1,070 | | 1,070 |
| 2009 | 2-87 MW | - | - | 138 | Two connections at existing North Pole 138 kV substation. | 3,180 | | |
| | | | | | Subtotal 2009 | 3,180 | | |
| | | | | | Contingency[2] | 480 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 550 | | |
| | | | | | Total 2009 | 4,210 | | 4,210 |
| 2012 | 87 MW | - | - | - | Connection to high voltage transmission and substation to match existing voltage. | 810 | | |
| | | | | | Subtotal 2012 | 810 | | |
| | | | | | Contingency[2] | 210 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 140 | | |
| | | | | | Total 2012 | 1,070 | | 1,070 |
| 2015 | 87 MW | - | - | 115 | Connection between Station-2 unit and existing 115 kV Station-2 substation. | 810 | | |
| | | | | | Subtotal 2015 | 810 | | |
| | | | | | Contingency[2] | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 140 | | |
| | | | | | Total 2015 | 1,070 | | 1,070 |

TABLE D.2.9.4: (Page 5 of 5) SHCA FORECAST

| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line 1/ | Total |
|---|---|---|---|---|---|---|---|---|
| 2017 | 87 MW | - | - | - | Connection to high voltage transmission and substation to match existing voltage. | 810 | | |
| | | | | | Subtotal 2017 | 810 | | |
| | | | | | Contingency 2/ | 210 | | |
| | | | | | Engineering, Administration and Owners Overhead 3/ | 140 | | |
| | | | | | Total 2017 | 1,070 | | 1,070 |
| 2019 | 200 MW-Beluga | - | 48 | 230 | 4/ | | | |
| 2025 | 200 MW-Beluga | - | 48 | 230 | 4/ | | | |

1_/ All new transmission line cost estimates include the cost of terminations. Existing line cost estimates as described in the table include the cost of terminations only.

2_/ Contingency allowance of 15%

3_/ Engineering, Administration and Owners Overhead of 15%.

4_/ Transmission costs from the Beluga and Nenana plant site to the high voltage power grid are included in power plant estimates.

TABLE D.2.9.5: TRANSMISSION SYSTEM EXPANSION, WITHOUT-SUSITNA ALTERNATIVE, COMPOSITE FORECAST



| Year | Generation Capacity Added | Required/Substation Transmission Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1/] | Total |
|---|---|---|---|---|---|---|---|---|
| 1996 | | - | - | 230 | Use existing line between Lorraine and Teeland. Termination at 230 KV Lorraine substation. | 1,590 | | |
| 1996 | | - | - | 230 | Use two existing lines between Pt. MacKenzie and Lorraine. Terminations at 230 KV Lorraine substations. | 3,180 | - | |
| 1996 | | - | - | 230 | Use existing line between Fossil Creek and Lorraine. Terminations at 230 kV Fossil Creek and Lorraine substations (includes 2-25 MVAR 230 kV reactors). | 3,590 | - | |
| 1996 | | - | - | 230 | Use two existing lines between Fossil Creek and Station-2. Terminations at 230 kV Fossil Creek and Station-2 substations. | 3,490 | - | |
| 1996 | | - | - | 230 | Use two existing lines between Station-2 and University. Terminations at 230 kV Station-2 and University substations. | 5,640 | - | |
| 1996 | | 2-954 | 57 | 345 | Healy 345 kV substation to Nenana 230 kV substation (includes 2-30 MVAR 345 kV reactors). | 6,760 | 26,290 | |
| 1996 | | 1-1272 | 26 | 230 | Willow 230 kV substation to Teeland, with termination at Willow only. | 1,590 | 9,630 | |
| 1996 | | - | - | 230 | 230 kV Palmer substation power supply to existing 115 kV Palmer substation. | 2,510 | - | |
| 1996 | | - | - | 230 | 230 kV Fairbanks substation power supply to GVEA system. | 5,640 | - | |
| 1996 | | - | - | 345 | Use existing line from Gold Creek to Willow. Terminations at 345 kV Gold Creek and 230 kV Willow substations (Includes 2-30 MVAR 345 kV reactors). | 6,040 | - | |
| 1996 | | - | - | 345 | Use existing line from Gold Creek to Healy. Terminations at Gold Creek and Healy 345 kV substations (Includes 2-30 MVAR 345 kV reactors). | 5,790 | - | |
| 1996 | | 1-1272 | 60 | 230 | Nenana 230 kV substation to Fairbanks 230 kV substation. | 9,540 | 22,220 | |
| 1996 | | 1-1272 | 50 | 230 | Palmer 230 kV substation to Fossil Creek 230 kV substation. | 3,180 | 18,510 | |

TABLE D.2.9.5: (Page 2 of 5) COMPOSITE FORECAST

| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1] | Total |
|---|---|---|---|---|---|---|---|---|
| 1996 | | 1-1272 | 36 | 230 | Willow 230 kV substation to Palmer 230 kV substation (Includes a 300 MVA 230 kV phase shifting transformer). | 3,800 | 13,330 | |
| 1996 | | - | - | | Energy Management System | 11,540 | - | |
| | | | | | Subtotal 1996 | 73,880 | 89,980 | |
| | | | | | Contingency[2] | 11,080 | 13,500 | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 12,740 | 15,520 | |
| | | | | | Total 1996 | 97,700 | 119,000 | 216,700 |
| 1999 | 2-200 MW-Beluga | - | 48 | 230 | [4] | | | |
| 1999 | | 1-1272 | 7 | 230 | Station-2 230 kV substation to University 230 kV substation. | 3,180 | 2,590 | |
| 1999 | | 1-1272 | 6 | 230 | Fossil Creek 230 kV substaion to Station-2 230 kV substation. | 2,460 | 2,220 | |
| 1999 | | 2-954 | 91 | 345 | Gold Creek 345 kV substaion to Healy 345 kV substation (Includes 2-30 MVAR 345 kV reactors). | 5,790 | 41,980 | |
| 1999 | | 2-954 | 79 | 345 | Gold Creek 345 kV substation to Willow 230 kV substation (Includes 2-30 MVAR 345 kV reactors). | 6,920 | 36,440 | |
| 1999 | | 1-1272 | 41 | 230 | Willow 230 kV Substation to Lorraine 230 kV substation. | 2,460 | 15,180 | |
| 1999 | | 2-954 | 57 | 345 | Healy 345 kV substation to Nenana 230 kV substation (Includes 2-30 MVAR 345 kV Reactors). | 6,920 | 26,290 | |
| 1999 | | 1-1272 | 60 | 230 | Nenana 230 kV substation to Fairbanks 230 kV substation. | 2,460 | 22,220 | |
| 1999 | | - | - | 230 | 230 kV Palmer substation second transformer. | 2,510 | - | |
| 1999 | | 1-1272 | 14 | 230 | Lorraine 230 kV substation to Fossil Creek 230 kV substaion (Includes 4 miles of submarine cable which has 2-25 MVAR 230 kV reactors). | 2,870 | 52,400 | |
| 1999 | | - | - | 230 | Addition of a phase shifting transformer at 230 kV Pt. Mackenzie substation. | 2,360 | - | |

TABLE D.2.9.5: (Page 3 of 5) COMPOSITE FORECAST

| Year | Generation Capacity Added | Required Transmission/Substation Facility: Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Cost of Facility (thousand 1985 $): Substation | Transmission Line[1] | Total |
|---|---|---|---|---|---|---|---|---|
| 1999 | | – | – | | Energy Management System. | 11,540 | – | |
| | | | | | Subtotal 1999 | 49,470 | 199,320 | |
| | | | | | Contingency[2] | 7,420 | 29,900 | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 8,530 | 34,380 | |
| | | | | | Total 1999 | 65,420 | 263,600 | 329,020 |
| 2000 | 87 MW | – | – | 115 | Connection of unit to existing 115 kV Station-2 substation. | 810 | – | |
| | | | | | Subtotal 2000 | 810 | | |
| | | | | | Contingency[2] | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 140 | | |
| | | | | | Total 2000 | 1,070 | – | 1,070 |
| 2003 | 87 MW | – | – | – | Connection to high voltage transmission and substation to match existing Voltage | 810 | | |
| | | | | | Subtotal 2003 | | | |
| | | | | | Contingency[2] | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 140 | | |
| | | | | | Total 2003 | 1,070 | | 1,070 |
| 2005 | 200 MW-Nenana | – | 10 | 230 | [4] Two terminations of 230 kV line from Nenana Powerplant at 230 kV Nenana substation. | 1,740 | | |
| | | | | | Subtotal 2005 | 1,740 | | |
| | | | | | Contingency [2] | 260 | | |
| | | | | | Engineering, Administration and Owners Overhead[3] | 300 | | |
| | | | | | Total 2005 | 2,300 | | 2,300 |

TABLE D.2.9.5: (Page 4 of 5) COMPOSITE FORECAST

| Year | Generation Capacity Added | Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Substation | Transmission Line1/ | Total |
|---|---|---|---|---|---|---|---|---|
| | | | | | Required Transmission/Substation Facility | Cost of Facility (thousand 1985 $) | | |
| 2007 | 200 MW-Nenana | - | 10 | 230 | 4/ | | | |
| 2007 | 2-87 MW | - | - | 138 | Two Connections at existing North Pole 138 kV substation. | 3,180 | | |
| | | | | | Subtotal 2007 | 3,180 | | |
| | | | | | Contingency 2/ | 480 | | |
| | | | | | Engineering, Administration and Owners Overhead3/ | 550 | | |
| | | | | | Total 2007 | 4,210 | | 4,210 |
| 2009 | 87 MW | - | - | - | Connection to high voltage Transmission and substation to match existing voltage. | 810 | | |
| | | | | | Subtotal 2009 | | | |
| | | | | | Contingency2/ | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead3/ | 140 | | |
| | | | | | Total 2009 | 1,070 | | 1,070 |
| 2010 | 200 MW-Beluga | - | 48 | 230 | 4/ | | | |
| 2012 | 87 MW | - | - | 115 | Connection between unit and existing 115 kV Station-2 substation. | 810 | | |
| | | | | | Subtotal 2012 | 810 | | |
| | | | | | Contingency 2/ | 120 | | |
| | | | | | Engineering, Administration and Owners Overhead3/ | 140 | | |
| | | | | | Total 2012 | 1,070 | | 1,070 |

TABLE D.2.9.5: (Page 5 of 5) COMPOSITE FORECAST

| | | Required Transmission/Substation Facility | | | | Cost of Facility (thousand 1985 $) | | |
|---|---|---|---|---|---|---|---|---|
| Year | Generation Capacity Added | Conductor Size (kc mil) | Length Miles | Voltage kV | Description | Substation | Transmission Line1/ | Total |
| 2017 | 87 MW | - | - | - | Connection to high voltage transmission and substation to match existing voltage. | 810 | | - |
| 2017 | 87 MW | 1-1272 | 1 | 230 | Connection of new unit to 230 kV Fairbanks substation. | 870 | 370 | |
| | | | | | Subtotal 2017 | 1,680 | 370 | |
| | | | | | Contingency2/ | 250 | 60 | |
| | | | | | Engineering, Administration and Owners Overhead3/ | 290 | 60 | |
| | | | | | Total 2017 | 2,220 | 490 | 2,710 |
| 2021 | 87 MW | | | 115 | Connection between unit and existing 115 kV Station-2 substation. | 810 | | |
| | | | | | Subtotal 2021 | 810 | | |
| | | | | | Contingency2/ | 810 | | |
| | | | | | Engineering, Administration and Owners Overhead3/ | 140 | | |
| | | | | | Total 2021 | 1,070 | | 1,070 |
| 2025 | 200 MW-Beluga | - | 48 | 230 | 4/ | | | |

1/ All new transmission line cost estimates include costs of terminations. Existing line cost estimates as described in the table include the cost of terminations only.

2/ Contingency allowance of 15%.

3/ Engineering, Administration, and Owners Overhead of 15%.

4/ Transmission costs from the Beluga and Nenana plant site to the high voltage power grid are included in the power plant estimates.

TABLE D.2.10.1: PRINCIPAL ECONOMIC PARAMETERS

1. All Costs in January 1985 Dollars

2. Base Year for Present Worth Analysis: 1985

3. Analysis Periods:

   System Expansion: 1996-2025

   Annual Cost Extension: 2026-2054

4. Electrical Load Forecast: 1985 to 2025

5. Discount Rate: 3.5 percent

6. Inflation Rate: 0 percent

7. Economic Life of Projects:

| | |
|---|---|
| Combustion Turbines: | 25 years |
| Combined Cycle Turbines: | 30 years |
| Steam Turbines | 35 years |
| Hydroelectric Projects | 50 years |
| Transmission | 50 years |

8. Annual Fixed Carrying Charges

| | 25-year Life | 30-year Life | 35-year Life | 50-year Life |
|---|---|---|---|---|
| Cost of Money | 3.50 | 3.50 | 3.50 | 3.50 |
| Amortization | 2.57 | 1.94 | 1.50 | 0.70 |
| Insurance | 0.25 | 0.25 | 0.25 | 0.10 |
| Total | 6.32 | 5.69 | 5.25 | 4.36 |

TABLE D.2.10.2: EXAMPLE OF REAL INTEREST RATE CALCULATION1/

| Year | Inflation Rate2/ | Nominal Debt Service3/ | Real Debt Service4/ |
|---|---|---|---|
| 1991 | 5.0 | 107.2 | 102.1 |
| 1992 | 4.9 | 107.2 | 97.4 |
| 1993 | 5.2 | 107.2 | 92.5 |
| 1994 | 5.3 | 107.2 | 87.9 |
| 1995 | 5.1 | 107.2 | 83.6 |
| 1996 | 5.1 | 107.2 | 79.5 |
| 1997 | 5.1 | 107.2 | 75.7 |
| 1998 | 5.1 | 107.2 | 72.0 |
| 1999 | 5.1 | 107.2 | 68.5 |
| 2000 | 5.1 | 107.2 | 65.2 |
| 2001 | 5.1 | 107.2 | 62.0 |
| 2002 | 5.1 | 107.2 | 59.0 |
| 2003 | 5.1 | 107.2 | 56.2 |
| 2004 | 5.1 | 107.2 | 53.4 |
| 2005 | 5.1 | 107.2 | 50.8 |
| 2006 | 5.1 | 107.2 | 48.4 |
| 2007 | 5.1 | 107.2 | 46.0 |
| 2008 | 5.1 | 107.2 | 43.8 |
| 2009 | 5.1 | 107.2 | 41.7 |
| 2010 | 5.1 | 107.2 | 39.6 |
| | | Real Interest Rate5/ | 3.4% |

1/ This table presents data necessary to calculate the real interest rate for a 20-year bond issued in 1981. A $1000 denomination has been selected for the example, through any denomination will produce the same result. Review of historical data indicates that the yield on 20-year bonds is nearly the same as the yield on 35-year bonds, and that therefore the real interest rate calculated for the former is a close proxy for the latter. The table assumes that a $1000 bond is issued on Jan. 1, 1991, and that annual payments begin on Dec. 31, 1991.

2/ The inflation shown for 1995-2010 is the average of inflation rates forecast for the years 1990-1994.

3/ Level nominal debt service for a 20-year, $1000 bond issued at 8.7 nominal interest.

4/ Level nominal debt service adjusted for inflation, producing debt service expressed in Jan 1, 1991 dollars.

5/ The real interest rate is the discount rate which, when applied to the stream of real debt service payments, produces a present value equal to the initial amount of the bond. In this case, a $1000 sum invested at 3.4% interest would produce the stream of payments shown as "real debt service," and would then be exhausted at the end of 20 years.

TABLE D.2.10.3: EX-POST REAL INTEREST RATES ON SELECTED TREASURY ISSUES 1945-1984

| Year | Maturity Range | | | | Composite Series |
|---|---|---|---|---|---|
| | 3-Month | 3-5 Year | 10-Year | 15-Year + | |
| 1945 | -1.9 | -7.1 | -1.1 | -1.1 | -1.1 |
| 1946 | -8.1 | -6.3 | -2.7 | -1.3 | -1.3 |
| 1947 | -13.8 | -4.2 | -1.9 | -0.6 | -0.6 |
| 1948 | -6.8 | -2.3 | -0.8 | -0.6 | -0.6 |
| 1949 | 2.1 | -1.1 | -0.2 | 0.7 | 0.7 |
| 1950 | 0.2 | -1.5 | -0.2 | 0.5 | 0.5 |
| 1951 | -6.3 | -0.9 | 0.2 | 0.7 | 0.7 |
| 1952 | -4.3 | 1.4 | 1.0 | 1.3 | 1.3 |
| 1953 | 1.1 | 2.0 | 1.5 | 1.6 | 1.6 |
| 1954 | 0.5 | 0.5 | 1.0 | 0.9 | 0.9 |
| 1955 | 2.2 | 0.7 | 1.4 | 0.7 | 0.7 |
| 1956 | 1.2 | 1.0 | 1.5 | 0.6 | 0.6 |
| 1957 | -0.3 | 1.4 | 1.9 | 0.8 | 0.8 |
| 1958 | -0.9 | 1.4 | 1.6 | 0.7 | 0.7 |
| 1959 | 2.6 | 3.2 | 2.5 | 1.2 | 1.2 |
| 1960 | 1.3 | 2.8 | 1.8 | 0.4 | 0.4 |
| 1961 | 1.4 | 2.5 | 1.1 | -0.2 | -0.2 |
| 1962 | 1.7 | 2.2 | 0.9 | -0.5 | -0.5 |
| 1963 | 2.0 | 1.9 | 0.7 | -0.8 | -0.8 |
| 1964 | 2.2 | 1.9 | 0.4 | -1.1 | -1.1 |
| 1965 | 2.3 | 1.3 | -0.5 | -1.7 | -1.7 |
| 1966 | 2.0 | 1.3 | -0.6 | -2.0 | -2.0 |
| 1967 | 1.4 | 0.5 | -0.7 | -2.3 | -2.3 |
| 1968 | 1.1 | 0.6 | -0.5 | -2.1 | -2.1 |
| 1969 | 1.3 | 2.1 | 0.1 | -1.2 | -1.2 |
| 1970 | 0.6 | 2.4 | 0.2 | -0.6 | -0.6 |
| 1971 | 0.0 | -0.4 | -1.7 | | -1.7 |
| 1972 | 0.8 | -1.6 | -2.3 | | -2.3 |
| 1973 | 0.8 | -1.1 | -1.9 | | -1.9 |
| 1974 | -3.1 | -0.3 | -0.9 | | -0.9 |
| 1975 | -3.3 | 0.2 | 0.3 | | 0.3 |
| 1976 | -0.8 | -1.1 | | | -1.1 |
| 1977 | -1.2 | -3.1 | | | -3.1 |
| 1978 | -0.5 | -2.4 | | | -2.4 |

TABLE D.2.10.4: ECONOMIC ANALYSIS OF SUSITNA PROJECT

| Plan | Components | 1985 Present Worth of System Costs Million $ 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
|---|---|---|---|---|---|
| **SHCA Forecast** | | | | | |
| Without-Susitna | 1000 MW Coal-Beluga<br>400 MW Coal-Nenana<br>611 MW SCCT<br>0 MW CCCT | 4627 | 604.0 | 3093 | 7720 |
| With-Susitna | 1023 MW Watana<br>508 MW Devil Canyon<br>611 MW SCCT | 3512 | 423.3 | 2015 | 5527 |
| Net Benefit of Susitna Plan-Million $ | | | | | 2193 |
| Benefit/Cost Ratio | | | | | 1.40 |
| **Composite Forecast** | | | | | |
| Without-Susitna | 800 MW Coal-Beluga<br>400 MW Coal-Nenana<br>698 MW SCCT<br>0 MW CCCT | 4479 | 553.4 | 2679 | 7158 |
| With-Susitna | 1023 MW Watana<br>508 MW Devil Canyon<br>524 MW SCCT | 3384 | 315.8 | 1439 | 4823 |
| Net Benefit of Susitna Plan-Million $ | | | | | 2335 |
| Benefit/Cost Ratio | | | | | 1.48 |

TABLE D.2.11.1: FORECASTS OF ELECTRIC POWER DEMAND NET AT PLANT

| Year | SHCA Forecast | | Composite Forecast | | Wharton Forecast | |
|---|---|---|---|---|---|---|
| | MW | GWh | MW | GWh | MW | GWh |
| 1990 | 757 | 3978 | 753 | 3959 | 741 | 3897 |
| 2000 | 845 | 4442 | 868 | 4560 | 894 | 4701 |
| 2010 | 1042 | 5478 | 1034 | 5432 | 1074 | 5646 |
| 2020 | 1285 | 6755 | 1231 | 6471 | 1290 | 6780 |

TABLE D.2.11.2: WHARTON FORECAST SENSITIVITY ANALYSIS

| Plan | 1985 Present Worth of System Costs Million $ | | | |
|---|---|---|---|---|
| | 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
| Wharton Forecast | | | | |
| Without-Susitna | 4048 | 570.6 | 2786 | 6884 |
| With-Susitna | 3351 | 380.6 | 1797 | 5148 |
| Net Benefit-Million $ | | | | 1736 |
| Benefit/Cost Ratio | | | | 1.34 |
| SHCA Forecast | | | | |
| Without-Susitna | 4627 | 604.0 | 3093 | 7720 |
| With-Susitna | 3512 | 423.3 | 2015 | 5527 |
| Net Benefit-Million $ | | | | 2193 |
| Benefit/Cost Ratio | | | | 1.40 |
| Composite Forecast | | | | |
| Without-Susitna | 4479 | 553.4 | 2679 | 7158 |
| With-Susitna | 3384 | 315.8 | 1439 | 4823 |
| Net Benefit-Million $ | | | | 2335 |
| Benefit/Cost Ratio | | | | 1.48 |

TABLE D.2.11.3: DISCOUNT RATE SENSITIVITY ANALYSIS

| Plan | Real Discount Rate (Percent) | 1985 Present Worth of System Costs Million $ 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
|---|---|---|---|---|---|
| SHCA Forecast | | | | | |
| Without-Susitna | 4.5 | 3834 | 646.9 | 1978 | 5812 |
| With-Susitna | 4.5 | 3216 | 488.2 | 1395 | 4611 |
| Net Benefit - Million $ | | | | | 1201 |
| Benefit/Cost Ratio | | | | | 1.26 |
| Composite Forecast | | | | | |
| Without-Susitna | 4.5 | 3609 | 591.4 | 1720 | 5329 |
| With-Susitna | 4.5 | 3120 | 380.5 | 1048 | 4168 |
| Net Benefit - Million $ | | | | | 1161 |
| Benefit/Cost Ratio | | | | | 1.28 |

TABLE D.2.11.4: WATANA CAPITAL COST SENSITIVITY ANALYSIS

| | 1985 Present Worth of System Costs $ Million | | | |
|---|---|---|---|---|
| Plan | 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
| SHCA Forecast | | | | |
| Without-Susitna | 4627 | 604.0 | 3093 | 7720 |
| With-Susitna | 3734 | 443.5 | 2107 | 5841 |
| Net Benefit-Million $ | | | | 1879 |
| Benefit/Cost Ratio | | | | 1.32 |
| Composite Forecast | | | | |
| Without-Susitna | 4479 | 553.4 | 2679 | 7158 |
| With-Susitna | 3607 | 336.0 | 1530 | 5137 |
| Net Benefit-Million $ | | | | 2021 |
| Benefit/Cost Ratio | | | | 1.39 |

TABLE D.2.11.5: REAL ESCALATION OF COAL PRICE SENSITIVITY ANALYSIS

| Plan | 1985 Present Worth of System Costs $ Million | | | |
|---|---|---|---|---|
| | 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
| SHCA Forecast | | | | |
| Without-Susitna | 4156 | 489.7 | 2237 | 6393 |
| With-Susitna | 3509 | 423.3 | 2016 | 5524 |
| Net Benefit-Million $ | | | | 869 |
| Benefit/Cost Ratio | | | | 1.16 |
| Composite Forecast | | | | |
| Without-Susitna | 4088 | 455.8 | 2077 | 6164 |
| With-Susitna | 3382 | 315.8 | 1438 | 4820 |
| Net Benefit-Million $ | | | | 1344 |
| Benefit/Cost Ratio | | | | 1.28 |

TABLE D.2.11.6: NATURAL GAS AVAILABILITY FOR BASELOAD GENERATION

| Plan | 1985 Present Worth of System Costs $ Million 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
|---|---|---|---|---|
| SHCA Forecast | | | | |
| Without-Susitna | 4595 | 589.9 | 3037 | 7632 |
| With-Susitna | 3488 | 404.0 | 1913 | 5400 |
| Net Benefit-Million $ | | | | 2232 |
| Benefit/Cost Ratio | | | | 1.41 |
| Composite Forecast | | | | |
| Without-Susitna | 4432 | 552.0 | 2673 | 7105 |
| With-Susitna | 3374 | 315.8 | 1439 | 4813 |
| Net Benefit-Million $ | | | | 2292 |
| Benefit/Cost Ratio | | | | 1.48 |

TABLE D.2.11.7: COMBINED SENSITIVITY CASE

| Plan | 1985 Present Worth of System Costs $ Million | | | |
|---|---|---|---|---|
| | 1996-2025 | 2025 Annual Cost | Estimated 2026-2054 | 1996-2054 |
| Wharton Forecast | | | | |
| Without-Susitna | 3548 | 475.6 | 2206 | 5754 |
| With-Susitna | 3339 | 355.0 | 1645 | 4984 |
| Net Benefit-Million $ | | | | 770 |
| Benefit/Cost Ratio | | | | 1.15 |

TABLE D.4.2.2: BOND ISSUE SUMMARY (Millions of Dollars)
SUSITNA HYDROELECTRIC PROJECT

| | WATANA I | | DEVIL CANYON II | | WATANA III | | TOTAL | |
|---|---|---|---|---|---|---|---|---|
| YEAR | NOMINAL DOLLARS | 1985 DOLLARS 1/ | NOMINAL DOLLARS | 1985 DOLLARS 1/ | NOMINAL DOLLARS | 1985 DOLLARS 1/ | NOMINAL DOLLARS | 1985 DOLLARS |
| 1991 2/ | 1,000 | 725 | --- | --- | --- | --- | 1,000 | 725 |
| 1992 | 1,000 | 687 | --- | --- | --- | --- | 1,000 | 687 |
| 1993 | --- | --- | --- | --- | --- | --- | --- | --- |
| 1994 | 1,000 | 618 | --- | --- | --- | --- | 1,000 | 618 |
| 1995 | 1,200 | 703(3) | 500 | 293 | --- | --- | 1,700 | 996 |
| 1996 | 1,104 | 613(3) | 500 | 277 | --- | --- | 1,604 | 890 |
| 1997 | 1,500 | 789 | --- | --- | --- | --- | 1,500 | 789 |
| 1998 | 800 | 299 | 500 | 249 | --- | --- | 1,100 | 548 |
| 1999 | --- | --- | --- | --- | --- | --- | --- | --- |
| 2000 | --- | --- | 1,000 | 448 | --- | --- | 1,000 | 448 |
| 2001 | --- | --- | 1,000 | 425 | --- | --- | 1,000 | 425 |
| 2002 | --- | --- | 1,000 | 402 | --- | --- | 1,000 | 402 |
| 2003 | --- | --- | 1,300 | 496 | --- | --- | 1,300 | 496 |
| 2004 | --- | --- | --- | --- | --- | --- | --- | --- |
| 2005 | --- | --- | --- | --- | --- | --- | --- | --- |
| 2006 | --- | --- | --- | --- | 1,000 | 325 | 1,000 | 325 |
| 2007 | --- | --- | --- | --- | 1,000 | 308 | 1,000 | 308 |
| 2008 | --- | --- | --- | --- | 1,500 | 438 | 1,500 | 438 |
| 2009 | --- | --- | --- | --- | 1,500 | 415 | 1,500 | 415 |
| 2010 | --- | --- | --- | --- | 1,500 | 393 | 1,500 | 393 |
| 2011 | --- | --- | --- | --- | 500 | 124 | 500 | 124 |
| 2012 | --- | --- | --- | --- | 300 | 71 | 300 | 71 |
| | 7,404 | 4,434 | 5,800 | 2,590 | 7,300 | 2,074 | 20,504 | 9,098 |
| Average Annual Issue (1991-2012) | | | | | | | 932 | 413 |

1/ Based on an assumed average annual inflation rate of 5.5 percent.

2/ Expenditures incurred prior to 1991 are assumed to be funded through continuing State appropriations. Those costs incurred after June 30, 1985, are assumed to be reimbursed from bond proceeds.

3/ Includes issues of $200,000,000 and $104,000,000 for 1995 and 1996, respectively for 345 kV transmission upgrade.

