BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SUSITNA HYDROELECTRIC PROJECT

VOLUME 2

D R A F T

EXHIBIT B

HARZA-EBASCO
SUSITNA JOINT VENTURE

Alaska Power Authority

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

APPLICATION FOR LICENSE FOR MAJOR PROJECT

SUSITNA HYDROELECTRIC PROJECT
DRAFT LICENSE APPLICATION

VOLUME 2

EXHIBIT B
PROJECT OPERATION AND RESOURCE UTILIZATION

November 1985

NOTICE

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

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

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

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

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

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

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VOLUME NUMBER COMPARISON

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1 - DAMSITE SELECTION (o)

This section summarizes the previous site selection studies and the studies done during the Alaska Power Authority Susitna Hydroelectric Project Feasibility Study (Acres 1982c, Vol. 1).

1.1 - Previous Studies (*)

Prior to the undertaking of the Susitna Hydroelectric Project Feasibility Study by the Applicant, the hydroelectric development potential of the Alaskan Railbelt had been studied by several entities.

1.1.1 - Early Studies of Hydroelectric Potential (*)

Shortly after World War II ended, the United States Bureau of Reclamation (USBR) conducted an initial investigation of hydroelectric potential in Alaska and issued a report of the results in 1948. Responding to a recommendation made in 1949 by the nineteenth Alaska territorial legislature that Alaska be included in the Bureau of Reclamation program, the Secretary of the Interior provided funds to update the 1948 work. The resulting report, issued in 1952, recognized the vast hydroelectric potential within the territory and placed particular emphasis on the strategic location of the Susitna River between Anchorage and Fairbanks as well as its proximity to the connecting Railbelt (Figure B.1.1.1).

A series of studies was commissioned over the years to identify damsites and conduct geotechnical investigations. By 1961, the Department of the Interior proposed authorization of a two-dam power system on the Susitna River involving the Devil Canyon and the Denali sites (Figure B.1.1.2). The definitive 1961 report was subsequently updated by the Alaska Power Administration (an agency of the USBR) in 1974, at which time the desirability of proceeding with hydroelectric development was reaffirmed.

The Corps of Engineers (COE) was also active in hydropower investigations in Alaska during the 1950s and 1960s, but focused its attention on a more ambitious development at Rampart on the Yukon River. This project was capable of generating five times as much annual electric energy as the prior Susitna proposal. The sheer size and the technological challenges associated with Rampart captured the imagination of supporters and effectively diverted attention from the Susitna basin for more than a decade. The Rampart report was finally shelved in the early 1970s because of strong environmental concerns and the uncertainty of marketing prospects for so much energy, particularly in light of abundant natural gas which had been discovered and developed in Cook Inlet.

The energy crisis precipitated by the OPEC oil boycott in 1973 provided some further impetus for seeking development of renewable resources. Federal funding was made available both to complete the Alaska Power Administration's update report on Susitna in 1974 and to launch a prefeasibility investigation by the COE. The State of Alaska itself commissioned a reassessment of the Susitna project by the Henry J. Kaiser Company in 1974.

Salient features of the various reports to date are outlined in the following sections.

1.1.2 - U.S. Bureau of Reclamation - 1953 Study (*)

The USBR 1952 report to the Congress on Alaska's overall hydroelectric potential was followed shortly by the first major study of the Susitna basin in 1953. Ten damsites were identified above the railroad crossing at Gold Creek. These sites are identified on Figure B.1.1.2, and are listed below:

- Gold Creek
- Olson
- Devil Canyon
- Devil Creek
- Watana
- Vee
- Maclaren
- Denali
- Butte Creek
- Tyone (on the Tyone River).

Fifteen more sites were considered below Gold Creek. However, more attention has been focused over the years on the upper Susitna basin, where the topography is better suited to dam construction and where less impact on anadromous fisheries is expected. Field reconnaissance eliminated half the original upper basin list, and further USBR consideration centered on Olson, Devil Canyon, Watana, Vee, and Denali. All of the USBR studies since 1953 have regarded these sites as the most appropriate for further investigation.

1.1.3 - U.S. Bureau of Reclamation - 1961 Study (*)

In 1961 a more detailed feasibility study resulted in a recommended five-stage development plan to match the load growth curve as it was then projected. Devil Canyon was to be the first development--a 635-foot high arch dam with an installed capacity of about 220 MW. The reservoir formed by the Devil Canyon Dam alone would not store enough water to permit higher capacities to be economically installed, since long periods of relatively low flow occur in the winter months. The second stage would have increased storage capacity by adding an earthfill dam at Denali in the upper reaches of the basin. Subsequent stages involved adding generating capacity to the Devil Canyon Dam. Geotechnical investigations at Devil Canyon were more thorough than at Denali. At Denali, test pits were dug, but no drilling occurred.

1.1.4 - Alaska Power Administration - 1974 Study (*)

Little change from the basic USBR 1961, five-stage concept appeared in the 1974 report by the Alaska Power Administration. This later effort offered a more sophisticated design, provided new cost and schedule estimates, and addressed marketing, economics, and environmental considerations.

1.1.5 - Kaiser Proposal for Development (*)

The Kaiser study, commissioned by the Office of the Governor in 1974, proposed that the initial Susitna development consist of a single dam known as High Devil Canyon (for location, see Figure B.1.1.2). No field investigations were made to confirm the technical feasibility of the High Devil Canyon location because the funding level was insufficient for such efforts. Visual observations suggested the site was probably favorable. The USBR had always been uneasy about foundation conditions at Denali, but had to rely upon the Denali reservoir to provide storage during long periods of low flow. Kaiser chose to avoid the perceived uncertainty at Denali by proposing to build a rockfill dam at High Devil Canyon which, at a height of 810 feet, would create a large enough reservoir to overcome the storage problem. Although the selected sites were different, the COE reached a similar conclusion when it later chose the high dam at Watana as the first to be constructed.

Subsequent developments suggested by Kaiser included a downstream dam at the Olson site and an upstream dam at a site known as Susitna III (Figure B.1.1.2). The information developed for these additional dams was confined to estimated energy potential. As in the COE study, future development of Denali remained a possibility if foundation conditions were found to be adequate and if the value of additional firm energy provided economic justification at some later date.

1.1.6 - U.S. Army Corps of Engineers - 1975 and 1979 Studies (*)

The most comprehensive study of the upper Susitna basin prior to the current study was completed in 1975 by the COE. A total of

23 alternative developments were analyzed, including those proposed by the USBR, as well as consideration of coal as the primary energy source for Railbelt electrical needs. The COE agreed that an arch dam at Devil Canyon was appropriate, but found that a high dam at the Watana site would form a large enough reservoir for seasonal storage and would permit continued generation during low flow periods.

The COE recommended an earthfill dam at Watana with a height of 810 feet. In the longer term, development of the Denali site remained a possibility which, if constructed, would increase the amount of firm energy available in dry years.

An ad hoc task force was created by Governor Jay Hammond upon completion of the 1975 COE study. This task force recommended endorsement of the COE request for Congressional authorization, but pointed out that extensive further studies, particularly those dealing with environmental and socioeconomic questions, were necessary before any construction decision could be made.

At the federal level, concern was expressed at the Office of Management and Budget regarding the adequacy of geotechnical data at the Watana site as well as the validity of the economics. The apparent ambitiousness of the schedule and the feasibility of a thin arch dam at Devil Canyon were also questioned. Further investigations were funded and the COE produced an updated report in 1979. Devil Canyon and Watana were reaffirmed as appropriate sites, but alternative dam types were investigated. A concrete gravity dam was analyzed as an alternative for the thin arch dam at Devil Canyon and the Watana Dam was changed from earthfill to rockfill. Subsequent cost and schedule estimates still indicated economic justification for the project.

1.2 - Plan Formulation and Selection Methodology (*)

The proposed plan which is the subject of this License Application was selected after a review and reassessment of all previously considered sites (Acres 1982c, Vol. 1).

This section of the report outlines the engineering and planning studies carried out as a basis for formulation of Susitna basin development plans and selection of the preferred plan.

In the description of the planning process, certain plan components and processes are frequently discussed. It is appropriate that three particular terms be clearly defined:

- Damsite - An individual potential damsite in the Susitna basin, referred to in the generic process as "candidate."

- Basin Development Plan - A plan for developing energy within the upper Susitna basin involving one or more dams, each of specified height, and corresponding power plants of specified capacity. Each plan is identified by a plan number and subnumber indicating the staging sequence to be followed in developing the full potential of the plan over a period of time.

- Generation Scenario - A specified sequence of implementation of power generation sources capable of providing sufficient power and energy to satisfy an electric load growth forecast for the 1980-2010 period in the Railbelt area. This sequence may include different types of generation sources such as hydroelectric and coal-, gas- or oil-fired thermal. These generation scenarios were developed for the comparative evaluations of Susitna basin generation versus alternative methods of generation.

In applying the generic plan formulation and selection methodology, five basic steps are required: defining the objectives, selecting candidates, screening, formulation of development plans, and, finally, a detailed evaluation of the plans (Figure B.1.2.1). The objective is to determine the optimum Susitna basin development plan. The various steps required are outlined in subsections of this section.

Throughout the planning process, engineering layout studies were made to refine the cost estimates for power generation facilities or water storage development at several damsites within the basin. These data were fed into the screening and plan formulation and evaluation studies.

The second objective, the detailed evaluation of the various plans, is satisfied by comparing generation scenarios that include the selected Susitna basin development plan with alternative generation scenarios, including all-thermal and a mix of thermal plus alternative hydropower developments.

1.3 - Damsite Selection (*)

In previous Susitna basin studies, twelve damsites were identified in the upper portion of the basin, i.e., upstream from Gold Creek. These sites are listed in Table B.1.3.1 with relevant data concerning facilities, cost, capacity, and energy.

The longitudinal profile of the Susitna River and typical reservoir levels associated with these sites are shown in Figure B.1.3.1. Figure B.1.3.2 illustrates which sites are mutually exclusive, i.e., those which cannot be developed jointly, since the downstream site would inundate the upstream site.

It can be readily seen that there are several mutually exclusive schemes for power development of the basin. The development of the

Watana site precludes development of High Devil Canyon, Devils Creek, Susitna III and Vee but fits well with Devil Canyon. Conversely, the High Devil Canyon site would preclude Watana and Devil Canyon but fits well with Olson and Vee or Susitna III. These downstream sites do not preclude development of the upstream storage sites, Denali or Butte Creek and Maclaren.

All relevant data concerning dam type, capital cost, power, and energy output were assembled and are summarized in Table B.1.3.1. For the Devil Canyon, High Devil Canyon, Watana, Susitna III, Vee, Maclaren, and Denali sites, conceptual engineering layouts were produced and capital costs were estimated based on calculated quantities and unit rates. Detailed analyses were also undertaken to assess the power capability and energy yields. At the Gold Creek, Devil Creek, Olson, Butte Creek, and Tyone sites, no detailed engineering or energy studies were undertaken; data from previous studies were used with capital cost estimates updated in 1980 levels. Approximate estimates of the potential average energy yield at the Butte Creek and Tyone sites were undertaken to assess the relative importance of these sites as energy producers.

The data presented in Table B.1.3.1 show that Devil Canyon, High Devil Canyon, and Watana are the most economic large energy producers in the basin. Sites such as Vee and Susitna III have only medium energy production, and are slightly more costly that the previously mentioned damsites. Other sites such as Olson and Gold Creek are competitive provided they have additional upstream regulation. Sites such as Denali and Maclaren produce substantially higher cost energy than the other sites but can also be used to increase regulation of flow for downstream use.

1.3.1 - Site Screening (*)

The objective of this screening process was to eliminate sites which would obviously not be included in the initial stages of the Susitna basin development plan and which, therefore, did not deserve further study at this stage. Three basic screening criteria were used: environmental, alternative sites, and energy contribution.

The screening process involved eliminating all sites falling in the unacceptable environmental impact and alternative site categories. Those failing to meet the energy contribution criteria were also eliminated unless they had some potential for upstream regulation. The results of this process were as follows:

- The "unacceptable site" environmental category eliminated the Gold Creek, Olson, and Tyone sites.

- o The alternative sites category eliminated the Devil Creek and Butte Creek sites.

- o No additional sites were eliminated for failing to meet the energy contribution criteria. The remaining sites upstream from Vee, i.e., Maclaren and Denali, were retained to insure that further study be directed toward determining the need and viability of providing flow regulation in the headwaters of the Susitna.

1.3.2 - Engineering Layouts (*)

In order to obtain a uniform and reliable data base for studying the seven sites remaining, it was necessary to develop engineering layouts and reevaluate the costs. In addition, staged developments at several of the larger dams were studied.

The basic objective of these layout studies was to establish a uniform and consistent development cost for each site. These layouts are consequently conceptual in nature and do not necessarily represent optimum project arrangements at the sites. Also, because of the lack of geotechnical information at several of the sites, judgmental decisions had to be made on the appropriate foundation and abutment treatment. The relative accuracy of cost estimates made in these studies is on the order of plus or minus 30 percent.

(a) Design Assumptions (*)

In order to maximize standardization of the layouts, a set of basic design assumptions was developed. These assumptions covered geotechnical, hydrologic, hydraulic, civil, mechanical, and electrical considerations and were used as guidelines to determine the type and size of the various components within the overall project layouts. As stated previously, other than at Watana, Devil Canyon, and Denali, little information regarding site conditions was available. Broad assumptions were made on the basis of the limited data, and those assumptions and the interpretation of data have been conservative.

It was assumed that the relative cost differences between rockfill and concrete dams at the site would either be marginal or greatly in favor of the rockfill. The more detailed studies carried out subsequently for the Watana and Devil Canyon sites support this assumption. Therefore, a rockfill dam has been assumed at all developments in order to eliminate cost discrepancies that might result from a consideration of dam-fill unit costs compared to concrete unit costs at alternative sites.

(b) General Arrangements (*)

Brief descriptions of the general arrangements developed for the various sites are given below. Descriptions of Watana and Devil Canyon in this section are of the preliminary layouts and should not be confused with the proposed layouts in Exhibit A and Exhibit F. Figures B.1.3.3 to B.1.3.9 illustrate the layout details. Table B.1.3.3 summarizes the crest levels and dam heights considered.

In laying out the developments, conservative arrangements have been adopted, and whenever possible there has been a general standardization of the component structures.

(i) Devil Canyon (Figure B.1.3.3) (*)

The development at Devil Canyon, located at the upper end of the canyon at its narrowest point, consists of a rockfill dam, single spillway, power facilities incorporating an underground powerhouse, and a tunnel diversion.

The rockfill dam would rise above the valley on the south abutment and terminate in an adjoining saddle dam of similar construction. The dam would be 675 feet above the lowest foundation level with a crest elevation of 1,470 and a volume of 20 million cubic yards.

The spillway would be located on the north bank and would consist of a gated overflow structure and a concrete-lined chute linking the overflow structure with intermediate and terminal stilling basins. Sufficient spillway capacity would be provided to pass the Probable Maximum Flood safely.

The power facilities would be located on the north abutment. The massive intake structure would be founded within the rock at the end of a deep approach channel and would consist of four integrated units, each serving individual tunnel penstocks. The powerhouse would house four 150-MW vertically mounted Francis type turbines driving overhead 165-MVA synchronous generators.

As an alternative to the full power development in the first phase of construction, a staged powerhouse alternative was also investigated. The dam would be completed to its full height but with an initial plant installed capacity in the 300-MW range. The complete powerhouse would be constructed together with penstocks and a tailrace tunnel for the initial two 150-MW units, together with concrete foundations for future units.

(ii) Watana (Figures B.1.3.4 and B.1.3.5) (*)

For initial comparative study purposes, the dam at Watana is assumed to be a rockfill structure located on a similar alignment to that proposed in the previous COE studies. It would be similar in construction to the dam at Devil Canyon with an impervious core founded on sound bedrock and an outer shell composed of blasted rock excavated from a single quarry located on the south abutment. The dam would rise 880 feet from the lowest point on the foundation and have an overall volume of approximately 63 million cubic yards for a crest elevation of 2,225.

The spillway would be located on the north bank and would be similar in concept to that at Devil Canyon with intermediate and terminal stilling basins.

The power facilities located within the south abutment with similar intake, underground powerhouse, and water passage concepts to those at Devil Canyon would incorporate four 200-MW turbine/generator units giving a total output of 800 MW.

As an alternative to the initial full development at Watana, staging alternatives were investigated. These included staging of both dam and powerhouse construction. Staging of the powerhouse would be similar to that at Devil Canyon, with a Stage I installation of 400 MW and a further 400 MW in Stage II.

In order to study the alternative dam staging concept, it was assumed that the dam would be constructed for a maximum operating water surface elevation some 200 feet lower than that in the final stage (Figure B.1.3.5).

The powerhouse would be completely excavated to its final size during the first stage. Three oversized 135-MW units would be installed together with base concrete for an additional unit. A low-level control structure and twin concrete-lined tunnels leading into a downstream stilling basin would form the first stage spillway.

For the second stage, the dam would be completed to its full height, the impervious core would be appropriately raised, and additional rockfill would be placed on the downstream face. It was assumed that, before construction commenced, the top 40 feet of the first stage dam would be removed to ensure the complete integrity of the impervious core for the raised dam. A second spillway control structure would be constructed at a higher level and would incorporate a downstream chute leading to the Stage I spillway structure. The original spillway tunnels would be closed with concrete plugs. A new intake structure would be constructed utilizing existing gates and hoists, and new penstocks would be driven to connect with the existing ones. The existing intake would be sealed off. One additional 200-MW unit would be installed and the required additional penstock and tailrace tunnel constructed. The existing 135-MW units would be upgraded to 200 MW.

(iii) High Devil Canyon (Figure B.1.3.6) (*)

The development would be located between Devil Canyon and Watana. The 855-foot high rockfill dam would be similar in design to Devil Canyon, containing an estimated 48 million cubic yards of rockfill with a crest elevation of 1,775. The south bank spillway and the north bank powerhouse facilities would also be similar in concept to Devil Canyon, with an installed capacity of 800 MW.

Two stages of 400 MW were envisaged, each of which would be undertaken in the same manner as at Devil Canyon, with the dam initially constructed to its full height.

(iv) Susitna III (Figure B.1.3.7) (*)

The development would involve a rockfill dam with an impervious core approximately 670 feet high, a crest elevation of 2,360, and a volume of approximately 55 million cubic yards. A concrete-lined spillway chute and a single stilling basin would be located underground, with the two diversion tunnels on the south bank.

(v) Vee (Figure B.1.3.8) (*)

A 610-foot high rockfill dam founded on bedrock with a crest elevation of 2,350 and total volume of 10 million cubic yards was considered.

Since Vee is located farther upstream than the other major sites, the flood flows are correspondingly lower, thus allowing for a reduction in size of the spillway facilities. A spillway utilizing a gated overflow structure, chute, and flip bucket was adopted.

The power facilities would consist of a 400-MW underground power house located in the south bank with a tailrace outlet well downstream of the main dam. A secondary rockfill dam would also be required in this vicinity to seal off a low point. Two diversion tunnels would be provided on the north bank.

(vi) Maclaren (Figure B.1.3.9) (*)

The development would consist of a 185-foot high earthfill dam founded on pervious riverbed materials. The crest elevation of the dam would be 2,405. This reservoir would essentially be used for regulating purposes. Diversion would occur through three conduits located in a open cut on the south bank, and floods would be discharged via a side chute spillway and stilling basin on the north bank.

(vii) Denali (Figure B.1.3.9) (*)

Denali is similar in concept to Maclaren. The dam would be 230 feet high, of earthfill construction, and with a crest elevation of 2,555. As for Maclaren, no generating capacity would be included. A combined diversion and spillway facility would be provided by twin concrete conduits founded in open cut excavation in the north bank and discharging into a common stilling basin.

1.3.3 - Capital Costs (*)

For purposes of initial comparisons of alternatives, construction quantities were determined for items comprising the major works and structures at the site. Where detail or data were not sufficient for certain work, quantity estimates were made on the basis of previous development of similar sites and general knowledge of site conditions reported in the literature. In order to determine total capital costs for various structures, unit costs have been developed for the items measured. These have been estimated on the basis of review of rates used in previous studies, and of rates used on similar works in Alaska and elsewhere. Where applicable, adjustment factors based on geography, climate, manpower and accessibility were used. Technical publications have also been reviewed for basic rates and escalation factors.

The total capital costs developed are shown in Tables B.1.3.1 and B.1.3.2. It should be noted that the capital costs for Maclaren and Denali shown in Table B.1.3.1 have been adjusted to incorporate the costs of generation plants with capacities of 55 MW and 60 MW, respectively. Additional data on the projects are summarized in Table B.1.3.3.

1.4 - Formulation of Susitna Basin Development Plans (*)

The results of the site screening process described above indicate that the Susitna basin development plan should incorporate a combination of several major dams and powerhouses located at one or more of the following sites:

- o Devil Canyon
- o High Devil Canyon
- o Watana
- o Susitna III
- o Vee.

Supplementary upstream flow regulation could be provided by structures at Maclaren and Denali.

Cost estimates of these projects are itemized on Table B.1.4.1.

A computer-assisted screening process identified the plans of Devil Canyon/Watana or High Devil Canyon/Vee as most economic. In addition to these two basic development plans, a tunnel scheme which provides potential environmental advantages by replacing the Devil Canyon Dam with a long power tunnel and a development plan involving Watana Dam were also introduced.

The criteria used at this stage of the process for selection of preferred Susitna basin development plans were mainly economic (Figure B.1.2.1). Environmental considerations were incorporated into the further assessment of the plans finally selected.

The results of the screening process are shown in Table B.1.4.2 Because of the simplifying assumptions that were made in the screening model, the three best solutions from an economic point of view are included in the table.

The most important conclusions that can be drawn are as follows:

- o For energy requirements of up to 1,750 GWh, the High Devil Canyon, Devil Canyon or the Watana sites individually provided the most economic energy. The difference between the costs shown on Table B.1.4.2 is around 10 percent, which is similar to the accuracy that can be expected from the screening model.

- For energy requirements of between 1,750 and 3,500 GWh, the High Devil Canyon site is the most economic.

- For energy requirements of between 3,500 and 5,250 GWh, the combinations of either Watana and Devil Canyon or High Devil Canyon and Vee are most economic.

- The total energy production capability of the Watana/Devil Canyon development is considerably larger than that of the High Devil Canyon/Vee alternative and is the only plan capable of meeting energy demands in the 6,000 GWh range.

1.4.1 - Tunnel Alternatives (*)

A scheme involving a long power tunnel could conceivably be used to replace the Devil Canyon Dam in the Watana/Devil Canyon development plan. It could develop similar head for power generation and might provide some environmental advantages by avoiding inundation of Devil Canyon. Obviously, because of the low winter flows in the river, a tunnel alternative could be considered only as a second stage to the Watana development.

Conceptually, the tunnel alternatives would comprise the following major components in some combination, in addition to the Watana Dam, reservoir and associated powerhouse:

- Power tunnel intake works;

- One or two power tunnels up to 40 feet in diameter and up to 30 miles in length;

- A surface or underground powerhouse with a capacity of up to 1,200 MW;

- A re-regulation dam if the intake works are located downstream from Watana; and

- Arrangements for compensation flow in the bypassed river reach.

Four basic alternative schemes were developed and studied. Figure B.1.4.1 is a schematic illustration of these schemes. All schemes assumed an initial Watana development with full reservoir supply level at elevation 2,200 and the associated powerhouse with an installed capacity of 800 MW. Table B.1.4.3 lists all the pertinent technical information. Table B.1.4.4 lists the power and energy yields for the four schemes. Table B.1.4.5 itemizes the capital cost estimate.

Based on the foregoing economic information, Scheme 3 (Figures B.1.4.2 and B.1.4.3) produces the lowest cost energy by a factor of nearly 2.

A review of the environmental impacts associated with the four tunnel schemes indicates that Scheme 3 would have the least impact, primarily because it offers the best opportunities for regulating daily flows downstream from the project. Based on this assessment and because of its almost 2 to 1 economic advantage, Scheme 3 was selected as the only scheme worth further study. (See Development Selection Report for detailed analysis.) The capital cost estimate for Scheme 3 appears in Table B.1.4.5. The estimates also incorporate single and double tunnel options. For purposes of these studies, the double tunnel option has been selected because of its superior reliability. It should also be recognized that the cost estimates associated with the tunnels are probably subject to more variation than those associated with the dam schemes, due to geotechnical uncertainties. In an attempt to compensate for these uncertainties, economic sensitivity analyses using both higher and lower tunnel costs have been conducted.

1.4.2 - Additional Basin Development Plan (*)

As noted, the Watana and High Devil Canyon damsites appear to be individually superior in economic terms to all others. An additional plan was therefore developed to assess the potential for developing these two sites together. For this scheme, the Watana Dam would be developed to its full potential. The High Devil Canyon Dam would be constructed to a crest elevation of 1,470 to fully utilize the head downstream from Watana.

1.4.3 - Selected Basin Development Plans (*)

The essential objective of this step in the development selection process was defined as the identification of those plans which appear to warrant further, more detailed evaluation. The results of the final screening process indicate that the Watana/Devil Canyon and the High Devil Canyon/Vee plans are clearly superior to all other dam combinations. In addition, it was decided to study Tunnel Scheme 3 further as an alternative to the High Devil Canyon Dam and a plan combining Watana and High Devil Canyon.

Associated with each of these plans are several options for staged development. For this more detailed analysis of these basic plans, a range of different approaches to staging the developments was considered. In order to keep the total options to a reasonable number and also to maintain reasonably large staging steps consistent with the total development size, staging of only the two larger developments (i.e., Watana and High Devil Canyon) was considered. The basic staging concepts adopted for these developments involved staging both dam and powerhouse construction or, alternatively, just staging powerhouse construction. Powerhouse stages were considered in 400-MW increments.

Four basic plans and associated subplans are briefly described below. Plan 1 involves the Watana/Devil Canyon sites, Plan 2 the High Devil Canyon/Vee sites, Plan 3 the Watana-tunnel concept, and Plan 4 the Watana/High Devil Canyon sites. Under each plan several alternative subplans were identified, each involving a different staging concept. Summaries of these plans are given in Table B.1.4.6.

(a) Plan 1 (*)

(i) Subplan 1.1 (*)

The first stage involves constructing Watana Dam to its full height and installing 800 MW. Stage 2 involves constructing Devil Canyon Dam and installing 600 MW.

(ii) Subplan 1.2 (*)

For this subplan, construction of the Watana Dam is staged from a crest elevation of 2,060 to 2,225. The powerhouse is also staged from 400 MW to 800 MW. As for Subplan 1.1, the final stage involves Devil Canyon with an installed capacity of 600 MW.

(iii) Subplan 1.3 (*)

This subplan is similar to subplan 1.2 except that only the powerhouse and not the dam at Watana is staged.

(b) Plan 2 (*)

(i) Subplan 2.1 (*)

This subplan involves constructing the High Devil Canyon Dam first with an installed capacity of 800 MW. The second stage involves constructing the Vee Dam with an installed capacity of 400 MW.

(ii) Subplan 2.2 (*)

For this subplan, the construction of High Devil Canyon is staged from a crest elevation of 1,630 to 1,775. The installed capacity is also staged from 400 to 800 MW. As for subplan 2.1, Vee follows with 400 MW of installed capacity.

(iii) Subplan 2.3 (*)

This subplan is similar to subplan 2.2 except that only the powerhouse and not the dam at High Devil Canyon is staged.

(c) Plan 3 (*)

(i) Subplan 3.1 (*)

This subplan involves initial construction of Watana and installation of 800-MW capacity. The next stage involves the construction of the downstream reregulation dam to a crest elevation of 1,500 and a 15-mile long tunnel. A total of 300 MW would be installed at the end of the tunnel and a further 30 MW at the re-regulation dam. An additional 50 MW of capacity would be installed at the Watana powerhouse to facilitate peaking operations.

(ii) Subplan 3.2 (*)

This subplan is essentially the same as subplan 3.1 except that construction of the initial 800- MW powerhouse at Watana is staged.

(d) Plan 4 (*)

This single plan was developed to jointly evaluate the development of the two most economic damsites, Watana and High Devil Canyon. Stage 1 involves constructing Watana to its full height with an installed capacity of 400 MW. Stage 2 involves increasing the capacity at Watana to 800 MW. Stage 3 involves constructing High Devil Canyon to a crest elevation of 1,470 so that the reservoir extends to just downstream of Watana. In order to develop the full head between Watana and Portage Creek, an additional smaller dam is added downstream of High Devil Canyon. This dam would be located just upstream from Portage Creek so as not to interfere with the anadromous fisheries, and would have a crest elevation of 1,030 and an installed capacity of 150

MW. For purposes of these studies, this site is referred to as the Portage Creek site.

1.5 - Evaluation of Basin Development Plans (*)

The overall objective of this step in the evaluation process was to select the preferred basin development plan. A preliminary evaluation of plans was initially undertaken to determine broad comparisons of the available alternatives. This was followed by appropriate adjustments to the plans and a more detailed evaluation and comparison.

In the process of initially evaluating the final four schemes, it became apparent that there would be environmental problems associated with allowing daily peaking operations from the most downstream reservoir in each of the plans described above. In order to avoid these potential problems while still maintaining operational flexibility to peak on a daily basis, re-regulation facilities were incorporated in the four basic plans. These facilities incorporate both structural measures such as re-regulation dams and modified operational procedures. Details of these modified plans, referred to as E1 to E4, are listed in Table B.1.5.1.

The plans listed in Table B.1.5.1 were subjected to a more detailed analysis as described in the following section.

1.5.1 - Evaluation Methodology (*)

The approach to evaluating the various basin development plans described above is twofold:

- For determining the optimum staging concept associated with each basic plan (i.e., the optimum subplan), only economic criteria are used and the least-cost staging concept is adopted.

- For assessing which plan is the most appropriate, a more detailed evaluation process incorporating economic, environmental, social and energy contribution aspects is taken into account.

Economic evaluation of any Susitna basin development plan requires that the impact of the plan on the cost of energy to the Railbelt area consumer be assessed on a systemwide basis. Since the consumer is supplied by a large number of different generating sources, it is necessary to determine the total Railbelt system cost in each case to compare the various Susitna basin development options.

The primary tool used for system costs was the mathematical model developed by the Electricity Utility Systems Engineering Department of General Electric Company. The model is commonly known as OGP5 or Optimized Generation Planning Model, Version 5. The following information is paraphrased from GE literature on the program (General Electric 1979).

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

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

The unit resulting in the lowest system production cost is selected and added to the system. Finally, an investment cost analysis of the capital costs is completed to answer the question of "what kind" of generation to add to the system.

The model is then further used to compare alternative plans for meeting variable electrical demands, based on system reliability and production costs for the study period.

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

The first segment has been assumed to be from 1980 to 1990. The model of this time period included all committed generation units and is assumed to be common to all generation scenarios.

The end point of this model becomes the beginning of each 1990-2010 model.

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

- All investment costs to plants in service prior to 1981;
- Costs of transmission systems in service both at the transmission and distribution level; and
- Administrative costs of utilities for providing electric service to the public.

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

The third period, 2010 to 2040, was modeled by assuming that production costs of 2010 would recur for the additional 30 years to 2040. This assumption is believed to be reasonable given the limitations on forecasting energy and load requirements for this period. The additional period to 2040 is required to at least take into account the benefit derived or value of the addition of a hydroelectric power plant which has a useful life of 50 years or more.

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

A summary of the input data to the model and a discussion of the results follow.

(a) Initial Economic Analyses (*)

Table B.1.5.2 lists the results of the first series of economic analyses undertaken for the basic Susitna basin development plans listed in Table B.1.5.1. The information provided includes the specified on-line dates for the various stages of the plans, the OGP5 run index number, the total installed capacity at year 2010 by category, and the total system present worth cost in 1980 for the period 1980 to 2040. Matching of the Susitna development to the load growth for Plans E1, E2, and E3 is shown in Figures B.1.5.1, B.1.5.2 and B.1.5.3, respectively. After 2010, steady state conditions are assumed and the then-existing generation mix and annual costs for 2010 are applied to the years 2011 to 2040. This extended period of time is necessary to ensure that the hydroelectric options being studied, many of which only come on line around 2000, are simulated as operating for periods approaching their economic lives and that their full impact on the cost of the generation system is taken into account.

(i) Plan E1 - Watana/Devil Canyon (*)

Staging the dam at Watana (Plan E1.2) is not as economic as constructing it to its full height (Plan E1.1 and E1.3). The present worth advantage of not staging the dam amounts to $180 million in 1980 dollars.

The results indicate that, with the level of analysis performed, there is no discernible benefit in staging construction of the Watana powerhouse (Plan E1.1 and E1.3). However, Plan E1.4 results indicate that, should the powerhouse size at Watana be restricted to 400 MW, the overall system present worth costs would increase.

Additional runs performed for variations of Plan E1.3 indicate that system present worth would increase by $1,110 million if the Devil Canyon Dam were not constructed. A five-year delay in construction of the Watana Dam would increase system present worth by $220 million.

(ii) Plan E2 - High Devil Canyon/Vee (*)

The results for Plan E2.3 indicate that the system present worth is $520 million more than Plan E1.3. Present worth increases also occur if the Vee Dam stage is not constructed. A reduction in present worth of approximately $160 million is possible if the Chakachamna hydroelectric project is constructed instead of the Vee Dam.

The results of Plan E2.1 indicate that total system present worth would increase by $250 million if the total capacity at High Devil Canyon were limited to 400 MW.

(iii) Plan E3 - Watana-Tunnel (*)

The results for Plan E3.1 illustrate that the tunnel scheme versus the Devil Canyon Dam scheme (E1.3) adds approximately $680 million to the total system present worth cost. The availability of reliable geotechnical data would undoubtedly have improved the accuracy of the cost estimates for the tunnel alternative. For this reason, a sensitivity analysis was made as a check to determine the effect of halving the tunnel costs. This analysis indicates that the tunnel scheme is still more costly than constructing the Devil Canyon Dam.

(iv) Plan E4 - Watana/High Devil Canyon/Portage Creek (*)

The results indicate that system present worth associated with Plan E4.1, excluding the Portage Creek site development, is $200 million more than the equivalent E1.3 plan. If the Portage Creek development is included, the present worth difference would be even greater.

(b) Load Forecast Sensitivity Analyses (*)

The plans with the lowest present worth cost were subjected to further sensitivity analysis. The objective of the analysis was to determine the impact on the development decision of a variance in forecast. The load forecasts used for this analysis were made by ISER and are presented in Section 5.4.5 of this Exhibit. These results are summarized in Table B.1.5.3.

At the low load forecast, full capacity development of Watana/Devil Canyon Scheme 1.3 is not warranted. Under Scheme 1.4, the most economic development includes a 400-MW development at each site, as compared to Watana only. Similarly, it is more economic to develop High Devil Canyon and Vee, as compared to High Devil Canyon only, but at a total capacity of only 800 MW.

At this level of projected demand, the Watana/Devil Canyon plan is more economic than the High Devil Canyon/Vee plan or any singular development ($210 million, present worth basis). As individual developments, however, the High Devil Canyon only plan is slightly superior economically to the Watana project ($90 million, present worth basis).

At the high load forecast, the larger capacities are clearly needed. In addition, both the High Devil Canyon/Vee and Watana/Devil Canyon plans are improved economically by the addition of the Chackachamna project. This illustrates the superiority of the Chackachamna project to the addition of alternative coal and gas projects using the study price projections. Similar to the low load forecast, the Watana/Devil Canyon project is superior to the High Devil Canyon/Vee alternative but the margin of difference on a present worth basis is much greater ($1.0 billion, present worth basis).

1.5.2 - Evaluation Criteria (*)

The following criteria were used to evaluate the short-listed basin development plans. These criteria generally contain the requirements of the generic process with the exception that an additional criterion, energy contribution, is added in order to ensure that full consideration is given to the total basin energy potential developed by the various plans.

(a) Economic (*)

Plans were compared using long-term present worth costs, calculated using the OGP5 generation planning model. The parameters used in calculating the total present worth cost of the total Railbelt generating system for the period 1980 to 2040 are listed in Tables B.1.5.4 and B.1.5.5. Load forecasts used in the analysis are presented in Section 5.4.5.

(b) Environmental (*)

A qualitative assessment of the environmental impact on the ecological, cultural, and aesthetic resources is undertaken for each plan. Emphasis is placed on identifying major concerns so that these can be combined with the other evaluation attributes in an overall assessment of the plan.

(c) Social (*)

This attribute includes determination of the potential nonrenewable resource displacement, the impact on the state and local economy, and the risks and consequences of major structural failures due to seismic events. Impacts on the economy refer to the effects of an investment plan on economic variables.

(d) Energy Contribution (*)

The parameter used is the total amount of energy produced from the specific development plan. An assessment of the energy development foregone is also undertaken. The energy loss that is inherent to the plan and cannot easily be recovered by subsequent staged developments is of greatest concern.

1.5.3 - Results of Evaluation Process (*)

The various attributes outlined above have been determined for each plan and are summarized in Tables B.1.5.6 through B.1.5.14. Some of the attributes are quantitative while others are qualitative. Overall evaluation is based on a comparison of similar types of attributes for each plan. In cases where the attributes associated with one plan all indicate equality or superiority with respect to another plan, the decision as to the best plan is clear cut. In other cases where some attributes indicate superiority and others inferiority, differences are highlighted and trade-off decisions are made to determine the preferred development plan. In cases where these trade-offs have had to be made, they were relatively straightforward, and the decision-making process can therefore be regarded as effective and consistent. In addition, these trade-offs are clearly identified so that independent assessment can be made.

The overall evaluation process is conducted in a series of steps. At each step, only two plans are compared. The superior plan is then taken to the next step for evaluation against a third plan.

(a) Devil Canyon Dam Versus Tunnel (*)

The first step in the process involves the comparison of the Watana/Devil Canyon Dam plan (E1.3) and the Watana-tunnel plan (E3.1). Since Watana is common to both plans, the evaluation is based on a comparison of the Devil Canyon Dam and the Scheme 3 tunnel alternative.

In order to assist in the evaluation in terms of economic criteria, additional information obtained by analyzing the results of the OGP5 computer runs is shown in Table B.1.5.6. This information illustrates the breakdown of the total system present worth cost in terms of capital investment, fuel, and operation and maintenance costs.

(i) Economic Comparison (*)

From an economic point of view, the Watana/Devil Canyon Dam scheme is superior. As summarized in Tables B.1.5.6 and B.1.5.7, on a present worth basis the tunnel scheme is $680 million more expensive than the dam scheme. For a low demand growth rate, this cost difference would be reduced slightly to $650 million. Even if the tunnel scheme costs are halved, the total cost difference would still amount to $380 million. As highlighted in Table B.1.5.7, consideration of the sensitivity of the basic economic evaluation to potential changes in capital cost estimates, the period of economic analysis, the discount rate, fuel costs, fuel cost escalation, and economic plant life do not change the basic economic superiority of the dam scheme over the tunnel scheme.

(ii) Environmental Comparison (*)

The environmental comparison of the two schemes is summarized in Table B.1.5.8. Overall, the tunnel scheme is judged to be superior because:

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

- It would inundate 13 miles less of resident fisheries habitat in the river and major tributaries;

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

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

(iii) Social Comparison (*)

Table B.1.5.9 summarizes the evaluation of the two schemes in terms of the social criteria. In terms of impact on state and local economics and risks because of seismic exposure, the two schemes are rated equal. However, due to its higher energy yield, the dam scheme has more potential for displacing nonrenewable energy resources and therefore has a slight overall advantage in terms of the social evaluation criteria.

(iv) Energy Comparison (*)

Table B.1.5.10 summarizes the evaluation in terms of the energy contribution criteria. The results show that the dam scheme has a greater potential for energy production and develops a larger portion of the basin's potential. The dam scheme is therefore judged to be superior from the energy contribution standpoint.

(v) Overall Comparison (*)

The overall evaluation of the two schemes is summarized in Table B.1.5.11. The estimated cost saving of $680 million in favor of the dam scheme plus the additional energy produced are considered to outweigh the reduction in the overall environmental impact of the tunnel scheme. The dam scheme is therefore judged to be superior overall.

(b) Watana/Devil Canyon Versus High Devil Canyon/Vee (*)

The second step in the development selection process involves an evaluation of the Watana/Devil Canyon (E1.3) and the High Devil Canyon/Vee (E2.3) development plans.

(i) Economic Comparison (*)

In terms of the economic criteria (see Table B.1.5.6 and B.1.5.7) the Watana/Devil Canyon plan is less costly by $520 million. Consideration of the sensitivity of this decision to potential changes in the various parameters considered (i.e., load forecast, discounted rates, etc.) does not change the basic superiority of the Watana/Devil Canyon plan.

Under the low load-growth forecast, the Watana/Devil Canyon plan is favored by only $210 million, while under the high load-growth forecast the advantage is $1,040 million.

(ii) Environmental Comparison (*)

The evaluation in terms of the environmental criteria is summarized in Table B.1.5.12. In assessing these plans, a reach-by-reach comparison was made for the section of the Susitna River between Portage Creek and the Tyone River. The Watana/Devil Canyon scheme would create more potential environmental impacts in the Watana Creek area. However, it is judged that the potential environmental impacts which would occur above the Vee Canyon Dam with a High Devil Canyon/Vee development are more severe in overall comparison.

Of the seven environmental factors considered in Table B.1.5.12, except for the increased loss of river valley, bird and black bear habitat, the Watana/Devil Canyon development plan is judged to be more environmentally acceptable than the High Canyon/Vee plan.

The other six areas in which Watana/Devil Canyon was judged to be superior are fisheries, moose, caribou, furbearers, cultural resources, aesthetics, and land use.

(iii) Energy Comparison (*)

The evaluation of the two plans in terms of energy contribution criteria is summarized in Table B.1.5.13. The Watana/ Devil Canyon scheme is assessed to be superior because of its higher energy potential and the fact that it develops a higher proportion of the basin's energy potential.

The Watana/Devil Canyon plan annually develops 1,160 GWh and 1,650 GWh more average and firm energy, respectively, than the High Devil Canyon/Vee plans.

(iv) Social Comparison (*)

Table B.1.5.9 summarizes the evaluation in terms of the social criteria. As in the case of the dam versus tunnel comparison, the Watana/Devil Canyon plan is judged to have a slight advantage over the High Devil Canyon/Vee plan. This is because of its greater potential for displacing nonrenewable resources. In other social impact areas there are minimal differences between plans.

(v) Overall Comparison (*)

The overall evaluation of the two schemes is summarized in Table B.1.5.14. The $520 million estimated cost saving coupled with the lower environmental impacts and a marginal social advantage make the Watana/Devil Canyon plan superior to High Devil Canyon/Vee.

1.6 - Preferred Susitna Basin Development Plan (**)

One-on-one comparisons of the Watana/Devil Canyon plan with the Watana-tunnel plan and the High Devil Canyon/Vee plan are judged to favor the Watana/Devil Canyon plan in each case. The Watana/Devil Canyon plan was therefore selected as the preferred Susitna basin development plan.

In May 1985, the Applicant concluded that a number of benefits would be derived from a modification of the Watana/Devil Canyon two-dam plan providing for completion of construction in three stages.

Accordingly, the Applicant has prepared alternative facility designs and operation studies of a construction plan that permits construction in three stages: first, construction and operation of a facility at the Watana site with a dam elevation of 2,025 feet (Stage I); second, proposed Devil Canyon dam elevation of 1,463 feet (Stage II); and third, further elevation of the dam at the Watana facility to the 2,205 foot level proposed in the July 1983 License Application (Stage III). Although the three-stage construction plan will not alter the character of the fully completed project, staging construction in three steps will accomplish certain desirable changes over the course of project development.

The development of Watana to its full height results in concentration of expenditures in the early years of the Susitna Project. Completion of Watana Stage I at a 2,025 foot crest elevation would reduce the initial materials requirements and construction time. The result would be both a reduction in initial state financial commitments and improved opportunity for private financing. Moreover, stretching out the pace of development of project energy and capacity would permit a better matching of load growth and capacity available, thereby ensuring greater flexibility in responding to future rates of system growth.

2 - ALTERNATIVE FACILITY DESIGN, PROCESSES AND OPERATIONS (*)

2.1 - Susitna Hydroelectric Development (o)

As originally conceived, the Watana project initially comprised an earthfill dam with a crest elevation of 2,225 and 400 MW of generating capacity scheduled to commence operation in 1993. An additional 400 MW would be brought on line in 1996. At Devil Canyon, an additional 400 MW would be installed to commence operation in the year 2000. Detailed studies of each project have led to refinement and optimization of designs in terms of a number of key factors, including updated load forecasts and economics. Geotechnical and environmental constraints identified as a result of continuing field work have also greatly influenced the currently recommended design concepts.

Plan formulation and alternative facility designs considered for the Watana and Devil Canyon developments are discussed in this section. Background information on the site characteristics as well as additional detail on the plan formulation process are included in the Supporting Design Report of Exhibit F and the referenced reports.

2.2 - Watana Project Formulation (*)

This section describes the evolution of the general arrangement of the Watana-Stages I & III projects which, together with the Devil Canyon project Stage II, comprises the development plan proposed. The process by which reservoir operating levels and the installed generating capacity of the power facilities were established is presented, together with the means of handling floods expected during construction and subsequent project operation.

The main components of the Watana development are as follows:

- o Dam embankment
- o Diversion facilities
- o Spillway facilities
- o Outlet facilities
- o Emergency release facilities
- o Power facilities.

A number of alternatives are available for each of these components and they can be combined in a number of ways. The following paragraphs describe the various components and methodology for the preliminary, intermediate, and final screening and review of alternative general arrangement of the components, together with a brief description of the selected scheme. This section presents the alternative arrangements studied for the Watana project.

2.2.1 - Selection of Reservoir Level (o)

The selected elevation of the Watana Dam crest is based on considerations of the value of the hydroelectric energy produced from the associated reservoir, geotechnical constraints on reservoir levels, and freeboard requirements. Firm energy, average annual energy, construction costs, and operation and maintenance costs were determined for the Watana development with dam crest elevations of 2,240, 2,190, and 2,140. The relative value of energy produced in terms of the present worth of the long-term production costs (LTPWC) for each of these three dam elevations was determined by means of the OGP5 generation planning model described in Section 1 of this Exhibit. The physical constraints imposed on dam height and reservoir elevation by geotechnical considerations were reviewed and incorporated into the crest elevation selection process. Finally, freeboard requirements for the Probable Maximum Flood (PMF) and settlement of the dam after construction or as a result of seismic activity were taken into account.

(a) Methodology (o)

Firm and average annual energy produced by the Susitna development is based on 32 years of hydrological records. The energy produced was determined by using a multi-reservoir simulation of the operation of the Watana and Devil Canyon reservoirs. A variety of reservoir drawdowns was examined, and drawdowns producing the maximum firm energy consistent with engineering feasibility and cost of the intake structure were selected. Minimum flow requirements were established at both project sites based on downstream fisheries considerations.

To meet system demand, the required maximum generating capability at Watana in the period between 1994 and 2010 ranges from 665 MW to 908 MW. For the reservoir level determinations, energy estimates were made on the basis of assumed average annual capacity requirements of 680 MW at Watana in 1994, increasing to 1,020 MW at Watana in 2007, with an additional 600 MW at Devil Canyon coming on line in the year 2002. The long term present worth costs of the generation system required to meet the Railbelt energy demand were then determined for each of the three crest elevations of the Watana Dam using the OGP5 model.

The construction cost estimates used in the OGP5 modeling process for the Watana and Devil Canyon projects were based on preliminary conceptual layouts and construction schedules. Further refinement of these layouts has taken place during the optimization process. These refinements have had no significant impact on the reservoir level selection.

