SUSITNA HYDROELECTRIC PROJECT

DEVELOPMENT SELECTION REPORT

APPENDICES A THROUGH J

TASK 6 - DESIGN DEVELOPMENT

DECEMBER 1981

Prepared by:

ACRES

ALASKA POWER AUTHORITY

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SUSITNA HYDROELECTRIC PROJECT

TASK 6 - DEVELOPMENT SELECTION

SUBTASK 6.05
DEVELOPMENT SELECTION REPORT

APPENDICES A THROUGH J

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ACRES AMERICAN INCORPORATED
1577 C Street
Suite 305
Anchorage, Alaska 99501
Telephone : (907) 279-9631

ACRES AMERICAN INCORPORATED
1000 Liberty Bank Building
Main at Court
Buffalo, New York 14202
Telephone: (716) 853-7525

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

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APPENDIX A - GENERIC PLAN FORMULATION AND SELECTION METHODOLOGY

On numerous occasions during the feasibility studies for the Susitna Hydroelectric Project, decisions must be made in which a single or a small number of courses of action are selected from a larger number of possible alternatives.

This appendix presents a generalized framework for this decision-making process that has been developed for the Susitna planning studies. It outlines, in general terms, the approach used in screening a large multitude of options and finally establishing the best option or plan. It is comprehensive in that it takes into account not just economic aspects but also a broad range of environmental and social factors.

The application of this generalized methodology is particularly relevant to the following decisions to be made during the Susitna studies:

- Selection of alternative plans involving thermal and/or non-Susitna hydroelectric developments in the primary assessment of the economic feasibility of the Susitna Basin development plan (Task 6).

- Selection of the preferred Susitna Basin hydroelectric development plan (i.e. identification of best combination of dam sites to be developed) (Task 6).

- Selection of the preferred Railbelt generation expansion plan (i.e. comparison of Railbelt plans with and without Susitna).

- Optimization of the selected Susitna Basin development plan (i.e. determining the best dam heights, installed capacities, and staging sequences) (Task 6).

- Selection of the preferred transmission line routes (Task 8).

- Selection of the preferred mode of access and access routes (Task 2).

- Selection of the preferred location and size of construction and operational camp facilities (Task 2).

It is recognized that the above planning activities embrace a very diverse set of decision-making processes. The generalized methodology outlined here has been carefully developed to be flexible and readily adaptable to a range of objectives and data availability associated with each decision.

The following sections briefly outline the overall decision-making process and discuss the guidelines to be used for establishing screening and evaluation criteria.

A.1 - Plan Formulation and Selection Methodology

The methodology to be used in the decision process can generally be subdivided into five basic steps (Figure A.1):

- Step 1: Determine basic objectives of the planned course of action
- Step 2: Identify all feasible candidate courses of action
- Step 3: Establish a basis to be used and perform screening of candidates
- Step 4: Formulate plans incorporating preferred alternatives
- Step 5: Re-establish a basis to be used, evaluate plans and select preferred plan

Under Step 2, the candidate courses of action are identified such that they satisfy, either individually or in combinations, the stated objectives (Table A1). In Step 3, the basis of screening these candidates is established in items of redefined, specific objectives, assumptions, data base, criteria and methodology. This process follows a sub-series of seven steps as shown in Table A.2 to produce a short list, ideally of no more than five or six preferred alternatives. Plans are then formulated in Step 4 to incorporate single alternatives or appropriate combinations of alternatives. These plans are then evaluated in Step 5, using a further redefined set of objectives, criteria and methodology, to arrive at a selected plan. This six step procedure is illustrated in Table A.3. Tables A.2 and A.3 also indicate the review process that must accompany the planning process.

It is important that, within the plan formulation and selection methodology, the objectives of each phase of the decision process be redefined as necessary. At the outset the objectives will be broad and somewhat general in nature. As the process continues, there will be at least two redefinitions of objectives. The first will take place during Step 3 and the second during Step 5. As an example, the basic objectives at Step 1 might be the development and application of an appropriate procedure for selection of a single, preferred course of action. Step 2 might involve the selection of those candidates which are technically feasible on the basis of a defined data base and set of assumptions. The objectives at Step 3 might be the establishment and application of a defined set of criteria for elimination of those candidates which are less acceptable from an economical and environmental standpoint. This would be accomplished on the basis of an appropriately modified data base and assumptions. Having developed a series of plans incorporating the remaining or preferred alternatives under Step 4, the objectives under Step 5 might be the selection of the single alternative which best satisfies an appropriately redefined set of criteria for economic, environmental and social acceptability.

A.2 - Guidelines for Establishing Screening and Evaluation Criteria

The definition of criteria for the screening and evaluation procedures will largely depend on the precise nature of the alternatives under consideration. However, in most cases comparisons will be based on technical, economic, environmental and socioeconomic factors which will usually involve some degree of trade-off in making a preferred selection. It is usually not possible to adequately quantify such trade-offs.

Additional criteria may also be separately considered in some cases, such as safety or conservation of natural resources. Guidelines for consideration of the more common overall factors are discussed in the following paragraphs.

(a) Technical Feasibility

Basically, all options considered must be technically feasible, complete within themselves, and must ensure public safety. They must be adequately designed to cope with all possible conditions including flood flows, seismic events, and all other types of normal loading conditions.

(b) Economic Criteria

In cases where a specific economic objective can be met by various alternative plans, the criteria to be used is the least present worth cost. For example, this would apply to the evaluation of the various Railbelt power generation scenarios, optimizing Susitna Basin hydroelectric developments, and selection of the best transmission and access routes. In cases where screening of a large number of options is to be carried out, unit commodity costs can be used as a basis of comparison. For instance, energy cost in $/kwh would apply to screening a number of hydroelectric development sites distributed throughout southern Alaska. Similarily the screening of alternative access or transmission line route segments would be based on a $/mile comparison.

Because the Susitna Basin development is a state project, economic parameters are to be used for all analyses. This implies the use of real (inflation adjusted) interest rates and only the differential escalation rates above or below the rate of general price inflation. Intra-state transfer payments such as taxes and subsidies are excluded, and opportunity values (or shadow prices) are used to establish parameters such as fuel and transportation costs.

Extensive use should also be made of sensitivity analyses to ensure that the conclusions based on economics are valid for a range of the values of parameters used. For example, some of the more common parameters considered in comparisons of alternative generation plans particularly lend themselves to sensitivity analyses. These may include:

- Load forecasts

- Fuel costs

- Fuel cost escalation rates

- Interest and discount rates

- Economic life of system components

- Capital cost of system components

(c) Environmental Criteria

Environmental criteria to be considered in comparisons of alternatives are based on the FERC (1) requirements for the preparation of the Exhibit E "Environmental Report" to be submitted as part of the license application for the project. These criteria include project impacts on:

- Physical resources, air, water and land

- Biological resources, flora, fauna and their associated habitats

- Historical and cultural resources

- Land use and aesthetic values

In addition to the above criteria, which are used for comparing or ranking alternatives, the following economic aspects should also be incorporated in the basic alternatives being studied:

- In developing the alternative concepts or plans, measures should be incorporated to minimize or preclude the possibility of undesirable and irreversible changes to the natural environment.

- Efforts should also be made to incorporate measures which enhance the quality aspects of water, land and air.

Care should be taken when incorporating the above aspects in the alternatives being screened or evaluated to ensure consistency between alternatives, i.e. that all alternatives incorporate the same degree of mitigation. As an example, these measures could include reservoir operational constraints to minimize environmental impact, incorporation of air quality control measures for thermal generating stations, and adoption of access road and transmission line design standards and construction techniques which minimize impact on terrestrial and aquatic habitat.

(d) Socioeconomic Criteria

Based generally on FERC requirements, the project impact assessment should be considered in terms of socioeconomic criteria which include:

- Impact on local communities and the availability of public facilities and services

- Impact of employment on tax and property values

- Displacement of people, businesses and farms

- Disruption of desirable community and regional growth

A.3 - Plan Selection Procedure

As noted above, for each successive screening exercise, the criteria can be refined or modified in order to reduce or increase the number of alternatives being considered. As a general rule, no attempt will be made to ascribe numerical values to non-quantifiable attributes such as environmental and social impacts in order to arrive at an overall numerical evaluation. Such a process tends to mask the judgemental tradeoffs that are made in arriving at the best plan. The adopted approach involves utilizing combinations of both quantifiable and qualitative parameters in the screening exercise without making tradeoffs. For example, the screening criteria used might be:

- "... alternatives will be excluded from further consideration if their unit costs exceed X and/or if they are judged to have a severe impact on wildlife habitat ..."

This approach is preferable to criteria which might state:

- "... alternatives will be excluded if the sum of their unit cost index plus the environmental impact index exceeds Y ..."

Nevertheless, it is recognized that under certain circumstances, particularly where a relatively large number of very diverse alternatives must be screened very quickly, the latter quantitative approach may have to be used.

In the final plan evaluation stages, care will be taken to ensure that all tradeoffs that have to be made between the different quantitative and qualitative parameters used, are clearly highlighted. This will facilitate a rapid focus on the key aspects in the decision-making process.

An example of such an evaluation result might be:

- "... Plan A is superior to Plan B. It is $X more economic and this benefit is judged to outweigh the lower environmental impact associated with Plan B ..."

Sufficient detailed information should be presented to allow a reviewer to make an independent assessment of the judgemental tradeoffs made.

The application of this procedure in the evaluation stage is facilitated by performing the evaluations for paired alternatives only. For example, if the shortlist plans are A, B, and C, then in the evaluation Plan A is first evaluated against Plan B, then the better of these two is evaluated against C to select the best overall plan.

LIST OF REFERENCES

(1) Code of Federal Regulations - Title 18; Parts 2, 4, 5, 16 and 131.

TABLE A.1 - STEP 2 - SELECT CANDIDATES

Step 2.1 - Identification of candidates:

- objectives
- assumptions
- data base
- selection criteria
- selection methodology

Step 2.2 - List and describe candidates that will be used in Step 3.

TABLE A.2 - STEP 3 - SCREENING PROCESS

Step 3.1 - Establish:

- objectives
- assumptions
- data base
- screening criteria
- screening methodology

Step 3.2 - Screen candidates, using methodology established in Step 3.1 to conduct screening of alternatives.

Step 3.3 - Identify any remaining individual alternatives (or combinations of alternatives) that satisfy the objectives and meet the criteria established in Step 3.1 under the assumptions made.

Step 3.4 - Determine whether a sufficient number of alternatives remain to formulate a limited number of plans. If not, additional screening via Steps 3.1 through 3.3 is required.

Step 3.5 - Prepare interim report.

Step 3.6 - Review screening process via (as appropriate):

- Acres
- APA
- External groups

Step 3.7 - Revise interim report.

TABLE A.3 - STEP 5 - PLAN EVALUATION AND SELECTION

Step 5.1 - Establish:

- objectives
- evaluation criteria
- evaluation methodology

Step 5.2 - Establish data requirements and develop data base.

Step 5.3 - Proceed with the plan evaluation and selection process as follows:

- Identify plan modifications to improve alternative plans

- Based on the established data base and the selection criteria, use a paired comparison technique to rank the plans as (1) the preferred plan, (2) the second best plan, and (3) other plans;

- Identify tradeoffs and assumptions made in ranking the plans.

Step 5.4 - Prepare draft plan selection report.

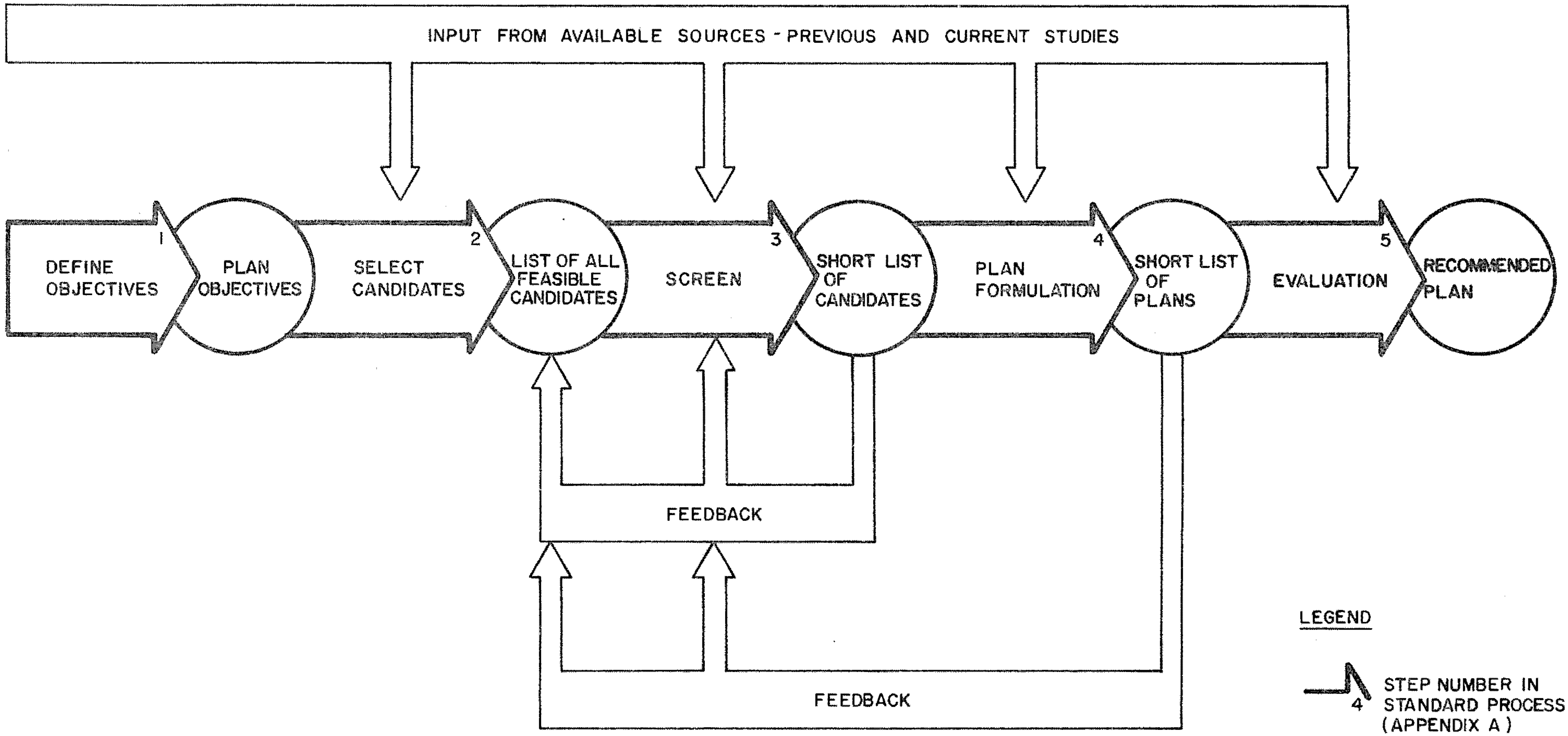
Step 5.5 - Review plan selection process via (as appropriate):

- Acres
- APA
- External groups

Step 5.6 - Prepare final plan selection report.

TABLE A.4 - EXAMPLES OF PLAN FORMULATION AND SELECTION METHODOLOGY

Activity	1. Define Objectives	2. Select Alternatives	3. Screen	4. Plan Formulation	5. Evaluation
Susitna Basin Development Selection	Select best Susitna Basin hydropower development plan	All alternative dam sites in the basin, e.g.: Devil Canyon; High Devil Canyon; Watana Susitna III; Vee; Maclaren; Butte Creek; Tyone; Denali; Gold Creek; Olson; Devil Creek; Tunnel Alternative	Screen out sites which are too small or are known to have severe environmental impacts	Select several combinations of dams which have the potential for delivering the lowest cost energy in the basin, e.g.: Watana-Devil Canyon dams; High Devil Canyon-Vee dams; Watana Dam - Tunnel	Conduct detailed evaluation of development plans
Access Route Selection	Select best access route to the proposed hydropower development sites within the basin for purposes of construction and operation	All alternative road, rail, and air transport component links, e.g.: road and rail links from Gold Creek to sites via north and south routes; Road links to sites from Denali Highway; Air links to sites and associated landing facilities	Screen out links which are either more costly or have higher environmental impact than equivalent alternatives. Ensure sufficient links remain to allow formulation of plans	Select several different access plans, e.g.: Gold Creek road access; Gold Creek road/rail access; Denali Highway road access	Conduct detailed evaluation of development plans



PLAN FORMULATION AND SELECTION METHODOLOGY

FIGURE A.1

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APPENDIX B - THERMAL GENERATING RESOURCES

The purpose of this Appendix is to define the thermal generating resources available to the Railbelt during the 1980-2010 study period. To address thermal resources, it is necessary to review the existing thermal capacity, fuel availability and associated costs as well as review future plant capacities and capital costs for development. To develop the parameters necessary for generation planning studies, it is also necessary to assess operation and maintenance costs, and planned and forced outages. The contents of this section document the data used in the generation planning studies described in Sections 6 and 8.

B.1 - Fuel Availability and Costs

Fuel sources available in the Railbelt region for future electric generation plants are primarily coal and natural gas. Distillate, although not expected to play a major role, is discussed briefly. It is unlikely that oil will be used as the primary fuel for additions to the generation system in the Railbelt due to public policy and high value for other uses. Tables B.1, B.2 and B.3 summarize estimated fuel reserves. Table B.4 lists current (1980) fuel prices in the Railbelt region. Table B.5 summarizes the developed fuel costs which represent opportunity (shadow) values, assuming active international marketing of Alaskan fuels, as discussed in the following sections.

(a) Coal

Alaskan coal reserves include the following coal producing fields (2):

- Nenana
- Matanuska
- Beluga
- Kenai
- Bering River
- Herendeen Bay
- Chignik Bay

Of these eight regions, only four have potential for Railbelt use. Table B.1 lists pertinent information of these four coal reserves.

The Beluga field, which is part of the larger Susitna Coal District, is an undeveloped source located 45 to 60 miles west of Anchorage on the west bank of Cook Inlet. Coal mining at this location would require the establishment of a mining operation, transportation system and supporting community and infrastructure. A number of studies have been conducted on the reserves located in the Beluga Coal Fields. It has been estimated that three areas (the Capps, Chuitna and Three Mile fields) contain 2.4 billion tons of coal and that in excess of 400 million tons can be stripped without exceeding economic limits on coal/overburden ratios.

The existing Nenana coal field, which is located in the vicinity of Fairbanks, is primarily leased by Usibelli Coal Mine Incorporated. The field ranges from less than a mile to more than 30 miles in width for about 80 miles along the north flank of the Alaska Range. Nenana coal is primarily mined by surface methods. An estimated 95 million tons of coal is available by stripping, and an estimated total in excess of 2 billion additional tons of coal could be extracted by underground mining.

The Matanuska coal fields, east of Anchorage, occupy most of the Matanuska Valley. Although stripping and underground mining of this source have been undertaken, stripping is limited due to relatively steep dips and increasingly thick overburden. Reserves are estimated at 50 million tons, and ultimate resource value may be 100 million tons. Although limited usage is possible locally, potential as a significant Railbelt source is unlikely (3).

The fourth potential coal producing region is the Kenai coal field in the Kenai lowlands, south of Tustumena Lake on the eastern shore of Cook Inlet. Resources are estimated at 300 million tons. These coal seams are thin and separated vertically, making mining extremely difficult.

Limited use of coal in the Railbelt at present is a result of an undeveloped export market and the relatively small local demand for this fuel. Currently the Usibelli Coal Company mines Nenana coal at a facility located in Healy and produces approximately 0.7 million tons/year. This coal represents the only major commercial coal operation in Alaska. The coal is trucked several miles from the mine site to a 25 MW power plant owned and operated by the Golden Valley Electric Association (GVEA) at Healy. The delivered cost is approximately $1.25 per million Btu (MMBtu). The Nenana coal is also trucked 8-1/2 miles to a railway spur loading station at Susitana for transport to Fairbanks, a distance of 111 miles. This coal is delivered to the Chena Station (capacity 29 MW), owned by Fairbanks Municipal Utility System (FMUS), at an extra cost of approximately $0.34/MMBtu bringing the price to FMUS to $1.40/MMBtu. Coal mined at Healy is also used for generation in units at Fort Wainwright Army base and the University of Alaska power plants. Various proposals have been made for expanded production in the Nenana coal field which would nearly double the production. In September, 1980, a contract between Japan and the owners of the Healy operation was signed to transport coal to Seward via the Alaskan Railroad for barging to Japan. Details and costs of this proposal are not available at this time. Other expansion options include:

- Enlarge the Healy generation plant to 100 MW (75 MW addition). This was proposed jointly by GVEA and FMUS. However, the location of the Healy plant 4.5 miles from Mt. McKinley National Park may restrict development due to increased costs associated with meeting air quality standards.

- Expand the FMUS Chena generation plant or build a new joint FMUS/GVEA plant at Fairbanks to supply district heat and increased electric power capability.

- Transport Healy mined coal approximately 55 miles north via the Alaska Railroad to Nenana and build a 100 MW expansion there. However, according to GVEA and FMUS, this expansion plan has been postponed due in part to slowing demand growth and environmental restrictions.

- Transport Healy mined coal approximately 200 miles south via the Alaska Railroad to Anchorage for utilization in new 200 or 400 MW coal-fired plants. This option is thought possible, but the economics of coal transport at the necessary capacity via the existing rail system is in question. Development at Beluga may also preclude this option.

Two potential developers have authorized studies of the Beluga coal district to determine the economics and feasibility of extensive development. Placer-Amex Incorporated has extensive holdings throughout the Beluga district and Bass-Hunt-Wilson Venture has holdings in the Chuitna field.

(i) Placer-Amex Holdings

An extensive study of the potential of the Placer-Amex holdings was completed in 1980 by the Alaska Division of Energy and Power Development (16). This report summarizes the potential of development of the Cook Inlet Region coal field. Several options were shown to exist for development. The first option would be development by Beluga Coal Company (a wholly owned subsidiary of Placer-Amex Inc.) within the next two or three years. However, since most of the proposed project output is exported, they cannot begin initiation until a firm market is contracted for the coal. The second option is the construction of a coal-fired generating plant by the Chugach Electric Association (CEA). This option is dependent upon government mandated requests for utilities to convert from natural gas to coal. The CEA has currently no firm plans to construct such a plant.

Based on these two options, four possible levels of development at Beluga are considered and were evaluated in the 1980 report noted above.

- Low level of coal mining to supply local generating facilities. Development could occur if the CEA is required by govenment mandate to replace natural gas units with coal units. This scenario would require moderate development of a work camp at Beluga, and would include two 200 MW generators using approximately 1.5 million tons per year. Construction would be during the period 1980 - 1986.

- A sufficiently large (at least six million tons per year (MMTPY)) export market is developed and no generating stations are constructed. This figure is considered the minimum amount necessary for cost effective exporting. In this case, a permanent work camp would be established similar to the first scenario. Exporting would begin in 1990.

- Two 200 MW coal-fired generating plants and a six MMTPY coal exporting facility could justify the necessary front-end capital investment to establish a permanent community at Beluga. This would also entail secondary economic development.

- There is a distinct possibility that no development of the Beluga coal field will occur before 1990.

Export scenarios also include barging 3500 miles to Japan or 2100 miles to San Francisco and a slurry pipeline scheme to the Pacific Northwest (28). Supplying Anchorage with coal via a new railroad tie does not appear to be an option considered for the near future development (28).

(ii) Bass-Hunt-Wilson Holdings

The study of the Beluga Coal Field potential at the Bass-Hunt-Wilson (BHW) coal leases in the Chuitna River Field was completed by Bechtel Corporation in April 1980 (27). This study resulted in a 7.7 MMTPY economic export production rate with no consideration of local coal-fired generating developments.

Potential export markets for Beluga coal as defined in the previous section include the entire Lower 48 states or California, Pacific Northwest and Japan markets. The average market price for coal in California and the Pacific Northwest region, as reported in June, 1980 to the U.S. Department of Energy, ranged from $1.55/MMBtu to $1.46/MMBtu. These prices are slightly higher than the average U.S. price. The costs of transporting Beluga mined coal to the Pacific Northwest or to California were estimated in a 1977 Report on "Alaska Coal and the Pacific." (2) These prices were estimated and appear in Table B.5.

The Beluga coal studies done for Placer-Amex and the Bass-Hunt-Wilson venture have resulted in opportunity costs for coal of $1.00 - $1.33/MMBtu. For purposes of this study the value of $1.15/MMBtu will be used for supplies to future coal-fired generating plants constructed in Alaska (Table B.5).

A report issued in December, 1980 by Battelle Pacific Northwest Laboratory (50) analyzed market opportunities for Beluga coal. Results reported in this report were generally consistent with earlier Battelle and DOE studies.

(b) Natural Gas

Natural gas resources available or potentially available to the Railbelt region include the North Slope (Prudhoe Bay) reserves and the Cook Inlet reserves. Information on these reserves is summarized in Table B.2.

The Prudhoe Bay Field contains the largest accumulation of oil and gas ever discovered on the North American continent. The in-place gas volumes in the field are estimated to be in excess of 40 trillion cubic feet (Tcf). With losses considered, recoverable gas reserves are estimated at 29 Tcf. Gas can be made available for sale from the Prudhoe Bay Field at a rate of at least 2.0 billion cubic feet per day (Bcfd) and possibly slightly more than 2.5 Bcfd. At this rate, gas deliveries can be sustained for 25 to 35 years, depending on the sales rate and ultimate gas recovery efficiency.

During the mid-seventies, three natural gas transport systems were proposed to market natural gas from the North Slope Fields to the Lower 48 states. Two overland pipeline routes (Alcan and Arctic) and a pipeline/LNG tanker (El Paso) route were considered. The Alcan and Arctic pipeline routes traversed Alaska and Canada for some 4000 to 5000 miles, terminating in the central U.S. for distribution to points east and/or west. The El Paso proposal involved an overland pipeline route that would generally follow the Alyeska oil pipeline utility corridor for approximately 800 miles. A liquefaction plant would process approximately 37 million cubic meters of gas per day. The transfer station was proposed at Point Gravinia south of the Valdez termination point. Eleven 165,000 cubic meter cryogenic tankers would transport the LNG to Point Conception in California for regasification.

The studies noted above have concluded with the initiation of a 4800 mile, 2.4 Bcfd, Alaska-Canada natural gas pipeline project, costing between $22 and $40 billion, expected to be operational by 1984-1985. The pipeline project passes approximately 60 miles northeast of Fairbanks.

The Cook Inlet Reserves (Table B.2) are relatively small in comparison to the North Slope reserves. Gas reserves are estimated at 4.2 Tcf as compared to 29 Tcf in Prudhoe Bay. Of the 4.2 Tcf, approximately 3.5 Tcf is available for use; the remaining reserves are considered shut-in at this time. The gas production capability in the Kenai Peninsula and Cook Inlet region far exceeds demand, as no major transportation system exists to export markets. As a result of this situation, the two Anchorage electric utilities have a supply of natural gas at a very economic price. Export facilities for Cook Inlet natural gas include one operating and one proposed LNG scheme. The facility in operation, the Nikiski terminal, owned and operated by Phillips-Marathon, is located on the eastern shore of Cook Inlet. Two Liberian cryogenic tankers transport LNG some 4000 miles to Japan. The volume produced is 185 MMCFD with raw natural gas requirements of 70 percent from a platform in Cook Inlet and 30 percent from existing onshore fields.

In 1979, the Pacific Alaska LNG Company (PALNG) proposed to ship LNG to California from a terminal to be constructed at Nikiski on the Kenai Peninsula. This plant would ultimately process up to 430 MMCFD for shipment via two cryogenic tankers to Little Cojo (near Point Conception), California. The Federal Energy Regulatory Commission (FERC) has placed a rider on the project permit, stipulating that in-place and committed gas reserves must total 1.6 Tcf before a license is granted. To date PALNG estimates 1.0 Tcf is in place.

There is also some potential for a gasline spur to be constructed from the Cook Inlet region some 310 miles north to intersect with the Alaska-Canada natural gas pipeline project in order to market the Cook Inlet gas. This concept has not been extensively studied but could prove to be a viable alternative.

Markets for Prudhoe Bay gas were not considered in developing a market price for Railbelt fuel alternatives since an existing market and transportation system has been developed with the inception of the Alaska-Canada pipeline project.

Markets for Cook Inlet gas include the Lower 48 states via two transportation modes: LNG tankers or a pipeline spur constructed from Anchorage to Delta Junction and intersecting with the Alaska-Canada pipeline. The regulated ceiling market price for natural gas on the west coast as reported in the Federal Register, Department of Energy, Tuesday, October 27, 1980 was $4.89/MMBtu in the Region 10 area (Washington, Oregon, California). The average reported U.S. price was $3.58/MMBtu. Shipment of gas to these markets via the LNG tanker scheme as proposed by PALNG was

was estimated to cost $2.50/MMBtu for transportation and processing. Alternatively, the cost for shipment via a 310-mile pipeline spur from Cook Inlet to the Al- Can pipeline was estimated (based on cost data available from the current pipeline project) to be $1.97/MMBtu. This includes the incremental cost of the Alaska-Canada pipeline ($1.27/MMBtu) and the cost of the tap from Cook Inlet ($0.70/MMBtu). Table B.5 lists the resulting Alaskan opportunity values under these two assumptions for markets in Region 10 and the Lower 48 states.

The current Japanese market price for natural gas sales from the Nikiski LNG project is $4.50 to $4.65/MMBtu (46). Based on information collected from Nikiski, transportation and processing costs were estimated to be $3.00/MMBtu. This results in an Alaskan opportunity value of $1.50 to $1.65/MMBtu.

The resulting prices developed in these analyses range from $1.08 to $2.92/MMBtu. For purposes of this study $2.00/MMBtu was adopted as the opportunity value of natural gas in Alaska.

(c) Oil

Both the North Slope and the Cook Inlet Fields have significant quantities of oil resources as seen in Table B.3. North Slope reserves are estimated at 8375 million barrels. Oil reserves in the Cook Inlet region are estimated at 198 million barrels (14). As of 1979, the bulk of Alaska crude oil production (92.1 percent) came from Prudhoe Bay, with the remainder from Cook Inlet. Net production in 1979 was 1.4 million barrels per day (11).

Oil resources from the Prudhoe Bay field are transported via the 800 mile trans-Alaska pipeline at a rate of 1.2 million barrels per day. In excess of 600 ships per year deliver oil from the port of Valdez to the west, Gulf and east coasts of the U.S. Approximately 2 percent (or 10 million barrels) of the Prudhoe Bay crude oil was used in Alaska refineries and along the pipeline route to power pump stations (14). The North Pole Refinery, located 14 miles southeast of Fairbanks, is supplied by the trans-Alaska pipeline via a spur. Refining capacity is around 25,000 barrels per day with home heating oils, diesel and jet fuels the primary products.

Much of the installed generating capacity owned by Fairbanks' utilities is fueled by oil. FMUS has 38.2 MW and GVEA has 186 MW of oil-fired capacity. Due to the high cost of oil, these utilities use available coal-fired capacity as much as possible with oil used as standby and for peaking purposes.

Crude oil from offshore and onshore Kenai oil fields is refined at Kenai, primarily for use in-state. Thermal generating stations in Anchorage rely on oil as standby fuel only.

Since the installation of the Alyeska oil pipeline, which has made Alaskan oil marketable, the opportunity cost of oil to Alaska has been the existing market price. Contracts for oil to utilities have ranged from $3.45/MMBtu to $4.01/MMBtu as reported to FERC. For purposes of the generation expansion study, where oil is considered only available for standby units, the price adopted for use is $4.00/MMBtu (Table B.5).

B.2 - Thermal Generating Options - Characteristics and Costs

The analysis of thermal generating resources available to meet future Railbelt needs requires the detailed determination of existing generating capacity, its use, condition and planned retirement policy in addition to committed thermal plant expansions. Of the 943.6 MW of existing (1980) capacity in the Railbelt region, 95 percent of capacity relies on fossil fuels (Table B.6). A summary of capacity by unit type is given in Table B.7.

By far the most important thermal generating resources available to the Railbelt in 1980, are the natural gas-fired gas turbines in the Anchorage/Cook Inlet region (Table B.7). The recent trend of both Anchorage Municipal Light and Power Department (AMLPD) and the CEA has been to meet future generating needs using combined cycle additions to existing gas turbine units. This ongoing trend is illustrated by the anticipated expansion of CEA's system with the Beluga No. 8 unit (60 MW) and the most recent AMLPD expansion of unit No. 6 at their George M. Sullivan Plant. These units all rely on locally contracted Cook Inlet natural gas for generation.

Oil-fired generation by gas turbines is generally confined to the Fairbanks region with units owned and operated by GVEA and FMUS. In addition, these two utilities own and operate the 54 MW of coal-fired steam capacity using Healy coal. Small diesel units are used for peaking and standby service in the Fairbanks region.

The capital costs for four different types of thermal generating plants considered available to the Railbelt region were estimated. Capital cost estimates for coal-fired steam, combined cycle, gas turbines and diesels appear in Tables B.8 to B.13. Table B.13 summarizes the generation parameters necessary for the production cost model in the generation planning studies described in Section 8.

Capital costs for new fossil (coal) thermal plant alternatives are an input to any generation planning study. The development of capital cost estimates of high accuracy generally consumes substantial time and effort for a single plant design at a specified location. The development of detailed cost estimates for numerous plant types at non-specific locations to be selected at some future time would be a formidable task. The approach taken in this study has been to develop generic coal-fired plant cost estimates, largely based upon published Lower 48 states' cost data, previous studies of Alaskan construction cost differentials, and recent Alaskan construction experiences.

Gas turbine combined cycle and diesel plants are typically modularized units, with major cost variations largely tied to specified site conditions or restrictions. Costs used for these items were based on manufacturer supplied information and published bid information for units to be installed in the Railbelt region.

(a) Coal-Fired Steam

As previously mentioned there are currently four coal-fired steam plants in operation. The 29 MW Chena unit is operated by FMUS and another 25 MW plant is operated by GVEA at Healy. Two more coal units, with a total capacity of 6 MW, supply Fort Wainwright and the University of Alaska at Fairbanks with heat and electric power. These two units supply FMUS on a contractual basis, when available. All of these plants are small in comparison to new electric utility units typically under consideration in the Lower 48 states. Up-to-date cost comparisons for potential new installations in Alaska were therefore difficult.

Other factors that have been considered in developing costs for new installations include:

- Large, new coal-fired plants will require extensive emission control equipment to meet current EPA emission standards

- Larger plants involve longer construction periods

- Current high interest and escalation rates have driven costs of new plants to much higher levels than previously experienced

(i) Deviation of Plant Costs

Based on projected Alaskan plant capacity additions developed in previous studies, coal-fired unit sizes of 100, 250, and 500 MW were considered for capacity additions. It is unlikely that a 500 MW plant would be proposed for local supply to either Anchorage or Fairbanks due to limited power demand and fuel transportation capacity. The remoteness of Fairbanks also possibly precludes the use of 500 MW plants. However, installation of such a plant as a baseload unit, perhaps in the Beluga coal field region, to feed an integrated utility grid is a possibility. Since typical plant unit sizes required in Alaska are substantially smaller than those typical of the Lower 48 states, previous studies have therefore incorporated relationships for economy of scale, based upon Lower 48 data (3,17). The regional differences in Alaskan construction costs can also be substantial, with the result that Alaskan location adjustment factors have also been used in these recent studies (3). Cost differences may be due to transportation requirements, labor costs, climate, and distance from equipment supplies.

A review of Alaskan construction cost location adjustment factors was undertaken by Battelle in March 1978 (3). These adjustment factors, identified for different locations in the Railbelt, ranged from 1.35 to 1.7 for Anchorage, 1.8 to 2.75 for Beluga, and 2.20 to 2.42 for the Healy/Nenana/Fairbanks area. The factors finally adopted by Battelle for their study were 1.65, 1.80 and 2.20 for Anchorage, Beluga and the Healy-Fairbanks area, respectively. The Battelle study included a review of material cost additions due to transportation and labor cost variations due to lack of developed social infrastructure in many areas in the state.

The Battelle study examined the Beluga coal fields as a power plant site. Particular attention was paid to the variation in costs associated with development of a largely uninhabited area. Land was considered to be lower in cost than in other regions, and the site favored use of preassembled plant modules barged to the site; both items produced cost reductions. Cost increases resulted from construction of worker towns and transport of equipment, food, fuel and other supplies.

In the Healy area, modularized construction of large units would not be possible since transportation opportunities are limited to the ability of Alaskan railroads to carry large loads. Therefore, the net effect on the adjustment factor is increased.

There is a significant amount of uncertainty regarding the use of Alaskan location adjustment factors derived in previous studies. Consequently, attempts were made to cross check the validity of the Battelle factors with independent development of costs for ongoing Alaskan projects and evaluation of the Battelle sources whenever possible.

Capacity scaling factors, as used by EPRI and Battelle in previous studies, extrapolate costs of larger units (500-1000 MW) to smaller units (100-500 MW). Under this procedure, the cost of a smaller unit can be computed given the cost of a larger unit and an exponential scaling factor. This procedure, exercised with caution over no more than a tenfold range of capacity, can produce preliminary figures for cost comparison. Battelle, in their study of Alaskan electric power, used capacity scaling factors of 0.85 in the 200-1000 MW range and 0.60 in the 100-200 MW range (3). Recognizing the inaccuracies associated with using capacity scaling factors, the use of the exponent approach was limited and was reviewed for consistency once applied. A further check was made by means of cost sensitivity assessments in generation planning studies (Section 8).

(ii) Basis of Plant Cost Estimates

The coal-fired plant cost estimates developed for input into thermal generating options were based on an EPRI document number AF-342, prepared by Bechtel (17). This report extensively details the costs of 1000 MW coal plants in various Lower 48 locations. The baseline plant, used to develop Alaskan costs, was designed for a remote location in Oregon with maximum environmental controls. This plant used Wyoming coals which have similar characteristics to Alaskan coals.

The cost estimates were based on the following design assumptions:

- The plant location assumes both make-up water and rail access available, but at some distance from the site.

- A river intake and pumping plant would supply raw river water to a surge pond through a thirteen-mile long pipeline.

- Coal would be rail delivered by unit train in open gondola cars for rotary dump service.

The plant design has assumed to include the following systems:

- Coal handling system
- Auxiliary boiler system
- Raw water supply system
- Fire protection system
- Plant rain run-off system
- Light oil supply system
- Heating and ventilating system
- Boiler system
- Turbine generator system
- Condensate system
- Extraction steam system
- Main steam and reheat system
- Circulating water and cooling tower system
- Rain water system
- Chemical treatment
- Ash handling
- Waste water disposal
- Air quality control

The air quality control system is designed to control sulphur dioxide emissions and particulates. This system was considered particularly important due to the air quality of the Alaskan environment.

The switchyard cost includes:

- Circuit breakers
- Disconnect switches
- Line traps
- Potential devices
- Lightning arresters
- Foundations
- Control buildings
- Supporting structures
- Take-off towers
- Single aluminum bus-single breaker scheme with bus sectionalizing breakers of 345 kV
- Two start-up transformers
- Emergency power supply (low voltage)

In the EPRI baseline design, water from the condensors would be cooled in two mechanical draft cooling towers, with make-up water coming by pipeline. There is, of course, the potential for open cycle cooling using a cooling pond which offers a potential cost savings. However, due to the scope of this study, this was not investigated. The use of natural waterbodies for once-through cooling is generally cheaper than cooling towers. However, due to environmental constraints, this cooling method is restricted.

Site access costs included in the EPRI plant design were based upon a remote area; accessories included 15 miles of railroad and switching station, and 13 miles of water pipeline. This would adequately represent a remote development in the Beluga area.

Table B.6 summarizes the cost estimate of the EPRI plant in 1976. The cost in 1976 dollars for a 1000 MW plant was determined to be \$566.6 million.

(iii) <u>Cost Adjustments</u>

Updated costs for 1980 were developed using the Handy-Whitman indices (54). The Handy-Whitman indices are widely used for cost updating. They are developed bi-annually by Whitman-Requardt and Associates and are based on extensive utility plant cost research in each of six regions of the United States. The Handy-Whitman indices used for this study are for the Region 6 - Pacific Northwest area. They are represented as a ratio of the January 1, 1980 dollar values to the January 1, 1976 dollar values for a variety of plant cost estimates. The 1976 cost was therefore updated to give a 1980 dollar cost of \$792 million. This cost represents the cost of a 1000 MW plant in the Lower 48 and therefore is required to be scaled to reflect the cost of a unit size applicable to the Railbelt region.

Two methods were considered in scaling the cost. The first was developed from EPRI research which reported that approximately 54 percent of the total construction cost was attributable to the first unit (17). The cost of a single 500 MW unit would thus be 54 percent of the cost of a 1000 MW plant, or \$428 million. The capacity scaling equation used was:

$$\frac{\text{Cost of Unit A}}{\text{Cost of Unit B}} = \left(\frac{\text{Capability of Unit A}}{\text{Capability of Unit B}}\right)^{\text{exponent}}$$

This equation was solved for the exponent by substituting the various costs and capabilities. This yielded a value of 0.89 which is substantially greater than the usual 0.6 value. However, as discussed in an article on the subject of computing economy of scale values (51), inflation, high interest rates and lengthened schedules have negated to a large degree the 0.6 economy of scale and brought the exponent up to values of 0.79 to 0.86. This compares favorably to the 0.85 value obtained in analyses conducted by Battelle for 200 to 500 MW units. It is assumed that the 0.85 value used by Battelle in previous studies is an accurate representation of the current economy of scale in power plant estimation. Consequently, this value was used for the plant costs in this study. Tables B.8, B.9 and B.10 reflect this application. For the 100 MW plant the scaling factor used was 0.85 rather than the 0.60 suggested by Battelle for plants in the 100 to 200 MW range. Applying the 0.85 factor results in a more conservative figure for the 100 MW plant by almost \$90 million dollars (\$111 vs \$199 million).

The application of the established Lower 48 cost to the Railbelt situation must take into account a variety of other factors. Short-term additions to existing coal-fired plants are a viable possibility for extension of Railbelt generation capability. Ongoing studies in the Fairbanks region to expand existing coal-fired capacity for electricity and district heating, although for a smaller plant capacity than the 100 MW considered here, have shown the cost of new mechanical equipment alone to be approximately 1.77 times more compared to a similar installation in the Lower 48. This result, in addition to research by the U.S. Army Corp of Engineers and

Battelle, indicates increases in Lower 48 plant costs in the range of 1.2 to 2.65 for the Railbelt. Additionally, due to the limitations of most optimized production cost models, allowance is made for a number of future size additions; however, the additions are site-constricted, allowing no variability in capital cost versus site conditions.

Reviewing the long-term coal production and use potential in the Railbelt indicates that large scale development at Beluga is a good possibility. This development would entail export operations and local generation usage. Therefore, to develop and represent to a production cost model an indication of likely site development and cost, the Lower 48 capital costs were adjusted to represent a Beluga-sited development. This representation in no way disallows the possibility of expansion or even small scale development of coal potential at other Railbelt locations. It does, however, serve to represent an overall Railbelt coal potential cost for a remote Alaskan situation. The Beluga cost figures shown in Tables B.8 to B.10 reflect a 1.8 Alaskan adjustment factor, which represents the middle range of all Railbelt estimates and is similar to the developed Beluga factor reported by Battelle (3).

In addition to the direct costs shown in Tables B.8, B.9 and B.10, a contingency of 16 percent, 10 percent for utilities and other construction facilities and 12 percent for engineering and administration was added. Interest of 3 percent, net of escalation, during the construction period of six years for the 500 and 250 MW plants and five years for the 100 MW plant would be an added cost.

(iv) <u>Operating Characteristics</u>

Coal-fired plant operating characteristics which are incorporated in the generation planning analysis are heat rate, unit availability and operation and maintenance costs. The heat rate selected for the three plant sizes is 10,500 Btu/kWh, which is consistent with the EPRI plant design.

Outages for coal-fired steam plants are taken into account in terms of scheduled (planned) and forced outages as a percent of time. Data published by the Edison Electric Institute (EEI) indicates a forced outage of approximately 5.4 percent for large coal-fired plants (41). This figure was rounded to 5 percent to represent forced outages for study purposes. Scheduled outages, as reported by GVEA for their Healy plant, are in the 5.1 to 16.3 percent range. An average of 11 percent, which also correlates with the EEI data, was adopted as the scheduled outage rate for coal-fired plants for this study. The parameters given above for thermal generating plants are given in Table B.13.

Operation and maintenance (O&M) costs for use in generation planning are divided into two components: fixed costs and variable costs (exclusive of fuel). Fixed O&M costs for typical U.S. plants are reported periodically in the DOE publication, Steam Plant Construction and Annual Production Expenses (21). Trends indicated in these reports led to adoption of values for fixed cost of 0.50, 1.05 and 1.30 $yr/kw for 500 MW, 250 MW and 100 MW plants respectively. Variable costs in the DOE publication (21) are shown to decrease with increasing unit size. The values used in this study are $1.40, $1.80 and $2.20/yr/kW for 500 MW, 250 MW and 100 MW plants respectively.

(b) Combined Cycle

A number of factors have recently led to an increased interest in combined cycle generating plants, both in the Lower 48 and Alaska. These factors include rising fuel prices, increasing environmental requirements and greater flexibility for mid- and base-load applications dictated by changing system load requirements. These conditions have prompted two Anchorage utilities, AMLPD and CEA, to look to combined cycle generation to meet their needs.

Presently there are two combined cycle plants in operation in Alaska. An operational unit, known as the G.M. Sullivan plant and owned by AMLPD, consists of three units which, when operating in tandem, produce a net capacity of 140.9 MW. Another plant under construction for CEA and known as Beluga No. 9 unit will add a 60 MW steam turbine to the system sometime in 1982. These two units represent expansions to existing gas-turbine plants and are considered to be essentially short-term generation planning commitments for the Railbelt. For the longer term, a unit capacity of 250 MW for new combined cycle plants was considered to be representative of potential future additions in the Railbelt area. This assumption is based on trends in the Lower 48 and load growth projections in Alaska. A heat rate of 8500 Btu/kWh was adopted based on Alaskan experience. The EPRI report AF-610 (18), was used as the basis of cost estimates for this type of plant.

A substantial quantity of natural gas could be available to utilities with the implementation of the Alaskan Natural Gas Pipeline. However, construction of a natural gas pipeline spur to supply combined-cycle installations in the Railbelt region is not likely during the critical study planning period of 1990-1995. All generating resources in Fairbanks are currently fueled with coal or oil. In addition, despite the close proximity of the Beluga region to the Cook Inlet gas reserves, development at Beluga would not be predicated on combined cycle plants. Therefore, the potential installation of combined cycle plants will most likely be limited to the Anchorage area. This premise is based on the local electric utilities' most recent generation expansion programs and readily available Cook Inlet natural gas.

Recent experience in combined cycle construction in Alaska has been limited to small expansions of existing facilities. For purposes of this study, it was therefore necessary to rely on Lower 48 cost estimates for larger installations, extrapolated to apply to Alaska conditions.

Lower 48 costs for 250 MW combined cycle generating units are given in Table B.13. These costs were obtained from General Electric Corporation in 1980 dollars. Estimates were made for costs of foundations and buildings, fuel handling facilities and other mechanical and electrical equipment. An additional cost of 25 percent of the cost of the generating equipment has been included for transportation of the basic unit to the Pacific Northwest. These costs were compared to prior cost estimates of combined cycle power plants in EPRI-AF-610 and were found to be consistent. Using an Alaskan location adjustment factor of 1.6 recommended by Battelle (3), the account items were adjusted for a plant located in the Anchorage area. Transportation to Anchorage was assumed to be 25 percent more than to the Pacific Northwest coast. This may be slightly high for transportation costs to Alaska, however, considering limited navigation periods and size

size of the 250 MW units, it is believed to be a reasonable assumption and within limits of accuracy for study cost estimates. As for coal-fired plants, indirect costs of 16 percent for contingency, 10 percent for construction facilities and utilities, and 12 percent for engineering and administration were added to the directed cost.

Table B.13 summarizes the results of these estimates. Allowance for funds during construction (AFDC) for these years is included in this total. Operation and maintenance (O&M) costs for large combined cycle plants, as reported in EPRI, AF-610 (18) approximate $2.75/yr/kW for fixed O&M and $0.30/MWh for variable O&M. These were adopted for Alaskan application.

Based on information provided by AMLPD for their G.M. Sullivan combined cycle plant, scheduled outage rates are approximately 11 percent. For a larger plant of 250 MW, based on EEI data, a 14 percent scheduled outage rate was selected. A forced outage rate of 6 percent was also considered appropriate based on the AMLPD and EEI data. The combined-cycle plant parameters are summarized in Table B.13.

(c) Gas Turbines

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at the present time. There are 470.5 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 168.3 MW of oil-fired gas turbines in the Fairbanks area (Table B.7). Low initial cost and simplicity of construction and operation in addition to available low cost gas have made gas turbines very attractive as a Railbelt generating scource. New oil-fired gas turbines were not considered in this study primarily because of the price of distillate. This price has been historically higher than natural gas and is expected to remain so.

A unit size of 75 MW was considered to be representative of a modern gas turbine plant addition to the Railbelt system. The possibility of installing gas turbine units at Beluga was not considered, as this development is intended primarily for coal. Coal conversion to methanol is a possibility; but this consideration is beyond the scope of this study.

The gas turbine plants are assumed to have a two-year construction period (22). The base plant costs were obtained from the Gas Turbine World Handbook (19), which lists "turnkey" bids in 1978 dollars for a gas turbine project in Anchorage. These estimates are quoted in Table B.14. These estimates had an estimated heat rate of 12,000 Btu/kWh. The costs were escalated by 13.7 percent using the developed Handy-Whitman indices to January, 1980 dollars. A 10 percent increase was included for construction facilities and utilities as well as a 14 percent engineering and administration fee (Table B.15). The resultant cost of $25.80 million (excluding AFDC) was considered representative of the cost of gas turbine construction regardless of location within the Railbelt. Potentially higher cost could, however, be incurred for remote Alaskan locations.

Operation and maintenance (O&M) costs adopted are $2.50/yr/kW and $0.30/MWh for the fixed and variable components. These values reflect intermediate levels of O&M costs in the FMUS/GVEA Unit Study (32).

Three sources of data were consulted for planned and forced outages of gas turbine units; the EEI report and information from AMLPD and GVEA. Scheduled outage rates of 11 to 12 percent and forced outage rates of 3.8 percent appear to be valid in the Alaska area. Gas-turbine parameters are given in Table B.12.

(d) Diesels

Most diesel plants in operation today are standby units or peaking generation equipment. Nearly all the continuous duty units have been placed on standby service for several years due to the high oil prices and the consequent high cost of operation. The lack of system interconnection and the remote nature of localized village load centers has required the installation of many small diesel units. The installed capacity of these diesel units is 64.9 MW, and these units are solely used for load following. The high cost of diesel fuel makes new diesel plants expensive investments for all but emergency use.

A unit size of 10 MW was selected to represent an addition of a small amount of standby capacity in the Alaskan Railbelt. To develop a capital cost of these units, three manufacturers' quotes for generating units were obtained:

- Six 16 cylinder units totalling 10,685 kW at 900 RPM at $5,050,000 F.O.B. Additional costs would be incurred for transportation to Alaska (10 percent of generating units), controls and buildings/site development.

- A four unit (2500 kW/unit) diesel generating plant at $3,000,000 F.O.B. A $10,000/unit transportation cost to Alaska was suggested as well as additional costs for pre-engineered building, foundations, controls and electrical equipment.

- Ten 100 kW units plus two for continuous duty, each unit costing $150,000, giving a total cost for 12 units of $1,800,000 F.O.B. A $5,000/unit transportation cost was assessed and additional costs for mechanical controls.

Also added to the cost of the generating units are auxiliary mechanical and fuel handling equipment and electrical system/switchyard costs.

A construction period of one year was assumed since these plants are modular and quick to assemble. In addition, contingencies (16 percent), construction facilities and utilities (10 percent), engineering and administration (14 percent) are added to costs. An average cost of $7.67 million 1980 dollars (excluding AFDC) was adopted and used for the entire Railbelt region regardless of location based on the modular and rapid construction techniques associated with these small diesel units.

Diesel O&M costs quoted in the Williams Brothers Report for GVEA and FMUS (32) are considered typical for small diesel units operating in Alaska. Fixed costs of $0.50/yr/kW and $5.00/MWh for variable costs are used in this study.

Diesel units have a low (1 percent) scheduled outage rate. This rate is based on EEI utility experience. However, the EEI data correspond to units in locations where parts and service are for the most part readily available. Canadian Electrical Associates data for remote isolated units with difficult access for parts and service are far worse. Alaska could be somewhere between these extremes, with heavy dependence on unit manufacturers and location giving forced outages rates of between 4.0 - 5.0 percent. Consequently, a 5 percent rate was adopted for the system planning study. Diesel parameters are summarized in Table B.12.

B.3 - Environmental Considerations

The investigation of thermal alternatives for inclusion in proposed generation expansion sequences dealt with generic plant types which were generally not site specific. The underlying assumption for input was that environmentally acceptable sites could be found within the Railbelt region. Thus, the concern addressed was the identification of major cost items incurred by necessary environmental protection measures.

The major environmental protection cost component of coal-fired, gas turbine, combined cycle, and diesel units will be that required for air pollution control to meet the National New Source Performance Standards (NSPS).

Siting of thermal plants in the Railbelt region may be limited by the Prevention of Significant Deterioration (PSD) standards for Class I, II, and III airsheds. Plants located near National Parks which are designated Class I will be subject to the scrutiny of the effects of its emissions on visibility and air quality within the park. Class II areas that are not presently in compliance with one or more of the ambient air quality standards (Anchorage and Fairbanks) or that are close to exceeding the PSD increment for the airshed (such as Valdez) may not be acceptable sites for thermal plants.

Other environmental controls, such as those required for water use, effluent discharge, solid waste disposal, noise control and construction activities, are important with respect to the present quality of the Alaskan environment. These factors, although not significant at this time for cost estimating purposes, would have to be considered in the evaluation of any plant siting.

(a) Air Quality Requirements

The cost of air pollution control equipment is based on satisfaction of the national NSPS and National Ambient Air Quality Standards (NAAQS) (36). It is assumed that compliance with NSPS and NAAQS for the final site selection for specific facilities will assure compliance with the Prevention of Significant Deterioration (PSD) aspects of air quality regulation. The State of Alaska has adopted the National Ambient Air Quality Standards, with addition of a standard for reduced sulfur compounds (36,37). The State may also require measures for control of ice fog (38).

Three New Source Performance Standards cover the plant types under consideration. The NSPS for Electric Utility Steam Generating Units is applicable to coal-fired steam units. Specific standards are set for control of sulfur dioxide (SO_2), particulate, and nitrogen oxides (NO_x). For the coal-fired units, the use of highly efficient combustion technology is accepted for control of NO_x. Flue gas desulfurization is required for SO_2 removal, and dry scrubber technology is recommended by EPA for use with low sulfur fuel. Low sulfur fuel is generally considered to have a sulfur content less than 3 lb/million BTU or less than approximately 1.5 percent sulfur by weight in coal. Typical Alaskan coals have sulfur contents of around 1.5 percent by weight. Dry technology is appropriate also for reduction of potential ice fog problems. Baghouses are preferred by EPA for removal of particulates in facilities burning low sulfur fuel.

Pollution control for gas turbine units and for combined cycle units burning gas is designated by the New Source Performance Standards for gas turbines. Installation of gas turbine units requires wet control technology such as water or steam injection for control of NO_x emissions. Turbines using the injection process, however, are exempt from meeting the NO_x emissions standards during periods when ice fog is deemed a traffic hazard. SO_2 emissions are limited by limitations on fuel sulful content. NSPS for Stationary Internal Combustion Engines which apply to the proposed diesel units require NO_x control. Reduction of NO_x emissions will be achieved by an efficient fuel injection process.

New pollution sources must meet the PSD requirements for Class I, II, and III airsheds (39). Most areas of the state are designated Class II areas (40) in which implementation of NSPS technologies will be sufficient to satisfy the PSD increment. There are several exceptions to this status (40).

Mt. McKinley National Park is designated as a Class I area. A plant located in the vicinity of the Park would be subject to the restrictions based on the effects of its emissions on visibility and air quality within the park. Anchorage and Fairbanks - North Pole urban areas are presently the only Class II areas not in compliance with one or more of ambient air quality standards. Valdez is close to exceeding the POS increment allowed for the airstand.

Compliance with stricter regulations in any of these sensitive areas could incur higher pollution control costs, or could effectively result in barring the development of a thermal plant in that area. It is likely that new thermal plants will not be located in these areas if the cost of additional pollution control equipment substantially affects the cost of energy supplied to the consumer. These siting limitations, however, barely limit the number of possible plant locations within the Railbelt. Therefore, the assumption of compliance with NSPS is believed to be appropriate for derivation of air pollution control costs.

(b) Other Requirements

The costs for other environmental controls were also included in cost estimates. These controls are mandated by national and state water discharge standards, solid waste disposal standards and occupational health and safety standards. These controls will have the greatest relative impact on the cost of coal-fired plants compared to the other thermal plant types. This is due to the large permanent staff required at coal plants for coal handling and plant operations and maintenance, and to the treatment facilities required for flue gas desulfurization wastes. However, compared to the costs of air pollution control, these costs are of minor significance.

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(47) Personal communication with Mr. Schandler of Superior Products, Springfield, Ohio, September, 1980.

(48) Personal communication with Belyea Company, Jersey City, New Jersey, September, 1980.

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(53) Battelle Pacific Northwest Labortory, Cook Inlet Natural Gas; Future Availability and Price Forecasts for the State of Alaska, Office of the Governor, February, 1981.

(54) Handy-Whitman, Cost Index for Hydropower Production in the Pacific Northwest, 1978.