TABLE D.4.3.1: SUSITNA HYDROELECTRIC PROJECT ANNUAL COSTS
(Millions of Dollars)

| Calendar Year | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Debt Service........... | 669 | 702 | 702 | 702 | 702 | 702 | 1,224 | 1,251 | 1,251 | 1,251 | 1,251 | 1,251 | 1,251 |
| Interest Earnings...... | (70) | (70) | (70) | (70) | (70) | (70) | (125) | (125) | (125) | (125) | (125) | (125) | (125) |
| Net Debt Service....... | 599 | 632 | 632 | 632 | 632 | 632 | 1,099 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 | 1,126 |
| Operating Costs........ Renewals and Replacements | 24 | 26 | 27 | 28 | 30 | 32 | 37 | 39 | 42 | 44 | 46 | 49 | 51 |
| Total Annual Cost | 623 | 658 | 659 | 660 | 662 | 664 | 1,136 | 1,165 | 1,168 | 1,170 | 1,172 | 1,175 | 1,177 |
| Energy Sales (GWh) | 2,196 | 2,207 | 2,220 | 2,232 | 2,245 | 2,257 | 4,116 | 4,145 | 4,174 | 4,204 | 4,353 | 4,480 | 4,574 |
| Cost/Unit of Sales (cents/kWh) | | | | | | | | | | | | | |
| - Nominal | 28.3 | 29.8 | 29.7 | 29.6 | 29.5 | 29.4 | 27.6 | 28.1 | 28.0 | 27.8 | 26.9 | 26.2 | 25.7 |
| - 1985 Dollars | 13.4 | 13.3 | 12.6 | 11.9 | 11.2 | 10.6 | 9.5 | 9.1 | 8.6 | 8.1 | 7.4 | 6.9 | 6.4 |

| Calendar Year | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Debt Service(1)....... | 1,888 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 | 1,942 |
| Interest Earnings..... | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) | (200) |
| Net Debt Service...... | 1,688 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 | 1,742 |
| Operating Costs and Renewals and Replacements | 54 | 57 | 60 | 64 | 67 | 64 | 67 | 71 | 75 | 79 | 83 | 88 | 93 |
| Total Annual Cost | 1,742 | 1,799 | 1,802 | 1,806 | 1,809 | 1,806 | 1,809 | 1,813 | 1,817 | 1,821 | 1,825 | 1,830 | 1,835 |
| Energy Sales (GWh) | 4,911 | 5,007 | 5,105 | 5,204 | 5,307 | 5,404 | 5,512 | 5,622 | 5,731 | 5,842 | 5,955 | 6,069 | 6,151 |
| Cost/Unit of Sales (cents/KWh) | | | | | | | | | | | | | |
| - Nominal | 35.5 | 35.9 | 35.3 | 34.7 | 34.1 | 33.4 | 32.8 | 32.2 | 31.7 | 31.2 | 30.6 | 30.2 | 29.8 |
| -1985 Dollars | 8.4 | 8.0 | 7.5 | 7.0 | 6.5 | 6.0 | 5.6 | 5.2 | 4.9 | 4.5 | 4.2 | 3.9 | 3.7 |

TABLE D.4.1.1: FINANCIAL PARAMETERS

| | |
|---|---|
| General Inflation | 5.5% |
| Revenue Bond Interest Rate | 9.0% |
| Short-term Reinvestment Rate | 8.0% |
| Long-term Reinvestment Rate | 10.0% |
| Bond Amortization Period | 35 years |
| Bond Reserve Funds: | |
| Capital Reserve Fund | One Years Debt Service |
| Working Capital Fund | Two months operating costs (including debt service) |

TABLE D.4.2.1: CONSTRUCTION CASH FLOW
SUSITNA HYDROELECTRIC PROJECT
(Millions of Dollars)

| | WATANA I | | DEVIL CANYON II | | WATANA III | |
|---|---|---|---|---|---|---|
| YEAR | JAN. 1985$ | NOMINAL $ | JAN. 1985$ | NOMINAL $ | JAN. 1985$ | NOMINAL $ |
| PRIOR | 134.2 | 134.2 1/ | --- | --- | --- | --- |
| 1986 | 25.8 | 28.0 1/ | --- | --- | --- | --- |
| 1987 | 28.5 | 32.6 1/ | --- | --- | --- | --- |
| 1988 | 32.6 | 39.3 1/ | --- | --- | --- | --- |
| 1989 | 51.5 | 65.5 1/ | --- | --- | --- | --- |
| 1990 | 67.8 | 91.0 | --- | --- | --- | --- |
| 1991 | 186.5 | 264.1 | --- | --- | --- | --- |
| 1992 | 326.1 | 487.2 | --- | --- | --- | --- |
| 1993 | 170.1 | 268.1 | --- | --- | --- | --- |
| 1994 | 205.4 | 341.6 | --- | --- | --- | --- |
| 1995 | 253.5 | 444.8 | 46.7 | 81.9 | --- | --- |
| 1996 | 355.1 | 657.3 | 47.7 | 88.3 | --- | --- |
| 1997 | 491.0 | 958.8 | 75.7 | 147.8 | --- | --- |
| 1998 | 325.0 | 669.6 | 127.7 | 263.1 | --- | --- |
| 1999 | 28.9 | 62.8 | 137.0 | 297.8 | --- | --- |
| 2000 | --- | --- | 149.4 | 342.6 | --- | --- |
| 2001 | --- | --- | 243.7 | 589.6 | --- | --- |
| 2002 | --- | --- | 211.8 | 540.6 | --- | --- |
| 2003 | --- | --- | 218.7 | 588.9 | --- | --- |
| 2004 | --- | --- | 114.0 | 323.8 | --- | --- |
| 2005 | --- | --- | 21.6 | 64.7 | --- | --- |
| 2006 | --- | --- | --- | --- | 147.8 | 467.3 |
| 2007 | --- | --- | --- | --- | 203.8 | 679.8 |
| 2008 | --- | --- | --- | --- | 197.2 | 694.0 |
| 2009 | --- | --- | --- | --- | 286.0 | 1,061.8 |
| 2010 | --- | --- | --- | --- | 271.9 | 1,065.0 |
| 2011 | --- | --- | --- | --- | 135.3 | 559.1 |
| 2012 | --- | --- | --- | --- | 77.0 | 335.7 |
| Total | 2,682.0 | 4,544.9 | 1,394.0 | 3,329.0 | 1,319.0 | 4,862.7 |

1/ Estimated costs related to engineering, administration and environmental studies expected to be incurred prior to issuance of FERC license and prior to beginning of construction.

TABLE D.4.4.1: VALUE OF POWER (Millions of Dollars)



**SHCA FORECAST**

| YEAR | SYSTEM COSTS W/SUSITNA 1/ | SYSTEM COSTS W/O SUSITNA 1/ | SAVINGS (LOSSES) W/SUSITNA NOMINAL $ | SAVINGS (LOSSES) W/SUSITNA 1985$ | ACCRUED SAVINGS W/SUSITNA NOMINAL $ | ACCRUED SAVINGS W/SUSITNA 1985$ | RATE STABILIZATION REQUIRED |
|---|---|---|---|---|---|---|---|
| 1985 | 121.4 | 121.4 | --- | --- | --- | --- | --- |
| 1986 | 124.3 | 124.3 | --- | --- | --- | --- | --- |
| 1987 | 131.1 | 131.1 | --- | --- | --- | --- | --- |
| 1988 | 145.2 | 145.2 | --- | --- | --- | --- | --- |
| 1989 | 159.3 | 159.3 | --- | --- | --- | --- | --- |
| 1990 | 167.2 | 167.2 | --- | --- | --- | --- | --- |
| 1991 | 176.5 | 176.5 | --- | --- | --- | --- | --- |
| 1992 | 187.3 | 187.3 | --- | --- | --- | --- | --- |
| 1993 | 200.5 | 200.5 | --- | --- | --- | --- | --- |
| 1994 | 286.8 | 286.8 | --- | --- | --- | --- | --- |
| 1995 | 321.2 | 321.2 | --- | --- | --- | --- | --- |
| 1996 | 339.6 | 339.6 | --- | --- | --- | --- | --- |
| 1997 | 370.8 | 370.8 | --- | --- | --- | --- | --- |
| 1998 | 405.7 | 405.7 | --- | --- | --- | --- | --- |
| 1999 | 853.1 | 755.9 | ( 97.2) | ( 45.9) | ( 97.2) | ( 45.9) | 97.2 |
| 2000 | 908.9 | 804.2 | (104.7) | ( 48.9) | (201.9) | ( 92.8) | 104.6 |
| 2001 | 935.6 | 841.0 | ( 94.6) | ( 40.2) | (296.5) | (133.0) | 94.6 |
| 2002 | 985.0 | 878.8 | (106.2) | ( 42.7) | (402.7) | (175.7) | 106.6 |
| 2003 | 1,025.0 | 924.9 | (100.1) | ( 38.2) | (502.8) | (213.9) | 100.1 |
| 2004 | 1,079.6 | 1,097.9 | 18.3 | 6.6 | (484.5) | (207.3) | --- |
| 2005 | 1,239.4 | 1,146.3 | ( 93.1) | ( 31.9) | (577.6) | (239.2) | 93.1 |
| 2006 | 1,274.5 | 1,368.8 | 94.3 | 30.6 | (483.3) | (208.6) | --- |
| 2007 | 1,374.4 | 1,619.1 | 244.7 | 75.3 | (238.6) | (133.2) | --- |
| 2008 | 1,449.4 | 1,676.3 | 226.9 | 66.2 | ( 11.7) | ( 67.0) | --- |
| 2009 | 1,418.6 | 1,767.3 | 348.7 | 96.5 | 337.0 | 29.5 | --- |
| 2010 | 1,508.9 | 1,835.2 | 326.3 | 85.6 | 663.3 | 115.0 | --- |
| 2011 | 1,544.8 | 1,908.9 | 364.1 | 90.5 | 1,027.4 | 205.5 | --- |
| 2012 | 1,857.5 | 2,007.6 | 150.1 | 35.4 | 1,177.5 | 240.9 | --- |
| 2013 | 1,910.6 | 2,093.3 | 182.7 | 40.8 | 1,360.2 | 281.7 | --- |
| 2014 | 1,913.5 | 2,189.3 | 275.8 | 58.4 | 1,636.0 | 340.1 | --- |
| 2015 | 1,918.9 | 2,325.3 | 406.4 | 81.5 | 2,042.4 | 421.6 | --- |
| 2016 | 1,924.6 | 2,463.6 | 539.0 | 102.5 | 2,581.4 | 524.1 | --- |
| 2017 | 1,973.0 | 2,633.0 | 680.0 | 119.0 | 3,241.4 | 643.1 | --- |
| 2018 | 2,122.8 | 2,876.8 | 754.0 | 128.8 | 3,995.4 | 771.9 | --- |
| 2019 | 1,983.3 | 3,183.2 | 1,199.8 | 194.3 | 5,195.3 | 966.3 | --- |
| 2020 | 2,012.8 | 3,344.5 | 1,331.7 | 204.4 | 6,427.0 | 1,170.7 | --- |
| | | | | | | | 595.8 |

1/ Estimated costs of production only for the Railbelt utilities. Costs shown include an estimated amount for existing utility debt service allocated to generation and tranmission.

TABLE D.4.4.1 (Page 2 of 2)

**COMPOSITE FORECAST**

| YEAR | SYSTEM COSTS W/SUSITNA[1] | SYSTEM COSTS W/O SUSITNA[1] | SAVINGS (LOSSES) W/SUSITNA NOMINAL $ | SAVINGS (LOSSES) W/SUSITNA 1985$ | ACCRUED SAVINGS W/SUSITNA NOMINAL $ | ACCRUED SAVINGS W/SUSITNA 1985$ | RATE STABILIZATION REQUIRED |
|---|---|---|---|---|---|---|---|
| 1985 | 121.4 | 121.4 | --- | --- | --- | --- | --- |
| 1986 | 124.3 | 124.3 | --- | --- | --- | --- | --- |
| 1987 | 131.1 | 131.1 | --- | --- | --- | --- | --- |
| 1988 | 145.2 | 145.2 | --- | --- | --- | --- | --- |
| 1989 | 159.3 | 159.3 | --- | --- | --- | --- | --- |
| 1990 | 167.2 | 167.2 | --- | --- | --- | --- | --- |
| 1991 | 176.5 | 176.5 | --- | --- | --- | --- | --- |
| 1992 | 187.3 | 187.3 | --- | --- | --- | --- | --- |
| 1993 | 200.5 | 200.5 | --- | --- | --- | --- | --- |
| 1994 | 286.8 | 286.8 | --- | --- | --- | --- | --- |
| 1995 | 321.2 | 321.2 | --- | --- | --- | --- | --- |
| 1996 | 336.4 | 336.4 | --- | --- | --- | --- | --- |
| 1997 | 361.3 | 361.3 | --- | --- | --- | --- | --- |
| 1998 | 390.3 | 390.3 | --- | --- | --- | --- | --- |
| 1999 | 846.3 | 775.4 | ( 90.9) | ( 43.0) | ( 90.9) | ( 43.0) | 90.9 |
| 2000 | 900.0 | 801.8 | ( 98.2) | ( 44.0) | (189.1) | ( 86.9) | 98.2 |
| 2001 | 925.9 | 834.1 | ( 91.8) | ( 39.0) | (280.9) | (125.9) | 91.9 |
| 2002 | 968.8 | 867.9 | (100.9) | ( 40.6) | (381.8) | (166.5) | 100.9 |
| 2003 | 1,000.9 | 922.5 | ( 78.4) | ( 29.9) | (460.2) | (196.4) | 78.4 |
| 2004 | 1,042.9 | 962.0 | ( 80.9) | ( 29.3) | (541.1) | (225.7) | 80.9 |
| 2005 | 1,239.4 | 1,158.9 | ( 80.5) | ( 27.6) | (621.6) | (253.3) | 80.5 |
| 2006 | 1,274.5 | 1,211.7 | ( 62.8) | ( 20.4) | (684.4) | (273.7) | 62.8 |
| 2007 | 1,353.3 | 1,488.8 | 135.5 | 41.7 | (548.9) | (232.0) | --- |
| 2008 | 1,415.1 | 1,554.6 | 139.5 | 40.7 | (409.4) | (191.2) | --- |
| 2009 | 1,364.1 | 1,642.0 | 277.9 | 76.9 | (131.5) | (114.4) | --- |
| 2010 | 1,431.4 | 1,899.4 | 468.0 | 122.7 | 336.5 | 8.4 | --- |
| 2011 | 1,486.8 | 1,967.0 | 480.2 | 119.4 | 816.7 | 127.7 | --- |
| 2012 | 1,857.5 | 2,041.9 | 184.4 | 43.4 | 1,001.1 | 171.2 | --- |
| 2013 | 1,910.6 | 2,116.6 | 206.0 | 46.0 | 1,207.1 | 217.2 | --- |
| 2014 | 1,913.5 | 2,205.2 | 291.7 | 61.7 | 1,498.8 | 278.9 | --- |
| 2015 | 1,918.9 | 2,302.0 | 383.1 | 76.9 | 1,891.9 | 335.8 | --- |
| 2016 | 1,924.6 | 2,408.7 | 484.1 | 92.1 | 2,366.0 | 447.9 | --- |
| 2017 | 1,940.8 | 2,577.0 | 636.2 | 114.7 | 3,002.2 | 562.6 | --- |
| 2018 | 1,995.8 | 2,721.6 | 725.8 | 124.0 | 3,728.0 | 686.6 | --- |
| 2019 | 1,978.4 | 2,768.5 | 790.1 | 128.0 | 4,518.1 | 814.5 | --- |
| 2020 | 1,985.1 | 3,044.0 | 1,058.9 | 162.6 | 5,577.0 | 977.1 | --- |
| | | | | | | | 684.5 |

1/ Estimated costs of production only for the Railbelt utilities. Costs shown include an estimated amount for existing utility debt service allocated to generation and tranmission.

TABLE D.4.5.1: RATE STABILIZATION SUMMARY (Page 1 of 2)
(Millions of Dollars)

**SHCA FORECAST**

| YEAR | SYSTEM COSTS W/SUSITNA 1/ | SYSTEM COSTS W/O SUSITNA 1/ | RATE STABILIZATION REQUIRED | STATE CONTRIBUTION | COSTS PRE-BOND ISSUANCE 2/ | ACCRUED STATE CONTRIBUTION 3/ |
|---|---|---|---|---|---|---|
| 1985 | 121 | 121 | --- | 100.0 | 16.8 | 83.2 |
| 1986 | 124 | 124 | --- | 118.7 | 28.0 | 181.9 |
| 1987 | 131 | 131 | --- | --- | 32.6 | 165.9 |
| 1988 | 145 | 145 | --- | --- | 39.3 | 141.3 |
| 1989 | 159 | 159 | --- | --- | 85.6 | 86.8 |
| 1990 | 167 | 167 | --- | --- | 91.0 | 0.0 |
| 1991 | 176 | 176 | --- | --- | (171.2) | 179.6 |
| 1992 | 187 | 187 | --- | --- | --- | 197.6 |
| 1993 | 200 | 200 | --- | --- | --- | 217.4 |
| 1994 | 286 | 286 | --- | --- | --- | 239.1 |
| 1995 | 321 | 321 | --- | --- | --- | 263.0 |
| 1996 | 340 | 340 | --- | --- | --- | 289.3 |
| 1997 | 371 | 371 | --- | --- | --- | 318.2 |
| 1998 | 406 | 406 | --- | --- | --- | 350.0 |
| 1999 | 853 | 756 | 97.0 | --- | --- | 385.1 |
| 2000 | 909 | 804 | 105.0 | --- | --- | 321.8 |
| 2001 | 936 | 841 | 95.0 | --- | --- | 254.4 |
| 2002 | 985 | 879 | 106.0 | --- | --- | 168.6 |
| 2003 | 1,025 | 925 | 100.0 | --- | --- | 80.6 |
| 2004 | 1,080 | 1,098 | --- | --- | --- | 88.7 |
| 2005 | 1,239 | 1,146 | 93.0 | --- | --- | --- |
| 2006 | 1,275 | 1,369 | --- | --- | --- | --- |
| 2007 | 1,374 | 1,619 | --- | --- | --- | --- |
| 2008 | 1,449 | 1,676 | --- | --- | --- | --- |
| 2009 | 1,419 | 1,767 | --- | --- | --- | --- |
| 2010 | 1,509 | 1,835 | --- | --- | --- | --- |
| 2011 | 1,545 | 1,909 | --- | --- | --- | --- |
| 2012 | 1,057 | 2,008 | --- | --- | --- | --- |
| 2013 | 1,911 | 2,093 | --- | --- | --- | --- |
| 2014 | 1,914 | 2,189 | --- | --- | --- | --- |
| 2015 | 1,919 | 2,325 | --- | --- | --- | --- |
| 2016 | 1,925 | 2,464 | --- | --- | --- | --- |
| 2017 | 1,973 | 2,633 | --- | --- | --- | --- |
| 2018 | 2,123 | 2,877 | --- | --- | --- | --- |
| 2019 | 1,983 | 3,183 | --- | --- | --- | --- |
| 2020 | 2,013 | 3,344 | --- | --- | --- | --- |
| | | | 595.8 | 218.7 | | |

1/ Estimated costs of production only for the Railbelt utilities. Costs shown include an estimated amount for existing utility debt service allocated to generation and transmission

2/ Costs incurred prior to July 1, 1985, are not shown as those amounts were funded from other sources. Amount shown in 1988 is repayment from bond proceeds and assumed to be deposited into the Rate Stabilization Fund.

3/ Includes interest earnings on the Rate Stabilization Fund starting July 1, 1986. Interest earnings based on an assumed annual reinvestment rate of 10.0 percent.

TABLE D.4.5.1: (Page 2 of 2)

**COMPOSITE FORECAST**

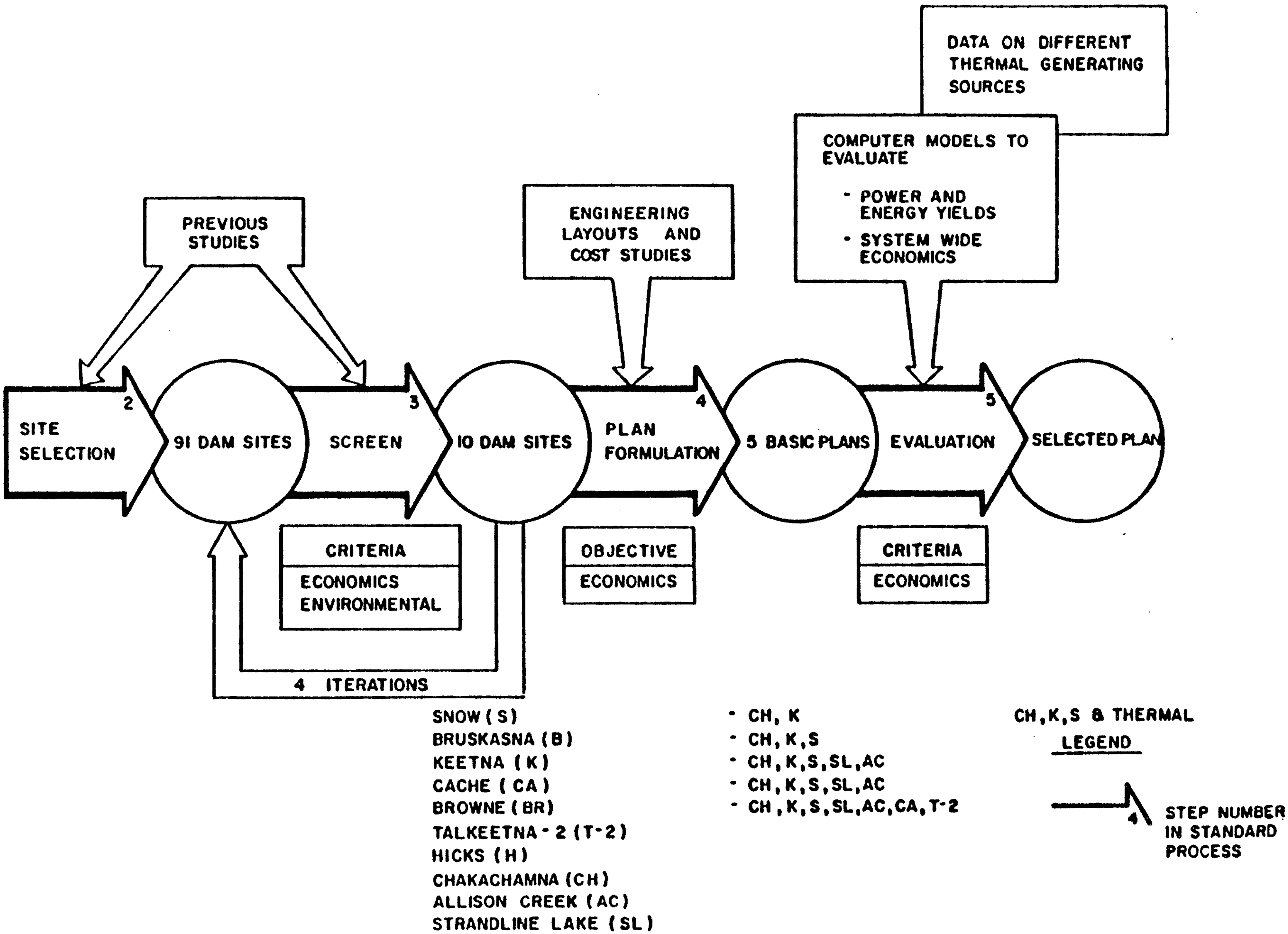
| YEAR | SYSTEM COSTS W/SUSITNA 1/ | SYSTEM COSTS W/O SUSITNA 1/ | RATE STABILIZATION REQUIRED | STATE CONTRIBUTION | COSTS PRE-BOND ISSUANCE 2/ | ACCRUED STATE CONTRIBUTIO |
|---|---|---|---|---|---|---|
| 1985 | 121 | 121 | --- | 100.0 | 16.8 | 83.2 |
| 1986 | 124 | 124 | --- | 118.7 | 28.0 | 181.9 |
| 1987 | 131 | 131 | --- | --- | 32.6 | 165.9 |
| 1988 | 145 | 145 | --- | --- | 39.3 | 141.9 |
| 1989 | 159 | 159 | --- | --- | 85.6 | 86.8 |
| 1990 | 167 | 167 | --- | --- | 91.0 | 0.0 |
| 1991 | 176 | 176 | --- | --- | (239.6) | 251.3 |
| 1992 | 187 | 187 | --- | --- | --- | 276.4 |
| 1993 | 200 | 200 | --- | --- | --- | 304.1 |
| 1994 | 286 | 286 | --- | --- | --- | 334.5 |
| 1995 | 321 | 321 | --- | --- | --- | 367.9 |
| 1996 | 336 | 336 | --- | --- | --- | 404.7 |
| 1997 | 361 | 361 | --- | --- | --- | 445.2 |
| 1998 | 390 | 390 | --- | --- | --- | 489.7 |
| 1999 | 846 | 755 | 91.0 | --- | --- | 443.3 |
| 2000 | 900 | 802 | 98.0 | --- | --- | 384.8 |
| 2001 | 926 | 834 | 92.0 | --- | --- | 326.8 |
| 2002 | 969 | 868 | 101.0 | --- | --- | 253.5 |
| 2003 | 1,001 | 923 | 78.0 | --- | --- | 197.1 |
| 2004 | 1,043 | 962 | 81.0 | --- | --- | 131.8 |
| 2005 | 1,239 | 1,159 | 81.0 | --- | --- | 60.1 |
| 2006 | 1,275 | 1,212 | 63.0 | --- | --- | --- |
| 2007 | 1,353 | 1,489 | --- | --- | --- | --- |
| 2008 | 1,415 | 1,555 | --- | --- | --- | --- |
| 2009 | 1,364 | 1,642 | --- | --- | --- | --- |
| 2010 | 1,431 | 1,899 | --- | --- | --- | --- |
| 2011 | 1,487 | 1,967 | --- | --- | --- | --- |
| 2012 | 1,857 | 2,042 | --- | --- | --- | --- |
| 2013 | 1,911 | 2,117 | --- | --- | --- | --- |
| 2014 | 1,914 | 2,205 | --- | --- | --- | --- |
| 2015 | 1,919 | 2,302 | --- | --- | --- | --- |
| 2016 | 1,925 | 2,409 | --- | --- | --- | --- |
| 2017 | 1,941 | 2,577 | --- | --- | --- | --- |
| 2018 | 1,996 | 2,722 | --- | --- | --- | --- |
| 2019 | 1,978 | 2,769 | --- | --- | --- | --- |
| 2020 | 1,985 | 3,044 | --- | --- | --- | --- |
| | | | 684.5 | 218.7 | | |

1/ Estimated costs of production only for the Railbelt utilities. Costs shown include an estimated amount for existing utility debt service allocated to generation and tranmission.

2/ Costs incurred prior to July 1, 1985, are not shown as those amounts were funded from other sources. Amount shown in 1988 is repayment from bond proceeds and assumed to be deposited into the Rate Stabilization Fund.

