SOUTH-CENTRAL RAILBELT AREA, ALASKA (HYDROELECTRIC POWER), UPPER SUSITNA RIVER BASIN

LETTER

FROM

THE SECRETARY OF THE ARMY

TRANSMITTING

A LETTER FROM THE CHIEF OF ENGINEERS, DEPARTMENT OF THE ARMY, DATED FEBRUARY 8, 1977, SUBMITTING A REPORT, TOGETHER WITH ACCOMPANYING PAPERS AND ILLUSTRATIONS, ON SOUTH-CENTRAL RAILBELT AREA, ALASKA (HYDROELECTRIC POWER), UPPER SUSITNA RIVER BASIN, IN PARTIAL RESPONSE TO A RESOLUTION OF THE COMMITTEE ON PUBLIC WORKS, UNITED STATES SENATE, ADOPTED JANUARY 18, 1972

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SOUTHCENTRAL RAILBELT AREA, ALASKA
UPPER SUSITNA RIVER BASIN
SUPPLEMENTAL FEASIBILITY REPORT

HYDROELECTRIC POWER AND RELATED PURPOSES

Prepared by the
Alaska District, Corps of Engineers
Department of the Army

February 1979

INTRODUCTION

A survey investigation of the Southcentral Railbelt Area of Alaska was initiated by the Alaska District in 1974, and an Interim Feasibility Report on the upper Susitna River basin was completed in 1976. Considerable effort had been expended previously by the Bureau of Reclamation for geotechnical exploration, and by other State and Federal groups. The survey investigation entailed a review of energy alternatives available to meet intermediate range power requirements of Alaska's railbelt area, a screening of these alternatives, and an assessment of effects for the more feasible alternatives. A number of development schemes for the upper Susitna River were analyzed, and at least three were found to be economically feasible. As an alternative to Susitna hydropower, coal was found to be the most likely future energy source for both Anchorage and Fairbanks although it would be approximately 30 percent more expensive than Susitna power.

The Interim Feasibility Report established with reasonable certainty that Susitna hydropower development is economically justified, and that there are no adverse environmental impacts of such magnitude that the project should not be considered further. The study found that the plan best serving the public interest consists of a two-dam system utilizing the Watana and Devil Canyon damsites on the Susitna River. Power would be provided to the Fairbanks-Tanana Valley and Anchorage-Kenai Peninsula load centers via a 364-mile transmission line.

The Interim Feasibility Report was the basis for conditional authorization of Phase I studies. Section 160 of Public Law 94-587, the <u>Water</u>

Resources Development Act of 1976 enacted by the 94th Congress on 22 October 1976, states:

> The Secretary of the Army, acting through the Chief of Engineers, is authorized to undertake the Phase I design memorandum stage of advanced engineering and design of the project for hydroelectric power on the Susitna River, Alaska, in accordance with the recommendations of the Board of Engineers for Rivers and Harbors in its report dated June 24, 1976, at an estimated cost $25,000,000. This shall take effect upon submittal to the Secretary of the Army by the Chief of Engineers and notification to Congress of the approval of the Chief of Engineers.

Notification to Congress of the Chief of Engineers' approval has been forestalled because of Office of Management and Budget (OMB) reservations regarding economic justification. In a letter to the Secretary of the Army dated 9 September 1977, Eliot R. Cutler, OMB Associate Director for Natural Resources, Energy and Science stated, "...we strongly believe further information is needed to verify the benefit-cost status before the project proceeds to Phase I planning."

During 1978, additional geological explorations, engineering and environmental resource studies, and economic analyses were undertaken to address the concerns expressed by OMB. This Supplemental Feasibility Report presents the results of those additional investigations.

The report consists of three documents: a main report that responds specifically to the comments and suggestions offered by OMB and a two part supporting appendix that is comprised of Sections A through I. These correspond directly to the sections of Appendix 1 of the 1976 Interim Feasibility Report. This Supplemental Feasibility Report is not designed as a comprehensive document. Rather, only changes to the original report and new information pertinent to OMB's comments are presented here.

MAIN REPORT

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SUMMARY

SCOPE OF INVESTIGATIONS

The purpose of this supplemental feasibility study was to reevaluate the economic justification of the proposed upper Susitna River basin hydropower development (see Plate 1). Both benefits and costs were reanalyzed in the process of responding to the concerns expressed by the Office of Management and Budget. Certain additional studies not specifically suggested by OMB, but required to insure comparability in the data, were also undertaken. Study efforts were directed at those aspects of feasibility to which the benefit and cost estimates are most sensitive.

Project costs are highly dependent upon site foundation conditions, and a significant amount of new geological information was gathered during the supplemental studies in 1978. Geological reconnaissance and mapping were conducted at the Watana damsite to identify and trace the surface expressions of discontinuities and shear zones, and also in the reservoir area to identify potential slide hazards. Core borings were made at the damsite to verify the depth of overburden materials and quality of bedrock. Potential borrow sources were explored to determine the extent and quality of available construction materials. Refraction seismograph studies were performed to supplement the data gained from the borings and test pits. Refer to Plate 2 for exploration locations as the Watana site.

Supplemental explorations at the Devil Canyon site where drilling had previously been conducted were limited to three seismic refraction lines, each approximately 1,100 feet long.

While foundation conditions play a key role in estimating project costs, those costs are also very dependent upon the contingency factors used. A feature-by-feature analysis was made to determine the appropriate contingency factor on the basis of cost histories of similar projects, experience in Alaskan construction, and analysis of the uncertainties associated with the design and material requirements of the various features.

A third element of the supplemental studies that impacted cost was the construction schedule. Mobilization, river diversion, and material placement requirements were closely examined along with the interdependencies among construction activities to determine the length of time required for construction.

The newly acquired geological information led to design modifications which, of course, also affected the cost estimates.

In addition to the factors influencing project costs, there are a number of determinants of project benefits that were also analyzed. First, the project's power capability was reexamined using an additional 3 years of historical streamflow data and an updated seasonal load curve. Load growth forecasts were revised using 3 additional years of historical data, more sophisticated population and economic activity forecasting tools, and more conservative economic development assumptions. A range of forecasts were made, reflecting the uncertainties involved in power demand projections.

A load-resource analysis was developed and used to explore the sequence and timing of powerplant additions for the railbelt area and to determine how quickly Susitna power would be absorbed into the load.

Power benefit estimates were evaluated using 1978 cost estimates of thermal generation, the cost of which establishes the value of the hydropower project's output. The other categories of benefits, including load center interconnection, recreation, flood control, and employment, were also updated.

Finally, a comprehensive sensitivity analysis was conducted to ascertain those conditions under which the Susitna project would become uneconomic. This was augmented by a marketability analysis that estimates the cost of Susitna power relative to thermal generation under various load growth, timing and price level assumptions.

Other aspects of feasibility which were the subject of supplemental analyses included seismicity and environmental impact studies.

STUDY RESULTS

At the Watana damsite, the technical feasibility of constructing a dam in the general vicinity was reconfirmed. The rock at the damsite was found to be as good or better than previously assumed. Gravel borrow appears to be less abundant than anticipated, but large deposits of impervious material were located during the explorations. To take advantage of these findings, the dam design was altered by changing the gravel shells to rock shells and by widening the semipervious core (see Plates 3 and 4). Other modifications of the original Watana design included relocation of the spillway to take better advantage of rock lines, relocation of the diversion tunnel portals to place them in better rock, terraced rather than continuous rock cuts and other minor changes.

At Devil Canyon a gravity dam design was evaluated as an alternative to the original concrete thin arch concept (see Plates 5 and 6). The gravity structure, which is more costly but less sensitive to foundation problems, offers greater assurance that a dam can be built at the Devil Canyon site at a cost equal to or less than the estimated cost presented in the report. The less costly thin arch dam with separate spillway will be considered further if additional explorations during Phase I studies establish acceptable foundation conditions. By including in the economic analysis the higher cost of the gravity dam, the project's economic justification is presented on a more conservative basis.

The construction period for the entire project is now estimated at 14 years, with power-on-line for the initial phase occurring in 1994. The schedule allows 10 years for Watana construction and 8 years for Devil Canyon, with 4 years of concurrent construction. The transmission intertie could be available in 1991 to interconnect the Anchorage and Fairbanks load centers. This schedule is based on a construction start in October 1984.

The Susitna project is estimated to cost $2.59 billion at October 1978 prices. This includes $1.77 billion for Watana and the transmission facilities and $0.82 billion for the Devil Canyon phase. The 1978 combined project cost estimate amounts to a 70 percent increase over the cost estimate presented in the 1976 Interim Feasibility Report, which was based on January 1975 prices. Approximately 56 percent of this increase is due to price level changes over the 3-3/4 years between estimates. Another 15 percent is the result of using the cost of the alternate concrete gravity design at Devil Canyon. The remainder of the increase resulted from design changes and more detailed information on local construction materials.

When interest during construction is added, along with operation, maintenance and replacement costs, the average annual equivalent cost becomes $228 million, based on a discount rate of 6-7/8 percent.

The project's combined power output is estimated at 6.9 billion kilowatt hours average annual energy and 1,392 megawatts dependable capacity. Railbelt area power requirements are forecasted to grow to 12.7 billion kilowatt hours annual energy and 2,850 megawatts peak power by the year 2000 according to the medium range projection. Susitna power would need to be augmented by additional capacity from other powerplants, presumably coal-fired, within 9 years after initial power-on-line.

The estimated average annual benefits of the Susitna project amount to $324 million. This represents an increase of 119 percent over those presented in the 1976 report, which were based on a January 1975 price level.

By far the largest category of benefits is that which results from the sale of power. The value of the power is derived from the cost of producing it by means of the least cost nonhydro alternative which, in this case, is coal-fired generation. The cost of the thermal alternative was provided by the Federal Energy Regulatory Commission (FERC) and is based on 1978 price levels. The FERC composite Anchorage-Fairbanks capacity value of $186.58 per kilowatt-year represents a 107 percent increase over the comparable estimate provided by FERC (then the Federal Power Commission) in 1975. The 1978 composite energy value of 12.76 mills per kilowatt-hour amounts to a 144 percent increase over the comparable estimate of 1975. These higher estimates more than double the power benefit to an average annual equivalent of $289 million.

Besides those from the sale of power, there are power-related benefits derived from interconnection of the Anchorage and Fairbanks load centers. An interconnected system allows the sharing of capacity reserves so that fewer reserves are required in the system. Thus, interconnection offers benefits equal to the cost savings from not constructing additional capacity that would otherwise have been necessary. This benefit amounts to an average annual equivalent of $11 million.

Recreation benefits estimated at $300,000 annually are no change from the 1976 report. The benefits associated with flood control are estimated at $65,000 annually, an increase of 30 percent over the 1975 figure due solely to price changes associated with repair to damaged facilities.

The final benefit category, that attributable to the use of otherwise unemployed labor in project construction, is estimated at an average annual equivalent of $24 million. The 155 percent increase in this benefit over the original 1975 estimate is due to the higher cost of construction and more detailed analysis of labor requirements.

Under the base case set of assumptions, the proposed Susitna project offers annual net benefits of $95 million and a benefit-cost ratio of 1.42. The hydropower project's net benefits exceed those of the thermal alternative by $76 million annually. With an assumption of stable prices and medium load growth, the year 2000 average power system rates with the Susitna project are estimated at 5.5¢/kWh in Anchorage and 6.7¢/kWh in Fairbanks. This represents a 17 percent and 25 percent savings over the anticipated 6.6¢/kWh and 8.9¢/kWh rates without Susitna power.

In summary, the supplemental feasibility studies undertaken during 1978 have confirmed the adequacy of the Watana site for construction of the proposed facilities. The project design has been refined in light of the newly acquired geologic and foundation information. The need for additional power in the railbelt area has been verified, and additional environmental resource information has been added to the data base. The review of project costs and benefits has indicated that the Susitna project is economically justified under a broad range of possible futures. Finally, Susitna power has been shown to be marketable and less costly than any viable alternative.

The direction taken in the conduct of these supplemental feasibility studies was largely dictated by the concerns regarding project justification expressed by the Office of Management and Budget. The remainder of the main report responds to the specific questions raised by OMB. The Alaska Power Administration of the Department of Energy and Battelle Pacific Northwest Laboratories both contributed significantly to the analysis and to the formulation of the responses. Supplementary data and analysis in support of the responses are contained in the appendix.

WATANA SITE GEOLOGY AND TEST BORINGS

OMB COMMENT

> The cost estimates for Watana have been derived without benefit of any test borings at the Watana site. This is a departure from standard Corps practice, which calls for exploratory drilling at all sites before projects are proposed for authorization. Test borings would provide more reliable data on which to base cost estimates and on which to assess any potential seismic problems. The Watana site is located near the Susitna Fault and also within 50 miles of the Denali Fault - an area where major earthquakes have occurred in the past.

SCOPE OF GEOLOGICAL INVESTIGATIONS

Field Reconnaissance

Geologic reconnaissance and mapping of the reservoir area and damsite were conducted concurrently with subsurface investigations throughout the spring and early summer of 1978. Within the damsite area the primary purpose was to locate, identify, and trace the surface expressions of discontinuities and shear zones to aid in directing the drilling program and to provide a preliminary geologic map of the site. Within the reservoir area, the primary thrust of the reconnaissance was to identify by reason of shape, structure, or overburden mantle the slopes that could develop slumps or slides as a result of permafrost degradation or seismic action.

Borings and Test Pits

During 1978, explorations were conducted in the dam foundation and relict channel area. Core borings in the valley walls and floor were used to explore the quality and structure of the foundation rock and to obtain representative samples for testing. Borings in the relict channel area were used to define depth of overburden, the extent of permafrost, and the location of the water table as well as to examine the nature and condition of the materials by drilling.

Also during 1978, numerous test pits were dug in potential borrow areas utilizing tractor-mounted backhoes. Bulk sack samples were retrieved from each test pit for later testing. Shallow auger holes were also used to determine the extent of deposits and to verify the existence of quantities necessary for embankment construction.

Seismic Refraction Surveys

A seismic refraction exploration program consisting of 22,500 lineal feet of seismic refraction lines was completed by Dames and Moore, Consultants, in 1975. In the fall of 1978, an additional seismic refraction survey was completed by Shannon and Wilson, Consultants, which included 47,665 feet of seismic refraction lines. The survey confirmed the Dames and Moore findings of a buried relict channel and, in general, supported conclusions relating to rock quality in the abutments as interpreted from the recent core borings and geologic reconnaissance. The Shannon and Wilson study also confirmed the existence of large quantities of borrow materials on Tsusena Creek.

The specific locations of the exploratory borings, test pits, and seismic refraction lines are shown on Plate 2.

FINDINGS AND DESIGN CHANGES

As a result of the additional field exploration and geologic studies in 1978, a more knowledgeable assessment of the proposed project can be made. Following is a summary of the items which reflect changes to the 1976 Interim Feasibility Report or reinforce its basic concepts.

Nothing was found during this phase of the study to cast doubt on the feasibility of a dam at the Watana site. All exploration and geologic studies reinforce the previous conclusion that a large earth and rock-fill or concrete gravity dam could be built in this vicinity.

Explorations at the damsite indicate that the rock is as good or better than previously assumed. Foundation rock is considered adequate to support either an earth and rockfill or concrete gravity structure at this site.

The 1978 exploration program confirmed the existence of marginal permafrost in the area. Specific locations of permafrost were identified and a number of temperature measuring devices were installed. It was determined that this is a very "warm" permafrost, ranging in temperature from 0° C to -1° C. Permafrost was encountered in bedrock in the left abutment of the dam and its effects on the grouting in this area are discussed in the appendix. Permafrost was also encountered in the impervious borrow area; however, it is not considered to be a serious problem as it is quite warm and can be easily excavated.

The 1976 report envisioned rather large amounts of gravels available for construction of the shells of the dam and limited amounts of impervious core material. However, the recent explorations indicate that the reverse is true. Large quantities of gravel were not located, but large quantities of impervious core material were discovered near the damsite. Because of the apparent shortage of large quantities of gravel and the excess of impervious material, the dam section has been revised with gravel shells having been changed to rock shells. This change to rockfill has allowed the use of a steeper slope on the upstream face of the dam. A large portion of the rock will come from required excavation of the spillway and the remainder will come from excavation of underground facilities and access roads and from a large borrow source on the left abutment.

The core has been widened somewhat from that shown in the 1976 report and a zone of semipervious material, approximately of the same width as the core, has been added. This was done because of the large amounts of this material available and because our estimates show that it can be placed within the dam at a considerably lower cost than the rock shell material. The total thickness of these impervious or semipervious zones was determined by considering their effect on the total stability of the dam and the difficulties of placing materials which require careful moisture control in the arctic environment. Laboratory tests performed on these materials indicate that optimum moisture will be a critical factor in their compaction.

The foundation excavation has been increased in order to remove all gravels from beneath the embankment and strip the entire dam foundation to bedrock.

The 1976 report showed a vertical access shaft to the low-level drain system which passed through the embankment of the dam. This has been changed to a tunnel through the right abutment thereby eliminating any structures in the dam embankment.

A grout gallery has been added to the lower portions of the dam to facilitate grouting and to accommodate the process of thawing the permafrost rock for grouting.

The spillway shown in the 1976 report has been relocated to the southwest to insure rock cut for its entire length. The rock and overburden material from this large excavation will be utilized in the dam embankment. Also, the diverison tunnel portals have been shifted to insure their location in sound rock.

The 1976 report discusses a potential problem of seepage along a relict channel in the right abutment area. The 1978 exploration program verified the existence of this channel; however, studies indicate that it is not a problem and no remedial actions are necessary.

Ellis Krinitzsky of the Waterways Experiment Station and Ruben Kachadoorian and Henry J. Moore of the U.S. Geological Survey were contracted to perform seismic studies and evaluate the earthquake risk at these sites. Their work was divided into two phases: Kachadoorian and Moore performed the final reconnaissance of active faults and other geologic hazards, and Krinitzsky assessed the potential for earthquakes associated with such faulting. The resulting USGS report recognized that this is a highly seismic region; however, their reconnaissance of the proposed Devil Canyon and Watana damsites and reservoirs did not uncover evidence of recent or active faulting along any of the known or inferred faults. Their studies did not find any evidence of the Susitna Fault which was previously thought to exist a short distance west of the Watana damsite; therefore, they were not able to confirm the existence of such a fault. USGS also noted the areas where slides might be expected to occur along the valley walls under the influence of saturation and thawing permafrost. Krinitzsky's work assessed the possible occurrence of earthquakes at the damsites and the motions that are likely to be associated with earthquake activity. His findings indicate that the design of the proposed dams to withstand such motion is within the state of the art for seismic design.

CONTINGENCY ESTIMATES

OMB COMMENT

> A standard 20 percent contingency factor was used in arriving at cost estimates. A contingency of 30 percent could result in reducing the benefit-cost-ratio to 1. A larger contingency factor could reduce the ratio below unity. The recently completed Snettisham project in Alaska cost 36 percent more than original estimates, after correction for inflation.
>
> A review of the 20 percent contingency factor should be undertaken, in light of the best existing information on comparable projects and project locations.

Contingency factors have been reviewed and adjusted. The review included incorporation of the new 1978 foundation, material, and topographic information. Instead of utilizing a single contingency factor for the project as a whole, each major feature was examined individually to derive a contingency that reflects the uncertainties associated with the design and cost of that specific feature. The total estimated contingencies for the Watana project are approximately $246 million or 18 percent of the estimated total construction cost. Individual factors range from 15 percent for the relatively well defined earth and rockfill main dam to 20 percent for many of the other features.

The contingencies used for the Devil Canyon project were adjusted in two ways. First, a fundamental change in the design concept was made. To insure that the cost estimates in this supplemental feasibility study were sufficient to cover the possibility of unexpected foundation conditions at the Devil Canyon site, a concrete gravity dam design was analyzed. The concrete gravity structure requires less ideal foundation conditions than does the concrete thin arch structure recommended in the 1976 report. While the concrete arch design is still deemed engineeringly feasible on the basis of the available Devil Canyon geological explorations, the less sensitive and more costly concrete gravity structure has been used as the basis of the 1978 cost estimate. In this way, sufficient cost is included in the estimate to allow construction of either the concrete thin arch if favorable site conditions are found during preconstruction planning or the concrete gravity structure if less favorable conditions are found to exist. Thus, economic feasibility has been presented using the most conservative set of conditions.

In addition to the more conservative gravity design at Devil Canyon, normal contingency factors were also applied. The total contingencies for the Devil Canyon gravity dam estimate are about $121 million or 17 percent of total construction costs.

With the 1978 estimates of Susitna project benefits and costs, a 68 percent contingency factor would be required to have costs exceed benefits under the base case set of assumptions.

The Snettisham Hydroelectric Project that provides power to the Juneau area was mentioned by OMB as an example of cost overruns. The reported 36 percent cost increase over original estimates is not entirely correct since the 36 percent factor included additional construction not contemplated in the original cost estimate. The original estimate was for a project that included only the Long Lake phase of development with associated camp facilities and transmission system. The planned Crater Lake phase of development was added in fiscal year 1973, but construction has been deferred. The actual cost overrun as of 1978 is 22 percent. More than half of this 22 percent overrun from original cost estimates was accounted for by the temporary repairs and subsequent permanent relocation of a failed portion of the transmission line. Environmental considerations had dictated its original location in an area of extreme winds and ice conditions not previously encountered on any transmission line in North America.

AREA REDEVELOPMENT BENEFITS

OMB COMMENT

> These benefits are a correction for the use of otherwise unemployed labor during construction. Though standard procedures permit this benefit category for power projects, it would seem that such benefits should not be accepted in the Susitna report because private development for power purposes would produce equivalent benefits.
>
> An evaluation of the validity of the use of ARA benefits in the Susitna report should be made.

Project costs are considered to be an adverse effect on the national economy because resources required for construction would normally be diverted from other uses. The value of resources in their alternative uses is therefore the true economic cost of the project. If some resources used in the proposed plan would otherwise be unemployed, these resources would not be diverted from production of other goods and services and, hence, are not an economic cost to the national economy. Procedurally, the credit for using unemployed labor is conventionally tabulated as an addition to benefits rather than a deduction from costs.

The basis for determination of employment benefits as with benefits associated with all other project purposes, is a comparison of conditions <u>with</u> and <u>without</u> a plan to provide the planning objective. The <u>with</u> condition is the plan under consideration, namely the provision of additional power. The <u>without</u> condition is without provision of additional power. The relevant without condition for purposes of benefit evaluation is not an alternative solution to the planning objective even though in the absence of the recommended project, an alternative will be provided. Therefore, the entire applicable employment benefit is credited to each project considered in the plan formulation process. If, alternatively, wage payments of otherwise unemployed labor is credited as a savings in economic costs, it is even more apparent that such wage payments would be fully deductible from costs of any and all projects constructed.

CONSTRUCTION SCHEDULE

OMB COMMENT

> The 11-year construction schedule for the Watana project, based on preliminary inspection of comparable projects, appears to be on the short side. A longer schedule of 14 years appears more reasonable because of (1) normal slippages and (2) a 3-year peak construction schedule that calls for more work to be put in place on a single site than the Corps has ever accomplished in similar time periods. This should be reexamined and its effects on the project B/C ratio calculated.

GENERAL

The construction schedule has been reanalyzed and lengthened from 10 to 14 years. The Watana dam and powerplant will take 10 years to construct, an increase of 4 years over the previous schedule. The Devil Canyon project construction will require 8 years rather than the previously estimated 5 years. There will be 4 years of concurrent construction to meet power-on-line dates.

DIVERSION PLANS

The time for Watana diversion works construction and stream diversion has been extended to 3 years from the previously estimated 2 years, because the construction access to the tunnel portals requires extensive rock cuts and added time. The start of construction of the diversion works for the Devil Canyon dam has been delayed from the 5th to the 7th year of Watana construction because it is dependent on stream regulation by the upstream Watana dam.

MAIN DAMS

Foundation preparation at Watana would be delayed to the 4th year as a result of the extended diversion requirements which would delay the start of cofferdam construction. Watana embankment construction, scheduled to begin in the 5th year and continue into the 10th, would require 6 years instead of the previously estimated 3 years, based on construction seasons of 5 months with average daily placement rates of 80,000 cubic yards. Water impoundment would start in the 8th year with power-on-line in October of the 10th year. The reservoir filling would continue beyond the power-on-line date and would depend on the rates of inflow and power generation.

Foundation preparation for Devil Canyon dam would start in the 9th year, a 2 year delay from the earlier estimate. Concrete placement and dam completion would begin in the 10th year and require 5 years, an increase of 2 years over the earlier schedule. Impoundment would commence in the 13th year and end with a full reservoir in October of the 14th year.

EFFECT OF DELAY

The presently scheduled power-on-line dates are 1994 for Watana and 1998 for Devil Canyon. These were previously scheduled for 1986 and 1990 respectively. These dates include the result of the changes in assumed congressional construction authorization from July 1980 to October 1984 and the revised construction schedule. Transmission line construction could be completed in 1991, permitting connection of the Anchorage and Fairbanks load centers in advance of Watana power-on-line. The economic evaluation is based on this longer 14-year construction schedule and the delayed power-on-line dates.

Even with the longer 14-year construction period, additional construction delays are possible. The impacts, however, would be minimized by the recommended two-stage construction sequence. If significant delays were experienced on Watana, the start and schedule of Devil Canyon construction could be adjusted with minimal cost impact. Delays in Devil Canyon construction would have no effect on Watana's schedule.

The project's economic justification has been analyzed to assess the impact of construction delays that would extend the power-on-line dates. As an example, a 2-year delay in Watana completion was evaluated. The primary effect on project cost would be the accumulation of additional interest during construction. The 2-year delay increases average annual costs by about $17 million.

The delay of Watana power-on-line would also affect project benefits, although the change would be small. The impact on benefits is due to the mix and schedule of thermal plants coming on line prior to Watana and to the rate of load growth during the years after power-on-line. For a 2-year delay, equivalent average annual power benefits would be reduced about $4 million.

The net change in project economics would be an increase in total annual costs to $245 million and a reduction in annual benefits to $320 million. This decreases the benefit-cost ratio from 1.42 to 1.31.

Analysis shows that the construction period would have to be prolonged at least an extra 9 years before the Susitna project would become uneconomic.

SUPPLY ESTIMATES

OMB COMMENT

The analysis of the without project condition needs to be expanded considerably to clearly analyze the following:

a. Why, with natural gas projected to be in such short supply, the Anchorage utilities have only contracted for 55 percent of proved reserves or 25 percent of estimated ultimate reserves.

b. The sensitivity of the analysis to the collapse of OPEC and the cost of shipping oil to the east coast.

c. The necessity for an Anchorage-Fairbanks intertie at a cost of $200-300 million.

d. Scheduling of powerplants and the reduced risk of building small increments.

INTRODUCTION

The first two items must be considered in terms of national energy policy. The United States needs to reduce dependency on oil imports on both a short-term and a long-term basis and to accomplish a major shift away from oil and natural gas to alternative energy sources. The reasons for this include national economic considerations, as well as very real limits on national and world supplies of oil and natural gas.

In terms of national energy policy, oil and natural gas are not available alternatives for long-term production of electric power. There are remaining questions as to how quickly existing uses will be phased out and on how complete the prohibitions will be on new oil and natural gas-fired powerplants.

There is general agreement that implementation of national policy must include strong efforts in conservation, substantial increase in use of coal, and major efforts to develop renewable energy sources. Each of these components is sensitive to energy price and supply variables. A reduction in world oil prices or a period of oversupply serves as a marketplace disincentive for conservation efforts and work on alternative energy sources.

The lowest cost alternatives and those with fully proven technology are the least sensitive; those that depend on further research and development are most easily sidetracked.

The Susitna project involves large blocks of power and new energy from a renewable source, fully proven technology, long revenue-producing period (in excess of 100 years), and essential freedom from long-term price increases. Its power costs appear attractive in comparison to coal-fired powerplants. It is a two-stage project with opportunity to defer the second stage if demands are lower than present estimates or if price relationships change.

The above factors suggest that the Susitna project is much less sensitive to short-term oil price and supply variations than most other U.S. energy options.

If it is assumed that Alaskan oil and natural gas will be isolated from U.S. and world demand and pricing, Alaska would probably continue to use its oil and gas for most of its power. This assumption did, in fact, prevail between the initial oil and gas discoveries in the

Cook Inlet area and the 1973 oil embargo. In 1960, the Anchorage-Cook Inlet power supplies came almost entirely from coal and hydro. The low cost, abundant gas brought a halt to hydro development and destroyed the area's coal industry. The one remaining Alaskan coal mine barely survived the 1960's because of competition from relatively cheap oil.

Cook Inlet gas has been subjected to increasing competition in the last few years, including proposals for LNG facilities, additional petrochemical plants, and consideration of pipeline alternatives to tie in with the Alcan pipeline project. The competition resulted in increasing prices and increasing difficulty in obtaining long-term commitments of gas for power. The competitions and the price increases are expected to continue.

The real question on gas availability as it pertains to the Susitna project is: what is the outlook for long-term gas supplies for power after 1990? The answer is that the outlook is not good in terms of competing uses and national policy.

NATURAL GAS AVAILABILITY

The primary reason for not considering natural gas-fired generation as the alternative to Susitna hydropower development is not gas availability, but national energy policy. The Powerplant and Industrial Fuel Use Bill of the National Energy Act of 1978 clearly indicates that the intent of the Administration and Congress is to strongly discourage the use of natural gas for electrical generation. The law

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contains a prohibition against the use of natural gas as a primary fuel in any newly constructed utility generation facility. Permanent exemptions from this prohibition for a new base load powerplant may be obtained under certain circumstances. The Department of Energy's draft implementing regulations permit exemptions if utilities can prove it would be overly costly, environmentally unsound, or impossible because of insufficient or unavailable supplies of coal or other fuels at the plant's location. None of these exemptions appear applicable to Alaska. The Federal Energy Regulatory Commission, in not providing gas-fired generation costs, agrees with that assessment.

While national energy policy is reason enough to discount natural gas-fired generation as a long-term alternative to a major hydropower project, data on the local supplies of natural gas was presented in the 1976 report as additional evidence. That data has been updated using 1978 information.

There are an estimated 4,428 billion cubic feet (BCF) of recoverable gas reserves in Cook Inlet, with an additional speculative potential of from 6 to 29 trillion cubic feet. Approximately 3,698 BCF, or 84 percent of the estimated recoverable reserves are presently committed to Alaskan and export uses. The proportion of committments would even be higher but for an unwillingness on the part of natural gas owners to enter into contracts for the provision of gas during a period of rapidly escalating gas prices and great uncertainty regarding gas price deregulation. Additional committments are anticipated as the pricing structure stabilizes.

In 1976, 34 percent of Alaska's total energy consumption was provided by Cook Inlet natural gas. Several forecasts of gas demand have been completed, and estimated proven Cook Inlet gas reserves are inadequate to meet the requirements in all forecasted cases. The deficit through the year 2000 varies from a low of 783 BCF to a high of 3,804 BCF, depending on the forecasted use. The use of Cook Inlet gas for new gas-fired electrical generation after 1985 would increase the year 2000 deficit by about 532 BCF.

OIL PRICE CHANGE IMPACTS

The economic justification for the Susitna hydropower project is sensitive to changes in the price of oil only if oil-fired generation is considered a realistic long-term alternative for electrical generation in the railbelt area. However, the use of oil in benefit determination for 100 years of power for a major new hydro project does not seem appropriate in light of national energy policy in general and the National Energy Act of 1978 in particular. As in the case of natural gas, the use of oil in newly constructed generation facilities is prohibited with limited exception. The exemptions contained in the legislation do not appear pertinent in the face of the large supplies of coal and hydropower potential available to the railbelt area.

Despite the strong arguments against new oil-fired generation in the mid-1990's and beyond, project justification was examined using an oil-fired powerplant as the basis of benefit calculation. Oil-fired costs provided by FERC were used in the analysis, and the midrange load forecast was assumed. With stable prices, the project's annual power benefits fall $78 million from the $289 million calculated on the basis of the coal-fired alternative. Net benefits become $18 million, giving a benefit-cost ratio of 1.08.

To calculate the impact of relative changes in the price of oil on project feasibility, three sample cases were analyzed. First, there is an assumption that fuel costs esclate at 2 percent per year between 1978 and the 30th year beyond power-on-line, after which there is no additional escalation. The 30-year period corresponds to the service life of the initial thermal plant. The 2 percent rate is selected as representative of long-term real price increases arising from depleting more distant sources, increasing environmental safeguards in extra-ction, processing and handling, and anticipated producing nation pricing policy. Two percent annual escalation in the price of oil results in a 57 percent increase in annual power benefits over that with stable prices; the benefit-cost ratio becomes 1.60.

The second case looks at the possibility of no price escalation prior to power-on-line followed by a 30-year period of 2 percent annual escalation. This case is designed to reflect the possibility of a near-term softening of the market for oil due to slackening demand or increased supply in the short-term. With stable prices in the near term followed by a 30-year period of escalation, annual power benefits increase 22 percent over the stable price case, giving a benefit-cost ratio of 1.29.

The final case explores the impact of real oil price declines prior to power-on-line. An immediate sharp drop in price is assumed, with no change in price thereafter. This scenario is included to show the possible effect on project justification of a breakup of the OPEC cartel. The immediate decline in oil prices followed by stable prices results in costs exceeding benefits and a benefit-cost ratio of 0.85.

To summarize, oil-fired generation is not an appropraite long-term alternative to Susitna hydropower. If, nonetheless, oil-fired costs are used in benefit calculation, the project remains economically justified except in the extreme case of an immediate and precipitous drop in the price of oil.

OMB suggested that the issue of shipping costs be explored. The FERC fuel cost estimate that was used in the benefit calculation is net of transportation costs between Alaska and continental U.S. ports. The fuel costs used are the estimated cost of processed Alaskan oil at the power-plant. No additional consideration of shipping costs to the East Coast is deemed necessary.

ANCHORAGE-FAIRBANKS INTERTIE

The estimated construction cost (1978 dollars) for the transmission lines associated with the Susitna project is $338 million. The portion from the Susitna project to Fairbanks accounts for $152 million of the total.

There are several previous studies that demonstrate inherent feasibility of an Anchorage-Fairbanks intertie with or without construction of the Susitna project. The main reason that the intertie is not now in place is that short-term benefits to the Anchorage area are quite small; most of the short-term benefits for the intertie would occur through reduced energy and power costs in the Fairbanks area.

The Alaska Power Administration, in the 1976 Interim Feasibility Report, evaluated the provision of Susitna project power to Fairbanks on a cost-of-service basis (see Appendix I, p. 6-89 of the 1976 report). This was a specific demonstration of feasibility of including Fairbanks as part of the upper Susitna power market area.

Further verification of feasibility of the intertie is provided in the new load-resource analyses and system cost analyses prepared for the current studies. These general cases were analyzed:

Case 1. All future generating capacity assumed to be coal-fired steam turbines <u>without</u> intertie.

Case 2. All future generating capacity assumed to be coal-fired steam turbines <u>with</u> intertie.

Case 3. Future generating capacity to include the Susitna project plus coal-fired steam plants as needed. This includes the intertie.

The following table presents the costs of power in the year 2000 for each of the three cases. As shown, the costs of power are less with the intertie. The reduction in the cost of power is typically greater in the Fairbanks-Tanana Valley area than in the Anchorage-Cook Inlet area because the Anchorage-Cook Inlet area will have a higher percent of its generation supplied by steamplants which are more costly than Susitna.

COMPARISON OF POWER COSTS FOR YEAR 2000
(¢/kWh - 0% inflation)

	Anchorage			Fairbanks		
	High	Medium	Low	High	Medium	Low
Case 1	6.2	6.6	7.1	8.8	8.9	9.2
Case 2	6.1	6.2	6.2	8.0	8.4	8.8
Case 3	5.8	5.5	6.1	6.2	6.7	7.8

Following are the percent savings in total system costs between 1990 and 2011 for Cases 2 and 3 compared to Case 1, under the midrange load forecast.

	Anchorage	Fairbanks	Total
Case 2	-0.4	-7.9	-1.4
Case 3	-10.7	-28.1	-14.1

POWERPLANT SCHEDULING AND RISK REDUCTION

The risks associated with the overbuilding of powerplants is generally reduced by building small incremental additions to a system. In other words, as closely as possible, load growth should be matched as it occurs. The validity of this generalization increases as the degree of confidence or certainty in load growth forecasts decreases. This risk minimization is accompanied by an increase in economic costs, however, since economies of scale are a significant factor in powerplant costing.

The evaluation for the Susitna project recognized this risk factor in that a range of area load growth possibilities and assumptions required for their realization was developed. Those assumptions considered most likely were reviewed to form a most probable future condition. Therefore, the load forecast used represented a high degree of confidence by the cross section of disciplines and agencies who developed it. The evaluation further recognized the principle of load growth matching when determining the most likely alternative thermal plant in the absence of Susitna hydropower. Alternative thermal plants were phased in to match the portion of load demand provided from Susitna. For the initial years this means that only annual increases due to new load were evaluated.

As a further confirmation, an analysis of hydropower alternatives indicates that economical sites are not available in sufficient quantity to be comparable to Susitna. Small individual sites might be available, but they would satisfy only a small portion of the market area demand. Other sites with apparently acceptable power and economic capability have been or will be precluded by land status designation. This finding was supported by Alaska Power Administration's 1978 draft report on Analysis of Potential Alternative Hydroelectric Sites to Serve Railbelt Area and by the Corps of Engineers' Review of South-central Alaska Hydropower Potential completed in January 1979.

DEMAND ESTIMATES

OMB COMMENT

The analysis of load growth should be more specific with respect to:

a. Increasing use by consumers; and,

b. Increasing number of consumers.

c. Industrial growth, i.e., where does Alaska's comparative advantage lie outside the area of raw materials and government functions?

FORECAST METHODOLOGY

In order to explore the causative factors of load growth in greater detail, the method of forecasting has been changed in certain respects from that which was used in the 1976 Interim Feasibility Report. The Alaska Power Administration (APA) has used a simplified end-use model to forecast future power requirements, augmented by trend analysis and an econometric model. Total power demand has been categorized into three primary end uses: the residential/commercial/industrial loads supplied by electric utilities, the national defense installation sector, and the self-supplied industrial component.

Those factors in each category that best explain historical trends in energy use were identified. In the utility sector, those explanatory variables are population and per capita use. Population was forecasted with the help of a committee of experts using a regional econometric model, while per capita use estimates are an extrapolation of past trends adjusted to account for anticipated departures from those trends. National defense needs are assumed to depend on the level of military activity and the number of military personnel in the study area. Future self-supplied industrial power requirements are based on explicit assumptions regarding future economic development and the energy needs associated with such development.

POPULATION AND ECONOMIC ACTIVITY FORECAST

The most important sector in terms of magnitude of electrical energy use is the utility sector, and population is the key factor in this sector's future power requirements. Population forecasts in turn, are highly dependent upon assumptions of future economic activity. Economic activity assumptions are also important because they have a direct impact on energy requirements in the self-supplied industrial sector.

The population and economic activity assumptions used in this forecast are based on a draft report of the Economics Task Force, Southcentral Alaska Water Resources Study, dated September 18, 1978. The report is entitled, "Southcentral Alaska's Economy and Population, 1965-2025: A Base Study and Projection."

The report was a joint effort of economists, planners, and agency experts who were members of the Economics Task Force of the Southcentral Alaska Water Resources Study (Level B). It is being conducted by the Alaska Water Study Committee, a joint committee of Federal and State agencies, the Alaska Federation of Natives, the Alaska Municipal League, the Municipality of Anchorage, the Southcentral region borough governments, and regional Native corporations.

The projections reported relied on two long-run econometric models devised by economists from the University of Alaska Institute of Social and Economic Research (ISER) and from the MIT-Harvard Joint Center for Urban Studies with funding by the National Science Foundation's Man in the Arctic Program (MAP). The two specific models used here were modifications of the Alaska State and regional models developed under that program. The models produced estimates of gross output, employment, income, and population for the years 1975-2000. Population and employment were disaggregated and extrapolated to the year 2025 by ISER researchers under Economics Task Force direction, and using Task Force concensus methodology. The data required to run the model were provided by various members of the Economics Task Force. Assumptions were reviewed by the Task Force, and the model outputs and tentative projections were reviewed for internal consistency and plausibility by ISER researchers and by the Task Force.

The use of the econometric model requires a set of assumptions related to the level and timing of development. The assumptions primarily consist of time series on employment and output in certain of the export-base industries and in government.

FORECAST RESULTS

The Level B population forecast for the Anchorage-Cook Inlet subregion was adopted by APA for estimating power requirements without any modification. APA applied projected statewide growth rates to the Fairbanks-Tanana Valley area to develop population forecasts for that region. Actual population growth will likely fall within the limits established by the high and low forecasts.

UTILITY SECTOR

The midrange net generation forecast from 1977 to 1980 was based on the average annual growth rate between 1973 and 1977. This rate was adjusted upward and downward by 20 percent to establish the 1980 high and low forecasts respectively. Beyond 1980, the high and low case net generation is estimated by multiplying forecasted population by projected per capita use. Between 1973 and 1977, per capita use of electricity grew at an annual rate of 3.8 percent in Anchorage and 9.4 percent in Fairbanks. The lower Anchorage growth rate was adopted as the basis of the per capita use trend. Increasing electrification is assumed to be partly offset by increasing effectiveness of conservation programs, resulting in a gradually slower rate of growth in per capita use.

As a check on the validity of the per capita use projections, a comparison was made with two regions of the Pacific Northwest. The regions were selected for comparison on the basis of their similarity in population and commercial/industrial characteristics to the railbelt area. The Pacific Northwest regions' present per capita use rates of electrical power are significantly higher than those of the railbelt area. In fact, the current rates in the Pacific Northwest are comparable to those that are projected for the railbelt area in 1990. Without doubt, Alaska exhibits a considerable potential for increased electrification.

With the high and low population forecasts and with high, mid, and low per capita use assumptions, six different net generation forecasts were calculated. From these, the high population-high energy use and the low population-low energy use combinations were used for the high and low range net generation forecasts. The midrange utility sector forecast came from averaging the high population-low energy use and the low population-high energy use forecasts.

Peak load forecasts were calculated from projected net generation using a 50 percent load factor. For the low range forecast, utility sector peak load requirements are expected to increase from 667 megawatts (MW) in 1980 to 1,617 MW in the year 2000. Fifty-one percent of that increase is due simply to population growth, while the remainder of the increase is a result of increased per capita use. The comparable increase in forecasted peak load requirements between 1980 and 2000 for the high range forecast is 3,087 MW. In this case, population growth accounts for 43 percent of the increase, with the remainder accounted for by changes in per capita use.

NATIONAL DEFENSE SECTOR

The forecast for this relatively minor sector is based on historical data from Army and Air Force installations in the railbelt area. Zero growth is assumed for the midrange forecast. For the high range, growth at 1 percent per year is assumed, while the low range forecast is based on a decline of 1 percent annually.

SELF-SUPPLIED INDUSTRIES SECTOR

This category of load is comprised of those existing industries that generate their own power, along with all similar type facilities expected to be constructed in the future. It is likely that such industries would purchase power and energy if available at reasonable cost. The specific assumptions for this sector are based on Battelle's March 1978 report entitled Alaskan Electric Power, An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region.

The high range development forecast includes enlargement of existing facilities as well as new industry. The new developments include an LNG plant, refinery, coal gasification plant, mining and mineral processing plants, timber industry, capital city, and some large energy intensive industry. This set of assumptions coincides with the Level B Study Task Force high case development assumptions with two exceptions. Coal gasification and an energy intensive industry were included by APA because informed judgement indicates their definite potential. Their impact on population and economic activity is relatively minor but their effect on peak load requirements could be substantial. Therefore, they have both been included in the development assumptions for the high range forecast.

The midrange forecast is the same as the high range except that the large energy intensive industry (aluminium smelter) is excluded. The low range further excludes the new capital city. There is also some reduction of peak load requirements of the mid and low range cases.

Alaska is not a heavily industrialized state nor is it expected to be. The oil and gas industry is presently the dominating sector of the State's GNP and will continue to be so for at least the balance of the 20th century. This is the principle source of revenues for the State and thus the driving force behind state programs for education, local government assistance, welfare, and so on. Other important industries are fisheries, forest products, and recreation-tourism.

The low and mid-range population estimates incorporate very modest assumptions of industrial expansion based on pioneering of Alaskan natural resources for the most part; the specific industrial assumptions reflect proven sources of natural resources and projects that are well along in the planning stages.

Extraction and processing of natural resources will undoubtedly continue to be major aspects of the Alaska economy. Other important aspects include business activities of Native Corporations and increasing amount of land made available to State and private ownership. Actions pending on the new National Parks, Refuges, and Wild and Scenic Rivers will encourage further development of the recreation and tourism industries.

As in most parts of the country, Alaska employment is not dominated by the industrial sectors. Most jobs are in service industries, commercial establishments, transportation, utilities, and government. The new population estimate by ISER indicates that the distribution of employment will not change appreciably. The anticipated growth in the economy, employment, and in power demands is primarily in the non-industrial sectors.

It should be noted that the railbelt area demands for electric energy in 1977 were 2.7 billion kilowatt-hours, which is approaching the firm energy capability of the Watana project. The load resource analyses demonstrate full utilization of Watana energy essentially as soon as it becomes available, even under the lower power demand case. This basically leads to a finding that the upper Susitna justification is not dependent on major industrial expansion in Alaska.

SENSITIVITY ANALYSIS

OMB COMMENT

> Power demand should be subjected to a sensitivity analysis to better assess the uncertainties in development of such a large block of power. The typical utility invests on the basis of an 8-10 year time horizon. The Susitna plan has an 11-16 year horizon in face of risks that loads may not develop and the option of wheeling power to other markets is not available. It should be noted that the power demand for Snettisham was unduly optimistic when it was built. This resulted in delays in installing generators. A similar error in a project the size of Susitna would be much more costly and would have a major adverse effect on the project's economics.

INTRODUCTION

The new power demand estimates and load/resource, economic, and financial analyses presented in this report all provide a better basis for examining these questions. In addition, there is need to review some of the Snettisham project history to bring out similarities and differences with the upper Susitna case.

SNETTISHAM REVIEW

The Snettisham Hydroelectric Project is located near Juneau, Alaska and is now the main source of power for the greater Juneau area. The project was authorized in 1962 on the basis of feasibility investigations by the Bureau of Reclamation, constructed by the Corps of Engineers, and operated by the Alaska Power Administration.

The project was conceived as a two-stage development and construction of the first, or Long Lake, stage was completed in late 1973 with first

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commercial power to Juneau in December 1973. The second, or Crater Lake, stage was to be added when power demands dictated.

Juneau remains an isolated power market area. Difficult terrain and long distance have thus far prevented electrical interconnection with other southeast Alaska communities and neighboring areas of Canada; however, such interconnections may prove feasible within the next 15 to 20 years. The project planning and justification was premised on service only to the greater Juneau area.

The Snettisham authorization was based on power demand estimates done in 1961 by the Alaska District, Bureau of Reclamation (now Alaska Power Administration). The estimates were based on actual power use through 1960 and projections to the year 1987. The outlook at that time was that the first stage construction would be completed in 1966 and that total project capability would not be needed until 1987. The actual 1977 energy load was 112,197 megawatt-hours or 81 percent of the 1977 estimate forecasted in 1961 on the basis of historical records through 1960.

The inherent flexibility of a staged project proved to be very beneficial in the case of Snettisham. APA made periodic updates of the power demand estimates during construction of the Long Lake stage. For several years, these forecasts indicated a need to proceed with the Crater Lake stage construction immediately on completion of the Long Lake stage. The Corps of Engineers construction schedules and budget requests, based on the APA power demand estimates, anticipated start of construction on Crater Lake in FY 77. Major factors in these forecasts were plans for a new pulp mill in the Juneau area and for an iron ore mining and reduction facility in the vicinity of Port Snettisham. Neither of these developments were anticipated at the time of authorization. Both of these resource developments failed to materialize, and this resulted in a substantial reduction in the APA power demand estimate and a decision in late 1975 to defer the Crater Lake construction start.

Many other factors influenced Juneau area power demands and utilization of project power. Of particular concern at the moment is impact of Alaska's capital move initiative. This would certainly change use of project power, with the most likely outcome that the community would move more quickly into an all-electric mode (space heating and electric vehicles appear particularly attractive in this area), and industrial use of power would increase through economic diversification.

The key points of the Snettisham review are:

1. The project was planned and authorized with intent to handle growth in area power requirements for a 20-year period.

2. The load forecasts used as a basis for authorization were reasonably accurate.

3. The actual use of project power may turn out to be substantially different than originally anticipated.

4. The flexibility of staged projects was used to great advantage.

5. The outlook for financial viability appears excellent at this time.

IMPLICATIONS FOR SUSITNA

First, the typical planning horizon for utility investments is in excess of 8 to 10 years. This is evidenced by experiences dating from about 1970 on the time required to plan, obtain necessary permits or authorizations, find financing, and then build new powerplants and major transmission facilities. The 8 to 10 years is specifically much too short for nuclear, coal, or hydro plants or for major transmission lines.

A 20-year planning horizon is more appropriate with careful checks at each step in the process and business-like decisions to shift construction schedules if conditions (demands) change. The Snettisham experience is very positive in this light.

The Susitna project is similar in that project investment is keyed to three major stages of development: transmission interconnection, Watana, and then Devil Canyon. The commitment of construction funds for Watana would be needed in 1984 to have power-on-line by 1994. If conditions in 1984 indicate the need to defer the project, it should be deferred. Similarly, start of actual construction on Devil Canyon can and should be based on conditions that actually prevail at the time the decision is made.

The degree of uncertainty for upper Susitna is greater in one respect than was the case for Snettisham because of higher interest costs and larger total investment. At the same time, sensitivity to change in demands is much less for Susitna because of its large and diversified power market area. There are many more ways that Susitna project power could be effectively utilized in the event that traditional utility power markets are smaller than anticipated at the present. The whole field of oil and gas fuel displacement could be explored with emphasis on electric heat for office buildings, electric vehicles, and electrification of oil and gas pipeline pump and compressor stations.

Further, the Susitna project does not have as many uncertainities in terms of environmental questions as would equivalent power supplies from coal or nuclear plants. Uncertainties regarding air quality are particularly relevant for any large Alaskan coal-fired powerplants.

CURRENT EVALUATION

Power demands were estimated for high, medium, and low cases to year 2025 assuming logical variations in population and energy use per capita. The projections reflect per capita energy use based on detailed studies of 1970-1977 data from both the Anchorage and Fairbanks areas. The projections considered variations in per capita use ranging from increased use of electricity in the home to anticipated effects of conservation.

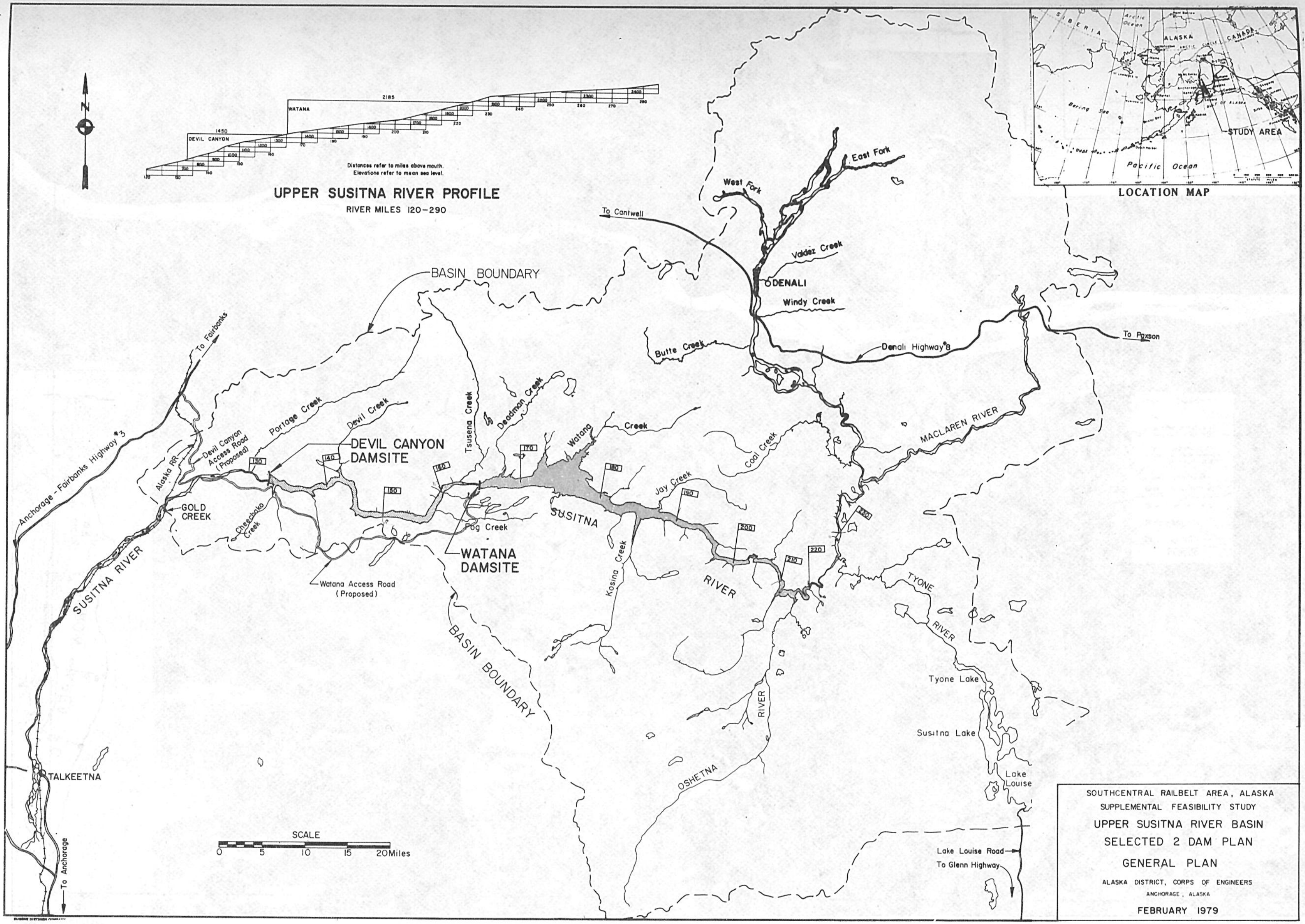
The project's economic justification was tested to determine, among other things, its degree of sensitivity to variations in load growth. The circumstance potentially most damaging to the economic viability of the project entails a sudden decrease in the rate of load growth immediately after the project is completed. The analysis indicated that the annual rate of load growth would have to fall to 0.8 percent before project costs exceed benefits. This rate should be compared to the annual growth rates of 12.7 percent in Anchorage and 10.5 percent in Fairbanks between 1973 and 1977 and to the low range forecast for the post-1994 period of 4.2 percent.

The load/resource and cost analysis provided system costs for comparison of cases both with and without the Susitna project. The analysis also compared the power demands to the resources required to determine sizes and timing of new plants. Even under the most conservative load growth condition, 1,500 MW is needed to meet the continued Anchorage-Fairbanks demands during the 1990's; this is roughly the capability of the Susitna project.

Cost of system power estimates indicate that, in the medium case for the year 2000, Anchorage costs are 5.5¢/kWh or 17 percent less than without Susitna. For Fairbanks the difference is much larger, 6.7¢/kWh or 25 percent less than without Susitna.

Examination of the system cost on an annual basis reveals the case "with" Susitna is cheaper than the "without" Susitna case for each year except the first few years after Watana comes on line.

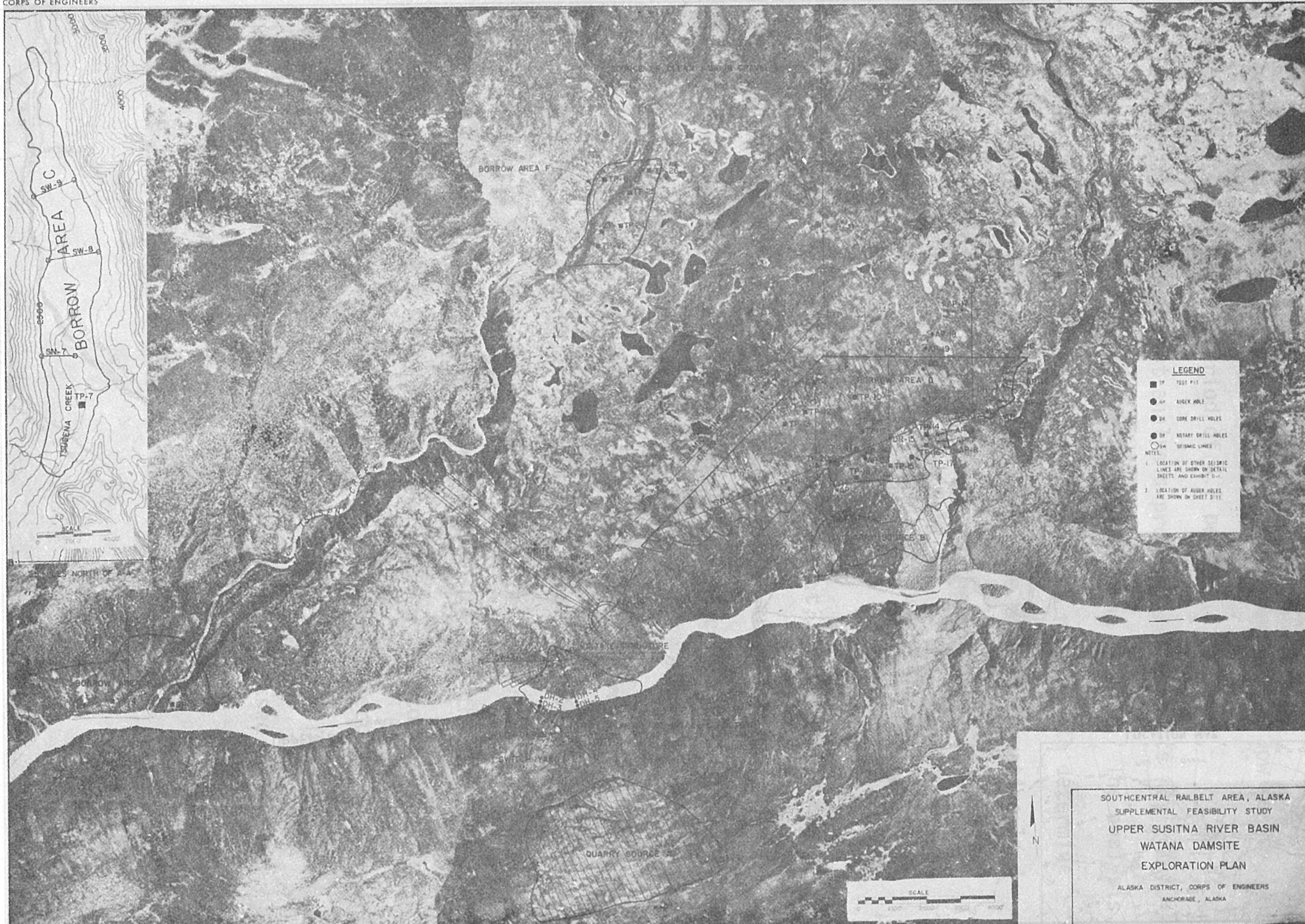
It should be noted that in the low energy use case the total system cost for the railbelt area during the period from 1990 to 2011 amounts to $1.1 million less with Susitna than without the project. The difference is even larger in the medium and high cases. The combined Anchorage-Fairbanks cash savings for the same period based on the medium power use estimate is over $2 billion.



UPPER SUSITNA RIVER PROFILE
RIVER MILES 120-290
Distances refer to miles above mouth.
Elevations refer to mean sea level.
DEVIL CANYON
1450
WATANA
2185
LOCATION MAP
STUDY AREA
ALASKA
CANADA
Pacific Ocean
Bering Sea
To Cantwell
West Fork
East Fork
Valdez Creek
DENALI
Windy Creek
Butte Creek
Denali Highway 8
To Paxson
BASIN BOUNDARY
To Fairbanks
Anchorage - Fairbanks Highway 3
Alaska RR
Devil Canyon Access Road (Proposed)
Portage Creek
Devil Creek
DEVIL CANYON DAMSITE
Tsusena Creek
Deadman Creek
Watana
Creek
Coal Creek
MACLAREN RIVER
Jay Creek
GOLD CREEK
Cheechako Creek
Fog Creek
SUSITNA
WATANA DAMSITE
Watana Access Road (Proposed)
Kosina Creek
RIVER
TYONE RIVER
SUSITNA RIVER
BASIN BOUNDARY
Tyone Lake
Susitna Lake
Lake Louise
OSHETNA RIVER
TALKEETNA
To Anchorage
SCALE
0 5 10 15 20 Miles
Lake Louise Road
To Glenn Highway
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
SELECTED 2 DAM PLAN
GENERAL PLAN
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

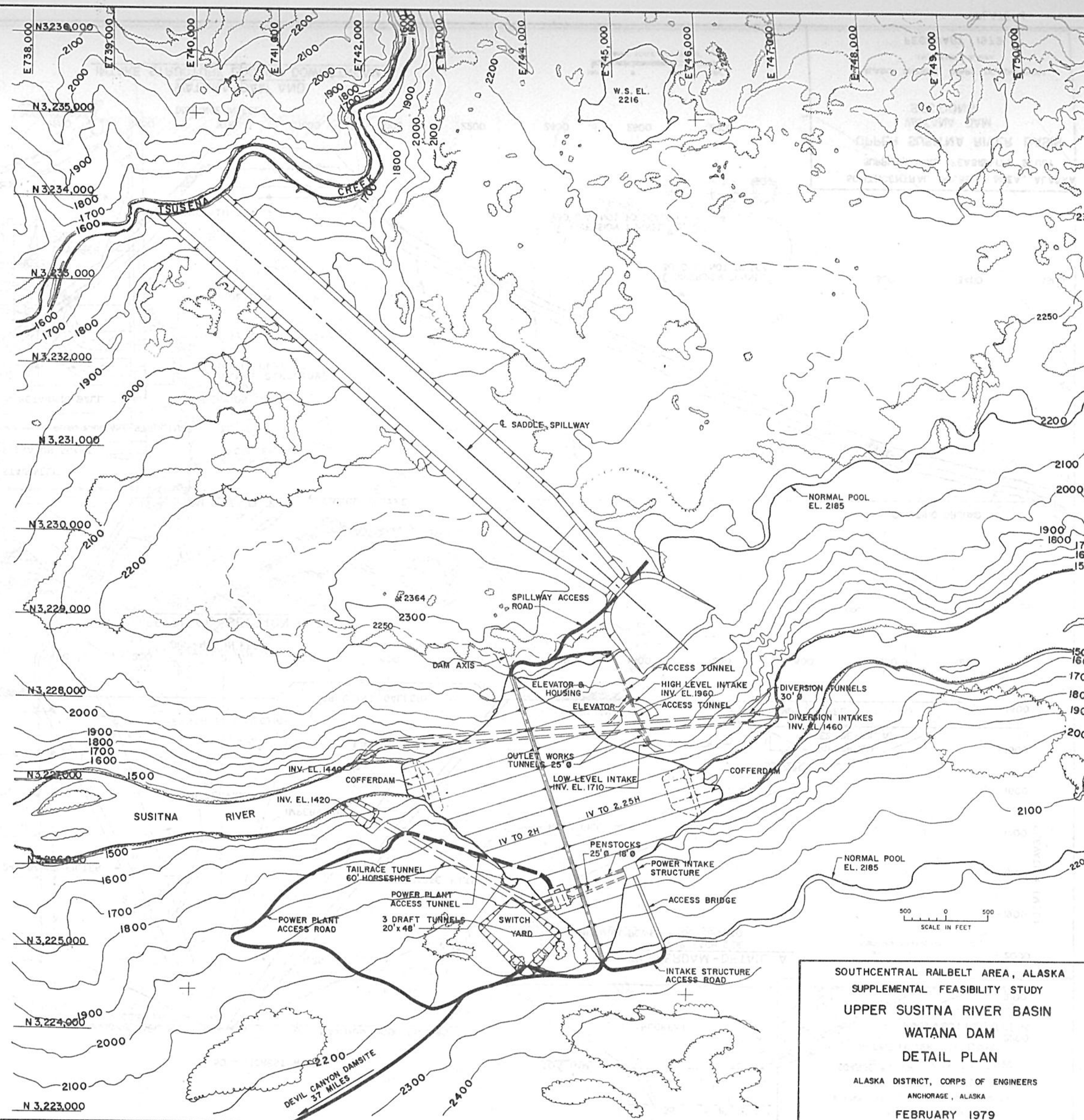
PLATE 1

CORPS OF ENGINEERS U. S. ARMY



INV. NO. DACW85- PLATE 2

NOTES:
1. TOPOGRAPHIC CONTOURS ARE BASED ON AERIAL PHOTOGRAPHY DATED 10 JUNE 1978. VERTICAL DATUM IS MEAN SEA LEVEL (MSL)



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN

WATANA DAM

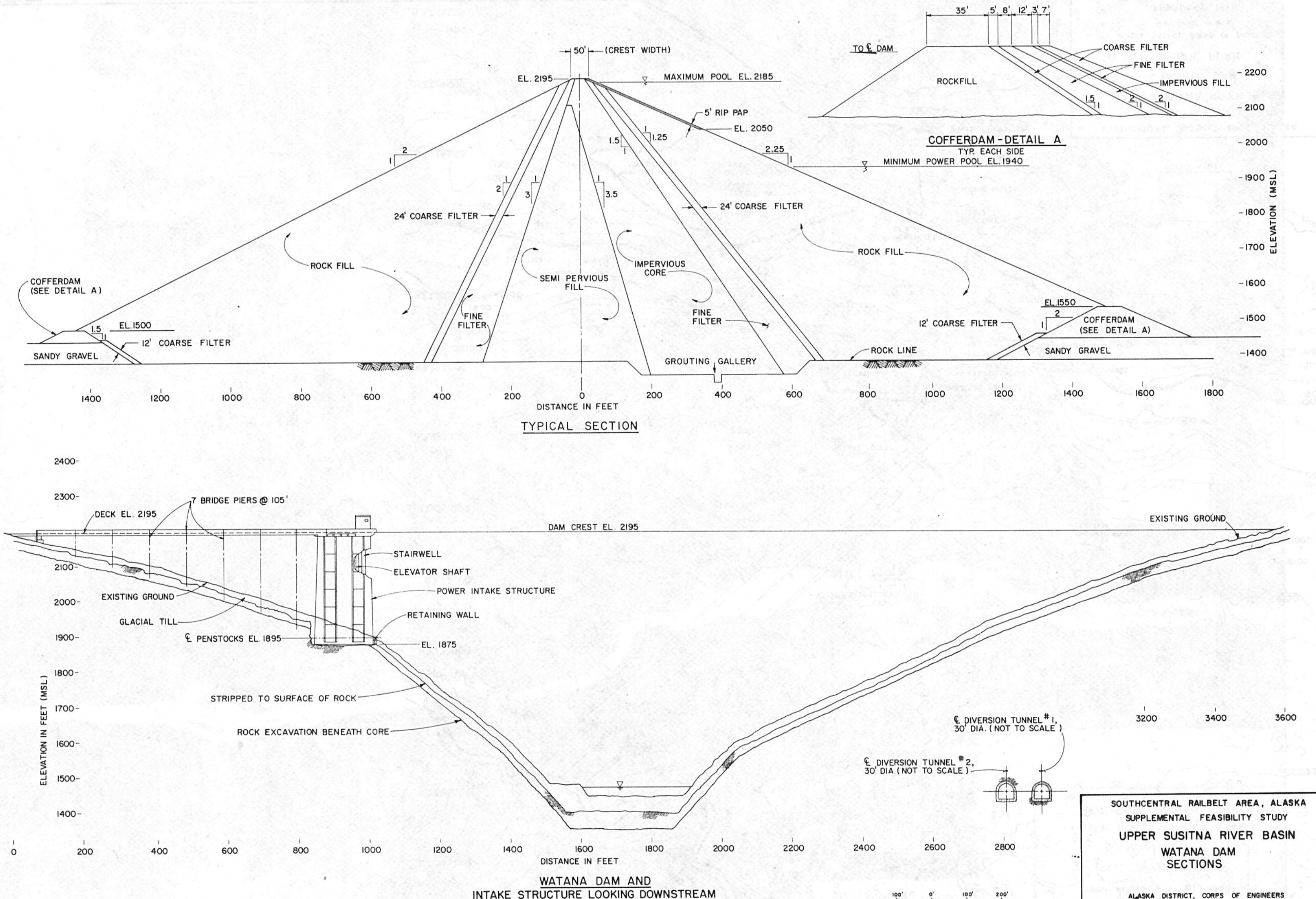
DETAIL PLAN

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

FEBRUARY 1979

PLATE 3

56



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAM
SECTIONS

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

FEBRUARY 1979

PLATE 4

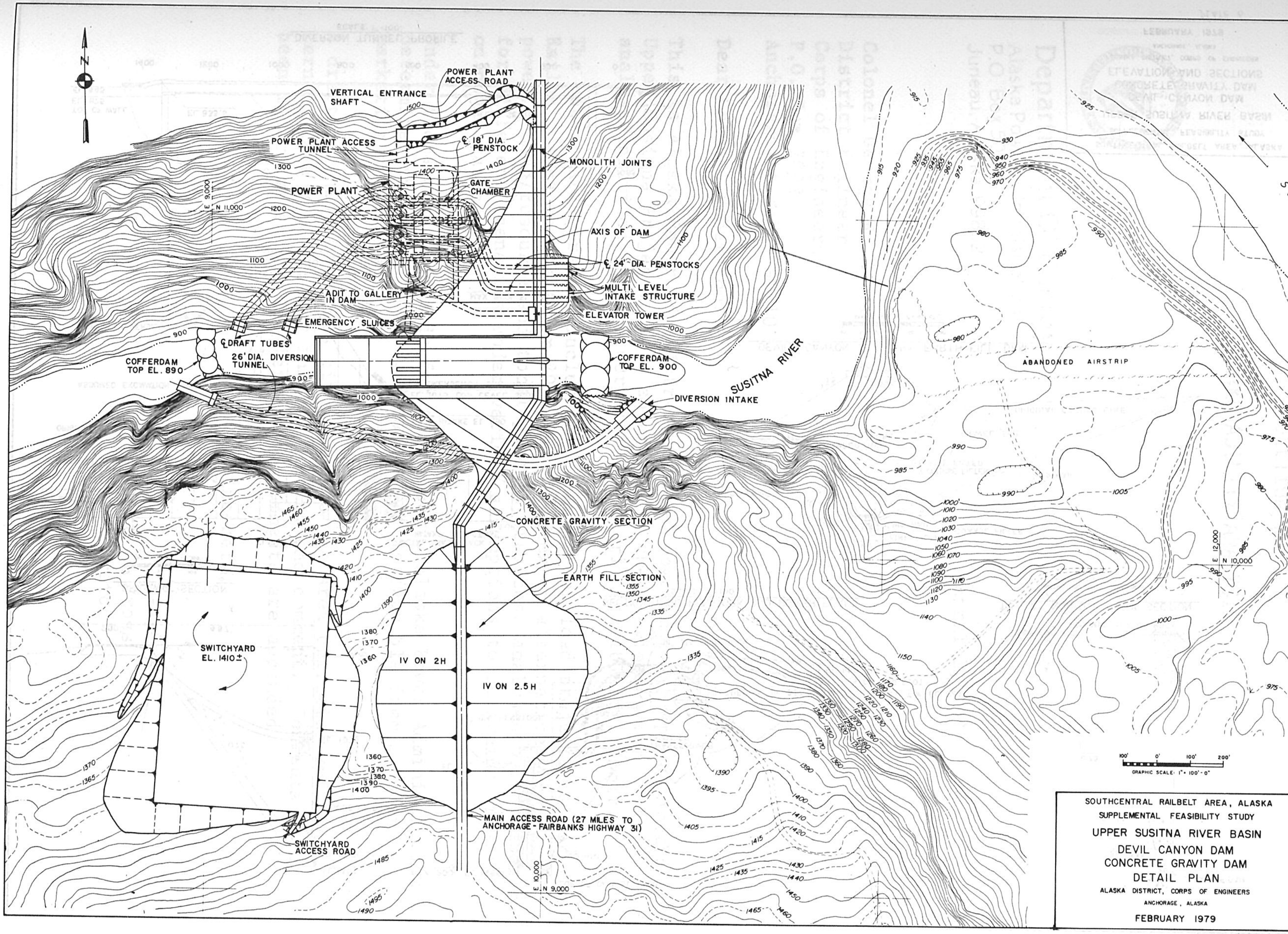
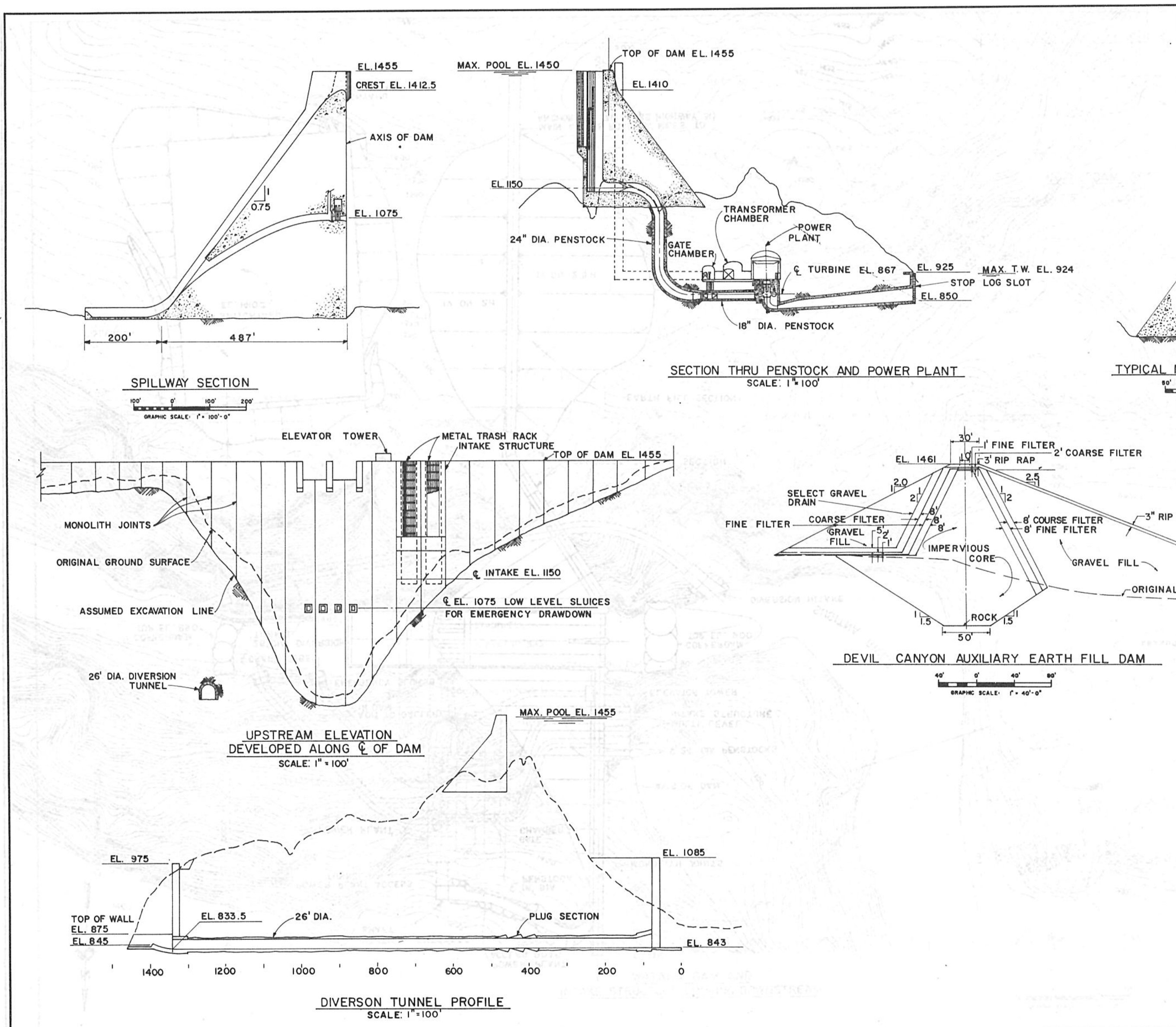

N
POWER PLANT ACCESS ROAD
VERTICAL ENTRANCE SHAFT
POWER PLANT ACCESS TUNNEL
℄ 18' DIA. PENSTOCK
MONOLITH JOINTS
POWER PLANT
GATE CHAMBER
E 9,000
N 11,000
AXIS OF DAM
℄ 24' DIA. PENSTOCKS
ADIT TO GALLERY IN DAM
MULTI LEVEL INTAKE STRUCTURE
ELEVATOR TOWER
EMERGENCY SLUICES
℄ DRAFT TUBES
26' DIA. DIVERSION TUNNEL
COFFERDAM TOP EL. 890
COFFERDAM TOP EL. 900
SUSITNA RIVER
DIVERSION INTAKE
ABANDONED AIRSTRIP
CONCRETE GRAVITY SECTION
EARTH FILL SECTION
SWITCHYARD EL. 1410 ±
IV ON 2H
IV ON 2.5H
MAIN ACCESS ROAD (27 MILES TO ANCHORAGE - FAIRBANKS HIGHWAY 31)
SWITCHYARD ACCESS ROAD
E 10,000
N 9,000
E 12,000
N 10,000
GRAPHIC SCALE: 1" = 100'-0"
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DEVIL CANYON DAM
CONCRETE GRAVITY DAM
DETAIL PLAN
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

PLATE 5



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DEVIL CANYON DAM
CONCRETE GRAVITY DAM
ELEVATION AND SECTIONS
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

PLATE 6

SECTION G

MARKETABILITY ANALYSIS

Department Of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

April 2, 1979

Colonel George R. Robertson
District Engineer
Corps of Engineers
P.O. Box 7002
Anchorage, Alaska 99510

Dear Colonel Robertson:

This is Alaska Power Administration's new power market report for the Upper Susitna Project. It's an update of the previous power market analyses provided for the Corps' 1976 Interim Feasibility report.

The power market report includes: a new set of load projections for the Railbelt area through year 2025 and a review of alternative sources of power. Load/resource and total power system cost analyses were prepared for different scenarios under various assumptions to determine effects on power rates.

Under the assumptions made for this report, Alaska Power Administration determines that the Upper Susitna Project is feasible from a power marketing standpoint.

A draft of this report was circulated to the area utilities and concerned State officers for informal review and comment. Comments have been incorporated and the letters of comments are appended.

Sincerely,

Robert J. Cross
Administrator

CONTENTS

CONTENTS (Continued)

1. Letter dated January 3, 1979 to Col. G.R. Robertson, Alaska District Corps of Engineers, transmitting responses to OMB questions falling in APA's area of responsibility.

2. Previous Studies and Bibliography.

3. LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010 --Informal Report-- by Battelle Pacific Northwest Laboratories, Richland, Washington - January, 1979.

4. Comments.
   a. Federal Energy Regulatory Commission, San Francisco, California.
   b. Battelle Pacific Northwest Laboratories, Richland, Washington.
   c. Corps of Engineers, Anchorage, Alaska
   d. The Alaska State Clearinghouse, Juneau, Alaska
   e. Municipal Light and Power, Anchorage, Alaska

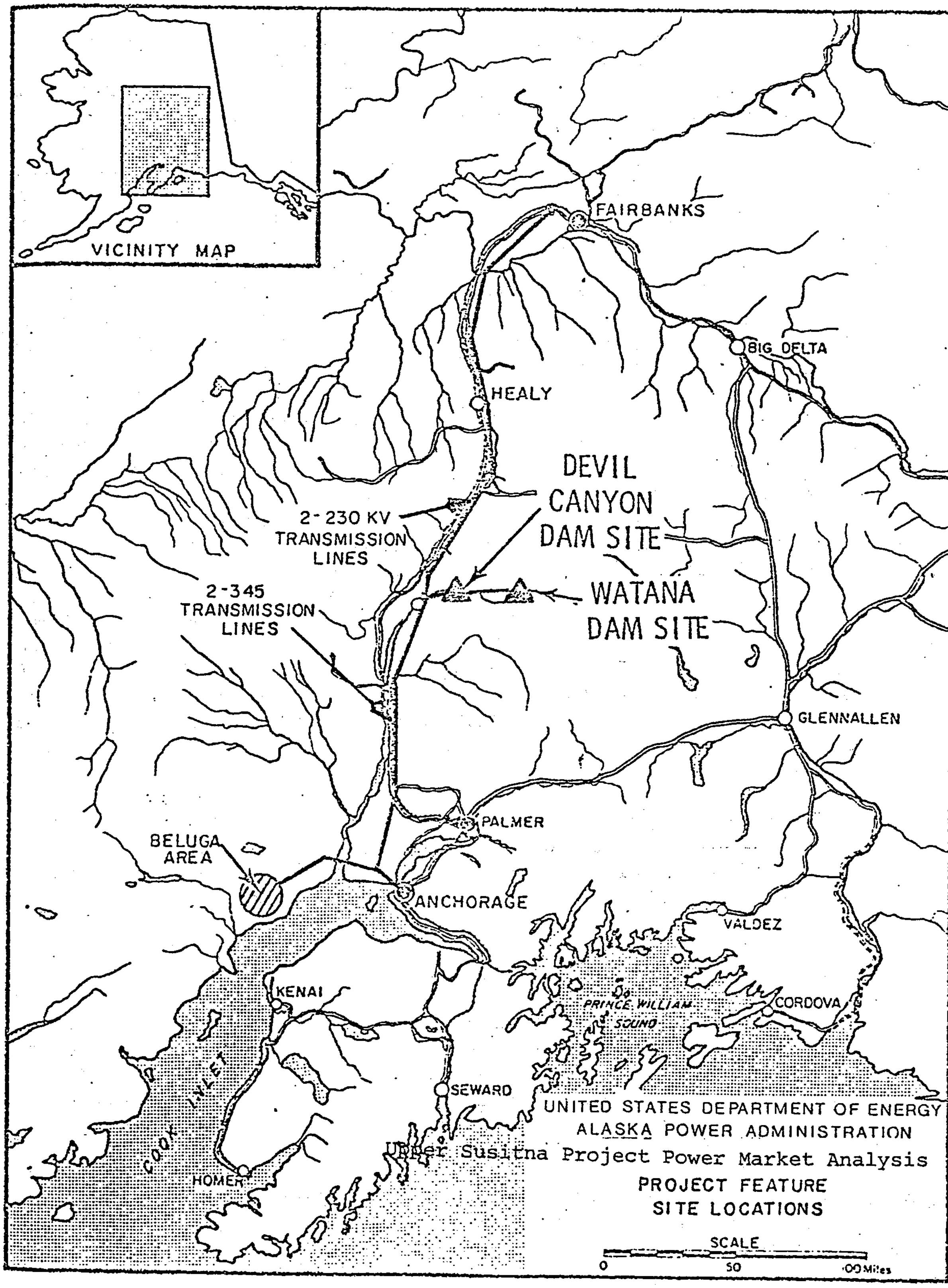
TABLES

TABLES (Continued)

TABLES (Continued)

FIGURES

Figure 1


VICINITY MAP
FAIRBANKS
BIG DELTA
HEALY
DEVIL CANYON DAM SITE
2-230 KV TRANSMISSION LINES
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Upper Susitna Project Power Market Analysis
PROJECT FEATURE
SITE LOCATIONS
SCALE
0
50
Miles

PART I. INTRODUCTION

The Interim Feasibility Report of the Upper Susitna River Basin Project (1976 report) was completed by the Alaska District Corps of Engineers (Corps) in 1976. Alaska Power Administration (APA) provided the transmission system and power market analyses for that report.

The Corps submitted the 1976 report to the Office of Management and Budget (OMB) for review. In September 1977, OMB requested the Corps obtain additional data before submitting the report to Congress. The requested data were to: (1) provide additional geologic data for the Watana damsite; (2) reanalyze the cost estimate contingency factor; (3) reanalyze area development benefits; and (4) reanalyze the projected construction schedule. There were also questions about power supply and demand, including sensitivity to developing a large block of power in APA's area of responsibility.

This report updates the power market analysis and addresses OMB concerns. It uses three years additional data on power usage, effects of the oil embargo, and other factors. Specifically, it (1) updates the power demand forecasts reflecting data since the 1976 report; (2) updates the transmission and project OM&R costs; (3) presents load/resource analyses to determine timing of major generation and transmission investments and reflect resulting impacts on power system costs; (4) presents system power cost analyses that show annual system-wide costs of power with and without the Upper Susitna Project; (5) examines the value of an Anchorage to Fairbanks interconnection with and without Susitna; (6) provides a subanalysis of the feasibility of delivering Susitna power to the Valdez-Glennallen area; (7) determines power rates and marketability of Susitna power compared with alternative generation methods; and (8) responds to the OMB questions in APA's areas of responsibility.

APA gave the Corps, for their report purposes: updated transmission system costs and project OM&R estimates; load estimates; detailed load/resource and system cost analyses with and without Susitna project; and proposed responses to OMB questions pertinent to APA areas of responsibility.

The Corps' current proposal for the Upper Susitna Project is essentially the same as plan 5 in the 1976 report: a two-phase, two-dam complex including Watana and Devil Canyon dams and powerplants, with the Watana phase and a transmission system interconnecting Anchorage and Fairbanks coming on-line first. Power production facilities include Watana dam, reservoir, and powerplant, and Devil Canyon dam, reservoir, and powerplant. Watana dam would be an earthfill structure with reservoir normal water surface elevation of 2,185 feet; the powerplant would have 795 MW capacity. Devil Canyon dam would be a double-curvature concrete-arch structure with maximum pool elevation of 1,450 feet, providing water for a 778-MW powerplant. The transmission system would be constructed in conjunction with the first stage (Watana), and, as planned, would be totally required for system reliablilty. The system would incude two parallel 230-kv single circuit lines from Watana to Devil Canyon (30 miles), two parallel single circuit 345-kv lines from Devil Canyon to Pt. McKenzie (Anchorage, 135 miles), and two parallel single circuit 230-kv lines from Devil Canyon to Ester-Gold Hill (Fairbanks, 198 miles).

Several significant changes were made by the Corps since the 1976 report:

(1) The Devil Canyon dam design and costs are presented for both a gravity structure and a thin-arch concrete structure. The 1976 report was based on a thin-arch concrete structure.

(2) The construction period for Watana was increased from 6 years to 11; Devil Canyon from 4 years to 7; and the Anchorage-Fairbanks intertie re-scheduled for 1991--three years before Watana POL.

(3) Watana dam (earth fill) was redesigned, based on new geologic data.

The APA power market report uses certain assumptions that differ from the Corps plan, namely:

(1) Design power generation capacity: The Corps design capacity is based on critical year primary energy and 50 percent annual plant factor (1,392 MW). The APA load/resource analyses assume a design capacity based on average annual energy and 50 percent plant factor (1,573 MW). APA analyses include both primary and secondary energy as well as firm and non-firm power.

(2) Transmission intertie schedule:

The Corps plans show a 1991 on-line date for the transmission intertie. The APA system cost analyses examine alternative on-line dates of 1990, 1992, and 1994. The load/resource analysis showed the earliest intertie dates could be 1986, 1989, and 1991. APA financial analyses are consistent with the Corps schedule.

(3) For Devil Canyon Design:

The APA system cost and financial analyses assume the thin-arch design for Devil Canyon as presented in the 1976 report, rather than the more costly gravity structure alternative now being used by the Corps for feasibility testing. A separate analysis demonstrates the effect of the gravity dam alternative on cost of power.

The term "1976 report" is used throughout this report. This term refers to the Corps of Engineers Interim Feasibility Report on the Upper Susitna project, dated December 1975, revised June 1976. It also refers to APA's Power Market analysis dated 1975 and included as Appendix G in the revised Interim Feasibility Report.

Part II. SUMMARY

Current studies have updated and revised the power market analyses of the 1976 Upper Sustina Report (1976 report). New estimates of power requirements through the year 2025 have been prepared.

The 1976 report used energy and power estimates based on data through December 1974. The new analyses benefit from three full years of additional data through December 1977. This provides a full four years of "post oil-embargo" data--especially significant from the viewpoint of identifying conservation trends. Evidence of conservation shows in the Anchorage-Cook Inlet area growth comparisons before and after the 1973-74 fuel crisis. The 1970-73 average annual growth in net generation dropped from 14.2 percent to 12.7 percent in the 1973-77 period. The decrease was more dramatic for per capita net generation: A drop from 8 percent to 3.8 percent.

Because the net generation kwh/capita raio seemed to reflect the closest correlations, particularly in recent years, this ratio and population were used to forecast net generation values between 1980 and 2025.

The following Railbelt totals are detailed in Part V. Trended values offer an interesting comparison but are not presented as part of the forecast. The trend is an average annual growth of 12.3 percent resulting from 12.7 percent for the Anchorage area and 10.5 percent for the Fairbanks area.

Railbelt Area Energy Forecast
(GWH)

		1977 (Historic)	1980	1990	2000	2025
Utility:						
	High		3,410	8,200	16,920	38,020
	Mid	2,273	3,155	6,110	10,940	17,770
	Low		2,920	4,550	7,070	8,110
National Defense:						
	High		348	384	425	544
	Mid	338	338	338	338	338
	Low		330	299	270	210
Self-Supplied Industry:						
	High		170	2,100	3,590	8,490
	Mid	70	170	630	1,460	3,470
	Low		141	370	550	1,310
Total:						
	High		3,928	10,684	20,935	47,054
	Mid	2,681	3,663	7,078	12,738	21,578
	Low		3,391	5,219	7,890	9,630
Trend @ 1973-77 annual/growth:			(3,215)	(10,270)	(33,000)	(601,000)

Area load characteristics data were updated and new estimates of monthly energy distribution were made. The conclusion was that the 50 percent plant factor sizing assumption is still valid.

A further review of possible power supply alternatives included oil and natural gas, coal, alternative hydro projects, nuclear, wind, geothermal, and tide. It concluded again that coal-fired steam plants are the most logical alternatives for major railbelt area power supplies in the proposed Susitna project timeframe.

New estimates of cost of power from coal-fired steamplants were prepared using results of several recent studies. They indicate:

Investment costs of $1,620-$1,860/kw

Unit cost of power of 5.2-6.4¢/kwh (including transmission to load center)

A set of load/resource and annual system cost analyses were performed to examine the effects of Susitna and the transmission intertie from an overall power system approach. These analyses were needed to provide responses to OMB questions regarding: (1) the value of an interconnected transmission system between Anchorage and Fairbanks; (2) scheduling of major powerplants; and, (3) sensitivity of developing large blocks of power. APA's response to the OMB questions are appended. Three cases were analyzed using three projected load growth estimates:

Case 1. A without Susitna Project and without transmission intertie situation assuming all generating capacity to be supplied by coal-fired steamplants.

Case 2. Same as case 1 but with transmission intertie.

Case 3. A with Susitna Project and with intertie situation assuming additional generating capacity supplied by coal-fired steamplants. The load/resource analyses showed the schedule of new plant additions needed for all three cases for 1978-2011.

The system cost analyses compared annual power system costs for all three cases, assuming 0 and 5 percent inflation rates. The analyses showed annual system cost savings of $2.23 billion between 1990 and 2011, with the Susitna project. Average power system rates for the year 2000 assuming no inflation will be:

¢/KWH

Load Forecast	Case 1 Without Susitna or Intertie	Case 2 Without Sustina With Intertie	Case 3 With Susitna and Intertie
High	6.6 1/	6.4	5.8
Mid	6.9 1/	6.6	5.7
Low	7.5 1/	6.7	6.4

1/ Anchorage and Fairbanks are not interconnected for case 1; the combined system rate is shown for academic purposes only.

For the medium energy use range, system rates, compared to those without Susitna or interconnections, will be 5.7 percent less with interconnections 18.6 percent less with Susitna.1/ The analyses showed Susitna will result in cheaper power cost to Anchorage and Fairbanks in all load growth cases. It also shows that the project power could be fully used under all projected power demand cases.2/

In comparison with the 1976 report, investment costs are 89 percent ($1.567 billion) greater. Contributing factors are: interest rate increase from 6 5/8 to 7 1/2 percent total construction period increase from 6 years to 10 years, cost inflation; and redesign of Watana dam and powerplant facilities. New construction cost estimates for Watana dam (containing effects of both design quanitity changes and unit cost inflation) are $595 million (72 percent) higher. Construction cost estimates for Devil Canyon dam (thin-arch concrete) power plant facilities, and the transmission system were updated primarily by indexing. This resulted in a 54 percent increase over the 1976 report ($233 million for Devil Canyon and $82 million for the transmission system). The total interest during construction increase is 265 percent ($657 million). In summary, the increases in construction costs are:

Watana	$ 595 million	
Devil Canyon	233 "	
Transmission System	82 "	
Interest during Construction	657 "	
Total	$1567 million	- project investment cost increase

Financial analyses were based on the October 1978 price level, Fiscal Year 1979 Federal interest rate of 7 1/2 percent, intertie in 1991 or 1992, and repayment of all principal and interest within 50 years after the last unit is installed.

1/ $\frac{\text{Case 2 Value (6.6\%)}}{\text{Case 1 Value (7.0\%)}} -1 = -5.7\%$; $\frac{\text{Case 3 Value (5.7\%)}}{\text{Case 1 Value (7.0\%)}} -1 = -18.6\%$

2/ Interconnection benefits leading to lower rates involve load supply flexibility, economics of scale and operations, decreased reserve requirements, and better reliability.

A comparison of the rate for Sustina at 4.7¢/kwh with the coal-fired steamplant alternative at 5.2/kwh to 6.4¢/kwh shows Susitna is less costly.

The Glennallen-Valdez area was considered as a market area supplementary to the Railbelt. The Copper Valley Electric Association (CVEA) plans to construct a Glennallen-Valdez transmission line, and the presence of the pipeline terminal in Valdez with its related economy has made this area a more attractive market since the 1976 report. Service to the area would require a 138-kv line from Palmer to Glennallen (136 miles). Area market factors are subject to fluctuation. Potential industrial loads are difficult to project at this time, but service to utility loads can be evaluated for a probable range of demands. Energy costs to serve the incremental market area will range from 2.6¢/kwh to 1.3¢/kwh for a range of loads from 150 to 300 kwh/year in addition to the project energy cost of 4.7¢/kwh. Inclusion of the market area costs with other project costs for a single project-wide rate would not adversely affect the rate.

PART III. POWER MARKET AREAS

Throughout its history of investigations, the Upper Susitna River Basin Project has been of interest for hydroelectric power generation because of its central location to the Fairbanks and Anchorage areas. These areas have Alaska's largest concentrations of population, economic activity, services, and industry. Under any plan of development, major portions of the project power will be used in these two areas. In addition, the basic project transmission system serving Anchorage and Fairbanks could provide electric service to present and future developments between the two cities.

The potential major market areas are the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area.

Anchorage-Cook Inlet Area

This area includes the developed areas of the Matanuska Valley, Greater Anchorage Area, and Kenai Peninsula.

This general area has been the focal point for most of the State's growth in terms of population, business, services, and industry since World War II. Major building of defense installations, expansion of government services, discovery and development of natural gas and oil in the Cook Inlet area, and emergence of Anchorage as the State's center of government, finance, travel, and tourism are major elements in the history of this area.

Because of its central role in business, commerce, and government, the Anchorage area is directly influenced by economic activity elsewhere in the State. Much of the buildup in construction and operation of the Alyeska pipeline, much of the growth related to Cook Inlet oil development, and much of the growth in State and local government services since Statehood has occurred in the immediate Anchorage vicinity.

Initially, economists overestimated the impacts of completion of the trans-Alaska oil pipeline. In a recent study prepared by the University of Alaska Institute of Social and Economic Research, the projected 1980 population for Anchorage-Cook Inlet was lower than that of the historical 1977 population. Though this has been corrected, it indicates that the area's economy has been stronger than anticiapted.

The Greater Anchorage Area Borough estimated its July 1, 1977 population at 195,800, an increase of nearly 55 percent since the 1970 census. This was more than 48 percent of the total estimated State population in 1977.

The Matanuska Valley includes several small cities (Palmer, Wasilla, Talkeetna) and the State's largest agricultural community. Other economic activities include recreation and light manufacturing. Much recent growth in the Borough has been in residential and recreational homes for workers in the Anchorage area. Estimated 1977 population was 15,740, a 61 percent increase since 1974.

The Kenai Peninsula Borough includes the cities of Kenai, Soldotna, Homer, Seldovia, and Seward, with important fisheries, oil and gas, and recreation resources. Estimated 1977 population was 23,100, a 39 percent increase since 1974.

Present and proposed activities indicate likelihood of rapid growth in this general Cook Inlet area for the future. Much of this activity is related to oil and natural gas, including expansion of the refineries.

The State capital city site relocation issue remains unresolved. In the November 1978 general election, voters turned down the $966 million bond issue to relocate the capital. In the same election, voters approved an initiative which would require full disclosure of the costs to move the capital. Therefore, it is impossible at this time to include specific assumptions concerning the capital move.

The area will continue to serve as the transportation hub of western Alaska, and tourism will likely continue to increase rapidly. Major local development seems probable.

Fairbanks-Tanana Valley Area

Fairbanks is Alaska's second largest city - the trade center for much of Alaska's Interior, the service center for several major military bases, and the site of the main campus of the University of Alaska with its associated research center. The outlying communities of Nenana, Clear, North Pole, and Delta Junction are included in the Fairbanks-Tanana Valley area. Historically, the area is famous for its gold.

The completion of the pipeline construction has taken its toll in Fairbanks. The area is experiencing a severely depressed economy. Employment in the construction industry has decreased to half of the previous pipeline level. There has been a slight increase in employment generated by government, distributive industries, and retail trade. In 1977-78, Fairbanks and its outlying areas experienced a 16 percent decline in population.

The decision favoring the ALCAN route for the proposed natural gas pipeline was made in late 1977. The proposed gas pipeline will follow the route of the trans-Alaska oil pipeline route from Prudhoe Bay to Delta Junction. Fairbanks has been selected as the operation headquarters by the Northwest Pipeline Company, responsible for construction and operation of the gas pipeline. The Fairbanks-Tanana Valley area will probably be heavily impacted again by the pipeline construction; however, a more stable permanent employment base is likely to become established.

The Fairbanks-North Star Borough had an estimated 1977 population of 44,262 and an estimated additional 8,000 in the outlying communities within the power market area. The total population decreased 10 percent since 1974.

PART IV. EXISTING POWER SYSTEMS

Utility Systems and Service Areas

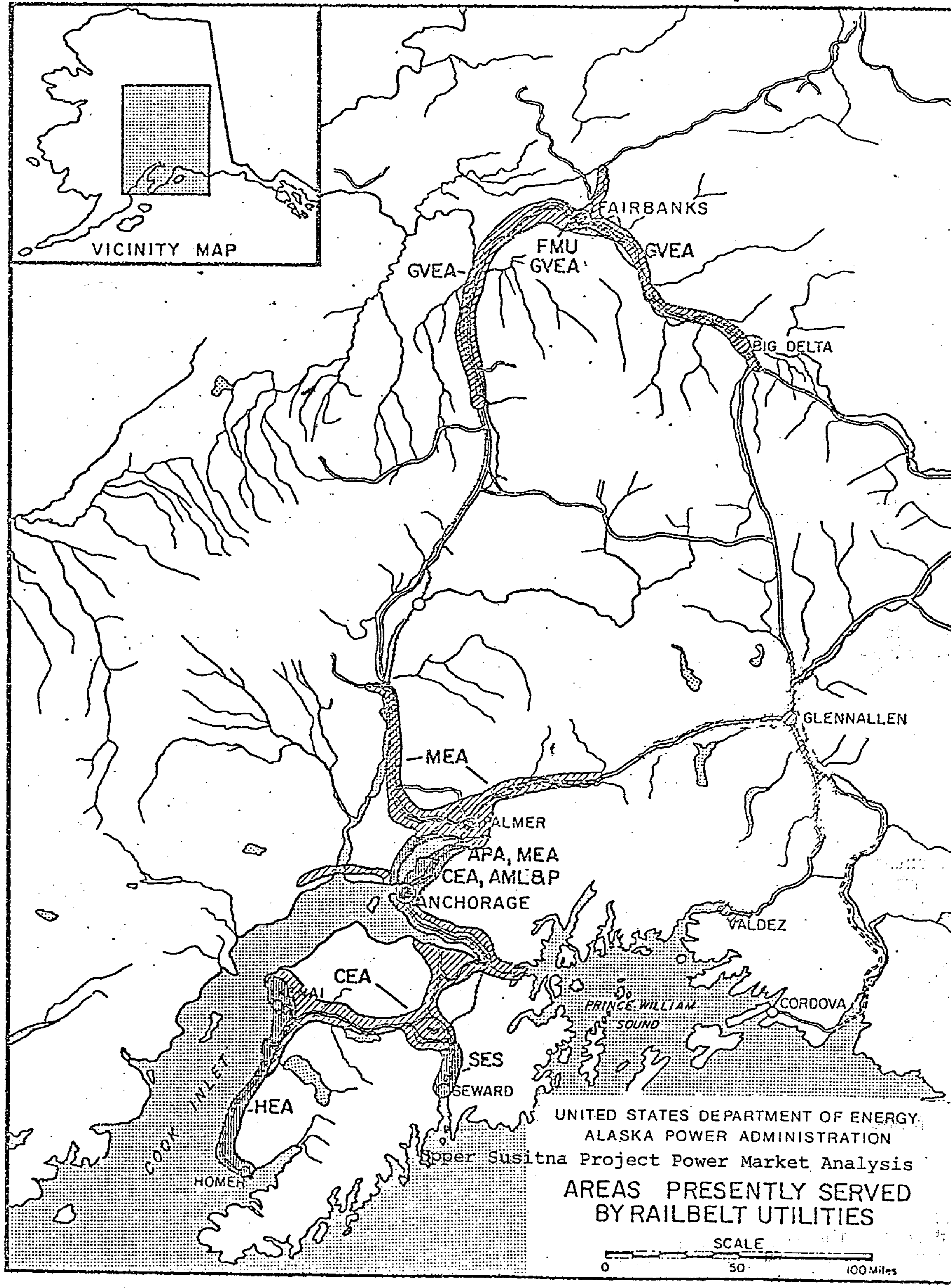
The electric utilities in the Railbelt power market area are listed below, and areas now receiving electric service are shown on figure 2. A detailed listing of power generating units is in the appended Battelle report, table 3.4.

Anchorage-Cook Inlet Area	Installed Nameplate Capacity MW 2/
Alaska Power Administration (APA)	30.0
Anchorage Municipal Light and Power (AML&P)	121.1
Chugach Electric Association (CEA)	345.7
Matanuska Electric Association (MEA)	1/
Homer Electric Association (HEA)	
Homer (Standby)	0.3 1/
Seldovia, English Bay, Port Graham	1.8
Seward Electric System (SES)	5.5 1/
Fairbanks-Tanana Valley Area	
Fairbanks Municipal Utility System (FMUS)	69.6
Golden Valley Electric Association (GVEA)	219.2

1/ Major generation supplied by CEA system.

2/ Consists of 45 MW hydro. All the rest are fuel-fired (80% gas turbine)

Figure 2



VICINITY MAP
FAIRBANKS
FMU
GVEA
GVEA-
GVEA
BIG DELTA
GLENNALLEN
MEA
PALMER
APA, MEA
CEA, AML&P
ANCHORAGE
VALDEZ
CEA
KENAI
PRINCE WILLIAM SOUND
CORDOVA
SES
SEWARD
HEA
COOK INLET
HOMER
UNITED STATES DEPARTMENT OF ENERGY
ALASKA POWER ADMINISTRATION
Upper Susitna Project Power Market Analysis
AREAS PRESENTLY SERVED BY RAILBELT UTILITIES
SCALE
0
50
100 Miles

These totals differ from the Battelle appended report because the report includes some planned units not installed in 1977 as well as use of some ratings other than nameplate.

APA operates the Eklutna hydroelectric project and markets wholesale power to CEA, AML&P, and MEA.

AML&P serves the Anchorage Municipal area. CEA supplies power to the Anchorage suburbs and surrounding rural areas, and provides power at wholesale rates to HEA, SES, and MEA. The HEA service area covers the western portion of the Kenai Peninsula, including Seldovia, across the bay from Homer. MEA serves the town of Palmer and the surrounding rural area in the Matanuska and Susitna Valleys.

The utilities serving the Anchorage-Cook Inlet area are now loosely interconnected through facilities of APA and CEA. An emergency tie is available between the AML&P and Anchorage area military installations.

FMUS serves the Fairbanks municipal area, while GVEA provides service to the rural areas. The Fairbanks area power suppliers have the most complete power pooling agreement in the State. FMUS, GVEA, the University of Alaska, and most of the military bases have an arrangement which includes provisions for sharing reserves and energy interchange.

The delivery point for Upper Susitna power to the GVEA and FMUS systems is assumed at a substation of GVEA near Fairbanks.

Other small power generating systems in the Fairbanks-Tanana Valley area were included in determining the power requirements of the region. They include:

Fairbanks-Tanana Valley Area	Installed Capacity MW
Alaska Power and Telephone Company (Tok and Dot Lake vicinity)	2.28
Northway Power and Light Company (Northway vicinity)	0.48

National Defense Power Systems

The six major national defense installations in the power market area are:

Anchorage area--

Elmendorf Air Force Base
Fort Richardson

69-738 O - 80 - 6

Fairbanks area--

Clear Air Force Base
Eielson Air Force Base
Fort Greely
Fort Wainwright

Each major base has its own steamplant that is used for power and for central space heating. Except for Clear Air Force Base, each is interconnected with the local utility. Numerous small isolated installations are not included in this study.

In the past, national defense electric generation has been a major portion of the total installed capacity. With the projected stability of military sites and the growth of the utilities, the national defense installation will become a less significant part of the total generating capacity.

Industrial Power Systems

Three industrial plants on the Kenai Peninsula maintain their own powerplants, but are interconnected with the HEA system. The Union 76 Chemical Division plant generates its basic power to satisfy its energy needs, receiving only standby capacity from HEA. The Kenai liquified natural gas plant buys energy from HEA, but has its own standby generation. Tesoro Refinery buys from HEA and also satisfies part of its own needs.

Other self-supplied industrial generators include oil platform and pipeline terminal facilities in the Cook Inlet area.

Existing Generation Capacity

Table 1 provides a summary of existing generating capacity. The table was generally current as of 1978. The Anchorage-Cook Inlet area had a total utility installed capacity of 504.5 MW in 1977-78. Natural gas-fired turbines were the predominant energy source with 435.1 MW. Hydroelectric capacity of 45 MW was available from two projects, Eklutna and Cooper Lake. Steam turbines comprised 14.5 MW. Diesel generation, mostly in standby service, accounted for the remaining 9.8 MW.

The Fairbanks-Tanana Valley area utilities had a total installed capacity of 288.8 MW in 1977. Gas turbines (oil-fired) provided the largest block of power in the area with an installed capacity of 203.1 MW. Steam turbine generation provided 53.5 MW of power and diesel generators contributed 32.1 MW to the area.

Table 1
RAILBELT AREA GENERATION CAPACITY
Summary - 1977

Upper Susitna Project Power Market Analysis

Area	Installed Capacity - MW				
	Hydro	Diesel Int. Comb.	Gas Turbine	Steam Turbine	Total
Anchorage-Cook Inlet					
Utility System	45.0	9.8	435.1	14.5	504.5
National Defense		9.2		40.5	49.7
Industrial System		10.2	14.8		25.0
Subtotal	45.0	29.3	449.9	55.0	579.2
Fairbanks-Tanana Valley					
Utility System		32.1	203.1	53.5	288.8
National Defense		14.0		63.0	77.0
Subtotal		46.1	203.1	116.5	365.8

Notes: The majority of the diesel generation is in standby status. Rounding causes differences between summations of the parts and the totals shown.

Source: Utility reports to Alaska Public Utility Commission to the Department of Energy, the Alaska Air Command, the oil and gas companies, and APA files.

(Minor differences exist between this table and the appended Battelle Report.)

Planned Generation Capacity

The two major utilities in the Anchorage-Cook Inlet area, AML&P and CEA, plan to add a total of approximately 420 MW installed capacity to their existing system between 1979 and 1985. AML&P plans to add a 16.5-MW combined cycle system to their existing combustion turbine. In addition, CEA has plans to complete the 230-kv interconnection loop with MEA.

In December 1978, GVEA decided to postpone development of their proposed Healy II steam turbine system (104 MW) until more favorable economic conditions prevail.

A unit by unit breakdown of planned generating systems is presented in the appended Battelle report, table 3.8.

PART V. POWER REQUIREMENTS

Introduction

This summarizes the analyses of historic data and estimates of future needs in the power market areas. The study examines in detail electric utility statistics 1970 to 1977 with special effort to identify changes in use patterns related to conservation measures since the 1973 oil embargo.

Estimates of future utility power needs are derived from estimates of individual energy use and area population. Population projections were developed by the University of Alaska, Institute of Social and Economic Research (ISER). The individual use forecast was estimated by assumed conservation-induced changes in kwh/capita growth rates. The end results are forecasts of net generation (kwh) and peak load demand (kw).

The three energy use sectors analyzed in this study are:

Utility - Includes all utilities which serve residential and commercial/industrial customers.

National Defense - Includes all military installations.

Self-Supplied Industry - Includes limited number of heavy industries, i.e., natural gas and oil processing industries on the Kenai Peninsula which generate their own power. The study assumes that these industries will purchase energy if it becomes economically feasible. Some have interchange agreements with local utilities.

Evaluations of monthly energy distribution and installed capacity requirements are included and are premised on characteristics of area power demands.

Data

This presents the basic parameters used in the analyses leading to the Susitna Power Market forecast assumptions.

The historical data summarizes the Anchorage-Cook Inlet and Fairbanks-Tanana Valley areas which comprise the Railbelt area. Each area is divided into utility, national defense, and self-supplied industrial components (Fairbanks-Tanana Valley area has no known significant self-supplied industries).

The utility component is divided into four sectors: Residential, Commercial-Industrial, Total Sales, and Net Generation.

Data was collected from utility and industry reports to various government agencies, from utilities directly, from Alaska military commands, by correspondence with industry, and from various statistical publications and news media.

Basic data needed for the 1970-1977 analysis are presented on tables 2, 3, and 4 included is utility annual energy and customers for each sector, national defense and industrial annual energy consumption, utility and national défense annual peak load, industrial installed capacity, annual population, and average annual employment. In addition, utility net generation, listed on tables 5 and 6, was compiled for the 1960-1977 period.

As part of the forecasting foundation, the following historical chronology indicates fluctuations affecting Railbelt energy use.

1970. Uncertainty concerning the oil pipeline design, construction, and approval. Native land claims legislation pending. Above average temperature.

1971. Uncertainty concerning pipeline. Below average temperature.

1972. Uncertainty concerning pipeline. Coldest year of period.

1973. Start of fuel crisis and conservation publicity in December. Below average temperature.

1974. Start of pipeline construction. Near average temperature.

1975. Peak of pipeline construction activity. Near average temperature.

1976. Start of pipeline construction "wind-down." Electric power cable across Knik Arm out of service for an extended period (all but one circuit). Above average temperature.

1977. Oil started flowing in pipeline. Warmest year of period. Residential construction boom in Anchorage. Large increase in non-residential authorizations issued.

Table 2
BASIC POWER AND ENERGY FORECASTING DATA
ANCHORAGE-COOK INLET AREA (INCLUDING SEWARD)

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation (GWH)		
Year	Resi.	Comm./Indu.	Total 1/	Utility 2/	Nat. Def. 3/	Indu.
1970	310.5	342.3	678.7	744.1	156.2	1.65
1971	369.7	393.9	792.5	886.9	161.2	
1972	421.6	454.0	911.6	1,003.8	166.5	45.3
1973	459.5	514.8	1,012.2	1,108.5	160.6	
1974	496.1	552.8	1,087.4	1,189.7	155.1	45.3
1975	595.1	631.9	1,270.6	1,413.0	132.8	
1976	677.6	738.7	1,462.2	1,615.3	140.3	
1977	741.0	813.4	1,600.8	1,790.1	130.6	69.5

	Utility Customers			Peak Load (MW)		
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu. 4/
1970	39,271	5,230	45,042	165.2	34.6	12.3
1971	42,501	5,581	48,670	184.8		
1972	46,724	6,104	53,278	212.8	33.9	12.3
1973	49,307	6,491	56,280	229.9		
1974	52,585	6,798	59,893	257.2	32.6	12.3
1975	56,801	7,478	64,797	345.8		
1976	61,881	8,220	70,622	349.9		
1977	68,320	9,221	78,066	423.9	40.5	24.8

	Population		Employment
	Civilian	Total	Avg. Annual
1970	135,963	149,428	47,408
1971	145,108	159,046	51,092
1972	155,084	167,765	54,329
1973	160,162	174,280	57,157
1974	165,938	179,544	65,919
1975	196,320	209,049	78,786
1976	207,090	219,337	83,604
1977	222,424	234,674	88,869

1/ Excludes deliveries to national defense.
2/ Total retail sales of energy + non-revenue energy used + losses.
3/ Includes receipts from utilities, excludes deliveries to utilities.
4/ Self-supplied industrial data is installed capacity rather than peak load.

GWH = million KWH
MW = thousand KW
KW = Kilowatt

Table 3
BASIC POWER AND ENERGY FORECASTING DATA
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation (GWH)	
Year	Resi.	Comm./Indu.	Total 1/	Utility 2/	Nat. Def. 3/
1970	91.7	108.3	210.2	239.3	203.5
1971	112.4	119.8	244.3	275.5	201.4
1972	122.3	127.3	262.9	306.7	203.3
1973	134.4	139.5	282.3	323.7	200.0
1974	155.8	150.3	323.0	353.8	197.0
1975	193.0	196.3	409.2	450.8	204.4
1976	195.9	204.2	420.5	468.5	217.5
1977	200.7	221.6	442.7	482.9	206.8

	Utility Customers			Peak Load (MW)	
Year	Resi.	Comm./Indu.	Total	Utility	Nat. Def.
1970	10,364	1,721	12,268	56.3	44.4
1971	11,014	1,779	12,947	65.3	
1972	11,584	1,839	13,611	66.6	41.4
1973	11,931	1,929	14,041	72.7	
1974	12,832	2,069	15,084	87.5	40.8
1975	14,025	2,247	16,447	110.0	
1976	15,569	2,435	18,179	102.6	
1977	16,709	2,580	19,463	118.9	41.0

	Population		Employment
	Civilian	Total	Avg. Annual
1970	42,310	52,141	15,681
1971	43,188	50,585	15,817
1972	45,516	52,383	16,873
1973	45,396	52,246	16,794
1974	51,137	57,836	21,960
1975	60,884	67,011	34,451
1976	58,051(e)	63,762	34,325
1977	47,155(e)	52,155	27,385

1/ Excludes deliveries to national defense.
2/ Total sales + non-revenue use + losses.
3/ Includes receipts from utilities, excludes deliveries to utilities.
4/ Self-supplied industrial data is installed capacity rather than peak l

GWH = million KWH
MW = thousand KW

Table 4
BASIC POWER AND ENERGY FORECASTING DATA
RAILBELT AREA

Upper Susitna Project Power Market Analysis

Year	Utility Energy Sales (GWH)			Net Generation (GWH)			
	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu.	Total
1970	402.2	450.6	888.9	983.4	359.7	1.6	1,344.7
1971	482.1	513.7	1,036.8	1,162.4	362.6	25(e)	1,550.0
1972	543.9	581.3	1,174.5	1,310.5	369.8	45.3	1,725.6
1973	593.9	654.3	1,294.5	1,432.2	360.6	45.3(e)	1,838.1
1974	651.9	703.1	1,410.4	1,543.5	352.1	45.3	1,940.9
1975	788.1	828.2	1,679.8	1,863.8	337.2	45.3(e)	2,246.3
1976	873.5	942.9	1,882.7	2,083.8	357.8	45.3(e)	2,486.9
1977	941.7	1,035.0	2,043.5	2,273.0	337.4	69.5	2,679.9

Year	Utility Customers			Peak Load (MW)			
	Resi.	Comm./Indu.	Total	Utility	Nat. Def.	Indu.	Total
1970	49,635	6,951	57,310	221.5	79.0	12.3	312.8
1971	53,515	7,380	61,617	250.1	77(e)	12.3(e)	3[illegible]4
1972	58,308	7,943	66,889	279.4	75.3	12.3	36[illegible].0
1973	61,238	8,420	70,321	302.6	74(e)	12.3(e)	388.9
1974	65,417	8,867	74,977	344.7	73.4	12.3	430.4
1975	70,826	9,725	81,244	455.8	73(e)	12.3(e)	541.1
1976	77,450	10,654	88,801	452.5	76(e)	12.3(e)	540.8
1977	85,029	11,801	97,529	542.8	81.5	24.8	649.1

Year	Total Population	Avg. Annual Employment
1970	201,569	63,089
1971	209,631	66,909
1972	220,148	71,202
1973	226,526	73,951
1974	237,380	87,879
1975	276,060	113,237
1976	283,099	117,929
1977	286,829	116,254

Table 5
NET GENERATION (GWH)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis
(Includes receipts of electric energy from military; excludes electric energy deliveries to military)

Year	AML&P	CEA	APA	MEA	HEA	KU	SES	Total	Growth %
1960	0.8	27.5	187.6	0.1	8.2	1.8	5.7	231.6	
1961	3.2	44.8	193.8	0.1	3.6	2.0	6.2	253.7	9.5
1962	20.0	101.8	150.3	0.2	0	2.3	3.7	278.2	9.7
1963	55.7	100.5	152.7	0.2	0	2.7	0	311.8	12.1
1964	97.3	94.5	146.1	0.5	1.2	3.8	0	343.4	10.1
1965	101.2	167.4	132.1	0.6	1.4	4.1	0	406.8	18.5
1966	108.6	204.6	138.2	0.7	1.4	5.2	0	458.7	12.8
1967	100.1	217.1	178.5	0.8	1.5	6.7	0	504.6	10.0
1968	125.3	280.0	155.5	0.8	1.7	10.1	0	573.4	6.5
1969	148.1	314.6	158.2	0.9	2.2	8.9	0.1	633.0	17.8
1970	186.0	385.5	154.7	1.1	2.4	9.0	0.1	738.8	16.7
1971	245.3	476.6	144.9	1.3	2.7	8.0	0.1	878.9	19.0
1972	270.0	554.2	164.0	1.5	3.3	7.0	0.1	1,000.1	13.8
1973	359.0	657.3	96.3	0.3	3.6	--	0.1	1,116.5	11.6
1974	389.6	678.4	1.1	--	4.2	--	0.1	1,197.4	7.2
1975	384.3	888.8	135.1	--	3.4	--	3.2	1,414.9	18.2
1976	442.9	1,054.5	118.5	--	0.5	--	1.5	1,617.3	14.3
1977	420.3	1,179.7	203.6	--	0.5	--	0.8	1,804.9	11.5

AML&P - Anchorage Municipal Light and Power
CEA - Chugach Electric Association
APA - Alaska Power Administration
MEA - Matanuska Electric Association
HEA - Homer Electric Association
KU - Kenai Utilities
SES - Seward Electric System

Table 6
NET GENERATION (GWH)
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis
(Includes receipts of electric energy from military;
excludes electric energy deliveries to military)

Year	FMU	GVEA	AP&T	DLE	NP&L	Total	Growth %
1960	36.7	24.4	--	0.1	0.6	61.8	
1961	38.8	29.4	--	0.1	0.6	68.9	11.5
1962	42.3	33.3	1.	0.1	0.6	77.2	12.1
1963	45.4	39.1	1.2	0.1	0.6	86.4	11.9
1964	48.4	53.6	1.5	0.1	0.6	104.2	20.6
1965	49.5	56.6	1.8	0.1	0.6	108.6	4.2
1966	52.6	67.0	2.1	0.1	0.6	122.4	12.7
1967	55.9	75.9	2.0	0.2	0.6	134.6	10.0
1968	64.0	97.9	2.0	0.2	0.6	164.7	22.4
1969	72.2	118.1	2.1	0.2	0.6	193.3	17.4
1970	85.6	150.2	1.9	0.2	0.6	238.6	23.4
1971	106.7	164.9	2.4	0.2	0.6	274.7	15.1
1972	120.3	182.2	2.6	0.2	0.8	306.1	11.4
1973	115.4	202.2	2.7	0.2	0.9	321.4	5.0
1974	123.0	214.3	3.5	0.2	1.2	342.1	6.4
1975	137.2	286.9	3.9	0.2	1.6	429.7	25.6
1976	139.6	315.1	4.2	0.2	1.4	460.4	7.1
1977	133.5	346.3	4.5	0.2	1.4	485.8	5.5

FMU - Fairbanks Municpal Utilities
GVEA - Golden Valley Electric Association
AP&T - Alaska Power and Telephone (Tok)
DLE - Dot Lake Electric (Purchased by AP&T in 1978)
NP&L - Northway Power and Light

Analysis

Detailed investigations of relationships among the basic data components are listed in tables 2, 3, and 4. Analysis was done separately for each major sector (utility, national defense, and self-supplied industry) within each geographic area.

Utility

The analysis of utility data set out to develop assumptions for forecasting net generation and peak load. Investigations evaluated the impact of changes in population, employment, customers, weather, tariffs, and other events upon energy use. These evaluations then helped to: (1) determine if energy sectors (residential, commercial-industrial, total sales) other than net generation needed to be forecast; (2) determine which energy ratio (kwh/capita, kwh/employee, kwh/customer) to use in the forecasting procedure; (3) develop procedure for forecasting utility annual net generation from energy use assumptions and demographic parameters (population, employees, or customers); (4) determine load factor with which to calculate peak load forecast from the net generation forecast.

Constants, small amplitude cycles, or trends in relationships among the energy use and customer sectors were investigated for use as forecasting aids. If, for instance, the residential energy use/net generation ratio remained almost constant from 1970 through 1977, only net generation need be subjected to the forecasting procedure. The same type of analysis was applied to energy use ratios: a look for an average or trend to be used as a factor in forecasting net generation.

After developing the net generation forecast, the peak load forecast was calculated using energy and an assumed load factor. Analysis of historic load factors determined an average or trend from which the assumed load factor was derived. Forecasted net generation and the assumed future load factor were then used in the formula: Peak load = 8,760 hr/yr. x load factor x net generation.

The evaluations showed a mix of similarity and contrast between the two Railbelt areas. In both areas, the major energy use determinants were the trans-Alaska oil pipeline construction and the fuel crisis of 1973-74. Other correlations with weather, tariffs, etc., seemed insignificant. For instance, energy growth increased in some years despite above average temperatures which reduced energy need.

Anchorage-Cook Inlet Area Analysis Results - The foregoing evaluation procedures resulted in the following observations for the Anchorage-Cook Inlet area.

(a) Observations indicate no significant shift in energy use patterns or in share of total load among the various utility sectors (residential, etc.). The ratios among the sectors (residential/total sales; total sales/net generation, etc.) remained essentially constant through the study period. This was true for both energy and customers. Therefore, only one sector--net generation--represents all sectors in the forecast.

(b) Energy rate of growth per customer and per capita had a significant reduction after the 1973-74 fuel crisis. The 1973-77 per capita average growth rate was about half that for 1970-73. It appears that conservation can be considered an influence after 1973.

(c) Events impinging upon energy use are listed in the previous section. Between 1973 and 1977, several events bear repeating for emphasis: fuel crisis in 1974; start of pipeline construction in 1974; peak pipeline activity in 1975; decrease of pipeline activity in 1976 and 1977; cables across Knik Arm, which carry a large share of Anchorage energy, went out of service in 1976; warmer than average weather in 1974, 1976, and especially 1977. Yearly growth rates reflected rather large fluctuations as different historical events influenced each parameter. (This is a recurring phenomenon in Alaskan history).

(d) Parameters were not influenced alike as figures 3 through 8 attest. For instance, customer growth reacted to events in a steadier pattern than did population and employment. Reasons for this are more people per customer and time needed for connecting more customers to a utility system at the initial onslought of large demographic growth.

(e) Comparing the energy fluctuations with others, such as population and employment, gave a measure of correlation between parameters. (The energy use and customer growth fluctuations correlated only in part; their patterns did not coincide every year). However, energy and population growth rate changes were coincidental for every year but 1977. That is, when the energy growth rate increased, so did the population growth rate; when the population growth rate decreased, so did the energy growth rate.

(f) Energy use and weather comparisons were inconclusive. Warm weather did not bring corresponding reduction in energy use. Cold weather increases in energy use were buried in other events (pipeline construction, etc.).

(g) Because the net generation kwh/capita ratio seemed to reflect the closest correlations, particularly in recent years, this ratio and population were used to forecast net generation values between 1980 and 2025.

(h) Values basic to the forecasting assumptions are the kwh/capita ratio averaging 3.8 percent average annual growth between 1973 and 1977 and net generation averaging 12.7 percent.

(i) Average annual growth results are summarized on table 7. Figures 3, 4, and 5 are graphs of pertinent elements of the analysis.

Fairbanks-Tanana Valley Area Analysis Results - Some of the Anchorage-Cook Inlet area evaluation results apply also to the Fairbanks-Tanana Valley area, others do not. The following observations parallel those of Anchorage-Cook Inlet.

(a) No significant shift in energy use patterns or in share of total load among the various utility sectors (residential, etc.). Again, only one sector--net generation--need be forecast.

(b) Energy growth was similar to that of Anchorage (somewhat smaller in the pre-1973 period); but customer, population, and employee growth were different in the two areas. Consequently, the energy use per customer, per capita, and per employee ratios indicate different growth patterns in Fairbanks. The large swings of employment and population in Fairbanks during pipeline construction compared to almost constant preconstruction values cloud comparisons of the two periods.

(c) Although the effects of pipeline construction are evident, the population/employee ratio (2.29 average through the study period) was constant enough to indicate that either population or employment can be used as a forecasting parameter.

(d) The effects of weather on energy use could not be detected. In some years, degree day variations were not in phase with energy use variations.

(e) Energy use/capita exhibited wider variations than the other two ratios, but, nevertheless, had the nearest to constant average annual growth rates. Because of this and the other observations, net generation kwh/capita and population were used to forecast net generation.

(f) As in the Anchorage-Cook Inlet area, values basic to the forecasting assumptions are the net generation/capita growth, averaging 10.6 percent per year, and net generation growth, averaging 10.5 percent per year between 1973 and 1977.

(g) Growth rate results are summarized on table 7. Figures 6, 7, and 8 are graphs of some pertinent elements of the analysis.

Table 7
AVERAGE ANNUAL UTILITY GROWTH SUMMARY
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

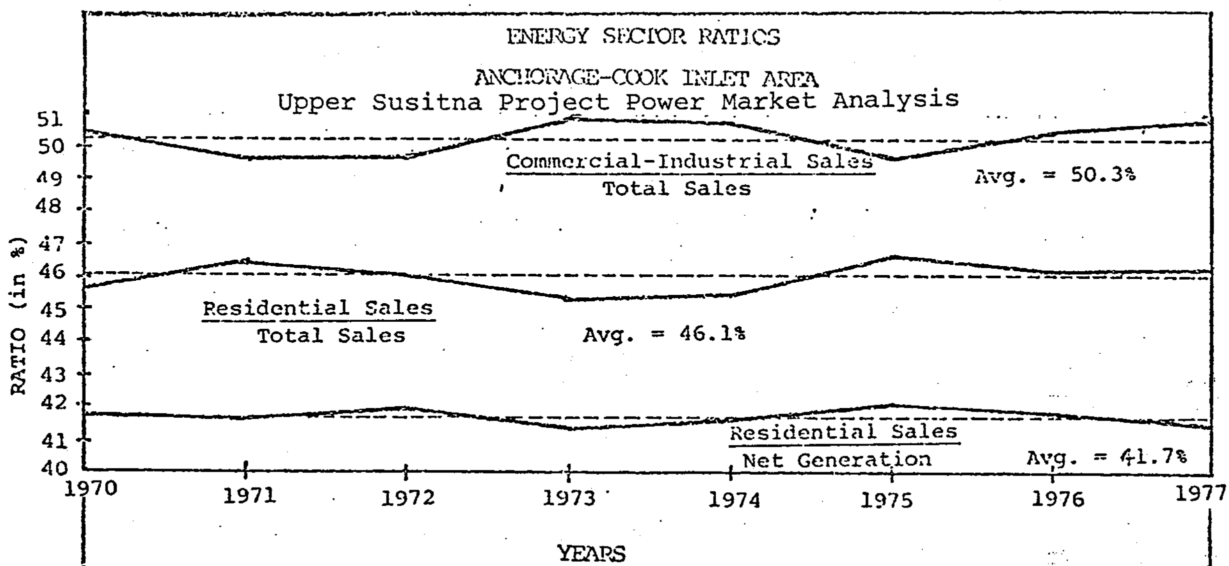
	1970	1973	1977	Avg. Growth 1970-1973	Avg. Growth 1973-1977
Energy GWH					
Residential Sales	310	460	741	14.0%	12.6%
Commercial/Industrial	342	515	813	14.7	12.1
Total Sales	679	1,012	1,601	14.2	12.1
Net Generation	744	1,108	1,790	14.2	12.7
Energy Use, kwh/Customer					
Residential	7,907	9,319	10,846	5.6	3.8
Commercial/Industrial	65,449	79,310	88,212	5.6	2.6
Total Sales	15,068	17,985	20,506	6.0	3.3
Energy Use, kwh/Capita					
Residential	2,284	2,869	3,332	8.0	3.8
Commercial/Industrial	2,518	3,214	3,657	8.6	3.3
Total Sales	4,992	6,320	7,197	8.3	3.3
Net Generation	5,473	6,921	8,048	8.0	3.8

Fairbanks-Tanana Valley Area

	1970	1973	1977	Avg. Growth 1970-1973	Avg. Growth 1973-1977
Energy GWH					
Residential Sales	92	134	201	13.4%	10.7%
Commercial/Industrial	108	140	222	9.1	12.2
Total Sales	210	282	443	10.2	11.9
Net Generation	239	324	483	10.8	10.5
Energy Use, kwh/Customer					
Residential	8,852	11,262	12,010	8.3	1.7
Commercial/Industrial	62,931	72,303	85,899	4.8	4.4
Total Sales	17,134	20,104	22,746	5.4	3.1
Energy Use, kwh/Capita					
Residential	1,759	2,572	3,848	13.5	10.6
Commercial/Industrial	2,077	2,670	4,249	8.7	12.3
Total Sales	4,031	5,403	8,488	10.3	12.0
Net Generation	4,589	6,196	9,259	10.5	10.6

APA 11/78

Figure 3


ENERGY SECTOR RATIOS
ANCHORAGE-COOK INLET AREA
Upper Susitna Project Power Market Analysis
Commercial-Industrial Sales / Total Sales
Avg. = 50.3%
Residential Sales / Total Sales
Avg. = 46.1%
Residential Sales / Net Generation
Avg. = 41.7%
RATIO (in %)
51
50
49
48
47
46
45
44
43
42
41
40
1970
1971
1972
1973
1974
1975
1976
1977
YEARS

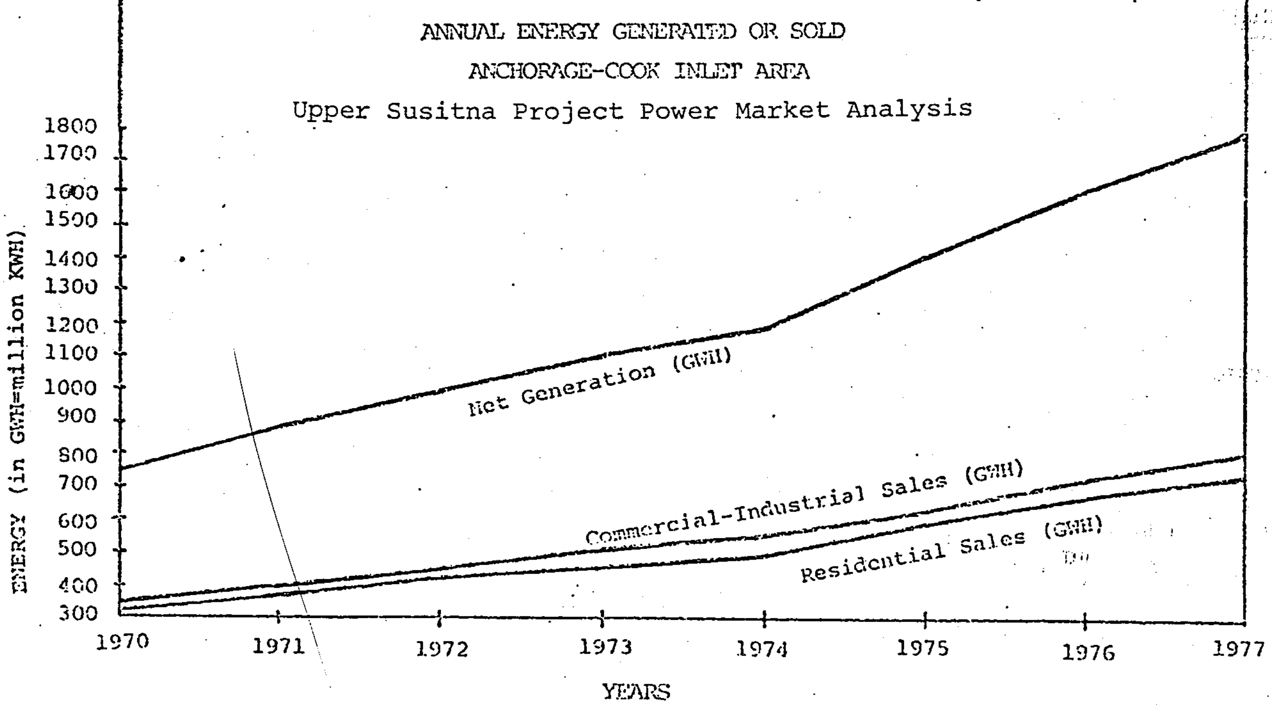

ANNUAL ENERGY GENERATED OR SOLD
ANCHORAGE-COOK INLET AREA
Upper Susitna Project Power Market Analysis
Net Generation (GWH)
Commercial-Industrial Sales (GWH)
Residential Sales (GWH)
ENERGY (in GWH=million KWH)
1800
1700
1600
1500
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
1970
1971
1972
1973
1974
1975
1976
1977
YEARS

Figure 4

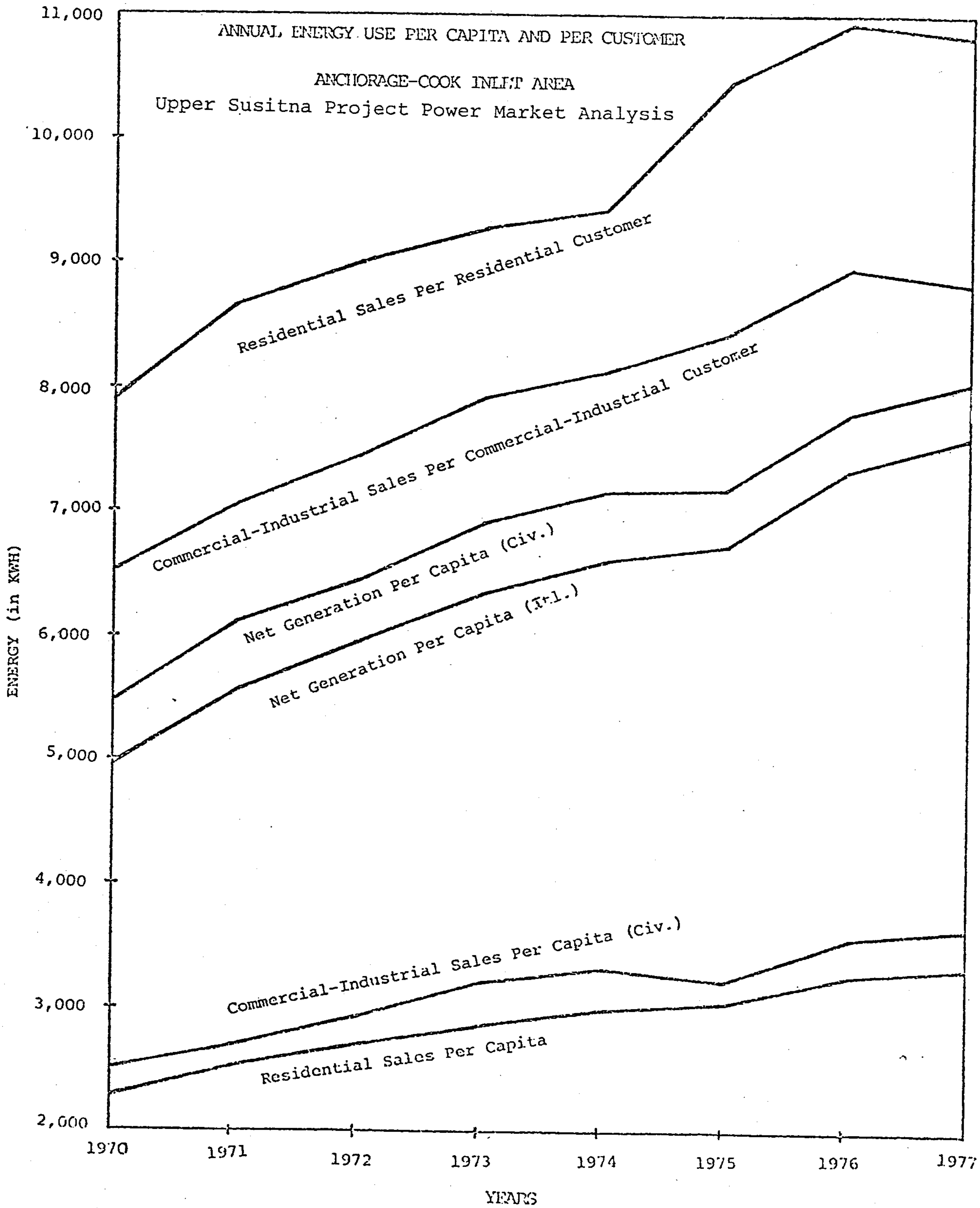


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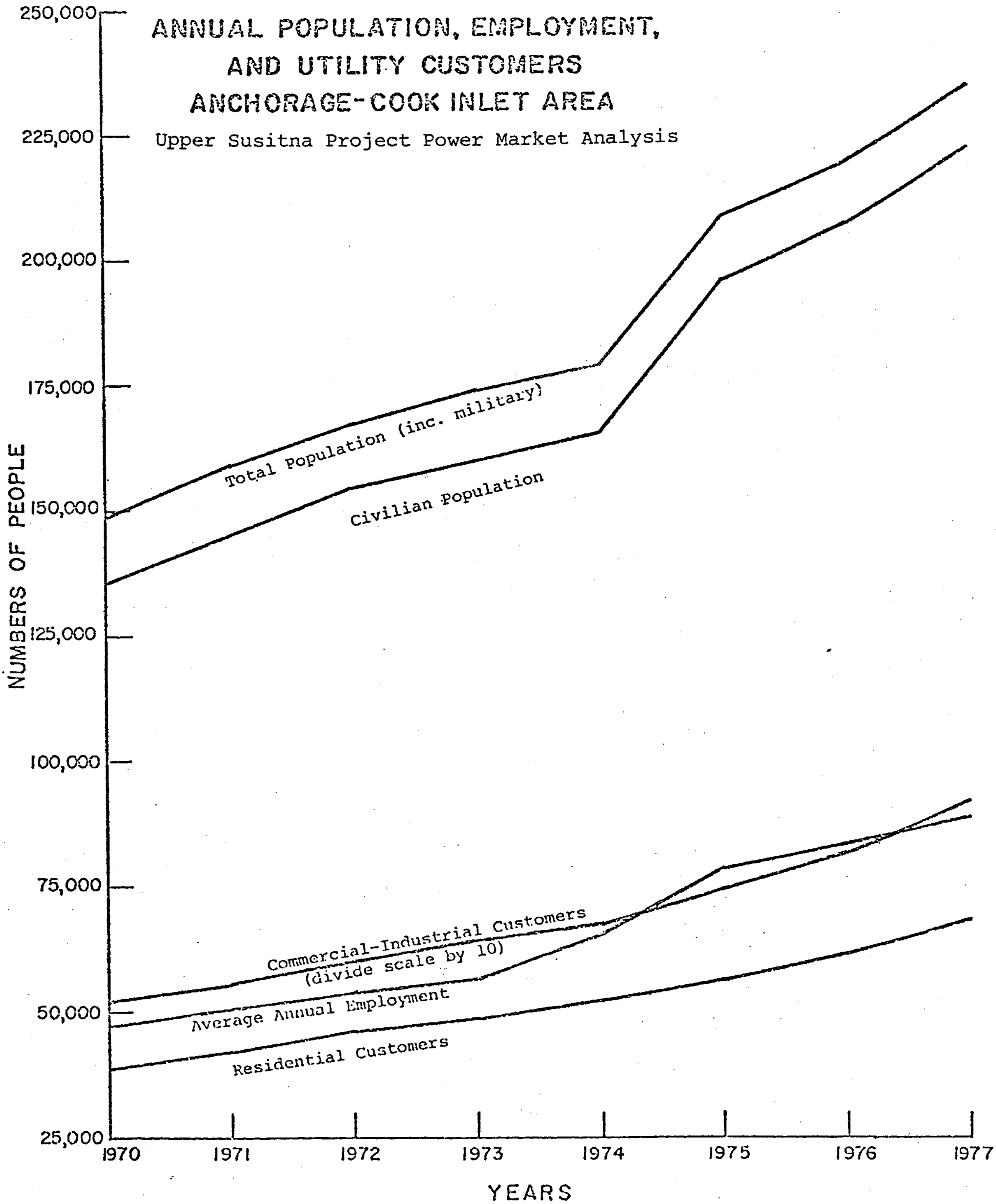
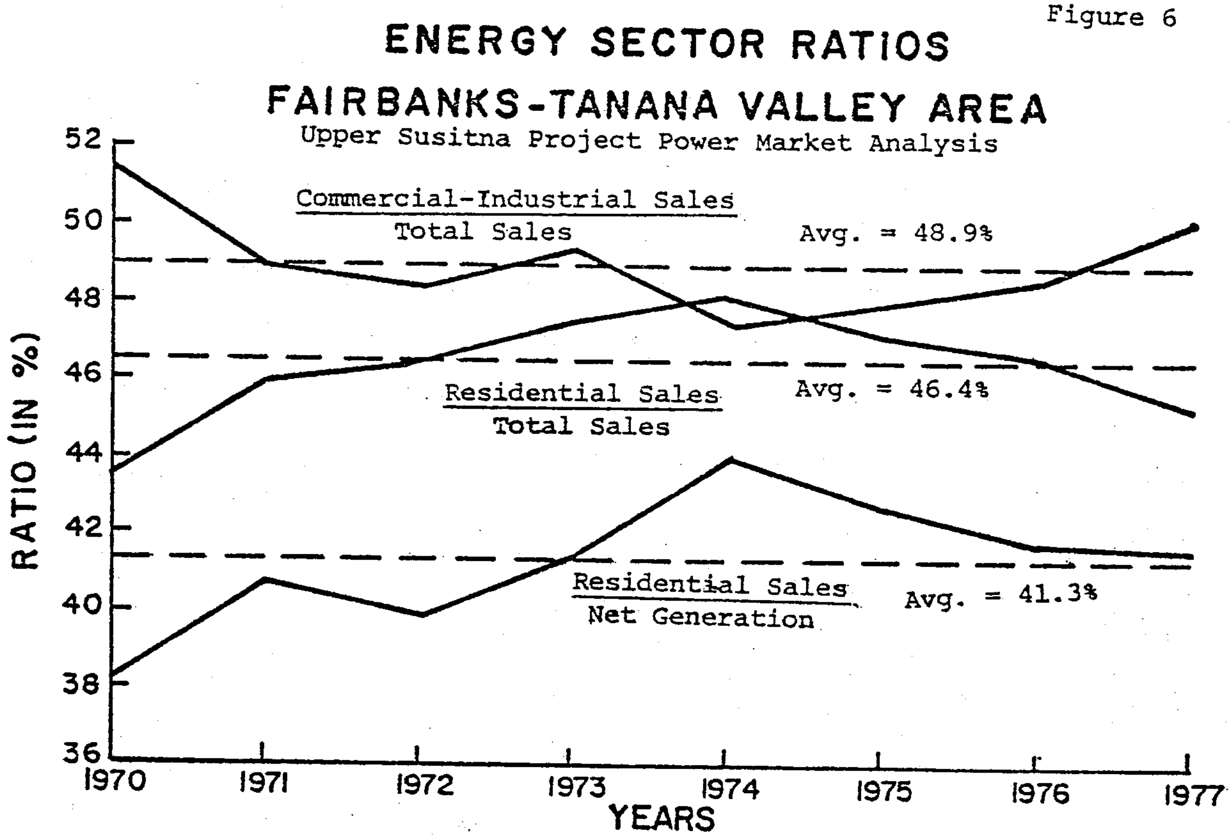
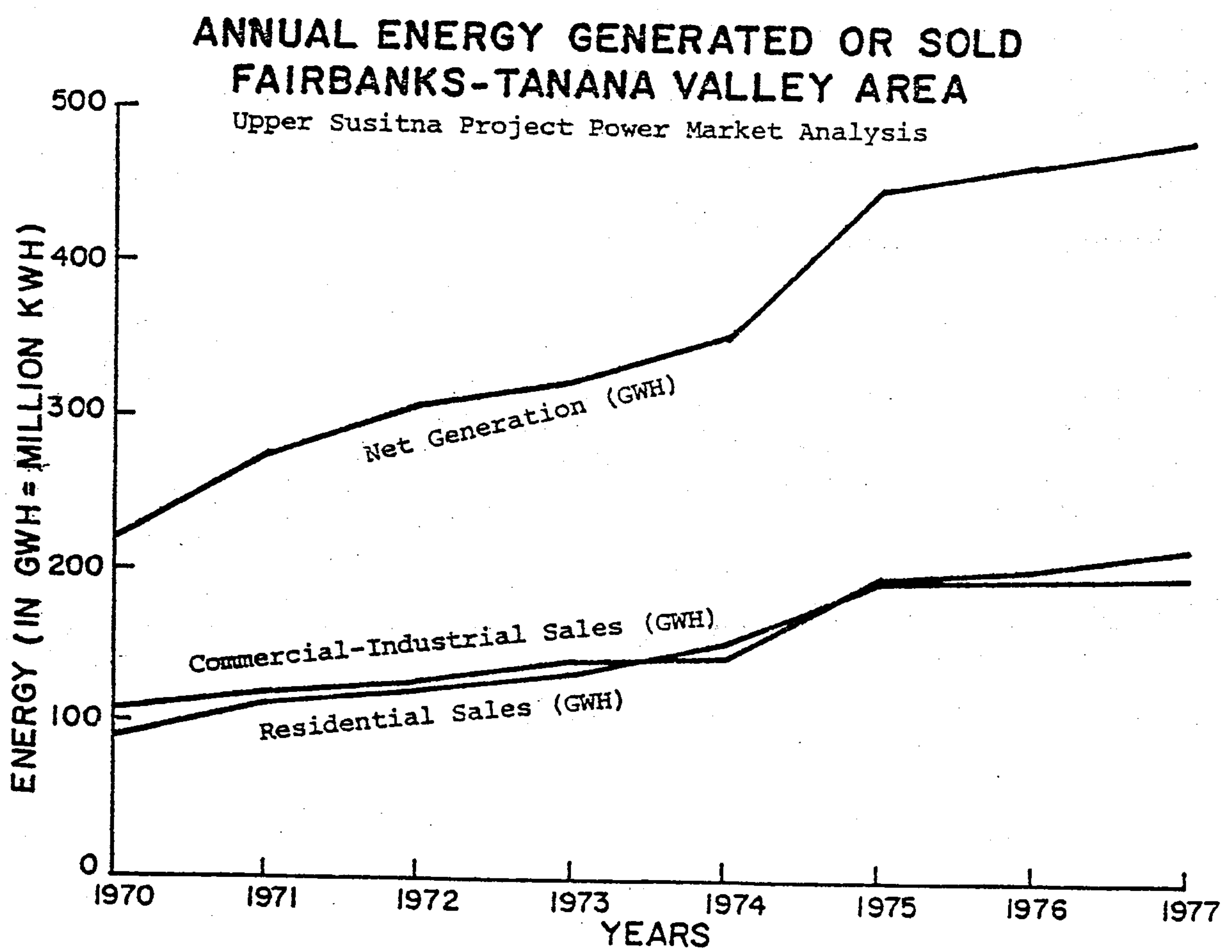
Figure 5


ANNUAL POPULATION, EMPLOYMENT,
AND UTILITY CUSTOMERS
ANCHORAGE-COOK INLET AREA
Upper Susitna Project Power Market Analysis
250,000
225,000
200,000
175,000
150,000
125,000
100,000
75,000
50,000
25,000
NUMBERS OF PEOPLE
Total Population (inc. military)
Civilian Population
Commercial-Industrial Customers
(divide scale by 10)
Average Annual Employment
Residential Customers
1970
1971
1972
1973
1974
1975
1976
1977
YEARS


ENERGY SECTOR RATIOS
FAIRBANKS-TANANA VALLEY AREA
Upper Susitna Project Power Market Analysis
Commercial-Industrial Sales / Total Sales
Avg. = 48.9%
Residential Sales / Total Sales
Avg. = 46.4%
Residential Sales / Net Generation
Avg. = 41.3%
RATIO (IN %)
52
50
48
46
44
42
40
38
36
1970
1971
1972
1973
1974
1975
1976
1977
YEARS


ANNUAL ENERGY GENERATED OR SOLD
FAIRBANKS-TANANA VALLEY AREA
Upper Susitna Project Power Market Analysis
Net Generation (GWH)
Commercial-Industrial Sales (GWH)
Residential Sales (GWH)
ENERGY (IN GWH = MILLION KWH)
500
400
300
200
100
0
1970
1971
1972
1973
1974
1975
1976
1977
YEARS

ANNUAL ENERGY USE PER CAPITA AND PER CUSTOMER FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

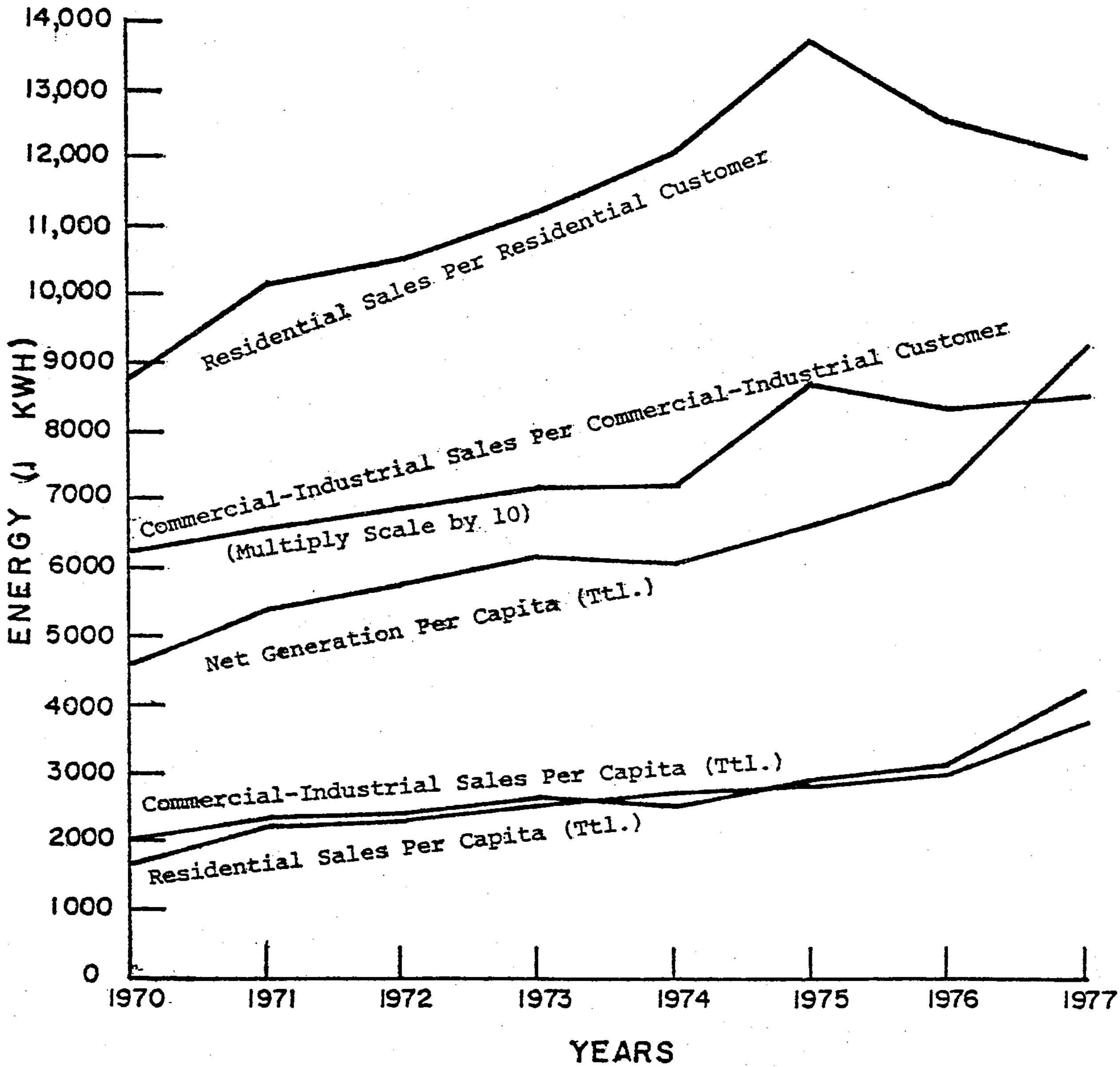
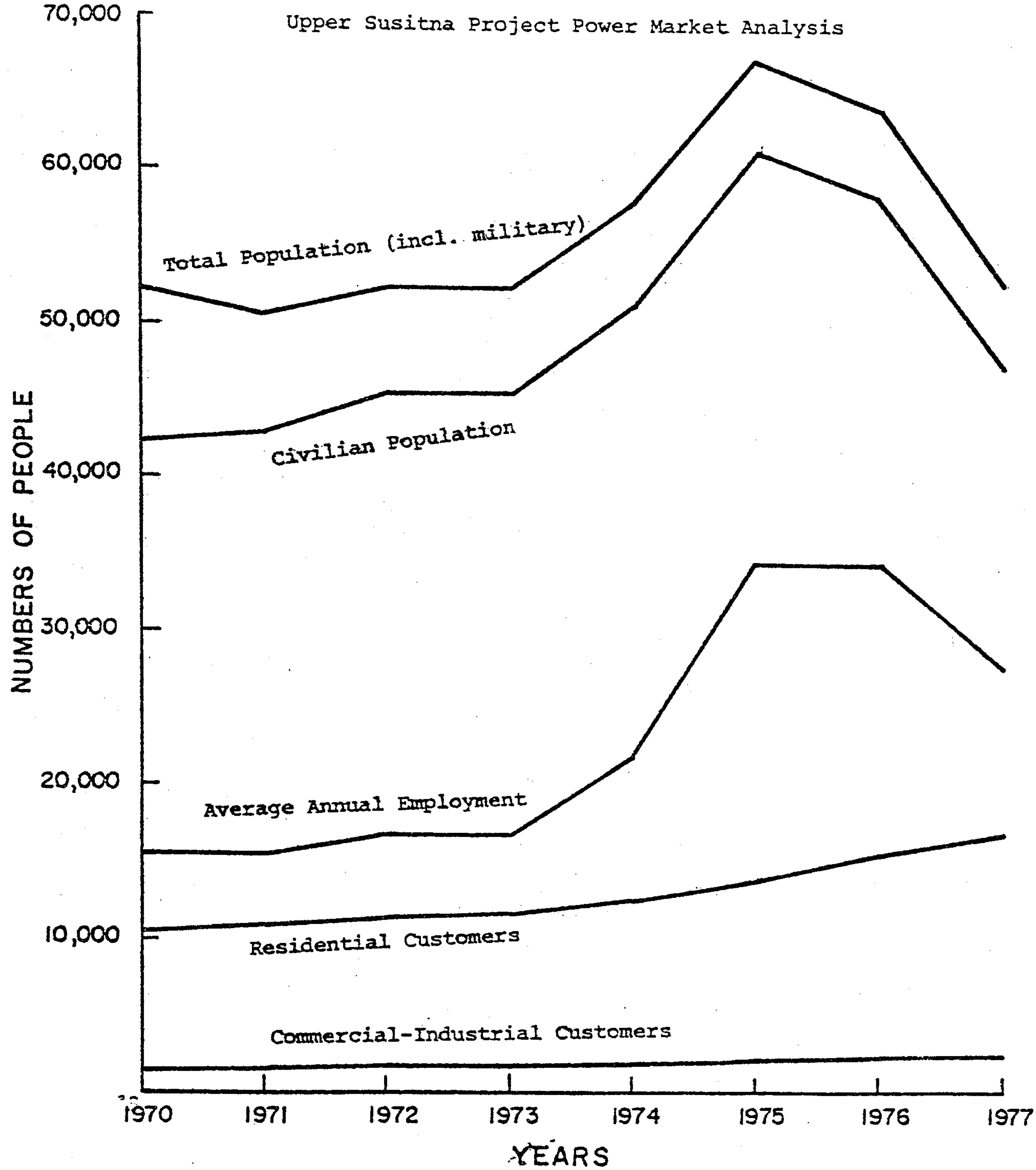


Figure 8

ANNUAL POPULATION, EMPLOYMENT, AND UTILITY CUSTOMERS FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis



National Defense

Evaluation of historical national defense data resulted in net generation and peak load averages. The analysis encompassed the U.S. Army and Air Force installations in the Anchorage and Fairbanks areas. No definite trends surfaced--only a small, cyclic decrease in the Anchorage area net generation and an increase in peak load. In the Fairbanks area, net generation increased slightly and peak load decreased. Total national defense is about 15 percent of utility for both net generation and peak load.

Self-Supplied Industry

Railbelt industry and the upper Kenai Peninsula complex showed no significant change in capacity and energy generation until 1977 when the chemical plant expanded. Therefore, the analysis consisted of a plant factor determination only. Other factors needed in forecasting are discussed as assumptions in the next section.

Energy and Power Demand Forecasts

This section presents future energy and power requirement estimates developed from the previous analyses. Work for the new estimates consisted of: (1) using the analyses to obtain forecasting assumptions; (2) using the assumptions in forecasting utility net generation/capita; (3) combining net generation/capita with Institute of Social and Economic Research (ISER) population projections to obtain the utility net generation forecast, and forecasting national defense and industry generation from pertinent assumptions; and (4) combining the net generation forecast with load factors resulting from the historical data analysis to obtain peak load (power requirement) forecasts.

Assumptions and Methodology

Population - The ISER econometric model of the Southcentral Region Water Study (Level B) furnished high and low range population forecasts. The model disaggregated the Anchorage-Cook Inlet area from a statewide population forecast. No recent, applicable forecast of Fairbanks-Tanana Valley population was available; therefore, APA assumed statewide growth rates from the ISER model applied to the Fairbanks-Tanana Valley areas. (See table 8).

Utility - Assumptions, based on the preceding analyses, lead to the net generation and peak load forecast. Net generation is the product of forecasted energy use per capita and projected population. Peak load demand is derived from net generation and the assumed utility load factor. Multiplying these growth rates by forecasted 1980 values of kwh/capita resulted in the energy use estimates.

Table 8
POPULATION ESTIMATES

1980-2025
RAILBELT AREA

Upper Susitna Project Power Market Analysis

Year	Anchorage-Cook Inlet 1/		Statewide 1/		Fairbanks-Tanana Valley 2/	
	High	Low	High	Low	High	Low
1980	270,200	239,200	513,766	500,225	62,020	60,390
1985	320,000	260,900	640,718	563,303	77,350	68,010
1990	407,100	299,200	790,042	618,397	95,370	74,660
1995	499,200	353,000	947,312	680,286	114,360	82,130
2000	651,300	424,400	1,157,730	743,034	139,760	89,700
2025	904,000	491,100	1,484,784	820,369	179,240	99,040

Notes: * No mid-range estimates are shown because, when the forecasts were done, ISER 1/ had made only the high and low projections. A comparison of the mid-range forecast already performed (see text for method) with one using the mid-range population, when received, indicated no reason to re-do the forecasts.

* Values shown include national defense population

1/ From Iser, Southcentral Alaska's Economy and Population: A base Study 1965-2025. September 1978 with December 1978 revisions.

2/ Calculated from statewide growth rates.

Since the ratios of residential, commercial-industrial, and total sales energy to net generation remain constant, net generation is assumed to be an appropriate forecasting parameter. The evaluations indicated that the other sectors do not need individual forecasting.

The basic energy use (net generation kwh/capita) assumption for the entire Railbelt area is a 3.5 percent average annual, mid-range, 1980-85 growth rate. It is based on the Anchorage-Cook Inlet area value of 3.8 percent annual growth from 1973-77 and an assumed continuation of the post-1973 conservation[1/] trend. As mentioned in the Anchorage-Cook Inlet area evaluations, a conservation trend was apparent when comparing energy use growth rates for 1973-77 and 1970-73 (see table 7). Tied to this is the assumption of gradually increasing effectiveness of future conservation programs coupled with perhaps upper limits of electric energy use. These are reflected in an average annual growth by the year 2000 or 2 percent for high range, 1 percent for mid-range, and 0 percent for low range. These assumptions result in decreased growth rates for each five-year increment, as shown below:

Time Period	High	Mid	Low
1980-1985	4.5%	3.5%	2.5%
1985-1990	3.5%	3.0%	2.0%
1990-1995	3.0%	2.5%	1.5%
1995-2000	2.5%	2.0%	1.0%
2000-2025	2.0%	1.0%	0%

Multiplying these growth rates by forecasted 1980 values of kwh/capita resulted in the energy use estimates.

The 1980 mid-range value of kwh/capita was derived from the 1973-1977 average annual growth of net generation. The 1980 net generation was estimated. The Anchorage-Cook Inlet mid-range assumption of 12 percent annual load growth rate for 1977-80 net generation came from a historical 12.7 percent. The respective Fairbanks-Tanana Valley values were 10.5 percent assumed, 10.6 percent historical. Mid-range 1980 kwh/capita was calculated using the estimated net generation and projected population. The 1980 high and low range average annual kwh/capita growth rates for Fairbanks-Tanana Valley were assumed 120 percent and 80 percent of the calculated mid-range value respectively. Comparable values for Anchorage-Cook Inlet were 130 percent and 80 percent. The differences between the two areas reflect population estimates and an attempt to derive a reasonable 1977-80 transition period coupled with the population estimates.

Peak load (MW) forecasts were calculated using a 50 percent load factor. Anchorage-Cook Inlet area load factor averaged 51.9 percent between 1970 and 1977 and 51.0 percent between 1973 and 1977. Fairbanks area averaged 48.9 percent and 48.4 percent in the same periods.

1/ Conservation here includes results of the fuel crisis and perhaps of nationwide publicity on the need for saving energy. Other factors may be involved, but no other events are as coincidental with reduced energy use as is the fuel crisis.

National Defense - Historical data from Army and Air Force installations in the Anchorage and Fairbanks areas indicate reasonable energy assumptions to be:

1. 0 percent annual growth for mid-range forecast, 1 percent for high range, and -1 percent for low range.

2. A 50 percent load factor was assumed for use with energy (net generation) to obtain peak load.

Self-Supplied Industries - The following assumptions were developed from existing data and conditions, consultations with many knowledgeable people in government and industry, and from reports on future developments.

1. Industries will purchase power and energy if economically feasible.

2. Forecast based on listing in the March 1978 Battelle report.

3. High range includes existing chemical plant, LNG plant, and refinery as well as new LNG plant, refinery, coal gasification plant, mining and mineral processing plants, timber industry, city and aluminum smelter or some other large energy intensive industry.

4. Mid-range includes all of the above except the aluminum smelter.

5. Low range includes all listed under high range except the aluminum smelter and the new capital.

6. In some instances, high, mid, and low range may be differentiated by amount of installed capacity as well as the type of installations assumed.

7. No self-supplied industries are assumed for the Fairbanks-Tanana Valley area. Any industrial growth has been assumed either (1) included in utility forecasts or (2) not likely to be interconnected with the area power systems.

8. Net generation forecast calculated from forecasted capacity and a plant factor of 60 percent.

The ISER model assumed the following Cook Inlet area industrial scenario. It is compared to industries assumed for the self-supplied industrial forecasts of this report.

Cook Inlet Industrial Scenarios
Assumptions

ISER	Self-Supplied Industries Forecast
HIGH RANGE	
Oil treatment and shipping facilities	Existing refinery (2.4 MW)
Small LNG	Existing LNG plant (.4 to .6 MW)
Beluga Coal (40 employees in shipping)	Coal gasification (0 to 250 MW) 2/
New capital (2,750 employees 1982-84)	New city (0 to 30 MW)
Refinery-petrochemical complex 1/	New refinery (0 to 15.5 MW)
Pacific LNG	New LNG plant (0 to 17 MW)
Bottom fish industry	
Oil lease development	Mining and mineral plants (5 to 50 MW)
No new pulp mills or sawmills	Timber (2 to 12 MW)
	Existing chemical plant (22 to 26 MW)
	Aluminum smelter or other energy intensive industry (0 to 280 MW)
MID RANGE 3/	
LOW RANGE	
Pacific LNG	New LNG plant (0 to 17 MW)
	Existing refinery (2.4 MW)
	Existing LNG plant (.4 MW)
	Existing chemical plant (22 MW)
	Coal gasification (0 to 10 MW)
	New refinery (0 to 15.5 MW)
	Mining and mineral plants (0 to 25 MW)
	Timber (2 to 12 MW)

1/ A recent decision by ALPETCO changes this to the Valdez area. The changes involved were not enough to warrant forecast revisions.

2/ Part of coal gasification could be equivalent to "Beluga Coal," but it is much more than "40 employees in shipping."

3/ At the time this forecast and analysis was performed, no ISER mid-range projections of populations and employment had been developed.

Estimate of Future Demands

Using the high and low population projections and high, mid, and low kwh/capita assumptions, six different net generation utility forecasts were obtained. From these, the high population/high energy use and the low population/low energy use were used for the high and low range final forecasts. The mid-range final forecast came from averaging the high population/low energy use and the low population/high energy use forecasts. In lieu of a mid-range net generation based on a mid-range population projection, these last two forecasts were enough alike to justify the average as mid-range net generation.

Near the completion of this analysis, ISER provided APA with a mid-range population projection. Comparing the previous results with forecasts using these mid-range projections, APA concluded that the two were consistent and that no changes were necessary.

National defense and self-supplied industrial forecasts were calculated from the assumptions and summarized with the utilities on table 10 for the Anchorage-Cook Inlet area and table 11 for the Fairbanks-Tanana Valley area. Railbelt totals, both peak load demand and net generation, are summarized on table 12. Appropriate graphs follow each table on figures 9 and 10 for Anchorage-Cook Inlet, 11 and 12 for Fairbanks-Tanana Valley, and 13 and 14 for the Railbelt totals.

Trend lines based on 1973-1977 average annual energy growth are superimposed on the energy graphs, figures 9, 11, and 13.

1973-1977 Average Annual Growth

Anchorage-Cook Inlet	10.9%
Fairbanks-Tanana Valley	7.1%
Railbelt	9.9%

Historical and forecast energy use comparisons are summarized in table 9.

Comparison with Other Forecasts

This section compares the present forecast (1978) with two previous forecasts, and forecasts available from various utilities.

The previous forecasts included the 1976 report and its 1977 update. The 1977 update used 1975 criteria and assumptions. See table 13 for a comparison tabulation. In general, the present forecasts produced values less than the previous ones.

Table 9
NET ANNUAL PER CAPITA GENERATION (KWH)
RAILBELT AREA UTILITIES

Upper Susitna Project Power Market Analysis

	1970	1977	1990	2000	2025
			Anchorage-Cook Inlet Area		
Historical	4980	7630			
High			16,300	21,400	35,100
Mid			14,000	17,500	22,400
Low			12,000	13,600	13,600
			Fairbanks-Tanana Valley Area		
Historical	5655	10,240			
High			18,400	24,000	39,000
Mid			16,300	20,300	26,000
Low			14,100	15,800	15,900

APA 11/78

Energy use per capita nearly doubled in both areas in the historical seven years. Growing use of electric space heating, electric cooking in place of gas and oil, and many other possibilities can justify the assumptions shown. Again, conservation has been factored in through decreasing growth rates.

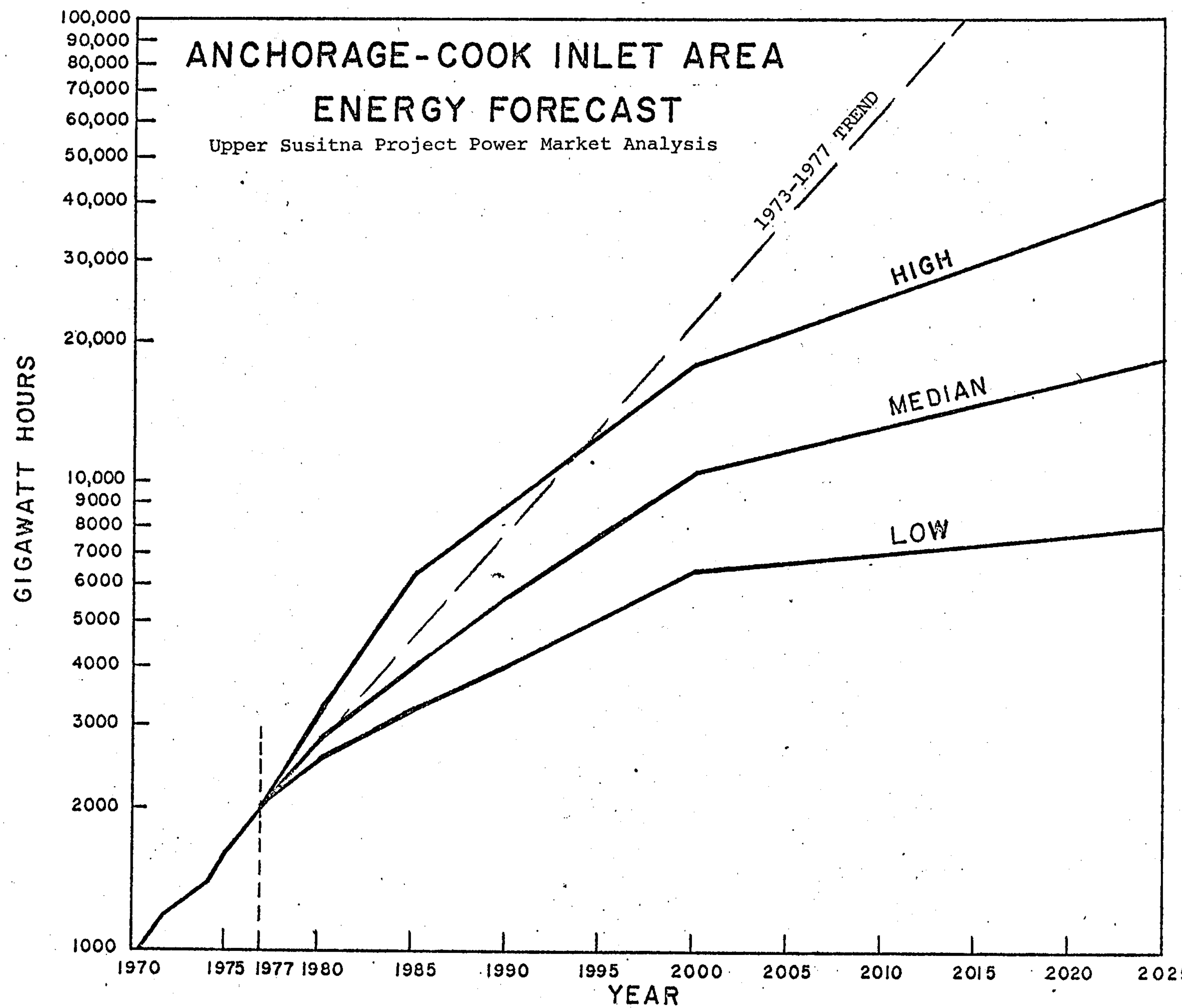
Table 10

POWER AND ENERGY REQUIREMENTS
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

PEAK POWER	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY									
High				620	1,000	1,515	2,150	3,180	7,240
Mid	165	230	424	570	810	1,115	1,500	2,045	3,370
Low				525	650	820	1,040	1,320	1,520
NATIONAL DEFENSE									
High				31	32	34	36	38	48
Mid	35	33	41	30	30	30	30	30	30
Low				29	28	26	24	24	18
INDUSTRIAL									
High				32	344	399	541	683	1,615
Mid	12	12	25	32	64	119	199	278	660
Low				27	59	70	87	104	250
TOTAL									
High				683	1,376	1,948	2,727	3,901	8,903
Mid	212	275	490	632	904	1,264	1,729	2,353	4,060
Low				581	737	916	1,151	1,448	1,788

ANNUAL ENERGY	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY									
High				2,720	4,390	6,630	9,430	13,920	31,700
Mid	744	1,108	1,790	2,500	3,530	4,880	6,570	8,960	14,750
Low				2,300	2,840	3,590	4,560	5,770	6,670
NATIONAL DEFENSE									
High				135	142	149	157	165	211
Mid	156	161	131	131	131	131	131	131	131
Low				127	121	115	105	104	81
INDUSTRIAL									
High				170	1,810	2,100	2,840	3,590	8,490
Mid	2	45	70	170	340	630	1,050	1,460	3,470
Low				141	312	370	460	550	1,310
TOTAL									
High				3,025	6,342	8,879	12,427	17,675	40,401
Mid	902	1,314	1,990	2,801	4,001	5,641	7,751	10,551	18,351
Low				2,568	3,273	4,075	5,125	6,424	8,061


ANCHORAGE-COOK INLET AREA
ENERGY FORECAST
Upper Susitna Project Power Market Analysis
1973-1977 TREND
HIGH
MEDIAN
LOW
GIGAWATT HOURS
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
9000
8000
7000
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2025
YEAR

Figure 9

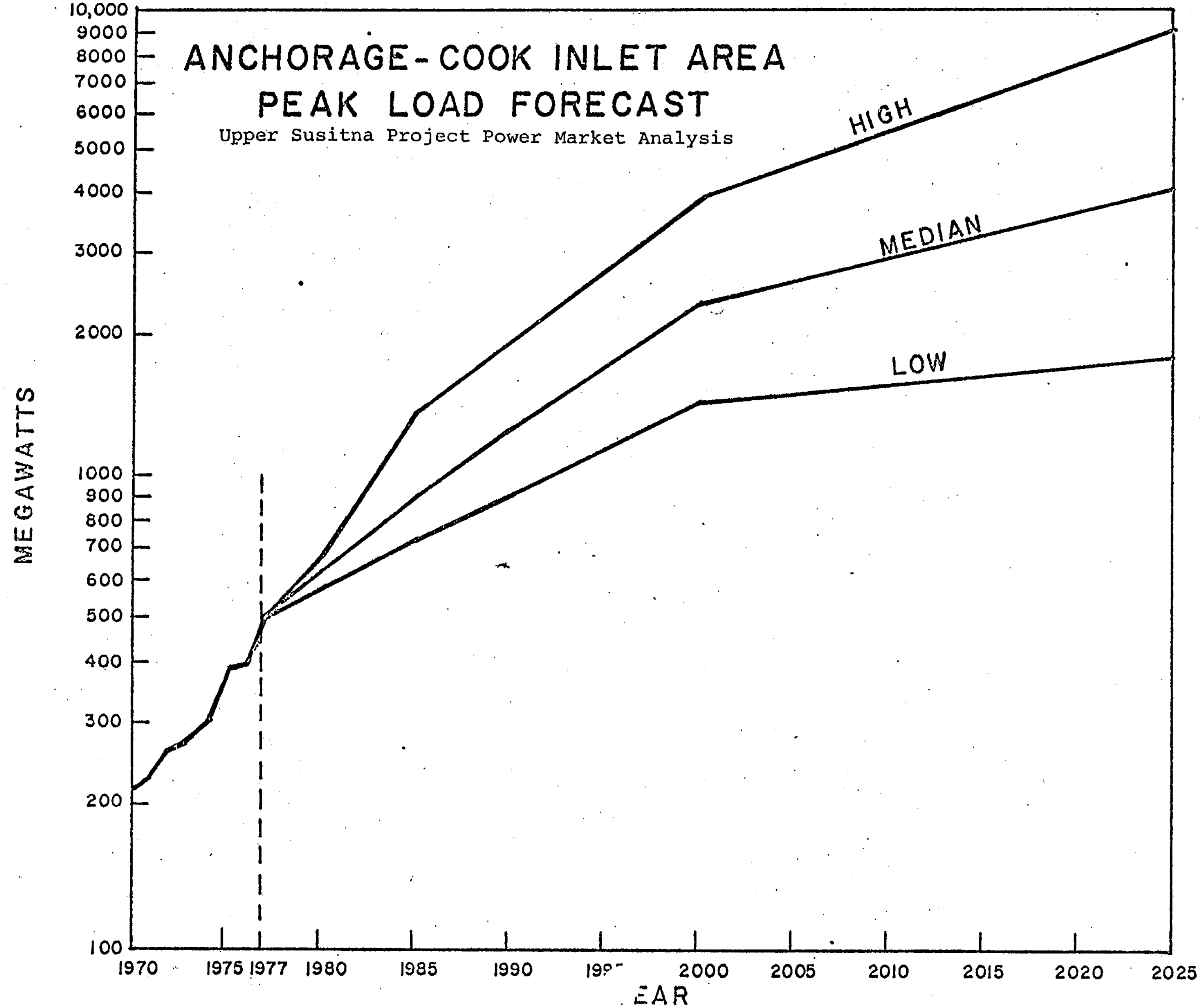
ANCHORAGE-COOK INLET AREA
PEAK LOAD FORECAST
Upper Susitna Project Power Market Analysis
HIGH
MEDIAN
LOW
MEGAWATTS
10,000
9000
8000
7000
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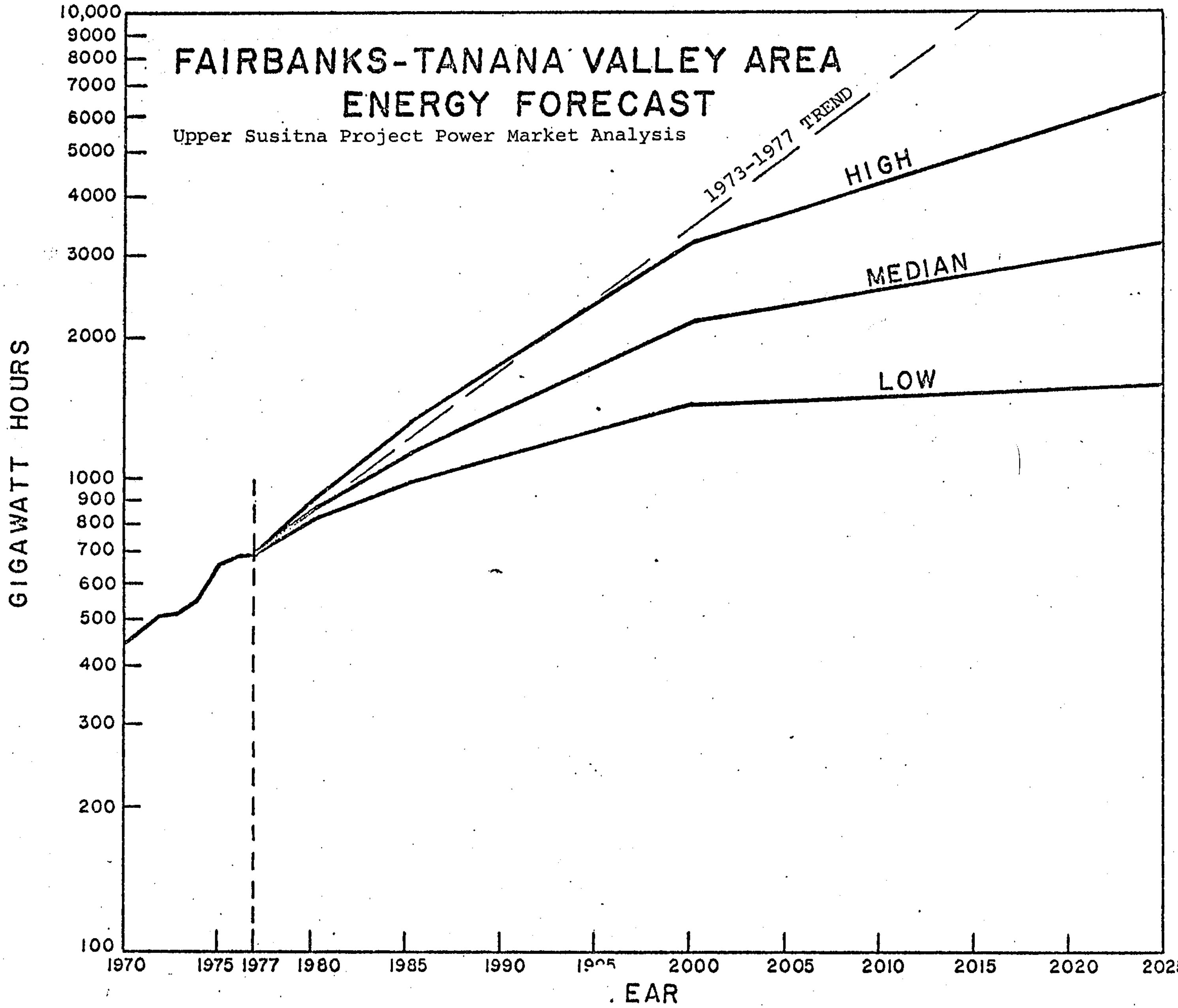
Figure 10

Table 11
POWER AND ENERGY REQUIREMENTS
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

PEAK POWER	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY									
High				158	244	358	495	685	1,443
Mid	56	73	119	150	211	281	358	452	689
Low				142	180	219	258	297	329
NATIONAL DEFENSE									
High				49	51	54	56	59	76
Mid	44	41	41	47	47	47	47	47	47
Low				46	44	42	40	38	29
TOTAL									
High				207	295	412	551	744	1,519
Mid	101	114	160	197	258	328	405	499	736
Low				188	224	261	298	335	358

ANNUAL ENERGY	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY									
High				690	1,070	1,570	2,170	3,000	6,320
Mid	239	324	483	655	925	1,230	1,570	1,980	3,020
Low				620	790	960	1,130	1,300	1,440
NATIONAL DEFENSE									
High				213	224	235	247	260	333
Mid	203	200	207	207	207	207	207	207	207
Low				203	193	184	175	166	129
TOTAL									
High				903	1,294	1,805	2,417	3,260	6,653
Mid	443	524	690	862	1,132	1,437	1,777	2,187	3,227
Low				823	983	1,144	1,305	1,466	1,569



FAIRBANKS-TANANA VALLEY AREA
ENERGY FORECAST
Upper Susitna Project Power Market Analysis
1973-1977 TREND
HIGH
MEDIAN
LOW
GIGAWATT HOURS
10,000
9000
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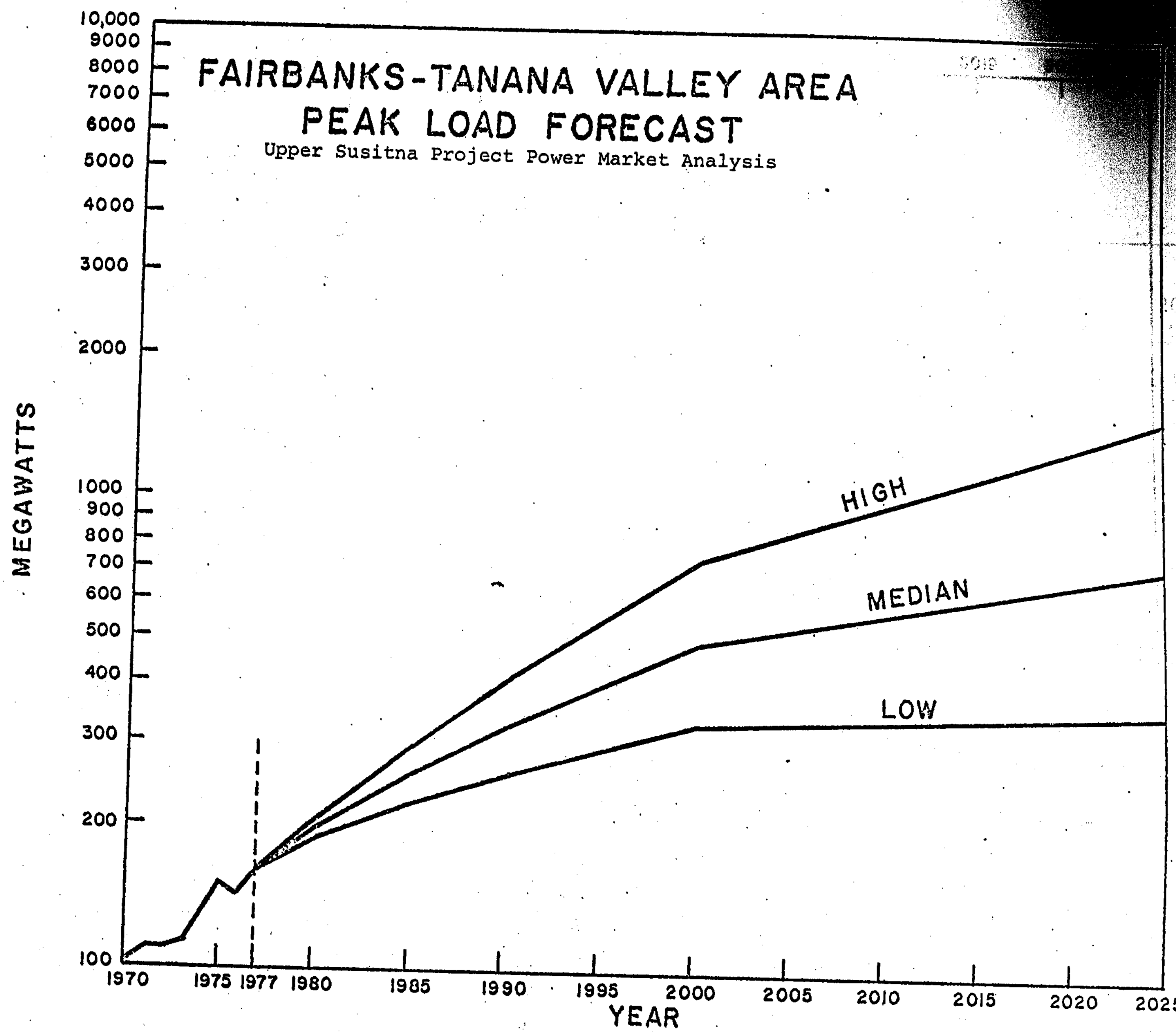
2025
YEAR

Figure 11


FAIRBANKS-TANANA VALLEY AREA
PEAK LOAD FORECAST
Upper Susitna Project Power Market Analysis
MEGAWATTS
10,000
9000
8000
7000
6000
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2025
YEAR

Figure 12

Table 12
POWER AND ENERGY REQUIREMENTS
(RAILBELT AREA)

Upper Susitna Project Power Market Analysis

PEAK POWER

	1970 MW	1973 MW	1977 MW	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
TOTAL									
High				890	1,671	2,360	3,278	4,645	10,422
Mid	313	389	650	829	1,162	1,592	2,134	2,852	4,796
Low				769	961	1,177	1,449	1,783	2,146

Average Annual Growth for period	%	%	%	%	%	%	%	%
High			11.0	13.4	7.1	6.8	7.2	3.3
Mid	7.5	13.7	8.4	7.0	6.5	6.0	6.0	2.1
Low			5.8	4.6	4.1	4.2	4.2	0.7

ANNUAL ENERGY

	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH	GWH
TOTAL									
High				3,928	7,636	10,684	14,844	20,935	47,054
Mid	1,345	1,838	2,681	3,663	5,133	7,078	9,528	12,738	21,578
Low				3,391	4,256	5,219	6,430	7,890	9,630

Average Annual Growth for period	%	%	%	%	%	%	%	%
High			13.6	14.2	6.9	6.8	7.1	3.3
Mid	11.0	9.9	11.0	7.0	6.6	6.1	6.0	2.1
Low			8.1	4.6	4.2	4.3	4.2	0.8

Note: The increase in 1980-1985 high range growth rates reflects the addition in 1985 of the energy intensive self-supplied industry load (280 MW).

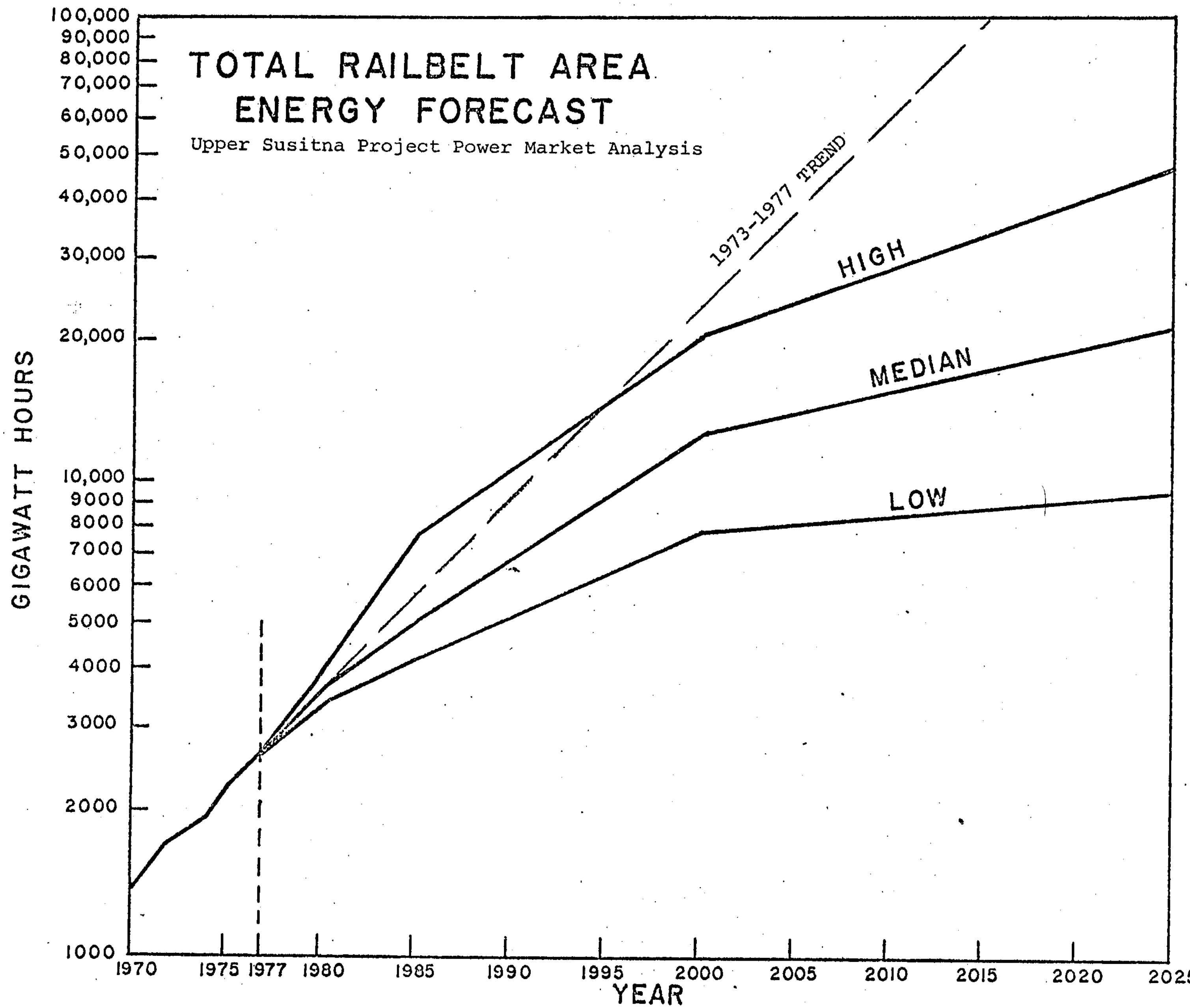
TOTAL RAILBELT AREA
ENERGY FORECAST
Upper Susitna Project Power Market Analysis
GIGAWATT HOURS
YEAR
1973-1977 TREND
HIGH
MEDIAN
LOW
100,000
90,000
80,000
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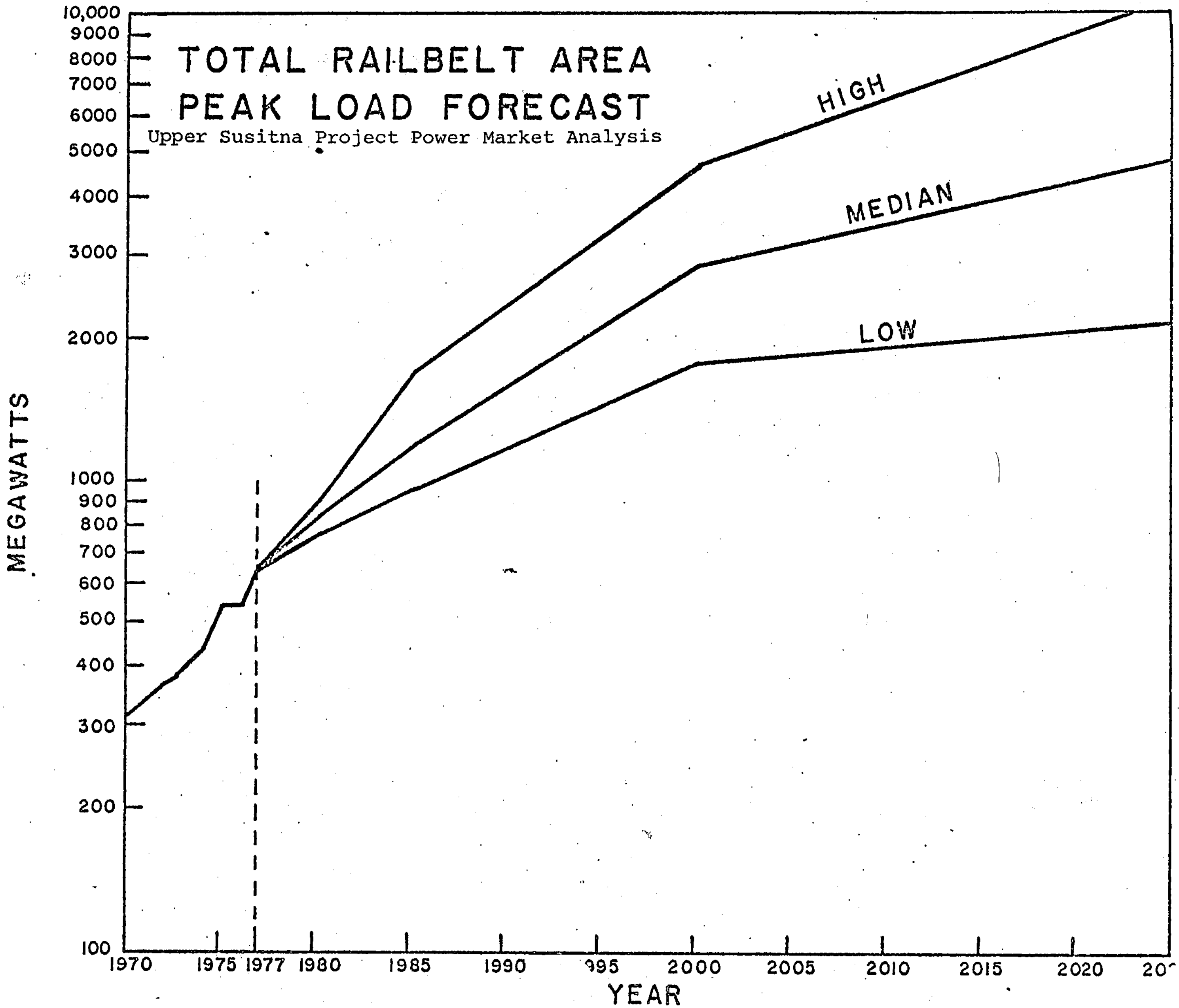
Figure 13


TOTAL RAILBELT AREA
PEAK LOAD FORECAST
Upper Susitna Project Power Market Analysis
HIGH
MEDIAN
LOW
MEGAWATTS
10,000
9000
8000
7000
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YEAR

Figure 14

Table 13
COMPARISON OF UTILITY ENERGY ESTIMATES
1976 MARKETABILITY REPORT, UPDATE OF 1976, AND 1978 ANALYSIS

Upper Susitna Project Power Market Analysis

		Anchorage-Cook Inlet			Fairbanks-Tanana Valley			Total Railbelt		
Year	Forecast Range	1976 Report	Update of 1976	1978 Forecast	1976 Report	Update of 1976	1978 Forecast	1976 Report	Update of 1976	1978 Forecast
1974	Historic	1,305 1/		1,189.7 1/	330		353.8	1,635		1,543.5
1975	High	1,489			377			1,866		
	Mid	1,467			371			1,838		
	Low	1,450			367			1,816		
	Historic			1,413.0			450.8			1,863.8
1976	High	1,699			430			2,129		
	Mid	1,649			417			2,066		
	Low	1,611			407			2,018		
	Historic			1,615.3			468.5			2,083.8
1977	High	1,939			490			2,429		
	Mid	1,853			469			2,322		
	Low	1,790			453			2,242		
	Historic		1,790.1	1,790.1		482.9	482.9		2,273.0	2,273.0
1980	High	2,850	2,660	2,720	700	720	690	3,550	3,380	3,410
	Mid	2,580	2,540	2,500	660	690	655	3,240	3,230	3,155
	Low	2,410	2,460	2,300	610	660	620	3,020	3,120	2,920
1990	High	6,880	6,300	6,630	1,660	1,700	1,570	8,540	8,000	8,200
	Mid	5,210	5,000	4,880	1,270	1,360	1,230	6,480	6,360	6,110
	Low	4,420	4,410	3,590	1,050	1,180	960	5,470	5,590	4,550
2000	High	15,020	13,600	13,920	3,500	3,670	3,000	18,520	17,270	16,920
	Mid	9,420	8,950	8,960	2,230	2,440	1,980	11,650	11,390	10,940
	Low	6,570	6,530	5,770	1,530	1,750	1,300	8,100	8,280	7,070

1/ 1974 historic data revised between 1975 and 1978.

GWH = million kwh

Further comparisons confirm that the 1976 report forecast was valid. Historic values through 1977 fell between the high and low ranges of the forecast.

The 1976 report was based on load data through 1974 and the following assumptions for utility load growth:

Average Annual Growth Rates

	1974-1980	1980-1990	1990-2000
High Range	14.1%	9.0%	8.0%
Mid-Range	12.4	7.0	6.0
Low Range	11.1	6.0	4.0

The following percentages compare this report and the above assumptions.

Average Annual Growth Rates From
1978 Utility Energy Forecast

	1977-1980	1980-1990	1990-2000
High Range	14.5%	9.0%	7.5%
Mid-Range	11.5	6.8	6.0
Low Range	8.7	4.5	4.5

The 1976 report based the utility energy forecast on assumed average annual growth rates. The 1978 report based the forecast on assumed growth in population and per capita energy use. Both reports considered energy conservation, but it was given more specific and higher importance in the 1978 forecast.

Forecasts available from various utilities are tabulated on tables 14, 15, and 16. Some were done by the utilities, some by consultants, and some by REA. All data was tabulated and, where necessary, extrapolated as part of the State Alaska Power Authority Railbelt Intertie Study. Comparisons are summarized in 5-year increments.

	Utility Forecasts	1978 Susitna Forecasts		
Energy (GWH)		High	Mid	Low
1980	3,344	3,410	3,155	2,920
1985	6,277	5,460	4,455	3,630
1990	10,965	8,200	6,110	4,550
1995	17,748	11,600	8,140	5,690
2000	26,550	16,920	10,940	7,070
Peak (MW)				
1980	725	778	720	667
1985	1,377	1,244	1,021	830
1990	2,986	1,873	1,396	1,039
1995	3,835	2,645	1,858	1,298
2000	5,641	3,865	2,497	1,617

The utility forecasts run higher than those of this report. No definite reason for the differences can be made other than the utilities assumed higher growth rates. The basis of the utility assumptions was not considered in this study.

Table 14
UTILITY ENERGY FORECASTS (GWH)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

Year	AML&P 1/	CEA 2/	MEA 3/	HEA 4/	Total
1979	634	1,109	280	310	2,333
1980	699	1,283	333	374	2,689
1981	771	1,468	395	452	3,086
1982	847	1,679	468	546	3,541
1983	930	1,921	559	620	4,030
1984	1,018	2,197	668	705	4,588
1985	1,111	2,509	799	800	5,219
1986	1,210	2,810	954	909	5,883
1987	1,313	3,147	1,140	1,033	6,634
1988	1,422	3,525	1,322	1,155	7,424
1989	1,534	3,948	1,534	1,290	8,306
1990	1,650	4,422	1,779	1,442	9,293
1991	1,770	4,864	2,064	1,611	10,309
1992	1,891	5,350	2,394	1,801	11,437
1993	2,014	5,885	2,706	1,978	12,584
1994	2,138	6,474	3,057	2,173	13,843
1995	2,245	7,121	3,455	2,388	15,209
1996	2,357	7,691	3,904	2,623	16,575
1997	2,475	8,306	4,412	2,882	18,075
1998	2,599	8,971	4,853	3,111	19,533
1999	2,729	9,638	5,338	3,359	21,113
2000	2,865	10,463	5,872	3,626	22,826

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Anchorage Municipal Light & Power Department
2/ Chugach Electric Association
3/ Matanuska Electric Association
4/ Homer Electric Association

Table 15
UTILITY PEAK DEMAND FORECASTS (MW)
ANCHORAGE-COOK INLET AREA

Upper Susitna Project Power Market Analysis

Year	AML&P 1/	CEA 2/	MEA 3/	HEA 4/	Total
1979	124	239	67	64	495
1980	138	271	81	78	567
1981	152	310	97	94	653
1982	167	355	116	113	752
1983	184	406	142	129	860
1984	202	465	171	146	983
1985	221	530	207	166	1,124
1986	241	594	251	188	1,274
1987	263	655	303	214	1,445
1988	285	745	343	239	1,612
1989	309	835	389	267	1,800
1990	333	935	442	299	2,008
1991	358	1,028	501	334	2,222
1992	384	1,131	569	373	2,458
1993	411	1,244	630	410	2,695
1994	437	1,369	698	451	2,954
1995	461	1,505	773	495	3,234
1996	486	1,626	857	544	3,512
1997	512	1,756	950	598	3,816
1998	539	1,901	1,026	645	4,111
1999	568	2,048	1,108	696	4,421
2000	599	2,212	1,197	752	4,759

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Anchorage Municipal Light & Power Department
2/ Chugach Electric Association
3/ Matanuska Electric Association
4/ Homer Electric Association

Table 16
UTILITY ENERGY AND PEAK DEMAND FORECASTS
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Net Energy (GWH)			Peak Demand (MW)		
Year	GVEA 1/	FMU 2/	Total	GVEA	FMU	Total
1979	450	144	594	111	33	144
1980	502	153	655	123	35	158
1981	560	162	722	136	37	173
1982	625	172	796	151	39	190
1983	693	182	875	167	42	209
1984	769	193	962	186	44	230
1985	853	205	1,058	206	47	253
1986	947	217	1,164	228	50	278
1987	1,050	230	1,280	252	53	305
1988	1,155	244	1,399	278	56	334
1989	1,271	259	1,529	305	59	364
1990	1,398	274	1,672	335	63	398
1991	1,537	288	1,825	368	66	434
1992	1,691	302	1,993	405	69	474
1993	1,843	317	2,160	440	72	512
1994	2,009	333	2,342	480	76	556
1995	2,190	350	2,540	521	80	601
1996	2,387	367	2,754	569	84	653
1997	2,602	386	2,987	619	88	707
1998	2,810	405	3,215	668	92	760
1999	3,035	425	3,460	722	97	819
2000	3,278	446	3.724	780	102	882

Source: Obtained from utilities in 1978 for Alaska Power Authority Railbelt Intertie Study.

1/ Golden Valley Electric Association
2/ Fairbanks Municipal Utilities

Load Distribution

Reservoir operation studies used in sizing reservoirs need an average monthly distribution of annual energy to help relate hydroelectric output to the electric load. This section reports updated averages of monthly energy use divided by annual energy use within the Anchorage-Cook Inlet area.

This section also reports a study of hourly load distribution in the weeks of winter peak load (same as annual peak) and summer minimum peak load. By studying these load curves from several years, hydroelectric plant factor is evaluated. (See capacity section).

The utility systems have had combined annual load factors slightly over 50 percent in the past few years (54 percent in 1977 as shown on figure 17). Data presented in table 17 shows that mid-summer peaks have been running about 60 percent of mid-winter peaks and that monthly load factors generally exceeded 70 percent. For 1977, the December load factor was 76 percent. Figures 15 and 16 illustrate that winter and summer loads are quite similar. The load duration curves of figure 17 present these daily load curves concisely. The 1976 report contains daily load curves of previous years. Winter and summer curves are plotted together showing similarities of slope and shape.

The update of average monthly energy is presented as percent of the annual value in table 18. Average percentages used in the 1976 report compare closely with 1970-77 averages. Slight changes are reflected in the "recommended distribution" column. Winter load is about two-thirds of total.

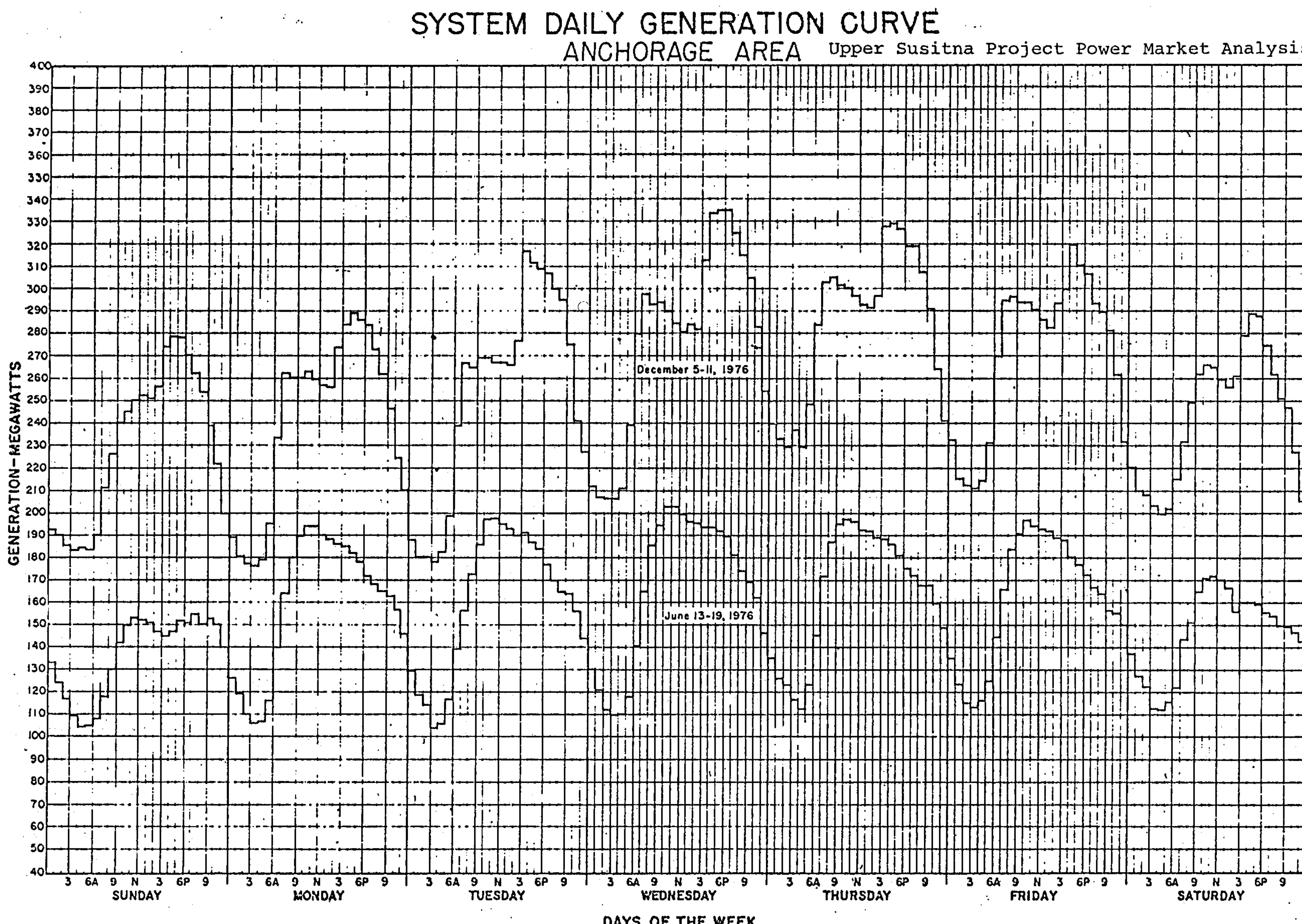

SYSTEM DAILY GENERATION CURVE
ANCHORAGE AREA
Upper Susitna Project Power Market Analysis
GENERATION-MEGAWATTS
December 5-11, 1976
June 13-19, 1976
3 6A 9 N 3 6P 9
SUNDAY
MONDAY
TUESDAY
WEDNESDAY
THURSDAY
FRIDAY
SATURDAY
DAYS OF THE WEEK

Figure 15

SYSTEM DAILY GE ERATION CURVE

ANCHORAGE AREA Upper Susitna Project Power Market Analysis

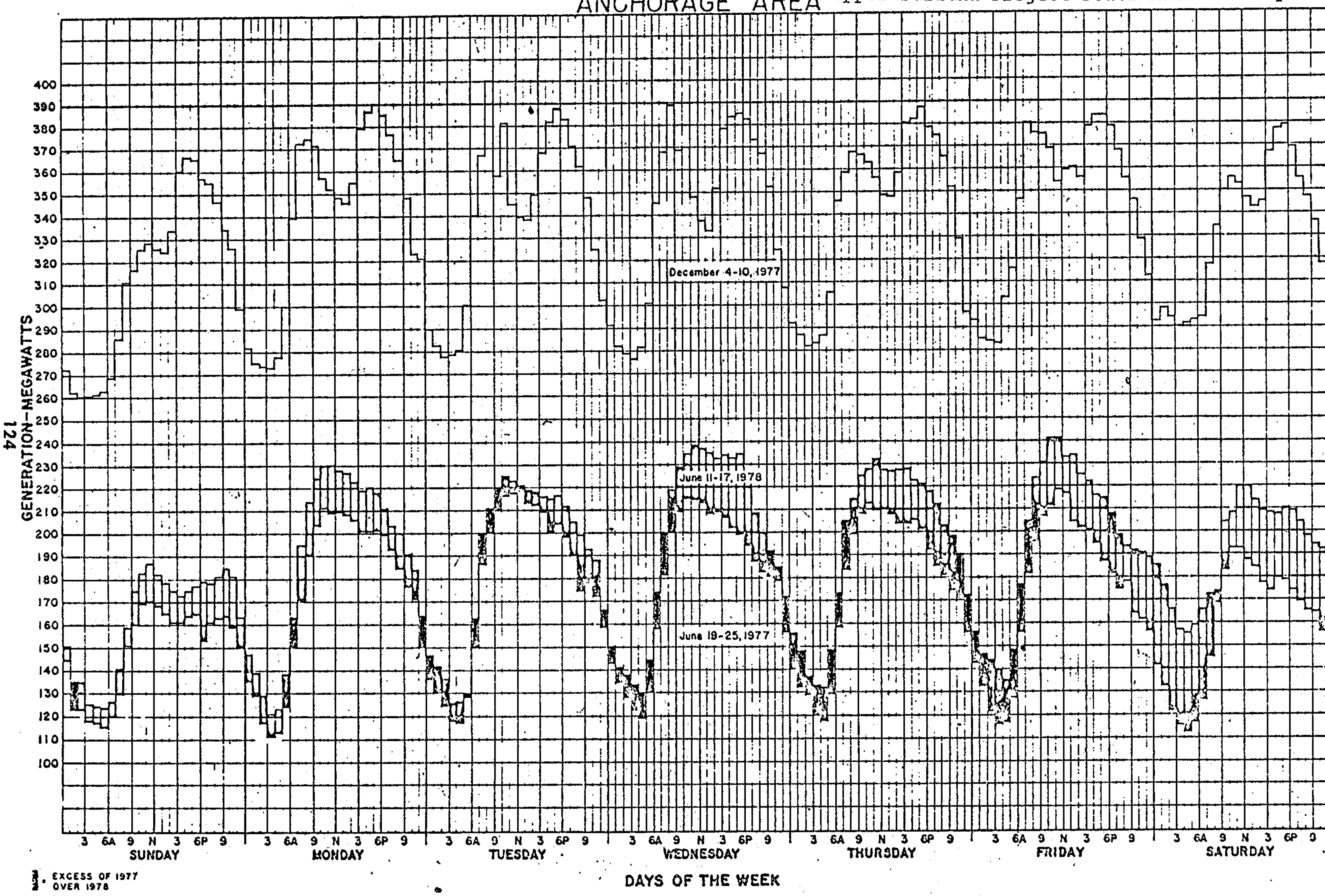


Figure 16

ANCHORAGE AREA LOAD DURATION CURVE 1977

Upper Susitna Project Power Market Analysis

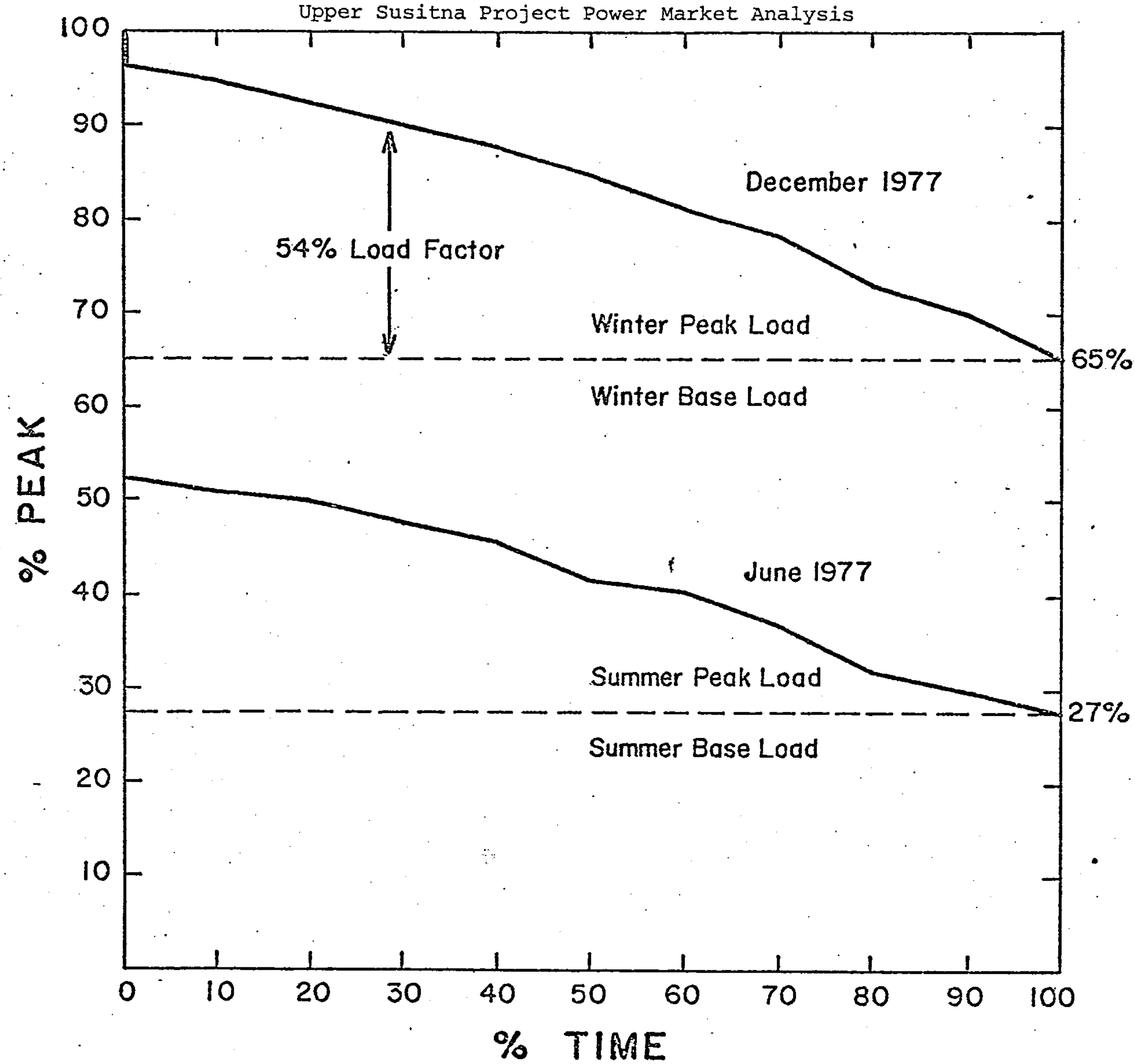


Table 17
LOAD DISTRIBUTION CHARACTERISTICS
MONTHLY PEAK LOADS AND LOAD FACTORS

Upper Susitna Project Power Market Analysis

Month	1971-1972 Peak MW	1971-1972 % Annual Peak	1971-1972 Energy 10^6 KWH	1971-1972 Mon. Load Fact.	1972-1973 Peak MW	1972-1973 % Annual Peak	1972-1973 Energy 10^6 KWH	1972-1973 Mon. Load Fact.	1973-1974 Peak MW	1973-1974 % Annual Peak	1973-1974 Energy 10^6 KWH	1973-1974 Mon. Load Fact.
October	185.8	73	94.1	68	209.2	74	108.8	70	224.3	82	122.7	73
November	222.8	88	113.0	70	236.3	83	124.4	73	269.6	98	144.6	74
December	236.2	93	121.1	70	260.7	92	143.3	74	266.9	97	147.0	74
January	254.5	100	135.3	72	283.0	100	153.6	72	274.5	100	159.3	78
February	224.5	88	115.3	76	259.6	92	127.5	73	264.5	96	139.4	79
March	222.8	87	119.2	70	225.1	80	125.5	75	249.4	91	135.5	73
April	176.7	69	96.6	76	196.4	69	105.4	75	201.6	73	112.4	77
May	157.9	62	87.8	75	176.7	62	98.5	75	180.4	66	104.1	78
June	152.1	66	78.5	72	165.2	58	87.6	74	176.2	64	95.4	75
July	146.8	52	76.6	70	162.8	59	89.8	74	178.9	65	97.5	73
August	154.5	54	86.9	75	175.9	64	96.2	73	195.7	71	101.9	70
September	179.6	64	92.9	72	194.5	71	100.8	72	210.3	77	106.1	70
Min. Summer Peak / Max. Winter Peak	= 57.7%				57.5%				64.2%			

Month	1974-1975 Peak MW 1/	1974-1975 % Annual Peak	1974-1975 Energy 10^6 KWH	1974-1975 Mon. Load Fact.	1975-1976 Peak MW	1975-1976 % Annual Peak	1975-1976 Energy 10^6 KWH	1975-1976 Mon. Load Fact.	1976-1977 Peak MW	1976-1977 % Annual Peak	1976-1977 Energy 10^6 KWH	1976-1977 Mon. Load Fact.
October	252.9	71	134.3	71	342.2	81	153.0	60	359.8	88	182.2	68
November	266.2	75	156.0	81	367.6	87	196.2	74	360.7	88	193.8	75
December	314.9	89	170.7	73	420.5	100	226.3	72	408.3	100	223.4	74
January	354.1	100	180.8	69	394.1	94	213.3	73	376.4	92	209.9	75
February	316.7	89	166.9	78	383.3	91	203.5	76	356.8	87	181.7	76
March	268.6	76	156.6	78	342.1	81	187.6	74	369.0	90	208.6	76
April	249.0	70	129.2	72	285.3	68	159.0	77	334.4	82	177.0	73
May	222.0	63	120.9	73	253.6	60	145.0	77	284.8	70	161.3	76
June	209.0	59	113.0	75	236.1	56	128.9	76	265.0	65	148.1	78
July	207.0	58	110.9	72	248.0	59	134.4	73	257.1	63	141.3	74
August	211.5	61	118.3	73	250.6	60	139.9	75	271.8	67	151.7	75
September	247.4	70	131.9	74	278.0	66	151.2	76	318.9	79	166.7	73
Min. Summer Peak / Max. Winter Peak	58.5%				56.1%				63.0%			

1/ Represents sum of loads for the Anchorage (AML&P, CEA) and Fairbanks (FMU, GVEA) utilities

Table 18

MONTHLY ENERGY REQUIREMENTS AS PERCENT OF ANNUAL REQUIREMENT

Upper Susitna Project Power Market Analysis

MONTH	1970-1972 Utility Loads 1/	1970-1977 Utility Loads 2/	Recommended Distribution 3/
Oct.	7.9	8.1	8.2
Nov.	8.9	9.2	9.0
Dec.	10.2	10.2	9.7
Jan.	11.3	10.8	10.2
Feb.	9.2	9.3	9.1
Mar.	9.8	9.4	9.1
April	8.0	7.8	7.9
May	7.2	7.3	7.6
June	6.5	6.6	7.0
July	6.4	6.7	7.1
Aug.	7.1	7.1	7.4
Sept.	7.5	7.5	7.7
Total	100.0	100.0	100.0
SEASONAL			
Oct.-April	65.3	64.8	63.2
May-Sept.	34.7	35.2	36.8

1/ Combined loads of CEA, AML&P, GVEA, FMUS, for Oct. 1970-Sept. 1972. Basis for (1975 Susitna Power market analysis) 1976 report.

