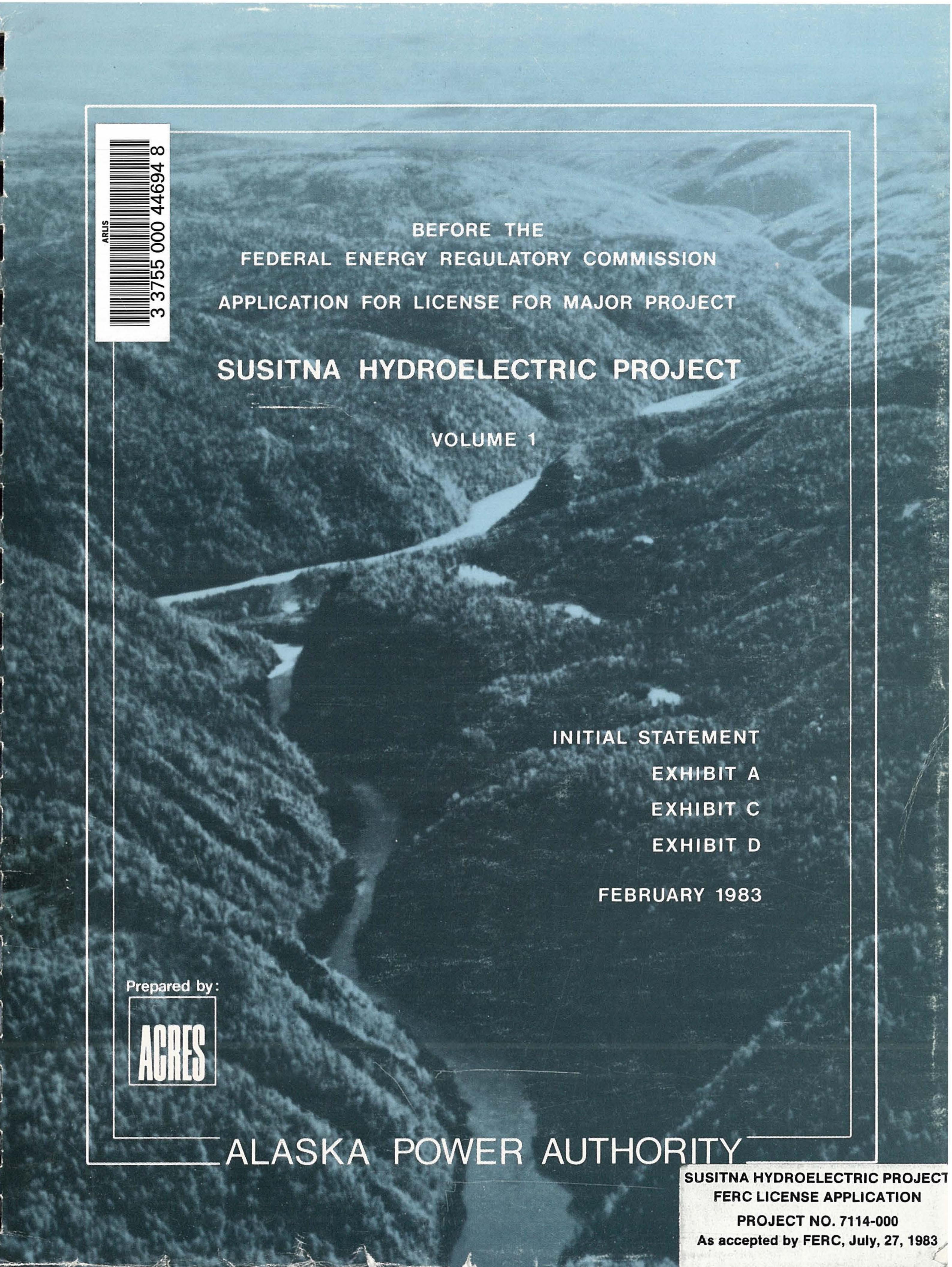

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

INITIAL STATEMENT
EXHIBIT A
EXHIBIT C
EXHIBIT D

FEBRUARY 1983

Prepared by:

ACRES

ALASKA POWER AUTHORITY

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

INITIAL STATEMENT
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FEBRUARY 1983

EXHIBIT D
REVISED JULY 1983

ALASKA POWER AUTHORITY

INITIAL STATEMENT

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION:
APPLICATION FOR LICENSE FOR A
MAJOR UNCONSTRUCTED PROJECT OR MAJOR MODIFIED PROJECT

(1) The Alaska Power Authority applies to the Federal Energy Regulatory Commission for a license for the Susitna Hydroelectric Water Power Project, as described in the attached exhibits.

(2) The location of the proposed project is:

State:	Alaska
Borough:	Matanuska-Susitna
Stream or Other Body of Water:	Susitna River

(3) The exact name, business address and telephone number of the applicant is:

Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501
(970) 276-0001

The exact names, business addresses and telephone numbers of the persons authorized to act as agents for the applicant in this application are:

Mr. Robert A. Mohn
Project Manager
Alaska Power Authority
334 West 5th Avenue
Anchorage, Alaska 99501
(907) 276-0001

and

D. Jane Drennan
Pillsbury, Madison & Sutro
Suite 900
1050 Seventeenth Street, N.W.
Washington, D.C. 20036
(202) 887-0300

(4) The applicant is a public corporation of the State of Alaska in the Department of Commerce and Economic Development but with separate and independent legal existence.

(5)(i) The statutory or regulatory requirements of the state in which the project would be located and that affect the project as proposed with respect to bed and banks and to the appropriation, diversion, and use of water for power purposes, and with respect to the right to engage in the business of developing, transmitting, and distributing power and in any other business necessary to accomplish the purposes of the license under the Federal Power Act, are:

(A) ALASKA STAT. §§44.83.010-44.83.425 (1977, 1982 Supp.) ("Alaska Power Authority") (including §§44.83.300-44.83.360, entitled "Susitna River Hydroelectric Project"); 1982 Alaska Sess. Laws, Chapter 133, §21.

The above-cited sections of the Alaska Statutes establish the Alaska Power Authority as a legal entity, the purpose of which is "to promote, develop and advance the general prosperity and economic welfare of the people of Alaska by providing a means of constructing, acquiring, financing and operating power projects," including hydroelectric facilities. ALASKA STAT. §44.83.070 (1982 Supp.) The Alaska Power Authority has a number of specific powers, including (1) the right to perform reconnaissance studies, feasibility studies, and engineering and design with respect to power projects, (2) the right to enter into contracts, (3) the right to issue bonds, (4) the right to exercise the power of eminent domain and (5) the right to construct and operate power projects. See ALASKA STAT. §44.83.080 (1982 Supp.).

Sections 44.83.300-44.83.360 deal specifically with the Susitna River Hydroelectric Project, the purpose of which is to generate, transmit and distribute electric power in a manner that will (1) minimize market area electrical power costs, (2) minimize adverse environmental and social impacts while enhancing environmental values to the extent possible and (3) safeguard both life and property. ALASKA STAT. §§44.83.300-44.83.310 (1977). 1982 Alaska Sess. Laws, Chapter 133, §21 now permits the Alaska Power Authority to contract for preliminary work on the Susitna Project (including preparation of plans and studies, preparation and submission of license applications, and other types of work necessary before actual construction of the project can begin) without seeking state legislative approval. See ALASKA STAT. §44.83.325 (1982 Supp.) (Editor's note). However, the Alaska Power Authority is still required to obtain approval by the state legislature of its preliminary report on the Susitna Project in the manner specified in ALASKA STAT. §44.83.325 (1977) before contracting for preparation of the site or contracting for actual construction of the project. In addition, state legislative approval of the financing of the project is required. See ALASKA STAT. §44.83.360 (1977).

(B) ALASKA STAT. §§46.15.030-46.15.185 (1982) ("Appropriation and Use of Water"); ALASKA ADMIN. CODE tit. 11, §§93.040-93.140 (Jan. 1980) ("Appropriation of Water").

These statutory provisions and regulations set forth the manner by which a right to appropriate water in Alaska may be acquired. They require that application for a permit to appropriate be made to the Department of Natural Resources. See ALASKA STAT. §46.15.040 (1982); ALASKA ADMIN. CODE tit. 11, §93.040 (Jan. 1980). They also list certain criteria which must be considered when evaluating the application. See ALASKA STAT. §46.15.080 (1982); ALASKA ADMIN. CODE tit. 11, §93.120 (Jan. 1980). In addition, the cited statute and regulations specify under what conditions one who has been granted a permit to appropriate shall be granted a certificate of appropriation.

(C) ALASKA ADMIN. CODE tit. 11, §§93.150-93.200.185 (Jan. 1980) ("Dam Safety and Construction").

These regulations (also promulgated pursuant to ALASKA STAT. §46.15.030-46.15.185 (1982), discussed in (B) above) require a "certificate of approval" to be obtained from the Department of Natural Resources prior to construction of dams as large as those proposed for the Susitna Project. Approval is based on information contained in drawings and design data submitted with the application for the certificate.

(D) ALASKA STAT. §16.05.870 (1982 Supp.) ("Protection of Fish and Game").

This section requires that any person or governmental agency intending to "use, divert... or change the natural flow or bed" of a river, lake or stream, such as the Susitna River, which has been designated as important to the spawning, rearing or migration of anadromous fish (1) notify the Department of that intent and (2) await its approval of the construction.

(E) ALASKA STAT. §§16.10.010-16.10.020 (1977) ("Interference With Salmon Spawning Streams and Waters", "Grounds for Permit or License").

These sections essentially require that any person who will erect a dam which may affect salmon spawning streams or waters first apply for and obtain a permit or license from the Department of Environmental Conservation. One purpose for which a permit or license may be granted is the development of power. As a condition for such a permit, however, adequate fishways may be required.

(F) ALASKA STAT. §16.05.840 (1977) ("Fishway Required").

The Commissioner of the Department of Fish and Game may require that a fishway be provided for a dam built across a stream frequented by salmon or other fish. In the event that a fishway is considered necessary, plans and specifications must be submitted for approval.

(G) ALASKA ADMIN. CODE tit. 18, §§15.130-15.180 (Jan. 1978) ("Certification").

Under Federal law, an applicant for a Federal license to construct or operate a facility must obtain from the State a certification of compliance with the Federal Water Pollution Control Act. 33 U.S.C. §1341 (1977). The certificate is governed by ALASKA ADMIN. CODE tit. 18, §§15.130-15.180. The procedures governing that certification process are set forth in these sections of the Code.

(H) ALASKA STAT. §38.05.020-38.05.330 (1982 Supp.) ("Alaska Lands Act").

These sections of the Alaska Statutes provide the methods by which the Alaska Power Authority may obtain use of state lands. The Department of Natural Resources may lease, sell or otherwise dispose of state land to a state or political subdivision for less than its appraised value if such action is found by the Department to be fair and proper and in the best interests of the public. ALASKA STAT. §38.05.315 (1982 Supp.). The Department may issue permits, rights-of-way or easements on state land for roads and electric transmission and distribution lines. ALASKA STAT. §38.05.330 (1982 Supp.). However, prior to disposing of state land which is adjacent to a body of water or a waterway, the Department must determine whether the body of water or waterway is navigable or public water or neither. If it is navigable or public water, the Department may provide for easements or rights-of-way. ALASKA STAT. §38.05.127 (1982 Supp.).

(I) ALASKA STAT. §§46.40.030-46.40.040; §§46.40.090-46.40.100 (1982) ("Development of Alaska Coastal Management Program").

These sections require that state agencies control the resources within a coastal area in a manner consistent with the applicable district coastal management plan. The Susitna Project is located within a designated coastal resource district.

(5)(ii) The steps which the applicant has taken, or plans to take, to comply with each of the laws cited above are:

(A) ALASKA STAT. §§44.83.010-44.83.425 (1977, 1982 Supp.).

The Alaska Power Authority plans to seek legislative approval of its preliminary report on the Susitna Project.

(B) ALASKA STAT. §§46.15.030-46.15.185 (1982); ALASKA ADMIN. CODE tit. 11, §§93.040-93.140 (Jan. 1980).

An investigation of existing water rights has been completed in connection with the permit required by the cited statute and regulations. The results indicate that the project would not have a materially adverse impact on existing water rights. In addition, the Alaska Power Authority has applied for a permit to appropriate water for the Susitna Project.

(C) ALASKA ADMIN. CODE tit. 11, §§93.150-93.200 (Jan. 1980).

The required drawings and design data are contained in Exhibits B, F, and G of this Initial Statement. The Alaska Power Authority has applied for a certificate of approval.

(D) ALASKA STAT. §16.05.870 (1982 Supp.).

The Alaska Power Authority has notified the Department of Fish and Game of its intent to construct the project on the Susitna River.

(E) ALASKA STAT. §§16.10.010-16.10.020 (1977).

The Alaska Power Authority has apprised the appropriate Departments of the Susitna Project and requested a ruling of its permitting requirements pursuant to these sections.

(F) ALASKA STAT. §16.05.840 (1977).

The Alaska Power Authority has notified the Department of Fish and Game of the Susitna Project.

(G) ALASKA ADMIN. CODE tit. 18, §§15.130-15.180 (Jan. 1980).

The Alaska Power Authority has notified the Department of Environmental Conservation that it will seek a certificate of compliance with the Federal Water Pollution Control Act. Under Alaska regulations, application for such a certificate is made by serving on the Department a copy of the Federal license application contemporaneously with submission of the application to the Federal agency. ALASKA ADMIN. CODE tit. 18, §15.180(c). The Alaska Power Authority will comply with this requirement.

(H) ALASKA STAT. §§38.05.020-38.05.030 (1982 Supp.).

The Alaska Power Authority has requested a right-of-way for transmission lines from the Department of Natural Resources. Rights-of-way may be requested for an access road and a railroad spur. If any state land acquired for the Susitna Project is adjacent to public or navigable waters, the Department of Natural Resources will determine whether easements or rights-of-way shall be provided.

(I) ALASKA STAT. §§46.40.030-46.40.040; §§46.40.040-46.40.100 (1982).

The Susitna Project will be reviewed for consistency with the coastal management plan of the borough of Matanuska. This review process is initiated when federal permit-granting agencies forward copies of the Susitna application to the Alaska Division of Policy Development and Planning as part of the federal permit process.

IN WITNESS WHEREOF, the applicant, Alaska Power Authority, has caused its name to be signed below by Eric P. Yould, its Executive Director, and its seal to be affixed hereto by Eric P. Yould, its Executive Director, this 15th day of February 1982.

ALASKA POWER AUTHORITY

By ______________________

Eric P. Yould
Executive Director

SEAL

JURISDICTIONAL

LEGISLATION

(3) "entire transmission system" means the gas transmission pipeline (together with all related facilities) to extend from the Prudhoe Bay area on the North Slope of Alaska into the contiguous United States, substantially as described in the President's report entitled "Decision and Report to Congress on the Alaska Natural Gas Transportation System", issued by the President on September 22, 1977, under provisions of the Alaska Natural Gas Transportation Act of 1976, and includes planning, design and construction of the pipeline and facilities;

(4) "project" means the gas transmission pipeline (together with all related property and facilities) to extend from the Prudhoe Bay area on the North Slope of Alaska to a connection with the Trans-Canada Pipeline on the Alaska-Canada border, substantially as described in the President's report entitled "Decision and Report to Congress on the Alaska Natural Gas Transportation System", issued by the President on September 22, 1977, under provisions of the Alaska Natural Gas Transportation Act of 1976, and includes planning, design, and construction of the pipeline and facilities;

(5) "project sponsor" means any partner of the Alaskan Northwest Natural Gas Transportation Company or its successors;

(6) "Prudhoe Bay natural gas" means natural gas produced from the Prudhoe Bay reservoir;

(7) "Prudhoe Bay oil" means oil produced from the Prudhoe Bay reservoir;

(8) "Prudhoe Bay reservoir" means those areas defined in Article 5.1 of the "Prudhoe Bay Unit Agreement" of April 1, 1977. (§ 2 ch 90 SLA 1978)

Chapter 83. Alaska Power Authority.

Article 1. Creation and Organization.

Sec. 44.83.010. Legislative finding and policy. (a) The legislature finds, determines and declares that

(1) there exist numerous potential hydroelectric and fossil fuel gathering sites in the state;

(2) the establishment of power projects at these sites is necessary to supply power at the lowest reasonable cost to the state's municipal electric, rural electric, cooperative electric, and private electric utilities, and regional electric authorities, and thereby to the consumers of the state, as well as to supply existing or future industrial needs;

(3) the achievement of the goals of lowest reasonable consumer power costs and beneficial long-term economic growth and of establishing, operating and developing power projects in the state will be accelerated and facilitated by the creation of an instrumentality of the state with powers to construct, acquire, finance, and operate power projects.

(b) It is declared to be the policy of the state, in the interests of promoting the general welfare of all the people of the state, and public purposes, to reduce consumer power costs and otherwise to encourage the long-term economic growth of the state, including the development of its natural resources, through the establishment of power projects by creating the public corporation with powers, duties and functions as provided in this chapter. (§ 1 ch 278 SLA 1976; am § 1 ch 156 SLA 1978)

Effect of amendment. — The 1978 amendment in subsection (a), substituted "power at the lowest reasonable cost" for "lower cost power" in paragraph (2) and "lowest reasonable consumer power costs and beneficial" for "lower consumer power costs and" and "construct, acquire, finance, and" for "incur debt for constructing, and with powers to" in paragraph (3).

Sec. 44.83.020. Creation of authority. There is created the Alaska Power Authority. The authority is a public corporation of the state in the Department of Commerce and Economic Development but with separate and independent legal existence. (§ 1 ch 278 SLA 1976)

Sec. 44.83.030. Membership of the authority. (a) The authority shall consist of the following directors:

(1) four directors at large to be appointed by the governor and confirmed by the legislature;

(2) the commissioner of commerce and economic development.

(b) The commissioners of community and regional affairs, natural resources, transportation and public facilities, and revenue shall have the rights and privileges of directors except for the right to vote and may not be considered for purposes of quorum or voting. (§ 1 ch 278 SLA 1976; am § 2 ch 156 SLA 1978)

Effect of amendment. — The 1978 amendment rewrote this section.

Sec. 44.83.040. Officers and quorum. The director shall elect one of the directors at large as chairman and other officers they determine desirable. The powers of the authority are vested in the directors, and three directors of the authority constitute a quorum. Action may be taken and motions and resolutions adopted by the authority at a meeting by the affirmative vote of at least three directors. The directors of the authority serve without compensation, but they shall receive the same travel pay and per diem as provided by law for board members. (§ 1 ch 278 SLA 1976; am § 3 ch 156 SLA 1978)

Effect of amendment. — The 1978 amendment substituted "directors at large" for "public members" in the first sentence.

Sec. 44.83.045. Qualifications, powers, and duties of officers and directors. (a) The directors at large must be residents and qualified voters of Alaska and shall comply with the requirements of AS 39.50 (conflict of interests). The directors at large shall serve four-year terms. The four original directors at large have terms of one, two, three, and four years, respectively.

(b) A vacancy in a directorship occurring other than by expiration of a term shall be filled in the same manner as the original appointment, but for the unexpired portion of the term only.

(c) The authority shall employ an executive director who may, with the approval of the authority, employ additional staff as necessary. In addition to its staff of regular employees, the authority may contract for and engage the services of legal and bond counsel, consultants, experts, and financial and technical advisors the authority considers necessary for the purpose of conducting studies, investigations, hearings, or other proceedings. The board of directors shall establish the compensation of the executive director. The executive director of the authority is subject to the provisions of AS 39.25. (§ 4 ch 156 SLA 1978)

Sec. 44.83.050. Staff.
Repealed by § 23 ch 156 SLA 1978.

Editor's note. — The repealed section derived from § 1, ch. 278, SLA 1976.

Article 2. Purpose and Powers.

Sec. 44.83.070. Purpose of the authority. The purpose of the authority is to promote, develop and advance the general prosperity and economic welfare of the people of Alaska by providing a means of constructing, acquiring, financing and operating power production facilities limited to fossil fuel, wind power, tidal, geothermal hydroelectric, or solar energy production and waste energy conservation facilities. (§ 1 ch 278 SLA 1976; am § 5 ch 156 SLA 1978)

Effect of amendment. — The 1978 amendment substituted the language beginning "power production facilities" for "hydroelectric and fossil fuel generating projects" at the end of the section.

Sec. 44.83.080. Powers of the authority. In furtherance of its corporate purposes, the authority has the following powers in addition to its other powers:

(1) to sue and be sued;

(2) to have a seal and alter it at pleasure;

(3) to make and alter bylaws for its organization and internal management;

(4) to make rules and regulations governing the exercise of its corporate powers;

(5) to acquire, whether by construction, purchase, gift or lease, and to improve, equip, operate, and maintain power projects;

(6) to issue bonds to carry out any of its corporate purposes and powers, including the acquisition or construction of a project to be owned or leased, as lessor or lessee, by the authority, or by another person, or the acquisition of any interest in a project or any right to capacity of a project, the establishment or increase of reserves to secure or to pay the bonds or interest on them, and the payment of all other costs or expenses of the authority incident to and necessary or convenient to carry out its corporate purposes and powers;

(7) to sell, lease as lessor or lessee, exchange, donate, convey or encumber in any manner by mortgage or by creation of any other security interest, real or personal property owned by it, or in which it has an interest, when, in the judgment of the authority, the action is in furtherance of its corporate purposes;

(8) to accept gifts, grants or loans from, and enter into contracts or other transactions regarding them, with any person;

(9) to deposit or invest its funds, subject to agreements with bondholders;

(10) to enter into contracts with the United States or any person and, subject to the laws of the United States and subject to concurrence of the legislature, with a foreign country or its agencies, for the financing, construction, acquisition, operation and maintenance of all or any part of a power project, either inside or outside the state, and for the sale or transmission of power from a project or any right to the capacity of it or for the security of any bonds of the authority issued or to be issued for the project;

(11) to enter into contracts with any person and with the United States, and, subject to the laws of the United States and subject to the

concurrence of the legislature, with a foreign country or its agencies for the purchase, sale, exchange, transmission, or use of power from a project, or any right to the capacity of it;

(12) to apply to the appropriate agencies of the state, the United States and to a foreign country and any other proper agency for the permits, licenses, or approvals as may be necessary, and to construct, maintain and operate power projects in accordance with the licenses or permits, and to obtain, hold and use the licenses and permits in the same manner as any other person or operating unit;

(13) to perform reconnaissance studies, feasibility studies, and engineering and design with respect to power projects;

(14) to enter into contracts or agreements with respect to the exercise of any of its powers, and do all things necessary or convenient to carry out its corporate purposes and exercise the powers granted in this chapter;

(15) to exercise the power of eminent domain in accordance with AS 09.55.250 — 09.55.410;

(16) to recommend to the legislature

(A) the issuance of general obligation bonds of the state to finance the construction of a power project if the authority first determines that the project cannot be financed by revenue bonds of the authority at reasonable rates of interest;

(B) the pledge of the credit of the state to guarantee repayment of all or any portion of revenue bonds issued to assist in construction of power projects;

(C) an appropriation from the general fund

(i) for debt service on bonds or other project purposes; or

(ii) to reduce the amount of debt financing for the project;

(D) an appropriation to the power project fund for a power project;

(E) an appropriation of a part of the income of the renewable resources investment fund for a power project;

(F) development of a project under financing arrangements with other entities using leveraged leases or other financing methods. (§ 1 ch 278 SLA 1976; am §§ 6 — 11 ch 156 SLA 1978; am §§ 16, 17 ch 83 SLA 1980)

Effect of amendments. — The 1978 amendment substituted "equip, operate, and maintain" for "equip and operate" in paragraph (5), inserted "or by another person" in paragraph (6), substituted "a project" for "it" in two places in paragraph (6), substituted "any person" for "a federal agency or an agency or instrumentality of the state, municipality, private organization or other source" in paragraph (8), inserted "financing" near the middle of paragraph (10), deleted "for the purchase, sale, exchange, transmission, or use of power generated by a project, or any right to the capacity of it" following "enter into contracts" near the beginning of paragraph (11), added the language beginning "for the purchase, sale, exchange" to the end of paragraph (11), and deleted "hydroelectrical and fossil fuel" following "with respect to" and "generating" following "power" in paragraph (13).

The 1980 amendment inserted in the middle of paragraph (13), "feasibility studies, and engineering and design," and added paragraph (16).

AMENDMENTS

institution in contemplation of the extension of credit or the collection of loans.

(4) Impersonal information based solely on transactions or experience with a member, such as amounts of loans, terms, and payment records may be given by the bank for the confidential use of a reliable organization in contemplation of the extension of credit.

(5) Credit information concerning a member may be given when the member consents to it in writing.

(6) In litigation between a member (or his successor in interest) and the bank, any competent evidence may be introduced with respect to relevant statements made orally or in writing by or to the member or his successor. (§ 8 ch 109 SLA 1981)

Sec. 44.81.270. Audit of bank. The legislative auditor may cause the bank to be audited in the manner and under the conditions prescribed by AS 24.20.271 for audits performed by the legislative audit division. The legislative audit division has free access to all books and papers of the bank that relate to its business and books and papers kept by a director, officer, or employee relating to or upon which a record of its business is kept, and may summon witnesses and administer oaths or affirmations in the examination of the directors, officers, or employees of the bank or any other person in relation to its affairs, transactions, and conditions, and may require and compel the production of records, books, papers, contracts, or other documents by court order if not voluntarily produced. (§ 8 ch 109 SLA 1981)

Sec. 44.81.280. Prohibition on disclosure. The legislative auditor and his employees may not disclose information acquired by them in the course of an audit of the bank concerning the particulars of the business or affairs of a borrower of the bank or another person, unless the information is required to be disclosed by law or under a court order. (§ 8 ch 109 SLA 1981)

Chapter 83. Alaska Power Authority.

Article

Article 1. Creation and Organization.

Section

Sec. 44.83.030. Membership of the authority. The authority shall consist of the following directors:

(1) three public directors to be appointed by the governor and confirmed by the legislature; only one director may be appointed from each judicial district described in AS 22.10.010;

(2) the director of the division of budget and management and three commissioners of principal executive departments appointed by the governor. (§ 1 ch 278 SLA 1976; am § 2 ch 156 SLA 1978; am § 2 ch 118 SLA 1981)

Effect of amendments. — The 1981 amendment deleted the subsection designation (a) and repealed subsection (b) which read "The commissioners of community and regional affairs, natural resources, transportation and public facilities, and revenue shall have the rights and privileges of directors except for the right to vote and may not be considered for purposes of quorum or voting." The amendment also substituted "three public" for "four" preceding "directors," deleted "at large" preceding "to be appointed" and added "only one director may be appointed from each judicial district described in AS 22.10.010" in paragraph (1) and substituted "the director of the division of budget and management and three commissioners of principal executive departments appointed by the governor" for "the commissioner of commerce and economic development" in paragraph (2).

Editor's notes. — Section 15, ch. 118, SLA 1981, provides: "APPLICABILITY OF ACT TO DIRECTORS. (a) The terms of office of all members of the Board of Directors of the Alaska Power Authority serving on the effective date of this section terminate on the effective date of this section [July 1, 1981].

"(b) The governor shall appoint three public directors of the Alaska Power Authority. When making his appointments under this subsection, the governor shall appoint persons to serve in accordance with AS 44.83.030(1) and shall specify the length of the term of office of each member he appoints. Of the public members first appointed by the governor under this subsection,

"(1) one member shall serve a two-year term;

"(2) one member shall serve a three-year term;

"(3) one member shall serve a four-year term."

Sec. 44.83.040. Officers and quorum. The directors shall elect one of their number as chairman and may elect other officers they determine desirable. The powers of the authority are vested in the directors, and four directors of the authority constitute a quorum. Action may be taken and motions and resolutions adopted by the authority at a meeting by the affirmative vote of at least three directors. The directors of the authority serve without compensation, but they shall receive the same travel pay and per diem as provided by law for board members. (§ 1 ch 278 SLA 1976; am § 3 ch 156 SLA 1978; am § 3 ch 118 SLA 1981)

Effect of amendments. — The 1981 amendment substituted "directors" for "director," substituted "their number" for "the directors at large" and added "may elect" preceding "other officers" in the first sentence and substituted "four" for "three" preceding "directors" in the second sentence.

Sec. 44.83.045. Qualifications, powers, and duties of officers and directors. (a) The public directors shall be residents and qualified voters of Alaska and shall comply with the requirements of AS 39.50.010 — 39.50.200 (conflict of interests). The public directors shall serve overlapping four-year terms.

(b) A vacancy in a directorship occurring other than by expiration of a term shall be filled in the same manner as the original appointment, but for the unexpired portion of the term only.

(c) The authority shall employ an executive director who may, with the approval of the authority, employ additional staff as necessary. In addition to its staff of regular employees, the authority may contract for and engage the services of legal and bond counsel, consultants, experts, and financial and technical advisors the authority considers necessary for the purpose of conducting studies, investigations, hearings, or other proceedings. The board of directors shall establish the compensation of the executive director. The executive director of the authority is subject to the provisions of AS 39.25.010 — 39.25.220. (§ 4 ch 156 SLA 1978; am § 4 ch 118 SLA 1981)

Effect of amendments. — The 1981 amendment added "public" preceding "directors" and substituted "shall" for "at large must" preceding "be residents" in the first sentence, added "public" preceding "directors," deleted "at large" following "directors" and added "overlapping" preceding "four-year terms" in the second sentence and deleted the former third sentence which read "The four original directors at large have terms of one, two, three, and four years, respectively."

Article 2. Purpose and Powers.

Sec. 44.83.070. Purpose of the authority. The purpose of the authority is to promote, develop and advance the general prosperity and economic welfare of the people of Alaska by providing a means of constructing, acquiring, financing and operating

(1) power projects; and

(2) facilities that recover and use waste energy. (§ 1 ch 278 SLA 1976; am § 5 ch 156 SLA 1978; am § 1 ch 133 SLA 1982)

Effect of amendments. — The 1982 amendment, effective June 25, 1982, substituted paragraphs (1) and (2) for "power production facilities limited to fossil fuel, wind power, tidal, geothermal, hydroelectric, or solar energy production and waste energy conservation facilities."

Sec. 44.83.080. Powers of the authority. In furtherance of its corporate purposes, the authority has the following powers in addition to its other powers:

(1) to sue and be sued;

(2) to have a seal and alter it at pleasure;

(3) to make and alter bylaws for its organization and internal management;

(4) to make rules and regulations governing the exercise of its corporate powers;

(5) to acquire, whether by construction, purchase, gift or lease, and to improve, equip, operate, and maintain power projects;

(6) to issue bonds to carry out any of its corporate purposes and powers, including the acquisition or construction of a project to be owned or leased, as lessor or lessee, by the authority, or by another person, or the acquisition of any interest in a project or any right to capacity of a project, the establishment or increase of reserves to secure or to pay the bonds or interest on them, and the payment of all other costs or expenses of the authority incident to and necessary or convenient to carry out its corporate purposes and powers;

(7) to sell, lease as lessor or lessee, exchange, donate, convey or encumber in any manner by mortgage or by creation of any other security interest, real or personal property owned by it, or in which it has an interest, when, in the judgment of the authority, the action is in furtherance of its corporate purposes;

(8) to accept gifts, grants or loans from, and enter into contracts or other transactions regarding them, with any person;

(9) to deposit or invest its funds, subject to agreements with bondholders;

(10) to enter into contracts with the United States or any person and, subject to the laws of the United States and subject to concurrence of the legislature, with a foreign country or its agencies, for the financing, construction, acquisition, operation and maintenance of all or any part of a power project, either inside or outside the state, and for the sale or transmission of power from a project or any right to the capacity of it or for the security of any bonds of the authority issued or to be issued for the project;

(11) to enter into contracts with any person and with the United States, and, subject to the laws of the United States and subject to the concurrence of the legislature, with a foreign country or its agencies for the purchase, sale, exchange, transmission, or use of power from a project, or any right to the capacity of it;

(12) to apply to the appropriate agencies of the state, the United States and to a foreign country and any other proper agency for the permits, licenses, or approvals as may be necessary, and to construct, maintain and operate power projects in accordance with the licenses or permits, and to obtain, hold and use the licenses and permits in the same manner as any other person or operating unit;

(13) to perform reconnaissance studies, feasibility studies, and engineering and design with respect to power projects;

(14) to enter into contracts or agreements with respect to the exercise of any of its powers, and do all things necessary or convenient to carry out its corporate purposes and exercise the powers granted in AS 44.83.010 — 44.83.510;

(15) to exercise the power of eminent domain in accordance with AS 09.55.250 — 09.55.410;

(16) to recommend to the legislature

(A) the issuance of general obligation bonds of the state to finance the construction of a power project if the authority first determines that the project cannot be financed by revenue bonds of the authority at reasonable rates of interest;

(B) the pledge of the credit of the state to guarantee repayment of all or any portion of revenue bonds issued to assist in construction of power projects;

(C) an appropriation from the general fund

(i) for debt service on bonds or other project purposes; or

(ii) to reduce the amount of debt financing for the project;

(D) an appropriation to the power project fund for a power project;

(E) an appropriation of a part of the income of the renewable resources investment fund for a power project;

(F) development of a project under financing arrangements with other entities using leveraged leases or other financing methods;

(G) an appropriation for a power project acquired or constructed under the energy program for Alaska (AS 44.83.380 — 44.83.425). (§ 1 ch 278 SLA 1976; am §§ 6 — 11 ch 156 SLA 1978; am §§ 16, 17 ch 83 SLA 1980; am § 5 ch 118 SLA 1981)

Revisor's notes. — In paragraph (16) (G), a reference to AS 44.83.400 — 44.83.510 was changed to AS 44.83.380 — 44.83.425 to reflect numbering changes made by the revisor of statutes pursuant to AS 01.05.031 (b).

Effect of amendments. — The 1981 amendment added subparagraph (G) of paragraph (16).

Sec. 44.83.090. Power contracts and the Alaska Public Utilities Commission. (a) The authority shall, in addition to the other methods which it may find advantageous, provide a method by which municipal electric, rural electric, cooperative electric, or private electric utilities and regional electric authorities, or other persons authorized by law to engage in the distribution of electricity may secure a reasonable share of the power generated by a project, or any interest in a project, or for any right to the power and shall sell the power or cause the power to be sold at the lowest reasonable prices which cover the full cost of the electricity or services, including capital and operating costs, debt coverage as considered appropriate by the authority, and other charges that may be authorized by AS 44.83.010 — 44.83.510. Except for a contract or lease entered into under AS 44.83.380 — 44.83.425, a contract or lease for the sale, transmission and distribution of power generated by a project or any right to the capacity of it shall provide:

(1) for payment of all operating and maintenance expenses of a project and costs of renewals, replacements and improvements of it;

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EXHIBIT A - PROJECT DESCRIPTION

The Susitna Hydroelectric Project will comprise two major developments on the Susitna River some 180 miles north and east of Anchorage, Alaska. The first phase of the project will be the Watana project which will incorporate an earthfill dam together with associated diversion, spillway, and power facilities. The second phase will include the Devil Canyon concrete arch dam and associated facilities.

The description of the Watana project is presented in the following Sections 1 through 5; the Devil Canyon project is described in Sections 7 through 11. Project lands for the entire project are discussed in Section 6. Reference drawings will be found in Exhibit F.

1 - PROJECT STRUCTURES - WATANA DEVELOPMENT

1.1 - General Arrangement

The Watana Dam will create a reservoir approximately 48 miles long, with a surface area of 38,000 acres, and a gross storage capacity of 9,500,000 acre-feet at Elevation 2185, the normal maximum operating level.

The maximum water surface elevation during flood conditions will be 2201. The minimum operating level of the reservoir will be 2065, providing a live storage during normal operation of 3,700,000 acre-feet.

The dam will be an embankment structure with a central core. The nominal crest elevation of the dam will be 2205, with a maximum height of 885 feet above the foundation and a crest length of 4,100 feet. The embankment crest will initially be constructed to Elevation 2210 to allow for potential seismic settlement. The total volume of the structure will be approximately 62,000,000 cubic yards. During construction, the river will be diverted through two concrete-lined diversion tunnels, each 38 feet in diameter and 4100 feet long, on the north bank of the river.

The power intake will be located on the north bank with an approach channel excavated in rock. The intake will be a concrete structure with multi-level gates capable of operation over the full 120-foot drawdown range. From the intake structure, six concrete-lined penstocks, each 17 feet in diameter, will lead to an underground powerhouse complex housing six 170 MW generating units with Francis turbines and semi-umbrella type generators.

Access to the powerhouse complex will be by means of an unlined access tunnel and a road which will pass from the crest of the dam, down the south bank of the river valley and across the embankment near the downstream toe. Turbine discharge will flow through six draft tube tunnels to a surge chamber downstream from the powerhouse. The surge chamber will discharge to the river through two 34-foot diameter concrete-lined tailrace tunnels. A separate transformer gallery just upstream from the powerhouse cavern will house nine single-phase 15/345 kV transformers (three transformers per group of two generators). The transformers will be connected by three 345 kV single-phase, oil-filled cables through two cable shafts to the switchyard at the surface.

Outlet facilities will also be located on the north bank to discharge all flood flows of up to 24,000 cfs. With 7000 cfs passing through the powerhouse, the combination of the powerhouse and the outlet facilities will handle 31,000 cfs, during the estimated 50-year flood. The passage of this flood assumes only two units of Watana operating and the pool elevation going from 2185 to 2193 from flood surcharge. The upstream gate structure will be adjacent to the power intake and will convey flows through a 28-foot diameter concrete-lined tunnel to six fixed-cone discharge valves downstream of the dam. These valves will be housed beneath the spillway flip bucket and will be used to dissipate energy and eliminate undesirable nitrogen supersaturation in the river downstream from the dam during spillway operations.

The main spillway will also be located on the north bank. This spillway will consist of an upstream ogee control structure with three vertical fixed-wheel gates and an inclined concrete chute and flip bucket designed to pass a maximum discharge of 120,000 cfs. This spillway, together with the outlet facilities and the powerhouse, will be capable of discharging the estimated 10,000-year flood (156,000 cfs). An emergency spillway and fuse plug on the north bank will provide sufficient additional capacity to permit discharge of the Probable Maximum Flood (PMF) without overtopping the dam. Emergency release facilities will be located in one of the diversion tunnels after closure to allow lowering of the reservoir over a period of time to permit emergency inspection or repair of impoundment structures.

A local depression on the north rim of the reservoir upstream of the dam will be closed by a low freeboard dike with a crest elevation of 2210. Provision will be made for monitoring potential seepage through this area and placement of appropriate filter blankets at Tsusena Creek downstream.

1.2 - Main Dam

The main dam at Watana will be located at mile 184 above the mouth of the Susitna River, in a broad U-shaped valley approximately 2.5 miles upstream of the Tsusena Creek confluence. The dam will be of compacted earth and rockfill construction and will consist of a central impervious core protected by fine and coarse filters upstream and downstream. The downstream outer shell will consist of rockfill and alluvial gravel underlain by a toe drain and filter, and the upstream outer shell of clean alluvial gravel. A typical cross section is shown on Plate F6 and is described below.

(a) Typical Cross Section

The central core slopes will be 1H:4V with a top width of 15 feet. The thickness of the core at any horizontal section will be slightly more than 0.5 times the head of water at that section. Minimum core-foundation contact will be 50 feet, requiring flaring of the cross section at each end of the embankment.

The upstream and downstream filter zones will increase in thickness from 45 and 30 feet respectively near the crest of the dam to a maximum in excess of 100 feet at the filter foundation contact. They are sized to provide protection against possible piping through transverse cracks that could occur because of settlement or resulting from internal displacement during a seismic event.

The shells of the dam will consist primarily of compacted alluvial gravels. The saturated upstream shell will consist of compacted clean alluvial gravels processed to remove fines so that not more than 10 percent of the materials are less than 3/8 inch in size to minimize pore pressure generation and ensure rapid dissipation should seismic shaking occur. The downstream shell will be unsaturated and therefore will not be affected by pore pressure generation during a seismic event. This will be constructed with compacted, unprocessed alluvial gravels and rockfill from the surface or underground excavations.

Protection against wave and ice action on the upstream slope will consist of a 10-foot layer of riprap comprising quarried rock up to 36 inches in size.

The volume of material required to construct the Watana Dam is presently estimated as follows:

. Core material:	8,250,000 cubic yards
. Fine filter material:	4,260,000 cubic yards
. Coarse filter material:	3,560,000 cubic yards
. Gravel and rockfill material:	45,500,000 cubic yards

(b) Crest Details and Freeboard

The typical crest detail is shown in Plate F7. Because of the narrowing at the dam crest, the filter zones are reduced in width and the upstream and downstream coarse filters are eliminated. A layer of filter fabric is incorporated to protect the core material from damage by frost penetration and desiccation, and to act as a coarse filter where required.

The nominal crest elevation of the Watana Dam, after estimated static and seismic settlement have taken place, will be 2205.

Allowances will be made during construction of the dam to allow for static settlement of the fill following completion, settlement on saturation of the upstream shell, and possible settlement because of seismic shaking.

An allowance will be made for settlement due to seismic loading of up to 0.5 percent of the height of the dam, or approximately 5 feet. The elevation at the center of the dam prior to any seismic settlement will therefore be 2210. At each abutment the crest elevation will be 2207, allowing for 2 feet of seismic settlement. Under normal operating conditions the minimum freeboard relative to the maximum operating pool elevation of 2185 will therefore be 20 feet, not including settlement allowances.

During construction of the dam, additional allowances will be made for post-construction settlement of the dam under its own weight and for the effects of saturation on the upstream gravel fill when the reservoir is first filled. These allowances will be provided in construction specifications and are consequently not shown on the drawings at this time. For initial cost estimating purposes, 1 percent of the height of the dam has been allowed, or approximately 9 feet. The additional height constructed into the dam for these settlements will be accomplished by steepening both slopes above approximately Elevation 2090 on the upstream slope and 2110 on the downstream slope. These settlement allowances are conservative when compared with observed settlements of similar structures. However, provision will be made during construction for placement of additional fill at the crest should settlements exceed these estimates.

The freeboard allowance of 20 feet is based on the worst conceivable combination of flood, wave and runup water levels which may occur after all settlement has taken place.

Ultimate security against overtopping of the main dam will be provided by the emergency spillway. Under normal operation this spillway will be sealed by a fuse plug dam across the entrance channel. This plug will be a gravel dam with a lowest crest elevation of 2200 and with strict design of the core, upstream face, and shell materials to ensure that it will erode rapidly if overtopped, allowing flood flows to be discharged freely through the emergency spillway. The maximum reservoir level during passage of the PMF is estimated as 2201.5 prior to erosion of the plug. The location and typical cross section through the fuse plug are shown on Plate F18.

(c) Grouting and Pressure Relief System

A combination of consolidation grouting, cutoff curtain grouting and installation of a downstream pressure relief (drainage) system will be undertaken for the Watana Dam.

The curtain grouting and drilling for the pressure relief system will be largely carried out from galleries in the rock foundation in the abutments and beneath the dam. Details of the grouting, pressure relief and galleries are shown on Plate F8.

(d) Instrumentation

Instrumentation will be installed to provide monitoring of performance of the dam and foundation during construction as well as during operation. Instruments for measuring internal vertical and horizontal displacements, stresses and strains, and total and fluid pressures, as well as surface monuments and markers, will be installed. Estimates of quantities of instrumentation have been allowed for conservatively on the basis of currently available geotechnical data for the site. These include:

- Piezometers

  Piezometers are used to measure static pressure of fluid in the pore spaces of soil, rockfill and in the rock foundation.

- Internal Vertical Movement Devices

  . Cross-arm settlement devices as developed by the USBR
  . Various versions of the taut-wire devices which have been developed to measure internal settlement
  . Hydraulic-settlement devices of various kinds

- Internal Horizontal Movement Devices

  . Taut-wire arrangements
  . Cross-arm devices
  . Inclinometers
  . Strain meters

- Other Measuring Devices

  . Stress meters
  . Surface monuments and alignment markers
  . Seismographic records and seismoscopes
  . Flow meters to record discharge from drainage and pressure relief system

1.3 - Diversion

(a) Tunnels

Diversion of the river flow during construction will be accomplished with two 38-foot diameter circular diversion tunnels. The tunnels will be concrete-lined and located on the north bank of the river. The tunnels are 4,050 feet and 4,140 feet in length. The diversion tunnels are shown in plan and profile on Plate F9.

The tunnels are designed to pass a flood with a return frequency of 1:50 years, equivalent to peak inflow of 87,000 cfs. Routing effects are small, and thus at peak flow the tunnels will discharge 80,500 cfs. The estimated maximum water surface elevation upstream from the cofferdam for this discharge will be 1536.

The upper tunnel (Tunnel No. 1) will be converted to the permanent low-level outlet after construction. A local enlarging of the tunnel diameter to 45 feet will accommodate the low-level outlet gates and expansion chamber.

(b) Cofferdams

The upstream cofferdam will be a zoned embankment founded on the closure dam (see Plate F10). The closure dam will be constructed to Elevation 1475 based on a low water elevation of 1470, and will consist of coarse material on the upstream side grading to finer material on the downstream side. Provision has been made for a cutoff through the river bed alluvium to bedrock to control seepage during dam construction. The cement/bentonite slurry wall cutoff and downstream pumping system is shown on Plate F10.

Above Elevation 1475 the cofferdam will be a zoned embankment consisting of a central core, fine and coarse upstream and downstream filters, and rock and/or gravel supporting shell zones with riprap on the upstream face to resist ice action. This cofferdam will provide a 9-foot freeboard for wave runup and ice protection.

The downstream cofferdam will consist of only a closure dam constructed from approximate Elevation 1440 to 1472, and consisting of coarse material on the downstream side grading to finer material on the upstream side. Control of underseepage similar to that for the upstream cofferdam will be required.

(c) Tunnel Portals and Gate Structures

A reinforced concrete gate structure will be located at the upstream end of each tunnel, each housing two closure gates (see Plate F11).

Each gate will be 38 feet high by 15 feet wide separated by a center concrete pier. The gates will be of the fixed-roller vertical lift type operated by a wire rope hoist. The gate hoist will be located in an enclosed, heated housing. Provision will be made for heating the gates and gate guides. The gate in Tunnel No. 1 will be designed to operate with the reservoir at Elevation

1536, a 46-foot operating head. The gate in Tunnel No. 2 will be designed to operate with the reservoir at Elevation 1536, a 116-foot operating head. The gate structures for each tunnel will be designed to withstand external (static) heads of 135 feet (No. 1) and 520 feet (No. 2), respectively. The downstream portals will be reinforced concrete structures with guides for stoplogs.

(d) Final Closure and Reservoir Filling

As discussed above, the upper diversion tunnel (No. 1) will be converted to a low-level outlet or emergency release facility during construction.

It is estimated that one year will be required to construct and install the permanent low-level outlet in the existing tunnel. This will require that the lower tunnel (No. 2) pass all flows during this period. The main dam will, at this time, be at an elevation sufficient to allow a 100-year recurrence interval flood (97,000 cfs) to pass through Tunnel No. 2. This flow will result in a reservoir elevation of 1625. During the construction of the low level outlet, the intake gates in the upper tunnel (No. 1) will be closed. Prior to commencing operation of the low-level outlet, coarse trashracks will be installed at the entrance to Tunnel No. 1 intake structure.

Upon commencing operation of the low-level outlet, the lower tunnel (No. 2) will be closed with the intake gates, and construction of the permanent plug and filling of the reservor will commence.

When the lower tunnel (No. 2) is closed the main dam crest will have reached an elevation sufficient to start filling the reservoir and still have adequate storage available to store a 250-year recurrence period flood.

During the filling operation, the low-level outlet will pass summer flows of up to 12,000 cfs and winter flows of up to 800 cfs. In case of a large flood occurring during the filling operation, the low-level outlet would be opened to its maximum capacity of 30,000 cfs until the reservoir pool was lowered to a safe level.

The filling of the reservoir is estimated to take four years to complete to the full reservoir operating elevation of 2185. After three years of filling, the reservoir will be at Elevation 2150 and will allow operation of the power plant to commence.

The filling sequence is based on the main dam elevation at any time during construction and the capability of the reservoir storage to absorb the inflow volume from a 250-year recurrence period flood without overtopping the main dam.

1.4 - Emergency Release Facilities

The upper diversion Tunnel No. 1 will be converted to a permanent low-level outlet, or emergency release facility. These facilities will be used to pass the required minimum discharge during the reservoir filling period and will also be used for draining the reservoir in an emergency.

During operation, energy will be dissipated by means of two gated concrete plugs separated by a 340-foot length of tunnel (see Plate F19). Each plug will contain three water passages.

Bonnetted type high pressure slide gates will be installed in each of the passages in the tunnel plugs. The gate arrangement will consist of one emergency gate and one operating gate in the upstream plug and one operating gate in the downstream plug. A 340-foot length of tunnel between plugs will act as an energy dissipating expansion chamber.

The 7.5-foot by 11.5-foot gates will be designed to withstand a total static head of about 740 feet; however, they will only be operated with a maximum head of about 600 feet.

During operation, the operating gate opening in the upstream plug will be equal to the opening of the corresponding gate in the downstream plug. This should effectively balance the head across the gates. The maximum operating head across a gate should not exceed 340 feet.

Each gate will have a hydraulic cylinder operator designed to raise or lower it against a maximum head of 600 feet. Three hydraulic units will be installed, one for the emergency gates, one for the upstream operating gates and one for the downstream operating gates. Each gate will have an opening/closing time of about 30 minutes. A grease injection system will be installed in each gate to reduce frictional forces when the gates are operated.

The design of the gate will be such that the hydraulic cylinder as well as the cylinder packing may be inspected and repaired without dewatering the area around the gate. All gates may be locally or remotely operated.

To prevent concrete erosion, the conduits in each of the tunnel plugs will be steel-lined. An air vent will be installed at the downstream side of the operating gate in the downstream plug. Energy dissipation at the downstream tunnel exit will be accomplished by means of a concrete flip bucket in the exit channel (Plate F20).

1.5 - Outlet Facilities

The primary function of the outlet facilities will be to discharge floods with recurrence frequencies of up to once in 50 years after they have been routed through the Watana reservoir. The use of fixed-cone discharge valves will ensure that downstream erosion will be minimal and the dissolved nitrogen content in the discharges will be reduced sufficiently to avoid harmful effects on the downstream fish population. A secondary function will be to provide the capability to rapidly draw down the reservoir during an extreme emergency situation.

The facilities will be located on the north bank and will consist of a gate structure, pressure tunnel, and an energy dissipation and control structure housing located beneath the spillway flip bucket. This structure will accommodate six fixed-cone valves which will discharge into the river 105 feet below.

(a) Approach Channel and Intake

The approach channel to the outlet facilities will be shared with the power intake. The channel will be 350 feet wide and excavated to a maximum depth of approximately 150 feet in the bedrock with an invert elevation of 2025. The gate structure will be founded deep in the rock at the forebay end of the channel. The single intake passage will have an invert elevation of 2027. It will be divided upstream by a central concrete pier which will support steel trashracks located on the face of the structure, spanning the openings to the water passage. The racks will be split into panels mounted one above the other and run in vertical steel guides installed at the upstream face. The trashrack panels can be raised and lowered for cleaning and maintenance by a mobile gantry crane located at deck level.

Two fixed-wheel gates will be located downstream of the racks between the pier and each of the sidewalls. These gates will be operated by a mechanical hoist mounted above the deck of the structure. The fixed-wheel gates will not be used for flow control but will function as closure gates to isolate the downstream tunnel and allow dewatering for maintenance of the tunnel or ring gates located in the discharge structure. Stoplog guides will be provided upstream from the two fixed-wheel gates to permit dewatering of the structure and access to the gate guides for maintenance.

(b) Intake Gates and Trashracks

The gates will be of the fixed-wheel vertical lift type with downstream skinplate and seals. The nominal gate size will be 14 feet wide by 28 feet high. Each gate will be operated by a single drum wire rope hoist mounted in an enclosed tower structure at the top of the intake. The height of the tower structure will permit raising the gates to the intake deck for inspection and maintenance.

The gates will be capable of being lowered either from a remote control room or locally from the hoist area. Gate raising will be from the hoist area only.

The trashracks will have a bar spacing of 6 inches and will be designed for a maximum differential head of 40 feet. The maximum net velocity through the racks will be 12 ft/sec. Provision will be made for monitoring the head loss across the trashracks.

(c) Shaft and Tunnel

Discharges will be conveyed from the upstream gate structure by a concrete-lined tunnel terminating in a steel liner and manifold. The manifold will branch into six steel-lined tunnels which will run through the main spillway flip bucket structure to the fixed-cone valves mounted in line with the downstream face.

The water passage will be 28 feet in diameter as far as the steel manifold. The upstream concrete-lined portion will run a short distance horizontally from the back of the intake structure before dipping at an angle of 55° to a lower level tunnel of similar cross section. The lower tunnel will run at a 5 percent gradient to a centerline elevation of 1560 approximately 450 feet upstream of the flip bucket. At this point the depth of overlying rock is insufficient to withstand the large hydrostatic pressure which will occur within the tunnel. Downstream of this point the tunnel will be steel-lined. The steel liner will be 28 feet in diameter and embedded in mass concrete filling the space between the liner and the surrounding rock. The area between the outside face of the liner and the concrete will be contact grouted.

(d) Discharge Structure

The concrete discharge structure is shown on Plate F15. It will form a part of the flip bucket for the main spillway and will house the fixed-cone valves and individual upstream ring follower gates. The valves will be set with a centerline elevation of 1560 and will discharge into the river approximately 105 feet below. Openings for the valves will be formed in the concrete and the valves will be recessed within these openings sufficiently to allow enclosure for ease of maintenance and heating of the movable valve sleeves. An access gallery upstream from the valves will run the length of the discharge structure, and will terminate in the access tunnel and access road on either side of the structure.

Housing for the ring follower gates will be located upstream from the fixed-cone valve chambers. The ring follower gates will serve to isolate the discharge valves. Provision will be made for relatively easy equipment maintenance and removal by means of a 25-ton service crane, transfer trolley and individual 25-ton monorail hoists.

(e) Fixed-Cone Discharge Valves

Six 78-inch diameter fixed-cone discharge valves will be installed at the downstream end of the outlet manifold, as shown on Plate F15. The valves will be operated by two hydraulic cylinder operators. The valves may be operated either locally or remotely.

(f) Ring Follower Gates

A ring follower gate will be installed upstream from each valve and will be used:

- To permit inspection and maintenance of the fixed-cone valves;
- To relieve the hydrostatic pressure on the fixed-cone valves when they are in the closed position; and
- To close against flowing water in the event of malfunction or failure of the valves.

The ring follower gates will have a nominal diameter of 90 inches and will be designed to withstand a total static head of 630 feet.

The ring follower gates will be designed to be lowered under flowing water conditions and raised under balanced head conditions. A grease injection system will be installed in each gate to reduce frictional forces when the gates are operated. The gates will be operated by hydraulic cylinders from either a local or remote location.

(g) Discharge Area

Immediately downstream from the discharge structure, the rock will be excavated at a slope of 2H:3V to a lower elevation of 1510. This face will be heavily reinforced by rock bolts and protected by a concrete slab anchored to the face. The lower level will consist of unlined rock extending to the river.

1.6 - Main Spillway

The main spillway will provide discharge capability for floods exceeding the capacity of the outlet facilities. The combined total capacity of the main spillway and outlet facilities will be sufficient to pass routed floods with a frequency of occurrence of up to once in 10,000 years.

The main spillway, shown on Plate F12, will be located on the north bank of the river and will consist of an approach channel, a gated ogee control structure, a concrete-lined chute, and a flip bucket.

The spillway is designed to discharge flows of up to 120,000 cfs with a corresponding reservoir elevation of 2193.5. The total head dissipated by the spillway is approximately 730 feet.

(a) Approach Channel and Control Structure

The approach channel will be excavated to a maximum depth of approximately 100 feet into rock. It will be located on the south side of the power intake and, in order to minimize its length, it will be partially integrated with the power approach channel upstream of the intake structure.

The concrete control structure will be located at the end of the approach channel, adjacent to the north dam abutment in line with the dam crest. Flows will be controlled by three 49-foot high by 36-foot wide vertical lift gates, as shown on Plate F13. The structure will be constructed in individual monoliths separated by construction joints. The main access route to the dam will pass across the roadway deck and along the dam crest.

Hydraulic model tests will be undertaken during the detailed design stage to confirm the precise geometry of the control structure.

The sides of the approach channel will be excavated to 1H:4V slopes. Only localized rock bolting and shotcrete support are required. The control structure will be founded deep in sound rock and consolidation grouting is not anticipated. However, minor shear or fracture zones passing through the foundation may require dental excavation, concrete backfill and/or consolidation grouting. The slope of the contact surface between the dam core and the spillway control structure will be constructed at 1H:3V to ensure sufficient contact stress and therefore prevent leakage.

The main dam grout curtain and drainage system will pass beneath the structure. Access to the grouting tunnels will be via a vertical shaft within the control structure side wall and a gallery running through the ogee weir.

(b) Spillway Gates and Stoplogs

The three spillway gates will be of the fixed-wheel vertical lift type operated by double drum wire rope hoists located in an enclosed tower structure. The gate size is 36 feet wide by 49 feet high, including freeboard allowance. The gates will have upstream skinplates and will be totally enclosed to permit heating in the event that winter operation is necessary. Provision will also be made for heating the gate guides.

The height of the tower and bridge structure will permit raising of the gates above the top of the spillway pier for gate inspection and maintenance.

An emergency engine will be provided to enable the gates to be raised in the event of loss of power to the spillway gate hoist motors.

Stoplog guides will be installed upstream of each of the three spillway gates. One set of stoplogs will be provided to permit servicing of the gate guides.

(c) Spillway Chute

The control structure will discharge down an inclined chute that tapers slightly until a width of 80 feet is reached. A constant width of 80 feet is maintained over the remainder of its length. Convergence of the chute walls will be gradual to minimize any shock wave development.

The chute section will be rectangular in cross section, excavated in rock, and lined with concrete anchored to the rock. An extensive underdrainage system will be provided to ensure stability of the structure. The dam grout curtain and drainage system will also extend under the spillway control structure utilizing a gallery through the mass concrete rollway. A system of box drains will be constructed in the rock under the concrete slab in a herringbone pattern at 20 feet spacing for the entire length of the spillway. To avoid blockage of the system by freezing of the surface drains, a drainage gallery will be excavated to a depth of 30 feet over the entire length of the spillway. Drain holes from the surface drains will intersect the gallery. Drainage holes drilled into the high rock cuts will also ensure increased stability of excavations.

A series of four aeration galleries will be provided at intervals down the chute to prevent cavitation damage of the concrete. Details of these aeration devices are shown in Plate F14.

(d) Flip Bucket

The function of the flip bucket will be to direct the spillway flow clear of the concrete structures and well downstream into the river below. A mass concrete block will form the flip bucket for the main spillway. Detailed geometry of the bucket, as well as dynamic pressures on the floor and walls of the structure, will be confirmed by model studies.

1.7 - Emergency Spillway

The emergency spillway will be located on the north side of the river upstream from the main spillway and power intake structure (see Plate F18). The emergency spillway will consist of a long straight chute excavated in rock and leading in the direction of Tsusena Creek. An erodible fuse plug, consisting of an impervious core and fine gravel materials, will be constructed at the upstream end. The plug will be designed to wash away when overtopped, releasing flows of up to 120,000 cfs in excess of the combined main spillway and outlet facility capacities, thus preventing overtopping of the main dam under PMF conditions.

(a) Fuse Plug and Approach Channel

The approach channel to the fuse plug will be excavated in rock and will have a width of 310 feet and invert elevation of 2170. The main access road to the dam and powerhouse will cross the channel by means of a bridge. The fuse plug will close the approach channel, and will have a maximum height of 31.5 feet with a crest elevation of 2201.5. The plug will have a core up to 10 feet wide, steeply inclined in the upstream direction, with fine filter zones upstream and downstream. It will be supported on a downstream erodible shell of crushed stone or gravel up to 1.5 inches in diameter. The crest of the plug will be 10 feet wide and will be traversed by a 1.5-foot deep pilot channel. The principle of the plug is based on erosion progressing rapidly downward and laterally from the pilot channel as soon as water levels rise above the channel invert.

(b) Discharge Channel

The rock channel downstream from the fuse plug will narrow to 200 feet and continue in a straight line over a distance of 5000 feet at gradients of 1.5 percent to 5 percent in the direction of Tsusena Creek. The flow will discharge into a small valley on the west side of and separate from the area of the relict channel. It is estimated that flows down the channel would continue for a period of 20 days under PMF conditions. Some erosion in the channel would occur, but the integrity of the main dam would not be impaired. The reservoir would be drawn down to Elevation 2170. Reconstruction of the fuse plug would be required prior to refilling of the reservoir.

1.8 - Power Intake

(a) Intake Structure

The power intake will be a concrete structure located deep in the rock on the north bank. Access to the structure will be by road from the south side of the emergency spillway bridge.

In order to draw from the reservoir surface over a drawdown range of 120 feet, four openings will be provided in the upstream concrete wall of the structure for each of the six independent power intakes. The upper opening will always be open, but the lower three openings can be closed off by sliding steel shutters operated in a common guide. All openings will be protected by upstream trashracks. A heated boom will operate in guides upstream from the racks following the water surface, keeping the racks ice free.

A lower control gate will be provided in each intake unit. A single set of upstream bulkhead gates will be provided for routine maintenance of the six intake gates. In an emergency, stoplogs can be installed on the trashrack guides to permit work on the trashracks or shutter guides.

The overall base width of the intake will be 300 feet, providing a minimum spacing of penstock tunnel excavations of 2.5 times the excavated diameter.

The upper level of the concrete structure will be set at Elevation 2201. The level of the lowest intake is governed by the vortex criterion for flow into the penstock from the minimum reservoir level elevation of 2065. The foundation of the structure will be approximately 180 feet below existing ground level and is expected to be in sound rock.

Mechanical equipment will be housed in a steel-frame building on the upper level of the concrete structure. The general arrangement of the power intake is shown on Plate F24.

(b) Approach Channel

The overall width of the approach channel is governed by the combined width of the power intake and the outlet facilities gate structure, and will be approximately 350 feet. The length of the channel will be 1000 feet.

The maximum flow in the intake approach channel will occur when six machines are operating and the outlet facilities are discharging at maximum design capacity. With the reservoir drawn down to Elevation 2065, the velocity in the approach channel will be 3.5 ft/sec, which will not cause any erosion problems. Velocities of 10 ft/sec may occur where the intake approach channel intersects the approach channel to the main spillway.

(c) Mechanical Arrangement

(i) Ice Boom

A heated boom will be installed in guides immediately upstream from the trashracks for each of the six power intakes. The boom will be operated by a movable hoist and will automatically follow the reservoir level. The boom will serve to minimize ice accumulation in the trashrack and intake shutter area, and prevent thermal ice-loading on the trashracks.

(ii) Trashracks

Each of the six power intakes will have four sets of trashracks, one set in front of each intake opening. Each set of trashracks will be in two sections to facilitate handling by the intake service crane. Each set of trashracks will cover an opening 30 feet wide by 26 feet high. The trashracks will have a bar spacing of 6 inches and will be designed for a maximum differential head of 20 feet.

(iii) Intake Shutters

Each of the six power intakes will have three intake shutters which will serve to prevent flow through the openings behind which the shutters will be installed. As the reservoir level drops, the sliding shutters will be removed as necessary using the intake service crane.

Each of the shutters will be designed for a differential head of 15 feet. The lowest shutter at each power intake will incorporate a flap gate which, with a 15-foot differential head across the shutter, will allow maximum turbine flow through the gate. This will prevent failure of the shutters in the event of accidental blocking of all intake openings.

The shutter guides will be heated to facilitate removal in sub-freezing weather. In addition, a bubbler system will be provided in the intake behind the shutters to keep the intake structure water surface free of ice.

(iv) Intake Service Crane

A single overhead traveling-bridge type intake service crane will be provided in the intake service building. The crane will be used for:

- Servicing the ice bulkhead and ice bulkhead hoist
- Handling and cleaning the trashracks
- Handling the intake shutters
- Handling the intake bulkhead gates and
- Servicing the intake gate and hoist

The overhead crane will have a double point lift and followers for handling the trashrack shutters and bulkhead gates. The crane will be radio-controlled with a pendant or cab control for backup.

(v) Intake Bulkhead Gates

One set of intake bulkhead gates will be provided for closing any one of the six intake openings upstream from the intake gates. The bulkhead gates will be used to permit inspection and maintenance of the intake gate and intake gate guides. The gates will be designed to withstand full differential pressure.

(vi) Intake Gates

The intake gates will close a clear opening of 13 feet 5 inches by 17 feet. They will be of the vertical fixed-wheel lift type with upstream seals and skinplate.

Each gate will be operated by a hydraulic cylinder type hoist. The length of a cylinder will allow withdrawal of the gate from the water flow. The intake service crane will be used to raise the gate above deck level for maintenance. The gates will normally be closed under balanced flow conditions to permit dewatering of the penstock and turbine water passages for inspection and maintenance of the turbines. The gates will also be designed to close in an emergency with full turbine flow conditions in the event of loss of control of the turbine.

1.9 - Penstocks

The general arrangement of the penstocks is shown on Plates F21 and F23.

Six penstocks will be provided to convey water from the power intake to the powerhouse, one penstock for each generating unit. Each penstock will be a concrete-lined rock tunnel 17 feet in internal diameter. The mininum lining thickness will be 12 inches, which will be increased as appropriate to withstand design internal pressures. The lateral spacing between penstocks will be 50 feet on centers at the intake and this will increase to 60 feet on centers at the powerhouse. The difference in lateral spacing will be taken out at the upper horizontal bend. The inclined sections of the concrete-lined penstocks will be at 55° to the horizontal.

The design static head on each penstock is 763 feet at centerline distributor level (Elevation 1422). An allowance of 35 percent has been made for pressure rise in the penstock caused by hydraulic transients.

(a) Steel Liner

The rock immediately adjacent to the powerhouse cavern will be incapable of resisting the internal hydraulic forces within the penstocks. Consequently, the first 50 feet of each penstock upstream of the powerhouse will be reinforced by a steel liner designed to resist the maximum design head, without support from the surrounding rock. Beyond this section the steel liner will be extended a further 150 feet, and support from the surrounding rock will be assumed, up to a maximum of 50 percent of the design pressure.

The steel liner will be surrounded by a concrete infill with a minimum thickness of 24 inches. The internal diameter of the steel lining will be 15 feet. A steel transition will be provided between the liner and the 17-foot diameter concrete-lined penstock.

(b) Concrete Lining

The penstocks will be fully lined with concrete from the intake to the steel-lined section, the thickness of lining varying with the external hydrostatic head. The internal diameter of the concrete-lined penstock will be 17 feet. The minimum lining thickness will be 12 inches.

(c) Grouting and Pressure Relief System

A comprehensive pressure relief system will protect the underground caverns against seepage from the high pressure penstock. The system will comprise small diameter boreholes set out to intercept the jointing in the rock. A grouting and drainage gallery will be located upstream from the transformer gallery.

1.10 - Powerhouse

The underground powerhouse complex will be constructed beneath the north abutment of the dam. This will require the excavation in rock of three major caverns, the powerhouse, transformer gallery, and surge chamber, with interconnecting rock tunnels for the draft tubes and isolated phase bus ducts.