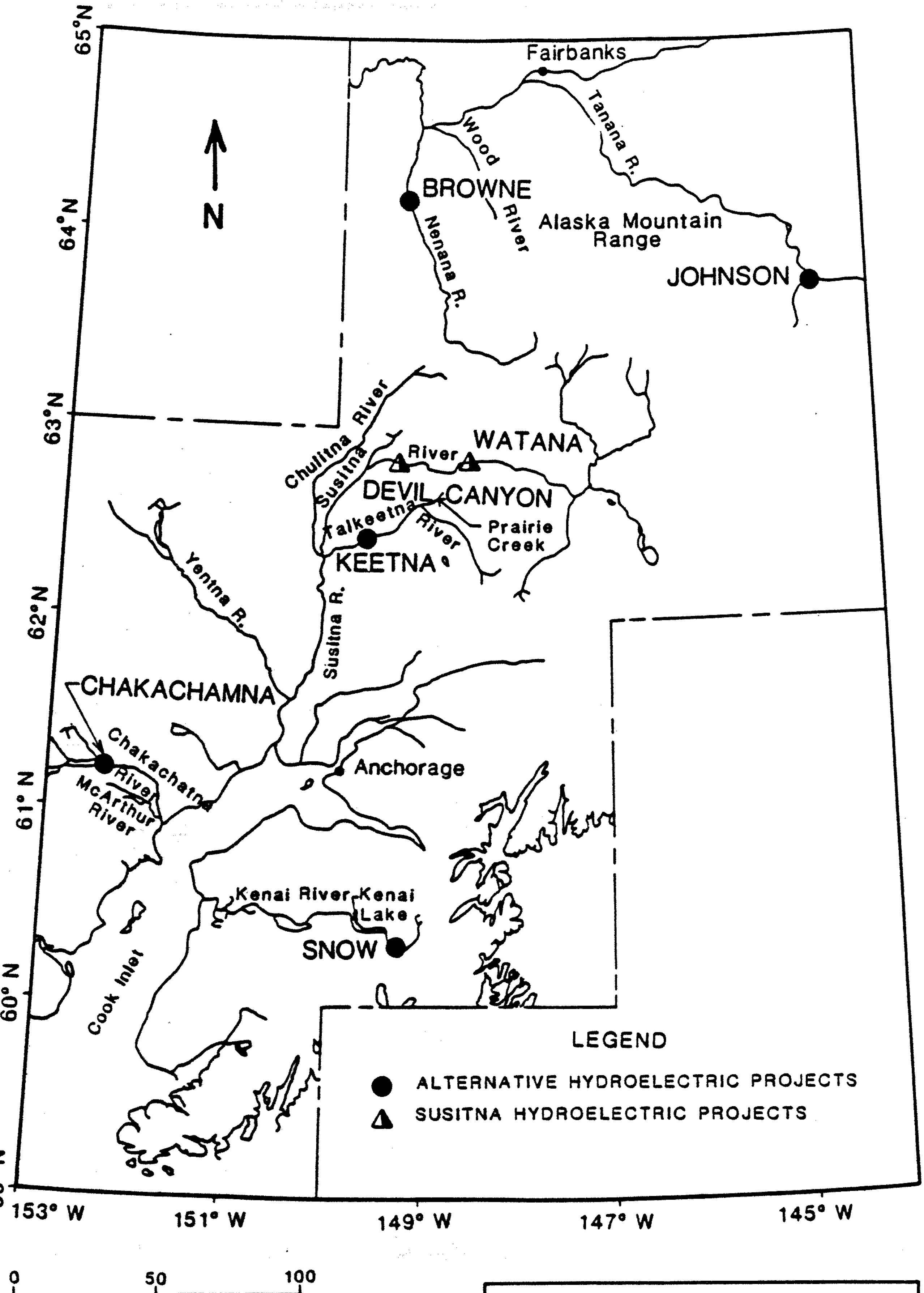
3/ Includes interest earnings on the Rate Stabilization Fund starting July 1, 1986. Interest earnings based on an assumed annual reinvestment rate of 10.0 percent.

# FIGURES



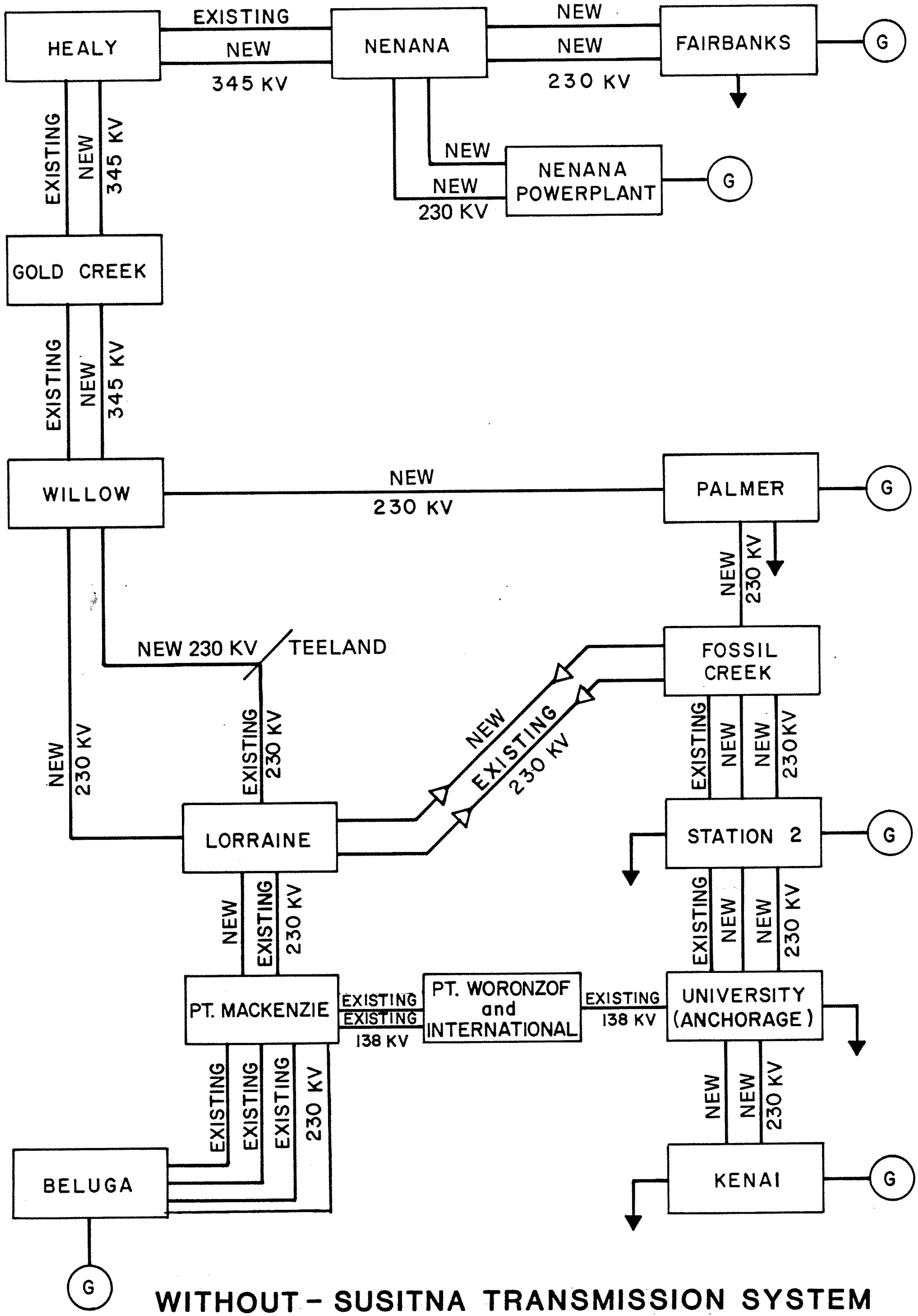

FORMULATION OF PLANS
INCORPORATING NON-SUSITNA HYDRO GENERATION

FIGURE D.2.2.1



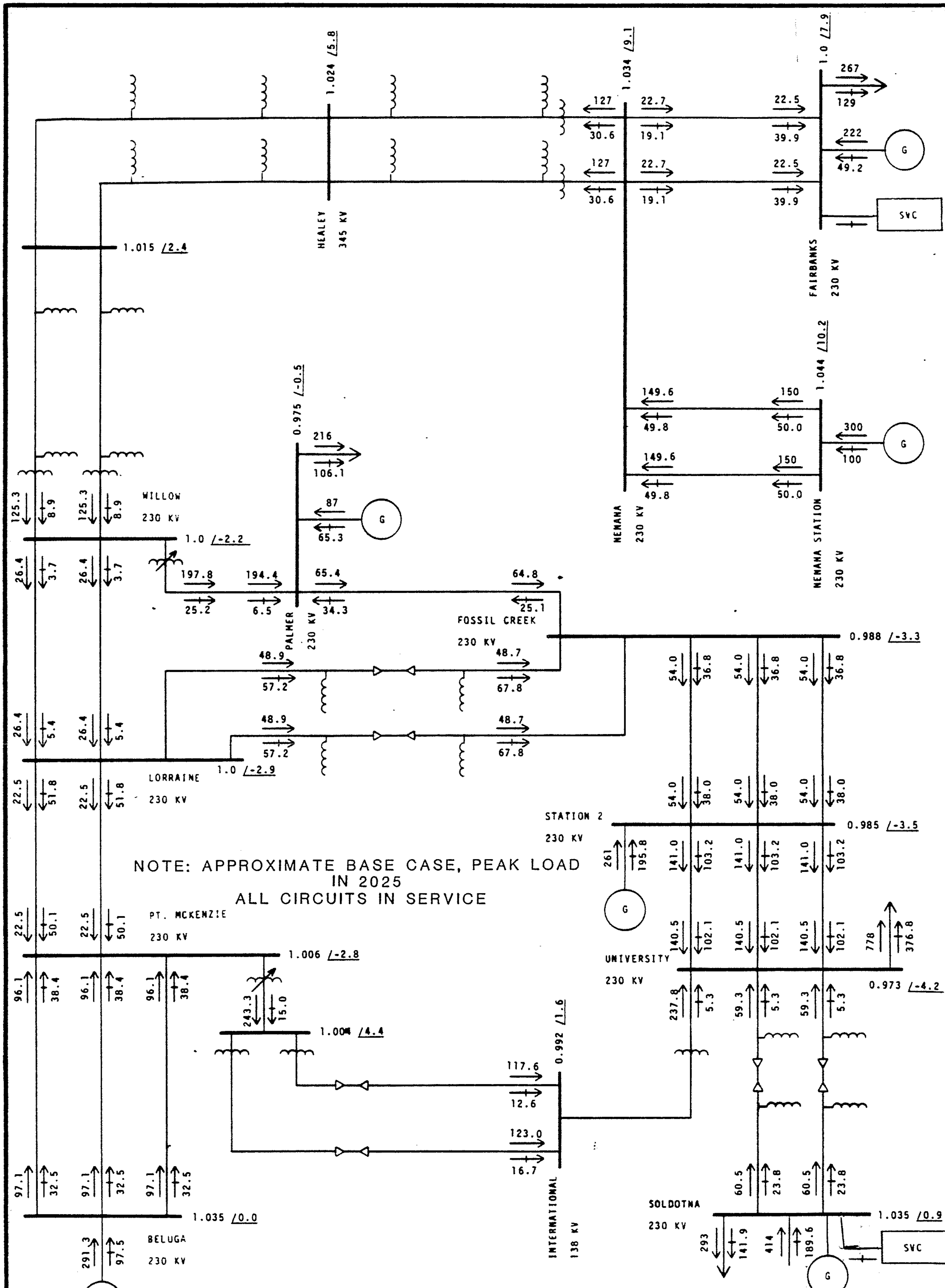

ALTERNATIVE
HYDROELECTRIC PROJECTS
LOCATION PLAN

FIGURE D.2.2.2



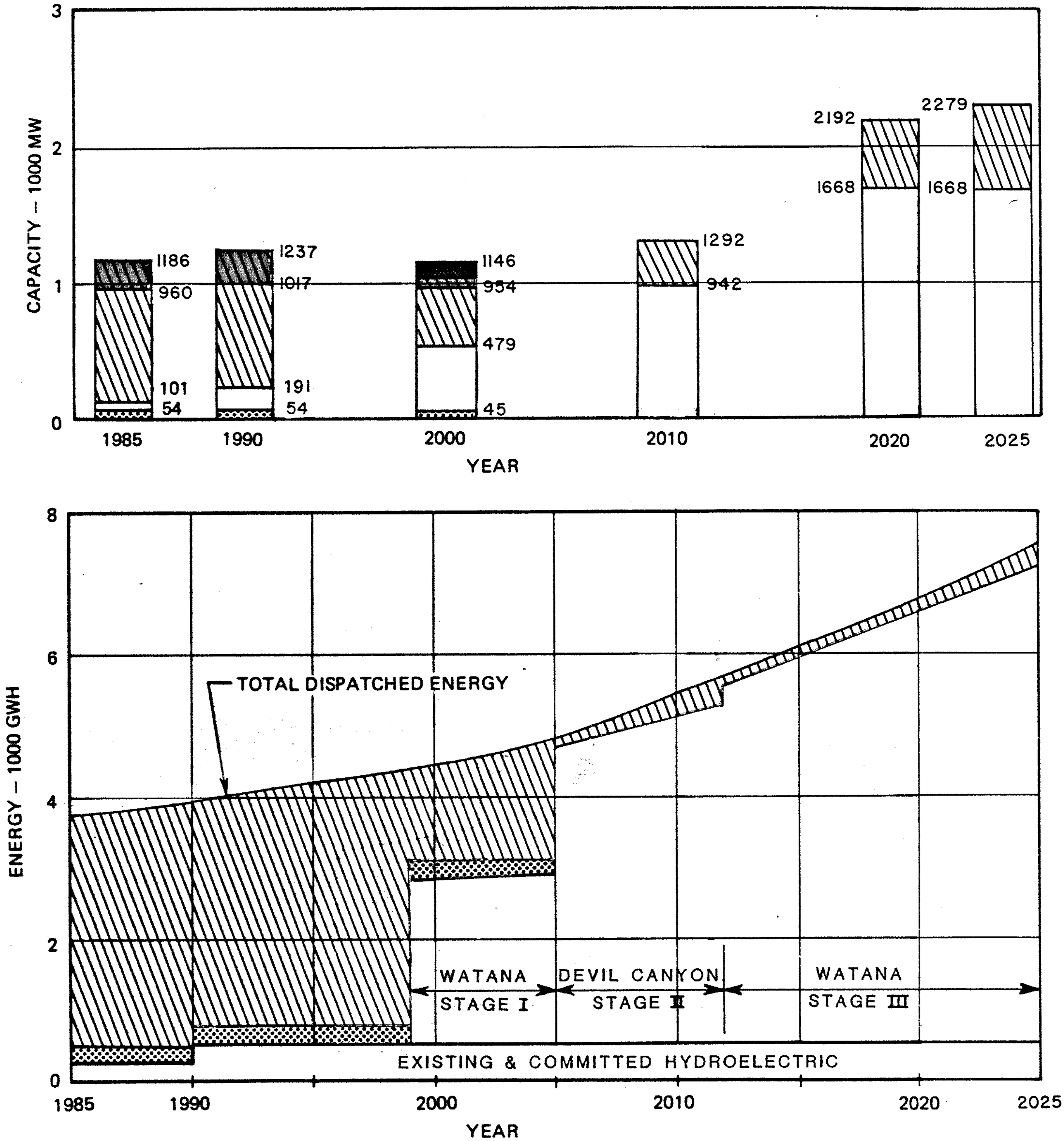

WITHOUT - SUSITNA TRANSMISSION SYSTEM

FIGURE D.2.9.1




# WITHOUT-SUSITNA TRANSMISSION RELIABILITY STUDIES

**FIGURE D.2.9.2**

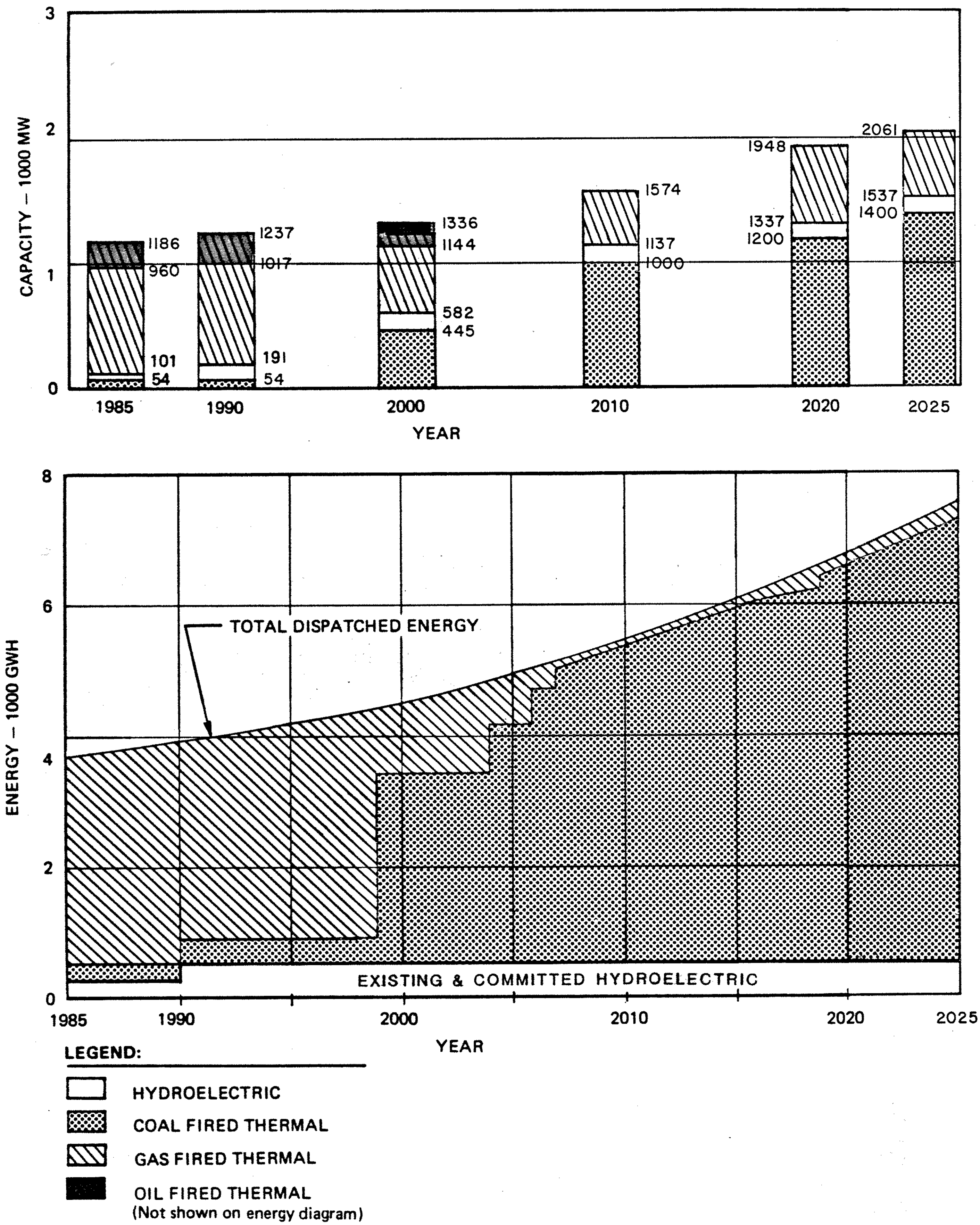



**LEGEND:**

- HYDROELECTRIC
- COAL FIRED THERMAL
- GAS FIRED THERMAL
- OIL FIRED THERMAL (Not shown on energy diagram)

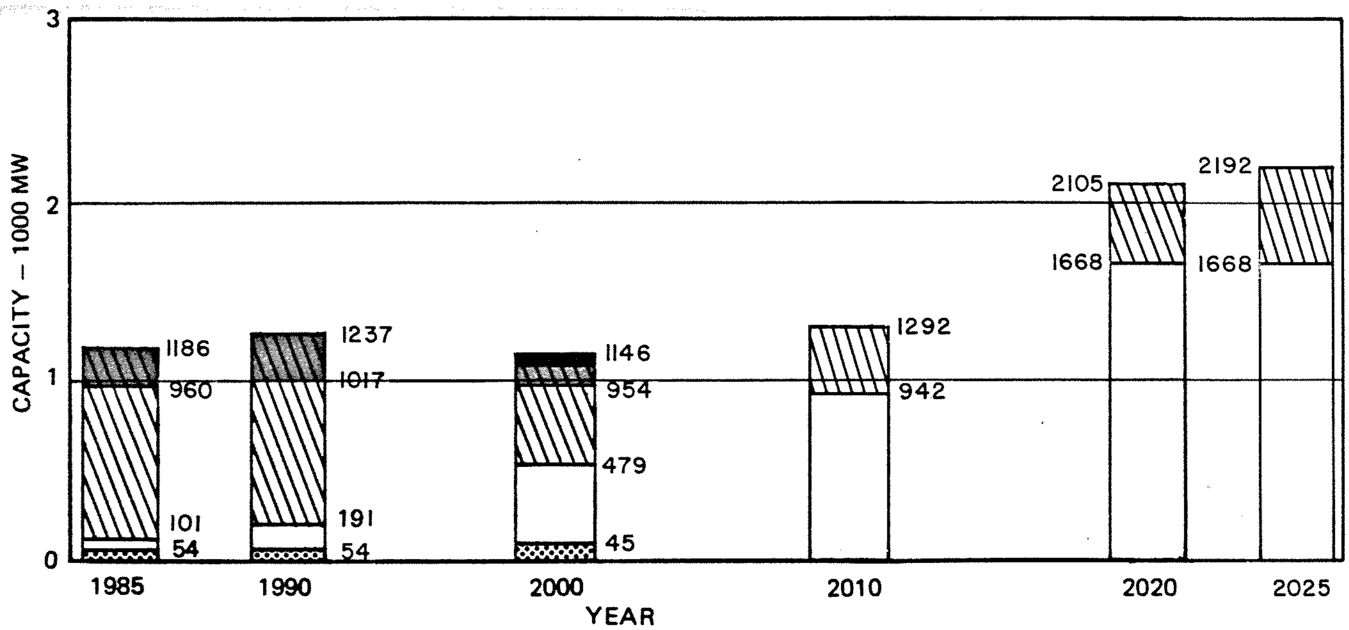
**WITH - SUSITNA**
**ALTERNATIVE GENERATION SCENARIO**
**SHCA LOAD FORECAST**

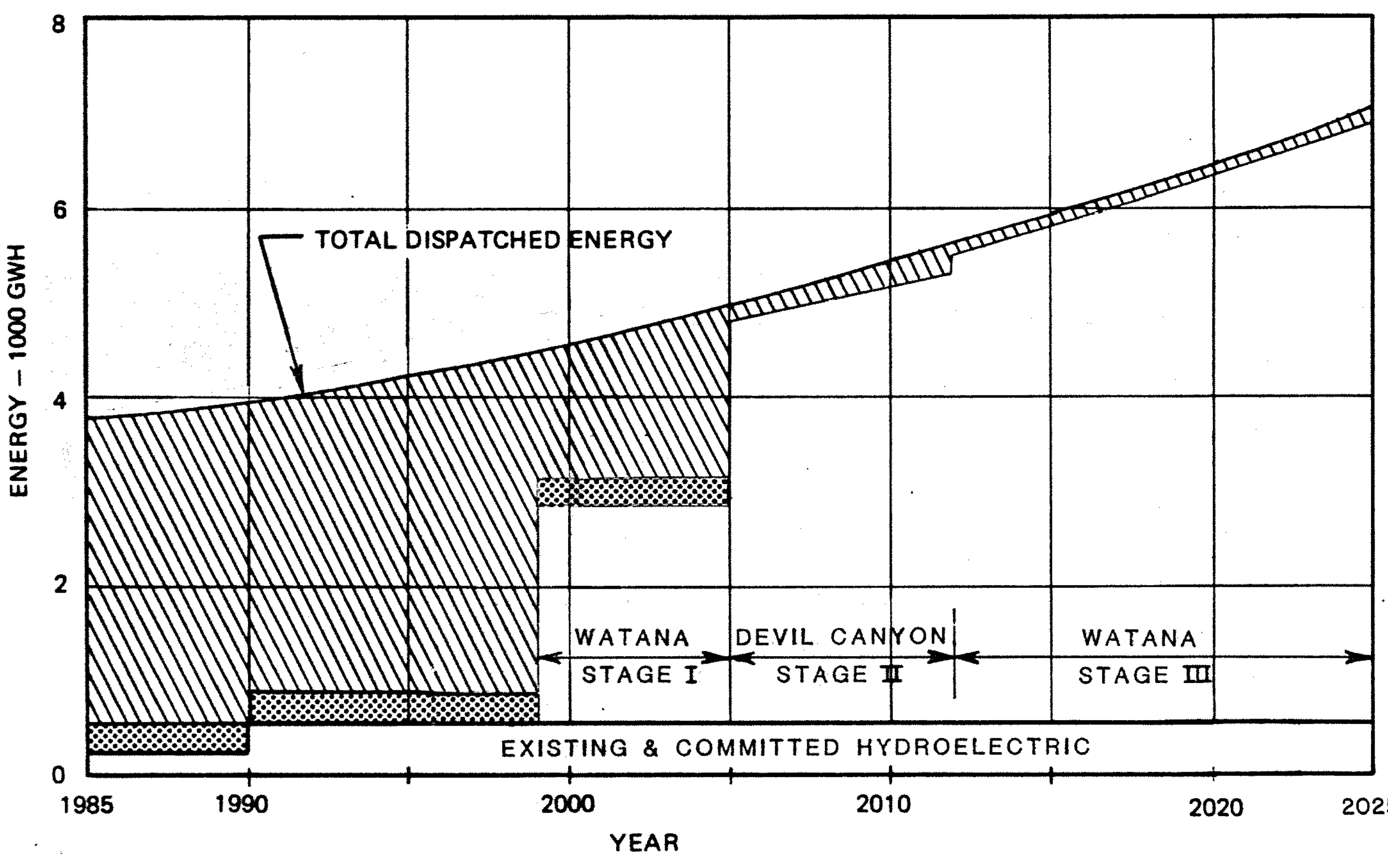
**FIGURE D.2.9.3**




**WITHOUT - SUSITNA**
**ALTERNATIVE GENERATION SCENARIO**
**SHCA LOAD FORECAST**

**FIGURE D.2.9.4**




**LEGEND:**

HYDROELECTRIC

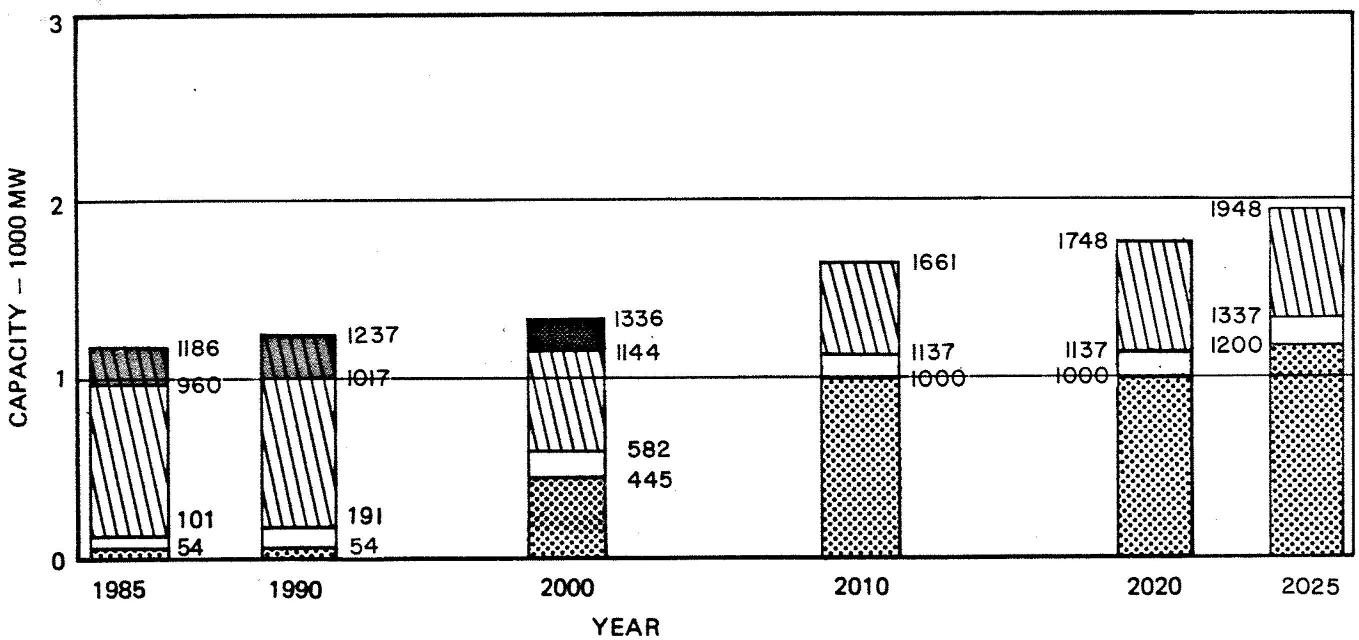
COAL FIRED THERMAL

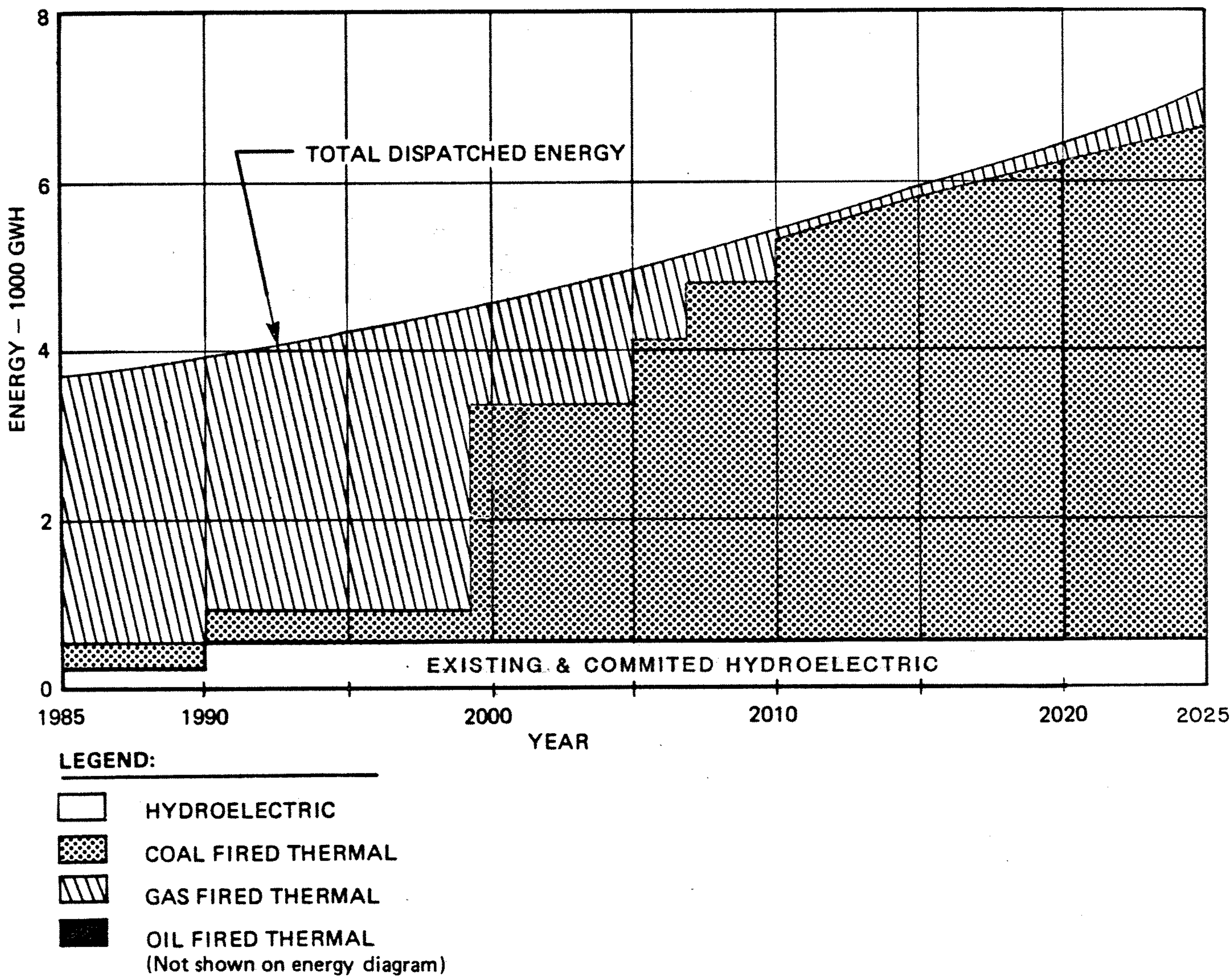
GAS FIRED THERMAL

OIL FIRED THERMAL
(Not shown on energy diagram)