Table B.1 - ALASKAN RAILBELT COAL DATA[1]

Coal Field	ASTM Rank	Approximate Reserves million tons	% Moisture (range)	% Volatile Matter	% Fixed Carbon	% Ash (range)	Heating Value Btu/lb (range)	% C	% H	% N	% O	% Sulfur (range)
Beluga		2400	(12-33)	-	-	(3-25)	(7200-8900)	-	-	-	-	(0.2)
Water Fall	Sub Bit C		20.56	36.62	34.68	8.14	8,665	49.9	6.0	0.56	35.2	0.15
Yentna #2 Lower	Lignite		29.80	38.26	28.61	3.33	7,943	45.2	6.8	0.53	44.1	0.11
Kenai Cabin	Sub Bit C		23.01	35.63	32.71	8.65	8,028	47.2	6.1	0.62	37.2	0.23
Nenana	Sub Bit	2000	(17-27)	-	-	(3-13)	(7500-9400)	-	-	-	-	(0.1-0.3)
Poker Flat #4	Sub Bit C		25.29	32.51	32.55	9.85	7,779	45.3	6.3	1.10	37.1	0.33
Poker Flat #6 Mid	Sub Bit C		25.23	35.71	31.40	7.66	8,136	46.1	6.3	0.60	39.2	0.12
Moose Seam	Sub Bit C		21.42	36.62	34.88	7.68	8,953	51.7	6.3	0.81	33.3	0.15
Caribou Seam	Sub Bit C		21.93	35.88	32.85	9.34	8,567	49.4	6.1	0.69	34.3	0.13
#2 Seam	Sub Bit C		26.76	33.12	32.25	7.87	7,966	46.4	6.4	0.63	38.5	0.17
Jarvis Creek	Sub Bit c		20.58	36.20	34.16	9.06	8,746	49.8	5.8	0.86	33.4	1.05
Matanuska		100 (limited)	(2-9)	-	-	(4-21)	(10,300-14,000)	-	-	-	-	(0.2-1.0)
Castle Mountain	Uv Ab		1.78	28.23	52.20	17.78	12,258	69.3	4.7	1.60	6.3	0.46
Premier	Uv Bb		5.87	35.73	43.96	14.44	11,101	63.6	5.1	1.60	15.3	0.35
Kenai	Sub Bit C	300	(21-30)	-	-	(3-22)	(6500-8500)	-	-	-	-	(0.1-0.4)

Notes:

(1) Proximate and ultimate analysis

Table B.2 - ALASKAN GAS FIELDS

Location/Field	Remaining Reserves[1] Gas (billion cubic feet)	Product Destination or Field Status
North Slope:		
Prudhoe Bay	29,000	Pipeline construction to Lower 48 underway
East Umiat	Unknown	Shut-in
Kavik	Unknown	Shut-in
Kemik	Unknown	Shut-in
South Barrow[2]	25	Barrow residential & commercial users
TOTAL:	29,025+	
Cook Inlet:		
Albert Kaloa	Unknown	Shut-in
Beaver Creek	250	Local
Beluga	767	Beluga River Power Plant (CEA)
Birch Hill	20	Shut-in
Falls Creek	80	Shut-in
Ivan River	5	Shut-in
Kenai	1313	LNG Plant, Anchorage & Kenai Users
Lewis River	Unknown	Shut-in
McArthur River	78	Local
Moquawkie	None	Field Abandoned
Nicolai Creek	17	Granite Pt. Field
North Cook Inlet	1074	LNG Plant
North Fork	20	Shut-in
North Middle Ground Shoal	125	Shut-in
Sterling	23	Kenai Users
Swanson River	300	Shut-in
West Foreland	120	Shut-in
West Fork	7	Shut-in
TOTAL:	4189+	

Notes:

(1) Recoverable reserves estaimed to show magnitude of field only.
(2) Producing

Table B.3 - ALASKAN OIL FIELDS

Location/Field	Remaining Reserves[1] Oil (million barrels)	Product Destination or Field Status
North Slope:		
Prudhoe Bay[2]	8,375	Pipeline to Valdez
Simpson	Unknown	Shut-in
Ugnu	Unknown	Shut-in
Umiat	Unknown	Shut-in
TOTAL	8,375+	
Cook Inlet:		
Beaver Creek	1	Refinery
Granite Point	21	Drift River Terminal
McArthur River	118	Drift River Terminal
Middle Ground Shoal	36	Nikiski Terminal
Redoubt Shoal	None	Field Abandoned
Swanson River	22	Nikiski Terminal
Trading Bay	4	Nikiski Terminal
TOTAL	198+	

Notes:

(1) Recoverable reserves estaimed to show magnitude of field only.
(2) Producing

Table B.4 - ALASKAN RAILBELT FUEL PRICES (1980)

Fuel	Source/Use	Cost $80/MMBTU	References
Coal[1]			
	Healy/Mine-Mouth (GVEA)	1.25	( ) & ( )
	Healy/Fairbanks (FMUS)	1.40	( ) & ( )
	Average Lower 48	1.35	(9) June 1980
	DOE Region 10	1.55	(45) October 1980
	DOE U.S. Average	1.46	(45) October 1980
Natural Gas[2]			
	Kenai-Cook Inlet/ Anchorage Utilities AMLPD	1.00	(31)
	CEA: Beluga	0.24	(9) June 1980
	Other	1.04	(9) June 1980
	Average	0.34	(9) June 1980
	Cook Inlet/LNG export to Nikiski	4.50 - 4.65	(46)
	Average Lower 48	1.98	(9) June 1980
	DOE Region 10	4.89	(45) October 1980
	DOE U.S. Average	3.58	(45) October 1980
Oil			
	Prudhoe Bay/Fairbanks Utilities:		
	GVEA	3.45	(31)
	FMUS	4.01	(32)
	Average Lower 48	5.44	(9) June 1980
	DOE U.S. Average	4-63 - 4.93	(45) October 1980

Notes:

(1) Healy Coal = 8,500 Btu/lb
(2) Natural Gas = 1,005 Btu/cf

Table B.5 - SUMMARY OF ALASKAN FUEL OPPORTUNITY VALUES

Fuel	Market	Via	Market Price $/MMBTU	Transport Cost $/MMBTU	Alaskan Opportunity Value $/MMBTU
Coal	Pacific NW	barge	1.55	0.50	1.05
	Lower 48	barge	1.46	0.63	0.83
	Japan	barge	N/A	N/A	1.33
	Japan	Placer-Amex	N/A	N/A	1.33
	Japan	barge	N/A	N/A	1.00-1.30
	Japan	B-H-W	N/A	N/A	1.00-1.30
Natural Gas	Region 10	LNG-tanker	4.89	2.50	2.39
	Region 10	Pipeline spur	4.89	1.97	2.92
	Lower 48	LNG-tanker	3.58	2.50	1.08
	Lower 48	Pipeline spur	3.58	1.97	1.61
	Japan	LNG-tanker	4.50-4.65	3.00[1]	1.50-1.65
Oil	Lower 48	Pipeline-tanker	N/A	N/A	4.00

Notes:

(1) estimated

Table B.6 - GENERATING UNITS WITHIN THE RAILBELT - 1980

Railbelt Utility	Station Name	Unit #	Unit Type	Installation Year	Heat Rate (BTU/kWH)	Installed Capacity (MW)	Minimum Capacity (MW)	Maximum Capacity (MW)	Fuel Type	Retirement Year
Anchorage	AMLPD	1	GT	1962	15,000	14	2	15	NG	1992
Municipal	AMLPD	2	GT	1964	15,000	14	2	15	NG	1994
Light & Power	AMLPD	3	GT	1968	14,000	15	2	20	NG	1998
Department	AMLPD	4	GT	1972	12,000	28.5	2	35	NG	2002
(AMLPD)	G.M. Sullivan	5,6,7	CC	1979	8,500	140.9	NA	NA	NG	2009
Chugach	Beluga	1	GT	1969	13,742	15.1	NA	NA	NG	1998
Electric	Beluga	2	GT	1968	13,742	15.1	NA	NA	NG	1998
Association	Beluga	3	GT	1973	13,742	53.5	NA	NA	NG	2003
(CEA)	Beluga	4	GT	1976	13,742	9.3	NA	NA	NG	2006
	Beluga	5	GT	1975	13,742	53.5	NA	NA	NG	2005
	Beluga	6	GT	1976	13,742	67.8	NA	NA	NG	2006
	Beluga	7	GT	1978	13,742	67.8	NA	NA	NG	2008
	Bernice Lake	1	GT	1963	23,440	8.2	NA	NA	NG	1993
		2	GT	1972	23,440	19.6	NA	NA	NG	2002
		3	GT	1978	23,440	24.0	NA	NA	NG	2008
	International Station	1	GT	1965	39,973[1]	14.5	NA	NA	NG	1995
		2	GT	1975	39,973[1]	14.5	NA	NA	NG	1995
		3	GT	1971	39,973[1]	18.6	NA	NA	NG	2001
	Knik Arm	1	GT	1952	28,264	14.5	NA	NA	NG	1985
	Copper Lake	1	HY	1961	--	15.0	NA	NA	--	2011
Golden Valley	Healy	1	ST	1967	11,808	25.0	7	27	Coal	2002
Electric		2	IC	1967	14,000	2.7	2	3	Oil	1997
Association	North Pole	2	GT	1976	13,500	64.0	5	64	Oil	1996
(GVEA)		2	GT	1977	13,000	64.0	25	64	Oil	1997
	Zehander	1	GT	1971	14,500	17.65	10	20	Oil	1991
		2	GT	1972	14,500	17.65	10	20	Oil	1992
		3	GT	1975	14,900	2.5	1	3	Oil	1995
		4	GT	1975	14,900	2.5	1	3	Oil	1995
		5	IC	1970	14,000	2.5	1	3	Oil	2000
		6	IC	1970	14,000	2.5	1	3	Oil	2000
		7	IC	1970	14,000	2.5	1	3	Oil	2000
		8	IC	1970	14,000	2.5	1	3	Oil	2000
		9	IC	1970	14,000	2.5	1	3	Oil	2000
		10	IC	1970	14,000	2.5	1	3	Oil	2000

Table B.6 (Continued)

Railbelt Utility	Station Name	Unit #	Unit Type	Installation Year	Heat Rate (BTU/kWH)	Installed Capacity (MW)	Minimum Capacity (MW)	Maximum Capacity (MW)	Fuel Type	Retirement Year
Fairbanks Municipal Utiltiy System (FMUS)	Chena	1	ST	1954	14,000	5.0	2	5	Coal	1989
		2	ST	1952	14,000	2.5	1	2	Coal	1987
		3	ST	1952	14,000	1.5	1	1.5	Coal	1987
		4	GT	1963	16,500	7.0	2	7	Oil	1993
		5	ST	1970	14,500	20.0	5	20	Coal	2005
		6	GT	1976	12,490	23.1	10	29	Oil	2006
	FMUS	1	IC	1967	11,000	2.7	1	3	Oil	1997
		2	IC	1968	11,000	2.7	1	3	Oil	1998
		3	IC	1968	11,000	2.7	1	3	Oil	1998
Homer Elec. Association (HEA)	Homer= Kenai	1	IC	1979	15,000	0.9	NA	NA	Oil	2009
	Pt. Graham	1	IC	1971	15,000	0.2	NA	NA	Oil	2001
	Seldovia	1	IC	1952	15,000	0.3	NA	NA	Oil	1982
		2	IC	1964	15,000	0.6	NA	NA	Oil	1994
		3	IC	1970	15,000	0.6	NA	NA	Oil	2000
Matanuska Elec. Assoc. (MEA)	Talkeetna	1	IC	1967	15,000	0.9	NA	NA	Oil	1997
Seward Electric System (SES)	SES	1	IC	1965	15,000	1.5	NA	NA	Oil	1995
		2	IC	1965	15,000	1.5	NA	NA	Oil	1995
Alaska Power Administration (APAd)	Eklutna	-	HY	1955	--	30.0	NA	NA	--	2005
TOTAL						943.6				

Notes:

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

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

TABLE B.7 - EXISTING GENERATING CAPACITY IN THE RAILBELT REGION

Type	No. Units	Capacity (MW)
Coal-fired steam	5	54.0
Natural gas gas-turbines (Anchorage)	18	470.5
Oil-fired gas turbines (Fairbanks)	6	168.3
Diesels	21	64.9
Combined cycle (natural gas)	1	140.9
Hydro	2	45.0
TOTAL	53	943.6 MW

TABLE B.8 - 1000 MW COAL-FIRED STEAM PLANT COST ESTIMATE - LOWER 48

Account/Item		$ MILLIONS 1976	Handy-Whitman Adjustment	1980
10	Concrete	22.40	547/394	31.10
20	Civil/Structural/Architectural			
21,22,24	Structural & Misc. Iron & Steel	23.70	559/397	33.37
25	Architectural & Finish	11.90	500/361	16.76
26	Earthwork	23.70	500/361	32.82
28	Site Improvements	14.80	500/361	20.50
30	Steam Generators	119.70	571/407	167.93
41	Turbine Generators	48.40	413/293	68.22
42	Main Condenser & Auxiliaries	4.20	518/361	6.03
43	Rotating Equipment, Ex. T/G	12.80	518/361	18.36
44	Heaters & Exchangers	3.70	518/361	5.31
45	Tanks, Drums & Vessels	1.50	518/361	2.15
46	Water Treatment/Chemical Feed	2.40	518/361	3.44
47	Coal/Ash/FGD Equipment			
47.1	Coal Unloading Equipment	3.50	461/338	4.77
47.2	Coal Reclaiming Equipment	3.40	461/338	4.63
47.3	Ash Handling Equipment	1.40	461/338	1.90
47.4	Electrostatic Precipitators	61.30	461/338	83.60
47.6	FGD Removal Equipment	87.90	461/338	119.88
47.8	Stack (Lining, Lights, etc.)	5.20	461/338	7.09
48	Other Mechanical Equipment Incl. Insulation & Lagging	9.70	518/361	13.92
49	Heating, Ventilating, Air Conditioning	1.70	518/361	2.43
50	Piping	44.60	629/422	66.47
60	Control & Instrumentation	11.10	461/322	15.41
70	Electrical Equipment (Switchgear/Transformers/ MCCs/Fixtures)	11.30	461/332	15.69
80	Electrical Bulk Materials			
81,82,83	Cable Tray & Conduit	11.60	173/123	16.31
84,85,86	Wire & Cable	13.40	173/123	18.85
	Switchyard	11.30	173/123	15.89
	CONSTRUCTION COST TOTAL	$566.60		$792.82

TABLE B.9 - 500 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM		$ MILLIONS (1980) Lower 48	Beluga
10-20	Civil/Structural/Architectural	$ 72.66	$ 130.79
30-46	Mechanical Equipment	146.57	263.82
47	Coal/Ash/FGD	131.52	236.73
48-60	Other Mechanical	53.04	95.47
70-80	Electrical Equipment	36.05	64.89
	CONSTRUCTION COST TOTAL:	$ 439.84	$ 791.70
	Contingency (16%)	70.37	126.67
	Subtotal	510.21	918.37
	Construction Facilities/ Utilities (10%)	51.02	91.84
	Subtotal	561.23	1010.20
	Engineering & Administration (12%)	67.35	121.23
	TOTAL (EXCLUDING AFDC)	$ 628.57	$1131.43

TABLE B.10 - 250 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM		$ MILLIONS (1980) Lower 48	Beluga
10-20	Civil/Structural/Architectural	$ 39.23	$ 70.61
30-46	Mechanical Equipment	79.15	142.47
47	Coal/Ash/FGD	77.52	139.53
48-60	Other Mechanical	28.65	51.57
70-80	Electrical Equipment	9.46	35.02
	CONSTRUCTION COST TOTAL	$ 244.01	$ 439.20
	Contingency (16%) Subtotal	283.05	509.47
	Construction Facilities/ Utilities (10%) Subtotal	311.35	560.41
	Engineering & Administration (12%)		
	TOTAL (EXCLUDING AFDC)	$ 348.71	$ 627.65

TABLE B.11 - 100 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM		$ MILLIONS (1980) Lower 48	Beluga
10-20	Civil/Structural/Architectural	$ 21.19	$ 38.14
30-46	Mechanical Equipment	42.74	76.93
47	Coal/Ash/FGD	22.08	39.74
48-60	Other Mechanical	15.47	27.85
70-80	Electrical Equipment	10.50	18.90
	CONSTRUCTION COST TOTAL	$ 111.98	$ 201.56
	Contingency (16%) Subtotal	129.89	233.80
	Construction Facilities/ Utilities (10%) Subtotal	142.88	257.19
	Engineering & Administration (12%)		
	TOTAL (EXCLUDING AFDC)	$ 160.03	$ 288.05

TABLE B.12 - 250 MW COMBINED CYCLE PLANT COST ESTIMATES

ACCOUNT/ITEM	$ MILLIONS (1980) Lower 48	Beluga
20 Civil/Structural/Architectural		
21,22,23 Buildings/Structures	2.83	4.53
26,28 Foundations Site Work	5.63	9.00
40 Mechanical		
41-47 Generating Units	37.50	60.00
45 Fuel Handling	1.40	2.24
48 Other Mechanical	5.28	8.45
70/80 Electrical Equipment	11.79	18.86
100 Transportation: (25%)(41-47 total) Pacific NW (50%)(41-47 total) Anchorage	9.38	18.75
CONSTRUCTION COST TOTAL	73.81	121.83
Contingency (16%) Subtotal	85.61	141.34
Construction Facilities/ Utilities (10%) Subtotal	94.17	155.47
Engineering & Administration (12%)		
TOTAL (EXCLUDING AFDC)	$105.47	$174.13

TABLE B.13 - SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS

Parameter	PLANT TYPE					
	COAL-FIRED STEAM			COMBINED CYCLE	GAS TURBINE	DIESEL
	500 MW	250 MW	100 MW	250 MW	75 MW	10 MW
Heat Rate (Btu/kWh)	10,500	10,500	10,500	8,500	12,000	11,500
O&M Costs						
Fixed O&M ($/yr/kW)	0.50	1.05	1.30	2.75	2.75	0.50
Variable O&M ($/MWH)	1.40	1.80	2.20	0.30	0.30	5.00
Outages						
Planned Outages (%)	11	11	11	14	11	1
Forced Outages (%)	5	5	5	6	3.8	5
Construction Period (yrs)	6	6	5	3	2	1
Start-up Time (yrs)	6	6	6	4	4	1
Total Capital Cost ($ million)						
Railbelt:	-	-	-	175	26	7.7
Beluga:	1,130	630	290	-	-	-
Unit Capital Cost ($/kW)[1]						
Railbelt:	-	-	-	728	250	778
Beluga:	2473	2744	3102	-	-	-

Notes:

(1) Including AFDC at 0 percent escalation and 3 percent interest.

TABLE B.14 - GAS TURBINE TURNKEY COST ESTIMATE[1]

Installed Capacity	Turnkey Bids ($ million 1978)
63	13.95
75	18.10
77	18.80
78	14.32

Notes:

(1) Source: Reference (19)

TABLE B.15 - GAS 75 MW GAS TURBINE COST ESTIMATE

Item	Cost ($ million 1978)	($ million 1980)[1]
Turnkey Cost	18.10	20.58
Construction Facilities/Utilities (10%)	--	2.06
Engineering and Administration (14%)	--	3.16
TOTAL (EXCLUDING AFDC)	--	25.80

Notes:

(1) Adjusted by Handy-Whitman Cost Indices for Steam Plants (258/227)

APPENDIX C - ALTERNATIVE HYDRO GENERATING SOURCES

The analysis of alternative sites for non-Susitna hydropower development followed the plan formulation and selection methodology discussed in Section 1.4 of Volume I and Appendix A. The general application of the five-step methodology (Figure A.1) for the selection of non-Susitna plans is presented in Section 6 of this report. Additional data and explanation of the selection process are presented in more detail in this Appendix.

The first step in the plan formulation and selection process is to define the overall objective of the exercise. For step 2 of the process, all feasible sites are identified for inclusion into the subsequent screening process. The screening process (step 3) eliminates those sites which do not meet the screening criteria and yields candidates which could be refined to include into the formulation of Railbelt generation plans (step 4).

Details of each of the above planning steps are given below. The objective of the process is to determine the optimum Railbelt generation plan which incorporates the proposed non-Susitna hydroelectric alternatives.

C.1 - Assessment of Hydro 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 U.S. Army Corps of Engineers (COE), the United States Bureau of Reclamation (USBR), the United States Geological Survey (USGS) 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.

Review of the above studies and in particular the inventories of potential sites published in the U.S. Army Corps of Engineers National Hydropower Study (1) and the Alaska Power Administration (APAd) "Hydroelectric Alternatives for the Alaska Railbelt" (2) identified a total of 91 potential sites (Figure C.1). All of these sites are technically feasible and, under step 2 of the planning process, were identified for inclusion in the subsequent screening exercise.

C.2 - Screening of Candidate Sites

The screening process for this analysis required the application of four iterations with progressively more stringent criteria.

(a) First Iteration

The first screen or iteration determined which sites were technically infeasible or not economically viable and rejected these sites. The standard for economic viability in this iteration was defined as energy production cost less than 50 mills per kWh, based on economic parameters. This value for energy production cost was considered to be a reasonable upper limit consistent with Susitna Basin alternatives for this phase of the selection process.

Cost data provided in published COE and APAd reports were updated to represent the current level of economics in hydropower development for a total of 91 sites inventoried within the Railbelt Region. As discussed in Section 8, annual costs were derived on the basis of a 3 percent cost of money, net of general inflation. Construction costs were developed by making uniform the field costs provided in the COE and APAd reports. This was necessary as the two agencies used different location factors in their estimates, to account for higher price levels in Alaska. Contingencies of 20 percent and engineering-administration adjustments of 12 to 14 percent were added to finally yield the project cost. Project costs were subsequently updated to a July 1, 1980 price level based on the "Handy-Whitman Cost Index for Hydropower Production in the Pacific Northwest" (3).

Using updated project costs as well as a series of plant size-dependent economic factors preliminarily selected for the rough economic screening, the average annual production costs in mills/kWh were estimated for the 91 sites. Typical factors considered were construction period, annual investment carrying charges, and operation and maintenance expenditures. Plant capacity factors ranged from 50 to 60 percent, based on source data. A range of average annual production costs resulted for most of the sites, similar to those initially estimated by both the COE and the APAd.

As a result of this screen, 26 sites were eliminated from the planning process. The sites rejected are given in Table C.1. The remaining 65 sites were subjected to a second iteration of screening which included additional criteria on environmental acceptability. The location of the 65 remaining sites are given in Figure C.1.

(b) Second Iteration

The inclusion of environmental criteria into the planning process required a significant data survey to obtain information on the location of existing and published sources of environmental data. The 27 reference sources used in preparing the evaluation matrix include publications and maps for which data were collected, prepared and/or adopted by the following agencies:

- University of Alaska, Arctic Environmental Information and Data Center
- Alaska Department of Fish and Game
- Alaska Division of Parks
- National Park Service
- Bureau of Land Management, U.S. Department of Interior
- U.S. Geological Survey
- Alaska District Corps of Engineers
- Joint Federal State Land Use Planning Commission

In addition, representatives of state and federal agencies (including AEIDC, ADNR, ADF&G, ADEC and Alaska Power Administration) were interviewed to provide subjective input to the planning process.

The basic data collected identified two levels of detail of environmental screening. The purpose of the first level of screening was to eliminate those sites which were unquestionably unacceptable from an environmental standpoint. Rejection of sites occurred if:

(i) They would cause significant impacts within the boundaries of an existing National Park or a proclaimed National Monument area;

(ii) They were located on a river in which:

- Anadromous fish are known to exist;

- The annual passage of fish at the site exceeds 50,000;

- Upstream of the site, a confluence with a tributary occurs in which a major spawning or fishing area is located.

The definition of the above exclusion criteria was made only after a review of the possible impacts of hydropower development on the natural environment and the effects of land issues on particular site development.

The first exclusion criterion reflects the existing restrictions to the development of hydropower in certain classified land areas. Information regarding the interpretations of land use regulations was gathered in discussions with state and federal officials, including representatives of the Federal Regulatory Commission (FERC) who are responsible for the licensing of hydropower projects affecting federal lands. Many land classifications were identified, such as national and state parks, forests, game refuge or habitat areas, wild and scenic rivers, and wilderness areas. Additionally, the land ownership question in Alaska was further complicated by federal land withdrawals (under the Federal Land Policy and Management Act) and Administration National Monument Proclamations.

After the various restrictions were evaluated, it became clear that the only lands where hydropower development is strictly prohibited are National Parks and Monuments, Wild and Scenic Rivers and National Wilderness Areas. At this time, many lands were still protected by the National Monument Proclamations, pending the passage of the Alaska National Interest Lands Bill in Congress. Other land classifications allow for monitoring and regulation of development by the controlling agency and, in some cases, veto power if the development is not consistent with the purposes of the land designation. Note that no sites coincided with either Wild and Scenic Rivers or Wilderness Areas; these were not included as exclusion criteria.

At the time of evaluation, the Alaska Lands Bill had not yet been passed by the U.S. Congress. Thus, the determination of impacts of restricted land use was based on the existing legislation, which included the

Administration National Monument Proclamation of December 1, 1978, and the Federal Land Policy and Management Act of 1976. The Lands Bill became Public Law 96-487 on December 2, 1980. The resulting land status changes have been evaluated to the extent that they affected the chosen hydropower sites.

Many significant sensitivities were identified in the Alaskan setting. However, only one of these was determined to be so highly sensitive to hydro development and so important to the state that it alone could prohibit the development of a site. Thus, sites located on a stretch of river used as a major artery for anadromous fish passage were excluded. It was believed that the potential for mitigation of adverse affects of such sites was limited, and that even a relatively small percentage loss of fish could have a devastating result for the fishery.

Of the 65 sites remaining after the preliminary economic screening, 19 sites were unable to meet the requirements set for the second screen. These sites are given in Table C.1, and the reason for their rejection in Table C.2

(c) Third Iteration

The reduction in the number of sites to 46 allowed a reasonable reassessment of the capital and energy production costs for each of the remaining sites to be made. Adjustments were made to take into account transmission line costs necessary to link each site to the proposed Anchorage-Fairbanks intertie. This iteration resulted in the rejection of 18 sites based on judgemental elimination of the more obvious uneconomic or less environmentally acceptable sites. The remaining 28 sites were subjected to a fourth iteration which entailed a more detailed numerical environmental assessment. The 18 sites rejected in the third iteration are given in Table C.1.

(d) Fourth Iteration

To facilitate analysis, the sites were categorized into sizes as follows:

- Less than 25 MW: 5 sites;

- 25 MW to 100 MW: 15 sites

- Greater than 100 MW: 8 sites.

The fourth and final screen was performed using detailed numerical environmental assessment which considered eight criteria chosen to represent the sensitivity of the natural and human environments at each of the sites. Three main aspects were incorporated into the selection of these criteria:

- Criteria must represent the important components of the environmental setting that may be impacted by the development of a hydroelectric project.

- Criteria must include components that represent existing and potential land use and management plans.

- Information relating to these criteria must be reasonably available and easily incorporated into a screening/evaluation process.

The eight evaluation criteria are listed in Table C.3. Each criterion was defined to identify the objectives used for investigating that criterion. Following the selection of the evaluation criteria, it was necessary to define the significance of a variety of factors within each set of criteria. Under the category of anadromous fisheries, for example, it is necessary to differentiate between a site which would adversely affect a major spawning area and a site which is used only for passage by a relatively small number of fish.

For each of the evaluation criteria, therefore, a system of sensitivity scaling was used to rate the relative sensitivity of each site. A letter (A, B, C or D) was assigned to each site for each of the eight criteria to represent this sensitivity. The scale rating system is defined in Table C.4.

Each evaluation criterion has a definitive significance to the Alaskan environment and degree of sensitivity to impact. A discussion of each criterion is appropriate to determine the importance of that criterion in the continued study or rejection of the hydroelectric sites.

(i) Big Game

The presence of big game is especially significant in the Alaskan environment. Special protection and management techniques are employed to ensure propagation of the species and continued abundance for subsistance and commercial harvesting as well as recreation uses. This criterion has a very high importance in the life style and economic well being of the Alaskan people.

Site specific information was extracted from a series of map overlays which identified types of big game habitats with varying importance to survival of the species considered. For example, a map may have a large area designated as "moose present" or "moose distribution". Within that large distribution area, smaller areas were identified as seasonal concentration areas or calving areas. These smaller areas were considered to be more sensitive to development than the large areas because they satisfy specific needs within the life cycle of the moose, and because the availability of appropriate land is limited.

Of the references inspected, "Alaska's Wildlife Atlas, Vol 1" was regarded as the most authoritative source, and took precedence in the case of conflicting information. References "Musk Oxen and Caribou" and "Large Mammals" generally added to the body of knowledge. References "Bear Denning and Goat Range", "Dall Sheep, Deer and Moose Concentrations" and "Distribution of Caribou Herds in Alaska" were reviewed, but had little input which corresponded with the sites surveyed.

(ii) Argicultural Potential

Agricultural potential was assigned a relatively high importance. This is because it is an indicaton of the potential for the self sufficiency of any area, and the avenues towards self sufficiency require special consideration in the economic climate of Alaska.

The best agricultural resources identified in the Railbelt region are located in the lowlands adjacent to the lower Susitna basin. These include the Yentna/Skwentna system and the northern and eastern shores of Cook Inlet as well as the Tanana and Nenana River valleys and the upper part of the Copper River basin. The latter was identified as climatically marginal.

The amount of land identified with suitable farming soils is relatively small and was assigned a higher sensitivity than land with marginal farming soils. Lands with no suitable soils identified were assigned the lowest sensitivity.

Map reference "Cultivatable Soils" and "Alaska Resources Inventory, Agricultural and Range Resources" were used to identify lands with agricultural potential in the Railbelt.

(iii) Waterfowl, Raptors and Endangered Species

The Railbelt provides extensive habitats for many species of waterfowl as well as habitats for some threatened and endangered bird species. The protection of these habitats in the face of development is a concern of many environmentalists and ecologists. As an evaluation criterion, this was considered to be slightly less important than the big game or fisheries criteria because of the combined ecological and economic importance of those two criteria.

In evaluating the sensitivity of the various factors providing input to these criteria, three reference maps were surveyed: "Alaska's Wildlife Atlas Vol II" provided information regarding waterfowl and seabirds; "Migratory Birds: Seabirds, Raptors & Endangered Species" had information regarding seabirds and raptor habitats; and "Birds" identified endangered and threatened species habitats. Generally, raptor and endangered species' habitats were considered most sensitive. High density and key waterfowl areas were considered to be moderately sensitive.

(iv) Anadromous Fisheries

The anadromous fisheries resource is an essential component of Alaska's economy and life style as well as its natural environment. It is the single resource most affected by hydropower development due to the nature of the development itself which not only hampers the passage of fish but may also alter flow conditions essential to the anadromous life cycle. Because of its sensitivity to hydropower development, the anadromous fisheries resource was very highly considered in this evaluation.

The comparative sensitivity of the sites was based on the number of species identified as present or spawning in the vicinity. Particular emphasis was placed on the river upstream of proposed dam sites and, when information was available, on the estimated number of fish identified passing certain points. Some sites were excluded in preliminary screening because they were identified as major locations for fish passage (greater than 50,000 annually.) The most sensitive of the remaining sites were those with the largest number of species present and with the most extensive spawning areas upsteam of the dam site. Lowest sensitivity corresponded with the absence of anadromous fish in the area.

Several compiled references were available for determining the extent of fisheries' presence at each of the hydro sites considered. The most comprehensive reference was "Alaska Fisheries Atlas" Volume I, which indicated on USGS topographical maps the presence of each of five species of salmon and their spawning areas for all areas of interest. Two map overlays were used to determine more generally the presence of anadromous fisheries: "Fisheries" and "Marine Mammals and Fish". This information was also checked against the Ch_2M-Hill report "Review of South Central Alaska Hydropower Potential" for some of the sites.

(v) Wilderness Consideration

National and state interest in the preservation of natural aesthetic qualities in Alaska continue to be the impetus for studies and land use legislation. Substantial amounts of land have been identified and protected under state and federal law. However, other lands have been identified for their unique wilderness, scenic, natural and primitive qualities but have received no particular protection. This factor was considered to the extent that any of the potential hydro sites would impact the aesthetic quality of these unprotected lands.

Two map overlays prepared by the Joint Federal State Land Use Planning Commission were used: "Selected Primitive Areas in Alaska for Consideration for Wilderness Designation" and "Scenic, Natural and Primitive Values".

(vi) Cultural, Recreation and Scientific Features

These criteria reflect the importance placed on the historical, cultural and recreational values of certain landmarks, as well as the values of scientific resources at identified locations. Areas of varying significance were identified by the reference sources and comparative sensitivities were assigned accordingly if potential hydro sites corresponded with identified areas.

Three map overlays were used to substantiate these criteria: "Recreation, Cultural and Scientific Features", "Nationally Significant Cultural Features", and "Proposed Ecological Reserve System for Alaska".

(vii) Restricted Land Use

A significant amount of land in Alaska is classified as national or state parks, wildlife areas, monuments, etc. These classifications afford varying levels of protection from complete exclusion of any development activity to a monitoring or regulation of development occurring on the protected lands. Using this criterion as an indication of the legal restrictions that might hinder the implementation of a hydroelectric development, the comparative sensitivities were defined. If a potential hydro site was located within a national park or monument, the site was excluded during preliminary screening from further consideration. Other land classifications were less severe. This criterion, although it may be more of an indication of institutional factors than the actual sensitivity of the site area, represents real issues that would affect development.

Land status was identified using maps and reference materials prepared by state sources: "Generalized State Land Activity", "Game Refuges, Critical Habitat Areas and Sanctuaries", and federal sources, USGS Alaska Map E and Quadrangle Maps, "Administration National Monument Proclamation and FLDMA Withdrawals", "Alaska Illustrated Land Status". It should be noted that this evaluation was performed before the passing of the Alaska National Interest Lands Conservation Act (PL 96-487). The results of the application of this criterion were subsequently compared against the mandates of this federal act. No substantial effects on the screening results were found.

(viii) Access

The main purpose of this criterion was to indicate how the potential hydro sites fit into the existing infrastructure. In other words, the concern was to identify those areas which would be most and least affected or changed by the introduction of roads, transmission lines and other facilities. The highest sensitivity was assigned to the sites which were the farthest from the existing infrastructure, indicating areas with the greatest potential for impacts. Lower sensitivities were assigned to areas where roads, transmission lines and settlements already exist.

Although this was an important criterion to consider, it was not given a high weighting when compared to other criteria due to the subjective nature of the interpretations made. It could be, for example, that an existing small settlement would be more adamantly opposed to development in an area where nobody has presently settled.

Information was garnered from notes in "Review of the Southcentral Hydropower Potential" and road maps of the area.

(ix) Summary of Criteria Weighting

The first four criteria - big game, agricultural potential, birds and anadromous fisheries, were chosen to represent the most significant features of the natural environment. These resources require protection and careful management due to their position in the Alaskan environment, their roles in the existing patterns of life of the state residents and their importance in the future growth and economic independence of the state. These four criteria were viewed as more important than the following four criteria due to their quantifiable and significant position in the lives of the Alaskan people.

The remaining four criteria - wilderness, cultural, recreation and scientific features, restricted land use, and access were chosen to represent the institutional factors to be considered in determining any future land use. These are special features which have been identified or protected by governmental laws or programs and may have varying degrees of protected status, or the criteria represent existing land status which may be subject to change by the potential developments.

It must be noted that the interpretations placed on these criteria are subjective, although care was taken to ensure that the many viewpoints which make up Alaska's sociopolitical climate were represented in the evaluation. The latter four criteria were considered less important in the comparative weighting of criteria mainly because of the subjective nature and lower degree of reliability of the facts collected.

Data relating to each of these criteria were complied separately and recorded for each site, forming a data-base matrix. Then, based on these data, a system of sensitivity scaling was developed to represent the relative sensitivity of each environmental resource (by criterion) at each site.

The scale ratings used are summarized below. A detailed explanation of the scale rating may be found in Table C.5.

A - Exclusion (used for sites excluded in preliminary screening)

B - High Sensitivity

C - Moderate Sensitivity

D - Low Sensitivity

The scale ratings for the criteria at each site were recorded in the evaluation matrix. Site evaluations of the 28 sites under consideration are given in Table C.6. Preliminary data regarding technical factors were also recorded for each potential development. Parameters included installed capacity, development type (dam or diversion), dam height, and new land flooded by impoundment. The complete evaluation matrix may be found in Table C.7.

In this manner, the environmental data were reduced to a form from which a relative comparison of sites could be made. The comparison was carried out by means of a ranking process.

(x) Rank Weighting and Scoring

For the purpose of evaluating the environmental criteria, the following relative weights were assigned to the criteria. A higher value indicates greater importance or sensitivity than a lower value.

Big Game	8
Agricultural Potential	7
Birds	8
Anadromous Fisheries	10
Wilderness Values	4
Cultural Values	4
Land Use	5
Access	4

The criteria weights for the first four criteria were then adjusted down, depending on related technical factors of the development scheme.

Dam height was assumed to be the factor having the greatest impact on anadromous fisheries. All the sites were ranked in terms of their dam heights as follows:

- Height $\leq$150': Rank +

- Height 150' - 350': Rank ++

- Height $\geq$350': Rank +++

A dam with the lowest height ranking (+) would have least impact, and would therefore result in the fisheries weight to be adjusted down by two points. Similarly, a dam of height (++) was adjusted down by one point. A dam of height (+++) would have the greatest impact and the weight remained at its designated value.

The amount of new land flooded by creation of a reservoir was considered to be the one factor with greatest impact on agriculture, bird habitat, and big game habitat. Sites were ranked in terms of their new reservoir area as follows:

- Area $\leq$5000 acres: Rank +

- Area 5000 - 100,000 acres: Rank ++

- Area $\geq$100,000 acres: Rank +++

The same adjustments were made for the big game, agricultural potentials, and bird habitat weights based on this flooded area impact (see Table C.8).

Note that for developments which utilized an existing lake for storage, the new area flooded was assumed to be minimal (+).

The scale indicators were also given a weighted value as follows:

- B = 5

- C = 3

- D = 1

To compute the ranking score, the scale weights were multiplied by the adjusted criteria weights for each criteria and the resulting products were added.

Two scores were then computed. The total score is the sum of all eight criteria. The partial score is the sum of the first four criteria only, which gives an indication of the relative importance of the existing natural resources in comparison to the total score.

(xi) Evaluation

The evaluation of sites took place in the following manner: sites were first divided into three groups in terms of their capacity.

Based on the economics, the best sites were chosen for environmental evaluation. Table C.10 lists the number of sites evaluated in each of the capacity groups. The sites were then evaluated as described above. They were listed in ascending order according to their total scores for each of the groups. The partial score was also compared. The sites were then grouped as better, acceptable, questionable, or unacceptable, based on the scores. The same general standards (e.g, cut-off points) were used for all groups.

(xii) Analysis

The partial and total scores for each of the sites, grouped according to capacity, are given in Table C.10.

- 0 - 25 MW

  Of the five sites evaluated, all five were determined to be acceptable, based on the overall standards. Three of these sites were judged as a group to be better than the other two which had higher partial and total scores.

- 25 - 100 MW

  A cutoff point of approximately 134 for the total score and approximately 100 for the partial score was used. Sites scoring higher were eliminated. The seven sites scoring lower were re-examined.

  Three developments at Bruskasna, Bradley Lake, and Snow were the best sites identified.

Of the remaining four, Coffee and Seetna were identified as questionable because of anticipated salmon fisheries problems. Lowe and Cache scored only slightly better, but Lowe has minimal fisheries problems, and the Cache site is farthest upstream on the Talkeetna River, beyond which the salmon migrate only about five miles.

- >100 MW

Again, the same cutoff point for acceptable sites with total scores of 134 and partial scores of 100 used. The sites fell easily into the two groupings of acceptable and unacceptable.

(xiii) Results

Sixteen sites were chosen for further consideration. Three constraints were used to identify these 16 sites. First, the most economical sites which had passed the environmental screening were chosen. Secondly, sites with a very good environmental impact rating which had passed the economic screening were chosen. And finally, a representative number of sites in each capacity group were to be chosen, Table C.10.

From the list of 16 sites, 10 were selected for detailed development and cost estimates required as input to the generation planning. The ten sites chosen are underlined in Table C.1.

Three sites, Strandline Lake, Hicks, and Browne were identified by the Ch_2M-Hill Report to COE as being environmentally very good. These sites were included, even though their associated economics were not as good as many of the other sites which had also passed the economic screening.

The Chakachamna site had both a very high economic ranking and a good environmental rating in terms of the sensitivity of its natural resources to development. Chakachamna was also identified by the Ch_2M-Hill report as having minimal environmental impacts. It should be noted that under the recently passed Alaska National Interest Lands Conservation Act (PL 96-487, December 2, 1980) the lands including the Chakachamna site have not received protected status of any type. This applies to both the project area and the existing Lake Chakachamna. Although the boundary of designated wilderness area is located a few miles from the eastern end of the lake, operation of the lake would have little direct effect on the wilderness area. Because the Chakachamna site is desirable in other respects, it is being considered as a viable alternate competing with the Susitna Project.

Three sites were chosen on the Talkeetna River. These are Cache, Keetna, and Talkeetna-2 which are being studied as an integrated system alternative. Although the identified environmental problems are significant, the system is being studied for several reasons. It is believed that with the system approach, the incremental impacts of building a second or third plant on the same river system would be smaller than the impacts associated with building plants on completely separate rivers. The integrated system not only improves the economic potential of the operating capacity, but also allows for better control over regulation of stream flows as needed by the downstream ecosystems. Secondly, the choice of the Talkeetna River was made over other rivers with potential for development of similar systems, because the environmental sensitivity of the Talkeetna was not as great as that of the Yentna-Skwentna basin, the Chulitna River or the lower Susitna basin, particularly with regards to the presence of anadromous fish or big game. And finally, the Talkeetna River developments were some of the best sites economically, thus providing better competition to Susitna.

The remaining sites of the 10 studied in detail are Allison Creek, Snow, and Bruskasna. These are sites that were identified by the environmental evaluation as being the best environmentally of the 28 economically superior sites.

(e) Plan Formulation and Evaluation

Steps 4 and 5 in the planning process are the formulation of the preferred sites identified in Step 3 into Railbelt generation scenarios. To adequately formulate these scenarios, the engineering, energy and environmental aspects of the ten shortlisted sites were further refined (Step 4).

Engineering sketch layouts (Figures C.2 to C.10) were produced for seven of the sites with capacities of 50 MW or greater, and site specific construction cost estimates were prepared on the basis of this more detailed information (Tables C.12 through C.18). For the three remaining sites, construction costs were developed by a process of judgemental interpolation on the basis of the estimates for the seven larger developments. Costs and parameters associated with all ten sites are summarized in Table C.19. These costs incorporate a 20 percent allowance for contingencies and 10 percent for engineering and owner's administration. Cost of money has again been assumed to be three percent, net of inflation. Energy and power capability was determined for each of the sites using a monthly streamflow simulation program (Appendix F). The annual average energy for each of the the sites are also given in Table C.19. Installed capacities were generally assumed that would yield a plant factor for the developments of approximately 50 percent. This ensures general consistency with Susitna developments and Railbelt system requirements.

The formulation of the ten sites into development plans resulted in the identification of five plans incorporating various combinations of these sites as input to the Step 5 evaluations. The five development plans are given in Table C.20.

The essential objective of Step 5 was established as the derivation of the optimum plan for the future Railbelt generation incorporating non-Susitna hydro generation as well as required thermal generation. The methodology used in the evaluation of alternative generation scenarios for the Railbelt are discussed in detail in Section 8. The criterion on which the preferred plan was finally selected in these activities was least present worth cost based on economic parameters established in Section 8.

The selected potential non-Susitna hydro developments (Table C.19) were ranked in terms of their economic cost of energy. Chakachamna is the highest ranked (preferred) with a cost of energy of 40 $/1000 kWh and Hicks is the lowest ranked with a cost of energy of 1612 $/1000 kWh. The potential developments were then introduced into the all-thermal generating scenario in groups of two or three. The most economic schemes were introduced first followed by the less economic schemes.

The results of these runs are given in Table C.21 and illustrate that a minimum total system cost of $7040 million can be achieved by the introduction of the Chakachamna, Keetna and Snow projects (Plan C.2). This plan includes 1211 MW of thermal capacity and assumes a medium load forecast. No renewal of gas plants at retirement is also assumed. The make-up of the Railbelt generation system under this least cost scenario is shown in Figure C.11. Additional sites such as Snow, Strandline and Allison Creek could be introduced without significantly changing the economics of the generation scenarios. The introduction of these latter projects would be beneficial in terms of displacing non-renewable energy resource consumption.

LIST OF REFERENCES

(1) U.S. Army Corps of Engineers, National Hydropower Study, July, 1979.

(2) Alaska Power Administration, Hydroelectric Alternatives for the Alaska Railbelt, February, 1980.

(3) Handy-Whitman, Cost Index for Hydropower Production in the Pacific Northwest, 1978.

TABLE C.1 - SUMMARY OF RESULTS OF SCREENING PROCESS

Site[1]	Elimination Iteration 1	2	3	4	Site[1]	Elimination Iteration 1	2	3	4	Site[1]	Elimination Iteration 1	2	3	4	Site[1]	Elimination Iteration 1	2	3	4
Allison Creek					Fox	*				Lowe				*	Talachulitna River	*			
Beluga Lower			*		Gakona		*			Lower Chulitiua				*	Talkeetnna R. -Sheep	*			
Beluga Upper				*	Gerstle			*		Lucy	*				Talkeetna - 2				
Big Delta	*				Granite Gorge			*		McClure Bay			*		Tanana River			*	
Bradley Lake				*	Grant Lake			*		McKinley River		*			Tazlina				*
Bremmer R. -Salmon	*				Greenstone			*		McLaren River	*				Tebay Lake		*		
Bremmer R. -S.F.	*				Gulkana River			*		Million Dollar		*			Teklanika		*		
Browne					Hanagita		*			Moose Horn	*				Tiekel River	*			
Bruskasna					Healy		*			Nellie Juan River	*				Tokichitna				*
Cache					Hicks					Nellie Juan R. -Upper				*	Totatlanika	*			
Canyon Creek	*				Jack River	*				Ohio			*		Tustumena				*
Caribou Creek	*				Johnson				*	Power Creek		*			Vachon Island		*		
Carlo		*			Junction Island		*			Power Creek - 1	*				Whiskers				*
Cathedral Bluffs				*	Kanhshna River			*		Ramport		*			Wood Canyon		*		
Chakachamna					Kasilof River		*			Sanford		*			Yanert - 2		*		
Chulitna E.F.	*				Keetna					Sheep Creek			*		Yentna			*	
Chulitna Hurrican			*		Kenai Lake				*	Sheep Creek - 1	*								
Chulitna W.F.	*				Kenai Lower			*		Silver Lake				*					
Cleave		*			Killey River	*				Skwentna				*					
Coal			*		King Mtn	*				Snow									
Coffee				*	Klutina				*	Solomon Gulch			*						
Crescent Lake			*		Kotsina	*				Stelters Ranch	*								
Crescent Lake - 2		*			Lake Creek Lower		*			Strandline Lake									
Deadman Creek	*				Lake Creek Upper				*	Summit Lake	*								
Eagle River	*				Lane				*	Talachulitna			*						

NOTES:

(1) Final site selection underlined.

* Site eliminated from further consideration.

TABLE C.2 - SITES ELIMINATED IN SECOND ITERATION

Site	Criterion
Healy Carlo Yanert - 2	National Park (Mt. McKinley)
Cleave	National Monument (Wrangell-St. Elias National Park) and Major Fishery
Tebay Lake Hanagita Gakona Sanford	National Monument (Wrangell-St. Elias National Park)
Lake Creek Upper McKinley River Teklanika	Naional Monument (Denali Naitonal Park)
Crescent Lake	National Monument (Lake Clark National Park)
Kasilof River Million Dollar Rampart Vachon Island Junction Island Power Creek	Major Fishery

TABLE C.3 - EVALUATION CRITERIA

Evaluation Criteria	General Concerns
(1) Big Game	- protection of wildlife resources
(2) Agricultural Potential	- protection of existing and potential agricultural resources
(3) Waterfowl, raptors & endangered species	- protection of wildlife resources
(4) Anadromous fisheries	- protection of fisheries
(5) Wilderness Consideration	- protection of wilderness and unique features
(6) Cultural, recreation & scientific features	- protection of existing and identified potential features
(7) Restricted land use	- consideration of legal restriction to land use
(8) Access	- identification of areas where the greatest change would occur

TABLE C.4 - SENSITIVITY SCALING

Scale Rating	Definition
A. EXCLUSION	The significance of one factor is great enough to exclude a site from further consideration. There is little or no possibility for mitigation of extreme adverse impacts or development of the site is legally prohibited.
B. HIGH SENSITIVITY	1) The most sensitive components of the environmental criteria would be disturbed by development, or 2) There exists a high potential for future conflict which should be investigated in a more detailed assessment.
C. MODERATE SENSITIVITY	Areas of concern were less important than those in "B" above.
D. LOW SENSITIVITY	1) Areas of concerns are common for most or many of the sites. 2) Concerns are less important than those of "C" above. 3) The available information alone is not enough to indicate a greater significance.

TABLE C.5 - SENSITIVITY SCALING OF EVALUATION CRITERIA

Evaluation Criteria	SCALE A Exclusion	B High	C Moderate	D Low
Big Game:	--	- seasonal concentration are key range areas - calving areas	- big game present - bear denning area	- habitat or distribution area for bear
Agricultural Potential	--	- upland or lowland soils suitable for farming	- marginal farming soils	- no identified agricultural potential
Waterfowl, Raptors and Endangered Species	--	- nesting areas for: . Peregrine Falcon . Canada Geese . Trumputee Swan - year round habitat for Neritic seabirds and raptors - key migration area	- high density waterfowl area - waterfowl migration and hunting area - waterfowl migration route - waterfowl nesting or or molt area	- medium or low density waterfowl areas - waterfowl present
Anadromous Fisheries	- major anadromous fish corridor for three or more species - more than 50,000 salmon passing site	- three or more species present or spawning - identified as a major anadromous fish area	- less than three species present or spawning - identified as an important fish area	- not identified as a spawning or rearing area.
Wilderness Consideration	--	All of the following - good to high quality: . scenic area . natural features . primitive values - selected for wilderness consideration	Two of the following - good to high quality: . scenic area . natural features . primitive value - site in or close to an area selected for wilderness consideration	One or less of the following - good to high quality: . scenic area . natural features . primitive value
Cultural, Recreational and Scientific Features	--	- existing or proposed historic landmark - reserve proposed for the Ecological Reserve System	- Site affects one or more of the following: . boating potential . recreational potential . historic feature . historic trail . archeological site . ecological reserve nomination . cultural feature	- site near one of the factors in B or C

TABLE C.5 (Continued)

Evaluation Criteria	SCALE			
	A Exclusion	B High	C Moderate	D Low
Restricted Land Use	- Significant impact to: . Existing National Park . Federal Lands withdrawn by National Monument Proclaimations	- Impact to: . National Wildlife Range . State Park . State game refuge, range, or wilderness preservation area	- Increase: . National Forest . Proposed wild and scenic river . National resource area . Forest land withdrawn for mineral entry	- In one of the following: . State land . Native land . None of A, B, C
Restricted Land Use	--	- no existing roads, railroads or airports - terrain rough and access difficult - increase access to wilderness area	- existing trails - proposed roads or - existing airports - close to existing roads	- existing roads or railroads - existing power lines

TABLE C.6 - SITE EVALUATIONS

Site	Evaluation Criteria						
	Big Game	Agricultural Potential	Waterfowl, Raptors, Endangered Species	Anadromons Fisheries	Wilderness Consideration	Cultural, Recreational, and Scientific Fisheries	Restricted Land Use
Allison Creek	- Black and Grizzly bear present	- None identified	- Year round habitat for neritic seabirds and raptors - Peregrine falcon nesting area - Waterfowl present	- Spawning area for 2 salmon species	- High to good quality scenic area	- None identified	- Near Chugach National Forest
Bradley Lake	- Black and Grizzly bear presnt - Moose present	- 25 to 30 percent of soil marginall suitable for farming - high quality forests	- Peregrine Falcon nesting areas	- None identified	- Good to high quality scenery	- Boating area	- None identified
Browne	- Black and Grizzly bear present - Moose present - Caribou winter range	- More than 50 percent marginally suitable for farming	- Low density of waterfowl	- None	- None	- Boating potential	- None identified
Bruskasna	- Black and Grizzly bear present - Moose present - Caribour winter range	- None identified	- Low density of waterfowl - Nesting and molting area	- None	- Good to high quality scenery	- Boating potential - Proposed ecological reserve site	- None identified
Chakachamna	- Black bear habitat - Moose present	- Upland spruce, hardwood forest	- Waterfowl nesting and molting area	- Two species present	- Area under wilderness conisdeation, - Good to high quality scenery - Primitive and natural features	- Boating areas	- None identified
Coffee	- Black and Grizzly bear present - Moose present	- More than 50% of upper lands suitable for agricultural - Good forests	- Key waterfowl habitat	- Four species present, two spawning in area	- None identified	- Boating area	- None identified
Cathedral Bluffs	- Black and Grizzly bear present - Moose present - Dall sheep present - Moose concentration area	- More than 50% of land marginal for farming - Upland spruce-hardwood forest	- Low density of waterfowl - Nesting and molting area	- One species present	- Good scenery	- None identified	- None identified
Hicks	- Black and Grizzly bear present - Caribou present - Moose wintering area	- None identified	- Waterfowl nesting and molting area	- Far downstream of site only	- None identified	- None identified	- No present restrictions
Johnson	- Black and Grizzly bear present - Moose, caribou and bison present	- 25 to 50% of upland soil suitable for farming - Upland spruce-hardwood forest	- Low density waterfowl area - Nesting and molting area	- Salmon spawning area, one species present	- None identified	- Boating potential	- None identified
Keetna	- Black and Grizzly bear present - Caribou winter area - Moose fall/winter concentration area	- None identified	- None identified	- Four species present, one species spawning near site	- Good to high quality primitive lands	- High boating potential	- None identified
Kenai Lake	- Black and Grizzly bear present - Dall sheep habitat - Moose fall/winter concentration area	- None identified - Coastal hemlock-sitka spruce forest	- Waterfowl nesting and molting area	- Four species present, two spawning	- High quality scenery - Natural features	- Boating potential	- Chugach National Forest

TABLE C.6 (Continued)

Site	Evaluation Criteria						
	Big Game	Agricultural Potential	Waterfowl, Raptors, Endangered Species	Anadromous Fisheries	Wilderness Consideration	Cultural, Recreational, and Scientific Fisheries	Restricted Land Use
Klutina	- Black and Grizzly bear present - Caribou present - Moose fall concentration area	- 25 to 50 percent of soils marginal for farming - Climate marginal for farming upland spruce-hardwood forest	- Low density waterfowl area - Nesting and molting area	- Two species present, one species spawn in vicinity of site	- High quality scenery - Natural formations - Primitive lands - Selected for wilderness consideration	- Boating potential	- None identifed
Lane	- Black bear present - Moose present - Caribou present	- More than 50 percent of the soils in upperlands suitable for farming - Bottomland spruce-poplar forest	- Low density waterfowl area - Nesting and molting area	- Five species present and spawn in site vicinity	- None identified	- Boating opportunities identified	- None identified
Lowe	- Black and Grizzly bear present - Moose present	- None identified - Coastal western hemlock-sitka spruce forest	- Perigrene falcon nesting area	- One species present, others downstream of site	- Good to high quality scenery - Area selected for wilderness consideration	- Historical feature - Proposed ecological reserve site	- Located near the border of Chugach National Forest
Lower Chulitna	- Black and Grizzly bear present - Caribou present	- More than 50 percent of the upland soils suitable for farming	- Medium density waterfowl area - Nesting and molting area	- Four species present, three spawning in vicinity	- Area selected for wilderness consideration	- Boating potential	- None identified
Silver Lake	- Black and Grizzly bear present - High density of seals	- None identified - Coastal western hemlock-sitka spruce forest	- Year round habitat for neritic seabirds and raptors	- One species present, more downstream	- Good to high quality scenery - Primitive value	- Boating area potential	- Chugach National Forest
Skwentna	- Black and Grizzly bear present - Moose winter concentration area	- 50 percent of upperlands suitable for farming - Lowland spruce - hardwood forest	- Low density waterfowl area - Nesting and molting area	- Three species present, spawning in area	- None identified	- Boating area - Historical trails	- None identified
Snow	- Black bear present - Dall sheep habitats - Moose winter concentration area	- None identified	- Nesting and molting area	- None	- None identified	- Proposed ecological reserve site	- Located in Chugach National Forest
Strandline Lake	- Moose, black bear habitat - Grizzly bear present	- 25 to 50 percent marginal farming soils - Alpine tundra	- Nesting and molting area	- None present	- Good to high quality scenery - Primitive lands	- None identified	- None identified
Talkeetna 2	- Black and Grizzly bear preant - Moose fall/winter concentration area - Caribou winter range	- None identified	- None identified	- Four species present, one species spawns at site	- Good to high quality scenery - Primitive lands	- Boating potential	- None identified
Coche	- Black and Grizzly bear present - Moose winter concentration area - Caribou winter range	- None identified	- None identified	- Four species of salmon present, spawning areas identified	- Good to high quality scenery - Primitive lands	- Boating potential	- None identified
Tazlina	- Black and Grizzly bear present - Moose winter range - Caribou winter range	- None identified - Lowland spruce-hardwood forest	- Medium density waterfowl area - Nesting and molting area	- Two species present at site and upstream	- None identified	- Boating potential	- None identified
Tokichitna	- Black bear present - Moose present - Caribou present	- More than 50 percent of soils are usable for farming (in upper lands)	- Medium density waterfowl area - Nesting and molting area	- Four species present, three species spawn in site vicinity	- Border primitive area	- Boating potential	- None identified

TABLE C.6 (Continued)

Site	Evaluation Criteria						
	Big Game	Agricultural Potential	Waterfowl, Raptors, Endangered Species	Anadromous Fisheries	Wilderness Consideration	Cultural, Recreational, and Scientific Fisheries	Restricted Land Use
Tustumena	- Black bear habitat - Dall sheep habitat	- None identified	- None identified	- None identified	- Selected for wilderness consideration - Good to high quality scenery - Natural features - Primitive lands	- None identified	- Located in Kenai National Moose Range - Site within a designated National Wilderness area
Upper Beluga	- Moose present	- More than 50 percent of upper lands are suitable for farming - Lowland spruce-hardwood forest	- Medium density waterfowl area - Nesting and molting area	- Four species present, two species spawn in area	- None identified	- Boating area	- None identified
Upper Nellie Juan	- Grizzly bear present - Moose present - Black bear habitat	- None identified - Coastal western hemlock-sitka spruce forest	- None identified	- None identified	- Selected for wilderness consideration - High primitive, scenic, and natural features	- Boating potential	- Chugach National Forest
Whiskers	- Black and Grizzly bear present - Moose present - Caribou present	- 50 percent of upperlands suitable for farming - Bottomland spruce-poplar forest	- Low density waterfowl area - Nesting and molting area	- Five species present, two spawn in area	- None identified	- Boating potential	- None identified
Yentna	- Black and Grizzly bear present - Moose, spring/summer/winter concentration	- 25 to 50 percent of soils in lowlands are suitable for farming - Bottomland spruce- poplar forest	- Medium density waterfowl area - Nesting and molting area	- Five species spawn in area	- None identified	- Boating potential	- None identified

TABLE C.7 - SITE EVALUATION MATRIX

	Big Game	Agricultural Potential	Waterfowl, Raptors, Endg. Species	Anadromous Fisheries	Wilderness Consideration	Cult, Recrea, & Scientific	Restricted Land Use	Access	Installed Capacity (MW)	Scheme	Dam Height (ft)	Land Flooded (Acres)
Crescent Lake	C	D	D	B	C	C	A	B	--	Reservoir w/Diversion	<150	<5000
Chakachamna	C	D	C	C	B	C	B	C	>100	Reservoir w/Diversion	<150	<5000
Lower Beluga	C	D	C	B	D	C	D	D	<25	Reservoir and Dam	<150	<5000
Coffee	C	B	C	B	D	C	D	D	25-100	Dam and Reservoir	<150	<5000
Upper Beluga	C	D	C	B	D	C	D	D	25-100	Dam and Reservoir	150-350	5000 to 100,000
Strandline Lake	C	C	C	D	C	D	D	D	<25	Reservoir w/Diversion	<150	<5000
Bradley Lake	C	C	B	D	C	C	D	D	25-100	Reservoir w/Diversion	<150	<5000
Kasilof River	C	B	C	A	D	C	B	D	--	Reservoir w/Diversion	150-350	>100,000
Tustumena	C	D	D	D	B	D	B	B	<25	Reservoir w/Diversion	<150	<5000
Kenai Lower	C	B	C	B	C	C	B	D	25-100	Dam and Reservoir	<150	<5000
Kenai Lake	B	D	C	B	C	D	C	D	>100	Dam and Reservoir	>350	5000 to 100,000
Crescent Lake-2	C	D	C	C	C	C	C	D	<25	Reservoir w/Diversion	<150	<5000
Grant Lake	B	D	C	B	C	C	C	D	<25	Reservoir w/Diversion	<150	<5000
Snow	B	D	C	D	D	C	C	D	25-100	Reservoir w/Diversion	150-350	5000 to 100,000
McClure Bay	D	D	B	C	B	D	C	C	<25	Reservoir w/Diversion	<150	<5000
Upper Nellie Juan R	C	D	D	D	B	C	C		<25	Reservoir w/Diversion	<150	<5000
Allison Creek	D	D	B	C	D	D	D	D	<25	Reservoir w/Diversion	<150	<5000
Solomon Gulch	D	D	B	C	D	D	D	D	<25	Reservoir w/Diversion	<150	<5000
Lowe	C	D	B	C	C	C	D	D	25-100	Dam and Reservoir	150-350	5000 to 100,000
Silver Lake	D	D	B	C	C	C	C	C	<25	Reservoir w/Diversion	<150	<5000
Power Creek	D	D	B	A	C	C	C	C	<25	Reservoir w/Diversion	<150	<5000
Million Dollar	D	D	B	A	B	C	C	C	--	Dam and Reservoir	<150	5000 to 100,000

TABLE C.7 (Continued)