(b) Economic Optimization (*)

Economic optimization of the Watana reservoir level was based on an evaluation of three dam crest elevations of 2,240, 2,190, and 2,140. These crest elevations applied to the central portion of the embankment with appropriate allowances for freeboard and seismic settlement, and correspond to maximum operating levels of the reservoir of 2,215, 2,165, and 2,115 feet, respectively. Average annual energy calculated for each case using the reservoir simulation model are given in Table B.2.2.1, together with corresponding project construction costs.

In the determination of LTPWC, the Susitna capital costs were adjusted to include an allowance for interest during construction and then used as input to the OGP5 model. Simulated annual energy yields were distributed on a monthly basis by the reservoir operation model to match as closely as possible the projected monthly energy demand of the Railbelt and then input to the OGP5 model. The LTPWC of meeting the Railbelt energy demand using the Susitna development as the primary source of energy was then determined for each of the three reservoir levels.

The results of these evaluations are shown in Table B.2.2.2, and a plot showing the variation of the LTPWC with dam crest elevation is shown in Figure B.2.2.1. This figure indicates that, on the basis of the assumptions used, the minimum LTPWC occurs at a Watana crest elevation ranging from approximately 2,160 to 2,200 (reservoir levels 2,140 to 2,180 feet). A higher dam crest will still result in a development which has an overall net economic benefit relative to thermal energy sources. However, it is also clear that, as the height of the Watana Dam is increased, the unit cost of additional energy produced at Watana is somewhat greater than for the displaced thermal energy source. Hence, the LTPWC of the overall system would increase. Conversely, as the height of the dam is lowered, and thus Watana produces less energy, the unit cost of the energy produced by a thermal generation source to replace the lost Susitna energy is higher than that of Susitna. In this case also, the LTPWC increases.

(c) Relict Channel (**)

On the north side of the reservoir created by the Watana Dam, an infilled relict channel, reaching a depth of 400 feet, exists between the reservoir and Tsusena Creek. A potential problem caused by the relict channel involves subsurface seepage resulting in potential downstream piping and/or loss of water from the reservoir. Details of the geology and potential impacts of the relict channel are addressed in Exhibits A and F. In response to these potential seepage problems, $57,100,000 have been provided in the cost estimate for the construction of a downstream toe drain during Stage I and a slurry trench cutoff across the buried channel thalweg during Stage III. The Stage I pool (el. 2,000) is 185 feet lower than Stage III (el. 2,185); therefore minimal remedial measures have been programmed, including observation device monitoring, during this period.

(d) Conclusions (o)

It is important to establish clearly the overall objective used as a basis for setting the Watana reservoir level. An objective which would minimize the LTPW energy cost would lead to selection of a slightly lower reservoir level than an objective which would maximize the amount of energy which could be obtained from the available resource, while doing so with a technically sound project.

The three values of LTPWC developed by the OGP5 computer runs defined a relationship between LTPWC and Watana Dam height which is relatively insensitive to dam height. This is highlighted by the curve of LTPWC versus dam height in Figure B.2.2.1. This figure shows that there is only a slight variation in the LTPWC for the range of dam heights included in the analysis. Thus, from an economic standpoint, the optimum crest elevation could be considered as varying over a range of elevations from 2,140 to 2,220 with little effect on project economics.

The normal maximum operating level of the reservoir was therefore set at elevation 2,185, allowing the objective of maximizing the economic use of the Susitna resource still to be satisfied.

2.2.2 - Selection of Installed Capacity (*)

The generating capacity to be installed at both Watana and Devil Canyon was determined on the basis of generation planning studies together with appropriate consideration of the following (Acres 1982c, Vol. 1):

- o Available firm and average energy from Watana and Devil Canyon;
- o The forecast energy demand and peak load demand of the system;
- o Available firm and average energy from other existing and committed plant;
- o Capital cost and annual operating costs for Watana and Devil Canyon;
- o Capital cost and annual operating costs for alternative sources of energy and capacity;
- o Environmental constraints on reservoir operation; and
- o Turbine and generator operating characteristics.

Table B.2.2.3 lists the design parameters used in establishing the dependable capacity at Watana.

(a) Installed Capacity (*)

A computer simulation of reservoir operation over 32 years of hydrological record was used to predict firm (dependable) and average energy available from Watana and Devil Canyon reservoirs on a monthly basis. Seven alternative reservoir operating rules were assumed, varying from a maximum power generation scenario which would result in significant impact on downstream fisheries through to a scenario that provides guaranteed minimum summer releases which minimize the impact on downstream fisheries. For the preliminary design, predicted energies from a moderate flow case, referred to as Case C, have been used to assess the required plant capacity.

The computer simulation gives an estimate of the monthly energy available from each reservoir, but the sizing of the plant capacity must take into account the variation of demand load throughout each month on an hourly basis. Load forecast studies have been undertaken to predict the hourly variation of load through each month of the year and also the growth in peak load (MW) and annual energy demand (GWh) through the end of the planning horizon (2010).

The economic analysis for the proposed development assumes that the average energy from each reservoir is available every year. The hydrological record, however, is such that this average energy is available only from a series of wetter and drier years. In order to utilize the average energy, capacity must be available to generate the energy available in the wet years up to the maximum requirement dictated by the system energy demand, less any energy available from other committed hydroplants.

Watana has been designed to operate as a peaking station, if required. Tables B.2.2.4 and B.2.2.5 show the estimated maximum capacity required in the peak demand month (December) at Watana to fully utilize the energy available from the flows of record. If no thermal energy is needed (i.e., in wetter years), the maximum requirement is controlled only by the shape of the demand curve. If thermal energy is required (in average to dry years), the maximum capacity required at Watana will depend on whether the thermal energy is provided by high merit order plant at base load (Option 1, Table B.2.2.4), or by low merit order peaking plant (Option 2, Table B.2.2.5).

On the basis of this evaluation, the ultimate power generation capability at Watana was selected as 1,020 MW for design purposes to allow a margin for hydro spinning reserve and standby for forced outage. This installation also provides a margin in the event that the load growth exceeds the medium load forecast.

(b) Unit Capacity (*)

Selection of the unit size for a given total capacity is a compromise between the initial least-cost solution, generally involving a scheme with a smaller number of large capacity units, and the improved plant efficiency and security of operation provided by a larger number of smaller capacity units. Other factors include the size of each unit as a proportion of the total system load and the minimum anticipated load on the station. Any requirement for a minimum downstream flow would also affect the selection. Growth of the actual load demand is also a significant factor, since the installation of units may be phased to match the actual load growth. The number of units and their individual ratings were determined by the need to deliver the required peak capacity in the peak demand month of

December at the minimum December reservoir level with the turbine wicket gates fully open.

An examination was made of the economic impact on power plant production costs of various combinations of a number of units and rated capacity which would provide the selected total capacity of 1,020 MW. For any given installed capacity, plant efficiency increases as the number of units increases. The assumed capitalized value used in this evaluation was $1.00 per average annual kWh over project life, based on the economic analysis completed for the thermal generation system. Variations in the number of units and capacity will affect the cost of the power intakes, penstocks, powerhouse, and tailrace. The differences in these capital costs were estimated and included in the evaluation. The results of this analysis are presented below.

Number of Units	Rated Capacity of Unit (MW)	Capitalized Value of Additional Energy ($ Millions)	Additional Capital Cost ($ Millions)	Net Benefit ($ Millions)
4	250	-	-	-
6	170	40	31	9
8	125	50	58	-8

It is apparent from this analysis that a six-unit scheme with a net benefit of approximately $9 million is the most economic alternative. This scheme also offers a higher degree of flexibility and security of operation compared to the four-unit alternative, as well as advantages if unit installation is phased to match actual load growth. The net economic benefit of the six-unit scheme is $17 million greater than that of the eight-unit scheme, while at the same time no significant operational or scheduling advantages are associated with the eight-unit scheme.

A scheme incorporating six units, each with a rated capacity of 170 MW, for a total of 1,020 MW, has been adopted for all Watana alternatives.

2.2.3 - Selection of the Spillway Design Flood (*)

Normal design practice for projects of this magnitude, together with applicable design regulations, requires that the project be capable of passing the Probable Maximum Flood (PMF) routed through the reservoir without endangering the dam.

In addition to this requirement, the project should have sufficient spillway capacity to safely pass a major flood of lesser magnitude than the PMF without damaging the main dam or ancillary structures. The frequency of occurrence of this flood, known as the spillway design flood or Standard Project Flood (SPF), is generally selected on the basis of an evaluation of the risks to the project if the spillway design flood is exceeded, compared to the costs of the structures required to safely discharge the flood. For this study, a spillway design flood with a return frequency of 1:10,000 years was selected for Watana. A list of spillway design flood frequencies and magnitudes for several major projects is presented below.

Project	Spillway Design Flood Frequency	Spillway Design Flood Peak Inflow (cfs)	Basin PMF (cfs)	Spillway Capacity After Routing (cfs)*
Mica, Canada	PMF	250,000	250,000	150,000
Churchill Falls, Canada	1:10,000	600,000	1,000,000	230,000
New Bullards, USA	PMF	226,000	226,000	170,000
Oroville, USA	1:10,000	440,500	711,400	440,500
Guri, Venezuela (final stage)	PMF	1,000,000	1,000,000	1,000,000
Itaipu, Brazil	PMF	2,195,000	2,195,000	2,105,000
Sayano, USSR	1:10,000	480,000	N/A	680,000

*All spillways except Sayano have capacity to pass PMF with surcharge.

The flood frequency analysis produced the following values:

Flood	Frequency	Inflow Peak
Probable Maximum	--	326,000 cfs
Spillway Design	1:10,000 years	156,000 cfs

Additional capacity required to pass the PMF will be provided by an emergency spillway consisting of a fuse plug and rock channel on the right bank.

2.2.4 Main Dam Alternatives (*)

This section describes the alternative types of dams considered at the Watana site and the basis for the selected alternative.

(a) Comparison of Embankment and Concrete Type Dams (o)

The selection between an embankment type or a concrete type dam is usually based on the configuration of the valley, the condition of the foundation rock, depth of the overburden, and the relative availability of construction materials. Previous studies by the COE envisaged an embankment dam at Watana. Initial studies completed as part of this current evaluation included comparison of an earthfill dam with a concrete arch dam at the Watana site. An arrangement for a concrete arch dam alternative at Watana is presented in Figure B.2.2.2. The results of this analysis indicated that the cost of the embankment dam was somewhat lower than the arch dam, even though the concrete cost rates used were significantly lower than those used for the Devil Canyon Dam. This preliminary evaluation did not indicate any overall cost savings in the project in spite of some savings in the earthworks and concrete structures for the concrete dam layout. A review of the overall construction schedule indicated a minimal savings in time for the concrete dam project.

Based on the above and the likelihood that the cost of the arch dam would increase relative to that of the embankment dam, the arch dam alternative was eliminated from further consideration.

(b) Concrete Face Rockfill Type Dam (*)

The selection of a concrete face rockfill dam at Watana would appear to offer economic and schedule advantages when compared to a conventional impervious-core rockfill dam. For example, one of the primary areas of concern with the earth-core rockfill dam is the control of water content for the core material and the available construction period during each summer. The core material will have to be protected against frost penetration at the end of each season and the area cleared and prepared to receive new material after each winter. On the other hand, rockfill materials can be worked almost year-round and the quarrying and placing/compacting operations are not affected by rain and only marginally by winter weather.

The concrete face rockfill dam would also require less foundation preparation, since the critical foundation contact area is much less than that for the impervious-core/rock foundation contact. The side slopes for faced rockfill could probably be on the order of 1.5H:1V or steeper as compared to the 2.5 and 2.0H:1V for the earth-core rockfill. This would allow greater flexibility for layout of the other facilities, in particular the upstream and downstream portals of the diversion tunnels and the tailrace tunnel portals. The diversion tunnels could be shorter, giving further savings in cost and schedule.

However, the ultimate height of the Watana Dam as currently proposed is 885 feet, some 70 percent higher than the highest concrete face rockfill dam built to date (the 525-foot high Areia Dam in Brazil completed in 1980). A review of concrete face rockfill dams indicates that increases in height have been typically in the range of 20 percent; for example, Paradela - 370 feet completed in 1955; Alto Anchicaya - 460 feet completed in 1974; Areia - 525 feet completed in 1980. Although recent compacted rockfill dams have generally performed well and a rockfill dam is inherently stable even with severe leakage through the face, a one-step increase in height of 70 percent over existing structures is well beyond precedent.

In addition to the height of the dam, other factors which are beyond precedent include the seismic and climatic conditions at Susitna. It has been stated that concrete face rockfill dams are well able to resist earthquake forces and it is admitted that they are very stable structures in themselves. However, movement of rock leading to failure of the face slab near the base of the dam could result in excessive leakage through the dam. To correct such an occurrence would require lowering the water level in the reservoir which would take many years and involve severe economic penalties from loss of generating capacity.

No concrete face rockfill dam has yet been built in an arctic environment. The drawdown at Watana is in excess of 100 feet and the upper section of the face slab will be subjected to severe freeze/thaw cycles.

Although the faced rockfill dam appears to offer schedule advantages, the overall gain in impoundment schedule would not be so significant. With the earth-core rockfill dam, impoundment can be allowed as the dam is constructed. This is not the case for a concrete face rockfill since the concrete face slab is normally not constructed until all rockfill has been placed and construction settlement has taken place. The slab is then poured in continuous strips from the foundation to the crest. Most recent high faced rock-fill dams also incorporate an impervious earth fill cover over the lower section to minimize the risk of excessive leakage through zones which, because of their depth below normal water level, are difficult to repair. Such a zone at Watana might cover the lower 200 to 300 feet of the slab and require considerable volumes of impervious fill, none of which could be placed until all other construction work had been completed. This work would be on the critical path with respect to impoundment and, at the same time, be subject to interference by wet weather.

The two types of dam were not costed in detail because cost was not considered to be a controlling factor. It is of interest to note, however, that similar alternatives were estimated for the LG 2 project in northern Quebec and the concrete face alternative was estimated to be about 5 percent cheaper. However, the managers, on the recommendation of their consultants, decided against the use of a concrete face rockfill dam for the required height of 500 feet in that environment.

In summary, a concrete face rockfill dam at Watana is not considered appropriate as a firm recommendation for the feasibility stage of development of the Susitna project because of:

- the 70 percent increase in height over precedent; and
- the possible impacts of high seismicity and climatic conditions.

(c) Selection of Dam Type (*)

Selection of the configuration of the embankment dam cross section was undertaken within the context of the following basic considerations:

- The availability of suitable construction materials within economic haul distance, particularly core material;
- The requirement that the dam be capable of withstanding the effects of a significant earthquake shock as well as the static loads imposed by the reservoir and by its own weight;
- The relatively limited construction season available for placement of compacted fill materials.

The dam would consist of a compacted core protected by fine and coarse filter zones on both the upstream and downstream slopes of the core. The upstream and downstream outer supporting fill zones would contain relatively free draining compacted gravel or rockfill, providing stability to the overall embankment structure. The location and inclination of the core are fundamental to the design of the embankment. Two basic alternatives exist in this regard:

- o A vertical core located centrally within the dam; and
- o An inclined core with both faces sloping upstream.

A central vertical core was chosen for the embankment based on a review of precedent design and the nature of the available impervious material.

The exploration program undertaken during 1980-81 indicated that adequate quantities of materials suitable for dam construction were located within reasonable haul distances from the site. The well-graded silty sand material is considered the most promising source of impervious fill. Compaction tests indicate a natural moisture content slightly on the wet side of optimum moisture content, so that control of moisture content will be critical in achieving a dense core with high shear strength.

Potential sources for the upstream and downstream shells include either river gravel from borrow areas along the Susitna River or compacted rockfill from quarries or excavations for spillways.

During the intermediate review process, the upstream slope of the dam was flattened from 2.5H:1V used during the initial review to 2.75H:1V. This slope was based on a conservative estimate of the effective shear strength parameters of the available construction materials, as well as a conservative allowance in the design for the effects of earthquake loadings on the dam.

During the final review stage, the exterior upstream slope of the dam was steepened from 2.75H:1V to 2.4H:1V, reflecting the results of the preliminary static and dynamic design analyses being undertaken at the same time as the general arrangement studies. As part of the final review, the volume of the dam with an upstream slope of 2.4H:1V was computed for four alternative dam axes. The locations of these alternative axes are shown on Figure B.2.2.3. The dam volume associated with each of the four alternative axes is listed below:

Alternative Axis Number	Total Volume (million yd^3)
1	69.2
2	71.7
3	69.3
4	71.9

A section with a 2.4H:1V upstream slope and a 2H:1V downstream slope located on alternative axis number 3 was used for the final review of alternative schemes.

2.2.5 Diversion Scheme Alternatives (*)

The topography of the site generally dictates that diversion of the river during construction be accomplished using diversion tunnels with upstream and downstream cofferdams protecting the main construction area.

The configuration of the river in the vicinity of the site favors location of the diversion tunnels on the north bank, since the tunnel length for a tunnel on the south bank would be approximately 2,000 feet greater. In addition, rock conditions on the north bank are more favorable for tunneling and excavation of intake and outlet portals.

(a) Design Flood for Diversion (*)

The recurrence interval of the design flood for diversion is generally established based on the characteristics of the flow regime of the river, the length of the construction period for which diversion is required and the probable consequences of overtopping of the cofferdams. Design criteria and experience from other projects similar in scope and nature have been used in selecting the diversion design flood.

At Watana, damage to the partially completed dam could be significant or, more importantly, would probably result in at least a one-year delay in the completion schedule. A preliminary evaluation of the construction schedule indicates that the diversion scheme would be required for four or five years until the dam is of sufficient height to permit initial filling of the reservoir. A design flood with a return frequency of 1:50 years was selected based on experience and practice with other major hydroelectric projects. This approximates a 90 percent probability that the cofferdam will not be overtopped during the five-year construction period. The diversion design flood together with average flow characteristics of the river significant to diversion are presented below:

- o Average annual flow 7,990 cfs
- o Maximum average monthly flow 42,800 cfs (June)
- o Minimum average monthly flow 570 cfs (March)
- o Design flood inflow (1:50 years) 87,000 cfs

(b) <u>Cofferdams</u> (*)

For the purposes of establishing the overall general arrangement of the project and for subsequent diversion optimization studies, the upstream cofferdam section adopted comprises an embankment structure approximately 100 feet high placed in the dry.

(c) <u>Diversion Tunnels</u> (*)

Concrete-lined tunnels and unlined rock tunnels were compared. Preliminary hydraulic studies indicated that the design flood routed through the diversion scheme would result in a design discharge of approximately 80,500 cfs. For concrete-lined tunnels, design velocities on the order of 50 ft/sec have been used in several projects. For unlined tunnels, maximum design velocities ranging from 10 ft/sec in good quality rock to 4 ft/sec in less competent material are typical. Thus, the volume of material to be excavated using an unlined tunnel would be at least 5 times that for a lined tunnel. The reliability of an unlined tunnel is more dependent on rock conditions than is a lined tunnel, particularly given the extended period during which the diversion scheme is required to operate. Based on these considerations, given a considerably higher cost, together with the somewhat questionable feasibility of four unlined tunnels with diameters approaching 50 feet in this type of rock, the unlined tunnels have been eliminated.

The following alternative lined tunnel schemes were examined as part of this analysis.

- o Pressure tunnel with a free outlet
- o Pressure tunnel with a submerged outlet
- o Free flow tunnel

(d) <u>Emergency Release Facilities</u> (*)

The emergency release facilities influenced the number, type, and arrangement of the diversion tunnels selected for the final scheme.

At an early stage of the study, it was established that some form of low-level release facility was required to meet instream flow requirements during filling of the reservoir, and to permit lowering of the reservoir in the event of an extreme emergency. The most economical alternative available would involve converting one of the diversion tunnels to permanent use as a low-level outlet facility. Since it would be necessary to maintain the diversion scheme in service during construction of the emergency facilities outlet works, two or more diversion tunnels would be required. The use of two diversion tunnels also provides an additional measure of security to the diversion scheme in case of the loss of service of one tunnel.

The low-level release facilities will be operated for approximately three years during filling of the reservoir. Discharge at high heads usually requires some form of energy dissipation prior to returning the flow to the river. Given the space restrictions imposed by the size of the diversion tunnel, it was decided to utilize a double expansion system constructed within the upper tunnel.

(e) Optimization of Diversion Scheme (*)

Given the considerations described above relative to design flows, cofferdam configuration, and alternative types of tunnels, an economic study was undertaken to determine the optimum combination of upstream cofferdam height and tunnel diameter.

Capital costs were developed for three heights of upstream cofferdam embankment with a 30-foot wide crest and exterior slopes of 2H:1V. A freeboard allowance of 5 feet for settlement and wave runup and 10 feet for the effects of downstream ice jamming on tailwater elevations was adopted.

Capital costs for the 4,700-foot long tunnel alternatives included allowances for excavation, concrete liner, rock bolts, and steel supports. Costs were also developed for the upstream and downstream portals, including excavation and support. The cost of intake gate structures and associated gates was determined not to vary significantly with tunnel diameter and was excluded from the analysis.

Curves of headwater elevation versus tunnel diameter for the various tunnel alternatives with submerged and free outlets are presented in Figure B.2.2.4. The relationship between capital cost and crest elevation for the upstream cofferdam is shown in Figure B.2.2.5. The capital cost for various tunnel diameters with free and submerged outlets is given in Figure B.2.2.6. The results of the optimization study are presented in Figure B.2.2.7 and indicate the following optimum solutions for each alternative.

Type of Tunnel	Diameter (feet)	Cofferdam Crest Elevation (ft)	Total Cost ($)
Two pressure tunnels	30	1,595	66,000,000
Two free flow tunnels	32.5	1,580	68,000,000
Two free flow tunnels	35	1,555	69,000,000

The cost studies indicate that a relatively small cost differential (4 to 5 percent) separates the various alternatives for tunnel diameter from 30 to 35 feet.

(f) Selected Diversion Scheme (*)

An important consideration at this point is ease of cofferdam closure. For the pressure tunnel scheme, the invert of the tunnel entrance is below riverbed elevation, and once the tunnel is complete diversion can be accomplished with a closure dam section approximately 10 feet high. The free flow tunnel scheme, however, requires a tunnel invert approximately 30 feet above the riverbed level, and diversion would involve an end-dumped closure section 50 feet high. The velocities of flows which would overtop the cofferdam before the water levels were raised to reach the tunnel invert level would be prohibitively higher, resulting in complete erosion of the cofferdam, and hence the dual free flow tunnel scheme was dropped from consideration.

Based on the preceding considerations, a combination of one pressure tunnel and one free flow tunnel (or pressure tunnel with free outlet) was adopted. This will permit initial diversion to be made using both tunnels, thereby simplifying the critical closure operation and avoiding potentially serious delays in the schedule. Three alternatives were re-evaluated as follows:

Tunnel Diameter (feet)	Upstream Cofferdam Crest Elevation (feet)	Upstream Cofferdam Approximate Height (feet)
30	1595	150
35	1555	110
36	1550	100

More detailed layout studies indicated that the higher cofferdam associated with the 30-foot diameter tunnel alternative would require locating the inlet portal further upstream into "The Fins" shear zone. Since good rock conditions for portal construction are essential and the 36-foot diameter tunnel alternative would permit a portal location downstream of "The Fins", this latter alternative was adopted. As noted in (e), the overall cost difference was not significant in the range of tunnel diameters considered, and the scheme incorporating two 36-foot diameter tunnels with an upstream cofferdam crest elevation of 1,550 was incorporated as part of the selected general arrangement.

2.2.6 Spillway Facilities Alternatives (*)

As discussed in subsection 2.2.3 above, the project has been designed to safely pass floods with the following return frequencies:

Flood	Frequency	Inflow Peak (cfs)	Total Spillway Discharge (cfs)
Spillway Design	1:10,000 years	156,000	120,000
Probable Maximum	—	326,000	150,000

Discharge of the spillway design flood will require a gated service spillway on either the left or right bank. Three basic alternative spillway types were examined:

- o Chute spillway with flip bucket
- o Chute spillway with stilling basin
- o Cascade spillway.

Consideration was also given to combinations of these alternatives with or without supplemental facilities such as valved tunnels and an emergency spillway fuse plug for handling the PMF discharge.

Clearly, the selected alternative utilizing one service spillway will greatly influence and be influenced by the project general arrangement.

(a) Energy Dissipation (*)

The two chute alternatives considered achieve effective energy dissipation either by means of a flip bucket which would direct the spillway discharge in the form of a free-fall jet into a plunge pool well downstream from the dam or a stilling basin at the end of the chute which would dissipate energy in a hydraulic jump. The cascade type spillway would limit the free-fall height of the discharge by utilizing a series of 20- to 50-foot steps down to river level, with energy dissipation at each step.

All spillway alternatives were assumed to incorporate a concrete ogee type control section controlled by fixed-roller vertical lift gates. Chute spillway sections were assumed to be concrete-lined, with ample provision for air entrainment in the chute to prevent cavitation erosion, and with pressure relief drains and rock anchors in the foundation.

(b) Environmental Mitigation (*)

During development of the general arrangements for both the Watana and Devil Canyon Dams, a restriction was imposed on the amount of excess dissolved nitrogen permitted in the spillway discharges. Supersaturation occurs when aerated flows are subjected to pressures greater than 30 to 40 feet of head which forces excess nitrogen into solution. This occurs when water is subjected to the high pressures that occur in deep plunge pools or at large hydraulic jumps. The excess nitrogen would not be dissipated within the downstream Devil Canyon reservoir and a buildup of nitrogen concentration could occur throughout the body of water. It would eventually be discharged downstream from Devil Canyon with harmful effects on the fish population. On the basis of an evaluation of the related impacts and discussions with interested federal and state agencies, spillway facilities were designed to limit discharges of water from either Watana or Devil Canyon that may become supersaturated with nitrogen to a recurrence period of not less than 1:50 years.

2.2.7 - Power Facilities Alternatives (*)

Selection of the optimum power plant development involved consideration of the following:

- Location, type and size of the power plant
- Geotechnical considerations
- Number, type, size and setting of generating units
- Arrangement of intake and water passages
- Environmental constraints.

(a) Comparison of Surface and Underground Powerhouse (*)

Studies were carried out to compare the construction costs of a surface powerhouse and of an underground powerhouse at Watana. These studies were undertaken on the basis of preliminary conceptual layouts assuming four or six units and a total installed capacity of 840 MW. The comparative cost estimates for powerhouse civil works and electrical and mechanical equipment (excluding common items) indicated an advantage in favor of the underground powerhouse of $16,300,000. A summary comparison of the cost estimates for the two types of powerhouses is in Table B.2.2.6. The additional cost for the surface powerhouse arrangement is primarily associated with the longer penstocks and the steel linings required.

The underground powerhouse arrangement is also better suited to the severe winter conditions in Alaska, is less affected by river flood flows in summer, and is aesthetically less obtrusive. This arrangement has therefore been adopted for further development.

(b) Comparison of Alternative Locations (*)

Preliminary studies were undertaken during the development of conceptual project layouts at Watana to investigate both right and left bank locations for power facilities. The configuration of the site is such that south bank locations required longer penstock and/or tailrace tunnels and were therefore more expensive.

The location on the south bank was further rejected because of indications that the underground facilities would be located in relatively poor quality rock. The underground powerhouse was therefore located on the north bank such that the major openings lay between the two major shear features ("The Fins" and the "Fingerbuster").

(c) Underground Openings (*)

Because no construction adits or extensive drilling in the powerhouse and tunnel locations have been completed, it has been assumed that full concrete-lining of the penstocks and tailrace tunnels would be required. This assumption is conservative and is for preliminary design only; in practice, a large proportion of the tailrace tunnels would probably be unlined, depending on the actual rock quality encountered.

The minimum center-to-center spacing of rock tunnels and caverns has been assumed for layout studies to be 2.5 times the width or diameter of the larger excavation.

(d) Selection of Turbines (*)

The selection of turbine type is governed by the available head and flow. For the design head and specific speed, Francis type turbines have been selected. Francis turbines have a reasonably flat load-efficiency curve over a range from about 50 percent to 115 percent of rated output with peak efficiency of about 92 percent.

The number and rating of individual units is discussed in detail in subsection 2.2.2 above. The final selected arrangement comprises six units producing 170 MW each, rated at minimum reservoir level (from reservoir simulation studies) in the peak demand month (December) at full gate. The unit output at best efficiency and a rated head of 680 feet is 181 MW.

(e) Transformers (*)

The selection of transformer type, size, location and stepup rating is summarized below:

- Single-phase transformers are required because of transport limitations on Alaskan roads and railways;

- Direct transformation from 15 kV to 345 kV is preferred for overall system transient stability;

- An underground transformer gallery has been selected for minimum total cost of transformers, cables, bus, and transformer losses; and

- A grouped arrangement of three sets of three single-phase transformers for each set of two units has been selected (a total of nine transformers) to reduce the physical size of the transformer gallery and to provide a transformer spacing comparable with the unit spacing.

(f) Power Intake and Water Passages (*)

The power intake and approach channel are significant items in the cost of the overall power facilities arrangement. The size of the intake is controlled by the number and minimum spacing between the penstocks, which in turn is dictated by geotechnical considerations.

The preferred penstock arrangement comprises six individual penstocks, one for each turbine. With this arrangement, no inlet valve is required in the powerhouse since turbine dewatering can be performed by closing the control gate at the intake and draining the penstocks and scroll case through a valved bypass to the tailrace. An alternative arrangement with three penstocks was considered in detail to assess any possible advantages. This scheme would require a bifurcation and two inlet valves on each penstock and extra space in the powerhouse to accommodate the inlet valves. Estimates of relative cost differences are summarized below:

	Cost Difference ($ x 10^6)	
Item	6 Penstocks	3 Penstocks
Intake	Base Case	-20.0
Penstocks	0	- 3.0
Bifurcations	0	+ 3.0
Valves	0	+ 4.0
Powerhouse	0	+ 8.0
Capitalized Value of Extra Head Loss	0	+ 6.0
Total	0	- 2.0

Despite a marginal saving of $2 million (or less than 2 percent in a total estimated cost of $120 million) in favor of three penstocks, the arrangement of six individual penstocks has been retained. This arrangement provides improved flexibility and security of operation.

The preliminary design of the power facilities involves two tailrace tunnels leading from a common surge chamber. An alternative arrangement with a single tailrace tunnel was adopted to achieve significant cost saving.

Optimization studies on all water passages were carried out to determine the minimum total cost of initial construction plus the capitalized value of anticipated energy losses caused by conduit friction, bends and changes of section. For the penstock optimization, the construction costs of the intake and approach channel were included as a function of the penstock diameter and spacing. Similarly, in the optimization studies for the tailrace tunnel the costs of the surge chamber were included as a function of tailrace tunnel diameter.

(g) Environmental Constraints (*)

Apart from the potential nitrogen supersaturation problem discussed, the major environmental constraints on the design of the power facilities are:

- Control of downstream river temperatures, and

- Control of downstream flows.

The intake design has been modified to enable power plant flows to be drawn from the reservoir at four different levels throughout the anticipated range of reservoir drawdown for energy production in order to control the downstream river temperatures within acceptable limits.

Minimum flows at Gold Creek during the critical summer months have been studied to mitigate the project impacts on salmon spawning downstream of Devil Canyon. These minimum flows represent a constraint on the reservoir operation and influence the computation of average and firm energy produced by the Susitna development.

2.3 - Selection of Watana General Arrangement (o)

Preliminary alternative arrangements of the Watana project were developed and subjected to a series of review and screening processes. The layouts selected from each screening process were developed in greater detail prior to the next review and, where necessary, additional layouts were prepared combining the features of two or more of the alternatives. Assumptions and criteria were evaluated at each stage and additional data incorporated as necessary. The selection process followed the general selection methodology established for the Susitna project and is outlined below.

2.3.1 - Selection Methodology (*)

The determination of the project general arrangement at Watana was undertaken in three distinct review stages: preliminary, intermediate, and final.

(a) Preliminary Review (completed early in 1981) (*)

This comprised four steps:

Step 1: Assemble available data, determine design criteria, and establish evaluation criteria.

Step 2: Develop preliminary layouts and design criteria based on the above data including all plausible alternatives for the constituent facilities and structures.

Step 3: Review all layouts on the basis of technical feasibility, readily apparent cost differences, safety, and environmental impact.

Step 4: Select those layouts that can be identified as most favorable, based on the evaluation criteria established in Step 1, and taking into account the preliminary nature of the work at this stage.

(b) Intermediate Review (completed by mid-1981) (*)

This involved a series of five steps:

Step 1: Review all data, incorporating additional data from other work tasks.

Review and expand design criteria to a greater level of detail.

Review evaluation criteria and modify, if necessary.

Step 2: Revise selected layouts on basis of the revised criteria and additional data. Prepare plans and principal sections of layouts.

Step 3: Prepare quantity estimates for major structures based on drawings prepared under Step 2.

Develop a preliminary construction schedule to evaluate whether or not the selected layout will allow completion of the project within the required time frame.

Prepare a preliminary contractor's type estimate to determine the overall cost of each scheme.

Step 4: Review all layouts on the basis of technical feasibility, cost impact of possible unknown conditions and uncertainty of assumptions, safety, and environmental impact.

Step 5: Select the two most favorable layouts based on the evaluation criteria determined under Step 1.

(c) Final Review (completed early in 1982) (*)

Step 1: Assemble and review any additional data from other work tasks.

Revise design criteria in accordance with additional available data.

Finalize overall evaluation criteria.

Step 2: Revise or further develop the two layouts on the basis of input from Step 1 and determine overall dimensions of structures, water passages, gates, and other key items.

Step 3: Prepare quantity take-offs for all major structures.

Review cost components within a preliminary contractor's type estimate using the most recent data and criteria, and develop a construction schedule.

Determine overall direct cost of schemes.

Step 4: Review all layouts on the basis of practicability, technical feasibility, cost, impact of possible unknown conditions, safety, and environmental impact.

Step 5: Select the final layout on the basis of the evaluation criteria developed under Step 1.

2.3.2 - Design Data and Criteria (*)

As discussed above, the review process included assembling relevant design data, establishing preliminary design criteria, and expanding and refining these data during the intermediate and final reviews of the project arrangement. The design data and design criteria which evolved through the final review are presented in Table B.2.3.1.

2.3.3 - Evaluation Criteria (*)

The various layouts were evaluated at each stage of the review process on the basis of the criteria summarized in Table B.2.3.2. These criteria illustrate the progressively more detailed evaluation process leading to the final selected arrangement.

2.3.4 - Preliminary Review (*)

The development selection studies (Acres 1982c, Vol. 1; Acres 1981) involved comparisons of hydroelectric schemes at a number of sites on the Susitna River. As part of these comparisons a preliminary conceptual design was developed for Watana incorporating a double stilling basin type spillway.

Eight further layouts were subsequently prepared and examined for the Watana project during this preliminary review process in review process in addition to the scheme shown on Figure B.1.3.4 These eight layouts are shown in schematic form on Figure B.2.3.1. Alternative 1 of these layouts was the scheme recommended for further study.

This section describes the preliminary review undertaken of alternative Watana layouts.

(a) Basis of Comparison of Alternatives (*)

Although it was recognized that provision would have to be made for downstream releases of water during filling of the reservoir and for emergency reservoir drawdown, these features were not incorporated in these preliminary layouts. These facilities would either be interconnected with the diversion tunnels or be provided for separately. Since the system selected would be similar for all layouts with minimal cost differences and little impact on other structures, it was decided to exclude these facilities from overall assessment at this early stage.

Ongoing geotechnical explorations had identified the two major shear zones crossing the Susitna River and running roughly parallel in the northwest direction. These zones enclose a stretch of watercourse approximately 4,500 feet in length. Preliminary evaluation of the existing geological data indicated highly fractured and altered materials within the actual shear zones which would pose serious problems for conventional tunneling methods and would be unsuitable for founding of massive concrete structures. The originally proposed dam axis was located between these shear zones; since no apparent major advantage appeared to be gained from large changes in the dam location, layouts generally were kept within the confines of these bounding zones.

An earth and rockfill dam was used as the basis for all layouts. The downstream slope of the dam was assumed as 2H:1V in all alternatives, and upstream slopes varying between 2.5H:1V and 2.25H:1V were examined in order to determine the influence of variance in the dam slope on the congestion of the layout. In all preliminary arrangements except the one shown on Figure B.1.3.4, cofferdams were incorporated within the body of the main dam.

Floods greater than the routed 1:10,000-year spillway design flood and up to the probable maximum flood were assumed to be passed by surcharging the spillways, except in cases where an unlined cascade or stilling basin type spillway served as the sole discharge facility. In such instances, under large surcharges, these spillways would not act as efficient energy dissipators but would be drowned out, acting as steep open channels with the possibility of their total destruction. In order to avoid such an occurrence, the design flood for these latter spillways was considered as the routed probable maximum flood.

On the basis of information existing at the time of the preliminary review, it appeared that an underground powerhouse could be located on either side of the river. A surface powerhouse on the north bank appeared feasible but was precluded from the south bank by the close proximity of the downstream toe of the dam and the adjacent broad shear zone. Locating the powerhouse further downstream would require tunneling across the shear zone, which would be expensive and would require excavating a talus slope. Furthermore, it was found that a south bank surface powerhouse would either interfere with a south bank spillway or would be directly impacted by discharges from a north bank spillway.

(b) Description of Alternatives (*)

(i) Double Stilling Basin Scheme (*)

The scheme as shown on Figure B.1.3.4 has a dam axis location similar to that originally proposed by the

COE, and a north bank double stilling basin spillway. The spillway follows the shortest line to the river, avoiding interference with the dam and discharging downstream almost parallel to the flow into the center of the river. A substantial amount of excavation is required for the chute and stilling basins, although most of this material could probably be used in the dam. A large volume of concrete is also required for this type of spillway, resulting in a spillway system that would be very costly. The maximum head dissipated within each stilling basin is approximately 450 feet. Within world experience, cavitation and erosion of the chute and basins should not be a problem if the structures are properly designed. Extensive erosion downstream would not be expected.

The diversion follows the shortest route, cutting the bend of the river on the north bank, and has inlet portals as far upstream as possible without having to tunnel through "The Fins." It is possible that the underground powerhouse is in the area of "The Fingerbuster," but the powerhouse could be located upstream almost as far as the system of drain holes and galleries just downstream of the main dam grout curtain.

(ii) Alternative 1 (*)

This alternative (Figure B.2.3.1) is recommended for further study and is similar to the layout described above except that the north side of the dam has been rotated clockwise, the axis relocated upstream, and the spillway changed to a chute and flip bucket. The revised dam alignment resulted in a slight reduction in total dam volume compared to the above alternative. A localized downstream curve was introduced in the dam close to the north abutment in order to reduce the length of the spillway. The alignment of the spillway is almost parallel to the downstream section of the river and it discharges into a pre-excavated plunge pool in the river approximately 800 feet downstream from the flip bucket. This type of spillway should be considerably less costly than one incorporating a stilling basin, provided that excessive pre-excavation of bedrock within the plunge pool area is not required. Careful design of the bucket will be required, however, to prevent excessive erosion downstream, causing undermining of the valley sides and/or buildup of material downstream which could cause elevation of the tailwater levels.

(iii) Alternatives 2 through 2D (*)

Alternative 2 consists of a south bank cascade spillway with the main dam axis curving downstream at the abutments. The cascade spillway would require an extremely large volume of rock excavation, but it is probable that most of this material, with careful scheduling, could be used in the dam. The excavation would cross "The Fingerbuster" and extensive dental concrete would be required in that area. In the upstream portion of the spillway, velocities would be relatively high because of the narrow configuration of the channel, and erosion could take place in this area in proximity to the dam. The discharge from the spillway enters the river perpendicular to the general flow, but velocities would be relatively low and should not cause substantial erosion problems. The powerhouse is in the most suitable location for a surface alternative where the bedrock is close to the surface and the overall rock slope is approximately 2H:1V.

Alternative 2A is similar to Alternative 2 except that the upper end of the channel is divided and separate control structures are provided. This division would allow the use of one structure or upstream channel while maintenance or remedial work is being performed on the other.

Alternative 2B is similar to Alternative 2 except that the cascade spillway is replaced by a double stilling basin type structure. This spillway is somewhat longer than the similar type of structure on the north bank in the alternative described above. However, the slope of the ground is less than the rather steep north bank and may be easier to construct, a factor which may partly mitigate the cost of the longer structure. The discharge is at a sharp angle to the river and more concentrated than the cascade, which could cause erosion of the opposite bank.

Alternative 2C is a derivative of 2B with a similar arrangement, except that the double stilling basin spillway is reduced in size and augmented by an additional emergency spillway in the form of an inclined, unlined rock channel. Under this arrangement the concrete spillway acts as the main spillway, passing the 1:10,000-year design flood with greater flows passed down the unlined channel which is closed at its upstream end by an erodible fuse plug. The problems of erosion of the opposite bank still remain, although these could be overcome by excavation and/or slope protection. Erosion of the chute would be extreme for significant flows, although it is highly unlikely that this emergency spillway would ever be used.

Alternative 2D replaces the cascade of Alternative 2 with a lined chute and flip bucket. The comments relative to the flip bucket are the same as for Alternative 1 except that the south bank location in this instance requires a longer chute, partly offset by lower construction costs because of the flatter slope. The flip bucket discharges into the river at an angle which may cause erosion of the opposite bank. The underground powerhouse is located on the north bank, an arrangement which provides an overall reduction of the length of the water passages.

(iv) Alternative 3 (*)

This arrangement has a dam axis location slightly upstream from Alternative 2, but retains the downstream curve at the abutments. The main spillway is an unlined rock cascade on the south bank which passes the design flood. Discharges beyond the 1:10,000-year flood would be discharged through the auxiliary concrete-lined chute and flip bucket spillway on the north bank. A gated control structure is provided for this auxiliary spillway which gives it the flexibility to be used as a backup if maintenance should be required on the main spillway. Erosion of the cascade may be a problem, as mentioned previously, but erosion downstream should be a less important consideration because of the low unit discharge and the infrequent operation of the spillway. The diversion tunnels are situated in the north abutment, as with previous arrangements, and are of similar cost for all these alternatives.

(v) Alternative 4 (*)

This alternative involves rotating the axis of the main dam so that the south abutment is relocated approximately 1,000 feet downstream from its Alternative 2 location. The relocation results in a reduction in the overall dam quantities but would require siting the impervious core of the dam directly over "The Fingerbuster" shear zone at maximum dam height. The south bank spillway, consisting of chute and flip bucket, is reduced in length compared to other south bank locations, as are the power facility water passages. The diversion tunnels are situated on the south bank; there is no advantage to a north bank location, since the tunnels are of similar length owing to the overall downstream relocation of the dam. Spillways and power facilities would also be lengthened by a north bank location with this dam configuration.

(vi) Selection of Schemes for Further Study (*)

A basic consideration during design development was that the main dam core should not cross the major shear zones because of the obvious problems with treatment of the foundation. Accordingly, there is very little scope for realigning the main dam apart from a slight rotation to place it more at right angles to the river.

Location of the spillway on the north bank results in a shorter distance to the river and allows discharges almost parallel to the general direction of river flow. The double stilling basin arrangement would be extremely expensive, particularly if it must be designed to pass the probable maximum flood. An alternative such as 2C would reduce the magnitude of design flood to be passed by the spillway but would only be acceptable if an emergency spillway with a high degree of operational predictability could be constructed. A flip bucket spillway on the north bank, discharging directly down the river, would appear to be an economic arrangement, although some scour might occur in the plunge pool area. A cascade spillway on the south bank could be an acceptable solution provided that most of the excavated material could be used in the dam, and adequate rock conditions exist.

The length of diversion tunnels can be decreased if they are located on the north bank. In addition, the tunnels would be accessible by a preliminary access road from the north, which is the most likely route. This location would also avoid the area of "The Fingerbuster" and the steep cliffs which would be encountered on the south side close to the downstream dam toe.

The underground configuration assumed for the powerhouse in these preliminary studies allows for location on either side of the river with a minimum of interference with the surface structures.

Four of the preceding layouts, or variations of them, were selected for further study:

- A variation of the double stilling basin scheme, but with a single stilling basin main spillway on the north bank, a rock channel and fuse plug emergency spillway, a south bank underground powerhouse and a north bank diversion scheme;

- Alternative 1 with a north bank flip bucket spillway, an underground powerhouse on the south bank, and north bank diversion;

- A variation of Alternative 2 with a reduced capacity main spillway and a north bank rock channel with a fuse plug serving as an emergency spillway; and

- Alternative 4 with a south bank rock cascade spillway, a north bank underground powerhouse, and a north bank diversion.

2.3.5 - Intermediate Review (*)

For the intermediate review process, the four schemes selected as a result of the preliminary review were examined in more detail and modified. A description of each of the schemes is given below and shown on Figures B.2.3.2 through B.2.3.7. The general locations of the upstream and downstream shear zones shown on these plates are approximate and have been refined on the basis of subsequent field investigations for the proposed project.

(a) Description of Alternative Schemes (*)

The four schemes are shown on Figures B.2.3.2 through B.2.3.7.

(i) Scheme WP1 (Figure B.2.3.2) (*)

This scheme is a refinement of Alternative 1. The upstream slope of the dam is flattened from 2.5:1

to 2.75:1. This conservative approach was adopted to provide an assessment of the possible impacts on project layout of conceivable measures which may prove necessary in dealing with severe earthquake design conditions. Uncertainty with regard to the nature of river alluvium also led to the location of the cofferdams outside the limits of the main dam embankment. As a result of these conditions, the intake portals of the diversion tunnels on the north bank are also moved upstream from "The Fins". A chute spillway with a flip bucket is located on the north bank. The underground powerhouse is located on the south bank.

(ii) Scheme WP2 (Figures B.2.3.4 and B.2.3.5) (*)

This scheme is derived from the double stilling basin layout. The main dam and diversion facilities are similar to Scheme WP1 except that the downstream cofferdam is relocated further downstream from the spillway outlet and the diversion tunnels are correspondingly extended. The main spillway is located on the north bank, but the two stilling basins of the preliminary scheme (Acres 1981) are combined into a single stilling basin at the river level. An emergency spillway is also located on the north bank and consists of a channel excavated in rock, discharging downstream from the area of the relict channel. The channel is closed at its upstream end by a compacted earthfill fuse plug and is capable of discharging the flow differential between the probable maximum flood and the surcharged capacity of the main spillway. The underground powerhouse is located on the south bank.

(iii) Scheme WP3 (Figures B.2.3.3 and B.2.3.4) (*)

This scheme is similar to Scheme WP1 in all respects except that an emergency spillway is added consisting of north bank rock channel and fuse plug.

(iv) Scheme WP4 (Figures B.2.3.6 and B.2.3.7) (*)

The dam location and geometry for Scheme WP4 are similar to that for the other schemes. The diversion is on the north bank and discharges downstream from the powerhouse tailrace outlet. A rock cascade spillway is located on the south bank and is served by two separate control structures with downstream stilling basins. The underground powerhouse is located on the north bank.

(b) Comparison of Schemes (*)

The main dam is in the same location and has the same configuration for each of the four layouts considered. The cofferdams have been located outside the limits of the main dam in order to allow more extensive excavation of the alluvial material and to ensure a sound rock foundation beneath the complete area of the dam. The overall design of the dam is conservative, and it was recognized during the evaluation that savings in both fill and excavation costs can probably be made after more detailed study.

The diversion tunnels are located on the north bank. The upstream flattening of the dam slope necessitates the location of the diversion inlets upstream from "The Fins" shear zone which would require extensive excavation and support where the tunnels pass through this extremely poor rock zone and could cause delays in the construction schedule.

A low-lying area exists on the north bank in the area of the relict channel and requires approximately a 50-foot high saddle dam for closure, given the reservoir operating level assumed for the comparison study. However, the finally selected reservoir operating level will require only a nominal freeboard structure at this location.

A summary of capital cost estimates for the four alternative schemes is given in Table B.2.3.3.

The results of this intermediate analysis indicate that the chute spillway with flip bucket (Scheme WP1) is the least costly spillway alternative.