**WITH - SUSITNA**
**ALTERNATIVE GENERATION SCENARIO**
**COMPOSITE LOAD FORECAST**

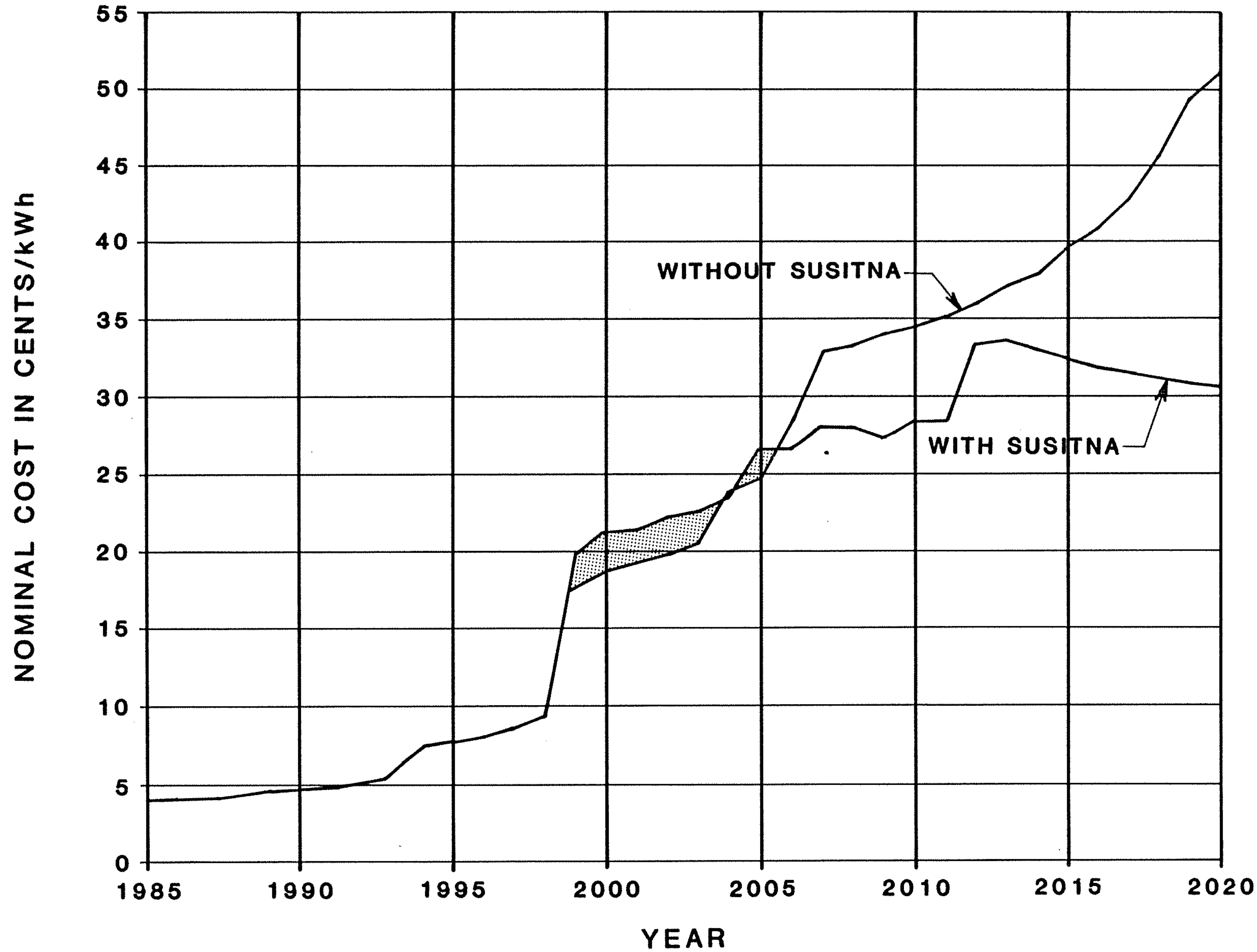
**FIGURE D.2.9.5**



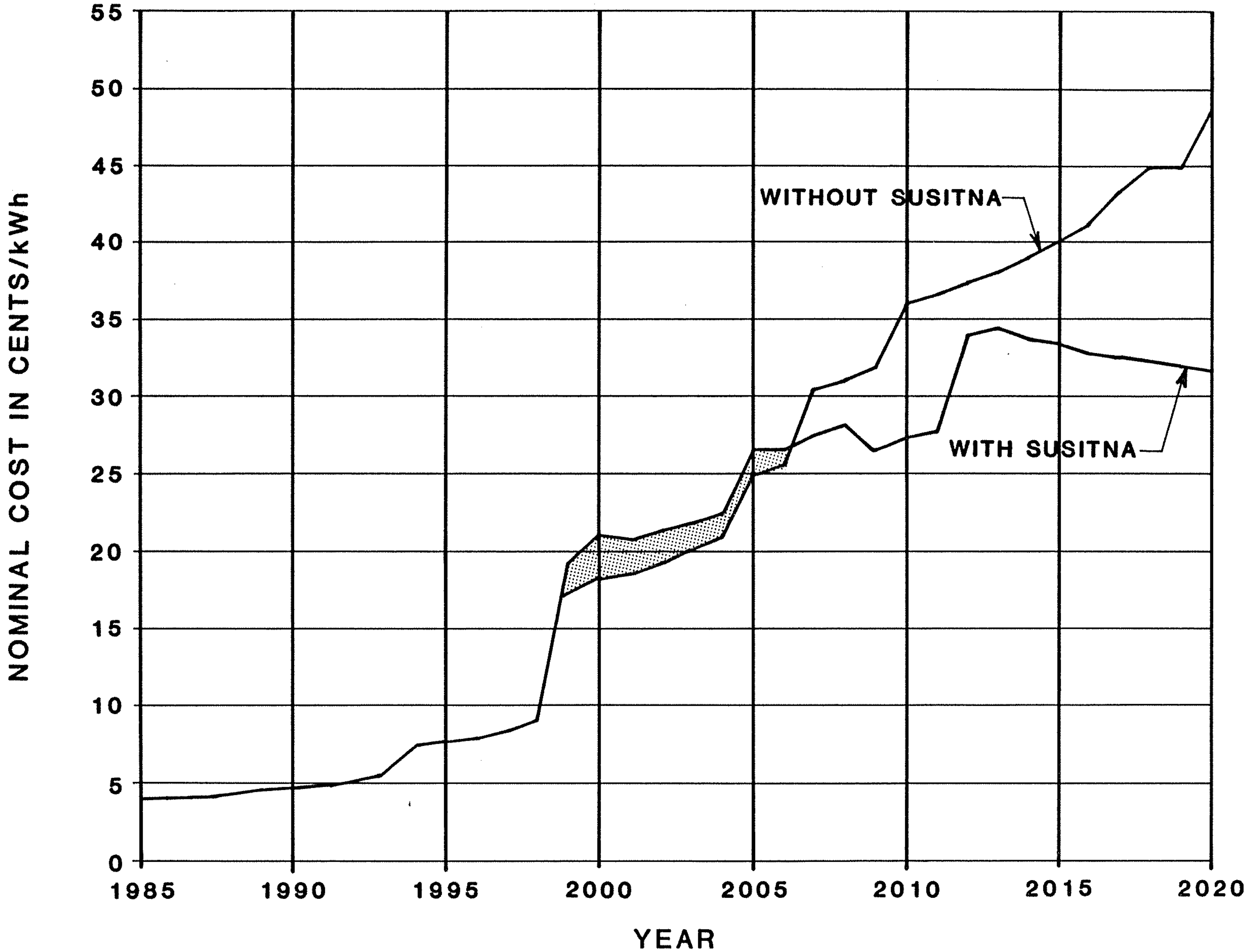

**WITHOUT - SUSITNA**
**ALTERNATIVE GENERATION SCENARIO**
**COMPOSITE LOAD FORECAST**

**FIGURE D.2.9.6**




COMPARISON OF NOMINAL COST OF ENERGY
SHCA LOAD FORECAST

FIGURE D.4.5.1
(PAGE 1 OF 2)




COMPARISON OF NOMINAL COST OF ENERGY
COMPOSITE LOAD FORECAST

FIGURE D.4.5.1
(PAGE 2 OF 2)

# D1 - FUELS PRICING

SUSITNA HYDROELECTRIC PROJECT
LICENSE APPLICATION

APPENDIX D1
FUELS PRICING

TABLE OF CONTENTS

**APPENDIX D1**
**FUELS PRICING**

## LIST OF TABLES

## APPENDIX D1
## FUELS PRICING

LIST OF TABLES (cont'd)

## APPENDIX D1
## FUELS PRICING

### LIST OF FIGURES

APPENDIX D1
FUELS PRICING

## 1 - INTRODUCTION

The Susitna Project, when constructed, will be the heart of a modern system generating electricity for an integrated Railbelt electricity grid. The Susitna Project therefore must be evaluated on a system-wide basis comparing the costs of the system with Susitna to those of the system that would evolve if Susitna is not built.

To determine whether the Susitna-based system expansion plan compares favorably with its alternatives, the Alaska Power Authority (APA) has constructed and evaluated an optimal least cost Without-Susitna plan of generation capacity necessary to meet projected Railbelt electricity demand over the 1985-2025 expansion planning period.

Exhibit D, Chapter 2, Section 2.9.2, of this application describes the alternative expansion plan in considerable detail. To summarize, the Power Authority has determined that a combination of thermal power plants using coal and natural gas are the indicated components of a Without-Susitna Railbelt electricity generation system. Through the use of the Optimized Generation Planning (OGP) model, (described in Exhibit D), the Power Authority has constructed a thermal-based alternative expansion plan in which necessary incremental additions to capacity beyond currently planned projects are selected from among the feasible thermal alternatives. This selection is based upon a comparison of the long-term costs of the thermal power plant options, evaluated at such time as increased demand would warrant additions to generation capacity. Because fuel costs are major components of the cost of a system based primarily on thermal power, the Power Authority has developed a supporting analysis of fuel costs which is set out in this Appendix D1.

## 2 - WORLD OIL PRICE

Of special significance to the Applicant's fuel cost analysis is the projected world price of crude oil. Oil-fired power generation is not likely to be widely used for Railbelt electricity production. However, forecasted world oil price directly influences cost assumptions with respect to all fuels assumed to be available in the thermal alternative case. As described more fully below, the forecasted world price of oil in large measure drives the forecasted price of natural gas, and also influences some components of the projected cost of coal.

Forecasting any future series of oil prices is subject to uncertainties that are characteristic of commodity markets generally, and oil markets in particular. To reduce the risks associated with this uncertainty, the Power Authority has evaluated the Susitna project against the background of two different oil price forecasts: 1) the forecast of Sherman H. Clark Associates (SHCA) which has been used as a basis for this case in previous documents (e.g., Appendix 1 of the Alaska Power Authority comments on the FERC DEIS, August 1984) and 2) a composite of six independent oil price forecasts published in 1985 by private organizations and public agencies. A forecast developed by Wharton Econometrics (Wharton), which shows a somewhat lower price path than either of the other two forecasts is used as a low sensitivity analysis.

### 2.1 - The Sherman H. Clark Associates Forecast

The SHCA forecast has been used as a basis for the Power Authority's analysis of the Susitna hydroelectric project in prior submissions to the FERC (e.g., Appendix 1 of the comments on the Draft Environmental Impact Statement filed August, 1984, and the July, 1983, License filing). Earlier iterations of the forecast are described in the comments on the DEIS prepared in August 1984. The forecast was updated by the Power Authority in February 1985 for the Alaska Power Authority (SHCA, 1985). That update forecast was made in 1984 dollars. It has been restated, in January 1985 dollars, using the GNP Implicit Price Deflator series (the conversion factor is 1.0252). The results are shown below:

| Year | SHCA Forecast (1985$/bbl) |
|---|---|
| 1985 | $26.09 |
| 1986 | 27.68 |
| 1987 | 27.68 |
| 1988 | 27.68 |
| 1989 | 27.68 |
| 1990 | 27.68 |
| 1995 | 32.80 |
| 2000 | 41.00 |

| Year | SHCA Forecast (1985$/bbl) |
|---|---|
| 2010 | 61.50 |
| 2020 | 85.00 |
| 2030 | 96.00 |
| 2040 | 106.00 |
| 2050 | 117.00 |

The analytic reasoning supporting the SHCA forecast is summarized as follows:

- The free world economy is projected to grow in real terms at a long-term rate of about three percent, and this will increase total demand for energy of all forms (at growth rates of less than three percent/year);
- Real world oil prices will decline slightly and then stabilize or flatten in real terms during the remainder of this decade;
- During this period, the incentive to cheat among OPEC nations will diminish, and OPEC will continue to hold a significant market position; and
- By the next decade, non-OPEC oil production will face serious limitations based upon stable and potentially declining reserves, and will flatten out in the 22.5-23.0 million barrels/day range. OPEC market power will increase in the 1990s and beyond as a consequence of their position as the marginal oil producer.

The Without-Susitna thermal alternative plan which results from using the SHCA forecast is presented in Exhibit D, Section 2.9.2.

## 2.2 - The Composite Oil Price Forecast

In addition to using the SHCA forecast, the APA has evaluated the Susitna project or system on the basis of a composite forecast which represents the average of a range of independent forecasts. The use of such a composite provides a means for reflecting mainstream oil price forecasting opinion and avoids the risk of reliance upon a position that is significantly above or below the mainstream of informed opinion.

In developing its composite, the APA considered as a point of departure, a recent survey of forecasts published by the International Energy Workshop (IEW) (Manne and Schrattenholzer 1985). The survey included 36 organizations forecasting oil prices to the year 1990, 33 organizations forecasting oil prices to the year 2000, and 11 organizations making projections to the year 2010. The forecasts were made during the period 1983-85. The median values shown in the International Energy Workshop survey of forecasts published during 1984-1985 are shown below.

| Year | Forecast (1985$/bbl) |
|---|---|
| 1990 | $39.14 |
| 2000 | 47.67 |
| 2010 | 61.66 |

What becomes apparent, from an analysis of the survey, is that the European forecasts tend to be higher than the U.S. forecasts due to intermingling of oil price effects and currency effects. Accounting for this currency effect will produce a higher price trend. It is significant that oil price forecasts have been dropping steadily over the last four years (Manne and Schrattenholzer 1985). The median oil price as forecast for the year 2000 has declined as follows:

| Date of IEW Survey | Approximate Index Value | Approximate Year 2000 Forecast (1985$/bbl) |
|---|---|---|
| December 1981 | 175 | $76.00 |
| July 1983 | 150 | 65.00 |
| January 1985 | 109 | 48.00 |

On this basis, three minimum criteria were established for developing a composite oil price forecast appropriate for this analysis:

- o The forecasting organization must be based in the U.S. to avoid the intermingling of price and currency effects;
- o The forecast must have been performed in 1985 to incorporate recent experience and to account for current trends; and
- o To be meaningful for Power Authority planning purposes, the forecast must extend at least to the year 2010.

In developing these criteria and in selecting from among available forecasts, the Power Authority seeks to devise a composite which is representative of the weight of current forecasting opinion. It is also considered desirable to have represented in the composite a variety of forecasting techniques (econometric, scenario, and Delphic).

With these objectives in mind, the following forecasts were selected in the present analysis:

- Sherman H. Clark Associates (SHCA)
- Wharton Econometrics (Wharton)
- U.S. Department of Energy (USDOE)
- Data Resources Inc. (DRI)
- Cambridge Energy Research Group (CERG)
- Alaska Department of Revenue (ADOR)

World Oil Price by Forecast (1985 $/bbl)

| | Year | | | |
|---|---|---|---|---|
| Forecaster | 1985 | 1990 | 2000 | 2010 |
| SHCA (1) | $28.09 | $27.68 | $41.00 | $61.50 |
| Wharton (2) | 27.12 | 24.80 | 31.26 | 40.65 |
| USDOE (3) | -- | 28.34 | 46.14 | 71.94 |
| DRI (3) | 27.83 | 24.29 | 37.91 | 50.95 |
| CERG (3) | -- | 34.28 | 52.48 | 61.22 |
| ADOR (4) | 25.50 | 19.21 | 20.03 | 21.26 |
| AVERAGE/COMPOSITE | 27.14 | 26.55 | 38.14 | 51.25 |
| Average Growth Rates (%/yr) | | | 1985-2010 | 2.6 |
| | | | 1990-2010 | 3.4 |
| | | | 2000-2010 | 3.0 |

(1) SHCA (1985).
(2) French (1985).
(3) Manne and Schrattenholzer (1985). All such forecasts are represented based upon their index values.
(4) Alaska Department of Revenue (1985).

The 3 percent annual growth rate forecast, shown above for 2000 to 2010, was used to extrapolate the composite forecast beyond the year 2010. In reality, 3 percent represents the approximate annual growth rate for all periods as calculated. The extrapolation is performed from the 2010 value to a level of $75/bbl. This ceiling level of $75/bbl is assumed to be the price at which synthetic fuel alternatives to petroleum products are freely available in the world economy (French 1985).

A composite forecast has been developed for the entire planning period, based on the average of prices forecast to the year 2010, the extrapolation percentage, and the assumed technological limit to world oil prices. This composite is shown below.

| Year | World Oil Price (1985$/bbl) |
|---|---|
| 1985 | $27.10 |
| 1990 | 26.50 |
| 1995 | 31.80 |
| 2000 | 38.10 |
| 2005 | 44.00 |
| 2010 | 51.00 |
| 2015 | 59.00 |
| 2020 | 69.00 |
| 2023 | 75.00 |
| . | . |
| . | . |
| . | . |
| 2050 | 75.00 |

The Without-Susitna thermal alternative plan which results from using the Composite forecast is presented in Exhibit D, Section 2.9.2.

## 2.3 - The Wharton Forecast

The Wharton Econometric Forecasting Associates (Wharton) forecast was selected for use as a lower sensitivity forecast to evaluate the Susitna hydroelectric project. The Wharton forecast is the lowest of the econometrically based analyses used in the composite. The Wharton forecast assumes declining or flat demand for oil in the near term, a phenomenon significantly suppressing demand for OPEC oil.

In the midterm (1986-1994), Wharton expects a modest decline, followed by a rebounding of oil prices as non-OPEC oil production reaches the full capacity of non-OPEC producers, as world oil demand begins rising, and as OPEC members outside the Gulf Cooperation Council begin producing at or near full capacity. From 1995-2005, Wharton projects a price increase, largely based upon economic growth. Beyond 2005, Wharton projects a three percent annual price increase in oil until a $75/bbl synthetic fuel price cap is reached.

Given the assumptions presented above, the Wharton forecast of world oil prices (expressed as the prices for Saudi light crude oil) is shown below (French 1985).

| Year | World Oil Price (1985$/bbl) |
|---|---|
| 1980 | $41.41 |
| 1985 | 27.12 |
| 1990 | 24.80 |
| 1995 | 27.64 |
| 2000 | 31.26 |

| Year | World Oil Price (1985$/bbl) |
|---|---|
| 2005 | 35.07 |
| 2010 | 40.65 |
| 2020 | 54.63 |
| 2030 | 73.42 |
| 2031 | 75.00 |
| . | . |
| . | . |
| . | . |
| 2050 | 75.00 |

The sensitivity analysis of the present worth of base and alternative generation plans based on the Wharton forecast are provided in Exhibit D, Section 2.11.1.

## 3 - NATURAL GAS

This section describes the Applicant's primary assumptions concerning the expected price and supply of natural gas that are used in the evaluation of the thermal alternative expansion plan.

### 3.1 - Cook Inlet Gas Prices

There are four components used to derive a natural gas price forecast: 1) definition of a pricing methodology, 2) development of a data base for price forecasting calculation, 3) calculation of the price forecast, and 4) confirmation of the price forecast. In developing a pricing forecast, it must be recognized that the problem is largely of a long-term nature. Short-term perturbations, therefore, are of less significance than the fundamentals and trends.

#### (a) Pricing Methodology

Several methods could be used to determine the price trend for natural gas, including: 1) netback pricing, 2) contract extrapolation, and 3) production costing. Of these options, the Power Authority believes netback pricing to be the most appropriate method for measuring natural gas prices over the long term.

Netback pricing is a means for estimating a value of any commodity at some point (e.g., wellhead). It has been accepted by the State of Alaska as a means for establishing the wellhead value of natural gas for royalty interest valuation purposes (see State of Alaska versus Phillips Petroleum Company, 1984, Joint Stipulation of Facts. Also State of Alaska versus Phillips Petroleum, 1984, Settlement Agreement). Netback pricing requires establishing a market value for any commodity, and then subtracting all costs associated with getting the commodity to market in order to establish a netback value.

Netback pricing of natural gas employs LNG to establish the marginal or economic value of natural gas. Ultimately, the economic value determines what consumers will pay unless regulation forces a lower price and a consequent underevaluation of the commodity. Currently, exported LNG provides the highest wellhead value of natural gas, and the highest value for royalty gas. The Power Authority believes that for long-term planning purposes it cannot be assumed that Cook Inlet gas will be priced at anything less than this economic value.

Evaluation of the market potential for LNG exports to the Pacific Rim must begin with an examination of Japanese markets. Over the last ten to fifteen years the Japanese have developed the institutions and infrastructure necessary to use LNG for industrial, commercial, and general fuel requirements. They have receiving/gasification facilities capable of handling tens of millions of tonnes/yr of LNG. The importation of LNG furthers explicit Japanese policy to develop alternative energy sources including nuclear, coal, and LNG in response to the political unpredictability of the Middle East (Itoh, 1985). At the same time, oil will remain an important fuel (Itoh, 1985). Forecasts of MITI reported by Itoh (1985), Marubeni (1984), and others show oil consumption as flat in absolute terms, with LNG and other fuels assuming increasing shares of the market.

LNG has the advantage of supplying a clean burning fuel to urban areas (Marubeni, 1984). Its anti-pollution aspects make it highly desirable to general industry in Japan (Marubeni, 1984).

Because LNG is a highly desirable fuel in Japan, national policy has been reinforced with credits by the Export-Import Bank of Japan, by loans from the Development Bank of Japan, by exemptions from import duties, and by loans for LNG users (Hickel, et al., 1983). Institutionally, then, LNG has been embedded into the Japanese economy.

The LNG market in Japan is substantial, having grown from pioneer beginnings in 1969-70 to its current relatively mature state (Sumitomo 1985). Historical LNG consumption in Japan is summarized below based upon data contained in Marubeni (1984).

| Year | Japanese LNG Consumption (thousand tonnes) | (trillion Btu) |
|---|---|---|
| 1969 | 167 | 8.8 |
| 1970 | 958 | 50.4 |
| 1972 | 955 | 50.2 |
| 1974 | 3,775 | 198.6 |
| 1976 | 5,909 | 310.8 |
| 1978 | 11,519 | 605.9 |
| 1980 | 16,779 | 882.6 |
| 1982 | 17,584 | 924.9 |

That growth trajectory is impressive. The annual rate of growth shown above is 43 percent. Even the growth before the oil embargo is significant.

The dimensions of the future LNG market in Japan are equally impressive. Forecasts by the Japanese Ministry of International Trade and Industry (MITI) as quoted by C. Itoh & Co., Ltd. (1985) are shown below:

| Year | Japanese LNG Imports (million tonnes) | (quadrillion Btu) | TCF |
|---|---|---|---|
| 1982 (1) | 17.6 | 0.93 | 0.88 |
| 1990 | 36.5 | 1.92 | 1.83 |
| 1995 | 40.0 | 2.10 | 2.00 |

(1) Actual historical values.

Current country-by-country market shares measured by capacity are shown below (C. Itoh & Co., Ltd. 1985):

| Country | Japanese LNG Imports (thousand tonnes) | | Percent | |
|---|---|---|---|---|
| USA (Alaska) | | 960 | | 3.2 |
| Brunei | | 5,140 | | 17.1 |
| Abu Dhabi | | 2,860 | | 9.5 |
| LNG | 2,060 | | 6.8 | |
| LPG | 800 | | 2.7 | |
| Indonesia | | 15,180 | | 50.4 |
| Malaysia | | 6,000 | | 19.9 |
| TOTAL | | 30,140 | | 100.1 |

Alaska is thought to be in a favorable position to increase its exports of LNG to Japan. Increased LNG shipments from Alaska to Japan would be consistent with the Japanese strategy of energy supply diversification (Hickel, et al., 1983). Further, it is reasonably close to Japan (3,200 nautical miles versus 3,300 nautical miles for Arun, Indonesia, and 6,500 nautical miles for Abu Dhabi), and its shipments are cost competitive (Mitsui and Co. 1985). Alaska, as part of the U.S., represents a source of supply that is politically stable, and stability among energy suppliers to Japan is considered an objective along with cost competitiveness (Itoh, 1985). Alaska exports of LNG also could contribute to a redressing of the balance of payments difficulties between the U.S. and Japan (Hickel, et al., 1983). The calorific value of Alaska's gas is slightly higher than the calorific value of competing LNG products when measured on a heat content per unit mass basis (Mitsui and Co. 1985).

During this century, LNG opportunities outside Japan will be limited. However, Korea has signed a contract to import 2 million tonnes/yr of LNG from Indonesia (equal to 100 BCF of gas or 103 x $10^{12}$ Btu) and is seeking an additional 1 million tonnes/yr of gas (equal to 50 BCF/yr) from another source (Marubeni 1984). Taiwan is also progressing toward LNG imports (Marubeni 1984). Korea, like Japan, follows a strategy of energy resource diversification.