2/ Combined net generation of CEA, AML&P, APA, GVEA, FMUS, for Oct. 1970-Sept. 1977. Updated Basis.

3/ Assumes total requirements consisting of 25 percent industrial loads and 75 percent utility loads. Update of previous recommendations.

Capacity Requirements

With reference to the load factor evaluations in the previous section, a trend towards somewhat higher annual load factors in the future is anticipated. In addition to benefitting from any load diversity in the interconnected system, peak load management (including such practices as peak load pricing) offers considerable opportunity for improving load factors, which in turn reduces overall capacity requirements for the system in any given year. For planning purposes, it is assumed that the annual system load factor will be in the range of 55 to 60 percent by the latter part of the century.

System capacity requirements are determined by winter peak load requirements plus allowances for reserves and unanticipated load growth. The lower summer peaks provide latitude for scheduled unit maintenance and repairs.

System daily peak load shapes indicate that a very small portion of the capacity is needed for very low load factor operation. Some of the gas turbine capacity now used for base load is expected to be used mainly for peak shaving purposes, eventually. It will be operating during peak load hours for the few days each year when loads approach annual peak, and will be in standby reserve for the balance of the year. Figure 17, the annual peak week duration curve, shows that the highest 10 percent load occurs for 30 percent of the week (about two days).

Reliability standards would be upgraded as the power systems develop. Likely inclusions are specific provisions for maintaining spinning reserve capacity to cover possible generator outages and substantial improvements in system transmission reliability.

Results - Examination of the winter load duration curve (figure 9) indicates that the base load portion is about 65 percent of total load and the peak load is about 35 percent of total load. Load factor for the peak portion is about 54 percent. Winter weekly load factors are approximately 80 percent. This is illustrated in the winter and summer load duration curves by proportioning the areas under the curves to the total possible area if peak load occurred 100 percent of the time.

An annual plant factor of 50 percent is recommended for the proposed Upper Susitna Project. This is largely a judgment factor and is based on the following considerations:

1. The recommended plant factor provides for serving a proportional share of both peaking and energy requirements throughout the year while maintaining adequate flexibility to meet changing conditions in any given year.

2. Any significant reduction in this capacity could materially reduce flexibility.

3. A significant market for low load factor peaking capacity seems unlikely within the foreseeable future. Load management and additional industrial loads will probably increase the overall system load factor in the future. It is expected that several existing and planned gas turbine units could eventually be used for peak shaving.

4. It is recognized that the mode of operation for the hydro will change through time. In the initial years of operation, it is likely that the full peaking capacity will be used infrequently. For example, the mid-range Railbelt estimated system peak load for the year 2000 is 2,852 MW. Assuming load shapes similar to the current Anchorage area loads, the winter peak week would require about 1,850 MW of continuous power to cover the base loads and about 1,000 MW of peaking power. Load factors of the peak portion would be about 50 percent.

A design capacity based on 50 percent plant factor applied to average annual energy (primary plus secondary) appears appropriate. Machine overload capability contributes to spinning reserves for emergencies or other short term contingencies.

The Corps based nameplate capacity on 50 percent plant factor applied to critical year firm energy. This smaller capacity, when applied to average annual energy, results in a 56 percent plant factor. APA feels the smaller design capacity may unduly reduce flexibility.

PART VI. ALTERNATIVE POWER SOURCES

Introduction

This section examines alternative power supply options in the Railbelt in lieu of the Upper Susitna Project and presents detailed cost estimates of power from new coal-fired steam plants.

Alternatives premised on unproven technology were eliminated.

Alternatives Considered

Potential alternative sources of electric power generation are identified by energy type. They are coal, oil and natural gas, hydro, nuclear, wind, geothermal, and tide.

Some alternatives will be restricted in time or capacity because of Federal energy policy controlling use of energy resource. Others will be restricted by practical available energy supply. Still others are impractical because of lack of large-scale technology.

Coal

Evaluation of coal utilization is based on mine-mouth coal-fired steam generation. Potential advanced technology, such as gasification, is not considered because development would not be available within this study period.

Recent studies provide general information about possible locations, sizing, and cost of new steamplants, but Alaska specific data are limited and extrapolations have been made for local conditions.

Information sources of specific interest for this analysis are: studies by Battelle Pacific Northwest Laboratories (March 1978); the Electric Power Research Institute (EPRI) (January 1977); and the Washington Public Power Supply System (WPPSS) (June 1977); the Federal Energy Regulatory Commission (FERC) determination of power values for the Bradley Lake Project (October 1977) and the Upper Susitna Project (October 1978); and evaluations of costs for the proposed Golden Valley Electric Association (GVEA) plant additions at Healy. These are all listed in the bibliography.

Location - It is assumed that new coal-fired steamplants would be located near the Beluga fields for service to the Anchorage-Cook Inlet area and at Healy for service to the Fairbanks-Tanana Valley area. The plants would use known but undeveloped coal resources at Beluga and the existing coal mining operation near Healy.

It is recognized that other locations are possible. For example, it may be possible to locate a coal-fired plant on the Kenai Peninsula and use coal from either local reserves or Beluga. A Kenai location might offer co-generation possibilities because steam could be reused in manufacturing by the petrochemical industry. The potential for mining coal on the Kenai Peninsula is substantially less attractive than for Beluga because of thin coal seams and other geologic factors.

Capacity - These analyses are for two-unit 200-MW and 500-MW plants. This size range is considered appropriate for new coal-fired plants that might come on-line between 1985 and 2000.

Investment Cost - Table 19 summarizes unit investment costs for new coal-fired plants presented in several recent studies. The data assembled by each entity is quite complex with respect to original estimated price levels, inflation to updated price levels, or projected future on-line dates, size, pollution control equipment, location, type of plant, and other items. Price levels were not adjusted to a uniform date because of the complexity of data involved.

All 1977 and 1978 estimates are substantially higher than APA estimates for the 1976 Alaska Power Survey and the 1976 report.

The most in-depth analysis was the WPPSS study which investigated the construction of 1,000-MW steamplants at 10 plant sites in Washington, Montana, and Wyoming. Several grades and sources were assumed. Costs were estimated for with and without sulphur dioxide scrubbers (scrubbers). Twenty-two options of plant sites, coal supply, and transportation were investigated.

APA's estimate of coal-fired steamplant investment costs is derived from the WPPSS study. Procedures for adjusting costs to current Alaska conditions are similar to the analysis used in the appended Battelle report.

The basic cost in the WPPSS study for a 1,000 MW single unit plant in operation during mid-1976 was:

Without Scrubbers	\$554/kw
With Scrubbers	\$684/kw

The WPPSS procedure increased these costs for the quality of the coal used and other specific powerplant site conditions. The coal quality problems have not been considered in this estimate, and the construction site variable is assumed to be included in the Alaska factor.

Table 19
COMPARISON OF INVESTMENT COSTS FOR COAL-FIRED STEAMPLANTS
Upper Susitna Project Power Market Analysis

Source of Estimate	Price Level	Location	Size, MW	No. of Units	Scrubbers	Investment Cost, $/kw
ALASKA LOCATIONS						
APA 1/	Oct. 1978	Healy or Beluga	200	2	No	1,500
	Oct. 1978	Healy or Beluga	200	2	Yes	1,860
	Oct. 1978	Healy or Beluga	500	2	No	1,300
	Oct. 1978	Healy or Beluga	500	2	Yes	1,610
APA Susitna River Studies						
	Jan. 1975	Healy or Beluga	200	2	Yes	726
	Jan. 1975	Healy or Beluga	500	2	Yes	630
Golden Valley Electric Association 2/	1974	Healy	132	2	No	950
	1977	Healy	150	2	No	1,400
	1977	Healy	150	2	Yes	1,700
	1978	Healy	100	1	Yes	1,800
Battelle 3/	Jan. 1977	Beluga	200	1	No	1,220 to 1,571
	Jan. 1977	Beluga	200	1	Yes	1,400 to 1,766
	Jan. 1977	Healy or Nenana	200	1	No	1,470 to 1,920
	Jan. 1977	Healy or Nenana	200	1	Yes	1,710 to 2,158
	Jan. 1977	Anchorage	200	1	No	1,120 to 1,440
	Jan. 1977	Anchorage	200	1	Yes	1,280 to 1,690
Federal Energy Regulatory Commission 4/	Jan. 1977	Anchorage or Kenai Areas	450	2	Yes	900
	Oct. 1978	Anchorage or Kenai Areas	450	2	Yes	1,220 to 1,240
	Oct. 1978	Healy	230	2	Yes	1,475 to 1,510

Table 19 (cont.)
COMPARISON OF INVESTMENT COSTS FOR COAL-FIRED STEAMPLANTS

Upper Susitna Project Power Market Analysis

Source of Estimate	Price Level	Location	Size, MW	No. of Units	Scrubbers	Investment Cost, $/kw
PACIFIC NORTHWEST AND WESTERN U.S. LOCATIONS						
Washington Public Power Supply System 5/	Mid 1976	Pacific Northwest	1,000	2	No	554
	Mid 1976	Pacific Northwest	1,000	2	Yes	684
	July 1987	Pacific Northwest	1,000	2	No	848
	July 1987	Pacific Northwest	1,000	2	Yes	1,056
Electric Power Research Institute 6/	July 1976	Western U.S. Remote	500	1	No	896
	July 1976	Western U.S. Remote	500	1	Yes	1,036
	July 1976	Western U.S. Remote	1,000	2	No	830
	July 1976	Western U.S. Remote	1,000	2	Yes	960
Idaho Nuclear Energy Commission 7/	1984	Boise, Idaho	1,000	2	No	828
	1984	Boise, Idaho	1,000	2	Yes	934

1/ APA's estimate is based largly on the WPPSS study with adjustments for Alaska conditions and size of plant. Future inflation not shown.

2/ GVEA 1974 estimate assumed units becoming operational in 1983 and 1986. The 1978 estimates assume operation in 1984 at $2,500/kw assuming 7% inflation.

3/ Battelle's estimates are based on adjusting both WPPSS and EPRI study data. The higher figures are from the EPRI study. Their studies with future operation dates include inflation.

4/ Scrubbers are assumed included in the cost.

5/ This is the basic study adjusted by APA and Battelle above. The 1987 costs include 5 percent annual inflation.

6/ The July 1976 price level includes costs for init[illegible] operation in 1978.

7/ The price level is 1975 costs adjusted to show costs for a 1984 operation date.

Adjusting the cost for the time between mid-1976 and October 1978 using the Handy-Whitman Steamplant Cost Index increased the cost 18.4 percent.

Without Scrubbers	$656/kw
With Scrubbers	$810/kw

Powerplants smaller than the 1,000 MW that will fit near-future Alaska power needs have a smaller total cost, but a larger cost per installed kilowatt. An adjustment needs to be applied to the costs to compensate for the loss of economy of the large scale plants. The factor recommended is the ratio of the plant size to the 0.85 exponent. A 500-MW plant thus costs 55.5 percent of a 1,000 MW plant, and a 200-MW plant costs 25.5 percent. Scaling the plants to 200 MW and 500 MW gives:

Plant Size	200 MW		500 MW	
	$ Million	$/kw	$ Million	$/kw
Without Scrubbers	167,000	835	364,000	728
With Scrubbers	207,000	1,035	450,000	899

An Alaska factor of 1.8 was used to adjust Pacific Northwest costs to Alaska wages and conditions:

Plant Size	200 MW		500 MW	
	$ Million	$/kw	$ Million	$/kw
Without Scrubbers	300,000	1,500	655,000	1,310
With Scrubbers	372,000	1,860	810,000	1,620

Fuel Cost and Availability - There is a wide range of opinions about the probable future cost of coal. For many years, coal prices were set at a small margin above production costs so that coal could compete with low-cost oil and natural gas. This situation has changed drastically because of price increases for oil and gas and incentives for power generation and has resulted in industrial conversion to coal. Coal production costs are also increasing rapidly due to normal inflationary and regulation factors. FERC reported the national average price of coal at 96.2¢/million Btu in July 1977, up from 80.8¢ in July 1975, and 39.8¢ in August 1973.

Alaskan coal prices have shown sizable increases recently. The cost of coal at Healy in September 1978 was 80 cents per million Btu, up from 62 cents in 1975. The Fairbanks Municipal Utility System (FMUS) pays an additional $6/ton shipping cost for Healy coal resulting in a price of $1.15 per million Btu at the powerplant in Fairbanks.

In October 1978, owners of the Beluga coal field stated that large reserves in the Beluga coal field may compete in the world energy market at a price of $1.10 to $1.40/million Btu stockpiled on the shore of Cook Inlet. The conclusions were based on company studies that included geologic investigations, drilling, bulk sampling programs, mining preparation, environmental evaluation, and navigation and shipping studies.

FERC estimated $1.00/million Btu for determination of power values in the Bradley Lake Project (October 1977). Other recent studies suggest this is a reasonable current (1978) cost for Beluga coal delivered to a steamplant at Beluga, with no allowance for price increase in future years.

Earlier APA studies for the 1976 FPC Power Survey and the 1976 Susitna report assumed $1.00 to $1.50/million Btu for coal at 1985 price levels in 1974 dollars. This included consideration of future economies of scale of larger mining operations.

APA analyses for this report are still based on a coal cost of $1.00 to $1.50/million Btu for a mine-mouth plant at either Beluga or Healy for mid-1980 conditions. This is comparable with $1.28 in 1985, estimated by GVEA for Healy coal by increasing the current 80 cents by 7 percent annually. Because of the wide diversity of studies and opinions, analyses based on a range of costs are presented.

In this study, we are assuming fuel values will increase about 2 percent per year--more rapidly than overall price indexes. This is consistent with other analyses.

Table 20
GENERATION COSTS FOR CONVENTIONAL COAL-FIRED STEAMPLANTS

Upper Susitna Project Power Market Analysis

1985 COSTS (1978 PRICES)1/	Plant Size, MW			
	200		500	
Number of Units	2		2	
Investment Cost, Railbelt, $/kw	1,860		1,620	
Capital Cost, mills/kwh	38.5		33.5	
Operation and Maintenance, mills/kwh	6.5		5.6	
Subtotal	45.0		39.1	
			1.00/mmBtu	1.50/mmBtu
Assumed Fuel Costs, mills/kwh	10.0	15.0	10.0	15.0
Transmission Cost to Load Center	4.0	4.0	3.0	3.0
Total Energy Cost, mills/kwh	59.0	64.0	52.1	57.1
1994 ENERGY COST	Fuel escalated 2%/year 1985 to 1994			
Capital Cost, mills/kwh	38.5		33.5	
Operation and Maintenance, mills/kwh	6.5		5.6	
Transmission Cost, mills/kwh	4.0		3.0	
Subtotal	49.0		42.1	
Fuel, Inflated 2% 1985 to 1994	12.0	17.9	12.0	17.9
Total	61.0	66.9	54.1	60.0
Fuel Escalated 7%/Year from 1985 to 1994; Capital Cost and O&M Escalated 5%/Year from 1978 to 1994				
Capital Cost	80.0		69.7	
Operation and Maintenance	13.5		11.6	
Transmission	8.3		6.2	
Subtotal	101.8		87.5	
Fuel	18.4	27.6	18.4	27.6
Total	120.2	129.4	105.9	115.1

1/ APA estimate based on studies by Washington Public Power Supply System Studies 1977.

Cost of Power - The estimated total cost of electric power that would be generated by a coal-fired steamplant alternative to the Susitna project is presented in table 20. Development of the estimated cost applied to a plant in either the Beluga or Healy area is based on the investment and fuel costs discussed earlier in this section, and includes other criteria developed in this report. In summary, the parameters are:

1. Investment cost includes all construction, overhead, and interest during construction, and is based on updating and adjusting WPPSS Pacific Northwest costs for Alaska conditions. Annual capital costs are based on a 35-year life and 7 percent interest rate.

2. Operation and maintenance costs are based on a detailed WPPSS personnel and materials estimate adjusted for plant capacity in the same manner as investment costs, increased by 50 percent for Alaska conditions, as developed in the 1976 Alaska Power Survey, and indexed from January 1977 to October 1978 using the U.S. Department of Labor index.

3. Fuel costs of both $1.00 and $1.50/kw are presented with a heat rate of 10,000 Btu/kwh.

4. Transmission costs are for lines connecting Beluga with Anchorage, and Healy with Fairbanks.

The resulting average unit cost of electric power from coal-fired steamplants to supply the Railbelt market area ranges from 5.21 to 6.40¢/kwh, varying with fuel cost and plant capacity.

Table 20 also presents an analysis of the cost of energy with fuel costs escalated at 2 percent anually from 1985 through 1994 (Susitna project, Watana phase on-line) and fuel cost escalated at 7 percent annually from 1985 through 1994.

Comparative Cost of Power (FERC) - FERC evaluated alternative costs for coal-fired steam plants at Beluga for the Anchorage area and Healy for the Fairbanks area as part of their power benefit studies for the Upper Susitna Project.

The FERC estimates of 4.93 to 5.64¢/kwh are in the same range as those estimated by APA for the Anchorage area. However, the FERC estimates of 4.02 to 4.30¢/kwh for the Fairbanks area are low compared to APA estimates. FERC estimated construction costs (July 1978) at $1,475/kw compared to $1,810/kw estimated by APA. In addition, GVEA recently estimated a cost of $1,800/kw for a comparable Healy steamplant.

FERC data are based on:

1. An Anchorage area plant assumed to be a two-unit 450-MW plant with fuel cost of $1.10/million Btu and a heat rate of 10,000 Btu/kwh. The Fairbanks plant is assumed to be two units, totaling 230 MW, with a fuel cost of $0.80/million Btu and a heat rate of 10,500 Btu/kwh. For non-Federal cases, the Anchorage area plant investment cost was estimated at $1,240/kw and the Fairbanks investment cost at $1,475/kw.

2. Financing is based on a composite Anchorage-Kenai interest rate of 7.9 percent with 75 percent financing by REA at 8.5 percent and 25 percent by the municipality of Anchorage at 6.25 percent. The interest rate for Fairbanks is 5.75 percent assuming State of Alaska Power Authority financing. In comparison, a Federal rate of 6.875 percent is used for both areas, the same rate used in the Corps of Engineers benefit analysis.

Oil and Natural Gas

The Upper Susitna Project involves a large new power supply beginning in 1994, with an expected life in excess of 100 years.

APA does not believe that oil and natural gas are realistic alternatives for equivalent power supplies, particularly in view of the timeframe (start in 1994) and very long life (through 2094).

Hydro

Criteria - Evaluation of possible hydroelectric generation alternatives to the Susitna project is based on comparing: (1) the potential generation capability, and (2) unit cost of power. Possible sites are identified by: (1) single sites with sufficient capacity to supply the projected power demands; (2) combinations of smaller sites within selected geographic areas and river basins; and (3) a combination of the best sites from all areas accessible to the Railbelt.

The hydro evaluation considered power requirements ranging from 600 MW to 2,290 MW, which are, respectively, the low-range and high-range projected increases in Railbelt demands from 1990 to 2000. Associated annual firm energy requirements would range from 2,670 gwh to 10,260 gwh. By comparison, the Susitna project is scheduled to provide about 1,573 MW capacity and 6,100 gwh annual firm energy.

Possible hydro generation alternatives were selected from the APA inventory of hydroelectric resources. The inventory estimates unit cost of power at the generator bus bar based on 1965-1966 cost at 3 1/4 percent interest rate. Susitna inventory cost data indexed to 1975 price levels give unit costs within 10 percent of that determined for the 1976 report.

Single Large Capacity Sites - Seven single sites have sufficient capacity potential to be an alternative to supplying minimum Susitna market area requirements. These are within a maximum of 1.4 times the unit cost for Susitna power. However, land use designations (National Parks and Monuments and Wild and Scenic Rivers) and/or known major environmental impacts preclude consideration of developing any of the sites at the present time.

The sites are:

Site	Stream	Firm Energy GWH/yr	Capacity MW	Percent of Susitna Cost
Holy Cross	Yukon R.	12,300	2,800	140
Ruby	Yukon R.	6,400	1,460	62
Rampart	Yukon R.	34,200	5,040	32
Porcupine	Porcupine R.	2,320	530	79
Woodchopper	Yukon R.	14,200	3,200	71
Yukon-Taiya	Yukon R.	21,000	3,200	52
Wood Canyon	Copper R.	21,900	3,600	51

None of the above sites can be considered available resources in the 1990's timeframe. This is due to: (1) Holy Cross, Ruby, Rampart, and Woodchopper are main-stem Yukon River sites with known major environmental problems, (2) Porcupine, Woodchopper, and Yukon-Taiya have major international considerations, and (3) Wood Canyon has a known major fishery problem.

Sites within the Nenana River basin have also been identified in past work. Their economic feasibility depends upon being developed as a unit. However, several of the sites are located partially within Mount McKinley National Park and are precluded from development.

In conclusion, no single, large hydro generation sites are available as alternatives to the Upper Susitna Project.

Combination of Small Capacity Sites - Combinations of single sites with less capacity than the Susitna project consist of 78 sites within the Matanuska, Tanana, Yentna-Skwentna, Talkeetna, and Chulitna River basins, the northwest drainage of Cook Inlet, the Kenai Peninsula, and scattered small sites and small basins within the Railbelt area. None of these areas contain sites with total capacity potential to supply minimum Susitna requirements. (Site combinations with the most capacity--the Yentna-Skewntna River basin and Kenai Peninsula--total 609 MW and 646 MW respectively, but with costs for individual sites ranging from 1.4 to 20 times Susitna costs.)

If consideration is given to combining the best small sites from each of the geographic areas, 12 sites totalling 1,276 MW are within the range of twice the cost of Susitna. Only one (Chakachamna) is near Susitna cost (103 percent), and has 366 MW potential.

Chakachamna is partly within the new Lake Clark National Monument. Other new or proposed Federal land withdrawals would preclude sites with about half of the total potential of the combined sites. Other sites have various environmental impact potentials. Some streams that would be affected have major anadromous fish resources. Also, because the sites are widely distributed, the needed transmission systems would be fairly extensive and costly.

Summary - Based on examination of individual sites and combinations of sites, there are no hydro generation opportunities available to provide enough power to be an alternative to the Susitna Project. Small individual sites may be available, but would satisfy only a small portion of the market area demand. Other sites, with apparently acceptable quantity and economic capability, have been or will be precluded by land status designation.

Nuclear

Nuclear generation may be technically viable in Alaska, but probable cost and siting problems eliminate it as a potential alternative to Susitna. Available information indicates that in other states, nuclear is economically competitive with coal, depending on specific conditions. Difficult conditions, possible seismic and environmental siting problems, and readily available coal indicate that nuclear generation will probably not be economically attractive in Alaska in the foreseeable future.

Wind

The State has shown serious interest in wind generation technology by developing pilot projects in the bush communities of Ugashik, Nelson Lagoon, and Kotzebue. Wind seems to provide near-term power for small communities presently dependent on high-cost diesel generation.

The cost and applicable scale of technology does not make wind power a viable alternative for large near-future power demands.

Geothermal

Investigations to date have found no high quality geothermal resources suitable for power development in areas accessible to the Railbelt area. Geothermal potential is considered high in the Wrangell Mountains and portions of the Alaska Range, and may be applicable to the Railbelt in the future. At this time, insufficient data are available to define the resource, even for appraisal of the large Susitna project market.

Tide

There is a large physical potential for tidal power development in the Cook Inlet area where the State estimates that a total of 8,560 MW could be harnessed. A potential of 785 MW is estimated for Knik Arm alone, and approximately twice that amount for Turnagain Arm.

Several different concepts have been developed for the Cook Inlet tidal potential because of the interest in alternative energy sources. There is merit to preparing a good reconnaissance of this alternative, as pointed out in the 1976 report. However, the scope of work involved to develop the tidal resource, the large cost of development, and the important environmental considerations eliminate tidal power as a reasonable alternative to the Susitna project.

Conclusion

The range of power options for the Alaska Railbelt is narrowing rapidly.

1. Oil and natural gas are very suspect in terms of long-range national supply and availability for use in power production.

2. Coal is proving to be far more expensive as a power source than previously anticipated.

3. Many hydroelectric alternatives have moved to the "unavailable" classes because of land area designations. The remaining are less desirable in terms of cost and ability to meet projected requirements.

4. Nuclear is expected to be as expensive as coal.

5. Geothermal, tide, and wind are unrealistic planning alternatives at this time.

PART VII. LOAD/RESOURCE AND SYSTEM POWER COST ANALYSES

Introduction

A series of load/resource and system cost analyses were made to demonstrate impacts of the Susitna project in terms of overall power system costs.

The load/resource analysis determined probable timing of new major investments in generation and transmission facilities. It also shows annual energy from each type of plant. The load/resource analyses were prepared for these basic power supply strategies:

Case 1. All additional generating capacity assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2. All additional generating capacity assumed to be coal-fired steam turbines, including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna project (including transmission intertie) plus additional coal as needed, and for the three load limits (high, medium, and low).

The system cost analyses, keyed to the load/resource, determined cost by year to amortize investments and pay all annual costs (fuel, O&M expenses, etc). Inflation rates of 0 and 5 percent were considered.

APA developed a number of the key inputs, e.g., demands, unit sizes and costs, etc. APA contracted with Battelle to make the studies and prepare the report.

This section summarizes key assumptions and results. More detailed information is available in the appended Battelle report.

Basic Data and Assumptions

Basic data and assumptions used in the load/resource and system power cost analyses are:

1. Interest rate for repayment of facilities = 7 1/2 percent.

2. Inflation rates of 0 and 5 percent, with construction costs increasing at inflation rate, and fuel costs increasing at 2 percent above inflation rate.

3. System reserve capacity of 25 percent for non-interconnected load centers and 20 percent for interconnected systems.

4. Transmission losses of 1.5 percent for energy and 5 percent for capacity.

5. Retirement schedules for proposed generating facilities (economic facility lifetime):1/

	Years
Coal-Fired Steam	35
Oil-Fired Steam	35
Gas-Fired Combustion Turbine	20
Oil-Fired Combustion Turbine	20
Hydroelectric	50
Diesel	20

6. Plant factors for new and most of the existing facilities are:

	Percent
Hydro	50
Steam	75
Combustion turbine	50
Diesel	10

The factor for combustion turbines was reduced to 10 percent in the study when adequate steam turbine capacity was available.

1/ See tables 3.4 and 3.5 of appended Battelle report for estimated retirement dates of existing facilities.

7. Hydro plants designed for 115 percent of nameplate capacity for limited reserve requirements.

8. Watana power on-line (POL) in 1994 and Devil Canyon POL in 1998.

9. Existing and planned generating facilities for Anchorage and Fairbanks are shown in the appended Battelle report.

10. New coal-fired steamplants for Fairbanks assumed to be 100-MW units (first six), then 200-MW units. Anchorage units assumed to be 200 MW (first five), then 400-MW units.

11. New coal-fired steamplants to be located at Beluga for Anchorage area and at Healy (or other sites within 100 miles) for Fairbanks.

12. Fuel costs--see appended Battelle report.

13. Power demands will be met by resource allocation using Susitna hydro generation first, coal-fired second, and natural gas and oil last.

14. Heat rate for new coal-fired steamplants = 10,500 Btu/kwh.

15. Total investment cost in October 1978 dollars.

Plant	($ million)	($/kw)
100-MW Coal Steam Turbine	245.4	2,454
200-MW Coal Steam Turbine	372.0	1,860
400-MW Coal Steam Turbine	646.8	1,617
Watana Dam (795 MW) and	2,020.7	2,554
Transmission Line	470.5	--
Devil Canyon Dam (778 MW)	834.0	1,072
Total Susitna Project (1,573 MW)	3,335.2	2,120

16. Operation, maintenance, and replacement costs.

Plant	($ million/yr.)	($/KW/yr.)
100-MW Coal Steam Turbine	3.76	37.6
200-MW Coal Steam Turbine	5.7	28.5
400-MW Coal Steam Turbine	9.8	24.5
Watana Dam (795 MW)	0.74	0.94 1/
Devil Canyon Dam (778 MW)	0.73	0.94 1/
New Transmission Facilities	--	2.0 1/

Study Methodology

As stated in the introduction, three cases were analyzed to determine timing of generation and transmission (G&T) investments and their impact on total power system costs.

The first step in estimating the cost of power from alternative generation and transmission system configurations was to perform a series of load/resource analyses. These analyses determined the schedule of major investments based on assumptions of load growths, capacity and energy production of the potential generating facilities, and constraints as to when the facilities could come on-line. The load/resource analyses also determined the annual power production from each type of generating plant in the system.

The system cost analyses then determined the annual cost for amortizing and operating the facilities. Summing the annual cost for generation and transmission of each of the generating facilities gave a total cost, by year, for the entire system being analyzed. Dividing the total annual cost by the power produced gave an average annual cost of power for the entire system.

1/ This breakdown of OM&R costs by project feature for convenience of the load/resource analysis resulted in slightly higher cost. Significance to Susitna rate is, at most, less than 1 percent.

Rounded Thermal generating capacity additions to the year 2010 from the previous tables are summarized as follows:

Table 21
SUMMARY OF THERMAL GENERATING CAPACITY ADDITIONS TO THE YEAR 2010

Upper Susitna Project Power Market Analysis

Case 1: Without Interconnection & Without Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2,600	471	3,071
Mid	4,600	871	5,471
High	8,200	1,471	9,671

Case 2: Interconnection Without Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2,200	471	2,671
Mid	4,200	671	4,871
High	8,200	1,271	9,471

Case 3: Interconnection With Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	1,000	171	1,171
Mid	3,000	371	3,371
High	6,600	1,071	7,671

Note: Bradley Lake and Susitna hydroelectric projects are not included.

Results

Load/Resource Analyses

The schedule of new plant additions for Anchorage and Fairbanks for 1978-2011 are shown in the appended Battelle report. A summary of the thermal generating capacity additions is in table 21. Further discussion of the computer model results and graphs are also shown in the appended Battelle report.

Under the criteria used, completion of construction for interconnection is scheduled in 1986, 1989, and 1994 for high, mid and low load growth cases, respectively, without Upper Susitna. With Upper Susitna, the corresponding dates are 1986, 1989, and 1991.

System Power Costs

Annual system costs and unit power costs are presented in detail, both tabular and graphically, in the appended Battelle report. The following tabulations summarize these findings. Table 22 shows annual power system costs for cases 1, 2, and 3, high, mid and low range, with 0 percent inflation. The first few years after Watana comes on-line, the total annual power system costs increase slightly. However, comparing the total annual power system costs for the 1990-2011 period to case 1, construction of the Susitna project results in a savings of $2.20 billion, or 12 percent.

Figure 18 shows the relative savings in annual cost for case 3, with Susitna, and case 1, without Susitna, for the three load growth assumptions.

Tables 23, 24, and 24a summarize Anchorage and Fairbanks separately plus the combined system average annual power costs in ¢/kwh for 1978-2011. The tables verify the feasibility of the intertie in power cost savings for Anchorage and Fairbanks. By the year 2000, system wide power rates would be:

Average Power System Rates for Anchorage and Fairbanks - 0% Inflation
(¢/kwh)

	Case 1 Without Susitna or Intertie			Case 2 With Intertie			Case 3 With Susitna and Intertie		
	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System
High	6.2	8.8	6.6 1/	6.1	8.0	6.4	5.8	6.2	5.8
Mid	6.6	8.9	6.9 1/	6.2	8.4	6.6	5.5	6.7	5.7
Low	7.1	9.2	7.5 1/	6.2	8.8	6.7	6.1	7.8	6.4

Comparison of Power Costs by Year 2000
Percent Change in Cost of Power Below Case 1 - 0% Inflation

	Case 2			Case 3		
	Anch.	Fbks.	Combined System	Anch.	Fbks.	Combined System
High	-1.6	-10.0	-3.1	-6.7	-41.9	-13.8
Mid	-6.5	-6.0	-4.5	-20.0	-32.8	-21.1
Low	-14.5	-4.5	-11.9	-16.4	-17.9	-17.2

For the Anchorage-Cook Inlet area, inclusion of the Susitna Project into the system (case 3) generally raises the cost of power above cases 1 and 2 during the first two to four years after Watana comes on-line, but lowers power costs during the 1996-2011 period. This reduction in the cost of power is significant in most cases.

For the Fairbanks-Tanana Valley load center construction of the interconnection (case 2) again generally reduces the cost of power compared to without an interconnection (case 1). The inclusion of the Susitna project (case 3) generally raises the cost of power above case 2 for about two years after Watana comes on-line, but, as with the Anchorage-Cook Inlet area, results in lower power costs during the 1996-2011 period.

1/ Anchorage and Fairbanks are not interconnected for case 1, the combined system rate is shown for academic comparison purposes only.

Table 22

COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY ANNUAL POWER SYSTEM COSTS - 0% INFLATION

Upper Susitna Project Power Market Analysis ($ Million)

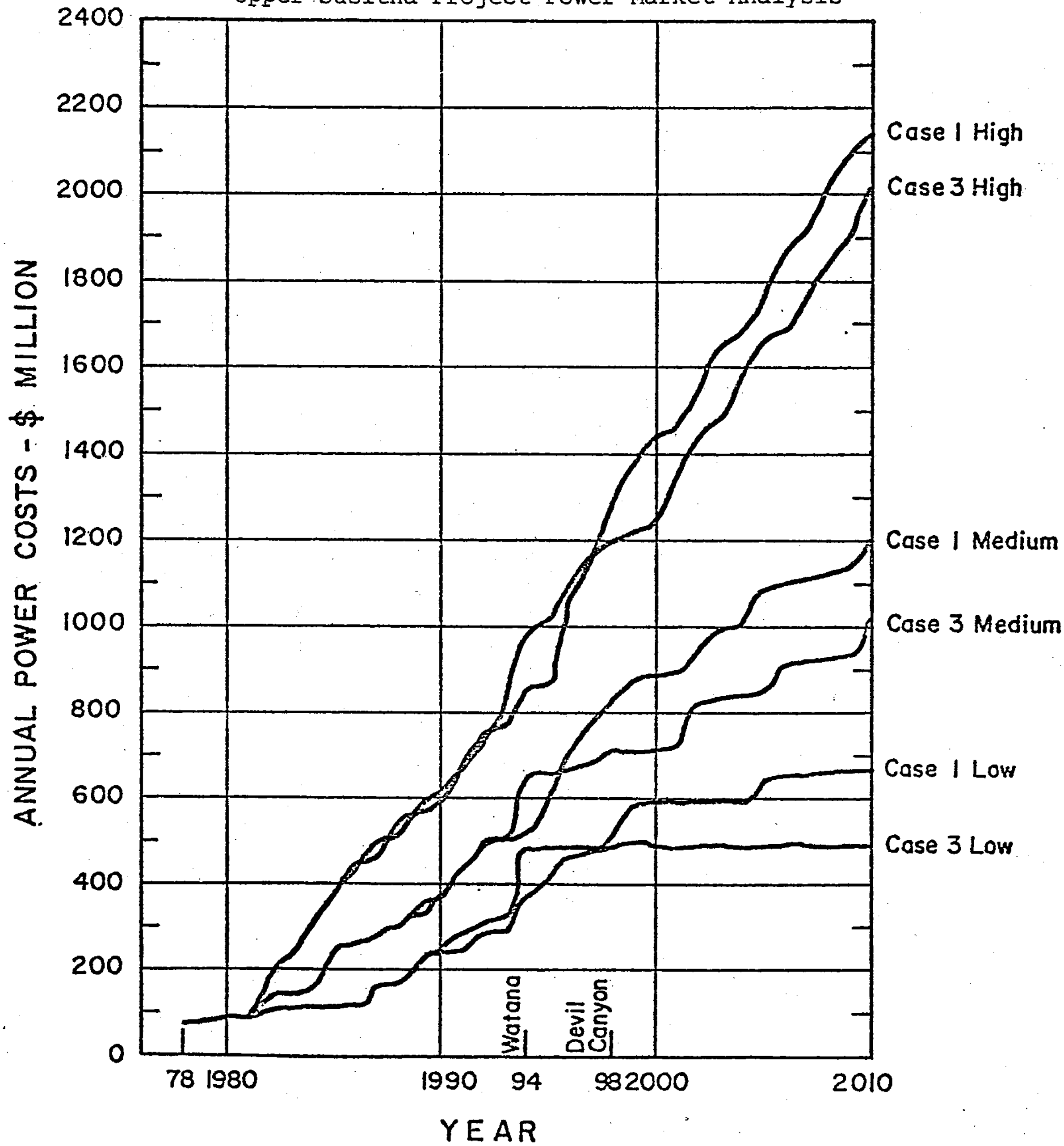
	CASE I			CASE II			CASE III		
YEAR	LOW	MEDIUM	HIGH	LOW	MEDIUM	HIGH	LOW	MEDIUM	HIGH
1978-79	68.4	68.3	68.3	68.4	68.3	68.3	68.4	68.3	68.3
1979-80	80.3	80.2	80.2	80.3	80.2	80.2	80.3	80.2	80.2
1980-81	89.1	89.0	89.0	89.1	89.0	89.0	89.1	89.0	89.0
1981-82	95.9	95.9	95.9	95.9	95.9	95.9	95.9	95.9	95.9
1982-83	108.4	146.0	203.5	108.4	146.0	203.5	108.4	146.0	203.5
1983-84	107.1	147.4	245.3	107.1	147.4	245.3	107.1	147.4	245.3
1984-85	109.3	152.1	321.6	109.3	152.1	321.6	109.3	152.1	321.6
1965-86	120.7	252.5	383.2	120.7	252.5	383.2	120.7	252.5	383.2
1986-87	119.1	257.9	456.8	119.1 *	257.9	434.0	119.1 *	257.9	434.0
1987-88	173.4	296.7	464.7	173.4	296.7	502.1	173.4	296.7	502.1
1988-89	170.8	298.5	547.9	170.8	298.5	510.8	170.8	298.5	510.8
1989-90	236.8	362.6	575.3	236.8	338.7 *	593.7	236.8	338.7 *	593.7
1990-91	243.5	371.0	587.7	243.5	382.8	603.1	243.5	382.8	603.1
1991-92	256.8	422.4	667.7	256.8	434.0	682.0	293.4	434.0	682.0 *
1992-93	292.5	507.0	754.9	292.5	498.1	735.1	290.5	498.1	735.1
1993-94	297.3	512.6	766.1	297.3	503.3	832.8	330.9	503.3	832.8
1994-95	364.4	521.1	865.0	339.6	536.2	847.4 *	487.9 #	658.0 #	990.7 #
1995-96	404.8	591.3	863.6	382.7	629.8	951.3	487.6	662.7	1,004.1
1996-97	464.4	701.4	1,060.8	441.0	714.7	1,068.2	486.0	667.0	1,097.1
1997-98	480.6	783.7	1,164.7	517.4	737.2	1,172.2	479.1	688.5	1,165.6
1998-99	511.1	819.7	1,282.6	525.1	832.8	1,254.6	485.8 +	721.4 +	1,210.4 +
1999-2000	592.9	888.2	1,389.3	527.2	841.7	1,333.7	506.6	722.9	1,222.4
2000-2001	586.2	886.7	1,450.2	600.2	899.8	1,423.1	495.9	719.9	1,253.7
2001-2002	588.7	894.8	1,471.2	602.7	907.9	1,503.9	494.8	725.9	1,355.3
2002-2003	584.1	955.3	1,544.0	598.1	931.3	1,576.7	487.2	827.2	1,426.4
2003-2004	587.5	998.7	1,661.5	601.6	999.4	1,634.5	488.6	834.7	1,482.0
2004-2005	590.1	1,008.2	1,684.5	604.1	1,009.5	1,691.9	488.9	841.4	1,583.7
2005-2006	651.9	1,096.1	1,787.1	606.2	1,018.0	1,774.8	488.7	847.8	1,662.9
2006-2007	655.6	1,106.3	1,872.1	632.6	1,028.2	1,859.8	490.2	915.6	1,686.0
2007-2008	659.2	1,117.0	1,935.1	636.2	1,118.2	1,965.2	491.7	923.9	1,769.6
2008-2009	662.4	1,127.6	2,021.4	639.9	1,128.9	1,991.8	493.3	932.4	1,853.8
2009-2010	666.6	1,139.7	2,108.5	643.6	1,140.0	2,078.9	494.9	941.3	1,913.4
2010-2011	670.4	1,209.5	2,136.6	647.5	1,151.1	2,163.1	496.6	1,010.0	2,018.6
Total	12,290.3	19,905.4	32,606.3	12,115.1	19,666.1	32,671.7	10,981.4	17,682.0	31,076.3
Subtotal 1990-2010	10,811.0	17,658.3	29,074.6	10,796.4	17,442.9	29,144.1	9,502.1	15,458.8	27,548.7

Note: Savings to total power system 1990-2010 for mid range case 1 of $17,658.3 million less case 3 $15,458.8 million is $2,199.5 million.

* Interconnection installed
\# Watana on-line
\+ Devil Canyon on-line

COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY ANNUAL POWER SYSTEM COSTS WITH AND WITHOUT SUSITNA

Upper Susitna Project Power Market Analysis



Case I: without Susitna
Case 3: with Susitna

Table 23
ANCHORAGE-COOK INLET AREA
AVERAGE POWER COSTS - CENTS PER KILOWATT HOUR - 0% INFLATION

Upper Susitna Project Power Market Analysis

	Case 1			Case 2			Case 3		
Year	High	Medium	Low	High	Medium	Low	High	Medium	Low
78-79	1.3	1.3	1.4	1.3	1.3	1.4	1.3	---	1.4
79-80	1.4	1.5	1.7	1.4	1.5	1.7	1.4	---	1.7
80-81	1.3	1.6	1.8	1.3	1.6	1.8	1.3	---	1.8
81-82	1.2	1.6	1.9	1.2	1.6	1.9	1.2	---	1.9
82-83	3.2	2.9	2.2	3.2	2.9	2.2	3.2	---	2.2
83-84	3.6	2.8	2.1	3.6	2.8	2.1	3.6	---	2.1
84-85	4.0	2.8	2.2	4.0	2.8	2.2	4.0	---	2.2
85-86	4.6	4.3	2.4	4.6	4.3	2.4	4.6	---	2.4
86-87	5.0	4.2	2.3	4.8 *	4.2	2.3	4.8 *	---	2.3
87-88	4.8	4.7	3.7	5.3	4.7	3.7	5.3	---	3.7
88-89	5.4	4.4	3.5	5.1	4.4	3.5	5.1	4.4	3.5
89-90	5.1	4.8	4.2	5.7	4.5 *	4.2	5.7	4.5 *	4.2
90-91	4.8	4.5	4.1	5.4	4.8	4.1	5.4	4.8	4.1
91-92	5.2	5.0	4.1	5.7	5.3	4.1	5.7	5.3	4.6 *
92-93	5.5	5.6	4.7	5.4	5.9	4.7	5.4	5.9	4.4
93-94	5.3	5.3	4.6	5.7	5.6	4.6	5.7	5.6	5.0
94-95	5.5	5.1	5.3	5.5	5.4	4.9 *	6.4 #	6.9 #	7.3 #
95-96	5.8	5.6	5.7	5.6	5.8	5.4	6.0	6.5	6.8
96-97	5.9	6.2	6.5	5.8	6.4	5.8	6.2	6.1	6.5
97-98	6.0	6.5	6.3	5.9	6.1	6.6	6.2 +	5.8 +	6.3 +
98-99	6.1	6.3	6.1	6.0	6.5	6.4	6.1	5.8	6.1
99-2000	6.2	6.6	7.1	6.1	6.2	6.2	5.8	5.5	6.1
00-01	6.3	6.4	6.9	6.2	6.6	7.2	5.5	5.3	5.9
01-02	6.1	6.3	6.9	6.3	6.4	7.2	5.6	5.2	5.6
02-03	6.2	6.6	6.8	6.4	6.3	7.1	5.7	5.7	5.7
03-04	6.3	6.5	6.8	6.2	6.7	7.1	5.6	5.6	5.6
04-05	6.1	6.4	6.7	6.1	6.6	7.0	5.8	5.5	5.6
05-06	6.3	6.9	7.6	6.2	6.5	7.0	5.9	5.4	5.5
06-07	6.4	6.8	7.5	6.3	6.4	7.0	5.8	5.8	5.5
07-08	6.3	6.8	7.5	6.5	6.9	7.0	5.9	5.8	5.5
08-09	6.4	6.7	7.5	6.3	6.8	6.9	6.0	5.7	5.4
09-10	6.5	6.6	7.5	6.4	6.7	6.9	5.9	5.6	5.4
10-11	6.3	6.9	7.5	6.5	6.7	6.9	6.0	5.9	5.4

* Interconnection Installed
\# Watana on-line
\+ Deveil Canyon on-line

Table 24
AVERAGE POWER COSTS - 0% INFLATION (¢/KWH)
FAIRBANKS-TANANA VALLEY AREA

Upper Susitna Project Power Market Analysis

	Case 1			Case 2			Case 3		
Year	High	Medium	Low	High	Medium	Low	High	Medium	Low
78-79	4.1	4.3	4.4	4.1	4.3	4.4	1.3	4.3	4.4
79-80	4.1	4.3	4.5	4.1	4.3	4.5	1.4	4.3	4.5
80-81	4.1	4.3	4.7	4.1	4.3	4.7	1.3	4.3	4.7
81-82	4.0	4.3	4.7	4.0	4.3	4.7	1.2	4.3	4.7
82-83	3.8	4.2	4.7	3.8	4.2	4.7	3.2	4.2	4.7
83-84	3.4	3.8	4.3	3.4	3.8	4.3	3.6	3.8	4.3
84-85	5.2	3.4	3.9	5.2	3.4	3.9	4.0	3.4	3.9
85-86	4.7	5.4	3.6	4.7	5.4	3.6	4.6	5.4	3.6
86-87	5.9	5.1	3.3	5.5 *	5.1	3.3	4.8 *	5.1	3.3
87-88	5.6	4.8	3.0	5.1	4.8	3.0	5.3	4.8	3.0
88-89	5.5	4.8	3.1	5.0	4.8	3.1	5.1	4.8	3.1
88-90	6.5	6.3	5.6	4.7	5.8 *	5.6	5.7	5.8 *	5.6
90-91	6.5	6.4	5.8	4.6	5.9	5.8	5.4	5.9	5.8
91-92	6.2	6.2	5.9	4.4	5.7	5.9	5.7	5.7	7.2
92-93	6.8	7.3	5.6	6.3	5.4	5.6	5.4	5.4	6.9
93-94	6.6	7.1	5.5	7.3	5.2	5.5	5.7	5.2	6.8
94-95	7.4	6.9	7.1	7.0	6.5	6.7 *	6.4 #	6.8 #	8.8 #
95-96	7.2	6.9	7.3	7.8	7.7	6.9	6.0	6.7	8.9
96-97	7.6	7.8	7.1	8.2	7.4	8.3	6.2	6.4	8.6
97-98	8.1	8.3	7.9	8.7	7.8	9.1	6.2	6.9	7.8
98-99	8.9	9.1	9.4	8.3	8.7	8.9	6.1 +	6.9 +	7.6 +
99-2000	8.8	8.9	9.2	8.0	8.4	8.8	5.8	6.7	7.8
00-01	8.3	8.7	9.3	7.7	8.3	8.8	5.5	6.6	7.8
01-02	8.0	8.6	9.3	7.5	8.2	8.8	5.6	6.5	7.7
02-03	7.7	8.4	9.1	7.2	9.0	8.7	5.7	7.3	7.6
03-04	8.5	9.8	9.1	8.0	8.9	8.7	5.6	7.2	7.6
04-05	8.2	9.7	9.1	8.7	8.8	8.7	5.8	7.1	7.5
05-06	8.0	9.5	9.0	8.4	8.6	8.6	5.9	7.0	7.4
06-07	7.8	9.4	9.0	8.2	8.6	10.1	5.8	6.9	7.4
07-08	8.5	9.3	9.1	8.1	8.5	10.1	5.9	6.8	7.4
08-09	8.4	9.2	9.0	7.9	8.4	10.1	6.0	6.8	7.4
09-10	8.2	9.1	9.1	7.7	8.3	10.2	5.9	6.7	7.4
10-11	8.0	9.1	9.1	7.6	8.2	10.2	6.0	6.6	7.4

* Interconnection Installed
# Watana on-line
+ Devil Canyon on-line

Table 24a
COMBINED ANCHORAGE-COOK INLET AND FAIRBANKS-TANANA VALLEY
AREA AVERAGE ANNUAL POWER COST 1/(¢/KWH)

Upper Susitna Project Power Market Analysis

	Case 2			Case 3		
YEAR	HIGH	MEDIUM	LOW	HIGH	MEDIUM	LOW
1978-79						
1979-80						
1980-81						
1981-82						
1982-83						
1983-84						
1984-85						
1985-86						
1986-87	4.90 *			4.90 *		
1987-88	5.31			5.31		
1988-89	5.07			5.07		
1989-90	5.56	4.79 *		5.56	4.79 *	
1990-91	5.24	5.06		5.24	5.06	
1991-92	5.52	5.39		5.52	5.39	5.14
1992-93	5.58	5.83		5.58	5.83	4.89
1993-94	5.94	5.57		5.94 #	5.57 #	5.35 #
1994-95	5.71	5.63	5.28 *	6.67	6.91	7.59
1995-96	5.92	6.19	5.69	6.25	6.52	7.25
1996-97	6.18	6.61	6.29	6.35	6.17	6.93
1997-98	6.34	6.44	7.08	6.30	6.01	6.56
1998-99	6.36	6.88	6.91	6.14 +	5.96 +	6.39 +
1999-2000	6.37	6.61	6.68	5.84	5.68	6.42
2000-2001	6.47	6.87	7.54	5.70	5.50	6.23
2001-2002	6.53	6.75	7.51	5.89	5.40	6.16
2002-2003	6.55	6.75	7.39	5.93	5.99	6.02
2003-2004	6.51	7.06	7.37	5.90	5.90	5.98
2004-2005	6.47	6.96	7.33	6.05	5.80	5.93
2005-2006	6.52	6.85	7.30	6.11	5.71	5.88
2006-2007	6.58	6.76	7.55	5.97	6.02	5.85
2007-2008	6.71	7.18	7.53	6.04	5.94	5.82
2008-2009	6.57	7.09	7.51	6.11	5.86	5.79
2009-2010	6.62	7.01	7.50	6.10	5.78	5.76
2010-2011	6.67	6.92	7.48	6.23	6.07	5.74

1/ Case I not interconnected, therefore combined system rate does not apply.

* Interconnection Installed
\# Watana on-line
\+ Devil Canyon on-line

Part VIII. INVESTMENT COSTS

Construction costs for power producing facilities were prepared by the Corps of Engineers (Corps); those for the transmission facilites by Alaska Power Administration (APA). APA prepared estimates of interest during construction based on 7 1/2 percent.

Corps estimates include alternative design concepts for Devil Canyon--thin-arch, as orginally proposed by Bureau of Reclamation (USBR), and the concrete gravity design, which is more costly and conservative.

Transmission estimates are based on same plan presented in 1976 report, with costs updated by indexing.

Current costs for transmission facilities are based on indexing construction costs presented in the 1976 report (January 1975 prices) to current levels (October 1978 prices) by applying a factor of 1.38 to clearing and rights-of-way, 1.33 to all other transmission line components (access roads, structures, etc.), and 1.28 to substations and switchyards, resulting in an overall factor of about 1.32. The clearing and rights-of-way factor is based on experience of the Alaska Department of Transportation and on recent experience of the USBR and Bonneville Power Administration (BPA). The 1975 prices are based on component prices from BPA with an increase of 90 percent for labor and 10 percent for material transportation from the Pacific Northwest to Alaska. Examination indicated that these factors are also valid for this analysis, but should be reevaluated if more detailed cost estimates are made in future years.

Transmission system costs are summarized in table 25.

Investment costs are calculated by adding interest during construction at the annual rate of 7 1/2 percent to construction costs presented previously.

The project schedule includes (1) first-stage construction of Watana dam and powerplant and the total project transmission system, and (2) second-stage Devil Canyon dam and powerplant. The transmission system will be completed about three years before completion of Watana to develop interconnection benefits by deferring of required steamplant capacity (discussed in Part XIII, Load Resource Analysis).

Table 26 summarizes the investment costs required.

Table 25
CONSTRUCTION COST SUMMARY
Upper Susitna Project Power Market Analysis

Item	Construction Cost ($1,000 - 10/78) System No. 5
Transmission Lines	
Clearing	$ 3,350
Right-of-Way	5,000
Access Roads	19,110
Line Structures	242,190
Subtotal - T.L.	$269,650
Switchyards and Substations	
Fairbanks Substation	$ 11,710
Talkeetna Substation	10,100
Anchorage Substation	15,890
Healy Switchyard	4,770
Watana Switchyard	6,360
Devil Canyon Switchyard	19,660
Subtotal - S.S.	$ 68,490
Total	$338,140
Rounded	$338,000

Table 26

INVESTMENT COST SUMMARY ($/MILLION)

Upper Susitna Project Power Market Analysis

Stage	Watana (1st)	Devil Canyon (2nd)	Total
Power Production Facilities			
Construction	1,427.0	665.0	2,092.0
Interest during Construction	603.7	168.6	772.3
Investment	2,030.7	833.6	2,864.3
Power Transmission Facilities			
Construction	338.0		338.0
Interest during Construction	132.5		132.5
Investment	470.5		470.5
Total Investment - Susitna	2,501.2	833.6	3,334.8

PART IX. OPERATION, MAINTENANCE, AND REPLACEMENT PLAN AND COSTS

Operation and Maintenance

This updates information furnished in the 1976 report. Operation, maintenance, and replacement costs were indexed for this report.

Plan Description

This plan assumes Federal operation of the facilities.

The plan assumes the headquarters and main operations center for the Susitna project will be near Talkeetna or at some other equally accessible point. Equipment at the center will remotely control the operation of the generation and transmission system and operation of Devil Canyon and Watana dams and reservoirs. Electrician/operators and mechanic/operators will be located at the powerplants to provide routine maintenance and manual operation when required.

Specialized personnel, such as electronic technicians and meter and relay repairmen, will service both powerplants and the substations and switchyards from the project headquarters. Project administration, including supervision of power production, water scheduling, and transmission facilities, will also be from the project headquarters.

Major turbine and generator inspection and maintenance will be done by electricians, mechanics, engineers, and other experienced personnel from APA. Manufacturers' representatives and other specialized expertise will be consulted.

Alaska Power Administration's (APA) headquarters office in Juneau will handle power marketing, accounting, personnel management, and general administrative services.

Transmission line maintenance will be performed by two line crews, with assistance from the existing Eklutna Project line crew. Transmission line maintenance warehouses and parts storage yards will be at Devil Canyon or Watana, approximately mid-way between Devil Canyon and Fairbanks, and at the project headquarters. Line crew personnel will be stationed along the lines at designated maintenance stations and at the major substations to provide routine line patrol and maintenance tasks. Crews from throughout the project will be assembled for major work.

Visitor facilities with provisions for self-guided powerplant tours will need assistance from operation personnel.

Project-related recreation facilities will require cooperation between Federal, State, and local interests, and are assumed to be maintained by a State or local entity.

Project operation, maintenance, and administration could be combined with the existing Eklutna Project. Eklutna could be supervisory controlled from the Susitna project operations center with electrician/operators and mechanic/operators stationed at Eklutna. It is estimated that approximately $100,000/year could be saved by joint operation.

Marketing and Administration

Marketing and administration include three main functions:

1. Administration

    Personnel management
    Property management
    Budgeting
    Marketing policy
    Rate and repayment studies

2. Accounting

    Customer billing
    Collecting
    Accounts payable
    Financial records
    Payroll

3. Marketing

    Rate schedules
    Power sales contracts
    Operating agreements
    System reliability and coordination

Part of this work would be carried out by the project, with overall administration and support services provided by the APA headquarters staff.

Annual Costs

The estimated annual costs for operation, maintenance, marketing, and administration are based on itemized estimates of personnel, equipment, supplies, and services needed to do the work, with a provision for contingencies.

The estimate assumes Federal classified personnel providing management and administrative functions and wage grade personnel performing technical operation and maintenance activities. Classified salaries are based on a mid-grade rate. Wage grade rates are based on those in effect in the Anchorage area and include basic hourly rates, benefits, and overtime.

Costs of supplies, equipment, and personnel requirements are based on Bureau of Reclamation (USBR) guidelines and the experience of the Eklutna and Snettisham Projects. The Eklutna Project is fully staffed, including a line crew, which has been in operation since 1955. The Snettisham Project is isolated; it is separated from the Juneau load center by 45 miles of rugged terrain and water. A maintenance crew resides and performs routine maintenance at the powerplant; project operations are remotely controlled from Juneau. The Susitna project would have some characteristics of both projects.

Itemized costs for operation, maintenance, marketing, and administration are presented in table 27.

Costs by major category and number of personnel are summarized in table 28.

Replacements

The annual replacement cost provision establishes a sinking fund to finance replacement of major items which have an expected service life of less than the 50-year project repayment period. The objective is to cover costs and ensure financing for a timely replacement of major cost items to keep the project operating efficiently throughout its life.

The replacement cost is based on factors developed from USBR experience. The factors apply to the total powerplant, substation, switchyard, transmission tower, fixtures, and conductors. Replaceables include generator windings, communication equipment, a small percent of the transmission towers, and items in the substation and switchyards. Items covered by routine annual maintenance costs include vehicles, small buildings, camp utilities, and materials and supplies. Major features, such as dams and powerplant structures, are considered to have service lives longer than the 50-year repayment period. Their costs are not covered by the replacement funds. Right-of-way and clearing costs are not included. The 7½ percent interest rate used for project repayment was used to establish the replacement sinking fund.

Table 29 presents calculations of the annual replacement fund.

The following tabulation summarizes the operation, maintenance, and replacement costs:

	Annual Operation and Maintenance $1,000	Annual Replacement $1,000	Total OM&R $1,000
Watana	$2,360	$260	$2,620
Devil Canyon	530	170	700
Total	$2,890	$430	$3,320

Price base - October 1978.

Table 27
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Upper Susitna Project Power Market Analysis

October 1978 Prices
Dam and Powerplant, Total Transmission System

Personnel	Number	Grade or Rate	Annual Cost
Supervisory & Classified			
Project Manager	1	GS-14	$ 35,000
Assistant Project Manager	1	GS-13	29,500
Electrical Engineer	1	GS-12	24,800
Mechanical Engineer	1	GS-12	24,800
Supply & Property Clerk	1	GS-9	17,100
Administrative Assistant	1	GS-7	14,000
Clerk-Steno	1	GS-5	11,300
Subtotal Supervisory & Classified	7		$ 156,500
Wage Grade			
Electrician	2	17.00/hr.	$ 70,720
Mechanic	2	17.00/hr.	70,720
Heavy Duty Equip. Operator	1	17.00/hr.	35,360
Laborer	2	13.00/hr.	54,080
Meter Relay Mechanic	1	17.00/hr.	35,360
Electronic Technician	1	17.00/hr.	35,360
Powerplant Operator	6	17.00/hr.	212,160
Ass't. Powerplant Operator	4	15.00/hr.	124,800
Subtotal Wage Grade	19		$ 638,560
Line Crew			
Foreman	2	19.00/hr.	$ 79,040
Lineman	4	17.00/hr.	141,440
Equipment Operator	2	17.00/hr.	70,720
Groundman	4	17.00/hr.	141,440
Subtotal Line Crew	12		$ 432,640
Allowances			
C.O.L.A.-Sup. & Class x 25%			39,130
Shift Differential			22,430
Sunday Pay			12,030
Overtime			32,000
Government Contributions			96,410
Longevity N. A.			--
Subtotal-Allowances			$ 202,000
TOTAL PERSONNEL COST	38		$1,429,700

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Table 27 (cont.)
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Miscellaneous				Annual Cost
Telephone				$ 10,000
Official travel				19,000
Vacation travel				19,000
Supplies, Services & Maintenance--Powerplant				125,000
Supplies & Services--Vehicles & Equipment				50,000
Employee training				6,000
Line spray				25,000
Government camp maintenance				19,000
Subtotal - Miscellaneous				$ 273,000
Equipment Operation, Maintenance, and Replacement				
	No.	Initial Cost	Service Life	
Tractor with Dozer	1	$150,000	10	$ 15,000
Loader	1	75,000	10	7,500
Maintainer	1	75,000	10	7,500
Pickup	10	80,000	7	11,400
Sedan	1	5,000	7	700
Tractor & Lowboy	1	75,000	10	7,500
Dumptruck	1	25,000	10	2,500
Flatbed	2	20,000	7	2,900
Firetruck	1	25,000	10	2,500
Sno trac	2	16,000	7	2,300
Backhoe	1	35,000	10	3,500
Crane, 50 ton	1	200,000	20	10,000
Hydraulic Crane, 20 ton	1	100,000	20	5,000
Line truck	4	200,000	10	20,000
Subtotal - Equipment				$ 98,300
APA Headquarters Marketing and Administration				165,000
Subtotal				1,966,000
Contingencies (20% ±)				394,000
TOTAL WATANA & TRANSMISSION				$2,360,000

Table 27 (cont.)
ANNUAL OPERATION & MAINTENANCE COST ESTIMATE

Devil Canyon Dam and Powerplant

Personnel

Watana and Devil Canyon, supervisory controlled from a remote operation-dispatch center.

Increase base staff for Devil Canyon.		
Assistant operators	2@15.00/hr.	$ 62,400
Electricians	2@17.00/hr.	70,720
Mechanics	1@17.00/hr.	70,720
Maintenance	1@15.00/hr.	31,200
Subtotal		$ 235,040
Overtime		12,000
Government Contributions		21,160
Foreman Pay		6,500
Subtotal		$ 39,660
Subtotal - Personnel		$ 274,700

Miscellaneous

Vacation travel	$ 3,800
Employee training	1,200
Supplies, Services & Materials	112,500
Supplies and Services	13,400
Subtotal - Miscellaneous	$ 130,900

Equipment

	Initial Cost	Service/ Life	
Pick up	2 @ 16,000	7	$ 2,300
Snow tractor	1 @ 10,000	7	1,100
Subtotal - Equipment			$ 3,400

APA Headquarters Marketing and Administration	$ 35,000
Subtotal Devil Canyon Additions	444,000
Contingencies (20% $\pm$)	86,000
TOTAL DEVIL CANYON O&M ADDITION	$ 530,000
TOTAL WATANA AND TRANSMISSION	2,360,000
TOTAL SUSITNA PROJECT	$2,890,000

Table 28
OPERATION AND MAINTENANCE COST SUMMARY

Upper Susitna Project Power Market Analysis

	Watana & Transmission System		Devil Canyon		Total Devil Canyon, Watana & Transmission	
	Number	Dollars	Number	Dollars	Number	Dollars
Personnel:						
Salaries/Wages, Allowances		$1,429,700		$274,700		$1,704,400
Classified Personnel	7		0		7	
Wage Board Personnel	31		7		38	
Miscellaneous:						
Telephone, Travel, Supplies, Services, Training, Line Spray, Camp Maintenance		273,000		130,900		403,900
Equipment:						
Annual cost Replacement		98,300		3,400		101,700
Marketing and Administration						
APA Headquarters		165,000		35,000		200,000
Subtotal		$1,966,000		$444,000		$2,410,000
Contingencies (20% ±)		394,000		86,000		480,000
TOTAL		$2,360,000		$530,000		$2,890,000

Table 29
REPLACEMENT COSTS

Upper Susitna Project Power Market Analysis

Feature	Annual Replacement Factor	Watana and Transmission System		Devil Canyon		Total	
		Construction Cost	Annual Replacement Cost	Construction Cost	Annual Replacement Cost	Construction Cost	Annual Replacement Cost
Powerplant	0.0010	$197,370,000	$197,370	$120,860,000	$120,860	$318,230,000	$318,230
Transmission towers, fixtures, & conductors	0.0001	251,324,000	25,130	--	--	251,324,000	25,130
Substations and switchyards	0.0033	11,000,000	36,300	14,760,000	48,710	25,760,000	85,010
Total			$258,000		$169,570		$428,370
Rounded			$260,000		$170,000		$430,000

Replacement factors are based on 7 1/2 percent interest rate.

Construction cost based on the portion of the feature subject to replacement.

PART X. FINANCIAL ANALYSIS

This part estimates the market for project power and evaluates power rates needed to repay the investment in power facilities. Power market size is in more detail in this study than in the 1976 report. Likewise, costs are slightly more detailed.

The Upper Susitna Project is primarily for hydroelectric power generation and transmission. Minor portions of project costs (less than 1 percent) would be allocated to other purposes, such as recreation and flood control. Project financial viability is the essential element in demonstrating feasibility of the power development. The repayment rate is influenced principally by size of the market, amount of investment, and applicable interest rates. Operation, maintenance, and replacement costs are a minor part of total annual costs; they influence these rates insignificantly. If rates needed to repay the hydro project are attractive in comparison to other available alternatives, the project is economically justifiable.

The 1976 report compared the costs of five dam and reservoir plans for developing the Susitna River hydroelectric potential and found all costs were within a 15 percent range. Therefore, the scoping analysis was not repeated for this study.

In addition to analyzing the basic Susitna project plan, variations were also analyzed for sensitivity. These included interconnection with additional service areas, different timing for interconnection between Anchorage and Fairbanks, use of the more expensive Devil Canyon gravity dam instead of the arch dam, low load growth, and the effect of inflation. In addition, the load/resource and system cost analyses examine impact of the Susitna Project on overall system costs.

Market for Project Power

Upper Susitna will operate as part of a hydro/thermal power system.

The 1976 report assumed the market for Susitna firm energy as 75 percent of the mid-range utility requirements. Average rates for firm energy were estimated on that basis.

For this analysis, the market for firm energy was assumed to be approximated by load growth after Susitna power becomes available, plus market made available through retirement of older plants.

The balance of the Susitna energy is assumed marketable as secondary energy for fuel replacement, as long as all energy fits under the load curve. A value is assigned for marketable secondary energy based on estimated future coal costs. The actual value is probably significantly higher.

The value of fuel replacement energy is the same as that used in the load resource analysis, which is $1.00 to $1.50/million Btu by 1985. This is based on the concept that large, efficient coal mines will be developed in the Beluga area by then. The price is escalated at 2 percent per year above the zero inflation rate from 1985 to 1994, resulting in a cost of $1.20 and $1.80/million Btu's.

Table 30 summarizes the estimated market for Susitna energy using these criteria.

Cost of Project

Table 31 summarizes the construction cost, interest during construction, operation, maintenance, and replacement costs for Devil Canyon and Watana phases. Construction costs were furnished by the Corps for an October 1978 price level. Interest during construction was calculated from Corps construction cash flow estimates with interest accumulated until the project becomes operational. OM&R costs were updated from APA earlier estimates.

Costs have increased from the 1976 report for several reasons. Table 32 presents a summary comparison of the cost factors. Interest rates have increased from 6 5/8 to 7 1/2 percent. Design and cost changes were made by the Corps as a result of foundation drilling. Costs were updated for the Devil Canyon dam and the transmission line by indexing procedures. The major change in operation, maintenance, and replacement costs was due to inflation in personnel wages and provisions for contingencies such as unlisted items and state of the art. Watana's construction period was extended from 6 years to 10 years, increasing its construction period from 10 years to 14 years. The revised project investment cost is 89 percent higher than in the 1976 report.

TABLE 30
MARKET FOR UPPER SUSITNA POWER
ANCHORAGE AND FAIRBANKS AREAS

Upper Susitna River Project Power Market Analysis

MEDIUM ESTIMATE

Year	Firm Energy Sales GWH	Fuel Replacement Sales GWH
1994	633	2,401
1995	1,385	2,043
1996	2,231	1,197
1997	2,873	555
1998	3,531	2,872
1999	4,244	2,543
2000	4,686	2,101
2001	5,055	1,732
2002	5,630	1,115
2003	5,983	804
2004	6,352	235
2005	6,767	20
2006	6,787	0

COMPARISON WITH TOTAL AREA POWER REQUIREMENTS

	Estimated Anchorage and Fairbanks Energy	Estimated Market for New Hydroelectric Power
Year	Annual Energy Million KWH	Annual Energy Million KWH
1995	10,323	1,385 (13)1/
2000	13,288	4,686 (35)1/
2005	15,083	6,767 (45)1/

1/ Percent of total area requirements

Data Source: APA Load/Resources Analysis
Medium Load Growth Estimates,
Energy Losses are included.

Table 31
INVESTMENT AND OM&R COST SUMMARY

Upper Susitna Project Power Market Analysis

Unit	Watana	Devil Canyon	Total System
Completion Date	1994	1998	
Costs - $1,000			
Power Production Facilities			
Construction Costs	1,427,000	665,000 1/	
Interest During Construction	603,700	168,600	
Investment Cost	2,030,700	833,600	2,864,300
Transmission Facilities 2/			
Construction Costs	338,000		
Interest During Construction	132,500		470,500
Investment Cost	470,500		3,334,800
Total System Investment Cost			
Annual Operation and Maintenance			2,890
Annual Replacement			430
Annual OM&R			3,320

Price level is October 1978. Interest rate for repayment purposes in FY 1979 is 7-1/2%.

1/ Costs are for arch dam plan at Devil Canyon.
2/ Transmission system assumed online in 1991.

Average Rate Determination

Table 33 summarizes the estimated average firm energy rate for firm energy needed to repay project facilities investment for mid-range load growth conditions. The method used is similar to that used in the 1976 report. Present Federal criteria for power producing facilities require repayment of project costs, with interest, within 50 years after the unit becomes revenue producing. The applicable interest rate for Fiscal Year 1979 is 7 1/2 percent. Revenues were credited to the project from sale of secondary energy at a fuel replacement rate of 1.2¢/kwh during early years of project operation. The average required rate for repayment over 50 years after the last unit is installed is 4.7¢/kwh. Total repayment period will be 54 years with Devil Canyon coming on-line four years after Watana.

Alternatives to the basic project plan were analyzed to determine effects on average power rates:

1. Devil Canyon gravity dam in lieu of the thin-arch dam:

Investment cost increased $204.9 million.

Average rate for firm energy increased to a total of 4.9¢/kwh.

2. Transmission investment deferred until Watana phase comes on-line (1994):

Watana phase investment reduced $76 million.

Average rate reduced 0.1¢/kwh to a total of 4.6¢/kwh.

3. Mid load growth case, 5 percent inflation:

Investment cost increased $3.598 billion.

Revenue needs increased $243 million annually.

Firm energy is the same for all mid growth cases.

Average rate for firm energy increased 4.7¢/kwh to 9.7¢/kwh.

4. Low load growth case:

Revenue needs same as for mid range growth case.

Firm energy sales decreased; fuel replacement sales increased.

Average firm energy rate increased 1.7¢/kwh.

All Corps plans are based on completing Watana first, followed by Devil Canyon four years later. This is appropriate for mid range and high range growth conditions, but if low range conditions remain, it may mean the Devil Canyon unit could be deferred a few years.

Power Marketing Considerations

The average rate is useful for comparing the proposal with the alternatives. Actual marketing contracts will likely include separate provisions for demand and energy charges, wheeling charges, reserve agreements, and other factors.

There are some built-in inequities for any method of pricing. What amounts to a postage stamp rate is used by most utilities and large Federal systems. That is, power rates are the same for all delivery points on the system. Actual costs vary with the distance, size, and characteristics of load--it is more costly to serve a small load several miles from the power source than to serve a large load nearby. Policies vary from system to system as to "hookup" costs born by the customers.

Table 32
COST SUMMARY COMPARISON
WITH 1976 INTERIM FEASIBILITY REPORT

Upper Susitna Project Power Market Analysis

Item (Costs $ Million)	1976 Interim Feasibility Report	1978 Marketability Analysis Update	Difference Amount	Difference Percent
Interest Rate for Repayment	6-5/8%	7-1/2%	+ 7/8%	+ 13
Construction Period				
Watana	6 yrs.	10 yrs.	+ 4 yrs.	+ 67
Devil Canyon	5	8	+ 3	+ 60
Transmission System	3	3	0	0
Total	10 yrs.	14 yrs.	+ 4 yrs	+ 40
Construction Cost				
Watana	832.0	1,427.0	+ 595.0	+ 72
Devil Canyon	432.0	665.0	+ 233.0	+ 54
Transmission System	256.0	338.0	+ 82.0	+ 32
Total	1,520.0	2,430.0	+ 910.0	+ 60
Interest During Construction				
Watana	165.4	603.7	+438.3	+265
Devil Canyon	57.2	168.6	+111.4	+195
Transmission System	25.4	132.5	+107.1	+422
Total	248.0	904.8	656.8	+265
Investment Cost				
Watana	997.4	2,030.7	+1,033.3	+104
Devil Canyon	489.2	833.6	+ 344.4	+ 70
Transmission System	281.4	470.5	+ 189.1	+ 67
Total	1,768.0	3,334.8	+1,566.8	+ 89
Annual Cost for Repayment of Investment	113.34	239.20	+125.86	+111
Annual Equivalent OM&R	2.27	3.14	+ 0.87	+ 38
Total Annual Equiv. Cost	115.61	242.34	+126.73	+110
(Less Secondary Energy Sales (Fuel Replacement Sales)1/	5.77	11.34	+ 5.57	+ 97
Total Net Annual Equiv. Cost	109.84	231.00	121.16	+110
Annual Equiv. Energy GWH1/	5,218	4,923	-295	-6
Total Annual Equiv. Energy Cost - ¢/KWH	2.11	4.69	2.58	+123

1/ Median load growth

Note: Total energy during period of analysis is the same in both reports. Difference is due to variation in load build-up.

Table 33
AVERAGE RATE DETERMINATION
(WATANA AND DEVIL CANYON)
Upper Susitna Project Power Market Analysis

Year	Project Costs $1,000: Revenue Producing Investment	Project Costs $1,000: OM&R	1994 PW Costs $1,000: Investment	1994 PW Costs $1,000: OM&R	Firm Energy	Fuel Replacement Energy Sales	Project Energy Sales Million KWH: 1994 PW Firm Energy (1994-2005)	Project Energy Sales Million KWH: Fuel Replacement Sales
1994	2,501,200	2,620	2,501,200	2,437	633	2,401	589	2,233
1995		2,620		2,267	1,385	2,043	1,198	1,768
1996		2,620		2,109	2,231	1,197	1,796	964
1997		2,620		1,962	2,873	555	2,151	416
				(1998-2047)				
1998	833,600	3,320	624,200	32,256	3,531	2,872	2,459	2,000
1999		3,320			4,244	2.543	2.750	1,648
2000		3,320			4,686	2,101	2,824	1,266
2001		3,320			5,055	1,732	2,834	971
2002		3,320			5,630	1,115	2,937	582
2003		3,320			5,983	804	2,903	390
2004		3,320			6,352	235	2,867	106
2005		3,320			6,767	20	2,841	8
2006-2047					6,787	000	36,171	
Totals	3,334,800		3,125,400	41,031			64,320	12,352
Annual Equivalents			239,200	3,141			4,923	845

Average Rate Computation:

(1) Annual Costs:

	Capital	$239,200,000
	OM&R	3,140,000
	Total	$242,340,000
(2) Revenue From Fuel Replacement Energy at 12 mills per kilowatt hour		-11,340,000
		$231,000,000
(3) Equivalent Annual Firm Energy Sales		4,923,000,000 KWH
(4) Average Rate For Repayment ($231,000,000/ 4,923,000,000 KWH)	=	46.9 mills/KWH

Actual rates for the Susitna system could reflect several items of costs and revenues not identified in the project studies. For example, during its life, project facilities would likely be used to wheel power from other sources. Wheeling revenues will lower overall project power rates somewhat. Conversely, wheeling costs for project power delivered over non-Federal transmission lines will be added to project rate schedules. This is now done under APA marketing contracts for the Snettisham Project; there are similar situations in other Federal power systems.

Market Aspects of Other Transmission Alternatives

It is reasonable to expect modifications of the project transmission system as requirements (or needs) change. The main 345-kv and 230-kv lines could be upgraded substantially by adding compensation and transformer capacity. Substations could be added as future loads increase to a case-by-case determination of economics. Similarly, extensions of the project transmission lines to serve other areas would be considered on the basis of needs, economics, and available alternatives.

Anchorage-Cook Inlet Area

The costs in the proposed plan are premised on delivery points to substations near Talkeetna and Anchorage. Rough estimates indicate similar costs for a plan with delivery points at Talkeetna, Anchorage, and the existing APA Palmer substation. Basically the proposed plan includes costs to provide for delivery points on the existing CEA and APA systems north of Knik Arm, but does not include costs of delivering power across or around the Arm.

With or without the Susitna project, additional transmission capability is needed on the approaches to Anchorage. CEA plans for a Knik Arm system considers 230-kv transmission an important step in developing this capability, but more capacity will be needed by the mid-1980's. Essentially the same problems will exist with alternative power sources, such as the Beluga coals.

Following project authorization, detailed studies will be needed to consider alternatives for providing power across Knik Arm. Costs would be worked into rate structures through wheeling charges on non-Federal lines or annual costs on project lines, if needed.

The transmission plan to deliver project power in Anchorage will need to be worked out in the detailed post authorization studies. It will involve added costs, either wheeling charges for project power over non-Federal lines, or constructing project transmission lines around or under Knik Arm. These costs could be about the same for alternative power sources such as the Beluga coals.

It is essential that scheduling of project facilities be closely tied to the marketing function.

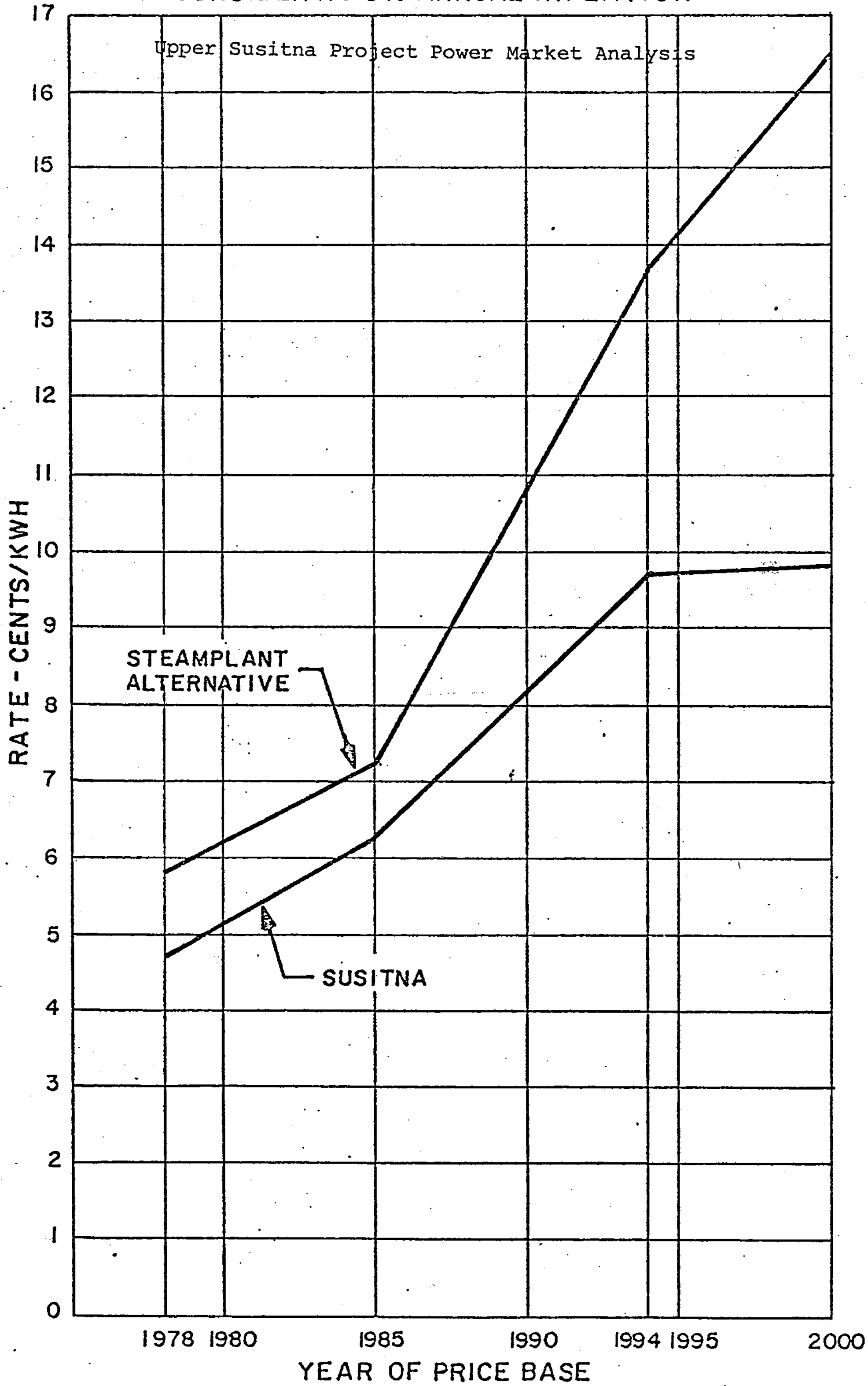
Comparison of Susitna to Steamplants With and Without Inflation

Without inflation, the 4.7¢/kwh rate for the Susitna project is significantly lower than the estimated cost of power from coal-fired steamplants at 5.2 to 6.4¢/kwh at October 1978 costs. Considering inflation, the capital costs of both the steamplant and hydro powerplant increase until construction is complete. For the completed projects, inflation affects only the hydro project operation and maintenance cost, a small part of the energy cost. For the steamplant, inflation continues to increase the fuel cost as well as the much larger operation and maintenance cost.

The difference of the effect of inflation is shown on figure 19. Capital and O&M costs are assumed to inflate at 5 percent per year for both. Fuel costs are assumed to inflate 2 percent per year higher than a base price of $1.00 or $1.50 per million Btu in 1985. The conclusions are that Susitna is considerably less susceptible to inflation than steamplants.

COMPARISON OF SUSITNA AND ALTERNATIVE COAL-FIRED STEAMPLANT RATES CONSIDERING 5% ANNUAL INFLATION

Figure 19



*(Fuel cost inflated 2% higher)

PART XI. GLENNALLEN AND VALDEZ

Introduction

The primary justification for the Upper Susitna project is to supply power and energy to the State's two largest power market areas, Anchorage-Cook Inlet and Fairbanks-Tanana Valley.

The Glennallen-Valdez area is recognized as a possible additional market area. The two communities are the principal load centers for the Copper Valley Electric Association (CVEA). At present, both are supplied from oil-fired generators.

CVEA is now moving into initial construction phases of its Solomon Gulch hydroelectric plant near Valdez, and is in final design stages for a 138-kv transmission line extending 104 miles to interconnect Valdez and Glennallen. CVEA could be interconnected with the major uitlities in the Anchorage-Cook Inlet area by adding a transmission line between Palmer and Glennallen. The transmission distance is 136 miles; minimum transmission voltage would likely be 139 kv. Depending on future demand, a higher voltage such as 230 kv may be justified.

Very preliminary studies summarized in the following section indicate a good chance that the Palmer-Glennallen intertie is feasible.

Power Market Area

Introduction

Similar to Fairbanks, both Glennallen and Valdez have been heavily impacted by trans-Alaska oil pipeline construction and operation. The pipeline terminal storage and shipping facilities are at Valdez. The pipeline was completed and went into operation in 1977. The Glennallen-Valdez area 1977 population was approximately 9,905, 39 percent higher than in 1974. However, the 1976 population (13,000) decreased 31 percent in 1977.

Valdez is the proposed site of a major refinery and petrochemical complex to process the State's royalty share of Prudhoe Bay oil. Plans are not yet finalized, but construction could begin as early as 1980. This would have major impacts in terms of both construction employment and a long term increase in employment and population for Valdez. The operations phase of the refinery involves 1,000 new jobs according to recent reports. Glennallen's population and economy are expected to continue to grow.

Existing Power System

The Copper Valley Electric Association (CVEA) serves both Glennallen and Valdez. CVEA's radial distribution lines extend from Glennallen, 30 miles north on the Copper River, 55 miles south on the Copper River to Lower Tonsina, and 70 miles west on the Glenn Highway. Figure 2 outlines the area.

CVEA plans to construct 104 miles of 138-kv long transmission line between Valdez and Glennallen. This is related to the Solomon Gulch 12-MW hydro development now beginning construction. At present, the utility loads are served totally by diesel generation of 17.7 MW: 10.1 MW at Valdez and 7.6 MW at Glennallen. Two small utilities serving limited areas on the highways north of Glennallen are included in historical data. Their installed diesel capacity totals 1/3 MW.

The Alyeska oil terminal facility at Valdez has 37.5 MW in oil-fired steam-turbine capacity. This is a total energy facility that satisfies the terminal's electrical and steam requirements.

Power Requirements

This section summarizes historic energy use and related data, information from a 1976 load forecast prepared for CVEA, and some general observations on likely magnitude of future power requirements.

Historic Data

Energy use and peak demand data were obtained from three power generating sources in the Valdez-Glennallen area: CVEA, the utility serving over 95 percent of the area; Chistochina Trading Post; and Paxson Lodge, Incorporated. The utility data yielded information on energy use, peak demand, and customer sector breakdowns.

Population and employment data were derived from statistics provided by the State of Alaska Department of Labor. This information illustrates demographic characteristics of the study area.

The 1970-77 Valdez-Glennallen area is summarized on table 34. Net generation by utility from 1960-77 is on table 35.

Analysis

The energy use, population, and employment data reflect events tied to construction and operation of the Alyeska oil pipeline. The large jumps in population and employment during the construction years cannot be directly tied to utility power requirements since most of the workers were housed in construction camps that supplied their own power.

The 1977 use data show total utility requirements at more than four times the 1970 level. Total number of customers tripled during the period.

Per customer residential use increased from 3,846 to 6,423 kwh per year over the 7-year period.

This historic data provides no clear insight to probable future levels of power use--any trends that would be useful in forecasting are hidden by the construction impacts.

Forecast

Table 36 summarizes future power demand estimates from CVEA's 1976 power requirements study. The study included estimates of demands through 1991; APA made a rough extension to the year 2000, assuming a 6 percent rate of increase.

The average energy capability of the Solomon Gulch project is estimated at 55 million kwh/year. The forecasts indicate that the Solomon Gulch power would be fully utilized as soon as it comes on-line. By the time Upper Susitna power would be available, CVEA total demands would exceed Solomon Gulch capability by around 100 million kwh/year.

The CVEA study predated the plans for the oil refinery at Valdez, hence there is substantial likelihood that the actual requirements will exceed the forecast amounts.

Transmission Plan And Cost

Incremental service to the Glennallen-Valdez market areas would require constructing transmission facilities from Palmer to Glennallen to connect to the CVEA system serving the market area. Susitna project generation and transmission to the Anchorage-Cook Inlet area would be sufficient to accomodate the incremental service.

The Palmer-Glennallen transmission system would have 136 miles of single circuit 138-kv line, with a substation at Palmer and a switchyard at Glennallen. The Palmer substation would have a 230/138-kv transformer, a 230-kv breaker, and a 138-kv circuit breaker. The Glennallen switchyard would include two 138-kv circuit breakers, and would connect with the planned CVEA 138-kv line extending to Valdez. Peak capacity of the 138-kv Palmer-Glennallen line would likely be from 50 to 80 MW. This is an assumption for study purposes (stability, sizing, and power flow studies were not made).

System costs are based on comparable elements of other project transmission systems, indexed from the 1976 report (January 1975 prices) to October 1978 prices (about 32 percent increase). The basic prices are based on Bureau of Reclamation (USBR) and Bonneville Power Administration (BPA) with adjustments for Alaska conditions (refer to Part VIII). Advance planning would analyze evaluations of structural, operation control, environment, and other elements affecting route location, design, and operation of the system serving this area.

Investment costs are calculated by adding 7½ percent interest annually during construction. The Palmer-Glennallen line would be constructed during the same period as other facilities, and would be ready for service when project power is available in 1994. Table 37 summarizes construction and investment costs.

Table 34
HISTORIC DATA
GLENNALLEN-VALDEZ AREA

Upper Susitna Project Power Market Analysis

	Utility Energy Sales (GWH)			Net Generation	
	Res	CI	Total	Utility	Industry
1970	2.1	7.4	9.9	11.9	
1971	2.6	7.8	10.8	12.8	
1972	2.8	7.6	10.8	13.0	
1973	2.9	8.3	11.6	13.8	
1974	3.7	10.4	14.5	16.8	
1975	7.7	16.0	24.4	28.2	
1976	10.3	22.4	33.5	40.7	
1977	10.9	31.0	42.9	48.7	39.4

	Utility Customers			Peak Load (MW)	
	Res	CI	Total	Utility	Industry
1970	546	221	793	2.4	
1971	681	226	939	2.5	
1972	655	237	926	2.6	
1973	684	247	965	2.7	
1974	911	317	1,268	4.0	
1975	1,172	361	1,576	7.3	
1976	1,677	404	2,128	8.6	
1977	1,697	427	2,183	9.3	37 (38.6 installed capacity)

	Population (Total)	Employment (Avg. Annual)
1970	3,098	831
1971	2,932	1,085
1972	3,464	904
1973	3,568	985
1974	3,833	1,526
1975	9,639	4,626
1976	13,000	7,818
1977	9,905	3,918

Res = residential
CI = Commercial-industrial

Table 35
UTILITY NET GENERATION (GWH)
GLENNALLEN-VALDEZ AREA

Upper Susitna Project Power Market Analysis

Year	CVEA	CTP	PLI	Total	Growth %
1960	3.2		0.1	3.3	
1961	3.4		0.1	3.5	6.1
1962	4.0		0.1	4.1	17.1
1963	4.5		0.1	4.6	12.2
1964	4.2		0.1	4.3	-6.5
1965	6.5		0.2	6.7	55.8
1966	8.0		0.2	8.2	22.4
1967	8.2		0.3	8.5	3.7
1968	8.6		0.4	9.0	5.9
1969	9.7	0.4	0.5	10.6	17.8
1970	10.7	0.4	0.7	11.8	11.3
1971	11.7	0.4	0.7	12.8	8.5
1972	11.8	0.4	0.7	12.9	0.8
1973	12.6	0.4	0.7	13.7	6.2
1974	16.6	0.4	0.7	17.7	29.2
1975	26.9	0.4	0.7	28.0	58.2
1976	39.3	0.4	0.7	40.4	44.3
1977	47.4	0.4	0.7	48.5	20.1

CVEA - Copper Valley Electric Association
CTP - Chistochina Trading Post
PLI - Paxson Lodge, Inc.

Table 36
VALDEZ-GLENNALLEN AREA UTILITY FORECASTS

Upper Susitna Project Power Market Analysis

	Energy (gwh)				Peak Demand (MW)	
	CVEA 1/				CVEA 1/	
Year	Glennallen	Valdez	Total		Glennallen	Valdez
1976	12.5	24.5	37.0	40.7 2/	3.1	6.0
1977	21.0	27.0	48.0	48.7 2/	4.2	5.9
1978	22.1	27.2	49.3		4.4	5.8
1979	24.0	27.6	51.6		4.6	5.8
1980	45.9	27.9	73.8		7.3	5.8
1981	48.5	30.5	79.0		7.7	6.3
1982	50.0	33.0	83.0		8.1	6.8
1983	52.2	35.5	87.7		8.5	7.4
1984	55.0	38.2	93.2		9.0	8.0
1985	57.6	41.4	99.0		9.5	8.6
1986	60.0	45.0	105.0		10.1	9.3
1987	63.1	48.5	111.6		10.6	10.1
1988	66.0	52.5	118.5		11.1	10.9
1989	69.1	56.8	125.9		11.7	11.8
1990	72.3	61.4	133.7		12.4	12.8
1991	75.0	66.4	141.4		13.0	13.8
1995			180			
2000			240			
2025			1,025			

1/ Copper Valley Electric Association Forecast from 1976 REA Power Requirements Study.

2/ Historical values

Table 37
INVESTMENT COST SUMMARY
GLENNALLEN-VALDEZ AREA TRANSMISSION SYSTEM

Upper Susitna Project Power Market Analysis

	(Costs-$1,000 10/78)		
	Construction	Interest During Construction	Investment
Transmission Line (Palmer-Glennallen)			
Clearing	$ 1,540		
Right-of-Way	310		
Access Roads	5,490		
Line Structures	25,760		
Subtotal	$33,100		
Switchyards & Substations			
Palmer Substation	$ 3,880		
Glennallen Switchyard	920		
Subtotal	$ 4,800		
Total	$37,900	$2,900	$40,800

Operation and Maintenance Costs

Addition of the 136-mile Palmer-Glennallen transmission line would involve comparatively minor increases in overall system operation, maintenance, and replacement costs.

For purpose of this analysis we are assuming the incremental O&M costs would be roughly equivalent to 1/3 of the annual cost of one transmission line maintenance crew. Adding an allowance for replacements, the annual OM&R cost is estimated at $131,000 per year. This is indicated on Table 38.

Table 38
OPERATION, MAINTENANCE, AND REPLACEMENT COST SUMMARY
GLENNALLEN-VALDEZ AREA TRANSMISSION SYSTEM

Upper Susitna Project Power Market Analysis

	Annual Cost - $1,000	
Operation and Maintenance	Full Crew	1/3 Crew
Personnel		
Salary & allowances for 6 Wage Grades	240	80
Miscellaneous		
Telephone, travel, supplies, services training, line spray, camp maintenance	10	3.3
Equipment (Replacement)	8	2.7
Marketing and Administration	22	7.3
Subtotal	280	93.3
Contingencies 20% ±	60	20
Subtotal - O&M	340	113.3
Rounded		113
Replacement		
Transmission towers, fixtures, conductors 0.0001 x $25,766,000	2.6	
Substations & Switchyards 0.0033 x $4,800,000	15.8	
Subtotal - Replacement	18.4	
Rounded	18	
Total OM&R	131	

Assessment of Feasibility

A minimum intertie between Palmer and Glennallen would involve incremental investment costs on the order of $40.8 million. Incremental annual costs are estimated as:

Amortization	$3,140,000
OM&R	131,000
Total Annual Cost	$3,271,000

Based on the utility forecast for CVEA, it is possible that a market in excess of 100 million kwh/year could be supplied over the Palmer-Glennallen line. This would equate to transmission costs of 3.3¢/kwh.

The 100 million kwh/year would be equivalent to 22.8 MW at 50 percent annual load factor. This is substantially less than half the estimated capacity for a 138-kv Palmer-Glennallen line.

Full utilization of the intertie could involve transmission of 200 to 300 million kwh/year, in which case, average transmission cost would drop from one-half to one-third the cost indicated above.

Regardless of the source of power--coal, oil, hydro--generation costs for CVEA will likely be higher than for the larger utility systems serving the Anchorage-Cook Inlet area. In this context, transmission costs on the order of 1.1 to 3.3¢/kwh between Palmer and Glennallen may be justifiable.

APA concludes that the Palmer-Glennallen intertie has a good chance for feasibility, and that a more detailed examination is warranted.

APPENDIX

1. Letter dated January 3, 1979 to Col. G. R. Robertson, Alaska District Corps of Engineers, transmitting responses to OMB questions falling in APA's area of responsibility.

2. Previous Studies and Bibliography.

3. LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010 -- Informal Report - by Battelle Pacific Northwest Laboratories, Richland, Washington - January, 1979.

4. Comments.
   a. Federal Energy Regulatory Commission, San Francisco, California, March 6, 1979.

   b. Battelle Pacific Northwest Laboratories, Richland, Washington, February 27, 1979.

   c. Corps of Engineers, Anchorage, Alaska, March 19, 1979.

   d. The Alaska State Clearinghouse, Juneau, Alaska, March 23, 1979.

   e. Municipal Light and Power Company, Anchorage, Alaska, March 1, 1979.

Department Of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

January 3, 1979

Colonel George R. Robertson
Alaska District Engineer
Corps of Engineers
P.O. Box 7002
Anchorage, AK 99510

Dear Colonel Robertson:

Attached are our responses to the Susitna Project OMB questions we agreed to provide (re: our letters dated January 20, 24, 1978).

Copies of these responses were sent via Goldstreak direct to Captain Mohn December 28, 1978.

Sincerely,

Donald L. Shira
Chief, Planning Division

OMB question 5.1, and .2.

OMB asked that the analysis of the "without" project condition be expanded to clearly analyze:

1. *Why, with natural gas projected to be in such short supply, the Anchorage utilities have only contracted for 55 percent of proved reserves or 25 percent of estimated ultimate reserves, and,*

2. *The sensitivity of the analysis to the collapse of OPEC and the cost of shipping oil to the East Coast.*

Both questions must be considered in terms of national energy policy. The Nation needs to reduce dependency on oil imports on both a short-term and a long-term basis, and to accomplish a major shift away from oil and natural gas to alternative energy sources. The reasons for this include national economic considerations, as well as very real limits on national and world supplies of oil and natural gas.

In terms of national energy policy, oil and natural gas are not available alternatives for long-term production of electric power. There are remaining questions as to how quickly existing uses will be phased out and on how complete the prohibitions will be on new oil and natural gas-fired powerplants.

There is general agreement that implementation of national policy must include strong efforts in conservation, substantial increase in use of coal, and major efforts to develop renewable energy sources. Each of these components is sensitive to energy price and supply variables. A reduction in world oil prices or a period of oversupply serves as a marketplace disincentive for conservation efforts and work on alternative energy sources.

The lowest cost alternatives and those with fully proven technology are the least sensitive; those that depend on further R&D are most easily sidetracked.

The Susitna Project involves large blocks of power and new energy from a renewable source, fully proven technology, long revenue-producing period (in excess of 100 years), and essential freedom from long-term price increases. Its unit costs appear attractive in comparison to coal-fired powerplants. It is a two-stage project with opportunity to defer the second stage if demands are lower than present estimates or if price relationships change.

The above factors suggest that the Upper Susitna Project is much less sensitive to short-term oil price and supply variations than most other U.S. energy options.

If it is assumed that Alaskan oil and natural gas will be isolated from U.S. and world demand and pricing, Alaska would probably continue to use its oil and gas for most of its power. This assumption did, in fact, prevail between the initial oil and gas discoveries in the Cook Inlet area and the 1973 oil embargo. In 1960, the Anchorage-Cook Inlet area power supplies came almost entirely from coal and hydro. The low cost, abundant gas brought a halt to hydro development and destroyed the area's coal industry. The one remaining Alaskan coal mine barely made it through the 1960's because of competition from relatively cheap oil.

The Cook Inlet gas has been subjected to increasing competition in the last few years, including proposals for LNG facilities, additional petrochemical plants, and consideration of pipeline alternatives to tie in with the Alcan pipeline project. The competition resulted in increasing prices and increasing difficulty in obtaining long-term commitments of gas for power. The competitions and the price increases are expected to continue.

The real question on gas availability as it pertains to Upper Susitna is: What is the outlook for long-term gas supplies for power after 1990? That outlook is not good in terms of competing uses and national policy.

Response to OMB question 5.3.

"The Necessity for an Anchorage-Fairbanks intertie at a cost of $200-300 million"

The estimated construction cost (1978 dollars) for the transmission lines from the Susitna Project to the Fairbanks area is $152 million, and $186 million for the lines from the project to the Anchorage area (total $338 million).

There are several previous studies[1/] that demonstrate inherent feasibility of an Anchorage-Fairbanks intertie with or without construction of the Upper Susitna Project. The main reason that the intertie is not now in place is that short term benefits to the Anchorage area are quite small, i.e., most of the short term benefits for the intertie would occur through reduced energy and power costs in the Fairbanks area.

APA studies in the 1975 feasibility report evaluated Susitna Project power to Fairbanks on a cost-of-service basis (see Appendix I, p. 6-89). This was a specific demonstration of feasibility of including Fairbanks as part of the Upper Susitna Power Market area.

1/ Among the previous studies are:

Alaska Power Survey, Federal Power Commission, 1969.

Central Alaska Power Pool, working paper, Alaska Power Administration, October 1969.

Alaska Railbelt Transmission System, working paper, Alaska Power Administration, December 1967.

Electric Generation and Transmission Intertie System for Interior and Southcentral Alaska, CH2M Hill, 1972.

Central Alaska Power Study, The Ralph M. Parsons Company, undated.

Alaska Power Feasibility Study, The Ralph M. Parsons Company, 1962.

Further verification of feasibility of the intertie is provided in the new load-resource analyses and system cost analyses prepared for the current studies. These general cases were analyzed:

Case 1. All future generating capacity assumed to be coal-fired steam turbines <u>without</u> intertie.

Case 2. All future generating capacity assumed to be coal-fired steam turbines <u>with</u> intertie.

Case 3. Future generating capacity to include Upper Susitna Project plus coal-fired steam plants as needed. Includes intertie.

Results of power cost analyses for Anchorage and Fairbanks for the year 2000, with and without intertie are as follows:

Power Costs for Anchorage and Fairbanks (0% Inflation)
(¢/KWH)

	Case 1 Without Intertie		Case 2 With Intertie		Case 3 With Susitna and Intertie	
	Anchorage	Fairbanks	Anchorage	Fairbanks	Anchorage	Fairbanks
High	6.2	8.8	6.1	8.0	5.8	6.2
Med	6.6	8.9	6.2	8.4	5.5	6.7
Low	7.1	9.2	6.2	8.8	6.1	7.8

The following table presents a comparison of the costs of power in the year 2000 for Case 2, and 3 as compared to Case 1. As shown the costs of power are reduced below the cost of power for Case 1 in all cases. The reduction in the cost of power is typically greater in the

Fairbanks-Tanana Valley area than in the Anchorage-Cook Inlet area because the Anchorage-Cook Inlet area will have a higher percent of its generation supplied by steam plants which are more costly than Susitna.

Comparison of Power Costs for Year 2000

Percent Change in Cost of Power Below Case 1 - 0% Inflation

	Anchorage			Fairbanks		
	High	Medium	Low	High	Medium	Low
Case 2	-1.6	-6.5	-14.5	-10.0	-6.0	-4.5
Case 3	-6.9	-20.0	-16.4	-41.9	-32.8	-17.9

Table 1 compares annual system costs for all three cases for Anchorage and Fairbanks during the 1990-2011 period.

Table 1 shows the following percent savings in system costs (1990-2011) for Cases 2 and 3 compared to Case 1:

	Anchorage	Fairbanks	Total
Case 2	-0.4	-7.9	-1.4
Case 3	-10.7	-28.1	-14.1

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Table 1. Annual Power System Costs for Power Supply Under Cases I, II, and III - Mid-Range Load Projections - 0% Inflation ($Million)

Period	Case I		Case II		Case III	
	Anchorage	Fairbanks	Anchorage	Fairbanks	Anchorage	Fairbanks
1980-90	272.0	90.6	254.5	84.2	254.5	84.2
90-91	274.2	96.8	293.8	89.0	293.8	89.0
91-92	324.2	98.2	343.8	90.2	343.8	90.2
92-93	387.5	119.5	409.9	88.2	409.9	88.2
93-94	391.7	120.9	414.1	89.2	414.1	89.2
94-95	398.9	122.2	421.3	114.9	537.5	120.5
95-96	463.7	127.6	486.1	143.7	537.9	124.8
96-97	549.0	152.4	571.5	143.2	543.0	124.0
97-98	615.9	167.8	578.7	158.5	549.3	139.2
98-99	627.7	192.0	650.2	182.6	576.3	145.1
1999-2000	694.4	193.8	657.2	184.5	577.2	145.7
Sub total	4,999.4	1,481.8	5,081.1	1,368.2	5,037.3	1,240.1
00-01	691.8	194.9	714.3	185.5	573.4	146.5
01-02	698.6	196.2	721.1	186.8	578.5	147.4
02-03	760.3	195.0	723.1	208.2	658.6	168.6
03-04	767.9	230.8	789.8	209.6	665.1	169.6
04-05	776.0	232.2	798.5	211.0	670.8	170.6
05-06	864.0	232.1	807.1	210.9	677.6	170.2
06-07	872.8	233.5	815.9	212.3	744.4	171.2
07-08	881.9	235.1	904.4	213.8	751.6	172.3
08-09	891.1	236.5	913.6	215.2	759.0	173.4
09-10	901.6	238.1	923.1	216.9	766.7	174.6
10-11	969.9	239.6	932.7	218.4	834.3	175.7
Total	14,075.1	3,945.8	14,124.7	3,656.9	12,717.3	3,080.2

Response to OMB question 5.4.

"Scheduling of powerplants and the reduced risk of building small increments."

The Load/Resource analysis for without project condition addresses the scheduling of steamplants and size of units needed. This is demonstrated in Chapter VII of the marketability report. Annual power system costs shown in Table 1 under question 5.3 show savings from Susitna over the without Susitna case. The steamplants are smaller units than Susitna, but their higher cost contributes to higher overall system costs. An analysis of hydro alternatives indicate that there are not economical sites available in sufficient quantity to be comparable to Susitna. This is supported by APA's draft report on "Analysis of Potential Alternative Hydroelectric Sites to Serve Railbelt Area."

Response to OMB question 6.1, .2, and .3.

Demand Estimates

The analysis of load growth should be more specific with respect to:

1. Increasing use by consumers; and,

2. Increasing number of consumers.

3. Industrial growth, i.e., where does Alaska's comparative advantage lie outside the area of raw materials and government functions?

The new estimates of future power demand are responsive to the first two parts of this question. APA completed a very careful analysis of recent power use trends by class of customer, with particular emphasis on identifying recent trends that could be attributed to conservation efforts. The future demands are based on future population estimates developed by the University of Alaska's Institute of Social and Economic Research and incorporate assumptions of substantially improved efficiency in use of electric power through conservation.

The third part of the question requires consideration of the overall Alaskan economy, present and future, and the role of Upper Susitna power.

Alaska is not a heavily industrialized State nor is it expected to be. The oil and gas industry is presently the dominating sector of the State's GNP, and will continue to be so for at least the balance of the 20th century. This is the principle source of revenues for the State and thus the driving force behind State programs for education, local government assistance, welfare, and so on. Other important industries are the fisheries, forest products, and recreation-tourism.

The low- and mid-range population estimates incorporate very modest assumptions of industrial expansion based on pioneering of Alaskan natural resources for the most part. The specific industrial assumptions reflect proven sources of natural resources and projects that are well along in the planning stages.

Extraction and processing of natural resources will undoubtedly continue to be major aspects of the Alaskan economy. Other important aspects include business activities of Native Corporations and increasing amounts of land made available to State and private ownership. Actions pending on the new National Parks, Refuges, and Wild and Scenic Rivers will encourage further development of the recreation and tourism industries.

As in most parts of the country, Alaska employment is not dominated by the industrial sectors. Most jobs are in service industries, the commercial establishments, transportation, utilities, and government. The new population estimate by ISER indicates that the distribution of employment will not change substantially. The anticipated growth in the economy, employment, and in power demands is primarily in the non-industrial sectors.

It should be noted that the Railbelt area demands for electric energy in 1977 were 2.7 billion kilowatt-hours, which is approaching the firm energy capability of the Watana Project. The load resource analyses demonstrate full utilization of Watana energy essentially as soon as it becomes available, even under the lower power demand case. This basically leads us to a finding that the Upper Susitna justification is not dependent on major industrial expansion in Alaska.

Response to OMB Question 7.

Under the topic Sensitivity Analysis, OMB provided the following comments:

"Power demand should be subjected to a sensitivity analysis to better assess the uncertainties in development of such a large block of power. The typical utility invests on the basis of an 8-10 year time horizon. The Susitna plan has an 11-16 year horizon in face of risks that loads may not develop and the option of wheeling power to other markets is not available. It should be noted that the power demand for Snettisham was unduly optimistic when it was built. This resulted in delays in installing generators. A similar error in a project the size of Susitna would be much more costly and would have a major adverse effect on the project's economics."

The new power demand estimates, load resources analyses, and financial analysis presented in this report, all provide a better basis for examining these questions. In addition, there is need to review some of the Snettisham Project history to bring out similarities and differences with the Upper Susitna case.

Snettisham Review

The Snettisham Hydroelectric Project is located near Juneau, Alaska, and is now the main source of power for the greater Juneau area. The project was authorized in 1962 on the basis of feasibility investigations by the Bureau of Reclamation, constructed by the Corps of Engineers, and operated by the Alaska Power Administration.

The project was conceived as a two-stage development and construction of the first, or Long Lake, stage was completed in late 1973 with first commercial power to Juneau in December 1973. The second, or Crater Lake, stage would be added when power demands dictate.

Juneau was, and is, an isolated power market area. Difficult terrain and long distances have thus far prevented electrical interconnection with other Southeast Alaska communities and neighboring areas of Canada; however, such interconnections may prove feasible within the next 15 to 20 years. The project planning and justification was premised on service only to the greater Juneau area.

The Snettisham authorization was based on power demand estimates by the Alaska District, Bureau of Reclamation (now Alaska Power Administration). 1/ The estimates were based on actual power use through 1960 and projections to the year 1987. The outlook at that time was that the first stage construction would be completed in 1966, and that total project capability would not be needed until 1987.

A comparison of power demand estimates at the time of authorization with actual demands is shown on Table 1. The 1977 energy load was 112,197 megawatt-hours or 81 percent of the amount estimated in 1961 based on historical records through 1960.

1/ Reappraisal of the Crater-Long Lakes Division, Snettisham Project, Alaska, USBR, November 1961.

Table 1 Power and Energy Requirements-Juneau Area

Fiscal Year	Actual Demands MWH	Actual Demands Peak MW	Forecasted Demands at Time of Authorization 1/ MWH	Forecasted Demands at Time of Authorization 1/ Peak MW
(Oct. 1 - Sept. 30)				
1958	23,945	4,788,		
1959	26,297	5,321		
1960	28,499	5,465		
1970	58,266	12,420	73,400	15,230
1971	63,786	13,780	80,700	16,750
1972	70,225	14,910	88,800	18,430
1973	75,753	15,470	97,500	20,240
1974	83,059	16,220	106,900	22,190
1975	94,609	17,840	116,900	24,260
1976	106,296	19,800	127,600	26,480
1977	112,197	20,440	139,100	28,870

1/ From Reappraisal of the Crater-Long Lakes Division, Snettisham Project, Alaska, USBR, November 1961.

The inherent flexibility of a staged project proved to be very beneficial in the case of Snettisham. APA made periodic updates of the power demand estimates during construction of the Long Lake stage. For several years, these forecasts indicated a need to proceed with the Crater Lake stage construction immediately on completion of the Long Lake stage. The Corps of Engineers construction schedules and budget requests, based on the APA power demand estimates, anticipated start of construction on Crater Lake in FY 1977. Major factors in these forecasts were plans for a major new pulp mill in the Juneau area and for iron ore mining and reduction facility in the vicinity of Port Snettisham. Neither of these developments were anticipated at the time of authorization. Both of these resource developments fell through, and this resulted in a substantial reduction in the APA power demand estimate and a decision in late 1975 to defer the Crater Lake construction start.

The pulp mill was particularly influential in the change in demand estimates. The mill was planned for operation in the early 1970's with a large population and commercial impact on Juneau. Initial access facilities were constructed and site preparation was well underway when the project became entangled in protracted law suits involving logging practices in Southeast Alaska. Several court decisions were made in favor of the development, but a last minute remand put the project back to base one and led to cancellation in early 1975.

This type of uncertainty faces all utility planners. The staged project like Snettisham affords a great deal of capability to adjust to changes in demand.

Many other factors influenced Juneau area power demands and utilization of project power. Of particular concern at the moment is impact of Alaska's capital move initiative. This would certainly change use of project power, with the most likely outcome that the community would move more quickly into an all-electric mode (space heating and electric vehicles appear particularly attractive in this area) and industrial use of power would increase through economic diversification.

The key points of the Snettisham review are:

1. The project was planned and authorized with intent to handle growth in area power requirements for a 20-year period.

2. The load forecasts used as a basis for authorization were reasonably accurate.

3. The actual use of project power may turn out to be substantially different than originally anticipated.

4. The flexibility of staged projects was actually used.

5. The outlook for financial viability appears excellent at this time in history.

Implications for Susitna

First, the norm for utility investments cannot remain as the basis of an 8 to 10 year time horizon. This is evidenced by experiences since about 1970 on time required to plan, obtain necessary permits or authorizations, find financing, and then build new powerplants and major transmission facilities. The 8 to 10 years is much too short for nuclear, coal, and hydro plants and for major transmission lines.

It appears appropriate to require a 20-year planning horizon with careful checks at each step in the process and business-like decisions to shift construction schedules if conditions (demands) change. We believe the Snettisham experience is very positive in this light.

The Susitna Project is similar in that project investment is keyed to two major stages. The commitment of construction funds for Watana would be needed in 1986 or 1987 to have power on line by 1993 or 1994. If conditions in 1986 indicate need to defer the project, it should be deferred. Similarly, start of actual construction on Devil Canyon can and should be based on conditions that actually prevail at the time the decision is made.

The level of uncertainty for Upper Susitna is greater than was the case for Snettisham on counts of higher interest costs and larger total investment. Sensitivity to change in demands is much less for Susitna because of its large and diversified power market area. There are many more ways that Susitna Project power could be effectively utilized in the event that traditional utility power markets are smaller than anticipated at the present.

Upper Susitna does not have as many uncertainities in terms of environmental questions as would equivalent power supplies from coal or nuclear plants. Uncertainties on air quality are particularly relevant for any larger Alaskan coal-fired powerplants.

Current Evaluation

Power demands were estimated for High, Medium, and Low cases to year 2025 assuming logical variations in population and energy use per capita. The projections reflect energy use per capita based on detailed studies of 1970-1977 data from both the Anchorage and Fairbanks areas. The projections considered variations in per capita use ranging from increased use of electricity in the home to anticipated effects of conservation on decreasing the growth rates. A detailed discussion of the development of the power demands is included in Chapter 5 of this report.

The load/resource and cost analysis provided system cost for comparison of cases both with and without the Susitna Project. The analysis also compared the power demands to the resources required to determine sizes and timing of new plants (the load/resource analysis is summarized in Chapter VII). Table 2 summarizes the resources needed during the 1990's for the range of projections.

The Table indicates that even under the most conservative load growth condition (low), 1,500 MW are needed to meet the combined Anchorage-Fairbanks demands, which is roughly the capability of Susitna.

Tables 3 and 4 show the power costs for Anchorage and Fairbanks during the 1990's with an interconnection and with and without the Susitna Project. It is readily apparent the rates are less for the case with Susitna.

For example, in the medium case for the year 2000, Anchorage costs are 5.5¢/kwh or 13 percent less than without Susitna. In the Fairbanks costs, the difference is much larger, 6.7¢/kwh or 25 percent less than without Susitna.

In Table 5, annual system interest costs are composed with and without Susitna with intertie from 1990 to 2011. Examination of the system cost on an annual basis reveals the case with Susitna is cheaper than the without Susitna case for each year except the first few years after Watana comes on line.

Table 2. Schedule of Plant Additions -MW

Cases with Interconnection without Upper Susitna

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	400	*	200	-	*	100
90-91	-	200	-	-	-	-
91-92	400	200	-	-	-	-
92-93	-	400	200	200	-	-
93-94	400	-	-	100	-	-
94-95	-	-	*	-	100	*
95-96	400	400	200	100	100	-
96-97	400	400	200	100	-	100
97-98	400	-	400	200	100	100
98-99	400	400	-	-	100	-
99-00	400	-	-	-	-	-
TOTAL 90-2000	3200	2000	1200	700	400	300

*Interconnection Installed in 1987 for high case, 1990 for median case, & 1995 for low case.

Replacement of military powerplants, many of which also supply heat for buildings are additional but not shown here.

TABLE 3. Power Costs for Anchorage and Fairbanks Areas With Interconnection and Without Upper Susitna - 0% Inflation (cents/kwh)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	5.7	4.5	4.2	4.7	5.8	5.6
90-91	5.4	4.8	4.1	4.6	5.9	5.8
91-92	5.7	5.3	4.1	4.4	5.7	5.8
92-93	5.4	5.9	4.7	6.3	5.4	5.6
93-94	5.7	5.6	4.6	7.3	5.2	5.5
94-95	5.5	5.4	4.9	7.0	6.5	6.7
95-96	5.6	5.8	5.4	7.8	7.7	6.9
96-97	5.8	6.4	5.8	8.2	7.4	8.3
97-98	5.9	6.1	6.6	8.7	7.8	9.1
98-99	6.0	6.5	6.4	8.3	8.7	8.9
99-00	6.1	6.2	6.2	8.0	8.4	8.8

TABLE 4. Power Costs for Anchorage and Fairbanks Areas With Interconnection and With Upper Susitna Coming on Line in 1994 - 0% Inflation
(cents/kwh)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	5.7	4.5	4.2	4.7	5.8	5.6
90-91	5.4	4.8	4.1	4.6	5.9	5.8
91-92	5.7	5.3	4.6	4.4	5.7	7.2
92-93	5.4	5.9	4.4	6.3	5.4	6.9
93-94	5.7	5.6	5.0	7.3	5.2	6.8
94-95	6.4	6.9	7.3	7.9	6.8	8.8
95-96	6.0	6.5	6.8	7.7	6.7	8.9
96-97	6.2	6.1	6.5	7.2	6.4	8.6
97-98	6.2	5.8	6.3	6.6	6.9	7.8
98-99	6.1	5.8	6.1	6.5	6.9	7.6
99-00	5.8	5.5	6.1	6.2	6.7	7.8

TABLE 5. Power System Annual Costs for Anchorage and Fairbanks With Upper Susitna Coming On Line in 1994 - 0% Inflation

(million $)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	508.5	254.5	173.4	85.2	84.2	63.4
90-91	514.1	293.8	175.0	89.0	89.0	68.5
91-92	591.8	343.8	206.0	90.2	90.2	87.4
92-93	597.3	409.9	205.0	137.8	88.2	85.5
93-94	666.0	414.1	244.5	166.8	89.2	86.4
94-95	798.5	537.5	372.3	192.2	120.5	115.6
95-96	806.1	537.9	368.4	198.0	124.8	119.2
96-97	898.6	543.0	368.5	198.5	124.0	117.5
97-98	793.1	549.3	369.9	192.5	139.2	109.2
98-99	1,009.1	576.3	376.1	201.3	145.1	109.7
99-00	1,018.9	577.2	391.7	203.5	145.7	114.9
00-01	1,025.1	573.4	381.4	228.6	146.5	114.5
01-02	1,101.3	578.5	380.3	254.0	147.4	114.5
02-03	1,172.1	658.6	375.3	254.3	168.6	111.9
03-04	1,190.4	665.1	376.6	291.6	169.6	112.0
04-05	1,287.7	670.8	376.8	296.0	170.6	112.1
05-06	1,366.8	677.6	378.0	296.1	170.2	110.7
06-07	1,386.8	744.4	379.4	299.2	171.2	110.8
07-08	1,467.2	751.6	380.8	302.4	172.3	110.9
08-09	1,548.1	759.0	382.2	305.7	173.4	111.1
09-10	1,569.9	766.7	383.7	343.5	174.6	111.2
10-11	1,671.6	834.3	385.2	347.0	175.7	111.4
Total	22,989.0	12,717.3	7,430.5	4,973.4	3,080.2	2,308.4

(continued)

TABLE 5. Power System Annual Costs for Anchorage and Fairbanks Without Upper Susitna Coming On Line in 1994 - 0% Inflation (million $)

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
89-90	508.5	254.5	173.4	85.2	84.2	63.4
90-91	514.1	293.8	175.0	89.0	89.0	68.5
91-92	591.8	343.8	185.7	90.2	90.2	71.1
92-93	597.3	409.9	223.3	137.8	88.2	69.2
93-94	666.0	414.1	227.2	166.8	89.2	70.1
94-95	678.0	421.3	252.4	169.4	114.9	87.2
95-96	750.0	486.1	290.9	201.3	143.7	91.8
96-97	843.4	571.5	327.9	224.8	143.2	113.1
97-98	918.8	578.7	389.8	253.4	158.5	127.6
98-99	998.3	650.2	396.7	256.3	182.6	128.4
99-00	1,074.0	657.2	397.9	259.7	184.5	129.3
00-01	1,160.8	714.3	470.6	262.3	185.5	129.6
01-02	1,238.6	721.1	472.5	265.3	186.8	130.2
02-03	1,310.9	723.1	469.8	265.8	208.2	128.3
03-04	1,331.0	789.8	472.8	303.5	209.6	128.8
04-05	1,350.7	798.5	474.8	341.2	211.0	129.3
05-06	1,431.7	807.1	477.8	343.1	210.9	128.4
06-07	1,513.3	815.9	480.9	346.5	212.3	151.7
07-08	1,615.1	904.4	484.0	350.1	213.8	152.2
08-09	1,638.1	913.6	487.1	353.7	215.3	152.8
09-10	1,721.4	923.1	490.3	357.5	216.9	153.3
10-11	1,801.7	932.7	493.6	361.4	218.4	153.9
Total	24,253.5	14,124.7	8,314.4	5,484.3	3,656.9	2,558.2

It should be noted that in the low energy use estimate the total system cost for Anchorage during this period amounts to $883.9 million less with Susitna than without the project. The difference is even larger in the medium and high cases. The combined Anchorage-Fairbanks cash savings for the same period based on the medium power use estimate is almost $2 Billion.

Previous Studies

There was a fairly substantial backlog of power system and project studies relevant to the 1976 evaluation of the Upper Susitna River Project. The previous studies most relevant include:

1. Advisory Committee studies completed in 1974 for the Federal Power Commission's (FPC) 1976 Alaska Power Survey. The studies include evaluation of existing power systems and future needs through the year 2000, and the main generation and transmission alternatives available to meet the needs. The power requirement studies and alternative generation system studies for the 1976 power survey were used extensively.

2. A series of utility system studies for Railbelt area utilities include assessments of loads, power costs, and generation and transmission alternatives.

3. Previous work by the Alaska Power Administration, the Bureau of Reclamation, the utility systems, and industry on studies of various plans for Railbelt transmission interconnections and the Upper Susitna hydroelectric potential.

It should be noted that many of the studies listed in the bibliography represent a period in history when there was very little concern about energy conservation, growth, and needs for conserving oil and natural gas resources. Similarly, many of these studies reflected anticipation of long term, very low cost energy supplies. In this regard, the studies for the 1976 power survey are considered particularly significant in that they provide a first assessment of Alaska power system needs reflecting the current concerns for energy and fuels conservation and the environment, and the rapidly increasing costs of energy in the economy.

The latter concern for conservation, etc. has been carried even further in this report. As yet unpublished studies by the Alaska Power Administration have made a definite reflection of conservation assumptions. The resulting load forecasts were used in load/resource analyses done and reported by Battelle Pacific Northwest Laboratories in 1978 and 1979. (Battelle also published a report in 1978 entitled <u>Alaska Electric Power, and Analysis of Future Requirements and Supply Alternatives for the Railbelt Region</u>.) Population and employment used in the recent forecasts were projected and reported by the Institute of Social and Economic Research in September 1978. The result of their econometric model is entitled <u>South Central Alaska's Economy and Population, 1965-2025: A Base Study and Projection</u>. A partial bibliography of related studies including those of the 1976 Susitna report, is appended.

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Appendix I, Part I: (A) Hydrology, (B) Project Description and Cost Estimates, (C) Power Studies and Economics, (D) Foundation and Materials, (E) Environmental Assessment, (F) Recreational Assessment

Appendix I, Part II: (G) Marketability Analysis, (H) Transmission System, (I) Environmental Assessment for Transmission Systems

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INFORMAL REPORT

LOAD/RESOURCE AND SYSTEM COST ANALYSIS FOR THE RAILBELT REGION OF ALASKA: 1978-2010

for
ALASKA POWER ADMINISTRATION
U.S. DEPARTMENT OF ENERGY

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January 1979

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FOR THE RAILBELT REGION OF ALASKA - 1978-2010

Prepared for the
Alaska Power Administration

by

Battelle
Pacific Northwest Laboratories

January 1979

1.0 INTRODUCTION

The Alaska Railbelt region presents some unique attributes for consideration in future power system planning. The region currently consumes 83% of the State's electric power and even the lower estimates of electrical load growth (5% per annum) for the region are above the national average.

The State, and particularly this region, is a difficult one in which to forecast load growths. This difficulty results from the nature of the economic activity base being influenced by external forces such as oil and gas developments and transportation systems with their cyclical tendency. Also, since the economic base is still not large, the injection of a competitively scaled industry such as major petroleum refinery or electrochemical industry can significantly perturb a forecast.

A major shift in the Alaskan Railbelt future power generating mode appears inevitable. The Cook Inlet Region's capacity is presently dominated by combustion turbines fired by currently low-cost natural gas; the Fairbanks-North Star Borough by a mix of coal-fired steam turbine generation and oil-fired combustion turbines. The oil and gas based mode of generation, however, are highly exposed to inflationary pressures, external market forces, and Federal regulatory intervention.

The Railbelt region, however, does have a number of options open in the future. These include:

- Continued use of oil and gas in existing plants.
- Increased coal based thermal generation both in the interior based on the Healy Coal Field and in the Cook Inlet Region based on several coal fields, including the very large reserves in the Beluga Region.
- Development of the significant hydroelectric potential, including Upper Susitna River and Bradley Lake.
- A transmission intertie between the Cook Inlet and Fairbanks load centers is of obvious interest as a means of increasing reliability or alternately reducing additional generating capacity needed for reliability. Marketing of power from Upper Susitna projects will be dependent upon such an intertie.

Electric power generation by whatever means is a very capital intensive activity. Different forms of generation, however, have different levels of exposure to inflation and escalation and, cost comparisons on a straight $/kW of installed capacity can be misleading. Thus a higher cost per kilowatt hydroelectric project has this exposure largely limited to the time period during planning and construction. On the other hand, a fossil fueled plant faces rising fuel costs as well as operating and maintenance costs in the future. Regardless of these factors, all generation options are faced with long lead times from decision to proceed to commercial operating date.

The purpose of this report is to examine the probable timing of major generation and transmission investments and their impact on system power costs under a range of assumptions about power demands and inflation and escalation rates for the following general Railbelt power supply strategies:

Case 1. All additional generating capacity assumed to be coal fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2. All additional generating capacity assumed to be coal fired steam turbines, including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna Project (including transmission intertie) plus additional coal as needed.

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The first step involved in estimating the cost of power from alternative generation and transmission system configurations is to perform a series of load/resource analyses. These analyses determine the schedule of major investments based on assumptions about the load growth, the capacity and power production of the prospective generating facilities, and constraints as to when the facilities can come on line.

The load/resource analyses provide information on the annual power production of the various types of generating plants. Once the annual plant utilizations are known, they can be used in conjunction with estimates of annual system costs to calculate the annual cost of producing power from the facilities. Summing the annual cost for generation and transmission of each of the generating facilities gives a total cost for the entire system being analyzed. Dividing the total annual cost by the power produced gives an average annual cost of power for the entire system. By comparing the average annual power costs over the period of interest (1978-2010) the alternative configurations can be ranked based on the cost of power. All other things being equal, the system configuration producing power at the lowest cost should be selected as the most desirable system.

The report was prepared on contract to the Alaska Power Administration (APA) as input to APA's power market analysis for the Upper Susitna Project. The APA furnished, and is responsible for, all data on power requirements, cost assumptions, and certain key criteria for the study. The balance of the criteria were developed jointly by the APA and Battelle.

Chapter 2 contains a brief summary of the results of the study. The load/resource analyses are described in Chapter 3. Chapter 4 presents the methodology and results of the cash flow and power cost calculations. Appendix A contains the data used in the load/resource analyses. Appendix B contains a listing of the computer model (AEPMOD) used to perform the load/resource matching. The output of AEPMOD for the cases analyzed in this report are presented in Appendix C. Appendix D contains a listing of the model used to compute the cost of power and Appendix E contains some selected results of ECOST 4 model runs.

2.0 SUMMARY AND CONCLUSIONS

Load/Resource Matching

- Forecasted peak loads for the Anchorage/Cook Inlet and the Fairbanks/Tanana Valley load centers have been matched with schedules of plant additions for low, median, and high forecasted load growths. These were replicated for cases considering 1) continued separation of the load centers, 2) interconnection without development of Upper Susitna hydroelectric power, 3) interconnection including development of the proposed Upper Susitna hydroelectric projects beginning in 1994.
- Thermal generating capacity additions to the year 2010 were estimated as follows:

Case 1: Without Interconnection and Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2600	471	3071
Median	4600	871	5471
High	8200	1471	9671

Case 2: Interconnection without Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	2200	471	2671
Median	4200	671	4871
High	8200	1271	9471

Case 3: Interconnection with Upper Susitna

Assumed Load Growth	Megawatts Anchorage	Fairbanks	Total
Low	1000	171	1171
Median	3000	371	3371
High	6600	1071	7671

- Provision of the interconnection without Upper Susitna reduces thermal plant addition requirements by 200 to 600 MW over the period.
- Interconnection with Upper Susitna reduces thermal plant addition requirements by 1500 to 1800 MW depending on the assumed load growth.
- Under the criteria used, the interconnection is called for in 1986, 1989, and 1994 for high, median, and low load growth cases, respectively, without Upper Susitna projects. With Upper Susitna, the corresponding dates are 1986, 1989, and 1991.

<u>System Power Cost</u>

- For the Anchorage-Cook Inlet load center construction of the interconnection reduces the cost of power compared to the case without an interconnection.
- For the Anchorage-Cook Inlet area inclusion of the Upper Susitna project into the system generally raises the cost of power above the other cases during the first 2 to 4 years after the Watana Dam comes on line with results in lower power costs during the 1996-2010 time period.
- For the Fairbanks-Tanana Valley area construction of the interconnection again generally reduces the cost of power.
- For the Fairbanks-Tanana Valley load center inclusion of the Upper Susitna project generally raises the cost of power above the case with the interconnection for about 2 years after the Watana Dam comes on line but, as with the Anchorage-Cook Inlet area, results in lower power costs during the 1996-2010 time period.
- Table 2.1 presents a comparison of the costs of power in the year 2005 for the cases evaluated in the report using the case without either the interconnection or the Upper Susitna projects (Case 1) as the base. The costs of power computed in Case 1 are compared to cases with the interconnection (Case 2), and with Upper Susitna coming on line in 1994 (Case 3). As shown, the costs of power are reduced below the cost of power for Case 1 in but one case. This reduction varies from 4.3% to 39.3% depending upon the situation.

TABLE 2.1. Comparison of Power Costs for Year 2005

	Percent Change in Cost of Power Below Case 1 5% Inflation					
	Anchorage			Fairbanks		
	High	Median	Low	High	Median	Low
Case 2	-4.3	-10.1	-12.2	+8.9	-9.6	-4.2
Case 3	-10.5	-30.3	-39.3	-8.9	-30.8	-26.3

3.0 LOAD/RESOURCE ANALYSES

The load/resource analysis is intended to match forecasted electric power requirements with appropriate generating capability additions. The analysis schedules new plant additions, keeps track of older plant retirements, and computes the loading of installed capacity on a year-by-year basis over the period 1978 to 2010.

The analysis schedules the additions to assure that both peak loads and energy requirements (including reserves) are met on a year-by-year basis with the least amount of installed capacity and with generating plants loaded in any preselected order, typically in order of lowest to highest marginal power costs.

A number of factors must be taken into account:

1. Forecasted loads in terms of peak power requirements in megawatts (MW) and annual energy requirements in millions of killowatt hours (MMkWh).
2. The stock of existing generating capacity by type, size, year of retirement, and maximum allowable plant factor.
3. Desired reliability reserve margin to provide insurance against forced outages, unforeseen delays in plant availability, or load growths in excess of those anticipated.
4. Transmission and distribution losses.
5. Construction schedule constraints; i.e., lead times necessary between unit selection and first power on line date.
6. Plant availability constraints based on types and age. (Thermal plants generally have lower availability at the start and end of their economic life.)
7. Assumptions about the economic size of future generating plants in relation to the loads.
8. System configuration; i.e., interconnections, alternative siting strategies.

3.1 ANALYSIS METHODOLOGY

The load/resource matching is done on an annual basis. The Alaskan electric utility systems experience their annual peak load requirements during the winter months and resources must be available to meet these peak loads. During recent years the *annual* load factor for Railbelt electrical demand has typically been about 46-50%. It is expected to remain in the range of 50-52% during the time horizon of this study. The existing and planned future generating capacity in the Railbelt region is capable of operating at a capacity factor either equal to or greater than 50%. Because of this, the decision to add new capacity will usually be based on the need for capacity (kW) rather than energy (kWh). Thus in this analysis capacity additions are scheduled based on peak loads rather than upon average annual energy.

The general approach to load/resource analysis is to summarize existing and planned gross resources for each year, adjust them downward for a reliability margin and for system transmission losses to arrive at net resources. If these net resources exceed the critical period load for the year being analyzed, plant additions are not called up and the analysis proceeds to the next year and is repeated. At some point, the net resources will not meet the forecasted peak loads and additional capacity must be added. Also, for each year, the energy generated by each class of plants (e.g., hydro, steam turgine, combustion turbine, and diesel is computed so that plant utilization factors are available for review and system energy costs can be developed. The stepwise calculations are continued to the end of the period being studies (2010).

3.2 ASSUMPTIONS

3.2.1 Forecasted Power and Energy Requirements

The analyses are based on forecasts prepared by the Alaska Power Administration for both the Anchorage-Cook Inlet and the Fairbanks-Tanana Valley areas. Probable high and low bounds were provided along with median forecasts. These are presented in Tables 3.1 through 3.3 and are shown graphically in Figures 3.1 through 3.3. In addition to utility loads, Anchorage-Cook Inlet forecasts include both national defense and industrial loads and the Fairbanks-Tanana Valley forecasts include national defense loads.

TABLE 3.1. Anchorage-Cook Inlet Area Power and Energy Requirements

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		620	1,000	1,515	2,150	3,180	7,240
Median	424	570	810	1,115	1,500	2,045	3,370
Low		525	650	820	1,040	1,320	1,520
NATIONAL DEFENSE							
High		31	32	34	36	38	48
Median	41	30	30	30	30	30	30
Low		29	28	26	24	24	18
INDUSTRIAL							
High		32	344	399	541	683	1,615
Median	[illegible]5	32	64	119	199	278	660
Low		27	59	70	87	104	250
TOTAL							
High		683	1,376	1,948	2,727	3,901	8,903
Median	490	632	904	1,264	1,729	2,353	4,060
Low		581	737	916	1,151	1,448	1,788

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
UTILITY							
High		2,720	4,3[illegible]	[illegible]	9,430	13,920	31,700
Median	1,790	2,500	3,530	4,[illegible]	6,570	8,960	14,750
Low		2,300	2,840	3,5[illegible]	4,56[illegible]	5,770	6,670
NATIONAL DEFENSE							
High		135	142	149	157	165	211
Median	131	131	131	131	131	131	131
Low		127	121	115	105	104	81
INDUSTRIAL							
High		170	1,810	2,100	2,840	3,590	8,490
Median	70	170	34[illegible]	630	1,050	1,460	3,470
Low		141	312	370	460	550	1,310
TOTAL							
High		3,025	6,342	8,879	12,427	17,675	40,401
Median	1,991	2,801	4,001	5,641	7,751	10,551	18,351
Low		2,568	3,273	4,075	5,125	6,424	8,061

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, October 1978

TABLE 3.2. Fairbanks-Tanana Valley Area Power and Energy Requirements

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		158	244	358	495	685	1,443
Median	119	150	211	281	358	452	689
Low		142	180	219	258	297	329
NATIONAL DEFENSE							
High		49	51	54	56	59	76
Median	41	47	47	47	47	47	47
Low		46	44	42	40	38	29
TOTAL							
High		207	295	412	551	744	1,519
Median	160	197	258	328	405	499	736
Low		188	224	261	298	335	358

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
UTILITY							
High		690	1,070	1,570	2,170	3,000	6,320
Median	483	655	925	1,230	1,570	1,980	3,020
Low		620	790	960	1,130	1,300	1,440
NATIONAL DEFENSE							
High		213	224	235	247	260	333
Median	207	207	207	207	207	207	207
Low		203	193	184	175	166	129
TOTAL							
High		903	1,294	1,805	2,417	3,260	6,653
Median	690	862	1,132	1,437	1,777	2,187	3,227
Low		823	983	1,144	1,305	1,466	1,569

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, October 1978

TABLE 3.3. Total Power Requirements; Anchorage-Cook Inlet Area and Fairbanks-Tanana Valley Area Combined

PEAK POWER

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
TOTAL							
High		890	1,671	2,360	3,278	4,645	10,422
Median	650	829	1,162	1,592	2,134	2,852	4,796
Low		769	961	1,177	1,449	1,783	2,146

ANNUAL ENERGY

	GWh 1/	GWh	GWh	GWh	GWh	GWh	GWh
TOTAL							
High		3,928	7,636	10,684	14,844	20,935	47,054
Median	2,681	3,663	5,133	7,078	9,528	12,738	21,578
Low		3,391	4,256	5,219	6,430	7,890	9,630

1/ MW = Megawatts
GWh = Gigawatt-hours (Equivalent to MMkWh = Millions of kilowatt-hours)

Source: Alaska Power Administration, October

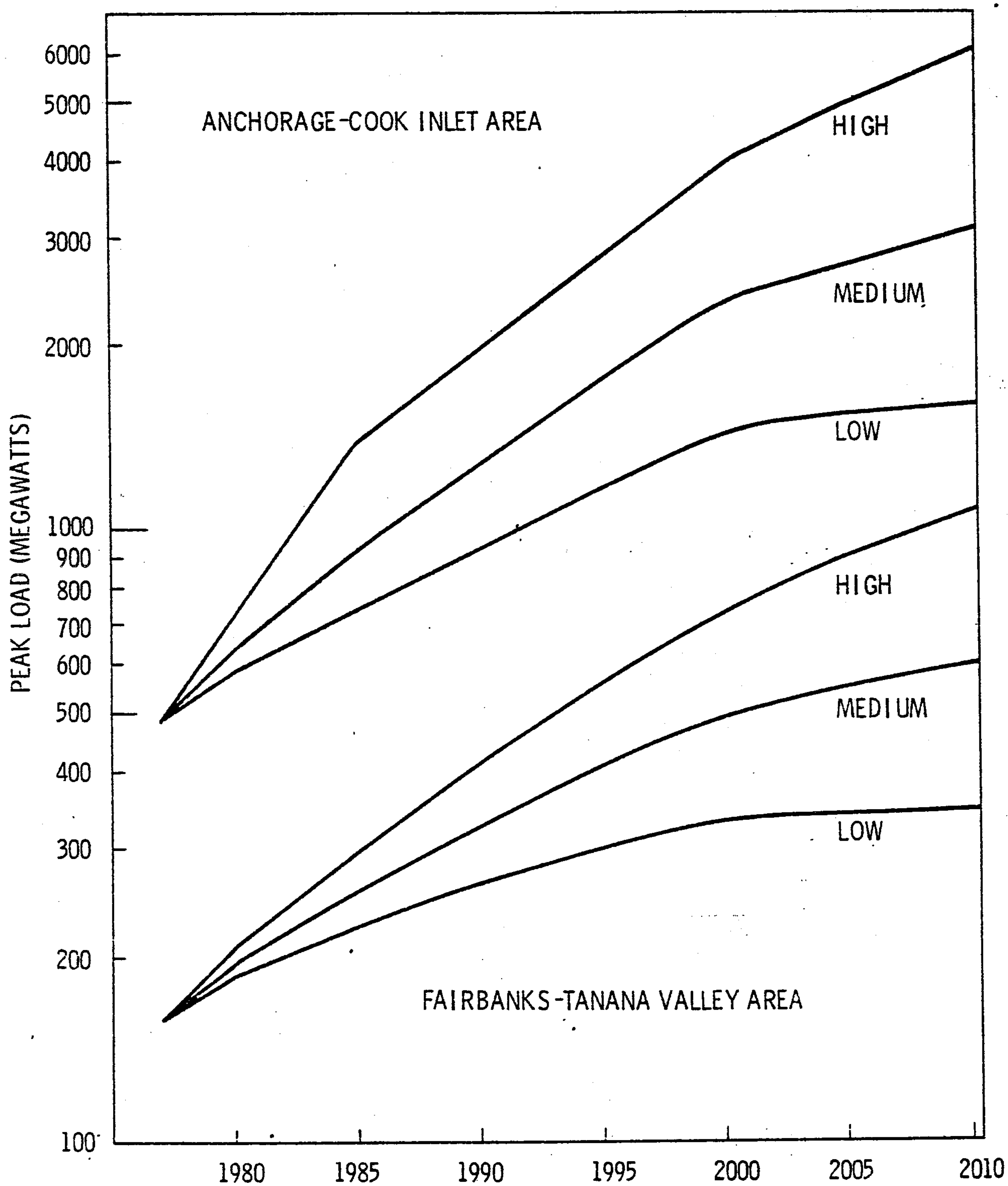

FIGURE 3.1. Railbelt Region Peak Loads

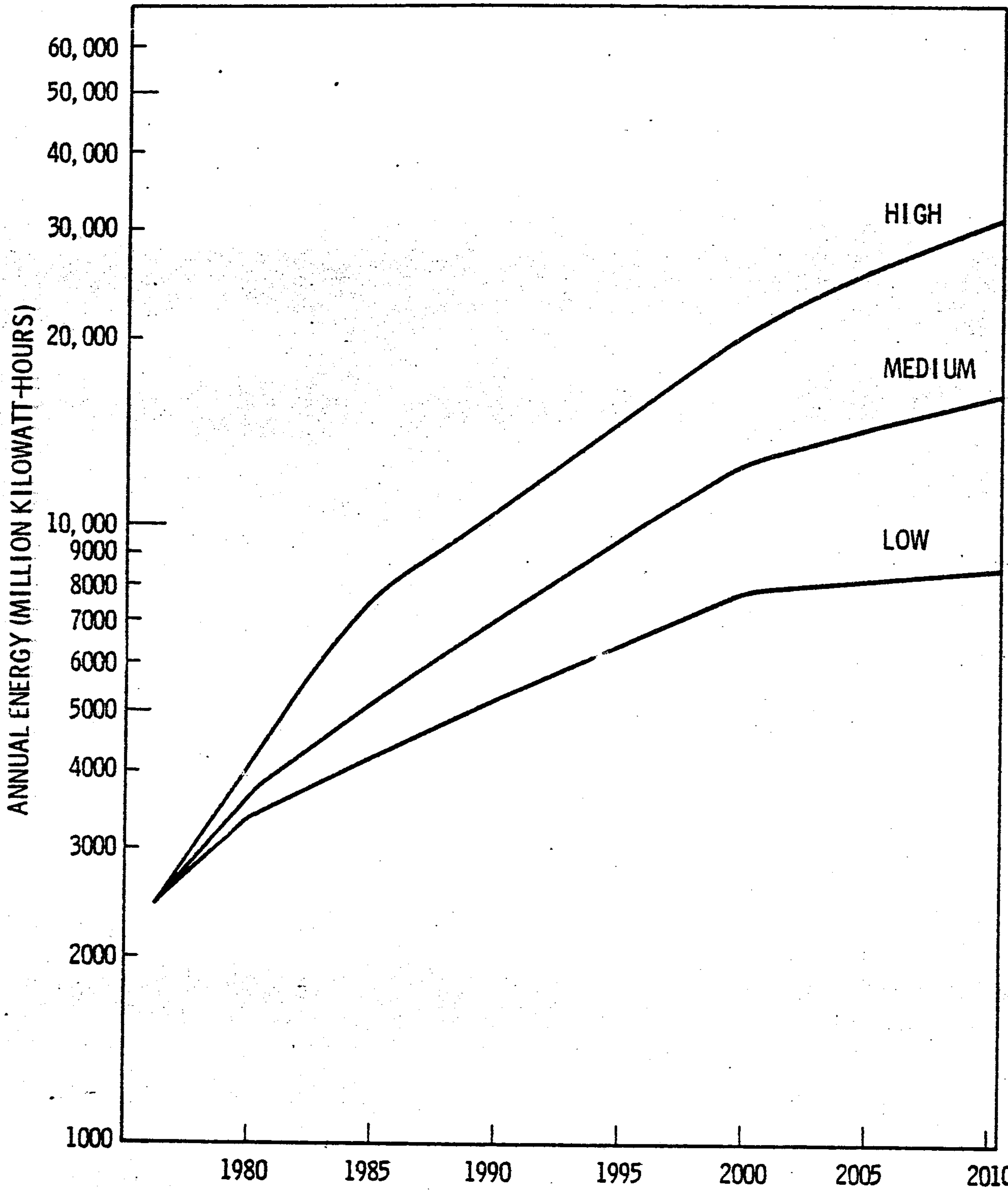

FIGURE 3.2. Anchorage-Cook Inlet Area Annual Energy

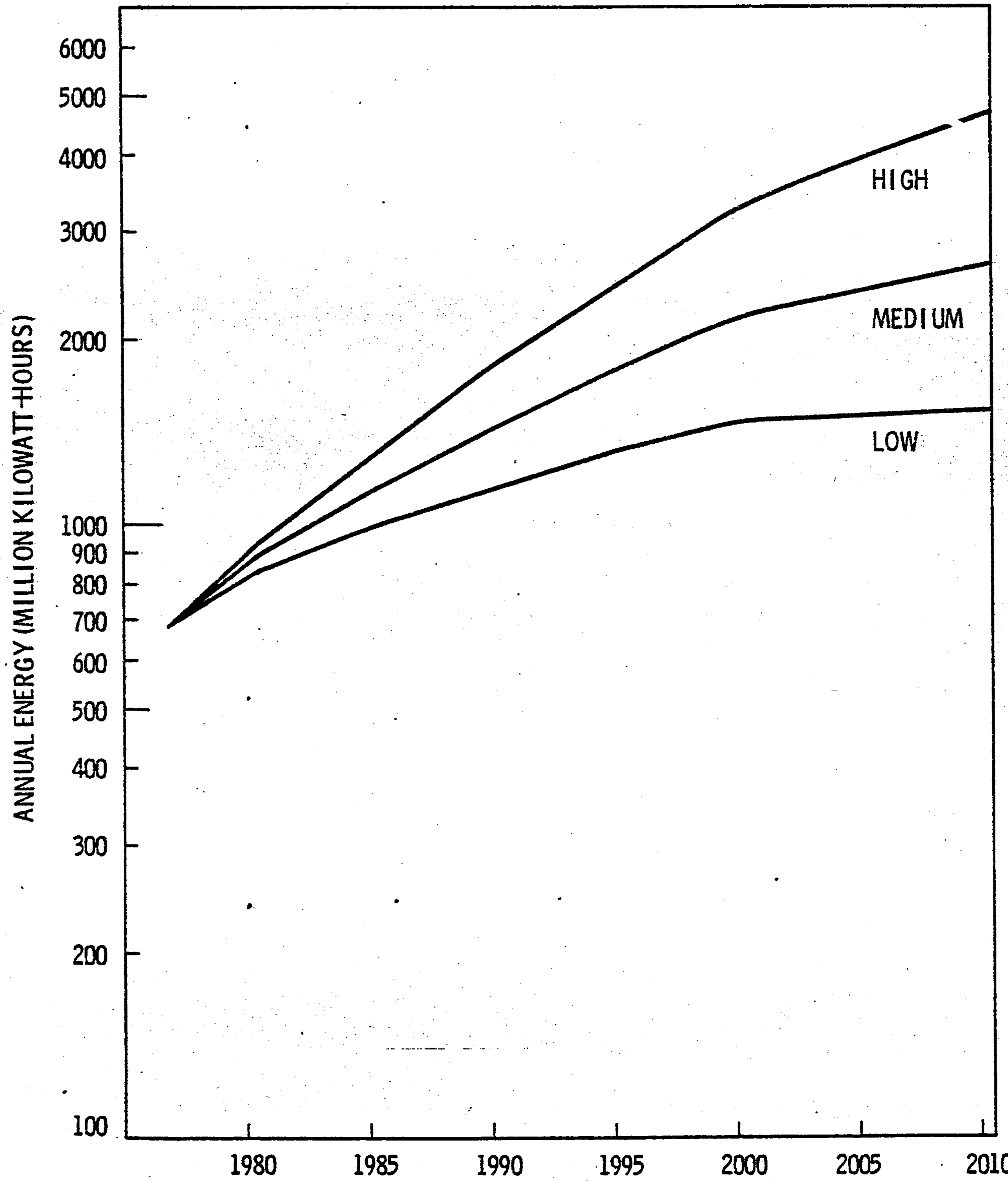

FIGURE 3.3. Fairbanks Area Annual Energy

The Alaska Power Administration data indicate that approximately 80% of the Railbelt region loads are expected to be in the Anchorage-Cook Inlet area. These loads have been interpreted as recognizing distribution losses.

3.2.2 Existing and Planned Generating Capacity

The existing stock of generating capacity for the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area is presented in Tables 3.4 and 3.5, respectively.

The total existing capacities and maximum plant utilization factors for the various generating types for the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area are shown in Tables 3.6 and 3.7, respectively. The load/resource matching analyses use these totals for the first year of the analyses (1978-1979).

Generating capacity additions can be specified to be added in one of two ways. It can either be added in a specified year or can be added when it is required to maintain adequate generating capacity. In the former case the generating units are added whether they are required or not. The planned additions shown in Table 3.8 are brought on line in the years specified. National defense generating units are assumed to be replaced in steam turbine generating units the same year as they are retired. (See Section S.2.7 for a discussion of the units added as required to maintain adequate generating capacity.)

3.2.3 Reserve Margin

Utility systems invariably carry a reserve margin of generating and transmission capacity as insurance against loss of load, unexpected peak requirements as a result of severe weather, load growths more rapid than anticipated, adverse hydroelectric conditions, and delays in the commercial operation of new generation. The most appropriate reserve margin will vary from system to system depending on the nature of the loads and types of resources and special factors. Typically, a reserve capacity at peak of 20% is used nationally. However, this can vary to as low as 12% as is the present case for the Pacific Northwest with its predominance of reliable hydropower and interruptable loads.

TABLE 3.4. Existing (Fall 1978) Generating Capacities for Anchorage-Cook Inlet Area

Unit Reference/Name	Location	Type of Generation	Capacity (kW)	Retirement Year
ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)				
Deisel	Anchorage	Diesel	2,200	1982
Unit 1	Anchorage	S.C.C.T.*	15,130	1982
Unit 2	Anchorage	S.C.C.T.	15,130	1984
Unit 3	Anchorage	S.C.C.T.	18,650	1988
Unit 4	Anchorage	S.C.C.T.	31,700	1992
Unit 5	Anchorage	S.C.C.T.	36,000	1995
Unit 6	Anchorage	C.C.	16,500	1995
		Subtotal	137,500[a]	
CHUGACH ELECTRIC ASSOCIATION (CEA)				
Beluga				
Unit 1	Beluga	S.C.C.T.	33,000	1988
Unit 2	Beluga	S.C.C.T.		
Unit 3	Beluga	R.C.C.T.*	54,600	1993
Unit 4	Beluga	S.C.C.T.	9,300	1996
Unit 5	Beluga	R.C.C.T.	65,000	1995
Unit 6	Beluga	S.C.C.T.	67,810	1996
Unit 7	Beluga	S.C.C.T.	68,000[e]	1996
Unit 8	Beluga	C.C.	32,200	1996
Bernice Lake				
Unit 1	Bernice Lake	S.C.C.T.	8,370	1983
Unit 2	Bernice Lake	S.C.C.T.	17,860	1992
Unit 3	Bernice Lake	S.C.C.T.	18,000	1998
Cooper Lake	Cooper Lake	Hydro	16,500	NA
International				
Unit 1		S.C.C.T.	30,510	1985
Unit 2		S.C.C.T.		
Unit 3		S.C.C.T.	18,140	1991
Knik Arm Combined		S.T.*	10,000[f]	1987
		Subtotal	449,790	
MATANUSKA ELECTRIC ASSOCIATION (MEA)				
Talkeetna	Talkeetna	Diesel	600[b]	1993
HOMER ELECTRIC ASSOCIATION (HEA)				
English Bay	English Bay	Diesel	100	1993
Homer & Kenaie Combined	Homer	Diesel	300[c]	1993
Homer Combined	Homer	S.C.C.T.	7,000[d]	1995
Port Graham Combined	Port Graham	Diesel	200	1993

TABLE 3.4. (contd)

Unit Reference/Name	Location	Type of Generation	Capacity (kW)	Retirement Year
		HOMER ELECTRIC ASSOCIATION (HEA) (contd)		
Seldovia Combined	Seldovia	Diesel	1,500	1980
		Subtotal	9,100	
		SEWARD ELECTRIC SYSTEM (SES)		
Seward Combined	Seward	Diesel	3,000(b)	1985
			2,500	1996
		Subtotal	5,500	
		ALASKA POWER ADMINISTRATION (APA)		
Eklutna	Eklutna	Hydro	30,000	NA
		Subtotal	30,000	
		NATIONAL DEFENSE		
Ft. Richardson/ Emendorf	-	S.T.	40,500	1991
	-	Diesel	7,300	1985
	-	Diesel	2,000	1991
		Subtotal	49,800	
		INDUSTRIAL		
Kenai	-	S.C.C.T.	12,300(g)	1988
		TOTAL	685,290	

* S.C.C.T. - Simple Cycle Combustion Turbine
R.C.C.T. - Regenerative Cycle Combustion Turbine
S.T. - Steam Turbine
C.C. - Combined Cycle

(a) Capacities for individual units are from sources 1 and 2. These sum to 118,810 kW. Total shown is from source 2.
(b) Standby
(c) Leased to CEA
(d) Leased to HEA by Golden Valley Electric Association for 1977-1979.
(e) Included in this study, but late 1978 plans are to defer Betuga 8 until 1980 and double the capacity.
(f) Nameplate capacity derated to 10,000 KW from 14,500 KW.
(g) Recent data shows industrial load to be 25,000 KW rather than 12,300 KW.

SOURCES:

1. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.
2. Alaska Electric Power Statistics 1960-1976, Alaska Power Administration, pp. 15-17, July 1977.
3. 1976 Power System Study, Chugach Electric Association, Inc., Tippett and Gee, Dallas, TX, p. 7, March 1976.
4. Alaska Power Administration, August 1978.

TABLE 3.5. Existing (Fall 1978) Generating Capacities for Fairbanks-Tanana Valley Area

Unit Reference Name	Location	Type Generation	Capacity (kW)	Year of Retirement
FAIRBANKS MUNICIPAL UTILITIES SYSTEM (FMUS)				
Chena 2	Fairbanks	S.T.	2,000	1988
Chena 3	Fairbanks	S.T.	1,500	1988
Chena 1	Fairbanks	S.T.	5,000	1988
Chena 4	Fairbanks	S.C.C.T.	5,350	1983
Diesel 1	Fairbanks	Diesel	2,664	1988
Diesel 2	Fairbanks	Diesel	2,665	1988
Diesel 3	Fairbanks	Diesel	2,665	1988
Chena 5	Fairbanks	S.T.	20,000	2005
Chena 6	Fairbanks	S.C.C.T.	23,500	1996
		Subtotal	65,345	
GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)				
-	Fairbanks	Diesel	24,000	1984
Healy #1	Healy	S.T.	25,000	2002
-	Fairbanks	S.C.C.T.	40,000	1992
-	Delta	Diesel	500	1988
North Pole #1	North Pole	S.C.C.T.	70,000	1997
North Pole #2	North Pole	S.C.C.T.	70,000	1997
		Subtotal	229,500	
NATIONAL DEFENSE				
Combined	-	Diesel	14,000	1988
Clear A.F.B. and Ft. Greely	-	S.T.	24,500	1995
Ft. Wainwright and Eilson A.F.B.	-	S.T.	32,000 [(a)]	1990
		Subtotal	70,500	

(a) 5 MW plant at Eilson A.F.B. installed in 1970 and old 1.5 MW plant at Ft. Wainwright were inadvertantly omitted.

SOURCE:
1. Interior Alaska Energy Analysis Team, Final Report, June 1977.
2. Alaska Power Administration, August 1978.

TABLE 3.6. Anchorage-Cook Inlet Area Existing Capacity and Maximum Annual Plant Utilization (October 1978)

	Capacity (MW)	Plant Utilization (%)
Hydro	46.5	50.0
Steam Electric	50.5	75.0
Combustion Turbine	575.01	50.0
Diesel	19.13	15.0

TABLE 3.7. Fairbanks-Tanana Valley Area Existing Capacity and Maximum Annual Plant Utilization (October 1978)

	Capacity (MW)	Plant Utilization (%)
Hydro	0	50.0
Steam Electric	110	75.0
Combustion Turbine	208.9	50.0
Diesel	46	10.0

TABLE 3.8. Planned Additions for Railbelt Region (1979-1995)

Unit Reference/ Name	Year of Installation	Location	Type of Generation	Capacity (kW)
		ANCHORAGE MUNICIPAL LIGHT AND POWER (AML&P)		
Unit 7	1979	Anchorage	S.C.C.T.	65,000[a]
Unit 6	1979	Anchorage	C.C.	16,500[b]
		CHUGACH ELECTRIC ASSOCIATION (CEA)		
Beluga #9	1979	Beluga	C.C.	32,200[c]
X-1	1980		S.C.C.T.	100,000
Bernice Lake #4	1981	Bernice Lake	S.C.C.T.	18,000
X-2	1982		S.C.C.T.	100,000
Bernice Lake #5	1984	Bernice Lake	S.C.C.T.	18,000
		GOLDEN VALLEY ELECTRIC ASSOCIATION (GVEA)		
Healy #2	As Required	Healy	S.T.	100,000
		ALASKA POWER ADMINISTRATION (APA)		
Bradley Lake	1985	Bradley Lake	Hydro	70,000
		NATIONAL DEFENSE		
-	1985	Ft. Richardson and Emendorf A.F.G.	S.T.	7,300
-	1988	Fairbanks Combined	S.T.	14,000
-	1990	Ft. Greely and Clear A.F.B.	S.T.	32,000
-	1991	Ft. Richardson and Emendorf A.F.B.	S.T.	42,500
-	1995	Ft. Greely and Clean A.F.B.	S.T.	24,500

(a) Unit #7 is a simple cycle combustion turbine unit which also supplies exhaust heat to Unit #6.
(b) This increase reflects the increase in capacity resulting from the addition of Unit #7.
(c) Beluga #9 is a steam unit addition to Beluga #7 (converts these to a 100 MW combined cycle unit).

SOURCES:
1. 1976 Power System Study, Chugach Electric Association, Inc., Tippett and Gee, Dallas, TX, pp. 7 and 25, March 1976.
2. Electric Power in Alaska, 1976-1995, ISER, University of Alaska, pp. J.5.2-7.4, August 1976.
3. Alaska Power Administration, August 1978.

Since a reserve margin effectively increases the amount of generating ca ity in place at any given time, it does contribute costs to the system. Therefore, an excessive reserve margin is to be avoided while at the same time recognizing that an inadequate reserve margin could, on outage, result in a wide variety of social costs.

For the purposes of this study, the Alaska Power Administration has suggested that the analysis be based on reserve margins of 25% and 20% for non-interconnected load centers and the interconnected systems, respectively. In the future, a more refined analysis of the desired reserve margin appears warranted.

3.2.4 Transmission Losses

Transmission losses must be added to forecasts of peak and energy loads to establish net capacity and energy at the plant substations. The Alaska Power Administration expects losses as follows:

	%
Capacity	5
Energy	1.5

The results of the load/resource analysis are thus in *net* deliverable capacity and energy and do not include energy and capacity required for internal plant operations.

The above losses are reasonably applicable for the independent operation of the load centers, for interconnected systems including the Upper Susitna project and for configurations with future generation capacity additions being distributed proportionally near the load centers. In the case of interconnection without Upper Susitna and with a tendency to centralize Railbelt thermal generation, the transmission losses may be considerably higher as discussed later in Section 3.2.8.

3.2.5 Construction Schedule Constraints

Due to the lead times necessary for the permit processes and construction, generating unit and site selection must take place a number of years in advance of the forecasted date when the units commercial operation will be required. For coal-fired thermal plants, the Pacific Northwest Utilities Conference Committee estimates a 62 month (5.2 years) period from final site selection to commercial operation for plants in the 500 MW and higher range based on recent U.S. experience.

Although individual thermal plant capacities appropriate to Alaska's loads are somewhat smaller and may require less field erection work, the construction season is shorter and the 5 to 6 year scheduling period appears reasonable.

For the potential Upper Susitna hydroelectric projects, the scale of effort is more demanding and increased site evaluation is necessary. Current understanding is that the Watana Dam and power plant could be brought to commercial operation by 1994, followed by Devil Canyon no sooner than 1998.

A transmission interconnection between Anchorage-Cook Inlet and Fairbanks-Tanana Valley could be brought into service prior to completion of Watana, possibly as early as 1986.

The load/resource analysis technology recognizes the above schedule constraints by not allowing callup of new generation or transmission capacity that could not be made available.

3.2.6 Plant Availability Constraints

Generating and transmission plant availability can be expressed in terms of maximum and minimum plant utilization factors (PUF). These factors are primarily dependent upon plant type and plant age. For purposes of this analysis we have assumed the following economic facility lifetimes after which the facility is retired from service.[1]

	Years
Coal-Fired Thermal Generation	35
Oil-Fired Steam Generation	35
Gas-Fired Combustion Turbine	20
Oil-Fired Combustion Turbine	20
Hydroelectric Generation	50

(1) See Tables 3.4 and 3.5 for dates of expected retirements for existing systems.

Due to the nature of the system, some plants could be retired from service pr - to the expiration of their economic life. In actual practice, however, it is expected that utilities may elect to retain the units on standby. In order to assure their availability in emergencies, the utilities will periodically operate the units to make sure they are in working condition.

Experience has shown that large thermal plants experience a learning curve during the first few years of operation as "bugs" are worked out. Once past this period they reach a maximum that allows for scheduled maintenance and replacement conducted during the off-peak season. Toward the end of the economic life, increased frequency and duration of outages for maintenance usually occur and the maximum plant utilization factor declines. For purposes of this analysis, we have assumed constraints on the maximum PUF for new coal-fired steam electric plants as shown in Figure 3.4.

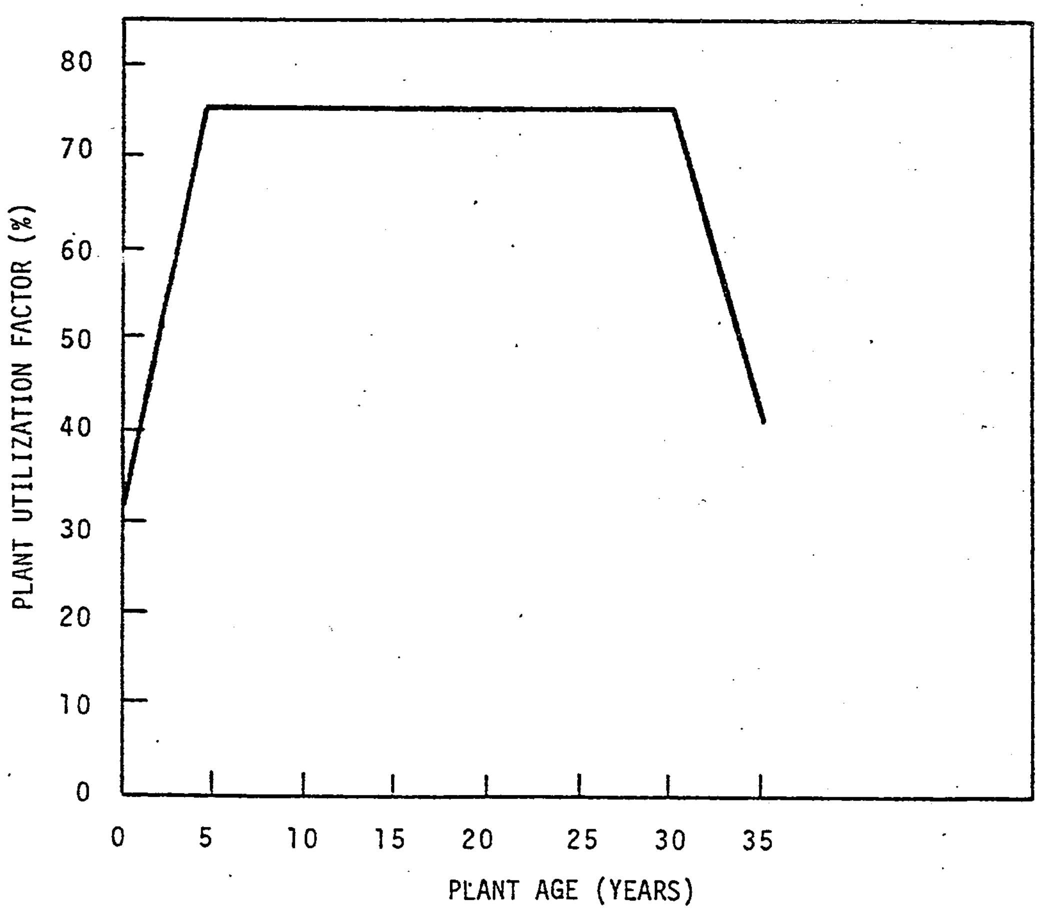

FIGURE 3.4. Plant Utilization Factor versus Plant Age

Other types of generating capacity are allowed to run at their maximum PUF from the start. For new capacity and most types of existing capacity, the following maximum PUFs are assumed:

	Maximum Plant Utilization (%)
Hydro	50.0
Steam Electric	75.0
Combustion Turbine	50.0
Diesel	10.0

Hydroelectric generation systems, as a result of their storage ability and conservative ratings, can make additional power available for peaking and it is assumed they can be scheduled at 115% of design capacity for this service.

As pointed out earlier in Section 3.1, the peak demand during the winter usually determines the amount of generating capacity required rather than the annual energy. Because of this, some generating units are utilized at less than their maximum annual plant utilization factors. The decision as to which units should not be loaded is usually based on the margin cost of operating the facilities. In this analysis it is assumed that diesel capacity has the highest margin operating cost followed by combustion turbines, steam turbines and hydroelectric capacity in that order. It is assumed that diesel PUFs can be reduced to 0.0 while the PUFs for combustion turbine and steam electric capacity is not allowed to go below 10%.

Transmission plant availability is generally not as schedule constrained as are generating plants with their long lead times. For purposes of these analyses, the interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area will be provided 3 years before the completion of the Watana dam or when the Healy 1 (existing 25 MW) and Healy 2 (planned 100 MW net) plants become fully loaded, whichever occurs first.[2] This assumption in effect places oil-fired plants serving the area on standby after that date.

(2) It will probably be desirable to provide at least a portion of the interconnection prior to Watana date on-line as a source of power for construction.

3.2.7 Economic Generating Unit Size

The selection of optimum generating size can be a complex process involving uncertain assumptions regarding probability of future load growth paths, desirability of sizing individual units in comparable sizes and types for each of maintenance, assuring that system reliability is not penalized by addition of too large a single unit, smoothing of construction schedules for possible multiunit plants, and maintaining as small as possible departure from the desired reliability margin. A full optimization does not appear warranted at this stage and is beyond the scope of this analysis.

Thus for the purposes of this study, the first six coal-fired steam electric plants in the Fairbanks-Tanana Valley area are assumed to be 100 MW units. Any additional units are assumed to be 200 MW units. In the Anchorage-Cook Inlet area the first five coal-fired steam electric plants are assumed to be 200 MW units, while any additional plants are assumed to be 400 MW units. These size ranges, though probably not exact optimums, appear reasonable block sizes for introduction and typically become fully loaded at about 10% of plant life.

3.3 SYSTEM CONFIGURATIONS: DEFINITION OF CASES ANALYZED

3.3.1 Case 1: Without Interconnection and Without Upper Susitna Project

The base case consists of power supply to the Anchorage-Cook Inlet and Fairbanks-Tanana Valley on a noninterconnected basis. In this instance, no power is available from the Upper Susitna project.

Future capacity additions for the Anchorage-Cook Inlet load center are assumed to be near-mine-mouth coal-fired units located on the west side of Cook Inlet with a nominal 50-mile transmission distance using two 345 kV circuits with a capacity of 1600 MW. Capital cost of this transmission system is $228 million in October 1978 prices.

Further capacity additions for the Fairbanks-Tanana Valley load center are assumed to be coal-fired units with a nominal 100-mile transmission distance. The Healy site is used as a proxy recognizing, however, that the Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act may preclude the siting of additional plants beyond the planned Healy 2 100 MW unit. A 230 kV single circuit will transmit up to 400 MW and a 230 kV double circuit, 800 MW. Capital costs are $44 million and $70 million, respectively. Table 3.9 provides a summary of the transmission system alternatives. A map of the Railbelt region showing the Watana and Devil Canyon dam sites, a possible route for the interconnection, and the Beluga area is presented in Figure 3.5.

3.3.2 Case 2: With Interconnection, Without Upper Susitna Project

In the case of an interconnected system *without* the Upper Susitna project and all new capacity coal fired, the load/resource analysis is not as straightforward in that it is not readily apparent what strategy for siting plants should be followed. Two primary options are apparent:

1. All coal plants sited at a single location(1) (Concentrated Siting).

   Advantages

   a) Lower capital and operating costs for generation.
   b) Economies of scale can be achieved.
   c) Siting problems in the interior may be avoided.

   Disadvantages

   a) Higher transmission losses (and costs) are incurred for the fraction of power flowing to the Fairbanks-Tanana Valley load center. These costs may cancel out savings from the advantages.

   b) The latter area becomes strongly dependent upon reliability of the transmission system--possibly to the point of requiring a second circuit or maintenance of additional standby combustion turbine capacity.

   c) Any adverse environmental effects are borne by a single area not necessarily benefiting in proportion.

2. Coal Plants Sited in Proportion to Relative Load Growth (Distributed Siting).

(1) For the purposes of this analysis, mine-mouth location at Beluga is used as a proxy.

TABLE 3.9. Transmission System Alternatives[1]

Location	Circuit	Capacity MW	Capacity Loss %	Approx. Investment Cost - $MM	$/kW
Isolated Load Centers					
Healy - Fairbanks 100 miles	230 kV Single	400	6	44	110
	230 kV Double	800	6	70	88
Beluga - Anchorage 100 miles	345 kV Single	400	2	114	285
		800	3	114	142
	Two 345 kV Single	800	2	228	285
		1600	3	228	142
Interconnected Without Susitna					
Anchorage - Healy 200 miles	230 kV Single	200	6	88	293
		300	8	88	225
	345 kV Single	400	3	228	570
		560	5	228	407
Interconnection With Susitna		1573[2]	5	471	(299)

(1) Source: Alaska Power Administration
(2) Actual peak power availability could be about 15% higher or 1808 MW.

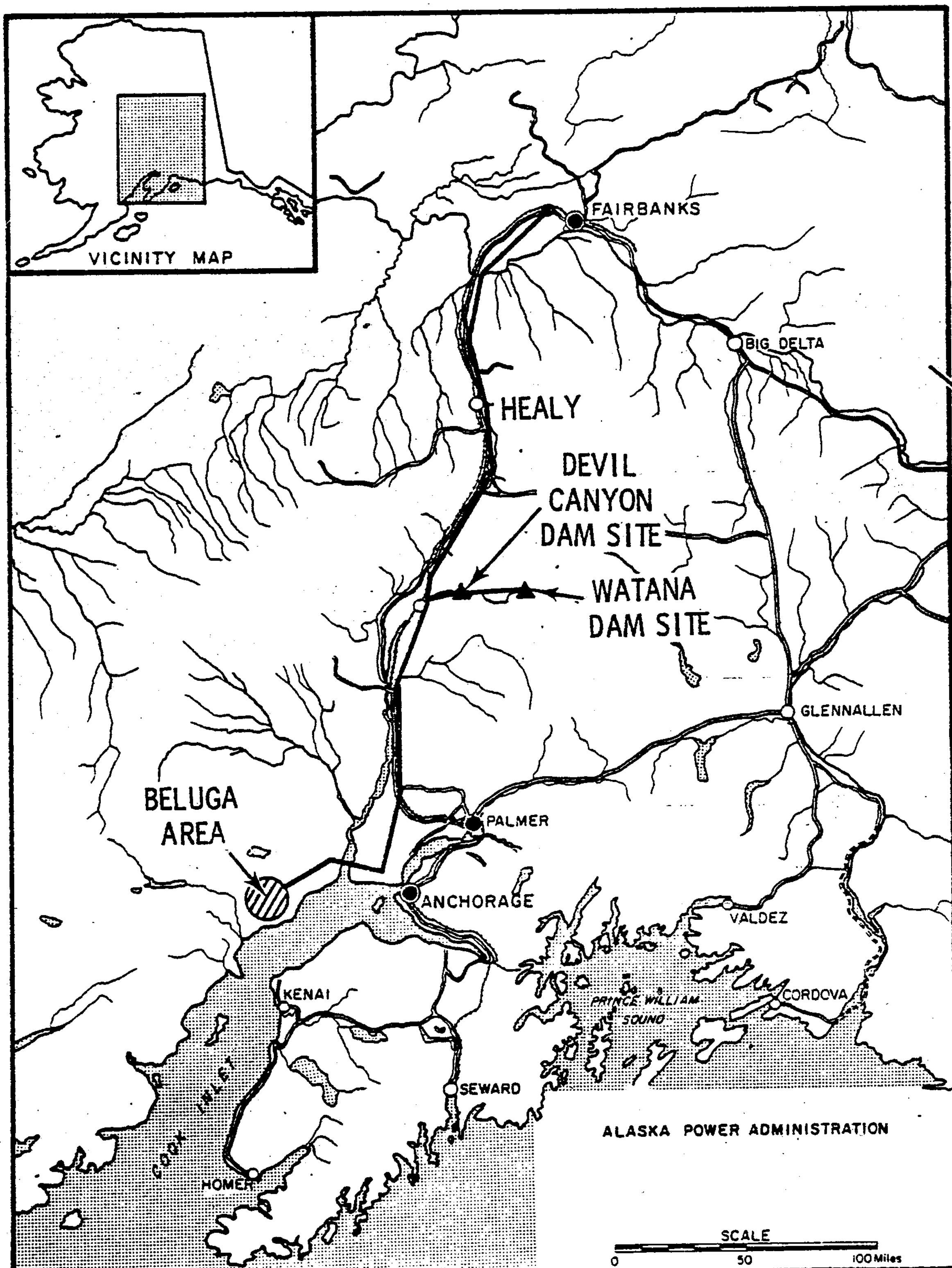

FIGURE 3.5. Railbelt Region Showing the Watana and Devil Canyon Damsites, a Possible Route for the Interconnection, and the Beluga Area

Advantages

a) The interconnection becomes lightly loaded, thus reducing transmission losses to some degree although charging losses would continue.

b) Transmission interconnection reliability dependence is reduced as the intertie assumes more of a capacity reserve characteristic.

c) Environmental burdens are distributed, possibly with more equity.

Disadvantages

a) Possible economies of scale are lost.

b) Generation costs in the Fairbanks-Tanana Valley are increased.

c) Siting problems related to meteorological considerations may result in the latter area.

In this report coal plants are assumed to be sited in proportion to the relative load growths of the two load centers. As with Case 1, additional coal-fired generating units are sited at Beluga to serve the Anchorage-Cook Inlet area and at Healy/Nenana to serve the Fairbanks-Tanana Valley areas.

The transmission interconnection is used for capacity reserve allowing the reserve margin for both load centers to be reduced from 25% to 20% (see Section 3.2.? Under this scenario there is no net energy transfer during any single year. If one load center is low on capacity the other load center provides the additional capacity required assuming it has a surplus. If no surplus exists the original load center must add capacity.

The interconnection is assumed to be brought on line in the same year as the Healy 2 coal plant becomes fully loaded and new generating capacity would be required in the Fairbanks-Tanana Valley area. Addition of the interconnection allows the Fairbanks-Tanana Valley area to get capacity reserve from the Anchorage-Cook Inlet Area. This allows the Fairbanks area to postpone the construction of additional capacity by 2 to 6 years depending upon the scenario.

In the high load growth case the interconnection would be completed in 1986, in the medium load growth case it would come on line in 1989, and in the low load growth case it would come on line in 1994. In all cases 45% of the cost of the interconnection is assigned to the Fairbanks-Tanana Valley load center.

3.3.3 Case 3: Interconnected System With Upper Susitna Project

In addition to the interconnection described in the previous section, Case 3 includes two hydroelectric generating facilities. The Watana dam is scheduled to come on line in 1994. The date is assumed to be the same for all three load growth scenarios. The Devil Canyon dam is assumed to come on line as soon as required following 1994 but not before 1998. It is assumed it would take at least 4 years to complete the Devil Canyon dam following completion of the Watana dam. It turns out that the Devil Canyon dam is required in 1998 in the medium of high load growth scenarios but not until 1999 in the low load growth scenario.

Because of reservoir filling requirements it is assumed that both dams will take 2 years to reach full capacity and power output. The capacities, power production and plant utilization factors for the two dams are show below.

Year	Capacity (MW)	Energy (MMkWh)	Utilization (%)
Watana			
1	703	3080	50.0
2+	795	3480	50.0
Devil Canyon			
1	689	3020	50.0
2+	778	3410	50.0

For the medium and high load growth the transmission interconnection is assumed to come on line in 1989 and 1986 respectively; the same years as for Case 2. In the low load growth scenario the interconnection comes on line in 1991 rather than 1994. This earlier completion date will allow the Watana dam construction site to be supplied with power from either the Anchorage-Cook Inlet area or the Fairbanks-Tanana Valley area.

The power output of the two dams is divided between the two load centers in proportion to their relative energy consumption in 1994. This results in the percentage divisions shown below.

Load Growth Scenario	Anchorage-Cook Inlet	Fairbanks-Tanana Valley
Low	80%	20%
Medium	81%	19%
High	84%	16%

3.4 RESULTS OF LOAD/RESOURCE ANALYSES

Using the methodology outlined in Section 3.1 and the assumptions explained in Section 3.2, a series of load/resource analyses were performed. As pointed out earlier, three basic cases were evaluated:

Case 1 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area load centers.

Case 2 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines including a transmission interconnection.

Case 3 All additional generating capacity beyond utility plans assumed to be coal-fired steam turbines but including the Upper Susitna project (including a transmission intertie) coming on line in 1994.

For each of these three cases. Three load growth scenarios (low, medium and high) are evaluated resulting in a total of nine load/resource analyses.

The assumptions discussed in this chapter are incorporated in a computer model called AEPMOD. The output of AEPMOD for Case 3 assuming the medium load growth scenario is presented in Table 3.10. The results of all nine cases are presented in Appendix C. The AEPMOD computer code is presented in Appendix B and the data base necessary to make the runs is presented in Appendix A.

The capacity additions called up in the various cases are presented in Tables 3.11, 3.12 and 3.13.

The results of the runs are summarized in Figures 3.6 through 3.11.

TABLE 3.10. Load/Resource Balance for Case 3: Medium Load Growth Scenario

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1978-1979 PEAK	1978-1979 MPUF	1978-1979 APUF	1978-1979 ENERGY	1979-1980 PEAK	1979-1980 MPUF	1979-1980 APUF	1979-1980 ENERGY	1980-1981 PEAK	1980-1981 MPUF	1980-1981 APUF	1980-1981 ENERGY
REQUIREMENTS	585.			2531.	632.			2801.	686.			3041.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	51.	.75	.75	332.
COMB.TURBINE	575.	.50	.40	2034.	575.	.50	.36	1810.	689.	.50	.35	2113.
DIESEL	19.	.15	.00	0.	19.	.15	.00	0.	19.	.15	.00	0.
TOTAL	698.			2569.	698.			2346.	812.			2649.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	114.	.50	.50	497.	100.	.50	.50	438.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	2.	.00	.00	0.
GROSS RESOURCES	698.			2569.	812.			2843.	910.			3087.
CAP RES. MARGIN	0.193				0.284				0.326			
RESERVE REQ.	146.				158.				172.			
LOSSES	29.			38.	32.			42.	34.			46.
NET RESOURCES	523.			2531.	622.			2801.	704.			3041.
TRANSFERED	0.				0.				0.			
SURPLUS	-62.			0.	-10.			0.	18.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1978-1979 PEAK	MPUF	APUF	ENERGY	1979-1980 PEAK	MPUF	APUF	ENERGY	1980-1981 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	184.			804.	197.			862.	209.			916.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.66	633.	110.	.75	.72	692.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.10	183.	209.	.50	.10	183.	209.	.50	.11	207.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			816.	365.			875.	365.			930.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			816.	365.			875.	365.			930.
CAP RES. MARGIN	0.983				0.852				0.746			
RESERVE REQ.	46.				49.				52.			
LOSSES	9.			12.	10.			13.	10.			14.
NET RESOURCES	310.			804.	306.			862.	302.			916.
TRANSFERED	0.				0.				0.			
SURPLUS	126.			0.	109.			0.	93.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982 PEAK	MPUF	APUF	ENERGY	1982-1983 PEAK	MPUF	APUF	ENERGY	1983-1984 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	741.			3281.	795.			3521.	850.			3761.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	251.	.75	.42	923.
COMB.TURBINE	789.	.50	.39	2716.	807.	.50	.32	2250.	891.	.50	.35	2691.
DIESEL	17.	.15	.00	0.	17.	.15	.00	0.	15.	.15	.00	0.
TOTAL	910.			3251.	928.			2785.	1210.			3817.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	200.	.75	.20	350.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	100.	.50	.50	438.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	15.	.00	.00	0.	8.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	928.			3330.	1210.			3574.	1202.			3817.
CAP RES. MARGIN	0.252				0.523				0.414			
RESERVE REQ.	185.				199.				213.			
LOSSES	37.			49.	40.			53.	43.			56.
NET RESOURCES	706.			3281.	972.			3521.	947.			3761.
TRANSFERED	-0.				0.				0.			
SURPLUS	-35.			0.	177.			0.	97.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1981-1982				1982-1983				1983-1984			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	221.			970.	233.			1024.	245.			1078.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.14	262.	209.	.50	.17	317.	209.	.50	.21	371.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			985.	365.			1039.	365.			1094.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	5.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			985.	365.			1039.	360.			1094.
CAP RES. MARGIN	0.651				0.566				0.467			
RESERVE REQ.	55.				58.				61.			
LOSSES	11.			15.	12.			15.	12.			16.
NET RESOURCES	299.			970.	295.			1024.	286.			1078.
TRANSFERED	0.				0.				0.			
SURPLUS	73.			0.	62.			0.	41.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1984-1985 PEAK	MPUF	APUF	ENERGY	1985-1986 PEAK	MPUF	APUF	ENERGY	1986-1987 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	904.			4001.	976.			4329.	1048.			4657.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	134.	.50	.50	510.
STEAM/ELEC	251.	.75	.53	1164.	251.	.75	.64	1405.	456.	.75	.56	2259.
COMB.TURBINE	883.	.50	.34	2615.	886.	.50	.28	2116.	855.	.50	.26	1958.
DIESEL	15.	.15	.00	0.	15.	.15	.00	0.	5.	.15	.00	0.
TOTAL	1202.			3982.	1205.			3724.	1452.			4727.
ADDITIONS												
HYDRO	-	-	-	-	81.	.50	.50	307.	-	-	-	-
STEAM/ELEC	-	-	-	-	207.	.75	.20	363.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	15.	.00	.00	0.	31.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	10.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	1205.			4061.	1452.			4394.	1452.			4727.
CAP RES. MARGIN	0.333				0.488				0.385			
RESERVE REQ.	226.				244.				262.			
LOSSES	45.			60.	49.			65.	52.			70.
NET RESOURCES	934.			4001.	1159.			4329.	1138.			4657.
TRANSFERED	0.				0.				0.			
SURPLUS	30.			0.	183.			0.	90.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS).

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1984-1985				1985-1986				1986-1987			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	258.			1132.	272.			1193.	286.			1254.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	210.	.75	.55	1018.
COMB.TURBINE	204.	.50	.24	426.	204.	.50	.18	313.	204.	.50	.14	254.
DIESEL	46.	.10	.00	0.	22.	.10	.00	0.	22.	.10	.00	0.
TOTAL	360.			1149.	336.			1036.	436.			1273.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	24.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	336.			1149.	436.			1211.	436.			1273.
CAP RES. MARGIN	0.300				0.601				0.523			
RESERVE REQ.	65.				68.				72.			
LOSSES	13.			17.	14.			18.	14.			19.
NET RESOURCES	258.			1132.	354.			1193.	350.			1254.
TRANSFERED	0.				0.				0.			
SURPLUS	0.			0.	82.			0.	64.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1987-1988 PEAK	1987-1988 MPUF	1987-1988 APUF	1987-1988 ENERGY	1988-1989 PEAK	1988-1989 MPUF	1988-1989 APUF	1988-1989 ENERGY	1989-1990 PEAK	1989-1990 MPUF	1989-1990 APUF	1989-1990 ENERGY
REQUIREMENTS	1120.			4985.	1192.			5313.	1264.			5641.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	458.	.75	.63	2413.	643.	.75	.58	3254.	645.	.75	.66	3745.
COMB.TURBINE	855.	.50	.24	1786.	855.	.50	.23	1628.	791.	.50	.21	1471.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	5.	.15	.00	0.
TOTAL	1452.			4709.	1637.			5393.	1573.			5726.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	200.	.75	.20	350.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	15.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	64.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	1637.			5060.	1573.			5393.	1573.			5726.
CAP RES. MARGIN	0.462				0.320				0.245			
RESERVE REQ.	284.				298.				253.			
LOSSES	56.			75.	60.			80.	63.			85.
NET RESOURCES	1301.			4985.	1216.			5313.	1257.			5641.
TRANSFERED	0.				0.				7.			
SURPLUS	181.			0.	24.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1987-1988 PEAK	1987-1988 MPUF	1987-1988 APUF	1987-1988 ENERGY	1988-1989 PEAK	1988-1989 MPUF	1988-1989 APUF	1988-1989 ENERGY	1989-1990 PEAK	1989-1990 MPUF	1989-1990 APUF	1989-1990 ENERGY
REQUIREMENTS	300.			1315.	314.			1376.	328.			1437.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	210.	.75	.62	1139.	210.	.75	.68	1194.	216.	.75	.68	1280.
COMB.TURBINE	204.	.50	.11	196.	204.	.50	.10	178.	204.	.50	.10	178.
DIESEL	22.	.10	.00	0.	22.	.10	.00	0.	0.	.10	.00	0.
TOTAL	436.			1335.	436.			1372.	419.			1459.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	14.	.75	.20	25.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	9.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	22.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	436.			1335.	419.			1397.	419.			1459.
CAP RES. MARGIN	0.452				0.334				0.277			
RESERVE REQ.	75.				79.				66.			
LOSSES	15.			20.	16.			21.	16.			22.
NET RESOURCES	46.			1315.	325.			1376.	337.			1437.
TRANSFERED	[illegible]				0.				-7.			
SURPLUS	46.			0.	11.			0.	2.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1990-1991				1991-1992				1992-1993			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1357.			6063.	1450.			6485.	1543.			6907.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	643.	.75	.71	3986.	843.	.75	.65	4552.	1045.	.75	.56	5166.
COMB.TURBINE	791.	.50	.19	1308.	791.	.50	.16	1095.	773.	.50	.10	634.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	3.	.15	.00	0.
TOTAL	1573.			5804.	1773.			6157.	1955.			6310.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	200.	.75	.20	350.	243.	.75	.20	425.	400.	.75	.20	701.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	41.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	18.	.00	.00	0.	50.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	1773.			6154.	1955.			6582.	2306.			7011.
CAP RES. MARGIN	0.307				0.349				0.494			
RESERVE REQ.	271.				290.				309.			
LOSSES	66.			91.	73.			97.	77.			104.
NET RESOURCES	1434.			6063.	1593.			6485.	1920.			6907.
TRANSFERED	0.				-29.				-89.			
SURPLUS	77.			0.	114.			0.	289.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1990-1991				1991-1992				1992-1993			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	343.			1505.	358.			1573.	374.			1641.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	216.	.75	.73	1172.	216.	.75	.68	1283.	216.	.75	.71	1339.
COMB.TURBINE	204.	.50	.17	300.	204.	.50	.18	313.	204.	.50	.23	327.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	419.			1472.	419.			1597.	419.			1666.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.75	.20	56.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	40.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	419.			1528.	419.			1597.	379.			1666.
CAP RES. MARGIN	0.222				0.170				0.013			
RESERVE REQ.	69.				72.				75.			
LOSSES	17.			23.	18.			24.	19.			25.
NET RESOURCES	333.			1505.	330.			1573.	286.			1641.
TRANSFERED	0.				29.				89.			
SURPLUS	-10.			0.	0.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1993-1994 PEAK	MPUF	APUF	ENERGY	1994-1995 PEAK	MPUF	APUF	ENERGY	1995-1996 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1636.			7329.	1729.			7751.	1854.			8311.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	792.	.50	.50	3015.
STEAM/ELEC	1445.	.75	.50	6343.	1445.	.75	.34	4266.	1445.	.75	.36	4614.
COMB.TURBINE	724.	.50	.10	586.	669.	.50	.10	586.	669.	.50	.10	477.
DIESEL	3.	.15	.00	0.	3.	.15	.00	0.	3.	.15	.00	0.
TOTAL	2306.			7439.	2251.			5362.	2909.			8106.
ADDITIONS												
HYDRO	-	-	-	-	658.	.50	.50	2505.	86.	.50	.50	329.
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	55.	.00	.00	0.	-	-	-	-	125.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	2251.			7439.	2909.			7867.	2871.			8436.
CAP RES. MARGIN	0.376				0.682				0.548			
RESERVE REQ.	327.				346.				371.			
LOSSES	82.			110.	86.			116.	93.			125.
NET RESOURCES	1842.			7329.	2476.			7751.	2407.			8311.
TRANSFERED	-107.				0.				0.			
SURPLUS	99.			0.	747.			0.	553.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1993-1994 PEAK	MPUF	APUF	ENERGY	1994-1995 PEAK	MPUF	APUF	ENERGY	1995-1996 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	389.			1709.	405.			1777.	423.			1859.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	151.	.50	.50	574.
STEAM/ELEC	216.	.75	.73	1377.	216.	.75	.58	1086.	216.	.75	.63	1053.
COMB.TURBINE	164.	.50	.25	357.	164.	.50	.10	143.	164.	.50	.10	143.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	379.			1735.	379.			1229.	530.			1770.
ADDITIONS												
HYDRO	-	-	-	-	151.	.50	.50	574.	19.	.50	.50	74.
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.75	.20	43.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.00	.00	0.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	379.			1735.	530.			1804.	549.			1887.
CAP RES. MARGIN	-0.026				0.308				0.298			
RESERVE REQ.	78.				81.				85.			
LOSSES	19.			26.	20.			27.	21.			28.
NET RESOURCES	282.			1709.	429.			1777.	443.			1859.
TRANSFERED	107.				0.				0.			
SURPLUS	0.			0.	24.			0.	20.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

	1996-1997 PEAK	1996-1997 MPUF	1996-1997 APUF	1996-1997 ENERGY	1997-1998 PEAK	1997-1998 MPUF	1997-1998 APUF	1997-1998 ENERGY	1998-1999 PEAK	1998-1999 MPUF	1998-1999 APUF	1998-1999 ENERGY
	CRITICAL PERIOD											
REQUIREMENTS	1979.			8871.	2103.			9431.	2228.			9991.
RESOURCES												
EXISTING												
HYDRO	878.	.50	.50	3344.	878.	.50	.50	3344.	678.	.50	.50	3344.
STEAM/ELEC	1445.	.75	.42	5366.	1445.	.75	.47	5934.	1445.	.75	.32	4025.
COMB.TURBINE	545.	.50	.10	294.	335.	.50	.10	294.	335.	.50	.10	278.
DIESEL	3.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	2871.			9004.	2659.			9572.	2659.			7648.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	654.	.50	.50	2493.
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	210.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	2.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	2659.			9004.	2659.			9572.	3295.			10141.
CAP RES. MARGIN	0.343				0.264				0.479			
RESERVE REQ.	396.				421.				446.			
LOSSES	99.			133.	105.			141.	111.			150.
NET RESOURCES	2164.			8871.	2133.			9431.	2738.			9991.
TRANSFERED	-27.				0.				0.			
SURPLUS	158.			0.	30.			0.	510.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
*ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

	CRITICAL PERIOD											
	1996-1997				1997-1998				1998-1999			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	442.			1941.	461.			2023.	480.			2105.
RESOURCES												
EXISTING												
HYDRO	170.	.50	.50	648.	170.	.50	.50	648.	170.	.50	.50	648.
STEAM/ELEC	216.	.75	.64	1200.	216.	.75	.65	1230.	316.	.75	.35	963.
COMB.TURBINE	164.	.50	.10	123.	140.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	549.			1970.	526.			1878.	486.			1611.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	138.	.50	.50	525.
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	24.	.00	.00	0.	140.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	526.			1970.	486.			2053.	624.			2137.
CAP RES. MARGIN	0.189				0.053				0.299			
RESERVE REQ.	88.				92.				96.			
LOSSES	22.			29.	23.			30.	24.			32.
NET RESOURCES	415.			1941.	370.			2023.	504.			2105.
TRANSFERED	27.				0.				0.			
SURPLUS	0.			0.	-91.			0.	24.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1999-2000				2000-2001				2001-2002			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2553.			10551.	2421.			10863.	2490.			11175.
RESOURCES												
EXISTING												
HYDRO	1533.	.50	.50	5837.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1445.	.75	.34	4343.	1445.	.75	.37	4747.	1445.	.75	.40	5080.
COMB.TURBINE	317.	.50	.10	206.	236.	.50	.10	119.	136.	.50	.10	103.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3295.			10386.	3298.			11026.	3198.			11343.
ADDITIONS												
HYDRO	85.	.50	.50	323.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	82.	.00	.00	0.	100.	.00	.00	0.	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3298.			10709.	3198.			11026.	3180.			11343.
CAP RES. MARGIN	0.402				0.321				0.277			
RESERVE REQ.	471.				484.				498.			
LOSSES	118.			158.	121.			163.	125.			168.
NET RESOURCES	2710.			10551.	2593.			10863.	2558.			11175.
TRANSFERED	0.				0.				-6.			
SURPLUS	357.			0.	172.			0.	61.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1999-2000				2000-2001				2001-2002			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	499.			2187.	508.			2229.	518.			2270.
RESOURCES												
EXISTING												
HYDRO	308.	.50	.50	1173.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	316.	.75	.35	980.	316.	.75	.37	1022.	316.	.75	.38	1064.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	624.			2153.	641.			2262.	641.			2304.
ADDITIONS												
HYDRO	18.	.50	.50	67.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	641.			2220.	641.			2262.	641.			2304.
CAP RES. MARGIN	0.285				0.262				0.238			
RESERVE REQ.	100.				102.				104.			
LOSSES	25.			33.	25.			33.	26.			34.
NET RESOURCES	516.			2187.	514.			2229.	512.			2270.
TRANSFERED	0.				0.				6.			
SURPLUS	17.			0.	6.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2002-2003 PEAK	MPUF	APUF	ENERGY	2003-2004 PEAK	MPUF	APUF	ENERGY	2004-2005 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2558.			11487.	2626.			11799.	2694.			12111.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1445.	.75	.38	4783.	1845.	.75	.36	5801.	1845.	.75	.38	6133.
COMB.TURBINE	118.	.50	.10	15.	18.	.50	.10	15.	18.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3180.			10959.	3480.			11976.	3480.			12293.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	400.	.75	.20	701.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	100.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3480.			11659.	3480.			11976.	3462.			12293.
CAP RES. MARGIN	0.361				0.325				0.285			
RESERVE REQ.	512.				525.				539.			
LOSSES	126.			172.	131.			177.	135.			182.
NET RESOURCES	2841.			11487.	2824.			11799.	2789.			12111.
TRANSFERED	0.				0.				0.			
SURPLUS	283.			0.	198.			0.	95.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2002-2003 PEAK	MPUF	APUF	ENERGY	2003-2004 PEAK	MPUF	APUF	ENERGY	2004-2005 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	527.			2312.	537.			2353.	546.			2395.
RESOURCES												
EXISTING												
HYDRO	326.	.50	.50	1240.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	316.	.75	.37	931.	391.	.75	.34	1148.	391.	.75	.35	1191.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	641.			2171.	716.			2388.	716.			2431.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	100.	.75	.20	175.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	25.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	716.			2347.	716.			2388.	716.			2431.
CAP RES. MARGIN	0.359				0.333				0.311			
RESERVE REQ.	105.				107.				109.			
LOSSES	26.			35.	27.			35.	27.			36.
NET RESOURCES	584.			2312.	582.			2353.	580.			2395.
TRANSFERED	0.				0.				0.			
SURPLUS	57.			0.	45.			0.	34.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2005-2006 PEAK	2005-2006 MPUF	2005-2006 APUF	2005-2006 ENERGY	2006-2007 PEAK	2006-2007 MPUF	2006-2007 APUF	2006-2007 ENERGY	2007-2008 PEAK	2007-2008 MPUF	2007-2008 APUF	2007-2008 ENERGY
REQUIREMENTS	2763.			12423.	2831.			12735.	2899.			13047.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	1845.	.75	.40	6450.	1845.	.75	.38	6066.	2245.	.75	.36	7083.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3462.			12609.	3462.			12225.	3862.			13243.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	400.	.75	.20	701.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3462.			12609.	3862.			12926.	3862.			13243.
CAP RES. MARGIN	0.253				0.364				0.332			
RESERVE REQ.	553.				566.				580.			
LOSSES	138.			186.	142.			191.	145.			196.
NET RESOURCES	2771.			12423.	3154.			12735.	3137.			13047.
TRANSFERED	0.				-10.				-23.			
SURPLUS	8.			0.	313.			0.	216.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2005-2006 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	556.			2437.
RESOURCES				
EXISTING				
HYDRO	326.	.50	.50	1240.
STEAM/ELEC	391.	.75	.38	1234.
COMB.TURBINE	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.
TOTAL	716.			2474.
ADDITIONS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	20.	.00	.00	0.
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
GROSS RESOURCES	696.			2474.
CAP RES. MARGIN	0.252			
RESERVE REQ.	111.			
LOSSES	28.			37.
NET RESOURCES	557.			2437.
TRANSFERED	0.			
SURPLUS	1.			0.

	2006-2007 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	565.			2478.
RESOURCES				
EXISTING				
HYDRO	326.	.50	.50	1240.
STEAM/ELEC	371.	.75	.39	1275.
COMB.TURBINE	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.
TOTAL	696.			2515.
ADDITIONS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
GROSS RESOURCES	696.			2515.
CAP RES. MARGIN	0.232			
RESERVE REQ.	113.			
LOSSES	28.			37.
NET RESOURCES	555.			2478.
TRANSFERED	10.			
SURPLUS	0.			0.

	2007-2008 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	575.			2520.
RESOURCES				
EXISTING				
HYDRO	326.	.50	.50	1240.
STEAM/ELEC	371.	.75	.41	1318.
COMB.TURBINE	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.
TOTAL	696.			2558.
ADDITIONS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB.TURBINE	-	-	-	-
DIESEL	-	-	-	-
GROSS RESOURCES	696.			2558.
CAP RES. MARGIN	0.211			
RESERVE REQ.	115.			
LOSSES	29.			38.
NET RESOURCES	552.			2520.
TRANSFERED	23.			
SURPLUS	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2008-2009 PEAK	MPUF	APUF	ENERGY	2009-2010 PEAK	MPUF	APUF	ENERGY	2010-2011 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2968.			13359.	3036.			13671.	3104.			13983.
RESOURCES												
EXISTING												
HYDRO	1617.	.50	.50	6160.	1617.	.50	.50	6160.	1617.	.50	.50	6160.
STEAM/ELEC	2245.	.75	.38	7400.	2245.	.75	.39	7716.	2245.	.75	.37	7332.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3862.			13559.	3862.			13876.	3862.			13492.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	400.	.75	.20	701.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3862.			13559.	3862.			13876.	4262.			14193.
CAP RES. MARGIN	0.301				0.272				0.373			
RESERVE REQ.	594.				607.				621.			
LOSSES	148.			200.	152.			205.	155.			210.
NET RESOURCES	3120.			13359.	3103.			13671.	3486.			13983.
TRANSFERED	-34.				-46.				-58.			
SURPLUS	118.			0.	21.			0.	325.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
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ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.10. (contd)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1990.
NOTES:DEC. 6, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2008-2009				2009-2010				2010-2011			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	584.			2561.	594.			2603.	603.			2645.
RESOURCES												
EXISTING												
HYDRO	326.	.50	.50	1240.	326.	.50	.50	1240.	326.	.50	.50	1240.
STEAM/ELEC	371.	.75	.42	1359.	371.	.75	.43	1402.	371.	.75	.45	1445.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	696.			2599.	696.			2642.	696.			2685.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	696.			2599.	696.			2642.	696.			2685.
CAP RES. MARGIN	0.192				0.172				0.154			
RESERVE REQ.	117.				119.				121.			
LOSSES	29.			38.	30.			39.	30.			40.
NET RESOURCES	50.			2561.	548.			2603.	545.			2645.
TRANSFERED	34.				46.				58.			
SURPLUS	0.			0.	0.			0.	0.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

TABLE 3.11. Schedule of Plant Additions - (Megawatts)
Base Cases Without Interconnections

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[4]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[4]	18[1]	18[1]	100	-	-
85-86	288[6]	288[6]	88[5]	-	100	-
86-87	400	-	-	100	-	-
87-88	-	200	200	-	-	-
88-89	400	-	-	14[7]	14[7]	14[7]
89-90	-	200	200	100	100	100
90-91	-	-	-	32[7]	32[7]	32[7]
91-92	443[9]	243[8]	43[7]	-	-	-
92-93	400	400	200	100	100	-
93-94	-	-	-	-	-	-
94-95	400[3]	-	200	100	-	100
95-96	400[3]	400	200	25[7]	25[7]	25[7]
96-97	400[3]	400	400	100	100	-
97-98	400[3]	400	-	200	100	100
98-99	400[3]	-	-	200	100	100
99-00	400[3]	400	400	-	-	-
00-01	400[3]	-	-	-	-	-
01-02	-	-	-	-	-	-
02-03	400[3]	400	-	-	-	-
03-04	400[3]	-	-	200	200	-
04-05	-	-	-	-	-	-
05-06	400[3]	400	400	-	-	-
06-07	400[3]	-	-	-	-	-
07-08	-	-	-	200	-	-
08-09	400[3]	-	-	-	-	-
09-10	400[3]	-	-	-	-	-
10-11	-	400	-	-	-	-
TOTAL 78-11	8,281	4,681	2,681	1,471	871	471

See footnotes next page

TABLE 3.11. (contd)

(1) Scheduled Combustion Turbines

(2) Scheduled Combustion Turbines + 400 MW S.T.

(3) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Capacity Units

(4) Scheduled Combustion Turbine + 200 MW S.T.

(5) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(6) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + 7 MW S.T. National Defense

(7) National Defense

(8) 200 MW S.T. + 43 MW S.T. National Defense

(9) 400 MW S.T. + 43 MW S.T. National Defense

TABLE 3.12. Schedule of Plant Additions - (Megawatts) Cases With Interconnection Without Upper Susitna

Period	Anchorage High	Anchorage Median	Anchorage Low	Fairbanks High	Fairbanks Median	Fairbanks Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[3]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[6]	18[1]	18[1]	100	-	-
85-86	288[5]	288[5]	88[4]	-	100	-
86-87	-*	-	-	-*	-	-
87-88	400	200	200	-	-	-
88-89	-	-	-	14[8]	14[8]	14[8]
89-90	400	-*	200	-	-*	100
90-91	-	200	-	32[8]	32[8]	32[8]
91-92	443[11]	243[9]	43[8]	-	-	-
92-93	-	400	200	200	-	-
93-94	400	-	-	100	-	-
94-95	-	-	-*	-	100	-*
95-96	400[7]	400	200	125[10]	125[10]	25[8]
96-97	400[7]	400	200	100	-	100
97-98	400[7]	-	400	200	100	100
98-99	400[7]	400	-	-	100	-
99-00	400[7]	-	-	-	-	-
00-01	400[7]	400	400	-	-	-
01-02	400[7]	-	-	-	-	-
02-03	400[7]	-	-	-	100	-
03-04	-	400	-	200	-	-
04-05	-	-	-	200	-	-
05-06	400[7]	-	-	-	-	-
06-07	400[7]	-	-	-	-	100
07-08	400[7]	400	-	-	-	-
08-09	-	-	-	-	-	-
09-10	400[7]	-	-	-	-	-
10-11	400[7]	-	-	-	-	-
TOTAL 78-11	8,281	4,281	2,231	1,271	671	471

See footnotes next page

TABLE 3.12. (contd)

*Interconnection Installed

(1) Scheduled Combustion Turbine Additions

(2) 100 MW Scheduled Combustion Turbine + 400 MW S.T.

(3) 100 MW Scheduled Combustion Turbine + 200 MW S.T.

(4) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(5) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + 7 MW S.T. National Defense

(6) 18 MW Scheduled Combustion Turbine + 200 MW S.T.

(7) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Units

(8) National Defense

(9) 200 MW S.T. + 43 MW S.T. National Defense

(10) 100 MW S.T. + 25 MW S.T. National Defense

(11) 400 MW S.T. + 43 MW S.T. National Defense

TABLE 3.13. Schedule of Plant Additions - (Megawatts) Cases With Interconnection With Upper Susitna Coming On Line in 1994

	Anchorage			Fairbanks		
Period	High	Median	Low	High	Median	Low
78-79	-	-	-	-	-	-
79-80	114[1]	114[1]	114[1]	-	-	-
80-81	100[1]	100[1]	100[1]	-	-	-
81-82	18[1]	18[1]	18[1]	-	-	-
82-83	500[2]	300[5]	100[1]	-	-	-
83-84	200	-	-	-	-	-
84-85	218[8]	18[1]	18[1]	100	-	-
85-86	288[7]	288[7]	88[6]	-	100	-
86-87	-*	-	-	-*	-	-
87-88	400	200	200	-	-	-
88-89	-	-	-	14[10]	14[10]	14[10]
89-90	400	-*	200	-	-*	100
90-91	-	200	-	32[10]	32[10]	32[10]
91-92	443[14]	243[12]	43[10]	-	-	-*
92-93	-	400	-	200	-	-
93-94	400	-	200	100	-	-
94-95	677[3]	658[3]	644[3]	132[3]	151[3]	164[3]
95-96	89[3]	86[3]	85[3]	42[11]	44[11]	46[11]
96-97	400	-	-	-	-	-
97-98	400	-	-	-	100	-
98-99	688[4]	654[4]	-	124[4]	138[4]	-
99-00	86[4]	85[4]	645[4]	16[4]	18[4]	147[4]
00-01	-	-	83[4]	100	-	19[4]
01-02	400[9]	-	-	100	-	-
02-03	400[9]	400	-	-	100	-
03-04	-	-	-	200	-	-
04-05	400[9]	-	-	-	-	-
05-06	400[9]	-	-	-	-	-
06-07	-	400	-	-	-	-
07-08	400	-	-	-	-	-
08-09	400[9]	-	-	-	-	-
09-10	-	-	-	200	-	-
10-11	400[9]	400	-	-	-	-
TOTAL 78-11	8,221	4,564	2,538	1,360	697	522

See footnotes next page

TABLE 3.13. (contd)

*Interconnection Installed

(1) Scheduled Combustion Turbine Additions

(2) Scheduled 100 MW Combustion Turbine + 400 MW S.T.