Unlined rock tunnels, with concrete inverts where appropriate, will be provided for vehicular access to the three main rock caverns and the penstock construction adit. Vertical shafts will be provided for personnel access to the underground powerhouse, for cable ducts from the transformer gallery, for surge chamber venting, and for the heating and ventilation system.

The general layout of the powerhouse complex is shown in plan and section in Plates F25 and F26, and in isometric projection in Plate F24. The transformer gallery will be located on the upstream side of the powerhouse cavern; the surge chamber will be located on the downstream side.

The draft tube gate gallery and crane will be located in the surge chamber cavern, above the maximum anticipated surge level. Provision will also be made in the surge chamber for tailrace tunnel intake stoplogs, which will be handled by the same crane.

(a) <u>Access Tunnels and Shafts</u>

Vehicular access to the underground facilities at Watana will be provided by a single unlined rock tunnel from the north bank area adjacent to the diversion tunnel portal. The access tunnel will cross over the diversion tunnels and then descend at a uniform gradient to the south end of the powerhouse cavern at generator floor level, Elevation 1463. Separate branch tunnels from the main tunnel will provide access to the transformer gallery at Elevation 1507, the penstock construction adit at Elevation 1420, and the surge chamber at Elevation 1500. The maximum gradient will be 6.9 percent on the construction access tunnel and on the permanent access tunnels.

The cross section of the access tunnel has a modified horseshoe shape, 35 feet wide by 28 feet high. The access tunnel branch to the surge chamber and draft tube gallery will have a reduced section consistent with the anticipated size of vehicle and loading required.

The main access shaft will be at the north end of the powerhouse cavern, providing personnel access from the surface control building by elevator. Access tunnels will be provided from this shaft for pedestrian access to the transformer gallery and the draft tube gate gallery. Elevator access will also be provided to the fire protection head tank, located approximately 250 feet above powerhouse level. The main access shaft will be 20 feet in internal diameter with a concrete lining of 9 to 18 inches.

(b) <u>Powerhouse Cavern</u>

The main powerhouse cavern is designed to accommodate six vertical-shaft Francis turbines, in line, with direct coupling to synchronous generators. Each unit has a design output capability of

170 MW. The length of the cavern will allow for a unit spacing of 60 feet, with a 110-foot long service bay at the south end for routine maintenance and for construction erection. Vehicular access will be by tunnel to the generator floor at the south end of the cavern; pedestrian access will be by elevator from the surface control building to the north end of the cavern. Multiple stairway access points will be available from the main floor to each gallery level. Access to the transformer gallery from the powerhouse will be by tunnel from the main access shaft, or by stairway through each of the isolated phase bus shafts. A service elevator will be provided for access to the various powerhouse floors.

Hatches will be provided through all main floors for installation and maintenance of heavy equipment using the powerhouse cranes.

(c) Transformer Gallery

The transformers will be located underground in a separate gallery, 120 feet upstream from the main powerhouse cavern, with three connecting tunnels for the isolated phase bus. There will be nine single-phase transformers rated at 15/345 kV, 145 MVA, installed in groups of three transformers for two generating units. Generator circuit breakers will be installed in the powerhouse on the lower generator floor level.

The transformer gallery is 45 feet wide, 40 feet high, and 414 feet long; the bus tunnels are 16 feet wide and 16 feet high.

High voltage cables will be taken to the surface by two cable shafts, each with an internal diameter of 7.5 feet. Provision has been made for installation of an inspection hoist in each shaft. A spare transformer will be located in the transformer gallery, and a spare HV circuit will also be provided for improved reliability. The station service auxiliary transformers (2 MVA) and the surface auxiliary transformer (7.5/10 MVA) will be located in the bus tunnels. Generator excitation transformers will be located in the powerhouse on the main floor.

Vehicle access to the transformer gallery will be the main powerhouse access tunnel at the south end. Pedestrian access will be from the main access shaft or through each of the three isolated phase bus tunnels.

(d) Surge Chamber

A surge chamber will be provided 120 feet downstream from the powerhouse cavern to control pressure fluctuations in the turbine draft tubes and tailrace tunnels under transient load conditions, and to provide storage of water for the machine start-up sequence.

The chamber will be common to all six draft tubes, and under normal operation will discharge equally to the two tailrace tunnels. The overall surge chamber size is 350 feet long, 50 feet wide, and 145 feet high (including the draft tube gate gallery).

The draft tube gate gallery and crane will be located in the same cavern, above the maximum anticipated surge level. The crane has also been designed to allow installation of tailrace tunnel intake stoplogs for emergency closure of either tailrace tunnel.

The chamber will generally be an unlined rock excavation, with localized rock support as necessary for stability of the roof arch and walls. The gate guides for the draft tube gates and tailrace stoplogs will be of embedded in reinforced concrete anchored to the rock by rock bolts.

Access to the draft tube gate gallery will be by an adit from the main access tunnel. This access will be widened locally for storage of tailrace tunnel intake stoplogs.

(e) Grouting and Pressure Relief System

Control of seepage in the powerhouse area will be achieved by a grout curtain upstream from the transformer gallery and an arrangement of drainage holes downstream from this curtain. In addition, drain holes will be drilled from the caverns extending to a depth greater than the rock anchors. Seepage water will be collected by surface drainage channels and directed into the powerhouse drainage system.

(f) Cable Shafts

Cable shafts will be 8.5 feet in excavated diameter. Although not required for rock stability, a 6-inch thick concrete lining has been specified for convenience of installing hoist, stairway and cable supports.

(g) Draft Tube Tunnels

The draft tube tunnels will be shaped to provide a transition to a uniform horseshoe section with a 19-foot diameter and a concrete lining at least 2.5 feet thick. The initial rock support will be concentrated at the junctions with the powerhouse and surge chamber where the two free faces give greatest potential for block instability.

1.11 - Tailrace

Two tailrace pressure tunnels will be provided at Watana to carry water from the surge chamber to the river. The tunnels will have a modified horseshoe cross section with a major internal dimension of 34 feet.

The tunnels will be fully concrete-lined throughout, with a minimum concrete thickness of 12 inches and a length of 1800 feet. The tailrace tunnels will be arranged to discharge into the river between the main dam and the main spillway.

The upstream sections of the tailrace tunnels will be bearing 249° and will parallel the main access tunnel. The southern tunnel will join the lower diversion tunnel and utilize the diversion portal for the tailrace outlet. The northern tunnel will change direction at the downstream end to bear 238° and the portal will be situated between the diversion tunnel portals and the spillway flip bucket. The tunnels will be concrete-lined for hydraulic considerations.

The downstream portal of the northern tunnel will be located between the spillway flip bucket and diversion tunnel portal. A rock berm will be left in place to the south of the portal to separate the outlet and diversion tunnel channels.

The tailrace portals will be reinforced concrete structures designed to reduce the outlet flow velocity, and hence the velocity head loss at the exit to the river.

1.12 - Access Plan

(a) Access Objectives

The primary objective of access is to provide a transportation system that will support construction activities and allow for the orderly development and maintenance of site facilities.

(b) Access Plan Selection

Detailed access studies resulted in the development of eighteen alternative access plans within three distinct corridors. The three corridors were identified as:

- A corridor running west to east from the Parks Highway to the damsites on the north side of the Susitna River;
- A corridor running west to east from the Parks Highway to the damsites on the south side of the Susitna River; and
- A corridor running north to south from the Denali Highway to the Watana damsite.

Criteria were established to evaluate the responsiveness of the plans to project objectives and the desires of the resource agencies and affected communities. The selected access plan (Plan 18, otherwise referred to as Denali-North) represents the most favorable solution to meeting both project related goals and minimizing impacts to the environment and the surrounding communities. Where adverse environmental impacts are unavoidable or project objectives compromised, mitigation and management measures have been formulated to reduce these impacts to a minimum. These mitigation measures are outlined in detail within Exhibit E of the license application.

(c) <u>Description of Access Plan</u>

Access to the Watana damsite will connect with the existing Alaska Railroad at Cantwell where a railhead and storage facility occupying 40 acres will be constructed. This facility will act as the transfer point from rail to road transport and as a storage area for a two-week backup supply of materials and equipment. From the railhead facility the road will follow an existing route to the junction of the George Parks and Denali Highways (a distance of two miles), then proceed in an easterly direction for a distance of 21.3 miles along the Denali Highway. A new road, 41.6 miles in length, will be constructed from this point due south to the Watana camp site. On completion of the dam, access to Native lands on the south side of the Susitna River will be provided from the Watana camp site with the road crossing along the top of the dam. This will involve the construction of an additional 2.6 miles of road bringing the total length of new road to 44.2 miles.

Plate F32 shows the proposed access plan route. Plate F33 shows details, for both the Watana and Devil Canyon developments, of typical road and railroad cross sections, railhead facilities, and the high-level bridge at Devil Canyon.

Assessment of projected traffic volumes and loadings during construction resulted in the selection of the following design parameters for the access roads.

Surfacing	Unpaved (Treated Gravel Surface)
Width of Running Surface	24 feet
Shoulder Width	5 feet
Design Speed	55 mph
Maximum Grade	6%
Maximum Curvature	5°
Design Loading	
- during construction	80^k axle, 200^k total
- after construction	HS - 20

These design parameters were chosen for the efficient, economical, and safe movement of supplies and are in accordance with current highway design standards. Adhering to these grades and curvatures the entire length of the road would result in excessively deep cuts and extensive fills in some areas, and could create serious technical and environmental problems. From an engineering standpoint, it is advisable to avoid deep cuts because of the potential slope stability problems, especially in permafrost zones. Also, deep cuts and large fills are detrimental to the environment for they act as a barrier to the migration of big game and disrupt the visual harmony of the wilderness setting. Therefore, in areas where adhering to the aforementioned grades and curvatures involves extensive cutting and filling, the design standards have been reduced to allow steeper grades and shorter radius turns.

This flexibility of design standards has provided greater latitude to "fit" the road within the topography and thereby enhance the visual quality of the surrounding landscape. For reasons of driver safety, the design standards will in no instance be less than those applicable to a 40 mph design speed.

In the community of Cantwell the road will be paved from the marshalling yard to 4 miles east of the junction of the George Parks and Denali Highways. This will eliminate any problem with dust and flying stones in the residential district. In addition, the following measures will be taken.

- Speed restrictions will be imposed along the above segment;

- A bike path will be provided along the same segment to safeguard children in transit to and from a school which is situated close to the road; and

- Improvements will be made to the intersection of the George Parks and Denali Highways including pavement markings and traffic signals.

(d) Right-of-Way

The 21.3 miles of existing road along the Denali Highway will be upgraded to the aforementioned standards. However, the present alignment is such that any realignment required should be possible within the existing easement.

The majority of the new road will follow terrain and soil types which allow construction using side borrow techniques, resulting in a minimum of disturbance to areas away from the alignment. A berm type cross section will be formed, with the crown of the road being approximately 2 to 3 feet above the elevation of adjacent ground. To reduce the visual impact, the side slopes will be flattened and covered with excavated peat material. A 200-foot right-of-way will be sufficient for this type of construction. Although sidehill cuts must be minimized to avoid the effects of thawing permafrost and winter icing on the section of road running parallel to Deadman Creek, in isolated spots of extensive sidehill cutting it may be necessary to exceed the 200-foot width.

(e) Construction Schedule

The overall schedule for the Watana development relies heavily on the ability to move supplies, materials and equipment to the site as soon as possible after the start of project construction. The selected plan involves the least mileage of new road construction and follows relatively level, open terrain in comparison with the alternative routes in the two other corridors. Consequently, construction of this route has the highest probability of meeting schedule and hence affords the least risk of project delay. It has been estimated that it will take approximately 6 months to secure initial access with an additional year for completion and the upgrading of the Denali Highway section.

1.13 - Site Facilities

(a) General

The construction of the Watana development will require various facilities to support the construction activities throughout the entire construction period. Following construction, the operation of the Watana hydroelectric development will require certain permanent staff and facilities to support the permanent operation and maintenance program.

The most significant item among the site facilities will be a combination camp and village that will be constructed and maintained at the project site. The camp/village will be a largely self-sufficient community housing 3300 people during construction of the project. After construction is complete, it is planned to dismantle and demobilize most of the facility and to reclaim the area. The dismantled buildings and other items from the camp will be used as much as possible during construction of the Devil Canyon development. Other site facilities include contractors' work areas, site power, services, and communications. Items such as power and communications will be required for construction operations independent of camp operations. The same will be true regarding a hospital or first aid room.

Permanent facilities required will include a permanent town or small community for approximately 130 staff members and their families. Other permanent facilities will include a maintenance building for use during subsequent operation of the power plant.

A conceptual plan for the permanent town is shown on Plate F36.

(b) Temporary Camp and Village

The proposed location of the camp and village will be on the north bank of the Susitna River between Deadman and Tsusena Creek, approximately 2.5 miles northeast of the Watana Dam. The north side of the Susitna River was chosen because the main access will be from the north and south-facing slopes can be used for siting the structures. The location is shown in Plate F34.

The camp will consist of portable woodframe dormitories for bachelors with modular mess halls, recreational buildings, bank, post office, fire station, warehouses, hospital, offices, etc. The camp will be a single status camp for approximately 3000 workers.

The village, accommodating approximately 300 families, will be grouped around a service core containing a school, gymnasium, stores, and recreation area.

The village and camp areas will be separated by approximately 1.5 miles to provide a buffer zone between areas. The hospital will serve both the main camp and village.

The camp location will separate living areas from the work areas by a mile or more and keep travel time to work to less than 15 minutes for most personnel.

The camp/village will be constructed in stages to accommodate the peak work force. The facilities have been designed for the peak work force plus 10 percent for turnover. The turnover will include allowances for overlap of workers and vacations. The conceptual layouts for the camp and village are presented on Plates F36 and F37.

(i) Site Preparation

Both the camp and the village areas will be cleared and in select areas filter fabric will be installed and granular material placed over it for building foundations. At the village site, selected areas will be left with trees and natural vegetation intact. Topsoil stripped from the adjacent dam borrow site will be utilized to reclaim camp and village sites.

Both the main camp and the village site have been selected to provide well-drained land with natural slopes of 2 to 3 percent.

(ii) Facilities

Construction camp buildings will consist largely of trailer-type factory-built modules assembled at site to provide the various facilities required. The modules will be fabricated complete with heating, lighting and plumbing services, interior finishes, furnishings, and equipment. Larger structures such as the central utilities building, warehouses and hospital will be pre-engineered, steel-framed structures with metal cladding.

(c) Permanent Town

The permanent town will be located at the north end of the temporary village (see Plate F34) and be arranged around a small lake for aesthetic purposes.

The permanent town will consist of permanently constructed buildings. The various buildings in the permanent town are as follows:

- Single family dwellings;
- Multifamily dwellings;
- Hospital;
- School;
- Fire station;
- A town center will be constructed and will contain the following:
  . a recreation center
  . a gymnasium and swimming pool
  . a shopping center

The concept of building the permanent town at the beginning of the construction period and using it as part of the temporary village was considered. This concept was not adopted, since its intended occupancy and use is a minimum of 10 years away, and the requirements and preferences of the potential long-term occupants cannot be predicted with any degree of accuracy.

(d) Site Power and Utilities

(i) Power

Electrical power required to maintain the camp/ village and construction activities will be provided by diesel generators. Generating capacity will be provided for peak load with sufficient backup for essential services should the main generating station be out of service.

The peak demand during the peak camp population year is estimated at 10 MW for the camp/village and 6 MW for construction requirements. The distribution system in the camp/village and construction area will be 4.16 kV.

Power for the permanent town will be supplied from the station service system after the power plant is in operation.

(ii) Water

The water supply system will provide for potable water and fire protection for the camp/village and selected contractors' work areas. The estimated peak population to be served will be 4000 (3000 in the camp and 1000 in the village).

The principal source of water will be Tsusena Creek, with a backup system of wells drawing on ground water. The water will be treated in accordance with the Environmental Protection Agency's (EPA) primary and secondary requirements.

A system of pumps and storage reservoirs will provide the necessary system capacity. The distribution system will be contained within utilidors constructed using plywood box sections integral with the permawalks. The distribution and location of major components of the water supply system are presented in Plate F34. Details of the utilidors are presented in Plate F38.

(iii) Wastewater

A wastewater collection and treatment system will serve the camp/village. One treatment plant will serve the camp/-village. Gravity flow lines with lift stations will be used to collect the wastewater from all of the camp and village facilities. The "in-camp" and "in- village" collection systems will be run through the utilidors so that the collection system will be protected from freezing.

The chemical toilets located around the construction site will be serviced by sewage trucks, which will discharge directly into the sewage treatment plant. The sewage treatment system will be a biological system with lagoons designed to meet Alaskan and EPA standards. The sewage plant will discharge its treated effluent through a force main to Deadman Creek. All treated sludge will be disposed in a solid waste sanitary landfill.

The location of the treatment plant is shown in Plate F37. The location was selected to avoid unnecessary odors in the camp as the winds are from the southeast only 4 percent of the time, which is considered minimal.

(e) Contractors' Area

The on-site contractors will require office, shop, and general work areas. Partial space required by the contractors for fabrication shops, maintenance shops, storage or warehouses, and work areas will be located between the main camp and the main access road.

1.14 - Relict Channel

A relict channel exists on the north bank of the reservoir approximately 2600 feet upstream from the dam. This channel runs from the Susitna River gorge to Tsusena Creek, a distance of about 1.5 miles. The surface elevation of the lowest saddle is approximately 2205, and depths of up to 454 feet of glacial deposits have been identified. This channel represents a potential source of leakage from the Watana reservoir. Along the buried channel thalweg, the highest or controlling bedrock surface is some 450 feet below reservoir level, while along the shortest leakage path between the reservoir and Tsusena Creek the highest rock surface is some 250 feet below reservoir level. The maximum average hydraulic gradient along any flow path in the buried channel from the edge of pool to Tsusena Creek is approximately 9 percent, while the average gradient is believed to be less than 6 percent. There is no indication of any existing water-level connection between the Susitna River and Tsusena Creek. Tsusena Creek at the relict channel outlet area is at least 120 feet above the natural river level. There are several surface lakes within the channel area, and some artesian water is present in places. Zones of permafrost have also been identified throughout the channel area.

To preserve the integrity of the rim of the Watana reservoir and to control losses due to potential seepage, a number of remedial measures will be undertaken. These measures are designed to deal with potential problems which may arise due to settlement of the reservoir rim, subsurface flows, permafrost and liquefaction during earthquakes.

(a) Surface Flows

To eliminate the potential problems associated with settlement and breaching of a saddle dam allowing surface flows through the buried channel area, the maximum operating level of the reservoir has been set at 2185 feet, leaving a natural saddle width of at least 1500 feet of ground above pool level at this elevation. A freeboard dike with a crest elevation of 2210 will be constructed to provide protection against extreme reservoir water levels under PMF conditions. The shortest distance between the toe of the dike and the edge of the reservoir pool (Elevation 2185) is at least 450 feet, and under a PMF flood the static water level will just reach the toe of the dike before the emergency fuse plug washes out. The freeboard dike will consist of compacted granular material placed on a prepared foundation from which all surface soils and organic materials will be removed.

(b) Subsurface Flows

The potential for progressive piping and erosion in the area of discharge into the Tsusena Creek will be controlled by the placement of properly graded granular materials to form a filter blanket over any zones of emergence. Further field investigations will be carried out to fully define critical areas, and only such areas will be treated. Continuous monitoring of the outlet area will be undertaken for a lengthy period after reservoir filling to ensure that a state of equilibrium is established with respect to permafrost and seepage gradients in the buried channel area.

If the permeability of the base alluvium is found to be excessive, a provision will also be made to carry out grouting of the upstream alluvium at a natural narrow reach to reduce the total leakage.

(c) Permafrost

Thawing of permafrost will occur and may have an impact on subsurface flows and ground settlement. Although no specific remedial work is foreseen at this time, flows, groundwater elevation, and ground surface elevation in the buried channel area will be carefully and continuously monitored by means of appropriate instrumentation systems and any necessary maintenance work carried out to maintain freeboard and control seepage discharge.

(d) Liquefaction

To guarantee the integrity of the reservoir rim through the channel area requires that either:

- There be no potential for a liquefaction slide into the reservoir, or

- If there is such potential, there be a sufficient volume of stable material at the critical section so that, even if the upstream materials were to slide into the reservoir, the failure zone could not cut back to the reservoir rim.

Any requirement of remedial treatment will depend on the location and extent of critical zones and could range from stabilization by compaction (vibroflotation), grouting techniques (either cement, colloidal or chemical grouting), or, in the limit, removal of material and replacement with compacted nonsusceptible fill.

Available geotechnical information indicates that there is no widespread potentially liquefiable material in the upper 200-250 feet of glacial deposits in the relict channel. Further geotechnical studies will be required to fully define the extent and characteristics of the materials in the relict channel. Provisions will be made in design for treatment to cover the worst conditions identified. These measures include:

- Densification

  Layers within about 100 feet of the surface could be compacted by vibroflotation techniques to eliminate the risk of liquefaction and provide a stable zone by increasing the relative density of the in situ material.

- Stabilization

  Critical layers at any depth could be grouted, either with cement for fine gravels and coarse sands or by chemical grouting for fine sands and silts.

- Removal

  This could range from the replacement of critical material near the valley slopes with high-quality, processed material, which would stabilize the toe of a potential slide and so prevent the initiation of failure that might otherwise cut back and cause major failures, to the excavation, blending, and replacement of large volumes of material to provide a stable zone.

The most positive solution to a worst case scenario is the replacement of the critical zone with material that would not liquefy. This would involve, in effect, the rearrangement of the in-place materials to create an underground dam section constructed of selected materials founded on the dense till layer beneath the critical alluvium. Such an operation will require the excavation of a trench up to 135 feet deep with a surface width up to 1000 feet. Selected materials would be compacted to form a central stable zone, while surplus and unsuitable materials would be placed on both sides of this central "dam" to complete backfilling to ground surface. The central zone would be designed to remain stable in the event that all upstream material did slide into the reservoir. Such a structure would be about 5000 feet long, with a total cut volume of about 13 million cubic yards, of which 4-1/2 million cubic yards could be used in the compacted center zone. The cost of such work is estimated to be about $100 million. Although this is considered an unlikely scenario, contingency allowances will be adequate to cover this cost.

2 - RESERVOIR DATA - WATANA

The Watana reservoir, at normal operating level of 2185 feet (mean sea level), will be approximately 48 miles long with a maximum width in the order of 5 miles. The total water surface area at normal operating level is 38,000 acres. The minimum reservoir level will be 2065 feet during normal operation, resulting in a maximum drawdown of 120 feet. The reservoir will have a total capacity of 9.5 million acre-feet, of which 3.7 million acre-feet will be live storage.

3 - TURBINES AND GENERATORS - WATANA

3.1 - Unit Capacity

The Watana powerhouse will have six generating units with a design capability of 170 MW corresponding to the minimum December reservoir level (Elevation 2114) and a corresponding gross head of 652 feet on the station.

The head on the plant will vary from 610 feet to approximately 735 feet.

The rated head for the turbine has been established at 680 feet, which is the weighted average operating head on the station. The rated turbine output will be 250,000 hp (186.5 MW) at full gate.

The generator rating has been selected as 190 MVA with a 90 percent power factor. The generators will be capable of a continuous 15 percent overload allowing a unit output of 196 MW. At maximum reservoir water level, the turbines will be operated below maximum output to avoid overloading of the generators.

3.2 - Turbines

The turbines will be of the vertical-shaft Francis type with steel spiral casing and a concrete elbow-type draft tube. The draft tube will comprise a single water passage without a center pier.

The rated output of the turbine net will be 250,000 hp at 680 feet rated net head. Maximum and minimum heads on the units will be 725 feet and 600 feet, respectively. The full gate output of the turbines will be about 275,000 hp at 725 feet net head and 209,000 hp at 600 feet net head. Overgating of the turbines may be possible, providing approximately 5 percent additional power; however, at high heads the turbine output will be restricted to avoid overloading the generators. The best efficiency point of the turbines will be established at the time of preparation of bid documents for the generating equipment and will be based on a detailed analysis of the anticipated operating range of the turbines. For preliminary design purposes, the best efficiency (best-gate) output of the units has been assumed as 85 percent of the full gate turbine output.

The full-gate and best-gate efficiencies of the turbines will be about 91 percent and 94 percent, respectively, at rated head. The efficiency will be about 0.5 percent lower at maximum head and 1 percent lower at minimum head.

3.3 - Generators

(a) Type and Rating

The six generators in the Watana powerhouse will be of the vertical-shaft, overhung type directly connected to the vertical Francis turbines. The arrangement of the units is shown in Plates F25 and F26, and the single line diagram is shown in Plate F30.

There will be two generators per transformer bank, with each transformer bank comprising three single-phase transformers. The generators will be connected to the transformers by isolated phase bus through generator circuit breakers directly connected to the isolated phase bus ducts.

Each generator will be provided with a high initial response static excitation system. The units will be controlled from the Watana surface control room, with local control facility also provided at the powerhouse floor. The units will be designed for black start operation.

The generators will be rated as follows:

Rated Capacity	190 MVA, 0.9 power factor
Rated Power	170 MW
Rated Voltage	15 kV, 3 phase, 60 Hertz
Synchronous Speed	225 rpm
Inertia Constant	3.5 MW-sec/MVA
Transient Reactance	28 percent (maximum)
Short Circuit Ratio	1.1 (minimum)
Efficiency at Full Load	98 percent (minimum)

The generators will be of the air-cooled type, with water-to-air heat exchangers located on the stator periphery. The ratings given above are for a temperature rise of the stator and rotor windings not exceeding 60°C with cooling air at 40°C.

The generators will be capable of delivering 115 percent of rated power continuously (195.5 MW) at a voltage of ±5 percent without exceeding 80°C temperature rise in accordance with ANSI Standard C50.10.

The generators will be capable of continuous operation as synchronous condensers when the turbine is dewatered, with an underexcited reactive power rating of 140 MVAR and an overexcited rating of 110 MVAR. Each generator will be capable of energizing the transmission system without risk of self-excitation.

(b) Unit Dimensions

Approximate dimensions and weights of the principal parts of the generator are given below:

Stator pit diameter	36 feet
Rotor diameter	22 feet
Rotor length (without shaft)	7 feet
Rotor weight	385 tons
Total weight	740 tons

It should be noted that these are approximate figures and they will vary between manufacturers.

(c) Generator Excitation System

The generator will be provided with a high initial response type static excitation system supplied with rectified excitation power from transformers connected directly to the generator terminals. The excitation system will be capable of supplying 200 percent of rated excitation field (ceiling voltage) with a generator terminal voltage of 70 percent. The power rectifiers will have a one-third spare capacity to maintain generation even during failure of a complete rectifier module.

The excitation system will be equipped with a fully static voltage regulating system maintaining output from 30 percent to 115 percent, within ± 0.5 percent accuracy of the voltage setting. Manual control will be possible at the excitation board located on the powerhouse floor, although the unit will normally be under remote control.

3.4 - Governor System

The governor system which controls the generating unit will include a governor actuator and a governor pumping unit. A single system will be provided for each unit. The governor actuator will be the electric hydraulic type and will be connected to the computerized station control system.

4 - TRANSMISSION FACILITIES FOR WATANA DEVELOPMENT

4.1 - Transmission Requirements

The purpose of the project transmission facilities will be to deliver power from the Susitna River basin generating plants to the major load centers at Anchorage and Fairbanks in an economical and reliable manner. The facilities will consist of overhead transmission lines, under-water cables, switchyards, substations, a load dispatch center, and a communications system. The development of the full potential of the river basin will be phased over a number of years and the transmission facilities will be arranged so that reliable operations will be insured at all phases of the development. The design will provide for delivery of power to one substation in Fairbanks, one substation at Willow, and two substations in Anchorage. As the power generated by the Watana hydroelectric station will be used to serve all the substations noted above, the transmission facilities associated with Watana will extend over the full length of the corridor. Later when Devil Canyon is developed, the facilities will be supplemented with additional components along some parts of the corridor.

4.2 - Description of Facilities

(a) Corridor

The corridor that the transmission lines will follow as they leave the generating plants is generally westward, following the Susitna River valley to Gold Creek near the Alaska Railroad route. At this point, the corridor divides to provide for lines running north to Fairbanks and south to Anchorage; in both cases, the corridor generally follows the Railbelt. However the lines to Anchorage will leave the Railbelt just outside Willow. At this point, the corridor continues in a southerly direction to reach the north shore of Knik Arm. The corridor enters military reserved territory and is constrained to pass near the northern and eastern perimeter of Fort Richardson through the reservation, and finally loops south and west to the site of the existing University substation located some four miles southeast of the center of Anchorage.

The length of the corridor sections and the number of lines contained within them are shown in the following table:

	LENGTH (Mi)	NUMBER OF 345 KV CIRCUITS Watana	Canyon	Developed
1. Watana to Gold Creek	37	2	--	2
2. Devil Canyon to Gold Creek	8	--	2	2
3. Gold Creek to Knik Arm (West)	123	2	1	3
4. Knik Arm Crossing	3	2	1	3
5. Knik Arm to Anchorage	19	2	--	2
6. Gold Creek to Fairbanks	185	2	--	2

The physical location of the corridor is shown in a regional context, together with the single line diagram of the system, on Plate No. F74, Exhibit F.

(b) Components

At the Watana development a switchyard will be provided on the "breaker-and-a-half" layout arrangement which will provide high reliability. This switchyard will allow the output of the development to be divided between the two outgoing lines, or concentrated on one line or the other in the event of an outage of one line. (Refer to Plate F31, Exhibit F)

From Watana, two single-circuit 345 kV lines will leave the switchyard and run westward to the Gold Creek switching station. From the Watana substation, both lines will continue in a northwest direction, a distance of approximately two miles crossing Tsuesena Creek, then will turn west and share the same general corridor as the proposed access road all the way to the Devil Canyon damsite. From Devil Canyon, the lines will head in a southwest direction, crossing the Susitna River at river mile 149.8, then will turn westward and follow the proposed railroad extension a distance of approximately six miles to the Gold Creek switching station. The Gold Creek switching station will be located in a wooded area on the south bank terraces of the Susitna River at approximately river mile 142.

The Gold Creek switching station layout will be based on the breaker-and- a-half arrangement for a reliable and secure operation. At this station switching will be provided so that the output of the Watana development can be dispatched partly north along the two lines to Fairbanks and partly to Anchorage along the two lines that run south. Power dispatched in either of these directions will be able to be switched to one line of the pair in the event of an outage on the other. Switching also will allow either of the incoming lines from Watana to feed either Fairbanks or Anchorge, providing complete flexibility. Access to the Gold Creek switching station site will be by an 8-mile long all-weather road from the railroad at Gold Creek. (Refer to Plate F76, Exhibit F)

The two 345 kV single-circuit lines to Fairbanks from Gold Creek will share the same right-of-way north, generally following the Railbelt past Chulitna, Cantwell, Denali Park and Healy, sited to the east of the railroad. About 1 mile north of Healy the lines will cross to the west side of the Nenana River and the railroad, continuing northwards for about 14 miles between the Parks Road on the west and the railroad on the east. At this point the lines will recross to the east side of the Nenana River and the railroad, continuing north to cross the Tanana River about 8 miles east of the town of Nenana, and then will continue northeastward to a point six miles west of Fairbanks at Ester substation, the northern terminal of the 345 kV system.

At Ester substation provision will be made to step down the voltage to 138 kV for delivery to the Golden Valley Electric Association through up to three 150 MVA transformer banks. Switching will be provided at 345 kV to enable the load to be fed from both or either of the incoming lines, using a breaker-and- a-half arrangement for reliability. The Ester switchyard will also be provided with switchable 75 MVAR shunt reactors on each of the 345 kV lines for use during line energizing; switching will allow the reactor to be removed from the line if necessary during emergency heavy line loading if one line suffers an outage. For purposes of control of the system status VAR compensation will be required on the 138 kV buses at Ester consisting of units with +200/-100 MVAR continuous, and +300/-100 MVAR short time ratings. The ratings of the VAR control equipment will be confirmed and, if necessary, refined during final design. Access to the Ester Substation will be provided by an all-weather gravel road linked to the nearby Fairbanks Highway. (Refer to Plate F75, Exhibit F)

The description of the line components from Gold Creek switching station south to Anchorage follows.

Two single-circuit 345 kV lines will exit from the Gold Creek switching station in a southwesterly direction following the east bank of the Susitna River past the village of Gold Creek. At this point while the river and the Alaska Railroad continue southwest, the line route will head south departing up to 10 miles to the east from the Railbelt. Approximately 50 miles south of Gold Creek the lines will rejoin the Railbelt near the Kashwitna River. From here the lines will run 6 miles parallel to the Railbelt on the east of the road to reach the Willow switching station sited about 2 miles north of Willow.

The Willow switching station will serve a dual function; firstly, it will provide a facility to feed load in the locality at 138 kV through up to three 75 MVA, three-phase transformers. Secondly the station will provide complete line switching through a breaker-and-a-half arrangement for reliability. This switching will facilitate line energizing by limiting overvoltages. It will also allow flexibilty to isolate a line section that might suffer an outage and to route load through the remaining lines. The Willow site access will be provided with an all-weather gravel road about 1 mile long across Willow Creek to the Willow Creek Road. (Refer to Plate F77, Exhibit F)

Also located at Willow will be the Energy Management Center where the control of the entire operation of the power generation and transmission facilities will be centralized. Remote control will be provided through communications via a microwave system. Existing microwave communications from Anchorage to Willow and from Fairbanks to Healy will be augmented and extended to provide a continuous link between Fairbanks and Anchorage with a spur into the power developments at Devil Canyon and Watana.

Two single-circuit 345 kV lines leaving Willow switching station will run due west for about 4 miles, then turn south and cross Willow Creek. The lines will continue in a generally southward direction to cross the Little Susitna River about 25 miles from Willow Creek. At this point the lines will bear in a south-easterly direction for about 15 miles to arrive at the west side of Knik Arm about five and a half miles north of Pt. MacKenzie, adjacent to the site of an existing 230 kV line.

Knik Arm will be crossed by submarine cable buried in the inlet bed. Two circuits will be provided, each consisting of three individual single-phase 345 kV submarine cables. On each shore a cable termination station will contain disconnects, arrestors and ground connection devices required for operation of the cable facility. Another feature of the terminals will be an arrangement of an upper level bus which will allow for temporary connections to bring into contingency service a spare phase cable, to replace any cable which might suffer accidental damage. In the bed of the inlet, the circuits will be physically separated into three back-filled trenches; two will contain three single-phase cables making up the two main circuits, the third will contain the spare phase. Each trench will be separated from the other by approximately 1/4 mile with a similar distance being maintained from the existing 230 kV crossing. The separation in the navigation area will be achieved by curving the trenches in plan on the foreshore of the inlet. This arrangement of separating the circuits will provide an added measure of protection against multiple circuit damage due to navigation in the inlet. Access to the east and west terminals will be by gravel road built along the transmission line right-of-way to the nearest public access about 3 miles distant on the east side and 12 miles on the west.

On the east side of Knik Arm the line route will pass through the military reservation forming Fort Richardson. The route will follow a path parallel to the existing 230 kV line. Beyond the Knik Arm substation it will consist of two 345 kV circuits. Because of the restricted width available for right-of-way there is a requirement to use compact line design techniques. Double-circuit steel pole structures will be designed with extra conservative safety factors to increase reliability against loss of both circuits due to structural failure. Separation of the circuit onto two separate single pole structures using post type insulators to prevent conductor swing will be adopted where right-of-way width permits. From the east shore of Knik Arm the route will run east to the intersection of Glen and Davis Highways, where it will turn south following the Glen Highway on the east side, and then pass east of Homesite Park and west to the vicinity of the existing University substation on Tudor Road.

The Knik Arm substation will be located in the general vicinity of the Glen and Davis Highway intersection near where the existing 230 kV and 115 kV lines share the same right-of-way. This facility will allow for a breaker-and-a-half layout with complete flexibility in switching at 345 kV between the incoming and outgoing pairs of lines to cope with possible outage situations. Each of the incoming lines from Willow will have a switchable 30 MVAR shunt reactor to assist with voltage control during energizing of the line. Also the facility will provide one 75 MVA, three-phase transformer to feed into the 115 kV existing system that passes nearby. (Refer to Plate F78, Exhibit F)

The University substation site will represent the southernmost terminal of the 345 kV transmission facility. The substation will serve as the major distribution point for power from Watana into the Anchorage area. Provision will be made for transformation to 230 kV and 115 kV to suit the existing distributions in the area. At the 230 kV level up to three 250 MVA banks of single-phase transformers will be accommodated, and at 115 kV one 250 MVA bank of single-phase transformers. For transient stability, static VAR compensation will be provided on outgoing lines to Anchorage consisting of units with ratings on the 230 kV system of +150/-100 MVAR continuous and +200/-75 MVAR short time; on the 115 kV system rated at +200/-75 MVAR continuous, and +300/-75 MVAR short time. The ratings of the VAR control equipment will be confirmed and, if necessary, refined in final design. Access to the University substation will be by gravel road directly off Tudor Road. (Refer to Plate F79, Exhibit F)

It should be noted that the Alaska Power Authority is proceeding with an "Intertie" project to build approximately 170 miles of one of the 345 kV lines between Healy and Willow on the Fairbanks to Anchorage corridor (Commonwealth Associates 1982). This line will be built to operate eventually at 345 kV but will be energized initially at 138 kV, until it is integrated into the Watana transmission system.

(c) Right-of-Way

The right-of-way for the transmission corridor will consist of a linear strip the width of which depends on the number of lines it contains. North of the cable crossing of Knik Arm the right-of-way will include that area necessary for the additions to the facilities planned in conjunction with the Devil Canyon development. Where the total development will consist of two lines, the right-of-way width will be 300 feet; for three lines it will become 400 feet. Between Gold Creek and Devil Canyon, where ultimately four lines will be required, the width will be 510 feet. In the Knik Arm crossing area the right-of-way will be widened to accommodate the fact that each circuit of the total development will be separated from the adjacent circuits by a distance of about 1/4 mile, as will be the spare phase. The width of the bed affected by the crossing will be approximately one mile. East of Knik Arm the right-of-way width will be restricted in the military reservation. In this section the right-of-way will be 300 feet from the centerline of the 220 kV line.

The right-of-way areas to be occupied by the switching and substations are listed below. They are stated in acres because, until final design is completed, overall dimensions may be varied, although the area should remain within the limits indicated.

	Area of Right-of-Way (acres)
Gold Creek Switchyard	16
Fairbanks (Ester) Substation	25
Willow Substation	25
Knik Arm Substation	15
Anchorage (University) Substation	45

Rights-of-way for permanent access to switchyard and substations will be required linking back to a public road or in some cases rail access. These rights-of-way will be 100 feet wide.

(d) Transmission Lines

Access to the transmission line corridor will be via trails from existing access routes at intermittent points along the corridor. The exact location of these trails will be established in the final design phase. Within the transmission corridor itself an access strip 25 feet wide will run along the entire length of the corridor, except at areas such as major river crossings and deep ravines where an access strip would not be utilized for the movement of equipment and materials. This access strip and the trails leading to the corridor will be constructed to the minimum standard suitable for four wheel drive vehicles.

The conductor capacity for the lines will be in the range of 1950 MCM; this can be provided in several ways. Typical of these is a phase bundle consisting of two 954 MCM "Rail" (45/7) Aluminum Conductor Steel Reinforced (ACSR) or a single 2156 MCM "Bluebird" (84/17) ACSR conductor, both of which provide comparable levels of corona and radio noise within normally accepted limits. The single "Bluebird" conductor attracts less load under wind or ice loadings and avoids the need to provide the space damper devices required for a bundled phase. The single conductor is stiffer and heavier to handle during stringing operations, although this will tend to be balanced out due to the extra work involved in handling the twin bundle. Selection of the optimum conductor arrangement will be made in final design. The conductor will be specified to have a dull finish treatment to reduce its visibility at a distance. The conductor capacity between Knik Arm and University will be 2700 MCM per phase to handle the output of Devil Canyon without an additional circuit in this section of the route.

Two overhead ground wires will be provided the full length of the line. These will consist of 3/8-inch diameter galvanized steel stands. The arrangement will be based on a shielding angle of 15 degrees over the outer phases; this will provide protection against lightning strikes to the line. More refined studies of the lightning performance of the line will be made during final design to confirm the arrangement outlined above.

Highly effective vibration control devices will be required on both the conductors and the ground wire. Due to the very exposed nature of much of the line route, the rating and spacing of the devices will be specified with special care. Stockbridge-type dampers on single wires and spacer dampers with an elastometer damping element are expected to be most suitable.

Conductor suspension and dead-end assemblies will be detailed according to "corona free" design and prototype tested to check that corona and radio interference are below nuisance levels when operating at elevations of up to 3500 feet. Insulators will be standard porcelain or glass disc type suspension units. A chain of 18 units is expected to be sufficient to provide acceptable flashover performance of the line. The configuration will be "M" type with vertical strings on the outside phases and a "V" string supporting the center phase.

The transmission structures and foundations that serve to support the conductors and ground wires will be designed for a region where foundation movement due to permafrost and annual freeze-thaw cycling is common. Of the structural solutions that have proved successful in similar conditions, all utilize an arrangement of guy cables to support the structure. All depend upon the basic flexibility inherent in guyed structures to resist effects of foundation movement. For tangent and small angle applications the guyed type of structure such as the guyed "V", guyed "Y", guyed delta and the guyed portal are the most common economical arrangements. The guyed "X" design has been selected for use on the 345 kV Intertie (1) and is therefore a prime candidate for consideration on the Watana lines. Experience gained during the Intertie project will be used in the final structure design. (Refer to Plate F80, Exhibit F)

Structures for larger angle and dead end applications will be in the form of individual guyed masts, one for each phase. Individual guyed masts will also be used for lengths of line that are judged to be in unusually hazardous locations due to exposure to special wind load effects, or slow slide effects if the terrain is extremely rugged. All structures will utilize a "weathering" steel which matures over several years to a dark brown color which is considered to have a more aesthetically pleasing appearance than galvanized steel or aluminum. (Refer to Plate F80, Exhibit F)

Foundations for structures will utilize driven steel piles in unstable soil conditions. In better soils steel grillage foundations will be used and set sufficiently deep to avoid the effects of the freeze-thaw cycle. Rock footings will employ grouted rock anchors with a minimum use of concrete to facilitate winter construction. Foundations for cantilever pole type structures will be large diameter cast-in-place concrete augered piles. Several types of guy anchor will be available for use; they include the screw-in helix type, the grouted bar earth anchor, driven piles and grouted rock anchors. Selection of the most economical solution in any given situation will depend on the site specific constraints including soil type, access problems and expected guy load. Foundation sites will be graded after installation to contour the disturbed surface to suit the existing grades. Tower grounding provisions will depend upon the results of soil electrical resistivity measurements both prior to and during construction. Continuous counterpoise may be required in sections where rock is at or close to the surface; it also may be required in other areas of high soil resistance. The counterpoise will take the form of two galvanized steel wires remaining at a shallow bury parallel to and under the lines. These will be connected to each tower and cross connected between lines in the right-of-way. Elsewhere, grounding will be installed in the form of ground rods driven into the soil adjacent to the towers.

(e) Switching and Substations

The physical location of the stations and the system single line diagram is shown on Plate F74 of Exhibit F. The single line diagram and layout of the individual stations are contained on Plates F75 through F79 of Exhibit F.

The construction access to all sites will be over the route of the permanent access provided for each location. Any grading of the sites will be carried out on a balanced cut-and-fill basis wherever possible. Equipment will be supported on reinforced concrete pad-and-column type footings with sufficient depth-of-bury to avoid the active freeze-thaw layer. Backfill immediately around footings will be granular to avoid frost heave effects.

Light equipment may be placed on spread footings if movements are not a significant factor in operational performance.

The station equipment requirements are determined by the breaker-and-a-half arrangement adopted for reasons of reliability and security of operation. One and one-half breakers will be needed for every element (line or transformer circuit). The transformer capacities are determined by the load requirements at each substation. Control and metering provisions will cater to the plan for remote operation of all the facilities in normal circumstances. Protective relaying schemes for the 345 kV system will be in accordance with conventional practices, using the general philosophy of dual relaying and the local backup principle.

The station layouts are based on conventional outdoor design with a two-level bus which will result in a relatively low profile to the station. This will assist in limiting the visual impact of the stations and make the most of any available neutral buffers. Although they will be remotely controlled, all stations will be provided with a control building; in larger stations an additional relay building will be provided. A storage building will also be provided for maintenance purposes. Each station will have auxiliary power at 480 V; the normal 480 V ac power will be supplied from the tertiaries on the autotransformers or the local utility. The Willow station will include the Energy Management Center and the headquarters of the system maintenance group.

(f) Cable Crossing

The cable crossing will consist of two 345 kV circuits each comprising three individual 2,000 MCM single-phase submarine cables; in addition a spare phase cable will be provided. Each circuit will be buried in the inlet bottom, the three cables of the circuit sharing the same trench. Beyond the foreshore area it is anticipated that cables can be buried by a combination of dredging and ploughing as the bed materials are reported to be soft. At each shore, gravel deposits are expected to be encountered so that conventional excavate-and-fill methods are more probable with work being performed from barges in the tidal zone.

The centerline of each circuit will be routed on the foreshore so as to obtain a physical separation of approximately 1/4 mile between circuits and the spare phase; a similar spacing will be maintained from the existing 220 kV circuit which runs adjacent to the crossing site.

On each side of the inlet a terminal yard will be provided to contain the disconnects, arrestors, and grounding for the cables as well as the cable terminals. The yards will have bus arrangements which will permit the spare phase to be brought into service by installation of temporary bus connections.

(g) Dispatch Centers - Energy Management Centers and Communications

The operation of the transmission facility and the dispatch of power to the load centers will be controlled from a central dispatch and Energy Management System (EMS) center. It has been proposed that the center be located at Willow since a suitable site could be developed at the Willow switching station site. The location of the center could alternatively be at one of the other key points along the line route. University substation could be considered in final design studies if close proximity to an existing major center of population is thought to be a major advantage in siting. The center will operate in conjunction with northern and southern area control systems in Fairbanks and Anchorage which would control generation in those two areas. The generation at the Susitna hydroelectric sites would be controlled at the Watana power facility. The Energy Management Center would orchestrate the overall operation of the system by request to the three local generation control centers for action and direct operation of the Gold Creek switching station and the four 345 kV switching and substations along the transmission system.

The system communications requirements will be provided by means of a microwave system. The system will be an enlargement of the facility being provided for the operation of the Intertie between Healy and Willow. Communications into the hydroelectric plants will be by a microwave extension from the Gold Creek switching station.

4.3 - Construction Staging

The initial development of Watana will require staged development of transmission facilities to Fairbanks and Anchorage. The first stage includes the following:

Substations	Line Section	Number of Circuits
Watana	Watana to Intertie switchyard near Gold Creek	2
Gold Creek	Switchyard to Willow	2
Willow	Willow to Knik Arm	2
Knik Arm	Knik Arm Crossing	2
University (Anchorage)	Knik Arm to University	2
Ester (Fairbanks)	Devil Canyon to Fairbanks	2

The transmission will consist of two circuits from Watana to the load centers. The conductor for the sections from Watana to Knik Arm and Watana to Fairbanks will consist of bundled 2 x 954 kcmil, ACSR. The section between Knik Arm and University will employ bundled 2 x 1351 kcmil, ACSR. The submarine cable crossing will consist of two circuits. The cable will be single conductor, 345 kV self-contained oil-filled. For project purposes, the cable size will be 500 mm^2. A size of up to 1500 mm^2 may be installed if duty requirements are increased. For reliability, a spare cable will be included on a standby basis.

The Matanuska Electric Association will be serviced from the Willow and Knik Arm substations via step-down transformers to suit the local voltage. Chugach Electric Association, Anchorage Municipal Light and Power, and Golden Valley Electric Association will be serviced through the University substation in Anchorage and Ester substation at Fairbanks.

5 - APPURTENANT MECHANICAL AND ELECTRICAL EQUIPMENT - WATANA

5.1 - Miscellaneous Mechanical Equipment

(a) Powerhouse Cranes

Two overhead traveling-bridge type powerhouse cranes will be installed in the powerhouse. The cranes will be used for:

- Installation of turbines, generators, and other powerhouse equipment; and
- Subsequent dismantling and reassembly of equipment during maintenance overhauls.

Each crane will have a main and auxiliary hoist. The combined capacity of the main hoist for both cranes will be sufficient for the heaviest equipment lift, which will be the generator rotor, plus an equalizing beam. A crane capacity of 205 tons has been established. The auxiliary hoist capacity will be about 25 tons.

(b) Draft Tube Gates

Draft tube gates will be provided to permit dewatering of the turbine water passages for inspection and maintenance of the turbines. The draft tube gate openings (one opening per unit) will be located in the surge chamber. The gates will be of the bulkhead type, installed under balanced head conditions using the surge chamber crane. Four sets of gates have been assumed for the six units. Each gate will be 20 feet wide by 10 feet high.

(c) Surge Chamber Gate Crane

A crane will be installed in the surge chamber for installation and removal of the draft tube gates as well as the tailrace tunnel intake stoplogs. The crane will either be a monorail (or twin monorail) crane, a top running crane, or a gantry crane. The crane will have a capacity of 30 tons and a two point lift.

(d) Miscellaneous Cranes and Hoists

In addition to the powerhouse cranes and surge chamber gate crane, the following cranes and hoists will be provided in the power plant:

- A 5-ton monorail hoist in the transformer gallery for transformer maintenance;

- A 4-ton monorail hoist in the circuit breaker gallery for handling the main circuit breakers;

- Small overhead jib or A-frame type hoists in the machine shop for handling material; and

- A-frame or monorail hoists for handling miscellaneous small equipment in the powerhouse.

(e) Elevators

Access and service elevators will be provided for the power plant as follows:

- An access elevator from control buildings to powerhouse;
- A service elevator in the powerhouse service bay; and
- Inspection hoists in the cable shafts.

(f) Power Plant Mechanical Service Systems

The mechanical service systems for the power plant can be grouped into six major categories:

(i) Station Water Systems

The station water systems will include the water intake, cooling water systems, turbine seal water systems, and domestic water systems. The water intakes will supply water for the various station water systems in addition to fire protection water.

(ii) Fire Protection System

The power plant fire protection system will consist of fire hose stations located throughout the powerhouse, transformer gallery, and bus tunnels; sprinkler systems for the generators, transformers, and the oil rooms; and portable fire extinguishers located in strategic areas of the powerhouse and transformer gallery.

(iii) Compressed Air Systems

Compressed air will be required in the powerhouse for the following:

- Service air;
- Instrument air;

- Generator brakes;
- Draft tube water level depression;
- Air blast circuit breakers; and
- Governor accumulator tanks.

For the preliminary design, two compressed air systems have been assumed: a 100-psig air system for service air, brake air, and air for draft tube water level depression; and a 1,000-psig high-pressure air system for governor air and circuit breaker air. For detailed plant design, a separate governor air system and circuit-breaker air system may be provided.

(iv) Oil Storage and Handling

Facilities will be provided for replacing oil in the transformers and for topping-off or replacing oil in the turbine and generator bearings and the governor pumping system. For preliminary design purposes, two oil rooms have been included, one in the transformer gallery and one in the powerhouse service bay.

(v) Drainage and Dewatering Systems

The drainage and dewatering systems will consist of:

- A unit dewatering and filling system
- A clear water discharge system
- A sanitary drainage system.

The unit dewatering and filling systems will consist of two sumps each with two dewatering pumps and associated piping and valves from each of the units. To prevent station flooding, the sump will be designed to withstand maximum tailwater pressure. A valved draft tube drain line will connect to a dewatering header running along the dewatering gallery. The spiral case will be drained by a valved line connecting the spiral case to the draft tube. It will be necessary to insure that the spiral case drain valve is not open when the spiral case is pressurized to headwater level. The dewatering pump discharge line will discharge water into the surge chamber. The general procedure for dewatering a unit will be to close the intake gate, drain the penstock to tailwater level through the unit, then open the draft tube and spiral case drains to dewater the unit. Unless the drainage gallery is below the bottom of the draft tube elbow, it will not be possible to completely dewater the draft tube through the dewatering header. If necessary, the remainder of the draft tube can be dewatered using a submersible pump lowered through the draft tube access door. Unit filling to tailwater level will be accomplished from the surge chamber through the dewatering pump discharge line (with a bypass around the pumps) and then through the draft tube and spiral case drain lines. Alternatively, the unit can be filled to tailwater level through the draft tube drain line from an adjacent unit. Filling the unit to headwater pressure will be accomplished by "cracking" the intake gate and raising it about 2 to 4 inches.

(vi) Heating, Ventilation, and Cooling

The heating, ventilation, and cooling system for the underground power plant will be designed primarily to maintain suitable temperatures for equipment operation and to provide a safe and comfortable atmosphere for operating and maintenance personnel.

The power plant will be located in mass rock which has a constant year-round temperature of about 40°F. Considering heat given off from the generators and other equipment, the primary requirement will be for air cooling. Initially, some heating will be required to offset the heat loss to the rock, but after the first few years of operation an equilibrium will be reached with a powerhouse rock surface temperature of about 60 to 70°F.

(g) Surface Facilities Mechanical Service Systems

The mechanical services at the control building on the surface will include:

- A heating, ventilation, and air conditioning system for the control room;

- Domestic water and washroom facilities; and

- A halon fire protection system for the control room.

Domestic water will be supplied from the powerhouse domestic water system, with pumps located in the powerhouse and piping up through the access shaft. Sanitary drainage from the control building will drain to the sewage treatment plant in the powerhouse through piping in the access tunnel.

The standby generator building will have the following services:

- A heating and ventilation system;

- A fuel oil system with buried fuel oil storage tanks outside the building, and transfer pumps and a day tank within the building; and

- A fire protection system of the carbon dioxide or halon type.

(h) Machine Shop Facilities

A machine shop and tool room will be located in the powerhouse service bay area with sufficient equipment to take care of all normal maintenance work at the plant, as well as machine shop work for the larger components at Devil Canyon.

5.2 - Accessory Electrical Equipment

The accessory electrical equipment described in this section includes the following:

. Main generator step-up 15/345 kV transformers
. Isolated phase bus connecting the generator and transformers
. Generator circuit breakers
. 345 kV oil-filled cables from the transformer terminals to the switchyard
. Control systems of the entire hydro plant complex
. Station service auxiliary ac and dc systems.

Other equipment and systems described include grounding, lighting system, and communications.

The main equipment and connections in the power plant are shown in the single line diagram, Plate F30. The arrangement of equipment in the powerhouse, transformer gallery, and cable shafts is shown on Plates F25 through F27.

(a) Transformers and HV Connections

Nine single-phase transformers and one spare transformer will be located in the transformer gallery. Each bank of three single-phase transformers will be connected to two generators through generator circuit breakers by isolated phase bus located in individual bus tunnels. The HV terminals of the transformer will be connected to the 345 kV switchyard by 345 kV single-phase, oil-filled cable installed in 700-foot long vertical shafts. There will be two sets of three single-phase 345 kV oil-filled cables installed in each cable shaft. One set will be maintained as a spare three-phase cable circuit in the second cable shaft. These cable shafts will also contain the control and power cables between the powerhouse and the surface control room, as well as emergency power cables from the diesel generators at the surface to the underground facilities.

(b) Main Transformers

The nine single-phase transformers (three transformers per group of two generators) and one spare transformer will be of the two-winding, oil-immersed, forced-oil water-cooled (FOW) type, with rating and electric characteristics as follows:

Rated capacity	145 MVA
High voltage winding	345 / $\sqrt{3}$ kV, Grounded Y
Basic insulation level (BIL) of H.V. winding	1300 kV
Low voltage winding	15 kV, Delta
Transformer impedance	15 percent

The temperature rise above ambient (40°C) will be 55°C for the windings for continuous operation at the rated kVA.

Fire walls will separate each single-phase transformer. Each transformer will be provided with fog-spray water fire protection equipment, automatically operated from heat detectors located on the transformer.

(c) Generator Isolated Phase Bus

The isolated phase bus main connections will be located between the generator, generator circuit breaker, and the transformer.

Tap-off connections will be made to the surge protection and potential transformer cubicle, excitation transformers, and station service transformers. Bus duct ratings are as follows:

	Generator Connection	Transformer Connection
Rated current, amps	9,000	18,000
Short circuit current momentary, amps	240,000	240,000
Short circuit current, symmetrical, amps	150,000	150,000
Basic insulation level, kV (BIL)	150	150

The bus conductors will be designed for a temperature rise of 65°C above 40°C ambient.

(d) Generator Circuit Breakers

The generator circuit breakers will be enclosed air circuit breakers suitable for mounting in line with the generator isolated phase bus ducts. They are rated as follows:

Rated Current	9,000 Amps
Voltage	23 kV class, 3-phase, 60 Hertz
Breaking capacity, symmetrical, amps	150,000

The short circuit rating is tentative and will depend on detailed analysis in the design stage.

(e) 345 kV Oil-Filled Cable

The recommended 345 kV connection is a 345 kV oil-filled cable system between the high voltage terminals of the transformer and the surface switchyard. Cables from two transformers will be installed in a single vertical cable shaft.

The cable will be rated for a continuous maximum current of 800 amps at 345 kV $\pm$5 percent. The maximum conductor temperature at the maximum rating will be 70°C over a maximum ambient of 35°C. This rating will correspond to 115 percent of the generator overload rating. The normal operating rating of the cable will be 87 percent, with a corresponding lower conductor temperature which will improve the overall performance and lower cable aging over the project operating life. Depending on the ambient air temperature, a further overload emergency rating of about 10 to 20 percent will be available during winter conditions.

The cables will be of single-core construction with oil flow through a central oil duct within the copper conductor. The oil duct provided within the cables will permit low viscosity oil to flow automatically into or out of hermetically sealed reservoirs or "pressure tanks" directly connected to the cable during a heating/cooling cycle. Cables will have an aluminum sheath and PVC oversheath. No cable jointing will be required for the 700- to 800-foot cable installation.

(f) Control Systems

(i) General

A Susitna Area Control Center will be located at Watana to control both the Watana and the Devil Canyon power plants. The control center will be linked through the supervisory system to the Central Dispatch Control Center at Willow as described in Exhibit B, Section 3.6.

The supervisory control of the entire Alaska Railbelt system will be accomplished at the Central Dispatch Center at Willow. A high level of control automation with the aid of digital computers will be sought, but not complete computerized control of the Watana and Devil Canyon power plants. Independent operator controlled local-manual and local-auto operations will still be possible at Watana and Devil Canyon power plants for testing/commissioning or during emergencies. The control system will be designed to perform the following functions at both power plants:

- Start/stop and loading of units by operator;
- Load-frequency control of units;
- Reservoir/water flow control;
- Continuous monitoring and data logging;
- Alarm annunciation; and
- Man-machine communication through visual display units (VDU) and console.

In addition, the computer system will be capable of retrieval of technical data, design criteria, equipment characteristics and operating limitations, schematic diagrams, and operating/ maintenance records of the unit.

The Susitna Area Control Center will be capable of completely independent control of the Central Dispatch Center in case of system emergencies. Similarly it will be possible to operate the Susitna units in an emergency from the Central Dispatch Center, although this should be an unlikely operation considering the size, complexity, and impact of the Susitna generating plants on the system.

The Watana and Devil Canyon plants will be capable of "black start" operation in the event of a complete blackout or collapse of the power system. The control systems of the two plants and the Susitna Area Control Center complex will be supplied by a non-interruptible power supply.

(ii) Unit Control System

The unit control system will permit the operator to initiate an entire sequence of actions by pushing one button at the control console, provided all preliminary plant conditions have been first checked by the operator, and system security and unit commitment have been cleared through the central dispatch control supervisor. Unit control will be designed to:

- Start a unit and synchronize it with the system
- Load the unit
- Stop a unit
- Operate a unit as spinning reserve (runner in air with water blown down in turbine and draft tube)
- Operate as a synchronous condenser (runner in air as above).

(iii) Computer-Aided Control System

The computer-aided control system at the Susitna Area Control Center at Watana will provide for the following:

- Data acquisition and monitoring of units (MW, MVAR, speed, gate position, temperatures, etc.);
- Data acquisition and monitoring of reservoir headwater and tailwater levels;
- Data acquisition and monitoring of electrical system voltage and frequency;
- Load-frequency control;
- Unit start/stop control;
- Unit loading;
- Plant operation alarm and trip conditions (audible and visual alarm on control board, full alarm details on VDU on demand);
- General visual plant operation status on VDU and on large wall mimic diagram;
- Data logging, plant operation records;
- Plant abnormal operation or disturbance automatic recording; and
- Water management (reservoir control).

(iv) Local Control and Relay Boards

Local boards will be provided at the powerhouse floor equipped with local controls, alarms, and indications for all unit control functions. These boards will be located near each unit and will be utilized mainly during testing, commissioning, and maintenance of the turbines and generators. They will also be utilized as needed during emergencies if there is a total failure of the remote or computer-aided control systems.

(v) Load-Frequency Control

The load-frequency system will provide remote control of the output of the generator at Watana and Devil Canyon from the central dispatch control center through the supervisory and computer-aided control system at Watana. The basic method of load-frequency control will use the plant error (differential) signals from the load dispatch center and will allocate these errors to the power plant generators automatically through speed-level motors. Provision will be made in the control system for the more advanced scheme of a closed-loop control system with digital control of generator power.

The control system will be designed to take into account the digital nature of the controller-timed pulses as well as the inherent time delays caused by the speed-level motor runup and turbine-generator time constants.

(g) Station Service Auxiliary AC and DC Systems

(i) Auxiliary AC System

The station service system will be designed to achieve a reliable and economic distribution system for the power plant and switchyard in order to satisfy the following requirements:

- Station service power at 480 volts will be obtained from two 2,000 kVA auxiliary transformers connected directly to the generator circuit breaker outgoing leads of Units 1 and 3;
- Surface auxiliary power at 34.5 kV will be supplied by two separate 7.5/10 MVA transformers connected to the generator leads of Units 1 and 3;
- Station service power will be maintained even when all units are shut down and the generator circuit breakers are open;
- 100 percent standby transformer capacity will be available;
- A spare auxiliary transformer will be maintained, connected to Unit 5; and
- "Black start" capability will be provided for the power plant in the event of total failure of the auxiliary supply system, and 500 kW emergency diesel generators will be automatically started to supply the power plant and switchyard with auxiliary power to the essential services to enable start-up of the generators.

The main ac auxiliary switchboard will be provided with two bus sections separated by bus-tie circuit breakers. Under normal operating conditions, the station-service load is divided and connected to each of the two-end incoming transformers. In the event of failure of one end supply, the tie breakers will close automatically. If both end supplies fail, the emergency diesel generator will be automatically connected to the station service bus.

Each unit will be provided with a unit auxiliary board supplied by separate feeders from the two bus section feeder from the two bus section of the main switchboard interlocked to prevent parallel operation. Separate ac switchboards will furnish the auxiliary power to essential and general services in the power plant.

The unit auxiliary board will supply the auxiliaries necessary for starting, running, and stopping the generating unit. These supplies will include those to the governor and oil pressure system, bearing oil pumps, cooling pumps and fans, generator circuit breaker, excitation system, and miscellaneous pumps and devices connected with unit operation.

The 34.5 kV supply to the surface facilities will be distributed from a 34.5 kV switchboard located in the surface control and administration building. Power supplies to the switchyard, power intake, and spillway as well as the lighting systems for the access roads and tunnels will be obtained from the 34.5 kV switchboard.

The two 2000 kVA, 15,000/480 volt stations service transformers and the spare transformer will be of the 3-phase, dry-type, sealed gas-filled design. The two 7.5/10 MVA, 15/34.5 kV transformers will be of the 3-phase oil-immersed OA/FA type.

Emergency diesel generators, each rated 500 kW, will separately supply the 480 volt and 34.5 kV auxiliary switchboards during emergencies. Both diesel generators will be located in the surface control building.

An uninterruptible high security power supply will be provided for the computer control system.

(ii) DC Auxiliary Station Service System

The dc auxiliary system will supply the protective relaying, supervisory, alarm, control, tripping and indication circuit in the power plant. The generator excitation system will be started with "flashing" power from the dc battery. The dc auxiliary system will also supply the emergency lighting system at critical plant locations.

6 - LANDS OF THE UNITED STATES

The Susitna Hydroelectric Project will include numerous parcels of federal land within the project boundary as defined in Exhibit G of this application. The following is a tabulation of those lands with ownership and acreage. Included under the federal lands are those with non-federal owners but which are subject to Section 24 of the Federal Power Act.