The scheme has the additional advantage of relatively simple operating characteristics. The control structure has provision for surcharging to pass the design flood. The probable maximum flood can be passed by additional surcharging up to the crest level of the dam. In Scheme WP3 a similar spillway is provided, except that the control structure is reduced in size and discharges above the routed design flood are passed through the rock channel emergency spillway. The arrangement in Scheme WP1 does not provide a backup facility to the main spillway, so that if repairs caused by excessive plunge pool erosion or damage to the structure itself require removal of the spillway from service for any length of time, no alternative discharge facility would be available. The additional spillway of Scheme WP3 would permit emergency discharge if it were required under extreme circumstances.

The stilling basin spillway (Scheme WP2) would reduce the potential for extensive erosion downstream, but high velocities in the lower part of the chute could cause cavitation even with the provision for aeration of the discharge. This type of spillway would be very costly, as can be seen from Table B.2.3.3.

The feasibility of the rock cascade spillway is entirely dependent on the quality of the rock, which dictates the amount of treatment required for the rock surface and also the proportion of the excavated material which can be used in the dam. For determining the capital cost of Scheme WP4, conservative assumptions were made regarding surface treatment and the portion of material that would have to be wasted.

The diversion tunnels are located on the north bank for all alternatives examined in the intermediate review. For Scheme WP2, the downstream portals must be located downstream from the stilling basin, resulting in an increase of approximately 800 feet in the length of the tunnels. The south bank location of the powerhouse requires its placement close to a suspected shear zone, with the tailrace tunnels passing through this shear zone to reach the river. A longer access tunnel is also required, together with an additional 1,000 feet in the length of the tailrace. The south-side location is remote from the main access road, which will probably be on the north side of the river, as will the transmission corridor.

(c) Selection of Schemes for Further Study (*)

Examination of the technical and economic aspects of Schemes WP1 through WP4 indicates there is little scope for adjustment of the dam axis, owing to the confinement imposed by the upstream and downstream shear zones. In addition, passage of the diversion tunnels through the upstream shear zone could result in significant delays in construction and additional cost.

From a comparison of costs in Table B.2.3.3, it can be seen that the flip bucket type spillway is the most economical, but because of the potential for erosion under extensive operation it is undesirable to use it as the only discharge facility. A mid-level release will be required for emergency drawdown of the reservoir, and use of this release as the first-stage service spillway with the flip bucket as a backup facility would combine flexibility and safety of operation with reasonable cost. The emergency rock channel spillway would be retained for discharge of PMF flows.

The stilling basin spillway is very costly and the operating head of 800 feet is beyond precedent experience. Erosion downstream should not be a problem but cavitation on the chute could occur. Scheme WP2 was therefore eliminated from further consideration.

The cascade spillway was also not favored, for technical and economic reasons. However, this arrangement does have an advantage in that it provides a means of preventing nitrogen supersaturation in the downstream discharges from the project which could be harmful to the fish population. A cascade configuration would reduce the dissolved nitrogen content; hence, this alternative was retained for further evaluation. The capacity of the cascade was reduced and the emergency rock channel spillway was included to pass the extreme floods.

The results of the intermediate review indicated that the following components should be incorporated into any scheme carried forward for final review:

- o Two diversion tunnels located on the north bank of the river;

- o An underground powerhouse also located on the north bank;

- o An emergency spillway, comprising a rock channel excavated on the north bank and discharging well downstream from the north abutment. The channel is sealed by an erodible fuse plug of impervious material designed to fail if overtopped by the reservoir; and

- o A compacted earthfill and rockfill dam situated between the two major shear zones which traverse the project site.

As discussed above, two specific alternative methods exist with respect to routing of the spillway design flood and minimizing the adverse effects of nitrogen supersaturation on the downstream fish population. These alternatives are:

- o A chute spillway with flip bucket on the north bank to pass the spillway design flood, with a mid-level release system designed to operate for floods with a frequency of up to about 1:50 years; or

- A cascade spillway on the south bank.

Accordingly, two schemes were developed for further evaluation as part of the final review process. These schemes are described separately in the paragraphs below.

2.3.6 - Final Review (*)

The two schemes considered in the final review process were essentially derivations of Schemes WP3 and WP4.

(a) Scheme WP3A (Figure B.2.3.8) (*)

This scheme is a modified version of Scheme WP3 described above. Because of scheduling and cost considerations, it is extremely important to maintain the diversion tunnels downstream from "The Fins." It is also important to keep the dam axis as far upstream as possible to avoid congestion of the downstream structures. For these reasons, the inlet portals to the diversion tunnels were located in the sound bedrock forming the downstream boundary of "The Fins." The upstream cofferdam and main dam are maintained in the upstream locations as shown on Figure B.2.3.8. As mentioned previously, additional criteria have necessitated modifications in the spillway configuration, and low-level and emergency drawdown outlets have been introduced. The main modifications to the scheme are as follows.

(i) Main Dam (*)

Continuing preliminary design studies and review of world practice suggest that an upstream slope of 2.4H:1V would be acceptable for the rock shell. Adoption of this slope results not only in a reduction in dam fill volume but also a reduction in the base width of the dam which permits the main project components to be located between the major shear zones.

The downstream slope of the dam is retained as 2H:1V. The cofferdams remain outside the limits of the dam in order to allow complete excavation of the riverbed alluvium.

(ii) Diversion (*)

In the intermediate review arrangements, diversion tunnels passed through the broad structure of "The Fins," an intensely sheared area of breccia, gouge, and infills. Tunneling of this material would be difficult, and might even require excavation in open cut from the surface. High cost would be involved, but more important would be the time taken for construction in this area and the possibility of unexpected delays. For this reason, the inlet portals have been relocated downstream from this zone with the tunnels located closer to the river and crossing the main system of jointing at approximately 45°. This arrangement allows for shorter tunnels with a more favorable orientation of the inlet and outlet portals with respect to the river flow directions.

A separate low-level inlet and concrete-lined tunnel is provided, leading from the reservoir at approximate Elevation 1,550 to downstream of the diversion plug where it merges with the diversion tunnel closest to the river. This low-level tunnel is designed to pass flows up to 12,000 cfs during reservoir filling. It would also pass up to 30,000 cfs under 500-foot head to allow emergency draining of the reservoir.

Initial closure is made by lowering the gates to the tunnel located closest to the river and constructing a concrete closure plug in the tunnel at the location of the grout curtain underlying the core of the main dam. On completion of the plug, the low-level release is opened and controlled discharges are passed downstream. The closure gates within the second diversion tunnel portal are then closed and a concrete closure plug constructed in line with the grout curtain. After closure of the gates, filling of the reservoir would commence.

(iii) Outlet Facilities (*)

As a provision for drawing down the reservoir in case of emergency, a mid-level release is provided. The The intake to these facilities is located at depth adjacent to the power facilities intake structures. Flows would then be passed downstream through a concrete-lined tunnel, discharging beneath the downstream end of the main spillway flip bucket. In order to overcome potential nitrogen supersaturation problems, Scheme WP3A also incorporates a system of fixed-cone valves at the downstream end of the outlet facilities. The valves were sized to discharge in conjunction with the powerhouse operating at 7,000 cfs capacity (flows up to the equivalent routed 50-year flood). Eight feet of reservoir storage is utilized to reduce valve capacity. Six cone valves are required, located on branches from a steel manifold and protected by individual upstream closure gates. The valves are partly incorporated into the mass concrete block forming the flip bucket of the main spillway. The rock downstream is protected from erosion by a concrete facing slab anchored back to the sound bedrock.

(iv) Spillways (*)

As discussed above, the designed operation of the main spillway facilities was arranged to limit discharges of potentially nitrogen-supersaturated water from Watana to flows having an equivalent return period greater than 1:50 years.

The main chute spillway and flip bucket discharge into an excavated plunge pool in the downstream river bed. Releases are controlled by a three-gated ogee structure located adjacent to the outlet facilities and power intake structure just upstream from the dam centerline. The design discharge is approximately 120,000 cfs, corresponding to the routed 1:10,000-year flood (150,000 cfs) reduced by the 31,000 cfs flows attributable to outlet and power facilities discharges. Maximum reservoir level is 2,194 feet. The plunge pool is formed by excavating the alluvial river deposits to bedrock. Since the excavated plunge pool approaches the limits of the calculated maximum scour hole, it is not anticipated that, given the infrequent discharges, significant downstream erosion will occur.

An emergency spillway is provided by means of a channel excavated in rock on the north bank, discharging well downstream from the north abutment in the direction of Tsusena Creek. The channel is sealed by an erodible fuse plug of impervious material designed to fail if overtopped by the reservoir, although some preliminary excavation may be necessary. The crest level of the plug will be set at Elevation 2,230, well below that of the main dam. The channel will be capable of passing, in conjunction with the main spillway and outlet facilities, the probable maximum flood of 326,000 cfs.

(v) Power Facilities (*)

The power intake is set slightly upstream from the dam axis deep within sound bedrock at the downstream end of the approach channel. The intake consists of six units with provision in each unit for drawing flows from a variety of depths covering the complete drawdown range of the reservoir. This facility also provides for drawing water from the different temperature strata within the upper part of the reservoir and thus regulating the temperature of the downstream discharges close to the natural temperatures of the river or temperatures advantageous to fishery enhancement. For this preliminary conceptual arrangement, flow withdrawals from different levels are achieved by a series of upstream vertical shutters moving in a single set of guides and operated to form openings at the required level. Downstream from these shutters each unit has a pair of wheel-mounted closure gates which will isolate the individual penstocks.

The six penstocks are 18-foot diameter, concrete-lined tunnels inclined at 55° immediately downstream from the intake to a nearly horizontal portion leading to the powerhouse. This horizontal portion is steel-lined for 150 feet upstream from the turbine units to extend the seepage path to the powerhouse and reduce the flow within the fractured rock area caused by blasting in the adjacent powerhouse cavern.

The six 170-MW turbine/generator units are housed within the major powerhouse cavern and are serviced by an overhead crane which runs the length of the powerhouse and into the service area adjacent to the units. Switchgear, maintenance room and offices are located within the main cavern, with the transformers situated downstream in a separate gallery excavated above the tailrace tunnels. Six inclined tunnels carry the connecting bus ducts from the main power hall to the transformer gallery. A vertical elevator and vent shaft run from the power cavern to the main office building and control room located at the surface. Vertical cable shafts, one for each pair of transformers, connect the transformer gallery to the switchyard directly overhead. Downstream from the transformer gallery the underlying draft tube tunnels merge into two surge chambers (one chamber for three draft tubes) which also house the draft tube gates for isolating the units from the tailrace. The gates are operated by an overhead traveling gantry located in the upper part of each of the surge chambers. Emerging from the ends of the chambers, two concrete-lined, low-pressure tailrace tunnels carry the discharges to the river. Because of space restrictions at the river, one of these tunnels has been merged with the downstream end of the diversion tunnel. The other tunnel emerges in a separate portal with provision for the installation of bulkhead gates.

The orientation of water passages and underground caverns is such as to avoid, as far as possible, alignment of the main excavations with the major joint sets.

(vi) Access (*)

Access is assumed to be from the north side of the river. Permanent access to structures close to the river is by a road along the north downstream river bank and then via a tunnel passing through the concrete forming the flip bucket. A tunnel from this point to the power cavern provides for vehicular access. A secondary access road across the crest of the dam passes down the south bank of the valley and across the lower part of the dam.

(b) Scheme WP4A (Figure B.2.3.9) (*)

This scheme is similar in most respects to Scheme WP3A previously discussed, except for the spillway arrangements.

(i) Main Dam (*)

The main dam axis is similar to that of Scheme WP3A, except for a slight downstream rotation at the south abutment at the spillway control structures.

(ii) Diversion (*)

The diversion and low-level releases are the same for the two schemes.

(iii) Outlet Facilities (*)

The outlet facilities used for emergency drawdown are separate from the main spillway for this scheme.

The outlet facilities consist of a low-level gated inlet structure discharging up to 30,000 cfs into the river through a concrete-lined, free-flow tunnel with a ski jump flip bucket. This facility may also be operated as an auxiliary outlet to augment the main south bank spillway.

(iv) Spillways (*)

The main south bank spillway is capable of passing a design flow equivalent to the 1:10,000-year flood through a series of 50-foot drops into shallow pre-excavated plunge pools. The emergency spillway is designed to operate during floods of greater magnitude up to and including the PMF.

Main spillway discharges are controlled by a broad multi-gated control structure discharging into a shallow stilling basin. The feasibility of this arrangement is governed by the quality of the rock in the area, requiring both durability to withstand erosion caused by spillway flows and a high percentage of sound rockfill material that can be used from the excavation directly in the main dam.

On the basis of the site information developed concurrently with the general arrangement studies, it became apparent that the major shear zone known to exist in the south bank area extended further downstream than initial studies had indicated. The cascade spillway channel was therefore lengthened to avoid the shear area at the lower end of the cascade. The arrangement shown on Figure B.2.3.9 for Scheme WP4A does not reflect this relocation, which would increase the overall cost of the scheme.

The emergency spillway consisting of rock channel and fuse plug is similar to that of the north bank spillway scheme.

(v) Power Facilities (*)

The power facilities are similar to those in Scheme WP3A.

(c) Evaluation of Final Alternative Schemes (*)

An evaluation of the dissimilar features for each arrangement (the main spillways and the discharge arrangements at the downstream end of the outlets) indicates a saving in capital cost of $197,000,000, excluding contingencies and indirect cost, in favor of Scheme WP3A. If this difference is adjusted for the savings associated with using an appropriate proportion of excavated material from the cascade spillway as rockfill in the main dam, this represents a net overall cost difference of approximately $110,000,000 including contingencies, engineering, and administration costs.

As discussed above, although limited information exists regarding the quality of the rock in the downstream area on the south bank, it is known that a major shear zone runs through and is adjacent to the area presently allocated to the spillway in Scheme WP4. This would require relocating the south bank cascade spillway several hundred feet farther downstream into an area where the rock quality is unknown and the topography less suited to the gentle overall slope of the cascade. The cost of the excavation would substantially increase compared to previous assumptions, irrespective of the rock quality. In addition, the resistance of the rock to erosion and the suitability for use as excavated material in the main dam would become less certain. The economic feasibility of this scheme is largely predicated on this last factor, since the ability to use the material as a source of rockfill for the main dam represents a major cost saving.

In conjunction with the main chute spillway, the problem of the occurrence of nitrogen supersaturation can be overcome by the use of a regularly operated dispersion-type valve outlet facility in conjunction with the main chute spillway. Since this scheme presents a more economical solution with fewer potential problems concerning the geotechnical aspects of its design, the north bank chute arrangement (Scheme WP3A) has been adopted as the final selected scheme.

Subsequent to adoption of the final scheme and prior to submission of the July 1983 License Application, refinements to the design were made as presented in Exhibit F.

2.3.7 - Amendment to License Application (***)

Since the filing of the License Application, additional studies and geotechnical investigations have been conducted. These have been directed toward reviewing and refining project design concepts and estimating costs of alternative features and layouts. With more information available after the completion of two drilling programs conducted during the Winter of 1982-83 and the Summer of 1984, estimated project costs have been reduced. Studies of alternatives have also shown where cost reductions can be made. Revisions of the project design concepts are therefore shown in this amendment to the License Application and are described below.

(a) Staged Construction (***)

In this amended License Application, the Susitna Project will be constructed in three stages. The initial construction of the Watana development will be for normal maximum operating reservoir at el. 2,000, and is designated Stage I. Construction of the Devil Canyon development for normal maximum operating reservoir at el. 1,455 is designated Stage II and is scheduled after the Watana initial construction. The raising of Watana dam for the el. 2,185 reservoir, its ultimate height, is designated Stage III. The layouts of the three stages are presented in Figures B.2.3.10, B.2.3.11, and B.2.3.12.

Constructing the Watana development in stages will reduce the initial financial commitment of the state and the burden on electric rate payers by providing more flexibility in meeting load growth.

(b) Diversion Tunnels and Cofferdams (***)

The diversion tunnel concept shown in Exhibit F of the initial application consists of two 38-foot diameter tunnels. Tunnel 1 was set high in order to pass ice without pressurizing. Tunnel 2 was set below the river bed to divert flow from the upstream cofferdam area, easing its closure. Tunnel 1 would later be converted to an emergency release facility, as previously described in the application.

Studies were conducted to verify the necessity of passing ice through a tunnel with free surface flow. It was concluded that a pressurized tunnel can pass ice, therefore, lowering Tunnel 1 is feasible to increase its hydraulic capacity. The two 36-foot diameter diversion tunnels, as proposed in this amendment, will pass the 1:50-year flood. This same criterion was in the initial License Application.

In the amended project, Tunnel 2 is raised by 25 feet to avoid the potential for clogging by bed load deposition in a continuously submerged tunnel.

These revisions will result in improved performance of the diversion tunnels and reduce cost.

Cofferdam crest elevations have been increased, to provide a greater level of protection to the dam foundation excavation area during construction from a possible ice jam causing higher river level. The combination of greater cofferdam heights and reduced tunnel diameters still results in a decrease in construction cost.

(c) Excavation and Foundation Treatment for Dam (***)

The main dam foundation treatment, as shown in this License Application Amendment, would reduce rock excavation beneath the core and shells and limit excavation of the river valley alluvium to the central 80% of the dam foundation. The areas of the dam in proximity to the upstream and downstream toes of the embankment are now planned to be founded on the riverbed alluvium.

The 1983 Winter Geologic Exploration showed that the bedrock is of a better quality than originally anticipated. Therefore, only limited excavation of bedrock beneath the embankment is foreseen. Fresh hard diorite in most instances exists from the bedrock surface. Removal or foundation treatment (dental excavation of concrete backfill) will be performed in local areas beneath the shells where erodible or otherwise unsatisfactory foundation bedrock is encountered. The quantity of rock to be removed under the embankment will be reduced from that estimated in the License Application by about 3.75 million cubic yards. The License Application cost estimates assumed a trench beneath the impervious core and filters averaging 40 feet deep, and an average excavated depth under the shells of 10 feet. The amended design provides a core trench 10 feet deep in the river section, and 20 feet deep on the abutments. Excavation under the shells on the abutments averages one foot. A reduction in the grout curtain drilling and grouting was also made, in view of the better quality foundation bedrock.

(d) Dam and Cofferdam Configuration and Composition (***)

The License Application design for the dam cross section has been essentially retained in this amendment, as it is considered to be satisfactory and will produce a stable structure. To increase safety against seismic shaking, the steepening of the exterior slopes near the embankment crest has been eliminated. This results in the same exterior slope from crest to toe both upstream and downstream. The embankment internal zoning design has also been modified to incorporate materials from the required excavations along with by-product materials from the processing operations. The amended layout includes the use of rock and processed granular materials in the shells outside the impervious core. This section increases the utilization of available materials and will reduce required borrow as well as reduce spoil requirements.

The cofferdam sections have been revised to a more conservative design, and a positive slurry trench cutoff to bedrock is provided.

(e) Spillway (***)

This License Application Amendment eliminates the emergency spillway and increases the discharge capacity of the chute spillway and flip bucket to pass the routed PMF. This revision will reduce cost of the development and reduce terrestrial and aesthetic impacts by reducing ground surface disturbance.

The capacity of the spillway will be increased by providing larger gates and increasing the width of the chute and flip bucket. The three gates will be increased from 36 feet wide by 49 feet high to 44 feet wide by 64 feet high.

The width of the chute, which varied from 140 to 80 feet, will be increased to vary from 164 to 120 feet. The flip bucket will be increased from 80 feet to 120 feet wide.

In Stage I the crest of the spillway control structure will be at el. 1,950, and in Stage III the crest will be at el. 2,135. The ultimate crest will be 13 feet lower than previously shown to accomodate the larger gates for the increased discharge capacity.

This amendment also includes a revision of the type of spillway gate from fixed wheel gate to radial gate and revises the type of hoist from electric motor driven drum to hydraulic cylinder operator. The revised type of gate will cost less and will have improved operating characteristics.

(f) Relocation and Reorientation of Caverns (***)

A review of the site geology indicated a major set of fractures which trended N 50°W and a second minor set perpendicular to these. The caverns for the powerhouse, transformer gallery, and surge chamber, as shown in the License Application, trend in a direction approximately N 20°W, straddling between the major joint system and a subjoint system.

Excavation of the longitudinal walls would be improved if the major joint planes were to intersect the walls as near to the perpendicular as possible. Consequently, the caverns have been rotated accordingly, resulting in less overbreak of rock in the cavern faces, fewer construction problems and improved safety during construction. This change will also be beneficial to the changes in the power conduits and access tunnel geometry described below.

(g) Power Conduits and Intake (***)

The License Application indicates a single structure power intake with six intake passages located approximately 1,000 feet upstream from the dam axis. The power conduits consist of six individual penstock tunnels and shafts with a developed length of about 1,500 feet each connecting the intake structure to the powerhouse, and two tailrace tunnels approximately 2,000 feet long connecting the powerhouse to the river. The dowstream 300 feet of one of the tailrace tunnels utilized the downstream portion of one of the diversion tunnels.

To reduce the power conduit length in the amended design, the intake structure was shifted to a location between the spillway and the river channel and nearer to the dam axis, resulting in relocation and shortening of the power conduits. The number of penstock tunnels was reduced from six to three power tunnels, each of which will bifurcate to smaller penstock tunnels. Guard valves will be provided for each turbine. The net head on the generating units will be greater, and the shorter, more efficient power conduits will provide better unit operation. Vertical shafts are also shown instead of sloping shafts because excavation and concreting of vertical shafts requires less time, personnel, and equipment, and given the geologic conditions, should result in less overbreak.

(h) Power Intake and Spillway Approach Channels (***)

The hydraulic conditions of the approach channels to the power intake and spillway as shown in the License Application can be improved with the relocation of the powerhouse and the power conduits. In the License Application, the power intake is located such that it appears to impede flow to the spillway. The amended location of the power intake will eliminate this effect. The approach channels as shown will require larger quantities of rock excavation; however, this material can be used for fill in the dam and for concrete aggregate.

(i) Turbine-Generator Unit Speed (***)

The synchronous speed of the turbine-generator units has been increased from 225 rpm, as shown in the License Application, to 257.1 rpm. Basically, the higher speed unit required a deeper setting of the turbine distributor below tailwater. The depth shown in the License Application is, however, greater than necessary for the 225-rpm turbine and is sufficient for the 257.1-rpm turbine. This increase in speed will reduce the physical size and cost of the turbine-generator set and also may possibly result in some reduction in the powerhouse size at the time the final design is made.

(j) Gas Insulated Switchgear and Bus (***)

Revisions of the high voltage conductors from the main power transformers to the ground surface and elimination of the ground level switchyard and bus are shown in Exhibit A. These revisions include use of a single 9-foot diameter vertical SF6 bus shaft instead of two vertical 7-foot 6-inch diameter cable shafts from the transformer gallery to the surface. All switching equipment will be underground, thus simplifying maintenance. This will provide an improved environment for operation and maintenance by elimination of the potential for icing of equipment in a ground level switchyard. Substitution of SF6 buses for oil-filled cables will improve safety, removing fire hazards from the cable shaft area. Elimination of the switchyard will also reduce environmental impact and improve aesthetics by the construction of fewer and smaller surface structures.

2.4 - Devil Canyon Project Formulation (o)

This section describes the development of the general arrangement of the Devil Canyon project. The method of handling floods during construction and subsequent project operation is also outlined in this section.

The reservoir level fluctuations and inflow for Devil Canyon will essentially be controlled by operation of the upstream Watana project. This aspect is also briefly discussed in this section.

2.4.1 - Selection of Reservoir Level (*)

The selected normal maximum operating level at Devil Canyon Dam is el. 1,455. Studies by the USBR and COE on the Devil Canyon project were essentially based on a similar reservoir level, which corresponds to the average tailwater level at the Watana site. Although the narrow configuration of the Devil Canyon site and the relatively low costs involved in increasing the dam height suggest that it might be economic to do so, it is clear that the upper economic limit of reservoir level at Devil Canyon is the Watana tailrace level.

Although significantly lower reservoir levels at Devil Canyon would lead to lower dam costs, the location of adequate spillway facilities in the narrow gorge would become extremely difficult and lead to offsetting increases in cost. In the extreme case, a spillway discharging over the dam would raise concerns regarding safety from scouring at the toe of the dam, which have already led to rejection of such schemes.

2.4.2 - Selection of Installed Capacity (*)

The methodology used for the preliminary selection of installed capacity at Devil Canyon is similar to the Watana methodology described in Section 2.2.2.

The decision to operate Devil Canyon primarily as a base-load plant was governed by the following main considerations:

- o Daily peaking is more effectively performed at Watana than at Devil Canyon; and
- o Excessive fluctuations in discharge from the Devil Canyon Dam may have an undesirable impact on mitigation measures incorporated in the final design to protect the downstream fisheries.

Given this mode of operation, the required installed capacity at Devil Canyon has been determined as the maximum capacity needed to utilize the available energy from the hydrological flows of record, as modified by the reservoir operation rule curves. In years where the energy from Watana and Devil Canyon exceeds the system demand, the usable energy has been reduced at both stations in proportion to the average net head available, assuming that flows used to generate energy at Watana will also be used to generate energy at Devil Canyon.

Table B.2.4.1 shows an assessment of maximum plant capacity required at Devil Canyon in the peak demand month (December). The Devil Canyon capacity is the same whether thermal energy is used for base load or for peaking, since Devil Canyon is designed for peaking only.

The selected total installed capacity at Devil Canyon has been established as 600 MW for design purposes. This will provide some margin for standby during forced outage and possible accelerated growth in demand.

The major factors governing the selection of the unit size at Devil Canyon are the rate of growth of system demand, the minimum station output, and the requirement of standby capacity under forced outage conditions.

The power facilities at Devil Canyon have been developed using four units at 150 MW each. This arrangement will provide for efficient station operation during low load periods as well as during peak December loads. During final design, consideration of phasing of installed capacity to match the system demand may desirable. However, the uncertainty of load forecasts and the additional contractual costs of mobilization for equipment installation are such that for this study it has been assumed that all units will be commissioned by 2002.

The Devil Canyon Reservoir will usually be full in December; hence, any forced outage could result in spilling and a loss of available energy. The units have been rated to deliver 150 MW at maximum December drawdown occurring during an extremely dry year; this means that, in an average year, with higher reservoir levels, the full station output can be maintained even with one unit on forced outage.

2.4.3 - Selection of Spillway Capacity (*)

A flood frequency of 1:10,000 years was selected for the spillway design on the same basis as described for Watana. An emergency spillway with an erodible fuse plug will also be provided to safely discharge the probable maximum flood. The development plan envisages completion of the Watana project prior to construction at Devil Canyon. Accordingly, the inflow flood peaks at Devil Canyon will be less than pre-project flood peaks because of routing through the Watana reservoir. Spillway design floods are:

Flood	Inflow Peak (cfs)
1:10,000 years	165,000
Probable Maximum	345,000

The avoidance of nitrogen supersaturation in the downstream flow for Watana also will apply to Devil Canyon. Thus, the discharge of water possibly supersaturated with nitrogen from Devil Canyon will be limited to a recurrence period of not less than 1:50 years by the use of fixed-cone valves similar to Watana.

2.4.4 - Main Dam Alternatives (*)

The location of the Devil Canyon damsite was examined during previous studies by the USBR and COE. These studies focused on the narrow entrance to the canyon and led to the recommendation of a concrete arch dam. Notwithstanding this initial appraisal, a comparative analysis was undertaken as part of this feasibility study to evaluate the relative merits of the following types of structures at the same location:

- o Thick concrete arch
- o Thin concrete arch
- o Fill embankment.

(a) Comparison of Embankment and Concrete Type Dams (*)

The geometry was developed for both the thin concrete arch and the thick concrete arch dams, and the dams were analyzed and their behavior compared under static, hydrostatic, and seismic loading conditions. The project layouts for these arch dams were compared to a layout for a rockfill dam with its associated structures.

Consideration of the central core rockfill dam layout indicated relatively small cost differences from an arch dam cost estimate, based on a cross section significantly thicker than the finally selected design. Furthermore, no information was available to indicate that impervious core material in the necessary quantities could be found within a reasonable distance of the damsite. The rockfill dam was accordingly dropped from further consideration. It is further noted that, since this alternative dam study, seismic analysis of the rockfill dam at Watana has resulted in an upstream slope of 2.4H:IV, thus indicating the requirement to flatten the 2.5H:IV slope adopted for the rockfill dam alternative at Devil Canyon.

Neither of the concrete arch dam layouts was intended as the final site arrangement, but were sufficiently representative of the most suitable arrangement associated with each dam type to provide an adequate basis for comparison. Each type of dam was located just downstream of the point where the river enters Devil Canyon and close to the canyon's narrowest point, which is the optimum location for all types of dams. A brief description of each dam type and configuration is given below.

(i) Rockfill Dam (*)

For this arrangement the dam axis would be some 625 feet downstream of the crown section of the concrete dams. The assumed embankment slopes would be 2.25H:1V on the upstream face and 2H:1V on the downstream face. The main dam would be continuous with the south bank saddle dam, and therefore no thrust blocks would be required. The crest length would be 2,200 feet at el. 1,470; the crest width would be 50 feet.

The dam would be constructed with a central impervious core, inclined upstream, supported on the downstream side by a semi-pervious zone. These two zones would be protected upstream and downstream by filter and transition materials. The shell sections would be constructed of rockfill obtained from blasted bedrock. For preliminary design all dam sections would be assumed to be founded on rock; external cofferdams would be founded on the river alluvium, and would not be incorporated into the main dam. The approximate volume of material in the main dam would be 20 million cubic yards.

A single spillway would be provided on the north abutment to control all flood flows. It would consist of a gate control structure and a double stilling basin excavated into rock; the chute sections and stilling basins would be concrete-lined, with mass concrete gravity retaining walls. The design capacity would be sufficient to pass the 1:10,000-year flood without damage; excess capacity would be provided to pass the PMF without damage to the main dam by surcharging the reservoir and spillway.

The powerhouse would be located underground in the north abutment. The multi-level power intake would be constructed in a rock cut in the north abutment on the dam centerline, with four independent penstocks to the 150-MW Francis turbines. Twin concrete-lined tailrace tunnels would connect the powerhouse to the river via an intermediate draft tube manifold.

(ii) Thick Arch Dam (*)

The main concrete dam would be a single-center arch structure, acting partly as a gravity dam, with a vertical cylindrical upstream face and a sloping downstream face inclined at 1V:0.4H. The maximum height of the dam would be 635 feet, with a uniform crest width of 30 feet, a crest length of approximately 1,400 feet, and a maximum foundation width of 225 feet. The crest elevation would be 1,460. The center portion of the dam would be founded on a massive mass concrete pad constructed in the excavated riverbed. This central section would incorporate the main spillway with sidewalls anchored into solid bedrock and gated orifice spillways discharging down the steeply inclined downstream face of the dam into a single large stilling basin set below river level and spanning the valley.

The main dam would terminate in thrust blocks high on the abutments. The south abutment thrust block would incorporate an emergency gated control spillway structure which would discharge into a rock channel running well downstream and terminating at a level high above the river valley.

Beyond the control structure and thrust block, a low-lying saddle on the south abutment would be closed by means of a rockfill dike founded on bedrock. The powerhouse would house four 150-MW units and would be located underground within the north abutment. The intake would be constructed integrally with the dam and connected to the powerhouse by vertical steel-lined penstocks.

The main spillway would be designed to pass the 1:10,000-year routed flood. The probable maximum would be passed by combined discharges through the main spillway, outlet facility, and emergency spillway.

(iii) Thin Arch Dam (*)

The main dam would be a two-center, double-curved arch structure of similar height to the thick arch dam, but with a 20-foot uniform crest and a maximum base width of 90 feet. The crest elevation would be 1,460. The center section would be founded on a concrete pad, and the extreme upper portion of the dam would terminate in concrete thrust blocks located on the abutments.

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

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

The concrete dam would terminate in a massive thrust block on each abutment which, on the south abutment, would adjoin a rockfill saddle dam.

The main and auxiliary spillways would be designed to discharge the 1:10,000-year flood. The probable maximum flood would be discharged through the emergency south abutment spillway, main spillway and auxiliary spillway.

(b) Comparison of Arch Dam Types (*)

Sand and gravel for concrete aggregates are believed to be available in sufficient quantities within economical distances from the damsite. The gravel and sands are formed from the granitic and metamorphic rocks of the area; at this time it is anticipated that they will be suitable for the production of aggregates after screening and washing.

The bedrock geology of the site is discussed in the 1980-81 Geotechnical Report (Acres 1982a). At this time it appears that there are no geological or geotechnical concerns that would preclude either of the dam types from consideration.

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

The thick arch arrangement did not appear to have a distinct technical advantage compared to a thin arch dam and would be more expensive because of the larger volume of concrete needed. Studies therefore continued on refining the feasibility of the thin arch alternative.

2.4.5 - <u>Diversion Scheme Alternatives</u> (*)

In this section the selection of general arrangement and the basis for sizing of the diversion scheme are presented.

(a) <u>General Arrangements</u> (*)

The steep-walled valley at the site essentially dictated that diversion of the river during construction be accomplished using one or two diversion tunnels, with upstream and downstream cofferdams protecting the main construction area.

The selection process for establishing the final general arrangement included examination of tunnel locations on both banks of the river. Rock conditions for tunneling did not favor one bank over the other. Access and ease of construction strongly favored the south bank or abutment, the obvious approach being via the alluvial fan. The total length of tunnel required for the south bank is approximately 300 feet greater; however, access to the north bank could not be achieved without great difficulty.

(b) Design Flood for Diversion (*)

The recurrence interval of the design flood for diversion was established in the same manner as for Watana Dam. Accordingly, at Devil Canyon a risk of exceedance of 10 percent per annum has been adopted, equivalent to a design flood with a 1:10-year return period for each year of critical construction exposure. The critical construction time is estimated at 2.5 years. The main dam could be subjected to overtopping during construction without causing serious damage, and the existence of the Watana facility upstream would offer considerable assistance in flow regulation in case of an emergency. These considerations led to the selection of the design flood with a return frequency of 1:25 years.

The equivalent inflow, together with average flow characteristics of the river significant to diversion, are presented below:

- Average annual flow:
  9,080 cfs

- Design flood inflow (1:25 years routed through Watana reservoir):
  37,800 cfs

(c) Coffердams (*)

As at Watana, the considerable depth of riverbed alluvium at both cofferdam sites indicates that embankment-type cofferdam structures would be the only technically and economically feasible alternative at Devil Canyon. For the purposes of establishing the overall general arrangement of the project and for subsequent diversion optimization studies, the upstream cofferdam section adopted will comprise an initial closure section approximately 20 feet high constructed in the wet, with a zoned embankment constructed in the dry. The downstream cofferdam will comprise a closure dam structure approximately 30 feet high placed in the wet. Control of underseepage through the alluvium material may be required and could be achieved by means of a grouted zone. The coarse nature of the alluvium at Devil Canyon led to the selection of a grouted zone rather than a slurry wall.

(d) Diversion Tunnels (*)

Although studies for the Watana project indicated that concrete-lined tunnels are the most economically and technically feasible solution, this aspect was reexamined at Devil Canyon. Preliminary hydraulic studies indicated that the design flood routed through the diversion scheme would result in a design discharge of approximately 37,800 cfs. For concrete-lined tunnels, design velocities of approximately 50 ft/sec would permit the use of one concrete-lined tunnel with an equivalent diameter of 30 feet. Alternatively, for unlined tunnels a maximum design velocity of 10 ft/sec in good quality rock would require four unlined tunnels, each with an equivalent diameter of 35 feet, to pass the design flow. As was the case for the Watana diversion scheme, considerations of reliability and cost were considered sufficient to eliminate consideration of unlined tunnels for the diversion scheme.

For the purposes of optimization studies, only a pressure tunnel was considered, since previous studies indicated that cofferdam closure problems associated with free flow tunnels would more than offset their other advantages.

(e) Optimization of Diversion Scheme (*)

Given the considerations described above relative to design flows, cofferdam configuration, and alternative types of tunnels, an economic study was undertaken to determine the optimum combination of upstream cofferdam elevation (height) and tunnel diameter.

Capital costs were developed for a range of pressure tunnel diameters and corresponding upstream cofferdam embankment crest elevations with a 30-foot wide crest and exterior slopes of 2H:1V. A freeboard allowance of 5 feet was included for settlement and wave runup.

Capital costs for the tunnel alternatives included allowances for excavation, concrete liner, rock bolts, and steel supports. Costs were also developed for the upstream and downstream portals, including excavation and support. The cost of an intake gate structure and associated gates was determined not to vary significantly with tunnel diameter and was excluded from the analysis.

The centerline tunnel length in all cases was estimated to be 2,000 feet.

Rating curves for the single pressure tunnel alternatives are presented in Figure B.2.4.1. The relationship between capital costs for the upstream cofferdam and various tunnel diameters is given in Figure B.2.4.2.

The results of the optimization study indicated that a single 30-foot diameter pressure tunnel results in the overall least cost (Figure B.2.4.2). An upstream cofferdam cofferdam 60 feet high, with a crest elevation of 945, was carried forward as part of the selected general arrangement.

2.4.6 - Spillway Alternatives (*)

The project spillways have been designed to safely pass floods with the following return frequencies:

Inflow Peak Flood	Discharge Frequency	Inflow (cfs)
Spillway Design	1:10,000 years	165,000
Probable Maximum	--	345,000

A number of alternatives were considered singly and in combination for Devil Canyon spillway facilities. These included gated orifices in the main dam discharging into a plunge pool, chute or tunnel spillways with either a flip bucket or stilling basin for energy dissipation, and open channel spillways. As described for Watana, the selection of the type of spillway was influenced by the general arrangement of the major structures. The main spillway facilities would discharge the spillway design flood through a gated spillway control structure with energy dissipation by a flip bucket which directs the spillway discharge in a free-fall jet into a plunge pool in the river. As noted above, restrictions with respect to limiting nitrogen supersaturation in selecting acceptable spillway discharge structures have been applied. The various spillway arrangements developed in accordance with these considerations are discussed in Section 2.5.

2.4.7 - Power Facilities Alternatives (*)

The selection of the optimum arrangements for the power facilities involved consideration of the same factors as described for Watana.

(a) Comparison of Surface and Underground Powerhouses (*)

A surface powerhouse at Devil Canyon would be located either at the downstream toe of the dam or along the side of the canyon wall. As determined for Watana, costs favored an underground arrangement. In addition to cost, the underground powerhouse layout has been selected based on the following:

- o Insufficient space is available in the steep-sided canyon for a surface powerhouse at the base of the dam;
- o The provision of an extensive intake at the crest of the arch dam would be detrimental to stress conditions in the arch dam, particularly under earthquake loading, and would require significant changes in the arch dam geometry; and
- o The outlet facilities located in the arch dam are designed to discharge directly into the river valley; these would cause significant winter icing and spray problems to any surface structure below the dam.

(b) Comparison of Alternative Locations (*)

The underground powerhouse and related facilities have been located on the north bank for the following reasons:

- o Generally superior rock quality at depth;
- o The south bank area behind the main dam thrust block is unsuitable for the construction of the power intake; and
- o The river turns north downstream from the dam, and hence the north bank power development is more suitable for extending the tailrace tunnel to develop extra head.

(c) Selection of Units (*)

The turbine type selected for the Devil Canyon development is governed by the design head and specific speed and by economic considerations. Francis turbines have been adopted for reasons similar to those discussed for Watana in subsection 2.2.7.

The selection of the number and rating of individual units is discussed in detail in subsection 2.4.2. The four units will be rated to deliver 150 MW each at full gate opening and minimum reservoir level in December (the peak demand month).

(d) Transformers (*)

Transformer selection is similar to Watana subsection 2.2.7(e).

(e) Power Intake and Water Passages (*)

For flexibility of operation, individual penstocks are provided to each of the four units. Detailed cost studies showed that there is no significant cost advantage in using two larger diameter penstocks with bifurcation at the powerhouse compared to four separate penstocks.

A single tailrace tunnel with a length of 6,800 feet to develop 30 feet of additional head downstream from the dam has been incorporated in the design. Detailed design may indicate that two smaller tailrace tunnels for improved reliability may be superior to one large tunnel since the extra cost involved is relatively small. The surge chamber design would be essentially the same with one or two tunnels.

The overall dimensions of the intake structure are governed by the selected diameter and number of the penstocks and the minimum penstock spacing. Detailed studies comparing construction cost to the value of energy lost or gained were carried out to determine the optimum diameter of the penstocks and the tailrace tunnel.

(f) Environmental Constraints (*)

In addition to potential nitrogen-supersaturation problems caused by spillway operation, the major impacts of the Devil Canyon power facilities development are:

- Changes in the temperature regime of the river; and
- Fluctuations in downstream river flows and levels.

Temperature modeling has indicated that a multiple-level intake design at Devil Canyon would aid in controlling downstream water temperatures.

Consequently, the intake design at Devil Canyon incorporates two levels of draw-off.

The Devil Canyon station will normally be operated as a base-load plant throughout the year to satisfy the requirement of no significant daily variation in power flow.

2.5 - Selection of Devil Canyon General Arrangement (*)

The approach to selection of a general arrangement for Devil Canyon was a similar but simplified version of that used for Watana.

2.5.1 - Selection Methodology (*)

Preliminary alternative arrangements of the Devil Canyon project were developed and selected using two rather than three review stages. Topographic conditions at this site limited the development of reasonably feasible layouts, and four schemes were initially developed and evaluated. During the final review, the selected layout was refined based on technical, operational and environmental considerations identified during the preliminary review.

2.5.2 - Design Data and Criteria (*)

The design data and design criteria on which the alternative layouts were based are presented in Table B.2.5.1. Subsequent to selection of the preferred Devil Canyon scheme, the information was refined and updated as part of the ongoing study program.

2.5.3 - Preliminary Review (*)

Consideration of the options available for types and locations of various structures led to the development of four primary layouts for examination at Devil Canyon in the preliminary review phase. Previous studies had led to the selection of a thin concrete arch structure for the main dam and indicated that the most acceptable technical and economic location was at the upstream entrance to the canyon. The dam axis has been fixed in this location for all alternatives.

(a) Description of Alternative Schemes (*)

The schemes evaluated during the preliminary review are described below. In each of the alternatives evaluated, the dam is founded on the sound bedrock underlying the riverbed. The structure is 635 feet high, has a crest width of 20 feet, and a maximum base width of 90 feet. Mass concrete thrust blocks are founded high on the abutments, the south block extending approximately 100 feet above the existing bedrock surface and supporting the upper arches of the dam. The thrust block on the north abutment makes the cross-river profile of the dam more symmetrical and contributes to a more uniform stress distribution.

(i) Scheme DC1 (Figure B.2.5.1) (*)

In this scheme, diversion facilities comprise upstream and downstream earthfill and rockfill cofferdams and two 24-foot diameter tunnels beneath the south abutment.

A rockfill saddle dam occupies the lower-lying area beyond the south abutment running from the thrust block to the higher ground beyond. The impervious fill cut-off for the saddle dam is founded on bedrock approximately 80 feet beneath the existing ground surface. The maximum height of this dam above the foundation is approximately 200 feet.

The routed 1:10,000-year design flood of 165,000 cfs is passed by two spillways. The main spillway is located on the north abutment. It has a design discharge of 120,000 cfs, and flows are controlled by a three-gated ogee control structure. This discharges down a concrete-lined chute and over a flip bucket which ejects the water in a diverging jet into a pre-excavated plunge pool in the riverbed. The flip bucket is set at el. 925, approximately 35 feet above the river level. An auxiliary spillway discharging a total of 35,000 cfs is located in the center of the dam, 100 feet below the dam crest, and is controlled by three wheel-mounted gates. The orifices are designed to direct the flow into a concrete-lined plunge pool just downstream from the dam.

An emergency spillway is located in the sound rock south of the saddle dam. This is designed to pass, in conjunction with the main spillway and auxiliary spillway, a probable maximum flood of 345,000 cfs, if such an event should ever occur. The spillway is an unlined rock channel which discharges into a valley downstream from the dam leading into the Susitna River.

The upstream end of the channel is closed by an earthfill fuse plug. The plug is designed to be eroded if overtopped by the reservoir. Since the crest is lower than either the main or saddle dams, the plug would be washed out prior to overtopping of either of these structures.

The underground power facilities are located on the north bank of the river, within the bedrock forming the dam abutment. The rock within this abutment is of better quality with fewer shear zones and a lesser degree of jointing than the rock on the south side of the canyon, and hence more suitable for underground excavation.

The power intake is located just upstream from the bend in the valley before it turns sharply to the right into Devil Canyon. The intake structure is set deep into the rock at the downstream end of the approach channel. Separate penstocks for each unit lead to the powerhouse.

The powerhouse contains four 150-MW turbine/generator units. The turbines are Francis type units coupled to overhead synchronous generators. The units are serviced by an overhead crane running the length of the powerhouse and into the end service bay. Offices, the control room, switchgear room, maintenance room, etc., are located beyond the service bay. The transformers are housed in a separate upstream gallery located above the lower horizontal section of the penstocks. Two vertical cable shafts connect the gallery to the surface. The draft tube gates are housed above the draft tubes in separate annexes off the main powerhall. The draft tubes converge in two bifurcations at the tailrace tunnels which discharge under free flow conditions to the river. Access to the powerhouse is by means of an unlined tunnel leading from an access portal on the north side of the canyon.

The switchyard is located on the south bank of the river just downstream from the saddle dam, and the power cables from the transformers are carried to it across the top of the dam.

(ii) Scheme DC2 (Figure B.2.5.2) (*)

The layout is generally similar to Scheme DC1 except that the chute spillway is located on the south side of the canyon. The concrete-lined chute terminates in a flip bucket high on the south side of the canyon, dropping the discharge into the river below. The design flow is 120,000 cfs, and discharge are controlled by a three-gated ogee-crested control structure similar to that for Scheme DC1, which abuts the south side thrust block.

The saddle dam axis is straight, following the shortest route between the control structure at one end and the rising ground beyond the low-lying area at the other.

(iii) Scheme DC3 (See Figure B.2.5.3) (*)

The layout is similar to Scheme DC1 except that the north-side main spillway takes the form of a single tunnel rather than an open chute. A two-gated ogee-control structure is located at the head of the tunnel and discharges into an inclined shaft 45 feet in diameter at its upper end. The structure will discharge up to a maximum of 120,000 cfs.

The concrete-lined tunnel narrows to 35 feet in diameter and discharges into a flip bucket which directs the flows in a jet into the river below, as in Scheme DC1.

An auxiliary spillway is located in the center of the dam and an emergency spillway is excavated on the south abutment.

The layout of dams and power facilities are the same as for Scheme DC1.

(iv) Scheme DC4 (See Figure B.2.5.4) (*)

The dam, power facilities, and saddle dam for this scheme are the same as those for Scheme DC1. The major difference is the substitution of a stilling basin type spillway on the north bank for the chute and flip bucket. A three-gated ogee control structure is located at the end of the dam thrust block and controls the discharges up to a maximum of 120,000 cfs.

The concrete-lined chute is built into the face of the canyon and discharges into a 500-foot long by 115-foot wide by 100-foot high concrete stilling basin formed below river level and deep within the north side of the canyon. Central orifices in the dam and the south bank rock channel and fuse plug form the auxiliary and emergency spillways, respectively, as in the other alternative schemes.

The downstream cofferdam is located beyond the stilling basin and the diversion tunnel outlets are located farther downstream to enable construction of the stilling basin.

(b) Comparison of Alternatives (*)

The arch dam, saddle dam, power facilities, and diversion vary only in a minor degree among the four alternatives. Thus, the comparison of the schemes rests solely on a comparison of the spillway facilities.