	Big Game	Agricultural Potential	Waterfowl, Raptors, Endg. Species	Anadromous Fisheries	Wilderness Consideration	Cult, Recrea, & Scientific	Restricted Land Use	Access	Installed Capacity (MW)	Scheme	Dam Height (ft)	Land Flooded (Acres)
Keetna	B	D	D	B	D	C	D	C	25-100	Dam and Reservoir	>350	5000 to 100,000
Granite Gorge	B	D	D	B	C	C	D	C	25-100	Reservoir w/Diversion	150-350	<5000
Talkeetna-2	B	D	D	B	C	C	D	C	25-100	Dam and Reservoir	>350	5000 to 100,000
Greenstone	B	D	D	B	C	C	D	C	25-100	Reservoir w/Diversion	150-350	<5000
Cache	B	D	D	B	C	C	D	C	25-100	Dam and Reservbir	150-350	<5000
Hicks	B	D	C	D	D	D	D	D	25-100	Dam and Reservoir	150-350	<5000
Rampart	C	B	B	A	D	C	C	--	>100	Dam and Reservoir	>350	>100,000
Vachon Island	B	B	C	A	D	C	D	C	>100	Dam and Reservoir	<150	>100,000
Junction Island	B	B	C	A	D	C	D	C	>100	Dam and Reservoir	150-350	>100,000
Kantishna River	C	B	C	B	D	C	D	C	25-100	Dam and Reservoir	<150	>100,000
McKinley River	B	D	C	D	B	C	A	--	--	Dam and Reservoir	150-350	<5000
Teklanika River	B	D	D	D	B	D	A	B		Dam and Reservoir	>350	5000 to 100,000
Browne	B	C	D	D	D	C	D	D	>100	Dam and Reservoir	150-350	5000 to 100,000
Healy	B	C	D	D	B	B	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Carlo	B	D	D	D	B	C	A	D	--	Dam and Reservoir	150-350	<5000
Yanert-2	B	D	D	D	B	C	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Bruskasna	B	D	C	D	D	B	D	D	25-100	Dam and Reservoir	150-350	5000 to 100,000
Tanana	B	B	C	B	D	C	D	D	25-100	Dam and Reservoir	<150	5000 to 100,000
Gerstle	B	B	C	C	D	C	D	C	25-100	Dam and Reservoir	<150	<5000
Johnson	C	B	C	C	D	C	D	D	>100	Dam and Reservoir	<150	5000 to 100,000
Cathedral Bluffs	B	C	C	C	D	D	D	D	>100	Dam and Reservoir	150-350	5000 to 100,000

TABLE C.7 (Continued)

	Big Game	Agricultural Potential	Waterfowl, Raptors, Endg. Species	Anadromous Fisheries	Wilderness Consideration	Cult, Recrea, & Scientific	Restricted Land Use	Access	Installed Capacity (MW)	Scheme	Dam Height (ft)	Land Flooded (Acres)
Cleave	C	D	B	B	B	C	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Wood Canyon	C	D	C	B	B	B	A	D	--	Dam and Reservoir	>350	>100,000
Tehay Lake	C	D	D	C	B	D	A	B	--	Reservoir w/Diversion	<150	<5000
Hanagita	C	D	D	D	B	D	A	B	--	Reservoir w/Diversion	<150	<5000
Klutina	B	C	C	C	B	C	D	--	25-100	--	--	--
Tazlina	B	D	C	C	D	C	C	--	>100	Dam and Reservoir	150-350	5000 to 100,000
Gakona	B	C	C	C	D	C	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Sanford	B	C	C	C	D	C	A	D	--	Dam and Reservoir	--	--
Gulkana	B	D	C	C	D	B	B	D	25-100	Reservoir w/Diversion	150-350	5000 to 100,000
Yentna	B	B	C	B	D	C	D	C	>100	Dam and Reservoir	<150	>100,000
Talachulitna	B	B	C	B	D	C	D	C	25-100	Dam and Reservoir	<150	5000 to 100,000
Skwentna	B	B	C	B	D	C	D	C	25-100	Dam and Reservoir	>350	5000 to 100,000
Lake Creek Upper	C	D	C	C	C	D	A	C	--	Reservoir w/Diversion	<150	<5000
Lake Creek Lower	C	B	C	B	D	C	D	C	--	Dam and Reservoir	150-350	<5000
Lower Chulitna	C	B	C	B	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Tokichitna	C	B	C	B	C	C	D	D	>100	Dam and Reservoir	150-350	5000 to 100,000
Coal	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Ohio	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Chulitna	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Whiskers	C	B	C	B	D	C	D	C	25-100	Dam and Reservoir	<150	<5000
Lane	C	B	C	B	D	C	D	C	>100	Dam and	150-350	<5000

TABLE C.7 (Continued)

	Big Game	Agricultural Potential	Waterfowl, Raptors, Endg. Species	Anadromous Fisheries	Wilderness Consideration	Cult, Recrea, & Scientific	Restricted Land Use	Access	Installed Capacity (MW)	Scheme	Dam Height (ft)	Land Flooded (Acres)
Cleave	C	D	B	B	B	C	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Wood Canyon	C	D	C	B	B	B	A	D	--	Dam and Reservoir	>350	>100,000
Tebay Lake	C	D	D	C	B	D	A	B	--	Reservoir w/Diversion	<150	<5000
Hanagita	C	D	D	D	B	D	A	B	--	Reservoir w/Diversion	<150	<5000
Klutina	B	C	C	C	B	C	D	--	25-100	--	--	--
Tazlina	B	D	C	C	D	C	C	--	>100	Dam and Reservoir	150-350	5000 to 100,000
Gakona	B	C	C	C	D	C	A	D	--	Dam and Reservoir	150-350	5000 to 100,000
Sanford	B	C	C	C	D	C	A	D	--	Dam and Reservoir	--	--
Gulkana	B	D	C	C	D	B	B	D	25-100	Reservoir w/Diversion	150-350	5000 to 100,000
Yentna	B	B	C	B	D	C	D	C	>100	Dam and Reservoir	<150	>100,000
Talachulitna	B	B	C	B	D	C	D	C	25-100	Dam and Reservoir	<150	5000 to 100,000
Skwentna	B	B	C	B	D	C	D	C	25-100	Dam and Reservoir	>350	5000 to 100,000
Lake Creek Upper	C	D	C	C	C	D	A	C	--	Reservoir w/Diversion	<150	<5000
Lake Creek Lower	C	B	C	B	D	C	D	C	--	Dam and Reservoir	150-350	<5000
Lower Chulitna	C	B	C	B	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Tokichitna	C	B	C	B	C	C	D	D	>100	Dam and Reservoir	150-350	5000 to 100,000
Coal	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Ohio	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Chulitna	B	D	C	C	C	C	D	D	25-100	Dam and Reservoir	150-350	<5000
Whiskers	C	B	C	B	D	C	D	C	25-100	Dam and Reservoir	<150	<5000
Lane	C	B	C	B	D	C	D	C	>100	Dam and Reservoir	150-350	<5000
Sheep Creek	B	D	D	D	C	C	D	C	25-100	Dam and Reservoir	>350	<5000

TABLE C.8 - CRITERIA WEIGHT ADJUSTMENTS

	Initial Weight	Adjusted Weights					
		Dam Height			Reserv. Area		
		+	++	+++	+	++	+++
Big Game	8				6	7	8
Agricultural Potential	7				5	6	7
Birds	8				6	7	8
Fisheries	10	8	9	10			

TABLE C.9 - SITE CAPACITY GROUPS

Site Group	No. of Sites Evaluated	No. of Sites Accepted
≤ 25 MW	5	3
25- 100 MW	15	4 - 6
≥100 MW	8	4

TABLE C.10 - RANKING RESULTS

Site Group	Partial Score	Total Score
Sites: < 25 MW		
Strandline Lake	59	85
Nellie Juan Upper	37	96
Tustumena	37	106
Allison Creek	65	82
Silver Lake	65	111
Sites: 25 - 100 MW		
Hicks	62	79
Bruskasna	71	104
Bradley Lake	71	104
Snow	71	106
Cache	86	127
Lowe	89	122
Keetna	89	131
Talkeetna - 2	98	134
Coffee	101	126
Whiskers	101	134
Klutina	101	142
Lower Chulitiua	106	139
Beluga Upper	117	142
Talachultna River	126	159
Skwentna	136	169
Sites > 100 MW		
Chakachamna	65	134
Browne	69	94
Tazlina	89	124
Johnson	96	121
Cathedral Bluffs	101	126
Lane	106	139
Kenai Lake	112	147
Tokichitna	117	150

TABLE C.11 - SHORTLISTED SITES

Environmental Rating	Capacity 0 - 25 MW	25 - 100 MW	100 MW
Good	Strandline Lake*	Hicks*	Browne*
	Allison Creek*	Snow*	Johnson
	Tustumena	Cache*	
	Silver Lake	Bruskasna*	
Acceptable		Keetna*	Chakachamna*
Poor		Talkeetna-2*	Lane
		Lower Chulitna	Tokichitna

* 10 selected sites

Table C.12 - PRELIMINARY COST ESTIMATE - SNOW

Description	Quantity	Unit	Cost/Unit $	Amount $$10^6$	Totals $$10^6$
Diversion Tunnel	2,000	LF	3,060.00	6.12	
Earth Cofferdams	132,000	cy	10.25	1.35	
Excavation - Overburden	768,000	cy	4.50	3.46	
- Spillway					
Impervious Fill	638,000	cy	5.00	3.19	
Pervious Fill	3,028,000	cy	5.00	15.14	
Filter Stone	83,000	cy	8.00	0.66	
Coarse Rock Fill	57,000	cy	8.50	0.49	
Concrete Spillway	1,600	LF	24,900.00	39.80	
9 Ft Ø Power Tunnel	10,000	LF	1,978.00	19.78	
22 Ft Ø Surge Shaft	200	VLF	7,000.00	1.40	
50 MW Underground Powerhouse	1	ea		25.00	
Tailrace Tunnel	505	LF	1,978.00	1.00	
Tailrace Channel	2,000	LF	510.00	1.02	
Subtotal					118.41
Land/Damages				.98	
Reservoir Clearing				4.16	
Switchyard				3.00	
Transmission				7.20	
Roads				4.20	
Bridges				--	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				7.54	
Subtotal					158.49
Camp				20.00	
Catering				14.40	
Subtotal					192.89
Engineering, Administration Contingency				61.72	
TOTAL					254.61

Table C.13 - PRELIMINARY COST ESTIMATE - KEETNA

Description	Quantity	Unit	Cost/Unit $	Amount $$10^6	Totals $$10^6
Diversion Tunnel	2,000	LF	9,460.00	18.92	
Earth Cofferdams	824,000	cy	10.25	8.45	
Excavation - Overburden	1,474,000	cy	4.50	6.63	
Impervious Dam Fill	1,850,000	cy	5.00	9.25	
Pervious Dam Fill	8,513,000	cy	5.00	42.50	
Filter Stone	193,000	cy	8.00	1.54	
Coarse Rock - Rip Rap	148,000	cy	8.50	1.26	
Spillway Excavation	410,000	cy			
130 Ft Concrete Spillway	1,000	LF	100,500.00	100.50	
Power Tunnel	2,100	LF	4,110.00	8.64	
100 MW Surface Powerhouse	1	ea		50.00	
Subtotal					247.69
Lands/Damage				1.66	
Reservoir Clearing				12.18	
Switchyard				3.00	
Transmission				3.20	
Roads				3.60	
Bridges				5.00	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				14.47	
Subtotal					303.80
Camp				30.00	
Catering				27.30	
Subtotal					361.10
Engineering, Administration, Contingency				115.55	
TOTAL					476.65

Table C.14 - PRELIMINARY COST ESTIMATE - CACHE

Description	Quantity	Unit	Cost/Unit $	Amount $$10^6$	Totals $$10^6$
Diversion Tunnel	2,200	LF	8,390.00	18.45	
Earth Cofferdams	301,000	cy	10.25	3.09	
Excavation - Overburden	2,946,000	cy	4.50	13.25	
- Spillway	490,000	cy			
Impervious Fill	2,750,000	cy	5.00	13.75	
Pervious Fill	12,018,000	cy	5.00	60.09	
Filter Stone	284,000	cy	8.00	2.27	
Coarse Rock Fill	196,000	cy	8.50	1.67	
Concrete Spillway	2,000	LF	71,400.00	142.80	
13 Ft Ø Power Tunnel	2,000	LF	2,870.00	5.74	
50 MW Surface Powerhouse	1	ea		25.00	
Subtotal					286.11
Lands/Damages				1.89	
Reservoir Clearing				13.96	
Switchyard				3.00	
Transmission				8.80	
Roads				12.00	
Bridges				5.00	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				17.19	
Subtotal					360.95
Camp				33.75	
Catering				32.40	
Subtotal					427.10
Engineering, Administration, Contingency				136.67	
TOTAL					563.77

Table C.15 - PRELIMINARY COST ESTIMATE - BROWNE

Description	Quantity	Unit	Cost/Unit $	Amount $10^6	Totals $10^6
Diversion Tunnel	1,000	LF	12,000.00	12.00	
Earth Cofferdams	196,000	cy	10.25	2.00	
Excavation - Overburden - Spillway	7,197,000	cy	4.50	32.39	
Impervious Fill	2,497,000	cy	5.00	12.49	
Pervious Fill	11,895,000	cy	5.00	59.48	
Filter Stone	337,000	cy	8.00	2.70	
Coarse Rock Fill	329,000	cy	8.50	2.80	
Concrete Spillway	1,100	LF	128,000.00	141.00	
23 Ft Ø Power Tunnel	1,000	LF	5,540.00	5.54	
100 MW Surface Powerhouse	1	ea		50.00	
Tailrace Channel	300	LF	510.00	0.15	
Subtotal					320.55
Lands/Damages				4.62	
Reservoir Clearing				28.21	
Switchyard				3.00	
Transmission				2.00	
Roads				4.20	
Bridges				5.00	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				19.03	
Subtotal					399.61
Camp				37.50	
Catering				36.00	
Subtotal					473.11
Engineering, Administration, Contingency				151.40	
TOTAL					624.51

Table C.16 - PRELIMINARY COST ESTIMATE - TALKEETNA-2

Description	Quantity	Unit	Cost/Unit $	Amount $10^6	Totals $10^6
Diversion Tunnel	2,800	LF	8,660.00	24.25	
Earth Cofferdams	445,000	cy	10.25	4.56	
Excavation - Overburden	4,668,000	cy	4.50	21.00	
- Spillway	333,000	cy			
Impervious Fill	2,932,000	cy	5.00	14.66	
Pervious Fill	14,213,000	cy	5.00	71.07	
Filter Stone	294,000	cy	8.00	2.35	
Coarse Rock Fill	197,000	cy	8.50	1.67	
Concrete Spillway	1,200	LF	81,600.00	97.90	
12.5 Ft Ø Power Tunnel	2,400	LF	2,750.00	6.60	
50 MW Surface Powerhouse	1	ea		25.00	
Subtotal					269.06
Lands/Damages				0.48	
Reservoir Clearing				3.27	
Switchyard				3.00	
Transmission				5.60	
Roads				7.20	
Bridges				5.00	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				15.33	
Subtotal					321.94
Camp				27.50	
Catering				29.10	
Subtotal					378.54
Engineering, Administration, Contingency				121.13	
TOTAL					499.67

Table C.17 - PRELIMINARY COST ESTIMATE - HICKS

Description	Quantity	Unit	Cost/Unit $	Amount $10^6	Totals $10^6
Diversion Tunnel	2,400	LF	8,450.00	20.28	
Earth Cofferdams	641,000	cy	10.25	6.60	
Excavation - Overburden	2,136,000	cy	4.50	9.60	
- Spillway	292,000	cy			
Impervious Fill	2,160,000	cy	5.00	10.80	
Pervious Fill	8,713,000	cy	5.00	43.60	
Filter Stone	238,000	cy	8.00	1.90	
Coarse Rock Fill	154,000	cy	8.50	1.30	
Concrete Spillway	1,800	LF	79,444.00	143.00	
15 Ft Ø Power Tunnel	1,900	LF	3,342.00	6.35	
Surge Shaft					
60 MW Surface Powerhouse	1	ea		30.00	
Subtotal					273.43
Lands/Damages				1.76	
Reservoir Clearing				1.48	
Switchyard				3.00	
Transmission				20.00	
Roads				3.00	
Bridges				5.00	
On-site Roads				5.00	
Buildings/Equipment				8.00	
Mobilization				16.05	
Subtotal					336.72
Camp				33.75	
Catering				30.30	
Subtotal					400.77
Engineering, Administration, Contingency				128.25	
TOTAL					529.02

Table C.18 - PRELIMINARY COST ESTIMATE - CHAKACHAMNA

Description	Quantity	Unit	Cost/Unit $	Amount $10^6	Totals $10^6
Main Dam	1	ea		2.00	
26 Ft Concrete Lined Power Tunnel	57,000	LF	8,380.00	477.66	
Adit Tunnels	14,000	LF	1,680.00	23.50	
35 Ft Tailrace Tunnel	1,000	LF	3,500.00	3.50	
88 Ft Ø Surge Shaft	500	LF	50,000.00	25.00	
16 Ft Ø Penstocks	3,700	LF	5,090.00	18.85	
500 MW Underground Powerhouse	1	ea		273.50	
Diversion Tunnel	2,000	LF	9,580.00	19.15	
Subtotal					843.16
Lands/Damages				0.50	
Reservoir Clearing				--	
Switchyard				3.00	
Transmission				14.00	
Roads				31.80	
Bridges				10.00	
On-site Roads				10.00	
Buildings/Equipment				8.00	
Mobilization				44.40	
Subtotal					964.86
Camp				72.50	
Catering				84.00	
Subtotal					1121.36
Engineering, Administration, Contingency				359.05	
TOTAL					1480.41

Table C.19 - OPERATING AND ECONOMIC PARAMETERS FOR SELECTED HYDROELECTRIC PLANTS

No.	Site	River	Max. Gross Head Ft.	Installed Capacity (MW)	Average Annual Energy (Gwh)	Plant Factor (%)	Capital Cost[1] ($$10^6$)	Economic Cost of Energy ($/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	477	47
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	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.

TABLE C.20 - ALTERNATIVE HYDRO DEVELOPMENT PLANS

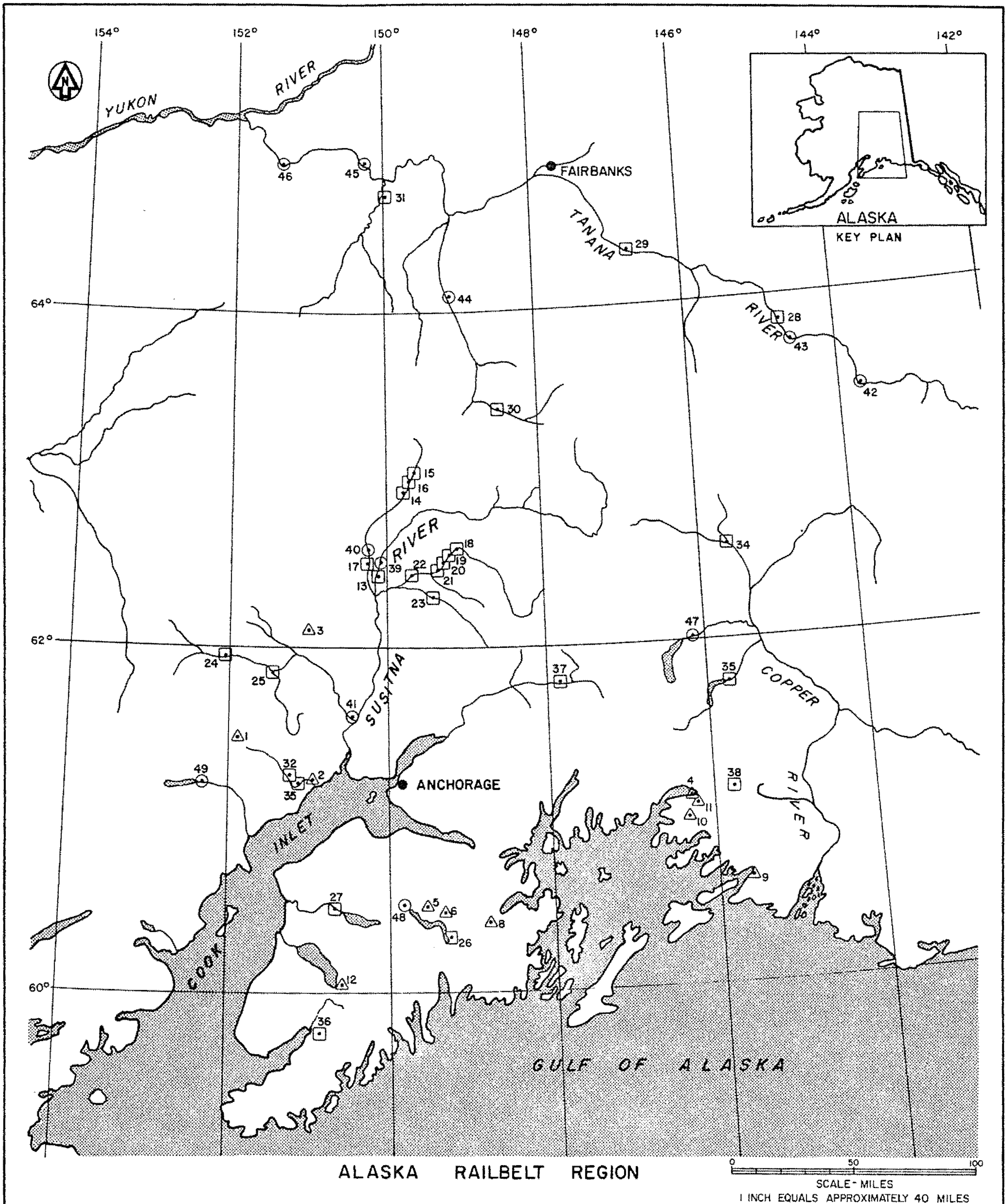
Plan	Description	Installed Capacity	On-Line Date
A.1	Chakachamna	500	1993
	Keetna	100	1997
A.2	Chakachamna	500	1993
	Keetna	100	1997
	Snow	50	2002
A.3	Chakachamna	500	1993
	Keetna	100	1996
	Snow	50	1998
	Strandline	20	1998
	Allison Creek	8	1998
A.4	Chakachamna	500	1993
	Keetna	100	1996
	Snow	50	2002
	Strandline	20	2002
	Allison Creek	8	2002
A.5	Chakachamna	500	1993
	Keetna	100	1996
	Snow	50	2002
	Talkeetna - 2	50	2002
	Cache	50	2002
	Strandline	20	2002
	Allison Creek	8	2002

TABLE C.21 - 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 - ($10⁶)
All Thermal	No Renewals	Very Low[1]	LBT7	500	426	90	144	1160	4930
	No Renewals	Low	L7E1	700	300	40	144	1385	5920
	With Renewals	Low	L2C7	600	657	30	144	1431	5910
	No Renewals	Medium	LME1	900	801	50	144	1895	8130
	With Renewals	Medium	LME3	900	807	40	144	1891	8110
	No Renewals	High	L7F7	2000	1176	50	144	3370	13520
	With Renewals	High	L2E9	2000	576	130	144	3306	13630
	No Renewals	Probabilistic	LOF3	1100	1176	100	144	3120	8320
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500)[2]-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	794	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) Incorporating load management and conservation
(2) Installed capacity

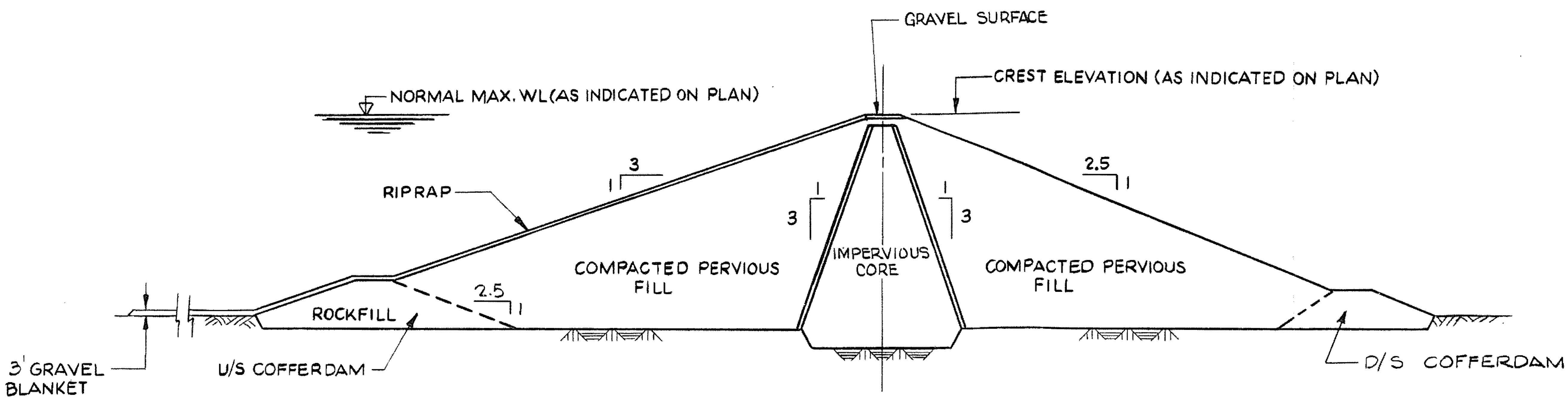


0 - 25 MW	25 - 100 MW	> 100 MW	
1. STRANDLINE L.	13. WHISKERS	26. SNOW	39. LANE
2. LOWER BELUGA	14. COAL	27. KENAI LOWER	40. TOKICHITNA
3. LOWER LAKE CR.	15. CHULITNA	28. GERSTLE	41. YENTNA
4. ALLISON CR.	16. OHIO	29. TANANA R.	42. CATHEDRAL BLUFFS
5. CRESCENT LAKE 2	17. LOWER CHULITNA	30. BRUSKASNA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

SELECTED ALTERNATIVE HYDROELECTRIC SITES

FIGURE C.1

ACRES



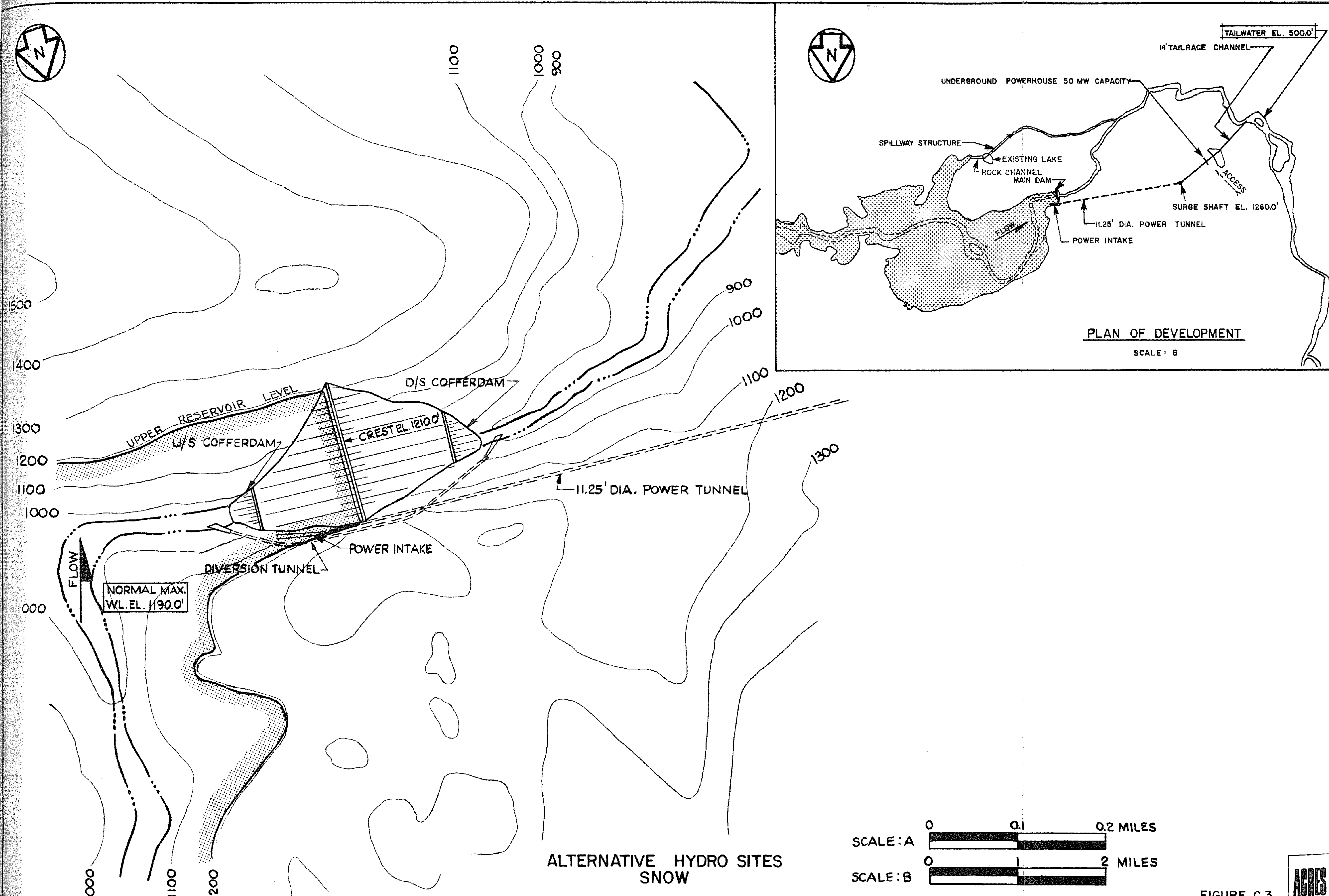
DAM CROSS SECTION

SCALE : 0 200 400 FEET

ALTERNATIVE HYDRO SITES
TYPICAL DAM SECTION

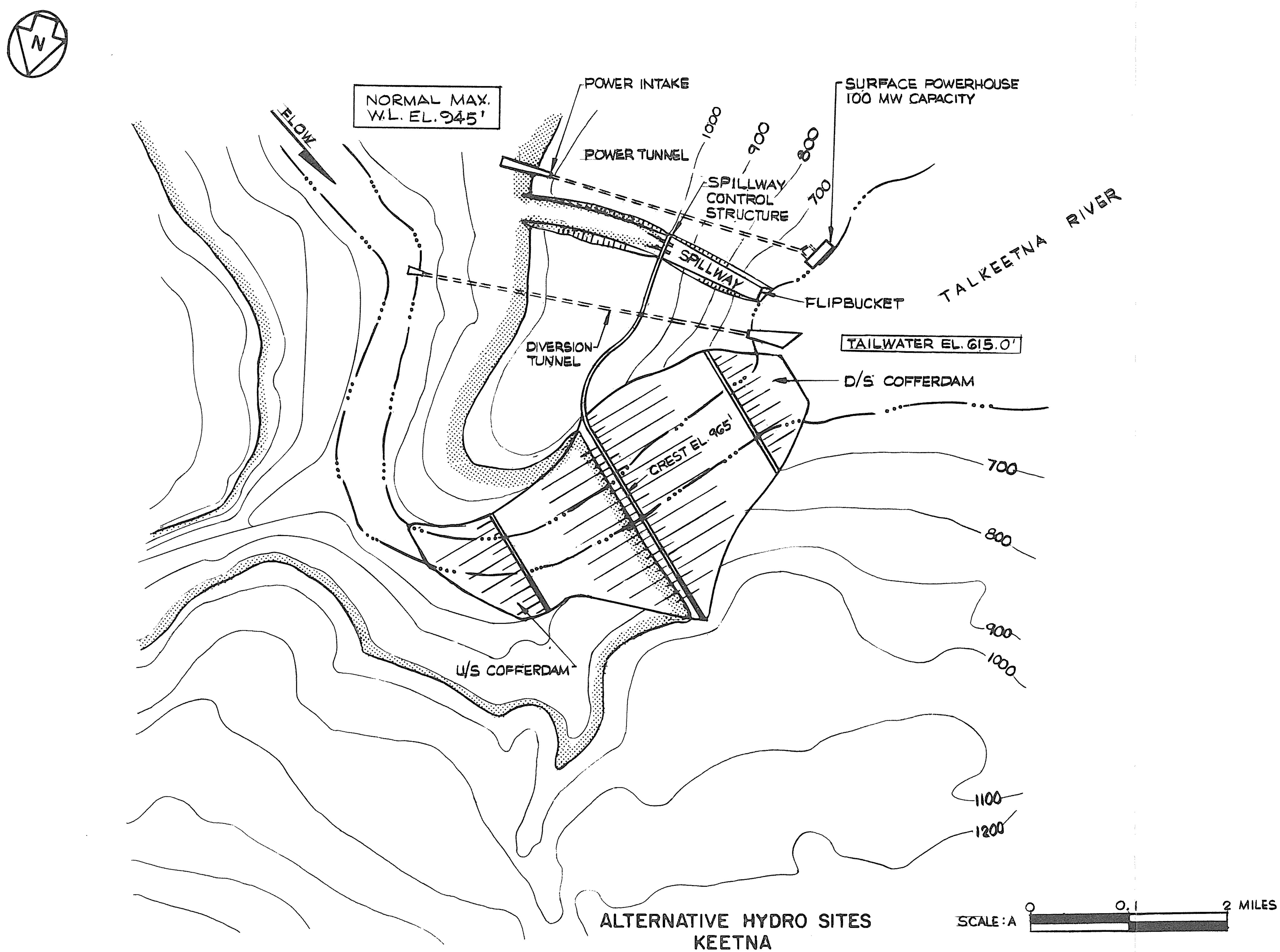
ACRES

FIGURE C.2



ALTERNATIVE HYDRO SITES
SNOW

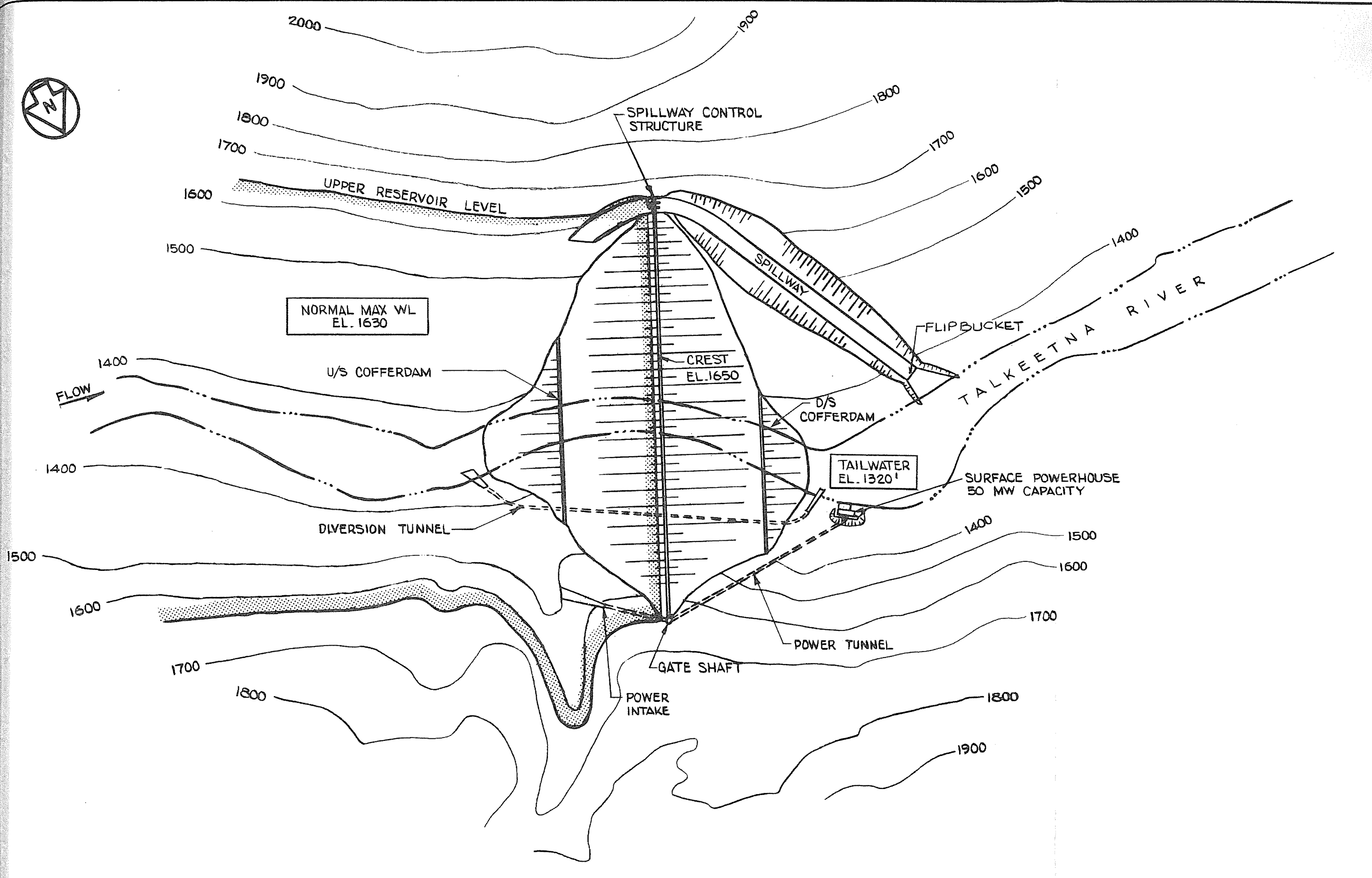
FIGURE C.3



ALTERNATIVE HYDRO SITES
KEETNA

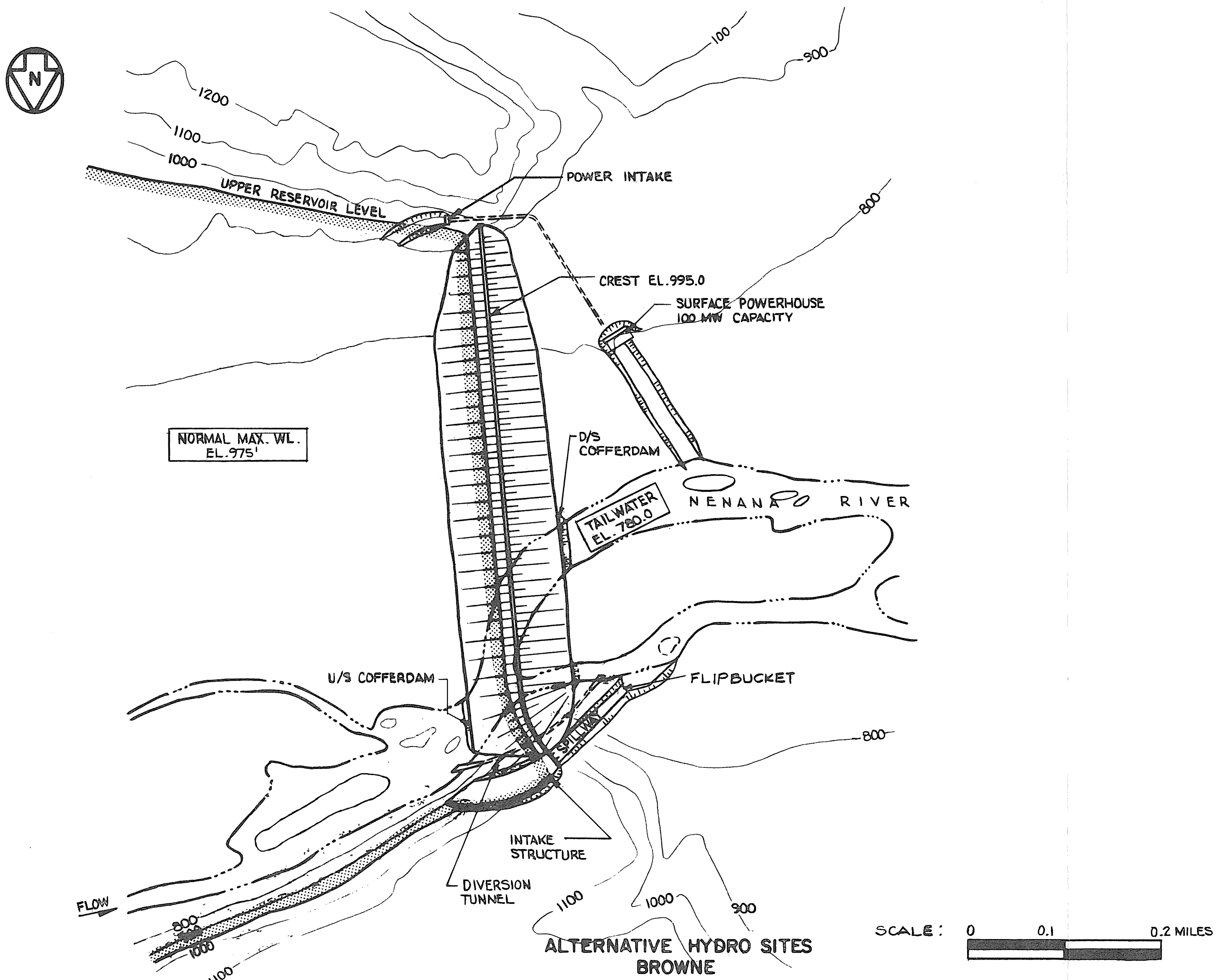
ACRES

FIGURE C.4



ALTERNATIVE HYDRO SITES
CACHE

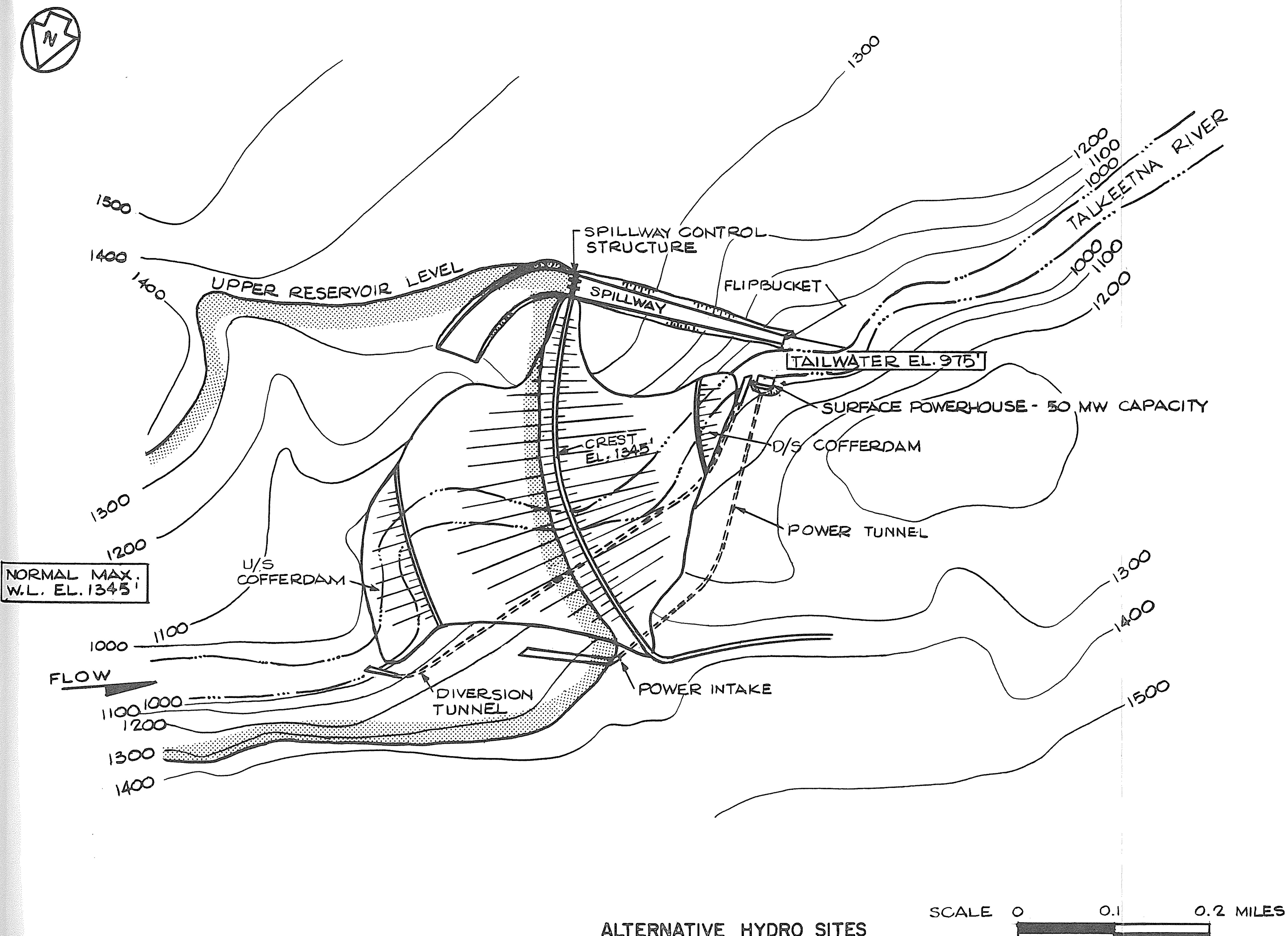
FIGURE C.5



ALTERNATIVE HYDRO SITES
BROWNE

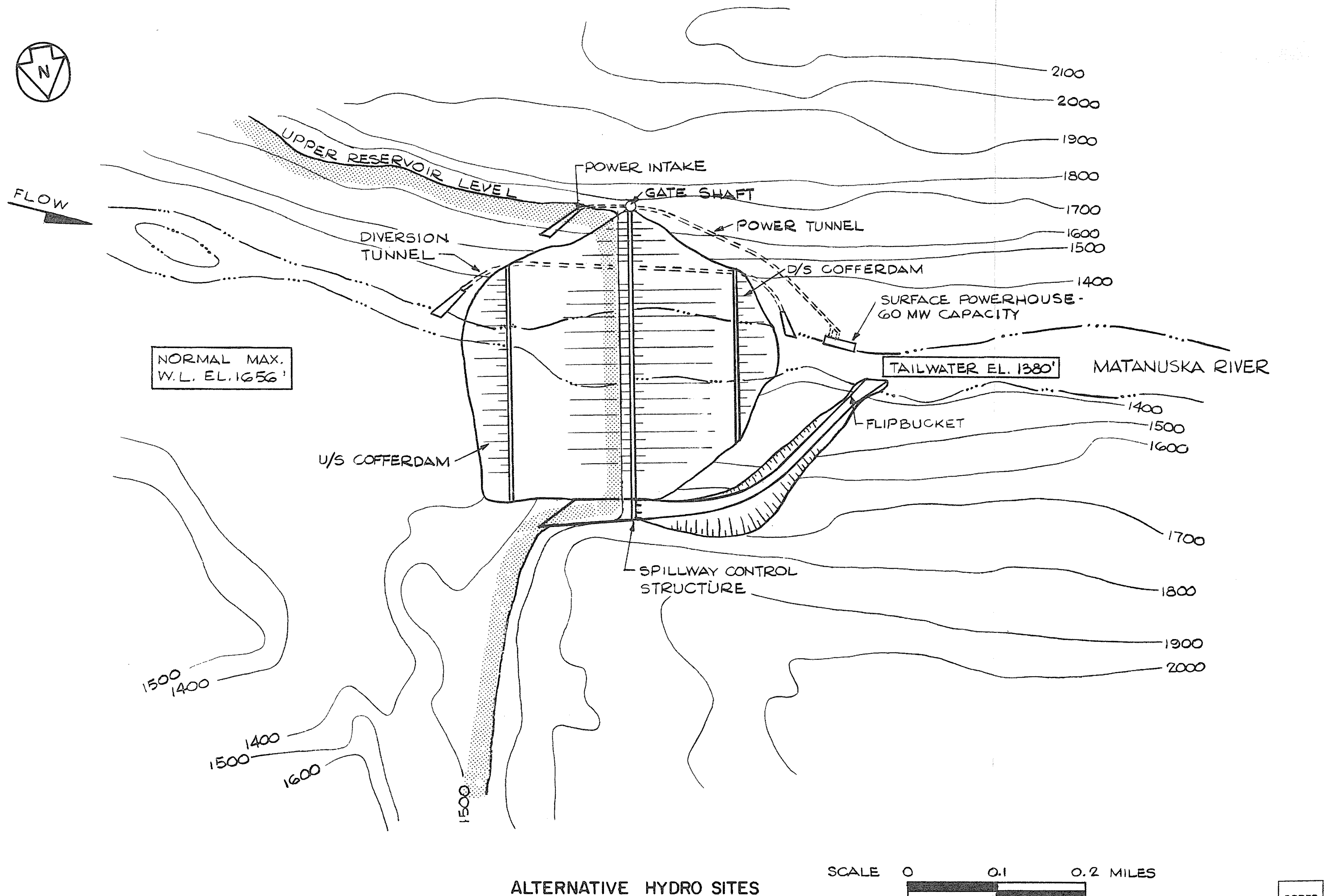
FIGURE C.6

ACRES



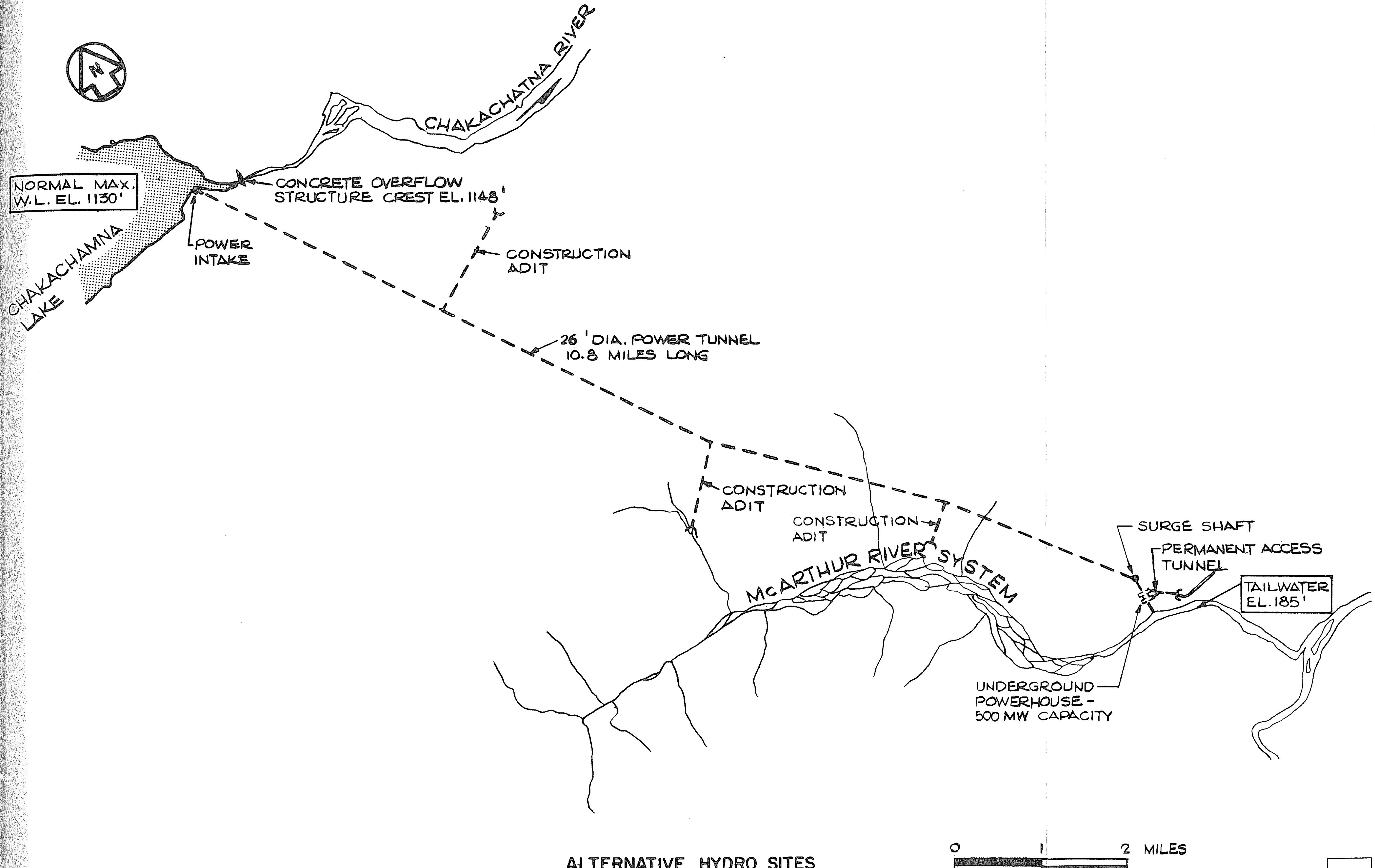
ALTERNATIVE HYDRO SITES
TALKEETNA 2

FIGURE C.7



ALTERNATIVE HYDRO SITES
HICKS

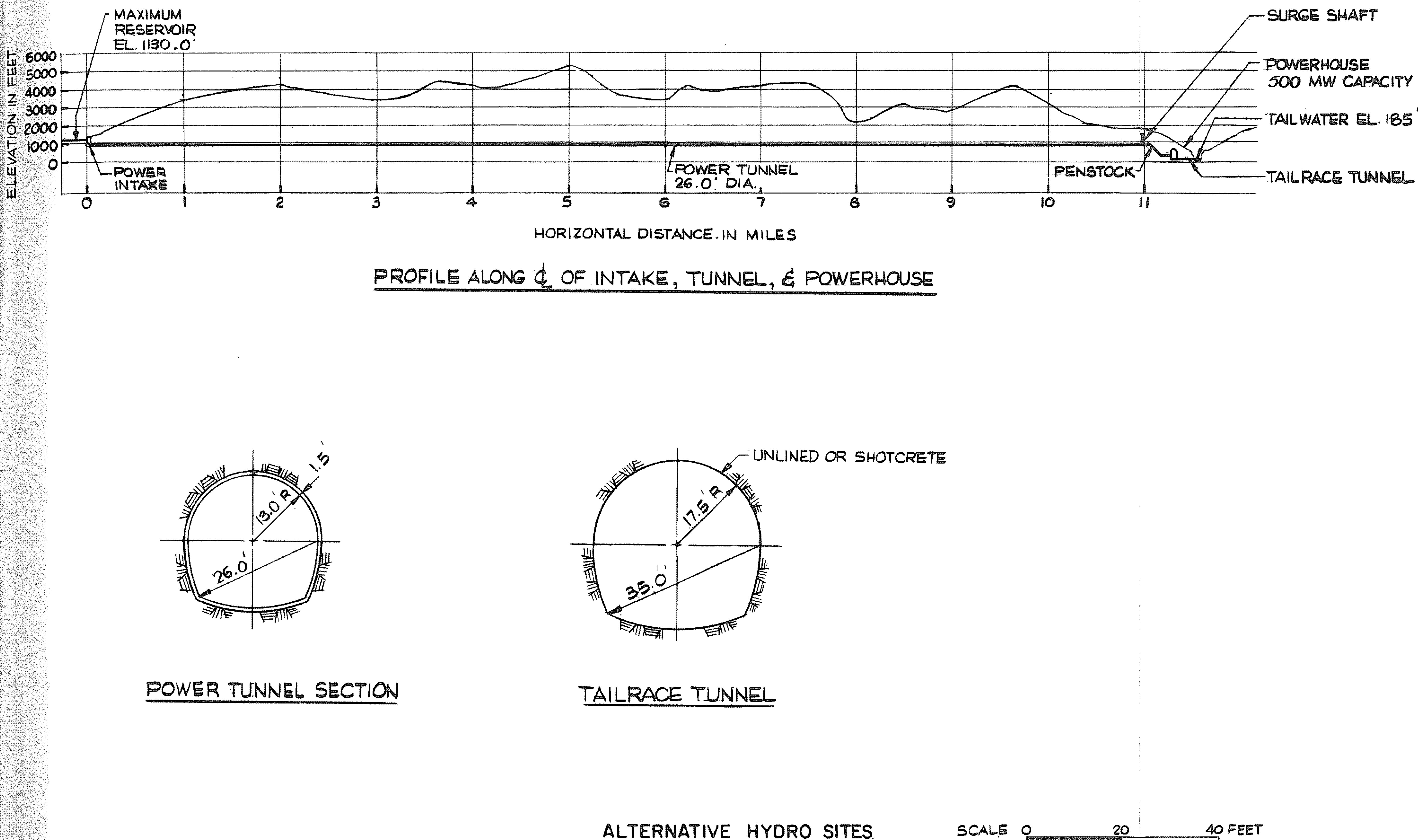
FIGURE C.8



ALTERNATIVE HYDRO SITES
CHAKACHAMNA

ACRES

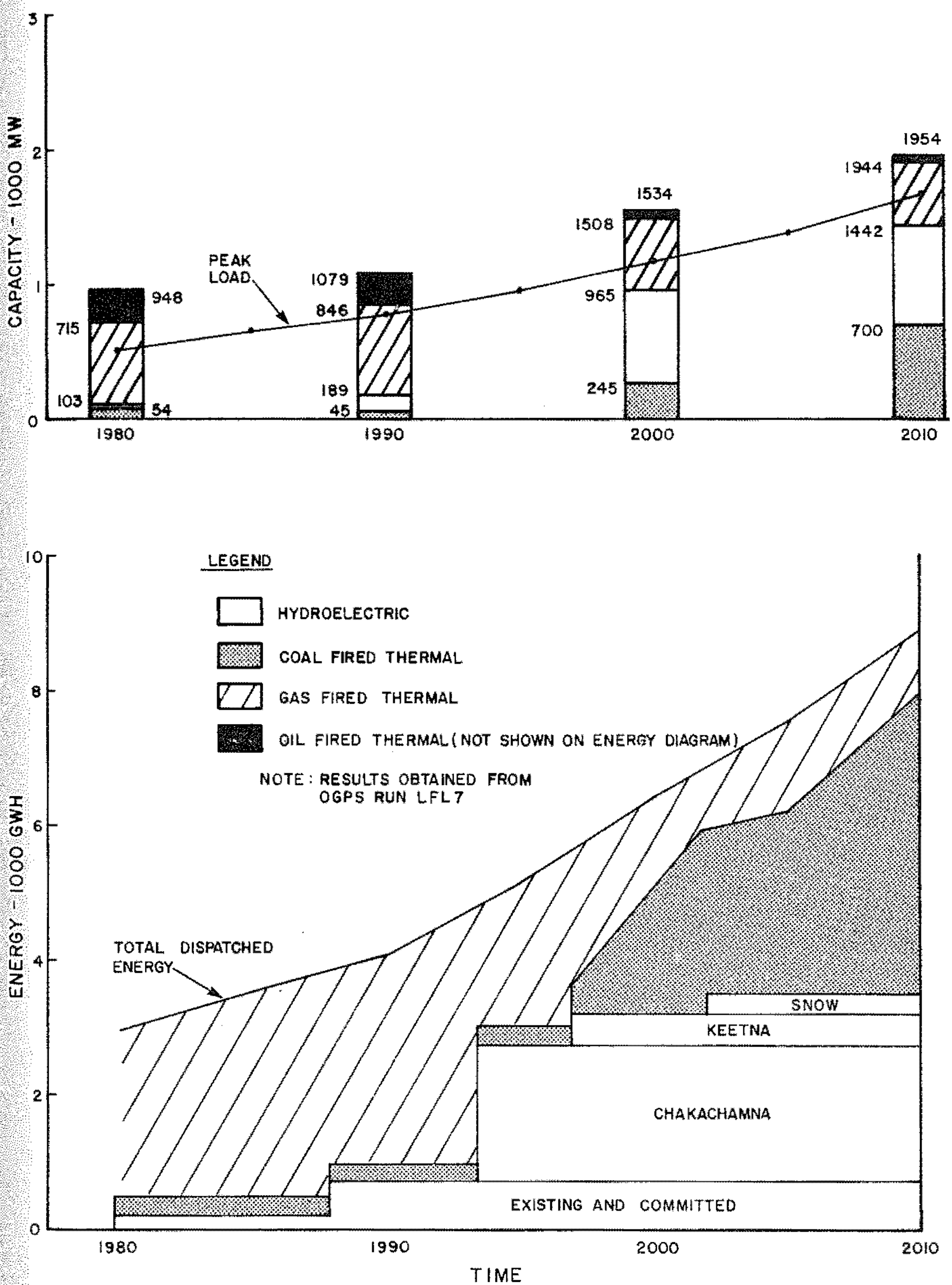
FIGURE C.9



ALTERNATIVE HYDRO SITES
CHAKACHAMNA - PROFILE AND SECTIONS

ACRES

FIGURE C.10



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

FIGURE C.11

ACRES

APPENDIX D - ENGINEERING LAYOUT DESIGN ASSUMPTIONS

The objective of documenting the following design considerations is to facilitate a standarized approach to the engineering layout work being done as part of Subtasks 6.02 "Investigate Tunnel Alternative", 6.03 "Evaluate Alternative Susitna Developments" and 6.06 "Staged Development". It is emphasized that for purposes of these initial project definition studies, layouts are essentially conceptual and the material presented is based on published data modified by judgement and experience.

D.1 - Approach to Project Definition Studies

The general approach to the project definition studies involves three steps:

(a) Single Site Developments

All sites are treated as single projects.