DAMSITES, QUARRYSITES AND RESERVOIR AREAS
(Federal Ownership)

SEWARD MERIDIAN, ALASKA

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T31N,R1W				
Section 1	BLM**	G6	640.0	0
Section 2	BLM**	G6	640.0	0
T32N,R1W				
Section 35	BLM**	G6	320.0	0
Section 36	CIRI	G6	0	28.5
T31N,R1E				
Section 1	CIRI	G7	0	235.5
Section 2	CIRI	G7	0	340.7
Section 3	CIRI	G7	0	367.5
Section 4	CIRI	G6&G7	0	188.2
Section 5	CIRI	G6	0	19.4
Section 6	BLM**	G6	607.4	88.7
Section 7	BLM**	G6	152.1	0
Section 8	BLM**	G6	160.0	0
Section 9	BLM**	G6	60.0	0.7
Section 10	BLM**	G7	00.6	00.6
Section 11	BLM**	G7	00.5	00.5
T32N,R1E				
Section 31	CIRI	G6	0	264.4
Section 32	CIRI	G6	0	370.0
Section 33	CIRI	G6&G7	0	251.8
Section 34	BLM**	G7	22.9	22.9
T31N,R2E				
Section 1	CIRI	G8	0	189.3
Section 4	BLM**	G7&G8	137.4	137.4
Section 5	BLM**	G7	200.2	200.2
Section 6	BLM**	G7	275.0	275.0
Section 7	BLM**	G7	57.9	57.9
Section 8	BLM**	G7	00.7	00.7
Section 12	CIRI	G8	0	197.1
Section 13	BLM**	G8&G9	207.5	207.5
Section 24	BLM**	G9	07.4	07.4

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T32N,R2E				
Section 22	BLM**	GB	00.2	00.2
Section 27	BLM**	G8	51.2	51.2
Section 31	BLM	G7	01.1	01.1
Section 32	CIRI	G7	0	48.0
Section 33	CIRI	G7&G8	0	222.3
Section 34	CIRI	G8	0	176.5
Section 35	CIRI	G8	0	161.8
Section 36	CIRI	G8	0	120.9
T31N,R3E				
Section 13	BLM**	G10	43.4	43.4
Section 14	BLM**	G10	97.8	97.8
Section 15	BLM**	G10	108.8	108.8
Section 16	BLM**	G10	17.2	17.2
Section 17	BLM**	G9&G10	59.9	59.9
Section 18	BLM**	G9	148.0	148.0
Section 19	CIRI	G9	0	157.9
Section 20	CIRI	G9&G10	0	149.3
Section 21	CIRI	G10	0	226.2
Section 22	CIRI	G10	0	196.0
Section 23	BLM**	G10	201.3	201.3
Section 24	CIRI	G10	0	323.4
T31N,R4E				
Section 2	CIRI	G12	0	51.7
Section 3	CIRI	G11&G12	0	268.6
Section 9	BLM**	G11	38.3	38.3
Section 10	BLM**	G11	300.0	300.0
Section 15	BLM**	G11	95.6	95.6
Section 16	CIRI	G11	0	318.5
Section 18	BLM	G10	00.2	00.2
Section 19	CIRI	G10	0	374.4
Section 20	BLM**	G10&G11	445.7	445.7
Section 21	CIRI	G11	0	319.5
Section 29	BLM**	G11	02.7	02.7
T32N,R4E				
Section 25	CIRI	G12	0	32.6
Section 26	BLM	G12	225.0	03.5
Section 34	BLM**	G12	130.0	33.1
Section 35	CIRI	G12	0	388.0
Section 36	CIRI	G12	0	262.9

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T31N,R5E				
Section 3	BLM**	G13&G15	420.0	0
Section 4	BLM**	G13	480.0	0
Section 5	BLM**	G13	360.0	0
T32N,R5E				
Section 13	BLM	G16	60.6	0
Section 14	BLM	G16	260.0	0
Section 15	BLM	G14&G16	400.0	0
Section 16	BLM	G14	330.0	0
Section 17	BLM	G14	30.0	0
Section 19	BLM	G13&G14	160.0	0
Section 20	BLM	G13&G14	560.0	0
Section 21	BLM	G13&G14	640.0	0
Section 22	BLM	G13,G14&G15	640.0	0
Section 23	BLM	G15&G16	631.1	00.7
Section 24	BLM	G15&G16	75.2	0
Section 25	BLM**	G15	560.3	72.5
Section 26	CIRI	G15	0	327.2
Section 27	CIRI	G13&G15	0	238.3
Section 28	CIRI	G13	0	47.3
Section 29	BLM	G13	640.0	0
Section 30	CIRI	G13	0	38.1
Section 31	CIRI	G13	0	127.7
Section 32	CIRI	G13	0	196.5
Section 33	CIRI	G13	0	204.3
Section 34	BLM**	G13&G15	598.4	104.8
Section 35	BLM**	G15	303.5	84.4
Section 26	BLM**	G15	329.3	180.1
T31N,R6E				
Section 1	BLM**	G17	233.8	00.2
Section 2	BLM**	G17	01.9	0
T32N,R6E				
Section 2	BLM	G18	09.3	0
Section 3	BLM	G18	01.0	0
Section 10	BLM	G18	201.1	0
Section 11	BLM	G18	70.6	0
Section 13	BLM	G18	482.3	0
Section 14	BLM	G18	243.2	0
Section 15	BLM	G18	507.2	0

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T32N,R6E (Cont'd)				
Section 16	BLM	G18	00.7	0
Section 21	BLM	G15,G16&G18	162.5	0
Section 22	BLM	G17&G18	640.0	74.8
Section 23	BLM	G17&G18	640.0	03.2
Section 24	BLM	G17&G18	640.0	214.9
Section 25	BLM**	G17	640.0	556.5
Section 26	BLM**	G17	640.0	573.9
Section 27	BLM**	G17	640.0	496.8
Section 28	BLM**	G15&G17	630.2	407.0
Section 29	BLM**	G15	496.0	212.3
Section 30	BLM	G15	382.2	73.0
Section 31	BLM**	G15	333.6	204.0
Section 32	BLM**	G15	256.1	92.6
Section 33	BLM**	G15&G16	184.9	01.3
Section 34	BLM**	G17	257.8	0
Section 35	BLM**	G17	396.5	14.4
Section 36	BLM**	G17	633.3	219.8
T31N,R7E				
Section 1	BLM	G19	338.0	61.3
Section 2	BLM	G19	634.4	481.2
Section 3	BLM	G19	629.8	523.1
Section 4	BLM***	G17&G19	495.8	304.4
Section 5	BLM**	G17	332.4	111.7
Section 6	BLM**	G17	302.3	01.1
Section 10	BLM	G19	88.1	00.4
Section 11	BLM***	G19	311.4	146.3
Section 12	BLM***	G19	621.8	462.1
Section 13	BLM	G19	141.4	41.5
Section 14	BLM	G19	01.1	0
T32N,R7E				
Section 3	BLM	G20	246.4	0
Section 4	BLM	G18&G20	160.7	17.1
Section 7	BLM	G18	166.5	0
Section 8	BLM	G18	331.0	91.9
Section 9	BLM	G18&G20	517.5	96.7
Section 10	BLM	G20	31.9	0
Section 16	BLM	G18	141.8	0
Section 17	BLM	G18	637.5	175.5
Section 18	BLM	G18	563.9	151.2
Section 19	BLM	G17&G18	601.8	290.0

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T32N,R7E (Cont'd)				
Section 20	BLM	G17&G18	640.0	0
Section 21	BLM	G17,G18&G20	391.6	0
Section 22	BLM	G19&G20	60.7	0
Section 27	BLM	G19	174.4	0
Section 28	BLM	G17&G19	624.1	0
Section 29	BLM	G17	640.0	0
Section 30	BLM**	G17	603.7	226.9
Section 31	BLM**	G17	605.5	483.9
Section 32	BLM***	G17	640.0	497.2
Section 33	BLM***	G17&G19	640.0	344.2
Section 34	BLM	G19	423.5	97.3
Section 35	BLM	G19	53.5	0
Section 36	BLM	G19	11.0	0
T33N,R7E				
Section 27	BLM	G21	80.2	0
Section 28	BLM	G21	40.0	0
Section 33	BLM	G20&G21	74.0	0
Section 34	BLM	G20&G21	182.9	0
T30N,R8E				
Section 4	BLM	G23	08.2	0
T31N,R8E				
Section 1	BLM	G24	56.9	0
Section 7	BLM	G19	386.4	251.9
Section 8	BLM	G19&G24	535.0	311.6
Section 9	BLM	G24	576.7	381.6
Section 10	BLM	G24	372.9	225.8
Section 11	BLM	G24	138.5	44.3
Section 12	BLM	G24	287.9	53.1
Section 13	BLM	G23&G24	598.6	381.8
Section 14	BLM	G23&G24	612.2	431.8
Section 15	BLM	G23&G24	640.0	476.8
Section 16	BLM	G24&G23	280.3	128.6
Section 17	BLM	G19,G22&G24	334.7	211.0
Section 18	BLM	G19	353.1	193.5
Section 21	BLM	G23	182.3	35.3
Section 22	BLM	G23	248.9	52.4
Section 23	BLM	G23	09.1	0
Section 24	BLM	G23	55.1	0
Section 27	BLM	G23	06.1	0
Section 28	BLM	G23	245.8	01.2
Section 33	BLM	G23	138.4	0

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T30N,R9E				
Section 1	BLM	G26	143.0	33.5
Section 12	BLM	G26	105.3	03.8
Section 13	BLM	G26	05.8	0
T31N,R9E				
Section 6	BLM	G24	49.2	0
Section 7	BLM	G24	00.7	0
Section 17	BLM	G24&G25	178.0	97.7
Section 18	BLM	G23&G24	450.2	376.9
Section 19	BLM	G23	175.3	24.3
Section 20	BLM	G23&G24	432.8	306.7
Section 21	BLM	G25	499.3	357.1
Section 22	BLM	G25	267.1	159.1
Section 23	BLM	G25	185.4	73.2
Section 25	BLM	G25	280.1	112.9
Section 26	BLM	G25	316.2	172.0
Section 27	BLM	G25	309.3	148.1
Section 28	BLM	G25	107.8	17.9
Section 36	BLM	G25&G26	408.1	136.7
T30N,R10E				
Section 6	BLM	G26	216.0	122.2
Section 7	BLM	G26&G27	389.3	193.5
Section 8	BLM	G27	313.7	180.5
Section 9	BLM	G27	170.8	13.9
Section 10	BLM	G27	96.4	13.6
Section 11	BLM	G27	312.9	312.9
Section 12	BLM	G27	254.6	254.6
Section 13	BLM	G27	120.2	120.2
Section 14	BLM	G27	105.1	102.8
Section 15	BLM	G27	251.1	117.1
Section 17	BLM	G27	77.9	14.2
T31N,R10E				
Section 31	BLM	G26&G27	143.2	74.4
T29N,R11E				
Section 1	BLM	G29	45.2	45.2
Section 2	BLM	G29	199.2	199.2
Section 3	BLM	G29	222.6	222.6
Section 4	BLM	G29	68.2	68.2

DAMSITES, QUARRYSITES AND RESERVOIR AREAS (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE	SEC.24 FPA ACREAGE*
T29N,R11E (Cont'd)				
Section 5	BLM	G29	176.6	101.5
Section 6	BLM	G29	135.3	12.3
Section 9	BLM	G29	00.4	00.4
Section 10	BLM	G29	204.5	103.1
T30N,R11E				
Section 7	BLM	G27&28	293.8	165.1
Section 8	BLM	G28	01.8	0.18
Section 17	BLM	G28	241.0	167.1
Section 18	BLM	G27&G28	280.4	195.7
Section 20	BLM	G28	445.9	206.7
Section 21	BLM	G28	00.9	0.0
Section 25	BLM	G29	21.2	21.2
Section 28	BLM	G28&G29	177.9	141.6
Section 29	BLM	G28&29	480.0	163.4
Section 32	BLM	G29	482.7	293.1
Section 33	BLM	G29	437.3	385.4
Section 34	BLM	G29	640.0	270.8
Section 35	BLM	G29	471.8	269.0
Section 36	BLM	G29	35.6	35.6
TOTAL			61,628.0±	28,344.8±

* Areas shown are true areas at elevation
** Selected by Cook Inlet Region Incorporated
*** Partially selected by Cook Inlet Region Incorporated

ELECTRICAL TRANSMISSION LINE CORRIDOR RIGHT-OF-WAY ACREAGES
(Federal Ownership)

SEWARD MERIDIAN, ALASKA

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T13N,R2W			
Section 4	U.S. Army	G30	10.21
Section 5	U.S. Army	G30	35.51
Section 7	U.S. Army	G30	37.20
Section 8	U.S. Army	G30	06.36
Section 18	U.S. Army	G30	30.68
Section 19	U.S. Army	G30	30.66
Section 30	U.S. Army	G30	30.31
Section 31	U.S. Army	G30	04.46
T14N,R2W			
Section 19	U.S. Army	G30	33.66
Section 20	U.S. Army	G30	31.36
Section 21	U.S. Army	G30	38.29
Section 22	U.S. Army	G30	03.06
Section 28	U.S. Army	G30	31.12
Section 33	U.S. Army	G30	36.52
T14N,3W			
Section 9	U.S. Army	G30	19.56
Section 10	U.S. Army	G30	33.29
Section 11	U.S. Army	G30	05.31
Section 13	U.S. Army	G30	14.15
Section 14	U.S. Army	G30	44.50
Section 24	U.S. Army	G30	24.64
T31N,1W			
Section 3	BLM**	G39	62.74
Section 4	BLM**	G39	54.77
Section 5	BLM**	G39	62.74
Section 6	BLM**	G39	61.36
T32N,R1E			
Section 13	BLM**	G39	11.77
Section 23	BLM**	G39	34.22
Section 24	BLM**	G39	33.23
Section 26	BLM**	G39	07.35
Section 27	BLM**	G39	38.03
Section 28	BLM**	G39	38.03
Section 29	BLM**	G39	37.95
Section 30	BLM**	G39	02.70

ELECTRICAL TRANSMISSION LINE CORRIDOR
RIGHT-OF-WAY ACREAGES (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T32N,R2E			
Section 3	BLM**	G39	41.90
Section 4	BLM**	G39	20.02
Section 8	BLM**	G39	36.99
Section 9	BLM**	G39	24.88
Section 17	BLM**	G39	07.91
Section 18	BLM**	G39	42.13
T33N,R2E			
Section 25	BLM**	G40	34.20
Section 34	BLM**	G40	09.28
Section 35	BLM**	G40	44.90
Section 36	BLM**	G40	07.81
T32N,R3E			
Section 2	BLM**	G40	19.69
Section 3	BLM**	G40	37.52
Section 11	BLM**	G40	22.42
Section 12	BLM**	G40	40.01
T32N,R4E			
Section 7	BLM**	G40	34.69
Section 8	BLM**	G40	15.67
Section 13	BLM**	G40	37.10
Section 14	BLM**	G40	37.10
Section 15	BLM**	G40	35.22
Section 16	BLM**	G40	37.10
Section 17	BLM**	G40	21.43
T32N,R5E			
Section 18	BLM**	G40	16.45
Section 19	BLM**	G40	20.47
Section 20	BLM**	G40	07.68
SEWARD MERIDIAN SUB-TOTAL			1,598.31±

ELECTRICAL TRANSMISSION LINE CORRIDOR
RIGHT-OF-WAY ACREAGES (Cont'd)

FAIRBANKS MERIDIAN, ALASKA

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T12S,R7W			
Section 7	FED R.R.	G46	43.77
Section 17	FED R.R.	G46	15.71
Section 18	FED R.R.	G46	14.52
T7S,R8W			
Section 24	USAF	G48	23.27
Section 25	USAF	G48	51.86
Section 26	USAF	G48	51.86
T7S,R7W			
Section 5	USAF	G48	48.93
Section 6	USAF	G48	02.76
Section 7	USAF	G48	51.36
Section 8	USAF	G48	00.50
Section 18	USAF	G48	51.86
Section 19	USAF	G48	28.59
T6S,R7W			
Section 4	BLM	G49	49.43
Section 9	BLM	G49	48.70
Section 16	BLM	G49	48.25
Section 17	BLM	G49	00.45
Section 20	BLM	G49	34.86
Section 21	BLM	G49	13.81
Section 29	BLM	G49	49.63
Section 32	BLM	G49	51.78
FAIRBANKS MERIDIAN SUB-TOTAL			681.90±
TOTAL			2,280.21±

ACREAGE SHOWN IS TRUE AREA AT ELEVATION

ACCESS CORRIDOR RIGHT-OF-WAY ACREAGES
(Federal Ownership)

FAIRBANKS MERIDIAN, ALASKA

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T18S,R4W			
Section 16	BLM	G53	19.80
Section 21	BLM	G53	24.74
Section 22	BLM	G53	00.23
Section 27	BLM	G53	02.09
Section 28	BLM	G53	23.43
Section 33	BLM	G53	20.00
Section 34	BLM	G53	06.41
T19S,R4W			
Section 4	BLM	G53	29.59
Section 5	BLM	G53	06.41
Section 8	BLM	G53	29.94
Section 16	BLM	G53	20.70
Section 17	BLM	G53	08.41
Section 21	BLM	G53	23.57
Section 22	BLM	G53	04.95
Section 27	BLM	G53	25.35
Section 34	BLM	G53	25.61
T20S,R4W			
Section 3	BLM	G53	25.35
Section 10	BLM	G53	26.73
Section 14	BLM	G53	18.93
Section 15	BLM	G53	08.25
Section 23	BLM	G53	22.64
Section 24	BLM	G54	12.48
Section 25	BLM	G54	24.86
Section 36	BLM	G54	24.97
T21S,R4W			
Section 1	BLM	G54	28.28
Section 11	BLM	G54	34.94
Section 12	BLM	G54	03.36
Section 14	BLM	G54	24.63
Section 23	BLM	G54	24.38
Section 26	BLM	G54	24.38
Section 27	BLM	G54	00.11
Section 34	BLM	G54	25.30
Section 35	BLM	G54	01.00

ACCESS CORRIDOR RIGHT-OF-WAY ACREAGES (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T22S,R4W			
Section 3	BLM	G54	24.39
Section 10	BLM	G54	24.53
Section 15	BLM	G54	26.96
Section 16	BLM	G54	08.55
FAIRBANKS MERIDIAN SUB-TOTAL			686.25+
SEWARD MERIDIAN, ALASKA			
T31N,R1W			
Section 3**	BLM**	G59	26.20
Section 4**	BLM**	G59	27.92
Section 5**	BLM**	G59	12.92
Section 6**	BLM**	G59	21.80
T32N,R1E			
Section 23	BLM**	G58	14.19
Section 24	BLM**	G58	27.63
Section 26	BLM**	G58	12.91
Section 27	BLM**	G58	29.85
Section 28	BLM**	G58	24.33
Section 29	BLM**	G58	13.52
T32N,R2E			
Section 2	BLM**	G57	15.01
Section 3	BLM**	G57	28.29
Section 4	BLM**	G57	06.29
Section 8	BLM**	G58	07.92
Section 9	BLM**	G57&G58	31.71
Section 17	BLM**	G58	21.70
Section 18	BLM**	G58	13.94
Section 19	BLM**	G58	13.94
T33N,R2E			
Section 35	BLM**	G57	19.42
Section 36	BLM**	G57	26.34

ACCESS CORRIDOR RIGHT-OF-WAY ACREAGES (Cont'd)

TOWNSHIP/Section	OWNER	PLATE	U.S. ACREAGE*
T32N,R3E			
Section 2	BLM**	G57	01.15
Section 3	BLM**	G57	37.09
Section 11	BLM**	G57	28.62
Section 12	BLM**	G57	20.09
Section 13	BLM**	G57	07.22
T32N,4E			
Section 11	BLM**	G56	22.96
Section 12	BLM**	G56	16.60
Section 13	BLM**	G56	21.23
Section 14	BLM**	G56	10.80
Section 15	BLM**	G56	26.86
Section 16	BLM**	G57	24.72
Section 17	BLM**	G57	24.75
Section 18	BLM**	G57	24.45
T32N,R5E			
Section 3	BLM**	G56	47.60
Section 4	BLM**	G56	26.86
Section 5	BLM**	G56	28.06
Section 8	BLM**	G56	26.46
Section 10	BLM	G56	25.32
Section 15	BLM	G56	09.51
Section 17	BLM**	G56	09.62
Section 18	BLM**	G56	23.69
SEWARD MERIDIAN SUB-TOTAL			863.59+
TOTAL			1,549.84+

* Areas shown are true areas at elevation
** Selected by Cook Inlet Region Incorporated

7 - PROJECT STRUCTURES - DEVIL CANYON DEVELOPMENT

This section describes the various components of the Devil Canyon development, including diversion facilities, emergency release facilities, main dam, primary outlet facilities, reservoir, main and emergency spillways, saddle dam, power intake, penstocks, and the powerhouse complex, including turbines, generators, mechanical and electrical equipment, switchyard structures, and equipment and project lands. A summary of project parameters is presented in Table A.1.

A description of permanent and temporary access and support facilities is also included.

7.1 - General Arrangement

The Devil Canyon reservoir and surrounding area are shown on Plate F39. The site layout in relation to main access facilities and camp facilities is shown on Plate F70. A more detailed arrangement of the various site structures is presented in Plate F40.

The Devil Canyon Dam will form a reservoir approximately 26 miles long with a surface area of 7,800 acres and a gross storage capacity of 1,100,000 acre-feet at Elevation 1455, the normal maximum operating level. The operating level of the Devil Canyon reservoir is controlled by the tailwater level of the upstream Watana development. The maximum water surface elevation during flood conditions will be 1466. The minimum operating level of the reservoir will be 1405, providing a live storage during normal operation of 350,000 acre-feet.

The dam will be a thin arch concrete structure with a crest elevation of 1463 (not including a three-foot parapet) and maximum height of 646 feet. The dam will be supported by mass concrete thrust blocks on each abutment. On the south bank, the lower bedrock surface will require the construction of a substantial thrust block. Adjacent to this thrust block, an earth- and rockfill saddle dam will provide closure to the south bank. The saddle dam will be a central core type generally similar in cross section to the Watana Dam. The dam will have a nominal crest elevation of 1469 with an additional 3 feet of overbuild for potential seismic settlement. The maximum height above foundation level of the dam is approximately 245 feet.

During construction, the river will be diverted by means of a single 30-foot diameter concrete-lined diversion tunnel on the south bank of the river.

A power intake on the north bank will consist of an approach channel excavated in rock leading to a reinforced concrete gate structure. From the intake structure four 20-foot diameter concrete-lined penstock tunnels will lead to an underground powerhouse complex housing four 150 MW units with Francis turbines and semi-umbrella type generators.

Access to the powerhouse complex will be by means of an unlined access tunnel approximately 3200 feet long as well as by a 950-foot deep vertical access shaft. The turbines will discharge to the river by means of a single 38-foot diameter tailrace tunnel leading from a surge chamber downstream from the powerhouse cavern. A separate transformer gallery just upstream from the powerhouse cavern will house twelve single-phase 15/345 kV transformers. The transformers will be connected by 345 kV single-phase, oil-filled cable through a cable shaft to the switchyard at the surface.

Outlet facilities consisting of seven individual outlet conduits will be located in the lower part of the main dam. These will be designed to discharge all flood flows of up to 38,500 cfs, the estimated 50-year flood with Watana in place. This assumes that only one of the generating units will be operating. Each outlet conduit will have a fixed--cone valve similar to those provided at Watana to dissipate energy and minimize undesirable nitrogen supersaturation in the flows downstream. The main spillway will also be located on the north bank. As at Watana, this spillway will consist of an upstream ogee control structure with three vertical fixed-wheel gates and an inclined concrete chute and flip bucket designed to pass a maximum discharge of 123,000 cfs. This spillway, together with the outlet facilities, will thus be capable of discharging the estimated 10,000-year flood. An emergency spillway and fuse plug on the south bank will provide sufficient additional capacity to permit discharge of the PMF without overtopping the dam.

7.2 - Arch Dam

The Devil Canyon Dam will be located at the Devil Canyon gorge, river-mile 152, approximately 32 river-miles downstream from Watana. The arch dam will be located at the upstream entrance of the canyon.

The dam will be a thin arch concrete structure 646 feet high, with a crest length-to-height ratio of approximately two, and designed to withstand dynamic loadings from intense seismic shaking. The proposed height of the dam is well within precedent.

(a) Foundations

Bedrock is well exposed along the canyon walls, and the arch dam will be founded on sound bedrock. Approximately 20 to 40 feet of weathered and/or loose rock will be removed beneath the dam foundation. All bedrock irregularities will be smoothed out beneath the foundation to eliminate high stress concentrations within the concrete. During excavation the rock will also be trimmed as far as is practical to increase the symmetry of the centerline profile and provide a comparatively uniform bearing stress distribution across the dam. Areas of deteriorated dikes and the local areas of poorer quality rock will be excavated and supplemented with dental concrete.

The foundation will be consolidation grouted over its entire area, and a double grout curtain up to 300 feet deep will run beneath the dam and its adjacent structures as shown in Plate F47. Grouting will be done from a system of galleries which will run through the dam and into the rock. Within the rock these galleries will also serve as collectors for drainage holes which will be drilled just downstream of the grout curtain and intercept any seepage passing through the curtain.

(b) Arch Dam Geometry

The canyon is V-shaped below Elevation 1350. Sound bedrock does not exist above this level on the south abutment and an artificial abutment will be provided up to crest Elevation 1463 in the form of a massive concrete thrust block designed to take the thrust from the upper arches of the dam. A corresponding block will be formed on the north abutment to provide as symmetrical a profile as possible bordering the dam and to give a symmetrical stress distribution across the faces of the horizontal arches.

Two slight ridges will be formed by the rock at both abutments. The arch dam will abut the upstream side of these such that the plane of the contact of the horizontal arches is generally normal to the faces of the dam. An exception will be in the lower portion of the dam where the rock in the upstream corners will be retained in order to decrease the amount of excavation.

The dam will bear directly on the rock foundation over the entire length of the contact surface. The bedrock at the foundation will be excavated to remove all weathered material and further trimmed to provide a smooth line to the foundation, thus avoiding abrupt changes in the dam profile and consequent stress concentrations.

The dam will be a double curvature structure with a cupola shape of the crown cantilever defined by vertical curves of approximately 1352-foot and 893-foot radii. The horizontal arches are based on a two-center configuration with the arches prescribed by varying radii moving along two pairs of centerlines. The shorter radii of the intrados face cause a broadening of the arches at the abutment, thus reducing the contact stresses. The dam reference plane is approximately central to the floor of the canyon and the two-center configuration assigns longer radii to the arches on the wider north side of the valley, thus providing comparable contact areas and central angles on both sides of the arches at the concrete/rock interface. The longer radii will also allow the thrust from the arches to be directed more into the abutment rather than parallel to the river. The net effect of this two-center layout will be to improve the symmetry of the arch stresses across the dam.

The crown cantilever will be 643 feet high. It will be 20 feet thick at the crest and 90 feet at the base, a base width-to-height ratio of 0.140. The radii of the dam axis at crest level will be 699 feet and 777 feet for the south and north sides of the dam, respectively. The central angles vary between 53° at Elevation 1300 and 10° at the base for the south side of the arch, and 57° to 10° for the north side. The dam crest length is 1260 feet and the ratio of crest length to height for the dam is 1.96 (thrust blocks not included). The volume of concrete in the dam is approximately 1.3×10^6 cubic yards.

(c) Thrust Blocks

The thrust blocks are shown on Plate F46. The massive concrete block on the south abutment is 113 feet high and 200 feet long. It will be formed to take the thrust from the upper part of the dam above the existing sound rock level. It will also serve as a transition between the concrete dam and the adjacent rockfill saddle dam. The inclined end face of the block will abut and seal against the impervious saddle dam core and be enveloped by the supporting rock shell.

The 113-foot high, 125-foot long thrust block formed high on the north abutment at the end of the dam, adjacent to the spillway control structure, will transmit thrust from the dam through the intake control structure and into the rock.

7.3 - Saddle Dam

The saddle dam at Devil Canyon, which is of similar configuration as the main Watana Dam, will be of earth and rockfill construction and will consist of a central compacted core protected by fine and coarse filters upstream and downstream. The downstream outer shell will consist of two zones: a lower zone of clean processed rockfill material, and an upper zone of unprocessed rockfill material. The upstream outer shell will consist of cleaned and graded rockfill material. A typical cross section is shown on Plate F49 and described below.

(a) Typical Cross Section

The central core slopes are 1H:4V with a top width of 15 feet. The thickness of the core at any section will be slightly more than 0.5 times the head of water at that section. Minimum core-foundation contact will be 50 feet, requiring flaring of the cross section at the abutments.

The upstream and downstream filter zones will increase in thickness from 45 and 30 feet, respectively, near the crest of the dam to a maximum of approximately 60 feet at the filter-foundation contact. They are sized to provide protection against possible piping through transverse cracks that could occur because of settlement or resulting from internal displacement during a seismic event.

Protection against wave and ice action on the upstream slope will consist of a 10-foot layer of riprap comprising quarried rock up to 36 inches in size.

The estimated volumes of material needed to construct the saddle dam are:

- core material	310,000 cubic yards
- fine filter material	230,000 cubic yards
- coarse filter material	180,000 cubic yards
- rockfill material	1,200,000 cubic yards

The saturated sections of both shells will be constructed of compacted clean rockfill processed to remove fine material in order to minimize pore pressure generation and ensure rapid dissipation during and after a seismic event. The lower section of the downstream shell, due to a unique combination of bedrock and topographic elevations, may become saturated by natural runoff or dam seepage. During design the cost of a major drainage system to prevent this occurrence will be weighed against the added cost of processing the materials for the lower portion of the fill. Since pore pressures cannot develop in the unsaturated upper section of the downstream shell, the material in that zone will be unprocessed rockfill from surface or underground excavations.

(b) Crest Details and Freeboard

A 3-foot high parapet will be constructed on the crest of the arch dam to provide a freeboard of 11 feet.

The highest reservoir level will be Elevation 1466 under PMF conditions. At this elevation, the fuse plug in the emergency spillway will be breached and the reservoir level will fall to the emergency spillway sill elevation of 1434. The normal maximum pool elevation will be 1455.

The typical crest detail for the saddle dam is shown in Plate F50. Because of the narrowing of the dam crest, the filter zones are reduced in width and the upstream and downstream coarse filters are eliminated. A layer of filter fabric is incorporated to protect the core material from damage by frost penetration and dessication, and to act as a coarse filter where required.

A minimum saddle dam freeboard of three feet will be provided for the PMF; hence, the nominal crest of the saddle dam will be Elevation 1469. In addition, an allowance of one percent of the height of the dam will be made for potential settlement of the rockfill shells under seismic loading. An allowance of one foot has been made for settlement adjacent to the abutments; hence, the constructed crest elevations of the saddle dam will be 1470 at the abutments, rising in proportion to the total height of the dam to Elevation 1472 at the maximum section. Under normal operating conditions, the freeboard will range from 15 feet at the abutments to 17 feet at the center of the dam. Further allowances will be made to compensate for static settlement of the dam after completion due to its own weight and the effect of saturation of the upstream shell, which will tend to produce additional breakdown of the rockfill at point contacts. Therefore, one percent of the dam height will be allowed for such settlement, giving a maximum crest elevation on completion of the construction of 1475 at the maximum height, and 1471 at the abutments.

The allowances for post-construction settlement and seismic slumping will be achieved by steepening both slopes of the dam above Elevation 1400. These allowances are considered conservative.

(c) Grouting and Pressure Relief System

The rock foundation will be improved by consolidation grouting over the core contact area and by a grouted cutoff along the centerline of the core. The cutoff at any location will extend to a depth of a least 0.7 of the water head at that location, as shown on Plate F47.

A grouting and drainage tunnel will be excavated in bedrock beneath the dam along the centerline of the core and will connect with a similar tunnel beneath the adjacent concrete arch dam and thrust block. Pressure relief and drainage holes will be drilled from this tunnel, and seepage from the drainage system will be discharged through the arch dam drainage system to ultimately exit downstream below tailwater level.

(d) Instrumentation

Instrumentation will be installed within all parts of the dam to provide monitoring during construction as well as during operation. Instruments for measuring internal vertical and horizontal displacements, stresses and strains, and total and fluid pressures, as well as surface monuments and markers similar to those proposed for the Watana Dam, will be installed.

7.4 - Diversion

(a) General

Diversion of the river flow during construction will be through a single 30-foot diameter concrete-lined diversion tunnel on the south bank. The tunnel will have a horseshoe-shaped cross section and be 1,490 feet in length. The diversion tunnel plan and profile are shown on Plate F51.

The tunnel is designed to pass a flood with a return frequency of 1:25 years routed through the Watana reservoir. The peak flow that the tunnel will discharge will be 39,000 cfs. The maximum water surface elevation upstream of the cofferdam will be Elevation 944.

(b) Cofferdams

The upstream cofferdam will consist of a zoned embankment founded on a closure dam (see Plate F52). The closure dam will be constructed to Elevation 915 based on a low water elevation of 910 and will consist of coarse material on the upstream side grading to finer material on the downstream side. When the closure dam is completed, a grout curtain or slurry wall cutoff will be constructed to minimize seepage into the main dam excavation. Final details of this cut-off will be determined following further investigations to define the type and properties of river alluvium. The abutment areas will be excavated to sound rock prior to placement of any cofferdam material.

The cofferdam, from Elevation 915 to 947, will be a zoned embankment consisting of a central core, fine and coarse upstream and downstream filters, and rock and/or gravel shells with riprap on the upstream face. The downstream cofferdam will be a similar closure dam constructed from Elevation 860 to 898, with a cutoff to bedrock.

The upstream cofferdam crest elevation will have a 3-foot freeboard allowance for settlement and wave runup. Under the proposed schedule, the Watana development will be operational when this cofferdam is constructed. Thermal studies conducted show that discharge from the Watana reservoir will be at 34°F when passing through Devil Canyon. Therefore, an ice cover will not form upstream of the cofferdam, and no freeboard allowance for ice will be necessary.

(c) Tunnel Portals and Gates

A gated concrete intake structure will be located at the upstream end of the tunnel (see Plate F53). The portal and gate will be designed for an external pressure (static) head of 250 feet.

Two 30-foot high by 15-foot wide water passages will be formed in the intake structure, separated by a central concrete pier. Gate guides will be provided within the passages for the operation of 30-foot high by 15-foot wide fixed-wheel closure/control gates.

Each gate will be operated by a wire rope hoist in an enclosed housing, and will be designed to operate with a 75-foot operating head (Elevation 945).

Stoplog guides will be installed in the diversion tunnel to permit dewatering of the diversion tunnel for plugging operations. The stoplogs will be in sections to facilitate relatively easy handling, with a mobile crane using a follower beam.

(d) Final Closure and Reservoir Filling

Upon completion of the Devil Canyon Dam to a height sufficient to allow ponding to a level above the outlet facilities, the intake gates will be partially closed, allowing for a discharge of minimum environmental flows while raising the upstream water level. Once the level rises above the lower level of discharge valves, the diversion gates will be permanently closed and discharge will be through the 90-inch diameter fixed-cone valves in the dam. The diversion tunnel will be plugged with concrete and curtain grouting performed around the plug. Construction will take approximately 1 year. During this time the reservoir will not be allowed to rise above Elevation 1135.

7.5 - Outlet Facilities

The primary function of the outlet facilities is to provide for discharge through the main dam, in conjunction with the power facilities, of routed floods with up to 1:50 years recurrence period at the Devil Canyon reservoir. This will require a total discharge capacity of 38,500 cfs through the valves. The use of fixed-cone valves will ensure that downstream erosion will be minimal and nitrogen supersaturation of the releases will be reduced to acceptable levels, as in the case of the Watana development. A further function of these releases is to provide an emergency drawdown for the reservoir, should maintenance be necessary on the main dam or low level submerged structures, and also to act as a diversion facility during the latter part of the construction period.

The outlet facilities will be located in the lower portion of the main dam, as shown on Plate F48, and will consist of seven fixed-cone discharge valves set in the lower part of the arch dam.

(a) Outlet

The fixed-cone type discharge valves will be located at two elevations: the upper group, consisting of four 102-inch diameter valves, will be set at Elevation 1050, and the lower group of three 90-inch diameter valves will be set at Elevation 930. The valves will be installed nearly radially (normal to the dam centerline) with the points of impact of the issuing jets staggered as shown in Plate F48.

The fixed-cone valves will be installed on individual conduits passing through the dam, set close to the downstream face, and protected by upstream ring follower gates located in separate chambers within the dam. Provisions will be made for maintenance and removal of the valves and gates. The gates and valves will be linked by a 20-foot high gallery running across the dam and into the left abutment, where access will be provided by means of a vertical shaft exiting through the thrust block. Although secondary access will be provided via a similar shaft from the north abutment, primary access and installation are both from the south side.

The valve and gate assemblies will be protected by individual trashracks installed on the upstream face. The racks will be removable along guides running on the upstream dam face. A travelling gantry crane will be used for raising the racks. Guides will be installed for the installation of bulkhead gates, if required, at the upstream face. The bulkhead gates will be handled by the travelling gantry crane.

(b) Fixed-Cone Valves

The 102-inch diameter valves operating at a gross head of 405 feet and the 90-inch diameter valves operating at a head of 525 feet are within current precedent considering the valve size and the static head on the valve. The valves will be located in individually heated rooms and will be provided with electric jacket heaters installed around the cylindrical sleeve of each valve. The valves will be capable of year-round operation, although winter operation is not contemplated. Normally, when the valves are closed, the upstream ring follower gates will also be closed to minimize leakage and freezing of water through the valve seats.

The valves will be operated remotely by two hydraulic operators. Operation of the valves will be from either Watana or by local operation.

(c) Ring Follower Gates

Ring follower gates will be installed upstream of each valve. The ring follower gates will have nominal diameters of 102 and 90 inches and will be of welded or cast steel construction. The gates will be designed to withstand the total static head under full reservoir.

The design and arrangement of the ring follower gates will be as for Watana.

(d) Trashracks

A steel trashrack will be installed at the upstream entrance to each water passage to prevent debris from being drawn into the discharge valves. The bar spacing on the racks will be approximately 6 inches. Provision will be made for monitoring head loss across the racks.

(e) Bulkhead Gates

The bulkhead gates will be installed only under balanced head conditions using the gantry crane. The gates will be 13 feet and 11 feet square for the upper and lower valves, respectively.

Each gate will be designed to withstand full differential head under maximum reservoir water level. One gate for each valve size has been assumed. The gates will be stored at the dam crest level.

A temporary cover will be placed in the bulkhead gate check at trashrack level to prevent debris from getting behind the trashracks.

The bulkhead gates and trashracks will be handled by an electric travelling gantry type crane located on the main dam crest at Elevation 1463. The crane and lifting arrangement will have provision for lowering a gate around the curved face of the dam.

7.6 - Main Spillway

The main spillway at Devil Canyon will be located on the north side of the canyon (see Plate F54). The upstream control structure will be adjacent to the arch dam thrust block and will discharge down an inclined concrete-lined chute constructed on the steep face of the canyon wall. The chute will terminate in a flip bucket which will direct flows downstream and into the river.

The spillway will be designed to pass the 1:10,000 year Watana routed flood in conjunction with the outlet facilities. The spillway will have a design capacity of 123,000 cfs discharged over a total head drop of 550 feet. No surcharge will occur above the normal maximum reservoir operating level of 1455 feet during passage of this flood.

(a) Approach Channel and Control Structure

The approach channel will be excavated to a depth of approximately 100 feet in the rock with a width of just over 130 feet and an invert elevation of 1375.

The control structure, as shown in Plate F55, will be a three-bay concrete structure set at the end of the channel. Each bay will incorporate a 56-foot high by 30-foot wide gate on an ogee-crested weir and, in conjunction with the other gates, will control the flows passing through the spillway. The gates will be fixed-wheel gates operated by individual rope hoists.

A gallery will be provided within the mass concrete weir from which grouting can be carried out and drain holes can be drilled as a continuation of the grout curtain and drainage beneath the main dam. The main access route will cross the control structure deck upstream of the gate tower and bridge structure.

(b) Spillway Chute

The spillway chute will be excavated in the steep north face of the canyon for a distance of approximately 900 feet, terminating at Elevation 1000. The chute will taper uniformly over its length from 122 feet at the upstream end to 80 feet downstream. The chute will be concrete-lined with invert and wall slabs anchored to the rock.

The velocity at the lower end of the chute will be approximately 150 ft/sec. In order to prevent cavitation of the chute surfaces, air will be introduced into the discharges. As at Watana, air will be drawn in along the chute via an underlying aeration gallery and offshoot ducts extending to the downstream side of a raised step running transverse to the chute.

An extensive underdrainage system will be provided, similar to that described for Watana, to ensure adequate underdrainage of the spillway chute and stability of the structure. This system is designed to prevent excessive uplift pressures due to reservoir seepage under the control structure and from groundwater and seepage through construction joints from the high velocity flows within the spillway itself.

The dam grout curtain and drainage system will be extended under the spillway control structure utilizing a gallery through the rollway. A system of box drains will be installed for the entire length of the spillway under the concrete slab. To avoid blockage of the system by freezing of the surface drains, a 30-foot deep drainage gallery will also be constructed along the entire length of the spillway. Drain holes from the surface drains will intersect the gallery. To ensure adequate foundation quality for anchorage, consolidation grouting will be undertaken to a depth of 20 feet. Drainage holes drilled into the base of the high rock cuts will ensure increased stability of the excavation.

(c) Flip Bucket

The spillway chute will terminate in a mass concrete flip bucket founded on sound rock at Elevation 970, approximately 100 feet above the river. Detailed geometry of the curve of the flow surface of the bucket will be confirmed by means of hydraulic model tests. A grouting/drainage gallery will be provided within the bucket. The jet issuing from the bucket will be directed downstream and parallel to the river alignment.

(d) Plunge Pool

The impact area of the issuing spillway discharge will be limited to the area of the river surface downstream to prevent excessive erosion of the canyon walls. This will be done by appropriate shaping of the flow surface of the flip bucket on the basis of model studies. Over this impact area the alluvial material in the riverbed will be excavated down to sound rock to provide a plunge pool in which most of the inherent energy of the discharges will be dissipated, although some energy will already have been dissipated by friction in the chute and in dispersion and friction through the air.

7.7 - Emergency Spillway

The emergency spillway will be located on the south side of the river south of the rockfill saddle dam. It will be excavated within the rock underlying the south side of the saddle and will continue downstream for approximately 2,000 feet.

An erodible fuse plug, consisting of impervious material and fine gravels, will be constructed at the upstream end of the spillway. It will be designed to wash out when overtopped by the reservoir, releasing flows of up to 150,000 cfs in excess of the combined main spillway and outlet capacities, thus preventing overtopping of the main or saddle dams during the passage of the PMF.

(a) Fuse Plug and Approach Channel

The approach channel to the fuse plug will be excavated in the rock and will have a width of 220 feet and an invert elevation of 1434. The channel will be crossed by the main access road to the dam on a bridge consisting of concrete piers, precast beams, and an in situ concrete bridge deck. The fuse plug will fill the approach channel and will have a maximum height of 31.5 feet with a crest elevation of 1465.5. The plug will be located on top of a flatcrested concrete weir placed on an air-excavated rock foundation. The plug will be traversed by a pilot channel with an invert elevation of 1464.

(b) Discharge Channel

The channel will narrow downstream, leading into a steep valley tributary above the Susitna River. This channel will rapidly erode under high flows but will serve the purpose of training the initial flows in the direction of the valley and away from the permanent project facilities. The erosion of the channel would happen only during an event of very rare frequency. The material which would erode is alluvial material which would be deposited downstream. Should the Susitna basin experience flood of this magnitude, the volume of material eroded would be small relative to other changes which would take place in the river.

7.8 - Devil Canyon Power Facilities

(a) Intake Structure

The intake structure will be located on the north side of the canyon as shown on Plates F59 and F62. Four sets of intake openings will be provided. The intake openings and power tunnels will be grouped in pairs so that each turbine may be supplied by water passing through two sets of intake openings. Each set of intake openings will consist of an upper and lower opening. The reservoir level will vary between Elevations 1455 (October through July) and 1405 (August and September). During the period October through July, the water will normally be withdrawn from the top opening in each set. As the reservoir is drawn down in August and September, the lower opening will be used. Each opening will be provided with a set of trashracks and a provision for placing sliding steel closure shutters upstream from the intake opening. In an emergency, stoplogs will be installed on the upstream wall of the power intake structure for work on the trashracks or shutters.

The intake will be located at the end of a 200-foot long unlined approach channel. The overburden in this area is estimated to be approximately 10 feet deep. The excavation for the intake structure will require four tunnel portals on 60-foot centers. Rock pillars 32 feet wide and 38 feet deep will separate the portals.

(b) Intake Gates

Each of the four powerhouse intake tunnels will have a single fixed-wheel intake gate 20 feet wide by 25 feet high. The gates will have an upstream skinplate and seal and will be operated by hydraulic or wire rope hoists located in heated enclosures immediately below deck level. The gates, which will normally close under balanced head conditions to permit dewatering of the penstock and turbine water passages for turbine inspection and maintenance, will also be capable of closing under their own weight with full flow conditions and maximum reservoir water level in the event of runaway of the turbines. A heated air vent will be provided at the intake deck to satisfy air demand requirements when the intake gate is closed with flowing water conditions.

(c) Intake Bulkhead Gates

A bulkhead gate consisting of two sections will be provided for closing the intake openings. The gate will be used to permit inspection and maintenance of the intake gate and intake gate guides. The gates will be raised and lowered under balanced head conditions only.

(d) Intake Gantry Crane

A 50-ton capacity electrical traveling gantry crane will be provided on the intake deck at Elevation 1466 for handling the trash-racks, and intake bulkhead gates and for servicing the intake gate equipment.

7.9 - Penstocks

The power plant will have four penstocks, one for each unit. The maximum static head on each penstock will be 638 feet, as measured from normal maximum operating level (Elevation 1455) to centerline distributor level (Elevation 817). An allowance of 35 percent has been made for pressure rise in the penstock under transient conditions, giving a maximum head of 861 feet. Maximum extreme head (including transient loadings) corresponding to maximum reservoir flood level will be 876 feet.

The penstock tunnels are fully concrete-lined except for a 250-foot section upstream of the powerhouse which is steel-lined. The inclined sections of the concrete-lined penstocks will be at 55° to the horizontal.

(a) Steel Liner

The steel-lined penstock will be 15 feet in diameter. The first 50 feet of steel liner immediately upstream of the powerhouse will be designed to resist the full internal pressure. The remainder of the steel liner, extending another 200 feet upstream, will be designed to partially resist the internal pressure together with the rock. Beyond the steel liner, the hydraulic loads will be supported solely by the rock tunnel with a concrete liner.

The steel liner is surrounded by a concrete infill with a minimum thickness of 24 inches. A tapered steel transition will be provided at the junction between the steel liner and the concrete liner to increase the internal diameter from 15 feet to 20 feet.

(b) Concrete Liner

The thickness of the concrete lining will vary with the design head, with the minimum thickness of lining being 12 inches. The internal diameter of the concrete liner will be 20 feet.

(c) Grouting and Pressure Relief System

A comprehensive pressure relief system will be installed to protect the underground caverns against seepage from the high pressure penstocks and reservoirs. The system will consist of small diameter boreholes set out in an array to intercept the jointing in the rock. Grouting around the penstocks will also be undertaken.

7.10 - Powerhouse and Related Structures

The underground powerhouse complex will be constructed in the north side of the canyon. This will require the excavation of three major caverns (powerhouse, transformer gallery and surge chamber), with interconnecting rock tunnels for the draft tubes and isolated phase bus ducts.

An unlined rock tunnel will be constructed for vehicular access to the three main rock caverns. A second unlined rock tunnel will provide access from the powerhouse to the foot of the arch dam.

Vertical shafts will be required for personnel access by elevator to the underground powerhouse, for oil-filled cable from the transformer gallery, and for surge chamber venting.

The draft tube gate gallery and cavern will be located in the surge chamber cavern, above maximum design surge level.

The general layout of the powerhouse complex is shown on Plates F63, F64 and F65. The transformer gallery will be located upstream of the powerhouse cavern and the surge chamber will be located downstream of the powerhouse cavern. The spacing between the underground caverns will be fixed so as to be at least 1.5 times the main span of the larger excavation.

(a) Access Tunnels and Shafts

The 3,000-foot long main access tunnel will connect the powerhouse cavern at Elevation 858 with the canyon access road on the north bank. A secondary access tunnel will run from the main powerhouse access tunnel to the foot of the arch dam for routine maintenance of the fixed-cone valves. Branch tunnels from the secondary access tunnel will provide construction access to the lower section of the penstocks at Elevation 820. Separate branch tunnels from the main access tunnel will give vehicle access to the transformer gallery at Elevation 896 and the draft tube gate gallery at Elevation 908. The maximum gradient on the permanent access tunnel will be 8 percent; the maximum gradient on the secondary access tunnel will be 9 percent.

The cross section of the access tunnels, which will be dictated by requirements for the construction plant, will be a modified horseshoe shape 35 feet wide by 28 feet high.

The main access shaft will be located at the north end of the powerhouse cavern, providing personnel access by elevator from the surface. Horizontal tunnels will be provided from this shaft for pedestrian access to the transformer gallery and the draft tube gate gallery. At a higher level, access will also be available to the fire protection head tank.

Access to the upstream grouting gallery will be from the transformer gallery main access tunnel at a maximum gradient of 13.5 percent.

(b) Powerhouse Cavern

The main powerhouse cavern is designed to accommodate four vertical-shaft Francis turbines, in line, with direct coupling to overhung generators. Each unit will have a design capability of 150 MW.

The unit spacing will be 60 feet with an additional 110-foot service bay at the south end of the powerhouse for routine maintenance and construction erection. The control room will be located at the north end of the main powerhouse floor. The width of the cavern will be sufficient for the physical size of the generator plus galleries for piping, air-conditioning ducts, electrical cables, and isolated phase bus. The overall size of the powerhouse cavern will be 74 feet wide, 360 feet long, and 126 feet high.

Multiple stairway access points will be available from the powerhouse main floor to each gallery level. Access to the transformer gallery from the powerhouse will be by a tunnel from the access shaft or by a stairway through each of the four bus tunnels. Access will also be available to the draft tube gate gallery by a tunnel from the main access shaft.

A service elevator will be provided for access from the service bay area on the main floor to the machine shop, and the dewatering and drainage galleries on the lower floors. Hatches will be provided through all main floors for installation and routine maintenance of pumps, valves and other heavy equipment using the main powerhouse crane.

(c) Transformer Gallery

The transformers will be located underground in a separate unlined rock cavern, 120 feet upstream of the powerhouse cavern, with four interconnecting tunnels for the isolated phase bus. There will be 12 single-phase transformers with one group of three transformers for each generating unit. Each transformer is rated at 15/345, 70 MVA. For increased reliability, one spare transformer and one spare HV circuit will be provided. The station service transformers and the surface facilities transformers will be located in the bus tunnels. Generator excitation transformers will be located on the main powerhouse floor. The overall size of the transformer gallery will be 43 feet wide, 40 feet high, and 446 feet long; the bus tunnels will be 14 feet wide and 14 feet high.

High voltage cables will be taken to the surface in two 7.5-foot internal diameter cable shafts, and provision will be made for an inspection hoist in each shaft.

Vehicle access to the transformer gallery will be from the south end via the main powerhouse access tunnel. Personnel access will be from the main access shaft or through each of the four isolated phase bus tunnels.

(d) Surge Chamber

A simple surge chamber will be constructed 120 feet downstream of the powerhouse to control pressure fluctuations in the turbine draft tubes and tailrace tunnel under transient load conditions, and on machine start-up. The chamber will be common to all four draft tubes. The overall size of the chamber will be 75 feet wide, 240 feet long, and 190 feet high.

The draft tube gate gallery and crane will be located in the same cavern, above the maximum anticipated surge level. Access to the draft tube gate gallery will be by a rock tunnel from the main access tunnel. The tunnel will be widened locally for storage of the draft tube gates.

The chamber will be an unlined rock excavation with localized rock support as necessary for stability of the roof arch and walls. The guide blocks for the draft tube gates will be of reinforced concrete anchored to the rock excavation by rock bolts.

(e) Draft Tube Tunnels

The orientation of the draft tube tunnels will be 300°. The tunnels will be 19 feet in diameter and steel- and concrete-lined, with the concrete having a thickness of about 2 feet.

7.11 - Tailrace Tunnel

The tailrace pressure tunnel will convey power plant discharge from the surge chamber to the river. The tunnel will have a modified horseshoe cross section with an internal dimension of 38 feet, and will be concrete-lined throughout with a minimum thickness of 12 inches. The length of the tunnel is 6800 feet.

The tailrace portal site will be located at a prominent steep rock face on the north bank of the river. The portal outlet is rectangular in section, which reduces both the maximum outlet velocity (8 ft/sec) as well as the velocity head losses. Vertical stoplog guides will be provided for closure of the tunnel for tunnel inspection and/or maintenance.

7.12 - Access Plan

(a) Description of Access Plan

Access to the Devil Canyon development will consist primarily of a railroad extension from the existing Alaska Railroad at Gold Creek to a railhead and storage facility adjacent to the Devil Canyon camp area. From here materials and supplies will be distributed using a system of site roads.

To provide flexibility of access the railroad extension will be augmented by a road between the Devil Canyon and Watana damsites. The availability of both road and rail access will reduce the schedule and cost risks associated with limited access.

This road connection is also required for travel between Watana and Devil Canyon by the post-construction operation and maintenance personnel who will be stationed at Watana.

(b) Rail Extension

Except for a 2-mile section where the route traverses steep terrain alongside the Susitna River, the railroad will climb steadily for 12.2 miles from Gold Creek to the railhead facility near the Devil Canyon camp.

Nearly all of the route traverses potentially frozen Basal till on side slopes varying from flat to moderately steep. Several streams are crossed, requiring the construction of large culverts. However, where the railroad crosses Jack Long Creek small bridges will be built to minimize impacts to the aquatic habitat. In view of the construction conditions it is estimated that it will take eighteen months to two years to complete the extension. Therefore construction should start two years prior to commencement of the main works at Devil Canyon.

The railroad extension will be designed in accordance with the parameters set out below:

Maximum grade	2.5%
Maximum curvature	10°
Design loading	E-72

These parameters are consistent with those presently being used by the Alaska Railroad.

(c) Connecting Road

From the railhead facility at Devil Canyon a connecting road will be built to a high-level suspension bridge approximately one mile downstream of the damsite. The route then proceeds in a northeasterly direction, crosses Devil Creek and swings around past Swimming Bear Lake at an elevation of 3500 feet before continuing in a southeasterly direction through a wide pass. After crossing Tsusena Creek, the road continues south to the Watana damsite. The overall length of the road is 37.0 miles.

In general the alignment crosses good soil types with bedrock at or near the surface. Erosion and thaw settlement problems should not be a problem since the terrain has gentle to moderate slopes which will allow roadbed construction without deep cuts.

The connecting road will be built to the same standards and in accordance with the design parameters used for the Watana access road. However, as will be the case for the Watana damsite access road, the design standards will be reduced to as low as 40 mph in areas where it is necessary to minimize the extent of cutting and filling. The affected areas are the approaches to some of the stream crossings, the most significant being those of the high-level bridge crossing the Susitna River downstream of Devil Canyon.

(d) Construction Schedule

The 1790-foot long high-level suspension bridge crossing the Susitna River is the controlling item in the construction schedule, requiring three years for completion. Therefore, it will be necessary to begin construction three years prior to the start of the main works at the Devil Canyon damsite.

(e) Right-of-Way

The road and railroad routes mainly traverse terrain with gentle to moderate side slopes, where a right-of-way width of 200 feet will be sufficient. Only in areas of major sidehill cutting and deep excavation will it be necessary to go beyond 200 feet.

7.13 - Site Facilities

The construction of the Devil Canyon development will require various facilities to support the construction activities throughout the entire construction period. Following construction, the planned operation and maintenance of the development will be centered at the Watana development; therefore, a minimum of facilities at the site will be required to maintain the power facility.

As described for Watana, a camp and construction village will be constructed and maintained at the project site. The camp/village will provide housing and living facilities for 1,800 people during construction. Other site facilities will include contractors' work areas, site power, services, and communications. Items such as power and communications and hospital services will also be required for construction operations independent of camp operations.

Buildings used for the Watana development will be used where possible in the Devil Canyon development. Current planning calls for dismantling and reclaiming the site after construction. Electric power will be provided from the Watana development. The salvaged building modules used from the Watana camp/village will be retrofitted from fuel oil heating to electric heat.

(a) Temporary Camp and Village

The proposed location of the camp/village is on the south bank of the Susitna River between the damsite and Portage Creek, approximately 2.5 miles southwest of the Devil Canyon Dam (see Plate F70). The south side of the Susitna was chosen because the main access road in this area will be from the south. South-facing slopes will be used for the camp/village location.

The camp will consist of portable woodframe dormitories with modular mess halls, recreational buildings, bank, post office, fire station, warehouses, hospital, offices, etc. The camp will be a single status camp for approximately 1,650 workers.

The village, designed for approximately 150 families, will be grouped around a service core containing a school, gymnasium, stores, and recreation area.

The two areas will be separated by approximately 1/2 mile to provide a buffer zone. The hospital will serve both the main camp and the village.

This camp location will be separated from the work areas by approximately one mile. Travel time to the work area will generally be less than 15 minutes.

The camp/village will be constructed in stages to accommodate the peak work force. The facilities will be designed for the peak work force plus 10 percent for "turnover". The "turnover" will include provisions for overlap of workers and vacations. The conceptual layouts for the camp/village are presented in Plates F72 and F73.

Construction camp buildings will consist largely of trailer-type factory-built modules assembled at site to provide the various facilities required. The modules will be fabricated with heating, lighting, and plumbing facilities, interior finishes, furnishings, and equipment. Trailer modules will be supported on timber cribbing or blocking approximately two feet above grade.

Larger structures such as the central utilities building, gym, and warehouses will be pre-engineered steel-framed structures with metal cladding.

The various buildings in the camp are identified on Plate F72.

(b) Site Power and Utilities

(i) Power

A 345 kV transmission line from Watana and a substation will be in service during the construction activities. Two transformers will be installed at the substation to reduce the line voltage to the desired voltage levels.

Power will be sold to the contractors by the Power Authority. The peak demand during construction is estimated at 20 MW for the camp/village and 4 MW for construction requirements. The distribution system for the camp/village will be 4.16 kV.

(ii) Water

The water supply system will serve the entire camp/village and selected contractors' work areas. The water supply system will provide for potable water and fire protection. The estimated peak population to be served will be 2,150 (1,650 in the camp and 500 in the village).

The principal source of water will be the Susitna River. The water will be treated in accordance with the Environmental Protection Agency (EPA) primary and secondary requirements.

(iii) Wastewater

One wastewater collection and treatment system will serve the camp/village. Gravity flow lines with lift stations will be used to collect the wastewater from all of the camp and village facilities. The "in-camp" and "in-village" collection systems will be run through the permawalks and utilidors so that the collection system will always be protected from the elements.

At the village, an aerated collection basin will be installed to collect the sewage. The sewage will be pumped from this collection basin through a force main to the sewage treatment plant.

Chemical toilets located around the site will be serviced by sewage trucks which will discharge directly into the sewage treatment plant.

The sewage treatment system will be a biological system with lagoons. The system will be designed to meet Alaskan State water law secondary treatment standards. The lagoons and system will be modular to allow for growth and contraction of the camp/village.

The location of the treatment plant is shown on Plate F70. The location was selected to avoid unnecessary odors in the camp.

The sewage plant will discharge its treated effluent to the Susitna River. All treated sludge will be disposed of in a solid waste sanitary landfill.

(c) Contractors' Area

Constractors on the site will require offices, workshops, warehouses, storage areas, and fabrication shops. These will be located on the south side of the Susitna River near the owner/manager's office. Additional space required by contractors will be in the area between the access road and the camp.

8 - DEVIL CANYON RESERVOIR

The Devil Canyon reservoir, at a normal operating level of 1455 feet, will be approximately 26 miles long with a maximum width of approximately 1/2 mile. The total surface area at normal operating level will be 7800 acres. Immediately upstream of the dam, the maximum water depth will be approximately 580 feet. The minimum reservoir level will be 1405 feet during normal operation, resulting in a maximum drawdown of 50 feet. The reservoir will have a total capacity of 1,100,000 acre-feet of which 350,000 acre-feet will be live storage.

9 - TURBINES AND GENERATORS - DEVIL CANYON

9.1 - Unit Capacity

The Devil Canyon powerhouse will have four generating units with a design capability of 150 MW based on the minimum December reservoir level (Elevation 1405) and a corresponding gross head of 555 feet. The head on the plant will vary from 555 feet to 605 feet.

The rated average operating head for the turbine will be 575 feet. Allowing for generator losses, this will result in a rated turbine output of 225,000 hp (168 MW) at full gate.

The generator rating will be 180 MVA with a 90 percent power factor. The generators will be capable of continuous operation at 115 percent rated power. Because of the high capacity factor for the Devil Canyon station, the generators will therefore be sized on the basis of maximum turbine output at maximum head, allowing for a possible 5 percent addition in power from the turbine. This maximum turbine output (250,000 hp) will be within the continuous overload rating of the generator.

9.2 - Turbines

The turbines will be of the vertical-shaft Francis type with steel spiral casing and a concrete elbow-type draft tube. The draft tube will have a single water passage (no center pier).

Maximum and minimum heads on the unit will be 603 feet and 541 feet, respectively. The full-gate output of the turbines will be about 205,000 hp at maximum net head and 180,000 hp at minimum net head. Overgating of the turbines may be possible, providing approximately 5 percent additional power. For preliminary design purposes, the best efficiency (best-gate) output of the units has been assumed at 85 percent of the full-gate turbine output.

The full-gate and best-gate efficiencies of the turbines will be about 91 percent and 94 percent, respectively, at rated head. The efficiency will be about 0.2 percent lower at maximum head and 0.5 percent lower at minimum head

9.3 - Generators

The four generators in the Devil Canyon powerhouse will be of the vertical-shaft, overhung semi-umbrella type directly connected to the vertical Francis turbines.

The generators will be similar in construction and design to the Watana generators. The general features described in Section 3.2 for the stator, rotor, excitation system, and other details also will apply for the Devil Canyon generators.

The rating and characteristics of the generators will be as follows:

Rated Capacity:	167 MVA, 0.9 power factor with overload rating of 115 percent.
Rated Power:	162 MW
Rated Voltage:	15 kV, 3 phase, 60 Hertz
Synchronous Speed:	225 rpm
Inertia Constant:	3.5 MW-Sec/MVA
Short Circuit Ratio:	1.1 (minimum)
Efficiency at Full Load:	98 percent (minimum)

9.4 - Governor System

A governor system with electric hydraulic governor actuators will be provided for each of the Devil Canyon units. The system will be the same as for Watana (See Section 3.4).

10 - TRANSMISSION LINES - DEVIL CANYON

As part of the Devil Canyon development, the transmission systems will be supplemented as described in the following paragraphs.

Two single-circuit 345 kV transmission lines will be built between the Devil Canyon switchyard at the power development and the Gold Creek switching station. From the Devil Canyon substation the lines will head directly west for a distance of approximately one mile where they will intersect the Watana to Gold Creek transmission corridor. From this point to the Gold Creek switching station the lines will share the same corridor as the Watana lines.

At Gold Creek, three 345 kV breakers will be added in an additional bay within the switching station to receive the incoming lines and to accommodate a new line to Anchorage.

Between Gold Creek and Knik Arm switching stations, a third 345 kV single-circuit line will be built parallel to the two Watana lines. The crossing of Knik Arm will be by cable with a similar arrangement to the original two circuits. At Willow switching station, four 345 kV breakers will be added, one in an existing bay, the rest in a new bay. These handle the new line and allow the installation of a third 75 MVA transformer for local supply, if required. Similarly, at Knik Arm switching station, a breaker will be installed in an existing bay to receive the incoming Watana line. Between the Knik Arm and University stations, the lines built for Watana were sized to accommodate the Devil Canyon need in order to limit right-of-way requirements. At University an additional transformer bank at each of 230 kV and 115 kV levels will be provided; this will involve the addition of two breakers in existing bays. At the Ester substation in Fairbanks, an additional 150 MVA transformer bank will be installed to serve the local load; this will require one new breaker in an existing bay.

11 - APPURTENANT EQUIPMENT - DEVIL CANYON

11.1 - Miscellaneous Mechanical Equipment

(a) Powerhouse Cranes

Two overhead type powerhouse cranes will be provided at Devil Canyon as at Watana. The crane capacity will be approximately 200 tons.

(b) Draft Tube Gates

Draft tube gates will be provided to permit dewatering of the turbine water passages for inspection and maintenance of the turbines. The arrangement of the draft tube gates will be the same as for Watana, except that only two sets of gates will be provided, each set with two 21-foot wide by 10.5-foot high sections.

(c) Draft Tube Gate Crane

A crane will be installed in the surge chamber for installation and removal of the draft tube gates. The crane will be either a monorail (or twin monorail) or a gantry crane with an approximate capacity of 30 tons. The crane will be pendant-operated and have a two point lift. A follower will be used with the crane for handling the gates. The crane runway will be located along the upstream side of the surge chamber and will extend over the intake for the compensation flow pumps as well as a gate unloading area at one end of the surge chamber.

(d) Miscellaneous Cranes and Hoists

In addition to the powerhouse cranes and draft tube gate cranes, the following cranes and hoists will be provided in the power plant:

- A 5-ton monorail hoist in the transformer gallery for transformer maintenance;

- Small overhead, jib, or A-frame type hoists in the machine shop for handling material; and

- A-frame or monorail hoists in other powerhouse areas for handling small equipment.

(e) Elevators

Access and service elevators will be provided for the power plant as follows:

- Access elevator from the control building to the powerhouse;
- Service elevator in the powerhouse service bay; and
- Inspection hoists in cable shafts.

(f) Power Plant Mechanical Service Systems

The power plant mechanical service systems for Devil Canyon will be essentially the same as discussed in Section 5.1(f) for Watana, except for the following:

- There will be no main generator breakers in the power plant; therefore, circuit breaker air will not be required. The high-pressure air system will be used only for governor as well as instrument air. The operating pressure will be 600 to 1000 psig depending on the governor system operating pressure.

- An air-conditioning system will be installed in the powerhouse control room.

- Heating and ventilating will be required for the entrance building to the access shaft in the south abutment.

- For preliminary design purposes, only one drainage and one dewatering sump have been provided in the powerhouse. The dewatering system will also be used to dewater the intake and discharge lines for the compensation flow pumps.

(g) Surface Facilities Mechanical Service Systems

The entrance building above the power plant will have only a heating and ventilation system. The mechanical services in the standby power building will include a heating and ventilation system, a fuel oil system, and a fire protection system, as at Watana.

(h) Machine Shop Facilities

A machine shop and tool room will be located in the powerhouse service bay area to take care of maintenance work at the plant. The facilities will not be as extensive as at Watana. Some of the larger components will be transported to Watana for necessary machinery work.

11.2 - Accessory Electrical Equipment

(a) General

The accessory electrical equipment described below includes the following:

- Main generator step-up 15/345 kV transformers;
- Isolated phase bus connecting the generator and transformers;
- 345 kV oil-filled cables from the transformer terminals to the switchyard;
- Control systems; and
- Station service auxiliary ac and dc systems.

Other equipment and systems described include grounding, lighting system and communications.

The main equipment and connections in the power plant are shown in the single line diagram (Plate F68). The arrangement of equipment in the powerhouse, transformer gallery, and cable shafts is shown in Plates F63 to F65.

(b) Transformers and HV Connections

Twelve single-phase transformers and one spare transformer will be located in the transformer gallery. Each bank of the three single-phase transformers will be connected to one generator by isolated phase bus located in bus tunnels. The HV terminals of the transformer will be connected to the 345 kV switchyard by 345 kV single-phase, oil-filled cables installed in 800-foot long vertical shafts. There will be two sets of three single-phase 345 kV oil-filled cables installed in each cable shaft. One additional set will be maintained as a spare three-phase cable circuit in the second cable shaft. These cable shafts will also contain the control and power cables between the powerhouse and the surface control room, as well as emergency power cables from the diesel generators at the surface to the underground facilities.

(c) Main Transformers

The transformers will be of the single-phase, two-winding, oil-immersed, forced-oil water-cooled (FOW) type. A total of twelve single-phase transformers and one spare transformer will be provided, with rating and characteristics as follows:

Rated capacity:	70 MVA
High Voltage Winding:	$345/\sqrt{3}$ kV, grounded Y
Basic Insulation Level (BIL) of HV Winding:	1300 kV
Low Voltage Winding:	15 kV, Delta
Transformer Impedance:	15 percent

(d) Generator Isolated Phase Bus

Isolated phase bus connections will be located between the generator and the main transformer. The bus will be of the self-cooled, welded aluminum tubular type with design and construction details generally similar to the bus at the Watana power plant. The rating of the main bus will be as follows:

Rated current:	9000 amps
Short circuit current momentary:	240,000 amps
Short circuit current symmetrical:	150,000 amps
Basic Insulation Level (BIL):	150 kV

(e) 345 kV Oil-Filled Cable

The cables will be rated for a continuous maximum current of 400 amps at 345 kV ± 5 percent. The cables will be of single-core construction with oil flowing through a central oil duct within the copper conductor. The cables will be installed in the 800-foot cable shafts from the transformer gallery to the surface. No cable jointing will be necessary for this installation length.

(f) Control Systems

The Devil Canyon power plant will be designed to be operated as an unattended plant. The plant will be normally controlled through supervisory control from the Susitna Area Control Center at Watana. The plant will, however, be provided with a control room with sufficient control, indication, and annunciation equipment to enable the plant to be operated during emergencies by one operator in the control room. In addition, for the purpose of testing and commissioning and maintenance of the plant, local control boards will be mounted on the powerhouse floor near each unit.