The long term forecast reported by Marubeni (1984) from the Central Research Institute of Electric Power Industry (CRIEPI) in Japan calls for demand of 42 million tonnes of LNG in the year 2000. Beyond the year 2000 there is little quantitative data available and the Marubeni report suggests caution in projecting market growth for LNG beyond the year 2000.

Notwithstanding the above-noted limitations with respect to the ability to forecast long-term demand in LNG markets, the Power Authority believes that netback pricing is a reasonable methodology given the available market data. Moreover, netback pricing has a sounder analytic footing than either of the alternative methodologies available for this purpose -- (1) pricing by reference to existing clients, or (2) pricing by reference to estimates of future natural gas production costs.

With respect to contract pricing, only a few contracts (Enstar-Shell, Marathon-Shell, and Phillips) have been entered into in the last several years. Of these, the Phillips contract uses a netback methodology. The others employ a methodology under which price is redetermined periodically by reference to the price of distillate fuel oil. But, while it is clear that the price of distillate fuel oil is the economic basis for the price escalator provisions, neither the contract terms nor information otherwise available offer any basis for understanding the source of the base contract price. As might be expected, the Enstar-Shell and Marathon-Shell contracts appear to be the product of individual negotiations, and there is no basis upon which to determine whether the factors governing the development of those contract terms may be generally applicable to future circumstances. As a result, such agreements make particularly unreliable tools for forecasting prices for long-term future periods, particularly for periods beyond the term of the contract.

The Power Authority has also concluded that production costing is not a reliable method for forecasting the price of natural gas. This is due largely to the substantial uncertainties associated with geologic data supporting reserve estimates, a factor that significantly affects the accuracy of production costs. Past regulatory attempts at the federal level to determine future production costs of natural gas have been an adject failure and have been abandoned. The consequence is that natural gas production costs cannot be reliably estimated for pricing purposes.

(b) The Database for Netback Calculation

In order to establish a netback price for natural gas, it is necessary to determine a market value for this commodity at the point of delivery. That market value is considered to be the world price of crude oil delivered in Japan. The relationship between LNG and world oil prices is evident in contractual terms, (see Thirteenth Amendatory Agreement to Liquefied Natural Gas Sales Agreement between Tokyo Electric Power Company, Inc., Tokyo Gas Company, Ltd., Marathon Oil Company, and Phillips Petroleum Company, effective April 1, 1982, and the Supplementary Administrative Memorandum), as summarized in Table D1.3.1. This relationship is further shown by C. Itoh and Co. (1985) and by Mitsui and Co. (1985).

The value of the gas as sold, then, can be derived from projections of the world oil price. It should be noted that LNG will compete for gas supplies with urea and with other uses. In order for ammonia and urea manufacture to exist into the 21st century, they must be capable of paying the same price for natural gas as LNG producers. In such cases, LNG will set a floor for market pricing of natural gas previously, in \$/bbl. They are recast in terms of \$/MMBtu in Table D1.3.2 employing the world oil price values discussed in Section 2.0 of this analysis.

Given the values of natural gas in Japan, it is necessary to calculate the costs of liquefying that gas, transporting it, and then regasifying it for use. These costs include capital related charges, nonfuel operating and maintenance costs, and fuel costs. The liquefaction and regasification facilities can be accumulated into a production facilities category. Fuel costs can be disaggregated from nonfuel costs. This leaves a generic formula as follows:

Value of Gas in Japan

$$G_w = G_j - (C+O)_{l,r} - C_f - C_t \qquad (1)$$

where $G_w$ is the value of the gas at the wellhead; $G_j$ is the value of the gas in Japan (equal to the value of crude oil in Japan on a \$/Btu x $10^6$ basis); $(C+O)_{l,r}$ is the capital and (non-fuel) operating costs of liquefaction and regasification; $C_f$ is the fuel costs associated with liquefaction and regasification, and $C_t$ is the cost of gas transportation. All terms identified above are expressed in 1985\$/Btu x $10^6$.

(i) Nonfuel Liquefaction and Regasification Costs

Nonfuel liquefaction and regasification costs vary depending upon whether the facility is existing or new. Existing plants have depreciated capital investments and therefore have lower capital recovery costs. New facilities must provide for full capital recovery. New facility netback costs are of more relevance here, due to the long-term nature of the forecast.

Liquefaction and regasification costs for this analysis have been estimated based upon the TAGS report (Hickel, et al., 1983). The TAGS data, however, are for a system gasifying 950-2,830 MMCF/day of (raw) natural gas, and shipping 740-2,190 MMCF/day to Japan. Further, the TAGS report assumed use of existing regasification facilities in Japan. Finally, the data were provided in 1982 dollars. The following modifications were made to the TAGS data: 1) the plant was scaled back to 200 MMCF/day output, consistent with the size of the current Phillips plant and the CIRI proposal (Tarrant 1985); 2) regasification facilities were added to all costs; and 3) costs were updated to January 1985 dollars. The exponential scaling factors employed were 0.83 for capital investments and 0.91 for operating costs. These were derived directly from the TAGS report (Hickel, et al., 1983). Regasification costs were based upon Purvin and Gertz (1983) data. Updating was based upon the Chemical Engineering Plant Cost Index for capital costs, and the GNP implicit price deflator series for operating costs.

Table D1.3.3 summarizes the nonfuel production costs for an LNG facility based upon the estimating procedure described above. Also shown in Table D1.3.3 are the fuel costs required for the liquefaction and regasification operations.

In order to convert the data in Table D1.3.3 into a levelized nonfuel cost associated with production operations, certain financial assumptions were made. The project life was assumed to be 20 years (Hickel, et al., 1983). The accelerated cost recovery period was assumed to be 5 years. A real (inflation-free) cost of capital of 9.9 percent was calculated based upon data obtained from Value Line Investment Survey for the following sample of energy companies: ARCO, Chevron, Exxon, Mobil, Phillips, Sohio, and Tenneco.

Inflation was assumed at 5.5 percent. The total state and federal tax rate was assumed to be 51 percent (Hickel, et al., 1983).

The cost and financial data presented above led to a long term nonfuel liquefaction and regasification cost of $2.15/MMBtu of LNG. The individual cost components of this value are shown in Table D1.3.4.

(ii) Transportation Costs

The TAGS report estimated a cost of $1.00/MMBtu in 1988 for transporting LNG from the Kenai Peninsula to Japan. Their cost was deescalated to 1982 dollars at their assumed inflation rate of 7 percent/yr, and then inflated to 1985 dollars by the GNP implicit price deflator series. This procedure yielded a base transport cost of 74¢/MMBtu. Transportation costs were escalated/deescalated at 50 percent of the rate of change for fuel costs. This 50 percent factor represented the split between fuel and nonfuel charges in LNG shipping. The estimated transportation costs for each oil price scenario are shown in Table D1.3.5.

(iii) Fuel Costs for Production

Fuel costs for production are expressed as a percentage of total gas entering the system. Fuel costs were treated as an opportunity cost. They were deducted by using the following equation:

o Delivered gas value - (nonfuel production costs + transport costs) x .889 = wellhead netback value

(iv) Alternative Cost Values

The above paragraphs describe the netback valuation methodology. Alternative costs also have been used for sensitivity tests on the netback calculation. These alternative costs include the direct TAGS estimates, capturing capital, and operating gains from scale. At the same time, a variety of transportation cost assumptions were used. The results are discussed in Section 3.1(c) below.

(c) Netback Wellhead Value Results

The netback valuation of Cook Inlet natural gas was calculated as described above. The wellhead gas values, by oil price scenario, are as follows ($/MMBtu):

| | Scenario | | |
|---|---|---|---|
| Year | Wharton | Composite | SHCA |
| 1985 | 1.57 | 1.58 | 1.73 |
| 1990 | 1.26 | 1.50 | 1.68 |
| 2000 | 2.17 | 3.13 | 3.55 |
| 2010 | 3.49 | 4.97 | 6.43 |
| 2020 | 5.43 | 7.45 | 9.75 |
| 2030 | 8.08 | 8.30 | 11.30 |
| 2040 | 8.30 | 8.30 | 12.72 |
| 2050 | 8.30 | 8.30 | 14.27 |

The derivation of the Composite-based netback wellhead price is shown in Figure D1.3.1. It demonstrates the deduction of costs from the delivered value of the natural gas. It is significant to note that the value of natural gas rises at a more rapid rate than the value of oil. This phenomenon is based upon the presence of constant costs (e.g. $2.15/MMBtu in nonfuel production costs) in the netback calculation.

(d) Verification of Wellhead Gas Netback Values

The values described above were subjected to a significant verification process. Costs associated with the processes were independently checked as described above. Further, ten sensitivity cases were constructed for the Composite oil price scenario based upon the alternative liquefaction, regasification, and transportation costs as shown in Tables D1.3.6 and D1.3.7. These 10 cases reflect variations in the size, capital cost, O&M cost, and thermal efficiency of liquefaction facilities projected for Alaska, either by TAGS (Hickel, et. al., 1983) or by CIRI (see Tarrant 1985). These alternative cases permit capturing substantial economies of scale in liquefaction and regasification costs; and more optimistic assumptions about LNG transport charges (caused in part by assuming larger ships). The economies of scale reduced the costs of LNG manufacture and transport, thus raising the netback value of the gas at the wellhead. The results of sensitivity runs are shown in Figure D1.3.2. These calculations provide a netback envelope depending upon case assumptions. The Phillips settlement and Enstar contracts were then used to validate the netback calculations to the year 2000. This cutoff date represents the termination point of the Enstar contract (1989 is the termination point of the Phillips contract). The results of this validation are shown below for the Composite oil price forecast.

| Year | Wellhead Gas Price (1985 $/MMBtu) | | | |
|---|---|---|---|---|
| | Base Netback | Enstar | Phillips | High Sensitivity |
| 1985 | 1.58 | 2.21 | 2.25 | 2.30 |
| 1990 | 1.50 | 2.50 | 2.20 | 2.22 |
| 1995 | 2.25 | 2.92 | 2.65 | 2.97 |
| 2000 | 3.13 | 3.40 | 3.20 | 3.88 |

Of particular importance to the analysis is the year 2000 value, particularly because Watana is proposed to come on-line in 1999. In that timeframe, the calculated netback wellhead prices are within ten percent of the contract prices - and base case netback values are more conservative than the Enstar or Phillips contract values. It should be noted, also, that an average of old plant and new plant netback costs would be $4.00/MMBtu in the year 2000. Beyond the year 2000, when oil prices are expected to rise significantly in real terms, netback gas prices rise concomitantly. It should be pointed out that netback prices in the base case analysis assume a new LNG plant. If an existing LNG plant is assumed, and capital charges are treated as sunk costs, the netback values are $4.87/MMBtu in 2000. Significantly, the Marathon settlement associated with the Phillips case documents a 1984 netback price of about $3.03/MCF, or $3.18/MMBtu using an 18 percent rate of return. The technique documented above yields a current netback value of $3.32/MMBtu assuming a nominal discount rate of 15.9 percent. The differential is well within the error estimations. One could well argue that the netback value based on the Phillips plant would hold until 1999, when a new plant netback value would assume precedence. The current forecast offers the lowest calculated natural gas values to the year 2000. Beyond 2000, natural gas prices rise more rapidly than contract extrapolations, reflecting the total impact of petroleum prices on natural gas economics.

(e) Delivery Charges to Utilities

Utilities must pay not only the wellhead cost of natural gas, but also charges associated with natural gas delivery. These costs include metering, billing, overhead functions, capital recovery, recovery on gas distribution pipelines, and related costs.

The Alaska Public Utilities Commission performed a revenue requirements study on a test year, 1981 (APUC 1984). Revenue requirements were calculated not only for the system as a whole, but also for each major customer class.

Specific data were gathered for Chugach Electric Association (CEA) and Anchorage Municipal Light and Power (AML&P). Table D1.3.8 contains the revenue requirements data for 1981. These data have been updated to 1985 dollars using the GNP implicit price deflator series. Table D1.3.9 contains the same estimate in 1985 dollars. Because the Alaska Public Utilities Commission is moving toward rates based upon cost of service (Pratt 1985), the 40¢/MCF charge is used. This charge is held constant over the life of the analysis in real dollars. Table D1.3.10 demonstrates the calculation of the delivered cost of natural gas for the Composite oil price scenario using the base case netback assumptions.

Given the data presented above, an electric utility gas price forecast has been developed as follows:

| | Oil Price Scenarios | | |
|---|---|---|---|
| Year | Wharton | Composite | Sherman H. Clark |
| 1985 | 1.97 | 1.98 | 2.13 |
| 1990 | 1.66 | 1.90 | 2.08 |
| 1995 | 2.05 | 2.65 | 2.80 |
| 2000 | 2.57 | 3.53 | 3.95 |
| 2010 | 3.89 | 5.37 | 6.83 |
| 2020 | 5.83 | 7.85 | 10.15 |
| 2030 | 8.48 | 8.70 | 11.70 |
| 2040 | 8.70 | 8.70 | 13.12 |
| 2050 | 8.70 | 8.70 | 14.67 |

This forecast represents the estimated economic value of natural gas to electric utilities in the Railbelt region, if that economic value is determined by gas liquefied and sold to a Pacific Rim market.

(f) Lower Sensitivity Analysis

The above paragraphs describe the Power Authority analysis of natural gas prices for the Cook Inlet region of Alaska. At the same time, however, the Power Authority has analyzed the Susitna project assuming that natural gas pricing will follow either the Enstar or Phillips contract formulas. When calculated over a wide range of prices, both the Enstar and Phillip's contracts provide natural gas valued at about 50 percent of the Btu value of crude oil. Despite such steep discounts in the price of natural gas, the benefit/cost (B/C) ratio of the project remained favorable as discussed in Exhibit D, Chapter 2, Section 2.11.6.

## 3.2 - Regulatory Constraints on the Availability of Natural Gas

Title II of the Power Plant and Industrial Fuel Use Act of 1978 (FUA), and 42 U.S.C. §8311-8324, generally prohibits the construction of new electric power plants that do not have a capacity to use coal or another alternative fuel (other than oil or natural gas) as a primary energy source. The FUA provides various opportunities for exemption from this general prohibition. Thus, although the express policy objective of the Act is to preclude future reliance on oil and natural gas for electric generation, the Act's terms do not operate as an absolute bar to the development of new gas-fired generating capacity. Nevertheless, the prospect of federal regulatory constraints on use of natural gas significantly clouds the landscape of Railbelt power planning. It can generally be assumed that peak load facilities will not be prohibited under the FUA so long as operation is held to the statutory limit of 1500 hours/year (42 U.S.C. §8302(18)A, 8322(g)(2)). However, neither the FUA nor its implementing regulations provide comparable reassurance with respect to base load power plants. In 1982, Congress did enact a limited exemption from the FUA restrictions for new electric power plants in Alaska using Cook Inlet natural gas. However, this general "Alaska exemption" expires on December 31, 1985, and no extension of the specialized exemptive authority for Alaska has been secured to date. Moreover, the administration of the specialized Alaska exemptive authority to date suggests that to qualify, applicants must develop environmental and other data specific to a particular plant site and design. The level of detail required appears to preclude use of the exemption prior to its scheduled expiration to gain authorization for future plants whose dates of service, design, or location are yet to be determined.

After expiration of the special "Alaska exemption," the construction of new gas-fired generation capacity in the Railbelt is possible only if a proposed new electric power plant is found to qualify for one of the other exemptions available under the FUA. While certain exemptions may eventually be found to apply in individual cases, such exemptions cannot be gained except by discretionary federal administrative action. Again, requirements for detailed, case-specific factual findings make it difficult to predict the application of those provisions to future generating capacity that, at this point, is only generally defined. As a practical matter, neither the APA nor any of the Railbelt utilities can plan for the availability of a FUA exemption substantially in advance of a decision to build any natural gas-fired combustion turbine, combined cycle, or steam turbine power plant.

The consequences of the FUA for Railbelt utility planners is quite significant. The availability of natural gas for base load power generation is generally assumed to be an essential prerequisite to any economically feasible thermal system for the Railbelt. The prospect that FUA exemptions would not be available threatens confidence in the validity of any long-term generation planning that includes the possibility of building base load natural gas facilities.

In order to evaluate the Susitna system strictly on economic terms, the Power Authority has not accounted for the effect of the FUA on natural gas availability to utilities in performing its economic analysis of the thermal system expansion plan. For analytic purposes the thermal alternative expansion plan ignores this regulatory risk, and assumes that utility planners will have unfettered discretion within the bounds of price and physical supply constraints to select the least cost thermal response as demand for new capacity emerges.

In reality, however, the FUA creates considerable risk of regulatory impediment to the realization of any presumed benefits of the thermal option. A utility may, over the long term, plan for the freedom to select between coal and gas on the basis of comparative economic factors such as physical availability and price. If those factors dictate selection of a natural gas plant, however, a FUA exemption would be required. If the exemption proves unavailable, the utility would be forced away from the natural gas facilities to coal-fired plants even if the gas alternative were to be economically preferable. In the context of a system expansion plan substantially dependent upon the availability of natural gas, this would significantly impair pursuit of the optimum generation additions. The regulatory constraints on gas availability imposed by the FUA raise a substantial question whether the Railbelt can reasonably rely upon the opportunity to actually implement a "least cost" thermal alternative, in the event a FERC license to construct the Susitna project is denied.

## 3.3 - Physical Constraints on the Availability of Cook Inlet Natural Gas Supply

In addition to the regulatory constraints, there is a potential physical limitation to Cook Inlet natural gas supply. This potential physical limitation introduces added uncertainties into the power generation planning process as discussed below.

### 3.3.1 - Estimates of Cook Inlet Gas Resources and Reserves

The Cook Inlet region has nine natural gas producing fields. During the period 1980 to 1984, estimates of proven and recoverable natural gas reserves ranged from 3.3 to 3.8 trillion cubic feet (TCF). The Alaska Department of Natural Resources (ADNR) January 1984 estimate was 3.3 TCF (Wunnicke 1985). However, ADNR recently reevaluated its reserve estimates and concluded that about one TCF of additional natural gas in the Ivan River and MacArthur River fields had not been accounted for in prior estimates. Accordingly, ADNR's January 1, 1985 estimate indicates that there are about 4.5 TCF of proven recoverable gas reserves in the Cook Inlet fields. For purposes of this analysis, the Power Authority has relied upon this last official state estimate of proven and recoverable reserves as shown in Table D1.3.11. The best evidence available suggests that the size of the Cook Inlet natural gas resource may be substantially larger than the estimated proven and recoverable reserves. Estimates of the size of potential undiscovered reserves have been developed by Ross G. Schaff of the ADNR's Division of Geological and Geophysical Services (Schaff 1983). The Schaff analysis assigns a probability value to various estimates of undiscovered Cook Inlet resources. The results of Schaff's analysis (which have been confirmed by McGee (1985)) are shown as a probability distribution contained in Table D1.3.12. The reported distribution of total estimated in-place and recoverable resources in Cook Inlet also is shown in Figure D1.3.3.

The Schaff estimate posits a mean probability that 3.36 TCF of natural gas exists as undiscovered resources. The probability that substantially greater undiscovered resources exists is less than 50 percent. The number shown has been rounded upward to 3.4 TCF.

Although the Schaff and McGee probability distributions constitute the best source known to the Power Authority for estimating undiscovered reserves in Cook Inlet, it is recognized that there are substantial uncertainties associated with estimating undiscovered resources. This is particularly true in the Cook Inlet where substantial new exploration programs have not been carried out within recent years. Despite this uncertainty, it is necessary to estimate total field size for planning purposes. The Power Authority has attempted to compensate for the uncertainties involved by certain adjustments which tend to bias the estimation of natural gas towards more, rather than less, fossil energy being available. The Power Authority has used total in-place undiscovered resources, rather than economically recoverable resources, as a basis for analysis.

The distinction between resources and reserves is both informational and economic. A resource is, generally, a concentration of mineral deposits in the earth's crust. Whether or not a resource is considered to be a reserve depends upon its size, depth, and other factors which dictate whether the resource is capable of production (Thrush, et al., 1968). The distinctions between resources and reserves are illustrated by the McKelvey Diagram, shown in Figure D1.3.4.

This total estimated undiscovered resource (3.36 rounded up to 3.5 TCF) is added to the estimated proven reserves (4.5 TCF), yielding 8 TCF. The Power Authority therefore assumes that 8 TCF of gas will be available for all future uses of Cook Inlet natural gas.

### 3.3.2 - Current Use of Cook Inlet Natural Gas

Cook Inlet natural gas currently serves a full range of residential, industrial, and commercial uses. Natural gas is used by electric utilities for generation of electricity for typical residential and commercial end-uses. In addition, the Railbelt's gas utilities deliver natural gas at retail for residential and commercial end-users. An ammonia-urea plant, owned by the Union Oil Company, produces fertilizer from Cook Inlet gas for delivery to agricultural use markets in the Lower 48 states. Also, the Phillips Petroleum Company operates a plant on the Kenai Peninsula which produces liquefied natural gas (LNG) for export to Japanese markets. The following sets out data developed by ADNR regarding consumption of Cook Inlet gas in 1984:

| | | |
|---|---|---|
| Field Operations | 20.5 BCF | |
| Vented or Flared: | | 3.3 BCF |
| Used on Leases: | | 14.6 BCF |
| Shrinkage | | 2.6 BCF |
| Other | | 0.003 BCF |
| LNG | 65.5 BCF | |
| Ammonia-Urea | 50.9 BCF | |
| Public Power Generation | 30.5 BCF | |
| Military | 4.1 BCF | |
| Residential and Commercial | 19.3 BCF | |
| Producers | 12.0 BCF | |
| Other | 4.3 BCF | |
| SUM | 207.1 BCF | |

Source: Alaska Department of Natural Resources 1985.

Table D1.3.13 summarizes the growth of Cook Inlet natural gas production and use for the period 1971-1984. As is shown in Table D1.3.13, Cook Inlet natural gas production and use has undergone a 2.3 percent rate of increase over the past 13 years, with the most dramatic growth occurring in ammonia-urea production and in power generation.

### 3.3.3 - Future Use of Cook Inlet Natural Gas

The availability of Cook Inlet gas for expanded use for Railbelt power generation depends on the extent to which forecasted demand is likely to absorb the available natural gas resource over the course of the 1985-2050 planning period. The Applicant has therefore made estimates of future use of Cook Inlet gas over the planning period. This projected use is then measured against the estimated available Cook Inlet natural gas resource. The difference suggests the bound of supply limitations that would constrain expanded use of natural gas for electricity generation. Two forecasts are used in this analysis--a near-term analysis covering demand projections over the 1985-1999 planning period, and a long-term projection covering the years 1999-2050.

The Applicant has relied upon official state forecasts developed by ADNR as the basis of its near- and midterm residential forecast. The ADNR forecast predicts production and consumption of gas in the Railbelt (Table D1.3.14) through 1999. The cumulative demand for Cook Inlet region gas as projected by ADNR is 2.3 TCF for the period 1985-1999.

The Applicant's near-term forecast supplements the ADNR forecast in two respects. The ADNR does not attempt to forecast the use of gas for LNG production or for field operations associated with producing Cook Inlet gas supplies. It was therefore necessary to make assumptions with respect to both of these uses.

Projected LNG use was derived from an extrapolation of current levels of LNG use for the Phillips LNG production facility. This facility consumed 65.5 BCF in 1984. Prior years are within the same range as shown in Table D1.3.13. The life expectancy of the facility spans the period of the short-term forecast. Moreover, Mitsui and Co. (1985) reports their expectation that the Phillips contract will be extended 5-10 years beyond 1989. Therefore, it can be confidently assumed that LNG use will continue, and will account for a comparable share of gas use annually for the remainder of the century. The cumulative projected demand for the period 1985-1999 based on 65.5 BCF annual consumption is approximately 1.0 TCF.

With respect to field operations, this analysis assumes that field operations will continue to account for approximately 10 percent of total gas use (Table D1.3.14). Therefore, the cumulative total consumption for field operation over the short term, through 1999, is assumed to be approximately 0.34 TCF.

Thus, over the near-term planning period, the Applicant's forecast projects a cumulative demand for 3.4 TCF of Cook Inlet natural gas. Subtracting the 3.4 TCF of projected demand for 1985-1999 from the 8.0 TCF of natural gas resource assumed to be available in Cook Inlet, a remaining resource level of 4.6 TCF is assumed to be available for use in the next century.

ADNR does not forecast natural gas use beyond the year 2000. Therefore, to project the demand for Cook Inlet gas in the long-term period (2000-2050), it is necessary to develop a forecast for each of the current categories of natural gas use.

These include: 1) residential and commercial, 2) existing power systems, 3) military, 4) industrial markets, 5) LNG exports, and 6) field operations. These markets will draw from the 4.6 TCF of natural gas assumed to be available after the year 2000.

As a general matter, these market analyses are extrapolated from current trends as well as trends projected by ADNR in the short term analytic period in each use category. It is assumed that field operations use will remain constant at 10 percent of total production (this is equivalent to 11 percent of the natural gas sold). Thus, the projected use for each market category has been increased by 11 percent to reflect gas used for field operations in connection with production of gas necessary to serve that particular market. A summary of these market analyses is described below:

(a) Residential and Commercial

Residential and commercial natural gas use (represented in consumption data for gas utilities) increased from 10.2 BCF/yr to 19.8 BCF/yr during the period 1971-1984. This represents a compound annual growth rate for gas consumption of 5.2 percent (ADNR 1985). ADNR has forecast that these uses will grow at a compound annual rate of 3.8 percent to the year 1999. Considerable growth is forecast for the Matanuska Valley, where natural gas is only now being introduced as a residential fuel.

The current, more mature Anchorage residential and commercial natural gas market is forecast by ADNR to grow at a rate of 3.3 percent per year to the end of this century. By 1999, residential and commercial gas consumption in the Railbelt is forecast at 34 BCF/year.

For the development of projections from 2000-2050, several growth rates may be assumed. The assumed growth rate may be an extension of the ADNR mature market forecast trend (3.3 percent), zero, or the midpoint between those two rates. All three mathematical trends are shown below.

| Forecast | Total Requirements 2000-2050 | | | |
|---|---|---|---|---|
| Growth Rate (%/yr) | Year 2000 Consumption | Year 2050 Consumption | Without Field Operations | With Field Operations 10% of Total |
| -0- | 34 BCF | 34 BCF | 1734 BCF | 1930 BCF |
| 1.65 | 34 BCF | 79 BCF | 2650 BCF | 2940 BCF |
| 3.30 | 34 BCF | 177 BCF | 4300 BCF | 4770 BCF |

The range of possible consumption levels is 1.9 to 4.8 TCF. The midpoint rate of growth in residential and commercial gas consumption was chosen for this analysis. On this basis, a 2.9 TCF consumption level is assumed for residential, commercial, and related uses of natural gas from Cook Inlet.

It should be noted that the 2.9 TCF estimate involves a decline in the rate of market growth for natural gas used in residential and commercial applications, as shown below:

| Period | Annual Growth Rate in Residential and Commercial Natural Gas Consumption |
|---|---|
| 1971-1984 | 5.2% (1) |
| 1985-1999 | 3.3% (2) |
| 2000-2050 | 1.65% |

(1) Historical growth rate.
(2) Anchorage market, excludes Matanuska Valley.

(b) Electricity Generation

If Susitna is not constructed, electricity will be generated and supplied to the Railbelt Region by a combination of generation systems burning natural gas and coal. Assuming gas supplies are unlimited and the use of netback pricing grounded on the Composite oil forecasts, the OGP model has forecast that the Railbelt consumption of natural gas will peak at 40.0 BCF/yr in the Year 1998, decline to about 16 to 18 BCF/yr in 2000 to 2004, and then decline to 5 to 8 BCF/yr for the period 2005 to 2050. Total consumption will be about 300 BCF (0.30 TCF). Total consumption for the period 2000 to 2050 will be 0.20 TCF, assuming the Sherman H. Clark forecast.

(c) Military Use

Military uses of natural gas are small and largely devoted to power generation. They have been projected as a constant load of 4.6 BCF/yr to the turn of the century (ADNR 1985). They are projected to remain at that level through 2050. The military requirement is therefore considered to be approximately 260 BCF (0.3 TCF) with field operations for the period 2000-2050.

(d) Ammonia and Urea

The Union Oil Company ammonia-urea plant is a successful venture for exporting Alaskan natural gas in the form of fertilizer. Reserves are committed contractually to this use through 1998. This use is also reflected in the ADNR (1985) forecast of gas usage.

There is some evidence demonstrating that the long-term outlook for ammonia/urea manufacture in the U.S. compared to overseas locations is favorable. Such favorable circumstance may exist for the long term due to several factors, including favorable capital costs of new capacity in the U.S. vis-a-vis overseas locations, and more favorable currency exchange rates for U.S. manufactured commodities based upon a projected weakening of the dollar (AGA 1985; Hay 1985). Moreover, the Cook Inlet region may be strategically located to serve the market place. This view is not universally held, however. The World Fertilizer Review posits the belief that the U.S. will have difficulty competing in the nitrogenous fertilizer market over the long term (Sheldrick 1984).