(3) Share of Watana Capacity x 1.15 for Peaking

(4) Share of Devil Canyon Capacity x 1.15 for Peaking

(5) Scheduled 100 MW Combustion Turbine + 200 MW S.T.

(6) Bradley Lake (70 MW) x 1.15 for Peaking + 7 MW S.T. National Defense

(7) Bradley Lake (70 MW) x 1.15 for Peaking + 200 MW S.T. + MW S.T. National Defense

(8) Scheduled 18 MW Combustion Turbine +200 MW S.T.

(9) Anchorage 400 MW Coal-Fired Units Could be Replaced with Staged 800 MW Units

(10) National Defense

(11) Share of Watana Capacity x 1.15 for Peaking + 25 MW S.T. National Defense

(12) 200 MW S.T. + 43 MW S.T. National Defense

(13) Share of Watana Capacity x 1.15 for Peaking + 25 MW S.T. National Defense

(14) 400 MW S.T. + 43 MW S.T. National Defense

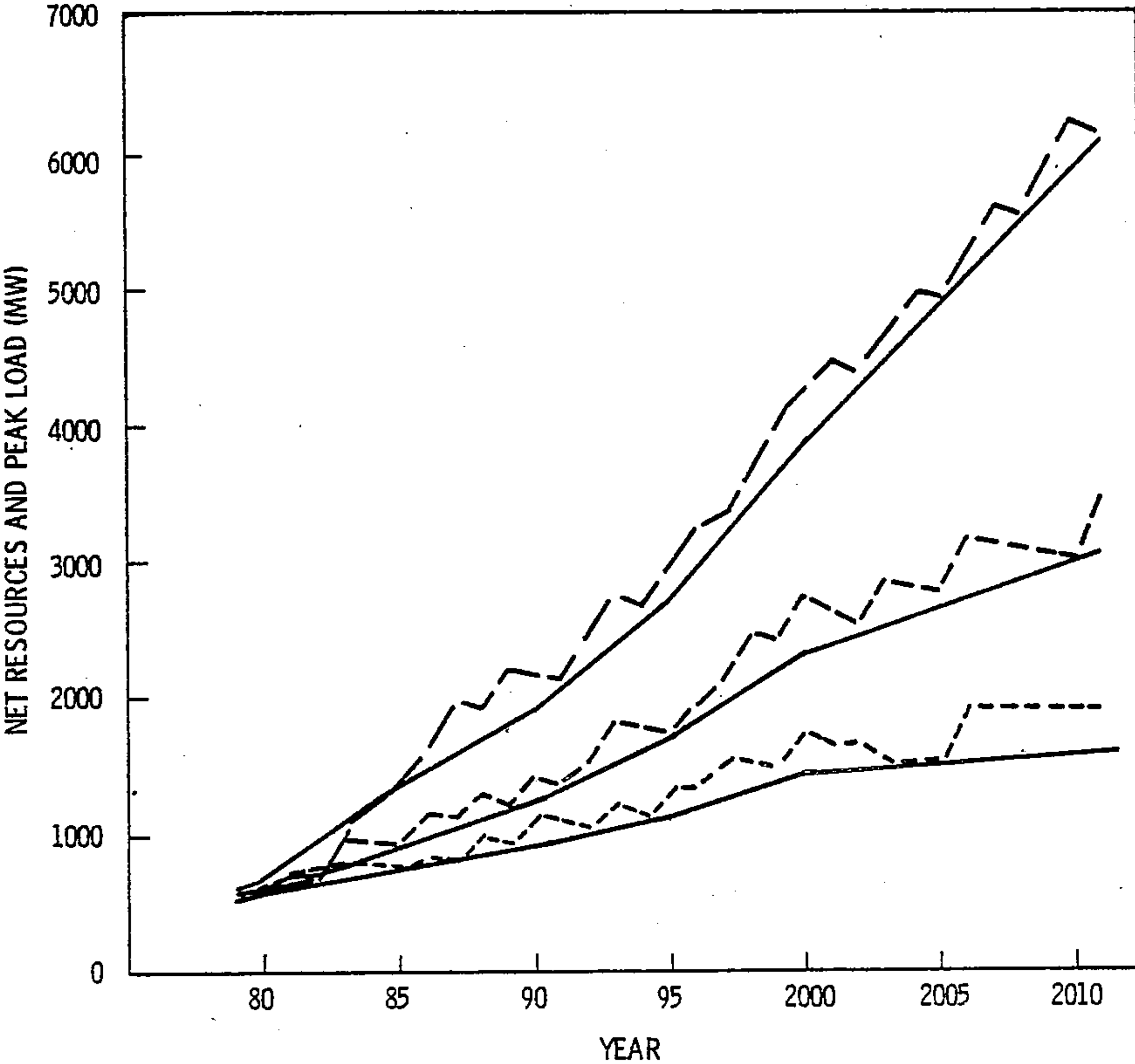

FIGURE 3.6. Load/Resource Analysis for Anchorage-Cook Inlet Area Without Interconnection and Without Susitna Project (Case 1). Low, Medium, and High Load Growth Scenarios

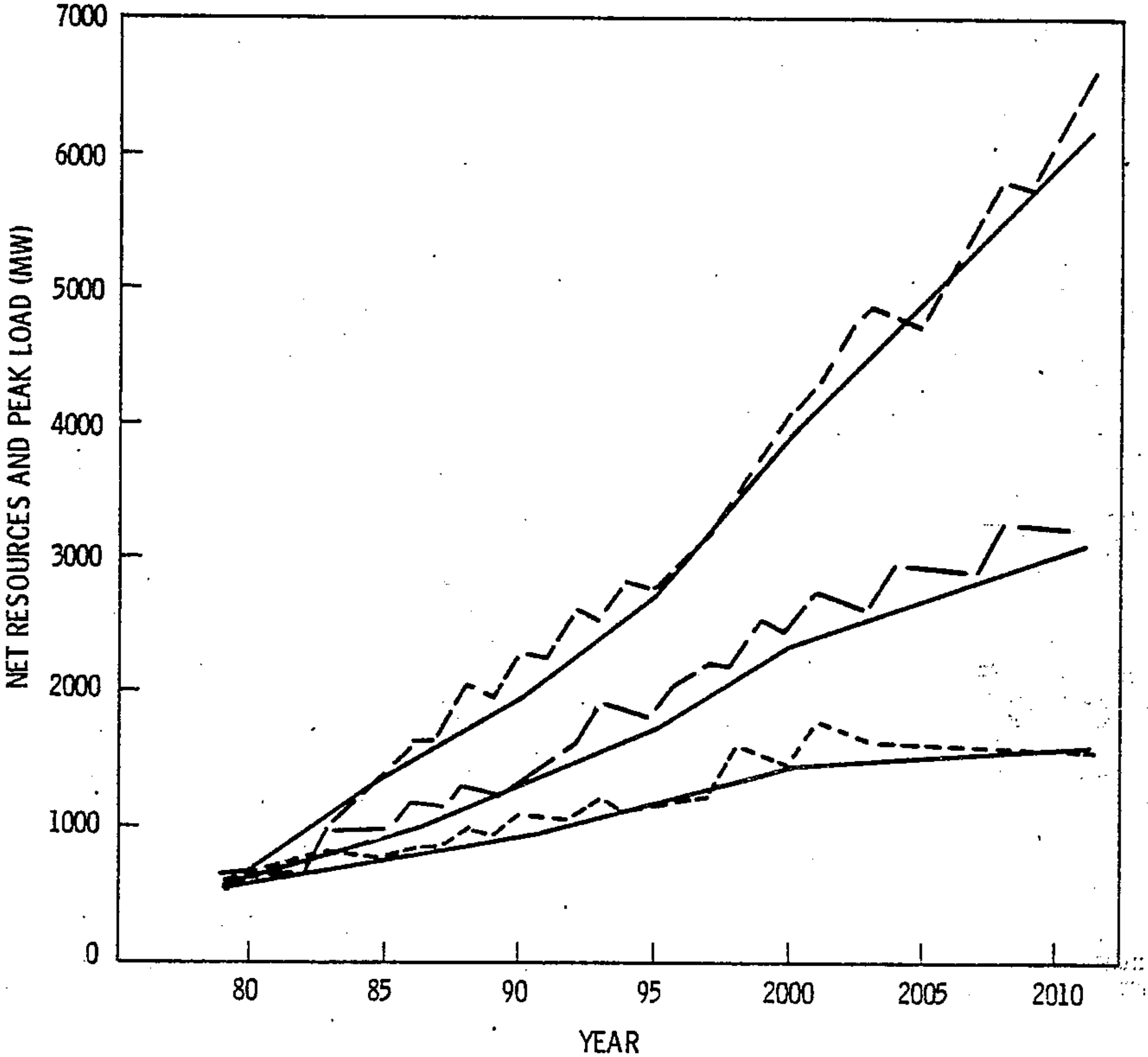

FIGURE 3.7. Load/Resource Analysis for Anchorage-Cook Inlet Area With Interconnection but Without Upper Susitna Project (Case 2). Low, Medium, and High Load Growth Scenarios

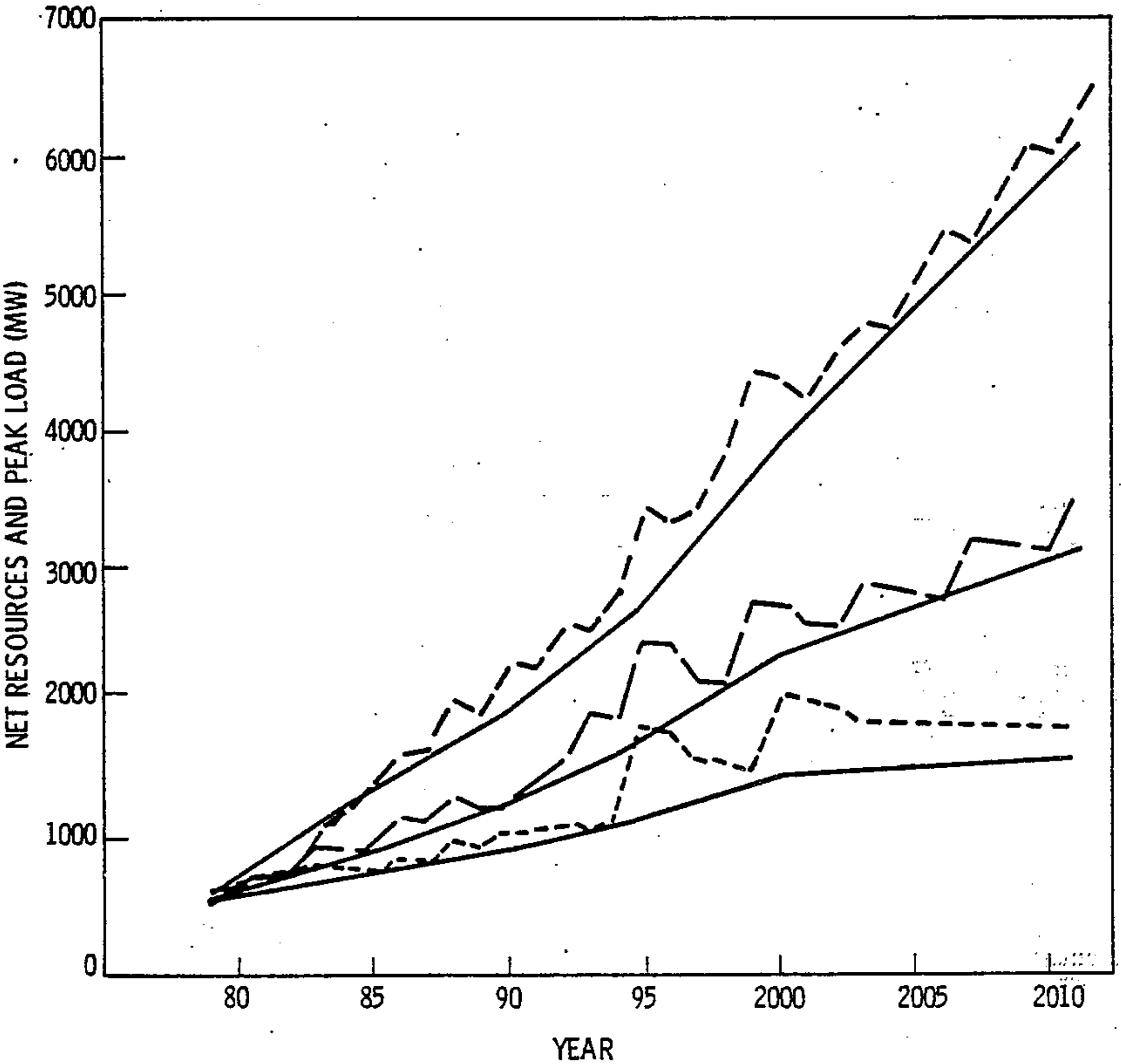

FIGURE 3.8. Load/Resource Analysis for Anchorage-Cook Inlet Area With Interconnection and With Upper Susitna Project Coming On Line in 1994 (Case 3). Low, Medium, and High Load Growth Scenarios

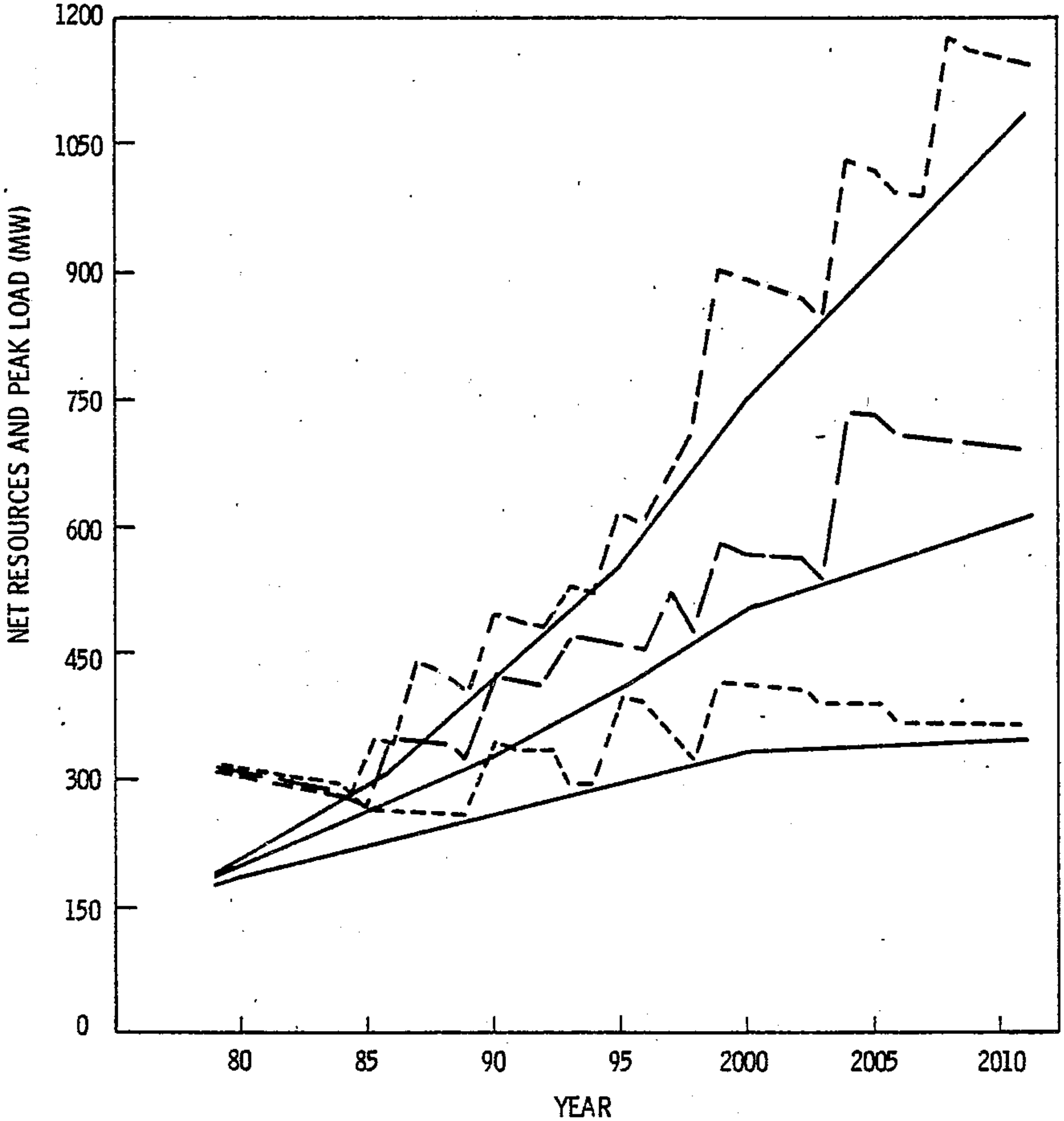

FIGURE 3.9. Load/Resource Analysis for Fairbanks-Tanana Valley Area Without Interconnection and Without Upper Susitna Project (Case 1). Low, Medium, and High Load Growth Scenario

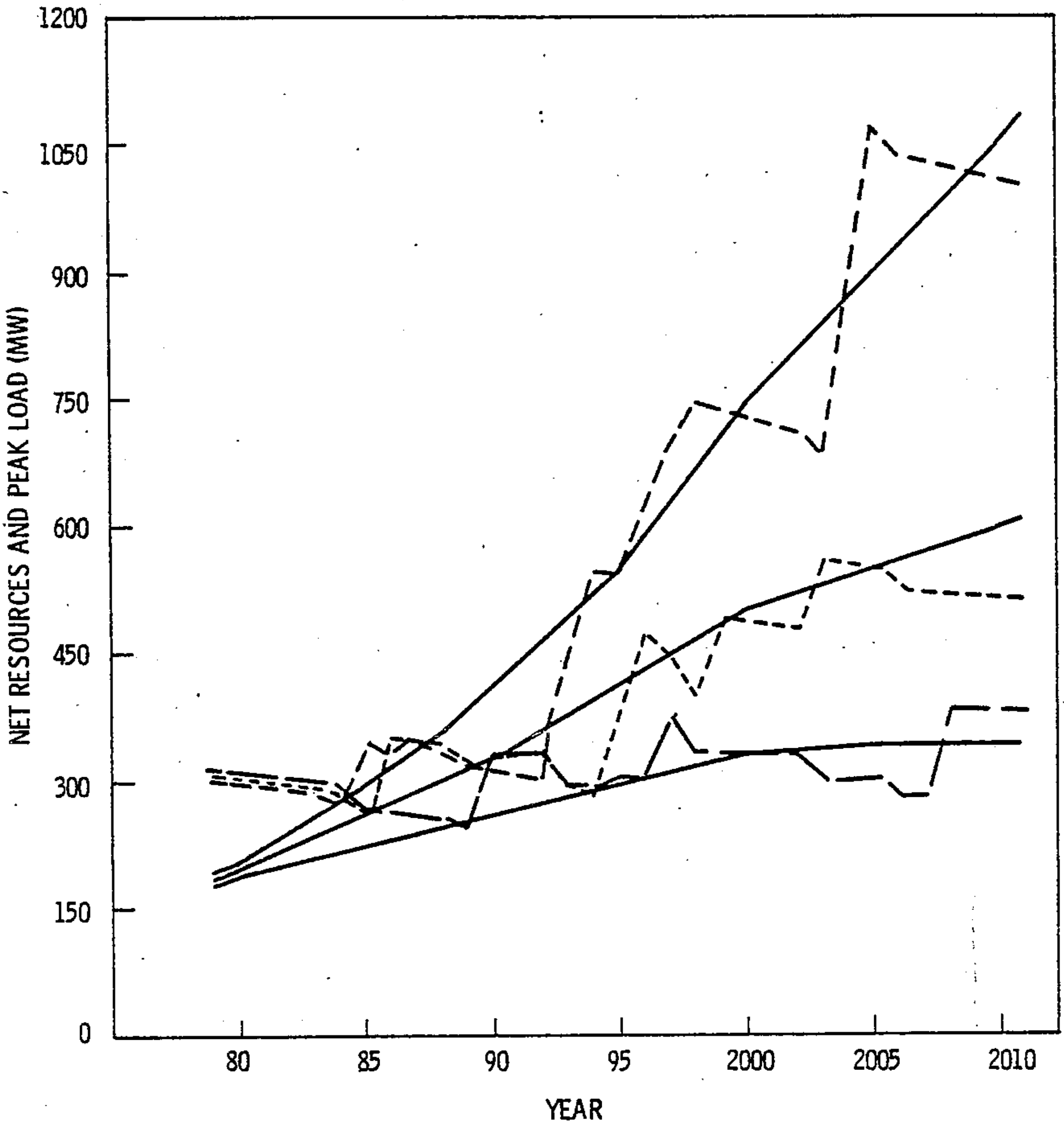

FIGURE 3.10. Load/Resource Analysis for Fairbanks-Tanana Valley Area With Interconnection but Without Upper Susitna Project (Case 2). Low, Medium, and High Load Growth Scenari

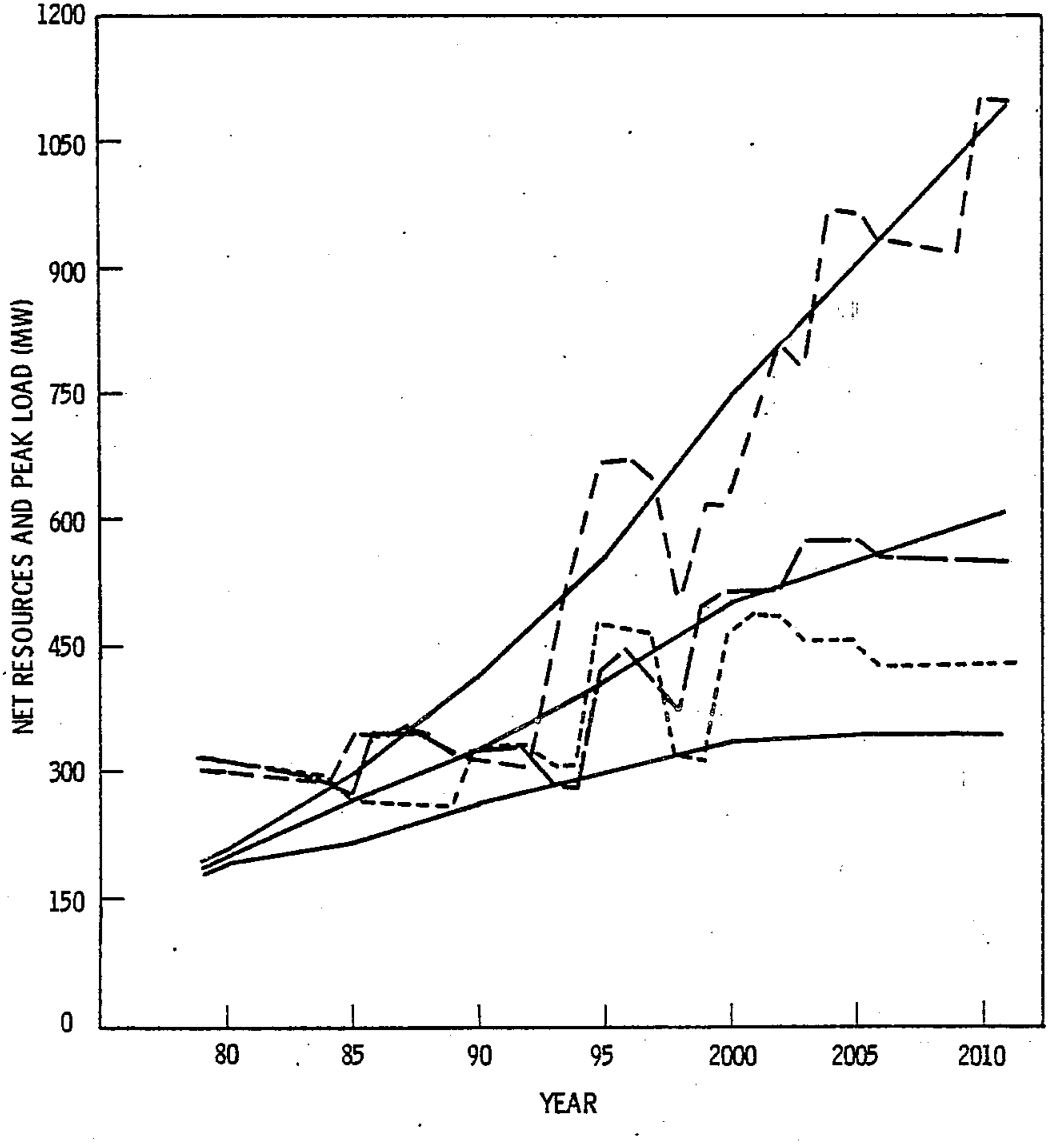

FIGURE 3.11. Load/Resource Analysis for Fairbanks-Tanana Valley Area With Interconnection and With Upper Susitna Project Coming On Line in 1994 (Case 3). Low, Medium, and High Load Growth Scenarios

4.0 SYSTEM POWER COST ANALYSES

This chapter describes the methodology used to evaluate the annual cost of power from individual generating facilities (or groups of similar generating facilities), the method of computing the average system-wide power costs, and presents the results of the system power cost analyses. The first section briefly discusses the factors which determine the cost of power. The second section describes the computational method used to compute the annual cost of power. This method is incorporated into a computer model titled ECOST4. A listing of the computer code is given in Appendix D.

The third section of this chapter contains a discussion of how the system-wide power costs are computed given the power costs for the individual facilities. The results are presented in the last part of the chapter.

4.1 FACTORS DETERMINING THE COST OF POWER

Three cost categories are evaluated in this report: 1) interest and amortization charges (capital cost); 2) fuel costs; and 3) operating, maintenance and replacement costs. Of course, there are other cost items included in the cost of power to the consumer, such as taxes, insurance, distribution and billing charges, but these costs are not evaluated in this report since they typically do not vary among the three cases evaluated.

These components of the cost of power are shown in Figure 4.1. The annual plant capital expenses are fixed by the initial financing and are typically constant over the life of the plant. Operation, maintenance, and replacement fuel costs typically increase over time as affected by inflation and real price increases. As a result, the total annual cost of power progressively increases over time.

4.1.1 Capital Costs

The capital costs represent the total cost of constructing a generating facility. The capital cost estimates used in this analysis include

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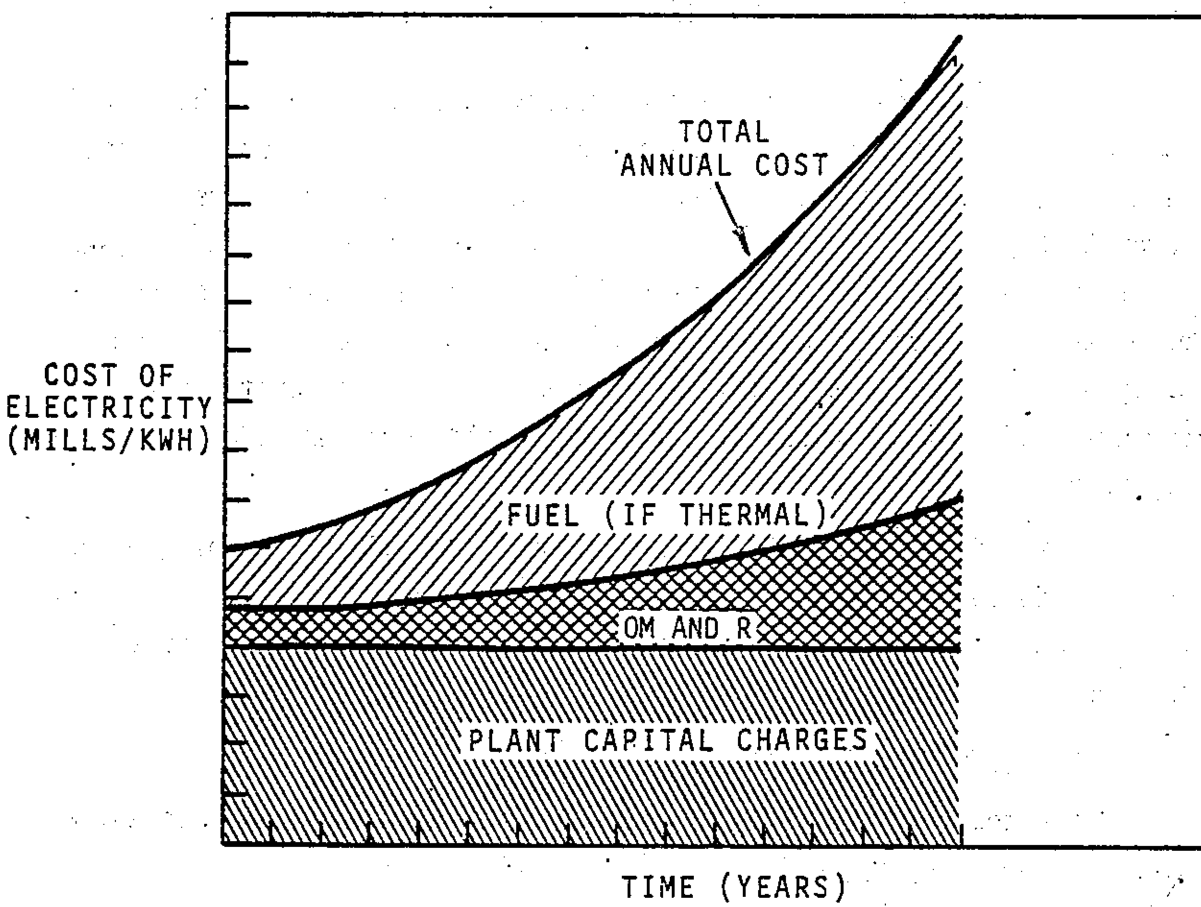

FIGURE 4.1. Components of the Total Annual Cost of Power

interest and escalation during construction. It is assumed that the capital costs are repaid in equal annual payments over the payback period of the plant. The capital cost estimates used are in terms of constant October 1978 dollars.

The total investment cost for the coal-fired and hydroelectric generating facilities are shown below.

	Total Investment Cost	
	(million $)	($/kW)
100 MW Coal Steam Turbine	245.4	2454
200 MW Coal Steam Turbine	372.0	1860
400 MW Coal Steam Turbine	646.8	1617
Watana Dam (795 MW)	2501.2	3146
Devil Canyon Dam (778 MW)	834.0	1071.9

SOURCE: Alaska Power Administration, August 1978.

Transmission facility costs are presented in Table 3.7.

4.1.2 Heat Rate

The heat rate is the ratio of the Btu's going into the plant as fuel to the kWh's of electricity produced by the plant. The heat rate is assumed to remain constant for all plant utilization factors over the lifetime of the plant. The heat rate for new coal-fired steam electric plants is assumed to be 10,500 Btu/kWh.

4.1.3 Operation, Maintenance, and Replacement Costs

The operating, maintenance, and replacement (OM&R) costs include the administrative and general expenses as well as the interim replacement costs. All estimates are expressed in terms of October 1978 dollars. They are escalated at a rate equal to the rate of general inflation.

The OM&R costs for coal-fired steam electric and hydroelectric generating facilities and transmission facilities are shown below.

	OM&R Costs (million $)	OM&R Costs ($/kW/yr)
100 MW Coal Steam Turbine	3.76	37.6
200 MW Coal Steam Turbine	5.7	28.5
400 MW Coal Steam Turbine	9.8	24.5
Watana Dam (795 MW)	0.74	0.94
Devil Canyon Dam (778 MW)	0.73	0.94
New transmission facilities	-	2.0

SOURCE: Alaska Power Administration, August 1978.

4.1.4 Financing Discount Rate

The financing discount rate represents the cost of capital to utility. A rate of 7.0% is assumed in this report. This is assumed to be an average of all types of financing available.

4.1.5 Payback Period

The length of time over which the plant is financed is the payback period. This is assumed to be equal to the plant lifetime except for hydro projects where a 50-year payback period is assumed versus at least a 100-year plant lifetime (see Section 3.2.6).

4.1.6 Annual Plant Utilization Factor

The plant utilization factor (PUF) is the ratio of the actual power production during a year to the theoretical maximum if the plant was to run 8760 hours at 100% capacity during the year.

The annual plant utilization factor is highly variable depending upon many factors (e.g., forced outage rate, cost of power from alternative sources, and power production requirements). Because of this, it is necessary to explicitly consider the effects of the PUF on the cost or power over the lifetime of a plant. As pointed out earlier, the PUFs used in the report are determined by the load/resource analyses (see Section 3.2.6).

4.1.7 Unit Fuel Costs

Fuel costs for thermal generation plants are expected to increase over times following paths shown in Figures 4.2 through 4.4 for natural

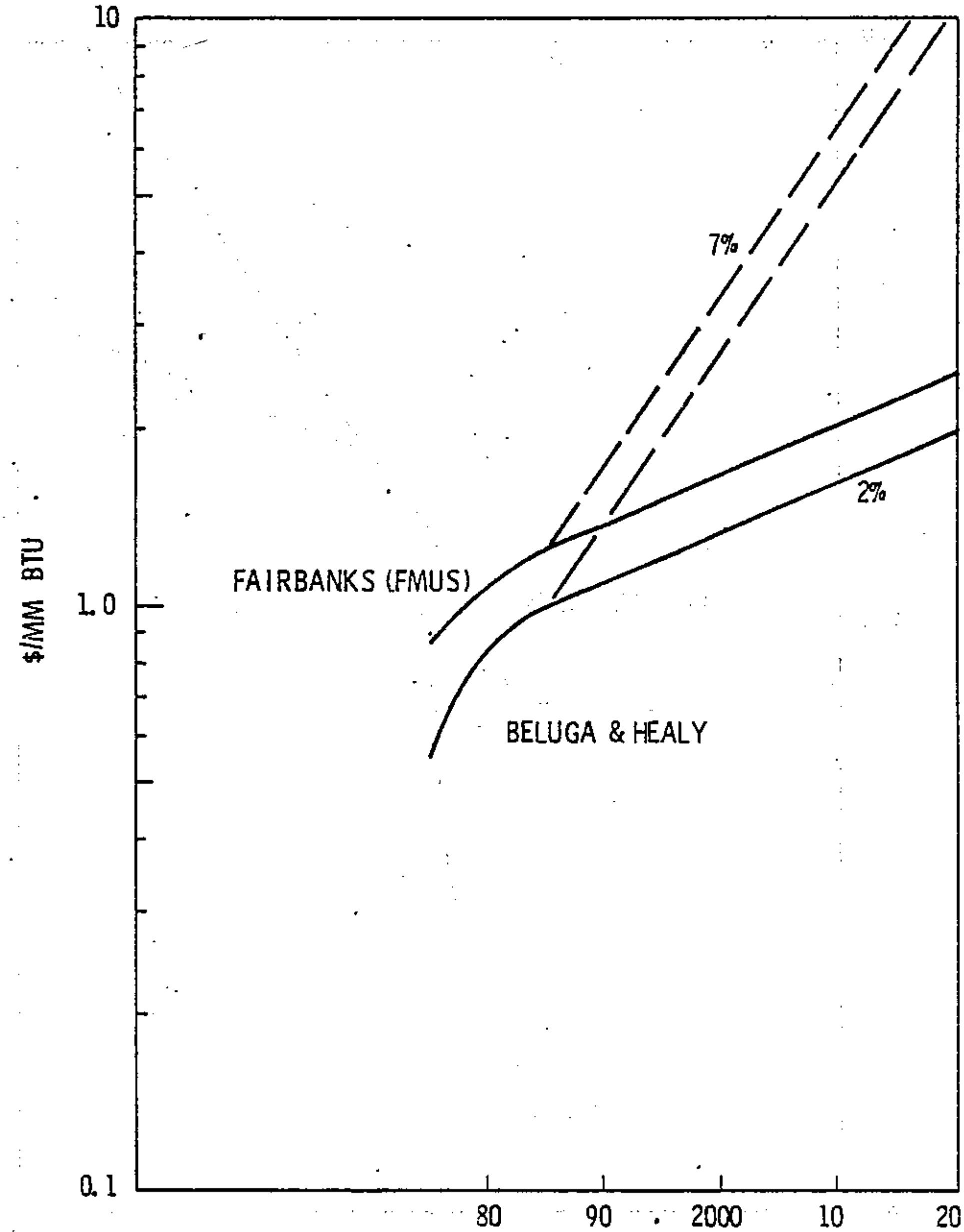

FIGURE 4.2. Estimates of Future Coal Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978.

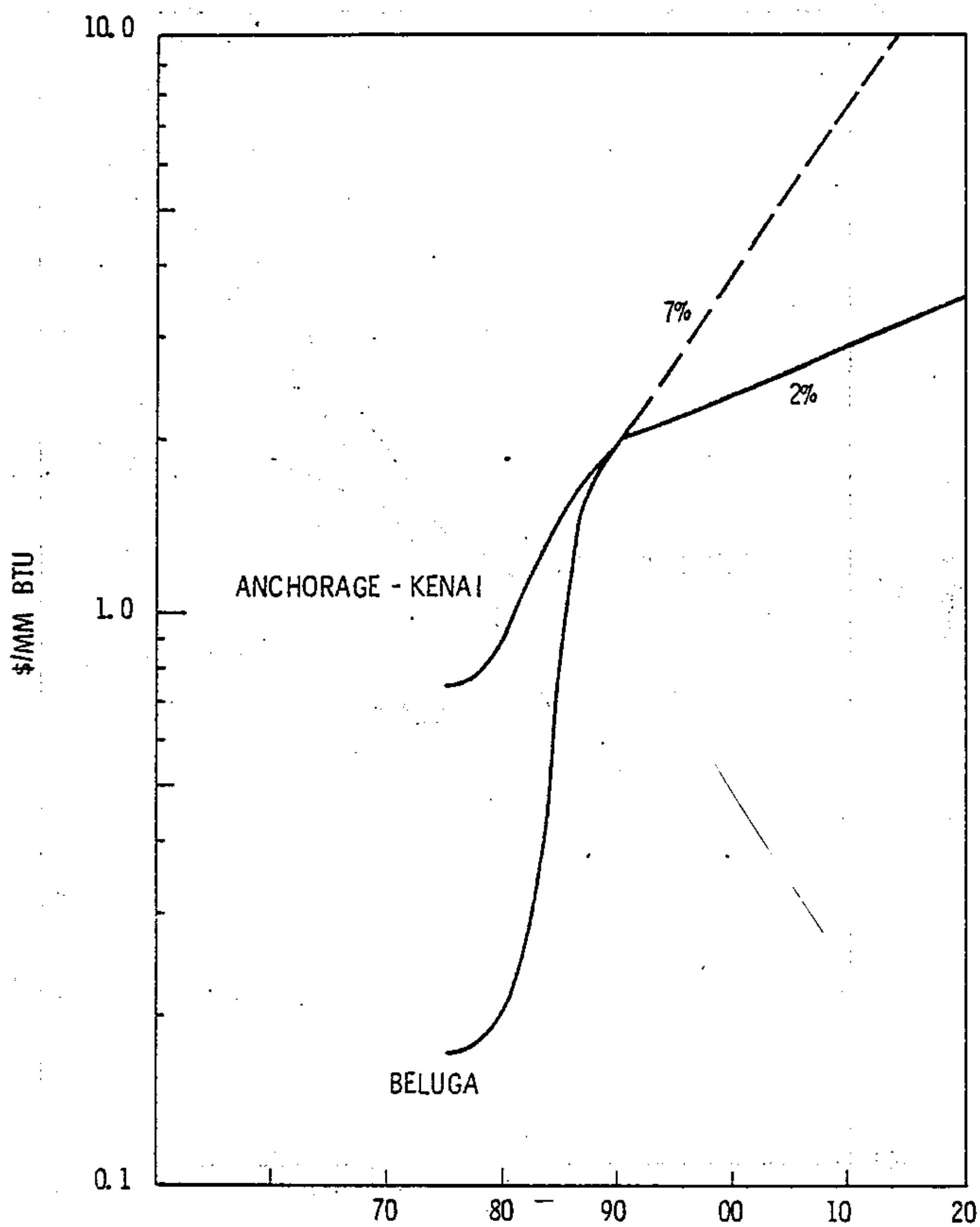

FIGURE 4.3. Estimates of Future Natural Gas Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978

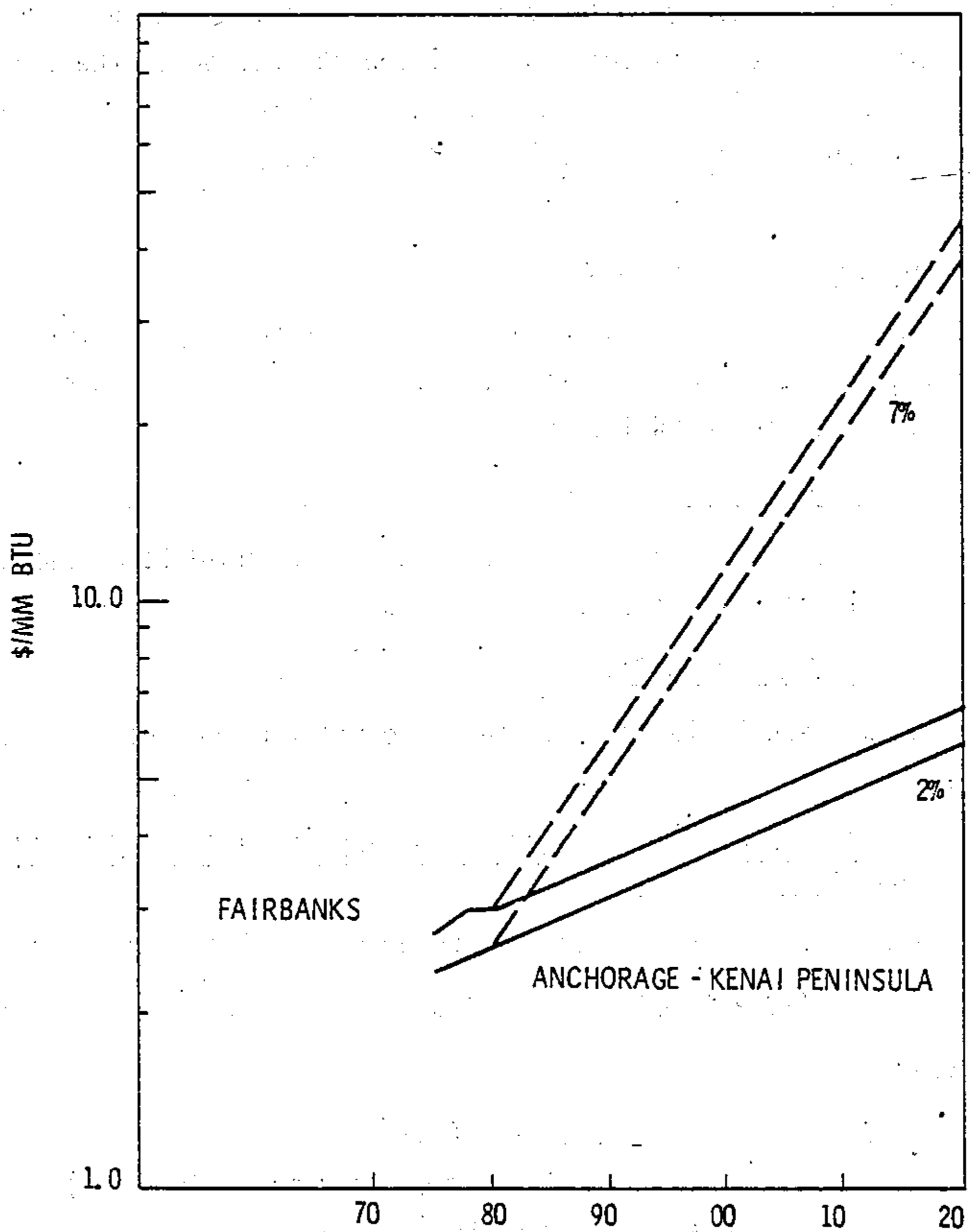

FIGURE 4.4. Estimates of Future Fuel Oil and Diesel Prices - 2% and 7% Escalation

SOURCE: Alaska Power Administration, August 1978.

gas (Cook Inlet areas), coal and distillable oil. Although natural gas is likely to become available in the Fairbanks region in the early to mid 1980's, Federal policies are expected to preclude its use for power generation except for probing and the cost is indeterment at the present time.

4.1.8 General Inflation Rate

Because of the uncertainty involved in estimating the future rate of inflation, two alternative cases are evaluated. A constant dollar case (0% inflation), and a 5% inflation case.

4.1.9 Construction Escalation Rate

In this analysis, construction costs are assumed to escalate at the same rate as the rate of general inflation.

4.1.10 Fuel Escalation Rate

The fuel escalation rate is set to equal the general inflation rate plus 2%.

4.2. METHOD OF COMPUTING THE ANNUAL COST OF POWER FROM INDIVIDUAL GENERATING FACILITIES

During any year the electrical power production is computed thus:

$$EPPR_i = (ICAP * PUF_i * HPY) / 1000^*$$

where:

ICAP = Installed capacity (MW)

PUF_i = Plat utilization factor in year i (fraction)

HPY = Hours per year (8760 hours/year)

---

* Parameters with the subscript i are assumed to vary each year over the lifetime of the plant. Parameters without the subscript are assumed to be constant over the lifetime of the plant.

The total annual costs (TAC) are composed of two elements: variable costs and fixed costs. In equation form:

$$TAC_i = VARC_i + FIXC_i$$

where:

$VARC_i$ = Variable costs in year i ($/Year)
$FIXC_i$ = Fixed costs in year i ($/Year)

The variable costs consist only of the fuel costs.

$$VARC_i = FUELC_i$$

where:

$FUELC_i$ = Fuel costs in year i ($/Year).

In turn, fuel costs are computed:

$$FUELC_i = HEATR * EPPRO_i * UFUELC_i$$

where:

HEATR = Heat rate (Btu/kWh)
$EPPRO_i$ = Electrical power production in year i (MMkWh)
$UFUELC_i$ = Unit fuel costs in year i ($/MMBtu)

The fixed costs consist of two factors. These factors can be written in the following equation form:

$$FIXC_i = INTAM + OMRC_i$$

where:

INTAM = Interest and amortization (capital recovery) charges ($/Year)
$OMRC_i$ = Operations, maintenance and replacement costs in year i ($/Year).

The interest and amortization charges (INTAM) represent the annual debt service payments.

$$INTAM = CRF * TINVC$$

where:

CRF = Capital Recovery Factor

TINVC = Total Investment Costs ($)

The capital recovery factor is used to compute a future series of equal end-of-year payments that will just recover a present sum p over n periods at compound interest (IR). It is computed thus:(1, p.26)

$$CRF = \frac{IR(1 + IR)^{PBP}}{(1 + IR)^{PBP} - 1}$$

where:

PBP = Payback period (years)

The methodology described in this section is incorporated into a computer model called ECOST4.

4.3 METHOD OF COMPUTING AVERAGE SYSTEM POWER COST

Once the costs of producing power from the various individual generating facilities in a system are known, a method of comparing the total cost of power from the three alternative system configurations evaluated in this report is needed.

To compare the overall cost of power produced by these alternatives a relatively straightforward method is used. The costs of producing and transmitting power for each of the generation and transmission facilities are added together for each year during the period 1978-2010. In equation form:

$$TAC_j = \sum_{i=1}^{n} AC_{ij}$$

where:

TAC_j = total annual cost of power production for the system in year j ($)

AC_{ij} = annual cost of producing or transmitting power for facility i during year j ($)

n = number of generation and transmission facilities in system.

Likewise the amount of power produced by each facility during each year is summed to give a system-wide total.

$$TAPP_j = \sum_{i=1}^{n} PP_{ij}$$

where:

$TAPP_j$ = total annual power production for the system in year j (kWhs)

PP_{ij} = power produced by each generating facility i during year j (KWHs)

n = number of generating facilities in system

By dividing the total cost by the total generation an average cost of power for the system is obtained for each year.

$$EPCOST_j = \frac{TAC_j}{TAPP_j}$$

where:

$EPCOST_j$ = average system-wide cost of power for year j ($/kWh)

By comparing the costs of power, the system producing the lowest cost of power can be selected.

4.4 RESULTS OF SYSTEM CASH FLOW AND POWER COST CALCULATIONS

The results of the system cash flow and power cost calculations are presented in this section. As pointed out earlier in the report three cases were evaluated:

Case 1. All additional generating capacity assumed to be coal-fired steam turbines without a transmission interconnection between the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley load centers.

Case 2. All additional generating assumed to be coal-fired steam turbines including a transmission interconnection.

Case 3. Additional capacity to include the Upper Susitna project (including transmission interconnection) plus additional coal as needed. Upper Susitna assumed to come on line in 1994.

Tables 4.1 through 4.36 present the cash flow and power cost calculated for the 3 cases. The contents of these tables are summarized below:

Table Number	Area	Load Growth Scenario	Case	Inflation Rate (%)
4.1	Anchorage	Low	1	0
2	"	"	"	5
3	"	"	2	0
4	"	"	"	5
5	"	"	3	0
6	"	"	"	5
7	"	Medium	1	0
8	"	"	"	5
9	"	"	2	0
10	"	"	"	5
11	"	"	3	0
12	"	"	"	5
13	"	High	1	0
1[illegible]	"	"	"	5
15	"	"	2	0
16	"	"	"	5
17	"	"	3	0
18	"	"	"	5
19	Fairbanks	Low	1	0
20	"	"	"	5
21	"	"	2	0
22	"	"	"	5
23	"	"	3	0
24	"	"	"	5
25	"	Medium	1	0
26	"	"	"	5
27	"	"	2	0
28	"	"	"	5
29	"	"	3	0
30	"	"	"	5
31	"	High	1	0
32	"	"	"	5
33	"	"	2	0
34	"	"	"	5
35	"	"	3	0
36	"	"	"	5

TABLE 4.1. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	17.1	3.6	94.8	185.7	4495	4.1
92-93	42.4	95.5	18.9	34.5	10.9	0.4	17.1	3.6	123.5	223.3	4705	4.7
93-94	38.9	95.5	18.9	41.9	10.9	0.4	17.1	3.6	123.5	227.2	4915	4.6
94-95	39.4	124.2	24.6	50.7	10.9	0.4	17.1	3.6	152.2	270.9	5125	5.3
95-96	34.5	152.9	30.3	56.9	10.9	0.4	17.1	3.6	180.9	306.6	5385	5.7
96-97	28.3	202.8	40.1	64.1	10.9	0.4	17.1	3.6	230.8	367.3	5645	6.5
97-98	25.4	202.8	40.1	69.1	10.9	0.4	17.1	3.6	230.8	369.4	5904	6.3
98-99	27.4	202.8	40.1	74.1	10.9	0.4	17.1	3.6	230.8	376.4	6164	6.1
99-2000	22.6	252.7	49.9	80.4	10.9	0.4	33.5	6.8	297.1	457.2	6424	7.1
00-01	12.2	252.7	49.9	83.8	10.9	0.4	33.5	6.8	297.1	450.2	6489	6.9
01-02	11.0	252.7	49.9	86.9	10.9	0.4	33.5	6.8	297.1	452.1	6555	6.9
02-03	4.8	252.7	49.9	90.4	10.9	0.4	33.5	6.8	297.1	449.4	6620	6.8
03-04	4.8	252.7	49.9	93.3	10.9	0.4	33.5	6.8	297.1	452.3	6686	6.8
04-05	3.6	252.7	49.9	96.6	10.9	0.4	33.5	6.8	297.1	454.4	6751	6.7
05-06	3.6	302.6	59.7	99.6	10.9	0.4	33.5	6.8	347.0	517.1	6817	7.6
06-07	3.6	302.6	59.7	102.7	10.9	0.4	33.5	6.8	347.0	520.2	6882	7.5
07-08	3.6	302.6	59.7	105.8	10.9	0.4	33.5	6.8	347.0	523.3	6948	7.5
08-09	3.6	302.6	59.7	108.9	10.9	0.4	33.5	6.8	347.0	526.4	7013	7.5
09-10	3.6	302.6	59.7	112.1	10.9	0.4	33.5	6.8	347.0	529.6	7079	7.5
10-11	3.6	302.6	59.7	115.4	10.9	0.4	33.5	6.8	347.0	532.9	7144	7.5

TABLE 4.2. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.8	2.0	0.4	3.9	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.2	14.8	0.7	24.1	6.6	150.0	267.2	4495	5.9
92-93	47.4	168.0	37.4	48.4	14.8	0.8	24.1	6.9	206.9	347.8	4705	7.4
93-94	46.5	168.0	39.2	61.3	14.8	0.8	24.1	7.3	206.9	362.0	4915	7.4
94-95	48.5	230.7	51.6	77.9	14.8	0.9	24.1	7.7	269.6	456.2	5125	8.9
95-96	43.8	296.5	67.3	92.2	14.8	0.9	24.1	8.1	335.4	547.7	5385	10.2
96-97	36.3	416.7	94.3	108.6	14.8	0.9	24.1	8.5	455.6	704.2	5645	12.5
97-98	37.7	416.7	99.0	122.6	14.8	1.0	24.1	8.0	455.6	724.8	5904	12.3
98-99	37.5	416.7	103.9	138.4	14.8	1.0	24.1	9.3	455.6	745.7	6164	12.1
99-2000	31.7	555.8	136.4	156.6	14.8	1.1	68.3	18.4	638.9	983.1	6424	15.3
00-01	16.7	555.8	143.3	172.0	14.8	1.1	68.3	19.3	638.9	991.3	6498	15.3
01-02	15.3	556.8	150.4	186.5	14.8	1.2	68.3	20.3	638.9	1012.6	6555	15.4
02-03	5.4	555.8	157.9	204.8	14.8	1.3	68.3	21.3	638.9	1029.6	6620	15.5
03-04	5.5	555.8	165.8	221.6	14.8	1.3	68.3	22.4	638.9	1055.5	6686	15.8
04-05	3.6	555.8	174.1	240.4	14.8	1.4	68.3	23.5	638.9	1081.9	6751	16.0
05-06	3.7	742.3	219.4	259.8	14.8	1.5	68.3	24.6	825.4	1334.4	6817	19.6
06-07	3.9	742.3	230.4	280.8	14.8	1.5	68.3	25.9	825.4	1367.9	6882	19.9
07-08	4.0	742.3	241.9	303.6	14.8	1.6	68.3	27.2	825.4	1403.7	6948	20.2
08-09	4.1	742.3	254.0	328.2	14.8	1.7	68.3	28.5	825.4	1441.9	7013	20.6
09-10	4.2	472.3	266.7	354.6	14.8	1.8	68.3	30.0	825.4	1482.7	7079	20.9
10-11	4.4	742.3	280.1	382.9	14.8	1.9	68.3	31.5	825.4	1526.2	7144	21.4

TABLE 4.3. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	17.1	3.6	94.8	185.7	4495	4.1
92-93	42.4	95.5	18.9	34.5	10.9	0.4	17.1	3.6	123.5	223.3	4705	4.7
93-94	38.9	95.5	18.9	41.9	10.9	0.4	17.1	3.6	123.5	227.2	4915	4.6
94-95	39.4	95.5	18.9	46.3	10.9	0.4	35.9	5.6	142.3	252.4	5125	4.9
95-96	34.5	124.2	24.6	55.3	10.9	0.4	35.9	5.6	171.0	290.9	5385	5.4
96-97	28.3	152.9	30.3	64.1	10.9	0.4	35.9	5.6	199.7	327.9	5645	5.8
97-98	25.4	202.8	40.1	69.2	10.9	0.4	35.9	5.6	249.6	389.8	5904	6.6
98-99	27.4	202.8	40.1	74.1	10.9	0.4	35.9	5.6	249.6	396.7	6164	6.4
99-2000	22.6	202.5	40.1	80.4	10.9	0.4	35.9	5.6	249.6	397.9	6424	6.2
00-01	12.2	252.7	49.9	83.8	10.9	0.4	52.4	8.8	316.0	470.6	6489	7.2
01-02	11.0	252.7	49.9	86.9	10.9	0.4	52.4	8.8	316.0	472.5	6555	7.2
02-03	4.8	525.7	49.9	90.4	10.9	0.4	52.4	8.8	316.0	469.8	6620	7.1
03-04	4.8	252.7	49.9	93.4	10.9	0.4	52.4	8.8	316.0	472.8	6686	7.1
04-05	3.6	252.7	49.9	96.6	10.9	0.4	52.4	8.8	316.0	474.8	6751	7.0
05-06	3.6	525.7	49.9	99.6	10.9	0.4	52.4	8.8	316.0	477.8	6817	7.0
06-07	3.6	252.7	49.9	99.6	10.9	0.4	52.4	8.8	316.0	480.9	6882	7.0
07-08	3.6	252.7	49.9	105.7	10.9	0.4	52.4	8.8	316.0	484.0	6948	7.0
08-09	3.6	252.7	49.9	108.9	10.9	0.4	52.4	8.8	316.0	487.1	7013	6.9
09-10	3.6	252.7	49.9	112.1	10.9	0.4	52.4	8.8	316.0	490.3	7079	6.9
10-11	3.6	252.7	49.9	115.4	10.9	0.4	52.4	8.8	316.0	493.6	7144	6.9

TABLE 4.4. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---		---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.8	2.0	0.4	3.[illegible]	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.2	14.8	0.7	24.1	6.6	150.0	267.2	4495	5.9
92-93	47.4	168.0	37.4	48.4	14.8	0.8	24.1	6.9	206.9	347.8	4705	7.4
93-94	46.5	168.0	39.2	61.3	14.8	0.8	24.1	7.3	206.9	362.0	4915	7.4
94-95	48.5	168.0	39.3	71.2	14.8	0.9	63.6	9.7	246.4	416.0	5125	8.1
95-96	43.8	233.8	54.4	89.5	14.8	0.9	63.6	10.3	312.2	511.1	5385	9.5
96-97	36.3	302.9	70.8	108.6	14.8	0.9	63.6	10.8	381.3	608.7	5645	10.8
97-98	37.7	429.1	99.1	122.6	14.8	1.0	63.6	11.3	507.5	779.2	5904	13.2
98-99	37.5	429.1	104.1	138.4	14.8	1.0	63.6	11.9	507.5	800.4	6164	13.0
99-2000	31.7	429.1	109.3	156.6	14.8	1.1	63.6	12.5	507.5	818.7	6424	12.7
00-01	16.7	575.2	143.4	172.0	14.8	1.1	110.0	22.1	700.0	1055.3	6489	16.3
01-02	15.3	575.2	150.6	186.4	14.8	1.2	110.0	23.2	700.0	1076.7	6555	16.4
02-03	5.4	575.2	158.1	204.9	14.8	1.3	110.0	24.4	700.0	1094.1	6620	16.5
03-04	5.5	575.2	166.1	221.6	14.8	1.3	110.0	25.6	700.0	1120.1	6686	16.7
04-05	3.6	575.2	174.4	240.4	14.8	1.4	110.0	26.9	700.0	1146.7	6751	17.0
05-06	3.7	575.2	183.1	259.8	14.8	1.5	110.0	28.2	700.0	1176.3	6817	17.2
06-07	3.9	575.2	192.2	280.8	14.8	1.5	110.0	29.6	700.0	1208.0	6882	17.5
07-08	4.0	575.2	201.8	303.6	14.8	1.6	110.0	31.1	700.0	1242.1	6948	17.9
08-09	4.1	575.2	211.9	328.2	14.8	1.7	110.0	32.7	700.0	1278.6	7013	18.2
09-10	4.2	575.2	222.5	354.6	14.8	1.8	110.0	34.3	700.0	1317.4	7079	18.6
10-11	4.4	575.2	233.7	382.9	14.8	1.9	110.0	36.0	700.0	1358.9	7144	19.0

TABLE 4.5. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2376	1.4
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2568	1.7
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	2706	1.8
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	2850	1.9
82-83	61.1	---	---	3.1	---	---	0.6	0.4	---	65.3	2991	2.2
83-84	62.0	---	---	3.3	---	---	0.6	0.4	---	66.3	3132	2.1
84-85	66.7	---	---	3.3	---	---	0.6	0.4	---	71.1	3273	2.2
85-86	66.7	1.3	0.2	3.6	10.9	0.4	0.6	0.4	12.8	84.1	3433	2.4
86-87	67.2	1.3	0.2	3.7	10.9	0.4	0.6	0.4	12.8	84.8	3594	2.3
87-88	66.4	30.0	5.9	6.7	10.9	0.4	17.1	3.6	58.0	141.0	3754	3.7
88-89	59.0	30.0	5.9	9.6	10.9	0.4	17.1	3.6	58.0	136.6	3915	3.5
89-90	54.5	58.7	11.6	16.6	10.9	0.4	17.1	3.6	86.7	173.4	4075	4.2
90-91	50.2	58.7	11.6	22.5	10.9	0.4	17.1	3.6	86.7	175.0	4285	4.1
91-92	47.1	66.8	13.2	26.6	10.9	0.4	35.9	5.6	113.6	206.0	4495	4.6
92-93	42.4	66.8	13.2	30.3	10.9	0.4	35.9	5.6	113.6	205.0	4705	4.4
93-94	38.9	95.5	18.9	38.9	10.9	0.4	35.9	5.6	142.3	244.5	4915	5.0
94-95	39.4	95.5	18.9	20.6	155.9	1.0	35.9	5.6	287.3	372.3	5125	7.3
95-96	34.5	95.5	18.9	21.6	155.9	1.0	35.9	5.6	287.3	368.4	5385	6.8
96-97	28.3	95.5	18.9	27.9	155.9	1.0	35.9	5.6	287.3	368.5	5645	6.5
97-98	25.4	95.5	18.9	32.2	155.9	1.0	35.9	5.6	287.3	369.9	5904	6.3
98-99	27.4	95.5	18.9	26.4	155.9	1.0	35.9	5.6	287.3	376.1	6164	6.1
99-2000	22.6	95.5	18.9	7.9	204.2	1.6	35.9	5.6	335.6	391.7	6424	6.1
00-01	12.2	95.5	18.9	8.0	204.2	1.6	35.9	5.6	335.6	381.4	6489	5.9
01-02	11.0	95.5	18.9	8.1	204.2	1.6	35.9	5.6	335.6	380.3	6555	5.6
02-03	4.8	95.5	18.9	9.3	204.2	1.6	35.9	5.6	335.6	375.3	6620	5.7
03-04	4.8	95.5	18.9	10.6	204.2	1.6	35.9	5.6	335.6	376.6	6686	5.6
04-05	3.6	95.5	18.9	12.0	204.2	1.6	35.9	5.6	335.6	376.8	6751	5.6
05-06	3.6	95.5	18.9	13.2	204.2	1.6	35.9	5.6	335.6	378.0	6817	5.5
06-07	3.6	95.5	18.9	14.6	204.2	1.6	35.9	5.6	335.6	379.4	6882	5.5
07-08	3.6	95.5	18.9	16.0	204.2	1.6	35.9	5.6	335.6	380.8	6948	5.5
08-09	3.6	95.5	18.9	17.4	204.2	1.6	35.9	5.6	335.6	382.2	7013	5.4
09-10	3.6	95.5	18.9	18.9	204.2	1.6	35.9	5.6	335.6	383.7	7079	5.4
10-11	3.6	95.5	18.9	20.4	204.2	1.6	35.9	5.6	335.6	385.2	7144	5.4

TABLE 4.6. Anchorage-Cook Inlet Area, Low Load Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2376	1.3
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.1	2568	1.6
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	2706	1.7
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	2850	1.7
82-83	59.5	---	---	3.1	---	---	0.7	0.5	---	63.9	2991	2.1
83-84	63.6	---	---	3.3	---	---	0.7	0.5	---	68.1	3132	2.2
84-85	68.7	---	---	3.3	---	---	0.7	0.5	---	73.3	3273	2.2
85-86	68.9	2.0	0.4	3.6	14.8	0.6	0.7	0.5	17.5	90.8	3433	2.6
86-87	69.3	2.0	0.4	3.9	14.8	0.6	0.7	0.5	17.5	92.7	3594	2.6
87-88	67.1	46.6	9.2	7.3	14.8	0.6	24.1	5.4	85.5	175.2	3754	4.7
88-89	60.6	46.6	9.7	11.1	14.8	0.6	24.1	5.7	85.5	173.2	3915	4.4
89-90	56.4	95.7	19.9	20.1	14.8	0.7	24.1	6.0	134.6	237.8	4075	5.8
90-91	52.5	95.7	20.9	28.6	14.8	0.7	24.1	6.3	134.6	243.6	4285	5.7
91-92	49.8	111.1	24.8	35.3	14.8	0.7	58.2	8.4	184.1	303.1	4495	6.7
92-93	47.4	111.1	26.1	42.5	14.8	0.8	58.2	8.8	184.1	309.7	4705	6.6
93-94	46.5	170.8	29.2	56.9	14.8	0.8	58.2	9.3	243.8	396.5	4915	8.1
94-95	48.5	170.8	41.1	31.7	319.9	2.1	58.2	9.7	548.9	682.0	5125	13.3
95-96	43.8	170.8	43.2	35.0	319.9	2.2	58.2	10.2	548.9	683.3	5385	12.7
96-97	36.3	170.8	45.4	47.4	319.9	2.3	58.2	10.7	548.9	691.0	5645	12.2
97-98	37.7	170.8	47.6	56.9	319.9	2.4	58.2	11.3	548.9	704.8	5904	11.9
98-99	37.5	170.8	50.0	68.1	319.9	2.5	58.2	11.8	548.9	718.8	6164	11.7
99-2000	31.7	170.8	52.5	15.4	449.7	4.2	58.2	12.4	678.7	794.9	6424	12.4
00-01	16.7	170.8	55.0	16.3	449.7	4.5	58.2	13.5	678.7	784.8	5489	12.1
01-02	15.3	170.8	57.9	17.4	449.7	4.7	58.2	13.7	678.7	787.7	6555	12.0
02-03	5.4	170.8	60.8	21.2	449.7	4.9	58.2	14.4	678.7	785.4	6620	11.9
03-04	5.5	170.8	63.8	25.1	449.7	5.2	58.2	15.1	678.7	793.4	6686	11.9
04-05	3.6	170.8	67.0	29.9	449.7	5.4	58.2	15.9	678.7	800.5	6751	11.9
05-06	3.7	170.8	70.4	34.3	449.7	5.7	58.2	16.7	678.7	809.5	6816	11.9
06-07	3.9	170.8	73.9	40.0	449.7	6.0	58.2	17.5	678.7	820.0	6882	11.9
07-08	4.0	170.8	77.6	45.9	449.7	6.3	58.2	18.4	678.7	830.9	6948	11.9
08-09	4.1	170.8	81.5	52.4	449.7	6.6	58.2	19.3	678.7	842.6	7013	12.0
09-10	4.2	170.8	85.5	59.7	449.7	6.9	58.2	20.2	678.7	855.2	7079	12.1
10-11	4.4	170.8	89.8	67.5	449.7	7.3	58.2	21.3	678.7	869.0	7144	12.2

TABLE 4.7. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	.6	.4	---	34.1	2531	1.3
79-80	42.2	---	---	---	---	---	.6	.4	---	43.2	2801	1.5
80-81	48.2	---	---	---	---	---	.6	.4	---	49.2	3041	1.6
81-82	52.8	---	---	---	---	---	.6	.4	---	53.8	3281	1.6
82-83	61.1	28.7	5.7	6.5	---	---	.6	.4	29.3	103.0	3521	2.9
83-84	62.0	28.7	5.7	9.2	---	---	.6	.4	29.3	106.6	3761	2.8
84-85	66.7	28.7	5.7	11.8	---	---	.6	.4	29.3	114.0	4001	2.8
85-86	66.7	58.7	11.6	18.5	10.9	.4	17.1	3.6	86.7	187.6	4329	4.3
86-87	67.2	58.7	11.6	24.19	10.9	.4	17.1	3.6	86.7	193.7	4657	4.2
87-88	66.4	87.4	17.3	29.9	10.9	0.4	17.1	3.6	115.4	233.0	4985	4.7
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	116.1	23.0	46.4	10.9	0.4	17.1	3.6	144.1	272.0	5641	4.8
90-91	50.2	116.1	23.0	52.9	10.9	0.4	17.1	3.6	144.1	274.2	6063	4.5
91-92	47.1	152.9	30.3	61.9	10.9	0.4	17.1	3.6	180.9	324.2	6485	5.0
92-93	42.4	202.8	40.1	70.2	10.9	0.4	17.1	3.6	230.8	387.5	6907	5.6
93-94	38.9	202.8	40.1	77.9	10.9	0.4	17.1	3.6	230.8	391.7	7329	5.3
94-95	39.4	202.8	40.1	84.6	10.9	0.4	17.1	3.6	230.8	398.9	7751	5.1
95-96	34.5	252.7	49.9	94.6	10.9	0.4	17.1	3.6	280.7	463.7	8311	5.6
96-97	28.3	302.6	59.7	106.8	10.9	0.4	33.5	6.8	347.0	549.0	8871	6.2
97-98	25.4	352.5	69.5	116.9	10.9	0.4	33.5	6.8	396.9	615.9	9431	6.5
98-99	27.4	353.5	69.5	126.7	10.9	0.4	33.5	6.8	396.9	627.7	9991	6.3
99-2000	22.6	402.4	79.3	138.5	10.9	0.4	33.5	6.8	446.8	694.4	10551	6.6
00-01	12.2	402.4	79.3	146.3	10.9	0.4	33.5	6.8	446.8	691.8	10863	6.4
01-02	11.0	402.4	79.3	15[illegible].3	10.9	0.4	33.5	6.8	446.8	698.6	11175	6.3
02-03	4.8	452.3	89.1	162.5	10.9	0.4	33.5	6.8	496.7	760.3	11487	6.6
03-04	4.8	452.3	89.1	170.7	10.9	0.4	33.5	6.8	496.7	767.9	11799	6.5
04-05	3.6	452.3	89.1	179.4	10.9	0.4	33.5	6.8	496.7	776.0	12111	6.4
05-06	3.6	502.2	98.9	188.0	10.9	0.4	50.0	10.0	563.1	864.0	12423	6.9
06-07	3.6	502.2	98.9	196.8	10.9	0.4	50.0	10.0	563.1	872.8	12735	6.8
07-08	3.6	502.2	98.9	205.9	10.9	0.4	50.0	10.0	563.1	881.9	13047	6.8
08-09	3.6	502.2	98.9	215.1	10.9	0.4	50.0	10.0	563.1	891.1	13359	6.7
09-10	3.6	502.2	98.9	224.6	10.9	0.4	50.0	10.0	563.1	901.6	13671	6.6
10-11	3.6	552.1	108.7	234.2	10.9	0.4	50.0	10.0	613.0	969.9	13983	6.9

TABLE 4.8. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.8	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	171.0	39.3	56.3	14.8	0.7	23.0	6.0	208.8	367.5	5641	6.5
90-91	52.5	171.0	41.3	67.3	14.8	0.7	23.0	6.3	208.8	376.9	6063	6.2
91-92	49.8	240.6	56.9	82.2	14.8	0.7	23.0	6.6	278.4	474.6	6485	7.3
92-93	47.4	339.5	79.2	98.6	14.8	0.8	23.0	6.9	377.3	608.6	6907	8.8
93-94	46.5	339.5	83.2	113.9	14.8	0.3	23.0	7.2	377.3	628.9	7329	8.6
94-95	48.5	339.5	87.3	130.1	14.8	0.9	23.0	7.6	377.3	659.3	7751	8.5
95-96	43.8	454.0	114.2	153.3	14.8	0.9	23.0	8.0	491.8	812.0	8311	9.7
96-97	36.3	574.2	143.5	180.8	14.8	0.9	63.0	16.0	652.0	1029.5	8871	11.6
97-98	37.7	700.4	175.5	207.2	14.8	1.0	63.0	16.6	778.2	1216.2	9431	12.9
98-99	37.5	700.4	184.2	236.7	14.8	1.0	63.0	17.4	778.2	1255.0	9991	12.6
99-2000	31.8	839.5	220.8	269.7	14.8	1.1	63.0	18.3	917.3	1459.0	10551	13.8
00-01	16.7	839.5	231.8	300.2	14.8	1.1	63.0	19.2	917.3	1486.3	10863	13.7
01-02	15.3	839.5	243.4	331.2	14.8	1.2	63.0	20.2	917.3	1528.6	11175	13.7
02-03	5.4	1000.6	287.2	368.3	14.8	1.3	63.0	21.2	1078.4	1761.8	11487	15.3
03-04	5.5	1000.6	301.5	405.2	14.8	1.3	63.0	22.2	1078.4	1814.1	11799	15.4
04-05	3.6	1000.6	316.6	446.6	14.8	1.4	63.0	23.3	1078.4	1869.9	12111	15.4
05-06	3.7	1187.1	369.0	490.4	14.8	1.5	116.7	34.9	1319.6	2218.1	12423	17.8
06-07	3.9	1187.1	387.5	538.4	14.8	1.5	116.7	36.6	1318.6	2286.5	12735	17.9
07-08	4.0	1187.1	406.8	590.9	14.8	1.6	116.7	38.5	1318.6	2360.4	13047	18.1
08-09	4.1	1187.1	427.2	648.1	14.8	1.7	116.7	40.4	1318.6	2440.1	13359	18.3
09-10	4.2	1187.1	448.5	710.1	14.8	1.8	116.7	42.4	1318.6	2525.6	13671	18.5
10-11	4.4	1425.1	517.7	777.3	14.8	1.9	116.7	44.6	1556.6	2902.5	13983	20.7

TABLE 4.9. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2531	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	2801	1.5
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3041	1.6
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	3281	1.6
82-83	61.1	28.7	5.7	6.5	---	---	0.6	0.4	29.3	103.0	3521	2.9
83-84	62.0	28.7	5.7	9.2	---	---	0.6	0.4	29.3	106.6	3761	2.8
84-85	66.7	28.7	5.7	11.8	---	---	0.6	0.4	29.3	114.0	4001	2.8
85-86	66.7	58.7	11.6	18.5	10.9	0.4	17.1	3.6	86.7	187.6	4329	4.3
86-87	67.2	58.7	11.6	24.19	10.9	0.4	17.1	3.6	86.7	193.7	4657	4.2
87-88	66.4	87.4	17.3	29.9	10.9	0.4	17.1	3.6	115.4	233.0	4985	4.7
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	87.4	17.3	42.5	10.9	0.4	35.9	5.6	134.2	254.5	5641	4.5
90-91	50.2	116.1	24.6	50.1	10.9	0.4	35.9	5.6	162.9	293.8	6063	4.8
91-92	47.1	152.9	31.9	59.1	10.9	0.4	35.9	5.6	199.7	343.8	6485	5.3
92-93	42.4	202.8	41.7	70.2	10.9	0.4	35.9	5.6	249.6	409.9	6907	5.9
93-94	38.9	202.8	41.7	77.9	10.9	0.4	35.9	5.6	249.6	414.1	7329	5.6
94-95	39.4	202.8	41.7	84.6	10.9	0.4	35.9	5.6	249.6	421.3	7751	5.4
95-96	34.5	252.7	51.5	94.6	10.9	0.4	35.9	5.6	299.5	486.1	8311	5.8
96-97	28.3	302.6	61.3	106.8	10.9	0.4	52.4	8.8	365.9	571.5	8871	6.4
97-98	25.4	302.6	61.3	116.9	10.9	0.4	52.4	8.8	365.9	578.7	9431	6.1
98-99	27.4	352.5	71.1	126.7	10.9	0.4	52.4	8.8	415.8	650.2	9991	6.5
99-2000	22.6	352.5	71.1	138.5	10.9	0.4	52.4	8.8	415.8	657.2	10551	6.2
00-01	12.2	402.4	80.9	146.3	10.9	0.4	52.4	8.8	465.7	714.3	10863	6.6
01-02	11.0	402.4	80.9	154.3	10.9	0.4	52.4	8.8	465.7	721.1	11175	6.4
02-03	4.8	402.4	80.9	162.5	10.9	0.4	52.4	8.8	465.7	723.1	11487	6.3
03-04	3.6	452.3	90.7	170.7	10.9	0.4	52.4	8.8	515.6	789.8	11799	6.7
04-05	3.6	452.3	90.7	179.4	10.9	0.4	52.4	8.8	515.6	798.5	12111	6.6
05-06	3.6	452.3	90.7	188.0	10.9	0.4	52.4	8.8	515.6	807.1	12423	6.5
06-07	3.6	452.3	90.7	196.8	10.9	0.4	52.4	6.6	515.6	815.9	12735	6.4
07-08	3.6	502.2	100.5	205.9	10.9	0.4	68.9	12.0	582.0	904.4	13047	6.9
08-09	3.6	502.2	100.5	215.1	10.9	0.4	68.9	12.0	582.0	913.6	13359	6.8
09-10	3.6	502.2	100.5	224.6	10.9	0.4	68.9	12.0	582.0	923.1	13671	6.7
10-11	3.6	502.2	100.5	234.2	10.9	0.4	68.9	12.0	582.0	932.7	13983	6.7

TABLE 4.10. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---	- -	---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.3	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	121.9	29.6	51.5	14.8	0.7	53.9	9.3	190.6	338.1	5641	6.0
90-91	52.5	173.6	41.3	63.7	14.8	0.7	53.9	9.7	242.2	410.1	6063	6.8
91-92	49.8	243.1	56.9	78.3	14.8	0.7	53.9	10.2	311.8	507.8	6485	7.8
92-93	47.4	342.0	79.2	98.5	14.8	0.8	53.9	10.7	410.7	647.4	6907	9.4
93-94	46.5	342.0	83.2	113.8	14.8	0.8	53.9	11.3	410.7	666.4	7329	9.1
94-95	48.5	342.0	87.3	130.1	14.8	0.9	53.9	11.8	410.7	689.3	7751	8.9
95-96	43.8	465.5	114.2	153.3	14.8	0.9	53.9	12.4	534.2	858.8	8311	10.3
96-97	36.5	576.7	143.5	180.8	14.8	0.9	93.9	20.9	685.4	1067.8	8871	12.0
97-98	37.7	576.7	150.6	207.1	14.8	1.0	93.9	21.9	685.4	1103.8	9431	11.7
98-99	37.5	709.2	184.2	236.6	14.8	1.0	93.9	23.0	817.9	1300.3	9991	13.0
99-2000	31.7	709.2	193.4	269.7	14.8	1.1	93.9	24.2	817.9	1338.1	10551	12.7
00-01	16.7	855.3	231.7	300.2	14.8	1.1	93.9	25.4	964.0	1539.1	10863	14.2
01-02	15.3	855.3	243.3	331.2	14.8	1.2	93.9	26.7	964.0	1581.7	11175	14.1
02-03	5.4	955.3	225.5	368.3	14.8	1.3	93.9	28.0	964.0	1592.5	11487	13.9
03-04	5.5	1024.4	301.5	405.2	14.8	1.3	93.9	29.4	1133.1	1876.0	11799	15.9
04-05	3.6	1024.4	316.6	446.6	14.8	1.4	93.9	30.9	1133.1	1932.2	12111	15.9
05-06	3.7	1024.4	332.4	490.4	14.8	1.5	93.9	32.4	1133.1	1993.5	12423	16.0
06-07	3.9	1024.4	349.0	538.4	14.8	1.5	93.9	34.0	1133.1	2059.9	12735	16.2
07-08	4.0	1230.0	406.8	590.9	14.8	1.6	148.9	46.7	1393.7	2443.7	13047	18.7
08-09	4.1	1230.0	427.1	648.1	14.8	1.7	148.9	49.0	1393.7	2523.7	13359	18.9
09-10	4.2	1230.0	448.4	710.1	14.8	1.8	148.9	51.5	1393.7	2609.7	13671	19.1
10-11	4.4	1230.0	470.8	777.3	14.8	1.9	148.9	54.1	1393.7	2702.2	13983	19.3

TABLE 4.11. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	33.1	---	---	---	1.0	---	---	---	---	34.1	2531	---
79-80	42.2	---	---	---	1.0	---	---	---	---	43.2	2801	---
80-81	78.2	---	---	---	1.0	---	---	---	---	49.2	3041	---
81-82	52.8	---	---	---	1.0	---	---	---	---	53.8	3281	---
82-83	61.1	28.7	5.7	6.5	1.0	---	---	---	29.3	103.0	3521	---
83-84	62.0	28.7	5.7	9.2	1.0	---	---	---	29.3	106.6	3761	---
84-85	66.6	28.7	5.7	11.8	20.7	---	---	---	29.3	114.0	4001	---
85-86	66.7	58.7	11.6	18.4	20.7	---	---	---	86.7	187.6	4329	---
86-87	67.1	58.7	11.6	24.1	20.7	---	---	---	86.7	193.7	4657	---
87-88	66.3	87.4	17.3	30.1	20.7	---	---	---	115.4	233.0	4985	---
88-89	59.0	87.4	17.3	36.2	10.9	0.4	17.1	3.6	115.4	231.9	5313	4.4
89-90	54.5	87.4	17.3	42.5	10.9	0.4	35.9	5.6	134.2	254.5	5641	4.5
90-91	50.2	116.1	24.6	50.1	10.9	0.4	35.9	5.6	162.9	293.8	6063	4.8
91-92	47.1	152.9	31.9	59.1	10.9	0.4	35.9	5.6	199.7	343.8	6485	5.3
92-93	42.4	202.8	41.7	70.2	10.9	0.4	35.9	5.6	249.6	409.9	6907	5.9
93-94	38.9	202.8	41.7	77.9	10.9	0.4	35.9	5.6	249.6	414.1	7329	5.6
94-95	39.4	202.8	41.7	53.3	157.7	1.1	35.9	5.6	396.4	537.5	7751	6.9
95-96	31.5	202.8	41.7	58.6	157.7	1.1	35.9	5.6	396.4	537.9	8311	6.5
96-97	28.3	202.8	41.7	69.9	157.7	1.1	35.9	5.6	396.4	543.0	8871	6.1
97-98	25.4	202.8	41.7	79.1	157.7	1.1	35.9	5.6	396.4	549.3	9431	5.8
98-99	27.4	202.8	41.7	54.5	206.6	1.8	35.9	5.6	445.3	576.3	9991	5.8
99-2000	22.6	202.8	41.7	60.2	206.6	1.8	35.9	5.6	445.3	577.2	10,551	5.5
00-01	12.2	202.8	41.7	66.8	206.6	1.8	35.9	5.6	445.3	573.4	10,863	5.3
01-02	11.0	202.8	41.7	73.1	206.6	1.8	35.9	5.6	445.3	578.5	11,175	5.2
02-03	4.8	252.7	51.5	80.0	206.6	1.8	52.4	8.8	511.7	658.6	11,487	5.7
03-04	4.8	252.7	51.5	86.5	206.6	1.8	52.4	8.8	511.7	665.1	11,799	5.6
04-05	3.6	252.7	51.5	93.4	206.6	1.8	52.4	8.8	511.7	670.8	12,111	5.5
05-06	3.6	252.7	51.5	100.2	206.6	1.8	52.4	8.8	511.7	677.6	12,423	5.4
06-07	3.6	302.6	61.3	107.3	206.6	1.8	52.4	8.8	561.6	744.4	12,735	5.8
07-08	3.6	302.6	61.3	114.5	206.6	1.8	52.4	8.8	561.6	751.6	13,047	5.8
08-09	3.6	302.6	61.3	121.9	206.6	1.8	52.4	8.8	561.6	759.0	13,359	5.7
09-10	3.6	302.6	61.3	129.6	206.6	1.8	52.4	8.8	561.6	766.7	13,671	5.6
10-11	3.6	352.5	71.1	137.5	206.6	1.8	52.4	8.8	611.5	834.3	13,983	5.9

TABLE 4.12. Anchorage-Cook Inlet Area, Medium Load Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2531	1.2
79-80	39.1	---	---	---	-	---	0.7	0.4	---	40.2	2801	1.4
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3041	1.5
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	3281	1.5
82-83	59.5	34.9	6.9	6.5	---	---	0.7	0.5	35.6	109.1	3521	3.1
83-84	63.6	34.9	7.2	9.2	---	--	0.7	0.5	35.6	116.1	3761	3.1
84-85	68.7	34.9	7.6	11.8	---	---	0.7	0.5	35.6	124.3	4001	3.1
85-86	68.9	77.3	16.4	18.1	14.3	0.6	23.0	4.9	115.1	224.0	4329	5.2
86-87	69.8	77.3	17.2	25.3	14.8	0.6	23.0	5.1	115.1	233.2	4657	5.0
87-88	67.1	121.9	26.8	32.7	14.8	0.6	23.0	5.4	159.7	292.3	4985	5.9
88-89	60.6	121.9	28.2	41.6	14.8	0.6	23.0	5.7	159.7	296.5	5313	5.6
89-90	56.4	121.9	29.6	51.5	14.8	0.7	53.9	9.3	190.6	338.1	5641	6.0
90-91	52.5	173.5	41.3	63.7	14.8	0.7	53.9	9.7	242.2	410.1	6063	6.8
91-92	49.8	243.1	56.9	78.3	14.8	0.7	53.9	10.2	311.8	507.8	6485	7.8
92-93	47.4	342.0	79.2	98.5	14.8	0.8	53.9	10.7	410.7	647.4	6907	9.4
93-94	46.5	342.0	83.2	113.8	14.8	0.8	53.9	11.3	410.7	666.4	7329	9.1
94-95	48.5	342.0	87.4	82.1	323.7	2.4	53.9	11.8	719.6	951.8	7751	12.3
95-96	43.8	342.0	91.7	94.9	323.7	2.5	53.9	12.4	719.6	964.9	8311	11.6
96-97	36.3	342.0	96.3	118.3	323.7	2.7	53.9	13.0	719.6	986.2	8871	11.1
97-98	37.7	342.0	101.1	140.2	323.7	2.8	53.9	13.7	719.6	1015.1	9431	10.8
98-99	37.5	342.0	106.2	101.8	448.8	4.4	53.9	14.3	844.7	1109.0	9991	11.1
99-2000	31.7	342.0	111.5	117.2	448.8	4.6	53.9	15.1	844.7	1124.8	10,551	10.7
00-01	16.7	342.0	117.1	137.1	448.8	4.9	53.9	15.8	844.7	1136.3	10,863	10.5
01-02	15.3	342.0	122.9	156.8	448.8	5.1	53.9	16.6	844.7	1161.4	11,175	10.4
02-03	5.4	503.1	160.7	181.4	448.8	5.4	104.9	26.9	1056.8	1436.6	11,487	12.5
03-04	5.5	503.1	168.7	205.3	448.8	5.6	104.9	28.2	1056.8	1470.1	11,799	12.4
04-05	3.6	503.1	177.1	232.5	448.8	5.9	104.9	29.6	1056.8	1505.5	12,111	12.4
05-06	3.7	503.1	185.9	261.4	448.8	6.2	104.9	31.1	1056.8	1545.1	12,423	12.4
06-07	3.9	698.9	233.7	293.5	448.8	6.5	104.9	32.7	1252.6	1822.9	12,735	14.3
07-08	4.0	698.9	245.4	328.7	448.8	6.8	104.9	34.3	1252.6	1871.8	13,047	14.3
08-09	4.1	698.9	257.6	367.5	448.8	7.2	104.9	36.0	1252.6	1925.0	13,359	14.4
09-10	4.2	698.9	270.5	409.9	448.8	7.5	104.9	37.8	1252.6	1982.2	13,671	14.5
10-11	4.4	936.9	330.7	456.3	448.8	7.9	104.9	39.7	1490.6	2329.6	13,983	16.7

TABLE 4.13. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	164.7	38.5	66.2	10.9	0.4	17.1	3.6	192.7	368.6	7357	5.0
87-88	66.4	164.7	38.5	73.4	10.9	0.4	17.1	3.6	192.7	375.0	7864	4.8
88-89	59.0	214.6	48.3	81.2	10.9	0.4	33.6	6.8	259.1	454.8	8372	5.4
89-90	54.5	214.6	48.3	88.6	10.9	0.4	33.6	6.8	259.1	457.7	8879	5.1
90-91	50.2	214.6	48.3	98.5	10.9	0.4	33.6	6.8	259.1	463.3	9589	4.8
91-92	47.1	272.6	59.7	109.9	10.9	0.4	33.6	6.8	317.1	541.0	10,298	5.2
92-93	42.4	322.5	69.5	120.1	10.9	0.4	33.6	6.8	367.0	606.2	11,008	5.5
93-94	38.9	322.5	69.5	132.6	10.9	0.4	33.6	6.8	367.0	615.2	11,717	5.3
94-95	39.4	372.4	79.3	143.9	10.9	0.4	33.6	6.8	416.9	686.7	12,427	5.5
95-96	34.5	422.3	89.1	161.3	10.9	0.4	50.1	10.0	483.3	778.6	13,477	5.8
96-97	28.3	472.2	98.9	181.5	10.9	0.4	50.1	10.0	533.2	852.3	14,526	5.9
97-98	25.4	522.1	108.7	200.1	10.9	0.4	50.1	10.0	583.1	927.7	15,576	6.0
98-99	27.4	572.0	118.5	217.9	10.9	0.4	50.1	10.0	633.0	1008.2	16,625	6.1
99-2000	22.6	621.9	128.3	238.7	10.9	0.4	66.6	13.2	699.4	1102.6	17,675	6.2
00-01	12.2	671.8	138.1	256.6	10.9	0.4	66.6	13.2	749.3	1169.8	18,584	6.3
01-02	11.0	671.8	138.1	275.8	10.9	0.4	66.6	13.2	749.3	1187.8	19,493	6.1
02-03	4.8	721.7	147.9	294.6	10.9	0.4	66.6	13.2	799.2	1260.1	20,402	6.2
03-04	4.8	771.6	157.7	314.7	10.9	0.4	66.6	13.2	849.1	1339.9	21,311	6.3
04-05	3.6	771.6	157.7	335.6	10.9	0.4	66.6	13.2	849.1	1359.6	22,220	6.1
05-06	3.6	821.5	167.5	356.9	19.9	0.4	83.1	16.4	915.5	1460.3	23,129	6.3
06-07	3.6	871.4	177.3	378.8	10.9	0.4	83.1	16.4	965.4	1541.9	24,038	6.4
07-08	3.6	871.4	177.3	401.2	10.9	0.4	83.1	16.4	965.4	1564.3	24,947	6.3
08-09	3.6	921.3	187.1	424.2	10.9	0.4	83.1	16.4	1015.3	1647.0	25,856	6.4
09-10	3.6	971.2	196.9	447.8	10.9	0.4	83.1	16.4	1065.2	1730.3	26,765	6.5
10-11	3.6	971.2	196.9	472.0	10.9	0.4	83.1	16.4	1065.2	1754.5	27,674	6.3

TABLE 4.14. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	--	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	261.1	49.2	69.4	14.8	0.6	21.0	5.4	296.9	491.3	7356	6.7
87-88	67.1	261.1	51.7	80.5	14.8	0.6	21.0	5.6	296.9	502.4	7864	6.4
88-89	60.6	342.5	70.2	93.4	14.8	0.6	48.1	11.2	405.4	641.4	8372	7.7
89-90	56.4	342.5	73.7	107.4	14.8	0.7	48.1	11.7	405.4	655.3	8870	7.4
90-91	52.5	342.5	77.4	125.4	14.8	0.7	48.1	12.3	405.4	673.7	9589	7.0
91-92	49.8	452.1	102.6	145.9	14.8	0.7	48.1	12.9	515.0	826.9	10,298	8.0
92-93	47.4	551.0	127.2	168.5	14.8	0.8	48.1	13.6	613.9	971.4	11,008	8.8
93-94	46.5	551.0	133.5	193.8	14.8	0.8	48.1	14.3	613.9	1002.8	11,717	8.6
94-95	48.5	660.0	161.6	221.3	14.8	0.9	48.1	15.0	722.9	1170.2	12,427	9.4
95-96	43.8	774.5	192.2	261.2	14.8	0.9	87.1	22.7	876.4	1397.2	13,477	10.4
96-97	36.3	894.7	225.4	307.4	14.8	0.9	87.1	23.9	996.6	1590.5	14,526	10.9
97-98	37.7	1020.9	261.5	354.5	14.8	1.0	87.1	25.1	1122.8	1802.6	15,576	11.6
98-99	37.5	1153.4	300.5	407.1	14.8	1.0	87.1	26.3	1255.3	2027.7	16,625	12.2
99-2000	31.7	1292.6	342.8	464.8	14.8	1.1	131.3	36.2	1438.7	2315.3	17,675	13.1
00-01	16.7	1438.7	388.7	526.5	14.8	1.1	131.3	37.9	1584.8	2555.7	18,584	13.8
01-02	15.3	1438.7	408.1	592.6	14.8	1.2	131.3	39.9	1584.8	2641.9	19,493	13.6
02-03	5.4	1599.8	460.1	667.5	14.8	1.3	131.3	41.9	1745.9	2922.1	20,402	14.3
03-04	5.5	1769.0	516.3	746.8	14.8	1.3	131.3	43.9	1915.1	3228.9	21,311	15.1
04-05	3.6	1769.0	542.2	835.5	14.8	1.4	131.3	46.1	1915.1	3343.9	22,220	15.0
05-06	3.7	1955.5	605.9	930.8	14.8	1.5	184.3	58.4	2154.6	3754.9	23,129	16.2
06-07	3.9	2151.3	674.6	1035.9	14.8	1.5	184.3	61.3	2350.4	4127.6	24,038	17.2
07-08	4.0	2151.3	708.3	1151.5	14.8	1.6	184.3	64.4	2350.4	4280.2	24,947	17.2
08-09	4.1	2367.2	786.1	1278.1	14.8	1.7	184.3	67.6	2566.3	4703.9	25,856	18.2
09-10	4.2	2593.9	869.9	1416.3	14.8	1.8	184.3	70.9	2793.0	5156.1	26,765	19.3
10-11	4.4	2593.9	913.4	1566.6	14.8	1.9	184.3	74.5	2793.0	5353.8	27,674	19.3

TABLE 4.15. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	144.8	28.7	58.7	10.9	0.4	35.9	5.6	191.6	352.2	7357	4.8
87-88	66.4	194.7	33.5	73.4	10.9	0.4	35.9	5.6	241.5	420.8	7864	5.3
88-89	59.0	194.7	38.5	81.2	10.9	0.4	35.9	5.6	241.5	426.2	8372	5.1
89-90	54.5	244.6	48.3	88.6	10.9	0.4	52.4	8.8	307.9	508.5	8879	5.7
90-91	50.2	244.6	48.3	98.5	10.9	0.4	52.4	8.8	307.9	514.1	9589	5.4
91-92	47.1	302.6	59.7	109.9	10.9	0.4	52.4	8.8	365.9	591.8	10,298	5.7
92-93	42.4	302.6	59.7	120.1	10.9	0.4	52.4	8.8	365.9	597.3	11,008	5.4
93-94	38.9	352.5	69.5	132.6	10.9	0.4	52.4	8.8	415.8	666.0	11,717	5.7
94-95	39.4	352.5	69.7	143.9	10.9	0.4	52.4	8.8	415.8	678.0	12,427	5.5
95-96	34.5	402.4	79.3	161.3	10.9	0.4	52.4	8.8	465.7	750.0	13,477	5.6
96-97	28.3	452.3	89.1	181.5	10.9	0.4	68.9	12.0	532.1	843.4	14,526	5.8
97-98	25.4	502.2	98.9	200.1	10.9	0.4	68.9	12.0	582.0	918.8	15,576	5.9
98-99	27.4	552.1	108.7	217.9	10.9	0.4	68.9	12.0	631.9	998.3	16,625	6.0
99-2000	22.6	602.0	118.5	238.7	10.9	0.4	68.9	12.0	681.8	1074.0	17,675	6.1
00-01	12.2	651.9	128.3	256.5	10.9	0.4	85.4	15.2	748.2	1160.8	18,584	6.2
01-02	11.0	701.8	138.1	275.8	10.9	0.4	85.4	15.2	798.1	1238.6	19,493	6.3
02-03	4.8	751.7	147.9	294.6	10.9	0.4	85.4	15.2	848.0	1310.9	20,402	6.4
03-04	4.8	751.7	147.9	314.7	10.9	0.4	85.4	15.2	848.0	1331.0	21,311	6.2
04-05	3.6	751.7	147.9	335.6	10.9	0.4	85.4	15.2	848.0	1350.7	22,220	6.1
05-06	3.6	801.6	157.7	356.9	10.9	0.4	85.4	15.2	897.9	1431.7	23,129	6.2
06-07	3.6	851.5	167.5	378.8	10.9	0.4	85.4	15.2	947.8	1513.3	24,038	6.3
07-08	3.6	901.4	177.3	401.2	10.9	0.4	101.9	18.4	1014.2	1615.1	24,947	6.5
08-09	3.6	901.4	177.3	424.2	10.9	0.4	101.9	18.4	1014.2	1638.1	25,856	6.3
09-10	3.6	951.3	187.1	447.8	10.9	0.4	101.9	18.4	1064.1	1721.4	26,765	6.4
10-11	3.6	1001.2	195.9	472.0	10.9	0.4	101.9	18.4	1114.0	1801.7	27,674	6.5

TABLE 4.16. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	187.3	40.8	61.5	14.8	0.6	47.7	8.1	249.8	430.6	4357	5.8
87-88	67.1	264.8	58.0	80.5	14.8	0.6	47.7	8.6	327.3	542.1	7864	6.9
88-89	60.6	264.8	60.9	93.4	14.8	0.6	47.7	9.0	327.3	551.8	8372	6.6
89-90	56.4	350.2	80.8	107.4	14.8	0.7	74.8	14.7	439.8	699.8	8879	7.9
90-91	52.5	350.2	84.8	125.4	14.8	0.7	74.8	15.4	439.8	718.6	9589	7.5
91-92	49.8	459.8	110.5	145.9	14.8	0.7	74.8	16.2	549.4	872.5	10,298	8.5
92-93	47.4	459.8	115.9	168.5	14.8	0.8	74.8	17.0	549.2	899.0	11,008	8.2
93-94	46.5	563.6	142.2	193.9	14.8	0.8	74.8	17.9	653.2	1054.5	11,717	9.0
94-95	48.5	563.6	149.3	221.3	14.8	0.9	74.8	18.8	563.2	1092.0	12,427	8.8
95-96	43.8	678.1	179.2	261.2	14.8	0.9	74.8	19.7	767.7	1272.5	13,477	9.4
96-97	36.3	798.3	211.8	307.4	14.8	0.9	113.8	27.7	926.9	1511.0	14,526	10.4
97-98	37.7	924.5	247.2	354.5	14.8	1.0	113.8	29.1	1053.1	1722.6	15,576	11.1
98-99	37.5	1057.0	285.5	407.1	14.8	1.0	113.8	30.5	1185.6	1947.2	16,625	11.7
99-2000	31.7	1196.2	327.1	464.8	14.8	1.1	113.8	32.0	1324.8	2181.5	17,675	12.3
00-01	16.7	1342.3	372.2	526.5	14.8	1.1	160.2	42.6	1517.3	2476.4	18,584	13.3
01-02	15.3	1495.7	420.9	591.8	14.8	1.2	160.2	44.7	1670.7	2744.6	19,493	14.1
02-03	5.4	1656.8	473.5	667.5	14.8	1.3	160.2	46.9	1831.8	3026.4	20,402	14.8
03-04	5.5	1656.8	497.2	746.8	14.8	1.3	160.2	49.3	1831.8	3131.9	21,311	14.7
04-05	3.6	1656.8	522.1	835.5	14.8	1.4	160.2	51.8	1831.8	3246.2	22,220	14.6
05-06	3.7	1843.3	584.8	930.8	14.8	1.5	160.2	54.4	2018.3	3593.5	23,129	15.5
06-07	3.9	2039.1	652.4	1035.9	14.8	1.5	160.2	57.1	2214.1	3964.9	24,038	16.5
07-08	4.0	2244.7	725.3	1151.5	14.8	1.6	215.2	70.9	2474.7	4428.0	24,947	17.7
08-09	4.1	2244.7	761.6	1278.1	14.8	1.7	215.2	74.5	2474.7	4594.7	25,856	17.8
09-10	4.2	2471.4	844.2	1416.3	14.8	1.8	215.2	78.2	2701.4	5046.1	26,765	18.8
10-11	4.4	2709.4	933.1	1566.6	14.8	1.9	215.2	82.1	2939.4	5527.5	27,674	19.9

TABLE 4.17. Anchorage-Cook Inlet Area, High Load Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.1	---	---	---	---	---	0.6	0.4	---	34.1	2680	1.3
79-80	42.2	---	---	---	---	---	0.6	0.4	---	43.2	3025	1.4
80-81	48.2	---	---	---	---	---	0.6	0.4	---	49.2	3688	1.3
81-82	52.8	---	---	---	---	---	0.6	0.4	---	53.8	4352	1.2
82-83	61.1	57.4	11.4	9.8	---	---	17.1	3.6	74.5	160.5	5015	3.2
83-84	62.0	86.1	17.1	18.6	---	---	17.1	3.6	103.2	204.5	5679	3.6
84-85	66.7	114.8	22.8	29.9	---	---	17.1	3.6	131.9	254.9	6342	4.0
85-86	66.7	144.8	28.7	44.8	10.9	0.4	17.1	3.6	142.8	317.0	6849	4.6
86-87	67.2	144.8	28.7	58.7	10.9	0.4	35.9	5.6	191.6	352.2	7357	4.8
87-88	66.4	194.7	33.5	73.4	10.9	0.4	35.9	5.6	241.5	420.8	7864	5.3
88-89	59.0	194.7	38.5	81.2	10.9	0.4	35.9	5.6	241.5	426.2	8372	5.1
89-90	54.5	244.6	48.3	88.6	10.9	0.4	52.4	8.8	307.9	508.5	8879	5.7
90-91	50.2	244.6	48.3	98.5	10.9	0.4	52.4	8.8	307.9	514.1	9589	5.4
91-92	47.1	302.6	59.7	109.9	10.9	0.4	52.4	8.8	365.9	591.8	10,298	5.7
92-93	42.4	302.6	59.7	120.1	10.9	0.4	52.4	8.8	365.9	597.3	11,008	5.4
93-94	38.9	352.5	69.5	132.6	10.9	0.4	52.4	8.8	415.8	666.0	11,717	5.7
94-95	39.4	352.5	69.5	111.7	163.1	1.1	52.4	8.8	568.0	798.5	12,427	6.4
95-96	34.5	352.5	69.5	124.2	163.1	1.1	52.4	8.8	568.0	806.1	13,477	6.0
96-97	28.3	402.4	79.3	143.5	163.1	1.1	68.9	12.0	634.4	898.6	14,526	6.2
97-98	25.4	452.3	89.1	161.2	163.1	1.1	68.9	12.0	684.3	973.1	15,576	6.2
98-99	27.4	452.3	89.1	143.9	213.8	1.7	68.9	12.0	684.3	1009.1	16,625	6.1
99-2000	22.6	452.3	89.1	158.5	213.8	1.7	68.9	12.0	684.3	1018.9	17,675	5.8
00-01	12.2	452.3	89.1	175.1	213.8	1.7	68.9	12.0	684.3	1025.1	18,584	5.5
01-02	11.0	502.5	98.9	192.5	213.8	1.7	68.9	12.0	785.2	1101.3	19,493	5.6
02-03	4.8	552.1	108.7	210.1	213.8	1.7	68.9	12.0	834.8	1172.1	20,402	5.7
03-04	4.8	552.1	108.7	228.4	213.8	1.7	68.9	12.0	834.8	1190.4	21,311	5.6
04-05	3.6	602.0	118.5	247.5	213.8	1.7	85.4	15.2	901.2	1287.7	22,220	5.8
05-06	3.6	651.9	128.3	266.9	213.8	1.7	85.4	15.2	951.1	1366.8	23,129	5.9
06-07	3.6	651.9	128.3	286.9	213.8	1.7	85.4	15.2	951.1	1386.8	24,038	5.8
07-08	3.6	701.8	138.1	307.6	213.8	1.7	85.4	15.2	1001.0	1467.2	24,947	5.9
08-09	3.6	751.7	147.9	328.8	213.8	1.7	85.4	15.2	1050.9	1548.1	25,856	6.0
09-10	3.6	751.7	147.9	350.6	213.8	1.7	85.4	15.2	1050.9	1569.9	26,765	5.9
10-11	3.6	801.6	157.7	372.9	213.8	1.7	101.9	18.4	1117.3	1671.6	27,674	6.0

TABLE 4.18. Anchorage-Cook Inlet Area. High Load Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	29.7	---	---	---	---	---	0.7	0.4	---	30.8	2680	1.1
79-80	39.1	---	---	---	---	---	0.7	0.4	---	40.2	3025	1.3
80-81	45.7	---	---	---	---	---	0.7	0.4	---	46.8	3688	1.3
81-82	47.9	---	---	---	---	---	0.7	0.5	---	49.1	4352	1.1
82-83	59.5	69.8	13.8	9.9	---	---	21.0	4.4	90.8	178.4	5015	3.6
83-84	63.6	106.4	21.8	18.6	---	---	21.0	4.6	127.4	236.0	5679	4.2
84-85	68.7	144.9	30.5	29.9	---	---	21.0	4.9	165.9	299.9	6342	4.7
85-86	68.9	187.3	38.9	44.8	14.8	0.6	21.0	5.1	223.1	381.4	6849	5.6
86-87	69.8	187.3	40.8	61.5	14.8	0.6	47.7	8.1	249.8	430.6	4357	5.8
87-88	67.1	264.8	58.0	80.5	14.8	0.6	47.7	8.6	327.3	542.1	7864	6.9
88-89	60.6	264.8	60.9	93.4	14.8	0.6	47.7	9.0	327.3	551.8	8372	6.6
89-90	56.4	350.2	80.8	107.4	14.8	0.7	74.8	14.7	439.8	699.8	8879	7.9
90-91	52.5	350.2	84.8	125.4	14.8	0.7	74.8	15.4	439.8	718.6	9589	7.5
91-92	49.8	459.8	110.5	145.9	14.8	0.7	74.8	16.2	549.4	872.5	10,298	8.5
92-93	47.4	459.8	115.9	168.5	14.8	0.8	74.8	17.0	549.2	899.0	11,008	8.2
93-94	46.5	563.6	142.2	193.9	14.8	0.8	74.8	17.9	653.2	1054.5	11,717	9.0
94-95	48.5	563.6	149.3	171.3	335.2	2.2	74.8	18.8	973.6	1364.2	12,427	10.9
95-96	43.8	563.6	156.8	201.2	335.2	2.3	74.8	19.7	973.6	1397.4	13,477	10.4
96-97	36.3	683.8	188.2	243.1	335.2	2.4	114.8	27.7	1133.8	1595.2	14,526	10.9
97-98	37.7	810.0	222.4	285.6	335.2	2.5	114.8	29.1	1260.0	1837.3	15,576	11.8
98-99	37.5	810.0	233.5	268.9	464.9	4.2	114.8	30.5	1389.7	1964.3	16,625	11.8
99-2000	31.7	810.0	245.2	308.5	464.9	4.4	114.8	32.0	1389.7	2011.5	17,675	11.4
00-01	16.7	810.0	257.5	359.3	464.9	4.6	114.8	33.6	1389.7	2061.4	18,584	11.1
01-02	15.3	963.4	300.5	413.1	464.9	4.8	114.8	35.3	1543.1	2312.1	19,493	11.9
02-03	5.4	1124.5	347.1	476.1	464.9	5.1	114.8	37.1	1704.2	2575.0	20,402	12.6
03-04	5.5	1124.5	364.4	541.9	464.9	5.3	114.8	38.9	1704.2	2660.2	21,311	12.5
04-05	3.6	1302.1	417.5	616.1	464.9	5.6	168.5	51.9	1935.5	3030.2	22,220	13.6
05-06	3.7	1488.6	474.9	696.2	464.9	5.9	168.5	54.5	2122.0	3357.2	23,129	14.5
06-07	3.9	1488.6	498.7	784.9	464.9	6.2	168.5	57.2	2122.0	3472.9	24,038	14.4
07-08	4.0	1694.2	563.9	882.8	464.9	6.5	168.5	60.1	2327.6	3844.9	24,947	15.4
08-09	4.1	1910.1	634.5	990.5	464.9	6.8	168.5	63.1	2543.5	4238.4	25,856	16.4
09-10	4.2	1910.1	666.3	1108.7	464.9	7.1	168.5	66.2	2543.5	4396.0	26,765	16.4
10-11	4.4	2148.1	746.3	1237.8	464.9	7.5	222.0	81.5	2835.0	4912.5	27,674	17.7

TABLE 4.19. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---			0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---			0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---			0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9			0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3			0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5			0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7			0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8			0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7			0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0			3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0			3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4			3.5	1.0	31.7	71.1	1208	5.9
92-93	18.2	27.6	5.5	13.3			3.5	1.0	31.1	69.2	1240	5.6
93-94	18.4	27.6	5.5	14.1			3.5	1.0	31.1	70.1	1272	5.5
94-95	18.5	46.5	9.3	14.7			3.5	1.0	50.0	93.5	1305	7.1
95-96	16.9	51.2	10.2	15.4			3.5	1.0	54.7	98.2	1337	7.3
96-97	14.3	51.2	10.2	16.4			3.5	1.0	54.7	97.1	1369	7.1
97-98	3.8	70.1	14.0	18.9			3.5	1.0	73.6	111.2	1401	7.9
98-99	3.8	89.0	17.8	19.6			3.5	1.0	92.5	134.7	1433	9.4
99-2000	3.8	89.0	17.8	20.6			3.5	1.0	92.5	135.7	1466	9.2
00-01	3.8	89.0	17.8	20.9			3.5	1.0	92.5	136.0	1470	9.3
01-02	3.8	89.0	17.8	21.5			3.5	1.0	92.5	136.6	1474	9.3
02-03	1.5	89.0	17.8	21.9			3.5	1.0	92.5	134.7	1478	9.1
03-04	1.5	89.0	17.8	22.4			3.5	1.0	92.5	135.2	1482	9.1
04-05	1.5	89.0	17.8	22.9			3.5	1.0	92.5	135.7	1437	9.1
05-06	---	89.0	17.8	23.5			3.5	1.0	92.5	134.8	1491	9.0
06-07	---	89.0	17.8	24.1			3.5	1.0	92.5	135.4	1495	9.0
07-08	---	89.0	17.8	24.6			3.5	1.0	92.5	135.9	1499	9.1
08-09	---	89.0	17.8	24.7			3.5	1.0	92.5	136.0	1503	9.0
09-10	---	89.0	17.8	25.7			3.5	1.0	92.5	137.0	1507	9.1
10-11	---	89.0	17.8	26.2			3.5	1.0	92.5	137.5	1511	9.1

TABLE 4.20. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---			0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---			0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---			0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---			0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5			0.2	0.2	---	40.3	1015	4.0
86-87	30.4	---	---	8.1			0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6			0.2	0.3	---	37.0	1079	3.5
88-89	27.9	4.2	0.7	8.9			0.2	0.3	4.6	42.4	1111	3.8
89-90	29.3	36.6	7.0	12.1			4.5	1.7	41.1	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7			4.5	1.8	52.5	102.8	1176	8.7
91-92	30.1	48.0	7.4	16.5			4.5	1.9	52.5	108.2	1208	8.9
92-93	26.7	48.0	7.4	18.7			4.5	2.0	52.5	107.6	1240	8.6
93-94	28.1	48.0	7.8	20.6			4.5	2.1	52.5	110.8	1272	8.7
94-95	29.5	89.4	17.0	22.6			4.5	2.2	93.9	165.1	1305	12.7
95-96	28.8	100.2	17.2	24.9			4.5	2.3	104.7	177.6	1337	13.3
96-97	27.7	100.2	18.0	27.9			4.5	2.4	104.7	180.4	1369	13.2
97-98	6.1	148.1	28.5	33.5			4.5	2.5	152.6	222.9	1401	15.9
98-99	6.4	198.4	39.6	36.7			4.5	2.6	202.9	287.9	1433	20.1
99-2000	6.6	198.4	41.6	40.1			4.5	2.7	202.9	294.0	1466	20.0
00-01	7.0	198.4	43.6	43.1			4.5	2.8	202.9	299.4	1470	20.4
01-02	7.3	198.4	46.0	46.2			4.5	2.9	202.9	305.2	1474	20.7
02-03	2.7	198.4	48.4	49.6			4.5	3.0	202.9	306.5	1478	20.7
03-04	2.8	198.4	50.8	53.2			4.5	3.2	202.9	312.6	1482	21.1
04-05	2.9	198.4	53.6	57.1			4.5	3.3	202.9	319.6	1487	21.5
05-06	---	198.4	56.0	61.3			4.5	3.4	202.9	323.6	1491	21.7
06-07	---	198.4	58.8	65.8			4.5	3.5	202.9	330.9	1495	22.1
07-08	---	198.4	60.0	70.6			4.5	3.7	202.9	337.0	1499	22.5
08-09	---	198.4	56.2	75.8			4.5	3.9	202.9	347.5	1503	23.1
09-10	---	198.4	68.0	81.3			4.5	4.2	202.9	356.4	1507	23.6
10-11	---	198.4	71.6	87.1			4.5	4.3	202.9	365.9	1511	24.2

TABLE 4.21. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---			0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---			0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---			0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9			0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3			0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5			0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7			0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8			0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7			0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0			3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0			3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4			3.5	1.0	31.7	71.1	1208	5.9
92-93	18.2	27.6	5.5	13.3			3.5	1.0	31.1	69.2	1240	5.6
93-94	18.4	27.6	5.5	14.1			3.5	1.0	31.1	70.1	1272	5.5
94-95	18.5	27.6	5.5	14.7			18.8	2.0	46.4	87.2	1305	6.7
95-96	16.9	32.3	6.4	15.4			18.8	2.0	51.1	91.8	1337	6.9
96-97	14.3	51.2	10.2	16.4			18.8	2.0	70.0	113.1	1369	8.3
97-98	3.7	70.1	14.0	18.9			18.8	2.0	88.9	127.6	1401	9.1
98-99	3.7	70.1	14.0	19.6			18.8	2.0	88.9	128.4	1433	8.9
99-2000	3.7	70.1	14.0	20.6			18.8	2.0	88.9	129.3	1466	8.8
00-01	3.8	70.1	14.0	20.9			18.8	2.0	88.9	129.6	1470	8.8
01-02	3.8	70.1	14.0	21.5			18.8	2.0	88.9	130.2	1474	8.8
02-03	1.5	70.1	14.0	21.8			18.8	2.0	88.9	128.3	1478	8.7
03-04	1.5	70.1	14.0	22.4			18.8	2.0	88.9	128.8	1482	8.7
04-05	1.5	70.1	14.0	22.9			18.8	2.0	88.9	129.3	1487	8.7
05-06	---	70.1	14.0	23.5			18.8	2.0	88.9	128.4	1491	8.6
06-07	---	89.0	17.8	24.0			18.8	2.0	107.8	151.7	1495	10.1
07-08	---	89.0	17.8	24.5			18.8	2.0	107.8	152.2	1499	10.1
08-09	---	89.0	17.8	25.1			18.8	2.0	107.8	152.8	1503	10.1
09-10	---	89.0	17.8	25.7			18.8	2.0	107.8	153.3	1507	10.2
10-11	---	89.0	17.8	26.2			18.8	2.0	107.8	153.9	1511	10.2

TABLE 4.22. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.57	---	---	---			0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---			0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---			0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---			0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5			0.2	0.2	---	40.3	1015	4.0
86-87	30.4	---	---	8.1			0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6			0.2	0.3	---	37.8	1079	3.5
88-89	27.9	4.2	0.7	8.9			0.2	0.3	4.4	42.4	1111	3.8
89-90	29.3	36.6	7.0	12.1			4.5	1.7	41.1	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7			4.5	1.8	52.5	102.8	1176	8.7
91-92	30.1	48.0	7.4	16.5			4.5	1.9	52.5	108.2	1208	8.9
92-93	26.7	48.0	7.4	18.7			4.5	2.0	52.5	107.0	1240	8.6
93-94	28.1	48.0	7.8	20.6			4.5	2.1	52.5	110.8	1272	8.7
94-95	29.5	48.0	11.9	22.6			36.8	4.0	84.8	153.0	1305	11.7
95-96	28.8	58.8	14.6	24.9			36.8	4.2	95.6	168.1	1337	12.6
96-97	27.7	105.4	24.4	27.9			36.8	4.4	142.2	226.6	1369	16.5
97-98	6.1	153.3	35.2	33.5			36.8	4.6	190.1	269.6	1401	19.2
98-99	6.4	153.3	36.9	36.7			36.8	4.8	190.1	275.0	1433	19.2
99-2000	6.6	153.3	38.7	40.1			36.8	5.1	190.1	280.6	1466	19.1
00-01	7.0	153.3	40.7	43.0			36.8	5.3	190.1	286.2	1470	19.4
01-02	7.3	153.3	42.7	46.1			36.8	5.6	190.1	291.9	1474	19.8
02-03	2.7	153.3	44.9	49.6			36.8	5.9	190.1	293.2	1478	19.8
03-04	2.8	153.3	47.1	53.2			36.8	6.2	190.1	299.4	1482	20.2
04-05	2.9	153.3	49.5	57.1			36.8	6.5	190.1	306.2	1487	20.6
05-06	---	153.3	51.9	61.3			36.8	6.8	190.1	310.1	1491	20.8
06-07	---	227.6	69.2	65.7			36.8	7.2	264.4	406.6	1495	27.2
07-08	---	227.6	72.6	70.5			36.8	7.5	264.4	415.1	1499	27.7
08-09	---	227.6	76.3	75.7			36.8	7.9	264.4	424.4	1503	28.2
09-10	---	227.6	80.1	81.2			36.8	8.3	264.4	434.1	1507	28.8
10-11	---	227.6	84.1	87.1			36.8	8.7	264.4	443.3	1511	29.4

TABLE 4.23. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---	---	---	0.3	0.2	---	34.3	778	4.4
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.1	823	4.5
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.9	855	4.7
81-82	41.6	---	---	---	---	---	0.3	0.2	---	42.1	887	4.7
82-83	35.6	---	---	6.9	---	---	0.3	0.2	---	43.1	919	4.7
83-84	33.1	---	---	7.2	---	---	0.3	0.2	---	40.8	951	4.3
84-85	30.3	---	---	7.3	---	---	0.3	0.2	---	38.2	983	3.9
85-86	28.2	---	---	7.5	---	---	0.3	0.2	---	36.6	1015	3.6
86-87	26.1	---	---	7.7	---	---	0.3	0.2	---	34.3	1047	3.3
87-88	24.0	---	---	7.8	---	---	0.3	0.2	---	32.4	1079	3.0
88-89	22.9	2.6	0.5	7.7	---	---	0.3	0.2	2.9	34.2	1111	3.1
89-90	23.1	21.5	4.3	10.0	---	---	3.5	1.0	25.0	63.4	1144	5.6
90-91	20.9	27.6	5.5	10.0	---	---	3.5	1.0	31.4	68.5	1176	5.8
91-92	21.1	27.6	5.5	12.4	---	---	18.8	2.0	46.4	87.4	1208	7.2
92-93	18.2	27.6	5.5	13.3	---	---	18.8	2.0	46.4	85.5	1240	6.9
93-94	18.4	27.6	5.5	14.1	---	---	18.8	2.0	46.4	86.4	1272	6.8
94-95	18.5	27.6	5.5	6.9	36.2	0.1	18.8	2.0	82.6	115.6	1305	8.8
95-96	16.9	32.3	6.4	6.5	36.2	0.1	18.8	2.0	82.6	119.2	1337	8.9
96-97	14.3	32.3	6.4	7.3	36.2	0.1	18.8	2.0	82.6	117.5	1369	8.6
97-98	3.8	32.3	6.4	9.6	36.2	0.1	18.8	2.0	82.6	109.2	1401	7.8
98-99	3.8	32.3	6.4	10.1	36.2	0.1	18.8	2.0	82.6	109.7	1433	7.6
99-2000	3.8	32.3	6.4	3.1	48.3	0.2	18.8	2.0	99.4	114.9	1466	7.8
00-01	3.8	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	114.5	1470	7.8
01-02	3.8	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	114.5	1474	7.7
02-03	1.5	32.3	6.4	2.4	48.3	0.2	18.8	2.0	99.4	111.9	1478	7.6
03-04	1.5	32.3	6.4	2.5	48.3	0.2	18.8	2.0	99.4	112.0	1482	7.6
04-05	1.5	32.3	6.4	2.6	48.3	0.2	18.8	2.0	99.4	112.1	1487	7.5
05-06	---	32.3	6.4	2.7	48.3	0.2	18.8	2.0	99.4	110.7	1491	7.4
06-07	---	32.3	6.4	2.8	48.3	0.2	18.8	2.0	99.4	110.8	1495	7.4
07-08	---	32.3	6.4	2.9	48.3	0.2	18.8	2.0	99.4	110.9	1499	7.4
08-09	---	32.3	6.4	3.1	48.3	0.2	18.8	2.0	99.4	111.1	1503	7.4
09-10	---	32.3	6.4	3.2	48.3	0.2	18.8	2.8	99.4	111.2	1507	7.4
10-11	---	32.3	6.4	3.4	48.3	0.2	18.8	2.0	99.4	111.4	1511	7.4

TABLE 4.24. Fairbanks-Tanana Valley Area, Low Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---	---	---	0.2	0.2	---	30.9	778	4.0
79-80	33.9	---	---	---	---	---	0.2	0.2	---	34.2	823	4.2
80-81	37.4	---	---	---	---	---	0.2	0.2	---	37.8	855	4.4
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	887	4.6
82-83	36.6	---	---	6.9	---	---	0.2	0.2	---	43.9	919	4.8
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	951	4.5
84-85	33.5	---	---	7.3	---	---	0.2	0.2	---	41.3	983	4.2
85-86	32.3	---	---	7.5	---	---	0.2	0.2	---	40.3	1015	4.0
86-87	30.4	---	---	8.1	---	---	0.2	0.3	---	38.9	1047	3.7
87-88	28.7	---	---	8.6	---	---	0.2	0.3	---	37.8	1079	3.5
88-89	27.9	4.2	0.7	8.9	---	---	0.2	0.3	4.4	42.4	1111	3.8
89-90	29.3	36.6	7.0	12.1	---	---	4.5	1.7	41.1	91.3	1144	7.9
90-91	28.4	48.0	7.4	12.7	---	---	4.5	1.8	52.5	102.8	1176	8.7
91-92	30.1	48.0	10.3	16.4	---	---	32.4	3.5	80.4	140.7	1208	11.6
92-93	26.7	48.0	10.8	18.7	---	---	32.4	3.6	80.4	140.3	1240	11.3
93-94	28.1	48.0	11.4	20.6	---	---	32.4	3.8	80.4	144.3	1272	11.3
94-95	29.5	48.0	11.9	10.7	76.2	0.3	32.4	4.0	156.6	213.1	1305	16.3
95-96	28.8	58.8	14.6	10.5	76.2	0.3	32.4	4.2	167.4	225.8	1337	16.9
96-97	27.7	58.8	15.3	12.4	76.2	0.3	32.4	4.4	167.4	227.5	1369	16.6
97-98	6.1	58.8	16.1	16.9	76.2	0.4	32.4	4.6	167.4	211.5	1401	15.1
98-99	6.4	58.8	16.9	18.9	76.2	0.4	32.4	4.8	167.4	214.8	1433	15.0
99-2000	6.6	58.8	17.7	5.9	108.6	0.8	32.4	5.1	199.8	236.0	1466	16.1
00-01	7.0	58.8	18.6	5.4	108.6	0.8	32.4	5.3	199.8	236.9	1470	16.1
01-02	7.3	58.8	19.6	5.8	108.6	0.9	32.4	5.6	199.8	239.0	1474	16.2
02-03	2.7	58.8	20.5	5.5	108.6	0.9	32.4	5.9	199.8	235.3	1478	15.9
03-04	2.8	58.8	21.6	5.9	108.6	1.0	32.4	6.2	199.8	237.3	1482	16.0
04-05	2.9	58.8	22.6	6.5	108.6	1.0	32.4	6.5	199.8	239.3	1487	16.1
05-06	---	58.8	23.7	7.1	108.6	1.1	32.4	6.8	199.8	238.5	1491	16.0
06-07	---	58.8	24.9	7.8	108.6	1.1	32.4	7.2	199.8	240.8	1495	16.1
07-08	---	58.8	26.2	8.5	108.6	1.2	32.4	7.5	199.8	243.2	1499	16.2
08-09	---	58.8	27.5	9.3	108.6	1.2	32.4	7.9	199.8	245.7	1503	16.3
09-10	---	58.8	28.9	10.2	108.6	1.3	32.4	8.3	199.8	248.5	1507	16.5
10-11	---	58.8	30.3	11.1	108.6	1.4	32.4	8.7	199.8	251.3	1511	16.6

TABLE 4.25. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---			0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---			0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---			0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9			0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3			0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4			3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9			3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4			3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3			3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	40.4	8.1	14.5			3.5	1.0	43.9	90.6	1437	6.3
90-91	20.9	46.5	9.3	15.5			3.5	1.0	50.0	96.8	1505	6.4
91-92	21.1	46.5	9.3	16.8			3.5	1.0	50.0	98.2	1573	6.2
92-93	18.2	65.4	13.1	18.2			3.5	1.0	68.9	119.5	1641	7.3
93-94	18.4	65.4	13.1	19.5			3.5	1.0	68.9	120.9	1709	7.1
94-95	18.5	65.4	13.1	20.7			3.5	1.0	68.9	122.2	1777	6.9
95-96	16.9	70.1	14.0	22.1			3.5	1.0	73.6	127.6	1859	6.9
96-97	14.3	89.0	17.8	24.0			5.3	1.8	94.3	152.4	1941	7.8
97-98	3.7	107.9	21.6	27.3			5.3	1.8	113.2	167.8	2023	8.3
98-99	3.7	126.8	25.4	28.9			5.3	1.8	132.1	192.0	2105	9.1
99-2000	3.7	126.8	25.4	30.7			5.3	1.8	132.1	193.8	2187	8.9
00-01	3.8	126.8	25.4	31.8			5.3	1.8	132.1	194.9	2229	8.7
01-02	3.8	126.8	25.4	33.1			5.3	1.8	132.1	196.2	2270	8.6
02-03	1.5	126.8	25.4	34.2			5.3	1.8	132.1	195.0	2312	8.4
03-04	1.5	155.5	31.1	35.6			5.3	1.8	160.8	230.8	2353	9.8
04-05	--	155.5	31.1	37.0			5.3	1.8	160.8	232.2	2395	9.7
05-06	---	155.5	31.1	38.4			5.3	1.8	160.8	232.1	2437	9.5
06-07	---	155.5	31.1	39.9			5.3	1.8	160.8	233.5	2478	9.4
07-08	---	155.5	31.1	41.4			5.3	1.8	160.8	235.1	2520	9.3
08-09	---	155.5	31.1	42.8			5.3	1.8	160.8	236.5	2561	9.2
09-10	---	155.5	31.1	44.4			5.3	1.8	160.8	238.1	2603	9.1
10-11	---	155.5	31.1	45.9			5.3	1.8	160.8	239.6	2645	9.1

TABLE 4.26. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---			0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---			0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---			0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---			0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4			4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4			4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6			4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4			4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	63.2	13.6	17.6			4.4	1.5	67.6	129.7	1437	9.0
90-91	28.4	74.6	16.4	19.8			4.4	1.6	79.0	145.3	1505	9.6
91-92	30.1	74.6	16.4	22.3			4.4	1.7	79.0	149.5	1573	9.5
92-93	26.7	112.1	23.8	25.5			4.4	1.8	116.5	194.4	1641	11.8
93-94	28.1	112.1	25.0	28.5			4.4	1.9	116.5	200.1	1709	11.7
94-95	29.5	112.1	26.2	31.8			4.4	2.0	116.5	206.1	1777	11.6
95-96	28.8	122.9	29.7	35.8			4.4	2.2	127.3	223.8	1859	12.0
96-97	27.7	169.5	40.1	40.7			8.5	2.3	178.0	288.8	1941	14.9
97-98	6.1	217.4	51.7	48.5			8.5	2.4	225.9	334.6	2023	16.5
98-99	6.4	267.7	64.1	54.0			8.5	2.6	276.2	403.4	2105	19.2
99-2000	6.6	267.7	67.3	59.9			8.5	2.7	276.2	412.7	2187	18.9
00-01	7.0	267.7	70.7	65.3			8.5	2.8	276.2	422.0	2229	18.9
01-02	7.3	267.7	74.3	71.1			8.5	3.0	276.2	431.9	2270	19.0
02-03	2.7	267.7	77.9	77.6			8.5	3.2	276.2	437.6	2312	18.9
03-04	2.8	365.0	77.9	77.6			8.5	3.4	373.5	561.5	2353	23.9
04-05	2.9	365.0	102.1	92.1			8.5	3.6	373.5	574.2	2395	24.0
05-06	---	365.0	107.2	100.3			8.5	3.7	373.5	584.7	2437	24.0
06-07	---	365.0	112.6	109.1			8.5	3.8	373.5	599.0	2478	24.2
07-08	---	365.0	118.2	118.7			8.5	4.2	373.5	614.4	2520	24.4
08-09	---	365.0	124.1	129.1			8.5	4.2	373.5	630.9	2561	24.6
09-10	---	365.0	130.3	140.4			8.5	4.4	373.5	648.6	2603	24.9
10-11	---	365.0	136.8	152.5			8.5	4.5	373.5	667.3	2645	25.2

TABLE 4.27. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---			0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---			0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---			0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9			0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2			0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3			0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4			3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9			3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4			3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3			3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	21.5	4.3	14.5			18.8	2.0	40.3	84.2	1437	5.8
90-91	20.9	27.6	5.5	19.1			18.8	2.0	46.4	89.0	1505	5.9
91-92	21.1	27.6	5.5	15.2			18.8	2.0	46.4	90.2	1573	5.7
92-93	18.2	27.6	5.5	16.0			18.8	2.0	26.4	88.2	1641	5.4
93-94	13.4	27.6	5.5	16.9			18.8	2.0	46.4	89.2	1709	5.2
94-95	18.5	46.5	9.2	19.8			18.8	2.0	65.3	114.9	1777	6.5
95-96	16.9	70.1	13.8	22.1			18.8	2.0	88.9	143.7	1859	7.7
96-97	14.3	70.1	13.8	24.0			18.8	2.0	88.9	143.2	1941	7.4
97-98	3.76	89.0	17.5	27.3			18.8	2.0	107.8	158.5	2023	7.8
98-99	3.7	107.9	21.2	28.9			18.8	2.0	126.7	182.6	2105	8.7
99-2000	3.7	107.9	21.2	30.7			18.8	2.0	126.7	184.5	2187	8.4
00-01	3.8	107.9	21.2	31.8			18.8	2.0	126.7	185.5	2229	8.3
01-02	3.8	107.9	21.2	33.1			18.8	2.0	126.7	186.8	2270	8.2
02-03	1.5	126.8	24.9	34.2			18.8	2.0	145.6	208.2	2312	9.0
03-04	1.5	126.8	24.9	35.6			18.8	2.0	145.6	209.6	2353	8.9
04-05	1.5	126.8	24.9	37.0			18.8	2.0	145.6	211.0	2395	8.8
05-06	---	126.8	24.9	38.44			18.8	2.0	145.6	210.9	2437	8.6
06-07	---	126.8	24.9	39.8			18.8	2.0	145.6	212.3	2478	8.6
07-08	---	126.8	24.9	41.3			18.8	2.0	145.6	213.8	2520	8.5
08-09	----	126.8	24.9	42.8			18.8	2.0	145.6	215.3	2561	8.4
09-10	---	126.8	24.9	44.3			18.8	2.0	145.6	216.9	2603	8.3
10-11	---	126.8	24.9	45.9			18.8	2.0	145.6	218.4	2645	8.2

TABLE 4.28. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity			New Hydroelectric Costs		Transmission Systems		Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
		Investment Costs	OM&R Costs	Coal Costs	Investment Costs	OM&R Costs	Investment Costs	OM&R Costs				
78-79	30.5	---	---	---			0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---			0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---			0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---			0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9			0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3			0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4			4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4			4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6			4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4			4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	30.9	7.3	17.6			29.7	3.2	60.6	118.1	1437	8.2
90-91	28.4	42.3	9.8	18.0			29.7	3.4	72.0	131.8	1505	8.7
91-92	30.1	42.3	10.3	20.2			29.7	3.5	72.0	136.1	1573	8.6
92-93	26.7	42.3	10.8	22.4			29.7	3.7	72.0	135.7	1641	8.3
93-94	28.1	42.3	11.4	24.7			29.7	3.9	72.0	140.1	1709	8.2
94-95	29.5	83.7	20.2	30.5			29.7	4.1	113.4	197.8	1777	11.1
95-96	28.8	137.9	31.9	35.8			29.7	4.3	167.6	268.5	1859	14.4
96-97	27.7	137.9	33.5	40.7			29.7	4.5	167.6	274.0	1941	14.1
97-98	6.1	185.8	44.7	48.5			29.7	4.7	215.5	319.5	2023	15.8
98-99	6.4	236.1	56.8	54.0			29.7	5.0	265.8	388.1	2105	18.4
99-2000	6.6	236.1	59.6	59.9			29.7	5.2	265.8	397.1	2187	18.2
00-01	7.0	236.1	62.6	65.3			29.7	5.5	265.8	406.2	2229	18.2
01-02	7.3	236.1	65.7	71.1			29.7	5.7	265.8	415.6	2270	18.3
02-03	2.7	297.2	81.1	77.5			29.7	6.0	326.9	494.3	2312	21.4
03-04	2.8	297.2	85.2	84.4			29.7	6.3	326.9	505.7	2353	21.5
04-05	2.9	297.2	89.5	92.1			29.7	6.7	326.9	518.2	2395	21.6
05-06	---	297.2	93.9	100.2			29.7	7.0	326.9	528.1	2437	21.7
06-07	---	297.2	98.6	109.1			29.7	7.3	326.9	541.9	2478	21.9
07-08	---	297.2	103.6	118.7			29.7	7.7	326.9	556.9	2520	22.1
08-09	---	297.2	108.7	129.1			29.7	8.1	326.9	572.8	2561	22.4
09-10	---	297.2	114.2	140.3			29.7	8.5	326.9	590.0	2603	22.7
10-11	---	297.2	119.9	152.5			29.7	8.9	326.9	608.2	2645	23.0

TABLE 4.29. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---	---	---	0.3	0.2	---	34.2	804	4.3
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.0	862	4.3
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.8	916	4.3
81-82	41.6	---	---	---	---	---	0.3	0.2	---	42.1	970	4.3
82-83	35.6	---	---	6.9	---	---	0.3	0.2	---	43.0	1024	4.2
83-84	33.1	---	---	7.2	---	---	0.3	0.2	---	40.8	1078	3.8
84-85	30.3	---	---	7.3	---	---	0.3	0.2	---	38.1	1132	3.4
85-86	28.2	18.9	3.8	9.4	---	---	3.5	1.0	22.4	64.9	1193	5.4
86-87	26.1	18.9	3.8	10.9	---	---	3.5	1.0	22.4	64.2	1254	5.1
87-88	24.0	18.9	3.8	12.4	---	---	3.5	1.0	22.4	63.7	1315	4.8
88-89	22.9	21.5	4.3	13.3	---	---	3.5	1.0	25.0	66.6	1376	4.8
89-90	23.1	21.5	4.3	14.5	---	---	18.8	2.0	40.3	84.2	1437	5.8
90-91	20.9	27.6	5.5	19.1	---	---	18.8	2.0	46.4	89.0	1505	5.9
91-92	21.1	27.6	5.5	15.2	---	---	18.8	2.0	46.4	90.2	1573	5.7
92-93	18.2	27.6	5.5	16.0	---	---	18.8	2.0	26.4	88.2	1641	5.4
93-94	13.4	27.6	5.5	16.9	---	---	18.8	2.0	46.4	89.2	1709	5.2
94-95	18.5	27.6	5.5	13.6	34.4	0.1	18.8	2.0	80.8	120.5	1777	6.8
95-96	16.9	32.3	6.4	13.9	34.4	0.1	18.8	2.0	85.5	124.8	1859	6.7
96-97	14.3	32.3	6.4	15.6	34.4	0.1	18.8	2.0	85.4	124.0	1941	6.4
97-98	3.7	51.2	10.2	18.7	34.4	0.1	18.8	2.0	104.4	139.2	2023	6.9
98-99	3.7	51.2	10.2	13.0	45.9	0.2	18.8	2.0	115.9	145.1	2105	6.9
99-2000	3.7	51.2	10.2	13.6	45.9	0.2	18.8	2.0	115.9	145.7	2187	6.7
00-01	3.8	51.2	10.2	14.4	45.9	0.2	18.8	2.0	115.9	146.5	2229	6.6
01-02	3.8	51.2	10.2	15.3	45.9	0.2	18.8	2.0	115.9	147.4	2270	6.5
02-03	1.5	70.1	14.0	16.1	45.9	0.2	18.8	2.0	134.8	168.6	2312	7.3
03-04	1.5	70.1	14.0	17.1	45.9	0.2	18.8	2.0	134.8	169.6	2353	7.2
04-05	1.5	70.1	14.0	18.1	45.9	0.2	18.8	2.0	134.8	170.6	2395	7.1
05-06	---	70.1	14.0	19.2	45.9	0.2	18.8	2.0	134.8	170.2	2437	7.0
06-07	---	70.1	14.0	20.2	45.9	0.2	18.8	2.0	134.8	171.2	2478	6.9
07-08	---	70.1	14.0	21.3	45.9	0.2	18.8	2.0	134.8	172.3	2520	6.8
08-09	---	70.1	14.0	22.4	45.9	0.2	18.8	2.0	134.8	173.4	2561	6.8
09-10	---	70.1	14.0	23.6	45.9	0.2	18.8	2.0	134.8	174.6	2603	6.7
10-11	---	70.1	14.0	24.7	45.9	0.2	18.8	2.0	134.8	175.7	2645	6.6

TABLE 4.30. Fairbanks-Tanana Valley Area, Medium Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.5	---	---	---	---	---	0.2	0.2	---	30.9	804	3.8
79-80	33.9	---	---	---	---	---	0.2	0.2	---	34.2	862	4.0
80-81	37.4	---	---	---	---	---	0.2	0.2	---	37.8	916	4.1
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	970	4.2
82-83	36.6	---	---	6.9	---	---	0.2	0.2	---	43.9	1024	4.3
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	1078	4.0
84-85	33.5	---	---	7.3	---	---	0.2	0.2	---	41.3	1132	3.6
85-86	32.3	26.6	5.3	9.4	---	---	4.4	1.2	31.0	79.2	1193	6.6
86-87	30.4	26.6	5.5	11.4	---	---	4.4	1.3	31.0	79.6	1254	6.3
87-88	28.7	26.6	5.8	13.6	---	---	4.4	1.4	31.0	80.5	1315	6.1
88-89	27.9	30.8	7.0	15.4	---	---	4.4	1.5	35.2	87.0	1376	6.3
89-90	29.3	30.9	7.3	17.6	---	---	29.7	3.2	60.6	118.1	1437	8.2
90-91	28.4	42.3	9.8	18.0	---	---	29.7	3.4	72.0	131.8	1505	8.7
91-92	30.1	42.3	10.3	20.2	---	---	29.7	3.5	72.0	136.1	1573	8.6
92-93	26.7	42.3	10.8	22.4	---	---	29.7	3.7	72.0	135.7	1641	8.3
93-94	28.1	42.3	11.4	24.7	---	---	29.7	3.9	72.0	140.1	1709	8.2
94-95	29.5	42.2	11.9	20.9	72.5	0.2	29.7	4.1	144.4	211.2	1777	11.8
95-96	28.8	53.0	14.7	22.6	72.5	0.3	29.7	4.3	155.2	225.9	1859	12.1
96-97	27.7	53.0	15.4	26.5	72.5	0.3	29.7	4.5	155.2	229.6	1941	11.8
97-98	6.15	100.9	25.7	33.2	72.5	0.3	29.7	4.7	203.1	273.1	2023	13.5
98-99	6.4	100.9	26.9	24.4	101.8	0.7	29.7	4.9	232.4	295.7	2105	14.0
99-2000	6.6	100.9	28.3	26.4	101.8	0.7	29.7	5.2	232.4	299.6	2187	13.7
00-01	7.0	100.9	29.7	29.5	101.8	0.8	29.7	5.5	232.4	305.1	2229	13.7
01-02	7.[illegible]	100.9	31.2	32.8	101.8	0.8	29.7	5.7	232.4	310.2	2270	13.7
02-03	2.7	162.0	44.9	36.6	101.8	0.9	29.7	6.1	293.5	384.7	2312	16.6
03-04	2.8	162.0	47.1	40.6	101.8	0.9	29.7	6.4	293.5	391.3	2353	16.6
04-05	2.9	162.0	49.5	45.1	101.8	1.0	29.7	6.7	293.5	398.7	2395	16.6
05-06	---	162.0	51.9	50.0	101.8	1.0	29.7	7.0	293.5	403.4	2437	16.6
06-07	---	162.0	54.6	55.3	101.8	1.1	29.7	7.3	293.5	411.8	2478	16.6
07-08	---	162.0	57.3	61.2	101.8	1.1	29.7	7.7	293.5	420.8	2520	16.7
08-09	---	162.0	60.2	67.5	101.8	1.2	29.7	8.7	293.5	430.5	2561	16.8
09-10	---	162.0	63.2	74.5	101.8	1.2	29.7	8.5	293.5	440.9	2603	16.9
10-11	---	162.0	66.4	82.1	101.8	1.3	29.7	8.9	293.5	452.2	2645	17.1

TABLE 4.31. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 1, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	38.8	---	---	---			0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---			0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---			0.3	0.2	---	39.8	931	4.1
81-82	41.7	---	---	---			0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9			0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2			0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1			3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6			3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	37.8	7.6	12.1			3.5	1.0	41.3	88.2	1498	5.9
87-88	24.1	37.8	7.6	15.6			3.5	1.0	41.3	89.7	1600	5.6
88-89	22.9	40.4	8.1	17.2			3.5	1.0	43.9	93.1	1702	5.5
89-90	23.1	59.3	11.9	18.7			3.5	1.0	62.8	117.6	1805	6.5
90-91	20.9	65.4	13.1	20.5			3.5	1.0	68.9	124.4	1927	6.5
91-92	21.1	65.4	13.1	22.5			3.5	1.0	68.9	126.7	2049	6.2
92-93	18.3	84.3	16.9	24.6			3.5	1.0	87.8	148.7	2172	6.8
93-94	18.4	84.3	16.9	26.8			3.5	1.0	87.8	150.9	2294	6.6
94-95	18.5	103.2	20.7	28.8			5.3	1.8	108.5	178.3	2417	7.4
95-96	16.9	107.9	21.6	31.5			5.3	1.8	113.2	85.0	2585	7.2
96-97	14.4	126.8	25.4	34.8			5.3	1.8	132.1	208.5	2754	7.6
97-98	3.8	155.5	31.1	39.5			5.3	1.8	160.8	237.0	2922	8.1
98-99	3.8	184.2	36.8	42.4			5.3	1.8	189.5	274.4	3091	8.9
99-2000	3.8	184.2	36.8	45.8			5.3	1.8	189.5	286.7	3260	8.8
00-01	3.8	184.2	36.8	48.5			5.3	1.8	189.5	280.4	3396	8.3
01-02	3.8	184.2	36.8	51.5			5.3	1.8	189.5	283.4	3531	8.0
02-03	1.5	184.2	36.8	54.3			5.3	1.8	189.5	283.9	3667	7.7
03-04	1.5	212.9	42.5	57.6			5.3	1.8	218.2	321.6	3803	8.5
04-05	1.5	212.9	42.5	60.9			5.3	1.8	218.2	324.9	3939	8.2
05-06	--	212.9	42.5	64.3			5.3	1.8	218.2	326.8	4074	8.0
06-07	---	212.9	42.5	67.7			5.3	1.8	218.2	330.2	4210	7.8
07-08	---	241.6	48.2	71.3			7.1	2.6	248.7	370.8	4346	8.5
08-09	---	241.6	48.2	74.9			7.1	2.6	248.7	374.4	4481	8.4
09-10	---	241.6	48.2	78.7			7.1	2.6	248.7	378.2	4617	8.2
10-11	---	241.6	48.2	82.6			7.1	2.6	248.7	382.1	4753	8.0

TABLE 4.32. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 1, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.6	---	---	---			0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---			0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---			0.2	0.2	---	37.8	081	3.9
81-82	40.7	---	---	---			0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9			0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1			4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6			4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	43.3	11.0	12.7			4.4	1.3	57.7	113.2	1498	7.6
87-88	28.7	53.3	11.5	17.1			4.4	1.4	57.7	116.5	1600	7.3
88-89	27.9	57.5	13.0	19.8			4.4	1.5	61.9	124.1	1702	7.3
89-90	29.4	89.9	20.1	22.7			4.4	1.6	94.3	168.1	1805	9.3
90-91	28.5	101.3	23.2	26.1			4.4	1.7	105.7	185.3	1927	9.6
91-92	30.1	101.3	24.3	29.9			4.4	1.7	105.7	191.7	2049	9.4
92-93	26.8	138.8	32.9	34.6			4.4	1.8	143.2	239.3	2172	11.0
93-94	28.1	138.8	34.6	39.2			4.4	1.9	143.2	247.0	2294	10.8
94-95	29.6	180.2	44.5	44.3			8.4	3.6	188.6	310.7	2417	12.8
95-96	28.8	191.0	48.9	51.0			8.4	3.8	199.4	331.9	2585	12.8
96-97	25.7	237.6	57.9	58.9			8.4	4.0	246.0	392.5	2754	14.2
97-98	6.2	310.2	75.2	70.0			8.4	4.3	318.6	474.3	2922	16.2
98-99	6.4	386.4	94.0	79.3			8.4	4.6	394.8	579.2	3091	18.7
99-2000	6.7	386.4	98.7	89.3			8.4	4.8	394.8	594.3	3260	18.2
00-01	7.0	386.4	103.7	99.5			8.4	5.1	394.8	610.1	3396	17.9
01-02	7.3	386.4	108.8	110.7			8.4	5.3	394.8	626.9	3531	17.7
02-03	2.7	386.4	114.3	123.1			8.4	5.6	394.8	640.5	3667	17.5
03-04	2.8	483.7	139.3	136.6			8.4	5.8	492.1	776.6	3803	20.4
04-05	2.9	433.7	146.3	151.5			8.4	6.0	492.1	798.8	3939	20.3
05-06	---	433.7	153.6	167.6			8.4	6.3	492.1	819.6	4074	20.1
06-07	---	483.7	161.2	185.3			8.4	6.7	492.1	845.3	4210	20.1
07-08	---	602.0	192.8	204.7			16.5	10.2	618.5	1026.2	4346	23.6
08-09	---	602.0	202.5	225.9			16.5	10.5	618.5	1057.4	4431	23.6
09-10	---	602.0	212.6	248.9			16.5	10.9	618.5	1090.9	4617	23.6
10-11	---	602.0	223.2	274.0			16.5	11.4	618.5	1127.1	4753	23.7

TABLE 4.33. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 2, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	33.8	---	---	---			0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---			0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---			0.3	0.2	---	39.8	981	4.1
81-82	41.7	---	---	---			0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9			0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2			0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1			3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6			3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	18.9	3.8	12.1			18.8	2.0	37.7	81.8	1498	5.5
87-88	24.0	18.9	3.8	13.7			18.8	2.0	37.7	81.3	1600	5.1
88-89	22.9	21.5	4.3	15.0			18.8	2.0	40.3	84.6	1702	5.0
89-90	23.1	21.5	4.3	15.4			18.8	2.0	40.3	85.2	1805	4.7
90-91	20.9	27.6	5.5	14.1			18.8	2.0	46.4	89.0	1927	4.6
91-92	21.1	27.6	5.5	15.2			18.8	2.0	46.4	90.2	2049	4.4
92-93	18.2	65.4	13.1	20.2			18.8	2.0	84.2	137.8	2172	6.3
93-94	18.4	84.3	16.9	26.3			18.8	2.0	103.1	166.8	2294	7.3
94-95	18.5	84.3	16.9	28.8			18.8	2.0	103.1	169.4	2417	7.0
95-96	16.9	107.9	21.6	31.5			20.6	2.8	128.5	201.3	2585	7.8
96-97	14.3	126.8	25.4	34.8			20.6	2.8	147.4	224.8	2754	8.2
97-98	3.7	155.5	31.1	39.5			20.6	2.8	176.1	253.4	2922	8.7
98-99	3.7	155.5	31.1	42.4			20.6	2.8	176.1	256.3	3091	8.3
99-2000	3.7	155.5	31.1	45.8			20.6	2.8	176.1	259.7	3260	8.0
00-01	3.8	155.5	31.1	48.4			20.6	2.8	176.1	262.3	3396	7.7
01-02	3.8	155.5	31.1	51.5			20.6	2.8	176.1	265.3	3531	7.5
02-03	1.5	155.5	31.1	54.3			20.6	2.8	176.1	265.8	3667	7.2
03-04	1.5	184.2	36.8	57.5			20.6	2.8	204.8	303.5	3803	8.0
04-05	1.5	212.9	42.5	60.8			20.6	2.8	233.5	341.2	3939	8.7
05-06	---	212.9	42.5	64.2			20.6	2.8	233.5	343.1	4074	8.4
06-07	---	212.9	42.5	67.7			20.6	2.8	233.5	346.5	4210	8.2
07-08	---	212.9	42.5	71.3			20.6	2.8	233.5	350.1	4346	8.1
08-09	---	212.9	42.5	74.9			20.6	2.8	233.5	353.7	4481	7.9
09-10	---	212.9	42.5	78.7			20.6	2.8	233.5	357.5	4617	7.7
10-11	---	212.9	42.5	82.5			20.6	2.8	233.5	361.4	4753	7.6

TABLE 4.34. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 2, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.6	---	---	---			0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---			0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---			0.2	0.2	---	37.8	981	3.9
81-82	40.7	---	---	---			0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9			0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2			0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1			4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6			4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	25.4	5.5	12.7			26.3	2.8	51.7	103.3	1498	6.9
87-88	28.7	25.4	5.8	14.9			26.3	2.9	51.7	104.1	1600	6.5
88-89	27.9	29.6	7.0	17.2			26.3	3.1	55.9	111.2	1702	6.5
89-90	29.3	29.6	7.3	18.7			26.3	3.2	55.9	114.6	1805	6.3
90-91	28.4	41.0	9.8	18.0			26.3	3.4	67.3	127.1	1927	6.6
91-92	30.1	41.0	10.3	20.2			26.3	3.6	67.3	131.5	2049	6.4
92-93	26.7	116.0	25.6	28.3			26.3	3.7	142.3	226.8	2172	10.4
93-94	28.1	155.4	34.7	38.4			26.3	3.9	181.7	286.9	2294	12.5
94-95	29.5	155.4	36.4	44.3			26.3	4.1	181.7	296.2	2417	12.3
95-96	28.8	209.6	48.9	51.0			30.4	6.0	240.0	374.8	2585	14.5
96-97	27.7	256.2	60.3	58.9			30.4	6.3	286.6	439.8	2754	16.0
97-98	6.1	328.8	77.7	70.7			30.4	6.6	359.2	519.7	2922	17.8
98-99	6.4	328.8	81.6	79.3			30.4	6.9	359.2	533.5	3091	17.3
99-2000	6.6	328.8	85.7	89.2			30.4	7.3	359.2	548.1	3260	16.8
00-01	7.0	328.8	89.9	99.5			30.4	7.7	359.2	563.3	3396	16.6
01-02	7.3	328.8	94.5	110.6			30.4	8.1	359.2	579.7	3531	16.4
02-03	2.7	328.8	99.2	123.1			30.4	8.5	359.2	592.7	3667	16.2
03-04	2.8	426.1	123.4	136.6			30.4	8.9	456.5	728.2	3803	19.2
04-05	2.9	528.3	149.9	151.5			30.4	9.3	558.7	672.3	3939	22.1
05-06	---	528.3	157.4	167.6			30.4	9.8	558.7	893.5	4074	21.9
06-07	---	528.3	165.3	185.3			30.4	10.3	558.7	919.6	4210	21.8
07-08	---	528.3	173.5	204.7			30.4	10.8	558.7	947.7	4346	21.8
08-09	---	528.3	182.2	225.8			30.4	11.4	558.7	978.1	4481	21.8
09-10	---	528.3	191.3	248.9			30.4	11.9	558.7	1010.8	4617	21.9
10-11	---	528.3	200.9	274.0			30.4	12.5	558.7	1046.1	4753	22.0

TABLE 4.35. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 3, 0% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity: Investment Costs	New Coal Fired Capacity: OM&R Costs	New Coal Fired Capacity: Coal Costs	New Hydroelectric Costs: Investment Costs	New Hydroelectric Costs: OM&R Costs	Transmission Systems: Investment Costs	Transmission Systems: OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	38.8	---	---	---	---	---	0.3	0.2	---	34.2	832	4.1
79-80	36.6	---	---	---	---	---	0.3	0.2	---	37.0	903	4.1
80-81	39.4	---	---	---	---	---	0.3	0.2	---	39.8	931	4.1
81-82	41.7	---	---	---	---	---	0.3	0.2	---	42.1	1059	4.0
82-83	35.7	---	---	6.9	---	---	0.3	0.2	---	43.0	1137	3.8
83-84	33.2	---	---	7.2	---	---	0.3	0.2	---	40.8	1215	3.4
84-85	30.4	13.9	3.8	9.1	---	---	3.5	1.0	22.4	66.7	1294	5.2
85-86	28.3	18.0	3.8	10.6	---	---	3.5	1.0	22.4	66.2	1396	4.7
86-87	26.1	18.9	3.8	12.1	---	---	18.8	2.0	37.7	81.8	1498	5.5
87-88	24.0	18.9	3.8	13.7	---	---	18.8	2.0	37.7	81.3	1600	5.1
88-89	22.9	21.5	4.3	15.0	---	---	18.8	2.0	40.3	84.6	1702	5.0
89-90	23.1	21.5	4.3	15.4	---	---	18.8	2.0	40.3	85.2	1805	4.7
90-91	20.9	27.6	5.5	14.1	---	---	18.8	2.0	46.4	89.0	1927	4.6
91-92	21.1	27.6	5.5	15.2	---	---	18.8	2.0	46.4	90.2	2049	4.4
92-93	18.2	65.4	13.1	20.2	---	---	18.8	2.0	84.2	137.8	2172	6.3
93-94	18.4	84.3	16.9	26.3	---	---	18.8	2.0	103.1	166.8	2294	7.3
94-95	18.5	84.3	16.9	22.6	29.0	0.1	18.8	2.0	132.1	192.2	2417	7.9
95-96	16.9	89.0	17.8	24.4	29.0	0.1	18.8	2.0	136.8	198.0	2585	7.7
96-97	14.4	89.0	17.8	27.4	29.0	0.1	18.8	2.0	136.8	198.5	2754	7.2
97-98	3.8	89.0	17.8	32.0	29.0	0.1	18.8	2.0	136.8	192.5	2922	6.6
98-99	3.8	89.0	17.8	28.4	38.7	0.2	20.6	2.8	148.3	201.3	3091	6.5
99-2000	3.8	89.0	17.8	30.6	28.7	0.2	20.6	2.8	148.3	203.5	3260	6.2
00-01	3.8	107.9	21.6	33.0	38.7	0.2	20.6	2.8	167.2	228.6	3396	6.7
01-02	3.8	126.8	25.4	35.7	38.7	0.2	20.6	2.8	186.1	254.0	3531	7.2
02-03	1.5	126.8	25.4	38.3	38.7	0.2	20.6	2.8	186.1	254.3	3667	6.9
03-04	1.5	155.5	31.1	41.2	38.7	0.2	20.6	2.8	214.8	291.6	3803	7.7
04-05	1.5	155.5	31.1	45.6	38.7	0.2	20.6	2.8	214.8	296.0	3939	7.5
05-06	---	155.5	31.1	47.2	38.7	0.2	20.6	2.8	214.8	296.1	4074	7.3
06-07	---	155.5	31.1	50.3	38.7	0.2	20.6	2.8	214.8	299.2	4210	7.1
07-08	---	155.5	31.1	53.5	38.7	0.2	20.6	2.8	214.8	302.4	4346	7.0
08-09	---	155.5	31.1	56.8	38.7	0.2	20.6	2.8	214.8	305.7	4481	6.8
09-10	---	184.2	36.8	60.2	38.7	0.2	20.6	2.8	243.5	343.5	4617	7.4
10-11	---	184.2	36.8	63.7	38.7	0.2	20.6	2.8	243.5	347.0	4753	7.3

TABLE 4.36. Fairbanks-Tanana Valley Area, High Growth Scenario, Case 3, 5% Inflation

Year	Total Cost of Existing Capacity	New Coal Fired Capacity Investment Costs	New Coal Fired Capacity OM&R Costs	New Coal Fired Capacity Coal Costs	New Hydroelectric Costs Investment Costs	New Hydroelectric Costs OM&R Costs	Transmission Systems Investment Costs	Transmission Systems OM&R Costs	Total Investment Costs	Total System Costs, $	Total System Consumption, MMKWH	Average Power Costs, ¢/KWH
78-79	30.6	---	---	---	---	---	0.2	0.2	---	30.9	832	3.7
79-80	33.9	---	---	---	--	---	0.2	0.2	---	34.2	903	3.8
80-81	37.5	---	---	---	---	---	0.2	0.2	---	37.8	981	3.9
81-82	40.7	---	---	---	---	---	0.2	0.2	---	41.0	1059	3.9
82-83	36.7	---	---	6.9	---	---	0.2	0.2	---	43.9	1137	3.9
83-84	35.6	---	---	7.2	---	---	0.2	0.2	---	43.2	1215	3.6
84-85	33.6	25.4	5.0	9.1	---	---	4.4	1.2	29.8	78.8	1294	6.1
85-86	32.4	25.4	5.2	10.6	---	---	4.4	1.3	29.8	79.4	1396	5.7
86-87	30.4	25.4	5.5	12.7	---	---	26.3	2.8	51.7	103.3	1498	6.9
87-88	28.7	25.4	5.8	14.9	---	---	26.3	2.9	51.7	104.1	1600	6.5
88-89	27.9	29.6	7.0	17.2	---	---	26.3	3.1	55.9	111.2	1702	6.5
89-90	29.3	29.6	7.3	18.7	---	---	26.3	3.2	55.9	114.6	1805	6.3
90-91	28.4	41.0	9.8	18.0	---	---	26.3	3.4	67.3	127.1	1927	6.6
91-92	30.1	41.0	10.3	20.2	---	---	26.3	3.6	67.3	131.5	2049	6.4
92-93	26.7	116.0	25.6	28.3	---	---	26.3	3.7	142.3	226.8	2172	10.4
93-94	28.1	155.4	34.7	38.4	---	---	26.3	3.9	181.7	286.9	2294	12.5
94-95	29.6	155.4	36.4	34.8	61.0	0.3	26.3	4.1	242.7	347.9	2417	14.4
95-96	28.8	166.2	40.3	39.5	61.0	0.3	26.3	4.3	253.5	366.7	2585	14.2
96-97	27.7	166.2	42.3	46.4	61.0	0.3	26.3	4.5	253.5	374.7	2754	13.6
97-98	6.2	166.2	44.5	56.7	61.0	0.3	26.3	4.7	253.5	365.9	2922	12.5
98-99	6.4	166.2	46.7	53.1	85.7	0.7	30.5	6.8	282.4	396.1	3091	12.8
99-2000	6.7	166.2	49.1	59.6	85.7	0.7	30.5	7.1	282.4	405.6	3260	12.4
00-01	7.0	224.4	62.4	67.8	85.7	0.8	30.5	7.5	340.6	486.1	3396	14.3
01-02	7.3	282.6	77.0	76.7	85.7	0.8	30.5	7.8	398.8	568.4	3531	16.1
02-03	2.7	282.6	80.9	86.7	85.7	0.8	30.5	8.2	398.8	578.1	3667	15.8
03-04	2.8	380.0	104.2	97.7	85.7	0.9	30.5	8.6	496.2	710.4	3803	18.7
04-05	2.9	380.0	109.5	113.6	85.7	0.9	30.5	9.1	496.2	732.2	3939	18.6
05-06	---	380.0	114.9	123.0	85.7	1.0	30.5	9.5	496.2	744.6	4074	18.3
06-07	---	380.0	120.7	137.6	85.7	1.0	30.5	10.0	496.2	765.5	4210	18.2
07-08	---	380.0	126.7	153.7	85.7	1.1	30.5	10.5	496.2	788.2	4346	18.1
08-09	---	380.0	133.0	171.3	85.7	1.1	30.5	11.0	496.2	812.6	4481	18.1
09-10	---	510.4	165.5	190.5	85.7	1.2	30.5	11.6	626.6	995.4	4617	21.6
10-11	---	510.4	173.7	211.5	85.7	1.3	30.5	12.2	626.4	1025.3	4753	21.6

All entries in the tables are in millions of dollars unless noted. The first column is the total cost of the existing capacity. This includes investment, OM&R, and fuel costs except coal costs after 1982-1983 as noted below. This column includes the cost of the combustion turbine units planned through 1984 in the Anchorage area. The cost of existing capacity is assumed to be the same for all load growth scenarios and system configurations. This assumption is warrented in this case for two reasons. First, an examination of the load resource analyses for the alternative load growth scenarios and cases reveals relatively little variation in the plant utilization factors among the various scenarios and cases. Second, the cost of operating the existing capacity is a relatively small part of the overall system costs in the 1990-2010 time period which is of primary interest in this report.

The next three columns present the costs for the new coal-fired capacity. The investment cost is the total of all the individual plant investments. The OM&R costs are the sum of all the OM&R costs of the individual plants. Entries in these two columns begin the same year as the first coal-fired plant comes on line. The coal costs include the coal costs of the new coal-fired capacity. In addition, the coal costs of the existing capacity are included in this column after 1982-1983. (It is subtracted out of the existing capacity after 1982-1983.)

The next two columns present the costs for any new hydroelectric capacity that is added. These are the Bradley Lake project, the Watana dam and the Devil Canyon dam. As pointed out earlier the Watana and Devil Canyon costs are divided between the Anchorage-Cook Inlet area and the Fairbanks-Tanana area in proportion to their relative energy consumption in 1994.

The transmission system costs are shown in the next two columns. These columns contain the investment and OM&R costs for all the transmission lines required. The total investment cost column represents the sum of the new coal-fired capacity investment costs, the hydroelectric capacity investment costs, and the transmission system investment costs.

The total system cost is the sum of all the costs (not including the new investment cost column). The total system consumption figures are the same as

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the energy demand forecasts presented in Chapter 3. The average cost of power in the total system costs divided by the total system consumption.

The costs of power for the 5% inflation cases are presented in Figures 4.5 through 4.10. While the power costs are different (lower) for the 0% inflation cases. The relationships among the various cases are the same for both inflation rates.

For the Anchorage-Cook Inlet load center construction of the interconnection (Case 2) reduces the cost of power compared to the case without an interconnection (Case 1). In general, construction of the interconnection also reduces the total investment costs.

For the Anchorage-Cook Inlet area inclusion of the Upper Susitna project into the system (Case 3) generally raises the cost of power above Cases 1 and 2 during the first 2 to 4 years after the Watana Dam comes on line but results in lower power costs during the 1996-2010 time period. This reduction in the cost of power is significant in most cases. The addition of the Upper Susitna project appears to slightly increase the total investment costs for the Anchorage-Cook Inlet area although this varies from year to year.

For the Fairbanks-Tanana Valley load center construction of the interconnection (Case 2) again generally reduces the cost of power compared to the case without an interconnection (Case 1). In general, construction of the interconnection also reduces the total investment costs.

For the Fairbanks-Tanana Valley load center inclusion of the Upper Susitna project (Case 3) generally raises the cost of power above Case 2 for about 2 years after the Watana Dam comes on line but, as with the Anchorage-Cook Inlet area, results in lower power costs during the 1996-2010 time period. The addition of the Upper Susitna project appears to slightly lower the total investment cost.

In some of the scenarios it is difficult to determine which case results in the lowest total investment or the lowest cost of power over the entire 1978-2010 time period by looking at the tables or figures. One method of comparing investment or cost over a period of years is to compute the present worth. In equation form:

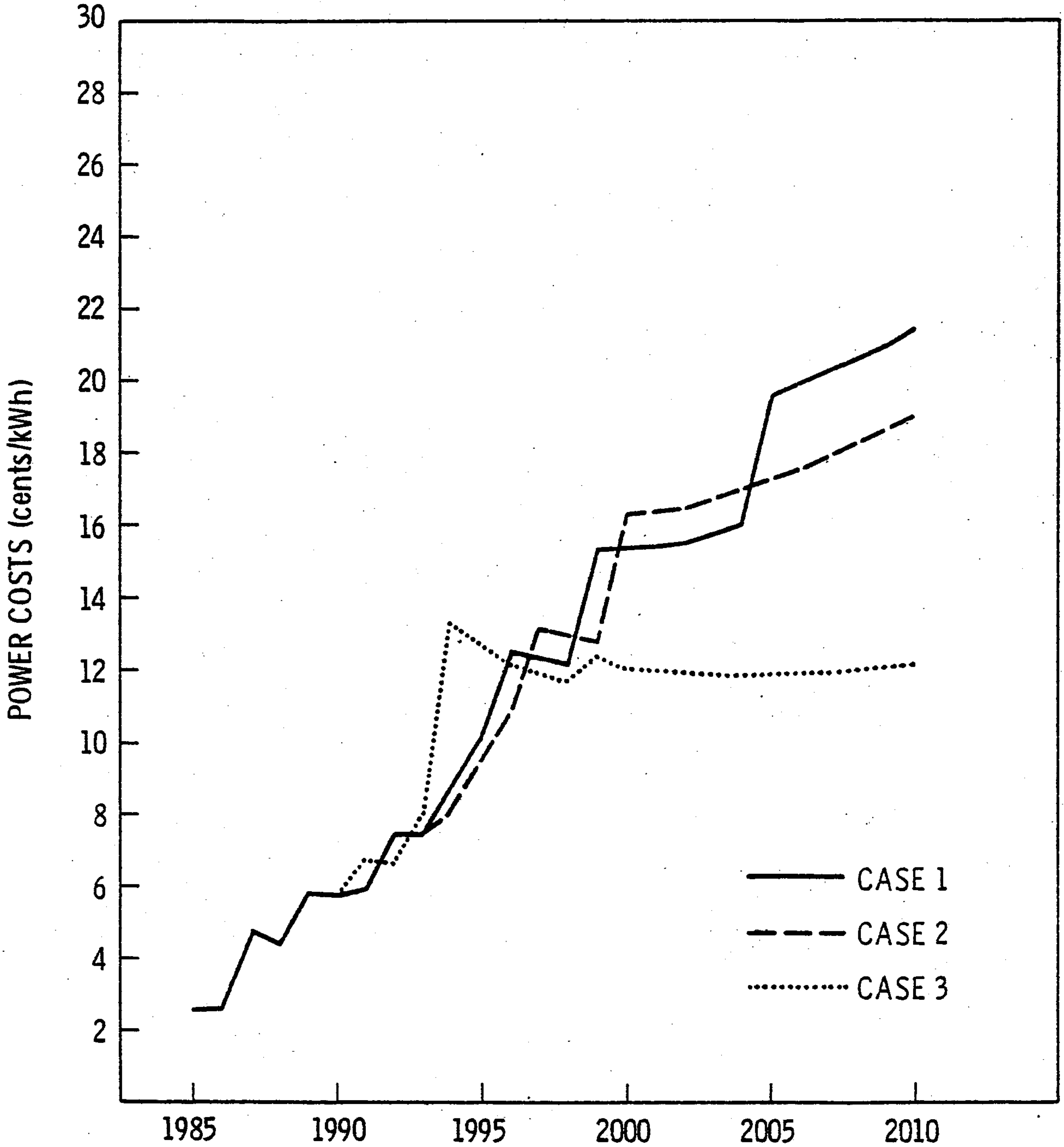

FIGURE 4.5. Power Costs for Anchorage Low Load Growth Scenario

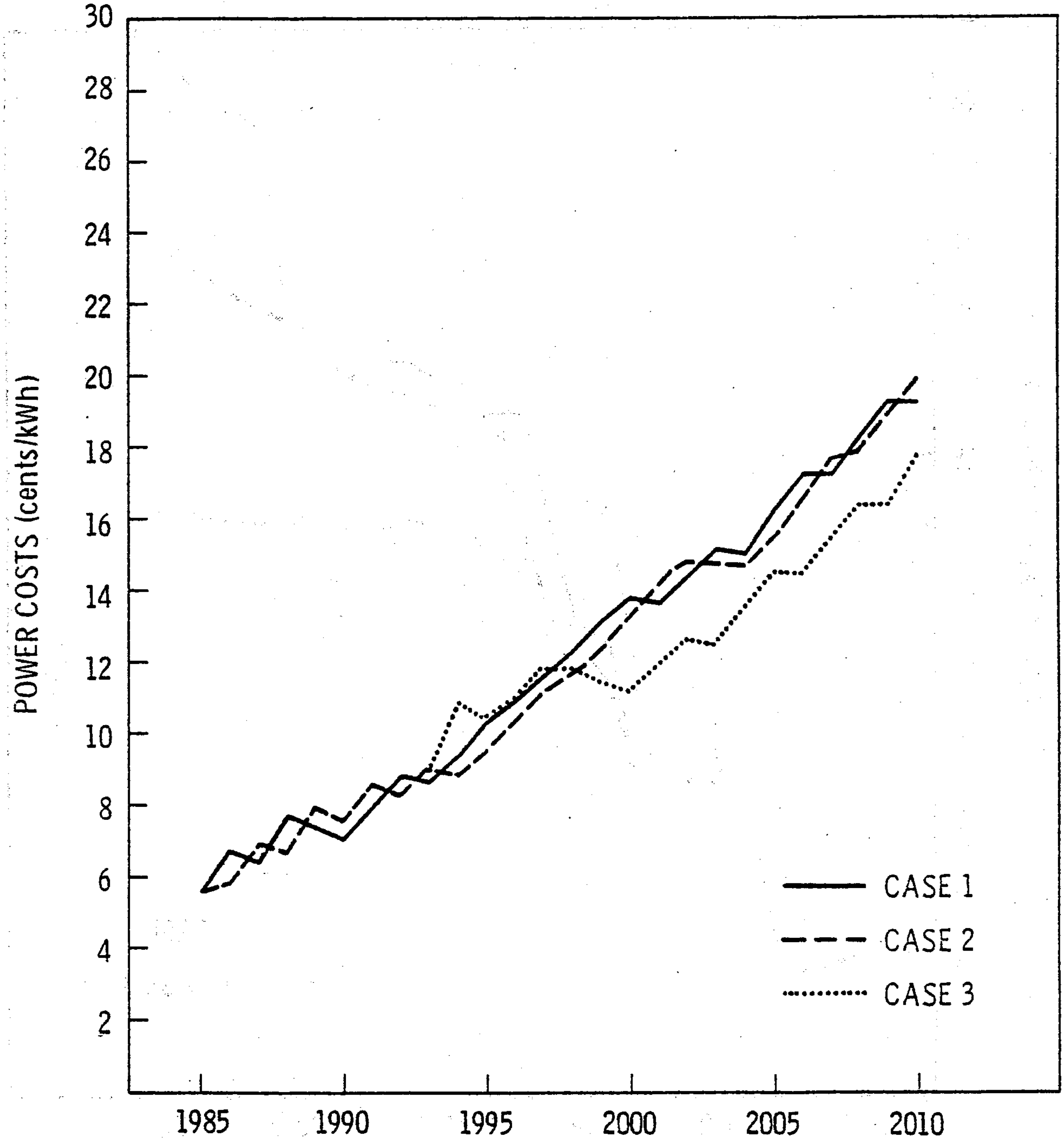

FIGURE 4.7. Power Costs for Anchorage High Load Growth Scenario

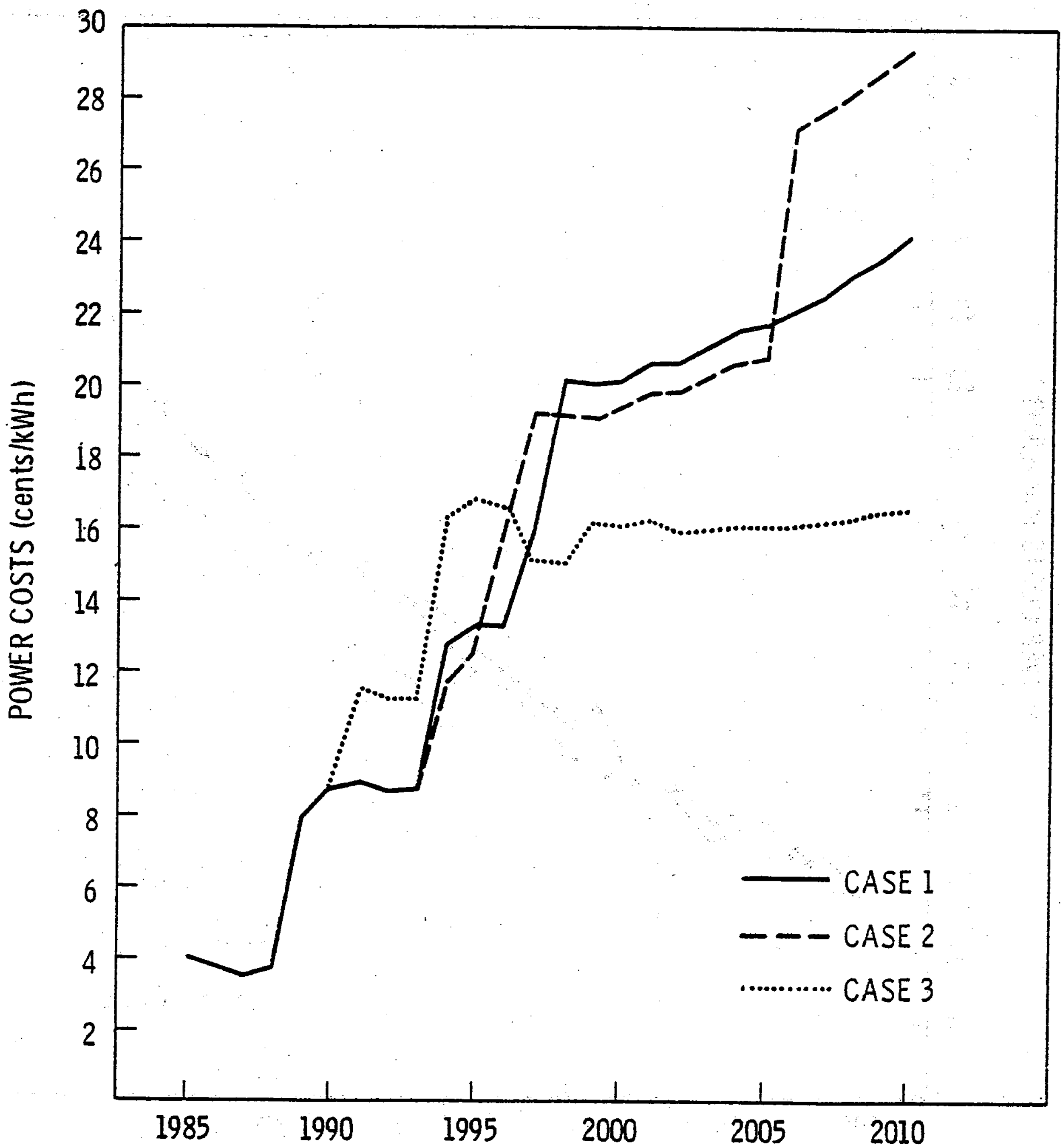

FIGURE 4.8. Power Costs for Fairbanks Low Load Growth Scenario

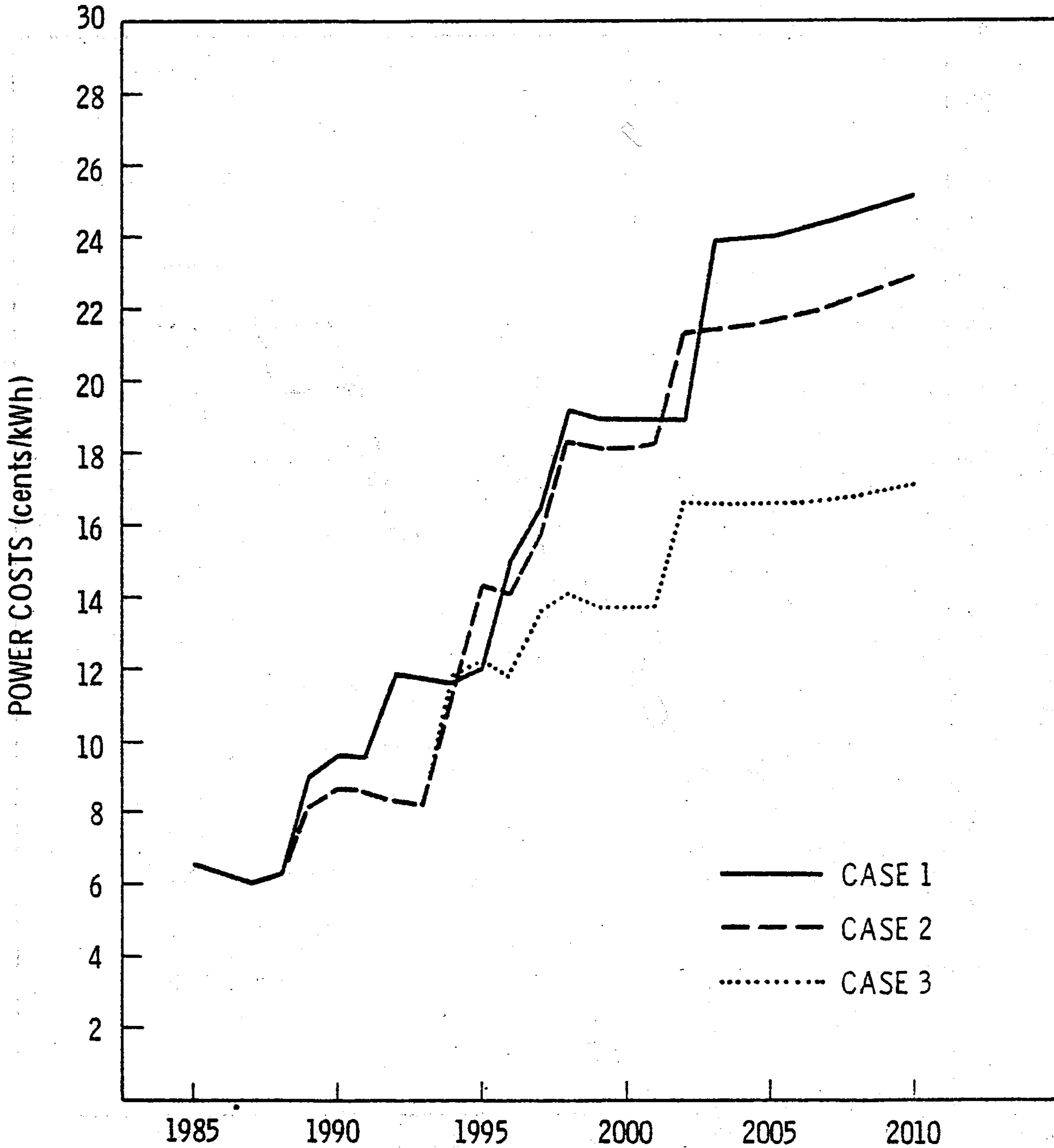

FIGURE 4.9. Power Costs for Fairbanks Medium Load Growth Scenario

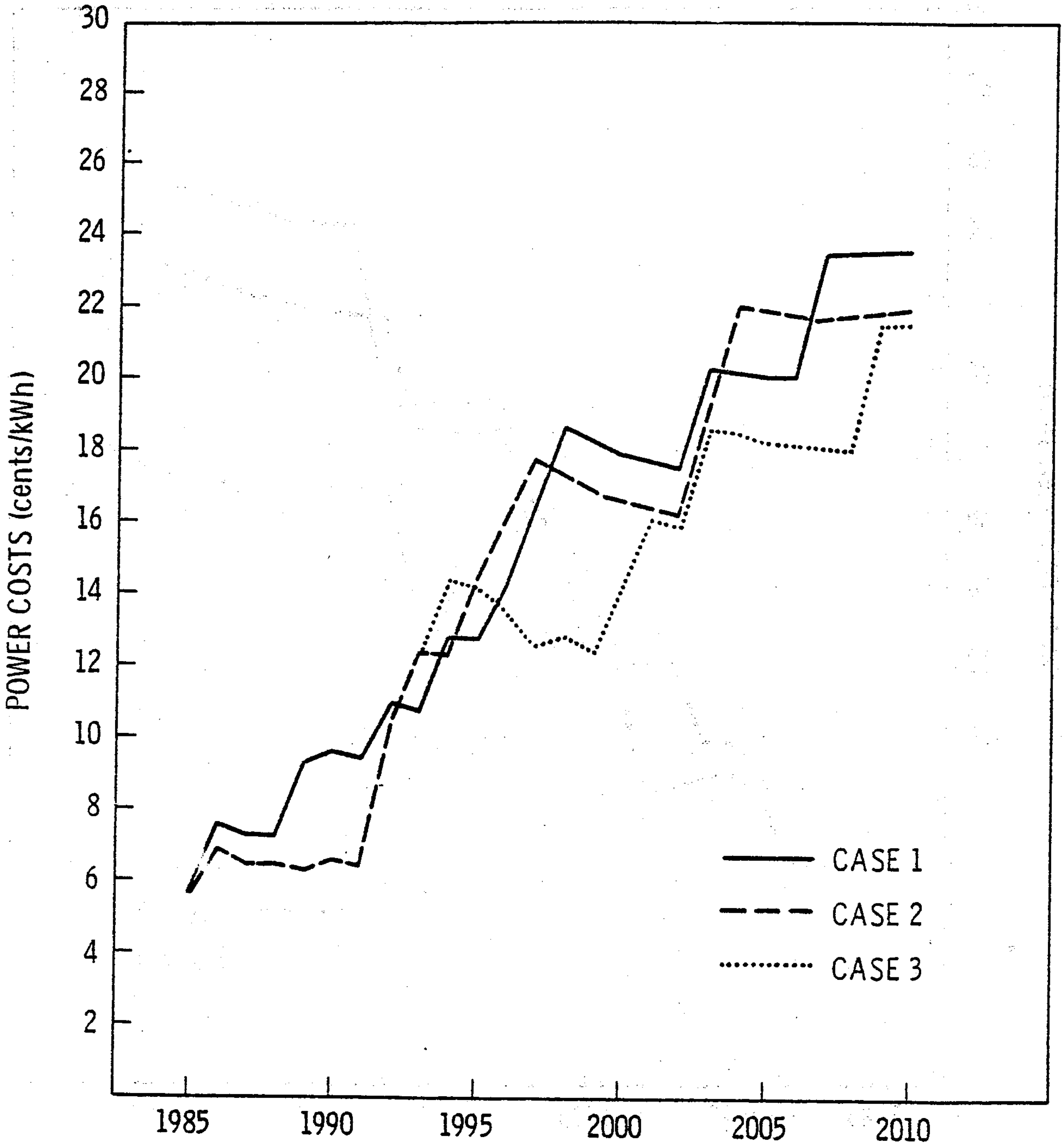

FIGURE 4.10. Power Costs for Fairbanks High Load Growth Scenario

$$PW = \sum_{i=n}^{n} APC_i * \frac{1}{(1+r)^i}$$

where:

PW = Present worth of the cost of power

APC_i = Average power cost in year i

r = Discount rate

n = Total number of years.

Using this formula the total investment cost and the average power cost over a period of years can be more easily compared. A 7% discount rate is used in these analyses.

The results for each of the load growth scenarios for both of the load centers are briefly discussed below.

Anchorage-Cook Inlet - Low Load Growth

The present worth of the total investment and the present worth of average power costs are shown below.

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	2	2329	78
2	4	2251	76
3	6	2504	70

Case 3 results in the lowest cost of power followed by Case 2 and Case 1. Case 2 gives the lowest overall investment costs while Case 3 results in the highest investment costs.

Anchorage-Cook Inlet - Medium Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	8	3920	83
2	10	3930	83
3	12	3920	77

The present worth of the total investment is almost identical for all three cases. The present worth of the cost of power is the same for Cases 1 and 2, while the present worth power cost for Case 3 is lowest.

Anchorage-Cook Inlet - High Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	14	7053	86
2	16	6837	85
3	18	7084	83

Again Case 3 results in the lowest present worth for the cost of power. For this scenario Case 2 results in the lowest present worth investment with Cases 1 and 3 slightly higher.

Fairbanks-Tanana Valley - Low Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	20	666	110
2	22	699	113
3	24	742	104

Case 3 gives the lowest cost of power while Case 1 gives the lowest investment cost. Case 3 results in the highest present worth investment cost.

Fairbanks-Tanana Valley - Medium Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	26	1128	117
2	28	1042	111
3	30	970	99

Again Case 3 results in the lowest present worth cost of power. In this scenario however, Case 3 also gives the lowest present worth total investment costs.

Fairbanks-Tanana Valley - High Load Growth

Case	Reference Table No.	P.W. Total Investment ($)	P.W. Average Power Costs (¢/kWh)
1	32	1642	115
2	34	1587	110
3	36	1527	103

Again Case 3 results in the lowest present worth cost of power and the lowest present worth total investment.

REFERENCES - CHAPTER 4

1. Taylor, G. A., Managerial and Engineering Economy, D. van Nostrand Company, Inc., Princeton, NJ, 1964.

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ALASKA POWER ADM.

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555 BATTERY STREET, ROOM 415
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March 6, 1979

Mr. Robert J. Cross
Administrator
Department of Energy
Alaska Power Administration
P. O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

This will respond to your letter of February 2, 1979, requesting our informal review and comments on your Upper Susitna Project Power Market Draft Report.

Although we were unable to make an in-depth review of the draft report due to time and staffing limitations, we do wish to make the following comments:

Page 9 , second paragraph, third sentence. FERC estimated costs are as of Jul 1, 1978, not October 1978 as stated.

Page 95, second paragraph, last sentence. The San Francisco Regional Office of FERC did include cost adjustments for Alaska conditions in its power value study as it routinely does for all studies in Alaska.

Page 95, last paragraph, last sentence. The investment cost estimates of the Fairbanks plant are \$1475/kW (@ 5.75% financing) and \$1510/kW (@ 6.875% financing). Cost estimates of the Anchorage-Kenai area plant are \$1240/kW (@ 7.94% financing) and \$1220/kW (@ 6.875% financing).

Page 96, <u>Oil and Natural Gas</u>. Our thoughts on this subject were stated in our October 31, 1978, letter to the District Engineer, Alaska District, Corps of Engineers. In that letter we stated that oil-fired combined cycle and regenerative combustion turbine plants were significantly less costly than alternative coal-fired plants for the Upper Susitna River Basin. We are not able to state, however, which alternative is the more probable source. The determining factors would be the Alaska fuel situation and the interpretation of the Fuel Use Act.

While the Fuel Use Act prohibits the use of oil or natural gas as primary fuel for electrical generation, the Department of Energy, Economic Regulatory Administration (ERA), is promulgating regulations which will provide for various exemptions. The regulations are expected to be issued in May. We suggest that you contact ERA on this matter.

Page 105, item 5. The retirement schedule for combustion turbine is stated to be 20 years. Most studies in the Continental United States use 30 years.

Pages 159 and 160, <u>Assessment of Feasibility.</u> A cost estimate of Copper Valley Electric Association's purchase of Upper Susitna power would be useful to this discussion.

Appendix, page 21, 3.2.4, <u>Transmission Losses</u>. The 1.5% for energy loss appears to be low.

We appreciate the opportunity to review and comment on your draft report.

Sincerely,

Eugene Neblett
Regional Engineer

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February 27, 1979

Mr. Robert Cross
Department of Energy
Alaska Power Administration
P. O. Box 50
Juneau, AK 99802

Dear Mr. Cross:

Thank you for the opportunity to comment on your Draft Power Market Analysis. Both Ward Swift and I read it over and came up with only a few minor comments. The primary focus of our review was the consistency between the body of the report and our background analysis presented in Appendix 3.

1. Page 4, 2nd paragraph - The alternative on-line dates of 1990, 1992, and 1994 seem to refer to the interconnection on-line dates for high, medium, and low load growth cases respectively. I believe those dates should be 1986, 1989, and 1991. This would be consistent with the dates given in the last line on page 109.

2. Page 8, table at bottom - It appears that the costs of power listed for Case should be the same numbers listed for the Case 1 of the combined system in the table at the top of page 111.(i.e., the costs of power should be 6.6, 6.9, and 7.5¢/KWh rather than 7.0, 7.0 and 6.6¢/KWh for the high, medium, and low load growths respectively).

3. Page 17, Installed name plate capacities - As pointed out on page 19 the totals differ from those used by us in Appendix 3. Most of the differences are relatively minor. The only major difference seems to be the capacity listed for the Chugach Electric Association. As you indicate these differences are due to recent changes in plans to install new capacity. The difference would have a minor impact on the 1978 through 1985 results and practically no impact on the results after 1985.

4. Pages 52, 59, 80, and Appendix 3 page 8 - Annual Load Factors - On page 42 and Appendix 3, page 8, both reports are generally in agreement that the annual load factor is presently between 46-52%. In Appendix 3 we go on to say that it appears the annual load factor will remain in the 50-52% range during the time horizon of the report. On page 80 it is stated that for planning purposes it is assumed that the annual system load factor will be in the range of 55-60% by the latter part of the century.

If the load factor is defined as:

$$ALF = \frac{GEN}{CAP * 8.760}$$

where:

ALF = Annual load factor (fraction)
GEN = Generation (MW)
CAP = Capacity (GWH)

and use data for the year 2000, low load growth as presented on page 59 we compute an annual load factor of 51%.

i.e.

$$ALF = \frac{6424}{1448 * 8.760} = .51$$

This is lower than the 55-60% mentioned on page 80.

5. Page 95, Healy II plant costs - It would be good to point out that the GVEA estimate is probably in terms of 1985$.

6. Page 101-102, Conclusions - I think your summary of the alternatives available to Alaska is good.

7. Cover Sheet, Appendix 3 - Enclosed are different cover pages for our report presented in Appendix 3 and the Appendices to our report. Please replace the cover pages you presently have.

Thank you for the opportunity to comment on the report.

Sincerely,

Jay Jacobsen

J. Jay Jacobsen
Energy Assessment Unit
Energy Systems Department

JJJ:tw
Enclosures

DEPARTMENT OF THE ARMY
ALASKA DISTRICT, CORPS OF ENGINEERS
P.O. BOX 7002
ANCHORAGE, ALASKA 99510

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Juneau, Alaska
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ALASKA POWER ADM.

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REPLY TO
ATTENTION OF:

NPAEN-PL-R

19 MAR 1979

Mr. Robert J. Cross
Administrator
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

I am writing to advise you of actions taken in response to your comments on the draft Susitna Supplemental Feasibility Report and also to comment on your draft Power Market Analysis.

Your letter of 26 January 1979 transmitting your comments on our draft report arrived during the final report printing. Any delay at that point would have caused us to miss our deadline which I was unwilling to permit except under extreme circumstances. On the verbal assurance from your staff that there was nothing of such gravity that the integrity of the report would be jeopardized, the decision was made to proceed with the printing as scheduled.

I regret that your written comments did not arrive sooner, because the report would have benefited from their incorporation. I am especially sensitive to your contention that insufficient credit was given where APA materials were used. In the future, my staff will be more careful in this regard.

Our review of your excellent draft Power Market Analysis has resulted in only one comment. On page 4 you note that the more costly gravity structure for Devil Canyon is "currently proposed" by the Corps. This is inaccurate in that the gravity structure was presented to insure that estimated costs were sufficient to cover a range of possible foundation conditions at the Devil Canyon site. With appropriate word changes to correct this matter, we find nothing else requiring alteration.

Since the Main Report and Appendix Part 1 are already in Washington, please transmit 20 copies of the final Appendix Part 2 to HQDA (DAEN-CWP-W), Washington D.C. 20314; 2 copies to Division Engineer, North Pacific Corps of Engineers, 210 Custom House, Portland, Oregon 97209, ATTN; NPDPL; and the remaining 138 copies to the Alaska District, ATTN: NPAEN-US.

If you have any questions, Mr. Chuck Bickley at (907) 752-5135 can provide assistance.

Sincerely yours,

VERNELLE T. SMITH
Lt Colonel, Corps of Engineers
Acting District Engineer

DEPARTMENT OF THE ARMY
ALASKA DISTRICT, CORPS OF ENGINEERS
P.O. BOX 7002
ANCHORAGE, ALASKA 9951

REPLY TO
ATTENTION OF:

NPAEN-PL-R

19 MAR 1979

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Administrator
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

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If you have any questions, Mr. Chuck Bickley at (907) 752-5135 can provide assistance.

Sincerely yours,

s/LTC. Vernelle T. Smith

VERNELLE T. SMITH
Lt Colonel, Corps of Engineers
Acting District Engineer

Municipal Light & Power

1200 EAST FIRST AVENUE — ANCHORAGE, ALASKA 99501
TELEPHONE (907) 272-7671

RECEIVED
Juneau, Alaska
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ALASKA POWER ADM.

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740		3-5

March 1, 1979

Robert J. Cross, Administrator
Department of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

Dear Mr. Cross:

This letter responds to your letter of February 2, 1979, which requested informal comments on the draft Power Market Analyses of the Upper Susitna River Project.

Mr. Stahr is out of town and I am writing without knowledge of his personal opinion and comments. The Municipal Light and Power's staff comments appear in the two attached memorandums. Mr. Stahr may forward more comments upon his return.

Thank you for the opportunity to review the draft. If you have any questions or want more comments please do not hesitate to contact us.

Very truly yours,

Max Foster

Max Foster
Revenue Requirements Supervisor

MF:bw

Enclosure

RECEIVED
Juneau, Alaska
26
ALASKA POWER ADM.

STATE OF ALASKA

OFFICE OF THE GOVERNOR

DIVISION OF POLICY DEVELOPMENT AND PLANNING

JAY S. HAMMOND
GOVERNOR

POUCH AD–JUNEAU 99811
PHONE 465-3577

CODE	INIT	DATE
700		3/26
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900	file	

March 23, 1979

Mr. Jim Cheatham
U.S. Department of Energy
Alaska Power Administration
P.O. Box 50
Juneau, AK 99801

Subject: Power Market Analysis - Draft on the Upper Susitna River Project
State I.D. No. 79020902

Dear Mr. Cheatham:

The Alaska State Clearinghouse has completed review on the subject project.

The State Clearinghouse has no comment on this project.

This letter wi.. satisfy the review requirements of the office of Management and ..udget's Circular A-95.

Sincerely,

Jerry L. Madden

Jerry Madden
State-Federal Coordinator

JM/cz

Municipality of Anchorage

MEMORANDUM

DATE: February 15, 1979

TO: Thomas R. Stahr, General Manager

FROM: H. C. Purcell, Assistant Chief Engineer

SUBJECT: DOE APA UPPER SUSITNA RIVER PROJECT POWER MARKET ANALYSES

I have reviewed the January 1979 draft of this report and find nothing controversial in it. There is an error, and there are a few points I will comment on, none of which, however, affect the conclusions reached.

On page 33, Table 5 shows AML&P generation in 1965 as 156.2 GWH. This results in area growth 1964-1965 of 34.4% and 1965-1966 growth of -0.6%. AML&P generation in 1965 was actually 101.5 GWH. This changes the area total in 1965 to 407.0 GWH, 1964-1965 growth to 18.5% and 1965-1966 growth to 12.7%.

On pages 37 and 38, the report states ". . . correlations with weather . . . seemed indeterminable or of little significance." and "Energy use and weather comparisons were inconclusive." This does not agree with my work or with plain common sense. Growth between 1973 and 1977 is used to forecast energy requirements. In three of these four years, 1974, 1976 and 1977, the weather was warmer than normal. Ignoring the influence of weather depresses the growth rate. However, this does not affect the report materially, since it winds up using three different growth rates (low, medium and high) in its market analyses.

It is interesting that the situation hasn't changed in twenty years. Page 98 lists six major hydro projects with much better economics than the Upper Susitna. But they all remain tied up by "major environmental and land use problems.".

On pages 100-102 the report brushes off exotic energy sources as "not realistic planning alternatives . . ." I applaud this, but suspect that much more work will have to be done to convince the vocal proponents of "natural energy."

On page 104 the report specifies "System reserve capacity of 25 percent for non-interconnected load centers and 20 percent for interconnected systems." I checked these numbers against the PROBS runs I made in connection with DOE regulations on transitional facilities. For the Anchorage area at present, PROBS showed a loss of load probability of 0.2 days per year with a peak load of 466.3 MW. On the same basis, 25% reserve capacity would correspond to a peak load of 468.8 MW. 25% reserve capacity would result in LOLP only slightly over 0.2 days per year. With the larger interconnected system ten or twelve years in the future, 20% reserve capacity will probably provide reasonable LOLP.

Page 34 of the Battelle Informal Report schedules a 200 MW steam plant to be on line in 1982, three years hence. Yet Battelle page 22 says "the 5 to 6 year scheduling period [from final site selection to commercial operation] appears reasonable." Either CEA is about to break ground for its coal-fired steam plant or Battelle's dates are inconsistent. Again, however, it doesn't really matter. The relative economics of Susitna vs. coal-fired steam would not be affected.

HCPurcell

H. C. Purcell

cc: Koski

Municipality of Anchorage

MEMORANDUM

DATE: March 1, 1979

TO: Thomas R. Stahr, General Manager, ML&P

FROM: MF Max Foster, Revenue Requirements Supervisor, ML&P

SUBJECT: DOE-APA Upper Susitna River Project Power Market Analyses

This memo comments on the Alaska Power Administration's Upper Susitna River Project Power Market Analysis draft dated January 1979. My impression is that the demand projections for the Anchorage area are conservative. I also think that the installed cost of coal plants is conservative. The Susitna project costs are probably the most reliable cost estimates appearing in the report. I am not happy with the methodology developing the cost of coal. I think coal could actually cost much more than \$1.00 to \$1.50 per million BTU. The inflation rates used in the analysis (0% and 5%) seem low in light of recent trends.

Significantly, despite the conservative assumptions contained within the report, the Susitna project represented the least cost option in every case.

My page by page review of the report elicited the following comments:

Page 37 - The lack of correlation to weather and price disburbs me. It may indicate improper equation specification caused by omitting important variable or failing to insert dummy variables in the regression equations to correct for cyclical abnormalities. Additionally, it seems to me demand projections by rate class would be more statistically significant. Correlation w/ weather is strong on a monthly, cyclical basis but not annually.

Page 77 - The shape of the Anchorage Area load duration curve suggests that a heavy proportion of generation for the area could be large base load increments. This is very favorable for hydroelectric development.

Page 94 - I don't like the treatment of O & M costs. How does this relate to prosent actual Anchorage labor costs and trends? I think the prices should be measured directly, not arbitrarily increased.

Page 150 - The pipline terminal's 37.5 MW generation plant is not interconnected with CVEA. It is not a cogeneration facility. Total energy facility rather than S

Appendix 3, Pages 66 to 75 - Where is the present worth or annualized cost of power computed? This is a major change from the earlier ECOST2 model. I think the present worth analysis is an important part of any power cost analysis.

In general, the analysis seems complete. The conclusions echo those of previous studies. From an economic prospective, the Susitna Project is unquestionably justified. Its time to stop revising feasibility analyses and get on with licensing and construction. Ame.

MF:bw

SECTION H

TRANSMISSION SYSTEM

None of the OMB comments were directed at the engineering aspects of the transmission system. There are therefore no changes made to this section. Costs of transmission have been updated and appear in Section B, Project Description and Cost Estimates. The economic justification for the transmission intertie is discussed in Section G, Marketability Analysis.

SECTION I

ENVIRONMENTAL ASSESSMENT FOR TRANSMISSION SYSTEMS

This section has not been supplemented because no changes were made to the transmission plan.

SOUTHCENTRAL RAILBELT AREA, ALASKA
UPPER SUSITNA RIVER BASIN
SUPPLEMENTAL FEASIBILITY REPORT

APPENDIX - PART I

Prepared by the
Alaska District, Corps of Engineers
Department of the Army

February 1979

SECTION A

HYDROLOGY

The 1976 Interim Feasibility Study was based on 25 years of historical streamflow records. Data through 1977 has been added, extending the period of historical streamflow to 28 years. The annual runoff for the additional 3-year period was 96 percent of the long-term average.

Power capabilities of the hydroelectric projects were reevaluated on the basis of the extended period of record. The results of this analysis appear in Section C, Power Studies and Economics.

SECTION B

PROJECT DESCRIPTION AND COST ESTIMATES

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69-738 O - 80 - 24

LIST OF PLATES

LIST OF FIGURES

SUMMARY OF CHANGES

GENERAL

Field surveys during 1978 revealed that topography for Watana dam shown in the 1976 Interim Feasibility Report was 15 feet higher than actual conditions. Data in this report has base elevations corrected to the 1978 topography. Only plates or text revised for this submittal will reflect the new elevations which are 15 feet lower. The top of dam is now shown at elevation 2,195 feet and normal pool at elevation 2,185 feet.

Quantities and cost estimates have been revised and updated to October 1978 levels. The cost for Watana dam and reservoir (first-added) is $1,765,000,000 versus $1,088,000,000 in the 1976 report. The cost for Devil Canyon dam and reservoir (second-added) is $823,000,000 (concrete gravity) and $665,000,000 (concrete arch) versus $432,000,000 (concrete arch) in the 1976 report.

A construction schedule reanalysis resulted in the extension of the construction period from 10 to 14 years. Initial power-on-line is anticipated in 1994.

WATANA

The main dam cross section was revised to best utilize materials as determined in 1978 field investigations. A grouting gallery was added under a portion of the dam.

The spillway was moved laterally and revised to take better advantage of rocklines and to discharge directly into Tsusena Creek at stream level.

The outlet works were revised to improve hydraulic layout and access into the intake structures.

The diversion tunnel portals were relocated in better rock based upon information obtained from the exploration program.

The power intake selective withdrawal system was revised to be more comparable with those currently in use at other projects.

Rock excavation quantities in the 1976 report were based on a continuous cut slope. Foundation explorations concluded that the rock cuts should be terraced. Data in this report is based upon rock cuts that are compatible with this latest field information.

As a result of new and more accurate topography, the length of the dam has changed; therefore, total embankment quantities have increased.

DEVIL CANYON

A gravity dam was evaluated and is presented with an overdam spillway, and the diversion structure modified to be more compatible with a gravity structure.

Elevator access was provided to the powerplant instead of a road access tunnel.

The power intake selective withdrawal system was revised to be more comparable with those currently in use at other projects.

The general plan showing the locations of the two dams is on Plate B-1.

DAM

The crest length of the dam has changed from 3,450 feet to 3,765 feet, based upon new topography.

As a result of explorations in the river bottom, the foundation excavation has been revised. The river alluvium will be removed to bedrock under the dam. A grout gallery, excavated into rock, has been added to insure adequate treatment of the permanently frozen bedrock.

The 1976 Interim Feasibility Report presented an earthfill dam utilizing local gravel deposits for shell material. Explorations have revealed that there are insufficient gravel deposits within economic haul distances. Since a large amount of sound rock will be generated from spillway excavation and an excellent quarry source is available immediately adjacent to the damsite, the design has been revised to substitute rockfill for gravel in the upstream and downstream shells. Field explorations revealed an abundance of glacial till in the area suitable for use as core material. For this reason, a semipervious zone has been added to use the less expensive glacial material rather than quarried rock. The filters have also been revised to take advantage of adequate quantities of gravelly sand and the readily available rock quarry (see Plate B-3). The gravelly sand from Borrow Pit E, near the mouth of Tsusena Creek, will be used for the fine filter, and rockfill, in the smaller sizes from the quarry, will be used for the coarse filter. Details of the revisions are discussed in Appendix D, Foundations and Materials.

SPILLWAY

The saddle spillway centerline has been moved approximately 800 feet southwest (see Plates B-2 and B-5). The foundation explorations more definitely located top of rock in this area; therefore, the spillway was relocated to insure construction in rock. Crest gate widths were reduced from 59 feet to 55 feet after additional hydraulic calculations. The concrete lined downstream channel section was lengthened from 150 feet to 800 feet to protect against rock plucking caused by high water velocities. The length of channel divergence was revised from 930 feet downstream of the crest to 1,360 feet to improve hydraulics. The spillway channel slope was revised, requiring excavation its full length, so that it emerges at the Tsusena Creek level to reduce environmental damage expected from the 400-foot vertical water drop over natural terrain with the original spillway design. This substantially increases excavation; however, almost all of the material will be used in the dam embankment.

OUTLET WORKS

The intake structures were moved, shifting the high level intake structure away from the dam embankment, realining both intake tunnels to improve connections to the diversion tunnels and changing the access shafts from within the embankment to tunnels through the right abutment rock upstream of the dam (see Plates B-4 and B-6). This improves access, eliminates problems associated with a structural shaft in the embankment, and reduces susceptibility to damage from seismic events. The high level intake invert was raised to restrict operating heads on gates to under 250 feet.

DIVERSION FEATURES AND OPERATION

The two diversion tunnels were lengthened, both upstream and downstream, to locate the portals in better rock as a result of exploration data obtained in 1978. The roller gates for controlling the diversion tunnels have been deleted because stream regulation is not required during diversion. Wheeled bulkhead gates will be used to close one tunnel at a time during periods that closures are required. The diversion tunnel inverts have been raised to reduce cofferdamming and dewatering requirements at tunnel portals. Cofferdam height will remain unchanged since there is outlet control of diversion tunnel flows up to cofferdam design flood. The scheme of tunnel plugging and water control during pool filling has not changed. See Plate B-6 for plug and fill valve details.

PENSTOCKS AND WATERWAYS

The selective withdrawal system, designed to select water at elevations within the reservoir which will allow meeting downstream water quality requirements, has been revised to be more comparable with those currently in use on other projects. This revision requires a larger concrete structure on the upstream face of the dam to accommodate the gates, trashracks, bulkheads, and operating equipment.

DEVIL CANYON

MAIN DAM

A concrete gravity dam (see Plates B-7 and B-8) is substituted in this report for the double curvature thin arch structure of the 1976 Interim Feasibility Report. The thin arch dam's structural integrity is dependent on the adequacy and integrity of the rock abutments. Foundation investigations to date have raised no doubts concerning the abutment rock structures but are inadequate to clearly establish abutment conditions. The necessary horizontal drill holes at the vertical canyon walls were estimated to be so costly that to proceed in the summer of 1978 would have prevented obtaining other required foundation data at Watana damsite with the funds available. A careful reevaluation of the situation indicated a study of the more conservative and technically feasible gravity structure should be made. The concrete gravity structure is economically feasible. The required foundation investigations will be conducted during the preconstruction advance engineering and design period and the less expensive arch structure will be constructed if adequate foundation conditions exists.

The gravity section will be 650 feet high from bottom of excavation, based on indications that the rock is fractured near the surface. The crest remains at elevation 1,455 feet. The concrete crest length will be 1,590 feet and the earthfill portion will have a 720-foot crest length.

No field explorations were conducted at this site under the 1978 program except for three refraction seismograph lines. This information, combined with the borings data collected by the Bureau of Reclamation that was discussed in the initial report, is the basis of the foundation design for the site.

SPILLWAY

The gravity dam will have a central gated overdam spillway discharging into the existing river channel.

DIVERSION STRUCTURE

The diversion tunnel has been lengthened from 1,150 feet to 1,230 feet because of the longer gravity dam base length. Since flow regulation during diversion is not required, the intake gates have been replaced with wheeled bulkhead gates. Regulation of Watana reservoir to release water into Devil Canyon reservoir will be utilized to fill the reservoir to the low level outlets in a matter of hours after diversion tunnel closure. Proper timing will allow maintaining of downstream flows with minimum interruption.

POWERPLANT

The access tunnel to the powerplant has been replaced with a housed vertical entrance shaft and elevator. This shaft will be 20 feet by 30 feet wide by 548 feet deep and will house an elevator capable of lifting the largest items required in the powerhouse. The 185-foot long access tunnel will connect the access shaft to the powerplant. The elevator will provide equipment, personnel, and vehicular access to the powerplant level at elevation 907 feet.

PENSTOCKS AND WATERWAYS

The selective withdrawal system has been revised to be more comparable with those currently in use at other projects. The system has been designed to select water at elevations within the reservoir which will allow meeting downstream water quality requirements. This revision required a larger concrete structure on the upstream face of the dam to accommodate the gates, trashrack, bulkheads, and operating equipment.

CONSTRUCTION SCHEDULE

GENERAL

The construction period has been reanalyzed and extended from 10 to 14 years. The Watana dam and powerplant will take 10 years to construct, an increase of 4 years over the previous schedule. The Devil Canyon project construction will require 8 years rather than the previously reported 5 years. There will be 4 years of overlapping construction to meet power-on-line dates. The schedule is portrayed graphically on Figure B-1.

DIVERSION PLANS

The Watana diversion works construction and stream diversion period has been extended to 3 years, from the previously reported 2 years, because the construction access to the tunnel portals requires extensive rock cuts and additional time. The start of construction of the diversion works for the Devil Canyon dam has been delayed from the 5th to the 7th year of Watana construction because it is dependent on stream regulation by the upstream Watana dam.

MAIN DAMS

Foundation preparation at Watana is delayed to the 4th year as a result of the extended diversion requirements which delay the start of cofferdam construction. Watana embankment construction is scheduled to begin in the 5th year and continue into the 10th, now requiring 6 years instead of the previously reported 3 years, based on construction seasons of 5 months with daily placement rates of 80,000 cubic yards. Water impoundment starts in the 8th year with power-on-line in October of the 10th year. The reservoir filling would continue beyond the power-on-line date and is dependent on inflow and power generation.

Foundation preparation for Devil Canyon dam would start in the 9th year, a delay from the earlier reported 7th year of Watana dam construction. Concrete placement and dam completion would start in the 10th year, requiring 5 years, an increase of 2 years over the earlier schedule. Impoundment would begin in the 13th year with reservoir filling completed by October of the 14th year.

POWER-ON-LINE

The scheduled power-on-line dates are 1994 for Watana and 1998 for Devil Canyon compared to those previously scheduled in 1986 and 1990, respectively. These dates include the result of the changes in scheduled

Congessional construction authorization from July 1980 to October 1984 and the reanalyzed construction schedule. The construction schedule in the 1976 report was based on an authorization for construction, while the Chief of Engineer's Report recommended authorization for Phase I AE&D. This recommendation incorporated 4 years for study prior to seeking construction authorization.

TRANSMISSION LINE

Transmission line construction is scheduled to be completed in 1991, making it available to tie the Anchorage and Fairbanks areas together in advance of Watana power-on-line.

COST ESTIMATES

DETAILED COST ESTIMATES

Tables B-1 and B-2 present the cost estimates for Watana and Devil Canyon.

The estimates are presented in as much detail as possible based on the concept drawings. Unit cost for a major items also includes minor items that will appear as bid items as the design progresses.

Extensive use has been made of bid abstracts from similar projects constructed in the western United States and Canada. All abstracted costs have been escalated to the October 1978 level and an additional factor applied to reflect the higher cost of construction in Alaska.

The Alaska Power Administration (APA) prepared the transmission line cost estimate and have updated the estimate to the October 1978 level. The transmission line cost estimate includes all structures, equipment and transformers for the switchyards and substations for Watana, Devil Canyon, Fairbanks, and Anchorage. The transmission line cost is shown in Table B-1, Watana.

The transformers listed under "Switchyard" in Tables B-1 and B-2 are located in an underground transformer chamber adjacent to the powerhouse. The cables listed connect the transformers to potheads located in the switchyard.

The APA estimate did not include earthwork for the switchyards. This cost is shown under "Switchyard" in Tables B-1 and B-2.

The following lists the estimated January 1975 cost and the October 1978 cost.

	Jan 1975 ($1,000)	Oct 1978 ($1,000)
Watana	$1,088,000	$1,765,000
Devil Canyon		
Thin Arch Dam	432,000	665,000
Concrete Gravity Dam	---	823,000

The project cost used in the economic analysis includes Watana and the concrete gravity dam plan at Devil Canyon. The total cost is $2,588,000,000.

CONTINGENCIES

Watana Dam

The total estimated contingencies for Watana dam are $245,917,000, or 18 percent of the estimated Watana construction cost. The main dam, the largest single feature of Watana project, has a contingency of 15 percent, or $58,178,000. This is a relatively uncomplicated earth and rockfill structure. The 1978 exploration program established foundation conditions and sources of suitable embankment materials in sufficient quantities to construct the dam. The overburden is minimal and foundation rock exposed over much of the site. Radical changes in foundation conditions and borrow sources are not anticipated.

The design approach for the spillway is conservative for a relatively uncomplicated structure. Fifteen percent contingencies, or $20,528,000, were estimated.

The outlet works estimate includes 20 percent contingencies, or $7,016,000. The estimate includes 100 percent lining of the diversion and outlet tunnels. If rock quality is good, some of the lining may be deleted.

The power intake works estimate includes 20 percent contingencies, or $40,772,000.

The powerhouse estimate includes 20 percent contingencies or $13,294,000. The underground powerhouse interior feature requirements are known from comparison with other projects and a careful review of this item.

Turbines, generators, accessory electrical equipment, and miscellaneous powerplant equipment are estimated with 15 percent contingencies. These are known features with quantities and basic costs furnished by experienced powerhouse design personnel.

The tailrace tunnels are assumed to be 100 percent concrete lined. If the rock quality is good, some of these lining requirements may be deleted. Contingencies for this feature are 15 percent.

Twenty percent contingencies were used for transmission facilities. The transmission system estimate was prepared by the Alaska Power Administration with consultation with Bonneville Power Administration.

Contingencies of 20 percent were used for roads and bridges. Assumptions on foundations assume extensive tundra removal and replacement with nonfrost susceptable fill which requires large borrow quantities for replacement.