(b) Multisite Developments

Two or three sites are developed in a series. This means that the downstream sites may have installed capacities, spillway and diversion capacities, and drawdown levels which differ considerably from the single site development.

(c) Staged Developments

Development at a site may be staged, i.e. in subsequent stages of development, the dam crest level may be increased and the powerhouse capacity expanded.

Although these steps normally follow consecutively, there is considerable overlap, and work could be progressing on all three steps at the same time.

This appendix essentially addresses the step (a) type studies. Careful interpretation of the information is required when applying it to step (b) and (c) studies.

D.2 - Electrical System Considerations

The current total system plant factor is reported to be of the order of 50 to 55 percent. Study projections (Section 5) indicate that this factor may go up to between 56 and 63 percent in future years.

Initially, all projects should be sized for a 45 to 55 percent plant factor and should incorporate daily peaking to satisfy this requirement. As a later step, some of the proposed developments could have higher or lower plact factors, if this is justified in economic studies.

All projects should be capable of meeting a seasonally varying power demand. Table D.1 is based on load forecasting studies undertaken as discussed in Section 5 and lists the monthly variation in power and energy demand that should be used. In general, the installed capacity and reservoir level regulating rules used in this study are established so that the firm energy output of the project is maximized.

A number of terms relative to energy assessments which are used in the project definition studies are listed and defined below. These definitions may be modified during the subsequent steps of the feasibility studies to reflect the higher sophistication of the studies and consequently the need for a more exact or specific terminology definition.

- Average Monthly or Annual Energy

  The average monthly annual energy produced by a hydro project over a given period of operation.

- Firm Monthly or Annual Energy

  The minimum amount of monthly or annual energy that can be guaranteed even during low flow periods. For purposes of this preliminary study this should correspond to the energy produced during the second lowest energy producing year on record. This corresponds roughly to an annual level of assurance of 95%.

- Secondary Energy

  Electric energy having limited availability. In good water years a hydro plant can generate energy in excess of its firm energy capability. This excess energy is classified as secondary energy because it is not available every year, and varies in magnitude in those years when it is available.

- Installed Capacity

  The rating of generators at design head and best gate available for production of saleable power.

D.3 - Geotechnical Considerations

(a) Main and Saddle Dams

Geotechnical considerations inherent for each of the dam sites are summarized in Table D.2.

(b) Temporary Cofferdams

It is assumed that all cofferdams are of fill-type. Since much of the original river bed material under the main dam shell may have to be excavated, all cofferdams have been located outside the upstream and downstream limits of the main dam in each case.

D.4 - Hydrologic and Hydraulic Considerations

Tables D.3, D.4, D.5 and D.6 list the provisional hydrologic and hydraulic parameters used in initial project definition studies. Table D.7 details preliminary freeboard requirements. An example is worked out in Table D.8 to calculate freeboard requirements.

(a) General

Figures D.1 to D.8 illustrate the storage capacity and reservoir area at each Susitna Basin dam site for the applicable range of water levels.

(b) Sizing of Hydraulic Components

- Power Conduits - For dam schemes the sizes should be based on the maximum velocities listed in Table D.6. For long tunnel schemes the diameter is determined such that the cost of energy is minimized. That is, tunnel diameter is optimized between cost of excavating larger tunnels against reduced head losses.

- Diversion System - The cofferdam-diversion tunnel system is sized as follows:

  - The diversion tunnel is sized to accommodate the maximum velocity permissible (Table D.6) for the design diversion flow. The top of the upstream cofferdam is then determined by computing head loss through the tunnel, adding to the elevation of the energy grade line at the outlet portal, and providing a 10 feet freeboard allowance.

  - The downstream cofferdam height is determined from the available stage-discharge relationship with similar freeboard allowances.

- Spillway - Spillway size was based on the accommodation of the Project Design Flood shown in Table D.3 and D.4. Supplementary emergency spillways are used where necessary. All service spillways have downstream stilling basins. The capacity of each structure is checked for the PMF flow with a reduction up to 9 feet in freeboard (Table D.7). The energy to be dissipated by the spillway structure was set at 45,000 hp per foot width under PMF conditions.

D.5 - Engineering Layout Considerations

Table D.9 lists the components that are incorporated in the engineering layouts and describes the types of components to be used. Table D.9 was used as a guide to design for all layouts.

D.6 - Mechanical Equipment

(a) Powerhouse

- Number of Units

  In general, a decrease in the number of units will result in a reduction in power plant cost. For preliminary studies it has been assumed that unit capacities range from 100 to 250 MW. The minimum number of units assumed is two and the maximum number is four.

- Turbines

The rated net head has been assumed to be approximately equal to the minimum net head plus 75 percent of the difference between the maximum and minimum net heads. For rated heads above 130 feet, vertical Francis type units with steel spiral cases have been assumed. Vertical Kaplan units are used for heads lower than 130 feet. Turbines are directly connected to vertical synchronous generators in all cases.

(b) Overflow Spillway Gates

The spillway gates have been assumed to be fixed wheel vertical lift gates operated by a double drum with rope hoists located in an enclosed tower and bridge structure. Maximum gate size for preliminary design has been set at 50 feet width and 60 feet height. In all cases a provision of 3 feet of freeboard for gates over maximum operating level has been assumed. The gates are heated for winter operation.

(c) Miscellaneous Mechanical Equipment

Cost estimates provide for a full range of power station equipment including cranes, gates, valves, etc.

D.7 - Electrical Equipment

(a) Powerhouse

Generators are of the vertical synchronous type with separate transformer galleries provided for main and station transformers. Provision is made in the cost estimates for a full range of miscellaneous operating and control equipment including where necessary allowance for remote station operations.

(b) Switchyard and Transmission Lines

The switchyard is designed to be located on the surface and as close to the powerhouse as possible. Size guidelines for the yards are approximately 900 x 500 feet. Cost estimates allow for transmission lines and substations (Table D.9).

D.8 - Environmental Considerations

Previous investigations have shown that a prime environmental consideration is the effect of possible development on fisheries. In order to avoid a severe detrimental impact on the fisheries habitat, tentative water level fluctuations and downstream flow release constraints have been developed. These are guidelines only for the present studies and will be further addressed and refined as work proceeds.

(a) Flow Constraints

Table D.10 lists preliminary values of minimum flows required downstream of any development at all times. The lower flows are based on preliminary assessment of the requirements of resident fish while the higher flows are estimated anadromous fish needs.

(b) Water Level Constraints

Daily reservoir level fluctuations should be kept below 5 feet while seasonal drawdown should be limited to between 100 and 150 feet.

TABLE D.1 - MONTHLY VARIATIONS OF ENERGY AND PEAK POWER DEMAND

Month	Energy	Variation Peak Demand
October	.086	.80
November	.101	.92
December	.109	1.00
January	.100	.92
February	.094	.87
March	.086	.78
April	.076	.70
May	.069	.64
June	.067	.62
July	.066	.61
August	.070	.64
September	.076	.70

TABLE D.2 - GEOTECHNICAL DESIGN CONSIDERATIONS

General Conditions	DAMSITE Denali	Maclaren	Vee
Dam Type	Earth-Rockfill	Earth-Rockfill	Earth-Rockfill
U/S Slope	4:1 (H/V)	4:1	2.25:1
D/S Slope	4:1	4:1	2:1
General Foundation Conditions	All structures would have soil foundations. Depth to bedrock is believed to be 200'+. Inter-stratified till and alluvium foundation material, local liquefaction potential. 40'+ alluvium in valley.	Assume soil foundations. Depth to bedrock estimated at 200'. Compressible, permeable and liquefiable zones probably exist.	River alluvium 125', drift or talus on abutments is 10-40' thick. Saddle dam located on deep permafrost alluvium.
Required Foundation Excavation (in addition to overburden)	Total Excavation Depth Core / Shell Abutment 30' / 10' Channel 70' / 50'	Unknown. Assume same as for Denali.	Assume: Core - Remove average of 50' of rock Shell - Remove top 10' of rock
Required Foundation Treatment and Grouting	Assume core-grout in five rows of holes to 70 percent of head up to a maximum of 300'. Probable drain curtain or drain blanket under downstream shell. Foundation surface - no special treatment.	Assume same as for Denali.	Assume grouting same as for Watana. No special treatment under shell. Assume extensive sand drains in saddle dam permafrost area.
Seismic Considerations (MCE = Maximum Credible Earthquake)	High exposure, no known site faults. MCE = Richter 8.5 @ 40	High exposure, no known site faults. MCE = 8.5 @ 40 miles.	High exposure, no known site faults. MCE = 8.5 @ 40 miles.
Powerhouse Location	Underground powerhouse unsuitable.	Underground powerhouse unsuitable.	Unknown. Assume suitable for underground with substantial rock support.
Permafrost	>100' deep in abutments, probable lenses under river.	Probably >100'.	>60' in saddle area, sporadic in abutments.
Construction Material Availability	No borrow areas identified. Assume suitable materials are available within a five-mile radius. Processing of impervious material will be required.	Assume same as for Denali.	Assume available 0.5 to 5 mile radius. Impervious will require processing.
Remarks	Based on Kachadoorian, 1959.	No report on site. Parameters based on regional geology.	Based on USBR studies.

NOTES:

(1) Actual estimates on Watana and Devil Canyon have been taken from overburden contour maps.
(2) Data compiled prior to January 1, 1981. Estimates made after this date have used updated excavation criteria.

TABLE D.2 (Continued)

General Conditions	DAMSITE Susitna	Watana	High Devil Canyon
Dam Type	Earth-Rockfill	Earth-Rockfill or concrete arch	Earth-Rockfill
U/S Slope	2.25:1	2.25:1 (for earth)	2.25:1
D/S Slope	2:1	2:1	2:1
General Foundation Conditions	Unknown but rock probable over 50' in depth. Possible permeable compressible and liquefiable strata.	Abutments-assume 15' overburden (OB) Valley bottom - 48-78' alluvium. Assume 70'. Right bank upstream - approximately 475' deep relict channel on right bank, upstream of dam site.	Assume 30-60' overburden and alluvium.
Required Foundation Excavation (in addition to overburden)	Assume same as for Watana.	Core: Remove top 40' of rock. Shell: Remove top 10' of rock.	Core: Remove top 40' of rock. Shell: Remove top 15' of rock.
Required Foundation Treatment and Grouting	Assume grout and drain system full width of dam, dependent on foundation quality. Drain gallery and drain holes.	Extensive grouting to depth = 70% of head but not to exceed 300'. Drain gallery and drain holes.	Assume same as for Watana.
Seismic Considerations (MCE = Maximum Credible Earthquake)	High exposure. MCE=8.5 @ 40 miles. Also near zone of intense shearing.	MCE = Richter 8.5 @ 40 miles <u>or</u> 7.0 @ 10 miles.	Same as for Watana.
Powerhouse Location	Unknown. Assume suitable for underground with substantial rock support.	Underground favorable, extensive support may be required.	Probably favorable for underground but assume support needed.
Permafrost	Probably sporadic and deep.	>100' on left abutment. More prevalent and deeper on north facing slopes.	Sporadic, possibly 100'±.
Construction Material Availability	Assume available within five miles. Processing similar to that at Watana.	Available with 0-5 miles. Processing required.	No borrow areas defined. Assume available within 5 miles.
Remarks	No reports available. Parameters based on regional geology of the area.	Based on Corps studies and 1980 Acres exploration.	No geotechnical data available. Parameters based on regional geology.

TABLE D.2 (Continued)

	DAMSITE		
General Conditions	Devil Canyon	Devil Canyon	Portage Creek
Dam Type	Concrete arch or gravity	Rockfill	Concrete gravity
U/S Slope	---	2.25:1	---
D/S Slope	---	2:1	---
General Foundation Conditions	Assume 35' alluvium in river bottom. Shears and fault zones in both abutments, 35-50' of weathered rock. Saddle dam overburden up to 90' deep. Assume excavation for spillway totals 90' to sound rock on valley walls.		Unknown - assume same as for Devil Canyon
Required Foundation Excavation (in addition to overburden)	Remove 50' of rock. Extensive dental work and shear zone over-excavation will be required. Saddle dam: Excavation 15' into rock.	Core: Excavation 40' into rock Shell: Excavate 15' into rock	Rock type is similar to Devil Canyon, so assume foundation conditions are similar.
Required Foundation Treatment and Grouting	Extensive grouting to 70% of head, limited to 300'. Allow for long anchors into rock for thrust blocks. Extensive dental treatment. Deep cutoff under saddle dam, 15' into rock.	Extensive grouting to 70% of head, limited to 300'. Extensive dental treatment under core. Deep cutoff under saddle dam, 15' into rock.	Assume same as Devil Canyon.
Seismic Considerations (MCE = Maximum Credible Earthquake)	Same as for Watana.	Same as Watana.	MCE = Richter 8.5 @ 40 miles <u>or</u> 7.0 at 10 miles.
Powerhouse Location	Favorable for underground powerhouse, assume moderate support.	Favorable for underground powerhouse, assume moderate support.	Probably favorable for underground powerhouse, assume moderate support.
Permafrost	None expected, but possibly sporadic.	None expected, but possibly sporadic.	None expected, but may be local areas on north exposures or in overburden.
Construction Material Availability	Concrete aggregate within 0.5 miles, embankment material - assume within 3 miles.	Concrete aggregate within 0.5 miles, embankment material - assume within 3 miles.	Unknown - expect adequate sources 2-5 miles downstream.
Remarks	Based on USBR, Corps and 1980 Acres exploration.	Based on USBR, Corps and 1980 Acres exploration.	No previous investigations are available on this site.

TABLE D.3 - INITIAL HYDROLOGIC DESIGN CONSIDERATIONS

	DAMSITES									
Parameter	Denali	Maclaren	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Portage Creek	Tunnel Alternative	Remarks
Catchment area-sq.mi.^{2}:	1,269	2,320	4,140	4,225	5,180	5,760	5,810	5,840	--	--
Mean annual flow-cfs:	3,290	4,360	6,190	6,350	8,140	9,140	9,230	9,230	--	--
Spillway design flood-cfs:	89,800	106,000	133,000	137,000	175,000	198,000	200,000	200,000	175,000	1:10,000 year flood peak without routing
Construction diversion flood cfs:	42,500	50,000	63,000	64,600	82,600	93,500	94,400	20,000[1]	20,000[1]	1:50 year flood peak
50 year sediment accumulation Acre-ft[1]: *	290,000	243,000	162,000	165,000	204,000	248,000	252,000	--	--	assumes no upstream development

Notes:

(1) Assumes upstream reservoir.

TABLE D.4 - REVISED DESIGN FLOOD FLOWS FOR COMBINED DEVELOPMENT

Parameters	DEVELOPMENT					Remarks
	Scheme 1		Scheme 2			
	(Watana &	Devil Canyon)	(High Devil Canyon &	Portage Creek &	Vee)	
Spillway design flood - cfs	115,000	135,000	145,000	150,000	105,000	1:10,000 year flood routed through the reservoir at FSL as in Table D.5
Construction diversion	89,100	20,000	99,100	20,000	71,200	Subsequent developments enjoy regulation by upstream reservoir(s).
PMF for checking design - cfs	235,000	270,000	262,000	270,000	189,000	

Notes:

This table is based on Acres Flood Frequency Analyses and supercedes Table D.3 for Watana and High Devil Canyon first developments.

TABLE D.5 - SITE SPECIFIC HYDRAULIC DESIGN CONSIDERATIONS

	DAMSITES									
Parameter	Denali	Maclaren	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Portage Creek[1]	Tunnel Alternative[1]	Remarks Tunnel Alternative Only
Reservoir Full Supply Level - ft	2,540	2,395	2,330	2,340	2,220/ 2,000	1,750	1,445	1,020	2,200/ 1,475	Tunnel alternative consists of Watana and re-regulation dams
Dam Crest Level - ft	2,555	2,405	2,350	2,360	2,225/ 2,060	1,775	1,465 (rock fill) 1,459 (concrete)[2]	1,030	2,225/ 1,490	See above remarks
Average Tail Water Level - ft	2,405	2,320	1,925	1,810	1,465	1,030	880	850	1,465/ 1,260/ 900	Watana/Re-regulation dam/Devil Canyon, respectively
Installed Capacity - MW	50	10	230	330	800/400	800	400	150	--	--
Maximum Power Flow - cfs	5,400	2,000	8,300	9,000	18,000/ 11,000	18,000	10,000	15,000	8,400	In Tunnel between re-regulation and Devil Canyon Power House
Minimum Compensation Flow - cfs	600	1,200	1,500	1,500	2,000	2,000	2,000	2,000	1,000	In reach between tunnel outfall at Devil Canyon
Low Level Outlet Capacity - cfs[3]	8,900	4,700	8,300	10,000	20,800	15,600	10,600	9,300	20,800	

Notes:

(1) Considered only as second developments after u/s dam(s) is built.
(2) Includes 4' high wave wall on top of dam.
(3) Empties reservoir to 10 percent capacity in 12 months.

TABLE D.6 - GENERAL HYDRAULIC DESIGN CONSIDERATIONS

Waterpassage[1]	Maximum Velocity fps
Steel penstocks:	20
Power tunnels - lined:	15
Tailrace - lined:	15
- unlined:	10
Diversion tunnels - lined:	50

Notes:

(1) For tunnel-alternative schemes (tunnel length greater than 5 miles) optimize velocity with respect to cost of tunneling and energy loss in friction.

TABLE D.7 - PRELIMINARY FREEBOARD REQUIREMENT

Parameter	DAM TYPE: Rockfill/ Earthfill Dam	DAM TYPE: Concrete Dam
Design Conditions		
Dry freeboard - ft	3	3
Wave run up and wind set up - ft	6	6
Flood surcharge over full supply level (FSL) - ft	5	5
Allowance for post-construction settlement	1% dam height	nil
Total freeboard - ft	14'	14'
Dam crest level - ft	FSL + 14' + 1% dam height	FSL + 14'
Extreme Conditions for Checking Design		
Seismic slump[1]	1-1/2% of dam height	nil
PMF surcharge over FSL allowable	14'	14'

Notes:

(1) If seismic slump $\leq$14' design conditions fix dam crest level. If seismic slump >14' dam crest level = FSL + seismic slump $\pm$ 1 percent allowance for post-construction settlement.

TABLE D.8 - EXAMPLE CALCULATION OF FREEBOARD REQUIREMENT AT DEVIL CANYON

Parameter	DAM TYPE Rockfill Dam	DAM TYPE Concrete Dam
<u>Design Conditions</u>[1]		
Dry freeboard - ft	3	3
Wave run up and wind set up - ft	6	6
Flood surcharge - ft	5	5
Height of dam - ft	600	600
1% of height for post-construction settlement	6	nil
Dam crest level	1445 + 14 + 6 = 1465'	1445 + 14 = 1459'
<u>Extreme Conditions</u>		
Seismic slump (1-1/2%) - ft	9	nil
Seismic slump < 14 feet		
Thus, dam crest level remains the same as calculated above		
PMF condition Maximum allowble water level	1445 + 14 = 1459'	1445 + 14 = 1459'

Notes:

(1) Full supply level = 1445 ft; dam height = 600 ft

TABLE D.9 - ENERGINEERING LAYOUT CONSIDERATIONS AS SINGLE DEVELOPMENTS

	DAM SITE							
Components	Denali	Maclaren (1)	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Tunnel Alternatives
Dam	← Conventional earth/rockfill —						Concrete	Earth/rockfill
Spillway	← Service: Gated, open chute with downstream stilling basing →							
	← Emergency: (if required) as above with downstream flip bucket →							
Power Facilities								
Intake:	← Single level →		← Multilevel →					
Power Tunnel:	← Single concrete lined →		← Minimum of two, concrete lined —					Two partially lined tunnels (1/3 concrete lined, 1/3 shot-creted, 1/3 unlined)
Penstocks:	← Steel lining where necessary (near U.G. Powerhouse) (length = 1/5 turbine head) →							
Powerhouse:	← Underground if feasible →							
Tailrace Tunnel:	← One lined/unlined → (Lined or unlined - based on cost/energy loss optimization		← Two lined/unlined →					
Low Level Outlet Works Intake and Tunnel:	← One or two with gates - use diversion tunnel(s) if possible →							
Construction Facilities U/S & D/S Cofferdams:	← Earth or rockfill →						← Fill or cellular →	← Fill →
Diversion Tunnels:	← Minimum of two →							
Access Road Access:	← To Denali Highway →		← to Gold Creek →					
Transmission Line	← To Cantwell along Denali Highway →		← to Gold Creek →					
Local	← Roads/tunnels and bridges as required →							
Compensation Flow Outlet	← Independent intake with control valve discharghing through low level outlet works or independent conduit →							
Surge Chamber	← Upstream surge tank required if net head on machines < 1/6 of distance between reservoir and machine →							
	← Downstream surge tank is required if tailrace is pressurized →							
	← Size differential surge chambers for all locations where required →							

Notes:

(1) Portage Creek development will be similar to Maclaren except that access roads and transmission lines will be to Gold Creek.

TABLE D.10 - TENTATIVE ENVIRONMENTAL FLOW CONSTRAINTS

Site	Required Minimum Flow Release - cfs: With Project Located Downstream[1]	Required Minimum Flow Release - cfs: Without Project Located Downstream[1]	Maximum Allowable Flow for Daily Peaking Operations CFS[2]	Remarks
Denali	300	600	5,000	
Maclaren	600	1,200	6,500	
Vee	800	1,500	9,500	
Susitna III	800	1,500	9,500	
Watana	1,000	2,000	12,000	
High Devil Canyon	1,000	2,000	13,500	
Devil Canyon	1,000	2,000	14,000	
Alternative Tunnel Scheme	1,000		14,000	In the reach between re-reg. dam and tail-race outfall at Devil Canyon

Notes:

(1) Does not apply if downstream dam backs up to tailwater level of dam above.
(2) Would not necessarily apply if scheme considered did not include a substantial amount of seasonal regulation.

APPENDIX E - SUSITNA BASIN SCREENING MODEL

As discussed in Section 8, a screening model was developed for use in the selection of Susitna Basin sites for incorporation in the basin development plans. The purpose of this Appendix is to provide the required background information necessary to establish the validity and reasonableness of the screening model used to determine these optimum basin developments for the selection process. As in most models which try to optimize a desired product, the screening model is dependent upon the availability and detail of information used as input. The screening model is therefore only as good as the input estimates of cost, dam types, environmental criteria, and energy output and requirements. The use of the model should therefore be treated in a subjective manner appropriate to the quality of the input data used.

E.1 - Screening Model

The basic screening model is a useful tool, even when data bases are thought inadequate or incomplete. The usefulness of the model stems from its ability to reject alternatives that are obviously inferior to others and to rank all alternatives according to the information available. The net result is a reduction in the amount of analyses and investigations required to produce definitive conclusions as to selection or rejection of development alternatives.

Development selection is determined through mathematical programming techniques (optimization). The advantages of this technique are:

- Developments are never fully rejected from the list by the model;

- Comparisons of developments are based on the same objective function and imposed constraints. The decisions are based on a homogenous and consistent set of generated alternatives;

- Algorithms used to solve the objective function are mathematically proven and efficient;

- Sensitivity analyses are relatively simple to conduct.

The disadvantages of the technique are more operational or economic than philosophical in nature. The main program is large and expensive to run. However, costs can usually be reduced by making simplifying assumptions.

The program selected for Susitna Basin screening uses a simplified Mixed Integer Programming (MIP) Model. The MIP models are adaptions of classical Linear Programming Models with integer variables. Generally MIP models optimize (either minimize or maximize) a linear objective function which is subject to a set of constraints or linear irregularities. In some circumstances MIP models can optimize nonlinear objective functions but this is an unusual condition. The selection of this modeling approach to screen possible developments is based on the following observations:

- Many of the relationships between the model variables are linear or can be made piecewise linear;

- Mixed integer programming offers one of the fastest algorithms for solving optimization problems;

- Standard software for MIP is available;

- Mutually exclusive situations can be modelled through zero-one variables and logical constraints;

- Sensitivity analyses are usually part of the program;

- The MIP model is cheaper than other techniques;

- Operational procedures are user oriented; and

- The solving algorithms are reliable.

E.2 - Model Components

The model components consist of three basic sets: variables, constraints and objective function. In some cases, depending upon study type, a variable in one study will be a constraint in another. Consequently care is usually required to ensure that a reasonable set of variables and constraints are selected. The objective function is less open to the vagaries of study type but is subject to economic, social, environmental and political pressures.

(a) Variables

The variables of the model are the unknowns. Generally the variables can be divided into three groups:

- State variables which characterize the behavior of the system;
- Decision variables that express a result of a choice; and
- Logical variables used to set up relationships among the various decision variables.

No physical difference exists between state and decision variables, and in some, model cases are reversible. Each variable can be continuous or discrete (integer). In the model of the Susitna Basin, state variables are: seasonal reservoir storage variation, seasonal energy yield and spills. Decision variables are: sites (system configuration), reservoir capacity (dam heights), installed capacity, and discharges.

(b) Constraints

Constraints are relationships which limit the value of a variable, usually within a given range. Linear inequalities and bounds limiting one variable are the two types of constraint used in the MIP model. Linear inequalities can also be replaced by, or supplemented with, equations linking several variables to a limiting condition.

The constraints included in the Susitna Basin model are: reservoir water balance, maximum storage, power and energy equations, level of development (quantified by the total installed capacity), convexity of logical equations (Section E4) and logical conditions for mutually exclusive alternatives.

(c) Objective Function

The objective of the Susitna Basin studies as applied to this screening model is to minimize costs of the system.

E.3 - Application of the Screening Model

The assumptions used and the approach to the site screening process are discussed in Section 8 of this report. The results of the site screening process described in Section 8 indicate that the Susitna Basin development plan should incorporate a combination of several major dams and powerhouses located at one or more of the following sites:

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

In addition, sites at Watana and Denali are also recommended as candidates for supplementary upstream flow regulation.

The main criterion (objective function) in selecting the Susitna Basin development plans is economic (see Figure 8.1). Environmental considerations are incorporated into the assessment of the plans finally selected.

The computer model used selects the least cost basin development plan for a given total basin power and energy demand. In the selection the program determines the approximate dam height and installed capacity at each site. The model is provided with basic hydrologic data, dam volume-cost curves at all the sites, an indication of which sites are mutually exclusive and a total power demand required from the basin. It then performs a time period by time period energy simulation process for individual and group sites. In this process, the model systematically searches out the least cost system of reservoirs and selects installed capacities to meet the specified power and energy demand.

E.4 - Input Data

Input data to the model consists of the various variables and constraints required by the model to solve for the objective function. Input data to the model takes the following form.

(a) Streamflow

As noted in the discussion of the model characteristics, simplifying assumptions could be made to reduce the complexity of the model analysis. One such simplification is to divide streamflow into two periods, summer and winter. This assumption is reasonable for the Susitna River because of the nature of streamflows in the region.

Flows are specified for these two periods for thirty years at all dam sites except Devil Canyon, Vee, Maclaren and Denali. Streamflow records used are historical data collected at the four gaging stations in the Upper Susitna Basin, which have been extended where necessary to thirty years by correlation with the thirty year record at Gold Creek. The smaller dam sites at Devil Canyon, Vee, Maclaren and Denali, which have little or no overyear storage capability, utilize only two typical years of hydrology as input. These typical years correspond to a dry year (90 percent probability of exceedence) and an average year (50 percent probability of exceedence). Streamflow records used as input to the model are given in Tables E.1 to E.7.

(b) Site Characteristics

For each of the seven sites, storage capacity versus cost curves were developed based on engineering layouts presented in Section 8. Utilizing these layouts as a basis, the quantities for lower level dam heights were determined and used to estimate the costs associated with these lower levels. Figures E.1 to E.3 depict the curves used in the model runs. These curves also incorporate the cost of the appropriate generating equipment except for the Denali and Maclaren reservoirs which are treated solely as storage facilities.

(c) Basin Characteristics

Basin characteristics are inputed to the model to represent which sites are mutually exclusive; that is, those sites which cannot be developed without causing the elimination of another site. Mutually exclusive sites are given in Figure E.4.

(d) Power and Energy Demand

The model is supplied with a power and energy demand that is representative of the future load requirements of the Railbelt region. The total generation capacity required from the river basin and an associated annual plant factor has been used. The capacity and annual plant factor are used to determine the annual energy demand. The values used are discussed in Section E.5.

E.5 - Model Runs and Results

The review of the energy forecasts given in Section 5 reveals that between the earliest online date of the Susitna Project in 1993 and the end of the planning period in 2010, approximately 2210, 4210 and 9620 GWh of additional energy would be required for the low, medium and high energy forecasts respectively. Based on these energy projections, the screening model was run with the following total capacities and energy values:

- Run 1: 400 MW - 1750 GWh
- Run 2: 800 MW - 3500 GWh
- Run 3: 1200 MW - 5250 GWh
- Run 4: 1400 MW - 6150 GWh

For initial study purposes, the annual plant factor associated with all these combinations was assumed to be 50 percent.

The results of the four screening model runs are given in Table E.8. The three best solutions (optimal, first suboptimal and second suboptimal) from an economic point of view are presented only. The most important conclusions that can be drawn from these results are as follows:

- For energy requirements of up to 1750 GWh, the High Devil Canyon, Devil Canyon or the Watana sites individually provide the most economic energy. The difference between the costs shown on Table E.8 are around 10 percent which is similar to the accuracy that can be expected from the screening model;

- For energy requirements of between 1750 and 3500 GWh, the High Devil Canyon site is the most economic. Developments at Watana and Devil Canyon are 20 to 25 percent more costly;

- For energy requirements of between 3500 and 5250 GWh the combinations of either Watana and Devil Canyon or High Devil Canyon and Vee are the most economic. The High Devil/Susitna III combination is also competitive. Its cost exceeds the Watana/Devil Canyon option by 11 percent which is within the accuracy of the model;

- The total energy production capability of the Watana/Devil Canyon development is considerably larger than that of the High Devil Canyon/Vee development and is the only plan capable of meeting energy demands in the 6000 GWh range.

Of the seven sites available to the model for inclusion into plans of Susitna Basin development two were rejected and only one included in a second suboptimal solution. The rejected sites at Maclaren and Denali do not significantly impact the systems' energy capability and are relatively costly so were eliminated from the plans. Susitna III was rejected, except in the one case, due to high capital costs.

TABLE E. 1 - COMPUTED STREAMFLOW AT DEVIL CANYON

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
5758.2	2404.7	1342.5	951.3	735.7	670.0	802.2	10490.7	18468.6	21383.4	18820.6	7950.8
3652.0	1231.2	1030.8	905.7	767.5	697.1	1504.6	13218.5	19978.5	21575.9	18530.0	19799.1
5221.7	2539.0	1757.5	1483.7	943.2	828.2	878.5	4989.5	30014.2	24861.7	19647.2	13441.1
7517.6	3232.6	1550.4	999.6	745.6	766.7	1531.8	17758.3	25230.7	19184.0	19207.0	13928.4
5109.3	1921.3	1387.1	1224.2	929.7	729.4	1130.6	15286.0	23188.1	19154.1	24071.6	11579.1
4830.4	2506.8	1868.0	1649.1	1275.2	1023.6	1107.4	8390.1	28081.9	26212.8	24959.6	13989.2
4647.9	1788.6	1206.6	921.7	893.1	852.3	867.3	15979.0	31137.1	29212.0	22609.8	16495.8
5235.3	2773.8	1986.6	1583.2	1388.9	1105.4	1109.0	12473.6	28415.4	22109.6	19389.2	18029.0
7434.5	3590.4	2904.9	1792.0	1212.2	1085.7	1437.4	11849.2	24413.5	21763.1	21219.8	6988.8
4402.8	1999.8	1370.9	1316.9	1179.1	877.9	1119.9	13900.9	21537.7	23390.4	28594.4	15329.6
6060.7	2622.7	2011.5	1686.2	1340.2	1112.8	1217.8	14802.9	14709.8	21739.3	22066.1	18929.9
7170.9	2759.9	2436.6	2212.0	1593.6	1638.9	2405.4	16030.7	27069.3	22880.6	21164.4	12218.6
5459.4	2544.1	1978.7	1796.0	1413.4	1320.3	1613.4	12141.2	40679.7	24990.6	22241.8	14767.2
6307.7	2696.0	1896.0	1496.0	1387.4	938.4	810.9	17697.6	24094.1	32388.4	22720.5	11777.2
5998.3	2085.4	1387.1	978.0	900.2	663.8	696.5	4046.9	47816.4	21926.0	15585.8	8840.0
5744.0	2645.1	1160.8	925.3	828.8	866.9	1314.4	12267.1	24110.3	26195.7	19789.3	18234.2
6496.5	1907.8	1478.4	1278.7	1187.4	1187.4	1619.1	8734.0	30446.3	18536.2	20244.6	10844.3
3844.0	1457.9	1364.9	1357.9	1268.3	1089.1	1053.7	14435.5	27796.4	25081.2	30293.0	15728.2
4585.3	2203.5	1929.7	1851.2	1778.7	1778.7	1791.0	14982.4	29462.1	24871.0	16090.5	8225.9
3576.7	1531.8	836.3	686.6	681.8	769.6	1421.3	10429.9	14950.7	15651.2	8483.6	4795.5
2866.5	1145.7	810.0	756.9	708.7	721.8	1046.6	10721.6	17118.9	21142.2	18652.8	8443.5
4745.2	3081.8	2074.8	1318.8	943.6	866.8	986.2	3427.9	31031.0	22941.6	30315.9	13636.0
5537.0	2912.3	2312.6	2036.1	1836.4	1659.8	1565.5	19776.8	31929.8	21716.5	18654.1	11884.2
4638.6	2154.8	1387.0	1139.8	1128.6	955.0	986.7	7896.4	26392.6	17571.8	19478.1	8726.0
3491.4	1462.9	997.4	842.7	745.9	689.5	949.1	15004.6	16766.7	17790.0	15257.0	11370.1
3506.8	1619.4	1486.5	1408.8	1342.2	1271.9	1456.7	14036.5	30302.6	26188.0	17031.6	15154.7
7003.3	1853.0	1007.9	896.8	876.2	825.2	1261.2	11305.3	22813.6	18252.6	19297.7	6463.3
3552.4	2391.7	2147.5	1657.4	1469.7	1361.0	1509.8	11211.9	35606.7	21740.5	18371.2	11916.1
6936.3	3210.8	2371.4	1867.9	1525.0	1480.6	1597.1	11693.4	18416.8	20079.0	15326.5	8080.4
4502.3	2324.3	1549.4	1304.1	1203.6	1164.7	1402.8	13334.0	24052.4	27462.8	19106.7	10172.4

TABLE E. 2 - COMPUTED STREAMFLOW AT HIGH DEVIL CANYON

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
5675.8	2379.2	1328.8	940.5	728.3	662.0	792.5	10345.1	18307.0	21209.6	18669.2	7900.8
3624.0	1221.3	1020.9	898.0	760.0	691.0	1488.5	13094.0	19862.6	21433.9	18367.1	19593.3
5171.8	2509.7	1737.1	1467.1	935.1	820.8	872.6	4928.2	29677.6	24643.4	19465.4	13292.7
7419.8	3194.9	1529.1	985.3	735.0	759.1	1519.9	17542.3	24932.2	19038.9	19006.6	13736.7
5038.7	1895.7	1371.0	1213.4	919.6	722.1	1115.7	15001.1	22893.5	18981.9	23781.9	11387.6
4753.3	2470.7	1842.8	1628.4	1257.3	1012.7	1094.2	8257.4	27827.9	26020.4	24846.7	13946.2
4604.6	1772.7	1193.3	913.4	882.2	839.8	855.4	15738.9	30822.4	28943.6	22335.5	16233.8
5153.7	2734.3	1964.4	1566.5	1373.0	1091.8	1096.0	12291.3	28166.1	21938.1	19224.8	17776.0
7323.4	3538.4	2853.6	1767.3	1198.7	1076.8	1423.8	11699.1	24229.7	21603.5	21031.2	6908.6
4344.5	1978.4	1350.6	1298.2	1160.9	863.3	1101.3	13602.5	21283.1	23160.5	28225.1	15102.4
5989.6	2590.2	1984.6	1663.5	1324.2	1100.7	1206.1	14663.4	14592.6	21562.1	21848.4	18704.1
7081.9	2725.6	2399.8	2177.7	1570.7	1614.5	2370.4	15840.8	26729.2	22639.3	21030.7	12054.2
5394.2	2521.8	1961.4	1781.2	1401.0	1308.9	1601.0	12077.1	40309.6	24867.8	22055.0	14606.8
6248.3	2681.2	1881.2	1481.2	1371.3	952.5	808.2	17507.2	23821.8	32101.0	22584.9	11699.6
5934.0	2061.9	1371.8	968.0	890.8	656.8	689.6	4009.8	47421.6	21779.7	15463.8	8735.6
5665.9	2623.2	1153.6	920.4	824.4	862.2	1307.9	12163.9	23880.4	25960.8	19599.2	18074.8
6395.3	1880.6	1456.5	1261.4	1171.3	1171.3	1596.8	8603.8	30088.6	18347.1	20018.1	10715.0
3798.4	1437.6	1345.5	1337.6	1249.5	1073.3	1037.5	14286.3	27551.6	24835.6	29960.6	15565.0
4540.4	2182.1	1911.8	1832.7	1761.4	1761.4	1774.0	14811.3	29163.9	24649.7	15936.3	8141.5
3541.6	1517.7	829.7	681.2	675.9	762.9	1408.6	10341.3	14872.3	15587.1	8427.1	4753.0
2829.7	1135.8	802.0	747.4	700.3	714.0	1041.8	10627.5	16903.1	20925.3	18463.2	8346.7
4667.6	3035.3	2044.1	1301.2	930.5	855.0	972.5	3382.6	30759.7	22797.5	30088.2	13521.2
5492.7	2886.5	2284.5	2007.1	1809.0	1636.5	1544.9	19475.0	31572.6	21566.0	18563.3	11810.5
4611.8	2140.7	1375.8	1131.2	1118.5	948.5	980.9	7848.1	26191.5	17475.0	19362.1	8676.3
3456.9	1454.3	992.2	838.3	741.5	684.5	943.0	14836.7	16609.0	17645.7	15119.5	11244.4
3473.6	1607.9	1469.8	1393.5	1323.8	1253.6	1437.2	13848.9	30015.8	25969.1	16880.4	14989.7
6898.2	1833.0	997.4	885.8	865.6	814.6	1245.2	11117.5	22589.8	18154.4	19225.9	6403.7
3506.4	2354.8	2111.0	1632.9	1448.6	1341.1	1485.5	11002.2	35269.1	21579.1	18247.1	11812.7
6845.7	3165.9	2340.3	1844.9	1504.6	1462.8	1582.2	11636.8	18326.4	19944.6	15174.5	8005.2
4444.5	2294.1	1530.6	1290.8	1191.9	1159.7	1396.1	13257.5	23961.3	27260.3	18913.3	10087.0

TABLE E. 3 - COMPUTED STREAMFLOW AT WATANA

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
4719.9	2083.6	1168.9	815.1	641.7	569.1	680.1	8655.9	16432.1	19193.4	16913.6	7320.4
~~3299.1~~	~~1107.3~~	~~906.2~~	~~808.0~~	~~673.0~~	~~619.8~~	~~1302.2~~	~~11649.8~~	~~18517.9~~	~~19786.6~~	~~16478.0~~	~~17205.5~~
4592.9	2170.1	1501.0	1274.5	841.0	735.0	803.9	4216.5	25773.4	22110.9	17356.3	11571.0
6285.7	2756.8	1281.2	818.9	611.7	670.7	1382.0	15037.2	21469.8	17355.3	16681.6	11513.5
~~4218.9~~	~~1599.6~~	~~1183.8~~	~~1087.8~~	~~803.1~~	~~638.2~~	~~942.6~~	~~11696.8~~	~~19476.7~~	~~16983.6~~	~~20420.6~~	~~9165.5~~
3859.2	2051.1	1549.5	1388.3	1050.5	886.1	940.8	6718.1	24881.4	23787.9	23537.0	13447.8
4102.3	1588.1	1038.6	816.9	754.8	694.4	718.3	12953.3	27171.8	25831.3	19153.4	13194.4
~~4208.0~~	~~2276.6~~	~~1707.0~~	~~1373.0~~	~~1189.0~~	~~935.0~~	~~945.1~~	~~10176.2~~	~~25275.0~~	~~19948.9~~	~~17317.7~~	~~14841.1~~
6034.9	2935.9	2258.5	1480.6	1041.7	973.5	1265.4	9957.8	22097.8	19752.7	18843.4	5978.7
3668.0	1729.5	1115.1	1081.0	949.0	694.0	885.7	10140.6	18329.6	20493.1	23940.4	12466.9
~~5165.5~~	~~2213.5~~	~~1672.3~~	~~1400.4~~	~~1138.9~~	~~961.1~~	~~1069.9~~	~~13044.2~~	~~13233.4~~	~~19506.1~~	~~19323.1~~	~~16085.6~~
6049.3	2327.8	1973.2	1779.9	1304.8	1331.0	1965.0	13637.9	22784.1	19839.8	19480.2	10146.2
4637.6	2263.4	1760.4	1608.9	1257.4	1176.8	1457.4	11333.5	36017.1	23443.7	19887.1	12746.2
~~5560.1~~	~~2508.9~~	~~1708.9~~	~~1308.9~~	~~1184.7~~	~~883.6~~	~~776.6~~	~~15299.2~~	~~20663.4~~	~~28767.4~~	~~21011.4~~	~~10800.0~~
5187.1	1789.1	1194.7	852.0	781.6	575.2	609.2	3578.8	42841.9	20082.8	14048.2	7524.2
4759.4	2368.2	1070.3	863.0	772.7	807.3	1232.4	10966.0	21213.0	23235.9	17394.1	16225.6
~~5221.2~~	~~1565.3~~	~~1203.6~~	~~1060.4~~	~~984.7~~	~~984.7~~	~~1338.4~~	~~7094.1~~	~~25939.6~~	~~16153.5~~	~~17390.9~~	~~9214.1~~
3269.8	1202.2	1121.6	1102.2	1031.3	889.5	849.7	12555.5	24711.9	21987.3	26104.5	13672.9
4019.0	1934.3	1704.2	1617.6	1560.4	1560.4	1576.7	12826.7	25704.0	22082.8	14147.5	7163.6
~~3135.0~~	~~1354.9~~	~~753.9~~	~~619.2~~	~~607.5~~	~~686.0~~	~~1261.6~~	~~9313.7~~	~~13962.1~~	~~14843.5~~	~~7771.9~~	~~4260.0~~
2403.1	1020.9	709.3	636.2	602.1	624.1	986.4	9536.4	14399.0	18410.1	16263.8	7224.1
3768.0	2496.4	1687.4	1097.1	777.4	717.1	813.7	2857.2	27612.8	21126.4	27446.6	12188.9
~~4979.1~~	~~2587.0~~	~~1957.4~~	~~1670.9~~	~~1491.4~~	~~1366.0~~	~~1305.4~~	~~15973.1~~	~~27429.3~~	~~19820.3~~	~~17509.5~~	~~10955.7~~
4301.2	1977.9	1246.5	1031.5	1000.2	873.9	914.1	7287.0	23859.3	16351.1	18016.7	8099.7
3056.5	1354.7	931.6	786.4	689.9	627.3	871.9	12889.0	14780.6	15971.9	13523.7	9786.2
~~3088.8~~	~~1474.4~~	~~1276.7~~	~~1215.8~~	~~1110.3~~	~~1041.4~~	~~1211.2~~	~~11672.2~~	~~26689.2~~	~~23430.4~~	~~15126.6~~	~~13075.3~~
5679.1	1601.1	876.2	757.8	743.2	690.7	1059.8	8938.8	19994.0	17015.3	18393.5	5711.5
2973.5	1926.7	1687.5	1348.7	1202.9	1110.8	1203.4	8569.4	31352.8	19707.3	16807.3	10613.1
~~5793.9~~	~~2645.3~~	~~1979.7~~	~~1577.9~~	~~1267.7~~	~~1256.7~~	~~1408.4~~	~~11231.5~~	~~17277.2~~	~~18385.2~~	~~13412.1~~	~~7132.6~~
3773.9	1944.9	1312.6	1136.8	1055.4	1101.2	1317.9	12369.3	22904.8	24911.7	16670.7	9096.7

TABLE E. 4 - COMPUTED STREAMFLOW AT SUSITNA 3

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
~~3137.7~~	~~1594.5~~	~~904.3~~	~~607.5~~	~~498.3~~	~~415.4~~	~~494.0~~	~~5860.1~~	~~13328.9~~	~~15856.4~~	~~14007.7~~	~~6359.8~~
2761.4	918.5	716.3	659.1	529.0	502.1	993.8	9259.4	16292.1	17060.0	13351.1	13253.3
3634.8	1607.9	1110.2	955.6	685.2	592.9	690.2	3038.5	19311.4	17919.1	13865.3	8721.4
~~4408.5~~	~~2031.6~~	~~871.0~~	~~543.5~~	~~407.6~~	~~524.5~~	~~1153.8~~	~~10890.7~~	~~15739.0~~	~~14568.7~~	~~12833.3~~	~~7833.7~~
2862.1	1109.4	874.1	880.0	610.2	499.4	656.3	6227.6	13821.2	13676.0	14857.0	5487.7
2379.1	1356.7	1064.1	990.8	708.1	676.6	686.9	4170.3	20004.4	20092.8	21369.2	12622.8
~~3270.9~~	~~1282.7~~	~~782.5~~	~~657.1~~	~~544.0~~	~~453.8~~	~~491.4~~	~~8342.6~~	~~21129.4~~	~~20679.8~~	~~13886.5~~	~~8163.5~~
2642.6	1519.0	1280.8	1052.6	884.3	675.4	695.4	6675.3	20489.7	16656.5	14161.2	9983.4
3902.2	1938.5	1273.5	1006.0	781.8	802.6	1003.3	7075.7	18569.2	16689.2	15222.2	4439.4
~~2548.4~~	~~1317.5~~	~~725.3~~	~~721.5~~	~~598.2~~	~~413.8~~	~~528.8~~	~~4410.5~~	~~13441.0~~	~~16078.2~~	~~16848.6~~	~~8104.7~~
3801.4	1590.0	1155.3	964.9	832.2	730.1	844.6	10364.3	10983.7	16103.2	15143.3	11751.6
4340.1	1669.3	1267.0	1121.5	864.9	861.8	1294.0	9991.8	16254.2	15206.1	16913.9	6988.2
~~3385.4~~	~~1835.6~~	~~1427.7~~	~~1323.8~~	~~1019.8~~	~~958.2~~	~~1219.8~~	~~10102.6~~	~~28912.2~~	~~21086.4~~	~~16299.0~~	~~9666.6~~
4420.9	2223.8	1423.8	1023.8	875.7	769.5	724.4	11644.6	15435.6	23249.8	18407.0	9311.1
3951.0	1337.6	901.4	660.0	601.0	440.2	476.1	2865.4	35261.7	17274.1	11705.2	5519.1
~~3259.0~~	~~1946.2~~	~~932.5~~	~~767.9~~	~~687.1~~	~~716.6~~	~~1107.4~~	~~8983.2~~	~~16797.9~~	~~18725.8~~	~~13744.2~~	~~13165.0~~
3277.9	1043.5	784.9	727.7	675.7	675.7	910.6	4595.2	19072.3	12522.6	13042.4	6730.0
2394.9	812.5	750.9	712.5	670.1	585.3	538.9	9690.7	20011.7	17272.9	19721.9	10541.0
~~3155.9~~	~~1524.2~~	~~1360.6~~	~~1261.7~~	~~1227.7~~	~~1227.7~~	~~1250.2~~	~~9541.7~~	~~19977.2~~	~~17834.1~~	~~11186.7~~	~~5544.9~~
2462.1	1085.5	628.5	516.6	494.4	558.6	1018.3	7612.7	12455.5	13612.6	6687.4	3444.0
1696.9	830.8	555.8	452.3	439.5	475.4	894.6	7730.5	10254.4	14246.9	12623.4	5365.9
~~2279.1~~	~~1604.3~~	~~1097.2~~	~~759.2~~	~~524.1~~	~~489.0~~	~~550.9~~	~~1987.5~~	~~22404.1~~	~~18360.5~~	~~23074.4~~	~~9983.8~~
4128.9	2091.3	1416.1	1114.4	965.8	918.3	909.0	10177.0	20571.5	16930.8	15765.3	9540.9
3787.1	1708.5	1032.4	866.4	804.5	750.4	803.5	6358.4	19999.0	14491.0	15789.9	7145.3
~~2393.7~~	~~1189.7~~	~~831.4~~	~~700.6~~	~~604.6~~	~~532.6~~	~~754.3~~	~~9665.2~~	~~11754.3~~	~~13201.5~~	~~10882.5~~	~~7372.7~~
2451.8	1253.4	957.1	921.8	757.0	690.1	837.3	8069.4	21183.0	19228.4	12223.6	9906.6
3661.3	1217.2	675.6	546.0	540.7	485.6	733.1	5332.7	15697.4	15129.9	17015.6	4566.0
~~2091.3~~	~~1218.1~~	~~986.6~~	~~878.1~~	~~796.2~~	~~729.6~~	~~736.6~~	~~4542.7~~	~~24870.7~~	~~16609.2~~	~~14424.3~~	~~8627.7~~
4053.2	1783.5	1382.8	1135.9	875.5	915.4	1120.8	10527.7	15540.5	15804.2	10494.9	5688.4
2664.0	1366.9	951.8	881.8	829.4	1004.4	1188.5	10899.3	21155.9	21024.3	12958.6	7457.5

TABLE E. 5 - COMPUTED STREAMFLOW AT VEE

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
3005.9	1553.7	882.3	590.2	486.4	402.6	478.5	5627.1	13070.3	15578.3	13765.5	6279.8
2716.6	902.8	700.5	646.7	517.0	492.3	968.1	9060.2	16106.6	16832.8	13090.5	12924.0
3555.0	1561.0	1077.6	929.0	672.2	581.1	680.7	2940.3	18772.9	17569.8	13574.4	8483.9
4252.1	1971.2	836.8	520.6	390.6	512.3	1134.8	10545.2	15261.4	14336.5	12512.6	7527.0
2749.0	1068.5	848.3	862.7	594.1	487.8	632.4	5771.8	13349.9	13400.4	14393.4	5181.2
2255.8	1298.8	1023.7	957.7	679.6	659.1	665.7	3958.0	19598.0	19784.9	21188.5	12554.0
3201.6	1257.2	761.2	643.8	526.4	433.8	472.5	7958.4	20625.9	20250.5	13447.6	7744.3
2512.1	1455.9	1245.3	1025.9	858.9	653.8	674.6	6383.6	20090.9	16382.1	13898.2	9578.6
3724.5	1855.4	1191.4	966.5	760.1	788.4	981.5	6835.5	18275.1	16433.9	14920.4	4311.1
2455.1	1283.2	692.8	691.5	569.0	390.5	499.1	3933.0	13033.6	15710.3	16257.6	7741.2
3687.7	1538.0	1112.2	928.6	806.6	710.8	825.8	10141.0	10796.2	15819.6	14795.0	11390.4
4197.7	1614.4	1208.2	1066.6	828.2	822.7	1238.1	9688.0	15710.0	14820.0	16700.0	6725.0
3281.0	1800.0	1400.0	1300.0	1000.0	940.0	1200.0	10000.0	28320.1	20890.0	16000.0	9410.0
4326.0	2200.0	1400.0	1000.0	850.0	760.0	720.0	11340.0	15000.0	22790.0	18190.0	9187.0
3848.0	1300.0	877.0	644.0	586.0	429.0	465.0	2806.0	34630.0	17040.0	11510.0	5352.0
3134.0	1911.0	921.0	760.0	680.0	709.0	1097.0	8818.0	16430.0	18350.0	13440.0	12910.0
3116.0	1000.0	750.0	700.0	650.0	650.0	875.0	4387.0	18500.0	12220.0	12680.0	6523.0
2322.0	780.0	720.0	680.0	640.0	560.0	513.0	9452.0	19620.0	16880.0	19190.0	10280.0
3084.0	1490.0	1332.0	1232.0	1200.0	1200.0	1223.0	9268.0	19500.0	17480.0	10940.0	5410.0
2406.0	1063.0	618.0	508.0	485.0	548.0	998.0	7471.0	12330.0	13510.0	6597.0	3376.0
1638.0	815.0	543.0	437.0	426.0	463.0	887.0	7580.0	9909.0	13900.0	12320.0	5211.0
2155.0	1530.0	1048.0	731.0	503.0	470.0	529.0	1915.0	21970.0	18130.0	22710.0	9800.0
4058.0	2050.0	1371.0	1068.0	922.0	881.0	876.0	9694.0	20000.0	16690.0	15620.0	9423.0
3744.3	1686.0	1014.6	852.6	788.2	740.1	794.3	6281.0	19677.3	14336.0	15604.3	7065.8
2338.5	1176.0	823.0	693.5	597.5	524.7	744.5	9396.5	11502.1	12970.6	10662.4	7171.6
2398.7	1235.0	930.5	897.3	727.6	660.8	806.1	7769.2	20724.2	18878.2	11981.7	9642.5
3493.1	1185.2	658.9	528.4	523.8	468.5	727.5	5032.2	15339.4	14972.8	16900.8	4470.5
2017.8	1159.1	928.2	838.9	762.3	697.8	697.7	4207.1	24330.5	16351.0	14225.7	8462.2
3908.1	1711.7	1333.1	1099.1	842.8	887.0	1096.8	10469.1	15395.8	15589.1	10251.8	5568.0
2571.5	1318.7	921.7	860.6	810.6	996.3	1177.7	10776.8	21010.2	20700.3	12649.3	7320.9

TABLE E. 6 - COMPUTED STREAMFLOW AT MACLAREN

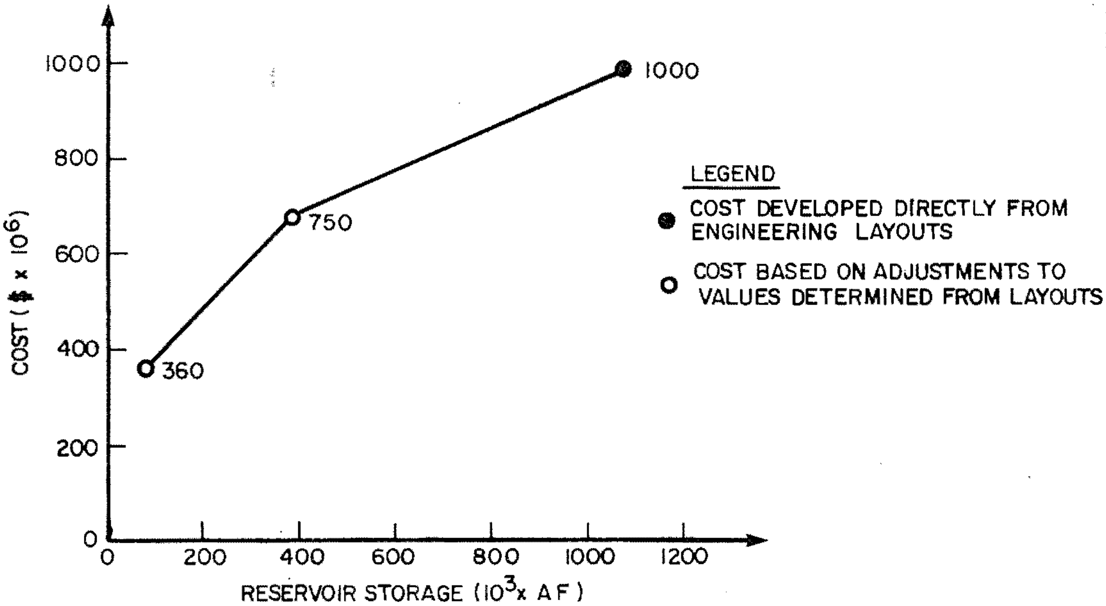
OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1851.5	930.0	557.2	340.3	308.0	229.9	296.0	3345.8	8595.6	11824.2	9947.8	3932.9
1579.9	529.7	408.8	348.9	279.7	276.2	566.3	5420.9	10605.6	12631.5	9898.4	8174.3
2043.6	845.0	583.8	544.9	436.3	384.7	441.3	2224.2	12442.8	13272.1	10301.1	5261.9
2392.9	1158.0	490.4	326.4	240.8	288.2	705.7	7047.4	11176.5	11218.7	9206.1	4547.9
1778.3	620.8	483.7	532.7	363.1	307.0	368.5	3616.3	8975.5	10546.4	10528.9	3368.0
1408.2	818.3	562.2	532.8	370.2	379.6	390.1	2753.9	13038.6	13381.9	15813.8	8225.5
1961.5	709.6	454.1	416.2	285.3	263.4	289.2	6372.9	18316.8	16750.4	13544.8	6560.6
1932.0	1040.5	783.2	576.9	484.6	359.4	436.9	4708.5	15590.9	13406.0	11540.4	6402.9
2327.0	1144.3	675.6	539.7	411.7	406.7	541.0	3596.5	12617.6	12274.8	10132.9	2922.4
1589.4	773.2	394.3	364.6	290.4	191.3	238.7	2704.8	10668.2	11497.9	11475.1	4747.3
2482.5	1093.8	805.5	651.9	529.3	462.0	505.6	6262.8	7621.9	11947.9	10863.7	7637.0
2817.8	1069.4	794.1	646.6	510.0	513.4	768.1	5845.7	10400.8	10970.3	11305.8	4423.9
2144.1	1160.5	851.8	717.6	566.0	528.9	674.7	5544.5	17338.0	14797.4	12262.2	6120.5
2472.0	1235.0	777.6	571.8	496.0	440.2	428.8	6722.3	10296.7	15772.4	13633.4	6196.1
2179.0	723.3	481.9	356.2	331.3	246.9	273.7	1723.4	21497.0	11636.6	8679.0	3799.5
2182.7	1220.7	554.4	451.7	405.9	422.9	653.3	5189.9	9701.9	11729.8	9057.0	9509.7
1862.1	600.3	458.8	420.2	393.1	393.1	535.3	2812.2	11847.9	9974.3	9112.4	4625.6
1891.8	637.5	504.2	485.6	411.5	430.0	362.0	6395.0	13647.0	13610.8	13784.5	6087.5
2256.2	926.3	771.4	674.9	694.7	708.5	648.9	4428.6	12364.3	14259.6	10303.3	3572.5
1431.9	629.6	363.3	300.7	288.0	317.9	558.9	4214.6	9940.9	11188.9	5067.9	2711.9
1274.8	635.7	426.5	338.8	308.9	308.8	562.7	4513.7	7113.4	10790.3	8834.6	3346.7
1226.0	881.9	607.2	410.7	287.2	270.1	304.0	1180.7	14049.7	13721.9	15681.0	6081.6
2334.2	1152.4	805.1	651.7	570.8	541.3	530.0	6139.0	12326.9	13127.0	11648.1	5628.7
1987.2	907.7	555.7	467.4	431.8	404.9	428.1	3289.5	11719.7	10915.7	10844.3	4427.3
1503.4	768.3	562.1	474.5	411.1	359.3	469.0	5482.0	8156.0	11015.7	9879.9	6189.7
2248.1	914.1	616.7	556.2	426.3	397.7	460.0	4269.4	12910.5	15013.6	9305.6	6175.7
2377.3	722.6	379.2	290.6	280.1	252.4	382.3	3189.5	9971.8	11309.9	13006.1	2958.2
1376.1	763.9	587.2	511.8	464.1	431.3	439.8	2660.2	15150.2	12730.3	11915.6	5747.0
2332.1	1106.6	822.6	670.2	532.9	521.0	620.7	5650.9	9602.5	11822.7	9333.7	4456.8
1597.1	830.1	573.6	519.4	478.5	543.3	648.0	6216.9	13381.5	14307.2	10667.2	5717.0