As can be seen from a comparison of the costs in Table B.2.5.2, the flip bucket spillways are substantially less costly to construct than the stilling basin type of Scheme DC4. The south-side spillway of Scheme DC2 runs at a sharp angle to the river and ejects the discharge jet from high on the canyon face toward the opposite side of the canyon. Over a longer period of operation, scour of the heavily jointed rock could cause undermining of the canyon sides and their subsequent instability. The possibility also exists of deposition of material in the downstream riverbed with a corresponding elevation of the tailrace. Construction of a spillway on the steep south side of the river could be more difficult than on the north side because of the presence of deep fissures and large unstable blocks of rock which are present on the south side close to the top of the canyon.

The two north-side flip bucket spillway schemes, based on either an open chute or a tunnel, take advantage of a downstream bend in the river to discharge parallel to the course of the river. This will reduce the effects of erosion but could still present a problem if the estimated maximum possible scour hole should occur.

The tunnel type spillway could prove difficult to construct because of the large diameter inclined shaft and tunnel paralleling the bedding planes. The high velocities encountered in the tunnel spillway could cause problems with the possibility of spiraling flows and severe cavitation both occurring.

The stilling basin type spillway of Scheme DC4 reduces downstream erosion problems within the canyon. However, cavitation could be a problem under the high flow velocities experienced at the base of the chute. This would be somewhat alleviated by aeration of the flows. There is, however, little precedent for stilling basin operation at heads of over 500 feet; even where floods of much less than the design capacity have been discharged, severe damage has occurred.

(c) Selection of Final Scheme (*)

The chute and flip bucket spillway of Scheme DC2 could generate downstream erosion problems which could require considerable maintenance costs and cause reduced efficiency in operation of the project at a future date. Hydraulic design problems exist with Scheme DC3 which may also have severe cavitation problems. Also, there is no cost advantage in Scheme DC3 over the open chute Scheme DC1. In Scheme DC4, the operating characteristics of a high head stilling basin are little known, and there are few examples of successful operation. Scheme DC4 also costs considerably more than any other scheme (Table B.2.5.2).

All spillways operating at the required heads and discharges will eventually cause some erosion. For all shemes, the use of solid-cone valve outlet facilities in the lower portion of the dam to handle floods up to 1:50 - year frequency is considered a more reasonable approach to reduce erosion and eliminate nitrogen supersaturation problems than the gated high-level orifice outlets in the dam. Since the cost of the flip bucket type spillway in the scheme is considerably less than that of the stilling basin in Scheme DC4, and since the latter offers no relative operational advantage, Scheme DC1 has been selected for further study as the selected scheme.

2.5.4 - Final Review (*)

The layout selected in the previous section was further developed in accordance with updated engineering studies and criteria. The major change compared to Scheme DC1 is the elimination of the high-level gated orifices and introduction of low-level fixed-cone valves, but other modifications that were introduced are described below.

The revised layout is shown on Figure B.2.5.5. A description of the structures is as follows.

(a) Main Dam (*)

The maximum operating level of the reservoir was raised to el. 1,455 in accordance with updated information relative to the Watana tailwater level. This requires raising the dam crest to el. 1,463 with the concrete parapet wall crest at el. 1,466. The saddle dam was raised to el. 1,472.

(b) Spillways and Outlet Facilities (*)

To eliminate the potential for nitrogen supersaturation problems, the outlet facilities were designed to restrict supersaturated flow to an average recurrence interval of greater than 50 years. This led to the replacement of the high-level gated orifice spillway by outlet facilities incorporating seven fixed-cone valves, three with a diameter of 90 inches and four with a diameter of 102 inches, capable of passing a design flow of 38,500 cfs.

The chute spillway and flip bucket are located on the north bank, as in Scheme DC1; however, the chute length was decreased and the elevation of the flip bucket raised compared to Scheme DC1.

More recent site surveys indicated that the ground surface in the vicinity of the saddle dam was lower than originally estimated. The emergency spillway channel was relocated slightly to the south to accommodate the larger dam.

(c) Diversion (*)

The previous twin diversion tunnels were replaced by a single tunnel scheme. This was determined to provide all necessary security and will cost approximately one-half as much as the two tunnel alternative.

(d) Power Facilities (*)

The drawdown range of the reservoir was reduced, allowing a reduction in height of the power intake. In order to locate the intake within solid rock, it has been moved into the side of the valley, requiring a slight rotation of the water passages, powerhouse, and caverns comprising the power facilities.

Subsequent to the adoption of this scheme and prior to submission of the July 1983 License Application, refinements to the design were made as presented in Exhibit F.

2.5.5. - Amendment to License Application (***)

The amended layout of Devil Canyon (Stage II) is presented in Figure B.2.3.11. This eliminates the emergency spillway and increases the discharge capacity of the chute spillway and flip bucket to pass the routed PMF. This revision will reduce cost of the development and reduce terrestrial and aesthetic impacts by reducing ground surface disturbance.

The capacity of the spillway will be increased by providing larger gates and increasing the width of the chute and flip bucket. Each of the three gates will be increased from 30 feet wide by 56 feet high to 48 feet wide by 58 feet high.

The chute width, which varied from 122 feet to 80 feet, will be increased to vary from 176 feet to 150 feet. The flip bucket width will be increased from 80 feet to 150 feet wide. The crest of the spillway control structure will be lowered from el. 1,404 to el. 1,398.

The type of gate and operator will be revised from fixed wheel gate with electric motor driven drum hoist to tainter gate with hydraulic cylinder hoist. The gate type revision will cost less and provide improved operating characteristics.

The flood hydrology for the higher frequency floods has been reevaluated based on additional years of records. The peak inflows for the 1:25 and 1:50 year floods routed through Watana (Stage I) reservoir and the intervening flow are, respectively 43,300 and 46,900cfs.

The impact of this change will be principally on the construction diversion, requiring the tunnel diameter to be increased from 30 feet to 35.5 feet while maintaining the upstream cofferdam crest at elevation 945. This solution is conservative and during the design phase optimization studies will be made to determine the optimum cofferdam height versus tunnel diameter.

The outlet facilities of three 90-inch and four 102-inch fixed cone valves operating at an 80 percent opening are capable of passing the 1:50 year flood without surcharging the reservoir above Elevation 1,456.

2.6 - Selection of Access Road Corridor (*)

2.6.1 - Previous Studies (*)

The potential for hydroelectric power generation within the Susitna basin has been the subject of considerable investigation over the years, as described in Section 1.1 of this exhibit. These studies produced much information on alternative development plans but little on the question of access.

The first report to incorporate an access plan was that of the Corps of Engineers in 1975. The proposed plan consisted of a 24-foot wide road with a design speed of 30 miles per hour that connected with the Parks Highway near Chulitna Station, paralleled the Alaska Railroad south and east to a crossing of the Susitna River, then proceeded up the south side of the river to Devil Canyon. The road continued on the south side of the Susitna River to Watana, passing by the north end of Stephan Lake and the west end of the Fog Lakes. In addition, a railhead facility was to be constructed at Gold Creek. This plan is similar to one of the selected alternative plans, Plan 16 (South), discussed later in this section.

Other studies concerning the Susitna Hydroelectric Project mentioned access only in passing and did not involve the development of an access plan.

This section of the License Application outlines the studies carried out as a basis for formulation and selection of the preferred hydroelectric plans. These studies were conducted over the period 1979 through 1982 and are based on cost data and load forecasts from that period of study. These data were analyzed consistently in each study iteration and the resulting development plans are the most attractive alternatives.

2.6.2 - Selection Process Constraints (*)

Throughout the development, evaluation and selection of the access plans, the foremost objective has been to provide a transportation system that would support construction activities and allow for the orderly development and maintenance of site facilities.

Meeting this fundamental objective involved the consideration not only of economics and technical ease of development, but also many other diverse factors. Of prime importance was the potential for impacts to the environment, namely impacts to the local fish and game populations. In addition, since the Native villages and the Cook Inlet Region will acquire surface and subsurface rights adjacent to the project, their interests were recognized and taken into account as were those of the local communities and general public.

With so many different factors influencing the choice of an access plan, it is evident that no one plan will satisfy all interests. The aim during the selection process has been to consider all factors in their proper perspective and produce a plan that represents the most favorable solution to meeting both project-related goals and minimizing impacts to the environment and surrounding communities.

2.6.3 - Corridor Identification and Selection (*)

Three general corridors were identified leading from the existing transportation network to the damsites. This network consists of the Parks Highway and the Alaska Railroad to the west of the damsites and the Denali Highway to the north. The three general corridors are identified in Figure B.2.6.1.

Corridor 1 - From the Parks Highway to the Watana damsite via the north side of the Susitna River.

Corridor 2 - From the Parks Highway to the Watana damsite via the south side of the Susitna River.

Corridor 3 - From the Denali Highway to the Watana damsite.

The access road studies identified a total of eighteen alternative plans within the three corridors. The alternatives were developed by laying out routes on topographic maps in accordance with accepted road and rail design criteria. Subsequent field investigations resulted in minor modifications to reduce environmental impacts and improve alignment.

2.6.4 - Development of Plans (*)

At the beginning of the study a plan formulation and initial selection process was developed. The criteria that most significantly affected the initial selection process were identified as:

- o Minimizing impacts on the environment;
- o Minimizing total project costs;
- o Providing transportation flexibility to minimize construction risks; and
- o Providing ease of operation and maintenance.

During evaluation of the access plans, input from the public agencies and Native organizations was sought and their response resulted in an expansion of the original list of eight alternative plans to eleven. These studies culminated in the production of the Access Route Selection Report (Acres 1982b) which recommended Plan 5 as the route which most closely satisfied the selection criteria. Plan 5 starts from the Parks Highway near Hurricane and traverses southeast along the Indian River to Gold Creek. From Gold Creek the road continues east on the south side of the Susitna River to the Devil Canyon damsite, crosses a low-level bridge and continues east on the north side of the Susitna River to the Watana damsite. For the project to remain on schedule it would have been necessary to construct a pioneer road along this route to facilitate bridge construction prior to the FERC license being issued.

In March of 1982 the Alaska Power Authority (APA) presented the results of the Susitna Hydroelectric Feasibility Report (Acres 1982c), of which access Plan 5 was a part, to the public, agencies and organizations. During April, comment was obtained from these groups relative to the feasibility study. As a result of these comments, the pioneer road concept was eliminated, the evaluation criteria were refined, and six additional access alternatives were developed.

During the evaluation process the Applicant formulated an additional plan, thus increasing the total number of plans under evaluation to eighteen. This subsequently became the plan recommended by Applicant's staff to the Applicant's Board of Directors, and was formally adopted as the Proposed Access Plan in September 1982.

2.6.5 - Evaluation of Plans (*)

The refined criteria used to evaluate the eighteen alternative access plans were:

- o No pre-license construction
- o Minimize environmental impacts
- o Minimize construction duration
- o Provide access between sites during project operation phase
- o Provide access flexibility to ensure project is brought on line within budget and schedule
- o Minimize total cost of access
- o Minimize initial investment required to provide access to the Watana damsite
- o Minimize risks to project schedule
- o Accommodate current land uses and plans
- o Accommodate agency preferences
- o Accommodate preferences of Native organizations
- o Accommodate preferences of local communities
- o Accommodate public concerns

All eighteen plans were evaluated using these refined criteria to determine the most responsive access plan in each of the three basic corridors.

To meet the overall project schedule requirements for the Watana development, it is necessary to secure initial access to the Watana damsite within one construction season of the FERC license being issued. The constraint of no pre-license construction resulted in the elimination of any plan in which initial access could not be completed within one year. This constraint eliminated six plans (plans 2, 5, 8, 9, 10, 12) from further consideration.

On completion of both the Watana and Devil Canyon Dams it is planned to operate and maintain both sites from one central location, Watana. To facilitate these operation and maintenance activites, access plans with a road connection between the sites were considered superior to those plans without a road connection. Plans 3 and 4 do not have access between the sites and were discarded.

The ability to make full use of both rail and road systems from southcentral ports of entry to the railhead facility provides the project management with far greater flexibility to meet contingencies, and control costs and schedule. Limited access plans utilizing an all-rail or rail-link system with no road connection to an existing highway have less flexibility and would impose a restraint on project operation that could result in delays and significant increases in cost. Four plans with limited access (plans 8, 9, 10 and 15) were eliminated because of this constraint.

Residents of the Indian River and Gold Creek communities are generally not in favor of a road access near their communities. Plan 1 was discarded because plans 13 and 14 achieve the same objectives without impacting the Indian River and Gold Creek areas.

Plan 7 was eliminated because it includes a circuit route connecting to both the George Parks and Denali Highways. This circuit route was considered unacceptable by the resource agencies since it aggravated the control of public access.

The seven remaining plans found to meet the selection criteria were plans 6, 11, 13, 14, 16, 17 and 18. Of these plans, plans 13, 16 and 18 in the North, South, and Denali corridors, respectively, were selected as being the most responsive plan in each corridor. The three plans are described below and the route locations shown in Figures B.2.6.2 through B.2.6.4.

(a) Plan 13 'North' (see Figure B.2.6.2) (*)

This plan utilizes a roadway from a railhead facility adjacent to the George Parks Highway at Hurricane to the Watana damsite following the north side of the Susitna River. A spur road, seven miles in length, would be constructed at a later date to service the Devil Canyon development. This route is mountainous and includes terrain at high elevations. In addition, extensive sidehill cutting in the region of Portage Creek will be necessary; however, construction of the road would not be as difficult as under plan 16.

(b) Plan 16 'South' (see Figure B.2.6.3) (*)

This route generally parallels the Susitna River, traveling west to east from a railhead at Gold Creek to the Devil

Canyon damsite, and continues following a southerly loop to the Watana damsite. Twelve miles downstream of the Watana damsite a temporary low-level crossing of the Susitna River will be used until completion of a permanent bridge. A connecting road from the George Parks Highway to Devil Canyon with a major high-level bridge across the Susitna River is necessary to provide full road access to either site. The topography from Devil Canyon to Watana is mountainous and the route involves the most difficult construction of the three plans, requiring a number of sidehill cuts and the construction of two major bridges. To provide initial access to the Watana damsite this route presents the most difficult construction problems of the three routes and has the highest potential for schedule delays and related cost increases.

(c) Plan 18 'Denali-North' (see Figure B.2.6.4) (*)

This route originates at a railhead in Cantwell, utilizing the existing Denali Highway to a point 21 miles east of the junction of the George Parks and Denali Highways. A new road will be constructed from this point due south to the Watana damsite. The majority of the new road will traverse relatively flat terrain which will allow construction using side borrow techniques, resulting in a minimum of disturbance to areas away from the alignment. This is the most easily constructed route for initial access to the Watana site. Access to the Devil Canyon development will consist primarily of a railroad extension from the existing Alaska Railroad at Gold Creek to a railhead facility adjacent to the Devil Canyon camp area. To provide access to the Watana damsite and the existing highway system, a connecting road will be constructed from the Devil Canyon railhead following a northerly loop to the Watana damsite. Access to the north side of the Susitna River will be attained via a high-level suspension bridge constructed approximately one mile downstream of the Devil Canyon Dam. In general, the alignment crosses terrain with gentle to moderate slopes which will allow roadbed construction without deep cuts.

2.6.6 - Comparison of the Selected Alternative Plans (*)

To determine which access plan best accommodates both project-related goals and the concerns of the resource agencies, Native organizations, and affected communities, the three selected alternative plans were subjected to a multi-disciplinary evaluation and comparison. The key issues addressed in this evaluation and comparison were:

(a) Costs (*)

For the development of access to the Watana site, the Denali-North Plan has the least cost and the lowest probability of increased costs resulting from unforeseen conditions. The North Plan is ranked second. The North Plan has the lowest overall cost while the Denali-North has the highest. However, a large portion of the cost of the Denali-North Plan would be incurred more than a decade in the future. When converting costs to equivalent present value, the overall costs of the Denali-North and the South Plans are approximately equal. The costs of the three alternative plans can be summarized as follows:

Estimated Total Cost ($\$ \times 10^6$)

Plan	Watana	Devil Canyon	Total	Discounted Total
North (13)	241	127	368	287
South (16)	312	104	416	335
Denali-North (18)	224	213	437	326

The costs are in terms of 1982 dollars and include all costs associated with design, construction, maintenance and logistics.

(b) Schedule (*)

The schedule for providing initial access to the Watana site was given prime consideration since the cost ramifications of a schedule delay are highly significant. The elimination of pre-license construction of a pioneer access road has resulted in the compression of on-site construction activities during the initial construction seasons. With the present overall project scheduling, should diversion not be completed prior to spring runoff in the fourth construction season, dam foundation preparation work will be delayed one year and hence cause a delay to the overall project of one year. It has been estimated that the resultant increase in cost would likely be in the range of 100-200 million dollars. The access route that assures the quickest completion and hence the earliest delivery of equipment and material to the site has a distinct advantage. The forecasted construction period, including mobilization, for the three plans is:

- o Denali-North — 6 months
- o North — 9 months
- o South — 12 months

It is evident that, with the Denali-North Plan, site activities can be supported at an earlier date than by either of the other routes. Consequently the Denali-North Plan offers the highest probability of meeting schedule and hence the least risk of project delay and increase in cost. The schedule for access in relation to diversion is shown for the three plans in Figure B.2.6.5.

(c) Environmental Issues (*)

Outlined below are the key environmental impacts which have been identified for the three routes. The specific mitigation measures necessary to avoid, minimize or compensate for these impacts are discussed in Exhibit E.

(i) Wildlife and Habitat (*)

The three selected alternative access routes are made up of five distinct wildlife and habitat segments:

- Hurricane to Devil Canyon (Segment 1): This segment is composed almost entirely of productive mixed forest, riparian, and wetlands habitats important to moose, furbearers, and birds. It includes three areas where slopes of over 30 percent will require side hill cuts, all above wetland zones vulnerable to erosion-related impacts.

- Gold Creek to Devil Canyon (Segment 2): This segment is composed of mixed forest and wetland habitats, but includes less wetland habitat and fewer wetland habitat types than the Hurricane to Devil Canyon segment. Although this segment contains habitat suitable for moose, black bears, furbearers and birds, it has the least potential for adverse impacts to wildlife of the five segments considered.

- Devil Canyon to Watana (North Side)(Segment 3): The following comments apply to both the Denali-North and North routes. This segment traverses a varied mixture of forest, shrub, and tundra habitat types, generally of medium-to-low productivity as wildlife habitat. However, it crosses the Devil and Tsusena Creek drainages, which are important moose and brown bear habitat.

- Devil Canyon to Watana (South Side)(Segment 4): This segment is highly varied with respect to habitat types, containing complex mixtures of forest, shrub, tundra, wetlands, and riparian vegetation. The western portion is mostly tundra and shrub, with forest and wetlands occurring along the eastern portion in the vicinity of Prairie Creek, Stephan Lake, and Tsusena Creek. Prairie Creek supports a very high seasonal concentration of brown bears and the lower Tsusena Creek area supports concentrations of moose and black bears. The Stephan Lake area also supports relatively high densities of moose and bears. In addition to habitat loss or alteration and increased hunting, significant human-bear conflicts would probably result from access development in this segment.

- Denali Highway to Watana (Segment 5): This segment is primarily composed of shrub and tundra vegetation types, with little productive forest habitat present. Although habitat diversity is relatively low along this segment, the southern portion along Deadman Creek contains important brown bear habitat and browse for moose. This segment crosses a peripheral portion of the range of the Nelchina caribou herd which is occupied by a subherd that uses the area year-round including during calving. Although it is not possible to predict with any certainty how the physical presence of the road itself or traffic will affect caribou movements, population size, or productivity, it is likely that a variety of site-specific mitigation measures will be necessary to protect the herd.

The three access plans are made up of the following combinations of wildlife habitat segments:

North	Segments 1 and 3
South	Segments 1, 2, and 4
Denali-North	Segments 2, 3, and 5

The North route has the least potential for creating adverse impacts to wildlife and habitat, for it traverses or approaches the fewest areas of productive habitat and zones of species concentration or movement. The wildlife impacts of the South Plan can be expected to be greater than those of the North Plan due to the proximity of the route to Prairie Creek, Stephan Lake and the Fog Lakes, which currently support high densities of moose and black and brown bears. In particular, Prairie Creek seasonally supports what may be the highest concentration of brown bears in the Susitna basin. Although the Denali-North Plan has the potential for disturbances of caribou, brown bear and black bear concentrations and movement zones, it is considered that the potential for adverse impacts with the South Plan is greater.

(ii) Fisheries (*)

All three alternative routes would have direct and indirect impacts on the fisheries. Direct impacts include the effects on water quality and aquatic habitat whereas increased angling pressure is an indirect impact. A qualitative comparison of the fishery impacts related to the alternative plans was undertaken. The parameters used to assess impacts along each route included: the number of streams crossed, the number and length of lateral transits (i.e., where the roadway parallels the streams and runoff from the roadway can run directly into the stream), the number of watersheds affected, and the presence of resident and anadromous fish.

The three access plan alternatives incorporate combinations of seven distinct fishery segments:

- Hurricane to Devil Canyon (Segment 1): Seven stream crossings will be required along this route, including Indian River which is an important salmon spawning river. Both the Chulitna River watershed and the Susitna River watershed are affected by this route. The increased access to Indian River will be an important indirect impact to the segment. Approximately 1.8 miles of cuts into banks greater than 30 degrees occur along this route requiring erosion control measures to preserve the water quality and aquatic habitat.

- Gold Creek to Devil Canyon (Segment 2): This segment would cross six streams and is expected to have minimal direct and indirect impacts. Anadromous fish spawning is limited to the lower reaches of Jack Long Creek, the tributary to Slough 21 at road corridor mile 43.3, Waterfall Creek, and Gold Creek (ADF&G 1984a). Approximately 2.5 miles of cuts into banks greater than 30 degrees occur in this section. In the Denali North Plan this segment would be railroad, whereas in the South Plan it would be road.

- Devil Canyon to Watana (North Side, North Plan) (Segment 3): This segment crosses twenty streams and laterally transits four rivers for a total distance of approximately 12 miles. Seven miles of this lateral transit parallels Portage Creek, which is an important salmon spawning area.

- Devil Canyon to Watana (North Side, Denali-North Plan)(Segment 4): The difference between this segment and segment 3 described above is that it avoids Portage Creek by traversing through a pass 4 miles to the east. The number of streams crossed is consequently reduced to twelve, and the number of lateral transits is reduced to two with a total distance of 4 miles.

- Devil Canyon to Watana (South Side)(Segment 5): The portion between the Susitna River crossing and Devil Canyon requires nine steam crossings, but it is unlikely that these contain significant fish populations. The portion of this segment from Watana to the Susitna River is not expected to have any major direct impacts; however, increased angling pressure in the vicinity of Stephan Lake may result due to the proximity of the access road. The segment crosses both the Susitna and the Talkeetna watershed. Seven miles of cuts into banks of greater than 30 degrees occur in this segment.

- Denali Highway to Watana (Segment 6): The segment from the Denali Highway to the Watana damsite has twenty-two stream crossings and passes from the Nenana into the Susitna watershed. Much of the route crosses or is in proximity to seasonal grayling habitat and runs parallel to Deadman Creek for nearly 10 miles.

If recruitment and growth rates are low along this segment, it is unlikely that resident populations could sustain heavy fishing pressure. Hence, this segment has a high potential for impacting the local grayling population.

- Denali Highway (Segment 7): The Denali Highway from Cantwell to the Watana access turnoff will require upgrading. The upgrading will involve only minor realignment and negligible alteration to present stream crossings. The segment crosses eleven streams and laterally transits two rivers for a total distance of 5 miles. There is no anadromous fish spawning in this segment and little direct or indirect impact is expected.

The three alternative access routes comprise the following fisheries segments:

- North — Segments 1 and 3
- South — Segments 1, 2, and 5
- Denali-North — Segments 2, 4, 6 and 7

The Denali-North Plan is likely to have both direct and indirect impacts on grayling fisheries given the number of stream crossings, lateral transits, and watersheds affected. Anadromous fisheries impacts will be minimal and will only be of concern along the railroad spur between Gold Creek and Devil Canyon.

The South Plan is likely to create significant direct and indirect impacts at Indian River, which is an important salmon spawning river. Anadromous fisheries impacts may also occur in the Gold Creek to Devil Canyon segment, as for the Denali-North Plan. In addition, indirect impacts may occur in the Stephan Lake area.

The North Plan, like the South Plan, may impact salmon spawning activity in Indian River. Direct impacts may occur along Portage Creek due to temporary water quality changes through increased erosion; indirect impacts, such as increased angling pressure, could also occur.

With any of the selected plans, direct and indirect effects can be minimized through proper engineering design and prudent management. Criteria for the development of borrow areas and the design of bridges and culverts for the proposed access plan together with mitigation recommendations are discussed in Exhibit E.

(d) Cultural Resources (**)

A preliminary evaluation of the relative cultural resources sensitivity of the three access plans was made. This consisted of a review of relevant literature and information on previously recorded sites in the general area, and a flyover of the three routes by archeologists. Random ground checks were made during the course of the latter. The Denali-North plan, because of its greater overall length and its location parallel to Deadman Creek, is believed to have the greatest potential for impacting archeological sites. the South Plan, although it traverses less archeologically sensitive terrain than the North Plan, by virtue of its greater length, is believed to have a greater potential for impacting acheological resources than the latter plan. The ranking from the least to the highest with regard to cultural resources impacts is therefore South, North, and Denali-North.

Impacts on archeological sites can to be adequately mitigated by avoidance or data recovery; consequently, this issue is not critical to the selection process. It should be noted, however, the less forested nature of the terrain along the Denali-North and portions of the North Plan would allow for more efficient identification of cultural resources in these areas than along the more forested South Route during pre-construction surveys.

(e) Socioeconomics (o)

Socioeconomic impacts on the Mat-Su Borough as a whole would be similar in magnitude for all three plans. However, each of the three plans affects future socioeconomic conditions in differing degrees in certain areas and communities. The important differences affecting specific communities are outlined below.

(i) Cantwell (o)

The Denali-North Plan would create substantial increases in population, local employment, business activity, housing and traffic. These impacts result because a railhead facility would be located at Cantwell, and because Cantwell would be the nearest community to the Watana damsite. Both the North and

South Plans would impact Cantwell to a far lesser extent.

(ii) Hurricane (o)

The North Plan would substantially affect the Hurricane area since currently there is little population, employment, business activity or housing. Socioeconomic impacts for Hurricane would be less under the South Plan and considerably less under the Denali-North Plan.

(iii) Trapper Creek and Talkeetna (o)

Trapper Creek would experience slightly greater changes in economic indicators with the North Plan than under the South or Denali-North Plans. The South Plan would impact the Talkeetna area slightly more than the other two plans.

(iv) Gold Creek (*)

With the South Plan, a railhead facility would be developed at Gold Creek, creating significant socioeconomic impacts in this area. The Denali-North Plan includes construction of a railhead facility at the Devil Canyon site, which would create impacts at Gold Creek, but not to the same extent as with the South Plan. Minimal impacts would result in Gold Creek under the North Plan.

(f) Preferences of Native Organizations (*)

The Cook Inlet Region Inc. (CIRI) and most of its associated village corporations all prefer the South Plan since it provides full road access to their lands south of the Susitna River. AHTNA, Inc. and the Cantwell Village Corporation support the Denali-North Plan. None of the Native organizations supports the North Plan.

(g) Relationship to Current Land Stewardships, Uses and Plans (**)

As described in Exhibit E, Chapter 9, much of the land required for project development has been or may be conveyed to Native organizations. The remaining lands are generally under state and federal control. The South Plan traverses more Native-selected lands than either of the other two routes, and Native organizations have expressed an interest in potentially developing their lands for mining, recreation, forestry or residential use.

The other land management plans that have a large bearing on access development are the Bureau of Land Management's (BLM) recent decision to open the Denali Planning Block to mineral exploration, and the Susitna Area Plan. In general, none of the plans would be in major conflict with any present federal, borough or Native management plans.

2.6.7 - Summary (o)

In reaching the decision as to which of the three alternative access plans would be recommended, it was necessary to evaluate the highly complex interplay that exists between the many issues involved. Analysis of the key issues indicates that no one plan satisfied all the selection criteria nor accommodated all the concerns of the resource agencies, Native organizations and the public. Therefore, it was necessary to make a rational assessment of trade-offs between the sometimes conflicting environmental concerns of impacts on fisheries, wildlife, socioeconomics, land use and recreational opportunities on the one hand, with project cost, schedule, construction risk and management needs on the other. With all these factors in mind, it should be emphasized that the primary purpose of access is to provide and maintain an uninterrupted flow of materials and personnel to the damsite throughout the life of the project. Should this fundamental objective not be achieved, significant schedule and budget overruns will occur.

2.6.8 - Final Selection of Plan (o)

(a) Elimination of 'South Plan' (o)

The South route, Plan 16, was eliminated primarily because of the construction difficulties associated with building a major low-level crossing 12 miles downstream of the Watana damsite. This crossing would consist of a floating or fixed temporary bridge which would need to be removed prior to spring breakup during the first three years of the project (the time estimated for completion of the permanent bridge). This would result in a serious interruption in the flow of materials to the site. Another drawback is that floating bridges require continual maintenance and are generally subject to more weight and dimensional limitations than permanent structures.

A further limitation of this route is that for the first three years of the project all construction work must be supported solely from the railhead facility at Gold Creek.

This problem arises because it will take an estimated three years to complete construction of the connecting road across the Susitna River at Devil Canyon to Hurricane on the George Parks Highway. Limited access such as this does not provide the flexibility needed by the project management to meet contingencies and control costs and schedule.

Delays in the supply of materials to the damsite, caused by either an interruption of service of the railway system or the Susitna River not being passable during spring breakup, could result in significant cost impacts. These factors, together with the realization that the South Plan offers no specific advantages over the other two plans in any of the areas of environmental or social concern, led to the South Plan being eliminated from further consideration.

(b) Schedule Constraints (*)

The choice of an access plan thus narrowed down to the North and Denali-North plans. Of the many issues addressed during the evaluation process, the issue of "schedule" and "schedule risk" was determined to be the most important in the final selection of the recommended plan.

Schedule plays an extremely important role in the evaluation process because of the special set of conditions that exist in a sub-arctic environment. Building roads in these regions involves the consideration of many factors not found in other environments. Specifically, the chief concern is one of weather, and the consequent short duration of the construction season. The roads for both the North and Denali-North Plans will, for the most part, be constructed at elevations in excess of 3,000 feet. At these elevations the likely time available for uninterrupted construction in a typical year is 5 months, and at most 6 months.

The forecasted construction period including mobilization is 6 months for the Denali-North Plan and 9 months for the North. At first glance a difference in schedule of 3 months does not seem great; however, when considering that only 6 months of the year are available for construction, the additional 3 months become highly significant.

If diversion is not achieved prior to spring runoff in the fourth year of construction, dam foundation preparation work will be delayed one year, and hence cause a delay to the overall project of one year.

(c) Cost Impacts (o)

The increase in costs resulting from a one-year delay have been estimated to be in the range of 100-200 million dollars. This increase includes the financial cost of investment by the date of scheduled river diversion, the financial costs of rescheduling work for a one-year delay, and replacement power costs.

(d) Summary (*)

The Denali-North Plan has the highest probability of meeting schedule and least risk of increase in project cost for two reasons. First, it has the shortest construction schedule (six months). Second, a passable route could be constructed even under winter conditions due to the relatively flat terrain along its length. In contrast the North route is mountainous and involves extensive sidehill cutting, especially in the Portage Creek Area. Winter construction along sections such as this would present major problems and increase the probability of schedule delay.

(e) Plan Recommendation (o)

It is recommended that the Denali-North route be selected so as to ensure completion of initial access to the Watana damsite as soon as possible after receipt of a project license, for it is considered that the risk of significant cost overruns is too high with any other route.

(f) Environmental Concerns - Recommended Plan (*)

The main disadvantage of the Denali-North route is that it has a higher potential for adverse environmental impacts than the North route alternative. These impacts have been identified and, following close consultation with environmental subconsultants, many of the impacted areas have been avoided both by careful alignment of the road and the development of design criteria which do not detract from the semi-wilderness character of the area. Some environmental impacts and conflicts are unavoidable, however, and where these impacts occur, specific mitigation measures have been developed to reduce them to a minimum. These measures are outlined in detail within the relevant sections of Exhibit E.

2.7 - Selection of Transmission Facilities (o)

The objective of this section is to describe the studies performed to select a power delivery system from the Susitna River basin generating plants to the major load centers in Anchorage and Fairbanks. This system will comprise transmission lines, substations, a dispatch center, and means of communications.

The major topics of the transmission studies include:

- o Electric system studies,
- o Transmission corridor selection,
- o Transmission route selection,
- o Transmission towers, hardware and conductors,
- o Substations, and
- o Dispatch center and communications.

2.7.1 Electric System Studies (o)

Transmission planning criteria were developed to ensure the design of a reliable and economic electrical power system, with components rated to allow a smooth transition through early project stages to the ultimate developed potential.

Strict application of optimum, long-term criteria would require the installation of equipment with ratings larger than necessary, at excessive cost. In the interest of economy and long-term system performance, these criteria were temporarily relaxed during the early development stages of the project. Although allowing for satisfactory operation during early system development, final system parameters must be based on the ultimate Susitna potential.

The criteria are intended to ensure maintenance of rated power flow to Anchorage and Fairbanks during the outage of any single line or transformer element. The essential features of the criteria are:

- o Total power output of Susitna to be delivered to one or two stations at Anchorage and one at Fairbanks;
- o "Breaker-and-a-half" switching station arrangements;
- o Overvoltages during line energizing not to exceed specified limits;
- o System voltages to be within established limits during normal operation;
- o Power delivered to the loads to be maintained and system voltages to be kept within established limits for system operation under emergency conditions;

- o Transient stability during a 3-phase line fault cleared by breaker action with no reclosing; and

- o Where performance limits are exceeded, the most cost-effective corrective measures are to be taken.

(a) Existing System Data (*)

Data compiled in a report by Acres (1982c) have been used for preliminary transmission system analysis. Other system data were obtained in the form of single line diagrams from the various utilities.

(b) Power Transfer Requirements (**)

The Susitna transmission system must be designed to ensure the reliable transmission of power and energy generated by the Susitna Hydroelectric Project to the load centers in the Railbelt area. The power transfer requirements of this transmission system are determined by the following factors:

- o System demand at the various load centers;
- o Generating capabilities at the Susitna project; and
- o Other generation available in the Railbelt area system.

The electric load demand in the Railbelt area is located in two main centers: Anchorage and Fairbanks. The largest load center is Anchorage, with most of its load concentrated in the Anchorage urban area. The second largest load center is Fairbanks. Two small load centers (Willow and Healy) are located along the Susitna transmission route. The Glennallen-Valdez load center is not planned to be interconnected with the Railbelt nor to be served by the Susitna project. It is therefore excluded from disscusion in this License Application.

A survey of past and present load demand levels as well as forecasts of future trends indicates these approximate load levels at the two load centers:

Load Area	Percent of Total Railbelt Load
Anchorage - Cook Inlet	83
Fairbanks - Tanana Valley	17

Accordingly, it has been assumed for study purposes that about 83 percent of the generation at Susitna will be transmitted to the Anchorage area and 17 percent to Fairbanks.

The potential of the Susitna Hydroelectric Project is expected to be developed in three stages as the system load grows over the next three decades. The transmission system must be designed to serve the ultimate Susitna development, but staged to provide reliable transmission at every intermediate stage. Present plans call for three stages of Susitna capacity additions: 360 MW installed at Watana in 1999, 600 MW at Devil Canyon in 2005, and an additional 660 MW at Watana in 2012. The 660 MW addition at Watana Stage III reflects two additional units at 170 MW each (340 MW), plus an incremental increase in the four existing units of 320 MW due to the increased head from the raised dam.

Development of other generation resources could alter the geographic load and generation sharing in the Railbelt, depending on the location of this development. However, current studies indicate that no other very large projects are likely to be developed until the full potential of the Susitna project is utilized. The proposed transmission configuration and design should, therefore, be able to satisfy the bulk transmission requirements for at least the next three decades. The next major generation development after Susitna will then require a transmission system determined by its own magnitude and location.

The resulting power transfer requirements for the Susitna transmission system are indicated in Table B.2.7.1.

(c) Transmission Alternatives (*)

Because of the geographic location of the various centers, transmission from Susitna to Anchorage and Fairbanks will result in a radial system configuration. This allows significant freedom in the choice of transmission voltages, conductors, and other parameters for the two line sections, with only limited dependence between them. Transmission alternatives were developed for each of the two system areas, including voltage levels, number of circuits required, and other parameters, to satisfy the necessary transmission requirements of each area. This work is described by Acres (1982c) in their electrical system studies closeout report.

To maintain a consistency with standard ANSI voltages used in other parts of the United States, the following voltages were considered for Susitna transmission:

- Watana and Devil Canyon
  to Gold Creek and on
  to Anchorage: 500 kV or 345 kV

- Devil Canyon to Fairbanks: 345 kV or 230 kV

(i) Susitna to Anchorage (**)

Transmission at either of two different voltage levels (345 kV or 500 kV) could reasonably provide the necessary power transfer capability over the distance of approximately 132 miles between Gold Creek and Anchorage. This transfer capability is higher than the projected load in year 2020. At 345 kV, either three circuits uncompensated or two circuits with series compensation are required to provide the necessary reliability for the single contingency outage criterion. At lower voltages, an excessive number of parallel circuits are required, while above 500 kV, two circuits are still needed to provide service in the event of a line outage.

(ii) Susitna to Fairbanks (o)

Applying the same reasoning used in choosing the transmission alternatives to Anchorage, two circuits of either 230 kV or 345 kV were chosen for the section from Devil Canyon to Fairbanks. The 230 kV alternative requires series compensation to satisfy the planning criteria in case of a line outage.

(iii) Total System Alternatives (*)

The transmission system alternatives mentioned above were combined into five realistic total system alternatives. Three of the five alternatives have different voltages for the two sections. The principal parameters of the five transmission system alternatives analyzed in detail are as follows:

	Susitna to Anchorage		Susitna to Fairbanks	
Alternative	Number of Circuits	Voltage (kV)	Number of Circuits	Voltage (kV)
1	2	345	2	345
2	3	345	2	345
3	2	345	2	230
4	3	345	2	230
5	2	500	2	230

Electric system analyses, including simulations of line energizing, load flows of normal and emergency operating conditions, and transient stability performance, were carried out to determine the technical feasibility of the various alternatives. An economic comparison of transmission system life cycle costs was carried out to evaluate the relative economic merits of each alternative. All five transmission alternatives were found to have acceptable performance characteristics. The most significant difference was that single-voltage systems (345 kV, Alternatives 1 and 2) and systems without series compensation (Alternative 2) offered reduced complexity of design and operation and therefore were likely to be marginally more reliable. The present worth life cycle costs of Alternatives 1 through 4 were all within 1 percent of each other. Only the cost of the 500/230 kV scheme (Alternative 5) was 14 percent above the others. A summary of the life cycle cost analyses for the various alternatives is shown in Table B.2.7.2.

A technical and economic comparison was also carried out to determine possible advantages and disadvantages of HVDC transmission, as compared to an a.c. system, for transmitting Susitna power to Anchorage and Fairbanks. HVDC transmission was found to be technically and operationally more complex as well as having higher life cycle costs.

(d) Configuration at Generation and Load Centers (o)

Interconnections between generation and load centers and the transmission system were developed after reviewing the existing system configurations at both Anchorage and Fairbanks as well as the possibilities and current development plans in the Susitna, Anchorage, Fairbanks, Willow, and Healy areas.

(i) Susitna Configuration (**)

Preliminary development plans indicated that the first project to be constructed (Stage 1) would be Watana with an initial installed capacity of 360 MW. The next project considered in this study (Stage II), would be Devil Canyon, with an installed capacity of 600 MW. The last project (Stage 3) will be the raising of the Watana Dam and addition of two more generating units to increase the total generating capacity at Watana to 1,020 MW.

(ii) Switching at Willow (*)

Transmission from Susitna to Anchorage is facilitated by the introduction of an intermediate switching station. This has the effect of reducing line energizing overvoltages and reducing the impact of line outages on system stability. Willow is a suitable location for this intermediate switching station; in addition, it would make it possible to supply local load when this is justified by development in the area. This local load is expected to be less than 16 percent of the total Railbelt area system load, but the availability of an EHV line tap would definitely facilitate future power supply.

(iii) Switching at Healy (o)

A switching station at Healy was considered early in the analysis but was found to be unnecessary to satisfy the planning criteria. The predicted load at Healy is small enough to be supplied by local generation and the existing 138-kV transmission from Fairbanks.

(iv) Anchorage Configuration (**)

Analysis of system configuration, distribution of loads, and development in the Anchorage area led to the conclusion that a transformer station near Palmer would be of little benefit. Most of the major loads are concentrated in and around the urban Anchorage area, at the mouth of Knik Arm. To reduce the length of subtransmission feeders, the transformer stations should be located as close to Anchorage as possible.

The routing of transmission into Anchorage was chosen from the following three possible alternatives:

- Submarine Cable Crossing From Point MacKenzie to Point Woronzof

  This would require transmission through a very heavily developed area. It would also expose the cables to damage by ships' anchors, which has been the experience with existing cables, resulting in questionable transmission reliability.

- Overland Route North of Knik Arm via Palmer

  This may be most economical in terms of capital cost, in spite of the long distance involved. However, overhead transmission through this developed area may have significant environmental consequences. A longer overland route around the developed area may be technically unacceptable because of the mountainous terrain.

- Submarine Cable Crossing of Knik Arm, In the Area of Lake Lorraine and Six Mile Creek

  This option, approximately parallel to the new 230 kV cable under construction for Chugach Electric Association (CEA), includes some 3 to 4 miles of submarine cable and involves a high capital cost. Since the area is upstream from the shipping lanes to the port of Anchorage, it will result in a reliable transmission link, and one that does not have to cross environmentally sensitive conservation areas.

(v) Fairbanks Configuration (o)

Susitna power for the Fairbanks area is recommended to be delivered to a single EHV/138 kV transformer station located at Ester. No alternatives were given detailed consideration.

2.7.2 Corridor Selection (o)

(a) Methodology (o)

Development of the proposed Susitna Project will require a transmission system to deliver electric power to the Railbelt area. The building of the Anchorage to Fairbanks Intertie system will result in a defined corridor and route for the Susitna transmission lines between Willow and Healy. Therefore, three areas require study for corridor selection: the northern area to connect Healy with Fairbanks, the central area to connect the Watana and Devil Canyon damsites with the Intertie, and the southern area to connect Willow with Anchorage.

Using the selection criteria discussed below, corridors three to five miles wide were selected in each of the three study areas. These corridors were then evaluated to determine which ones meet the more specific screening criteria. This screening process resulted in one corridor in each area being designated as the recommended corridor for the transmission line.

(b) Selection Criteria (o)

Since the corridors studied range in width from three to five miles, the base criteria had to be applied in broad terms. The study also indicated that the criteria listed for technical purposes could reappear in the economic or environmental classification. The technical criteria were defined as requirements for the normal and safe performance of the transmission system and its reliability.

The selection criteria were in three categories: technical, economic and environmental. The criteria are listed in Table B.2.7.3.

(c) Identification of Corridors (o)

As discussed previously, the Susitna transmission line corridors studied are located in three geographical areas, namely:

- The southern study area between Willow and Anchorage;
- The central study area between Watana, Devil Canyon, and the Intertie, and
- The northern study area between Healy and Fairbanks.

(d) Description of Corridors (o)

Figures B.2.7.1 through B.2.7.3 portray the corridors evaluated in the southern, central, and northern study areas, respectively. For purposes of simplification, only the centerline of the three-to-five-mile wide corridors are shown in the figures.

In each of the three figures, each corridor under consideration has been identified by the use of letter symbols. The various segment intersections and the various segments, where appropriate, have been designated. Thus, segments in each of the three study areas can be separately referenced. Furthermore, the segments are joined together to form corridors. For example, in the northern study area Corridor ABC is composed of Segments AB and BC.

The alternative corridors selected for each study area are described in detail in the following paragraphs. In addition, Tables B.2.7.4, B.2.7.5 and B.2.7.6 contain detailed environmental data for each corridor segment.

(i) Southern Study Area (o)

- Corridor One - Willow to Anchorage via Palmer (o)

Corridor ABC', consisting of Segments AB and BC', begins at the intersection with the Intertie in the vicinity of Willow. From here, the corridor travels in a southeasterly direction, crossing wetlands, Willow Creek, and Willow Creek Road before turning slightly to the southeast following the drainage of Deception Creek. The topography in the vicinity of this segment of the corridor is relatively flat to gently rolling with standing water and tall-growing vegetation in the vicinity of the creek drainages.

At a point northwest of Bench Lake, the corridor turns in an easterly direction, crossing the southern foothills of the Talkeetna Mountains. The topography here is gently to moderately rolling with shrub- to treesized vegetation occurring throughout. As the corridor approaches the crossing of the Little Susitna River, it turns and heads southeast again, crossing the Little Susitna River and Wasilla Fishhook Road.

Passing near Wolf Lake and Gooding Lake, the corridor then crosses a secondary road, some agricultural lands, State Route 3, and the Glenn Highway, before intersecting existing transmission lines south of Palmer. In the vicinity of the Little Susitna River, the topography is gently rolling. As the corridor travels toward Palmer, the land flattens, more lakes are present, and some agricultural development is occurring. After crossing the Glenn Highway, the corridor passes through a residential area before crossing the broad floodplain of the Matanuska River.

Just west of Bodenburg Butte, the corridor turns due south through more agricultural land before crossing the Knik River and eventually connecting with the Eklutna Power Station. All of the land south of Palmer is very flat with some agricultural development. Just south of Palmer, the proposed corridor intersects existing transmission facilities and parallels or replaces them from a point just south of Palmer, across the river and into the vicinity of the Eklutna Power House. From here into Anchorage, the corridor as proposed would parallel existing facilities, crossing near or through the communities of Eklutna, Peters Creek, Birchwood, and Eagle River by using one of the two existing transmission line rights-of-way in this area. The land here is flat to gently rolling with a great deal of residential development. This corridor segment is the most easterly of the three considered in the southern study area and avoids an underwater crossing of Knik Arm.

- Corridor Two - Willow to Point MacKenzie via Red Shirt Lake (o)

Corridor ADFC, consisting of Segments ADF and FC, commences again at the point of intersection with the Intertie in the vicinity of Willow but immediately turns to the southwest, first crossing the railroad, then the Parks Highway, then Willow Creek just west of Willow. The land in the vicinity of this part of the segment is very flat, with wetlands dominating the terrain.

Southwest of Florence Lake, the proposed corridor turns, crosses Rolly Creek, and heads nearly due south, passing through extensive wetlands west and south of Red Shirt Lake. The corridor in this area parallels existing tractor trails crossing very flat lands with significant amounts of tall-growing vegetation in the better drained locations.

Northwest of Yohn Lake, the corridor segment turns to the southeast, passing Yohn Lake and My Lake before crossing the Little Susitna River. Just south of My Lake, the corridor turns in a generally southerly direction, passing Middle Lake, and east of Horseshoe Lake before finally intersecting the existing Beluga 230-kV transmission line at a spot just north of MacKenzie Point. From here, the corridor parallels MacKenzie Point's existing transmission facilities before crossing under Knik Arm to emerge on the easterly shore of Knik Arm in the vicinity of Anchorage. The land in the vicinity of this segment is extremely flat and very wet, supporting dense stands of tallgrowing vegetation on any of the higher or better drained areas.

- Corridor Three - Willow to Point MacKenzie via Lynx Lake (o)

  Corridor AEFC is very similar to and is a derivation of Corridor ADFC; it consists of Segments AEF and FC. This corridor also extends to the southwest of Willow. West of the Parks Highway, however, just north of Willow Lake, this corridor turns and travels southwest of Willow and east of Long Lake, passing between Honeybee Lake and Crystal Lake. The corridor then turns southeastward to pass through wetlands east of Lynx Lake and Butterfly Lake before crossing the Little Susitna River. The land is well developed in this area. It is very flat and, while it is wet, also supports dense stands of tall-growing vegetation on the better drained sites. Corridor Three rejoins Corridor Two at a point south of My Lake.