The construction facility requirements have been reviewed and compared with facilities required for similar structures on similar projects such as Dworshak, Mica and Oroville. The Trans Alaska Oil Pipeline construction camp experience was also reviewed. Diversion tunnels are assumed to be fully lined and rock support assumptions during tunneling have been conservative. Careful analyses of means of diversion and procedures have been made. Contingencies for construction facilities are 20 percent.

Devil Canyon Dam

The total contingencies used for the Devil Canyon gravity dam estimate are $120,551,000, or 20 percent of the Devil Canyon construction costs. Contingencies for all features are the same percentages as for Watana dam for the same reasons, except that contingencies for the main dam, spillway, and auxiliary dam features have been increased to 20 percent.

Twenty percent contingencies were used for the main dam. Assumptions on foundation excavation and preparation for a gravity dam are conservative. Both abutments are exposed rock. The concrete gravity structure is relatively simple with known features. Aggregate locations and quantities available have been established.

The auxiliary earthfill and concrete dam was estimated at 20 percent contingencies. The borrow source is known, partially explored, and quantities determined. This is a simple, uncomplicated structure. Foundation excavation and preparation assumptions are conservative.

The total contingencies for the thin arch dam alternate are $103,756,000 or 21.2 percent of the updated total estimated construction cost of $665,000,000.

In general, the contingencies used for this project are based on intensive study and comparison with cost histories and experience with other projects.

The Office of Management and Budget (OMB) has questioned the contingencies used based on a 36 percent overrun on the Snettisham project. The project cost estimate for the Snettisham project was $41,500,000 for fiscal year 1967, the first year of construction. This estimate included the Long Lake phase of project development, camp facilities, the transmission system, and related features. The Crater Lake phase of project development was added in fiscal year 1973, but design and construction were subsequently deferred.

The estimate submitted to Congress for fiscal year 1976 was $98,540,000, of which $22,132,000 was a price level adjustment, reflecting a 35 percent cost overrun; however, with deferment of the Crater Lake phase, total expenditures through fiscal year 1978 are $81,386,975, an actual cost overrun of $17,754,975, or 22 percent. This cost overrun includes the temporary repair and subsequent permanent relocation of a failed portion of the transmission line. Environmental considerations dictated its original location in an area of unanticipated and unknown extreme winds and ice conditions not previously encountered on any transmission line in North America. The increased cost for the transmission line temporary repairs and permanent relocation was $9,976,000 of the overrun, reducing the remainder of the overrun to $7,778,985 or 10 percent. This information is reflected in the General Accounting Office Report to Congress on Financial Status of Major Civil Acquisitions - December 31, 1975, dated 24 February 1975.

TABLE B-1--DETAILED COST ESTIMATE
WATANA DAM AND RESERVOIR ELEVATION 2185
OCTOBER 1978 PRICE LEVEL
(FIRST-ADDED)

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
01	LANDS AND DAMAGES				
	Reservoir				
	Public domain	AC	2,560	195.00	500
	Private land	AC	99,170	186.00	18,446
	Site and other	AC	1,080	185.00	200
	Access road	AC	780	186.00	145
	Transmission facilities	AC	3,965	965.00	3,826
	Recreation	AC	90	222.00	20
	Mining claims	EA	4	8,000.00	32
	Subtotal				23,169
	Contingencies 20%				4,634
	Government administrative costs				880
	TOTAL LANDS AND DAMAGES				(28,683)
	Construction cost				28,000
	Economic cost				(500)
03	RESERVOIR				
	Mob and Prep	LS	1		204
	Clearing	AC	5,100	800.00	4,080
	Contingencies 20%				857
	TOTAL, RESERVOIR				5,000
04	DAMS				
04.1	MAIN DAM				
	Excavation common				
	Left abutment	CY	1,466,000	5.00	7,330
	Right abutment	CY	1,292,000	5.00	6,460
	River channel	CY	1,547,000	5.00	7,735
	Rock Excavation				
	Left abutment	CY	616,000	18.00	11,088
	Right abutment	CY	428,000	18.00	7,704
	River channel	CY	198,000	18.00	3,564
	Drainage system	LF	135,000	35.00	4,725
	Foundation preparation	SY	114,000	35.00	3,990
	Drilling-grouting	LF	145,000	50.00	7,250
	Care of water and pumping	LS	1		2,000
	Mobilization and Prepatory work	LS	1		19,000
	Instrumentation	LS	1		960
	Clearing grubbing	AC	111	3,500.00	389

TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.1	MAIN DAM (Cont'd)				
	Embankment				
	Semi Pervious				
	From stockpile	CY	1,335,000	3.50	4,673
	From req. excavation	CY	4,743,000	1.00	4,743
	Impervious				
	From req. excavation	CY	3,342,000	1.00	3,342
	From borrow	CY	4,031,000	4.00	16,124
	Rock				
	From abutments				
	Req. excavation	CY	1,123,000	.75	842
	Stockpile	CY	420,000	3.25	1,365
	From Spillway Req. exca.	CY	13,693,000	.75	10,270
	From roads (stockpile)	CY	2,348,000	3.25	7,631
	From grout gallery	CY	36,000	.75	27
	From stockpile misc.	CY	800,000	3.25	2,600
	From borrow	CY	17,876,000	9.00	160,884
	Filters from borrow	CY	7,822,000	8.00	65,576
	Riprap	CY	223,000	22.00	4,906
	Grout gallery				
	Excavation	CY	26,700	75.00	2,003
	Concrete (roof-sides)	CY	19,000	375.00	7,125
	Cement	Cwt	87,000	8.00	696
	Reinforcement	LB	6,793,000	.55	3,736
	Concrete floor steps, landings, etc	CY	2,750	500.00	1,375
	Ventilation				375
	Access tunnel from Powerhouse				
	Excavation rock	CY	10,768	190.00	2,046
	Concrete	CY	6,528	600.00	3,917
	Cement	Cwt	26,109	8.00	209
	Resteel	LB	2,164,000	.55	1,190
	Subtotal				387,850
	Contingencies 15%				58,178
	TOTAL, MAIN DAM				446,000
04.2	SPILLWAY				
	Clearing & stripping	AC	158	2,500.00	395
	Foundation prep.	SY	33,700	50.00	1,685
	Excavation				
	Common	CY	10,568,000	2.00	21,136

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.2	SPILLWAY				
	Rock	CY	10,533,000	8.00	84,264
	Concrete				
	Mass	CY	16,900	100.00	1,690
	Structural	CY	9,750	500.00	4,875
	Lining	CY	15,600	450.00	7,020
	Cement	Cwt	182,500	8.00	1,460
	Reinforcement	Lb	1,123,000	.55	618
	Drill & grout for anchors	LF	17,200	20.00	344
	Tainter gates 1200000# gate hoists	EA	3	1,250,000.00	3,750
	Stoplogs (400000#)	LS	1		600
	Spillway bridges (55'L by 26'W) (3EA)	LS	1		500
	Drainage	LS	1		2,000
	Mob-Prep	LS	1		6,517
	Subtotal				136,854
	Contingencies 15%				20,528
	TOTAL, SPILLWAY				157,000
04.3	OUTLET WORKS				
	Excavation				
	Common	CY	35,700	15.00	536
	Rock	CY	115,400	50.00	5,770
	Tunnel 25 Ø				
	45° slope	CY	29,400	190.00	5,586
	Vertical	CY	1,880	140.00	263
	Horizontal	CY	4,250	125.00	531
	Concrete				
	Lining				
	45° slope	CY	6,000	600.00	3,600
	Rebar	LB	322,000	.55	177
	Vertical	CY	350	500.00	175
	Rebar	LB	14,100	.55	8
	Horizontal	CY	820	300.00	246
	Rebar	LB	33,100	.55	18
	Structural	CY	9,600	600.00	5,760
	Rebar	LB	900,000	.55	495
	Rockbolts				
	In vertical face				
	Drill & grout bolts (92,200 LB)	LF	21,400	20.00	428

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TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.3	OUTLET WORKS				
	45° Slope	LF	4,800	20.00	96
	Horizontal	LF	4,400	20.00	88
	Tainter gates (4)	LB	496,000	3.00	1,488
	Slide gates (4)	LB	2,200,000	3.00	6,600
	Trashracks (2)	LB	64,800	2.00	130
	Cement	Cwt	110,700	8.00	886
	Elevators (50-ton)	LS	2	250,000.00	500
	Mob and Prep work	LS	1		1,700
	Subtotal				35,081
	Contingencies 20%				7,016
	TOTAL, OUTLET WORKS				42,000
04.4	POWER INTAKE WORKS				
	Mob and Prep Work	LS	1		9,700
	Intake structure				
	Excavation (rock)	CY	222,000	30.00	6,660
	Foundation preparation	SY	3,700	50.00	185
	Mass concrete	CY	39,500	100.00	3,950
	Structural concrete	CY	102,900	500.00	51,450
	Cement	Cwt	555,600	8.00	4,445
	Resteel	LB	9,372,000	.55	5,155
	Emb. metal	LB	35,000	4.50	158
	Trash rack	LB	938,000	2.00	1,876
	Stairs	LS	1		100
	Elevator	LS	1		300
	Bulkhead gates	LB	3,860,000	2.00	7,720
	Stoplogs	LB	1,594,000	2.00	3,188
	Electrical and mechanical work	LS	1		2,250
	Truck crane	LS	1		300
	Bridge	LS	1		3,500
	Trash boom	LS	1		425
	Tunnel excavation	CY	95,100	175.00	16,643
	Concrete	CY	35,200	350.00	12,320
	Cement	Cwt	140,800	8.00	1,126
	Resteel	LB	483,000	.55	266
	Steel liner	LB	24,350,000	2.70	65,745
	Bonnetted gates	EA	3	1,800,000.00	5,400
	Log Boom	LS	1		500

TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.4	POWER INTAKE WORKS (Cont'd)				
	Electrical and mechanical work	LS	1		500
	Subtotal				203,862
	Contingencies 20%				40,772
	TOTAL, POWER INTAKE WORKS				245,000
	TOTAL DAMS				890,000
07	POWERPLANT				
07.1	POWERHOUSE				
	Mob and prep work	LS	1		3,000
	Rock excavation, tunnels, P.H. chamber, transformer chamber, etc	CY	202,000	75.00	15,150
	Concrete	CY	57,600	500.00	28,800
	Cement	Cwt	261,000	8.00	2,088
	Reinforcement	LB	6,912,000	.55	3,802
	Architectural features	LS			1,500
	Elevators	LS	1		600
	Mechancial and electrical work	LS	1		5,000
	Structural steel	LB	1,250,000	2.00	2,500
	Misc. Metalwork	LB	150,000	4.50	675
	Draft tube bulkhead gates - guides	LS	1		750
	Rock bolts	LF	8,445	30.00	253
	Steel sets	LB	102,000	2.00	204
	600 ton bridge crane	LS	1		1,000
	30 ton bridge crane	LS	1		250
	Airshaft (transformer chamber) 3' DIA 880'	LS	1		900
	Subtotal				66,472
	Contingencies 20%				13,294
	TOTAL, POWERHOUSE				80,000

TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
07	POWERPLANT (Cont'd)				
07.2	TURBINES AND GENERATORS				
	Turbines	LS	1		18,900
	Governors	LS	1		814
	Generators	LS	1		21,600
	Subtotal				41,314
	Contingencies 15%				6,197
	TOTAL, TURBINES AND GENERATORS				48,000
07.3	ACCESSORY ELECTRICAL EQUIPMENT				
	Accessory Electrical Equipment	LS	1		3,532
	Contingencies 15%				530
	TOTAL, ACCESSORY ELECTRICAL EQUIPMENT				4,000
07.4	MISCELLANEOUS POWERPLANT EQUIPMENT				
	Miscellaneous Powerplant Equipment	LS	1		1,716
	Contingencies 15%				257
	TOTAL, MISCELLANEOUS POWERPLANT EQUIPMENT				2,000
07.5	TAILRACE				
	Mob and Prep Work	LS	1		2,400
	Tunnel excavation	CY	233,000	85.00	19,805
	Concrete lining	CY	28,200	250.00	7,050
	Cement	Cwt	112,800	8.00	902
	Reinforcement	LB	5,202,000	.55	2,861
	Rock bolts	LF	51,000	20.00	1,020
	Steel sets	LB	1,115,000	1.50	1,673
	Outlet Portal				
	Excavation rock	CY	2,500	75.00	188
	Concrete	CY	450	500.00	225
	Cement	Cwt	1,800	8.00	14
	Reinforcement	LB	207,000	.55	114
	Stoplogs-steel	LB	737,100	1.50	1,106
	Tailrace channel				
	Excavation rock	CY	176,300	50.00	8,815
	Concrete	CY	4,425	300.00	1,328
	Cement	Cwt	17,700	8.00	142
	Reinforcement	LB	177,000	.55	97
	Anchor bars #9	LF	5,700	15.00	86

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
07	POWERPLANT (Cont'd)				
07.5	TAILRACE (Cont'd)				
	Cofferdam	LS	1		2,000
	Subtotal				49,826
	Contingencies 20%				9,965
	TOTAL, TAILRACE				60,000
07.6	SWITCHYARD				
	Transformers	LS	1		5,434
	Insulated cables	LS	1		2,832
	Earthwork	LS	1		1,300
	Subtotal				9,566
	Contingencies 20%				1,913
	TOTAL, SWITCHYARD				11,000
07.7	TRANSMISSION FACILITIES				
	Transmission facilities	LS	1		255,000
	Contingencies 20%				51,000
	TOTAL, TRANSMISSION FACILITIES				306,000
	TOTAL, POWERPLANT				511,000
08	ROADS AND BRIDGES				
	Permanent Access Road - 27 miles (Highway No. 3 to Devil Canyon)				
	Clearing and grubbing	AC	135	1,500.00	203
	Excavation				
	Rock	CY	200,000	20.00	4,000
	Common	CY	60,000	3.00	180
	Embankment	CY	890,000	3.50	3,115
	Riprap	CY	2,700	30.00	81
	Road surfacing (crushed)	CY	216,000	15.00	3,240
	Bridges	LS	1		15,000
	Culverts and guardrail	LS	1		1,250
	Permanent Access Road - 37 miles (Devil Canyon to Watana)				
	Clearing	AC	195	1,500.00	293
	Excavation				
	Rock	CY	300,000	20.00	6,000
	Common	CY	90,000	3.00	270

TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
08	ROADS AND BRIDGES (Cont'd)				
	Embankment	CY	1,244,000	3.50	4,354
	Riprap	CY	3,800	30.00	114
	Road surfacing (crushed)	CY	304,000	15.00	4,560
	Bridges	LS	1		5,000
	Culverts and guardrail	LS	1		2,250
	Permanent on-site roads				
	Power plant access tunnel	LS	1		15,459
	Power plant access road	LS	1		1,971
	Dam crest road	LS	1		125
	Mob and prep	LS	1		3,500
	Spillway access road	LS	1		560
	Switchyard access road	LS	1		300
	Road to operating facility	LS	1		300
	Power intake structure access road	LS	1		375
	Airstrip access road	LS	1		650
	Subtotal				73,150
	Contingencies 20%				14,630
	TOTAL, ROAD AND BRIDGES				88,000
14	RECREATION FACILITIES				
	Site D				
	Camp units (tent camp)	EA	10	3,000.00	30
	Vault toilets	EA	2	3,000.00	6
	Subtotal				36
	Contingencies 20%				7
	Total Site D				43
	Site E				
	Trail system	MI	12	15,000.00	180
	Contingencies 20%				36
	Total Site E				216
	TOTAL, RECREATION FACILITIES				1,000
19	BUILDINGS, GROUND, AND UTILITIES				
	Living quarters and O&M facilities	LS	1		2,500

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
19	BUILDINGS, GROUNDS, AND UTILITIES (Cont'd)				
	Visitor facilities				
	Visitor building	LS	1		100
	Parking area	SF	12,000	3.00	36
	Boat ramp	LS	1		200
	Vault toilets	EA	2	3,000.00	6
	Runway facility	LS	1		250
	Subtotal				3,192
	Contingencies 20%				638
	TOTAL, BUILDINGS, GROUNDS, AND UTILITIES				4,000
20	PERMANENT OPERATING EQUIPMENT				
	Operating Equipment and Facilities	LS	1		2,500
	Contingencies 20%				500
	TOTAL, PERMANENT OPERATING EQUIPMENT				3,000
50	CONSTRUCTION FACILITIES				
	Diversion tunnels				
	D.S. Bulkhead	LS	1		75
	Excavation				
	Common	CY	37,700	15.00	566
	Rock	CY	173,600	50.00	8,680
	Tunnel 33 H.S.	CY	336,200	90.00	30,258
	Concrete				
	Lining	CY	58,350	275.00	16,046
	Reinforcement	LB	3,155,000	.55	1,735
	Structural	CY	9,150	500.00	4,575
	Reinforcement	LB	1,045,000	.55	575
	Rock bolts				
	Vertical face	LF	24,900	20.00	498
	Tunnel roof	LF	40,000	20.00	800
	Bulkheads	LS	1		900
	Cement	Cwt	386,700	8.00	3,094
	Plug tunnels	LS	1		1,352
	Care of water	LS	1		1,250
	Mob and prep work	LS	1		3,500
	Subtotal				73,924
	Contingencies 20%				14,785
	TOTAL, CONSTRUCTION FACILITIES				89,000

TABLE B-1--DETAILED COST ESTIMATE--Continued

WATANA DAM AND RESERVOIR

Cost Account Number	Description or Item	Unit	Quant	Unit Cost ($)	Total Cost ($1,000)
TOTAL CONSTRUCTION COST					1,619,000
ENGINEERING AND DESIGN 4%					65,000
SUPERVISION AND ADMINISTRATION 5%					81,000
TOTAL PROJECT COST WATANA DAM AND RESERVOIR ELEVATION 2185 (First-Added)					1,765,000

TABLE B-2--DETAILED COST ESTIMATE

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

OCTOBER 1978 PRICE LEVEL
(SECOND-ADDED)

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
01	LAND AND DAMAGES				
	Reservoir				
	Public Domain				(0)
	State & Private Land				14,160
	Mining Claim				8
	Subtotal				14,168
	Contingencies 20%				2,834
	Government Administrative Cost				558
	TOTAL, LAND AND DAMAGES				18,000
	Construction Cost				18,000
	Economic Cost				18,000
03	RESERVOIR				
	Mob-Prep Work				77
	Clearing	AC	1,920	800.00	1,536
	Subtotal				1,613
	Contingencies 20%				323
	TOTAL, RESERVOIR				2,000
04	DAMS				
04.1	MAIN DAM				
	Excavation Rock	CY	476,400	20.00	9,528
	Excavation common	CY	89,400	5.00	447
	Exterior mass concrete	CY	256,100	80.00	20,488
	Interior mass concrete	CY	2,138,000	75.00	160,350
	Structural concrete (dam structure)	CY	8,883	475.00	4,219
	Concrete (spillway)	CY	18,600	450.00	8,370
	Post cooling	LS	1		8,000
	Instrumentation	LS	1		900
	Pier & spillway rebar	Lb	3,255,000	.55	1,790
	Taintor gates	EA	2	1,500,000.00	3,000
	Bridges	LS	1		700
	Prevention or water pollution	LS	1		1,000

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.1	MAIN DAM (Cont'd)				
	Scaling canyon walls	LS	1		1,000
	Stoplog, complete	LS	1		1,000
	Gantry crane	LS	1		750
	Elevator	LS	1		600
	Stairways	LS	1		686
	Rock bolts	LS	1		1,500
	Electrical and mechancial work	LS	1		1,500
	Miscellaneous metalwork	Lb.	2,500	4.50	11
	Foundation treatment	LF	400,000	5.56	2,224
	Drilling and grouting	LF	70,000	50.00	3,500
	Drilling drainage holes	LF	52,500	35.00	1,838
	Concrete for parapet and overhang	CY	3,352	500.00	1,676
	Resteel	Lb	4,296,115	.55	2,363
	Slide gates, frames, guides and operators	Sets	4	1,350,000.00	5,400
	Chain link fence	LF	1,845	20.00	37
	Resteel for sluce conduits	Lb	891,560	.55	490
	Exploratory tunnels (excavation)	CY	3,500	400.00	1,400
	Rock bolts	LF	50,000	20.00	1,000
	Contraction joint & cooling system grouting	LS	1		2,750
	Cement	Cwt	7,441,000	8.00	59,528
	Mob and Prep	LS	1		15,400
	Subtotal				323,445
	Contingencies 20%				64,689
	TOTAL, MAIN DAM				388,000
04.4	POWER INTAKE WORKS				
	Mob and Prep	LS	1		4,496
	Excavation				
	Open cut	CY	7,200	75.00	540
	Tunnels	CY	34,400	175.00	6,020
	Concrete				
	Mass	CY	7,300	100.00	730
	Structural and backfill	CY	10,430	500.00	5,215
	Cement	Cwt	74,000	8.00	592
	Reinforcing steel	Lb	2,478,000	.55	1,363
	Penstocks	Lb	9,582,270	2.25	21,560

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
04	DAMS				
04.4	POWER INTAKE WORKS (Cont'd)				
	Bonnetted gates and controls	EA	4	1,800,000.00	7,200
	Stoplogs, (936000#)	LS	1		1,875
	Trashracks (421,000# each)	EA	2	1.50	1,263
	Intake selector gate tower				
	Excavation rock	CY	7,400	50.00	370
	Concrete structural	CY	47,100	500.00	23,550
	Cement	Cwt	188,400	8.00	1,507
	Reinforcement	Lb	7,065,000	.55	3,886
	Selector gates (1,500,000#)	EA	4	3,375,000.00	13,500
	Subtotal				94,417
	Contingencies 20%				18,883
	TOTAL, POWER INTAKE WORKS				113,000
04.5	AUXILIARY DAM (EARTH FILL AND CONCRETE)				
	Mob and Prep	LS	1		312
	Excavation				
	Dam foundation	CY	100,000	6.00	600
	Foundation prepareation	SY	2,100	50.00	105
	Dam embankment	CY	835,000	6.00	5,010
	Drilling and grouting	LF	8,800	60.00	528
	Subtotal				6,555
	Contingencies 20%				1,311
	TOTAL, AUXILIARY DAM				8,000
	TOTAL, DAMS				509,000
07	POWERPLANT				
07.1	POWERHOUSE				
	Mob and Prep work	LS	1		2,000
	Excavation, rock	CY	208,400	75.00	15,630
	Concrete	CY	22,000	500.00	11,000
	Cement	Cwt	88,000	8.00	704
	Reinforcing steel	Lbs	5,400,000	.55	2,970
	Architectural features	LS	1		1,500

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
07	POWERPLANT				
07.1	POWERHOUSE (Cont'd)				
	Elevator	LS	1		200
	Mechancial and electrical work	LS	1		4,812
	Structural steel	Lb	1,200,000	2.25	
	Miscellaneous metalwork	Lb	150,000	4.50	675
	Subtotal				42,191
	Contingencies 20%				8,438
	TOTAL, POWERHOUSE				51,000
07.2	TURBINES AND GENERATORS				
	Turbines	LS	1		20,250
	Governors	LS	1		1,053
	Generators	LS	1		22,950
	Subtotal				44,253
	Contingencies 15%				6,638
	TOTAL, TURBINES AND GENERATORS				51,000
07.3	ACCESSORY ELECTRICAL EQUIPMENT				
	Accessory Electrical Equipment	LS	1		2,512
	Contingencies 15%				377
	TOTAL, ACCESSORY ELECTRICAL EQUIPMENT				3,000
07.4	MISCELLANEOUS POWERPLANT EQUIPMENT				
	Miscellaneous Powerplant Equipment	LS	1		1,798
	Contingencies 15%				270
	TOTAL, MISCELLANEOUS POWERPLANT EQUIPMENT				2,000
07.5	TAILRACE				
	Mob and Prep	LS	1		766
	Excavation tunnel	CY	74,500	85.00	6,333
	Concrete	CY	17,500	300.00	5,250
	Cement	Cwt	70,200	8.00	562
	Resteel	Lb	3,029,000	.55	1,666
	Draft tube bulkhead gate and guides	LS	1		700
	Tailrace tunnel stoplogs (370,000#)	LS	1		800
	Subtotal				16,077
	Contingencies 20%				3,215
	TOTAL, TAILRACE				19,000

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
07	POWERPLANT				
07.6	SWITCHYARD				
	Transformers	LS	1		6,545
	Insulated cables	LS	1		3,312
	Excavation				
	Rock	CY	36,000	20.00	720
	Common	CY	75,000	5.00	375
	Embankment	CY	470,000	4.00	1,880
	Subtotal				12,832
	Contingencies 20%				2,566
	TOTAL, SWITCHYARD				15,000
	TOTAL, POWERPLANT				141,000
08	ROADS AND BRIDGES				
	Mob and Prep	LS	1		400
	On-site road				
	Clearing and earthwork	Mile	2.3	300,000.00	690
	Paving	Mile	2.3	110,000.00	253
	Culverts	LF	850	100.00	85
	Powerhouse and tailrace access	LS			6,000
	Road to operating facility	Mile	2	125,000.00	250
	Portals	EA	2	500,000.00	1,000
	Subtotal				8,678
	Contingencies 20%				1,736
	TOTAL, ROADS AND BRIDGES				10,000
14	RECREATION FACILITIES				
	Site A				
	(Boat access only)				
	Boat dock	EA	1	40,000.00	40
	Camping units	EA	10	3,000.00	30
	Two-vault toilets	EA	2	3,000.00	6
	Subtotal				76
	Contingencies 20%				15
	Total Site A				91
	Site B				
	Access road	Mile	0.5	150,000.00	75
	Overnight camps	EA	50	4,000.00	200

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
14	RECREATION FACILITIES				
	Site B (Cont'd)				
	Comfort stations	EA	2	60,000.00	120
	Power	LS	1		40
	Sewage	LS	1		75
	Subtotal				510
	Contingencies 20%				102
	Total Site B				612
	Site C				
	Trailhead picnic area access road	Mile	.2	150,000.00	30
	Picnic units w/parking	EA	12	3,000.00	36
	Trail system	Mile	30	15,000.00	450
	Two-vault toilets	EA	2	3,000.00	6
	Subtotal				522
	Contingencies 20%				104
	Total Site C				626
	TOTAL, RECREATION FACILITIES				1,000
19	BUILDINGS, GROUND, AND UTILITIES				
	Living quarters and O&M facilities	LS	1		2,500
	Visitor facilities				
	Visitor buildings	LS	1		300
	Parking Area	LS	1		70
	Boat ramp	LS			220
	Vault toilets	EA	2	3,000.00	6
	Subtotal				3,496
	Contingencies 20%				699
	TOTAL, BUILDINGS, GROUNDS, AND UTILITIES				4,000
20	PERMANENT OPERATING EQUIPMENT				
	Operating Equipment and facilities	LS	1		2,200
	Contingencies 20%				440
	TOTAL, PERMANENT OPERATING EQUIPMENT				3,000

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
50	CONSTRUCTION FACILITIES				
	Mob and Prep work	LS	1		1,885
	Coffer dams				
	Sheet pile	Ton	1,024	1,500.00	1,536
	Earth fill	CY	38,000	15.00	570
	Pumping	LS	1		3,500
	Remove Coffer dams	LS	1		600
	Diversion workds				
	Tunnel excavation	CY	35,700	100.00	3,570
	Concrete	CY	9,200	300.00	2,760
	Cement	Cwt	36,800	8.00	294
	Reinforcement	Lb	1,564,000	.55	860
	Steel sets	Lb	157,000	3.00	471
	Rock bolts	EA	1,150	300.00	345
	Tunnel Plug				
	Concrete	CY	1,100	600.00	660
	Cement	Cwt	4,400	8.00	35
	Reinforcement	Lb	187,000	.55	103
	Diversion Intake Structure				
	Excavation rock	CY	104,000	30.00	3,120
	Concrete structural	CY	3,800	500.00	1,900
	Cement	Cwt	15,200	8.00	122
	Reinforcement	Lb	380,000	.55	209
	Bulkhead	Lb	960,000	1.50	1,440
	Approach Channel Lining				
	Concrete	CY	1,600	300.00	480
	Cement	Cwt	6,400	8.00	51
	Reinforcement	Lb	80,000	.55	44
	Diversion Outlet Structure				
	Excavation Rock	CY	274,000	50.00	13,700
	Concrete	CY	1,100	500.00	550
	Cement	Cwt	4,400	8.00	35
	Reinforcement	Lb	110,000	.55	61
	Stoplogs	Lb	100,000	1.50	150
	Outlet Channel Lining				
	Concrete	CY	900	500.00	450
	Cement	Cwt	3,600	8.00	29
	Reinforcement	Lb	45,000	.55	25
	Subtotal				39,555
	Contingencies 20%				7,911
	TOTAL, CONSTRUCTION FACILITIES				47,000

TABLE B-2--DETAILED COST ESTIMATE--Continued

DEVIL CANYON DAM AND RESERVOIR, ELEVATION 1450, GRAVITY DAM

Cost Account Number	Description or Item	Unit	Quantity	Unit Cost ($)	Total Cost ($1,000)
	TOTAL, CONSTRUCTION COST				735,000
30	ENGINEERING AND DESIGN 7%				51,000
31	SUPERVISION AND ADMINISTRATION 5%				37,000
	TOTAL PROJECT COST DEVIL CANYON DAM AND RESERVOIR ELEVATION 1450, GRAVITY DAM (SECOND-ADDED)				823,000

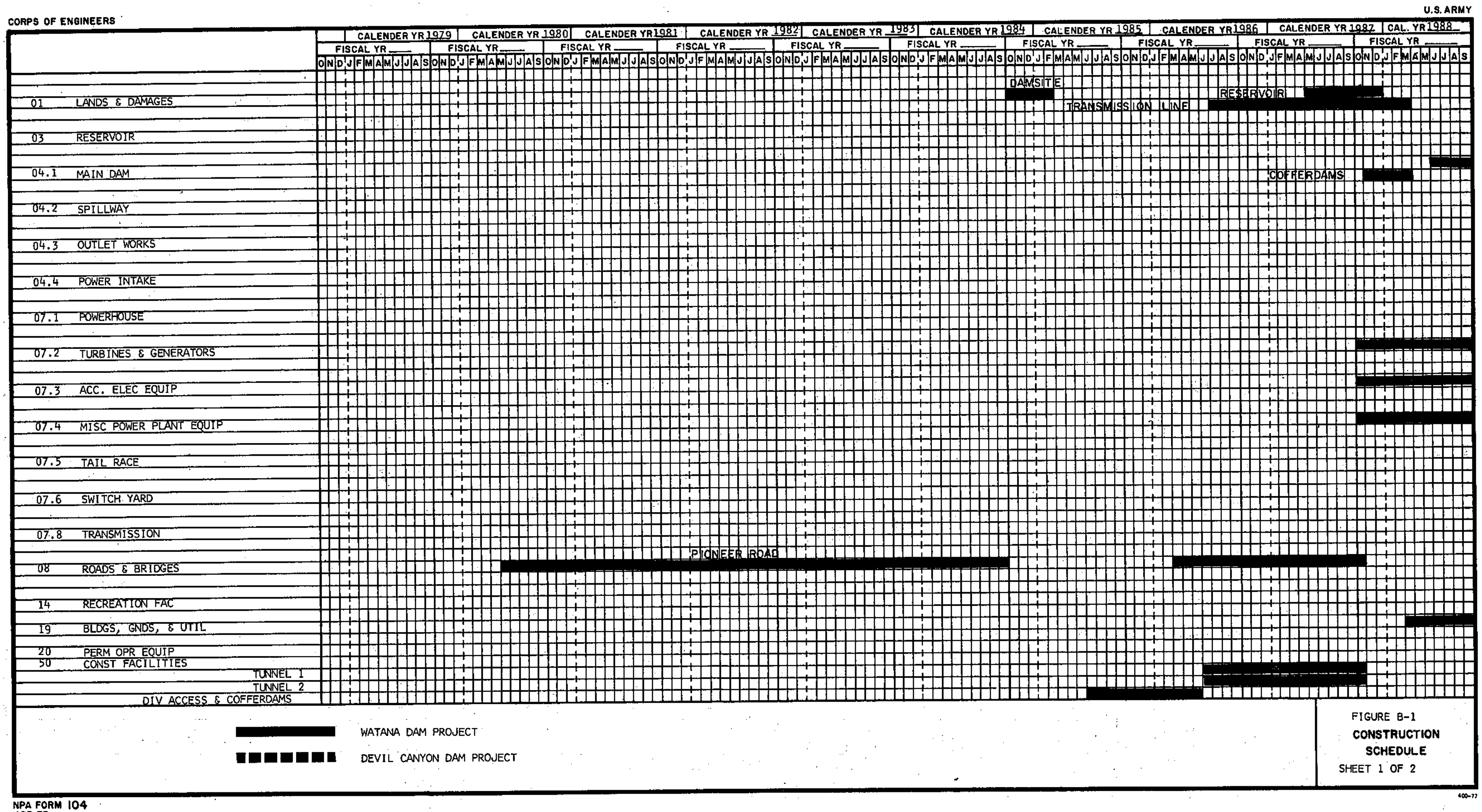


FIGURE B-1
CONSTRUCTION SCHEDULE
SHEET 1 OF 2

CORPS OF ENGINEERS

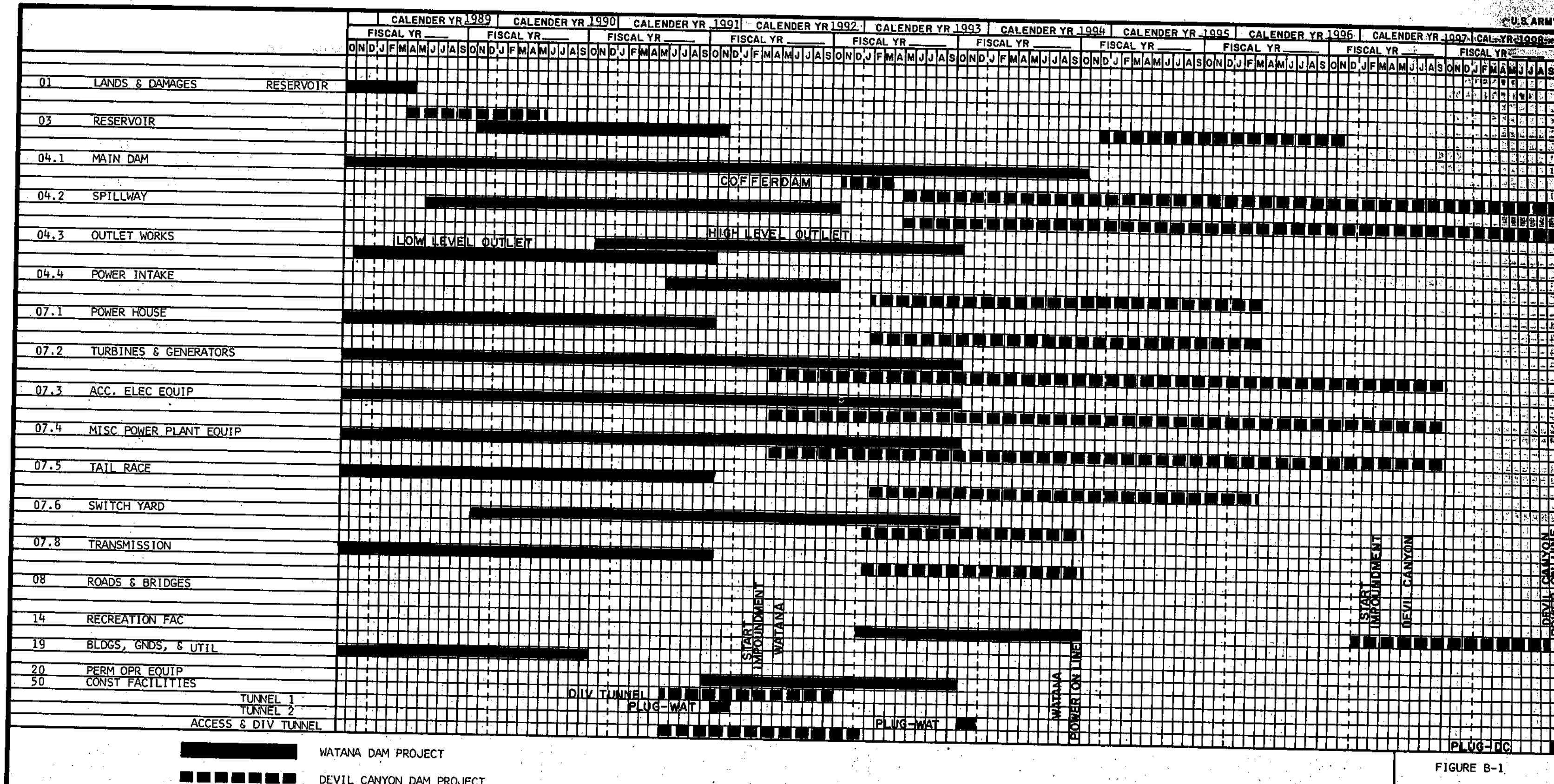


FIGURE B-1

CONSTRUCTION SCHEDULE

SHEET 2 OF 2

NPA FORM 104
APR 75

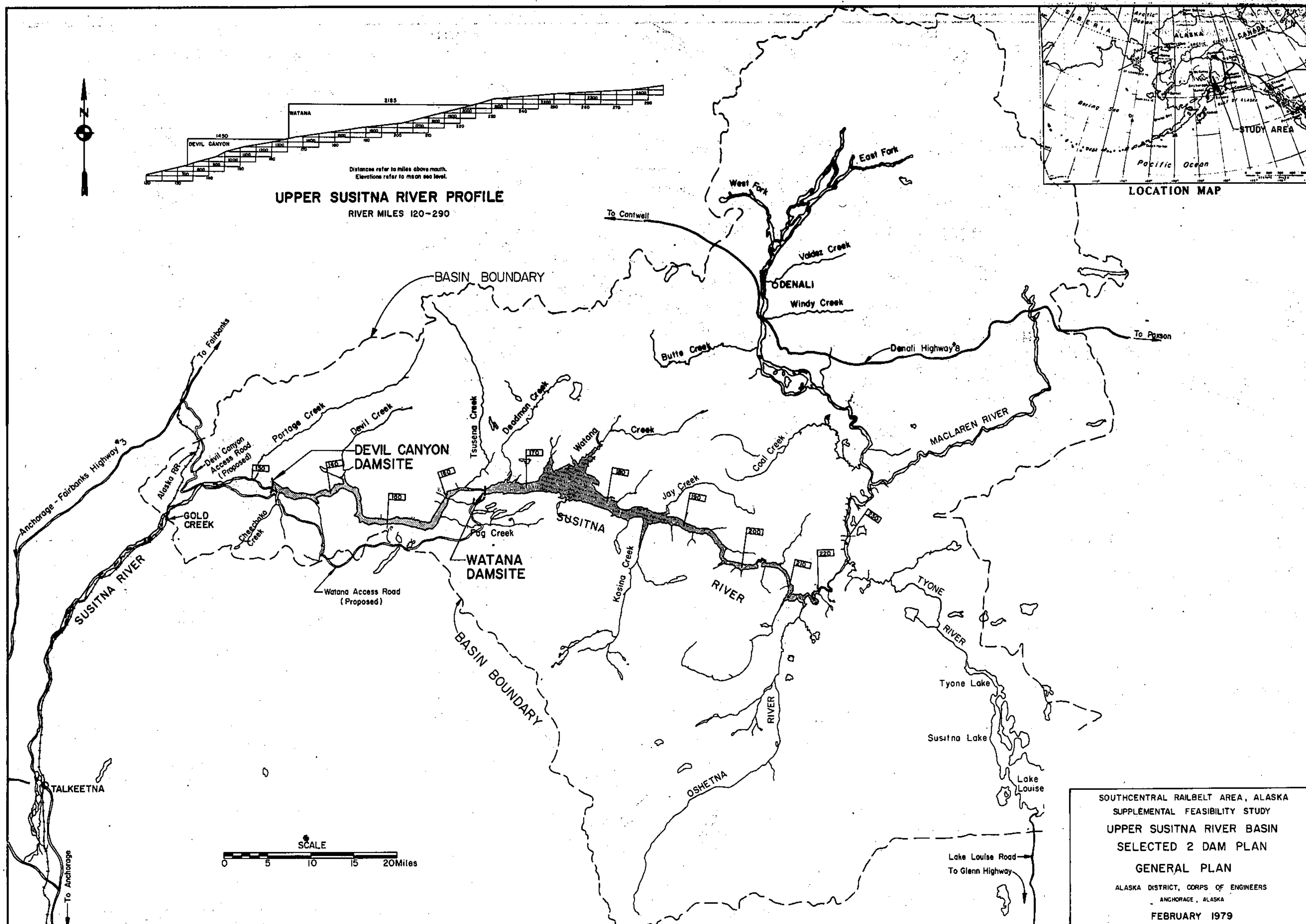
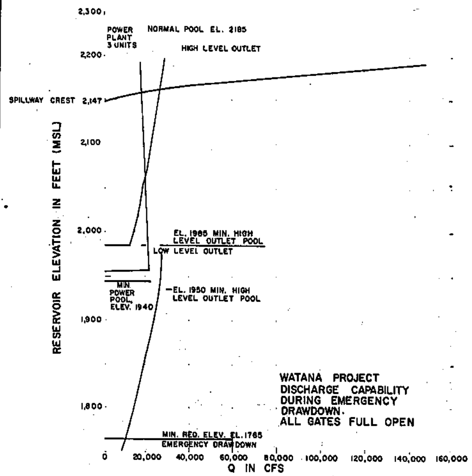


PLATE B-1

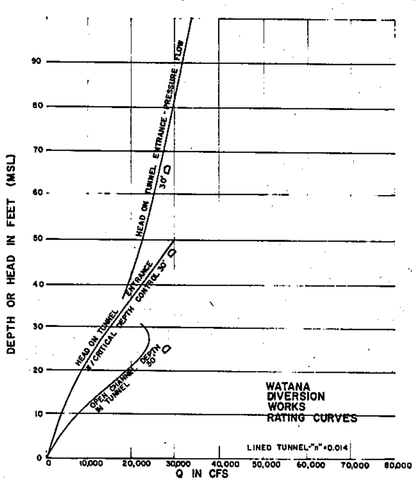
1032-79

NOTES:

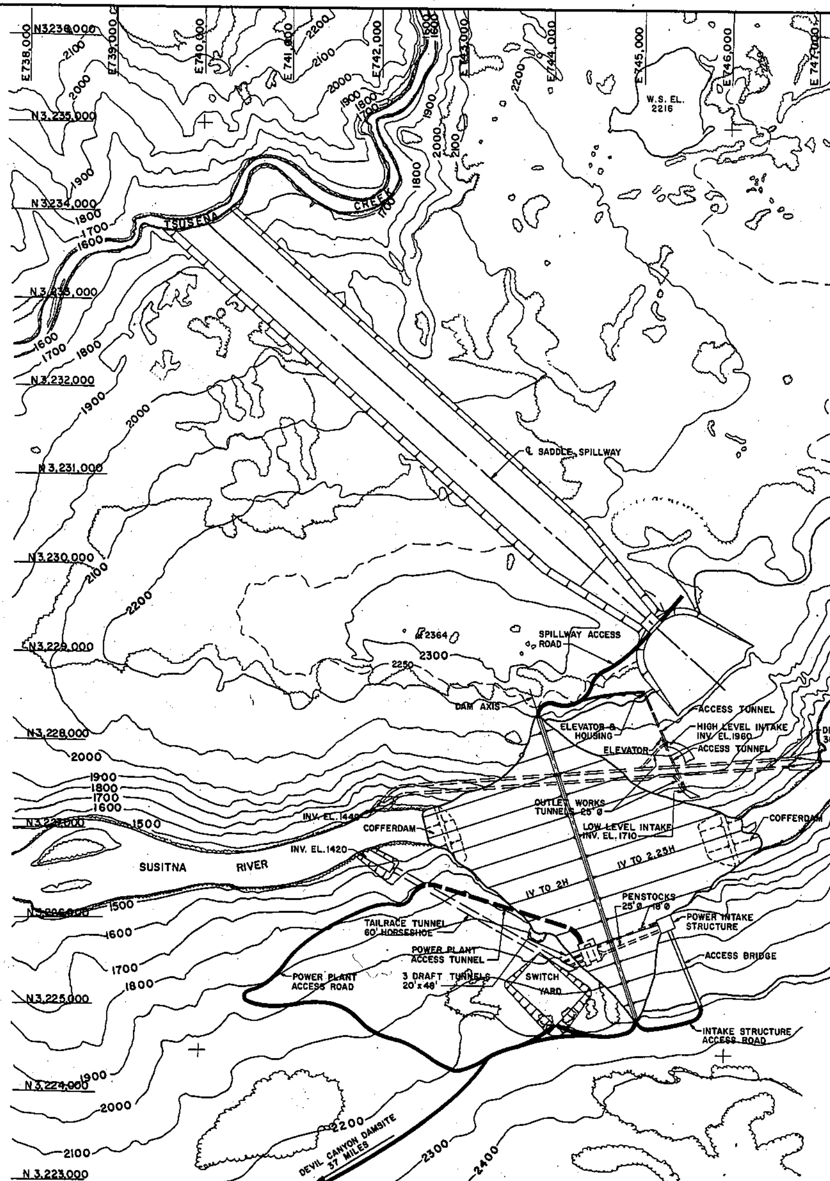
1. TOPOGRAPHIC CONTOURS ARE BASED ON AERIAL PHOTOGRAPHY DATED 10 JUNE 1978. VERTICAL DATUM IS MEAN SEA LEVEL (MSL)



WATANA PROJECT DISCHARGE CAPABILITY DURING EMERGENCY DRAWDOWN. ALL GATES FULL OPEN



WATANA DIVERSION WORKS RATING CURVES



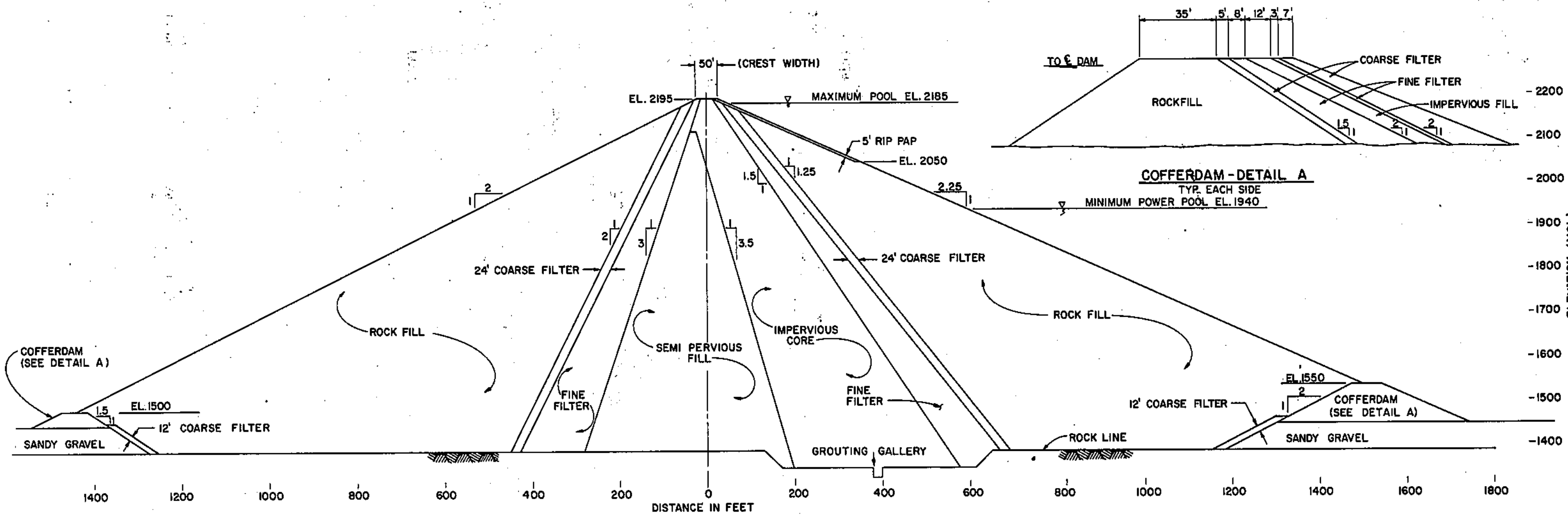
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAM
DETAIL PLAN

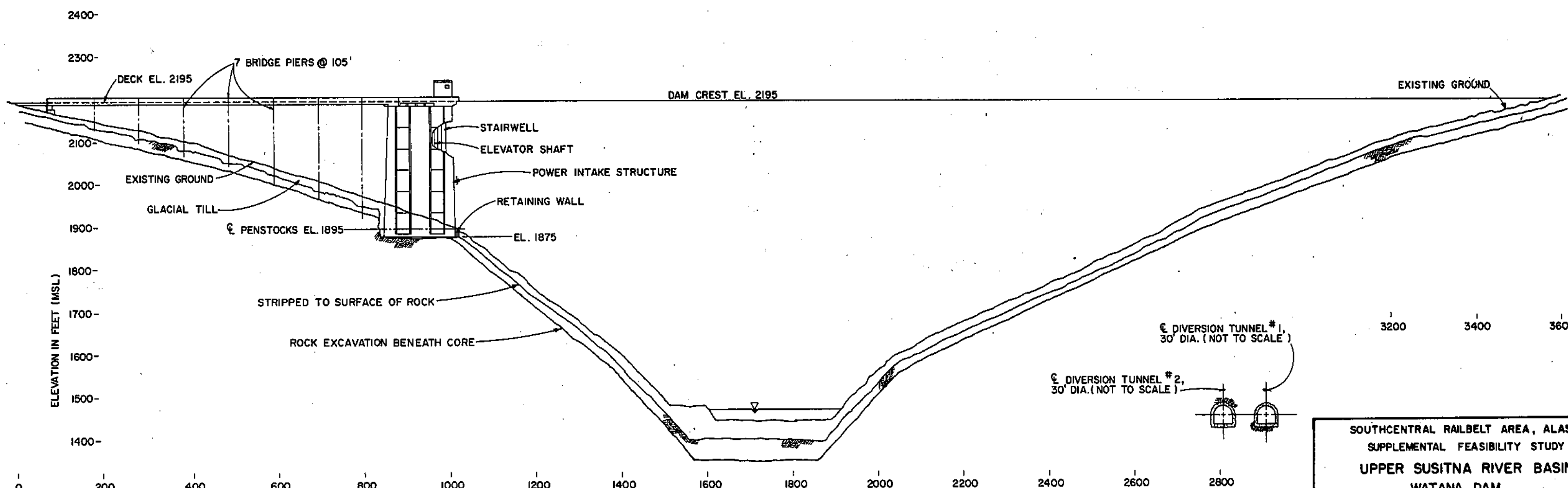
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

FEBRUARY 1979

PLATE B-2



TYPICAL SECTION



WATANA DAM AND
INTAKE STRUCTURE LOOKING DOWNSTREAM

100' 0' 100' 200'
GRAPHIC SCALE: 1" = 100'-0"

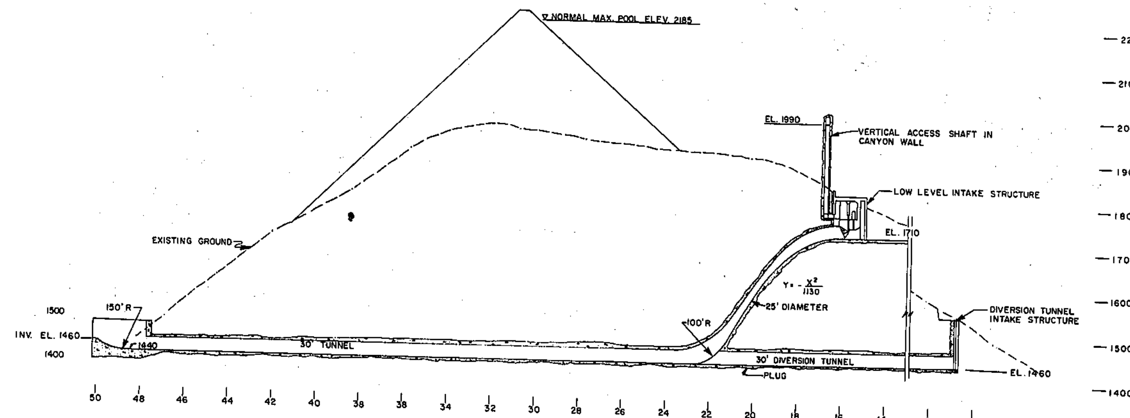
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAM
SECTIONS

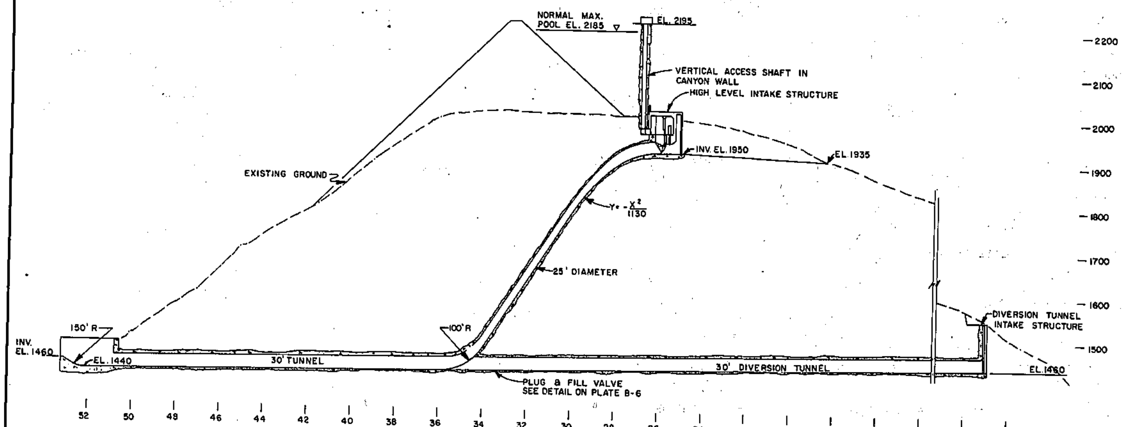
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

PLATE B-3

NOTE:
THE HIGH AND LOW LEVEL INTAKE STRUCTURES ARE PLOTTED AT TWICE NORMAL SCALE FOR CLARITY.



PROFILE LOW LEVEL OUTLET & DIVERSION TUNNEL #2

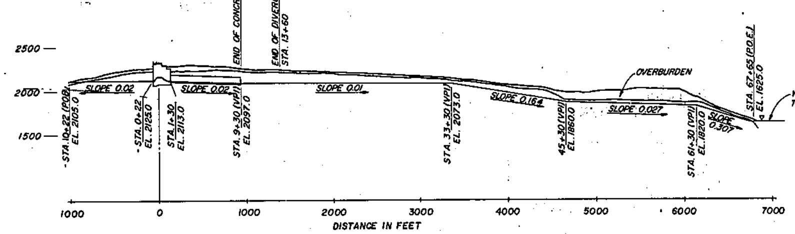


PROFILE HIGH LEVEL OUTLET & DIVERSION TUNNEL #1

HORZ: 0 200 400 600 GRAPHIC SCALE IN FEET
VERT: 0 100 200 300 GRAPHIC SCALE IN FEET

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM
PROFILES
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

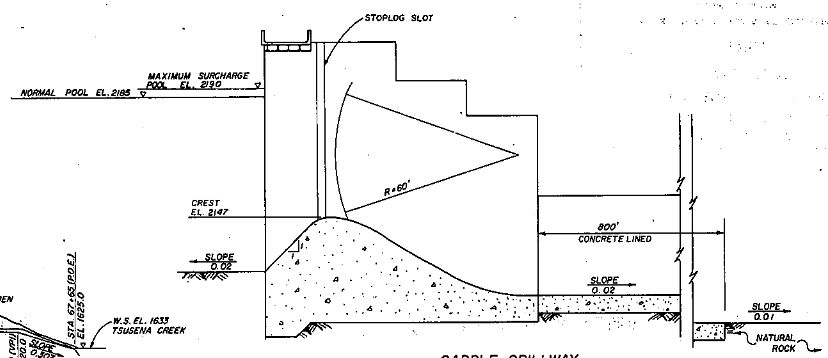
PLATE B-4



SADDLE SPILLWAY ℄ PROFILE

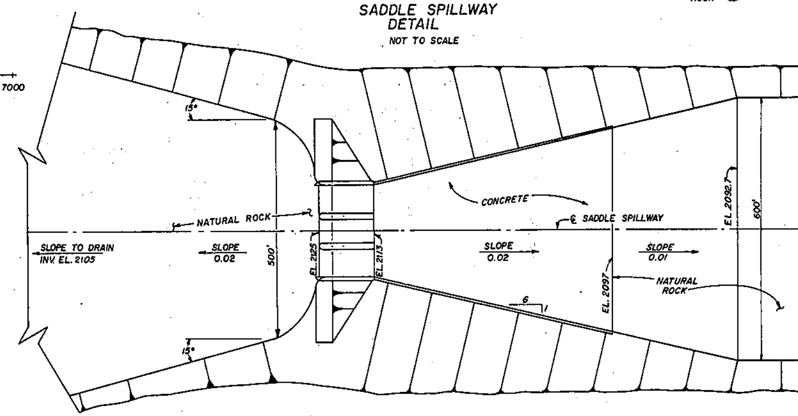
SCALE IN FEET

500 0 500



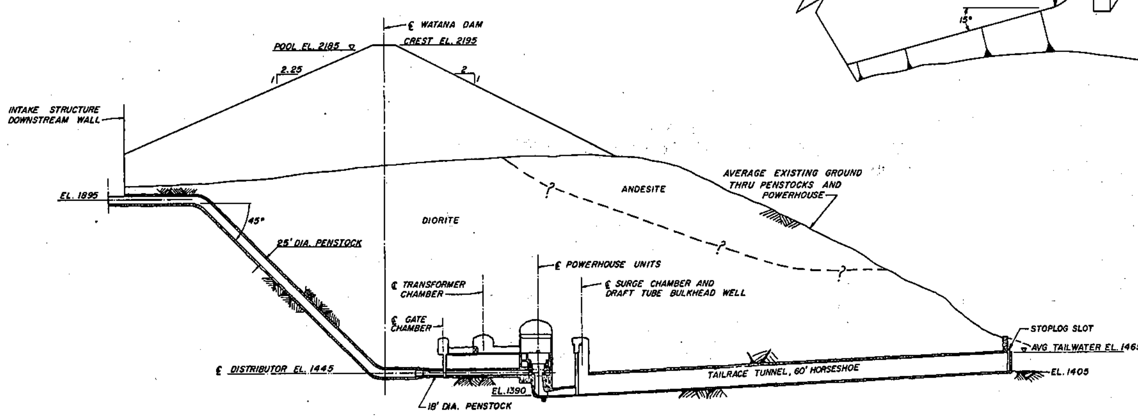
SADDLE SPILLWAY DETAIL

NOT TO SCALE



SADDLE SPILLWAY SECTION A–A

NOT TO SCALE



PENSTOCK ℄ PROFILE

NOT TO SCALE

SOUTHCENTRAL RAILBELT AREA, ALASKA

SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN

WATANA DAM

SADDLE SPILLWAY AND PENSTOCK

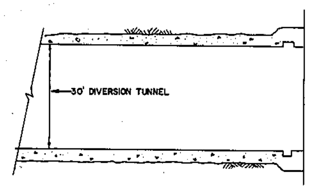
PROFILES, SECTIONS AND DETAILS

ALASKA DISTRICT, CORPS OF ENGINEERS

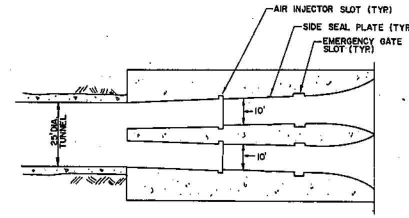
ANCHORAGE, ALASKA

FEBRUARY 1979

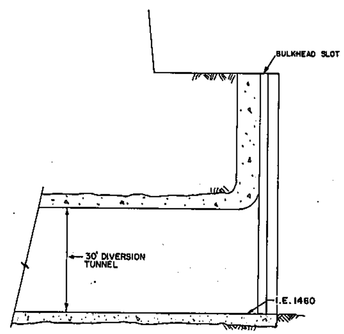
PLATE B-5



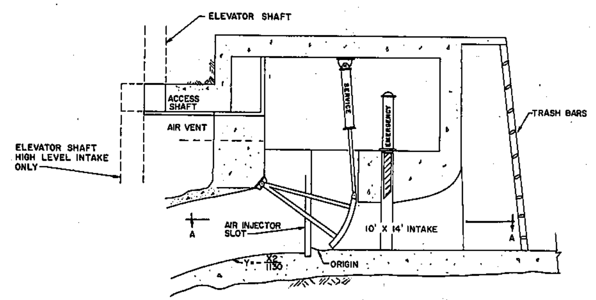
DIVERSION TUNNELS #1 AND #2 INTAKE STRUCTURE
PLAN @ EL. 1485



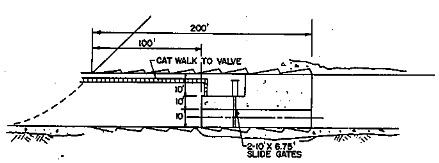
HIGH AND LOW LEVEL INTAKE
PLAN @ A-A



DIVERSION TUNNELS #1 AND #2 INTAKE STRUCTURE
SECTION



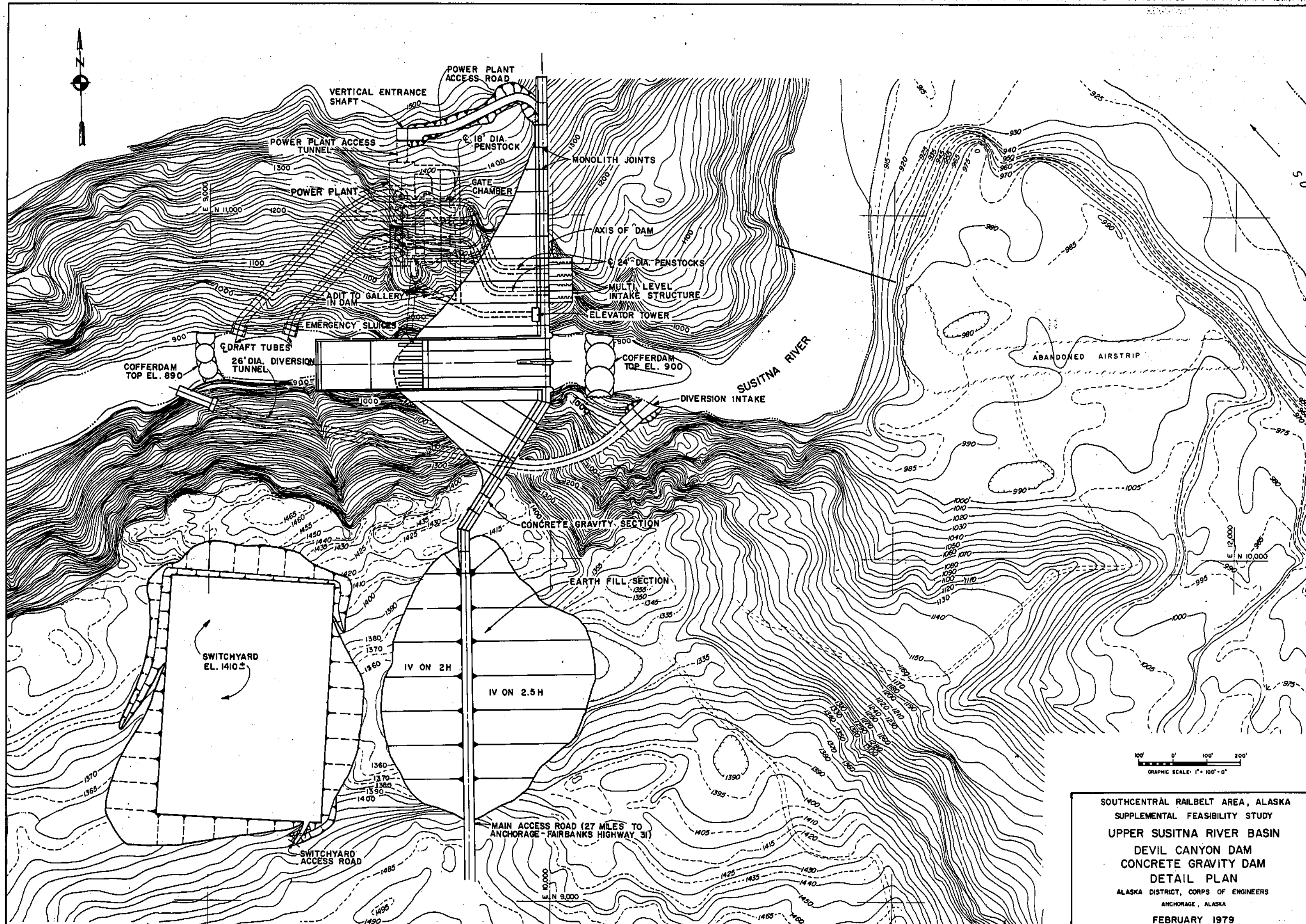
HIGH AND LOW LEVEL INTAKES
SECTION



PLUG AND FILL VALVE DETAIL
NOT TO SCALE

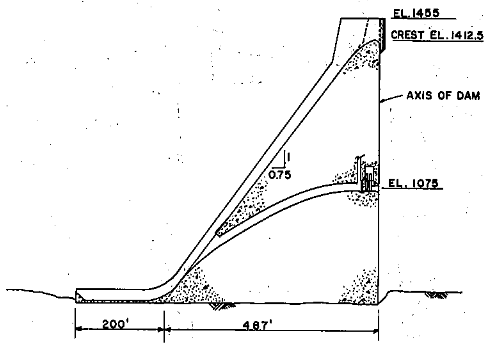
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM
DETAILS
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

PLATE B-6

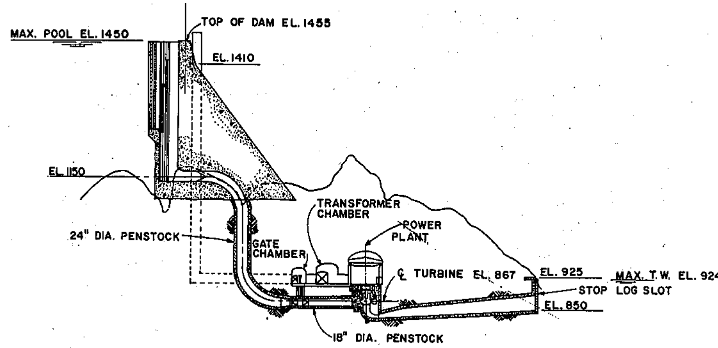


N
POWER PLANT ACCESS ROAD
VERTICAL ENTRANCE SHAFT
POWER PLANT ACCESS TUNNEL
℄ 18' DIA. PENSTOCK
MONOLITH JOINTS
POWER PLANT
GATE CHAMBER
AXIS OF DAM
℄ 24' DIA. PENSTOCKS
MULTI LEVEL INTAKE STRUCTURE
ADIT TO GALLERY IN DAM
ELEVATOR TOWER
EMERGENCY SLUICES
℄ DRAFT TUBES
26' DIA. DIVERSION TUNNEL
COFFERDAM TOP EL. 890
COFFERDAM TOP EL. 900
DIVERSION INTAKE
SUSITNA RIVER
ABANDONED AIRSTRIP
CONCRETE GRAVITY SECTION
EARTH FILL SECTION
SWITCHYARD EL. 1410±
IV ON 2H
IV ON 2.5H
SWITCHYARD ACCESS ROAD
MAIN ACCESS ROAD (27 MILES TO ANCHORAGE - FAIRBANKS HIGHWAY 3)
E 9,000
N 11,000
E 12,000
N 10,000
E 10,000
N 9,000
GRAPHIC SCALE: 1" = 100'-0"
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DEVIL CANYON DAM
CONCRETE GRAVITY DAM
DETAIL PLAN
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

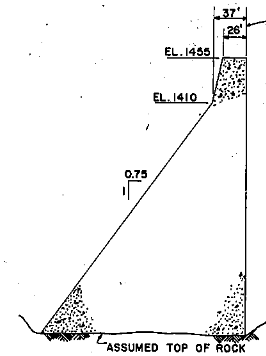
PLATE B-7



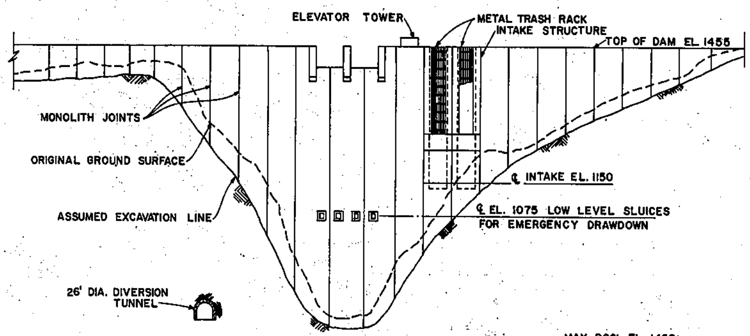
SPILLWAY SECTION
GRAPHIC SCALE: 1" = 100'-0"



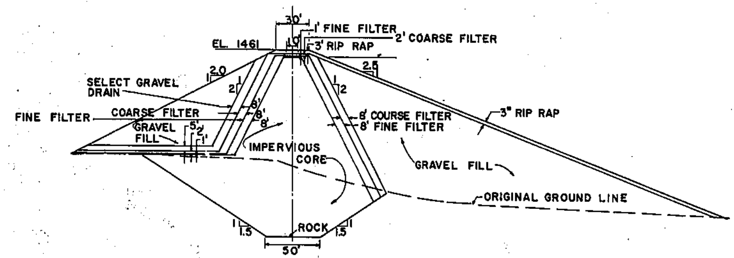
SECTION THRU PENSTOCK AND POWER PLANT
SCALE: 1" = 100'



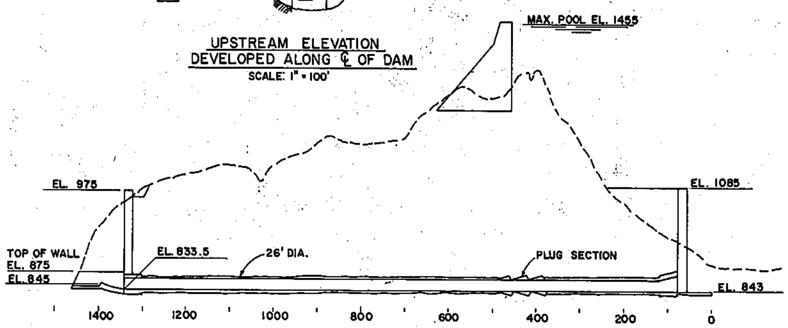
TYPICAL NON-OVERFLOW SECTION
GRAPHIC SCALE: 1" = 50'-0"



UPSTREAM ELEVATION
DEVELOPED ALONG ℄ OF DAM
SCALE: 1" = 100'



DEVIL CANYON AUXILIARY EARTH FILL DAM
GRAPHIC SCALE: 1" = 40'-0"



DIVERSON TUNNEL PROFILE
SCALE: 1" = 100'

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DEVIL CANYON DAM
CONCRETE GRAVITY DAM
ELEVATION AND SECTIONS
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
FEBRUARY 1979

PLATE B-8

SECTION C

POWER STUDIES AND ECONOMICS

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LIST OF FIGURES

LIST OF PLATES

EXHIBITS

SUMMARY OF CHANGES

This section updates benefit calculations and the determination of the project's economic justification presented in the 1976 Interim Feasibility Report. Economic trends and power usage continue to indicate that significant amounts of new generation will be required in the railbelt area of southcentral Alaska. A new load forecasting methodology and the three additional years of historical data result in slightly decreased peak load projections. The estimated costs of both the hydroelectric project and the coal-fired alternative have risen significantly since 1975. Under the base case set of assumptions, hydroelectric development in the upper Susitna River basin continues to appear economically justified. The 1978 updated benefit-cost ratio of the proposed development is 1.4 compared to the earlier estimate of 1.3.

STUDY AREA ECONOMY

SUMMARY OF CHANGES

The economic base analysis presented in the 1976 Interim Feasibility Report was based on the market area's economic performance through 1974. Fears of a severe post-pipeline depression in Alaska have been largely dissipated by the sustained performance of the State's economy in the 2 years since the pipeline phased down in 1976. In 1977, higher production levels were reached in the forest products, fisheries, and agricultural industries when compared to 1976. The State's financial institutions reached record high levels in 1977 in deposits, loans, and total assets. In addition, more houses and commercial and industrial buildings were constructed in 1977 than during any previous year. In fact, by excluding contract construction employment (under which pipeline workers were classified), there appears to have been a net increase in 1977 of 1,500 nonagricultural jobs in Alaska.

INTRODUCTION

The discussion that follows both augments and updates the economic base analysis of the 1976 report. It is based on three primary sources. One is a detailed analysis of the southcentral Alaska economy between 1965 and 1975. This work was done by the Institute of Social and Economic Research of the University of Alaska for the Southcentral Level B Study. Two other reports, one by the State's Department of Commerce and Economic Development and the other by the Department of Labor, provide information on the performance of the economy since 1975. Some of the population and income estimates through 1974 presented here differ from the estimates reported in the 1976 Interim Feasibility Report. These differences result from recent efforts by the State and others to develop a consistent data base.

HUMAN RESOURCES

The rapid economic growth in the Railbelt area of Alaska and in Alaska as a whole has resulted in substantial immigration of people seeking jobs in the Alaskan economy. Table C-1 summarizes population growth in the study area and in the state as a whole.

TABLE C-1

STUDY AREA POPULATION AS PERCENT OF TOTAL

Year	Total Alaska	Study Area	Percent of Total
1960	226,167	149,186	66
1970	302,361	209,178	69
1973	330,365	234,768	71
1974	351,159	245,846	70
1975	404,634	290,522	72
1976	413,289	301,250	73

Source: State of Alaska Department of Commerce and Economic Development, The Alaskan Economy, Year-End Performance Report 1977.

There are two major economic motivating factors which explain the large population increase. One is the fact that real incomes have been rising in Alaska faster than the rate in the U.S. as a whole. This is an indication that Alaska has been a region of improving economic opportunity in comparison to nationwide averages. In addition, individuals see explicit opportunities in the growth in employment. 1/ The Alaska Department of Labor estimates that net migration accounted for a 73,000 increase in resident population between 1970 and 1975, about 72 percent of the increase, while natural increase accounted for only 29,000, or about 28 percent of the total.

EMPLOYMENT

Employment shares of major industrial categories are presented in Table C-2. As can be seen, some significant changes in employment percentages have taken place over the past 5 years. In 1973, government claimed by far the largest share (38 percent) of total employment with services and retail trade a distant second at 14 percent. By 1978, Government's share declined to 30 percent. Manufacturing is the only other sector to show a significant decline - its share drops from 8.5 percent to 7 percent. Mining, construction, and services show the largest gains.

1/ Institute for Social and Economic Research, University of Alaska, Southcentral Alaska's Economy 1965-75, draft report.

TABLE C-2

INDUSTRY EMPLOYMENT SHARES
(Percent)

Industry	1973	1978 (Projection)
Mining	1.79	3.06
Manufacturing	8.50	7.11
Government	37.75	30.49
Construction	7.09	10.02
Retail Trade	13.60	14.02
Wholesale Trade	3.10	3.40
Finance, Insurance and Real Estate	3.86	4.87
Transportation	2.40	2.46
Communications	2.40	2.46
Public Utilities	0.92	0.78

Source: Alaska Department of Labor, Alaska Economic Outlook to 1985, July 1978.

Data for 1977 indicates that while the mid-year completion of the trans-Alaska oil pipeline had an impact on the State's economy, it has not been as severe as expected. As a result of the large decrease in contract construction employment, total nonagricultural employment declined accordingly. The decline in nonagricultural employment, however, was less than that of contract construction, indicating a previously unexpected economic stability.

PERSONAL INCOME

Total personal income is defined as the sum of wage and salary income, proprietor's income, dividends, interest and rental income, and transfer payments. Subtracted from this are personal contributions for social insurance. Once total personal income is compiled, it is then adjusted by the residency of the worker.

From statehood in 1959 through 1973, there has been stable growth in the State's personal income, paralleling the national trends. Alaska's per capita income estimate increased 86 percent from $2,498

69-738 O - 80 - 27

in 1959 to $4,644 in 1970 while the U.S. average rose 83 percent from $2,167 to $3,966 respectively during this same time period. This trend continued through 1973 with Alaska's per capita income rising an additional 28 percent while the national level rose 27 percent.

Since 1973 per capita income in Alaska has demonstrated a phenomenal rate of growth. In 1974 it increased 17 percent to $7,117 while in 1975 the reported increase was 33 percent to $9,440. During 1976 the annual rate of increase slowed considerably to 10 percent, boosting per capita income to $10,415. Correspondingly, on the national level it increased 9 percent in 1974, 8 percent in 1975, and 9 percent in 1976.

Clearly, Alaska's resident personal income has increased substantially the past few years. The State's economy has received a tremendous boost from construction of the oil pipeline, Native land claims, outer continental oil development, and government expenditures. With the completion of the oil pipeline, personal income of Alaskans is initially declining in real terms. As additional projects come on line in the future, the rate of growth in real personal income will again turn positive.

TABLE C-3

TOTAL PERSONAL INCOME IN ALASKA, 1970-1977

Year	Personal Income (In billions of $)
1970	1.3
1971	1.5
1972	1.6
1973	1.9
1974	2.4
1975	3.3
1976	3.8
1977	3.9

Source: Alaska Department of Commerce and Economic Development, The Alaska Economy, Year-End Performance Report 1977.

AGGREGATE ECONOMIC PERFORMANCE

It has generally been assumed that there existed a direct cause and effect relationship between pipeline construction and the State's economic expansion. Preliminary data for 1977 indicate that while pipeline construction employment declined during the year, it did not trigger massive layoffs in other nonpipeline sectors of the State's economy. Indeed, even with an annual average loss of 11,300 construction workers, total employment in Alaska for 1977 declined by only about 9,700 workers, or less than 6 percent, from the historic high level in 1976. Refer to Table C-4.

Obviously, there have been other factors which have contributed significantly to the State's recent economic expansion. By the end of September 1977, over $348 million had passed through the Alaska Native Fund to the Native corporations. Of this amount, a considerable portion had been invested in Alaska businesses and industry. In addition, public sector expenditures by Federal, State, and local governments have demonstrated dramatic increases in recent years, and mineral exploration activity has continued at a strong pace. These and other sources of nonpipeline economic stimulation have occurred during the pipeline construction time period and they appear to have played a significant role in expanding and strengthening Alaska's economy.

The forest products industry, after considerable expansion in 1976 from the previous depressed levels, maintained a stable high level of activity in 1977. Pulp and lumber production remained constant in 1977 although the production of wood chips declined significantly as a result of world market conditions. Japan, the major purchaser of Alaska's forest products, continues to be hampered by the slow recovery of its national economy, especially in its residential housing sector.

The State's commercial fisheries industry greatly surpassed all expectations during 1977. The salmon harvest was the highest since 1970 with strong returns of pink salmon to the southern portion of southeast Alaska and with good returns to most other areas of the State. Generally, the shellfish harvest and prices paid to fishermen were higher than in 1976.

As a result of the overall increases in 1977's fin and shellfish harvest, higher employment levels were stimulated in the State's fish processing sector.

Investment in hard rock mineral exploration increased substantially during 1977 to an estimated record high of $60 million. Oil exploration continued with 33 wildcat and step-out wells drilled in 1977, representing nearly a threefold increase in activity over the 1976 total. Major oil discoveries were announced in 1977 at Point Thompson and Flaxman Island (located east of Prudhoe Bay), indicating the possibility of additional North Slope oil and gas fields of significant scale. In October 1977, the Lower Cook Inlet lease sale was held in Anchorage.

TABLE C-4

ALASKA ECONOMIC INDICATORS

	1970	1971	1972	1973	1974	1975	1976	1977e
Resident Population (000)	302.4	312.9	324.3	330.4	351.2	404.6	413.3	N.A.
Civilian Labor Force #(000)	87.2	92.9	98.6	103.8	119.5	148.5	158.0	158.9
Employment #(000)	81.1	85.4	90.5	95.2	110.3	138.5	145.0	136.4
Nonagricultural Employment (000). . .	92.5	97.6	104.2	109.9	128.2	161.3	171.7	162.0
Number Unemployed #(000).	6.0	7.5	8.0	8.6	9.2	10.0	13.0	20.5
Wage & Salary Payments ($000,000) . .	$1,253	$1,359	$1,471	$1,621	$2,167	$3,449	$4,247	$3,737
Resident Personal Income *($000,000).	$1,412	$1,563	$1,698	$2,006	$2,429	$3,443	$3,979	$4,000
Anchorage CPI (1967 = 100).	109.6	112.6	115.9	120.8	133.9	152.3	164.1	175.7
Percent Change in CPI	3.5	3.0	2.7	4.2	10.9	13.8	7.8	7.1

N.A. = Not Available
e = Estimate
# = Current Population Survey Basis
* = Place of Residence Basis

Source: Alaska Department of Commerce and Economic Development, The Alaska Economy, Year-End Performance Report 1977.

Although drilling results in the Gulf of Alaska have been disappointing to date, other oil and gas exploration activities are continuing on the National Petroleum Reserve Alaska (old PET-4) and on Native corporation lands.

PRESENT AND HISTORICAL POWER REQUIREMENTS

This section presents the existing and planned generating capacities of the railbelt area as of 1977 along with generating resources that are planned for the near future. Also shown are the historical net generation estimates through 1977.

TABLE C-5

SUMMARY OF EXISTING GENERATING CAPACITY

	Installed Capacity (MW)				
	Hydro	Diesel	Gas Turbine	Steam Turbine	Total
Anchorage-Cook Inlet Area:					
Utility System	45.0	27.5	435.1	14.5	522.1
National Defense	-	9.2	-	40.5	49.7
Self-Supplied Industries	-	11.3	15.2	37.5	64.0
SUBTOTAL	45.0	48.0	450.3	92.5	635.8
Fairbanks-Tanana Valley Area:					
Utility Systems	-	35.1	203.1	53.5	291.7
National Defense	-	14.0	-	63.0	77.0
SUBTOTAL	0	49.1	203.1	116.5	368.7
TOTAL	45.0	97.1	653.4	209.0	1004.5

Source: Alaska Power Administration, "Power Market Analysis," January 1979. Anchorage-Cook Inlet figures include the Valdez-Glennallen area which totals 56.8 MW.

The total 1977 installed capacity of 1,004.5 MW represents a 45 percent increase over the 692 MW of installed capacity that existed in 1974.

TABLE C-6

NEAR-TERM PLANNED RESOURCES

	Year	Installed Capacity (MW) Gas Turbine	Steam Turbine	Total
Anchorage-Cook Inlet Utilities	1978	66.7	-	66.7
	1979	113.7	-	113.7
	1980	100.0	-	100.0
	1981	18.0	-	18.0
	1982	100.0	-	100.0
	1984	18.0	400.0	418.0
SUBTOTAL		416.4	400.0	816.4
Fairbanks-Tanana Valley Utilities	1982	-	104.0	104.0
TOTAL		416.4	504.0	920.4

Source: Battelle Pacific Northwest Laboratories, "Alaskan Electric Power: An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region," March 1978.

TABLE C-7

HISTORICAL NET GENERATION (GWH)

Year	Anchorage-Cook Inlet Area Util	Nat. Def	Indu	Fairbanks-Tanana Valley Area Util	Nat. Def	Indu	Total
1970	744.1	156.2	1.7	239.3	203.5	-	1,344.8
1971	886.9	161.2	25.0(e)1/	275.5	201.4	-	1,550.0
1972	1,003.8	166.5	45.3	306.7	203.3	-	1,725.6
1973	1,108.5	160.6	45.3(e)	323.7	200.0	-	1,838.1
1974	1,189.7	155.1	45.3	353.8	197.0	-	1,940.9
1975	1,413.0	132.8	45.3(e)	450.8	204.4	-	2,246.3
1976	1,615.3	140.3	45.3(e)	468.5	217.5	-	2,486.9
1977	1,790.1	130.6	69.5	482.9	206.8	-	2,679.9

1/ (e): estimated industrial load, revised by APA, January 1979.

Source: APA, Upper Susitna Project Marketability Analysis, November 1978.

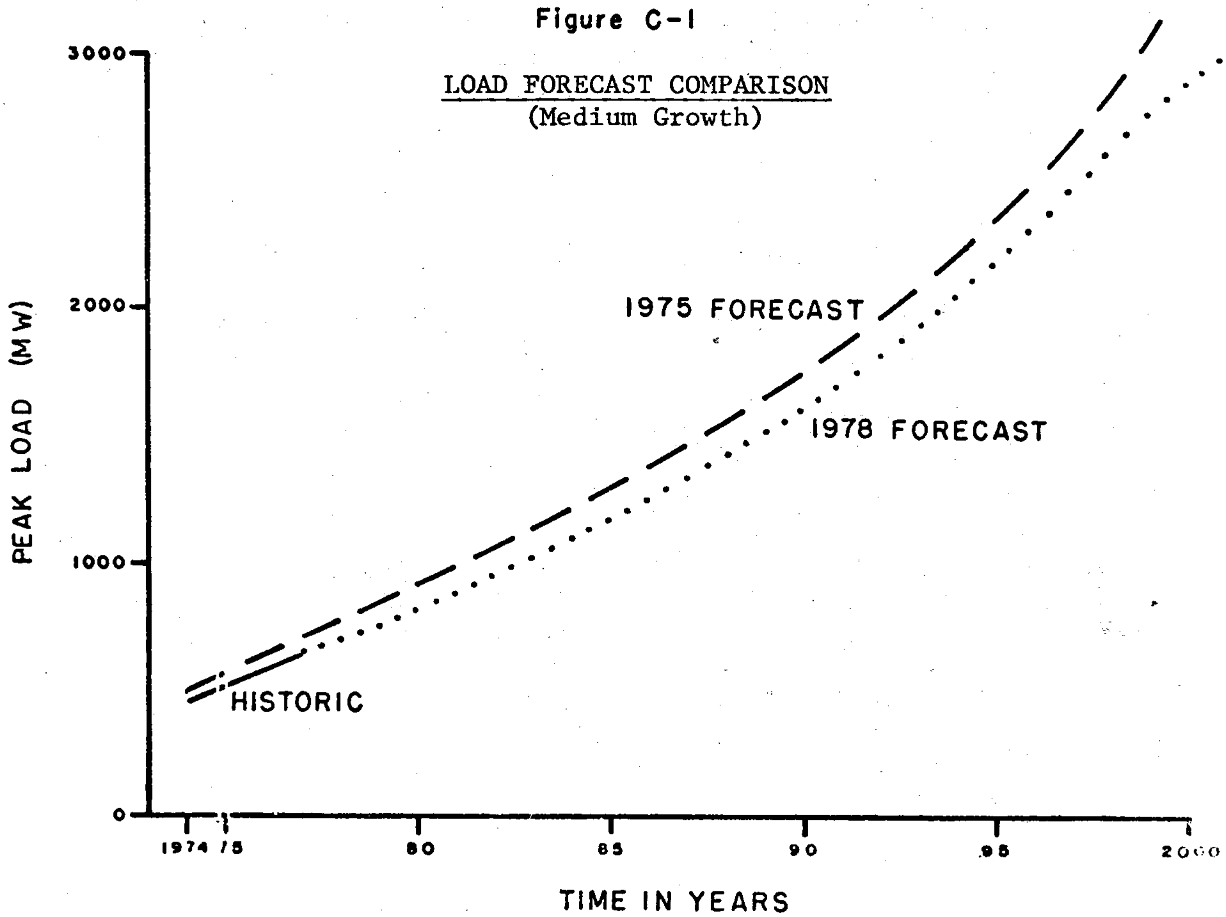
SUMMARY OF CHANGES

The forecasted demand for electrical power presented in this section constitutes a downward revision from those estimates used in the 1976 Interim Feasibility Report. The cumulative changes are due to the use of a different forecast methodology, 3 additional years of historical data, and generally more conservative economic development assumptions. The extent of change in the forecasts, however, is not great. For instance, the midrange forecast of peak load for the year 2000 has been revised to 2,852 MW, a 10 percent decrease from the earlier estimate of 3,170 MW (refer to Figure C-1). The most noticeable change occurs in the high range forecast which was reduced 36 percent in the year 2000.

Additionally, the revised forecast has been extended an additional 25 years to 2025 in order to facilitate longer range planning.

Figure C-1

LOAD FORECAST COMPARISON
(Medium Growth)



FORECAST METHODOLOGY

The Alaska Power Administration (APA) has used a simplified end-use model to forecast future power requirements, augmented by trend analysis and an econometric model. Total power demand has been categorized into three primary end uses: the residential/commercial/industrial loads supplied by electric utilities, the national defense installation sector, and the self-supplied industrial component.

Those factors in each category that best explain historical trends in energy use were identified. In the utility sector, those explanatory variables are population and per capita use. Population was forecasted with the help of a committee of experts using a regional econometric model, while per capita use estimates are an extrapolation of past trends adjusted to account for anticipated departures from those trends. National defense needs are assumed to depend on the level of military activity and the number of military personnel in the study area. Future self-supplied industrial power requirements are based on explicit assumptions regarding future economic development and the energy needs associated with such development.

POPULATION AND ECONOMIC ACTIVITY FORECAST

The most important sector in terms of magnitude of electrical energy use is the utility sector, and population is the key factor in this sector's future power requirements. Population forecasts in turn, are highly dependent upon assumptions of future economic activity. Economic activity assumptions are also important because they have a direct impact on energy requirements in the self-supplied industrial sector.

The population and economic activity assumptions used in this forecast are based on a draft report of the Economics Task Force, Southcentral Alaska Water Resources Study, dated September 18, 1978. The report is entitled, Southcentral Alaska's Economy and Population, 1965-2025: A Base Study and Projection.

The report was a joint effort of economists, planners, and agency experts who were members of the Economics Task Force of the Southcentral Alaska Water Resources Study (Level B), being conducted by the Alaska Water Study Committee, a joint committee of Federal and State agencies, the Alaska Federation of Natives, the Alaska Municipal League, the Municipality of Anchorage, the Southcentral region borough governments, and regional Native corporations.

The projections reported relied on two long-run econometric models devised by economists from the University of Alaska Institute of Social and Economic Research and from the MIT-Harvard Joint Center for Urban Studies. Funding was provied by the National Science Foundation's Man in the Arctic Program (MAP). The two specific models used here were modifications of the Alaska State and regional models developed under that program. The models produced estimates of gross output, employment, income, and population for the years 1975-2000. Population and employment were disaggregated and extrapolated to the year 2025 by ISER researchers under Economics Task Force direction, and using Task Force concensus methodology. The data required to run the model were provided by various members of the Economics Task Force, the assumptions were reviewed by the Task Force, and the model outputs and tentative projections were reviewed for internal consistency and plausibility by ISER researchers and by the Task Force.

The use of the econometric model requires a set of assumptions related to the level and timing of development. The assumptions primarily consist of time series on employment and output in certain of the export-base industries and in government. Because of the importance of these assumptions to the electrical energy load forecast, they are presented here in full on pages C-13 through C-31 from the Economic Task Force Report.

<u>Assumptions Used to Produce Economic and Population Projections, 1975-2000</u>

The critical assumptions are organized into two scenarios which consist of all low-range assumptions taken together and, alternatively, all high-range assumptions taken together. The scenarios were intended to show a "reasonable" high and reasonable low development series of specific projects which together would offer about the broadest range of employment and population outcomes which could be foreseen. This does <u>not</u> mean that the Task Force predicts that all or any of the projects assumed will actually occur; on the contrary, there is a highly variable degree of uncertainty with respect to the level and timing of all developments in the scenarios. However, some projects were subjectively rated more likely than others, some unlikely, and some very unlikely. Task Force consensus assigned most of the more likely projects to the low development scenario, some of the less likely to the high development scenario, and the remainder were assumed not to occur within the time horizon of the study.

The resulting low and high scenarios should <u>not</u> be considered synonyms for the terms "minimum" and "maximum" development. The Task Force did not feel competent to say what the theoretical minimum or maximum <u>possible</u> level of economic development in Southcentral Alaska might be, since this could be influenced by Government policy at Federal, State, and local levels and by market developments beyond the power of anyone to predict at this time; nor would that exercise have been of much use to planners.

The assumptions are organized by industry and discussed in the following sections.

Agriculture: Agriculture is currently a marginal industry in Alaska, employing about 1,000 people statewide (depending upon the definition of part-time, family help, and proprietors). In southcentral Alaska, about 115 man-years per year are expended in agriculture. Under a set of very favorable public policy decisions and favorable markets, considerable further development might occur. Primary requirements include: public priority given to agricultural production in Alaska at the same level as petroleum, minerals, and marine products; active pursuit of statutes and programs to reserve and preserve agricultural lands; and public aid to innovative settlement and development techniques. In this case, the agricultural experts on the Task Force could foresee possible commercial agricultural employment of around 800 man-years in southcentral Alaska per year, and about 4,600 statewide by the year 2000, rising to 6,900 by 2025. This reflects the current emphasis on development of the Tanana Valley, rather than the southcentral area. Total statewide sales of agricultural products in the high case rise to about $400 million (1975 dollars) per year in the year 2000, and to about $500 million in 2025. Value of output in constant 1958 dollars rises to $51 million by 2000, about $8.5 million from southcentral. By the end of the study period in the high case, about 1.06 million acres would be cultivated for crops, and 5.2 million acres of range land utilized. (Currently, about 20,000 acres are used for crops and grass in the State, about 12-13 thousand in southcentral.)

In the low case, public priority is given to "national" and "public" interest in esthetic, recreational, subsistence, and wilderness values, tending to reduce the amount of land available for crops and reducing the access and usability of land for agriculture. In addition, public agricultural agencies and institutions which support agriculture are allowed to atrophy. In this case, and with market conditions continuing to be unfavorable to Alaskan agriculture, the southcentral industry output and commercial employment drops to zero as the land is subdivided for homesites and recreational use. Value of commercial output drops to zero by 1991, with only "amenity" (part-time, partly subsistence) output remaining.

Forestry: Aggregated in State statistics under Agriculture-Forestry-Fisheries, this is a tiny sector which employs about 22 people statewide. Virtually all employment in logging occurs in lumber and wood products manufacturing. Value added is likewise negligible. In the high case, this sector grows in proportion to growth in lumber and wood products. In the low case, it stays at current levels.

Fisheries: The fisheries sector primarily consists of persons actually engaged in fishing, but it is troublesome for several reasons. It is difficult to count fishermen since this is an industry in which proprietors do much of the work, often with unpaid family help, the work is seasonal in nature, and many out-of-state persons take part. This causes the State's employment statistics, based on employment covered by unemployment insurance, to be misleading. Likewise, multiple licenses and unfished licenses make fisherman licenses a misleading indicator. Area-of-catch statistics collected on fish landed in Alaska, together with independent data on crew size, by gear type, give a pretty good picture of total persons actually engaged in fishing. For southcentral Alaska (but including the Aleutian chain), annual average employment on this basis is about 2,000 persons, while it was 4,359 statewide in 1975. In the high case, it is assumed that in existing fisheries, expansion of fishing productivity would be offset by limited entry and labor-saving improvements in the fleet, leaving employment constant at existing levels despite a fourfold increase in the salmon catch. However, given very favorable conditions, major development of the American trawl fishery off Alaska's coast could result in 100 percent replacement of the foreign fishing effort inside the 200-mile limit by the year 2000, employing about 17.5 thousand persons in fishing statewide and 8.7 thousand (or 50 percent) in southcentral. This was considered to be a very speculative development; consequently, no bottomfishing development was considered in the low case, while existing fisheries just maintained current employment.

Output level of existing fisheries in the high case expands considerably, since the State is assumed to undertake an aggressive hatchery and habitat improvement program, together with the 200-mile economic zone. The combined effect is assumed to be a quadrupling of salmon catch, while shellfish remain at about existing levels. The expansion of the trawl fishery was assumed to result in a southcentral catch of 1.85 billion pounds per year, worth $361 million exvessel in the high case. In the low case, all fisheries maintain their approximate 1975 levels.

Mining, Including Oil and Gas: The mining sector is dominated by employment and output in oil and gas, with lesser amounts in coal, sand, and gravel, and a few persons engaged in precious metal exploration and extraction. For the State as a whole, oil and gas developments are expected to dwarf all other considerations in this industry. Within southcentral Alaska, an important local issue is the development of the Beluga coal field.

The developments in mining in the high case are assumed to be as follows: There is a small find of hydrocarbons in the Northern Gulf of Alaska, but no important production. If the mean expected reserves are found, peak production would be about 932 thousand barrels of oil per day in 1985, and peak gas production of 0.5 billion cubic feet per day in 1987. The Sadlerochit, Kuparuk River, and Lisburne formations at Prudhoe Bay all combine in the high case for a 1,785 million barrels/day flow of oil in 1985. In addition, the joint State/Federal offshore lease sale is assumed to contain oil and gas resources equivalent to total reserves of 1.9 billion barrels. There are also two lease sales--in the Northern Gulf of Alaska (Sale 55) and Western Gulf/Kodiak area (Sale 46)--which result in moderate sized oil finds. Peak oil production in the Northern Gulf is about 0.550 million barrels per day in 1986, and 0.515 million barrels per day in 1992 in the Western Gulf. Daily gas production peaks at 1.0 bcf/day in the Northern Gulf and 0.26 bcf/day in the Western Gulf. Coal production in the high case would begin in 1983, with full-scale mining of 730,000 tons of coal per year by 1984 to feed a mine-mouth powerplant, twice that amount by 1986 to feed a second plant, and development of 6 million tons/year exports by 1990. In the high case, employment peaks at slightly over 9,000 in 1984, subsequently declining to 8,200 in 1995, while output rises to \$3.2 billion (constant 1958 dollars1/), tailing off to \$2.6 billion.

Low case oil and gas development basically consists of development at or around Prudhoe Bay. There is exploration in all the areas noted in the previous case, but exploration turns up far fewer prospects worth developing. While the Kuparuk and Lisburne are developed in this case and there is a joint offshore sale, the Beaufort sale turns up only 0.8 billion barrels of reserves instead of 1.9 billion. The lower Cook Inlet turns up only a small find, while the northern and western regions of the Gulf of Alaska are dry and result in "exploration only" employment. Beluga coal is not developed in the low case. As a result of all this, statewide peak employment in mining rises to about 7,000 in 1984, dropping to less than 4,800 by the end of the century.

Within the region, exploration plus development of oil and gas employ almost 4,800 persons by 1984 in the high case, declining to almost one-fourth that number by 1993. Beluga coal adds about 220 workers by 1990, the first year of coal export. In the low case, the peak employment is only 2,700 persons in 1984, the peak year, declines sharply thereafter, and levels off at 1,200 after 1987.

Food Manufacturing: The food manufacturing industry in Alaska is dominated by seafood processing, a situation which is not expected to change in the near furure. In the high case, the projected fourfold increase in the output of the salmon fisheries implies about a doubling

1/ The 1958 base year was used for convenience since U.S. Department of Commerce estimates of gross product were in terms of 1958 dollars when the study began.

in employment required to process the salmon. Since it was the consensus of the Task Force that shellfish are at or near maximum sustained yield, the overall processing plant employment for existing fisheries is projected to increase about 25 percent. Also in the high case, by the year 2000 the 100 percent replacement of foreign bottom fish effort off Alaska results in a catch of 3.7 million metric tons per year, requiring estimated total processing employment of about 12,000 and short-term (5-month) seasonal employment of 21,211--for an annual average of 21,000 by 2000. However, we assumed that only about one-third of total catch would be processed in Alaska shore-based facilities, resulting in total Alaska shore-based employment of 3,759, half of whom are employed in southcentral, and affect the local economy. The remainder of the 21,000 work on processing vessels near shore and offshore, but their incomes probably would affect the Anchorage economy and the statewide economy to some degree. Output for this industry was estimated by taking the expected exvessel value and using the historic ratio of exvessel to wholesale value, and the ratio of value-added to wholesale value. In the high cases, the value of catch in existing fisheries was assumed to rise at the same rate as total catch, yielding $145 million in value added in 2000, while catch in the emergent trawl fishery was assumed to rise to $722 million (3.7 million metric tons), yielding about $167 million of value added in processing (all value added in constant 1958 dollars). In the low case, a growth rate of 1 percent per year was projected for total output, yielding $81.5 million per year value-added by 2000.

<u>Lumber and Wood Products Manufacturing</u>: The two critical assumptions for this industry are the annual cut of timber in the State, determined mostly by Forest Service allowable cut and Japanese market conditions, and whether any dimension sawmills are built in Alaska. In the high case, the annual cut by the year 2000 was assumed to be 1,260 million board feet (probably partly from Native lands), compared with 660 million in 1970. In the low case, the increase is to only 960 million. No new mills are built in either case. While not exactly proportional, the increase in employment is similar: in the high case, statewide employment rises to 3,834 from 2,176 in 1975; in the low case, the rise is from 2,176 to 3,280. The output of this industry was estimated by calculating the 1975 ratio of output per employee. This was assumed to escalate at its 1965-1975 rate of growth in the high case (about 1.66 percent), but stayed at 1975 levels in the low case.

Since almost all the prime timber likely to be exploited by an expanding industry is located outside the southcentral region, we assumed that outside of Anchorage, the employment of firms in this sector would escalate by about 1 percent per year in the low case, by 2.3 percent per year in the high case, which is about the same or less than the statewide rates. Employment was assumed constant in Anchorage.

Pulp and Paper Manufacturing: The growth in this sector is determined by most of the same factors as lumber and wood products. In neither case is there a pulp mill built in southcentral Alaska, so there is no employment or output in this sector within the region. In the State, the increase in total cut results in average employment increases of about 1.6 percent per year in the low case, 1.8 percent per year in the high, resulting in totals of 1,777 and 1,886, respectively. In the low case, productivity per worker remains at its 1975 value; in the high case, it increases at 2.76 percent annually, its 1965-1975 rate, resulting in value added of $88.2 million and $93.6 million, respectively, in the year 2000.

Other Manufacturing: This sector is an odd mixture of a wide variety of cottage industries, printing and publishing, and consumer goods manufacture, together with a few major petrochemical plants and refineries. The major possible sources of new employment in this sector were assumed to be the Alpetco royalty oil refinery-petrochemical complex, Alaska Pacific LNG plant, and whatever other LNG or gas treatment facilities might be associated with gas output from lower Cook Inlet and the Gulf of Alaska. In the high case, the total operating employment of these facilities was about 2,000 persons (mostly working for Alpetco). In the low case, the only source was Pacific LNG, employing about 60 persons. Statewide output in this sector was more of a problem since it was unclear how much the output to be added by any of the LNG plants might be. It was decided to subsume LNG value-added under mining, and in the high case, value-added in other manufacturing was estimated as the existing level of output, plus total revenues of Alpetco, minus cost of feedstocks, from the Alpetco pro forma financial projections of March 10, 1978. All the growth was entered outside of Anchorage. In the low case, the existing level of output was used.

Construction: For modeling purposes, it was only necessary to estimate total employment working on major projects exogenous to the economy, since the rest of construction is projected with the support sector and output is determined by employment in this sector in the models. In the high case, the significant projects within the region were assumed to be oil treatment and shipment facilities in the Gulf of Alaska and Kodiak subregions and the Kenai-Cook Inlet Census Division, small LNG facilities associated with the Northern Gulf and lower Cook Inlet development, a Beluga coal transshipment facility, Pacific LNG and Alpetco plants, and a new State capital in Willow. Outside the region, there is augmentation of TAPS pipeline capacity, the northwest Alaska gas pipeline is constructed, and field development facilities are projected for the Beaufort Sea and the Kuparuk and Lisburne formations. Statewide, total exogenous construction employment peaks at a total of about 14,000 in 1981, declining rapidly thereafter to less than 1,000 by 1991. In the region, the peak employment is a bit less than 7,000 in 1981.

The level of construction employment was considerably less in the low case, both because of fewer developments in oil and gas, and because several projects needing State support do not occur, e.g, Alpetco and the State capital move. In this case, the northwest Alaska pipeline is constructed, but the oil finds at Prudhoe Bay offshore areas are relatively small, as are those in lower Cook Inlet. The Kuparuk and Lisburne formations are developed, and the Pacific LNG plant is built. However, there is no new substantial augmentation to fish processing in the form of new plants to process bottom fish. In the low case, statewide peak employment in exogenous construction is about 9,500, while in the region it is about 1,800.

Federal Government: Federal Government employment has been growing very little over the last 10 years, with civilian increases about offset by decreases in military employment. The rate of civilian increase has been about 0.5 percent per year, and lacking the boost of any massive developments requiring Federal support, and lacking a new State capital, the likely rate of increase in Federal civilian employment for the low case is assumed to remain at 0.5 percent, increasing employment from 18,000 to 21,000 statewide, and from 10,900 to 12,250 in the region by 2000. In the high case, general development results in a doubling of the average rate of increase to about 1 percent per year in Federal Government in most of the State, and 1.2 percent per year in south-central to reflect the State capital move. This increases statewide Federal civilian employment from 18,000 to 22,000, and regional employment from 10,900 to 14,500. Federal military employment is assumed to remain constant at 1975 levels in both the State and region.

State Government: State Government employment went through several revisions because of concern about State budgets. Historically, the rate of growth in this sector averaged 8.5 percent per year, a rate which most Task Force members believed was unlikely to continue. On the other hand, in the high case bottomfish development, major oil development, and the moving of the State capital to Willow were likely to result in fairly substantial increases in State employment. In the high case, it is assumed that 2,750 positions were transferred from Juneau to Willow and that total State Government employment would increase from 14,700 to about 39,000 in the year 2000, declining from around 7.6 percent of civilian wage and salary employment to about 7.2 percent. In the region, State employment bulks fairly large because of the State capital move, with the total from Anchorage and other southcentral combined moving from 5,400 to 14,900, or from 5.2 percent to 13.1 percent of total employment.

In the low case, it was assumed that government growth was restricted by lower development needs, by funding constraints or public opinion, and by the fact that the State capital did not move. Before 1985, State Government employment growth was held to about 2 percent per year, with zero growth thereafter. State employment as a result goes from 14,700 in 1975 to 19,159 in 2000, about 6.4 percent of civilian employment in the latter year. In the region, total State employment rises from 5,400 to 7,140 in 1985-2000, about 6.1 percent of civilian employment in 1975 and 3.1 percent in the year 2000.

Local Government: Local government was assumed to be influenced in the future by many of the same factors influencing the rate of growth in State employment. The historic rate from 1965 to 1975 was 10.5 percent (10.1 percent in southcentral), partly a result of development of school systems and the transfer of State-operated rural schools in the unorganized borough to local control. Due to increasing numbers of functions being performed at the local level and rural development in the high case, statewide growth was expected to be faster than in southcentral, where local governments are already well organized. Due to the moving of the State capital and due to local government response to fishing and oil, local government employment was projected to sustain about a 4 percent per year growth rate outside the region and about 3.4 percent within the southcentral region. This meant a statewide increase in local employment from 14,200 in 1975 to 34,900 in 2000. In the low case, since the State capital does not move and State-local transfers are expected to be sharply curtailed after 1985, the assumed rates of growth are about 2 percent until 1985 and about 1 percent thereafter. Total employment in local government goes from 14,200 in 1975 to 20,100 in 2000. Within the region, local government in the high case grows from about 8,100 to about 18,600. In the low case, regional local government employment grows from 8,100 to 11,300.

Miscellaneous Assumptions: In the model, Alaskan wage rates are determined in most industries as a function of Alaskan prices and U.S. average weekly wages in the private economy, deflated by the U.S. Consumer Price Index for Urban Clerical Workers. (Both the latter series are published by the Bureau of Labor Statistics.) Alaskan prices are in turn determined as a function of U.S. prices and local demand conditions, reflected by changes in employment. Finally, migration to Alaska is calculated as a function of the change in employment opportunities and relative per capita income in Alaska, compared to the rest of the country. In order to project a "high" and "low" scenario, the economics Task Force reexamined the assumptions usually used to run the model for impact-assessment purposes in Alaska and concluded that "high" or "low" growth could occur because of movements of the economy outside the State as well as inside the State. In particular, the rates of growth of U.S. disposable personal income per capita (2.0 percent) and wages (1.2 percent) appeared a bit optimistic for the low case. Therefore, in the low case, "pessimistic" forecasts by Data Resources, Inc. were used: 1.0 percent per annum average increase in real wages and 1.77 percent average increase in real disposable personal income per capita. These two changes had little influence.

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Government expenditures other than wages and salaries directly influence output in the construction sector. To avoid having to make a series of complex assumptions of doubtful validity concerning government capital spending programs, the Task Force assumed other Government spending increased proportionately to Government employment.

Finally, the Task Force recognized that some of the service, public utilities, and transporation employment in the southcentral area would not be local-serving employment at all. Particularly, employment in these sectors for Alyeska Pipeline Service Company and Beluga coal extraction would be essentially exogenous to the local economy. Consequently, an exogenous component was added for employment in these three sectors to adjust for the employment by Alyeska and by Beluga.

These assumptions are summarized in Table C-8.

Assumptions Used to Estimate Employment and Populations, 2000-2025

The Task Force was charged with estimating total employment and population after the year 2000, but the econometric models' results were doubtful that far in the future. The Task Force instead developed some educated guesses concerning the Alaskan economy in the post-2000 period, and these were used to extrapolate the year 2000 results to 2025.

Basically, the same methodology was used as above. The basic sector employment was projected by individual industry, a relationship between nonbasic and basic employment was assumed, and then a relationship between population and employment assumed and projected.

Basic employmemt was projected as follows: Since there were no significant additional prospects for oil development in southcentral Alaska after 2000, this sector was assumed to stabilize at its year 2000 level, replacing old fields with some additional development. This was true in both cases. Exogenous construction tends to follow oil development, so it, too, was left at its year 2000 level. Federal civilian employment continued to grow to serve the expanding post-2000 population; by 1.2 percent per year in the high case and 0.5-0.6 percent in the low case. State and local government continued to grow at the rates projected for their respective cases from 1975 to 2000, with fairly rapid expansion in the high case, and virtually no expansion in the low case. Agriculture continued to expand after 2000 in the high case, with some significant opening up of lands. There was no post-2000 development in the low case. Since manufacturing of fish products, lumber, wood, and pulp was assumed to fully utilize the available resources (as in the high case), or its growth was restricted by external institutional market factors (as in the low case), the level

TABLE C-8

DEVELOPMENT ASSUMPTIONS

SECTORS	HIGH	LOW
Exogenous Construction Employment	1. Oil treatment and shipment facilities: Gulf of Alaska Kodiak Kenai - Cook Inlet	
	2. Small LNG facilites in: Lower Cook Inlet North Gulf of Alaska	
	3. Beluga coal developed and tranship facility	
	4. State capital built at Willow	
	5. ALPETCO built on Kenai Peninsula	
	6. Pacific LNG built on Kenai Peninsula	Pacific LNG built on Kenai Peninsula
	7. Northwest Gas Pipeline built	Northwest Gas Pipeline built
	8. TAPS expanded	
	9. Facilties developed for Kaparuk and Lisburne at Prudhoe Bay	Facilites developed for Kaparuk and Lisburne at Prudhoe Bay
	10. Major Beaufort Sea oil discovery	Small oil find offshore
	11. Peak employment of 7,000 in 1981 in Southcentral, 14,000 Statewide	Peak employment of 1,800 in Southcentral, 9,500 Statewide

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Agriculture Employment	1. Major development: 800 man-years by 2000 in Southcentral, 4,600 Statewide, 6,400 by 2025	Zero employment by 1990
Agriculture Value of Output	1. 1958 dollars: 8.5 million in Southcentral by 2000, 51 million Statewide	Amenity only
Forestry Employment	1. Essentially none	Essentially none
Forestry Value of Output	1. Negligible increase	Negligible increase
Fishery Employment	1. No increase in existing fisheries	No increase in existing fisheries
	2. 17,500 increase in bottom fishing Statewide, 8,750 in Southcentral by 2000	No bottom fish development
Fisheries Value of Output	1. Salmon quadruples by 2000	No increase in salmon
	2. No increase in shellfish	No increase in shellfish
	3. Bottom fish: 722 million 1958 dollars Statewide by 2000, 361 million Southcentral	No bottom fish development

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Pulp and Paper Manufacturing Employment	1. Employment increases by 1.8% per year, to 1,886 by 2000 Statewide	Employment increases by 1.6% per year, to 1,777 by 2000 Statewide
	2. No employment in Southcentral	No employment in Southcentral
	3. Value added of $93.6 million by 2000	Value added of $88.2 million by 2000
Pulp and Paper Value of Output	1. Real output per employee grows at 2.76% Statewide	Real output per employee remains constant
	2. Employment does not grow in Southcentral	
Outer Manufacturing Employment	1. Dominated by petroleum industry	Only increase is for Pacific LNG, employing 60 people
	2. Increases reflect employment by ALPETCO, Pacific LNG, and two small LNG plants	
	3. Total employment of 2,000	
Other Manufacturing Value of Output	1. Existing level, plus additons from ALPETCO	Existing level of output

TABLE C-8 (cont)

SECTORS		HIGH	LOW
Lumber and Wood Products Manufacturing Employment	1.	Annual cut by 2000 is 1,260 million board feet	Annual cut by 2000 is 960 million board feet
	2.	No new mills	No new mills
	3.	Statewide rises to 3,834	Statewise rises to 3,280
	4.	Other Southcentral employment increases 2.3% per year	Other Southcentral employment increases 1% per year
	5.	Employment constant in Anchorage	Employment constant in Anchorage
Lumber and Wood Products Value of Output	1.	Real output per employee grows at 1.659% per year	Output per employee does not grow
Food Manufacturing Employment	1.	Fourfold increase in output of salmon fisheries	Existing fisheries stay at existing levels
	2.	Doubling of salmon processing employment	
	3.	Existing fisheries plant employment increases 25%	
	4.	By 2000, 100% replacement of foreign bottomfish effort	No bottomfish development
	5.	3.7 million metric tons/year catch by 2000	

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Food Manufacturing Employment (cont)	6. Total processing employment of 12,000 by 2000	
	7. Short-term (5-month) processing employment of 21,211	
	8. Annual processing employment average of 21,000 by 2000	
	9. Total Alaska shore-based employment of 3,759, 1/2 in Southcentral	
Food Manufacturing Value of Output	1. Existing fisheries value added (1958 $) $145 million by 2000	Growth at 1% per year for total output, $81.5 million per year value added by 2000
	2. Trawl fishery catch rises to 3.7 million metric tons, $722 million, $167 million value added in processing	No enhancement of fisheries output
Mining Oil and Gas Employment	1. Development of Kaparuk River sand and Lisburne formation, 1.785 million barrels/day in 1985	Development of Kaparuk River sands and Lisburne formation
	2. 1.0 billion barrels developed offshore Prudhoe Bay	0.8 billion barrels developed offshore Prudhoe Bay
	3. North Gulf of Alaska: .550 million barrels/day in 1986	No find in North Gulf of Alaska

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Mining Oil and Gas Employment (cont)	4. West Gulf/Kodiak Area: .515 million barrels/day in 1992	No find in West Gulf/Kodiak Area
	5. 1.0 BCF/day gas production in North Gulf of Alaska	No gas production in North Gulf of Alaska
	6. .26 BCF/day gas production in West Gulf/Kodiak Area	No gas production in West Gulf/Kodiak Area
	7. Coal production begins in 1983: 730,000 tons/year by 1984 to feed mine mouth plant; 1,460,000 tons/year by 1986 to feed second plant; 6 million tons/year exports by 1990	No Beluga coal development
	8. 9,000 employed in 1984 Statewide 8,200 employed in 1995 Statewide	7,000 employed in 1984 Statewide 4,800 employed in 2000 Statewide
	9. North Gulf of Alaska: 932,000 barrels of oil per day by 1985, 0.5 billion cubic feet per day in 1987	
	10. 4,800 employed regionwide by 1984, declining thereafter	2,700 employed in 1984 regionwide declines sharply thereafter
	11. 220 employed by Beluga coal by 1990	
Value of Hard Mineral Production	1. Present levels plus output of Beluga coal	Present levels

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Value of Oil and Gas Production	1. Production is multiplied times estimated wellhead values of $17.00/bbl ($1.80/MCF for gas), new fields only in Southcentral 1/	Production is multiplied times estimated wellhead values of $7.50/bbl (1.40/MCF for gas), new fields only in Southcentral 1/
	2. Prudhoe and other North Slope production starts at $5.32/bbl and 25¢/MCF in 1977, with oil rising to $29.28 by 2000 1/	Prudhoe and other North Slope production starts at $5.20/bbl and 25¢/MCF in 1977, with oil rising to $29.28 by 2000 1/
Federal Government Employment	1. Rises at 1.2% per year in Southcentral, 10,857 to 14,500 by 2000	Rises at 0.5% per year in Southcentral, 10,900 to 12,250 by 2000
	2. Rises at 1% per year outside Southcentral	Rises at 0.5% per year outside Southcentral
Total Local Government Employment	1. 4% growth rate outside the region	2% growth rate until 1985, 1% thereafter
	2. 3.4% growth rate within Southcentral region	
	3. Statewide increase from 14,200 to 34,900 in 2000	Statewide increase from 14,200 to 20,100 in 2000
	4. Southcentral region increase from 8,100 to 18,600	Southcentral region increase from 8,100 to 11,300
Total Local and State Government Expenditures	1. Proportional to increase in wages and salaries of Government workers	Proportional to increase in wages and salaries of Government workers

1/ Estimates are in current dollars incorporating a 5 percent annual rate of inflation.

TABLE C-8 (cont)

SECTORS		HIGH	LOW
Total State Government Employment	1.	2,750 positions transferred from Juneau to Willow, 1982-1984	
	2.	Total employment increases from 14,700 to 38,000 in 2000	Total employment increase from 14,700 to 19,159 in 2000
	3.	Declines from 7.6% of civilian wage and salary employment to about 7.2% by 2000	Declines to 6.4% of civilian employment by 2000
	4.	Southcentral employment increases from 5,400 to 14,900, or from 5.2% to 13.1% of total employment	Southcentral employment rises from 5,400 to 7,140, from 6.1% of civilian employment to 3.1% by 2000
	5.	Statewide rate of employment growth is about 5.4% per year	Before 1985, government employment growth held to 2% per year, with zero growth thereafter
Value of Facilities Oil and Gas Production, Transportation	1.	Based on Dept. of Revenue, Alaska's Oil and Gas Tax Structure, February 1977, Page IV, 23, thru 1985, declined at 5% per year thereafter	Based on Dept. of Revenue, Alaska's Oil and Gas Tax Structure, February 1977, Page IV, 23, thru 1985, declined at 5% per year thereafter
Value of Facilities, Manufacturing	1.	Includes estimated value of LNG and Petrochemical facilities for local property tax	Includes value of Pacific LNG facilities

TABLE C-8 (cont)

SECTORS	HIGH	LOW
Exogenous Transporation and Services Employment	1. Estimated Alyeska employees in these sectors, plus 40 workers at the Beluga coal transshipment facilities	Alyeska workforce only
Rate of Growth of Disposable Personal Income Per Capita and Wages	1. Income - 2% 2. Wages - 1.2%	Income - 1.77% Wages - 1.0%

of employment in these industries was held constant at the year 2000 level. Fishing itself was assumed to replace 10 percent of the foreign bottomfishing effort after 2000 by the year 2025 in the low case, but there was assumed to be no change in the traditional fisheries beyond their year 2000 level. In other manufacturing, the year 2000 employment level was sustained, except that nonpetrochemical "other" manufacturing was projected to double after the year 2000 to serve local markets in the high case.

In projecting the nonbasic/basic ratio, somewhat different procedures were used for Anchroage and the rest of the region. In Other Southcentral, the year 2000 regional ratio of nonbasic to basic employment was multiplied times regional basic employment each year out to 2025 and disaggregated, using year 2000 proportions, which permitted proportional growth in the nonbasic sector in each subregion after the year 2000. In the high case, the nonbasic/basic ratio was assumed to converge to the existing 1975 U.S. ratio by 2025, but it was found to be already there by 2000. In Anchorage, it was recognized that much of the "support sector" employment in fact serves statewide needs in transportation, financial services, etc. Therefore, an estimate was made of local-serving nonbasic employment by multiplying the statewide nonbasic/basic ratio by local basic sector employment. The remainder was designated "statewide-serving" nonbasic employment, which was assumed to grow at the same rate as basic employment because Anchorage statewide services in both the basic sector and this part of the nonbasic sector can be assumed to grow in response to similar statewide demands for central offices and general support services. With the Anchorage economy relatively mature by that time, it is more difficult to argue that statewide-serving nonbasic firms would continue to grow faster than their counterparts in the basic industries after 2000 than before 2000.

Finally, civilian non-Native population not employed in exogenous construction was estimated using year 2000 population/employment ratios at the regional level and allocated to subregions using year 2000 proportions. Any assumption other than proportional population growth among subregions after 2000 was judged too difficult to defend, since so little is known about the character of Alaska's economy at that point. To this was added exogenous construction employment (no growth). Native population (2 percent growth per year), and military (no growth).

FORECAST RESULTS

The Level B population forecast for the Anchorage-Cook Inlet subregion was adopted by APA for estimating power requirements without any modification. APA applied projected statewide growth rates to the Fairbanks-Tanana Valley area to develop population forecasts for that region. The resulting population projections upon which the load forecast is based are presented in Table C-9. The figures include national defense personnel. Actual population growth will likely fall within the limits established by the high and low forecasts. The APA population and load forecasts are discussed at length in Section G, Marketability Analysis.

TABLE C-9

POPULATION ESTIMATES

Year	Anchorage-Cook Inlet Low	Anchorage-Cook Inlet High	Fairbanks-Tanana Valley Low	Fairbanks-Tanana Valley High	Statewide Low	Statewide High
1980	239,200	247,200	60,390	62,020	500,225	513,766
1985	260,900	320,000	68,010	77,350	563,303	640,718
1990	299,200	407,100	74,660	95,370	618,397	790,042
1995	353,000	499,200	82,130	114,360	680,286	947,312
2000	424,400	651,300	89,700	139,760	743,034	1,157,730
2025	491,100	904,000	99,040	179,240	820,369	1,484,784

UTILITY SECTOR

The midrange net generation forecast from 1977 to 1980 was based on the average annual growth rate between 1973 and 1977. This rate was adjusted upward and downward by 20 percent to establish the 1980 high and low forecasts respectively. Beyond 1980, the high and low case net generation is estimated by multiplying forecasted population by projected per capita use. Between 1973 and 1977, per capita use of electricity grew at an annual rate of 3.8 percent in Anchorage and 9.4 percent in Fairbanks. The lower Anchorage growth rate was adopted as the basis of the per capita use trend. Increasing electrification is assumed to be partly offset by increasing effectiveness of conservation programs, resulting in a gradually slower rate of growth in per capita use. The future rate of growth in per capita use was projected to decline as shown in Table C-10.

In order to test the validity of this methodology for estimating per capita power consumption, comparable regions in the Pacific Northwest were examined. The Eugene metropolitan area, Oregon, (population 150,450) as well as the Richland-Kennewick SMSA, Washington, (population 100,100) were selected on the basis of their similarity in population and commercial/industrial characteristics to the railbelt area (i.e., substantial population coupled with relatively little heavy industry).

In the period from 1970-1977 per capita electricity use increased by an average of 5.4 percent and 7.1 percent for Eugene and the Richland-Kennewick SMSA, respectively. This compares to a 3.8 percent per capita growth rate for Anchorage (1973-1977). Furthermore, the power sales anticipated by the utilities which serve Eugene and the Richland-Kennewick SMSA, coupled with the population projections for these two regions, reveal an ever increasing rate of per capita consumption. Clearly, these utilities make little or no provision for energy conservation.

In 1977, per capita use in Eugene and the Richland-Kennewick SMSA was 13,424 kWh and 17,297 kWh, respectively. These current rates meet or exceed the high forecast for Alaska in the 1980-1985 period. Without doubt, Alaska holds a considerable potential for increased electrification.

Pacific Northwest current per capita consumption (excluding aluminum and others that buy at bus bar) is 13,550 kWh/yr.

TABLE C-10

PER CAPITA USE PROJECTIONS

Period	Low Rate (%)	Low Forecast (KWH/Cap)	Mid-Range Rate (%)	High Rate (%)	High Forecast (KWH/Cap)
1980-1985	2.5	11,000	3.5	4.5	13,800
1985-1990	2.0	12,400	3.0	3.5	16,300
1990-1995	1.5	13,100	2.5	3.0	18,900
1995-2000	1.0	13,800	2.0	2.5	21,400
2000-2025	0	13,800	1.0	2.0	35,000

With the high and low population forecasts and with high, mid, and low per capita use assumptions, six different net generation forecasts were calculated. From these, the high population-high energy use and the low population-low energy use combinations were used for the high and low range net generation forecasts. The midrange utility sector forecast came from averaging the high population-low energy use and the low population-high energy use forecasts.

The resulting forecasts are shown in Tables C-12 through C-14. Peak load forecasts were calculated from projected net generation using a 50 percent load factor.

NATIONAL DEFENSE SECTOR

The forecast for this relatively minor sector is based on historical data from Army and Air Force installations in the railbelt area. Zero growth is assumed for the midrange forecast. For the high range, growth at 1 percent per year is assumed, while the low range forecast is based on a decline of 1 percent annually (see Tables C-12 through C-14).

SELF-SUPPLIED INDUSTRIES SECTOR

This category of load is comprised of those existing industries that generate their own power, along with all similar type facilities expected to be constructed in the future. It is likely that such industries would purchase power and energy if available at reasonable cost. The specific assumptions for this sector are based on Battelle's March 1978 report entitled Alaskan Electric Power, An Analysis of Future Requirements and Supply Alternatives for the Railbelt Region.

The high range of development includes an existing chemical plant, LNG plant and refinery, along with a new LNG plant, refinery, coal gasification plant, mining and mineral processing plants, timber industry, capital city, and some large energy intensive industry. This set of assumptions coincides with the Level B Study Task Force high case development assumptions with two exceptions. Coal gasification and an energy intensive industry were included by APA because informed judgement indicates their definite potential. Their impact on population and economic activity is relatively minor but their effect on peak load requirements could be substantial.

The University of Alaska and Battelle completed a study entitled Energy Intensive Industries for Alaska in September 1978. The study evaluated a number of energy intensive industries that might be attracted to the State as a consequence of the availability of its large and diversified sources of primary energy. For a number of economic reasons, it was concluded that the availability of energy resources per se would not be sufficient to overcome the higher capital, operating and marketing costs for a world scale primary industry located in the State. However, it was also concluded that of all industries examined, the primary aluminium metal industry appeared to be the most likely to succeed in Alaska. It was further concluded that a large electro-process industry would have important implications to Alaska's electric power supply planning. The viability of such an industry is contingent upon the availability of low cost hydropower. For these reasons, the development assumptions for the high range case include some large energy intensive industry.

The assumed peak load requirements in the year 2000 are presented in Table C-11. The midrange forecast is the same as the high range except that the large energy intensive industry (aluminium smelter) is excluded. The low range further excludes the new capital city. There is also some reduction of peak load requirements of the mid and low range cases. The resulting forecast is shown on Tables C-12 through C-14.

TABLE C-11

SELF-SUPPLIED INDUSTRY SECTOR ASSUMPTIONS, 2000
(High Range)

Type of Load	Load (MW)
Existing Facilities:	
Chemical Plant	26.0
LNG Plant	0.6
Refinery	2.4
Timber	5.0
New Facilities:	
LNG Plant	17.0
Refinery	15.5
Aluminium Smelter	280.0
Coal Gasification Plant	250.0
Mining and Mineral Processing Plant	50.0
Timber	7.0
New City	30.0
Total Peak Load	683.5

TABLE C-12

TOTAL POWER AND ENERGY REQUIREMENTS

Anchorage-Cook Inlet Area and Fairbanks-Tanana Valley Area Combined

Peak Power

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
TOTAL							
High		890	1,671	2,360	3,278	4,645	10,422
Median	650	829	1,162	1,592	2,134	2,852	4,796
Low		769	961	1,177	1,449	1,783	2,146

Annual Energy

	GWH 1/	GWH	GWH	GWH	GWH	GWH	GWH
TOTAL							
High		3,928	7,636	10,684	14,844	20,936	47,054
Median	2,681	3,663	5,133	7,078	9,528	12,738	21,578
Low		3,391	4,256	5,219	6,430	7,890	9,630

1/ Thousand KW = MW
Million KWH = GWH

Source: Alaska Power Administration, Department of Energy

TABLE C-13

ANCHORAGE-COOK INLET AREA POWER AND ENERGY REQUIREMENTS

Peak Power

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		620	1,000	1,515	2,150	3,180	7,240
Median	424	570	810	1,115	1,500	2,045	3,370
Low		525	650	820	1,040	1,320	1,520
NATIONAL DEFENSE							
High		31	32	34	36	38	48
Median	41	30	30	30	30	30	30
Low		29	28	26	24	24	18
INDUSTRIAL							
High		32	344	399	541	683	1,615
Median	25	32	64	119	199	278	660
Low		27	59	70	87	104	250
TOTAL							
High		683	1,376	1,948	2,727	3,901	8,903
Median	490	632	904	1,264	1,729	2,353	4,060
Low		581	737	916	1,151	1,448	1,788

Annual Energy

	GWH 1/	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY							
High		2,720	4,390	6,630	9,430	13,920	31,700
Median	1,790	2,500	3,530	4,880	6,570	8,960	14,750
Low		2,300	2,840	3,690	4,560	5,770	6.670
NATIONAL DEFENSE							
High		135	142	149	157	165	211
Median	131	131	131	131	131	131	131
Low		127	121	115	105	104	81
INDUSTRIAL							
High		170	1,810	2,100	2,840	3,590	8,490
Median	70	170	340	630	1,050	1,460	3,470
Low		141	312	370	460	550	1,310
TOTAL							
High		3,025	6,342	8,879	12,427	17,675	40,401
Median	1,991	2,801	4,001	5,641	7,751	10,551	18,351
Low		2,568	3,273	4,075	5,125	6,424	8,061

1/ Thousand KW = MW Million KWH = GWH

Source: Alaska Power Administration, Department of Energy

TABLE C-14

FAIRBANKS-TANANA VALLEY AREA POWER AND ENERGY REQUIREMENTS

Peak Power

	1977 MW 1/	1980 MW	1985 MW	1990 MW	1995 MW	2000 MW	2025 MW
UTILITY							
High		158	244	358	495	685	1,443
Median	119	150	211	281	358	452	689
Low		142	180	219	258	297	329
NATIONAL DEFENSE							
High		49	51	54	56	59	76
Median	41	47	47	47	47	47	47
Low		46	44	42	40	38	29
TOTAL							
High		207	295	412	551	744	1,519
Median	160	197	258	328	405	499	736
Low		188	224	261	298	335	358

Annual Energy

	GWH 1/	GWH	GWH	GWH	GWH	GWH	GWH
UTILITY							
High		690	1,070	1,570	2,170	3,000	6,320
Median	483	655	925	1,230	1,570	1,980	3,020
Low		620	790	960	1,130	1,300	1,440
NATIONAL DEFENSE							
High		213	224	235	247	260	333
Median	207	207	207	207	207	207	207
Low		203	193	184	175	166	129
TOTAL							
High		903	1,294	1,805	2,417	3,260	6,653
Median	690	862	1,132	1,437	1,777	2,187	3,227
Low		823	983	1,144	1,305	1,466	1,569

1/ Thousand KW = MW   Million KWH = GWH

Source: Alaska Power Administration, Department of Energy

CREDIT FOR ENERGY AND CAPACITY

The amount of project power for which benefit can be claimed depends on both the project's capability and the market requirements. The latter, in turn, is a function of total loads and the mix of available generating resources. The determination of this "usable" energy and capacity from the Susitna project is based on a load/resource analysis conducted by Battelle Pacific Northwest Laboratories for APA.

The load/resource analysis matches forecasted electric power requirements with appropriate generating capacity additions. The computer aided analysis schedules new plant additions, keeps track of older plant retirements, and computes the loading of installed capacity on a year-by-year basis over the period 1978 to 2011.

The analyses are based on the load forecasts and the existing and planned generating resources described in the previous sections. Reserve margins of 25 percent for noninterconnected load centers and 20 percent for the interconnected systems are assumed. The results of the load/resource analysis are in terms of net deliverable capacity and energy after deductions for anticipated transmission losses. The load/resource analysis methodology recognizes construction schedule constraints by not allowing call-up of new generation or transmission capacity that could not be made available. For purposes of this analysis, the following economic facility lifetimes have been assumed:

Type	Years
Coal-fired Thermal Generation	35
Oil-fired Steam Generation	35
Gas-fired Combustion Turbine	20
Oil-fired Combustion Turbine	20
Hydroelectric Generation	50 1/

At the end of its economic life, the facility is retired from service.

Generating plant availability can be expressed in terms of plant utilization factors (PUF's), which are primarily dependent upon plant type and plant age. For new capacity and most types of existing capacity, the following maximum PUF's are assumed:

1/ While the payback period for financial calculations is 50 years, the physical life of a hydroelectric project is typically in excess of 100 years. The effect of this discrepancy is insignificant because there are only 53 MW of hydro capacity.

Type	Maximum PUF
Hydro	0.50
Stream Electric	0.75
Combustion Turbine	0.50
Diesel	0.10

Plants are allowed to run at the maximum PUF from the start, except for new coal-fired steam electric plants which generally experience lower plant utilization in the first few years and also toward the end of their economic lives.

Hydroelectric generation systems, as a result of their storage ability and conservative ratings, can make additional power available for peaking and it is assumed they can be scheduled at 115 percent of design capacity for this service, except during the critical hydraulic period when head limits plant output.

The results of the base case are presented as Exhibit C-1. In those years when Susitna hydropower is available, the total system's surplus capacity in any given year is subtracted from Susitna hydro capability in that year to give the actual amount of Susitna capacity that is usable. The remainder of the Susitna capacity is considered temporarily surplus to the needs of the market area and no capacity benefit is claimed. For instance, refer to Exhibit C-1, Watana POL in 1994 and the midrange load forecast. In 1995-96 (Pages C-1-13 and C-1-14), adding Anchorage and Fairbanks, Watana is on line with 703 MW dependable capacity and 808 MW overload capacity. The combined Anchorage and Fairbanks surplus peak capacity in that year is 543 MW. 1/ Therefore, only 265 MW, or 808 less 543, is usable Susitna capacity. Although no benefits are claimed for the hydro capacity that appears surplus to the needs of the market area, that capacity in actuality would be utilized to generate power. This would result in older thermal generation being placed in a cold reserve status. This, in turn, extends the useful life of these temporarily retired plants and postpones the need for future capacity additions. Though real, the monetary benefits attributable to this postponement of new capaicty are minor and has been ignored in this analysis.

For both the medium and high range load growth cases, additional coal-fired generation would have to be installed after Watana completion

1/ The load resource analysis shows 101 MW surplus in Fairbanks, but this must be adjusted down by 25 MW to account for the 25 MW steam plant that comes on line subsequent to Watana.

but before Devil Canyon power would be available. Unfortunately, due to construction timing requirements, Devil Canyon cannot be advanced in order to postpone the coal-fired addition.

Once the Susitna project's dependable capacity is fully absorbed by increasing peak load requirements, there is the opportunity to capitalize on the hydroelectric projects' capability to produce additional peaking capacity on an intermittent basis. This additional capacity is available when the net power head exceeds the critical head. (The critical head is where rated capacity is available at full gate opening.) The amount of additional capacity increases with head until the full 15 percent overload is reached. This occurs at full gate and average head (where generator output is maximum), which is at about 630 feet for Watana and 545 feet at Devil Canyon, as can be seen on Figure C-2. Figure C-3 shows that the head at Watana exceeds 630 feet about 75 percent of the time. Because the power pool at Devil Canyon is almost never drafted, Devil Canyon head is sufficient to produce 15 percent overload essentially 100 percent of the time.

Since this interruptible capacity cannot be guaranteed, its value is typically less than that for dependable capacity. In keeping with accepted practice, interruptible capacity, when needed to meet peak load requirements, is valued at 50 percent of dependable capacity. 1/ For purposes of benefit calculations, Watana is credited with 15 percent of its at-market dependable capacity, or 103 MW of interruptible capacity. (Since the full amount is available only 75 percent of the time, the figure is adjusted downward to 77 MW.) The comparable figure for Devil Canyon is 100 MW, which brings the combined project's interruptible capacity to 177 MW for benefit calculation.

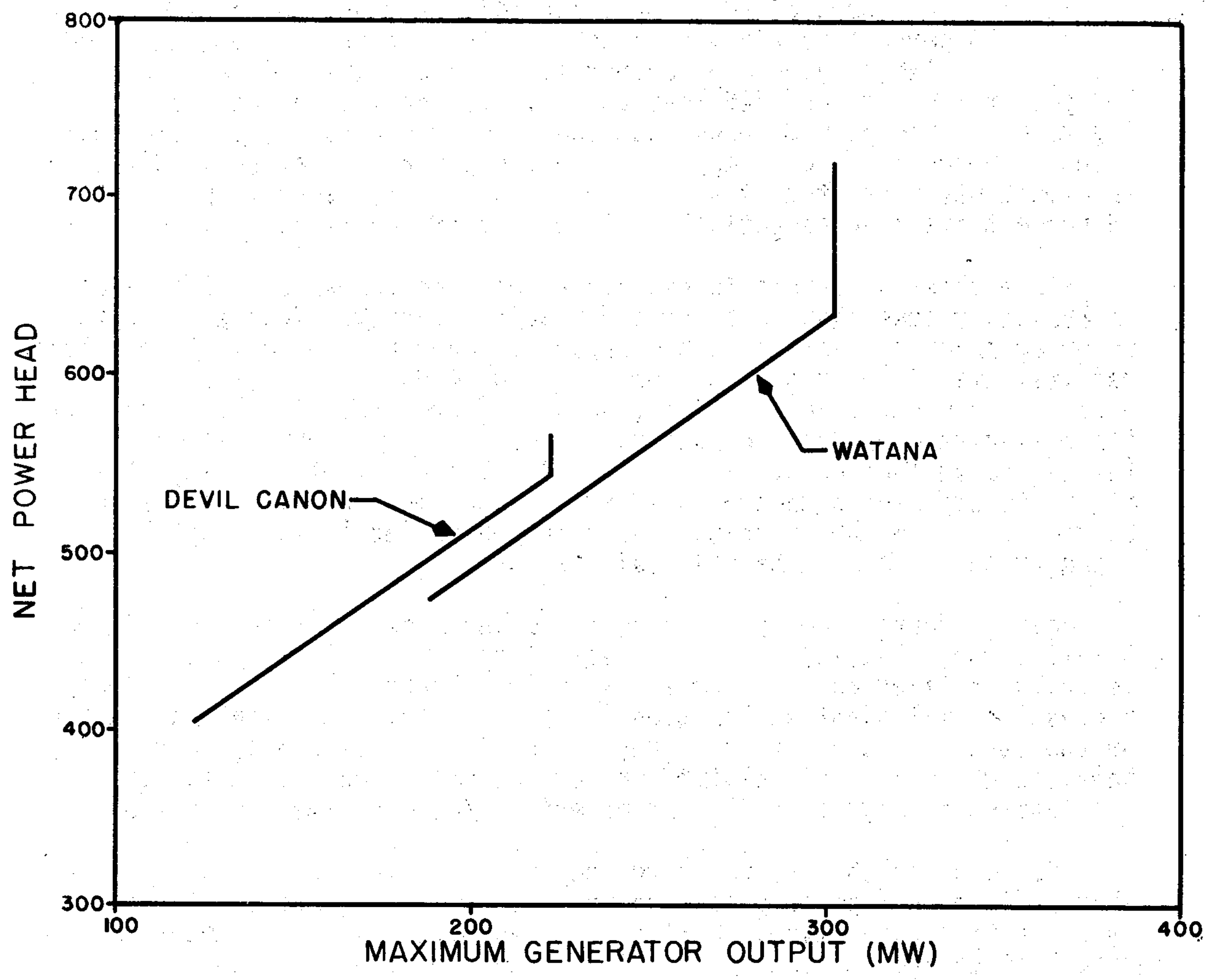
Again referring to the load resource analyses in Exhibit C-1 (Pages C-1-13 through C-1-18), it can be seen that the Susitna project's energy is fully utilized as it becomes available. There is no surplus energy because thermal plant utilization factors are reduced to take advantage of the less expensive hydro energy. Therefore, unlike Susitna capacity benefits which are only claimed through assimilation into the system, all Susitna energy is useful and benefits can be claimed for all of it.

The value of this hydro energy depends upon the type of generation that would otherwise be producing the energy in the absence of the hydroelectric generation. Part of the hydro energy goes to meet the growth in demand for energy over time. In the absence of the hydroelectric project, this load growth would be met by new coal-fired

1/ Department of the Army, Office of the Chief of Engineers, Digest of Water Resources Policies, p. A-129.

Figure C-2

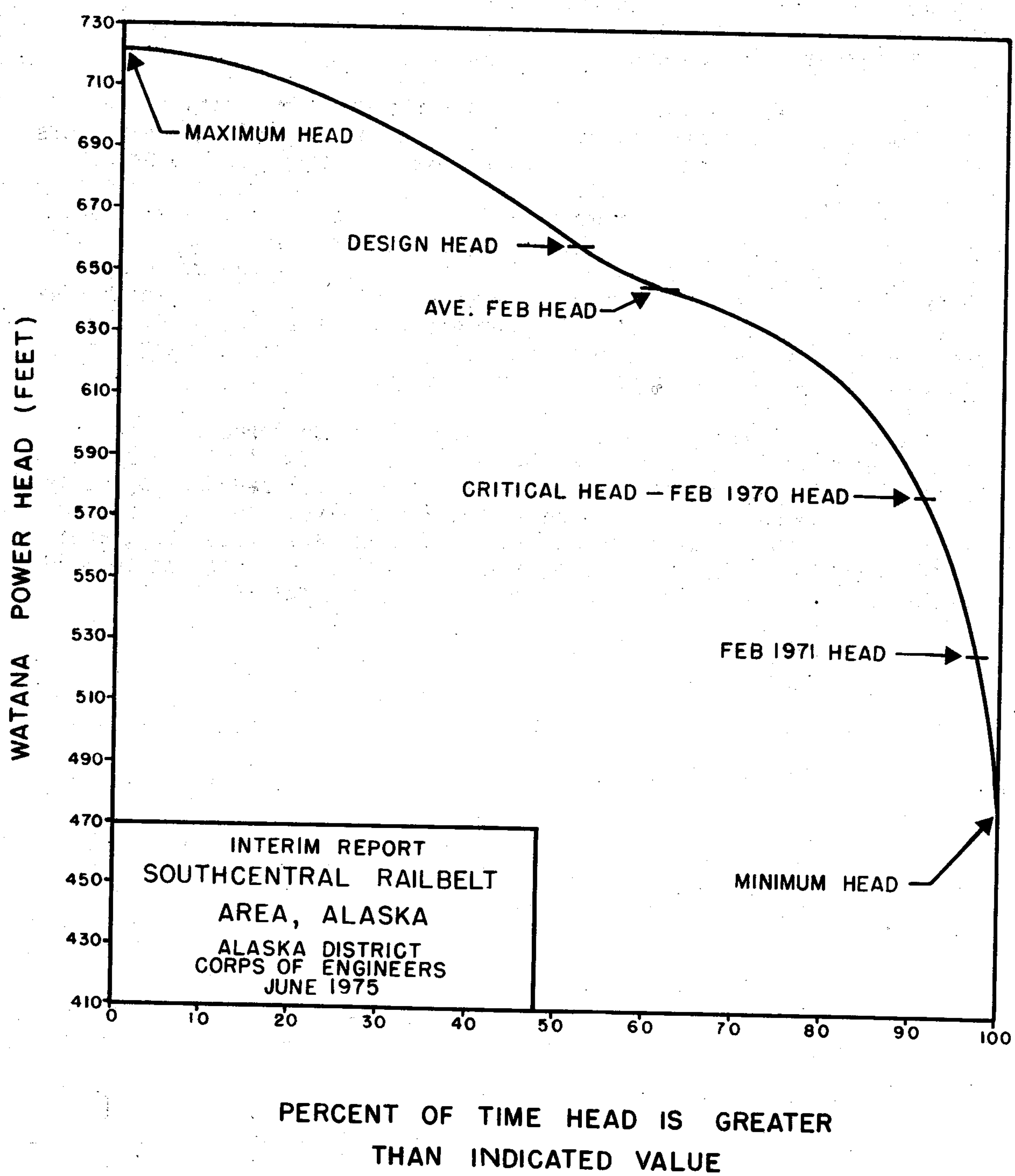
DEVIL CANYON AND WATANA
UNIT MAXIMUM PERFORMANCES



INTERIM REPORT
SOUTHCENTRAL RAILBELT
AREA, ALASKA
ALASKA DISTRICT
CORPS OF ENGINEERS
JUNE 1975

Figure C-3

ANNUAL HEAD DURATION CURVE
WATANA RESERVOIR



generation, and the value of this portion of the hydro energy is therefore the cost of coal-fired energy. The remainder of the hydro energy displaces more costly thermal generation. While the existing thermal plants continue to provide peak load capacity, the utilization of the plants decline. This displaced energy is comprised of several types of generation: coal-fired steam, oil-fired and gas-fired plants, and diesel plants, each having its unique energy cost. The value of the hydro energy produced in any year, then, is a composite value determined by the relative shares of generation type that would be producing energy in the absence of the hydro.

The load-resource analysis shows that the great majority of the displaced generation is coal-fired, since the plant utilization factors of the diesel, gas, and oil-fired plants were already reduced prior to Susitna hydropower availability. This results in a composite energy value that, in the most extreme year, is only 5 percent greater than the coal-fired energy value. Within 12 years after power-on-line, all Susitna energy goes toward meeting load growth and is therefore valued entirely at the coal-fired value. Because the effect on project justification is so minor over the 100-year economic life, the benefit of the hydro energy has been calculated using the coal-fired energy value, not the slightly higher composite energy value.

The usable capacity and energy for the midrange forecast with interconnection in 1991, Watana power-on-line in 1994 followed by Devil Canyon in 1998 is presented in Table C-15 and is portrayed graphically on Figures C-4 and C-5. The usable capacity analysis results for the various cases analyzed appear as Exhibit C-3 and are presented graphically in Exhibit C-2. Shown are cases for the low and high-range load forecasts, as well as for delayed power-on-line dates.

TABLE C-15

USABLE CAPACITY AND ENERGY, BASE CASE

Year	Dependable Capacity (MW)	Interruptible Capacity (MW)	Prime Energy	Secondary Energy
1994 *	27	0	2,997	0 **
1995	265	0	3,058	397
1996	680	0	3,058	397
1997	680	0	3,058	397
1998 #	950	0	6,057	397 **
1999	1,035	0	6,057	785
2000	1,231	0	6,057	785
2001	1,347	1	6,057	785
2002 ##	1,347	177	6,057	785

* Watana power-on-line with interconnection.
** Less than full energy availabe due to reservoir filling.
\# Devil Canyon power-on-line.
\## Full utilization of Susitna power.

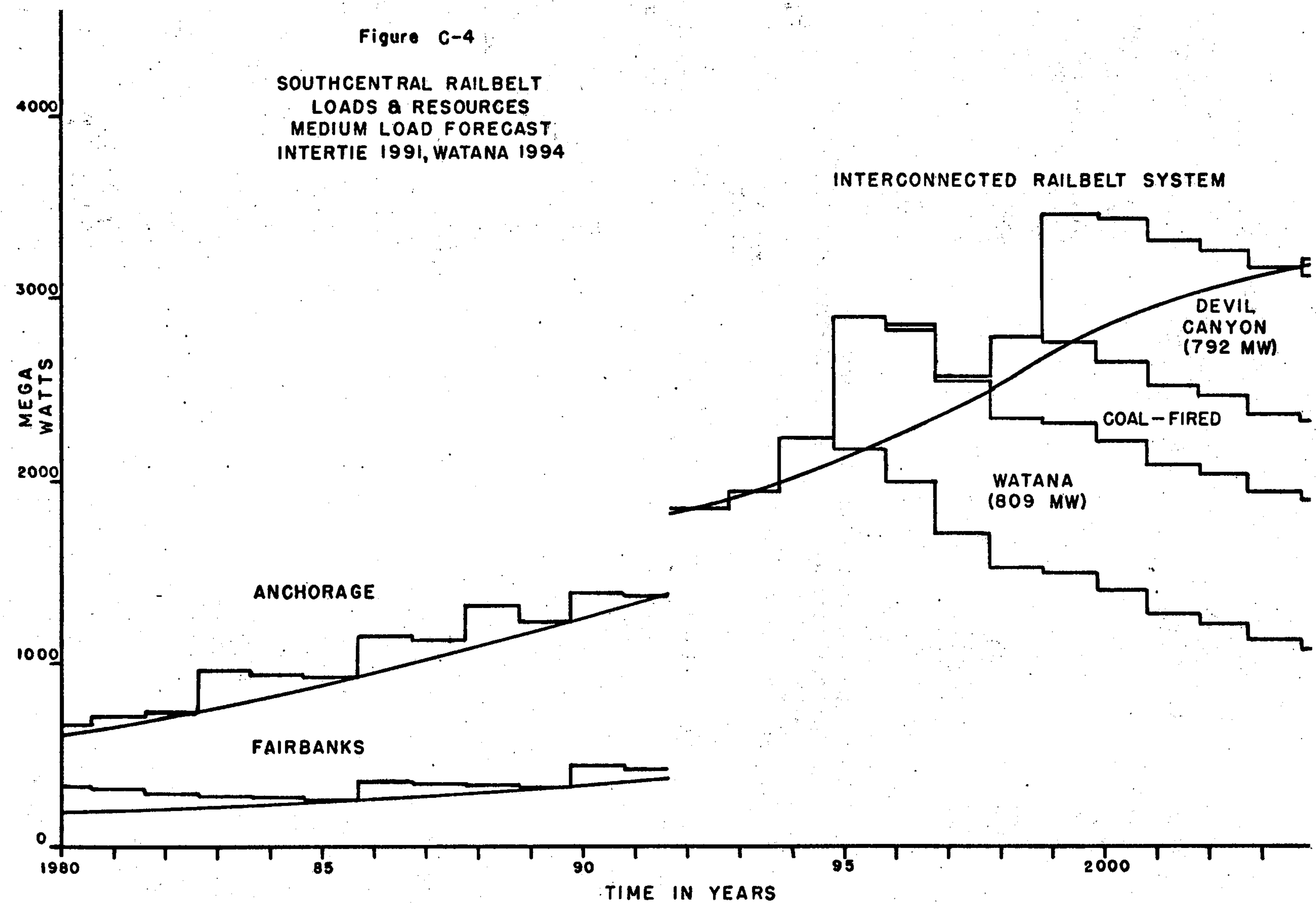


Figure C-4
SOUTHCENTRAL RAILBELT
LOADS & RESOURCES
MEDIUM LOAD FORECAST
INTERTIE 1991, WATANA 1994
INTERCONNECTED RAILBELT SYSTEM
DEVIL
CANYON
(792 MW)
COAL-FIRED
WATANA
(809 MW)
ANCHORAGE
FAIRBANKS
MEGA WATTS
4000
3000
2000
1000
0
1980
85
90
95
2000
TIME IN YEARS

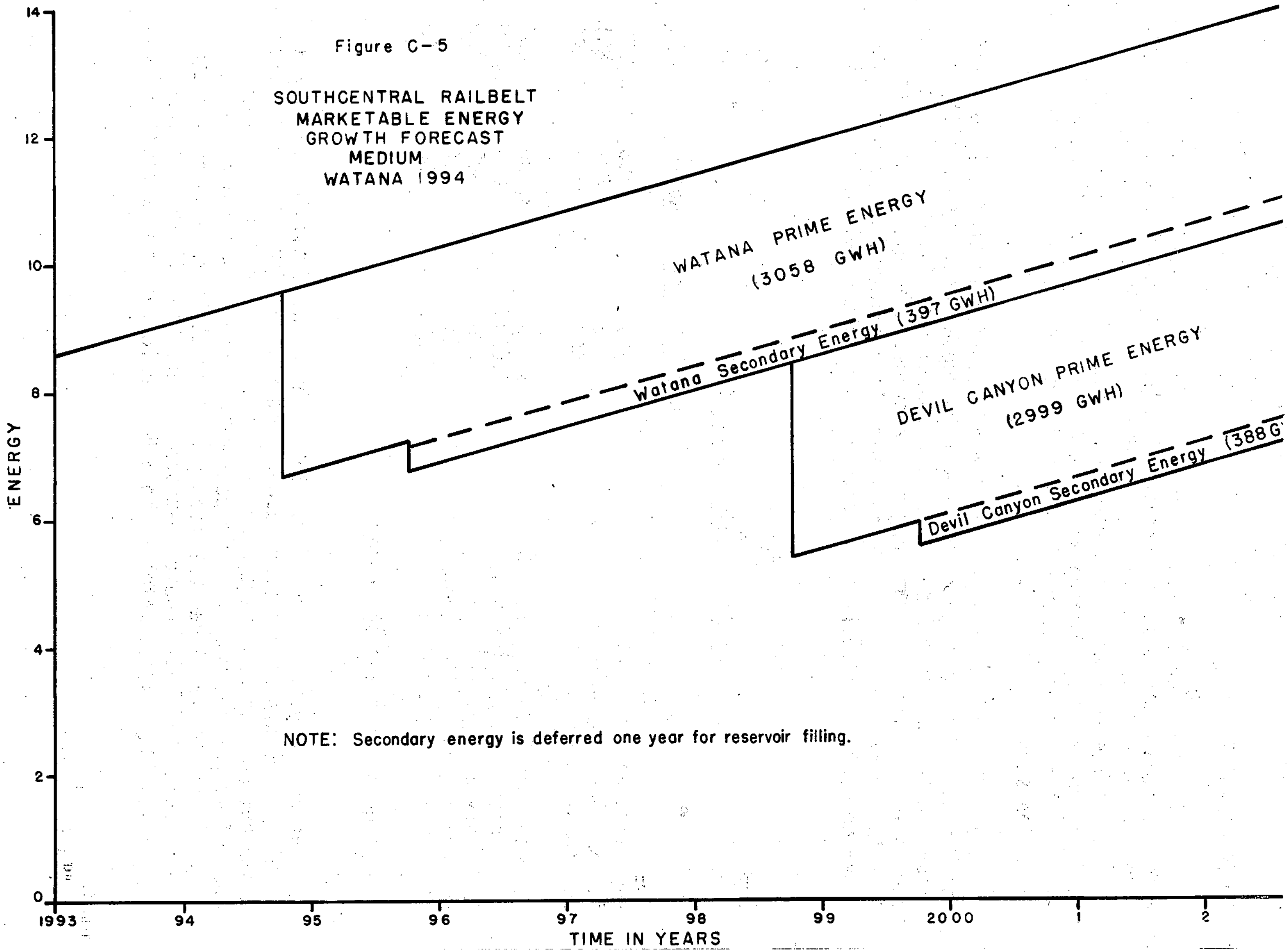


Figure C-5

SOUTHCENTRAL RAILBELT
MARKETABLE ENERGY
GROWTH FORECAST
MEDIUM
WATANA 1994

POWER CAPABILITIES

The installed capacities at Devil Canyon and Watana reservoirs were selected based upon the project firm annual energy produced in a 28-year period of historical streamflow (1950-1977). This period included three new years of streamflow, in addition to the 25 years used in the original scoping analysis prepared in 1975. An updated seasonal load curve prepared by APA was used in the new simulated operation study.

The addition of the 3-year period of recorded streamflows resulted in changes to the average annual and firm annual energy capability amounting to less than 2 percent. The annual runoff for the 3-year period is 96 percent of the long-term average. Therefore, no adjustment in the original energy capabilities is considered necessary. The power generating capabilities for the project are given in Table C-16.

TABLE C-16

AT-SITE POWER CAPABILITIES

	Devil Canyon	Watana	Total
Installed Capacity, MW	689	703	1,392
Peaking Capacity, MW	792	809	1,601
Dependable Capacity, MW	689	703	1,392
Average Annual Energy, 10^3 MWh	3,410	3,480	6,890
Firm Annual Energy, 10^3 MWh	3,020	3,080	6,100
Secondary Energy, 10^3 MWh	390	400	790
Average Annual Spilled Energy, 10^3 MWh	31	44	75
Plant Factor - Percent 1/	50	50	50

1/ Based on firm annual energy.

The driest year of record was 1969, which was estimated to have a 1,000 year return period based upon a Log Pearson Type III probability distribution, with an average annual runoff at Devil Canyon of 5,600 cubic feet per second, or 59 percent of average. The second driest year of record (1950) had a return period of 20 years with an average annual runoff of 7,340 cubic feet per second. The 100-year average annual low flow is estimated to be 6,500 cubic feet per second or 68 percent of average. The 10 month period immediately following the 100-year low flow would likely be the most critical power period to be encountered in the life of the project.

The project dependable capacity is based upon the firm annual energy and is equal to the installed capacity. The project firm annual energy using the 28-year record of historical flows occurred in 1971. During May of that year total project storage was reduced to its lowest level of the entire period (230,000 acre-feet or 3 percent of usable storage). The annual energy produced by the project in 1971 was approximately 6,100,000 megawatt hours.

The maximum peaking capacity for both powerplants is 115 percent of installed or rated capacity at 0.9 power factor. This 15 percent overload capability was assumed to be available only at or near maximum head on each unit for routing purposes.

The large storage capacity of Watana reservoir provides nearly full river control. Spills occurred in 8 of the 28 years of record and were only about 1 percent of the average annual project energy.

The transmission losses have been estimated by APA to be 3.2 percent on-peak and 0.7 percent for the long-term average. The at-market power capabilities are shown in Table C-17.

TABLE C-17

AT-MARKET POWER CAPABILITY

	At-Site	Losses	At-Market
Installed Capacity, MW	1,392	45	1,347
Peaking Capacity, MW	1,601	51	1,550
Dependable Capacity, MW	1,392	45	1,347
Average Annual Energy, 10^3 MWh	6,890	48	6,842
Firm Annual Energy, 10^3 MWh	6,100	43	6,057
Secondary Energy, 10^3 MWh	790	6	784

SEASONAL RESERVOIR OPERATION

The 1978 update of the simulated operation study did not result in any substantial revisions to the overall pattern of project operation. The general criterion as before was to maintain Devil Canyon reservoir at maximum pool to realize the greatest possible head on that reservoir. During the winter, withdrawals were made from Watana storage to meet the system power demand. Devil Canyon storage was used only after the supply in Watana reservoir was exhausted.

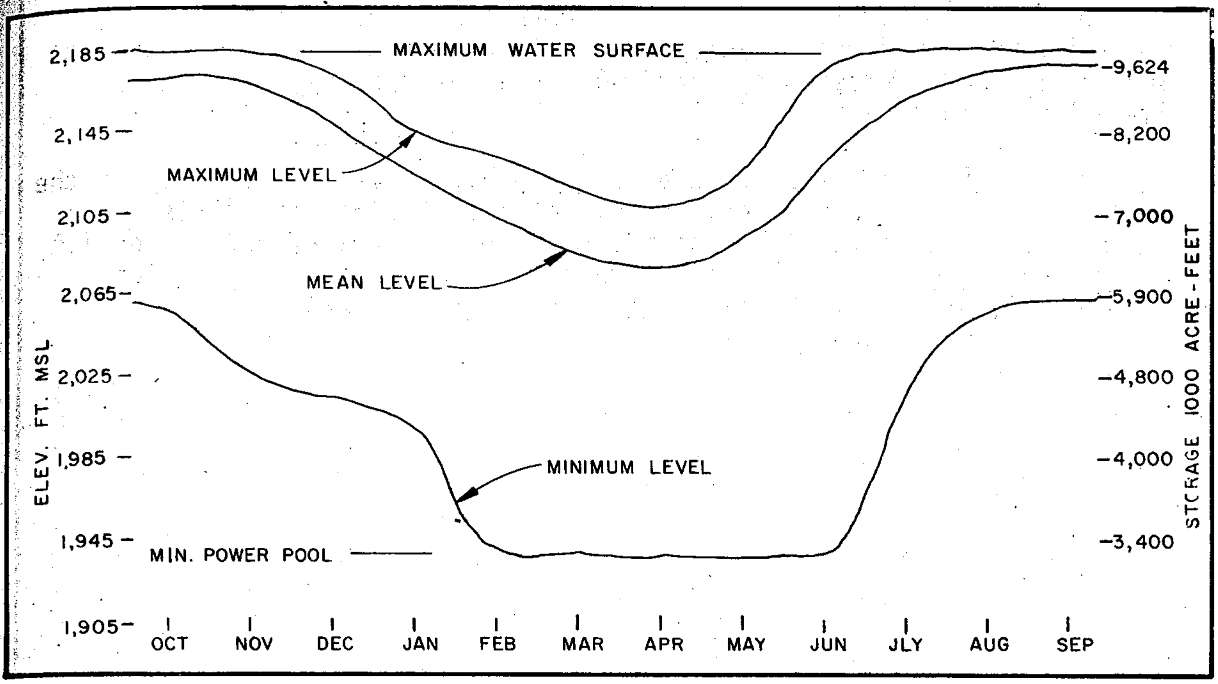
The general characteristics of the Watana operation are shown in Figure C-6. The pool elevations shown have been adjusted in accordance with the topographic information obtained in the 1978 field surveys at the Watana damsite. In years of average streamflow the maximum drawdown on Watana reservoir was about 100 feet. The reservoir reached minimum active pool (elevation 1,940 feet) on only two occasions in the 28-year period.

In the simulated operation, one criteria was to fill Watana reservoir on September 30 each year. This was not possible, however, in 13 of 28 years of record. In such years of reduced streamflow, it proved to be inefficient to draw the Watana pool to a low level on September 30 in order to meet the system load requirement. If the reservoir was consistently drawn below elevation 2,100 feet (storage = 6,700,000 acre-feet) on September 30 each year, the resulting head loss was of such magnitude that the project was unable to recover sufficiently to meet minimum system load requirements, even in years with above average runoff. The minimum September 30 carry-over for Watana reservoir was therefore set at 6,700,000 acre-feet for the updated 1978 simulated operation studies. The generation and water storage levels for Devil Canyon and Watana reservoirs for the entire 28-year period of record are shown on Plates C-1 and C-2.

The spring and summer filling operation for Watana reservoir in the operation studies was guided only by a fixed flood control rule curve. In later scoping studies this operation could be improved somewhat through the use of a variable rule curve based upon both 7-day and seasonal volume forecasts.

In the simulated operation, only the releases necessary for minimum generation requirements were made until the month when the reservoir would fill or encroach the flood space. Only during that month could the excess runoff be used to generate secondary energy. The method of operation results in unnecessary spillage of water.

In order to obtain a more realistic estimate of the spill frequency at Watana reservoir, a separate study was conducted. In this study the daily inflow to Watana reservoir was estimated using the records from the stream gage at Gold Creek. It was assumed that the full hydraulic capability of the Watana turbines could be used for 15 days in advance of the spills observed in the other simulation study. In addition, for 5 days in advance of the spills, the outlet tunnel with discharge capacity of 30,000 cfs was used to maintain the pool below



NOTE: DATA FROM OPERATIONAL STUDY OF AVERAGE MONTHLY STREAMFLOW FOR PERIOD OF RECORD 1950-1977 WITH JAN 1976 SELECTED PROJECT PLAN.

Figure C—6

OPERATING LEVELS

WATANA RESERVOIR

ALASKA DISTRICT, CORPS OF ENGINEERS

ANCHORAGE, ALASKA

OCTOBER 1978

the crest of the spillway as much as possible. When the inflows exceeded the discharge capacity of both the powerplant and the outlet works and the reservoir reached full pool, the spillway, of course, had to be used.

The results of the study are shown in Figure C-7. The curve on the right indicates the frequency of spills if the outlet tunnel is not used; the curve on the left assumes both the powerplant and the outlet tunnel are used. The curve illustrates that the spillway at Watana reservoir would be used approximately once in 10 years.

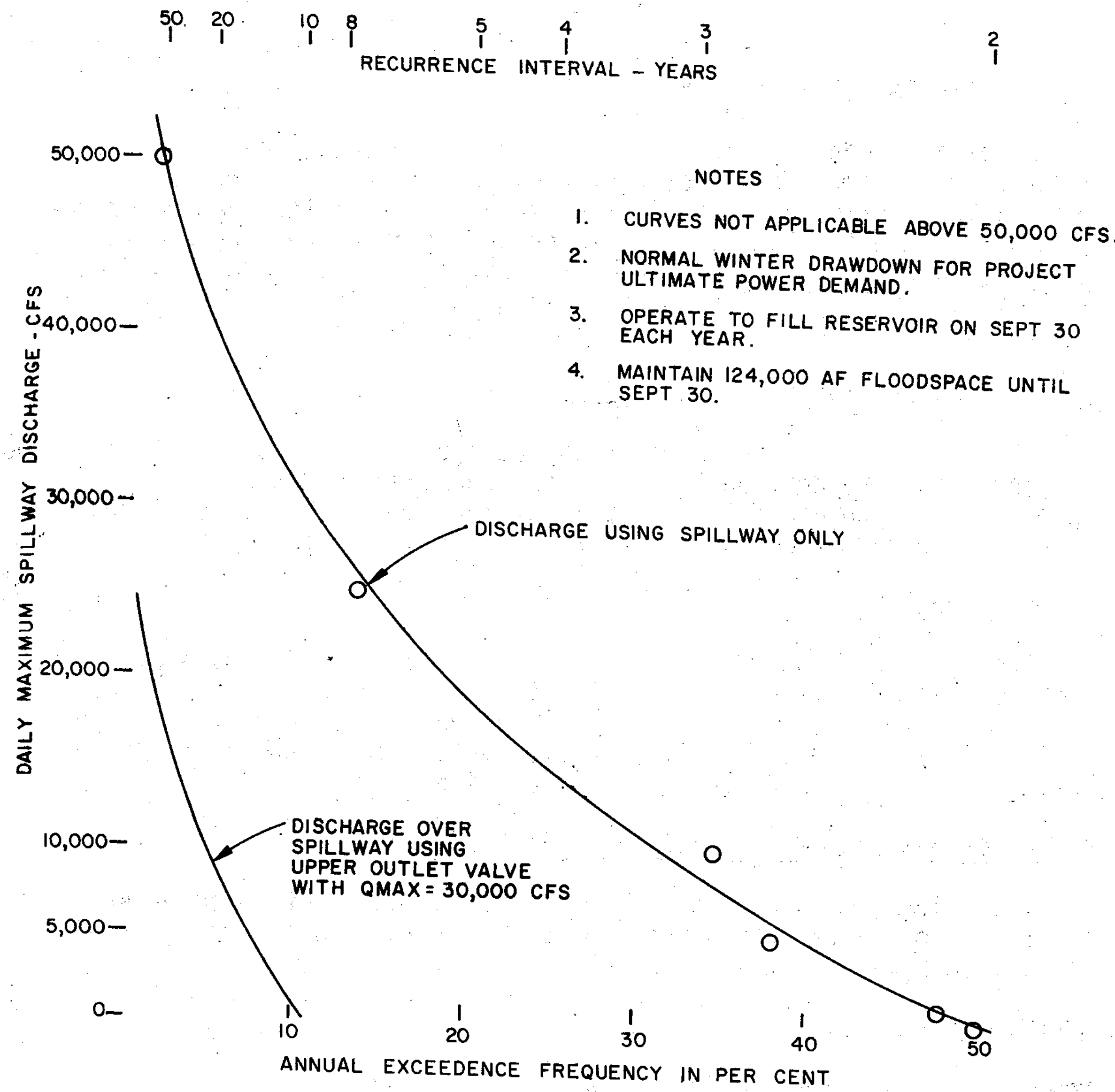


Figure C-7

SPILL FREQUENCY
DIAGRAM
WATANA RESERVOIR

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

OCTOBER 1978

69-738 O - 80 - 30

COSTS - THE BASE CASE

A detailed construction cost estimate for Watana, Devil Canyon, and the connecting transmission systems is presented in Section B, Project Description and Cost Estimates. It is expected that construction will begin in 1984, the transmission intertie would be complete in 1991, Watana would be complete in 1994, and Devil Canyon would be complete in 1998. Total estimated first cost of Devil Canyon and Watana plus the transmission system is $2.588 billion.

Interest During Construction (IDC)

The interest charged on money expended during the construction period is considered an additional cost of the construction phase. Simple interest is calculated at 6-7/8 percent for each year's expenditure and added to first cost to establish the investment cost.

System Annual Costs

Expenditures and IDC made after the October 1994 POL date of Watana are discounted to 1994. The resultant total investment cost is then transformed into an equivalent average annual fixed cost by applying the appropriate capital recovery factor associated with the 6-7/8 percent interest rate and 100-year project life.

Annual Operations, Maintenance, and Replacement

Operations, maintenance, and replacement costs estimated by APA are added to the average annual costs to obtain a total average annual cost of $228 million. See Table C-18.

HYDROPOWER BENEFITS

Power Values and Alternative Costs

The power values and alternative costs for use in power benefit calculations were developed by the San Francisco Regional Office of the Federal Energy Regulatory Commission (FERC), an agency of the Department of Energy. A copy of the letter forwarding the power values is included in Exhibit C-7. The method of analysis used by the FERC staff in developing the power values is explained in Hydroelectric Power Evaluation, by the Federal Power Commission (FPC), dated March 1968. The calculations were based on a 50 percent plant factor for the upper Susitna basin projects. Based on future load estimates, FERC

TABLE C-18

ANNUAL COST COMPUTATIONS
(in thousands of dollars)

Year	Watana: Expenditure	Watana: Accumulated Expenditure	Watana: IDC	Devil Canyon Gravity Dam: Expenditure	Devil Canyon Gravity Dam: Present Worth of Expenditure	Devil Canyon Gravity Dam: Accumulated Expenditure	Devil Canyon Gravity Dam: IDC	Devil Canyon Gravity Dam: Present Worth of IDC
1984	30,500		1,048					
1985	107,000	30,500	5,775					
1986	114,000	137,500	13,372					
1987	159,000	251,500	22,756					
1988	218,500	410,500	35,733					
1989	214,000	629,000	50,600					
1990	248,000	843,000	66,481					
1991	258,000	1,091,000	83,875					
1992	223,000	1,349,000	100,409	39,000	39,000		1,341	1,341
1993	161,000	1,572,000	113,609	98,500	98,500	39,000	6,067	6,067
1994	32,000	1,733,000	120,244	117,000	117,000	137,500	13,475	13,475
1995	1,765,000	1,765,000	613,902	137,000	128,187	254,500	23,581	22,064
1996				144,000	126,070	391,500	38,191	33,436
1997				158,000	129,428	535,500	43,622	35,734
1998				129,500	99,258	693,500	53,505	41,010
				823,000	737,443	823,000	179,782	153,127

	Watana	Devil Canyon	Total Watana & Devil Canyon
Construction Cost	$1,765,000	$737,443	$2,502,443
I.D.C.	613,902	153,127	767,029
Investment Cost	$2,378,902	$890,570	$3,269,472
Interest and Amortization	$ 163,761	$ 61,307	$ 225,068
Operation, Maintenance, and Replacement	2,620	700	3,320
Average Annual Cost	$ 166,381	$ 62,007	$ 228,388

assumed that the output of the proposed hydropower project would be utilized between the two major railbelt area load centers in the ratio of 80 percent to Anchorage-Kenai and 20 percent to Fairbanks-Tanana Valley.

Power values are provided for two generation alternatives at each of the load centers. An oil-fired combined cycle plant located near Anchorage and a mine-mouth coal-fired steam-electric generating plant located near the Beluga coal fields are considered as alternatives to hydropower for the Anchorage-Kenai area. For the Fairbanks load center, an oil-fired regenerative combustion turbine plant near Fairbanks and a mine-mouth coal-fired steam-electric plant near Healy are suggested as the proper alternative power sources. FERC notes that the agency is unable to state that either is the most probable source, despite the oil-fired alternatives appearing less expensive.

Whereas in 1975 FPC presented gas-fired generation as a possible alternative, it is no longer considered a viable option because of national policy and, specifically, the National Energy Act.

The Anchorage area coal-fired power values are based on a two unit, 450 MW plant with a service life of 30 years. The heat rate is 10,000 BTU/kwh and the annual plant factor is 55 percent. The investment cost estimate is $1,240 per kilowatt, while the cost of fuel is estimated at $1.10 per million BTU. Included in the estimate are baghouse filters and SO_2 scrubbers at $187 per kilowatt and cooling towers at $35 per kW. These are July 1978 costs, and neither inflation nor fuel cost escalation are considered.

The coal-fired alternative at Fairbanks is a two unit 230 MW plant, also with a 30 year service life. Its heat rate is 10,500 BTU/Kwh and has a 55 percent plant factor. The estimated investment cost is $1,475 per kilowatt and the fuel cost is assumed to be $.80 per million BTU. Included in this estimate are electrostatic precipitators and SO_2 scrubbers at $357 per kW and cooling towers at $44 per kW. Again, these are the costs as of July 1978.

Financing for the Anchorage alternative is a combination of 75 percent REA and 25 percent municipal. In Fairbanks, the assumption is that financing would be provided by the Alaska Power Authority.

The composite capacity value of the coal-fired alternative is $186.58 per kilowatt-year. The corresponding energy value is 12.76 mills per kWh. This and other sets of power values are shown in more detail in Exhibit C-4.

Natural Gas Alternative

In not providing power values for a gas-fired thermal alternative, FERC indicates its agreement with APA and the Corps of Engineers that natural gas is not an appropriate long-term alternative to hydropower in the Anchorage area. This is in keeping with the National Energy Act which prohibits such use in base-load plants with very limited exception.

The strongest argument against the use of natural gas for electrical generation is the national energy policy, but limited Cook Inlet supplies offer additional rationale. Since the Office of Management and Budget specifically commented on the Cook Inlet gas supply situation, updated information has been gathered.

The estimated Cook Inlet natural gas balance through the year 2000 is presented in Table C-19. The reserve estimates are based on an analysis entitled "Estimated Recoverable Gas Reserves from Gas Fields in the Cook Inlet Area" by the State Division of Oil and Gas Conservation, April 13, 1978. Division analysts believe that more detailed study would likely result in as much as a 20 percent increase in the estimate for three fields. 1/ This correction would result in an increase of 436 BCF over the 13 April 1978 estimate of 3,776 BCF. Not included in the Division's estimate are approximately 216 BCF of Kenai Field gas that has been leased for reservoir pressure maintenance. This gas will be returned in future years and will be available for sale. The adjusted estimate of recoverable Cook Inlet gas reserves is therefore 4,428 BCF. The Alaska Division of Mineral and Energy Management estimates potential additional resources of about 7 trillion cubic feet; such estimates are speculative with little agreement among experts.

Approximately 3,698 BCF, or 84 percent of those reserves are presently committed to Alaskan and export uses. Table C-20 presents the estimated reserves and commitments by field. The Pacific Alaska LNG contracts, amounting to 952 BCF, have lapsed as a result of failure to gain FERC approval of the project. The approval has been delayed largely due to the PALNG's inability to gain gas committments sufficient to operate at required scale. PALNG continues to explore for gas in Cook Inlet and eventual FERC approval is anticipated. PALNG expects the lapsed contracts to be readily reinstated with an extended deadline for project approval and some renegotiation of price. The PALNG lapsed contracts are therefore considered committments for this analysis.

1/ Conversation with staff of the Division of Oil and Gas Conservation, 27 September 1978.

There has been an unwillingness on the part of natural gas owners to enter into contracts for the provision of gas during a period of rapidly escalating gas prices and great uncertainty regarding gas price deregulation. Additional commitments are anticipated as the pricing structure stabilizes.

In 1976, 34 percent of Alaska's total energy consumption was provided by Cook Inlet natural gas. The uses are detailed in Table C-21. In the same year, 54 percent of Alaska's electrical generation was provided by Cook Inlet gas. Natural gas is exported in large quantities in the form of both LNG (liquified natural gas) and ammonia-urea fertilizer. Comparing consumption in 1976 with the previous year, natural gas use was up 12 percent with the largest increase, 18 percent, in electricity generation.

Projections of natural gas consumption levels between 1980 and 2000 were developed in a study for the Alaska Royalty Oil and Gas Development Advisory Board and the 1978 Alaska State Legislature. The report, published in January 1978, is entitled <u>Oil and Gas Consumption in Alaska, 1976-2000</u>. A base case projection of gas demands is presented and possible departures from the base case are analyzed. Over the entire period, natural gas use is forecasted to grow at 2 percent annually. This low rate is attributable to the base case assumptions of prohibition on the use of gas in new electricity generating facilities in the mid-1980's and only moderate increases in industrial use. As a result, use of gas in 1980 is 238 billion cubic feet, up from 165 BCF in 1976. By 2000 its has risen to 267 BCF, reflecting the fact that most of the growth in natural gas consumption is assumed to occur in the near term and in the industrial sector.

The forecast shows gas use in space heating to be the most rapidly growing demand throughout the period at 5 percent. Gas use in electricity generation remains essentially constant, while industrial use of gas rises sharply in the near future, but further increases are assumed to be zero because of supply constraints. The base case assumes population growth of about 3 percent annually, per capita demand somewhat moderated by high energy prices, and no significant new industrial consumers of large amounts of gas.

The sensitivity of the projection to changes in several of the assumptions was tested. All resulted in increased demand relative to the base case. Two of the possible scenarios are of special interest and appear in Table C-19.

One possibility is the continued use of gas in new electricity generating units in Anchorage after the mid-1980's. By 1990 this would add about 23 BCF annually to gas demands for electric power, essentially doubling gas use by that sector. This would add 10 percent to total gas requirements in that year and increase the overall growth rate in gas consumption from 2 percent up to 3 percent for the projection period.

The active proposal to liquify Cook Inlet natural gas for transport to California is a second scenario of interest. As noted earlier, required FERC approvals have yet to be given, but PALNG continues to actively explore for additional Cook Inlet gas and to plan for construction of facilities beginning in 1980. This proposal would require about 80 BCF annually in its initial phase. Were adequate reserves available, this would be essentially doubled to 161.6 BCF annually. Over a period of 15 years (assuming a start in 1985) such a project would thus require from 1,200 to 2,424 BCF of Cook Inlet gas.

Another source of Cook Inlet gas demand forecasts is Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of South Central Alaska, a November 1977 report compiled by the Stanford Research Institute (SRI) for Pacific Alaska LNG Company. The SRI forecast is somewhat higher than that previously discussed. This difference is accounted for primarily in the industrial component, where SRI does not limit growth as was done in the 1978 base case forecast to accommodate anticipated supply constraints. The SRI intermediate forecast is presented along with the other three scenarios in Table C-19.

Summing the annual estimates of Cook Inlet demand requirements from 1976 to 2000 results in total estimated requirements of 5,211 BCF in the base case. The addition of Pacific Alaska LNG increases the forecast to 6,411 BCF or 7,635 BCF depending on the scope of the operation. The addition to the base case of new gas-fired electrical generation increases the forecast to 5,743 BCF. The SRI intermediate forecast of total demand over the period is 8,232 BCF, which includes full scale PALNG, but no new gas-fired generation.

Estimated proven Cook Inlet gas reserves are inadequate to meet the requirements in all forecasted cases. The deficit through the year 2000 varies from a low of 783 BCF in the base case to 3,804 BCF in the SRI intermediate forecast (see Table C-19). The use of Cook Inlet gas for new gas-fired electrical generation after 1985 would increase the year 2000 deficit by about 532 BCF.

There may or may not be sufficient undiscovered gas reserves in the Cook Inlet area to meet the anticipated deficit. Estimates of undiscovered reserves range from 6-29 trillion cubic feet. Because the Cook Inlet gas supply has historically far exceeded local demand and because

TABLE C-19

COOK INLET NATURAL GAS BALANCE
1977 to 2000 1/
(Billion Cubic Feet)

	Base Case	LNG to California (80 BCF/161 BCF Annually)	New Gas Generation in Anchorage (79 BCF Annually in 2000)	SRI Intermediate Case
Demand				
(A) Estimated Requirements	5,211	6,411/7,635 2/	5,743 3/	8,232 4/
(B) Committed Reserve 5/	3,698	3,698	3,698	3,698
(C) Remaining Requirements 6/	1,513	2,713/3,937	2,105	4,534
Supply				
(D) Estimated Recoverable Reserves 7/	4,428	4,428	4,428	4,428
(E) Uncommitted Reserves 8/	730	730	730	730
(F) Undiscovered Reserves 9/	?	?	?	?
Balance				
(G) Deficit (Not Including Possible Undiscovered Reserves) 10/	783	1,983/3,207	1,375	3,804

NOTES TO TABLE C-19:

1/ Based on "Oil and Gas Consumption in Alaska, 1976-2000," January 1978 by the Division of Energy and Power Development and the Division of Minerals and Energy Management, Table IV.1, with modifications explained below.

2/ Base case requirements plus additional LNG export from 1985 to 2000 of either 80 BCF annually or 161 BCF annually.

3/ Gas use in new gas-fired electrical generation increases from zero in 1985 to 79 BCF annually in 2000.

4/ Intermediate case without additional gas-fired electrical generation from "Natural Gas Demand and Supply to the Year 2000 in the Cook Inlet Basin of southcentral Alaska," November 1977 by the Stanford Research Institute for Pacific Alaska LNG Company, Table II.

5/ See Table 2.

6/ (C) = (A) - (B)

7/ See Table 2.

8/ (E) = (D) - (B)

9/ Estimates range from 6 to 29 trillion cubic feet but are too speculative for purposes of power planning.

10/ (G) = (A) - (D) or (C) - (E)

TABLE C-20

COOK INLET NATURAL GAS RESERVES AND COMMITTMENTS

Field	Source 1/	Committed (BCF)	Total Reserves 2/ (BCF)
Beaver Creek	PALNG	112	239
Beluga River	DOGC, PALNG	1,003	1,057
Birch Hill			11
Falls Creek			13
Ivan River	PALNG	101	101
Kenai	DOGC	1,708	1,785 3/ 4/
Lewis River	PALNG	22	90
McArthur River	DOGC, PALNG	87	140 3/
Nicolai Creek			17
North Cook Inlet	DOGC	666	912 3/
North Fork			12
Sterling			23
Swanson River			0
West Forelands			20
West Fork			8
TOTAL		3,698	4,428

NOTES:

1/ DOGC is short for "Summary of Gas Sales Contracts, Cook Inlet Area, March 15, 1976" by the Division of Oil and Gas Conservation. PALNG refers to data provided by Len McLean of Pacific Alaska LNG Company in an interview on 4 October 1978.

2/ The total reserve estimates are taken from "Estimated Recoverable Gas Reserves from Gas Fields in the Cook Inlet Area," April 13, 1978 by the State Division of Oil and Gas Conservation. The report was augmented by information provided by Lonnie Smith, Chief Petroleum Engineer, DOGC, in an interview on 28 September 1978.

3/ Includes a 20 percent increase over estimate contained in April 13, 1978 DOGC report on the basis of new information available to DOGC.

4/ Includes 216 BCF leased for reservoir pressure maintenance that was not included in the DOGC report.

TABLE C-21

1976 ALASKA GAS USE 1/

Use	Quantity (MMCF)
Final Consumption (Heating)	16,804
Electrical Generation	29,284
Extraction and Processing Uses	137,880 2/
Exports	87,765 3/
TOTAL	271,733

NOTES:

1/ Source is "Oil and Gas Consumption in Alaska, 1976-2000," January 1978.

2/ 26,798 MMCF production related; 111,082 MMCF reinjected, much of which can be eventually recovered.

3/ 63,509 MMCF for LNG; 24,256 MMCF for ammonia-urea.

until recently there has been no substantial export market, the Cook Inlet area has not yet been extensively explored for natural gas. Despite the possibilities, the speculative reserves are inappropriate for consideration in power planning. Regardless of availability, however, the worldwide competition for natural gas will escalate the price of gas to levels which will likely make new gas-fired base load generation uneconomic in the face of large available supplies of coal and hydropower potential.

Oil-Fired Generation Alternative

As noted previously, FERC provided power values based on both oil-fired and coal-fired generation for both Anchorage and Fairbanks. The National Energy Act generally prohibits the use of oil as fuel in new large-scale base load generating plants. The act also includes, however, several provisions under which a utility may be exempted from the restrictions on use of oil. Under the law, companies may be exempted from the fuel-switching requirement for new plants if they can prove it would be overly costly, environmentally unsound, or impossible because of insufficient or unavailable supplies of coal or other fuels at the plant's location.

Proposed regulations to implement the coal-conversion portion of the energy bill have been issued by the Department of Energy. 1/ To gain an exemption on cost grounds, for instance, a company would have to prove that a coal or alternate fuel plant was much more expensive than the oil or gas plant. Under the proposed rules, coal plants costing 30 to 80 percent more than oil or gas plants would not necessarily be considered too costly to avoid mandatory conversion. Based on the FERC-provided power values, annual costs for coal-fired generation are approximately 40 percent higher than for oil-fired. This is based on a 50 percent plant utilization factor and includes capital expenses as well as the costs for operation and fuels.

To gain an environmental exemption under the proposed rules, companies would be required to produce decisions from the Environmental Protection Agency or State agencies proving that coal plants would be environmentally unacceptable. Although some proposed plant sites in Alaska are extremely sensitive, such as at Healy adjacent to Mt. McKinley Park, there is no evidence that acceptable sites cannot be found.

To gain an exemption based on fuel availability at a plant's location, a utility would have to show it fully considered a range of alternative sites, including sites outside the utility's traditional service area. The substantial proven coal resources at both Healy and Beluga argue against using this rationale in seeking an exemption.

1/ As reported in the Wall Street Journal, November 14, 1978, p 14.

To gain an exemption based on an inability to raise capital, a company would have to show that the added capital needed to burn coal or alternate fuels, instead of oil or gas, equals 25 percent or more of the annual average capital budget.

In writing these regulations, it is clear that the administration's intent is to severly limit the scope of exemptions and place a heavy burden of proof on utilities seeking an exemption. Based on the proposed regulations, it would appear that railbelt utilities would have a difficult time obtaining exemption for new base load plants. The Alaska Power Administration, Department of Energy, agrees with this assessment. The APA Administrator, Robert J. Cross, writes that "(APA's) finding is that exemptions don't seem all that permanent or pertinent in terms of a large new hydro project coming on line in 1992. I just don't see the logic of the oil assumption in benefit determinations for 100-years of power from a major new hydro project." 1/ Also agreeing that oil is an inappropriate alternative for benefit calculation is the State's Alaska Power Authority. The Power Authority's Executive Director, Eric P. Yould, states that, "oil-fired generation for the railbelt area may not be acceptable either for legal and regulatory reasons or from the standpoint of fuel availability." 2/ He notes further that Golden Valley Electric Cooperative at Fairbanks recently analyzed the coal versus oil-fired generation question. GVEA has determined that the coal-fired generation alternative is preferable to oil if capital costs are not prohibitive. The full text of both pieces of correspondence are contained in Exhibit C-7.

Based on the foregoing, coal-fired generation has been selected as the most likely and appropriate alternative against which to compare the Susitna hydroelectric proposal. Coal is therefore the basis for the base case benefit calculations. Oil-fired generation is addressed in the sensitivity analysis.

Derivation of Power Benefits - The Base Case

Annual power benefits were computed by applying the unit value of capacity and energy to the usable output of the hydropower project. Benefits were computed for each year of the 100-year economic life of the project and were then discounted to the base date to determine the combined present worth. The base date in all cases is the power-on-line date of the Watana project. The prescribed Federal discount rate of 6-7/8 percent was used. The last step of the calculations

1/ Robert J. Cross, Administrator, Alaska Power Administration in a memo to FERC dated 9 November 1978.

2/ Eric P. Yould, Executive Director, Alaska Power Authority in a letter to Colonel George Robertson dated 17 November 1978.

entailed the conversion of the present worth value to an equivalent average annual benefit, again using the 6-7/8 percent discount rate. The results of the computer-aided calculations are shown in Exhibit C-5.

For the base case, which included coal-fired power values, the median load forecast, power-on-line dates of 1994 and 1998 for the two stages of development, transmission line completion in 1991, public/non-Federal financing of the thermal alternative, and stable prices, the average annual power benefits are estimated at $289 million. For Watana alone, the corresponding figure is $158 million.

OTHER BENEFITS

Recreation

Recreation-day values for 1978 were researched in order to check the need for changing the values as originally reported in the 1976 Interim Feasibility Report. A review of other projects such as the Chena Lakes Project at Fairbanks indicated that the former values are typical of 1978 visitor-day recreation values and remain unchanged. Therefore, the average annual benefit for recreation is $300,000.

Flood Control

The extent of damage prevention from downstream flooding remains unchanged. The dollar value of those losses has been adjusted to reflect the time elapsed since the original estimate. The annual benefits for flood control are $65,000.

Employment

When otherwise unemployed labor resources are used in the construction of a project, the economic cost of those resources is less than the prevailing wage rate. Conceptually, this adjustment can be made either by an appropriate reduction to the project's cost or by an increase in project benefits. The latter approach has been adopted by Corps of Engineers regulations.

The labor area for this project is to be Anchorage and Fairbanks. The proposed project will be located in an unpopulated area and will draw heavily from these two population centers. Alaska is designated by the U.S. Department of Labor as an area of substantial and persistent unemployment.

The present labor force in the Anchorage/Fairbanks area is 114,800, with approximately 12,534 in the construction industry. With an average 10,443 unemployed, approximately 25 percent or 2,610 are construction labor. The possibility of a gas pipeline project and the capital relocation will affect the availability of otherwise unemployed workers to the Susitna project. The adjustment depends on whether these projects occur prior to or concurrent with the Susitna project.

During the oil pipeline construction a preferential hire law was in force which directed pipeline contractors to hire qualified Alaska residents in preference to nonresidents. The Alaska Department of Labor reports that during construction of the oil pipeline the average percent of manpower requirements drawn from within Alaska was 40 to 50 percent. The proposed upper Susitna hydro project is much smaller than was the oil pipeline project. It is thought that an 80 percent local hire goal could easily be met. The proposed gas pipeline project is planned to begin in the early 1980's and completion is anticipated before Susitna construction begins.

Estimated yearly manpower expenditures for construction of the Devil Canyon and Watana dams and the transmission line are shown in Table C-22. These figures were derived by estimating the labor cost associated with each major feature of the project, net of contingencies. Overall, 38 percent of project costs are estimated to be labor expenses.

TABLE C-22

MANPOWER EXPENDITURES
($1,000)

Year	Skilled	Unskilled	Total	Percent of Total
1984	8,307	2,077	10,384	1.2
1985	28,378	7,094	35,472	4.1
1986	30,454	7,614	38,068	4.4
1987	42,221	10,555	52,776	6.1
1988	58,140	14,535	72,675	8.4
1989	57,448	14,362	71,810	8.3
1990	66,446	16,611	83,057	9.6
1991	69,214	17,304	86,518	10.0
1992	69,906	17,477	87,383	10.1
1993	69,214	17,304	86,518	10.0
1994	40,144	10,036	50,180	5.8
1995	36,683	9,171	45,854	5.3
1996	38,760	9,690	48,450	5.6
1997	42,221	10,555	52,776	6.1
1998	34,607	8,651	43,259	5.0
	692,143	173,036	865,179	100.0

Approximately 6 percent of these labor expenses are attributable to the contractors' supervisory and managerial functions. Of the remaining $813 million labor costs, 80 percent are expected to be paid to locally hired labor. Of this total an estimated 20 percent or $130,000,000 will be for unskilled labor, while 80 percent or $521,000,000 will be for skilled labor. Following the recommendations of Draft ER 1105-2-354, the proportion of labor costs claimed as employment benefits for skilled and unskilled categories are 40 percent and 55 percent respectively.

Using an interest rate of 6-7/8 percent, each year's benefits are present-worth to POL. Then, using the summation of all years, the appropriate capital recovery factor is applied to obtain the annual employment benefit for each category of workers (skilled and unskilled). The annual skilled labor benefit is $17,562,000 and the annual unskilled labor benefit is $6,037,000. Thus, the total employment benefit for the Susitna project is $23,599,000.

Similar procedures have been applied to the coal-fired and oil-fired generation alternatives to estimate their respective employment benefits. This is in keeping with Draft ER 1105-2-354 which directs that employment impacts of each alternative plan are to be assessed. The estimated labor portion of the total project cost was calculated using FERC investment cost data and labor percentages for the planned Healy II coal-fired plant. At a composite (Anchorage-Fairbanks) investment cost of $1,287 per kilowatt, the total cost of coal-fired plant construction, equivalent in output to the Susitna project, is $2,060,487,000. This total amount was scheduled over the planning period to reflect capacity additions indicated by the load-resource analysis medium range case.

According to Stanley Consultants, the engineering firm that has developed the plans for Healy II on behalf of Golden Valley Electric, approximately 40 percent of construction costs are payments to labor. 1/ Using the same proportion of skilled and unskilled labor as was used with the hydro project calculations and the same discounting procedures, the average annual equivalent employment benefit for the coal-fired generation alternative is $19,635,000. 2/ The comparable figure for the oil-fired alternative is $5,203,000. These estimates are presented for rough comparison only since they do not reflect a detailed study of labor requirements for thermal plant construction. Since, on average, a more skilled workes is required for construction of the thermal plant and since such a worker would probably not be available locally, the thermal alternative employment benefit estimate is probably somewhat overstated.

1/ Per conversation with Stanley Consultants, 20 December 1978.
2/ This amount incorporates a 20 percent reduction to account for contingency factors in the cost estimates, thus insuring comparability with the hydro project.

The thermal alternatives are procedurally defined to have power benefits equal to plan costs. The crediting of employment benefits, therefore, results in the thermal alternatives each having positive net benefits equal in magnitude to the employment benefit.

Intertie Benefits

The original feasibility report discussed the value of interconnected load centers made possible by the construction of a transmission line between Anchorage and Fairbanks. It was noted that intertie benefits arise from two aspects of interconnection, shared reserves and energy transfer.

The load-resource analysis has demonstrated that capacity additions can be postponed as a result of reduced reserve requirements in an interconnected system. Since the reserve margin effectively increases the amount of generating capacity in place at any given time, it contributes costs to the system. Therefore a reduction in that reserve margin will reduce cost. Realizing that a more refined analysis of desired reserve margins will be needed at a later date, APA now estimates that a 25 percent margin would be required without interconnection while only 20 percent reserves would be needed with interconnected load centers. These estimates are based largely on the experience in other market areas.

The flexibility afforded by the transmission line decreases as the line becomes loaded with Susitna power. The reserve reduction capability is limited by the unused portion of the line segment with the least capacity - that portion from Devil Canyon to Fairbanks. When the line is completed and before Watana power production begins, a full 300 MW capacity is available in the line. 1/ This is reduced as time goes on by the amount of Susitna capacity allocated to the Fairbanks load center. The capacity savings due to interconnection for each year, then, is the lesser of unused line capacity and the 5 percent reserve differential applied to the total peak load requirement. This is shown graphically in Figure C-8, and the results are presented in Table C-23. Each year's capacity saving is valued at the capacity value of a coal-fired steam plant as provided by FERC, $170 per kW. The values are discounted at 6-7/8 percent to give the present worth as of the Watana power-on-line date. The 100-year capital recovery factor is then applied to the summation to give the equivalent annual capacity benefit from interconnection.

1/ This figure is not an absolute maximum capacity, but rather a reasonable limit for the Devil Canyon-Fairbanks segment based on acceptable line loss.

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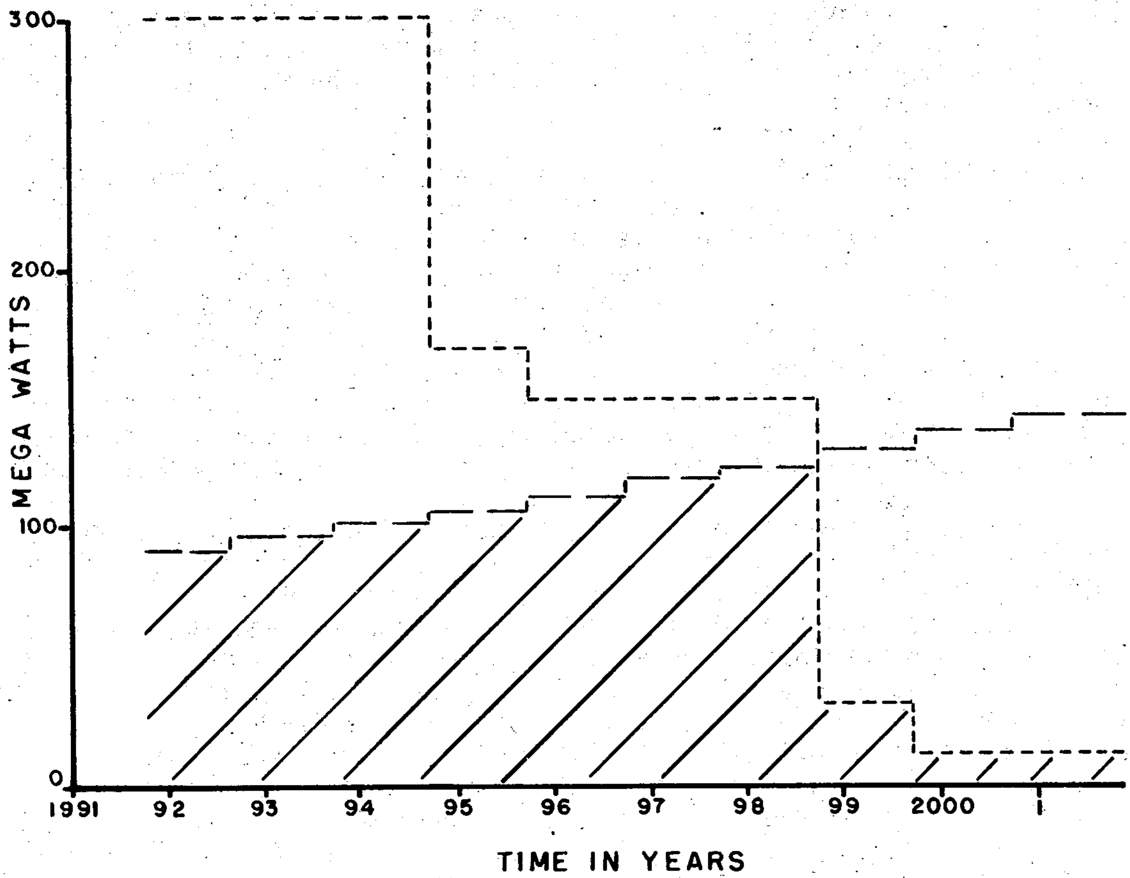
Figure C-8

TRANSMISSION LINE CAPACITY CREDIT



------ Unused Capacity

— — — 5 % Reserve Differential Applied To Total Peak Load Requirements.

TABLE C-23

INTERTIE CAPACITY BENEFITS

Year	Capacity Saving (MW)	Capacity Value ($1,000)	Present Worth ($1,000)
1991	90	15,300	18,700
1992	96	16,300	18,600
1993	101	17,200	18,400
1994	107	18,200	18,200
1995	114	19,400	18,200
1996	121	20,600	18,000
1997	128	21,800	17,900
1998	30	5,100	3,900
1999 through 2041	12	2,000	27,300
Total ($1,000)			$159,200
Annual Benefit ($1,000)			$ 10,959

The other aspect of interconnection discussed in the original feasibility report was the capability for transfer of energy from the low energy cost producing load center to the high cost area. The transfer allows a cost saving equal to the differential cost of energy production for the amount transferred. Estimates in 1975 indicated that energy could be transferred from Anchorage to Fairbanks for a cost saving of 2.48 mills/kWh. The 1978 estimates by FERC indicate that coal will be cheaper in Fairbanks than in Anchorage with the result that Fairbanks energy would be 2.65 mills/kWh cheaper than that produced by coal plants in Anchorage. This reversal in 3 years highlights the volatility of this cost differential. For instance, if new coal plants had to be located at some distance from the Healy coal fields due to their proximity to Mt. McKinley National Park's clean air, the additional cost for transporting the coal would essentially eliminate any energy cost differential. Therefore, although the opportunity remains to take advantage of energy cost differentials through the transfer of energy, no energy transfer benefits are claimed because of the possibility that energy production costs in the two load centers might well be almost equal.

PLAN JUSTIFICATION - THE BASE CASE

A summary of project costs and benefits for the proposed two stage development as well as for Watana alone are presented in Tables C-24 and C-25. The base case set of assumptions applies.

TABLE C-24

AVERAGE ANNUAL COSTS

Development	Interest & Amortization ($1,000)	O, M & R ($1,000)	Total (Rounded) ($1,000)
Watana	163,761	2,620	166,381
Watana and Devil Canyon	225,068	3,320	228,388

TABLE C-25

AVERAGE ANNUAL BENEFITS

	Watana ($1,000)	Watana and Devil Canyon ($1,000)
Power	163,958	288,700
Recreation	100	300
Flood Control	65	65
Intertie	10,959	10,959
Employment	18,654	23,599
Total	193,736	323,623

Benefits and costs are compared in Table C-26.

TABLE C-26

PLAN JUSTIFICATION

	Watana	Watana and Devil Canyon	Devil Canyon Last Added
Annual Costs ($1,000)	166,381	228,388	63,007
Annual Benefitis ($1,000)	193,736	323,623	129,887
Net Benefits ($1,000)	27,355	95,235	67,880
Benefit Cost Ratio	1.16	1.42	2.09

These figures indicate that, given the base case assumptions, the Watana-Devil Canyon system is economically justified; the Watana project first added is economically feasible by itself; and Devil Canyon is incrementally justified on a last added basis.

SENSITIVITY OF PROJECT JUSTIFICATION

This section presents the results of various sensitivity tests conducted to determine the impact on the project's economic justification of possible departures from the basic set of assumptions that underlie the calculation of benefits and costs. Each test was conducted using the same procedures as described earlier in this section, but with certain specific assumptions altered as outlined in the following paragraphs.

Comparability Test

The power values for the base case are computed using the most likely means of financing the various thermal alternatives. These included municipal, REA, and Alaska Power Authority financing. This test examines project justification when the power values are calculated on the basis of thermal alternative financing at the same rate applied to the hydropower alternative, the Federal discount rate of 6-7/8 percent. Using power values based on Federal financing, the average annual power benefits are $264 million, a decrease of 9 percent. The hydro project costs and nonpower benefits are already based on the Federal discount rate and therefore remain unchanged. The effect on project justification is noticeable; net benefits fall from $95 million to $71 million, while the justification ratio becomes 1.31.

With Federal financing, Watana alone offers net benefits of $14 million and a justification ratio of 1.08.

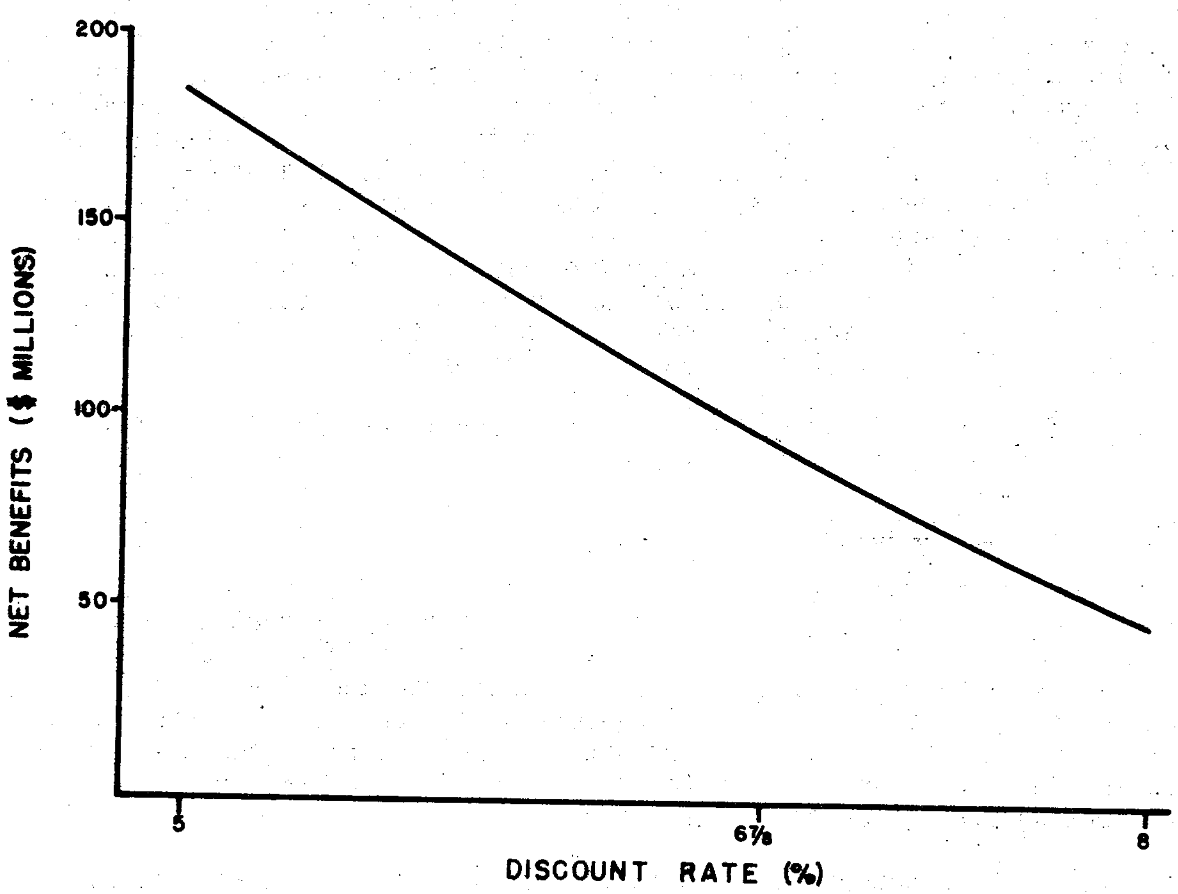
Alternate Discount Rates

The rate at which future project benefits are discounted and at which interest during construction is calculated can affect the comparison of projects. The discount rate to be used in the evaluation of Federal water resource projects is established annually and is pegged to the interest rate on long-term government bonds. This serves as an approximation of the opportunity cost of Federal funds. The established rate has risen to the current value of 6-7/8 percent, reflecting the influence of inflation.

In order to determine the magnitude of impact a different discount rate would have on the project's economic justification, benefits and costs were recalculated using interest rates lower and higher than the established rate. With a discount rate of 5 percent, annual costs decline while benefits increase. Net benefits rise from $95 million in the base case to $180 million, and the benefit-cost ratio becomes 2.14. With an 8 percent rate, the effects are reversed. Net benefits fall to $42 million with a benefit-cost ratio of 1.15. Refer to Figure C-9. It can be concluded that the project's economic justification is sensitive to changes in the discount rate. The effects would be dampered, however, if the costs of the alternative generation mode were similarly calculated using the alternate rates.

Figure C-9

PLAN JUSTIFICATION,
ALTERNATE DISCOUNT RATES



Variations in the Load Forecast and Project Timing

The base case set of assumptions incorporates the mid-range load forecast because it has been judged to reflect the most likely future power requirements. The actual demand for electrical power, however, will almost certainly depart from the mid-range forecast, and it is important to determine how such departures can effect the viability of the project. A significant departure on the low side could have several results. The first, and most likely, would entail a planned delay in the start of project construction when it became apparent that the load was not growing as rapidly as expected. Another possibility would be that the departure from anticipated growth only becomes apparent after construction has already begun. In this case, the construction period would be stretched out so that the project is not completed until the project's power is needed. A third possibility would be to postpone or cancel other generating resource additions with shorter lead times. The last and potentially most damaging possible circumstance would entail the sudden slackening of load growth immediately after the project was completed.

If, on the other hand, the load requirements grow more rapidly than expected, Susitna power would be needed earlier than presently planned. The Watana project, however, probably cannot be completed any earlier than the planned 1994 power-on-line date, and the Devil Canyon project cannot be completed earlier than 4 years after Watana.

To assess the impacts of these various circumstances, the load-resource analysis was conducted using the low and high range forecasts. With the low range forecast, the initial project continues to be required as soon as it is available, ie., 1994. A coal-fired steam plant addition in 1997 is no longer needed, but Devil Canyon is still required in 1998. The net effect is that Susitna capacity is absorbed at a slower rate, and power benefits fall 3 percent to $280 million. Net benefits become $87 million and the benefit-cost ratio is 1.38.

As noted above, the most damaging possibility in terms of project economics would occur if there was a sudden decrease in the rate of load growth immediately after power-on-line. This would mean that Susitna power would be needed less rapidly, and less Susitna capacity would be usable in the early years. In the base case, Susitna power is fully absorbed in the railbelt system by 2002. The annual growth rate in peak load during the period between power-on-line and 2002 is 4.6 percent. In the low-load growth case, Susitna power is absorbed over a longer period, between 1994 and 2010. The annual growth rate in peak load for this case is 1.9 percent. Additional cases were analyzed to determine how sensitive project justification was to the post-POL rate of load growth. At zero rate of load growth after 1994, the project offers net benefits of $26 million and a benefit-cost ratio of 1.1.

This test was premised on the low-load forescast prior to power-on-line. The Devil Canyon phase was constrained to come on line in 1998 even though in practice the sudden stabilizing of demand would have suggested postponing Devil Canyon completion. Under this test, the entire market area energy requirement, with the exception of energy from existing hydro sources, is provided by Susitna after Devil Canyon completion. With this assumption of no load growth, Susitna capacity is credited with benefits only as thermal plants reach their retirement age.

Despite the greater peak load requirements of the high range forecast, there is no opportunity to advance project construction since the projects cannot be brought on line prior to 1994 and 1998.

Using the high-range load forecast results in more rapid utilization of Susitna power and an increase of $12 million in net benefits. The benefit-cost ratio becomes 1.47.

Construction Delays

The base case analysis is predicated on a 14-year combined construction schedule. Watana construction is planned to take 10 years and Devil Canyon 8 years. There is overlapping construction to meet load requirements.

Construction delays are possible for any of a number of reasons. Project economics have been analyzed to assess the impact such delays would have on project justification. A 2-year construction delay was adopted for analysis. The effect of the delay is to postpone power-on-line and increase interest during construction. If fossil fuel costs are escalating, the delay also increases the value of power produced. With stable prices, a 2-year construction delay causes annual costs to rise to $245 million and net benefits to fall to $75 million, with a benefit-cost ratio of 1.31. It would require a delay of at least 9 years before the Susitna project's net benefits would fall as low as those of the coal-fired alternative.

Alternate Investment Cost Estimates for Coal-Fired Plants

The Alaska Power Administration has provided independent estimates of coal-fired generation costs that serve as useful comparisons to those estimates provided by the Federal Energy Regulatory Commission. APA data primarily reflects experience in the lower 48 states with adjustment to reflect Alaska price levels, smaller sized plants, and construction conditions. The basic reference is the Comparative Study of Coal and Nuclear Generation Options in the Pacific Northwest, June 1977 by the Washington Public Power Supply System (WPPSS).

APA's estimate is premised on powerplant locations near mining operations at Beluga and Healy. Plants of 200 MW and 500 MW are examined. The investment costs, which include construction and interest during construction assume that flue gas desulpherization would be required. Mid-1976 costs from the WPPSS study were increased to October 1978 using the Handy-Whitman Steamplant cost trends and a 1.8 Alaska factor to account for cost differentials. The resulting composite investment cost estimate of $1,644 per kilowatt for the 450 and 230 MW plants in Anchorage and Fairbanks respectively was used in the calculation of power values in lieu of the FERC composite estimate of $1,299 per kilowatt. This resulted in an increased capacity value. See Exhibit C-4. Using the adjusted value results in a $40 million increase in the power benefit. Net benefits rise to $135 million, and the benefit-cost ratio becomes 1.59.

Oil-Fired Thermal Alternative

As discussed in a previous section, oil-fired generation is not the most appropriate alternative for derivation of power values. National energy policy priorities strongly suggest that coal-fired generation is the likely and proper alternative to hydropower in the mid-1990's and beyond. Since oil-fired power values were provided by FERC along with coal values, however, and since the Office of Management and Budget raised questions specifically addressing the sensitivity of project justification to oil prices, power benefits were also calculated using oil-fired power values.

In Anchorage, FERC reports that the likely oil-fired alternative is a combined cycle plant consisting of four units of 105 MW each. The service life is 30 years, and the heat rate is 8,350 BTU/kWh. The investment cost is estimated at $360 per kilowatt, while the oil fuel cost is $3.00 per million BTU.

For Fairbanks, the oil-fired alternative is a regenerative combustion turbine with four 60 MW units. The service life is again 30 years, while the heat rate in this case is 10,000 BTU/kWh. The investment cost is $265 per kilowatt, and fuel is estimated at $2.00 per million BTU.

The composite railbelt oil-fired power values with public, non-Federal financing are $43.95 per kilowatt and 26.92 mills per kilowatt hour. Power benefits amount to $212 million which is 27 percent less than the base case. The corresponding benefit-cost ratio is 1.08, with net benefits of $18 million.

Inflation

The economic evaluation procedures normally followed in Federal water resource studies ignore the effects of inflation and escalation. 1/ The implicit assumption is that price level changes will impact equally on all alternatives being compared. In time of relatively stable prices, this is a reasonable simplifying assumption.

Ever since the 1930's, however, there has been an accelerating rise in costs in the United States. Nationwide, the annual increase in construction costs from 1970 to 1976 approximated 10 percent. The Anchorage composite consumer price index has increased at an annual rate of 4 percent since 1960 and at almost 7 percent since 1970. In spite of possible temporary periods of price stability, it appears that substantial inflation may become a regular aspect of the economic scene. The extent and persistence of inflationary trends indicates the need to examine their effect on the comparison between hydroelectric and thermal generation.

Inflation does not affect hydro and thermal alternatives equally because there is a differential susceptibility to rising prices. The extent of these differential impacts is determined by adjusting the capacity and energy values as well as the hydro project costs to account for inflation. A distinction has to be made between interest and amortization costs on the one hand and all other charges on the other, because the affect of inflation on these two categories of expenditure is quite different. The latter category is addressed first.