TABLE E. 7 - COMPUTED STREAMFLOW AT DENALI

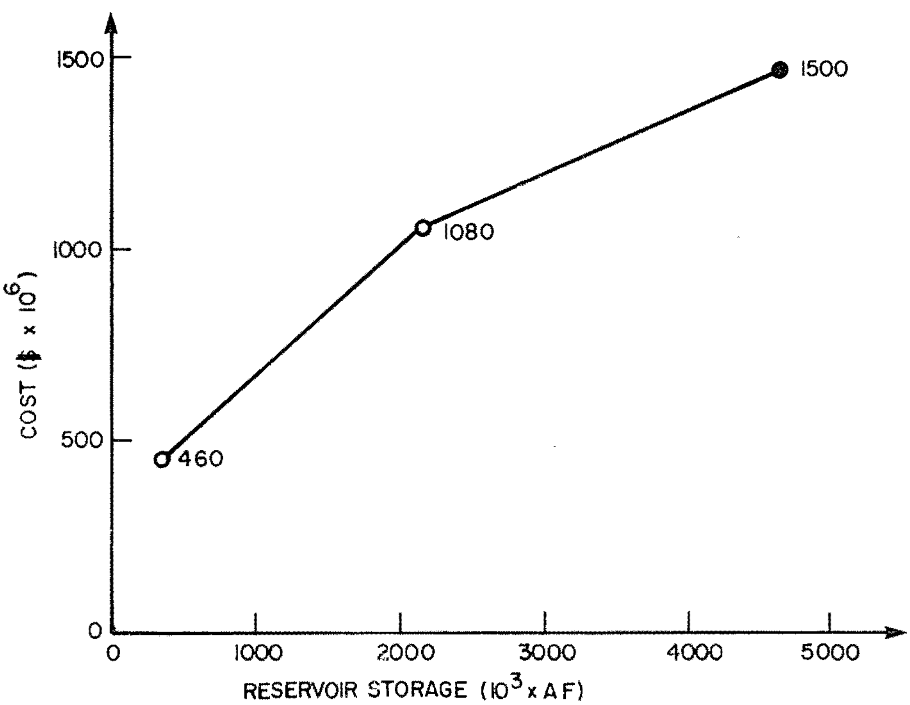
OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1493.5	618.9	398.2	219.4	220.1	149.6	218.8	2531.9	6232.7	10078.0	8015.0	2478.8
899.0	310.2	250.8	173.1	147.9	151.8	363.7	3456.3	7189.2	10352.8	8506.8	5878.0
1216.4	488.0	338.6	359.1	309.3	282.9	298.1	2065.4	9767.3	11392.7	8965.7	3758.5
1600.3	780.5	362.2	269.1	193.9	166.9	456.8	5754.4	9952.4	9773.4	7960.8	3494.4
1485.8	442.3	309.4	351.6	251.6	215.9	262.5	3757.7	7509.7	9467.0	9416.6	3189.8
1247.9	680.9	371.8	341.6	248.0	237.1	264.7	2669.5	9680.5	9760.9	12473.6	5239.0
1297.5	396.4	305.7	296.6	172.0	212.7	224.6	6666.0	18527.2	15779.2	15313.5	7290.9
2000.2	972.3	573.3	342.6	301.4	221.9	338.7	4577.1	13750.6	12230.0	10785.2	5580.9
1963.6	931.1	605.1	371.8	233.7	175.0	294.4	2090.9	9503.0	10136.3	7701.8	2374.6
1299.5	522.6	295.5	234.7	193.9	131.9	157.9	3626.7	10464.8	9754.3	10165.1	3902.4
2016.2	960.7	741.4	584.2	419.7	349.4	337.6	4211.8	5961.3	10134.5	9255.6	6212.3
2331.2	872.0	710.3	543.0	412.6	432.1	631.0	4132.8	8514.2	9569.8	8079.2	3711.7
1693.2	817.7	547.1	371.8	316.5	290.4	356.5	2593.3	11374.3	10978.9	10609.2	4640.4
1445.7	601.8	401.8	341.8	329.5	236.7	226.8	4429.6	8446.0	12276.3	11048.4	4428.3
1323.0	435.4	279.4	201.8	198.1	153.5	172.8	1139.7	14070.3	8481.2	7306.3	3278.5
1951.0	837.9	323.4	250.6	227.5	237.2	360.2	3102.3	6068.4	8208.0	6939.0	7940.3
1545.6	468.0	374.8	317.1	299.5	299.5	417.7	2433.5	9060.8	9455.9	7832.0	3999.7
1850.3	655.9	461.4	465.1	356.1	430.2	348.6	5020.6	10672.6	12672.4	11778.1	3946.0
1912.1	634.8	460.8	371.0	422.1	446.4	322.7	1850.2	8846.9	13207.8	10778.2	2713.1
916.6	390.8	212.4	178.0	176.4	186.0	307.3	2315.6	8631.0	9841.3	4268.1	2475.7
1229.4	562.2	388.4	324.2	273.3	240.9	348.5	2791.4	6347.3	9794.3	7388.0	2544.2
1007.3	682.2	466.0	278.8	206.5	193.4	219.6	909.0	9775.9	11300.5	11807.6	3997.9
1312.7	637.6	554.3	518.2	476.2	430.1	397.6	5334.0	8769.8	11380.2	9225.5	3233.5
832.5	409.8	279.9	231.2	227.0	192.8	188.6	1341.0	6983.8	8944.8	7984.9	2752.3
1089.4	515.1	398.3	337.6	298.5	265.5	299.9	3578.9	6616.3	10438.9	10142.3	6229.0
2340.1	744.1	483.9	394.7	313.7	313.1	320.4	2799.9	8812.6	13462.8	8229.6	4591.1
2188.6	498.6	233.6	180.2	162.2	156.0	221.8	2965.9	7322.2	9165.0	10523.6	2190.8
1178.0	695.1	556.6	417.5	370.9	353.7	396.3	2794.4	10339.8	11007.4	10947.2	4346.2
1708.4	929.4	631.2	490.3	426.3	355.9	355.6	2257.6	5809.1	9823.9	9583.1	4087.0
1222.3	649.1	428.2	345.1	301.7	234.2	291.7	3264.3	8213.0	10755.5	10373.0	5039.7

TABLE E.8 - RESULTS OF SCREENING MODEL

	Total Demand		Optimal Solution				First Suboptimal Solution				Second Suboptimal Soultion			
Run	Cap. MW	Energy GWh	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $\$ \times 10^6$	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $\$ \times 10^6$	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $\$ \times 10^6$
1	400	1750	High Devil Canyon	1580	400	885	Devil Canyon	1450	400	970	Watana	1950	400	980
2	800	3500	High Devil Canyon	1750	800	1500	Watana	1900	450	1130	Watana	2200	800	1860
							Devil Canyon	1250	350	710				
							TOTAL		800	1840				
3	1200	5250	Watana	2110	700	1690	High Devil Canyon	1750	800	1500	High Devil Canyon	1750	820	1500
			Devil Canyon	1350	500	800	Vee	2350	400	1060	Susitna III	2300	380	1260
			TOTAL		1200	2490	TOTAL		1200	2560	TOTAL		1200	2760
4	1400	6150	Watana	2150	740	1770	N O S O L U T I O N				N O S O L U T I O N			
			Devil Canyon	1450	660	1000								



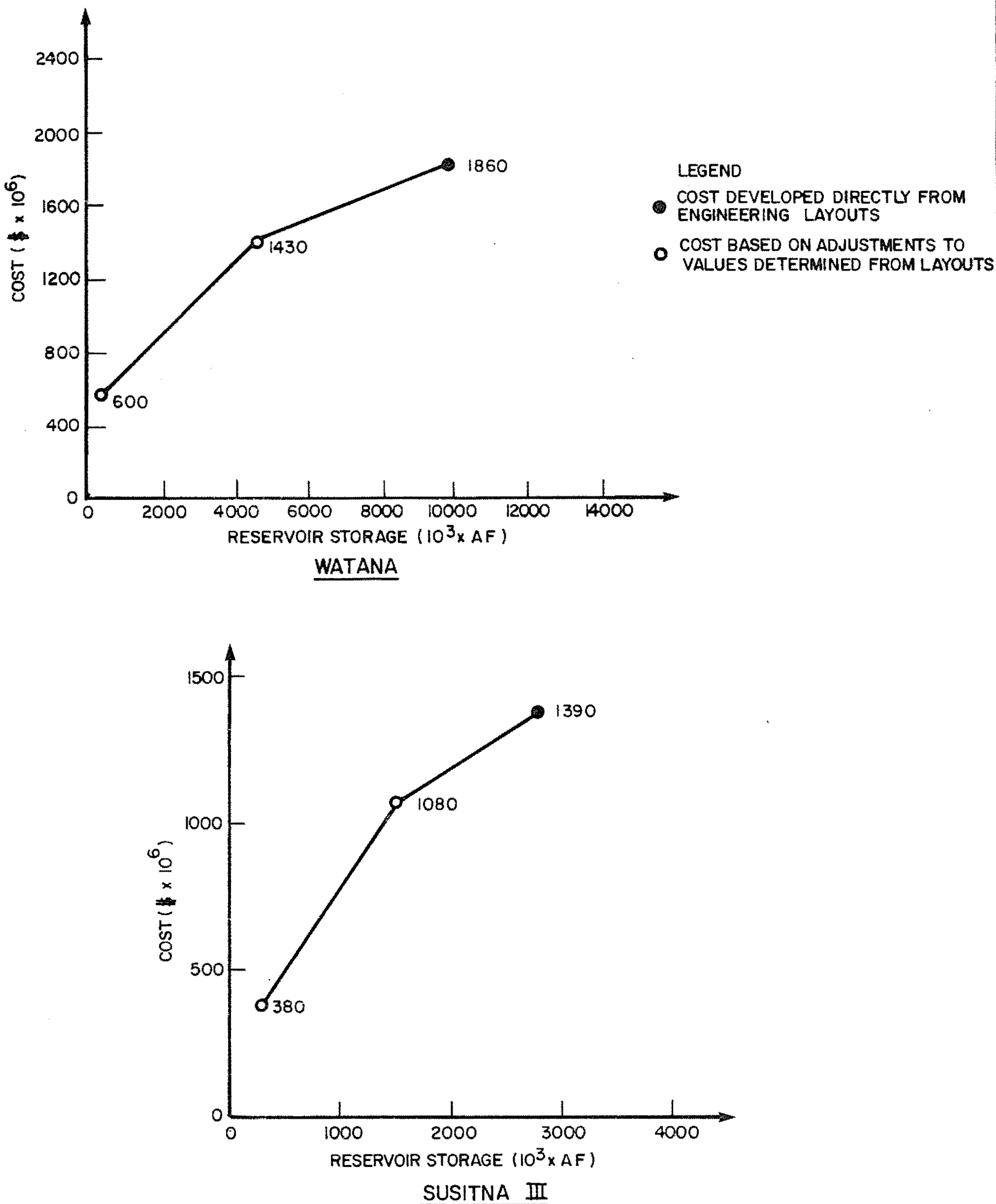
DEVIL CANYON



HIGH DEVIL CANYON

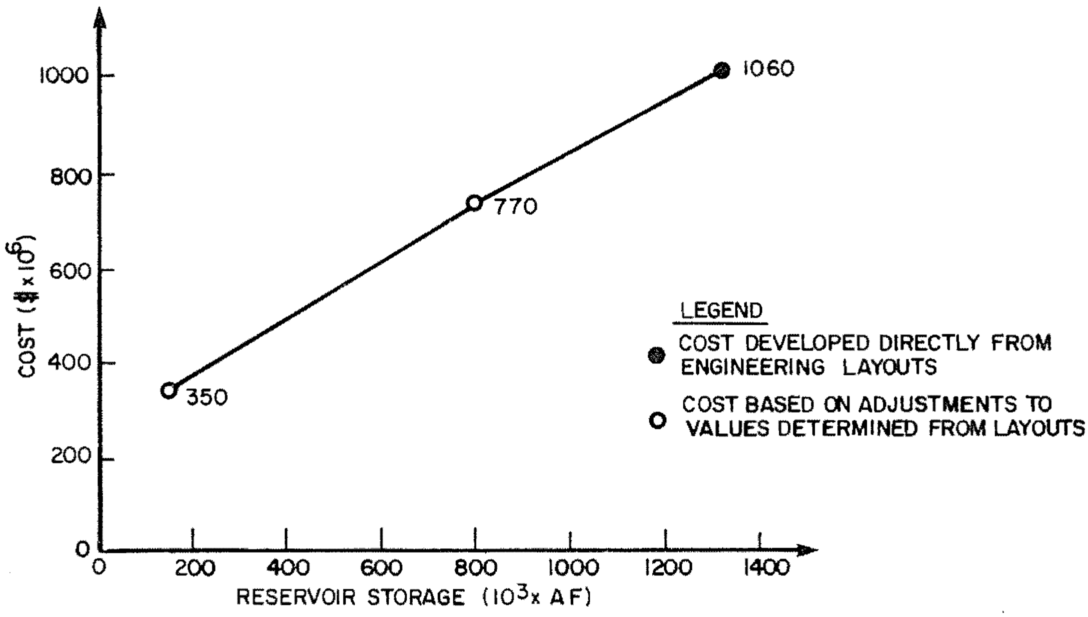
DAMSITE COST VS RESERVOIR STORAGE CURVES

FIGURE E.1

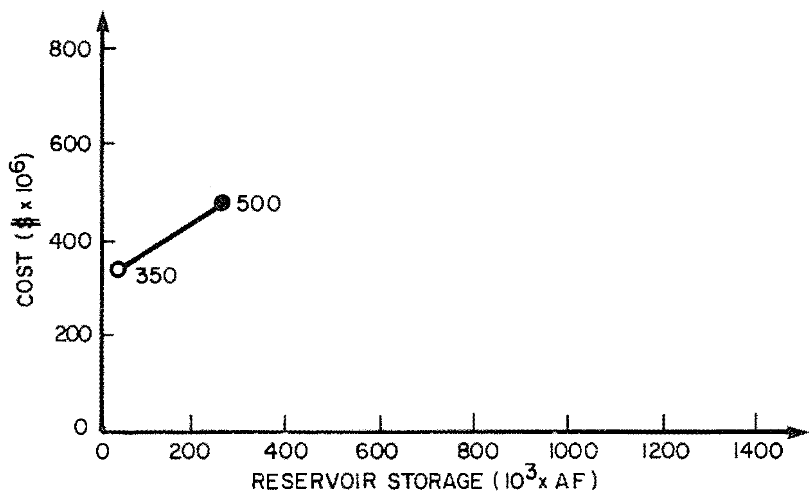


DAMSITE COST VS RESERVOIR STORAGE CURVES

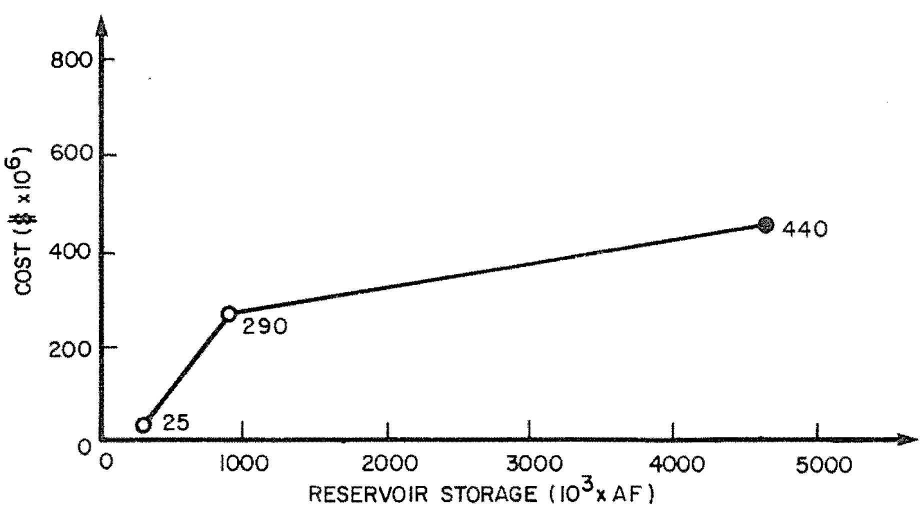
FIGURE E.2



VEE



MACLAREN



DENALI

DAMSITE COST VS RESERVOIR STORAGE CURVES

FIGURE E.3

ACRES

	GOLD CREEK	OLSON	DEVIL CANYON	HIGH DEVIL CANYON	DEVIL CREEK	WATANA	SUSITNA III	VEE	MACLAREN	DENALI	BUTTE CREEK	TYONE
GOLD CREEK												
OLSON			890 (30)									
DEVIL CANYON				1030 (160)	1070 (200)							
HIGH DEVIL CANYON						1465 (445)						
DEVIL CREEK						1465 (405)						
WATANA							1810 (355)	1925 (470)				
SUSITNA III								1925 (125)	2320 (520)			
VEE									2320 (405)			
MACLAREN												
DENALI												
BUTTE CREEK												
TYONE												

LEGEND

COMPATIBLE ALTERNATIVES

MUTUALLY EXCLUSIVE ALTERNATIVES

1465 (405) — DAM IN COLUMN IS MUTUALLY EXCLUSIVE IF FULL SUPPLY LEVEL OF DAM IN ROW EXCEEDS THIS VALUE - FT.

VALUE IN BRACKET REFERS TO APPROXIMATE DAM HEIGHT.

MUTUALLY EXCLUSIVE DEVELOPMENT ALTERNATIVES

FIGURE E.4

APPENDIX F - SINGLE AND MULTI-RESERVOIR HYDROPOWER SIMULATION STUDIES

The economic comparisons of various Susitna Basin dam sites described in Section 8, both individually and in combination, were accomplished to a large extent through simulation of energy availability from a given development. The purpose of this Appendix is to describe the two computer models which were used to simulate energy yields according to the storage and hydrology available at the various dam sites.

F.1 - Introduction

The reservoir simulation models determine the energy yield from the Susitna developments given using inflow data for the thirty year period from 1949 to 1979, the installed capacity at each hydro plant and a specified annual energy demand pattern and plant factor. The total energy supplied by Susitna was assumed to be a fraction of the forecast electrical system demand for the Railbelt region as discussed in Section 5. The monthly distribution of the generated energy is assumed to be equal to the monthly peak load multiplied by the load factor in that month.

Environmental constraints incorporated into the model include a maximum seasonal reservoir level fluctuation, a maximum daily reservoir fluctuation and a minimum downstream flow requirement. These constraints are preliminary at this stage and are only used to provide consistency between energy estimates at the respective dam sites.

F.2 - Single Reservoir Model

(a) Energy Demand

The simulation model is driven by an energy demand curve and will attempt to meet this demand in each month. A deficit is noted when the demand is not met and a failure of the system is recorded. If the number of failures in the study period is excessive, the energy demand is too high for the system and another simulation must be made with a lower energy demand. This process is repeated until deficits are recorded in none or in only one year of the simulation.

(b) Utilization of Monthly Inflow

The average monthly inflow in any month is utilized as follows in order of priority:

- Powerhouse flow to meet demand;
- Fill reservoir;
- Generate secondary energy; and
- Spill.

If inflow is inadequate to meet demand energy under constant head conditions, then storage from the reservoir is used to supplement the inflow and the reservoir is drawn down. Conversely, if available inflow exceeds power demand needs, the reservoir storage is replenished by any surplus inflow.

(c) Actions at Reservoir Boundary Conditions

Under boundary conditions of either minimum reservoir level or maximum reservoir level, the following actions are taken:

(i) Minimum Reservoir Level

Turbine discharge is assumed equal to inflow plus the storage available to reduce the reservoir to the minimum level at the end of the month. If discharge is inadequate to meet the energy demand, a failure is recorded.

(ii) Maximum Reservoir Level

When the reservoir is full, the total capacity of the plant is theoretically available if the inflow is adequate. Consequently, the discharge is set equal to the inflow except when the inflow exceeds the installed capacity. In this case, the discharge equals the plant capacity and the surplus water is spilled. Energy generated above demand is designated as secondary energy.

(d) Simulation Procedure

(i) Monthly Simulation

The model computes the discharge that will give the energy demand for the head available. If reservoir storage is depleted or replenished, an iterative process is used to determine the combination discharge flow and head necessary to meet demand. For these preliminary studies it has been assumed that if the energy generated is within 5 percent of energy demand for single reservoir and 1 percent for multi-reservoir, the result has converged sufficiently.

As noted earlier, a deficit is noted when energy generated does not meet energy demand. Because of the nature of this system, a deficit can only occur when the reservoir is drawn down to the specified minimum level. However, energy is generated since the powerhouse flow is assumed equal to inflow, giving no change in reservoir level.

(ii) Daily Simulation

The monthly simulation has superimposed on it a daily requirement due to peaking operation. The operation has been divided into base load capacity, peaking capacity and secondary capacity. The peaking capacity has been assumed to be needed for 10 hours.

Baseload capacity and peaking capacity are determined so that the sum of each daily generation for any month equals the energy determined in the monthly simulation. In effect, monthly peaking capacity is equal to the ratio of monthly peak to annual peak given in Figure F.1 multiplied by the nominal installed capacity. Baseload capacity is variable and determined to produce the necessary energy to make the daily operation consistent with monthly energy values. Secondary capacity is only used when the reservoir is full and would have to spill. Secondary energy is assumed to be generated for 24 hours by the difference in installed capacity and the sum of base load and peaking capacities. Secondary energy can also be produced during the off peak period by the capacity difference between installed capacity and base load capacity.

A lower limit on baseload powerhouse flow is the constraint of minimum downstream flow which must always be met except when necessary to violate the minimum reservoir level boundary. If baseload powerhouse flows have to be set equal to downstream flow requirements, then peaking period powerhouse flows must be reduced to maintain the monthly energy balance. A peaking capacity deficit is therefore produced and this event is recorded and printed.

F.3 - Multi-Reservoir Simulation

The multi-reservoir simulation follows the same operating rules as the single reservoir program except that the energy demand in a particular month is allocated to each hydropower plant according to the reservoir status in that month. This allocation rule prevents the storage of water in one reservoir when another reservoir is being drawn down. The allocation of the energy demand between reservoirs is given by:

$$E_{ij} = E_j \frac{H_{ij}}{H_{ij}}$$

where: E_j = the energy demand in month j

E_{ij} = the fraction of the energy demand in month j allocated to the hydropower plant i

H_{ij} = the net head in month j of the hydropower plant i

H_{ij} = the total head of the cascade in month j

After this allocation, the single reservoir operating rules are applied for every hydropower plant. The reservoir is checked for its final status solving the same nonlinear system of inequalities iteratively for every month of the simulation period.

F.4 - Annual Demand Factor

An annual demand factor is initially specified to enable an estimate of the monthly energy demand to be made for a given installed capacity and monthly peak to annual peak ratios. The intention of this demand factor is to allow easy adjustment to the energy demand curve which drives the simulation program.

Adjustment of the specified installed capacity would also adjust the energy demand curve if the demand factor was held constant. Consequently, the demand factor used coupled with installed capacity must be considered only as a means of determining the energy demand that can be supplied by a given hydropower system. Environmental constraints and hydrology (shortages and surpluses) lead to an actual plant factor which is slightly different than the nominal demand factor specified to determine demand.

F.5 - Input to Simulation Models

Input to the simulation models has been determined from existing definitive studies of the Susitna Basin hydro potential and from published and unpublished USGS records. Input to the model can be classed under three main categories: reservoir and power generation facility description, energy demand curve and inflow records.

(a) Reservoir and Power Generation Facilities

(i) Reservoir Storage - Elevation Curves

The storage curves for the seven dams identified in the Susitna Basin screening model have been determined from 50 foot contour maps of the reservoir areas being studied.

(ii) Reservoir Storage Constraints

Due to the possible environmental limitations to seasonal and daily draw down of the reservoirs, tentative values have been set to allow consistency in comparisons. The maximum daily reservoir fluctuation, due to peaking operation, has been set at five feet. Seasonal fluctuations vary according to the sized reservoir. The fluctuations assumed are given in Table F.1. These constraints may be changed due to more information on, and analyses of, the environmental impact of these fluctuations.

(iii) Downstream Flow Constraint

This constraint only affects daily peaking operation. As such, it occasionally limits the plant capability to produce either full or demand power. The flow constraint has been set so that the plant at least gives approximately the historical winter flow in the reach immediately downstream of the dam site. Flow constraints are given in Table F.1.

(iv) Installed Capacity

Installed capacity for each of the dam sites has been determined from the plans identified during the optimum screening of Susitna Basin developments (Appendix E). In some cases phased powerhouse alternatives have been considered and are usually 50 percent of full development. Installed capacities considered are given in Tables F.3 and F.4.

(v) Tailwater Elevation and Efficiency

Average tailwater elevations have been determined from topographical maps and from information contained in reports of past studies. Tailwater elevations are given in Table F.1. The assessment of more precise tailwater elevation rating curves developed during later stages of the studies and further definition of channel geometry at selected development sites will be undertaken during detailed project feasibility studies.

Combined efficiency of generators, turbines and penstocks, etc. has been assumed to be 81 percent. This value is conservative and is believed to be a reasonable assumption for these initial assessments.

(b) Energy Demand Curve

This distribution has been taken from studies of the Railbelt region energy growth as discussed in Section 5. The distribution selected is that for 1995 under a medium load growth scenario and is given in Figure F.1.

(c) Inflow

The streamflow network of the Upper Susitna Basin consists of three gages at Gold Creek (2920), Cantwell (2915) and Denali (2910) on the Susitna River and one at Maclaren on the Maclaren River (2912). The longest record is at Gold Creek, which has 30 years of record from 1949 to 1979. The others have shorter, intermittent records.

The records at the three gages with less than 30 years have been extended by correlation with streamflows at Gold Creek. To estimate the streamflow at each of the proposed dam sites, a relationship between drainage area and upstream and downstream gage streamflow was determined. Basically, this relationship was used to estimate the streamflow at a dam site by adding the nearest upstream gage records to the flow difference between the nearest upstream and downstream gages which were prorated to reflect the drainage area at the dam site with respect to the nearest downstream gage. These streamflow relationships are given in Table F.2. Streamflows at each dam site for the 30 year period are given in Tables E.1 to E.7 of Appendix E.

F.6 - Model Results

The screening model identified potential Susitna developments consisting of either single dams or multi-dam developments (Appendix E). The main dams considered optimum for development are Devil Canyon, High Devil Canyon, Vee and Watana. The optimization process indicated that Watana and High Devil Canyon would be first stage developments in multi-dam development schemes. Second-stage developments would result in a Watana/Devil Canyon plan and a High Devil Canyon/Vee plan.

Adjustment of the specified installed capacity would also adjust the energy demand curve if the demand factor was held constant. Consequently, the demand factor used coupled with installed capacity must be considered only as a means of determining the energy demand that can be supplied by a given hydropower system. Environmental constraints and hydrology (shortages and surpluses) lead to an actual plant factor which is slightly different than the nominal demand factor specified to determine demand.

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This constraint only affects daily peaking operation. As such, it occasionally limits the plant capability to produce either full or demand power. The flow constraint has been set so that the plant at least gives approximately the historical winter flow in the reach immediately downstream of the dam site. Flow constraints are given in Table F.1.

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The simulation models were run to estimate energy yields from the single reservoir developments (Watana and High Devil Canyon), and then from basin developments (Watana/Devil Canyon and High Devil Canyon/Vee).

The average annual energy levels obtained from the various development plans possible (staged powerhouse, staged dams, etc.) are given in Table F.3 and F.4. Details of monthly average energy and monthly firm energy are given in Tables F.5 to F.15.

F.7 - Interaction of OGP5

The final plant factor and the monthly peak ratios or demand curve are determined in an interactive run with OGP5. Basically, the input of the simulation results to OGP5 can be assumed to apply to various installed capacities provided the energy demand curve determined in the simulation procedure is not violated. OGP5 then selects optimum plant factors (and installed capacity) which then forms the basis for new reservoir simulation work.

TABLE F.1 - RESERVOIR AND FLOW CONSTRAINTS

Dam	Maximum Seasonal Drawdown (ft)	Downstream Compensation Flow (cfs)	Tailwater Elevation (ft)	Normal Maximum Elevation (ft)
Devil Canyon	100	2000	880	1450
High Devil Canyon	100	2000	1020	1750
Watana	150	2000	1465	2200
Vee	150	2000	1905	2350

TABLE F.2 - DAM SITE STREAMFLOW RELATIONSHIP

Site	Drainage Area	Discharge Relationship
Gold Creek (g)	6160	Q_g
Cantwell (c)	4140	Q_c
Denali (d)	950	Q_d
Devil Canyon (DC)	5810	$Q_{DC} = 0.827 (Q_g - Q_c) + Q_c$
High Devil Canyon (HDC)	5760	$Q_{HDC} = 0.802 (Q_g - Q_c) + Q_c$
Watana (W)	5180	$Q_W = 0.515 (Q_g - Q_c) + Q_c$
Susitna III (S)	4225	$Q_S = 0.042 (Q_g - Q_c) + Q_c$
Vee (V)	4140	$Q_V = Q_c$
Denali (D)	950	$Q_D = 0.153 (Q_g - Q_c) + Q_d$
Maclaren (M)	2319	$Q_M = 0.429 (Q_c - Q_d) + Q_d$

TABLE F.3. SUSITNA DEVELOPMENT PLANS

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft	Annual Energy Production Firm GWH	Avg. GWH.	Plant Factor %
1.1	1	Watana 2225 ft 800MW	1860	1993	2200	150	2670	3250	46
	2	Devil Canyon 1470 ft 600 MW	1000	1996	1450	100	5500	6230	51
		TOTAL SYSTEM 1400 MW	2860						
1.2	1	Watana 2060 ft 400 MW	1570	1992	2000	100	1710	2110	60
	2	Watana raise to 2225 ft	360	1995	2200	150	2670	2990	85
	3	Watana add 400 MW capacity	130[2]	1995	2200	150	2670	3250	46
	4	Devil Canyon 1470 ft 600 MW	1000	1996	1450	100	5500	6230	51
		TOTAL SYSTEM 1400 MW	3060						
1.3	1	Watana 2225 ft 400 MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400 MW capacity	150	1993	2200	150	2670	3250	46
	3	Devil Canyon 1470 ft 600 MW	1000	1996	1450	100	5500	6230	51
		TOTAL SYSTEM 1400 MW	2890						

TABLE F.3 (Continued)

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Avg. GWH	Plant Factor %
2.1	1	High Devil Canyon							
		1775 ft 800 MW	1500	1994[3]	1750	150	2460	3400	49
	2	Vee 2350 ft 400 MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200 MW	2560						
2.2	1	High Devil Canyon							
		1630 ft 400 MW	1140	1993[3]	1610	100	1770	2020	58
	2	High Devil Canyon add 400 MW Capacity raise dam to 1775 ft	500	1996	1750	150	2460	3400	49
	3	Vee 2350 ft 400 MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200 MW	2700						
2.3	1	High Devil Canyon							
		1775 ft 400 MW	1390	1994[3]	1750	150	2400	2760	79
	2	High Devil Canyon add 400 MW capacity	140	1994	1750	150	2460	3400	49
	3	Vee 2350 ft 400 MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200 MW	2590						
3.1	1	Watana 2225 ft 800 MW	1860	1993	2200	150	2670	3250	46
	2	Watana add 50 MW tunnel 330 MW	1500	1995	1475	4	4890	5430	53
		TOTAL SYSTEM 1180 MW	3360						

TABLE F.3 (Continued)

				Stage/Incremental Data			Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Avg. GWH	Plant Factor %
3.2	1	Watana 2225 ft 400 MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400 MW capacity	150	1994	2200	150	2670	3250	46
	3	Tunnel 330 MW add 50 MW to Watana	1500	1995	1475	4	4890	5430	53
			3390						
4.1	1	Watana 2225 ft 400 MW	1740	1995[3]	2200	150	2670	2990	85
	2	Watana add 400 MW capacity	150	1996	2200	150	2670	3250	46
	3	High Devil Canyon 1470 ft 400 MW	860	1998	1450	100	4520	5280	50
	4	Portage Creek 1030 ft 150 MW	650	2000	1020	50	5110	6000	51
		TOTAL SYSTEM 1350 MW	3400						

NOTES:

(1) Allowing for a 3 year overlap construction period between major dams.
(2) Plan 1.2 Stage 3 is less expensive than Plan 1.3 Stage 2 due to lower mobilization costs.
(3) Assumes FERC license can be filed by June 1984, ie. 2 years later than for the Watana/Devil Canyon Plan 1.

TABLE F.4. SUSITNA ENVIRONMENTAL DEVELOPMENT PLANS

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft	Annual Energy Production Firm GWH	Avg. GWH.	Plant Factor %
E1.1	1	Watana 2225 ft 800MW and Re-Regulation Dam	1960	1993	2200	150	2670	3250	46
	2	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2860						
E1.2	1	Watana 2060 ft 400MW	1570	1992	2000	100	1710	2110	60
	2	Watana raise to 2225 ft	360	1995	2200	150	2670	2990	85
	3	Watana add 400MW capacity and Re-Regulation Dam	230[2]	1995	2200	150	2670	3250	46
	4	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	3060						
E1.3	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400MW capacity and Re-Regulation Dam	250	1993	2200	150	2670	3250	46
	3	Devil Canyon 1470 ft 400 MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2890						

TABLE F.4 (Continued)

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Annual Energy Production Avg. GWH	Plant Factor %
E2.4	1	High Devil Canyon 1755 ft 400MW	1390	1994[3]	1750	150	2400	2760	79
	2	High Devil Canyon add 400MW capacity and Portage Creek Dam 150 ft	790	1995	1750	150	3170	4080	49
	3	Vee 2350 ft 400MW	1060	1997	2330	150	4430	5540	47
		TOTAL SYSTEM	3240						
E3.2	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400 MW capacity and Re-Regulation Dam	250	1994	2200	150	2670	3250	46
	3	Watana add 50MW Tunnel Scheme 330MW	1500	1995	1475	4	4890	5430	53
		TOTAL SYSTEM 1180MW	3490						
E4.1	1	Watana 2225 ft 400MW	1740	1995[3]	2200	150	2670	2990	85
	2	Watana add 400MW capacity and Re-Regulation Dam	250	1996	2200	150	2670	3250	46
	3	High Devil Canyon 1470 ft 400MW	860	1998	1450	100	4520	5280	50
	4	Portage Creek 1030 ft 150MW	650	2000	1020	50	5110	6000	51
		TOTAL SYSTEM 1350 MW	3500						

NOTES:
(1) Allowing for a 3 year overlap construction period between major dams.
(2) Plan 1.2 Stage 3 is less expensive than Plan 1.3 Stage 2 due to lower mobilization costs.
(3) Assumes FERC license can be filed by June 1984, ie. 2 years later than for the Watana/Devil Canyon Plan 1.

TABLE F.4 (Continued)

				Stage/Incremental Data			Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Avg. GWH	Plant Factor %
E1.4	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5190	5670	81
		TOTAL SYSTEM 800MW	2640						
E2.1	1	High Devil Canyon 1775 ft 800MW and Re-Regulation Dam	1600	1994[3]	1750	150	2460	3400	49
	2	Vee 2350ft 400MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200MW	2660						
E2.2	1	High Devil Canyon 1630 ft 400MW	1140	1993[3]	1610	100	1770	2020	58
	2	High Devil Canyon raise dam to 1775 ft add 400MW and Re-Regulation Dam	600	1996	1750	150	2460	3400	49
	3	Vee 2350 ft 400 MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200MW	2800						
E2.3	1	High Devil Canyon 1775 ft 400MW	1390	1994[3]	1750	150	2400	2760	79
	2	High Devil Canyon add 400MW capacity and Re-Regulation Dam	240	1995	1750	150	2460	3400	49
	3	Vee 2350 ft 400MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200	2690						

TABLE F.5 - PLAN 1.1 - ENERGIES

MONTH	STAGE 1 Watana (2200) 800 MW		STAGE 2 Add Devil Canyon (1450) 600 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	264	263	542	538
FEBRUARY	250	249	514	511
MARCH	224	224	452	458
APRIL	201	201	394	406
MAY	186	186	418	405
JUNE	187	183	437	383
JULY	285	183	473	373
AUGUST	499	190	707	394
SEPTEMBER	370	204	667	421
OCTOBER	233	233	488	478
NOVEMBER	266	266	544	540
DECEMBER	287	287	591	587
TOTAL ANNUAL	3252	2669	6227	5494

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2200): Reservoir full supply level

TABLE F.6 - PLAN 1.2 - ENERGIES

MONTH	STAGE 1 Watana (2000) 400 MW		STAGE 3(1) Raise Watana (2200) Add 400 MW		STAGE 4 Add Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	138	137	264	263	542	538
FEBRUARY	130	129	250	249	514	511
MARCH	117	116	224	224	452	458
APRIL	103	57	201	201	394	406
MAY	100	100	186	186	418	405
JUNE	154	102	187	183	437	383
JULY	322	103	285	183	473	373
AUGUST	355	365	499	190	707	394
SEPTEMBER	269	188	370	204	667	421
OCTOBER	131	123	233	233	488	478
NOVEMBER	140	139	266	266	544	540
DECEMBER	150	149	287	287	591	587
TOTAL ANNUAL	2109	1708	3252	2669	6227	5494

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2000): Reservoir full supply level (ft)

(1) Stage 2 is as for Stage 1 on Table F.6 (Plan 1.3)

TABLE F.7 - PLAN 1.3 - ENERGIES

MONTH	STAGE 1 Watana (2200) 400 MW		STAGE 2 Add 400 MW to Watana (2200)		STAGE 3 Add Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	263	263	264	263	542	538
FEBRUARY	250	249	250	249	514	511
MARCH	224	224	224	224	452	458
APRIL	201	201	201	201	394	406
MAY	186	186	186	186	418	405
JUNE	187	184	187	183	437	383
JULY	245	183	285	183	473	373
AUGUST	333	190	499	190	707	394
SEPTEMBER	315	204	370	204	667	421
OCTOBER	233	233	233	233	488	478
NOVEMBER	266	265	266	266	544	540
DECEMBER	287	287	287	287	591	587
TOTAL ANNUAL	2990	2669	3252	2669	6227	5494

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2000): Reservoir full supply level (ft)

TABLE F.8 - PLAN 2.1 - ENERGIES

MONTH	STAGE 1 High Devil Canyon (1750) 800 MW		STAGE 2 Add Vee (2355) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	235	232	368	368
FEBRUARY	222	219	349	350
MARCH	197	151	303	313
APRIL	173	30	268	276
MAY	169	171	254	258
JUNE	231	172	290	247
JULY	480	173	526	319
AUGUST	554	307	752	298
SEPTEMBER	429	303	575	280
OCTOBER	219	213	394	366
NOVEMBER	239	233	403	393
DECEMBER	257	254	425	401
TOTAL ANNUAL	3405	2458	4907	3869

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(1750): Reservoir full supply level (ft)

TABLE F.9 - PLAN 2.2 - ENERGIES

MONTH	STAGE 1 High Devil Canyon (1610) 400 MW		STAGE 2 Raise High Devil Canyon (1750)		STAGE 3 Add Vee (2330) 400 MW Total 1200 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	117	116	235	232	368	368
FEBRUARY	110	109	222	219	349	350
MARCH	99	98	197	141	303	313
APRIL	89	87	173	30	268	276
MAY	92	87	169	171	254	258
JUNE	265	93	231	172	290	247
JULY	292	291	480	173	526	319
AUGUST	290	292	554	307	752	298
SEPTEMBER	270	243	429	303	575	280
OCTOBER	150	105	219	213	394	366
NOVEMBER	120	119	239	233	403	393
DECEMBER	129	127	257	254	425	401
TOTAL ANNUAL	2023	1767	2759	2415	4907	3869

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(1610): Reservoir full supply level (ft)

TABLE F.10 - PLANS 2.3 and E2.3 - ENERGIES

MONTH	STAGE 1 High Devil Canyon (1750) 400 MW		STAGE 2 Add 400 MW to High Devil Canyon		STAGE 3 Add Vee (2330) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	235	232	235	232	368	368
FEBRUARY	222	219	222	219	349	350
MARCH	197	141	197	152	303	313
APRIL	173	30	173	30	268	276
MAY	169	171	169	171	254	258
JUNE	200	172	231	172	290	247
JULY	275	173	480	173	526	319
AUGUST	288	286	554	307	752	298
SEPTEMBER	285	292	429	303	575	280
OCTOBER	219	213	219	213	394	366
NOVEMBER	239	232	239	233	403	393
DECEMBER	257	254	257	254	425	401
TOTAL ANNUAL	2759	2415	3405	2459	4907	3869

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(1750): Reservoir full supply level (ft)

TABLE F.11 - PLAN 3.1 - ENERGIES

MONTH	STAGE 1 Watana (2200) 800 MW		STAGE 2 Add Tunnel 380 MW	
	EA	EF	EA	EF
JANUARY	264	263	490	488
FEBRUARY	250	249	463	467
MARCH	224	224	411	423
APRIL	201	201	364	376
MAY	186	186	345	351
JUNE	187	183	332	332
JULY	285	183	390	321
AUGUST	499	190	633	337
SEPTEMBER	370	204	574	364
OCTOBER	233	233	419	417
NOVEMBER	266	266	483	481
DECEMBER	287	287	529	527
TOTAL ANNUAL	3252	2669	5433	4885

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2200): Reservoir full supply level (ft)

TABLE F.12 - PLAN 4.1 - ENERGIES

MONTH	STAGE 1 Watana (2200) 800 MW		STAGE 2 Add H.D.C. (1450) 400 MW		STAGE 3 Add Portage Creek (1020) 150 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	264	263	447	444	504	501
FEBRUARY	250	249	424	422	478	476
MARCH	224	224	379	378	428	426
APRIL	201	201	334	335	379	378
MAY	186	186	338	330	391	376
JUNE	187	183	349	313	406	356
JULY	285	183	419	306	481	347
AUGUST	499	190	670	323	799	366
SEPTEMBER	370	204	583	346	661	392
OCTOBER	233	233	400	393	454	445
NOVEMBER	266	265	499	446	507	503
DECEMBER	287	287	488	485	550	546
TOTAL ANNUAL	3252	2669	5281	4522	5997	5112

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2200): Reservoir full supply level (ft)

TABLE F.13 - PLAN E1.2 - ENERGIES

MONTH	STAGE 2 (1) Watana Raise Dam (2200) 400 MW		STAGE 3 Add 400 MW to Watana (2200)		STAGE 4 Add Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	263	263	264	263	544	560
FEBRUARY	250	249	250	249	515	516
MARCH	224	224	224	224	450	460
APRIL	201	201	201	201	396	408
MAY	186	186	186	186	419	406
JUNE	187	184	187	183	436	385
JULY	245	183	285	183	453	375
AUGUST	333	190	499	190	616	395
SEPTEMBER	315	204	370	204	606	423
OCTOBER	233	233	233	233	490	480
NOVEMBER	266	265	266	266	547	545
DECEMBER	287	287	287	287	594	589
TOTAL ANNUAL	2990	2669	3252	2669	6065	5520

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(2200): Reservoir full supply level (ft)

(1) Stage 1 is as for Stage 1 on Table 2 Plan (1.2)

TABLE F.14 - PLAN E1.3 - ENERGIES

MONTH	STAGE 1 Watana (2200) 400 MW		STAGE 2 Add 400 MW to Watana		STAGE 3 Add Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	263	263	264	263	544	560
FEBRUARY	250	249	250	249	515	516
MARCH	224	224	224	224	450	460
APRIL	201	201	201	201	396	408
MAY	186	186	186	186	419	406
JUNE	187	184	187	183	436	385
JULY	245	183	285	183	453	375
AUGUST	333	190	499	190	616	395
SEPTEMBER	315	204	370	204	606	423
OCTOBER	233	233	233	233	490	480
NOVEMBER	266	265	266	266	547	545
DECEMBER	287	287	287	287	594	589
TOTAL ANNUAL	2990	2669	3252	2669	6065	5520

Notes:

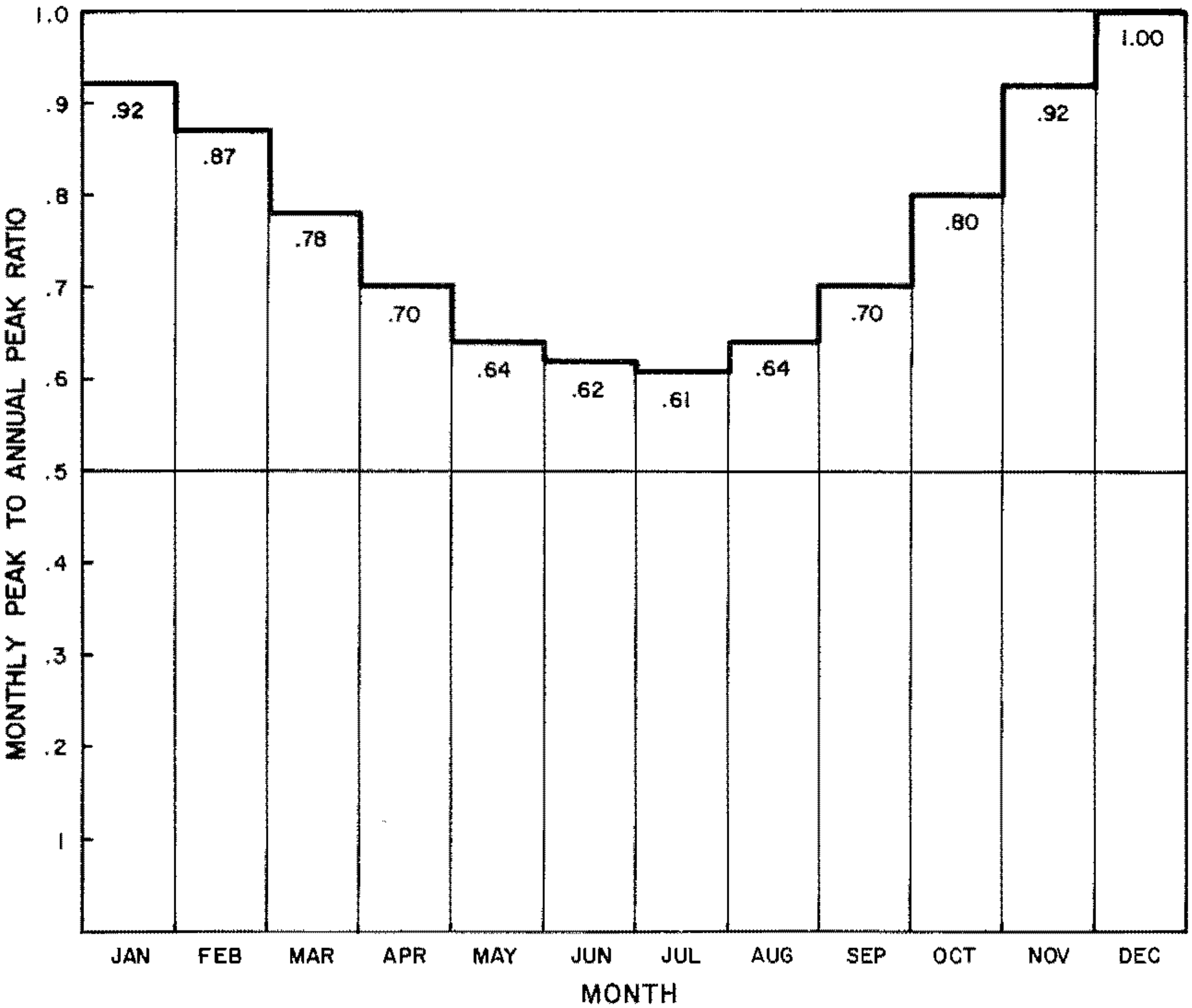
EA: Average Monthly Energy
EF: Monthly Firm Energy
(2200): Reservoir full supply level (ft)

TABLE F.15 - PLAN E2.4 - ENERGIES

MONTH	STAGE 1		STAGE 2		STAGE 3	
	High Devil Canyon (1750) 400 MW		Add 400 MW to High Devil Canyon and Portage Creek (150 MW)		Add Vee (2350) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	235	232	317	317	432	435
FEBRUARY	222	219	296	302	411	415
MARCH	197	141	261	270	360	372
APRIL	173	30	231	239	318	328
MAY	169	171	220	221	287	290
JUNE	200	172	232	208	321	277
JULY	275	173	460	214	564	349
AUGUST	288	286	629	221	820	332
SEPTEMBER	285	292	492	241	646	315
OCTOBER	219	213	282	276	447	415
NOVEMBER	239	232	317	317	457	446
DECEMBER	257	254	346	346	480	456
TOTAL ANNUAL	2759	2415	4083	3171	5543	4430

Notes:

EA: Average Monthly Energy
EF: Monthly Firm Energy
(1750): Reservoir full supply level (ft)



1995 MONTH/ANNUAL PEAK LOAD RATIOS

REF: WOODWARD CLYDE CONSULTANTS,
"FORECASTING PEAK ELECTRIC
DEMAND FOR ALASKA'S RAILBELT"

FIGURE F.1

ACRES

APPENDIX G - SYSTEMWIDE ECONOMIC EVALUATION

The Railbelt System will be developed in the future by means of an appropriate continuation of existing and new proven generation alternatives to supply the necessary demand.

The objectives of generation planning in the evaluation process is to determine the preferred Susitna Basin development plan which will form part of the Railbelt System. The preferred Susitna Basin plan would be that plan which gives the lowest system present worth cost of generation for the energy and capacity demands and economic criteria selected.

G.1 - Introduction

Generation planning analyses were performed by making a comparison of Susitna Basin development alternatives with the aid of a production cost model to assess the system costs for the various development alternatives available. Standard numerical evaluation techniques were then used to make direct comparison of alternatives. Initially, a set of variables was established for use in making broad comparisons of available basin developments. In this preliminary evaluation, the study focused on the medium load forecast to identify various plans; a base plan which consisted of an all-thermal development, plans composed of thermal plus various Susitna developments, and a plan composed of thermal plus other hydroelectric developments.

The second phase of generation planning assessed the impact of varying the load forecast. System generation plans with and without the Susitna Basin development plan were identified for the high and low load forecasts. A plan was also developed for the low load forecast considering an additional reduction in load growth due to conservation and load management. Also under this phase, a plan was developed considering a probabilistic forecast centered around the medium load forecast.

Since it is recognized that the selection of a generation plan may be sensitive to the underlying assumptions, the third phase of generation planning assessed the impacts of variable planning parameters and the sensitivity of these parameters with respect to the generation plans. This analysis dealt with variable interest rates, fuel cost and escalation, retirement policies, and capital cost estimates.

G.2 - Generation Planning Models

(a) Selection of Planning Model

The major tool used in the economic evaluation of the various Railbelt generation plans is a computer generation system simulation program. There are a number of generation planning models available commercially and accepted for use in the utility industry that will simulate the operation, growth and cost of a electric utility system. Some of the more widely used models include the following:

- GENOP by Westinghouse
- OGP5 by General Electric.
- PROMOD by Energy Management Associates.
- WASP by Tennessee Valley Authority.

The WASP program was not available for use at the start of this study so is not considered or discussed further in this report.

Key considerations for use in selection of a model for this study are data processing costs, method of production cost modeling, treatment of system reliability, selection of new capacity, dispatching of hydroelectric capacity to meet load projections and ability of the model to address load uncertainty. Although these items are handled differently in each program, common traits of operation exist. Some of the salient features of each model are shown on Table G.1. Major differences in the models are given below.

(i) Forced Outages

One significant factor which varies between the models is the method of determining forced outages of the various units of system power generation installations which are represented in the production cost algorithm. The three methods used are:

- Deterministic methods which devote unit capacity by a multiplier or by extending planned maintenance schedules.
- Stochastic methods which can be reduced to deterministic methods. Strictly speaking stochastic representations of outages is a random selection of some units in each commitment zone to be put out of service. The load previously served will be transferred to higher cost units.
- Probabilistic methods, which are described by the modified Booth - Baleriaux method of production simulation which allows for probability distribution of generation unit outages.

The selection of one of these methods may be critical in the use of a model for short-term outage scheduling. However, it is generally found that virtually no difference in planning results is obtained from models using the three methods available over a long term period.

(ii) Dispatching Hydropower Resources

The method of dispatching hydropower resources to meet load demands is another significant feature which affects the model's representation of the system. The GENOP program will dispatch or select, from available units, hydroelecric units first to meet a given demand. Generally, the run-of-river units will meet load demand and units with storage capability will be used to shave peak demands.

The OGP5 program uses a similar method, utilizing hydroelectric energy as much as possible to minimize system operating costs. Hydropower is scheduled first on a monthly basis to account for seasonal conditions. An additional feature of the program is the ability to use dry year or firm energy on a monthly basis to determine system reliability, while using average annual energy to determine system production costs.

The PROMOD program allows for three levels of annual runoff and associated hydroelectric energy. These energy levels can be entered into the program in a probabilistic manner to be used in determining reliability and production costing. Run-of-river and storage units are dispatched as in the other programs.

Other factors are also important such as program availability and experience of staff in using the models. On the basis of this assessment of model features, model availability and Acres' knowledge of the intricacies of the model procedures, the OGP5 model was selected for use in this study. This model is believed to be the most appropriate to accurately model the Railbelt generation system as it exists today and in the future, with the various generation alternatives available to the region.

(b) OGP5 Model

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

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

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

The unit resulting in the lowest system production cost 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. Further discussion on the load requirements, load uncertainty and plant reliability is given below:

(i) Load Representation

Besides generation unit data and system reliability criteria, the program uses a model of the system load including month to year peak load ratios, typical daily load shapes for days and weekends, and projected growth for the period of study in terms of capacity and energy supply.

Load forecasts used for generation planning are represented in detail in Section 5, "Railbelt Load Forecast", of the main report. Figure G.1 depicts the four energy forecasts in the systemwide analysis.

The forecasts used for generation planning are based on Acres' analysis of the ISER energy forecast. The energy forecast used by Acres for establishing the "base case" generation plan is the medium load forecast (Table G.2). Sensitivity analyses have also been undertaken using variable loads developed from the ISER scenarios of high and low levels of both economic activity and government spending. Table G.2 gives the range of load forecasts considered.

The energy and load forecasts developed in Section 5 of this report include energy projections for self-supplied industrial and military sectors. These markets will not be a part of the future electrical demand to be met by the Railbelt Utility Company. Likewise, the capacity owned by these sectors will not be available as a supply to the general market. A review of the industrial self suppliers indicates that they are primarily offshore operations, drilling operations and others which would not likely add nor draw power from the system. The forecasts have been appropriately adjusted for use in generation planning studies, as described in Section 5. Additionally, although it is considered likely that the military would purchase available cost effective power from a general market, much of their capacity resource is tied to district heating systems, and thus would be expected to continue operation. For these reasons only 30 percent of the military generation total will be considered as a load on the total system. This amount is about 4 percent of total energy in 1980 and decreases to 2.5 percent in 1990. This method of accounting for these loads has no significant effect on total capacity additions needed to meet projected loads after 1985. Table G.2 illustrates the medium load and energy forecasts at five year intervals throughout the planning period.

(ii) Load Uncertainty

The load forecast used to develop a generation plan will have a significant bearing on the nature of the plan. In addition, the plan can be significantly changed due to uncertainties associated with the forecasted loads. To address the question of the impact of load uncertainty on a development plan, two procedures will be used. The first procedure will be to develop plans using the high and low load forecasts assuming no uncertainty to the forecast. This will identify the upper and lower bounds of development which will be needed in the Railbelt. The second method will be to incorporate the variable forecasts and uncertainty of the load forecasts into the planning process.

The medium load forecast (used in preliminary evaluation of plans) is introduced into the program in detail. This would include daily load shapes, monthly variability and annual growth of peaks and energy. Additional variables are added which introduce forecast uncertainty in terms of higher and lower levels of peak demand and the probability of the occurrence of these forecasts. For example, in the year 2000 the medium load forecast demand entered is 1175 MW. Variable forecasts are entered for 950, 1060, 1530 and 1670 MW, with associated probabilities of occurrence of 0.10, 0.20, 0.20 and 0.10, respectively. The middle level forecast of 1175 MW would have a probability of occurrence of 0.40.

The OGP5 program uses this variable forecast in determining generating system reliability only. A loss of load probability is calculated for each projected demand level as compared to the available capacity and a weighted average is taken. This loss of load probability is then used for capacity addition decisions. After capacity decisions are made, the program uses the medium load forecast detail for operating the production cost model.

This method of dealing with uncertainty is directly applicable to the data available on Railbelt load forecasts. There are five forecasts which could be plugged into the reliability calculations, three by ISER and two extremes calculated by Acres represented in Table G.2. Subjectivity is reduced to the decision of placing probabilities on the load forecasts. Based on commmunication with the ISER group in Alaska as well as General Electric OPG5 personnel, the above example probability set has been considered in the analysis. This is based on the assumption that each extreme forecast is half as likely to happen as the adjacent forecast which is closer to the medium. The loads and probabilities analyzed are given in Table G.3.

(iii) Generation Plant Reliability

In order to perform a study of the generation system, criteria are required to establish generating plant and system reliability. These criteria are important in determining the adequacy of the available generating capacity as well as the sizing and timing of additional units. Plant reliability is expressed in the form of forced and planned outage rates which have been presented within the individual resource descriptions in Section 6. System reliability is expressed as the loss of load probability (LOLP).

An LOLP for a system is a calculated probability based on the characteristics of capacity, forced and scheduled outage, and cycling ability of individual units in the generating system. The probability defines the likelihood of not meeting the full demand within a one year period. For example, an LOLP of 1 relates to the probability of not meeting demand one day in one year; an LOLP of 0.1 is one day in ten years. For this study, an LOLP of 0.1 has been adopted. This value is widely used by utility planners in the United States as a target for independent systems. This target value will be used both for the base case plan and for sensitivity analyses dealing with the effects of over or under capacity availablility.

(iv) Economic and Financial Parameters

As a public investment, it was determined that the Susitna project should be evaluated initially from an economic perspective, using economic parameters. Initial analysis and screening of Susitna alternatives employed a numerical economic analysis and the general aid of the OGP5 model.

The differences between economic and financial (cost of power) analyses pertain to the following parameters:

- Project Life

  In economic evaluations, an economic life is used without regard to the terms (repayment period) of debt capacity employed to finance the project. A financial (or cost of power) perspective uses an amortization period that is tied to the terms of financing. A retirement period (policy) is generally equivalent to project life in economic evaluations; financial analysis may use a retirement period that differs from project life.

- Denomination of Cash Flows and Discount Rates

  Economic evaluations use real dollars and real discount rates that exclude the effects of general price inflation with the exception of fuel escalation.

- Market or Shadow Prices

  Whenever market and shadow prices diverge, economic evaluations use shadow prices (opportunity costs or values). Financial analysis uses market prices projected as applicable. Fuel prices are discussed in detail in Section 6 and Appendix B.

It is important to note that application of the various parameters contained herein will not necessarily provide an accurate reflection of the true life cycle cost of any single generating resource of the system. From the public (State of Alaska) perspective, the relevant project costs are based on opportunity values and exclude transfer payments such as taxes and subsidies. Further study into this comparative analysis of project economics will be continuing during 1981.

- Interest Rates and Annual Carrying Charges

The assumed generation planning study based on economic parameters and criteria has a 3 percent real discount rate for the base case analysis. This figure corresponds to the historical and expected real cost of debt capacity. The issue of tax-exempt financing does not impinge on these economic evaluations.

In comparison, analysis requires a nominal or market rate of interest for discounted cash flow analysis. This rate is dependent upon general price inflation, capital structure (debt-equity ratios) and tax-exempt status. In the base case, a general rate of price inflation of seven percent is assumed for the period 1980 to 2010. Given a 100 percent debt capitalization and a three percent real discount rate, the appropriate nominal interest rate is approximately 10 percent in the base case. The nominal interest is computed as:

$$\begin{aligned}\text{Nominal Interest Rate} &= (1 + \text{inflation rate}) \times \\ &\quad (1 + \text{real interest rate}) \\ &= 1.07 \times 1.03\end{aligned}$$

To calculate annual carrying charges, the following assumptions were made regarding the economic life of various power projects. As noted earlier, these lives were also assumed as the plant lives.

- Large steam plants - 30 years
- Small steam plants - 35 years
- Gas turbines, oil-fired - 20 years
- Gas turbines, gas-fired - 30 years
- Diesels - 30 years
- Hydroelectric projects - 50 years

It should be noted that the 50-year life for hydro projects was selected as a conservative estimate and does not include replacement investment expenditures.

- Cost Escalation Rates

In the initial set of generation planning parameters, it was assumed that all cost items except energy escalate at the rate of general price inflation (assumed in the economic sense to be 0 percent per year). This results in real growth rates of zero percent for non-energy costs in the set of economic parameters used in real dollar generation planning.

Base period (January 1980) energy prices were estimated based on both market and shadow values. The initial base case analysis used base period costs (market and shadow prices) of $1.15/million Btu (MMBtu) and $4.00/MMBtu for coal and distillate respectively. For natural gas, the current actual market price is about $1.05/MMBtu and the shadow price is estimated to be $2.00/MMBtu. The shadow price for gas represents the expected market value assuming an export market was developed.