(ii) Central Study Area (o)

The central study area encompasses a broad area in the vicinity of the damsites. From Watana, the study area extends to the north as far as the Denali Highway and to the south as far as Stephan Lake. From this point westward, the study area encompasses the foothills of the Alaska Range and, to the south, the foothills of the Talkeetna Mountains. Included ~~in this study area are lands under consideration by the Intertie Project investigators. The alternative~~ corridors would connect both Devil Canyon and Watana Dams with the Intertie at one of four locations, which are identified in Figure B.2.7.2.

As for the southern study area, individual corridor segments are listed in the text. This is to aid the reader both in determining corridor locations in the figures and in examining the environmental inventory data listed for each segment in Tables B.2.7.4, B.2.7.5 and B.2.7.6.

- Corridor One - Watana to Intertie via South Shore, Susitna River (o)

  Corridor ABCD consists of three segments: AB, BC, and CD. This corridor originates at the Watana damsite and follows the southern boundary of the river at an elevation of approximately 2,000 feet from Watana to Devil Canyon. From Devil Canyon, the corridor continues along the southern shore of the Susitna River at an elevation of about 1,400 feet to the point at which it connects with the Intertie, assuming the Intertie follows the railroad corridor. The land surface in this area is relatively flat, though incised at a number of locations by tributaries to the Susitna River. The relatively flat hills are covered by discontinuous stands of dense, tall-growing vegetation.

- Corridor Two - Watana to Intertie via Stephan Lake (o)

  ABECD, the second potential corridor, is essentially a derivation of Corridor One and is formed by replacing Segments BC with BEC. Originating at Point B, Corridor Segment BEC leaves the river and generally parallels one of the proposed Watana Dam access road corridors. This corridor extends southwest from the river, passing near Stephan Lake to a point northwest of Daneka Lake. Here the route turns back to the northwest and intersects Corridor One at the Devil Canyon damsite. The terrain in this area, again, is gently rolling hills with relatively flat benches. Vegetation cover ranges from sparse at the higher elevations to dense along the river bottom and along gentler slopes of the Susitna River and its tributaries.

- Corridor Three - Watana to Intertie via North Shore, Susitna River (o)

  Corridor Three (AJCF), located on the north side of the river, consists of Segments AJ and CF. Starting at the Watana damsite, the corridor crosses Tsusena Creek and heads westerly, following a small drainage tributary to the Susitna River. Once crossing Devil Creek, the corridor passes north and west of High Lake.

The corridor stays below an elevation of 3,700 feet as it crosses north of the High Lake area, east of Devil Creek, on its approach to Devil Canyon. From Devil Canyon, the corridor again extends to the west, crossing Portage Creek and intersecting the Intertie in the vicinity of Indian River. In the drainages, to elevations of about 2,000 feet, tree heights range to 60 feet. Between Devil Creek and Tsusena Creek, however, at the higher elevations, very little vegetation grows taller than 3 feet. Once west of Devil Creek, discontinuous areas of tall-growing vegetation exist.

- Corridor Four - Watana to Intertie via Devil Creek Pass/East Fork Chulitna River (o)

Another means of connecting the two dam schemes with the Intertie is to follow Corridor One from Watana to Devil Canyon and then exit the Devil Canyon project to the north (ABCJHI). This involves connecting Corridor Segments AB, BC, CJ, HJ, and HI. With this alternative, the corridor extends northeast at Devil Canyon past High Lake to Devil Creek drainage. From there, it moves northward to a point north of the south boundary of the Fairbanks Meridian. The corridor then follows the Portage Creek drainage beyond its point of origin to a site within the Tsusena Creek drainage. Likewise, it follows the Tsusena Creek drainage to a point near Jack River, at which point it parallels this drainage into Caribou Pass. From Caribou Pass, the corridor turns to the west, following the Middle Fork Chulitna River until meeting the Intertie in the vicinity of Summit Lake.

While along much of this corridor the route follows river valleys, the plan also requires crossing high mountain passes in rugged terrain. This is especially true in the crossing between Portage Creek and Tsusena Creek drainages, where elevations of over 4,600 feet are involved. Tall-growing vegetation is restricted to the lower elevations along the river drainages with little other than low-growing forbs and shrubs present at higher elevations.

- Corridor Five - Watana to Intertie via Stephan Lake and the East Fork Chulitna River (o)

  A variation of Corridor Four, Corridor Five (ABECJHI) replaces Segment BC with Corridor Segment BEC (of Corridor Two). This results in a corridor that extends from the Watana damsite southwesterly to the vicinity of Stephan Lake, and from Stephan Lake into the Devil Canyon damsite. From Devil Canyon to the Intertie, the corridor follows the Devil Creek, Portage Creek, and Middle Fork Chulitna drainages previously mentioned. As before, the corridor crosses rolling terrain throughout the length of the paralleled drainages, with some confined, higher elevation passes encountered between Portage Creek and Tsusena Creek.

- Corridor Six - Devil Canyon to the Intertie via Tsusena Creek/Chulitna River (o)

  Another option (CBAHI) for connecting the dam projects to the Intertie involves connecting Devil Canyon and Watana along the south shore of the Susitna River via Corridor Segment CBA, then exiting Watana to the north on Segments AH and HI along Tsusena Creek to follow this drainage to Caribou Pass. The corridor then contains the previously-described route along the Jack River and Middle Fork Chulitna until connecting with the Intertie near Summit Lake. The terrain in this corridor proposal would be of moderate elevation with some confined, higher elevation passes between the drainages of Tsusena Creek and the Jack River.

- Corridor Seven - Devil Canyon to Intertie via Stephan Lake and Chulitna River (o)

  This alternative uses Corridor Six but replaces Segment BC with Segment BEC from Corridor Two. This route would thus be designated CEBAHI. Terrain features are as described in Corridors Two and Six.

- Corridor Eight - Devil Canyon to Intertie via Deadman/Brushkana Creeks and Denali Highway (o)

  Yet another option to the previously-described corridors is the interconnection of Devil Canyon with Watana via Corridor One (Segment CBA), with a segment then extending from Watana northeasterly along the Deadman Creek drainage (Segment AG). The segment proceeds north of Deadman Lake and Deadman Mountain, then turns to the west and intersects the Brushkana Creek drainage. It then follows Brushkana Creek north to a point east of the Kana Bench Mark. This segment of the corridor would parallel one of the proposed access roads. From there, the corridor turns west, generally parallel to the Denali Highway, to the point of interconnection with the Intertie in the vicinity of Cantwell. The area encompasses rolling hills with modest elevation changes and some forest cover, especially at the lower elevations.

- Corridor Nine - Devil Canyon to Intertie via Stephan Lake and Denali Highway (o)

  Corridor Nine (CEBAG) is exactly the same as Corridor Eight with the exception of Corridor Segment BEC, utilized to replace Segment BC. Each combination of segments has been previously described.

- Corridor Ten - Devil Canyon to Intertie via North Shore, Susitna River, and Denali Highway (o)

  Corridor Ten connects Devil Canyon-Watana with the Intertie in the vicinity of Cantwell by means of Corridor Segments CJAG. Segment CJA is part of Corridor Three and, as such, has been previously described. Segment AG has also been described above as part of Corridor Eight. As noted earlier, the Corridor Ten terrain consists of mountainous stretches with accompanying gently-rolling to moderately-rolling hills and flat plains covered in places with tall-growing vegetation.

- Corridor Eleven - Devil Canyon to the Intertie via Tsusena Creek/Chulitna River (o)

  Another northern route connecting Devil Canyon with Watana is that created by connecting Corridor Segment CJA (part of Corridor Three) with Segment AHI of Corridor Six.

- Corridor Twelve - Devil Canyon-Watana to the Intertie via Devil Creek/Chulitna River (o)

  Another route under consideration is Corridor JA-CJHI. From north to south, this involves a corridor extending from the Intertie near Summit Lake, heading easterly along the Middle Fork Chulitna drainage into Caribou Pass. From here, it parallels the Jack River and connects with the Portage Creek-Devil Creek route, Segment HJ. At point J, located in the Devil Creek drainage east of High Lake, the corridor splits, with one segment extending westerly to Devil Canyon and the other extending east to the Watana damsite along previously-described Corridor Segments JC and JA, respectively. Terrain features of this route have been previously described.

- Corridor Thirteen - Watana to Devil Canyon via South Shore, Devil Canyon to Intertie via North Shore, Susitna River (o)

  Corridor Segments AB, BC, and CF are combined to form this corridor. Descriptions of the terrain crossed by these segments appear in discussions of Corridor One (ABCD) and Corridor Three (AJCF).

- Corridor Fourteen - Watana to Devil Canyon via North Shore, Devil Canyon to Intertie via South Shore, Susitna River (o)

  This corridor would connect the damsites in the directionally opposite order of the previous corridor, and include Corridor Segment AJCD. Again, as parts of Corridors One and Three, the terrain features of this corridor have been previously described.

- Corridor Fifteen - Watana to Devil Canyon via Stephan Lake, Devil Canyon to Intertie via North Shore, Susitna River (o)

  Corridor Two (ABEC) and Corridor Three (CF) form to create this study-area corridor. Terrain features have been presented under the discussions of each of these two corridors.

(iii) Northern Study Area (o)

In the northern study area, four transmission line corridor options exist for connecting Healy and Fairbanks (Figure B.2.7.3).

- Corridor One - Healy to Fairbanks via Parks Highway (o)

Corridor One (ABC), consisting of Segments AB and BC, starts in the vicinity of the Healy Power Plant. From here, the corridor heads northwest, crossing the existing Golden Valley Electric Association Transmission Line, the railroad, and the Parks Highway before turning to the north and paralleling this road to a point due west of Browne. Here, as a result of terrain features, the corridor turns northeast, crossing the Parks Highway once again as well as the existing transmission line, the Nenana River, and the railroad, and continues northeasterly to a point northeast of the Clear Missile Early Warning Station (MEWS).

Continuing northward, the corridor eventually crosses the Tanana River east of Nenana, then heads northeast, first crossing Little Goldstream Creek, then the Parks Highway just north of the Bonanza Creek Experimental Forest. Before reaching the drainage of Ohio Creek, this corridor turns back to the northeast, crossing the old Parks Highway and heading into the Ester substation west of Fairbanks.

Terrain along this entire corridor segment is relatively flat, with the exception of the foothills north of the Tanana River. Much of the route, especially that portion between the Nenana and the Tanana River crossings, is very broad and flat, has standing water during the summer months and, in some places, is overgrown by dense stands of tall-growing vegetation. This corridor segment crosses the foothills northeast of Nenana, also a heavily-wooded area.

An option to the above (and not shown in the figures), that of closely paralleling and sharing rights-of-way with the existing Healy-Fairbanks transmission line, has been considered. While it is usually attractive to parallel existing corridors wherever possible, this option necessitates a great number of road crossings and an extended length of the corridor paralleling the Parks Highway. A potentially significant amount of highway-abutting land would be usurped for containment of the right-of-way. These features, in combination, eliminated this corridor from further evaluation.

- Corridor Two - Healy to Fairbanks via Crossing Wood River (o)

  The second corridor (ABDC) is a variation of Corridor One and consists of Segments AB and BDC. At point B, east of the Clear MEWS, instead of turning north, the corridor continues to the northeast, crossing Fish Creek, the Totatlanika River, Tatlanika Creek, the Wood River, and Crooked Creek before turning to the north. At a point equidistant from Crooked and Willow Creeks, the corridor turns north, crosses the Tanana River east of Hadley Slough, and extends to the Ester substation. North of the Tanana River, this corridor segment also crosses Rose Creek and the Parks Highway.

  Where it diverges from the original corridor, this corridor traverses extensive areas of flat ground, with standing water very prevalent throughout the summer months. Heavily-wooded areas occur in the broad floodplain of the Tanana River, in the vicinity of the river crossing, and in the foothills around Rose Creek.

- Corridor Three - Healy to Fairbanks via Healy Creek and Japan Hills (o)

  Corridor Three (AEDC), consisting of Segments AE and EDC, exits the Healy Power Plant in an easterly direction. Instead of proceeding northwest, this corridor, following its interconnection with the Intertie Project, heads east up Healy Creek, passing the Usibelli Coal Mine. Near the headwaters of Healy Creek, the corridor cuts to the east, crossing a high pass of approximately 4,700 feet elevation and descending into the Cody Creek drainage. From Healy to the Cody Creek drainage, the terrain is relatively gentle but bounded by very rugged mountain peaks. The elevation gain from the Healy Power Plant to the pass between the

Healy Creek-Cody Creek drainages is approximately 3,300 feet. From here, the segment turns to the northeast, following the lowlands accompanying the Wood River. The corridor next parallels the Wood River from the Anderson Mountain area, past Mystic Mountain, and out into the broad floodplain of the Tanana River east of Japan Hills. Near the confluence of Fish Creek and the Wood River, the corridor turns north and intersects the north-south portion of Corridor Two (Segment DC), after first passing through Wood River Buttes. Much of the area north of Japan Hills is flat and very wet with stands of dense, tall-growing vegetation.

- Corridor Four - Healy to Fairbanks via Wood River and Fort Wainwright (o)

Corridor Four (AEF) is a derivation of Corridor Three and is composed of Segments AE and EF. Point E is located just north of Japan Hills along the Wood River. From here, the corridor deviates from Corridor Three by running north across the Blair Lake Air Force Range, Fort Wainwright, and several tributaries of the Tanana River, before reaching the crossing of Salchaket Slough. Corridor Four passes Clear Creek Butte on the east. A new substation would be located on the Fairbanks side of the Tanana River just north of Goose Island. From Point E to Point F, the terrain of the corridor is flat and very wet, and again, dense stands of tall-growing vegetation exist both in the better drained portions of the flat lands and in the vicinity of the river crossing.

2.7.3 Corridor Screening (o)

The objectives of the screening process were to focus on the previously-selected corridors and select those best meeting technical, economic, and environmental criteria.

(a) Reliability (o)

Reliability is an uncompromising factor in screening alternative transmission line corridors. Many of the criteria utilized for economic, environmental, and technical reasons also relate to the selection of a corridor within which a line can be operated with minimum power interruption. Six basic factors were considered in relation to reliability:

- o Elevation: Lines located at elevations below 4,000 feet will be less exposed to severe wind and ice conditions, which can interrupt service.

- o Aircraft: Avoidance of areas near aircraft landing and takeoff operations will minimize risks from collisions.

- o Stability: Avoidance of areas susceptible to land, ice, and snow slides will reduce chance of power failures.

- o Existing Power Lines: Avoidance of crossing existing transmission lines will reduce the possibility of lines touching during failures and will facilitate repairs.

- o Topography: Lines located in areas with gentle relief will be easier to construct and repair.

- o Access: Lines located in reasonable proximity to transportation corridors will be more quickly accessible and therefore more quickly repaired if any failures occur.

(b) Technical Screening Criteria (o)

Four primary and two secondary technical factors were considered in the screening of alternative corridors.

(i) Primary Aspects (o)

- Topography (o)

- Climate and Elevation (o)

Low temperatures, snow depth, icing, and severe winds are very important parameters in transmission design, operation, and reliability.

Climatic factors become more severe in the mountains, where extreme winds are expected for exposed areas and passes. The Alaska Power Administration believes that elevations above 4,000 feet in the Alaska Range and Talkeetna Mountains are completely unsuitable for locating major transmission facilities. Significant advantages of reliability and cost are expected if the lines are routed below 3,000 feet in elevation. This elevation figure was used in the screening process.

- Soils (o)

Although transmission lines are less affected by soils and foundation limitations than railroads and pipelines, it is more reliable to build a transmission line on soil that does not appear to be underlain by seismically-induced ground failures. It is also desirable to avoid swampy areas where maintenance and inspection may create problems. These factors were utilized in the screening process. Because of the vast areas of wetlands in the study area, particularly in the southern portion, it was not possible to locate a corridor that would avoid all wetland areas.

- Length of Corridors (o)

(ii) Secondary Aspects (o)

- Vegetation and Clearing (o)

Heavily-forested areas must be cleared prior to construction of the transmission line. Clearing the vegetation will cause some disruption of the soil. If the cleared right-of-way is not properly stabilized through restoration and revegetation, increased erosion will result. If the vegetation is cleared up to river banks on stream crossings, additional sedimentation may result. During the corridor screening, those corridors crossing large expanses of heavily timbered areas were eliminated.

- Other (o)

Highway and river crossings were avoided where possible.

(c) Economic Screening Criteria (o)

Three primary and one secondary aspect of the economic criteria were considered.

(i) Primary Aspects (o)

- Length (o)
- Right-of-Way (o)

  Whenever possible, existing rights-of-ways were shared or paralleled to avoid problems associated with pioneering a corridor in previously inaccessible areas.

- Access Roads (o)

(ii) Secondary Aspects (o)

In addition to the major considerations concerning economic screening of corridors, some other aspects were also considered. These include topography (since it is more economical to build a line on a flat corridor than on a rugged or a mountainous one) and limiting the number of stream, river, highway, road, and railroad crossings in order to minimize costs.

(d) Environmental Screening Criteria (o)

Because of the potential adverse environmental impacts from transmission line construction and operation, environmental criteria were carefully scrutinized in the screening process. Past experience has shown the primary environmental considerations to be:

- o Aesthetic and Visual (including impacts on recreation);
- o Land Use (including ownership and presence of existing rights-of-way).

Also of significance in the evaluation process are:

- o Length,
- o Topography,
- o Soils,

- Cultural Resources,
- Vegetation,
- Fishery Resources, and
- Wildlife Resources.

A description and rationale for use of these criteria are presented below.

(i) Primary Aspects (o)

- Aesthetic and Visual (o)

The presence of large transmission line structures in undeveloped areas has the potential for adverse aesthetic impacts. Furthermore, the presence of these lines can conflict with recreational use, particularly those nonconsumptive recreational activities such as hiking and bird watching where great emphasis is placed on scenic values. The number of road crossings encountered by transmission line corridors is also a factor that needs to be inventoried because of the potential for visual impacts. The number of roads crossed, the manner in which they are crossed, the nature of existing vegetation at the crossing site (i.e., potential visual screening), and the number and type of motorists using the highway all influence the desirability of one corridor versus another. Therefore, when screening the previously-selected corridors, consideration was focused on the presence of recreational areas, hiking trails, heavily utilized lakes, vistas, and highways where views of transmission line facilities would be undesirable.

- Land Use (o)

The three primary components of land use considerations are: 1) land status/ownership, 2) existing rights-of-way, and 3) existing and proposed development.

. Land Status/Ownership (o)

The ownership of land to be crossed by a transmission line is important because certain types of ownership present more restrictions than others. For example, some recreation areas such as state and federal parks and areas such as game refuges and military lands, among others, present possible constraints to corridor routing. Private landowners generally do not want transmission lines on their lands. This information, when known in advance, permits corridor routing to avoid such restrictive areas and to occur in areas where land use conflicts can be minimized.

- Existing Rights-of-Way (o)

  Paralleling existing rights-of-way tends to result in less environmental impact than that which is associated with a new right-of-way because the creation of a new right-of-way may provide a means of access to areas normally accessible only on foot. This can be a critical factor if it opens sensitive, ecological areas to all-terrain vehicles.

  Impact on soils, vegetation, stream crossings, and other inventory categories can also be lessened through the paralleling of existing access roads and cleared rights-of-way. Some impact is still felt, however, even though a right-of-way may exist in the area. For example, cultural resources may not have been identified in the original routing effort.

  Wetlands present under existing transmission lines may likewise be negatively influenced if ground access to the vicinity of the tower locations is required.

  There are common occasions where paralleling an existing facility is not desirable. This is particularly true in the case of highways that offer the potential for visual impacts and in situations where paralleling a poorly sited transmission facility would only compound an existing problem.

- Existing and Proposed Developments (o)

  This inventory identifies such items as agricultural use, planned urban developments, existing residential and cabin developments, the location of airports and lakes used for float planes, and similar types of information. Such information is essential for locating transmission line corridors appropriately, as it presents conflicts with these land use activities.

(ii) Secondary Aspects (o)

- Length (o)

The length of a transmission line is an environmental factor and, as such, was considered in the screening process. A longer line will require more construction activity than a shorter line, will disturb more land area, and will have a greater inherent probability of encountering environmental constraints.

- Topography (o)

The natural features of the terrain are significant from the standpoint that they offer both positive and negative aspects to transmission line routing. Steep slopes, for example, present both difficult construction and soil stabilization problems with potentially long-term, negative environmental consequences. Also, ridge crossings have the potential for visual impacts. At the same time, slopes and elevation changes present opportunities for routing transmission lines so as to screen them from both travel routes and existing communities. Hence, when planning corridors the identification of changes in relief is an important factor.

- Soils (o)

Soils are important from several standpoints. First of all, scarification of the land often occurs during the construction of transmission lines. As a result, vegetation regeneration is affected, as are the related features of soil stability and erosion potential. In addition, the development and installation of access roads, where necessary, are very dependent upon soil types. Tower designs and locations are dictated by the types of soils encountered in any particular corridor segment. Consequently, the review of existing soils information is very significant.

This inventory was conducted by means of a Soil Associations Table, Table B.2.7.7. Table B.2.7.8 presents the related definitions as they apply to the terms used in Table B.2.7.7.

- Cultural Resources (o)

The avoidance of known or potential sites of cultural resources is an important component in the routing of transmission lines. A level-one cultural resources survey has been conducted along a large portion of the transmission corridors. In those areas where no information has been collected to date an appropriate program for identifying and mitigating impacts will be undertaken. This program is discussed in more detail in Chapter 4 of Exhibit E.

- Vegetation (o)

The consideration of the presence and location of various plant communities is essential in transmission line siting. The inventory of plant communities, such as those of a tall-growing nature or wetlands, is significant from the standpoint of construction, clearing, and access road development requirements. In addition, identification of locations of endangered and threatened plant species is also critical. While several Alaskan plant species are currently under review by the U.S. Fish and Wildlife Service, no plant species are presently listed under the Endangered Species Act of 1973 as occurring in Alaska. No corridor currently under consideration has been identified as traversing any location known to support these identified plant species.

- Fishery Resources (o)

The presence or absence of resident or anadromous fish in a stream is a significant factor in evaluating suitable transmission line corridors. The corridor's effects on a stream's resources must be viewed from the standpoint of possible disturbance to fish species, potential loss of habitat, and possible destruction of spawning beds. In addition, certain species of fish are more sensitive than others to disturbance.

Closely related to this consideration is the number of stream crossings. The nature of the soils and vegetation in the vicinity of the streams and the manner in which the streams are to be crossed are also important environmental considerations when routing transmission lines. Potential stream degradation, impact on fish habitat through disturbance, and long-term negative consequences resulting from siltation of spawning beds are all concerns that need evaluation in corridor routing. Therefore, the number of stream crossings and the presence of fish species and habitat value were considered when data were available.

- Wildlife Resources (o)

The three major groups of wildlife which must be considered in transmission corridor screening are big game, birds, and furbearers. Of all the wildlife species to be considered in the course of routing studies for transmission lines, big game species (together with endangered species) are most significant. Many of the big game species, including grizzly bear, caribou, and sheep, are particularly sensitive to human intrusion into relatively undisturbed areas. Calving grounds, denning areas, and other important or unique habitat areas as identified by the Alaska Department of Fish and Game were identified and incorporated into the screening process.

Many species of birds such as raptors and swans are sensitive to human disturbance. Identifying the presence and location of nesting raptors and swans permits avoidance of traditional nesting areas. Moreover, if this category is investigated, the presence of endangered species (viz, peregrine falcons) can be determined.

Important habitat for furbearers exists along many potential transmission line corridors in the Railbelt area, and its loss or disruption would have a direct effect on these animal populations. Investigating habitat preferences, noting existing habitat, and identifying populations through available information are important steps in addressing the selection of environmentally acceptable alternatives.

(e) Screening Methodology (o)

(i) Technical and Economic Screening Methodology (o)

The parameters required for the technical and economic analyses were extracted from the environmental inventory tables (Tables B.2.7.4 through B.2.7.6). These tables, and Tables B.2.7.9 through B.2.7.15 are derived from studies carried out prior to the issuance of the Feasibility Report in March 1982; at that time the routing of the proposed access route was undecided. Subsequent to the publication of the Feasibilty Report the decision was made to select the Denali-North Plan as the proposed access route. Since the location of the access route is of major importance in relation to the transmission line within the central study area, the tables have been modified to reflect this decision and the ratings assigned to each corridor adjusted accordingly. The reasons for changing these ratings are discussed in more detail in subsection 2.7.4.

The tables, together with the topographic maps, aerial photos, and existing published materials, were used to compare the alternative corridors from a technical and economic point of view. The parameters used in the analysis were: length of corridors, approximate number of highway/road crossings, approximate number of river/creek crossings, land ownership, topography, soils, and existing rights-of-way. The main factors contributing to the economic and technical analyses are combined and listed in Tables B.2.7.9, B.2.7.10, and B.2.7.11. It should be noted that most of the parameters are in miles of line length, except the tower construction. In this analysis, it was decided to assign 4.5 towers for each mile of 345-kV line.

In order to screen the most qualified corridor, it was decided to rate the corridors as follows:

Corridor rated A - recommended,
Corridor rated C - acceptable but not preferred, and
Corridor rated F - unacceptable.

From a technical point of view, reliability is the main objective. An environmentally and economically sound transmission line was rejected if the line was not reliable. Thus, any line that received an F technical rating was assigned an overall rating of F and eliminated from further consideration.

The ratings appear in each of the economic and technical screening tables (Tables B.2.7.9, B.2.7.10, and B.2.7.11) and are summarized in Table B.2.7.12.

(ii) Environmental Screening Methodology (o)

In order to compare the alternative corridors (Figures B.2.7.1, B.2.7.2, and B.2.7.3) from an environmental standpoint, the environmental criteria discussed above were combined into environmental constraint tables (Tables B.2.7.13, B.2.7.14 and B.2.7.15). These tables combine information for each corridor segment into the proper corridors under study. This permits the assignment of an environmental rating, which identifies the relative rating of each corridor within each of the three study areas. The assignment of environmental ratings is a subjective, qualitative technique intended as an aid to corridor screening. Those corridors that are recommended are identified with an "A," while those corridors that are acceptable but not preferred are identified with a "C." Finally, those corridors that are considered unacceptable are identified with an "F."

2.7.4 Selected Corridor (o)

The selected corridor consists of the following segments:

- o Southern Study Area: Corridor ADFC (Figures B.2.7.4 and B.2.7.5)
- o Central Study Area: Corridor AJCD (Figures B.2.7.6 and B.2.7.7)
- o Northern Study Area: Corridor ABC (Figures B.2.7.8 - B.2.7.11)

Specifics of these corridors and reasons for rejection of others are discussed below. More detail on the screening process and the specific technical ratings of each alternative are in Chapter 10 of Exhibit E.

(a) Southern Study Area (o)

In the southern study area, Corridor Segment AEF and, hence, Corridor Three (AEFC) were determined unacceptable. This results primarily from the routing of the segment through the relatively well-developed and heavily-utilized Nancy

Lake state recreation area. Adjustments to this route to make it more acceptable were attempted but no alterations proved successful. Consequently, it was recommended that this corridor be dropped from further consideration.

Corridor One (ABC'), identified as acceptable but not preferred, was thus given the C rating. Its great length, its traversing of residential and other developed lands, and the numerous creek crossings and extensive forest clearing involved relegate this corridor to this environmental rating. Economically and technically, this corridor has more difficulties than the other two considered. This is a longer line and crosses areas which may require easements in the area north of Anchorage.

Corridor Two (ADFC) was identified as the candidate which would satisfy most of the screening criteria. This corridor is shown in Figures B.2.7.4 and B.2.7.5 and stretches from an area north of Willow Creek to Point MacKenzie in the south. The corridor is located east of the lower Susitna River and crosses the Little Susitna River. The corridor also crosses an existing 138-kV line owned and operated by Chugach Electric Association (CEA), which starts at Point MacKenzie and extends to Teeland Substation.

Up to this point in the corridor selection study, Point MacKenzie has been considered a terminal point for Susitna power. It was assumed that an underwater cable crossing would be provided at this location. Upon further study and data gathering it has become known that the existing crossing at Point MacKenzie has experienced power interruptions caused by ships' anchors snagging the submarine cables. CEA, which owns the submarine cables, required additional transmission capacity to Anchorage. After thoroughly studying the matter, it has opted for a combined submarine/overhead cable transmission across Knik Arm and on to Anchorage. This was the most desirable option to CEA from both the environmental and technical point of view.

The CEA crossing will be located approximately 8 miles northeast of Point MacKenzie on the west shore of the Knik Arm and across from Elmendorf Air Force Base in the vicinity of Six Mile Creek. This crossing is located northeast of Anchorage Harbor, away from heavy ship traffic, thereby reducing the risk of anchor damage to the cable.

It is intended to terminate Corridor ADFC at this new crossing point and extend the transmission corridor to Elmendorf Air Force Base and beyond to Anchorage.

Although the crossing is approximately 8 miles northeast of Point MacKenzie, it does not influence the results of this corridor selection and screening process. The best corridor has been selected and screened. During routing studies minor deviations outside the corridor will have to occur in order to terminate at the revised crossing point. However, preliminary investigations indicate it will be possible to select a technically, economically, and environmentally acceptable route, particularly since an existing transmission line can likely be paralleled from the selected corridor to the revised crossing point. Furthermore, CEA has received the necessary permits and is constructing an underwater crossing at Knik Arm, indicating acceptable levels of environmental impact.

(b) Central Study Area (o)

In the central study area, several corridor segments and their associated corridors were determined to be unacceptable. The first of these, Corridor Segment BEC, appears as part of Corridors Two (ABECD), Five (ABECJHI), Seven (CEJAHI), Nine (CEBAG), and Fifteen (ABECF). The primary reason for rejecting this segment is that the developed recreation area around Stephan Lake would be needlessly harmed because viable options exist to avoid intruding into this area. An acceptable modification could not be found and, consequently, it is recommended that these five corridors be dropped from further consideration.

Corridor Segment AG was also determined not to warrant further consideration, because of its approximate 65-mile length, two-thirds of which would possibly require a pioneer access road. Also, extensive areas of clearing would be required, opening the corridor to view in some scenic locations. Finally, the impacts on fish and wildlife habitats are potentially severe. These preliminary findings, coupled with the fact that more viable options to Segment AG exist, suggest that consideration of this corridor segment and therefore Corridors Eight (CBAG) and Ten (CJAG) should be terminated.

Corridors Eleven (CJAHI) and Twelve (JA-CJHI) were identified as not acceptable. This rating arose from the fact that, as shown in Environmental Constraint Table B.2.7.14, numerous constraints affect this routing. Information from recently completed field investigations suggest that these constraints cannot be overcome and the routes should be rejected. Furthermore, the technical and economical ratings preclude these corridors from further consideration.

Corridor Segment HJ has been moved so that it no longer parallels the Devil Creek drainage; the new location HC is selected to avoid both High Lake and the Devil Creek drainage. It then follows the Portage Creek drainage to the point of intersection with Corridor Segment JH, near the creek's headwaters. Subsequent investigations have confirmed that this corridor segment is not viable and, consequently, Corridors Four and Five are eliminated from further consideration.

Corridor Six (CBAHI) intrudes on valuable wildlife habitat and would cross numerous creeks, none of which are currently crossed by existing access roads. In addition, a high mountain pass and its associated shallow soils, steep slopes, and surficial bedrock constrain this routing. Finally, its crossing of areas over 4,000 feet in elevation makes it technically unacceptable, so this corridor is dropped from further consideration.

The four remaining corridors (Corridors One, Three, Thirteen and Fourteen) were each identified as being acceptable in terms of the technical, economic and environmental criteria described in subsection 2.7.3.

The Denali-North Plan was selected as the proposed access route for the Susitna development (subsection 2.6.8). The location of existing and proposed access is of prime importance both from an economic and environmental standpoint. Therefore, subsequent to the access decision, each of the four corridors was subjected to a more detailed evaluation and comparison. In order to more directly compare the four corridors a preliminary route was selected in each of the segments. The final route selection process leading to the perferred route in the corridor, which was subsequently recommended, is discussed in more detail in subsection 2.7.5. The four corridors comprise the following segments:

- o Corridor One ABCD,
- o Corridor Three AJCF,
- o Corridor Thirteen ABCF, and
- o Corridor Fourteen AJCD.

Segments ABC and AJC link Watana with Devil Canyon and, similarly, segments CD and CF link Devil Canyon with the Intertie.

(i) The Choice Between CD and CF (o)

On closer examination of the possible routes between Devil Canyon and the Intertie, segment CD was found to be superior to segment CF for the following reasons.

- Economic (o)

  A four-wheel drive trail is already in existence on the south side of the Susitna River between Gold Creek and the proposed location of the railhead facility at Devil Canyon. Therefore, the need for new roads along segment CD, both for construction and operation and maintenance, is significantly less than for segment CF, which requires the construction of a pioneer road. In addition, the proposed Gold Creek to Devil Canyon railroad extension will also run parallel to segment CD. The lengths of Segments CD and CF are 8.8 miles and 8.7 miles, respectively--not a significant difference. Among the secondary economic considerations is that of topography. Segment CF crosses more rugged terrain at a higher elevation than segment CD and would therefore prove more difficult and costly to construct and maintain. Hence, segment CD was considered to have a higher overall economic rating.

- Technical (o)

  Although both segments are routed below 3,000 feet elevation, segment CF crosses more rugged, exposed terrain with a maximum elevation of 2,600 feet. Segment CD, on the other hand, traverses generally flatter terrain and has a maximum elevation of 1,800 feet. The disadvantages of segment CF are somewhat offset, however, by the Susitna River crossing that will be needed at river mile 150 for segment CD. Overall, the technical difficulties associated with the two segments may be regarded as being similar.

- Environmental (o)

  One of the main concerns of the various environmental groups and agencies is to keep any form of access away from sensitive ecological areas previously inaccessible other than by foot. Creating a pioneer road to construct and maintain a transmission line along segment CF would open that area to all-terrain vehicles and public use, and thereby increase the potential for adverse impacts to the environment. The potential for environmental impacts along segment CD would be present regardless of where the transmission line was built since there is an existing four-wheel drive trail together with the proposed railroad extension in that area. It is clearly desirable to restrict environmental impacts to a single common corridor; for that reason, segment CD is preferable to segment CF.

Because of potential environmental impacts and economic ratings, segment CF was dropped in favor of segment CD. Consequently, corridors Three (AJCF) and Thirteen (ABCF) were eliminated from further consideration.

(ii) The Choice Between ABC and AJC (o)

The two corridors remaining are therefore corridors One (ABCD) and Fourteen (AJCD). This reduces to a comparison of segment ABC on the south side of the Susitna River and segment AJC on the north side. The two segments were then screened in accordance with the criteria set out in subsection 2.7.3. The key points of this evaluation are outlined below:

- Economic (o)

  For the Watana development, two 345 kV transmission lines will be constructed from Watana through to the Intertie. When comparing the relative lengths of transmission line, it was found that segment ABC was 33.6 miles in total length compared to 36.4 miles for the northern route using segment AJC. Although at first glance a difference in length of 2.8 miles (equivalent to 12 towers at a spacing of 1,200 feet) seems significant, other factors were taken into account. Segment ABC contains mostly woodland, black spruce in segment AB. Segment BC contains open and woodland spruce forests, low shrub, and open and closed mixed forest in about equal amounts. segment AJC, on the other hand, contains significantly less vegetation and is composed predominantly of low shrub and tundra in segment AJ and tall shrub, low shrub and open mixed forest in segment JC. Consequently, the amount of clearing associated with segment AJC is considerably less than with segment ABC, resulting in savings not only during construction but also during periodic recutting. Additional costs would also be incurred with segment ABC due to the increased spans needed to cross the Susitna River (at river mile 165.3) and two other major creek crossings. In summary, the cost differential between the two segments would probably be marginal.

- Technical (o)

Segment AJC traverses generally moderately-sloping terrain ranging in height from 2,000 feet to 3,500 feet with 9 miles of the segment being at an elevation in excess of 3,000 feet. Segment ABC traverses more rugged terrain, crossing several deep ravines and ranges in elevation from 1,800 feet to 2,800 feet. In general there are advantages of reliability and cost associated with transmission lines routed under 3,000 feet. The 9 miles of segment AJC at elevations in excess of 3,000 feet will be subject to more severe wind and ice loadings than segment ABC, and the towers will have to be designed accordingly. However, these additional costs will be offset by the construction and maintenance problems with the more rugged topography and major river and creek crossings of segment ABC. The technical difficulties associated with the two segments are therefore considered similar.

- Environmental (o)

From the previous analysis, it is evident that there are no significant difference between the two segments in terms of technical difficulty and economics. The deciding factor therefore reduces to the environmental impacts. The access road routing between Watana and Devil Canyon was selected because it has the least potential for creating adverse impacts to wildlife, wildlife habitat and fisheries. Similarly, Segment AJC, within which the access road is located, is environmentally less sensitive than Segment ABC, for it traverses or approaches fewer areas of productive habitat and zones of species concentration or movement. The most important consideration, however, is that for ground access during operation and maintenance, it will be necessary to have some form of trail along the transmission line route. This trail would permit human entry into an area which is relatively inaccessible at present, causing both direct and indirect impacts. By placing the transmission line and access road within the same general corridor as in Segment AJC, impacts will be confined to that one corridor. If access and transmission are placed in separate corridors, as in Segment ABC, environmental impacts would be far greater.

Segment AJC is thus considered superior to Segment ABC. Consequently, Corridor One (ABCD) was eliminated and Corridor Fourteen (AJCD) selected as the proposed route.

(c) Northern Study Area (o)

Corridors Three (AEDC) and Four (AEF) were determined unacceptable because of many constraints, and thus rated F. They include: the lack of an existing access road; problems in dealing with tower erection in shallow bedrock zones; the need for extensive wetland crossings and forest clearing; the 75 river or creek crossings involved; and the fact that prime habitat for waterfowl, peregrine falcons, caribou, bighorn sheep, golden eagle, and brown bear would be crossed. In addition, Corridor Four crosses areas of significant land use constraints and elevations of over 4,000 feet.

Corridor Two (ABDC) was identified as acceptable but not preferred, and thus rated C. Certain constraints indentified for this corridor suggest that an alternative is preferable. Compared with Corridor One, Corridor Two crosses additional wetlands and requires the development of more access roads and the clearing of additional forest lands.

Corridor One (ABC), shown in Figures B.2.7.8 to B.2.7.11, was the only recommended corridor in the northern study area. While many constraints were identified under the various categories, it appears possible to select a route within this corridor to minimize constraint influences. This corridor is attractive economically, because it is close to access roads and the Parks Highway. The visual impact can be lessened by strategic placement of the line. This line also best meets technical and economical requirements.

2.7.5 Route Selection (o)

(a) Methodology (o)

After identification of the preferred transmission line corridors, the next step in the route selection process involved the analysis of the data as gathered and presented on the base map. Overlays were compiled so that various constraints affecting construction or maintenance of a transmission facility could be viewed on a single map. The map was used to select possible routes within each of the three selected corridors. By placing all major constraints (e.g., areas of high visual exposure, private lands, endangered species, etc.) on one map, a route of least impact was selected. Existing facilities, such as transmission lines and tractor trails within the study area, were also considered during the selection of a minimum impact route. Whenever possible, the routes were selected near existing or proposed access roads, sharing werever possible existing rights-of-way.

The data base used in this analysis was obtained from the following sources:

- An up-to-date land status study,
- Existing aerial photos,
- New aerial photos conducted for selected sections of the previously-recommended transmission line corridors,
- Environmental studies including aesthetic considerations,
- Climatological studies,
- Geotechnical exploration,
- Additional field studies, and
- Public opinions.

(b) Selection Criteria (o)

The purpose of this section is to identify three selected routes: one from Healy to Fairbanks, the second from the Watana and Devil Canyon damsites to the Intertie, and the third from Willow to Anchorage.

The previously-chosen corridors were subject to a process of refinement and evalution based on the same technical, economic, and environmental criteria used in corridor selection. In addition, special emphasis was placed on the following points:

- Satisfying the regulatory and permit requirements;
- Selection of routing that provides for minimum visibility from highways and homes; and
- Avoidance of developed agricultural lands and dwellings.

(c) Environmental Analysis (o)

The corridors selected were analyzed to arrive at the route which is most compatible with the environment and also meets engineering and economic objectives. The environmental analysis was conducted by the process described below:

- Literature Review (o)

  Data from various literature sources, agency communications, and site visits were reviewed to inventory existing environmental variables. From such an inventory, it was possible to identify environmental constraints in the recommended corridor locations. Data sources were cataloged and filed for later retrieval.

- Avoidance Routing by Constraint Analysis (o)

  To establish the most appropriate location for a transmission line route, it was necessary to identify those environmental constraints that could be impediments to the development of such a route. Many specific constraints were identified during the preliminary screening; others were determined during the 1981 field investigations.

  By utilizing information on topography, existing and proposed land use, aesthetics, ecological features, and cultural resources as they exist within the corridors, and by careful placement of the route with these considerations in mind, impact on these various constraints was minimized.

- Base Maps and Overlays (o)

  Constraint analysis information was placed on base maps. Constraints were identified and presented on overlays to the base maps. This mapping process involved using both existing information and that acquired through Susitna project studies. This information was first categorized as to its potential for constraining the development of a transmission line route within the preferred corridor and then placed on maps of the corridors. Environmental constraints were identified and recorded directly onto the base maps. Overlays to the base maps were prepared indicating the type and extent of the encountered constraints.

Three overlays were prepared for each map: one for visual constraints, one for man-made, and one for biological constraints (Acres, TES 1982).

(d) Technical and Economic Analysis (o)

Route location objectives are to obtain an optimum combination of reliability and cost with the fewest environmental problems. In many cases, these objectives are mutually compatible.

Throughout the evaluation, much emphasis was placed on locating the route relatively close to existing surface transportation facilities whenever possible.

The factors that contributed heavily in the technical and economic analysis were: topography, climate and elevation, soils, length, and access roads. Other factors of less importance were vegetation and river and highway crossings. These factors are detailed in Tables B.2.7.3 and B.2.7.16.

(i) Selection of Alternative Routes (o)

The next step in the route selection process involved analysis of the data presented on the base maps. The data were used to select possible routes within each corridor. By placing all major constraints on one map, routes of smallest impacts were selected. Existing facilities, such as transmission lines and tractor trails within the study area, were also taken into consideration during the selection of a least impact route.

(ii) Evaluation of a Primary Route (o)

The evaluation and selection of alternative routes to arrive at a primary route involved a closer examination of each of the possible routes using mapping processes and data previously described. Preliminary routes were compared to determine the route of least impact within the primary corridors of each study area. For example, such variables as number of stream and road crossings required were noted. Then, following the field studies and through a comparison of routing data, including the route's total length and its use of existing facilities, one route was designated the primary route. Land use, land ownership, and visual impacts were key factors in the selection process.

(e) Route Soil Conditions (o)

(i) Description (o)

Baseline geological and geotechnical information was compiled through photo interpretation and terrain unit mapping. The general objective was to document the conditions that would significantly affect the design and construction of the tranmission line towers. More specifically, these conditions include the origins of various land forms, noting the occurrence and distribution of significant geologic features such as permafrost, potentially unstable slopes, potentially erodible soils, possible active fault traces, potential construction materials, active floodplains, organic materials, etc.

Work on the air photo interpretation consisted of several activities culminating in a set of terrain unit maps showing surface materials, geologic features, and conditions in the project area.

The first activity consisted of a review of the literature concerning the geology of the Intertie corridors and transfer of the information gained to high-level photographs at a scale of 1:63,000. Interpretation of the high-level photos created a regional terrain framework which assisted in interpretation of the low-level 1:30,000 project photos. Major terrain divisions identified on the high-level photos were then used as an aerial guide for delineation of more detailed terrain units on the low-level photos. The primary effort of the work was the interpretation of over 140 photos covering about 300 square miles of varied terrain. The land area covered in the mapping exercise is shown on map sheets and displayed in detail on photo mosaics (R&M Consultants 1981a).

As part of the terrain analysis, the various bedrock units and dominant lithologies were identified using published U.S. Geological Survey reports. The extent of these units was shown on the photographs, and, using exposure patterns, shade, texture, and other features of the rock unit as they appeared on the photographs, unit boundaries were drawn.

Physical characteristics and typical engineering properties of each terrain unit were considered and a chart for each corridor was developed. These charts identify the terrain units as they have been mapped and characterize their properties in numerous categories. This allows an assessment of each unit's influence on various project features.

(ii) Terrain Unit Analysis (o)

The terrain unit is a special purpose term comprising the land forms expected to occur from the ground surface to a depth of about 25 feet.

The terrain unit maps for the proposed Anchorage-to-Fairbanks transmission line show the aerial extent of the specific terrain units which were identified during the air photo investigation and were corroborated in part by a limited on-site surface investigation. The units document the general geology and geotechnical characteristics of the area.

The north and south corridors are separated by several hundred miles and, not surprisingly, encounter different geomorphic provinces and climatic conditions. Hence, while there are many landforms (or individual terrain units) that are common to both corridors, there are also some landforms mapped in just one corridor. The landforms or individual terrain units mapped in both corridors were briefly described.

Several of the landforms have not been mapped independently but rather as compound or complex terrain units. Compound terrain units result when one landform overlies a second recognized unit at a shallow depth (less than 25 feet), such as a thin deposit of glacial till overlying bedrock or a mantle of lacustrine sediments overlying till. Complex terrain units have been mapped where the surficial exposure pattern of two landforms are so intricately related that they must be mapped as a terrain unit complex, such as some areas of bedrock and colluvium. The compound and complex terrain units were described as a composite of individual landforms comprising them. The stratigraphy, topographic position, and aerial extent of all units, as they appear in each corridor, were summarized on the terrain unit properties and engineering interpretations chart (R&M Consultants 1981a).

(f) Results and Conclusions (o)

A study of existing information and aerial overflights, together with additional aerial coverage, was used to locate the recommended route in each of the southern, central, and northern study areas.

Terrain unit maps describing the general material expected in the area were prepared specifically for transmission line studies and were used to locate the route away from unfavorable soil conditions wherever possible. Similarly, environmental constraint analysis information was placed on base maps and overlays (Acres, TES 1982) and the route modified accordingly.

Subsequent to the submission of the Feasibility Study (Acres 1982c), additional environmental and land status studies made it possible to further refine the alignments to the extent that most environmentally sensitive areas and areas where land acquisition may present a problem have been avoided. In the Fairbanks-to-Healy and the Willow-to-Anchorage line sections, these refinements have resulted in an improved alignment which is generally in close proximity to the earlier proposal.

Also subsequent to the Feasibility Study, the proposals for access to the power development were reassessed. As mentioned earlier, this resulted in a decision to provide access to Watana for the Denali Highway and build a connecting road between the dams on the north side of the Susitna River. The earlier line routing proposals were accordingly reviewed to establish the optimum alignment. The desire to limit environmental impacts to a single corridor led to the routing of the transmission line more or less parallel to the access road. Hence, between the dams, the line shares the same general corridor as the access road to the north of the Susitna River. From Devil Canyon to the intersection with the Intertie (at a switching station approximately four miles northeast of Gold Creek), the line is located south of the Susitna River paralleling the proposed railroad extension, and an existing four-wheel drive trail.

The original corridors, which were three to five miles in width, were narrowed to a half mile and, after final adjustment, to a finalized route with a defined right-of-way. The selected transmission line route for the three study areas is presented in Exhibit G. Preliminary studies have indicated that, for a hinged-guyed X-configuration tower having horizontal phase spacing of 33 feet, the following right-of-way widths should be sufficient:

o 1 tower	190 feet,
o 2 towers	300 feet,
o 3 towers	400 feet, and
o 4 towers	510 feet.