Automatic load-frequency control of the four units at Devil Canyon will be accomplished through the central computer-aided control system located at the Watana Area Control Center.

The power plant will be provided with "black start" capability similar to that provided at Watana to enable the start of one unit without any power in the powerhouse or at the switchyard, except that provided by one emergency diesel generator. After the start-up of one unit, auxiliary station service power will be established in the power plant and the switchyard; the remaining generators can then be started one after the other to bring the plant into full output within the hour.

As at the Watana power plant, the control system will be designed to permit local-manual or local-automatic starting, voltage adjusting, synchronizing, and loading of the unit from the powerhouse control room at Devil Canyon.

The protective relaying system is shown in the main single line diagram (Plate F68) and is generally similar to that provided for the Watana power plant.

(g) Station Service Auxiliary AC and DC Systems

(i) AC Auxiliary System

The auxiliary system will be similar to that in the Watana power plant except that the switchyard and surface facilities power will be obtained from a 4.16 kV system supplied by two 5/7.5 MVA, OA/FA, oil-immersed transformers connected to generators Nos. 1 and 4, respectively. The 4.16 kV double-ended switchgear will be located in the powerhouse. It will have a normally-open tie breaker which will prevent parallel operation of the two sections. The tie breaker will close on failure of one or the other of the incoming supplies. The 1400 hp compensation flow pumps will be supplied with power directly from the 4.16 kV system. Two 4.16 cables installed in the cable shafts will supply power to the surface facilities.

The 480 V station service system will consist of a main 480 V switchgear, separate auxiliary boards for each unit, essential auxiliaries board, and a general auxiliaries board. The main 480 V switchgear will be supplied by two 2000 kVA, 15,000/480 V grounded wye sealed gas dry-type transformers. A third 2000 kVA transformer will be maintained as a spare.

Two emergency diesel generators, each rated 500 kW, will be connected to the 480 V powerhouse main switchgear and 4.16 kV surface switchboard, respectively. Both diesel generators will be located at the surface.

An uninterruptible high-security power supply will be provided for the supervisory computer-aided plant control systems.

(ii) DC Auxiliary Station Service System

The dc auxiliary system will be similar to that provided at the Watana plant and will consist of two 125 V dc lead-acid batteries. Each battery system will be supplied by a double-rectifier charging system. A 48 V dc battery system will be provided for supplying the supervisory and communications systems.

(h) Other Accessory Electrical Systems

The other accessory electrical systems including the grounding system, lighting system, and powerhouse communications system will be similar in general design and construction aspects to the system described in Section 5.2 for the Watana power plant.

11.3 - Switchyard Structures and Equipment

(a) Single Line Diagram

A breaker-and-a-half single line arrangement will be used at the switchyard. This arrangement was selected for reliability and security of the power system. Plate F69 shows the details of the switchyard single line diagram.

(b) Switchyard Structures and Layout

The switchyard layout will be based on a conventional outdoor type design. The design adopted for this project will provide a two-level bus arrangement. This design is commonly known as a low station profile.

The two-level bus arrangement is desirable because it is less prone to extensive damage in case of an earthquake. Due to the lower heights, it is also easier to maintain.

REFERENCES

Commonwealth Associates Inc. January 1982. Anchorage-Fairbanks Transmission Intertie Route Selection Report. Prepared for the Alaska Power Authority.

TABLE A.1: PRINCIPAL PROJECT PARAMETERS

Item	Watana	Devil Canyon
Hydrology		
- Average River Flow (cfs)	7,990	9,080
- Peak Flood Inflows (cfs)		
. PMF	326,000	345,000 with Watana 362,000 without Watana
. 10,000-year	156,000	165,000 with Watana 161,000 without Watana
. 50-year	87,000	39,000 with Watana 98,000 without Watana
. 25-year	76,000	37,800 with Watana 85,000 without Watana
- Peak Flood Flows through the Dam (cfs)		
. PMF	293,000	345,000 with Watana
. 10,000-year	150,000	165,000 with Watana
. 50-year	31,000	39,000 with Watana
Reservoir Characteristics		
- Normal Maximum Operating Level (ft)	2,185	1,455
- Maximum Level, PMF (ft)	2,201	1,466
- Minimum Operating Level (ft)	2,065	1,405
- Area at NMOL (acres)	38,000	7,800
- Length (miles)	48	26
- Total Storage (acre-feet)	9.5×10^6	1.1×10^6
- Live Storage (acre-feet)	3.7×10^6	0.35×10^6
Project Outputs		
- Plant Design Capability (MW)	1,020	600
- Annual Generation (GWh)		
. Firm	2,620	2,718
. Average	3,460	3,450
Dams		
- Type	Earth/Rockfill, Central Core	Concrete Arch (Earth/Rockfill Saddle)
- Crest Elevation (ft)	2,210	1,463 (1472)
- Crest Length (ft)	4,100	1,650 (950)
- Height Above Foundation (ft)	885	646 (245)
- Crest Width (ft)	35	20 (35)
- Upstream Slope (H:V)	2.4:1	(2.4:1)
- Downstream Slope (H:V)	2:1	(2:1)
Diversion		
- Cofferdams		
. Type	Rockfill, Central Core	Rockfill, Central Core
. Upstream Crest Elevation (ft)	1,545	947
. Downstream Crest Elevation (ft)	1,472	898
. Maximum U/S Water Level (ft)	1,536	944
- Tunnels		
. Number/Type	2 - Circular, concrete-lined	1 - Horseshoe, concrete-lined
. Diameter (ft)	38	30
. Capacity (cfs)	80,500	39,000

TABLE A.1 (Cont'd)

Item	Watana	Devil Canyon
Outlet Facilities		
- Central Structures	6-fixed cone valves	7-fixed cone valves
- Diameter (in)	78	4-102, 3-90
- Water Passage Diameter (ft)	28	8.5/7.5
- Capacity (cfs)	24,000	38,500
Main Spillways		
- Capacity (cfs)	120,000	123,000
- Control Structure		
. Type	gated ogee	gated ogee
. Crest Elevation (ft)	2,148	1,404
. Gates (H x W, ft)	3-49 x 36	3-56 x 30
- Chute Width (ft)	144/80	122/80
- Energy Dissipation	Flip bucket	Flip bucket
Emergency Spillways		
- Capacity (cfs)	120,000	150,000
- Control Structure		
. Type	Open channel/ fuse plug	Open channel/ fuse plug
. Crest Elevation (ft)	2200/2201.5	1464/1465.5
- Chute Width (ft)	310/200	220
Power Intakes		
- Control Structures	Multi-level, gated	Multi-level, gated
- Gates (H x W, ft)	4-20 x 30	2-20 x 30
- Crest Elevation (ft)	2,030	1,365
- Maximum Drawdown (ft)	120	50
- Capacity, per unit (cfs)	3,870	3,670
Penstocks		
- Number	6	4
- Type	Inclined/horizontal	Inclined/horizontal
- Diameter (ft)		
. Concrete-lined	17	20
. Steel-lined	15	15
Powerhouses		
- Type	Underground	Underground
- Cavern Size (L x W x H, ft)	455 x 74 x 126	360 x 74 x 126
- Turbine/Generator	6 Vertical Francis/ Synchr.	4 Vertical Francis/ Synchr.
- Speed (rpm)	225	225
- Design Unit Capability		
. Net head (ft)	652	542
. Flow (cfs)	3,490	3,680
. Output (MW)	170	150
- Rated Unit Capability		
. Net Head (ft)	680	590
. Full-Gate Flow (cfs)	3,550	3,790
. Full-Gate Output (MW)	183	164
. Best-Gate Output (MW)	156	140

TABLE A.1 (Cont'd)

Item	Watana	Devil Canyon
- Transformers		
. Location	Upstream gallery	Upstream gallery
. Cavern Size (L x W x H, ft)	314 x 45 x 40	446 x 43 x 40
. Number/Type	9 - single phase	12 - single phase
. Voltage (kV)	15/345	15/345
. Rating (MVA)	145	70
Tailrace Tunnels		
- Number/Type	2 - Horseshoe, concrete-lined	1 - Horseshoe concrete-lined
- Diameter (ft)	34	38
- Surge Chamber Size (L x W x H, ft)	350 x 50 x 150	240 x 75 x 190
- Capacity (cfs)	22,000	15,500

SUSITNA HYDROELECTRIC PROJECT
VOLUME 1
EXHIBIT C
PROPOSED CONSTRUCTION SCHEDULE

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT C

PROPOSED CONSTRUCTION SCHEDULE

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EXHIBIT C - PROPOSED CONSTRUCTION SCHEDULE

This section describes the development schedules prepared for both Watana and Devil Canyon to meet the on-line power requirements of 1994 and 2002, respectively. These schedules span the period from 1983 until 2004. Schedules for the development of both Watana and Devil Canyon are shown on Figures C.1 and C.2. 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 a license will be awarded by December 31, 1984.

At both sites the period for construction of the main dam is critical. Other activities are fitted to the main dam work. A study of the front end requirements at Watana concluded that initial access work should commence immediately after receipt of license and be completed in the shortest possible time to permit a sufficiently rapid buildup of manpower and equipment to meet construction requirements.

1 - WATANA SCHEDULE

Commencement of construction:

Initial access road	- April 1985
Site facilities	- April 1985
Diversion	- July 1985

Completion of construction:

Four of six units ready	- January 1994
Six units ready	- July 1994

Commencement of commercial operations:

Four of six units	- January 1994
Six units	- July 1994

The Watana schedules were developed to meet two overall project constraints:

- FERC license would be issued by December 31, 1984; and
- Four units would be on-line by the beginning of 1994.

The critical path of activities to meet the overall constraints was determined to be through site access, site facilities, diversion and main dam construction. In general, construction activities leading up to diversion in 1987 are on an accelerated schedule whereas the remaining activities are on a normal schedule. These are highlighted as follows:

1.1 - Access

Initial road access to the site is required by October 1, 1985. Certain equipment will be transported overland during the preceding winter months so that an airfield can be constructed by July 1985. This effort to complete initial access is required to mobilize labor, equipment, and materials in 1985 for the 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 1000 men must be constructed during the first eighteen 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 April 1986. On-site power generating equipment must be installed in 1985 to supply power for camp and construction activities.

1.3 - Diversion

Construction of diversion and dewatering facilities, the first major activity, should start by mid-1985. Excavation of the portals and tunnels requires a concentrated effort to allow completion of the lower tunnel for river diversion by October 1986. The upper tunnel is needed to handle the spring runoff by May 1987. The upstream cofferdam must be placed to divert river flows in October 1986 and raised sufficiently to avoid overtopping by the following spring.

1.4 - Main Dam

The progress of work in the main dam is critical throughout the period 1986 through 1992. Mobilization of equipment and start of site work must begin in 1986. Excavation of the right abutment as well as river alluvium under the dam core begins in 1986. During 1987 and 1988, 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	Quantity ($yd^3 \times 10^6$)	Accumulated Quantity ($yd^3 \times 10^6$)	Fill Elevation October 15 (feet)	Reservoir Elevation (feet)
1987	3	--	--	--
1988	6	9	--	--
1989	12	21	1660	--
1990	13	34	1810	1460
1991	13	47	1950	1865
1992	12	59	2130	2050
1993	3	62	2210	2185

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

1.5 - Spillways and Intakes

These structures have been scheduled for completion one season in advance of the requirement to handle flows. In general, excavation for these structures does not have to begin until most of the excavation work has been completed for the main dam.

1.6 - Powerhouse and Other Underground Works

The first four units are scheduled to be on line by the beginning of 1994 and the remaining two units in early 1994. Excavation of the access tunnel into the powerhouse complex has been scheduled to start in late 1987. Stage I concrete begins in 1989 with start of installation of major mechanical and electrical work in 1991. In general, the underground works have been scheduled to level resource demands as much as possible.

1.7 - Transmission Lines/Switchyards

Construction of the transmission lines and switchyards has been scheduled to begin in 1989 and to be completed before commissioning of the first unit.

1.8 - General

The Watana schedule requires that extensive planning, bid selection and commitments be made before the end of 1984 to permit work to progress on schedule during 1985 and 1986. The rapid development of site activities requires commitments, particularly in the areas of access and site facilities in order that construction operations have the needed support.

The schedule has also been developed to take advantage of possible early reservoir filling to the minimum operating level by October 1992. Should this occur, power could possibly be generated by the end of 1992.

2 - DEVIL CANYON SCHEDULE

Commencement of construction:

Main Access - April 1992
Site Facilities - June 1994
Diversion - June 1995

Completion of construction:

Four units - October 2002

Commencement of commercial operations:

Four units - October 2002

The Devil Canyon schedule was developed to meet the on-line power requirement of all four units in 2002. 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-1994.

2.2 - Site Facilities

Camp facilities should be started in 1994. It has been assumed that buildings can be salvaged from Watana. Site roads and power could also be started at this time.

2.3 - Diversion

Excavation and concreting of the single diversion tunnel should begin in 1995. River closure and cofferdam construction will take place to permit start of dam construction in 1996.

2.4 - Arch Dam

The construction of the arch dam will be the most critical construction activity from start of excavation in 1996 until topping out in 2001. The concrete program has been based on an average 8-month placing season for 4-1/2 years. The work has been scheduled so that a fairly constant effort may be maintained during this period to make best use of equipment and manpower.

2.5 - Spillways and Intake

The spillway and intake are scheduled for completion by the end of 2000 to permit reservoir filling the next year.

2.6 - Powerhouse and Other Underground Works

Excavation of access into the powerhouse cavern is scheduled to begin in 1996. Stage I concrete begins in 1998 with start of installation of major mechanical and electrical work in 2000.

2.7 - Transmission Lines/Switchyards

The additional transmission facilities needed for Devil Canyon have been scheduled for completion by the time the final unit is ready for commissioning in late 2001.

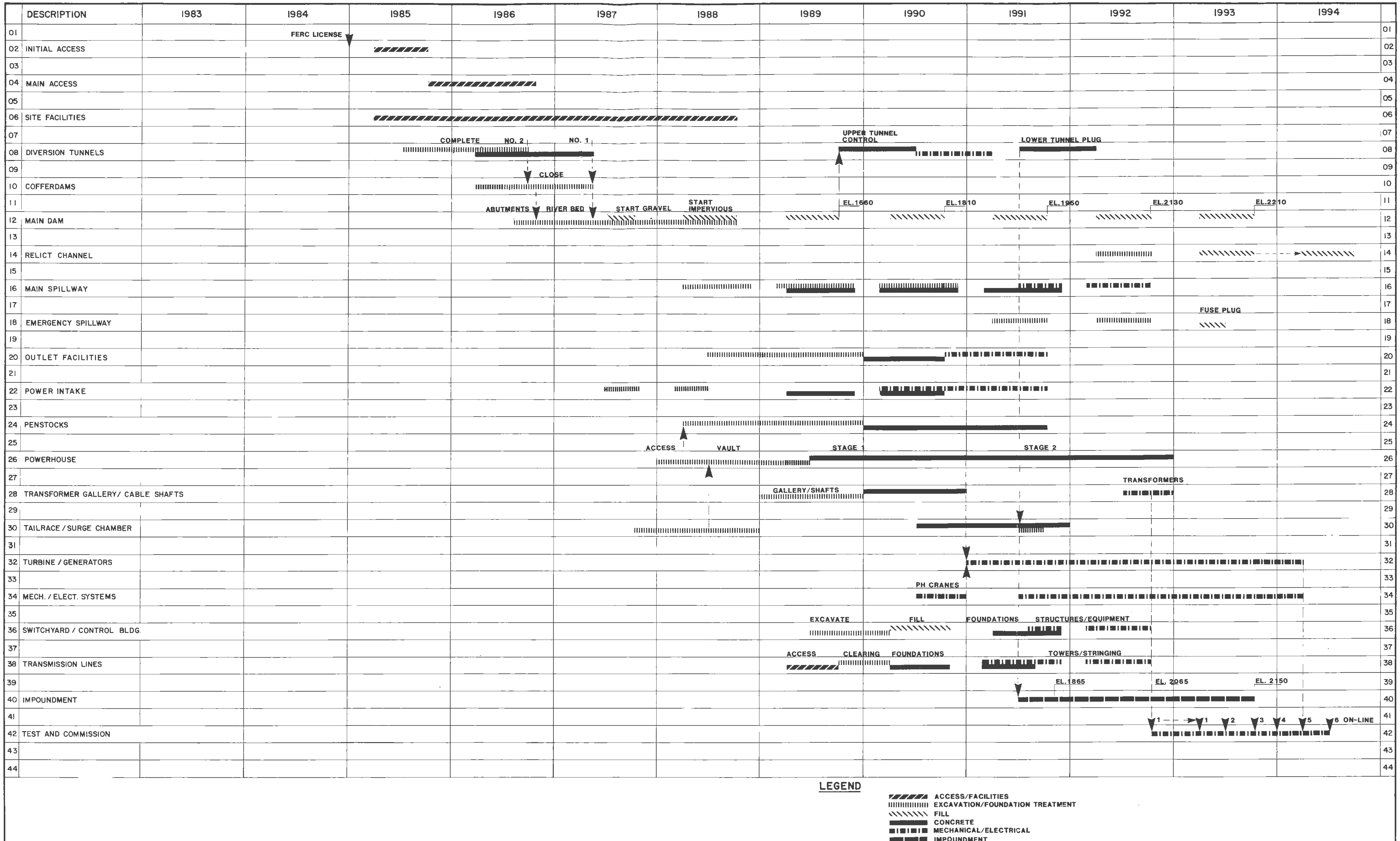
2.8 - General

The development of site facilities at Devil Canyon begins slowly in 1994 with a rapid acceleration in 1995 through 1997. Within a short period of time, construction begins on most major civil 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 - HISTORY OF EXISTING PROJECT

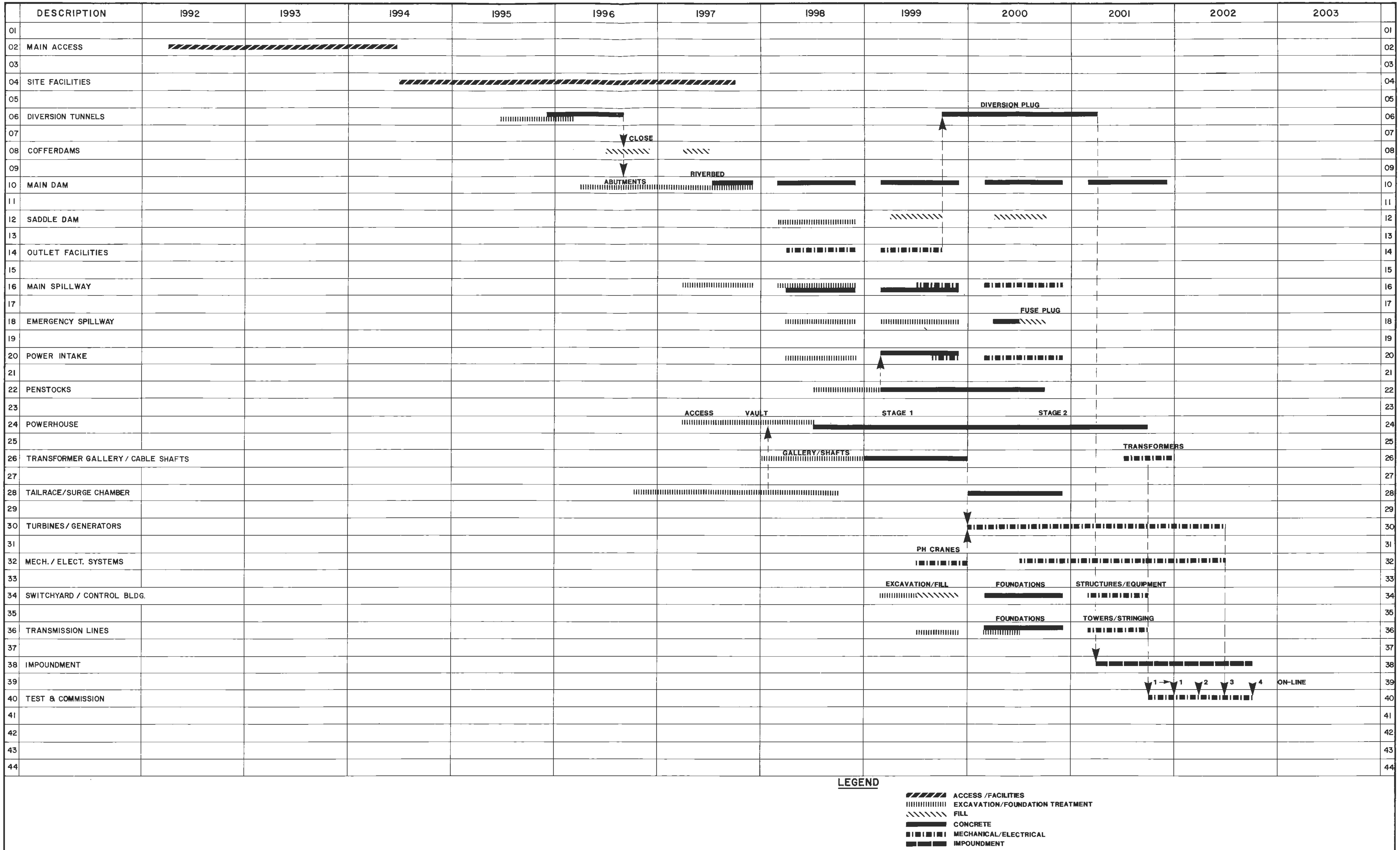
An intertie is planned to permit the economic interchange of up to 70 megawatts of power between major load centers at Anchorage and Fairbanks. Connecting to existing transmission systems at Willow in the south and Healy in the north, the intertie will be built to the same standards as those proposed for the Susitna project transmission system. It will be energized initially at 138 kV. Subsequent to construction of the Watana project, the intertie will be incorporated into the Susitna transmission system and will operate at 345 kV.

Construction of the intertie is scheduled to begin in March 1983. Completion and initial operation is planned for September 1984, well in advance of the anticipated date for receipt of a FERC license on December 31, 1984.



WATANA
CONSTRUCTION SCHEDULE

FIGURE C.1



DEVIL CANYON
CONSTRUCTION SCHEDULE

FIGURE C.2

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT D

PROJECT COSTS AND FINANCING

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT D

PROJECT COSTS AND FINANCING

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EXHIBIT D - PROJECT COSTS AND FINANCING

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

1 - ESTIMATES OF COST

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

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

1.1 - Construction Costs

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

(a) Code of Accounts

Estimates of construction costs were developed using the FERC format as outlined in the Federal Code of Regulations, Title 18 (GPO 1982).

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

Group	Description
Production Plant	Costs for structures, equipment, and facilities necessary to produce power.

Transmission Plant	Costs for structures, equipment, and facilities necessary to transmit power from the sites to load centers.
General Plant	Costs for equipment and facilities required for the operation and maintenance of the production and transmission plant.
Indirect Costs	Costs that are common to a number of construction activities. For this estimate only camps have been identified in this group. The estimate for camps includes electric power costs. Other indirect costs have been included in the costs under production, transmission, and general plant costs.
Overhead Construction Costs	Costs for engineering and administration.

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

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

The detailed schedule of costs using this breakdown is presented in Volume 6 of the Susitna Hydroelectric Project Feasibility Report (Acres 1982a).

(b) Approach to Cost Estimating

The estimating process used generally included the following steps:

- Collection and assembly of detailed cost data for labor, material, and equipment as well as information on productivity, climatic conditions, and other related items;

- Review of engineering drawings and technical information with regard to construction methodology and feasibility;

- Production of detailed quantity takeoffs from drawings in accordance with the previously developed Code of Accounts and item listing;

- Determination of direct unit costs for each major type of work by development of labor, material, and equipment requirements; development of other costs by use of estimating guides, quotations from vendors, and other information as appropriate;

- Development of construction indirect costs by review of labor, material, equipment, supporting facilities, and overheads; and

- Development of construction camp size and support requirements from the labor demand generated by the construction direct and indirect costs.

(c) Cost Data

Cost information was obtained from standard estimating sources, from sources in Alaska, from quotes by major equipment suppliers and vendors, and from representative recent hydroelectric projects. Labor and equipment costs for 1982 were developed from a number of sources (State of Alaska 1982; Caterpillar Tractor Co. 1981) and from an analysis of costs for recent projects performed in the Alaska environment.

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

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

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

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

(d) Seasonal Influences on Productivity

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:

- Watana dam fill - 6-month season
- 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 9.4°F to 20.3°F, with snowfall of 10 inches per month.

(e) Construction Methods

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

(f) Quantity Takeoffs

Detailed quantity takeoffs were produced from the engineering drawings using methods normal to the industry. The quantities developed are listed in the detailed summary estimates in the Susitna Hydroelectric Feasibility Report (Acres 1982a, Vol. 6).

(g) Indirect Construction Costs

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

Indirect costs included the following:

- Mobilization

- Technical and supervisory personnel above the level of trades foremen

- All vehicle costs for supervisory personnel

- Fixed offices, mobile offices, workshops, storage facilities, and laydown areas, including all services

- General transportation for workmen on site and off site

- Yard cranes and floats
- Utilities including electrical power, heat, water, and compressed air
- Small tools
- Safety program and equipment
- Financing
- Bonds and securities
- Insurance
- Taxes
- Permits
- Head office overhead
- Contingency allowance
- 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;
- Financing of progress payments has been estimated for 45 days, the average time between expenditure and reimbursement;
- Holdback would be limited to a nominal amount;
- Project all-risk insurance has been estimated as a contractor's indirect cost for this estimate, but it is expected that this insurance would be carried by the owner; and
- Contract packaging would provide for the supply of major materials to contractors at site at cost. These include fuel, electric power, cement, and reinforcing steel.

1.2 - Mitigation Costs

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

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

- Caribou barriers
- Raptor nesting platforms
- Fish channels
- Fish hatcheries
- Stream improvements
- Salt licks
- Habitat management for moose
- Fish stocking program in reservoirs

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.

Watana	$32 million (Approximately)
Devil Canyon	5 million (Approximately)
Total Project	$37 million

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

- Archaeological studies

- Fisheries and wildlife studies

- Right-of-way studies; and

- Socioeconomic planning studies.

The costs for the above work have been included 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:

- Account 71

  . Engineering and Project Management
  . Construction Management
  . Procurement

- Account 76

  . Owner's Costs

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

(a) Engineering and Project Management Costs

These costs include allowances for:

- Feasibility studies, including site surveys and investigations and logistics support;

- Preparation of the license application to the FERC;

- Technical and administrative input for other federal, state and local permit and license applications;

- Overall coordination and administration of engineering, con struction management, and procurement activities;

- Overall planning, coordination, and monitoring activities related to cost and schedule of the project;

- Coordination with and reporting to the Power Authority regarding all aspects of the project;
- Preliminary and detailed design;
- Technical input to procurement of construction services, support services, and equipment;
- Monitoring of construction to ensure conformance to design requirements;
- Preparation of start up and acceptance test procedures; and
- Preparation of project operating and maintenance manuals.

(b) Construction Management Costs

Construction management costs have been assumed to include:

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

(c) Procurement Costs

Procurement costs have been assumed to include:

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

(d) Owner's Costs

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

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

1.4 - Operation, Maintenance and Replacement Costs

The facilities and procedures for operation and maintenance of the project are described in the Susitna Feasibility Report (Acres 1982a, Vol. 1). Assumptions for the size and extent of these facilities have been made on the basis of experience at large hydroelectric developments in northern climates. The annual costs for operation and maintenance for the Watana development have been estimated at $10.4 million. When Devil Canyon is brought on line these costs increase to $15.2 million per annum. Interim replacement costs have been estimated at .3 percent per annum of the capital cost.

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

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

Allowances have also been made for environmental mitigation as well as a contingency for unforeseen costs.

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

1.5 - Allowance for Funds Used During Construction (AFDC)

At current levels of interest rates, AFDC will amount to a significant element of financing cost for the lengthy periods required for construction of the Watana and Devil Canyon projects. However, in economic evaluations of the Susitna project the low real rates of interest assumed would have a much reduced impact on assumed project development costs. Furthermore, direct state involvement in financing of the Susitna project will also have a significant impact on the amount, if any, of AFDC. Provisions for AFDC at appropriate rates of interest are made in the economic and financial analyses included in this Exhibit.

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 Phung 1978.

An S-shaped symmetric cash flow was adopted where:

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

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 computations are summarized in Table D.6. The Watana and Devil Canyon constructions periods were taken from Exhibit C as 8.5 years and 7.5 years, respectively.

The resultant total project cost was then calculated for each interest/escalation scenario used in OGP-6 economic and financial studies. Interest and escalation were calculated as a percent of annual capital expenditure for the financial analysis as shown in Table D.1.

1.6 - Escalation

All construction costs presented in this Exhibit are at January 1982 levels and consequently include no allowance for future cost escalation. Thus, these costs would not be 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 the previous paragraph.

1.7 - Cash Flow and Manpower Loading Requirements

The cash flow requirements for construction of Watana and Devil Canyon are an essential input to economic and financial planning studies. The bases for the cash flow are the construction cost estimates in January 1982 dollars and the construction schedules presented in Exhibit C, with no provision being made as such for escalation. The cash flow estimates were computed on an annual basis and do not include adjustments for advanced payments for mobilization or for holdbacks on construction contracts. The results are presented in Table D.7 and Figures D.1 through D.3. The manpower loading requirements were developed from cash flow projections. These curves were used as the basis for camp loading and associated socioeconomic impact studies.

1.8 - Contingency

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. These items have been accounted for in economic and financial planning studies.

1.9 - Previously Constructed Project Facilities

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

The current estimate for the completed intertie is $130.8 million. This cost is not included in the Susitna project cost estimates. A breakout of the cost estimate is shown in Table D.8.

1.10 - EBASCO Check Estimate

An independent check estimate was undertaken by EBASCO Services Incorporated (EBASCO 1982). The estimate was based on engineering drawings, technical information and quantities prepared by Acres American in the feasibility study. Major quantity items were checked. The EBASCO check estimated capital cost was approximately 7 percent above the Acres estimate.

A summary of EBASCO's check estimate has been included in Table D.9 of this exhibit.

2 - ESITMATED ANNUAL PROJECT COSTS

The cost of the project has been estimated by two methods. In the first, the cost of energy was determined by preparing a financial forecast for the project assuming 100 percent debt financing. Table 10 Sheet 1 to 4 shows the projected year-by-year energy trends of the project and a summary of revenue (RL516), operating costs (170), interest, and cash sources and uses. These costs are in nominal dollars assuming 7 percent inflation and 10 percent cost of capital. Costs are based on power sales at cost assuming 100 percent debt financing at 10 percent interest. This results in a nominal cost of power of 298 mills in 1994 (first full year of Watana) and 350 mills in 2003 (first full year of Watana and Devil Canyon) as shown on line 520 of the table . The real cost of power, adjusted for inflation of 7 percent per annum, would be 128 mills in 1994 and 82 mills in 2003 and would then fall progressively for the remaining life of the project. The annual cost of energy from the project for the period 1993 to 2021 in nominal dollars and real dollars is shown on Sheets 5 and 6, respectively, of Table 10.

The cost of power (capacity) from the project is shown on Table D-11. This cost is determined in accordance with FERC procedures and is the sum of the annual plant investment cost and the annual fixed operating cost. As can be seen from Table D.11, the total annual capacity cost in 1982 dollars is $225/kW.

No taxes have been assessed to the project's annual costs. Although these taxes would be expressed as a percentage of project plant in service in this type of annual cost estimate, the taxes would be based on revenues. As a corporation of the State, the Alaska Power Authority is a not-for-profit entity. As such the Authority would not be subject to a revenue tax.

3 - MARKET VALUE OF PROJECT POWER

This section presents an assessment of rates at which energy and capacity of the Susitna development could be priced, together with a proposed basis for contracting for the supply of Susitna energy. Both the marketing approach and financing plan are the subjects of ongoing review and development. The Susitna project is scheduled to begin generating power for the Railbelt in 1993. At that time the project will meet growing electrical demand, replace retiring units and displace capacity having more expensive running rates.

3.1 - The Railbelt Power System

The Railbelt region covers the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. A complete discussion of the Railbelt System is presented in Exhibit B.

Susitna capacity and energy will be partially delivered to the Region via the linkage of the Anchorage and Fairbanks systems by an intertie to be completed in the mid-1980s. The intertie will allow a capacity transfer of up to 70 MW in either direction. The interconnection is designed for initial operation at 138 kV with subsequent uprating to 345 kV allowing the line to be integrated into the Susitna transmission facilities.

3.2 - Regional Electric Power Demand and Supply

The Reference Case forecast of electric power demand is presented in Exhibit B. The results of studies presented in Exhibit B and Section 4 of the Exhibit call for Watana to come into operation in 1993 and to deliver a full year's energy generation in 1994. Devil Canyon will come into operation in 2002 and deliver a full year's energy in 2003. Energy demand in the Railbelt region and the deliveries from Susitna are shown in Figure D.4.

3.3 - Market and Price for Watana Output in 1994

It is anticipated that Watana energy will be supplied at a single wholesale rate to Railbelt utilities at a level to permit the maximum use of the Susitna Project, thus achieving its full economic benefit. This requires, in effect, that Susitna energy be priced so that it is attractive even to utilities with the lowest cost alternative source of energy. In evaluating the terms of power sales contracts, utilities can be expected to consider the advantages afforded by Susitna's long-term price stability, as well as the price offered in the initial years. That wholesale price at which consumers would be neither better nor worse off in 1994 under the with-Susitna plan or the best alternative plan has been selected for evaluation. The actual wholesale price charged for Susitna energy may vary from this price depending on the course of power sales contract negotiations and on the further development of the marketing approach.

This estimated 1994 price is based on calculations using the financial parameters in Table D.12, Reference Case fuel prices discussed in Section 4.5, and a prevailing 7 percent rate of inflation per annum. The most cost effective without-Susitna plan from which the estimated 1994 price is derived is specified in Secton 4.6. The associated plant capital and operating costs are shown in Table D.18.

In order to determine the cost of the alternative thermal capacity and energy which would replace Susitna generation, the cost of thermal generation under the with Susitna plan was subtracted from the cost of thermal generation under the without Susitna plan. This avoided thermal cost which would be replaced by Susitna generation is shown on Figure 5. The costs shown are expressed in mills per kilowatt-hour which is the total avoided thermal cost divided by the Susitna energy output in a given year. In 1994 this cost is estimated at 136 mills/kWh in nominal dollars.

The financing considerations under which it would be appropriate for Watana energy to be sold at approximately 136 mills per kWh price are considered in Section 6 of this Exhibit.

The Power Authority will seek to contract with Railbelt utilities for the purchase of Susitna capacity and energy on a basis appropriate to support financing of the project. Pricing policies for Susitna output will be constrained both by cost and by the price of energy from the best alternative option.

3.4 - Market and Price for Watana Output 1995-2001

After its first full year of operation in the system in 1994, 2957 GWh of the total 3105 GWh of Watana output is initially marketable. The excess energy occurs in the summer. The market for the project strengthens over the years to 2001 since energy demand will increase by 16 percent over this period as projected in the Reference Case forecast. Figure D.5 shows the avoided cost of energy for the period 1995 to 2001.

The addition of the Susitna project will add a large generating resource in the system in 1993, displacing a significant amount of the existing generating resources in the system. The project will provide about 70 percent of total energy demand. The displaced units will be used as reserve capacity and to meet growing load until the Devil Canyon project comes on line. This effect is illustrated on Figure D.4.

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

After the Devil Canyon project comes on line, the Susitna project will provide about 90 percent of the energy demand. The avoided thermal costs in 2003 is 230 mills per kWh (2003 dollars, 7 percent annual escalation) as shown on Figure D.5. The excess Susitna power occurs in the summer while additional energy from other resources is required in the winter. The generating resources displaced are units nearing retirement and will be used as reserve capacity.

3.6 - Potential Impact of State Appropriations

In the preceding paragraphs, the price facing Railbelt utilities in the absence of Susitna has been identified. Sale of Susitna energy at this price will depend upon the magnitude of any proposed state appropriation and upon the willingness of Railbelt utilities to pay an appropriate rate in light of the project's long-term benefits.

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

4 - EVALUATION OF ALTERNATIVE ENERGY PLANS

4.1 - General

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

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

During the pre-license phase of the Susitna project planning, two studies proceeded in parallel which addressed the alternatives in generating power in the Alaska Railbelt. These studies are the Susitna Hydroelectric Project Feasibility Study sponsored by the Alaska Power Authority and the Railbelt Electric Power Alternatives Study sponsored by the Office of the Governor, State of Alaska.

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

Although the studies were independent, several key factors were consistent. Both studies used the approach of comparing costs by using generation planning simulation models. Thus, selected alternatives were put into a plan context and their economic performance compared by comparing costs of the plans.

The following presentation focuses primarily on the Susitna Feasibility Study process and findings. A separate section provides findings of the Battelle study.

4.2 - Existing System Characteristics

(a) System Description

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

Table D.13 summarizes the total generating capacity within the Railbelt system in 1982, based on information provided by Railbelt utilities and other sources. Table D.14 presents the resulting detailed listing of units currently operating in the Railbelt, information on their performance characteristics, and their on-line and projected retirement dates for generation planning purposes. The total Railbelt installed capacity of 1122.8 MW consists of two hydroelectric plants totaling 46 MW plus 1076.8 MW of thermal generation units fired by oil, gas, or coal, as summarized in Table D.14.

(b) Retirement Schedule

In order to establish a retirement policy for the existing generating units, several sources were consulted, including the Power Authority's draft feasibility study guidelines, FERC guidelines (FERC 1979), the Battelle Railbelt Alternatives Study (Battelle 1982), and historical records. Utilities, particularly those in the Fairbanks area, were also consulted. Based on these sources, the following retirement periods of operation were adopted for use in this analysis:

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

Table D.14 lists the service dates for each of the current generating units which would be retired based on the above retirement policy.

(c) Schedule of Additions

Two new projects are assumed to be added to the Railbelt system prior to 1990, as shown in Table D.15. The Alaska Power Authority is conducting a feasibility study of the Bradley Lake Hydroelectric Project on the Kenai Peninsula. If the project is determined to be feasible the APA will take steps to build the project. For analysis purposes, the project is assumed to provide 90 MW of generating capacity and 347 GWh of annual energy, and to be in service by 1988.

Feasibility study of the Grant Lake Project has been completed by APA recently. This project is planned to serve the City of Seward, and to provide 7 MW of generating capacity and 33 GWh of annual energy. For the purpose of analysis, this project is assumed to be in service by 1988 also.

In addition, Fairbanks Municipal Utility Systems is considering the addition of a 25-30 MW cogeneration unit to replace Chena Units 1, 2 and 3; however, these plans are not definite.

4.3 - Fairbanks - Anchorage Intertie

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

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

- No costs were added for combined-cycle or gas-turbine units, since they were assumed to have sufficient siting flexibility to be placed near the major transmission works;

- A multiple coal-fired unit development in the Beluga fields was estimated to have a transmission system with security equal to that planned for Susitna, costing $220 million. This system would take power from the bus back to the existing load center; and

- A single coal-fired unit development in the Nenana area using coal mined in the Healy fields would require a transmission system costing $117 million dollars.

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

4.4 - Hydroelectric Alternatives

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

(a) Selection Process

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

Under Step 2 of the selection process, all feasible candidate sites were identified for inclusion in the subsequent screening exercise. A total of 91 potential sites were obtained from inventories of potential sites published in the COE National Hydropower Study and the Power Administration report "Hydroelectric Alternatives for the Alaska Railbelt."

The screening of sites under Step 3 required a total of four successive iterations to reduce the number of alternatives to a manageable short list. The overall objective of this process was defined as the selection of approximately ten sites for consideration in plan formulation, essentially on the basis of published data on the sites and appropriately defined criteria. Figure D.7 shows 49 of the sites which remained after the two initial screenings.

In Step 4 of the plan selection process, the ten sites short listed under Step 3 were further refined as a basis for formulation of Railbelt generation plans. Engineering sketch-type layouts were produced for each of the sites, and quantities and capital costs were evaluated. These costs, listed in Table D.16, incorporate a 20 percent allowance for contingencies and 10 percent for engineering and owner's administration. A total of five plans were formulated incorporating various combinations of these sites as input into the Step 5 evaluations.

Power and energy values for each of the developments were reevaluated in Step 5 utilizing monthly streamflow and a computer reservoir simulation model. The results of these calculations are summarized in Table D.16.

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

(b) Selected Sites

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

The results of these analyses, completed in early 1981, are summarized in Table D.17 and illustrate that a minimum total system cost can be achieved by the introduction of the Chakachamna, Keetna, and Snow projects. Note that further studies of the Chakachamna project were initiated in mid-1981 by Bechtel for the Alaska Power Authority.

(c) Lake Chakachamna

Bechtel Civil and Minerals studied the feasibility of developing the power potential of Lake Chakachamna (Bechtel Civil and Minerals 1981). The lake is on the west side of Cook Inlet 85 miles west of Anchorage. Its water surface lies at about Elevation 1140.

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

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

(i) Project Layout

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

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

The second alignment running more or less parallel to the Chakachatna River in the right (southerly) wall of the valley afforded two opportunities for intermediate access adits. These, plus the upstream and downstream portals would allow construction to proceed simultaneously in six headings and reduce the construction time by 18 months from that required for the McArthur tunnel.

If all the controlled water were used for power generation, the McArthur powerhouse could support 400 MW installed capacity and produce average annual firm energy of 1753 GWh. Making a provisional reservation of approximately 19 percent of the average annual inflow to the lake for instream flow requirements in the Chakachatna River reduced the economic tunnel diameter to 23 feet. The installed capacity in the powerhouse would then be reduced to 330 MW and the average annual firm energy to 1446 MW.

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

(ii) Technical Evaluation and Discussion

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

- Chakachatna Dam Alternative

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

- McArthur Tunnel Alternatives A and B

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

The geologic conditions for the various project facilities including intake, power tunnel, and powerhouse appear to be favorable based on a 1981 field reconnaissance. No insurmountable engineering problems appear to exist in development of the project.

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

- <u>Chakachatna Tunnel Alternatives C and D</u>

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

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

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

4.5 - Thermal Options - Development Selection

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

(a) Assessment of Thermal Alternatives

The overall objective established for this selection process was the selection of an optimum all-thermal Railbelt generation plan for comparison with other plans (Figure D.8).

Primary consideration was given to gas-, coal-, and oil-fired generation sources which are the most readily developable alternatives in the Railbelt from the standpoint of technical and economic feasibility. The broader perspectives of other alternative resources such as peat, refuse, geothermal, wind and solar and the relevant environmental, social, and other issues involved were addressed in the Battelle alternatives study (Battelle 1982).

As such, a screening process was therefore considered unnecessary in this study, and emphasis was placed on selection of unit sizes appropriate for inclusion in the generation planning exercise.

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

- Coal-fired steam
- Gas-fired combined-cycle
- Gas-fired gas turbine
- Diesel.

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

(b) Coal-Fired Steam

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

Aside from the military power plant at Fort Wainwright and the self-supplied generation at the University of Alaska, there are currently two coal-fired steam plants in operation in the Railbelt. These plants are small compared with most new plants installed to meet base load in the lower 48 states and new plants being considered for the railbelt thermal generation alternatives.

(i) Capital Costs

A detailed cost study was done by EBASCO Services Incorporated as part of Battelle's alternatives study (Battelle 1982, Vol. XII). The report found that it was feasible to establish a plant at either the undeveloped Beluga field or near Nenana, using Healy field coal. The study produced costs and operating characteristics for both plants. All new coal units were estimated to have an average heat rate of 10,000 Btu/kWh and involve an average construction period of five to six years. Capital costs and operating parameters are defined for coal and other thermal generating plants in Table D.18. Cost estimates by major account are presented in Tables D.19 and D.20.

It was found that, rather than develop solely at one field in the non-Susitna case, development would be likely to take place in both fields. Thus, two units would be developed near Nenana to service the Fairbanks load center, with the remaining units placed in the Beluga fields.

To satisfy the national New Performance Standards, the capital costs incorporate provision for installation of flue gas desulfurization for sulphur control, highly efficient combustion technology for control of nitrogen acids, and baghouses for particulate removal.

(ii) Fuel Costs

Coal in the Railbelt in quantities sufficient for electric power generation is available from the Nenana Field near Healy and the Beluga Field near Anchorage. The analysis presented in Appendix D-1 developed the base cost of coal from these sources, transportation costs, if required, and real price escalation rates.

For the purposes of the economic analysis, it was assumed that up to two 200-MW coal-fired steam units would be located at Nenana, rather than at mine-mouth, due to the mine's proximity to Denali National Park. A mine-mouth price of $1.40/MMBtu in 1983 dollars was estimated for Nenana coal-based on current contracts with Golden Valley Electric Association and Fairbanks Municipal Utility Systems adjusted for changes in production levels and new land reclaimation regulations. Transportation costs to Nenana are estimated to be $0.32/MMBtu in 1983 dollars. Therefore, the total cost of the coal delivered in Nenana would be $1.72/MMBtu. The coal has an average heat content of about 7800 Btu/lb.

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually long term contracts which include a base price for the coal and a method of escalation to provide prices in future years. 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 indexes such as the producer price index, various commodity and labor indexes, the consumer price index applied to operating and maintenance expenses, and or regulation related indices. The original capital investment is not escalated, so the base price of coal to the utility tends to increase with general inflation.

Several escalation rates have been estimated for utility coal in Alaska and in the lower 48 states, and they range from 2.0-2.7%/year (real). Several more generic rates have also been developed by Sherman H. Clark and Associates and by Data Resources Inc. (DRI). Because the forecasts of DRI and Sherman H. Clark are based upon supply-demand factors, they were applied to the base contract price of coal. The 2.6% real rate of increase used by DRI and Sherman H. Clark is applied to the mine-mouth price of Nenana Field coal as this mine is used principally to supply domestic markets. It should be noted, however, that this is the price before transport. Transportation costs over time are assumed to increase at 0.9%/yr. The overall real composite rate of escalation including transportation for coal consumed in a generating plant located at Nenana is 2.3%/yr.

Other than the two 200-MW units installed at Nenana, all other coal-fired units will be mine-mouth units installed at Beluga. The base price of coal has been determined under the assumption of an export market and was calculated as the net back cost in Alaska based on the value of coal in Japan as described in Appendix D-1. This cost is $1.86/MMBtu at 1983 price levels for coal with a heat content of about 7500 Btu/lb.

An escalation rate of 1.6%/yr. of the price of Beluga coal is based on escalation rates developed by DRI and Sherman H. Clark for coal exported to Pacific Rim countries.

Both Nenana and Beluga coal prices have been assumed to escalate to the date a given generating unit enters operation. At that time, the coal price for that unit is assumed to remain constant in real terms until the unit is replaced. Using this approach the average coal price escalation rate for the Reference Case all thermal generation alternative is about 1%/yr.

The coal escalation rates discussed above were used for the reference case and the DRI sensitivity case. Zero real price escalation of coal was assumed for the DOR-mean and -2 percent sensitivity cases.

(iii) Other Performance Characteristics

Annual operation and maintenance and representative forced outage rates are shown in Table D.18.

(c) Combined Cycle

Combined cycle plants achieve higher efficiencies than conventional gas turbines. There are two combined cycle plants in Alaska at present. One is the 139-MW G. M. Sullivan plant of Anchorage-Municipal Light and Power (AMLP). The other is the Beluga No. 8 unit owned by Chugach Electric Association (CEA). It is a 42-MW steam turbine, which was added to the system in late 1982, and utilizes heat from currently operating gas turbine units, Beluga Nos. 6 and 7.

(i) Capital Costs

A new combined cycle plant unit size of 200-MW capacity was considered to be representative of future additions to generating capability in the Anchorage area. This is based on economic sizing for plants in the lower 48 states and projected load increases in the Railbelt. A heat rate of 8000/Btu/kWh was adopted based on the alternative study completed by Battelle.

The capital cost was estimated using the Battelle study basis (Battele 1982, Vol. XXXI) and is listed in Table D.18. A bid line item cost is shown on Table 21.

(ii) Fuel Costs

The availability, use, and price of natural gas are presented in Appendix D-1. Known recoverable reserves of natural gas in Alaska are located in the Cook Inlet area near Anchorage and on Alaska's North Slope at Prudhoe Bay. Gas is presently being produced from the Cook Inlet area. Some of the gas is committed under firm contract but considerable quantities of gas remain uncommitted and could be used for power generation. There are substantial recoverable reserves on the North Slope that could be used for power generation, but until a pipeline or electrical transmission line is constructed, the gas cannot be utilized. Undiscovered gas resources are believed to exist in the Cook Inlet area and also in the Gulf of Alaska where no gas has been found to date.

Natural gas is produced and used in Alaska for heating, electrical generation, liquified natural gas (LNG) export, manufacture of ammonia/urea, reinjection in the recovery of oil, and for field operations. Most of the production and use (other than reinjection) currently takes place in the Cook Inlet area. Cook Inlet gas that has been injected (or actually reinjected) is not consumed and is still available for heating, electrical generation, or other uses. Gas used in field operations is the gas consumed at the wells and gathering areas to assist in the lifting and production of oil and gas.

LNG sales are for export to Japan and the manufactured ammonia/urea is exported to the lower forty-eight states. Both uses of gas have been fairly constant in the past and are expected to remain so in future years. Natural gas is used for electrical generation by Chugach Electric Association and Anchorage Municipal Light and Power. The use of gas by both of these utilities has been increasing to meet increases in electrical load and to replace oil-fired generation. The military bases in the Anchorage area, Elmendorf AFB and Fort Richardson, use gas to generate electricity and to provide steam for heating. The military gas use has been fairly constant in the past and is expected to remain so in the future. The gas utility sales are made principally by Enstar and are for space and water heating and other uses by residential, commerical, and industrial customers.

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and estimated undiscovered reserves in the Cook Inlet area, reserves will be exhausted at some time in the future. To estimate the quantity of Cook Inlet gas available for electrical generation, the requirements and prioritites of the major users are discussed in Appendix D-1. Natural gas consumption for electric generation represents only a small portion of the total Cook Inlet gas consumption. It is projected that, by the year 2005, only about 8 percent of the total cumulative consumption of natural gas would have been for electric generation based on the all thermal generation alternative for the Reference Case.

If other gas consumption by retail sales, and ammonia and gas conversion, continues at the projected rates, the proven reserves plus the mean of the undiscovered reserves estimates will be exhausted by 2010. The proven reserves by themselves will be exhausted by 2000. This is true for any of the world oil price forecast scenarios studied.

There is no single market price of gas in Alaska since a well developed market does not exist. In addition, the price of gas is affected by regulation via the Natural Gas Policy Act of 1978 (NGPA) which specifies maximum wellhead prices that producers can charge for various categories of gas (some categories will be deregulated in 1985). There are now some existing contracts for the sale/purchase of Cook Inlet gas which specify wellhead prices, but since there are no existing contracts for the sale of North Slope gas, the North Slope wellhead price can only be estimated based on an estimated final sales price and the estimated costs to deliver the gas to market.

The wellhead price agreed on in the Enstar contracts is \$2.32/Mcf with an additional charge of \$0.35/Mcf beginning in 1986. Estimated severance taxes of \$0.15/Mcf and a fixed pipeline charge of about \$0.30/Mcf for pipeline delivery from Beluga to Anchorage are additional costs. The pipeline charge of \$0.30/Mcf will, of course, not be incurred if the gas is used at Beluga to generate electricity. Future prices (Jan. 1, 1984 and on) are to be determined by escalating the wellhead price plus the demand charge based on the price of #2 fuel oil in the year of escalation versus the price on Janaury 1, 1983. If it were assumed that the generating units were located at the source of gas, the Jan. 1, 1983 price would be \$2.47/Mcf, as discussed in Appendix D-1.

Real escalation of the gas price is assumed to be dependent on the escalation of world oil prices because the current Enstar contract specifically provides for escalation of gas prices based on the price of No. 2 fuel oil on the Kenai peninsula which is closely related to world oil prices. Real escalation rates for the reference case are as follows:

Period	Real Escalation Rate
	%
1984	-4.6
1985	-4.7
1986-1988	0
1989-2010	3.0
2011-2020	2.5
2021-2030	1.5
2031-2051	1.0

Real escalation rates for the sensitivity oil price forecasts are presented in Appendix D-1.

(iii) Other Performance Characteristics

Annual operation and maintenance costs, along with a representative forced outage rates, are given in Table D.18.

(d) Gas-Turbine

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at present. There are 720 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 210 MW of oil-fired gas turbines supplying the Fairbanks area (see Table D.14). Their low initial cost, simplicity of construction and operation, and relatively short implementation lead time have made them attractive as a Railbelt generating alternative. The low-cost of gas in the Anchorage area has made this type of generating facility cost-effective for the Anchorage load center.

(i) Capital Costs

A unit size of 75 MW was considered to be representative of modern gas turbine plant addition in the Railbelt region.

Gas turbine plants can be built over a two year construction period and new plants have an average heat rate of approximately 12,200 Btu/kWh. The capital costs were again taken from the Battelle alternatives study.

(ii) Fuel Costs

Gas turbine units can be operated on oil as well as natural gas. The market No. 2 oil is \$6.23/MMBtu (1983) as discussed in Appendix D-1. The real annual growth rates in oil costs are also discussed in Appendix D-1.

(iii) Other Performance Characteristics

Annual operation and maintenance costs and forced outage rates are shown in Table D.18.

(e) Diesel Power Generation

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

(i) Capital Costs

The high cost of diesel fuel and low capital cost make new diesel plants most effective for emergency use or in remote areas where small loads exist. A unit size of 10 MW was selected as appropriate for this type of facility, large by diesel engine standards. Units of up to 20 MW are under construction in other areas. Potentially, capital cost savings of 10-20 percent could be realized by going to the larger units. However, these larger units operate at very low speeds and may not have the reliability required if used as a major alternative for Railbelt electrical power. The capital cost was derived from the same source as given in Table D.18 (Battelle 1982, Vol. IV).

(ii) Fuel Costs

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

(iii) Other Performance Characteristics

Annual operation and maintenance costs and the forced outage rate are given in Table D.18.

(f) Plan Formation and Evaluation

The four unit types and sizes discussed above were used to formulate plans for meeting future Railbelt power generation requirements. The purpose of this study was to formulate appropriate plans for meeting the projected Railbelt demand on the basis of economic preferences.

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

The primary tool used for electric system analysis is the mathematical model developed by the General Electric Company. The model is commonly known as OGP 6 or Optimized Generation Planning Model, Version 6. The general concept of the OGP program and its relationship with other computer models used in the power market forecast is described in Exhibit B, Section 5.3. That section deals specifically with the use of variables and assumptions in all the models to assure that they are consistent throughout the planning process. As explained in Section 4.6, the OGP 6 model was used for the period 1993-2020. The load forecasts produced by the RED model were extended from 2010 to 2020 using the average annual growth for the period 2000 to 2010. The following information is paraphrased from GE literature on the program. (General Electric, 1983)

The OGP6 program was developed over ten years to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis. OGP6 will automatically develop optimum generation expansion patterns in terms of economics, reliability and operation.

The OGP6 program requires an extensive system of specific data to perform its planning function. In developing an optimal plan, the program considers the existing and committed units (planned and under construction) available to the system and the characteristics of these units including age, heat rate, size and outage rates as the base generation plan. The program then considers the given load forecast and operation criteria to determine the need for additional system capacity based on given reliability criteria. This determines "how much" capacity to add and "when" it should be installed. If a need exists during any monthly iteration, the program will consider additions from a list of alternatives and select the available unit best fitting the system needs. Unit selection is made by computing production costs for the system for each alternative included and comparing the results.

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

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

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

4.6 Without Susitna Plan

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

Using the generation planning model, a base case "without Susitna" plan was structured based on the Reference Case power market forecast. The input to the model included:

- The reference case load forecast (Exhibit B Section 5.4.3);

- Fuel cost as specified above;

- Coal-fired steam and gas-fired combined-cycle and combustion turbine units as future additions to the system;

- Costs and characteristics of future additions as specified above;

- The existing system as specified and scheduled commitments listed in Tables D.14 and D.15.

- Fuel escalation as specified above;

- Economic parameters of 3 percent interest and 0 percent general inflation;

- Generation system reliability set to a loss of load probability of one day in ten years. This is a probabilistic measure of the inability of the generating system to meet projected load. One day in ten years is a value generally accepted in the industry for planning generation systems.

It was found that the critical period for capacity addition to the system would be in the winter of 1992-1993. Until that time, the existing system, given the additions of the planned intertie and the planned units, appears to be sufficient to meet Railbelt demands. Given this information, the period of plan development using the model was set as 1993-2020.

In early years (1993-1996), the economically preferred units are those which generate base load power. After 400MW of this type of power in the form of coal units are added, the preference switches to gas turbine units which are used to meet seasonal (winter) peak months and daily peaking needs. During the later years, the generating system needs capacity to meet target reliability rather than to generate power continually and adds a mix of coal-fired steam, combined cycle, and gas turbine units.

The following was established as the non-Susitna Railbelt base plan (see Figure D.9):

(a) System as of January 1993

Coal-fired steam:	59 MW
Natural gas GT:	452 MW
Oil GT:	137 MW
Diesel:	21 MW
Natural gas CC:	317 MW
Hydropower:	143 MW
Total (including committed conditions):	1129 MW

(b) System Additions

Year	Gas-Fired Gas Turbine (MW)	Gas-Fired Combined Cycle (MW)	Coal Fired Unit (MW)
1993			1 x 200 (Beluga)
1994	1 x 70		
1995	1 x 70		
1996			1 x 200 (Beluga)
1997	1 x 70		
1998	1 x 70		
1999			
2000			
2001			
2002	1 x 70		
2003	1 x 70		
2004			
2005			1 x 200 (Nenana)
2006	1 x 70		
2007			
2008	1 x 70		
2009			
2010			1 x 200 (Nenana)
2011	1 x 70		
2012			1 x 200 (Beluga)
2013		1 x 200	
2014			
2015			
2016			
2017			
2018			
2019	1 x 70		
Total	840	200	1000

(c) System as of 2020

Coal-fired steam:	1000 MW
Natural gas GT:	840 MW
Oil GT:	0 MW
Diesel:	0 MW
Natural gas CC:	200 MW
Hydropower:	143 MW
Total (accounting for retirements and additions)	2183 MW

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

The thermal plan described above has been selected as representative of the generation scenario that would be pursued in the absence of Susitna.

4.7 - Economic Evaluation

This section provides a discussion of the key economic parameters used in the study and develops the net economic benefits stemming from the Susitna Hydroelectric Project. Section 4.7 (a) deals with those economic principles relevant to the analysis of net economic benefits and develops inflation and discount rates.

Section 4.7 (b) presents the net economic benefits of the proposed hydroelectric power investments compared with this thermal alternative. These are measured in terms of present-value differences between benefits and costs. Recognizing that even the most careful estimates will be surrounded by a degree of uncertainty, particularly in regard to world oil prices, the benefit-cost assessments were subjected to sensitivity analyses as described in Section 4.8 (oil prices) and Section 4.9 (other variables).

(a) Economic Principles and Parameters

(i) Economic Principles - Concept of Net Economic Benefits

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

The energy costs of power generation are initially measured in terms of opportunity values or shadow prices which may differ from accounting or market prices currently prevailing in the state. The concept and use of opportunity values is fundamental to the optimal allocation of finite public resources. Energy investment decisions should not be made solely on the basis of accounting prices in the state if the international value of traded energy commodities such as coal and gas diverge from local market prices. The opportunity value represents the value of the resource if disposed of in the most economically attractive alternative manner. In the case of oil, gas, and coal, it would represent the sale of the Alaskan commodities on the world market, compared to their consumption in state. The world price must be adjusted through a net-back exercise which accounts for the costs of getting the resource to world markets.

The choice of a time horizon is also crucial. If a short-term planning period is selected, the investment rankings and choices will differ markedly from those obtained through a long-term perspective. In other words, the benefit-cost analysis would point to different generation expansion plans depending on the selected planning period. A short-run optimization of state income would, at best, allow only a moderate growth in fixed capital investment; at worst, it would lead to underinvestment in not only the energy sector but also in other infrastructure facilities such as roads, airports, hospitals, schools, and communications.

It therefore follows that the Susitna project, like other Alaskan investments, should be appraised on the basis of long-run optimization, where the long run is defined as the expected economic life of the facility. For hydroelectric projects, this service life is typically 50 years or more. The costs of a Susitna-inclusive generation plan have therefore been compared with the costs of the next-best alternative which is the all-thermal generation plan and assessed over a planning period extending from 1982 to 2051, using internally consistent sets of economic scenarios and appropriate opportunity values of Alaskan energy.

Throughout the analysis, all costs and prices are expressed in real (inflation-adjusted) terms using January 1982 dollars except for fuel which is expressed in January 1983 dollars. Hence, the results of the economic calculations are not sensitive to modified assumptions concerning the rates of general price inflation. In contrast, the financial and market analyses conducted in nominal (inflation-inclusive) terms will be influenced by the rate of general price inflation from 1982 to 2021.

(ii) Price Inflation and Discount Rates

- General Price Inflation

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

Forecasts of Alaskan prices extend only to 1986 (Alaska Department of Commerce and Economic Development 1980). These indicate an average rate of increase of 8.7 percent from 1980 to 1986. For the longer period between 1986 and 2051, it is assumed that Alaskan prices will escalate at the overall U.S. rate, or at 5 to 7 percent compounded annually. The average annual rate of price inflation is therefore about 7 percent between 1982 and 2051. Since this is consistent with long-term forecasts of the CPI advanced by leading economic consulting organizations, (Data Resources 1980; Wharton Econometric Forecasting Associates 1981) 7 percent has been adopted as the study value. This analysis could have been done with the GNP deflator in lieu of the CPI. Results would be essentially the same.

- Discount Rates

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

. Real Discount and Interest Rates

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

.. the social opportunity cost (SOC) rate;

.. the social time preference (STP) rate; and

.. the government's real borrowing rate or the real cost of debt capital (Baumol 1968; Mishan 1975; Prest and Turvey 1965).

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

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

A subset of STP rates used in project evaluations is the owner's real cost of borrowing; that is, the real cost of debt capital. This industrial or government borrowing rate may be readily measured and provides a starting point for determining project-specific discount rates. For example, long-term industrial bond rates have averaged about 2 to 3 percent in the U.S. in real (inflation-adjusted) terms (Data Resources 1980; U. S. Department of Commerce). Forecasts of real interest rates show average values of about 3 percent and 2 percent in the periods of 1985 to 1990 and 1990 to 2000, respectively. The U.S. Nuclear Regulatory Commission has also analyzed the choice of discount rates for investment appraisal in the electric utility industry and has recommended a 3 percent real rate (Roberts 1980). Therefore, a real rate of 3 percent has been adopted as the base case discount and interest rate for the period 1982 to 2051.

. Nominal Discount and Interest Rates

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

. Capital Cost Escalation

Based on present trends in construction costs, no real capital cost escalation has been assumed for either the hydro or the thermal units.

(b) Analysis of Net Economic Benefits

(i) Modeling Approach

Using the economic parameters discussed in the previous section and data relating to the electrical energy generation alternatives available for the Railbelt, an analysis was made comparing the costs of electrical energy production with and without the Susitna project.

The method of comparing the "with" and "without" Susitna alternative generation scenarios is based on the long-term present worth (PW) of total system costs. The planning model determines the total production costs of alternative plans on a year-by-year basis. These total costs for the period of modeling include all costs of fuel and operation and maintenance (O&M) for all generating units included as part of the system, and the annualized investment costs of any generating and system transmission plants added during the period of 1993 to 2020. Fuel price real cost escalation was included in the analysis at the rates specified above for the Reference Case.

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* (1 + the nominal rate) = (1 + the real rate) x (1 + the inflation rate) = 1.03 x 1.07, or 1.102

Factors which contribute to the ultimate consumer cost of power but which are not included as input to this model are investment costs for all generation plants in service prior to 1993 investment, cost of the transmission and distribution facilities already in service, and administrative costs of utilities. These costs are common to all scenarios and therefore have been omitted from the study.

In order to aggregate and compare costs on a significantly long-term basis, annual costs have been aggregated for the period 1993 to 2051. Costs have been computed as the sum of two components and converted to a 1982 PW. The first component is the 1982 PW of cost output from the first 28 years of model simulation from 1993 to 2020. The second component is the estimated PW of long-term system costs from 2021 to 2051.

For an assumed set of economic parameters on a particular generation alternative, the first element of the PW value represents the amount of cash (not including those costs noted above) needed in 1982 to meet electrical production needs in the Railbelt for the period 1993 to 2020. The second element of the aggregated PW value is the long-term (2021 to 2051) PW estimate of production costs. In considering the value to the system of the addition of a hydroelectric power plant which has a useful life of approximately 50 years, the shorter study period would be inadequate. A hydroelectric plant added in 1993 or 2002 would accrue benefits for only 28 or 19 years, respectively, using an investment horizon that extends to 2020. However, to model the system for an additional 31 years, it would be necessary to develop future load forecasts and generation alternatives which are beyond the extent of normal projections. For this reason, it has been assumed that the production costs for the final study year (2020) would simply recur for an additional 31 years, however they would be adjusted to take into account real fuel price escalation, and the PW of these was added to the 28-year PW (1993 to 2020) to establish the long-term cost differences between alternative methods of power generation.

(ii) Reference Case Analysis

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

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

The with Susitna case calls for Watana to come on line in 1993 to meet system capacity requirements. Although the initial installation at Watana will be 1020 MW only about 520 MW will be dependable during the period Watana operates on base before Devil Canyon comes on line in 2002, as discussed in Exhibit B, Sections 3.7 and 4.3.

The second stage of Susitna, the Devil Canyon project, is scheduled to come on line in 2002 with an installed capacity of 600 MW. The combined operation of Watana on peak and Devil Canyon on base will have a dependable capacity of 1270 MW in 2020 under flow regime C as discussed in Exhibit B, Section 4.

In addition to the Susitna projects, the with-Susitna plan calls for the addition of a 70-MW gas turbine unit in each of the following years, 2001, 2012, 2014, 2015, 2016, 2017, and2019. Also a 200-MW gas-fired combined cycle unit would be installed in 2020. The without Susitna plan is discussed in Section 4.5.

- Reference Case Net Economic Benefits

The economic comparison of these plans is shown in Table D.22. During the 1993 to 2020 study period, the 1982 PW cost for the Susitna plan is \$3.4 billion. The annual production cost in 2020 is \$0.3 billion. The PW of this level cost, which remains virtually constant except for fuel cost escalation for a period extending to the end of the life of the Devil Canyon plant (2051), is \$2.1 billion. The resulting total present worth of the with-Susitna plan is \$5.5 billion in 1982 dollars.

The non-Susitna plan (Section 4.5) which was modeled has a 1982 PW cost of \$3.9 billion for the 1993 to 2020 period with a 2020 annual cost of \$0.5 billion. The total long-term cost has a PW of \$7.3 billion. Therefore, the net economic benefit of adopting the Susitna plan is \$1.8 billion. In other words, the present value cost difference between the Susitna plan and the expansion plan based on thermal plant addition is $1.8 billion in 1982 dollars.