Real growth rates in energy costs (excluding general price inflation) are shown in Table G.4. These are based on fuel escalation rates from the Department of Energy (DOE) mid-term Energy Forecasting System for DOE Region 10 (including the States of Alaska, Washington, Oregon and Idaho. Price escalators pertaining to the industrial sector were selected over those available for the commercial and residential sectors to reflect utilities' bulk purchasing advantage. A composite escalation rate has been computed for the period 1980 to 1995 which reflects average compound growth rate per year. Since the DOE has suggested that the forecasts to 1995 may be extended to 2005, the composite escalation rates are assumed to prevail in the period 1996 to 2005. Beyond 2005, zero growth in energy prices is assumed.

Table G.5 summarizes the sets of economic and financial parameters assumed for generation planning.

- Other Parameters

Other parameters considered in generation planning studies include insurance and taxes. The factors for insurance costs (0.10 percent for hydroelectric projects and 0.25 percent for all others) are based on FERC guidelines. State and federal taxes were assumed to be zero for all types of power projects. This assumption is valid for planning based on economic criteria since all intra-state taxes should be excluded as transfer payments from Alaska's perspective. The subsequent financial analyses may relax this assumption if non-zero state and/or local taxes or payments in lieu of taxes are identified. Annual fixed carrying charges relevant to the generation planning analysis are given in Table G.5.

G.3 - Generation Planning Results

Generation planning runs were made for each of the Susitna development plans identified in Section 8.6 - Formulation of Susitna Basin Development Plans, and for system generation plans without Susitna developments. Plans without Susitna included alternative hydro and all-thermal generation scenarios.

A minor limitation inherent in the use of the OGP5 model is that the number of years of simulation is limited to 20 years. To overcome this, the study period of 1980 to 2040 has been broken into three separate segments for study purposes. These segments are common to all system generation plans.

The first segment has been assumed to be from 1980 to 1990. The model of this time period includes all committed generation units and is assumed to be common to all generation scenarios. This ten-year model is summarized in Table G-8. This table shows the 1980 to 1990 system configuration and details on committed units and retirements that occur during the period. The end point of this model becomes the beginning of each 1990-2010 model.

The model of the first two time periods considered (1980 to 1990, and 1990 to 2010) provides the total production costs on a year-to-year basis. These total costs include, for the period of modeling, all costs of fuel and operation and maintenance of all generating units included as part of the system. In addition, the completed production cost includes the annualized investment costs of any production plans added during the period of study. A number of factors which contribute to the ultimate cost of power to the consumer, are not included in this model. These are common to all scenarios and include:

- All investment costs to plants in service prior to 1981;

- Costs of transmission systems in service both at the transmission and distribution level; and

- Administrative costs of utilities for providing electric service to the public.

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

The third period, 2010 to 2040, was modeled by assuming that production costs of 2010 would recur for the additional 30 years to 2040. This assumption is believed to be reasonable given the limitations on forecasting energy and load requirements for this period. The addition period to 2040 is required to take into account the benefit derived from the value of the addition of a hydroelectric power plant which has a useful life of fifty years or more.

The selection of the preferred generation plan is based on numerous factors. One of these is the cost of the generation plan. To provide a consistent means of assessing the production cost of a given generation scenario each production cost total has been converted to a 1980 present worth basis. The present worth cost of any generation scenario is made up of three cost amounts. The first is present worth cost (PWC) of the first ten years of study (1981 to 1990), the second is the PWC of the scenario assumed during 1990 to 2010, and the third is the PWC of the scenario in 2010 assumed to recur for the period 2010 to 2040. In this way the long-term (60 years) PWC of each generation scenario in 1980 dollars can be compared.

The present worth cost of the generation system given by Table G.6 is $873.7 million in 1980 values. This cost is common to all generation scenarios and is added to all PWC values for each generation scenario during the modeling of the system in the period of 1990 to 2040.

Generation scenarios analyses include thermal generation with Susitna Basin plans, thermal generation with alternative non-Susitna hydro plans and all-thermal generation. Details of the analysis of these three generation mixes are given in the following sections.

(a) Susitna Basin Plans

(i) Base Case Medium Load Forecast

Essentially the Susitna Basin plans were developed from the studies described in Section 8. Some of the plans are similar in location and size but vary in staging concepts. Others are at totally different sites. These various Susitna plans were modeled in the OGP5 model as part of the Railbelt system. The characteristics of the Susitna plans are summarized in Table G.7 and their formulation is described fully in Section 8. The results of the OGP5 model runs assuming a medium load forecast for all the Susitna plans identified through the procedures outlined in Section 8 are given in Table G.8.

The plans developed included 800 MW and 1200 MW capacity plans in addition to variation in these plans to determine the effects on PWC of delaying implementation of the plan, the elimination of a stage in the plan, or staging construction of a particular dam in the plan. Inspection of the results given in Table G.8 indicates the following:

- The lowest present worth cost development at $5850 million is either Plan E1.1 or Plan E1.3 (see Table G.7). This result shows that there is no effective difference between full powerhouse development at Watana and staged powerhouse development;

- The highest present worth cost development at $6960 million is Plan 1.3 with Devil Canyon not constructed;

- Watana/Devil Canyon (Plan E1.1 or E1.3) is superior to Watana/Tunnel (Plan 3.1) by $680 million;

- Watana/Devil Canyon (Plan E1.1 or E1.3) remains superior to Watana/Tunnel (Special Plan 3.1) when tunnel capital costs are halved. Watana/Devil Canyon is superior by $380 million;

- Watana/Devil Canyon (Plan E1.1 or E1.3) is superior to High Devil Canyon/Vee developments (Plan E2.1 or Plan E2.3) by at least $520 million;

- Replacement of Vee Dam with Chakachamna development lowers present worth cost of Plan 2.3 to $6210 million. Watana/Devil Canyon remains superior by $360 million;

- Watana/Devil Canyon development limited to 800 MW (Plan E1.4) is $140 million more than full 1200 MW development (Plans E1.1 or E1.3) but remains superior to tunnel scheme or High Devil Canyon/ Vee plans;

- Delaying implementation of Watana/Devil Canyon Plan E1.3 by five years adversely affects present cost by an additional $220 million;

- Staging powerhouse and dam construction at Watana (Plan E1.2) costs $180 million more than Plans E1.1 or E1.3; and

- Watana/High Devil Canyon/Portage Creek (Plan E4.1) is $200 million more than either Plan E1.1 or E1.3.

(ii) Variable Load Forecast

As discussed in Section 5, the many uncertainities of load forecasting provide a wide range of possibilities for future generation planning. The medium load forecast (with moderate government expenditure) used above to show the present worth cost of the developments identified through site screening and plan formulation steps is thought to be the most likely load and energy forecast. However, due to the uncertainty associated with the load forecasting, approximate upper and lower limits to the load forecast have been defined.

The high forecast assumes high economic growth and high government expenditure whereas the lower bound, or low forecast, assumes low economic growth and low government expenditure. In addition to these two forecasts, the results of a determined effort at load management and conservation have been incorporated into a fourth load forecast. This very low forecast also assumes low government expenditure in addition to low economic growth with load management and conservation. Further details of these forecasts are given in Section 5 and load forecast values in five-year periods in Table G.8.

The results of the OGP5 analysis of the Railbelt generation system with Susitna under these various load forecasts are given in Table G.9. The conclusions that can be drawn from inspection of Table G.9 are:

- Watana/Devil Canyon development (Plan E1.4) has the least present worth cost at $4350 million of all developments under a low load forecast;

- Watana/Devil Canyon with Chakachamna as a fourth stage (modified Plan E1.3) has the least present worth cost of $10,050 million of all developments under a high load forecast;

- Plan E1.4 is superior to special Watana/tunnel (tunnel cost halved) by $380 million under a low load forecast;

- Plan E1.4 is superior to High Devil Canyon/Vee (Plan E2.1) by $320 million under a low load forecast;

- Modified Plan E1.3 is superior by $650 million to Plan E1.3 under a high load forecast; and

- Modified Plan E1.3 is superior to High Devil Canyon/Vee with Chakachamna (modified Plan E2.3) by $990 million.

(iii) Economic Sensitivity

The Watana/Devil Canyon development known as Plan E1.3 has been identified as the most economic development of Susitna alternatives under a medium load forecast (Table G.8). In addition, variations of the Watana/Devil Canyon development have been identified as the most economical under low and high load forecasts (Table G.9). Consequently, the Plan E1.3 is obviously the most reasonable to select as the one to determine the sensitivity of the plans to variations in the economic parameters which are subject to uncertainties.

Sensitivity analyses have been performed on critical parameters and are based on Plan E1.3 with a medium load forecast. The results of these analyses are summarized in Table G.10 and are discussed below. Base values for the parameters assumed in OGP5 modeling, particularly with respect to thermal plant costs, etc. are given in Appendix B.

- Interest Rates

  In the base plan selected (also in other plans) the interest rate assumed is 3 percent. This rate represents the cost of money, net of inflation. Variation of this rate to 5 and 9 percent has been assumed to determine the effect of interest rate variation on this capital intensive development. The effect of a 5 percent interest rate is to lower the present worth cost of Plan E1.3 by $1620 million to $4230 million. The higher rate of 9 percent lowers the present worth cost to $2690 million.

- Fuel Cost and Fuel Cost Escalation Rate

  The base plan has assumed a fuel cost ($/million Btu) of 2.00, 1.15, and 4.00, for natural gas, coal and oil respectively. The effect of reducing fuel costs by 20 percent to 1.60, 0.92 and 3.20 $/million Btu for natural gas, coal and oil respectively is to reduce the present worth cost of Plan E1.3 by $590 million to $5260. This reduction represents the lower cost associated with operating the thermal generation component of the system.

  Fuel cost escalation rates of 3.98, 2.93, and 3.58 percent have been derived as typical for the Railbelt region (Appendix B). The effect of lowering this escalation rate to zero percent for all-thermal fuels is to lower the present worth cost of Plan E1.3

to $4360 million. When coal cost escalation alone is set at zero percent the effect is much less, giving a reduction of only $590 million. Again the fuel cost escalation rate shows that the hydroelectric alternatives would become economically superior if thermal operation costs are lowered.

- Economic Life of Thermal Plants

  Increasing the economic lives of thermal plants incorporated into the generation system with Susitna Plan E1.3 results in an increase of the present worth cost of the system of $250 million. This result was for a 50 percent increase in thermal plant life and shows that the increase results in greater operational costs.

- Thermal Plant Capital Costs

  The effect of a reduction in thermal plant capital costs by 22 percent, to 350, 2135 and 778 $/kw for natural gas, coal and oil respectively, results in a slight reduction in present worth cost of the system. The reduction is $110 million and is a direct result of the lower capital costs of the thermal component of the system.

- Hydro Plant Capital Costs

  Various uncertainties in capital costs of the hydro development exist due to possible variations in amounts of foundation treatment, construction delays, etc. To take into account some of these uncertainties, an assessment has been made of increased hydro construction costs. An increase in construction cost of 10 percent to Devil Canyon results in an increase in present worth cost of the system of $360 million. A 50 percent increase in both Watana and Devil Canyon construction costs results in a $960 million increase in present worth cost.

The effects of the sensitivity analyses conducted above would be the same for whichever development plan is selected; the relative ranking of the various Susitna Basin development plans would remain essentially unchanged and Plan E1.3 would still be the most economic in terms of present worth cost under a medium load forecast.

(b) Alternative Hydro Generation Plans

In Section 6 and Appendix C, alternative hydroelectric developments to Susitna were identified. In Appendix C, the following ten sites were shown to be the most economically viable and environmentally acceptable sites outside of the Susitna Basin:

- Chakachamna: 480 MW
- Keetna: 100 MW
- Snow: 50 MW

- Strandline: 20 MW
- Allison Creek: 8 MW
- Cache: 50 MW
- Talkeetna-2: 50 MW
- Browne: 100 MW
- Bruskasna: 30 MW
- Hicks: 60 MW

In the OGP5 analyses these sites were combined into appropriate groups on the basis of least cost energy and incorporated with thermal generation sources to meet the medium load forecast defined earlier (Section 5). The results of the OGP5 runs are given in Table G.11.

The lowest present worth cost of the system with alternative Susitna hydro is $7040 million. This represents an increase of $1190 million over the lowest cost Susitna development plan (Plan E1.3) for the medium load forecast. This alternative hydro scenario includes Chakachamna, Keetna and Snow developments. The addition of Strandline Lake and Allison Creek to the system has minimum effect on present worth cost ($7041 million) but would eliminate the need of 55 MW of thermal generating capacity, thus saving a non-renewable resource.

The maximum development of alternative hydro considered has a present worth cost of $7088 million. The six sites included in this plan are given in Table G.11.

(c) Thermal Generation Scenarios

The thermal generating resources required to meet Railbelt energy and power demands can be identified through the use of the same production cost model as that which identified the most economic plan of development with Susitna Basin alternatives and non-Susitna hydro alternatives.

Using information developed in Appendix B for thermal generating resources available to the Railbelt and the five load forecasts outlined in Section 5, the OGP5 program was used to simulate the operation of the Railbelt generating system over the 30-year study period. As in Susitna and non-- Susitna hydro alternatives, the long term present worth cost (in 1980 dollars) of the thermal system was determined.

The medium load forecast is currently believed to be the most likely load to develop in the Railbelt over the next 40 years. Consequently, as before for hydro developments, this forecast forms the basis of the majority of OGP5 analysis.

(i) Medium Load Forecast:

The thermal generating plan for the medium load forecast is presented in Table G.11. Two cases were modeled for the thermal generation plan. The first model allowed the renewal of natural gas turbines at the end of their economic life; the second assumed no renewals and required the permanent retirement of the natural gas turbines at the end of their useful lives. This policy affects 456 MW of existing gas turbine units. The rationale behind these two renewal policies is related to the implementation of the Fuel Use Act (FUA) which prohibits the building of new generating units operating on natural gas. The FUA is discussed more fully in Section 6.6 where it was shown that Railbelt utilities would probably be restricted to new gas facilities for peaking applications only.

The policy of renewal or non-renewal of gas turbines has a minimal effect on long-term present worth cost of the thermal system model. This is clearly shown in Table G.11 where the present worth cost difference between the two policies, under a medium load forecast, is only $20 million. The natural gas turbines permanently retired are in fact simply replaced by peaking-only natural gas turbines. The long-term present worth cost of the thermal generating system is $8110 million assuming gas turbine renewals.

The same 10-year generation plan (for 1981-1990) applies to the thermal generating scenario as it does for the hydroelectric scenarios given above. This period sees the installation of the Beluga combine cycle Unit No. 8 by Chugach Electric Association and the 94 MW Bradley Lake hydro plant in 1988.

Under the medium load forecast the level of installed coal-fired units increases from 54 MW in 1990 to 900 MW in 2010 with the first coal unit addition in 1993 to meet loss of load probability requirements. The model selects 100 MW coal unit additions over 250 and 500 MW units. This selection is due in part to a relatively slow demand growth from year to year and the generous reserve capacity of peaking units in the existing Railbelt region. The 2010 system mix is comprised primarily of natural gas turbines and coal units, although energy dispatched is more reliant on coal plants operating at approximately 70 percent plant factor.

(ii) Other Load Forecasts

Section 5 identified load forecasts which took into account combinations of levels of economic growth and government expenditure. These load forecasts also included the cases with load management and conservation and the probabilistic variation on the medium load forecast. As in the medium forecast, the two cases of gas turbine renewal or non-renewal were determined.

- High Load Forecast

  The high load forecast requires the installation of a 100 MW coal-fired plant in 1990. This is the same as was determined for Susitna and non-Susitna hydro scenarios under the high load forecast. The long-term present worth cost of the thermal generation scenario under this load forecast is $13,630 million assuming a renewal policy of gas turbines. There is a slight benefit of $110 million if a policy of non-renewal is pursued. However, the two cases can be assumed to be effectively the same.

- Low Load Forecast

The low load forecast requires approximately one third of the capacity additions as the high load forecast (Table G.11). The present worth cost of the thermal system under the low load forecast, and assuming renewals of gas turbine units, is $5910 million. With no renewals, the present worth cost is very slightly increased to $5920 million.

- Load Management and Conservation Forecast

The thermal generation plan required to meet the low load forecast with a determined policy of load management and conservation was developed using the same principles and practice as for the Susitna plans. As would be expected this forecast resulted in a lower cost system than that found under the unadjusted low load forecast. The present worth cost was found to be $4930 million for this scenario (no renewals were assumed).

- Probabilistic Load Forecast

To complete the analysis of the thermal generation plan, the medium load forecast was operated under the assumption of a probabilistic load variation. The effect of assuming this variation to the medium forecast results, as was found for Susitna Basin developments, in an increase in long-term present worth cost. The present worth cost for this system (Table G.11) is $8320 million. This assumes no gas turbine renewals and represents an increase of $190 million over the comparable medium load forecast case.

(iii) Sensitivity Analyses

It is important to objectively determine the sensitivity of non-Susitna or non-renewal resource dependent generation plans or changes in costs and escalation of fuel, interest rates, construction costs, and plant life.

- Interest Rate Sensitivity

As in the Susitna development scenario and the investigation into the sensitivity of the plan to economic parameter changes, the assumed underlying escalation rate for the base case thermal plan is zero percent and the interest rate is three percent. Sensitivity of the thermal plan to changes in the interest rate to 5 and 9 percent was determined, again assuming a zero percent escalation or inflation rate. Table G.12 shows the change of the present worth cost for the plan from $8130 million to $5170 million and $2610 million for five and nine percent interest rates respectively.

If a comparison was to be drawn between thermal and Susitna scenarios studied under the sensitivity analyses, it would show that the two plans would be economically comparable (in terms of present worth cost) if interest rates were approximately eight percent.

To provide reasonable comparisons between interest rate sensitivity analyses it was necessary to assume that the generation system mix would be similar as that determined for the three percent OGP5 run. If this was not the case, then OGP5 would select cheaper generation units, particularly natural gas, which probably would not meet defined criteria on system components.

- Fuel Cost

The reduction of fuel costs by 20 percent produces significant reduction in present worth cost of approximately $1060 million to $7070 million. This reduction is due to the lower expense of supplying the plants with the necessary fuel to power the units.

- Fuel Cost Escalation

Fuel cost escalation sensitivity was assessed in two methods. The first was assuming zero percent escalation for all three major fuels and the second was to assume zero percent for coal only, with oil and natural gas remaining at an escalation rate of 3.58 and 3.98 percent respectively. In both cases escalation rates were assumed to apply between 1980 and 2005 and progressively dropping to zero in 2010.

The case of zero percent escalation for all fuels shows a dramatic reduction in present worth cost of $3570 million over the base case thermal scenario (Table G.12).

As would be expected for zero percent escalation in the cost of coal, the reduction in production cost is less than for no escalation in cost of any fuel. This reduction is, however, still significant and amounts to an annual savings of $1210 million over the base case thermal plan.

- Economic Life of Thermal Plant

The uncertainty associated with the probable plant life of installations in the Railbelt region naturally raises concerns. To address these concerns the thermal plant life, in each category, was extended by 50 percent. The plant life therefore became 45, 45, and 30 years for coal, gas and oil facilities respectively.

The extension of the economic life results in a gain in cost of approximately $280 million for the thermal generation scenario.

- Thermal Capital Costs

Capital cost is another area of concern which has been addressed in an attempt to negotiate the uncertainties associated with costing work or structures in remote areas. Although the costs developed are believed to be the best possible estimates that can be made at this time, the costs of all-thermal plant types have been reduced by 22 percent.

As would be expected from a logical inspection at the system, the reduction in coal plant costs results in coal becoming more economically viable as an energy scource. Capital costs reduction therefore shows a gain in coal capacity generation of 200 MW over the base case thermal plan. The long term present worth cost is reduced to $7590 million, a reduction of $540 million from the base case.

TABLE G.1 - SALIENT FEATURES OF GENERATION PLANNING PROGRAMS

Program/ Developer	Load Modeling	Generation Modeling	Optimization Available	Reliability Criterion	Production Simulation	Availability and Cost/Run
GENOP/ Westinghouse	Done by two external programs	Done by one external program	yes	LOLP or % reserve	Deterministic or Modified Booth - Baleriaux	$500 to validate Learning Curve Costs $300 - $800/run
PROMOD/EMA	Done by one external program	Done by one external program	no	LOLP or % reserve	Modified Booth - Baleriaux	$2,500 to validate on TYMSHARE Learning Curve Costs $300 - $500/run
OGP/GE	Done by one external program	Done by one external program	yes	LOLP or % reserve	Deterministic or Stochastic	AAI validated Columbia & Buffalo Experienced Personnel $50 - $800/run

TABLE G.2 - RAILBELT REGION LOAD AND ENERGY FORECASTS USED FOR GENERATION PLANNING STUDIES

	LOAD CASE											
	Low Plus Load Management and Conservation (LES-GL Adjusted)[1]			Low (LES-GL)[2]			Medium (MES-GM)[3]			High (HES-GH)[4]		
Year	MW	GWh	Load Factor	MW	GWh	Load Factor	MW	GWh	Load Factor	MW	GWh	Load Factor
1980	510	2790	62.5	510	2790	62.4	510	2790	62.4	510	2790	62.4
1985	560	3090	62.8	580	3160	62.4	650	3570	62.6	695	3860	63.4
1990	620	3430	63.2	640	3505	62.4	735	4030	62.6	920	5090	63.1
1995	685	3810	63.5	795	4350	62.3	945	5170	62.5	1295	7120	62.8
2000	755	4240	63.8	950	5210	62.3	1175	6430	62.4	1670	9170	62.6
2005	835	4690	64.1	1045	5700	62.2	1380	7530	62.3	2285	12540	62.6
2010	920	5200	64.4	1140	6220	62.2	1635	8940	62.4	2900	15930	62.7

Notes:

(1) LES-GL: Low economic growth/low government expenditure with load management and conservation.
(2) LES-GL: Low economic growth/low government expenditure.
(3) MES-GM: Medium economic growth/moderate government expenditure.
(4) HES-GH: High economic growth/high government expenditure.

TABLE G.3 - LOADS AND PROBABILITIES USED IN GENERATION PLANNING

FORECAST[1]	PROBABILITY SET
LES-LG	.10
LES-MG	.20
MES-MG	.40
HES-MG	.20
HES-HG	.10

Notes:

(1) LES: Low economic growth
MES: medium economic growth
HES: high economic growth
LG: low government expenditure
MG: moderate government expenditure
HG: high government expenditure

TABLE G.4 - FUEL COSTS AND ESCALATION RATES

	Natural Gas	Coal	Distillate
Base Period (January 1980)			
- Prices ($/million Btu)			
Market Prices	$1.05	$1.15	$4.00
Shadow (Opportunity) Values	2.00	1.15	4.00
Real Escalation Rates (Percentage)			
- Change Compounded (Annually)			
1980 - 1985	1.79%	9.56%	3.38%
1986 - 1990	6.20	2.39	3.09
1991 - 1995	3.99	-2.87	4.27
Composite (average) 1980-1995	3.98	2.93	3.58
1996 - 2005	3.98	2.93	3.58
2006 - 2010	0	0	0

TABLE G.5 - ANNUAL FIXED CARRYING CHARGES USED IN GENERATION PLANNING MODEL

	Project Life/Type			
	30-Year Thermal (%)	35-Year Thermal (%)	50-Year Hydro (%)	20-Year Thermal (%)
ECONOMIC PARAMETERS (0%-3%)				
Cost of Money	3.00	3.00	3.00	3.00
Amortization	2.10	1.65	0.89	3.72
Insurance	0.25	0.25	0.10	0.25
TOTALS	5.35	4.90	3.99	6.97
FINANCIAL PARAMETERS (7%-10%)				
Non-exempt				
Cost of Money	10.00	10.00	10.00	10.00
Amortization	0.61	0.37	0.09	1.75
Insurance	0.25	0.25	0.10	0.25
TOTALS	10.86	10.62	10.19	12.00
Tax-exempt				
Cost of Money	8.00	8.00	8.00	8.00
Amortization	0.88	0.58	0.17	2.19
Insurance	0.25	0.25	0.10	0.25
TOTALS	9.13	8.83	8.27	10.44

TABLE G.6 - TEN YEAR BASE GENERATION PLAN MEDIUM LOAD FORECAST

YEAR	MW Committed	MW Retired	SYSTEM (MW) COAL	NG GT	OIL GT	OIL DIESEL	CC	HY	TOTAL CAPABILITY (MW)
1980	-	-	54	470	168	65	141	49	947[1]
1981	-	-	54	470	168	65	141	49	947
1982	60 CC	-	54	470	168	65	201	49	1007
1983	-	-	54	470	168	65	201	49	1007
1984	-	-	54	470	168	65	201	49	1007
1985	-	14 (NGGT)	54	456	168	65	201	49	993
1986	-	-	50	456	168	65	201	49	993
1987	-	4 (Coal)	50	456	168	65	201	49	989
1988	95 HY	-	50	456	168	65	201	144	1084
1989	-	5 (Coal)	45	456	168	65	201	144	1079
1990	-	-	45	456	168	65	201	144	1079

Notes:

(1) This figures varies slightly from the 943.6 MW reported due to internal computer rounding.

TABLE G.7 - SUSITNA ENVIRONMENTAL DEVELOPMENT PLANS

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft	Annual Energy Production Firm GWH	Avg. GWH.	Plant Factor %
E1.1	1	Watana 2225 ft 800MW and Re-Regulation Dam	1960	1993	2200	150	2670	3250	46
	2	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2860						
E1.2	1	Watana 2060 ft 400MW	1570	1992	2000	100	1710	2110	60
	2	Watana raise to 2225 ft	360	1995	2200	150	2670	2990	85
	3	Watana add 400MW capacity and Re-Regulation Dam	230[2]	1995	2200	150	2670	3250	46
	4	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	3060						
E1.3	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400MW capacity and Re-Regulation Dam	250	1993	2200	150	2670	3250	46
	3	Devil Canyon 1470 ft 400 MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2890						

TABLE G.7 (Continued)

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Avg. GWH	Plant Factor %
E1.4	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5190	5670	81
		TOTAL SYSTEM 800MW	2640						
E2.1	1	High Devil Canyon 1775 ft 800MW and Re-Regulation Dam	1600	1994[3]	1750	150	2460	3400	49
	2	Vee 2350ft 400MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200MW	2660						
E2.2	1	High Devil Canyon 1630 ft 400MW	1140	1993[3]	1610	100	1770	2020	58
	2	High Devil Canyon raise dam to 1775 ft add 400MW and Re-Regulation Dam	600	1996	1750	150	2460	3400	49
	3	Vee 2350 ft 400 MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200MW	2800						
E2.3	1	High Devil Canyon 1775 ft 400MW	1390	1994[3]	1750	150	2400	2760	79
	2	High Devil Canyon add 400MW capacity and Re-Regulation Dam	240	1995	1750	150	2460	3400	49
	3	Vee 2350 ft 400MW	1060	1997	2330	150	3870	4910	47
		TOTAL SYSTEM 1200	2690						

TABLE G.7 (Continued)

			Stage/Incremental Data				Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date[1]	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft.	Annual Energy Production Firm GWH	Avg. GWH	Plant Factor %
E2.4	1	High Devil Canyon 1755 ft 400MW	1390	1994[3]	1750	150	2400	2760	79
	2	High Devil Canyon add 400MW capacity and Portage Creek Dam 150 ft	790	1995	1750	150	3170	4080	49
	3	Vee 2350 ft 400MW	1060	1997	2330	150	4430	5540	47
		TOTAL SYSTEM	3240						
E3.2	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400 MW capacity and Re-Regulation Dam	250	1994	2200	150	2670	3250	46
	3	Watana add 50MW Tunnel Scheme 330MW	1500	1995	1475	4	4890	5430	53
		TOTAL SYSTEM 1180MW	3490						
E4.1	1	Watana 2225 ft 400MW	1740	1995[3]	2200	150	2670	2990	85
	2	Watana add 400MW capacity and Re-Regulation Dam	250	1996	2200	150	2670	3250	46
	3	High Devil Canyon 1470 ft 400MW	860	1998	1450	100	4520	5280	50
	4	Portage Creek 1030 ft 150MW	650	2000	1020	50	5110	6000	51
		TOTAL SYSTEM 1350 MW	3500						

NOTES:
(1) Allowing for a 3 year overlap construction period between major dams.
(2) Plan 1.2 Stage 3 is less expensive than Plan 1.3 Stage 2 due to lower mobilization costs.
(3) Assumes FERC license can be filed by June 1984, ie. 2 years later than for the Watana/Devil Canyon Plan 1.

TABLE G.8 - RESULTS OF ECONOMIC ANALYSES OF SUSITNA PLANS - MEDIUM LOAD FORECAST

Susitna Development Plan Inc.	Online Dates Stages				OGP5 Run	Installed Capacity (MW) by Category in 2010					Total System Installed	Total System Present	Remarks Pertaining to
Plan						Thermal			Hydro		Capacity In	Worth Cost	the Susitna Basin
No.	1	2	3	4	Id. No.	Coal	Gas	Oil	Other	Susitna	2010-MW	$ Million[1]	Development Plan
E1.1	1993	2000	--	--	LXE7	300	426	0	144	1200	2070	5850	
E1.2	1992	1995	1997	2002	L5Y9	200	501	0	144	1200	2045	6030	
E1.3	1993	1996	2000	--	L8J9	300	426	0	144	1200	2070	5850	
	1993	1996	--	--	L7W7	500	651	0	144	800	2095	6960	Stage 3, Devil Canyon Dam not constructed
	1998	2001	2005	--	LAO7	400	276	30	144	1200	2050	6070	Delayed implementation schedule
E1.4	1993	2000	--	--	LCK5	200	726	50	144	800	1920	5890	Total development limited to 800 MW
Modified E2.1	1994	2000	--	--	LB25	400	651	60	144	800	2055	6620	High Devil Canyon limited to 400 MW
E2.3[1]	1993	1996	2000	--	L601	300	651	20	144	1200	2315	6370	
	1993	1996	--	--	LE07	500	651	30	144	800	2125	6720	Stage 3, Vee Dam, not constructed
Modified E2.3	1993	1996	2000		LEB3	300	726	220	144	1300	2690	6210	Vee dam replaced by Chakachamna dam
3.1	1993	1996	2000	--	L607	200	651	30	144	1180	2205	6530	
Special 3.1	1993	1996	2000	--	L615	200	651	30	144	1180	2205	6230	Capital cost of tunnel reduced by 50 percent
E4.1	1995	1996	1998	--	LTZ5	200	576	30	144	1200	2150	6050	Stage 4 not constructed

NOTES:

(1) Adjusted to incorporate cost of re-regulation dam

TABLE G.29 - RESULTS OF ECONOMIC ANALYSES OF SUSITNA PLANS - LOW AND HIGH LOAD FORECAST

Plan No.	Susitna Development Plan Inc. Online Dates Stages 1	2	3	4	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010 Thermal Coal	Gas	Oil	Hydro Other	Susitna	Total System Installed Capacity In 2010-MW	Total System Present Worth Cost $ Million	Remarks Pertaining to the Susitna Basin Development Plan
VERY LOW FORECAST[1]													
E1.4	1997	2005	--	--	L7B7	0	651	50	144	800	1645	3650	
LOW LOAD FORECAST													
E1.3	1993	1996	2000	--	--	--	--	--	--	--	--	--	Low energy demand does not warrant plan capacities
E1.4	1993	2002	--	--	LC07	0	351	40	144	800	1335	4350	
	1993	--	--	--	LBK7	200	501	80	144	400	1325	4940	Stage 2, Devil Canyon Dam, not constructed
E2.1	1993	2002	--	--	LG09	100	426	30	144	800	1500	4560	High Devil Canyon limited to 400 MW
	1993	--	--	--	LBU1	400	501	0	144	400	1445	4850	Stage 2, Vee Dam, not constructed
E2.3	1993	1996	2000	--	--	--	--	--	--	--	--	--	Low energy demand does not warrant plan capacities
Special 3.1	1993	1996	2000	--	L613	0	576	20	144	780	1520	4730	Capital cost of tunnel reduced by 50 percent
3.2	1993	2002	--	--	L609	0	576	20	144	780	1520	5000	Stage 2, 400 MW addition to Watana, not constructed
HIGH LOAD FORECAST													
E1.3	1993	1996	2000	--	LA73	1000	951	0	144	1200	3295	10680	
Modified E1.3	1993	1996	2000	2005[2]	LBV7	800	651	60	144	1700	3355	10050	Chakachamna hydroelectric generating station (480 MW) brought on line as a fourth stage
E2.3	1993	1996	2000	--	LBV3	1300	951	90	144	1200	3685	11720	
Modified E2.3	1993	1996	2000	2003[2]	LBY1	1000	876	10	144	1700	3730	11040	Chakachamna hydroelectric generating station (480 MW) brought on line as a fourth stage

NOTE:

(1) Incorporating load management and conservation

TABLE G.9 - RESULTS OF ECONOMIC ANALYSES OF SUSITNA PLANS - LOW AND HIGH LOAD FORECAST

Susitna Development Plan Inc. Online Dates						Installed Capacity (MW) by Category in 2010					Total System Installed Capacity In 2010-MW	Total System Present Worth Cost $ Million	Remarks Pertaining to the Susitna Basin Development Plan
	Stages					Thermal			Hydro				
Plan No.	1	2	3	4	OGP5 Run Id. No.	Coal	Gas	Oil	Other	Susitna			
VERY LOW FORECAST[1]													
E1.4	1997	2005	--	--	L7B7	0	651	50	144	800	1645	3650	
LOW LOAD FORECAST													
E1.3	1993	1996	2000	--	--	--	--	--	--	--	--	--	Low energy demand does not warrant plan capacities
E1.4	1993	2002	--	--	LC07	0	351	40	144	800	1335	4350	
	1993	--	--	--	LBK7	200	501	80	144	400	1325	4940	Stage 2, Devil Canyon Dam, not constructed
E2.1	1993	2002	--	--	LG09	100	426	30	144	800	1500	4560	High Devil Canyon limited to 400 MW
	1993	--	--	--	LBU1	400	501	0	144	400	1445	4850	Stage 2, Vee Dam, not constructed
E2.3	1993	1996	2000	--	--	--	--	--	--	--	--	--	Low energy demand does not warrant plan capacities
Special 3.1	1993	1996	2000	--	L613	0	576	20	144	780	1520	4730	Capital cost of tunnel reduced by 50 percent
3.2	1993	2002	--	--	L609	0	576	20	144	780	1520	5000	Stage 2, 400 MW addition to Watana, not constructed
HIGH LOAD FORECAST													
E1.3	1993	1996	2000	--	LA73	1000	951	0	144	1200	3295	10680	
Modified E1.3	1993	1996	2000	2005[2]	LBV7	800	651	60	144	1700	3355	10050	Chakachamna hydroelectric generating station (480 MW) brought on line as a fourth stage
E2.3	1993	1996	2000	--	LBV3	1300	951	90	144	1200	3685	11720	
Modified E2.3	1993	1996	2000	2003[2]	LBY1	1000	876	10	144	1700	3730	11040	Chakachamna hydroelectric generating station (480 MW) brought on line as a fourth stage

NOTE:

(1) Incorporating load management and conservation

TABLE G.10 - RESULTS OF ECONOMIC SENSITIVITY ANALYSES FOR GENERATION SCENARIO INCORPORATING SUSITNA BASIN DEVELOPMENT PLAN E1.3 - MEDIUM FORECAST

Description Parameter Varied	Parameter Values	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010: Thermal Coal	Thermal Gas	Thermal Oil	Hydro Other	Hydro Susitna	Total System Installed Capacity In 2010 MW	Total System Present Worth Cost $ Million	Remarks
Interest Rate	5%	LF85	300	426	0	144	1200	2070	4230	
	9%	LF87	300	426	0	144	1200	2070	2690	
Fuel Cost ($ million Btu, natural gas/coal/oil)	1.60/0.92/3.20	L533	100	576	20	144	1200	2040	5260	20% fuel cost reduction
Fuel Cost Escalation (%, natural gas/coal/oil)	0/0/0	L557	0	651	30	144	1200	2025	4360	Zero escalation
	3.98/0/3.58	L563	300	426	0	144	1200	2070	5590	Zero coal cost escalation
Economic Life of Thermal Plants (year, natural gas/coal/oil)	45/45/30	L585	45	367	233	144	1200	1989	6100	Economic lives increased by 50%
Thermal Plant Capital Cost ($/kW, natural gas/coal/oil)	350/2135/778	LED7	300	426	0	144	1200	2070	5740	Coal capital cost reduced by 22%
Watana/Devil Canyon Capital Cost[2] ($ million, Watana/Devil Canyon)	1990/1110	L5G1	300	426	0	144	1200	2070	6210	Capital cost for Devil Canyon Dam increased by 23%
	2976/1350	LD75	300	426	0	144	1200	2070	6810	Capital cost for both dams increased by 50%
Probabilistic Load Forecast		L8T5	200	1476	140	144	1200	3160	6290	

NOTES:

(1) Alaskan cost adjustment factor reduced from 1.8 to 1.4 (see Section 8.__)
(2) Excluding AFDC

TABLE G.11 - RESULTS OF ECONOMIC ANALYSES OF ALTERNATIVE GENERATION SCENARIOS

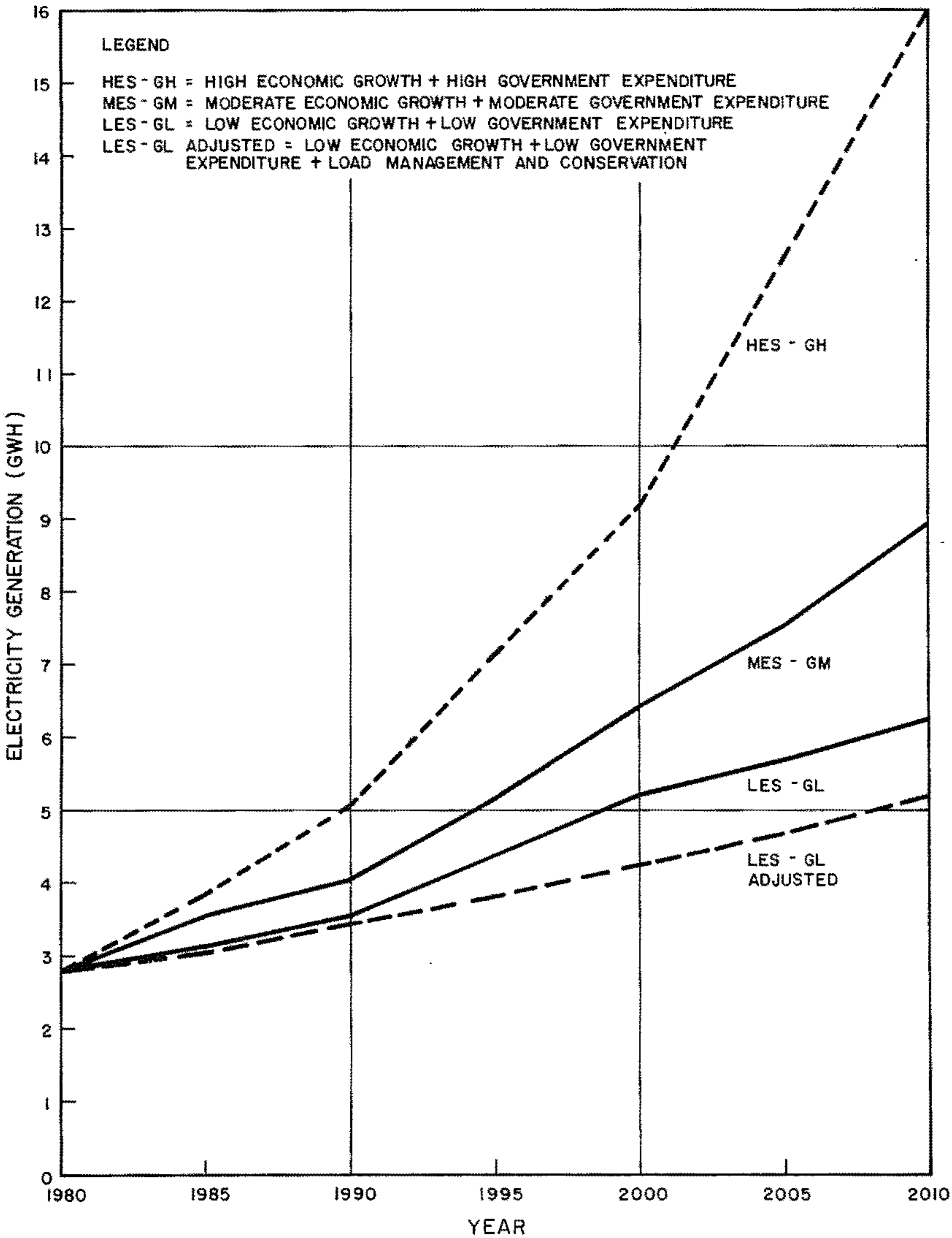
Generation Scenario				Installed Capacity (MW) by Category in 2010				Total System Installed Capacity in 2010 (MW)	Total System Present Worth Cost - ($$10^6$)
				Thermal			Hydro		
Type	Description	Load Forecast	OGP5 Run Id. No.	Coal	Gas	Oil			
All Thermal	No Renewals	Very Low[1]	LBT7	500	426	90	144	1160	4930
	No Renewals	Low	L7E1	700	300	40	144	1385	5920
	With Renewals	Low	L2C7	600	657	30	144	1431	5910
	No Renewals	Medium	LME1	900	801	50	144	1895	8130
	With Renewals	Medium	LME3	900	807	40	144	1891	8110
	No Renewals	High	L7F7	2000	1176	50	144	3370	13520
	With Renewals	High	L2E9	2000	576	130	144	3306	13630
	No Renewals	Probabilistic	LOF3	1100	1176	100	144	3120	8320
Thermal Plus Alternative Hydro	No Renewals Plus: Chakachamna (500)[2]-1993 Keetna (120)-1997	Medium	L7W1	600	576	70	764	2010	7080
	No Renewals Plus: Chakachamna (500)-1993 Keetna (120)-1997 Snow (50)-2002	Medium	LFL7	700	501	10	814	2025	7040
	No Renewals Plus: Chakachamna (500)-1993 Keetna (120)-1996 Strandline (20), Allison Creek (8), Snow (50)-1998	Medium	LWP7	500	576	60	847	1983	7064
	No Renewals Plus: Chakachamna (500)-1993 Keetna (120)-1996 Strandline (20), Allison Creek (8), Snow (50)-2002	Medium	LXF1	700	426	30	847	2003	7041
	No Renewals Plus: Chakachamna (500)-1993 Keetna (120)-1996 Snow (50), Cache (50), Allison Creek (8), Talkeetna-2 (50), Strandline (20)-2002	Medium	L403	500	576	30	947	2053	7088

Notes:

(1) Incorporating load management and conservation
(2) Installed capacity

TABLE G.12 - RESULTS OF ECONOMIC ANALYSES FOR GENERATION SCENARIO INCORPORATING THERMAL DEVELOPMENT PLAN - MEDIUM FORECAST

Description Parameter Varied	Parameter Value	OGP5 Run Id. No.	Installed Capacity (MW) by Category in 2010 Thermal Coal	Gas	Oil	Hydro	Total System Installed Capacity In 2010 Total MW	Total System Present Worth Cost $ Million	Remarks
Interest Rate	5%	LEA9	900	800	50	144	1895	5170	
	9%	LEB1	900	801	50	144	1895	2610	
Fuel Cost ($ million Btu, natural gas/coal/oil)	1.60/0.92/3.20	L1K7	800	876	70	144	1890	7070	20% fuel cost reduction
Fuel Cost Escalation (%, natural gas/coal/oil)	0/0/0	L547	0	1701	10	144	1855	4560	Zero escalation
	3.98/0/3.58	L561	1100	726	10	144	1980	6920	Zero coal cost escalation
Economic Life of Thermal Plants (year, natural gas/coal/oil)	45/45/30	L583	1145	667	51	144	2007	7850	Economic life increased 50%
Thermal Plant Capital Cost ($/kW, natural gas/ coal/oil)	350/2135/778	LAL9	1100	726	10	144	1980	7590	Coal capital cost reduced by 22%



ENERGY FORECASTS USED FOR GENERATION PLANNING STUDIES

ACRES

FIGURE G.1

APPENDIX H - ENGINEERING STUDIES

As the project planning studies outlined in Sections 6 and 7 were completed, a start was made with more detailed engineering studies for the selected Watana and Devil Canyon sites. The major thrust of these studies was twofold:

- To select the appropriate dam type for the two sites;
- To undertake some preliminary design of the selected dam types.

This section briefly outlines the results of the studies to date. A more detailed description will be incorporated in the Project Feasibility Report.

H.1 - Devil Canyon Site

(a) Dam Type Studies

A major advantage of an arch dam relative to a comparable rock/earthfill structure is the generally lower cost of the auxiliary structures, which can be incorporated within the dam itself or reduced in overall length corresponding to the reduced base width of the concrete dam. In order to study the relative economics of different dam types it was necessary to develop general arrangements of the sites including the diversion, power facilities and spillways. A representative arrangement was studied for each of the following dam types at the Devil Canyon site:

- A thick concrete arch dam;
- A thin concrete arch dam; and
- A rockfill dam.

None of these layouts are intended as the final site arrangement, but each will be sufficiently representative of the most suitable arrangement associated with each dam type to provide an adequate basis for comparison. Each type of dam is located just downstream of where the river enters Devil Canyon, close to the canyon's narrowest point, which is the optimum location for all types of dams. A brief description of each dam type and configuration is given below.

(i) Thick Arch Dam

As shown on Plates H.1 and H.2, the main concrete dam is a single center arch structure, acting partly as a gravity dam, with a vertical cylindrical upstream face and a sloping downstream face inclined at 1V:0.4H. The maximum height of the dam is 635 feet with a uniform crest width of 30 feet, a crest length of approximately 1400 feet and a maximum foundation width of 225 feet. The crest elevation is 1460 feet. The center portion of the dam is founded on a massive concrete pad constructed in the excavated river bed. This central section incorporates a service spillway with gated orifice spillways discharging down the steeply inclined downstream face of the dam into a single large stilling basin with sidewalls anchored into solid bedrock set below river level, spanning the valley.

The main dam terminates in thrust blocks high on the abutments. The left abutment thrust block incorporates an emergency gated control spillway structure which discharges into a rock channel running well downstream and terminating at a high level in the river valley.

Beyond the control structure and thrust block a low lying saddle on the left abutment is closed by means of a rockfill dike founded on bedrock. The powerhouse houses four 150 MW units and is located underground within the right abutment. The multi-level intake is constructed integrally with the dam and connected to the powerhouse by vertical steel-lined penstocks.

The service spillway is designed to pass the 1:10,000 year routed flood with larger floods discharged downstream via the emergency spillway.

(ii) Thin Arch Dam

As shown on Plate 10, the main dam is a two-center, double curved arch structure of similar height to the thick arch dam, but with a 20 foot uniform crest width and a maximum base width of 90 feet. The crest elevation is 1460 feet. The center section is founded on a concrete pad and the extreme upper portion of the dam terminates in concrete thrust blocks located on the abutments.

The main service spillway is located on the right abutment and consists of a conventional gated control structure discharging down a concrete-lined chute terminating in a flip bucket. The bucket discharges into an unlined plunge pool excavated in the riverbed alluvium and located sufficiently downstream to prevent undermining of the dam and associated structures.

The main spillway is supplemented by orifice type spillways located high in the center portion of the dam which discharge into a concrete-lined plunge pool immediately downstream of the dam. An emergency spillway consisting of a fuse plug discharging into an unlined rock channel which terminates well downstream, is located beyond the saddle dam on the left abutment.

The concrete dam terminates in a massive thrust block on each abutment which, on the left abutment, adjoins a rockfill saddle dam.

The service and auxiliary spillways are designed to discharge the 1:10,000 year flood. Excess flows for storms up to the probable maximum flood will be discharged through the emergency left abutment spillway.

(iii) Rockfill Dam

As shown on Plate 1, the rockfill dam is approximately 670 feet high. It has a crest width of 50 feet, upstream and downstream slopes of 1:2.25 and 1:2 respectively, and contains approximately 20 million cubic yards of material. The central impervious core is supported by a downstream semi-pervious zone. These two zones are protected upstream and downstream by filter and transition materials. The shell sections are constructed from blasted rock. All dam sections are founded on sound bedrock. External cofferdams are founded on the riverbed alluvium.

A single spillway consisting of a gated control structure, chute and downstream unlined plunge pool is located on the right abutment. This is designed to pass without damage the 1:10,000 year routed flood. Excess capacity is provided to allow discharge of the probable maximum flood with no damage to the main dam.

(b) Construction Materials

Sand and gravel for concrete aggregates are believed to be available in sufficient quantities immediately upstream in the Cheechako fan and terraces. The gravel and sands are formed from the granitic and metamorphic rocks of the area, and at this time it is anticipated that they will be suitable for the production of aggregates after a moderate amount of screening and washing.

Material for the rockfill dam shell would be blasted rock, some of it coming from the site excavations.

It is anticipated that some impervious material for the core is available from the till deposits forming the flat elevated areas on the left abutment and that other suitable borrow materials will be available in high lying areas within the three mile upstream reach of the river; however, none of these deposits have yet been proven.

(c) General Considerations

The geology of the site is as discussed in Section 7 and it appears at this stage that there are no geological or geotechnical concerns that would preclude any of the dam types from consideration. A rockfill dam would be more adaptable than a concrete arch dam to poorer foundation conditions although, at present, foundation and abutment loadings from the arch dams appear well within acceptable limits.

The thick arch dam allows for the incorporation of a main service spillway chute on the downstream face of the dam which discharges into a spillway located deep within the present riverbed. This spillway can pass routed floods with a return frequency of less than 1:10,000 years. For the thin arch and rockfill alternatives the equivalent discharge capacity has to be provided separately through the abutments.

Stresses under hydrostatic and temperature loadings within the thick arch dam are generally lower than those for the thin arch alternative. However, finite element analysis has shown that the additional mass of the dam under seismic loading produces stresses of a greater magnitude in the thick arch dam than in the thin arch dam. If the surface stresses approach the maximum allowable at a particular section, the remaining understressed area of concrete is greater for the thick arch and the factor of safety for the dam is correspondingly higher. The thin arch is, however, a more efficient design and better utilizes the inherent properties of the concrete. It is designed around acceptable predetermined factors of safety and requires a much smaller volume of concrete for the actual dam structure.

At the time of completion of layouts indications were that the thin arch dam would be feasible. A thick arch dam layout was completed to determine if it provided any outstanding advantages, and in case a thin arch, in spite of indications, should prove infeasible. It did not appear to have any outstanding merits compared to a thin arch dam and would be more expensive due to the larger volume of concrete.

A rockfill dam constructed to the design currently assumed offers no cost savings relative to the thin arch consideration of more conservative designs in which the upstream rockfill slopes are revised from 1:2.25 to 1:2.75 to meet possibly more stringent seismic design requirements. These cost increases would occur in the dam itself and in spillway and power facilities because of the larger base width of the dam.

Studies have therefore continued in an effort to confirm the feasibility of the thin arch alternative.

(d) Preliminary Arch Dam Design

Both thin and thick arch dam designs were originally analyzed by means of a computer program based on finite element analysis. Results from these analyses indicated significantly lower stresses for the thick arch under hydrostatic and temperature loadings, as would be anticipated. Substantially higher tensile stresses were found under seismic loading conditions for both dams, although somewhat higher in the case of the thick arch dam.

Stresses close to the foundations and abutments were distorted by the finite element model because of the coarse mesh spacing of the selected nodes. To produce results which could more readily be interpreted, it was decided to use the trial load method and the associated program Arch Dam Stress Analysis System (ADSAS) developed by the USBR. The results of this analysis are presented in the following paragraphs.

The thin, two-center arch dam design is located approximately normal to the valley. There is a gradual thickening of the dam towards the abutments, but the two-center configuration produces similar thickness and contact pressures at equivalent rock/concrete contact elevations and a symmetrical distribution of pressures across the dam. Under hydrostatic loads no tension is evident at the dam faces. Under extreme temperature distribution as determined by the USBR program HEATFLOW, full reservoir conditions bring about low tensile stresses on both faces across the crest of the dam. These approach the allowable tensile stress of 150 psi.

Although analysis has still to be finalized for seismic loadings, indications are that the concrete thin arch dam at Devil Canyon will be structurally feasible.

H.2 - Watana Site

(a) Dam Type Studies

A rockfill dam layout (Plate 12) has been studied at Watana with the dam sited between the northwest trending shear zones of the "Fins" and the "Fingerbuster". The dam is close to the alignment proposed by the Corps of Engineers and is skewed slightly to the valley in a north-northwest direction. The approximate height of the dam is 900 feet, the upstream and downstream slopes are 1V:2.75H and 1V:2H respectively, and the volume is approximately 62 million cubic yards. The assumed crest elevation of the dam is 2225 feet, subject to completion of reservoir level optimization studies.

For initial study purposes, the spillway has been assumed to discharge down the right abutment with an intermediate stilling basin and a downstream stilling basin founded below river level. Two 35 feet diameter diversion tunnels are located on the right bank and an 800 MW underground power station is located on the left abutment. Optimization studies of spillway, diversion and power plant facilities are continuing.

(b) Construction Materials

At this time it is assumed that 50 percent of the rockfill for the shell material for the dam will be blasted rock, a small proportion of which will be obtained from site excavations; the remainder will consist of blasted rock from borrow areas. The remaining 50 percent will be gravel materials obtained from the downstream alluvial riverbed deposits. Gravels for filter zones are available from alluvial deposits in Tsusena Creek. Core material is availabde from glacial tills located approximately three miles upstream above the right side of the river valley. This material will require very little processing.

(c) General Considerations

As an alternative to the rockfill dam, a three-center concrete thin arch has been considered, and layouts are shown on Plates H.3 and H.4. The volume of the dam is 8.25 million cubic yards with additional concrete required for the abutment thrust blocks. The overall cost of concrete will be approximately $1,300 million as compared to $950 million for the upper limit cost estimate for fill within the rockfill dam. Although water passages will be shorter for facilities associated with the concrete dam, it is anticipated that these will be offset by savings in the spillway excavation associated with the rockfill dam where excavated material can be utilized within the dam. The overall costs for both types of dam and their associated facilities will be evaluated further in the Project Feasibility Report. In the meantime, study of layouts associated with the rockfill dam has proceeded.

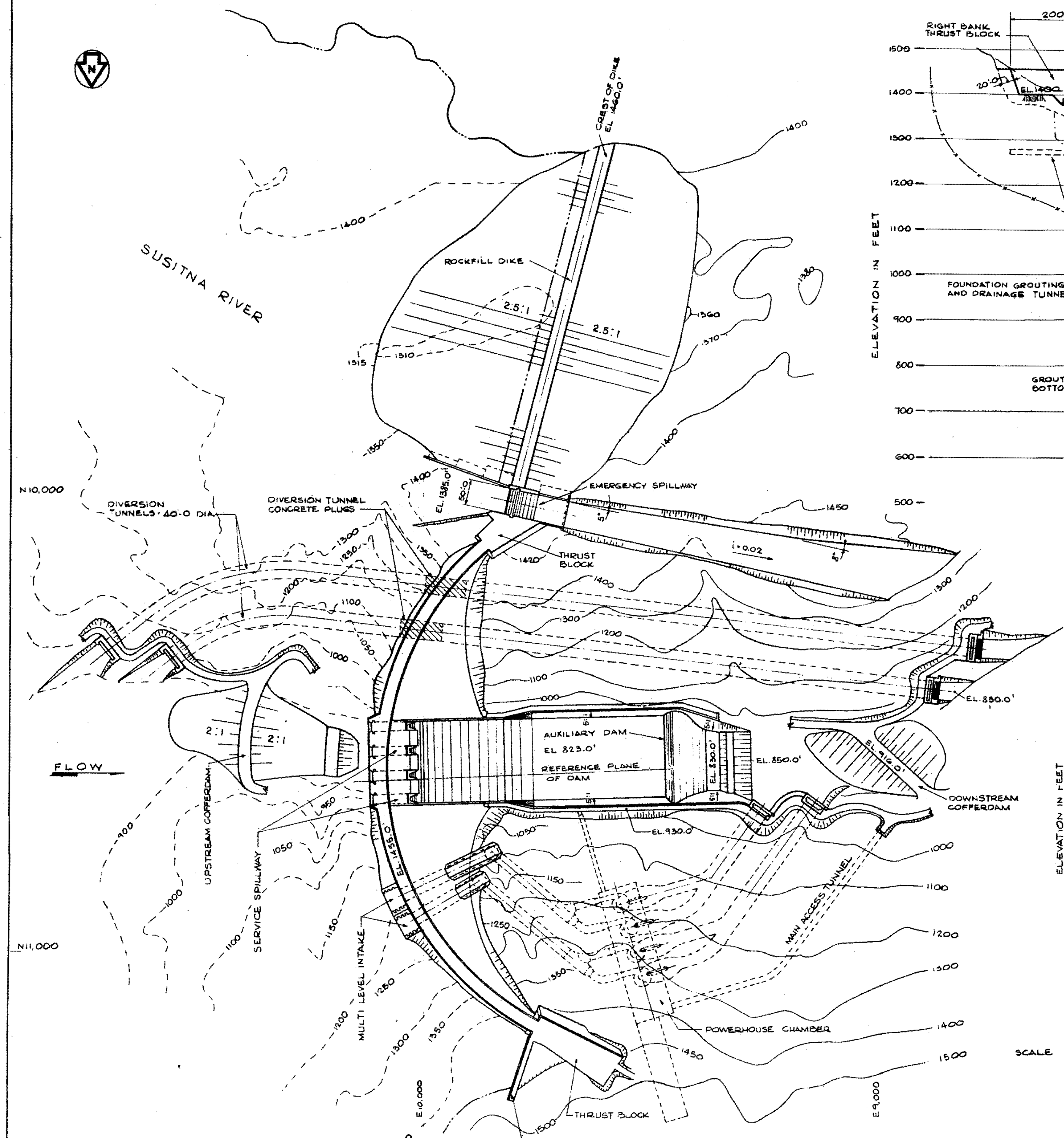
(d) Preliminary Dam Design

A section has been tentatively established for a rockfill dam with a near vertical impervious core (Plate 12). At this time, no stability analyses have been conducted on the dam, but the section is conservatively based on

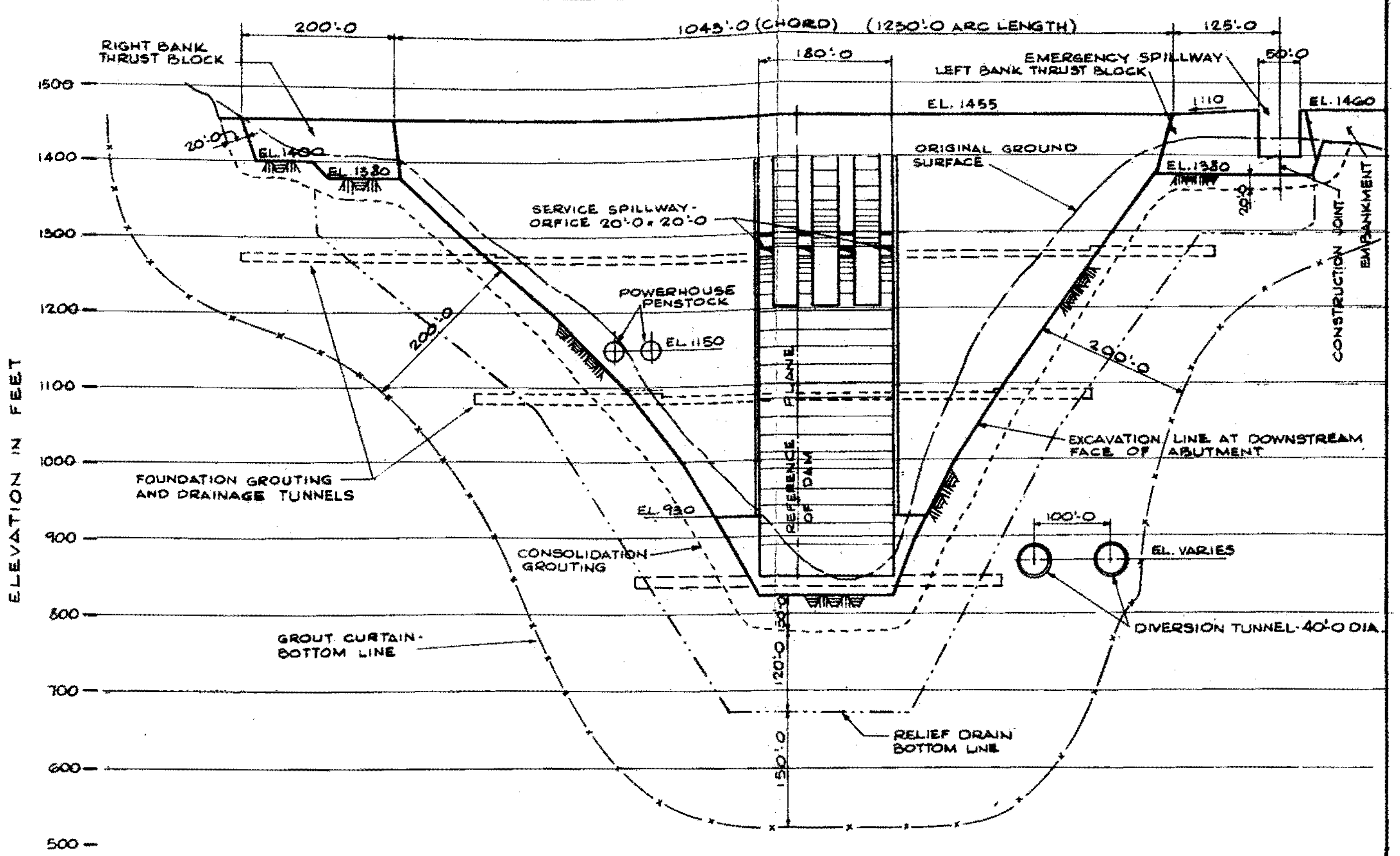
Acres' past experience and on general experience throughout the world concerning similar dam sizes and locations of similar seismic activity. There is a possibility that further analysis will lead to a reduction in size of the dam.