A multiplier is developed for adjustment of annual charges associated with operating costs, fuel costs, insurance, interim replacements, and taxes. Expenditures for these items are continually susceptible to rising prices. The initial annual expenditure associated with these cost components in the base year is the value used in the standard method of computing power values. With inflation, a higher figure must be used, since the annual expenditures increase from year to year. The assumed rate of inflation, the duration of the assumed inflation, and the discount rate together determine how large the increase will be. The appropriate adjustment multiplier is found by computing the sum of the present values of the inflated payments, and dividing that by the sum of the present values of the yearly payments without inflation. The resulting quotient is the multiplier by which the fixed initial payment of the standard method must be adjusted to take inflation into account.

1/ Throughout this report, "inflation" refers to increases in the general price level, while "escalation" refers to real price changes or changes over and above increases in the general price level.

For this analysis, inflation is assumed to prevail for a period of 15 years beyond the initial project's power-on-line date. This period of inflation is assumed to be followed by a period of stable prices to the end of the 100 year economic life of the project. 1/ Inflation rates of 3 and 5 percent have been adopted as reasonable values with which to explore the magnitude of inflationary impact. The corresponding annual expenditure multipliers for a discount rate of 6-7/8 percent are 1.34 and 1.64.

The second type of cost to examine is the interest and amortization charge. During the life of a hydroelectric project, an alternative thermal plan with a life of only 30 to 35 years will have to be replaced at least twice. Each time it is replaced, its cost will have risen in keeping with the compound rate of inflation. The multiplier reflecting the increase in these capital expenditures resulting from inflation is found by dividing the present worth of the interest and amortization with inflation affecting future replacements by their present worth without inflation. Again, inflation is confined to the first 15 years beyond power-on-line with stable prices assumed thereafter. The multipliers are 1.08 for 3 percent inflation and 1.15 for a 5 percent rate.

TABLE C-27

INFLATION ADJUSTMENT MULTIPLIERS
(6-7/8 percent discount rate, 30 year thermal plant life, 15 year period of inflation)

Cost Category	Inflation Rate 3%	Inflation Rate 5%
Variable Costs	1.34	1.64
Capital Expenses	1.08	1.15

These multipliers are then applied to the various cost components of the power values and to the elements of the hydro project cost as shown in Exhibit C-4. Note that the multiplier for interest and amortization of the hydro project is unity. This occurs because the hydro project does not have to be replaced during the period of analysis and is therefore not susceptable to inflating prices.

1/ Inflation in the years prior to power-on-line is ignored because there is little differential inflation impact before costs are actually incurred. Battelle in Alaskan Electric Power, March 1978, page 6-3, reports that prices for thermal powerplants have risen since 1970 at almost exactly the same rate as that for hydroelectric facilities.

Fuel Escalation

In deriving power values for use in benefit analysis, FERC uses present day costs for the fuel requirements of the thermal plant. Even after inflation is taken into account, this procedure is not equitable in a period of substantial fuel cost escalation, when fuel prices rise faster than the general price level. Whereas a hydro development will continue to produce its energy from falling water without cost, a thermal plant depends on fossil fuels that are susceptible to real price increases as well as to inflationary trends. Depleting supplies, intensified environmental controls, cartelized production, and the need to go further and deeper for supplies all tend to boost prices at rates higher than inflation.

Fuel Oil: As a practical matter the world oil market is controlled by the Organization of Petroleum Exporting Countries (OPEC). The OPEC cartel pricing strategy appears to be based on their perception of the marginal costs of production of their nearest competitor. This policy is intended to maximize their long-term profits. 1/

In the future OPEC's most probable strategy (assuming the cartel can be sustained and no other super-giant oil fields are found or alternative lower cost technologies are developed) will be to escalate its prices paralleling the market rate of interest occurring in its western world market area. The market rate of interest sets the basis from which OPEC can measure its opportunity cost and escalates at approximately 3 percentage points higher than the general inflation rate as measured by the GNP deflator. Thus for a general 5 percent per annum inflation rate, the OPEC oil price increase rate would be expected to be about 8 percent per annum.

If Mexico enters the continental market as a major source, it will probably shave prices slightly to gain market entry by displacing Middle East crude, but then generally trade at OPEC's world market price.

Another possibility is the collapse of the OPEC cartel. Iran and Saudia Arabia, the largest oil producers in OPEC, are committed along with many other OPEC nations to rapid economic development programs. These programs are dependent upon oil export revenues for their funding. Under the umbrella of OPEC's pricing policy, there is opportunity and strong incentive to develop substantial new productive capacity both within and outside the cartel. The increase in capacity imposes

1/ This discussion of fuel price behavior is based largely on a March 1978 report by Battelle Pacific Northwest Laboratories entitled, Alaska Electric Power, An Analysis of Future Requirements and Supply for the Railbelt Region and on discussions with Ward Swift of Battelle.

downward pressure on prices. To offset this pressue and maintain the cartel price, production must be cut back somewhat; principally this will fall on the largest producers, Iran and Saudia Arabia in this case. Thus they are caught in a dilemma between a declining market share and the need for export earnings for developmental programs. This situation could lead to price wars to regain market shares and thus the collapse of OPEC as an effective cartel.

Price cutting has a theoretical floor - the marginal cost of producing the level of output demanded at such a market price. This would likely be determined by Mexico, the North Sea producers and the costs of increased production in Iran. All of the conditions contributing to the initial cartelization would still be present, a highly concentrated market and very inelastic commodity demand. Thus a collapse might only be temporary and under this scenario, world prices could become rather volatile.

Given the many vested (U.S. and foreign) interests in maintaining oil prices, a major downward break in oil prices is not likely. As a case in point, if Saudi Arabia went back to pre-1973 prices, and could satisfy demand, (not likely at those prices) both North Sea and North Slope production could be shut in.

Given that scenario and without governmental intervention, U.S. and other nations' dependence on foreign oil would increase markedly, domestic exploration and field development would be severely cut back, and consumption would increase. Although existence of contingency policies to respond to such a case are unknown, it is hard to visualize that very rigorous governmental intervention would not occur either through import quotas or duties that would maintain the economic viability of the domestic industries.

In 1977, the domestic refinery acquisition cost of domestic crude was about 35 percent less than that of foreign crude ($9.20 per bbl versus $14.10 per bbl). A price decline of greater than 35 percent is deemed highly unlikely for the reasons outlined above.

Coal: Coal prices in Alaska appear much more predictable due to the absence of regulation and the currently limited influence of marketability factors.

Two sources of coal supply for the railbelt region are most pertinent to this analysis:

1. The Healy coal field is currently being mined by the Usibelli Coal Company at about 700,000 tons/year with plans for expansion to 1.5 million tons per year. This mine currently supplies the Golden Valley Electric Association (GVEA) plant located at Healy and the Fairbanks Municipal Utility System in Fairbanks.

2. A potential future coal source is the Beluga field in the Cook Inlet region. The latter field is known to contain very substantial reserves but the new mine development required will be costly due to lack of transporation facilities and mine supporting infrastructure.

The Healy coal field is the obvious supplier for future interior generation based on coal. Recent cost of coal delivered by truck to the GVEA Healy plant is $0.80/MMBTU and by rail at Fairbanks, $1.15/MMBTU. 1/ Although the Healy site may be able to expand to perhaps 200 MW capacity, its location 4.5 miles from Mt. McKinley National Park may restrict further development due to air quality considerations. Thus further coal fired expansion in the upper railbelt most probably will necessitate plant location in the Nenana area along the rail line. In this case, additional costs above mine mouth costs, will be incurred including tipple costs (approximately $0.11 per MMBTU currently) and Alaska Railroad tariffs. The latter may be reduced if unit trains were to be employed.

The Usibelli Coal Mine, Inc. has indicated that they expect their prices to rise at about 7 percent per annum. This pricing schedule appears reasonable if it is assumed that a 5 percent per annum general inflation rate continues and a 2 percentage point markup escalation is appropriate for the resource owner.

The Beluga/Susitna coal field is an obvious source of supply for coal fired generation. The reserves are very large and capable of supporting a world scale mine for export and mine mouth power generation. The coal is subbituminous (Rank C) and of relatively low heating value (7,100 BTU/lb) at run-of-mine but quite low in sulfur (0.15 percent typical). Coal preparation including washing and drying could raise the heating value to 9,000 BTU/lb. Some of the coal will be of too low a quality for export but would nevertheless be suitable for mine mouth power generation.

Fuel Cost Assumptions

To calculate the impact of relative changes in the price of fuels on project feasibility, adjustments are made to the power values upon which the calculation of power benefits is based. The period from 1978 to the initial project power-on-line date is looked at separately from the period after POL. For the initial period, the estimated 1978 fuel price is compounded at the assumed annual escalation rate to give the anticipated constant dollar fuel cost at the time of power-on-line. The energy and capacity values are then recalculated using standard FERC procedures. For the post-POL period, a multiplier is used to adjust the energy value using procedures identical to those used to adjust for inflation. The period of escalation is limited to the years prior to the 30th year after power-on-line. Thirty years corresponds to the service life of the initial thermal plant.

1/ September, 1978

Three sample cases are analysed. First, for both coal and oil, there is an assumption that fuel costs escalate at 2 percent per year between 1978 and the 30th year after power-on-line, after which there is no additional escalation. The 2 percent rate is selected as representative of long-term real price increases arising from depleting, more distant sources, increasing environmental safeguards in extraction, processing and handling, and anticipated producing nation pricing policy. (Refer to the previous discussion of fuel price trends.)

The second case looks at no escalation prior to power-on-line followed by a 30-year period of 2 percent annual escalation. This case is designed to reflect the possibility of a near-term softening of the market for oil due to slackening demand or increased supply in the short-term.

The final case explores the impact of real oil price declines prior to power-on-line. An immediate 35 percent drop in price is assumed, with no change in price thereafter. This scenario is included to show the possible effect on project justification of a breakup of the OPEC cartel. Exhibit C-4 shows how these various adjustments are made to the energy value provided by FERC.

Test Results

The results of the sensitivity tests for inflation and escalation are presented on Figures C-10 and C-11. Two percent annual escalation in the price of coal results in a 55 percent increase in net benefits and the benefit-cost ratio becomes 1.64. In the most extreme coal-fired case, 2 percent fuel escalation with 5 percent inflation, the benefit-cost ratio rises to 2.17. The worst case analyzed in terms of project justification is with the oil-fired alternative and a sudden 35 percent drop in oil prices. The resulting benefit-cost ratio is 0.85.

Summary

In summary, it has been shown that the benefit-cost ratio is sensitive to the source of financing, to the discount rate, to the type of alternative generation, to construction delays, and to inflation and fuel cost escalation. It is relatively insensitive, on the other hand, to variations in load requirement forecasts. Under the full range of forecasts, Susitna hydropower is needed as soon as it is available.

Despite the sensitivity of project economics to many of these parameters, the degree of sensitivity is not sufficient to make the project uneconomic, except in one case. Only if oil-fired generation were to be considered the appropriate long-term alternative to hydropower and if the price of oil were to suddenly fall drastically as a result of world market forces would net benefits of Susitna hydropower development be less than those of the thermal generation alternative.

Figure C-10

SENSITIVITY TO INFLATION AND ESCALATION — COAL

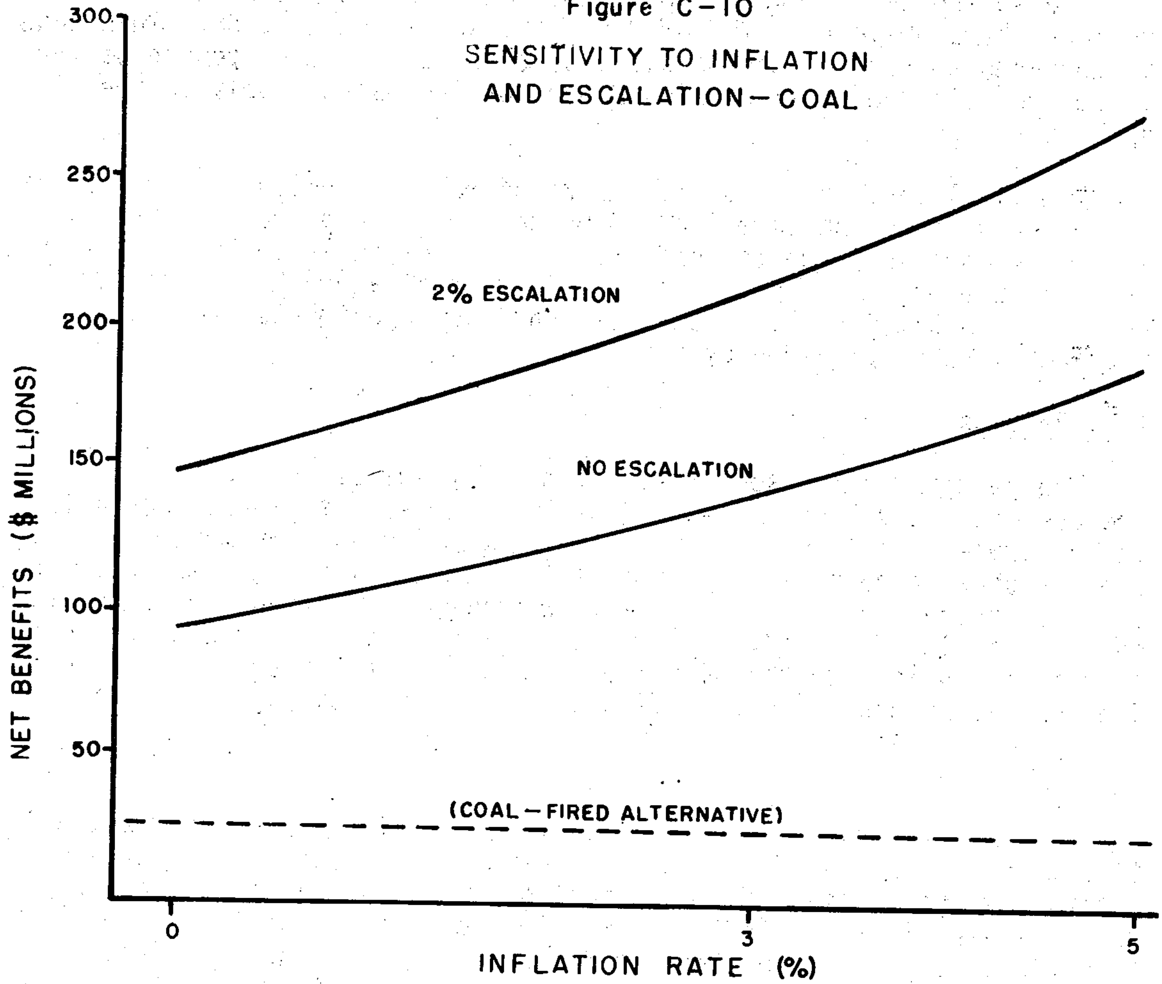
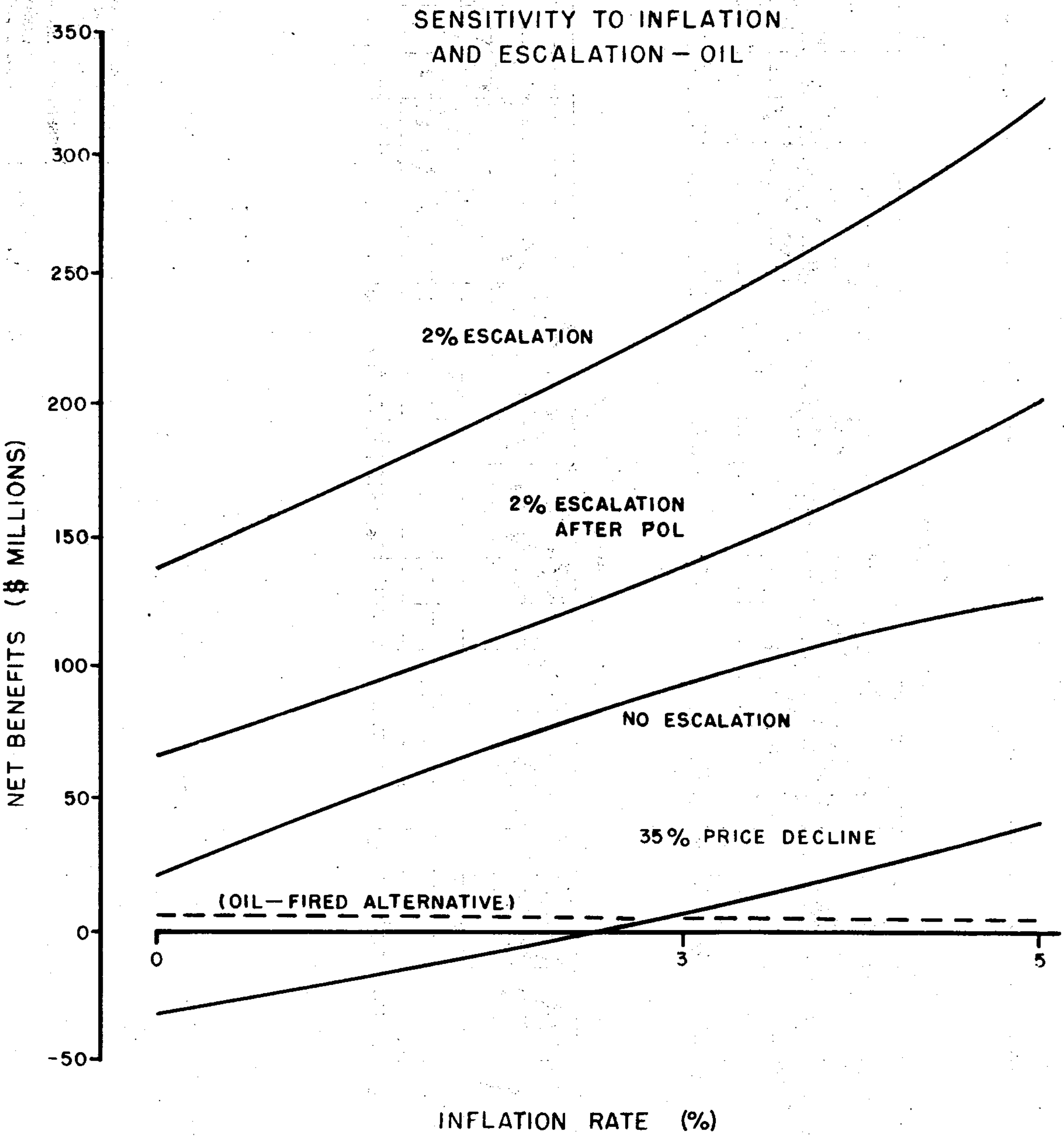
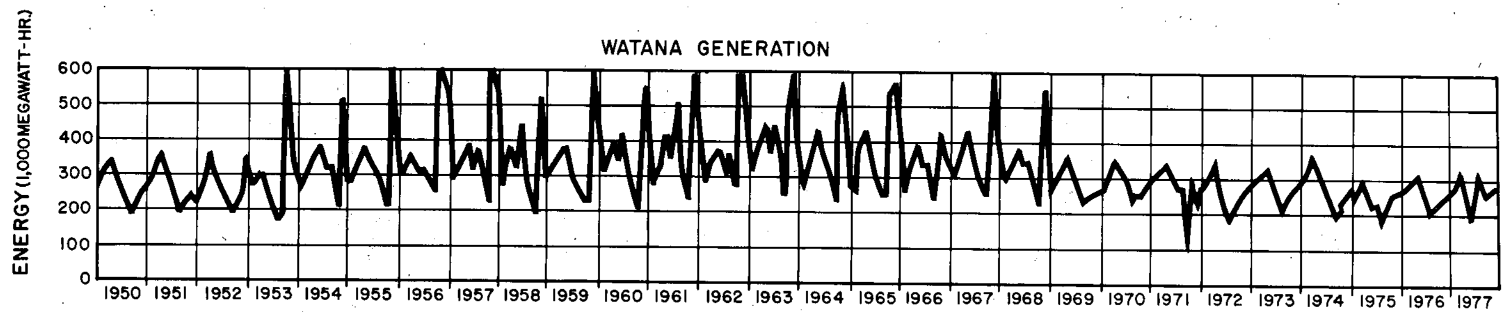


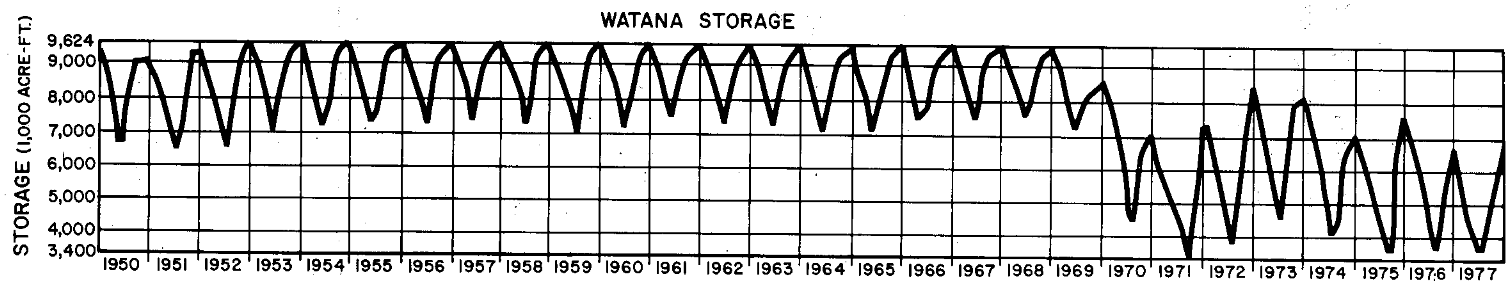
Figure C-11
SENSITIVITY TO INFLATION AND ESCALATION — OIL



CORPS OF ENGINEERS

U S ARMY





SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
RESERVOIR OPERATION & ENERGY OUTPUT
WATANA DAM

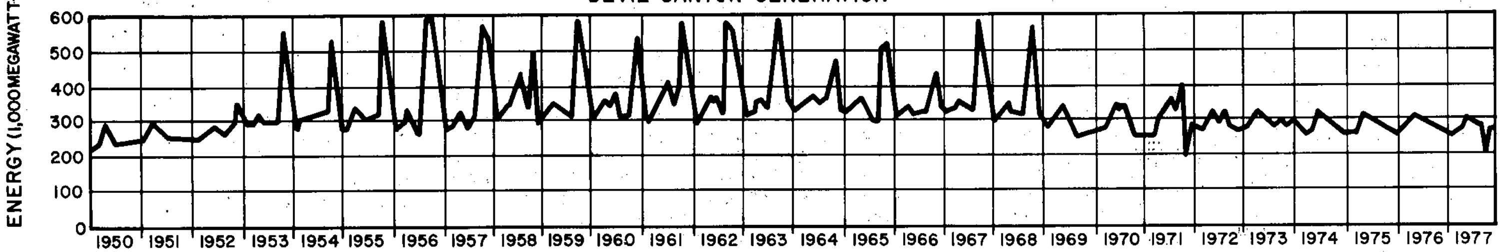
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
NOVEMBER, 1978

PLATE C-1

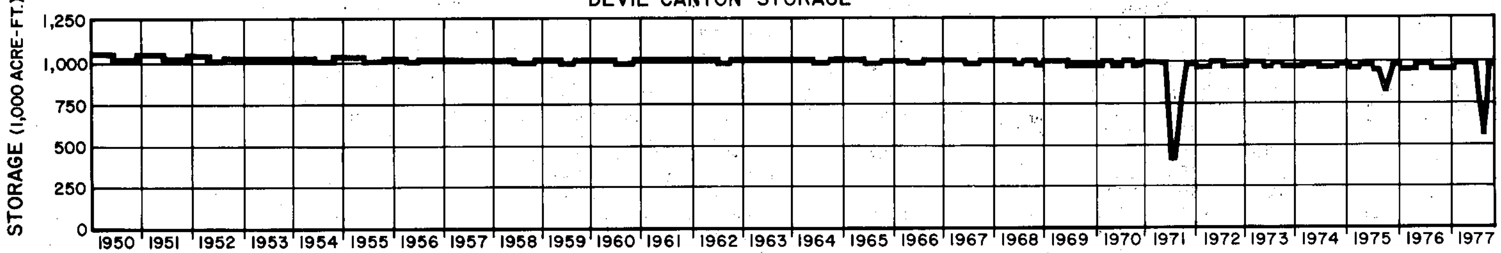
CORPS OF ENGINEERS

U.S. ARMY

DEVIL CANYON GENERATION



DEVIL CANYON STORAGE



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN

RESERVOIR OPERATION & ENERGY OUTPUT
DEVIL CANYON DAM

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
NOVEMBER, 1978

PLATE C-2

NSUFFICIENT PLANTS IN 1978-1979

NSUFFICIENT PLANTS IN 1978-1979

PLANNED ADDITION IN	1979-1980: CEA B 9	ANCH	32.	0.50	TURB	1980.
PLANNED ADDITION IN	1979-1980: AMLP-6 7	ANCH	82.	0.50	TURB	1980.

NSUFFICIENT PLANTS IN 1979-1980

NSUFFICIENT PLANTS IN 1979-1980

PLANNED ADDITION IN	1980-1981: X-1	ANCH	100.	0.50	TURB	1981.
PLANNED RETIREMENT IN	1980-1981: HEA	ANCH	2.	0.10	DIES	1981.
PLANNED ADDITION IN	1981-1982: CEA-BL4	ANCH	18.	0.50	TURB	1982.

NSUFFICIENT PLANTS IN 1981-1982

NSUFFICIENT PLANTS IN 1981-1982

PLANNED ADDITION IN	1982-1983: X-2	ANCH	100.	0.50	TURB	1983.
PLANNED RETIREMENT IN	1982-1983: AMLP-D	ANCH	2.	0.10	DIES	1983.
PLANNED RETIREMENT IN	1982-1983: AMLP-1	ANCH	15.	0.50	TURB	1983.
NEEDED ADDITION IN	1982-1983: COALA1	PSEA1	200.	0.75	STEA	1983.
PLANNED RETIREMENT IN	1983-1984: CEA-BL1	ANCH	8.	0.50	TURB	1984.
PLANNED RETIREMENT IN	1983-1984: CHENA4	FAIR	5.	0.50	TURB	1984.
PLANNED ADDITION IN	1984-1985: CEA-BL5	ANCH	18.	0.50	TURB	1985.
PLANNED RETIREMENT IN	1984-1985: AMLP-2	ANCH	15.	0.50	TURB	1985.
PLANNED RETIREMENT IN	1984-1985: GVEA	FAIR	24.	0.10	DIES	1985.
PLANNED ADDITION IN	1985-1986: BRADLEY LK	ANCH	70.	0.50	HYDR	1986.
PLANNED ADDITION IN	1985-1986: NATIONAL D.	ANCH	7.	0.75	STEA	1986.
PLANNED RETIREMENT IN	1985-1986: SES	ANCH	3.	0.10	DIES	1986.
PLANNED RETIREMENT IN	1985-1986: CEA-INT1-2	ANCH	31.	0.50	TURB	1986.
PLANNED RETIREMENT IN	1985-1986: NATIONAL D.	ANCH	7.	0.10	DIES	1986.
NEEDED ADDITION IN	1985-1986: COALA2	PSEA2	200.	0.75	STEA	1983.
NEEDED ADDITION IN	1985-1986: HEALY 2	PSEF1	100.	0.75	STEA	1978.
PLANNED RETIREMENT IN	1987-1988: CEA-KNIK	ANCH	15.	0.50	STEA	1988.
NEEDED ADDITION IN	1987-1988: COALA3	PSEA3	200.	0.75	STEA	1984.
PLANNED ADDITION IN	1988-1989: NATIONAL D.	FAIR	14.	0.75	STEA	1989.
PLANNED RETIREMENT IN	1988-1989: CEA-B1-2	ANCH	43.	0.50	TURB	1989.
PLANNED RETIREMENT IN	1988-1989: FMUS-123	FAIR	9.	0.75	STEA	1989.
PLANNED RETIREMENT IN	1988-1989: AMLP-3	ANCH	19.	0.50	TURB	1989.
PLANNED RETIREMENT IN	1988-1989: FMUS-D-123	FAIR	8.	0.10	DIES	1989.
PLANNED RETIREMENT IN	1988-1989: INDUSTRIAL	ANCH	12.	0.50	TURB	1989.
PLANNED RETIREMENT IN	1988-1989: NATIONAL D.	FAIR	14.	0.10	DIES	1989.
NEEDED ADDITION IN	1989-1990: COALA4	PSEA4	200.	0.75	STEA	1984.
NEEDED ADDITION IN	1989-1990: COALF1	PSEF1	100.	0.75	STEA	1985.
PLANNED ADDITION IN	1990-1991: NATIONAL D.	FAIR	32.	0.75	STEA	1991.
PLANNED RETIREMENT IN	1990-1991: NATIONAL D.	FAIR	32.	0.75	STEA	1991.
PLANNED ADDITION IN	1991-1992: NATIONAL D.	ANCH	43.	0.75	STEA	1992.
PLANNED RETIREMENT IN	1991-1992: CEA-INT3	ANCH	18.	0.50	TURB	1992.
PLANNED RETIREMENT IN	1991-1992: NATIONAL D.	ANCH	41.	0.75	STEA	1992.
PLANNED RETIREMENT IN	1991-1992: NATIONAL D.	ANCH	2.	0.10	DIES	1992.
PLANNED RETIREMENT IN	1992-1993: AMLP-4	ANCH	32.	0.50	TURB	1993.
PLANNED RETIREMENT IN	1992-1993: GVEA	FAIR	40.	0.50	TURB	1993.
PLANNED RETIREMENT IN	1992-1993: CEA-BL2	ANCH	18.	0.50	TURB	1993.
NEEDED ADDITION IN	1992-1993: COALA5	PSEA5	200.	0.75	STEA	1984.
PLANNED RETIREMENT IN	1993-1994: HEA	ANCH	0.	0.10	DIES	1994.
PLANNED RETIREMENT IN	1993-1994: CEA-BL3	ANCH	55.	0.50	TURB	1994.

NEEDED ADDITION IN	1993-1994:	COALA6	PSEA6	400.	0.75	STEA	1984.
UPPER SUSITNA ADDED	1994-1995:	WATANA-1	HYDRO	611.	0.56	HYDR	1995.
PLANNED ADDITION IN	1995-1996:	NATIONAL D.	FAIR	25.	0.75	STEA	1996.
UPPER SUSITNA ADDED	1995-1996:	WATANA-2	HYDRO	92.	0.56	HYDR	1996.
PLANNED RETIREMENT IN	1995-1996:	HEA	ANCH	7.	0.50	TURB	1996.
PLANNED RETIREMENT IN	1995-1996:	AMLP-56	ANCH	53.	0.50	TURB	1996.
PLANNED RETIREMENT IN	1995-1996:	CEA-95	ANCH	65.	0.50	TURB	1996.
PLANNED RETIREMENT IN	1995-1996:	NATIONAL D.	FAIR	25.	0.75	STEA	1996.
PLANNED RETIREMENT IN	1996-1997:	CHENA 6	FAIR	24.	0.50	TURB	1997.
PLANNED RETIREMENT IN	1996-1997:	SES	ANCH	2.	0.50	DIES	1997.
PLANNED RETIREMENT IN	1996-1997:	CEA-84	ANCH	9.	0.50	TURB	1997.
PLANNED RETIREMENT IN	1996-1997:	CEA86769	ANCH	200.	0.50	TURB	1997.
PLANNED RETIREMENT IN	1997-1998:	N.POLE 1&2	FAIR	140.	0.50	TURB	1998.
NEEDED ADDITION IN	1997-1998:	COALA7	PSEA7	400.	0.75	STEA	1984.
UPPER SUSITNA ADDED	1996-1999:	DEVIL CAN-1	HYDRO	600.	0.56	HYDR	1999.
PLANNED RETIREMENT IN	1998-1999:	CEA-GL3	ANCH	18.	0.50	TURB	1999.
UPPER SUSITNA ADDED	1999-2000:	DEVIL CAN-2	HYDRO	89.	0.56	HYDR	2000.
PLANNED RETIREMENT IN	1999-2000:	AMLP-6&7	ANCH	82.	0.50	TURB	2000.
PLANNED RETIREMENT IN	2000-2001:	CEA-X-1	ANCH	100.	0.50	TURB	2001.
PLANNED RETIREMENT IN	2001-2002:	CEA-GL4	ANCH	18.	0.50	TURB	2002.
PLANNED RETIREMENT IN	2002-2003:	CEA-X-2	ANCH	100.	0.50	TURB	2003.
PLANNED RETIREMENT IN	2002-2003:	HEALY1	FAIR	25.	0.75	STEA	2003.
NEEDED ADDITION IN	2003-2004:	COALF2	PSEF2	100.	0.75	STEA	1985.
PLANNED RETIREMENT IN	2004-2005:	CEA-GL5	ANCH	18.	0.50	TURB	2005.
NEEDED ADDITION IN	2004-2005:	COALF3	PSEF3	100.	0.75	STEA	1985.
PLANNED RETIREMENT IN	2005-2006:	CHENA5	FAIR	20.	0.75	STEA	2006.
NEEDED ADDITION IN	2005-2006:	COALA8	PSEA8	400.	0.75	STEA	1984.
NEEDED ADDITION IN	2009-2010:	COALA9	PSEA9	400.	0.75	STEA	1984.

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1982.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1978-1979				1979-1980				1980-1981			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	585.			2531.	632.			2801.	686.			3041.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	51.	.75	.75	332.
COMB.TURBINE	575.	.50	.40	2034.	575.	.50	.36	1810.	689.	.50	.35	2113.
DIESEL	19.	.15	.00	0.	19.	.15	.00	0.	19.	.15	.00	0.
TOTAL	698.			2569.	698.			2346.	812.			2649.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	114.	.50	.50	497.	100.	.50	.50	438.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	2.	.00	.00	0.
GROSS RESOURCES	698.			2569.	812.			2843.	910.			3087.
CAP RES. MARGIN	0.193				0.284				0.326			
RESERVE REQ.	146.				158.				172.			
LOSSES	29.			38.	32.			42.	34.			46.
NET RESOURCES	523.			2531.	622.			2801.	704.			3041.
TRANSFERED	0.				0.				0.			
SURPLUS	-62.			0.	-10.			0.	18.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1978-1979 PEAK	1978-1979 MPUF	1978-1979 APUF	1978-1979 ENERGY	1979-1980 PEAK	1979-1980 MPUF	1979-1980 APUF	1979-1980 ENERGY	1980-1981 PEAK	1980-1981 MPUF	1980-1981 APUF	1980-1981 ENERGY
REQUIREMENTS	184.			804.	197.			862.	209.			916.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.66	633.	110.	.75	.72	692.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.10	183.	209.	.50	.10	183.	209.	.50	.11	207.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			816.	365.			875.	365.			930.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			816.	365.			875.	365.			930.
CAP RES. MARGIN	0.983				0.852				0.746			
RESERVE REQ.	46.				49.				52.			
LOSSES	9.			12.	10.			13.	10.			14.
NET RESOURCES	310.			804.	306.			862.	302.			916.
TRANSFERED	0.				0.				0.			
SURPLUS	126.			0.	109.			0.	93.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1981-1982 PEAK	MPUF	APUF	ENERGY	1982-1983 PEAK	MPUF	APUF	ENERGY	1983-1984 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	741.			3281.	795.			3521.	850.			3761.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	251.	.75	.42	923.
COMB.TURBINE	789.	.50	.39	2716.	807.	.50	.32	2250.	891.	.50	.35	2691.
DIESEL	17.	.15	.00	0.	17.	.15	.00	0.	15.	.15	.00	0.
TOTAL	910.			3251.	928.			2785.	1210.			3817.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	200.	.75	.20	350.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	100.	.50	.50	438.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	15.	.00	.00	0.	8.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	928.			3330.	1210.			3574.	1202.			3817.
CAP RES. MARGIN	0.252				0.523				0.414			
RESERVE REQ.	185.				199.				213.			
LOSSES	37.			49.	40.			53.	43.			56.
NET RESOURCES	706.			3281.	972.			3521.	947.			3761.
TRANSFERED	0.				0.				0.			
SURPLUS	-35.			0.	177.			0.	97.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982				1982-1983				1983-1984			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	221.			970.	233.			1024.	245.			1078.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.14	262.	209.	.50	.17	317.	209.	.50	.21	371.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			985.	365.			1039.	365.			1094.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	5.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			985.	365.			1039.	360.			1094.
CAP RES. MARGIN	0.651				0.566				0.467			
RESERVE REQ.	55.				58.				61.			
LOSSES	11.			15.	12.			15.	12.			16.
NET RESOURCES	299.			970.	295.			1024.	286.			1078.
TRANSFERED	0.				0.				0.			
SURPLUS	78.			0.	62.			0.	41.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982				1982-1983				1983-1984			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	741.			3281.	795.			3521.	850.			3761.
RESOURCES												
EXISTING												
HYDRO	53.	.50	.50	204.	53.	.50	.50	204.	53.	.50	.50	204.
STEAM/ELEC	51.	.75	.75	332.	51.	.75	.75	332.	251.	.75	.42	923.
COMB.TURBINE	789.	.50	.59	2716.	807.	.50	.32	2250.	891.	.50	.35	2691.
DIESEL	17.	.15	.00	0.	17.	.15	.00	0.	15.	.15	.00	0.
TOTAL	910.			3251.	928.			2785.	1210.			3817.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	200.	.75	.20	350.	-	-	-	-
COMB.TURBINE	18.	.50	.50	79.	100.	.50	.50	438.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	15.	.00	.00	0.	8.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	928.			3330.	1210.			3574.	1202.			3817.
CAP. RES. MARGIN	0.252				0.523				0.414			
RESERVE REQ.	185.				199.				213.			
LOSSES	37.			49.	40.			53.	43.			56.
NET RESOURCES	706.			3281.	972.			3521.	947.			3761.
TRANSFERED	0.				0.				0.			
SURPLUS	-35.			0.	177.			0.	97.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1981-1982				1982-1983				1983-1984			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	221.			970.	233.			1024.	245.			1078.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	110.	.75	.75	723.
COMB.TURBINE	209.	.50	.14	262.	209.	.50	.17	317.	209.	.50	.21	371.
DIESEL	46.	.10	.00	0.	46.	.10	.00	0.	46.	.10	.00	0.
TOTAL	365.			985.	365.			1039.	365.			1094.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	5.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	365.			985.	365.			1039.	360.			1094.
CAP RES. MARGIN	0.651				0.566				0.467			
RESERVE REQ.	55.				58.				61.			
LOSSES	11.			15.	12.			15.	12.			16.
NET RESOURCES	299.			970.	295.			1024.	286.			1078.
TRANSFERED	0.				0.				0.			
SURPLUS	78.			0.	62.			0.	41.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

1984-1985	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	904.			4001.
RESOURCES				
EXISTING				
HYDRO	53.	.50	.50	204.
STEAM/ELEC	251.	.75	.53	1164.
COMB. TURBINE	883.	.50	.34	2615.
DIESEL	15.	.15	.00	0.
TOTAL	1202.			3982.
ADDITIONS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB. TURBINE	18.	.50	.50	79.
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB. TURBINE	15.	.00	.00	0.
DIESEL	-	-	-	-
GROSS RESOURCES	1205.			4061.
CAP RES. MARGIN	0.333			
RESERVE REQ.	226.			
LOSSES	45.			60.
NET RESOURCES	934.			4001.
TRANSFERED	0.			
SURPLUS	30.			0.

1985-1986	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	976.			4329.
RESOURCES				
EXISTING				
HYDRO	53.	.50	.50	204.
STEAM/ELEC	251.	.75	.64	1405.
COMB. TURBINE	886.	.50	.28	2116.
DIESEL	15.	.15	.00	0.
TOTAL	1205.			3724.
ADDITIONS				
HYDRO	81.	.50	.50	307.
STEAM/ELEC	207.	.75	.20	363.
COMB. TURBINE	-	-	-	-
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB. TURBINE	31.	.00	.00	0.
DIESEL	10.	.00	.00	0.
GROSS RESOURCES	1452.			4394.
CAP RES. MARGIN	0.488			
RESERVE REQ.	244.			
LOSSES	49.			65.
NET RESOURCES	1159.			4329.
TRANSFERED	0.			
SURPLUS	183.			0.

1986-1987	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1048.			4657.
RESOURCES				
EXISTING				
HYDRO	134.	.50	.50	510.
STEAM/ELEC	458.	.75	.56	2259.
COMB. TURBINE	855.	.50	.26	1958.
DIESEL	5.	.15	.00	0.
TOTAL	1452.			4727.
ADDITIONS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB. TURBINE	-	-	-	-
DIESEL	-	-	-	-
RETIREMENTS				
HYDRO	-	-	-	-
STEAM/ELEC	-	-	-	-
COMB. TURBINE	-	-	-	-
DIESEL	-	-	-	-
GROSS RESOURCES	1452.			4727.
CAP RES. MARGIN	0.385			
RESERVE REQ.	262.			
LOSSES	52.			70.
NET RESOURCES	1138.			4657.
TRANSFERED	0.			
SURPLUS	90.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
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APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1984-1985 PEAK	1984-1985 MPUF	1984-1985 APUF	1984-1985 ENERGY	1985-1986 PEAK	1985-1986 MPUF	1985-1986 APUF	1985-1986 ENERGY	1986-1987 PEAK	1986-1987 MPUF	1986-1987 APUF	1986-1987 ENERGY
REQUIREMENTS	258.			1132.	272.			1193.	286.			1254.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	110.	.75	.75	723.	110.	.75	.75	723.	210.	.75	.55	1018.
COMB.TURBINE	204.	.50	.24	426.	204.	.50	.18	313.	204.	.50	.14	254.
DIESEL	46.	.10	.00	0.	22.	.10	.00	0.	22.	.10	.00	0.
TOTAL	360.			1149.	336.			1036.	436.			1273.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	24.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	336.			1149.	436.			1211.	436.			1273.
CAP RES. MARGIN	0.300				0.601				0.523			
RESERVE REQ.	65.				68.				72.			
LOSSES	13.			17.	14.			18.	14.			19.
NET RESOURCES	258.			1132.	354.			1193.	350.			1254.
TRANSFERED	0.				0.				0.			
SURPLUS	0.			0.	82.			0.	64.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1987-1988				1988-1989				1989-1990			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1120.			4985.	1192.			5313.	1264.			5641.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	458.	.75	.63	2413.	643.	.75	.58	3254.	645.	.75	.66	3745.
COMB.TURBINE	855.	.50	.24	1786.	855.	.50	.23	1628.	791.	.50	.16	1120.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	5.	.15	.00	0.
TOTAL	1452.			4709.	1637.			5393.	1573.			5375.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	200.	.75	.20	350.	-	-	-	-	200.	.75	.20	350.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	15.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	64.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	1637.			5060.	1573.			5393.	1773.			5726.
CAP RES. MARGIN	0.462				0.320				0.403			
RESERVE REQ.	280.				298.				316.			
LOSSES	56.			75.	60.			80.	63.			85.
NET RESOURCES	1301.			4985.	1216.			5313.	1394.			5641.
TRANSFERED	0.				0.				0.			
SURPLUS	181.			0.	24.			0.	130.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1987-1988				1988-1989				1989-1990			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	300.			1315.	314.			1376.	328.			1437.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	210.	.75	.62	1139.	210.	.75	.68	1194.	216.	.75	.59	1105.
COMB.TURBINE	204.	.50	.11	196.	204.	.50	.10	178.	204.	.50	.10	178.
DIESEL	22.	.10	.00	0.	22.	.10	.00	0.	0.	.10	.00	0.
TOTAL	436.			1335.	436.			1372.	419.			1283.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	14.	.75	.20	25.	100.	.75	.20	175.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	9.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	22.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	436.			1335.	419.			1397.	519.			1459.
CAP RES. MARGIN	0.452				0.334				0.582			
RESERVE REQ.	75.				79.				82.			
LOSSES	15.			20.	16.			21.	16.			22.
NET RESOURCES	346.			1315.	325.			1376.	421.			1437.
TRANSFERED	0.				0.				0.			
SURPLUS	46.			0.	11.			0.	93.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1990-1991 PEAK	1990-1991 MPUF	1990-1991 APUF	1990-1991 ENERGY	1991-1992 PEAK	1991-1992 MPUF	1991-1992 APUF	1991-1992 ENERGY	1992-1993 PEAK	1992-1993 MPUF	1992-1993 APUF	1992-1993 ENERGY
REQUIREMENTS	1357.			6063.	1450.			6485.	1543.			6907.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	134.	.50	.50	510.
STEAM/ELEC	843.	.75	.62	4577.	843.	.75	.68	4793.	845.	.75	.70	5159.
COMB.TURBINE	791.	.50	.15	1067.	791.	.50	.18	1205.	773.	.50	.16	991.
DIESEL	5.	.15	.00	0.	5.	.15	.00	0.	3.	.15	.00	0.
TOTAL	1773.			6154.	1773.			6508.	1755.			6660.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	43.	.75	.20	74.	200.	.75	.20	350.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	41.	.00	.00	0.	-	-	-	-
COMB.TURBINE	-	-	-	-	16.	.00	.00	0.	50.	.00	.00	0.
DIESEL	-	-	-	-	2.	.00	.00	0.	-	-	-	-
GROSS RESOURCES	1773.			6154.	1755.			6582.	1906.			7011.
CAP RES. MARGIN	0.307				0.211				0.235			
RESERVE REQ.	339.				290.				309.			
LOSSES	68.			91.	73.			97.	77.			104.
NET RESOURCES	1366.			6063.	1393.			6485.	1520.			6907.
TRANSFERED	0.				57.				0.			
SURPLUS	9.			0.	0.			0.	-23.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1990-1991				1991-1992				1992-1993			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	343.			1505.	358.			1573.	374.			1641.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	0.	.50	.50	0.
STEAM/ELEC	316.	.75	.53	1293.	316.	.75	.51	1418.	316.	.75	.55	1522.
COMB.TURBINE	204.	.50	.10	176.	204.	.50	.10	176.	204.	.50	.10	143.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	519.			1472.	519.			1597.	519.			1666.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.75	.20	56.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	32.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	40.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	519.			1528.	519.			1597.	479.			1666.
CAP RES. MARGIN	0.513				0.450				0.281			
RESERVE REQ.	86.				72.				75.			
LOSSES	17.			23.	18.			24.	19.			25.
NET RESOURCES	416.			1505.	430.			1573.	386.			1641.
TRANSFERED	0.				-57.				0.			
SURPLUS	73.			0.	14.			0.	12.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1993-1994				1994-1995				1995-1996			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1636.			7329.	1729.			7751.	1854.			8311.
RESOURCES												
EXISTING												
HYDRO	134.	.50	.50	510.	134.	.50	.50	510.	706.	.55	.55	2949.
STEAM/ELEC	1045.	.75	.62	5642.	1445.	.75	.34	4333.	1445.	.75	.37	4641.
COMB.TURBINE	724.	.50	.10	586.	669.	.50	.10	586.	669.	.50	.10	477.
DIESEL	3.	.15	.00	0.	3.	.15	.00	0.	3.	.15	.00	0.
TOTAL	1906.			6738.	2251.			5429.	2822.			8067.
ADDITIONS												
HYDRO	-	-	-	-	572.	.56	.56	2438.	86.	.56	.56	369.
STEAM/ELEC	400.	.75	.20	701.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	55.	.00	.00	0.	-	-	-	-	125.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	2251.			7439.	2822.			7867.	2784.			8436.
CAP RES. MARGIN	0.376				0.632				0.502			
RESERVE REQ.	327.				346.				371.			
LOSSES	82.			110.	86.			116.	93.			125.
NET RESOURCES	1842.			7329.	2390.			7751.	2321.			8311.
TRANSFERED	-7.				0.				0.			
SURPLUS	199.			0.	661.			0.	467.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
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ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 19[illegible]2.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1993-1994				1994-1995				1995-1996			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	389.			1709.	405.			1777.	423.			1859.
RESOURCES												
EXISTING												
HYDRO	0.	.50	.50	0.	0.	.50	.50	0.	131.	.56	.56	559.
STEAM/ELEC	316.	.75	.58	1591.	316.	.75	.40	1101.	316.	.75	.42	1059.
COMB.TURBINE	164.	.50	.10	143.	164.	.50	.10	143.	164.	.50	.10	143.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	479.			1735.	479.			1245.	610.			1761.
ADDITIONS												
HYDRO	-	-	-	-	131.	.56	.56	559.	19.	.56	.56	82.
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.75	.20	43.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	25.	.00	.00	0.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	479.			1735.	610.			1804.	629.			1887.
CAP RES. MARGIN	0.231				0.506				0.488			
RESERVE REQ.	76.				81.				85.			
LOSSES	19.			26.	20.			27.	21.			28.
NET RESOURCES	382.			1709.	509.			1777.	524.			1859.
TRANSFERED	7.				0.				0.			
SURPLUS	0.			0.	104.			0.	101.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
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APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1996-1997				1997-1998				1998-1999			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	1979.			8871.	2103.			9431.	2228.			9991.
RESOURCES												
EXISTING												
HYDRO	792.	.55	.55	3317.	792.	.55	.55	3317.	792.	.55	.55	3317.
STEAM/ELEC	1445.	.75	.43	5393.	1445.	.75	.42	5261.	1845.	.75	.25	4115.
COMB.TURBINE	545.	.50	.10	294.	335.	.50	.10	294.	335.	.50	.10	278.
DIESEL	3.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	2784.			9004.	2572.			8872.	2972.			7710.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	570.	.56	.56	2431.
STEAM/ELEC	-	-	-	-	400.	.75	.20	701.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	210.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	2.	.00	.00	0.	-	-	-	-	-	-	-	-
GROSS RESOURCES	2572.			9004.	2972.			9572.	3524.			10141.
CAP RES. MARGIN	0.300				0.413				0.582			
RESERVE REQ.	396.				421.				446.			
LOSSES	99.			133.	105.			141.	111.			150.
NET RESOURCES	2078.			8871.	2447.			9431.	2967.			9991.
TRANSFERED	0.				-110.				-14.			
SURPLUS	99.			0.	233.			0.	725.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
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APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1996-1997 PEAK	1996-1997 MPUF	1996-1997 APUF	1996-1997 ENERGY	1997-1998 PEAK	1997-1998 MPUF	1997-1998 APUF	1997-1998 ENERGY	1998-1999 PEAK	1998-1999 MPUF	1998-1999 APUF	1998-1999 ENERGY
REQUIREMENTS	442.			1941.	461.			2023.	480.			2105.
RESOURCES												
EXISTING												
HYDRO	150.	.56	.56	642.	150.	.56	.56	642.	150.	.56	.56	642.
STEAM/ELEC	316.	.75	.44	1206.	316.	.75	.51	1412.	316.	.75	.36	983.
COMB.TURBINE	164.	.50	.10	123.	140.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	629.			1970.	606.			2053.	466.			1624.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	120.	.56	.56	512.
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	24.	.00	.00	0.	140.	.00	.00	0.	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	606.			1970.	466.			2053.	586.			2137.
CAP RES. MARGIN	0.371				0.011				0.221			
RESERVE REQ.	88.				92.				96.			
LOSSES	22.			29.	23.			30.	24.			32.
NET RESOURCES	495.			1941.	351.			2023.	466.			2105.
TRANSFERED	0.				110.				14.			
SURPLUS	53.			0.	0.			0.	0.			0.

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ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	1999-2000				2000-2001				2001-2002			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2353.			10551.	2421.			10863.	2490.			11175.
RESOURCES												
EXISTING												
HYDRO	1362.	.55	.55	5749.	1447.	.55	.55	6110.	1447.	.55	.55	6110.
STEAM/ELEC	1645.	.75	.27	4393.	1645.	.75	.30	4797.	1645.	.75	.32	5129.
COMB.TURBINE	317.	.50	.10	206.	236.	.50	.10	119.	136.	.50	.10	103.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3524.			10348.	3528.			11026.	3426.			11343.
ADDITIONS												
HYDRO	85.	.56	.56	362.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	82.	.00	.00	0.	100.	.00	.00	0.	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3528.			10709.	3428.			11026.	3410.			11343.
CAP RES. MARGIN	0.499				0.416				0.369			
RESERVE REQ.	471.				484.				498.			
LOSSES	118.			158.	121.			163.	125.			168.
NET RESOURCES	2939.			10551.	2822.			10863.	2787.			11175.
TRANSFERED	-20.				-31.				-44.			
SURPLUS	566.			0.	370.			0.	253.			0.

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ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	1999-2000				2000-2001				2001-2002			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	499.			2187.	508.			2229.	518.			2270.
RESOURCES												
EXISTING												
HYDRO	270.	.56	.56	1154.	288.	.56	.56	1229.	288.	.56	.56	1229.
STEAM/ELEC	316.	.75	.36	991.	316.	.75	.37	1034.	316.	.75	.39	1075.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	586.			2145.	604.			2262.	604.			2304.
ADDITIONS												
HYDRO	18.	.56	.56	75.	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	604.			2220.	604.			2262.	604.			2304.
CAP. RES. MARGIN	0.209				0.188				0.165			
RESERVE REQ.	100.				102.				104.			
LOSSES	25.			33.	25.			33.	26.			34.
NET RESOURCES	479.			2187.	477.			2229.	474.			2270.
TRANSFERED	20.				31.				44.			
SURPLUS	0.			0.	0.			0.	0.			0.

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AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2002-2003				2003-2004				2004-2005			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2558.			11487.	2626.			11799.	2694.			12111.
RESOURCES												
EXISTING												
HYDRO	1447.	.55	.55	6110.	1447.	.55	.55	6110.	1447.	.55	.55	6110.
STEAM/ELEC	1845.	.75	.34	5534.	1845.	.75	.36	5850.	1845.	.75	.38	6183.
COMB.TURBINE	118.	.50	.10	15.	18.	.50	.10	15.	18.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3410.			11659.	3310.			11976.	3310.			12293.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	100.	.00	.00	0.	-	-	-	-	18.	.00	.00	0.
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3310.			11659.	3310.			11976.	3292.			12293.
CAP RES. MARGIN	0.294				0.260				0.222			
RESERVE REQ.	512.				525.				539.			
LOSSES	128.			172.	131.			177.	135.			182.
NET RESOURCES	2670.			11487.	2653.			11799.	2518.			12111.
TRANSFERED	-80.				0.				76.			
SURPLUS	32.			0.	27.			0.	0.			0.

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AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES:NOV. 30, 1976 W/ U.S.-1994.

C R I T I C A L   P E R I O D

	2002-2003 PEAK	2002-2003 MPUF	2002-2003 APUF	2002-2003 ENERGY	2003-2004 PEAK	2003-2004 MPUF	2003-2004 APUF	2003-2004 ENERGY	2004-2005 PEAK	2004-2005 MPUF	2004-2005 APUF	2004-2005 ENERGY
REQUIREMENTS	527.			2312.	537.			2353.	546.			2395.
RESOURCES												
EXISTING												
HYDRO	288.	.56	.56	1229.	288.	.56	.56	1229.	288.	.56	.56	1229.
STEAM/ELEC	316.	.75	.44	1116.	291.	.75	.39	984.	391.	.75	.30	1027.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	604.			2347.	579.			2213.	679.			2256.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	100.	.75	.20	175.	100.	.75	.20	175.
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	25.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	579.			2347.	679.			2388.	779.			2431.
CAP RES. MARGIN	0.098				0.264				0.426			
RESERVE REQ.	105.				107.				109.			
LOSSES	26.			35.	27.			35.	27.			36.
NET RESOURCES	447.			2312.	544.			2353.	642.			2395.
TRANSFERED	80.				0.				-76.			
SURPLUS	0.			0.	7.			0.	20.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
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AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1978 W/ U.S.-1994.

CRITICAL PERIOD

	2005-2006 PEAK	2005-2006 MPUF	2005-2006 APUF	2005-2006 ENERGY	2006-2007 PEAK	2006-2007 MPUF	2006-2007 APUF	2006-2007 ENERGY	2007-2008 PEAK	2007-2008 MPUF	2007-2008 APUF	2007-2008 ENERGY
REQUIREMENTS	2763.			12423.	2831.			12735.	2899.			13047.
RESOURCES												
EXISTING												
HYDRO	1447.	.55	.55	6110.	1447.	.55	.55	6110.	1447.	.55	.55	6110.
STEAM/ELEC	1845.	.75	.36	5799.	2245.	.75	.35	6816.	2245.	.75	.36	7133.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3292.			11909.	3692.			12926.	3692.			13243.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	400.	.75	.20	701.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3692.			12609.	3692.			12926.	3692.			13243.
CAP RES. MARGIN	0.336				0.304				0.273			
RESERVE REQ.	553.				566.				580.			
LOSSES	138.			186.	142.			191.	145.			196.
NET RESOURCES	3001.			12423.	2984.			12735.	2967.			13047.
TRANSFERED	0.				0.				0.			
SURPLUS	238.			0.	153.			0.	68.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: [illegible] -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
RATES:NOV. 30, 1978 W/ O.S.-1994.

C R I T I C A L   P E R I O D

	2005-2006				2006-2007				2007-2008			
	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY	PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	556.			2437.	565.			2478.	575.			2520.
RESOURCES												
EXISTING												
HYDRO	288.	.56	.56	1229.	288.	.56	.56	1229.	288.	.56	.56	1229.
STEAM/ELEC	491.	.75	.30	1245.	471.	.75	.31	1286.	471.	.75	.32	1329.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	779.			2474.	759.			2515.	759.			2558.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	20.	.00	.00	0.	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	759.			2474.	759.			2515.	759.			2558.
CAP RES. MARGIN	0.364				0.343				0.319			
RESERVE REQ.	111.				113.				115.			
LOSSES	28.			37.	28.			37.	29.			38.
NET RESOURCES	620.			2437.	61[illegible].			2478.	615.			2520.
TRANSFERED	0.				0.				0.			
SURPLUS	64.			0.	52.			0.	40.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: ANCHORAGE
ANCHORAGE CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 19-2.
NOTES: NOV. 30, 1978 W/ U.S.-1[illegible]

CRITICAL PERIOD

	2008-2009 PEAK	MPUF	APUF	ENERGY	2009-2010 PEAK	MPUF	APUF	ENERGY	2010-2011 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	2968.			13359.	3036.			13671.	3104.			13983.
RESOURCES												
EXISTING												
HYDRO	1447.	.55	.55	6110.	1447.	.55	.55	6110.	1447.	.55	.55	6110.
STEAM/ELEC	2245.	.75	.35	7450.	2245.	.75	.36	7065.	2645.	.75	.35	8083.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.15	.00	0.	0.	.15	.00	0.	0.	.15	.00	0.
TOTAL	3692.			13559.	3692.			13175.	4092.			14193.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	400.	.75	.20	701.	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	3692.			13559.	4092.			13876.	4092.			14193.
CAP RES. MARGIN	0.244				0.348				0.318			
RESERVE REQ.	594.				607.				621.			
LOSSES	148.			200.	152.			205.	155.			210.
NET RESOURCES	2950.			13359.	3333.			13671.	3316.			13983.
TRANSFERED	18.				0.				0.			
SURPLUS	0.			0.	297.			0.	212.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

AREA: FAIRBANKS
FAIRBANKS CASE: 2 -- MEDIUM LOAD GROWTH
INTERTIE YEAR: 1992.
NOTES: NOV. 30, 1979 W/ U.S.-1994.

CRITICAL PERIOD

	2008-2009 PEAK	MPUF	APUF	ENERGY	2009-2010 PEAK	MPUF	APUF	ENERGY	2010-2011 PEAK	MPUF	APUF	ENERGY
REQUIREMENTS	584.			2561.	594.			2603.	603.			2645.
RESOURCES												
EXISTING												
HYDRO	288.	.56	.56	1229.	288.	.56	.56	1229.	288.	.56	.56	1229.
STEAM/ELEC	471.	.75	.33	1371.	471.	.75	.34	1413.	471.	.75	.35	1456.
COMB.TURBINE	0.	.50	.10	0.	0.	.50	.10	0.	0.	.50	.10	0.
DIESEL	0.	.10	.00	0.	0.	.10	.00	0.	0.	.10	.00	0.
TOTAL	759.			2599.	759.			2642.	759.			2685.
ADDITIONS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
RETIREMENTS												
HYDRO	-	-	-	-	-	-	-	-	-	-	-	-
STEAM/ELEC	-	-	-	-	-	-	-	-	-	-	-	-
COMB.TURBINE	-	-	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-	-	-
GROSS RESOURCES	759.			2599.	759.			2642.	759.			2685.
CAP RES. MARGIN	0.299				0.277				0.258			
RESERVE REQ.	117.				119.				121.			
LOSSES	29.			38.	30.			39.	30.			40.
NET RESOURCES	613.			2561.	610.			2603.	608.			2645.
TRANSFERED	-18.				0.				0.			
SURPLUS	10.			0.	16.			0.	5.			0.

PEAK -- PEAK LOAD/GENERATING CAPACITY REQUIREMENTS(MEGAWATTS)
MPUF -- MAXIMUM PLANT UTILIZATION FACTOR
APUF -- ACTUAL PLANT UTILIZATION FACTOR
ENERGY -- GENERATION/ANNUAL ENERGY REQUIREMENTS(MILLIONS OF KILOWATT-HOURS)

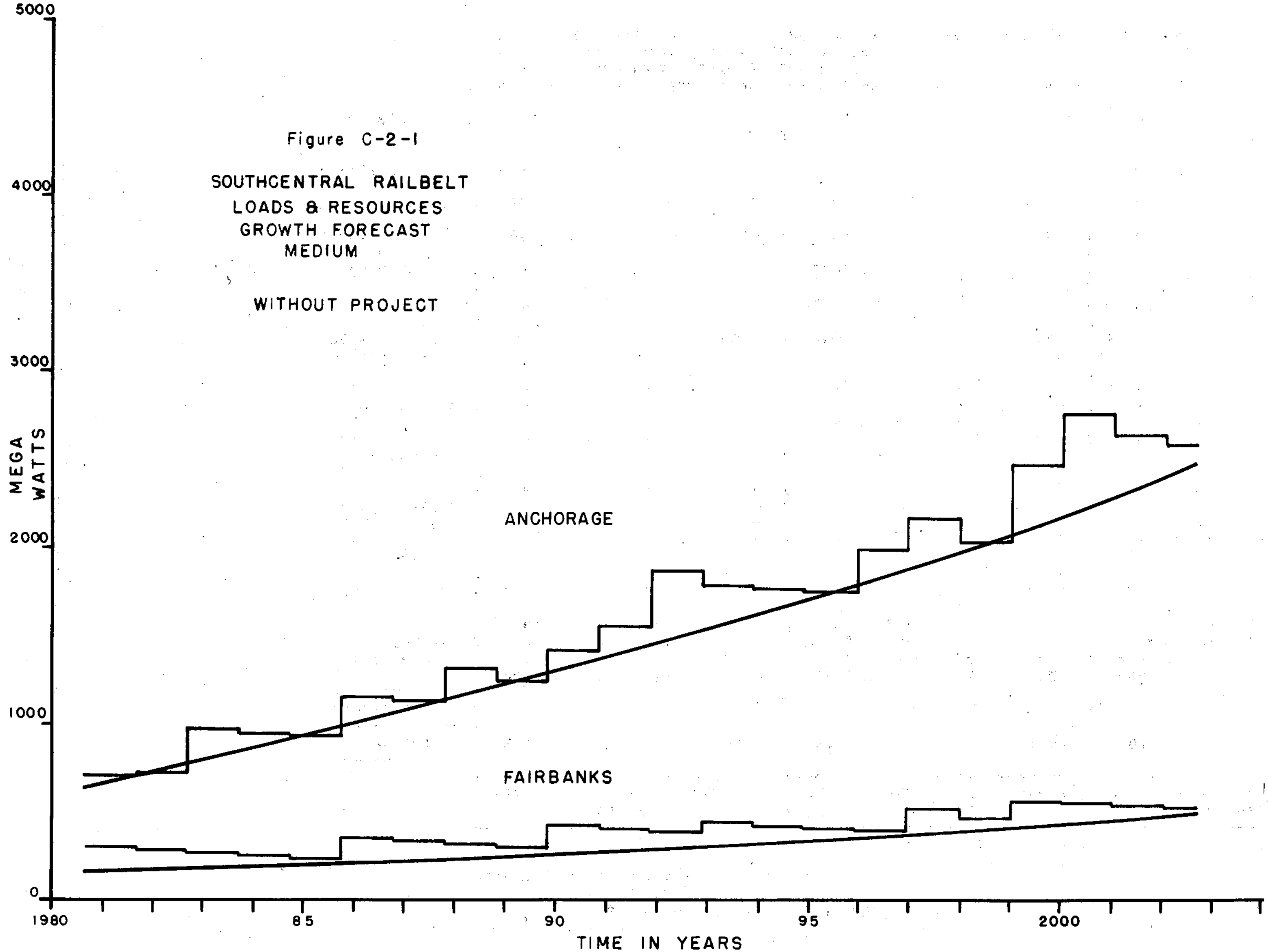


Figure C-2-1

SOUTHCENTRAL RAILBELT
LOADS & RESOURCES
GROWTH FORECAST
MEDIUM

WITHOUT PROJECT

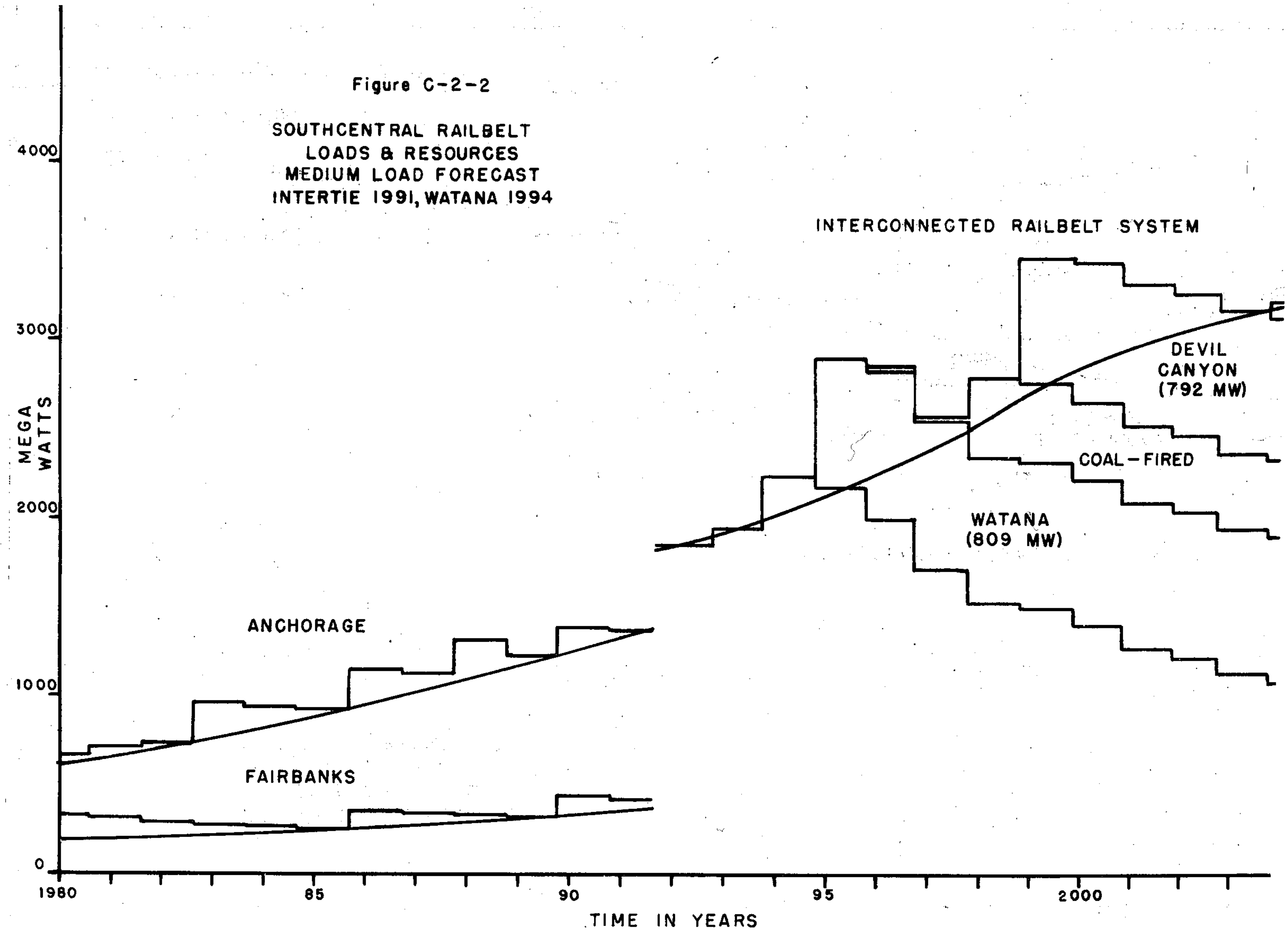
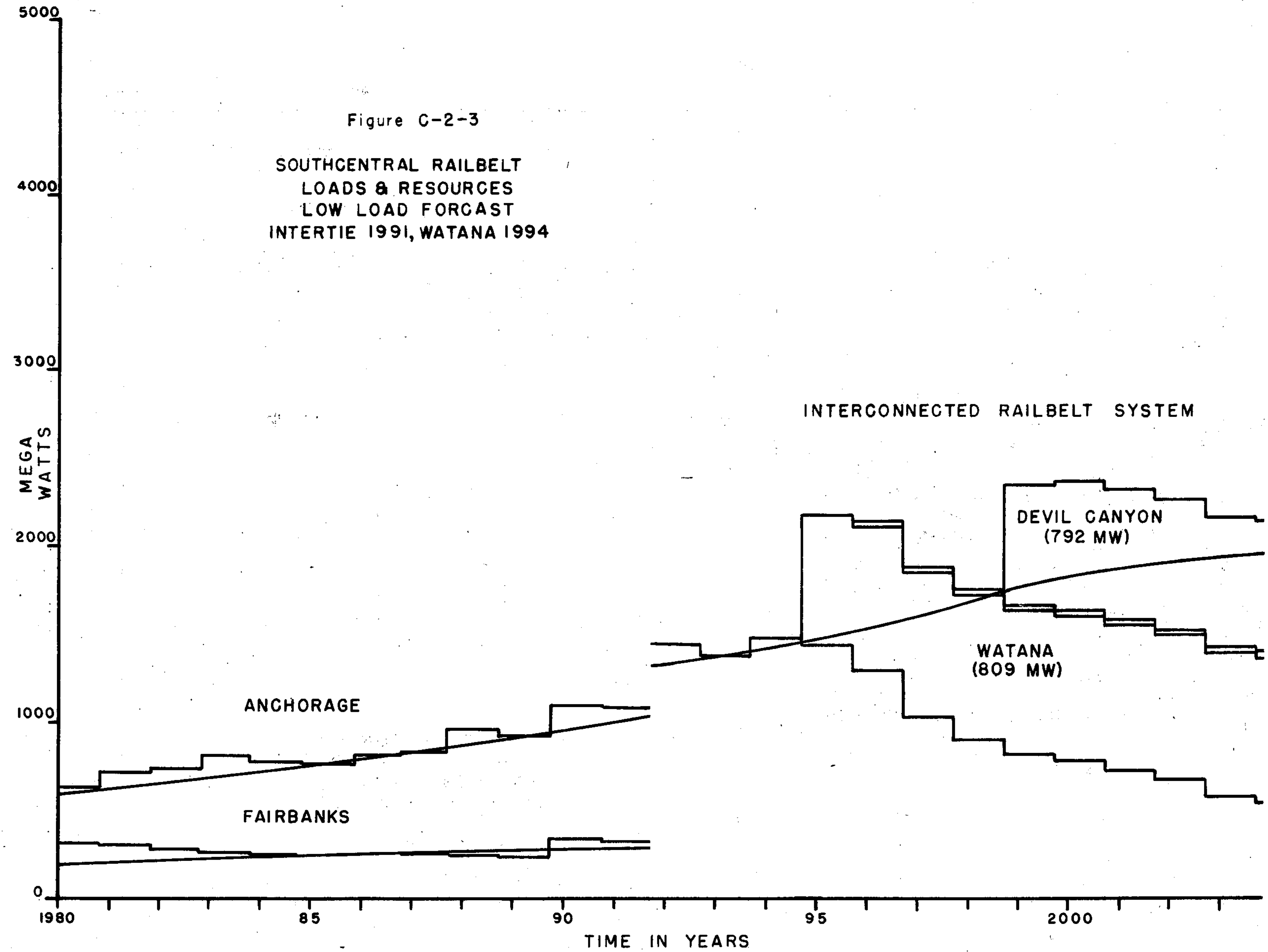


Figure C-2-2
SOUTHCENTRAL RAILBELT
LOADS & RESOURCES
MEDIUM LOAD FORECAST
INTERTIE 1991, WATANA 1994
INTERCONNECTED RAILBELT SYSTEM
DEVIL
CANYON
(792 MW)
COAL-FIRED
WATANA
(809 MW)
ANCHORAGE
FAIRBANKS
MEGA
WATTS
4000
3000
2000
1000
0
1980
85
90
95
2000
TIME IN YEARS

Figure C-2-3

SOUTHCENTRAL RAILBELT
LOADS & RESOURCES
LOW LOAD FORCAST
INTERTIE 1991, WATANA 1994



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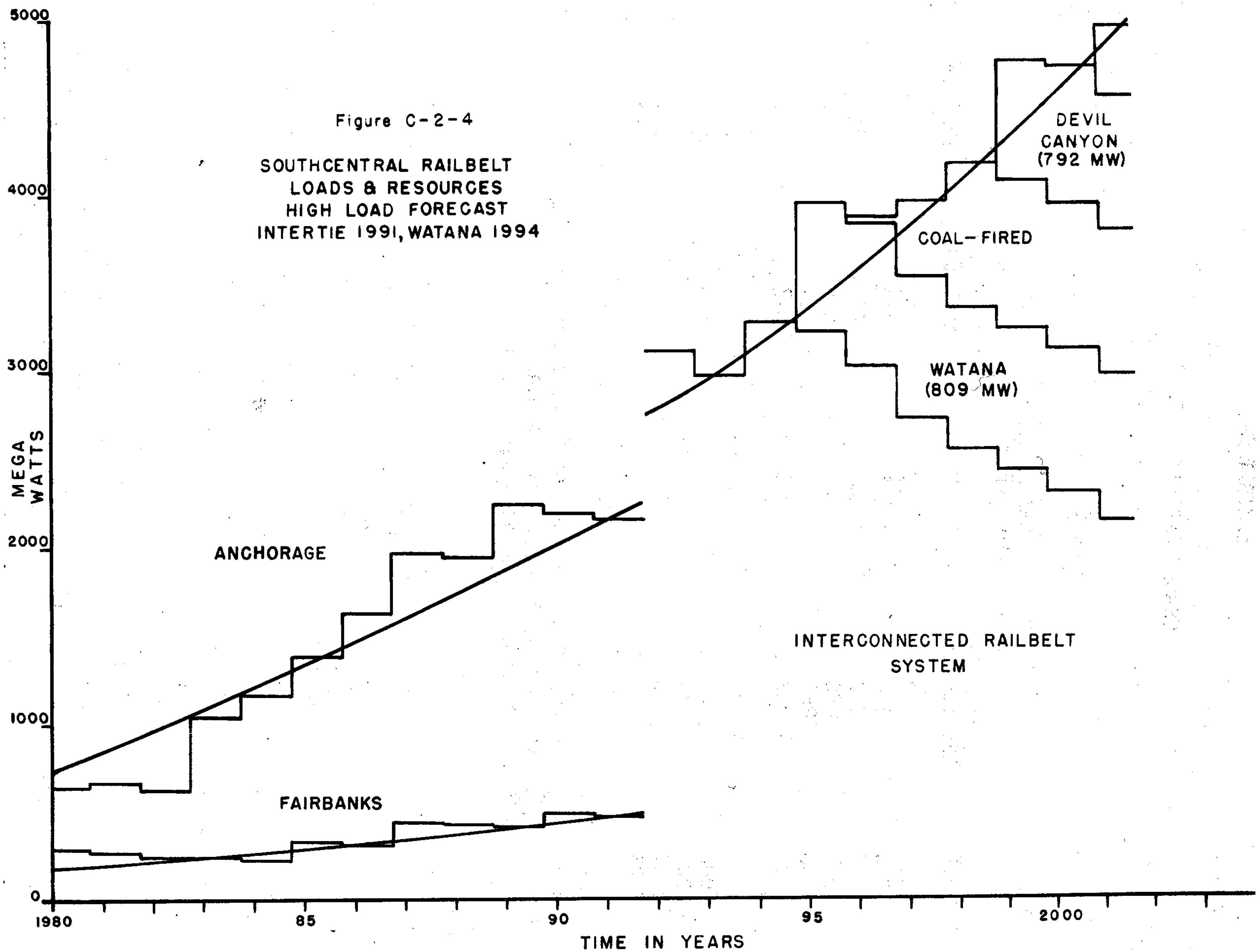
Figure C-2-4
SOUTHCENTRAL RAILBELT
LOADS & RESOURCES
HIGH LOAD FORECAST
INTERTIE 1991, WATANA 1994
5000
4000
3000
2000
1000
0
MEGA WATTS
1980
85
90
95
2000
TIME IN YEARS
ANCHORAGE
FAIRBANKS
INTERCONNECTED RAILBELT
SYSTEM
DEVIL
CANYON
(792 MW)
COAL-FIRED
WATANA
(809 MW)

EXHIBIT C-3

USABLE CAPACITY SUMMARY

TABLE C-3-1

USABLE CAPACITY SUMMARY
(Dependable Capacity Only)

Year	94 1/, Low 2/	94, Med	94, High	96, Med
1994	0	27	99	
1995	214	265	533	
1996	533	680	680	160
1997	680	680	680	476
1998	*858	*950	*1,151	674
1999	1,023	1,035	1,347	680
2000	1,143	1,231		*731
2001	1,178	1,347		847
2002	1,321			1,069
2003	1,339			1,167
2004	1,347			1,281
2005				1,347

NOTES: 1/ Watana power-on-line and interconnection date.
2/ Low, Medium or High load forecast.
* Year of Devil Canyon power-on-line.

TABLE C-4-1

COAL-FIRED, FERC VALUES
BASE CASE AND FUEL ESCALATION TO POL

Item of Cost	Anchorage	Fairbanks	(A) Base Case 1/	(B) Fuel Escalated to 1994 @ 2%
Interest & Amortization	110.77 X .80 = $ 88.62	99.64 X .20 = $19.93	$108.55	$108.55
Interim Replacements, Insurance, and Taxes	9.26 X .80 = 7.41	8.33 X .20 = 1.66	9.07	9.07
Annual Carrying Cost of Fuel Inventory	.91 X .80 = .73	.48 X .20 = .10	.83	1.20
Fixed Operating Costs	14.69 X .80 = 11.75	16.29 X .20 = 3.26	15.01	15.01
Administrative & General	5.65 X .80 = 4.52	6.68 X .20 = 1.34	5.86	5.86
Transmission Cost	30.25 X .80 = 24.20	30.50 X .20 = 6.10	30.30	30.30
Total Capacity Cost ($/Kw)	$137.23	$32.39	$169.62	$169.99
with Hydro Adjustment			186.58	186.99
Energy Fuel (mils/kWh)	11.00 X .80 = $ 8.80	8.40 X .20 = $ 1.68	$ 10.48	$ 14.39
Variable O&M	1.64 X .80 = 1.31	1.82 X .20 = .37	1.68	1.68
Transmission Cost	.65 X .80 = .52	.42 X .20 = .08	.60	.60
Total Energy Cost (mil/Kwh)	$ 10.63	$ 2.13	$12.76	$ 16.67

1/ Base case is a composite value based on the weighted average of Anchorage and Fairbanks values. The 80-20 proportion is derived from the relative future estimated electrical needs of Anchorage and Fairbanks.

TABLE C-4-2
COAL-FIRED, FERC VALUES

Item of Cost	(C) With 3% Inflation	(D) With 5% Inflation	(E) With 2% Fuel Escalation 1/	(F) With 3% Inflation & 2% Fuel Escalation	(G) With 5% Inflation & 2% Fuel Escalation
Interest & Amortization	A X 1.08 = 117.23	A X 1.15 = 124.83	108.55	E X 1.08 = 117.23	E X 1.15 = 124.83
Interim Replacements, Insurance & Taxes	A X 1.34 = 12.15	A X 1.64 = 14.87	9.07	E X 1.34 = 12.15	E X 1.64 = 14.87
Annual Carrying Cost of Fuel Inventory	A X 1.34 = 1.11	A X 1.64 = 1.36	B X 1.32 = 1.58	E X 1.34 = 2.12	E X 1.64 = 2.59
Fixed Operating Costs	A X 1.34 = 20.23	A X 1.64 = 24.62	15.01	E X 1.34 = 20.11	E X 1.64 = 24.62
Administrative & General	A X 1.34 = 7.85	A X 1.64 = 9.61	5.86	E X 1.34 = 7.85	E X 1.64 = 9.61
Transmission Cost	30.30	30.30	30.30	30.30	30.30
Total Capacity Cost ($/Kw)	188.87	205.59	170.37	189.76	206.82
with Hydro Adjustment	207.76	226.15	187.41	208.74	227.50
Energy Fuel	A X 1.34 = 14.04	A X 1.64 = 17.19	B X 1.32 =18.99	E X 1.34 = 25.45	E X 1.64 = 31.14
Variable O&M	A X 1.34 = 2.25	A X 1.64 = 2.76	1.68	E X 1.34 = 2.25	E X 1.64 = 2.76
Transmission Cost	.60	.60	.60	.60	.60
Total Energy Cost (mil/Kwh)	16.89	20.55	21.27	28.30	34.50

1/ Fuel escalates from 1978 to POL and from POL through 30-year life of initial thermal plant.

TABLE C-4-3

COAL-FIRED, FEDERAL FINANCING, & APA INVESTMENT COST

Item of Cost	(H) Federal Financing	(I) APA Investment Cost	(J) APA With 3% Inflation & 2% Fuel Escalation
Interest & Amortization	101.73	137.77	148.79
Interim Replacements, Insurance & Taxes		11.51	15.42
Annual Carrying Cost of Fuel Inventory	.71	.83	1.78
Fixed Operating Costs	15.01	15.01	20.11
Administrative & General	5.86	5.86	7.85
Transmission Cost	26.93	30.30	30.30
Total Capacity Cost ($/Kw)	150.24	201.28	224.25
with Hydro Adjustment	165.26	221.41	246.68
Energy Fuel	10.48	10.48	21.40
Variable O&M	1.68	1.68	2.25
Transmission Cost	.60	.60	.60
Total Energy Cost (mil/Kwh)	12.76	12.76	24.25

TABLE C-4-4

OIL-FIRED, FERC VALUES

Item of Cost	(K) Fuel Escalation to 1994	(L) No Inflation, No Escalation
Interest & Amortization	29.22	29.22
Interim Replacements, Insurance & Taxes	2.55	2.55
Annual Carrying Cost of Fuel Inventory	2.52	1.75
Fixed Operating Costs	--	--
Administrative & General	2.98	2.98
Transmission Cost	5.36	5.36
Total Capacity Cost ($/Kw)	42.63	41.86
with Hydro Adjustment	44.76	43.95
Energy Fuel	33.28	24.24
Variable O&M	1.70	1.70
Transmission Cost	.98	.98
Total Energy Cost (mil/Kwh)	35.96	26.92

TABLE C-4-5
OIL-FIRED, FERC VALUES

Item of Cost	(M) With 3% Inflation	(N) With 5% Inflation	(P) With 2% Fuel Escalation	(Q) With 3% Inflation & 2% Fuel Escalation	(R) With 5% Inflation & 2% Fuel Escalation
Interest & Amortization	L X 1.08 = 31.56	L X 1.15 = 33.60	29.22	P X 1.08 = 31.56	P X 1.15 = 33.60
Interim Replacements, Insurance & Taxes	L X 1.34 = 3.42	L X 1.64 = 4.18	2.55	P X 1.34 = 3.42	P X 1.64 = 4.18
Annual Carrying Cost of Fuel Inventory	L X 1.34 = 2.35	L X 1.64 = 2.87	K X 1.32 = 3.33	P X 1.34 = 4.46	P X 1.64 = 5.46
Fixed Operating Costs	--	--	--	--	--
Administrative & General	L X 1.34 = 3.99	L X 1.64 = 4.89	2.98	P X 1.34 = 3.99	P X 1.64 = 4.89
Transmission Cost	5.36	5.36	5.36	5.36	5.36
Total Capacity Cost ($/Kw)	46.68	50.90	43.44	48.79	53.49
with Hydro Adjustment	49.01	53.45	45.61	51.23	56.16
Energy Fuel	L X 1.34 = 35.48	L X 1.64 = 39.75	K X 1.32 =43.93	P X 1.34 = 58.87	P X 1.64 = 72.05
Variable O&M	L X 1.34 = 2.28	L X 1.64 = 2.79	1.70	P X 1.34 = 2.28	P X 1.64 = 2.79
Transmission Cost	.98	.98	.98	.98	.98
Total Energy Cost (mil/Kwh)	38.74	43.52	46.61	62.13	75.82

TABLE C-4-6

OIL-FIRED, FERC VALUES, FUEL ESCALATION AFTER POL

Item of Cost	(S) Without Inflation	(T) With 3% Inflation & 2% Fuel Escalation	(U) With 5% Inflation & 2% Fuel Escalation
Interest & Amortization	29.22	S X 1.08 = 31.56	S X 1.15 = 33.60
Interim Replacements, Insurance & Taxes	2.55	S X 1.34 = 3.42	S X 1.64 = 4.18
Annual Carrying Cost of Fuel Inventory (2% Esc after POL)	L X 1.32 = 2.31	S X 1.34 = 3.10	S X 1.64 = 3.79
Fixed Operating Costs	--	--	--
Administrative & General	2.98	S X 1.34 = 3.99	S X 1.64 = 4.89
Transmission Cost	5.36	5.36	5.36
Total Capacity Cost ($/Kw)	42.42	47.43	51.82
with Hydro Adjustment	44.54	49.80	54.41
Energy Fuel (2% Esc after POL)	L X 1.32 = 32.00	S X 1.34 = 42.88	S X 1.64 = 52.48
Variable O&M	1.70	S X 1.34 = 2.28	S X 1.64 = 2.79
Transmission Cost	.98	.98	.98
Total Energy Cost (mil/Kwh)	34.68	46.14	56.25

TABLE C-4-7

OIL-FIRED, FERC VALUES, FUEL COST DECLINE OF 35%

Item of Cost	(V) Without Inflation	(W) With 3% Inflation & 2% Fuel Escalation	(X) With 5% Inflation & 2% Fuel Escalation
Interest & Amortization	29.22	V X 1.08 = 31.56	V X 1.15 = 33.60
Interim Replacements, Insurance & Taxes	2.55	V X 1.34 = 3.42	V X 1.64 = 4.18
Annual Carrying Cost of Fuel Inventory	1.19	V X 1.34 = 1.59	V X 1.64 = 1.95
Fixed Operating Costs	--	--	--
Administrative & General	2.98	V X 1.34 = 3.99	V X 1.64 = 4.89
Transmission Cost	5.36	5.36	5.36
Total Capacity Cost ($/Kw)	41.30	45.92	49.98
with Hydro Adjustment	43.37	48.22	52.48
Energy Fuel	15.77	V X 1.34 = 21.13	V X 1.64 = 25.86
Variable O&M	1.70	V X 1.34 = 2.28	V X 1.64 = 2.79
Transmission Cost	.98	.98	.98
Total Energy Cost (mil/Kwh)	18.45	24.39	29.63

TABLE C-4-8

HYDROPOWER COSTS WITH INFLATION
($1,000)

Cost Item	No Inflation		3% Inflation		5% Inflation
Interest and Amortization	216,671	X 1 =	216,671	X 1 =	216,671
Operation and Maintenance	2,890	X 1.34 =	3,873	X 1.64 =	4,740
Replacement	430	X 1.34 =	576	X 1.64 =	705
Total	219,991		221,120		222,116

WATANA AND DEVIL CANYON MID RANGE

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	4713.6	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	40495.3
1995	0.8755	265.0	232.0	43287.1	3058.0	2677.2	33161.4	397.0	347.6	4435.0	0.0	81883.5
1996	0.8192	680.0	557.0	103931.1	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	140044.7
1997	0.7665	680.0	521.2	97245.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	131036.0
1998	0.7172	950.0	681.3	127116.3	6057.0	4343.9	55427.8	397.0	284.7	3633.0	0.0	186179.0
1999	0.6710	1035.0	694.5	129583.2	6057.0	4064.4	51862.3	785.0	526.8	6721.5	0.0	188166.9
2000	0.6279	1231.0	772.9	144208.3	6057.0	3803.0	48526.1	785.0	492.9	6289.1	0.0	199023.5
2001	0.5875	1347.0	791.3	147646.7	6057.0	3558.3	45404.5	785.0	461.2	5884.5	54.8	198990.5
2002	0.5497	1347.0	740.4	138148.9	6057.0	3329.4	42483.8	785.0	431.5	5506.0	9076.6	195215.3
				935882.7			375519.3			40501.4	9131.4	1361034.7
2003												
2096	7.9766	1347.0	10744.5	2004703.7	6057.0	48314.2	616489.6	785.0	6261.6	79898.4	131712.2	2832803.9
PRESENT WORTH BENEFITS				2940586.5			992008.9			120399.7	140843.6	4193838.6
CRF=	0.0688 AV ANN BENEFITS =			202427.5			68289.1			8288.2	9695.6	288700.4

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY	ENERGY	SECONDARY	INTEREST
1 186.58	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	TOTALS---POWER VALUES & INTEREST
NEW SYSTEM				
WATANA AND DEVIL CANYON MID RANGE	202428.	68289.	8288.	288700.
NEW SYSTEM				

EXHIBIT C-5
POWER BENEFIT CALCULATIONS

WATANA ALONE - COAL

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	4713.6	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	40495.3
1995	0.8755	265.0	232.0	43257.1	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	81883.5
1996	0.8192	680.0	557.0	103931.1	3058.0	2505.0	31963.9	397.0	325.2	4149.7	76.4	140121.1
1997	0.7665	680.0	521.2	97245.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	5505.8	136541.8
				249177.3			131814.8			12467.3	5582.2	399041.7
1998 2094	11.1298	680.0	7568.3	1412089.4	3058.0	34035.0	434286.5	397.0	4418.5	56380.6	79949.2	1982705.7
PRESENT WORTH BENEFITS				1661266.8			566101.3			68847.9	85531.4	2381747.4
CRF=	0.0688 AV ANN BENEFITS =			114360.2			38969.9			4739.4	5887.9	163957.5

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY ENERGY SECONDARY INTEREST
1 186.58 12.76 12.76 0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
WATANA ALONE - COAL
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
114360. 38970. 4739. 163958.

FEDERAL FINANCING

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	4175.0	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	39956.7
1995	0.8755	265.0	232.0	38340.6	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	76937.2
1996	0.8192	680.0	557.0	92055.2	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	128168.8
1997	0.7665	680.0	521.2	86133.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	119924.0
1998	0.7172	950.0	681.3	112592.8	6057.0	4343.9	55427.8	397.0	284.7	3633.0	0.0	171653.6
1999	0.6710	1035.0	694.5	114776.1	6057.0	4064.4	51862.3	785.0	526.8	6721.5	0.0	173359.8
2000	0.6279	1231.0	772.9	127730.0	6057.0	3803.0	48526.1	785.0	492.9	6289.1	0.0	182545.2
2001	0.5875	1347.0	791.3	130775.5	6057.0	3558.3	45404.5	785.0	461.2	5884.5	48.5	182113.1
2002	0.5497	1347.0	740.4	122363.0	6057.0	3329.4	42483.8	785.0	431.5	5506.0	8039.4	178392.2
				828941.9			375519.3			40501.4	8088.0	1253050.5
2003												
2094	7.9766	1347.0	10744.5	1775631.6	6057.0	48314.2	616489.6	785.0	6261.6	79898.4	116661.8	2588681.3
PRESENT WORTH BENEFITS				2604573.5			992008.9			120399.7	124749.7	3841731.8
CRF= 0.0688 AV ANN BENEFITS =				179296.7			68289.1			8288.2	8587.7	264461.6

CAPACITY VALUE = 165.26000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	165.26	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT — CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST

NEW SYSTEM

FEDERAL FINANCING — 179297. 68289. 8288. 264462.

NEW SYSTEM

FEDERAL FINANCING - WATANA ALONE

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	4175.0	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	39956.7
1995	0.8755	265.0	232.0	38340.8	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	76937.2
1996	0.8192	680.0	557.0	92055.2	3058.0	2505.0	31963.9	397.0	325.2	4149.7	67.7	128236.4
1997	0.7665	680.0	521.2	86133.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	4876.7	124800.7
				220704.5			131814.8			12467.3	4944.4	369931.0
1998												
2094	11.1298	680.0	7558.3	1250733.7	3058.0	34035.0	434286.5	397.0	4418.5	56380.6	70813.6	1812214.4
PRESENT WORTH BENEFITS				1471438.2			566101.3			68847.9	75758.0	2182145.4
CRF= 0.0688	AV ANN BENEFITS =			101292.6			38969.9			4739.4	5215.1	150217.1

CAPACITY VALUE = 165.26000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	165.26	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	TOTALS---POWER VALUES & INTEREST
NEW SYSTEM				
FEDERAL FINANCING - WATANA ALONE	101293.	38970.	4739.	150217.
NEW SYSTEM				

5% DISCOUNT RATE

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9524	27.0	25.7	4797.8	2997.0	2854.3	36429.7	0.0	0.0	0.0	0.0	41218.5
1995	0.9070	265.0	240.4	44646.9	3058.0	2773.7	35392.4	397.0	360.1	4594.8	0.0	84834.0
1996	0.8638	680.0	587.4	109598.9	3058.0	2641.6	33707.0	397.0	342.9	4376.0	0.0	147681.8
1997	0.8227	680.0	559.4	104379.9	3058.0	2515.8	32101.9	397.0	326.6	4167.6	0.0	140649.4
1998	0.7835	950.0	744.3	138890.8	6057.0	4745.8	60556.6	397.0	311.1	3969.1	0.0	203406.6
1999	0.7462	1035.0	772.3	144101.9	6057.0	4519.8	57673.0	785.0	585.8	7474.5	0.0	209249.4
2000	0.7107	1231.0	874.8	163229.3	6057.0	4304.6	54926.7	785.0	557.9	7118.6	0.0	225274.5
2001	0.6768	1347.0	911.7	170105.5	6057.0	4099.6	52311.1	785.0	531.3	6779.6	63.1	229259.3
2002	0.6446	1347.0	868.3	162005.2	6057.0	3904.4	49820.1	785.0	506.0	6456.8	10644.0	228926.1
				1041946.1			412909.5			44937.0	10707.1	1510499.6
2003												
2094	12.7401	1347.0	17160.9	3201880.6	6057.0	77166.7	984647.3	785.0	10001.0	127612.4	210368.5	4524508.8
PRESENT WORTH BENEFITS				4243826.6			1397556.8			172549.4	221075.7	6035008.4
CRF=	0.0504 AV ANN BENEFITS =			213817.3			70413.3			8693.6	11138.5	304062.7

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.05000

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	186.58	12.76	12.76	0.05000

1

SYSTEM OF DEVELOPMENT — CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST

NEW SYSTEM

5% DISCOUNT RATE — 213817. 70413. 8694. 304063.

NEW SYSTEM

8% DISCOUNT RATE

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9259	27.0	25.0	4664.5	2997.0	2775.0	35409.0	0.0	0.0	0.0	0.0	40073.5
1995	0.8573	265.0	227.2	42390.0	3058.0	2621.7	33453.4	397.0	340.4	4343.0	0.0	80186.5
1996	0.7938	680.0	539.8	100717.0	3058.0	2427.5	30975.4	397.0	315.2	4021.3	0.0	135713.7
1997	0.7350	680.0	499.8	93256.5	3058.0	2247.7	28680.9	397.0	291.8	3723.5	0.0	125660.9
1998	0.6806	950.0	646.6	120634.1	6057.0	4122.3	52600.5	397.0	270.2	3447.6	0.0	176682.1
1999	0.6302	1035.0	652.2	121692.2	6057.0	3816.9	48704.1	785.0	494.7	6312.2	0.0	176708.5
2000	0.5835	1231.0	718.3	134016.1	6057.0	3534.2	45096.4	785.0	458.0	5844.6	0.0	184957.1
2001	0.5403	1347.0	727.7	135782.1	6057.0	3272.4	41755.9	785.0	424.1	5411.7	50.4	183000.1
2002	0.5002	1347.0	673.8	125724.2	6057.0	3030.0	38662.9	785.0	392.7	5010.8	8260.3	177658.2
				878876.7			355338.6			38114.7	8310.7	1280640.6
2003												
2094	6.2473	1347.0	8415.3	1570124.4	6057.0	37840.7	482847.1	785.0	4904.2	62578.0	103159.6	2218709.1
PRESENT WORTH BENEFITS				2449001.1			838185.7			100692.7	111470.3	3499349.7
CRF=	0.0800 AV ANN BENEFITS =			196009.2			67085.3			8059.1	8921.7	280075.3

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.08000

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	186.58	12.76	12.76	0.08000

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
8% DISCOUNT RATE
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
196009. 67085. 8059. 280075.

LOW LOAD GROWTH

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	0.0	0.0	0.0	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	35781.7
1995	0.8755	214.0	187.4	34955.8	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	73552.8
1996	0.8192	533.0	436.6	81463.7	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	117577.2
1997	0.7665	680.0	521.2	97245.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	131036.0
1998	0.7172	858.0	615.3	114807.9	6057.0	4343.9	55427.8	397.0	284.7	3633.0	0.0	173868.6
1999	0.6710	1023.0	686.5	128080.8	6057.0	4064.4	51862.3	785.0	526.8	6721.5	0.0	186664.5
2000	0.6279	1143.0	717.7	133899.3	6057.0	3803.0	48526.1	785.0	492.9	6289.1	0.0	188714.5
2001	0.5875	1178.0	692.0	129122.3	6057.0	3558.3	45404.5	785.0	461.2	5884.5	0.0	180411.4
2002	0.5497	1321.0	726.1	135482.4	6057.0	3329.4	42483.8	785.0	431.5	5506.0	0.0	183472.1
2003	0.5143	1339.0	688.7	128494.5	6057.0	3115.3	39750.9	785.0	403.7	5151.8	0.0	173397.2
2004	0.4812	1347.0	648.2	120947.0	6057.0	2914.9	37193.8	785.0	377.8	4820.4	1302.0	164263.2
2005	0.4503	1347.0	606.5	113166.8	6057.0	2727.4	34801.2	785.0	353.5	4510.3	2856.5	155334.9
2006	0.4213	1347.0	567.5	105887.1	6057.0	2551.9	32562.6	785.0	330.7	4220.2	3301.6	145971.4
2007	0.3942	1347.0	531.0	99075.	6057.0	2387.8	30467.9	785.0	309.5	3948.7	3751.2	137243.4
2008	0.3689	1347.0	496.9	92702.4	6057.0	2234.2	28508.0	785.0	289.6	3694.7	4129.3	129034.3
2009	0.3451	1347.0	464.9	86739.0	6057.0	2090.4	26674.1	785.0	270.9	3457.0	4475.4	121345.6
2010	0.3229	1347.0	435.0	81159.3	6057.0	1956.0	24958.2	785.0	253.5	3234.6	5332.3	114684.5
				1683230.1			630436.0			73539.1	25148.2	2412353.4
2011							361572.8	785.0	3672.5	46860.6	77249.5	1661447.2
2094	4.6783	1347.0	6301.7	1175764.2	6057.0	28336.4				120399.7	102397.7	4073800.6
PRESENT WORTH BENEFITS				2858994.3			992008.9					
CRF= 0.0688 AV ANN BENEFITS =				196810.8			68289.1			8288.2	7049.0	280437.1

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	186.58	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
LOW LOAD GROWTH
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST

196811. 68289. 8288. 280437.

HIGH LOAD GROWTH

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	99.0	92.6	17283.2	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	53064.9
1995	0.8755	533.0	466.6	87064.3	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	125660.7
1996	0.8192	680.0	557.0	103931.1	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	140044.7
1997	0.7665	680.0	521.2	97245.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	131036.0
1998	0.7172	1151.0	825.5	154013.8	6057.0	4343.9	55427.6	397.0	284.7	3633.0	0.0	213074.6
1999	0.6710	1347.0	903.9	168646.0	6057.0	4064.4	51862.3	765.0	526.8	6721.5	11080.3	238310.0
				628183.9			239104.9			22821.8	11080.3	901190.8
2000												
2094	9.7416	1347.0	13122.0	2448296.7	6057.0	59005.0	752904.0	785.0	7647.2	97578.0	160856.9	3459635.6
PRESENT WORTH BENEFITS				3076480.6			992008.9			120399.7	171937.2	4360826.4
CRF=	0.0688 AV ANN BENEFITS =			211782.4			68289.1			8288.2	11836.0	300195.7

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875
1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	186.58	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
HIGH LOAD GROWTH
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST

211782. 68289. 8288. 300196.

TWO YEAR CONSTRUCTION DELAY

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1996	0.9357	160.0	149.7	27932.4	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	63714.2
1997	0.8755	476.0	416.7	77753.5	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	116349.8
1998	0.8192	674.0	552.1	103014.1	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	139127.6
1999	0.7665	680.0	521.2	97245.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	131036.0
2000	0.7172	731.0	524.2	97814.2	6057.0	4343.9	55427.8	397.0	284.7	3633.0	0.0	156874.9
2001	0.6710	847.0	568.4	106045.4	6057.0	4064.4	51862.3	785.0	526.8	6721.5	0.0	164629.1
2002	0.6279	1069.0	671.2	125230.4	6057.0	3803.0	48526.1	785.0	492.9	6289.1	0.0	180045.6
2003	0.5875	1167.0	685.6	127916.6	6057.0	3558.3	45404.5	785.0	461.2	5884.5	0.0	179205.7
2004	0.5497	1281.0	704.1	131379.9	6057.0	3329.4	42483.8	785.0	431.5	5506.0	0.0	179369.7
2005	0.5143	1347.0	692.8	129262.2	6057.0	3115.3	39750.9	785.0	403.7	5151.8	2543.0	176707.9
2006	0.4812	1347.0	648.2	120947.0	6057.0	2914.9	37193.8	785.0	377.8	4820.4	6689.4	169650.6
2007	0.4503	1347.0	606.5	113166.8	6057.0	2727.4	34801.2	785.0	353.5	4510.3	7435.2	159913.6
				1257708.1			487265.2			54983.9	16667.6	1816620.8
2008 2096	6.5307	1347.0	8796.9	1641327.7	6057.0	39556.7	504743.6	785.0	5126.6	65415.8	107837.8	2319325.0
PRESENT WORTH BENEFITS				2899035.8			992008.9			120399.7	124505.4	4135949.7
CRF= 0.0688 AV ANN BENEFITS =				199567.2			68289.1			8288.2	8570.8	284715.4

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY ENERGY SECONDARY INTEREST
1 186.58 12.76 12.76 0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
TWO YEAR CONSTRUCTION DELAY
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
199567. 68289. 8288. 284715.

APA INVESTMENT COST

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	5593.5	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	41375.2
1995	0.8755	265.0	232.0	51367.8	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	89964.2
1996	0.8192	680.0	557.0	123332.6	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	159446.1
1997	0.7665	680.0	521.2	115398.9	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	149189.4
1998	0.7172	950.0	681.3	150846.2	6057.0	4343.9	55427.8	397.0	284.7	3633.0	0.0	209909.0
1999	0.6710	1035.0	694.5	153773.3	6057.0	4064.4	51862.3	785.0	526.8	6721.5	0.0	212357.0
2000	0.6279	1231.0	772.9	171128.5	6057.0	3803.0	48526.1	785.0	492.9	6289.1	0.0	225943.7
2001	0.5875	1347.0	791.3	175208.6	6057.0	3558.3	45404.5	785.0	461.2	5884.5	65.0	226562.9
2002	0.5497	1347.0	740.4	163938.6	6057.0	3329.4	42483.8	785.0	431.5	5506.0	10771.0	222698.8
				1110589.5			375519.3			40501.4	10836.0	1537446.2
2003 2094	7.9766	1347.0	10744.5	2378933.7	6057.0	48314.2	616489.6	785.0	6261.6	79898.4	156299.7	3231621.3
PRESENT WORTH BENEFITS				3489523.2			992008.9			120399.7	167135.7	4769067.5
CRF= 0.0688 AV ANN BENEFITS =				240215.9			68289.1			8288.2	11505.5	328298.7

CAPACITY VALUE = 221.41000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	221.41	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	TOTALS---POWER VALUES & INTEREST
NEW SYSTEM				
APA INVESTMENT COST	240216.	68289.	8288.	328299.
NEW SYSTEM				

APA INVESTMENT COST AND 2% ESCALATION AND 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	6231.9	2997.0	2804.2	68002.1	0.0	0.0	0.0	0.0	74234.0
1995	0.6755	265.0	232.0	57230.5	3058.0	2677.2	64922.8	397.0	347.6	8428.5	0.0	130581.8
1996	0.8192	680.0	557.0	137408.8	3058.0	2505.0	60746.4	397.0	325.2	7886.3	0.0	206041.5
1997	0.7665	680.0	521.2	128569.6	3058.0	2343.9	56838.8	397.0	304.3	7379.0	0.0	192787.4
1998	0.7172	950.0	681.3	168064.9	6057.0	4343.9	105338.9	397.0	284.7	6904.3	0.0	280308.1
1999	0.6710	1035.0	694.5	171323.7	6057.0	4064.4	98562.7	785.0	526.8	12773.9	0.0	282660.4
2000	0.6279	1231.0	772.9	190659.8	6057.0	3803.0	92222.4	785.0	492.9	11952.2	0.0	294834.4
2001	0.5875	1347.0	791.3	195205.7	6057.0	3558.3	86290.0	785.0	461.2	11183.4	72.5	292751.5
2002	0.5497	1347.0	740.4	182648.6	6057.0	3329.4	80739.1	785.0	431.5	10464.0	12000.3	285852.0
				1237343.5			713663.2			76971.6	12072.8	2040051.0
2003												
2094	7.9766	1347.0	10744.5	2650446.5	6057.0	48314.2	1171620.1	785.0	6261.6	151844.4	174138.5	4148049.6
PRESENT WORTH BENEFITS				3887790.0			1885283.3			228816.1	186211.2	6188100.6
CRF=	0.0688	AV ANN BENEFITS =		267632.2			129781.3			15751.5	12818.6	425983.7

CAPACITY VALUE = 246.68000$/KW-YR
ENERGY VALUE = 24.25000MILLS/KWH
SECONDARY VALUE= 24.25000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	246.68	24.25	24.25	0.06875

1

SYSTEM OF DEVELOPMENT — CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
NEW SYSTEM
APA INVESTMENT COST AND 2% ESCALATION AND 3% INFLATION — 267632. 129781. 15752. 425984.
NEW SYSTEM

OIL FIRED ALTERNATIVE

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1110.3	2997.0	2804.2	75489.3	0.0	0.0	0.0	0.0	76599.7
1995	0.8755	265.0	232.0	10196.5	3058.0	2677.2	72071.0	397.0	347.6	9356.5	0.0	91624.0
1996	0.8192	680.0	557.0	24491.6	3058.0	2505.0	67434.8	397.0	325.2	8754.6	0.0	100671.0
1997	0.7665	680.0	521.2	22906.7	3058.0	2343.9	63096.9	397.0	304.3	8191.5	0.0	94195.1
1998	0.7172	950.0	681.3	29943.5	6057.0	4343.9	116937.0	397.0	284.7	7664.5	0.0	154545.0
1999	0.6710	1035.0	694.5	30524.1	6057.0	4064.4	109414.7	785.0	526.8	14180.4	0.0	154119.2
2000	0.6279	1231.0	772.9	33969.1	6057.0	3803.0	102376.4	785.0	492.9	13268.2	0.0	149613.7
2001	0.5875	1347.0	791.3	34779.0	6057.0	3558.3	95790.8	785.0	461.2	12414.7	12.9	142997.4
2002	0.5497	1347.0	740.4	32541.8	6057.0	3329.4	89628.8	785.0	431.5	11616.1	2138.0	135924.7
				220452.6			792239.7			85446.4	2151.0	1100289.7
2003 2094	7.9766	1347.0	10744.5	472219.6	6057.0	48314.2	1300619.1	785.0	6261.6	168563.0	31025.6	1972427.3
PRESENT WORTH BENEFITS				692672.2			2092858.8			254009.4	33176.5	3072716.9
CRF=	0.0688 AV_ANN BENEFITS =			47683.0			144070.7			17485.8	2283.8	211523.3

CAPACITY VALUE = 43.95000$/KW-YR
ENERGY VALUE = 26.92000MILLS/KWH
SECONDARY VALUE= 26.92000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	43.95	26.92	26.92	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
NEW SYSTEM	
OIL FIRED ALTERNATIVE	47683. 144071. 17486. 211523.
NEW SYSTEM	

NATANA ALONE - OIL

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1110.3	2997.0	2904.2	75489.3	0.0	0.0	0.0	0.0	76599.7
1995	0.8755	265.0	232.0	10196.5	3058.0	2677.2	72071.0	397.0	347.6	9356.5	0.0	91624.0
1996	0.8192	680.0	557.0	24481.6	3058.0	2505.0	67434.8	397.0	325.2	8754.6	18.0	100689.0
1997	0.7665	680.0	521.2	22906.7	3058.0	2343.9	63096.9	397.0	304.3	8191.5	1296.9	95492.0
				58695.2			278092.0			26302.6	1314.9	364404.7
1998 2094	11.1298	680.0	7568.3	332625.8	3058.0	34035.0	916222.0	397.0	4418.5	118947.1	18832.5	1386627.5
PRESENT WORTH BENEFITS				391321.0			1194314.1			145249.6	20147.4	1751032.1
CRF=	0.0688 AV ANN BENEFITS =			26938.2			82215.6			9998.9	1386.9	120539.6

CAPACITY VALUE = 43.95000$/KW-YR
ENERGY VALUE = 26.92000MILLS/KWH
SECONDARY VALUE= 26.92000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	43.95	26.92	26.92	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	TOTALS---POWER VALUES & INTEREST
NEW SYSTEM				
NATANA ALONE - OIL	26938.	82216.	9999.	120540.
NEW SYSTEM				

BASE CASE WITH 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	5248.7	2997.0	2904.2	47363.1	0.0	0.0	0.0	0.0	52611.8
1995	0.8755	265.0	232.0	48200.9	3058.0	2677.2	45218.4	397.0	347.6	5870.4	0.0	99289.7
1996	0.8192	680.0	557.0	115729.1	3058.0	2505.0	42309.6	397.0	325.2	5492.8	0.0	163531.4
1997	0.7665	680.0	521.2	108284.5	3058.0	2343.9	39587.9	397.0	304.3	5139.4	0.0	153011.9
1998	0.7172	950.0	681.3	141548.4	6057.0	4343.9	73368.0	397.0	284.7	4808.8	0.0	219725.2
1999	0.6710	1035.0	694.5	144293.1	6057.0	4064.4	68648.4	785.0	526.8	8897.0	0.0	221838.5
2000	0.6279	1231.0	772.9	160578.4	6057.0	3803.0	64232.4	785.0	492.9	8324.7	0.0	233135.5
2001	0.5875	1347.0	791.3	164407.1	6057.0	3558.3	60100.5	785.0	461.2	7789.2	61.0	232357.8
2002	0.5497	1347.0	740.4	153831.2	6057.0	3329.4	56234.4	785.0	431.5	7288.1	10106.9	227460.6
				1042121.3			497062.7			53610.3	10168.0	1602962.3
2003 2094	7.9766	1347.0	10744.5	2232271.7	6057.0	48314.2	816027.4	785.0	6261.6	105758.9	146663.7	3300721.7
PRESENT WORTH BENEFITS				3274393.0			1313090.1			159369.2	156831.7	4903684.0
CRF= 0.0688 AV ANN BENEFITS =				225406.5			90392.0			10970.8	10796.2	337565.5

CAPACITY VALUE = 207.76000$/KW-YR
ENERGY VALUE = 16.89000MILLS/KWH
SECONDARY VALUE= 16.89000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	207.76	16.89	16.89	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
BASE CASE WITH 3% INFLATION
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
225406. 90392. 10971. 337566.

BASE CASE WITH 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	5713.3	2997.0	2804.2	57626.5	0.0	0.0	0.0	0.0	63339.8
1995	0.8755	265.0	232.0	52467.5	3058.0	2677.2	55017.0	397.0	347.6	7142.5	0.0	114627.0
1996	0.8192	680.0	557.0	125972.9	3058.0	2505.0	51477.9	397.0	325.2	6683.0	0.0	184133.8
1997	0.7665	680.0	521.2	117869.4	3058.0	2343.9	48166.5	397.0	304.3	6253.1	0.0	172289.0
1998	0.7172	950.0	681.3	154077.6	6057.0	4343.9	89266.6	397.0	284.7	5850.9	0.0	249195.1
1999	0.6710	1035.0	694.5	157065.3	6057.0	4064.4	83524.3	785.0	526.8	10824.9	0.0	251414.5
2000	0.6279	1231.0	772.9	174792.1	6057.0	3803.0	78151.4	785.0	492.9	10128.6	0.0	263072.0
2001	0.5875	1347.0	791.3	178959.7	6057.0	3558.3	73124.1	785.0	461.2	9477.0	66.4	261627.2
2002	0.5497	1347.0	740.4	167447.6	6057.0	3329.4	68420.2	785.0	431.5	8867.4	11001.6	255736.8
				1134365.3			604774.3			65227.5	11068.0	1815435.1
2003												
2094	7.9766	1347.0	10744.5	2429862.5	6057.0	48314.2	992857.5	785.0	6261.6	128676.4	159645.8	3711042.2
PRESENT WORTH BENEFITS				3564227.8			1597631.8			193903.9	170713.8	5526477.3
CRF=	0.0688	AV ANN BENEFITS =		245358.5			109979.7			13348.2	11751.8	380438.1

CAPACITY VALUE = 226.15000$/KW-YR
ENERGY VALUE = 20.55000MILLS/KWH
SECONDARY VALUE= 20.55000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	226.15	20.55	20.55	0.06875

1

SYSTEM OF DEVELOPMENT — CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST

NEW SYSTEM

BASE CASE WITH 5% INFLATION — 245358. 109980. 13348. 380438.

NEW SYSTEM

BASE CASE WITH 2% ESCALATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	4734.6	2997.0	2804.2	59645.6	0.0	0.0	0.0	0.0	64380.1
1995	0.8755	265.0	232.0	43479.7	3058.0	2677.2	56944.6	397.0	347.6	7392.7	0.0	107817.1
1996	0.8192	680.0	557.0	104393.5	3058.0	2505.0	53281.5	397.0	325.2	6917.2	0.0	164592.2
1997	0.7665	680.0	521.2	97678.1	3058.0	2343.9	49854.1	397.0	304.3	6472.2	0.0	154004.4
1998	0.7172	950.0	681.3	127683.8	6057.0	4343.9	92394.1	397.0	284.7	6055.9	0.0	226133.8
1999	0.6710	1035.0	694.5	130159.6	6057.0	4064.4	86450.7	785.0	526.8	11204.2	0.0	227814.5
2000	0.6279	1231.0	772.9	144849.8	6057.0	3803.0	80889.5	785.0	492.9	10483.5	0.0	236222.8
2001	0.5875	1347.0	791.3	148303.5	6057.0	3558.3	75686.1	785.0	461.2	9809.1	55.0	233853.7
2002	0.5497	1347.0	740.4	138763.5	6057.0	3329.4	70817.4	785.0	431.5	9178.1	9117.0	227875.9
				940046.0			625963.5			67512.8	9172.0	1642694.4
2003												
2094	7.9766	1347.0	10744.5	2013621.6	6057.0	48314.2	1027643.7	785.0	6261.6	133184.8	132298.1	3306748.3
PRESENT WORTH BENEFITS				2953667.6			1653607.3			200697.6	141470.1	4949442.6
CRF=	0.0688 AV ANN BENEFITS =			203328.0			113833.0			13815.9	9738.7	340715.5

CAPACITY VALUE = 187.41000$/KW-YR
ENERGY VALUE = 21.27000MILLS/KWH
SECONDARY VALUE= 21.27000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	187.41	21.27	21.27	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
BASE CASE WITH 2% ESCALATION	203328.	113833.	13816.	9739.	340716.
NEW SYSTEM					

BASE CASE WITH 2% ESCALATION AND 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	5273.4	2997.0	2804.2	79359.2	0.0	0.0	0.0	0.0	84632.6
1995	0.8755	265.0	232.0	48428.3	3058.0	2677.2	75765.5	397.0	347.6	9636.1	0.0	134030.0
1996	0.8192	680.0	557.0	116275.0	3058.0	2505.0	70891.7	397.0	325.2	9203.4	0.0	196370.1
1997	0.7665	680.0	521.2	108795.3	3058.0	2343.9	66331.4	397.0	304.3	8611.4	0.0	183738.1
1998	0.7172	950.0	681.3	142216.1	6057.0	4343.9	122931.6	397.0	284.7	8057.4	0.0	273205.0
1999	0.6710	1035.0	694.5	144973.7	6057.0	4064.4	115023.7	785.0	526.8	14907.3	0.0	274904.7
2000	0.6279	1231.0	772.9	161335.8	6057.0	3803.0	107624.5	785.0	492.9	13948.4	0.0	282908.7
2001	0.5875	1347.0	791.3	165182.6	6057.0	3558.3	100701.3	785.0	461.2	13051.1	61.3	278996.3
2002	0.5497	1347.0	740.4	154556.8	6057.0	3329.4	94223.4	785.0	431.5	12211.6	10154.6	271146.4
				1047037.0			832852.3			89826.7	10215.9	1979931.9
2003												
2094	7.9766	1347.0	10744.5	2242801.2	6057.0	48314.2	1367292.8	785.0	6261.6	177204.0	147355.5	3934653.6
PRESENT WORTH BENEFITS				3289838.2			2200145.1			267030.7	157571.5	5914585.5
CRF=	0.0688 AV ANN BENEFITS =			226469.7			151456.2			18382.2	10847.1	407155.2

CAPACITY VALUE = 208.74000$/KW-YR
ENERGY VALUE = 28.30000MILLS/KWH
SECONDARY VALUE= 28.30000MILLS/KWH
INTEREST RATE = 0.06875
1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	208.74	28.30	28.30	0.06875

1
SYSTEM OF DEVELOPMENT
NEW SYSTEM
BASE CASE WITH 2% ESCALATION AND 3% INFLATION
NEW SYSTEM

CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
226470.	151456.	18382.	10847.	407155.

BASE CASE WITH 2 % ESCALATION AND 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	5747.4	2997.0	2804.2	96745.3	0.0	0.0	0.0	0.0	102492.6
1995	0.8755	265.0	232.0	52780.7	3058.0	2677.2	92364.3	397.0	347.6	11991.1	0.0	157136.1
1996	0.8192	680.0	557.0	126724.9	3058.0	2505.0	86422.8	397.0	325.2	11219.7	0.0	224367.4
1997	0.7665	680.0	521.2	118573.0	3058.0	2343.9	80863.4	397.0	304.3	10498.0	0.0	209934.4
1998	0.7172	950.0	681.3	154997.4	6057.0	4343.9	149863.6	397.0	284.7	9622.7	0.0	314683.6
1999	0.6710	1035.0	694.5	158002.9	6057.0	4064.4	140223.2	785.0	526.8	18173.2	0.0	316399.3
2000	0.6279	1231.0	772.9	175835.5	6057.0	3803.0	131203.0	785.0	492.9	17004.2	0.0	324042.7
2001	0.5875	1347.0	791.3	180028.0	6057.0	3558.3	122763.0	785.0	461.2	15910.3	66.8	318768.2
2002	0.5497	1347.0	740.4	168447.2	6057.0	3329.4	114866.0	785.0	431.5	14886.9	11067.2	309267.3
				1141136.9			1015314.6			109506.0	11134.1	2277091.6
2003												
2094	7.9766	1347.0	10744.5	2444367.6	6057.0	48314.2	1666841.0	785.0	6261.6	216026.1	160598.8	4487633.5
PRESENT WORTH BENEFITS				3585504.4			2682155.6			325532.1	171732.8	6764925.0
CRF= 0.0688 AV ANN BENEFITS =				246823.2			184637.4			22409.4	11821.9	465691.8

CAPACITY VALUE = 227.50000$/KW-YR
ENERGY VALUE = 34.50000MILLS/KWH
SECONDARY VALUE= 34.50000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	227.50	34.50	34.50	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
BASE CASE WITH 2 % ESCALATION AND 5% INFLATION
NEW SYSTEM

CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
246823.	184637.	22409.	11822.	465692.

OIL FIRED WITH 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	1238.1	2997.0	2804.2	108635.1	0.0	0.0	0.0	0.0	109873.3
1995	0.8755	265.0	232.0	11370.5	3058.0	2677.2	103715.8	397.0	347.6	13464.7	0.0	128551.0
1996	0.8192	680.0	557.0	27300.2	3058.0	2505.0	97044.0	397.0	325.2	12598.6	0.0	136942.8
1997	0.7665	680.0	521.2	25544.0	3058.0	2343.9	90801.4	397.0	304.3	11788.1	0.0	128133.6
1998	0.7172	950.0	681.3	33390.9	6057.0	4343.9	168281.6	397.0	284.7	11029.8	0.0	212702.3
1999	0.6710	1035.0	694.5	34038.3	6057.0	4064.4	157456.4	785.0	526.8	20406.7	0.0	211901.5
2000	0.6279	1231.0	772.9	37880.0	6057.0	3803.0	147327.7	785.0	492.9	19094.0	0.0	204301.6
2001	0.5875	1347.0	791.3	38783.2	6057.0	3558.3	137850.4	785.0	461.2	17865.7	14.4	194513.7
2002	0.5497	1347.0	740.4	36288.3	6057.0	3329.4	128982.9	785.0	431.5	16716.5	2384.2	184371.9
				245833.5			1140095.3			122964.1	2398.6	1511291.5
2003 2094	7.9766	1347.0	10744.5	526586.6	6057.0	48314.2	1871693.4	785.0	6261.6	242575.4	34597.6	2675453.0
PRESENT WORTH BENEFITS				772420.1			3011788.7			365539.6	36996.2	4186744.5
CRF=	0.0688 AV ANN BENEFITS =			53172.8			207329.0			25163.4	2546.8	288212.0

CAPACITY VALUE = 49.01000$/KW-YR
ENERGY VALUE = 38.74000MILLS/KWH
SECONDARY VALUE= 38.74000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY	ENERGY	SECONDARY	INTEREST
1 49.01	38.74	38.74	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
OIL FIRED WITH 3% INFLATION
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
53173. 207329. 25163. 288212.

OIL FIRED WITH 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1350.3	2997.0	2804.2	122039.2	0.0	0.0	0.0	0.0	123389.6
1995	0.8755	265.0	232.0	12400.6	3058.0	2677.2	116512.9	397.0	347.6	15126.1	0.0	144039.6
1996	0.8192	680.0	557.0	29773.4	3058.0	2505.0	109017.9	397.0	325.2	14153.1	0.0	152944.4
1997	0.7665	680.0	521.2	27858.1	3058.0	2343.9	102005.1	397.0	304.3	13242.6	0.0	143105.9
1998	0.7172	950.0	681.3	36415.9	6057.0	4343.9	189045.3	397.0	284.7	12390.8	0.0	237851.9
1999	0.6710	1035.0	694.5	37122.0	6057.0	4064.4	176884.5	785.0	526.8	22924.6	0.0	236931.1
2000	0.6279	1231.0	772.9	41311.7	6057.0	3803.0	165505.9	785.0	492.9	21449.9	0.0	228267.5
2001	0.5875	1347.0	791.3	42296.7	6057.0	3558.3	154859.4	785.0	461.2	20070.1	15.7	217241.8
2002	0.5497	1347.0	740.4	39575.8	6057.0	3329.4	144897.6	785.0	431.5	18779.0	2600.2	205852.7
				268104.5			1280767.9			138136.3	2615.9	1689624.5
2003												
2094	7.9766	1347.0	10744.5	574292.1	6057.0	48314.2	2102635.4	785.0	6261.6	272506.0	37731.9	2987165.4
PRESENT WORTH BENEFITS				842396.5			3383403.3			410642.3	40347.8	4676789.9
CRF= 0.0688 AV ANN BENEFITS =				57989.9			232910.7			28268.3	2777.5	321946.3

CAPACITY VALUE = 53.45000$/KW-YR
ENERGY VALUE = 43.52000MILLS/KWH
SECONDARY VALUE= 43.52000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	53.45	43.52	43.52	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
NEW SYSTEM	
OIL FIRED WITH 5% INFLATION	57990. 232911. 28268. 321946.
NEW SYSTEM	

OIL FIRED WITH 2% ESCALATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1152.3	2997.0	2804.2	130704.3	0.0	0.0	0.0	0.0	131856.5
1995	0.8755	265.0	232.0	10581.7	3058.0	2677.2	124785.6	397.0	347.6	16200.1	0.0	151567.3
1996	0.8192	680.0	557.0	25406.3	3058.0	2505.0	116758.4	397.0	325.2	15158.0	0.0	157322.6
1997	0.7665	680.0	521.2	23771.9	3058.0	2343.9	109247.6	397.0	304.3	14182.9	0.0	147202.5
1998	0.7172	950.0	681.3	31074.4	6057.0	4343.9	202467.8	397.0	284.7	13270.6	0.0	246812.8
1999	0.6710	1035.0	694.5	31677.0	6057.0	4064.4	189443.6	785.0	526.8	24552.3	0.0	2[illegible]5672.8
2000	0.6279	1231.0	772.9	35252.1	6057.0	3803.0	177257.2	785.0	492.9	22972.9	0.0	235482.2
2001	0.5875	1347.0	791.3	36092.6	6057.0	3558.3	165854.7	785.0	461.2	21495.1	13.4	223455.8
2002	0.5497	1347.0	740.4	33770.9	6057.0	3329.4	155185.6	785.0	431.5	20112.4	2218.8	211287.7
				228779.1			1371704.7			147944.2	2232.2	1750660.3
2003												
2094	7.9766	1347.0	10744.5	490055.4	6057.0	48314.2	2251926.4	785.0	6261.6	291854.4	32197.4	3066033.6
PRESENT WORTH BENEFITS				718834.5			3623631.1			439798.6	34429.6	4816693.9
CRF=	0.0688 AV ANN BENEFITS =			49484.0			249447.8			30275.4	2370.1	331577.2

CAPACITY VALUE = 45.61000$/KW-YR
ENERGY VALUE = 46.61000MILLS/KWH
SECONDARY VALUE= 46.61000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	45.61	46.61	46.61	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION	49484.	249448.	30275.	2370.	331577.
NEW SYSTEM					

OIL FIRED WITH 2% ESCALATION AND 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	1294.2	2997.0	2804.2	174225.6	0.0	0.0	0.0	0.0	175519.8
1995	0.8755	265.0	232.0	11885.5	3058.0	2677.2	166336.1	397.0	347.6	21594.3	0.0	199816.0
1996	0.8192	680.0	557.0	28536.8	3058.0	2505.0	155636.1	397.0	325.2	20205.2	0.0	204378.1
1997	0.7665	680.0	521.2	26701.1	3058.0	2343.9	145624.5	397.0	304.3	18905.5	0.0	191231.0
1998	0.7172	950.0	681.3	34903.4	6057.0	4343.9	269884.7	397.0	284.7	17689.3	0.0	322477.4
1999	0.6710	1035.0	694.5	35580.2	6057.0	4064.4	252523.7	785.0	526.8	32727.6	0.0	320831.5
2000	0.6279	1231.0	772.9	39595.8	6057.0	3803.0	236279.5	785.0	492.9	[illegible]9622.3	0.0	306497.7
2001	0.5875	1347.0	791.3	40539.9	6057.0	3558.3	221080.2	785.0	[illegible]	[illegible]552.5	13.0	290287.7
2002	0.5497	1347.0	740.4	37932.1	6057.0	[illegible]29.4	206858.7	785.0	431.5	26809.3	2492.2	274092.3
				256969.0			1828449.2			197206.0	2507.2	2285131.4
2003 2094	7.9766	1347.0	10744.5	550439.3	6057.0	48314.2	3001763.3	785.0	6261.6	389034.9	36164.7	3977402.2
PRESENT WORTH BENEFITS				807408.3			4830212.4			586240.9	38672.0	6262533.6
CRF=	0.0688 AV ANN BENEFITS =			55581.3			332507.8			40356.3	2662.1	431107.6

CAPACITY VALUE = 51.23000$/KW-YR
ENERGY VALUE = 62.13000MILLS/KWH
SECONDARY VALUE= 62.13000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	51.23	62.13	62.13	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION AND 3% INFLATION	55581.	332508.	40356.	2662.	431108.
NEW SYSTEM					

OIL FIRED WITH 2% ESCALATION AND 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	1418.8	2997.0	2804.2	212615.2	0.0	0.0	0.0	0.0	214034.0
1995	0.8755	265.0	232.0	13029.3	3058.0	2677.2	202987.4	397.0	347.6	26352.5	0.0	242369.2
1996	0.8192	680.0	557.0	31282.9	3058.0	2505.0	189929.7	397.0	325.2	24657.3	0.0	245870.0
1997	0.7665	680.0	521.2	29270.6	3058.0	2343.9	177712.0	397.0	304.3	23071.2	0.0	230053.8
1998	0.7172	950.0	681.3	38262.2	6057.0	4343.9	329352.3	397.0	284.7	21587.1	0.0	389201.6
1999	0.6710	1035.0	694.5	39004.1	6057.0	4064.4	308165.9	785.0	526.8	39939.0	0.0	387109.0
2000	0.6279	1231.0	772.9	43406.2	6057.0	3803.0	288342.4	785.0	492.9	37369.8	0.0	369118.4
2001	0.5875	1347.0	791.3	44441.2	6057.0	3558.3	269794.0	785.0	461.2	34965.9	16.5	349217.6
2002	0.5497	1347.0	740.4	41582.4	6057.0	3329.4	252438.9	785.0	431.5	32716.6	2732.0	329469.9
				281697.8			2231337.8			240659.3	2748.5	2756443.4
2003 2094	7.9766	1347.0	10744.5	603409.6	6057.0	48314.2	3663185.1	785.0	6261.6	474756.5	39645.0	4780996.2
PRESENT WORTH BENEFITS				885107.4			5894522.9			715415.8	42393.5	7537439.6
CRF=	0.0688 AV ANN BENEFITS =			60930.1			405774.1			49248.6	2918.3	518871.1

CAPACITY VALUE = 56.16000$/KW-YR
ENERGY VALUE = 75.82000MILLS/KWH
SECONDARY VALUE= 75.82000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	56.16	75.82	75.82	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION AND 5% INFLATION	60930.	405774.	49249.	2918.	518871.
NEW SYSTEM					

OIL FIRED WITH 2% ESCALATION AFTER POL

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY (MW)	PRESENT WORTH OF CAPACITY (MW)	CAPACITY BENEFITS ($1000)	MARKETABLE FIRM ENERGY (GWH)	PRESENT WORTH FIRM ENERGY (GWH)	FIRM ENERGY BENEFITS ($1000)	MARKETABLE SECONDARY ENERGY (GWH)	PRESENT WORTH SEC ENERGY (GWH)	SECONDARY ENERGY BENEFITS ($1000)	INTERRUP CAPACITY BENEFITS ($1000)	TOTAL BENEFITS ($1000)
1994	0.9357	27.0	25.3	1125.2	2997.0	2804.2	97250.0	0.0	0.0	0.0	0.0	98375.2
1995	0.8755	265.0	232.0	10333.4	3058.0	2677.2	92846.2	397.0	347.6	12053.6	0.0	115233.3
1996	0.8192	680.0	557.0	24810.2	3058.0	2505.0	86873.7	397.0	325.2	11278.2	0.0	122962.1
1997	0.7665	680.0	521.2	23214.2	3058.0	2343.9	81285.3	397.0	304.3	10552.7	0.0	115052.3
1998	0.7172	950.0	681.3	30345.4	6057.0	4343.9	150645.5	397.0	284.7	9873.9	0.0	190864.8
1999	0.6710	1035.0	694.5	30933.8	6057.0	4064.4	140954.8	785.0	526.8	18268.0	0.0	190156.7
2000	0.6279	1231.0	772.9	34425.1	6057.0	3803.0	131887.5	785.0	492.9	17092.9	0.0	183405.6
2001	0.5875	1347.0	791.3	35245.9	6057.0	3558.3	123403.5	785.0	461.2	15993.4	13.1	174655.9
2002	0.5497	1347.0	740.4	32978.6	6057.0	3329.4	115465.3	785.0	431.5	14964.5	2166.7	165575.2
				223412.0			1020611.9			110077.3	2179.8	1356281.1
2003 2094	7.9766	1347.0	10744.5	478558.8	6057.0	48314.2	1675537.6	785.0	6261.6	217153.2	31442.1	2402691.7
PRESENT WORTH BENEFITS				701970.8			2696149.5			327230.6	33621.9	3758972.8
CRF=	0.0688 AV ANN BENEFITS =			48323.1			185600.7			22526.3	2314.5	258764.6

CAPACITY VALUE = 44.54000$/KW-YR
ENERGY VALUE = 34.68000MILLS/KWH
SECONDARY VALUE= 34.68000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	44.54	34.68	34.68	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION AFTER POL	48323.	185601.	22526.	2315.	258765.
NEW SYSTEM					

OIL FIRED WITH 2% ESCALATION AFTER POL AND 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1258.1	2997.0	2804.2	129386.3	0.0	0.0	0.0	0.0	130644.4
1995	0.8755	265.0	232.0	11553.7	3058.0	2677.2	123527.3	397.0	347.6	16036.7	0.0	151117.7
1996	0.8192	680.0	557.0	27740.2	3058.0	2505.0	115581.1	397.0	325.2	15005.1	0.0	158326.4
1997	0.7665	680.0	521.2	25955.8	3058.0	2343.9	108146.0	397.0	304.3	14039.9	0.0	148141.7
1998	0.7172	950.0	681.3	33929.1	6057.0	4343.9	200426.2	397.0	284.7	13136.7	0.0	247492.0
1999	0.6710	1035.0	694.5	34587.0	6057.0	4064.4	187533.3	785.0	526.8	24304.7	0.0	246425.0
2000	0.6279	1231.0	772.9	38490.6	6057.0	3803.0	175469.8	785.0	492.9	22741.3	0.0	236701.6
2001	0.5875	1347.0	791.3	39408.3	6057.0	3558.3	164182.2	785.0	461.2	21278.4	14.6	224883.5
2002	0.5497	1347.0	740.4	36873.3	6057.0	3329.4	153620.8	785.0	431.5	19909.6	2422.6	212826.3
				249796.1			1357872.9			146452.4	2437.3	1756558.7
2003												
2094	7.9766	1347.0	10744.5	535074.7	6057.0	48314.2	2229218.7	785.0	6261.6	288911.5	35155.2	3086360.1
PRESENT WORTH BENEFITS				784870.9			3587091.6			435363.8	37592.5	4844918.8
CRF=	0.0688 AV ANN BENEFITS =			54029.9			246932.4			29970.1	2587.8	333520.2

CAPACITY VALUE = 49.80000$/KW-YR
ENERGY VALUE = 46.14000MILLS/KWH
SECONDARY VALUE= 46.14000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	49.80	46.14	46.14	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION AFTER POL AND 3% INFLATION	54030.	246932.	29970.	2588.	333520.
NEW SYSTEM					

OIL FIRED WITH 2% ESCALATION AFTER POL AND 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1374.6	2997.0	2804.2	157736.8	0.0	0.0	0.0	0.0	159111.4
1995	0.8755	265.0	232.0	12623.3	3058.0	2677.2	150594.0	397.0	347.6	19550.6	0.0	182767.9
1996	0.8192	680.0	557.0	30308.1	3058.0	2505.0	140906.7	397.0	325.2	18293.0	0.0	189507.8
1997	0.7665	680.0	521.2	28358.5	3058.0	2343.9	131842.5	397.0	304.3	17116.2	0.0	177317.3
1998	0.7172	950.0	681.3	37069.9	6057.0	4343.9	244342.8	397.0	284.7	16015.2	0.0	297427.9
1999	0.6710	1035.0	694.5	37788.7	6057.0	4064.4	228624.8	785.0	526.8	29630.3	0.0	296043.8
2000	0.6279	1231.0	772.9	42053.7	6057.0	3803.0	213917.9	785.0	492.9	27724.2	0.0	283695.8
2001	0.5875	1347.0	791.3	43056.4	6057.0	3558.3	200157.1	785.0	461.2	25940.8	16.0	269170.3
2002	0.5497	1347.0	740.4	40286.7	6057.0	3329.4	187281.5	785.0	431.5	24272.1	2646.9	254487.2
				272919.8			1655404.2			178542.4	2662.9	2109529.3
2003												
2094	7.9766	1347.0	10744.5	584606.8	6057.0	48314.2	2717675.6	785.0	6261.6	352216.5	38409.6	3692908.4
PRESENT WORTH BENEFITS				857526.6			4373079.8			530758.9	41072.5	5802437.8
CRF=	0.0688	AV ANN BENEFITS =		59031.4			301039.2			36537.0	2827.4	399435.0

CAPACITY VALUE = 54.41000$/KW-YR
ENERGY VALUE = 56.25000MILLS/KWH
SECONDARY VALUE= 56.25000MILLS/KWH
INTEREST RATE = 0.06875
1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	54.41	56.25	56.25	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
OIL FIRED WITH 2% ESCALATION AFTER POL AND 5% INFLATION	59031.	301039.	36537.	2827.	399435.
NEW SYSTEM					

OIL-SUDDEN DROP OF 35%

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1095.7	2997.0	2804.2	51737.7	0.0	0.0	0.0	0.0	52833.3
1995	0.8755	265.0	232.0	10062.0	3058.0	2677.2	49394.8	397.0	347.6	6412.6	0.0	65869.4
1996	0.8192	680.0	557.0	24158.5	3058.0	2505.0	46217.4	397.0	325.2	6000.1	0.0	76376.0
1997	0.7665	680.0	521.2	22604.4	3058.0	2343.9	43244.3	397.0	304.3	5614.1	0.0	71462.9
1998	0.7172	950.0	681.3	29548.3	6057.0	4343.9	80144.4	397.0	284.7	5253.0	0.0	114945.7
1999	0.6710	1035.0	694.5	30121.3	6057.0	4064.4	74988.9	785.0	526.8	9718.7	0.0	114828.9
2000	0.6279	1231.0	772.9	33520.6	6057.0	3803.0	70165.1	785.0	492.9	9093.5	0.0	112779.4
2001	0.5875	1347.0	791.3	34320.1	6057.0	3558.3	65651.5	785.0	461.2	8508.6	12.7	108492.9
2002	0.5497	1347.0	740.4	32112.3	6057.0	3329.4	61428.3	785.0	431.5	7961.2	2109.8	103611.7
				217543.3			542972.6			58561.9	2122.6	821200.4
2003												
2094	7.9766	1347.0	10744.5	465987.8	6057.0	48314.2	891397.6	785.0	6261.6	115527.0	30616.1	1503528.5
PRESENT WORTH BENEFITS				683531.1			1434370.2			174088.9	32738.7	2324728.9
CRF=	0.0688 AV ANN BENEFITS =			47053.7			98740.9			11984.1	2253.7	160032.4

CAPACITY VALUE = 43.37000$/KW-YR
ENERGY VALUE = 18.45000MILLS/KWH
SECONDARY VALUE= 18.45000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY	ENERGY	SECONDARY	INTEREST
1 43.37	18.45	18.45	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	TOTALS---POWER VALUES & INTEREST
NEW SYSTEM				
OIL-SUDDEN DROP OF 35%	47054.	98741.	11984.	160032.
NEW SYSTEM				

OIL-SUDDEN DROP OF 35% AND 3% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1218.2	2997.0	2804.2	68394.7	0.0	0.0	0.0	0.0	69612.9
1995	0.8755	265.0	232.0	11187.2	3058.0	2677.2	65297.6	397.0	347.6	8477.2	0.0	84961.9
1996	0.8192	680.0	557.0	26860.1	3058.0	2505.0	61097.1	397.0	325.2	7931.8	0.0	95889.1
1997	0.7665	680.0	521.2	25132.5	3058.0	2343.9	57166.9	397.0	304.3	7421.6	0.0	89720.8
1998	0.7172	950.0	681.3	32852.6	6057.0	4343.9	105947.0	397.0	284.7	6944.2	0.0	145743.8
1999	0.6710	1035.0	694.5	33489.7	6057.0	4064.4	99131.7	785.0	526.8	12847.7	0.0	145469.1
2000	0.6279	1231.0	772.9	37269.4	6057.0	3803.0	92754.8	785.0	492.9	12021.2	0.0	142045.4
2001	0.5875	1347.0	791.3	38158.0	6057.0	3558.3	86788.1	785.0	461.2	11247.9	14.2	136208.2
2002	0.5497	1347.0	740.4	35703.4	6057.0	3329.4	81205.3	785.0	431.5	10524.4	2345.8	129778.8
				241870.9			717783.3			77416.0	2359.9	1039430.1
2003												
2094	7.9766	1347.0	10744.5	518098.5	6057.0	48314.2	1178384.1	785.0	6261.6	152721.1	34039.9	1883243.6
PRESENT WORTH BENEFITS				759969.3			1896167.4			230137.1	36399.8	2922673.6
CRF=	0.0688	AV ANN BENEFITS =		52315.7			130530.6			15842.4	2505.7	201194.4

CAPACITY VALUE = 48.22000$/KW-YR
ENERGY VALUE = 24.39000MILLS/KWH
SECONDARY VALUE= 24.39000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY	ENERGY	SECONDARY	INTEREST
1 48.22	24.39	24.39	0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
OIL-SUDDEN DROP OF 35% AND 3% INFLATION
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
52316. 130531. 15842. 201194.

OIL-SUDDEN DROP OF 35% AND 5% INFLATION

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	27.0	25.3	1325.8	2997.0	2804.2	83088.8	0.0	0.0	0.0	0.0	84414.6
1995	0.8755	265.0	232.0	12175.5	3058.0	2677.2	79326.2	397.0	347.6	10298.4	0.0	101800.2
1996	0.8192	680.0	557.0	29233.1	3058.0	2505.0	74223.4	397.0	325.2	9635.9	0.0	113092.4
1997	0.7665	680.0	521.2	27352.6	3058.0	2343.9	69448.8	397.0	304.3	9016.1	0.0	105817.4
1998	0.7172	950.0	681.3	35755.0	6057.0	4343.9	128708.9	397.0	284.7	8436.1	0.0	172900.0
1999	0.6710	1035.0	694.5	36448.3	6057.0	4064.4	120429.4	785.0	526.8	15607.9	0.0	172485.6
2000	0.6279	1231.0	772.9	40562.0	6057.0	3803.0	112682.5	785.0	492.9	14603.9	0.0	167848.3
2001	0.5875	1347.0	791.3	41529.1	6057.0	3558.3	105433.9	785.0	461.2	13664.5	15.4	160642.8
2002	0.5497	1347.0	740.4	38857.6	6057.0	3329.4	98651.6	785.0	431.5	12785.5	2553.0	152847.7
				263239.0			871993.4			94048.2	255[illegible].4	1231849.0
2003 2094	7.9766	1347.0	10744.5	563869.9	6057.0	48314.2	1431550.7	785.0	6261.6	185532.0	37047.1	2217999.8
PRESENT WORTH BENEFITS				827108.9			2303544.1			279580.2	39615.6	3449848.7
CRF= 0.0688 AV ANN BENEFITS =				56937.5			158574.1			19246.1	2727.1	237484.7

CAPACITY VALUE = 52.48000$/KW-YR
ENERGY VALUE = 29.63000MILLS/KWH
SECONDARY VALUE= 29.63000MILLS/KWH
INTEREST RATE = 0.06875

1

CAPACITY ENERGY SECONDARY INTEREST
1 52.48 29.63 29.63 0.06875

1

SYSTEM OF DEVELOPMENT
NEW SYSTEM
OIL-SUDDEN DROP OF 35% AND 5% INFLATION
NEW SYSTEM

CAPACITY ENERGY SECONDARY TOTALS---POWER VALUES & INTEREST
56937. 158574. 19246. 237485.

LOW LOAD GROWTH, 0% GROWTH AFTER POL

YEAR	PRESENT WORTH FACTOR	MARKETABLE CAPACITY	PRESENT WORTH OF CAPACITY	CAPACITY BENEFITS	MARKETABLE FIRM ENERGY	PRESENT WORTH FIRM ENERGY	FIRM ENERGY BENEFITS	MARKETABLE SECONDARY ENERGY	PRESENT WORTH SEC ENERGY	SECONDARY ENERGY BENEFITS	INTERRUP CAPACITY BENEFITS	TOTAL BENEFITS
		(MW)	(MW)	($1000)	(GWH)	(GWH)	($1000)	(GWH)	(GWH)	($1000)	($1000)	($1000)
1994	0.9357	0.0	0.0	0.0	2997.0	2804.2	35781.7	0.0	0.0	0.0	0.0	35781.7
1995	0.8755	148.0	129.6	24175.4	3058.0	2677.2	34161.4	397.0	347.6	4435.0	0.0	62771.8
1996	0.8192	400.0	327.7	61136.0	3058.0	2505.0	31963.9	397.0	325.2	4149.7	0.0	97249.5
1997	0.7665	557.0	426.9	79655.5	3058.0	2343.9	29907.7	397.0	304.3	3882.7	0.0	113446.0
1998	0.7172	591.0	423.8	79081.0	6057.0	4343.9	55427.8	176.0	126.2	1610.6	0.0	136119.3
1999	0.6710	689.0	462.3	86263.6	6057.0	4064.4	51862.3	176.0	118.1	1507.0	0.0	139632.8
2000	0.6279	794.0	498.5	93014.9	6057.0	3803.0	48526.1	176.0	110.5	1410.0	0.0	142951.1
2001	0.5875	815.0	478.8	89333.4	6057.0	3558.3	45404.5	176.0	103.4	1319.3	0.0	136057.2
2002	0.5497	943.0	518.4	96714.5	6057.0	3329.4	42483.8	176.0	96.7	1234.5	0.0	140432.7
2003	0.5143	947.0	487.1	90877.0	6057.0	3115.3	39750.9	176.0	90.5	1155.1	0.0	131782.9
2004	0.4812	969.0	466.3	87006.5	6057.0	2914.9	37193.8	176.0	84.7	1080.8	0.0	125281.0
2005	0.4503	993.0	447.1	83425.9	6057.0	2727.4	34801.2	176.0	79.2	1011.2	0.0	119238.4
2006	0.4213	996.0	419.6	78295.1	6057.0	2551.9	32562.6	176.0	74.2	946.2	0.0	111803.9
2007	0.3942	999.0	393.8	73479.3	6057.0	2387.8	30467.9	176.0	69.4	885.3	0.0	104832.5
2008	0.3689	1003.0	370.0	69027.8	6057.0	2234.2	28508.0	176.0	64.9	828.4	0.0	98364.1
2009	0.3451	1007.0	347.5	64845.0	6057.0	2090.4	26674.1	176.0	60.7	775.1	0.0	92294.2
2010	0.3229	1011.0	326.5	60914.7	6057.0	1956.0	24958.2	176.0	56.8	725.2	0.0	86598.2
2011	0.3022	1019.0	307.9	57447.2	6057.0	1830.2	23352.7	176.0	53.2	678.6	0.0	81478.5
2012	0.2827	1045.0	295.4	55123.3	6057.0	1712.4	21850.5	176.0	49.8	634.9	0.0	77608.7
				1329815.9			675639.3			282[illegible]9.4	0.0	2033724.6
2013												
2094	4.0934	1045.0	4277.6	798119.3	6057.0	24793.9	316369.6	785.0	3213.3	41002.2	0.0	1155491.1
PRESENT WORTH BENEFITS				2127935.3			992008.9			69271.6	0.0	3189215.7
CRF=	0.0688 AV ANN BENEFITS =			146485.3			68289.1			4768.6	0.0	219543.0

CAPACITY VALUE = 186.58000$/KW-YR
ENERGY VALUE = 12.76000MILLS/KWH
SECONDARY VALUE= 12.76000MILLS/KWH
INTEREST RATE = 0.06875

1

	CAPACITY	ENERGY	SECONDARY	INTEREST
1	186.58	12.76	12.76	0.06875

1

SYSTEM OF DEVELOPMENT	CAPACITY	ENERGY	SECONDARY	INTERRUPTABLE	TOTALS
NEW SYSTEM					
LOW LOAD GROWTH, 0% GROWTH AFTER POL	146485.	68289.	4769.	0.	219543.
NEW SYSTEM					

TABLE C-6-1

INVESTMENT COST WITH 2 YEARS CONSTRUCTION DELAY
(in thousands of dollars)

	Watana			Devil Canyon Gravity Dam				
Year	Expenditure	Accumulated Expenditure	IDC	Expenditure	Present Worth of Expenditure	Accumulated Expenditure	IDC	Present Worth of IDC
1984	30,500		1,048					
1985	107,000	30,500	5,775					
1986	114,000	137,500	13,372					
1987	159,000	251,500	22,756					
1988	214,500	410,500	35,595					
1989	208,000	625,000	50,119					
1990	230,000	833,000	65,175					
1991	245,000	1,063,000	91,503					
1992	223,000	1,308,000	97,591					
1993	161,000	1,531,000	110,791					
1994	32,000	1,692,000	117,425	39,000	39,000		1,341	1,341
1995	25,000	1,724,000	119,384	98,500	98,500	39,000	6,067	6,067
1996	16,000	1,749,000	120,794	117,000	117,000	137,500	13,475	13,475
1997	1,765,000	1,765,000	851,328	137,000	128,187	254,500	23,581	22,064
1998				144,000	126,070	391,500	38,191	33,436
1999				158,000	129,428	535,500	43,622	35,734
2000				129,500	99,258	693,500	53,505	41,010
				823,000	737,443	823,000	179,784	153,127

	Watana	Devil Canyon	Total Watana & Devil Canyon
Construction Cost	$1,765,000	$737,443	$2,502,443
I.D.C.	851,328	153,127	1,004,455
Investment Cost	$2,616,328	$890,570	$3,506,898
Interest and Amortization	$ 180,106	$ 61,307	$ 241,413
Operation, Maintenance, and Replacement	2,620	700	3,320
Average Annual Cost	$ 182,726	$ 62,007	$ 244,733

TABLE C-6-2

INVESTMENT COST WITH 8% DISCOUNT RATE
(in thousands of dollars)

	Watana			Devil Canyon Gravity Dam				
Year	Expenditure	Accumulated Expenditure	IDC	Expenditure	Present Worth of Expenditure	Accumulated Expenditure	IDC	Present Worth of IDC
1984	30,500		1,220					
1985	107,000	30,500	6,720					
1986	114,000	137,500	15,560					
1987	159,000	251,500	26,480					
1988	218,500	410,500	41,580					
1989	214,000	629,000	58,920					
1990	248,000	843,000	77,360					
1991	258,000	1,091,000	97,600					
1992	223,000	1,349,000	116,840	39,000	39,000		1,560	1,560
1993	161,000	1,572,000	132,200	98,500	98,500	39,000	7,060	7,060
1994	32,000	1,733,000	139,920	117,000	117,000	137,500	15,680	15,680
1995	1,765,000	1,765,000	714,400	137,000	126,852	254,500	25,840	23,926
1996				144,000	123,457	391,500	37,080	31,790
1997				158,000	125,425	535,500	49,160	39,025
1998				129,500	95,186	693,500	60,660	44,587
				823,000	725,420	823,000	197,040	163,628

	Watana	Devil Canyon	Total Watana & Devil Canyon
Construction Cost	$1,765,000	$725,420	$2,490,420
I.D.C.	714,400	163,628	878,028
Investment Cost	$2,497,400	$889,048	$3,368,448
Interest and Amortization	$ 198,442	$ 71,156	$ 269,598
Operation, Maintenance, and Replacement	2,620	700	3,320
Average Annual Cost	$ 201,062	$ 71,856	$ 272,918

TABLE C-6-3

INVESTMENT COST WITH 5% DISCOUNT RATE
(in thousands of dollars)

	Watana			Devil Canyon Gravity Dam				
Year	Expenditure	Accumulated Expenditure	IDC	Expenditure	Present Worth of Expenditure	Accumulated Expenditure	IDC	Present Worth of IDC
1984	30,500		763					
1985	107,000	30,500	4,200					
1986	114,000	137,500	9,725					
1987	159,000	251,500	16,550					
1988	218,500	410,500	25,988					
1989	214,000	629,000	36,800					
1990	248,000	843,000	48,350					
1991	258,000	1,091,000	61,000					
1992	223,000	1,349,000	73,025	39,000	39,000		975	975
1993	161,000	1,572,000	82,625	98,500	98,500	39,000	4,413	4,413
1994	32,000	1,733,000	87,450	117,000	117,000	137,500	9,800	9,800
1995	1,765,000	1,765,000	446,476	137,000	130,476	254,500	19,575	18,643
1996				144,000	130,612	391,500	23,175	21,020
1997				158,000	136,486	535,500	30,725	26,541
1998				129,500	106,540	693,500	37,913	31,191
				823,000	758,614	823,000	126,576	112,583

	Watana	Devil Canyon	Total Watana & Devil Canyon
Construction Cost	$1,765,000	$758,614	$2,523,614
I.D.C.	446,476	112,583	559,059
Investment Cost	$2,211,476	$871,197	$3,082,673
Interest and Amortization	$ 111,421	$ 43,894	$ 155,315
Operation, Maintenance, and Replacement	2,620	700	3,320
Average Annual Cost	$ 114,041	$ 44,594	$ 158,635

TABLE C-6-4

INVESTMENT COST WITH ARCH DAM AT DEVIL CANYON
(in thousands of dollars)

	Watana			Devil Canyon Gravity Dam				
Year	Expenditure	Accumulated Expenditure	IDC	Expenditure	Present Worth of Expenditure	Accumulated Expenditure	IDC	Present Worth of IDC
1984	30,500		1,048					
1985	107,000	30,500	5,775					
1986	114,000	137,500	13,372					
1987	159,000	251,500	22,756					
1988	218,500	410,500	35,733					
1989	214,000	629,000	50,600					
1990	248,000	843,000	66,481					
1991	258,000	1,091,000	83,875					
1992	223,000	1,349,000	100,409	32,500	32,500	-	1,117	1,117
1993	161,000	1,572,000	113,609	61,000	61,000	32,500	4,331	4,331
1994	32,000	1,733,000	120,244	87,000	87,000	93,500	9,419	9,419
1995	1,765,000	1,765,000	613,902	113,000	105,731	180,500	16,294	15,246
1996				122,000	106,809	203,500	24,372	21,337
1997				148,500	121,646	415,500	33,670	27,581
1998				101,000	77,413	564,000	42,247	32,381
				665,000	592,009	665,000	131,449	111,412

	Watana	Devil Canyon	Total Watana & Devil Canyon
Construction Cost	$1,765,000	$592,099	$2,357,099
I.D.C.	613,902	111,412	725,314
Investment Cost	$2,378,902	$703,511	$3,082,413
Interest and Amortization	$ 163,761	$ 48,429	$ 212,190
Operation, Maintenance, and Replacement	2,620	700	3,320
Average Annual Cost	$ 166,381	$ 49,129	$ 215,510

EXHIBIT C-7

CORRESPONDENCE

FEDERAL ENERGY REGULATORY COMMISSION
REGIONAL OFFICE
555 BATTERY STREET, ROOM 415
SAN FRANCISCO, CA 94111

October 31, 1978

Colonel George R. Robertson
District Engineer
Alaska District, Corps of Engineers
P. O. Box 7002
Anchorage, Alaska 99510

Dear Colonel Robertson:

This is in response to your letter of April 14, 1978, in which you requested updated power values for use in your studies of the Upper Susitna River Basin. We regret that we were not able to provide the values earlier.

Attached Tables I through VI give details of our estimates. At Mr. Mohn's suggestion, an annual capacity factor of 50 percent was assumed for the Upper Susitna Basin projects.

At your request, we have provided a breakdown of our cost estimates in order that your staff may make sensitivity analyses of the effects of possible inflation of all components of the estimates including fuel cost escalation. Power values are provided based on estimated costs of power from two possible alternative thermal sources for both the Anchorage-Kenai and Fairbanks areas. An oil-fired combined cycle plant, located near Anchorage, and a mine-mouth coal-fired steam-electric generating plant located near the Beluga coal fields are considered as alternatives to hydro power for the Anchorage-Kenai area. For the Fairbanks area, an oil-fired regenerative combustion turbine plant near Fairbanks and a mine-mouth coal-fired steam-electric plant are believed to be the proper alternative power sources. A combined cycle plant alternative was not studied for Fairbanks because of its associated "ice fogging" problems and proximity to populated centers. Our estimates indicate that the combined-cycle plant near Anchorage and the regenerative combustion turbine plant near Fairbanks, respectively, are the least costly sources of power alternative to hydroelectric. However, we are not able to state that either is the most probable source.

As you know, there is significant speculation with respect to the practical and economic feasibility of the development of a coal mine in the Beluga area to serve a relatively small coal-fired steam-electric plant. To be feasible, it is probable that the field must be developed to provide coal for export in large quantities, or for added local use. It is not readily apparent to us that coal will be available near term to fuel a plant in the Beluga area. We have, nevertheless, included a power value based on the existence of such an installation in our estimates.

Coal is readily available in the Healy field near Fairbanks. Golden Valley Electric Association, Inc. has contracted for a consultant's study of the potential of installing additional coal-fired generation to its system. Coal-fired generation, according to our estimates, however, would be significantly more costly than that from a regenerative oil-fired combustion turbine.

The National Energy Act generally prohibits the use of oil or natural gas as fuel in large-scale base load generating plants. However, the Act also includes many provisions under which a utility may be exempted from the restrictions on use of oil. Exemptions may be obtained because of unavailability of coal, high cost of coal and associated facilities, site limitations, environmental requirements, and, most importantly, if the required use of coal would not allow the petitioner to obtain adequate capital for the financing of such a powerplant. Undoubtedly, rules regarding the above will be prescribed and interpretations of the Act will be made by proper authority. Care should be exercised in the selection of probable alternative power sources because of these exemption provisions. We suggest that inquiries be made of the intentions of local utility officials regarding possible requests for exemptions to the use of coal in lieu of other fuels in light of the high investment cost of coal-fired plants.

Pursuant to one of your requests, associated investment costs of pollution control equipment included in the total investment costs for coal-fired plants are given below. These costs include indirects and overheads as well as interest during construction.

(1) Fairbanks Area - Healy plant (PNF). Electrostatic precipitators and SO_2 scrubbers are estimated to cost \$357/kW, and cooling towers, \$44.20/kW. Costs at federal financing are slightly higher.

(2) Anchorage-Kenai Area - Beluga plant (PNF). Baghouse filters and SO_2 scrubbers are estimated to cost \$187/kW, and cooling towers, \$35/kW. Costs at federal financing are slightly lower.

Estimates of future loads are supplied the FERC on FPC Form 12E-2 by the four principal utilities operating in Fairbanks and Anchorage. These estimates show that in 1988 approximately 80 percent of the total electric needs of the so-called "railbelt area" will be in the Anchorage-Kenai area and 20 percent in the Fairbanks area. This division of requirements would probably be a useful guide in your allocation of Upper Susitna projects output.

These estimates of power values are subject to the approval of our Washington Office.

If we can be of further assistance, please advise.

Very truly yours,

Eugene Neblett
Regional Engineer

Attachments

TABLE I

Annual Fixed Charge Rates
Anchorage-Kenai Market Area

	Generating Stations and Substations	Steel Tower Transmission Lines
Service Life, years	30	50
REA Financing	%	%
Cost of Money	8.500	8.500
Depreciation (Sinking Fund)	0.805	0.146
Insurance	0.250	0.100
Taxes	0.350	0.350
Total, Fixed Charges	9.905	9.096
Use	9.91	9.10
Municipal Financing		
Cost of Money	6.250	6.250
Depreciation (Sinking Fund)	1.210	0.317
Insurance	0.250	0.100
Taxes	1.300	1.300
Total, Fixed Charges	9.010	7.967
Use	9.01	7.97
Composite - REA and Municipal 1/		
REA @ 75%	7.43	6.82
Municipal @ 25%	2.25	1.99
Total, Composite	9.68	8.81
Federal Financing		
Cost of Money	6.875	6.875
Depreciation (Sinking Fund)	1.083	0.257
Insurance 2/	-	-
Total, Fixed Charges	7.958	7.132
Use	7.96	7.13

1/ *Based on approximate proportion of total future loads in Anchorage-Kenai Market Area.*
2/ *Omitted at request of NPD, Corps of Engineers.*

TABLE II

Annual Fixed Charge Rates
Fairbanks Market Area

	Generating Stations and Substations	Steel Tower Transmission Lines
Service Life, Years	30	50
Public-nonfederal Financing 1/	%	%
Cost of Money	5.750	5.750
Depreciation (Sinking Fund)	1.322	0.374
Insurance	0.250	0.250
Taxes	-	-
Total, Fixed Charges	7.322	6.374
Use	7.32	6.37
Federal Financing		
Cost of Money	6.875	6.875
Depreciation (Sinking Fund)	1.083	0.257
Insurance 2/	-	-
Total, Fixed Charges	7.958	7.132
Use	7.96	7.13

1/ *Alaska Power Authority financing assumed.*

2/ *Omitted at request of NPD, Corps of Engineers.*

TABLE III

Hydroelectric Plant Power Values At Market
Anchorage-Kenai Area
(Costs as of 7/1/78)

A. Plant Description		Coal-fired Generating Plant	
Capacity	MW	450	
Unit Size	MW	225	
Service Life	Years	30	
Heat Rate	Btu/kWh	10 000	
Fuel Cost	¢/10^6 Btu	110	
Annual Plant Factor	%	55	
		Financing	
		Pub.-nonfed.1/	Federal
B. Investment Cost	$/kW	1 240	1 220
C. Annual Capacity Cost at Plant		$/kW-yr.	
Fixed Charges		120.03	97.11
Fuel Inventory		0.91	0.75
Fixed O&M		14.69	14.69
Administrative and General		5.65	5.65
Annual Capacity Cost at Generator Bus		141.28	118.20
D. Energy Cost		mills/kWh	
Fuel		11.00	11.00
Variable O&M		1.64	1.64
Energy Costs at Generator Bus		12.64	12.64

TABLE III (cont'd.)

Hydroelectric Plant Power Values At Market
Anchorage-Kenai Area
(Costs as of 7/1/78)

	Coal-fired Generating Plant		
	Financing		
	Pub.-nonfed.	Federal	
	--- $/kW-yr.	---	mills/kWh
E. Cost of Thermal Plant Output at Generator Bus	141.28	118.20	12.64
F. Plant to Market Thermal Plant Transmission Costs - 230 kV			
1. Step-up substation			
(a) Fixed charges	2.50	2.04	
(b) O&M and Adm. & Gen.	0.53	0.53	
2. Transmission Lines			
(a) Fixed charges	10.97	8.79	
(b) O&M and Adm. & Gen.	2.56	2.53	
3. Receiving Station			
(a) Fixed charges	1.83	1.50	
(b) O&M and Adm. & Gen.	0.39	0.39	
4. Losses			
(a) Capacity	11.45	9.58	
(b) Energy			0.65
G. Cost of Thermal Power Delivered at Market			
1. Capacity	171.51	143.56	
2. Energy			13.29
H. Hydro-thermal Capacity and Energy Value Adjustments			
1. Capacity	17.15	14.36	
2. Energy			- 2/
I. Value of Hydro Plant Output Delivered at Market			
1. Capacity	188.66	157.92	
2. Energy			13.29

1/ *REA, 75%; Municipal, 25%.*
2/ *Negligible.*

TABLE IV

Hydroelectric Plant Power Values At Market
Anchorage-Kenai Area
(Costs as of 7/1/78)

			Combined Cycle Generating Plant	
A.	Plant Description			
	Capacity	MW	420	
	Unit Size	MW	105	
	Service Life	Years	30	
	Heat Rate	Btu/kWh	8 350	
	Fuel Cost, Oil	¢/10^6 Btu	300	
	Annual Plant Factor	%	50	
			Financing	
			Pub.-nonfed. 1/	Federal
B.	Investment Cost	$/kW	360	355
C.	Annual Capacity Cost at Plant		$/kW-yr.	
	Fixed Charges		34.85	28.26
	Fuel Inventory		1.91	1.58
	Fixed O&M 2/		-	-
	Administrative and General		3.20	3.20
	Annual Capacity Cost at Generator Bus		39.96	33.04
D.	Energy Cost		mills/kWh	
	Fuel		25.05	25.05
	O&M		1.83	1.83
	Energy Costs at Generator Bus		26.88	26.88

TABLE IV (cont'd.)

Hydroelectric Plant Power Values At Market
Anchorage-Kenai Area
(Costs as of 7/1/78)

	Combined Cycle Generating Plant Financing		
	Pub.-nonfed.	Federal	
	--- $/kW-yr. ---		mills/kWh
E. Cost of Thermal Plant Output at Generator Bus	39.96	33.04	26.88
F. Plant to Market Thermal Plant Transmission Costs - 138 kV			
1. Step-up substation			
(a) Fixed charges	1.33	1.08	
(b) O&M and Adm. & Gen.	0.28	0.28	
2. Transmission Lines			
(a) Fixed charges	0.81	0.65	
(b) O&M and Adm. & Gen.	0.19	0.19	
3. Receiving Station			
(a) Fixed charges	0.19	0.16	
(b) O&M and Adm. & Gen.	0.04	0.04	
4. Losses			
(a) Capacity	2.30	1.89	
(b) Energy			1.02
G. Cost of Thermal Power Delivered at Market			
1. Capacity	45.10	37.33	
2. Energy			27.90
H. Hydro-thermal Capacity and Energy Value Adjustments			
1. Capacity	2.26	1.87	
2. Energy			- 3/
I. Value of Hydro Plant Output Delivered at Market			
1. Capacity	47.36	39.20	
2. Energy			27.90

1/ *REA, 75%; Municipal, 25%.*
2/ *Included in energy cost.*
3/ *Negligible.*

TABLE V

Hydroelectric Plant Power Values At Market
Fairbanks, Alaska
(Costs as of 7/1/78)

A. Plant Description		Coal-fired Generating Plant	
Capacity	MW	230	
Unit Size	MW	115	
Service Life	Years	30	
Heat Rate	Btu/kWh	10 500	
Fuel Cost	¢/10^6 Btu	80	
Annual Plant Factor	%	55	
		Financing	
		Pub.-nonfed.1/	Federal
B. Investment Cost	$/kW	1 475	1 510
C. Annual Capacity Cost at Plant		$/kW-yr.	
Fixed Charges		107.97	120.20
Fuel Inventory		0.48	0.57
Fixed O&M		16.29	16.29
Administrative and General		6.68	6.68
Annual Capacity Cost at Generator Bus		131.42	143.74
D. Energy Cost		mills/kWh	
Fuel		8.40	8.40
Variable O&M		1.82	1.82
Energy Costs at Generator Bus		10.22	10.22

TABLE V (cont'd.)

Hydroelectric Plant Power Values At Market
Fairbanks, Alaska
(Costs as of 7/1/78)

	Coal-fired Generating Plant		
	Financing		
	Pub.-nonfed.	Federal	
	- - - $/kW-yr.	- - -	mills/kWh
E. Cost of Thermal Plant Output at Generator Bus	131.42	143.74	10.22
F. Plant to Market Thermal Plant Transmission Costs - 230 kV			
1. Step-up substation			
(a) Fixed charges	3.18	3.47	
(b) O&M and Adm. & Gen.	0.89	0.90	
2. Transmission Lines			
(a) Fixed charges	11.19	12.66	
(b) O&M and Adm. & Gen.	3.61	3.65	
3. Receiving Station			
(a) Fixed charges	2.09	2.28	
(b) O&M and Adm. & Gen.	0.59	0.59	
4. Losses			
(a) Capacity	8.81	9.64	
(b) Energy			0.42
G. Cost of Thermal Power Delivered at Market			
1. Capacity	161.78	176.93	
2. Energy			10.64
H. Hydro-thermal Capacity and Energy Value Adjustments			
1. Capacity	16.18		
2. Energy			- 2/
I. Value of Hydro Plant Output Delivered at Market			
1. Capacity	177.96		
2. Energy			10.64

1/ *Alaska Power Authority financing assumed.*
2/ *Negligible.*

TABLE VI

Hydroelectric Plant Power Values At Market
Fairbanks, Alaska
(Costs as of 7/1/78)

			Regen. Combustion Turbine Plant	
A.	Plant Description			
	Capacity	MW	240	
	Unit Size	MW	60	
	Service Life	Years	30	
	Heat Rate	Btu/kWh	10 000	
	Fuel Cost, Oil	¢/10^6 Btu	210	
	Annual Plant Factor	%	50	
			Financing	
			Pub.-nonfed. 1/	Federal
B.	Investment Cost	$/kW	265	270
C.	Annual Capacity Cost at Plant		$/kW-yr.	
	Fixed Charges		19.40	21.49
	Fuel Inventory		1.09	1.30
	Fixed O&M 2/		-	-
	Administrative and General		2.08	2.08
	Annual Capacity Cost at Generator Bus		22.57	24.87
D.	Energy Cost		mills/kWh	
	Fuel		21.00	21.00
	O&M		1.19	1.19
	Energy Costs at Generator Bus		22.19	22.19

TABLE VI (cont'd.)

Hydroelectric Plant Power Values At Market
Fairbanks, Alaska
(Costs as of 7/1/78)

	Regen. Combustion Turbine Plant Financing		
	Pub.-nonfed.	Federal	
	- - - $/kW-yr.- - -		mills/kWh
E. Cost of Thermal Plant Output at Generator Bus	22.57	24.87	22.19
F. Plant to Market Thermal Plant Transmission Costs - 138 kV			
1. Step-up substation			
(a) Fixed charges	1.60	1.75	
(b) O&M and Adm. & Gen.	0.44	0.45	
2. Transmission Lines			
(a) Fixed charges	1.88	2.14	
(b) O&M and Adm. & Gen.	0.62	0.62	
3. Receiving Station			
(a) Fixed charges	0.25	0.27	
(b) O&M and Adm. & Gen.	0.07	0.07	
4. Losses			
(a) Capacity	1.39	1.52	
(b) Energy			0.81
G. Cost of Thermal Power Delivered at Market			
1. Capacity	28.82	31.69	
2. Energy			23.00
H. Hydro-thermal Capacity and Energy Value Adjustments			
1. Capacity	1.44	1.58	
2. Energy			- 3/
I. Value of Hydro Plant Output Delivered at Market			
1. Capacity	30.26	33.27	
2. Energy			23.00

1/ *Alaska Power Authority financing assumed.*
2/ *Included in energy cost.*
3/ *Negligible.*

Department of Energy
Alaska Power Administration
P.O. Box 50
Juneau, Alaska 99802

November 9, 1978

MEMORANDUM FOR EUGENE NEBLETT, REGIONAL ENGINEER
FEDERAL ENERGY REGULATORY COMMISSION

FROM: ROBERT J. CROSS, ADMINISTRATOR

SUBJECT: ALTERNATIVE POWER SOURCES FOR THE RAILBELT AREA

Colonel Robertson's office sent us a copy of your October 31 memorandum explaining your assumptions on likely alternatives to Upper Susitna power for the Anchorage and Fairbanks areas.

I am not in tune with the suggestion that oil-fired plants may be a realistic alternative for the 1,500 MW Upper Susitna Project.

Many utilities in Alaska and other parts of the country will continue their push for more and more exemptions to allow continued use of oil and gas in both existing and new plants. How successful they will be and for how long is conjecture. NEP legislation this year does, as your letter points out, provide a range of exemptions.

We've looked at the same issues as a part of our report on marketability of Upper Susitna power. Our finding is that the exemptions don't seem all that permanent or pertinent in terms of a large new hydro project coming on line in 1992.

I just don't see the logic of the oil assumption in benefit determinations for 100-years of power from a major new hydro project.

cc: Colonel Robertson
Robert Volk, OPMC

ALASKA POWER AUTHORITY

333 WEST 4th AVENUE - SUITE 31 - ANCHORAGE, ALASKA 99501 Phone: (907) 277-7641
(907) 276-2715

November 17, 1978

Colonel George Robertson
U.S. Army Corps of Engineers
Alaska District
Post Office Box 7002
Anchorage, Alaska 99510

Dear Colonel Robertson:

I have reviewed the material provided by the Federal Energy Regulatory Commission (FERC), associated with the Upper Susitna study power values. I feel that oil-fired generation as an alternative to Susitna hydroelectric must be questioned. Oil-fired generation for new plants in Anchorage and Fairbanks will require exemptions from the Secretary of Energy from the provisions of the Powerplant and Industrial Fuel Use Act of 1978. The ability of Anchorage and Fairbanks to qualify for the exemptions to meet peak load requirements is doubtful. Due to limited refining capability in Alaska, distillate fuel oil requirements by 1990 would require a major expansion of refining capabilities in Alaska. Without expansion the utilities will import distillate fuel and pay associated high transportation costs. Therefore, oil-fired generation for the railbelt area may not be acceptable either for legal and regulatory reasons or from the standpoint of fuel availability.

The cost of fuel for oil-fired generation is an area that is not adequately addressed in the economic analysis of hydroelectric alternatives by the federal government. The provision of power values by FERC and the subsequent present worth analysis of alternative power generation is insensitive to National Energy Policy and the inelastic commodity demand of non-renewable resources such as distillate fuel. I feel that the economic analysis of the alternatives must be sensitive to these considerations by appraising the true costs of energy to the consumer over a fifty year time frame with the capital intensive nature of facilities, the economic life of facilities, and the projected cost of fuel taken into account. The Golden Valley Electric Cooperative in Fairbanks has recently studied the coal vs. oil-fired generation question for the next addition to GVEA's base load capacity. GVEA has determined that the coal fired generation alternative is preferable to oil.

I hope these comments will assist the Corps of Engineers in the application of Upper Susitna power values in the supplemental feasibility studies currently in progress. Thank you for the opportunity to comment.

Sincerely,

Eric P. Yould
Executive Director

SECTION D

FOUNDATION AND MATERIALS

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EXHIBITS

Number	Title
D-1	Location Maps and Seismic Refraction Velocity Profiles, Watana and Devil Canyon Damsites. By Shannon & Wilson, Inc. Geological Consultants; Contract No. DACW85-78-C-0027, November 1978
D-2	Report - Reconnaissance of the Recent Geology of the Proposed Devil's Canyon and Watana Damsites, Susitna River, Alaska. By Kachadoorian & Henry J. Moore, U.S. Geological Survey, November 1978
D-3	Report - Earthquake Assessment at the Susitna Project by E.L. Krinitzsky, U.S. Army Engineer Waterways Experimental Station, Vicksburg, Mississippi, 10 November 1978
D-4	Technical Note - Procedure for Estimating Borehole Spacing and Thaw Water Pumping Requirements for Artificially Thawing the Bedrock Permafrost at the Watana Damsite. By F.H. Sayles, U.S. Army Engineers Cold Regions Research and Engineering Laboratory, Hanover, New Hampshire, October 1978
D-5	Open File Report 78-558-A, U.S. Geological Survey - Reconnaissance geologic map and geochronology, Talkeetna Mountains Quadrangle, northern part of Anchorage Quadrangle, and southwestern portion of Healy Quadrangle, Alaska by Csejtey, et al 1978

SUMMARY OF CHANGES

CHANGES TO THE 1976 INTERIM FEASIBILITY REPORT

In 1978, The Alaska District, Corps of Engineers, performed additional field explorations and geologic studies to verify the feasibility of the Watana damsite. As a result of these studies, considerably more information is now available concerning the site and the regional geology of the area. Therefore, the entire sections on Regional Geology, pages D-1 through D-9; Watana Site, pages D-10 through D-12; and the paragraph on Seismology at Devil Canyon, page D-7, of Appendix D, Foundations and Materials, of the 1976 Interim Feasibility Report are deleted and replaced by this supplemental report. No changes to the Vee Canyon and Denali sites have been made. Plate D-3, Watana - Site Plan and Centerline Profile is deleted and replaced with revised drawings. Several new plates showing geologic sections, borrow areas, and exploration logs have been added. These are listed in the index.

CHANGES IN DESIGN

As a result of the additional field exploration and geologic studies, a more knowledgeable assessment of the proposed project can now be made. A summary of the items which reflect changes to the 1976 Interim Feasibility Report, or reinforce the basic concepts of that report follows.

1. Nothing was found during this phase of the study to cast doubt on the feasibility of a dam at the Watana damsite. All exploration and geologic studies reinforced the concept that a large earth and rockfill or a concrete gravity dam could be built in this general vicinity.

2. Detailed surveys were performed at the Watana site. It was found that the topography used for the 1976 report was in error by approximately 15 feet. Therefore, the elevations shown on the plates or sections in this supplement are 15 feet lower than those shown in the 1976 report. The detailed survey showed the valley section to be a little wider than previously assumed and therefore, the crest length of the dam and the total quantities within the dam are somewhat larger.

3. The explorations at the damsite indicate that the rock is as good or better than previously assumed. Foundation rock is considered adequate to support either an earth-rockfill structure or a concrete gravity dam. To support this conclusion, the regional and site geology as well as the rock structure are discussed in much greater detail in this supplemental report.

4. The 1976 report recognized that the Watana damsite is an area of marginal permafrost and, therefore, permanently frozen ground could be expected in the vicinity. In the 1978 exploration program, specific locations of permafrost were identified and a number of temperature measuring devices were installed. The earlier assumption that permafrost does exist over much of this area was confirmed; however, it was determined that this is a very "warm" permafrost, ranging from 0° C to -1° C. Premafrost was encountered in bedrock in the left abutment of the dam and its effects on the grouting in this area are discussed in this supplemental report. Permafrost was also encountered in the impervious borrow area; however, because of its marginal temperature, it tends to be soft and can be easily excavated. A more detailed discussion is contained in the body of this report.

5. The 1976 report envisioned rather large amounts of gravel available for construction of the shells of the dam and limited amounts of impervious core material. The recent explorations indicate that this is not the case since gravels in large quantities were not verified but large quantities of impervious core material were discovered near the damsite. Because of the apparent shortage of gravel and an excess of impervious material, the dam section has been completely revised. The gravel shells have been changed to rock shells. This change to rockfill has allowed the use of a somewhat steeper slope on the upstream face of the dam. A large portion of the rock will come from required excavation of the spillway. The remainder will come from excavation of underground facilities and access roads and from a large borrow source on the left abutment.

6. The foundation excavation has been increased to require the entire foundation of the dam to be stripped to bedrock. The 1976 report envisioned excavation to bedrock under the core and filters only. However, because the evidence of the limited drilling performed is inconclusive, it was considered adviseable to require removal of in situ gravels beneath the entire embankment. If additional drilling supports a less conservative approach, the change can be made under subsequent feature design.

7. The core has been widened somewhat from that shown in the 1976 report and a zone of semipervious material, approximately of the same width as the core, has been added. This was done because large amounts of semipervious material are available and estimates show that it can be placed within the dam at a considerably lower cost than the rock shell material. The total thickness of these impervious and semipervious zones was determined by considering their effect on total stability of the dam and the difficulties of placing materials which require careful moisture control in the arctic environment. Laboratory tests performed on these materials indicate that optimum moisture will be a rather critical factor in their compaction. Therefore, the use of such materials has been held to within reasonable limits.

8. The 1976 report showed a vertical access shaft to the low-level drain system which passed through the embankment of the dam. This has now been changed to a tunnel through the right abutment, thereby eliminating any structures in the dam embankment.

9. A grout gallery has been added to the lower portions of the dam to facilitate grouting and to accommodate the process of thawing the permafrost. Use of the gallery will allow embankment placement and curtain grouting to proceed simultaneously, resulting in a shortened construction schedule. The gallery will also provide for "read-out" stations for instrumentation in the foundation and lower levels of the embankment and for general access.

10. The spillway location as shown in the 1976 report has been shifted southwest to a location which insures rock cut for its entire length. The rock and overburden material from this large excavation will be utilized in the dam embankment.

11. The 1976 report discusses a potential problem of seepage along a relict channel in the right abutment. The 1978 explorations verified the existence of this channel; however, studies indicate that it is not a problem and, therefore, no remedial action is required.

12. The diverison tunnel portals have been shifted to ensure their location in reasonably sound rock.

13. Professional services of Ellis Krinitzsky of the Waterways Experiment Station and Reuben Kachadoorian and Henry J. Moore from the U.S. Geological Survey were obtained by contract to perform seismic studies and evaluate the earthquake risk at these sites. Their work was divided into two phases. Kachadoorian and Moore of USGS performed the field reconnaissance to look for active faults and other geologic hazards. Krinitzsky's work was aimed at assessing the potential earthquakes which could be associated with such faulting. The USGS report recognized that this is a highly seismic region; however, the geologic reconnaissance of the proposed Devil Canyon and Watana damsites and reservoirs did not uncover evidence of recent or active faulting along any of the known or inferred faults. In their work they did not uncover evidence of the Susitna Fault, which was previously thought to exist a short distance west of the Watana damsite. Krinitzsky's work assessed the possible occurrance of earthquakes at the damsite and the motions that are likely to be associated with earthqauke activity. His findings indicate that the design of the proposed dams to withstand such activity is within the state of the art of seismic design.

14. In the fall of 1978, the consulting firm of Shannon & Wilson was engaged to perform refraction seismograph work at both the Watana and Devil Canyon damsites. This work supplemented the drilling information. The location maps and seismic velocity profiles from the Shannon & Wilson report are included as Exhibit D-1 to this appendix.

REGIONAL GEOLOGY

PHYSIOGRAPHY

The area of study is located within the Coastal Trough Province of southcentral Alaska. The Susitna River is a glacially fed stream which heads on the southern slopes of the Alaska Range, and flows by way of a continuously widening valley to the tidewaters of Cook Inlet. Within the upper 200 river miles, the Susitna passes through a variety of land forms related to the lithology and geology of the region. From its proglacial channel in the Alaska Range, it passes through a broad, glaciated, intermontane valley characterized by knob and kettle topography and by braided river channels. Turning westward along the northern edge of the Copper River lowlands, the river enters a deep, V-shaped valley and traverses the Talkeetna Mountains, emerging into an outwash plain and broad valley which it follows to the sea.

Three regional topographic lows, still identifiable today, are the Susitna River-Chulitna River area downstream of the Devil Canyon site, the middle reach of the Susitna River from Prairie Creek to Watana Creek, and the Oshetna River area at the Susitna Big Bend. These may represent drainage base levels that existed during the glacial periods. Whether they were interconnected at one time is not known since glaciation has modified the original drainages. One possible interpretation is that the ancestral Susitna River may have followed the course of the present Watana Creek and continued southwest along an ancestral valley through the area now occupied by Stephan Lake, Prairie Creek, and the Talkeetna River.

The Susitna River, presently incised 500 feet into that broad, ancestral, U-shaped valley, makes two sharp right-angle turns downstream of Watana Creek in the Fog Creek area and leaves the ancestral valley to flow westward into the steep, V-shaped Devil Canyon area. Glaciation probably blocked its former southwest course forcing the river to find a new outlet in Devil Canyon. Once established in a westward course, the Susitna River downcut its channel rapidly and became entrenched in Devil Canyon.

INFERRED GEOLOGIC HISTORY

The upper Susitna River basin is a complex geologic area with a variety of sedimentary, igneous, and metamorphic rock types. These range from Pennsylvanian to Pleistocene in age and have undergone at least three major periods of tectonic deformation.

The oldest outcrops in the area are Pennsylvanian and Permian aged metavolcanic flows and tuffs, locally containing limestone interbeds that have subsequently been altered to marble. This transitional shelf environment continued throughout the Triassic and into early Jurassic times, with alternate deposition of basalt and thin sedimentary interbeds. Metavolcaniclastics include altered marine sandstones and shales. This deposition was contemporaneous with a massive outpouring of lavas in the eastern Alaska Range, resulting in regional subsidence.

The first major tectonic upheaval in the Susitna area occurred in mid to late Jurassic time and consisted of large plutonic intrusions accompanied by uplift and intense metamorphism. Erosional remnants of these intrusives include amphibolites, greenschists, diorites, and acidic granitic types in the upper Watana reservoir areas. This uplift, and subsequent erosional period, was followed by marine deposition of argillite and graywacke in late Cretaceous. These rocks are exposed in the northwestern half of the upper Susitna basin and include the phyllites of the Devil Canyon site.

The second major tectonic event occurred in middle to late Cretaceous. Most of the structural features in the Talkeetna Mountains, including thrust faulting, complex folding, and uplift, occurred at that time. As a result of the thrust faulting, Pennsylvanian and Permian volcanic flows and tuffs were thrust over the much younger late Cretaceous argillite and graywacke.

In early Tertiary, approximately 65 million years ago, the northwestern portion of the upper Susitna basin was intruded by plutons of igneous rock. The diorite pluton that underlies the Watana site is one of these intrusives. Deposition of undifferentiated volcanic flows, pyroclastics, and associated near-surface intrusives occurred concurrent with and following the intrusion of the plutons.

The third major tectonic event was a period of extensive uplift and erosion in middle Tertiary to Quaternary. Uplift of 3,000 feet has been measured in the southern Talkeetna Mountains. The widespread erosion that occurred during this period removed thick rock sequences from the Susitna basin area.

Glaciation has been the prime erosion agent during the past several million years. At least two, and probably more, periods of glaciation occurred within the upper Susitna basin area. The central and eastern portions of the area may have been partially covered by glacial lakes during the latter glaciations. Renewed uplift in late Pleistocene rejuvenated the erosion cycle until the streams, with their increased gradients, became incised within glaciated valleys. The area currently is undergoing continued stream erosion, and is covered in many areas with a veneer of glacial and alluvial clay, silt, sand, and gravel deposits.

REGIONAL TECTONICS

The arcuate structure of southcentral Alaska reflect both the magnitude and direction of regional tectonic forces caused by the collision of the North American and Pacific Plates. The Talkeetna Mountains and adjacent Susitna River basin are believed to have been thrust northwestward onto the North American Plate from their parent continental blocks. It was this thrusting action which caused most of the structural features now seen in the upper Susitna basin.

Two major tectonic features bracket the basin area. The Denali Fault, about 43 miles north of the damsites and active during the Holocene, is one of the better known Alaskan faults. A second fracture, the Castle Mountain Fault, is 75 miles south of the river basin. The Susitna basin is roughly subdivided by the northeast-southwest trending Talkeetna Thrust, which roughly parallels the location of the Susitna Fault, as referred to in the 1976 Interim Feasibility Report. The Talkeetna River is a surface expression of the southern portion of both structures; however, Kachadoorian and Moore were unable to locate evidence of faulting in the Tsusena Creek area and, therefore, expressed doubt that the Susitna Fault exists. They found evidence of movement in the Talkeetna River and Watana Creek valleys and postulated that the Talkeetna Thrust could be a projection of this feature. Such a projection passes about 4 miles to the south of Watana damsite. The major alpine orogeny which formed many of the basins' present northeast-southwest trending compressional structures occurred in conjunction with the Talkeetna Thrust in late Cretaceous. Another contemporary zone of intense shearing, roughly parallel to the Talkeetna Thrust, is located about 15 miles east of the Talkeetna Thrust.

Two poorly exposed normal faults of probable Cenozoic age have been projected from gravimetric data as occurring in the Chulitna River valley about 15 miles northwest of the proposed Devil Canyon damsite. These faults have the northeast-southwest trend typical of the major structures within the area. No faults with recent movement have been observed within the upper Susitna River basin.

SEISMICITY

A seismological assessment of the basin area was prepared by Dr. E.L. Krinitzsky of the U.S. Army Engineer Waterways Experiment Station in the summer of 1978, under contract with the Alaska District, Corps of Engineers. Field reconnaissance to look for active faults and other geological hazards was conducted by U.S. Geological Survey under the direction of Reuben Kachadoorian and Henry J. Moore. These reports are included as Exhibits D-3 and D-2 in this appendix. They recognize that the Devil Canyon and Watana damsites are in a region of high seismicity and major faults. However, the geologic reconnaissance of the proposed Devil Canyon and Watana damsites and reservoir areas by the USGS experts did not uncover evidence of recent or active faulting along any of the known or inferred faults. The tectonic framework of the region is not well understood because of the lack of local seismic monitoring stations. Present knowledge indicates that historical earthquakes in the area often have hypocenter depths in excess of 50 km. Such events are associated with movement along the Benioff zone and often are not directly associated with local surface faulting. The Denali Fault in the Alaska Range, approximately 43 miles to the north, is the dominant surface feature in this area. The Susitna Fault, previously thought to exist west of the Watana damsite, was not confirmed in recent geologic mapping by the USGS team, nor did they find any evidence of faulting in the river channel at either of the damsites. The results of the core drilling and geologic reconnaissance at the damsite are strong evidence that no major faulting exists under the Watana damsite. The lack of significant shearing in DH-21, the 600-foot cross river hole, reinforces this conclusion.

Krinitzsky's work assessed the possible occurrence of earthquake activity based on the USGS field work. He assumes an earthquake of magnitude 8 along the Denali Fault, however, these motions are not critical when attenuated to the damsites. To account for the possibility that a major active fault could exist near the damsites, Krinitzsky has assigned a "floating" earthquake of magnitude 7 which could occur in the near vicinity of the dam. This generates the most severe design motions. The rational for the "floating" earthquake and a table of associated motions is included in his report (Exhibit D-3). This criteria is within the state of the art for earthquake design for large dams, and therefore, should not preclude proceeding with detailed design of the projects.

ROCK AND SOIL UNITS

The proposed Watana damsite and reservoir area is underlain by a complex series of metamorphic, igneous, and sedimentary rock. Specific formation names have not been applied to most of these units and they are instead assigned lithologic descriptions for correlation and mapping purposes. The distribution of various rock units that underlie the proposed reservoir are shown on Plate 5. Following is a brief description of the various rock units, beginning at the upper end of the reservoir and proceeding downstream to the damsite. Additional information and descriptive details concerning the rock units are included in the U.S. Geological Survey's Open File Report 78-558-A, <u>Reconnaissance Geologic Map and Geochronology, Talkeetna Mountains Quadrangle,</u>

Northern Part of Anchorage Quadrangle, and Southwest Corner of Healy Quadrangle, Alaska, by Csejtey, et. al., 1978. This report is included at the back of this appendix as Exhibit 5.

The upper reaches of the reservoir are underlain by an amphibolite unit. These are metamorphic rocks including greenschists, diorites, and local marble interbeds. Directly downstream of this unit is a zone of granitic types that are exposed north of the river at elevations above the proposed reservoir level.

The oldest rocks exposed within the area are farther downstream within the middle reservoir reaches and include both volcanics and limestone units. The volcanics consist mostly of metamorphosed basalt and andesite flows and tuffs that outcrop in the vicinity of Jay Creek and downstream from Kosina Creek. The limestone unit consists of marble interbeds that occur locally within the volcanics. The volcanics are overlain farther downstream by a volcanic unit of younger age consisting of a series of metamorphosed basaltic flows with interbeds of chert, argillite, and marble. This unit is exposed both near the mouth of Watana Creek and on the higher slopes west of Watana Creek. A much younger series of interbedded conglomerates, sandstones, and claystones is exposed along the lower reaches of Watana Creek directly upstream from its mouth.

The downstream reaches of the reservoir area are underlain by a sequence of argillites and graywackes. Exposed within the immediate damsite area is a granitic body intruded into these metasediments. It consists primarily of diorite with upstream and downstream margins that include associated schist, gneiss, and composite igneous and metamorphic rock types. Andesite flows and dikes are associated with this diorite pluton.

Other granitic intrusives occur east of the reservoir area. Locally, these intrusives are overlain by a series of younger igneous flows and tuffs and related shallow intrusives.

Overburden units in the proposed reservoir area include deposits of glacial till and drift with associated outwash and lake sediments, colluvium including slopewash and talus, alluvium and local slide debris.

ROCK STRUCTURE

Rocks within the reservoir area have undergone a complex deformation sequence, including uplift, intrusion, thrust faulting, folding, shearing, and associated metamorphism. The most significant structural feature within the reservoir area is the Talkeetna Thrust which strikes northeastward across the lower reservoir area and is roughly parallel to the lower reaches of Watana Creek. The Talkeetna Thrust, within the Watana reservoir area, has displaced the volcanic unit over the much younger metasediments.

A northeast striking shear zone that dips steeply southeasterly, and is roughly parallel to the Talkeetna Thrust, crosses the reservoir area about 15 miles east of the Talkeetna Thrust near Kosina Creek. Whether this shear zone represents a significant feature is not known.

The most significant rock structure in the immediate dam area is the intrusive diorite pluton of Tertiary age. It is observable for 4 miles parallel to the river and 2 miles north and south and is probably of great depth. Upstream and downstream border zones developed with several different metamorphic and igneous rock varieties. Two distinct northwest trending shear zones have been mapped in the vicinity of the damsite. One is 3,400 feet upstream and the other 2,500 feet downstream from the proposed dam axis. Attitudes vary with strikes ranging from N 40° W to 60° W and dips from 70° to 90° either SW or NE. The two shears can be seen in the right valley wall, but not on the left valley wall. The left wall is obscured by a slide block at the upstream shear, and the left wall at the downstream shear has a rock face that parallels the shear direction making observations difficult. The upstream shear zone has been named "The Fins," and has an observable width in excess of 400 feet. It includes seven near vertical rock fins averaging 5 to 25 feet in width bounded on both sides by altered and crushed rock. The downstream shear zone, named "Finger Buster", is somewhat less distinct and is partially covered by slope debris. It has an estimated width of 300 feet. Another northwest trending shear zone, similar to the two shears mentioned above, occurs downstream from the damsite in the vicinity of Tsusena Creek.

Fracture patterns including both joints and local shears have been mapped within accessible areas in the vicinity of the damsite. Details of this mapping are shown on Plates D-3 and D-4. Fractures include both cooling type jointing and structural deformation jointing resulting from the regional tectonic forces of uplift and thrust faulting. Shear, tension, and relief joints resulting from unloading by erosion of overlying sediments and/or melting of glacial ice are all present within the damsite area. A joint diagram plotted on an equal area stereographic projection is shown in Figure D-6. The dominant fracture orientation is to the northwest, but fractures strike in several directions. The major joint sets are N 50° W and the minor joint sets are N 30° E as observed within the area.

SEISMIC REFRACTION SURVEY

During September 1978, seismic refraction surveys were undertaken at Watana and Devil Canyon damsites by Shannon and Wilson, geotechnical consultants. At Devil Canyon, the seismic survey consisted of three lines, each approximately 1,100 feet long. One of these lines was located near the proposed alinement of the saddle dam on the left abutment and the remaining two lines were located near an abandoned airstrip on the alluvial fan at the confluence of Cheechako Creek and the Susitna River (see Plate D-1). The seismic line near the centerline of the left abutment saddle dam was alined to expand information derived from drilling accomplished on this site by the U.S. Bureau of Reclamation (USBR) in 1957. The refraction profile correlated well with the top of rock from the drilling data (see Sheet No. 10, Exhibit D-1). A lower velocity zone of rock sandwiched between competent phyllite indicates the possibility of a shear zone at the low point of the saddle. This correlates with hole DH-6 which indicated shearing in the 20 feet of bedrock penetrated by the boring.

The seismic lines on the Cheechako Creek aggregate deposit were alined to establish the depth to bedrock beneath these deposits and thereby confirm the quantity of material available for borrow. The velocities for the material in the alluvium indicate that the area is composed of a layer of sands and gravels or glacial materials several hundred feet thick overlying bedrock. This confirms the existence of material well in excess of the requirements for the project.

The location map and seismic velocity profiles from the Shannon & Wilson report and included in Exhibit D-1 to this appendix.

MATERIAL REQUIREMENTS

Concrete Requirements

Material requirements for Devil Canyon dam are based on a concrete gravity dam. Under this proposal approximately 2.6 million cubic yards of concrete will be required, most of which will be mass concrete. The remainder will be structural concrete for the appurtenant structures to the dam, including the powerplant. With stockpile losses, this amount of concrete will require approximately 3 million cubic yards of processed aggregate.

The USBR located an extensive deposit of material which will yield concrete aggregate of adequate quality in an alluvial fan approximately 1,000 feet upstream of the proposed dam axis. The fan was formed at the confluence of Cheechako Creek and the Susitna River.

Thirteen test pits and trenches were dug in the fan area by Bureau of Reclamation personnel in 1957. About 1,300 pounds of minus 3-inch material was tested by the USBR for basic aggregate suitability studies. An additional 200 pounds of material was collected by Corps of Engineers personnel in 1975 from the existing Bureau test pits and the riverbank. This material was tested by the North Pacific Division Materials Laboratory in 1978 .

If the excavation of materials is confined to that part of the alluvium located above river level (elevation 910 to 920 feet) with conservative back slopes through the ridges and benches, approximately 6,000,000 cubic yards of material is available in this location with all the resulting excavation in the reservoir area. Seismic refraction surveys indicate that usable gravel exists to approximately elevation 870 feet, so additional material could be retrieved if needed by bailing from below the water surface. Placement of the coffer dam, sizing of the diversion tunnel, and the ability to control the flow in the river at Watana dam will ultimately affect the method of exploitation of this source.

The locations of the test pits are shown on Plate D-1 and the detailed logs can be found in the U.S. Bureau of Reclamation's Alaska Geologic Report #7, Devil Canyon Project, dated March 1960. Laboratory investigations of the aggregate samples were reported in USBR Report #C-932 by their Concrete Laboratory Branch, dated 21 December 1959.

Petrographic analyses of the fine (sand sized) particles and coarse (gravel size) particles indicate that the sands and gravels in the fan are composed of quartz diorites, diorites, granites, andesites, dacites, metavolcanic rocks, aplites, breccias, schists, phyllites, argillites, and amphibolites. The gravel particles are stream worn and generally rounded in shape. The sand grains vary from nearly rounded to sharply angular in shape, averaging subangular. The specific gravity (BSSD) of the material ranges from 2.68 to 2.80.

Results from both labs indicate that the material in the Cheechako Creek fan is of adequate quality for use as concrete aggregate.

Embankment Material Requirements

The saddle dam on the left abutment, associated with the concrete gravity dam, will require approximately 835,000 cubic yards of material. These materials will be obtained from the same sources as discussed in the Interim Feasibility Report.

WATANA SITE

SCOPE OF INVESTIGATIONS

Field Reconnaissance

Geologic reconnaissance and mapping of the reservoir area and damsite were conducted concurrently with subsurface investigations throughout the spring and early summer of 1978. The work of the geologic teams was made easier in the early spring as rock outcrops were not obscured by the leaves on the trees and the dense ground foliage. Through the months of March and April, geologic mapping of the lower canyon was done from the frozen surface of the river, which allowed access to areas otherwise inaccessible after the ice had melted and high summer flows on the river had begun. Within the damsite area the primary purpose was to find, identify, and trace the surface expressions of discontinuities and shear zones as an aid in directing the drilling program and to provide preliminary geologic mapping of the site. Within the reservoir area, the primary thrust of the reconnaissance was toward identification of slopes, which by reason of shape, structure or overburden mantle could develop minor slumps and slides as a result of permafrost degradation or seismic action.

Borings and Test Pits

During 1978, explorations were conducted in the dam foundation and relict channel area. Core borings in the valley walls and floor were used to explore the quality and structure of the foundation rock and to obtain representative samples for testing. Borings in the relict channel area were used to define the depth of overburden, the extent of permafrost, the location of the water table and to examine, by drilling and sampling, the nature and condition of the materials.

Shallow auger holes were also used to determine the extent of deposits in the borrow areas and to verify the existence of quantities necessary for embankment construction.

Locations of explorations are shown on Plate D-2. Logs are shown on Plates D-19 through D-37; and core photos are shown on Plates D-38 through D-45.

Test pits were dug in potential borrow areas utilizing tractor-mounted backhoes. Bulk sack samples were retrieved from each test pit for testing later at the North Pacific Divison Materials Laboratory in Troutdale, Oregon.

A total of 27 test pits were dug in four areas as follows:

1. The mouth of Tsusena Creek (Borrow Area 'E') - 6 test pits.

2. The glacial till borrow area (Borrow Area 'D') - 14 test pits.

3. Upper Tsusena Creek, north of Tsusena Butte, (Borrow Area 'C') - 1 test pit.

4. Middle Tsusena Creek - 6 test pits.

The locations of Test Pits 1 through 5 and 8 through 21 are shown on Plates D-12 and D-11. The remainder of the test pits are located in areas which are not presently considered as borrow areas; however, they may be located on Plate D-2. The logs of all the test pits are shown on the appropriate borrow area Plates D-19 through D-22.

Seismic Refraction Surveys

A seismic refraction exploration program consisting of 22,500 lineal feet of seismic refraction lines was completed by Dames and Moore, Consultants, in 1975. Results of those investigations were presented as Exhibit D-1, Section D, Foundation and Materials, in the 1976 Interim Feasibility Report. In the fall of 1978, an additional seismic refraction survey was completed by Shannon and Wilson, Consultants, which includes 47,665 feet of seismic refraction lines. Locations of these additional seismic explorations are shown on Plate D-2, and the location map and seismic velocity profiles are presented as Exhibit D-1. The survey confirmed the findings of the Dames and Moore study. It confirmed the existence of a buried channel in the relict channel area and in general supported conclusions relating to shear zones in the abutments as interpreted from the recent core borings and geologic reconnaissance. The Shannon and Wilson survey also confirmed the existence of large quantities of borrow materials on Tsusena Creek in the proposed borrow area.

Instrumentation

Instrumentation conducted under this phase of the project consisted of the installation and data reading of ground water measurement devices, temperature logging devices, and the recording of the ambient temperature.

Ground Water: All piezometers installed were of the open well point type and were filled with diesel oil where they extend through permafrost zones to prevent freezing. A total of 10 piezometers were installed at the following locations.

TABLE D-1

Location	Surface Elevation	Tip Elevation	Date Set	Size
DR-14	2,340	2,271.0	26 Apr	4"
	2,340	2,295.2	19 Aug	1-1/2"
DR-20	2,207	2,123.8	30 May	1-1/2"
DR-18	2,172	2,107.0	21 Jun	1-1/2"
DR-17	2,167	2,136.3	8 Jun	1-1/2"
DR-16	2,099	2,053.8	5 Jun	1-1/2"
AP-1	2,202	2,188.6	20 Jun	1-1/2"
AP-2	2,200	2,189.0	20 Jun	1-1/2"
DR-19	2,151	2,109.0	3 Jul	1-1/2"
DR-22	2,229	2,005.5	3 Aug	1-1/2"
DR-26	2,295	2,229.5	11 Aug	1-1/2"

All locations are shown on Plate D-2 and Plate D-11. Plotted data is shown on Plates D-16 through D-18.

Subsurface Temperature: The principal temperature logging device consisted of a 3/4-inch galvanized pipe, with the lower end capped and sealed. The pipe was filled with a mixture of ethylene glycol and water (50/50) or arctic grade diesel fuel. Readings were taken using a digital volt-ohm meter and a single thermister which was lowered into the pipe.

At location DR-26 both a 3/4-inch galvanized and a 1-1/2-inch PVC pipe were installed to determine if readings could be duplicated in a pipe of larger diameter. A total of 14 devices were installed at the locations shown in Table D-2.

TABLE D-2

Location	Date Installed	Length	Stick Up	Buried Depth	Fluid
AP-8	23 Jun	64'	4.2'	58.9'	Diesel
AP-9	23 Jun	21'	3.2'	17.8'	Diesel
DH-12	3 Jul	129'	1.8'	127.2'	Diesel
DH-23	17 Jul	76'	0.5'	75.5'	Antifreeze
DH-24	1 Aug	86'	1.2'	84.8'	Antifreeze
DR-18	21 Jun	251'	3.4'	247.6'	Diesel
DR-19	3 Jul	83'	3.9'	79.1'	Diesel
DR-22	3 Aug	492'	2.0'	490.0'	Antifreeze
DH-28	30 Aug	124'	1.0'	123.0'	Antifreeze
DR-26 (3/4" pipe)	11 Aug	68'	3.8'	64.2'	Antifreeze
DR-26 (1-1/2" pipe)	11 Aug	99'	3.4'	95.6'	Antifreeze
DR-14	19 Aug	65'	2.8'	62.2'	Antifreeze
DH-21	23 Aug	160'	2.0'	158.0'	Antifreeze
DH-25	15 Aug	80'	4.0'	76.0'	Antifreeze

All locations are shown on Plate D-2 and Plate D-11. The plotted temperature data can be found on Plates D-13 through D-15.

A second type of temperature logging device, installed at DR-22, consisted of a multipoint thermistor string. The purpose of this installation was to act as a check against the 3/4-inch fluid filled devices described above.

Ambient Temperature: The ambient temperature was obtained using a standard high-low Mercury thermometer placed in the shade on the right abutment riverbank approximately 4 feet above the ground. Prior to this phase of the project, there was no ambient temperature data available for this section of Alaska. Data obtained is shown on Table D-3.

TABLE D-3

Date	High °F	Low °F	Date	High °F	Low °F
23 Mar 78	22	0	23 May 78	60	39
24 Mar 78	24	13	24 May 78	60	32
25 Mar 78	28	19	25 May 78	61	40
27 Mar 78	32	10	26 May 78	41	36
28 Mar 78	26	13	27 May 78	64	--
29 Mar 78	40	6	28 May 78	--	36
30 Mar 78	35	6	29 May 78	58	33
31 Mar 78	36	5	30 May 78	63	36
1 Apr 78	31	5	31 May 78	66	40
2 Apr 78	28	-4	1 Jun 78	54	36
3 Apr 78	28	3	2 Jun 78	58	38
4 Apr 78	36	4	3 Jun 78	68	41
5 Apr 78	36	20	4 Jun 78	68	38
6 Apr 78	33	11	5 Jun 78	57	39
7-8 Apr 78	40	28	6 Jun 78	66	44
9 Apr 78	41	10	11 Jun 78	72	44
10 Apr 78	43	13	12 Jun 78	62	39
11 Apr 78	38	20	14 Jun 78	57	40
12 Apr 78	38	15	16 Jun 78	58	34
13 Apr 78	40	30	19 Jun 78	52	33
14 Apr 78	44	32	20 Jun 78	61	33
15 Apr 78	40	38	21 Jun 78	63	--
16 Apr 78	39	29	22 Jun 78	--	46
17 Apr 78	38	21	27 Jun 78	55	38
18 Apr 78	43	21	28 Jun 78	59	37
19 Apr 78	44	20	30 Jun 78	62	43
20 Apr 78	48	24	1 Jul 78	57	41
21 Apr 78	44	25	2 Jul 78	62	43
22 Apr 78	45	30	4 Jul 78	70	47
23-24 Apr 78	47	32	7 Jul 78	62	40
25-26 Apr 78	50	26	8 Jul 78	73	43
30 Apr 78	59	32	9 Jul 78	70	49
1 May 78	60	34	10 Jul 78	66	42
9 May 78	64	30	11 Jul 78	71	--
10 May 78	72	33	12 Jul 78	--	50
11 May 78	70	33	14 Jul 78	59	50
12 May 78	65	40	16 Jul 78	58	47
13 May 78	72	30	26 Jul 78	66	45
14 May 78	72	31	27 Jul 78	78	40
15 May 78	66	36	28 Jul 78	74	55
16 May 78	55	32	29 Jul 78	78	39
17 May 78	60	30	30 Jul 78	82	46
18 May 78	64	37	31 Jul 78	84	52
19 May 78	60	37	1 Aug 78	80	58
20 May 78	75	24	9 Aug 78	71	46
21 May 78	70	43	10 Aug 78	68	54
22 May 78	--	36	11 Aug 78	66	49

Accuracy of Subsurface Temperature Data: Resistance measurements were obtained using a Keithley volt-ohm meter, which allowed readings to the nearest ohm. With a span of 225 ohms per degree centigrade, 1 ohm represents 0.005° C. The temperature data in this report has been reported to 0.01° C and is reliable to that degree of accuracy. To verify the accuracy of each thermister, its resistance was measured in an ice bath. It was found that the thermistors are very stable and do not tend to drift from their original resistance at 0.00° C.

General Comments

The drilling in the permafrost was performed with core drills and rotary drills, which introduce a large amount of heat into the ground. Where the permafrost temperature is only slightly below the freezing point, this tends to melt the permafrost and makes identification very difficult. Therefore, the drilling operation may or may not reflect the existence of permafrost, and it is necessary to rely heavily on the instrumentation for a true evaluation of the location and depth, at which permafrost exists. By December of 1978, the temperature logging devices may not have stabilized due primarily to the fact that the drilling method used was rotary with drilling "mud" as the circulation medium, which tends to thaw the permafrost. Upon inspection of the plotted data for the locations in this area it can be seen that the temperatures are gradually approaching the 0° C point. Through a continual program of monitoring these points, a great deal can be learned about "freeze back."

At location DR-26, 3/4 inch and 1-1/2 inch pipes were installed to determine if convection currents in the pipe would affect the accuracy of the near surface readings. It can be seen from the temperature plots, shown on Plates D-13 through D-15, that there is a degree of convection in the upper zones, while with depth the two readings are very similar. At location DR-22, the string had 14 thermistors in a 150 foot length. The data obtained from this string has not been included in this report since its reliability is in question. This is due to damage received during installation as well as the fact that the thermistors are of a lower quality and adequate calibration could not be obtained prior to installation. At location DH-12 the 3/4-inch pipe temperature logging device was lost when it was decided that the bore-hole camera should be run in this boring. At location DH-25 no data is available because the 3/4-inch pipe froze up during installation.

SITE GEOLOGY

Introduction

The river valley at the site has a V-shaped lower or bottom canyon deeply incised into an upper, much broader, U-shaped river valley of considerable extent and width.

The lower river valley floor ranges from 300 to 600 feet wide and has side slopes of 35 to 60 degrees with locally scattered rock outcrops that rise in near vertical cliffs. The incised portion of the canyon extends from subriver level upward about 500 feet to approximate elevation 2,000 feet, where it ranges in width from 1,500 to 3,000 feet. Above elevation 2,000 feet, there is a distinct flattening of the valley slopes and the area broadens out into a very wide former river valley. Width of this former valley base level is from 8 to 10 miles in the lower reservoir area, narrows to about 1 mile in the midreservoir area upstream of Jay Creek and widens to more than 20 miles in the upper reaches of the reservoir.

Foundation Conditions

The site was mapped and explored with 17 core holes, 12 of which are on the dam axis shown in this report. Six of the holes are angle holes, five were drilled normal to the dominant structural trend, and one drilled across the river valley. The exploration plan with hole locations is presented on Plate D-2.

The river valley is filled with alluvium consisting of gravels, cobbles, and boulders in a matrix of sand or silty sand. Overburden depths in the valley bottom range from 40 to 80 feet and may exceed 100 feet in places. Overburden depths on the valley slopes range up to 10 feet deep on the left abutment and up to 20 feet on the right abutment. However, overburden upstream of the left abutment is more than 56 feet deep.

Overburden on the valley slopes is mostly glacial debris and talus consisting of various gravel and sand mixtures and some silts, with cobbles and small boulders. The underlying rock is diorite, granodiorite, and quartz diorite with local andesite porphyry dikes and more widely scattered minor felsite dikes. Most of the rock, although fractured, is relatively fresh and hard to very hard within 5 to 40 feet of top of rock. Overburden and rock stripping depths along the dam axis are shown in cross section on Plate D-7.

Fractures are closely to moderately spaced at the bedrock surface, generally becoming more widely spaced with depth. Fracture zones found at all depths tend to be tight or recemented with calcite or silica. The northwest trending joints and high angle shears mapped in the rock outcrops are found at different depths within most drill holes and range from single fractures to broken zones more than 20 feet thick. Broken rock within the shear zones is locally decomposed but consists mainly of moderately hard to very hard fragments. Many fractures have thin clay gouge seams and slicken sides. Pyrite and chlorite mineralization is found as coatings on many fracture surfaces. Shears are spaced from a few feet to more than 100 feet apart, and since the shears are mostly vertical, greater lengths of sheared material were recovered in vertical drill holes. In addition to the shears, primary and rehealed breccia zones occur in some areas adjacent to the andesite porphyry dikes. Most of these rehealed breccias are relatively competent rock, but a primary breccia zone downstream of the axis on the left abutment includes locally decomposed materials.

Valley Conditions

The river valley bottom was explored with six core drill holes. Three holes are on the axis and three are about 1,000 feet downstream of centerline in the toe area. River alluvium varied in depth from 44 to 78 feet. This alluvium consists of gravels, cobbles, and boulders imbedded in sands with local gravelly or silty sand lenses. The gravels and larger sizes are mostly subrounded to rounded with occasional large boulders. Most large sizes are of dioritic composition, but metamorphic and other rock types were also noted. Most of the gravels are fresh, but a few are coated with plastic fines. Alluvial materials in some areas were frozen to depths in excess of 50 feet and possibly all the way to bedrock at the time of drilling.

The bedrock is a diorite that in most holes is very closely fractured in the upper 10 to 20 feet. Fractures become more widely spaced with depth; however, local zones of closely spaced fractures occur throughout. Joints are both open and rehealed or cemented with calcite and silica. The rock below river level is mostly fresh and hard to very hard. Shear zones occur in several of the holes and include some thin clay gouge coatings and slickensides. Soft chloritic materials were also encountered in one shear zone, and iron staining with pyrite mineralization is common. It should be noted that DH-21 was drilled essentially across the river from the left to the right abutment. No major fault or significant change in materials was seen although six minor shear zones were encountered in the hole. Most of these zones are less than 3 feet thick, whereas, some of the vertical holes penetrated sheared material for distances of more than 10 feet. This confirms the near vertical nature of most shearing. Geologic mapping in rock exposures along the riverbank also indicates the near vertical nature of shearing. An andesite porphyry dike was penetrated at depth by DH-21. This dike has an apparent thickness of about 13 feet, and the contacts with the diorite are tight and contain no notable planes of weakness.