It is noted that the magnitude of net economic benefits ($1.8 billion) is not particularly sensitive to alternative assumptions concerning the overall rate of price inflation as measured by the Consumer Price Index. The analysis has been carried out in real (inflation-adjusted) terms. Therefore, the present valued cost savings will remain close to $1.8 billion regardless of CPI movements, as long as the real (inflation-adjusted) discount and interest rates are maintained at 3 percent.

The Susitna project's internal rate of return (IRR), i.e., the real (inflation-adjusted) discount rate at which the with-Susitna plan has zero net economic benefits, or the discount rate at which the costs of the with-Susitna and the alternative plans have equal costs, has also been determined. The IRR is about 5.0 percent in real terms, and 10.6 percent in nominal (inflation-inclusive) terms. Therefore, the investment in Susitna would significantly exceed the 5 percent nominal rate of return "test" proposed by the State of Alaska in cases where state appropriations may be involved.*

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*See Alaska legislation A5 44.83.670

The generation planning analysis has implicitly assumed that all environmental costs for both the Susitna and the non-Susitna plans have been costed however there are factors relating to the non-Susitna plans which may increase the net economic benefits to the project. To the extent that the thermal generation expansion plan may carry greater environmental costs than the Susitna plan, the economic cost savings from the Susitna project may be understated. Due to the greater level of study of the Susitna project, costs for mitigation plans were included. This may not be the case with the coal alternative which may underestimate environmental costs. These differences or added costs cannot be quantified at this stage of study on the coal alternative.

The generation planning analysis also did not assume any restrictions on the supply of natural gas. As stated in Section 4.5(c) Cook Inlet proven reserves will be exhausted by the year 2000, and proven reserves plus the mean of the undiscovered reserves estimates will be exhausted by 2010. Under the Reference Case without Susitna expansion plan, gas consumption in 2020 would be about 8000 Mcf and total gas consumption for the period from 2020 to 2051 after proven plus undiscovered reserves are exhausted would be 210,000 Mcf or about 3.8 percent of the 1982 estimte of proven plus undiscovered reserves. Since this value is relatively small, errors in the estimate of the reserves and in the consumption rates for other gas uses could easily affect the date by which gas would be exhausted for electrical generation. Also over the planning horizon to 2051 North Slope gas will probably become available to the Railbelt market, albeit at a higher price than Cook Inlet gas.

Since the generation planning analysis did not assume any supply restrictions of natural gas nor any price increase for substitute gas becoming available, the analysis could underestimate the benefits available to the Susitna project.

4.8 - Sensitivity to World Oil Price Forecasts

Assumptions regarding future world oil prices impact the forecasts of electric power demand for the railbelt area. This relationship is discussed in detail in Exhibit B, Section 5.4. Table D.23 contains a summary of the load forecasts considered. A sensitivity analysis was performed to identify the effect of world oil price forecasts lower and higher than the reference case. Sensitivity analyses were performed for the DRI, DOR-mean and -2 percent load forecasts. The fuel price escalation rates which correspond to these forecasts are discussed in Appendix D-1. Table D.24 depicts the results of the sensitivity analysis.

As can been seen from Table D.24, the DOR mean case, with negative net benefits or a net cost of $85 million is approximately a break-even case in which the costs of the with Susitna plan are about equal to the costs of the without Susitna plan. Under the -2 percent case, the without Susitna plan is clearly more attractive, having a present worth about $1.9 billion less than the with Susitna plan. The DRI plan generates net benefits of $1.82 billion or about the same those of the Reference Case.

In performing the above analysis, it was assumed that the initial operating dates of Watana and Devil Canyon would be the same as under the reference case, or 1993 and 2002 respectively. A study of the expansion programs for the sensitivity case showed that new capacity, that could be provided by Watana, would be required in 1993 in all cases and that Devil Canyon could be delayed by up to 5 years under the -2 percent case. However, sensitivity analyses showed that delaying Devil Canyon would not significantly affect the results of the economic analysis.

4.9 - Other Sensitivity Assessments

Rather than relying on a single point comparison to assess the net benefit of the Susitna project, a sensitivity analysis was carried out to identify the impact of a change in assumptions on the results. The analysis was directed at the following variables other than those related to the world price of oil.

Variable, Reference Table	Reference Case Value	Sensitivity Values
Discount Rate (%), Table D.25	3.0	2, 5
Watana Cap. Costs ($\$x10^6$), Table D.26	3597	2917, 4316
Base fuel price ($/MMBtu), Table D.27		
Coal - Nenana	1.72	1.38, 2.06
- Beluga	1.86	1.49, 2.23
Natural Gas	2.47	1.98, 2.96
Real Fuel Escalation	Escalation to 2051	Escalation to 2020 only

Tables D.25 to D.27 depict the results of the sensitivity analysis for the variables except for real fuel escalation. Net benefits for the Reference Case would be reduced to about $1.0 billion from $1.8 billion if no real fuel price escalation is applied. Table D.28 summarizes the net economic benefits of the Susitna project associated with each sensitivity test. The net benefits have been compared using indexes relative to the Reference Case value ($1.827 billion) which is set to 100.

As can be seen from Table D.28 the economic analysis is most sensitive to the forecast of world oil prices and the corresponding power market forecast and related fuel price escalation rates. As stated in Section 4.8 under certain forecasts the with Susitna plan is marginal or unattractive when compared to the without Susitna plan.

The analysis is about equally sensitive to the other three variables mentioned above, discount rate, Watana capital cost, and fuel price as can be seen on Table D.28. Over the range of values given these variables, the with Susitna plan maintains positive net benefits over the without Susitna plan.

In addition to the above sensitivity analyses, the sensitivity of the analysis to a delay in the construction of the Devil Canyon project and to a change in the loss of load probability was evaluated. Changes in these assumptions had no significant affect on the results of the economic analysis.

4.10 - Battelle Railbelt Alternatives Study

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

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

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

Note that while each of the tasks contributed data and information to the final results of the project, they also developed important results that are of interest independently of the final results of this project. Output from the first three tasks contributed directly as input to analysis of the Susitna project presented in this Exhibit and in

Exhibit B. The results of the fourth task is presented in this subsection.

The first task evaluated the price and availability of fuels that either directly could be used as fuels for electrical generation or indirectly could compete with electricity in end-use applications suc as space or water heating.

The second task, electrical demand forecasts, was required for two reasons. The amount of electricity demanded determines both the size of generating units that can be included in the system and the number of generating units or the total generating capacity required. The forecast used from this study in the Susitna feasibility study is presented in Exhibit B.

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

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

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

This summary focuses on the third task: alternatives evaluation.

(a) <u>Alternatives Evaluation</u>

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

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

A wide variety of energy resources capable of being applied to the generation of electricity is found in the Railbelt. Resources currently used include coal, natural gas, petroleum-derived liquids and hydropower. Energy resources currently not being used but which could be developed for producing electric power within the planning period of this study include peat, wind power, solar energy, municipal refuse-derived fuels, and wood waste. Light water reactor fuel is manufactured in the lower 48 states and could be readily supplied to the Railbelt, if desired. Candidate electric generating technologies using these resources and most likely to be available for commercial order prior to the year 2000 are listed in Table D.29. The 37 generation technologies and combinations of fuel conversion-generation technologies shown in the table comprised the candidate set of technologies selected for additional study. Further discussion of the selection process and technologies rejected from consideration at this stage are provided in the Battelle Electric Power Alternatives Study (Battelle 1982, Vol. IV).

Selection of generation alternatives was based on the followinng considerations:

- the availability and cost of energy resources;

- the likely effects of minimum plant size and operational characteristics on system operation;

- the economic performance of the various technologies as reflected in estimated busbar power costs;

- public acceptance, both as reflected in the framework of electric energy plans within which the selection was conducted and as impacting specific technologies; and

- ongoing Railbelt electric power planning activities.

From this analysis, described more fully in the Battelle Electric Power Alternatives Study (Battelle 1982, Vol. IV), 13 generating technologies were selected for possible inclusion in the Railbelt electric power plans. For each nonhydro technology, a prototypical plant was defined to facilitate further development of the needed information. For the hydro technologies, promising sites were selected for further study. These prototypical plants and sites constitute the generating alternatives selected for consideration in the Railbelt electric energy plans. In the following paragraphs, each of the 13 preferred technologies is briefly described, along with some of the principal reasons for its selection. Also described are the prototypical plants and hydro sites selected for further study.

(i) <u>Coal-Fired Steam-Electric Plants</u>

Coal-fired steam-electric generation was selected for consideration in Railbelt electric energy plans because it is a commercially mature and economical technology that potentially is capable of supplying all of the Railbelt's base-load electric power needs for the indefinite future. An abundance of coal in the Railbelt should be mineable at costs allowing electricity production to be economically competitive with all but the most favorable alternatives throughout the planning period. Coal may be available from both the Beluga and Nenana fields. However, the Beluga fields are not yet opened and their opening is as yet uncertain. Should the fields not be mined for commercial use, the coal may not be competitive for Railbelt electrical power. Should the fields not open, the existing Nenana coal fields would need to supply an increased tonnage at higher prices.

The extremely low sulfur content of Railbelt coal and the availability of commercially tested oxides of sulfur (SO_x) and particulate control devices will facilitate control of these emissions to levels mandated by the Clean Air Act. Principal concerns of this technology are environmental impacts of coal mining, possible ambient air-quality effects of residual SO_x, oxides of nitrogen (NO_x) and particulate emissions, long-term atmospheric buildup of CO_2 (common to all combustion-based technologies) and the long-term susceptibility of busbar power costs to inflation.

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

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

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

These plants, when commercially available, should allow continued use of Alaskan coal resources at costs comparable to conventional coal steam-electric plants, while providing environmental and operational advantages compared to conventional plants. Environmental advantages include less waste-heat rejection and water consumption per unit of output due to higher plant efficiency. Better control of NO_x, SO_x and particulate emission is also afforded. From an operational standpoint, these plants offer a potential for load-following duty. (However, much of the existing Railbelt capacity most likely will be available for intermediate and peak loading during the planning period.) Because of superior plant efficiencies, coal gasifer - combined-cycle plants should be somewhat less susceptible to inflation fuel cost than conventional steam-electric plants. Principal concerns relative to these plants include land disturbance resulting from mining of coal, CO_2 production, and uncertainties in plant performance and capital cost due to the current state of technology development.

A prototypical plant was selected for in-depth analysis (Battelle 1982, VOl. XVII). This 200 MW plant is located in the Beluga area and uses coal mined from the Chuitna Field. The plant would use oxygen-blown gasifiers of Shell design, producing a medium-Btu synthesis gas for combustion turbine firing. The plant would be capable of load-following operation.

(iii) Natural Gas Combustion Turbines

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

Because the costs and performance of combustion turbines are relatively well understood, no prototype was selected for in-depth study.

(iv) Natural-Gas - Combined-Cycle Plants

Natural gas - combined-cycle plants were selected for consideration because of the current availability of low-cost natural gas in the Cook Inlet area and the likely future availability of North Slope supplies in the Railbelt (although at prices higher than those currently experienced). Combined-cycle plants are the most economical and environmentally benign method currently available to generate electric base-load or mid-range peaking power using natural gas. The principal economic concern is the sensitivity of busbar power costs to the possible substantial rise in natural gas costs. The principal environmental concern is CO_2 production and possible local noise problems.

A nominal 200 MW prototypical plant was selected for further study. The plant is located in the Beluga area and uses Cook Inlet natural gas (Battelle 1982, Vol. XIII).

(v) Natural Gas Fuel-Cell Stations

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

Natural gas fuel-cell stations were considered in the Railbelt electric energy plans primarily because of the apparent peaking duty advantages they may offer over combustion turbines for systems relying upon coal or natural-gas fired base and intermediate load units. Plant efficiencies most likely will be far superior to combustion turbines and relatively unaffected by partial power operation. Capital investment costs most likely will be comparable to that of combustion turbines. These costs and performance characteristics should lead to significant reduction in busbar power costs, and greater protection from escalation of natural gas prices compared to combustion turbines. Construction lead time should be comparable to those of combustion turbines. Because environmental effects most likely will be limited to CO_2 production, load-center siting will be possible and transmission losses and costs consequently will be reduced. Since the fuel cell is still an emerging technology with commercial availability scheduled for the late 1980's, it was not chosen as a major block in the Railbelt generation future. No prototypical plant was selected for further study.

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

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

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

(vii) Conventional Hydroelectric Plants

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

(viii) Small-Scale Hydroelectric Plants

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

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

(ix) Microhydroelectric Systems

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

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

(x) Large Wind Energy Conversion Systems

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

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

A prototypical large wind energy conversion system was selected for further study. The prototype consisted of a wind farm located in the Isabell Pass area and was comprised of ten 2.5 MW rated capacity, Boeing MOD-2, horizontal axis wind turbines (Battelle 1982, Vol. XVI).

(xi) Small Wind Energy Conversion Systems

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

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

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

(xii) Tidal Power

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

Tidal power was selected for consideration in Railbelt electric energy plans because of the substantial Cook Inlet tidal resource, because of the renewable character of this energy resource and because of the substantial interest in the resource, as evidenced by the first-phase assessment of Cook Inlet tidal power development (Acres 1981a).

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

(xiii) Refuse-Derived Fuel Steam Electric Plants

These plants consist of boilers, fired by the combustible fraction of municipal refuse, that produce steam for the operation of a steam turbine-generator. Rated capacities typically are low due to the difficulties of transporting and storing refuse, a relatively low energy density fuel. Supplemental firing by fossil fuel may be required to compensate for seasonal variation in refuse production.

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

Cost and performance characteristics of these alternatives as used in the Battelle study (Battelle 1982, Vol. II) are summarized in Table D.30.

5 - CONSEQUENCES OF LICENSE DENIAL

5.1 - Cost of License Denial

The forecast energy demand for the Railbelt through the year 2020 can be met without constructing the Watana-Devil Canyon hydroelectric project provided that other, albeit more costly, alternatives are developed. The best alternative generating system is outlined in Section 4.5 of this Exhibit. However, the economic comparison described in Section 4.7 concludes that the Susitna project will yield an expected present valued net benefit of $1.8 billion under the Reference Case.

The economic consequences of license denial will be the probable costs mentioned above.

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

The most likely alternative to Susitna is subject to a great deal of cost risk due to the uncertain future in fossil fuel prices and the unresolved issues about development in the Beluga coal fields. License denial will force the State into pursuing a less certain program in meeting power needs.

5.2 - Future Use of Damsites if License is Denied

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

6 - FINANCING

6.1 - Forecast Financial Parameters

The financial parameters used in the financial analysis are summarized in Table D.12. The interest rates and forecast rates of inflation are of special importance. They have been based on the forecast inflation rates and the forecast of interest rates on industrial bonds (Data Resources Inc.) and conform to a range of other authoritative forecasts. To allow for the factors which have brought about a narrowing of the differential between tax exempt and taxable securities, it has been assumed that any tax exempt financing would be at a rate of 80 percent rather than the historical 75 percent or so of the taxable interest rate. This identifies the forecast interest rates in the financing periods from 1985 in successive five-year periods as being on the order of 8.6 percent, 7.8 percent, and 7 percent. The accompanying rate of inflation would be about 7 percent. In view of the uncertainty attaching to such forecasts and in the interest of conservatism, the financial projections which follow have been based upon the assumption of a 10 percent rate of interest for tax-exempt bonds and an ongoing inflation rate of 7 percent.

6.2 - Inflationary Financing Deficit

The basic financing problem of Susitna is the magnitude of its "inflationary financing deficits." Under inflationary conditions these deficits (early year losses) are an inherent characteristic of almost all debt financed, long life, capital intensive projects (see Figure D.10). As such, they are entirely compatible (as in the Susitna case) with a project showing a good economic rate of return. However, unless additional state equity is included to meet this "inflationary financing deficit" the project may be unable to proceed without imposing a substantial and possibly unacceptable burden of high early-year costs on consumers.

6.3 - Legislative Status of Alaska Power Authority and Susitna Project

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

The Authority was created with all general powers necessary to finance, construct and operate power production and transmission facilities throughout the State. The Authority is not regulated by the Alaska Public 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 State Legislature has specifically addressed the Susitna project in legislation (Statute 44.83.300 Susitna River Hydroelectric Project). The legislation states that the purpose of the project is to generate, transmit and distribute electric power in a manner which will:

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

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

6.4 - Financing Plan

The financing of the Susitna project is expected to be accomplished by a combination of direct State of Alaska appropriations and revenue bonds issued by the Power Authority but carrying the "moral obligation" of the State. On this basis it is expected that project costs for Watana through early 1990 will be financed by approximately $1.8 billion (1982 dollars) of state appropriations. Thereafter completion of Watana is expected to be accomplished by issuance of approximately $2.0 billion (1982 dollars) of revenue bonds. The year-by-year expenditures in constant and then current dollars are detailed in Table D.31. These annual borrowing amounts do not exceed the Authority's estimated annual debt capacity for the period.

The revenue bonds are expected to be secured by project power sales contracts, other available revenues, and by a Capital Reserve Fund (funded by a State appropriation equal to a maximum annual debt service) and backed by the "moral obligation" of the State of Alaska.

The completion of the Susitna project by the building of Devil Canyon is expected to be financed (as detailed in Table D.31) by the issuance of approximately $2.0 billion of revenue bonds (in 1982 dollars) over the years 1994 to 2002 with no state contribution.

Summary financial statements based on the assumption of 7 percent inflation and bond financing at a 10 percent interest rate and other estimates in accordance with the above economic analysis are given in Tables D.32 and D.10, for the $1.8 billion state contribution and 100 percent debt financing cases, respectively. Figure D.10 shows the cost of energy from Susitna assuming the $1.8 billion state contribution.

The actual interest rates at which the project will be financed in the 1990s and the related rate of inflation cannot be determined with any certainty at the present time. Also, while the market for Susitna power is relatively insensitive to the world oil prices analyzed, the finance plan is affected by those prices through their impact on the wholesale prices Railbelt utilities would face in the absence of Susitna.

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

Because of the above conditions, the financing plan is the subject of continuing review and development.

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Volume IX: Alaska Economic Projections for Estimating Electricity Requirements for the Railbelt.

Volume XII: Coal-fired Steam-electric Power Plant Alternatives for the Railbelt Region of Alaska.

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TABLE D.1: SUMMARY OF COST ESTIMATE

Catagory	January 1982 Dollars $ X 10^6 Watana	Devil Canyon	Total
Production Plant	$ 2,293	$ 1,065	$ 3,358
Transmission Plant	456	105	561
General Plant	5	5	10
Indirect	442	206	648
Total Construction	3,196	1,381	4,577
Overhead Construction	400	173	573
TOTAL PROJECT CONSTRUCTION COST	$ 3,596	$ 1,554	$ 5,150
ECONOMIC ANALYSIS (OGP-6, 0 percent inflation, 3 percent interest)			
Escalation	----	----	----
AFDC	485	180	665
TOTAL PROJECT COST	$ 4,081	$ 1,734	$ 5,815
SUSITNA COST OF POWER (Table D.10, 100% Debt Finance)			
Escalation	2,560	3,200	5,760
AFDC	1,796	1,610	3,406
TOTAL PROJECT COST	7,952	6,364	14,316
FINANCIAL ANALYSIS (Table D.32, $1.8 Billion State Appropriation)			
Escalation	2,560	3,200	5,760
AFDC	314	1,610	1,924
TOTAL PROJECT COST	$ 6,470	$ 6,364	$ 12,834

TABLE D.2: ESTIMATE SUMMARY - WATANA

Line Number	Description	Amount ($\times 10^6$)	Totals ($\times 10^6$)	Remarks
	PRODUCTION PLANT			
330	Land & Land Rights	$ 51		
331	Powerplant Structures & Improvements	74		
332	Reservoir, Dams & Waterways	1,547		
333	Waterwheels, Turbines & Generators	66		
334	Accessory Electrical Equipment	21		
335	Miscellaneous Powerplant Equipment (Mechanical)	14		
336	Roads & Railroads	214		
	Subtotal	1,987		
	Contingency	306		
	TOTAL PRODUCTION PLANT		$ 2,293	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,293	
	TRANSMISSION PLANT			
350	Land & Land Rights	$ 8		
352	Substation & Switching Station Structures & Improvements	12		
353	Substation & Switching Station Equipment	131		
354	Steel Towers & Fixtures	131		
356	Overhead Conductors & Devices	100		
359	Roads & Trails	13		
	Subtotal	395		
	Contingency	61		
	TOTAL TRANSMISSION PLANT		456	
			$ 2,749	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,749	
	GENERAL PLANT			
389	Land & Land Rights	$ -		Included under 330
390	Structures & Improvements	-		Included under 331
391	Office Furniture/Equipment			Included under 399
392	Transportation Equipment			" "
393	Stores Equipment			" "
394	Tools Shop & Garage Equipment			" "
395	Laboratory Equipment			" "
396	Power-Operated Equipment			" "
397	Communications Equipment			" "
398	Miscellaneous Equipment			" "
399	Other Tangible Property	5		
	TOTAL GENERAL PLANT		$ 5	
			$ 2,754	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 2,754	
	INDIRECT COSTS			
61	Temporary Construction Facilities	$ -		See Note
62	Construction Equipment	-		See Note
63	Camp & Commissary	373		
64	Labor Expense	-		
65	Superintendence	-		See Note
66	Insurance	-		See Note
68	Mitigation	29		
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	402		
	Contingency	40		
	TOTAL INDIRECT COSTS		$ 442	
	TOTAL CONSTRUCTION COSTS		$ 3,196	

TABLE D.2 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL CONSTRUCTION COSTS BROUGHT FORWARD		$ 3,196	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)			
71	Engineering/ Administration	$ 386		
	Environmental Monitoring	14		
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		400	
	TOTAL PROJECT COST		$ 3,596	

TABLE D.3: ESTIMATE SUMMARY - DEVIL CANYON

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	PRODUCTION PLANT			
330	Land & Land Rights	$ 22		
331	Powerplant Structures & Improvements	69		
332	Reservoir, Dams & Waterways	646		
333	Waterwheels, Turbines & Generators	42		
334	Accessory Electrical Equipment	14		
335	Miscellaneous Powerplant Equipment (Mechanical)	11		
336	Roads & Railroads	119		
	Subtotal	923		
	Contingency	142		
	TOTAL PRODUCTION PLANT		$ 1,065	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,065	
	TRANSMISSION PLANT			
350	Land & Land Rights	$ -		Included in Watana Estimate
352	Substation & Switching Station Structures & Improvements	7		
353	Substation & Switching Station Equipment	21		
354	Steel Towers & Fixtures	29		
356	Overhead Conductors & Devices	34		
359	Roads & Trails	-		Included in Watana Estimate
	Subtotal	91		
	Contingency	14		
	TOTAL TRANSMISSION PLANT		$ 105	
			$ 1,170	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,170	
	GENERAL PLANT			
389	Land & Land Rights	$		Included under 330
390	Structures & Improvements			Included under 331
391	Office Furniture/Equipment			Included under 399
392	Transportation Equipment			" "
393	Stores Equipment			" "
394	Tools Shop & Garage Equipment			" "
395	Laboratory Equipment			" "
396	Power Operated Equipment			" "
397	Communications Equipment			" "
398	Miscellaneous Equipment			" "
399	Other Tangible Property	5		
	TOTAL GENERAL PLANT		$ 5	
			$ 1,175	

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL BROUGHT FORWARD		$ 1,175	
	INDIRECT COSTS			
61	Temporary Construction Facilities	$ -		See Note
62	Construction Equipment	-		See Note
63	Camp & Commissary	184		
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	188		
	Contingency	18		
	TOTAL INDIRECT COSTS		$ 206	
	TOTAL CONSTRUCTION COSTS		$ 1,381	

Sheet 4 of 5

TABLE D.3 (Cont'd)

Line Number	Description	Amount (x 10^6)	Totals (x 10^6)	Remarks
	TOTAL CONSTRUCTION COSTS BROUGHT FORWARD		$ 1,381	
	OVERHEAD CONSTRUCTION COSTS (PROJECT INDIRECTS)			
71	Engineering/Administration	$ 167		
	Environmental Monitoring	6		
72	Legal Expenses	-		Included in 71
75	Taxes	-		Not Applicable
76	Administrative & General Expenses	-		Included in 71
77	Interest	-		Not Included
80	Earnings/Expenses During Construction	-		Not Included
	Total Overhead Costs		173	
	TOTAL PROJECT COST		$ 1,554	

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

COSTS INCORPORATED IN CONSTRUCTION ESTIMATES	WATANA $\$ \times 10^3$	DEVIL CANYON $\$ \times 10^3$	
Outlet Facilities			
Main Dam at Devil Canyon		14,600	
Tunnel Spillway at Watana	47,100		
Restoration of Borrow Area D	1,600	NA	
Restoration of Borrow Area F	600	NA	
Restoration of Camp and Village	2,300	1,000	
Restoration of Construction Sites	4,100	2,000	
Fencing around Camp	400	200	
Fencing around Garbage Disposal Area	100	100	
Multilevel Intake Structure	18,400	NA	
Camp Facilities Associated with trying to Keep Workers out of Local Communities	10,200	9,000	
Restoration of Haul Roads	800	500	
SUBTOTAL	85,600	27,400	
Contingency 20%	17,100	5,500	
TOTAL CONSTRUCTION	102,700	32,900	
Engineering 12.5%	12,800	4,100	
TOTAL PROJECT	115,500	37,000	152,500

TABLE D.5: SUMMARY OF OPERATION AND MAINTENANCE COSTS

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

(1) Incremental

TABLE D.6: VARIABLES FOR AFDC COMPUTATIONS

	Analysis	
	Economic	Financial
Effective Interest Rate (x)%	3	10
Escalation Rate (y)%	0	7
Construction Period (B) yrs.		
Watana	8.5	8.5
Devil Canyon	7.5	7.5

TABLE D.7 - SUSITNA HYDROELECTRIC PROJECT

Watana and Devil Canyon Cumulative and Annual Cash Flow

JANUARY 1982 DOLLARS - IN MILLIONS

	ANNUAL CASH FLOW			CUMULATIVE CASH FLOW (TO END OF YEAR)		
YEAR	WATANA	DEVIL CANYON	COMBINED	WATANA	DEVIL CANYON	COMBINED
1981	27.6		27.6	27.6		27.6
82	12.9		12.9	40.4		40.5
83	28.7		28.7	69.2		69.2
84	48.5		48.5	117.7		117.7
85	199.5		199.5	317.2		317.2
86	283.9		283.9	601.1		601.1
87	295.4		295.4	896.5		896.5
88	369.0		369.0	1265.5		1265.5
89	438.4		438.4	1703.9		1703.9
90	627.6		627.6	2331.5		2331.5
91	608.8	4.9	613.7	2940.3	4.9	2945.2
92	429.0	47.9	476.9	3369.3	52.8	3422.1
93	153.2	68.6	221.8	3522.5	121.4	3643.9
94	73.7	64.3	138.0	3596.2	185.7	3781.9
95		64.9	64.9		250.6	3846.8
96		115.3	115.3		365.9	3962.1
97		201.3	201.3		567.2	4163.4
98		291.8	291.8		854.0	4455.2
99		279.7	279.7		1138.7	4734.9
2000		241.7	241.7		1380.4	4976.6
2001		156.0	156.0		1536.4	5132.6
2002		17.6	17.6		1554.0	5150.2
TOTAL	3596.2	1554.0	5150.2			

TABLE D.8: ANCHORAGE FAIRBANKS INTERTIE
PROJECT COST ESTIMATE

	TOTAL COST (Thousands of Dollars)
Total Line 175.1 miles	56,556
Total Substation Cost	9,449
Subtotal	66,005
R/W Acquisition ($40.00/Mile)	6,784
Mobilization - Demobilization 5%	3,300
Surveying	3,100
Engineering 6%	3,960
Construction Management 5%	3,300
Subtotal	86,449
Contingencies 25%	21,612
Total Sept. 1981 Dollars	108,061
Inflation @ 10%/year - 2 years	130,754

Source: Commonwealth Associates, January 1982

TABLE D.9: SUMMARY OF EBASCO CHECK ESTIMATE

The following figures and comments are taken from EBASCO's estimate dated March 26, 1982.

PROJECT COST SUMMARY

The hydroelectric development cost in January 1982 dollars is as follows:

DESCRIPTION	WATANA	DEVIL CANYON
Hydraulic Production Plant	$2,502,053,000	$ 955,723,000
Transmission Plant	411,774,000	77,712,000
General Plant	1,113,000	-
Total Direct Construction Cost	$2,914,940,000	$1,033,435,000
Indirect Construction Cost	362,681,000	170,688,000
Subtotal for Contingency	$3,277,621,000	$1,204,123,000
Contingency	503,979,000	184,177,000
Total Specific Construction Cost	$3,781,600,000	$1,388,300,000
Professional Services	280,000,000	115,000,000
Client Costs	Not Included	Not Included
Total Project Cost	$4,061,600,000	$1,503,300,000

The above costs are based on quantities contained in the Revision 4 Estimating Package dated February 12, 1982, as prepared by Acres American. We have not considered any quantities contained in the Revision 5 Estimating Package dated March 4, 1982, since the transmittal was received one month later than the revised information cutoff date of February 8, 1982.

Major cost quantities have been checked to verify Revision 4 quantities as compared to Acres' Project drawings. We have provided an asterisk next to the accounts added by Ebasco to reflect costs not properly included in other accounts. Unit prices supplied by Acres American Incorporated are footnoted.

REVISED SUMMARY (BY ACRES)

Watana Cost	$\$4,062 \times 10^6$
Devil Canyon Cost	$1,503 \times 10^6$
Total Project (Rev. 4)	$5,565 \times 10^6$
Adjustment for Revision 5	-79×10^6
Adjustment Total Project	$\$5,486 \times 10^6$

NOTE: Adjustments were given by EBASCO in meeting in New York on April 14, 1982.

DATA12K.012 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	2957	2957
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.55	125.05
465 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
523 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	260.30	295.71
-----INCOME-----------------										
515 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	769.6	882.1
179 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	24.2
317 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	857.9
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6
530 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.6
301 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	746.0	795.2
343 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	176.6
242 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.2
549 TOTAL SOURCES OF FUNDS	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	780.0	246.3
120 LESS CAPITAL EXPENDITURE	402.0	425.1	511.3	706.7	932.7	1413.2	1596.9	1579.2	653.7	201.7
551 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	15.3
250 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	29.3
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
544 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0	49.2
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.3	92.3
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
373 CUM. CAPITAL EXPENDITURE	402.0	827.1	1338.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8422.4
455 CAPITAL EMPLOYED	402.0	827.1	1333.4	2045.0	2977.7	4391.0	5987.8	7567.0	8347.0	8563.9
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.5
555 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	126.3	141.5
554 DEBT OUTSTANDING-LONG TERM	402.0	827.1	1333.4	2045.0	2977.7	4391.0	5987.8	7567.0	8220.7	8367.9
542 ANNUAL DEBT DRAWWDOWN $1982	317.2	313.5	352.4	455.2	561.5	795.1	839.7	776.0	300.2	75.9
543 CUM. DEBT DRAWWDOWN $1982	317.2	630.7	983.1	1438.3	1999.8	2795.0	3634.6	4410.7	4710.9	4786.7
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.03

NO STATE CONTRIBUTION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 1 OF 6

TABLE D.10

DATA12K.D12 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3005	3019	3028	3055	3057	3064	3105	4555	4670	4788
521 REAL PRICE-MILLS	118.38	110.59	103.51	96.35	90.45	84.80	78.66	85.99	81.62	74.88
466 INFLATION INDEX	249.23	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
520 PRICE-MILLS	295.10	294.97	295.43	294.22	295.54	296.47	294.25	344.22	349.58	343.17
-----INCOME-----------------										
516 REVENUE	886.7	890.5	894.5	898.8	903.4	908.3	913.6	1567.8	1632.4	1642.3
170 LESS OPERATING COSTS	25.9	27.7	29.7	31.8	34.0	36.4	38.9	60.8	65.1	69.7
517 OPERATING INCOME	860.8	862.7	864.8	867.0	869.4	871.9	874.7	1506.9	1567.3	1572.6
214 ADD INTEREST EARNED ON FUNDS	4.9	5.3	5.6	6.0	6.4	6.9	7.4	7.9	12.4	13.2
390 LESS INTEREST ON SHORT TERM DEBT	14.2	14.6	15.0	15.5	15.9	16.5	17.0	17.7	28.9	30.5
391 LESS INTEREST ON LONG TERM DEBT	792.4	789.2	785.6	781.7	777.4	772.7	767.5	1391.1	1391.9	1382.6
543 NET EARNINGS FROM OPERS	59.2	64.3	69.8	75.9	82.5	89.7	97.5	106.1	158.8	172.7
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	59.2	64.3	69.8	75.9	82.5	89.7	97.5	106.1	158.8	172.7
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	206.2	372.6	676.8	1061.1	1190.0	1240.1	1102.7	70.5	0.0	0.0
248 WORCAP DEBT DRAWDOWNS	4.0	4.4	4.6	4.9	5.2	5.7	6.1	112.5	15.8	10.5
549 TOTAL SOURCES OF FUNDS	269.4	441.2	751.3	1141.9	1277.8	1335.5	1206.4	289.5	174.6	183.7
320 LESS CAPITAL EXPENDITURE	233.1	401.3	707.6	1094.0	1225.2	1277.8	1143.0	113.6	66.2	70.8
148 LESS WORCAP AND FUNDS	4.0	4.4	4.6	4.9	5.2	5.7	6.1	112.9	15.8	10.9
260 LESS DEBT REPAYMENTS	32.3	35.5	39.1	43.0	47.3	52.0	57.2	62.9	92.7	101.9
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
223 RESERVE AND CONT. FUND	52.6	56.3	60.3	64.5	69.0	73.8	79.0	123.5	132.2	141.4
371 OTHER WORKING CAPITAL	92.9	93.6	94.3	95.0	95.7	96.6	97.5	165.9	173.1	174.7
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	8655.5	9056.8	9764.4	10858.4	12083.6	13361.5	14504.5	14618.1	14684.3	14755.1
465 CAPITAL EMPLOYED	8801.0	9206.7	9918.9	11017.8	12248.3	13531.8	14681.0	14907.6	14989.5	15071.2
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
462 RETAINED EARNINGS	113.6	177.9	247.8	323.7	406.2	495.5	593.4	699.5	858.4	1031.1
555 DEBT OUTSTANDING-SHORT TERM	145.5	149.9	154.5	159.4	164.7	170.4	176.5	289.4	305.2	316.2
554 DEBT OUTSTANDING-LONG TERM	8541.8	8878.9	9516.6	10534.7	11677.4	12865.6	13911.0	13918.6	13825.9	13724.0
542 ANNUAL DEBT DRAWDOWN $1982	82.7	139.7	237.1	347.4	364.2	354.7	294.7	17.6	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	4869.4	5009.1	5246.2	5593.7	5957.8	6212.5	6607.3	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.03	1.03	1.04	1.04	1.04	1.05	1.05	1.03	1.04	1.05

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

SHEET 2 OF 6

TABLE D.10

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******************************************************************************************************************************************
DATA12K.012 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN                                     24-JUN-83
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CASH FLOW SUMMARY
===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
73 ENERGY GWH	4902	5064	5224	5384	5544	5704	5862	6023	6148	6317
521 REAL PRICE-MILLS	68.73	62.59	57.11	52.15	47.70	43.69	40.08	36.79	34.02	31.27
465 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	901.52
520 PRICE-MILLS	337.03	328.42	320.62	313.30	306.62	300.48	294.94	289.72	286.62	281.86
-----INCOME-----------------										
516 REVENUE	1652.0	1663.0	1674.8	1686.7	1699.8	1713.8	1728.8	1744.9	1762.0	1780.4
170 LESS OPERATING COSTS	74.5	79.8	85.3	91.3	97.7	104.5	111.9	119.7	128.1	137.0
517 OPERATING INCOME	1577.5	1583.2	1589.5	1595.4	1602.1	1609.3	1617.0	1625.2	1634.0	1643.4
214 ADD INTEREST EARNED ON FUNDS	14.1	15.1	16.2	17.3	18.5	19.8	21.2	22.7	24.3	26.0
550 LESS INTEREST ON SHORT TERM DEBT	31.6	32.8	34.0	35.4	36.8	38.3	39.9	41.7	43.6	45.5
391 LESS INTEREST ON LONG TERM DEBT	1372.4	1361.2	1348.8	1335.3	1320.4	1303.9	1285.9	1266.0	1244.2	1220.1
342 NET EARNINGS FROM OPERS	187.6	204.4	222.8	242.1	263.5	286.9	312.4	340.2	370.5	403.7
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	187.6	204.4	222.8	242.1	263.5	286.9	312.4	340.2	370.5	403.7
443 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	11.5	12.5	13.4	14.2	15.2	16.4	17.5	18.7	20.0	21.4
340 TOTAL SOURCES OF FUNDS	199.1	216.9	236.1	256.3	278.7	303.3	329.8	358.8	390.5	425.1
320 LESS CAPITAL EXPENDITURE	73.8	81.1	86.7	92.8	99.3	106.3	113.7	121.7	130.2	139.3
543 LESS WORCAP AND FUNDS	11.5	12.5	13.4	14.2	15.2	16.4	17.5	18.7	20.0	21.4
260 LESS DEBT REPAYMENTS	112.1	123.4	135.7	149.3	164.2	180.6	198.7	218.5	240.4	264.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	-0.3	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
240 SHORT TERM DEBT	0.3	0.0	-0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	151.3	161.9	173.2	185.4	198.3	212.2	227.1	243.0	260.0	279.2
371 OTHER WORKING CAPITAL	176.4	178.3	180.3	182.4	184.7	187.2	189.8	192.6	195.5	198.8
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14430.9	14511.9	14598.7	15091.5	15190.8	15297.0	15410.7	15532.4	15662.6	15801.9
465 CAPITAL EMPLOYED	15158.5	15252.1	15352.2	15459.2	15573.8	15696.4	15827.6	15967.9	16113.1	16273.8
461 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
452 RETAINED EARNINGS	1218.7	1423.1	1645.9	1887.9	2151.4	2438.3	2750.6	3090.8	3461.4	3865.1
555 DEBT OUTSTANDING-SHORT TERM	323.0	340.5	353.5	367.8	383.0	399.4	416.9	435.5	455.5	476.9
554 DEBT OUTSTANDING-LONG TERM	13611.8	13488.5	13352.8	13203.5	13039.4	12858.8	12660.1	12441.6	12201.2	11936.8
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.05	1.05	1.06	1.06	1.07	1.07	1.08	1.08	1.09	1.09

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

SHEET 3 OF 6

TABLE D.10

DATA12K.C12 WATANA (ON LINE 1993)-NO STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 24-JUN-83

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

	2015	2016	2017	2018	2019	2020	2021	TOTAL
73 ENERGY GWH	6449	6616	6708	6760	6875	6984	6984	144802
521 REAL PRICE-MILLS	28.94	26.67	24.89	22.38	21.78	20.33	19.29	0.00
465 INFLATION INDEX	964.63	1032.15	1104.40	1181.71	1264.43	1352.94	1447.64	0.00
520 PRICE-MILLS	279.14	275.28	274.86	276.31	275.44	275.09	279.31	0.00
-----INCOME-----------------								
515 REVENUE	1800.1	1821.1	1843.6	1867.7	1893.5	1921.1	1950.6	42992.6
170 LESS OPERATING COSTS	146.6	156.9	167.9	179.6	192.2	205.6	220.0	2765.5
517 OPERATING INCOME	1653.4	1664.2	1675.7	1688.1	1701.3	1715.4	1730.5	40227.1
214 ADD INTEREST EARNED ON FUNDS	27.8	29.8	31.8	34.1	36.5	39.0	41.7	516.7
550 LESS INTEREST ON SHORT TERM DEBT	47.7	50.0	52.4	55.1	57.9	60.9	64.1	965.9
391 LESS INTEREST ON LONG TERM DEBT	1193.7	1164.6	1132.6	1097.4	1058.7	1016.1	969.3	31863.7
543 NET EARNINGS FROM OPERS	439.9	479.4	522.6	569.7	621.2	677.5	738.9	7914.2
-----CASH SOURCE AND USE----								
548 CASH INCOME FROM OPERS	439.9	479.4	522.6	569.7	621.2	677.5	738.9	7914.2
442 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14317.1
240 WORCAP DEBT DRAWDOWNS	22.9	24.5	26.2	28.1	30.0	32.1	34.4	675.2
549 TOTAL SOURCES OF FUNDS	462.8	503.9	548.8	597.8	651.2	709.6	773.3	22906.5
320 LESS CAPITAL EXPENDITURE	149.0	159.5	170.6	182.6	195.4	209.0	223.7	17091.6
443 LESS WORCAP AND FUNDS	22.9	24.5	26.2	28.1	30.0	32.1	34.4	675.2
260 LESS DEBT REPAYMENTS	290.9	319.9	351.9	387.1	425.8	468.4	515.3	5139.7
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
247 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------								
225 RESERVE AND CONT. FUND	297.6	318.5	340.8	364.6	390.2	417.5	446.7	446.7
371 OTHER WORKING CAPITAL	202.2	205.8	209.9	214.0	218.5	223.3	228.5	228.5
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	15950.9	16110.4	16281.0	16463.6	16658.9	16867.9	17091.6	17091.6
465 CAPITAL EMPLOYED	16450.7	16634.7	16831.5	17042.2	17267.6	17508.8	17766.8	17766.8
451 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
452 RETAINED EARNINGS	4305.0	4734.4	5306.9	5876.6	6497.8	7175.3	7914.2	7914.2
557 DEBT OUTSTANDING-SHORT TERM	495.8	524.3	550.6	578.7	608.7	640.8	675.2	675.2
554 DEBT OUTSTANDING-LONG TERM	11645.9	11326.0	10974.1	10586.9	10161.1	9692.7	9177.4	9177.4
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6624.9
543 CUM. DEBT DRAWDOWN $1982	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9	6624.9
519 DEBT SERVICE COVER	1.10	1.11	1.11	1.12	1.13	1.14	1.15	0.00

NO STATE CONTRIBUTION SCENARIO

7% INFLATION 10% INTEREST

TABLE D.10

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Nominal $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	8	11	12	12	13	13	14	15	15	15
Capital Renewals	0	8	9	10	10	11	12	12	13	9
Debt Service Cost	252	279	274	273	272	270	270	269	266	320
Total	260	298	295	295	295	294	296	296	294	344
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	17	18	19	19	20	20	21	22	22	23
Capital Renewals	14	15	15	16	17	17	18	19	19	20
Debt Service Cost	318	310	303	293	284	276	268	259	253	247
Total	349	343	337	328	321	313	307	300	295	290
	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Operating Expenses	24	25	26	27	28	30	31	33	35	
Capital Renewals	21	22	23	24	25	27	28	30	32	
Debt Service Cost	242	235	230	224	222	219	216	212	212	
Total	287	282	279	275	275	276	275	275	279	

NO STATE CONTRIBUTION SCENARIO
7% INFLATION 10% INTEREST

TABLE D.10

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	4	5	5	5	5	4	4	4	4	4
Capital Renewals	0	4	4	4	4	4	4	4	3	2
Debt Service Cost	116	119	109	102	95	88	82	77	72	80
Total	120	128	118	111	104	96	90	85	79	86

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	4	4	4	4	4	3	3	3	3	3
Capital Renewals	3	3	3	3	3	3	3	3	3	3
Debt Service Cost	75	68	62	56	50	46	42	38	34	31
Total	82	75	69	63	57	52	48	44	40	37

	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operating Expenses	3	3	3	3	3	2	2	2	2
Capital Renewals	3	2	2	2	2	2	2	2	2
Debt Service Cost	28	26	24	22	20	19	18	16	15
Total	34	31	29	27	25	23	22	20	19

NO STATE CONTRIBUTION SCENARIO
7% INFLATION 10% INTEREST

SHEET 6 OF 6

TABLE D.10

TABLE D.11: SUSITNA COST OF POWER

First Full Year of Watana & Devil Canyon - 2003

		$'s Per Net Kilowatt 1982 $'s
Total Plant Investment Inc. I.D.C (RL[1] 370 ÷ 466)		2116
I. Fixed Charges	Percent	
(a) Cost of Money	10.00	
(b) Depreciation (10% 50 yr S.F.)	.09	
(c) Insurance	.10	
(d) Taxes	.00	
1. Federal Income	0.00	
2. Federal Miscellaneous	0.00	
3. State & Local	0.00	
	10.19	
		215.62
II. Fixed Operating Costs (a) Operation & Maintenance Including Administrative and General Expense (RL171 divided by 466)		9.38
Total Annual Capacity Costs		225.00

Notes: (1) RL = Reference Line on far left of printout on Table D.10.

TABLE D.12: FORECAST FINANCIAL PARAMETERS

	Watana	Devil Canyon	Total
Project Completion - Year	1993	2002	
Energy Level - 1994			2,957 GWh
- 2002			4.555 "
- 2020			6,934 "
Costs in January 1982 Dollars			
Capital Costs	3,596.2 billion	1,554.0 billion	5,150.2 billion
Operating Costs - per annum	$10.4 million	$4.8 million	$15.20 million
Provision for Capital Renewals - per annum (0.3 percent of Capital Costs)	$10.79	$4.66	$15.45
Operating Working Capital		15 percent of Operating Costs 10 percent of Revenue	
Reserve and Contingency Fund		100 percent of Operating Costs 100 percent of Provision for Capital Renewals	
Interest Rate		10 percent per annum	
Debt Repayment Period		35 years	
Inflation Rate		7 percent per annum	

TABLE D.13: TOTAL GENERATING CAPACITY WITHIN THE RAILBELT SYSTEM-1982

Abbreviations	Railbelt Utility	Installed Capacity[1]
AMLP	Anchorage Municipal Light & Power Department	311.6
CEA	Chugach Electric Association	463.5
GVEA	Golden Valley Electric Association	221.6
FMUS	Fairbanks Municipal Utility System	68.5
MEA	Matanuska Electric Association	0.9
HEA	Homer Electric Association	2.6
SES	Seward Electric System	5.5
APAd	Alaska Power Administration	30.0
U of A	University of Alaska	18.6
TOTAL		1122.8[2]

(1) Installed capacity as of 1982 at 0°F
(2) Excludes National Defense installed capacity of 101.3 MW

TABLE D.14 (Sheet 1 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Alaska Power Administration			
Eklutna[a]	H	--	1955	30.0	--	--
			Anchorage Municipal Light and Power			
Station #1[b]						
Unit #1	SCCT	NG/O	1962	14.0	16.3	14,000
Unit #2	SCCT	NG/O	1964	14.0	16.3	14,000
Unit #3	SCCT	NG/O	1968	18.0	18.0	14,000
Unit #4	SCCT	NG/O	1972	28.5	32.0	12,500
Diesel 1[c]	D	O	1962	1.1	1.1	10,500
Diesel 2[c]	D	O	1962	1.1	1.1	10,500
Station #2[d]						
Unit #5	SCCT	O	1974	32.3	40.0	12,500
Unit #6	CCST	--	1979	33.0	33.0	--
Unit #7	SCCT	O	1980	73.6	90.0	11,000
Unit #8	SCCT	NG/O	1982	73.6	90.0	12,500
			Chugach Electric Association			
Beluga						
Unit #1	SCCT	NG	1968	15.25	16.1	15,000
Unit #2	SCCT	NG	1968	15.25	16.1	15,000
Unit #3	RCCT	NG	1973	53.3	53.0	10,000
Unit #4[e]	SCCT	NG	1976	10.0	10.7	15,000
Unit #5	RCCT	NG	1975	58.5	58.0	10,000
Unit #6	CCCT	NG	1976	72.9	68.0	15,000
Unit #7	CCCT	NG	1977	72.9	68.0	15,000
Unit #8[f]	CCST	NG	1982	55.0	42.0	--

TABLE D.14 (Sheet 2 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
			Chugach Electric Association (Continued)			
Cooper Lake(g)						
Unit #1,2	H	--	1961	15.0	16.0	--
International						
Unit #1	SCCT	NG	1964	14.0	14.0	15,000
Unit #2	SCCT	NG	1965	14.0	14.0	15,000
Unit #3	SCCT	NG	1970	18.5	18.0	15,000
Bernice Lake						
Unit #1	SCCT	NG	1963	7.5	8.6	23,400
Unit #2	SCCT	NG	1972	16.5	18.9	23,400
Unit #3	SCCT	NG	1978	23.0	26.4	23,400
Unit #4	SCCT	NG	1982	23.0	26.4	12,000
Knik Arm(h)						
Unit #1	ST	NG	1952	0.5	0.5	--
Unit #2	ST	NG	1952	3.0	3.0	--
Unit #3	ST	NG	1957	3.0	3.0	--
Unit #4	ST	NG	1957	3.0	3.0	--
Unit #5	ST	NG	1957	5.0	5.0	--
			Homer Electric Association			
Kenai						
Unit #1	D	O	1979	0.9	0.9	15,000
Pt. Graham						
Unit #1	D	O	1971	0.2	0.2	15,000
Seldovia						
Unit #1	D	O	1952	0.3	0.3	15,000
Unit #2	D	O	1964	0.6	0.6	15,000
Unit #3	D	O	1970	0.6	0.6	15,000

TABLE D.14 (Sheet 3 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
Matanuska Electric Association						
Talkeetna						
Unit #1	D	0	1967	0.9	0.9	15,000
Seward Electric System						
SES[j]						
Unit #1	D	0	1965	1.5	1.5	15,000
Unit #2	D	0	1965	1.5	1.5	15,000
Unit #3	D	0	1965	2.5	2.5	15,000
Military Installations - Anchorage Area						
Elmendorf AFB						
Total Diesel	D	0	1952	2.1	--	10,500
Total ST	ST	NG	1952	31.5	--	12,000
Fort Richardson						
Total Diesel[c]	D	0	1952	7.2	--	10,500
Total ST[i]	ST	NG	1952	18.0	--	20,000
Golden Valley Electric Association						
Healy Coal	ST	Coal	1967	64.7	65.0	13,200
Healy Diesel[c]	D	0	1967	64.7	65.0	10,500
North Pole						
Unit #1	SCCT	0	1976	64.7	65.0	14,000
Unit #2	SCCT	0	1977	64.7	65.0	14,000
Zendher						
GT1	SCCT	0	1971	18.4	18.4	15,000
GT2	SCCT	0	1972	17.4	17.4	15,000
GT3	SCCT	0	1975	2.8	3.5	15,000
GT4	SCCT	0	1975	2.8	3.5	15,000
Combined Diesel	D	0	1960-70	21.0	21.0	10,500

TABLE D.14 (Sheet 4 of 5)

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Plant/Unit	Prime Mover	Fuel Type	Date	Nameplate Capacity (MW)	Generating Capacity @ 0°F (MW)	Heat Rate (Btu/kWh)
University of Alaska - Fairbanks						
S1	ST	Coal	--	1.50	1.50	12,000
S2	ST	Coal	1980	1.50	1.50	12,000
S3	ST	Coal	--	10.0	10.0	12,000
D1	D	0	--	2.8	2.8	10,500
D2	D	0	--	2.8	2.8	20,500
Fairbanks Municipal Utilities System						
Chena						
Unit #1	ST	Coal	1954	5.0	5.0	18,000
Unit #2	ST	Coal	1952	2.5	2.5	22,000
Unit #3	ST	Coal	1952	1.5	1.5	22,000
Unit #4	SCCT	0	1963	5.3	7.0	15,000
Unit #5	ST	Coal	1970	21.0	21.0	13,320
Unit #6	SCCT	0	1976	23.1	28.8	15,000
Diesel #1	D	0	1967	2.8	2.8	12,150
Diesel #2	D	0	1968	2.8	2.8	12,150
Diesel #3	D	0	1968	2.8	2.8	12,150
Military Installations - Fairbanks						
Eielson AFB						
S1, S2	ST	0	1953	2.50	--	--
S3, S4	ST	0	1953	6.25	--	--
Fort Greeley						
D1, D2, D3[i]	D	0	--	3.0	--	10,500
D4, D5[i]	D	0	--	2.5	--	10,500
Ft. Wainwright[j]						
S1, S2, S3, S4	ST	Coal	1953	20	--	20,000
S5[i]	ST	Coal	1953	2	--	--

EXISTING GENERATING PLANTS IN THE RAILBELT REGION

Legend			
	H	-	Hydro
	D	-	Diesel
	SCCT	-	Simple cycle combustion turbine
	RCCT	-	Regenerstive cycle combustion turbine
	ST	-	Steam turbine
	CCCT	-	Combined cycle combustion turbine
	NG	-	Natural gas
	O	-	Distillate fuel oil

Notes

(a)Average annual energy production for Eklutna is approximately 148 GWh.

(b)All AMLP SCCTs are equipped to burn natural gas or oil. In normal operation they are supplied with natural gas. All units have reserve oil storage for operation in the event gas is not available.

(c)These are black-start units only. They are not included in total capacity.

(d)Units #5, 6, and 7 are designed to operate as a combined-cycle at plant. When operated in this mode, they have a generating capacity at 0°F of approximately 139 MW with a heat rate of 8500 Btu/kWh.

(e)Jet engine, not included in total capacity.

(f)Beluga Units #6, 7, and 8 operate as a combined-cycle plant. When operated in this mode, they have a generating capacity of about 178 MW with a heat rate of 8500 Btu/kWh. Thus, Units #6 and 7 are retired from "gas turbine operation" and added to "combined-cycle operations."

(g)Average annual energy production for Cooper Lake is approximately 42 GWh.

(h)Knik Arm units are old and have higher heat rates; they are not included in in total.

(i)Standby units.

(j)Cogeneration used for steam heating.

Source: Battelle Pacific Northwest Laboratories. Existing Generating Facilities and Planned Addition for the Railbelt Region of Alaska, Volume VI, September, 1982; updated by Harza-Ebasco Susitna Joint Venture, 1983.

TABLE D.15: SCHEDULE OF PLANNED UTILITY ADDITIONS (1982-1988)

Utility	Unit	Type	MW	Year	Avg. Energy (GWh)
APA	Bradley Lake	Hydro	90.0	1988	347
APA	Grant Lake	Hydro	7.0	1988	33
TOTAL			97.0		380

TABLE D.16: OPERATING AND ECONOMIC PARAMETERS FOR SELECTED HYDROELECTRIC PLANTS

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

Notes:

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

TABLE D.17: RESULTS OF ECONOMIC ANALYSES OF ALTERNATIVE GENERATION SCENARIOS

Generation Scenario Type	Generation Scenario Description	Load Forecast	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010: Thermal Coal	Thermal Gas	Thermal Oil	Hydro	Total System Installed Capacity in 2010 (MW)	Total System Present Worth Cost - ($$10^6$)
All Thermal	No Renewals	Medium	LME1	900	801	50	144	1895	8130
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500)[1]-1993 Keetna (100)-1997	Medium	L7W1	600	576	70	744	1990	7080
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1997 Snow (50)-2002	Medium	LFL7	700	501	10	894	2005	7040
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-1998	Medium	LWP7	500	576	60	822	1958	7064
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Strandline (20), Allison Creek (8), Snow (50)-2002	Medium	LXF1	700	426	30	822	1978	7041
	No Renewals Plus: Chakachamna (500)-1993 Keetna (100)-1996 Snow (50), Cache (50), Allison Creek (8), Talkeetna-2 (50), Strandline (20)-2002	Medium	L403	500	576	30	922	2028	7088

Notes:

(1) Installed capacity.

TABLE D.18: SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS/1982$

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

Notes:

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

Source: Battelle 1982, Vol. II, IV, XiII, XIII

TABLE D.19: BID LINE ITEM COSTS FOR BELUGA AREA STATION[a][c]
(January 1982 Dollars)

		Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1.	Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2.	Earthwork and Piling	2,541,000	3,888,000		5,706,000	16,000		12,151,000
3.	Circulating Water System	2,511,000	174,200		2,391,000	1,235,000	10,000,000	16,311,200
4.	Concrete	5,733,000	540,000		1,091,000	2,387,000		9,751,000
5.	Struct. Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6.	Buildings	682,000				800,000		1,482,000
7.	Turbine-Generator	1,800,000				19,500,000		21,300,000
8.	Steam Generator and Accessories	15,764,000				21,800,000		37,564,000
9.	Air Quality Control System	12,400,000				27,100,000		39,500,000
10.	Other Mechanical Equipment					8,950,000		8,950,000
11.	Coal and Ash Handling	576,000				1,500,000	5,000,000	7,076,000
12.	Piping	14,435,000				9,000,000		23,435,000
13.	Insulation and Lagging						1,500,000	1,500,000
14.	Instrumentation						3,000,000	3,000,000
15.	Electrical Equipment	1,000,000					30,000,000	31,000,000
16.	Painting	1,015,000				1,100,000		2,115,000
17.	Off-Site Facilities						3,000,000	3,000,000
18.	Waterfront Construction						600,000	600,000
19.	Substation	1,275,000	22,000		92,000	2,686,000		4,075,000
20.	Indirect Construction Cost and Architect/Engineer Services[b]	44,515,000	50,907,000	2,562,000	2,084,000	9,000		100,077,000
	Subtotal	$106,354,000	$55,533,300	$2,562,000	$12,265,000	$103,348,000	$53,100,000	$333,162,300
	Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
	Contingencies							47,000,000
	TOTAL PROJECT COST							$410,162,300

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $39,229,000 for construction camp, $31,300,000 for engineering services, and $29,548,000 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XII.

TABLE D.20: BID LINE ITEM COSTS FOR NENANA AREA STATION[a][c]
(January 1982 Dollars)

	Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Subcontracts	Total Direct Cost
1. Improvements to Site	$ 350,000	$ 2,100	$	$ 901,000	$ 110,000	$	$ 1,363,100
2. Earthwork and Piling	2,100,000	13,000		5,400,000	16,000		7,529,000
3. Circulating Water System	2,561,000	174,200		2,391,000	1,235,000	11,500,000	17,861,200
4. Concrete	5,982,000	540,000		1,091,000	2,387,000		10,000,000
5. Struct. Steel, Lifting Equip., Stacks	1,757,000				7,155,000		8,912,000
6. Buildings	682,000				800,000		1,482,000
7. Turbine-Generator	1,800,000				19,500,000		21,300,000
8. Steam Generator and Accessories	15,662,000	138,000		12,000	21,800,000		37,612,000
9. Air Quality Control System	12,400,000				27,100,000		39,500,000
10. Other Mechanical Equipment					8,950,000		8,950,000
11. Coal and Ash Handling	1,937,000	18,000		150,000	5,785,000		7,890,000
12. Piping	14,435,000				9,000,000		23,435,000
13. Insulation and Lagging	441,000	46,000		11,000	1,049,000		1,547,000
14. Instrumentation					3,000,000		3,000,000
15. Electrical Equipment	12,720,000	1,150,000		800,000	18,000,000		32,670,000
16. Painting	1,142,000	58,000		25,000	575,000		1,800,000
17. Off-Site Facilities	4,827,000			3,600,000	3,260,000		11,687,000
18. Waterfront Construction							N/A
19. Substation - Switchyard	1,623,000	34,000		143,000	3,017,000		4,817,000
20. Indirect Construction Cost and Architect/Engineer Services[b]	54,943,000	42,560,000	2,882,000	2,617,000	9,000		103,011,000
Subtotal	$135,362,000	$44,733,300	$2,882,000	$17,141,000	$132,748,000	$11,500,000	$344,366,300
Contractor's Overhead and Profit	21,000,000	9,000,000					30,000,000
Contingencies							47,000,000
TOTAL PROJECT COST							$421,366,300

N/A = Not Applicable.

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $40,816,000 for construction camp, $31,300,000 for engineering services, and $30,895,000 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XII.

TABLE D.21: BID LINE ITEM COSTS FOR NATURAL GAS-FIRED COMBINED-CYCLE 200-MW Station[a][c] (January 1982 Dollars)

		Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Total Direct Cost
1.	Improvements to Site	$ 95,600	$	$ 109,700	$ 83,700	$ 13,800	$ 302,800
2.	Earthwork and Piling	313,000	2,666,300	87,300	151,600		3,218,200
3.	Circulating Water System	2,455,600	484,400	16,100	28,500	4,400,000	7,384,600
4.	Concrete	3,450,700	348,000	372,700	226,600	1,496,000	5,894,000
5.	Structural Steel and Life Equipment	305,000				1,900,000	2,205,000
6.	Buildings	192,200				491,000	683,200
7.	Heat Recovery Boilers, Gas Turbines, and Generators	5,197,200	172,500		250,000	31,200,000	36,819,700
8.	Steam Turbines and Generator	3,631,900	115,000		200,000	8,600,000	12,546,900
9.	Other Mechanical Equipment	2,588,700	115,000		65,000	4,946,200	7,714,900
10.	Piping	3,164,500	345,000		120,000	4,500,000	8,129,500
11.	Insulation and Logging	126,500	86,300		50,000	250,000	512,800
12.	Instrumentation	379,500	46,000		10,000	700,000	1,135,500
13.	Electrical Equipment	4,586,000	57,500		15,000	5,250,000	9,908,500
14.	Painting	632,600	11,500		2,500	500,000	1,146,600
15.	Off-Site Facilities	2,451,400	211,000	3,621,100	2,693,600	979,200	9,956,400
16.	Waterfront Construction	14,400		31,800	23,700	131,700	201,600
17.	Substation	948,800	23,000		10,000	4,035,500	5,017,300
18.	Construction Camp Expenses	4,292,400	12,362,000				16,654,400
19.	Indirect Construction Costs and Architect/Engineer Services[b]	26,341,900	4,313,900	1,301,600	1,588,700		33,546,100
	SUBTOTAL	61,167,900	21,357,500	5,540,300	5,518,900	69,393,400	162,978,000
	Contractor's Overhead and Profit						15,000,000
	Contingencies						22,224,200
	TOTAL PROJECT COST						$200,202,200

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.

(b) Includes $14,816,200 for engineering services and $18,729,900 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

(c) Source Battelle 1982, Vol. XIII.