The crest width of the dam is 80 feet, the upstream slope is 1V:2.75H and the downstream slope is 1V:2H.

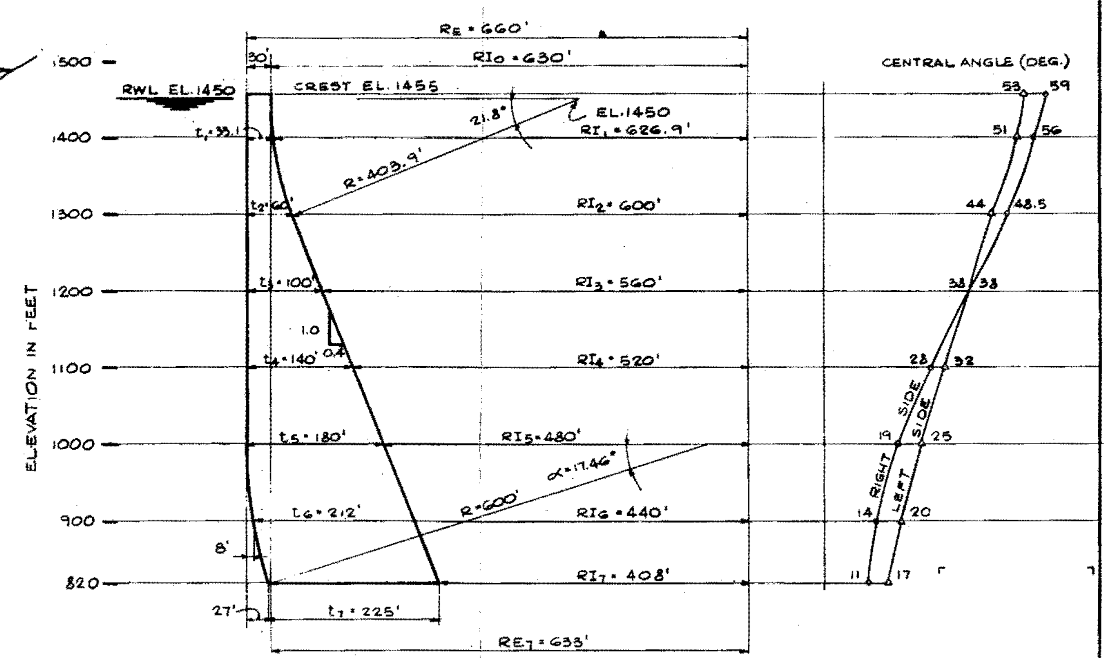
The core is composed of materials from the fine till deposits and the shell is presently to be constructed of blasted rock from site excavations and from borrow and gravel material taken from the riverbed.



GENERAL ARRANGEMENT



DOWNSTREAM ELEVATION OF DAM



ARCH-GRAVITY DAM GEOMETRY

SCALE 0 100 200 FEET

PLATE H1

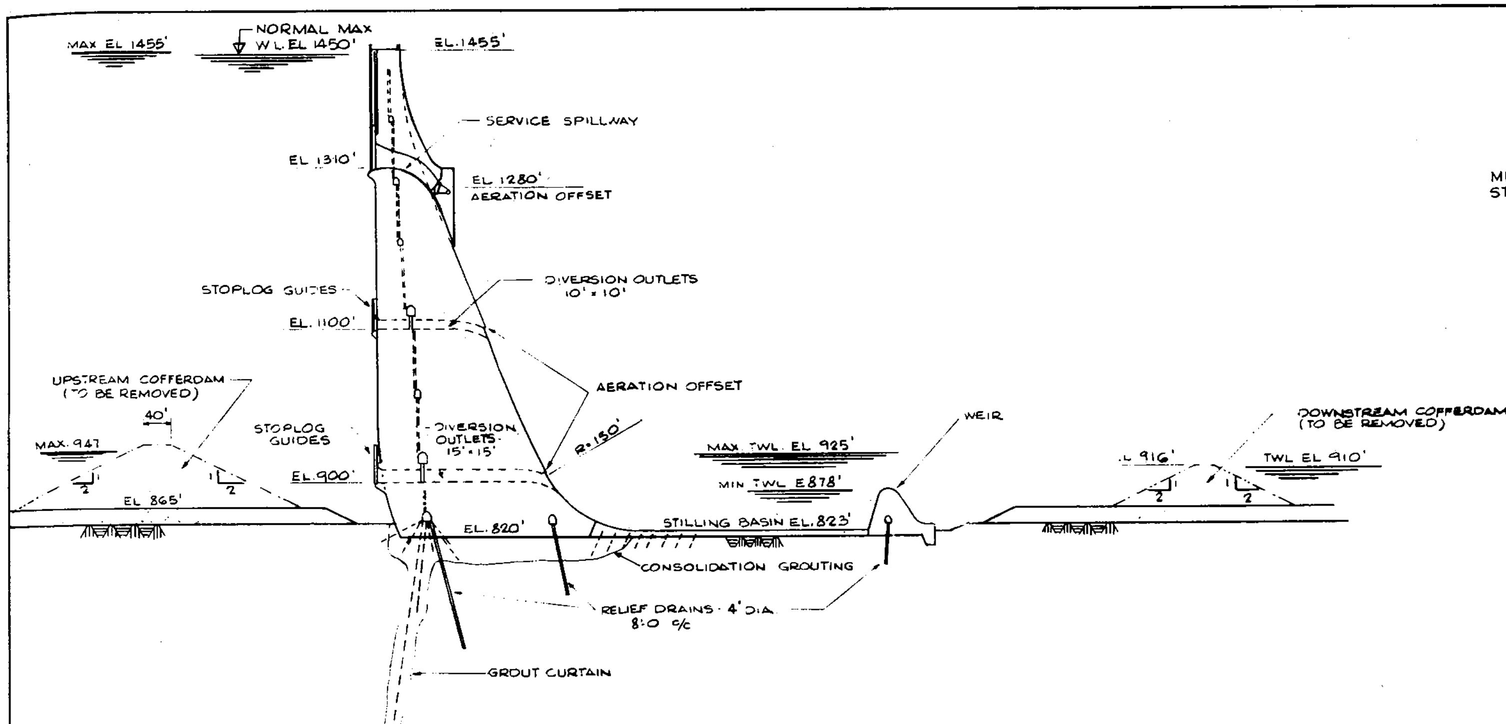
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
ARCH GRAVITY DAM SCHEME
PLAN AND SECTIONS

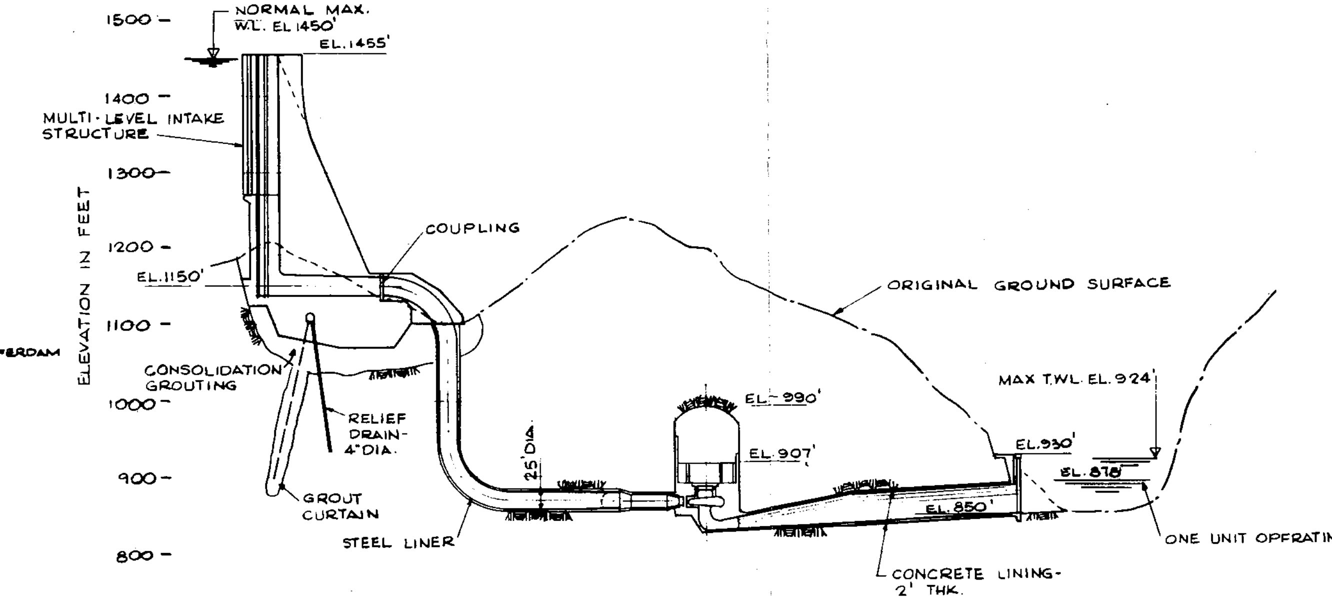
DATE	NO	REVISIONS	CH	APP	APP

ACRES AMERICAN INCORPORATED

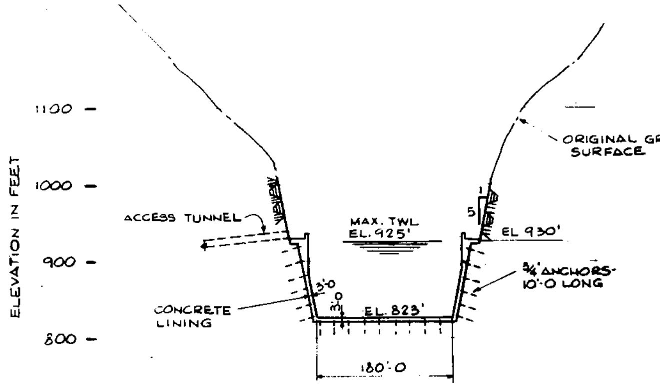
DATE DEC. 1981
SCALE 1" = 100'
DRAWING NO SK-5700-C6-301



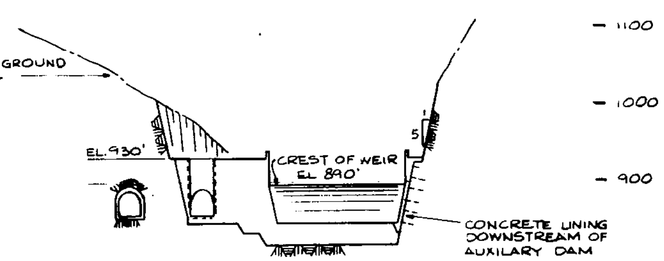
ARCH-GRAVITY DAM LAYOUT



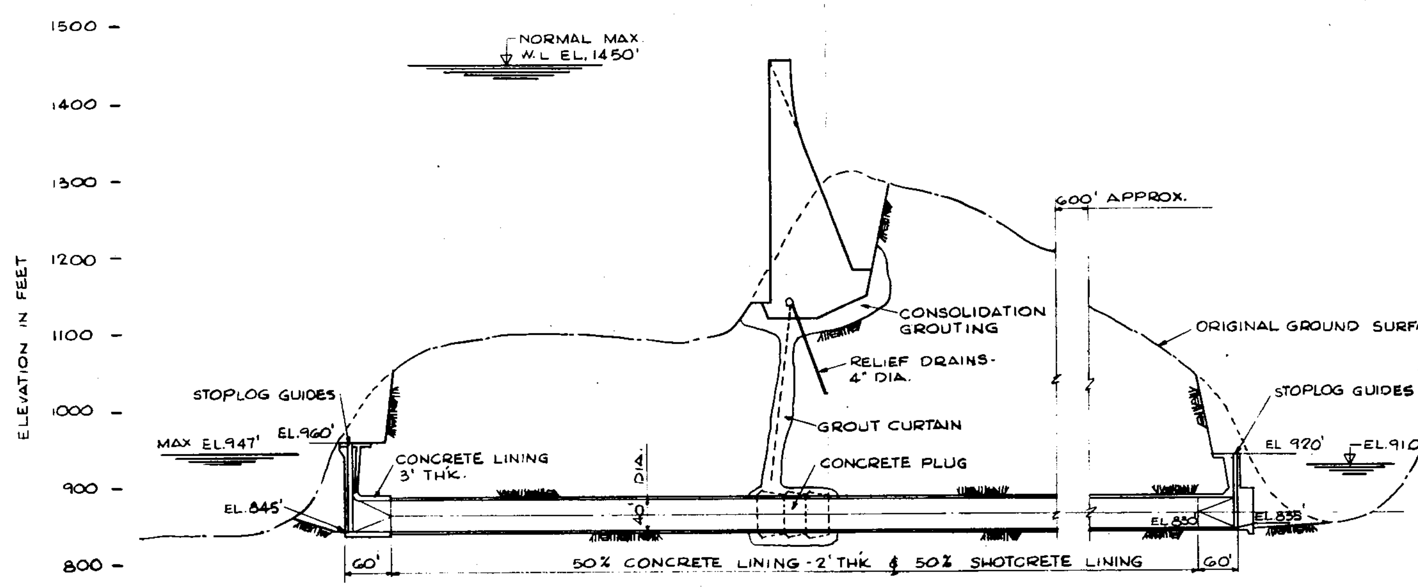
POWER FACILITIES PROFILE



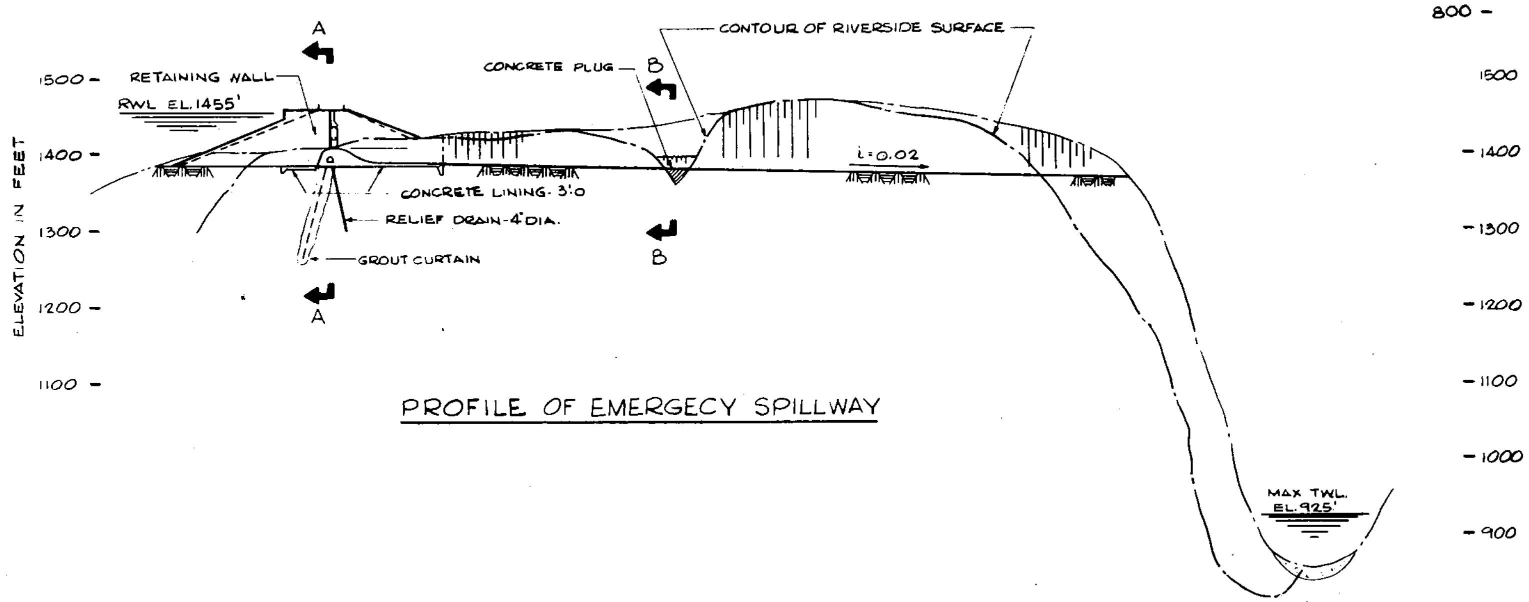
SECTION AT SPILLWAY



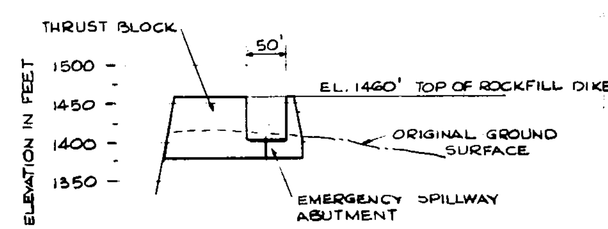
SECTION AT WEIR



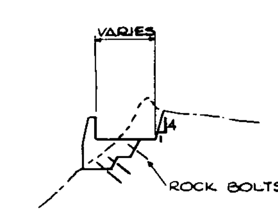
SECTION THRU DIVERSION TUNNEL



PROFILE OF EMERGECY SPILLWAY



SECTION A-A



SECTION B-B

SCALE 0 100 200 FEET

PLATE H2

ALASKA POWER AUTHORITY

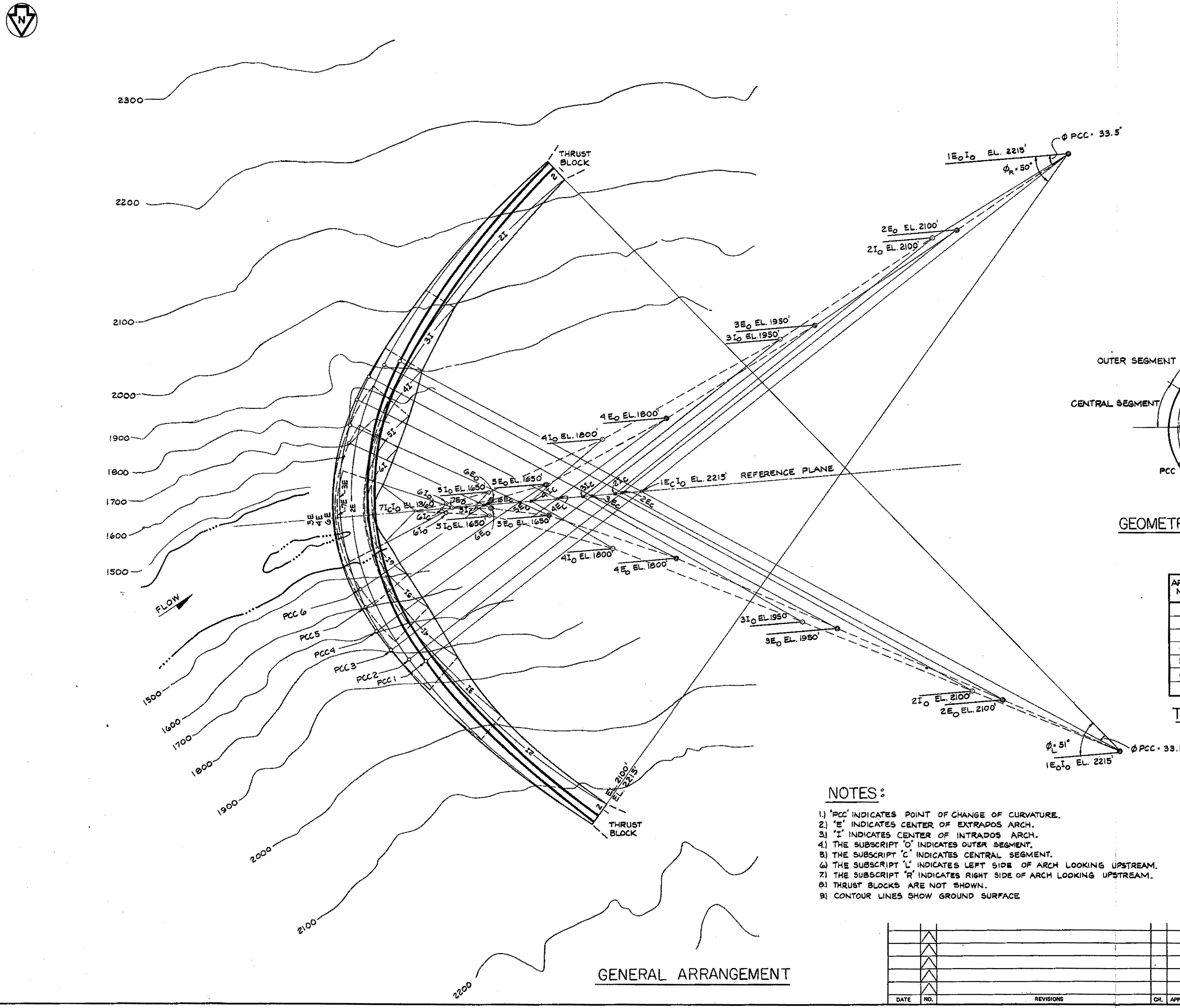
SUSITNA HYDROELECTRIC PROJECT

DEVIL CANYON
ARCH GRAVITY DAM SCHEME
SECTIONS

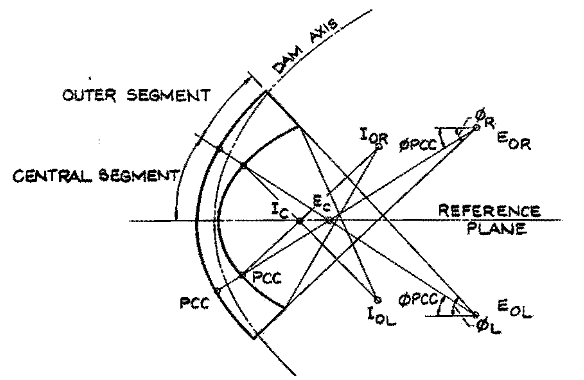
DATE	NO.	REVISIONS	CH.	APP.	APP.

ACRES AMERICAN INCORPORATED

DATE DEC. 1981 | SCALE 1" = 100' | DEPARTMENT | PROJECT | DRAWING NO. SK-5700-C6-302 | REV. | SHEET OF



GENERAL ARRANGEMENT



GEOMETRY TYPICAL ARCH SECTION

ARCH NO.	ELEV. (FEET)	COMPOUND ANGLE φ PCC (DEG.)	CENTER ANGLE (φ) (DEG.) LEFT	RIGHT
1	2215	33.5	51	50
2	2100	33.0	54	54
3	1950	32.5	45	46
4	1800	31.0	41.5	44
5	1650	29.0	40.5	41
6	1500	29.0	37	37
7	1360	0	23	23

TABLE OF ARCH ANGLES

NOTES:

1.) "PCC" INDICATES POINT OF CHANGE OF CURVATURE.
2.) "E" INDICATES CENTER OF EXTRADOS ARCH.
3.) "I" INDICATES CENTER OF INTRADOS ARCH.
4.) THE SUBSCRIPT "O" INDICATES OUTER SEGMENT.
5.) THE SUBSCRIPT "C" INDICATES CENTRAL SEGMENT.
6.) THE SUBSCRIPT "L" INDICATES LEFT SIDE OF ARCH LOOKING UPSTREAM.
7.) THE SUBSCRIPT "R" INDICATES RIGHT SIDE OF ARCH LOOKING UPSTREAM.
8.) THRUST BLOCKS ARE NOT SHOWN.
9.) CONTOUR LINES SHOW GROUND SURFACE

DATE	NO.	REVISIONS	CH.	APP.	APP.

PLATE H3

ALASKA POWER AUTHORITY

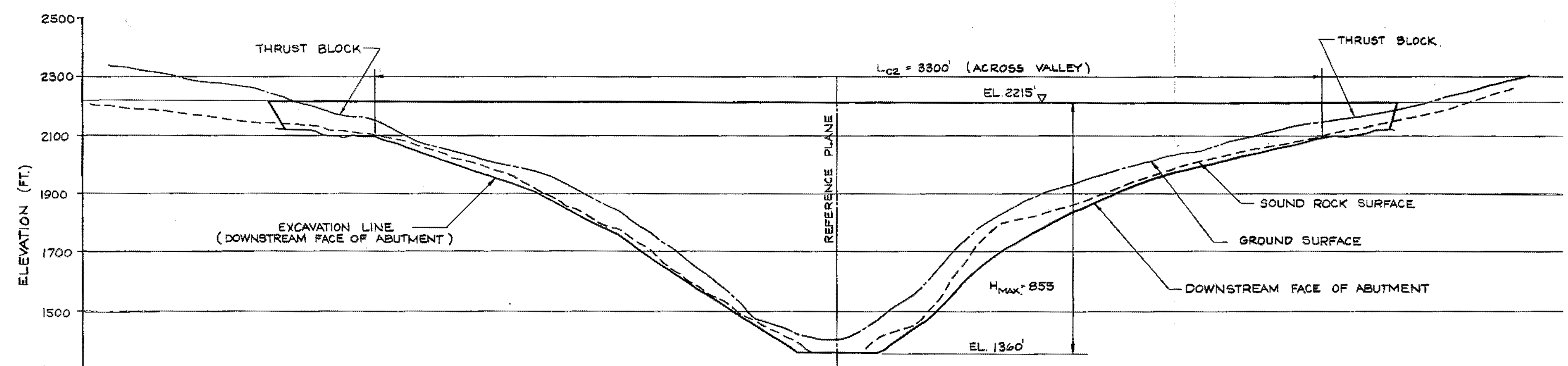
SUSITNA HYDROELECTRIC PROJECT

WATANA
ARCH DAM GEOMETRY

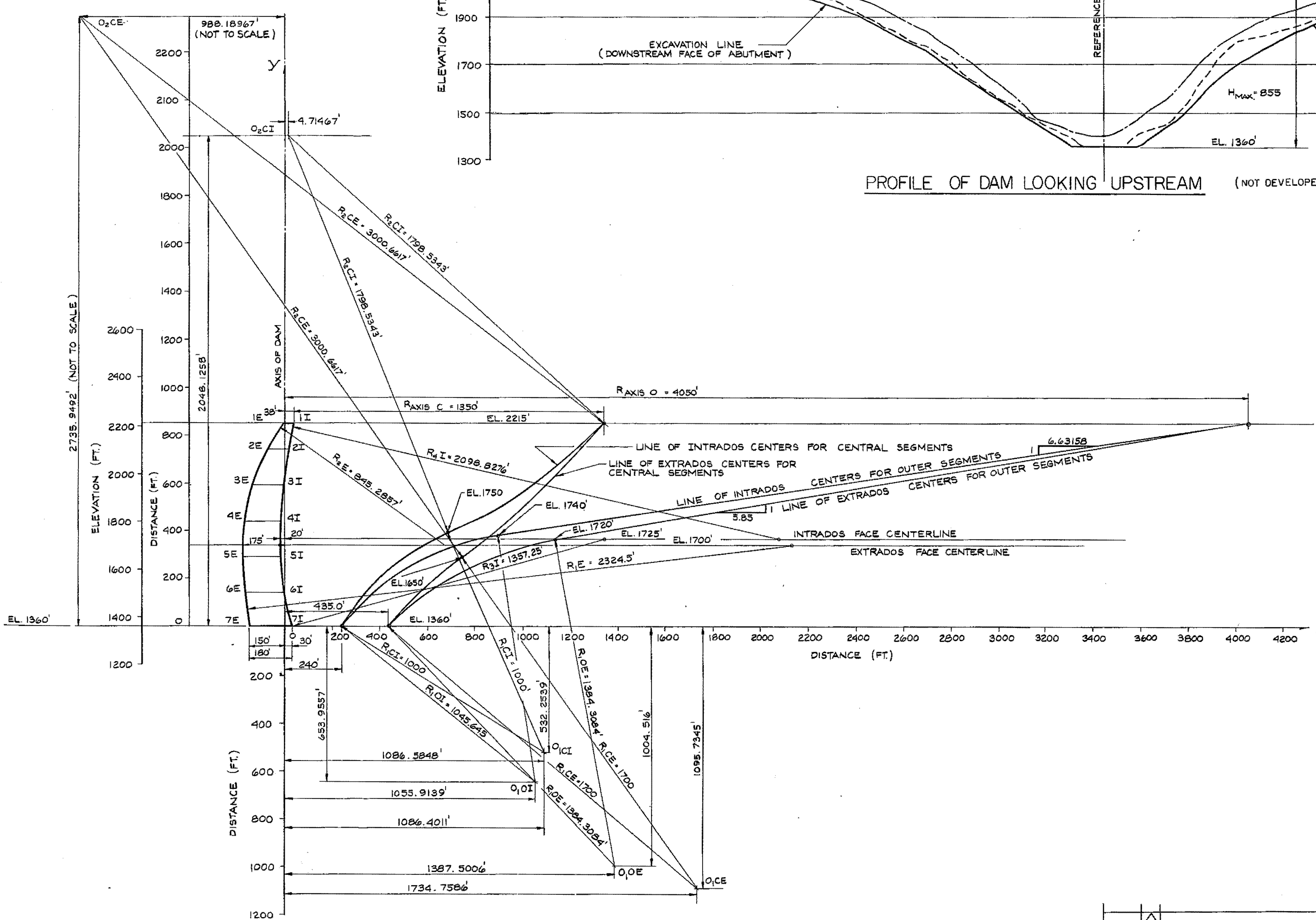
ACRES AMERICAN INCORPORATED

DATE DEC. 1981 | SCALE 1" = 200'

DRAWING NO. SK-5700-C6-201



PROFILE OF DAM LOOKING UPSTREAM (NOT DEVELOPED)



SECTIONS ALONG PLANES OF CENTERS

PLATE H4

ACRES

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

WATANA
ARCH DAM GEOMETRY

DATE	NO.	REVISIONS	CH.	APP.	APP.

ACRES AMERICAN INCORPORATED

DATE DEC. 1981 | SCALE 1" = 200'

DEPARTMENT

PROJECT

DRAWING NO. SK-5700-C6-202 | REV.

SHEET OF

APPENDIX I - ENVIRONMENTAL STUDIES

While performing an environmental review of the various development options within the Susitna Basin, Acres' environmental subconsultant, TES, prepared two reports entitled "Preliminary Environmental Assessment of Tunnel Alternatives" and "Environmental Considerations of Alternative Hydroelectric Development Schemes for the Upper Susitna Basin". These reports as submitted are contained in this Appendix.

I.1 - Summary

These reports, augmented by additional information that became available subsequent to their preparation, formed the basis of the comparison of the Devil Canyon Dam with the tunnel alternative and the reach by reach comparison of Watana/Devil Canyon versus High Devil Canyon/Vee development plans.

The environmental assessments of thermal developments and of alternative hydroelectric developments outside of the Susitna Basin are given in Appendix B and C, respectively.

(a) Devil Canyon Dam versus Tunnel Alternative

(i) Environmental Comparison

The environmental comparison of the two schemes is summarized in Table B.1. Overall, the tunnel scheme is judged to be superior because:

- It offers the potential for enhancing anadromous fish populations downstream of the re-regulation dam due to the more uniform flow distribution that will be achieved in this reach.

- It inundates 13 miles less of resident fisheries habitat in river and major tributaries.

- It has a lower impact on wildlife habitat due to the smaller inundation of habitat by the re-regulation dam.

- It has a lower potential for inundating archeological sites due to the smaller reservoir involved.

- It would preserve many of the characteristics of the Devil Canyon gorge, which is considered to be an aesthetic and recreational resource.

(ii) Social Comparison

Table I.2 summarizes the evaluation in terms of the social criteria of the two schemes. In terms of impact on state and local economics and risks due to seismic exposure, the two schemes are rated equally. However, the dam scheme has, due to its higher energy yield, more potential for displacing nonrenewable energy resources and therefore scores a slight overall plus in terms of the social evaluation criteria.

(b) Watana/Devil Canyon versus High Devil Canyon/Vee

(i) Environmental Comparison

The evaluation in terms of the environmental criteria is summarized in Table B.3. In assessing these plans, a reach by reach comparison is made for the section of the Susitna River between Portage Creek and the Tyone River. The Watana-Devil Canyon scheme would create more potential environmental impacts in the Watana Creek area. However, it is judged that the potential environmental impacts which would occur in the upper reaches of the river with a High Devil Canyon-Vee development are more severe in comparison overall.

From a fisheries perspective, both schemes would have a similar effect on the downstream anadromous fisheries, although the High Devil Canyon-Vee scheme would produce a slightly greater impact on the resident fisheries in the Upper Susitna Basin.

The High Devil Canyon-Vee scheme would inundate approximately 14 percent (15 miles) more critical winter river bottom moose habitat than the Watana-Devil Canyon scheme. The High Devil Canyon-Vee scheme would inundate a large area upstream of the Vee site utilized by three subpopulation of moose that range in the northeast section of the basin. The Watana-Devil Canyon schemes would avoid the potential impacts on moose in the upper section of the river; however, a larger percentage of the Watana Creek basin would be inundated.

The condition of the subpopulation of moose utilizing this Watana Creek Basin and the quality of the habitat appears to be decreasing. Habitat manipulation measures could be implemented in this area to improve the moose habitat. Nevertheless, it is considered that the upstream moose habitat losses associated with the High Devil Canyon-Vee scheme would probably be greater than the Watana Creek losses associated with the Watana-Devil Canyon scheme.

A major factor to be considered in comparing the two development plans is the potential effects on caribou in the region. It is judged that the increased length of river flooded, especially upstream from the Vee dam site, would result in the High Devil Canyon-Vee plan creating a greater potential diversion of the Nelchina herd's range. In addition, a larger area of caribou range would be directly inundated by the Vee reservoir.

The area flooded by the Vee reservoir is also considered important to some key furbearers, particularly red fox. In a comparison of this area with the Watana Creek area that would be inundated with the Watana-Devil Canyon scheme, the area upstream of Vee is judged to be more important for furbearers.

As previously mentioned, between Devil Canyon and the Oshetna River the Susitna River is confined to a relatively steep river valley. Along these valley slopes are habitats important to birds and black bears. Since the Watana reservoir would flood the river section between the Watana Dam site and the Oshetna River to a higher elevation than would the High Devil Canyon reservoir (2200 feet as compared to 1750 feet), the High Devil Canyon-Vee plan would retain the integrity of more of this river valley slope habitat.

From the archeological studies done to date, there tends to be an increase in site intensity as one progresses towards the northeast section of the Upper Susitna Basin. The High Devil Canyon-Vee plan would result in more extensive inundation and increased access to the northeasterly section of the basin. This plan is therefore judged to have a greater potential for directly or indirectly affecting archeological sites.

Due to the wilderness nature of the Upper Susitna Basin, the creation of increased access associated with project development could have a significant influence on future uses and management of the area. The High Devil Canyon-Vee plan would involve the construction of a dam at the Vee site and the creation of a reservoir in the more northeasterly section of the basin. This plan would thus create inherent access to more wilderness than would the Watana-Devil Canyon scheme. Since it is easier to extend access than to limit it, inherent access requirements are considered detrimental; the Watana-Devil Canyon scheme is judged to be more acceptable in this regard.

Except for the increased loss of river valley, bird, and black bear habitat, the Watana-Devil Canyon development plan is judged to be more environmentally acceptable than the High Devil Canyon-Vee plan. Although the Watana-Devil Canyon plan is considered to be the more environmentally compatible Upper Susitna development plan, the actual degree of acceptability is a question being addressed as part of ongoing studies.

(ii) Social Comparison

Table B.2 summarizes the evaluation in terms of the social criteria. As in the case of the dam versus tunnel comparison, the Watana-Devil Canyon plan is judged to have a slight advantage over the High Devil Canyon-Vee plan. This is because of its greater potential for displacing nonrenewable resources.

I.2 - TES Report

Reports prepared by TES on the environmental assessment of the Devil Canyon Dam versus the Tunnel alternative and Watana/Devil Canyon versus High Devil Canyon/Vee development plans are given in their entirety below.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

PRELIMINARY ENVIRONMENTAL ASSESSMENT OF TUNNEL ALTERNATIVES

by

Terrestrial Environmental Specialists, Inc.
Phoenix, New York

for

Acres American Incorporated
Buffalo, New York

December 15, 1980

TABLE OF CONTENTS

1 - INTRODUCTION

In response to a request by Acres American, Inc. for input into Subtask 6.02 of the Susitna Hydroelectric Project feasibility study, Terrestrial Environmental Specialists, Inc. (TES) did a preliminary assessment of tunnel alternatives. The objectives of this assessment were:

(1) to compare environmental aspects of four alternative tunnel schemes;
(2) to compare the best tunnel scheme, as selected by Acres, with the two-dam scheme (Watana and Devils Canyon) proposed by the U.S. Army Corps of Engineers;
(3) to compare two revised locations for the downstream powerhouse; and
(4) to comment on alternative methods of disposal of tunnel muck, the rock removed to create a tunnel.

The environmental assessment was based on both the project descriptions in a letter dated October 29, 1980, from Acres to TES, as amended by a letter dated December 11, 1980, and on conversations between representatives of these firms. Copies of these letters may be found in the appendices to this report. At the time this assessment was performed complete information was not available on the various tunnel schemes under consideration. Therefore, TES views this assessment as only a preliminary study.

One assumption made by TES, and confirmed by Acres, is that the dam, pool elevation, and pool level fluctuations of Watana are as described by the Corps of Engineers and would not differ among the five schemes. If, on the contrary, any of the tunnel schemes increase the probability that the pool level at Watana may be lower than that proposed by the Corps or if a particular scheme may moderate the pool fluctuations, then the environmental assessment of the tunnel schemes may, in turn, be affected.

It is recognized that an environmental assessment for ranking alternative schemes must include some subjective value judgements. A given scheme may be preferable from the standpoint of one environmental discipline (e.g. fisheries) whereas another scheme may be better from another aspect (e.g. terrestrial ecology or aesthetics). To recommend any one scheme over another involves the difficult task of making trade-offs among the environmental disciplines. Such trade-offs are likely to be controversial.

2 - COMPARISON OF TUNNEL ALTERNATIVES

2.1 Scheme 1

The environmental impacts associated with this tunnel scheme are likely to be greater than those of at least one of the other tunnel schemes evaluated (i.e. Scheme 3). The main criterion for this assessment is the adverse effects, particularly on fisheries and recreation, of the variable downstream flows (4000-14000 cfs daily) created by the Devils Canyon powerhouse peaking operation. Other negative impacts would result from construction of both the re-regulation dam and a relatively long tunnel. Tunnel impacts are similar to those of Schemes 2 and 4 and include disturbance of Susitna tributaries as a result of tunnel access and the potential problems associated with disposal of a relatively large volume of tunnel muck.

2.2 Scheme 2

Like Scheme 1, this scheme involves adverse environmental impacts associated with variable downstream flows caused by peaking operation at the Devils Canyon powerhouse (4000-14000 cfs). Without the re-regulation dam, however, less land would be inundated and the impacts associated with construction of this relatively small dam would be avoided, although flow fluctuations above Devils Canyon would be more severe. Like Scheme 1 too, the long tunnel proposed here will have negative consequences, including disturbance of tributaries for tunnel access and the potential problems connected with tunnel muck disposal.

2.3 Scheme 3

The overall environmental impact of this scheme is considered less than that related to the two previous schemes, and also less than that related to the fourth scheme as amended (Appendix B). The relatively constant discharge (about 8300-8900 cfs) from the Devils Canyon powerhouse is desirable for maintaining downstream fish habitat and recreational potential. Since it may allow anadromous fish access to a previously inaccessible 15-mile stretch of the Susitna River, Scheme 3 could, in fact, offer a rare opportunity for enhancement of the fisheries resource. The newly available section of river could perhaps be actively managed to create or improve spawning habitat for salmon. This mitigation potential is dependent upon the location of the downstream powerhouse (above or below the present rapids) and the determination of whether project flows through Devils Canyon will still constitute a barrier to fish passage. The data needed for this determination are not yet available.

A compensation flow release of 1000 cfs at the re-regulation dam is not the same as 1000 cfs at the Watana dam. Because fewer tributaries will augment the compensation flow under this re-regulation scheme, the compensation flow will need to be slightly greater than with the other schemes to result in the equivalent flow at Devils Canyon. Compensation flow should be sufficient to maintain a certain degree of riverine character, and thus should be kept to a maximum even in the absence of a salmon fishery. Of course, if the viability of a tunnel scheme is jeopardized, the impacts of the alternative scheme must be compared to the impacts of a lesser compensation flow.

As with any of the tunnel schemes, the wildlife habitat in the stretch of river bypassed by the tunnel might improve temporarily because of an increase in riparian zone vegetation. With Scheme 3, however, this stretch of river is shorter than with the other tunnel schemes; so a smaller area would benefit. The wildlife habitat downstream of Devils Canyon powerhouse may well benefit from the flow from the hydroelectric project, regardless of the tunnel scheme chosen. The improvements to that habitat may be somewhat greater, though, with the constant flows allowed in Scheme 3 than with the variable flows resulting from peaking in the other tunnel schemes.

One environmental disadvantage of this scheme compared to the others is the larger area to be inundated by the re-regulation reservoir. This area includes known archeological sites in addition to wildlife habitat. Nevertheless, it is felt that this disadvantage is offset by the more positive environmental factors associated with constant discharge from the Devils Canyon powerhouse.

2.4 Scheme 4

Scheme 4, as originally described (Appendix A), was determined to be environmentally superior to the other tunnel schemes, because of constant downstream flows combined with the lack of a lower reservoir. However, Acres' analysis determined that this baseload operation is most likely incapable of supplying the peak energy demand. Scheme 4, as amended (Appendix B), is a peaking operation at Watana with baseload operation at the tunnel. Since the net daily fluctuations in flow below Devils Canyon would be considerable (in the order of 4000-13000 cfs), the amended Scheme 4 was judged as less desirable than Scheme 3 from an environmental standpoint. Although Scheme 4 would avoid the impacts associated with the lower dam and its impoundment (as planned under Scheme 3), the adverse impacts that would result from fluctuating downstream flows are considered to be an overriding factor.

Another, less significant disadvantage of Scheme 4 (and shared by Schemes 1 and 2) in contrast to Scheme 3 is the longer tunnel length planned for the former and, perhaps, the proposed location of the tunnel on the north side of the river. The sites chosen for disposal of tunnel muck and for the required access roads in any of these schemes (as yet undetermined) will further influence this comparison.

2.5 Location of Devils Canyon Powerhouse

Alternative locations for the Devils Canyon powerhouse have been proposed. These consist of an upstream location about 5 miles above the proposed Corps of Engineers dam site and a downstream location about 1.5 miles below Portage Creek, as alternatives to the site illustrated in Appendix A. The major environmental consideration is that a powerhouse upstream of Devils Canyon would preserve much of the aesthetic value of the canyon. In addition, the shorter tunnel would confine construction activities to a smaller area and may result in slightly less ground disturbance, particularly if there are fewer access points, as well as a smaller muck disposal problem. A downstream powerhouse location, on the other hand, might create a mitigation opportunity by opening up a longer stretch of river that perhaps could be managed to create salmon spawning habitat. Until large-scale aerial photographs and cross-sectional data on the canyon have been received and analyzed, a determination cannot be made as to whether project flows through the canyon will still constitute a barrier to fish passage.

Our primary responsibility is to avoid, or at least to minimize, adverse impacts to the environment, and it must take precedence over our desire to enhance or expand a resource. It is our opinion that losing a resource (the aesthetic value of the Devils Canyon rapids) is worse than losing a possible mitigation opportunity. It is not yet known if this opportunity even exists. Furthermore, there are always other means by which to enhance the fishery, although not necessarily so conveniently associated with the hydroelectric project. Thus, at this time the upstream powerhouse location is preferred.

2.6 Disposal of Tunnel Muck

There are a number of options to be considered for disposal of the rock removed in creating the tunnel. These include: stockpiling the material for use in access road repair, construction of the re-regulation dam, or stabilization of the reservoir shoreline; disposal in Watana reservoir; dike construction; pile, cover, and seed; and disposal in a ravine or other convenient location. It is unlikely that the most environmentally acceptable option will also be the most economical. Because many unknown factors now exist, a firm recommendation cannot be made without further evaluation. It is quite likely, however, that a combination of disposal methods will be the best solution.

Stockpiling at least some of the material for access road repairs is environmentally acceptable, provided a suitable location is selected for the stockpile. Perhaps the material could be utilized for construction of any of the access road spurs or temporary roads that are not already completed at the time the tunnel is dug.

Another acceptable solution might be to stockpile the material for use in construction of the re-regulation dam. This rock could also be a potential source of material for stabilization of the reservoir shoreline if required. As with the previous option, an environmentally acceptable location of the stockpile would be required. Disposal of the material in Watana Reservoir might also be environmentally acceptable. Consideration should be given to the feasibility of using the material in the construction of any impoundment control structures such as dikes. A small amount of tunnel muck could possibly also be used for stream habitat development. With any of these options, the possible toxicity of minerals exposed to the water should be first determined by assay, if there is any reason to suspect the occurrence of such minerals.

To pile, cover, and seed the material is worthy of further consideration, and would require proper planning. For example, borrow areas used in dam construction could perhaps be restored to original contour by this method.. The source of soil for cover is a major consideration, as earth should only be taken from an area slated for future disturbance or inundation. If trucking soil from the reservoir area is determined to be feasible, it might also be worthwhile to transport a portion of the muck back for disposal in the reservoir area.

The most economical solution might be to fill a ravine with the material or to dispose of it in another convenient location. Unless the chosen disposal site will eventually be inundated, however, such an arrangement is environmentally unacceptable, especially since better options are obviously available.

3 - COMPARISON OF TUNNEL SCHEME 3 WITH CORPS OF ENGINEERS' SCHEME

Scheme 3 emerged as superior in Acres' preliminary economic and technical screening. After amendment of Scheme 4, Scheme 3 was also considered to be the best scheme from an environmental standpoint. Therefore, Scheme 3 is to be compared with the two-dam scheme proposed by the U.S. Army Corps of Engineers.

Further analysis will be in order after complete details are available on Tunnel Scheme 3. At present, many gaps exist in the available data. Additional information on design, operation, and hydrology, combined with environmental field investigations at the locations of project facilities, would permit a much more detailed comparison of these two development alternatives. Nevertheless, from what is presently understood about Scheme 3, there is little doubt that it is, by far, environmentally superior to the Corps of Engineers' proposal. Of course, extensive additional study needs to be performed on whatever scheme is selected to identify its impacts and to develop mitigation plans.

Tunnel Scheme 3 has, by any measure, a less adverse environmental impact than the Corps of Engineers' scheme. By virtue of size alone, construction of the smaller dam (245 ft.) would have less environmental impact than the Devils Canyon dam proposed by the Corps. The river miles flooded and the reservoir area created by the Scheme 3 re-regulation dam would be about half those of the Corps' plan for Devils Canyon, thereby reducing negative consequences, such as loss of wildlife habitat and possible archeological sites. In addition, the adverse effects upon the aesthetic value of Devils Canyon would be substantially lessened with Scheme 3, particularly with the powerhouse location upstream of the proposed Corps dam site. Furthermore, Tunnel Scheme 3 may possibly present a rare mitigation opportunity by creating new salmon spawning habitat that could be actively managed. With the increase in riparian zone vegetation allowed by Scheme 3, the wildlife habitat in the stretch of river bypassed by the tunnel might be temporarily improved. The impacts associated with tunnel access and disposal of tunnel muck necessitated by Scheme 3 are more than offset by the plan's advantages. Thus, Tunnel Scheme 3 far exceeds the U.S. Army Corps of Engineers' proposal in terms of environmental acceptability.

APPENDIX A

DESCRIPTIONS OF TUNNEL SCHEMES

4 Nov '80
C2.5.578
RECEIVED

October 29, 1980
P5700.06
T507

Terrestrial Environmental Specialists, Inc.
R.D. 1
Phoenix, NY 13135

Attention: Vince Lucid

Dear Vince:

Susitna Hydroelectric Project
Subtask 6.02

We would like you to review the environmental aspects of the tunnel alternative (Subtask 6.02), which you were introduced to on October 3, 1980. Your environmental assessment will be included in the Subtask 6.02 close-out report, November 1980. In order to complete this close-out report on schedule the environmental assessment is required by November 13, 1980.

The environmental assessment should include a small section on each of the four tunnel schemes (Schemes 1, 2, 3, & 4). Physical factors of the schemes and the COE selected plan are presented in Table 1. Tunnel scheme plan view and alignments are enclosed.

Scheme 1 is composed of the COE Watana Dam and powerhouse, and a small re-regulation dam with power tunnels leading to a powerhouse at Devil Canyon. Peaking operations will occur at both Watana and the Devil Canyon powerhouses. A constant compensation flow discharge will be provided between Watana and Devil Canyon. Peaking operations will create daily water level fluctuations of unknown magnitude downstream of Devil Canyon.

Scheme 2 is composed of the COE Watana Dam and powerhouse with power tunnels from the Watana Reservoir to a powerhouse at Devil Canyon. Upon completion of the tunnel scheme the Watana powerhouse will be reduced to 35 MW and will supply a constant compensation flow between Watana and Devil Canyon. The Devil Canyon powerhouse will operate as a peaking hydro facility. Water level fluctuations downstream of Devil Canyon are similar to that of Scheme 1.

Scheme 3 is composed of the COE Watana Dam and powerhouse, and a re-regulation dam with power tunnels leading to a powerhouse at Devil Canyon. The Watana powerhouse will operate as a peaking facility which discharges into a re-regulation reservoir. The re-regulation reservoir is capable of storing the daily peak discharges and releasing a constant discharge into the power tunnels. A four foot daily water level fluctuation in the re-regulation reservoir is required. The Devil Canyon powerhouse will operate as a base load facility, thus, no daily water level fluctuations will occur downstream of Devil Canyon.

ACRES AMERICAN INCORPORATED
Consulting Engineers
The Liberty Bank Building, Main at Court
Buffalo, New York 14202

Telephone 716-853-7525 Telex 91-6423 ACRES BUF

Other Offices: Columbia, MD; Pittsburgh, PA; Raleigh, NC; Washington, DC

The general layout of Scheme 4 is similar to Scheme 2. Scheme 4 is a base load scheme and has a very limited potential to produce additional peak energy. Daily water level fluctuations downstream of Devil Canyon are similar to Scheme 3.

Preliminary economic and technical screening showed Scheme 3 as superior. Preliminary environmental assessment ranked Scheme 4 environmentally superior. Scheme 4 is most likely not capable of supply the required peak energy demand. Thus, Scheme 3, ranked second environmentally, was preliminarily chosen as the best tunnel scheme. If you should disagree with the selection of Scheme 3 please contact me as soon as possible.

The objective of Subtask 6.02 is to compare the best tunnel scheme with the COE selected scheme (High Watana and Devil Canyon). The environmental assessment should include a section comparing the impacts of tunnel Scheme 3 with the COE selected scheme. Include conclusions and a description of additional study required.

In regards to disposal of tunnel muck (rock removed to create tunnel) we can assume that additional costs will be incured to dispose of the muck in an environmentally acceptable manner. An environmental assessment of alternative disposal methods would help to define this added cost. The following lists only a few disposal ideas, feel free to consider others.

- Stockpile and use for access road repairs.
- Stockpile and use for dam material (Scheme 3 only).
- Dump in Watana Reservoir.
- Fill the nearest ravine.
- Leave in the most convenient location.
- Pile, cover, and seed.

Please do not hesitate to contact me for any additional information that may be required.