The left abutment was explored with five drill holes, three on the dam axis and one each upstream and downstream of the embankment. Overburden depths in the downstream hole and the three axis holes are less than 10 feet. This overburden consists of small subangular to subrounded boulders in silt, sand, and gravel. Overburden in DH-28, located approximately 1,000 feet downstream of the axis at elevation 1,971 feet, consists of 6 feet of silty clay overlaying 2 feet of sand. DH-25, located about 750 feet upstream of the axis at elevation 2,045 feet, penetrated a vertical depth of 56 feet of glacial and alluvial deposits and had not yet encountered rock when it was abandoned. Overburden in DH-25 consists primarily of gravelly, silty sand with boulders to a depth of 15 feet, underlain by gravelly, clayey silt. Gravels are subrounded to rounded and the clayey silts are stiff and plastic.

Rock in the three axis holes is a hard quartz diorite, whereas in DH-28 downstream of the embankment, it is an andesite porphyry. The relationship between the quartz diorite as a plutontic rock and the andesite porphyry as a surface flow rock is not clearly understood. This contact area between the two type rocks is in the location of the underground powerhouse and will be closely explored during design investigations. It is assumed the underground powerhouse will be located in the dioritic rock. Weathering is primarily staining on fracture surfaces. Fracture spacings vary from very close to moderately spaced; spacing increases with depth.

Fractured zones, encountered in all holes, are from less than 1 to more than 20 feet thick and are separated by from 10 to more than 50 feet of relatively undisturbed rock. Many fractures include thin seams of clay gouge, slickensides, secondary pyrite, and breccia. DH-28, downstream of the embankment, appears to have been drilled in an andesite porphyry breccia contact zone adjacent to the diorite pluton. Much of the core is brecciated, moderately weathered to highly altered, and recovered in small fragments. Several zones of clay gouge were noted.

Right abutment conditions were explored with six core drill holes along the proposed dam axis. Three of these holes were angle holes drilled normal to the dominant structural trends. Overburden depths within the six holes range from 4 to 20 feet, with the greater depths in the holes farthest upslope. Overburden consists of gravelly sand with cobbles and small boulders.

Bedrock is moderately hard, but weathered, closely fractured and locally sheared in the upper 10 to 40 feet. The rock is diorite or quartz diorite with zones of quartz diorite breccia. The quartz diorite breccia is healed, probably formed during emplacement, and is not considered a zone of weakness.

Fractured zones encountered during drilling are similar to those noted on the left abutment. Shears range up to 22 feet thick and are separated from each other by about 10 to 100 feet of competent rock. Very thin films of clay gouge and slickensides occur on some fracture surfaces. Iron staining occurs on many fracture surfaces and fine disseminated pyrite mineralization occurs more widely.

Relict Channel Area

The relict channel is a suspected ancestoral Susitna River channel north of the right abutment under the broad terrace area between Deadman and Tsusena Creeks. Ground surfaces within the Relict Channel area are between elevation 2,100 and 2,300 feet along low elongated ridges and shallow depressions. This area was originally explored with two seismic lines and the results presented in the Feasibility Report, Appendix 1 as Exhibit D-1. Subsequent 1978 explorations include 1,814 linear feet of drilling, borrow explorations near Deadman Creek and 23,600 feet of seismic refraction lines. The 11 drill holes range from 21 to 494 feet in depth and were mostly noncore rotary holes supplemented with drive samples and some bedrock coring. The results of these 1978 explorations confirm the existence of the deeply buried bedrock surface depression discovered during the 1975 seismic investigations. The lowest bedrock elevation encountered in drilling was in DR-22 at 1,775 feet, MSL or 454 feet below ground surface.

Overburden consists of both glacial and alluvial materials occurring in varying sequences that are difficult to correlate with the limited drilling to date.

Outwash occurs over much of the area, consisting of gravelly, silty sands or silty, gravelly sands in varying proportions, with some local cobbles and boulders and more widely scattered clay lenses. These materials are mostly loose and the fines are predominantly non-plastic.

Glacial till is the most abundant overburden material found within the relict channel area. These tills occur in three separate sequences in the deepest drill holes, separated by lenses of alluvial materials. The near surface tills are normally consolidated while the tills from greater depths are highly over consolidated and dense. It is quite probable that this over consolidation was caused by glacial loading in the geologic past. All of the tills contain fines that are nonplastic or only moderately plastic. Smaller gravel sizes are rounded, while larger sizes are more subrounded to subangular. Materials are poorly sorted with little or no indication of bedding. The tills vary considerably in thickness from only a few feet to a maximum of 163 feet in DR-18.

Apparent river deposited alluvial lenses which represent inter-glacial periods, separate many of the till units. These deposits consist of sandy gravels with some silts. Sandy alluvial units have a tendency to cave during drilling and several appear to have relatively high permeabilities. Most of these river deposits were less than 50 feet in thickness but in DR-22, directly above bedrock, the alluvial unit was 159 feet thick.

At least two deposits of lake sediments were encountered during drilling. The larger of these was named "Lake Woller" and occurs in DR-13, DR-15, DR-26, and DR-27 in varying thicknesses. Maximum thickness is 60+ feet in DR-13. Lake Woller deposits appear to be confined between elevations 2,240 and 2,305 feet. Another apparent lake deposit was penetrated in DR-18 and DR-20. Maximum thickness of this deposit is 33 feet and appears to be confined between elevations 2,130 and 2,190 feet. Both lake deposits may represent either quiet lake deposition during an interglacial period, or possibly proglacial lakes formed during glacial retreats. The lake deposits consist primarily of highly to moderately plastic clays and silts with local gravel and sand lenses.

Spillway

The original location of the Saddle Spillway in the Interim Feasibility Report, Appendix I, Plate D-3, was found to lie directly upon two adverse structures. The overburden depths increased from 9 feet at DR-17 on the left side of the proposed alinement to 231 feet at DR-18 on the right or east side of the spillway. This depth of overburden prevailed throughout the length of the spillway, including the proposed gate structure area.

The glacial tills, clay, and intermittent sand lenses of the overburden would have required additional excavation and flatter sideslopes. Added expense would also have resulted from increased foundation requirements for the gate structure and from the full length lining which would have been required in the spillway channel. To avoid these disadvantages a change of the channel alinement was made.

The new proposed alinement lies approximately 800 feet laterally to the left (southwest) of the original design and will be in rock cut from inlet to final outlet at Tsusena Creek. This alinement will also avoid potential structural problems from the second adverse structure, the shear zone titled "The Fins" (Plate D-4) which will now parallel the spillway for its entire length. Rock quality is such that excavated rock will be used as dam shell rock.

As a result of the move, it is anticipated that sound bedrock will be encountered at a maximum depth of 25 feet at the gate structure and will continue down spillway for at least 2,500 feet. As the spillway dips down to Tsusena Creek, deeper glacial till is again encountered, so the final section of the outflow may not be totally founded on bedrock. The plunge pool at Tsusena Creek will be contained by existing rock cliffs.

Permafrost

The Watana damsite lies within the discontinuous permafrost zone of Alaska. For this reason it is to be expected that permafrost would be found during the exploratory effort, particularly on north facing slopes and areas where arctic vegetation has effectively insulated the ground surface. Depths of permafrost within the discontinuous zone are variable and often change drastically within short distances depending on exposure, ground cover, soil characteristics and other factors.

Permafrost conditions at Watana as indicated by the exploratory work done to date appear to be typical for the zone. The left abutment which faces north and is either continuously shaded or receives only low angle rays from the sun was explored with core drilling equipment. Five holes were drilled and pressure tested by pumping water into the drill holes at selected intervals using a double packer. Observation of drill water returns and pressure tests showed that permafrost exists for the entire depth of the holes. Holes drilled in the right abutment, where the sun's rays are most effective, did not indicate any permafrost. Within the relict channel areas, on the terrace north of the right abutment, indications of permafrost were observed as reflected by ground water conditions and water table measurements, drill action, and sampling. Drill hole DR-27 was sampled and ice lenses were retrieved from a depth of 30 through 36 feet. Permafrost was also encountered during test pit activities. However, in general, permafrost in the spillway and relict channel area, while encountered as near as 1 foot to the surface, is expected to be confined to a relatively shallow layer. This expectation has been reinforced by the fact that ground water has been encountered at various depths. In order to study the thermal regime of the permafrost and to more accurately define the lower limits of the frozen zone, temperature probes were installed at 13 locations. These locations are shown on Table 1 under the heading "Instrumentation" and the graphs of readings taken to date are shown on Plates D-13 through D-15. It is still too early to reach definite conclusions from the limited data obtained since installation due to the fact that heat was introduced into the regime by drilling and equilibrium may not yet be reestablished. However, it appears that the readings do support the conclusion that permafrost is not as widespread or as deep as was previous believed.

Of equal significance is the fact that the temperature probes indicate that the temperatures within the permafrost are generally within 1 degree of freezing. Construction in cold regious has shown that, within this range, materials can be excavated with considerably less dificulty than in areas where the permafrost temperatures are lower. Particularly in borrow areas, where a rather large area can be exposed, degradation is rapid and by alternating from side to side in the area, the material can be ripped, left exposed to the sun for a few hours and then handled in the normal fashion. The fragile nature of the permafrost regime as indicated by temperature studies will be of prime importance in the scheduling related to foundation grouting. Permafrost barely within the frozen range will be much easier to thaw and foundation grouting will be facilitated.

As explorations at the damsite continue, the installation of frost probes will be expanded to provide detailed knowledge of the extent of existing permaforst areas as well as their condition. A discussion of design type of probes installed and the degree of accuracy to be expected from data readings can be found under "Instrumentation."

Ground Water

Ground water conditions in the terrace area north of the spillway alinement were examined during exploratory drilling, but the use of drilling mud used for most of the rotary drilling made direct water table measurements difficult. Pervious zones were occasionally encountered where loss of drilling mud was noted. Examples are DR-22 where mud losses were experienced of approximately 50 gallons per foot of hole drilled between elevations 2,025 and 2,000 feet and losses of approximately 14 gallons per foot of hole drilled between elevation 1,940 and 1,855 feet. In a very few instances water tables could be measured at the time of drilling. A notable example of artesian head was measured while drilling DR-13 and DR-14. In both of these holes the ground water was under sufficient head to rise from elevation 2,240 and 2,270 feet, respectively, to elevation 2,300 $\pm$ feet when the overlying clay layer was penetrated by the drill.

A discussion of the overburden units encountered in the terrace area can be found under the heading "Relict Channel Area." It will be noted in that discussion that at least two deposits of lake sediments were encountered which appear to be rather extensive. As might be expected, perched water was encountered above the higher deposit, Lake Woller, in some holes because of the impermeability of the material. In the alluvial zones between the lake deposits water was usually encountered although, as previously noted, in only one instance was this water under artesian head. Below the lower lake deposit, approximate elevation 2,190 feet, the glacial tills were very compact and can be expected to be relatively impervious. The over consolidation of these materials as previously stated is probably due to being overloaded by the weight of ice in glacial times.

The significance of ground water conditions in this area lies in the fact that the deep deposits in the relict channel area will be under a head of approximately 400 feet from the proposed Watana reservoir. The decision as to whether or not an impervious cutoff across this channel is necessary depends on the pervious nature of the materials encountered. While a more detailed program of exploring, sampling, and testing will be undertaken to ensure that pervious layers will not present a seepage danger in this area, it is presently believed that no impervious barrier is required. A more detailed discussion of the rationale in support of this belief can be found under the heading "Seepage Control, Relict Channel."

Reservoir Geology

The Watana reservoir includes seven general zones of geology, as indicated by Plate D-5 (Watana Reservoir Surficial Geology). Glacial fill, outwash, and proglacial lake deposits predominate in the meandering reaches of the river upstream of the Oshetna River confluence. The next zone extends downstream along the incised channel to Jay Creek and Kosina Creek, and includes localized sedimentary and alluvial units with metamorphics such as the Vee Canyon schist. The predominating dioritic gneiss and amphibolite is laced with bands of mica schist, pyroxenite, and augen gneiss that are inferred to correspond with contact and shear zones trending northeast. The area around Jay and Kosina Creeks and downstream to Watana Creek includes two zones with outcrops of high grade schist and basalt flows at the river level. The surrounding hills are composed of volcanics with limestone interbeds on the south, and mixed volcanics and near surface intrusives to the north for a minimum of 10 miles. The Watana Creek area consists of basalt flows and semiconsolidated predominately clastic sediments overlain by thick glacial and outwash deposits. This area also contains the Talkeetna Thrust as identified by the U.S. Geological Survey. Downstream of Watana Creek lie the remaining two units, starting with moderately metamorphosed sediments (phyllite, argillite, graywacke) with two bands of schist. The final unit starts just upstream of Deadman Creek and includes all materials downstream to Fog Creek below the damsite. The predominate types are the diorites, granites, and migmatites of the damsite pluton.

The Watana reservoir includes many permafrost areas, especially on north facing slopes. Frozen overburden will tend to slough as the reservoir is filled and the permafrost degrades. Since most of the lower canyon elevations are covered with only shallow overburden deposits, sloughing will be minor and have minimal effects upon the reservoir. Deep overburden deposits, mostly of glacial origin, occur above approximate elevation 2,000 feet where the slopes flatten out into a broad river valley base level. Most of these glacial deposits will be stable due to the flat topography.

Some rock and overburden landslide deposits have occurred within the reservoir area. One such slide deposit, known as the "Slide Block," is located upstream of the axis on the south bank opposite "The Fins" shear. Several old and potential landslides are identified by Kachadoorian and Moore in their reconnaissance of the project area.

In general terms, the geology in the immediate damsite is controlled by the diorite intrusive believed to be the top of a stock which uplifted the surrounding sediments and volcanics and was later eroded by glaciers. Subsequent glacial and stream deposition has masked much of the flat upland areas and stream valleys.

DAM DESIGN

Dam Foundation Treatment

Main Dam: Foundation conditions are more than adequate for construction of an earth-rockfill dam. The underlying rock is a diorite or granodiorite which, in nonfractured fresh samples, had unconfined compressive strengths that ranged from 18,470 to 29,530 psi. Only the uppermost 20 to 40 feet of this rock is closely fractured and sufficiently weathered to require removal within the core area. Stripping depths along the centerline section are shown on Plate D-7. Stripping to sound foundation rock is required for the entire length and width of the impervious core. Foundation treatment within the rock excavation area will include removal of all loose and highly fractured rock and soft materials, cleanup, and dental treatment. If there are any zones where more than an 8 foot width of soft materials is removed, the dental concrete will be contact grouted to the adjoining rock. Stripping to rock will also be required under the remainder of the embankment area. However, in this area excavation will not include removal of the inplace rock. Only the loose and severly weathered surface rock will be removed. Steep or overhanging rock walls will be trimmed to a smooth shape for proper placement of embankment materials. Exploratory drilling in 1978 has shown the materials in the river channel to be a well graded mixture of gravels and cobbles as good, or better, than the materials that would be used to replace them. As the exploration program continues, these gravels will be more completely explored and it may be demonstrated at that time that there is no need for their removal beneath the shell zones. Should this prove to be the case, the change can be made during feature design.

Provision has been made for a 6- by 8-foot concrete grouting gallery with concrete lining to be constructed in foundation rock under the impervious core. This gallery will begin at elevation 1,900 feet on the left abutment and will terminate at elevation 1,800 feet on the right abutment. It will provide access for drilling and grouting which, in some areas may be delayed to allow thawing of permafrost. Access to the gallery will be provided from the powerhouse on the left abutment and, by adit, from the downstream toe of the right abutment. Grouting will be on a single line of holes utilizing split spacing, stage grouting techniques. Grout holes will be slanted upstream and may be included to intercept the dominant high angle northwest tending fracture system. Preliminary grout hole depths are estimated at two-thirds the height of the embankment to a maximum depth of 300 feet with primary spacing of 20 feet, secondary spacing of 10 feet, and tertiary spacing of 5 feet with additional holes as required.

Determination of final grout hole depths, spacing, inclination, grout mixtures, and grouting methods will be dependent on the results of future explorations, permeability studies, test grouting, and permafrost thawing investigations.

Rock permeability test results are shown on the drill logs presented on Plates D-28 through D-37. Coefficients of permeability (K) were computed in feet per minute times 10^{-4}. Permeability coefficients ranged from 0.0 to 23.1 and average 4.9 for those holes that were tested.

Drill holes in the left abutment area indicated very low permeability due to permafrost. River section hole DH-1 had variable permeability coefficients that range from 0.48 to 2.52 and averaged 1.98. Drill water returns in the river holes were quite variable throughout the entire hole depths and tended to drop off to low percentages at the greater depths in the axis area. Right abutment drill holes had permeability coefficients that ranged from 0.0 to 23.09 and averaged 5.47. DH-10 was the only hole tested that had relatively low permeability coefficients throughout. Drill water returns had similar patterns with variable percentage losses. DH-7 and DH-9 had 0 percent returns throughout and DH-8 and DH-11 maintained high percentages of drill water returns throughout.

The existence of permafrost in the left abutment and the possibility of minor amounts in the right abutment necessitates assessment of the problem of thawing a zone in the foundation bedrock sufficiently wide and deep to allow proper installation of the grout curtain. In anticipation of this need, the U.S. Army Cold Regions Research and Engineering Laboratory was asked to do a desk study on thawing the permanently frozen bedrock. The Technical Note which was submitted in response to the request is included as Exhibit D-4.

Embankment Design

Design of the dam embankment at Watana damsite has been based on the availability and proximity of construction materials in addition to their suitability as engineering materials. As a result of these considerations, the embankment contains a central section consisting of an impervious core buttressed on the downstream side by a semipervious zone.

This central section is supported, both upstream and downstream, by suitable fine and coarse filters and rockfill shells. A typical cross-section of the embankment is shown on Plate D-9.

The impervious core and semipervious zone will be constructed using the glacial till which is readily available in the area. The semi-pervious material will be obtained by selecting the coarser grained materials while the finer materials will be placed in the impervious zone. These materials, as discussed under "Embankment Materials," have been shown by exploration and test to be a well graded mixture, which, when compacted, has a very good shear strength and a high degree of impermeability. Tests have shown that this material is quite sensitive to moisture control; therefore, special attention must be paid to this aspect of the design and construction. The 14,000,000 cubic yards required are available within a very reasonable haul distance and will only require removal of oversize boulders prior to use.

The fine filter material can be obtained from the gravelly sand deposit at the mouth of Tsusena Creek. Chart D-3 shows an envelope of gradations from this source superimposed onto the envelope for the fine filter as established by engineering design criteria. This comparison indicates that the Tsusena Creek source can provide material within the ranges of sizes necessary to protect the core and semipervious zone against piping or migration of fines into the filter material.

Proven sources of gravel which can yield large quantities of material are scarce within short haul distances of the project. For this reason, the decision was made to use material from the rockfill source as a coarse filter. Chart D-5 is an envelope of the required gradation which will provide proper filtering action for the fine filter material. A curve has been superimposed on this envelope which represents the materials expected from the rockfill source. As indicated, the rockfill will provide the proper filter action. The maximum size material in the coarse filter and the lift thickness for placement will, of course, be limited to ensure design criteria are met.

The decision to utilize rockfill rather than gravel for the embankment shells was made when reconnaissance and exploration indicated that dependable deposits of gravels which would provide the necessary quantities could not be verified within reasonable haul distances of the damsite. On the other hand, rockfill can be readily obtained as discussed under "Embankment Materials." Riprap for wave protection can be obtained from the same source.

It is recognized that the 1 vertical on 2 to 2.25 horizontal side-slopes shown on the typical cross section for the dam are conservative for a rockfill dam, and, if rockfill is used, these slopes will be refined in accordance with sound engineering practice. Refraction seismic lines in the borrow areas show velocities which could represent large deposits of gravels or glacial materials but rather extensive explorations will be required to verify the true nature and quantity of the materials. Should these explorations reveal that suitable gravel deposits in the area are sufficiently extensive to provide the large quantities required for the dam shell sections, the gravel will be used in preference to borrowing quarried rock for rockfill.

Powerhouse and Underground Structures

An underground powerhouse is well suited to meet the restrictions of subarctic weather and other environmental factors. Topographically, the narrow Susitna Canyon is well situated for this type of underground construction. The diorite pluton that underlies the foundation area is expected to be competent for excavation and support of underground facilites, but the location and design of the various structures may have to be adjusted in some areas. "The Fins" and "Fingerbuster" Shear Zones shown on Plate D-3 and discussed in paragraph "Rock Structure" are the two most significant shears within the damsite area. Other northwest trending steep angled minor shears involving displacements of a fraction of an inch up to a few feet are common in the site area and were noted in many of the drill holes. These minor shears appear to represent mass adjustments to regional stress and compensation can be made for them in design and construction of the underground structures.

Prior to powerhouse excavation, exploratory adits located near the crown of the various chambers will be driven to confirm final design criteria. The chambers will be constructed with straight walls as required for maximum dimensions, and not notched or cut irregualarly for support of interior powerhouse facilities. Rock support will include pattern bolts consistent with wall and crown conditions. Use of steel channeling and remedial concrete is anticipated in local areas where fallout may occur or in fracture zones having a substantial width of crushed rock. Wire mesh will be utilized where necessary as a temporary facility prior to placing concrete. A thin layer of wire reinforced shotcrete may be placed on the main powerhouse chamber walls and crown as a protective measure against rock raveling. Additional shotcrete will be utilized, as required, to seal surfaces and retain rock strengths. Construction methods in the large chambers will include controlled blasting and rock removal in lifts from the top downward. Gutter and floor sloping for drainage will be provided in the interior structures between chambers.

Intake Structure

Consolidation grouting may be necessary for the intake structure foundation and the bridge pier footings. The higher bridge pier footings will also be recessed into sound rock. Tunnel portals will be designed so that there is a minimum of two tunnel diameters of sound rock above the heading where they go underground. Initial tunnel support will be by pattern bolts, with steel channeling and wire mesh where necessary in closely fractured areas. Major shear zones will require steel supports. Hydraulic and geologic considerations will necessitate final concrete linings for all but the access tunnels, and steel liners for the penstocks. Grout rings will be required in the penstock portal areas.

The two diversion tunnels are to be separated by a minimum of four tunnel diameters to provide greater structural stability. Downstream diversion tunnel portals will have to be located to avoid the "Finger Buster" shear zone to insure adequate portal construction conditions.

Spillway

The gated spillway has been relocated about 800 feet southeast of the alinement presented in the 1976 report so that it will be constructed in a through rock cut. The spillway will be unlined beyond the spillway gate structure and apron. The new spillway alinement extending from the Susitna north valley wall to Tsusena Creek and the spillway gradient are shown on Plates B-2 and B-5. It is anticipated that, with the exception of minor amounts of waste, all the excavated materials from the spillway will be used in the dam embankment. The major part of the excavation is in rock and this material will be used in the shell sections. The overburden materials are glacial till which, when separated from the boulders can be used in the impervious or semipervious zones.

Seepage Control - Relict Channel

The relict channel area is an overburden terrace underlain by a bedrock depression, and extends northward from the right abutment for about 6,000 feet. This terrace is composed of glacial till, some of which has been reworked by alluvial action. For this reason, consideration was given to the possibility of seepage through the area where rock contours are below the proposed reservoir elevation. However, preliminary seepage calculations indicate that even in the relict channel area, where the head differential approaches 350 feet, and using a very conservative 'k' value of 500 feet per day, the seepage would be less than 0.02 cubic feet per second per foot of width for a pervious layer assumed to be 80 feet thick. Assuming such a layer to be 200 feet wide, the seepage would be in the order of 4 cubic feet per second, which is a minor amount. The exit velocities associated with such seepage would be too low to cause serious piping or erosion. Investigations during the summer of 1978 support this conclusion. In holes DR-13 and DR-14, located in the vicinity of Borrow Area "D," ground water was encountered in alluvial layers between elevation 2,240 and 2,280 feet with an artesian head which exceeded the proposed reservoir level by 100 feet. In spite of this high head condition, no evidence was found indicating seepage out of this layer into either Deadman Creek or Tsusena Creek. Indeed, it is probable that the effect of this artesian water, which evidently has its access to the alluvial layer in the upper reaches of Tsusena or Deadman Creek, would be to resist flow from the reservoir into the aquifer. Because mud losses in DR-22, located at the center of the relict channel, indicated the possibility of permeable layers at approximate elevations 1,900 and 2,000 feet, a falling head permeability test was performed at this hole. The permeabilities calculated from this test are a further indication the seepage through the terrace would be minor or nonexistent. Consequently, it was unnecessary to include any cutoff through the saddle and relict channel area.

CONSTRUCTION MATERIALS

Material Requirements

Embankment: Approximately 57,792,000 cubic yards of embankment materials will be required to construct an earthfill dam at Watana site. The impervious core is estimated to require 7,373,000 cubic yards and the semipervious fill zone 6,077,000 cubic yards of material. The fine filters are estimated to require 5,621,000 cubic yards of material and the coarse filters 2,201,000 cubic yards. The pervious rock shells, which make up the largest portion of the dam, will require approximately 36,297,000 cubic yards. Slope protection on the upstream side of the dam is estimated to require 223,000 cubic yards of riprap.

Sources of Materials

General: Several sources of embankment materials were investigated in the damsite area. These sources included two quarry locations which could yield rock shell and coarse filter materials, a source of glacial till which could produce core material, and two areas containing relatively clean sands and gravels for the fine filter material. Additional embankment materials will be generated by required excavation for the dam foundation, underground facilities, and the spillway channel. All rock excavation from the spillway channel will be incorporated into the rock shell zone of the dam. The overburden encountered in the excavation for the spillway channel will be glacial till which can be processed by removal of oversize material for use as core material.

Rock Shell Materials: Rock shell materials may be obtained from two quarry locations shown on Plates D-10 and D-11.

Quarry sites were located on the left abutment of the dam (Quarry Source 'A') and in the northwest quadrant of the confluence of Deadman Creek and the Susitna River (Quarry Source'B'). The Quarry Source (A) on the left abutment is an outcrop of igneous rock ranging in elevation from approximately 2,300 to 2,630 feet. The total volume of the hill above the surrounding terrain is approximately 200 million cubic yards of rock. Development would consist of open faces on the north flank of the dome with the final quarry floor at an elevation of 2,300 feet. This type of development would maintain the visible profile of the hill essentially as it is now. The resulting quarry floor could provide an ideal site for parking areas, visitor facilities, and perhaps, the switchyard.

The material in the hill is a diorite on the western side and a rhyodacite porphory on the eastern half. The appearance of outcropings and exposed faces of each material indicates that the hill is composed of sound rock.

The product of this quarry will be used for the rockfill shell zones of the dam and in the coarse filter and riprap. This site (Quarry 'A') represents the nearest source of adequate quantities of rock materials for the dam. From the approximate center of the quarry to the approximate center of the dam is a distance of 4,000 feet and movement of material would be downhill. If properly developed, virtually all of the material removed from the quarry will be used in the dam and the oversize material, overburden and weathered waste material can be disposed of immediately adjacent to the quarry in the reservoir area upstream of the dam.

The quarry source at the confluence of Deadman Creek and the Susitna River (Source 'B') could be developed by excavating rock from the open faces visible on Deadman Creek and continuing the development of a face to the westward, maintaining the face between elevation 1,700 and 2,000 feet. Stripping and clearing would be minimized by developing a long, narrow quarry paralleling the river and using the quarry floor as a haul road for the length of development. If exploited in this way, the quarry could yield 17,000,000 cubic yards of material.

The rock exposed in this area is a moderately weathered diorite. The product of this quarry could be used on the rockfill shell sections of the dam. The distance from the center of the Quarry 'B' to the center of the dam is approximately 2 miles.

The only reason for utilizing this quarry source instead of the Quarry 'A' on the left abutment would be the lessened environmental impact since the quarry at Deadman Creek would be entirely in the reservoir area. However, since the haul distance is greater and the

69-738 O - 80 - 40

net environmental impact of the Quarry 'A' on the left abutment is small, this area is a less desirable source of embankment materials.

Core Material: Impervious and semipervious materials can be excavated from the glacial tills which are present at the damsite. The most logical source of glacial till appears to be in an area denoted as Borrow Area 'D' which lies between Deadman Creek and the saddle on the north side of the dam (see Plate D-11).

Exploration in this area was accomplished by drilling with a track-mounted, self-propelled auger and a Failing 1500 rotary drill, by test pitting with a backhoe, and by use of seismic refraction methods. Five holes were completed using the air rotary drill, 14 holes were completed using the auger, 14 pits were completed with the backhoe, and 4 seismic refraction lines were extended across the proposed limits of the borrow area. The material in the area is composed of a surface layer of natural ground cover of roots and moss, approximately 2 feet of boulders and organic silts underlain by the tills which are classified as gravelly silty sands. The tills range from 15 to 25 feet thick and usually overlie a clay, sandy gravelly clay and silty sandy gravel.

Sack samples from the test pits (in Borrow Area D) were tested at the North Pacific Division Materials Laboratory to determine gradations, compaction, consolidation characteristics, permeability, and triaxial shear strength.

Gradation tests were run on each sample from each test pit. An envelope of the gradation curves derived from the tests of samples from Test Pits 8 through 19 is shown on Chart D-2. Because the range of gradations of materials from the test pits centrally located in the area is limited, a composite sample was formed. Use of a composite sample was necessary to provide adequate material for a representative testing program since retrieval of large bulk samples from the site was not possible.

The coefficient of permeability (K_{20}) for the minus 1-inch fraction of the till material, compacted to 95 percent of maximum density with an optimum water content of 7.5 percent equals 10.90×10^{-6} cm/sec. This relatively low coefficient of permeability is coupled with an adequate shear strength at the optimum water content, acceptable consolidation values even when loaded to 32 tons/sq ft and a narrow band of gradation throughout the central portion of the outlined borrow area. The shape of the compaction curves indicates that moisture content is critical in obtaining maximum densities with a pronounced peak at the relatively low optimum moisture content of 7.5 percent. The results of the triaxial compression tests indicate that in the unsaturated and undrained condition the glacial tills will be sensitive to moisture contents higher than optimum but that if placed on the dry side of optimum they will maintain strength essentially equal to those obtained when placed at optimum.

The results of this testing program indicate that the glacial tills can be placed and compacted to provide a suitable material for both the impervious and semipervious zones. The specifications will need to provide for close controls of the moisture content and the quality assurance programs will have to be adequately staffed to provide for careful checks of moisture content in the pervious and semipervious fill. Detailed laboratory reports of the tests conducted are included as Charts D-6 through D-29.

The materials from Borrow Area D can be used with very little processing. The ground cover and organic silts and boulders will be stripped from the surface and disposed of as designated near the mouth of Deadman Creek in the reservoir area. The remainder of the material can be utilized in the core of the embankment if oversize (12 inch plus) material is removed by mechanically raking in the pit or on the embankment fill. Less than 10 percent of the material will be too large to use in the core. Since removal of only the silty, sandy gravel above the clays will result in the floor of Borrow Area 'D' being above reservoir elevation, it will be necessary to contour and seed the borrow area after the completion of removal of materials as a restoration measure. Approximately 630 acres will be restored.

<u>Filter Material</u>: The nearest source of clean sands and gravels for use in the fine filter of the embankment dam is an alluvial deposit formed by materials washed out of Tsusena Creek and deposited at the confluence of Tsusena Creek and the Susitna River on the right bank of the Susitna (Borrow Area 'E', see Plate D-12). Haul distance to the dam ranges from 3 to 5 miles. This area was explored by digging 5 test pits to a depth of 8 feet using a backhoe mounted on a small tractor.

The material in this area is composed of approximately 2 feet of organic, sandy silt overlaying 6 feet of clean, well graded sands and gravels having maximum size particles of up to 4 inches in diameter. The materials are sound, well rounded particles. The bottoms of the test pits indicate the possibility that the materials deeper than 8 feet below the ground surface contain up to 50 percent of boulders in excess of 8 inches in diameter and ranging up to 24 inches in diameter. The 6 feet of material which lies above the boulders may be used in the embankment with required processing limited to some blending and removal of material larger than 12 inches to produce fine filter material. An envelope of gradation curves derived from tests of samples from TP-1 through TP-5 is shown in Chart D-1. All of the samples are from the first 8 feet of material. All of this material lies above the water table and can be taken by front loaders. The quantity of material available in the first 8 feet is approximately 3.7 million cubic yards. After the boulders are encountered at a depth of 8 feet, the oversize material will have to be removed and material below the water table will have to be bailed from the area. A dike will be maintained to separate the borrow operations from the river so that all turbidity created by the excavation of materials will be filtered or settle prior to entering the Susitna River. In terms of grading, particle soundness and proximity, this area represents an excellent source of essential filter materials.

The second area in which clean sands and gravels were located is in the upper reaches of Tsusena Creek, north of Tsusena Butte (Borrow Area 'C'). The materials are sound, well rounded particles and are well graded with maximum sizes generally less than 4 inches. Considerable exploratory effort would be necessary to ensure quality and quantity of materials before this could be considered an acceptable source. Because of the haul distance of 12 miles, this source will not be considered unless further explorations and testing indicate that adequate materials may not be obtained from the sources closer to the damsite.

Exploration at Site 'C' was accomplished by digging one test pit, reconnaissance of the area on foot and from helicopter, and with a seismic survey.

Concrete Aggregates: Approximately 310,000 cubic yards of concrete will be required to construct the appurtenant structures for an embankment dam at Watana damsite. Most of this will be structural concrete placed in tunnel linings, the powerplant, gate structures, intake structures, and spillway channel lining. Maximum size aggregate will be 3 inches in all but the smaller structures or those with closely spaced reinforcing. The most readily available source of concrete aggregate is available at the confluence of Tususena Creek and the Susitna River (Borrow Area 'E'). The materials from the first 8 feet in the alluvium can be utilized with only limited screening. As oversize materials are encountered at greater depths, the larger particles will be crushed for use in the concrete aggregate, thereby achieving maximum utilization of gravels from the area and also to increase the tensile strain resistance of the concrete which will lessen problems with thermal cracking in the more massive sections. Since Borrow Area E represents the most economical source of concrete aggregate and the nearest acceptable source of essential filter material, maximum utilization of the material in this area is required.

A petrographic analysis of sands and gravels from Borrow Area E was conducted by the Missouri River Division Laboratory at Omaha, Nebraska. The results show the material to be approximately 70 percent granitic rock with the remainder composed of basalt, andesite, and ryholite. Chert is present in such small quantities as to be nondeleterious.

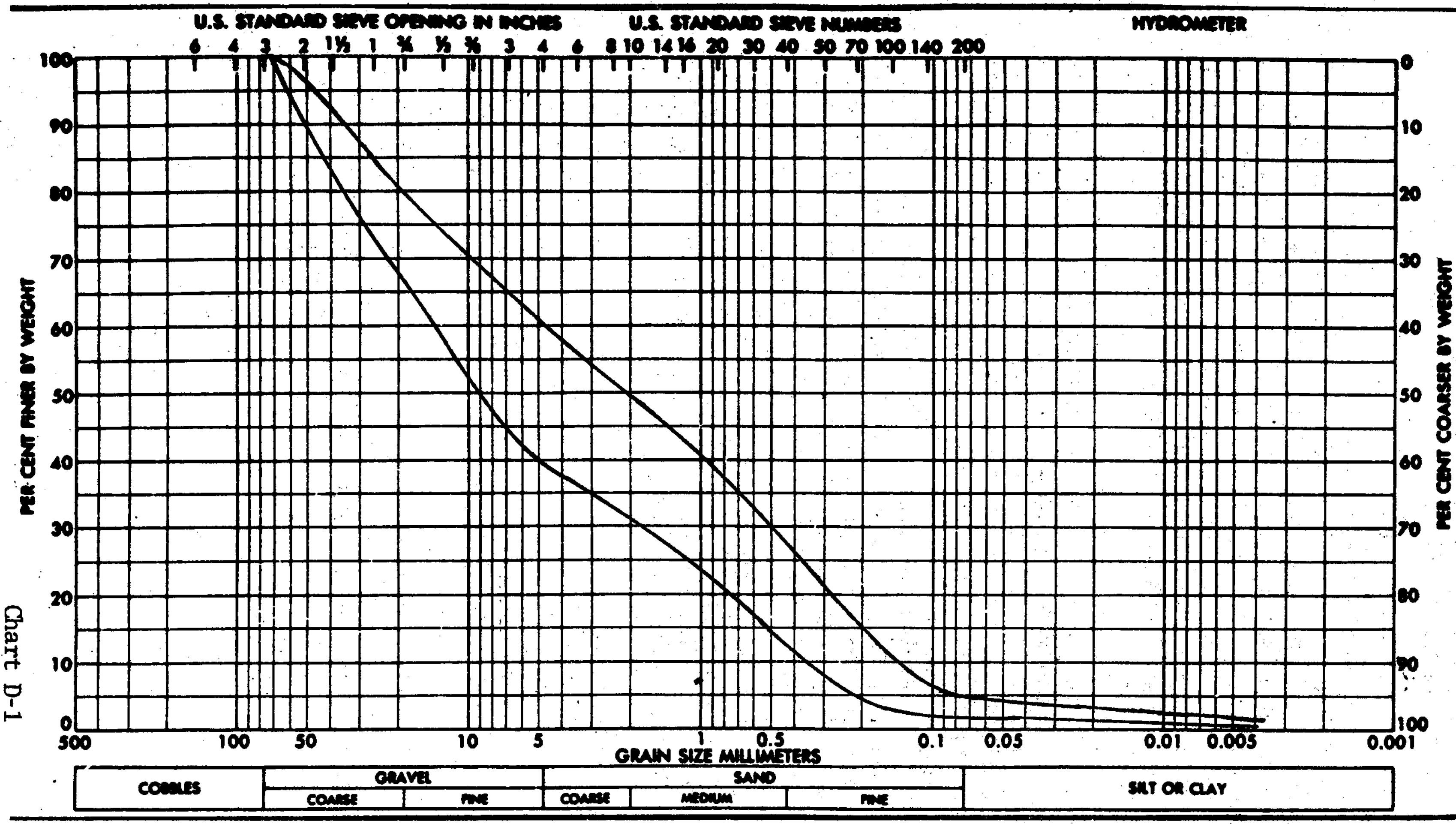
The quarry site on the left abutment (Quarry Source 'A') is considered an alternate source of concrete aggregate. If material from the quarry were used in the embankment dam aggregate could be produced by placing a crushing and screening plant in the quarry and producing the concrete aggregate incidental to the production of embankment material. The concrete aggregates would be produced from the diorites in the quarry to avoid the potential of problems caused by the reaction of the alkalis in the concrete with the rhyodacite porphory in the eastern half of the hill.

The materials in upper Tsusena Creek (Borrow Source 'C') would produce excellent concrete aggregate; however, because of the haul distance involved (10 miles), it is not anticipated that this source would be exploited to produce concrete aggregate unless embankment materials are also taken from the same source.

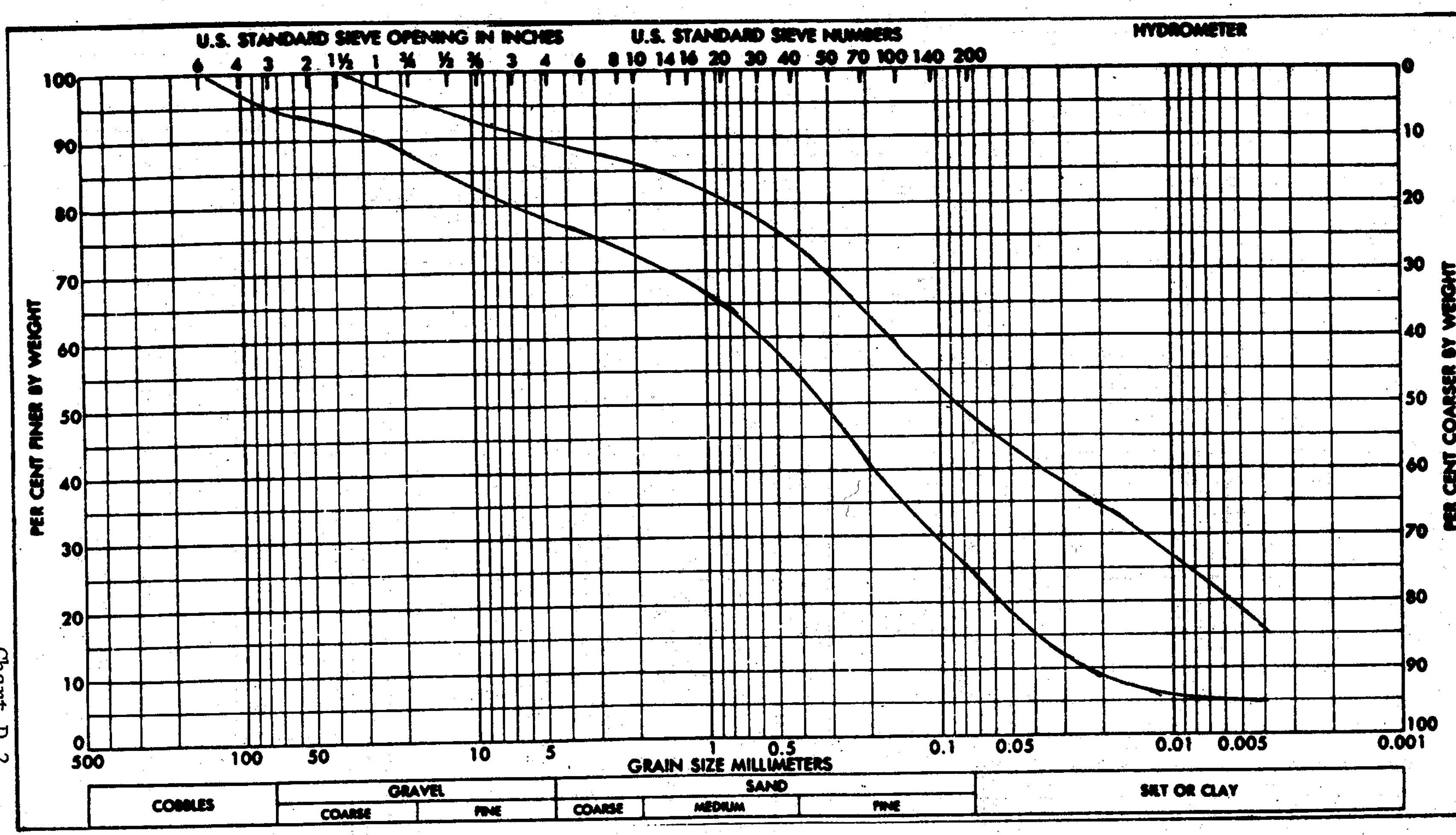
It is anticipated that because of the relatively small quantities of required concrete aggregate compared to the large quantities of the various classes of embankment materials, that concrete aggregates will be produced incidental to the production of embankment material and stockpiled adjacent to the batch plants used.

The first concrete required on the project will be that required to line the diversion tunnels and form gate and trashrack structures for river diversion. The aggregate for this work could be produced from Borrow Area E with a resulting haul distance of 2.3 miles.

Chart D-1

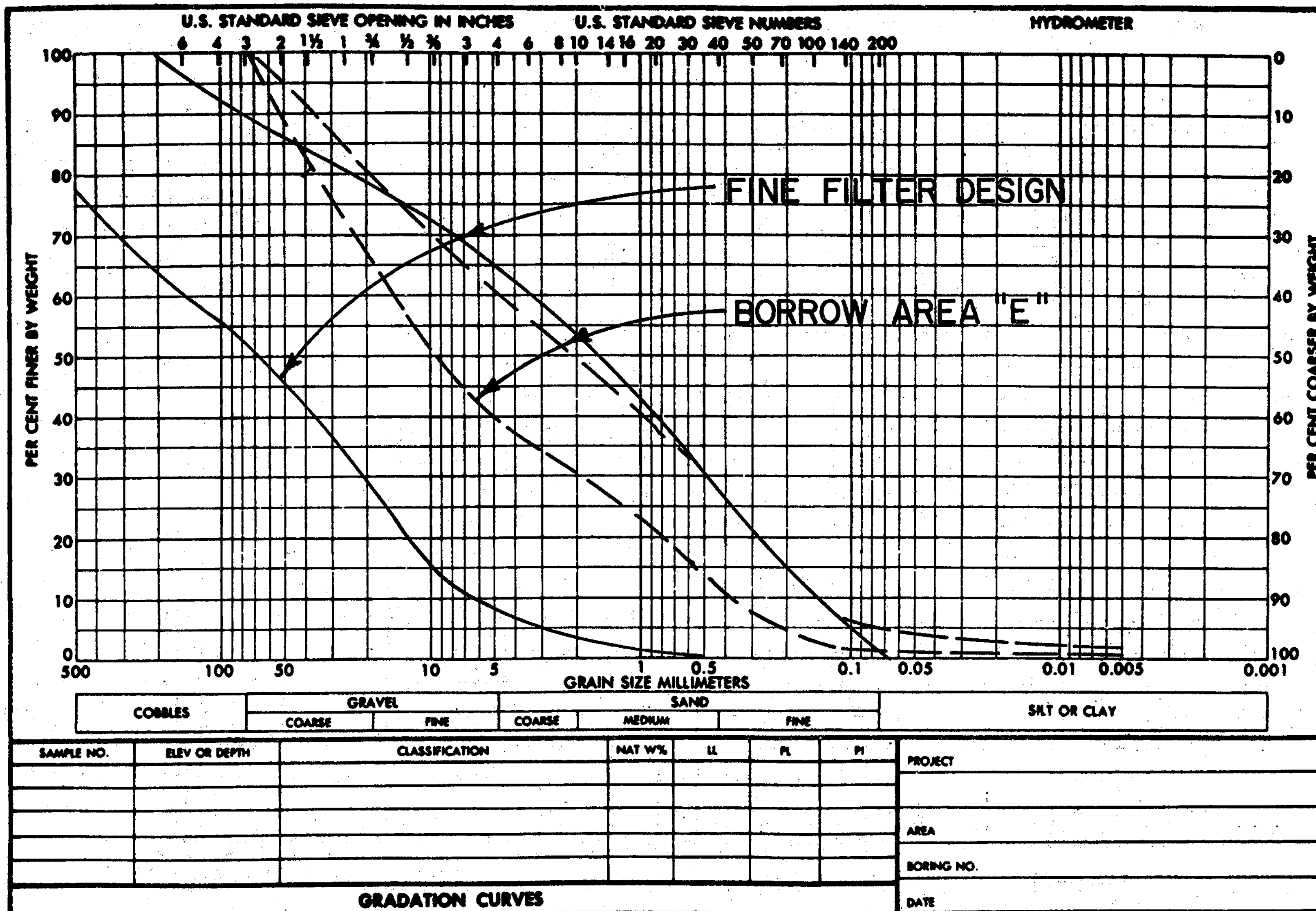


Envelope of gradation curves derived from tests of samples from test pits 1 thru 5, Borrow area E.



Envelope of gradation curves derived from tests of samples from test pits 8 thru 19, Borrow area D.

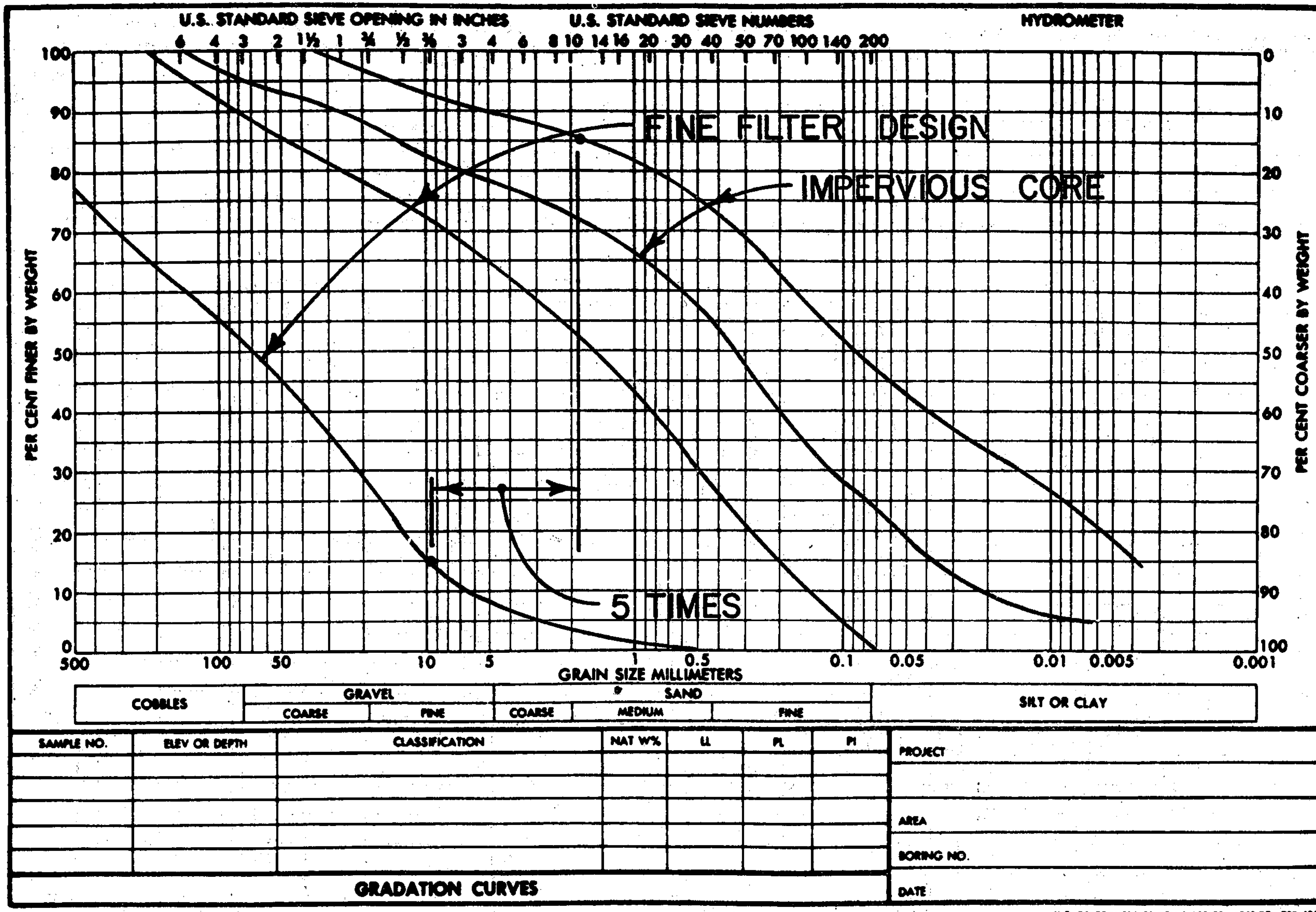
Chart D-2



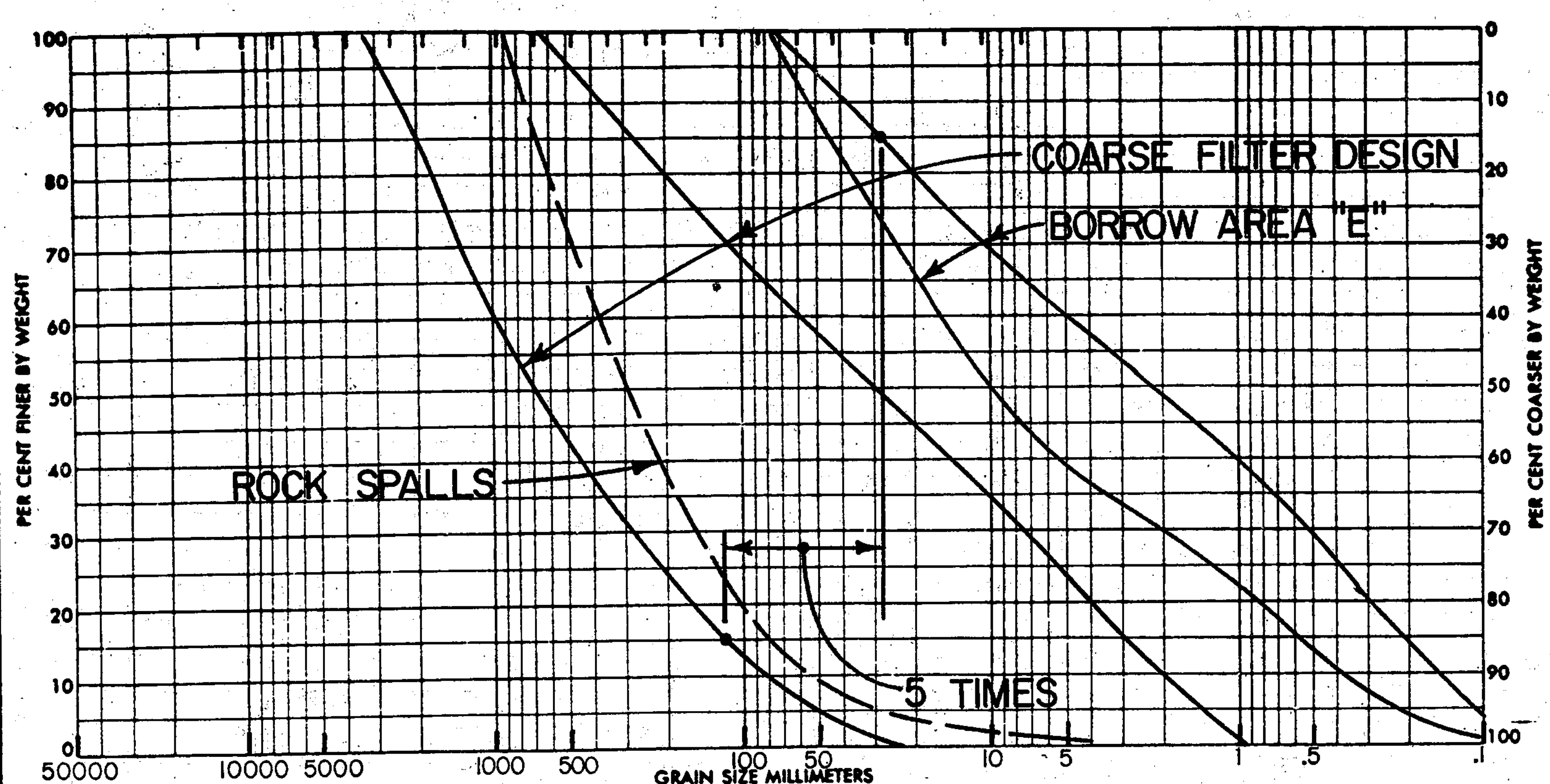
GRADATION ENVELOPES - BORROW AREA E   SUPERIMPOSED ON FINE FILTER

Chart D-3

Chart D-4



GRADATION ENVELOPES - FINE FILTERS AND IMPERVIOUS CORE



SAMPLE NO.	ELEV OR DEPTH	CLASSIFICATION	NAT W%	LL	PL	PI

PROJECT

AREA

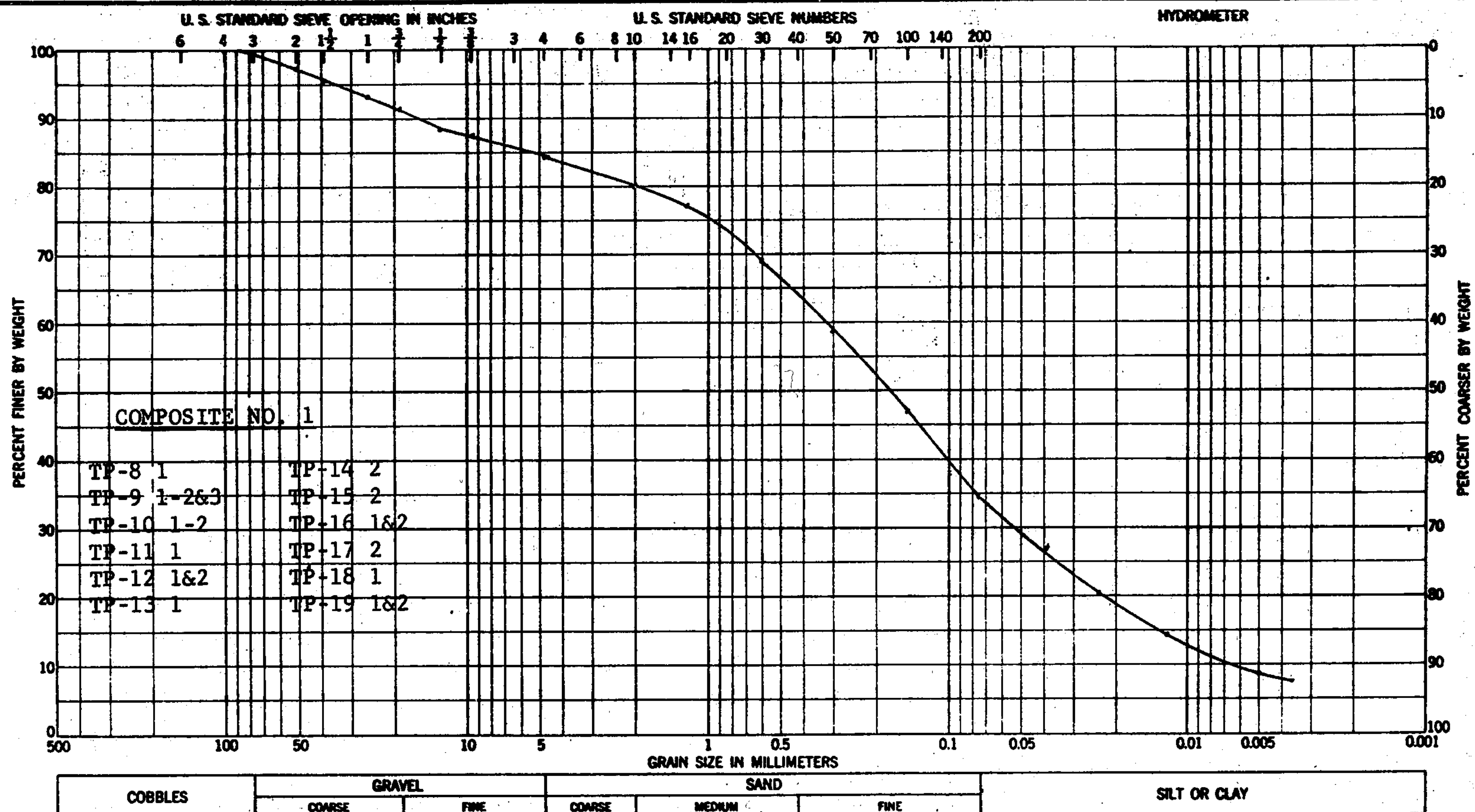
BORING NO.

DATE

GRADATION CURVES

GRADATION ENVELOPES - COARSE FILTER AND BORROW AREA E.

Chart D-5



Sample No.	Elev or Depth	Classification	Nat w %	LL	PL	PI
Composite No.1		Gr. Si. SAND (SM)				

Project WATANA DAM

Area

Boring No. Composite No. 1

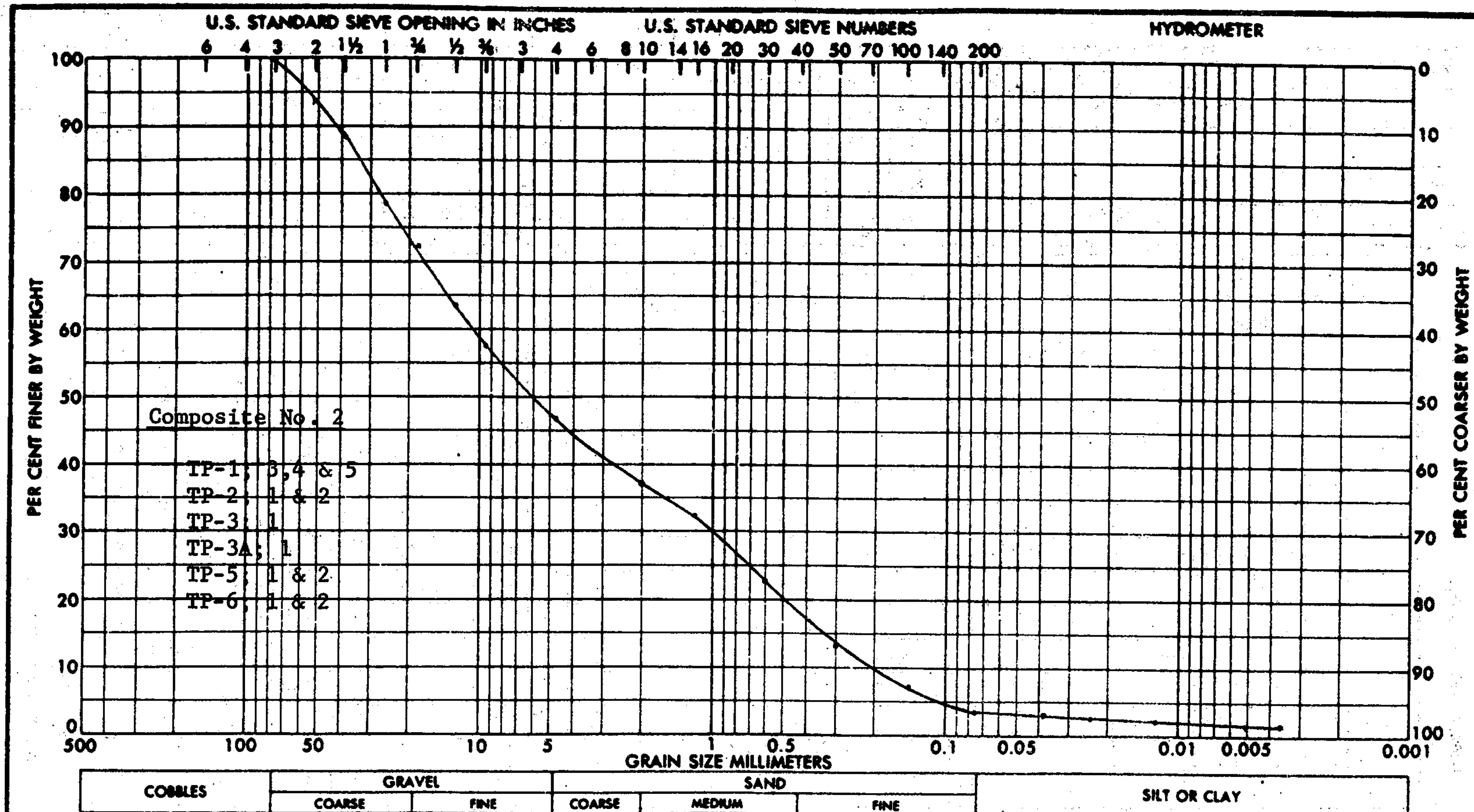
Date 14 NOV 1978 79-S-404

GRADATION CURVES NPD

ENG FORM 1 MAY 63 2087

Chart D-6

Chart D-7



SAMPLE NO.	ELEV OR DEPTH	CLASSIFICATION	NAT W%	LL	PL	PI
Composite No. 2		Sa. GRAVEL (GP)				

PROJECT WATANA DAM

AREA

BORING NO. Composite No. 2

DATE 20 NOV 1978 79-S-404

GRADATION CURVES NPD

ENG FORM 2087
1 MAY 63

REPLACES WES FORM NO. 1241, SEP 1962, WHICH IS OBSOLETE.

14 NOV 1978

NPDEN-GS-L (79-S-404)

WATANA DAM

Composite No. 1

Report of Specific Gravity & Permeability Tests

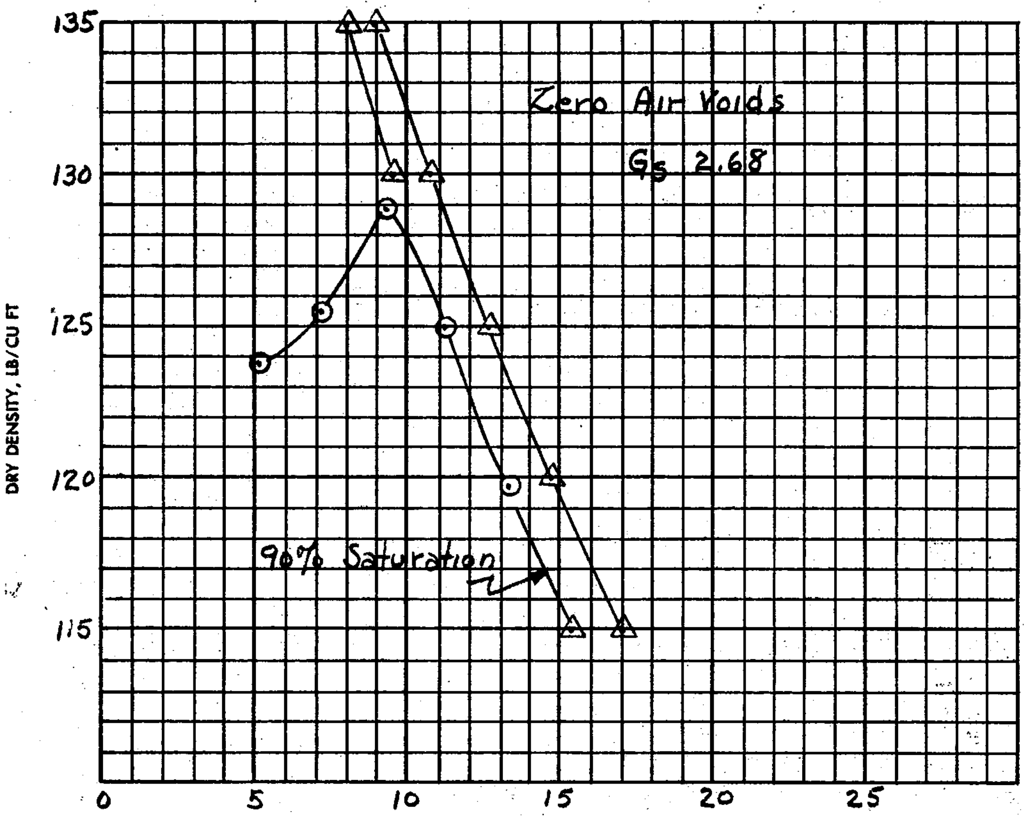
1. Specific Gravity & Absorption (ASTM C127 & C128)

	3/4 in. - No. 4	Minus No. 4
Bulk	2.633	
Bulk, SSD	2.671	
Apparent	2.737	2.683
% Absorption	1.44	

2. Coefficient of Permeability (Minus 1 inch material)

Remolded Density = 126.6 P.C.F.
Optimum Water Content = 7.5%
Permeability K_{20} = 10.90×10^{-6} cm/sec.

Chart D-8



WATER CONTENT, PER CENT OF DRY WEIGHT

Standard COMPACTION TEST

25 BLOWS PER EACH OF 3 LAYERS, WITH 5.5 LB RAMMER AND

12.0 INCH DROP. 4.0 INCH DIAMETER MOLD

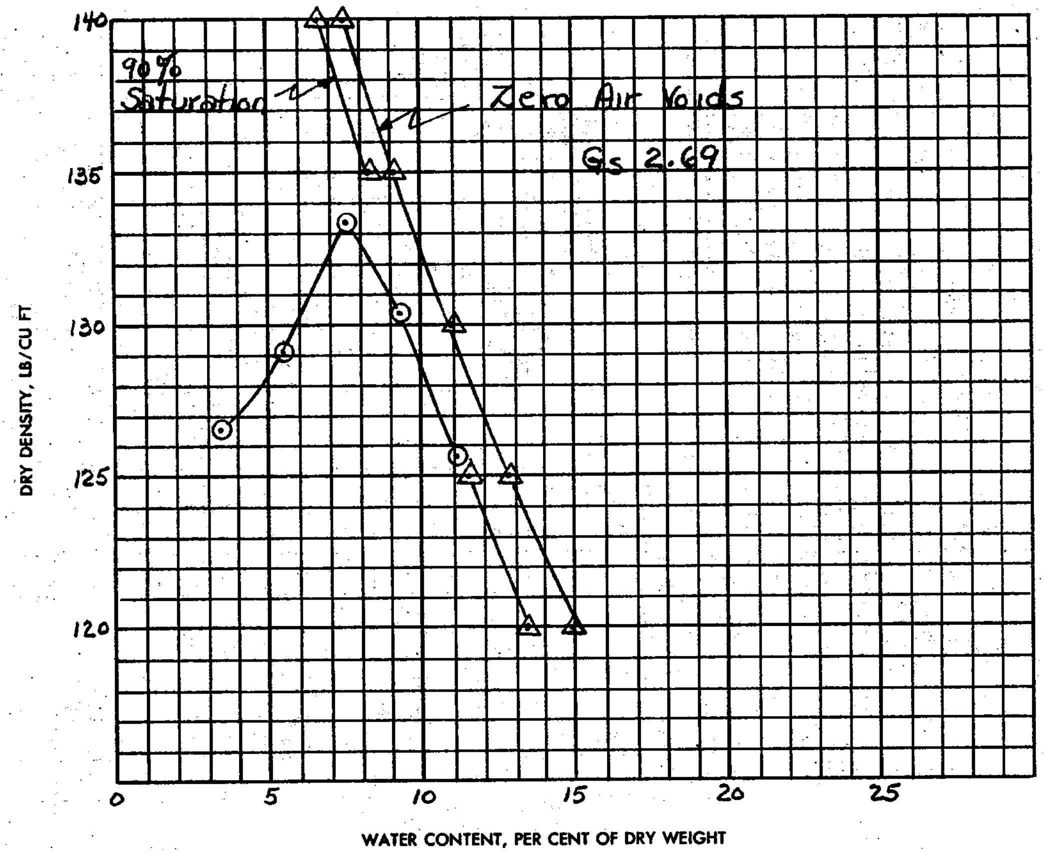
SAMPLE NO.	ELEV OR DEPTH	CLASSIFICATION	G	LL	PL	% > NO. 4	% > ¾ IN.
Composite No. 1		Si. SAND (SM)	2.68			—	—

SAMPLE NO.	Composite No. 1			
NATURAL WATER CONTENT IN PER CENT				
OPTIMUM WATER CONTENT IN PER CENT	9.3			
MAX DRY DENSITY IN LB/CU FT	128.9			

REMARKS	PROJECT WATANA DAM
AASHTO T-99	
Method A	AREA
	BORING NO. Composite No.1 — DATE 14 NOV 1978
	NPD **COMPACTION TEST REPORT**

ENG FORM 1 MAY 63 2091 PREVIOUS EDITIONS ARE OBSOLETE. *(TRANSLUCENT)* GPO : 1964 OF—715-176

Chart D-9



Standard COMPACTION TEST

56 BLOWS PER EACH OF 3 LAYERS, WITH 5.5 LB RAMMER AND

12.0 INCH DROP. 6.0 INCH DIAMETER MOLD

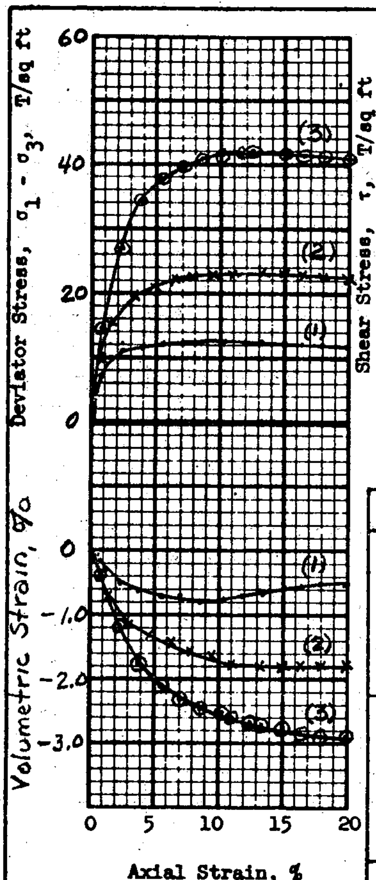
SAMPLE NO.	ELEV OR DEPTH	CLASSIFICATION	G	LL	PL	% > NO. 4	% > ¾ IN.
Composite No.1		Gr.Si. SAND (SM)	2.69			13.1	-

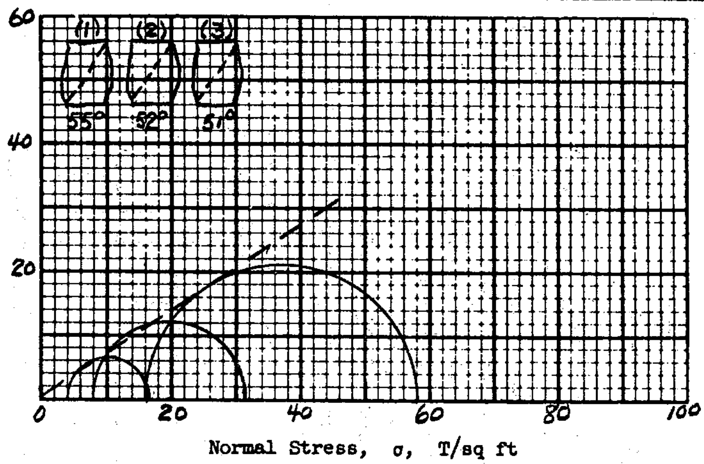
SAMPLE NO.	Composite No.1			
NATURAL WATER CONTENT IN PER CENT				
OPTIMUM WATER CONTENT IN PER CENT	7.5			
MAX DRY DENSITY IN LB/CU FT	133.3			

REMARKS	PROJECT WATANA DAM
AASHTO T-99	
Method D	AREA
	BORING NO. Composite No.1 DATE 14 NOV 1978
	NPD **COMPACTION TEST REPORT**

ENG FORM 1 MAY 63 **2091** PREVIOUS EDITIONS ARE OBSOLETE. *(TRANSLUCENT)* GPO : 1964 OF—715-175

Chart D-10





Shear Strength Parameters

ϕ = 33.5°

tan ϕ = 0.662

c = 0.66 T/sq ft

Method of saturation None

☐ Controlled stress

☒ Controlled strain

			1	2	3	
Test No.			1	2	3	
Initial	Water content	w_o	7.7 %	7.6 %	7.5 %	%
	Void ratio	e_o	0.329	0.326	0.326	
	Saturation	S_o	63 %	62 %	62 %	%
	Dry density, lb/cu ft	γ_d	126.3	126.5	126.6	
Before Shear	Water content	$w_{\sigma_{III}}$	7.7 %	7.3 %	7.3 %	%
	Void ratio	$e_{\sigma_{III}}$	0.317	0.312	0.309	
	Saturation	$S_{\sigma_{III}}$	65 %	65 %	65 %	%
	Final back pressure, T/sq ft	u_o				
Final	Water content	w_f	7.5 %	7.3 %	7.3 %	%
	Void ratio	e_f	0.307	0.289	0.274	
Minor principal stress, T/sq ft		σ_3	4.00	8.00	16.00	
Max deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{max}$	12.41	23.46	42.02	
Time to failure, min		t_f	26	35	32	
Rate of strain, percent/min			0.39	0.38	0.39	
Ult deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{ult}$	12.29	23.25	41.77	
Initial diameter, in.		D_o	5.87	5.87	5.87	
Initial height, in.		H_o	12.81	12.81	12.81	

Type of test Q | Type of specimen Remold

Classification Gr. Si. SAND (SM)

LL | PL | PI | | G_s 2.69

Remarks Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content (7.5%)

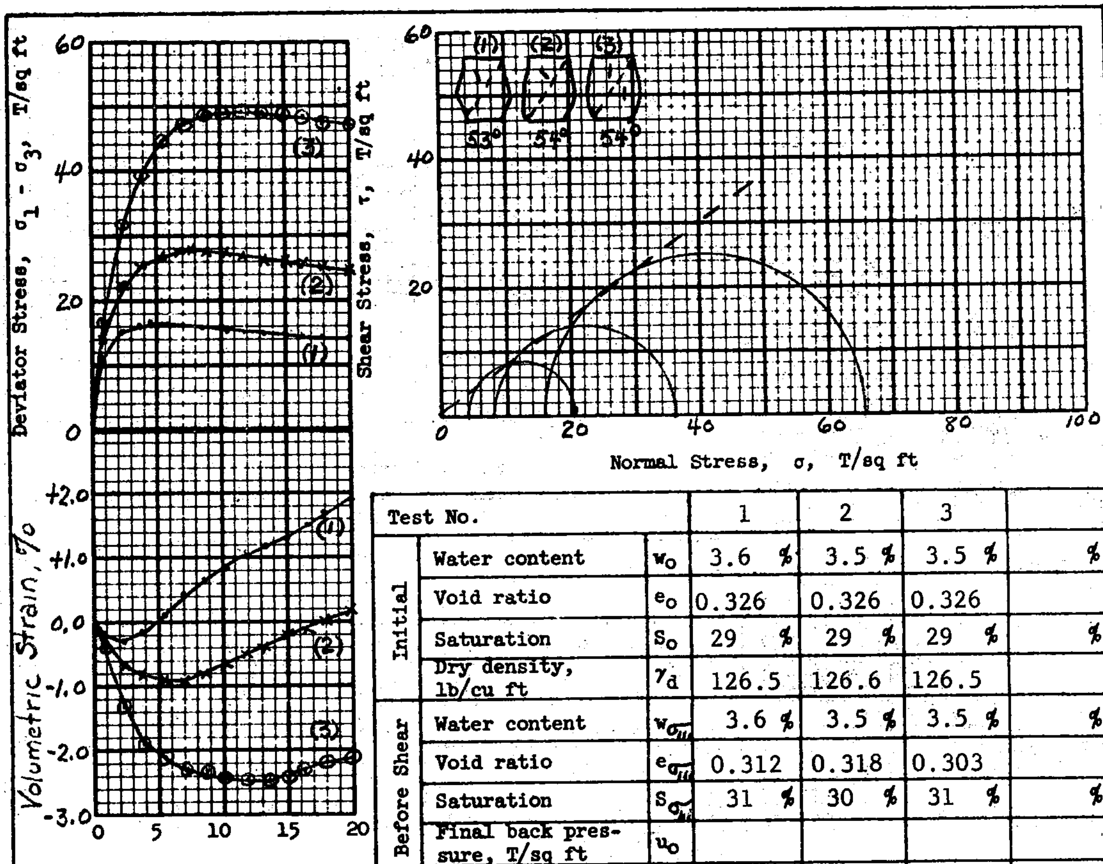
Project WATANA DAM

Area

Boring No. | Sample No. Composite No. 1

Depth El | Date 14 NOV 1978

NPD TRIAXIAL COMPRESSION TEST REPORT



Shear Strength Parameters

ϕ = 35.5 °

tan ϕ = 0.712

c = 0.14 T/sq ft

Method of saturation None

☐ Controlled stress

☒ Controlled strain

			1	2	3	
Test No.			1	2	3	
Initial	Water content	w_o	3.6 %	3.5 %	3.5 %	%
	Void ratio	e_o	0.326	0.326	0.326	
	Saturation	S_o	29 %	29 %	29 %	%
	Dry density, lb/cu ft	γ_d	126.5	126.6	126.5	
Before Shear	Water content	$w_{\sigma_{iii}}$	3.6 %	3.5 %	3.5 %	%
	Void ratio	$e_{\sigma_{iii}}$	0.312	0.318	0.303	
	Saturation	$S_{\sigma_{iii}}$	31 %	30 %	31 %	%
	Final back pressure, T/sq ft	u_o				
Final	Water content	w_f	3.4 %	3.4 %	3.4 %	%
	Void ratio	e_f	0.312	0.307	0.272	
Minor principal stress, T/sq ft		σ_3	4.00	8.00	16.00	
Max deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{max}$	16.49	28.10	49.64	
Time to failure, min		t_f	11	21	30	
Rate of strain, percent/min			0.43	0.37	0.39	
Ult deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{ult}$	14.95	26.25	48.72	
Initial diameter, in.		D_o	5.87	5.87	5.87	
Initial height, in.		H_o	12.81	12.81	12.81	

Type of test Q | Type of specimen Remold

Classification Gr. Si. SAND (SM)

LL | PL | PI | | G_s 2.69

Remarks Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content minus 4% (3.5%)

Project WATANA DAM

Area

Boring No. | Sample No. Composite No.1

Depth El | Date 14 NOV 1978

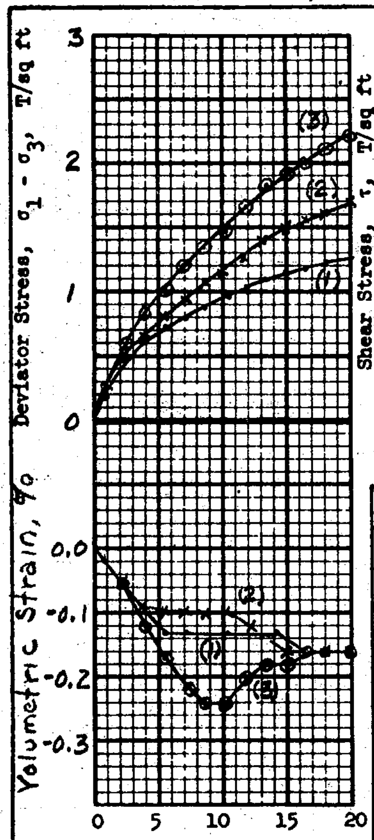
NPD TRIAXIAL COMPRESSION TEST REPORT

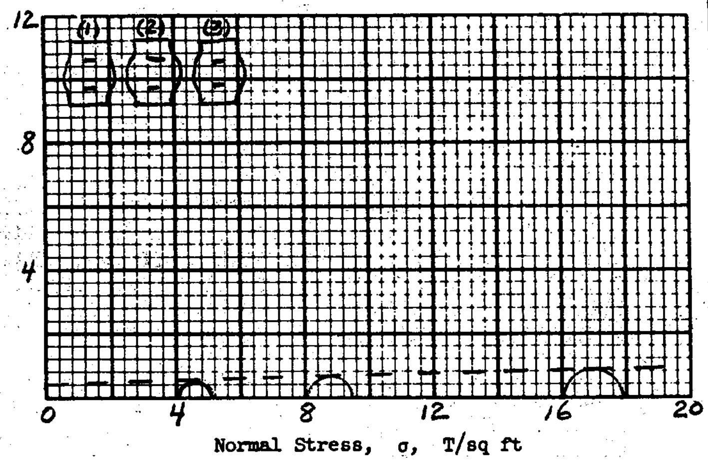
A 2 3 5 6 2

ENG FORM 1 JUN 65 2089 *(EM 1110-2-1902)* PREVIOUS EDITIONS ARE OBSOLETE

Chart D-12

TRANSLUCENT





Shear Strength Parameters

ϕ = 1.75 °

tan ϕ = 0.0307

c = 0.44 T/sq ft

Method of saturation None

☐ Controlled stress

☒ Controlled strain

Test No.			1	2	3	
Initial	Water content	w_o	11.2 %	11.2 %	11.2 %	%
	Void ratio	e_o	0.326	0.328	0.326	
	Saturation	S_o	92 %	92 %	92 %	%
	Dry density, lb/cu ft	γ_d	126.1	126.4	126.6	
Before Shear	Water content	w_{c}	11.2 %	11.2 %	11.2 %	%
	Void ratio	e_{c}	0.302	0.304	0.303	
	Saturation	S_{c}	100 %	99 %	99 %	%
	Final back pressure, T/sq ft	u_o				
Final	Water content	w_f	11.2 %	11.2 %	11.2 %	%
	Void ratio	e_f	0.301	0.302	0.301	
Minor principal stress, T/sq ft		σ_3	4.00	8.00	16.00	
Max deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{max}$	1.15	1.50	1.91	
Time to failure, min		t_f	38	38	38	
Rate of strain, percent/min			0.39	0.39	0.39	
Ult deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{ult}$	1.15	1.50	1.91	
Initial diameter, in.		D_o	5.87	5.87	5.87	
Initial height, in.		H_o	12.81	12.81	12.81	

Type of test Q	Type of specimen Remold			
Classification Gr. Si. SAND (SM)				
LL	PL	PI		G_s 2.69

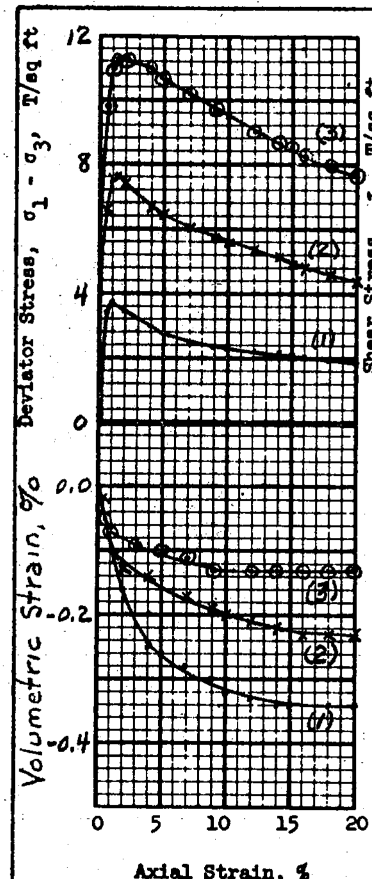
Remarks Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content plus 4% (11.5%) Lost water during compaction

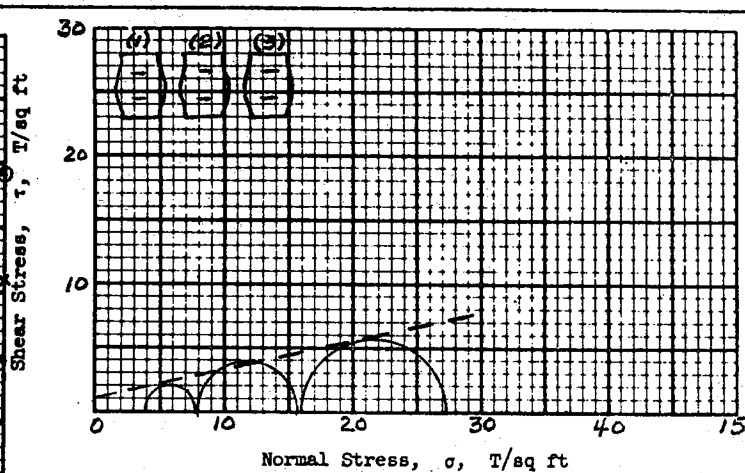
Project WATANA DAM	
Area	
Boring No.	Sample No. Composite No. 1
Depth El	Date 14 NOV 1978
NPD TRIAXIAL COMPRESSION TEST REPORT	

ENG FORM 1 JUN 65 2089 (EM 1110-2-1902) PREVIOUS EDITIONS ARE OBSOLETE TRANSLUCENT

Chart D-13

A 2 3 5 6 2





Test No.			1	2	3	
Initial	Water content	w_o	7.5 %	7.9 %	7.8 %	%
	Void ratio	e_o	0.326	0.331	0.331	
	Saturation	S_o	62 %	64 %	64 %	%
	Dry density, lb/cu ft	γ_d	126.6	126.1	126.2	
Before Shear	Water content	w_c	11.2 %	11.1 %	10.8 %	%
	Void ratio	e_c	0.303	0.300	0.291	
	Saturation	S_c	100 %	100 %	100 %	%
	Final back pressure, T/sq ft	u_o	5.04	7.20	5.04	
Final	Water content	w_f	11.2 %	11.1 %	10.8 %	%
	Void ratio	e_f	0.302	0.298	0.290	
Minor principal stress, T/sq ft		σ_3	4.00	8.00	16.00	
Max deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{max}$	3.84	7.59	11.28	
Time to failure, min		t_f	10	18	19	
Rate of strain, percent/min			0.10	0.08	0.08	
Ult deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{ult}$	2.13	4.92	8.49	
Initial diameter, in.		D_o	5.87	5.87	5.87	
Initial height, in.		H_o	12.81	12.81	12.81	

Shear Strength Parameters

ϕ = 12.3 °

tan ϕ = 0.218

c = 1.07 T/sq ft

Method of saturation Back Pressure

☐ Controlled stress

☒ Controlled strain

Type of test R	Type of specimen Remold		
Classification	Gr. Si. SAND (SM)		
LL	PL	PI	G_s 2.69

Remarks Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content (7.5%).

Project WATANA DAM	
Area	
Boring No.	Sample No. Composite No.1
Depth El	Date 14 NOV 1978
NPD	TRIAXIAL COMPRESSION TEST REPORT

NPDEN-GS-L (79-S-404) WATANA DAM 14 NOV 1978

Composite No. 1

"$\bar{R}$" Triaxial Back Pressure & Pore Pressure Test Data

Test Specimens Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content (7.5%).

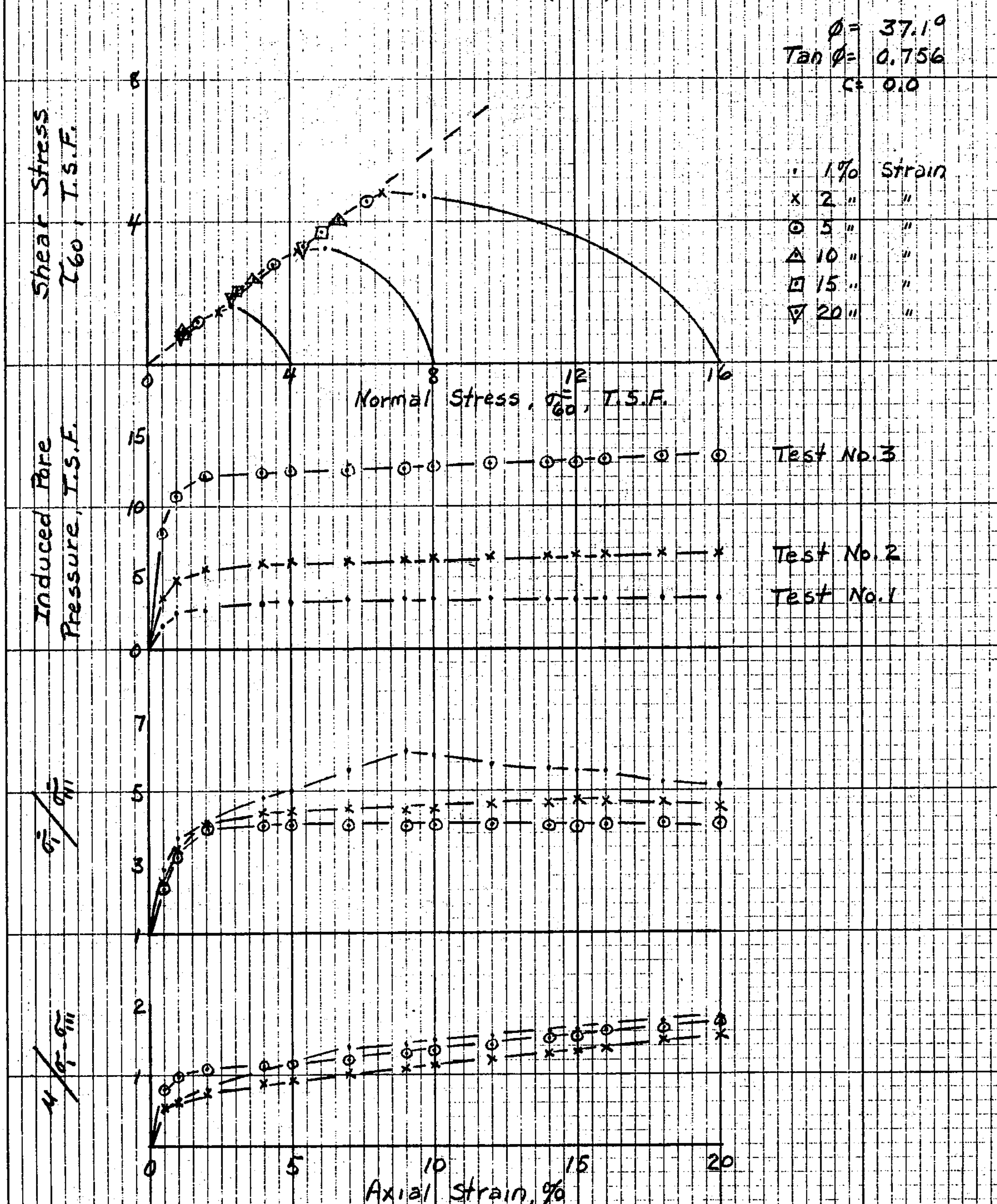
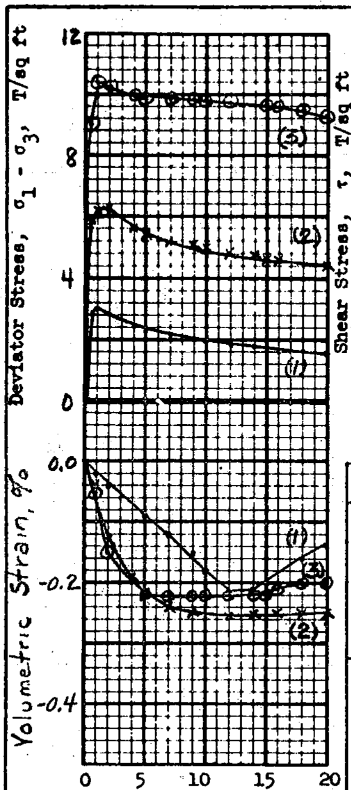
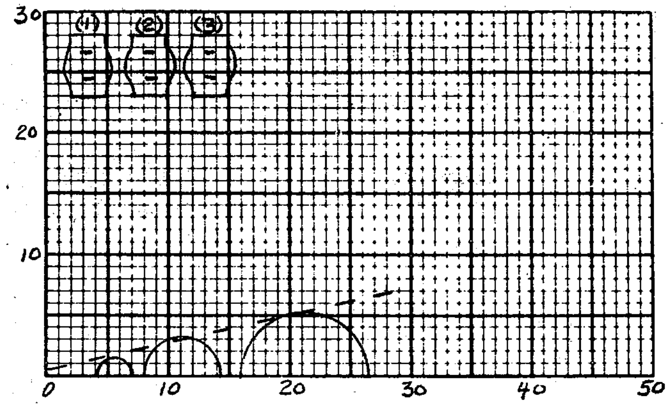


Chart D-15





Test No.			1	2	3	
Initial	Water content	w_o	3.9 %	3.9 %	3.9 %	%
	Void ratio	e_o	0.330	0.330	0.331	
	Saturation	S_o	31 %	31 %	32 %	%
	Dry density, lb/cu ft	γ_d	126.2	126.2	126.1	
Before Shear	Water content	w_c	11.7 %	11.0 %	10.5%	%
	Void ratio	e_c	0.314	0.298	0.282	
	Saturation	S_c	100 %	100 %	100 %	%
	Final back pressure, T/sq ft	u_o	5.76	5.76	5.76	
Final	Water content	w_f	11.7 %	11.0 %	10.5%	%
	Void ratio	e_f	0.313	0.297	0.282	
Minor principal stress, T/sq ft		σ_3	4.00	8.00	16.00	
Max deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{max}$	3.08	6.21	10.45	
Time to failure, min		t_f	12	19	12	
Rate of strain, percent/min			0.08	0.08	0.08	
Ult deviator stress, T/sq ft		$(\sigma_1-\sigma_3)_{ult}$	1.75	4.72	9.66	
Initial diameter, in.		D_o	5.87	5.87	5.87	
Initial height, in.		H_o	12.81	12.81	12.81	

Shear Strength Parameters

ϕ = 12.8 °

tan ϕ = 0.228

c = 0.52 T/sq ft

Method of saturation Back Pressure

☐ Controlled stress

☒ Controlled strain

Type of test R	Type of specimen Remold		
Classification Gr. Si. SAND (SM)			
LL	PL	PI	G_s 2.69

Remarks Remolded at 95 % Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content minus 4 % (3.5 %).

Project WATANA DAM	
Area	
Boring No.	Sample No. Composite No.1
Depth El	Date 20 NOV 1978
NPD TRIAXIAL COMPRESSION TEST REPORT	

ENG FORM 1 JUN 65 2089 *(EM 1110-2-1902)* PREVIOUS EDITIONS ARE OBSOLETE *TRANSLUCENT*

Chart D-16

NPDEN-GS-L (79-S-404)

WATANA DAM

Composite No. 1

"R" Triaxial Back Pressure & Pore Pressure Test Data

Test Specimens Remolded at 95% Standard Compaction Density (126.6 P.C.F.) and Optimum Water Content minus 4% (3.5%)

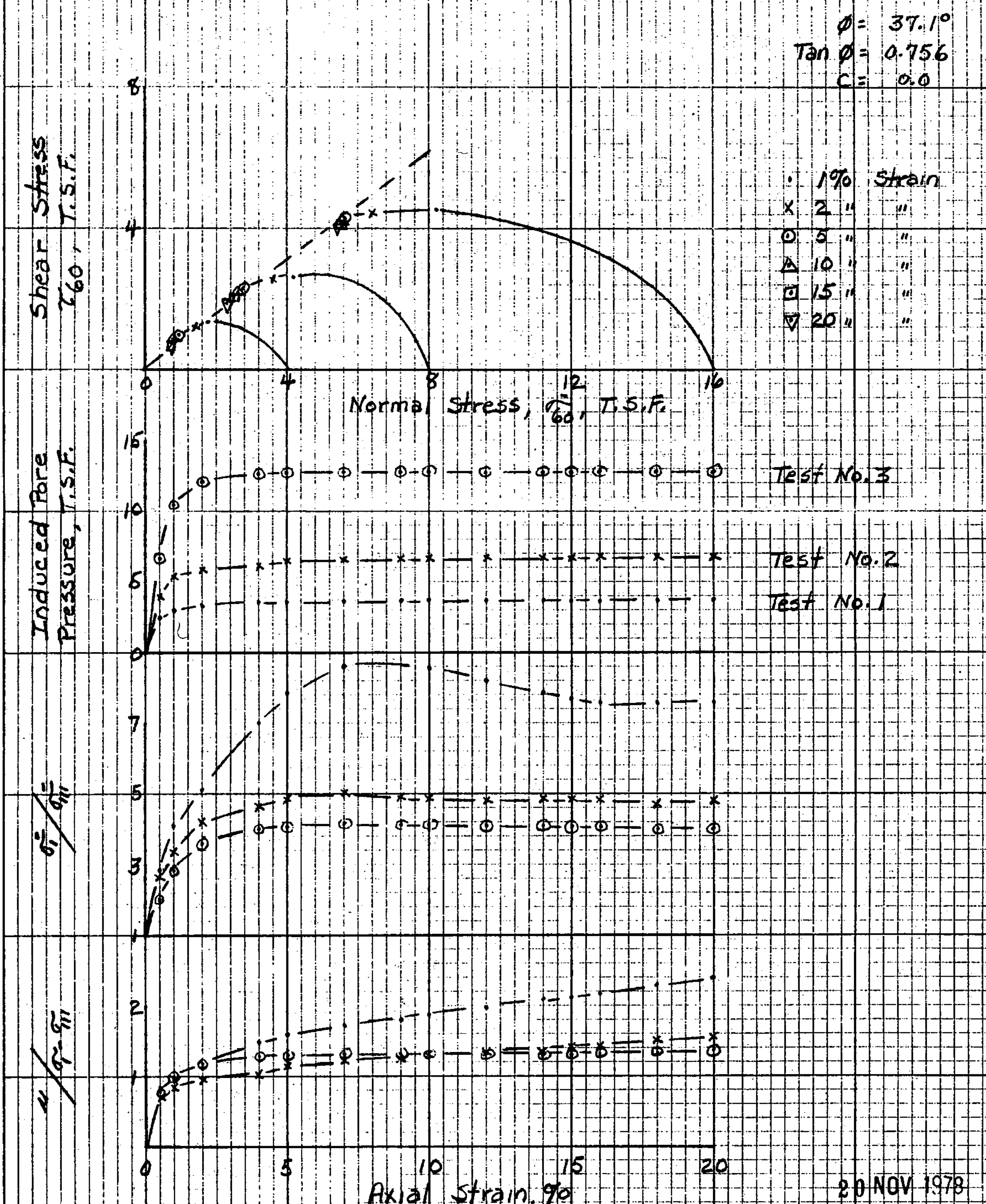
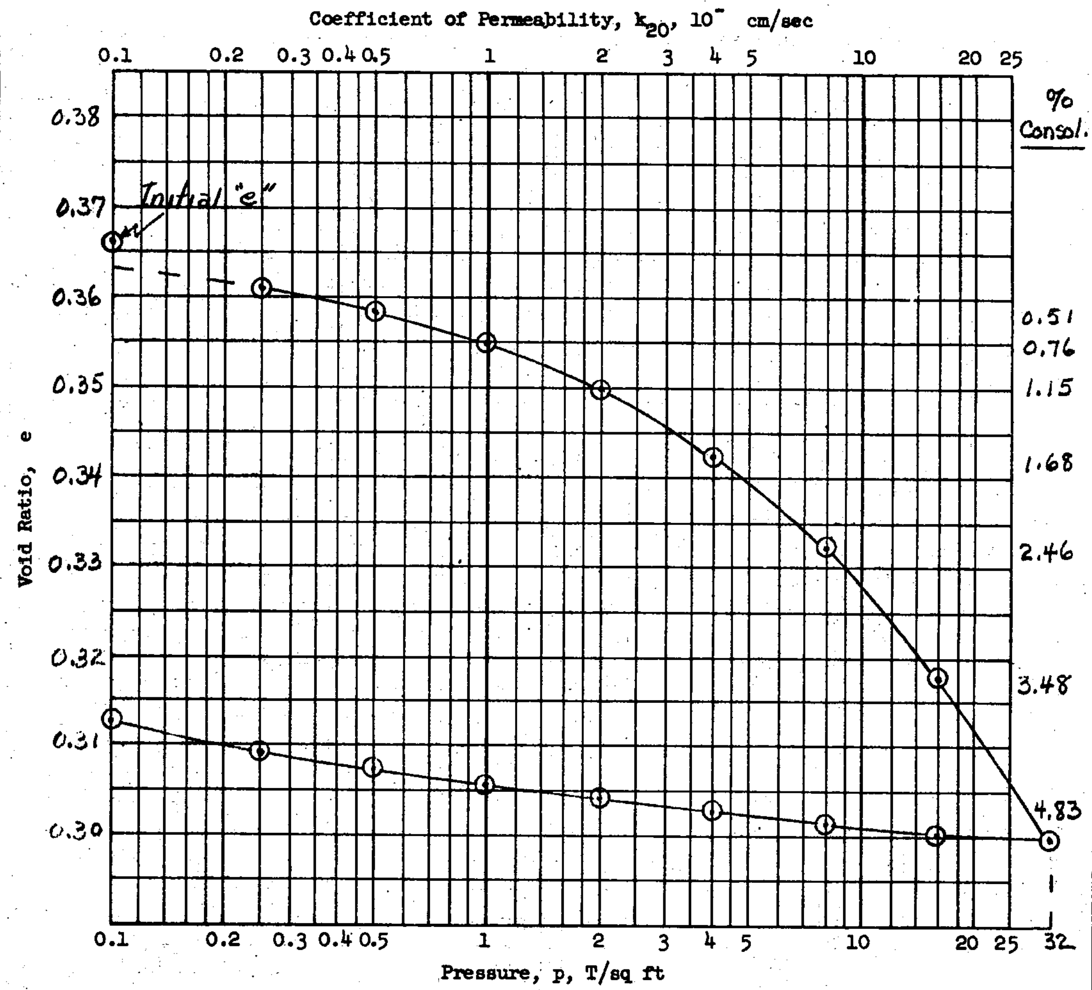


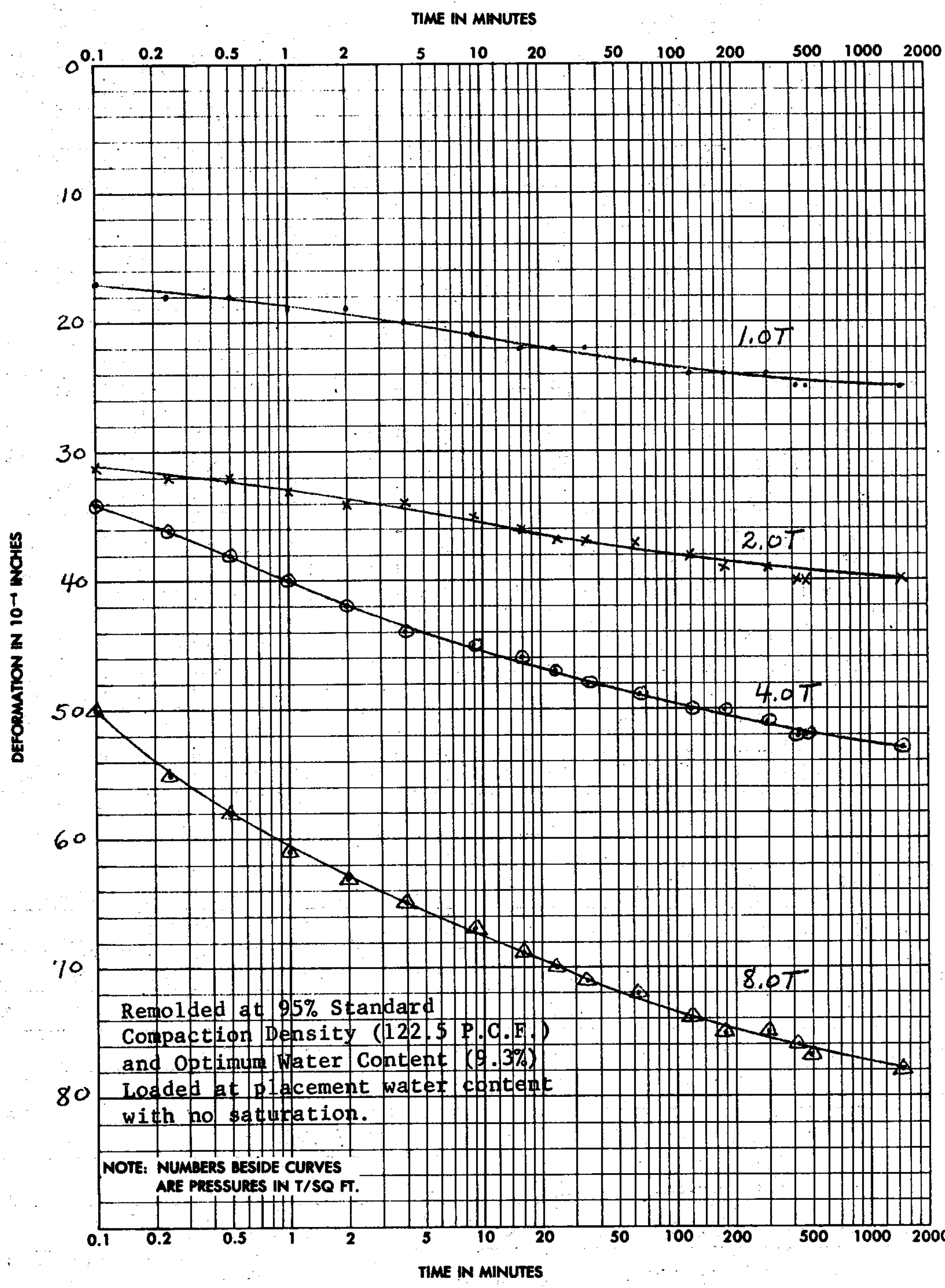
Chart D-17



Type of Specimen	Remold	Before Test		After Test	
Diam 4.445 in.	Ht 1.005 in.	Water Content, w_o	9.3 %	w_f	9.2 %
Overburden Pressure, p_o T/sq ft		Void Ratio, e_o	0.366	e_f	0.313
Preconsol. Pressure, p_c T/sq ft		Saturation, S_o	68 %	S_f	79 %
Compression Index, C_c	0.06	Dry Density, γ_d	122.5 lb/ft^3		127.4
Classification Si. SAND (SM)		k_{20} at e_o = $\times 10^{-}$ cm/sec			
LL	G_s 2.68	Project WATANA DAM			
PL	D_{10}				
Remarks Remolded at 95% Standard		Area			
Compaction Density (122.5 P.C.F.)		Boring No.		Sample No. Composite No.1	
and Optimum Water Content (9.3%)		Depth El		Date 14 NOV 1978	
Loaded at placement water content with no saturation		NPD CONSOLIDATION TEST REPORT			

ENG FORM 1 MAY 63 2090 PREVIOUS EDITIONS ARE OBSOLETE. (TRANSLUCENT) G 3424

Chart D-18



PROJECT WATANA DAM

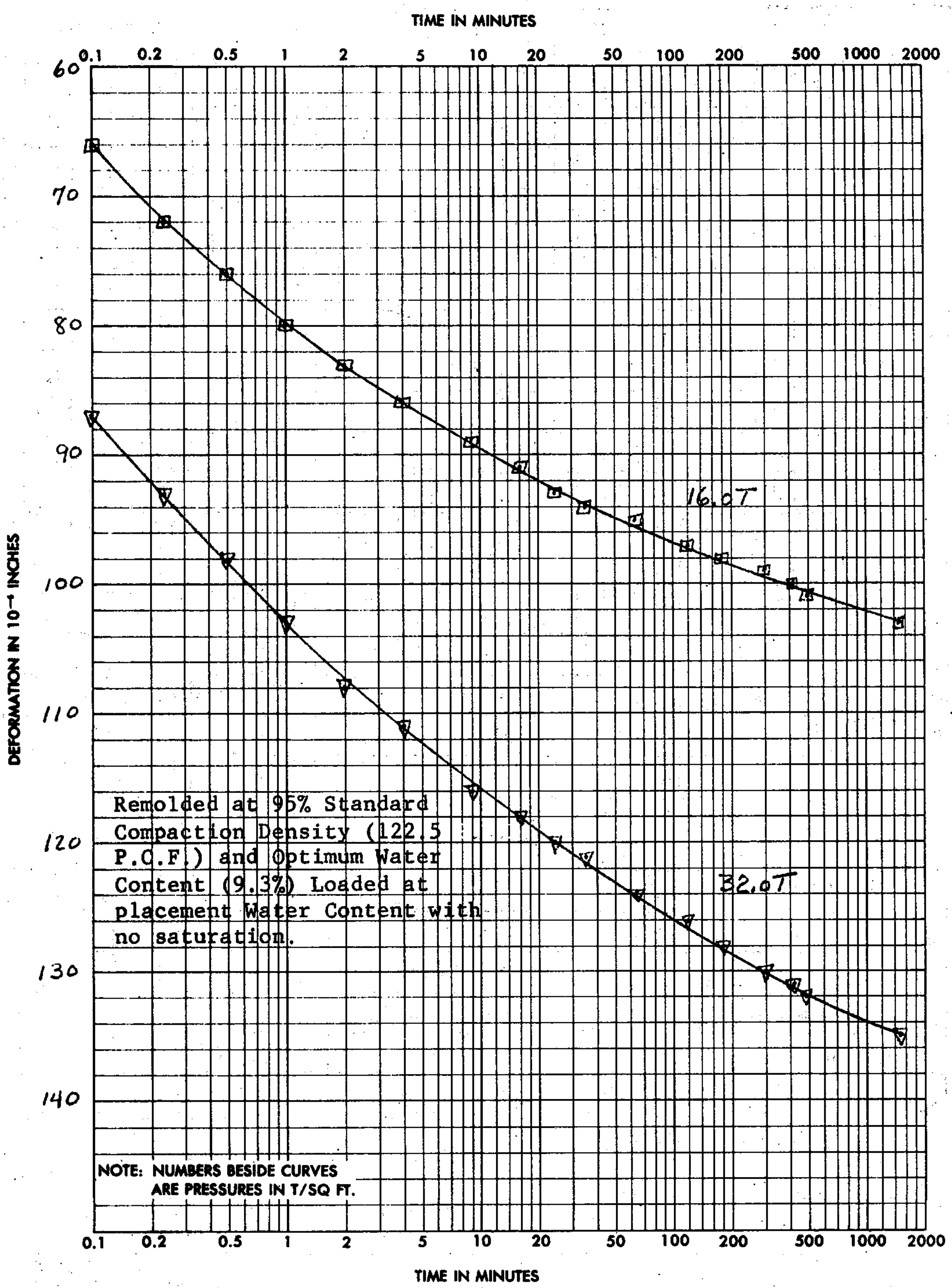
AREA

BORING NO. | SAMPLE NO. Composite No.1 | DEPTH EL | DATE 14 NOV 1978

ENG FORM 2088 1 MAY 63 PREVIOUS EDITIONS ARE OBSOLETE. NPD **CONSOLIDATION TEST—TIME CURVES** (TRANSLUCENT)

★ GPO : 1964 OF—715-965

Chart D-19

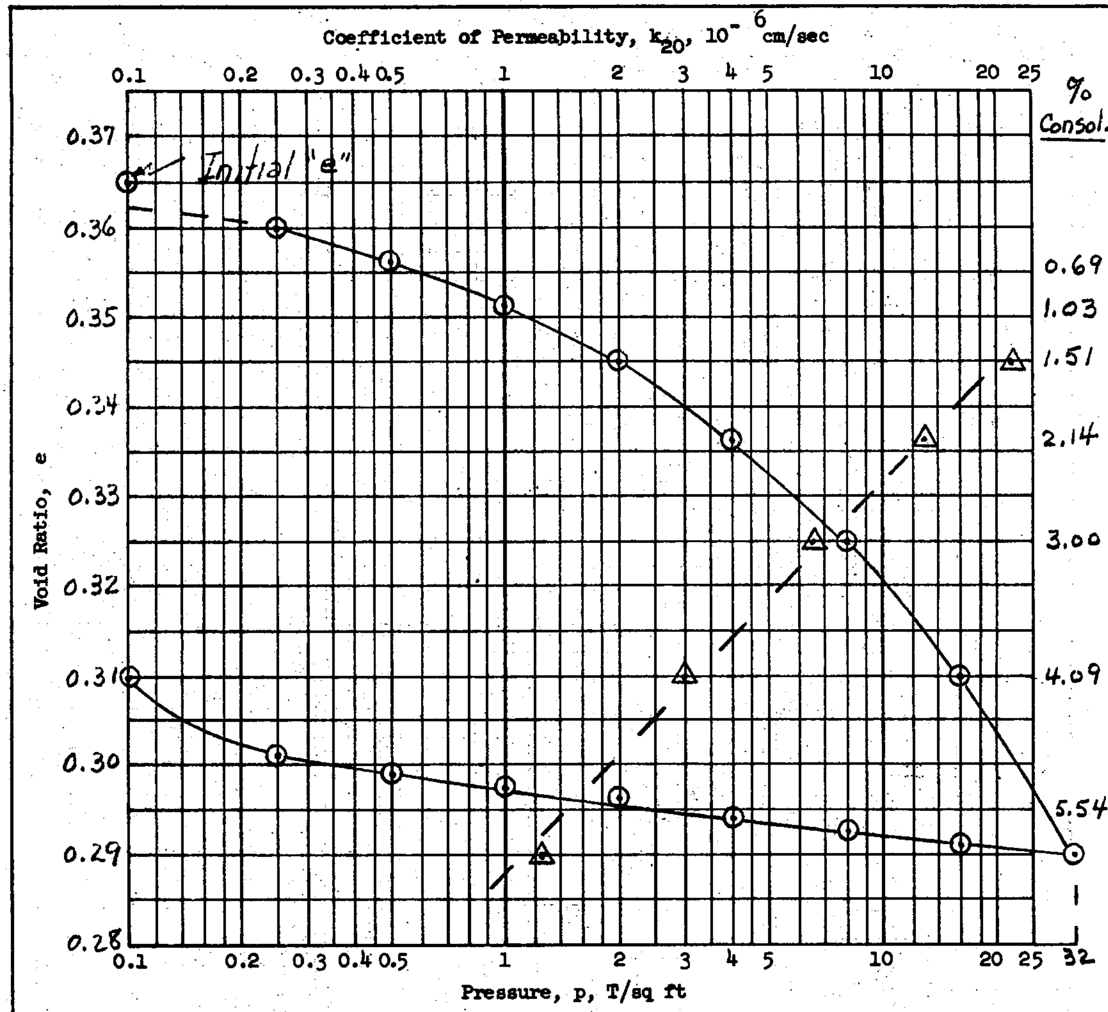


PROJECT WATANA DAM			
AREA			
BORING NO.	SAMPLE NO. Composite No.1	DEPTH EL	DATE 14 NOV 1978

ENG FORM 2088 1 MAY 63 PREVIOUS EDITIONS ARE OBSOLETE. NPD **CONSOLIDATION TEST—TIME CURVES** (TRANSLUCENT)

★ GPO : 1964 OF—715-965

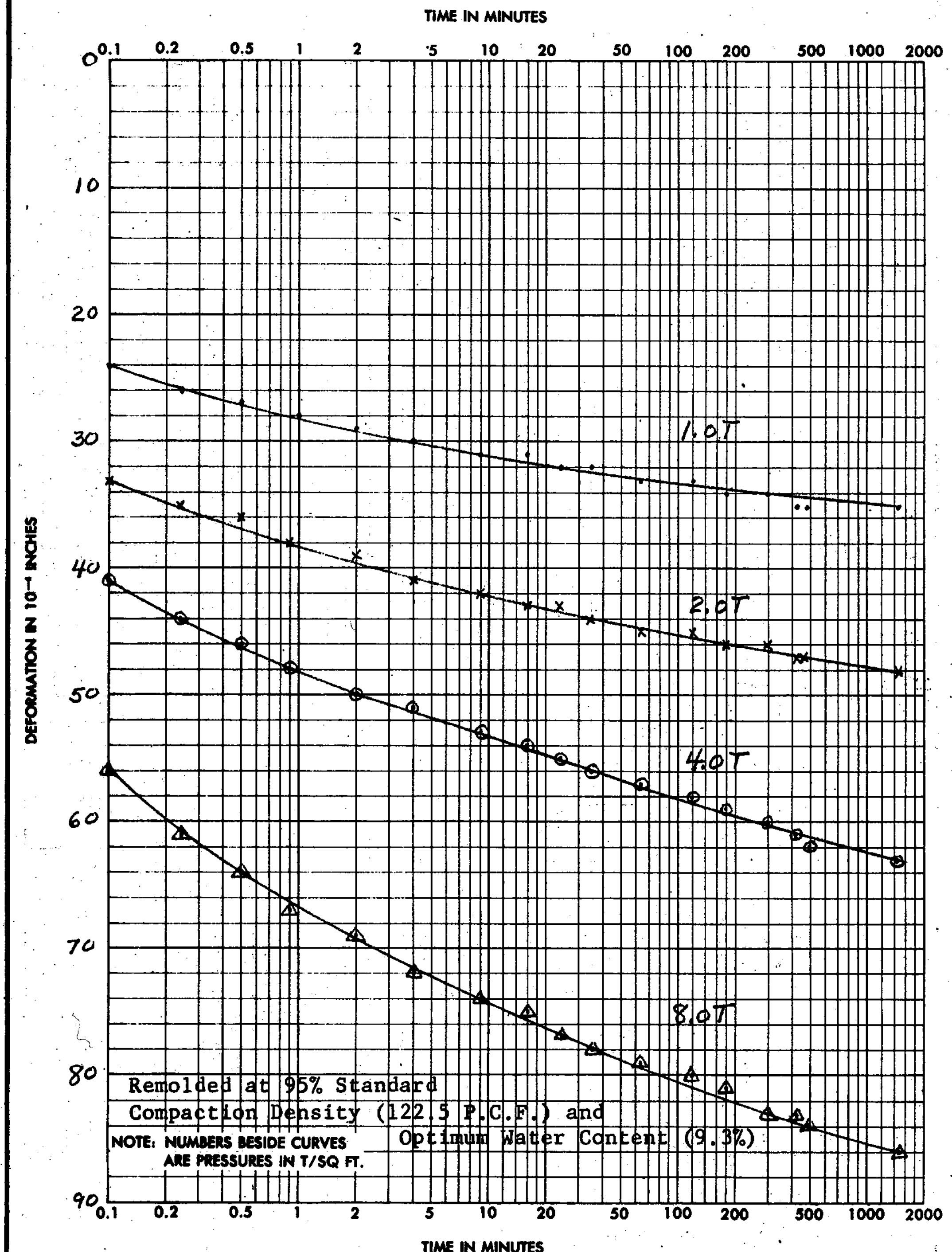
Chart D-20



Type of Specimen Remold		Before Test		After Test	
Diam 4.444 in.	Ht 1.005 in.	Water Content, w_o	9.3 %	w_f	11.8 %
Overburden Pressure, p_o T/sq ft		Void Ratio, e_o	0.365	e_f	0.310
Preconsol. Pressure, p_c T/sq ft		Saturation, S_o	68 %	S_f	100 %
Compression Index, C_c 0.06		Dry Density, γ_d	122.5 lb/ft^3		127.6
Classification Si. SAND (SM)		k_{20} at e_o = × 10^{-} cm/sec			
LL	G_s 2.68	Project WATANA DAM			
PL	D_{10}				
Remarks Remolded at 95%		Area			
Standard Compaction Density		Boring No.		Sample No. Composite No.1	
(122.5 P.C.F.) and Optimum		Depth El		Date 14 NOV 1978	
Water Content (9.3%)		NPD **CONSOLIDATION TEST REPORT**			

ENG FORM 1 MAY 63 2090 PREVIOUS EDITIONS ARE OBSOLETE. (TRANSLUCENT)

Chart D-21 0 3 4 2 4



PROJECT WATANA DAM

AREA

BORING NO.

SAMPLE NO. Composite No. 1

DEPTH EL

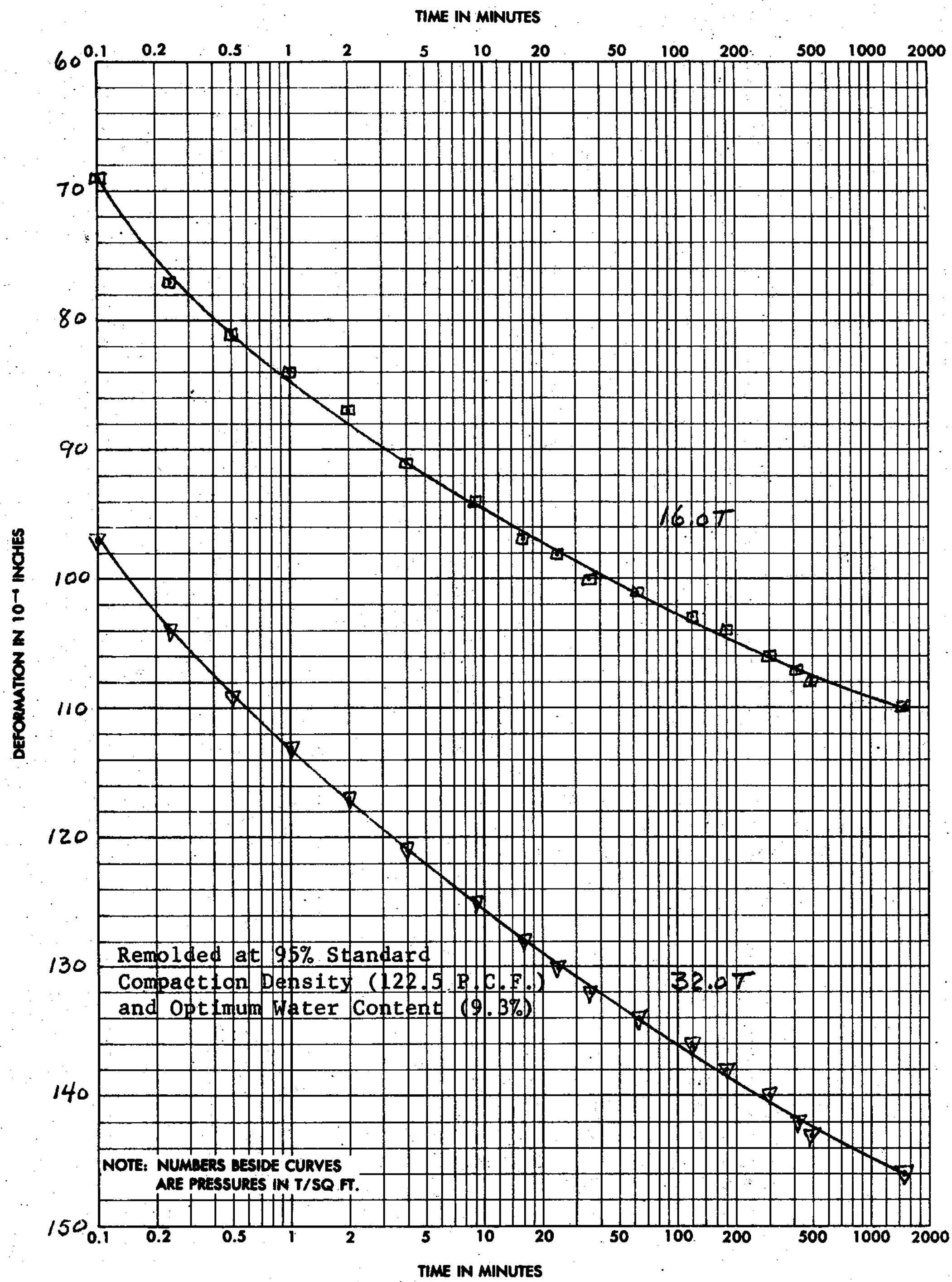
DATE 14 NOV 1978

ENG FORM 2088 1 MAY 63 PREVIOUS EDITIONS ARE OBSOLETE. NPD CONSOLIDATION TEST—TIME CURVES (TRANSLUCENT)

* GPO : 1964 OF—715-985

Chart D-22

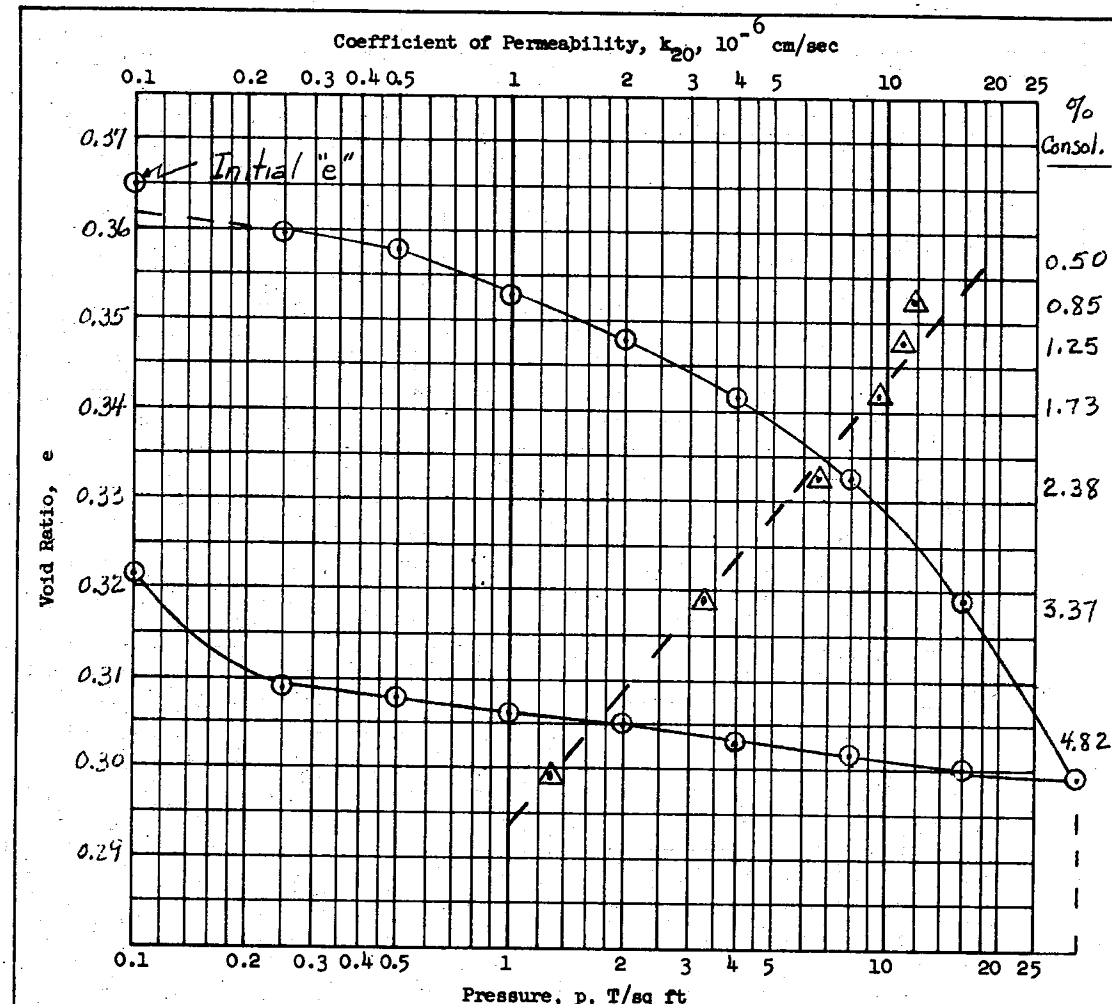
SHEET NO. 2



PROJECT WATANA DAM			
AREA			
BORING NO.	SAMPLE NO. Composite No. 1	DEPTH EL	DATE 14 NOV 1978
ENG FORM 2088 1 MAY 63	PREVIOUS EDITIONS ARE OBSOLETE.	NPD CONSOLIDATION TEST—TIME CURVES	(TRANSLUCENT)

* GPO : 1964 OF—715-965

Chart D-23



Type of Specimen Remold		Before Test		After Test	
Diam 4.445 in.	Ht 1.006 in.	Water Content, w_o	5.3 %	w_f	12.0 %
Overburden Pressure, p_o T/sq ft		Void Ratio, e_o	0.365	e_f	0.321
Preconsol. Pressure, p_c T/sq ft		Saturation, S_o	39 %	S_f	100 %
Compression Index, C_c 0.10		Dry Density, γ_d	122.5 lb/ft^3		126.6
Classification Si. SAND (SM)		k_{20} at e_o = × 10⁻ cm/sec			
LL	G_s 2.68	Project WATANA DAM			
PL	D_{10}				

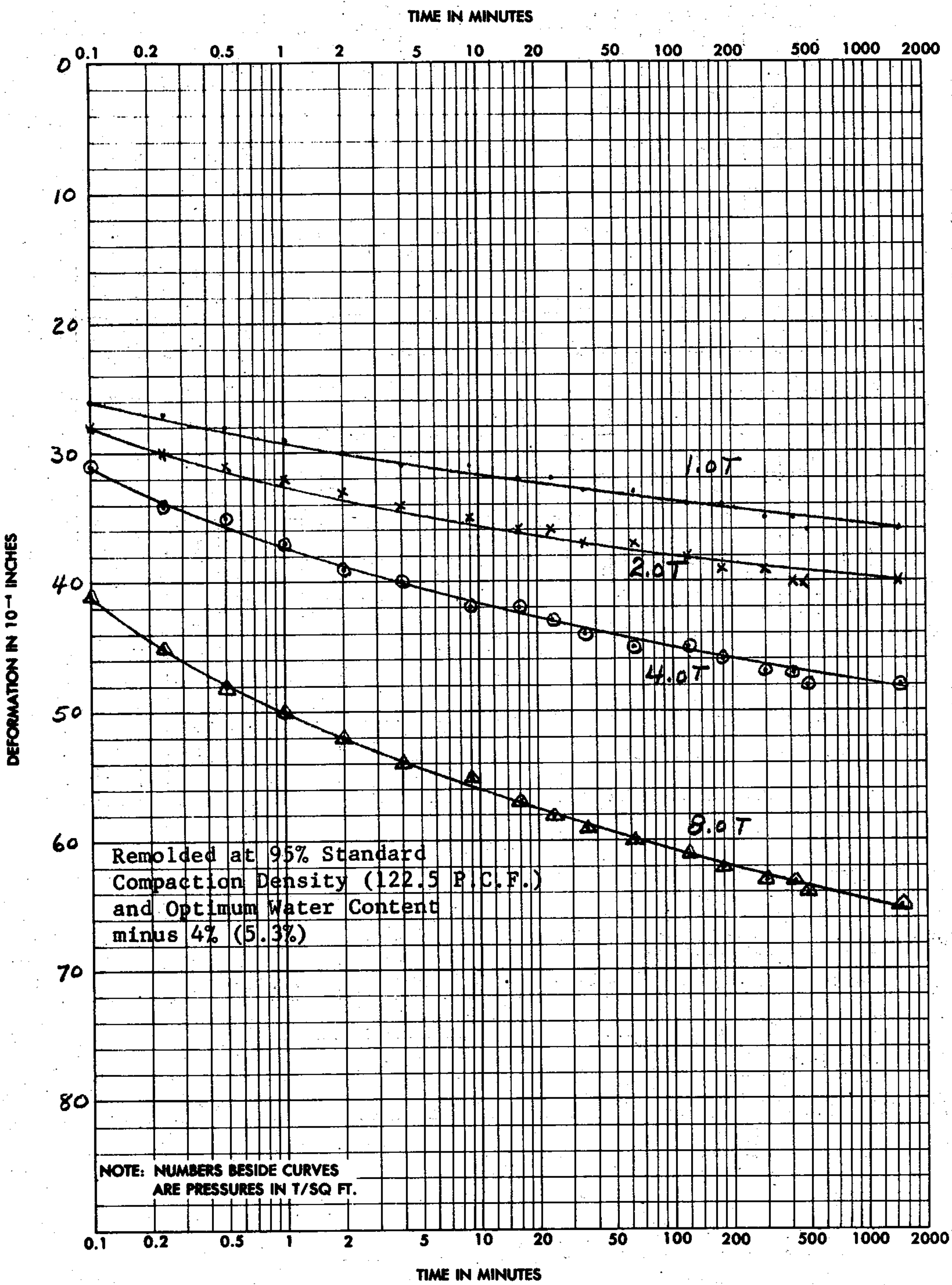
Remarks Remolded at 95%	Area
Standard Compaction Density	Boring No. / Sample No. Composite No.1
(122.5 P.C.F.) and Optimum	Depth El / Date 14 NOV 1978
Water Content minus 4% (5.3%)	NPE CONSOLIDATION TEST REPORT

ENG FORM 1 MAY 63 2090 PREVIOUS EDITIONS ARE OBSOLETE. *(TRANSLUCENT)*

0 3424

Chart D-24

SHEET NO. 1

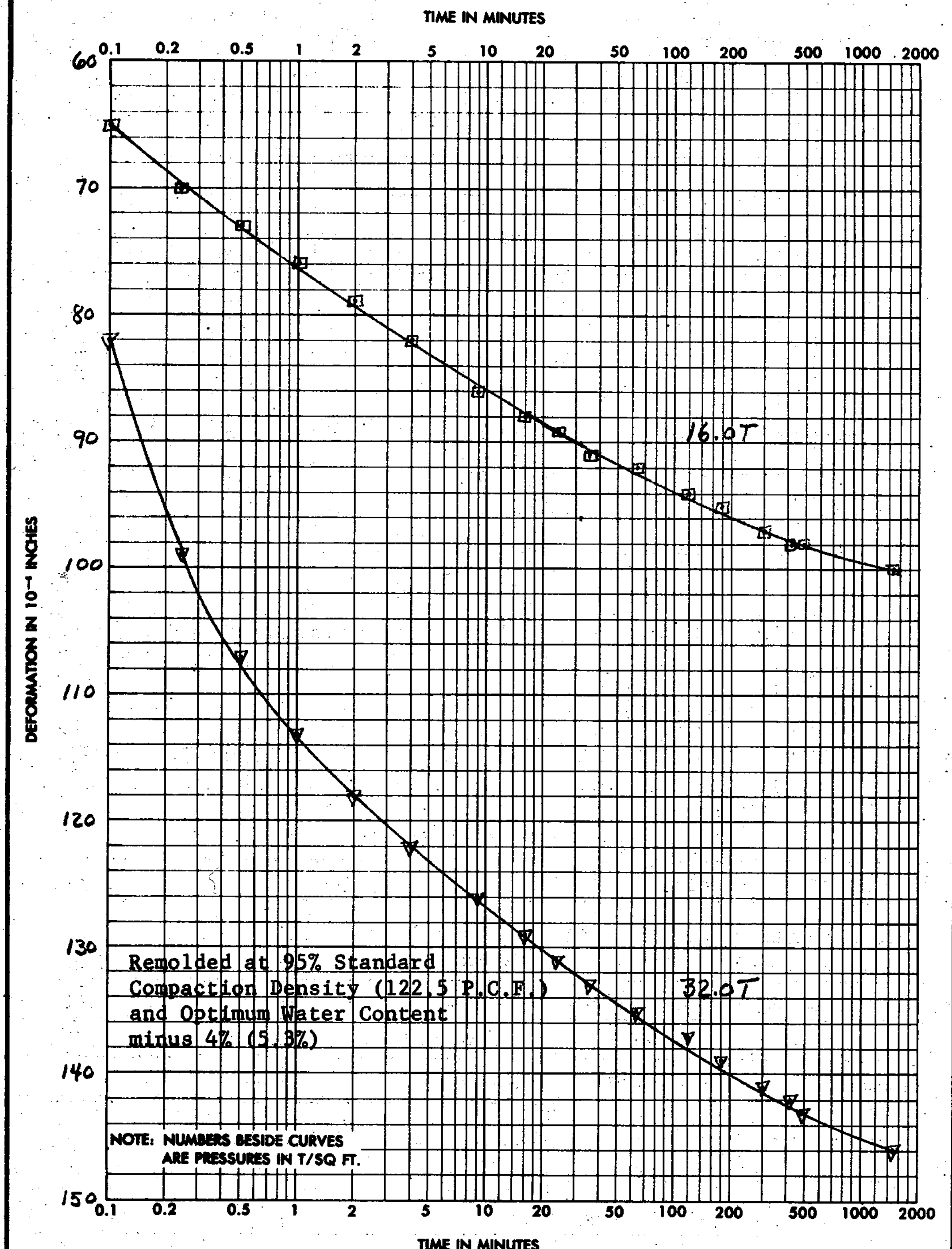


PROJECT WATANA DAM			
AREA			
BORING NO.	Composite No. 1 SAMPLE NO.	DEPTH EL	DATE 14 NOV 1978

ENG FORM 1 MAY 63 2088 PREVIOUS EDITIONS ARE OBSOLETE. NPI CONSOLIDATION TEST—TIME CURVES (TRANSLUCENT)

★ GPO : 1964 OF—715-965

Chart D-25



PROJECT WATANA DAM

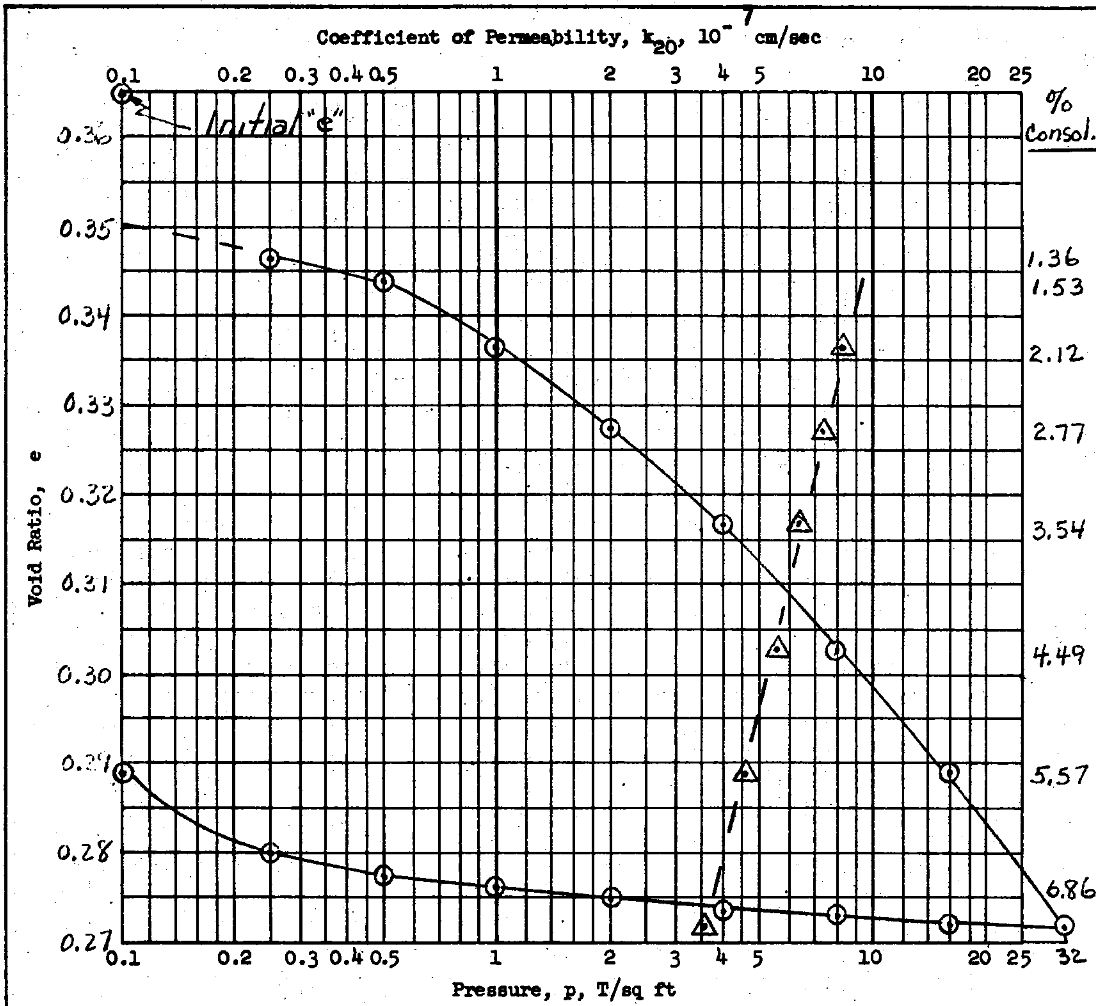
AREA

BORING NO. | SAMPLE NO. Composite No. 1 | DEPTH EL | DATE 14 NOV 1978

ENG FORM 2088 1 MAY 63 PREVIOUS EDITIONS ARE OBSOLETE. NPD **CONSOLIDATION TEST—TIME CURVES** (TRANSLUCENT)

★ GPO : 1964 OF—715-965

Chart D-26



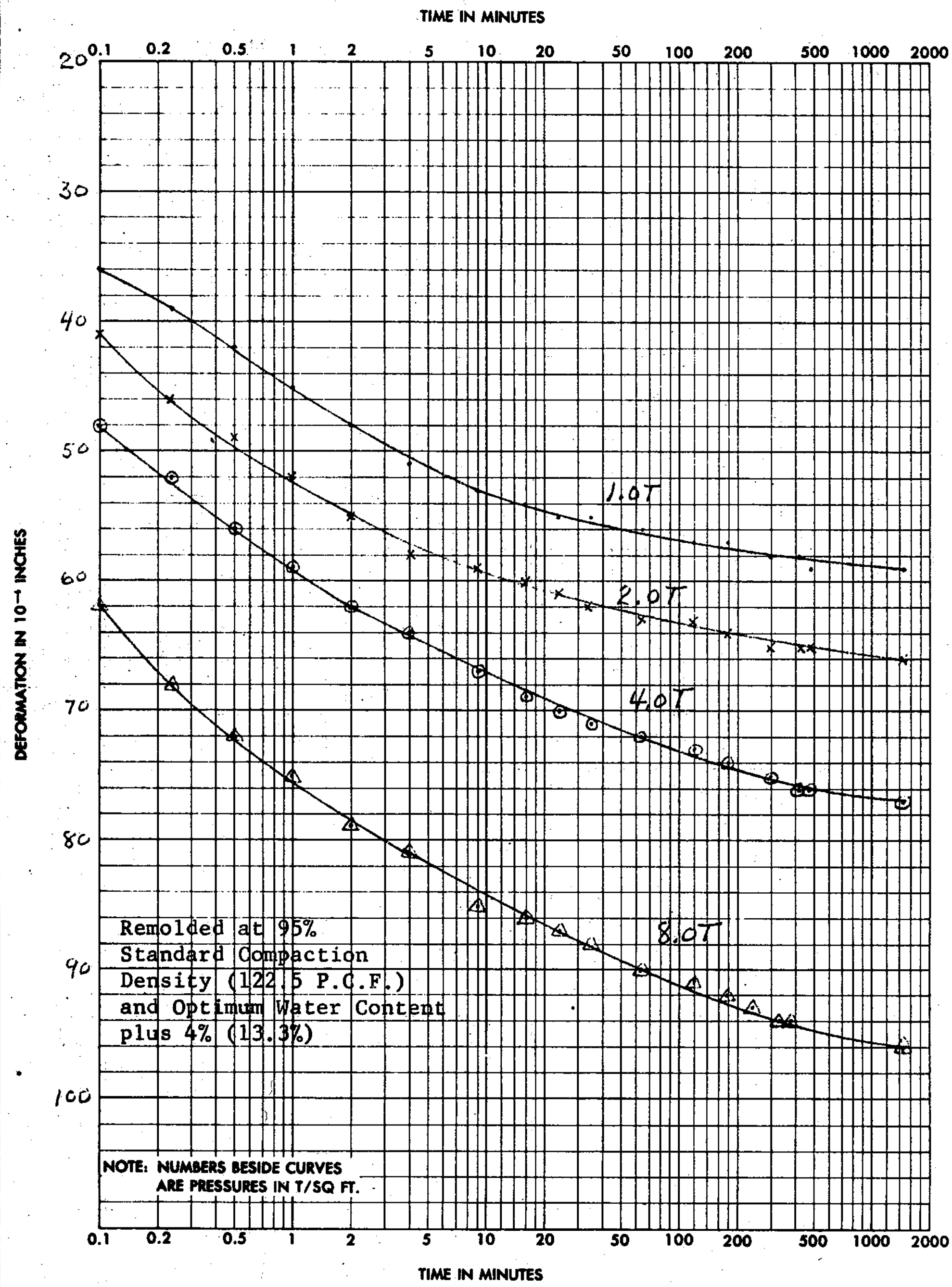
Type of Specimen	Remold			Before Test		After Test	
Diam 4.445 in.		Ht 1.006 in.		Water Content, w_o	13.3 %	w_f	10.9 %
Overburden Pressure, p_o			T/sq ft	Void Ratio, e_o	0.365	e_f	0.289
Preconsol. Pressure, p_c			T/sq ft	Saturation, S_o	98 %	S_f	100 %
Compression Index, C_c	0.06			Dry Density, γ_d	122.5 lb/ft^3		129.8
Classification	Si. SAND (SM)			k_{20} at e_o =	× 10^{-} cm/sec		

LL	G_s 2.68	Project	WATANA DAM
PL	D_{10}		
Remarks Remolded at 95% Standard		Area	
Compaction Density (122.5 P.C.F.)		Boring No.	Sample No. Composite No.1
and Optimum Water Content plus		Depth El	Date 14 NOV 1978
4% (13.3%)		NPD CONSOLIDATION TEST REPORT	

ENG FORM 1 MAY 63 2090 PREVIOUS EDITIONS ARE OBSOLETE. (TRANSLUCENT)

0 3424

Chart D-27



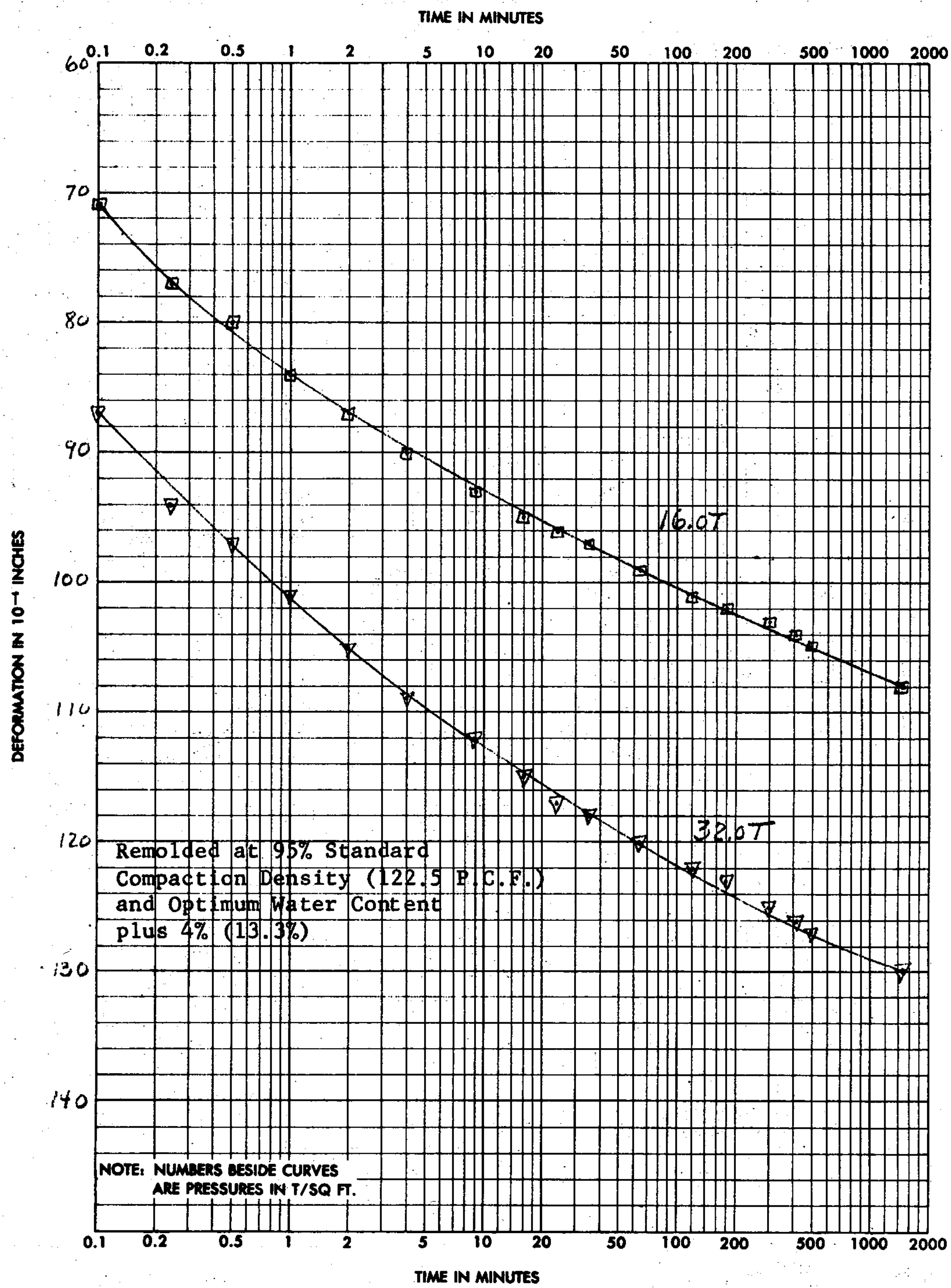
PROJECT WATANA DAM			
AREA			
BORING NO.	SAMPLE NO. Compsosite No.1	DEPTH EL	DATE 14 NOV 1978

ENG FORM 1 MAY 63 2088 PREVIOUS EDITIONS ARE OBSOLETE. NPD **CONSOLIDATION TEST—TIME CURVES** (TRANSLUCENT)

★ GPO : 1964 OF—715-965

Chart D-28

69-738 O - 80 - 42



PROJECT WATANA DAM

AREA

BORING NO. | SAMPLE NO. Composite No. 1 | DEPTH EL | DATE 14 NOV 1978

ENG FORM 2088 1 MAY 63 PREVIOUS EDITIONS ARE OBSOLETE. NPD CONSOLIDATION TEST—TIME CURVES (TRANSLUCENT)

★ GPO : 1964 OF—715-965

Chart D-29

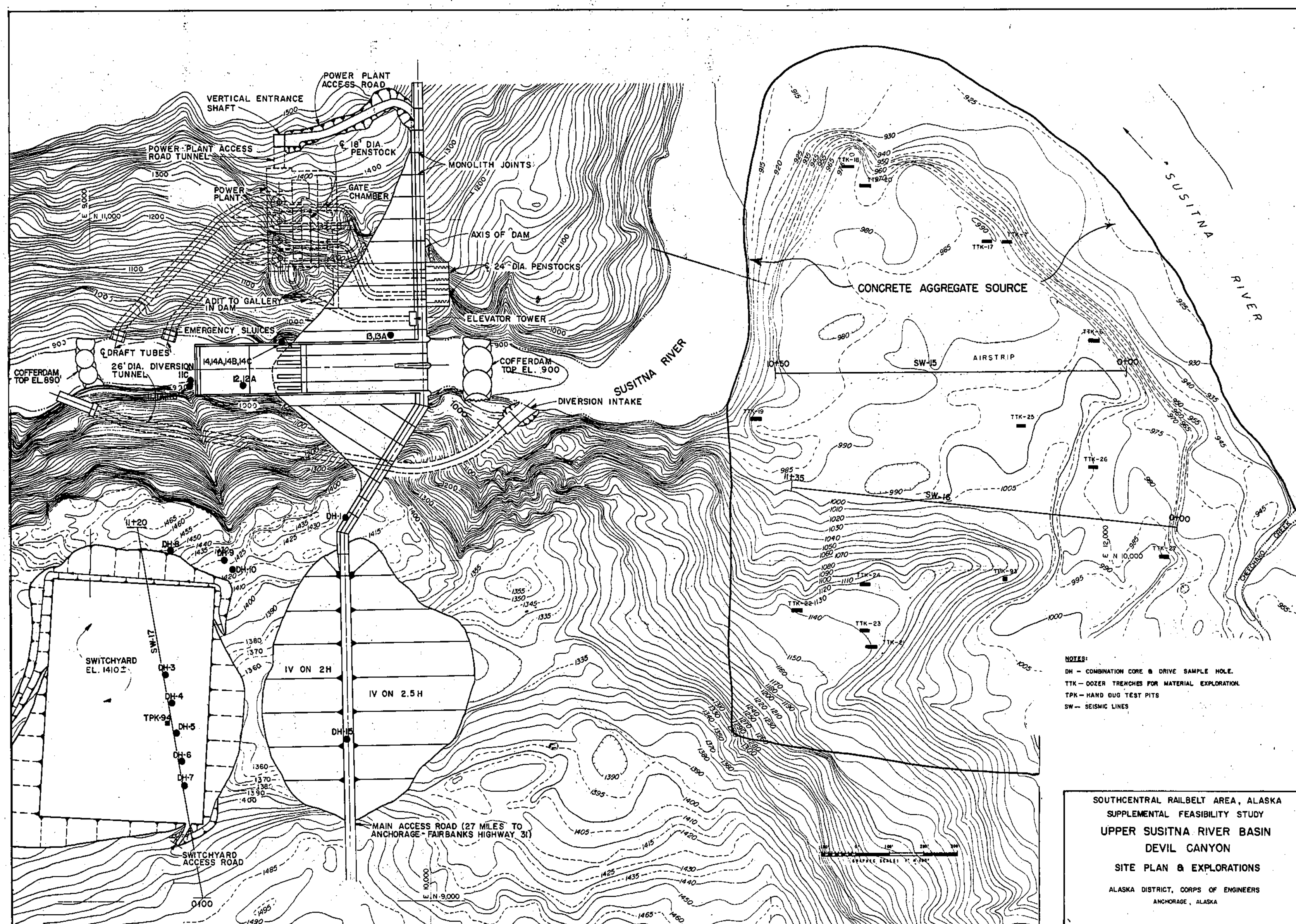

POWER PLANT ACCESS ROAD
VERTICAL ENTRANCE SHAFT
POWER PLANT ACCESS ROAD TUNNEL
℄ 18' DIA. PENSTOCK
MONOLITH JOINTS
POWER PLANT
GATE CHAMBER
AXIS OF DAM
℄ 24' DIA. PENSTOCKS
ADIT TO GALLERY IN DAM
EMERGENCY SLUICES
ELEVATOR TOWER
℄ DRAFT TUBES
26' DIA. DIVERSION TUNNEL
COFFERDAM TOP EL. 890'
COFFERDAM TOP EL. 900
DIVERSION INTAKE
SUSITNA RIVER
CONCRETE AGGREGATE SOURCE
AIRSTRIP
SW-15
SW-16
SW-17
SWITCHYARD EL. 1410±
SWITCHYARD ACCESS ROAD
IV ON 2H
IV ON 2.5H
MAIN ACCESS ROAD (27 MILES TO ANCHORAGE-FAIRBANKS HIGHWAY 3)
DEADMAN CREEK
NOTES:
DH - COMBINATION CORE & DRIVE SAMPLE HOLE.
TTK - DOZER TRENCHES FOR MATERIAL EXPLORATION.
TPK - HAND DUG TEST PITS
SW - SEISMIC LINES
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DEVIL CANYON
SITE PLAN & EXPLORATIONS
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-1

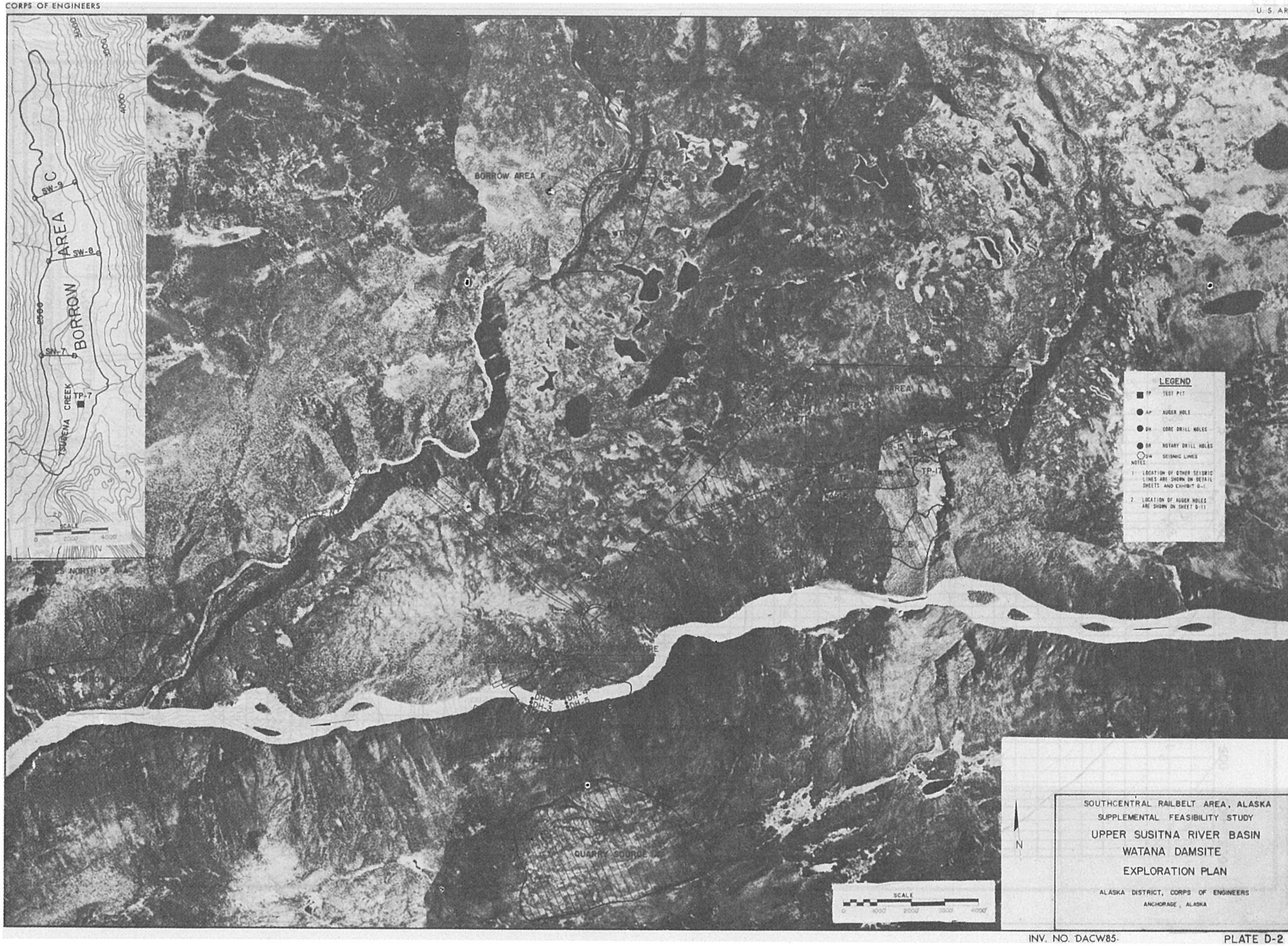
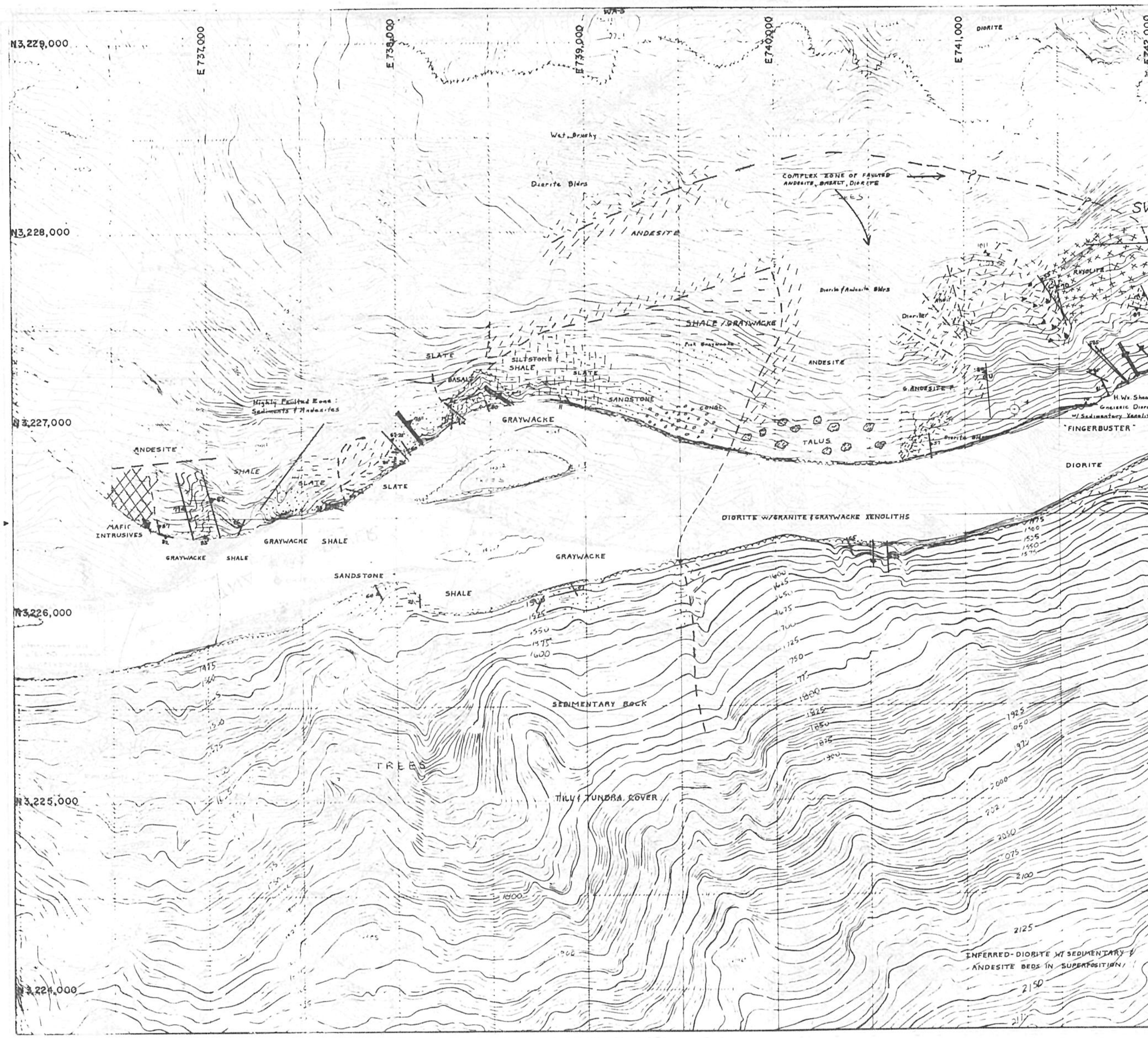

CORPS OF ENGINEERS
U. S. ARMY
BORROW AREA C
SW-9
SW-8
SW-7
TP-7
TSUSENA CREEK
SCALE
0 2000 4000
BORROW AREA F
LEGEND
TP TEST PIT
AP AUGER HOLE
DH CORE DRILL HOLES
DR ROTARY DRILL HOLES
SW SEISMIC LINES
NOTES
1 LOCATION OF OTHER SEISMIC LINES ARE SHOWN ON DETAIL SHEETS AND EXHIBIT D-1
2 LOCATION OF AUGER HOLES ARE SHOWN ON SHEET D-11
TP-17
QUARRY SOURCE
SCALE
0 1000 2000 3000 4000
N
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
EXPLORATION PLAN
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA
INV. NO. DACW85-
PLATE D-2

Chart D-29



LEGEND

- ACIDIC INTRUSIVES GRANITE, DIORITE
- ACIDIC EXTRUSIVES RHYOLITE, DACITE
- MAFIC INTRUSIVES GABBRO
- MAFIC EXTRUSIVES ANDESITE, BASALT
- PORPHORITIC ANDESITE, BASALT
- GRAVEL, CONGLOMERATE
- SAND, SANDSTONE
- SILT, SILTSTONE
- CLAY, SHALE
- BOULDERS * (ROCK TYPE SHOWN)
- ROCK FRAGMENTS
- BRECCIA (USED W/ROCK TYPE)
- INTENSE SHEAR ZONE
- GEOLOGIC CONTACT. ON INFERRED - ?
- SIGNIFICANT WATER SEEPAGE
- EROSIONAL FEATURE INFERRED TO INDICATE A SHEAR ZONE
- 55 BEDDING: WITH DIP VERTICAL
- 45 JOINT: WITH DIP VERTICAL
- 33 FAULT: WITH DIP VERTICAL
- 17 INFERRED
- 45 DIKE: WITH DIP, ROCK TYPE PER SYMBOL
- 42 QUARTZ VEINS, WITH DIP
- DH-25 DRILL HOLE
- 1401 SURVEY POINT
- WA-5 AIR PHOTO CONTROL POINT

ABBREVIATIONS

ALT	ALTERED	G	GREEN
B	BLACK	GR	GRANITE
BIO	BIOTITE	H	HIGHLY
BLDR	BOULDER	QTZ	QUARTZ
BR	BROWN	R	RED
CL	CLAY	S	SAND
DIOR	DIORITE	SS	SANDSTONE
FRAC	FRACTURED	WX	WEATHERED

NOTES:

1. DIORITE HAS INTRUDED AND UPLIFTED SEDIMENTS AND ANDESITES. ANDESITES ARE INFERRED TO BE A PRE-PLUTONIC INTERCANYON FLOW UPLIFTED AND ALTERED BY DIORITE EMPLACEMENT.
2. GLACIAL CLAY AND ALLUVIUM APPEAR TO FILL PREEXISTING EROSIONAL CHANNELS IN UPPER CANYON WALLS.

N

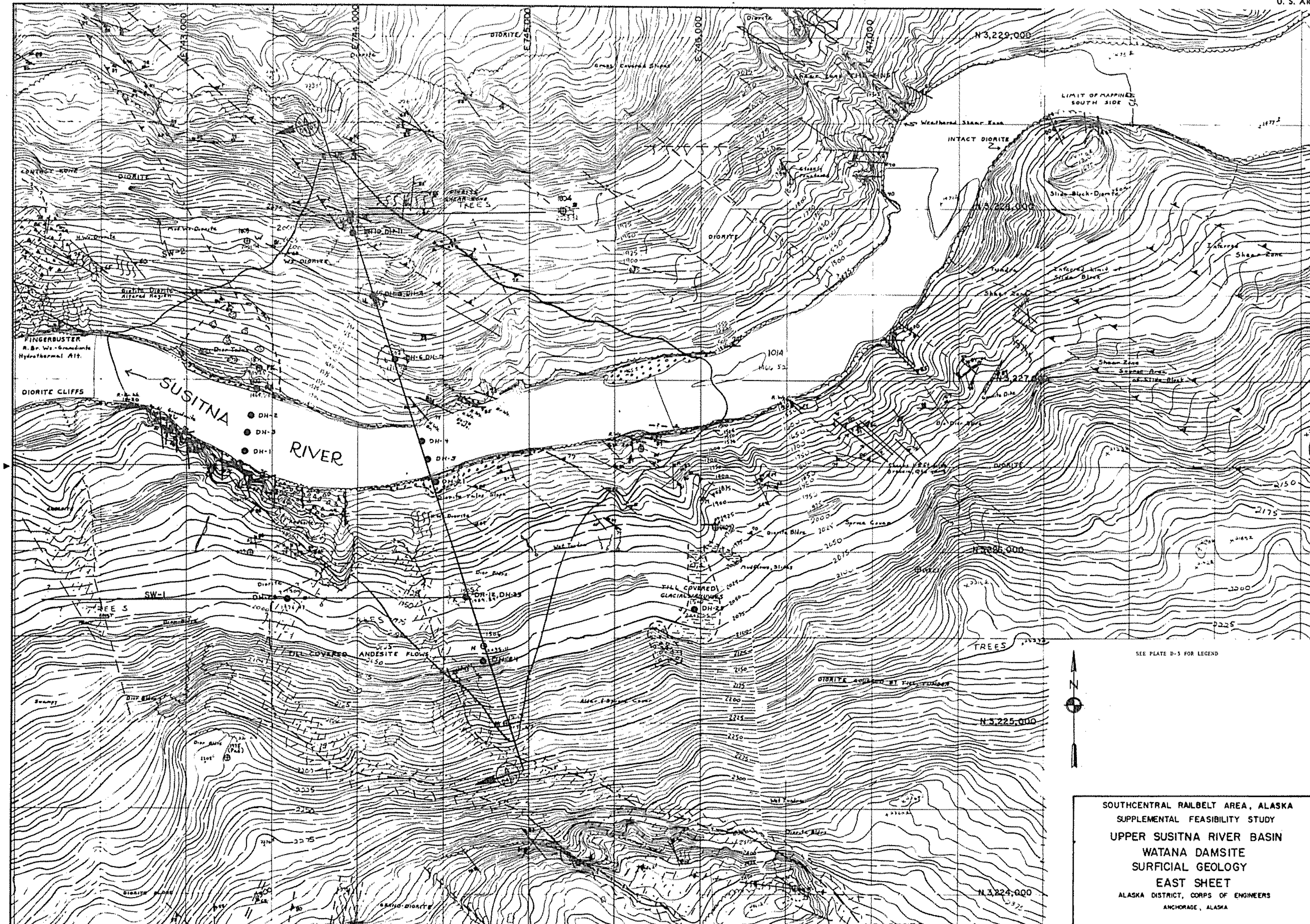
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
SURFICIAL GEOLOGY
WEST SHEET

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

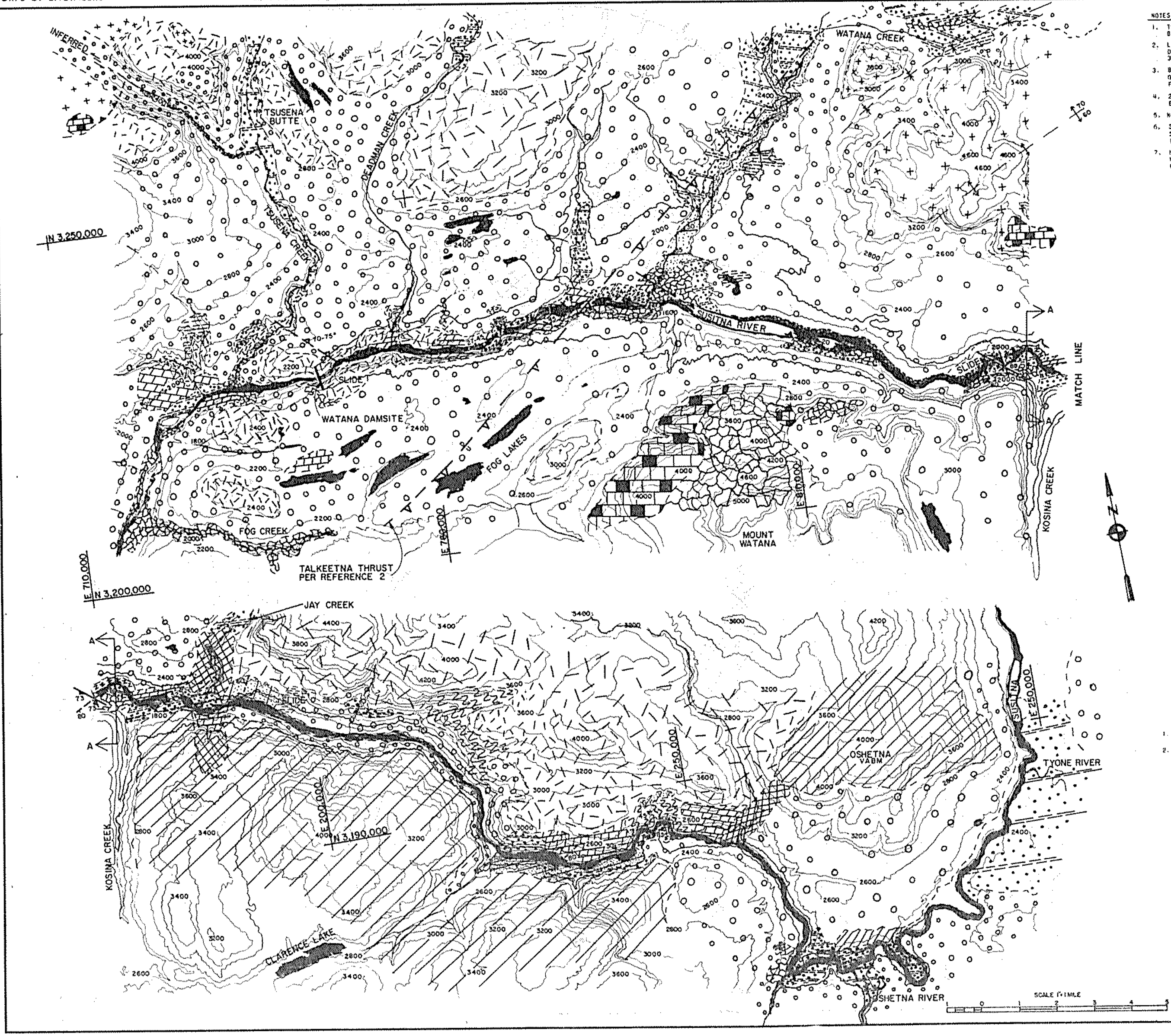
CORPS OF ENGINEERS

U. S. ARMY



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
SURFICIAL GEOLOGY
EAST SHEET
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-4



NOTES:

1. THIS SURFICIAL GEOLOGY MAP REPRESENTS GROSS LITHOLOGY AND STRUCTURE BASED ON LIMITED OUTCROP MAPPING. UNIT BOUNDARIES ARE APPROXIMATE.
2. LIMITS OF MAPPED UNITS CONFORMS WITH REFERENCE 2, EXCEPT AS MORE CLEARLY DEFINED BY CORPS OF ENGINEERS GEOLOGISTS. EXTENSIONS OF UNITS BEYOND 3 MILES FROM RESERVOIR BOUNDARY WERE BASICALLY DRAWN FROM REFERENCE 2.
3. BASE MAP (REFERENCE 1) IS NOT DUPLICATED IN FULL DETAIL. MAJOR BODIES OF WATER ARE SHOWN. ISLANDS, SMALL STREAMS AND MINOR TOPOGRAPHIC FEATURES HAVE BEEN DELETED.
4. 2200 FOOT CONTOUR HAS BEEN ACCEPTED AS APPROXIMATE LIMIT OF RESERVOIR EFFECT.
5. NO PERMAFROST OR INTERMITTENT FROST ACTION AREAS ARE SHOWN.
6. SLIDES ARE AS INDICATED BY SURFACE EXPRESSIONS. MINOR AND INCIPIENT SLIDE AREAS AND AREAS SUSCEPTIBLE TO MASS MOVEMENT UNDER RESERVOIR INFLUENCE HAVE NOT BEEN SHOWN.
7. MANY AREAS SHOWN AS GLACIAL TILL COVERED HAVE MINOR OUTCROPS THAT WERE NOT DETECTED IN MAPPING. DETAILED MAPPING IS REQUIRED TO DEFINE CONTACTS, ZONES OF DISTURBANCE, AND TILL-COVERED AREAS.

TOPOGRAPHIC SYMBOLS

WATER - LAKE, STREAM OR RIVER

N 3,200,000 REFERENCE MARKS

2200 200' CONTOUR INTERVALS IN FEET ABOVE MEAN SEA LEVEL (REF. 1)

STRUCTURAL SYMBOLS

CONTACT SURFACE EXPRESSION

SHEAR OR FAULT, WITH DIP (1); VERTICAL (2)

APPROXIMATE LOCATION OF FAULT OR SHEAR (ARROW DOWN DIP OF SHEAR PLANE)

BEDS - SEDIMENTARY OR FLOW STRUCTURE; WITH DIP (1); VERTICAL (2)

BEDS - APPROXIMATE DIP

SYNCLINE, SHOWING AXIS (APPROXIMATE LOCATION)

ANTICLINE, SHOWING CREST (APPROXIMATE LOCATION)

FLOW FOLIATION, SCHISTOSITY; INCLINE (1); VERTICAL (2)

JOINTS; INCLINED (1); VERTICAL DIPS (2)

LITHOLOGIC SYMBOLS

GLACIAL TILL

UNCONSOLIDATED CLASTIC ALLUVIAL DEPOSITS

UNCONSOLIDATED FINE ALLUVIAL DEPOSITS - CLAY, SILT, VARVED CLAYS

CONSOLIDATED BEDDED SEDIMENTARY DEPOSITS - ALL CLASTIC TYPES

LIMESTONE AND MARBLE

ALL TYPES ARGILLACEOUS ROCK INCLUDING METAMORPHIC FORMS THROUGH PHYLLITE

SCHIST INCLUDING LIT-PAR-LIT SCHIST, GREEN SCHIST AND CONTACT METAMORPHIC FORMS

AMPHIBOLITE, PYROXENITE, GABBROS, GNEISS, MAFIC INTRUSIVES AND HIGHGRADE METAMORPHICS

VOLCANIC FLOWS AND SILLS, ANDESITES AND BASALTS WITH INTERBEDS

HYPABYSSAL INTRUSIVES - DIABASE, DACITE, APLITE AND NEAR-SURFACE PORPHYRY.

GRANITICS - GRANITES, MONZONITES, DIORITES.

ZONES OF VERY HIGH-GRADE ALTERATION AND METAMORPHISM TO INCLUDE SERITIZATION, SERPENTIZATION, SAUSSURITIZATION AND PRODUCTS OF CONTACT REMELTING.

REFERENCES

1. US GEOLOGICAL SURVEY 1:63,360 SERIES (TOPOGRAPHIC), TALKEETNA MOUNTAIN QUADRANGLE, SHEETS C1, C2, D3, D4.
2. "RECONNAISSANCE GEOLOGIC MAP AND GEOCHRONOLOGY, TALKEETNA MOUNTAINS QUADRANGLE, NORTHERN PART OF ANCHORAGE QUADRANGLE, AND SOUTHWEST CORNER OF HEALY QUADRANGLE, ALASKA." OPEN FILE REPORT 78-558A (PRELIMINARY), US GEOLOGICAL SURVEY, MENLO PARK, CALIFORNIA 1978. CSEJTEY, ET AL.

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

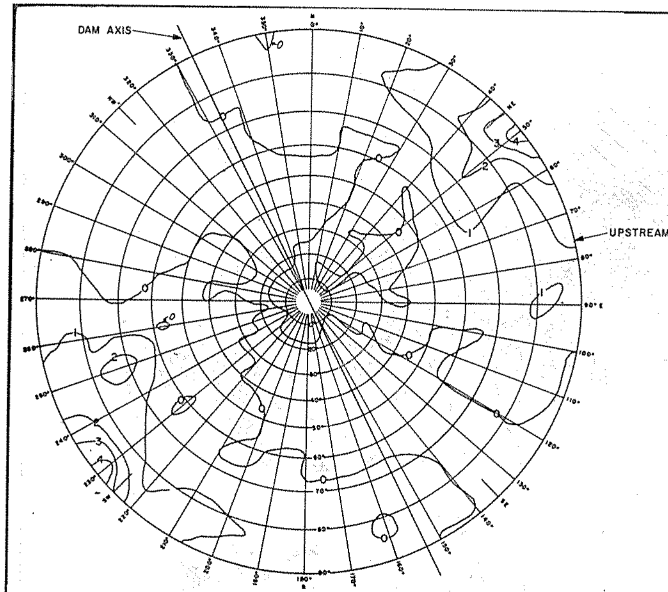
UPPER SUSITNA RIVER BASIN
WATANA RESERVOIR
SURFICIAL GEOLOGY

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

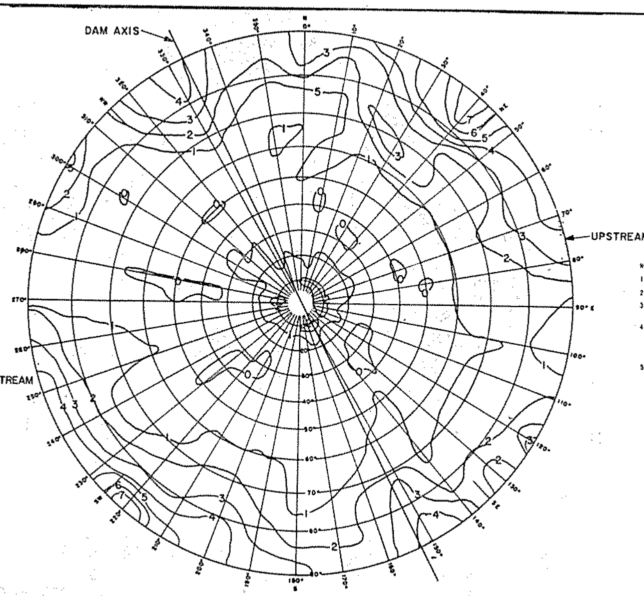
PLATE D-5

CORPS OF ENGINEERS

U. S. ARMY

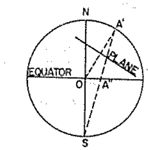


SHEARS
III POINTS



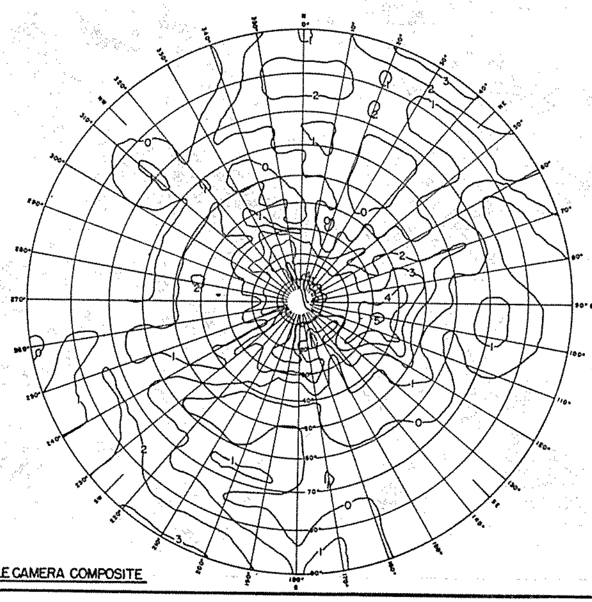
JOINTS
495 POINTS

MAJOR N50W VERTICAL (N40W-N65W, 80N-85S)
N60E VERTICAL (N45E-N70E, 75N-75S)
MINOR N55W 70N (N50W-N70W, 65N-75N)
N30E VERTICAL



NOTES

1. SINGLE POLE, UPPER HEMISPHERE PROJECTION OF JOINT AND SHEAR PLANES.
2. PERCENTAGE OF POINTS CONTOURED
3. UPPER DIAGRAMS REPRESENT RIVER MAPPING FROM 8000 FEET UPSTREAM OF AXIS DOWNSTREAM TO TSUSENA CREEK.
4. LOWER DIAGRAM IS A BORE HOLE CAMERA COMPOSITE OF THREE NX CORE HOLES REPRESENTING 518 POINTS IN 362.5 LINEAR FEET OF HOLE. NO SEPARATION OF JOINTS AND SHEARS MADE (DH-21, 23, 24).
5. STEREOGRAPHIC PROJECTIONS ARE USED TO DEFINE ANY PLANE. BY CONSTRUCTING A POLE PERPENDICULAR TO A PLANE AND PLOTTING THE POLE PROJECTION ON A HEMISPHERE (IN THIS CASE THE NORTHERN HEMISPHERE), THE ORIENTATION OF A PLANE CAN BE DEFINED AS A DISCREET POINT REGARDLESS OF SPACIAL COORDINATES. FOR EXAMPLE: A POLE CONSTRUCTED FROM A PLANE WITH A STRIKE OF N55°W AND A DIP OF N50°E WILL HAVE SPHERICAL COORDINATES OF 035°, 050°; A FLAT PLANE WILL PLOT AT THE NORTH POLE OF THE HEMISPHERE; A VERTICAL PLANE WILL PLOT AS TWO DISCREET POINTS ON THE EQUATOR, BOTH POINTS PERPENDICULAR TO STRIKE. POLE PROJECTIONS ARE THEN CONTOURED TO DEFINE DOMINANT AND SUBORDINANT PLANAR FEATURES.



BORE HOLE CAMERA COMPOSITE

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
STEREOGRAPHIC PROJECTIONS

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-6

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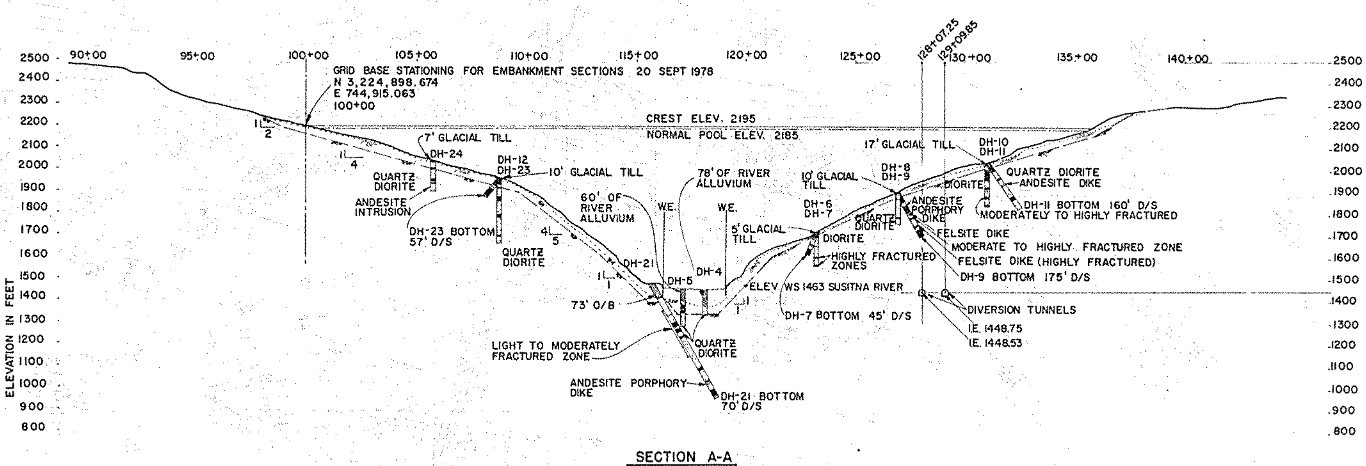
LEGEND

- SURFACE LINE
- TOP OF ROCK LINE
- FOUNDATION BEDROCK EXCAVATION LINE
- SHEAR ZONE
- D/S DOWNSTREAM
- U/S UPSTREAM
- O/B OVERBURDEN
- W.E. WATERS EDGE
- DH DRILL HOLE
- I.E INVERT ELEVATION
- TOP OF ROCK
- EXCAVATION LINE

NOTE:
TOP OF ROCK LINE & EXCAVATION LINE SUBJECT TO CHANGE.

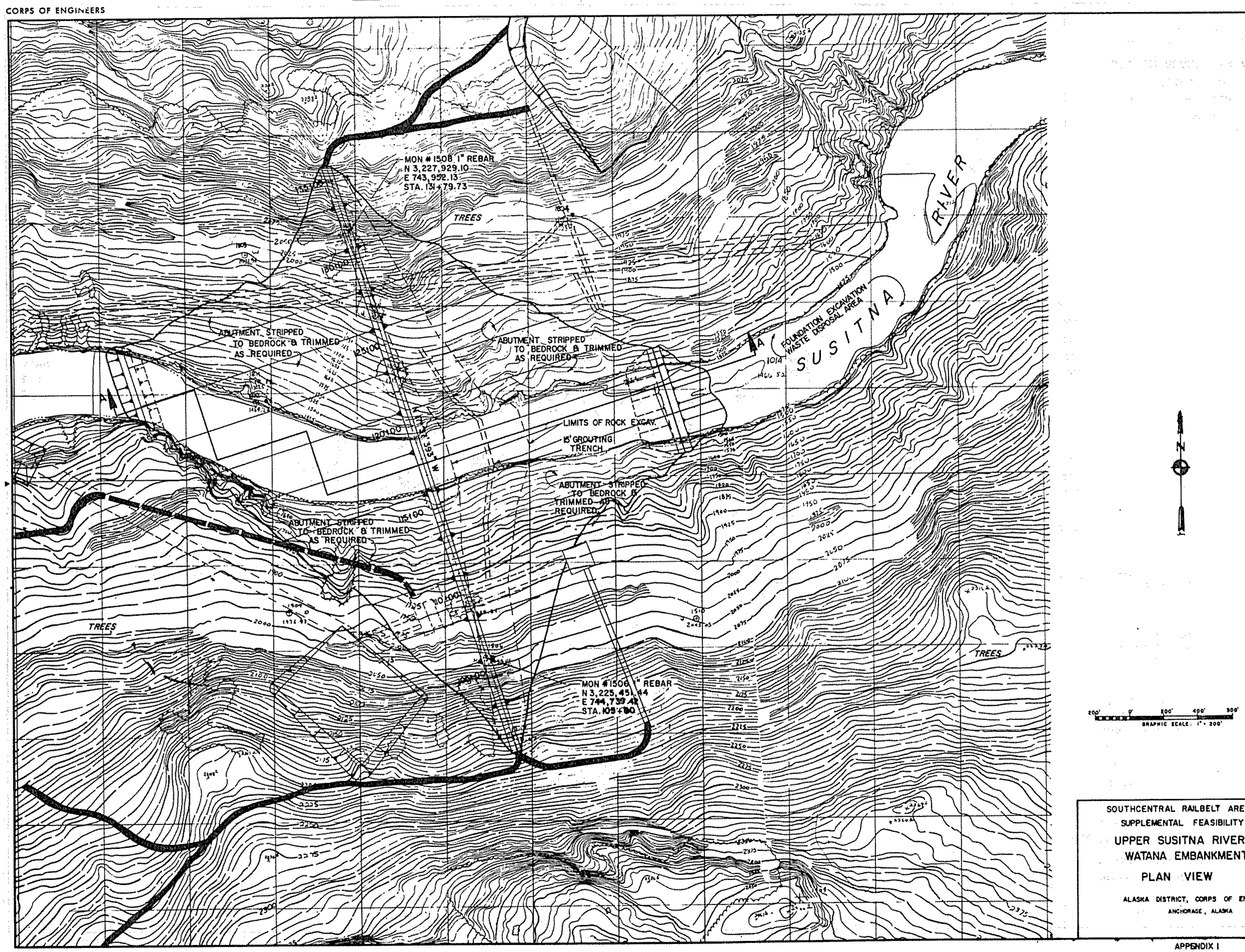
FOR LOCATION OF CROSS-SECTION SEE PLATE D-4



SECTION A-A

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM
SECTION ALONG DAM AXIS
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

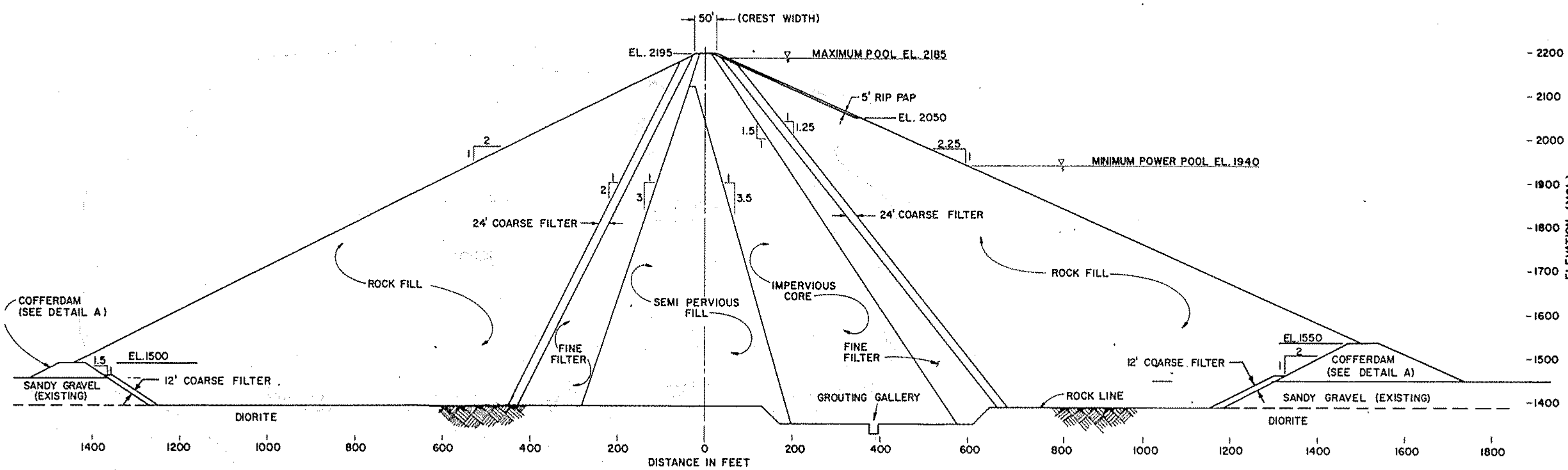
664



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

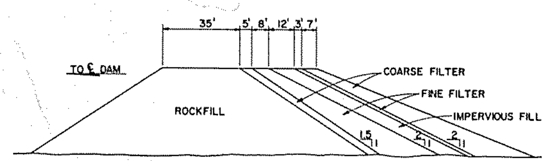
UPPER SUSITNA RIVER BASIN
WATANA EMBANKMENT
PLAN VIEW

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



SECTION A-A (FROM PLATE D-8)

GRAPHIC SCALE: 1" = 100'-0"



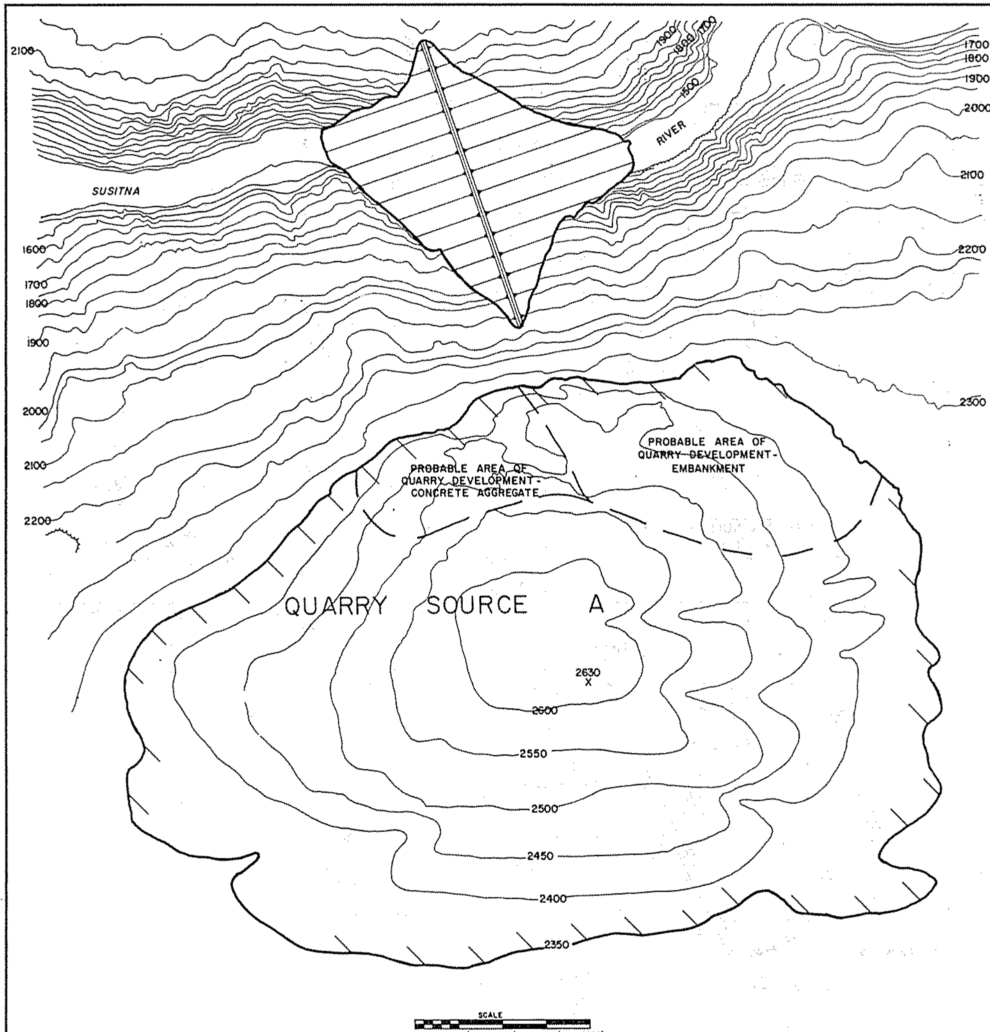
COFFERDAM - DETAIL A
TYP. EACH SIDE

GRAPHIC SCALE: 1" = 20'-0"

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA EMBANKMENT
SECTION A-A

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

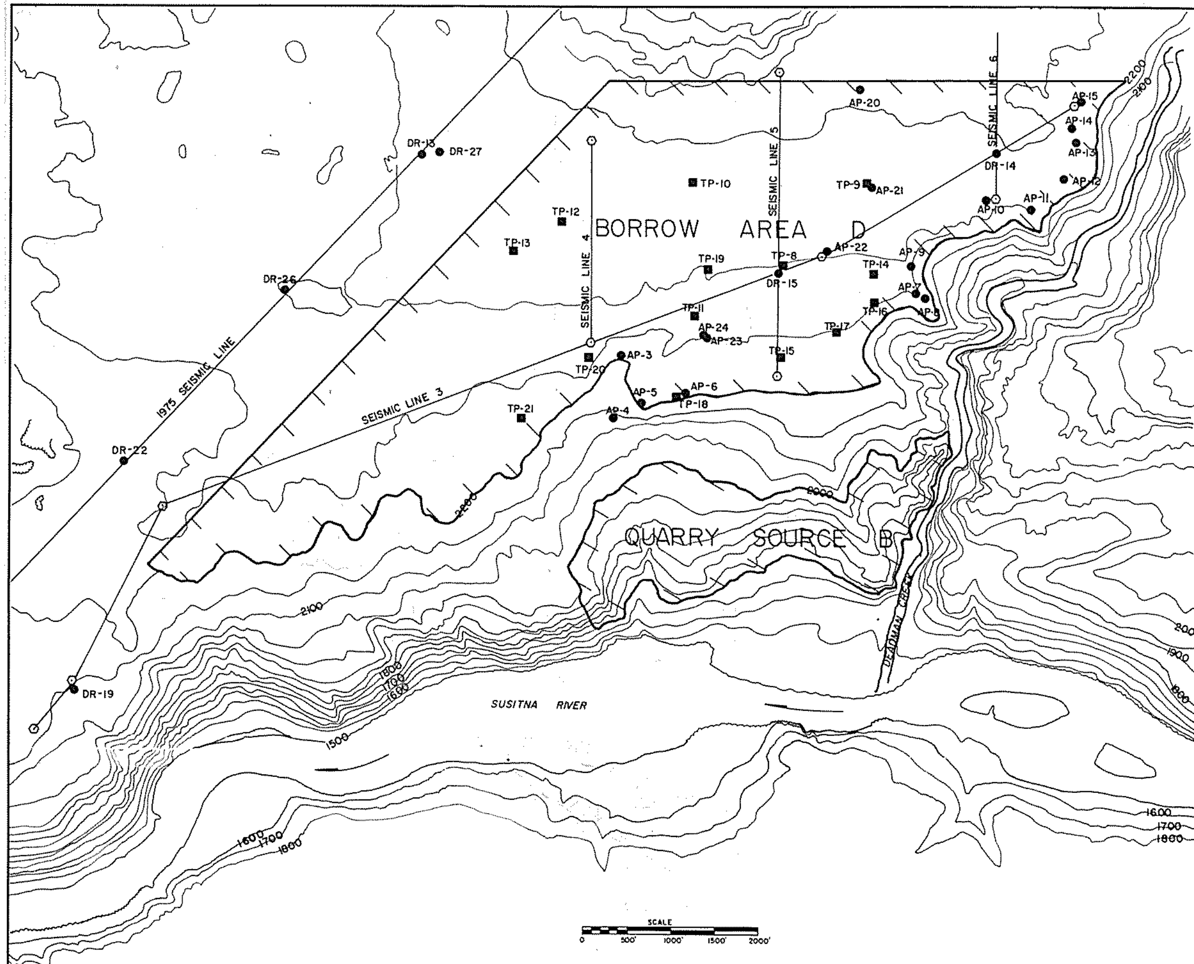


SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
QUARRY SOURCE A

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-10



N

LEGEND

TP	TEST PITS
DR	DRILL HOLE
AP	AUGER HOLE
SW	SEISMIC LINE

NOTES

1. SEISMIC LINE PROFILES MAY BE FOUND IN EXHIBIT D-1.
2. AUGER HOLES 16-19 LIE NORTH OF BORROW AREA D, ZERO TO ¼ MILE NORTH OF AND BETWEEN AP-15 AND AP-20. SEE PLATE D-2.
3. AP-1 AND AP-2 ARE NEAR DR-20 IN SPILLWAY AREA. SEE PLATE D-2.
4. FOR LOCATION OF TP 6-7 AND TP 22-26, SEE PLATE D-2.