These right-of-way widths will be subject to minor local variation where the need for special tower structures dictates or where difficult terrain is encountered and will be addressed fully in the final design phase of the project.

2.7.6 Towers, Foundations and Conductors (o)

The Anchorage and Fairbanks Intertie will consist of existing lines and a new section between Willow and Healy. The new section will be built to 345 kV standards but will be temporarily operated at 138 kV and will be fully compatible with Susitna requirements.

(a) Transmission Line Towers (o)

(i) Selection of Tower Type (o)

Because of the unique soil conditions in Alaska which are characterized by extensive regions of muskeg and permafrost, conventional self-supporting or rigid towers will not provide a satisfactory solution for the proposed transmission line.

Permafrost and seasonal changes in the soil are known to cause large earth movements at some locations, requiring towers with a high degree of flexibility and capability to sustain appreciable loss of structural integrity.

A guyed tower is well suited to these conditions; these include the guyed-V, guyed-Y, guyed delta, and guyed portal type structures. The type of structure selected for the construction of the Intertie is the hinged-guyed steel X-tower, a refinement of the guyed structure concept. This type of tower is therefore a prime candidate for use on the Watana transmission system. Guyed pole-type structures will be used on larger angle and dead end structures; a similar arrangement will be used in especially heavy loading zones.

The design features of the X-tower include hinged connections between the legs and the foundation and four longitudinal guys attached in pairs to two guy anchors, providing a high degree of flexibility with excellent structural strength. The wide leg spacing results in relatively low foundation forces which are carried on pile type footings in soil and steel grillage or rock anchor footings where rock is close to the surface.

In narrow right-of-way situations, cantilever steel pole structures are anticipated, with foundations consisting of cast-in-lace concrete augered piles.

In the final design process, experience gained in the construction and operation of the Intertie will be used in the final selection of the structure type to be used for the Watana transmission.

All tower structures will be of "weathering" type steel which matures to a dark brown color over a period of a few years and is considered to have a more aesthetically pleasing appearance than either galvanized steel or aluminum.

(ii) Climatic Studies and Loadings (o)

Climatic studies for transmission lines were performed to determine probable maximum wind and ice loads based on historical data. A more detailed study incorporating additional climatic data was carried out for the Intertie final design. These studies have resulted in the selection of preliminary loading for the line design (Acres 1982c, Vol. 4).

Preliminary loadings selected for line design should be confirmed by a detailed study, similar to that performed for the Intertie, that will examine conditions for the Healy-to-Fairbanks, Willow-to-Anchorage and Gold Creek-to-Watana sections of the route, together with an update of the Healy-to-Willow study incorporating any data from field measurement stations collected in the interim period.

Based on data currently available, it appears that the line can be divided up into zones as far as climatic loading is concerned as follows:

- o Normal Loading Zone,
- o Heavy Ice Loading Zone, and
- o Heavy Wind Loading Zone.

The heavy ice and heavy wind zones will have an additional critical loading case included to reflect the special nature of the zone.

(iii) Tower Family (o)

A family of tower designs will be developed as follows:

- o Suspension towers will be provided for both standard span plus angle (up to 3°) application and for long span or light angle (0° to 8°) application.

- o Tension towers will be provided for light angle and dead end (0° to 8°), for large angle and dead end (8° to 50°), and for minimum angle and dead end (50° to 90°).

The maximum wind span and weight span ratios to be utilized will be set in final design to reflect the rugged nature of the terrain along the line route. Some trial spotting of towers in representative terrains will be used to guide this selection. Minimum weight span to wind span ratio limits will be set during tower spotting and a "low temperature template" used to check that unexpected uplift will not develop at low weight span towers for very low temperatures.

The span to be used in design will be the subject of an economic optimization study. A span of not less than 1,200 feet is expected with spans in the field varying to greater and lesser values in specific cases depending upon span ratio and loading zone.

(b) Tower Foundations (o)

(i) Geotechnical Conditions (o)

The generalized terrain analysis (R&M Consultants 1981a) was conducted to collect geologic and geotechnical data for the transmission line corridors, a relatively large area. The engineering characteristics of the terrain units have been generalized and described qualitatively.

When evaluating the suitability of a terrain unit for a specific use, the actual properties of that unit must be verified by on-site subsurface investigation, sampling, and laboratory testing.

The three main types of foundation materials along the transmission line are:

- o Good material, which is defined as overburden which permits augered excavation and allows installation of concrete without special form work;

- o Wetland and permafrost material which requires special design details; and

- o Rock material defined as material in which drilled-in anchors and concrete footings can be used.

Based on aerial, topographic, and terrain unit maps, the following was noted:

- o For the southern study area: Wetland and permafrost materials constitute the major part of this area. Some rock and good foundation materials are present in this area in a very small proportion.

- o For the central study area: Rock foundation and good materials were observed in most of this study area.

For the northern study area: The major part of this area is wetland and permafrost materials. Some parts have rock materials.

(ii) <u>Types of Foundations</u> (o)

The types of tangent tower envisaged for these lines will require foundations to support the leg or mast capable of carrying a predominantly vertical load with some lateral shear, and a guy anchor foundation.

The cantilever pole structure foundation is required to resist the high overturning moment inherent in the cantilever arrangement.

The greater part of the combined maximum reactions on a transmission tower footing is usually from short duration loads such as broken wire, wind, and ice. With the exception of heavy-angled, dead end or terminal structures, only a part of the total reaction is of a permanent nature. As a consequence, the permissible soil pressure, as used in the design of building foundations, may be considerably increased for footings for transmission structures.

The permissible values of soil pressure used in the footing design will depend on the structure and supporting soil. The basic criterion is that displacement of the footing not be restricted because of the flexibility of the selected X-frame tower and its hinged connection to the footing. The shape and configuration of the selected tower are important factors in foundation considerations.

Loads on the tower consist of vertical and horizontal loads and are transmitted down to the foundation and then distributed to the soil. In a tower placed at an angle or used as dead end in the line, the horizontal loads are responsible for a large portion of the loads on the foundation. In addition to the horizontal shear, a moment is also present at the top of the foundation, creating vertical download and uplift forces on the footing.

To enable the selection of a safe and economical tower foundation design for each tower site, it is necessary to select a footing which takes account of the actual soil conditions at the site. This is done by matching the soil conditions to a series of ranges of soil types and groundwater conditions which have been predetermined during the design phase to cover the full range of soils expected to be encountered along the line length. Preconstruction drilling, soil sampling, and laboratory testing at representative locations along the line enable the design of a family of footings to be prepared for each tower type from which a selection of the appropriate footing for the specific site can be made during construction.

The foundation types for structure legs and masts will be grouted anchor where rock is very shallow or at surface and steel grillage with granular backfull where soil is competent and not unduly frost-sensitive. In areas where soils are weak and where permafrost or particularly frost-heave prone material is encountered, driven steel piles will be used.

Guy anchors will use grouted anchors in rock. Grouted earth or helical plate screw-in anchors with driven piles will be used in permafrost or very weak soils.

Proof load testing of piles and drilled-in anchors will be required both for design and to check on the as-built capacity of these foundation elements during construction.

(c) Voltage Level and Conductor Size (o)

Economic studies were carried out on transmission utilizing 500 kV, 345 kV, and 230 kV a.c. At each voltage level an optimum conductor capacity was developed. Schemes involving use of 500 kV or 345 kV on the route to Anchorage and 345 kV or 230 kV to Fairbanks were investigated. The study recommended the adoption of two 345-kV units to Fairbanks and three 345-kV units to Anchorage. Comparative studies were carried out on the possible use of HVDC. However, these studies indicated no economic advantage of such a scheme.

The 345-kV system studies indicated that a conductor capacity of 1,950 MCM per phase was economical with due account for the value of losses. A phase bundle consisting of twin 754-MCM Rail (45/7) ACSR was proposed as meeting the required capacity and also having acceptable corona and radio interference performance. Detailed design studies as part of the final design will compare the economics of this conductor configuration with the use of alternatives such as twin 954-MCM Cardinal (54/7) ACSR and single 215.6-MCM Bluebird (84/19) ACSR which could give comparable electrical performance with better structural performance. Cardinal, because of a 15 percent superior strength-to-weight ratio, can be sagged tighter than Rail, thereby resulting in savings in tower height and/or increased spans. Bluebird, because of a smaller circumference and projected area compared with a twin conductor bundle, attracts some 15 percent less load from ice or wind. Together with its greater strength, this leads to less sag under heavy loadings and lighter loads for the structures to carry. Conductor swing angles will also be reduced, thus reducing tower head size requirements and edge of right-of-way clearing.

3 - DESCRIPTION OF PROJECT OPERATION (***)

3.1 - Hydrology (**)

Operation of the Susitna project is dependent upon the hydrology of the basin. A complete discussion of the Susitna basin hydrology appears in Section 2.2 of Exhibit E, Chapter 2. A summary follows.

3.1.1 - Historical Streamflow Records (**)

Continuous historical streamflow records of various length (7 to 34 years through water year 1983) exist for gaging stations on the Susitna River and its tributaries. USGS gages are located at Denali, Cantwell (Vee Canyon), Gold Creek, and Susitna Station on the Susitna River; near Paxson on the Maclaren River; near Talkeetna on the Chulitna river; at Talkeetna on the Talkeetna River; and at Skwentna on the Skwentna River.

In 1980 a USGS gaging station was installed near Susitna Station on the Yentna River, and in 1981 a USGS gaging station was installed at Sunshine on the Susitna River. Statistics on river mile, drainage area, and years of record are shown in Table B.3.1.1. A summary of the recorded maximum, mean, and minimum monthly flows for water year 1951s through 1981 are shown in Table B.3.1.2. Because of the short duration of the streamflow records at Sunshine and on the Yentna, summaries for these two stations have not been included. The station locations are illustrated on Figure B.3.1.1.

Monthly and weekly streamflow sequences for the Susitna River at the Watana and Devil Canyon damsites and at Gold Creek were estimated from the existing USGS data. The procedures are outlined in a report by the Applicant (HE 1985). Tables B.3.1.3 through B.3.1.5 provide estimated monthly streamflow at Watana, Devil Canyon, and Gold Creek, respectively. Tables B.3.1.6 through B.3.1.8 provide weekly streamflow for the same locations. The streamflow sequences were used in weekly and monthly reservoir operation simulations. The 1969 low flow year was not modified for these sequences as it had been for the July 1983 License Application (APA 1983). Table B.3.1.9 compares the estimated monthly mean, maximum, and minimum flows at several sites in the basin.

Comparison of mean annual flows in Table B.3.1.9 indicates that 40 percent of the streamflow at Gold Creek originates above the Denali and Maclaren gages. It is in this catchment that the glaciers which contribute to the flow at Gold Creek are located.

Figure B.3.1.2 shows the average annual flow distribution within the Susitna River Basin. The Susitna River above Gold Creek contributes approximately 20 percent of the mean annual flow measured at Susitna Station near Cook Inlet. The Chulitna and Talkeetna Rivers contribute about 20 and 10 percent of the mean annual flow at Susitna Station, respectively. The Yentna provides 40 percent of the flow, with the remaining 10 percent from miscellaneous tributaries.

The variation between summer mean monthly flows and winter mean monthly flows is greater than a 10 to 1 ratio at all stations. This large seasonal difference is due to the characteristics of a glacial river system. Glacial melt, snow melt, and rainfall provide the majority of the annual river flow during the summer. At Gold Creek, for example, almost 90 percent of the annual streamflow volume occurs during the months of May through September.

A comparison of the maximum and minimum monthly flows for May through September indicates a high flow variability at all stations from year to year.

3.1.2 - Effect of Glaciers (***)

The glaciated portions of the Susitna River Basin above Gold Creek play a significant role in the hydrology of the area. Located on the southern slopes of the Alaska Range, the glaciated regions receive the greatest amount of snow and rainfall in the basin. During the summer months, these regions contribute significant amounts of snow and glacial melt. The glaciers, covering about 290 square miles (or about five percent of the total drainage area above Gold Creek Station), act as reservoirs that may produce a significant portion of the water in the basin above Gold Creek during drought periods. In the record drought year of 1969, the proportion of flow at Gold Creek contributed from upstream of the Denali and Maclaren gages was 53 percent. On average, the same area contributes only 40 percent.

Even though there is evidence that the glaciers have been wasting since 1949, there is little data available to determine what the impact of wasting has been on the recorded flow at Gold Creek or what will occur in the future (R&M; 1981c and 1982a). Large glaciers, such as those in the Susitna Basin, take decades to attain equilibrium after a change in climate.

For years of very low precipitation, runoff from the glaciers will be more important, and there may be substantial net waste of glaciers. However, if long-term mean precipitation remains approximately the same, it is likely that net waste of glaciers in one year will be replenished by excess snow in another.

The Applicant has analyzed the mass balance of the glaciers over the 1981-1983 period (Harrison 1985) and refined the estimate of glacier wasting from 1949 to the present (Clarke 1985). These analyses are dicussed in Exhibit E, Chapter 2, Section 2.2.

It is difficult to predict future trends. If the glaciers were to stop wasting due to, perhaps, a climate change, there could be hydrological changes throughout the basin. On the other hand, the wasting of the glaciers could easily continue over the life of the project. There is no way to judge whether wasting will continue into the future. Hence, no mechanism presently exists for analyzing what will occur during the life of the project. As a result, the recorded streamflow was not adjusted to account for glacier wasting.

3.1.3 - Floods (**)

The most common causes of floods in the Susitna River Basin are snow melt or a combination of snow melt and rainfall over a large area. This type of flood occurs between May and July, with the majority occurring in June. Floods attributable to heavy rains have occurred in August and September. These floods are augmented by snow melt from higher elevations and glacial runoff.

Examples of flood hydrographs can be seen in the daily discharges for 1964, 1967, and 1970 for Cantwell, Watana, and Gold Creek (Figures B.3.1.3 through B.3.1.5). The years 1964, 1967, and 1970 represent wet, average, and dry hydrological years on an annual flow basis, respectively. The daily flow at Watana has been approximated using a linear drainage area-flow relationship between Cantwell and Gold Creek. Figure B.3.1.3 shows the largest snow melt flood on record at Gold Creek. The 1967 spring flood hydrograph shown in Figure B.3.1.4 has a daily peak equal to the mean annual daily flood peak. In addition, the flood peak of 80,200 cfs is the fifth largest flood peak at Gold Creek on record. Figure B.3.1.5 illustrates a low flow spring flood hydrograph.

The maximum recorded instantaneous flood peaks for Maclaren, Denali, Cantwell, and Gold Creek, recorded by the USGS, are presented in Table B.3.1.10. Annual peak flood frequency curves for these stations are illustrated in Figures B.3.1.6 through B.3.1.9.

Based on the station record, estimates of the 100-year, 1000-year and 10,000-year floods at Gold Creek have been made. Since the station records are only available for 34 years, estimates of the 95 percent one-sided upper confidence limit have been provided.

Flood Return Period	Mean Estimate (cfs)	95 Percent One-Sided Upper Confidence Limit (cfs)
100-Year	108,000	138,000
1,000-Year	147,000	200,000
10,000-Year	190,000	270,000

The mean annual flood at Gold Creek is estimated as the flood having a return period of 2.33 years (Chow 1964) or approximately 50,000 cfs. The mean annual floods at Watana and Devil Canyon would be approximately 45,000 cfs and 48,000 cfs, respectively.

Probable maximum flood (PMF) studies were conducted for both the Watana and Devil Canyon damsites for use in the design of project spillways and related facilities (Acres 1982c). The PMF floods were determined by using the SSARR watershed model developed by the Portland District, U.S. Army Corps of Engineers (1975) and are based on Susitna Basin climatic data and hydrology. The probable maximum precipitation was derived from a maximization study of historical storms. The studies indicate that the PMF peak at the Watana damsite is 326,000 cfs.

3.1.4 - Flow Variability (***)

The variability of flow in a river system is important to all instream flow uses. To illustrate the variability of flow in the Susitna River, monthly and annual flow duration curves showing the proportion of time that the discharge equals or exceeds a given value were developed for three mainstem Susitna River gaging stations (Denali, Cantwell, and Gold Creek). These curves, based on mean daily flows, are illustrated in Figure B.3.1.10.

The shape of the monthly and annual flow duration curves is similar for each of the stations and is indicative of flow from northern glacial rivers (R&M 1982f). Streamflow is low in the winter months, with little variation in flow and no unusual peaks. Ground water contributions are the primary source of the small but relatively constant winter flows. Flow begins to increase slightly in April as breakup approaches. Peak flows in May are an order of magnitude greater than in April. Flow in May also shows the greatest variation for any month, as low flows may continue into May before the high snow melt/breakup flows occur.

June has the highest peaks and the highest median flow for the middle and upper basin stations. The months of July and August have relatively flat flow duration curves. This situation is indicative of rivers with strong base flow characteristics, as is the case for Susitna, with its contributions from snow and glacial melt during the summer. More variability of flow is evident in September and October as cooler weather becomes more prevalent accompanied by a decrease in glacial melt and, hence, discharge.

The daily hydrographs for 1964, 1967, and 1970, shown in Figures B.3.1.3 through B.3.1.5, illustrate the daily variability of the Susitna River at Gold Creek, Watana, and Cantwell. The years 1964, 1967, and 1970 represent wet, average, and dry hydrological years on an annual flow basis, respectively.

3.1.5 - <u>Flow Adjustments</u> (**)

Evaporation from the Watana and Devil Canyon reservoirs has been evaluated to determine its significance. Evaporation is influenced by air and water temperatures, wind, atmospheric pressure, and dissolved solids within the water. However, the evaluation of these factors' effects on evaporation is difficult because of their interdependence on each other. Consequently, more simplified methods were preferred and have been utilized to estimate evaporation losses. For Watana, only Stage III was evaluated, since this would be the more critical case.

The monthly evaporation estimates for the reservoirs are presented in Table B.3.1.11. The estimates indicate that evaporation losses will be less than or equal to additions due to precipitation on the reservoir surface. Therefore, a conservative approach was taken, with evaporation losses and precipitation gains neglected in the energy calculations.

Leakage is not expected to result in significant flow losses. Seepage through the relict channel is estimated as less than one-half of one percent of the average flow and therefore has been neglected in the energy calculations to date.

Minimum flow releases are required throughout the year to maintain downstream river stages. The most significant factor in determining the minimum flow value is the maintenance of downstream fisheries. After completion of Devil Canyon, flow releases from Watana will be regulated by system operation requirements. Because the tailwater of the Devil Canyon reservoir will extend upstream to the Watana tailrace, there will be no release requirements for streamflow maintenance of Watana for the Watana/Devil Canyon combined operating configuration. See Section 3.3 of this Exhibit for further discussion of the flow release requirements.

Existing water rights in the Susitna basin were investigated to determine impacts on downstream flow requirements. Based on inventory information provided by the Alaska Department of

Natural Resources, it was determined that existing water users will not be affected by the project. A listing of all water appropriations located within one mile of the Susitna River is provided in Table B.3.1.12.

3.2 Reservoir Operation Modeling (***)

3.2.1 - Reservoir Operation Models (***)

Two computer models used to simulate the operation of the Susitna Project reservoirs are: the monthly reservoir operation program (Monthly RESOP); and the weekly reservoir operation program (Weekly RESOP). The monthly RESOP was originally developed for the Susitna feasibility study and subsequently updated. The weekly RESOP was developed using selected subroutines from the monthly RESOP. The objective of the reservoir operation study is to determine the operation which maximizes the Susitna Project benefits under the specified constraints and to provide estimated reservoir outflows and water levels for environmental impact analyses.

The time increment used for the simulation affects both the computational effort required and the accuracy of the results obtained. A weekly time step is used for flow regime studies because the results more precisely show the fluctuation of water surface elevation and reflect the critical conditions. Weekly simulations also yield more gradual changes in outflow discharges from week to week than monthly simulations. Both simulations yield comparable estimates of Susitna power and energy production. The monthly program is used to determine the project capability for the economic analyses while the weekly simulation is used to provide input to the environmental analyses.

Either program simulates Susitna operation over 34 years of historical streamflow records (January 1950-December 1983). Key inputs to the models are the reservoir and powerplant characteristics, power demand distribution, and environmental constraints. The RESOP models simulate the reservoir storage, power generation, turbine discharge, outlet works release, and spill, as a function of time.

The resulting water levels, and releases from turbines, outlet works, and the spillway, are used for evaluation of environmental impacts of flow stability, fishery habitat, flood frequency, temperature, stage fluctuation, and ice conditions in the river downstream. The average energy production, firm energy production, and capacity of the project for various operation schemes are used by the electric generation expansion program in the economic evaluation of alternative expansion plans.

3.2.2 - Basic Concept and Algorithm of Reservoir Operation (***)

Reservoir operation simulation is basically an accounting procedure which monitors the reservoir inflow, outflow, and storage over time. The storage at the end of each time step is equal to the initial storage plus inflow minus outflow within the time step. The time step is either a month or a week, depending on the program used. A key constraint on the simulation is the minimum instream flow requirement at Gold Creek which must be satisfied each time step. The minimum project release is the minimum flow requirement at Gold Creek minus the intervening area flow between the downstream project site and Gold Creek. A rule curve or operation guide governs the release for power, with the total powerhouse release restricted by the discharge required to meet the system power demand.

The basic Susitna development scheme is as follows:

1. Watana Stage I is the initial project. At a normal maximum reservoir level of el. 2,000 feet above mean sea level (ft, msl), and with 150 ft of drawdown, 2.37 million acre-feet of active storage is provided. This is roughly 40 percent of the mean annual flow at the damsite, and affords some seasonal regulation. All Stage I units will be operational in 1999.

2. Devil Canyon is Stage II. It will be constructed in a narrow canyon with a normal maximum reservoir level of el. 1,455 ft, msl and only 50 ft. of drawdown. Hence, it mainly develops head, relying upon Watana to regulate flows for power production. All Stage II units will be operational in 2005.

3. Stage III involves raising the Watana dam 180 feet to its ultimate height, with a normal maximum reservoir elevation of el. 2,185 ft, msl and 120 feet of drawdown. The active storage will be 3.7 million acre-feet, about 64 percent of the mean annual flow. Commercial operation of the two new Stage III units will be in 2012.

The reservoir operation methodology attemps to keep the Devil Canyon Reservoir close to its normal maximum operating level while using Watana's storage to provide the necessary seasonal regulation. Therefore, the modeling effort in both single and double reservoir operation simulation is focused on the Watana operation. The operation level constraints are summarized in Table B.3.2.1. Curves of area and volume versus elevation for both the Watana and Devil Canyon Reservoirs are shown on Figure B.3.2.1.

(a) Watana Stage I (***)

An initial operation is done for each time step to begin the simulation. This algorithm is explained in detail in Section B-3.2.7 of this Exhibit. After the initial operation, the energy generated is compared to the system energy demand in each time step. If the energy produced is greater than that which the system can use, the energy production is reduced. This is done by decreasing the discharge through the powerhouse.

A minimum instream flow requirement is prescribed at Gold Creek to ensure that the project will release flows for environmental purposes. The historical intervening flow between Watana and Gold Creek is assumed to be available to supplement the project releases to meet the minimum flow requirement. If the flow requirement is not met, more water is released through the powerhouse in order to meet the requirement. The instream flow requirement may cause more energy to be generated than the required amount. The powerhouse discharge must again be decreased. However, instead of reducing the total project outflow, discharge is diverted from the powerhouse to the outlet works. This cone valve release is called an environmental release since it is made only to meet the environmental requirement and is not used for power generation.

The outlet works capacity at Watana I is 24,000 cfs, while the powerhouse capacity is about 14,000 cfs. In the event that a flood could not be passed through the powerhouse and outlet works, because of energy demand and hydraulic capacity limitations, the reservoir is allowed to surcharge above the normal maximum water surface elevation. This surcharging is done to avoid the use of the spillway for floods less than the 50-year event. A maximum surcharge level of el. 2,014 is permitted before the spillway operates.

(b) Watana Stage I or Stage III with Devil Canyon Stage II (***)

For simulation of double reservoir operation, the initial operation for each time step is the same as that for the single reservoir. Devil Canyon operates as run-of-river as long as the reservoir is full. The Devil Canyon reservoir is to be refilled if the reservoir is not full, and the total inflow is greater than the release required to meet the downstream flow requirement. After the initial operation, the total energy generated at Watana and Devil

Canyon is compared to the system energy demand. If the energy produced is greater than that which the system can use, the energy production is reduced. This is done by decreasing the discharge through the Watana powerhouse.

The intervening flow between Devil Canyon and Gold Creek is assumed to be available to supplement the project releases to meet the minimum flow requirements. If the flow requirement is not met, more water is released through the Devil Canyon powerhouse in order to meet the requirement and the Devil Canyon reservoir will draw down. If the increased release through the Devil Canyon powerplant will cause the total energy generation to be greater than the system demand, the release from the Watana powerplant is reduced. Continuous drawdown at Devil Canyon can occur in the summer of dry years when the system energy demand is low and the downstream flow requirement is high. If the water level at Devil Canyon reaches the minimum elevation of 1,405 ft, Watana must then release water to satisfy the minimum flow requirement. If the release from Watana for the minimum flow requirement will generate more energy than the required amount, part of the release is diverted to the outlet works.

The powerhouse hydraulic capacity is about 14,000 cfs for both Watana Stage I and Devil Canyon, and about 22,000 cfs for Watana Stage III. The outlet works capacity at Devil Canyon is 42,000 cfs while the capacity at Watana is 24,000 cfs in Stage I and 30,000 cfs in Stage III. In the event that a flood could not be passed through the powerhouse and cone valves, because of energy demand and hydraulic capacity limitations, Watana is allowed to surcharge above its normal maximum. The maximum surcharge level is el. 2,014 ft for the Watana Stage I dam and el. 2,193 for the Stage III dam. Since the capacity of the outlet works at Devil Canyon is large, and flood flows are attenuated at Watana before reaching Devil Canyon, a surcharge of only one foot above the normal maximum of el. 1,455 is allowed, and the spillway operates if the water surface exceeds el. 1,456 ft.

3.2.3 - Standard Weeks (***)

A system of standard weeks, in which the dates of weeks in a year are the same every year, is used in the weekly simulation. In accordance with the water year, standard weeks start on October 1 and end on September 30 with seven days a week in normal weeks but with eight days for the last week in September. The last week in February also has eight days in a leap year. A standard week begins on Sunday and ends on Saturday.

The weekly simulation is done on a calendar year basis, from January to December. In applying the standard weeks in the weekly simulation, the first week of a year starts on December 31 of the previous year and ends on January 6 of the current year. The standard week numbers and corresponding dates are listed in Table B.3.2.2.

3.2.4 - Demand Forecast (***)

The reservoir operation models use the system energy requirement at plant to define the expected demand. Since SHCA and Composite electric demand forecasts are similar (Exhibit B, Chapter 5, Tables B.5.4.6 and B.5.4.17), reservoir operation studies were conducted using the SHCA forecast. The annual peak and net energy generation projections of the railbelt system based on the SHCA forecast are listed in Table B.3.2.3. The monthly energy requirements are obtained by applying the monthly distribution of annual requirement as shown in Table B.3.2.4.

3.2.5 - Existing Hydroelectric Plants (***)

The existing Railbelt hydroplants are modeled as a combined plant in the simulation. These plants include Eklutna, Cooper Lake, and Bradley Lake. Eklutna and Cooper Lake are currently operating. Bradley Lake is assumed to go on-line in 1990. The monthly average energy generation of the existing hydroplants is given in Table B.3.2.5.

The difference between the total system energy requirement and the energy production of existing hydroplants is the residual requirement to be provided by either Susitna or thermal plants. In order to determine the energy requirement on a weekly basis, the monthly energy requirement and the energy production of existing hydroplants are converted to a weekly energy. The weekly energies were estimated from the monthly energies so that the sum of the weekly energy within a month equals the monthly energy.

3.2.6 - Release Constraints (***)

An instream flow regime is a series of minimum and maximum discharges for maintaining fish habitat. The degree of fish protection provided varies with the flow regime. The maximum limits at Gold Creek are, in general, about 15,000 cfs in winter and 35,000 cfs in summer. With Susitna operating, the discharge will not exceed this maximum limit. Therefore, no maximum limit on outflow discharge is set in the simulation.

The following definitions are used in describing the flow constraints:

Minimum instream flow requirement - The minimum instream flow requirement is a minimum discharge level which must be maintained at the Gold Creek gaging station. The minimum release from the downstream damsite is the minimum instream flow requirement at Gold Creek minus the intervening flow between the damsite and Gold Creek.

Minimum turbine discharge - In the monthly simulation, the minimum turbine release is the discharge necessary to meet the firm energy specified in the input. In the weekly simulation, the minimum percentage of the expected turbine flows defined in the input will set the minimum turbine release.

Maximum turbine flow - The maximum turbine discharge is the turbine hydraulic capacity or the discharge required to meet the system energy requirement, whichever is less.

Maximum outlet works release - The outlet works will operate in two cases; (1) the maximum turbine flow is less than the release required to meet the minimum instream flow requirement, and (2) the reservoir level is higher than the normal maximum level. For case 1, the outlet works release only the amount required to satisfy the downstream requirement.

For case 2, the outlet works discharge up to their maximum capacity to minimize surcharge above the normal maximum reservoir elevation.

For Watana, the maximum outlet works discharge is limited to 24,000 cfs in both Stage I and Stage III, even though the Stage III capacity is 30,000 cfs. This is to ensure that inflows to Devil Canyon do not exceed the outlet works capacity there for floods with return periods of 50 years or less.

Maximum daily fluctuation - Because of limitations on the accuracy of streamflow measurement, actual releases from the downstream project may vary up to plus or minus 10 percent of the weekly average flow for the week.

3.2.7 - Reservoir Operation (***)

To simulate the operation of the Watana development, two approaches are used; a conventional rule curve, and an operating guide. The monthly operation program (Monthly RESOP) uses rule curve operation while the weekly operation program (Weekly RESOP) uses the operating guide. The rule curve operation approach can be thought of as "predictive" because it attempts to achieve a target end-of-period elevation based on the expected reservoir inflow during the period (i.e., a monthly period). The historical record is used as a predictor of the inflow for the monthly period being simulated. The operating guide approach can be viewed as "nonpredictive" because its purpose is to achieve a specific discharge rate through the powerhouse based only upon the reservoir elevation at the beginning of the period. The operating guide is a family of rule curves, with each curve related to a powerhouse discharge rate.

The rule curve approach is easy to apply for simulation of the operation, but is operationally difficult to achieve because reservoir inflows are difficult to accurately forecast. The operating guide approach is more difficult to model, but it is more straightforward operationally.

The two approaches yield similar results in terms of overall power and energy production. The operating guide approach is used for input to analyses of reservoir temperature, river temperature, and downstream fisheries habitat, because the operating guides more closely simulate the expected project releases. The rule curve approach is used for input to economic analyses because it is easier to apply and yields comparable power and energy production.

The distinction between the rule curve and operating guide approaches applies only to Watana reservoir operation. In both cases, Devil Canyon operation is governed by a rule curve. The Devil Canyon operating rule is to keep the reservoir as full as possible throughout the simulation. Hence, the Devil Canyon rule curve is set equal to the normal maximum reservoir elevation (el. 1455 ft,msl) each period (Figure B.3.2.2).

(a) Rule Curve Operation (***)

The monthly simulation is governed by two primary constraints. The constraint on minimum energy production is a "target" value of firm energy to be generated. The constraint on maximum energy production is the rule curve or the system energy requirement, whichever results in less energy production.

The target value of annual firm energy is first input to the model. The corresponding monthly firm energy targets are then computed based on a specified distribution. The model will initially make the required powerhouse release to meet the monthly firm energy target. The end-of-month reservoir elevation is then computed based on the starting elevation, the powerhouse release, and inflow during the month. This end-of-month water surface elevation (WSEL) is then compared to the rule-curve elevation (RCEL) for the month. If the WSEL is below the specified RCEL, no additional release is made. If the WSEL is above the specified RCEL, the water stored between these two elevations is released to generate secondary energy. The secondary energy generated may be limited by the system energy requirement.

The simulation continues for each month of the simulation period until the annual firm energy is maximized. The annual firm energy is maximized when the reservoir elevation reaches the normal minimum reservoir elevation once during the simulation (in the critical period) without any shortfalls in firm energy production or in meeting the minimum instream flow requirement.

(b) Rule Curve Development (***)

The rule curve is developed by trial and error. Figure B.3.2.2 depicts example rule curves for Watana Stage I and Stage III. Two distinct periods, the drawdown season and the filling season, are defined by the shape of the rule curve. The drawdown season extends from the beginning of October through the end of April. During these months, the average natural inflow to the reservoir is less than the reservoir outflow, and the reservoir level decreases. The filling season extends from the beginning of May through the end of September. During these months, the average natural inflow to the reservoir exceeds the reservoir outflow, and the reservoir level increases. Hence, the general approach to developing the rule curve is as follows: at the end of the filling season, the reservoir should be full, and at the end of the drawdown season, the reservoir should be at the minimum rule curve elevation.

The higher the minimum rule curve elevation, the greater the firm energy production, because more water would be available during a drought, resulting in higher energy output. Alternatively, the lower the minimum rule curve elevation, the greater the average energy production, because there is more storage available for regulation on an average annual basis. Different minimum rule curve elevations will yield different values of firm energy and total energy production. The acceptable minimum rule curve elevation is selected based on an operation which provides a reasonable trade-off between firm and average energy production.

The maximum rule curve elevation is set equal to the normal maximum reservoir elevation at the end of the filling season.

Once the minimum and maximum rule curve elevations have been established, the rest of the rule curve elevations are determined by trial and error. The objectives of this procedure are to establish the monthly RCELs that distribute the hydroelectric energy such that the costs of thermal energy generation during the drawdown and filling seasons are minimized. In this approach, equal quantities of thermal energy are generated during each month within each season. The thermal energy generation required in each season is thus "levelized" as depicted in Figure B.3.2.3.

(c) Operating Guide (***)

The operating guide comprises three main elements, as described below.

Expected Powerhouse Discharge - This is a set of weekly powerhouse discharges (cfs) which will produce the desired distribution of energy production over a year.

Increasing Curves - This is a set of curves defining powerhouse discharge rates as a function of Watana reservoir elevation and time of year. The curves, which are expressed in terms of a percentage of the expected discharge for each week, are used to decide whether or not the present rate of discharge should be increased (Figure B.3.2.4).

Decreasing Curves - This is a second set of curves, similar to those described above, which are used to decide whether or not the present rate of discharge should be decreased (Figure B.3.2.4).

The expected powerhouse discharges represent the average annual flow volume distributed through the year to minimize the costs of generating the thermal energy component of the system energy requirement. In this approach, equal quantities of thermal energy are produced during each week of the drawdown season and also each week of the filling season.

The operating guide can be viewed as a "family" of rule curves. The guide is applied by comparing the current discharge rate to that prescribed by the guide based on the time of year and the water surface elevation. If the water surface elevation at the beginning of the week is higher than the increasing curve of the next higher rate, the discharge should be increased to the next higher rate in this week. If the water surface elevation is lower than the decreasing curve of the next lower rate, the rate should be decreased to the next lower rate in this week.

(d) Operating Guide Development (***)

The operating guide attempts to do the following:

- o Keep the powerhouse discharge close to the expected (100 percent) discharge;
- o Maximize total energy production;
- o Keep discharge rates nearly constant for at least several weeks at a time; and
- o Minimize cone valve releases (i.e., meet environmental flow constrants with powerhouse release).

The expected discharges are determined by first performing a monthly rule curve simulation. The weekly expected discharges are estimated from the monthly discharges through the powerhouse. The resulting weekly expected discharges will levelize the thermal energy requirement in the drawdown and filling seasons. Under average flow conditions, it would be optimal to always release at 100 percent of the weekly expected discharge. However, due to natural variations in reservoir inflow, the release rates must increase and decrease accordingly to optimize the power and energy production.

The development of the operating guide curves is an iterative process. The lowest decreasing curve (63%) is selected by examining the most critical drought period. Sixty-three percent was judged to be the highest percent discharge that would enable the project to satisfy the instream flow and minimum energy requirements through the most critical drought. The highest increasing curve (140%) is selected by examining the most extreme flood period. The rate should be high enough to minimize spills when streamflow is above average. The intermediate curves are adjusted in order to maintain adequate storage during the drought, minimize spills, and to keep the discharge rate fairly constant.

The "increasing" curve rates which have been used are 80, 100 120 and 140 percent of expected discharge; the "decreasing" curve rates are 120, 100, 80, and 63 percent. If the reservoir is operating at 100 percent, only the 120 percent "increasing" and the 80 percent "decreasing" curves are checked. This restricts the rate of change of discharge in any iteration to the difference in the rates assigned to the curves. If the water surface elevation is between these curves, such as Point A in Figure B.3.2.4, the discharge rate will stay at 100%. If the water surface elevation is above 120 percent increasing curve (Point B,) the discharge will increase to 120 percent. If the water surface elevation is below the 80 percent decreasing curve (Point C), the discharge will decrease to 80 percent.

3.2.8 - Special Considerations for Double Reservoir Operation (***)

The previous discussion has focused on the operation of the Watana Reservoir.

When both Watana and the Devil Canyon are operating, special considerations come into play. These are:

- o Ensuring that Watana generates enough energy each period to permit peaking operation; and
- o Ensuring that Devil Canyon cone valve releases are such that low-temperature releases are minimized.

The downstream flow requirement is high from May to October but the energy demand is low in this period. Releases to meet the downstream requirement through the powerplants at Watana and Devil Canyon could conceivably generate more energy than the system requires. The reservoir could operate in such a way that Devil Canyon draws down to meet the downstream requirement and generates most of the system requirement. Only a small part of the requirement which is not satisfied by Devil Canyon would then be satisfied by the Watana powerplant. In principle, Watana is operated for peak generation and Devil Canyon for base-load generation. If Watana energy generation is too small, it cannot satisfy the daily fluctuation of power demand. In order to permit peaking at Watana, a minimum Watana energy generation is assigned in the input. For any given time period, Watana is required to generate at least 30 percent of the total Susitna output.

On the other hand, if Watana were to generate too much energy in summer, then it could potentially meet the entire system demand without generating at Devil Canyon. Consequently, Watana would generate all of the system energy requirement, with Devil Canyon satisfying the downstream flow requirement by releasing water through its outlet works. Because the outlet works intakes are at a lower elevation than the powerhouse intakes, a release through them during the summer period would be at a lower temperature. As a result, the temperature in the downstream channel would be lowered.

In order to avoid low streamflow temperature in the downstream channel, a minimum Devil Canyon generation is also assigned. When the total project release would generate more energy than the system requirement, the program will attempt to meet the minimum target firm energy by generating at Devil Canyon. If Devil Canyon does not satisfy total energy requirement, the rest will be met by Watana.

3.2.9 - Reservoir Operation Computer Programs (***)

(a) Monthly RESOP Program (***)

The monthly reservoir operation program uses the rule curve approach to simulate the operation of the Susitna reservoirs on a monthly basis. The simulation is done on a water year basis. Water year n begins on October 1 of year n-1, and extends through September 30 of year n. A summary of the program input requirements and output data follows.

Input Data. The input data are organized as follows:

- o Titles, number of reservoirs, and simulation period;
- o Historical streamflow at damsites;
- o Reservoir area-volume curves and tailwater rating curves;
- o Turbine characteristics curves;
- o Reservoir minimum, and maximum, and rule curve elevations;
- o Historical streamflow at Gold Creek and minimum instream flow requirement; and
- o Annual energy demand, distribution of monthly demand, energy production of existing hydroplants, and minimum energy to be generated by each project.

Output. The output data is organized into three parts:

- o Echo of the input data;
- o Annual simulation results; and
- o Summary results.

The input data echoed includes the streamflow record, reservoir characteristics, tailwater rating, turbine characteristics, reservoir control elevations, and rule curve elevations for each reservoir, streamflow record at the downstream station (Gold Creek), minimum instream flow requirement at the downstream station, monthly energy demand, energy production of existing hydroelectric powerplants, distribution of monthly demands in a year, and monthly firm energy.

The second part of the output is the annual simulation results. For each year, simulation results for each reservoir and a summary of energy production and powerplant capability are printed. Reservoir inflow, turbine discharge, spills, end-of-month storage, end-of-month elevation, tailwater elevation, net head, plant efficiency and capability, and total energy are printed. Totals and averages are also printed.

The third part of the output is the summary results. Tables of reservoir inflow, turbine discharge, spill, net head, water surface elevation, energy production, intervening flow, and flows at the downstream station with and without the project are provided. Each table gives the monthly data in chronological order over the total simulation period. A summary table of plant capability and energy production is also provided. Average and minimum capability, and minimum energy production for each plant, are listed.

(b) Weekly RESOP Program (***)

The weekly reservoir operation program uses the operating guide approach to simulate the operation of the Susitna reservoirs on a weekly basis. The simulation is done on a calendar year basis (January 1 through December 31). A summary of the program input requirements and output data follows.

Input Data. The input data are organized as follows:

- o Titles, number of reservoirs, simulation period, and output options;
- o Historical streamflow at damsites;
- o Weekly or monthly expected (100%) discharge and increasing and decreasing curves of the operating guide;

- Reservoir area-volume curves and tailwater rating curves;
- Turbine characteristic curves;
- Maximum and minimum reservoir elevations;
- Historical streamflow at Gold Creek and minimum instream flow requirement; and
- Annual energy demand, distribution of weekly demand, energy production of existing hydroplants, and minimum energy to be generated by each project.

Output. The output data is organized into three parts:

- Standard output, similar to that provided by the monthly program;
- Flow duration and frequency output; and
- Output for Reservoir temperature studies.

Standard Output

The standard output is much the same as that described for the monthly program. The major difference is that the results are reported on a weekly, rather than monthly, basis.

Output for Duration and Frequency Curves

This output is designed for input to the environmental studies. Tables of flow duration and frequency are provided for: with-project flow at Gold Creek, reservoir inflow, turbine discharge, excess release and water surface elevation for each reservoir, and intervening flows between reservoirs and between the downstream reservoir and Gold Creek. For each parameter there are two tables; one provides simulation results in chronological order by week, and the other is in the form of duration relations, expressing the percent of time a given flow is equaled or exceeded. Water surface elevation, expressed as the probability of occurrence within assigned ranges, is also provided.

Output for Reservoir Temperature Studies

This output provides weekly turbine discharge, outlet works discharge, spill, and water surface elevation, in chronological order for a specified period of years.

3.3 - Operational Flow Regime Selection (***)

3.3.1 - Reservoir Storage Characteristics (***)

Storage characteristics of the Watana reservoir will vary, depending on whether Stage I or Stage III is operating. Devil Canyon storage characteristics are unchanged throughout its operation period. Area and volume versus elevation curves for both the Watana and Devil Canyon reservoirs are shown on Figure B.3.2.1.

Watana - Stage I

The Watana Stage I reservoir will have a normal operating level at el. 2,000 ft, msl. At this elevation, the reservoir will be approximately 39 miles long, with a maximum width on the order of three miles. The total volume and surface area at the normal operating level will be 4.25 million acre-feet and 19,900 acres, respectively. The minimum operating level is at el. 1,850 ft, msl, resulting in a 150-ft maximum drawdown. The active storage is 2.37 million acre-feet.

Devil Canyon - Stage II

The Devil Canyon reservoir will have a normal operating level at el. 1,455 ft, msl. At this level, the reservoir will be approximately 26 miles long, with a maximum width of approximately one-half mile. The total volume and surface area at the normal operating level will be 1.1 million acre-feet and 7,800 acres, respectively. The minimum operating level is at el. 1,405 ft, msl, resulting in a 50 ft. maximum drawdown. The active storage is 350,000 acre-feet.

Watana - Stage III

The Watana Stage III reservoir will have a normal operating level at el. 2,185 ft, msl. At this elevation, the reservoir will be approximately 48 miles long, with a maximum width on the order of five miles. The total volume and surface area at the normal operating level will be 9.5 million acre-feet and 38,000 acres, respectively. The minimum operating level is at el. 2,065 ft, msl, resulting in a 120-ft maximum drawdown. The active storage is 3.7 million acre-feet.

3.3.2 - Reservoir Operation (***)

The Applicant's goal is to operate the project to maximize power and energy benefits within environmental and operational constraints. Details of the reservoir operation are provided in Section 3.2 of this Exhibit.

3.3.3 - Development and Comparison of Alternative Flow Regimes (***)

Alternative flow regimes were compared, based on their performance in meeting economic and environmental objectives. The economic objective is to minimize the cost of producing energy to meet projected Railbelt system energy demands. The environmental objective is to provide sufficient habitat to maintain naturally producing populations, so called no-net-loss of habitat. The environmental objective may be achieved by providing the river flows necessary to meet the objective or by a combination of flows and other compensation such as rearing facilities. Environmental flow requirements affect Susitna energy production and may require the construction and operation of other generating facilities to meet Railbelt system energy demand. Therefore, the costs resulting from the implementation of environmental flow requirements are included in the economic evaluation of the costs to meet Railbelt energy demand. The economic and environmental objectives are combined in a single evaluation criteria which is the total cost of providing the Railbelt energy demand, including the costs of the Susitna Hydroelectric Project, other generation facilities and the costs of mitigation measures.

A complete description of each of the alternative flow regimes and of the selection process undertaken to develop the preferred flow regime is set out in Exhibit E, Chapter 2, Section 3. Based upon this combined economic and environmental selection process set out in that section, flow regime Cases E-VI and E-IV are judged to be the superior flow cases. Case E-VI is selected as the preferred case because of superior energy benefits. Table B.3.3.1 shows the weekly minimum flow requirements at Gold Creek for Case E-VI. Table B.3.3.2 shows the relative ranking of the alternative flow regimes based upon both economic and environmental costs.

4 - POWER AND ENERGY PRODUCTION (***)

4.1 - Plant and System Operation Requirements (**)

The main function of system planning and operation control is the allocation of generating plant on a short-term operational basis so that the total system demand is met by the available generation at minimum cost consistent with the security of supply. The objectives are generally the same for long-term planning or short-term operation load dispatching, but with important differences in the latter case. In the short-term case, the actual state of the system dictates system reliability requirements, overriding economic considerations in load dispatching. An important factor arising from economic and reliability considerations in the system planning and operation is the provision of stationary reserve and spinning reserve capacity. Figure B.4.1.1 shows the daily variation in demand for the Railbelt system during typical December (winter) and August (summer) weekdays. The variation in monthly peak demands as estimated for the year 1983 is shown on Figure B.4.1.2.

4.1.1 - System Reliability Criteria (**)

Reliability criteria for electric power system operation can be divided into those criteria which apply to generation capacity requirements and those which apply to transmission adequacy assessment.

The following basic reliability standards and criteria have been adopted for planning the Susitna project.

(a) Installed Generating Capacity (**)

Sufficient generating capacity is installed in the system to ensure that the probability of occurrence of load exceeding the available generating capacity shall not be greater than one day in ten years (Loss-of-load probability (LOLP) of 0.1). The evaluation of generation reserve by probability techniques has been used for many years by utilities and the traditionally adopted value of LOLP has been about one day in ten years (Sebasta 1978, IEEE 1982). Many utilities and reliability councils in the lower-48 states continue to employ such a criteria (IEEE 1977).

Economic evaluation of expansion plans across a range of LOLP levels from one day in ten years (0.1) to three days in ten years (0.33) were analyzed. These results indicated that the expansion plans and associated system costs of the With- and Without-Susitna plans are not significantly affected within the LOLP range studied. In addition, at least one major utility has expressed the aim of achieving an LOLP of one day in ten years (Stahr, 1983). Therefore, for the present level of study, an LOLP of one day in ten years has been adopted.

The above generation reliability criteria was used as an input to the generation planning model described in Section 5.3 of this Exhibit. This generation planning model was used to evaluate generation expansion with and without the Susitna project as presented in Exhibit D.