Sincerely,

Kevin Young

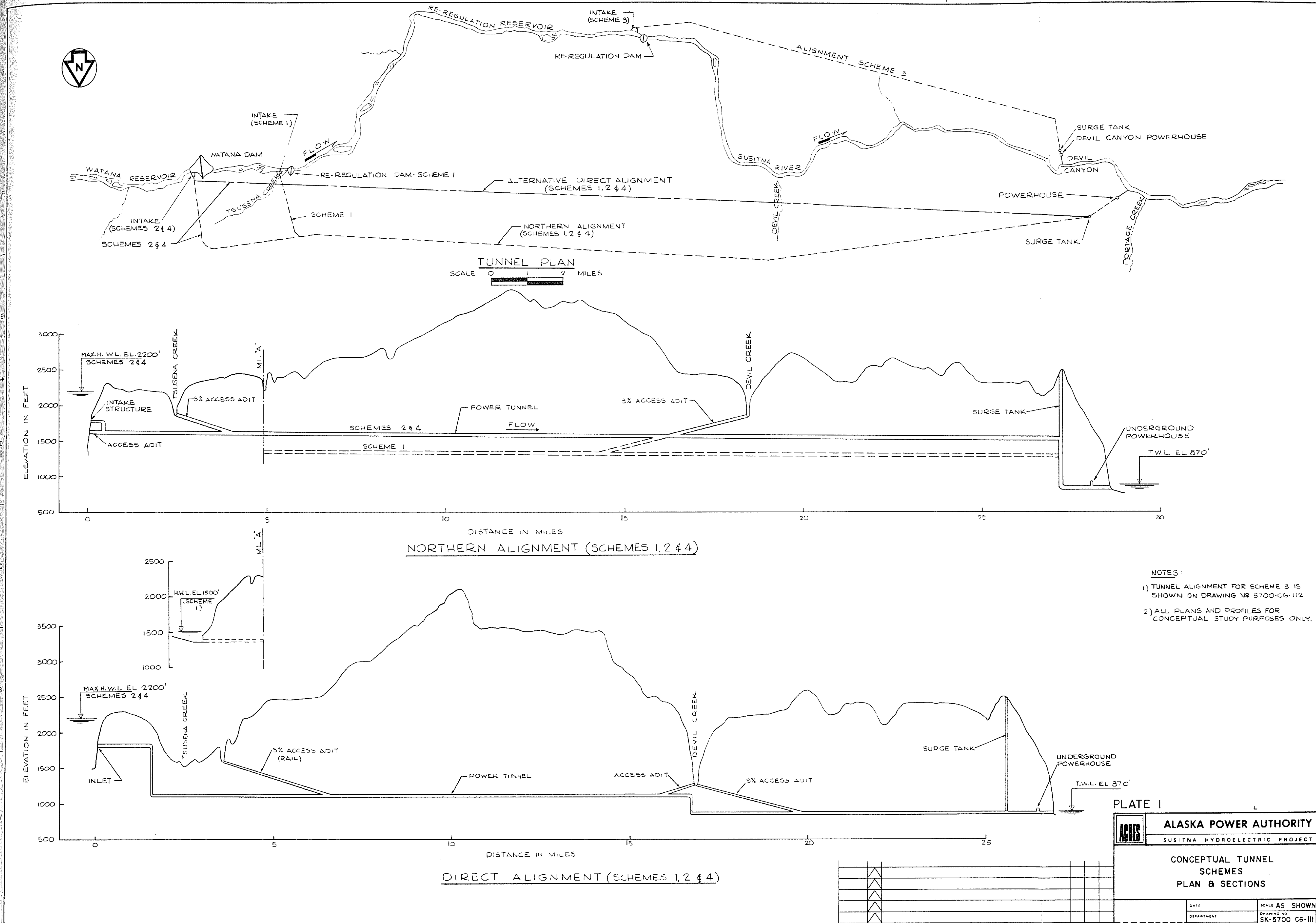
Kevin Young

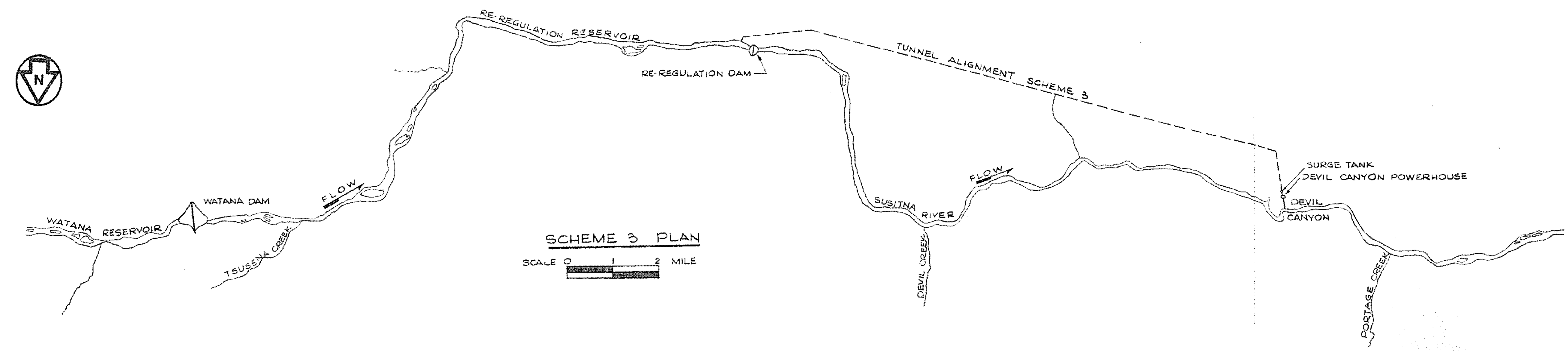
RJW:ccv

TABLE 1

Susitna Tunnel Schemes
Physical Factors

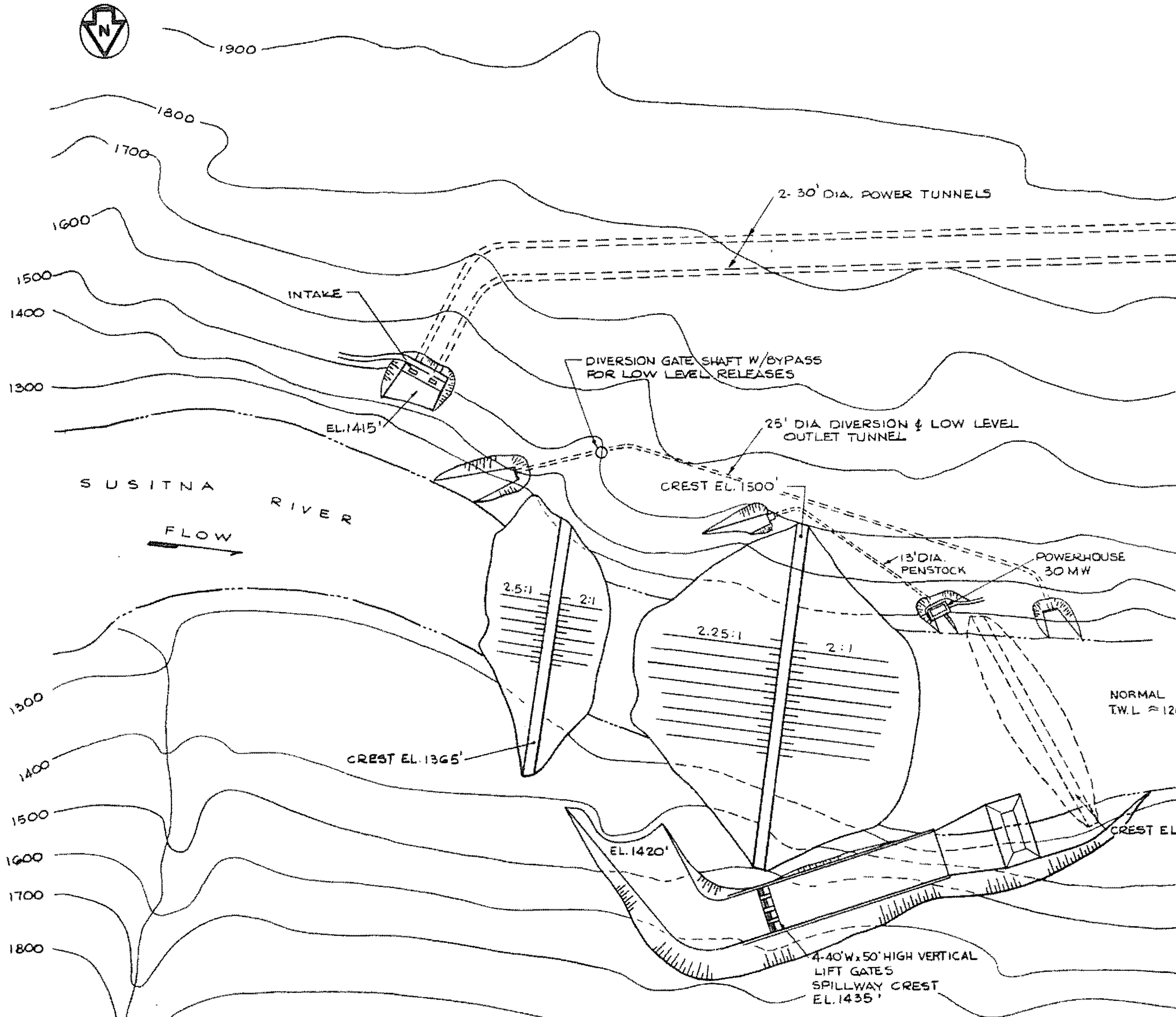
	COE Devil Canyon	1	2	3	4
Reservoir Area (Acres)	7,500	320	-0-	3,900	-0-
River Miles Flooded	31.6	2.0	-0-	15.8	-0-
Tunnel Length (Miles)	--	27	29	15.6	29
Tunnel Volume (Yd^3)	--	10,749,000	11,545,000	4,285,000	6,494,000
Compensation Flow (cfs)	--	500 to 1000	500 to 1000	500 to 1000	500 to 1000
Downstream Reservoir Volume (Acre-Feet)	1,100,000	9,500	-0-	350,000	-0-
Devil Canyon Powerhouse Discharge	Constant	Peaking	Peaking	Constant	Constant
Dam Height (feet)	520	75	--	245	--


RE-REGULATION RESERVOIR
INTAKE (SCHEME 3)
RE-REGULATION DAM
ALIGNMENT SCHEME 3
INTAKE (SCHEME 1)
WATANA DAM
FLOW
WATANA RESERVOIR
RE-REGULATION DAM - SCHEME 1
ALTERNATIVE DIRECT ALIGNMENT (SCHEMES 1, 2 & 4)
TSUSENA CREEK
SCHEME 1
INTAKE (SCHEMES 2 & 4)
SCHEMES 2 & 4
NORTHERN ALIGNMENT (SCHEMES 1, 2 & 4)
SUSITNA RIVER
DEVIL CREEK
SURGE TANK
DEVIL CANYON POWERHOUSE
DEVIL CANYON
POWERHOUSE
PORTAGE CREEK
TUNNEL PLAN
SCALE 0 1 2 MILES
MAX. H. W. L. EL. 2200' SCHEMES 2 & 4
INTAKE STRUCTURE
ACCESS ADIT
3% ACCESS ADIT
ML 'A'
POWER TUNNEL
SCHEMES 2 & 4
SCHEME 1
UNDERGROUND POWERHOUSE
T.W.L. EL. 870'
ELEVATION IN FEET
DISTANCE IN MILES
NORTHERN ALIGNMENT (SCHEMES 1, 2 & 4)
H.W.L. EL. 1500' (SCHEME 1)
MAX. H. W. L. EL 2200' SCHEMES 2 & 4
INLET
3% ACCESS ADIT (RAIL)
DIRECT ALIGNMENT (SCHEMES 1, 2 & 4)
NOTES:
1.) TUNNEL ALIGNMENT FOR SCHEME 3 IS SHOWN ON DRAWING Nº 5700-C6-112
2.) ALL PLANS AND PROFILES FOR CONCEPTUAL STUDY PURPOSES ONLY.
PLATE 1
ACRES
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
CONCEPTUAL TUNNEL SCHEMES PLAN & SECTIONS
SCALE AS SHOWN
SK-5700 C6-111
REVISIONS
ACRES AMERICAN INCORPORATED



SCHEME 3 PLAN

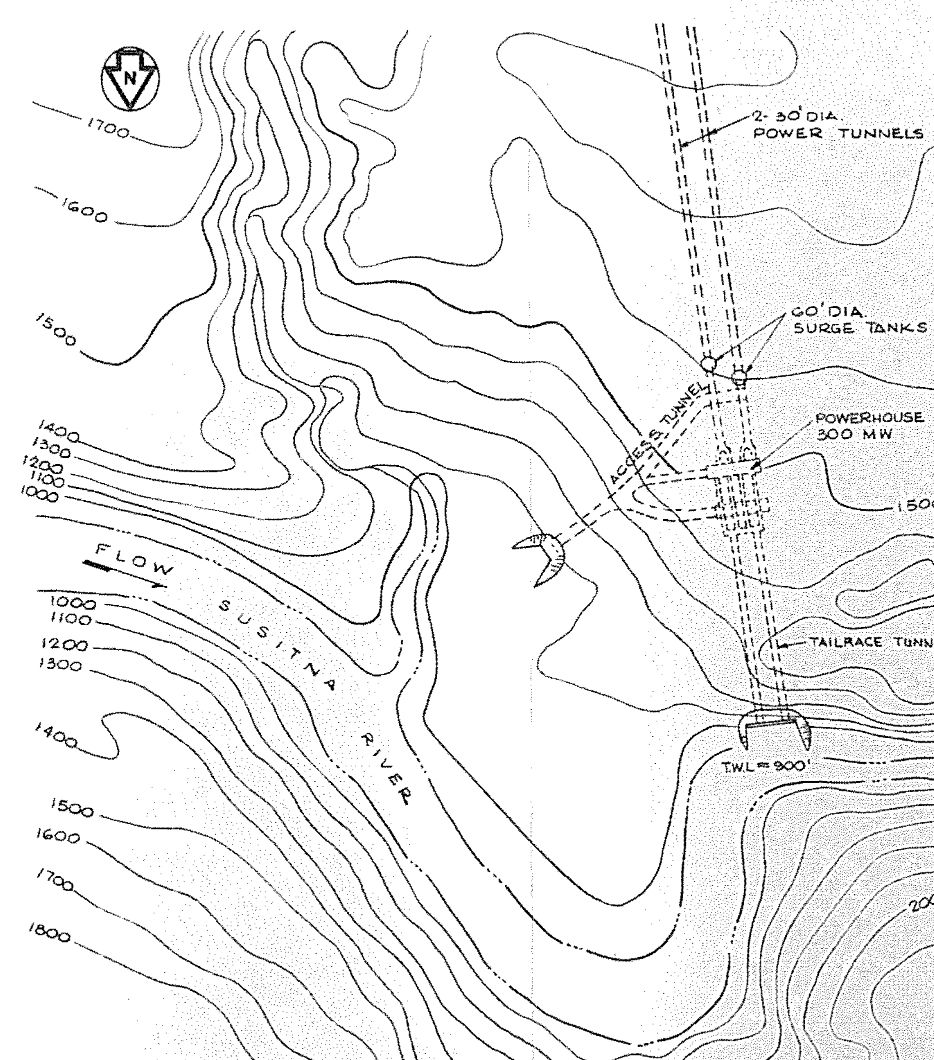
SCALE 0 1 2 MILE



GENERAL ARRANGEMENT
RE-REGULATION DAM

SCALE 0 300 600 FEET

NOTE:
ALL PLANS AND LAYOUTS FOR CONCEPTUAL STUDY PURPOSES ONLY.



GENERAL ARRANGEMENT
DEVIL CANYON POWERHOUSE

SCALE 0 400 800 FEET

PLATE 2

ACRES

ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

PREFERRED TUNNEL
SCHEME 3
PLAN VIEW

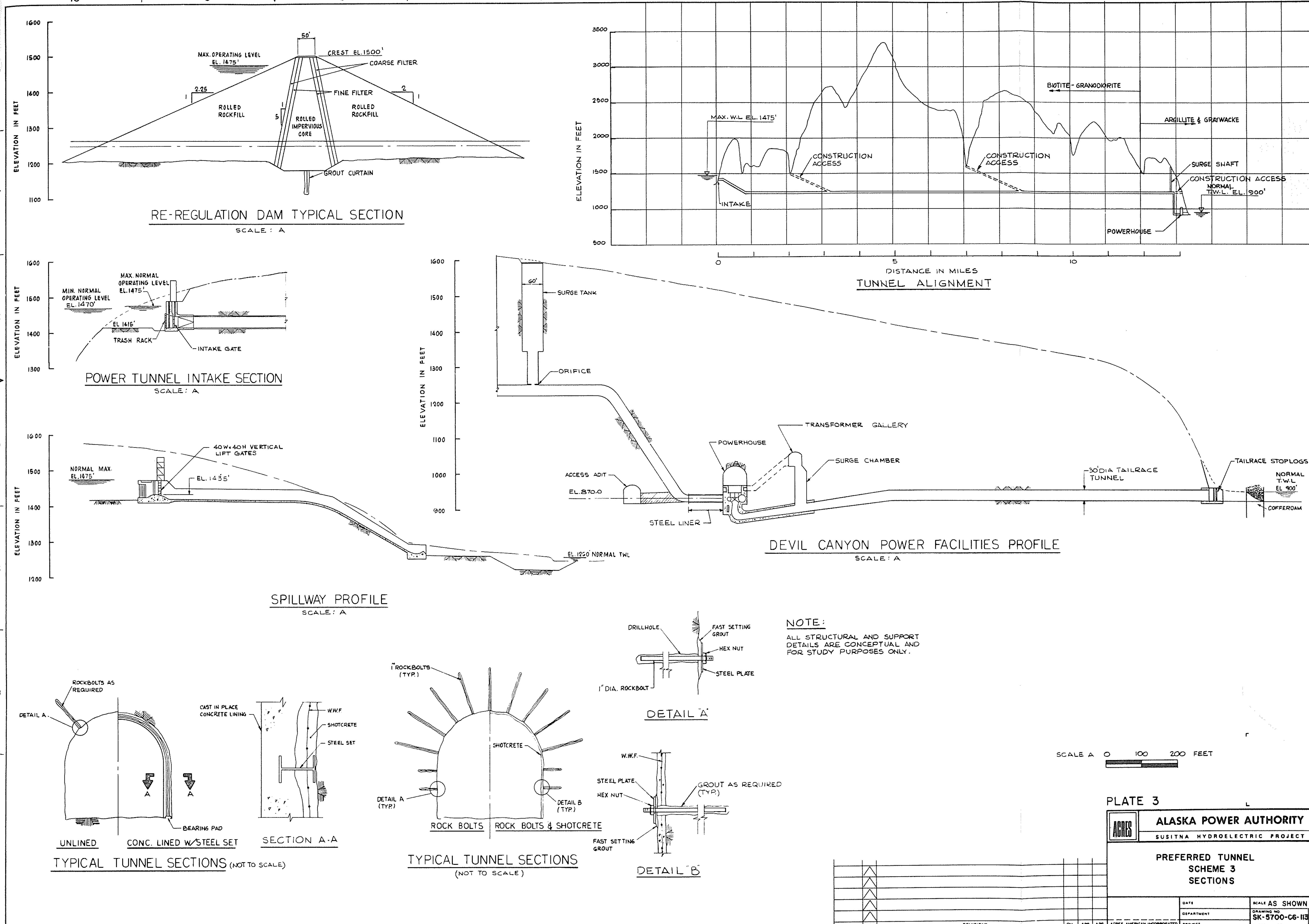
DATE	NO.	REVISIONS	CH.	APP.	APP.

ACRES AMERICAN INCORPORATED

SCALE AS SHOWN

DRAWING NO. SK-5700-C6-112

REV.


RE-REGULATION DAM TYPICAL SECTION
SCALE: A
50'
CREST EL. 1500'
MAX. OPERATING LEVEL EL. 1475'
COARSE FILTER
FINE FILTER
ROLLED ROCKFILL
ROLLED IMPERVIOUS CORE
GROUT CURTAIN
ELEVATION IN FEET
TUNNEL ALIGNMENT
DISTANCE IN MILES
MAX. W.L. EL. 1475'
CONSTRUCTION ACCESS
BIOTITE - GRANODIORITE
ARGILLITE & GRAYWACKE
SURGE SHAFT
NORMAL T.W.L. EL. 900'
INTAKE
POWERHOUSE
POWER TUNNEL INTAKE SECTION
SCALE: A
MIN. NORMAL OPERATING LEVEL EL. 1470'
MAX. NORMAL OPERATING LEVEL EL. 1475'
EL. 1415'
TRASH RACK
INTAKE GATE
SPILLWAY PROFILE
SCALE: A
NORMAL MAX. EL. 1475'
40W x 40H VERTICAL LIFT GATES
EL. 1435'
EL. 1220' NORMAL TWL
DEVIL CANYON POWER FACILITIES PROFILE
SCALE: A
SURGE TANK
60'
ORIFICE
TRANSFORMER GALLERY
POWERHOUSE
SURGE CHAMBER
ACCESS ADIT
EL. 870.0
STEEL LINER
30' DIA TAILRACE TUNNEL
TAILRACE STOPLOGS
NORMAL T.W.L. EL. 900'
COFFERDAM
NOTE:
ALL STRUCTURAL AND SUPPORT DETAILS ARE CONCEPTUAL AND FOR STUDY PURPOSES ONLY.
DETAIL "A"
DRILLHOLE
FAST SETTING GROUT
HEX NUT
STEEL PLATE
1" DIA. ROCKBOLT
DETAIL "B"
W.W.F.
STEEL PLATE
HEX NUT
GROUT AS REQUIRED (TYP.)
FAST SETTING GROUT
TYPICAL TUNNEL SECTIONS (NOT TO SCALE)
ROCKBOLTS AS REQUIRED
DETAIL A
CAST IN PLACE CONCRETE LINING
W.W.F.
SHOTCRETE
STEEL SET
BEARING PAD
UNLINED
CONC. LINED W/STEEL SET
SECTION A-A
TYPICAL TUNNEL SECTIONS
(NOT TO SCALE)
1" ROCKBOLTS (TYP.)
SHOTCRETE
DETAIL A (TYP.)
DETAIL B (TYP.)
ROCK BOLTS
ROCK BOLTS & SHOTCRETE
SCALE A 0 100 200 FEET
PLATE 3
ACRES
ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT
PREFERRED TUNNEL
SCHEME 3
SECTIONS
SCALE AS SHOWN
DRAWING NO. SK-5700-C6-113
DATE
NO.
REVISIONS
CH.
APP.
APP.
ACRES AMERICAN INCORPORATED

APPENDIX B

AMENDED DESCRIPTION OF TUNNEL SCHEME 4

ACRES

13 Dec '80
P215, 660
RECEIVED

December 11, 1980
P5700.11.30
T.606

Mr. Vince Lucid
Terrestrial Environmental Specialists, Inc.
RD 1
Box 388
Phoenix, New York 13135

Dear Vince:

Susitna Hydroelectric Project
Revised Description of Tunnel Alternatives

Enclosed please find a memo from B. Wart outlining our revised description of tunnel alternatives.

Please use this description in your assessment of tunnel alternatives.

In addition, I have completed your table outlining tunnel design information.

Sincerely,

Kevin Young
Environmental Coordinator

KRY/ljr

Enclosure

ACRES AMERICAN INCORPORATED
Consulting Engineers
The Liberty Bank Building, Main at Court
Buffalo, New York 14202

Telephone 716-853-7525 Telex 91-6423 ACRES BUF

Other Offices: Columbia, MD; Pittsburgh, PA; Raleigh, NC; Washington, DC

ACRES

OFFICE MEMORANDUM

TO:	K. Young	*Date:*	December 11, 1980
FROM:	B. Wart	*File:*	P5700.07.07
SUBJECT:	Susitna Hydroelectric Project Preliminary Environmental Assessment of Tunnel Alternatives		

The assumption made by TES that the dam, pool elevation, and pool level fluctuations of Watana are as described by the Corps of Engineers, and would not differ among the five schemes is correct.

The description of tunnel Scheme 4 has been revised so that Scheme 4 is capable of supplying a daily load curve similar to that of the other schemes. The revised description of tunnel Scheme 4 follows:

The general layout of Scheme 4 is similar to Scheme 2. The operation of Scheme 4 varies from that of Scheme 2 and is described below. The Watana powerhouse will remain at the stage one installed capacity or if necessary enlarged slightly. Peaking demands will be met with the Watana powerhouse. At all times the Watana powerhouse will generate a minimum of 35 MW to supplement base load demands and supply the required compensation flow between Watana and Devil Canyon. The Devil Canyon powerhouse and tunnel will operate as a base load facility. Scheme 4 fails to develop the full head for the entire flow and thus Scheme 4 is not expected to produce annual energy comparable to other schemes. Daily water level fluctuations downstream of Devil Canyon are similar to Schemes 1 and 2. Water level fluctuations between Watana and Devil Canyon are expected to be large.

RJW/ljr

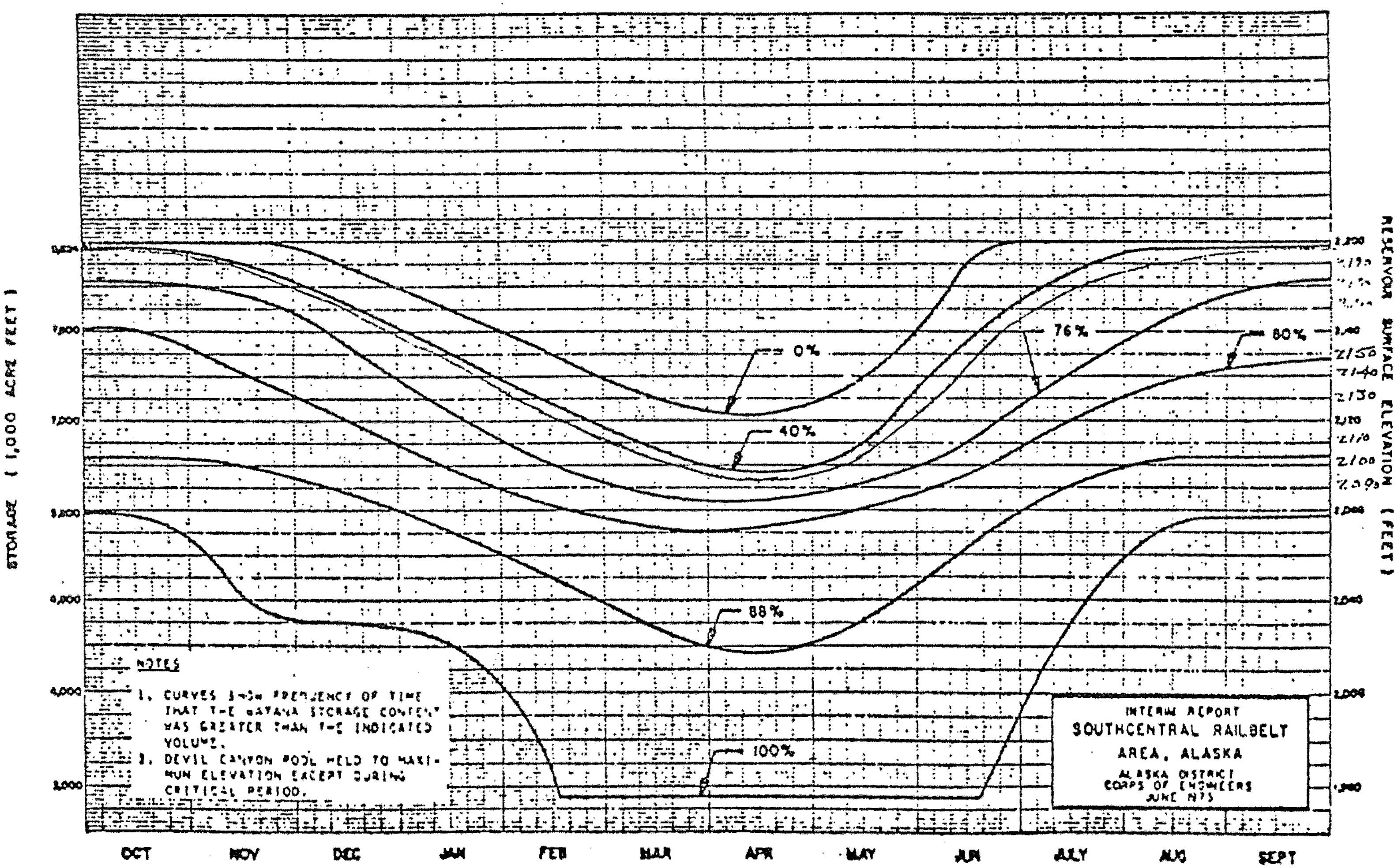
Robert J Wart
Bob Wart

SUSITNA TUNNEL SCHEMES - PHYSICAL FACTORS (Addendum)

	Typical	COE	1	2	3	4
Range of discharge (cfs) at Devil Canyon Powerhouse	daily	6,000 to 13,000	4,000 to 14,000	4,000 to 14,000	8,300 to 8,900	4,000 to 13,000
	seasonal	Fluctuations are less than existing natural fluctuations and are smaller for all plans.				
Range of river stage below Devil Canyon powerhouse (corresponding to discharges listed above)	daily	Small	Large	Large	Small	Large
		To date no detailed information is available.				
	seasonal	All plans have identical seasonal fluctuations which are less than natural fluctuations. To date no information is available.				
Maximum fluctuations (ft) in Watana Reservoir	daily	<1	Same as COE	Same as COE	Same as COE	Same as COE
	seasonal	See Graph	Same as COE	Same as COE	Same as COE	Same as COE
Maximum fluctuations (ft) in downstream reservoir	daily	2	Large	NA	4	NA
	seasonal	None	None	NA	None	NA
Generating Capacity (MW)	Watana	792	792	35 (792)*	792	792
	Devil Canyon	776	550	1,150	365	365
Total Project Costs ($)		2,150,000,000	2,502,100,000	2,394,600,000	2,144,300,000	2,074,200,000
Total Annual Energy (GwH)		6,895	5,704	5,056	5,924	4,140

*Watana capacity is reduced after completion of tunnel project.

WATANA MONTHLY STORAGE FREQUENCY FOR THE DEVIL CANYON AND WATANA SYSTEM



Terrestrial
Environmental
Specialists, inc.
R.D. 1 BOX 388 PHOENIX, N.Y. 13135

January 16, 1981
218.443

Project Manager
Susitna Hydroelectric Project
Acres American, Inc.
Liberty Bank Building
Main at Court
Buffalo, New York 14202

Attention: Kevin Young
Re: Alternative Development Schemes

Dear Kevin:

In response to your request of December 10, 1980, and as discussed in my letter to you on January 8, 1981, TES, Inc. has prepared some comments on the Vee/High Devil Canyon/Olson scheme in comparison with the Watana/Devil Canyon scheme. Enclosed for your review and comment is a draft of a brief report entitled "Environmental Considerations of Alternative Hydroelectric Development Schemes for the Upper Susitna Basin".

We will be pleased to discuss the contents of this report with you.

Sincerely,

Vince

Vincent J. Lucid, Ph.D.
Environmental Studies Director

VJL/vl
Enc.
cc: R. Krogseng

DRAFT

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

ENVIRONMENTAL CONSIDERATIONS OF ALTERNATIVE HYDROELECTRIC DEVELOPMENT SCHEMES FOR THE UPPER SUSITNA BASIN

by

Terrestrial Environmental Specialists, Inc.
Phoenix, New York

for

Acres American, Inc.
Buffalo, New York

January 16, 1981

TABLE OF CONTENTS

1 - INTRODUCTION

This report documents preliminary environmental considerations of alternative hydroelectric development schemes for the Upper Susitna Basin. The need for the report stems from discussion at a meeting held in Buffalo on December 2, 1980 between staff of Acres American and TES, Inc. The alternative development schemes are described in a December 4, 1980 memo from I. Hutchison to K. Young for transmittal to TES, Inc. (Appendix A). Additional details were obtained and the approach agreed upon in subsequent conversations and data transmittal between K. Young and V. Lucid concerning these alternative development schemes.

The following assessment is based upon a familiarity with the Watana/Devil Canyon area obtained during the first year of environmental studies. At this writing, however, we do not have the benefit of information to be contained in the 1980 Annual Reports, which are to be completed by TES subcontractors by March 1981. Because much of the Vee reservoir lies outside of the study area for many disciplines, comments concerning this impoundment rely heavily upon intuitive judgement.

2 - APPROACH

2.1 The Development Schemes

Environmental considerations were preliminarily identified for two different hydroelectric development schemes for the Upper Susitna Basin: Watana/Devil Canyon and Vee/High Devil Canyon/Olson. The three staging variations for each of these schemes (Appendix A) will likely have different short-term impacts, but an attempt to address these possible differences at this time would be too speculative in most disciplines to be meaningful. In disciplines such as socioeconomics and land use, however, the staging of the development will largely determine the magnitude of impacts. Thus, the environmental considerations identified in this report are based in most cases upon the two ultimate schemes with occasional references to the staging options. It was assumed that whatever staging alternative is selected, all stages of development would be completed. The result would be one of the two schemes outlined in Table 1.

2.2 Assumptions of Environmental Constraints

The identification of potential advantages and disadvantages of the two schemes, from an environmental standpoint, requires that certain assumptions be made concerning environmental constraints that will govern the design and operation of the facilities. Among these are:

(a) that constant, or nearly constant, downstream flows be maintained, both during and after development, whether by means of a re-regulation facility or operational constraints;

(b) that drawdown of the reservoirs would be similar in magnitude to corresponding reservoirs in the other scheme (e.g. Watana vs. Vee), and would be within environmental constraints; and

(c) that a minimum release or compensation flow be maintained (of a volume to be determined) to preserve the riverine habitat between the reservoirs.

Table 1
Descriptions of Two Alternative Hydroelectric Development Schemes for the Upper Susitna Basin[(a)]

	Watana/Devil Canyon	Vee/High Devil Canyon/Olson
Maximum pool elevation (ft)	2200/1450	2300/1750/1020
Dam Height (ft)	750/570	425/725/120
Installed Capacity (MW)	800/600	400/800/100$\pm$
Probable On-Line Date of Last Stage	2010 to 2020	2020
Daily Peaking	Yes/No	Yes/Yes/No
Approximate[(b)] Reservoir Area (acres)	40,000/7,500 (Total = 47,500)	16,000/21,700/900 (Total - 38,600)
Approximate[(b)] River Miles Flooded[(c)]	60/30 (Total = 90)	95/58/7 (Total = 160)

---

[a] Derived from descriptions of three staging alternatives for each scheme, which are presented in Appendix A.

[b] Preliminary values.

[c] Mainstream Susitna only, tributaries not included.

3 - DISCUSSION

Potential advantages and disadvantages of the two development schemes are presented below for each of the major environmental study disciplines.

3.1 Socioeconomics

There could be significant differences in type, degree, and chronology of socioeconomic impacts resulting from the various plans under consideration. An important concern relates to alternative staging plans and associated factors such as: (a) cost of stage, (b) scheduling of various stages (i.e., length of construction period per stage and spacing), (c) construction manpower requirements by time period, (d) access point of origin, and (e) whether or not a construction "community" will be established. Impacts generally will fall into two categories: those associated with project economics and construction, and those associated with power production and sales. Both types of impacts will exhibit a variety of local, Railbelt, and statewide ramifications. In the absence of practically any project economics information, detailed analysis is impossible at this time. In general, however, it can be expected that a scheme involving on-line production capability of 800 MW by the year 2000 will have greater and more significant impacts than a scheme in which that capability is not attained until 2010 (e.g., Plan 1 compared to Plan 2). This difference would occur because, in the latter plan, the demand on resources will be spread out over time. In addition, it is reasonable to expect that the economic base of Mat-Su Borough will be larger in 2010 than in 2000, even without the project. Therefore, there likely would be a greater capacity to deal with project impacts.

3.2 Cultural Resources

Field surveys in the Watana/Devil Canyon impoundment area during the summer of 1980 have documented 37 archeological sites. A preliminary assessment of the data indicates a greater number of archeological sites towards the east end of the study area. In 1953, a preliminary field survey conducted for the National Park Service near Lakes Louise, Susitna, and Tyone identified approximately six archeological sites. There is a high potential for discovering many more sites along the lakes, streams, and rivers in this easterly region of the Upper Susitna River Basin. Additional sites are expected to be identified near caribou crossings of the Oshetna River. In summary, a preliminary assessment of available information suggests that there perhaps could be a greater number of archeological sites associated with the Vee/High Devil Canyon/Olson scheme than with the Watana/ Devil Canyon scheme.

3.3 Land Use

At present, much of the Upper Susitna Basin is subjected to almost negligible human activity. Either of the development schemes (and any of the staging plans) will cause changes in land use patterns in the Upper Susitna Basin. Regardless of the scheme chosen, impacts on local land usage and human activity in the Upper Basin will be significant in terms of area inundated and land cover changes resulting from project facilities. With either the Watana/Devil Canyon or Vee/High Devil Canyon/Olson scheme, Deadman Falls will be inundated and Devil Canyon will be greatly reduced in scenic value. The Vee/High Devil Canyon/Olson scheme would also eliminate Tsusena Falls and would destroy the existing aesthetics of Vee Canyon by dam construction at this site. Although the Vee/High Devil Canyon/Olson scheme has a smaller reservoir area, it would inundate approximately 70 miles more of the Susitna River than would the Watana/Devil Canyon scheme (Table 1). Development of a recreation plan for the project would vary according to the design scheme and staging plan selected.

Broader concerns associated with land use are related to staging, as discussed in the previous section regarding socioeconomics. The influence of staging on land use impacts applies to land use factors concerned with existing regional transportation systems. The existing transportation systems (and communities and land uses associated with them) which connect to the selected access route will be affected by construction-related activity. In this context, the degree of construction-related activity within a given time frame could be a significant factor. This consideration is similar to the socioeconomic concern identified previously. The proportionately greater degree of construction activity associated with a plan in which 800 MW capability would be achieved by 2000 - as compared with one in which this would not be achieved until 2010 - concentrates impacts on land uses in a shorter time frame.

3.4 Fish Ecology

All development schemes must be examined with the downstream anadromous fishery receiving primary consideration. Any scheme or staging plan that allows for daily peaking without a re-regulation dam downstream could be detrimental to this resource. Therefore, the maintenance of constant, or nearly constant, downstream flows is an environmental constraint that must be met for any development scheme to be acceptable.

The Vee/High Devil Canyon/Olson scheme has at least one major disadvantage, with respect to fish ecology, in comparison to development at Watana/Devil Canyon. It is that the Olson site is downstream of Portage Creek, which is known to be a very important spawning stream for salmon. Dam development at the Olson site would provide an obstruction to anadromous fish passage and two miles of Portage Creek would be inundated. Even with facilities for fish passage, the impacts on this spawning area could be severe.

Because the Vee/High Devil Canyon/Olson scheme would inundate about 70 additional miles of the Susitna River, plus different tributaries, than would the Watana/Devil Canyon scheme, impacts on resident fish can be expected to differ between the two schemes. Data are not presently available to permit an assessment of these impacts.

3.5 Wildlife Ecology

Although the area that would be inundated by the Vee reservoir has not been thoroughly investigated, project personnel have sufficient familiarity with the area to make a fairly strong recommendation at this time. With the exception of impacts on avian species, it is felt that the Watana/Devil Canyon scheme is superior from a wildlife impact standpoint to the Vee/High Devil Canyon/Olson scheme. The basic trade-offs associated with this comparison involve the areas to be flooded by the Vee dam as opposed to the flooding of much of the Watana Creek drainage and the higher portions of the canyon walls along the Susitna. For a variety of reasons the area to be flooded by the Vee dam seems more valuable for wildlife than the areas that would be inundated by the Watana/Devil Canyon dams.

A Vee/High Devil Canyon/Olson scheme would flood more acreage of critical river bottom habitat than would the Watana/Devil Canyon scheme. These areas are important for moose during severe winters and the additional reduction in such habitat could have a major impact on moose populations. In addition, the Vee impoundment would flood key winter habitat for at least three subpopulations of moose that range over large areas east of the Susitna and north of the MaClaren River. The area that would be saved by the Vee dam scheme, the Watana Creek drainage, is inhabitated by a subpopulation of moose that appears to be declining in condition and increasing in age, thus indicating that within 10 to 15 years this subpopulation may be far less important than at present. The habitat quality within the Watana Creek drainage also seems to be decreasing. TES has previously recommended that the pool elevation of Watana be lowered to preserve as much of the Watana Creek drainage as possible. Nevertheless, the trade-off between Watana Creek and the Vee impoundment favors flooding the Watana Creek area.

The area that would be flooded by the Vee dam is historically used by the Nelchina caribou herd, particularly in moving to their calving grounds near Kosina Creek. Although caribou movement patterns are highly variable and appear to change as the size of the herd changes, this area has been frequently traversed by members of this herd. The potential for impacting caribou movement is greater than with the present Watana scheme. Like Watana, the Vee reservoir would be subject to large drawdown and possible ice-shelving. In addition, the three-dam scheme would result in a greater division of the Nelchina herd's range due to the greater length of the impoundments involved and thus increase the likelihood of impacts on this herd.

There is an indication that the area to be flooded by the Vee dam is more important to some key furbearers, the red fox in particular, than areas such as Watana Creek that would be spared by a Vee dam. There is also more trapping conducted by residents in the area upstream from the Vee site than in areas downstream from that area. The Vee dam, especially due to the drawdown schedule that would be operative with this dam, also has the potential of more severely impacting both muskrat and beaver populations.

It appears that only avian species might suffer less adverse impacts from the Vee/High Devil Canyon/Olson scheme than from Watana/Devil Canyon. Although the Vee dam would eliminate more river bottom habitat, it would spare a considerable amount of deciduous forest (birch and aspen) that exists along the south-facing slopes of the Susitna canyon and along some of the tributaries. This is the only area, of any extent, that contains this type of habitat, and its associated avifauna, within the Upper Susitna Basin.

Although a more detailed recommendation could be made if a better data base were available, the reasons given above seem to indicate that the Watana/Devil Canyon scheme is superior to a Vee/High Devil Canyon/Olson scheme. This is especially true if one considers that the greatest potential for more severe impacts concern moose and caribou, which are unquestionably the key big game species in the area.

3.6 Plant Ecology

Both schemes will primarily flood deciduous forests (white birch, balsam poplar, and aspen types), coniferous woodlands and forests (white spruce and black spruce), and shrub communities (alder, birch, and willow types). The relative amounts of habitats flooded will vary with the two schemes. The Vee/High Devil Canyon/Olson combination will probably flood more floodplain habitats such as balsam poplar forests, while the Watana/Devil Canyon scheme will probably flood more birch and aspen forests.

The primary advantage of the Vee/High Devil Canyon/Olson scheme is that approximately 9,000 fewer acres would be flooded (Table 1). The primary disadvantages of this scheme are: more lakes and wetlands flooded, more river floodplains flooded, and a greater amount of associated floodplain habitats, such as balsam poplar, eliminated. The amount of wetland eliminated would be a very small proportion of the total wetland in the region. Nevertheless, the importance of wetlands, floodplains, and associated habitats has been emphasized by Executive Orders and various federal agencies.

3.7 Transmission Line Impacts

Because of the distance traversed, the construction of a transmission line to the intertie from a Vee/High Devil Canyon/Olson project offers several disadvantages when compared to a line constructed from a Watana/Devil Canyon project. A line from the Parks Highway to Watana would be approximately 50 miles in length. Following the same route to Watana and extending the line to the Vee site would add approximately 40 miles to its total length, an increase in mileage of some 80 percent. Generally, the longer the line, the greater the impact. In addition, the added length would cross a presently roadless remote parcel of land, thereby necessitating additional miles of access road construction. Additional vegetation clearing would be required due to the longer route. Assuming a 300 foot wide right-of-way, approximately 1500 additional acres would need to be cleared during construction and maintained during operation of this line, thereby potentially impacting wildlife habitat. To the extent that land use, aesthetic and recreational opportunities are impaired by transmission facilities, a larger impact zone will be created. Similarly, areas of significant cultural resource potential will be impacted to a greater degree than with the shorter line. A greater number of streams tributary to the Susitna River will need to be crossed, posing additional areas of potential impact. In summary, constructing transmission facilities to the Vee site considerably increases the potential impact of project transmission lines.

3.8 Access Road Impacts

At present, an access route for the Watana/Devil Canyon scheme has not been decided upon, and no information at all is available with regard to access for the Vee/High Devil Canyon/Olson scheme. Also, it has not even been determined which of the two schemes would have the shorter access road. By virtue of the relative dispersion of the dam sites, however, the two schemes may differ with respect to the area opened up to access and the resultant dispersion of human disturbance over the Upper Susitna Basin. The Watana/Devil Canyon scheme may confine access to a smaller portion of the basin, especially if access is from the west. The Vee/High Devil Canyon/Olson scheme, especially if it is a staged development, may be more likely to have access from both north (Denali Highway) and west, thereby opening access to a larger area, and from several directions.

3.9 Summary

In each of the environmental study disciplines, differences exist in the potential impacts of the Vee/High Devil Canyon/Olson scheme in comparison to the Watana/Devil Canyon scheme. The Vee/High Devil Canyon/Olson scheme has more apparent disadvantages than advantages; most of these disadvantages are due to the Vee impoundment rather than the High Devil Canyon impoundment. In socioeconomics and in some aspects of land use, the differences due to staging are of more significance than those due to the location of the dams. Nevertheless, it is noteworthy that the Vee/High Devil Canyon/Olson scheme may affect more canyons and waterfalls of outstanding scenic value than would Watana/Devil Canyon. Existing information suggests that there is a high potential for occurrence of cultural resources in the vicinity of the Vee reservoir, perhaps even more than in the vicinity of Devil Canyon and Watana. A major disadvantage of the Vee/High Devil Canyon/Olson scheme is the impact of Olson on anadromous fish spawning in Portage Creek; daily peaking from High Devil Canyon without re-regulation is also environmentally unacceptable. There is evidence that impacts upon big game (particularly moose and caribou) and furbearers would be more severe with the Vee/High Devil Canyon/Olson scheme than with Watana/Devil Canyon, although this is not necessarily the case with birds. Although the Vee/High Devil Canyon/Olson scheme would flood less acreage than Watana/Devil Canyon, a larger amount of floodplain and wetland habitat would be inundated. Because of the longer distance traversed, potential impacts of the transmission line would be proportionately greater with development at the Vee site. The dispersion of the dam sites in the Upper Basin with Vee/High Devil Canyon/Olson would also likely result in a larger impact zone due to increased access.

4 - CONCLUSION

Although some potential advantages and disadvantages have been identified for both the Watana/Devil Canyon scheme and the Vee/High Devil Canyon/Olson scheme, sufficient information is not yet available upon which to base a firm recommendation. The evidence that is available, however, when combined with intuitive judgement, suggests that the Watana/Devil Canyon scheme may be preferable to the Vee/High Devil Canyon/Olson combination. The comments contained in this report will be reviewed and refined after the 1980 Annual Reports are available and when more construction and operational details are known. Comparison of the two schemes will still be hampered by the scarcity of information concerning the Vee impoundment area.

APPENDIX A

DESCRIPTION OF STAGING ALTERNATIVES

RECEIVED

K. Young
(for transmittal to TES)
I. Hutchison

December 4, 1980

P5700.14.06

Susitna HEP
Current Susitna Basin Development Schemes

As requested, the schemes currently being investigated are summarized on the attached sheets. Please note that the probable on-line dates are estimates at this stage and will be firmed up over the next two weeks.

I. Hutchison

IH:ccv
Attachments

cc: J.D. Lawrence
J.W. Hayden
P. Tucker (Col.)
A. Simon
G. Krishnan
D. Carlson
R. Wart
V. Singh
P. Rodrigue
E.N. Shadeed
R. Ibbotson

SCHEME Plan 1 (Total installed capacity = 1400 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site Watana (2200)	Dam Site Devil Canyon (1450)	Dam Site ______	Dam Site ______
Height 750 ft.	Height 570 ft.	Height ______ ft.	Height ______ ft.
Installed Capacity 800 MW	Installed Capacity 600 MW	Installed Capacity ______ MW	Installed Capacity ______ MW
Probable on Line Date 1995-2000	Probable on Line Date 2010-20	Probable on Line Date ______	Probable on Line Date ______
Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation ______	Mode of Operation ______
Separate Re-regulation Dam Possibly	Separate Re-regulation Dam No	Separate Re-regulation Dam ______	Separate Re-regulation dam ______

NOTE: Figures in brackers behind dam site name
indicate maximum water surface elevation in feet.

SCHEME Plan 2 (Total installed capacity = 1400 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site Watana (2000)	Dam Site Watana (2200)	Dam Site Devil Canyon (1450')	Dam Site ______
Height 550 ft.	Height 750 ft.	Height 570 ft.	Height ______ ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 600 MW	Installed Capacity ______ MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date ______
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation ______
Separate Re-regulation Dam Possibly	Separate Re-regulation Dam Possibly	Separate Re-regulation Dam No	Separate Re-regulation dam ______
	Watana Dam raised 200'		
	Installed Capacity Increased by 400 MW		

SCHEME Plan 3 (Total installed capacity = 1400 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site Watana (2200)	Dam Site Watana (2200)	Dam Site Devil Canyon	Dam Site ______
Height 750 ft.	Height 750 ft.	Height 570 ft.	Height ______ ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 600 MW	Installed Capacity ______ MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date ______
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation ______
Separate Re-regulation Dam Possibly	Separate Re-regulation Dam Possibly	Separate Re-regulation Dam No	Separate Re-regulation dam ______
	Installed Capacity Increased by 400 MW		

SCHEME Plan 4 (Total installed capacity = 1300 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site High D.C. (1755)	Dam Site Vee (2300)	Dam Site Olson (1010)	Dam Site
Height 725 ft.	Height 425 ft.	Height 120 ft.	Height ft.
Installed Capacity 800 MW	Installed Capacity 400 MW	Installed Capacity ±100 MW	Installed Capacity MW
Probable on Line Date 1995-2000	Probable on Line Date 2010-20	Probable on Line Date 2020 —	Probable on Line Date
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation
Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam No	Separate Re-regulation Dam No	Separate Re-regulation dam

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.

SCHEME Plan 5 (Total installed capacity = 1300 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site High Devil Canyon (1610)	Dam Site High Devil Canyon (1750)	Dam Site Vee (2300)	Dam Site Olson (1020)
Height 570 ft.	Height 725 ft.	Height 425 ft.	Height 120 ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 400 MW	Installed Capacity ±100 MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date 2020
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking
Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam No	Separate Re-regulation dam No
	High Devil Canyon Dam Raised 140'		
	Installed capacity Increased by 400 MW		

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.

SCHEME Plan 6 (Total installed capacity = 1300 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site High Devil Canyon (1750)	Dam Site High Devil Canyon (1750)	Dam Site Vee	Dam Site Olson (1020)
Height 725 ft.	Height 725 ft.	Height 425 ft.	Height 120 ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 400 MW	Installed Capacity ±100 MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date 2020
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking
Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam No	Separate Re-regulation dam No
	Installed Capacity increased by 400 MW		

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.

TABLE 1.1 - ENVIRONMENTAL EVALUATION OF DEVIL CANYON DAM AND TUNNEL SCHEME

Environmental Attribute	Concerns	Appraisal (Differences in impact of two schemes)	Identification of difference	Appraisal Judgement	Scheme judged to have the least potential impact: Tunnel	DC
Ecological:						
- Downstream Fisheries and Wildlife	Effects resulting from changes in water quantity and quality.	No significant difference between schemes regarding effects downstream of Devil Canyon.	---	Not a factor in evaluation of scheme.		
		Difference in reach between Devil Canyon dam and tunnel re-regulation dam.	With the tunnel scheme controlled flows between regulation dam and downstream powerhouse offers potential for anadromous fisheries enhancement in this 11 mile reach of the river.	If fisheries enhancement opportunity can be realized the tunnel scheme offers a positive mitigation measure not available with the Devil Canyon dam scheme. This opportunity is considered moderate and favors the tunnel scheme.	X	
Resident Fisheries:	Loss of resident fisheries habitat.	Minimal differences between schemes.	Devil Canyon dam would inundate 27 miles of the Susitna River and approximately 2 miles of Devil Creek. The tunnel scheme would inundate 16 miles of the Susitna River.	This reach of river is not considered to be highly significant for resident fisheries and thus the difference between the schemes is minor and favors the tunnel scheme.	X	
Wildlife:	Loss of wildlife habitat.	Minimal differences between schemes.	The most sensitive wildlife habitat in this reach is upstream of the tunnel re-regulation dam where there is no significant difference between the schemes. The Devil Canyon dam scheme in addition inundates the river valley between the two dam sites resulting in a moderate increase in impacts to wildlife.	The difference in loss of wildlife habitat is considered moderate and favors the tunnel scheme.	X	
Cultural:	Inundation of archeological sites.	Potential differences between schemes.	Due to the larger area inundated the probability of inundating archeological sites is increased.	A significant archeological site, if identified, can probably be excavated. This concern is not considered a factor in in scheme evaluation.	-	-
Land Use:	Inundation of Devil Canyon.	Significant difference between schemes.	The Devil Canyon is considered a unique resource, 80 percent of which would be inundated by the Devil Canyon dam scheme. This would result in a loss of both an aesthetic value plus the potential for white water recreation.	The aesthetic and to some extent the recreational losses associated with the development of the Devil Canyon dam is the main aspect favoring the tunnel scheme.	X	

OVERALL EVALUATION: The tunnel scheme has overall a lower impact on the environment.

TABLE I.2 - SOCIAL EVALUATION OF SUSITNA BASIN DEVELOPMENT SCHEMES/PLANS

Social Aspect	Parameter	Tunnel Scheme	Devil Canyon Dam Scheme	High Devil Canyon/ Vee Plan	Watana/Devil Canyon Plan	Remarks
Potential non-renewable resource displacement	Million tons Beluga coal over 50 years	80	110	170	210	Devil Canyon dam scheme potential higher than tunnel scheme. Watana/ Devil Canyon plan higher than High Devil Canyon/ Vee plan.
Impact on state economy	--	All projects would have similar impacts on the state and local economy.				Essentially no difference between plans/schemes.
Impact on local economy	--	All projects would have similar impacts on the state and local economy.				Essentially no difference between plans/schemes.
Seismic exposure	Risk of major structural failure	All projects designed to similar levels of safety.				Essentially no difference between plans/schemes.
	Potential impact of failure on human life.	Any dam failures would effect the same downstream population.				Essentially no difference between plans/schemes.
Overall Evaluation	1. Devil Canyon dam superior to tunnel. 2. Watana/Devil Canyon superior to High Devil Canyon/Vee plan.					

TABLE I.3 - ENVIRONMENTAL EVALUATION OF WATANA/DEVIL CANYON AND HIGH DEVIL CANYON/VEE DEVELOPMENT PLANS

Environmental Attribute	Plan Comparison	Appraisal Judgement	Plan judged to have the least potential impact HDC/V	W/DC
Ecological: 1) Fisheries	No significant difference in effects on downstream anadromous fisheries. HDC/V would inundate approximately 95 miles of the Susitna River and 28 miles of tributary streams, including the Tyone River. W/DC would inundate approximately 84 miles of the Susitna River and 24 miles of tributary streams, including Watana Creek.	Due to the avoidance of the Tyone River, lesser inundation of resident fisheries habitat and no significant difference in the effects on anadromous fisheries, the W/DC plan is judged to have less impact.		X
2) Wildlife a) Moose	HDC/V would inundate 123 miles of critical winter river bottom habitat. W/DC would inundate 108 miles of this river bottom habitat. HDC/V would inundate a large area upstream of Vee utilized by three sub-populations of moose that range in the northeast section of the basin. W/DC would inundate the Watana Creek area utilized by moose. The condition of this sub-population of moose and the quality of the habitat they are using appears to be decreasing.	Due to the lower potential for direct impact on moose populations within the Susitna, the W/DC plan is judged superior.		X
b) Caribou	The increased length of river flooded, especially upstream from the Vee dam site, would result in the HDC/V plan creating a greater potential division of the Nelchina herd's range. In addition, an increase in range would be directly inundated by the Vee reservoir.	Due to the potential for a greater impact on the Nelchina caribou herd, the HDC/V scheme is considered inferior.		X
c) Furbearers	The area flooded by the Vee reservoir is considered important to some key furbearers, particularly red fox. This area is judged to be more important than the Watana Creek area that would be inundated by the W/DC plan.	Due to the lesser potential for impact on furbearers the W/DC is judged to be superior.		X
d) Birds and Bears	Forest habitat, important for birds and black bears, exist along the valley slopes. The loss of this habitat would be greater with the W/DC plan.	The HDC/V plan is judged superior.	X	
Cultural:	There is a high potential for discovery of archeological sites in the easterly region of the Upper Susitna Basin. The HDC/V plan has a greater potential of affecting these sites. For other reaches of the river the difference between plans is considered minimal.	The W/DC plan is judged to have a lower potential effect on archeological sites.		X

TABLE 1.3 (Continued)

Environmental Attribute	Plan Comparison	Appraisal Judgement	Plan judged to have the least potential impact HDC/V	W/DC
Aesthetic/ Land Use				
	With either scheme, the aesthetic quality of both Devil Canyon and Vee Canyon would be impaired. The HDC/V plan would also inundate Tsusena Falls.	Both plans impact the valley aesthetics. The difference is considered minimal.	-	-
	Due to construction at Vee Dam site and the size of the Vee Reservoir, the HDC/V plan would inherently create access to more wilderness area than would the W/DC plan.	As it is easier to extend access than to limit it, inherent access requirements were considered detrimental and the W/DC plan is judged superior. The ecological sensitivity of the area opened by the HDC/V plan reinforces this judgement.		X

OVERALL EVALUATION: The W/DC plan is judged to be superior to the HDC/V plan. (The lower impact on birds and bears associated with HDC/V plan is considered to be outweighed by all the other impacts which favour the W/DC plan.)

NOTES:

W = Watana Dam
DC = Devil Canyon Dam
HDC = High Devil Canyon Dam
V = Vee Dam

APPENDIX J - AGENCY AND OTHER COMMENTS

The second draft of the Development Selection Report was distributed to the following agencies for review and comment. This section of the report addresses the comments received and responses to those comments.

Attachment 1, 2, 3, 4 and 5, which follow in their entirety, are the comments received from the following agencies:

- Attachment 1: University of Alaska Arctic Environmental Information and Data Center
- Attachment 2: State of Alaska, Department of Fish and Game
- Attachment 3: U.S. Department of Interior, Geological Survey
- Attachment 4: U.S. Department of Interior, National Park Service
- Attachment 5: State of Alaska, Department of Environmental Conservation

J.1 - Responses to AEIDC Comments

(a) Borrow Areas

It is agreed that there will be significant impacts due to development of borrow areas for construction of all earth or rockfill dams considered. For purposes of the study it has been assumed that the major portion of borrow material will be obtained from areas which will be subsequently submerged by the proposed reservoirs. The relatively short-term impacts of earth-moving operations during dam construction are considered to be similar for all alternatives considered and therefore not a significant factor in comparisons. The longer-term impacts of borrow areas which will be submerged were considered to be included in the comparisons of impacts of the reservoirs in each case.

(b) Continuation of Environmental Studies

It is true that detailed environmental studies of only the selected plan are continuing in support of the requirements of the FERC license application. The purpose of these studies is to allow more precise assessments to be made of such impacts and for development of mitigation plans where appropriate. The comparisons of environmental impacts of all alternatives considered have been based only on those aspects which will influence the selection of a development plan. The report provides appropriate support for these comparisons to be made and will not consider them further. Consideration of impacts which are similar in magnitude or which are relatively insignificant will not influence the selection process and have therefore been excluded.

J.2 - Responses to ADF&G Comments

(a) Page 1-4(g), Task 7 - Environmental Studies

The text has been revised as suggested.

(b) Pages 8-26 and 8-27, Environmental Comparisons

The background information used to support the environmental comparisons made consists of published data together with visual observation of personnel undertaking the current studies. The report provides appropriate references to and documentation of this information. The personnel involved in the studies are amply qualified in their respective fields and were approved as such by the Alaska Power Authority.

Appropriate mechanisms have been established for continuing the active involvement of ADF&G, USFWS and all other concerned agencies in the decision processes being used in this study. The scope and methodology for undertaking environmental studies have been reviewed by these agencies and modified where appropriate as a result of such reviews.

J.3 - Response to USGS Comments

No response required.

J.4 - Response to USNPS Comments

The Susitna Project Feasibility Report will deal with the specific impacts of the selected development plan and will not consider further the impacts of alternative Susitna Basin development plans. Sufficient information has been presented in the report to arrive at a selected development; further study of other basin alternatives is unwarranted at this time.

The impact of reservoir siltation for the selected development will be studied and the results presented in the Feasibility Report.

J.5 - Response to ADEC Comments

No response required.

ATTACHMENT 1

ctic Environmental Information and Data Center
707 A Street
Anchorage, Alaska 99501

PHONE (907) 279-4527

UNIVERSITY OF ALASKA

RECEIVED

AUG 5 1981

ALASKA POWER AUTHORITY

August 4, 1981

Dave Wozniak
Alaska Power Authority
333 W. 4th AVenue, Suite 31
Anchorage, AK 99501

Dear Dave:

Per your request to the members of the Susitna Steering Committee, I have quickly reviewed the Development Selection Report prepared by Acres. In general I found it logical in approach and complete in regards to the relevant factors one should evaluate when reducing multiple options.

I have only the following specific comments:

1. The location and environmental effects of developing borrow material sites is not well documented and incorporated into the first part of the report. Enormous qunatities would be required for most of the dams, and the removal, stockpiling, and transport of this material could be a significant factor influencing the decision-making process.

2. Significant efforts are currently being expended in environmental study of this region, the results of which are not yet available. Factoring this new knowledge into the decision-making process could have influenced the nature of the final scheme; or is the current environmental study effort geared only toward the effects of the "selected plan (page 9-1)" and not for input to the overall selection process? In general I found the environmental effects of the alternative options addressed very superficially.

I hope my comments are of interest.

Sincerely,

William J. Wilson

William J. Wilson
Supervisor, Resource and Science
Services Division
Senior Research Analyst in Fisheries

WJW/g

cc: Al Carson

ATTACHMENT 2

MEMORANDUM

State of Alaska

TO	Dave Wozniak Project Engineer Alaska Power Authority 333 W. 4th Avenue, Suite 31 Anchorage, Alaska 99501	DATE	July 29, 1981
		FILE NO	02-I-81-ADF&G-7.0 02-V-Acres-1.0
		TELEPHONE NO	
FROM	Thomas W. Trent TWT Aquatic Studies Coordinator Su Hydro Aquatic Studies Anchorage	SUBJECT	Review of Draft Development Selection Report - Su Hydro Project

RECEIVED
AUG 4 1981
ALASKA POWER AUTHORITY

I've reviewed the draft Development Selection Report for the Susitna Hydroelectric Project and my comments are as follows:

Page 1-4 (g) Task 7 - Environmental Studies

Comment: I recommend the words in the last sentence i.e., large game be changed to big game.

Page 8-26 Environmental Comparison - 2nd paragraph - a statement regarding enhancement potential for anadromous fish and, the statement on page 8-27 Environmental Comparison, 2nd paragraph.

Comment: A general observation addressed to these specific sections, is that development of the environmental comparisons has undoubtedly been a subjective process. The statements made really don't provide any detailing of the hows, whys, and rationale for the conclusions drawn. I believe we can accept a subjective process for evaluating the environmental merits or deficiencies of a particular dam scheme, but it would have been a helpful process for Acres to involve ADF&G, USFWS and others in such an analysis to discuss alternative positive/negative impact possibilities. I think this would have led to a healthy exchange of ideas. The exposure of the fish and wildlife or other resource agencies to the same design or operational schemes laid out to the Acres environmental review team may have led to conclusions which were the same or potentially quite different from the Acres analysis of the situation.

To sum up, we can't argue with Acres report since we don't know the background information used to support their rationalizations or the experience of the individuals involved in the report preparation that drew the conclusions on fisheries.

cc: S. Zrake - DEC
B. Wilson - AEIDC
G. Stackhouse - USFWS
R. Lamke - USGS
A. Carson - ADNR

ATTACHMENT 3

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY
Water Resources Division
733 W. Fourth Ave., Suite 400
Anchorage, Alaska 99501

RECEIVED
JUL 30 1981
ALASKA POWER AUTHORITY

July 27, 1981

Al Carson
State of Alaska
Department of Natural Resources
323 E. Fourth Avenue
Anchorage, Alaska 99501

Dear Mr. Carson:

I have reviewed the Draft Development Selection Report for the proposed Susitna Hydroelectric Project as requested in the APA transmittal of June 18, 1981. The review was limited to the evaluation process used by Acres, the relative impacts of several alternative development plans of Susitna hydroelectric resources, and the conclusion that the Watana-Devil Canyon plan is the preferred basin alternative.

There were no problems involved in understanding the selection process used by Acres and there were enough data and information presented to compare the final candidate (alternative) plans. The relative impacts of the candidates were presented in an understandable and credible manner. Although only a qualitative evaluation of impacts is presented (pending reports of on-going studies), a reasonable conclusion is that the Watana-Devil Canyon plan is the preferred candidate for Susitna hydroelectric development.

Robert D. Lamke

Robert D. Lamke

cc: David D. Wozniak, Project Engineer, APA, Anchorage, AK

ATTACHMENT 4

United States Department of the Interior

NATIONAL PARK SERVICE

ALASKA STATE OFFICE

334 West Fifth Avenue, Suite 250

Anchorage, Alaska 99501

IN REPLY REFER TO:

1201-03a

AUG 5 1981

RECEIVED

AUG 7 1981

ALASKA POWER AUTHORITY

Mr. David D. Wozniak
Susitna Hydro Project Engineer
Alaska Power Authority
333 West 4th Avenue, Suite 31
Anchorage, AK 99501

Dear David:

In response to your request I have reviewed the Draft Development Selection Report for the Susitna Project. Based upon the information presented in the report, I would judge the evaluation process to be satisfactory. However, I would not want to recommend or otherwise comment on a preferred basin alternative prior to the completion of ongoing studies which will further quantify the anticipated environmental impacts. I assume the final report will reflect a more precise comparison of environmental impacts for the dam sites under consideration.

An additional item of interest which should perhaps be included in the final report is a comparison of the expected life of the project for each alternative dam site considering the effect of silt accumulation in the reservoirs.

Thank you for the opportunity to review the report. The above comments are my own and should not be interpreted as representing the official position of the National Park Service.

Sincerely,

Larry M. Wright

Larry M. Wright
Outdoor Recreation Planner

ATTACHMENT 5

STATE OF ALASKA

DEPT. OF ENVIRONMENTAL CONSERVATION

SOUTHCENTRAL REGIONAL OFFICE

437 E Street
Second Floor
Anchorage, AK 99501

P.O. Box 1207
Soldotna, Alaska 99669
(907) 262-5210

P.O. Box 1064
Wasilla, Alaska 99687
(907) 376-5038

RECEIVED
1981
ALASKA POWER AUTHORITY

August 14, 1981

Dave Wozniak
Project Engineer
Alaska Power Authority
333 W. 4th Avenue, Suite 31
Anchorage, Alaska 99501

Dear Mr. Wozniak:

We have reviewed sections 7 and 8 of the Susitna Hydroelectric Project Development Selection Report (second draft June 1981). We find that the plan selection methodology used in section 8 meets the objectives of determining an optimum Susitna Basin Development Plan and of making a preliminary assessment of a selected plan by an alternatives comparison. The increased emphasis over previous analyses of the environmental acceptability of the alternatives is good.

At this time, this Department does not endorse any particular plan. We would, however, recommend the Steering Committee openly discuss the Watana Dam - Tunnel option because of its reduced environmental and aesthetic impact.

Thank you for the opportunity to review this document. We appreciate your effort in soliciting Su-Hydro Steering Committee involvement. If you have any questions regarding these comments please contact Steven Zrake of this office.

Sincerely,

Bob Martin

Bob Martin
Regional Environmental Supervisor

cc: Steve Zrake
Dave Studevant
Al Carson - DNR

BM/SZ/mn