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

Plan	Components	1982 Present Worth of System Costs $ x 10^6			
		1993-2020	2020	Estimated 2021-2051	1993-2051
Non-Susitna	600 MW Coal-Beluga	3,930	479	3,386	7,316
	400 MW Coal-Nenana				
	840 MW GT				
	200 MW CC				
Susitna	1020 MW Watana	3,396	316	2,093	5,489
	600 MW Devil Canyon				
	490 MW GT				
	200 MW CC				
Net Economic Benefit of Susitna Plan					1,827

TABLE D.23: FORECASTS OF ELECTRIC POWER DEMAND NET AT PLANT

Year	Reference Case MW	Reference Case GWh	DRI MW	DRI GWh	DOR MW	DOR GWh	-2 Percent Escalation MW	-2 Percent Escalation GWh
1990	844	4054	850	4085	793	3808	848	4072
2000	1020	4898	1158	5558	950	4567	959	4610
2010	1306	6280	1599	7681	1206	5799	1168	5628
2020	1672	8039	2208	10615	1528	7364	1422	6868

TABLE D.24: ELECTRIC POWER DEMAND SENSITIVITY ANALYSIS

Plan	1982 Present Worth of System Costs $ x 10^6 1993-2020	2020	Estimated 2021-2051	1993 2051	Net Benefits $ x 10^6
Reference Case					
Non-Susitna	3930	479	3386	7316	---
Susitna	3396	316	2093	5489	1827
DRI					
Non-Susitna	4906	624	4380	9286	---
Susitna	4084	499	3384	7468	1818
DOR					
Non-Susitna	2640	334	2392	5032	---
Susitna	3259	283	1858	5117	-85.2
-2 Percent					
Non-Susitna	1941	186	1056	2997	---
Susitna	3220	263	1711	4931	-1934

TABLE D.25: DISCOUNT RATE SENSITIVITY ANALYSIS

Plan	Real Discount Rate (Percent)	1982 Present Worth of System Costs ($ x 10^6) 1993-2020	2020	Estimated 2021-2051	1993-2051	Net Economic Benefit
Non-Susitna	2	4,829	457	5,418	10,247	-
Susitna	2	3,679	276	3,058	6,737	3,510
Non-Susitna	3	3,930	479	3,386	7,316	-
Susitna	3	3,396	316	2,093	5,489	1,827
Non-Susitna	5	2,669	562	1,374	4,043	-
Susitna	5	2,925	423	1,048	3,973	70

TABLE D.26: CAPITAL COST SENSITIVITY ANALYSIS

Plan	1982 Present Worth of System Costs ($ x 10^6) 1993-2010	2010	Estimated 2011-2051	1993-2051	Net Economic Benefit
Watana Capital Coats Costs up 20 Percent					
Non-Susitna	3,930	479	3,386	7,316	-
Susitna	3,839	347	2,300	6,139	1,117
Watana Capital Costs Costs Less 23 Percent					
Non-Susitna	3,930	479	3,386	7,316	-
Susitna	2,977	286	1,899	4,876	2,440

TABLE D.27: FUEL PRICE - SENSITIVITY ANALYSIS

	1982 Present Worth of System Costs ($ x 10^6) Costs of Non-Susitna Plan	Costs of Susitna Plan	Net Economic Benefits
Reference Case	7,316	5,489	1,827
Fuel Costs Increased 20 Percent	8,281	5,607	2,674
Fuel Costs Decreased 20 Percent	6,474	5,418	1,056

TABLE D.28: SUMMARY OF SENSITIVITY ANALYSIS INDEXES OF NET ECONOMIC BENEFITS

	Index Values
BASE REFERENCE CASE ($1,827 MILLION)	100
Oil Price Forecast	
DRI	100
DOR	-5
-2 Percent	-106
Discount Rates	
High (5%)	4
Low (2%)	192
Watana Capital Cost	
+ 20 Percent	61
- 23 Percent	134
Fuel Price	
+ 20 Percent	146
- 20 Percent	58
Real Fuel Price Escalation	
No Escalation after 2020	53

TABLE D.29: BATTELLE ALTERNATIVES STUDY FOR RAILBELT CANDIDATE ELECTRIC ENERGY GENERATING TECHNOLOGIES

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

TABLE D.29 Continued

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

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

TABLE D.30: BATTELLE ALTERNATIVES STUDY, SUMMARY OF COST AND PERFORMANCE CHARACTERISTICS OF SELECTED ALTERNATIVES

Alternative	Capacity (MW)[(a)]	Heat Rate (Btu/kWh)	Availability (%)	Average Annual Energy (GWh)	Capital Cost ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M (mills/kWh)
Coal Steam-Electric (Beluga)	200	10,000	87	-	2090	16.70	0.6
Coal Steam-Electric (Nenana)	200	10,000	87	-	2150	16.70	0.6
Coal Gasifier-Combined Cycle	220	9,290	85	-	-	14.80	3.5
Natl. Gas Combustion Turbines	70	13,800[(b)]	89	-	730	48	-
Natl. Gas Combined Cycle	200	8,200[(c)]	85	-	1050	7.30	1.7
Natl. Gas Fuel Cell Stations	25	9,200	91	-	890	42	-
Natl. Gas Fuel Cell Comb. Cyc.	200	5,700	83	-	-	50	-
Bradley Lake Hydroelectric	90	-	94	347	3190	9	-
Chakachamna Hydroelec. (330 MW)[(d)]	330	-	94	1570	3860	4	-
Chakachamna Hydroelec. (480 MW)[(e)]	480	-	94	1923	2100	4	-
Upper Susitna (Watana I)	680	-	94	3459	4669	5	-
Upper Susitna (Watana II)	340	-	94	-	168	5	-
Upper Susitna (Devil Canyon)	600	-	94	3334	2263	5	-
Snow Electric	63	-	94	220	5850	7	-
Keetna Hydroelectric	100	-	94	395	5480	5	-
Strandline Lake Hydroelec.	20(17)	-	94	85	7240	44	-
Browne Hydroelectric	100(80)	-	94	430	4470	5	-
Allison Hydroelectric	8	-	94	37	4820	44	-
Grant Lake Hydroelectric	7	-	-	-	2840	44	-
Isabell Pass Wind Farm	25	-	36	8	2490	3.70	3.3
Refuse-Derived Fuel Steam Electric (Anchorage)	50	14,000	N/A	-	2980	140	15
Refuse-Derived Fuel Steam Electric (Fairbanks)	20	14,000	N/A	-	3320	140	15

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

TABLE D.31: FINANCING REQUIREMENTS - $ MILLION FOR 1.8 BILLION STATE APPROPRIATION

		Nominal $\$ \times 10^6$ Interest Rate - 10% Inflation Rate - 7% Actual	1982 Purchasing Power $\$ \times 10^6$
1985	State Appropriation	402	317
86		385	284
87		429	296
88		573	369
89		728	438
90		171	96
Total	State Appropriation	2688	1800
1990		945	532
91		1252	658
92		1093	537
93		472	217
Total	Watana Bonds	3782	1953
1992		107	53
93		160	73
94		177	76
95		206	83
96		373	140
97		677	237
98		1061	347
99		1190	364
2000		1240	355
01		1103	295
02		70	18
Total	Devil Canyon Bonds	6364	2041
Total	Susitna Bonds	10146	3994
Total	Susitna Cost	12834	5794

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAFCOST $5.15 BN 23-JUN-83

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

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
73 ENERGY GWH	0	0	0	0	0	0	0	0	2353	2357
521 REAL PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	58.02	58.17
466 INFLATION INDEX	126.72	135.59	145.08	155.24	166.10	177.73	190.17	203.48	217.73	232.97
520 PRICE-MILLS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	126.32	135.52
-----INCOME-----------------										
516 REVENUE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	373.0	400.7
170 LESS OPERATING COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22.6	24.2
517 OPERATING INCOME	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	350.4	376.5
214 ADD INTEREST EARNED ON FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6
550 LESS INTEREST ON SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7
391 LESS INTEREST ON LONG TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	329.0	376.2
543 NET EARNINGS FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	-3.8
-----CASH SOURCE AND USE----										
543 CASH INCOME FROM OPERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	-3.8
446 STATE CONTRIBUTION	402.0	384.9	428.6	572.8	728.2	170.8	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	944.6	1252.2	1200.1	632.3	176.6
243 WORCAP DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	6.2
549 TOTAL SOURCES OF FUNDS	402.0	384.9	428.6	572.8	728.2	1115.4	1252.2	1200.1	740.4	179.0
320 LESS CAPITAL EXPENDITURE	402.0	384.9	428.6	572.8	728.2	1115.4	1252.2	1200.1	653.7	201.7
443 LESS WORCAP AND FUNDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	6.2
260 LESS DEBT REPAYMENTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-42.8
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.8
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.0	49.2
371 OTHER WORKING CAPITAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.7	43.7
434 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	402.0	786.9	1215.5	1788.3	2516.5	3631.9	4884.2	6084.2	6737.9	6939.6
465 CAPITAL EMPLOYED	402.0	786.9	1215.5	1788.3	2516.5	3631.9	4884.2	6084.2	6824.6	7032.5
461 STATE CONTRIBUTION	402.0	786.9	1215.5	1788.3	2516.5	2687.3	2687.3	2687.3	2687.3	2687.3
462 RETAINED EARNINGS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.4	17.6
553 DEBT OUTSTANDING-SHORT TERM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.7	135.7
554 DEBT OUTSTANDING-LONG TERM	0.0	0.0	0.0	0.0	0.0	944.6	2196.9	3397.0	4029.2	4191.9
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	531.5	659.5	599.7	250.4	75.8
543 CUM. DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	531.5	1189.9	1779.7	2070.1	2145.9
519 DEBT SERVICE COVER	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.07	0.95

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 1 OF 6

TABLE D.32

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

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

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
73 ENERGY GWH	3005	3019	3028	3055	3057	3064	3105	4555	4670	4796
521 REAL PRICE-MILLS	58.20	65.31	60.47	55.55	51.50	47.62	43.70	54.18	54.16	52.77
465 INFLATION INDEX	249.28	266.73	285.40	305.38	326.75	349.62	374.10	400.29	428.31	458.29
720 PRICE-MILLS	145.07	174.21	172.57	169.65	168.29	166.70	163.49	216.88	231.99	241.83
-----INCOME-----------------										
715 REVENUE	435.9	525.9	522.5	518.2	514.4	510.7	507.6	987.8	1083.3	1157.3
170 LESS OPERATING COSTS	25.9	27.7	29.7	31.8	34.0	36.4	38.9	60.8	65.1	69.7
517 OPERATING INCOME	410.0	498.1	492.8	486.5	480.4	474.4	468.7	927.0	1018.2	1087.6
214 ADD INTEREST EARNED ON FUNDS	4.9	5.2	5.6	6.0	6.4	6.9	7.4	7.9	12.4	13.2
550 LESS INTEREST ON SHORT TERM DEBT	13.6	15.9	10.9	4.9	-0.7	-6.3	-11.5	-16.6	2.2	12.8
551 LESS INTEREST ON LONG TERM DEBT	374.8	373.3	371.6	369.7	367.7	365.5	363.0	989.6	993.7	995.1
543 NET EARNINGS FROM OPERS	26.5	114.3	116.0	117.8	119.9	122.1	124.6	-38.2	34.7	99.9
-----CASH SOURCE AND USE----										
442 CASH INCOME FROM OPERS	26.5	114.3	116.0	117.8	119.9	122.1	124.6	-38.2	34.7	99.9
446 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	206.2	372.6	676.8	1061.1	1190.0	1240.1	1102.7	70.5	0.0	0.0
149 WORCAP DEBT DRAWDOWNS	7.2	19.2	7.2	8.2	6.2	7.8	6.5	76.2	18.8	17.3
541 TOTAL SOURCES OF FUNDS	240.0	506.1	800.0	1187.1	1316.1	1370.0	1233.7	109.4	53.5	117.2
320 LESS CAPITAL EXPENDITURE	233.1	401.3	707.6	1094.0	1225.2	1277.8	1143.0	113.6	66.2	70.8
447 LESS WORCAP AND FUNDS	7.2	19.2	7.2	8.2	6.2	7.8	6.5	76.2	18.8	17.3
250 LESS DEBT REPAYMENTS	15.3	16.8	13.5	20.3	22.4	24.6	27.0	25.8	56.2	61.5
327 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	-15.6	68.7	66.7	64.6	62.3	59.8	57.2	-111.2	-87.7	-32.7
247 SHORT TERM DEBT	15.6	-58.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	52.6	56.3	60.3	64.5	69.0	73.8	79.0	123.5	132.2	141.4
371 OTHER WORKING CAPITAL	47.5	53.0	66.3	70.3	72.0	74.9	76.3	107.9	119.1	126.[illegible]
454 CASH SURPLUS RETAINED	0.0	10.3	77.1	141.6	203.9	263.7	320.9	209.7	122.0	99.[illegible]
370 CUM. CAPITAL EXPENDITURE	7172.7	7574.1	8281.6	9375.6	10600.9	11878.7	13021.7	13135.4	13201.5	13272.4
465 CAPITAL EMPLOYED	7272.8	7703.7	8485.2	9652.0	10945.8	12291.2	13497.8	13576.5	13573.8	13629.2
461 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
462 RETAINED EARNINGS	44.2	158.5	274.5	392.3	512.2	634.3	758.8	720.6	755.3	855.2
553 DEBT OUTSTANDING-SHORT TERM	159.5	119.3	126.5	134.2	141.0	148.8	155.2	231.4	250.2	267.5
554 DEBT OUTSTANDING-LONG TERM	4382.8	4738.6	5396.9	6437.7	7605.3	8820.8	9896.5	9937.2	9887.9	9819.1
542 ANNUAL DEBT DRAWDOWN $1982	82.7	139.7	237.1	347.4	364.2	354.7	294.7	17.6	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	2228.6	2368.3	2605.4	2952.8	3317.0	3671.7	3966.5	3984.1	3984.1	3984.1
17 DEBT SERVICE COVER	1.03	1.25	1.25	1.25	1.25	1.25	1.25	0.93	0.98	1.04

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.32

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

CASH FLOW SUMMARY

===($MILLION)====

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
73 ENERGY GWH	4902	5064	5224	5384	5544	5704	5862	6023	6148	6317
521 REAL PRICE-MILLS	57.36	53.04	49.28	44.01	40.16	36.70	33.66	30.93	28.44	26.09
466 INFLATION INDEX	490.37	524.69	561.42	600.72	642.77	687.77	735.91	787.42	842.54	901.52
520 PRICE-MILLS	283.71	279.29	271.00	264.35	258.16	252.38	247.69	242.73	239.64	235.17
-----INCOME-----------------										
514 REVENUE	1390.6	1409.1	1416.0	1423.2	1431.2	1435.5	1451.9	1461.9	1473.2	1485.5
179 LESS OPERATING COSTS	74.5	79.8	85.3	91.3	97.7	104.5	111.9	119.7	128.1	137.0
517 OPERATING INCOME	1316.1	1329.4	1330.7	1331.9	1333.5	1334.9	1340.0	1342.2	1345.1	1348.4
214 ADD INTEREST EARNED ON FUNDS	14.1	15.1	16.2	17.3	18.5	19.8	21.2	22.7	24.3	26.0
530 LESS INTEREST ON SHORT TERM DEBT	17.9	32.1	34.5	36.8	39.6	42.4	48.8	52.5	57.0	62.0
391 LESS INTEREST ON LONG TERM DEBT	981.9	975.1	967.6	959.4	950.3	940.4	929.4	917.4	904.1	889.6
543 NET EARNINGS FROM OPERS	330.5	337.3	344.3	353.0	362.1	372.0	383.0	395.0	408.3	422.9
-----CASH SOURCE AND USE----										
540 CASH INCOME FROM OPERS	330.5	337.3	344.3	353.0	362.1	372.0	383.0	395.0	408.3	422.9
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
243 WORCAP DEBT DRAWDOWNS	53.6	23.5	23.0	28.2	27.8	64.6	36.6	45.3	50.0	79.0
549 TOTAL SOURCES OF FUNDS	384.1	360.7	367.8	381.2	389.9	436.6	419.6	440.3	458.3	501.9
329 LESS CAPITAL EXPENDITURE	75.9	81.1	86.7	92.8	99.3	106.3	113.7	121.7	130.2	139.3
443 LESS WORCAP AND FUNDS	53.6	23.5	23.0	28.2	27.8	64.6	36.6	45.3	50.0	79.0
260 LESS DEBT REPAYMENTS	68.0	74.8	82.3	90.5	99.6	109.5	120.5	132.5	145.8	160.4
395 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	186.7	181.4	175.7	169.7	163.2	156.2	148.8	140.8	132.3	123.2
249 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	276.0	181.4	175.7	169.7	163.2	156.2	148.8	140.8	132.3	123.2
-----BALANCE SHEET----------										
225 RESERVE AND CONT. FUND	151.3	161.9	173.2	185.4	198.3	212.2	227.1	243.0	260.0	278.2
371 OTHER WORKING CAPITAL	169.3	182.8	194.5	210.5	225.4	276.1	297.8	327.3	360.3	421.1
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	13248.1	13429.2	13515.9	13608.7	13708.0	13814.3	13928.0	14049.7	14179.8	14319.1
465 CAPITAL EMPLOYED	13569.3	13773.9	13883.6	14004.6	14131.8	14302.6	14452.9	14619.9	14800.1	15013.4
451 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
452 RETAINED EARNINGS	909.7	1065.6	1234.6	1418.0	1616.9	1832.6	2066.0	2321.0	2597.0	2896.6
553 DEBT OUTSTANDING-SHORT TERM	321.2	344.7	367.7	395.9	423.7	488.3	524.9	570.2	620.3	699.3
554 DEBT OUTSTANDING-LONG TERM	9751.1	9676.3	9594.0	9503.5	9403.9	9294.4	9173.9	9041.3	8895.5	8735.2
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
543 CUM. DEBT DRAWDOWN $1982	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.32

DATA12K.D12 WATANA (ON LINE 1993)-$1.8 BN($1982) STATE FUNDS-INFLATION 7%-INTEREST 10%-CAPCOST $5.15 BN 23-JUN-83

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

	2015	2016	2017	2018	2019	2020	2021	TOTAL
73 ENERGY GWH	6449	6616	6709	6760	6875	6984	6984	144902
521 REAL PRICE-MILLS	24.13	22.17	20.61	19.28	17.89	16.63	15.69	0.00
465 INFLATION INDEX	964.63	1032.15	1104.40	1181.71	1264.43	1352.94	1447.64	0.00
520 PRICE-MILLS	232.79	228.78	227.64	227.99	226.22	224.96	227.19	0.00
-----INCOME-----------------								
516 REVENUE	1501.1	1513.5	1526.9	1540.4	1555.2	1571.0	1586.6	32714.1
170 LESS OPERATING COSTS	146.6	156.9	167.9	179.6	192.2	205.6	220.0	2765.5
517 OPERATING INCOME	1354.5	1356.6	1359.0	1360.8	1363.0	1365.4	1366.5	29948.6
214 ADD INTEREST EARNED ON FUNDS	27.8	29.8	31.9	34.1	36.5	39.0	41.7	516.7
550 LESS INTEREST ON SHORT TERM DEBT	69.9	74.0	78.5	82.5	87.0	92.0	95.9	1037.1
391 LESS INTEREST ON LONG TERM DEBT	873.5	855.9	836.5	815.1	791.6	765.8	737.4	21353.2
540 NET EARNINGS FROM OPERS	438.9	456.5	475.9	497.3	520.8	546.6	575.0	8074.9
-----CASH SOURCE AND USE----								
542 CASH INCOME FROM OPERS	438.9	456.5	475.9	497.3	520.8	546.6	575.0	8074.9
445 STATE CONTRIBUTION	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2687.3
143 LONG TERM DEBT DRAWDOWNS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10125.6
249 WORCAP DEBT DRAWDOWNS	40.5	44.9	40.1	45.4	49.7	38.8	31.4	990.0
549 TOTAL SOURCES OF FUNDS	479.4	501.4	516.0	542.7	570.5	585.3	606.4	21877.9
320 LESS CAPITAL EXPENDITURE	149.0	159.5	170.6	182.6	195.4	209.0	223.7	15608.9
443 LESS WORCAP AND FUNDS	40.5	44.9	40.1	45.4	49.7	38.8	31.4	990.0
260 LESS DEBT REPAYMENTS	176.4	194.0	213.5	234.8	258.3	284.1	312.5	3064.1
393 LESS PAYMENT TO STATE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
141 CASH SURPLUS(DEFICIT)	113.4	103.0	91.9	79.9	67.1	53.5	38.9	2214.9
240 SHORT TERM DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
444 CASH RECOVERED	113.4	103.0	91.9	79.9	67.1	53.5	38.9	2214.9
-----BALANCE SHEET----------								
227 RESERVE AND CONT. FUND	297.6	318.5	340.8	364.6	390.2	417.5	446.7	446.7
371 OTHER WORKING CAPITAL	442.1	466.2	484.0	505.5	529.7	541.2	543.3	543.3
454 CASH SURPLUS RETAINED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
370 CUM. CAPITAL EXPENDITURE	14468.1	14627.6	14798.2	14980.8	15176.2	15385.2	15608.9	15608.9
465 CAPITAL EMPLOYED	15207.9	15412.3	15623.0	15851.0	16096.0	16343.8	16598.9	16598.9
461 STATE CONTRIBUTION	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3	2687.3
452 RETAINED EARNINGS	3222.1	3578.6	3959.7	4377.1	4830.7	5323.8	5860.0	5860.0
553 DEBT OUTSTANDING-SHORT TERM	739.3	784.7	824.8	870.2	919.9	958.6	990.0	990.0
554 DEBT OUTSTANDING-LONG TERM	8553.3	8364.7	8151.3	7916.5	7658.2	7374.1	7061.6	7061.6
542 ANNUAL DEBT DRAWDOWN $1982	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3984.1
543 CUM. DEBT DRAWDOWN $1982	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1	3984.1
519 DEBT SERVICE COVER	1.25	1.25	1.25	1.25	1.25	1.25	1.25	0.00

$1.8 BILLION (1982 DOLLARS) STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

SHEET 4 OF 6

TABLE D.32

ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	8	10	10	11	11	12	13	14	14	15
Capital Renewals	0	8	9	10	10	11	12	12	13	9
Debt Service Cost	111	132	130	129	129	128	128	127	126	224
Total	119	140	149	150	150	151	153	153	153	248
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	16	17	18	18	19	20	20	21	22	22
Capital Renewals	14	15	15	16	17	17	18	19	19	20
Debt Service Cost	225	219	214	207	201	195	189	184	179	174
Total	255	251	247	241	237	232	227	224	220	216
	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Operating Expenses	23	24	25	26	27	29	30	32	34	
Capital Renewals	21	22	23	24	25	27	28	30	32	
Debt Service Cost	171	166	163	159	157	155	153	150	150	
Total	215	212	211	209	209	211	211	212	216	

NOTE: FOR ANNUAL ENERGY SOLD, SEE LINE 73 OF SHEETS 1-3 OF THIS TABLE

ANNUAL ENERGY COST
$1.8 BILLION STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

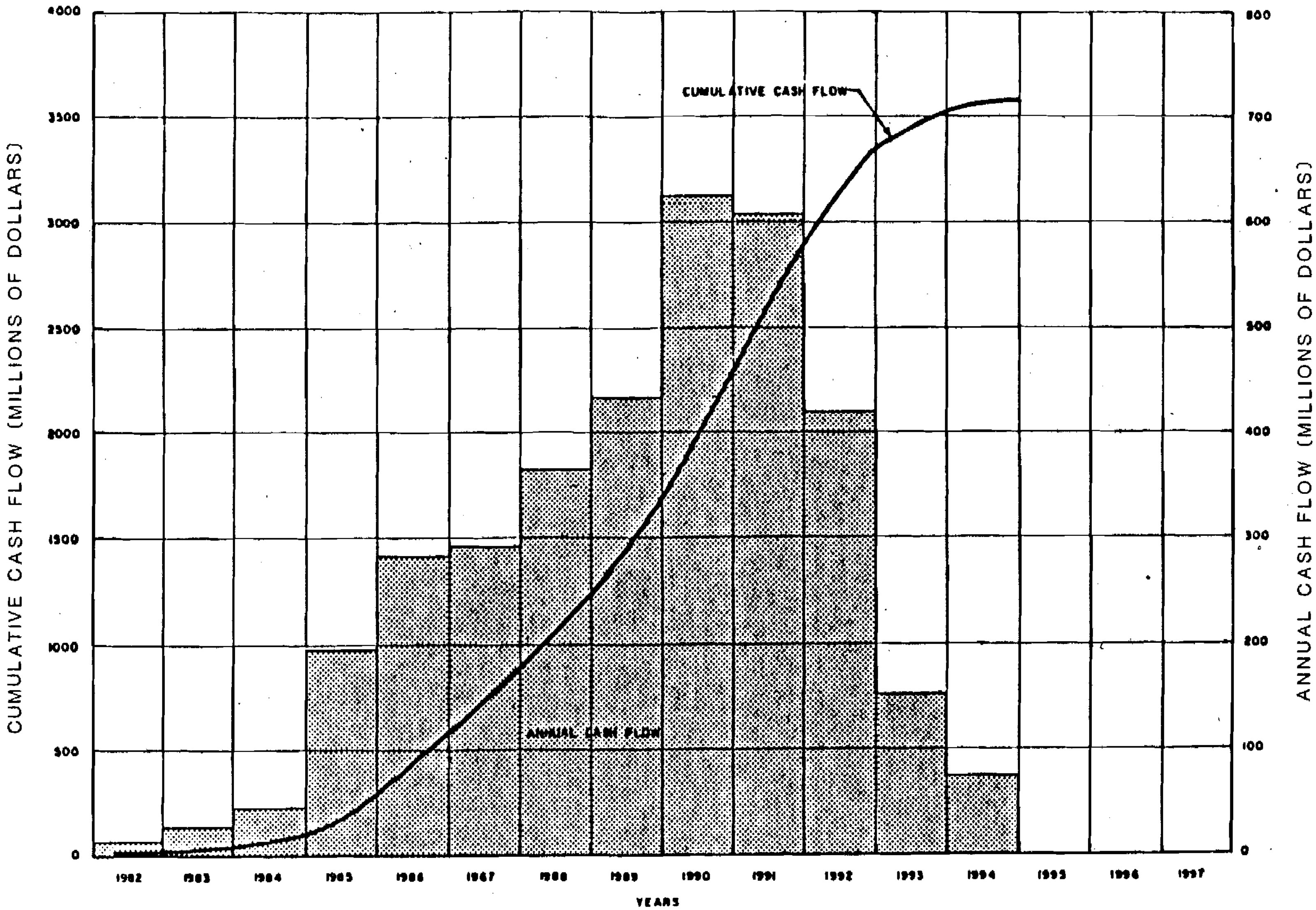
ANNUAL PROJECT COSTS
Mills/kWh

Cost in Real $	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Operating Expenses	4	4	4	4	4	4	4	4	4	4
Capital Renewals	0	4	4	4	4	4	4	4	3	2
Debt Service Cost	51	57	52	48	45	42	39	36	34	56
Total	55	65	60	56	53	48	47	44	41	62
	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Operating Expenses	4	4	4	4	3	3	3	3	3	3
Capital Renewals	3	3	3	3	3	3	3	3	3	3
Debt Service Cost	53	48	44	40	36	32	30	27	24	22
Total	60	55	51	47	42	38	36	33	31	28
	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Operating Expenses	3	3	3	3	2	2	2	2	2	
Capital Renewals	3	2	2	2	2	2	2	2	2	
Debt Service Cost	20	18	17	15	14	13	12	11	10	
Total	26	23	22	20	18	17	16	15	14	

NOTE: FOR ANNUAL ENERGY SOLD, SEE LINE 73 OF SHEET 1-3 OF THIS TABLE

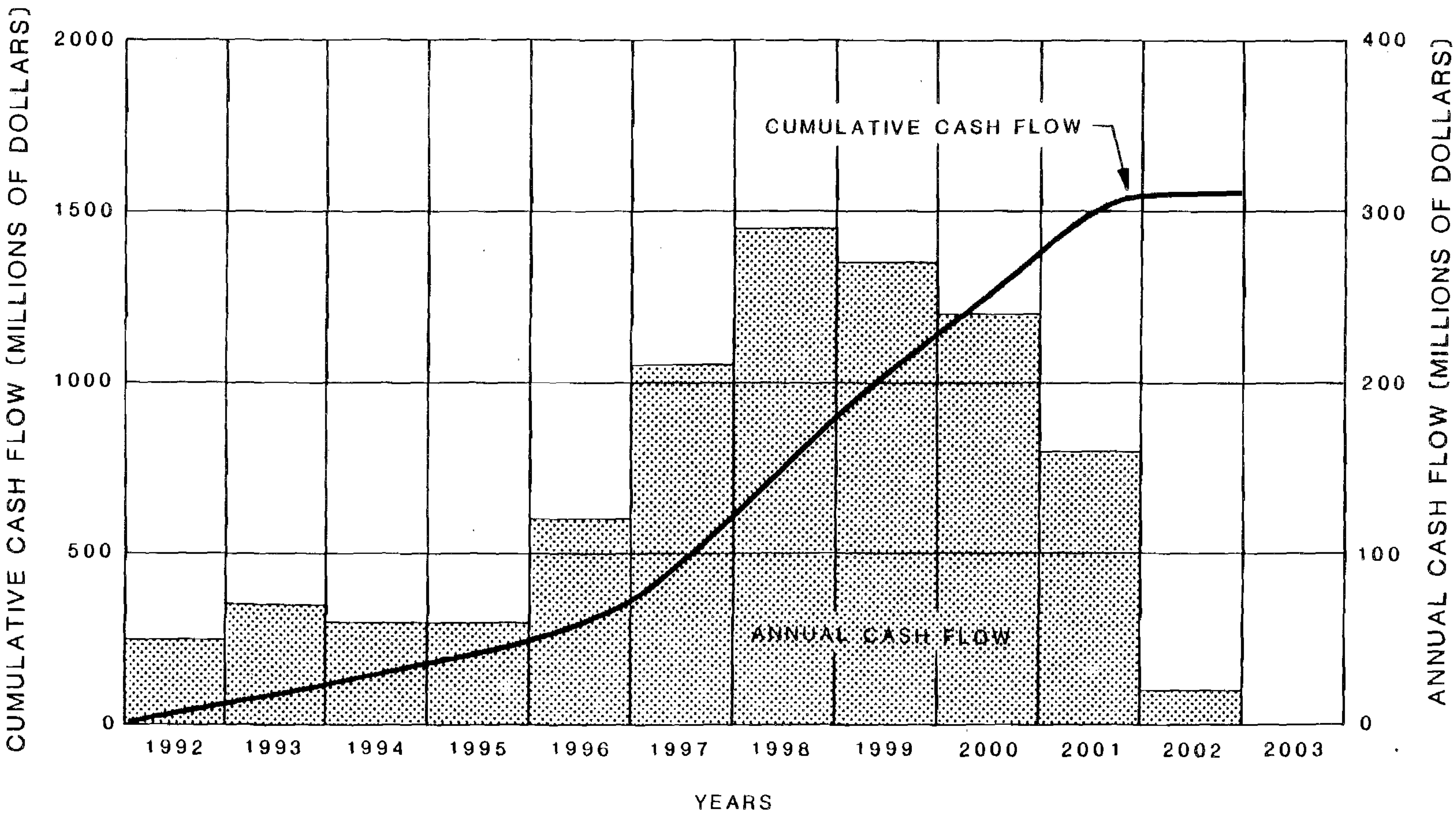
ANNUAL ENERGY COST
$1.8 BILLION STATE APPROPRIATION SCENARIO
7% INFLATION AND 10% INTEREST

TABLE D.32



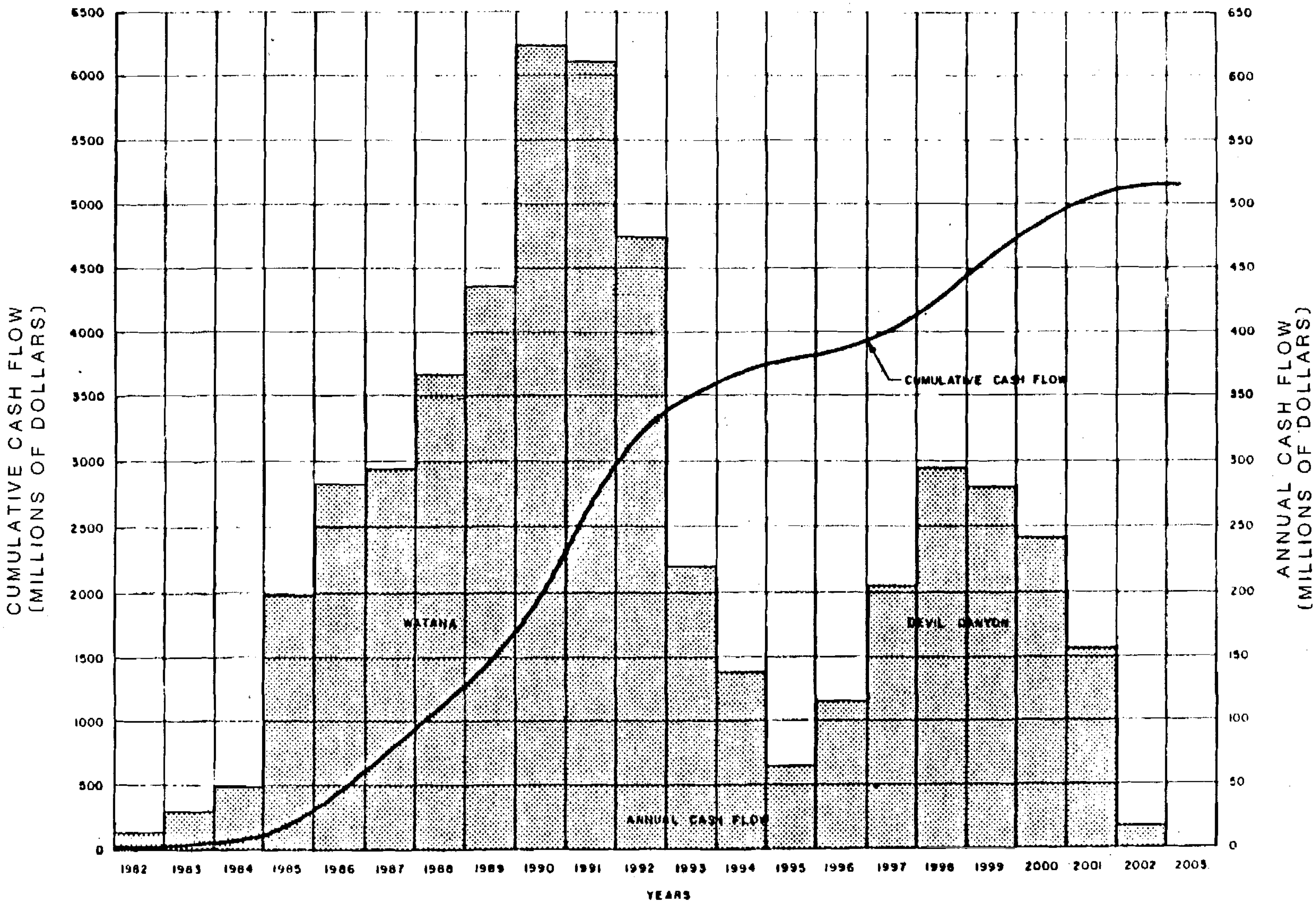
WATANA DEVELOPMENT
CUMULATIVE AND ANNUAL CASH FLOW
JANUARY, 1982 DOLLARS

FIGURE D.1



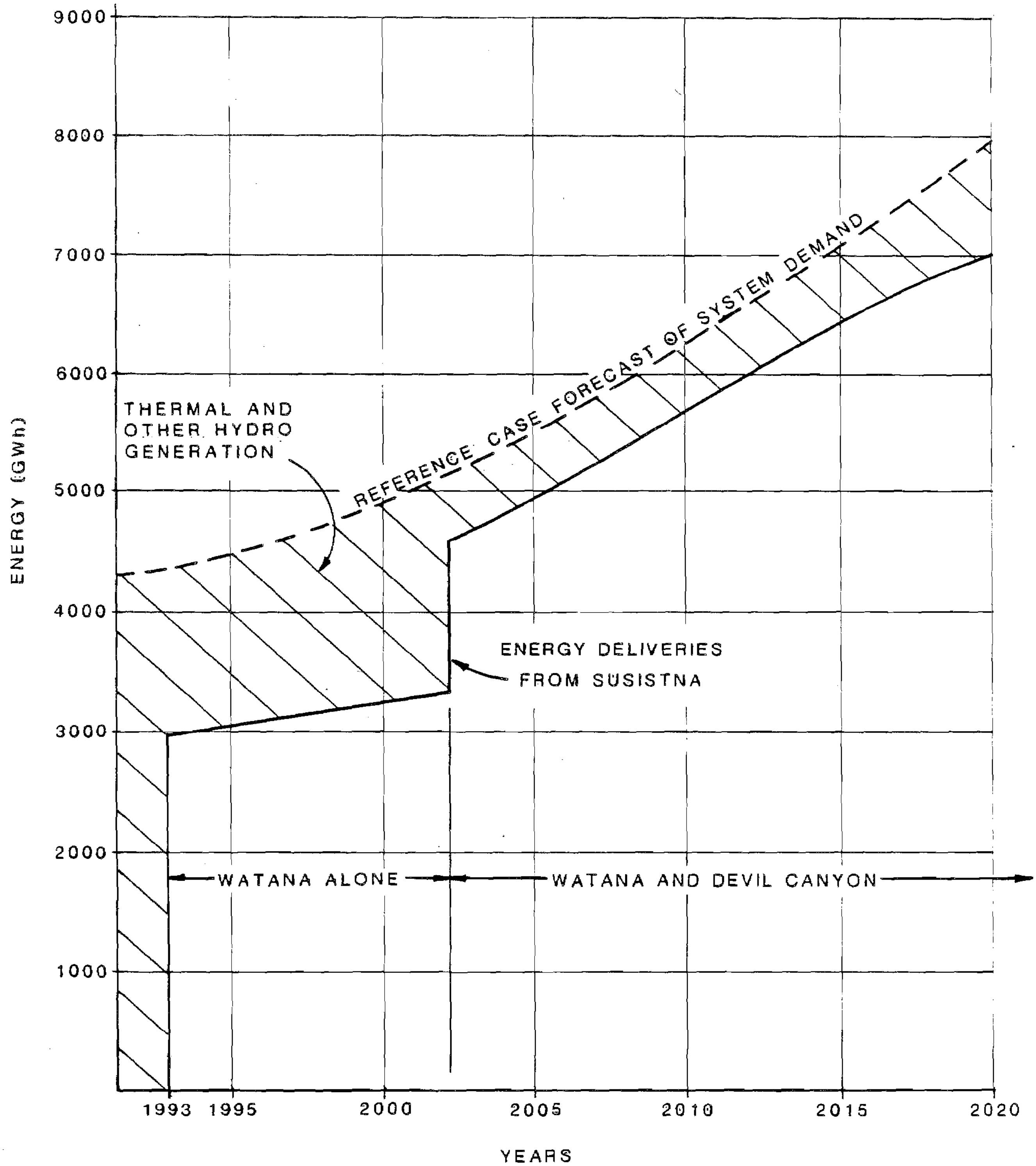
DEVIL CANYON DEVELOPMENT
CUMULATIVE AND ANNUAL CASH FLOW
JANUARY, 1982 DOLLARS

FIGURE D.2



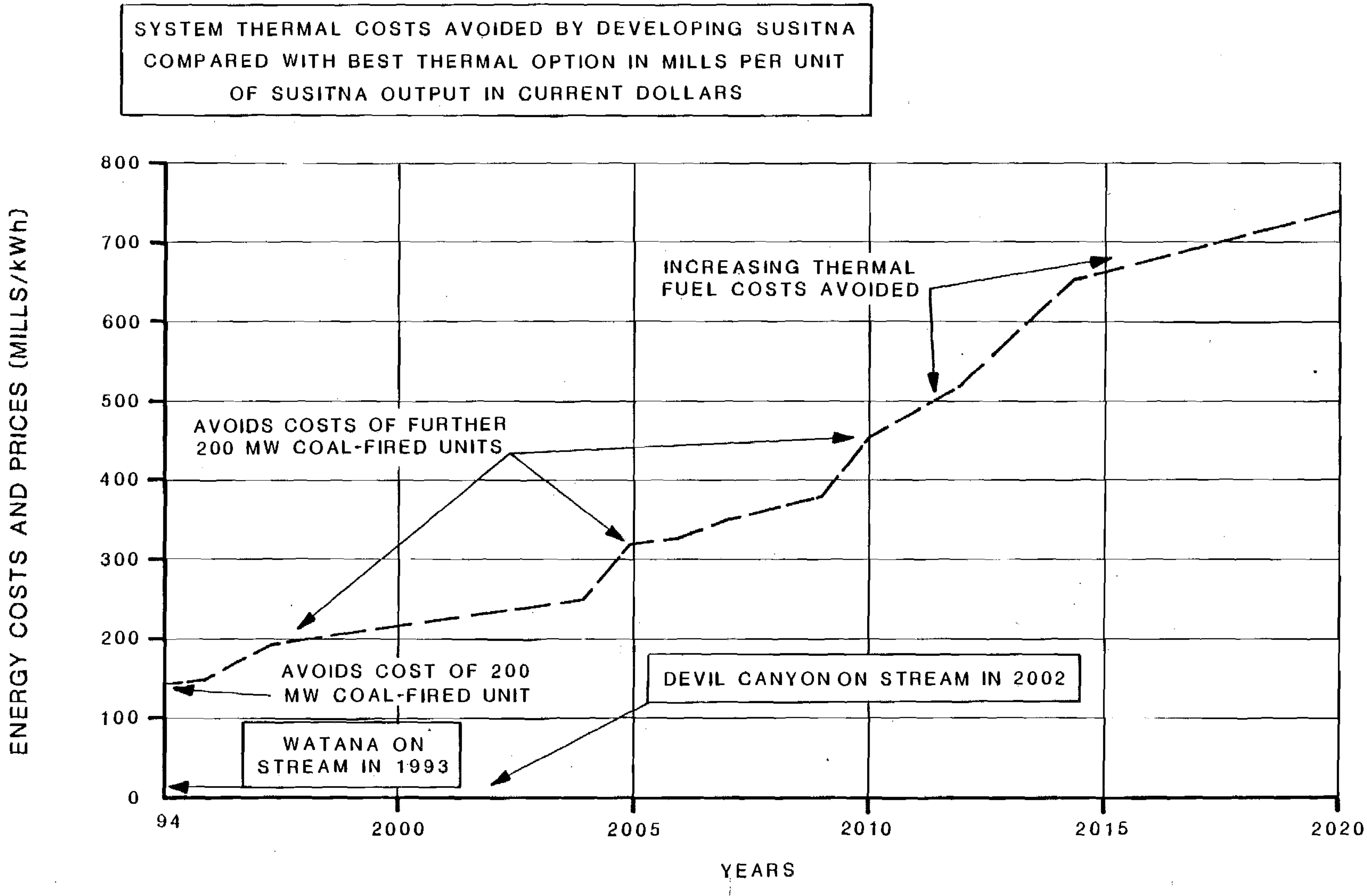
SUSITNA HYDROELECTRIC PROJECT
CUMULATIVE & ANNUAL CASH FLOW ENTIRE PROJECT
JANUARY 1982 DOLLARS

FIGURE D.3



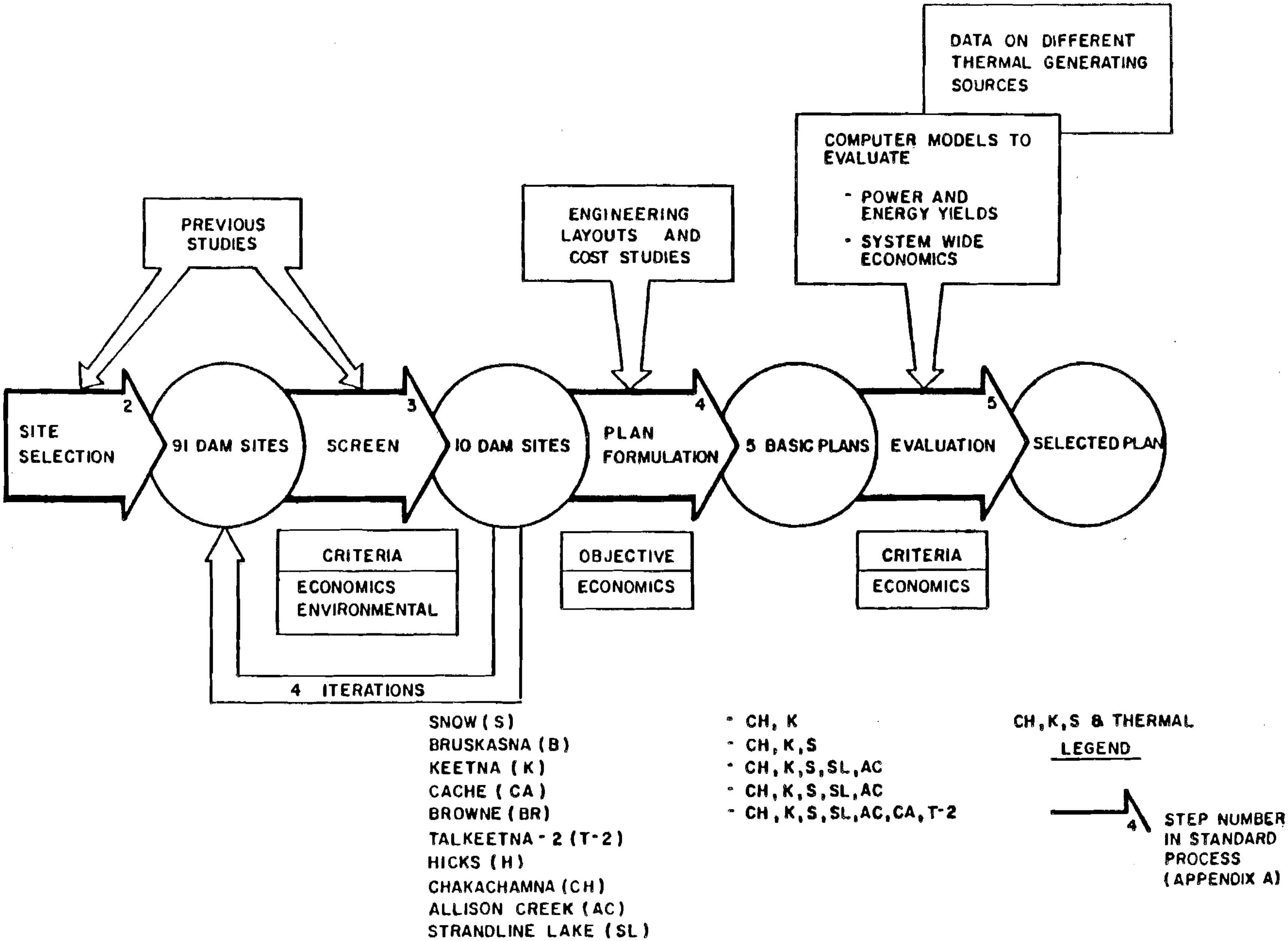
ENERGY DEMAND AND DELIVERIES FROM SUSITNA

FIGURE D.4



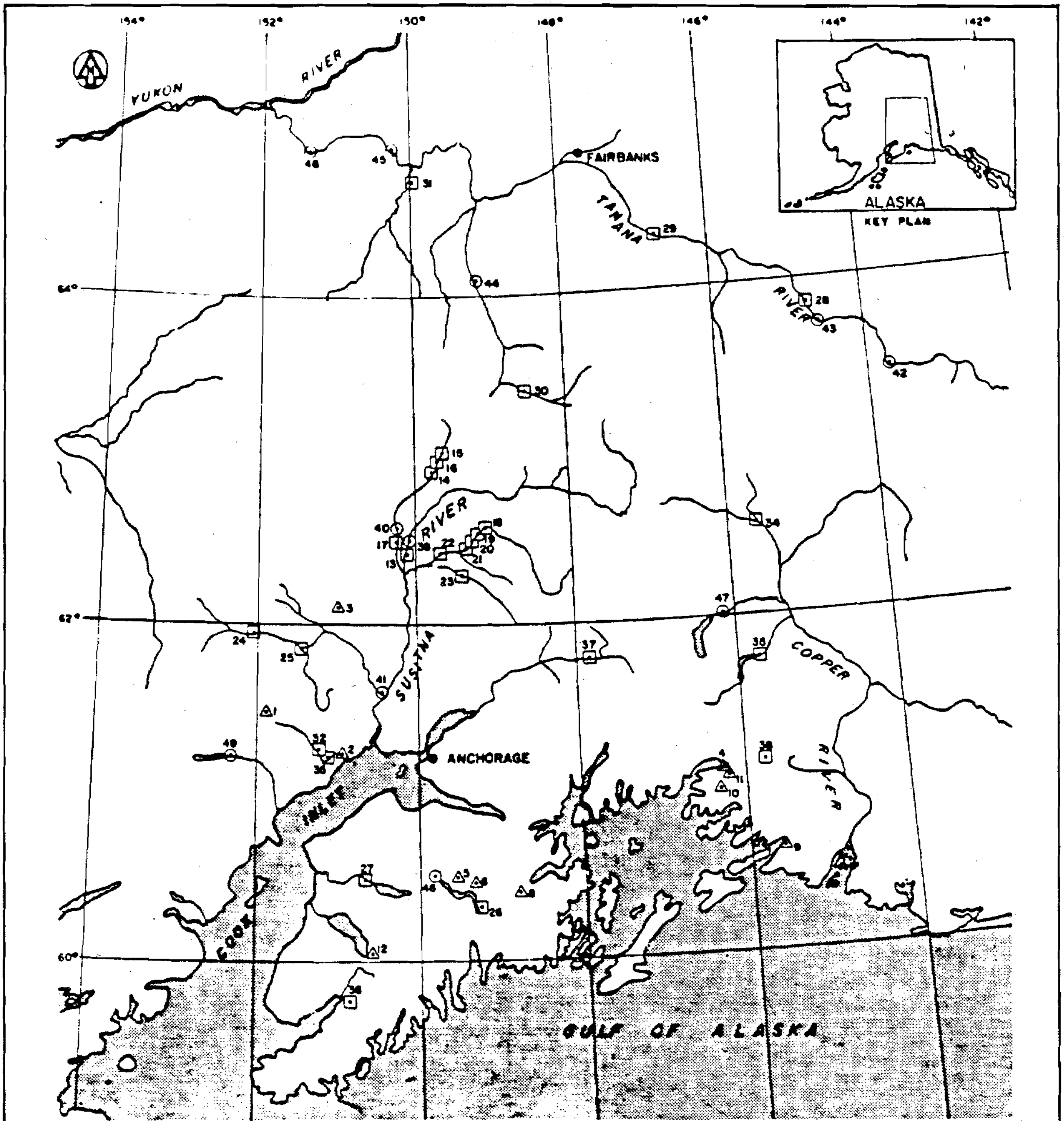
SYSTEM THERMAL COSTS AVOIDED BY DEVELOPING SUSITNA

FIGURE D-5



FORMULATION OF PLANS INCORPORATING NON-SUSITNA HYDRO GENRATION

FIGURE D.6



ALASKA RAILBELT REGION

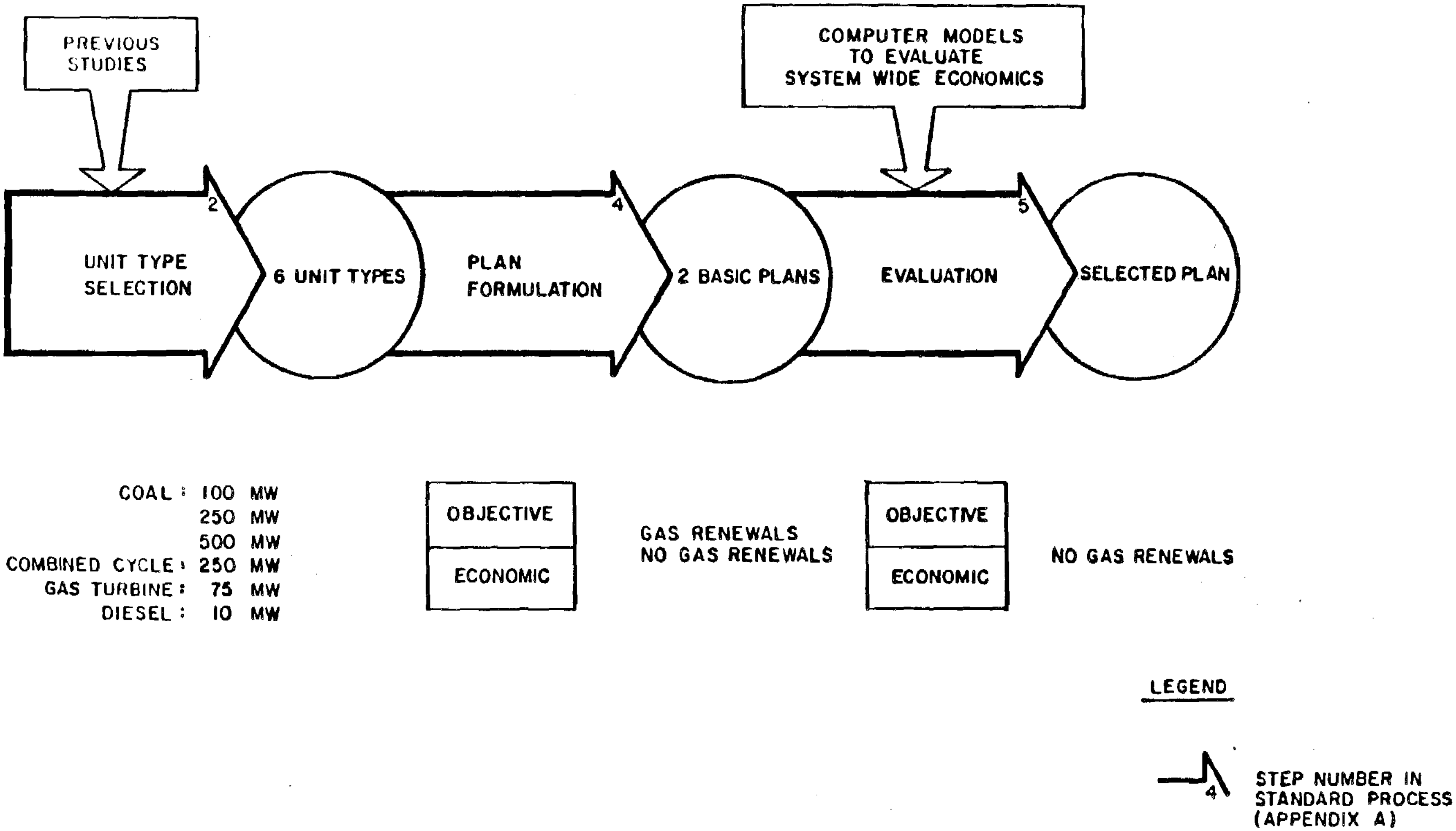
SCALE - MILES
1 INCH EQUALS APPROXIMATELY 40 MILES

△	⊡	⊙
0 - 25 MW	25 - 100 MW	> 100 MW

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

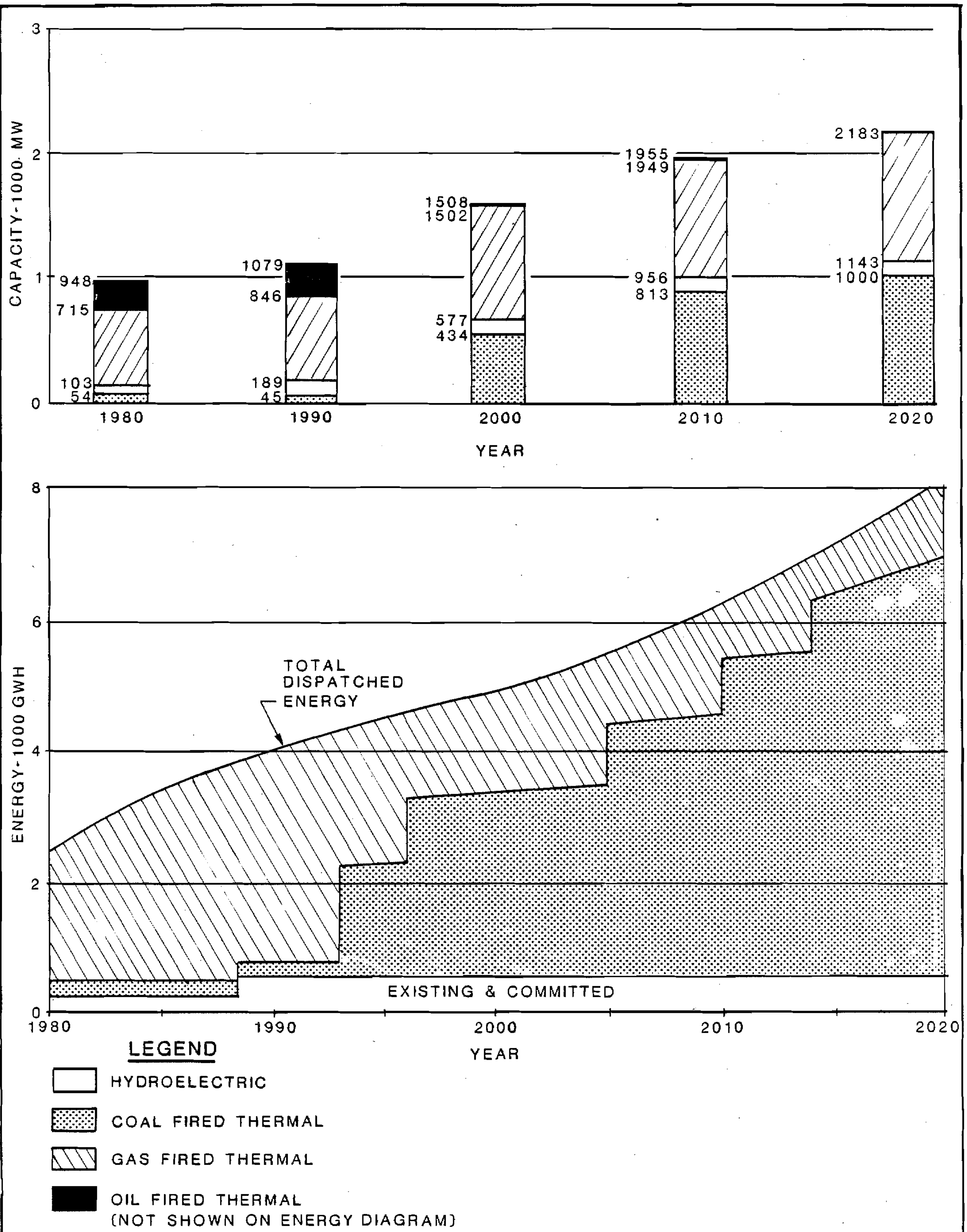
SELECTED ALTERNATIVE HYDROELECTRIC SITES

FIGURE D.7



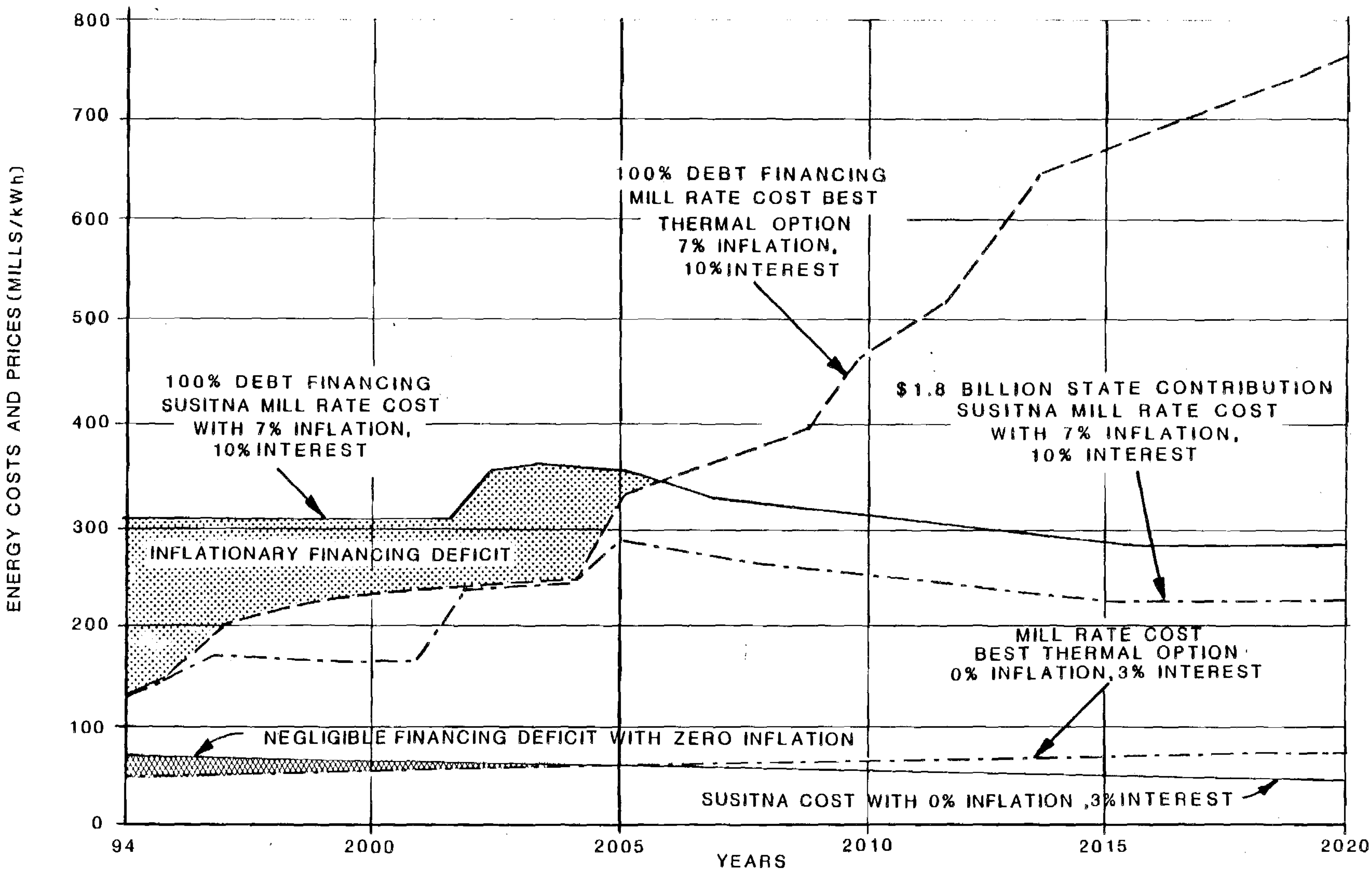
FORMULATION OF PLANS INCORPORATING ALL-THERMAL GENERATION

FIGURE D.8



ALTERNATIVE GENERATION SCENARIO
REFERENCE CASE LOAD FORECAST

FIGURE D.9



ENERGY COST COMPARISON-0 AND 7% INFLATION

FIGURE D.10

SUSITNA HYDROELECTRIC PROJECT

VOLUME 1

EXHIBIT D, APPENDIX D-1

FUELS PRICING STUDIES

APPENDIX D-1

FUELS PRICING STUDIES

Introduction

There are thermal alternatives to the Susitna Hydroelectric Project fueled by natural gas or coal. The economic viability of these alternatives and their competiveness with the Susitna Project depend heavily on the future availability and price of the required fuels.

The availability and price of fuels to meet Railbelt generation needs through the year 2040 are analyzed in this Appendix. The primary fuels that are analyzed are natural gas, coal, and distillate fuel oil. There are other potential fuels such as peat and wood, but these are not discussed due to the findings of previous studies that these fuels are not economically competitive when compared to natural gas and coal. Multiple data sources were employed including previous studies by consultants, information from state and federal agencies, and data, plans and other information from electric and gas utilities in the Railbelt Region of Alaska. Projections of future natural gas and distillate fuel prices are tied to the future world price of oil. Projections of future world oil prices are presented in Exhibit B, Section 5.4 of the Application.

Results concerning the availability and price of natural gas, coal and distillate oils are used as inputs into the Optimum Generation Planning Model (OGP) in the determination of the cost of thermal generating alternatives.

1. Natural Gas

1.1 Resources and Reserves

Known recoverable reserves of natural gas are located in the Cook Inlet area near Anchorage and on Alaska's North Slope at Prudhoe Bay. Gas is presently being produced from the Cook Inlet area. Some of the gas is committed under firm contract but considerable quantities of gas remain uncommitted and could be used for power generation. There are substantial recoverable reserves on the North Slope that could be used for power generation, but until a pipeline or electrical transmission line is constructed, the gas cannot be utilized. Undiscovered gas resources are believed to exist in the Cook Inlet area and also in the Gulf of Alaska where no gas has been found to date. Estimates of potential gas resources in these areas have been made by the United States Geological Survey and the Alaska Department of Natural Resources. The quantities of proven, potential and undiscovered gas from these areas are discussed below.

(a) Cook Inlet Proven Reserves

The locations of the Cook Inlet gas fields are shown in Figure D-1.1. Estimated recoverable reserves from the Cook Inlet fields and the commitment status of those reserves are shown in Figure D.1.2. This table has been developed from an earlier study[(1)*] and, updated and rearranged to reflect current conditions. Recoverable reserves are from the Alaska Oil & Gas Conservation Commission's latest estimate.[(2)]

New contracts between Enstar and Shell & Marathon are shown[(3)] in Figure D-1.2 as well as the five-year extension of the Phillips/Marathon LNG contract with Tokyo Gas and Tokyo Electric Companies.[(4)] Reserves that were formerly committed to Pacific Alaska Liquified Natural Gas (PALNG) Company are shown for reference purposes, but are included as uncommitted reserves, since PALNG's contracts for the gas expired in 1980. This is discussed further under Section 1.2(c). Much of the proven gas is not at present under contract. Figure D-1.2 shows that 1,654 billion cubic feet (BCF) of proven reserves is uncommitted.

In addition to proven recoverable reserves in the Cook Inlet area, there is the possibility of additional supplies in the form of undiscovered gas.

(b) Cook Inlet Undiscovered Gas

Earlier estimates of additional natural gas resources in the Cook Inlet area ranged from 6.7 trillion cubic feet (TCF) to 29.2 TCF.[(5)] These estimates may be high since subsequent drilling by Mobil and Arco in Lower Cook Inlet has not resulted in producing wells.

A recent study by the Department of Natural Resources of the State of Alaska presents estimates of undiscovered gas and oil and assigns probabilities to finding those quantities.[(6)] The mean or average quantity that is expected to be found is about 3.0 TCF. The estimate is presented in Table D-1.1.

The Department also estimated "economically recoverable" resources by assuming a recovery factor of 0.9 and a minimum commercial deposit size of 200 BCF. These are also presented in Table D-1.1. with an estimate of undiscovered gas is about 2.0 TCF.

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*References for the Natural Gas section are given on p. D1-23.

(c) North Slope Gas

Estimated recoverable natural gas reserves from the North Slope are about 29 TCF for the Sadlerochit Reservoir at Prudhoe Bay. Additional gas from the North Slope is estimated to be 4.5 TCF.[7] The State of Alaska royalty share of Prudhoe Bay reserves is 12.5% or 3.6 TCF. North Slope gas is currently either shut-in or reinjected into reservoirs to maintain pressure for oil extraction since there is no pipeline to areas where the gas can be utilized for electrical generation, heating or other uses.

(d) Gulf of Alaska Gas

The Gulf of Alaska lies to the east of the Kenai Peninsula and Anchorage and is close enough to the Railbelt area to be considered as a potential source of gas for Railbelt electric generation (see Figure D-1.3). To date, no oil or gas has been discovered in the Gulf of Alaska. The United States Geological Survey (U.S.G.S.) has, however, developed estimates of the quantities of gas that might exist in the Gulf.

The U.S.G.S. presents its estimates of undiscovered gas in terms of the probability of finding "economically recoverable" gas. Economically recoverable resources are those that can be economically extracted under price-cost relationships and technological trends prevailing at the time of the assessment.[8] For their low estimate, there is a probability of 95% that the estimated value will exceed. For the high estimate, there is a 5% probability that the estimated value will exceed recovering the cost of those volumes. The U.S.G.S. analysis can also be interpreted as having a probability of 90% that the amount of undiscovered gas will be between the low and high estimates. In addition to low and high estimates, the U.S.G.S. also provides a mean value as the quantity of gas most likely to be found. The U.S.G.S. estimates for the Gulf of Alaska Shelf (to a depth of 200 meters) are:[9]

Low	0.46 TCF
High	9.24 TCF
Mean	3.14 TCF

The estimate for the Gulf of Alaska Slope, i.e. those Gulf areas with a water depth from 200 meters to 2,400 meters, is:

Low	0.36 TCF
High	3.70 TCF
Mean	1.53 TCF

The long-term availability of Gulf of Alaska gas for electrical generation is at this time highly speculative. First, the gas (if any) must be found and developed; second, a pipeline must be constructed to deliver the gas to where electric generation would take place and third, the delivered price would have to be competitive with alternative fuels. Therefore, at this time, gas from the Gulf cannot be depended upon to supply Railbelt generation needs.

1.2 Production and Use of Natural Gas

Natural gas is produced and used in Alaska for heating, electrical generation, liquified natural gas (LNG) export and the manufacture of ammonia/urea. Most of the production and use (other than reinjection) currently takes place in the Cook Inlet area but the large proven quantities located on the North Slope and undiscovered potential in the Gulf of Alaska make these areas worthy of consideration for future use. Current and potential production from the three areas is discussed below.

(a) Cook Inlet Current Production and Use

The production and use of Cook Inlet gas for the past five years is shown in Table D-1.2. Gas that has been injected (or actually reinjected) was not consumed and is still available for heating, electrical generation, or other uses. The use of gas in field operations is the gas consumed at the wells and gathering areas to assist in the lifting and production of oil and gas. Use depends on the level of activity in oil and gas production which has been fairly constant over the last five years.

LNG sales are for export to Japan and the manufactured ammonia/urea is exported to the lower forty eight states. These uses of gas have been fairly constant in the past and are expected to remain so in future years.

Natural gas is used for electrical generation by Chugach Electric Association and Anchorage Municipal Light and Power. The use of gas by both of these utilities has been increasing to meet increases in electrical load and to replace oil-fired generation. The military bases in the Anchorage area, Elmendorf AFB and Fort Richardson, use gas to generate electricity and to provide steam for heating. The military gas use has been fairly constant in the past and is expected to remain so in the future.

The gas utility sales shown are made principally by Enstar and are for space and water heating, and other uses by residential, commercial, and industrial customers in the Anchorage area. These sales grow with increases in population and increased use by existing consumers. The growth is expected to continue in the future and will increase when Enstar begins gas service to the Matanuska Valley in 1986.

The item, Other Sales, shown in Table D-1.2 is a residual figure according to the Alaska Department of Natural Resources and is the difference between total sales as published by the Oil and Gas Commission and the sum of gas obtained from the utilities, Phillips/Marathon, Collier Chemical and other large users.

(b) Cook Inlet Future Use

The future consumption of Cook Inlet gas depends on the gas needs of the major users and their ability to contract for needed supplies. Since there is a limited quantity of proven gas and estimates of undiscovered reserves in the Cook Inlet area have yet to be proven, gas reserves will be exhausted by the late 1990's. In addition, there may not be sufficient gas for electrical generation beyond some point because of higher priorities accorded other uses, either through contract or by order of regulatory agencies such as the Alaska Public Utilities Comission. To estimate the quantity of Cook Inlet gas available for electrical generation, the requirements and priorities of the major users are discussed below.

Phillips/Marathon LNG currently have 360 BCF of gas under contract and Collier Chemical has 377 BCF (Figure D-1.2). It is highly probable that both entities will obtain enough of the uncommitted gas in Figure D-1.2 to meet their needs through 2010. The reason is that both Phillips/ Marathon LNG and Collier are established, economically viable facilities. They are also owned by Cook Inlet gas producers who control part of the uncommited reserves. Phillips/Marathon LNG and Collier are therefore estimated to consume 62 BCF and 55 BCF respectively per year from 1982 through 2010.