The American Gas Association (AGA) has calculated the costs of manufacturing ammonia from existing and new plants in the U.S. and in foreign countries. Their results are shown in Table D1.3.15, along with their estimated capital costs associated with ammonia plants.

Because there is some evidence supporting the belief that the U.S. can compete in the nitrogen fertilizer market, and that Cook Inlet has some advantages in that regard, it is not reasonable to assume that there will be no continued demand for urea production from Alaska beyond the year 2000. For planning purposes, it is assumed that the current level of natural gas consumption, some 50 BCF/yr, may be required for ammonia/urea production. The consequence of such natural gas demand would be a 2.5 TCF requirement before associated field operations, or a 2.8 TCF total natural gas requirement for the period 2000-2050.

(e) Liquefied Natural Gas (LNG)

The Phillips Petroleum LNG plant on the Kenai Peninsula exports 0.2 BCF of gas per day to Japan. The Phillips plant has a functional life expectancy to the end of this century (see Mitsui & Co. 1985). Continued demand for natural gas for the duration of this life expectancy is reflected in the Applicant's 1985-1999 forecast.

Demand beyond 1999 is anticipated to come from the Pacific Rim countries. This demand is discussed quantitatively in Section 3.3.3. Other evidence of such demand is shown below. Japan now imports LNG not only from Alaska, but also from Indonesia and other sources.

Several ventures conceived in recent years in response to perceived demand in the Pacific Rim lend credibility to the assumption that the LNG market opportunities will extend beyond the useful life of the Phillips plant. These include the TransAlaska Gas System (TAGS) proposal, and the facility proposed by Cook Inlet Region, Inc. (CIRI) and ARCO Alaska to be built in North Kenai (Tarrant 1985). This latter facility would be slightly larger than the Phillips Petroleum plant (consumption = 65 BCF/yr). If this plant were constructed, 3.5 to 4.7 TCF of natural gas would be required for LNG operations for the period 2000 to 2050.

The TAGS proposal is for a gas pipeline from Prudhoe Bay to the Kenai Peninsula. There, gas conditioning and liquefaction facilities would be constructed. The Phase I operation involves converting 0.95 BCF per day into 0.74 BCF of LNG. When Phase III is complete, the TAGS system would convert 2.83 BCF/day into daily shipments of 2.2 BCF of LNG. The LNG so produced would be shipped to Japan or other nations on the Pacific Rim. The TAGS proposal remains active, and in the gas marketing phase.

The TAGS proposal and the CIRI/ARCO Alaska program, along with the success of the Phillips Petroleum and Indonesion efforts, are evidence that a long term LNG market in the Pacific Rim exists. The Power Authority therefore has assumed a long-term opportunity for LNG production in Alaska. However, because information is not sufficient to estimate possible growth in LNG demand, it is assumed for purposes of the natural gas supply analysis that current LNG production levels will be sustained for the planning period.

(f) Market Totals

Projected market totals for the period 2000-2050 have been tabulated and they are presented in Table D1.3.16. The total estimated market demand for natural gas in the Cook Inlet area is 10.0 TCF for the 50-year period. This includes the consumption demands by the military, urea process facility, existing power plants with extended peaking capacity, liquified natural gas, and the residential and commercial demands.

(g) Conclusions Respecting Gas Availability

As described more fully above, the Applicant's analysis of natural gas prices indicates that by the end of this century, the economically preferred thermal fuel for baseload generation will be coal rather than natural gas.

Based on pricing considerations alone, natural gas will be an appropriate choice only for peaking facilities for the duration of the long-term planning period. As a practical matter, therefore, the foregoing discussion of likely supply constraints on Cook Inlet region natural gas is not central to the Applicant's base case analysis of the thermal alternative. Nevertheless, to the extent that different assumptions are made about natural gas prices, it is necessary for planning purposes to examine the potential effect of supply uncertainty on power planning in the Railbelt.

The foregoing analysis of gas supply and projected demand demonstrates that demand for Cook Inlet gas could substantially exceed the total estimated resource of eight TCF expected to be available over the course of the Applicant's planning period. By the Year 2000, it is anticipated that 3.4 TCF of the proven Cook Inlet reserves will have been consumed. The result is that if ADNR's official state estimates prove correct, the major share of the 4.5 TCF of proven reserves is expected to be consumed during the short-term planning period of 1985 to 2000.

The remaining 1.1 TCF of proven reserves is insufficient to meet even the most conservative estimate of demand from the residential and commercial sector for the long-term planning period. Simply to sustain current retail sales levels in the Railbelt region, natural gas utilities will require almost two TCF during the long-term planning period of 2000 to 2050.

As a result, some additional development will be necessary to meet minimum requirements for the long-term period for military and stable residential and commercial demand. If residential and commercial demand for the entire Railbelt does not remain flat, but grows only at the modest rate of 1.65 percent, the total requirements for military, residential, and commercial gas use will be 3.2 TCF. Thus, even assuming that the estimated 3.4 TCF of undiscovered resource is economically recoverable and is developed during the long term, there would still be significant competition between the industrial and power generation sectors for the remaining 1.3 TCF expected to be available.

Such uncertainty surrounding the availability of gas over the long term suggests that even if natural gas prices do not constrain gas use for power generation purposes, Cook Inlet gas supplies cannot reliably be expected to support baseload generation expansion beyond the next decade.

### 3.4 - North Slope Natural Gas

Vast resources of natural gas, approaching 36 TCF, have been found in connection with North Slope petroleum (ADNR 1985). Table D1.3.17 delineates proven and undiscovered reserves and resources of natural gas on the North Slope.

Currently, natural gas on the North Slope is used for local power generation and heating needs, and the operation of pumping stations. Most of the gas produced is reinjected into the producing formations in order to maintain pressure for oil production.

There is, at present, no infrastructure to move this natural gas into the Railbelt region, although several proposals have been offered. These proposals include the ANGST pipeline passing by Fairbanks on the way to the midwest, the TAGS pipeline to the Kenai Peninsula (Hickel, et al., 1983), and transmission lines for transporting natural gas in the form of electricity from Prudhoe Bay to the Railbelt.

Construction of such pipelines can only be justified in the movement of significant quantities of gas in order to reduce the unit cost of gas transmission. Such quantities far exceed the needs of the Railbelt market; this means that a substantial market for North Slope gas must materialize if TAGS or ANGTS is to be built. The TAGS project is predicated on an export market (from Alaska) and, as a consequence, the city gate cost of natural gas in Anchorage (or elsewhere in the Railbelt) delivered by the TAGS pipeline will be the LNG netback price. Thus, the Power Authority's pricing analysis effectively accounts for the availability of North Slope gas delivered through the TAGS system.

If instead the ANGTS system were developed, North Slope natural gas prices would necessarily be sufficient to include costs of conditioning and transporting it to the point of end use. As estimated by Batelle, the cost of ANGTS gas in the Fairbanks area would be between $4.03-$6.32/MMBtu in 1983 dollars in the first year of pipeline operation, assuming the wellhead price of gas is between $0.00/MMBtu and $2.30 per MMBtu, respectively. However, to the best of the Power Authority's knowledge, there is no present expectation that a market in the lower 48 states for ANGTS-delivered gas is likely to develop at a price sufficient to permit financing of the ANGTS system. In the absence of any present reasonable prospect that the financing to permit construction of ANGTS will be secured, the Power Authority has not attempted to account for North Slope gas delivered through ANGTS in its pricing analysis.

If an export LNG market does not exist, then the potential for moving natural gas to the Railbelt is "by wire." To date, the technical and environmental feasibility of such natural gas usage (including the construction and operation of a transmission line) has not been established. Until such feasibility is established, the Alaska Power Authority believes that it is inappropriate to attempt to account for this alternative in its analysis.

## 4 - COAL

This section describes the Applicant's analysis of the price and supply of coal, which is used in the thermal alternative expansion plan. This analysis examines four issues: 1) current and projected supply of Alaska coals; 2) present and projected demand for coals mined in Alaska; 3) appropriate concepts for projecting coal prices; and 4) current and projected prices of Alaska coals.

### 4.1 - Resources and Reserves

Alaska's identified coal reserves total nearly 10 billion tons. Its total resources of coal are in the 2-6 trillion ton range, as is shown in Table D1.4.1 (Davis 1984). Major coal resource regions include the arctic, the interior, and the south central areas of Alaska. Relatively few coal fields in these regions hold significant promise. Those fields which have substantial quantities of coal in the most favorable geologic settings are located largely in the Railbelt region. Such fields include Nenana, Beluga, Matanuska, and Kenai-Homer. Of these, the Nenana and Beluga fields are the largest and offer the greatest potential for economic development.

The Nenana and Beluga fields contain low sulfur bituminous coal with fairly low heating value. The market potential of these two deposits differs significantly, however, Nenana coal is situated in proximity to a populated area of Alaska with some infrastructural development (e.g. the Alaska Railroad). This coal field supplies the only currently operating coal mine in Alaska. The Beluga coal field, on the other hand, is in a totally undeveloped area located on the tidewater, where highways and railroad spurs are absent; only a few small settlements exist.

Nenana coal is accessible to the Alaska domestic market and is also shipped via the Alaska Railroad 360 miles to Seward for export to Korea. Beluga coal fields are close to tidewater. The proposed Diamond Alaska coal project, for example, is only about 12 miles inland. Because of transportation limitations, Beluga coal currently could only move into the local marketplace through mine mouth power plants tied into the Railbelt electric grid, although a railroad or road could be built connecting the Anchorage area to Beluga if sufficient development occurred to warrant it. It is assumed for these analytic purposes, however, that the market potential for Nenana coal will largely be domestically determined, and that Beluga development will be dependent primarily on export opportunities. Over time, the markets for Nenana and Beluga coals will tend to become distinct and separate.

The Matanuska coal field is fairly small. Its resource potential for surface mineable coal would be exhausted by the one power plant now in the planning stages (M.P.P. Assoc. 1985). The Kenai-Homer field is characterized by small, steeply dipping, faulted deposits of relatively high grade coal that would be difficult to develop. Thus, neither of the resources are further considered in this analysis.

4.1.1 - The Nenana Coal Field

The Nenana coal field is a large deposit of subbituminous coal in the center of the Railbelt region. It is located in an area about 200 miles north of Anchorage and 60 miles south of Fairbanks. Estimates of the size of this field are shown in Table D1.4.2.

The Nenana coal field consists of six noncontiguous individual coal-bearing areas extending in a belt up to 30 miles wide. These areas include the Healy Creek, Lignite Creek, Wood River, Tatlanika, and Totalanika fields. These basins (inset) and the Nenana field coal lease holders are shown in Figure D1.4.1. The coal being mined and shipped to Fairbanks Municipal Utility System has the following characteristics:

| | |
|---|---|
| Higher heating values (as received) | 7,600 Btu/lb |
| Ash | 8.3 percent |
| Moisture | 26.5 percent |

The principal advantage of Nenana coal is its low sulfur content -- typically 0.2 percent.

4.1.2 - The Beluga Coal Field

The Beluga field shown in Figure D1.4.2 is located in the Susitna coal field on Cook Inlet, approximately 50 miles west of Anchorage. The coal resources of the Susitna field are comprised of the Yenta area in the north and the Beluga area in the south. Both areas contain multiple seams of low sulfur, lignite-to-subbituminous coal. The National Research Council has listed the indicated and inferred resources for the Susitna field at 1.2 to 2.7 billion tons. Hypothetical resources are listed at 27 billion tons (Wierco 1985).

The quality of Beluga coal is comparable to that of Nenana coal. Weirco (1985) estimates the average as received calorific value at 7,500 Btu/lb. The Diamond Alaska Coal Company estimates the value to be 7,600-7,700 Btu/lb. Ash, moisture, and sulfur content are comparable to Nenana coal:

| | |
|---|---|
| Ash | 8 percent |
| Moisture | 28 percent |
| Sulfur | 0.2 percent |

## 4.2 - Demand and Supply

The locational and infrastructural differences between Nenana and Beluga make the economic analyses of each coal field distinctly different. The future potential of the Nenana field is largely oriented toward the domestic market, with some capacity dedicated to exports. This is consistent with historical trends, although currently about half of the coal mined is sold to each market. The Beluga field, however, lacks the infrastructure to serve a locationally dispersed domestic market. Its development is presumed to be largely predicated upon exports.

### 4.2.1 - Nenana Field Demand and Supply

At present there is a modest domestic demand for Nenana field coal, with some potential for growth in the market. The Usibelli mine, located in this coal producing region in the general vicinity of Fairbanks, is the only commercially active mine in Alaska. Usibelli supplies 830,000 tons annually for domestic consumption, and also has a 15 year contract with Sun Eel (a Korean export company) to export 880,000 tons annually to the Korean Electric Power Company. The Usibelli operations consist of a dragline and a fleet of front end loaders and trucks. The Usibelli mine has a present capacity of 2 million tons/year.

Nenana coal production could increase in relation to the existing Usibelli contract commitments under a thermal alternative expansion plan. Such a plan would include 200-400 MW of capacity in the Nenana area. The reserves of the Nenana field are sufficient to support both increased Sun Eel exports and a level of production associated with coal fired plants under the thermal expansion plan. The Usibelli Mining Company surface mining capacity is 80-90 percent fully utilized by the 1.7 million tons annual production at the existing Poker Flats mine. Expansion of production beyond 2 million tons annually (e.g., to 4 million tons/year) would entail a distinctly separate mining effort with some dependence on existing systems (e.g., shops). Additional capital equipment would be required.

### 4.2.2 - Beluga Field Demand and Supply

The export potential for Beluga coal far exceeds that presented by the domestic market. Table D1.4.3 shows the forecast of total steam coal potential imports by Pacific Rim nations through 2040 in metric tons coal equivalent (MTCE) and actual tons. One MTCE equals 27.8 MMBtu per metric ton (2,204 pounds). Beluga coal has about 15 MMBtu per ton (2,000 pounds). Hence, each MTCE equals 1.85 tons of Beluga coal. The total Pacific Rim market for coal for electric power generation is the potential market for Alaska coal. The Beluga field may serve a significant portion of this market.

New power plant demand for coal in Japan, Taiwan, and Korea will grow rapidly after 1990. If no internal Alaska constraints limit Beluga coal mine development, Beluga reserves are sufficient, and Beluga production costs are low enough to justify Beluga producers capturing 10 percent of the total steam coal market by 2000 and about 18 percent of the growing market by 2030. Beluga coal can be delivered to tidewater for under $22 a ton (1985 dollars) (Wierco 1985). Even after allowing for real production cost escalation, production costs will remain well below competitive market prices throughout the Susitna planning period, making this source of coal extremely competitive.

Based upon its competitive position, the potential for exports of Alaska coal is substantial. The approximate potential size of the market is shown in Table D1.4.4, assuming no internal constraints limit the number of mines opened or the environmental acceptability of mining growth. These estimates represent unconstrained potential demand for Alaska coal based on what the market could absorb, assuming 10 percent market penetration by 2000 and 18 percent by 2030 (Dames & Moore 1985a).

Currently no active mines exist in the Beluga coal field. Diamond Alaska Coal Company is planning for the development of a mine ultimately capable of producing 10 to 12 million tons per year by the early 1990s. Diamond Alaska Coal Company projects initiation of exports by 1990.

The export market exists, and competitive Beluga coal supplies exist. However, it would be exceptional for Beluga coal to be developed on a scale and at a pace sufficient to accommodate the potential demand. Any number of cultural, social, or ecological considerations could act to constrain development of Beluga coal well below what the Pacific market could absorb. While maximum allowable production levels cannot be predicted, a reasonable development path that considers effective management of potential sociological and environmental conflicts has been forecast to achieve production growth as shown on Table D1.4.5.

### 4.3 - Present and Potential Alaska Coal Prices

Pricing of Nenana and Beluga coals is as distinct as the estimation of markets, supplies, and production potentials. Pricing in both cases, however, requires the establishment of a base price and an escalation rate. Both aspects of price analysis are treated below.

#### 4.3.1 - Nenana Coal Production Prices

Because there are too few buyers and sellers to create a fully competitive market, coal prices in the localized Fairbanks market will be set by bilateral negotiation. No deterministic economic model can project the price trend for Nenana coal. Consequently, a present and projected production cost analysis of Nenana coal resources is proposed for resource valuation.

The wide range of contract prices for coal sold by Usibelli into the Fairbanks market demonstrates the analytically indeterminate nature of commodity prices in this small market. These mine mouth prices, stated in 1985 dollars, range from $1.30 to $2.40 per MMBtu (Mann, Tillman, and Wade 1985). Prices are set by negotiations between a single seller dealing with a few buyers. The resulting prices, therefore, cannot be analytically predicted except for the minimum and maximum prices. The minimum price is set by production (and transportation) cost; the maximum is set by the cost of substitute fuels.

Production costs were estimated to determine the minimum price that might conceivably apply to future Nenana deliveries. This is a conservative resource valuation approach and may understate the long-term market price of coal in Nenana. Table D1.4.6 shows the production cost of Nenana coal delivered by rail to a coal plant at Nenana.

The production costs shown in Table D1.4.6 were derived from a hypothetical mining study conducted by the Paul Weir Company (Weirco 1985). This study estimated the costs of owning and operating a 2 million ton per year major expansion of a mine in the Nenana coal field. The Weirco study is based on current costs. Cost escalation over time, as forecast by Dames & Moore, is discussed below. The reason for having current and projected costs on a new mine is the fact that the current Usibelli mine capability is large. Further, as Table D1.4.6 illustrates, a new mine would produce coal at a cost comparable to the price charged by Usibelli Mining Company to FMUS.

### 4.3.2 - Nenana Coal Production Cost Escalation

For planning purposes, it is essential to forecast the rate of cost escalation. Escalation is used here to mean cost increases at a rate faster than the general rate of inflation, i.e., "real" increases. Historical data support the fact that real coal prices have trended upward throughout the 20th century. This historical escalation in Alaska is shown in Table D1.4.7. Data for real coal prices in the lower contiguous 48 states were obtained from a time series of bituminous coal prices compiled by the U.S. Department of Commerce (1971). Overall, between 1900 and 1980, real coal prices have escalated at an average compound annual rate of 1.2 percent. Even prior to the dramatic price rise in 1973, coal prices from 1900 to 1973 escalated at a real annual rate of 0.3 percent.

Historically, the factors driving real price escalation of coal include real labor cost escalation, price escalation of substitute energy sources, and resource depletion effects. Countering the trend toward increasing coal mining costs were increases in productivity which occurred as large-scale mechanized surface mining techniques replaced labor-intensive underground mining. Despite these cost saving productivity increases, real coal prices have increased steadily. There is a good reason to expect this trend to continue into the next century; the forces causing the escalation will likely continue, while the productivity increases (which tend to lower prices) may occur at a lower rate.

Because of the evidence of increasing coal prices over the past 80 years (a period comparable to the future planning period of the proposed Susitna development), an analysis of factor costs was made focusing on the cost components of labor, energy, royalties, and other operating costs. Real increases in labor and other costs over the project life will be reflected in the price of coal.

Although long-term fuel supply contracts are usually negotiated prior to constructing a coal-fired power plant, these contracts ordinarily do not lock in a fixed price for coal. Agreements between coal suppliers and electric utilities for the sale/purchase of coal usually include a base price for the coal and a method of escalation to cover mining cost increases in future years (Dames & Moore 1985a). The base price provides for recovery of the capital investment, profit, and operating and maintenance costs at the level in existence when the contract is executed. The intent of the escalation mechanism is to recover actual increases in labor and material costs from operation and maintenance of the mine. Typically the escalation mechanism consists of an index or combination of indices such as the producer price index, various commodity and labor indices, and consumer price index applied to operating and maintenance expenses, and/or regulation-related indices. These characteristics are exhibited by the Usibelli contracts with FMUS and GVEA (FMUS 1976; Hufman 1981). The consequences in the Nenana field are shown in Table D1.4.8.

From the above discussion, it is clear that coal production costs with escalation of labor and energy input factors establish a minimum price for Nenana coal. The consequences of this escalation on the mine mouth cost of Nenana coal are shown in Table D1.4.9. The production factors which are projected to escalate are labor, fuels and lube, and electricity. Royalties, which are assumed to be a fixed 12.5 percent of the realized price, escalate in proportion to the increases in the above factors. For the 2 million ton per year mine, the projected mine mouth production costs are $22/ton in 1985 and $55/ton in the year 2050 (in 1985 $). That is equivalent to about $1.45 and $3.70 per million Btu, respectively. The composite real escalation associated with that production cost increase is 1.45 percent/year.

The above discussion of production costs for Nenana coal does not include the costs of coal transportation. Due to the proximity of the field to Denali National Park, the coal would have to be transported by rail before it is used in order to avoid violating air quality standards. The Alaska Railroad (ARR) is the only viable transportation alternative. Consideration of cost escalation must, therefore, include rail cost escalation.

Analysis and projection of rail cost factors based on American Association of Railroads' data yields an average annual escalation of 2 percent (real). A second estimate based on projection of historic data derived from the U.S. Department of Labor Price Index for Rail Transportation yields a real price escalation of 1.8 percent per year (Dames & Moore 1985a, pp. 34-37). The figure of 1.8 percent is used in this application.

Currently (1985), rail tariffs for moving coal from the existing loading facility at Suntrana to Nenana are $5.92 per ton. At a 1.8 percent real escalation rate, this tariff will rise to $18.88 (in 1985 $) by 2050. Nenana is the shortest rail haul destination which will not violate air quality standards. Other destinations (such as Anchorage or Fairbanks) would have higher tariffs.

The current base price and real escalation rate for Nenana coal provide a coal price trajectory. This trajectory includes both production and transportation costs and is shown in Table D1.4.9. The projected real rise in Nenana coal prices between 1985 and 2050 is 1.5 percent/year assuming that the coal is delivered in Nenana.

4.3.3 Beluga Coal Netback Prices

The price of coal in the Pacific Rim market will determine prices of Beluga coal under two conditions:

- o When there is a demand for Alaska coal in the Pacific Rim market at a price above Alaska production cost;
- o When the Pacific Rim market can absorb all of the Alaska production.

Unlike Nenana coal, the majority of Beluga coal will be sold internationally. The basis for forecasting future Beluga coal prices therefore is the value of Beluga coal on the Pacific Rim market. The Pacific Rim will become a large and rapidly growing coal market. Diamond Alaska anticipates producing 10 to 12 million tons annually for export before the end of this century. Beluga coal producers will be able to sell all coal that can reasonably be supplied into the Pacific Rim over the long term. The Pacific Rim steam coal market will be sufficiently robust that it will be capable of absorbing 3 to 4 times the amount of coal that the Beluga field will be capable of producing. Prevailing market prices should be well above Beluga production cost.

Over the long run--the 50-year period of the Susitna project evaluation--market conditions for coal in the Pacific Rim can be expected to change from time to time, reflecting short-term imbalances--relative surplus or shortage conditions--in the market. Temporary periods of recession may reduce demand for coal, causing lower prices. Temporary periods of fuel tightness, such as could be caused by oil embargoes or gas supply constrictions, could raise the demand for coal and cause higher prices. There is no systematic basis for predicting over a 50-year period when minimum or maximum prices might occur for a commodity such as coal. Thus, over the long run, the Pacific Rim competitive market price trend FOB Alaska remains the most reasonable economic basis for valuing Beluga coal.

The economic conditions of the competitive market model yield the lowest prices that will match coal production and consumption. Higher trend prices could be projected by assuming higher resource rents or higher taxes as world energy resources become more scarce over the long run. These "extra" market factors were not estimated. Adopting Pacific Rim competitive market basis for valuing the Alaska coal resource at Beluga accomplishes two results:

- The Alaska resource at Beluga is valued at its highest and best use that can reasonably be anticipated.

- The estimated coal price trend may remain understated because other plausible economic conditions in the Pacific Rim over the long term could exert an upward force on market clearing prices.

Pacific Rim market prices were projected based on a supply/demand analysis of the Pacific Rim market under both the SHCA and composite oil price forecasts. The difference between the two prices is largely caused by differences in diesel oil prices caused by higher or lower crude oil prices. Diesel oil prices determine the cost of transporting coal by rail from mine to deepwater ports. As coal from the Powder River Basin becomes increasingly significant, this differential is reflected in the netback value of Alaska coal. Coal import figures were obtained by projecting coal demand in Japan, Korea, Taiwan, and Southeast Asia. These demand estimates were then adjusted to reflect estimates of indigenous (i.e., nonimport) supplies (Gordon 1984;

Dames & Moore 1985c). Supply potential and costs were estimated for export coal delivered to Japan--the key market point. Coal supplies from Australia, Canada, China, the western lower 48 states and Alaska were included. The projected increase in prices reflects the effects of reserve depletion as well as increases in factor costs of coal production and transportation. The Pacific Rim market price for Beluga coal is shown below.

BELUGA COAL NETBACK PRICES
(1985 $ Million Btu)

| Year | Pacific Rim Market Price FOB Mines | |
|---|---|---|
| | Composite | SHCA |
| 1985 | -- | -- |
| 1990 | -- | -- |
| 1995 | -- | -- |
| 2000 | 1.78 | 1.78 |
| 2010 | 2.30 | 2.13 |
| 2020 | 2.57 | 2.55 |
| 2030 | 3.08 | 3.30 |
| 2040 | 3.22 | 4.10 |
| 2050 | 3.37 | 5.12 |

Based on Dames & Moore (1985a).
Deflated from 2000 to estimate 1985, 1990, and 1995 values.

### 4.3.4 - Beluga Coal Production Cost

Production costs also were estimated for Beluga coal, using procedures identical to those described for Nenana coal. The major difference was in the mine size. The Beluga analyses were based upon mines of 8-12 million tons/year (Wierco 1985). The base costs for this analysis are shown (in 1985 dollars) in Table D1.4.10.

Given these base costs, the 1985 production costs (as escalated) are as follows (based on Dames & Moore 1985a):

| Year | Mine Mouth Coal Beluga Production Cost (1985 $/MMBtu) |
|---|---|
| 1985 | 1.17 |
| 1990 | 1.26 |
| 1995 | 1.36 |
| 2000 | 1.46 |
| 2010 | 1.69 |
| 2020 | 1.96 |
| 2030 | 2.27 |
| 2040 | 2.63 |
| 2050 | 3.04 |

Note that Beluga production costs escalate over time but remain below the export market clearing price. Production costs for Beluga coal escalate for the same reasons identified for Nenana.

### 4.4 - Alaska Coal Prices Summarized

Table D1.4.11 summarizes the Nenana and Beluga coal cost and price trends discussed above.

## 5 - DISTILLATE OIL

Distillate oil, i.e., fuel oil used in diesel engine and gas turbine generating units, is not a significant factor in the analysis of Railbelt generation alternatives for the years 1993 to 2040. With an electric interconnection between Anchorage and Fairbanks, generation with diesel engines will be eliminated except in small isolated communities. Any generation provided by oil-fired units will either be the same for all alternatives or the differences will be so small that they can be ignored in the economic comparison of the alternatives. However, to provide a complete picture for fuels actually used in the Railbelt for electrical generation, the following information on distillate oil availability and price is presented.

### 5.1 - Availability

According to Battelle (1982), there is adequate availability of distillate oil during the analysis period. Although part of the distillate oil used in Alaska is imported, this fact alone will not affect its availability. It has been assumed that distillate oil in the required quantities will be available during the economic analysis period 1993 to 2040 from refineries within Alaska or the Lower 48 states.

### 5.2 - Distillate Price

Regression analysis demonstrates that distillate oil prices are generally $1.66/MMBtu above the cost of crude oil (Statistical Abstracts, USDOC 1975, 1984, 1985). The $1.66/MMBtu represents some refining charge plus a premium for fuel quality. Because netback analysis yields natural gas prices in Alaska that are below the costs of crude oil, while regression analysis demonstrates that distillate oil always costs more than crude oil, distillate oil will not be competitive fuel for future power generation in the Railbelt interconnected power generation system.

## 6 - REFERENCES


Alaska Department of Natural Resources. 1985. Historical and Projected Oil and Gas Consumption, January 1985. Alaska Department of Natural Resources Division of Oil and Gas.

Alaska Department of Revenue. 1985. Petroleum Production Revenue Forecast. Quarterly Report, June, 1985.

Alaska Public Utilities Commission. 1984. Cost of Service by Customer Class Analysis for Revenue Requirements Study. Docket No. U-84-59.