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
QUARRY SOURCE B & BORROW AREA D

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-II

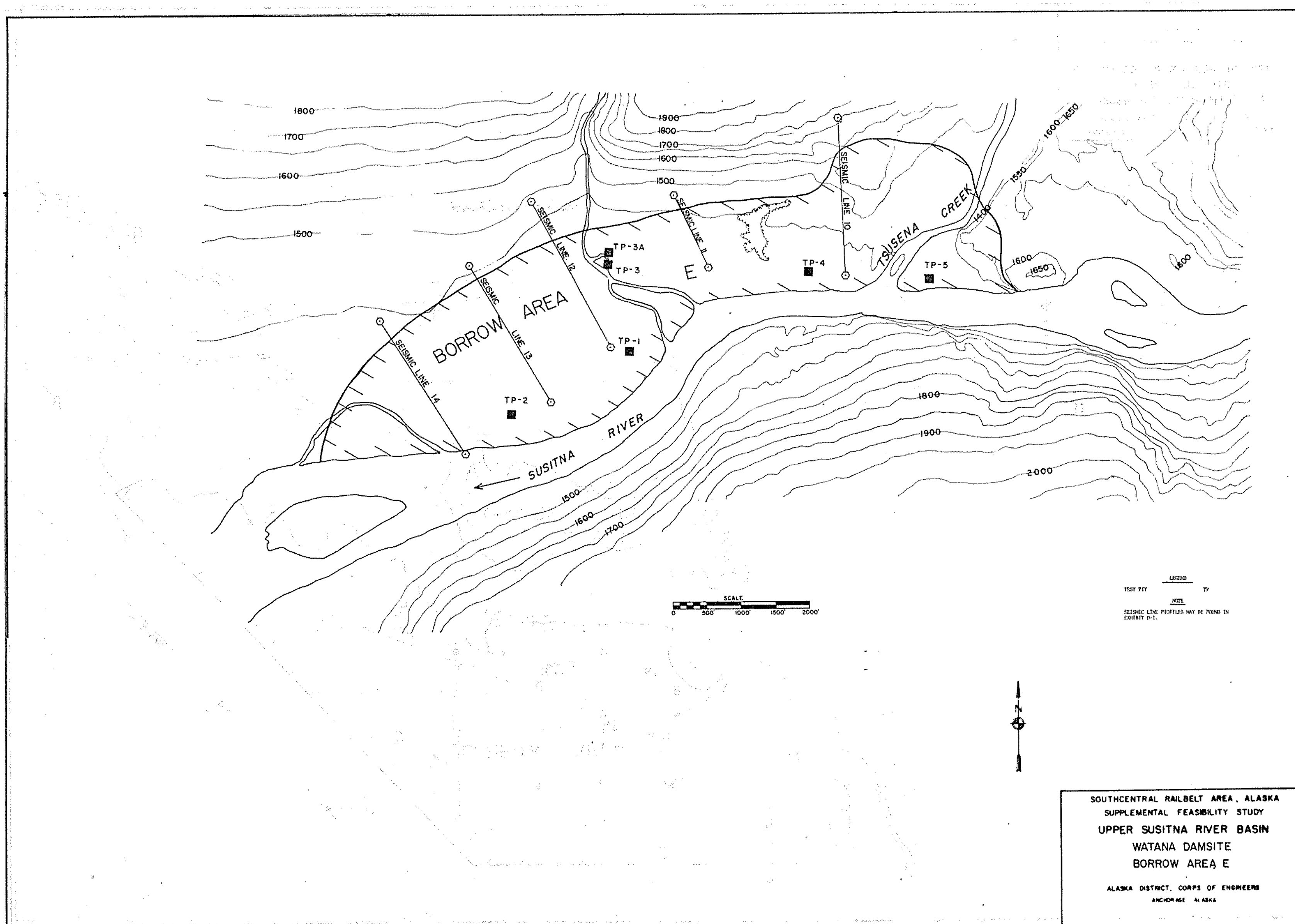
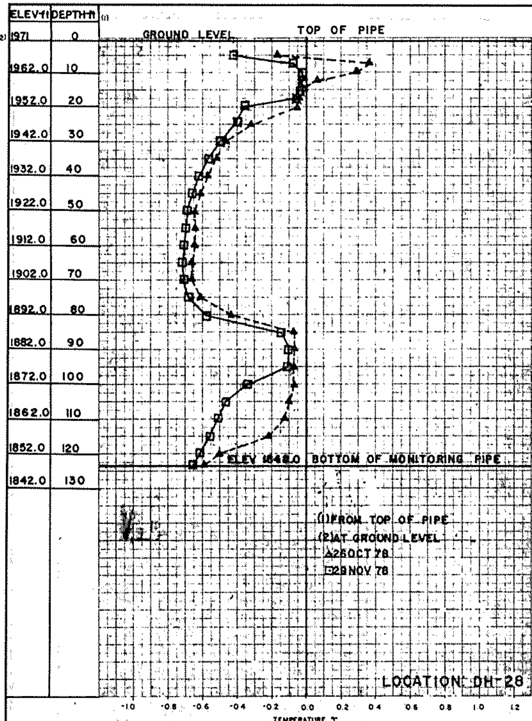
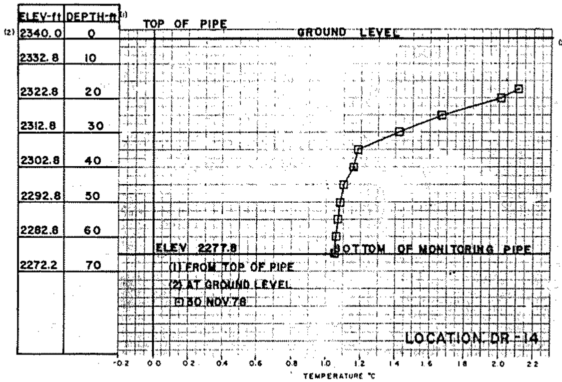
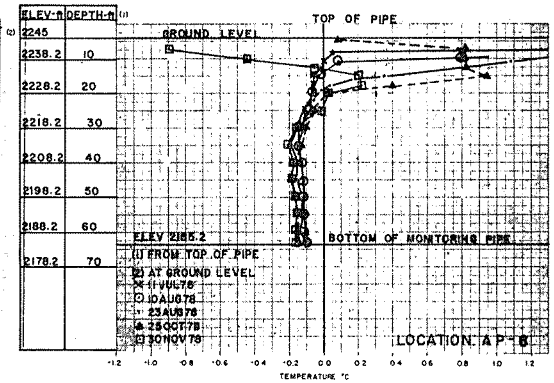
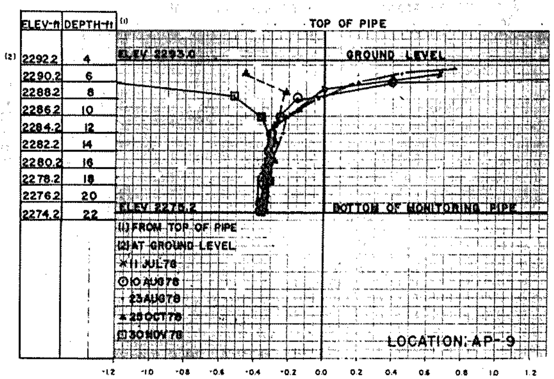

BORROW AREA E
SEISMIC LINE 10
SEISMIC LINE 11
SEISMIC LINE 12
SEISMIC LINE 13
SEISMIC LINE 14
TP-1
TP-2
TP-3
TP-3A
TP-4
TP-5
TSUSENA CREEK
SUSITNA RIVER
1400
1500
1550
1600
1650
1700
1800
1900
2000
SCALE
0 500' 1000' 1500' 2000'
LEGEND
TEST PIT TP
NOTE
SEISMIC LINE PROFILES MAY BE FOUND IN EXHIBIT D-1.
N
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA E
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE ALASKA

PLATE D-12









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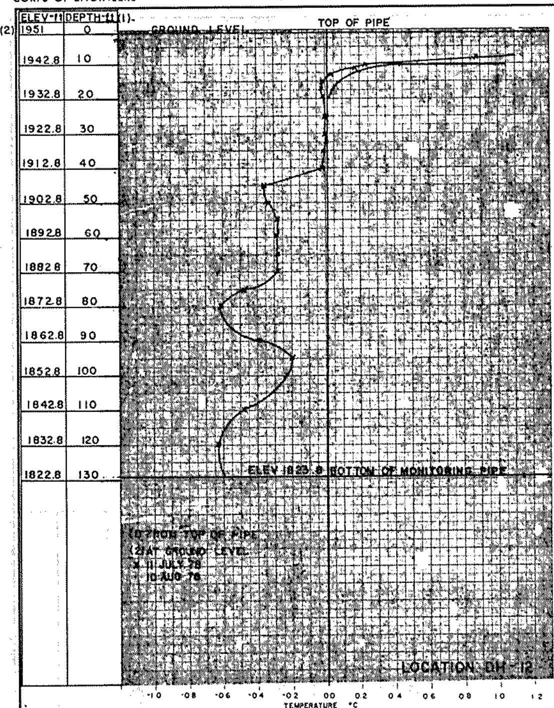
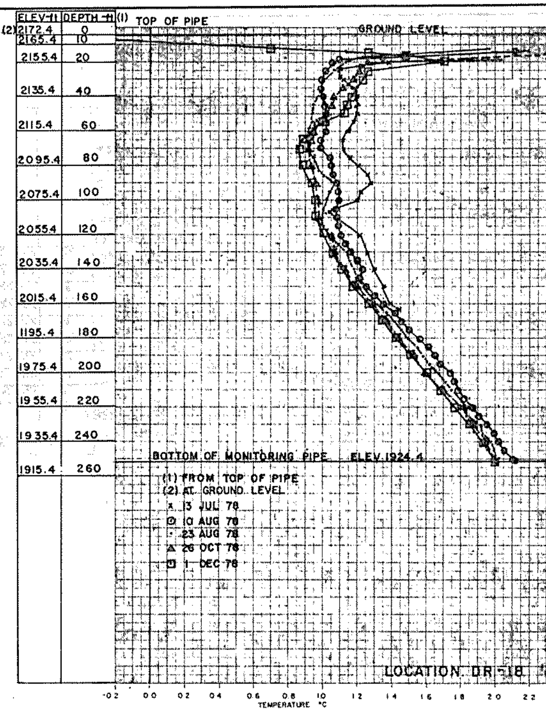
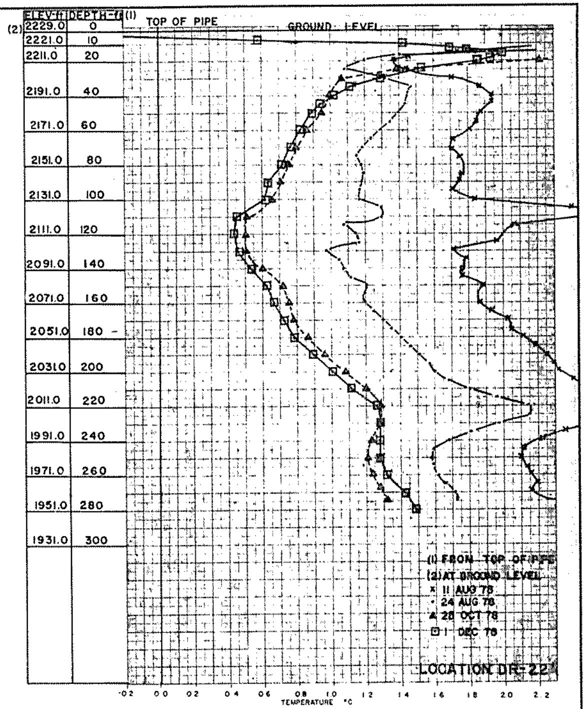
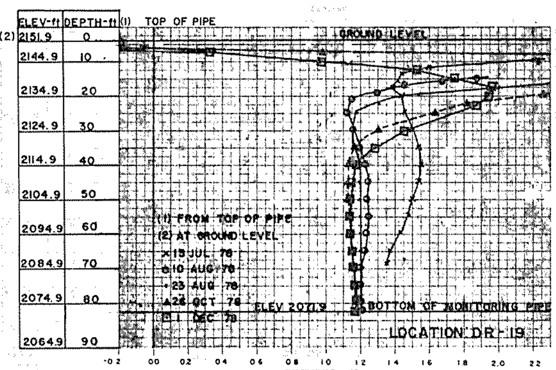
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM SITE
GROUND TEMPERATURE DATA I
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



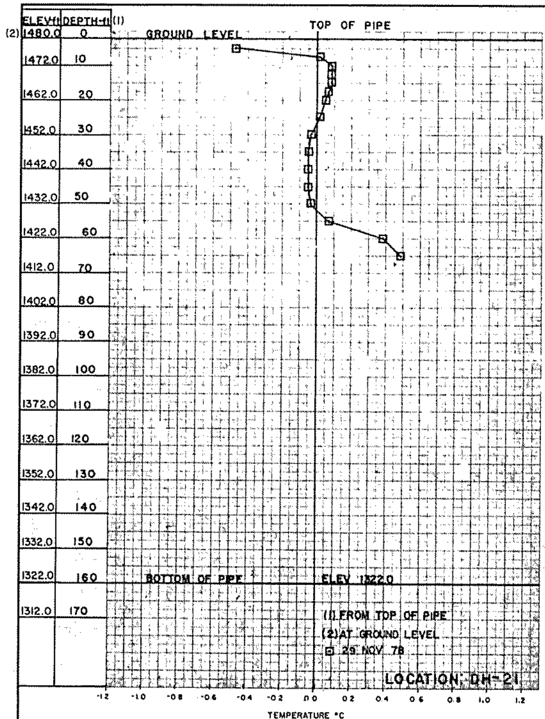


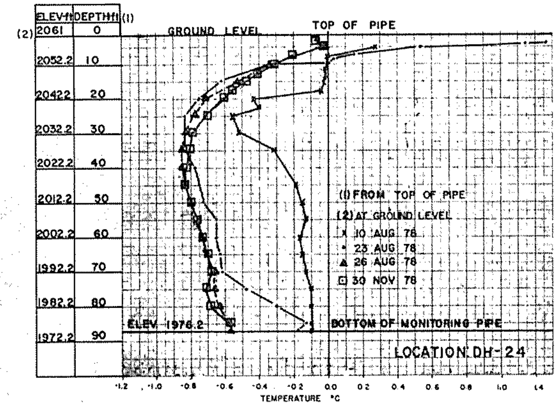


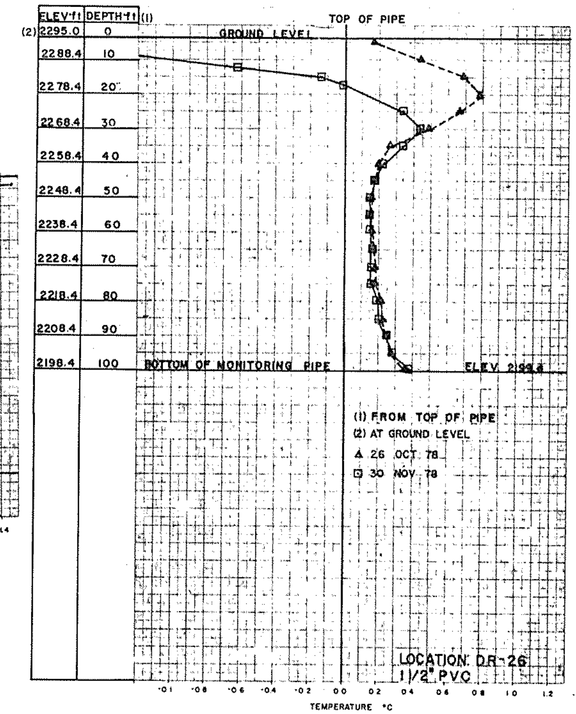


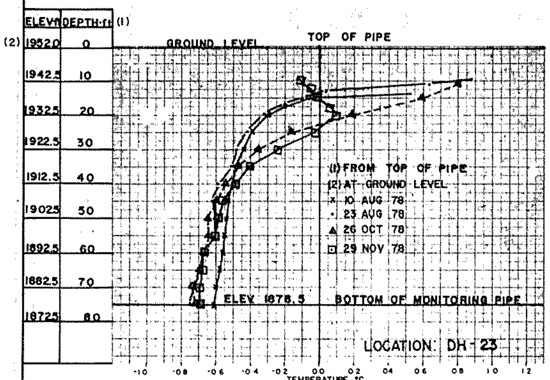
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM SITE
GROUND TEMPERATURE DATA II

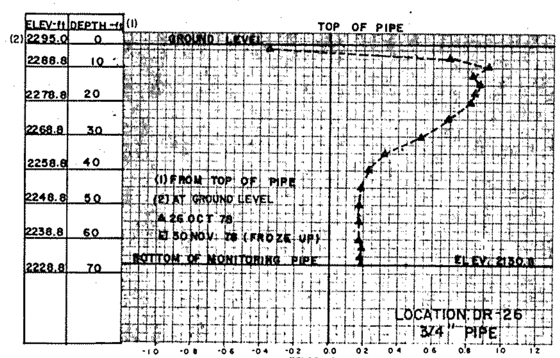
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA





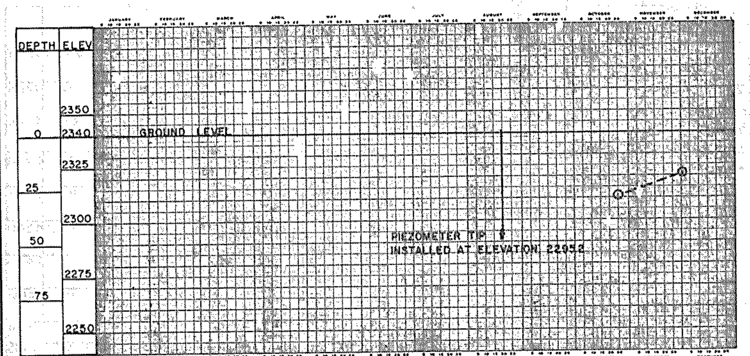




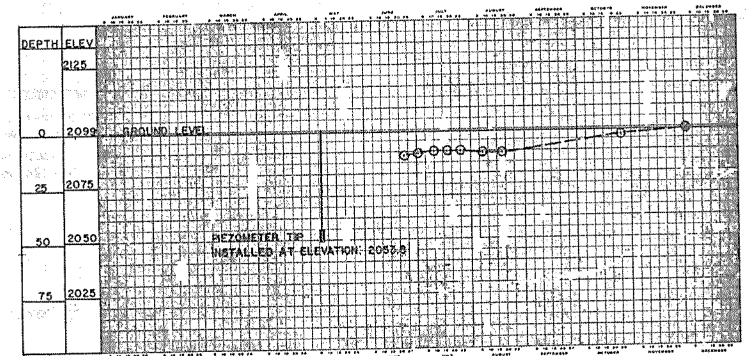


SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM SITE
GROUND TEMPERATURE DATA III

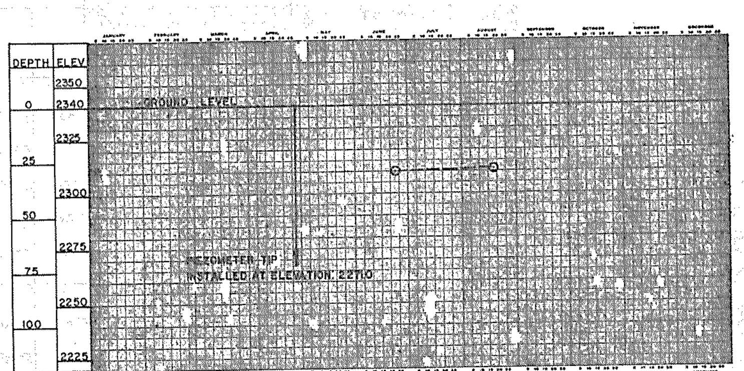
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



PIEZOMETER DATA
LOCATION: DR-14(1 1/2")



PIEZOMETER DATA
LOCATION: DR-16



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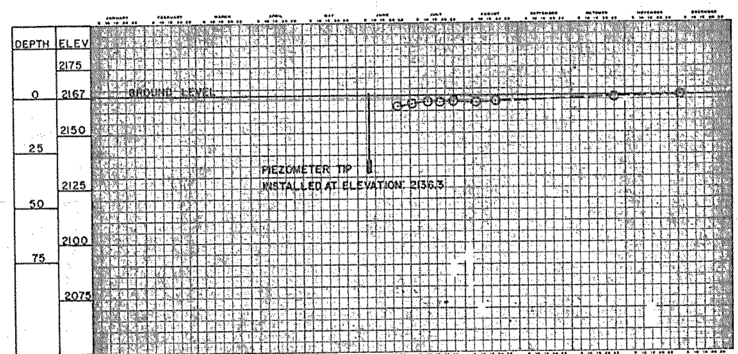


PIEZOMETER DATA
LOCATION: DR-17

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

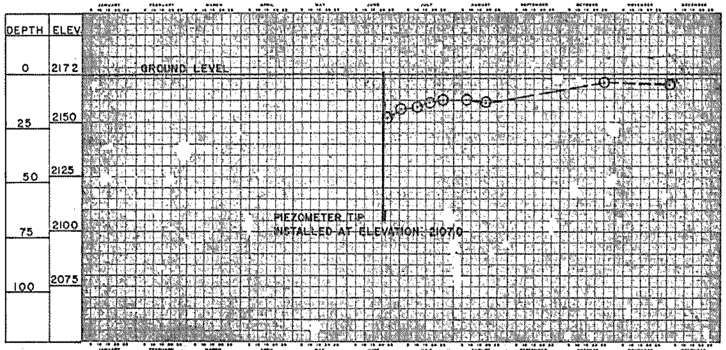
UPPER SUSITNA RIVER BASIN

WATANA DAM SITE

PIEZOMETER DATA I

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-16



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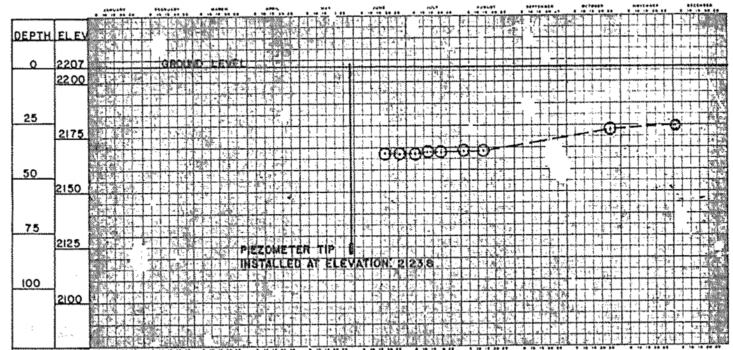

PIEZOMETER DATA
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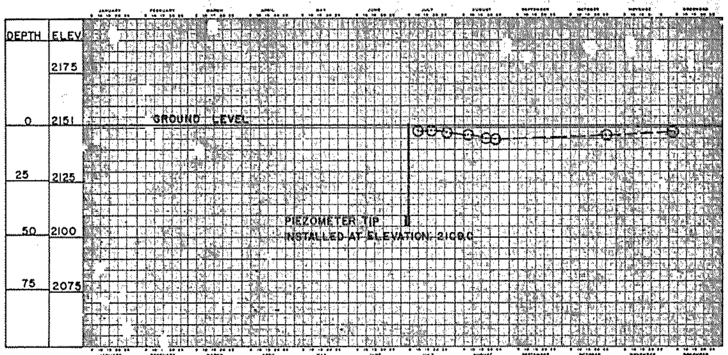

PIEZOMETER DATA
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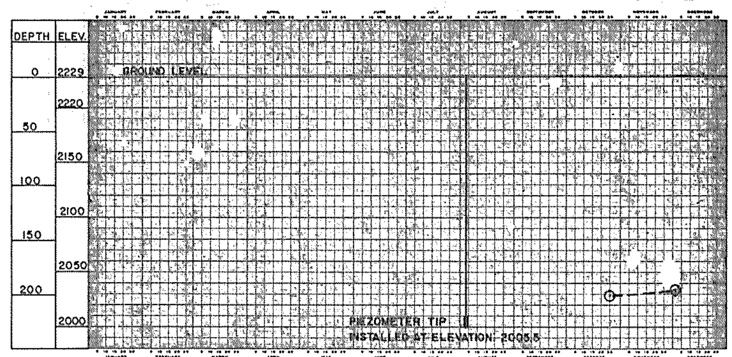
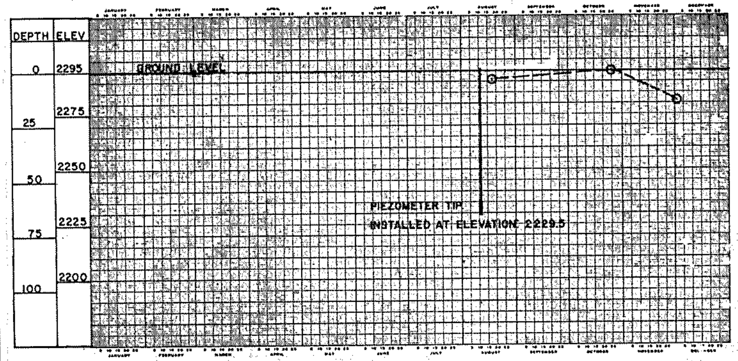
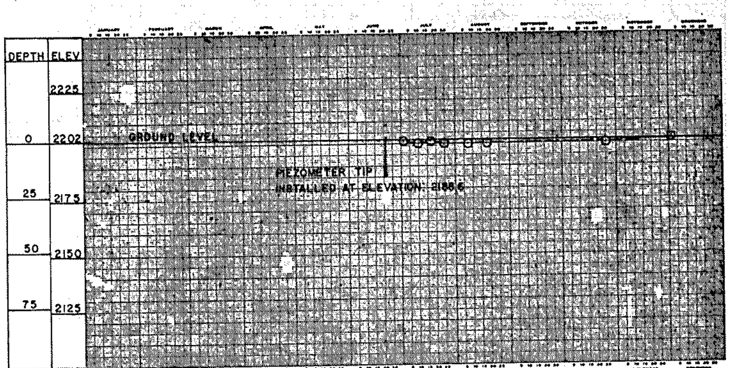


PIEZOMETER DATA
LOCATION: DR-22

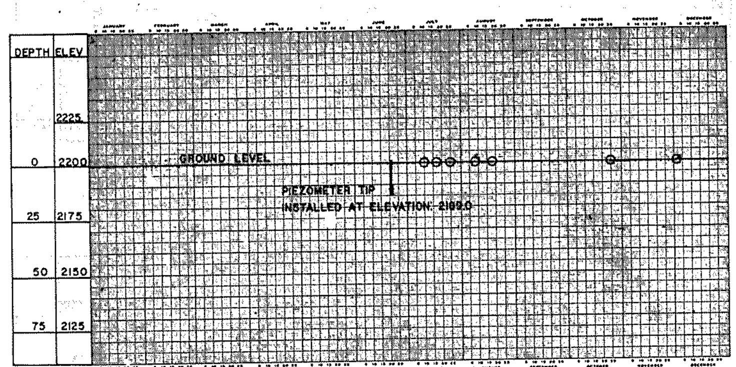
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM SITE
PIEZOMETER DATA II
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



PIEZOMETER DATA
LOCATION: DR-26



PIEZOMETER DATA
LOCATION: AP-1



PIEZOMETER DATA
LOCATION: AP-2

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAM SITE
PIEZOMETER DATA III
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

Exploration Log TP-1

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,225,930 E 728,700 — Drilling agency: Corps of Engineers
Hole No.: Field TP-1, Permanent TP-1 — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 8.0'
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 5 — Type of samples: Grab
Date hole started: 6/21/78 — Completed: 6/21/78
El. top of hole: 1420 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0–2		ML	Sandy Silt		Vegetation Top 0.2'; Some Organics, Fine
2		SP	Gravelly Sand	3"	Fine Clean; Traces of Clay
4–8	1&2; 3,4,&5	SP-SM	Silty Gravelly sand; Plus No. 4-39%, Minus No. 4-61%	14"	Boulders 30-40%; Coarse Sand; Boulders 50-60%
8					Bottom of Hole (Boulders). Note: Bobcat to 5', Backhoe to 8'

Project: Watana Dam — Permanent Hole No.: TP-1

Exploration Log TP-2

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,224,800 E 726,650 — Drilling agency: Corps of Engineers
Hole No.: Field TP-2, Permanent TP-2 — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 9.2'
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat And Backhoe
Total no. of samples: 2 — Type of samples: Grab
Date hole started: 6/29/78 — Completed: 6/29/78
El. top of hole: 1615 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0–3		ML	Sandy Silt		Vegetation, Roots; Some Organics; Very Little Sand
3–4		SP	Silty sand	1/2"	Clean
4–6		SM	Silty Sand		No Gravel
6–9.2	1&2	GP	Sandy Gravel; Plus No 4- 57%, Minus No. 4-43%		
9.2					Bottom Of Hole (Boulders). Note: Bobcat to 4', Backhoe to 9.2'

Project: Watana Dam — Permanent Hole No.: TP-2

Exploration Log TP-3

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,226,600 E 728,600 — Drilling agency: Corps of Engineers
Hole No.: Field TP-3, Permanent TP-3 — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 5.0'
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 1 — Type of samples: Grab
Date hole started: 9/25/78 — Completed: 9/25/78
El. top of hole: 1435 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0		ML	Sandy Silt		Vegetation, Roots
0–5	1	GP	Sandy Gravel; Plus No. 4-59%, Minus No. 4-41%		20-30% Gravel
5					Bottom Of Hole (Boulders). Note: Bobcate to 2.5', Backhoe to 5.0'

Project: Watana Dam — Permanent Hole No.: TP-3

Exploration Log TP-3A

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,226,820 E 728,750 — Drilling agency: Corps of Engineers
Hole No.: Field TP-3A, Permanent TP-3A — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 5.2'
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 1 — Type of samples: Grab
Date hole started: 7/25/78 — Completed: 7/25/78
El. top of hole: 1435 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0		ML	Sandy Silt		Vegetation, Roots
0–5.2	1	GP	Sandy Gravel; Plus No. 4-55%, Minus No. 4-45%		Boulders 30% w/ lots of roots
5.2					Bottom of hole (boulders). Note: Backhoe only

Project: Watana Dam — Permanent Hole No.: TP-3A

Exploration Log TP-4

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,226,600 E 731,300 — Drilling agency: Corps of Engineers
Hole No.: Field TP-4, Permanent TP-4 — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 9.2
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 2 — Type of samples: Grab
Date hole started: 7/26/78 — Completed: 7/26/78
El. top of hole: 1440 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0–1.5		SM	Silty Sand		Vegetation top 0.2'; Some organic silts
1.5–2		SW	Sand		Clean
2–5		SM	Silty Sand		Traces of organics and Clay; Some gravels
5–9.2	1&2	GP-GM	Silty Sandy Gravel; Plus No. 4-53%, Minus No. 4-47%	24"	25% Boulders
9.2					Bottom of Hole; Water table @ 9.2'. Note: Bobcat to 6', Backhoe to 9.2'

Project: Watana Dam — Permanent Hole No.: TP-4

Exploration Log TP-5

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,227,110 E 733,170 — Drilling agency: Corps of Engineers
Hole No.: Field TP-5, Permanent TP-5 — Type of hole: Test pit
Name of driller: D. Sullivan — P/C 60'
Total depth of hole: 8.2'
Datum for elevation shown: MSL — Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 2 — Type of samples: Grab
Date hole started: 7/29/78 — Completed: 7/29/78
El. top of hole: 1455 — T. Sherman

Depth (feet)	Sample No.	Soil Legend	Classification	Max size	Formation Description & Remarks
0–1.2		SM	Silty sand, gravelly		Vegetation top 0.2'; Organic Silts
1.2–2		SP	Sand		Traces of organics; some gravel
2–8.2	1&2	GP	Sandy gravel; Plus No. 4-61%, Minus No. 4-39%	24"	Sand, medium; 40% boulders; Sand, coarse
8.2					Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No.: TP-5

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA E
LOGS: TEST PITS 1 THRU 5

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-19

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,276,190 E 742,460 — Drilling agency: Corps of Engineers
Hole No.: Field TP-7, Permanent TP-7 — Name of driller: D. SULLIVAN — Weather: P/C 60°
Type of hole: Test pit
Type of equipment: MELROE BOBCAT AND BACKHOE
Total no. of samples: 1 — Type of samples: GRAB — Started: 23 JUN 78 — Completed: 24 JUN 78
El. top of hole: 2300 — Geologist: P. GALBRAITH

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–4	1&2		SANDY GRAVEL 60% GR, 40% SA	
4				BOTTOM OF HOLE

Project: WATANA DAM — Permanent Hole No.: TP-7

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,330 E 754,200 — Drilling agency: Corps of Engineers
Hole No.: Field TP-8, Permanent TP-8 — Name of driller: D. SULLIVAN — Weather: CLOUDY
Type of hole: Test pit — Total depth of hole: 7'
Size and type of bit: 1/4 YARD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE "3"
Total no. of samples: 2 — Type of samples: GRAB — Started: 16 AUG 78 — Completed: 16 AUG 78
El. top of hole: 2200 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–1.2		OL/PT	PEAT	PEAT, VEG. SOME COBBLES, 18" DIA ROCK
1.2–4	1	SM	SILTY GRAVELLY SAND 30%SI, 17%GR, 53%SA	GRAVELLY SILTY SAND, COBBLES
4–7	2	SM	SILTY SAND GRAVEL	WATER SEEPING IN @ 4.5' GRAVELLY SILTY SAND WATER TABLE @ 7.0' APPROX. HOLE CAVED IN.
7			BOTTOM OF HOLE	

Project: WATANA DAM — Permanent Hole No.: TP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,235,300 E 755,200 — Drilling agency: Corps of Engineers
Hole No.: Field TP-9, Permanent TP-9 — Name of driller: D. SULLIVAN — Weather: CLEAR
Type of hole: Test pit — Total depth of hole: 10'
Size and type of bit: 1/4 YARD³ BUCKET — Type of equipment: BACKHOE, JOHN DEERE "3" 1/4 YD³
Total no. of samples: 4 — Type of samples: GRAB — Started: 15 AUG 78 — Completed: 15 AUG 78
El. top of hole: 2303 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–0.3		OL	SILT	VEG. W/SILT, ROOTS, NOT FROZEN
0.3–1.5		ML	SILT	DARK BROWN SILT W/ROCK 16" DIA.
1.5–3	A	ML	SANDY SILT	SILTY SAND W/GRAVEL TO 4", TAN GREY COLOR.
3–7	1, 2	ML	SILTY GRAVELLY SAND 16% GR, 37%SI, 47%SA 13%GR, 37%SI, 50%SA	MOIST, TAN GREY COLOR SOME GRAVEL TO 4" COBBLES WERE EXCAVATED FROM ALL LAYERS FROM 0' TO B.O.H. LARGEST ROCK TO COME OUT WAS 2.5' x 1.5' x 9" THICK FROM ABOUT 6.0', ONE 2'x3'x1' FROM 9' DOWN.
7–9.3	3	SM	SILTY GRAVELLY SAND 41%SI, 15%GR, 45%SA	TAN GREY COLOR
9.3–10		SM	SILTY, GRAVELLY SAND	WATER TABLE @ 9.8'
10			BOTTOM OF HOLE	

Project: WATANA DAM — Permanent Hole No.: TP-9

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,870 E 753,270 — Drilling agency: Corps of Engineers
Hole No.: Field TP-10, Permanent TP-10 — Name of driller: D. SULLIVAN — Weather: COOL & CLOUDY
Type of hole: Test pit — Total depth of hole: 10.6'
Size and type of bit: 1/4 YD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE "3"
Total no. of samples: 2 — Type of samples: GRAB — Started: 21 AUG 78 — Completed: 21 AUG 78
El. top of hole: 2326 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–1.5		OL/PT	SILT	ORGANIC SILT
1.5–7.4	1	SM	SILTY GRAVELLY SAND 17%GR, 35%SI, 48%SA	SILTY GRAVELLY SAND W/COBBLES AND BOULDERS VARVED STRUCTURE I.E. W/SAND, 1.5'~7.4'
7.4–9	2	SM	SILITY GRAVELLY SAND 37%SI, 12%GR, 51%SA	LAYERS OF COARSE SAND
9–10.6		SM	SILTY GRAVELLY SAND	
10.6			BOTTOM OF HOLE	WATER SEEPING IN, HOLE CAVING

Project: WATANA DAM — Permanent Hole No.: TP-10

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,233,830 E 753,210 — Drilling agency: Corps of Engineers
Hole No.: Field TP-11, Permanent TP-11 — Name of driller: D. SULLIVAN — Weather: CLEAR
Type of hole: Test pit — Total depth of hole: 8.2'
Size and type of bit: 1/4 YD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE "3"
Total no. of samples: 2 — Type of samples: GRAB — Started: 18 AUG 78 — Completed: 18 AUG 78
El. top of hole: 2270 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–2.5		OL/PT	SILT	ORGANIC SILT, DARK BROWN W/ BOULDERS
2.5–4	1	SM	SILTY GRAVELLY SAND 26% SI, 17% GR, 57%SA	9" COBBLES
4–8.2	2	SM/SP	SILTY GRAVELLY SAND	STATIC WATER TABLE @ 4.2' MEASURED 19 AUG 78
8.2			BOTTOM OF HOLE	HOLE CAVED IN, WATER OOZING IN FROM THE SIDES.

Project: WATANA DAM — Permanent Hole No.: TP-11

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,030 E 751,690 — Drilling agency: Corps of Engineers
Hole No.: Field TP-12, Permanent TP-12 — Name of driller: D. SULLIVAN — Weather: COOL & CLOUDY
Type of hole: Test pit — Total depth of hole: 13.5'
Size and type of bit: 1/4 YD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE "3"
Total no. of samples: 2 — Type of samples: GRAB — Started: 21 AUG 78 — Completed: 21 AUG 78
El. top of hole: 2336 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–0.2		OL	SILT	ORGANIC SILT W/LARGE BOULDERS
0.2–1.5		ML	SILT	
1.5–4	1	SM	SILTY GRAVELLY SAND 44% SI, 13%GR, 43%SA	BROWN
4–13.5	2	SM	SILTY GRAVELLY SAND 25% SI, 16%GR, 59% SA	LIGHT GREY COLOR, COBBLES TO 10"
13.5			BOTTOM OF HOLE	WATER RUNNING INTO THE HOLE

Project: WATANA DAM — Permanent Hole No.: TP-12

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,565 E 754,435 — Drilling agency: Corps of Engineers
Hole No.: Field TP-13, Permanent TP-13 — Name of driller: D. SULLIVAN — Weather: CLEAR
Type of hole: Test pit — Total depth of hole: 10'
Size and type of bit: 1/4 YD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE, "3"
Total no. of samples: 1 — Type of samples: GRAB — Started: 22 AUG 78 — Completed: 22 AUG 78
El. top of hole: 2330 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–0.3		OL/ML	SILT	SILT WITH LARGE BOULDERS
0.3–2.3		GP/SM	SILTY GRAVELLY SAND	BROWN
2.3–10	1	SM	GRAVELLY SAND 36%SI, 15% GR, 49%SA	W/SILT LENSES, DARK GREY COLOR, COBBLES
10			BOTTOM OF HOLE	HOLE SLOUGHED IN, WATER INFILTRATION FROM THE SIDES.

Project: WATANA DAM — Permanent Hole No.: TP-13

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,330 E 755,230 — Drilling agency: Corps of Engineers
Hole No.: Field TP-14, Permanent TP-14 — Name of driller: D. SULLIVAN — Weather: CLOUDY
Type of hole: Test pit — Total depth of hole: 3'
Size and type of bit: 1/4 YARD³ BUCKET — Datum for elevation shown: MSL — Type of equipment: BACKHOE, JOHN DEERE "3"
Total no. of samples: 2 — Type of samples: GRAB — Started: 17 AUG 78 — Completed: 17 AUG 78
El. top of hole: 2296 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0–1		OL/PT	PEAT, ORGANIC SILT	PEAT, SILT, LARGE BOULDER
1–2.3	1	SM	SILTY SAND 32% SI, 16% GR, 52%SA	FROZEN 1' TO 2', GREY SAND TAN GREY COLOR
2.3–3	2		SILTY SAND	WATER SEEPING IN FROM THE SURFACE
3			B.O.H.	

Project: WATANA DAM — Permanent Hole No.: TP-14

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA C & D
LOGS: TEST PITS 7 THRU 14

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-20

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

TP-15

Project: Watana Dam — Sheet 1 of 1
Location: N 3,233,930 E 754,195 — Drilling agency: Corps of Engineers
Hole No.: Field TP-15, Permanent TP-15 — Name of driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 7'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Date hole started: 19 Aug 78, completed: 19 Aug 78
El. top of hole: 2233 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL/PT	Peat	Peat, organic silt. 1 rock 5'x4'x3½', w/cobbles on the surface
2	1	ML	Sandy gravelly silt	Light grey
4		SM	Silty gravelly sand	
6	2		34% Si, 23%Gr, 43%Sa	Water running in from the sides
7			B.O.H.	Hole caved in continually

Project: Watana Dam — Permanent Hole No. TP-15

TP-16

Project: Watana Dam — Sheet 1 of 1
Location: N 3,234,010 E 755,245 — Drilling agency: Corps of Engineers
Hole No.: Field TP-16, Permanent TP-16 — Name of driller: D. Sullivan — Weather: Cloudy
Type of hole: Test pit — Total depth of hole: 10.5'
Size and type of bit: 1/4 yard³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Date hole started: 16 Aug 78, completed: 16 Aug 78
El. top of hole: 2255 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL/ML	Silt	Dark brown color, 3' Boulder Found. Water table, measured 17 Aug 78
4.5	1		Silty gravelly sand; 41% Si, 14%Gr, 45%Sa	Grey color
6.5		SM	Silty gravelly sand	w/cobbles
10.5	2		35% Si, 18%Gr, 47%Sa; B.O.H.	Most of the boulders are in the top 2' of the ground, from 2' to 10.5' encountered cobbles.

Project: Watana Dam — Permanent Hole No. TP-16

TP-17

Project: Watana Dam — Sheet 1 of 1
Location: N 3,233,600 E 754,030 — Drilling agency: Corps of Engineers
Hole No.: Field TP-17, Permanent TP-17 — Name of driller: D. Sullivan — Weather: Cloudy
Type of hole: Test pit — Total depth of hole: 7'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Date hole started: 18 Aug 78, completed: 18 Aug 78
El. top of hole: 2247 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL/PT	Peat	Peat, Silt w/Veg
0.5		SM	Gravelly silty sand	
2	1	SM	Gravelly Silty sand	Frozen, no visible ice crystals.
6	2		37%Si, 12%Gr, 51%Sa	
6.8		SM		Frozen
7			B.O.H.	

Project: Watana Dam — Permanent Hole No. TP-17

TP-18

Project: Watana Dam — Sheet 1 of 1
Location: N 3,233,310 E 753,040 — Drilling agency: Corps of Engineers
Hole No.: Field TP-18, Permanent TP-18 — Name of driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 13.7'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 4 — Type of samples: Grab — Date hole started: 19 Aug 78, completed: 19 Aug 78
El. top of hole: 2211 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		ML	Silt	Silt ML, PT
0.3		SM	Gravelly silty sand	From approx. 2.0' frozen dry
2	1	SM	Silty gravelly sand; 40%Si, 11%Gr, 41%Sa	Dry frost. Digs easy and sides do not cave in. No visible ice, low MC
9	2	SP	Sand	Dry Frost w/ silt lenses, & gravel
10		ML	Silt	Frozen, Low MC
11	3	SP	Sand w/ silt lenses	No Frost
11.5	4	ML	Silt	Unfrozen, dark grey color, water seeping in at bottom of hole
13.7			B.O.H.	

Project: Watana Dam — Permanent Hole No. TP-18

TP-19

Project: Watana Dam — Sheet 1 of 1
Location: N 3,234,305 E 757,350 — Drilling agency: Corps of Engineers
Hole No.: Field TP-19, Permanent TP-19 — Name of driller: D. Sullivan — Weather: Cool & Cloudy
Type of hole: Test pit — Total depth of hole: 13.7'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Date hole started: 21 Aug 78, completed: 21 Aug 78
El. top of hole: 2302 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL/ML	Silt	Veg & silts
0.3		ML	Silt	Light brown w/cobbles
1	1	SM	Silty gravelly sand; 35%Si, 15%Gr, 50%Sa	Tan Grey w/cobbles
4	2		Silty gravelly sand; 35%Si, 15%Gr, 50%Sa	Grey color. Very little water oozing in
13.7			B.O.H.	

Project: Watana Dam — Permanent Hole No. TP-19

TP-20

Project: Watana Dam — Sheet 1 of 1
Location: N 3,233,570 E 752,000 — Drilling agency: Corps of Engineers
Hole No.: Field TP-20, Permanent TP-20 — Name of driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 13.2
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Date hole started: 21 Aug 1978, completed: 21 Aug 78
El. top of hole: 2265

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		ML	Silt	Organic & silt
0.2		SM	Sand	Organic stained sand w/ silt gravel
1	1	SM	Silty gravelly sand; 17%Si, 8%Gr, 75%Sa	
4	2	SM	Gravelly silty sand	w/cobbles. Static water table measured 22 Aug 78
13.2			B.O.H.	Static water at 11.8'

Project: Watana Dam — Permanent Hole No. TP-20

TP-21

Project: Watana Dam — Sheet 1 of 1
Location: N 3,232,670 E 751,240 — Drilling agency: Corps of Engineers
Hole No.: Field TP-21, Permanent TP-21 — Name of driller: D. Sullivan — Weather: Cloudy
Type of hole: Test pit — Total depth of hole: 12'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 4 — Type of samples: Grab — Date hole started: 23 Aug 78, completed: 23 Aug 78
El. top of hole: 2220 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		PT	Organics	Organics w/silt & Clay no boulders, only cobbles
1.5	1A	CL	Gravelly Clay; 60% finer than No. 200 LL=27, PL=15, PI=12	Lean gravelly clay no sand in it. Sample TP-21-A @ 4' at natural MC. Can be rolled to 1/16" not blue grey in color but brown grey
4	2	CL	Gravelly Clay	Grey color frozen from 3.8 4.9 but digs easy below 4.9 maybe border line frost
6.2	3, 4	CL	Gravelly clay	Grey color
12			Bottom of Hole	

Project: Watana Dam — Permanent Hole No. TP-21

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: TEST PITS 15 THRU 21

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-21

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam Site — Sheet 1 of 1
Location: N 3,244,100 E 746,910
Hole No.: Field TP-6, Permanent TP-6 — Weather: P/C 60°
Type of hole: Test pit — Total depth of hole: 5.7'
Type of equipment: Melroe Bobcat and Backhoe
Total no. of samples: 2 — Type of samples: Grab — Started: 6/29/78 — Completed: 6/29/78
El. top of hole: 2110 — Geologist: T. Sussman

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		OL	Organic silts		Vegetation
1		GM	Silty Sandy Gravel		Some Organics
2–5		GP	Sandy Gravel W/Cobbles	3"	Sand, Medium; Boulders 20-30%
	1&2		Plus No. 4-62%; Minus No. 4-38%		Sand, Coarse
					Bottom of hole (boulders)

Project: Watana Dam Site — Permanent Hole No. TP-6

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,240,115 E 746,850
Hole No.: Field TP-22, Permanent TP-22 — Driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 13'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 5 — Type of samples: Grab — Started: 24 Aug 78 — Completed: 24 Aug 78
El. top of hole: 2174 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		Pt/OL	Peat		
		SM	Silty gravelly sand		1 boulder 4'x6'x2' many boulders in top 2'
2	1	SP/SM	Gravelly sand		Clean, some cobbles
4	2		7%Si, 40%Gr, 53%Sa		
6	3	ML	Grey silt		
8	4	SP	Gravelly Sand		Brown Color clean
10–12		SM	Silty gravelly sand		Silt occurs as pockets
	5		28%Si, 22%Gr, 50% Sa		
14			B.O.H.		

Project: Watana Dam — Permanent Hole No. TP-22

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,240,525 E 745,935
Hole No.: Field TP-23, Permanent TP-23 — Driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 14'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 3 — Type of samples: Grab — Started: 25 Aug 78 — Completed: 25 Aug 78
El. top of hole: 2100 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		OL/ML	Silt		Veg & Silt, large boulders
		SM	Silty sand w/gravel		Stained by organics, w/boulders to 3' dia.
2–4			Sandy gravel		W/12" Cobbles
	1		55% Gr, 6%Si, 39%Sa		
6–10		SP/GP	Gravelly sand		Isolated silt pockets but few in number.
12		SP	Sand		Clean, uniform graded sand
	2		4%Si, 2%Gr, 94% Sa		
14	3		Fine sandy silt; B.O.H. @ 14'		No gravel

Project: Watana Dam — Permanent Hole No. TP-23

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,240,660 E 746,700
Hole No.: Field TP-24, Permanent TP-24 — Driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 6.6'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 1 — Type of samples: Grab — Started: 25 Aug 78 — Completed: 25 Aug 78
El. top of hole: 2265 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		ML	Sandy Silt		ML vegetation, boulders
2–4		GP/GM	Silty sandy gravel		Many rock fragments (broken) w/cobbles
	1		52%Gr, 12%Si, 36%Sa		
6		SM	Silty gravelly sand		Angular rock fragments, cobbles, boulders
8			Bottom of Hole		

Project: Watana Dam — Permanent Hole No. TP-24

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,241,570 E 746,820
Hole No.: Field TP-25, Permanent TP-25 — Driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 7.4'
Size and type of bit: 1/4 yd³ Bucket — Type of equipment: Backhoe, John Deere "3"
Total no. of samples: 2 — Type of samples: Grab — Started: 25 Aug 78 — Completed: 25 Aug 78
El. top of hole: 2190 — Geologist: D. Jensen

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		ML	Silt		Silt, veg. boulders
2	1	SM	Very fine sand		Very fine sand w/silt and gravel and cobbles
4		GP/GM	Silty sandy gravel		W/boulders
6	2		8%Si, 55%Gr, 37%Sa		
		SP	Gravelly sand		W/boulders
8			Bottom of Hole		

Project: Watana Dam — Permanent Hole No. TP-25

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: Watana Dam — Sheet 1 of 1
Location: N 3,242,210 E 747,470
Hole No.: Field TP-26, Permanent TP-26 — Driller: D. Sullivan — Weather: Clear
Type of hole: Test pit — Total depth of hole: 13.5'
Size and type of bit: 1/4 yd³ Bucket
Started: 25 Aug 78 — Completed: 25 Aug 78
El. top of hole: 2252

Depth (feet)	Sample No.	Soil Legend	Classification	Max Size	Formation Description & Remarks
		ML	Silt		Veg. boulders, cobbles
2	1	SM	Silty gravelly sand 48% Gr, 15% Sa, 37%Sa		W/Cobbles
4–6		SM	Silty gravelly sand		W/Cobbles
8	2		20%Si, 23%Gr, 57%Sa		
14			Bottom of Hole		

Project: Watana Dam — Permanent Hole No. TP-26

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA F
LOGS: TEST PITS 6 AND 22 THRU 26
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-22

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,230,477 E 745,110
Hole No.: Field AH-1, Permanent AP-1
Name of driller: K. MITCHELL — Weather: LIGHT RAIN
Total depth of hole: 15'
Size and type of bit: 4" FLIGHT AUGER — Type of equipment: B-56
Total no. of samples: 3 — Type of samples: DRIVE
Started: 13 JUL 78
El. top of hole: 2202 — Geologist: A. MACLEOD

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
						FROST AT 1-2 FT.
4		1				SAMPLE #1 AT 3.5 - 5' BROWN, WET, PERCHED WATERTABLE 3-4" COBBLES
8			SM SP	GRAVELLY SAND		SUB-ANGULAR GRAVELS, BROWN, WET
10		2				SAMPLE #2 AT 8.5-10 BROWN, DAMP
5'		3				SAMPLE #3 AT 13.5-15' BROWN, WET, SOME GRAVELS
15				BOTTOM OF HOLE		

Project: WATANA DAM — Permanent Hole No. AP-1

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,230,536 E 745,402
Hole No.: Field AH-2, Permanent AP-2
Name of driller: K. MITCHELL
Total depth of hole: 11.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-56
Total no. of samples: 1 — Type of samples: GRAB
Started: 20 JUN 78
El. top of hole: 2200 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
			OL/ML	ORGANICS		
4			SM	SILTY GRAVELLY SAND		GREY COLOR, BOULDERS, VERY HARD DRILLING, SATURATED
6		1		17%Gr, 31%Si, 52%Sa		SAMPLE #1 FROM 5' TO 6.5', SATURATED, CAME OUT AS A SLURRY, VERY COLD
10			GM	SANDY SILTY GRAVEL		BOULDERS, HARD DRILLING, GREY COLOR, SET PIEZOMETER AT BOTTOM OF HOLE
11				BOTTOM OF HOLE		

Project: WATANA DAM — Permanent Hole No. AP-2

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,233,690 E 752,434
Hole No.: Field AH-3, Permanent AP-3
Name of driller: K. MITCHELL
Total depth of hole: 18.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB
Started: 20-21 JUN 78
El. top of hole: 2279 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
			OL ML	SURFACE SILT		WITH ORGANICS
2			SM	SILTY SAND		COBBLES, GRAVEL, MOIST BUT NOT SATURATED, GREY
4		1		7%Gr, 46%Si, 47%Sa		SAMPLE #1 AT 4'
6			SM	SILTY SAND		COBBLES, GRAVEL, GREY
10			SM	SILTY SAND		COBBLES, SOME GREAVEL, GREY
13		2		11%Gr, 37%Si, 52%Sa		SAMPLE #2 AT 13'
14			SM	SILTY SAND		HUNG UP ON COBBLES

Project: WATANA DAM — Permanent Hole No. AP-3

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Hole No.: Field AH-3, Permanent AP-3
Name of driller: K. MITCHELL
Total depth of hole: 18.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB
Started: 20-21 JUN 78
El. top of hole: 2279 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
14						
16		3	CL	SILTY SANDY CLAY 55%Gr, 40%Sa, MINUS NO. 200-55% LL 25.6, PI 9.7		DARK GREY SAMPLE #3 AT 16' AT BOTTOM OF HOLE, ON TOP OF ROCK
18				BOTTOM OF HOLE		

Project: WATANA DAM — Permanent Hole No. AP-3

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,232,742 E 752,451
Hole No.: Field AH-4, Permanent AP-4
Name of driller: K. MITCHELL
Total depth of hole: 3.5 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: none — Type of samples: GRAB
Started: 21 JUN 78
El. top of hole: 2190 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
			ML	SILT		WITH ORGANICS AND ROOTS
2			GM	SILTY GRAVEL		BOULDERS, EXTREMELY DIFFICULT TO DRILL. REFUSAL AT 3.5'
4				BOTTOM OF HOLE		

Project: WATANA DAM — Permanent Hole No. AP-4

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,232,820 E 752,591
Hole No.: Field AH-5, Permanent AP-5
Name of driller: K. MITCHELL
Total depth of hole: 27.5 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB
Started: 21 JUN 78
El. top of hole: 2205 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
			SM	SAND		ORGANIC, STAINED
2			SM	SILTY GRAVELLY SAND		GREY, TAN
4		1		11%Gr, 41%Si, 48%Sa		SAMPLE #1 AT 3.5' BOULDERS ENCOUNTERED AT 4'
6			GM SM	SANDY SILTY GRAVEL		AUGER DOES NOT GIVE A GOOD GRAVEL SAMPLE
10			SM	SILTY GRAVELLY SAND		DARKER GREY COLOR, MOIST
14			SM	SILTY GRAVELLY SAND		

Project: WATANA DAM — Permanent Hole No. AP-5

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Hole No.: Field AH-5, Permanent AP-5
Name of driller: K. MITCHELL
Total depth of hole: 27.5 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB
Started: 21 JUN 78
El. top of hole: 2205 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
14		2	CL	SANDY CLAY 29%Sa MINUS NO. 200 71% LL 25.8, PI 7.9		DARK GREY, ALMOST PLASTIC SAMPLE #2 AT 15'
18			ML	SANDY SILT		WITH GRAVEL, MOIST, BROWN
20			SM	SILTY GRAVELLY SAND		BROWN-GREY, VERY COMPACT WITH MORE GRAVEL. HIT LARGE BOULDER/COBBLE AT 19.5'
24			SM	SILTY GRAVELLY SAND		MOIST
26		3	SM	SILTY GRAVELLY SAND 11%Gr, 41%Si, 48%Sa LL 19.2, PI 0.9		MOIST, HARD TO DRILL, TIGHT AND COMPACT SAMPLE #3 AT 26'
28				BOTTOM OF HOLE		

Project: WATANA DAM — Permanent Hole No. AP-5

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,233,022 E 752,170
Hole No.: Field AH-6, Permanent AP-6
Name of driller: K. MITCHELL
Total depth of hole: 27.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 6 — Type of samples: GRAB
Started: 21 JUN 78
El. top of hole: 2219 — Geologist: D. JENSEN

Depth feet	Water content	Sample no.	Soil legend	Classification	Max size	Formation description & remarks
			OL	VEGETATION		
2			SM	SILTY SAND		WITH GRAVEL, LIGHT TAN
3		1		49%Si, 51%Sa		SAMPLE #1 AT 3'
4			SM	SILTY SAND		LIGHT TAN
6			ML	GRAVELLY SANDY SILT		GREY BROWN, MOIST
10			ML	SANDY SILT		DARK GREY, MOIST, FEW ROCKS, DRILLS GOOD
12		2	ML	3%Gr, 44%Sa, 53%Si SANDY SILT		WITH FEW ROCKS, MORE MOIST THAN ABOVE. SAMPLE #2 AT 13'
14			ML	SANDY SILT		MOIST, ALMOST PLASTIC, DRILLS WELL, DARK GREY

Project: WATANA DAM — Permanent Hole No. AP-6

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: AUGER HOLES 1 THRU 6 (CONT.)
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-23

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Hole No.: Field AH-6, Permanent AP-6 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 27.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 6 — Type of samples: GRAB — Started: 21 JUN 78
El. top of hole: 2219 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
14		ML	SANDY SILT	SLURRY, COMPLETELY SATURATED
15	3		25%SA, MINUS NO. 200 75% LL 23.4, PI 9.0	SAMPLE #3 AT 15' MC = 20.3%
16–18		CL	SILTY CLAY	DENSE, DARK GREY
18–20	4	CL	35%SA, MINUS NO. 200 65% LL 34.5, PI 13.7 SILTY CLAY	SAMPLE #4 AT 18.5' DENSE, NO ROCKS, BLUE-GREY
20–24	5	CL	SILTY CLAY 13%SA, MINUS NO. 200 87% LL 30.0, PI 13.7	ALMOST PLASTIC, WITH GRAVEL, BLUE-GREY SAMPLE #5 AT 22'
24–27	6	CL	SANDY SILTY CLAY 7%GR, 40%SA MINUS NO. 200 53% LL 23.5, PI 11.0	BLUE GREY, MOIST, SOME GRAVEL SAMPLE #6 AT 27'
27–28			BOTTOM OF HOLE	

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-6

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,234,241 E 755,625
Hole No.: Field AH-7, Permanent AP-7 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 7.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: NONE — Type of samples: GRAB — Started: 21 JUN 78
El. top of hole: 2255 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL-ML	SILTY-VEGETATION	
0–4		SM	SILTY GRAVELLY SAND	EXTREMELY HARD TO DRILL, GREY, FROZEN
4–7		SM	SILTY SAND	WITH COBBLES, FROZEN, DRY FROST. HIT BOULDER AT 7.0'
7			BOTTOM OF HOLE	

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-7

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 5
Location: N 3,234,092 E 755,790
Hole No.: Field AH-8, Permanent AP-8 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 58.3FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 8 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2245 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL-ML	VEGETATION	
0–3	1	SM	SILTY SAND 9%GR, 39%SI, 52%SA	GREY SAMPLE #1 AT 3'
3–5		SM	SILTY SAND	WITH GRAVEL, GREY
5–8	2	CL	SANDY SILTY CLAY 5%GR, 35%SA MINUS NO. 200 60% LL 28.6 PI 11.9	GREY + BLUE SAMPLE #2 AT 7'
8–10	3		9%GR, 30%SA MINUS NO. 200 61% LL 29.3, PI 15.0	SAMPLE #3 AT 9'
10–14	4	CL	SANDY SILTY CLAY	BLUE-GREY, FEELS PLASTIC NOT FROZEN SAMPLE #4 AT 14'

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 5
Hole No.: Field AH-8, Permanent AP-8 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 58.3FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 8 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2245 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
14	4		25%GR, 22%SA MINUS NO. 200 53%	SAMPLE #4 AT 14'
14–18.5		CL	GRAVELLY SANDY CLAY SILTY CLAY	WITH GRAVEL, FROZEN WITH ICE CRYSTALS TO 1/2" SATURATED
18.5–20		CL	SANDY SILTY CLAY	WITH GRAVEL, FROZEN
20–23	5		5%GR, 24%SA MINUS NO. 200 71% LL 28.6, PI 13.2	SAMPLE #5 AT 20' MC = 23%
23–28	6	CL-ML	SILTY CLAY 25%SA, MINUS NO. 200 75% LL 27.4, PI 7.6	FROZEN, ICE CRYSTALS 1/4" TO 1/2" MAX SAMPLE # 6 AT 25' MC = 40%

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 3 of 5
Hole No.: Field AH-8, Permanent AP-8 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 58.3FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 8 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2245 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
28		CL-ML	SILTY CLAY	FROZEN, ICE CRYSTALS TO 1/2" MAX
28–33	7	CL-ML	23%SA, MINUS NO. 200 77% LL 26.2, PI 9.1, SILTY CLAY	SAMPLE #7 AT 30' MC = 31.3% BLUE GREY, MIGHT BE SILT ONLY, VERY SATURATED WITH ICE. DILLER REPORTS ICE LENSES IN DRILLING
33–38		CL-ML	SILTY CLAY	BLUE GREY, FROZEN ICE CRYSTALS
38–42		CL ML	SILTY CLAY	FROZEN, BLUE GREY, SATURATED WHEN THAWED

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 4 of 5
Hole No.: Field AH-8, Permanent AP-8 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 58.3FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 8 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2245 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
42–53		CL-ML	SILTY CLAY	FROZEN, BLUE GREY. SATURATED WHEN THAWED
53–56		ML-CL	SILTY CLAY	FROZEN, SATURATED

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 5 of 5
Hole No.: Field AH-8, Permanent AP-8 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 58.3FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 8 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2245 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
56–58.3	8	CL	SILTY CLAY MINUS NO. 200 99% LL 35.4, PI 13.9	FROZEN, SATURATED SAMPLE #8 AT 58' MC = 28%
58.3			BOTTOM OF HOLE	SET A 3/4" PIPE IN THE HOLE FOR FROST MEASUREMENTS 4.7' STICK UP, CAPS ON BOTH ENDS

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-8

DEPARTMENT OF THE ARMY — NORTH PACIFIC DIVISION — U.S. ARMY ENGINEER DISTRICT, ALASKA — EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,234,460 E 755,514
Hole No.: Field AH-9, Permanent AP-9 — Type of hole: Auger hole
Name of driller: K. MITCHELL — Total depth of hole: 18.0FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB — Started: 23 JUNE 1978
El. top of hole: 2293 — Geologist: D. JENSEN

Depth (ft)	Sample No.	Soil Legend	Classification	Formation Description & Remarks
0		OL-ML	SILT-VEGETATION	FROZEN
0–4	1	SM	SILTY GRAVELLY SAND 7%GR, 37%SI, 56%SA	LIGHT BROWN, FROZEN, SOME COBBLES SAMPLE #1 AT 3.5'
4–9		SM	SILTY GRAVELLY SAND	
9–14	2	SM	SILTY GRAVELLY SAND	DRILLER SAYS FROZEN SAMPLE #2 AT 14' DOESN'T APPEAR SATURATED. VERY COLD DRILLED UP IN LITTLE BALLS. BROWISH TAN

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-9

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: AUGER HOLES 6 (CONT.) THRU 9(CONT)
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-24

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Field hole no.: AH-9 — Permanent hole no.: AP-9
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 18.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB — Date hole started: 23 JUNE 1978
El. top of hole: 2293 — Inspector: D. JENSEN

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
14	2		15%Gr, 33%Si, 52%Sa LL 18.9, PI 4.0	
16	3	SM-SC	Silty Gravelly Sand 5%Gr, 43%Si, 52%Sa LL 11.8, PI 5.2	Frozen Sample #3 at 17'
18			Bottom Of Hole	Set 3/4" Galv. Pipe In Hole Caps Both Ends, 3' Stick Up

Project: WATANA DAM — Permanent hole no.: AP-9

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,235,158 E 756,514 — Corps of Engineers
Field hole no.: AH-10 — Permanent hole no.: AP-10
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 15.0 FT
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 3 — Type of samples: GRAB — Date hole started: 23 JUNE 1978
El. top of hole: 2319 — Inspector: D. JENSEN

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
0		OL	Organic Silt	Brown with Vegetation
2–4	1	SM	Silty Gravelly Sand 7%Gr, 31%Si, 62%Sa	Light Tan Sample #1 at 3.5'
4–8	2	SM	Silty Gravelly Sand 17%Gr, 17%Si, 66%Sa	Little Silt, moist, tan grey Sample #2 at 8'
8–15	3	SM	Silty Gravelly Sand 25%Gr, 18%Si, 57%Sa	Clean Moist Sample #3 at 13' Hit Boulder at 15'
10–15 (5 FT)			Bottom Of Hole	

Project: WATANA DAM — Permanent hole no.: AP-10

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,235,094. E 757,045. — Corps of Engineers
Field hole no.: AH-11 — Permanent hole no.: AP-11
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 25'
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 4 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2309 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
0		OL	SILT	WITH ORGANICS, VEGETATION
0–8		SP SM	SILTY GRAVELLY SAND	BROWN, GRAVELS ROUNDED MOIST
8–12	1	SM	SILTY SAND	SAMPLE # 1 AT 8.1 FT. MOIST, WET, BROWN
12–14	2	ML	SANDY SILT	SAMPLE #2 AT 13.0 FT FROZEN, ICE LENSES AT 12' LENSES OF ORGANIC CLAY

Project: WATANA DAM — Permanent hole no.: AP-11

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Location: N 3,235,094. E 757,045. — Corps of Engineers
Field hole no.: AH-11 — Permanent hole no.: AP-11
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 25'
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 4 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2309 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
14–18		ML	SANDY CLAYEY SILT	FROZEN, MARGINALLY PLASTIC WET, SATURATED WHEN THAWED. OCCASIONAL GRAVELS.
18–25	3, 4	GM	GRAVELLY, SANDY CLAYEY SILT	SAMPLE #3 AT 18.1' FROZEN, BROWN, WET SAMPLE # 4 AT 23 - 25'
25			BOTTOM OF HOLE	

Project: WATANA DAM — Permanent hole no.: AP-11

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,235,414. E 757,404. — Corps of Engineers
Field hole no.: AH-12 — Permanent hole no.: AP-12
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 14.1'
Size and type of bit: 4" AUGER — Type of equipment: B-50
Total no. of samples: 3 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2303 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
0		OL	SILT	W/ ROOTS, ORGANICS, BROWN
0–2.5		ML OL	CLAYEY SILT	W/ ORGANICS, BROWN FROZEN AT 2'
2.5–4	1	SM	GRAVELLY SILTY SAND	FROZEN, BROWN SAMPLE # 1 AT 3.5'
4–8	2	SM	SILTY SAND	FROZEN, BROWN, SOME ORGANIC ZONES SAMPLE # 2 AT 7.5'
8–14.1	3	SM	GRAVELLY, SILTY, SAND	FROZEN, BROWN, TAN, HIT BOULDER AT 14.1' SAMPLE # 3 AT 13.5' - 14.1'
14.1			BOTTOM OF HOLE	

Project: WATANA DAM — Permanent hole no.: AP-12

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 2 of 2
Location: N 3,235,805. E 757,509. — Corps of Engineers
Field hole no.: AH-13 — Permanent hole no.: AP-13
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 22'
Size and type of bit: 4" AUGER — Type of equipment: B-50
Total no. of samples: 4 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2306 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
14–19.5	3	SP	SAND	FROZEN, ISOLATED PEBBLES CLEAN SAMPLE # 3 AT 18.2 - 19'
19.5–22	4	SP	SAND	FROZEN WITH ISOLATED COBBLES, CLEAN SAMPLE #4 AT 21 - 22'
22			BOTTOM OF HOLE	

Project: WATANA DAM — Permanent hole no.: AP-13

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 2
Location: N 3,235,805. E 757,509. — Corps of Engineers
Field hole no.: AH-13 — Permanent hole no.: AP-13
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 22'
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 4 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2306 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
0		OL	SILT	W/ ORGANICS
0–2		OL ML		W/ ORGANICS, WET, BROWN
2–4.5		SM	GRAVELLY SILTY SAND	FROZEN AT 3', BROWN, TAN
4.5–13	1	ML	SANDY, CLAYEY SILT	FROZEN, ISOLATED PEBBLES TAN, PLASTIC, HARD DRILLING SAMPLE # 1 AT 7.5' - 8.2'
13–14	2	SP	SAND	FROZEN, CLEAN, ISOLATED PEBBLES/ SAMPLE #2 AT 13-14'

Project: WATANA DAM — Permanent hole no.: AP-13

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,236,005. E 757,565. — Corps of Engineers
Field hole no.: AH-14 — Permanent hole no.: AP-14
Name of driller: K. MITCHELL
Type of hole: Auger hole — Total depth of hole: 11'
Size and type of bit: 4" AUGER — Type of equipment: B-36
Total no. of samples: 2 — Type of samples: GRAB — Depth to ground water: NE — Date hole started: 28 JUN 78
El. top of hole: 2307 — Inspector: W. FRYE

Depth (feet)	Sample no.	Soil legend	Classification	Formation description & remarks
0		OL	SILT	W/ ORGANICS, VEGETATION
0–1		OL ML	SILT	W/ ORGANICS, DARK BROWN WET
1–4		ML	CLAYEY SILT	W/ ORGANICS, BROWN
4–10	1	SM	GRAVELLY, SILTY SAND	BROWN, TAN, DAMP SAMPLE # 1 AT 8 - 8.5'
10–11	2	SP	GRAVELLY SAND	CLEAN, MOIST, BROWN, TAN SAMPLE # 2 AT 10 - 10.5'
11			B.O.H.	

Project: WATANA DAM — Permanent hole no.: AP-14

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: AUGER HOLES 9 (CONT.) THRU 14

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

Exploration Log — AH-15 / AP-15

Department of the Army, North Pacific Division, U.S. Army Engineer District, Alaska — Exploration Log

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,236,240, E 757,630
- Hole No.: Field AH-15, Permanent AP-15
- Type of hole: Auger hole
- Name of driller: K. Mitchell
- Total depth of hole: 9.5'
- Size and type of bit: 4" Auger
- Type of equipment: B-36
- Total no. of samples: 1 — Type of samples: Grab
- Depth to ground water: NE
- Date hole started: 28 Jun 78
- El. top of hole: 2308 — Geologist: W. Frye

Sample No.	Soil Legend	Classification	Formation Description & Remarks
	OL	Silt	W/ organics and roots
	ML	Silt	W/ some gravel, brown; frozen at 1.5'
1	SM	Gravelly silty sand	Tan, grey, frozen; sample # 1 at 7-8'
		Bottom of hole	

Project: Watana Dam — Permanent Hole No. AP-15

Exploration Log — AH-16 / AP-16

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,236,881, E 758,027
- Drilling agency: Corps of Engineers
- Hole No.: Field AH-16, Permanent AP-16
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60° F
- Total depth of hole: 3.5'
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None — Type of samples: Grab
- Date hole started: 6/13/78 — Completed: 6/13/78
- El. top of hole: 2311 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
	Vegetation	Tundra
ML	Sandy silt w/ organics	Fine, brown
		Bottom of hole (hit boulders)

Project: Watana Dam — Permanent Hole No. AP-16

Exploration Log — AH-17 / AP-17

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,238,045, E 756,310
- Drilling agency: Corps of Engineers
- Hole No.: Field AH-17, Permanent AP-17
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°F
- Total depth of hole: 12.5
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 Mobile
- Total no. of samples: None
- Date hole started: 6/13/78 — Completed: 6/13/78
- El. top of hole: 2405 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
	Vegetation	
ML	Silt	Greyish brown
GM	Silty, sandy gravels	-3/4" rounded gravel. Note: probably frozen @ 9'
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AP-17

Exploration Log — AH-18 / AP-18

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,237,346, E 755,407
- Drilling agency: Corps of Engineers
- Hole No.: Field AH-18, Permanent AP-18
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°F
- Total depth of hole: 16.0'
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None
- Date hole started: 6/13/78 — Completed: 6/13/78
- Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
OL	Organic silt	Vegetation top 0.3'
GM	Silty, sandy gravels	Medium gray rock @ 5'
GM	Silty, sandy gravels	Fine; water table @ 14'
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AP-18

Exploration Log — AH-19 / AP-19

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,236,930, E 756,250
- Drilling agency: Corps of Engineers
- Hole No.: Field AH-19, Permanent AP-19
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°F
- Total depth of hole: 19.3
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None
- Date hole started: 6/13/78 — Completed: 6/13/78
- El. top of hole: 2375 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
OL	Organic silt	Vegetation top 0.3'
GM	Silty sandy gravel	Fine, gray; rocky @ 4'
ML	Sandy silt	Fine, saturated
SM	Silty sand	Fine, light brown, damp but not saturated
GM	Silty sandy gravel	Gray
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AP-19

Exploration Log — AH-20 / AP-20

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,236,325, E 755,158
- Drilling agency: Corps of Engineers
- Hole No.: Field AH-20, Permanent AP-20
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°
- Total depth of hole: 17
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None
- Date hole started: 6/15/78 — Completed: 6/15/78
- El. top of hole: 2355 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
OL	Organic silt	0.5'; vegetation top 0.2'
GM	Silty, sandy gravel	Gray
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AP-20

Exploration Log — AH-21 / AP-21

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,235,352, E 755,176
- Hole No.: Field AH-21, Permanent AP-21
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°F
- Total depth of hole: 19.3
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None
- Date hole started: 6/15/78 — Completed: 6/15/78
- El. top of hole: 2340 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
SM	Silty sand	Vegetation top 0.1'
SP	Silty, gravelly, sand	Grey, very little silt; saturated @ 13'
SM	Silty sand	W/ some gravel
CH	Clay	Dark gray frozen @ 15'
SM	Silty sand	W/ some gravel
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AH-21

Exploration Log — AH-22 / AP-22

- Project: Watana Dam — Sheet 1 of 1
- Location: N 3,234,632, E 754,641
- Hole No.: Field AH-22, Permanent AP-22
- Type of hole: Auger hole
- Name of driller: D. Sullivan — Weather: P/C 60°F
- Total depth of hole: 13.4
- Size and type of bit: 4" Flite Auger
- Datum for elevation shown: MSL
- Type of equipment: B-36 mobile
- Total no. of samples: None
- Date hole started: 6/13/78 — Completed: 6/13/78
- El. top of hole: 2323 — Geologist: T. Sherman

Soil Legend	Classification	Formation Description & Remarks
OL	Organic silt	Brown vegetation top 0.3'
GM	Silty sandy gravel	Brown rocky @ 5'; saturated @ 10'
		Bottom of hole (boulders)

Project: Watana Dam — Permanent Hole No. AP-22

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: AUGER HOLES 15 THRU 22

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-26

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DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,233,760 E 753,415
Drilling agency: Corps of Engineers
Field hole no.: AH-23 — Permanent: AP-23
Type of hole: Auger hole
Name of driller: D. SULLIVAN — Weather: P/C 60°F
Total depth of hole: 9.5'
Size and type of bit: 4" FLITE AUGER
Type of equipment: B-36 MOBILE
Total no. of samples: NONE
Date hole started: 6/15/73 — Completed: 6/15/73
El. top of hole: 2273 — Geologist: T. SHERMAN

DEPTH FEET	WATER CONTENT	SAMPLE NO	SOIL LEGEND	CLASSIFICATION	FORMATION DESCRIPTION & REMARKS
					VEGETATION TOP 0.2'
2			SM	SILTY SAND	SOME ORGANICS
4–8			SM	SILTY SAND, GRAVELLY	CLEAN W/ SOME ANGULAR GRAVEL ORGANICS @ 8' -2" ROUNDED GRAVEL @ 9.5'
10					BOTTOM OF HOLE (BOULDERS)

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-23

DEPARTMENT OF THE ARMY
NORTH PACIFIC DIVISION
U.S. ARMY ENGINEER DISTRICT, ALASKA
EXPLORATION LOG

Project: WATANA DAM — Sheet 1 of 1
Location: N 3,233,770 E 753,400
Drilling agency: Corps of Engineers
Field hole no.: AH-24 — Permanent: AP-24
Type of hole: Auger hole
Name of driller: D. SULLIVAN — Weather: P/C 60°F
Total depth of hole: 15.0'
Size and type of bit: 4" FLITE AUGER
Type of equipment: B-36 MOBILE
Total no. of samples: NONE
Date hole started: 6/15/73 — Completed: 6/15/73
El. top of hole: 2255 — Geologist: T. SHERMAN

DEPTH FEET	WATER CONTENT	SAMPLE NO	SOIL LEGEND	CLASSIFICATION	FORMATION DESCRIPTION & REMARKS
			SM	SILTY SAND	SOME ORGANICS
4–12			SM	SILTY SAND, GRAVELLY	SOME GRAVELS FROZEN @ 11.5'
16					BOTTOM OF HOLE (BOULDERS)

PROJECT WATANA DAM — PERMANENT HOLE NO. AP-24

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
BORROW AREA D
LOGS: AUGER HOLES 23 THRU 24

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-27

SUMMARY LOG — HOLE NO. DH-1 (Sheet 1 of 2)

N 3226585 / E 744341	SHEET 1 OF 2	SURFACE ELEV. 1459
PROJECT: Watana Dam	DRILL DATES: START 28 Mar 78	COMP. 2 Apr 78
DEPTH OF HOLE 122.8'	DEPTH OF OVERBURDEN 43.8'	DIAM. OF HOLE NCO
ROCK DRILLED 79.0'	CORE RECOVERED 79.0'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -----	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 122.8'; HORIZONTAL, -----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	0	Overburden: Gravels Cobbles And Boulders In Sand Matrix		Tricone Bit 0.0' To 11.5'. Core Drilled 11.5' To Bottom
	10	Boulders To 3' In Diameter 11' To 17'		4 Inch CSG To 13.6'
	20	Cobbles To 0.7' With Minor Clay On Surfaces. 21' To 24' Diorite Boulder 24.2' - 27.9'		
1415	40	Top Of Rock		43.8'
		Quartz Diorite, Soft To Hard, Medium Grained, Moderately Weathered (Highly Weathered In Shears), Highly Fractured, Light Gray. Clay Gouge And Slickensides Common.		NW Casing To 47.5'. Fracture Spacing 44'-60' <0.1' To 0.8'. 53.6'
1400	60	Diorite, Hard, Medium Grained, Lightly Weathered (Moderately Weathered On Fractures), Moderately To Lightly Fractured, Light Gray. Iron Stain In Fractures Common.		K=0.48. Fracture Spacing 60'-80' 0.1' To 1.6'. 1.6, 2, 1
	80	Fine, Disseminated Pyrite Present Throughout.		K=2.52. Fracture Spacing 80'-100' <0.1' To 0.9'. 2, 3
	100	Shear Zone 96.1' To 105.1'		

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-1

SUMMARY LOG — HOLE NO. DH-1 (Sheet 2 of 2)

N 3226585 / E 744341	SHEET 2 OF 2	SURFACE ELEV. 1459
PROJECT: Watana Dam	DRILL DATES: START 28 Mar 78	COMP. 2 Apr 78
DEPTH OF HOLE 122.8'	DEPTH OF OVERBURDEN 43.8'	DIAM. OF HOLE NCO
ROCK DRILLED 79.0'	CORE RECOVERED 79.0'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -----	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 122.8'; HORIZONTAL, -----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Shear Zone 96.1' To 105.1'. Rock Grades Between Diorite And Granodiorite 117.1' To Bottom. Gouge 111.6'. Porphoritic Andesite Inclusion 116.8' To 117.1'		Fracture Spacing 100'-110' 0.1' To 0.5'. K=1.98. Fracture Spacing 110'-122.8' 0.1' To 2.5'
1336	120			122.8' 3
		Bottom Of Hole. Depth of Hole 122.8'; Thickness of Overburden 43.8'; Rock Cored 79.0'; Core Recovered 79.0'; % Core Recovered 100		

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-1

SUMMARY LOG — HOLE NO. DH-2 (Sheet 1 of 1)

N 3226585 / E 744341	SHEET 1 OF 1	SURFACE ELEV. 1463
PROJECT: Watana Dam	DRILL DATES: START 25 Mar 78	COMP. 12 Apr 78
DEPTH OF HOLE 29.0'	DEPTH OF OVERBURDEN 29.0'	DIAM. OF HOLE NCO
ROCK DRILLED 0.0'	CORE RECOVERED 0.0'	% RECOVERY N/A
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -----	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 29.0'; HORIZONTAL, -----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	0	Overburden: Boulders, Cobbles And Gravel With Minor Sand.		Hole Attempted Four Times; Maximum Advance Was 29.0'
1434	30			29.0'
		Bottom Of Hole. Depth Of Hole 29.0'; Thickness of Overburden 29.0'; Rock Cored 0.0'; Core Recovered N/A		

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-2

SUMMARY LOG — HOLE NO. DH-3 (Sheet 1 of 2)

N 3226688 / E 743355	SHEET 1 OF 2	SURFACE ELEV. 1459
PROJECT: Watana Dam	DRILL DATES: START 3 Apr 78	COMP. 18 Apr 78
DEPTH OF HOLE 174.5'	DEPTH OF OVERBURDEN 77.6'	DIAM. OF HOLE NCO/BX
ROCK DRILLED 96.9'	CORE RECOVERED 81.3'	% RECOVERY 83.3
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 174.5'; HORIZONTAL, ----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	0	Overburden; Gravel, Cobbles And Boulders In Sand Matrix		River Hole. 4 Inch Csg To 15.6'
1433	26	Gravelly Sand		26'
1418	40	Gravel, Cobbles And Boulders In Sand Matrix		41'. NX CSG To 52.2'
	70	Boulders To 3.5' Below 65'		BX Csg To 74.5'
1381	77.6	Top Of Rock		77.6'
	80	Diorite, Hard, Medium Grained Moderate To Highly Fractured, Gray; Rock Irregularly Grades To Quartz Diorite And Granodiorite. Clay Coating on Fractures Common.		BX Core. Core Loss Due to Mechanical Problems. Fractures Spacing 77.6'-100' 0.1' To 0.8'

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-3

SUMMARY LOG — HOLE NO. DH-3 (Sheet 2 of 2)

N 3226688 / E 743355	SHEET 2 OF 2	SURFACE ELEV. 1459
PROJECT: Watana Dam	DRILL DATES: START 3 Apr 78	COMP. 18 Apr 78
DEPTH OF HOLE 174.5'	DEPTH OF OVERBURDEN 77.6'	DIAM. OF HOLE NCO/BX
ROCK DRILLED 96.9'	CORE RECOVERED 81.3'	% RECOVERY 83.3'
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -----	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 174.5'; HORIZONTAL, -----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Diorite; Ibid. Light To Moderate Fracture 100' To 130'		No DWR. Fracture Spacing 100'-130' 0.1' To 2.4'
	140	Moderately To Highly Fractured 130' To 150'		Fracture Spacing 130'-150' <0.1' To 0.9'
	160	Lightly Fractured 150' To Bottom.		Core Loss Due to Mechanical Problems. Fracture Spacing 150'-Bottom <0.1' To 1.5'
1285	174.5			174.5'
		Bottom Of Hole. Depth Of Hole 174.5'; Thickness of Overburden 77.6'; Rock Cored 96.9'; Core Recovered 81.3'; % Core Recovered 83.3%		Hole Not Pressure Tested; Hole Caved

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-3

SUMMARY LOG — HOLE NO. DH-4 (Sheet 1 of 2)

N 3226649 / E 744376	SHEET 1 OF 2	SURFACE ELEV. 1460
PROJECT: Watana Dam	DRILL DATES: START 17 Apr 78	COMP. 23 Apr 78
DEPTH OF HOLE 122.9'	DEPTH OF OVERBURDEN 77.7'	DIAM. OF HOLE NQ
ROCK DRILLED 45.2'	CORE RECOVERED 40.9'	% RECOVERY 90.5
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH —	COMPILED BY, DATE: 10 Oct 78
DISTANCES: VERTICAL, 122.9'; HORIZONTAL, —		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1460	0	Overburden: Gravels, Cobbles And Boulders With Sand.		5" Csg To 7.9'
1382	77.7	Top Of Rock		77.7'
	80	Quartz Diorite, Very Hard, Medium Grained, Lightly Weathered, Lightly Fractured, Gray.		NX Csg To 78.1'. Fracture Spacing 78' To 100' <0.1'-4.0'

NPA Form 7(Test) APR 66 — PROJECT Watana Dam — HOLE NO. DH-4

LEGEND

- Acidic intrusives including diorite, quartz diorite and granodiorite
- Andesite
- Breccia (used with rock type)
- Porphoritic andesite
- Shear
- Rock fragments
- Boulder
- Gravel
- Sand
- Silt
- Clay
- Core recovery: Recovered / Lost

NOTES

1. DH. Diamond drill hole (core). DR. Large diameter mud and air rotary. Coning in bedrock.
2. Holes DH-1 through DH-5 drilled from river ice: overburden thickness will vary
3. For core loss shown on DR holes, see remarks column
4. Lightly fractured - core lengths generally greater than 0.8 feet. Moderately fractured - core lengths generally between 0.4 feet and 0.8 feet. Highly fractured - core lengths generally less than 0.4 feet.
5. Lightly weathered - essentially fresh, hard rock. Moderately weathered - medium hard rock, stained, individual grains can be freed with some difficulty. Highly weathered - relatively soft rock, generally stained, individual grains can be freed with little difficulty
6. Pressure tests performed with air packers.
7. Drive samples - 300 pound hammer/30 inch drop and 3 inch drive spoon, unless noted
8. Following plates have photos of all core samples.

ABBREVIATIONS

- CSG - Casing
- DWR - Drill water return
- IBID - As described above, except as noted
- K - Transmissibility constant, measured in feet per minute per square foot $\times 10^{-4}$
- SWL - Static water level

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 1
DH-1 THRU DH-4

ALASKA DISTRICT CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUMMARY LOG — HOLE NO. DH-4 (Sheet 2 of 2)

N 3226680	E 704376	SURFACE ELEV. 1460
PROJECT Watana Dam	DRILL DATES: START 17 Apr 78	COMP. 23 Apr 78
DEPTH OF HOLE 122.9'	DEPTH OF OVERBURDEN 77.7'	DIAM. OF HOLE NQ
ROCK DRILLED 45.2'	CORE RECOVERED 40.9'	% RECOVERY 90.5
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE Sat 10 Oct 78
DISTANCES: VERTICAL, 122.9'; HORIZONTAL,		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz Diorite: Ibid		Fracture Spacing 100' To 122.9 0.1' To 3.3' Core Loss Due To Mechanical Problems
1337	120			122.9'
	130	Bottom Of Hole Depth of Hole 122.9' Thickness of Overburden 77.7' Rock Drilled 45.2' Core Recovered 40.9' Percent Core Recovery 90.5		Hole Not Pressure Tested Due To Caving

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-4

SUMMARY LOG — HOLE NO. DH-5 (Sheet 1 of 2)

N 3226539	E 744410	SURFACE ELEV. 1460
PROJECT Watana Dam	DRILL DATES: START 18 Apr 78	COMP. 3 May 78
DEPTH OF HOLE 176.9'	DEPTH OF OVERBURDEN 59.6'	DIAM. OF HOLE NQ
ROCK DRILLED 117.3'	CORE RECOVERED 114.0'	% RECOVERY 97%
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ------	COMPILED BY, DATE ASM 22 June 1978
DISTANCES: VERTICAL, 176.9'; HORIZONTAL, ------		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1460	0	Overburden: Gravels, Cobbles And Boulders With Some Sand		
1400	60	Top Of Bedrock		NX Csg Reamed To 59.2' 59.6'
		Quartz Diorite: Very Hard, Medium To Coarse Grained, Lightly Weathered, Moderately To Lightly Fractured Light Gray.		Fracture Spacing 60' To 70'; 0.1' To 0.3' Core Loss Due To Mechanical Problems Fracture Spacing 70' To 80' 0.01' To 1.4' 100% Dwr; 59.6' To 88.6'
	80	Shear Zone 73.0' To 100.0' Highly Fractured With Slicks And Gouge. Hole Following Near Vertical (35°) Shear		25% Dwr; 88.6' To 92.8' Fracture Spacing 80' To 100'; 0.1' 0.6' No Dwr 92.8' To Bottom
	100			

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-5

SUMMARY LOG — HOLE NO. DH-5 (Sheet 2 of 2)

N 3226539	E 744410	SURFACE ELEV. 1460
PROJECT Watana Dam	DRILL DATES: START 18 Apr 78	COMP. 3 May 78
DEPTH OF HOLE 176.9'	DEPTH OF OVERBURDEN 59.6'	DIAM. OF HOLE NQ
ROCK DRILLED 117.3'	CORE RECOVERED 114.0'	% RECOVERY 97%
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE AGM 22 June 1978
DISTANCES: VERTICAL, 176.9 HORIZONTAL,		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz Diorite: Ibid Healed Fractures Common To 111.3'		
	120	Slicks At 123.1'		
	140			Fracture Spacing 100' To 176.9'; 0.1' To 1.7'
1283	170			Left 0.2' In Hole 176.9'
	180	Bottom Of Hole Depth Of Hole 176.9 Thickness Of Overburden 59.6 Rock Drilled 117.3 Core Recovered 114.0 Percent Core Recovery 97%		Hole Not Pressure Tested-River Ice Deteriorated Rapidly
	200			

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-5

SUMMARY LOG — HOLE NO. DH-6 (Sheet 1 of 2)

N 3227119	E 744219	SURFACE ELEV. 1716
PROJECT Watana Dam	DRILL DATES: START 28 Apr 78	COMP. 2 May 78
DEPTH OF HOLE 149.5'	DEPTH OF OVERBURDEN 3.5'	DIAM. OF HOLE NCQ
ROCK DRILLED 146.0'	CORE RECOVERED 143.9'	% RECOVERY 98.6
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ------	COMPILED BY, DATE Sat 10 Oct 78
DISTANCES: VERTICAL, 149.5'; HORIZONTAL,		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1716 1712	0	Overburden, Organic Silt With Rock Fragments		3.5'
	10	Diorite, Medium Hard, Medium Grained, Moderately to Highly Weathered, Moderately To Highly Fractured, Light Gray Iron Staining Common On Fractures, Occassional Shears With Slickensides And Gauge Moderately Weathered From 10.0' To 40.0'		Fracture Spacing 3.5'-10' 0.1' To 0.5' NX Casing To 8.4' 1 No Dwr 0.0 To 31.0' K: 0.0 2 Fracture Spacing 10'-60' 0.1' To 2.0' 1 Dwr 50% 31.0' To 48.0'
	40	Diorite, Ibid, Very Hard, Lightly Weathered, Lightly To Moderately Fractured With Occassional Highly Fractured And Shear Zones Shear 59.0' To 59.2' (60°)		No Dwr 48.0' To Bottom. 3 2 K: 0.0 Fracture Spacing 60'-70' 0.1' To 0.8' 4 3 K = 2.13 Fracture Spacing 70'-90' <0.1' To 1.2' 5 4 K 0.34
	100			

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-6

SUMMARY LOG — HOLE NO. DH-6 (Sheet 2 of 2)

N 3227119	E 704219	SURFACE ELEV. 1716
PROJECT Watana Dam	DRILL DATES: START 28 Apr 78	COMP. 2 May 78
DEPTH OF HOLE 149.5'	DEPTH OF OVERBURDEN 3.5'	DIAM. OF HOLE NCQ
ROCK DRILLED 146.0'	CORE RECOVERED 143.9	% RECOVERY 98.6
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE Sat 10 Oct 78
DISTANCES: VERTICAL, 149.5'; HORIZONTAL,		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Diorite, Ibid		Fracture Spacing 90'-110' <0.1' To 0.8' 6
	110	Highly Fractured 112.1' To 122.4'		Fracture Spacing 110'-120' <0.1' To 1.1' K = 0.5
	120			Fracture Spacing 120'-130' <0.1' To 0.9' 6 7
	130			SWL 132.0' 2 May 78 Fracture Spacing 130'-140' 0.1' To 1.1' K: 0.38
1611	140	Moderately Fractured 142.2' To Bottom		Fracture Spacing 140'-149.5' <0.1' To 0.7' 149.5' 7
	150	Bottom Of Hole Depth of Hole 149.5 Thickness of Overburden 3.5 Rock Cored 146.0 Core Recovered 143.9 % Core Recovered 98.6		

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-6

SUMMARY LOG — HOLE NO. DH-7 (Sheet 1 of 2)

N 3227117	E 744219	SURFACE ELEV. 1716
PROJECT Watana Dam	DRILL DATES: START 6 May 1978	COMP. 17 May 1978
DEPTH OF HOLE 122.2'	DEPTH OF OVERBURDEN 8.5'	DIAM. OF HOLE NCQ
ROCK DRILLED 113.7'	CORE RECOVERED 108.3'	% RECOVERY 95
ANGLE FROM VERT. 31°	AZIMUTH FROM NORTH 210°	COMPILED BY, DATE ASM 22 June 1978
DISTANCES: VERTICAL, 104.8'; HORIZONTAL, 63.0'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1716	0	Overburden: Sand With Rock Fragments		No Dwr Full Depth
1709		Top Of Rock		8.5'
	10	Diorite: Hard, Medium Grained, Highly Fractured To Medium Fractured, Grey Highly Weathered Zone 8.5 To 16.0		NX Csg to 19.6'
	20	Shear Zone 24.0 To 29.0' Iron Staining On Fractures Common.		Fracture Spacing 8.5'-30' <0.1' To 0.5'
	40	Shear Zone 44.0' To 47.0'		Fracture Spacing 40' to 70' <0.1' To 1.6
	60	Quartz Rich, Veins 60.5'-61.9'		
	70	Shear Zone 79' To 90'		Fracture Spacing 70'-90' <0.1' To 0.6' Fracture Spacing 90' To 100' <0.1' To 1.7'
	100			

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-7

SUMMARY LOG — HOLE NO. DH - 7 (Sheet 2 of 2)

N 3227117	E 744219	SURFACE ELEV. 1716
PROJECT Watana Dam	DRILL DATES: START 6 May 1978	COMP. 17 May 78
DEPTH OF HOLE 122.2'	DEPTH OF OVERBURDEN 8.5'	DIAM. OF HOLE NQ
ROCK DRILLED 113.7'	CORE RECOVERED 108.3'	% RECOVERY 95
ANGLE FROM VERT. 31°	AZIMUTH FROM NORTH 210°	COMPILED BY, DATE AGM 22 June 1978
DISTANCES: VERTICAL, 104.8'; HORIZONTAL, 63.0'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Diorite: Ibid		Fracture Spacing 100' To 110' <0.1' To 1.0'
	110	Shear Zone W/Slicks And Gouge 111.0' - 113.9'		Fracture Spacing 100' -122.2' 0.1' To 1.7'
1610	120			122.2'
		Bottom of Hole Depth of Hole 122.2' Thickness of Overburden 8.5' Rock Cored 113.7' Core Recovered 108.3' % Core Recovered 95		Hole Not Pressure Tested Due to Caving

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DH-7

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

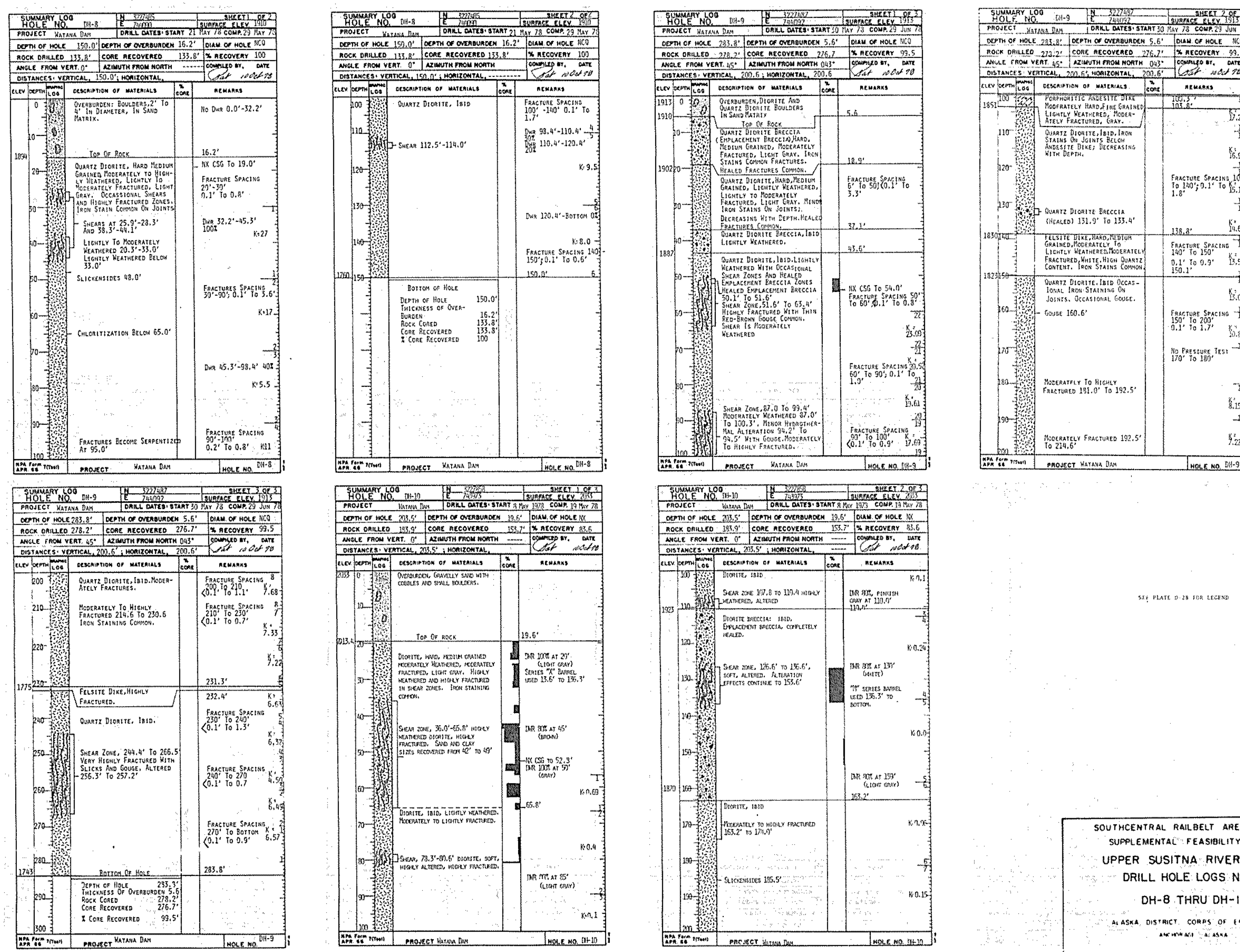
UPPER SUSITNA RIVER BASIN

DRILL HOLE LOGS NO. 2

DH-4 (CONT.) THRU DH-7

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-29



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 3

DH-8 THRU DH-10

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-30

SUMMARY LOG — HOLE NO. DH-10

N 3227858 | E 743073 | SHEET 3 OF 3 | SURFACE ELEV. 2033

PROJECT Watana Dam | DRILL DATES: START 8 May 1978 COMP. 19 May 78

DEPTH OF HOLE 203.5' | DEPTH OF OVERBURDEN 19.6' | DIAM. OF HOLE NX

ROCK DRILLED 183.9' | CORE RECOVERED 153.7' | % RECOVERY 83.6

ANGLE FROM VERT. 0° | AZIMUTH FROM NORTH ------ | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 203.5'; HORIZONTAL, -----

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1829.5	200	Diorite, Ibid.		203.5
	210	Bottom of Hole Depth of hole 203.5' Thickness of overburden 19.6' Rock cored 183.9' Core recovered 153.7' % Core recovered 83.6'		Hole drilled in near vertical shear zone.

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH-10

SUMMARY LOG — HOLE NO. DH 11

N 3227856 | E 743970 | SHEET 1 OF 3 | SURFACE ELEV. 2034

PROJECT Watana Dam | DRILL DATES: START 22 May 1978 COMP. 5 Jun 78

DEPTH OF HOLE 300.0' | DEPTH OF OVERBURDEN 22.7' | DIAM. OF HOLE NX

ROCK DRILLED 277.3' | CORE RECOVERED 276.1' | % RECOVERY 99.6

ANGLE FROM VERT. 45° | AZIMUTH FROM NORTH 032° | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 212.1'; HORIZONTAL, 212.1'

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
2034	0	Overburden, Gravelly Sand Boulders		Tricone Bit 0.0 to 10.8' Started Coring At 10.8'
	20	Boulder 20.6' To 22.7'		
2016		Top Of Rock		22.7'
	30	Quartz Diorite, Moderately Hard To Hard, Medium Grained, Moderately Weathered, Highly Fractured, Gray; Highly Weathered In Shears. Iron Staining Common On Joints, Slickensides Common.		NX Casing To 22.7'
	40			Lost All Dwr At 42.0'
	50	Shear Zone 47.2' To 52.4' Lightly Weathered Below 52.4' Moderately Fractured Below 52.4'		Fracture Spacing 50' To 80' 0.1' To 1.5'
	60			1 Dwr 50% To 100% 42' To 86'
	70			K: 0.11
	80			SWL 80' (7 Jun 78) 1/2 Fracture Spacing 80' to 90'; 0.1' to 0.9'
	90			Lost All Dwr 86.0' To 215.0' K: 13.05 Fracture Spacing 90' To 100'; 0.1' To 1.5'
	100			2

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH 11

SUMMARY LOG — HOLE NO. DH-11

N 3227856 | E 743970 | SHEET 2 OF 3 | SURFACE ELEV. 2034

PROJECT Watana Dam | DRILL DATES: START 22 May 1978 COMP. 5 Jun 78

DEPTH OF HOLE 300.0' | DEPTH OF OVERBURDEN | DIAM. OF HOLE NX

ROCK DRILLED 277.3' | CORE RECOVERED 276.1' | % RECOVERY 99.6'

ANGLE FROM VERT. 45° | AZIMUTH FROM NORTH 032° | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 212.1'; HORIZONTAL, 212.1'

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz Diorite; Ibid; Lightly Weathered, Moderately To Lightly Fractured.		Fracture Spacing 100' To 110'; 0.1' To 1.9' K: 0.58
	110	Shear Zone 114.0' To 120.0' Highly Fractured with Gouge		Fracture Spacing 110' To 120'; 0.1' To 0.7' 3/4
	120			
1929	130	Quartz Diorite Breccia; Ibid; Emplacement Breccia, Completely Healed.		K: 4.15
	140			4/5
1915	150	Andesite Dike, Hard, Fine Grained Lightly Fractured, Dark Gray, Porphoritic.		149.4' K: 4.1 152.2'
	160	Quartz Diorite Breccia, Ibid. Thin Clay Gouge At 161.8'		5/6 Fracture Spacing 120' To 190'; 0.1' To 2.1'
	170			K: 0.82
	180			6/7
	190	Shear 191.6' To 195.5' Very Highly Weathered, Very Highly Fractured.		K: 5.47 Fracture Spacing 190' To 200'; 0.1' To 0.4'
	200			7

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH 11

SUMMARY LOG — HOLE NO. DH-11

N 3227856 | E 743970 | SHEET 3 OF 3 | SURFACE ELEV. 2034

PROJECT Watana Dam | DRILL DATES: START 22 May 1978 COMP. 5 Jun 78

DEPTH OF HOLE 300.0' | DEPTH OF OVERBURDEN 22.7' | DIAM. OF HOLE NX

ROCK DRILLED 277.3' | CORE RECOVERED 276.1' | % RECOVERY 99.6'

ANGLE FROM VERT. 45° | AZIMUTH FROM NORTH 032° | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 212.1'; HORIZONTAL, 212.1'

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	200	Quartz Diorite Breccia; Ibid. Moderately To Highly Fractured 201.0 To 205.4 Moderately To Lightly Fractured 205.0 To Bottom. Breccia Grades To Quartz Diorite Between 205' And 210'		8 Fracture Spacing 200' To 300'; 0.1' To 2.6' K: 2.98
	220			Dwr 10% 215' To 245' 8/9
	230			K: 7.07
	240			9/10
	250			Dwr Lost 245' To Bottom. K: 3.24
	260			10/11
	270			K: 5.04
1796	280	Bottom Of Hole Depth Of Hole 300.0' Thickness Of Overburden 22.7' Rock Cored 277.3' Core Recovered 276.1' % Core Recovered 99.6		11/12
	290			K: 0.16
	300			0.3' Left In Hole 300.0' 12

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH 11

SUMMARY LOG — HOLE NO. DH-12

N 3225738 | E 744620 | SHEET 1 OF 4 | SURFACE ELEV. 1951

PROJECT Watana Dam | DRILL DATES: START 11 Jun 78 COMP. 3 Jul 78

DEPTH OF HOLE 301.1' | DEPTH OF OVERBURDEN 9.5' | DIAM. OF HOLE NX

ROCK DRILLED 291.6' | CORE RECOVERED 285.3' | % RECOVERY 9?%

ANGLE FROM VERT. 0° | AZIMUTH FROM NORTH ------- | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 301.1'; HORIZONTAL, -------

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1951	0	Overburden: Talus, 0.3' To 0.7' Diorite Cobbles, Subangular To Subrounded.		100% Dwr, Full Depth SWL 0.0' To 1.4' (21 Jun-3 Jul 78)
1942	10	Top Of Rock Quartz Diorite, Hard Medium Grained, Moderately Weathered Moderately Fractured, Gray. Iron Staining Common On Fractures. Occasional Hydrothermal Alteration, Healed Emplacement Breccia And Shear Zones.		9.5' Started Coring At 10.8' Top Of Permafrost 14' (11 Jul 78)
	20	Shear 26.5' To 27.7'		NX Csg to 19.4' Fracture Spacing 10'-30'; 0.1' To 0.7'
	30	Quartz Diorite, Ibid, Lightly Weathered.		27.7
	40			Fractured Spacing 30'-50'; 0.1' To 2.5'
	50	Hydrothermal Alteration 46.6' To 61.0' Healed Breccia 53.0' - 55.6'		Series X Core Barrel Used 10.8' To 97.2' Hole Pressure Tested 21.9' To 102.9' K 0.0; Permafrost.
	60	Pyrite Common on Fractures.		
	70			Fracture Spacing 50'-100'; 0.1' To 1.0'
	80	Shear 84.1' To 85.5' Minor Hydrothermal Alteration 84.1' To 102.9'		
	90	Shear 91.2' To 97.9'		
	100			

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH-12

SUMMARY LOG — HOLE NO. DH-12

N 3225738 | E 744620 | SHEET 2 OF 4 | SURFACE ELEV. 1951

PROJECT Watana Dam | DRILL DATES: START 11 Jun 78 COMP. 3 Jul 78

DEPTH OF HOLE 301.1' | DEPTH OF OVERBURDEN 9.5' | DIAM. OF HOLE NX

ROCK DRILLED 291.6' | CORE RECOVERED 285.3' | % RECOVERY 91%

ANGLE FROM VERT. 0° | AZIMUTH FROM NORTH ----- | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 301.1'; HORIZONTAL, --------

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Shear, 100.5' To 103.0' Highly Fractured; Decomposed 101.0' To 102.9'		Series M Core Barrel Used 97.2' To Bottom.
	110	Quartz Diorite, Ibid, Light To Moderately Fractured Except In Shears		No Pressure Tests Below 102.9'; Permafrost
	130	Healed Breccia 135.6' To 137.2'		Fracture Spacing 100'-200'; 0.1' To 1.8'
	180	Shear 175.0' To 184.2' Moderately To Highly Fractured; Decomposed With Gray Gouge 180.7' To 183.3'		
	190	Healed Shear 192.7' To 193.7'		
	200			

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH-12

SUMMARY LOG — HOLE NO. DH-12

N 3225738 | E 744620 | SHEET 3 OF 4 | SURFACE ELEV. 1951

PROJECT Watana Dam | DRILL DATES: START 11 Jun 78 COMP. 3 Jul 78

DEPTH OF HOLE 301.1' | DEPTH OF OVERBURDEN 9.5' | DIAM. OF HOLE NX

ROCK DRILLED 291.6' | CORE RECOVERED 285.3' | % RECOVERY 9?%

ANGLE FROM VERT. 0° | AZIMUTH FROM NORTH ------ | COMPILED BY, DATE 10 Oct 78

DISTANCES: VERTICAL, 301.1'; HORIZONTAL, ------

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	200	Quartz Diorite, Ibid		
	250	Healed Shear 249.5' To 250.9'		Fracture Spacing 200' To 300' 0.1' To 4.2'
	270	Healed Shear 269.5' To 279.0'		
	290	Quartz Diorite Emplacement Breccia 291.5' To 296.5'		
	300			

NPA Form APR. 66 1(Test) | PROJECT Watana Dam | HOLE NO. DH-12

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 4
DH-10 (CONT.) THRU DH-12

ALASKA DISTRICT CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-31

SUMMARY LOG — HOLE NO. DH-12

N 3225738	E 74600	SHEET 4 OF 4
PROJECT Watana Dam	DRILL DATES: START 11 Jun 78 COMP. 3 Jul 78	SURFACE ELEV. 1951
DEPTH OF HOLE 301.1'	DEPTH OF OVERBURDEN 9.5'	DIAM. OF HOLE NX
ROCK DRILLED 291.6'	CORE RECOVERED 285.3'	% RECOVERY 98%
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 301.1'; HORIZONTAL, --------		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1650	301	Quartz diorite ibid.		
		Bottom Of Hole		301.1'
	310	Depth Of Hole 301.1' Thickness Of Over-Burden 9.5' Rock Cored 291.6' Core Recovered 285.3' Percent Core Recovered 98%		3/4 Inch Galvanized Pipe Installed As Temperature Probe, Readable To 127.8' (11 Jul 78)

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-12

SUMMARY LOG — HOLE NO. DR-13

N 3235654	E 752106	SHEET 1 OF 1
PROJECT Watana Dam	DRILL DATES: START 17 Apr 1978 COMP. 20 Apr 1978	SURFACE ELEV. 2321
DEPTH OF HOLE 84'	DEPTH OF OVERBURDEN 84'	DIAM. OF HOLE See Remarks
ROCK DRILLED 0'	CORE RECOVERED N/A	% RECOVERY N/A
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ---	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 84'; HORIZONTAL,		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2321	0	ML, Gravelly, sandy silt, brown, non-plastic. Rounded minus 3/4 inch gravels. [Glacial Outwash]	1	8 inch roller bit and air 0'-19' Sample 1, 0'-17' cuttings 15'
2306	20	Silty clay, blue-gray, moist (15'-20') to damp (20'-78'), plastic (45'-65') non-plastic (15'-45' & 65'-78') varved.	2	SWL 15.6' (22 Apr '78) Sample 2, 17'-26' cuttings 6 inch roller bit and air 19'-60'
	30	CL 15'-45' Minor rounded gravel above 45'	3	8 inch CSG to 20' 6 inch CSG to 21' Sample 3, 26'-35' cuttings
	40		4	Sample 4, 35'-45' cuttings
	50	[Lake Deposit] CH 45'-65'	5	Sample 5, 45'-55' cuttings
	60		6, 7	Sample 6, 60.0'-60.5' Sample 7, 60.5'-61.0' Drive Samples
	70	CL 65'78'	8	Sample 8, 65'-75' cuttings 5 inch CSG to 81' 78'
2237	80	Sandy gravel, brown, wet, loose, non-plastic. Artesian head to 15.6'		NX Core 81'-84' No recovery 84'
	90	Bottom of Hole Depth of Hole 84'		
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-13

SUMMARY LOG — HOLE NO. DR-14

N 3235725	E 756634	SHEET 1 OF 1
PROJECT Watana Dam	DRILL DATES: START 25 Apr 1978 COMP. 26 Apr 78	SURFACE ELEV. 2340
DEPTH OF HOLE 75'	DEPTH OF OVERBURDEN 75'	DIAM. OF HOLE See Remarks
ROCK DRILLED 0'	CORE RECOVERED N/A	% RECOVERY N/A
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ---	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 75'; HORIZONTAL, ---		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2340	0	SM, Gravelly, silty sand, brown, damp. Gravels small and rounded. Sands angular with occasional mica. (Glacial Till/Outwash)	1	6 inch button bit and air 0'-20' 5 1/2 inch button bit and air 20'-61' 3 3/8 inch button bit and air 61'-75' 20' 6 inch Csg to 20'
2320	20	SM, Gravelly, silty sand, gray, damp, dense.	2	Perched water table at 20' SWL 28.6' (18 Aug 78) SWL 30.5' (23 Jun 78) 34'
	40	SM-SC, silty, gravelly sand gray, damp, dense.	3	SWL 37.8' (26 Apr 78) 41'
	50	GM, silty, sandy gravel, gray, damp, dense.	4	Sample 4, 41'-51' 53'
	60	SM-SM, silty, gravelly sand, gray, wet, permeable. Artesian head to 37.8'.	5 6	Sample 5, 51'-61' Sample 6, 61'-63' 70'
2265	70	SM, gravelly, silty sand, gray, wet. (Alluvial Deposit)	7	4 inch CSG to 71' 75'
	80	Bottom of Hole Depth of hole 75'		All samples from cuttings.
	90			
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-14

SUMMARY LOG — HOLE NO. DR-15 (Sheet 1)

N 3234335	E 754173	SHEET 1 OF 4
PROJECT Watana Dam	DRILL DATES: START 27 Apr 1978 COMP. 16 May 1978	SURFACE ELEV. 2294
DEPTH OF HOLE 316.5'	DEPTH OF OVERBURDEN 286'	DIAM. OF HOLE See Remarks
ROCK DRILLED 30.5'	CORE RECOVERED 21.3'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE 18 Oct 78
DISTANCES: VERTICAL, 316.5'; HORIZONTAL,		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2294	0	SM, Silty, gravelly sand, brown damp, non-plastic, Gravel sub-rounded to 2 inch diameter. (Outwash)	1	8 inch button bit and air, 0' to 18'. Sample 1, 0'-15' cuttings 15'
2279		GM-GC, silty, sandy gravel, gray, damp to wet, non-plastic. Occasional Rock fragments.	2	Sample 2, 15'-22', Cuttings 22' 8 inch Csg to 18.5'
2272	20	CL, sandy silt, gray, damp, non-plastic. Occasional sand and gravel. (Lake Deposit)	3 4	Sample 3, 25.0'-26.3' Drive sample Sample 4, 26.3'-36' cuttings 36'
2258	40	GP-GM, silty, sandy gravel to SP-SC, gravelly, silty sand, gray, wet, marginally plastic. Gravel rounded to 2 inch diameter. (Outwash)	5 6	Sample 5, 41.0'-42.0' Drive sample 6 inch button bit and air, 18'-51' 65'
2229	70	Gravelly clay with boulders and cobbles, gray, damp, dense, plastic. Random layers of sand and silt. (Till)	7	Sample 7, 67.0'-67.5' Drive sample
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-15

SUMMARY LOG — HOLE NO. DR-15 (Sheet 2)

N 3234335	E 754173	SHEET 2 OF 4
PROJECT Watana Dam	DRILL DATES: START 27 Apr 1978 COMP. 16 May 1978	SURFACE ELEV. 2294
DEPTH OF HOLE 316.5'	DEPTH OF OVERBURDEN 286'	DIAM. OF HOLE See Remarks
ROCK DRILLED 30.5'	CORE RECOVERED 21.3'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE 18 Oct 78
DISTANCES: VERTICAL, 316.5'; HORIZONTAL,		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	100	Gravelly clay, sandy, ibid.	8	Sample 8, 107.0'-108.0' 2-3/4 x 3-7/8 core.
	140	(Till)		5-5/8 Inch tricone bit and mud, 51'-295.2'
	200			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-15

SUMMARY LOG — HOLE NO. DR-15 (Sheet 3)

N 3234335	E 754173	SHEET 3 OF 4
PROJECT Watana Dam	DRILL DATES: START 27 Apr 1978 COMP. 16 May 1978	SURFACE ELEV. 2294
DEPTH OF HOLE 316.5'	DEPTH OF OVERBURDEN 286'	DIAM. OF HOLE See Remarks
ROCK DRILLED 30.5'	CORE RECOVERED 21.3'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE 18 Oct 78
DISTANCES: VERTICAL, 316.5'; HORIZONTAL,		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	200	Gravelly clay, ibid.		
	230	(Till)		5-5/8 inch tricone bit and mud, 51'-295.2'
2008	286	Top of Rock		286'
	290	Quartz diorite, hard, medium grained, lightly weathered, moderately fractured, light gray. Fractures at 45° and 75° dominant.		2-3/4 x 3-7/8 core 295.2'-305.1' 4 inch Csg to 296.0'
	300			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-15

SUMMARY LOG — HOLE NO. DR-15 (Sheet 4)

N 3234335	E 754173	SHEET 4 OF 4
PROJECT Watana Dam	DRILL DATES: START 27 Apr 1978 COMP. 16 May 78	SURFACE ELEV. 2294
DEPTH OF HOLE 316.5'	DEPTH OF OVERBURDEN 286'	DIAM. OF HOLE See Remarks
ROCK DRILLED 30.5'	CORE RECOVERED 21.3'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE 18 Oct 78
DISTANCES: VERTICAL, 316.5'; HORIZONTAL,		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	300	Quartz diorite, ibid.		NXC-3 Core 305.1'-316.5'
1978	310			
	320	Bottom of Hole Depth of Hole 316.5' Thickness of Overburden 286' Rock drilled 30.5' Rock cored 21.3' Core recovered 21.3' % Core recovered 100		
	330			
	340			
	350			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-15

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 5
DH-12 (CONT.) THRU DR-15
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-32

SUMMARY LOG — HOLE NO. DR-16

N 3231733 / E 742644		SHEET 1 OF 1 — SURFACE ELEV. 2099
PROJECT Watana Dam	DRILL DATES: START 31 May 1978 COMP. 4 Jun 78	
DEPTH OF HOLE 91.5'	DEPTH OF OVERBURDEN 67'	DIAM. OF HOLE See Remarks
ROCK DRILLED 24.5'	CORE RECOVERED 9.2'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH	COMPILED BY, DATE Pat 18 Oct 78
DISTANCES: VERTICAL, 91.5'; HORIZONTAL,		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2099	0	SM, Silty sand, gravelly with boulders, brown, moist, loose, non-plastic. Boulders to 1 foot diameter. (Outwash)	1	5-5/8 inch tricone bit and mud, 0.0'-78.5'. SWL 8.9'-11.0' (23 Jun-18 Aug 1978). Sample 1, 13.2'-14.2' Drive sample, 50 blows. 6 inch Csg to 20'
2076	20	Gravelly, silty sand, dark gray, moist, loose to dense, non-plastic. (Outwash)		23'
2068	30	CL-ML, sandy silt, dark gray, moist to wet, dense, non-plastic. Occasional clay layers and scattered grounded gravel to 1-1/2 inch diameter. (Lake Deposit)	2A, 2B	31'. Sample 2A, 32.2'-32.8' Shelby tube. Sample 2B, 32.8'-33.5' Pitcher barrel.
2052	50	Gravelly, silty sand with boulders, dark gray, dense, moist, non-plastic. Quartz diorite boulder 57'-64'. Top of Rock		47'. Description from cuttings.
2032	70	Diorite, moderately hard, medium grained, hydrothermally altered, highly fractured, light gray to white. Clay common on fractures.		67'. Piezometer installed to 71.5'. 2-3/4 x 3-7/8 core 78.5'-81.0' and 83.8'-91.5'. 5-5/8 inch tricone bit 81.0'-83.8'
2008	90	Depth of Hole 91.5'; Thickness of Overburden 67'; Rock drilled 24.5'; Rock cored 9.2'; Core Recovered 9.2'; % Core Recovered 100		91.5'
	100	Bottom of Hole		Casing left in hole.

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-16

SUMMARY LOG — HOLE NO. DR-17

N 3231232 / E 743625		SHEET 1 OF 1 — SURFACE ELEV. 2167
PROJECT Watana Dam	DRILL DATES: START 6 Jul 1978 COMP. 8 Jul 78	
DEPTH OF HOLE 35.7'	DEPTH OF OVERBURDEN 9.0'	DIAM. OF HOLE See Remarks
ROCK DRILLED 26.7'	CORE RECOVERED 21.2'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE Pat 10 Oct 78
DISTANCES: VERTICAL, 35.7'; HORIZONTAL, ----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
2167	0	SM, Silty sand, dark brown, wet, loose, non-plastic. (Till)	1	Sample 1, 5.0'-6.0' cuttings. 6.0'
2158	10	GP, Silty sand with cobbles and gravel, brown, wet, loose, non-plastic. Top of Rock. Diorite, hard, medium grained, lightly weathered, moderately to lightly fractured, light gray. Fractures high angle to vertical with occasional iron staining.		9.0'. 5-5/8 inch tricone bit and mud 0.0' to 14.5'. 2-3/4 x 3-7/8 inch core 14.5' to 35.7'; 100% recovery. SWL 5.6'-23 Jun 1978; 3.9'-1 Jul 1978; 2.8'-10 Jul 1978; 2.6'-17 Jul 1978; 2.5'-18 Aug 1978
2131	40	Bottom of Hole. Depth of hole 35.7'; Thickness of Overburden 9.0'; Rock drilled 26.7'; Rock cored 21.2'; Core Recovered 21.2'; % Core recovered 100		35.7'. Piezometer installed to 35'

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-17

SUMMARY LOG — HOLE NO. DR-18 (Sheet 1 of 3)

N 3231373 / E 744284		SHEET 1 OF 3 — SURFACE ELEV. 2172
PROJECT Watana Dam	DRILL DATES: START 9 Jun 1978 COMP. 21 Jun 1978	
DEPTH OF HOLE 248.3'	DEPTH OF OVERBURDEN 231'	DIAM. OF HOLE See Remarks
ROCK DRILLED 17.3'	CORE RECOVERED 5.5'	% RECOVERY 60
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ——	COMPILED BY, DATE Pat 18 Oct 78
DISTANCES: VERTICAL, 248.3'; HORIZONTAL, ——		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2172	0	ML, Sandy Silt, with boulders and and cobbles, brown, damp, non-plastic. (Outwash)	A, 1	Sample A, 0.5'-1.0' Grab sample. 12'
2160	10	ML, Sandy silt, gray-brown, damp, non-plastic. Occasional gravel and clay layers.		Sample 1, 12.0'-13.0' Drive sample, 100 blows. 20'
2152	20	CL-ML to ML, Sandy silt, gray, wet, dense, non-plastic. Frozen. Natural moisture content 42.5%. Liquid Limit 20.7%	2, 3	6 inch Csg to 20'. Sample 2, 28.1'-29.6' Drive sample, 68 blows. Sample 3, 38.5'-40.0' Drive Sample, 50 blows. No recovery. 48'
2124	50	SM, silty sand, gray, wet, dense, non-plastic. Frozen	4	Piezometer installed to 65'. Sample 4, 63'-65.0' Drive sample, 176 blows (2 inch spoon). 68'
2104	70	CH-ML, Sandy silt, gray, damp, dense, non-plastic. Minor sub-rounded coarse sand. Occasional sub-rounded small gravel below 90'	5, 6	Sample 5, 72.7'-74.5' Drive sample, 68 blows. 5-5/8 inch tricone bit and mud, 0'-239.2'. Sample 6, 97.6'-98.6' Drive Sample, 80 blows

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-18

SUMMARY LOG — HOLE NO. DR-18 (Sheet 2 of 3)

N 3231373 / E 744284		SHEET 2 OF 3 — SURFACE ELEV. 2172
PROJECT Watana Dam	DRILL DATES: START 9 Jun 78 COMP. 21 Jun 78	
DEPTH OF HOLE 248.3'	DEPTH OF OVERBURDEN 231'	DIAM. OF HOLE See Remarks
ROCK DRILLED 17.3'	CORE RECOVERED 5.5'	% RECOVERY 60
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ——	COMPILED BY, DATE Pat 18 Oct 78
DISTANCES: VERTICAL, 248.3'; HORIZONTAL, ——		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	100	CL-ML, Sandy silt, IBID.		110'
2062	110	GM, Sandy, Silty gravel with cobbles and boulders, gray-brown, damp, dense non-plastic. Gravel rounded to sub-rounded; boulders to 1.5 feet in diameter. Occasional weathered zones with iron staining. (Till)	7, 8	Sample 7, 118.5'-122.7' NXC-3 core. 5-5/8 inch tricone bit and mud, 0'-230.2'. Sample 8, 158.3'-159.6' Drive Sample, 7 blows. 170'
2002	170	Sandy silt with minor gravel, gray-brown, damp, dense to very dense, non-plastic. Boulders and cobbles absent. (Till)		190'
1982	190	MH Sandy silt interlayered with silty clay.		Sample 9, 199.1'-200.2' Drive sample, 100 blows.

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-18

SUMMARY LOG — HOLE NO. DR-18 (Sheet 3 of 3)

N 3231373 / E 744284		SHEET 3 OF 3 — SURFACE ELEV. 2172
PROJECT Watana Dam	DRILL DATES: START 9 Jun 1978 COMP. 21 Jun 78	
DEPTH OF HOLE 248.3'	DEPTH OF OVERBURDEN 231'	DIAM. OF HOLE See Remarks
ROCK DRILLED 17.3'	CORE RECOVERED 5.5'	% RECOVERY 60
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ——	COMPILED BY, DATE Pat 10 Oct 78
DISTANCES: VERTICAL, 248.3'; HORIZONTAL, ——		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	200	MH, sandy silt, gray-brown, damp, very dense, plastic, interlayered, with silty clay, blue-gray, damp, very dense, plastic. Occasional random scattered gravel and cobbles. (Till) Top of Rock	9	5-5/8 inch tricone bit and mud, 0'-239.2'
1941	230	Diorite, moderately hard, medium grained, altered, highly fractured, gray. Disseminated sulfides throughout.		231'. 4 inch Csg to 240'. 2-3/4 x 3-7/8 inch core 239.2'-248.3'
1924	250	Bottom of Hole. Depth of Hole 248.3'; Thickness of overburden 231'; Rock drilled 17.3'; Rock cored 9.1'; Core recovered 5.5'; % Core recovered 60		248.3'. 3/4 inch galvanized pipe installed to bottom; temperature measurement. 6 inch Csg left in Hole. SWL rising 19.9' - 23 Jun 1978; 15.6' - 1 Jul 1978; 13.8' - 10 Jul 1978; 12.8' - 17 Jul 1978; 12.3' - 25 Jul 1978; 12.1' - 7 Aug 1978; 12.6' - 13 Aug 1978; 12.1' - 23 Aug 1978

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-18

SUMMARY LOG — HOLE NO. DR-19

N 3229568 / E 746163		SHEET 1 OF 1 — SURFACE ELEV. 2151
PROJECT Watana Dam	DRILL DATES: START 29 Jun 78 COMP. 3 Jul 78	
DEPTH OF HOLE 78.3'	DEPTH OF OVERBURDEN 55'	DIAM. OF HOLE
ROCK DRILLED 23.3'	CORE RECOVERED 11.8'	% RECOVERY 96%
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ---	COMPILED BY, DATE Pat 10 Oct 78
DISTANCES: VERTICAL, 78.3'; HORIZONTAL, ---		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2151	0	Gravelly silty sand with boulders, brown, moist to wet, dense, non-plastic. Red-brown iron stain common. Gravel rounded, 1-2 inches in diameter.	1, 2, 3	7 7/8 inch tricone bit and mud, 0.0'-21.0'. Sample 1, 8.5'-9.4' cuttings. Sample 2, 21.0'-22.3' drive sample, 100 blows. 5 5/8 inch tricone bit and mud 21.0'-66.2'. 36'
2115	40	Silty, sandy gravel with boulders, brown, moist to wet, dense, non-plastic. Red-brown iron stain common. Gravels and cobbles rounded. Top of Rock		Sample 3, 36.2'-36.9' Drive sample, 150 blows. Low recovery. Piezometer installed to 42.0'. 55'
2096	60	Diorite, moderately hard, medium grained, moderately weathered, moderately fractured, gray. Iron stain common on fractures.		2 3/4 x 3 7/8 core 66.2'-78.3'. 78.3'
2073	80	Bottom of Hole. Depth of hole 78.3'; Thickness of overburden 55'; Rock drilled 23.3'; Rock cored 12.1'; Core recovered 11.8'; % Core recovered		3/4 inch galvanized pipe to bottom; temperature measurement. SWL 2.2' 10 Jul 78; 2.6' 17 Jul 78; 2.9' 25 Jul 78; 4.1' 7 Aug 78; 5.6' 18 Aug 78; 5.2' 23 Aug 78

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-19

SUMMARY LOG — HOLE NO. DR-20

N 3230729 / E 745062		SHEET 1 OF 3 — SURFACE ELEV. 2207
PROJECT Watana Dam	DRILL DATES: START 17 May 1978 COMP. 29 May 78	
DEPTH OF HOLE 252.6'	DEPTH OF OVERBURDEN 210'	DIAM. OF HOLE See Remarks
ROCK DRILLED 42.6'	CORE RECOVERED 17.5	% RECOVERY See Remarks
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE Pat 10 Oct 78
DISTANCES: VERTICAL, 252.6'; HORIZONTAL, ----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2207	0	SM, silty sand with occasional boulders, gravel and clay, brown, damp, loose, non-plastic. Gravels are rounded. [Glacial Outwash]	1	7 7/8 inch tricone bit with mud 0.0'-40.0'. Sample 1, 9.0'-11.0' cuttings. 20.5'
2187	20	Clayey, sandy silt, dark gray, moist, compact.	2A, 2B	Sample 2, 24.0'-25.5' Drive sample/25 blows. 30'
	30	CL, silty clay, dark gray, moist, compact to dense.	3	SWL 40.1'-38.7' (23 Jun-18 Aug 1978). Sample 3, 37.0'-38.5' Drive Sample/100 blows. 40'
	40	SM, sandy silt to CL, silty clay, dark gray, moist, compact. [Lake Deposit]	4A, 4B	Sample 4, 50.0'-51.5' Drive Sample/100 blows. 53'
2154	50	Sandy gravel, brown, wet, loose. Gravels are rounded. [Alluvial Deposit]	5	Sample 5, 58.3'-58.6' Drive sample/125 blows. Cuttings, 58.6'-63.0'. 5 5/8 inch tricone bit with mud 40.0'-237.6'. Samples 5, 6 & 7 lost. Descriptions from cuttings. Piezometer installed to 82.5'. 90'
2117	90	Silty, sandy gravel with rock fragments and occasional boulders, gray to dark gray, moist, compact to dense.		

NPA Form APR 66 7(Test) — PROJECT Watana Dam — HOLE NO. DR-20

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 6
DR-16 THRU DR-20
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUMMARY LOG — HOLE NO. DR-20 — SHEET 2 OF 3

N 3230729 / E 745062	SHEET 2 OF 3	SURFACE ELEV. 2207
PROJECT Watana Dam	DRILL DATES: START 17 May 1978	COMP. 28 May 78
DEPTH OF HOLE 252.6'	DEPTH OF OVERBURDEN 210'	DIAM. OF HOLE See Remarks
ROCK DRILLED 42.6'	CORE RECOVERED 17.2'	% RECOVERY See Remarks
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 252.6'; HORIZONTAL, ----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	100	Silty, sandy gravel, Ibid.		
			6	
	110–128	Sandy silt; 106'-128'		
	130	[Glacial Till]		
	160	Quartzdiorite boulder; 158'-167'	7	
2040	167			167'
	170	Clayey, silty sand with minor gravel and occasional boulders, light brown, moist, compact to dense. Occasional sand and clay layers.		
	180		8	Sample 8; 179'-185', cuttings
	190	[Glacial Till]	9	Sample 9; 189.5'-195.1' 2-3/4 x 3-7/8 inch core.
	200			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-20

SUMMARY LOG — HOLE NO. DR-20 — SHEET 3 OF 3

N 3230729 / E 745062	SHEET 3 OF 3	SURFACE ELEV. 2207
PROJECT Watana Dam	DRILL DATES: START 17 May 1978	COMP. 28 May 78
DEPTH OF HOLE 252.6'	DEPTH OF OVERBURDEN 210'	DIAM. OF HOLE See Remarks
ROCK DRILLED 42.6'	CORE RECOVERED 17.2'	% RECOVERY See Remarks
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 252.6'; HORIZONTAL, ----		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	200	Ibid [Glacial Till]	10	Sample 10; 200'-210' cuttings.
1997	210	Top of Rock		210'
		Diorite, soft, medium grained, highly fractured to decomposed, blue-gray. Clay gouge common. Shear zone.	11A, 11B	Sample 11; 218.0'-222.7' 2-3/4 x 3-7/8 inch core. (Sample not boxed; shipped to laboratory)
	230		0 100	
	240			Rock cored 237.6' to bottom.
1954	250			
		Bottom of Hole Depth of Hole 252.6' Thickness of Overburden 210.0' Rock drilled 42.6' Rock cored 19.7' Core recovered 17.2' % Core recovered 87%		
	260–300			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-20

SUMMARY LOG — HOLE NO. DH-21 — SHEET 1 OF 7

N 3226405 / E 744457	SHEET 1 OF 7	SURFACE ELEV. 1489
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78	COMP. 16 Aug 78
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100
ANGLE FROM VERT. 32.4°	AZIMUTH FROM NORTH 03.90°*	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	0	Overburden: Boulder 0.0 to 2.7' Organic Silt 2.7 to 6.3' Cobbles and Rock Fragments 6.3' To 11.2' (Colluvium)		Tundra Frozen At 0.9'
1469	10			11.2'
		River Sands & Gravels. Fine Sand 11.2' To 15.4' Sub-Angular to Sub-Rounded; Occasionally Angular Boulder 16.0' To 17.0' Fine Silty Sand 15.4' To 24.7 Occasional Organic Material Gravelly Sand 24.7' To 26.5' Rock Fragments 26.5' To 30.0'		100% Dwr 0.0' To 26.5' (Permafrost)
1450	30			30.0'
		Cobbles In Sand Matrix.		4" CSG To 33.4' 0%-20% Dwr 26.5 To 43.4' (Thawed)
	40			100% Dwr 43.4' To 49.5' (Permafrost)
1435				45.0'
	50	Sandy Gravel, Gravel Sub-Rounded, Occasional Boulders, Grading to Boulders in Sand Matrix From 50' to 84.5' (Alluvium)		0% Dwr 49.5' To 50.0' (Thawed) 100% Dwr 50.0' To 69.5' (Permafrost) Samples of Cobbles And Boulders Recovered. 0% Dwr 69.5' To 84.5' (Thawed)
	60–80			
1396		Top Of Rock		84.5'
	90	Quartz Diorite, Hard, Medium Grained, Lightly Weathered, Moderately Fractured, Gray. Light to Moderate Fracture Below 90.4' Locally Grades To Granodiorite		NXCSG To 84.7' Fracture Spacing 84.5' To 100'; Fragments To 2.1' 100% Dwr 84.5' To 100.0'
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DH-21 — SHEET 2 OF 7

N 3226405 / E 744457	SHEET 2 OF 7	SURFACE ELEV. 1489
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78	COMP. 16 Aug 78
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100
ANGLE FROM VERT. 32.4°	AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz Diorite, Ibid		
	120	Lightly Fractured 119.1' To 133.7' Healed Fractures Common Below 120'		
	130	Lightly To Moderately Fractured 133.7'-328.5'. Zone is Predominantely Lightly Fractured With Short Highly Fractured Sections.		100% Dwr 129.4'-200.0'
	160	Shear With Gouge, 162.6' To 163.8' Partially Healed. 45° To Core.		Fracture Spacing 100'-200'; 0.1' To 2.1'
	180	Healed Shear 187.0', 45° To Core		
	200			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DH-21 — SHEET 3 OF 7

N 3226405 / E 744457	SHEET 3 OF 7	SURFACE ELEV. 1489
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78	COMP. 16 Aug 78
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100
ANGLE FROM VERT. 32.4	AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	200	Quartz Diorite, Ibid Healed Shear 201.0-202.5. Moderately Soft		
	210	Healed Fractures More Common Below 200'		
	220	Highly Fractured 215.5' To 223.1 Healed Shear 218.3'-218.6'		Pink Feldspars Common (Local Granodiorite)
	230			100% Dwr 200'-300' Fracture Spacing 200' To 300'; 0.1' To 1.6'
	240	Shear 243.9' To 244.6' With Light Gray Gouge. Healed Shear 247.5' To 248.4'		
	260	Minor Alteration In Healed Shear 259.0'-259.8' Highly Fractured 260.0'-262.0'		
	280	Shear, 278.1'-280.0' Moderately Weathered To Partly Decomposed, Gouge Present. Highly Fractured 284.2'-286.7'		
	300			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DH-21 — SHEET 4 OF 7

N 3226405 / E 744457	SHEET 4 OF 7	SURFACE ELEV. 1489
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78	COMP. 16 Aug 78
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100
ANGLE FROM VERT. 32.4°	AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	300	Quartz Diorite Ibid. Highly Fractured 302.3'-305.0' Healed Fractures 303.6'-304.2' 305.2'-305.7'		Fracture Spacing 300'-330' 0.1' To 1.7'
	310	Pyrite Common On Fractures Below 315.7'		
	320			100% Dwr 300' To 345'
	330	Lightly Fractured 328.5'-391.2'		Fracture Spacing 330'-390' 0.1' To 3.7'
	340			0% Dwr 345'-354
	350			100% Dwr 354'-364.2'
	360			0% Dwr 364.2'-381.3'
	380			100% Dwr 381.3'-390'
	390	Moderately Fractured 391.2'-395.5' Highly Fractured 395.5'-397.1'		0% Dwr 390'-394' 50% Dwr 394'-400' Fracture Spacing 390'-400' 0.1' To 1.1'
	400			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DH-21 — SHEET 5 OF 7

N 3226405 / E 744457	SHEET 5 OF 7	SURFACE ELEV. 1489
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78	COMP. 16 Aug 78
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100
ANGLE FROM VERT. 32.4°	AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'		

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	400	Quartz Diorite Ibid Highly Fractured 402.5'-403.4' Moderately Fractured 417.3'-468.7'		50% Dwr 400'-414.2' 25% Dwr 414.2'-440'
	410			Fracture Spacing 400'-440 0.1' To 2.2'
	450	Shear 449.8'-452.0' Gouge 450.0' Slicks Show Movement Perpendicular To Core. Shear Partially Healed.		Fracture Spacing 440'-470' 0.1' To 1.9'
	460	Shear, 457.5'-463.0; Moderately To Highly Weathered, Partially Decomposed, Altered. Healed Fractures Common. Gouge 468.2'		0% Dwr 440'-500'
	470	Lightly Fractured 468.7'-499.1		
	480			Fracture Spacing 470'-499' 0.1' To 3.8'
	500	Highly Fractured 499.1'-500.5'		

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 7
DR-20 (CONT.) AND DH-21
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUMMARY LOG — HOLE NO. DH-21 — SHEET 6 OF 7

HOLE NO. DH-21	N 3226405 / E 744657	SHEET 6 OF 7	SURFACE ELEV. 1490
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78 COMP. 16 Aug 78		
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO	
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100	
ANGLE FROM VERT. 32.4°	AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78	
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	500	Quartz Diorite; Ibid. Minor Clay On Fractures 499.1'-500.5		50% Dwr 500'-522.5'. Fracture Spacing 500'-511.2' <0.1' To 1.4'
968	510	Moderately Fractured 509.5' To 511.2'		512.5'
	520	Andesite Porphory, Hard, Lightly Weathered Fine Grained, Lightly Fractured, Dark Gray. Contact 512.5-513.7' & 524.1-525.1', Green Chill Zone. Disseminated Pyrite Common Healed Fractures (Dike)		525.1'
955	530	Minor Alteration 525.1'-526.9' (Thermal)		Fracture Spacing 511.2'-570' <0.1' To 5.0'
	540	Quartz Diorite Ibid. Healed Breccia 535.0'-538.2'. Minor Alteration		
	550	Healed Fractures Rare Below 550'. Lightly Fractured 511.2'-568.0'		0% Dwr 522.5'-603.7'
	560			
	570	Shear 568.6'-580.4', Highly Fractured; Yellow-Brown Gouge Common, Decomposed 570.3'-570.9'		Fracture Spacing 570'-590' 0.1' To 0.4'. Core Breaks Common On Healed Fractures
	580	Lightly Fractured 580.4'-603.7'		
	590	Shear, 589.6', White Clay Gouge		Fracture Spacing 560'-603.7' <0.1'-1.6'
	600			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DH-21 — SHEET 7 OF 7

HOLE NO. DH-21	N 3226405 / E 744657	SHEET 7 OF 7	SURFACE ELEV. 1490
PROJECT Watana Dam	DRILL DATES: START 3 Jul 78 COMP. 16 Aug 78		
DEPTH OF HOLE 603.7'	DEPTH OF OVERBURDEN 84.5'	DIAM. OF HOLE NCO	
ROCK DRILLED 519.2'	CORE RECOVERED 519.2'	% RECOVERY 100	
ANGLE FROM VERT. 32.4°	*AZIMUTH FROM NORTH 03.9°*	COMPILED BY, DATE 10 Oct 78	
DISTANCES: VERTICAL, 509.7'; HORIZONTAL, 323.5'			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
976	600	Quartz Diorite; Ibid		603.7'
	610	Bottom Of Hole. Depth Of Hole 603.7'; Thickness of Overburden 84.5'; Rock Cored 519.2'; Core Recovered 519.2'; % Core Recovered 100		Hole Not Pressure Tested Due To Mechanical Problems, Hole Caped For Later Testing.

* Hole Survey

Depth	Bearing	Angle From Vert
598.7'	----	33°
548.7'	03°	32°
498.7'	03.5°	32°
448.7'	03°	32°
398.7'	04°	32°
348.7'	03°	32°
298.7'	06°	33°
248.7'	04.5°	33°
198.7'	04°	33°
148.7'	03°	32°
98.7'	05°	32°

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-21

SUMMARY LOG — HOLE NO. DR-22 — SHEET 1 OF 6

HOLE NO. DR-22	N 3232202 / E 749805	SHEET 1 OF 6	SURFACE ELEV. 2229
PROJECT Watana Dam	DRILL DATES: START 5 Jul 1978 COMP. 3 Aug 1978		
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE See Remarks	
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100	
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH —	COMPILED BY, DATE 19 Oct 78	
DISTANCES: VERTICAL, 493.6'; HORIZONTAL, —			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2229	0	SM, Silty Sand, Gravelly With Boulders, Brown, Wet, Dense; Rounded Gravels. Boulders 2'-3' In Diameter Common; Occassional Clay Layers.		Sample A; 0.5'-1.0' Grab Sample
	10			7-7/8 inch Tricone Bit And Mud, 0.0'-17.5'
	20		1	Sample 1; 17.5'-19.0' Drive Sample/77 Blows
	30	(Outwash)		5-5/8 inch Tricone Bit and Mud, 17.5'-417.0'
	40		2	Sample 2; 37.9'-39.8' Drive Sample/25 Blows
	50			6 inch Csg to 53'. 56'
2173	60	SM-SC, Gravelly, Silty Sand Clayey with Boulders, Gray, Moist, Dense. Moisture Content Avg. 8.1%	3	Sample 3; 58.0'-59.5' Drive Samples/199 Blows.
2157	70	(Till)		72'
	80	CL-ML, Gravelly, Sandy Silt, Dark Gray, Damp, very Dense, Non-plastic. Frozen Sub-rounded Gravel; Occasional Cobbles. (Till)	4	Sample 4; 77.4'-78.9' Drive Samples/144 Blows
2139	90	SM, Gravelly, Silty Sand Brown, Wet, Non-plastic; Occasional Layers of Gray Silt. (Alluvium)		90'
	100		5	Sample 5; 97.0'-98.5' Drive Sample/200 Blows

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-22

SUMMARY LOG — HOLE NO. DR-22 — SHEET 2 OF 6

HOLE NO. DR-22	N 3232202 / E 749805	SHEET 2 OF 6	SURFACE ELEV. 2229
PROJECT Watana Dam	DRILL DATES: START 5 Jul 1978 COMP. 3 Aug 1978		
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE See Remarks	
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100	
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH —	COMPILED BY, DATE 19 Oct 78	
DISTANCES: VERTICAL, 493.6'; HORIZONTAL, —			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	100	SM, Gravelly, Silty Sand, IBID. Frozen 90'-110'		5-5/8 inch Tricone Bit And Mud; 17.5'-417.8'. Thermistor to 105'
	110	Coarse to Medium Grained Becoming Finer With Depth.		
	120	(Alluvium)	6	Sample 6; 117.2'-118.5' Drive Sample/180 Blows
2098	130	SC, Silty, Gravelly Sand With Clay Layers and Boulders.		131'
	140	Sand, Coarse, Sub rounded to Subangular, Brown, Non-plastic. Gravel, Rounded to 1 Inch.	7	Sample 7; 139.5'-140.0' No recovery
	150	Clay, Gray, Plastic, Wet, Dense. Boulders Common, 2'-3' in Diameter.	8	Sample 8; 157.9'-158.4' Drive Sample/159 Blows
	160	LL 65.7, PL 21.4, PI 44.3		
	170	(Till)		
2046	180			183'
	190	SM, Sand With Interbedded Silt Layers. Silt, Gray, Non-plastic, Moist, Varved.		
	200	1 inch Silt Layer in Sample 9.	9	Sample 9; 198.3'-199.5' Drive Sample/500 Blows

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-22

SUMMARY LOG — HOLE NO. DR-22 — SHEET 3 OF 6

HOLE NO. DR-22	N 3232202 / E 749805	SHEET 3 OF 6	SURFACE ELEV. 2229
PROJECT Watana Dam	DRILL DATES: START 5 Jul 1978 COMP. 3 Aug 1978		
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE See Remarks	
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100	
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH —	COMPILED BY, DATE 19 Oct 78	
DISTANCES: VERTICAL, 493.6'; HORIZONTAL,			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	200	SM, Sand With Interbedded Silt Layers; IBID. (Alluvium)		5-5/8 inch Tricone Bit And Mud; 17.5'-417.8'. 208'
2021	210	GP, Sandy Gravel With Occassional Sand Layers.	10	Sample 10; 212'-217' Cuttings. Mud Loss 218'-231' 50± Gal./Ft.
	220	(Alluvium)		Piezometer to 222.9'
1998	230	SM-SC, Gravelly, Silty Sand With Boulders, Brown, Damp, Non-plastic, very dense.	11	231'. Sample 11; 238.4'-238.8' Drive Sample/500 Blows
	240	Boulder 242'-248'		
	250	Boulders normally 1'-2' in Diameter. Occassional Sand and Silt Layers.		
	260	Silt and Sand Common Around Boulders.		
	270	(Till)		
	280	Boulder 281'-291'		
1936	290			293'
	300	Sandy Gravel With Boulders		

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-22

SUMMARY LOG — HOLE NO. DR-22 — SHEET 4 OF 6

HOLE NO. DR-22	N 3232202 / E 749805	SHEET 4 OF 6	SURFACE ELEV. 2229
PROJECT Watana Dam	DRILL DATES: START 5 Jul 1978 COMP. 3 Aug 78		
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE See Remarks	
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100	
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH —	COMPILED BY, DATE 19 Oct 78	
DISTANCES: VERTICAL, 493.6'; HORIZONTAL,			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	300	Sandy Gravel With Boulders		
	310	Layered Sands And Gravels. Boulder Common, 2'-5' in Diameter.		Mud Loss 293'-375' 14± Gal/Ft.
	320			
	330			Description From Cuttings.
	340	(Alluvium)		5-5/8 inch Tricone Bit And Mud; 17.5'-417.8'
	350			
	360	Boulder 354'-366'		
1854	370			375'
	380	Gravel And Boulders, Sand And Silt Lenses Common.		
	390			
	400	Boulder 393'-401'		

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-22

SUMMARY LOG — HOLE NO. DR-22 — SHEET 5 OF 6

HOLE NO. DR-22	N 3232202 / E 749805	SHEET 5 OF 6	SURFACE ELEV. 2229
PROJECT Watana Dam	DRILL DATES: START 5 Jul 78 COMP. 3 Aug 78		
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE See Remarks	
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100	
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE 19 Oct 78	
DISTANCES: VERTICAL, 493.6'; HORIZONTAL,			

ELEV	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
	400	Boulders; Ibid. Gravels Rounded; Silts Laminated		5-5/8 inch Tricone Bit And Mud; 17.5'-417.8'
	410	Boulder 412'-422		4 Inch Csg to 417.8'
	420	Silt.	12	Sample 12; 422'-422'+ Grab between Boulders
	430	Boulder 422'+-432.7'		Cored With 2 3/4 X 3-7/8 Inch Barrel; 417.8'-432.7'
	440	(Alluvium)		3-3/8 Inch Tricone Bit And Mud; 432.7'-476.0'
	450	Top of Rock		454'
1775	460	Quartz Diorite, Soft To Hard Medium Grained, Lightly Weathered with Minor Alteration of Mafics, Moderately Fractured (45° And 85° Preferred), White To Light Gray.		
	470			Cored With 2-3/4 X 3-7/8 Inch Barrel 476.0-493.6'
	480			
	490			493.6'
1735	500	Bottom Of Hole		3/4 Inch Pipe (Temperature Probe) To 492.4'

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-22

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 8
DH-21 (CONT.) AND DR-22
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUMMARY LOG — HOLE NO. DR-22

N 3232432	SHEET 6 OF 6	SURFACE ELEV. 2229
PROJECT: WATANA DAM	DRILL DATES: START 5 JUL 78	COMP. 3 AUG 78
DEPTH OF HOLE 493.6'	DEPTH OF OVERBURDEN 454'	DIAM. OF HOLE SEE REMARKS
ROCK DRILLED 39.6'	CORE RECOVERED 17.6'	% RECOVERY 100
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 493.6'	HORIZONTAL, ---------	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
		Depth of Hole 493.6' Thickness of Overburden 454' Rock Drilled 39.6' Rock Cored 17.6' Core Recovered 17.6' % Core Recovered 100		

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DR-22

SUMMARY LOG — HOLE NO. DH-23

N 3225738 / E 744618	SHEET 1 OF 2	SURFACE ELEV. 1952
PROJECT: WATANA DAM	DRILL DATES: START 7 JUL 1978	COMP. 17 JUL 1978
DEPTH OF HOLE 119.2'	DEPTH OF OVERBURDEN 7.0'	DIAM. OF HOLE NX
ROCK DRILLED 112.2'	CORE RECOVERED 111.4'	% RECOVERY 99.4
ANGLE FROM VERT. 45°	AZIMUTH FROM NORTH 220°18'	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 84.3'	HORIZONTAL, 84.3'	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1952	0	Overburden; Talus in silt & sand.		
1951		Top of Rock.		7.0'
	10	Quartz diorite, lightly weathered, moderately to highly fractured, medium grained, hard, gray.		Top of permafrost 14' (23 Aug 1978)
	20	Shear 16.3' to 18.2'; shear contains healed breccia from prior movement.		NX CSG to 19.4'
			2, 1	Fracture spacing 7.0' to 30.0' <0.1' to 0.8'
	30	Shear 31.1' to 31.8'		
		Moderately to lightly fractured 30' to 40'.		K=0.0
	40			Fracture spacings 30.0' to 40.0' <0.1' to 1.3'
	50	Shear 45.5' to 47.9'; healed fractures and red-brown gouge common.	1	
		Moderately fractured 40' to 90'.		
	60	Shear 61.5' to 64.0'		Fracture spacing 40.0' to 90.0' <0.1' to 0.7'
	70	Fragments with slicks 74.4' to 75.6'		Healed fracture spacing 7.0' to 119.0' <0.1' to 2.0'
	80	Hydro thermal alteration 76.7' to 81.0'		K=0.0
	90	Shear zone 79.4' to 99.4' zones of fresh, hard, lightly weathered quartz diorite between shears. Highly fractured & altered 86.7' to 94.6'		
	100	0.2' clay gouge 99.2' to 99.4'		Fracture spacing 90.0' to 100.0' <0.1' to 0.4'

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DH-23

SUMMARY LOG — HOLE NO. DH-23

N 3225734 / E 744618	SHEET 2 OF 2	SURFACE ELEV. 1952
PROJECT: WATANA DAM	DRILL DATES: START 7 JUL 1978	COMP. 17 JUL 78
DEPTH OF HOLE 119.2'	DEPTH OF OVERBURDEN 7.0'	DIAM. OF HOLE NX
ROCK DRILLED 112.2'	CORE RECOVERED 111.4'	% RECOVERY 99.4
ANGLE FROM VERT. 45°	AZIMUTH FROM NORTH 220°18'	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 84.3'	HORIZONTAL, 84.3'	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz diorite, IBID, lightly fractured.		Fracture spacing 100.0' to 119.2' 0.1' to 2.0'
	110			Left 0.3' in hole
1861	120		2	119.2'
		Bottom of Hole Depth of hole 119.2' Thickness of overburden 7.0' Rock cored 112.2' Core recovered 111.4' % Core recovered 99.4		Hole left open and filled with antifreeze.

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DH-23

SUMMARY LOG — HOLE NO. DH-24

N 3225362 / E 744727	SHEET 1 OF 2	SURFACE ELEV. 2061
PROJECT: WATANA DAM	DRILL DATES: START 25 JUL 1978	COMP. 31 JUL 78
DEPTH OF HOLE 139.9'	DEPTH OF OVERBURDEN 6.9'	DIAM. OF HOLE NQ
ROCK DRILLED 133.0'	CORE RECOVERED 129.9'	% RECOVERY 97.7
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 139.9'	HORIZONTAL, ----	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
2061	0	Overburden: Talus in silt, sand and gravel.		Annual frost at 0.8' (25 Jul 1978)
2054		Top of Rock.		6.9'
	10	Quartz diorite, hard, medium grained, lightly to moderately fractured, highly fractured in shear zones, gray.		Top of permafrost 8' NX CSG to 8.6'
				Fracture spacing 10'-20' (0.1' to 2.7'
	20	Minor hydro thermal alteration below 21'.		
		Healed fractures common. Iron staining on joints common.		
	30			K (12.8'-139.9')0.0
	40	Shear 39.4'-40.5', highly fractured with light gray gouge.		
		Healed breccia 45.6'-46.7'		
	50			
	60			Fracture spacing 20'-80' (0.1' to 1.5'
	70			
	80	Shear Zone, 81.81'-86.0; Stained, Partially Decomposed, Highly Fractured.		
	90			Fracture spacing 80'-100' (0.1' to 0.8'
	100			

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DH-24

SUMMARY LOG — HOLE NO. DH-24

N 3225362 / E 744727	SHEET 2 OF 2	SURFACE ELEV. 2061
PROJECT: WATANA DAM	DRILL DATES: START 24 JUL 1978	COMP. 31 JUL 78
DEPTH OF HOLE 139.9'	DEPTH OF OVERBURDEN 6.9'	DIAM. OF HOLE NQ
ROCK DRILLED 133.0'	CORE RECOVERED 129.9'	% RECOVERY 97.7
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ----	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 139.9'	HORIZONTAL, ----	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Quartz diorite, IBID.		100.5'
		Small shear 102.2'-102.6' Healed quartz diorite breccia, hard, medium grained, light to moderately fractured, gray. Lightly fractured below 128.1'.		Fracture spacing 100'-120' <0.1' to 1.5'
	110			
	120	Cored edge of porphoritic andesite intrusion, 113.0'-139.9'. Brecciated (healed), hard, fine grained, lightly to moderately fractured, dark gray. Pyrite common.		
	130			Fracture spacing 120'-139.9' 0.1' to 4.0'
1921	140			139.9'
		Bottom of Hole Depth of hole 139.9' Thickness of overburden 6.9' Rock cored 133.0' Core recovered 129.9' % Core recovered 97.7		
	150			

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DH-24

SUMMARY LOG — HOLE NO. DH-25

N 3225661 / E 745950	SHEET 1 OF 1	SURFACE ELEV. 2045
PROJECT: WATANA DAM	DRILL DATES: START 8 AUG 78	COMP. 13 AUG 78
DEPTH OF HOLE 79.9'	DEPTH OF OVERBURDEN 79.9'	DIAM. OF HOLE NX
ROCK DRILLED 0.0'	CORE RECOVERED SEE REMARKS	% RECOVERY N/A
ANGLE FROM VERT. 46°	AZIMUTH FROM NORTH 047°	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 57.5'	HORIZONTAL, 55.5'	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
2045	0	Gravelly silty sand.		Permafrost below 1.5'
2039	10	Gravelly, silty sand with boulders. 70% silty sand 30% gravel and boulders.		9.0'
	20	Silty sand 60% sand, fine grained, blue-gray, wet, dense. 40% silt, plastic, blue-gray, wet, soft when thawed (Lake deposit)		Methane gas at 24.1' (Peat layer)
2023	30	Gravelly, clayey silt, blue-gray, wet, stiff; clayey silt is plastic. 70% Clayey silt 30% Gravel; 0.1'-0.3' Well rounded to sub-rounded.		32.0' Samples obtained by dry blocking NX barrel
	40		1	Sample 1 48.0'-48.7'
	50	60% Clayey silt, 40% Gravel } 43.4'-49.5'	2	Sample 2 56.0'-56.8'
	60	Occasional rock fragments below 60'		
	70	Density increases with depth. Occasional sand layers below 70.' (Lake deposit)	3	Sample 3 66.5'-68.3' NX Csg to 77.0'
1991	80			79.9'
		Bottom of Hole Depth of Hole 79.9'		Hole abandoned due to hill creep. 3/4 inch galvanized pipe installed as temperature probe
	90			
	100			

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DH-25

SUMMARY LOG — HOLE NO. DR-26

N 3234115 / E 748380	SHEET 1 OF 1	SURFACE ELEV. 2295
PROJECT: WATANA DAM	DRILL DATES: START 9 AUG 78	COMP. 11 AUG 78
DEPTH OF HOLE 94.8'	DEPTH OF OVERBURDEN 94.8'	DIAM. OF HOLE SEE REMARKS
ROCK DRILLED 0.0'	CORE RECOVERED N/A	% RECOVERY N/A
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH ------	COMPILED BY, DATE: Pat 10 Oct 78
DISTANCES: VERTICAL, 94.8'	HORIZONTAL, ------	

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2295	0	Gravelly, silty sand with boulders; brown, wet, loose. Boulders 1'-2'	A	Sample A 0.5'-7.0' grab sample SWL 4.2' (18 Aug 1978)
	10	(till)		19'
2276	20	Gravelly silt with occ. cobbles; gray-brown, damp, compact, frozen. Rounded gravels, occ. angular.		7-7/8 inch tricone bit and revert mud-0'-21'
	30	Random zones of gray (unweathered) material. (outwash)	1	Sample 1; 27.3'-28.6' Drive sample, 200 blows
	40		2	Sample 2; 37.5'-38.2' Drive sample, 200 blows
2250				46'
	50	Clayey silt, dark gray, damp, dense; occ. gravel. Frozen (Lake deposit)	3	Sample 3; 48'-50' cuttings
2240				55'
	60	Sandy gravel with interbedded silt layers. Coarse sand and rounded to sub-rounded gravel. (Alluvium)	4	Sample 4; 57.5'-58.0' drive sample 200 blows Piezometer to 65.5'
2228				67'
	70	Boulders, gravel, and silty sand, dark gray, wet, compact. Occ. sand layers and silty clay zones. Gravels sub-rounded to sub-angular		5-5/8 inch tricone bit and revert mud, 21'-94.8'
	80	Samples taken in wet silty sand.	5	Sample 5; 77.5'-78.7' drive sample 200 blows.
		Boulder to 1 foot diameter.		
	90	(till)	6	Sample 6; 94.1'-94.8' drive sample 205 blows 94.8'
2200	100	Bottom of Hole Depth of Hole 94.8'		3/4 inch PVC temperature probe to 94.8'

NPA Form 7(Test) APR. 66 — PROJECT WATANA DAM — HOLE NO. DR-26

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN
DRILL HOLE LOGS NO. 9
DR-22 (CONT.) THRU DR-26

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUMMARY LOG — HOLE NO. DR-27

SUMMARY LOG HOLE NO. DR-27	N 3235676 / E 750305	SHEET 1 OF 1 / SURFACE ELEV. 2322
PROJECT Watana Dam	DRILL DATES: START 13 Aug 78	COMP. 19 Aug 78
DEPTH OF HOLE 44.0'	DEPTH OF OVERBURDEN 44.0'	DIAM. OF HOLE SEE REMARKS
ROCK DRILLED N/A	CORE RECOVERED N/A	% RECOVERY N/A
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE
DISTANCES: VERTICAL, 44.0' ; HORIZONTAL, -------		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	SAMPLE	REMARKS
2322	0	Organic silt, tundra		1.0'
		Boulders		4.8'
	10	Cobbles with sand lenses. Sand lenses at 4.8'-5.1, 5.6'-6.0', 8.3'-8.8', 10.2'-10.7', 11.7'-11.9', 17.5'-17.6'		Permafrost at 1.0' GWL 8', 18 Aug 1978 7-7/8 inch tricone bit, water and mud 0.0'-20.0' 6 inch Csg to 24.3'
2301	20	Occ. gravel in sand lenses.		21'
	30	Clayey, sandy silt, blue-gray, plastic, frozen. Ice lenses to 3 inches thick common. Occ. rounded to subrounded gravel; 1 inch to 3-1/2 inches in diameter.	1, 2, 3, 4, 5, 6, 7, 8, 9	Sample 1; 22.1'-23.1' Drive sample, 6 inch air hammer 20.0' to 44.0' Sample 2; 28.3'-29.5' 4 x 4 1/2 inch core. Sample 3; 30.6'-32.1' drive sample (25 blows Sample 4; 33.1'-34.6' drive sample (25 blows Sample 5; 34.5'-36.0' drive sample Samples 4 and 5 waxed. Sample 6; 37.0'-38.5' Drive sample, 23 blows Sample 7; 38.5'-40.0' Drive sample, Sample 8, 40.0'-41.5' Drive sample, 24 blows Sample 9,42.5'-44.0'
2282	40			
	50	Bottom of Hole Depth of Hole 44.0'		Hole caved; abandoned
	60			
	70			
	80			
	90			
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DR-27

SUMMARY LOG — HOLE NO. DH-28 (Sheet 1 of 2)

SUMMARY LOG HOLE NO. DH-28	N 3225723 / E 743581	SHEET 1 OF 2 / SURFACE ELEV. 1971
PROJECT Watana Dam	DRILL DATES: START 17 Aug 78	COMP. 30 Aug 78
DEPTH OF HOLE 125.2'	DEPTH OF OVERBURDEN 9.2'	DIAM. OF HOLE NCO
ROCK DRILLED 116.0'	CORE RECOVERED 99.3'	% RECOVERY 89
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE Sat 18 Oct 78
DISTANCES: VERTICAL, 125.2'; HORIZONTAL, -------		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
1971	0	Overburden		SWL 7.6' (19 Aug 78)
		Top of Rock		9.2'
1962	10	Porphoritic andesite breccia, soft, fine grained, moderately weathered, highly fractured to fragments, gray. Iron stains and thin red-brown gouge common. Phenocrysts to 10 mm.		NX Csg bit to 13.1' Dwr 100% except 20%, 13.1'-14.2'
	20			
	30	Hole in permafrost.		Core lengths generally less than 0.5'
	40			
	50	Disseminated sulfide mineralization 49.0'-53.1'		
		Baked Zone 56.1'-58.3'		58.3'
1913	60	Porphoritic andesite, moderately hard, fine grained, lightly weathered, highly fractured to fragments, light gray. Brecciated 58.3'-60.1'		
	70	Phenocrysts generally less than 5mm. and widely scattered		
	80	Stiff lightgray clay gouge 78.9'-79.5'		
	90	Brecciated 80.4' to bottom. High angle (70°-90°) shear planes dominant. Fat clay gouge very common.		
	100			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-28

SUMMARY LOG — HOLE NO. DH-28 (Sheet 2 of 2)

SUMMARY LOG HOLE NO. DH-28	N 3225723 / E 743581	SHEET 2 OF 2 / SURFACE ELEV. 1971
PROJECT Watana Dam	DRILL DATES: START 17 Aug 78	COMP. 30 Aug 78
DEPTH OF HOLE 125.2'	DEPTH OF OVERBURDEN 9.2'	DIAM. OF HOLE NCO
ROCK DRILLED 116.0'	CORE RECOVERED 99.3'	% RECOVERY 89
ANGLE FROM VERT. 0°	AZIMUTH FROM NORTH -------	COMPILED BY, DATE Sat 18 Oct 78
DISTANCES: VERTICAL, 125.2'; HORIZONTAL, -------		

ELEV.	DEPTH	DESCRIPTION OF MATERIALS	% CORE	REMARKS
	100	Porphoritic andesite, Ibid. Soft, highly weathered and very highly fractured in shear		Hole follows near vertical shear zone.
	110	Brecciated porphoritic andesite.		
	120	Clay gouge, fat, lightgray 115.5'-115.9', 118.2'-118.4' 118.6'-118.8' 119.2'-119.3' and 124.9'-125.2'		
1846				125.2'
	130	Bottom of Hole Depth of hole 125.2' Thickness of Overburden 9.2' Rock Drilled 116.0' Rock Cored 112.1' Core Recovered 99.3' % Core Recovered		
	140			
	150			

NPA Form 7(Test) APR. 66 — PROJECT Watana Dam — HOLE NO. DH-28

SEE PLATE D-28 FOR LEGEND

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

UPPER SUSITNA RIVER BASIN

DRILL HOLE LOGS NO. 10

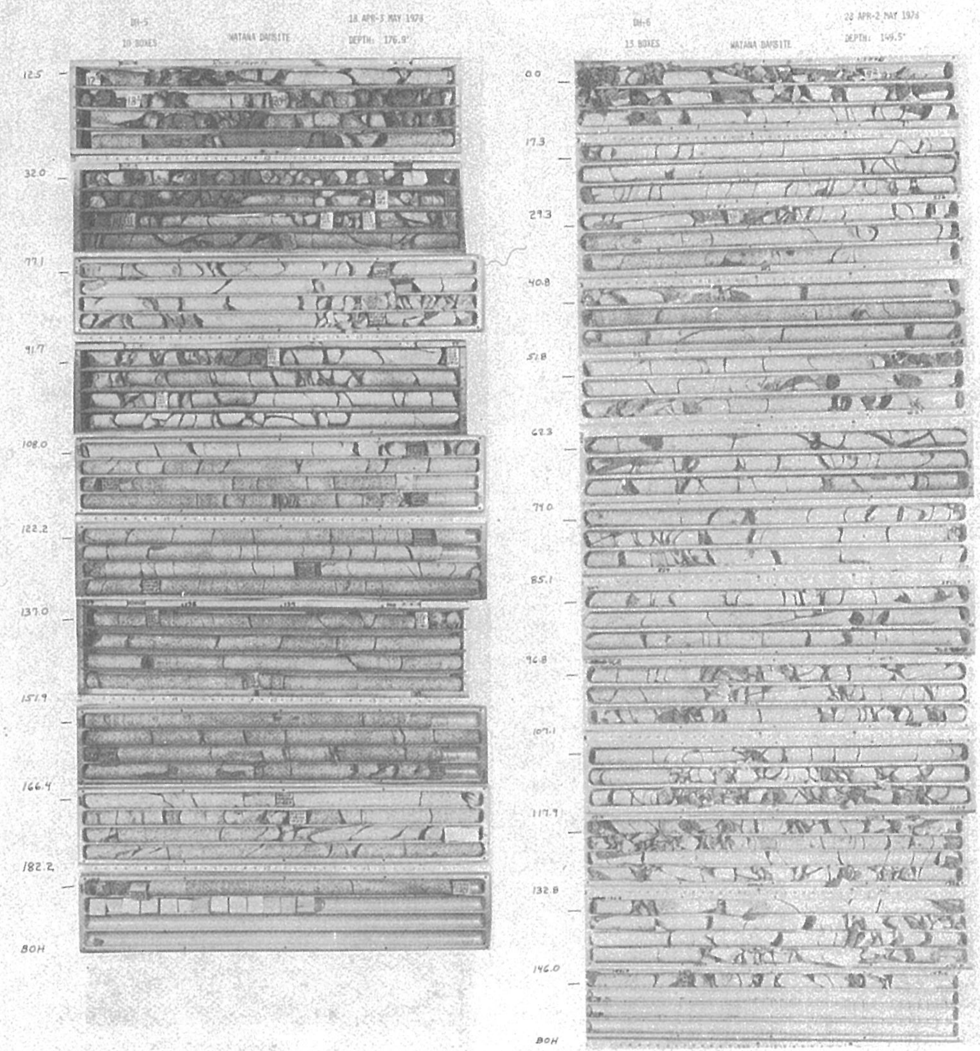
DR-27 AND DH-28

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE ALASKA

PLATE D-37

NOTES:
1. DEPTHS SHOWN ON DH-1 THRU DH-3 ARE FROM TOP OF RIVER ICE.

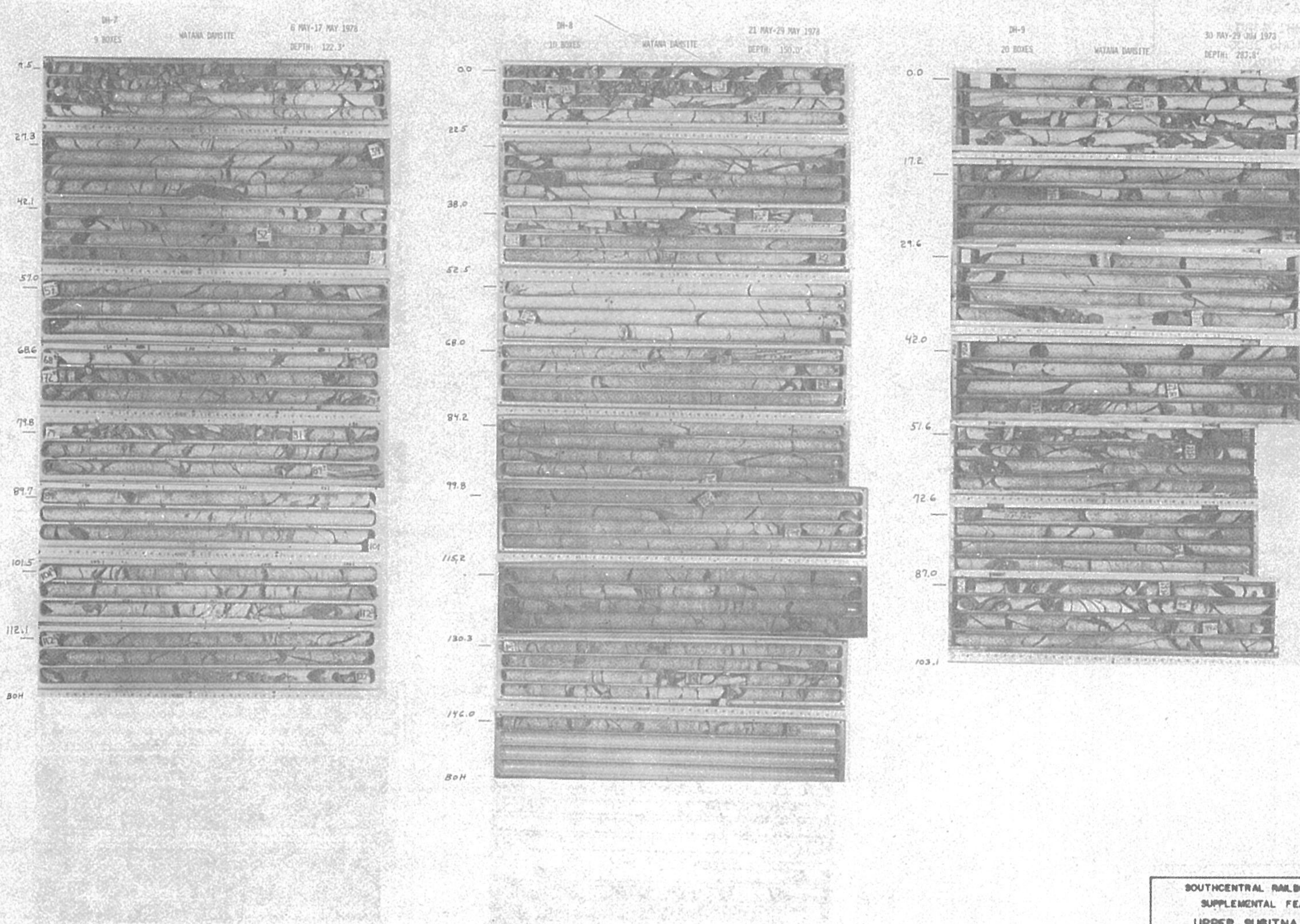
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 1
DH-1 THRU DH-4
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

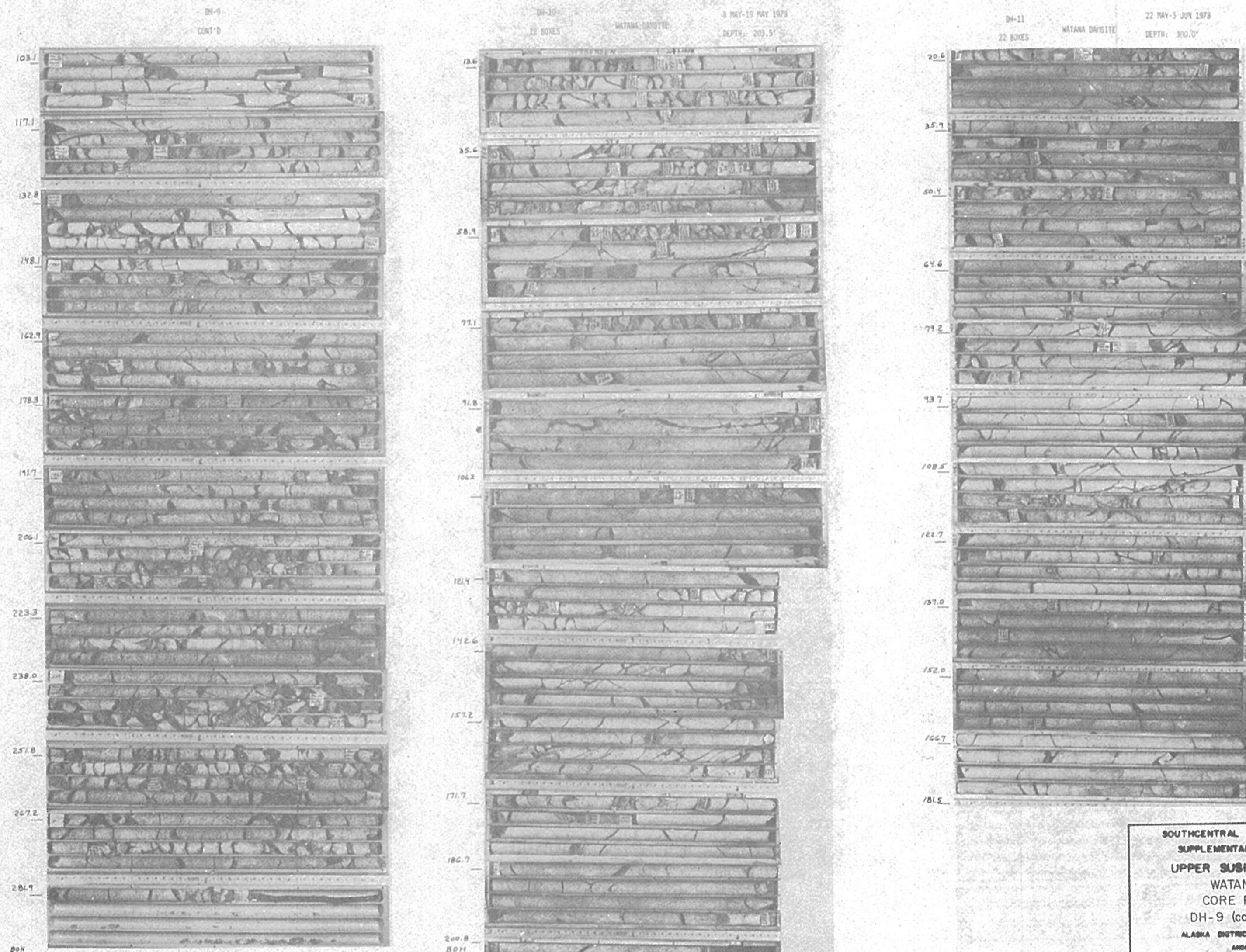
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 2
DH-5 THRU DH-6

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

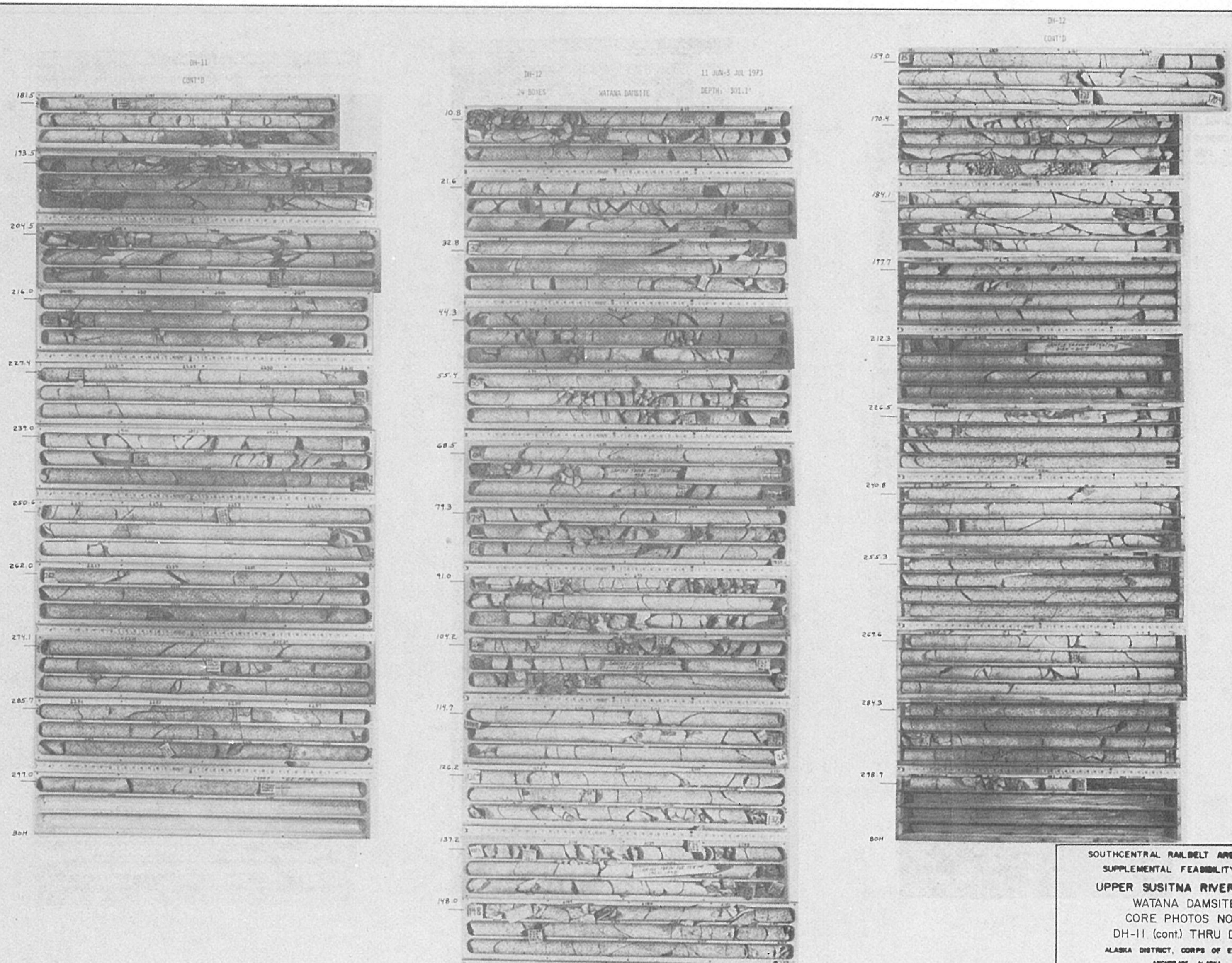


SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 3
DH-7 THRU DH-9
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-40



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 4
DH-9 (cont) THRU DH-11
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 5
DH-11 (cont.) THRU DH-12
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

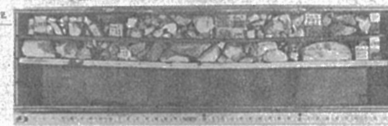
PLATE D-42

DR-15 2 BOXES WATANA DAMSITE 27 APR-16 MAY 1978 DEPTH: 516.5'

296.0
305.1

BOH

DR-18 1 BOX WATANA DAMSITE 9 JUN-21 JUN 1973 DEPTH: 240.3'

239.2

BOH

DR-16 1 BOX WATANA DAMSITE 31 MAY-4 JUN 1973 DEPTH: 91.5'

78.5

BOH

DR-19 1 BOX WATANA DAMSITE 29 JUN-5 JUL 1973 DEPTH: 78.3'

66.2

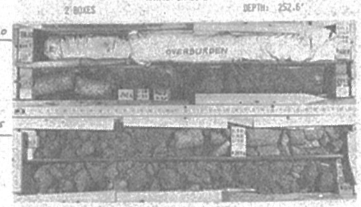
BOH

DR-17 2 BOXES WATANA DAMSITE 6 JUN-J JUN 1978. DEPTH: 35.7'

14.5
27.5

BOH

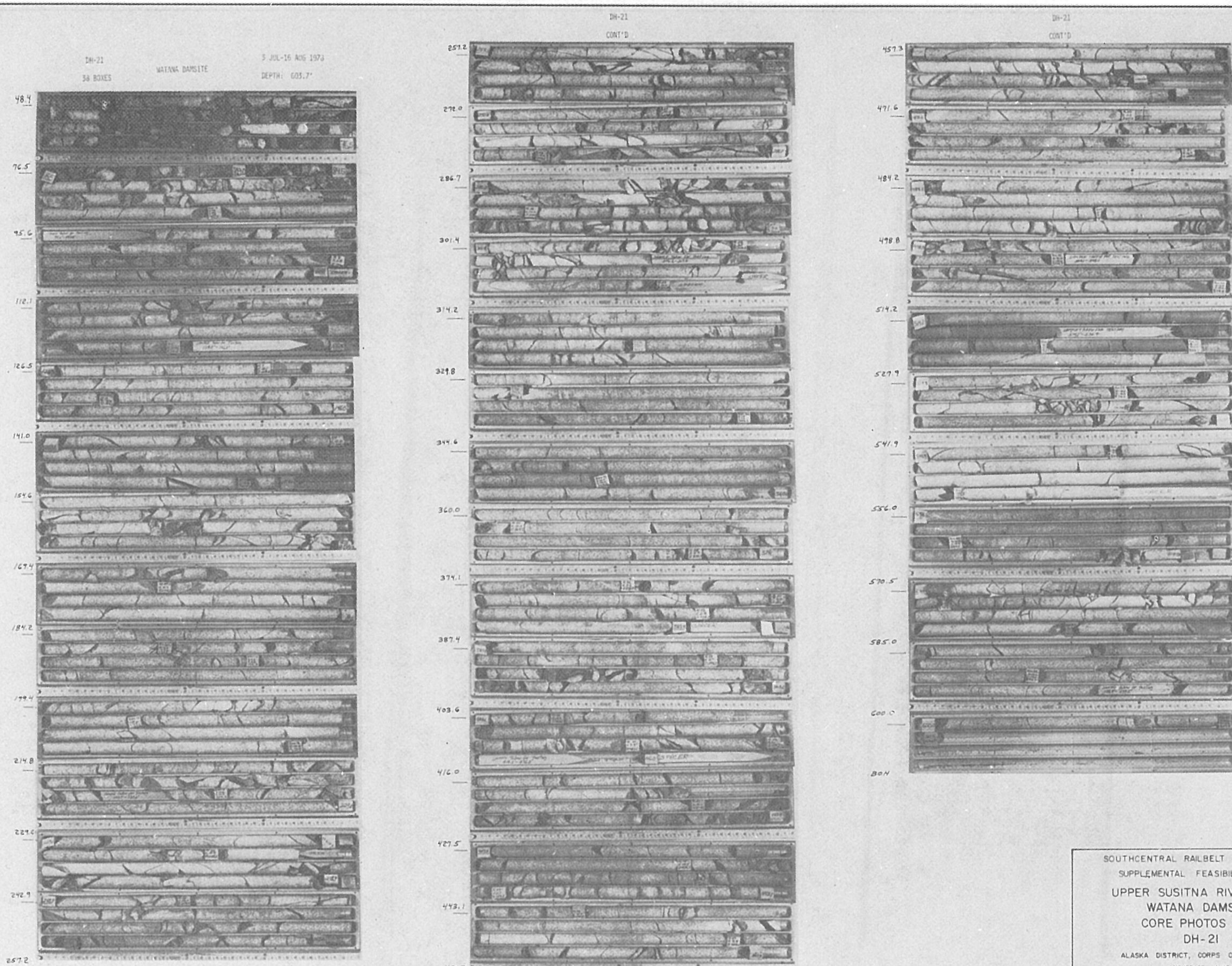
DR-20 2 BOXES WATANA DAMSITE 12 MAY-29 MAY 1973 DEPTH: 252.6'

218.0
244.5


BOH

SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 6
DR-15 THRU DR-20
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-43



SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY

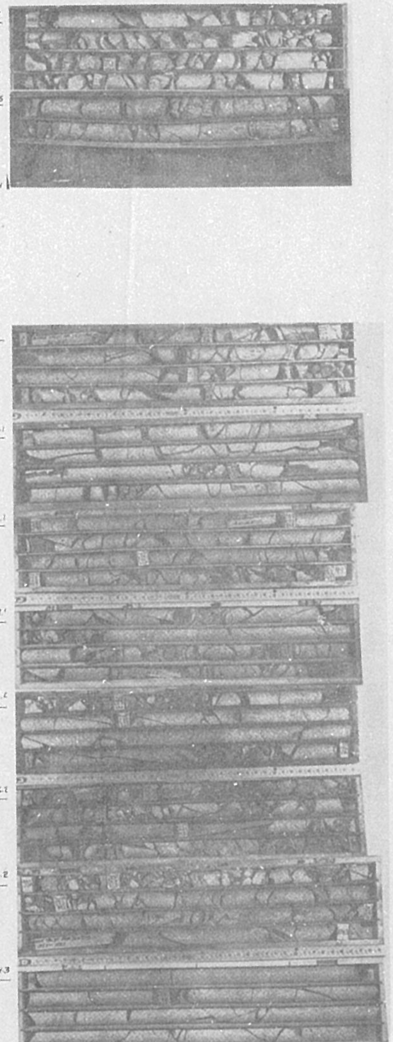
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 7
DH-21

ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-44

DR-22
2 BOXES WATANA DAMSITE
5 JUL-3 AUG 1978
DEPTH: 493.6'

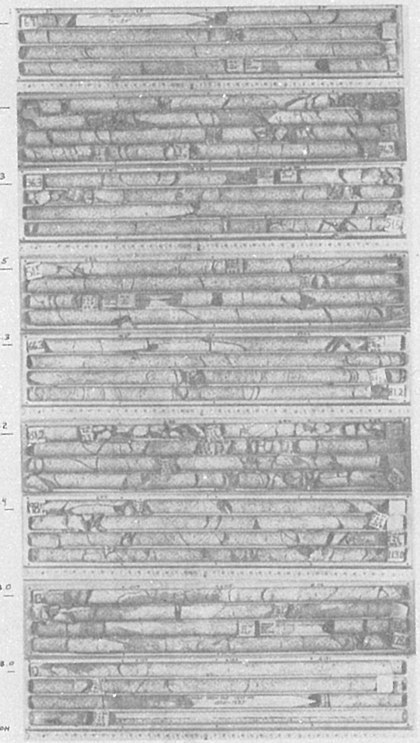
417.8
486.5
BOH



7.0
20.1
34.1
47.
62.0
76.1
90.2
104.3
119.2
BOH

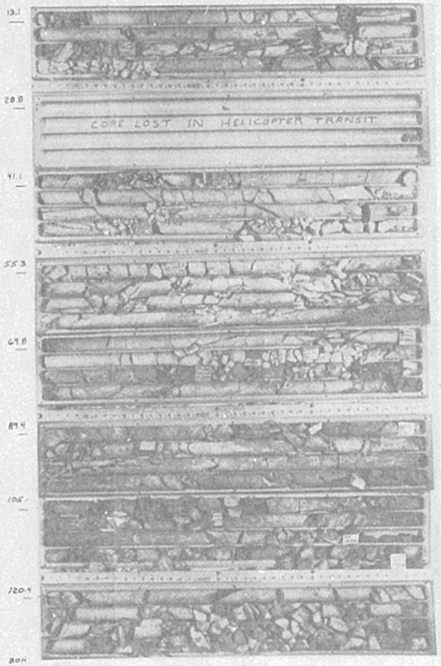
DH-24
9 BOXES WATANA DAMSITE
25 JUL-31 JUL 1973
DEPTH: 139.9'

6.9
21.9
36.3
51.5
66.3
81.2
98.4
113.0
128.0
BOH



DH-28
8 BOXES WATANA DAMSITE
17 AUG-30 AUG 1978
DEPTH: 129.2'

13.1
28.8
41.1
55.3
69.8
89.4
105.
120.4
BOH



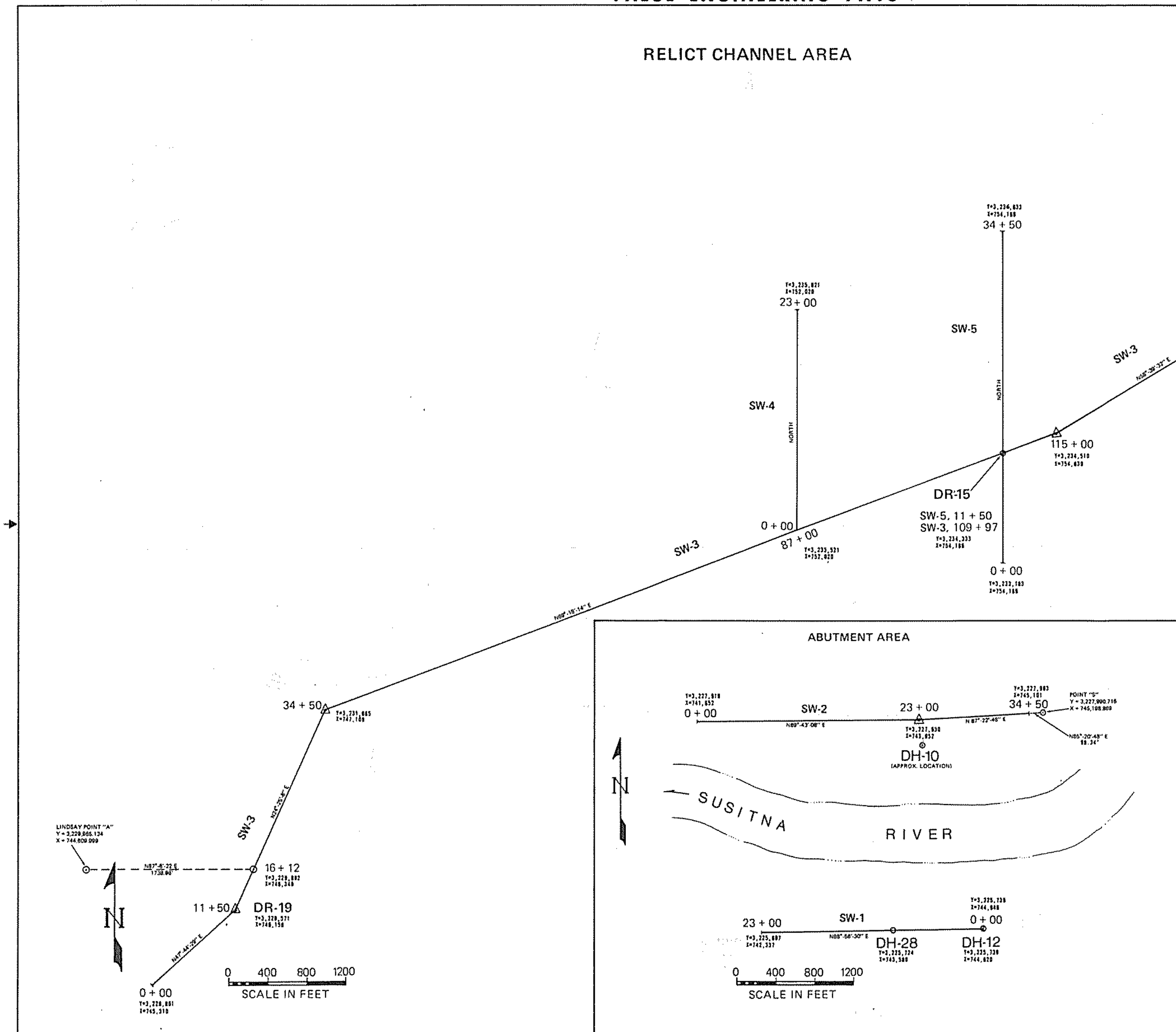
SOUTHCENTRAL RAILBELT AREA, ALASKA
SUPPLEMENTAL FEASIBILITY STUDY
UPPER SUSITNA RIVER BASIN
WATANA DAMSITE
CORE PHOTOS NO. 8
DR-22 THRU DH-28
ALASKA DISTRICT, CORPS OF ENGINEERS
ANCHORAGE, ALASKA

PLATE D-45

EXHIBIT D-1

Location Maps and Seismic Refraction Velocity Profiles, Watana and Devil Canyon Damsites.

705



REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

CONTRACT NO.
CONTRACTOR
CITY STATE
RECOMMENDED: APPROVED: DATE:

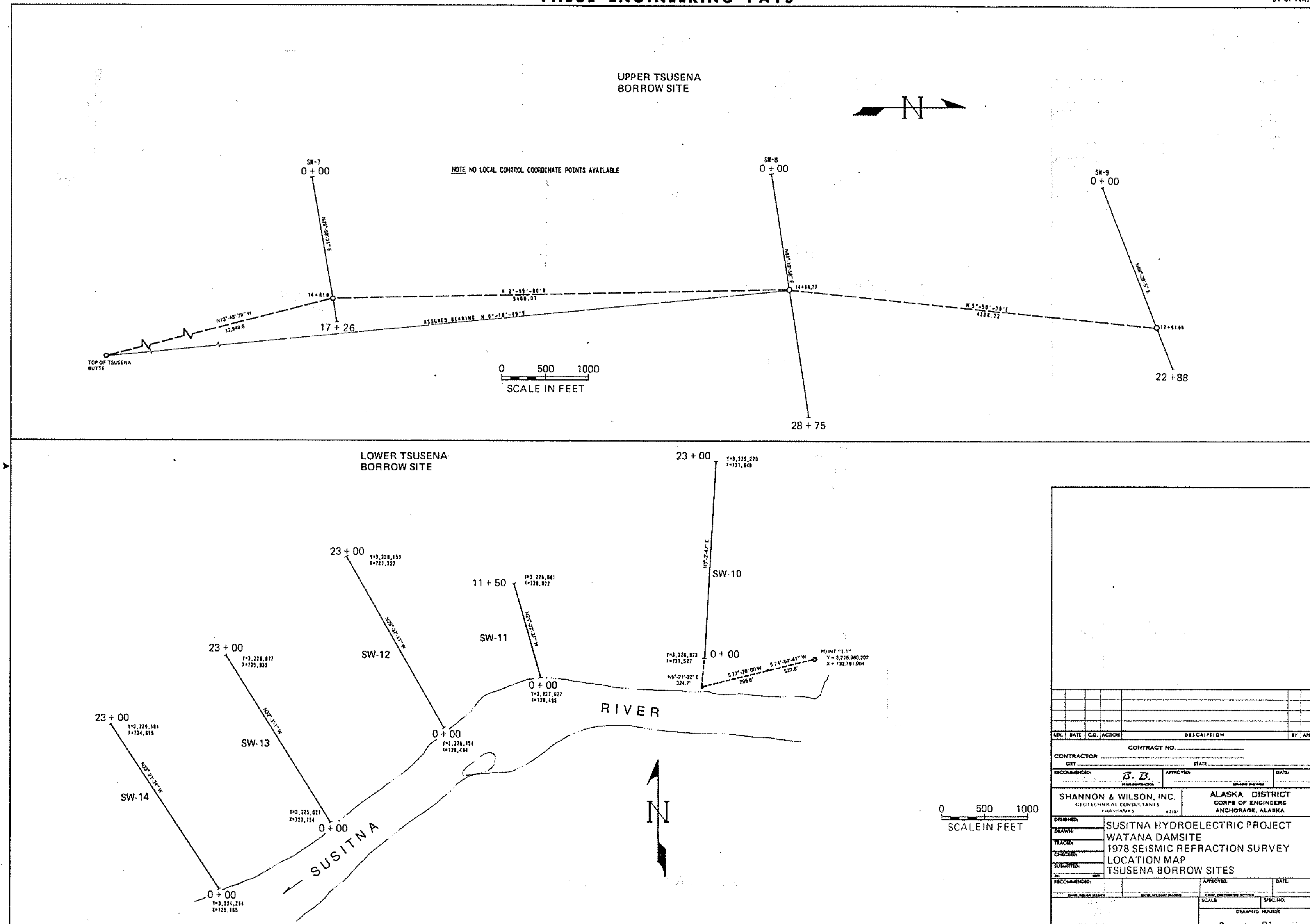
SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
FAIRBANKS

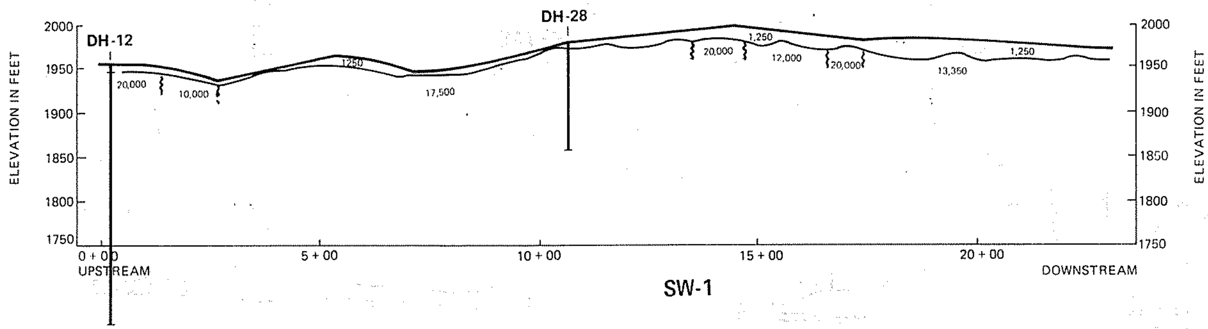
ALASKA DISTRICT
CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
LOCATION MAP

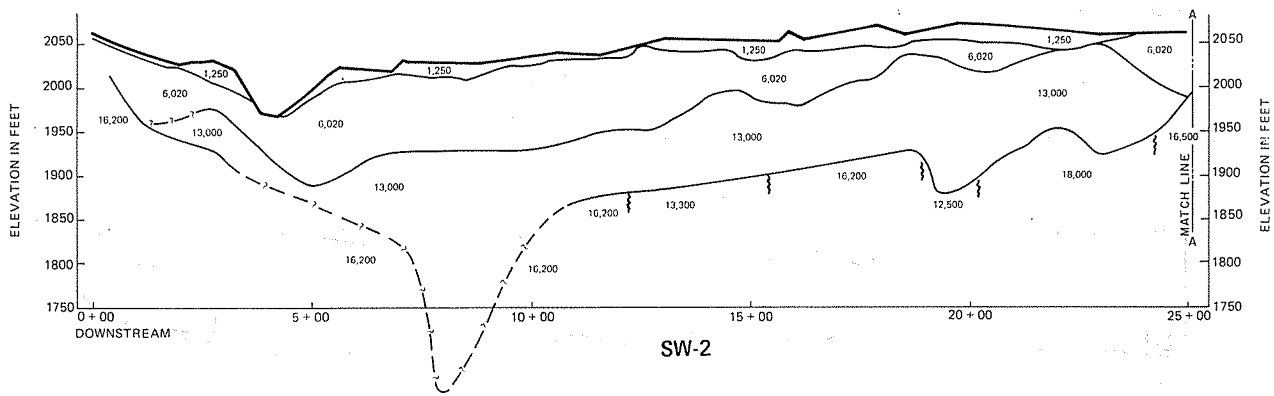
DESIGNED:
DRAWN:
TRACED:
CHECKED:
SUBMITTED:
RECOMMENDED: APPROVED: DATE:
SCALE: SPEC. NO.
DRAWING NUMBER
SHEET 1 OF 21

706

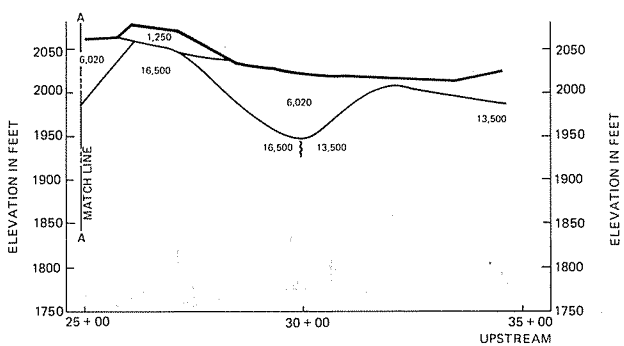

UPPER TSUSENA
BORROW SITE
N
NOTE NO LOCAL CONTROL COORDINATE POINTS AVAILABLE
SW-7
0 + 00
17 + 26
SW-8
0 + 00
28 + 75
SW-9
0 + 00
22 + 88
TOP OF TSUSENA BUTTE
ASSUMED BEARING
0 500 1000
SCALE IN FEET
LOWER TSUSENA
BORROW SITE
23 + 00
SW-10
0 + 00
POINT "T-1"
23 + 00
SW-12
0 + 00
11 + 50
SW-11
0 + 00
23 + 00
SW-13
0 + 00
23 + 00
SW-14
0 + 00
RIVER
SUSITNA
N
0 500 1000
SCALE IN FEET
REV. DATE C.O. ACTION DESCRIPTION BY APP'D.
CONTRACT NO.
CONTRACTOR
CITY STATE
RECOMMENDED: B. B.
APPROVED: DATE:
SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
FAIRBANKS
ALASKA DISTRICT
CORPS OF ENGINEERS
ANCHORAGE, ALASKA
DESIGNED:
DRAWN:
TRACED:
CHECKED:
SUBMITTED:
SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
LOCATION MAP
TSUSENA BORROW SITES
RECOMMENDED:
APPROVED: DATE:
SCALE: SPEC. NO.
DRAWING NUMBER
SHEET 2 OF 21



SW-1



SW-2



SW-2

LEGEND

POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DH-12 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

0 50 100 150
VERTICAL SCALE IN FEET

0 100 200 300
HORIZONTAL SCALE IN FEET

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

CONTRACT NO. ______
CONTRACTOR ______
CITY ______ STATE ______

RECOMMENDED: ______ APPROVED: ______ DATE: ______

SHANNON & WILSON, INC.
GEOTECHNICAL CONSULTANTS
FAIRBANKS

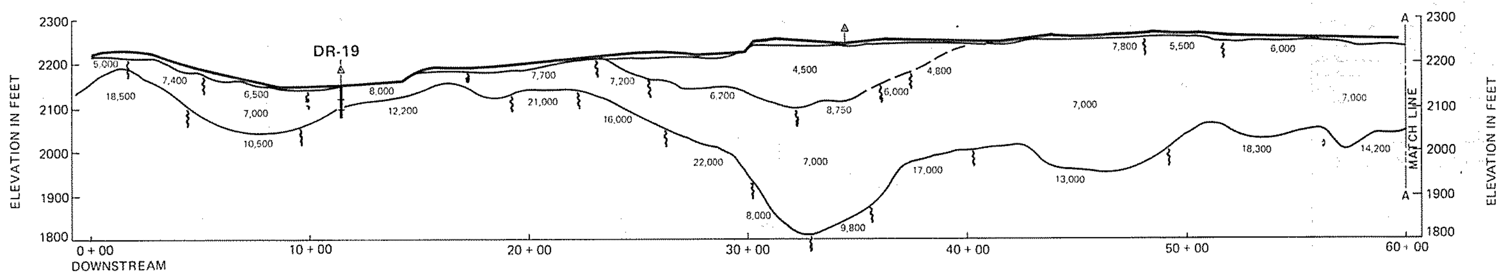
ALASKA DISTRICT
CORPS OF ENGINEERS
ANCHORAGE, ALASKA

DESIGNED:
DRAWN:
TRACED:
CHECKED:
SUBMITTED:

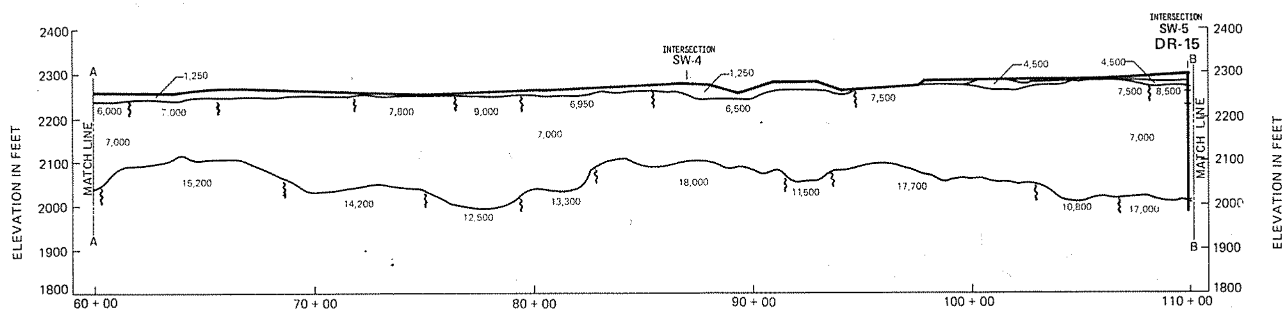
SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
SW-1 SW-2

RECOMMENDED: APPROVED: DATE:
SCALE: SPEC. NO.
DRAWING NUMBER
SHEET 3 OF 21

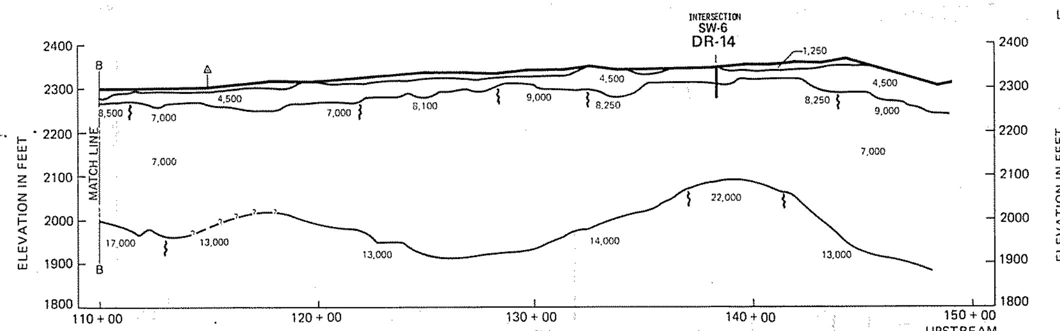
INV. NO. DACW85-78-C-0027



SW - 3



SW - 3



SW - 3

VERTICAL SCALE IN FEET (0, 100, 200, 300)

HORIZONTAL SCALE IN FEET (0, 200, 400, 600)

LEGEND

{ POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DR-15 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

CONTRACT NO.

CONTRACTOR

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ALASKA DISTRICT CORPS OF ENGINEERS ANCHORAGE, ALASKA

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SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
SW-3

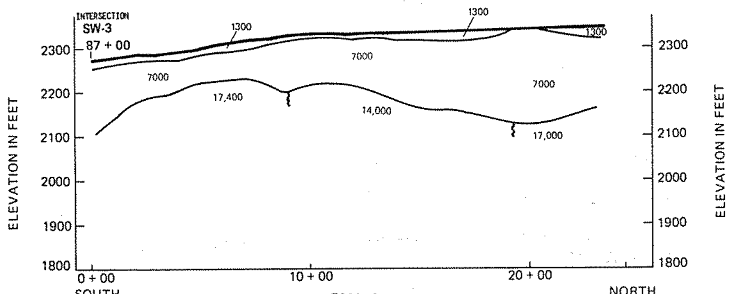
RECOMMENDED: APPROVED: DATE:

SCALE: SPEC. NO.

DRAWING NUMBER

SHEET 4 OF 21

INV. NO. DACW85-78-C-0027



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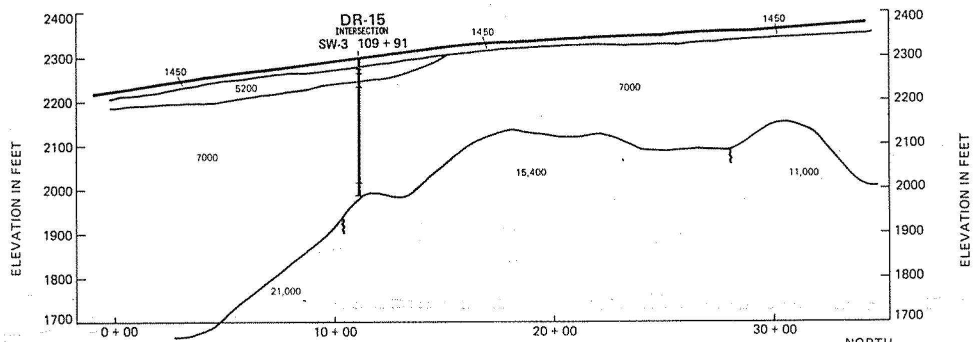

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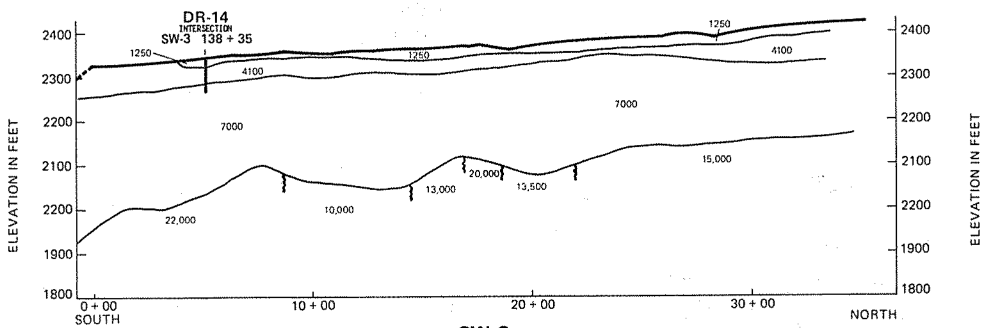

SW-6

LEGEND

POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DR-15 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

0 100 200 300

VERTICAL SCALE IN FEET

0 200 400 600

HORIZONTAL SCALE IN FEET

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

CONTRACT NO.

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ANCHORAGE, ALASKA

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SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
SW-4 SW-5 SW-6

RECOMMENDED: APPROVED: DATE:

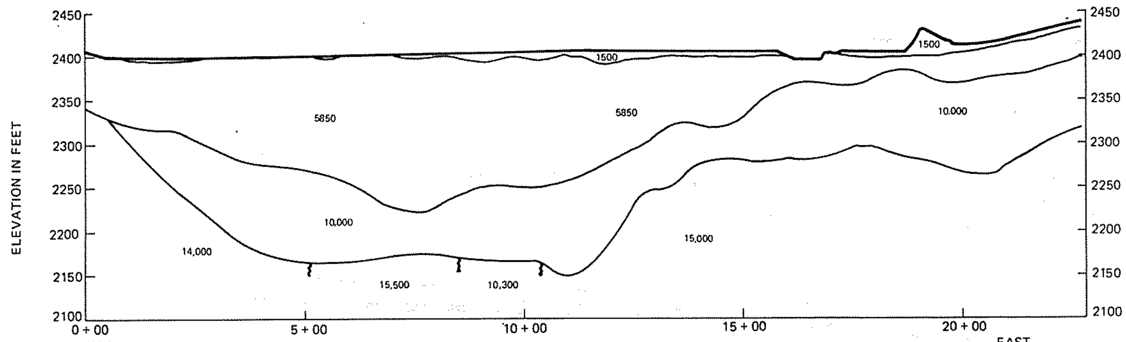
SCALE: SPEC. NO.

DRAWING NUMBER

SHEET 5 OF 21

INV. NO. DACW85-78-C-0027

UPPER TSUSENA BORROW SITE



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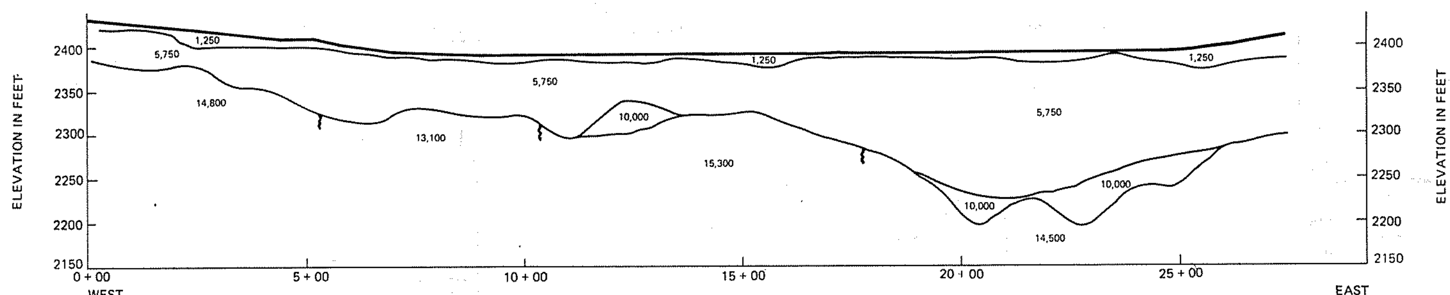

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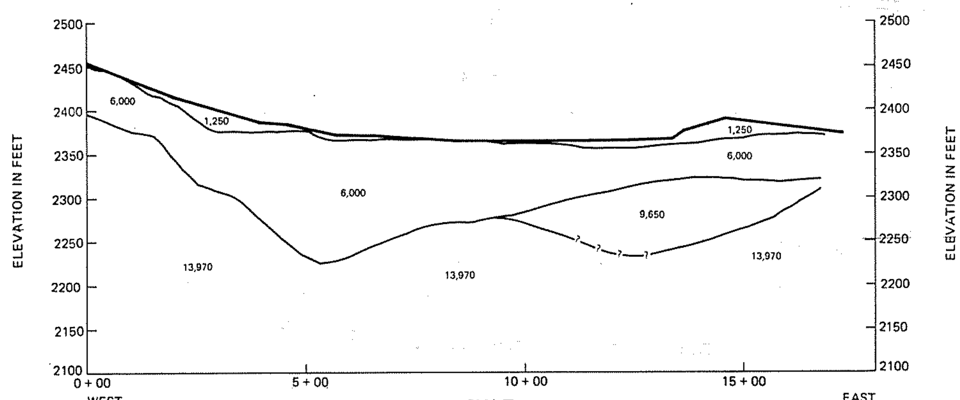

SW-7

LEGEND

POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DR-15 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

0 50 100 150
VERTICAL SCALE IN FEET

0 100 200 300
HORIZONTAL SCALE IN FEET

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APP'D.

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CONTRACTOR
CITY STATE

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SUSITNA HYDROELECTRIC PROJECT
WATANA DAM SITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
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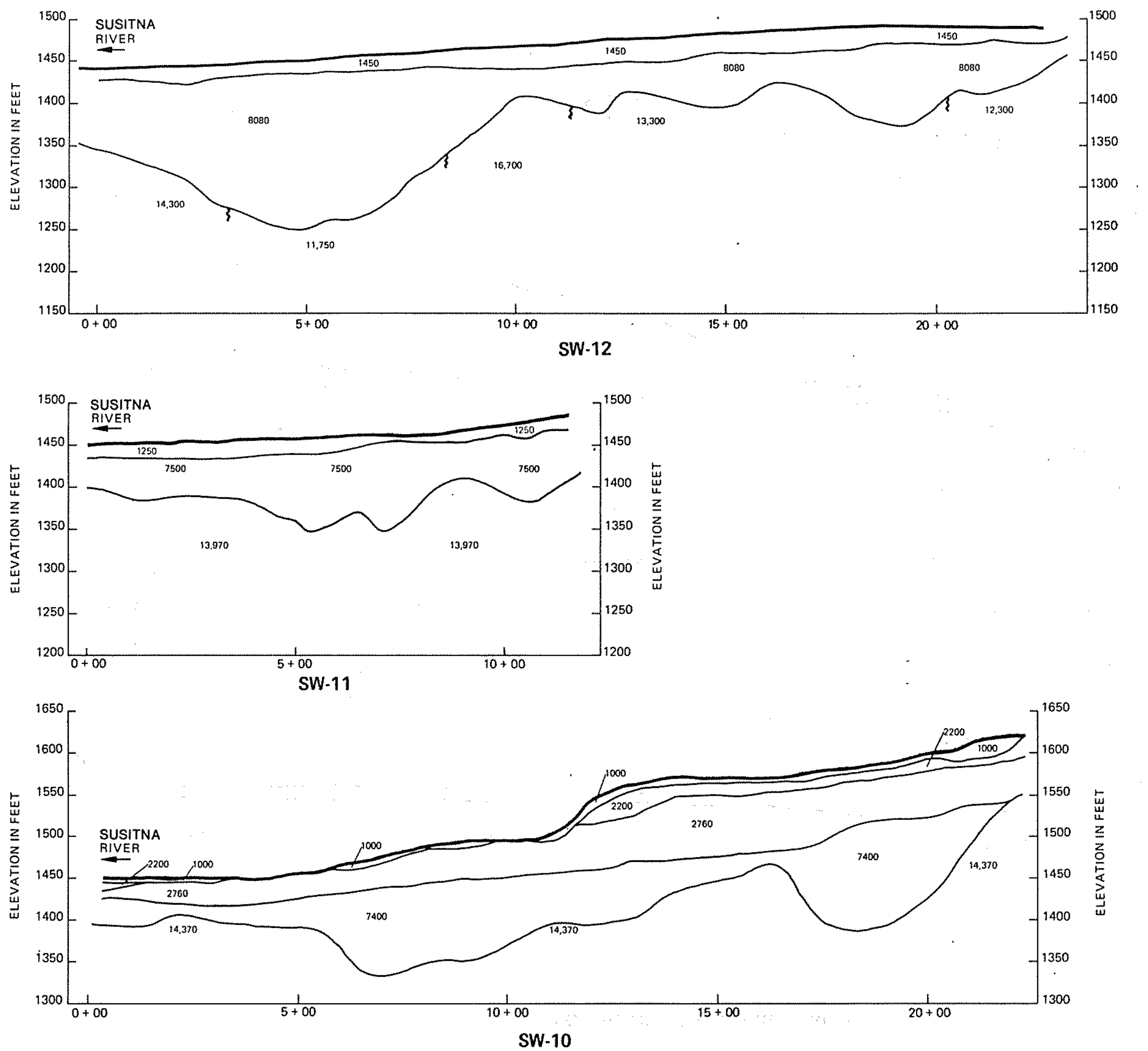
LOWER TSUSENA BORROW SITE



LEGEND

⌇ POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DR-15 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

0 50 100 150

VERTICAL SCALE IN FEET

0 100 200 300

HORIZONTAL SCALE IN FEET

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

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CORPS OF ENGINEERS
ANCHORAGE, ALASKA

SUSITNA HYDROELECTRIC PROJECT
WATANA DAMSITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
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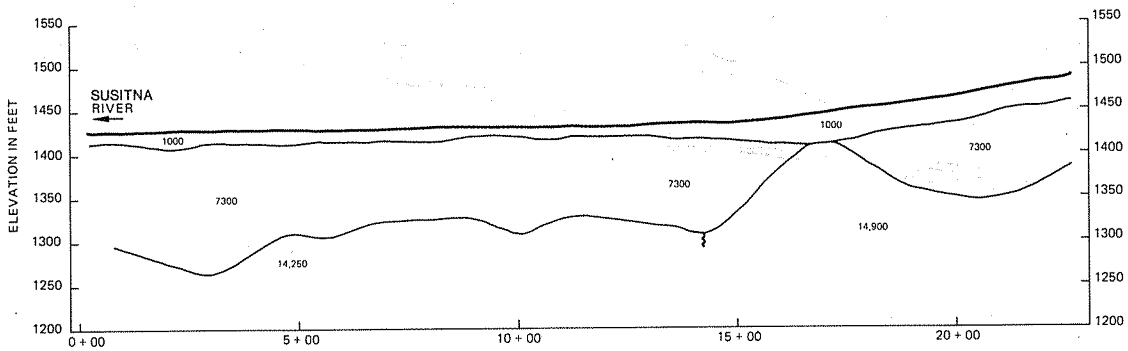
INV. NO. DACW85-78-C-0027

LOWER TSUSENA BORROW SITE

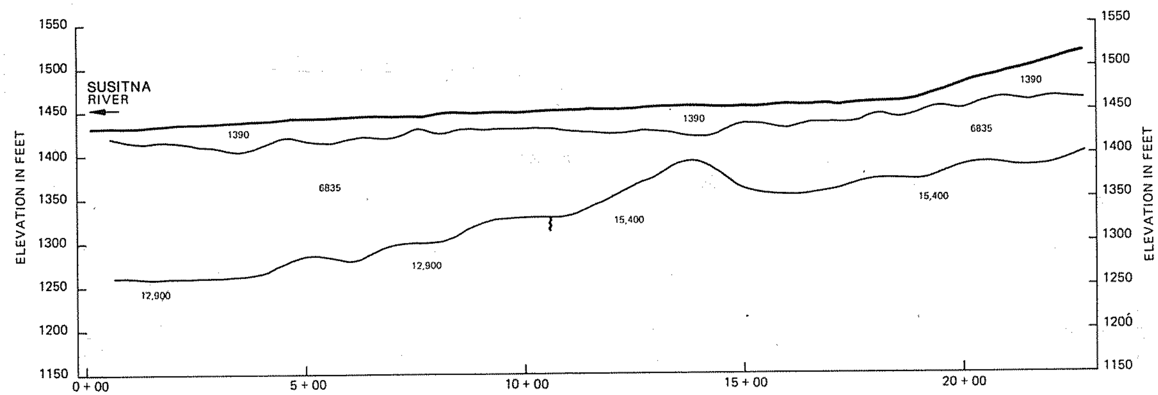


SW-14

LEGEND
} POSITION OF LATERAL VELOCITY CHANGE
NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

0 50 100 150
VERTICAL SCALE IN FEET

0 100 200 300
HORIZONTAL SCALE IN FEET



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CONTRACTOR
CITY STATE
RECOMMENDED: D. B. APPROVED: DATE:

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FAIRBANKS

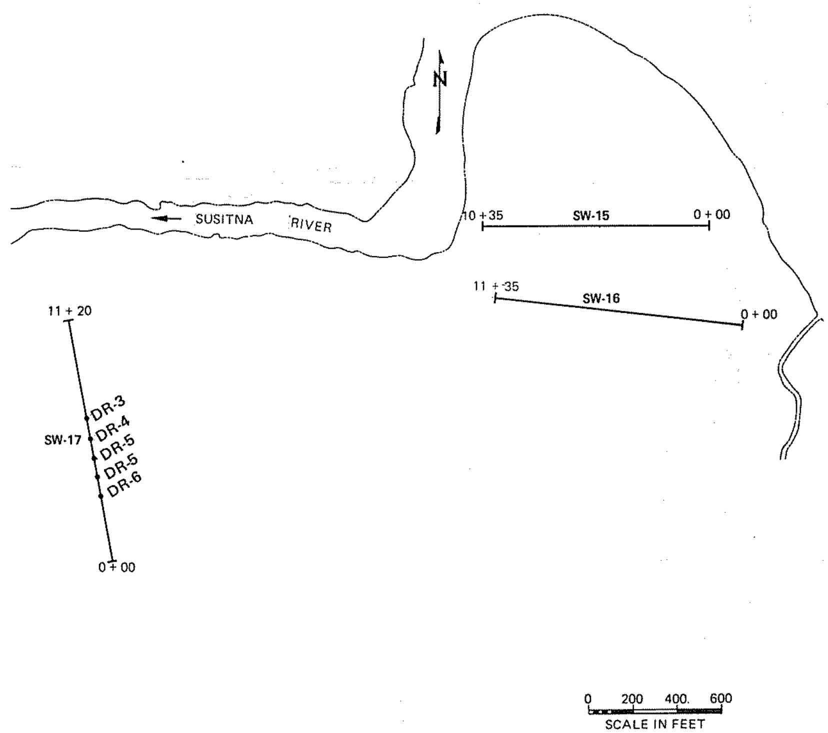
ALASKA DISTRICT
CORPS OF ENGINEERS
ANCHORAGE, ALASKA

DESIGNED:
DRAWN:
TRACED:
CHECKED:
SUBMITTED:
RECOMMENDED:

SUSITNA HYDROELECTRIC PROJECT
LOWER TSUSENA BORROW SITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
SW-13 SW-14

APPROVED: DATE:
SCALE: SPEC. NO.
DRAWING NUMBER
SHEET 8 OF 21

INV. NO. DACW85-78-C-0027



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CONTRACTOR ______
CITY ______ STATE ______

RECOMMENDED: B. B. — APPROVED: — DATE:

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ANCHORAGE, ALASKA

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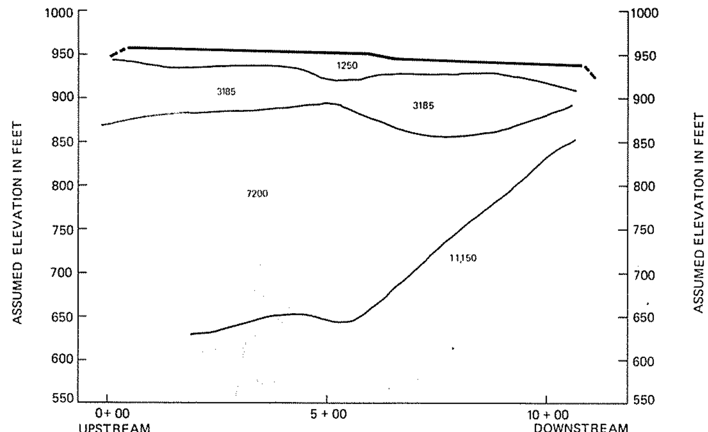
SUSITNA HYDROELECTRIC PROJECT
DEVIL'S CANYON DAMSITE
1978 SEISMIC REFRACTION SURVEY
LOCATION MAP
SW-15 SW-16 SW-17

RECOMMENDED: — APPROVED: — DATE:
SCALE: — SPEC. NO.
DRAWING NUMBER
SHEET 9 OF 21



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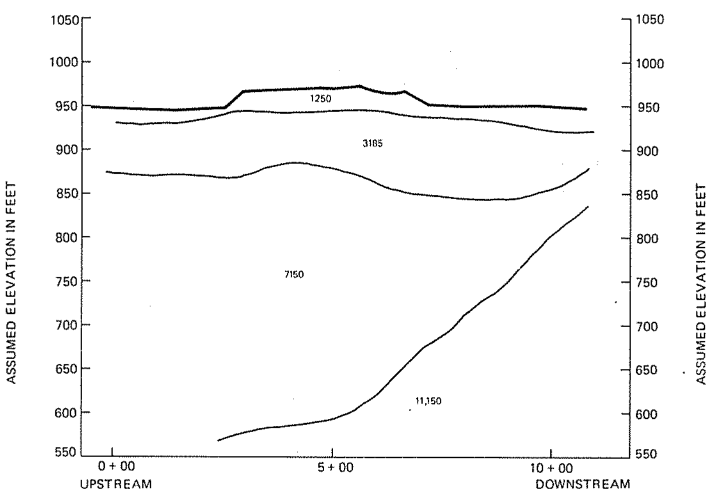

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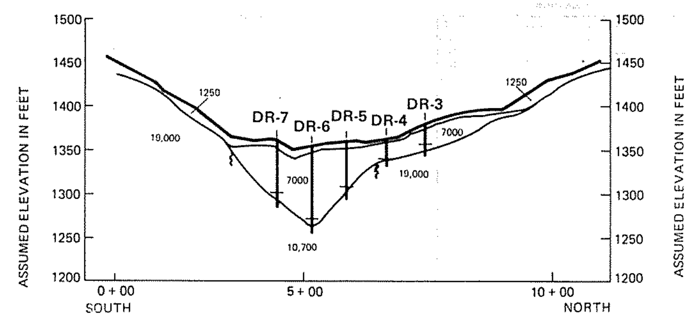

SW-17

LEGEND

POSITION OF LATERAL VELOCITY CHANGE

NUMBERS IN PROFILES ARE VELOCITIES, IN FEET PER SECOND

DR-15 BORING DESIGNATION

APPROXIMATE LOCATION OF CHANGE IN MATERIAL

0 50 100 150
VERTICAL SCALE IN FEET

0 100 200 300
HORIZONTAL SCALE IN FEET

REV.	DATE	C.O.	ACTION	DESCRIPTION	BY	APPD.