(b) Transmission System Capability (**)

The high-voltage transmission system should be operable at all load levels to meet the following unscheduled single or double contingencies without instability, cascading or interruption of load:

- The single contingency situation is the loss of any single generating unit, transmission line, transformer, or bus (in addition to normal scheduled or maintenance outages) without exceeding the applicable emergency rating of any facility; and

- The double contingency situation is the subsequent outage of any remaining equipment, except for line if outage of the line will result in the loss of the load center served, without exceeding the short time emergency rating of any facility.

In the single contingency situation, the power system must be capable of readjustment so that all equipment would be loaded within normal ratings and, in the double contingency situation, within emergency ratings for the probable duration of the outage.

During any contingency:

- Sufficient reactive power (MVAR) capacity with adequate controls is installed to maintain acceptable transmission voltage profiles.

- The stability of the power system is maintained without loss of load or generation during and after a three-phase fault, cleared in normal time, at the most critical location.

Having the transmission lines in parallel, instead of one line only, improves greatly the reliability of the transmission system. Besides removing the necessity of hot line maintenance, the frequency of failure of the transmission system will be lowered by a factor of about 15.

The transmission system performance was examined by performing load flow and transient stability studies. Load flow studies examined the system under normal operating conditions with all elements in service, then removal of one line segment which verified adequate system performance under single contingency. Double contingency operation was verified by further removal of a second element (not including a second line). The loss of two parallel line circuits would result in loss of the load center served and was not considered in double contingency studies.

The following criteria were used for the load flow studies:

1. For energization while the system is in normal status:

   a. Voltage at the sending end should not be reduced below .90 per unit.

   b. Initial voltage at the receiving end should not exceed 1.10 per unit.

   c. Following the switching of transformers and VAR control devices onto the system, the voltage at the receiving end should not exceed 1.05 per unit.

2. In case of normal status or single contingency and peak load:

   a. The voltages at all buses tapped for loading shall stay between 0.95 and 1.05 per unit.

   b. The voltage/load angle between the Susitna generators and any point of the system should not exceed 45 degrees.

3. In case of double contingency and peak load:

   a. The voltages at all buses tapped for loading shall stay between 0.90 and 1.10.

   b. The voltage/load angle between the Susitna generators and any point of the system should not exceed 55 degrees. The transmission system configuration was tested for energization (no load), and for peak load flow conditions. The load flows were prepared for normal transmission system conditions as well as selected contingency conditions. In addition to the load flow studies, dynamic stability studies were also prepared (Acres 1982f).

Figures B.4.1.3, B.4.1.4, and B.4.1.5 are one-line diagrams showing system performance for the approximate peak loadings in years 1999, 2005, and 2025 under a critical double contingency condition. This condition assumes that one of the Gold Creek-Willow lines is out of service and that there is an additional loss of one of the Willow-Knik Arm lines.

The critical parameters of the above cases are shown in Table B.4.1.1. As can be seen from the table, the system performs within the criteria established above.

The loss of two circuits on the same right-of-way has a low level of probability if the spacing between the two circuits are set far apart to minimize this potential problem. Part of the generation reserve capacity will be in the form of spinning reserve. As determined in the generation planning studies, this spinning reserve will be from the next most economical increment of capacity over those units required to meet load considering the system as a whole. In addition to spinning reserve, standby reserve can be maintained by the utilities in individual load centers using less economical units. The cost of this spinning and standby reserve has been included in the economic analyses presented in Exhibit D, Chapter 2.

(c) Summary (**)

Operational reliability criteria thus fall into four main categories:

- o LOLP of 0.1, or one day in ten years, is maintained for the recommended plan of operation;
- o The single and double contingency requirements are maintained for any of the more probable outages in the plant or transmission system;
- o System stability and voltage regulation are assured from the electrical system studies. The spinning reserve capacity with six units at Watana and four units at Devil Canyon will meet load frequency control criteria; and
- o The loss of all Susitna transmission lines on a single right-of-way has a low level of probability. In the event of the loss of all lines serving a load center, standby reserve in the affected load center can be brought on line to meet critical loads.

4.1.2 - Economic Dispatch of Units (*)

A Susitna Area Control Center will be located at Watana to control both the Watana and the Devil Canyon power plants. The control center will be linked through the supervisory system to a Central Dispatch Control Center near Anchorage.

Operation will be semi-automatic with generation instruction inputs from the Central Dispatch Center, but with direct control of the Susitna system at the Susitna Area Control Center for testing/commissioning or during emergencies. The control system will be designed to perform the following functions at both the Watana and Devil Canyon power plants:

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

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

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

The Central Dispatch Control Engineer decides which generating units should be operated at any given time. Decisions are made on the basis of known information, including an "order-of-merit" schedule, short-term demand forecasts, limits of operation of units, and unit maintenance schedules.

(a) Order-of-Merit Schedule (o)

In order to decide which generating unit should run to meet the system demand in the most economic manner, the Control

Engineer is provided with information of the running cost of each unit in the form of an "order-of-merit" schedule. The schedule gives the capacity and fuel costs for thermal units and reservoir regulation limits for hydro plants.

(b) Optimum Load Dispatching (o)

One of the most important functions of the Control Center is the accurate forecasting of the load demands in the various areas of the system.

Based on the anticipated demand, basic power transfers between areas, and an allowance for reserve, the planned generating capacity to be used is determined by taking into consideration the reservoir regulation plans of the hydro plants. The type and size of the units should also be taken into consideration for effective load dispatching.

In a hydro-dominated power system (such as the Railbelt system would be if Susitna is developed), the hydro unit will take up a much greater part of base load operation than in a thermal-dominated power system. The planned hydro units at Watana typically are well-suited to load following and frequency regulation of the system and providing spinning reserve. Greater flexibility of operation was a significant factor in the selection of six units of 170 MW capacity at Watana, rather than fewer, larger-size units.

(c) Operating Limits of Units (*)

There are strict constraints on the minimum load and the loading rates of machines; to dispatch load to these machines requires a systemwide dispatch program taking these constraints into consideration. In general, hydro units have excellent start-up and load following characteristics; thermal units have good part-loading characteristics.

Typical plant loading limitations are given below:

(1) Hydro Units (*)

- o Reservoir regulation constraints resulting in not-to-exceed maximum and minimum reservoir levels, daily or seasonally.
- o Part loading of units is undesirable in the zone of rough turbine operation (typically from above no-load-speed to 50 percent load) due to vibrations arising from hydraulic surges.

(2) Steam Units (*)

- o Loading rates are slow (10 percent per minute). The units may not be able to meet a sudden steep rate of rise of load demand.

- o The units have a minimum economic shutdown period of about twenty-four hours.

The total cost of using conventional units includes banking, raising pressure, and part-load operations prior to maximum economic operation.

(3) Gas Turbines (*)

- o Eight to ten minutes are required for normal start up from cold.

- o Emergency start-up times are on the order of five to seven minutes.

(d) Optimum Maintenance Program (o)

An important part of operational planning which can have a significant effect on operating costs is maintenance programming. The program specifies the times of year and the sequence in which plants are released for maintenance.

4.1.3 - Unit Operation Reliability Criteria (o)

During the operational load dispatching conditions of the power system, the reliability criteria often override economic considerations in scheduling of various units in the system. Also important in considering operational reliability are system response, load-frequency control, and spinning reserve capabilities.

(a) Power System Analyses (o)

Load-frequency response studies determine the dynamic stability of the system due to the sudden forced outage of the largest unit (or generation block) in the system. If the generation and load are not balanced, and, if the pick-up rate of new generation is not adequate, loss of load will eventually result from under-voltage and under-frequency relay operation, or load-shedding. The aim of a well-designed high security system is to avoid load-shedding by maintaining frequency and voltage within the specified statutory limits.

(b) System Response and Load-Frequency Control (*)

To meet the frequency requirements, it is necessary that the effective capacity of generating plant supplying the system at any given instant be in excess of the load demand. The capacity of the largest thermal unit in the system has been taken as a design criterion for spinning reserve to maintain system frequency within acceptable limits in the event of the instantaneous loss of the largest unit.

In the system expansion studies, thermal units are run part-loaded to provide sources of spinning reserve. Ideally, it would be advantageous to provide spinning reserve with the hydroelectric generation as well, in order to spread spinning reserves evenly throughout the system. The quickest response in system generation could come from the hydro units. The large hydro units at Watana and Devil Canyon can respond in the turbining mode within 30 seconds.

(c) Protective Relaying Systems and Devices (o)

The primary protective relaying systems provided for the generators and transmission system of the Susitna project are designed to disconnect the faulty equipment from the system in the fastest possible time. Independent protective systems are installed to the extent necessary to provide a fast-clearing backup for the primary protective system so as to limit equipment damage, limit the shock to the system, and speed restoration of service. The relaying systems are designed so as not to restrict the normal or necessary network transfer capabilities of the power system.

4.1.4 - Dispatch Control Centers (*)

The operation of the Watana and Devil Canyon powerplants in relation to the Central Dispatch Center can be considered to be the second tier of a three-tier control structure as follows:

- Central Dispatch Control Center (345-kV network) near Anchorage: manages the main system energy transfers, advises system configuration, and checks overall security.

- Area Control Center (Generation connected to 345-kV system; for example, Watana and Devil Canyon): deals with the loading of generators connected directly to the 345-kV network, switching and safety precautions of local systems, and checks security of interconnections to main system.

- District or Load Centers (138-kV and lower voltage networks): manages generation and distribution at lower voltage levels.

For the Anchorage and Fairbanks areas, the district center functions are incorporated into their respective area control centers.

Each generating unit at Watana and Devil Canyon is started, loaded and operated, and shut down from the Area Control Center at Watana according to the loading demands from the Central Dispatch Control Center. Due consideration is given to:

- Watana Reservoir regulation criteria;
- Devil Canyon Reservoir regulation criteria;
- Turbine loading and de-loading rates;
- Part-loading and maximum loading characteristics of turbines and generators;
- Hydraulic transient characteristics of waterways and turbines;
- Load-frequency control of demands of the system; and
- Voltage regulation requirements of the system.

The Watana Area Control Center is equipped with a computer-aided control system to efficiently carry out these functions. The computer-aided control system allows a minimum of highly trained and skilled operators to perform the control and supervision of Watana and Devil Canyon plants from a single control room. The data information and retrieval system will permit performance and alarm monitoring of each unit individually, as well as the plant/reservoir and project operation as a whole.

4.2 - Power and Energy Production (***)

The Watana-Stage I development will operate as a base load project until the Devil Canyon Stage II development enters operation. Under Stage II operation, the Devil Canyon development will operate on base load and the Watana-Stage I development will operate on peak load and as reserve. The power and energy output of both facilities are increased when Watana-Stage III comes on-line.

The operation simulation of the reservoirs and the power facilities at the two developments is carried out on a monthly basis to assess the dependable capacity and energy potential of the schemes. An optimum reservoir operation pattern was established by an iterative process to minimize net system operating costs while maximizing firm and average annual energy production, as discussed in Section 3.2 of this Exhibit.

4.2.1 - Operating Capability of Susitna Units (**)

The operating capability of the Susitna units are summarized in Table B.4.2.1 and are based on the three stages of project development as follows: First, construction and operation of a facility with four turbine/generators at the Watana site with a dam crest elevation of 2,025 feet (Stage I); second, completion and operation of the Devil Canyon facility with four turbine/generators at the originally-proposed dam crest elevation of 1,463 feet (Stage II); and third, construction of the dam crest at the Watana facility to the 2,205-foot level (Stage III) including the addition of two turbine/generators, for a total of six units, as proposed in the License Application (APA 1983).

(a) Watana (**)

The Watana powerhouse will have provisions for six generating units. Four units will be installed during Stage I construction and the remaining two units will be installed during Stage III construction. Both sets of units will have a capability of 170 MW when operating at reservoir elevation 2,110 feet. This reservoir elevation corresponds to the average of the minimum December and January elevations expected in Stage III, and defines the unit capacity in relation to the occurrence of the peak system demand. During Stage I, the average of the minimum December-January reservoir levels is at elevation 1,915 feet. The power output of each unit during this peak load period with this reservoir elevation is approximately 90 MW.

The four Watana Stage I turbines have been selected to operate within the expected reservoir elevation range of the initial Watana dam and the raised Watana dam (Stage III). These units will operate under net heads ranging from a minimum of 384 feet in Stage I to a maximum of 719 feet in Stage III operation; no modification is necessary to the units to permit Stage III operation.

The usual maximum range of operation of a Francis turbine is from approximately 65 percent of its design head (the head at which optimum efficiency is obtained) to approximately 125 percent of its design head. Using these criteria, the design head for the Stage I turbines is established at 590 feet in order to permit these units to operate with suitable efficiencies with the reservoir raised in Stage III. The two turbines which are installed in Stage III will have their design head at 680 feet to have their peak efficiency within the narrower range of heads which will prevail in Stage III.

The generating unit output versus net head relationship for the Watana Stage I and III units is shown on Figure B.4.2.1.

(b) Devil Canyon (**)

The Devil Canyon powerhouse will have four generating units each with a capability of 150 MW at the minimum reservoir level (el. 1,405) and a corresponding net head of 545 feet on the station. The generating unit output versus net head relationship for the Devil Canyon unit is shown in Figure B.4.2.2.

4.2.2 - Tailwater Rating Curves (o)

The tailwater rating curves for the Watana and Devil Canyon developments are shown on Figure B.4.2.3.

4.2.3 - Average Energy Generation (***)

Based on the hydrology, reservoir operation, and flow regime E-VI described above in Section 3, average energy generation from the Susitna project has been determined.

Table B.4.2.2 provides the estimated average annual energy production from the Watana Stage I development, from Watana Stage I operating with Devil Canyon Stage II, and from Watana Stage III operating with Devil Canyon Stage II. When Watana is raised (Stage III), the additional storage available for flow regulation at Watana increases the energy production of both Watana and Devil Canyon. Also, two additional units are installed in the Watana powerhouse to take advantage of the added head and flow regulation.

4.2.4 - Firm Energy Generation (***)

The firm or reliable energy generation from the Susitna project is taken as the energy generated with a 90 percent probability of exceedance, based upon 34 years of water records. Therefore the energy generation of the Susitna Project will be greater than or equal to the firm energy 90 percent of the time. Table B.4.2.2

shows the estimated firm annual energy production from the three Susitna stages.

4.2.5 - Dependable Capacity (***)

The dependable capacity of a hydroelectric project is defined as the capacity which, for a specified time interval and period, can be relied upon to carry system load, provide assured reserve and meet firm power obligations, taking into account unit operating variables, hydrologic conditions, and seasonal or other characteristics of the load to be supplied.

Section 4.2.1 of this Exhibit describes the operating characteristics of the units to be installed at Watana and Devil Canyon based on the hydrologic conditions discussed in Section 3.1, the reservoir operation studies presented in Section 3.2, and flow regime E-VI as discussed in Section 3.3. Based on those operation studies, the dependable capacity of the Susitna project has been determined.

The Watana development will operate as a base load project until the Devil Canyon development begins operation, at which time the Devil Canyon development will operate on base and the Watana development will operate on peak and reserve. The dependable capacity of the three Susitna stages was estimated by inputting to OGP the capability (MW) of each stage, based on reservoir operation studies, and tabulating the capacity dispatched at the time of peak load from the OGP output.

Figure B.4.2.4 shows the dependable capacity of Watana and Devil Canyon in relation to the peak load forecast for the E-VI flow regime. As can be seen from Figure B.4.2.4, in Stages II and III the dependable capacity of the development increases as the peak load increases. Table B.4.2.2 shows the dependable capacity for the three stages as limited by load, and with no limitation of load.

4.2.6 - Base-Load and Load-Following Operation (***)

The Watana plant initially would operate on base to maintain nearly uniform discharge from the power plant. The Watana project could also be utilized for spinning reserve, which could require that it follow load to some extent. When Devil Canyon comes on line, Watana would change to a peaking operation, while Devil Canyon operates on base.

The ultimate objective of any hydroelectric project operation is to have the flexibility to follow loads, regulate frequency and voltage, provide spinning reserve, and react to system needs under all normal and emergency conditions. The project should be dispatched to minimize thermal operation and fuel costs. Consequently, it would be desirable for the Susitna Project to follow load as closely as practical as it fluctuates on an hourly and seasonal basis.

To assess the economic impact of base load versus load following operation, the power and energy data for the load following case were input to the OGP model and an economic evaluation was made. The With-Susitna plan, assuming base-load operation of the downstream project, has a 1985 present worth of system costs of $4,823 million. For the same plan, assuming load-following operation, the 1985 present worth of system costs are $4,693 million. The difference of $129 million can be considered foregone project benefits or mitigation costs.

5 - STATEMENT OF POWER NEEDS AND UTILIZATION (**)

5.1 - Introduction (**)

Electric power demand forecasts have been developed for the Railbelt market that will be served by the Susitna Project.

The following sections present the existing electric power demand and supply situation and the basic approach used to develop the electric power forecasts for the Railbelt market that will be served by the Susitna Project.

Section 5.2 describes the electric power system in the Railbelt, including utility load characteristics, conservation programs and electricity rates. Section 5.3 presents the forecasting methodology. The section describes the four computer-based models that were utilized in preparing the economic and electric energy forecasts and the generation expansion plan for meeting the loads. Section 5.4 presents the key variables involved in producing the forecasts, the results of the forecasts, and the impact of world oil prices on the forecasts.

5.2 - Description of the Railbelt Electric Systems (**)

This section describes the present Railbelt electric systems. This includes a general description of the interconnected Railbelt market and the electric utilities serving the market, the characteristics of the loads, electricity rates, conservation programs, and historical data covering Railbelt electricity demands and regional economic factors.

5.2.1 - The Interconnected Railbelt Market (**)

The Railbelt region, shown in Figure B.5.2.1, contains two important electrical load centers: the Anchorage-Cook Inlet area and the Fairbanks-Tanana Valley area. These two load centers comprise the interconnected Railbelt market. The Glennallen-Valdez load center is not planned to be interconnected with the Railbelt nor to be served by the Susitna Project. It is therefore excluded from discussions in this document.

The existing transmission system of the Anchorage-Cook Inlet area extends from Anchorage north to Willow and consists of a network of 115-kV, 138-kV, and 230-kV lines with interconnection to Palmer. The Fairbanks-Tanana system extends from Fairbanks south to Cantwell over a 138-kV line. The Anchorage-Fairbanks Intertie, connecting Willow and Healy, was completed by the Alaska Power Authority in October 1985 and is currently operating at 138 kV. The existing transmission system in the Railbelt region is illustrated in Figure B.5.2.2.

(a) The Electric Utilities and Other Suppliers (**)

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

The Anchorage-Cook Inlet area has two municipal utilities, three Rural Electrification Administration (REA) cooperative associations, a Federal power agency, and two military installations, as follows:

- o Municipality of Anchorage-Municipal Light & Power Department (AMLP)
- o Seward Electric System (SES)
- o Chugach Electric Association, Inc. (CEA)
- o Homer Electric Association, Inc. (HEA)
- o Matanuska Electric Association, Inc. (MEA)
- o Alaska Power Administration (APAd)
- o Elmendorf AFB - Military
- o Fort Richardson - Military

All of these organizations, with the exception of MEA, have electrical generating facilities. MEA buys its power from CEA and the APAd. HEA and SES purchase power from CEA and maintain generating facilities primarily for standby operation.
AMLP and CEA are the two principal utilities servicing the Anchorage-Cook Inlet area. AMLP serves most areas within the City of Anchorage except for some sections served by CEA. In addition, AMLP serves the Anchorage International Airport, and provides electrical energy to Elmendorf AFB and Fort Richardson on a non-firm basis. AMLP also provides bulk power to CEA. The customers and associated sales of AMLP in 1984 are listed below. Residential sales represented slightly over one fourth of total commercial sales. Its most important load is the downtown business and commercial district.

AMLP

Customer Class	Number	1984 Energy Sales (MWh)
Residential	18,007	138,808
Commercial	3,921	523,088
Street Lighting	—	8,135
Sales to Public Authorities	1	15,907
Total	21,928	685,938

CEA serves certain urban and most suburban sections of Anchorage. In addition, CEA serves customers at Kenai Lake, Moose Pass, Whittier, Beluga and Hope. CEA also provides bulk power to AMLP. CEA's residential load is greater than its commercial and industrial loads.

Furthermore, CEA's average commercial customer is consistently smaller than that of AMLP. Its 1984 sales are presented below:

CEA

Customer Class	Number	1984 Energy Sales (MWh)
Residential	55,036	532,133
Commercial & Industrial (50 kVA or less)	5,874	410,812
Commercial & Industrial (over 50 kVA)	3	10,583
Public St. & Hwy. Lighting	—	5,444
Sales for Resale	3	834,228
Total	60,916	1,793,200

HEA, MEA and SES provide electricity service to approximately 43,000 customers by purchases from CEA. In 1984, HEA, MEA, and SES purchased about 349 GWh, 396 GWh, and 26 GWh of electrical energy, respectively. HEA serves the City of Homer and other customers on the Kenai peninsula. MEA has a service area encompassing Eagle River, the Matanuska Valley and surrounding areas. SES serves the City of Seward. These areas are depicted on Figure B.5.2.1.

The Alaska Power Administration provides wholesale power (firm and secondary) to MEA, CEA, and AMLP. These utilities are interconnected with the Alaska Power Administration on 115-kV lines owned by the Administration. Fort Richardson and Elmendorf AFB supply their own needs. Their electrical requirements in 1984 were approximately 59 and 72 GWh, respectively. Both bases have non-firm power agreements with AMLP. Fort Richardson has a contract with AMLP to purchase about 30 GWh on an interruptable basis.

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

The Fairbanks-Tanana Valley area is currently served by a municipal utility and an REA cooperative. In addition, a university and three military installations have their own electric systems, as follows:

- Fairbanks Municipal Utilities System (FMUS)
- Golden Valley Electric Association, Inc. (GVEA)
- University of Alaska, Fairbanks
- Eielson AFB - Military
- Fort Greeley - Military
- Fort Wainwright - Military

Fairbanks Municipal Utilities System and Golden Valley Electric Association, Inc. own and operate generation, transmission, and distribution facilities. The University and military bases maintain their own generation and distribution facilities. Fort Wainwright is interconnected with GVEA and FMUS and is providing both utilities with economy energy.

FMUS serves an area bounded by the city limits of Fairbanks, except for several residential subdivisions recently annexed by the city. The Chena River flows through the northern part of the service area with Fort Wainwright Military Reservation providing a border on the east. The downtown business district lies in the northeast corner of the FMUS service area along the south bank of the Chena River. There is an industrial area which is contained in part within the City of Fairbanks. The north bank of the Chena River provides the southern boundary of this industrial area. In addition to serving its own customers, FMUS provides economy energy to GVEA. The 1984 sales of FMUS are as follows:

FMUS

Customer Class	Number	1984 Energy Sales (MWh)
Residential	4,802	29,132
Commercial	1,201	80,834
Sales to Public Authorities	113	16,944
Street Lighting	--	2,500
GVEA	1	12,935
Total	6,117	142,345

The commercial customers are significant in number and, more importantly, in terms of total energy sales. The residential and government sectors had about the same level of energy sales in 1984.

GVEA serves the Fairbanks North Star Borough including portions of the City of Fairbanks not served by FMUS, the City of North Pole, the communities of Fox and Ester, and the two military bases - Eielson Air Force Base and Fort Wainwright. Other communities within its service area include Nenana, Healy, Cantwell, Clear, Anderson, and Rex. In 1984, GVEA sales were as follows:

GVEA		
Customer Class	Number	1984 Energy Sales (MWh)
Residential	20,275	172,958
Commercial & Industrial (50 kVA or less)	2,239	50,505
Commercial & Industrial (over 50 kVA)	264	136,678
Public St. & Hwy. Lighting	--	--
Sales to Public Authorities	1	3,140
Sales for Resale	1	17,132
Total	22,780	380,413

The University of Alaska at Fairbanks, Fort Wainwright, and Eielson AFB generate their own electrical requirements. At the present time, Fort Wainwright supplies all of Fort Greeley's electricity needs with GVEA wheeling the power on their transmission lines. Fort Wainwright provides economy energy to FMUS and GVEA from coal-fired units. In 1984, Fort Wainwright had net generation of about 75 GWh and Eielson AFB generated about 49 GWh of electricity.

(iii) Other Suppliers (*)

Several major industrial companies in the Railbelt provide their own electric power supply. During 1983, the latest year for which data are available, such generation accounted for nearly 361 GWh in the Anchorage-Cook Inlet area. The major industrial self suppliers are located in HEA's service area. The main industrial firms with operations in Kenai include Union Oil of California, Phillips Petroleum Company, Chevron U.S.A., Inc., and Tesoro-Alaskan Petroleum Corp.

In 1983, industrial sources of electrical generation in the Fairbanks-Tanana Valley area did not produce any electricity.

(b) The Existing Electric Energy Supply And Power Plant Capacity (**)

The Anchorage-Cook Inlet area is almost entirely dependent on natural gas to generate electricity. About 92 percent of the total capacity is provided by gas-fired units. The remaining are hydroelectric units (5 percent) and oil-fired diesel units (3 percent). Table B.5.2.1 presents the total generating capacity of the Anchorage-Cook Inlet utilities, the two military installations, and the industrial sector.

For the Fairbanks-Tanana Valley area, the total generating capacity of the utilities, the three military installations, and industrial self suppliers, by type of unit is presented in Table B.5.2.2. A large portion of the total installed capacity consists of oil-fired combustion turbines (58 percent) and coal-fired steam turbines (32 percent). The remaining capacity is provided by diesel units. The transmission intertie between Anchorage and Fairbanks allows Fairbanks utilities to purchase economy energy, fueled by natural gas, from Anchorage. It also allows both load centers to take advantage of reserve capacity available in both load centers to provide greater reliability.

Table B.5.2.3 provides a complete list of generating plants of the Railbelt area. The plant data and characteristics shown were developed by the Applicant from information provided by the Railbelt utilities.

5.2.2 - Railbelt Electric Utilities (**)

(a) Utility Load Characteristics (**)

This section presents monthly peak and energy demand, hourly load data for a typical week in April, August, and December, and an analysis of load diversity between the two load centers.

(i) Monthly Peak and Energy Demand (**)

Table B.5.2.4 presents monthly distributions of peak and energy demand for the two load centers and for the total Railbelt area. The average monthly values for the period 1976-1982 are based on Alaska Power Administration data. The monthly values for 1982 and 1983 and their averages are based on hourly load data supplied by AMLP, CEA, FMUS and GVEA. Figure B.5.2.3 shows the 1983 monthly load variation for each load center.

Both regions have winter peaks, occurring in December, January or February. The peak demand is lowest during the months of May through August, and the ratio of summer to winter peaks varies between 0.58 and 0.65. Although monthly peak demand varies from year to year, mainly due to weather conditions, Table B.5.2.4 shows that the pattern has remained relatively constant during the period 1976-1983.

As denoted by the data in Table B.5.2.4, the monthly distribution of energy (net generation) demand has remained about the same for the period 1976-1983 with both regions having a similar distribution. The winter months, November through February, had an average monthly demand of about 9.8 percent of the total annual energy. The summer months, June through August, had an average monthly demand of about 6.8 percent of the total annual energy.

The hourly load data for 1982 and 1983 have been used in the generation expansion studies described in Chapter 2 of Exhibit D. For these studies, monthly ratios and hourly ratios have been developed from the historical load records. The technique used is referred to as the Method of Indirect Averaging.

This method develops rank orders to compute load magnitudes and time orders to compute load sequences. Table B.5.2.5 summarizes the distribution of monthly peak demand to annual peak demand and monthly energy requirement as a percentage of the annual energy requirement resulting from the Method of Indirect Averaging analysis.

(ii) Daily Load Profiles (**)

Figure B.5.2.4 presents graphs of the hourly load data for typical weeks in April, August, and December 1983. The data from individual utilities were combined to produce representative load curves for each load center and the total Railbelt area. The following paragraphs describe the weekly load profiles.

In April, there is usually a morning peak between 8 and 10 a.m., and an evening peak between 6 and 8 p.m. The evening peak is usually greater than the morning peak. The night load is about 65-70 percent of the daily load. The average daily load factor is about 85 percent.

In August, the load begins to rise from about 7 a.m., continuing to increase until 11-12 a.m., when it reaches a peak, it then decreases slowly to about midnight before dropping off sharply. The night load is about 55-60 percent of the daily peak load. The average daily load factor is about 82 percent.

In December, there is usually a morning peak between 8 and 10 a.m., and an evening peak between 6 and 7 p.m. The evening peak is usually about 10 percent greater than the morning peak. The night load is about 60 percent of the daily peak load. The average daily load factor is about 85 percent.

Table B.5.2.6 presents twenty-four hour load-duration relations for typical weekday and weekend days for the months of April, August, and December. These data were developed from the utility hourly load data as discussed above. Similar load duration data were computed for the remaining months. These data have been used in the generation expansion studies described in Chapter 2 of Exhibit D.

(iii) Railbelt Load Diversity (**)

A system load diversity analysis was done by comparing the peak days in 1982 and 1983. The peak coincident and non-coincident loads were collected from the hourly load data provided by AMLP, CEA, FMUS, and GVEA and the load diversity was calculated based on the data. Table B.5.2.7 shows the hourly load demand for the January 6, 1982 and January 10, 1983 peak days. The diversity measure in the total Railbelt was about 0.99. The basic conclusion of the analysis is that the total coincident peak load for the Railbelt would be within two percent of the total non-coincident peak demand. For the expansion planning analysis, the Railbelt peak demand is considered to be the sum of the projected peak demand of the two load centers.

(b) Electricity Rates (**)

Tables B.5.2.8 and B.5.2.9 present the current residential and commercial electric rates for the utilities of the Anchorage-Cook Inlet area and Fairbanks-Tanana Valley area, respectively.

Electric rates are considerably less in the Anchorage-Cook Inlet area than in the Fairbanks-Tanana Valley area. The average residential cost per kWh is approximately 6 cents/kWh in the Anchorage-Cook Inlet area, and 8.4 cents/kWh and 12.4 cents/kWh for FMUS and GVEA respectively in the Fairbanks-Tanana Valley area. The lower rates in Anchorage-Cook Inlet can be explained by the relatively low cost natural gas supply and low capital cost facilities used for electric generation. The relatively high rates in Fairbanks-Tanana are a result of considerable oil-fired generation, and high capital cost of coal-fired facilities. A discussion of these rates is presented in the following paragraphs.

(i) <u>Anchorage Municipal Light and Power (AMLP)</u> (**)

The AMLP tariff for residential service and small general service customers comprises a fixed monthly customer charge and a flat energy charge per kWh. The large general service customer schedule has a monthly demand charge in addition to a fixed customer charge and a flat energy charge per kWh. In addition, AMLP has an experimental program for time-of-day rates for customers dependent upon electric space heating.

(ii) <u>Chugach Electric Association, Inc., (CEA)</u> (**)

CEA has tariffs for residential customers that reflect a declining block rate structure. Small commercial customer schedules provide for a fixed monthly customer charge and a flat energy charge per kWh. CEA's schedule for large commercial customers contains a demand charge as well as a fixed monthly customer charge and a flat energy charge per kWh.

CEA has a wholesale electric power and energy contract with HEA, MEA, and SES. MEA, HEA, and SES have tariff schedules which differ in specific details but are similar in structure to those of the larger Railbelt electric utilities, as shown in Table B.5.2.8. In addition, CEA has a rate schedule for intertie with AMLP which contains a flat energy charge and certain commitment and start/stop charges.

(iii) <u>Fairbanks Municipal Utilities System (FMUS)</u> (**)

In the Fairbanks-Tanana Valley area, FMUS has residential, all electric, and general service rate schedules which reflect declining rates as energy consumption increases in blocks. For general service customers with demand blocks of 30 kW or greater, there is (in addition to an energy charge) a monthly minimum charge per meter based on a fixed dollar amount times the highest demand reading of the preceding 11 months or times the estimated maximum demand of the first year, whichever is greater.

(iv) Golden Valley Electric Association, Inc. (GVEA) (**)

GVEA has a residential schedule with an energy charge for the first 500 kWh and a lower charge for each kWh over 500 kWh of consumption. There is a separate schedule for general service customers depending on their kW demand. For GVEA's general service customers with electrical demand not exceeding 50 kW, there is only a decreasing energy charge associated with three increasing blocks of consumption. General service customers with loads exceeding 50 kW have a schedule which provides for a fixed demand charge per kW plus declining energy charges in correspondence with four increasing consumption blocks.

(c) Conservation and Rate Structure Programs (*)

This section presents conservation and rate structure programs initiated by the electric utilities and government agencies. The effects of these existing programs are reflected in current electricity consumption which serves as the basis of the load forecast, described in Section 5.4 of this Exhibit.

The utilities have various programs aimed at supplying information to the public concerning the dollar savings associated with electricity conservation. In general, the utilities rely on market forces; however, they promote consumer recognition of those forces. Examples of conservation and rate structure programs introduced by AMLP and GVEA are described.

(i) The Anchorage Municipal Light and Power (AMLP) Program (**)

The AMLP program addresses electricity conservation in both residential and institutional settings. It is a formal conservation program mandated by the Powerplant and Industrial Fuel Use Act of 1978 (FUA). The AMLP program is designed to achieve a 10 percent reduction in electricity consumption. To achieve this level of conservation, AMLP provides information on available state and city programs to its consumers. Additionally, it has programs to:

- o Distribute hot water flow restrictors;

- o Insulate 1000 electric hot water heaters;

- o Heat the city water supply, increasing the temperature by 15°F (decreasing the thermal needs of hot water heaters);

- o Convert two of its boiler feedwater pumps from electricity to steam;

- o Convert city street lights from mercury vapor lamps to high pressure sodium lamps; and

- o Convert the transmission system from 34.5 kV to 115 kV.

AMLP also supplies educational materials to its customers along with "Forget-me-not" stickers for light switches. The utility has a full time energy engineer devoted to energy conservation program development.

The projected impacts of specific energy conservation programs are detailed in Table B.5.2.10 for the period 1981-1987. The greatest impact will occur as a result of street light conversion, transmission line conversion, and power plant boiler feed pump conversion. By 1987, these programs are expected to provide 35,000 MWh of electricity conservation, or 72% of the total programmatic energy conservation. In the case of conversion to new sodium lights, the record shows that AMLP installed 96 kW by the end of 1980, an additional 8 kW in 1981, 16.6 kW in 1982, and 14.3 kW of additional sodium lights in 1983. In addition to these conservation programs, AMLP has also projected conservation due to price-induced effects.

(ii) <u>The Golden Valley Electric Association, Inc. (GVEA) Program</u> (*)

GVEA has an energy conservation program based on a plan established pursuant to REA regulations. The utility employs an Energy Use Advisor who:

- o Performs advisory (non-quantitative) audits;

- o Counsels customers on an individual basis on means to conserve electricity;

- o Provides group presentations and panel discussions; and

- o Provides printed material, including press releases and publications.

GVEA also eliminated its special incentive rate for all-electric homes, and placed a moratorium on electric home hook-ups in 1977. It has given out flow restrictors. It has prepared displays and presentations for the Fairbanks Home Show and the Tanana Valley State Fair.

The efforts of GVEA, combined with price increases and other socioeconomic phenomena, produced a conservation effect in residential use per household. Although much of the decline in average consumption can be attributed to conversions from electric heat to some other fuels, part of the reduction is the direct result of conservation. A moderate upturn in electricity consumption per household in 1982 indicates that the practical limit of conservation may have been reached in the GVEA system.

Currently, GVEA's load management program is directed toward commercial consumers. A significantly lower rate schedule is available to commercial customers whose demand is maintained at less than 50 kW. Larger power customers are advised on ways to manage their electrical load to minimize demand. In addition, seasonal rates are available to those large consumers who significantly reduce their demand during the winter peak season. A program is underway to identify customers who operate large interruptible loads during periods of system peak demand. Various methods of residential load management are under study, but none appears cost effective at this time other than voluntary consumer response to education programs.

(iii) Other Utility Programs (o)

Other utilities have programs similar to the ones described above. For example, FMUS has two main programs aimed at electric conservation and reducing the consumer's electric bill. FMUS placed an advertisement in a local newspaper about energy conservation and offered to provide a free booklet on the topic. Also, FMUS plans to advertise the availability of an "Energy Teller" device to allow the customer to determine the direct cost of using a given appliance. These instruments are expected to be available for free loan for a period of up to two weeks.

(iv) Other Conservation Programs (o)

There are several efforts, both public and private, under way throughout Alaska. The two main programs that affect the Railbelt area are described in the following paragraphs.

The State Program. The Alaska Department of Community and Regional Affairs administers the United States Department of Energy's low-income weatherization program. The program is currently directed at rural areas and is gradually being phased out. It has involved the following activities;

- Training of energy auditors;
- Performance of residential energy audits, which are physical inspections including measurements of heat loss;
- Providing grants of up to $300 per household, or loans, for energy conservation improvements based upon the audit; and
- Providing home retrofitting (e.g. insulation, weatherization) for low income households.

The City of Anchorage Program. The City of Anchorage Program is operated by the Energy Coordinator for the City of Anchorage. This program also involves audits, weatherization, and educational efforts. Based on walk-through audits performed on city buildings and schools, detailed audits have been performed.

The city's weatherization program is available to low income families and provides grants of up to $1,600 for materials and incidental repairs.

The educational program has involved working with realtors, bankers, contractors, and businessmen. It also has involved informal contacts with commercial building maintenance personnel. Finally, it has involved contacts with the general public.

5.2.3 - Historical Data for the Market Area (**)

Historical economic and electric power data for Alaska and the Railbelt are summarized in Table B.5.2.11. The table shows the rapid growth that has occurred in the state's and the Railbelt's population, economy, and use of electric power. From 1960 to 1984, the state population has grown from 226,000 to 523,000, an average annual growth rate of 3.6 percent. The Railbelt population has grown at a faster rate of 4.1 percent, increasing from 140,000 in 1960 to about 371,000 in 1984. The growth has been especially rapid during the last five years.

Between 1960 and 1984, employment in the state grew from 94,000 to 264,000, an increase of 180 percent, or an average of 4.4 percent per year. Much of the population and economic growth that occurred during this period is attributable to several factors. During the 1960's, oil and gas resource development in Cook Inlet provided the beginning of a tax base and a stimulus to infrastructure development. The 1964 earthquake in Anchorage and the 1967 flood in Fairbanks resulted in significant construction activity. The 1970's were dominated by the anticipation and construction of the trans-Alaska pipeline. In 1979, a decline in the economy resulted from the reduction in construction employment, but it was significantly offset by expansion of state and local government, made possible by the tremendous increase in state petroleum revenues from Alaska's North Slope. The quadrupling of the world oil price at the beginning of the decade has provided the impetus for the current cycle of Alaska's economic growth.

State petroleum revenues have grown from only $4.2 million in 1960 to $2.9 billion in 1984 while state general fund expenditures have risen from less than $100 million per year to $3.3 billion. Figure B.5.2.5 illustrates the historical growth in Railbelt population, showing the annual growth rate for each five-year period from 1960 to 1980 and from 1980 to 1984.

Consumption of electric energy in the Railbelt has risen significantly faster than the rate of economic growth. Between 1965 and 1984 total utility energy generation increased from 487 GWh to 3208 GWh, a six-fold increase, or an average of 10.4 percent per year. Figure B.5.2.6 illustrates the historical growth in Railbelt net generation, showing the annual growth rate for each five-year period from 1965 to 1980 and from 1980 to 1984.

Tables B.5.2.12 and B.5.2.13 present monthly electric power use and peak demand during the period 1976 to 1983 for the Anchorage and Fairbanks load centers. These tables show that, while there has been a steady rise in the use of electric energy and in peak demand, there has been variation in monthly energy use and peak demand from one year to the next, due mostly to different weather conditions in the Railbelt. Table B.5.2.14 presents the annual net generation of each Railbelt utility between 1976 and 1984.

5.3 - Forecasting Methodology (*)

This section presents the methodological framework used for the forecasts of economic conditions and electricity demand in the Railbelt. First, the models used for forecasting purposes are identified and explained. Next, model validation is discussed for the petroleum revenue model (APR), economic model (MAP), and electricity demand model (RED) and the optimized generation planning model (OGP).

5.3.1 - Forecasting Models (**)

(a) Model Overview (**)

Four computer-based and functionally interrelated models were used to forecast Railbelt economic growth and the associated demand for electric power, and for evaluating alternative generation plans for meeting electric power demand. The models and their relationship are graphically displayed in Figure B.5.3.1.

The starting point for the demand forecast is a series of data inputs concerning the projected world oil price and the projected Alaska gas and oil prices and production levels. At this stage of the process, the world oil price forecast is important because it affects the wellhead price of oil in Alaska, and also affects the assumed price of natural gas.

The first economic model in the series, the Alaska Petroleum Revenue Sensitivity Model (APR), was designed by the Alaska Department of Revenue (ADOR) to translate petroleum price and production forecasts into forecasts of state petroleum revenue.

The model is a simplified version of ADOR's PETREV model, which the agency uses to make its quarterly petroleum revenue forecasts. The price and production forecasts input to the APR model are combined with assumptions about royalty rates, severance tax rates, and certain adjustment factors to produce forecasts of state petroleum revenue.

The state petroleum revenue forecast output by the APR model becomes input to the second economic model in the series. The Man-in-the-Arctic Program (MAP) was developed by the University of Alaska's Institute of Social and Economic

Research (ISER) for the purpose of forecasting economic growth in Alaska. The MAP model was designed to take assumptions concerning basic industrial development, state petroleum revenue forecasts, fiscal policies, and several national and state economic and demographic parameters, and from these assumptions forecast growth in the state economy. Railbelt economic growth in terms of population, households, and employment is then isolated from the state totals.

The Railbelt economic growth forecast output by the MAP model becomes input to the Railbelt Electricity Demand (RED) model, a partial end use model developed by ISER and later modified by Battelle Pacific Northwest Laboratories. The RED model also incorporates many other assumptions, including:

- residential and business end use data, including saturation rates for various electrical end uses
- an industrial/military load forecast
- estimates of heating oil, natural gas, propane, and electricity prices to be paid by residential and business consumers in the Anchorage and Fairbanks load centers
- long term and short term price elasticities, which define consumers' responses to changes in the price of electricity and competing fuels

Given these assumptions and the MAP model's economic growth forecast, the RED model produces a forecast of energy demand and peak load through 2010.

The output of the RED model is the product of one iteration of the demand forecasting process. The energy and peak load forecasts become input to the Optimized Generation Planning (OGP) model, which is part of the economic and financial analysis component of the Susitna project evaluation process. Given a load forecast, and the cost of building thermal generation alternatives, the OGP model chooses the optimal generation expansion path and calculates the cost of electricity associated with that path. If the resulting production cost of electricity is out of line with the retail prices assumed in the RED model, the RED model is rerun with new electricity prices, and OGP is rerun with the new load forecast until the prices converge.

The following sections describe each of the four principal models, including their respective submodels and modules, key input variables and parameters, and primary output variables. Additional information on the APR model assumptions which, except for oil and gas prices, are the same as the ADOR's PETREV model assumptions, is available in the quarterly issues of Petroleum Production Revenue Forecast (Alaska Department of Revenue 1985). Additional information on the MAP model may be found in the MAP model system documentation (ISER 1985). The system documentation presents a detailed description of the model, including a complete listing of its equations and input variables and parameters. Two other documents present similarly detailed documentation of the RED model. The RED model Technical Documentation Report (Battelle 1983) was part of the Susitna license application as accepted by FERC in July 1983. The model documentation included in that report is still current, except for those changes noted in a more recent report prepared by Battelle (Scott, King and Moe 1985). The OGP model is a proprietary program of General Electric Company. The version used in the current study is presented in the Descriptive Handbook, Optimized Generation Planning Program, by General Electric (GE 1983).

(b) Alaska Petroleum Revenue Sensitivity (APR) Model (**)

Petroleum revenues currently constitute a large proportion of total state revenues. State revenues and expenditures also have considerable potential variability and are important determinants of future state economic conditions. The Alaska Department of Revenue therefore produces quarterly projections of the most important sources of petroleum revenues, production taxes and royalties. Those projections are generated by a specialized model, PETREV. The APR model used for this load forecast is a special submodel of PETREV. The PETREV model will be described first, followed by a description of the APR model.

PETREV is structured to take into account the uncertainties of future oil prices and other factors associated with forecasting petroleum revenues. Using PETREV, the ADOR issues updated petroleum revenue projections on a quarterly basis covering a 17 year period. The ADOR uses current data available on petroleum production, a range of world oil prices, tax rates, regulatory events, natural gas prices, and inflation rates.

PETREV is an economic accounting model that utilizes a probability distribution of possible values for each of the factors that affect state petroleum revenues to produce a range of possible state royalties and production taxes. The principal factors influencing the level of petroleum revenues are petroleum production rates, mainly on the North Slope, the market price of petroleum, and tax and royalty rates applicable to the wellhead value of petroleum. Natural gas prices and production levels are also taken into account, as are Cook Inlet petroleum prices and production levels. This model description focuses on North Slope petroleum, which accounts for over 90 percent of state petroleum revenue.

For input into the PETREV model, wellhead value of oil is estimated by a netback approach. The costs of gathering and transporting crude oil and a quality differential value are subtracted from the market value at its destination on the West Coast or Gulf Coast of the United States. For petroleum produced on the North Slope, the source of most of the oil produced in Alaska subject to state royalties and production taxes, future wellhead value is estimated as follows. The projected world price of Ecuador Oriente petroleum[1/] is adjusted by subtracting (1) the projected cost of pumping oil through the Trans Alaska Pipeline System from Prudhoe Bay to Valdez, including the pipeline tariff, (2) the projected cost of shipping the oil to refineries on the West Coast and the Gulf Coast of the United States, and (3) a projected quality differential factor representing the difference in quality between North Slope petroleum and Ecuador Oriente grade. The result is the estimated value of petroleum at Pump Station #1 at Prudhoe Bay, Alaska. For other North Slope fields, the price is lowered by the respective pipeline charges between each field and Pump Station #1.

Future royalties collected by the state are estimated by multiplying total projected production in barrels from state lands by the estimated per barrel price at the pump, subtracting field costs, and multiplying the result by .125.

This amounts to a 1/8 royalty payment on oil produced after all gathering and transportation costs are met. The State of Alaska may receive the royalty either in kind or in dollars. Future severance, or production, taxes are estimated by multiplying forecasted production, net of the 12.5 percent taken by the state as royalties, by the estimated pump station price and the tax rate adjusted by an economic limit factor (ELF). The nominal tax rate varies

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1/ Ecuador Oriente is a common measure of petroleum grade and price. Other standards include Saudi light and Saudi medium grade petroleum.

between 12.25 and 15 percent of net production value, depending upon the age of production wells. The economic limit factor (ELF) adjustment takes into account declining well productivity and increased production costs. On the North Slope most production will be subject to a 15 percent nominal severance tax rate, but the effective tax rate after adjustment varies from 0.0 to 15.0 percent. A decline in the ELF in effect lowers the tax rate to which Alaskan petroleum is subject.

Due to the many uncertainties involved in forecasting revenues, the PETREV model projects a range, or frequency distribution, of state petroleum revenues by year, so that for each year a forecasted petroleum revenue figure may be selected based on a given cumulative frequency of occurrence. The model accomplishes this by iteratively selecting a set of input variable values from among the alternative values and computing a petroleum revenue figure for each time period. Each projection is computed using a set of accounting equations that estimate royalties and production taxes from each state oil and gas lease for each time period. By selecting the average value of all input data, the model can also produce an average petroleum revenue forecast.

For the Susitna Project evaluation it is necessary to examine the implications of more than one world oil price projection. This need is accommodated by ADOR through the Alaska Petroleum Revenue Sensitivity (APR) Model. With two exceptions, this sensitivity accounting model, which is in effect a submodel of the PETREV model, utilizes the accounting equations and average values from PETREV. The two exceptions are world oil price and Cook Inlet gas price. By executing the sensitivity model with the alternative oil and gas price projections, alternative petroleum revenue projections are developed for use in projecting state economic activity in the MAP model. The APR model structure is shown in Figure B.5.3.2.