American Gas Association. 1985. Energy Analysis: The Outlook for Ammonia Production in the U.S. AGA. Arlington, VA.

Battelle Pacific Northwest Laboratories. 1982. Railbelt Electric Power Alternative Study: Fossil Fuel Availability and Price Forecasts, Volume VII. March 1982. Page 81.

Booz, Allen and Hamilton. 1983. Evaluation of Alternatives for the Transportation and Utilization of Alaskan North Slope Gas: Summary Report.

C. ITOH & Co., LTD. (Itoh 1985). LNG Marketing in Japan. February.

Chemical Engineering Magazine. 1985. Vol. 92, No. 18. September 2. Page 7.

Dames & Moore, 1985a. Analysis of Factors Affecting Demand, Supply and Prices of Railbelt Coal. Volume 1 (Main Report).

____. 1985b. Analysis of Factors Affecting Demand, Supply and Prices. Volume 2.

____. 1985c. In house document containing calculations of Coal Price escalations. July.

____. 1984. Coal Production and Transportation Costs: U.S. and Canada Export Mines. February 1984 Revision of the April 1983 Report.

Davis, N. 1984. Energy/Alaska. University of Alaska Press.

Energy Resources Company. 1980. Low Rank Coal Study: National Needs for Resource Development. Volumes 1-6.

Fairbanks Municipal Utility System. 1976. Contract between FMUS and Usibelli Coal Mine for the sale of coal to the Chena Power Station.

French, M. 1985. Long Term Outlook for Petroleum Prices. Wharton Econometric Forecasting Associates, Philadelphia, PA. June 30.

Golden Valley Electric Association, Inc. 1981. Usibelli contract with G.V.E.A. for Current Coal Pricing.

Gordon, Andrew. 1984. Guide to World Coal Markets. Arlington: Pasha Publications.

Hay, N.E. 1985. The Outlook for Ammonia Production in the United States. Gas Energy Review (AGA) 13(7):9-12.

Hickel, W., et al. 1983. Trans Alaska Gas Systems: Economics of an Alternative for North Slope Natural Gas. Governor's Economic Committee on Natural Gas. Anchorage, AK.

Hufman, R. L. 1981. Letter from R. L. Huffman, General Manager, G.V.E.A, to B.J. Brown, Regional Manager, Acres American Inc.

Mann, C., D. Tillman and W. Wade. 1985. Analysis of the Coal Alternative for Supplying Power to the Railbelt Region of Alaska. Prepared for the Alaska Power Authority, October.

Manne, A. S. and L. Schrattenholzer. 1985. International Energy Workshop: A Progress Report. June.

Marubeni Corporation. 1984. Energy Situation and LNG Market in Japan. Prepared for New Alaskan LNG Project. Tokyo, Japan. January.

McGee, D. 1985. Letter to M. Seldman, Dames & Moore, from Don McGee, Chief Petroleum Geologist, State of Alaska, Department of Natural Resources. July 1, 1985.

Mitsui & Co., LTD. 1985. LNG Situation in Japan. Tokyo, Japan. January.

MPP Associates. 1985. Proposal for a Comprehensive Feasibility Study of the Matanuska Power Project. Prepared for Matanuska Electric Association, Inc., Palmer, Alaska.

National Research Council. 1980. Surface Coal Mining in Alaska: An Investigation of the Surface Mining Control and Reclamation Act of 1977 in Relation to Alaskan Conditions. With the National Academy of Sciences, Commission on Natural Resources, Board on Mineral and Energy Resources, and the Committee on Alaskan Coal Mining and Reclamation. As cited in Wierco 1985.

Pacific Alaska LNG Associates. Docket No. CP75-140 Exhibit No. 194 (JWO-15). Capital and Operating Cost Estimates.

Pratt, S. 1985. Personal Communication with Pratt, Financial Analyst APUC and D. Tillman of Harza-Ebasco on May 2, 1985.

Purvin and Gertz, Inc. 1983. Gas Processing Seminar. Presented to Panhandle Eastern Pipeline Co.

Sanders, R.B. 1982. Coal Resources of Alaska. Alaska Geographic 9(4): 146-165.

Schaff, R. 1983. Letter from Mr. Ross G. Schaff, State Geologist, Department of Natural Resources, Division of Geological and Geophysical Surveys, to Mr. Eric P. Yould, Executive Director, Alaska Power Authority. February 1, 1983.

Sheldrick, W.F. 1984. World Fertilizer Review and the Changing Structure of the International Fertilizer Industry. A Paper Presented at the Australian Fertilizer Manufacturer's Conference, Perth, Australia. Washington, D.C.: Industry Department, World Bank. November, 1984.

Sherman H. Clark and Associates. 1985. Oil Price Outlook: February 1985. Prepared for Harza-Ebasco Susitna Joint Venture.

Smith, D. 1985. Personal Communication between Marvin Feldman, Dames & Moore and Dennis Smith. Alaska Railroad. July 16, 1985.

State of Alaska vs. Phillips Petroleum Company. 1984. Joint Stipulation of Facts Dated April, 1984. In the Superior Court for the State of Alaska. No. I-JU-81-698 CIV.

State of Alaska vs. Phillips Petroleum Company. 1984. Settlement Agreement. In the Superior Court for the State of Alaska. No. 1-JU-81-698 CIV.

Sumitomo Corporation. 1985. LNG: Monthly Statistics in Japan. April.

Tarrant, B. 1985. Another LNG Plant for Peninsula. Alaska Oil and Gas News. Volume 4, Number 3, March, 1985.

Thirteenth Amendatory Agreement to Liquefied Natural Gas Sales Agreement between Tokyo Electric Power Company, Inc., Tokyo Gas Company, Ltd., Marathon Oil Company, and Phillips Petroleum Company, effective April 1, 1982, and the Supplementary Administrative Memorandum. State of Alaska, Department of Law.

Thrush, P., et al. 1968. A Dictionary of Mining, Mineral, and Related Terms. U.S. Bureau of Mines, Washington, D.C.

Title II of the Power Plant & Industrial Fuel Use Act of 1978 (FUA), 42 U.S.C. para. 8311-8324.

U.S. Department of Commerce. 1984. Statistical Abstract of the United States. 104th Edition.

____. 1985. Statistical Abstract of the United States. 105th Edition.

____. 1975. The U.S. Fact Book: The American Almanac. 95th Edition.

____. 1971. Historical Statistics of the U.S. Colonial Times to 1970, Part I (For 1910-1970) Series M96.

Weirco. 1985. Hypothetical Mining Studies and Coal Price Estimates - Beluga and Nenana Coal Fields, for Harza-Ebasco Susitna Joint Venture. Job. No. 2988-c. November.

Wunnicke, E. 1985. Letter from the Commissioner of the Alaska Department of Natural Resources to Ben Grussendorf, Speaker, Alaska State House of Representatives with Attachment, March 11.

# TABLES

TABLE D1.3.1: NATURAL GAS VALUES DELIVERED IN TOKYO COMPARED TO CRUDE OIL VALUES

| Crude Oil Price ($/bbl) | Crude Oil Price 1/ ($/MMBtu) | Natural Gas Price 2/ ($/MMBtu) |
|---|---|---|
| 10 | 1.72 | 1.71 |
| 20 | 3.45 | 3.44 |
| 30 | 5.17 | 5.16 |
| 40 | 6.90 | 6.87 |
| 50 | 8.62 | 8.60 |
| 60 | 10.34 | 10.31 |
| 70 | 12.07 | 12.03 |
| 75 | 12.93 | 12.89 |

1/ $\$/\text{bbl} \times \frac{\text{bbl}}{5.8\ \text{MMBtu}}$

2/ $P_{(n)} = 592.8 \times \frac{G(n-1)}{34.48}$ (from Supplementary Administrative Memorandum)

$P_{(n)}$ = LNG price (¢/MMBtu)

$G_{(n-1)}$ = Government selling price for crude oil in $/bbl. on the last day of the month (n-1) prior to the month when the LNG is sold.

Source: Thirteenth Amendatory Agreement to Liquefied Natural Gas Sales Agreement between Tokyo Electric Power Company, Inc., Tokyo Gas Company Ltd., Marathon Oil Company, and Phillip's Petroleum Company, Effective April 1, 1982 and the Supplementary Administrative Memorandum.

TABLE D1.3.2: WORLD OIL PRICE FORECASTS BY CASE
(1985 $/MMBtu)

| Year | Wharton Case | Composite Case | SHCA Case |
|---|---|---|---|
| 1985 | 4.70 | 4.70 | 4.80 |
| 1990 | 4.30 | 4.60 | 4.80 |
| 1995 | 4.80 | 5.50 | 5.70 |
| 2000 | 5.40 | 6.60 | 7.10 |
| 2010 | 7.00 | 8.80 | 10.60 |
| 2020 | 9.40 | 11.90 | 14.70 |
| 2030 | 12.70 | 12.90 | 16.60 |
| 2040 | 12.90 | 12.90 | 18.30 |
| 2050 | 12.90 | 12.90 | 20.20 |

TABLE D1.3.3: ESTIMATED CAPITAL, OPERATING AND MAINTENANCE, AND FUEL COSTS OF A 200 MMCF LIQUIFIED NATURAL GAS FACILITY FOR COOK INLET, ALASKA (Million 1985 $)

| Parameter | Cost |
|---|---|
| Capital Cost | |
| Liquefaction | 652 |
| Regasification | 304 |
| TOTAL | 956 |
| Operating and Maintenance Costs | |
| Liquefaction | 13.0/yr |
| Regasification | 4.1/yr |
| TOTAL | 17.1/yr |
| Fuel Requirements | |
| Liquefaction | 10.6% of delivered |
| Regasification | 0.5% of delivered |
| TOTAL | 11.1% of delivered |

Sources: Hickel, et al., 1983; Purvin & Gertz 1983; Chemical Engineering Magazine 1985

TABLE D1.3.4: LEVELIZED NON-FUEL PRODUCTION COSTS FOR LNG DELIVERED FROM COOK INLET TO JAPAN

| Cost Category | Real Levelized Cost (1985$/MMBtu) | Percent of Total Cost |
|---|---|---|
| Capital | | |
| Liquefaction | $1.32 | 61.4 % |
| Regasification | .61 | 28.4 % |
| Subtotal | 1.93 | 89.8 |
| Operating and Maintenance | | |
| Liquefaction | .17 | 7.9 % |
| Regasification | .05 | 2.3 % |
| Subtotal | 0.22 | 10.2 |
| Total | 2.15 | 100 % |

TABLE D1.3.5: ESTIMATED LNG TRANSPORTATION COSTS BY WORLD OIL PRICE SCENARIO (1985 $/MMBtu)

| Year | Wharton Case | Composite Case | SHCA Case |
|---|---|---|---|
| 1985 | .74 | .74 | .74 |
| 1990 | .71 | .73 | .73 |
| 2000 | .80 | .89 | .91 |
| 2010 | .93 | 1.07 | 1.18 |
| 2020 | 1.12 | 1.31 | 1.49 |
| 2030 | 1.38 | 1.40 | 1.63 |
| 2040 | 1.40 | 1.40 | 1.76 |
| 2050 | 1.40 | 1.40 | 1.90 |

TABLE D1.3.6: CAPITAL COSTS FOR LIQUEFACTION AND REGASIFICATION IN ALTERNATIVE LNG SENSITIVITY CASES (1985$)

| Parameter | Case | | | |
|---|---|---|---|---|
| | TAGS-Phase II | | TAGS-Phase III | |
| | Total$x10^6$ | $/MMBtu/Yr | Total$x10^6$ | $/MMBtu/Yr |
| Liquefaction | 1,923 | 7.51 1/ | 4,776 | 6.25 1/ |
| Regasification | 889 | 3.47 2/ | 2,209 | 2.89 2/ |
| Total | 2,812 | 10.98 3/ | 6,985 | 9.14 3/ |

1/ By means of comparison the base case value is $9.36/MMBtu/Yr
2/ By means of comparison the base case value is $4.36/MMBtu/Yr
3/ By means of comparison the base case value is $13.72/MMBtu/Yr

Sources: Hickel, et. al., 1983; Purvin & Gurtz 1983

TABLE D1.3.7: ALTERNATIVE TRANSPORTATION COSTS FOR SHIPPING LNG FROM COOK INLET TO JAPAN (1985 $/MMBtu)

| Condition/Scenario | Base Price |
|---|---|
| Booz, Allen & Hamilton TAGS Estimate | |
| Weak Economy | 0.35 |
| Strong Economy | 0.41 |
| Flat Prices | 0.33 |
| Governor's Economic Committee | |
| New LNG Tankers | 1.23 |
| Chartered Tankers 1/ | 0.74 |
| El Paso Tankers (Chartered) | 0.65 |

1/ Value used in this analysis.

Source: Booz, Allen & Hamilton 1983.

TABLE D1.3.8: 1981 NATURAL GAS REVENUE REQUIREMENTS (1981 $)

| Cost Category | CEA and AML&P Total ($) | CEA and AML&P $/MCF | Total Total ($) | $/MCF |
|---|---|---|---|---|
| Total Gas Consumed (MCF) | 9,959,127 | N/A | 29,835,835 | N/A |
| Expenses | | | | |
| Operation & Maintenance | | | | |
| Production & Gathering | 6,476,280 | .650 | 19,425,580 | .651 |
| Transmission | 170,714 | .017 | 640,770 | .021 |
| Distribution | 208,523 | .021 | 2,266,666 | .076 |
| Customer Accounts | 1,850 | NEGL | 1,643,280 | .055 |
| Service & Information | 224 | NEGL | 199,421 | .007 |
| Sales | 432 | NEGL | 384,394 | .013 |
| Administrative | 234,086 | .024 | 2,963,339 | .099 |
| Depreciation | 464,058 | .047 | 2,550,172 | .085 |
| Non-Income Taxes | 90,243 | .009 | 708,468 | .024 |
| Return on Investment | 1,331,532 | .134 | 7,304,108 | .245 |
| Income Taxes | 709,064 | .071 | 3,889,568 | .130 |
| Total Cost of Service | 9,759,006 | 0.98 | 41,975,766 | 1.41 |
| - Cost of Gas Acquisition 1/ | (6,444,723) | (0.65) | (19,307,344) | (0.65) |
| Net Non-Fuel Cost of Service | 3,134,283 | 0.33 | 22,668,422 | 0.76 |

1/ 65¢/MCF was the average cost of natural gas purchased by Enstar for sale to its customers in 1981. This is confirmed by Master Tariff filings of Enstar before the APUC.

Source: APUC 1984.

TABLE D1.3.9: 1981 NATURAL GAS REVENUE REQUIREMENTS TO UTILITIES EXPRESSED IN JAN. 1, 1985 $

| Cost Category | Total Cost[1/] | $/MCF |
|---|---|---|
| Total Gas Consumed | | 9,959,127 MCF |
| Expenses | | |
| Operation & Maintenance | | |
| Production & Gathering | 7,583,723 | .761 |
| Transmission | 199,906 | .020 |
| Distribution | 238,492 | .025 |
| Customer Accounts | 2,166 | NEGL |
| Service & Information | 262 | NEGL |
| Sales | 506 | NEGL |
| Administrative | 274,958 | .028 |
| Depreciation | 543,412 | .055 |
| Non-Income Taxes | 105,675 | .011 |
| Return on Investment | 1,559,224 | .157 |
| Income Taxes | 830,314 | .083 |
| Total Cost of Service | 11,427,796 | 1.140 |
| - Cost of Gas Acquisition | (7,546,771) | (.761) |
| Net Non-fuel Cost of Service | 3,670,245 | .38 |

1/ Escalated from 1981 dollars by a factor of 229.07/195.60 = 1.171.

Source: Calculated from Table D1.3.8.

TABLE D1.3.10: CALCULATION OF GAS COSTS DELIVERED TO UTILITIES FOR THE COMPOSITE OIL PRICE SCENARIO USING BASE CASE NETBACK PRICE ASSUMPTIONS (IN 1985$/MMBtu)

| YEAR | GAS Cost | | Total Cost |
|---|---|---|---|
| | Wellhead Value | Delivery Charge | |
| 1985 | 1.58 | 0.40 | 1.98 |
| 1990 | 1.50 | 0.40 | 1.90 |
| 1995 | 2.25 | 0.40 | 2.65 |
| 2000 | 3.13 | 0.40 | 3.53 |
| 2010 | 4.97 | 0.40 | 5.37 |
| 2020 | 7.45 | 0.40 | 7.85 |
| 2030 | 8.30 | 0.40 | 8.70 |
| 2040 | 8.30 | 0.40 | 8.70 |
| 2050 | 8.30 | 0.40 | 8.70 |

TABLE D1.3.11: ALASKA DNR ESTIMATES OF PROVEN AND RECOVERABLE COOK INLET NATURAL GAS RESERVES BY FIELD (Billion Cubic Feet)

| Field | Remaining Recoverable Reserves as of January 1, 1985 |
|---|---|
| Kenai | 850 |
| North Cook Inlet | 650 |
| Beluga River | 800 |
| Swanson River | 260 |
| Cannery Loop | 300 |
| McArthur River and Trading Bay | 650 |
| Beaver Creek | 230 |
| Cook Inlet Associated Gas | 60 |
| Ivan River - Lewis River - Pretty Creek - Stumplake | 600 |
| Other | 63 |
| Total | 4,463 |

Source: Wunnicke 1985.

TABLE D1.3.12: ALASKA DNR ESTIMATE OF UNDISCOVERED NATURAL GAS RESOURCES IN COOK INLET BASIN (Trillion Cubic Feet)

| Probability | Undiscovered Resources | |
|---|---|---|
| | Total | Economically Recoverable |
| .99 | .47 | .00 |
| .95 | .93 | .22 |
| .90 | 1.24 | .43 |
| .75 | 1.98 | .93 |
| .50 | 3.07 | 1.76 |
| .25 | 4.38 | 2.78 |
| .10 | 5.84 | 4.04 |
| .05 | 6.93 | 4.90 |
| .01 | 9.06 | 6.83 |

Source: Schaff 1983.

TABLE D1.3.13: ALASKA DNR COOK INLET NATURAL GAS PRODUCTION AND USE 1971-1984

| | Gas Production and Use (Billion Cubic Feet) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | Producers | | |
| Year | Field Ops | LNG | Ammonia Urea | Power | Gas Utilities 1/ | Refiners | Other | Total |
| 1971 | 45.3 | 63.2 | 19.5 | 14.7 | 10.2 | N/A | 14.1 | 154 |
| 1975 | 28.8 | 64.8 | 23.9 | 25.5 | 12.1 | 12.4 | 2.0 | 170 |
| 1978 | 25.9 | 60.9 | 48.9 | 29.7 | 13.5 | 10.5 | 0.9 | 190 |
| 1981 | 20.6 | 68.8 | 53.8 | 33.6 | 15.8 | 5.6 | 0.4 | 199 |
| 1984 | 20.5 | 65.5 | 50.9 | 34.5 | 19.3 | 12.0 | 4.3 | 207 |

1/ Residential and commercial use.

Source: ADNR 1985.

TABLE D1.3.14: ALASKA DNR PROJECTED COOK INLET NATURAL GAS DEMAND 1985-1999 (Billion Cubic Feet)

| Sector | Year | | | | |
|---|---|---|---|---|---|
| | 1985 | 1990 | 1995 | 1999 | Total |
| Ammonia Urea | 50.0 | 50.0 | 50.0 | 50.0 | 750 |
| Military | 4.6 | 4.6 | 4.6 | 4.6 | 69 |
| Utilities 1/ | 35.6 | 39.6 | 39.3 | 42.8 | 589 |
| Field Operations 2/ | 21.2 | 22.1 | 22.8 | 23.5 | 336 |
| LNG 3/ | 65.0 | 65.0 | 65.0 | 65.0 | 975 |
| Residential and Commercial 2/ | 20.1 | 24.5 | 30.2 | 34.0 | 402 |
| Other 3/ (producer, refiner, & misc.) | 17.5 | 18.2 | 18.1 | 18.1 | 266 |
| Total | 214 | 224 | 230 | 238 | 3,387 |

1/ This compares to an OGP derived forecast of 658 BCF. The ADNR forecast is 12 percent more conservative and is therefore used.
2/ Treated as 10 percent of Total based on 1971-1984 average.
3/ Extrapolated at current rates of consumption.

Source: ADNR 1985.

TABLE D1.3.15: COSTS ASSOCIATED WITH AMMONIA PRODUCTION IN SELECTED COUNTRIES (1985 $/ton)

| Country of Production | Cost of Ammonia Production | |
|---|---|---|
| | Capital Cost | Product Total Cost (delivered to U.S.) |
| USA | | |
| Existing Plant | $ 41 | $ 132 |
| New Plant | 185 | 256 |
| Mexico | 208-281 | 244-343 |
| Trinidad | 209-282 | 246-349 |
| Chile | 209-282 | 256-349 |
| Canada | 206 | 272-277 |
| USSR | 282 | 319-359 |
| Nigeria | 209-282 | 256-349 |
| Middle East | 209-282 | 266-369 |
| Indonesia | 209-282 | 266-379 |
| Australia | 206-267 | 313-405 |

Source: AGA 1985.

TABLE D1.3.16: POTENTIAL DEMAND FOR COOK INLET NATURAL GAS 2000-2050 (Trillion Cubic Feet)

| Market | Total Requirement for 50 Year Period<br>Field Operations = 10% |
|---|---|
| Residential & Commercial | 2.9 |
| Existing Power Plants and Peaking Units 1/ | 0.3 |
| Military | 0.3 |
| Urea | 2.8 |
| Liquefied Natural Gas | 3.7 |
| Total | 10.0 |

1/ There is an assumed commitment to any power plant that is forecast by the OGP model to come on-line.

TABLE D1.3.17: ESTIMATED NORTH SLOPE RECOVERABLE RESERVES OF NATURAL GAS (Billion Cubic Feet)

| | Low | Mid | High |
|---|---|---|---|
| Prudhoe Bay Unit | | | |
| Sadlerochit reservoir | 29,000 | 29,000 | 29,000 |
| Sag River reservoir | -- | -- | -- |
| Lisburne reservoir | 800 | 1,100 | 1,600 |
| Endicott | 600 | 800 | 1,200 |
| Point Thomson Area and Flaxman Island Area | 3,200 | 5,000 | 6,000 |
| North Prudhoe Bay West Dock Area | -- | -- | -- |
| Milne Point Area | -- | -- | -- |
| Gwydyr Bay Area | -- | -- | -- |
| Shallow Cretaceous Sands | -- | -- | -- |
| Kuparuk River Unit | 135 | 220 | 260 |
| Subtotal | 33,735 | 36,120 | 38,060 |
| Undiscovered 1/ | 3,264 | 3.264 | 15,000 |
| State Total | 36,999 | 39,384 | 53,060 |

1/ Derived by Harza/Ebasco.

Source: ADNR 1985.

TABLE D1.4.1: SUMMARY OF ALASKA'S COAL RESOURCES

Coal Resources (estimates in millions of tons)

| Region | Identified Resources: Demonstrated: Measured a | Identified Resources: Demonstrated: Indicated b | Identified Resources: Demonstrated: Total c=a+b | Identified Resources: Inferred d | Identified Resources: Total Identified e=c+d | Undis-covered Resources Hypothet-ical and Speculative f | Total Resources e+f |
|---|---|---|---|---|---|---|---|
| Arctic | 35 | 2,760 | 2,800 | 118,000-119,000 | 60,000-146,000 1/ | 402,000-4,000,000 | 462,000 4,150,000 |
| Northwest | -- | -- | -- | -- | -- | -- | -- |
| Interior | 862 | 2,700 | 3,560 | 3,380 | 6,940 | 10,400 | 17,300 |
| Southwest | -- | -- | -- | -- | -- | -- | -- |
| Southcentral | 767 | 2,070 | 2,820 | 7,850 | 10,700 | 1,480,000 | 1,490,000 |
| Southeast | -- | -- | -- | -- | -- | -- | -- |
| Totals 2/ | 1,664 | 7,530 | 9,180 | 129,000-130,000 | 77,600-164,000 | 1,900,000-5,500,000 | 1,980,000-5,660,000 |

1/ This entry reflects the range in estimates given by Sanders (1982) rather than the actual sum of demonstrated and inferred resources.

2/ Totals do not add due to rounding on demonstrated measured resources.

Source: Davis 1984.

TABLE D1.4.2: RESERVES AND RESOURCE OF THE NENANA FIELD

| Reserve/Resource Type | Quantity (million tons) |
|---|---|
| Reserve Base | 457 |
| Resources | |
| Measured | 862 |
| Indicated | 2,700 |
| Inferred | 3,400 |
| TOTAL | 6,900 1/ |

1/ Totals do not add due to rounding on measured and inferred. The reserve base is included in the measured resources.

Source: Energy Resources Company 1980.

TABLE D1.4.3: APPROXIMATE POTENTIAL PACIFIC RIM COAL IMPORTS 1990-2040 (MILLION TONS)

| Year | Metric Tons Coal Equivalent 1/ (MTCE) | Steam Coal for Electric Power Actual (Beluga) Tons 2/ |
|---|---|---|
| 1990 | 63 | 100 |
| 2000 | 108 | 200 |
| 2010 | 176 | 300 |
| 2020 | 256 | 500 |
| 2030 | 349 | 600 |
| 2040 | 395 | 700 |

1/ 27.8 million Btu/ton.

2/ May not convert due to rounding.

Source: Dames & Moore (1985a, Table 3-2, pg. 42).

TABLE D1.4.4: POTENTIAL UNCONSTRAINED ALASKA COAL EXPORTS (MILLION TONS)

| Year | Million Tons Per Year (Actual) |
|---|---|
| 2000 | 31 |
| 2010 | 78 |
| 2020 | 131 |
| 2030 | 195 |
| 2040 | 226 |

Source: Dames & Moore (1985a).

TABLE D1.4.5: POTENTIAL BELUGA COAL DEVELOPMENT UNDER MANAGED CONDITIONS

| Year | Million Tons Per Year |
|---|---|
| 2000 | 10-15 |
| 2010 | 25-30 |
| 2030 | 50-60 |
| 2050 | 75-100 |

Source: Dames & Moore (1985a).

TABLE D1.4.6: PRODUCTION COST ANALYSIS FOR NENANA COAL (1985 $)

| Parameter | 2 Million Ton/Yr Incremental Capacity 1/ |
|---|---|
| Production Rate (tons/yr) | 2,000,000 |
| Mine Life (yrs) | 20 |
| Average Stripping Ratio | 3.73 |
| Personnel Requirements | |
| Operating | 93 |
| Maintenance | 75 |
| Salaried | 34 |
| Total | 202 |
| Tons per Manshift | 39.6 |
| Capital Investment | |
| Initial Investment (thousands) | $75,059 |
| Initial Investment per Annual Ton | 37.53 |
| Life of Mine Investment (thousands) | 140,350 |
| Average Annual Operating & Maintenance Costs (per ton) | 13.12 |
| Average Depreciation of Total Capital | 3.54 |
| Average Total Production Costs | $16.66 |
| Levelized Coal Price Per Ton | |
| At 8.2 percent real discount rate 2/ | $22.10 |
| Levelized Coal Price Per Million Btu | |
| At 8.2 percent real discount rate 2/ | $1.45 |

1/ Incremental production to increase from 2 million to 4 million tons/yr.

2/ Reflects nominal rate of return of 14.2 percent and underlying rate of inflation of 5.5. percent.

TABLE D1.4.7: PRODUCTION COST ESCALATION FOR NENANA FIELD COAL

| Parameter | Usibelli Coal Golden Valley Electric Assn. | Contract Fairbanks Municipal Utility System |
|---|---|---|
| Base (Contract) Year | 1974 | 1976 |
| Base Coal Price | $0.47/MMBtu | $0.72/MMBtu 1/ |
| Current Coal Price 2/ | $1.30/MMBtu | $1.56/MMBtu |
| Escalation Period | 11.25 yrs 3/ | 8.5 yrs 4/ |
| Escalation Rate | 9.46%/yr | 9.52%/yr |
| Inflation Rate During Escalation Period | 7.2%/yr | 6.7%/yr |
| Real Rate of Coal Price Escalation | 2.2%/yr 5/ | 2.6%/yr |

1/ $12.61/ton x ton/17.4 MMBtu
2/ First quarter, 1985 as reported by GVEA and FMUS.
3/ Contract began December 1, 1973.
4/ Contract began July 1, 1976.
5/ If the GVEA rate is calculated over a 20 year period, the nominal escalation rate for coal is 8.0%/yr and the inflation rate is 5.9%. The real escalation rate is 2.0%/yr.

Sources: Utility current coal prices; Usibelli contracts with GVEA and FMUS.

Statistical Abstract (1984) and U.S. Department of Commerce.