CONTRACT NO.
CONTRACTOR
CITY STATE
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GEOTECHNICAL CONSULTANTS
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ALASKA DISTRICT
CORPS OF ENGINEERS
ANCHORAGE, ALASKA

DESIGNED:
DRAWN:
TRACED:
CHECKED:
SUBMITTED:

SUSITNA HYDROELECTRIC PROJECT
DEVIL'S CANYON DAMSITE
1978 SEISMIC REFRACTION SURVEY
SEISMIC VELOCITY PROFILES
SW-15 SW-16 SW-17

RECOMMENDED: APPROVED: DATE:
SCALE: SPEC. NO.
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SHEET 10 OF 21

EXHIBIT D-2

Reconnaissance of the Recent Geology of the Proposed Devil's Canyon and Watana Damsites, Susitna River, Alaska.

CONTENTS

Illustrations

Figures

Tables

Appendices

PRELIMINARY REPORT OF THE RECENT GEOLOGY
OF THE PROPOSED DEVILS CANYON AND WATANA
DAMSITES, SUSITNA RIVER, ALASKA

by

Reuben Kachadoorian and Henry J. Moore

ABSTRACT

At the request of the Corps of Engineers, the U.S. Geological Survey conducted a reconnaissance of the recent geology of the proposed Devils Canyon and Watana damsite areas, Susitna River, Alaska. The purposes of the reconnaissance were to look for active faults and other geologic hazards. Field work by the Geological Survey was conducted between July 25, 1978 and August 7, 1978 using a helicopter which was shared jointly and in cooperation with personnel of the Corps of Engineers.

The geologic reconnaissance of the proposed Devils Canyon and Watana damsite and reservoir areas did not uncover any evidence for recent or active faulting along any of the known or inferred faults. Recent movement of surficial deposits has occurred as the result of mass wasting processes and, possibly, by seismic shaking and minor displacements of bedrock along joints.

Landsliding has occurred in the past and future landsliding appears probable. The occurrence of unconsolidated glacial debris, alluvium, and Tertiary sediments at elevations below the proposed reservoir water levels may slump and slide into the reservoirs when they are inundated. Some of these sediments may be permanently frozen and, locally, may be

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ice-rich which increases the probability of slumping and sliding when the sediments are thawed by the water impounded behind the dams.

The tectonic framework of the Devils Canyon and Watana damsite areas is not well understood. The present knowledge of the area indicates that the seismicity of the region ranges in depth from less than 10 km to greater than 175 km.

Additional detailed geologic and seismic studies are necessary in order to reliably evaluate the potential geologic hazards in the region of the proposed dam and reservoir sites.

INTRODUCTION

The feasibility of two dams on the Susitna River, Alaska, is currently under evaluation by the U.S. Army Corps of Engineers. The Corps of Engineers has proposed two dams for the purpose of developing the hydroelectric power potential of the Susitna River: one at Devils Canyon and the other at the Watana site. The proposed Devils Canyon site is located about 29 km (18 miles) upstream from Gold Creek Station on The Alaska Railroad. This dam would be 194 m (635 ft) high and the reservoir formed would have a water altitude of 442 m (1,450 ft) above sea level and would extend about 45 km (28 miles) upstream to the proposed Watana site. The height of the proposed Watana dam would be 247 m (810 ft) and its reservoir would have a maximum water altitude of 671 m (2,200 ft) and extend upstream 87 km (54 miles). The total power produced by both structures would be about 600 megawatts (MW); approximately 270 MW at Devils Canyon and the remaining 330 (MW) at Watana. The current proposed locations for the damsites are shown in Figure 1.

The study of active faults, seismic activity, potential and recent landslides, and other potential geologic hazards are of particular concern in the preliminary evaluation of the proposed Devils Canyon and Watana damsites and their reservoirs. The U.S. Army Corps of Engineers requested the U.S. Geological Survey to make such a study. Authorization for the Geological Survey to make the study is embodied in a letter from F. R. Brown, Technical Director, Corps of Engineers Waterways Experiment Station to Dr. Dallas Peck, Chief Geologist, Geological Survey (Appendix A) and a proposal letter to Dr. Ellis

Krinitzsky, Corps of Engineers, by Reuben Kachadoorian (Appendix B). In practice, the scope of this reconnaissance was modified to include a much larger area than that stated in Appendix B.

This report is based essentially on reconnaissance geologic observations, both on the surface and from overflights, between July 25, 1978 and August 7, 1978. Field work was conducted using a helicopter which was shared jointly and in cooperation with Corps of Engineers personnel who were conducting detailed studies at the proposed Watana damsite. Unfortunately, adverse weather significantly curtailed the number of surface observations during the limited amount of time that the helicopter was available to us.

Details of the bedrock geology are beyond the scope of this report but the geologic map and report of Csejtey and others (1978) is included in this report as Appendix C for the sake of completeness and because we refer to some of the geologic map units. The geologic map in the report was important to our reconnaissance and wherever we field checked it, we found it to be correct and commensurate with its scale. It should be realized that mapping at a larger scale would permit finer subdivision of the map units and portrayal in more detail. Additionally, the definitions of the map units are not directed toward engineering problems, but rather geologic ones; and, therefore, this fact must be considered when using the enclosed geologic map. The map should be used only to determine the gross geologic setting of the proposed Devils Canyon and Watana damsites and their reservoirs. The map includes all of the Talkeetna Mountains, Alaska, Quadrangle, and small segments of the Healy, Alaska, Quadrangle, in the northwest part of the map and the Anchorage, Alaska, Quadrangle in the south.

Figure 1 is intended to clarify the discussions and data presented in this report. It has three parts: (1) a 1:250,000 scale topographic map of the Healy, Alaska, Quadrangle, (2) a 1:250,000 scale topographic map of the Talkeetna Mountains, Alaska, Quadrangle, and (3) a transparent overlay depicting the inferred and actual faults in the reconnaissance area. The overlay includes the northern three-fourths of the Talkeetna Mountains Quadrangle and the southern one-fourth of the Healy Quadrangle. The transparent overlay may be superposed on the topographic maps to locate the inferred and actual faults and other items in the text. Additionally, certain features discussed in the text can be located on the topographic maps by Townships, Ranges, and Sections. The geologic map in Appendix C also has the same scale as the topographic maps and transparent overlay.

We must emphasize that the data and conclusions presented in this report are based on a reconnaissance study of the proposed Devils Canyon and Watana dam and reservoir sites. To evaluate thoroughly the proposed damsites and their reservoirs additional studies must be made. We specify some of these studies later in this report.

GEOLOGIC BACKGROUND

The geology of the Susitna River area (Csejtey and others, 1978; Appendix C) is rather complex. Bedrock consists chiefly of tightly folded, metamorphosed, and faulted volcanic and sedimentary sequences that range in age from late Paleozoic to late Cretaceous and of late Cretaceous to Early Tertiary granodiorite (55 to 75 m.y. old). These rocks are overlain by Tertiary volcanic and sedimentary rocks (about 50 to 58 m.y. old). Tertiary sediments of possibly late Oligocene age (about 25 m.y. old) (Wolfe, written communication, 1977) are exposed in Watana Creek about 7 km (4.5 miles) upstream of its confluence with the Susitna River. The Tertiary sediments are gently tilted and possibly faulted.

Unconsolidated sediments of late Wisconsin glaciation (8,000-12,000-years ago; Péwé, 1975) cover much of the study area. These late Wisconsin glacial sediments consist of unconsolidated tills, moraines, sand and gravel deposits and eskers. Glacial scour features caused by this glaciation are also present. The glacial sediments, in turn, have been and are being eroded, cut, and modified by the Susitna River drainage system and by mass wasting. These recent geologic events are represented by V-shaped valleys, river sands and gravels, terrace sediments, solifluction, slumps, landslides, talus, lakes, stream channels, and other features due to mass wasting processes.

The late Wisconsin glaciation (8,000 to 12,000 y. old) covered the Devils Canyon, Watana dam, and reservoir sites. Kachadoorian (1974) reported field evidence from Devils Canyon indicating that the Susitna River occupies the same channel at the present as it did prior to the

Late Wisconsin glacial period. Recent discovery of glacial debris on the floor of the Susitna River Canyon upstream from the Watana damsite confirms Kachadoorian s previous observation at Devils Canyon.

Of particular interest here are the faults that have been inferred to exist by various investigators in the area. These faults are shown in Figure 1 and are listed in Table 1. Table 1 also includes the designation, type, and the reference from which we obtained the information about these faults.

Table 1. Inferred faults in the general area of the Devils Canyon and Watana damsites, Susitna River, Alaska[1]

Number	Designation	Reference	Type	Remarks
1.	Zone of intense shearing	Csejtey and others, 1978	Thrust	Evidence is stratigraphic and petrographic.
2.	Talkeetna Thrust	Csejtey and others, 1978	Thrust	Evidence is stratigraphic.
3.	Near Watana Creek	Csejtey and others, 1978	Thrust	Evidence is stratigraphic.
4.	Near Portage Creek	Csejtey and others, 1978	Thrust	Evidence is stratigraphic.
5.	Chulitna River	Csejtey and others, 1978	Thrust & Vertical	Evidence is stratigraphic.
6.	North of VABM Sheep	Csejtey and others, 1978	Strike Slip	Right lateral with some vertical displacement.
7.	West of VABM Sheep	Csejtey and others, 1978	Strike Slip	Two faults; left lateral and right lateral.
8.	Susitna Fault	Anon., 1974a, Turner and others, 1974; Gedney and Shapiro, 1975; Turner and Smith, 1974	Strike Slip	Evidence is topographic lineament; inferred to be right lateral from seismic data.
9.	Near Clarence Lake	Beikman, 1974; Smith and others, 1975; Turner and Smith, 1974	High Angle	Displacement apparently vertical.
10.	Near VABM Windus	Beikman, 1974; Smith and others, 1975, Turner and Smith, 1974	High Angle	Displacement apparently vertical.
11.	North of VABMs Grebe-Mt. Watana	Anon., 1974a; Beikman, Smith and others, 1975, Turner and Smith, 1974	Thrust	Evidence is apparently stratigraphic.
12.	East of VABM Sumartidason	Anon., 1974a	Strike Slip	Existence is questioned by the authors.
13.	Watana Creek	Anon., 1974a; Turner and Smith, 1974; Smith and others, 1975	Normal	Evidence is stratigraphic.
14.	Along Portage Creek	Csejtey, personal comm., 1975; Lahr and Kachadoorian, 1975	Thrust	Alternate trace for number 4
15.	North of Denali	Anon., 1974a; Beikman, 1974; Turner and Smith, 1974	Thrust	Evidence is apparently stratigraphic.
16.	Cretaceous to recent shearing	Csejtey, personal commun., 1975; Lahr and Kachadoorian, 1975	Complex	Evidence partly stratigraphic.

[1]Traces of these inferred faults are shown in Figure 1 and indicated by corresponding number.

PROCEDURES

Four kinds of information have been gathered in this preliminary reconnaissance: (1) ground and aerial observations on the traces of known and inferred faults, (2) visual observations of surficial deposits and landforms made during helicopter overflights and locally supplemented by ground observations, (3) a comparison of first order leveling elevations conducted in 1922 and 1965, and (4) the location of epicenters and hypocenters of seismic events in the general area. Additionally, relevant reports in the literature have been consulted for certain areas where our observations were incomplete due to inclement weather and lack of time.

Ground and aerial observations from a helicopter were intended to seek or confirm stratigraphic evidence for faults in the general area and to seek topograpic and geomorphic evidence for recent faulting along the mapped and inferred traces. These fault traces were obtained from the available literature and unpublished reports (Csejtey and others, 1978 and Appendix C; Anon., 1974a; Gedney and Shapiro, 1975; Turner and others, 1974; Beikman, 1974; Turner and Smith, 1974; Smith and others, 1975; Lahr and Kachadoorian, 1975).

Visual observations during helicopter overflights involved searching for scarps, topographic lineations, and offsets of landforms that might be the result of faulting--particularly active faulting. The criteria required to establish active faulting and recent movements were: (1) offsets of glacial landforms, (2) offsets of other landforms such as stream courses, (3) fresh scarps that were devoid of vegetation, and (4) superposition of landforms over preexisting ones. A partial list of the kinds of scarps and landforms that one might expect to observe are listed in Table 2.

First order leveling elevation data were obtained from literature supplied by Thomas Taylor, Topographic Division, U.S. Geological Survey, Anchorage, Alaska.

The section on Seismic Activity was written by John Lahr and Christopher Stephens, Center for Earthquake Studies, U.S. Geological Survey, Menlo Park, California. John Lahr made his unpublished data available to us.

Our criteria for designating a fault as active were constrained by the local geology. Much of the area around the Devils Canyon and Watana dam sites is mantled by late Wisconsin (8,000 to 12,000 y. ago) glacial sediments. In such cases our definition of an active fault necessarily is one that has moved within the last 8,000 to 12,000 years. In areas underlain by bedrock, a fault would be considered active if there were fresh scarps. Most inferred fault traces were locally mantled by late Wisconsin and younger surficial deposits.

Table 2. Partial list of scarps and landforms that may be found in a search for active faults.

Primary

Volcanoes, flow fronts

Rock structures

Joint scarps (mass wasting, rock terraces, shear zones, folds, foliations, etc.

Glacial features

Moraines (lateral, end, ground), eskers, kames, kettles.

Ice contact features (scours, channels, U-shaped valleys, rock terraces, roches mountonnée, etc.)

River

Bars, terraces, meander scars, valleys

Lake

Wave cut cliffs, bars, deltas, thaw scarps

Other unconsolidated deposits

Soil creep scarps, solifluction lobes, gravity slumps

Rock flow

Landslides, avalanches, rock glaciers

Tectonic

Fault scarps, sag features, offset drainage, etc.

Wind

Sand dunes

Ground and aerial observations along traces of known and inferred faults

During this part of our reconnaissance we found no evidence for active faulting that could be unequivocally related to the inferred or actual faults in the general area. Each of the faults is discussed below by their corresponding number in Table 1.

1. Zone of intense shearing. The zone of intense shearing was examined on the ground near the Talkeetna River (T28N, R5E, S34, NW 1/4). At this locality, cataclastically deformed Jurassic granodiorite was observed to be in contact with late Paleozoic metavolcanics rocks (unit Pzv, Appendix C) along an intense zone of shearing. The contact or faulted zone between these two units was oxidized. Thus, we concur with the existence of this shear zone as mapped by Csejtey and others (1978).

No evidence for active faulting was observed on the ground. Near the Talkeetna River, the flat top of the mountain was not vertically offset where it was intersected by the shear zone. In addition, observations during an overflight of the shear zone a few miles to the southwest across the Talkeetna River and to the northwest along Tsisi Creek to Kosina Creek and then to VABM Sumartidason yielded no evidence of fresh scarps and drainage offsets. Stratigraphic evidence indicates no movement has occurred since early Tertiary (Csejtey and others, 1978; Appendix C).

2. Talkeetna Thrust. This thrust fault is inferred to be concealed throughout almost all of its length. It is exposed along its

southwest trace (T27N, R1W, S6) where late Paleozoic metavolcanic rocks (unit Pzv, Appendix C) form the hanging wall and phyllites and schists (unit Kag, Appendix C) form the footwall. Unfaulted Tertiary volcanics overlie the thrust (T28N, R1W). The fault and Tertiary volcanics as mapped by Csejtey and others (1978) appear to be correct.

No evidence for scarps or active faulting along the inferred trace from Prairie Creek, by Fog Lakes, and along Watana Creek were found by us. Tertiary (Oligocene?) sediments in Watana Creek are gently tilted and possibly faulted, but not recently.

3. Near Watana Creek. This thrust is well exposed (T33N, T22S, R2W) and, where we examined it, Triassic metavolcanic rocks (unit TRv, Appendix C) make up the hanging wall and Jurassic sediments (unit Js, Appendix C) constitute the footwall. Near the fault trace, slickensided Jurassic sediments are abundant. We agree with both the existence and location of this fault as mapped by Csejtey and others (1978). Aerial reconnaissance suggests the fault continues into the Healy Quadrangle as indicated in Figure 1.

We found no evidence for active faulting at the locality examined or along the fault trace to the northeast in the Healy Quadrangle.

4. Near Portage Creek. This thrust is well exposed along its mapped length (T33N, R9W, R8W) and Triassic metabasalts and slates (unit TRvs, Appendix C) are found to the north of the fault trace while Cretaceous phyllites (unit Kag, Appendix C) are found to the south of the trace. Unfaulted Tertiary volcanics and sediments overlie the thrust to the east (T22S, R7W, R6W) and the thrust is terminated by intrusion of Tertiary granodiorite to the west (T33N, R1E, S18).

We found no evidence of active faulting along this trace and agree that movement occurred before the early Tertiary (Csejtey and others, 1978).

5. Chulitna River. Time and inclement weather did not permit adequate reconnaissance of this area but stratigraphic evidence shows a variety of faults are present (Csejtey and others, 1978). Existing maps indicate there is no active to recent faulting (Csejtey and others, 1978), Appendix C; Reed and Nelson, 1977). First order leveling elevations were measured across the Chulitna River; the results of these measurements are discussed later in this report.

6. North of VABM Sheep. Ground observations were not made by us. Evidence for strike slip and vertical movement is represented by offset of contacts between Tertiary granodiorites and older Cretaceous and Paleozoic rocks (Csejtey and others, 1978).

During overflights along the trace of the fault, no evidence for active faulting was found either over the wooded areas or along the Talkeetna River.

7. West of VABM Sheep. Ground observations were not made by us. Evidence for these faults is similar to that in 6 above. During overflights along the traces of these faults, no evidence for active faulting was found.

8. Susitna fault. The trace of this inferred fault passes from the vicinity of Stephan Lake, along Deadman Creek to Butte Lake in the Healy Quadrangle, and then across the west fork of the Susitna River (Anon., 1974a). Evidence for this fault is primarily geomorphic, and comprises a prominent linear on LANDSAT imagery (Gedney and Shapiro,

1975). Right lateral displacement has been postulated on the basis of seismic evidence (Gedney and Shapiro, 1975). In contrast to Gedney and Shapiro (1975), we find no compelling evidence for this fault in the seismic data reported by them or available to us (see Appendix D). This position is based on two factors. First, plots of our data and their data do not show a striking correlation, if any, of epicenters with the inferred trace of the fault. Second, the data are not complete enough or precise enough to be used in this way because the coverage of the seismic net is inadequate for precise determination of epicenter and hypocenter locations in the Susitna fault area. Additional seismic stations could resolve the problem.

Stratigraphic evidence for this fault is weak to non-existent. The geologic map of Turner and Smith (1974) indicates stratigraphic evidence which is contradicted by Csejtey and others (1978). Tertiary granodiorites and their border phases (unit Tsmg or migmatized rocks, Appendix C) lie along the trace of the fault. Tertiary volcanic rocks (unit Tv, Appendix C) occur at relatively low altitudes in Fog Creek (T31N, R4E, R5E) and may be down-faulted. Lack of time prevented us from making detailed studies of the volcanic rocks in Fog Creek.

Overflights along the inferred trace of this inferred fault indicate that active faulting has not occurred along the trace. Evidence for scarps and horizontal offsets are absent from Stephan Lake northeast to a point across the Susitna River. Numerous fresh scarps occur along lower Tsusena Creek and upper Deadman Creek to Butte Lake. Fresh scarps and horizontal offsets are absent northeast of Butte Lake where late Wisconsin re-advance (8,000 y. ago) glacial ground moraines are present. The fresh scarps observed are believed to be due to landsliding, slumping, solifluction, and stream erosion. Orientation of the scarps and the localized hummocky topography at the edge of Tsusena Creek near Watana the damsite (T32N, R5E, S21, 28, 29) are consistent with a landslide. In upper Deadman Creek, fresh scarps have a variety of orientations but they tend to face in southerly or in a downslope direction. The traces of the scarps are commonly arcuate and a kilometer (about 0.6 of a mile) or less in length. For these reasons, we believe these scarps are the result of recent slumping, solifluction and soil creep. It is noteworthy that fresh scarps are absent in the moraines northeast of Butte Lake. If these scarps were interpreted to result from faulting, it would follow that the faulting was pre-moraine (older than about 8,000 yrs and younger than 12,000 yrs). Other fresh scarps on Deadman Creek are clearly meander scars.

In summary, we find no conclusive evidence for a fault or active faulting along the inferred trace of the Susitna fault but rather landsliding, slumping, solifluction, and soil creep. The production of the fresh scarps may be partly related to general seismic activity in the area, however.

9. Near Clarence Lake. The evidence for this inferred fault is apparently stratigraphic (Turner and Smith, 1974), but no such stratigraphic evidence was found by Csejtey and others, (1978; Appendix C). Jurassic amphibolites (unit Jam, Appendix C) occur on both sides of the inferred fault trace but there is a change in metamorphic grade in zones parallel to it (Csejtey, personal comm., 1978). A few scarps occur along the hillsides near the trace but these are best

attributed to solifluction and slumping.

10. Near VABM Windus. This fault runs parallel to the Susitna River and passes to the south of VABM Windus. Here again, Turner and Smith (1974) report stratigraphic evidence for it whereas Csejtey and others (1978) do not report evidence for the fault. Jurassic amphibolites (unit Jam, Appendix C) occur on both sides of the inferred trace over nearly its entire length.

We found no evidence for active faults along the trace of this inferred fault. The eastern part of the trace transects glacial ground moraines and eskers. No vertical or horizontal offsets of the associated landforms were observed. Fresh scarps with 3 to 4.6 m (10 to 15 ft) of relief are particularly abundant near the trace in the vicinity of VABM Windus. Traces of these fresh scarps parallel the local elevation contours and a few occur on the northeast slopes of the Windus hill. This, combined with large amounts of surface and spring water runoff observed during the overflight, suggest that the scarps are due to slumping, solifluction, and soil creep. Tilted trees south of the scarp suggest movement of surface materials occurred within the last 40 to 50 years.

11. North of VABMs Grebe and Mt. Watana. This inferred fault transects Paleozoic rocks (unit Pzv, Appendix C) north of VABMs Grebe and Mt. Watana, crosses the Susitna River, and then more or less parallels the contact between the Paleozoic rocks (unit Pzv) and Triassic metavolcanics (TRv, Appendix C). Stratigraphic evidence for this fault is generally lacking, although the contact between the Paleozoic rocks and Triassic metavolcanics might be inferred to be a

fault. Csejtey and others (1978) do not report a fault along the inferred trace. When we checked this fault on the ground, we found no stratigraphic or geomorphic evidence for it.

During the overflight along the trace of the inferred fault, fresh scarps and horizontal offsets of glacial features (moraines, eskers, etc.) and other surficial deposits were not observed. Thus, active faulting has not occurred along the inferred trace after the glacial features were formed.

12. East of VABM Sumartidason. The existence of this fault is questioned by the authors (Anon., 1974a). The trace was not examined during an overflight because it was unknown to us prior to the reconnaissance.

13. Watana Creek. The trace of this fault generally coincides with the inferred traces of the Talkeetna thrust (see 2 above) and the "Near Watana Creek" (see 3 above) faults and has been inferred to have vertical displacement (north-side up) (Anon., 1974a; Turner and Smith, 1974). Stratigraphic evidence in support of this fault includes Jurassic sediments (unit Js, Appendix C) in fault contact with Triassic volcanics (unit TRv, Appendix C) and the occurrence of tilted Tertiary sediments (unit Tsu, Appendix C; T32N, R7E) at low altitudes.

We found no evidence for active faulting along the trace of this fault.

14. Along Portage Creek. This fault trace was an alternate trace to the eastern part of the thrust fault in 4 above (Csejtey, personal comm., 1975). We found no evidence for active faulting along Portage Creek.

15. North of Denali. Evidence for this fault is apparently stratigraphic and its trace is truncated by intrusives (Cretaceous in age?) (Anon., 1974a; Turner and Smith, 1974). Both the mapping and overflights in the general area indicate this fault is inactive.

16. Cretaceous to recent shearing. Time and inclement weather did not permit adequate reconnaissance of this area which is the same area as number 5 above. The reasons for inferring recent faulting are two poorly exposed normal faults in the Chulitna River valley (Csejtey and others, 1978). Csejtey (personal comm., 1978) states that apparently middle Tertiary or younger sediments have been displaced by the faults. However, existing maps indicate there is no active to recent faulting (Csejtey and others, 1978; Appendix C; Reed and Nelson, 1977).

As stated earlier, lack of time and inclement weather did not permit us to investigate these faults thoroughly. Therefore, it is unknown to us whether any active faulting has occurred along these faults in the Chulitna valley. We attempt, however, to evaluate this fault zone by studying first order leveling data. The results of first order leveling surveys across the fault zone are discussed later.

Visual observations during helicopter flights

Within the study area, a number of geologic phenomena were observed from the air which are relevant to the geologic problems related to dam construction. The most important are: 1) very steeply dipping joint sets and shear zones are common, 2) there are a significant number of short fresh scarps, 3) landslides have occurred in the past and new ones may occur in the future, 4) permafrost is present, at least locally, and 5) locally tills, alluvium, and Tertiary sediments with very low cohesions occur at altitudes near and below the expected water level of the Devils Canyon and Watana dam reservoirs.

1. Very steeply dipping joint sets and shear zones are common (see for example Kachadoorian, 1974). Although these joint sets and shear zones do not necessarily pose dam construction problems, their implications to active tectonic movements and landsliding are important. In regard to active tectonic movements, it seems conceivable that minor vertical and horizontal adjustments during tectonic activity could occur along them without producing long continuous faults but rather short scarps with small displacement (4.6 m, 15 ft). Thus, uplift and deformation could be accomplished by small vertical and horizontal movements along a myriad of joints. In some places, joint sets are so numerous that the Tertiary granodiorites superficially resemble columnar basalt (such as in T31N, R3E, S17). In many places both fresh scarps and graben-like structures appear to be controlled by these joints while in other places, fresh scarps parallel the shear zones.

In addition to providing planes of weakness for minor tectonic movements, the joint sets will also partly control landsliding and rock falls.

2. Fresh scarps are conspicuously abundant in the general area. None of these can be unequivocally ascribed to active faulting but local minor vertical adjustments of the order of 1.5 to 3 m (5 to 10 ft) cannot be excluded for some of them. Others are best attributed to slumping, solifluction, soil creep, and landslip.

a. Solifluction and slump scarps. Fresh scarps near VABM Windus are a good example of scarps produced by slumping and solifluction. They are fresh and unvegetated with reliefs to about 4.6 m (15 ft). They appear to be the result of recent movement by solifluction because segmented traces of scarps to the south of VABM Windus trend parallel to the topographic contours, a few of them occur on the northeast side of the Windus hill, and trees downslope have a variety of orientations. Judging from the tilted trees, movement has occurred within the last 40 to 50 years. Numerous springs were observed during the overflight and polygons are present 2.5 km (1.5 miles) west of VABM Windus.

Additional places where the fresh scarps can be attributed to solifluction and slumping are listed in Table 3.

b. Other scarps. A variety of other types of scarps are present (Table 4) and some of these need special discussion. In general, fresh appearing scarps face in southerly directions. A group of such scarps near the Watana damsite deserve special comment because detailed geologic studies and aerial observations reveal nearly vertical shear zones that trend northwest (Glen Greely, Corps of Engineers, personal commun., 1978) and the traces of nearby fresh scarps also trend in northwesterly directions. These scarps appear to be of two types which are unrelated to the shear zones. The first type (item 2, Table 4) is

Table 3. Location of selected examples of scarps in the Taleetna Mountains Quadrangle.

Number			Township	Range	Section
1.		C-1	T 30 N	R 11 E	1, 2, 11, 13, 14
2.	VABM Windus	C-2	T 31 N	R 10 E	26 through 30 33 through 36
3.		C-2	T 30 N	R 10 E	22
4.		C-2	T 30 N	R 9 E	15, 16
5.		C-2	T 30 N	R 8 E	3, 9, 15, 14
6.		C-2	T 29 N	R 1 E	19, 20, 21, 28, 29
7.		D-2	T 33 N	R 10 E	22
8.		D-3	T 22 S	R 4 W	21, 28, 29, 31, 33
9.		D-3	T 33 N	R 5 E	19, 20, 25, 26, 27, 34
10.	Watana Site	D-4	T 32 N	R 5 E	21
11.		D-4	T 33 N	R 4 E	28, 29, 31
12.		D-4	T 33 N	R 3 E	27, 28, 34, 36
13.		D-4	T 32 N	R 4 E	29, 32

Table 4. Selected examples of landforms with steep scarp-like surfaces.

Feature	Location[1]	Contents
Fresh appearing		
1. Meander scars/cut banks	(D-3) T33N R6E S19	In Deadman Creek
2. Meander scars/thaw lake shores	(D-3) T32N R5E S14	Near Watana damsite
3. Thaw lake shores	(C-2) T30N R9E S7,8	
4. Altiplanation scarps	(C-5) T29N R1E S21	
5. Landslide	(D-4) T32N R5E S29,S28	Near Watana damsite
6. Eskers	(C-1) T30N R11E, R12E, S24,25	
	(C-1) T30N R12E S9,16,17	
	(C-3) T30N R5E S24	
	(C-3) T30N R7E S19	
	(C-4) T30N R5E S30	
	(D-2) T31N R8E S9,16,17	Close to Susitna River
7. Moraines	(C-4) T30N R5E S5,8,17	Lateral
	(D-3) T22S R5W S36	End
	(D-3) T22S R4W S30	Lateral
8. Kames and Kettles	(C-3) T30N R8E S5,6,7,8	
	Healy Quad. T20S R1W S4,5,6	
Old appearing		
9. Glacial Scour	(C-4) T30N R2E S24	
	(C-1) T30N R11E S23	
	(D-4) T31N R3E S7,8,17	
10. Old River channels	(C-2) T31N R9E S25,36	
	(C-2) T30N R10E S11	
	(D-5) T32N R2E S33	

[1]Letter designations refer to 1:63,360 scale topographic maps of the Talkeetna Mountains.

believed to be due to the combined effects of ancient streams and thaw lakes. Excavation of the materials in one of the scarps revealed it is underlain by bedded, pebbly to cobbly fine- to medium-grained sands deposited by streams. The complex array of the scarps suggest that they are former meander scars. Additionally, many of the scarps partly surround thaw lakes and bouldery beds of former thaw lakes. Although fresh scarps in the area tend to face southwest, some vegetated ones that face in north to northeast directions are present. Thus, we attribute this type of scarp to the combined action of ancient lakes and streams and to recent thawing and freezing.

The second type (item 5, Table 4) is classified as a landslide because the hummocky surface of southwest facing scarps and benches are confined to a small area and are consistent with soil movement toward the southwest. The landslide is not related to the shear zones because sediments comprise the material of the slide and no bedrock occurs in it. Freezing and thawing may have been the major cause of movments producing these scarps and benches but we have classed them as landslides because of the relatively large amount of movement.

The origin of some fresh scarps is unclear and the relatively large abundance of scarps might be partly the result of mild tectonic activity and seismic shaking. Many scarps, both fresh and old, are aligned parallel to local joint directions (C-5, T31N, R1E, S34, 35; and C-5, T31N, R2E, S33) and could represent the results of local tectonic adjustments. The fresh scarps associated with joint sets and slumping are clearly recent as shown by their lack of vegetation and tilted trees. Seismic waves may be partly responsible for these recent movements.

2. Older Scarps. Older vegetated and lichen covered scarps are similar to the fresh scarps, but here, two additional types have been observed: graben-like structures in bedrock and old river channels. The graben-like structures (item 10, Table 4) are generally short in length (a fraction of a km) and shallow. Their lengths trend westerly which is the general direction of glacial movement in the area. Because of the short length, orientation, and graben-like form, we attribute them to glacial plucking and scouring. Old river channels also occur (item 9, Table 4). These old channels are arcuate graben-like landforms subparallel to the present course of the Susitna River.

3. Landslides. Although not particularly abundant throughout the Devils Canyon and Watana area, landslides have occurred in the past and new ones may occur in the future. We noted several large landslides along the Susitna River in the proposed Devils Canyon and Watana reservoir sites. The evidence for old landslides is straightforward. Those composed chiefly of rock occur as isolated blocks (or hills) downslope of arcuate scars with about the same aerial dimensions as the

block. Two such slides were observed and are listed in Table 5 (items 1 and 2). Landslides in unconsolidated sediments, such as alluvium and glacial till, form hummocky surfaces of scarps, terraces, and ridges (item 3, Table 5).

Identification of potential landslides using geomorphic evidence from overflights is problematical and the number of potential landslides listed in Table 5 could either be an overestimate or an underestimate of the potential landslides in the Devils Canyon and Watana reservoir areas. We have, however, listed them to indicate the potential for future landsliding in the area. Also, those listed do not include possible landsliding of bedrock and unconsolidated sediments once they become saturated with water during reservoir filling.

It was not within our charter to map in detail the abutments of the proposed Watana damsite as Kachadoorian (1974) did at the proposed Devils Canyon damsite. Therefore, the abutments of the Watana site should be thoroughly examined for possible potential landslides.

4. Permafrost. Permanently frozen ground or permafrost is present in the proposed dam and reservoir areas. During our overflights numerous ice wedge polygons were noted, some of which are listed in Table 6. We also noted slumping of surficial debris on permafrost in the Susitna River canyon at about altitude 580 m (1,900 ft) (T31N, R4E, S21), about 11 km (7 miles) downstream of the proposed Watana damsite. Permafrost was also reported in the surficial deposits during drilling at the proposed Vee Canyon damsite (Anon., 1962) about 65 km (40 miles) upstream of the Watana site and in unconsolidated sediments and bedrock of the left abutment of the proposed Watana damsite (Corps of Engineers, personal commun., 1978).

Table 5. Locations of old landslides and potential landslides.

Location[1]	Comments
Old Landslides	
1. (D-3) T32N R6E S-28 (SE 1/4)	Block of rocks is several hundred feet across.
2. (D-4) T32N R4E S-33 (NE 1/2) & S34 (NW 1/4)	Block of rocks is several hundred feet across.
3. (D-4) T32N R5E S-28 (NW 1/4) & S-29 (NE 1/4)	North of Watana damsite, slide material is alluvium and fill.
Potential Landslides	
4. (D-3) T32N R6E S-32 (N 1/2)	Weakly developed scarp at 549 m (1800 ft).
5. (D-4) T31N R2E S-12 (E 1/2)	Weakly developed scarp at 366 m (1200 ft).
6. (C-2) T31N R9E S-26 (S 1/2)	Top of mass at 610 m (2000 ft).

[1] Letter designations refer to 1:63,360 scale topographic maps of the Talkeetna Mountains Quadrangle.

Table 6. Locations where patterned ground was observed.

Location[1]
(D-4) T32N R5E S28
(C-2) T31N R10E S28,33
(C-2) T30N R9E S10,15
(C-4) T30N R5E S7,8
(C-4) T29N R4E S2
(C-5) T30N R1W S3
(C-5) T30N R1E S19

[1]Letter designations refer to 1:63,360 scale topographic maps of the Talkeetna Mountains Quadrangle.

In order to evaluate the permafrost-related geotechnical problems in the proposed Devils Canyon and Watana dam and reservoir sites, a detailed study of the nature, character, and distribution of permafrost should be made. Of particular importance is the permafrost that underlies the left abutment of the proposed Watana damsite.

5. Till, alluvium, and Tertiary sediments. Locally, poorly consolidated tills, alluvium, and Tertiary sediments occur at water levels that are lower than the planned altitudes of the filled reservoirs of the two dams (Devils Canyon: 442 m (1,450 ft); Watana 666 m (2,185 ft)). Wetting of the materials and thawing of ice in them will cause weakening of the materials and may cause subsequent slumping, mud slides, and other mass movements. This problem is more probable for the Watana reservoir than it is for the Devils Canyon reservoir. For the Devils Canyon reservoir, the frequency of outcrops of rock below altitudes of 442 m (1,450 ft) is striking along the entire length of the Susitna River valley that would be occupied by the reservoir. Tills appear to occur above about 610 m (2,000 ft) but some alluvial fans would be innundated.

For the Watana reservoir, the occurrence of till and sediments begins within 3 km (about 2 miles) upstream of the proposed damsite. Here, tills and sediments overlie bedrock and the contact between them is near 579 to 610 m (1,900 to 2,000 ft). The amount of bedrock exposed along the Susitna River upstream of the planned damsite is impressive but at altitudes near 610 m (2,000 ft) and higher, tills and other sediments are conspicuous. Eskers occur upstream at an altitude of 549 m (1,800 ft). Alluvium and talus are also common below 671 m (2,200 ft) along the river.

Both tills and Tertiary fluviatile sediments that would be inundated by the reservoir occur in Watana Creek. Some of the fluviatile Tertiary sediments are clays which, when wetted, become very weak and may even disaggregate.

First Order Leveling Observations

The results of first order leveling are included here because (1) the traverse passes across the zone of Cretaceous to recent shearing and faulting in the Chulitna River valley (Table 1, number 16) and across the Denali fault (Lahr and Kachadoorian, 1975), and (2) because the leveling was accomplished before and after the Alaskan earthquake of 1964. Comparisons of the first order altitudes, measured in the summers of 1922 and 1965 along The Alaska Railway from Sunshine to McKinley Park (Rappleye, 1930; Anon., 1973) reveal that differences in altitudes of bench marks measured in the two surveys cannot be attributed to faults with large displacements. These altitudes, which are tabulated in Table 7, are everywhere within 0.21 m (0.7 ft) of one another. According to Thomas Taylor of the Topographic Division of the Geological Survey in Anchorage, Alaska, differences in excess of 0.30 m (1 ft) would probably exceed the uncertainties in altitude changes of some benchmarks due to frost heaving. A tentative analysis of the data indicate, however, that there may be a systematic change in altitudes between the two surveys. The data indicate that there appears to be some tilting, of the order of a foot (0.3 m) with the south side down between Sunshine on the south to Yanert to the north. Because we do not know which of the benchmarks are in unconsolidated sediment and subject to frost heaving and which are not, we do not believe an analysis of the data can permit us to state that there has been any active faulting between 1922 and 1965.

Because of the differences in altitudes detected during the first-order leveling, we believe the Vertical Angle Bench Marks should be remeasured in order to detect possible displacements with the Devils Canyon and Watana damsite areas subsequent to the initial surveys.

Table 7. First-Order leveling from the vicinity of Sunshine to McKinley Park.

		Altitude (in feet)[1]		
Station	Designation	1922	1965	Difference
J-2	Sunshine	285.895	285.219	-0.676
M-2	Talkeetna	346.259	345.675	-0.584
O-2	Chase	411.239	410.718	-0.521
U-2	Curry	543.358	543.004	-0.354
V-2	Sherman	587.200	586.908	-0.292
X-2	Gold Creek	691.764	691.610	-0.154
Z-2	Canyon	856.173	856.015	-0.158
A-3	Canyon	1044.555	1044.417	-0.138
E-3	Hurricane Gulch	1629.974	1629.951	-0.023
F-3	Honolulu	1495.322	1495.381	+0.059
K-3	Colorado	2063.090	2063.247	+0.157
L-3	Broadpass	2059.569	2059.720	+0.151
P-3	Cantwell	2246.373	2246.547	+0.174
S-3	Windy	2076.036	2076.285	+0.249
T-3	Windy	1996.873	1996.974	+0.101
U-3	Carlo	1956.367	1956.627	+0.260
V-3	Yanert	1950.357	1950.678	+0.321
W-3	Yanert	1950.574	1950.905	+0.331
Y-3	McKinley Park	1717.201	1717.382	+0.181

[1] Altitude reported in feet because First-Orderleveling recorded in feet. The conversion factor is 0.3048 meters/foot.

- indicates decrease in altitude from 1922 to 1965.

+ indicates increase in altitude from 1922 to 1965.

Additional Observations

Although it may not be within our charter, we would like to comment about the sediment load in the glacially fed Susitna River. Of particular interest here is the rate at which the Watana reservoir might be filled by the suspended load and the bed load of the river. Our estimates of the time to fill the reservoir using nominal values of the rates and suspended load (Anon., 1974b), are near one or two thousand years. However, suspended and bed loads of glacially fed streams are highly variable. Thus, we feel that there may be insufficient detailed data to provide an adequate estimate of the lifetime of the dam and that such data should be gathered and analyzed to insure that there is an adequate lifetime for the Watana dam.

During our aerial and ground observations, we found no evidence for recent volcanism. Scoriaceous rocks do occur in the Tertiary sediments of Watana Creek but these are the result of heating by subsurface burning of the lignite beds in the distant past.

Henry Moore noted evidence for icing on or near the left abutment of the proposed Watana damsite. Such icing was verified by Glen Greely, Corps of Engineers (personal comm., 1978). We do not know the source of water for this icing. Therefore, we recommend that the left abutment be thoroughly investigated to determine the source and location of the water relative to the proposed dam.

We detected some lineaments in the active outwash plain of the West Fork Glacier. These lineaments occur about 5 km (3 miles) south of the present terminus of the glacier and are about 97 km (60 miles) northeast of the proposed Watana damsite. The lineaments are interpreted to be sand dikes that developed during seismic shaking from an earthquake. The age of the sand dikes is unknown but they are considered to be relatively young because they are well preserved and occur in the active outwash plain of the West Fork Glacier. Lack of time did not permit us to make an extensive investigation of the area to adequately determine the extent and distribution of the sand dikes.

Seismic Activity

The Devils Canyon and Watana damsite area lies within a region characterized by a high rate of seismic activity that is the result of tectonic interaction between the Pacific and North American lithospheric plates. The Pacific plate is being thrust to the northwest beneath the North American plate (Lahr and Kachadoorian, 1975). The earthquakes affecting this region are generally of three types: (1) shallow (depth less than about 50 km) earthquakes (such as the 1964 Alaska earthquake) which occur on the surface of contact between the Pacific and North American plates to accommodate their relative motion; (2) shallow earthquakes which occur within the North American plate (including Alaska) in response to the stresses produced by interaction with the Pacific plate; and (3) deeper earthquakes (depths from 50 to 200 km) that occur within the portion of the Pacific plate that has been thrust beneath Alaska. These latter earthquakes define a region called the Benioff zone. Earthquakes which are occurring in the region of the proposed damsites are of the types described in the last two categories, although earthquakes of all three types are capable of producing strong ground shaking at the proposed sites.

Lahr and Kachadoorian (1975) reviewed the seismic data available from the U.S.G.S. (formerly N.O.A.A.) Earthquake Data File for the period 1900 to February 1975. Using only the more reliable earthquake locations, they showed that the depth of earthquakes in the region of the proposed reservoirs range from less than 10 km to greater than 175 km. The depth to the Benioff zone directly beneath the proposed damsites is about 50 km to 80 km. Distribution of epicenters of shallow earthquakes, according to presently available data, is too scattered to reliably associate them with individual faults.

For design purposes there are two questions of major importance. First, are there potential active faults or other zones of weakness beneath the proposed structures which could cause direct structural damage during an earthquake? Second, what are the spatial, temporal, and magnitude distributions of earthquakes in the region and as a result, what accelerations will the proposed structures probably experience during their lifetime?

The process of identifying active faults on the basis of earthquake locations is limited by the accuracy to which the locations can be determined, as well as by the smallest magnitude earthquake that can be recorded. These two parameters are highly dependent upon the number and distribution of seismograph stations used in determining a location. A regional seismograph network did not exist in southern Alaska before 1967. Prior to that time, the accuracy of epicentral coordinates was 50 km or more, errors in depth were on the order of 100 km or more, and the smallest magnitude events that had been detected were about 4 1/2 on the Richter scale. Since 1967, routine locations for earthquakes as small in magnitude as about 3 have been determined with accuracies of 10-15 km in epicenter and about 25 km in depth. Since 1971 the U.S.G.S. has operated a network of seismic stations in southern Alaska. The distribution of earthquake hypocenters and magnitudes detemined using this network generally confirms the conclusions reached by Lahr and Kachadoorian (1975). Recent U.S.G.S. data allow more precise resolution of the depth to the top of the Benioff zone and of the extent of shallow crustal activity. The distribution of the epicenters of the shallow earthquakes does not show a strong correlation with mapped faults, although the current accuracy to which these epicenters are determined does not preclude the possibility that the earthquakes are occurring along mapped or as yet unknown faults. To obtain the number of accurately located earthquakes necessary to resolve this question it will be necessary to establish a local network of seismic stations in the region of the proposed damsites.

The tectonics of the region are too poorly known at this time to make a reliable prediction for the distribution of events that may strongly shake the damsites. Certainly the Benioff zone activity will continue as will the shallow regional activity. In addition, the Denali fault, which lies less than 80 km north of the proposed damsites, is a major strike-slip fault with geologic evidence for a 3 cm/yr average Holocene slip. This fault could sustain a magnitude 8.0 event.

In addition to the naturally occurring earthquake activity in the region, there is also the hazard that filling of a reservoir may trigger potentially damaging earthquakes (as large as magnitude 6 or greater) in the immediate vicinity of the damsites (Lahr and Kachadoorian, 1975). Continuous monitoring by a local network of seismic stations in the region beginning well in advance of filling the reservoirs would allow the level of natural ambient seismicity to be determined. Unless the natural level is well established, an important opportunity to study this phenomena will be lost, and possibly unwarranted conclusions concerning induced seismicity may be made in the future.

SUMMARY

Our geologic reconnaissance of the proposed Devils Canyon and Watana damsites and reservoir areas, Susitna River, Alaska, did not uncover evidence for recent or active faulting along any of the known and inferred faults. Recent movement of surficial deposits has occurred as the result of mass wasting processes that have produced scarps and downslope movement of surficial debris. It is possible that some fresh scarps may have been triggered or produced by seismic shaking and minor displacements of bedrock along joints.

Landsliding into the Susitna River has occurred in the past and future landsliding appears probable. Additionally, the occurrance of poorly consolidated glacial debris, alluvium, and Tertiary sediments at altitudes below the proposed reservoir water levels, especially at the Watana Dam reservoir, may slump and slide into the reservoirs. Some of these sediments contain permafrost and may be ice-rich which increases the probability of slumping and sliding when they are thawed by the water impounded behind the dams.

The proposed Devils Canyon and Watana dams are located in a region of high seismicity. The tectonic framework of the region is not well understood because of the lack of local seismic monitoring stations. Our present knowledge of the region indicates that hypocenters of earthquakes in the region of the proposed dams ranges in depth from less than 10 km to greater than 175 km. We are unable at this time to reliably predict the location and magnitude of future crustal earthquakes that could effect the proposed structures.

RECOMMENDATIONS

The conclusions presented in this report are based on a reconnaissance study of the proposed Devils Canyon and Watana dam and reservoir sites, and, therefore, should be considered to be preliminary. A thorough evaluation of the geotechnical problems of the proposed dam and reservoir sites will require more data. It will be necessary to (1) map the Healy, Alaska, Quadrangle, at a scale of 1:250,000, from the Talkteena Mountains Quadrangle to the Denali Fault, about 80 km (48 miles) north of the damsites, (2) map the proposed Devils Canyon and Watana damsites at an appropriate scale to determine the bedrock structure and distribution of unconsolidated sediments overlying the bedrock, (3) map the reservoir sites at a scale of 1:63,360 in order to (a) establish the type and distribution of unconsolidated sediments and bedrock, (b) locate additional potential landslide areas, and (c) determine the nature and distribution of permafrost, (4) initiate a seismic monitoring program of the dam and reservoir areas, (5) continue the active fault study, (6) redetermine the altitudes of the Vertical Angle Benchmarks, and (7) collect detailed data on the suspended loads and bed loads of the Susitna River in order to determine if the reservoir filling rates are acceptable.

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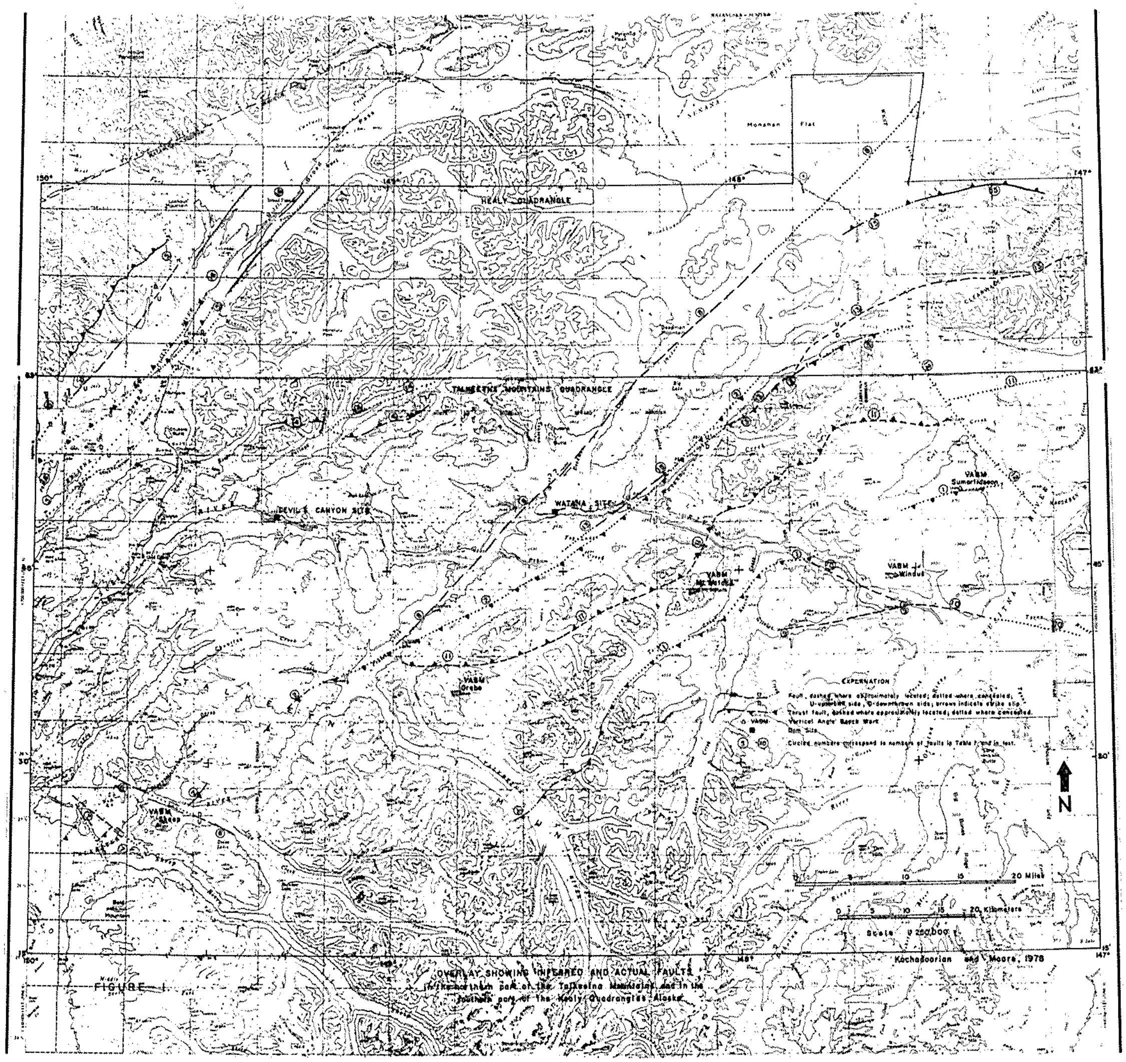

FIGURE 1 OVERLAY SHOWING INFERRED AND ACTUAL FAULTS in the northern part of the Talkeetna Mountains and in the southern part of the Healy Quadrangle, Alaska

EXHIBIT D-3

Earthquake Assessment of the Susitna Project

CONTENTS

PART I: INTRODUCTION

1. The following sections of this report will assess the possible occurrence of earthquakes at the dam sites and the motions that are likely to be associated with earthquake activity.

2. The assessments are preliminary since the investigations on which they are based were done on a reconnaissance level and are necessarily incomplete.

PART II: PROCEDURES FOR ASSIGNING EARTHQUAKE MOTIONS

3. Earthquakes are associated with faults. Tectonism causes gradual differential movements in the earth's crust. The rock is subjected to strain and the buildup of stresses. Relief then may come abruptly as slippage along a fault. When slip occurs, the adjacent rocks may rebound elastically with vibratory motions. The resulting shaking constitutes the earthquake.

4. Earthquakes may be assumed to result from movement along existing faults rather than from rock rupture that produces new faults. While new faults cannot be eliminated entirely, information extending through geological time and the ubiquitous occurrence of faults suggests that for practical purposes earthquakes can be considered to be associated with slippage along existing faults.

5. Since faults are found everywhere, the engineering geologist is faced with the problem of determining which faults are active, or subject to movement, and which are inactive. Of faults that are active, movement can be occurring steadily and slowly by creep and without earthquakes. The engineering geologist must determine which are the "capable" faults, capable meaning that they can generate earthquakes.

6. Corps of Engineers criteria for a capable fault (see ER 1110-2-1806 of 30 April 1977) are as follows:

a. Movement at or near the ground surface at least once within the past 35,000 years.

b. Macro-seismicity (3.5 magnitude or greater) instrumentally determined with records of sufficient precision to demonstrate a direct relationship with the fault.

c. A structural relationship to a capable fault such that movement on one fault could be reasonably expected to cause movement on the other.

7. The geological investigation of faults uses all of the techniques that are available: aerial and satellite imagery, inspection from

overflights, low sun angle photography, reviews of regional and local geology, geophysical surveys, details of geomorphology and relevant information from the seismic history.

8. For a careful investigation of a construction site, the field evidence may be checked further by borings, geophysical profiles, trenches, and stripping.

9. Monitoring programs for corroborative evidence may include strain gages, leveling points, geodimeter readings, and microearthquake monitoring.

10. Often, it is desirable to make a critical restudy of historic earthquake events using the original documentation in newspapers, diaries, etc. Relocation of epicenters may result and they may accord better with geologic information and possibly with specific faults. The maximum intensities of events may be subject to revision also.

11. The direction of future movement on an active fault is predictable since the past is a very good guide to the future. However, secondary and tertiary faults may have motions that are different from that of a major fault. Where such data are available, one can readily guard against the effects of fault movement under a structure simply by moving the structure.

12. Once a fault is identified as capable of generating earthquakes, and its dimensions are ascertained, the next factor to determine is the worst earthquake that the fault will produce. Toward this end, there are a number of relationships and assumptions that involve the size of faulting, or dimension of maximum movement, with the maximum earthquake that might reasonably be expected. The data are best for major strike-slip faults. The dispersion of data is much greater for normal and thrust faults. However, the variants in field conditions can be enveloped with a reasonable degree of dependability. Relationships between fault length and earthquake magnitude have been summarized for Corps use in a report by Slemmons (1977).

13. Though major active faults and major centers of earthquakes can be accounted for, small faults may be missed in any investigation so that often a floating earthquake of appropriate size may be provided in order to account for them.

14. The earthquakes that are thus determined can be expressed in terms of magnitude* but they need also to be expressed in Modified Mercalli (MM) intensity in order to relate to historic earthquake effects. The MM scale is shown in Table 1.

Table 1

MODIFIED MERCALLI INTENSITY SCALE OF 1931

(Abridged)

I. Not felt except by a very few under especially favorable circumstances.

II. Felt only by a few persons at rest, especially on upper floors of buildings. Delicately suspended objects may swing.

III. Felt quite noticeably indoors, especially on upper floors of buildings, but many people do not recognize it as an earthquake. Standing motor cars may rock slightly. Vibration like passing of truck. Duration estimated.

IV. During the day felt indoors by many, outdoors by few. At night some awakened. Dishes, windows, doors disturbed; walls made cracking sound. Sensation like heavy truck striking building. Standing motor cars rocked noticeably.

V. Felt by nearly everyone; many awakened. Some dishes, windows, etc., broken; a few instances of cracked plaster; unstable objects overturned. Disturbance of trees, poles and other tall objects sometimes noticed. Pendulum clocks may stop.

VI. Felt by all; many frightened and run outdoors. Some heavy furniture moved; a few instances of fallen plaster or damaged chimneys. Damage slight.

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* Magnitude (Richter scale) is calculated from a standard earthquake, one which provides a maximum trace amplitude of one micrometer on a Wood-Anderson torsion seismograph at a distance of 100 km. Magnitude is the $\log_{10}$ of the ratio of the amplitude of any earthquake at the standard distance to that of the standard earthquake. Though the scale is open-ended, the largest earthquake may be at a limit of magnitude 8.7. Each full numeral step in the scale (2 to 3, for example) represents an energy increase of about 32 times.

VII. Everybody runs outdoors. Damage negligible in buildings of good design and construction; slight to moderate in well-built ordinary structures; considerable in poorly built or badly designed structures; some chimneys broken. Noticed by persons driving motor cars.

VIII. Damage slight in specially designed structures; considerable in ordinary substantial buildings with partial collapse; great in poorly built structures. Panel walls thrown out of frame structures. Fall of chimneys, factory stacks, columns, monuments, walls. Heavy furniture overturned. Sand and mud ejected in small amounts. Changes in well water. Disturbed persons driving motor cars.

IX. Damage considerable in specially designed structures; well-designed frame structures thrown out of plumb; great in substantial buildings, with partial collapse. Buildings shifted off foundations. Ground cracked conspicuously. Underground pipes broken.

X. Some well-built wooden structures destroyed; most masonry and frame structures destroyed with foundations; ground badly cracked. Rails bent. Landslides considerable from river banks and steep slopes. Shifted sand and mud. Water splashed (slopped) over banks.

XI. Few, if any (masonry), structures remain standing. Bridges destroyed. Broad fissures in ground. Underground pipe lines completely out of service. Earth slumps and land slips in soft ground. Rails bent greatly.

XII. Damage total. Waves seen on ground surfaces. Lines of sight and level distorted. Objects thrown upward into the air.

15. Thus, a fault can be judged for its capacity to generate earthquakes and the maximum event it might produce expressed both in magnitude and intensity. The intensity can be attenuated from a source to a site.

16. Predicting the time of the maximum earthquake is of interest for other purposes but is of no interest for the design of a major

structure such as a dam. A dam has to be designed on the basis of the maximum earthquake without regard for its time of occurrence or its interval of recurrence, since a maximum earthquake may come at any time. Cost-risk benefits can be sought for appurtenant structures which, if failed, pose no hazard to life. For these lesser structures, probabilities may be used in order to select smaller events that will then serve as operational basis earthquakes. Arbitrarily lower numbers, such as a fraction of the motions for the maximum earthquake, can be equally suitable.

17. The foregoing considerations bring us to the point where motions must be selected to define the effects of earthquakes on a dam. These motions should be conservative so that the designs developed for a dam are safe for any eventuality. The motions are in the following categories:

a. Those that cause relative displacement in the foundation and consequently displacements in the dam, and

b. Those that induce unacceptable strains in a dam or liquefaction if it is an earth structure.

18. The examination of a major dam for the effects of earthquake shaking requires a dynamic analysis. If there are potentials for strain beneath the structure, earth fill may be specified as the construction material. For an earth dam it is essential to provide appropriate time histories of earthquake motion. The time histories are needed because the material is nonlinearly elastic. Each cycle of shaking may impart an effect on the material and the effects are cumulative. Thus, the time histories must be as realistic as possible in simulating the maximum earthquake.

19. In order to generate time histories, a synthesis may be made of motions recorded during earthquakes in order to develop peak motions (acceleration, velocity, displacement, duration and predominant period). In Corps of Engineers practice, the time histories are developed first and response spectra are made from the time histories.

20. Any large collection of strong motion records has a tremendous spread in the values for earthquake motions. There are many causes:

differences in fault mechanism and fault shape, rock types and configuration, refraction and reflection of waves, superposition and buildup of waves, or diminution, etc. Such factors contribute to an infinity of differences in the resulting motions. The accelerations for Modified Mercalli Intensity V range from 0.01 g to 0.61 g, a spread of 60 times. Mean values, in such circumstances, have no real significance.

21. The solution is to work with a large body of strong motion records and to provide envelopes that encompass the spread in the data.

22. Specific parameters, such as a given fault type plus some specified distance from epicenter, tend to restrict the number of records available to only a very few. They may have less spread. However, if there were more records, even for those limited conditions, there is every reason to believe there would be more spread. It is best not to be restrictive but to envelope a wide variety of conditions.

23. An extensive statistical analysis of strong motion data from the western United States in terms of intensity was made by Trifunac and Brady (1975). Their analyses included acceleration, velocity and displacement, and they distinguished vertical and horizontal components of motion. They showed the mean value for each intensity level and the mean with one standard deviation. The latter provides a measure of the dispersion. A problem arises with the sparseness of data for the higher intensities beginning with MM VIII. There are no data for MM IX, and one record for MM X. The latter is the Pacoima record with its peak horizontal acceleration of 1.25 g.

24. The same western United States data uniformly processed at the California Institute of Technology were used in studies made at the Waterways Experiment Station (see Krinitzsky and Chang, 1977) to find means for assigning motions for dynamic analyses of dams. The values were expressed in MM intensity.

25. The CIT data were separated by Krinitzsky and Chang (1977) into "near field" and "far field."

26. In the near field, complicated reflection and refraction of waves occur in the subsurface with resonance effects and a large range

in the scale of ground motions. Intense ground motions and high-frequency components of motion are present. In the far field the wave patterns are orderly; the oscillations in wave forms are more muted and more predictable; and frequencies are lower.

27. The distance from epicenter to the limits of the near field, and beginning of the far field, vary with the magnitude of the earthquake, consequently with the maximum epicentral intensity, and with the region in which the earthquake occurs. Usually, the intensity in the near field attenuates linearly and rapidly; in the far field, the rate of attenuation for intensity becomes smaller.

28. Limits of the near field are as follows:

Richter Magnitude M	MM Maximum Intensity I_O	Radius of Near Field KM
5.0	VI	5
5.5	VII	15
6.0	VIII	25
6.5	IX	35
7.0	X	40
7.5	XI	45

29. Figures 1 and 2 show the relation between MM intensity and acceleration for near field and far field, respectively. Figures 3 and 4 show intensity versus velocity, near and far field, and Figures 5 and 6 for displacement, near and far field. The motions are horizontal. Vertical components of motion are taken to be two-thirds the horizontal. The spread of data were divided into equal 10 percent increments between 50 percent, taken at the median line, and 100 percent, taken along a line which approximates the limit of observed data. The curves for these increments are suitable for obtaining peak motions at levels selected either at the maximum or at lesser levels determined by decisions on the seismic risk that is acceptable.

30. Figures 1 to 6 also show the mean-plus-one standard deviation for the respective intensity levels. Figure 1 shows that mean plus σ drops as the intensity increases from MM VII to VIII. The drop-off is

not from lesser motions but simply from a decrease in the quantity of data. The projection of the 10 percent lines attempts to compensate for this lack of data.

31. No distinction was made between data from soil and rock since the values overlap too greatly to provide useful comparison. The Figures 1 to 6 are intended to provide peak components of ground motion on bedrock at the surface.

32. The mean-plus-σ values show that the data points are concentrated far below the 100-percent line. In effect, the 70- to 80-percent band brackets an upper boundary for the great body of data. Peak motions at this level are conservative for nearly all designs. However, if at a site there was a capable fault seen at the ground surface, then the 100-percent motion, or even a higher value, might be appropriate.

33. The next element in developing a time history of motion is the duration. Duration was taken as the bracketed time interval in which the acceleration is greater than 0.05 g.

34. Some examinations of the data are appropriate. Figure 7 shows near field durations in terms of earthquake magnitude. There is a large dispersion with distinctly higher peak values for soil as compared to rock. Peak durations increase steeply with increase of earthquake magnitude. The same data are shown in Figure 8 by local MM intensity. Again, soil shows greater peak durations than rock. However, the slope of the peak duration for rock does not increase as steeply with greater intensity as it does for magnitude. The discrepancy results from incompleteness of data and the inexactness that is inherent in intensity and a difference in the comparability of the scales. Figure 8 provides conservative upper limits for duration to be used with MM intensities in the near field. Far field durations are shown in Figure 9.

35. The earthquake records selected for use or for rescaling may be either actual strong motion records or synthetic ones designed for specified geological settings. They should be for field conditions that are analogous to those for the site under study. They should be for comparable types of faults, comparable geology (whether crystalline rocks,

sedimentary basin, etc.), and similar distances from causative faults. Records should be selected also with predominant periods that may correspond to periods of engineering works that are being evaluated.

36. The time histories developed from rescaling earthquake records are preferable for such structures as earth dams since the structures are nonlinearly elastic and actual earthquake records are both more realistic and have fewer motions than the synthetic ones. For concrete portions of a structure, the necessary response spectra can be made from the time history or it can be obtained independently following the guidelines of the Nuclear Regulatory Commission.

37. The scaling for large motions (in the region of 1 g) presents a problem because there is only one record (Pacoima, San Fernando earthquake of 1971) and the rescaling of lesser records to this level may produce unrealistic motions. Instead of straight scaling, high-frequency motions may be added to lower earthquakes in combination with a process of scaling. Multiple records should be examined. Strong motion records should be selected that require as little rescaling as possible. Chang (1978) provided a first step toward cataloging earthquakes in a manner that will facilitate their selection for scaling. If a record has to be scaled as much as 4X, the record should be discarded.

38. The spectral composition and predominant period of a record is site dependent (whether soil or rock) and is dependent also on distance from source. Here again judgments must be made not on a few records but by envelopes of extensive collections of data. Some guidance is provided in compilations by Chang and Krinitzsky (1977).

PART III: EARTHQUAKE EVALUATION

39. A geological reconnaissance of the general area in which the Devils Canyon and Watana damsites are located was performed for this study by Drs. Reuben Kachadoorian and Henry J. Moore of the U.S. Geological Survey. Their study entitled "Preliminary Report of the Recent Geology of the Proposed Devils Canyon and Watana Damsites, Susitna River, Alaska," is included in the present overall report.

40. Drs. Kachadoorian and Moore were charged primarily with the task of investigating the area for the presence of absence of active faults. In addition, observations were made on the seismicity of the area and on the possibilities of landslides into the potential lakes.

41. Prior to the work done by Drs. Kachadoorian and Moore, a study has been made for the Corps of Engineers by Gedney and Shapiro (1975) of lineations interpretable for this area from Landsat and Slar imagery. The lineations were presented along with the seismic history and the general geology.

42. Gedney and Shapiro show a large number of lineations including ones that trend along the Susitna Valley and pass through the Devils Canyon and Watana damsites. Lineations may be caused by faults but they may be caused also by processes that have no relation to tectonism. In no case can a lineation be accepted as a fault unless confirmation is found on the ground by a process that is called "ground truthing." Thus the work by Kachadoorian and Moore was an important step in validating the earlier work. The judgments concerning faults should be those of the latter work.

43. Kachadoorian and Moore report a group of 16 faults. For the most part, these faults are identified by stratigraphic evidence. There

was no surface evidence of recent movement along any of these faults; consequently, the faults were tentatively judged to be inactive. However, confirmation of this judgment will require more detailed field work. The nearest known active fualt is the Denali fault, 80 km away, with the capacity to produce magnitufe 8.0 earthquakes.

44. Gedney and Shapiro generally found no relation between seismic events in the region and faults. However, for the Susitna fault (Fault No. 8 of Kachadoorian and Moore), Gedney and Shapiro associated two earthquakes of 1 October 1972 and 5 February 1974 (magnitudes 4.7 and 5.0 respectively). Gedney and Shapiro reported no associated breakage along the Susitna fault but these events gave suitable fault plane solutions indicating right-lateral offset. Kachadoorian and Moore question the reliability of associating these earthquakes with the mapped fault. Kachadoorian and Moore found no relation between seismicity and mapped faults, however they point out that a closer grid of seismometers may uncover such relationships.

45. In summary:

a. No faults of important regional extent were found to be present at the damsites.

b. Major faults in the region were reconnoitered and no evidence was found of recent movement.

c. The region is one of relatively high seismicity, however, no association was established between seismic events and specific faults.

d. The nearest positive capability for an earthquake is along the Denali faault, approximately 80 km distant, where a maximum magnitude of 8.0 can be expected.

e. Except for the conclusions concerning the Denali fault, the work done so far is preliminary. More work is needed.

PART IV: INTERPRETED PEAK MOTIONS

46. On the basis of the present incomplete geological and seismological information, earthquake motions at the damsites must be postulated by making certain conservative assumptions.

47. Potential earthquakes are as follows:

a. An earthquake originating at the Denali fault. The maximum magnitude is 8.0 in accordance with assumptions made by the U.S. Geological Survey in their Trans-Alaska Pipeline Study (see Page, et at, 1972). The earthquake is attenuated 80 km to the Devils Canyon and Watana damsites. Using the Krinitzsky-Chang (1977) attenuation for western United States, the event will produce a MM intensity of IX at these sites. The motions are far field. It is conservative to base the motions on the 70 percent spread level of the charts of Figures 2, 4, and 6 since that level encompasses over 95 percent of the data in the velocities (see Figure 4). The duration is taken for rock from Figure 9. The corresponding peak motions are acceleration, velocity, displacement, and duration are tabulated in Table 2.

TABLE 2
PEAK EARTHQUAKE MOTIONS AT DEVILS CANYON AND WATANA DAMSITES

				Peak Motions (hor.*) on Bedrock at Surface			
Earthquake Source	Magnitude	Field	Site Intensity MM	Accel. g	Vel. cm/sec	Displ. cm	Duration sec
Denali fault	8.0	Far	IX	0.28	40	22	10
Local floating event	7.0	Near	X	0.68	68	30	12

* Vertical motion may be taken as two-thirds of horizontal.

b. A local floating earthquake with fault breakage that does not occur at the damsites. The inconclusive nature of the geologic-seismologic studies requires that a floating earthquake be assigned. The earthquake may occur anywhere in the general vicinities of the damsites but not immediately under the dams themselves. The elimination of an earthquake beneath the dams is based ont hework of Kachadoorian and Moore for this study in which they identify no appropriate faults. The magnitude of the floating earthquake is 7.0. This magnitude is in accordance with the earthquake used for this area in the Trans-Alaska Pipeline Study of Page, et al (1972). The magnitude accords satisfactorily with the possible fault lengths presented by Kachadoorian and Moore, which are on the order of a hundred or more km. Such faults correspond to magnitude 7 earthquakes according to available worldwide data presented by Slemmons (1977) in his Figure 27. Since the near field for an earthquake of this size extends 40 km from the source, and Kachadoorian and Moore have located major fault trends within 3 to 15 km of the dams, the motions at the dams must be taken as near field. It is conservative to use the 70-percent spread lines of the moitons in Figures 1, 3, and 5 since that level envelopes all but a few extreme values. The duration for bedrock at the surface is taken from Figure 8. The peak motions are tabulated in Table 2.

c. An earthquake at the damsites. On the basis of present information, an earthquake from a major fault rupture at the damsite is not expected to occur. However, it is understood that present information may be subject to revision when further studies are made.

48. The motions in Table 2 of this report were developed somewhat differently from those of the USGS Trans-Alaska Pipeline Study (Page, et al, 1972). The floating earthquake for the near field but not at the site has no equivalent in the USGS analysis. The USGS values are for earthquakes that occur at a site. Also, the USGS peaks were reduced from what they might be by a filtering that they applied to the Pacoima record of the 1971 San Fernando earthquake. Their objective was to provide motions for a quasi-static analysis of the pipeline in which the input was restricted to a range of 2 to 8 Hz. Their resulting magnitude 7 at a site has values that are higher than ours (1.05 vs 0.68g) in acceleration, higher in velocity (120 vs 68 cm/sec) and higher in displacement (55 vs 45 cm). The durations also are greatly different. The USGS duration is 25 sec against 12 sec for ours. The difference is that their duration includes soils whereas ours is for bedrock alone.

49. Predominant period and records for rescaling are not recommended at this point since specification of types of faulting and distance from faulting are yet to be made.

50. The operating basis earthquake, which is lesser earthquake than that taken for the design of the dam, may be tested with peak motions that begin at half those of the maximum earthquakes.

51. Reservoir loading has in some cases induced significant earthquakes and earthquakes have triggered landslides and caused water waves or seiches. Also, in regions of tectonism there may be problems during excavation from overstressed conditions in rock.

Induced seismicity from reservoir loading

52. A few large reservoirs in the world have induced appreciable earthquakes. Simpson (1976) has provided a summary and critical review. The reservoir is a triggering agent. It does not cause earthquakes greater than the ones that may be expected from the normal tectonism. The maximum earthquakes will be the ones used in design. An induced earthquake, if such should occur, would not be greater though it may occur at a different time. Further, the worldwide experience, according to Simpson (1976), suggests that induced effects may be highest in regions of low to moderate natural seismicity. In areas of high levels of natural seismicity, as in Alaska, the stress changes induced by the reservoir are small compared to natural variations. Thus, induced seismicity should not add any input to design. Nonetheless, observations relating to induced seismicity made before and after reservoir filling are appropriate and will be valuable on a research level.

Water waves from earthquake shaking

53. Water waves produced by earthquake shaking, under certain circumstances, may be a factor though hardly comparable to the effects of large landslides and ordinarily not more severe than wind effects. The effects are dependent on the spectral composition of the horizontal ground motions, the shape and size of the reservoir, and the duration of shaking. If a resonance is developed there may be significant resulting wave amplitudes. Lee and Hwang (1977), in assessing this problem, suggest that wave heights of half the amplitude of horizontal ground motions are possible but they do not assess resonance. In practice, protection against the effects of landslides will probably more than adequately provide protection against water waves as well.

Earthquake-induced landslides

54. Landslides are a pronounced feature at the sites of major earthquakes. Kachadoorian and Moore have noted appreciable landslides in the Susitna Valley. These, and others that may be judged to be present as potential hazards, should be evaluated. The worst known potential slides can be monitored and remedial measures can be specified, including the removal of the potential slide material.

55. The problem when dealing with a major earthquake is that one cannot be sure that slides that might be generated have been anticipated. Given sufficient topographic relief and large masses of loose or fractured material, one should take into account major slides for which no prevention can be specified. Developments along the borders of the reservoir, the freeboard of the dam, etc., should be planned so that possible disasters are avoided.

56. Studies of the effects of landslides into reservoirs may be either theoretical, using a numerical model (see Raney and Butler, 1975), or they may be empirical. The latter is perhaps the most practical approach. They involve using undistorted hydraulic models (cf Davidson and Whalin, 1974). For both methods, the slide geometry, volume, velocity and reservoir configuration are essentials. Field investigations where actual landslides have occurred may aid in developing estimates of velocities (see Banks and Strohm, 1974). The procedures will produce assessments of wave heights and wave runups.

Tectonic strain and overstressed conditions in rock

57. A totally unknown set of conditions are those that relate to tectonic strain and resulting possible overstressing in the rock. Residual stresses from the movements of active faults can affect the making of excavations and the stability of the structure. At present there are no data. It is anticipated that field measurements relating to stresses and the buildup of strain will be made as part of any continuing investigations.

PART VI: CONCLUSIONS

58. The geological-seismological investigations to date were made on reconnaissance levels. The Devils Canyon and Watana damsites are in a region of high seismicity and major faults. However, no movements were found on the faults that might be indicative of earthquakes. Also, no seismic activity was identified as associated with these faults, though the data suffers from inexactness in the accuracy of locations. No active faults were found at the damsites. Active faults of appreciable length are required if large earthquakes are to be generated in close proximity of the proposed structures.

59. The area was provided with a floating earthquake of magnitude 7 placed at a short distance from the damsites. The magnitude 7 is in conformity with general fault lengths in this area and with worldwide experiences between such faults and resulting earthquakes. However, further field studies will be made to determine conclusively whether or not there are faults closer to the sites with possible more severe motions. An earthquake of magnitude 8 from the Denali fault at a distance of 80 km was evaluated by attenuating the event to the damsites.

60. Peak motions were assigned for the earthquakes following the practices of the Corps of Engineers. The magnitude 7 earthquake near the damsites has motions that are: acceleration 0.68 g, velocity 68 cm/sec, displacement 30 cm, and duration 12 sec. An earthquake at the Denali fault attenuated to the sites provides motions of 0.28 g, 40 cm/sec, 22 cm, and 10 sec.

61. A closer specification of which sets of peak motions to apply and the appropriate time histories will await further field studies.

62. Possible induced seismicity from reservoir loading is not a factor needing additional design but is accounted for in the existing motions. However, water waves from possible earthquake-triggered landslides and possible overstressed conditions in rock pose problems for which at present there is a paucity of data and a need for further evaluation.

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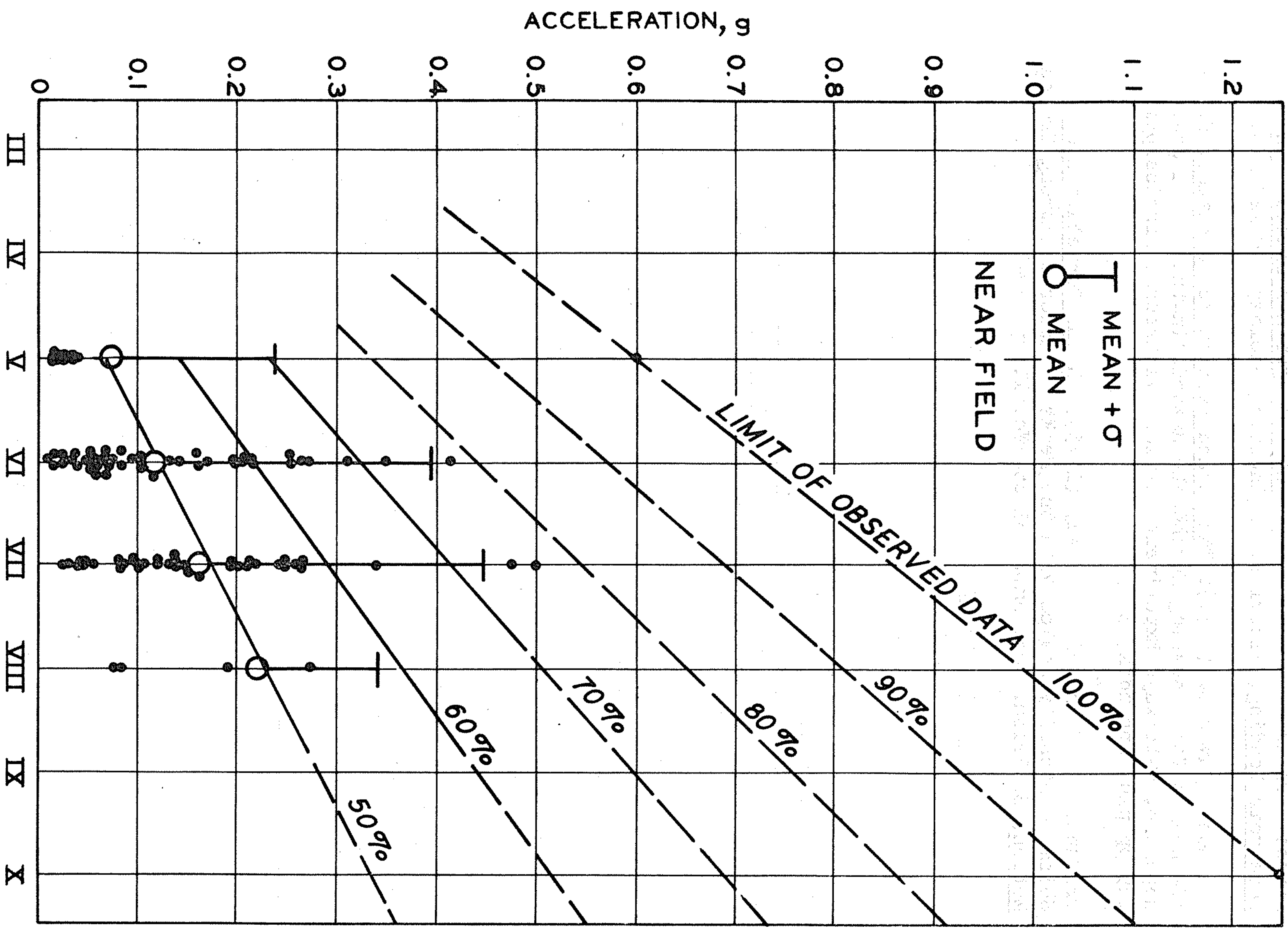

Figure 1. Acceleration versus MM Intensity in the Near Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

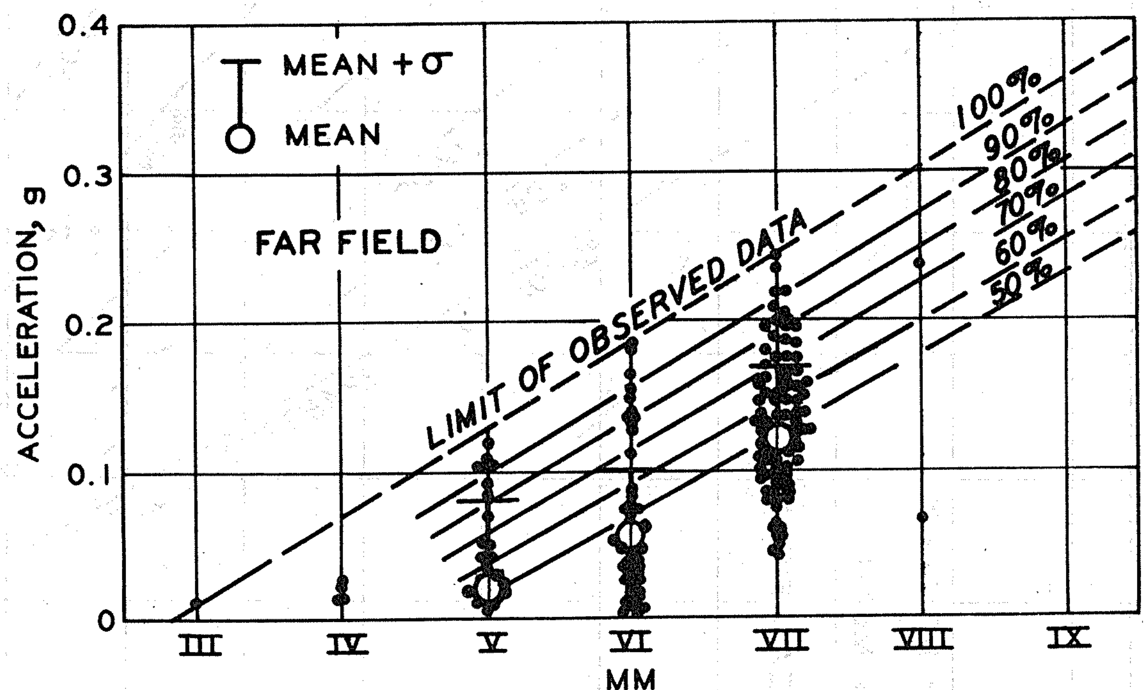

Figure 2. Acceleration versus MM Intensity in the Far Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

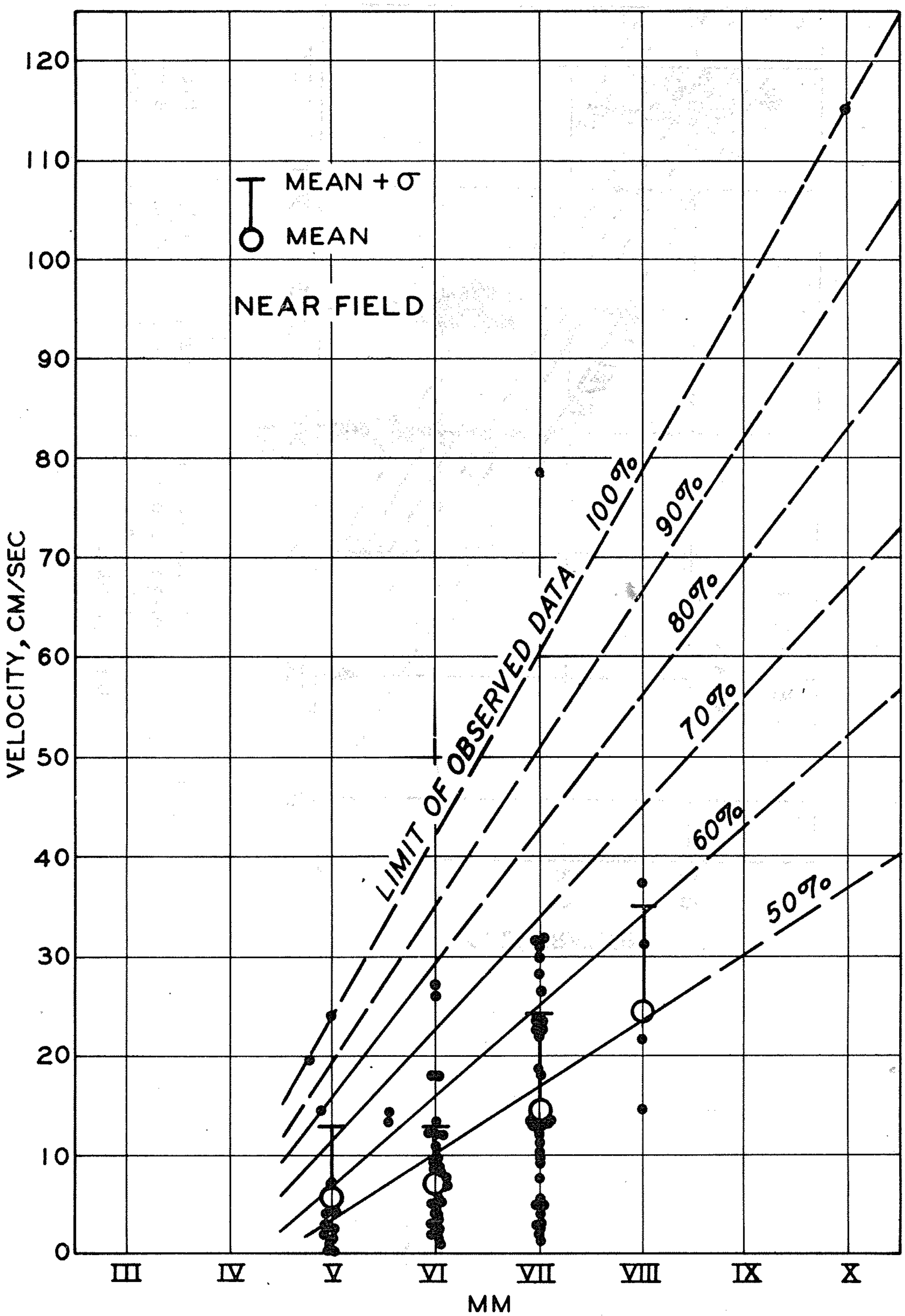

Figure 3. Velocity versus MM Intensity in the Near Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

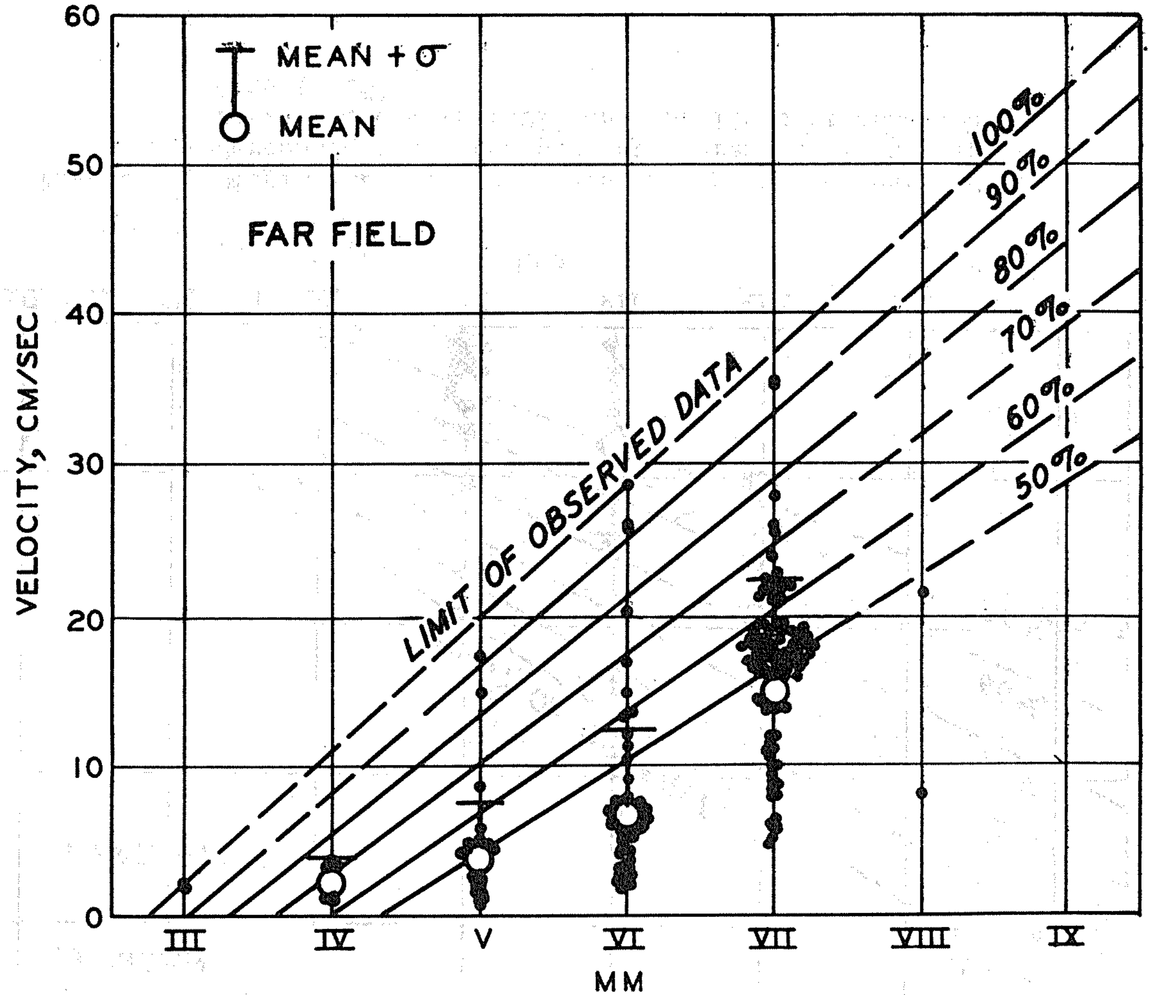

Figure 4. Velocity versus MM Intensity in the Far Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

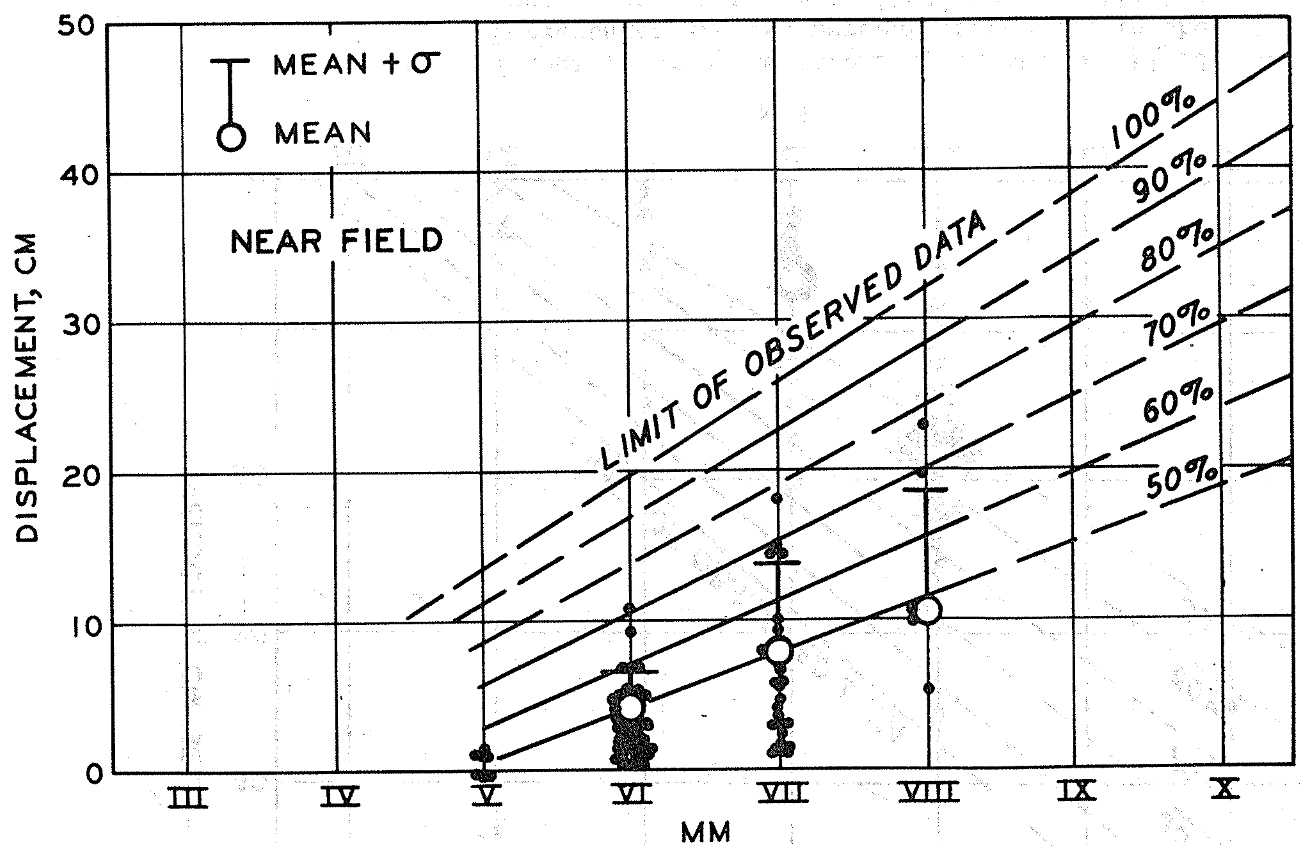

Figure 5. Displacement versus MM Intensity in the Near Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

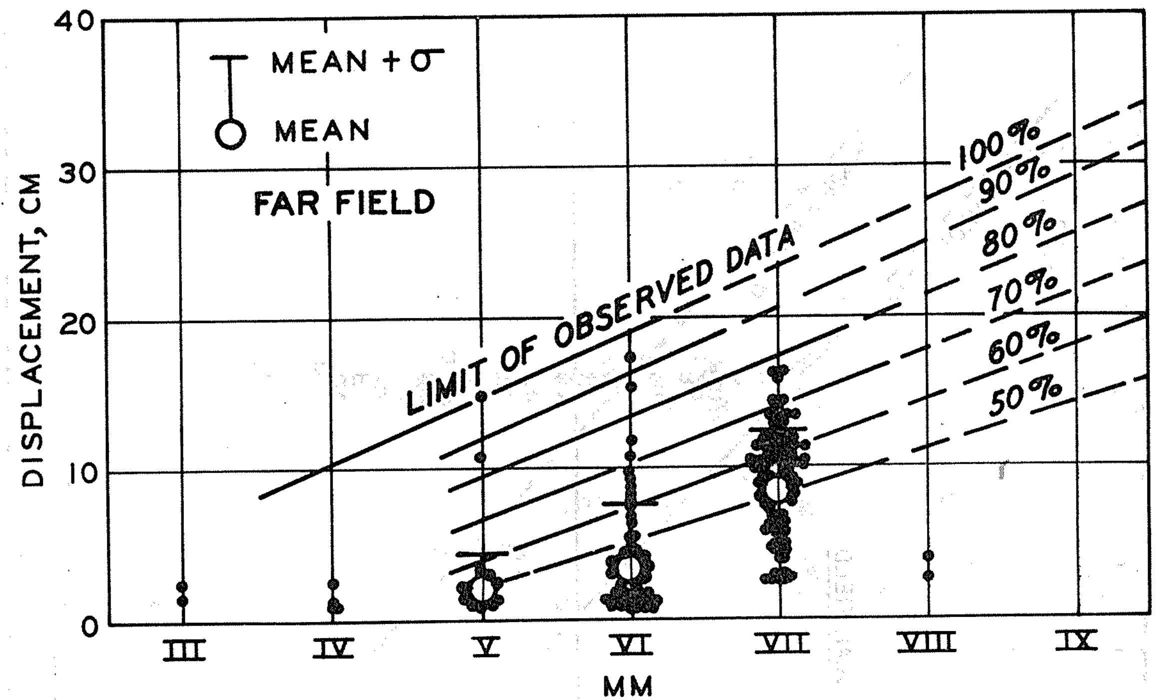

Figure 6. Displacement versus MM Intensity in the Far Field. Percentages are ten percent increments in the spread between the mean (50%) and the limit of observed data (100%).

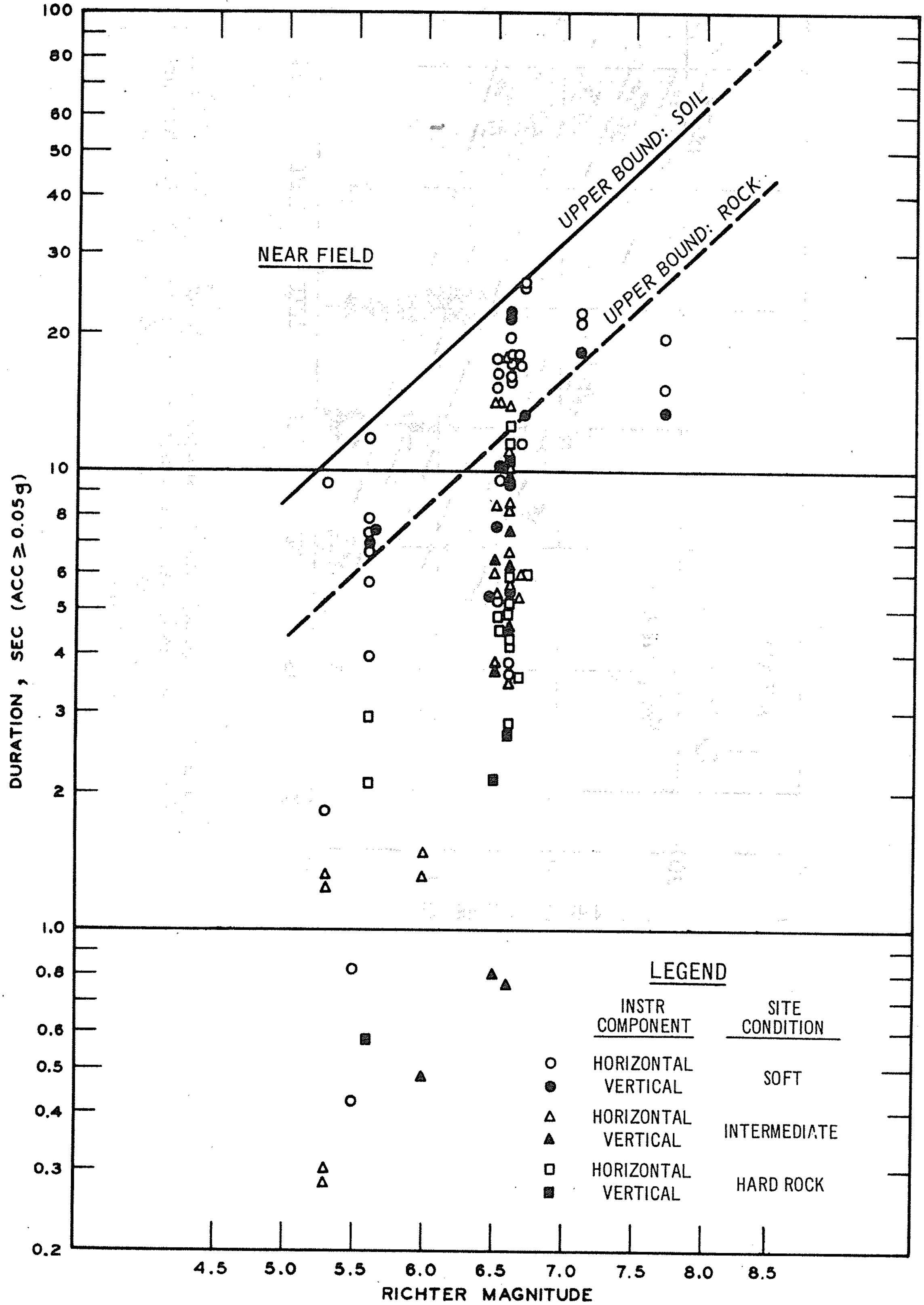

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Figure 7. Duration versus Richter Magnitude in the Near Field.

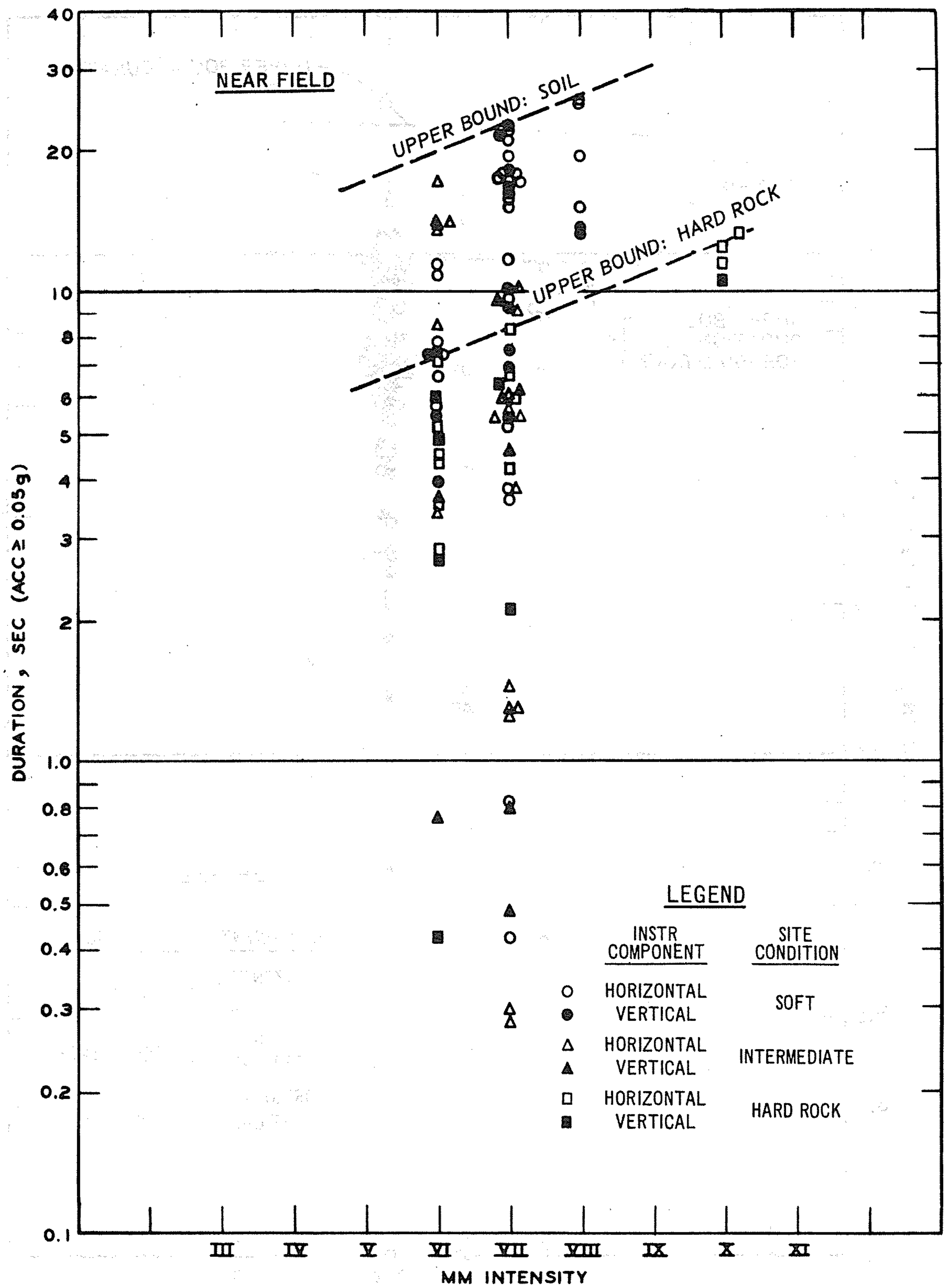

Figure 8. Duration versus MM Intensity in the Near Field.

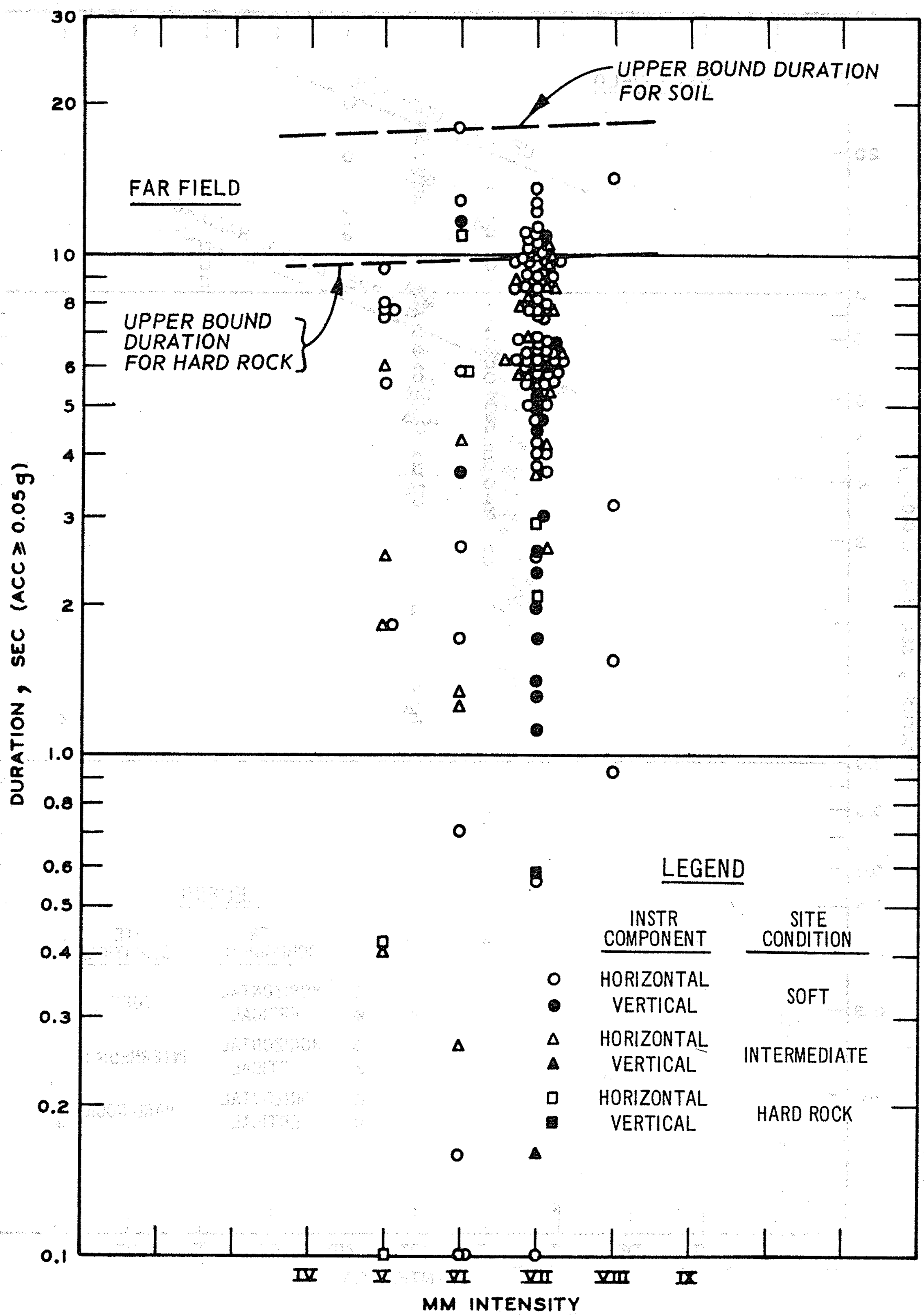

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Figure 9. Duration versus MM Intensity in the Far Field.

EXHIBIT D-4

Procedure for Estimating Borehole Spacing and Thaw Water Pumping Requirements for Artificially Thawing the Bedrock Permafrost at the Watana Damsite.

Introduction

The procedure outlined in this note for estimating the time to artificially thaw permafrost bedrock assumes that water will be pumped into a pattern of boreholes drilled to the bottom of the permafrost zone. The water would flow down a feed pipe to the bottom of the borehole and back up the annulus between the outside of the feed pipe and the wall of the borehole. During the upward flow, heat from the water would flow radially through the borehole wall to melt the existing ice and raise the temperature of the surrounding rock. During the first stage of this thawing process a series of essentially vertical parallel thawed cylinders would be formed, the diameter of which would grow with time until the surface of adjacent cylinders touched. Upon touching a fluted wall would exist which then will thicken as additional heat is supplied by the thaw-water in the boreholes until either the desired wall thickness is attained or a thermal equilibrium is established. Once the desired wall thickness is reached, the rate of thaw-water flow (i.e., pumping) can be reduced to establish thermal equilibrium. To avoid freezing back the bedrock it may be necessary to continue pumping water until grouting is initiated or until it is unnecessary to maintain the wall in a thawed condition. If the permafrost is at 32^{o}F at the Watana dam site, it probably would not be necessary to use maintenance pumping since freeze-back would be quite slow.

The purpose of this note is to furnish procedures for establishing a drilling pattern; estimating the time to thaw a 20 ft. wide zone of rock permafrost along the alignment of the Watana Dam; and estimating the thaw-water pumping requirements for the thawing operation.

Assumptions

The graphs used in this procedure were developed using the thermal computational methods outlined in the paper, "Thermal and Rheological Computations for Artificially Frozen Ground Construction," which is attached as Appendix B. The assumed rock properties and thermal conditions are listed in Appendix A. Graphs in figures 1 and 2 were developed for 1½ inch diameter boreholes. Use of larger diameter boreholes would reduce the thawing time (e.g., a 3 inch diameter borehole will reduce the thaw time by less than 10%).

It should be emphasized that this procedure assumes a uniform distribution of ice in the bedrock with an overall ice saturated porosity of 1½% and that it is quite probable that some of the rock will contain much larger volumes of ice. At locations where large volumes of ice do exist, the thawing would be much slower than predicted by Figure 1. More accurate predictions of the thawing times can be made when details of the amount and location of the ice-filled cracks are determined. The temperature of the permafrost bedrock at the dam site has not been established precisely. In this note, bedrock temperature is assumed to be 32°F with all water frozen.

To control the thawing process during construction, it is essential to monitor the bedrock temperature at several locations both horizontally and vertically. Good temperature and pumping records will assist in improving the thawing operations as the work progresses and will provide data for refining the procedure for predicting subsequent thawing times and pumping requirements.

Procedure

(1) From the curves on Figure 1 choose a borehole arrangement (i.e., single row or two rows of boreholes) and spacing. The choice would be based on the time available for thawing, the temperature of the available thaw-water and the economic trade-offs between additional holes vs heating the water and pumping water.

(2) After selecting the borehole spacing, enter the graph on Figure 2 using the borehole spacing and thaw-water temperature chosen in (1) to obtain a time at which the thawing cylinders will just touch each other. This time (t_I) is given in days on the abscissa.

(3) Using (t_I) from (2), enter the abscissa of the graph on Figure 3 and obtain an estimate of the number of gallons per minute (GPM) that must be supplied to each borehole for the thaw-water temperature selected. Note that this is the thaw-water flow required when the thawed cylinders just touch. This is more than that required to continue thawing until the wall obtains its full width but it is a conservative average value to use in estimating. The maximum flow rate is required at the start of pumping. Theoretically it is infinite but in practice it is close to the values shown at time zero on Figure 3. Therefore, after the first few days of pumping, the pumping capacity can be reduced, e.g., one or more of the pumps can be used somewhere else. The curves on this graph are based on the temperature gradient or temperature loss shown on the graph. If sufficient

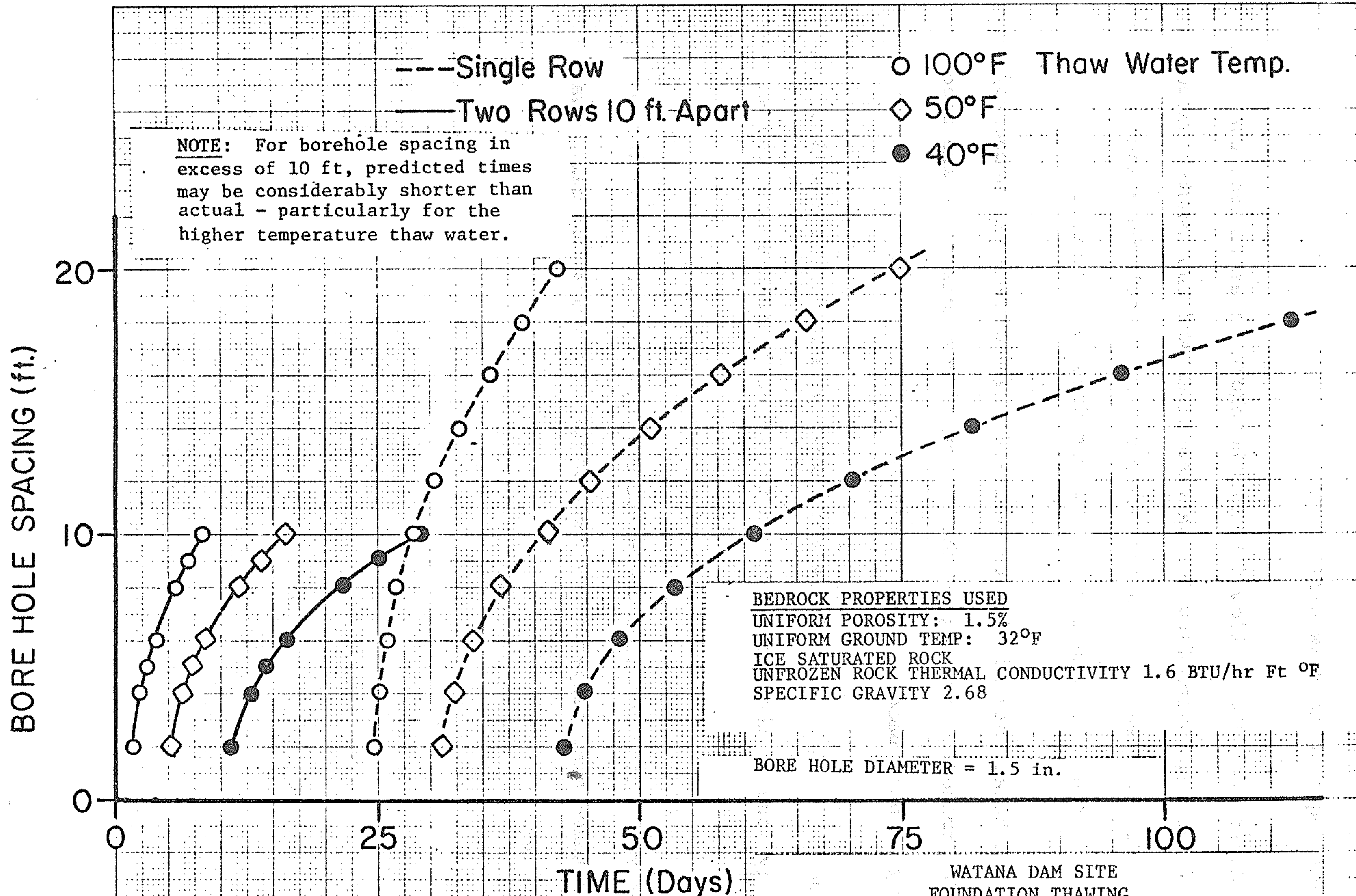
flow is not supplied to the boreholes, the temperature gradient will rise and the time required to thaw will increase.

(4) After the rate of flow for each borehole is estimated, the velocity of the thaw-water flow in the feed pipes and the annulus between the outside of the feed pipe and the borehole wall should be computed to determine if either the velocity or pressure drop is excessive.

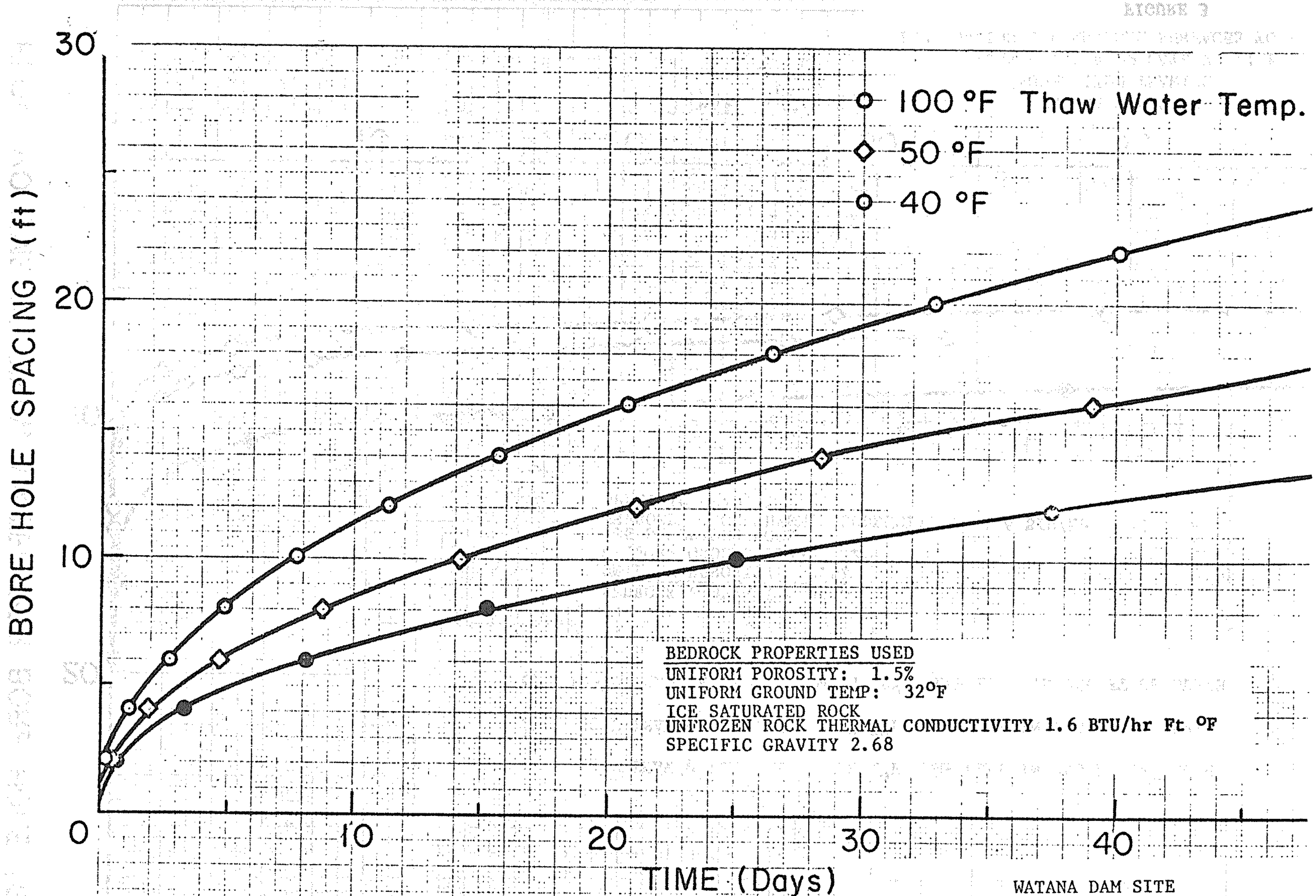
(5) The total rate of flow for determining the size and number of pumps is determined by summing up the number of boreholes that are used for thawing at one time.

It might be noted that if water is artificially heated, there will be a large energy loss if the overflow from the borehole is not captured and reused.

Ponding of water in a location where the sun can warm it is one way to get higher thaw-water temperatures than would be obtained by taking water directly from the river.

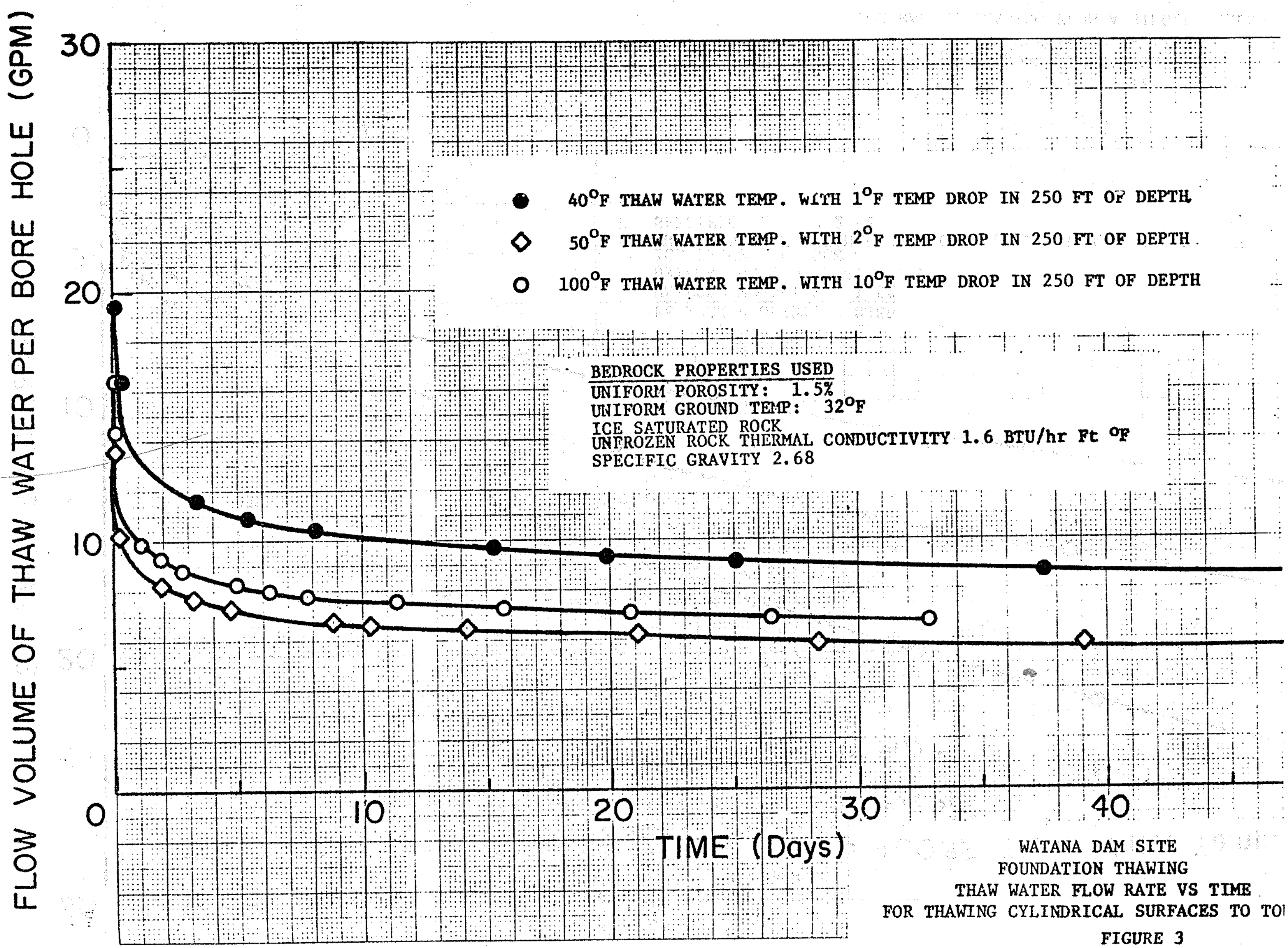


WATANA DAM SITE
FOUNDATION THAWING
BOREHOLE SPACING VS MINIMUM TIME
TO THAW A 20 FOOT WIDTH OF FROZEN ROCK FIGURE 1



WATANA DAM SITE
FOUNDATION THAWING
BOREHOLE SPACING VS TIME
FOR RADIAL THAWING FROM A SINGLE BOREHOLE

FIGURE 2



WATANA DAM SITE
FOUNDATION THAWING
THAW WATER FLOW RATE VS TIME
FOR THAWING CYLINDRICAL SURFACES TO TOI

FIGURE 3

APPENDIX A

ASSUMED ROCK PROPERTIES AND THERMAL VALUES

ROCK PROPERTIES

Uniform porosity	1.5%
Specific Gravity	2.68
Dry Unit Weight	165 lb/ft^3
Ice Saturate	

THERMAL VALUES

Volumetric Specific Heat	
Unfrozen Rock	33.9 BTU/ft^3
Frozen Rock	33.4 BTU/ft^3
Conductivity for Unfrozen Rock	1.6 BTU/hr. ft. ^{o}F
Latent Heat of Ice Saturated Rock	124 BTU/ft^3

EXHIBIT D-5

UNITED STATES
DEPARTMENT OF THE INTERIOR
GEOLOGICAL SURVEY

RECONNAISSANCE GEOLOGIC MAP AND GEOCHRONOLOGY, TALKEETNA MOUNTAINS QUADRANGLE, NORTHERN PART OF ANCHORAGE QUADRANGLE, AND SOUTHWEST CORNER OF HEALY QUADRANGLE, ALASKA

OPEN-FILE REPORT 78-558-A

This report is preliminary and has not
been edited or reviewed for conformity
with Geological Survey standards and
nomenclature

Menlo Park, California
1978

DESCRIPTION OF MAP UNITS

SEDIMENTARY AND VOLCANIC ROCKS

SURFICIAL DEPOSITS, UNDIFFERENTIATED (Quaternary)--Glacial and alluvial deposits, chiefly unconsolidated gravel, sand, and clay.

VOLCANIC ROCKS, UNDIFFERENTIATED (Paleocene to Miocene, uppermost part may be as young as Pleistocene)--Over 1,500-m-thick sequence of felsic to mafic subaerial volcanic rocks and related shallow intrusives. Lower part of sequence consists of small stocks, irregular dikes, lenticular flows, and thick layers of pyroclastic rocks; made up dominantly of medium- to fine-grained, generally medium-gray quartz latite, rhyolite, and latite. A few dikes and intercalated flows of brown andesite are also present. Rocks of the lower part of the sequence, occurring mostly in the upper Talkeetna River area, are interpreted to be vent facies deposits and near vent deposits of stratovolcanos. The upper part of the sequence consists of gently dipping brown andesite and basalt flows interlayered with minor amounts of tuffs. A few lenses of fluviatile conglomerate are also present. Locally, at Yellowjacket Creek for instance, the feeder dikes of the mafic flows make up more than half the volume of the underlying country rocks. According to E. M. MacKevett, Jr. (oral commun., 1975), the andesite and basalt flows are lithologically identical to the basal andesites of the Wrangell Lava in eastern Alaska.

Contact between the dominantly felsic lower part and mafic upper part of the sequence is gradational through intertonguing of the two rock types. The three samples for potassium-argon age determinations (map numbers 7, 8, 13 in table 1), indicating Paleocene and Eocene ages, were obtained from andesite flows near the middle of this sequence.

Tim HYPABYSSAL MAFIC INTRUSIVES (Paleocene to Miocene, youngest rocks may be Pleistocene)--Small stocks and irregular dikes of diorite porphyry, diabase, and basalt. They probably are the subvolcanic equivalents of the andesite and basalt flows of unit Tv.

Tif HYPABYSSAL FELSIC INTRUSIVES (Paleocene to Miocene, some rocks may be as young as Pleistocene)--Small stocks and irregular dikes of rhyolite, quartz latite, and latite. Lithologically, they are identical to, and thus probably correlative with the felsic subvolcanic rocks of unit Tv.

Ttw TSADAKA (Miocene) AND WISHBONE (Paleocene and Eocene) FORMATIONS, UNDIVIDED--Tsadaka Formation, occurring only at Wishbone Hill, consists of cobble-boulder conglomerate with thin interbeds of sandstone, siltstone, and shale; about 200 m thick. The Wishbone Formation, which unconformably underlies the Tsadaka, comprises well-indurated fluviatile conglomerate with thick interbeds of sandstone, siltstone, and claystone; about 600 to 900 m thick (Detterman and others, 1976; Barnes, 1962). The present map unit also includes over 150 m of fluviatile conglomerate and coaly sandstone (unit Tf of Grantz, 1960a, b) in the eastern Talkeetna Mountains.

Tc CHICKALOON FORMATION (Paleocene)--Well-indurated, continental, dominantly fluviatile sequence of massive feldspathic sandstone, siltstone, claystone, and conglomerate, containing numerous beds of bituminous coal; over 1,500 m thick (Barnes, 1962).

Tsu SEDIMENTARY ROCKS, UNDIFFERENTIATED (Tertiary)--Fluviatile conglomerate, sandstone, and claystone with a few thin interbeds of lignitic coal. Lithologically, these rocks look similar to the Tertiary sedimentary rocks of the southern Talkeetna Mountains, but lack of fossil evidence does not permit more definitive correlation. The largest exposure of these rocks is along Watana Creek, and, according to Smith (1974a), the sequence is over 160 m thick. Lithologically, it resembles the Paleocene Chickaloon Formation of the Matanuska Valley.

PLUTONIC AND METAMORPHIC ROCKS

Tgd TERTIARY GRANODIORITE (Eocene)--Contains hornblende and biotite. This granodiorite is part of a small pluton along the northern edge of the map area. Turner and Smith (1974) report an Eocene age for this pluton, determined by the potassium-argon method on biotite (48.8 ± 1.5 m.y.) and on hornblende (44.8 ± 1.3 m.y.) from a sample just north of the present map area.

Thgd BIOTITE-HORNBLENDE GRANODIORITE (Paleocene, in part may be Eocene)--Rocks of this unit occur in one large and several smaller, poorly exposed plutons in the western and northern Talkeetna Mountains. All of the plutons were forcibly intruded in the epizone of Buddington (1959). Granodiorite is the dominant rock, but locally it grades into adamellite (= granite with plagioclase and alkali feldspar in approximately equal proportions), tonalite, and quartz diorite. All these rocks are medium to dark gray, medium grained, generally structureless, and have granitic to seriate textures. In all of them, hornblende is the chief mafic mineral. Biotite- and hornblende-rich xenoliths of reconstituted country rock are common in every pluton. The lithologic compositions and available age determinations (see table 1) indicate that these granitic rocks are the plutonic equivalents of some of the felsic rocks in the lower portion of unit Tv.

Tbgd BIOTITE GRANODIORITE (Paleocene, in part may be Eocene)--Biotite granodiorite and adamellite in approximately equal proportions. Biotite is the chief mafic mineral, hornblende is occasionally present. Color is light to medium gray, grain size is from medium to coarse, texture is granitic to seriate. Very faint flow structures have developed only locally. These rocks occur in shallow, forcibly emplaced epizonal plutons in the northwestern Talkeetna Mountains. Aplitic and pegmatitic dikes are common in all the plutons. Just north of the map area, these plutonic rocks grade into felsic volcanic rocks. Potassium-argon age determinations (see table 1) indicate that the biotite granodiorite and adamellite of the present unit are essentially of the same age as the biotite-hornblende granodiorite (unit Thgd). Thus, the rocks of these two units, in view of their spatial proximity, probably are the products of differentiation of the same parent magma, either in situ or at some deeper levels in the Earth's crust. The biotite granodiorite intrusives are also considered to be the plutonic equivalents of some of the felsic volcanic rocks in the lower portion of unit Tv.

Tsmg SCHIST, MIGMATITE, AND GRANITE (Paleocene intrusive and metamorphic ages)--Undifferentiated terrane of andalusite and (or) sillimanite-bearing pelitic schist, lit-par-lit type migmatite, and small granitic bodies with moderately to well-developed flow foliation. These rocks occur in approximately equal proportions, and the contacts between them are generally gradational, as is the contact between the schist and its unmetamorphosed pelitic rock equivalents (unit Kag) outside the present map unit.

The pelitic schist is medium to dark gray, medium grained, has well-developed but wavy foliation, and contains lit-par-lit type granitic injections in greatly varying amounts. Rock-forming minerals of the schist include biotite (pleochroism Nz = dark reddish brown, Nx = pale brown), quartz, plagioclase, minor K-feldspar, muscovite, garnet, and sillimanite which locally coexists with andalusite.

The lit-par-lit type granitic injections within the schist are medium gray, medium grained, and consist of feldspar, quartz, and biotite.

The rocks of the small, granitic bodies range in composition from biotite adamellite to biotite-hornblende granodiorite. They are medium gray and medium grained, generally have granitic textures, and, in addition to the flow foliation, locally display flow banding of felsic and mafic minerals. These granitic bodies appear to be the source of the lit-par-lit intrusions.

The proximity of the schist to the small granitic bodies, the occurrence of the lit-par-lit injections, and the presence of andalusite in the schist indicate that the schist is the result of contact metamorphism. Perhaps this metamorphism took place in the roof zone of a large pluton, the cupolas of which may be the small granitic bodies.

TKt TONALITE (Upper Cretaceous and Lower Paleocene)--Dominantly biotite-hornblende tonalite, locally grades into quartz diorite. The tonalite is medium gray, coarse to medium grained, has a granitic texture and a fairly well-developed primary foliation. It occurs in a large, possibly composite, batholith, approximately 75 to 61 m.y. old (see table 1), which was emplaced in the epizone and mesozone of Buddington (1959). The tonalite is described in more detail in Csejtey (1974).

TKa ADAMELLITE (Upper Cretaceous and Lower Paleocene)--Occurs in a large epizonal pluton in the southwestern part of the map area. The dominant rock type is adamellite but locally includes granodiorite. Biotite is the chief mafic mineral, muscovite occurs in subordinate amounts. The typical adamellite is medium to light gray, medium to coarse grained, its texture ranges from granitic to seriate. The adamellite appears to be intrusive into the tonalite (unit TKt), but concordant potassium-argon ages on one sample (map no. 24, table 1) indicate the adamellite to be essentially the same age as the tonalite. These rocks apparently are comagmatic.

TKgr GRANITIC ROCKS, UNDIVIDED (Cretaceous and (or) Tertiary)--These rocks of uncertain age occur in four smaller epizonal plutons of granodiorite and tonalite. Their color is medium to dark gray, grain size is medium, texture is granitic. Mafic minerals are hornblende and (or) biotite. The largest of these plutons, in the northeast corner of the map area, is reported by Smith and others (1975) to be of Cretaceous age.

TKlg LEUCOGABBRO (Cretaceous and (or) Tertiary)--Small, poorly exposed intrusive of uncertain age in west-central part of map area, essentially consisting of plagioclase (around An70 and about 80 percent of volume), and pale-green hornblende. The leucogabbro is medium to light gray, coarse to medium grained, with a granitic to seriate texture.

SOUTHEASTERN TALKEETNA MOUNTAINS

Sedimentary and volcanic rocks

Kar ARKOSE RIDGE FORMATION (Cretaceous)--Arkosic sandstone, conglomerate, graywacke, siltstone, and shale (Detterman and others, 1976; Grantz and Wolfe, 1961). Clastic components consist chiefly of granitic and metamorphic rock fragments, quartz, feldspar, and biotite, indicating a dominantly plutonic and, to a lesser extent, metamorphic provenance (G. R. Winkler, oral commun., 1977). Numerous plant fragments suggest a dominantly terrestrial origin. Recent field and petrographic studies (Csejtey and others, 1977) indicate that this formation is of Cretaceous age. A pre-Tertiary age is also indicated by a potassium-argon age determination on biotite (map no. 37, table 1). The biotite was separated from a sample of graywacke with secondary biotite, obtained from near the tonalite pluton (unit TKt). The formation rests unconformably on Jurassic granitic and metamorphic rocks and is as much as 700 m thick. In this report the Arkose Ridge is considered to be a dominantly nonmarine facies of the Cretaceous Matanuska Formation.

Km MATANUSKA FORMATION (Lower and Upper Cretaceous)--Well-indurated shale, siltstone, sandstone, graywacke, with subordinate conglomerate interbeds; occurs along the southern edge of the map area, mostly in the Matanuska Valley. These rocks, having a total thickness in excess of 1,200 m, are generally dark gray and thinly bedded, and for the most part were deposited in a marine environment of moderate to shallow depths. Some of the sandstone beds contain fragmentary plant remains. Age of the formation ranges from Maestrichtian at the top to Albian at the base (Grantz, 1964). The formation rests with a pronounced angular unconformity on Lower Cretaceous and older strata. In part, the Matanuska Formation correlates with the Kennicott, the Shulze, the Chititna, and the MacCall Ridge Formations of the southern Wrangell Mountains (Jones, 1967).

Ksu SEDIMENTARY ROCKS, UNDIVIDED (Lower Cretaceous)--A shallow water marine sequence of thinly bedded calcareous sandstone, siltstone, claystone, minor conglomerate, and thick-bedded to massive clastic limestone; interpreted as a continental shelf-type deposit; over 100 m thick. These strata occur in the south-eastern Talkeetna Mountains, and they have been previously mapped and dated by Grantz (1960a, b). The present undivided unit includes Grantz' units Ks, Kc, and the Nelchina Limestone. The contact between these strata and the underlying Jurassic Naknek Formation (unit Jn) is a slightly angular unconformity. The Nelchina Limestone correlates with the Berg Creek Formation of the southern Wrangell Mountains (E. M. MacKevett, Jr., oral commun., 1977).

Jn NAKNEK FORMATION (Upper Jurassic)--Shallow water marine, thin to thick bedded, intercalated strata of fossiliferous gray siltstone, shale, sandstone, and conglomerate; over 1,400 m thick. Previously mapped and dated by Grantz (1960a, b). The Naknek Formation is restricted to the southeastern Talkeetna Mountains, lacks any contemporaneous volcanic material, and appears to have been deposited in a continental shelf environment. Its contact with the underlying Chinitna Formation is a very slightly angular unconformity. The Naknek correlates with the Root Glacier Formation of the southern Wrangell Mountains (E. M. MacKevett, Jr., oral commun., 1977).

Jct CHINITNA FORMATION (Upper Jurassic) AND TUXEDNI GROUP (Middle Jurassic), UNDIVIDED--The Chinitna Formation consists of a shallow marine, intercalated sequence of dark-gray shale, siltstone, and subordinate graywacke; contains numerous large limestone concretions; it is as much as 600 m thick. The Tuxedni Group unconformably underlies the Chinitna, and consists of shallow marine, well-indurated, thinly to thickly bedded graywacke, sandstone, and massive conglomerate in its lower part, and thinly to thickly bedded dark siltstone and shale in its upper part. The Tuxedni is about 300 to 400 m thick. Both the Chinitna and Tuxedni have been previously mapped and dated by Grantz (1960a, b; 1961a, b), by Grantz and others (1963), and by Detterman and others (1976). Both formations occur in the southeastern part of the map area, are devoid of coeval volcanic material, and are interpreted to have been deposited in a continental shelf environment. The contact between the Tuxedni Group and the underlying Talkeetna Formation (unit Jtk) is a major angular unconformity. The Chinitna and Tuxedni are partly correlative with the Nizina Mountain Formation of the southern Wrangell Mountains (E. M. MacKevett, Jr., oral commun., 1977).

Jtk TALKEETNA FORMATION (Lower Jurassic)--Andesitic flows, flow breccia, tuff, and agglomerate; subordinate interbeds of sandstone, siltstone, and limestone (mapped separately as unit Jls), especially in upper part of the formation. A dominantly shallow marine sequence, about 1,000 to 2,000 m thick (Grantz, 1960a, b; 1961a, b; Grantz and others, 1963; Detterman and others, 1976). This formation occurs only in the southeastern half of the mapped area and its base is nowhere exposed. The occurrence of marble (units Jmb and Jmbr) within the plutonic and metamorphic rocks just northwest of the Talkeetna Formation outcrop area suggests that the formation is underlain by volcanogenic rocks of Triassic (unit ℞v) and of Paleozoic age (unit Pzv).

Jls LIMESTONE (Lower Jurassic)--Light- to dark-gray, fine- to medium-grained unfossiliferous limestone; near granitic rocks recrystallized to medium- to coarse-grained marble. Forms discontinuous lenticular bodies, as much as 30 m thick, within Talkeetna Formation.

Plutonic and metamorphic rocks

Kum SERPENTINIZED ULTRAMAFIC ROCKS (Lower and (or) Upper Cretaceous)--These rocks occur in small, tectonically emplaced, discordant bodies (protrusions) within the probably Lower to Middle Jurassic pelitic schist (unit Jps) near Willow Creek. They are medium greenish gray to black in color, and are composed of aphanitic masses of serpentine, talc, minor amounts of actinolite-tremolite, chlorite, and opaque minerals. Relict textures were nowhere observed, and all these bodies are strongly sheared. Semiquantitative spectrographic analyses indicate chromium contents to be between 1,000 and 5,000 ppm and nickel between 1,000 and 2,000 ppm (analyses by D. F. Siems and J. M. Motooka, 1973). Fire assay analyses of ten samples show both platinum and palladium contents to range from 0.0 ppm to 0.030 ppm (analyses by R. R. Carlson, 1973). However, the average platinum to palladium ratio is only about three to one. Potassium-argon age determinations on actinolite-tremolite from two samples yielded early Late Cretaceous minimum ages (map nos. 32, 36, table 1). These minimum ages coincide in time with a middle to Late Cretaceous period of intense, alpine-type orogenic deformation (see Structure and Tectonics sections) of the Talkeetna Mountains region. Thus, the serpentinite bodies, whose original age is unknown, are assumed to have been emplaced during this orogeny.

Jtr TRONDHJEMITE (Upper Jurassic)--Forms a discordant, northeast-trending, elongate, epizonal pluton of fairly uniform lithology in the central Talkeetna Mountains. Large portions of the pluton have been sheared and saussuritized. Typically, the trondhjemite is light gray, medium to coarse grained with a granitic texture. A faint flow foliation is locally developed. Major rock forming minerals are plagioclase (oligoclase to sodic andesine), quartz, K-feldspar (between 0 to 10 percent of volume), and biotite, with subordinate amounts of muscovite, and opaque minerals. Color index ranges from 3 to 9. Average oxide percentages, by weight, of seven trondhjemite analyses are: SiO_2 - 70.30, Al_2O_3 - 16.74, K_2O - 1.27, Na_2O - 5.07, CaO - 3.33. Potassium-argon age determinations (map nos. 21, 22, 26, 31, table 1) from the southern part of the pluton show considerable variation in age, which is attributed to resetting. However, three age determinations from the northern half of the pluton (map nos. 10, 11, 14, table 1), including concordant ages on a mineral pair of muscovite and biotite, yielded very similar numbers indicating the emplacement of the trondhjemite pluton between 145 to 150 m.y. ago. The trondhjemite is the youngest member of a group of Jurassic plutonic and metamorphic rocks in the Talkeetna Mountains.

Jgd GRANODIORITE (Middle to Upper Jurassic)--Dominantly granodiorite but includes minor amounts of tonalite and quartz diorite.

These epizonal plutonic rocks, underlying considerable areas in the central and eastern Talkeetna Mountains, were probably emplaced as multiple intrusion of consanguineous magmas. They are medium to dark gray, medium grained, and in undeformed rocks the texture is granitic. Mafic minerals are hornblende and biotite in various proportions. Along the northwestern border of its exposure area, the granodiorite and related rocks have been cataclastically deformed, resulting in a pronounced northeast-trending secondary foliation and, to a lesser degree, lineation. The width of the deformed zone varies from about 2 km to 25 km. Isotopic age determinations (map numbers 15-17, 27, tables 1, 2) from four separate localities indicate that emplacement, probably multiple intrusions, took place approximately 150 and 175 m.y. ago. While the Upper Jurassic trondhjemite intrudes the granodiorite, the granodiorite itself intrudes the Talkeetna Formation of Lower Jurassic age (Grantz and others, 1963).

Jgdm MIGMATITIC BORDER ZONE OF GRANODIORITE (Middle to Upper Jurassic)--Forms a terrane of poorly exposed, intricately intermixed contact schist, amphibolite, and small dikes and veinlets of granodiorite; all of these rock types occur in approximately equal proportions.

The contact schist is dark to medium gray, medium grained; rock-forming minerals are quartz, biotite, and subordinate plagioclase.

The amphibolite is dark gray, medium grained, and consists of hornblende and plagioclase; megascopic schistosity is seldom conspicuous.

The granodiorite is the same as that of unit Jgd; most of the veinlets have been intruded along foliation planes.

The metamorphic rocks of this unit were probably derived from either the Talkeetna Formation (unit Jtk) or from the upper Paleozoic volcanogenic sequence (unit Pzv), or possibly in part from the Upper Triassic basaltic sequence (unit TRv).

Jmrb MARBLE (Middle to Upper Jurassic metamorphic age)--Contact metamorphosed marble bed more than 40 m thick within migmatitic border zone (unit Jgdm). The marble is poorly exposed and occurs only along John Creek, a tributary of upper Kosina Creek. The rock is white, coarse to medium grained, and contains numerous porphyroblastic crystals of andradite garnet and diopside. The marble was derived from a limestone bed, probably within the upper Paleozoic volcanogenic sequence (unit Pzv) or possibly within the Upper Triassic basaltic sequence (unit TRv).

Jqd QUARTZ DIORITE (Lower to Middle Jurassic)--Epizonal intrusive in the southern Talkeetna Mountains. Dominantly quartz diorite but also includes diorite and tonalite. Large portions of this rock have been sheared and intensively altered. The fresh quartz diorite is medium to dark greenish gray, medium to coarse grained, and has a granitic texture. Rock-forming minerals are plagioclase (andesine), quartz, hornblende, subordinate biotite and K-feldspar. Where altered, the quartz diorite consists of mineral aggregates of epidote, chlorite, and sericite, as well as some remnants of the primary minerals. The age of the quartz diorite is probably late Early Jurassic or early Middle Jurassic because it intrudes the Talkeetna Formation and is intruded by the Middle to Upper Jurassic granodiorite of unit Jgd.

Jam AMPHIBOLITE (Lower to Middle Jurassic metamorphic age)--Forms a metamorphic terrane consisting dominantly of amphibolite but includes subordinate amounts of greenschist and foliated diorite. This metamorphic terrane also includes several interbeds of coarsely crystalline marble which are mapped and described separately (unit Jmb).

The amphibolite is generally dark greenish gray, medium to coarse grained, but fine-grained varieties also occur. Foliation and lineation are generally poorly developed, and segregation layering is rare. Major rock-forming minerals are, in approximately equal proportions, anhedral to euhedral hornblende (Z = dark green to brownish green, occasionally bluish green) and anhedral, generally twinned plagioclase ranging from labradorite to calcic andesine. Accessory minerals are quartz, garnet, sphene, apatite, opaques, occasional epidote, and, in some of the rocks, shreds of biotite.

The greenschist is dark greenish gray, fine to medium grained, with a moderately well-developed schistosity. Major minerals are actinolite, untwinned plagioclase (probably albite), epidote, chlorite, quartz, and opaques. Some of the actinolite-like amphibole may actually be aluminous hornblende, thus some of these rocks may be transitional to amphibolite.

The foliated diorite is very similar to the amphibolite in appearance. It is dark greenish gray, medium to coarse grained, with a generally well-developed shear foliation. A remnant granitic texture is always discernible in thin section. Rock-forming minerals are hornblende, twinned and occasionally zoned plagioclase (andesine to sodic labradorite), with subordinate amounts of chlorite and epidote, minor quartz and biotite, and opaques.

All of the above rocks, as well as the quartz diorite of unit Jqd, apparently are the earliest products of a Jurassic plutonic and metamorphic event which appears to have started in the Talkeetna Mountains in late Early Jurassic time after the deposition of the Talkeetna Formation (unit Jtk). A potassium-argon age determination on hornblende of a diorite or amphibolite sample (map no. 5, table 1) from the northeast part of the map area yielded an age of 176.6 m.y. (Turner and Smith, 1974), suggesting an Early to Middle Jurassic age for the amphibolite and associated rocks. The quartz diorite of unit Jqd in the southern Talkeetna Mountains is probably correlative with the sheared diorite of the amphibolite terrane.

The metamorphic rocks of the amphibolite terrane probably were derived from any or all of the following dominantly basic volcanic formations: Talkeetna Formation (unit Jtk), upper Paleozoic volcanogenic sequence (unit Pzv), or the Upper Triassic basaltic sequence (unit TRv). The pods of greenschist, intercalated with the amphibolite, suggest that the metamorphism in the amphibolite terrane was not of uniform intensity.

Jmb MARBLE (Lower to Middle Jurassic metamorphic age)--White, medium- to coarse-grained marble. It occurs in massive interbeds, as much as 30 m thick, within the amphibolite terrane of unit Jam. The marble contains subordinate amounts of garnet and diopside. Its parent rock was a limestone bed, probably within the Talkeetna Formation (unit Jtk) or within the upper Paleozoic volcanogenic sequence (unit Pzv), or, least likely, within the Upper Triassic basaltic sequence (unit TRv).

Jmi AMPHIBOLITE AND QUARTZ DIORITE (Lower to Middle Jurassic metamorphic and plutonic ages)--Forms a terrane of intricately intermixed amphibolite and quartz diorite in about equal amounts in the southern Talkeetna Mountains.

The amphibolite is very similar to the amphibolite of unit Jam, thus the two amphibolites are considered to be correlative, and no description is given here. One difference is that segregation layering of mafic and felsic components is more prevalent in the amphibolite of unit Jmi. A thin wedge of biotite-quartz-feldspar gneiss, probably derived from a nonvolcanic clastic interbed, is intercalated with the amphibolite along lower Granite Creek (Detterman and others, 1976; Travis Hudson, oral commun., 1978).

The quartz diorite is petrographically identical to the quartz diorite in adjacent unit Jqd (see rock description there), and the two rocks are considered to be correlative. The quartz diorite of the present unit is generally more altered than that of unit Jqd.

Jgs GREENSTONE (Probably Lower to Middle Jurassic metamorphic age)--The basic metavolcanic rocks of this unit form small, isolated hills along the eastern edge of the map area near the Susitna River. The typical greenstone is a dark greenish gray, fine grained, generally structureless rock. Original rock-forming minerals were pyroxene, amphibole, and plagioclase (andesine to labradorite) which more or less altered to chlorite, epidote, serpentine, calcite, and minor sericite and quartz. The proximity of the amphibolite terrane (unit Jam) strongly suggests that the metavolcanic greenstones of the present unit represent a low-grade facies of the same metamorphism which produced the amphibolite. The relative position of the greenstone within the northeasterly structural trend of the Talkeetna Mountains suggests that the greenstone was probably derived from the Talkeetna Formation (unit Jtk) or, possibly, from either the upper Paleozoic volcanogenic sequence (unit Pzv) or the Upper Triassic basaltic sequence (unit ŦRv).

Jps PELITIC MICA SCHIST (Probably Lower to Middle Jurassic metamorphic age)--This rock occurs only in the southwestern corner of the map area near the headwaters of Willow Creek. The schist is medium to dark gray, medium grained, with uniform lithology throughout its exposure area. Its ubiquitous mineral constituents are quartz, muscovite, albite, chlorite, chloritized crystals of garnet and subordinate biotite. Very thin laminae of carbonaceous material occur sparsely. Small open folds and crenulations form an incipient slip cleavage at a large angle to the primary schistosity. Numerous thin veins and stringers of hydrothermal quartz occur throughout the schist. Detailed petrographic descriptions of the mica schist are given in Ray (1954).

The present mineralogy of the schist is indicative of the greenschist metamorphic facies of Turner (1968). However, it is probably retrograde from higher metamorphism, possibly the amphibolite facies. Evidence for this is the chloritized garnet and biotite crystals and the sparse mineral outlines consisting of chlorite which probably are pseudomorphs after hornblende.

The age of the schist is imperfectly known, but, based on regional geologic interpretations, the primary metamorphism is considered to be Early to Middle Jurassic in age. Thus, the schist and the amphibolite of unit Jam are interpreted to be the products of the same metamorphism. The retrograde metamorphism is assumed to be of middle to Late Cretaceous in age and related to an alpine-type orogeny in the Talkeetna Mountains at that time. However, the Late Cretaceous Arkose Ridge Formation, which lies unconformably on the schist, has not been affected by this retrograde metamorphism. The three potassium-argon age determinations, measured on muscovite from the schist (map nos. 33-35, table 1), yielded obviously reset Paleocene ages.

The parent rock of the schist is unknown because no pelitic rocks of comparable thickness (the schist is at least several hundred meters thick) are known to occur in the pre-Middle Jurassic rocks of the Talkeetna Mountains.

Jpmu PLUTONIC AND METAMORPHIC ROCKS, UNDIFFERENTIATED (Lower to Upper Jurassic plutonic and metamorphic ages)--This unit consists of an intricately intermixed mosaic of most of the previously discussed Jurassic metamorphic and plutonic rocks (units Jtr, Jgd, Jgdm, Jqd, Jam, Jgs, and Jps). Within the terrane of the present unit, the exposure area of an individual rock type is not more than a few square kilometers. Two rock types, amphybolite and sheared quartz diorite, comprise approximately 60 percent of the terrane. Next in importance are sheared granodiorite and associated migmatites. Subordinate amounts of pelitic mica schist and greenstone also occur. Numerous apophyses of trondhjemite, as much as several meters thick, occur along the eastern edge of the terrane adjacent to the large trondhjemite pluton (unit Jtr). All of these rocks are lithologically very similar to their correlative map units, and they will not be described here. At two localities, the sheared granodiorite (unit Jgd) was mapped separately to show the proximity of sheared Jurassic granitic rocks to the Late Cretaceous and early Paleocene unsheared tonalite (unit TKt).

NORTHWESTERN TALKEETNA MOUNTAINS AND UPPER CHULITNA RIVER AREA

Sedimentary and volcanic rocks; rocks of each column occur in separate fault blocks.

Central and northern Talkeetna Mountains

ꞦTv BASALTIC METAVOLCANIC ROCKS (Upper Triassic)--This shallow water marine unit consists of amygdaloidal metabasalt flows with very subordinate amounts of thin interbeds of metachert, argillite, metavolcaniclastic rocks, and marble (Smith and others, 1975). Rocks of this unit have been mapped only in the northeast portion of the map area. However, small blocks of the basaltic rocks may occur within the complexly deformed late Paleozoic volcanogenic sequence (unit Pzv) toward the southwest. The basaltic rocks rest with angular unconformity on the late Paleozoic volcanics (unit Pzv); the top of the basalts is unexposed. The minimal thickness of the basaltic metavolcanic rocks is 800 m.

The individual metabasalt flows are as much as 10 m thick, and, according to Smith and others (1975), display columnar jointing and locally pillow structures. The typical metabasalt is dark greenish gray, fine grained, and generally contains numerous amygdules. Thin sections show the metabasalts to consist of labrodorite, augite, and opaques in an intergranular or subophitic texture. Secondary minerals are chlorite, epidote, clinozoisite, very subordinate allanite, sericite, and possibly some kaolin. The amygdules consist of chlorite, silica, and zeolites. The present mineralogy is probably the result of deuteric alteration and low-grade regional metamorphism which apparently did not reach the intensity of the greenschist facies of Turner (1968).

From a marble interbed in upper Watana Creek (locality 1, table 3), T. E. Smith (unpub. data, 1974) collected fossil specimens which were identified and interpreted by K. M. Nichols and N. J. Silberling to be *Halobia* cf. *H. symmetrica* Smith, indicating a latest Karnian or early Norian age. Previously, Smith (1974a) and Smith and others (1975) have correlated the basaltic metavolcanic rocks of the present unit with the Amphitheater Group of the central Alaska Range. Accordingly, the fossils collected by T. E. Smith suggest that the Amphitheater Group is younger than, and thus not correlative with the lithologically very similar Nikolai Greenstone of pre-late Karnian age in eastern Alaska (Jones and others, 1977).

Pzv BASALTIC TO ANDESITIC METAVOLCANOGENIC ROCKS (Pennsylvanian(?) and Early Permian)--Rocks of this unit occur in a northeast-trending belt across the center of the Talkeetna Mountains, and they form an interlayered heterogeneous, dominantly marine sequence over 5,000 m thick. The base of the sequence is nowhere exposed, and the contact with the overlying Triassic metabasalts is an angular unconformity. The metavolcanogenic sequence consists dominantly of metamorphosed flows and tuffs of basaltic to andesitic composition, and of coarse- to fine-grained metavolcaniclastic rocks with clasts composed chiefly of mafic volcanic rocks. Mudstone, bioclastic marble (mapped and described separately as unit Pls), and dark-gray to black phyllite are subordinate. The various rock types of the sequence form conformable but lenticular units of limited areal extent. The crudely layered and poorly sorted metavolcaniclastic units have thicknesses in excess of 1,000 m, and the thickness of the phyllites ranges from a few meters to several hundred meters. The whole sequence has been tightly folded and complexly faulted, and the rocks have been regionally metamorphosed into mineral assemblages mostly of the greenschist and the prehnite-pumpellyite facies, but locally along Tsisi Creek of the amphibolite facies of Turner (1968). Detailed petrographic descriptions of these rocks were given by Csejtey (1974).

The age of the metamorphism is uncertain. The most intensive metamorphism in the mapped area probably took place in Early to Middle Jurassic time, contemporaneously with the development of the amphibolite terrane (unit Jam). Subsequent but less severe metamorphism, primarily shearing, occurred probably in middle to Late Cretaceous time during the alpine-type orogenic deformation of the Talkeetna Mountains (see discussions in Structure and Tectonics sections).

The composition and lithologic character of the metavolcanogenic sequence strongly suggest that this sequence is a remnant of a complex volcanic arc system (Csejtey, 1974, 1976). Fossil evidence (see description of unit Pls) from a marble interbed near the top of the sequence indicates an Early Permian age. However, because of the considerable thickness of the sequence, its lowermost portion may be as old as Late Pennsylvanian.

Pls MARBLE (Pennsylvanian(?) and Early Permian)--Forms lenticular interbeds, as much as a few tens of meters thick, within the basaltic to andesitic late Paleozoic metavolcanogenic sequence (unit Pzv). Most of the rock is light gray to white, medium to coarse grained, thick-bedded to massive marble, but some less metamorphosed varieties also occur. Still discernible organic remains and bedding features indicate that the marble interbeds were derived from bioclastic limestone which probably was deposited by high energy currents on shallow banks of limited areal extent. A number of the marble interbeds contain poorly preserved and generically unidentifiable crinoid columnals, brachiopods, bryozoans, and rarely corals (see table 3) of late Paleozoic or probable late Paleozoic ages. However, one of the marble interbeds near the top of the sequence (locality 8, table 3) yielded well-preserved brachiopods and crinoid columnals which were identified and interpreted by J. T. Dutro, Jr. (Csejtey, 1976) to be late Early Permian, that is, late Leonardian to early Guadalupian in age. The regional correlation of these rocks and that of the late Paleozoic metavolcanogenic sequence (unit Pzv) has been previously discussed by Csejtey (1976).

Northern Watana Creek area

Js SEDIMENTARY AND VOLCANIC ROCKS, UNDIVIDED (Upper Jurassic)--These rocks only occur in a small, apparently tectonic sliver along the northern edge of the map area. They comprise a section of intercalated argillite and graywacke, pebble conglomerate, and flows and dikes of andesitic to latitic feldspar porphyry. Some of these rocks are sheared but some, mostly the pebble conglomerates, are not sheared.

The argillite and fine-grained graywacke are thinly to moderately thickly bedded and generally are dark gray. However, dark-greenish-gray varieties also occur, suggesting the presence of volcanic ash or fine-grained tuffaceous material. The conglomerates are massive, and the well-rounded to subrounded pebbles consist chiefly of unmetamorphosed andesite, latite, and subordinate amounts of dacite. A minority of the pebbles are composed of dark-gray argillite and white quartz. The feldspar porphyry is dark gray, with flow alined phenocrysts of zoned andesine and oligoclase as much as 1 cm long, and some hornblende and biotite, in an aphanitic matrix.

An argillite bed at the top of the 5,053-ft hill in the Healy A-2 quadrangle, just north of the present map area, yielded well-preserved fossils of *Buchia rugosa* (Fischer), indicating a Late Jurassic age for these rocks (D. L. Jones, oral commun., 1977). On the basis of lithology and age, the rocks of the present unit are considered to be the westernmost occurrence of the Gravina-Nutzotin terrane of Berg and others (1972).

Northwest Talkeetna Mountains

Kag ARGILLITE AND LITHIC GRAYWACKE (Lower Cretaceous)--These rocks occur in a monotonous, intensely deformed flyschlike turbidite sequence, probably several thousand meters thick, in the northwest part of the mapped area, north of the Talkeetna thrust fault. The whole sequence has been compressed into tight and isoclinal folds and probably has been complexly faulted as well. The rocks are highly indurated, and many are sheared and pervasively cleaved as a result of low-grade dynamometamorphism, the intensity of which is only locally as high as the lowermost portion of the greenschist metamorphic facies of Turner (1968).

Most of the cleavage is probably axial plane cleavage. Neither the base nor the top of the sequence is exposed and, because of the intense deformation, even its minimal thickness is only an estimate.

The argillite is dark gray or black. Commonly it contains small grains of detrital mica as much as 1 mm in diameter. Because of the dynamometamorphism, in large areas the argillite is actually a slate or fine-grained phyllite. Thin sections show that some of the argillites are derived from very fine grained siltstone and that they contain considerable carbonaceous material.

The typical lithic graywacke is dark to medium gray, fine to medium grained, and occurs intercalated with the argillite in graded beds ranging in thickness from laminae to about 1.5 m. The individual graywacke beds are not uniformly distributed throughout the whole sequence, of which they comprise about 30 to 40 percent by volume, but tend to be clustered in zones 1 to 5 m thick. Thin sections of graywacke samples show them to be composed of angular or subrounded detrital grains of lithic fragments, quartz, moderately fresh plagioclase, and some, generally altered, mica in a very fine grained matrix; euhedral opaque grains, probably authigenic pyrite, are present in most thin sections. The lithic fragments consist in various proportions of little altered, fine-grained to aphanitic volcanic rocks of mafic to intermediate composition; fine-grained, weakly foliated low-grade metamorphic rocks; chert; and some fine-grained unmetamorphosed sedimentary rocks possibly of intraformational origin. No carbonate grains were seen. The matrix constitutes about 20 to 30 percent of the rock by volume, generally contains some secondary sericite and chlorite, and, in the more metamorphosed rocks, biotite and possibly some amphibole.

Analyses of paleocurrent features, such as small-scale cross-stratification, found in several exposures near the western edge of the mapped area, suggest that depositional currents came from the east or northeast (A. T. Ovenshine, oral commun., 1974).

Because fossils are extremely sparse, the exact age of the argillite and lithic graywacke sequence is imperfectly known. A poor specimen of *Inoceramus* sp. of Cretaceous age was found just west of the map area between the Chulitna and Susitna Rivers, and a block of *Buchia*-bearing limestone of Valanginian age was found in float near Caribou Pass in the Healy quadrangle north of the mapped area (D. L. Jones, oral commun., 1978).

Northwestern Talkeetna Mountains

TRvs METABASALT AND SLATE (Upper Triassic)--Shallow water marine, interbedded sequence of amygdaloidal metabasalt flows and slate, found only in two allochthonous klippen near the northwest corner of the mapped area. The sequence is tightly folded, along with the underlying Cretaceous rocks (unit Kag), and is slightly metamorphosed and unevenly sheared. The basalt and slate are intercalated in approximately equal proportions in individual units as much as 15 m thick.

The metabasalt is dark greenish gray, aphanitic, with numerous amygdules. In thin sections the primary minerals are twinned labradorite, augite, and opaques which probably are, for the most part, ilmenite. Secondary minerals are chlorite (much of it after glass), epidote, clinozoisite, minor zoisite, calcite, leucoxene, very minor sericite, very fine grained felty amphibole (probably uralite after augite), and possibly some very subordinate albite. The original texture was intersertal and subophitic. The amygdules consist of chlorite, zeolites (primarily prehnite), quartz, and some feldspar.

The slate is dark gray to black. Thin sections show that some of the rock is fine-grained metasiltstone. All of the rocks contain considerable carbonaceous material and some amounts of fine-grained, secondary sericite. Secondary biotite is present in some of the slates.

The secondary mineral assemblages suggest that, in addition to deuteric alteration, the metabasalt and slate sequence underwent very low grade regional metamorphism.

The metabasalt and slate sequence has been dated in the Healy quadrangle, north of the present map area, near the East Fork of the Chulitna River where D. L. Jones and N. J. Silberling (oral commun., 1977) found upper Norian fossils of *Monotis subcircularis* and *Heterostridium* sp. in slightly metamorphosed argillaceous beds. Thus, the age of the present sequence is similar to, and the lithology of its basalt is identical to, that of the Upper Triassic metabasaltic sequence (unit ȾRv) in the northeast Talkeetna Mountains. These two rock sequences may represent different facies, brought closer by thrusting, of the same geologic terrane.

Upper Chulitna River area

DSga GRAYWACKE, ARGILLITE, AND SHALE (Silurian(?) to Middle Devonian) --These rocks occur in an apparently allochthonous tectonic block along the western side of the Chulitna Valley and comprise a poorly and inaccessibly exposed, complexly deformed and sheared sequence. As a result, the sequence is poorly known; it was briefly examined in outcrop only along Long Creek. There the component rocks are medium to dark gray, sheared and tightly folded with vertical dips, and occur intercalated in beds as much as 1 m thick. The graywackes are fine grained and appear to contain some volcanogenic detritus. Reconnaissance field checking by D. L. Jones (oral commun., 1977) further to the north indicates that the sequence also includes some chert, cherty tuff, and phyllite.

In Long Creek, two fossiliferous limestone beds (mapped and described separately as unit DSls) were found; they probably are in depositional contact with, and thus date, the enveloping unfossiliferous clastic rocks. It is possible, however, that some of the limestone contacts are tectonic and that some of the enveloping rocks are of a different age.

DSls LIMESTONE (Silurian(?) to Middle Devonian)--Massive to thick-bedded, medium-gray, fine-grained, moderately sheared bioclastic limestone, probably formed in patch reefs. It occurs at three separate localities, in apparent depositional interbeds as much as 20 m thick, within fine-grained clastic rocks (unit DSga). Of the two limestone beds in Long Creek, one yielded fossils of Devonian, probably Middle Devonian, age, the other of Silurian or Devonian age (map nos. 12, 13, respectively, table 3). The fossils also indicate shallow marine deposition. The types of fossils and the characteristics of the host limestones and the enveloping clastic rocks suggest deposition along an ancient continental margin. These continental margin-type deposits crop out only about 6 km to the southeast of Upper Devonian ophiolitic rocks (unit Dbs) that are indicative of ocean floor deposition. The proximity of these rocks that are close in age but different in depositional environment is additional evidence for large-scale Alpine-type orogenic deformation in south-central Alaska (Csejtey and others, 1977; Jones and others, 1978).

Upper Chulitna River area

Jta CRYSTAL TUFF, ARGILLITE, CHERT, GRAYWACKE, AND LIMESTONE (Lower to Upper Jurassic)--Shallow to moderately deep marine sequence, tightly folded and internally faulted, at least several thousand meters thick. These rocks are interpreted to occur in a thrust block along the western slope of the upper Chulitna Valley. Four-fifths of the sequence is comprised of the massive, cliff-forming crystal tuff, while the remaining rocks form only a narrow outcrop belt along the western margin of the map unit. The contact between these two groups of rocks may be tectonic.

The crystal tuff is light to dark gray, locally with a greenish tint, and weathers to various shades of brown. It is massive with obscure rhythmic laminations and thin bedding. The tuff is composed of abundant small feldspar crystals (albite?) set in a very fine grained matrix of devitrified volcanic glass in which some shards can be recognized. Sparse but unidentifiable fragments of radiolaria were also found. A thin interbed of volcaniclastic sandstone yielded the following fossils: *Arctoasteroceras jeletskyi* Frebold, *Paltechioceras (Orthechioceras?)* sp., and *Weyla* sp. (Jones and others, 1978; fossil locality in Silberling and others, 1978). According to R. W. Imlay (written commun. to D. L. Jones, 1976), these fossils indicate a late Sinemurian age.

The argillite, chert, graywacke, and limestone occur interbedded in various proportions in individual units as much as several tens of meters thick. The argillite and chert are dark gray to black; the graywacke is medium to dark gray, very fine to medium grained, locally with graded bedding. The limestone is medium gray, generally phosphatic, in part sandy, locally is associated with limy siltstone and conglomerate; forms blocks and lenticular beds as much as several kilometers in extent. Some of the chert beds yielded radiolaria of late Kimmeridgian or early Tithonian age (Late Jurassic), and at five different localities, the limy rocks yielded Early Jurassic ammonite faunas of early Sinemurian age (Jones and others, 1978; fossil localities in Silberling and others, 1978). Probably these Lower and Upper Jurassic rocks originally formed a coherent stratigraphic sequence which subsequently was disrupted by folding and faulting.

Ohio Creek area

Dsb SERPENTINITE, BASALT, CHERT, AND GABBRO (Upper Devonian)--Tectonically intermixed assemblage that forms a northeast-trending belt of apparent thrust slivers in the northwest corner of the mapped area. Sheared serpentinite is the most abundant rock type; the remaining component rocks occur in various proportions in lenticular and podiform tectonic blocks as much as several hundred meters in extent. Many chert lenses occur intercalated with basalt flows which locally show poorly preserved pillow structures. Rocks of this map unit have been previously described and interpreted as a dismembered ophiolite assemblage by Clark and others (1972) and by Jones and others (1978).

The serpentinite is dark gray to dark greenish gray, always sheared, and consists almost entirely of clinochrysotile and lizardite with subordinate brucite, talc, and chromite. Sparse relict olivine crystals and a bastite texture suggest that the serpentinite originally was a pyroxene-olivine ultramafic rock.

Basalt is dark gray, aphanitic to fine grained with a few phenocrysts, as much as 4 mm in maximum dimension, of altered plagioclase, pyroxene, and olivine. The rock is locally vesicular or amygdaloidal and generally is fragmental; many of the fragments are palagonite. Some of the vesicles and amygdules are concentrated along spherical surfaces which may be parts of pillow structures. Depositionally intercalated marine chert beds further indicate that the basalts were formed as submarine flows.

The chert is generally red, but reddish-brown and greenish-gray varieties also occur. It is commonly in beds a few millimeters to a few centimeters in thickness, and contains abundant radiolaria.

The gabbro is medium to dark greenish gray, fine to coarse grained, and is composed of altered plagioclase, pyroxene, olivine, and opaques. Compositional layering, interpreted to be cumulate textures, is common, and the layers range in thickness from a few millimeters to a few centimeters. The best exposed gabbro occurs in a lens about 100 m thick and about 1 km long on the ridge north of the unnamed northern branch of Shotgun Creek.

Age determinations of radiolaria and conodonts in chert samples from eight separate localities reliably indicate a Late Devonian (Famennian) age for the ophiolitic rocks (Jones and others, 1978; Silberling and others, 1978).

Long Creek area

TRr RED BEDS (probably Upper Triassic)--Red sandstone, siltstone, argillite, and conglomerate similar to the red beds of unit JTRrs. Clasts of gabbro, serpentinite, and fossiliferous Permian(?) limestone are present in these rocks but have not been identified in rocks of unit JTRs. Also, a thin conglomerate bed containing angular clasts of rhyolite is locally present at the base. These rocks lie with depositional unconformity on late Paleozoic, possibly Triassic, and older strata in the map area. Just north of the map area, the red beds rest on Lower Triassic limestone (Jones and others, 1978). The red beds lack fossils and, therefore, have not been dated, but they are assumed to be equivalent in age to the Upper Triassic red beds of unit JTRrs (Jones and others, 1978).

Pzsv VOLCANOGENIC AND SEDIMENTARY ROCKS, UNDIVIDED (Upper Devonian to Lower Permian)--Heterogeneous intercalated sequence of greenish-gray to black tuffaceous chert, lesser amounts of maroon volcanic mudstone, breccia composed largely of basaltic detritus, laminated flyschlike graywacke and shale, and large lenses of light-gray, thick-bedded limestone. Fossils from the thick-bedded limestone are Early Permian in age; brachiopods from the conglomerate are also of Early Permian age; and fossils from the chert are Devonian and Carboniferous, but some poorly preserved fossils may possibly, though not likely, be as young as Triassic (Jones and others, 1978). The stratigraphic and structural relations between these diverse rocks are obscured by abundant folds and poor exposures. A detailed discussion of these rocks is given by Jones and others (1978), and fossil localities are shown in Silberling and others (1978).

Ohio Creek area

JTRs RED AND BROWN SEDIMENTARY ROCKS AND BASALT, UNDIVIDED (Upper Triassic and Lower Jurassic)--The basal part of this unit consists of a red-colored sequence of sandstone, siltstone, argillite, and conglomerate, with a few thin interbeds of brown fossiliferous sandstone, pink to light-gray dense limestone, and intercalated massive basalt flows. This red bed sequence grades upward into highly fossiliferous brown sandstone, which in turn grades upward into brownish-gray siltstone with yellowish-brown limy concretions.

Clasts in the red beds are dominantly basalt grains and pebbles which probably were derived from basalt flows of unit TRlb that lies unconformably below the red beds and from massive basalt flows within the red bed sequence. Subordinate amounts of the clasts consist of white, in part foliated, metaquartzite pebbles; flakes of white mica which, along with the metaquartzite, must have been derived from an unidentified siliceous metamorphic terrane; and red radiolarian chert pebbles and grains, which probably were derived from the ophiolitic rocks of unit Dsb. No other clasts that can be identified as coming from the ophiolitic rocks have been recognized.

Fossils from the limestone and the overlying brown sandstone are of Upper Triassic age, and those from the yellowish-brown limy concretions are of Upper Triassic and Lower Jurassic age.

Detailed discussions of both the red and brown beds are given by Jones and others (1978), and fossil localities are shown in Silberling and others (1978).

TRlb LIMESTONE AND BASALT (Upper Triassic)--Interlayered sequence of limestone, partly recrystallized to marble, and flows of altered amygdaloidal basalt. Individual units are as much as several tens of meters thick. These rocks occur in a complexly faulted zone in the northwest corner of the mapped area.

The limestone is medium gray, massive to thick bedded, but locally it has altered to fine- to medium-grained marble.

It contains sparse fragments of poorly preserved corals and thick-shelled *Megalodontid*(?) bivalves up to 20 cm in length. A single specimen of *Spondylospira* sp., in conjunction with the *Megalodontid* bivalves, suggests a Norian age for the sequence (Jones and others, 1978; fossil localities shown in Silberling and others, 1978).

The amygdaloidal basalt is dark gray to greenish gray, aphanitic, with numerous amygdules. Locally, it displays well-developed pillow structures. Primary rock-forming minerals are fine-grained labradorite, titanium-rich augite, and opaques in an originally intersertal or subophitic texture. The original mineral assemblage has been more or less altered to an aggregate of chlorite (much of it after glass), epidote, calcite, sericite, and some zeolite, probably prehnite. The amygdules consist of chlorite, calcite, prehnite, and minor quartz. Most of the secondary minerals are probably the result of deuteric alteration, but some might be the product of very low-grade regional metamorphism. Fifteen chemical analyses of least altered basalt samples indicate that the basalts are somewhat low in silica (normalized SiO_2 contents average 46.7 percent by weight, ranging from 43.7 to 48.7 percent), high in alkalis (normalized Na_2O contents average 3.06 percent by weight, ranging from 1.3 to 5.2 percent; and normalized K_2O contents average 0.47 weight percent, ranging from 0.07 to 1.5 percent), and are high in titanium (normalized TiO_2 contents average 3.8 weight percent, ranging from 2.5 to 5.0 percent). The chemistry and mineralogy suggest that these basalts had alkali affinities prior to alteration.

The fossils and the lithologies of the limestones and the basalts indicate shallow water marine deposition. The probable alkali affinity of the basalts further suggests that they either were part of an ocean island shield volcano, perhaps associated with a barrier reef, or that they were formed on a continental margin.

Upper Copeland Creek area

KJs ARGILLITE, CHERT, SANDSTONE, AND LIMESTONE (Upper Jurassic and Lower Cretaceous)--This unit consists of dark-gray argillite, dark-gray to greenish-gray bedded chert, thick-bedded sandstone, thin-bedded gray sandstone, and rare thin beds of shelly limestone. Both Upper Jurassic and Lower Cretaceous radiolarias were obtained from the chert. The thick-bedded sandstone contains abundant fragments of *Inoceramus* sp. of Hauterivian to Barremian age, and some of the limestone beds contain *Buchia sublaevis* of Valanginian age. Some of the thin-bedded sandstone contains abundant detrital white mica and may be as young as Albian (mid-Cretaceous). Thicknesses and the stratigraphic relations within these rocks and with adjacent rocks are unknown because of complex folding and faulting and poor exposures. A more detailed discussion of these rocks is given by Jones and others (1978), and fossil localities are shown in Silberling and others (1978).

Structure

The rocks of the Talkeetna Mountains region have undergone complex and intense thrusting, folding, faulting, shearing, and differential uplifting with associated regional metamorphism and plutonism. At least three major periods of deformation are recognized: a period of intense metamorphism, plutonism, and uplifting in the late Early to Middle Jurassic, the plutonic phase of which persisted into Late Jurassic; a middle to Late Cretaceous alpine-type orogeny, the most intense and important of the three; and a period of normal and high-angle reverse faulting and minor folding in the middle Tertiary, possibly extending into the Quaternary.

Most of the structural features in the Talkeetna Mountains region are the result of the Cretaceous orogeny which produced a pronounced northeast-southwest-trending structural grain of the region. The vergence of this structural grain is steeply to moderately toward the northwest, but across the Chulitna Valley in the northwest part of the map area, it abruptly reverses toward the southeast with steep attitudes. This Cretaceous deformation is most intense in the central and northwestern part of the map area, and it rapidly decreases toward the southeast. The complex fault pattern along and near the southern edge of the Talkeetna Mountains is part of the late Cenozoic Castle Mountain-Caribou fault systems, consisting chiefly of high-angle reverse and normal faults of probably local significance.

Evidence for the Jurassic deformation is provided by the post-Talkeetna Formation major unconformity and the apparently coeval regional metamorphism, up to the amphibolite grade, and associated plutonic rocks (all the Lower to Middle Jurassic metamorphic and plutonic units). The higher crustal level manifestation of this Jurassic tectonic event was regional uplift and consequent rapid denudation of the intruded epizonal plutons.

Complex folding produced by the Cretaceous orogeny is especially pronounced in the areas northwest of the belt of Jurassic metamorphic and plutonic rocks. The folds are chiefly tight or isoclinal, with amplitudes of several hundred to several thousand meters. The limbs are generally sheared out or faulted out. As a result, no individual beds can be traced in the field for more than a few kilometers. Many of the large folds, especially in the Cretaceous argillites and graywackes (unit Kag), have a well-developed axial plane slaty cleavage. Fine-grained sericite and biotite are commonly developed along these cleavages. The folding must have taken place in several episodes during the orogeny because thrust faults not only truncate folds within both the upper and lower plates but are themselves folded. The folded thrusts are especially evident in the Chulitna area where, in contrast to the regional northwest vergence, the axial planes of the folds steeply dip toward the northwest.

Most prominent of the Cretaceous faults is the Talkeetna thrust which has placed Paleozoic, Triassic, and, locally, Jurassic rocks over Cretaceous sedimentary rocks across the whole map area. The thrust is generally poorly exposed except near the Lower Talkeetna River. There it dips steeply toward the southeast. Another thrust, the one delineating the klippe of rocks of unit TRvs, has been sharply folded. The thrusts in the northwest corner of the map area are very complex, also have been intensely folded, and are more numerous than could be shown on the present map. A number of them are not fully understood, and thus their subsurface configuration is speculative. It is certain, however, that these thrusts stack and bring together on top of the Kag unit a wide variety of rock sequences of different ages and depositional environment. The root zone of all the thrusts in the northwest half of the map area is herein interpreted to be the Talkeetna thrust (see cross section).

Another Cretaceous feature is an intense shear zone, locally as much as 25 km wide, trending across the Talkeetna Mountains, parallel to, but southeast of the Talkeetna thrust. Although not supported by any evidence, it is possible that the shear zone marks a thrust zone of significant displacement. (The center of this shear zone is shown as a postulated thrust on the map.) The dips in the zone are generally southeasterly. The shearing is penetrative, and its most spectacular result is that portions of all the Jurassic plutonic rocks, including the Upper Jurassic trondhjemite, have been transformed to cataclastic gneiss. The 75 to 61 m.y. old Upper Cretaceous and lower Paleocene tonalite pluton (unit TKt) truncates this shear zone and is not affected by it.

The age of the Cretaceous orogeny, or at least its major phase, is rather well bracketed by stratigraphic evidence. The youngest rocks involved are the Cretaceous argillites and graywackes (unit Kag) which are as young as Valanginian or possibly even younger in age. A maximum upper age bracket is provided by the late Paleocene granitic plutons, which are structurally unaffected, and intrude the already folded and faulted country rocks in the northwest half of the map area. Two of the Cretaceous thrusts, including the Talkeetna thrust, are actually intruded by these plutons. A slightly older upper age bracket is provided by the previously discussed 61 to 75 m.y. old tonalite pluton (unit TKt) that cuts and is unaffected by the prominent shear zone in the central Talkeetnas. Thus, the most important orogenic deformation in the Talkeetna Mountains region must have taken place during middle to Late Cretaceous time. Such an age assignment for the orogeny is further supported by potassium-argon age determinations of 88 and 91 m.y. for the serpentinite protrusions in the southwest corner of the map area (unit Kum).

The dominant features of the middle Tertiary to Quaternary deformation are the already mentioned Castle Mountain-Caribou fault systems, along which the southern Talkeetna Mountains have been uplifted locally as much as 2,800 m (Detterman and others, 1976). The only other features of this Cenozoic deformation recognized within the map area are the two poorly exposed normal faults in the Chulitna River valley (see map and cross section). In addition to field observations, the existence of these faults is also supported by gravity data (R. L. Morin, oral commun., 1977; N. B. Harris, oral commun., 1977). No other Cenozoic faults, or any other faults with obvious Recent movement, were observed within the map area.

Tectonics

The Talkeetna Mountains and adjacent areas are part of the dominantly allochthonous terrane of southern Alaska. Previously, this terrane has been interpreted to have developed by accretion of allochthonous continental blocks to the ancient North American plate (Richter and Jones, 1973; Csejtey, 1974) in late Mesozoic time (Csejtey, 1976; Jones and others, 1978). Although the exact number or even the extent of these allochthonous blocks is still imperfectly known, they appear to have moved northward considerable distances prior to their collision with the North American plate. For one of the blocks in eastern Alaska (Wrangellia of Jones and others, 1977), a probable northward movement of several thousand kilometers has been shown by Hillhouse (1977). The results of the present investigations and those of Jones and others (1978) not only lend credence to the accretionary concept of southern Alaska but also provide additional evidence for the time, method, and direction of emplacement.

One of the keys to the tectonic history of the Talkeetna Mountains region, and to southern Alaska as well, is the occurrence of the tectonically emplaced diverse rock packages in the Chulitna area in the northwest part of the map area. Most of the Triassic and Jurassic rocks there, especially the Triassic red beds, do not occur anywhere else in Alaska, and the fossil faunas and lithologic characteristics of these Mesozoic rocks strongly suggest deposition in warm water at low paleolatitudes (Jones and others, 1978). Furthermore, the pre-middle Cretaceous rocks above the Talkeetna thrust, above the root zone of the Chulitna faults, are either structurally part of the allochthonous Wrangellia terrane of Jones and others (1977) or belong to a different terrane lying south (that is outboard) of Wrangellia. Thus, all available evidence strongly indicates that, with the exception of unit Kag, all pre-middle Cretaceous rocks of the Talkeetna Mountains region are allochthonous, and, after the collision of their parent continental blocks with the middle Cretaceous North American continent, they were thrust upon, that is obducted onto the margin of the continent. In turn, the middle Cretaceous Alaskan margin of the continental North American plate itself probably developed by still earlier accretions (D. L. Jones, oral commun., 1977). The distance the allochthonous rocks of the Talkeetna Mountains region were thrusted beyond the edge of the continent is not known with certainty, but it must be at least several hundred kilometers. In accordance with the present obduction concept, all the tectonic and depositional rock assemblages normally associated with the continental upper plate of a subducting system, especially trench deposits and volcanic arc rocks, are now hidden by the overthrust rock masses. Possibly the small tectonic sliver of Upper Jurassic sedimentary and volcanic rocks (unit Js) along the Talkeetna thrust is the only exposed remnant of these hidden assemblages. As shown on the cross section, the main thrust along which most movement presumably occurred is the Talkeetna thrust, and all other thrusts northwest of it are interpreted to be slivers below it.

The northeast-southwest-trending compressional structural features, that is the folding and thrusting, indicate a general northwestward tectonic transport. This is further supported by the sharp character of the suture zone in eastern Alaska, along which the allochthonous rocks of southern Alaska, especially the Wrangellia terrane, are in contact with the pre-middle Cretaceous North American continent. This suture zone in eastern Alaska trends northwesterly and is devoid of the structural complexities of the Chulitna area. This part of the suture, the part southeast of Paxson, which also coincides with the middle Tertiary to Holocene Denali fault, is thus interpreted to have been a transform or a wrench fault. In contrast, the great variety of tectonically juxtaposed rock packages in the Chulitna area may be the result of "bulldozing" by a large continental block drifting toward the northwest.

The age of this orogenic period of continental collision and subsequent obduction is indicated by the age of its structural features, which are discussed in the Structure section, to be middle to Late Cretaceous.

In summary, southern Alaska is interpreted to have developed geologically by the accretion of an indeterminate number of northwestward drifting continental blocks to the North American continent. After collision, at least parts of these blocks were thrust several hundred kilometers onto the North American continent in middle to Late Cretaceous time. The resulting structural features are truly alpine in character and compare favorably with the classic structures of the Alps in their grandeur and complexity.

A corollary of the present tectonic interpretation of southern Alaska is that the present Denali fault, a middle Tertiary and younger feature (Richter and Jones, 1973), has not played a significant role in the tectonic development of southern Alaska. The eastern, that is strike-slip portion of the Denali fault (Csejtey, 1976), may not have more than a few tens of kilometers of total movement.

An interesting, but still unresolved, tectonic problem in the Talkeetna Mountains region is the shallow depth of the present Benioff zone (Lahr, 1975). The 50-km contour (below sea level) for the upper surface of the Benioff zone strikes northeasterly and is approximately below the Jurassic trondhjemite batholith (unit Jtr). The 100-km contour, also striking northeasterly, is located approximately under the northwest corner of the map area. According to plate tectonic concepts, in conjunction with a subducting system, the top of the undergoing slab should descend at least 100 km below sea level for magma generation. It appears that in the Talkeetna Mountains region there is not enough thickness of upper plate for magma to form. For the Jurassic and older igneous rocks the problem can be explained that these rocks are allochthonous and have been tectonically cut off and transported away from their roots. However, for the Upper Cretaceous and younger igneous rocks, this mechanism cannot be invoked. Two explanations are possible. First, that the present shallow position of the Benioff zone is a relatively recent phenomenon achieved by shearing and cutting away of the base of the upper plate by the downgoing slab. Perhaps the development of the present Denali fault and other middle Tertiary and younger faults of southern Alaska could be related to this process. The other possibility is that all the Upper Cretaceous and younger igneous rocks of the Talkeetna Mountains region were formed in a thin upper plate by exceptionally high heat flow of unknown origin and mechanism (atectonic anatexis by Reed and Lanphere, 1974).

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Table 1.--Potassium-argon age determinations from the Talkeetna Mountains quadrangle and the northern part of the Anchorage quadrangle, Alaska

Map no.	Location Lat. (N)	Location Long. (W)	Field No.	Rock type	Mineral dated	K_2O* (weight percent)	$^{40}Ar_{rad}$ $\left(10^{-10}\ \frac{moles}{gram}\right)$	$\frac{^{40}Ar_{rad}}{^{40}Ar_{total}}$	Calculated age*** (millions of years)	Reference
1.	62°59'50"	149°23'48"	75ACy92	Granite (adamellite)	Biotite	7.54(2)	6.218	0.49	57.8±1.7	This report
2.	62°57'25"	148°48'18"	75ACy146	Granodiorite	Biotite	9.08(2)	7.583	0.89	58.6±1.8	This report
3.	62°58'28"	148°25'50"	TT-1-72	Grandiorite	Biotite	--	--	--	58.7±1.7	Turner and Smith (1974)
4.	62°45'46"	149°56'20"	75ACy2	Granite (adamellite)	Biotite	8.68(2)	6.970	0.78	56.3±1.7	This report
5.	62°45'36"	147°18'30"	72ASt290	Diorite or amphibolite	Hornblende	--	--	--	176.6±5.1	Turner and Smith (1974)
6.	62°37'30"	149°24'34"	75ACy7	Granite (adamellite)	Biotite	5.35 (2)	4.468	0.60	58.6±1.8	This report
7.	62°28'38"	149°29'30"	75ASj520	Andesite	Hornblende	0.555(2)	0.4077	0.56	50.4±2.0	This report
8.	62°35'24"	148°53'40"	75ASj521B	Andesite	Whole rock	2.348±0.045(4)	1.757	0.34	51.3±2.5	This report
9.	62°27'28"	148°18'34"	73ACy109	Quartz diorite	Biotite	8.68(2)	18.79	0.92	144±4.3	This report
					Hornblende	0.590(2)	1.365	0.63	154±4.6	This report
10.	62°30'43"	147°52'35"	73ASt275	Trondhjemite	Biotite	--	--	--	148.5±4.3	Turner and Smith (1974)
11.	62°34'55"	147°41'55"	73ASt256	Trondhjemite	Biotite	--	--	--	146.5±4.3	Turner and Smith (1974)
12.	62°18'42"	149°46'32"	73ACy101	Tonalite	Biotite	8.48(2)	6.783	0.83	54.8±1.6	This report
13.	62°16'51"	148°43'26"	75ASj526	Andesite	Whole Rock	0.843(2)	0.6942	0.31	56.3±2.5	This report
14.	62°19'03"	148°10'09"	62AE4	Trondhjemite	Biotite	6.21(2)	13.33	0.91	143±4.3	This report
					Muscovite	9.77(2)	21.49	0.92	146±4.4	This report
15.	62°21'22"	147°49'18"	59AGzM58	Granodiorite	Biotite	--	--	--	174	Grantz and others (1963)
					Hornblende	--	--	--	167±6.0	Detterman and others (1965)

See footnotes at end of table

Table 1.--Continued

Map no.	Location Lat. (N)	Location Long. (W)	Field No.	Rock type	Mineral dated	K_2O* (weight percent)	$^{40}Ar_{rad}$ $\left(10^{-10}\ \frac{moles}{gram}\right)$	$\frac{^{40}Ar_{rad}}{^{40}Ar_{total}}$	Calculated age*** (millions of years)	Reference
17.	62°12'50"	148°06'35"	59AGzH26	Quartz diorite	Biotite	--	--	--	173	Everndsn and others (1961)
					Biotite	--	--	--	170±6	Detterman and others (1965)
					Biotite	--	--	--	161	Grantz and others (1963)
					Hornblende	--	--	--	163±6	Detterman and others (1965)
18.	62°09'00"	149°13'30"	72ACy117	Quartz diorite	Biotite	9.33	9.207	0.79	67.3±2	Csejtey, 1974
					Hornblende	1.042(2)	9.869	0.77	64.6±2	Csejtey, 1974
19.	62°08'46"	149°18'30"	72ACy127	Tonalite	Biotite	9.30	9.055	0.87	66.4±2	Csejtey, 1974
					Hornblende	0.782(2)	0.7371	0.78	64.3±2	Csejtey, 1974
20.	62°06'27"	148°59'44"	73ACy95	Granodiorite	Biotite	9.64(2)	8.705	0.94	61.7±1.9	This report
					Hornblende	1.024(2)	1.071	0.88	71.3±2.1	This report
21.	62°04'51"	148°45'58"	73ACy114	Trondhjemite	Biotite	9.70(2)	9.643	0.88	67.8±2.0	This report
22.	62°04'49"	148°30'29"	73ACy115	Trondhjemite	Muscovite	9.91(2)	19.98	0.93	135±4.0	This report
					Biotite	9.62(2)	14.16	0.97	99.4±3.0	This report
23.	62°04'38"	149°11'14"	73ACy94	Tonalite	Biotite	9.46(2)	8.593	0.81	61.7±1.9	This report
					Hornblende	0.970(2)	0.8669	0.71	61.0±1.8	This report
24.	61°59'18"	149°25'00"	75ACy135	Granodiorite	Muscovite	10.64(2)	10.21	0.72	67.2±2.0	This report
					Biotite	9.68(2)	9.025	0.67	65.0±2.0	This report
25.	61°56'31"	148°59'38"	73ACy97	Quartz diorite	Biotite	8.70(2)	8.594	0.83	67.4±2.0	This report
					Hornblende	0.918(2)	0.9669	0.72	71.8±2.2	This report
26.	61°56'47"	148°41'04"	74ACy146	Trondhjemite	Muscovite	3.46(2)	6.680	0.69	129±3.9	This report
27.	61°59'33"	148°26'15"	74ACy149	Granodiorite	Biotite	8.06(2)	20.44	0.89	168±5.0	This report
28.	61°49'36"	149°14'30"	60AGz40	Tonalite	Hornblende	0.759(2)	0.8153	0.74	73.1±2.2	This report

See footnotes at end of table

Table 1.--Continued

Map no.	Location Lat.(N)	Long.(W)	Field no.	Rock type	Mineral dated	K_2O* (weight percent)	$^{40}Ar_{rad}$ $\left(10^{-10}\frac{\text{moles}}{\text{gram}}\right)$	$\frac{^{40}Ar_{rad}}{^{40}Ar_{total}}$	Calculated age*** (millions of years)	Reference
29.	61°48'48"	149°12'48"	66AGzW2	Tonalite	Biotite	8.61(2)	8.711	0.89	69.0±2.1	This report
					Hornblende	0.880(2)	0.9475	0.86	73.3±F2.2	This report
30.	61°47'12"	149°13'06"	66AGzW4	Tonalite	Biotite	7.22(2)	7.624	0.91	72.0±2.2	This report
					Hornblende	0.492±0.003(3)	0.5374	0.41	74.4±2.2	This report
31.	61°49'38"	148°53'50"	74ACy151	Trondhjemite	Muscovite	10.58(2)	21.23	0.95	134±4.0	This report
32	61°45'03"	149°25'08"	73ACy17	Serpentinite	Actinolite	0.032**	0.04194	0.064	88.9±4.4	This report
33.	61°43'00"	149°32'30"	73ACy85	Muscovite schist	Muscovite	8.34(2)	7.189	0.85	59.0±1.8	This report
34.	61°43'50"	149°26'05"	73ACy27	Muscovite schist	Muscovite	8.86(2)	8.554	0.89	65.9±3.0	This report
35.	61°44'32"	149°25'28"	73ACy11a	Muscovite schist	Muscovite	9.10(2)	7.928	0.84	59.6±1.8	This report
36.	61°44'03"	149°23'37"	74ASj100a	Serpentinite	Actinolite	0.029**	0.03897	0.10	91.0±4.6	This report
37.	61°46'20"	149°10'20"	76ACy19	Metamorphosed graywacke	Biotite	1.078(2)	1.067	0.45	67.5±2.4	This report

*Mean and, where more than two measurements were made, standard deviation. Number of measurements is in parentheses.
**Potassium determined by isotope dilution. Potassium determined by flame photometry for other samples.
***$\lambda_e = 0.572 \times 10^{-10} yr^{-1}$, $\lambda'_e = 8.78 \times 10^{-13} yr^{-1}$, $\lambda\beta = 4.963 \times 10^{-10} yr^{-1}$. $^{40}K/K = 1.167 \times 10^{-4}$ mol/mol. The ± figures are estimates of analytical precision at the 68 percent level of confidence. All previously published ages were recalculated using these decay constants. For this report, potassium analyses were done by L. B. Schlocker, G. E. Ambats, J. G. Smith, H. C. Whitehead, S. T. Neil, and M. L. Silberman; and argon measurements were done by M. A. Lanphere, J. C. von Essen, A. L. Berry, B. H. Myers, S. E. Sims, J. G. Smith, and M. L. Silberman.

Table 2.--*Lead-alpha age determinations on zircon from southeastern part of Talkeetna Mountains quadrangle, Alaska*

Map no.	Location		Field no.	Rock type	Apparent age (m.y.)	References
	Lat. (N)	Long. (W)				
15	62°21'22"	147°49'18"	59AGzM58	Granodiorite	165$\pm$20	Grantz and others (1973)
16	62°21'17"	147°49'12"	59AGzM57	Granodiorite	125$\pm$15	Grantz and others (1973)

Table 3.--*List of fossils from selected map units (units TRv, Pls, and DSls) in the northwest half of the Talkeetna Mountains quadrangle and the southwest corner of the Healy quadrangle, Alaska*

Map number and map unit	Field number	Fossils	Age	Identification and age determination	Reference
1 TRv	73ASt-63	*Halobia* cf. *H. symmetrica* Smith	Latest Karnian or Early Norian	K. M. Nichols and N. J. Silberling	T. E. Smith, written commun., 1974.
2 Pls	76ACy-47	Crinoid columnals 2 cm in diameter; echinoderm and brachiopod debris, indet.	Late Paleozoic	D. L. Jones	This report.
3 Pls	73ASt-1400	Echinoderm debris, indet. Platycrinitid, indet. (partial cup and columnals). Horn coral, indet. Fenestrate and ramose bryozoans, indet. (abundant). *Sulcoretepora*? sp. Rhynchonelloid brachiopod, indet. Productoid brachiopod (large, indeterminate). Spiriferoid brachiopod (perhaps *Spiriferella*). Martinioid brachiopod (perhaps *Pseudomartinia*). Phricodothyrid brachiopod fragments, indet. Punctate brachiopod (perhaps *Hustedia*). Pelecypods, indet. (several kinds). Pectenoid pelecypods, indet.	Late Paleozoic, probably Permian	T. J. Dutro, Jr.	T. E. Smith, written commun., 1974.
4 Pls	72ACy-15, 72ACy-21	Crinoid columnals as much as 1.6 cm in diameter. Bryozoan, indet. Brachiopod and coral fragments.	Probably late Paleozoic	A. K. Armstrong	Csejtey, 1974.
5 Pls	73ASt-309	Echinoderm debris, indet. Fenestrate and ramose bryozoans, indet. Horn coral, indet. Productoid brachiopod (indeterminate).	Late Paleozoic, possibly Permian	J. T. Dutro, Jr.	T. E. Smith, written commun., 1974.
6 Pls	74ACy-7	Crinoid columnals 1 cm in diameter.	Probably Paleozoic	A. K. Armstrong	This report.
7 Pls	75ANw-10	*Horridonia*? sp. Spiriferoid brachiopod. Crinoid columnals as much as 1.5 cm in diameter.	Late Paleozoic, probably Permian	A. K. Armstrong	-----Do.----
8 Pls	74ACy-16	*Arctitreta* sp. *Horridonia* sp. *Spiriferella* sp. Echinoderm debris, indet. Crinoid columnals as much as 2.5 cm in diameter.	Early Permian	J. T. Dutro, Jr.	Csejtey, 1976.
9 Pls	74ACy-80	Crinoid columnals as much as 1.5 cm in diameter.	Probably Paleozoic	A. K. Armstrong	This report.
10 Pls	74ACy-21	Crinoid columnals as much as 1 cm in diameter.	------do-------	-------do------	-----Do.----
11 Pls	74ACy-43	-----------------do----------------	------do-------	-------do------	-----Do.----
12 DSls	75ANw-75	*Dendrostella*? sp. Massive stromatoporoid, indet.	Devonian, probably Middle Devonian	W. A. Oliver, Jr.	-----Do.----
13 DSls	75ANw-76	*Labechia* sp. *Favosites* sp.	Silurian or Devonian	--------do--------	-----Do.----

SECTION E

ENVIRONMENTAL ASSESSMENT

TABLE OF CONTENTS

INTRODUCTION

In the almost 4 years since the original environmental assessment (EA) was prepared, much new information has been made available through the efforts of various Federal and State agencies. Some of the information would result in minor changes in the EA if incorporated. These minor changes would not substantially alter the reader's perception of the proposed project or its environmental impacts. Such information has therefore not been incorporated in this supplement. Some of the new information, however, could substantially alter the reader's perception of the proposed project or its environmental impacts. This type of new information has been summarized in this supplement. It should be noted, however, that the information obtained to date is only preliminary and lacks needed details and that additional biological and social information remains to be gathered in the future in order to complete an adequate and meaningful assessment of environmental impacts.

SUMMARY OF CHANGES

There is new biological information related to moose. In general, moose occupy the upper Susitna River basin to a greater degree than previously thought.

Also, archeological studies conducted by the Alaska District have resulted in archeological finds of potentially significant cultural value.

As a result of this new information, the potential for additional environmental impacts has been recognized, and the importance of previously identified impacts has been reevaluated. Impacts to moose will probably be far more significant than previously believed. Impacts on archeological resources could be potentially significant if not properly mitigated.

A discussion of the recognition of the need for a Section 404(b) evaluation has been added to address the requirements of the Federal Water Pollution Control Act and the Clean Water Act. An evaluation of flood plain considerations as per Executive Order 11988 has also been added.

Land use is in a constant state of change because of the Alaska Native Claims Settlement Act, the Federal Land Policy and Management Act, and various other regulations related to wilderness. A short update on these land use considerations has been added.

BIOLOGICAL CHARACTERISTICS

Mammals - Moose

Moose range throughout the entire Susitna River basin, and their numbers in the basin have fluctuated widely since the early 1900's. The population reached a peak in the early 1960's, then began a decline that has continued to the present time. Factors contributing to the decline have included loss of productive browse habitat as a result of effective fire suppression over the past two decades, a rapid increase in predator populations following cessation of control efforts in the mid-1950's, and a number of severe winters with deep accumulations of snow.

The preliminary movement data gathered thus far by the Alaska Department of Fish and Game (ADF&G) indicate that moose from several surrounding areas migrate across or utilize the portion of the upper Susitna River basin adjacent to the river during some portion of the year. ADF&G recorded observations of 2,037 moose during the fall 1977 counts. Studies indicate that an observer generally sees between 43 to 68 percent of the moose in an area during an aerial survey. Using 50 percent to extrapolate roughly, the resident population using the upper Susitna basin probably falls between 4,000 and 5,000 moose. This is a substantial increase when compared with 1973 figures which estimated the upper basin population at approximately 1,800 animals. This wide diversity in population estimates can be attributed to better research techniques and improved population estimating methods.

Present information indicates that moose depend heavily upon the river bottom and adjacent areas for winter habitat and calving areas, both above and below the Watana and Devil Canyon damsites. Increasing snow depths above timberline trigger moose migrations to the wintering areas in the lowlands. Additional observations of moose during normal and severe winter conditions are necessary to determine the importance of the area as critical winter range.

CULTURAL CHARACTERISTICS

Archeological Resources

An archeological reconnaissance was conducted by the Corps of Engineers in 1978 for the purpose of clearing specific sites within the project area so that geological investigations could be conducted. Four sites were found in the Watana damsite area which range in age from 3,700 to 12,000 years old. These sites, generally located on top of small knolls, were probably associated with the hunting activities of primitive man. No base camps or kill sites were found but they must also exist. The number of sites found shows that the potential for other finds is extremely high and indicates that prehistoric use of the area appears to have been considerable. At the present time, the sites found have not been nominated for inclusion on the National Register.

ENVIRONMENTAL IMPACTS OF THE DEVIL CANYON - WATANA HYDROPOWER PLAN

MAMMALS - MOOSE

According to ADF&G surveys conducted in 1977, construction of the Watana dam would have a highly detrimental effect on moose populations in that inundation of the lower, spruce-covered reaches of the Watana Creek valley, which are probably critical moose habitat, would substantially reduce the carrying capacity of the area. In addition, construction of the Devil Canyon dam would also adversely impact moose populations and substantially reduce the carrying capacity of a major portion of the Devil Creek drainages. The Devil Canyon impacts are not expected to be as significant as the Watana impacts because of the marginal habitat and limited moose populations in the Devil Canyon area.

Present information indicates moose depend heavily upon the river bottoms and adjacent areas for winter habitat both above and below the Watana and Devil Canyon damsites. Lack of adequate wintering areas in the lower Susitna valley below the Devil Canyon damsite has been a major limiting factor to moose population growth in the past. Most existing winter range is along the major rivers where periodic flooding has caused rechanneling of the main stream, allowing riparian willow to colonize the dry streambeds. Regulating the flow of water from the dam at Devil Canyon may have a highly detrimental effect on growth of riparian vegetation downstream to the mouth of the Susitna. It is possible that maintaining a steady flow of 8,000 to 10,000 cubic feet per second from the Devil Canyon dam would effectively prevent the flooding activity that presently occurs periodically. This could create a short-term abundance of winter range along the riverbanks that might last 30 or more years. The net long-term effect could well be a negative one, however, as it is suspected that the present natural flooding activity of the Susitna River produces favorable conditions for browse production. Without the annual floods, these riparian areas could become mature stands of hardwoods after 25 or 30 years and provide little or no winter forage. Research on riparian vegetation habitat types and associated moose usage downstream of dam construction is essential to determine potential impacts on moose populations.

Construction of the Devil Canyon dam would flood approximately 7,500 acres. The riverbanks along this portion of the river are generally steep and provide marginal moose habitat. Since water levels in the Devil Canyon reservoir will remain fairly constant, low mortality rates associated with ice shelving and steep mudbanks would be expected.

Construction of the Watana dam would result in the flooding of approximately 43,000 acres along Watana Creek and the Susitna River. Approximately 35,000 acres sustain moderate to heavy utilization by moose during an average winter. Data gathered by ADF&G indicate that moose from several surrounding areas of the Susitna basin migrate across or utilize this portion of the river during some period of the year. Effects of the construction of the Watana dam on moose populations could be substantial. The resident nonmigratory segment of the population could be eliminated. Migratory moose could also be substantially effected in that the reservoir could be an effective barrier to migrations during some seasons. Due to large fluctuating water levels, ice shelving and steep mud banks could be expected to cause high mortality among moose, especially calves.

This discussion of impacts on moose populations within the upper Susitna River basin is substantially different from the discussion contained in the 1976 Interim Feasibility Report, which predicted that the proposed project "would affect only a small percentage of the upper Susitna moose population." The newly gathered information has resulted in the reevaluation of previously identified impacts and the recognition that additional impacts potentially exist which may be important.

ARCHEOLOGICAL RESOURCES

An archeological reconnaissance conducted by the Corps of Engineers in 1978 resulted in the finding of several previously unknown archeological sites in the Watana damsite area. This reconnaissance indicates that the potential for other finds is extremely high. Intensive archeological surveys will be conducted during the project feasibility analysis to conform with cultural resource regulations. If the project is determined to be feasible, a program will be conducted to salvage archeological sites which will be impacted by the project.

SECTION 404(b) EVALUATION

To date a Section 404(b) evaluation (Discharge of Dredged or Fill Materials into Waters of the United States) under the Federal Water Pollution Control Act of 1972 (Public Law 92-500) as ammended has not been performed. A 404(b) evaluation will be performed with data gathered during the project feasibility analysis.

EXECUTIVE ORDER 11988 (FLOOD PLAIN) EVALUATION

In compliance with Executive Order 11988 the items under Paragraph 8 of General Procedures have been considered as follows:

1. The project is designed to impound water behind two dams in the natural channel of the river. The basic conditions of this hydropower project present no economically feasible alternatives.

2. The construction of the project will cause only minor induced development in the immediate area since the product (energy) will be transmitted to existing population centers far removed from the project site.

3. The natural and beneficial values of the flood plain will be disrupted only at the site of the reservoir and powerplant. Revegetation programs will be adopted to restore slopes along construction sites and roadways.

4. As the project progresses from its initial phase to the design and construction phases, there will be a continuing evaluation and dialogue with local interests and concerned agencies who will have constant input to the study.

RELATIONSHIP OF THE PROPOSED DEVELOPMENT TO LAND USE PLANS

Lands within the upper Susitna River basin are essentially in large block ownership with the majority under the control of the Department of the Interior, Bureau of Land Management (BLM). These lands are generally in their natural state and undeveloped with improvements or land access routes. Air transportation is the primary means of access to and within the area. There are some scattered small parcels of land in private ownership as homestead sites or mining claims. Many of these private parcels have no developed overland access. For the most part, development in the area is concentrated along the established transportation routes such as the Parks Highway and the Alaska Railroad on the west and the Denali Highway on the north.

Because of the absence of roads and other development in the basin, the area is subject to Section 603 of P.L. 94-579, "The Federal Land Policy and Management Act of 1976." This section provides for the protection and study by BLM of roadless areas of public land containing 5,000 or more acres. The intent is the protection of potential wilderness area values pending a determination of the ultimate classification and use of such lands. During the allotted 15 year study period, any use of the lands is subject to BLM authorization and must be conducted "...in a manner so as not to impair the suitability of such areas for preservation as wilderness...". Consequently, any development or construction in the area would be precluded pending a determination and classification by BLM.

Most of the public lands in the basin have been selected by Native corporations under the Alaska Native Claims Settlement Act (ANCSA), as amended of 18 December 1971. These selected lands remain under the jurisdiction of BLM pending final conveyance of fee simple title to the various Native corporations. Any use of these lands prior to conveyance of title is subject to specific permission from BLM with the concurrence of the various concerned Native groups.

The gross land area required (lands which must be acquired) for containment of the proposed Devil Canyon and Watana reservoirs is approximately 157,440 acres. Of this land, 67,200 acres are to be conveyed to the Cook Inlet Region, Incorporated (CIRI) for later reconveyance to various village corporations. This transfer of lands is directed by a 1976 amendment to ANCSA, P.L. 94-456 and will include both the surface and subsurface interests. This transfer also includes lands within Power Site Classification No. 443 which was established in 1958 for potential future development of the Susitna River for hydroelectric power production.

In addition to the lands discussed above, as many as 53,760 acres have been selected for conveyance to satisfy any deficiencies that may exist in total acreage entitlements under ANCSA. These "deficiency" selections in the area have a selection priority of nine (9) and, in all probability, will not be conveyed to CIRI on behalf of the village corporations. These lands have, however, been overselected by CIRI for its own benefit and could conceivably be conveyed to CIRI. A portion of these lands south of the Susitna River (24,686 acres) has been made available for selection by the State of Alaska pursuant to the agreement titled "Terms and Conditions for Land Consolidation and Management in the Cook Inlet Area" (Cook Inlet Land Swap Agreement). The State's right to select these lands for conveyance is superior to that of CIRI but is inferior to valid village corporation selections. Since the village corporation selections are priority nine (9) it is probable that the State could receive the title to the lands.

The remaining area within the proposed reservoir boundaries (36,480 acres) is controlled by BLM and has been withdrawn from appropriation for either study and classification or for selection by CIRI as a "deficiency" selection area. Again, this "deficiency" selection is an excess, or overselection, to make lands available for satisfaction of total acreage entitlements. Conveyance of any portion of such selected lands is limited to fulfillment of acreage entitlements and is indeterminable at this time. As discussed above, the State of Alaska will have a right to select a portion of this area south of the Susitna River (5,120 acres), and such a selection would be superior to that of CIRI.

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SECTION F

RECREATIONAL ASSESSMENT

None of the OMB comments were directed at the recreational aspects of the project. Therefore, no additional recreation studies were undertaken.