At present, Enstar has enough gas under contract to serve its retail customers until after the year 2000, but since Enstar also sells gas to the military, Chugach Electric Association, and Anchorage Municipal Light and Power for electric generation, it may have to seek additional reserves in order to meet the needs of those larger customers. It is assumed, however, that Enstar will be able to acquire sufficient gas to meet the needs of its retail customers (including new Matanuska Valley customers). Further, it is reasonable to assume that those customers' needs will have priority over the use of gas for electrical generation. Retail use is estimated to increase from about 18 BCF in 1982 to 52 BCF in 2010. This estimate incorporates an annual growth rate in sales of 3.5% from 1982 to 1998 plus additional sales of 1.5 BCF/year. beginning in 1986 (and growing at 3.5% annually) to customers in the Matanuska Valley. Sales from 1999 to 2010 were obtained by extrapolating total sales at the 1982-1998 growth rate of 3.5% per year. The effective growth rate for total sales from 1982-1998 is 4.5%. The Enstar estimate is reasonably close to a State of Alaska estimate which provides for a growth rate of 4.7% per year.[10]

Gas used in field operations and the residual, "Other Sales" vary from year to year but together are estimated to average about 25 BCF/yr. over the period 1982 to 2010 based on historical use as shown in Table D-1.3.

After satisfying all of the forementioned needs, there is still a considerable amount of gas remaining that could be used for electrical generation, at least for a number of years. Chugach Electric Association has 285 BCF committed through contract (see Figure D-1.2) and Enstar has 759 BCF contracted, some of which will be sold to Anchorage Municipal Power and Light and Chugach Electrical Association for electrical generation. Assuming that the Anchorage/Fairbanks intertie is completed in 1984-85, the electrical requirements of both cities could be met (at least in part) with generation using Cook Inlet gas.

An estimate of the quantities of Cook Inlet gas that would be required to meet all Railbelt electrical requirements was made using the estimated load and energy forecast (Reference Case) for the Railbelt area. Estimated generation from the existing Eklutna and Cooper Lake hydro units, and the proposed Bradley Lake hydro units, was subtracted, as well as generation from the existing Healy coal-fired unit. Average heat rates for the gas-fired units (principally simple-cycle combustion turbines) were assumed to be 15,000 Btu/KWh until 1995 when the heat rate would decrease to 8500 Btu/kWh to reflect the installation of high efficiency, combined cycle units.

The estimated annual gas requirements for power generation increase from 35 BCF in 1983 to 54 BCF in 2010. The quantity of gas used for electrical generations would, of course, vary with the load and energy use forecast that was assumed. The quantities calculated for electrical generation incorporate electrical energy use from the Reference Case forecast (see Exhibit B, Section 5.4). If the forecast for the DOR Mean case were assumed, the Cook Inlet proven reserves would provide for generation for a longer period while if the forecast for the SHCA Basecase was assumed, proven reserves would last for a shorter period.

The forecast annual and cumulative use of gas for each of the major users, and the total use of gas for the Railbelt, is shown in Table D-1.3. The remaining proven and undiscovered (mean or expected quantity) gas resources are also shown and as can be seen, proven reserves will be exhausted by about 1998, and expected undiscovered resources by about 2007. The estimated use of Cook Inlet proven reserves and undiscovered resources is graphically illustrated in Figure D-1.4.

The data from Table D-1.3 indicates that relying on all gas-fired electrical generation to provide the Railbelt's needs past the year 2000 is risky because it depends on the future availability of undiscovered reserves for electrical generation.

Other developments could also reduce or eliminate the availability of proven natural gas reserves for use in electrical generation. For example, there is the view that using natural gas for electric generation does not constitute the best use for the gas and that the gas should be conserved and used for space heating and process heat.(11)

The uncommitted, proven reserves and any undiscovered resources could be acquired by entities not shown in Table D-1.3, reducing or eliminating the availability of Cook Inlet gas for electric generation. This possibility is discussed next.

(c) Competition For Cook Inlet Gas

Known potential purchasers for the uncommitted, recoverable and undiscovered Cook Inlet gas reserves, in addition to those shown in Table D-1.3, are Pacific Alaska LNG Associates and whoever would own and operate the proposed Trans-Alaska Gas System (TAGS).

The proposed Pacific Alaska LNG (PALNG) project was initiated about ten years ago, but has been repeatedly delayed due to difficulties in obtaining final regulatory approval for a terminal in California. The project has also had difficulty in contracting for sufficient gas reserves in order to obtain Federal Energy Regulatory Commission (FERC) approval of the project. At one time, PALNG had 980 BCF of recoverable reserves under contract. The contracts expired in 1980, but producers did not give written notice of termination so the contracts have been in limbo. Recently, however, Shell Oil Company sold 220 BCF of gas that was formerly committed to PALNG to Enstar Natural Gas Company. This reduced reserves committed to the PALNG project to 760 BCF (see Figure D-1.2).

The FERC has approved the PALNG project, but with the condition that PALNG obtain 1.6 TCF of reserves for Phase I of the project and 2.6 TCF for Phase II.(12) Pacific Gas and Electric Company, one of the PALNG partners, does not plan to invest any more funds in the project and has filed with the California Public Utilities Commission (CPUC) for permission to place the expended funds into its "Plant Held for Future Use" account. PALNG also claims it requires additional equity partners to make the project viable, but, to date, has found none. Although PALNG is still searching for additional gas reserves, there is little chance that the project would begin construction prior to the erly 1990's.

Implementation of the project would depend primarily on the availability and price of alternative sources of natural gas for the lower forty eight market and particularly for the California market. According to one expert, Thomas J. Joyce, there are sufficient proven and probable reserves of conventional gas in the lower forty eight states to last fifteen to twenty years.(13) When all of these factors are considered, it does not appear that the PALNG project will be implemented prior to 1995. The recoverable reserves originally committed to PALNG can, therefore, probably be acquired by other purchasers such as Chugach Electric Association and Enstar.

The proposed TAGS project would build a natural gas transmission line from Prudhoe Bay on the North Slope to the Kenai Peninsula (near Nikishka). The gas from the North Slope would be liquefied and sold to Japan and other Asian countries.(14) The proposed project is an alternative method of bringing North Slope gas to market. If implemented it would eliminate the need for the Alaska Natural Gas Transportation System (ANGTS) which would pipe the gas across Alaska, through Canada and to market in the lower forty eight states.

If the project were implemented, Cook Inlet gas producers might be able to sell their gas to Trans Alaska Gas System for liquefaction and sale to Asia. Sale will depend on the capacity of the liquefaction plant and the market for LNG. The price paid by TAGS to Cook Inlet producers might be high enough to outbid competing purchasers, since the Cook Inlet gas would not be burdened with the costs of the transmission line from Prudhoe Bay (although shorter transmission and gathering lines would probably be required). Any estimate of the probability of whether TAGS will be implemented is difficult at this time, since the report on the project has just been published, and there has not been sufficient time for the proposal to be analyzed by many concerned and interested parties. However, an estimate of the maximum price that TAGS would probably be willing to pay Cook Inlet producers for gas delivered to the TAGS liquifacation plant has been made. (See a following section entitled, Current Prices).

(d) <u>North Slope Gas</u>

Over ninety percent of the North Slope gas is currently reinjected. Some is used in field operations, by Trans Alaska Pipeline System, by Prudhoe Bay refineries, and for North Slope local electrical generation. A small quantity from the South Barrow field is also used to meet residential heating needs. Table D-1.4 shows North Slope production and use for 1982. The problem in using North Slope gas for Railbelt electrical generation is that a pipeline must be constructed to bring the gas to where it is needed, i.e. Fairbanks or Anchorage. Alternatively, an electrical transmission line must be built so that power generated on the North Slope can be brought to load centers. The major proposals for utilization of North Slope gas are discussed below.

Alaska Natural Gas Transportation System (ANGTS): In this plan a pipeline would be constructed from the North Slope via Fairbanks and through Canada to the lower forty eight states. The project has been temporarily shelved due to a high estimated delivered price and the resulting difficulty in obtaining financing. The project will probably not be operational before the early to mid-1990s, so it is uncertain when North Slope gas can be transported to the Railbelt for electrical generation by this system.

Trans Alaska Gas System (TAGS): This alternative was recently proposed by the Governor's Economic Committee on North Slope Natural Gas. A pipeline would be constructed from Prudhoe Bay to the Kenai Peninsula where the gas would be liquified and sold to Japan and other Asian countries.(15) Some of the gas could be utilized for power generation at Kenai (or conceivably from a tap at Fairbanks although an additional processing plant would have to be installed since the gas is to be piped in an unprocessed state). Implementation of TAGS is highly uncertain at this time and therefore cannot be counted on to provide gas for future electric generation.

Pipeline to Fairbanks: In this plan, the North Slope gas would be transported to Fairbanks via a small diameter pipeline where it would be used to generate electricity for the Railbelt Area and also to meet residential and commercial heating needs in Fairbanks. Cost estimates indicate that this method is economically inferior to other proposed methods for utilization of North Slope gas and will therefore probably not be implemented.(16)

North Slope Generation: This proposed plan is an alternative to transporting the gas by some means, for the gas would be utilized in combustion turbines located on the North Slope and the electricity transmitted to the Railbelt Area. The costs of this plan are also believed to be prohibitive.(17)

(e) Gulf of Alaska Gas

To date, there have been no discoveries of gas in the Gulf of Alaska. This potential source of gas for Railbelt electrical generation is therefore too speculative at this time to incorporate its use into the future Railbelt generation alternatives.

1.3 Current Prices of Natural Gas

There is no single market price of gas in Alaska since a well developed market does not exist. In addition, the price of gas is affected by regulation via the Natural Gas Policy Act of 1978 (NGPA) which specifies maximum wellhead prices that producers can charge for various categories of gas (some categories will be deregulated in 1985). There are some existing contracts for the sale/purchase of Cook Inlet gas which specify wellhead prices but since there are no existing contracts for the sale of North Slope gas, the North Slope wellhead price can only be estimated based on an estimated final sales price and the estimated costs to deliver the gas to market. The current wellhead prices of natural gas for the Cook Inlet area and the North Slope are discussed below.

(a) Cook Inlet

Currently there are four contracts for the sale/purchase of Cook Inlet gas where the agreements were negotiated at arms length and the contracts are public documents. These are:

(1) Chugach Electric Assn./Chevron, ARCO, Shell contract for purchase of gas from the Beluga River Field.[18]

(2) Enstar/Union, Marathon, ARCO, Chevron contract for purchase of gas from the Kenai Field.[19]

(3) Enstar/Shell contract for purchase of gas from the Beluga River Field.[20]

(4) Enstar/Marathon contract for purchase of gas from the Kenai and Beaver Creek Fields.[20]

The Chugach contract current price is about \$0.28/MCF and under the terms of the contract is estimated to increase to about \$0.38/MCF in 1983 dollars by 1995. The contract will not be deregulated in 1985 by Subtitle B, Section 121 of the NGPA. The contract terminates in 1998 or whenever the contracted quantity of gas has been taken. At the maximum annual take of 21.9 BCF/yr., the contract will terminate in 1995 since 285 BCF remained under the contract on January 1, 1982 (See Figure D-1.2).

The Enstar/Union contract current wellhead price is about \$0.27/MCF and becomes about \$0.64/Mcf when delivered to Anchorage because of the addition of transmission costs. The wellhead price remains at \$0.27/MCF until 1986 where the price becomes the average price that Union/Marathon receives from new sales to third parties. If there are no new sales, the price will remain at \$0.27/MCF until contracted reserves are taken (estimated to be 1990 by Battelle) or the contract expires which is in 1992. Like the Chugach contract, this gas will not be deregulated by the NGPA in 1985.

The Enstar/Shell and Enstar/Marathon contracts were both signed in December 1982 and are essentially the same in that they have a base wellhead price of $2.32/MCF in 1983 with an additional demand charge of $0.35/MCF beginning in 1986. The base price and the demand charge are to be adjusted annually based on the price of No. 2 fuel oil at the Tesoro Refinery, Nikiski, Alaska. The contracts terminate in 1997 or whenever the contracted quantity of gas has been taken. The wellhead price of the gas under these contracts will be deregulated in 1985 under the NGPA.

The Phillips/Marathon LNG gas (see Section 1.2(b)) is not regulated and has a wellhead price that fluctuates with the delivered price of LNG in Japan which is tied to the world price of oil. Sources have quoted the wellhead price as $2.07/MCF in 1980[21] and $2.02/MCF in 1982.[22]

<u>Estimated Price For New Purchases:</u> If all current and future Railbelt electrical requirements are to be met with gas generation, new purchases of uncommitted Cook Inlet gas will be required. The price that will have to be paid for the additional gas is important in the evaluation of thermal alternatives versus the Susitna hydroelectric alternative.

Previous contracts for gas such as the Chugach/Chevron and Enstar/Union agreements are not indicative of the price that would have to be paid today for uncommitted gas since these contracts were entered into long ago and their current prices are substantially below any energy equivalency with oil or coal. Although low price gas from these contracts will be used for future electrical generation, the contracts expire in the 1990 - 1995 period therefore they are not relevant in the Susitna vs. gas-fired unit alternative economic analyses which covers the period 1993-2040. There may, however, be some marketing effects in the period 1993-1995 where electric utilities are still using low cost gas for fuel.

The price for new purchases would seem to depend heavily on whether the Cook inlet gas can be economically exported as LNG. With the postponement or demise of PALNG this possibility seems remote at the present time. Assuming therefore, that there is no competition from LNG exporters, the gas and electric utilities in the area would be the primary, remaining potential purchasers. The actual price that would be agreed upon between producers and the utilities is impossible to predict but an indication is provided by the Enstar/Shell and Enstar/Marathon contracts described below.

The wellhead price agreed on in the Enstar contracts was $2.32/MCF with an additional demand charge of $0.35/MCF beginning in 1986. The demand charge of $0.35/MCF in the Enstar/Marathon contract applies to all gas taken under the contract from January 1, 1986 to contract expiration. Under the Enstar/Shell contract, the demand charge of $0.35/MCF applies only if daily gas take is in excess of a designated maximum take. Enstar expects they will incur the demand charge because of electric utility requirements that increase the daily take. Estimated severance taxes of $0.15/MCF and a fixed pipeline charge of $0.30 for pipeline delivery from Beluga to Anchorage are additional costs. Future prices (Jan. 1, 1984 and on) are to be determined by escalating the wellhead price plus the demand charge based on the price of #2 fuel oil in the year of escalation versus the price on January 1, 1983. If it were assumed that the generating units were located at the source of gas, the pipeline charge would be eliminated giving a Jan. 1, 1983 price of $2.47/MCF. (See Table D-1.5).

The price in Table D-1.5 represents the best estimate currently available for the cost of Cook Inlet gas for electrical generation. Therefore this price was used as the base price of fuel for gas-fired generation in the thermal alternatives to Susitna over the period 1993-2040. Since the price is tied to the future price of oil, it was escalated based on the estimated future price of oil to obtain prices for 1993 to 2040 (See Projected Gas Prices Section).

Although the possibility of uncommitted Cook Inlet reserves being purchased for LNG export seems to be remote at the present time, conditions may change in the future. The price producers might be able to obtain if LNG export opportunities existed might then become important. A method that can be used to estimate wellhead prices for LNG export is to begin with the market price for delivered LNG and then subtract shipping, liquifaction, conditioning, and transmission costs to arrive at the maximum wellhead price.

Asian countries are probably the primary market for Alaska LNG, specifically Japan and Korea. Phillips/Marathon is presently selling LNG to Japan, and the TAGS study previously mentioned plans on selling to the Asian countries. LNG would compete with imported oil in those markets and its price would therefore be dependent upon the world price of oil. An example of this LNG/oil price competitivenesss is the existing contract between Phillips/Marathon and the Tokyo Gas and Toyko Electric Companies where the delivered price of gas is equal to the weighted average price of oil imported to Japan.(23) For an imported oil price of $34/bbl, the equivalent LNG price would be about $5.85/Mcf (1000 Btu/CF gas) and for an oil price of $29/bbl, about $5.00/MCF.

Conditioning, liquefaction, and shipping cost estimates were recently developed by the Governor's Economic Committee in their study of a Trans Alaska Gas System (TAGS) which would transport North Slope gas to the Kenai Peninsula via pipeline, then liquefy and ship the LNG to Japan.[24] These estimated costs are based on the large volumes of gas available from the North Slope. An LNG facillity for only Cook Inlet gas would be considerably smaller and there might be some economies of scale in going from a small to a large facility. These economies are not believed to be large however. In addition, it is just as likely that the TAGS will be implemented as a Cook Inlet only LNG facility and producers might therefore have the opportunity to sell their gas to either facility. The estimated costs for conditioning, liquefaction, and shipping of $2.00/MCF from the TAGS study are therefore believed to be representative for estimating the wellhead price of Cook Inlet gas where LNG export opportunities exist.

The estimated, netback, wellhead price of Cook Inlet gas for LNG export is shown in Table D-1.6. The price would vary depending on the average price of oil delivered to Japan so prices based on $34/bbl and $29/bbl oil are shown. The maximum price that could be paid to producers is $3.00-$3.85/MCF and these prices are higher than the estimated prices where no LNG export opportunities exist as shown in Table D-1.5. Therefore, if LNG opportunities did exist, the price of Cook Inlet gas for electrical generation would be higher than the price assumed herein (Table D-1.5) since the utilities would have to outbid potential LNG exporters.

(b) North Slope

The relevant price of North Slope gas for use in Railbelt electrical generation is the "delivered price", that is, the price of gas delivered to generating units located near the electric load centers or if generation were to take place on the North Slope, the equivalent price for electricity delivered to the load centers.

The delivered price is dependent upon the wellhead price that must be paid the North Slope producers and the cost of delivering the gas (or electricity) to the Railbelt load centers. The price that producers would accept is unknown but it is evident that they do not have a large number of alternatives to utilize the gas. They can shut the gas in or reinject as they are presently doing or sell to some entity that will transport the gas (or electricity) to market. There is a maximum price that the producers can charge since the gas is regulated by the Natural Gas Policy Act of 1978 but the only minimum would seem to be the value obtained from reinjection.

One method of estimating a North Slope wellhead price is to begin with a known or estimated price that the gas would bring in a given market and subtract the estimated costs to deliver the gas to that market. Since the sales price depends on the market to which the gas is delivered and the costs depend on the distance and method of delivery, it is best to anlayze the North Slope wellhead price and the cost of using the North Slope gas for electrical generation by the transportation method employed. This is done below for those transportation methods described under the section, "Production and Use of Natural Gas".

Alaska Natural Gas Transportation System (ANGTS): The ANGTS project if constructed as currently proposed, would deliver North Slope gas to the lower forty eight states by means of a large diameter pipeline traversing central Alaska, and Canada. A portion of the proposed line would be routed near Fairbanks, Alaska. Due to the line's proximity to Fairbanks, it would be feasible to construct a lateral line from the main ANGTS trunkline to Fairbanks, and thus bring North Slope gas to Fairbanks for use in both electric generation and heating. In a study conducted by Battelle, first year transportation costs to Fairbanks were estimated by apportioning the Alaska segment of the pipeline between Fairbanks customers and lower forty eight customers and adding the full costs of gas conditioning.(25) Battelle's estimated transportation costs in 1982 dollars were \$3.79/MMBtu (\$4.03 in 1983 dollars) and at the maximum wellhead price of \$2.30/MMBtu (June 1983) the delivered price to Fairbanks would be \$6.32/MMBtu in 1983 dollars.

In a 1982 study for the U.S. General Accounting Office (Study I), the fixed costs for ANGTS were estimated.(26) If the same allocation method that was used by Battelle is applied to the results of the General Accounting Office study, the first year transportation costs are about \$4.60/MMBtu in 1982 dollars (\$4.88/MMBtu in 1983 dollars). If the costs are levelized over the project's life, the costs would be about \$3.87/MMBtu in 1983 dollars.

In a separate 1983 study, the General Accounting Office (Study II) has also estimated conditioning and transportation costs associated with ANGTS.(27) The estimated cost of delivery to the lower forty eight is \$5.25/MMBtu (1982\$). When the allocation method used by Battelle to determine delivered costs at Fairbanks is employed, the conditioning and transportation costs are \$2.80/MMBtu in 1983 dollars. With a maximum wellhead price of \$2.30/MMBtu, the delivered price in Fairbanks is \$5.10/MMBtu. The cost estimates of Battelle and the GAO are summarized below in 1983 dollars per MMBtu.

Estimate	Transportation Costs	Maximum Wellhead Price	Maximum Total Cost Delivered to Fbks.
Battelle (1st yr.)	$4.03	$2.30	$6.32
GAO Study I			
First Year	4.88	2.30	7.18
Levelized	3.87	2.30	6.17
GAO Study II First Year	2.80	2.30	5.10

None of the cost estimates include severance or state of Alaska property taxes. These taxes are roughly estimated to total somewhere between $0.50 and $1.00/MMBtu.

The estimated costs delivered to Fairbanks are well above the Cook Inlet estimated gas costs for 1983 even with a North Slope wellhead price of $0.00. Because implementation of the ANGTS project is doubtful, its estimated gas costs are not considered to be reasonable prices to use as inputs to the thermal alternatives.

Trans Alaska Gas System (TAGS): The TAGS proposes to deliver gas to the Kenai Peninsula for liquefaction and export as LNG. Some of the gas could undoubtedly be used for electric generation at Kenai. The costs to electric utilities of the gas can be estimated from information in the TAGS report. This information is presented in Table D-1.7 for the total TAGS system and Phase I of the system. A low tariff which would provide a 30% after tax return to equity investors, and a high tariff which would provide 40%, are shown for both the total system and Phase I.

The price that electric utilites would have to pay is dependent upon the LNG sales price in Japan so prices of $5.85/MMBtu and $5.00/MMBtu have been shown. These correspond to oil prices in Japan of $34/bbl and $29/bbl respectively.

Using the netback approach, shipping and liquefaction costs are subtracted from the sales prices for these would be avoided by TAGS if the gas was sold to electric utilities at the LNG plant. As can be seen, prices vary from $3.03/MMBtu to $4.19/MMBtu but the lower prices may not be realistic since they may result in low or negative wellhead prices to the producers. In addition, at an estimated sales price of $5.00/MMBtu, the TAGS would probably not be implemented.

Subtraction of gas conditioning costs and pipeline transmission costs gives the wellhead price which varies from a negative $1.34 to $1.81/MMBtu depending on the system, tariff, and sales price assumed.

If it is assumed that TAGS would be implemented only at an LNG sales price of $5.85/MMBtu or above, that the total system would be constructed and that some point between the low and high tariff was acceptable to investors and North Slope producers, then the price of gas to electric utilities at Kenai would be $3.96-$4.19/MMBtu.* These assumptions seem to be reasonable and a 1983 cost of North Slope gas of $4.00/MMBtu delivered to the Kenai Peninsula for electric generation will therefore be assumed.

Pipeline to Fairbanks: Transportation costs of a small diameter pipeline to Fairbanks have been estimated to be about $4.80/MMBtu for electrical generation.(28) Using the average of the reasonable TAGS wellhead prices discussed above of $1.28/MMBtu (ave. of $0.75 and $1.81/MMBtu) provides a delivered cost in Fairbanks of $6.00/MMBtu. This cost is considerably higher than the estimated cost from TAGS and was therefore not used in the analysis of thermal alternatives.

North Slope Generation: This alternative uses the North Slope gas without incurring transportation costs for the gas. However, the generated electricity must be transmitted to the Fairbanks load center thereby requiring the construction of an electrical transmission line. The capital costs and O&M costs of this line have also been estimated and they are about 80% of the cost of the gas transmission lines.(26) Based on this, an equivalent "gas" transportation cost would be $3.84/MMBtu (0.8 x $4.80/MMBtu) which when added to a wellhead price of $1.28/MMBtu would result in an "equivalent delivered" cost of gas of $5.12/MMBtu. This is less than the small diameter pipeline alternative but still considerably more than the TAGS delivered cost. This price was therefore not used in the analysis of thermal generation alternatives.

The estimated delivered cost of gas to Railbelt load centers based on transportation costs and assumed wellhead prices are shown in Table D-1.8. The only cost for North Slope gas used as an input to the thermal alternatives analysis, however, is the cost derived from the TAGS study which was found to be about $4.00/MMBtu in 1983 dollars.

*This would provide investors an after-tax return on equity between 30 and 40% and North Slope producers a wellhead price between $0.75 and $1.81/MCF.

1.4 Projected Gas Prices

The estimated 1983 costs of Cook Inlet and North Slope gas were developed in the previous sections. Since the analysis of thermal alternatives covers the period 1983-2040, a method for projecting the 1983 price must be utilized.

The method selected is to tie the price of natural gas to the world price of oil since the two fuels can be substituted in many cases and particularly since the recent Enstar gas purchase contract price is tied to the price of oil. The Enstar price was used as the 1983 estimated price of gas for the Cook Inlet area and it is assumed to be representative of future contracts for Cook Inlet uncommitted and undiscovered gas.

If North Slope gas is sold as LNG to Japan or Korea, the delivered price will probably be tied to the world price of oil in the same manner as the existing Phillips/Marathon LNG contract. Electric utilities who purchase gas from future LNG exporters will probably also have to pay a price which is adjusted to the world oil price.

The future price of Cook Inlet natural gas was calculated by escalating the base 1983 price from Table D-1.5 with the world oil price change scenarios from Exhibit B, Section 5.4. Future gas prices using alternative oil price projections are shown in Table D-1.9.

The future price of North Slope natural gas was calculated by escalating the base 1983 price from Table D-1.8 with the same world oil price change scenarios used for Cook Inlet gas. The estimated future prices are shown in Table D-1.10.

The natural gas prices from Tables D-1.9 and D-1.10 were used as the price of gas fuel in the evaluation of Railbelt thermal alternatives.

1.5 Effect of Gas Price Deregulation

The wellhead price of all interstate and intrastate natural gas in the United States is currently set by the Natural Gas Policy Act of 1978 (NGPA). Among other things, the NGPA sets the maximum ceiling prices which can lawfully be changed for specific categories of gas production; extends federal price controls over the interstate market to include intrastate gas; and deregulates as of November 1, 1979 the price of certain categories of "high cost" gas, i.e. deep gas, geopressurized gas, coal seam gas and Devonian shale gas. In addition, the NGPA provides a schedule for price deregulation of additional categories of gas beginning January 1, 1985.

To speed up the process of natural gas price decontrol, the Reagan Administration has recently proposed a bill, appearing as S.615 in the Senate and as H.R.1760 in the House. It would deregulate the price of all natural gas, regardless of production category, for which a new contract had been entered, or an old contract amended, after the effective date of the legislation when passed. Several legislative proposals have surfaced in both the Senate and House in oppositon to this proposal. Primarily, the opposition is committed to retaining price controls on "old price", that is, gas which has been dedicated to interstate commerce prior to passage of the NGPA. Further, opponents would maintain, and in some areas restrict, the present NGPA schedule of phased decontrol of new gas. Representative of this oppositon is a measure sponsored by Senator John Heinz, (R-Pa.) Heinz's bill, the Natural Gas Policy Amendment of 1983 (S.689), would continue indefinitely price controls on all old gas, and for certain old gas would actually roll back the current price to November 1, 1978 levels. Further, it would continue the NGPA schedule for decontrolling the price for certain new gas categories by January 1, 1985.

In this section, an analysis and comparison has been made of the potential costs of both Cook Inlet and North Slope natural gas under several legislative scenarios. First, examination is made of the effects on existing Cook Inlet contracts and potential future contracts of continuing present NGPA pricing and phased decontrol provisions. Second, proposed legislative changes either to accelerate deregulation of both old and new gas, or to limit deregulation, are examined for their most likely effects on Alaska gas prices. These most likely resulting Alaska gas prices are then analyzed to determine the potential cost of electrical generation from thermal alternatives in the Railbelt area.

(a) Existing Law

Title I, Subtitle A, the NGPA establishes discrete categories of natural gas production, and sets a maximum ceiling price for each category of gas. In defining these categories, the NGPA draws a distinction between "old gas," which was under contract prior to passage of the NGPA, and "new gas," or post-NGPA supplies. Old gas generally has lower ceiling prices than new gas, and is governed by Sections 104 and 106 in the case of interstate contracts, and Sections 105 and 106 in the case of intrastate contracts. New gas is governed generally by Sections 102 and 103. In addition to enjoying higher ceiling prices under Subtitle A, this gas is potentially subject to decontrol in 1985 under the provisions of Subtitle B, Section 121. Further, North Slope gas to be transported by ANGTS can only be priced under Section 109 and is not eligible for decontrol under Section 121.

To adequately evaluate the effect of NGPA pricing on Alaska gas, all existing contracts are individually analyzed. Potential future contracts are also addressed.

(i) Chugach and Chevron, ARCO, Shell Contract. Chugach Electric Co-op has a contact with Chevron, ARCO and Shell for purchase of Beluga field gas, in the Cook Inlet area.

Production under the contract began in 1968, and the current price is approximately 27¢/mcf.

As an existing intrastate contract at the time of the NGPA's adoption, gas prices under this contract would be governed by Section 105 of the NGPA. Section 105 provides that the maximum lawful price shall be the lower of the existing contract price, or the new natural gas maximum price as computed under Section 102. The Section 102 ceiling price was \$1.75/MMBtu in April, 1977, and has been escalating monthly since that time, in accordance with the terms of Section 101 of the NGPA. The contract price of the 27¢/mcf for this Cook Inlet Area gas (which has an HV of approximately 1000 Btu/ft^3) obviously is lower than the Section 102 price. Therefore, in accordance with Section 105, the contract price must serve as the ceiling price, at least until 1985, when some of the gas under contract may be eligible for decontrol. However, Section 121(a)(3) pertaining to deregulation of prices for gas under existing intrastate contracts provides that such gas prices will only be deregulated if the price for such gas would exceed \$1.00/MMBtu on December 31, 1984. As gas under this contract is at present expected to stay at 27¢/MMBtu on December 31, 1984, deregulation may not change the contract price of this gas.

(ii) Enstar, Union, Marathon, ARCO, Chevron Contract. This contract for purchase of Kenai field gas from Union, Marathon, ARCO, and Chevron was originally executed by Enstar in 1960, but has been amended several times. The price currently is about \$0.64/Mcf. As such, it too is governed by Section 105 of the NGPA. As explained in the discussion of the Chugach/Chevron contract under Section 105 the contract price would serve as the NGPA ceiling price, for it also is lower than the Section 102 ceiling price.As with the Chugach/Chevron contract, some of the gas to be produced under this contrct may be eligible for decontrol in 1985. But if the price under this contract remains under \$1.00/MMBtu on December 31, 1984, decontrol will not alter this contract price.

(iii) Enstar/Shell, Enstar/Marathon Contracts. These contracts were signed in December, 1982 for purchase by Enstar of Kenai field gas from Shell and Marathon. The current price is \$2.32/Mcf. Most of the gas under contract is new gas governed by Section 102 of the NGPA. The contract also includes some Section 103 gas. The maximum prices for these categories of gas in June 1983 were \$2.78/MMBtu and \$3.42/MMBtu, respectively.

Pursuant to Subsection B, Section 121, prices for Section 102 and 103 gas would be decontrolled on January 1, 1985, therefore gas prices under these two contracts are subject to eventual decontrol.

(iv) New Cook Inlet Contracts. Contracts for Cook Inlet gas signed between now and January 1, 1985 will probably be regulated as to maximum price by Subtitle A, Section 102 or Section 103. The current maximum prices for these categories of gas (June 1983) are \$3.42/MMBtu and \$2.78/MMBtu respectively. The prices are allowed to increase at a rate in excess of the inflation rate for Section 102 gas and at the inflation rate (GNP deflator) for Section 103 gas.

New contracts will probably be decontrolled by Subtitle B, Section 121(a) of the NGPA on January 1, 1985. Further, Section 121(a)(3) provides for decontrol of existing intrastate contracts where the contract price of the gas is in excess of \$1.00/MMBtu on December 31, 1984.

(v) North Slope Gas. There are currently no contracts for sale/purchase of gas from the North Slope. Morever, Section 102(e) and Section 103(d) specifically exclude from regulation gas produced from the Prudhoe Bay Unit of Alaska and transported through ANGTS. North Slope gas transported via ANGTS is regulated under Section 109, Ceiling Price For Other Categories of Natural Gas. The base price under Section 109 was \$1.45/MMBtu in April 1977 and adjusted for inflation gives the current price of \$2.30/MMBtu (June 1983). If the North Slope gas were transported under another system, e.g. TAGS or a small diameter pipeline to Fairbanks, presumably it would be controlled under Section 102 or 103.

(b) Proposed Changes to the NGPA

Bills have been introduced into Congress which would change the NGPA and its effect on natural gas prices. Chief among these are the Reagan Administration bill (S.615) and a bill introduced by Senator Heinz of Pennsylvania (S.689.) A House bill advancing similar concepts as S.689 has been introduced by Congressman Philip Sharp (D-Ind.) The effects of S.615 and S.689, and the probable effect on Alaska natural gas prices of efforts to accelerate, or alternatively restrict, gas price decontrol are discussed below.

The Administrations' Bill. This proposed bill would immediately remove federal price controls from all gas not presently committed by contract. In addition, any existing contract could be abrogated by either seller or purchaser during a period from Jan. 1, 1985 to Nov. 15, 1985. If the contract was not abrogated during that period, its existing terms and conditions would remain in effect until contract expiration.

The Chugach/Chevron, ARCO, Shell contract would undoubtedly be abrogated by the producers if the Administration bill were implemented. The price of gas under that contract is estimated to be $0.32/MCF on Jan 1, 1985 and that price is well below any reasonable estimate of market price at that time (see Table D-1.9).

The Enstar/Union contract would also undoubtedly be abrogated since the estimated price of gas under that contract will be $0.64/MCF on Jan. 1, 1985, again well below estimates of market value.

The Enstar/Shell and Enstar/Marathon contracts signed in Dec. 1982 may or may not be abrogated depending on what the producers and Enstar believe the market price of gas to be relative to the contract price in 1985. The base contract price of $2.32/MCF (plus $0.35/MCF beginning in 1986) changes with the price of No. 2 fuel oil and is estimated to be about $2.16/MMBtu in 1985, jumping to about $2.51/MMBtu in 1986 (See Table D-1.9 - Reference Case). The estimated maximum price that will be obtainable for Cook Inlet gas if deregulation occurs is discussed in a later section.

The Heinz Bill. Introduced by Senator Heinz of Pennsylvania, the bill would amend the NGPA to prevent deregulation of certain intrastate contracts that would otherwise be deregulated in 1985 (Section 121 (a) (3) - Intrastate Contracts in Excess of $1.00) and declare indefinite price escalators to be null and void. The bill apparently makes no change in the status of North Slope gas, i.e. the gas will remain regulated as Section 109 gas, provided it is transported via ANGTS.

The bill would deregulate New Natural Gas and New Onshore Production Wells that are now scheduled for deregulation under Sections 121(a)(1) and 121(a)(2) of the NGPA. Any uncommitted or undiscovered gas in the Cook Inlet area and the Gulf of Alaska would therefore not be controlled after passage of the Bill.

The principal differential effect this bill would seem to have on Alaska gas when compared with the NGPA would be the nullification of the escalation clauses in the Enstar/Marathon and Enstar/Shell contracts.

(c) Deregulated Cook Inlet Gas Prices

Of the proposed bills, implementation of the Reagan bill would have the greatest effect on natural gas prices in Alaska. The greatest potential effect would be on Cook Inlet gas prices where producers would undoubtedly exercise their market out rights in 1985 for two of the existing contracts and possibly for the remaining two. There would probably be no effect on the price for future sales of North Slope gas for the wellhead price of that gas is dictated by the cost to deliver the gas to market and all estimates show that the netback wellhead price is already below the NGPA regulated price.

The price that Cook Inlet producers would be able to command for their deregulated gas is of course unknown, but an estimate of the maximum price that they would be able to charge for sales of gas to use in the generation of electricity is possible. The maximum price would be that price at which electric utilities became indifferent to whether they generated using gas or coal. If producers attempted to charge a higher price, the electric utilities would build coal-fired rather than gas-fired units.

The cost of generation using coal can be estimated from the capital, fuel, and operating and maintenance expense associated with coal-fired generation. The capital and operating and maintenance expenses for a gas-fired unit can also be estimated and when these costs are subtracted from the total costs of coal generation, the maximum amount that can be paid for gas fuel is left. This dollar difference can then be translated into a cost per MMBtu through use of the gas-fired units heat rate and annual generation.

The calculation of an indifferent gas fuel price is presented in Figure D-1.5. The size of both coal and gas-fired units are assumed to be 200MW and generate 1.5 billion kWh per year. Other key paramters for the two units are listed in the figure.

The resulting indifferent gas price is \$3.19/MMBtu. This price is the maximum estimated 1983 price that gas producers could charge electric utilities for gas fuel under full deregulation of gas prices. Future year prices for deregulated gas would be obtained by escalating the estimated 1983 price at the oil price rates of change from Exhibit B, Section 5.4.

1.6 References and Notes

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2 - Coal

This analysis of coal availability and cost in Alaska has been developed to provide the basis for evaluating thermal alternatives to the Susitna Hydroelectric Project. This assessment has been developed by a careful review of available literature plus contacts with Alaskan coal developers and exporters. The literature reviewed included the Bechtel (1980) report executive summary, selected Battelle reports (e.g., Secrest and Swift, 1982; Swift, Haskins, and Scott, 1980) and the U.S. Department of Energy (1980) study on transportation and marketing of Alaskan coal. Numerous other reports were used for data confirmation. In addition, Paul Weir Company of Chicago was engaged to develop the estimated cost of a mine in the Beluga field for the purpose of electric power generation for the Railbelt only.

2.1. Resources and Reserves

Alaska has three major coal fields: Nenana, Beluga, and Kukpowruk. It also has lesser deposits on the Kenai Peninsula, in the northwest and in the Matanuska Valley. Alaska deposits, in total, contain some 130 billion tons of resources (Averitt, 1973), and 6 billion tons of reserves as shown in Table D-2.1. The Nenana and Beluga fields are the most economically promising Alaska deposits as they are very large and have favorable mining conditions. The Kukpowruk deposits of North Slope cannot be mined economically, and also face substantial environmental problems (Kaiser Engineers, 1977). The northwest deposits in the area of Kotzebue Sound and Norton Sound are small and have high mining costs associated with them, although little is known about these fields (Dames and Moore 1980; Dames and Moore, 1981a; Dames and Moore, 1981b). The Kenai and Matanuska fields are also small and present additional mining difficulties (Battelle, 1980).

The Nenana Field, located in central Alaska, contains a reserve base of 457 million tons and a total resource of nearly 7 billion tons as is shown in Table D-2.2. Its subbituminous coal ranges in quality from 7400-8200 Btu/lb. It is high in moisture content, low in sulfur content, and very reactive (see Table D-2.3). Some 84% of this coal is contained in seams greater than 10 ft. in thickness, and stripping ratios of 4:1 are commonly encountered (Energy Resources Co., 1980).

The Beluga Field contains identified resources of 1.8 billion tons (Department of Energy, 1980) to 2.4 billion tons (Energy Resources Co., 1980). The quality of this subbituminous coal varies according to report. Several analyses are shown in Table D-2.4. Beluga deposits typically are in seams greater than 10 ft. in thickness (Energy Resources Co., 1980) and may be up to 50 ft. thick in places (Barnes, 1966). Stripping ratios from 2.2 to 6 are commonly found.

2.2 Present and Potential Alaskan Coal Production

Currently there is only one significant producing mine in Alaska, the Usibelli Coal Co. mine located in the Nenana Field. This mine produces 830 thousand tons of coal/yr for use by local utilities, military establishments, and the University of Alaska-Fairbanks. These users operate 87 Megawatts (MW) of electrical generation capacity, as shown in Table D-2.5. Plans exist at Fairbanks Municipal Utility System (FMUS) to increase the total coal-fired electric generating capacity in Alaska to 108 MW (Sworts, 1983). The FMUS capacity shown in Table D-2.5 also serves the Fairbanks district heating system.

To produce the 830 thousand tons/yr., Usibelli Coal Co. employs a 33 cubic yard dragline and a front end loader-truck system. This mine, with its existing equipment, has a production capacity of 1.7-2.0 million tons/yr. Much of that capacity would be employed when the Suneel Alaska Co. export contract for 880 thousand tons (800 thousand metric tons)/yr becomes fully operational. That contract calls for full-scale shipments, as identified above, to the Korean Electric Power Co. beginning in 1986.

Production at the Usibelli mine ultimately could be increased to 4 million tons/yr (Department of Energy, 1980; Battelle, 1982). The mine, which has been in operation since 1943, has 300 years of reserves remaining at current rates of production. Thus, at 4 million tons of production, mine life would exceed 70 years. This production, which may not be able to be used at the mine mouth for environmental reasons due to proximity to the Denali National Park (Ebasco, 1982), may be shipped to various locations via the Alaska Railroad.

The Beluga Field, which totally lacks infrastructure, currently is not producing coal; however, several developers have plans to produce in that region. These developers include the Diamond Alaska Coal Co., a joint venture of Diamond Shamrock and the Hunt Estates; and Placer Amex Co. Involved in their plans are such infrastructural requirements as the construction of a town, transportation facilities to move the coal to tidewater, roads, and other related systems. These auxiliary systems are necessary if one or more mines are to be made operational.

Diamond Alaska Coal Co. holds leases on 20 thousand acres of land (subleasing from the Hunt-Bass-Wilson Group), with 1 billion tons of subbituminous resources. Engineering has been performed for a 10 million ton/yr mine designed to serve export markets on the Pacific Rim; and the engineering has involved a mine, a 12 mile overland conveyor to Granite Point, shiploading facilities at Granite Point, town facilities, and power generation facilities. The mine itself involves two draglines plus power shovels and trucks. The target timeframe for production is 1988-1991. Placer-Amex plans involve a 5 million ton/yr mine in the Beluga field, also serving the export market (Department of Energy, 1980).

As can be seen, the primary plans for the Beluga Field are for exporting of coal to the Pacific Rim. The proponents of exports believe that Alaskan coal can compete on a cost basis with Austrailian coal, that Alaskan coal is more competitive than lower 48 U.S. coal (Swift, Haskins, and Scott, 1980), and that policy decisions in Japan and Korea to diversify their sources of coal supply favor the exporting of Alaskan coal (Swift, Haskins, and Scott, 1980). The export of U.S. coal to Japan also is seen as a means for treating the balance of payment problems between the two countries, and this could work in favor of Alaskan development. Certain factors, however, might impede development of an Alaskan coal export market, e.g. quality of coal and Japanese coal specifications (Swift, Hasins and Scott, 1980).

It is also feasible to develop the Beluga Field at a smaller scale for local needs, however. This potential is recognized, inferentially, by Olsen, et. al. (1979) of Battelle and supported explicitly by Placer-Amex (McFarland, 1983). Diamond Alaska Coal Co. currently is performing detailed engineering studies on a 1-3 million ton/yr mine in this field. As a consequence, it is reasonable to conclude that production in both the Nenana and Beluga fields could be used to support new coal fired power generation in Alaska, with or without the development of an export market.

2.3. Current Alaskan Coal Prices

The issue of coal prices can be addressed either from a production cost perspective or a market value perspective, or from a combination of the two. The production cost perspective is particularly appropriate if electric utilities serve as the primary market, since their contracts with coal suppliers typically are based upon providing the coal operator with coverage of operating costs plus a fair return on investment (typically treated as 15 percent after taxes -- See Bechtel, 1980; Stanford Research Institute, 1974; and other reports for use of this 15% ROI). The market value perspective is particularly appropriate when exports become the dominant coal market. These concepts are employed separately for Nenana and Beluga coal.

(a) Nenana Field

Coal pricing data exist for Usibelli coal, and these data provide a basis for estimating the cost of coal at future power generation facilities.

Currently, Usibelli coal is being sold to the Golden Valley Electric Association (GVEA) Healy generating station under long term contract at a price of \$1.16/MMBtu (Baker, 1983), and to FMUS at a mine-mouth price of \$1.35/MMBtu. The current average price for Usibelli coal is \$23.38/ton of 7800 Btu/lb coal, or \$1.50/MMBtu. This value is based, to a large extent, on labor productivity of 50 tons/man day. That is a slight decline in productivity, as Usibelli had achieved 60 tons/man day a value confirmed by the National Coal Association (1980).

The $1.50/MMBtu reflects the price of coal from the Usibelli mine operating at about 50 percent of capacity. If production were increased to 1.6 million tons/yr, coal prices would decline to $20/ton ($1.28/MMBtu). An immediate 10% increase in all coal prices associated with that mine can be expected in order to comply with new land reclaimation regulations. As a consequence, the marginal cost of Usibelli coal can be calculated (in 1983 dollars) as:

$20/ton x 1.1 x ton/15.6 million Btu = $1.40/MMBtu

The Usibelli mine could be expanded to 4 million tons/yr., given the reserve base available. At such production levels, the additional 2 million tons of production would exhibit the same prices as the current mine when operating at full capacity.

This pricing perspective of the additional two million tons of capacity, however, is not universally shared. The Department of Energy coal transportation study (USDOE, 1980), estimates that coal from the additional 2 million tons/yr. will cost $1.88-$2.03/MMBtu in January 1983 dollars ($1.62-$1.75/MMBtu in 1980 dollars).

Because there is an apparent disagreement on coal prices from a second unit of production, and because the Suneel contract is not yet in place, the $1.40/million Btu is used as a conservative base price for Nenana Field coal at the mine mouth. Such coal must be transported to market by railroad, however. FMUS, for example, pays $0.50/million Btu for rail shipment of Usibelli coal. Battelle (1982) developed railroad cost functions for coal transport and, on this basis, the following charges should be added to Usibelli coal:

Destination	Charge (1983 $/million Btu)
Nenana	0.32
Willow	0.51
Matanuska	0.60
Anchorage	0.70
Seward	0.78

Therefore, the delivered price of coal to a new power plant is estimated to be $1.72-$2.18 depending upon location. On this basis it is likely that new power plants fueled by Usibelli coal would be in the communities of Nenana or Willow. The appropriate base coal prices for use in power plant analysis are therefore \$1.72-\$1.91/MMBtu.

(b) Beluga Field

The methods for estimating the price of coal from the Beluga field depends, in large measure, on whether or not the export market for Alaskan coal develops in the Pacific Rim. If that market exists, then both marketing and production cost analyses may apply, with production costs establishing a minimum price. In the absence of that market, production costs must be estimated for smaller mines.

The factors affecting development of an export market for Alaskan coal have been previously noted. In this section the existence of the export market is assumed. Estimates of the magnitude of that potential market have been developed by Sherman H. Clark and Associates (Clark, 1983), and by Mitsubishi Research Institute (MRI, 1983). The Sherman H. Clark values are shown in Figure D-2.2 for Japan and Korea. As this figure illustrates, the projected total market in Japan alone could exceed 100 million metric tons by the end of this decade. The data from MRI are shown in Figures D-2.3 and D-2.4, with particular emphasis on the use of coal in electric utilities. MRI forecasts a smaller total coal market in Japan in 1990, some 72.7 million tons (vs. Sherman H. Clark's 108.1 million tons). MRI estimates that the U.S. share of that Japanese market is 11.1 million tons, as is shown in Table D-2.6.

There are other estimates of the export market in the Pacific Rim countries. The U.S. Department of Energy Interagency Task Force estimates that U.S. exports to the Pacific Rim will be 15 million tons in 1990, and 52 million tons in the year 2000; and Barry Levy, in Western Coal Survey, estimates U. S. exports to the Pacific Rim at 25 million tons in the year 2000 (Levy, 1982). These values are consistent with the MRI export estimate of 11.1 million metric tons to Japan in 1990, since they would assume smaller amounts of coal being exported to Korean and Taiwan (see Figures D-2.3 and D-2.4).

Regardless of whether the Japanese market will be 73 or 108 million metric tons in 1990, these forecasts do illustrate that a large potential market exists. They are consistent with the data from Swift, Haskins, and Scott (1980).

The Pacific Rim export market is potentially highly available to the Alaskan mines due to their favorable transportation cost differentials compared to other supply sources (Swift, Haskins, and Scott, 1980). Transportation cost differentials are based upon the distance to market, as illustrated in Figure D-2.5. Levy

(1982) argues this point most strongly when he states that Alaskan coal exports will "dwarf current production" in Alaska by the 1990's, and states that most western coal that is exported will come from the Alaskan fields, notably Beluga. Levy estimates that 15 - 20 million tons of coal will be exported each year from Alaska by the year 1995 (Levy, 1982). The ultimate proof of the viability of a Pacific Rim export market, and the ability of Alaskan coal to penetrate that market, is the existence of the Suneel Alaska - KEPCO contract. This 15-year contract demonstrates that Alaskan coal can compete successfully in the Pacific Rim.

Because of the strong evidence for an export market, particularly in Japan (MRI, 1982), it is essential to place a market value on the Alaskan coal. Various "shadow pricing" or "net back" approaches have been used previously to achieve this value (see, for example, Secrest and Swift, 1982). The approach taken here is quite similar. The value of coal in Japan is based upon the FOB price of coal at ports in the competing nations of Australia, Canada, and South Africa obtained from Clark (1983), and the transportation charges associated with that coal as estimated by Diamond Shamrock Corp. (1983). The value of coal in Japan, therefore, is $2.37-$2.49/ million Btu as is shown in Table D-2.7. Deductions are taken from this value to reflect the lower quality of Alaskan coal, and to reflect the transportation costs from Alaska to Japan. The market value of Alaskan coal FOB Granite Point is $1.78-$1.94/million Btu, as is shown in Table D-2.8.

Frequently it is argued that the market value FOB mine is substantially lower than the market value FOB Port. In arguing this case, all capital and operating charges associated with transporting the coal from mine to tidewater have to be deducted from the $1.78-$1.94/million Btu. However if the market value of coal assumes exports, then it necessarily assumes that the coal transport facilities are in place. The assumption of such transport facilities being in existence means that all capital costs associated with coal transport to tidewater must be treated as sunk costs, and that the only charges to be netted out are incremental O&M costs associated with whether the specific coal is or is not moved to tidewater. These charges would be minimal assuming the operation of the export system. As a consequence the values of $1.78-$1.94/million Btu are assumed to hold.

Production cost estimates for Beluga coal have also been developed. They are based upon large mines (5-10 million tons/yr) producing coal for export, and smaller mines (1-3 million tons/yr) serving only the power plant market (200-600 MW).

Production cost estimates have been made for large mines serving the export market, and these are reported in Table D-2.9. The lower bound values range from $1.16/million Btu to $1.27/million Btu and the higher bound values range from $1.65/million Btu to $1.74/million Btu. The average of these estimates, taken as a group, is $1.45/million Btu.

For the purposes of deriving a coal cost estimate assuming exports, the difference between the market value and the production cost value must be addressed. Battelle approached reconciliation by simple averaging (Secrest and Swift, 1982). That approach is shown here as well, with the average of the market values ($1.86/million Btu) being averaged with the production cost of $1.45/million Btu to achieve a price of $1.66/million Btu.

While this averaging technique provides one basis for analysis, it appears that the market value is a more meaningful number to use. If a coal operator could sell coal at $1.86/million Btu FOB Port, and if there were few cost savings to be achieved by not transporting the coal to tidewater, then there would be no reason to sell at some average price. Rather, assuming the export of 5-10 million tons/yr at 7200-7800 Btu/lb coal, the practice of selling at the average price rather than the market value would result in decreased revenues to the coal operation of $15-$32 million per year. It is not reasonable to assume that the operator would forego revenues based on market value, therefore the market value of coal is assumed.

The Beluga mines as currently projected have largely been considered as sources of coal to be exported to Pacific Rim countries such as Japan, Korea, and Taiwan. Further, there is a substantial constituancy promoting such exports (see Resource development Council of Alaska, 1983). Whether or not this market develops, however, is still a matter of uncertainty.

In the absence of strong export markets, production costs for smaller mines have to be considered. Production costs for smaller mines have been reported by various potential vendors, at $1.50/MMBtu to $2.00/MMBtu.

Independent estimates were made of the cost of producing Beluga coal at rates of one million tons/year and three million tons/year. These estimates were made by Paul Weir (1983) consulting mining engineers. These coal price estimates were developed under the following assumptions:

(1) a 100% equity investment,

(2) rates of return at 10%, 15%, and 20%,

(3) a mine investment including an ancillary town for workers (with town costs divided between the mine and the power plant);

(4) an investment including a road or conveying system between the mine and a power plant located at tidewater.

Because of the low levels of production, Paul Weir assumed that a truck-shovel operation would be more cost effective than a dragline operation on a bucket wheel excavator system. On this basis, Paul Wier estimated the delivered cost of coal to be as follows:

Cost of Coal	1 Million Ton/Year	3 Million Ton/Year
<u>Private Financing</u>		
At 10% ROE	\$2.72	1.91
At 15% ROE	3.20	2.23
At 20% ROE	3.76	2.65
<u>State Financing</u>		
At 3.5% ROR	2.23	1.61

Under the private financing case, it was assumed that the coal mine was financed without debt. If a 25 percent debt were incorporated into the analysis, the cost of coal would decrease slightly.

Paul Weir Company also estimated the cost of coal under the assumption that the State of Alaska would own and operate the mine. A real cost of capital of 3.5% was assumed and the resulting estimated cost of coal is shown in the table above. This cost can be compared with the private ownership, 10% ROE case which is close to the real rate of return that private equity investors would require as a minimum.

2.4. Coal Price Escalation

Agreements between coal suppliers and electric utilities for the sale/purchase of coal are usually long term contracts which include a base price for the coal and a method of escalation to provide prices in future years. 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 indexes such as the producer price index, various commodity and labor indexes, or the consumer price index. The index selected is applied to the beginning operating and maintenance expenses so that the level of operating and maintenance expense increases or decreases over time with changes in the index. The original capital investment is not escalated, so the price of coal to the utility tends to increase with general inflation, provided the escalation index selected reflects the general rate of inflation.

The free market price of coal, however, could increase or decrease at a rate above or below the general rate of inflation because of demand/supply relationships in the relevant coal market. The utility with an existing contract tied to a cost reflective index would not experience these real changes until the existing contract expired and was renegotiated, or a contract for new or additional quantities of coal was executed.

Several free market price escalation rates were estimated for utility coal in Alaska and in the lower 48 states, and they range from 2.0-2.7%/year as is shown in Table D-2.11. These are real escalation rates, that is in addition to or in excess of the inflation rate. Several more real market rates have also been developed by Sherman H. Clark and Associates and by DRI, and these are shown in Table D-2.12.

These rates of escalation can be compared to the real historical rate of increase of 2.3%/yr. experienced by Golden Valley Electric Association, since 1974. It is difficult to use that historical GVEA rate, however, for the following reasons: (1) the rate relates to an existing contract, and (2) the rate covers a period of time when the substantial provisions of the Coal Mine Safety Act of 1969 were being implemented thereby affecting the price of coal.

The estimates of Sherman H. Clark and DRI are based more upon supply-demand analyses rather than upon extrapolations of historical data. The demand/supply relationship varies for different types of coal which results in different estimated future price escalation rates. This relationship is shown in Figure D-2.6 where future real escalation rates for western coal (average 2.9%/year) and western lignite (average 2.3%/yr.) are graphed using data from Sherman Clark and Associates.

The SHCA estimated real escalation rates for new contract domestic U.S. coal are shown below by period.

Period	Real Escalation Rate - %/yr. Western Coal	Western Lignite
1980-1990	2.9	2.8
1990-2000	2.0	2.0
2000-2010	3.9	2.0
Average 1980-2010	2.9	2.3

The rates of price change from period to period for domestic U.S. coal are directly related to mine capacity utilization. The lignite price changes reflect projected declines in capacity utilization in Texas and North Dakota fields (Clark, 1983), while western coal capacity utilization is expected to increase. Capacity utilization rates in Alaska depend upon future use by electric utilities and cannot be readily determined. Therefore, when a domestic escalation rate is applicable, the long-term average rate is employed rather than period rates.

DRI's estimated real escalation rates (Spring 1983) for new contract, domestic, U.S. coal are shown below by period (DRI does not differentiate by coal type).

Period	Real Escalation Rate -%/yr.
1981-1990	3.1
1991-2000	1.7
2001-2005	2.5
Average 1983-2005	2.6

For coal exports, SHCA is forecasting a 2.6%/yr. growth in demand by Japan and a 5.2%/yr. demand growth by South Korea (Figure D-2.1). This growth in demand together with a forecast weakening in United States currency versus the currencies of the two Asian countries results in an estimated real price escalation rate of 1.6%/yr. which is below the forecast U.S. domestic rates.

The forecasts by SHCA and DRI of future coal prices are based on demand/supply analyses performed by knowledgable, experienced firms. The forecasts are reasonable assessments of the future price trends and have been applied to Alaskan coal produced from the Nenana and Beluga fields.

Coal from the Nenana Field is used principally to supply Alaskan domestic markets. Therefore a domestic price escalation rate of 2.6%/year based on the average of SCHA western coal and lignite (2.9% and 2.3%) and the DRI forecast (2.6%) has been assumed. The 2.6% rate is applied to the 1983 estimated mine-mouth price of $1.40/MMBtu to provide the future cost of coal at the Usibelli Mine. Prices for

Nenana coal that is consumed at other locations are determined by adding transportation costs which are shown in Table D-2.13. Composite real escalation rates which include transportation costs are shown below for Usibelli coal used at Nenana and Willow.

Location	Composite Real Escalation Rate-%/yr.
Usibelli mine-mouth	2.6
Nenana	2.3
Willow	2.2

Assuming that an export market for the Beluga field develops, all coal sold from the field will probably be at a price dictated by Pacific Rim market conditions. This includes sales to electric utilities for use as fuel for electric generation. Therefore, it is reasonable to escalate the estimated $1.86/MMBtu 1983 base price of Beluga Field coal at the estimated export market rate of escalation of 1.6%/yr. (Table D-2.12)

The resulting fuel prices for Nenana and Beluga field coal for the period 1983-2010 are shown in Table D-2.14. There are no known projections of coal prices past the year 2010.

If an export market for Beluga coal does not develop, the 1983 base price should be assumed to be based on the production costs for a small 1-3 million ton per year mine. This would result in higher coal costs, especially in the initial years when consumption in the Beluga steam plant would be in the 1 million ton per year range required by one 200 MW unit.

While there has been some correlation between export coal prices and world oil prices historically, such a correlation is tenuous, at best, with respect to utility coal contracts. Technical correlations must accommodate differences which exist between coal and oil fired units in the areas of capital costs ($/kW), operating costs, and fuel purchasing agreements. Further such correlations must accommodate significant differences in market flexibility and market opportunity between coal and oil suppliers. For these reasons it is necessary to treat coal prices as being independent of world oil prices.

Several scenarios of future world oil prices have been used in the economic analysis of thermal alternatives. Natural gas prices for these scenarios move with the oil prices since it is assumed that future natural gas prices in both the Cook Inlet area and the North Slope will be tied directly to the future price of oil (See Section 1.4).

Coal prices are treated independently of oil prices, but a coal price scenario is required with each oil and natural gas price scenario in order to carry out economic analysis of the thermal alternatives. Coal price escalation rates are summarized below for each oil price scenario analyzed and shown year-by-year in Table D-2.14.

Oil Price Scenario	Real Coal Price Escalation Rate -%/yr.				
	Nenana Field			Beluga Field	
	Mine	Nenana	Willow	Export	Domestic
DOR Mean	0.0	0.0	0.0	0.0	0.0
DOR 50%	0.0	0.0	0.0	0.0	0.0
DOR 30%	0.0	0.0	0.0	0.0	0.0
DRI	2.6	2.3	2.2	1.6	2.6
SCHA Base Case	2.6	2.3	2.2	1.6	2.6
Reference Case	2.6	2.3	2.2	1.6	2.6
Constant Change					
+2%	2.6	2.3	2.2	1.6	2.6
0%	0.0	0.0	0.0	0.0	0.0
-1%	0.0	0.0	0.0	0.0	0.0
-2%	0.0	0.0	0.0	0.0	0.0

For the DOR scenarios, and the constant change scenarios of 0%, -1.0%, and -2%, the real coal price for both the Nenana and Beluga fields is assumed to have a zero real escalation rate for the years 1983-2010. Even though there is only a tenuous correlation between oil and coal prices, the oil prices for all of these scenarios is so low (all below $30/bbl in 1983 dollars by 2010) that it would be unrealistic to expect coal prices to escalate in real terms over the 1983-2010 period.

In summary, then, an ample coal supply does exist in the Railbelt area to support coal fired power generation with 1983 prices ranging from $1.72 - $1.91 delivered at the power plant. The effective real rates of escalation will range from 1.6% to 2.6% depending upon the extent to which exports influence the market and the specific location(s) of projected power plant development.

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3 - 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 for small isolated communities. Both thermal and hydroelectric alternatives will utilize gas or coal for required thermal generation. 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.

3.1 Availability

According to Battelle, there is adequate availability of distillate oil during the analysis period.[1/] 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 forty-eight states.

3.2 Price

The average current price for medium distillate fuels in Anchorage and Fairbanks is shown in Table D-3.1. These prices will change with the world market price for oil.[2/] The estimated price changes for several projections of future world oil prices have been applied to the 1983 price of distillate oil to obtain the future prices during the period 1983 to 2040. These are shown in Table D-3.2.

1/ Battelle Pacific Northwest Laboratories. Railbelt Electric Power Alternative Study: Fossil Fuel Availability and Price Forecasts, Volume VII, March 1982, p. 8.1.

2/ See Battelle, p. 8.3-8.5.

Table D-1.1

PRELIMINARY ESTIMATES OF UNDISCOVERED GAS RESOURCES IN PLACE AND ECONOMICALLY RECOVERABLE GAS RESOURCES FOR THE COOK INLET BASIN[1]

Probability - %[2]	Quantity of Gas - TCF	
	In Place	Economically Recoverable
99	0.47	0.00
95	0.93	0.22
90	1.24	0.43
75	1.98	0.93
50	3.07	1.76
25	4.38	2.78
10	5.84	4.04
5	6.93	4.90
1	9.06	6.83

(1) Source: Letter to Mr. Eric P. Yould, Executive Director, APA from Ron G. Schaff, State Geologist, State of Alaska, Department of Natural Resources, Division of Geological and Geophysical Surveys, dated February 1, 1983.

(2) Probability that quantity is at least the given value. Mean or as expected value for Economically Recoverable gas is approximately 2.0 TCF due to skewed distribution.

Table D-1.2

HISTORICAL AND CURRENT PRODUCTION AND
USE OF COOK INLET NATURAL GAS

USE	QUANTITY - BCF 1978	1979	1980	1981	1982
Injection	114.1	119.8	115.4	100.4	103.1
Field Operations:					
Vented, Used on lease, shrinkage	23.5	17.5	28.0	20.6	21.3
Sales:					
LNG	60.9	64.1	55.3	68.8	62.9
Ammonia/Urea	48.9	51.7	47.6	53.7	55.3
Power Generation:					
Utilities	24.6	28.2	28.7	29.1	30.5
Military	5.1	5.0	4.8	4.6	4.7
Gas Utilities*	13.5	14.0	15.5	16.2	17.7
Other Sales	3.3	4.8	5.1	5.7	9.5
Total Sales	156.3	167.8	157.0	178.1	180.6
Total	293.9	305.1	300.4	299.1	305.0

Source: "Historical and Projected Oil and Gas Consumption, Jan. 1983", State of Alaska, Dept. of Natural Resources, Division of Mineral and Energy Management, Table 2.8.

*Does not include sales made by gas utilities to electric utilities for electric generation.

Table D-1.3
ESTIMATED USE OF COOK INLET NATURAL GAS BY USER - ALL VOLUMES IN BCF

Year	Phillips/Marathon LNG/Plant	Collier Ammonia/Urea	Enstar Retail Sales	Field Operations & Other Sales	Electric Generation Military	Electric Generation All Others	Total Gas Use	Total Cumulative Gas Use	Year End Remaining Reserves Proven	Year End Remaining Reserves Proven Plus Mean Undiscovered
1982	62	55	17.7	25	5	38.4	203.1	203.1	3337.9	5377.9
1983	62	55	19.2	25	5	40.8	207.0	410.1	3130.9	5170.9
1984	62	55	19.8	25	5	43.2	210.0	620.1	2920.9	4960.9
1985	62	55	20.5	25	5	45.5	213.0	833.1	2707.9	4747.9
1986	62	55	22.8	25	5	47.6	217.4	1050.5	2490.5	4530.5
1987	62	55	23.6	25	5	49.7	220.3	1270.8	2270.2	4310.2
1988	62	55	24.4	25	5	46.5	217.9	1488.7	2052.3	4092.3
1989	62	55	25.3	25	5	48.5	220.8	1709.5	1831.5	3871.5
1990	62	55	26.1	25	5	50.5	223.6	1933.1	1607.9	3647.9
1991	62	55	27.1	25	5	51.8	225.9	2159.0	1382.0	3422.0
1992	62	55	28.0	25	5	53.1	228.1	2387.1	1153.9	3193.9
1993	62	55	29.0	25	5	54.5	230.5	2617.6	923.4	2963.4
1994	62	55	30.1	25	5	55.8	232.9	2850.5	690.5	2730.5
1995	62	55	31.1	25	5	32.5	210.6	3061.1	479.9	2519.9
1996	62	55	32.2	25	5	33.1	212.3	3273.4	267.6	2307.6
1997	62	55	34.4	25	5	33.8	215.2	3488.6	52.4	2092.4
1998	62	55	34.6	25	5	34.5	216.1	3704.7	(163.7)	1876.3
1999	62	55	35.8	25	5	35.1	217.9	3922.6		1658.4
2000	62	55	37.0	25	5	35.8	219.8	4142.4		1438.6
2001	62	55	38.3	25	5	36.8	222.1	4364.5		1216.5
2002	62	55	39.7	25	5	37.7	224.4	4588.9		992.1
2003	62	55	40.1	25	5	40.0	227.1	4816.0		765.0
2004	62	55	42.6	25	5	41.0	230.6	5046.6		534.4
2005	62	55	44.1	25	5	42.0	233.1	5279.7		301.3
2006	62	55	45.6	25	5	44.6	237.2	5516.9		64.1
2007	62	55	47.2	25	5	46.0	240.2	5757.1		(176.1)
2008	62	55	48.9	25	5	47.3	243.2	6000.3		
2009	62	55	50.6	25	5	48.7	246.3	6246.6		
2010	62	55	52.4	25	5	50.1	249.5	6496.1		

1 Based on historical use from Table D-1.2 and telephone conversations with Mr. Jim Settle of Phillips Petroleum Co. and Mr. George Ford of Collier Chemical.

2 Estimate provided by Mr. Harold Schmidt, VP Enstar Co., Feb. 14, 1983. Includes sales to Matanuska Valley customers beginning in 1986. Consumption from 1991-2010 projected by Harza/Ebasco at average growth rates in Enstar estimates.

3 Estimate based on historic use shown in Table D-1.2.

4 Estimate based on historic use shown in Table D-1.2.

5 Calculated based on the Reference Case load and energy forecast; inclusion of generation from Eklutna, Cooper Lake and Bradley Lake hydro units and Healy coal unit; and assumed average Railbelt heat rates of 15,000 Btu/kWh from 1982-1995 which includes older, high heat rate units, and 8,500 Btu/kWh from 1996-2010, which assumes predomonately combined cycle units.

6 Proven reserves of 3,541 BCF on Jan 1, 1982. See Exhibit D-1.1.

7 Includes proven revenues of 3,541 BCF plus expected value for undiscovered economically recoverable reserves from Figure D-1.1.