TABLE D1.4.8: NENANA REAL COAL PRODUCTION COST ESCALATION
(Basis: Mine Mouth Coal Cost, 1985 $)

| Case | Parameter | 1985 Cost ($/ton) | Escalation Rate (percent) | 2050 Cost ($/ton) |
|---|---|---|---|---|
| 2 million ton/year | Labor | 8.26 | 2.2 | 36.04 |
| | Fuels and Lube | 0.97 | 2.2 | 2.25 |
| | Electricity | 0.76 | 1.3 | 1.76 |
| | Royalty | 2.76 | 1.4 1/ | 7.05 |
| | Other Operating Costs, Capital, and Taxes | 9.33 | 0.0 | 9.33 |
| | TOTAL | 22.08 | 1.45 1/ | 56.43 |

1/ Derived.

Source: Dames & Moore (1985a).

TABLE D1.4.9: PRESENT AND PROJECTED NENANA COAL PRICES
($1985 per Million Btu)

| Year | Cost Component: Mine Mouth Coal Production[1] | Cost Component: Rail Transportation[2] | Delivered Cost |
|---|---|---|---|
| 1985 | 1.45 | 0.39 | 1.84 |
| 1990 | 1.56 | 0.43 | 1.99 |
| 1995 | 1.67 | 0.47 | 2.14 |
| 2000 | 1.80 | 0.51 | 2.31 |
| 2010 | 2.08 | 0.61 | 2.69 |
| 2020 | 2.40 | 0.73 | 3.13 |
| 2030 | 2.77 | 0.87 | 3.64 |
| 2040 | 3.20 | 1.04 | 4.24 |
| 2050 | 3.70 | 1.24 | 4.94 |

1/ Derived from Wierco (1985) and Dames & Moore (1985a).

2/ Based on the 1985 ARR tariff of $5.92 per ton (personal communication, Dennis Smith, ARR, 7/16/85).

TABLE D1.4.10: SUMMARY OF RESULTS HYPOTHETICAL MINE STUDIES FOR LARGE BELUGA MINES (1985 $)

| Parameter | Production Rate | |
|---|---|---|
| | 8 Million Ton/Yr | 12 Million Ton/Yr |
| Mine life (years) | 30 | 30 |
| Average stripping ratio | 6.75 | 6.93 |
| <u>Personnel Requirements</u> | | |
| Operating | 297 | 473 |
| Maintenance | 306 | 505 |
| Salaried | 88 | 113 |
| Total | 691 | 1,091 |
| Tons per manshift | 46.3 | 44.0 |
| <u>Capital Investment</u> | | |
| Initial investment (thousands) | $277,176 | $424,369 |
| Initial investment per annual ton | $34.65 | $35.36 |
| Life of mine investment (thousands) | $573,660 | $866,420 |
| <u>Average Annual Operating and Maintenance Costs (Per Ton)</u> | $11.38 | $11.71 |
| Average depreciation of total capital | $ 2.48 | $ 2.46 |
| Average Total Production Costs | $13.86 | $14.17 |
| <u>Levelized Coal Price Per Ton</u> | | |
| At 8.2 percent real discount rate 2/ | $17.50 | $18.34 |
| <u>Levelized Coal Price Per Million Btu 1/</u> | | |
| At 8.2 percent real discount rate 2/ | $ 1.17 | $ 1.22 |

1/ Assumes 7,500 Btu/lb.

2/ Reflects nominal rate of return of 14.2 percent and underlying rate of inflation of 5.5 percent.

TABLE D1.4.11: PROJECTED COSTS OF COAL DELIVERED IN THE RAILBELT REGION OF ALASKA (in 1985$/MMBtu)

| Year | Nenana Field (Delivered) | Beluga Market Clearing | | Beluga Field Production |
|---|---|---|---|---|
| | | SHCA | Composite | |
| 1985 | 1.84 | (1.30) | (1.42) | 1.17 |
| 1990 | 1.99 | (1.45) | (1.54) | 1.26 |
| 1995 | 2.14 | (1.60) | (1.65) | 1.36 |
| 2000 | 2.31 | 1.78 | 1.78 | 1.46 |
| 2010 | 2.69 | 2.13 | 2.30 | 1.69 |
| 2020 | 3.13 | 2.55 | 2.57 | 1.96 |
| 2030 | 3.64 | 3.30 | 3.08 | 2.27 |
| 2040 | 4.24 | 4.10 | 3.22 | 2.63 |
| 2050 | 4.94 | 5.12 | 3.37 | 3.04 |

# FIGURES

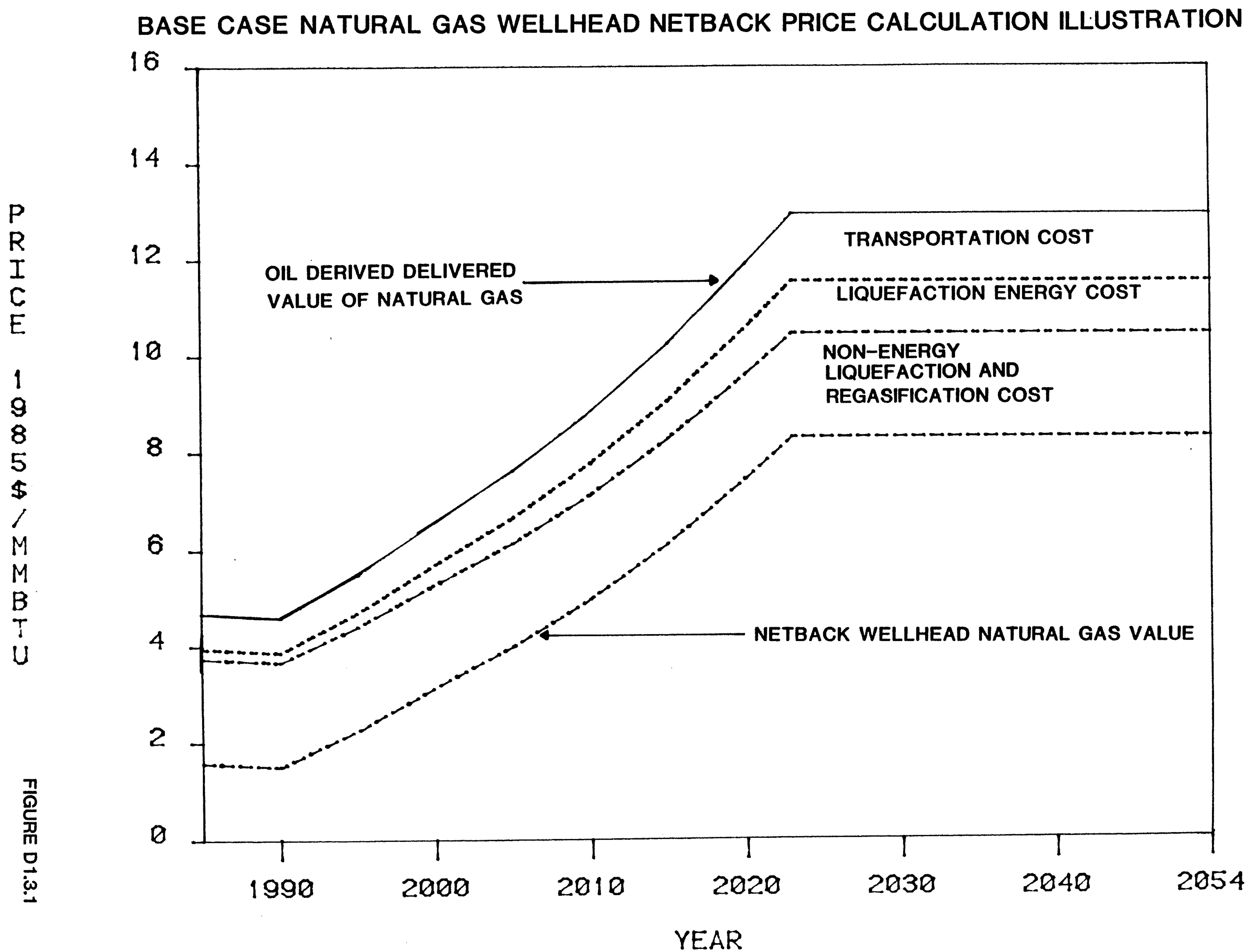

BASE CASE NATURAL GAS WELLHEAD NETBACK PRICE CALCULATION ILLUSTRATION
PRICE 1985$/MMBTU
16
14
12
10
8
6
4
2
0
OIL DERIVED DELIVERED VALUE OF NATURAL GAS
TRANSPORTATION COST
LIQUEFACTION ENERGY COST
NON-ENERGY LIQUEFACTION AND REGASIFICATION COST
NETBACK WELLHEAD NATURAL GAS VALUE
1990
2000
2010
2020
2030
2040
2054
YEAR

FIGURE D1.3.1

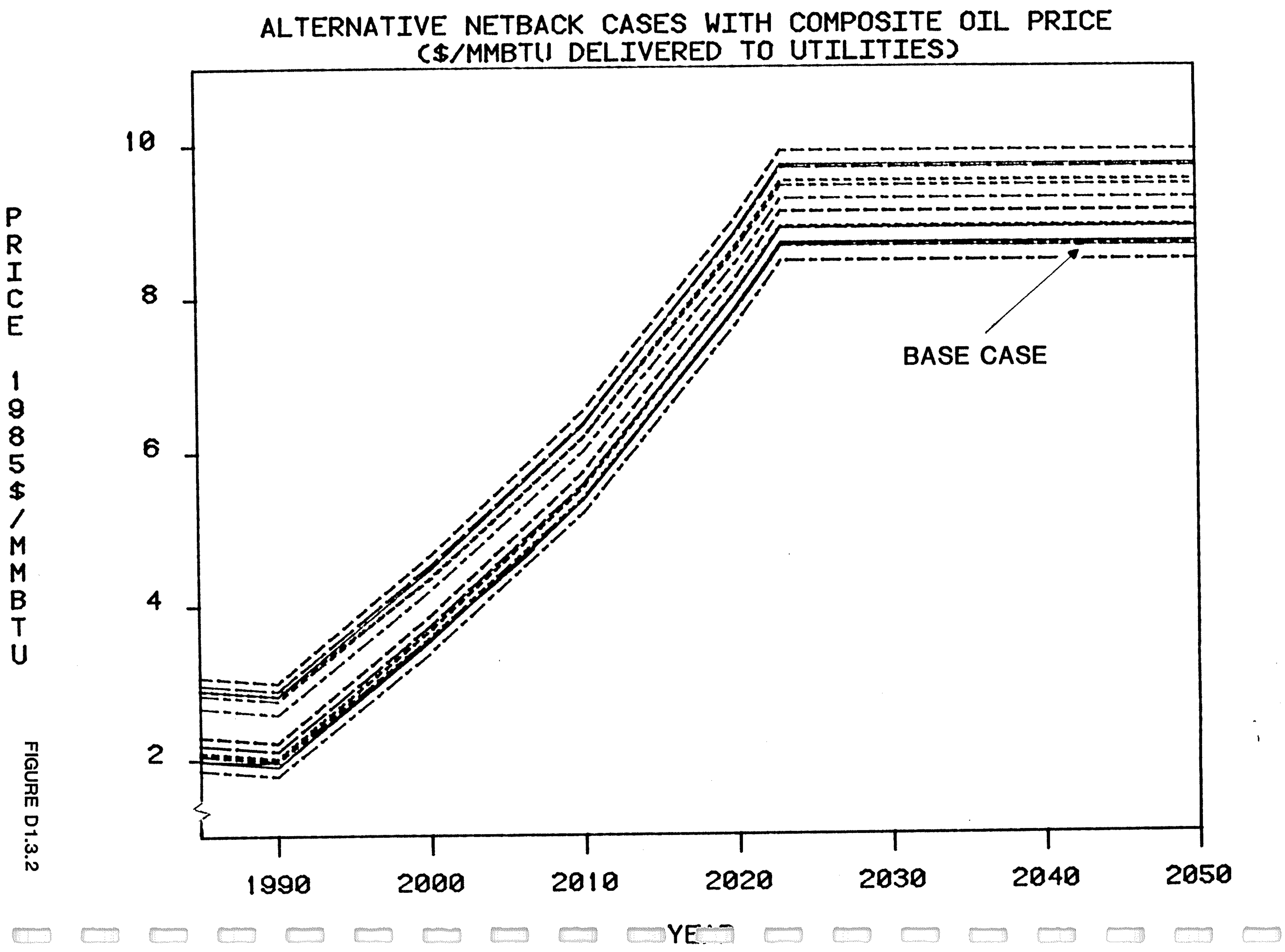

ALTERNATIVE NETBACK CASES WITH COMPOSITE OIL PRICE
($/MMBTU DELIVERED TO UTILITIES)
PRICE 1985$/MMBTU
10
8
6
4
2
BASE CASE
1990
2000
2010
2020
2030
2040
2050
YEAR

FIGURE D1.3.2

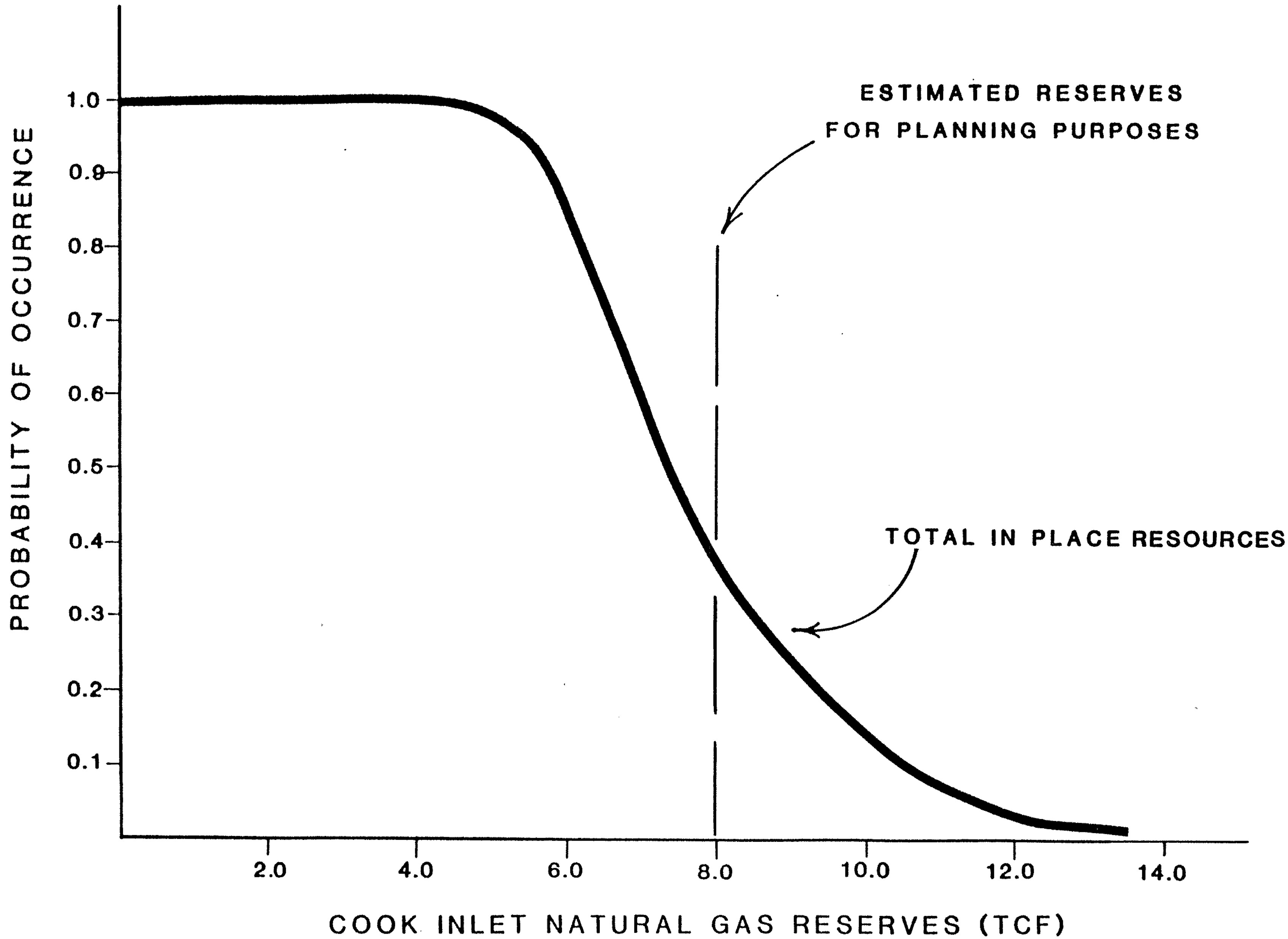

ESTIMATED RESERVES
FOR PLANNING PURPOSES
TOTAL IN PLACE RESOURCES
PROBABILITY OF OCCURRENCE
1.0
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
2.0
4.0
6.0
8.0
10.0
12.0
14.0
COOK INLET NATURAL GAS RESERVES (TCF)

FIGURE D1.3.3

## The McKelvey Diagram

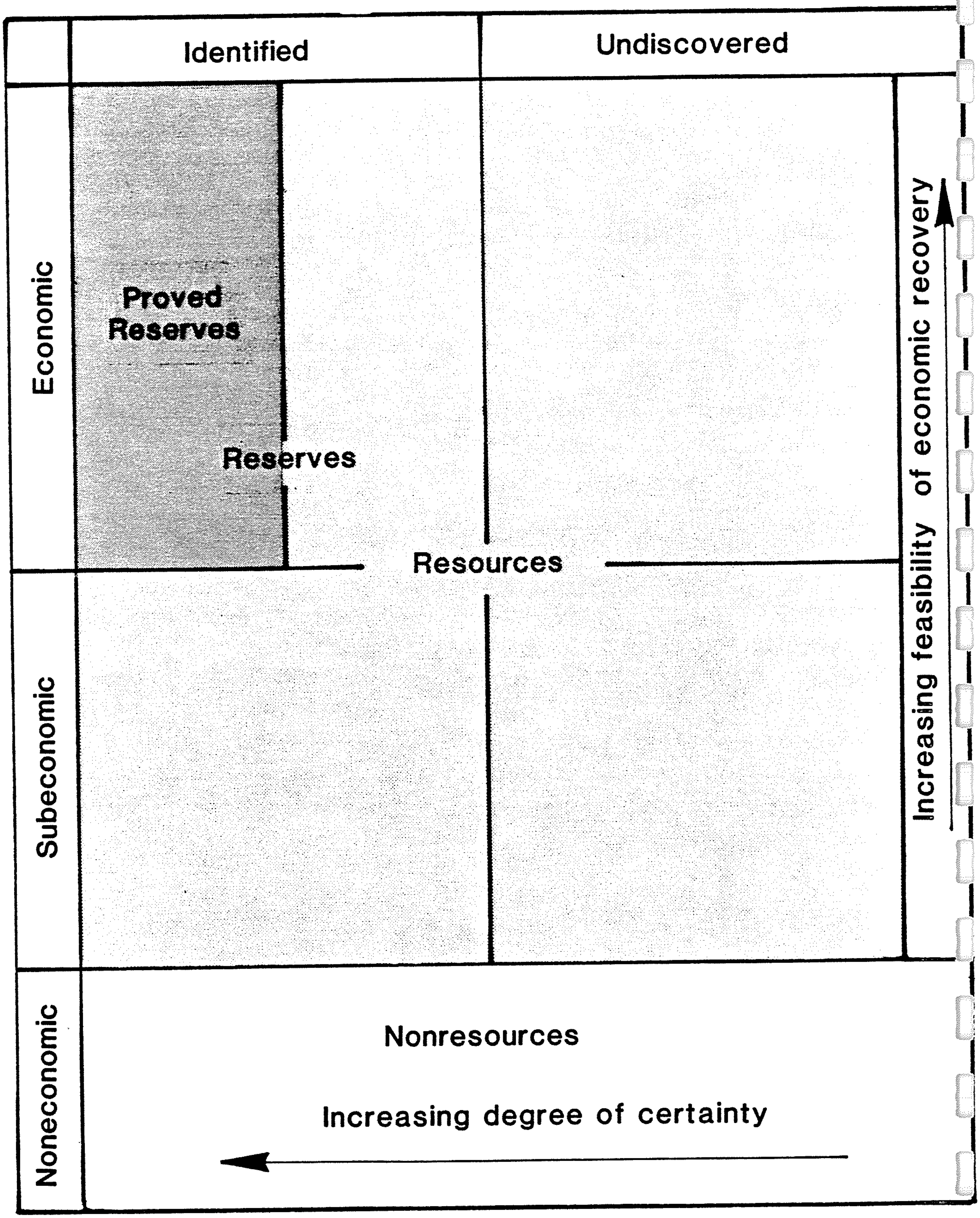
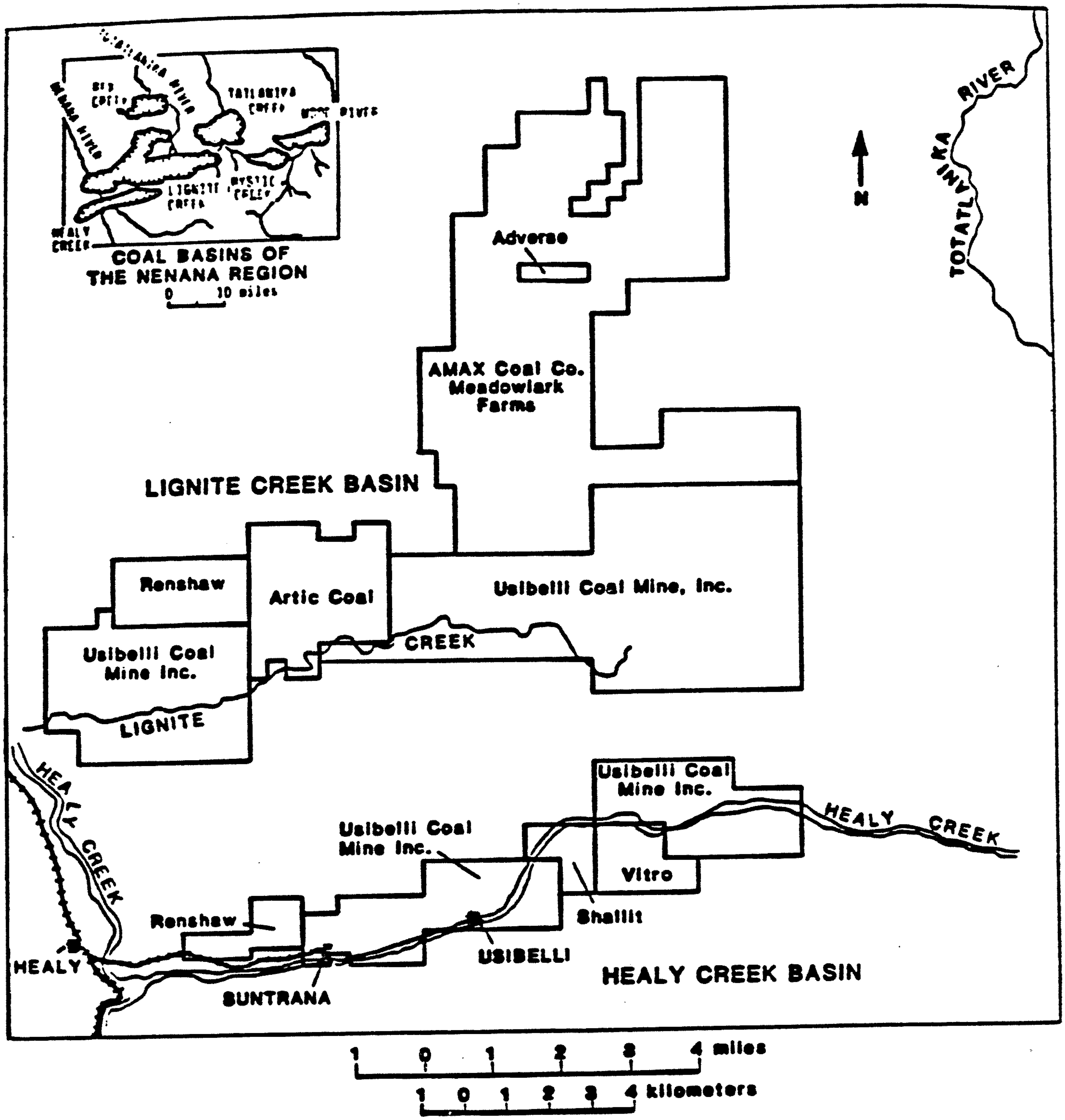


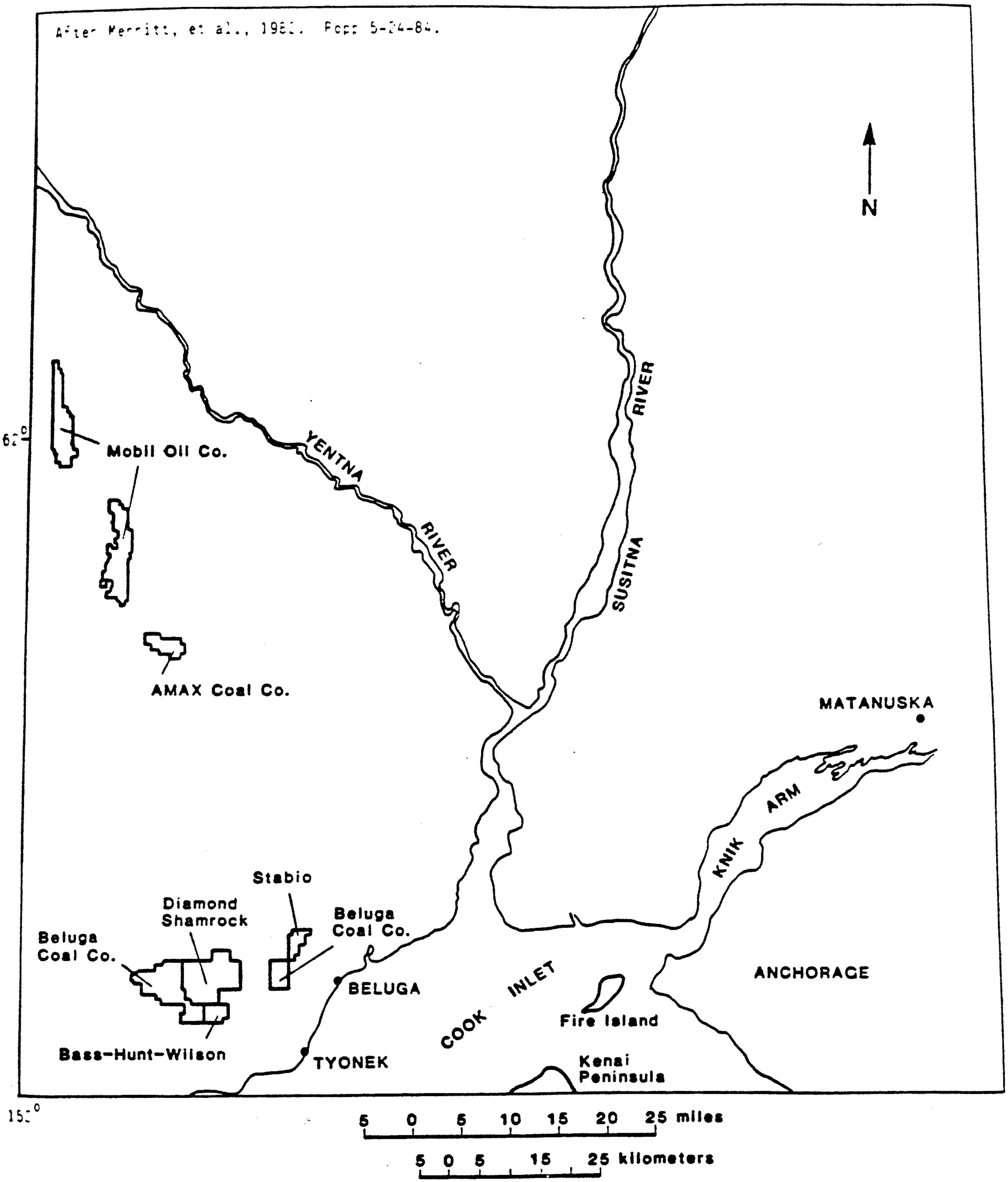

FIGURE D1.3.4




After Wahrhaftig, 1970 and Usibelli Coal Mine Inc. file map. Pers 5-23-84.

COAL LEASEHOLDERS IN THE NENANA COALFIELD
Lignite Creek and Healy Creek Basins

FIGURE D1.4.1




# MAJOR COAL LEASEHOLDERS
## Beluga-Yenta Coalfields

FIGURE D1.4.2