Table D-1.4

CURRENT PRODUCTION AND USE OF
NORTH SLOPE GAS FOR 1982

Use	Quanity - BCF
Injection	671.0
Field Operations:	
Vented, Used on shrinkage	50.2
Sales	
Power generation (civilian)	0.4
Gas utilities (residential)	0.5
Other sales	
Refineries	0.5
Trans Alaska Pipeline System	11.9
Misc.	0.2
Total	734.7

Source: "Historical and Projected Oil and Gas Consumption Jan. 1983", State of Alaska, Dept. of Natural Resources, Division of Minerals and Energy Management, Table 2.7.

Table D-1.5

ESTIMATED BASE PRICES FOR NEW
PURCHASES OF UNCOMMITTED AND UNDISCOVERED
COOK INLET GAS

Without LNG Export Opportunities

	1983-1986	1986-1997
Wellhead Price	$2.32/Mcf	$2.32/Mcf
Additional demand charge(1)	0.0	0.35
Severance tax(2)	0.15	0.15
Total (unescalated)(3)	$2.47/Mcf	$2.82/Mcf
Transmission charge(4)	0.30	0.30
Delivered to Anchorage	$2.77/Mcf	$3.12/Mcf

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(1) Demand charge of $0.35/MCF on Enstar/Marathon contract applies from January 1, 1986 on while demand of $0.35 on Enstar/Shell contract applies only if daily gas take is in excess of a designated maximum take.

(2) Severance taxes are the greater of $0.064/MCF or 10% of the wellhead cost adjusted by the "Economic Limit Factor." The economic limit factor is based on actual monthly production versus the wells production rate at the economic limit. See Alaska Statutes, Chapter 55, Section 43.55.013 and 43.55.016. The tax of $0.15/MCF was estimated based on conversations with Enstar Natural Gas Co.

(3) Prices are escalated based on the price of No. 2 fuel oil at the Tesoro Refinery, Nikiski, Alaska beginning Jan. 1, 1984.

(4) Estimated transmission charges would be about $0.30/MCF. Per telephone conversation with Mr. Harold Schmidt, VP Enstar.

Table D-1.6

ESTIMATED 1983 BASE PRICES FOR NEW
PURCHASES OF UNCOMMITTED AND UNDISCOVERED
COOK INLET GAS

With LNG Export Opportunities

LNG Price - Japan[(1)]	$5.85/MCF	$5.00/MCF
Less:[(2)]		
Conditioning	0.34	0.34
Liquefaction	0.95	0.95
Shipping	0.71	0.71
Subtotal	2.00	2.00
Maximum Price to Producer[(3)]	$3.85/MCF	$3.00/MCF

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(1) Based on oil prices of $34/bbl and $29/bbl.

(2) Based on implementation of the Trans-Alaska Gas System (TAGS) total System, lower tariff. Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas, Report by the Governor's Economic Committee on North Slope Natural Gas, January 1983. See Exhibits C1, C2 and page 18 and 46 of the Marketing Study Section. (Costs shown in the report were stated in 1988 dollars and were converted to 1983 dollars using the reports' assumed inflation rate of 7%/yr.)

(3) Delivered to LNG liquefaction facility. Transmission costs assumed to be negligible.

Table D-1.7

ESTIMATED COST OF NORTH SLOPE NATURAL GAS FOR ELECTRIC GENERATION AT KENAI ASSUMING IMPLEMENTATION OF THE TRANS ALASKA GAS SYSTEM (TAGS)
(1983 Dollars/MMBtu)

	Total System				Phase I System			
	Low Tariff		High Tariff		Low Tariff		High Tariff	
Estimated 1983 LNG Price Per MM Btu(1)	$5.85	$5.00	$5.85	$5.00	$5.85	$5.00	$5.85	$5.00
Less Costs:(2)								
Shipping	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
Liquefaction	0.95	0.95	1.18	1.18	1.00	1.00	1.26	1.26
Subtotal	$1.66	$1.66	$1.89	$1.89	$1.71	$1.71	$1.97	$1.97
Minimum 1983 Price(3)	$4.19	$3.34	$3.96	$3.11	$4.14	$3.29	$3.88	$3.03
Conditioning Costs(4)	0.34	0.34	0.42	0.42	0.42	0.52	0.51	0.51
Pipeline Costs(5)	2.04	2.04	2.79	2.82	2.82	3.86	3.86	3.86
Wellhead Price	1.81	0.96	0.75	(0.10)	0.90	0.05	(0.49)	(1.34)

(1) LNG prices are delivered prices to Japan and are equivalent to $34/bbl oil for the $5.85/MMBtu price and $29/bbl oil for the $5.00/MMBtu price.

(2) Costs in the report are shown in nominal 1988 dollars which were converted to 1983 dollars using an inflation rate of 7%/yr.

(3) Minimum price TAGS would accept from utilities for purchase of gas at LNG gas conditioning facility.

(4) For pipeline from North Slope to Kenai Peninsula.

(5) Maximum price that TAGS would be able to pay North Slope producers.

Source: Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas, Report by the Governor's Economic Committee on North Slope Gas, January, 1983. See Exhibits C1 and C2 and pgs 18 and 46 of the Marketing Study Section.

Table D-1.8

ESTIMATED 1983 DELIVERED COST OF NORTH SLOPE NATURAL GAS FOR RAILBELT ELECTRICAL GENERATION (1983 Dollars/MMBtu)

Delivery Method	Estimated Cost $/MMBtu	Value Used $/MMBtu
ANGTS(1)	4.03-5.30	N.A.
TAGS(2)	3.96-4.19	4.00
Pipeline to Fairbanks(3)	4.80-6.08	N.A.
North Slope Generation(4)	3.84-5.12	N.A.

N.A. Not Available

(1) Cost of $3.80/MMBtu in 1982$ assuming a zero wellhead cost was estimated by Battelle. This was adjusted to 1983$ to provide the $4.03/MMBtu. The $5.30/MMBtu includes an assumed wellhead cost of $1.28/MMBtu.

(2) Costs estimated using a "netback" approach. See Table D-1.7. Value of $4.00/MMBtu selected as reasonable value for thermal generation alternatives analysis.

(3) Costs estimated using capital and O&M costs from Reference 31. The cost of $4.80/MMBtu assumes a wellhead price of zero while the $6.08/MMBtu price assumes a wellhead price of $1.28/MMBtu.

(4) Costs estimated using capital and O&M costs from Reference 31. These costs are "equivalent" costs for the gas would be burned on the North Slope and the electricity delivered to Railbelt load centers via an electric transmission line. The "equivalent" costs were determined by comparing the costs of the electric transmission line with the costs of the gas pipeline to Fairbanks. The $3.84/MMBtu assumes a wellhead price of zero and the $5.12/MMBtu a wellhead price of $1.28/MMTbu.

Table D-1.9 (Sheet 1 of 2)

PROJECTED COOK INLET WELLHEAD NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

Year	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	Constant Change Cases +2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
1983(1)	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47	2.47
84	1.97	1.94	2.05	2.07	2.27	2.27	2.43	2.47	2.36	2.33
85	1.86	1.79	2.10	2.22	2.16	2.16	2.48	2.47	2.33	2.29
86(1)	2.18	2.07	2.19	2.74	2.51	2.51	2.88	2.73	2.66	2.58
87	2.14	1.99	2.14	2.92	2.51	2.51	2.94	2.73	2.63	2.53
88	2.17	1.97	2.12	3.11	2.51	2.59	3.00	2.73	2.60	2.48
89	2.20	1.95	2.11	3.31	3.82	2.66	3.06	2.73	2.58	2.43
1990	2.23	1.83	2.09	3.52	3.82	2.74	3.12	2.73	2.55	2.38
91		1.76	2.02	3.68	3.93	2.83		2.73		
92		1.73	2.00	3/84	4.05	2.91		2.73		
93		1.65	1.92	4.01	4.17	3.00		2.73		
94		1.63	1.88	4.19	4.30	3.09		2.73		
95	2.38	1.59	1.87	4.37	4.43	3.18	3.45	2.73	2.43	2.15
96		1.57	1.79	4.50	4.56	3.27		2.73		
97		1.53	1.79	4.64	4.70	3.37		2.73		
98		1.52	1.78	4.79	4.84	3.47		2.73		
99		1.51	1.76	4.94	4.98	3.58		2.73		
2000	2.54	1.48	1.74	5.09	5.13	3.69	3.80	2.73	2.31	1.95
01				5.15	5.31	3.80		2.73		
02				5.20	5.50	3.91		2.73		
03				5.26	5.69	4.03		2.73		
04				5.32	5.89	4.15		2.73		
05	2.71	1.38	1.64	5.38	6.09	4.27	4.20	2.73	2.10	1.76
06				5.44	6.31	4.40		2.73		
07				5.56	6.53	4.53		2.73		
08				5.62	6.76	4.67		2.73		
09				5.68	6.99	4.81		2.73		
2010	2.89	1.28	1.56	5.74	7.24	4.95	4.64	2.73	2.09	1.59

Table D-1.9 (Sheet 2 of 2)

PROJECTED COOK INLET WELLHEAD NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	Constant Change Cases +2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
2011				5.81	7.34	5.08		2.73		
12				5.87	7.46	5.20		2.73		
13				5.93	6.68	5.33		2.73		
14				6.00	7.80	5.47		2.73		
2015	3.08	1.18	1.47	6.00	7.91	5.60	5.12	2.73	1.98	1.44
16				6.07	8.03	5.74		2.73		
17				6.13	8.15	5.89		2.73		
18				6.20	8.27	6.04		2.73		
19				6.27	8.40	6.19		2.73		
2020	3.28	1.10	1.39	6.34	8.40	6.34	5.65	2.73	1.89	1.30
21				6.41	8.40	6.44				
22				6.48	8.40	6.53				
23				6.55	8.40	6.63				
24				6.62	8.40	6.73				
2025	3.50	1.10	1.32	6.69	8.40	6.83	6.24	2.73	1.79	1.17
26				6.77	8.40	6.93				
27				6.84	8.40	7.04				
28				6.92	8.40	7.14				
29				6.99	8.40	7.25				
2030	3.74	1.10	1.25	7.07	8.40	7.36	6.89		1.71	1.06
31				7.15	8.40	7.43				
32				7.23	8.40	7.51				
33				7.31	8.40	7.58				
34				7.39	8.40	7.66				
2035	3.99	1.10	1.18	7.47	8.40	7.73	7.61		1.62	0.96
36				7.55	8.40	7.81				
37				7.63	8.40	7.89				
38				7.72	8.40	7.97				
39				7.80	8.40	8.05				
2040	4.25	1.10	1.12	7.89	8.40	8.13	8.40	2.73	1.54	0.87

(1) Estimated 1983 price of Cook Inlet gas from Table D-2.5.
(2) Additional demand charge of $0.35/MMBtu applies from 1986 forwrd and is escalated by price of oil change.

Table D-1.10 (Sheet 1 of 2)

PROJECTED NORTH SLOPE DELIVERED NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case (Sherman Clark NSD Case)	Constant Change Cases +2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
1983(1)	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
1984	3.31	3.14	3.32	3.48	3.82	3.82	4.08	4.00	3.96	3.92
1985	3.13	2.90	3.40	3.73	3.64	3.64	4.16	4.00	3.92	3.84
1986	3.09	2.81	3.05	3.98	3.64	3.64		4.00		
1987	3.03	2.70	2.97	4.23	3.64	3.64		4.00		
1988	3.07	2.66	2.95	4.51	3.64	3.75		4.00		
1989	3.11	2.64	2.94	4.80	5.53	3.86		4.00		
1990	3.15	2.48	2.90	5.11	5.53	3.98	4.59	4.00	3.73	3.47
1991		2.38	2.81		5.69			4.00		
1992		2.34	2.78		5.86			4.00		
1993		2.24	2.66		6.04			4.00		
1994		2.20	2.61		6.22			4.00		
1995	3.36	2.15	2.59	6.34	6.41	4.61	5.07	4.00	3.55	3.14
1996		2.12	2.49					4.00		
1997		2.07	2.48					4.00		
1998		2.06	2.46					4.00		
1999		2.04	2.44					4.00		
2000	3.59	2.01	2.42	7.39	7.43	5.35	5.60	4.00	3.37	2.84
2001								4.00		
2002								4.00		
2003								4.00		
2004								4.00		
2005	3.83	1.86	2.29	7.81	8.82	6.20	6.18	4.00	3.21	2.56
2006								4.00		
2007								4.00		
2008								4.00		
2009								4.00		
2010	4.08	1.73	2.16	8.24	10.48	7.18	6.83	4.00	3.05	2.32
2011								4.00		
2012								4.00		
2013								4.00		
2014								4.00		
2015	4.36	1.60	2.05	9.20	11.29	8.13	7.54	4.00	2.90	2.10

Table D-1.10 (Sheet 2 of 2)

PROJECTED NORTH SLOPE DELIVERED NATURAL GAS PRICES
In 1983 Dollars Per MMBtu

YEAR	(DOR Mean)	DOR 30%	DOR 50%	DRI Spring 1983	Sherman Clark Base Case	Reference Case Sherman Clark NSD Case	+2/yr	0%/yr.	-1.0/yr.	-2.0%/yr.
2016								4.00		
2017								4.00		
2018								4.00		
2019								4.00		
2020	4.65	1.49	1.94	9.20	12.16	9.20	8.32	4.00	2.76	1.89
2021					12.16			4.00		
2022					12.16			4.00		
2023					12.16			4.00		
2024					12.16			4.00		
2025	4.96	1.49	1.83	9.71		9.91	9.19	4.00	2.62	1.71
2026					12.16			4.00		
2027					12.16			4.00		
2028					12.16			4.00		
2029					12.16			4.00		
2030	5.29	1.49	1.73	10.26	12.16	10.67		4.00	2.49	1.55
2031					12.16		10.15	4.00	2.49	1.55
2032					12.16			4.00		
2033					12.16			4.00		
2034					12.16			4.00		
2035	5.64	1.49	1.64	10.84	12.16	11.22	11.20	4.00	2.37	1.40
2036					12.16			4.00		
2037					12.16			4.00		
2038					12.16			4.00		
2039					12.16			4.00		
2040	6.02	1.49	1.55	11.45	12.16	11.79	12.37	4.00	2.26	1.26

(1)Estimated 1983 price of North Slope gas from Table D-1.8.

Table D-2.1

DEMONSTRATED RESERVE BASE IN ALASKA AND THE U.S. BY TYPE OF COAL
(values in millions of short tons)

Type of Coal	Alaska	Total U.S.
Anthracite	--	7341.7
Bituminous	697.5	239,272.9
Subbituminous	5,443.0	182,035.0
Lignite	14.0	44,063.9
Total	6,154.5	472,713.6
Percent of Total	1.3%	100%

Source: Demonstrated Reserve Base of Coal in the United States on January 1, 1980.

Table D-2.2

RESERVES AND RESOURCES OF THE NENANA FIELD

Reserve/Resource Type	Quantity (tons x 10^6)
Reserve Base	457
Resources	
Measured	862
Indicated	2,700
Inferred	3,377
Total	6,938[a]

[a] Totals do not add due to rounding on measured and inferred.

Source: Energy Resources Co., 1980.

Table D-2.3

PROXIMATE AND ULTIMATE ANALYSIS OF NENANA FIELD COAL

Proximate Analysis	Weight Percent
Moisure	26.1
Ash	6.4
Volatile Matter	36.3
Fixed Carbon	31.2
Ultimate Analysis, As Received (wt %)	
Hydrogen	3.6
Carbon	47.2
Oxygen	15.5
Nitrogen	1.05
Sulfur	0.12
Chlorine	---
Moisture	26.1
Ash	6.4
Higher Heating Value (Btu/lb)	7,950

Source: Hazen Laboratory Analyses for Fairbanks Municipal System.

Table D-2.4

ULTIMATE ANALYSIS OF BELUGA COAL

Element/ Compound (wt %)	Analyses		
	Stanford[a] Research Institute	Battelle[b] Waterfall Seam)	Diamond-Shamrock[c] Alaska Coal Co.
Carbon	44.7	---	45.4
Hydrogen	3.8	---	2.9
Nitrogen	0.7	---	0.7
Oxygen	15.8	---	14.4
Sulfur	0.2	0.18	0.14
Ash	9.9	16.0	7.9
Moisture	24.9	21.0	28.0
Higher Heating Value (Btu/lb)	7200	7536	7800

a/Stanford Research Institute, 1974

b/Swift, Haskins, and Scott, 1980

c/Diamond Shamrock Corporation, 1983

Table D-2.5

COAL FIRED GENERATING CAPACITY IN ALASKA

Owner	Location	Heat Rate (Btu/kWh)	Capacity (MW)
Golden Valley Electric Assn.	Healy	13,200	25
University of Alaska	Fairbanks	12,000	13
U.S. Air Force Ft. Wainwright	Fairbanks	20,000	20
Fairbanks Municipal Utility System	Fairbanks	13,300-22,000	29
Total	N/A	13,000-22,000	87

Source: Battelle, Vol VI, 1982.

Table D-2.6

PROJECTED NATIONAL SHARES OF JAPANESE COAL MARKET FOR IMPORTS IN THE YEAR 1990[a]

Nation	Market Share: Percentage	Market Share: Million Tons
Australia	41.8	30.4
Canada	11.9	8.7
United States	15.3	11.1
China	16.0	11.6
USSR	5.6	4.1
South Africa	4.2	3.0
All Others	5.2	3.8
Total	100.0	72.7

a/Includes steam coal and metallurgical coal.

Source: MRI, 1982

Table D-2.7

THE VALUE OF COAL DELIVERED IN JAPAN BY COAL ORIGIN
(Jan. 1983 Dollars)

Nation of Coal Origination	Value of Coal (FOB Port)	Shipping Cost ($/ton)	Value of Coal ($/ton)	Value of Coal ($/million Btu)
Australia[a]/	$45.00	10.50	$55.50	$2.49
South Africa[b]/	37.50	15.30	52.80	2.37
Canada[c]/	45.00	10.35	55.35	2.48

[a]/From Sherman H. Clark and Associates, 1983

[b]/From Diamond Shamrock Corp., 1983

[c]/Assumes 11,160 Btu/lb per Japanese Specification in Swift, Haskins, and Scott, 1980.

Table D-2.8

THE MARKET VALUE OF COAL FROM THE BELUGA FIELD
FOB GRANITE POINT, ALASKA
(Jan. 1983 Dollars)

	Value of Coal ($/Million Btu)	
	Low	High
The Value of Coal in Japan[a]	$2.37	$2.49
Price Discount Based upon the impact of lower quality on plant capital costs (1.6%)[b]	$0.04	$0.04
Net Value of Coal in Japan	$2.33	$2.45
Cost to Transport Coal[c]	$0.55	$0.51
Net Value of Coal at Granite Point	$1.78	$1.94

[a]/From Table D-2.7

[b]/See Swift, Haskins, and Scott (1980) analysis on Waterfall Seam Coal, pp. 7-5, 7-6.

[c]/Cost is $8.00/ton. Low value column reflects 7200 Btu/lb coal and high value column reflects 7800 Btu/lb coal (see Table D-2.4).

Table D-2.9

PRODUCTION COST ESTIMATES FOR BELUGA COAL IN 1983 DOLLARS

Source	Mine Site (tons/yr)	Coal Location (FOB)	Price[a] Range $/million Btu
Diamond Alaska[b]	10 million	ship	1.20-1.70
Bechtel[c]	7.7 million	ship	1.27-1.65
Placer Amex[d]	5 million	mine	1.16-1.74

[a] All previous estimates escalated by the implicit price deflation series.
[b] Source: Styles, 1983.
[c] Source: Bechtel Report for H-B-W (Bechtel, 1980).
[d] Source: DOE, 1980.

Table D-2.10

BELUGA AREA HYPOTHETICAL MINE
SUMMARY OF SELECTED DATA

	Case 1	Case 2
Production Rate Per Year (Tons)	1,000,000	3,000,000
Mine Life At Full Production (Years)	30	30
Average Stripping Ratio (BCY/Ton)	5.93	5.89
Personnel (Average)		
Operating	81	194
Maintenance	74	176
Salaried	33	56
Total	188	426
Tons Per Man-Shift (Average)	21.3	28.2
Initial Capital Investment	$101,041,000	$186,321,000
Initial Capital Investment Per Annual Ton	$101.04	$62.11
Life Of Mine Capital Required	$183,027,000	$353,450,000
Average Annual Operating Costs (Per Ton)		
Drainage Control and Reclamation	$0.60	$0.32
Stripping	9.19	8.52
Mining And Hauling Coal	1.11	1.08
Coal Handling And Transporting	3.05	1.77
Haul Road Construction And Maintenance	1.24	0.65
General Mine Services	1.22	0.79
Supervision And Administration	2.96	1.64
Production Taxes And Fees	0.35	0.35
Total Cash Costs	$19.72	$15.12
Average Depreciation	6.10	3.97
Average Total Cost	$25.82	$19.09
Average Coal Prices (Per Ton)		
At 10% R.O.R.	$40.85	$28.52
At 15% R.O.R.	47.99	33.52
At 20% R.O.R.	56.40	39.70
Average Coal Prices (Per MM Btu)(a)		
At 10% R.O.R.	$2.72	$1.90
At 15% R.O.R.	3.20	2.23
At 20% R.O.R.	3.76	2.65

Note:

(a) Assumes 7,500 Btu/Lb.

Source: Mining Cost Estimates, Beluga Area Hypothetical Mine, Paul Weir Company, June 27, 1983.

Table D-2.11

SOME PROJECTED REAL ESCALATION RATES FOR COAL PRICES

Forecastor	Coal	Real Escalation Rate to 2010 - %
Battelle (1982)[a]	Beluga	2.1
	Nenana	2.0
Acres (1981)[b]	Beluga	2.6
	Nenana	2.3
Acres (1982)[c]	Beluga	2.5
	Nenana	2.7

[a] Secrest and Swift, 1982.

[b] Diener, 1981.

[c] Diener, 1982.

Table D-2.12

COAL PRICE REAL ESCALATION RATES

Author	Coal Types	Long Term Real Escalation Rate - %
DRI	New Coal Contracts	2.6
Sherman H. Clark	New Coal Contracts and Spot Market Coal	
	Western Coal[a]	2.9
	Western Lignite[b]	2.3
	Coal Exports	1.6

[a]/HV of 10,000 Btu/lb.
[b]/HV of 7,500 Btu/lb.

Sources: DRI, 1983; Clark, 1983.

Table D-2.13

NENANA COAL TRANSPORTATION COSTS
FROM HEALY TO GENERATING PLAN LOCATION (1983 $/MMBtu)

	Plant Location				
Year	Nenana	Willow	Matanuska	Anchorage	Seward
1983	0.32	0.51	0.60	0.70	0.78
1984	0.30	0.48	0.57	0.67	0.74
1985	0.30	0.48	0.57	0.67	0.75
1986	0.32	0.49	0.58	0.67	0.76
1987	0.33	0.50	0.58	0.68	0.77
1988	0.33	0.50	0.59	0.69	0.78
1989	0.34	0.51	0.60	0.70	0.79
1990	0.34	0.52	0.61	0.71	0.80
1991	0.35	0.52	0.62	0.72	0.81
1992	0.35	0.53	0.63	0.73	0.82
1993	0.36	0.54	0.64	0.74	0.84
1994	0.36	0.54	0.64	0.75	0.84
1995	0.36	0.55	0.64	0.75	0.85
1996	0.37	0.55	0.65	0.76	0.86
1997	0.37	0.55	0.65	0.76	0.86
1998	0.37	0.56	0.66	0.77	0.87
1999	0.37	0.56	0.66	0.78	0.88
2000	0.38	0.57	0.67	0.78	0.88
2001	0.38	0.57	0.67	0.79	0.89
2002	0.38	0.57	0.68	0.79	0.90
2003	0.39	0.58	0.68	0.80	0.90
2004	0.39	0.58	0.69	0.81	0.91
2005	0.39	0.59	0.69	0.81	0.92
2006	0.40	0.59	0.70	0.82	0.92
2007	0.40	0.60	0.70	0.83	0.93
2008	0.40	0.60	0.71	0.83	0.04
2009	0.41	0.61	0.72	0.84	0.95
2010	0.41	0.61	0.72	0.85	0.95

Notes:

Transportation cost equations: (1983)
Healy to:

Nenana = $0.23 + 0.09 (oil escalation rates)
Willow = 0.36 + 0.15 (oil escalation rates)
Matanuska = 0.42 + 0.18 (oil escalation rates)
Anchorage = 0.49 + 0.21 (oil escalation rates)
Seward = 0.55 + 0.23 (oil escalation rates)

Table D-2.14

ESTIMATED DELIVERED PRICES OF COAL IN ALASKA BY YEAR
(In 1983 \$/Btu x10^6)

Year	Nenana Field Coal Delivered To			Beluga Field Coal
	Mine Mouth (2.6%/yr.)	Nenana (2.2%/yr)	Willow (2.2%/yr)	With Exports (1.6%/yr)
1983	1.40	1.72	1.91	1.86
1984	1.44	1.74	1.92	1.89
1985	1.47	1.77	1.95	1.92
1986	1.51	1.83	2.00	1.95
1987	1.55	1.88	2.05	1.98
1988	1.59	1.92	2.09	2.01
1989	1.63	1.97	2.14	2.05
1990	1.68	2.02	2.20	2.08
1991	1.72	2.07	2.24	2.11
1992	1.76	2.11	2.29	2.15
1993	1.81	2.17	2.35	2.18
1994	1.86	2.22	2.40	2.21
1995	1.91	2.27	2.46	2.25
1996	1.85	2.32	2.50	2.29
1997	2.01	2.38	2.56	2.32
1998	2.06	2.43	2.62	2.36
1999	2.11	2.48	2.67	2.40
2000	2.17	2.55	2.74	2.44
2001	2.22	2.60	2.79	2.48
2002	2.28	2.66	2.85	2.51
2003	2.34	2.73	2.92	2.55
2004	2.40	2.79	2.98	2.60
2005	2.46	2.85	3.05	2.64
2006	2.53	2.93	3.12	2.68
2007	2.59	2.99	3.19	2.72
2008	2.66	3.06	3.26	2.77
2009	2.73	3.14	3.34	2.81
2010	2.80	3.21	3.41	2.86

Table D-3.1

PRICES OF TURBINE AND DIESEL OIL
FOR ELECTRICAL GENERATION - 1983 $/MMBtu

Type Fuel	Location Anchorage	Fairbanks
Diesel oil - No. 1[1/]	6.87	7.46
Turbine oil - No. 1-2[2/]	6.23	7.02

1/ Based on average of price quotes from Chevron and Tesoro Oil Companies of about $0.95/gal. for Anchorage and $1.03/gal. for Fairbanks (June 1983) the heating value is about 5.8 X 10^6 Btu/bbl.

2/ Based on price quote by Tesoro Oil Comapny of $0.86/gal. in Anchorage and $0.97/gal. in Fairbanks (June 1983) the heating value is about 5.8 X 10^6 Btu/bbl.

Table D-3.2

PROJECTED PRICES OF DIESEL AND TURBINE FUEL AT ANCHORAGE
FOR VARIOUS OIL PRICE SCENARIOS[1/] - 1983--2010
(1983 $/MMBtu)

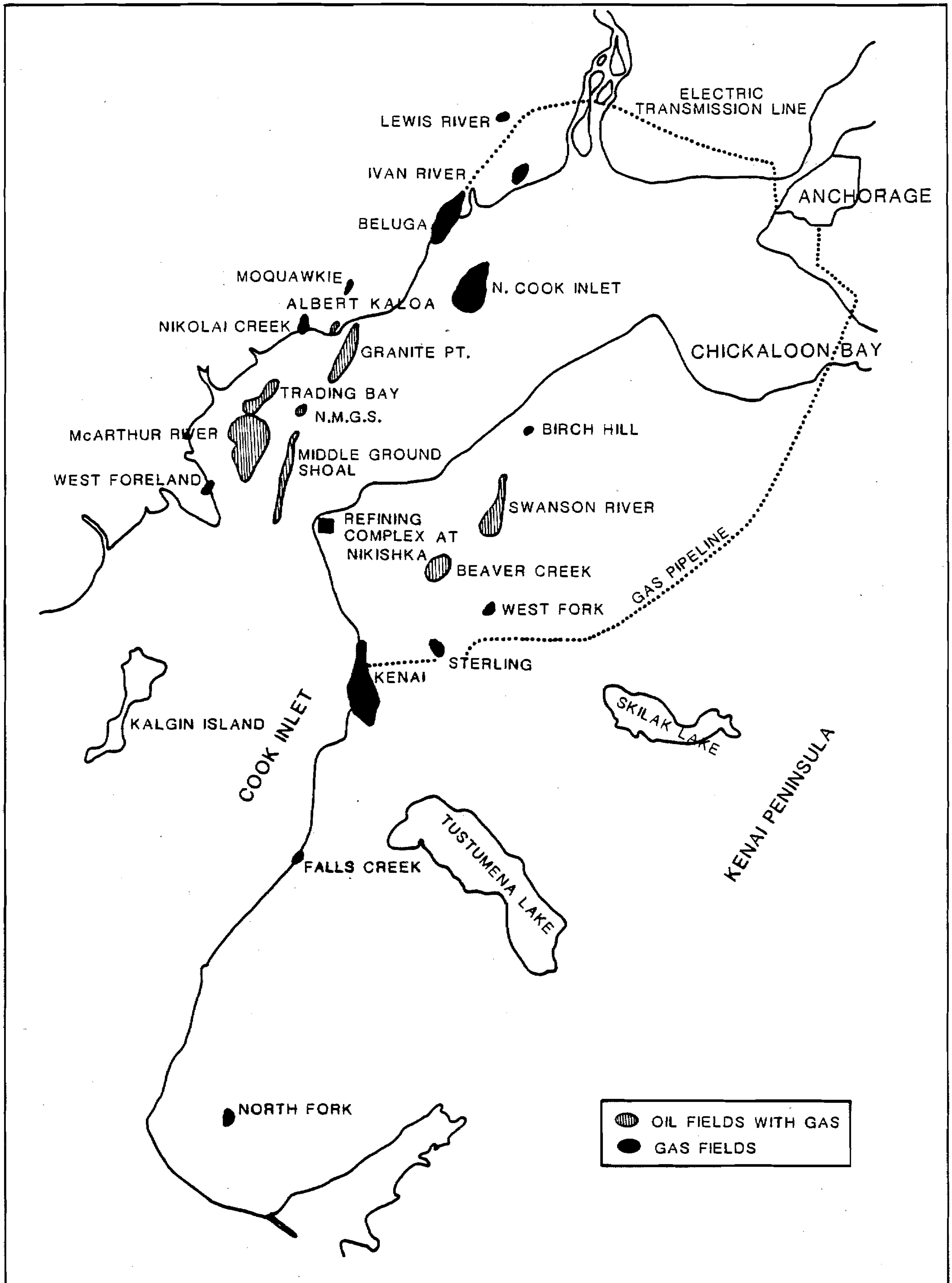
Year	DOR Mean Diesel	DOR Mean Turbine	DOR 30% Diesel	DOR 30% Turbine	DOR 50% Diesel	DOR 50% Turbine	DRI Spring 1983 Diesel	DRI Spring 1983 Turbine	SHCA Basecase Diesel	SHCA Basecase Turbine	Reference Case Diesel	Reference Case Turbine	Constant Rates of Change +2%/yr. Diesel	+2%/yr. Turbine	0%/yr. Diesel	0%/yr. Turbine	-1%/yr. Diesel	-1%/yr. Turbine	-2%/yr. Diesel	-2%/yr. Turbine
1983[2/]	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23	6.87	6.23
1984	5.69	5.16	5.39	4.89	5.70	5.17	5.97	5.41	6.55	5.94	6.55	5.94	7.01	6.35	6.87	6.23	6.80	6.17	6.73	6.11
1985	5.38	4.88	4.98	4.51	5.84	5.30	6.41	5.81	6.25	5.66	6.25	5.66	7.15	6.48	6.87	6.23	6.73	6.11	6.60	5.98
1986	5.31	4.81	4.82	4.37	5.23	4.74			6.25	5.66	6.25	5.66	7.29	6.61			6.67	6.04	6.47	5.86
1987	5.21	4.72	4.63	4.20	5.10	4.63			6.25	5.66	6.25	5.66	7.44	6.74			6.60	5.98	6.34	5.75
1988			4.57	4.15	5.06	4.59			6.25	5.66	6.25	5.66	7.59	6.88			6.53	5.92	6.21	5.63
1989			4.53	4.10	5.04	4.57			9.50	8.62	6.43	5.83	7.74	7.02			6.47	5.87	6.09	5.52
1990	5.49	4.98	4.25	3.85	4.99	4.52	8.78	7.97	9.50	8.62	6.63	6.01	7.89	7.16	6.87	6.23	6.40	5.81	5.96	5.41
1991			4.10	3.71	4.82	4.37														
1992			4.01	3.63	4.77	4.32														
1993			3.85	3.48	4.57	4.14														
1994			3.78	3.42	4.48	4.06														
1995	5.85	5.24	3.70	3.35	4.46	4.04	10.90	9.88	11.02	9.99	7.68	6.97	8.71	7.90	6.87	6.23	6.09	5.52	5.39	4.89
1996			3.64	3.30	4.27	3.88														
1997			3.55	3.21	4.26	3.86														
1998			3.53	3.20	4.22	3.83														
1999			3.50	3.20	4.20	3.81														
2000	6.24	5.52	3.45	3.15	4.15	3.76	12.69	11.51	12.78	11.58	8.91	8.08	9.62	8.72	6.87	6.23	5.79	5.25	4.87	4.42

1/See Exhibit B Section 5.4 for projected rates of change in oil prices.
2/Prices from Table D-3.1

Table D-3.2

PROJECTED PRICES OF DIESEL AND TURBINE FUEL AT ANCHORAGE
FOR VARIOUS OIL PRICE SCENARIOS[1/] - 1983-2010
(1983 $/MMBtu)

	DOR Mean		DOR 30%		DOR 50%		DRI Spring 1983		SHCA Basecase		Reference Case		Constant Rates of Change							
													+2 /yr.		0%/yr.		-1%/yr.		-2%/yr.	
Year	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine	Diesel	Turbine
2001																				
2002																				
2003																				
2004																				
2005	6.66	5.81	3.20	2.92	3.93	3.56	13.40	12.16	15.17	13.75	10.32	9.36	10.62	9.63	6.87	6.23	5.51	4.99	4.40	3.99
2006																				
2007																				
2008																				
2009																				
2010	7.10	6.12	2.97	2.71	3.72	3.37	14.16	12.84	18.02	16.33	11.97	10.85	11.73	10.63	6.87	6.23	5.24	4.75	3.98	3.61



COOK INLET GAS FIELDS

FIGURE D-1.1

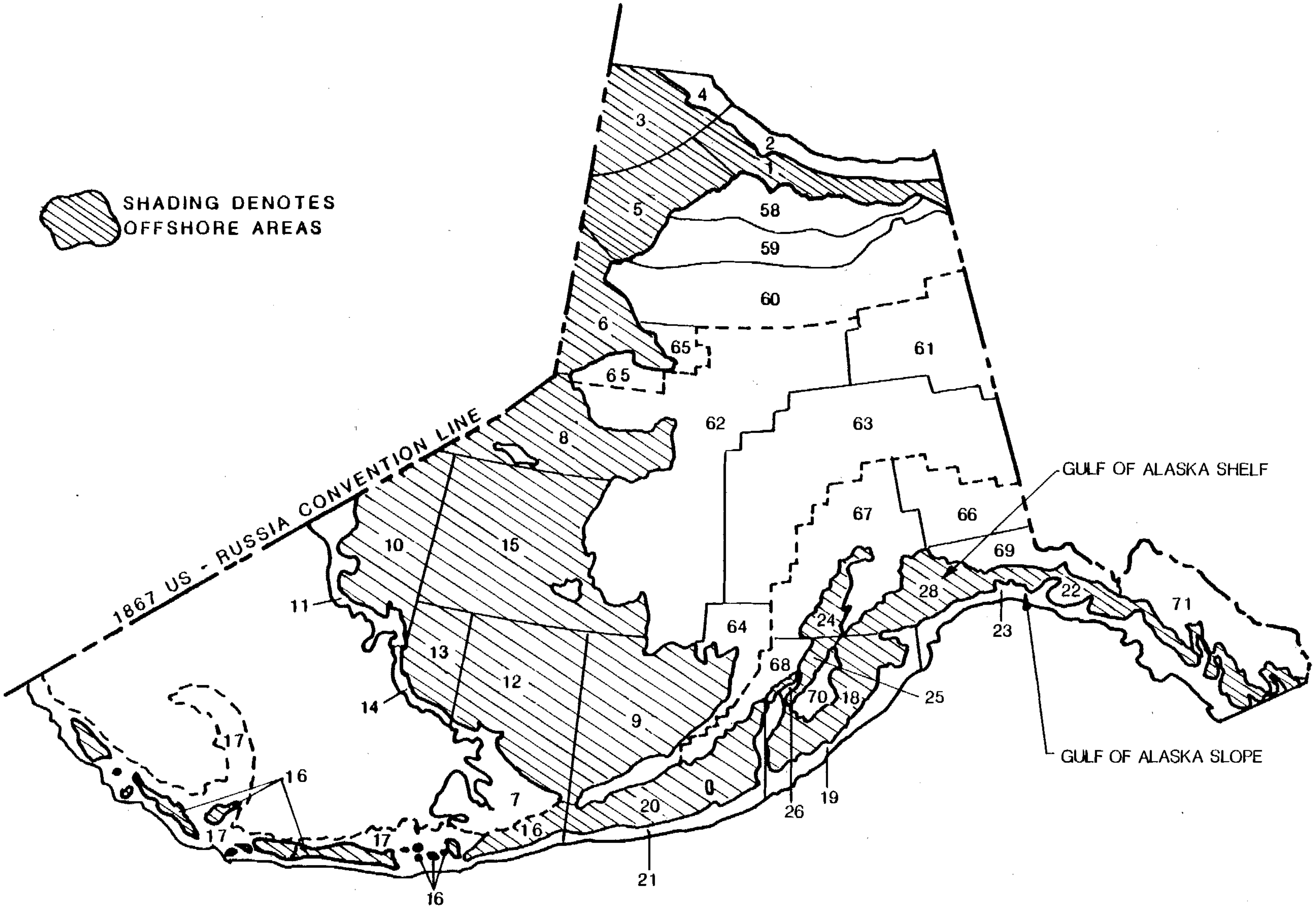
	Recoverable Reserves(1)	Enstar	Chugach Electric Assoc.	AMP&L	Collier Carbon & Chemical	Phillips/ Marathon LNG	SOCAL ARCO Rental	Uncommitted Reserves	Pacific Alaska LNG Assoc.
Beaver Creek	240	250(2)	--	--	--	--	--	0	--
Beluga River	742	220	285	--	--	--	--	237	404
Birch Hill	11	--	--	--	--	--	--	11	--
Cannery Loop	N/A	--	--	--	--	--	N/A		(3)
Falls Creek	13	--	--	--	--	--	--	13	--
Ivan River	26	--	--	--	--	--	--	26	106(4)
Kaldachabuna	N/A	--	--	--	--	--	N/A		--
Kenai	1,109	256	--	(5)	377	250	106	120	--
Lewis River	22	--	--	--	--	--	--	22	99(4)
McArthur River	90	--	--	--	--	--	--	90	--
Nicolai Creek	17	--	--	--	--	--	--	17	--
North Cook Inlet	951	27(6)	--	--	--	110(7)	--	814	--
North Fork	12	--	--	--	--	--	--	12	--
N. Middle Ground	N/A	--	--	--	--	--	N/A		--
Sterling	23	--	--	--	--	--	--	23	--
Stump Lake	N/A	--	--	--	--	--	N/A		--
Swanson River		--	--	--	--	--	--	259(8)	--
Trail Ridge	N/A	--	--	--	--	--	N/A		--
Tyonek	N/A	--	--	--	--	--	0		--
West Foreland	20	--	--	--	--	--	--	20	--
Total	3,541	759	285	--	377	360	106	1,654	760(9)

Notes

(1) Alaska Oil and Gas Conservation Commission.
(2) Part of gas will be taken from Kenai Field.
(3) Participant in exploration underway in 1980.
(4) Based on DeGolyer and MacNoughten reserve estimate in 1975.
(5) Uncertain royalty status.
(6) Royalty gas.
(7) This figure assumes that Tokyo Gas Co. and Tokyo Electric Co. contracts will be met by gas from the Cook Inlet Field. In actuality, a significant portion is supplied by the Kenai Field.
(8) Estimate of gas available on blowdown.
(9) PALNG's latest estimate of their previously committed reserve is 980 Bcf less the 220 lost to Enstar. This 760 Bcf is 151 greater than the sum of quantities from the individual fields. It is not known from which fields the additional 151 Bcf would come.

ESTIMATED COOK INLET NATURAL GAS RECOVERABLE RESERVES AND COMMITMENT STATUS AS OF JANUARY 1,1982

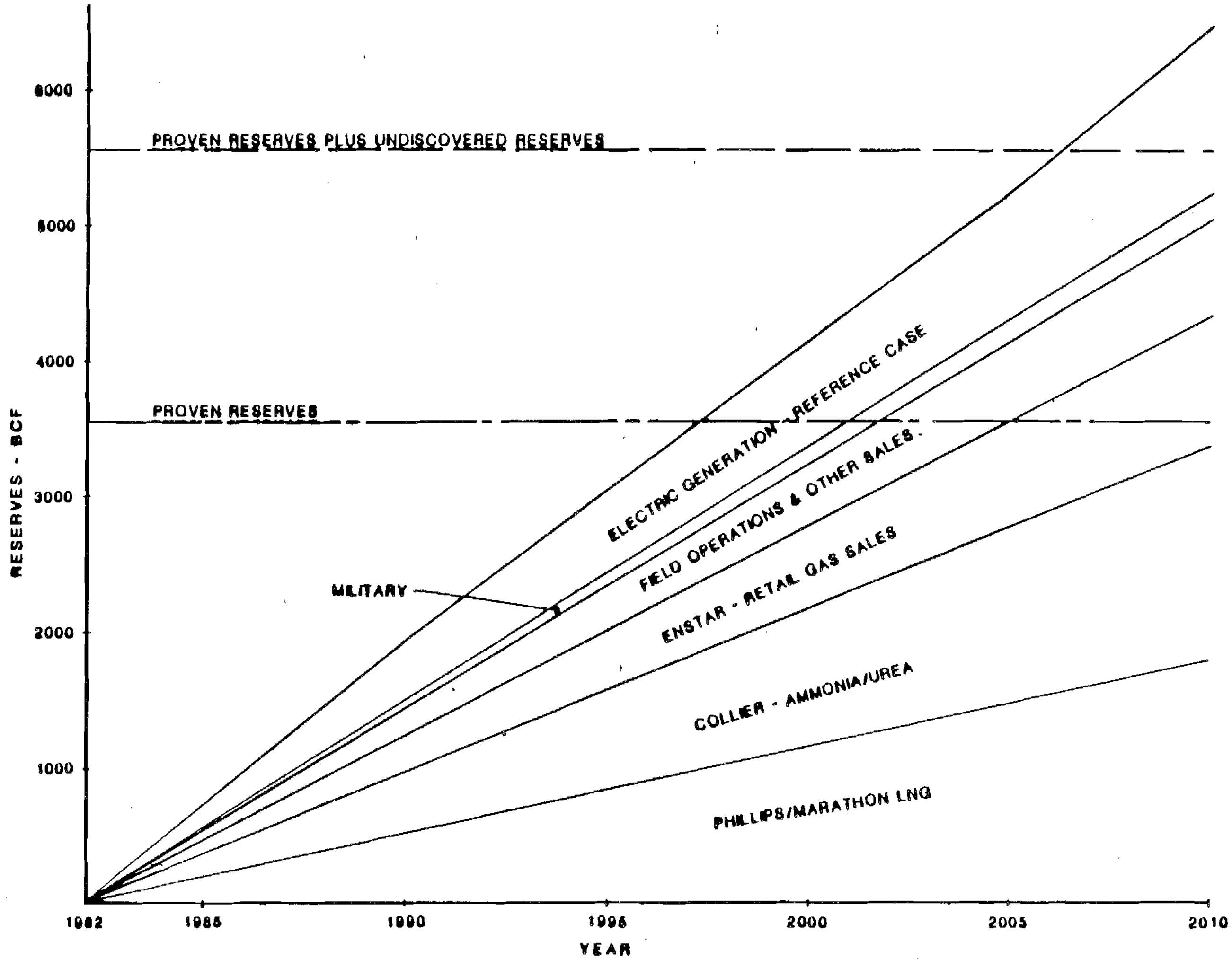
FIGURE D-1.2



AREAS OF ALASKA ASSESSED BY THE
U.S.G.S. FOR UNDISCOVERED RESOURCES

SOURCE: U.S. DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY, OPEN-FILE REPORT 82-666A, 1981.

FIGURE D-1.3



COOK INLET NATURAL GAS RESERVES AND
ESTIMATED CUMULATIVE CONSUMPTION

FIGURE D-1.4

Coal Generation Cost

Unit Size	200 MW
Unit Capital Cost	$2,340/kw
Availability	85%
Annual Generation	1.5×10^9 kwh
Fuel Cost	$1.70/MMBtu
Heat Rate	9,750 Btu/kwh
O & M Cost	$0.0032/kwh
Real Cost of Capital	3.5%
Economic Life	35 years

Annual Capital Cost:
C_{cap}=($2340/kw)(200,000 kw)(CRF; 35 yrs; 3.5%) = $\$22.6 \times 10^6$

Annual O & M Cost:
$C_{O\&M}$=(1.5×10^9 kwh/yr.)($0.0032/kwh) = $\$4.8 \times 10^6$

Annual Fuel Cost:
C_F=(1.5×10^9 kwh/yr)(9750 Btu/kwh)($\$1.70/10^6$ Btu) = $\$24.9 \times 10^6$

Total Annual Costs $\underline{\$52.3 \times 10^6}$

Gas Generation Cost

Unit Size (combined cycle)	200 MW
Unit Capital Cost	$650/kw
Availability	85%
Annual Generation	1.5×10^9 kwh
Fuel Cost	?
Heat Rate	8,200 Btu/kwh
O & M Cost	$0.0042/kwh
Real Cost of Capital	3.5%
Economic Life	30 years

Annual Capital Cost:
C_{cap}=($650/kw)(200,000 kw)(CFR; 30 yrs; 3.5%)= $\$6.8 \times 10^6$

Annual O & M Cost:
$C_{O\&M}$=(1.5×10^9 kwh/yr.)($0.0042/kwh) = $\$6.3 \times 10^6$

Total Annual Costs Without Fuel $\underline{\$13.1 \times 10^6}$

Gas Fuel Cost

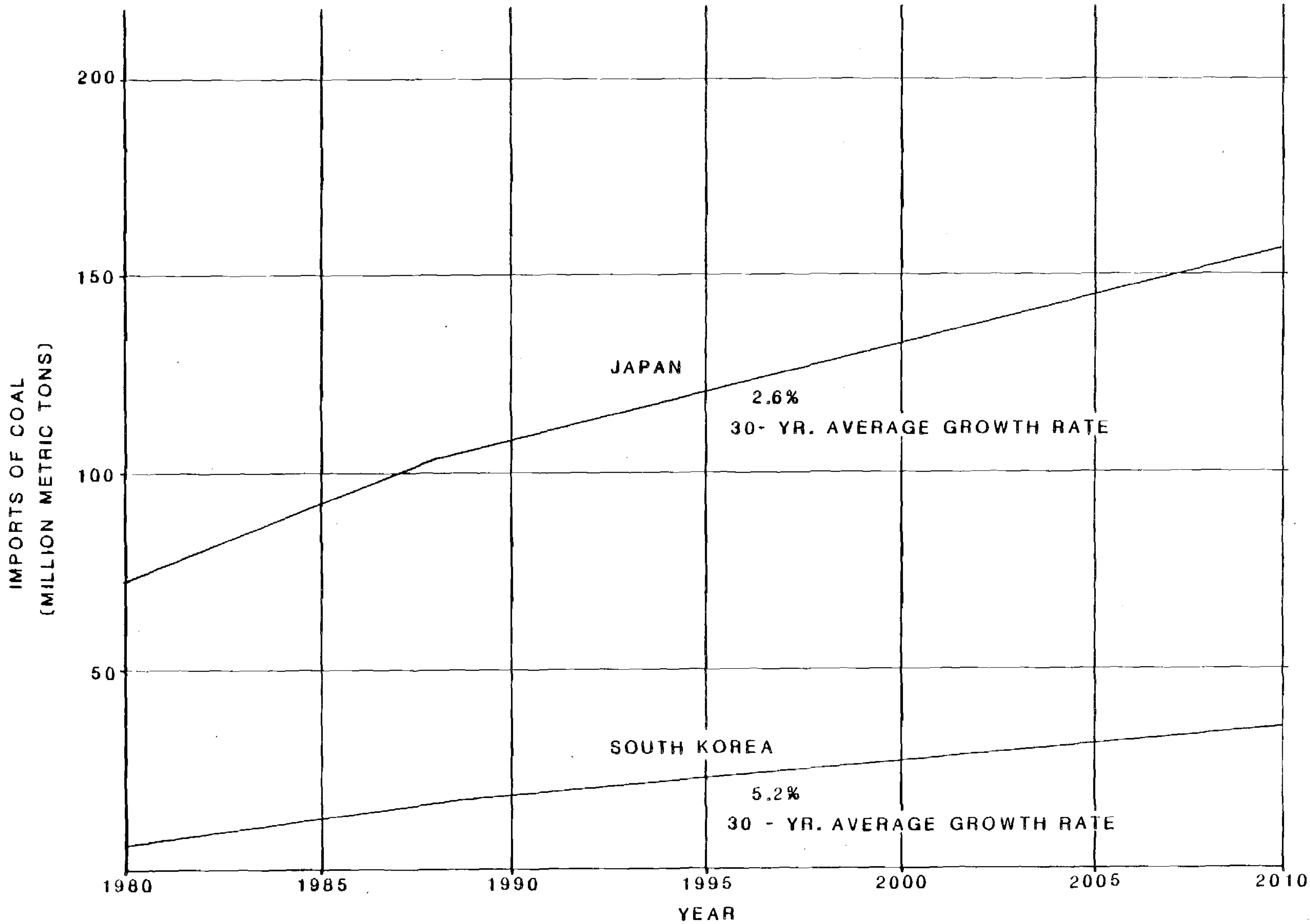
$$\text{Cost of Gas Fuel} = \frac{\text{Total annual coal generation costs less gas costs without fuel}}{\text{Annual gas generation times gas heat rate}}$$

$$= \frac{\$52.3 \times 10^6 - \$13.1 \times 10^6}{(1.5 \times 10^9 \text{ kwh})(8{,}200 \text{ Btu/kwh})}$$

$$= \underline{\$3.19/\text{MMBtu}}$$

MAXIMUM DEREGULATED COOK INLET GAS PRICES (BASED ON SUBSTITUTABILITY OF COAL-FIRED UNITS)

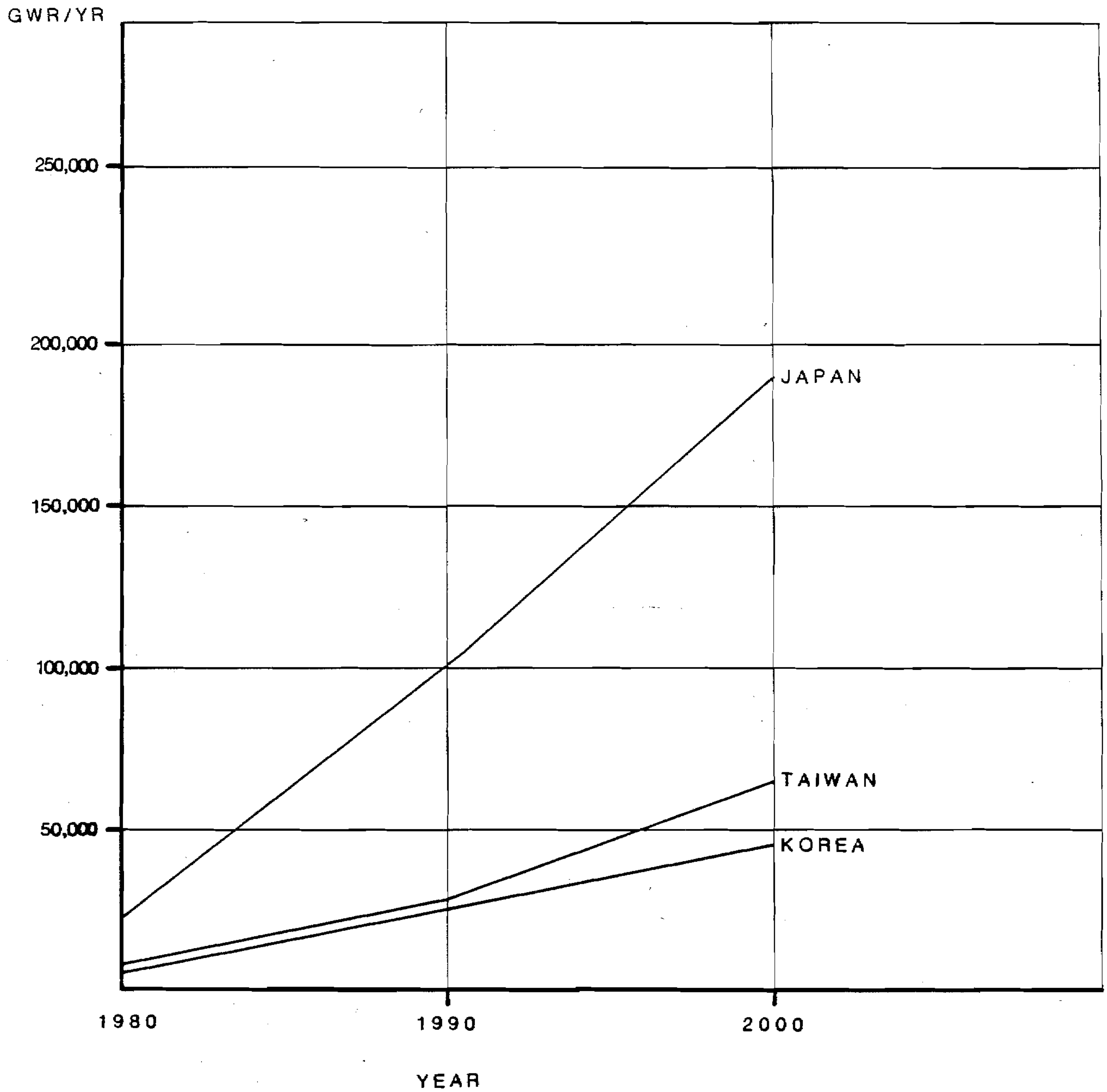
FIGURE D-1.5



PRESENT AND PROJECTED COAL IMPORTS
IN JAPAN AND SOUTH KOREA, 1980-2010

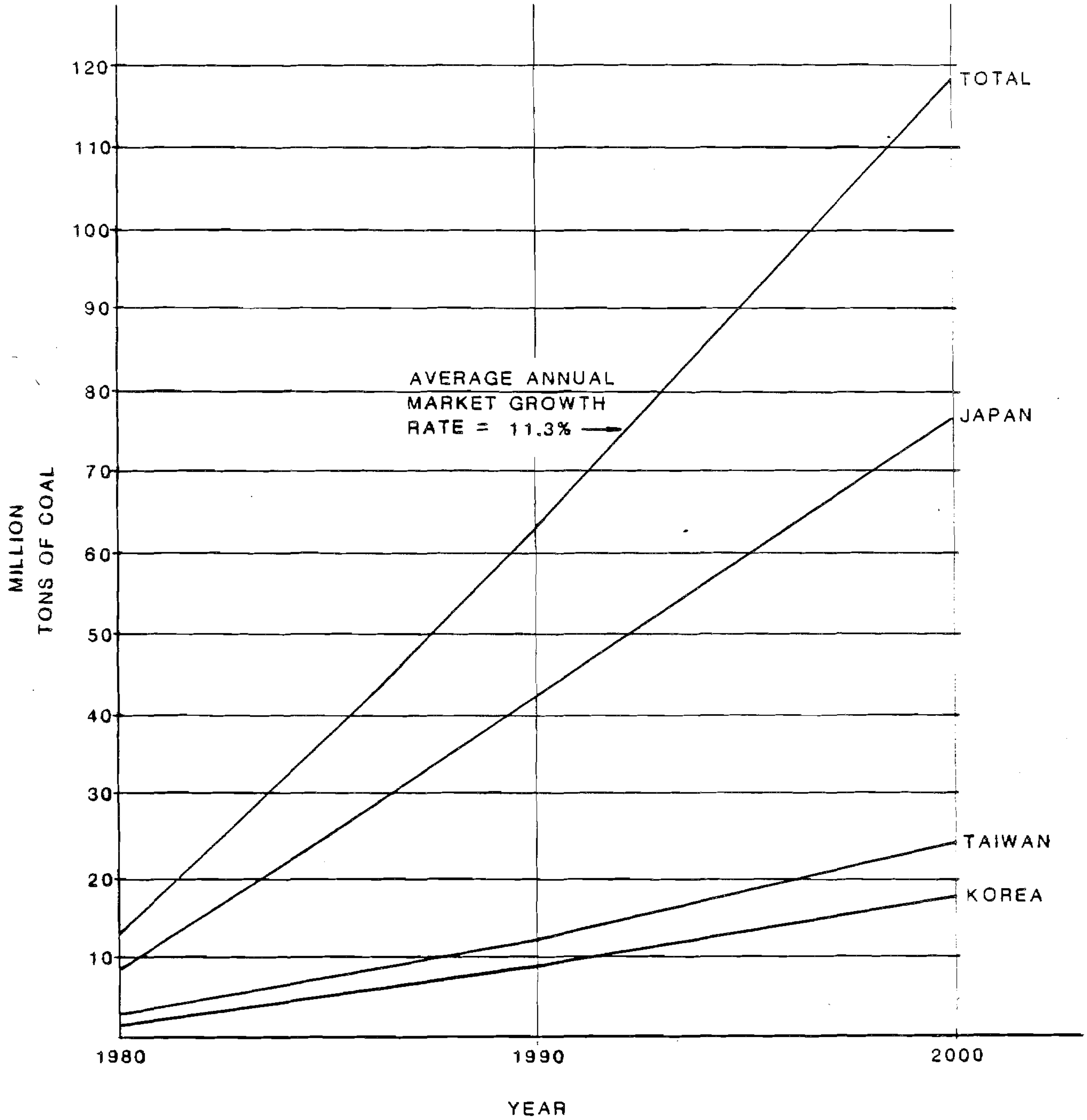
SOURCE: SHERMAN CLARK ASSOCIATES 1983

FIGURE D-2.1



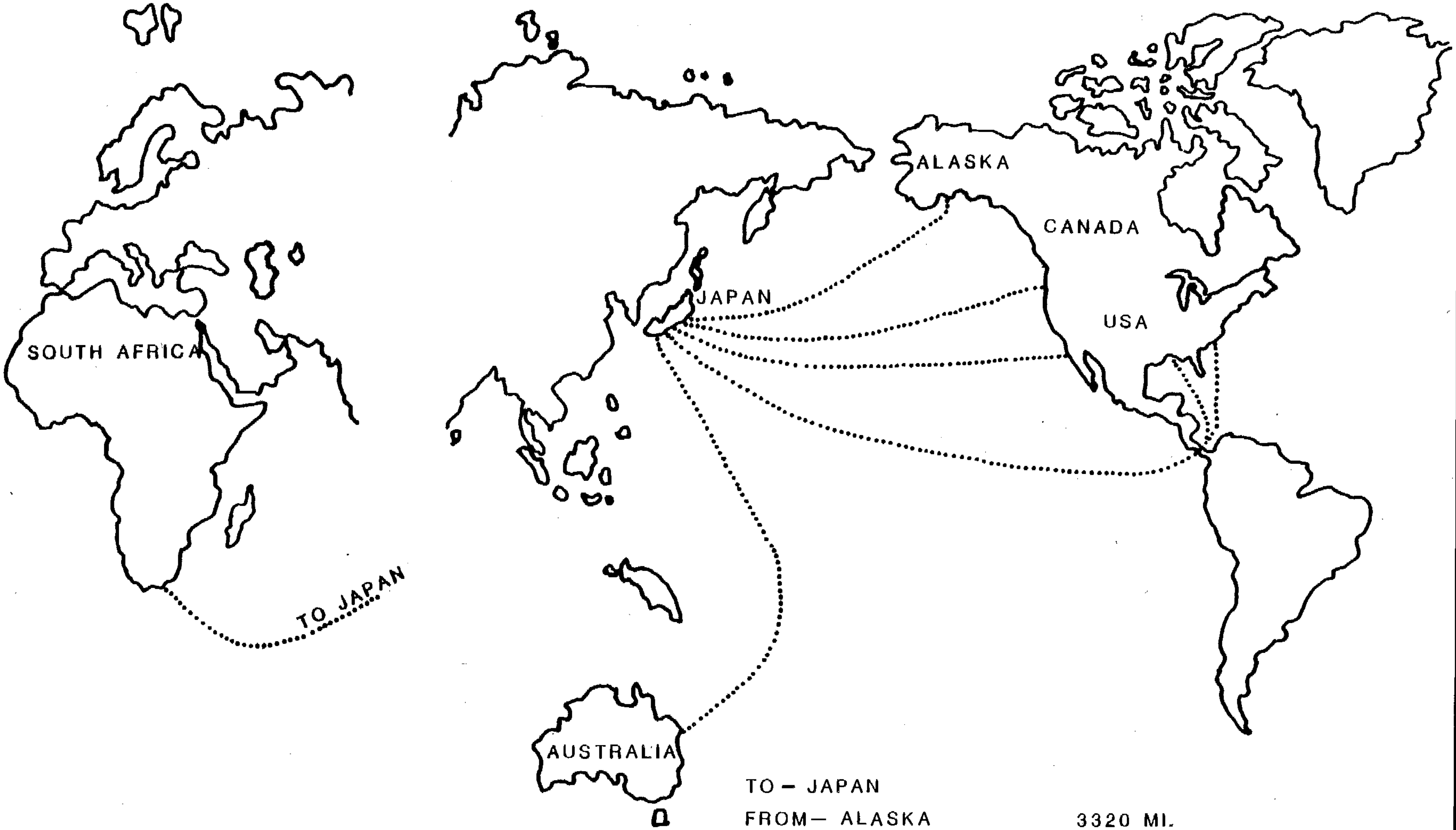
PROJECTED COAL FIRED ELECTRICITY GENERATION IN PACIFIC RIM COUNTRIES, 1980-2000 (GWR/YR)

FIGURE D-2.2



TOTAL COAL NEEDS FOR ELECTRIC POWER
GENERATION IN PACIFIC RIM NATIONS, 1980-2010

FIGURE D-2.3

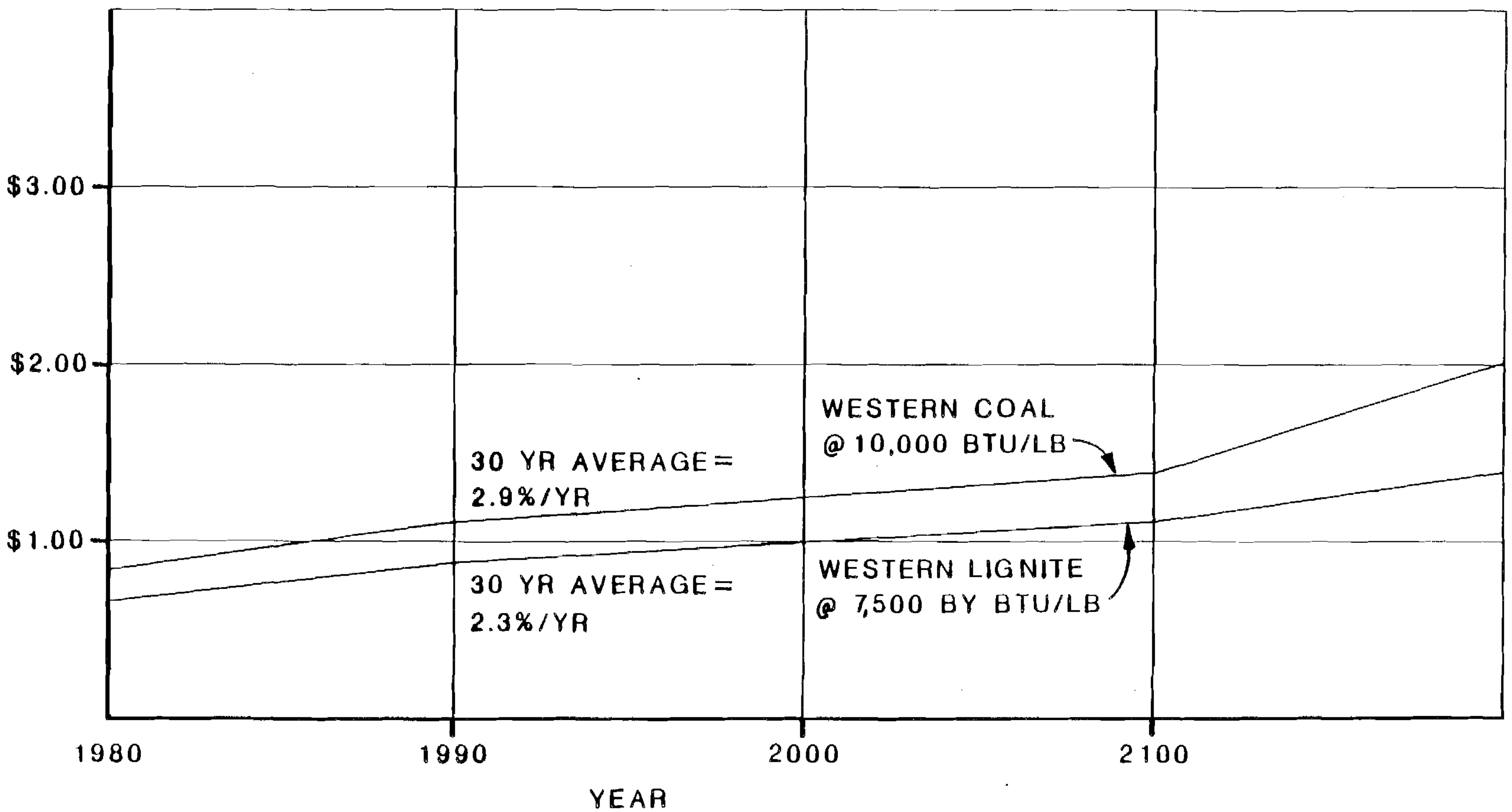


TO – JAPAN

FROM –	ALASKA	3320 MI.
	VANCOUVER	4262 MI.
	U.S. WEST COAST	4839 MI.
	AUSTRALIA	4265 MI.
	SOUTH AFRICA	7291 MI.
	U.S. GULF COAST	9095 MI.
	U.S. ATLANTIC COAST (PANAMA CANAL)	9504 MI.

DISTANCES FROM COAL PORTS TO JAPAN

FIGURE D-2.4



FORECAST REAL COAL PRICES FOR WESTERN COAL AND LIGNITE, 1980-2010; NEW CONTRACT AND SPOT MARKET STEAM COAL (1982DOLLLARS)

FIGURE D-2.5

SUSITNA HYDROELECTIC PROJECT
VOLUME 1
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FUELS PRICING STUDIES

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