The process of projecting state petroleum revenues and the functions of the PETREV model are presented in more detail in the quarterly "Petroleum Production Revenue Forecast" (ADOR 1985). The petroleum revenue projections used in preparing the electric power market and economic forecasts are based on the March 1985 average expected values of all factors other than oil prices and Cook Inlet gas prices. Those input assumptions are summarized in Section 5.4.1.

(i) Input Data (***)

As noted above, the APR model uses the mean values for the input data used in the PETREV model. The input includes both oil and gas revenue variables.

Oil revenue variables include:

- o World oil price;
- o Oil price adjustment factors for each field expected to operate at any time during the forecast period (Prudhoe Bay, Kuparuk River, Milne Point, Endicott, Lisburne, West Sak Sands, Seal Island, unspecified onshore North Slope production, and Cook Inlet);
- o Petroleum production for each field; and
- o Number of wells and economic limit factor for each field, nominal severance tax rate and royalty rate gathering and cleaning charges by field.

Gas revenue variables include

- o North Slope and Cook Inlet gas price;
- o North Slope and Cook Inlet gas production;
- o Economic limit factor by field; and
- o Severance tax and royalty rates.

(ii) APR Model Output (***)

The output data from the APR model includes oil and gas severance tax and royalties for each oil field and each gas producing area. The revenue estimates by field are summed to produce the input used in the MAP model, including:

- o State severance tax revenue by year, 1985-2010; and
- o State royalty revenue by year, 1985-2010.

(c) Man-in-the-Arctic Program (MAP) Economic Model (*)

The MAP model is a computer-based economic modeling system that simulates the behavior of the economy and population of the State of Alaska and each of 20 regions of the state. The regions correspond closely to Bureau of the Census divisions. The Railbelt consists of six of those regions: Anchorage, Fairbanks, Kenai-Cook Inlet, Matanuska-Susitna, Seward, and S.E. Fairbanks. The model was originally developed in the 1970s by the Institute of Social and Economic Research of the University of Alaska, under a grant from the National Science Foundation. The model has been continually improved and updated since it was originally developed. In addition to its use on the Susitna Project, it has been used in numerous economic analyses such as evaluations of the economic effects of alternative state fiscal policies and assessments of the economic effects of development of outer continental petroleum shelf leases.

The MAP model functions as three separate but linked submodels: the scenario generator submodel, the economic submodel, and the regionalization submodel, as illustrated in Figure B.5.3.3. The scenario generator submodel enables the user to quantitatively define scenarios of development in exogenous industrial sectors; i.e., sectors whose development is basic to the economy rather than supportive. Examples of such sectors are petroleum production and other mining, the federal government, and tourism. The scenario generator submodel also enables the user to implement assumptions concerning state revenues from petroleum production. The economic submodel produces statewide projections of numerous economic and demographic factors based on quantitative relationships between elements of the Alaskan economy such as employment in basic industries, employment in non-basic industries, state revenues and spending, wages and salaries, gross product, the consumer price index, and population. The regionalization submodel enables the user to disaggregate the statewide projections of population and employment to each of the 20 separate regions of the state, using data on historical and current economic conditions and assumptions concerning basic industrial development.

Each of the three MAP submodels exists as a computer program, and each program is supported by a set of input variables and parameters. Each of these programs and the supporting input variables and parameters are discussed briefly in the following sections. Detailed information on each submodel, including a complete model listing and the input variables and parameters used in executing the model, is provided in this License Amendment.

(i) <u>Scenario Generator Submodel</u> (*)

In order to operate the MAP model, the user must make a number of assumptions concerning the future development of basic industries in the State. Such assumptions are needed because the state economy is driven by interrelated systems of endogenous and exogenous demands for goods and services. Endogenous demands are generated by exogenous industries and the resident population which provides employment to all industries.

Exogenous demands originate outside Alaska due to the favorable position of the state to export its minerals and other resources to other states or countries. In Alaska, exogenous demands stem from the state's natural resource base, especially petroleum; non-energy minerals; federal property; and tourist attractions. Exogenous demands lead directly to employment in basic sectors such as mining, indirectly to employment and output in industries such as oil field services that support basic industry, and also to industries such as housing and restaurants that support workers in basic industries and their families.

The scenario generator model permits the user to build, from among a large number of alternative basic industrial cases, economic scenarios that can be used to project economic conditions in the State of Alaska and, for purposes of the Susitna Hydroelectric Project, the Railbelt. Input data for each of the scenarios are in the form of employment projections by sector and region of the state on an annual basis over the forecast period.

The scenario generator model is also used to select the level of state petroleum revenue that is assumed available to the state's general fund for expenditure on state government operations and capital investment.

Key input and output variables and assumptions for the scenario generator are summarized in Section 5.4.1 of this Exhibit.

(ii) <u>Statewide Economic Submodel</u> (*)

The statewide economic submodel is a simultaneous system of more than 1,000 equations that individually and collectively define the quantitative relationships between economic and demographic factors in Alaska. Some values for input variables come from the scenario generator, whose values can be expected to vary from one execution of the model to the next. Other values come from files of necessary exogenous data, such as files describing state fiscal behavior, whose values generally do not change across runs. Parameters, whose values are generally fixed from one model execution to the next, are provided from another input file. The equations are solved algebraically each time the model is executed to produce a unique set of values for the dependent variables.

While the equations in the statewide economic model are solved as a unit each time the model is executed, they are grouped for organizational and conceptual purposes into three modules: economic module, fiscal module, and demographic module, as illustrated in Figure B.5.3.4.

The equations in the economic module express relationships between economic factors such as employment in basic industrial sectors and output and employment in support sectors. Important products from the economic module include projections of employment and payroll by industry and personal income.

The fiscal module computes state government revenues and the mix of government expenditures. This information is used as input to the economic module. The fiscal module plays a key role in examining the fiscal and economic effects of different future world petroleum prices and state petroleum revenue levels.

The demographic module expresses the relationships between both households and population and economic factors recognized as key determinants of population. Population is determined by such factors as employment, labor force participation rates, fertility and mortality rates, and unemployment and wage rate differentials between Alaska and the rest of the United States.

Household formation is based upon a unique propensity to form households in each age, sex, and racial category. Over the last few years this household formation rate has generally increased. The increase is expected to continue at reduced rates.

(iii) Regionalization Submodel (*)

Statewide employment, population, and household projections are disaggregated by the regionalization model, the third submodel of the MAP economic modeling system. Disaggregation is accomplished by combining statewide projections with regional industrial development data and regional parameters based on historical, economic and demographic relationships between each region and the state. This process, illustrated in Figure B.5.3.5, produces projections by region or region group such as the Anchorage and Fairbanks greater metropolitan areas.

(iv) Input Variables and Parameters (*)

As indicated above, some input variables are factors whose values are provided by the user to the model and whose values can be expected to change from one execution of the model to the next. Parameter values are generally fixed both over time within each simulation and during the course of successive model executions.

The scenario generator model produces 16 input variables to define the exogenous economic assumptions for each model execution:

- Agriculture Employment
- Mining Employment
- High Wage Exogenous Construction Employment
- Regular Wage Exogenous Construction Employment
- High Wage Exogenous Manufacturing Employment
- Regular Wage Exogenous Manufacturing Employment
- Exogenous Transportation Employment
- Fish Harvesting Employment

- o Active Duty Military Employment
- o Civilian Federal Employment
- o Tourists Entering Alaska
- o State Production Tax Revenue
- o State Royalty Income
- o State Petroleum Lease Bonus Payment Revenue
- o State Petroleum Property Tax Revenue
- o State Corporate Petroleum Tax Revenue

Of these 16 variables, 10 are used to define discrete industrial development scenarios and are therefore region specific. One variable defines the level of tourism for the state. The remaining five input variables are elements of state revenue forecasts. Estimates of petroleum production taxes and royalties are obtained from the APR model. The Alaska Department of Revenue's March 1985 estimates of state petroleum corporate taxes are used (ADOR 1985). State petroleum property tax estimates are based on ADOR projections adjusted for ISER estimates of OCS-related activities. Future lease bonus payments were estimated by ISER.

The regionalization model is executed using a data series for 40 exogenous variables, based on 20 state regions in the scenario generator. For each region, there are basic sector employment and the government sector employment. Total state population, households, and the ratio of support to total employment are provided by the state economic submodel.

In addition to the variables discussed above, the MAP model utilizes three types of parameters: variable state fiscal policy parameters; stochastic parameters; and calculated, or non-stochastic, parameters.

Variable state fiscal policy parameters are used primarily in the fiscal module to represent policy options for the collection of revenues and the timing and composition of state expenditures. The most important function of these parameters is to quantitatively define state expenditure and revenue policies. In projecting economic conditions for the Susitna Hydroelectric Project, the following assumptions were made:

- State expenditures for operations and capital improvements in 1985 dollars will rise in proportion to state population as long as revenues can support this level of expenditure; this assumption is in accordance with a 1982 amendment to the Alaska State Constitution setting a ceiling on state expenditures.

- When revenues from existing sources cannot support expenditures at the constant real per capita level, earnings from the permanent fund will be made available for operating and capital expenditures at the expense of the Permanent Fund dividend program; as revenues decline, state spending priorities shift from subsidies and capital improvements toward the operating budget.

- When revenues from Permanent-Fund earnings and other sources are not sufficient to maintain expenditures at the constant real per capita level, a state personal income tax will be reimposed at its previous rate.

- When all of these revenue sources plus any accrued general fund balances are unable to support expenditures at the constant real per capita level, both capital and operating expenditures will be curtailed proportionately so that they will not exceed revenues.

Stochastic parameters are coefficients computed using regression analysis. They are used primarily in the economic module of the statewide economic model to express the functional relationships between economic factors such as employment, wages and salaries, wage rates, gross product, and other national and regional economic factors such as unemployment and consumer price indices. Stochastic parameters are also used in the population module to express the relationship between population migration into and out of Alaska and wage rate and unemployment level differentials.

Calculated or non-stochastic parameters are generally calculated rates or other quotients, and are used primarily in the population and household formation modules and the regionalization model. Calculated parameters include factors such as survival rates for the population by race, age group, and sex. Calculated parameters used in the regionalization model include factors such as the ratio of population to residence adjusted employment by region.

(v) MAP Model Output (*)

Economic forecasts through the year 2010 are generated for alternative oil and gas prices and state petroleum revenue cases and other input variables and parameters described above. Specific MAP Model output used directly as input to the Railbelt Electricity Demand (RED) Model include the following:

- o Population by load center, Greater Anchorage and Greater Fairbanks, by year 1985 through 2010
- o Total employment by load center by year
- o Total households in the state by age group of head of household - 24 and under years of age, 25-29, 30-54, and over 55 - by year
- o Total households by load center by year

(d) Railbelt Electricity Demand Model (*)

The Railbelt Electricity Demand Model is an end use - econometric model that projects both electric energy and peak load demand in the Anchorage-Cook Inlet and Fairbanks-Tanana Valley load centers of the Railbelt for the period 1980-2010. The Anchorage-Cook Inlet load center is defined to include the Anchorage, Kenai-Cook Inlet, Matanuska-Susitna, and Seward census regions. The Fairbanks-Tanana Valley load center includes the Fairbanks and SE Fairbanks census regions.

The RED model was originally written by the Institute of Social and Economic Research (ISER) of the University of Alaska (ISER 1980). It was later modified and expanded by Battelle Pacific Northwest Laboratories (Battelle 1982, Volume VIII). The present version is a further modification and improvement, and includes a validation of the model performance. The results of these efforts are fully documented in Battelle (1983) and Scott, King and Moe (1985). A summary description of the methodology used by the RED model and an explanation of each module are presented in the following paragraphs. These discussions are followed by a description of the input and output data.

The RED model is a simulation model designed to forecast annual electricity consumption for the residential, business (commercial, small industrial, government), large industrial, and miscellaneous end-use sectors of the two load centers of the Railbelt region. The model is made up of seven separate but interrelated modules, each of which has a discrete computing function within the model. They are the Uncertainty, Housing, Residential Consumption, Business Consumption, Program-Induced Conservation, Miscellaneous Consumption, and Peak Demand Modules. Figure B.5.3.6 shows the basic relationship of the seven modules.

The model may be operated probabilistically. In this mode, RED randomly selects values for key model parameters from frequency distributions in the model's data files. The model may also be operated on a deterministic basis, whereby only one set of forecasts is produced based on a single set of average input variables. When operated probabilistically, the RED model begins with the Uncertainty Module, which selects a trial set of values for model parameters to be used by other modules. These parameters include price elasticities, appliance saturations, end-use consumption per square foot of business floor space, and regional load factors. Exogenous forecasts of population, employment, and households from the MAP model, plus retail prices for fuel oil, gas, and electricity are used with the model's parameters by the Residential Consumption and Business Consumption Modules to produce forecasts of electricity consumption. These forecasts, along with additional trial parameters, are used in the Program-Induced Conservation Module to simulate the effects of government programs that subsidize or mandate the market penetration of certain technologies that reduce the need for power. This program-induced component of conservation is in addition to those savings that would be achieved through normal consumer reaction to energy prices. The consumption forecasts of residential and business (commercial, small industrial, and government) sectors are then adjusted to reflect these additional savings. The revised forecasts are used to estimate future miscellaneous consumption and total sales of electricity. These forecasts and separate assumptions regarding future major industrial loads are used along with a trial system load factor to estimate peak demand.

After a complete set of projections is prepared, the model begins preparing another set by returning to the Uncertainty Module to select a new set of trial parameters. After several sets of projections have been prepared, they are formed by RED into a frequency distribution to allow the user to determine the probability of occurrence of any given load forecast. When only a single set of projections is needed, the model is run in deterministic mode whereby a specific default set of parameters is used and only one trial is run. This deterministic formulation was used to produce alternative load forecasts for the Susitna Hydroelectric Project.

The RED model produces projections of electricity consumption by load centers and sectors at five-year intervals. A linear interpolation is performed to obtain yearly data.

The outputs from the RED model runs are used by the Optimized Generation Planning (OGP) model to plan and dispatch electric generating capacity for each year. The remainder of this section presents a description of each module in the RED model.

(i) <u>Uncertainty Module</u> (*)

When used in probabilistic mode, the purpose of the Uncertainty Module is to randomly select values for individual model parameters that are considered most subject to forecasting uncertainty. These parameters include the market saturations for major appliances in the residential sector; the price elasticity and cross-price elasticities of demand for electricity in the residential and business sectors; the intensity of electricity use per square foot of floorspace in the business sector; and the electric system load factors for each load center.

These parameters are generated by a Monte Carlo routine, which uses information on the distribution of each parameter (such as its expected value and range) and the computer's random number generator to produce sets of parameter values. An overview of information flows within the Uncertainty Module is given in Figure B.5.3.7. Each set of generated parameters represents a "trial". By running each successive trial set of generated parameters through the rest of the modules, the model builds distributions of annual electricity consumption and peak demand. The end points of each distribution reflect the probable range of annual electric consumption and peak demand, given the level of uncertainty.

The Uncertainty Module need not be run every time RED is run. The parameter file contains "default" values of the parameters that may be used to conserve computation time. In the current study, the RED model was used in deterministic mode for all forecasts. Default values for the parameters were set at their most probable level.

(ii) Housing Module (*)

The Housing Module calculates the number of households and the stock of housing by dwelling type in each load center. The Housing Module's structure is shown in Figure B.5.3.8. Using regional forecasts of households and total population, the housing module first derives a forecast of the number of households served by electricity in each load center. Next, using exogenous statewide forecasts of household headship rates and age distribution of Alaska's population, it estimates the distribution of households by age of head and size of household in each load center. Finally, it forecasts the demand for four types of housing stock: single family units, mobile homes, duplexes, and multifamily units.

The supply of housing is calculated in two steps. First, the supply of each type of housing from the previous period is adjusted for demolition and compared to the demand. If demand exceeds supply, construction of additional housing begins immediately. If excess supply of a given type of housing exists, the model examines the vacancy rate in all types of houses. Each type is assumed to have a maximum vacancy rate. If this rate is exceeded, demand is first reallocated from the closest substitute housing type, then from other types. The end result is a forecast of occupied housing stock for each load center for each housing type in each forecast year. This forecast is passed to the Residential Consumption Module.

(iii) Residential Consumption Module (*)

The Residential Consumption Module forecasts the annual consumption of electricity in the residential sector. The Residential Consumption Module employs an end-use approach that recognizes nine major end uses of electricity, and a "small appliances" category that encompasses a large group of other end uses. In addition to space heating, the major end uses are water heaters, cooking, clothes dryers, refrigerators, freezers, dishwashers, clothes washers, and saunas and jacuzzis. Figure B.5.3.9 shows the calculations that take place in this module.

For a given forecast of occupied housing, the Residential Consumption Module first adjusts the housing stock to net out housing units not served by an electric utility. It then forecasts the residential appliance stock and the portion using electricity, stratified by the type of dwelling and vintage of the appliance. Appliance efficiency standards and average electric consumption rates are applied to that portion of the stock of each appliance using electricity and the corresponding consumption rate to derive a preliminary consumption forecast for the residential sector. Finally, the Residential Consumption Module receives exogenous forecasts of residential fuel oil, natural gas, and electricity prices, along with values of price elasticities and cross-price elasticities of demand from the Uncertainty Module. It adjusts the preliminary consumption forecast for both short- and long-run price effects on appliance use and fuel switching. The adjusted forecast is passed to the Program-Induced Conservation Module.

(iv) Business Consumption Module (*)

The Business Consumption Module forecasts the consumption of electricity by load center for each forecast year. Because the end uses of electricity in the commercial, small industrial, and government sectors are more diverse and less known than in the residential sector, the Business Consumption Module forecasts electrical use on an aggregate basis rather than by end use. Figure B.5.3.10 presents a flowchart of the module.

RED uses a proxy (the stock of commercial and industrial floorspace) for the stock of capital equipment to forecast the derived demand for electricity. Using an exogenous forecast of regional employment, the module forecasts the regional stock of floorspace. Next, econometric equations are used to predict the intensity of electricity use for a given level of floorspace in the absence of any relative price changes. Finally, a price adjustment similar to that in the Residential Consumption Module is applied to derive a forecast of business electricity consumption. This total excludes large industrial demand, which is exogenously determined. The Business Consumption Module forecasts are passed to the Program-Induced Conservation Module.

(v) Program-Induced Conservation Module (*)

Battelle developed this module for the State of Alaska, Office of the Governor (Battelle 1982, Volume VIII) to analyze potential large scale conservation programs that would be subsidized by the State of Alaska. This module permits explicit treatment of government programs which could foster additional market penetration of technologies and programs that reduce the demand for utility-generated electricity. The module structure is designed to incorporate assumptions on the technical performance, costs, and market penetration of electricity-saving innovations in each end use, load center, and forecast year.

The module forecasts the additional electricity savings by end use that would be produced by government programs beyond that which would be induced by market forces alone. It also forecasts the costs associated with these savings, and adjusted consumption in the residential and business sectors.

In the current study, this module was not used. Existing conservation programs are being phased out and there are many uncertainties regarding the future of long term government conservation programs. The impact of past program-induced conservation is reflected, however, in the historical electricity consumption values used to initialize the model.

(vi) Miscellaneous Consumption Module (*)

The Miscellaneous Consumption Module forecasts total miscellaneous consumption for second (recreation) homes, vacant houses, and street lighting. The module uses the forecast of residential housing stock to predict electricity demand in second homes and vacant housing units. The sum of residential and business consumption is used to forecast street lighting requirements. Figure B.5.3.11 provides a flowchart of this module.

(vii) Peak Demand Module (*)

The Peak Demand Module forecasts the annual peak demand for electricity. The annual peak load factors were based on an analysis of historical Railbelt load patterns. A two-stage approach using load factors is used. The unadjusted residential and business consumption, miscellaneous consumption, plus load factors are used to forecast preliminary peak demand. Separate estimates of peak demand for major industrial loads are then added to compute annual peak demand for each load center. Figure B.5.3.12 provides a flowchart of this module.

(viii) Input Data (*)

There are five input data files to the RED model. One of the five, CONSER, which contains data on program-induced conservation, was not used in this project. The other four are described as follows. The RDDATA file contains output data of the MAP model, including load center population, households, and employment, plus state households by age group. The file also contains the real prices (in 1980 dollars) of fuel oil and natural gas, by load center and end-use sector.

The RATE DAT file contains the real prices of electricity by load center and end-use sector. These prices are derived from present costs of electricity adjusted to future conditions based on the OGP results.

The PARAMETER file contains the numerical values for certain parameters, including housing demand coefficients; saturation rate of electrical appliances; floorspace elasticities; short-term and long-term own-price and cross-price elasticities for electricity, fuel oil, and natural gas; and annual load factors.

The EXTRA DAT file contains information on the annual electrical consumption and peak demand of large industrial projects.

(x) RED Model Output (*)

The RED output report contains various tables generated by the program. The main tables include the following:

- Number of households for each load center, forecast year (1980, 1985, and at five-year intervals to 2010), and type of housing (single family, multifamily, duplex, and mobile homes)

- Residential appliance saturations for each load center, forecast year, and type of housing

- Residential use per household before price elasticity adjustments for each load center, forecast year, and appliance category (small appliance, large appliance, and space heat)

- Business use per employee before price elasticity adjustments, for each load center and forecast year

- Electric energy requirements, including price adjustments, for each load center, year, and category of consumption (residential, business, miscellaneous, incremental conservation savings, large industrial, and total)

- Peak electric requirements for each load center and year

Output from the RED model is used as input in the OGP computer model for the purposes of analyzing alternative expansion programs.

(e) Optimized Generation Planning (OGP) Model (*)

The OGP program was developed over 20 years ago by General Electric Company (GE) for two reasons. First, to combine the three main elements of generation expansion planning (system reliability, operating costs, and investment costs), and second, to automate the decision analysis for additions to the generating system. The following description of the model was extracted from GE literature and the Descriptive Handbook (GE 1983).

The first task in selecting the generating capacity to install in a future year is the reliability evaluation. The evaluation uses either percent installed reserves or loss-of-load probability (LOLP) to answer the questions of how much capacity to add and when it should be installed. A production costing simulation is also done to determine the operating costs for the generating system with the given unit additions. Finally, an investment cost analysis of the capital costs of the unit additions is performed. The operating and investment costs help to answer the question of what kind of generation to add to the system. Figure B.5.3.13 outlines the procedure used by OGP to determine an optimum generation expansion plan.

The next three sections (reliability evaluation, production simulation, and investment costing) review the elements of these computations. The OGP optimization procedure is then described, followed by a discussion of the input and output files.

(i) Reliability Evaluation (*)

Historically, electric utility system planners measured generation system reliability with a percent reserves index. This planning design criterion compared the total installed generating capacity to the annual peak load demand. However, this approach proved to be a relatively insensitive indicator of system reliability, particularly when comparing alternative units whose size and forced outage rate varied.

Since its introduction in 1946, the measure that has gradually gained widest acceptance in the industry is "loss-of-load probability" (LOLP). The LOLP method is a probabilistic determination of the expected number of days per year on which the demand exceeds the available capacity. It factors into the reliability calculation the forced and planned outage rates of the units on the system as well as their sizes. An LOLP of 1 day in 10 years is a usual industry standard.

Computing LOLP requires an identification of all outage events possible (in a system with n units, this means 2^n events) and then a determination of the probability of each outage event. However, since LOLP is concerned with system capacity outages and not so much with particular unit outages, the probability of a given total amount of capacity on outage is calculated.

Utilizing a highly efficient recursive computer technique, capacity outage tables are calculated directly from a list of unit ratings and forced outage rates.

The LOLP for a particular hour is calculated based on the demand and installed capacity for the hour. The reserves are given by capacity minus demand. On this basis, a deficiency in available capacity (i.e., loss of load) occurs if the capacity on forced outage exceeds the reserves. The probability of this happening is read directly from the cumulative outage table and is the LOLP for a single hour.

In addition to calculating the percent installed reserves, OGP can also calculate a daily LOLP (days/year). The daily LOLP is determined by summing the probabilities of not meeting the peak demand for each weekday in the year. The hourly LOLP is calculated by summing the probabilities of not meeting the load for all the hours in the year.

(ii) Production Simulation (*)

Once a system with sufficient generating capacity has been determined by the reliability evaluation, the fuel and related operating and maintenance (O&M) costs of the system must be calculated. OGP does this by an hourly simulation of a typical weekday and weekend day for each month of system operation.

The program commits and dispatches generation so as to minimize costs. However, the user has the option of biasing or overriding the normal economic operation of the system. This can be accomplished in two ways. The user may specify weighting factors for various environmental parameters such that the program will operate those units to minimize their impact. The user may also limit, on a monthly basis, the number of hours that units may run or the amounts of different fuels that may be consumed.

The production simulation in OGP is performed in six steps:

- Load modification based on recognition of contructual purchases and sales;
- Conventional hydro scheduling and its associated load modification;
- Monthly thermal unit maintenance scheduling based on planned outage rates;
- Pumped storage hydro or other energy storage scheduling;

- Thermal unit commitment for the remaining loads based on economics and/or environmental factors, spinning reserve rules, and unit cycling capabilities; and

- Unit dispatch based on incremental production costs and environmental emissions. The production simulation is for a single utility system or pool. Unrestrained power transfer capability is assumed between areas or companies internal to the pool represented.

(iii) Purchases and Sales (*)

The OGP production cost load model is an hour-by-hour model of a typical weekday and weekend day for each month, arranged in monotonically decreasing order. These hourly loads are modified to reflect the firm purchases and sales between the area being studied and entities outside that area. Each contract has associated with it a demand charge ($/kW/yr) and an energy charge ($/kWh).

(iv) Conventional Hydro Scheduling (*)

The power and energy available from any conventional hydroelectric project used in a simulation is divided into two types: base load and peak load. The base load energy that must be produced is accounted for by subtracting a constant capacity from every hourly load in the month as shown on Figure B.5.3.14. This capacity value is referred to as the plant minimum rating. After this baseload energy is used, any remaining energy available is used for peak shaving. In such situations, the program uses the remaining capacity and energy of the hydro unit to reduce the peak loads as much as possible. If any excess energy exists at the end of a month, a user-specified maximum storage amount can be carried forward into the next month.

(v) Thermal Unit Maintenance (*)

On a utility system, the planned maintenance of individual units is usually performed on a monthly basis. During these periods, the units are unavailable for energy production. Maintenance scheduling is normally done so as to minimize the effect on both system reliability and system operating costs. A common strategy for scheduling maintenance, and the method used in OGP, is the levelized reserves approach. The monthly peak loads are examined throughout the year, and incremental amounts of generating capacity maintenance are scheduled to try to levelize the peak load plus capacity on maintenance throughout the year.

Increased maintenance levels which might be required during the first few years of a unit's operation are modeled using an immaturity multiplier. OGP also allows the user to annually input a predetermined maintenance schedule for units for which this information is available.

(vi) Thermal Unit Commitment (*)

After modifications for contracts, hydro, unit maintenance, and energy storage, the remaining loads must be served by the thermal units on the system. In OGP, the units can be committed to minimize either the operating costs, as is usually done, or some combination of user specified environmental factors and operating costs. The operating costs are calculated from the fuel and variable O&M costs and input-output curve for each unit. Fixed O&M costs do not affect the order in which units are committed, but are included in the total production cost.

The unit commitment logic determines how many units will be on-line each hour and also attempts to provide an adequate level of operating reliability while minimizing the system operating costs and/or environmental emissions. The operating reliability requirement is met by committing sufficient generation to meet the load plus a user specified spinning reserve margin. Units are committed in order of their full load energy costs or emissions, starting with the least expensive.

(vii) Thermal Unit Dispatch (*)

If a unit is committed, the unit's minimum loading level requires that its output be at that level or higher. When the final commitment has been established, each unit will be loaded to at least its minimum. Typically the sum of the minimums does not equal the load. Additional load will be served by the units' incremental loading sections. The dispatching function in the OGP production simulation loads the incremental sections of the units committed in a manner which serves the demand at minimum system fuel cost or emissions. This dispatch technique is known as the equal incremental cost approach.

(viii) Investment Costing (*)

The investment cost analysis in OGP calculates the annual carrying charges for each generating unit added to the system. This is computed based on a $/kW installed cost, a kW nameplate rating, and an annual levelized fixed charge rate.

(ix) OGP Optimization Procedure (*)

For the year under study, a reliability evaluation is performed. This determines the need for additional generating capacity. If the capacity is sufficient, the program calculates the annual production and investment costs, prints these values, and proceeds to the next year.

If additional capacity is needed, the program will add units from a list of available additions until the reliability index is met. For each combination of units added to the system, OGP does a production simulation and investment cost calculation for the year under study. The program uses the information gained from the cost calculations to logically step through the different combinations of units to add, eliminating from consideration combinations that would produce higher annual costs than previously found. This process continues until the expansion giving the lowest annual costs is found. The selected units are added to the system, and the program proceeds to the next year of the study.

In cases where operating cost inflation and/or time variation in unit outage rates are present, the OGP optimization logic utilizes a look-ahead feature. The look-ahead feature develops levelized fuel and O&M costs and applicable outage rates for use in the economic evaluation. As part of the output information available, the user obtains documentation of the relative costs of all the alternatives examined. After the generating unit selection, the reliability and costing calculations are repeated for the chosen alternative so that the expansion report available for the user contains the correct annual values.

(x) Input Data (*)

There are two major input files to OGP: the Generation file and the Load file. The Generation file model is created for use as a data base representing the in-service and on-order generating units. For each unit, the following characteristics are described:

- o Types of Generator
- o Unit sizes and earliest service year allowable
- o Unit costs
- o Fuel types and costs
- o Operation and maintenance costs
- o Heat rates
- o Commitment minimum uptime rule
- o Forced outage rates
- o Planned outage rates

The Load file is specified by the user to represent peak and shape characteristics which are projected to occur for the years included in the OGP study. The user supplies the following load shape data:

- o Annual peak and energy demand
- o Month/annual ratios
- o The 0 percent, 20 percent, 40 percent, and 100 percent points on the peak load duration curve, by month
- o Typical reference weekday and weekend-day hourly ratios by month

In addition to these two input files, the user uses the Data Preparation (DP) program and the Generation Planning (GP) program to run the OGP model. The DP program produces standard tables which describe the thermal and hydro options. Included are tables for plant capital, O&M, and fuel costs; inflation patterns, planned and forced outage rates; minimum loading points; and environmental data. The GP program includes input data on loss of load probability criteria, hydro firm energy, economic parameters, and output options.

(xi) Output Data (*)

Output options have been designed and included in OGP to provide the user with flexibility in the level of detail and volume of documentation received. Complete output reports as well as summary outputs are available.

The output available from the OGP program includes the following information:

- Listing of the input data
- Standard tables, as defined by the user, for various unit characteristics
- Listing of the unit types and sizes available for optimization and their characteristics
- Listing of the Load file for the study period
- Listing of the generating units on the system and their characteristics
- Year-by-year summary of the firm contracts input by the user
- Production simulation summaries, listing all of the generating units of the system with their energy output, fuel and O&M costs, fuel consumption, and environmental emissions. These summaries can be obtained on a monthly or annual basis, for all the decision passes or just the optimum system
- Summary of all the expansion alternatives, with their associated costs and reliability measures, evaluated during the optimization
- Summaries of the final system expansion through time and the associated costs

5.3.2 - Model Validation (*)

The APR, MAP, and RED models are used to simulate future conditions based on alternative assumptions concerning world and state economic conditions and electricity demand in the Railbelt. Measures that have been taken to ensure that the models simulate economic and electricity utilization conditions and relationships as accurately as possible are summarized below.

(a) APR Model Validation (***)

As noted earlier, the APR model is a simplified, deterministic version of the Alaska Department of Revenue's probabilistic PETREV model. To test the ability of the APR model to reproduce PETREV's results, both results were compared for the March 1985 mean petroleum revenue case. The APR forecast performed as follows for the 17 year PETREV forecast period:

Maximum underestimate	1.6%
Maximum overestimate	2.0%
Average difference	0.9%

The PETREV model is used by ADOR to produce a probability distribution of new revenue forecasts each quarter. Table B.5.3.1 illustrates how the range and mean for FY1985 total revenues have varied since the September 1983 forecast. Each successive forecast becomes increasingly more reliable as the forecast period draws nearer, reflecting the increasing reliability of the data used in the model. The current model formulation has not been in use long enough to estimate its long term accuracy.

(b) MAP Model Validation (o)

Validation of the MAP model has been accomplished using two separate but interrelated techniques. First, a standard set of statistics was computed for each of the stochastic parameters used in the MAP model equations. These statistics provide information on the expected accuracy of each coefficient and the probability that each coefficient expresses the correct relationship between variables. Second, the MAP Model was tested to determine the accuracy with which it could simulate observed historical conditions.

(i) Stochastic Parameter Tests (*)

Stochastic parameters are, as indicated previously, coefficients computed using regression analysis, a statistical procedure whereby the quantitative relationship between variables is estimated by one or more computed coefficients.

Most of the equations in the economic module of the statewide economic model are computed using regression analysis.

In estimating coefficients using regression analysis a number of statistics are computed. These statistics indicate the accuracy of the coefficient and the overall efficiency of the equation in estimating the true value of the dependent variable. Among these statistics are t-values, R2, Durbin-Watson statistic, and the standard error of regression. They are used both in selecting the best independent variables for estimating a given dependent variable and in determining the expected accuracy of the final equation.

These statistics have been computed for each stochastic equation used in the MAP Model. In each equation efforts have been made to obtain the highest possible values for these statistics in order to ensure that the model reflects actual economic relationships as accurately as possible. As a result of this effort all the coefficients used in the MAP Model have a relatively high level of statistical significance.

(ii) <u>Simulation of Historical Economic Conditions</u> (*)

Although the MAP Model has been in use since 1975, analyses conducted for the Susitna Hydroelectric Project were the first applications of the model in long range projection of economic conditions. Previous applications of the model had been in analyses of economic effects of alternative state policies. It is not possible, therefore, to test the model's long-term projection accuracy using old forecasts. However, the model's accuracy was tested by simulating historical economic conditions by executing the model utilizing historical data and input variables. Table B.5.3.2 summarizes the results of simulation of selected historical conditions. The table shows that the MAP Model reproduces historical conditions with remarkable accuracy, in a period when significant growth and structural change occurred. The model's performance is acceptable for periods showing markedly different growth characteristics, such as during pipeline construction and during both pre- and post-pipeline development.

(c) RED Model Validation (**)

The accuracy of the RED Model was assessed by utilizing the MAP model's historical simulation of employment, population, and numbers of households; actual historical heating degree days; and actual historical energy prices to predict electricity consumption by sector and load center. The MAP historical simulation was considered superior to actual employment and population statistics because the actual series contain random and short-term disturbances that have little to do with planning and developing stocks of energy-using capital equipment. In addition, the model was run and adjustments were made using the best estimates of 1980 through 1983 economic drivers and fuel prices. Table B.5.3.3 summarizes the results of comparing the SHCA case with actual utility data for 1980 through 1983. The historical period used in the analysis was brief because of the lack of available data for the end-use forecasting model. Complete historical data on end-use (fuel mode split, appliance saturation, end-use energy consumption, etc.) are only available for 1980. Therefore, the accuracy tests which can be performed on the model are limited.

Even though the RED model is a long-term forecasting model which uses 5-year interval inputs, it produces forecasts that are fairly close to actual values in the short term. When the forecast is adjusted for weather conditions and price changes, the Anchorage-Cook Inlet residential and business sectors and the Fairbanks-Tanana Valley business sector closely match the actual values for consumption in most years. The Fairbanks-Tanana Valley residential sector is 15 to 20 percent high in all years but 1980. The probable cause is that existing electric heating equipment is not being utilized; rather, wood is being used to provide much of the heat in the area's residential sector. In Battelle-Northwest's residential survey (described in Scott, King and Moe 1985), wood was listed as an alternative heat source in 53.5 percent of dwellings having only one alternative and as the primary fuel in 16.3 percent of all homes.

The other difference is that Fairbanks-Tanana Valley forecasted business consumption is growing faster than its actual value as shown in Table B.5.3.3. This is partly due to the fact that, until recently, square footage per employee had been growing slowly to absorb the post-pipeline building stock. Fairbanks square footage per employee may soon increase again in response to a downtown redevelopment plan involving major hotel and convention facilities.

5.4 - Forecast of Electric Power Demand (**)

Two companion load forecasts, plus a third sensitivity case, have been produced following the methodology discussed in Section 5.3. This section discusses the three forecasts. First, there is a discussion of the data input to the APR, MAP, RED, and OGP models for the two companion forecasts. This is followed by a detailed presentation of the two companion forecasts and a briefer discussion of the third sensitivity forecast. Next, there is a discussion of the many sensitivity tests performed to estimate the impact of various input assumptions on model output. Finally, there is a brief discussion of other load forecasts and their relationship to the Susitna project studies.

5.4.1 - Variables and Assumptions (**)

Many variables and assumptions are used in the APR, MAP, RED, and OGP models described in Section 5.3. Input variables for each of these models are discussed in the following paragraphs.

(a) APR Model (**)

State petroleum revenues from North Slope oil production are expected to account annually for between 93 and 99 percent of state petroleum royalties and production taxes during the period 1985 to 2012. Remaining royalties and production taxes will be generated by petroleum production on state lands in Cook Inlet and from production of natural gas on the North Slope and Cook Inlet. The input to the APR model is therefore focused primarily on North Slope oil, and secondarily on Cook Inlet oil, North Slope gas, and Cook Inlet gas.

As stated in Section 5.3, the input to the APR model is taken directly from the Alaska Department of Revenue's PETREV model except for two variables: world oil price and Cook Inlet gas price. Three forecasts of petroleum revenue have been prepared, each associated with a different world oil price forecast and its companion gas price forecast. The three oil price cases include forecasts made by Sherman H. Clark Associates (SHCA) and Wharton Econometrics, as well as a Composite case representing the average forecast of several public agencies and private forecasting organizations. This discussion focuses on the SHCA and Composite cases. All three oil price forecasts are shown on Table B.5.4.1 and in Figure B.5.4.1. A detailed discussion of the forecasts appears in Exhibit D, Appendix D1. Other input to the APR model for the SHCA and Composite cases are shown on Table B.5.4.2. Of the factors listed on Table B.5.4.2, North Slope petroleum production has the largest potential impact on state petroleum revenues. Projected North Slope petroleum production is the sum of projected production from several fields: Prudhoe Bay-Sadlerochit, Kuparuk, Milne Point, Endicott, Lisburne, West Sak Sands, Seal Island, and unspecified onshore fields. Currently only Prudhoe Bay-Sadlerochit and Kuparuk are producing fields. The other fields are projected to begin production between 1986 and 1997. The currently producing fields are projected to remain the main producers, accounting for 72 percent of total North Slope production in 2000 and 79 percent in 2010.

While production rates during the next eight to ten years can be forecasted with some degree of certainty, production rates after this period will depend on the rate of exploration and development of oil fields. Exploration rates will depend largely on the level of world petroleum prices and the demand for petroleum, but development of oil fields will depend on oil discoveries and production costs as well as petroleum prices and demand.

(b) MAP Model (*)

Table B.5.4.3 lists ten categories of exogenous or basic employment, one measure of tourism, five categories of petroleum revenues, and four national economic parameters that are used as input to the MAP model. These factors are the principal input variables and parameters to the MAP Model.

For the current studies, the values of all the variables listed in Table B.5.4.3 other than petroleum production tax and royalty revenues were left unchanged during each of the MAP model executions. Sensitivity tests indicated that varying the value of several of these factors produced demonstrable effects on economic projections. Based on results of sensitivity tests, the key input factors to the MAP model other than petroleum revenues are: state mining employment, which includes petroleum production; state active duty military employment; tourists visiting Alaska; U.S. real wage growth rate; and price level growth rate. Employment relating to construction of the Susitna Hydroelectric Project was not included in the analysis. Construction employment for electric power generating stations that would be required in the absence of the project is included in the larger category of construction employment.

Table B.5.4.4 summarizes the basis for selecting the values for the variables listed in Table B.5.4.3. The values for many of the variables listed have been developed from the MAP model Data Base (Goldsmith et al. 1985), a volume of economic and demographic data compiled and maintained by the Institute of Social and Economic Research. These data are derived from information collected by various state and federal governmental agencies, published reports, and other sources. The data are organized, adjusted, and in the case of some variables, projected to the year 2010 to meet the input requirements of the MAP model.

(c) RED Model (*)

Table B.5.4.5 lists the main variables that are used in each module of the RED model. In the Uncertainty module, the fuel price forecasts, the housing demand coefficients, the saturation of residential appliances, and the price adjustment coefficients are the main variables.

Tables B.5.4.6 and B.5.4.7 show the projected customer real prices of heating fuel oil, natural gas, and electricity for the SHCA and Composite cases, respectively. The heating fuel oil price forecast was derived from the 1983 actual price, escalated at the same growth rate as the world oil price in each case. The natural gas price forecast for the Anchorage-Cook Inlet area was derived from average price (old and new contracts) of natural gas. The new contract prices were estimated as a function of the world oil price. In the Fairbanks-Tanana Valley area, a continuation of the present practice of using propane for heating was assumed. The price escalates with world oil prices. Retail electricity prices were calculated as a function of the levelized production costs for each case. The production costs were estimated by earlier OGP results for the same cases. All fuel prices shown in Tables B.5.4.6 and B.5.4.7 are expressed in 1980 dollars, the base year used in the RED model.

Table B.5.4.8 presents the housing demand coefficients which were used in the housing demand equations for single family, multifamily, and mobile homes. Table B.5.4.9 gives an example of market saturations of appliances in single family homes for the Anchorage-Cook Inlet area, and Table B.5.4.10 presents the parameter values of the price adjustment mechanism.

For the Housing module, the two main variables are the regional household forecast, and the state households by age group. These variables are directly obtained from the MAP output file.

The main variables in the Residential module include households by dwelling type and various appliance characteristics. Tables B.5.4.11, B.5.4.12, and B.5.4.13 provide detailed information on the percent of appliances using electricity, the annual consumption and growth rate of residential appliances, as well as the survival rate of the existing and new appliances.

The main variables of the Business Consumption module are regional employment, which is an output of the MAP model, and the floorspace consumption parameters listed on Table B.5.4.14. Vacant housing, second homes and street lighting, and their expected annual consumption are the variables of the Miscellaneous module. The annual load factor for the two load centers are the main variables of the Peak Demand module.

Of the many variables included in the RED model, several can be identified as key variables. Because the RED model is an end-use model, the appliance saturation rate based on the existing stock of appliances is important. Also, the energy usage per appliance has a major effect on electricity demand. Further, the growth rate of consumption per appliance type has a significant impact on residential electricity consumption in future years. In the business sector, the projections of the demand for floorspace and the consumption per unit of floorspace are key variables. Own- and cross-price elasticities of demand have a significant impact on electricity consumption by influencing consumption behavior in both the short and long term. The own-price elasticity values that are assumed in the model determine the extent and time path of electricity price impacts on residential and commercial consumption. The cross-price elasticities show the impact on electricity consumption due to changes in the price of substitute energy resources for electricity. The own- and cross-price elasticities of demand are used to adjust electricity consumption for price-induced conservation of electrical energy. The last key factor is the regional peak load factor, which is applied to the energy demand forecast to forecast peak loads.

(d) OGP Model (o)

Table B.5.4.15 presents the main variables of the OGP model. The variables are: fuel costs and escalation rates, thermal and hydro plant construction costs, and the discount rate. A detailed presentation of these variables is given in Exhibit D and Exhibit D, Appendix D1.

5.4.2 - Load Forecasts (**)

A total of three load forecasts were made. Two are discussed here, while the third — a low bound sensitivity case -- is presented in Section 5.4.3. The two cases presented here are associated with the two petroleum price forecasts discussed earlier, i.e., the SHCA and composite cases.

As described in Section 5.4.1, the petroleum prices served as the basis for the state petroleum revenue forecasts, which in turn comprised one of the inputs to the MAP model. The MAP model produced economic projections which were then used by the RED model to forecast electric energy demands.

Tables B.5.4.16 and B.5.4.17 summarize the data for the SHCA and Composite cases, showing the oil price scenarios and a corresponding set of input and output prices of other forms of energy, revenues, population, and employment. Table B.5.4.16 shows that in the SHCA case, Railbelt population will grow approximately 33 percent between 1985 and 2010, reaching 506,384 by the year 2010. During this same period the Railbelt's electric energy demand is forecasted to rise from 3,323 to 4,929 gigawatt-hours, a 48 percent increase. Peak demand is projected to rise from 632 to 938 megawatts, a 48 percent increase during the 25 year period and an average annual growth rate of 1.6 percent. Similarly, Table B.5.4.17 indicates that under Composite case assumptions, Railbelt population would be expected to grow by 32 percent by the year 2010. During the same period, the Railbelt's electric energy demand would rise to 4888 gigawatt-hours, a 47 percent increase. Peak demand is projected to rise to 930 megawatts.

The following sections summarize the SHCA and Composite case forecasts of state petroleum revenues, fiscal and economic conditions, and electric energy demand. Detailed input and output values for both cases appear in Tables B.5.4.18 through B.5.4.43.

(a) State Petroleum Revenues (**)

Table B.5.4.18 presents SHCA case projections of state petroleum revenues from each of the primary revenue sources through the year 2010. The first two columns of this table contain projected royalties and severance, or production, taxes, respectively. These projections are in nominal dollars, reflecting an annual change in the consumer price index of 5.5 percent. The projections of royalties and severance taxes through the year 2010 were produced by the Department of Revenue's APR petroleum revenue forecasting model. The same revenue information for the Composite case appears on Table B.5.4.19.

Tables B.5.4.18 and B.5.4.19 also present projections of state petroleum revenues derived from corporate income taxes, property taxes, lease bonuses, and federal shared royalties. Forecasts of future revenues from these sources were used, along with the projections of royalties and severance taxes, as input to the MAP economic model.

In nominal terms, as indicated on Tables B.5.4.18 and B.5.4.19, petroleum revenue is expected to rise and fall in cycles over the forecast period. In real terms, however, petroleum revenue is expected to fall continuously after 1987. In the SHCA case, real petroleum revenue is forecast to decline by 71 percent between 1987 and 2010, while contributions to the general fund (net of permanent fund contributions) fall by 73 percent during the same period. In the Composite case, total petroleum revenue and contributions to the general fund are forecast to fall by 74 percent and 76 percent, respectively.

(b) Fiscal and Economic Conditions (**)

State petroleum revenues constitute a major, but declining, portion of the total funds available to the State of Alaska for expenditure on operations and capital investment, which in turn affects the general level of economic activity in the state. The impact on economic activity, however, is not directly proportional to the decline in petroleum revenue. Basic sector economic activity is expected to continue to expand as it has in the past. This growth will include—in varying degrees--all of Alaska's resources but would continue to be dominated by petroleum and mining. Federal civilian and tourism employment will grow; although military employment will continue its secular decline. Manufacturing employment will be minimal.

This continuing, but gradual, expansion of basic activities will be the growth trend underlying several indentifiable phases in the economy in future decades. Four periods can be characterized as pause, renewed growth, structural realignment, and the post-Prudhoe economy.

The economy is expected to enter a flat period in the immediate future as the economy adjusts to lower petroleum prices as well as the excess capacity produced during the rapid growth years of the early 1980s. The primary forces driving the economy—construction, state and local government, petroleum employment--will stop growing or contract, causing the economy to pause. This pause in new job creation will result in net out-migration which will slow, but not eliminate growth in population and households.

Toward the end of the decade, economic growth is expected to resume as oil prices begin to rise and petroleum and mining activity increase. Activity in the state and local government sectors will be augmented by new revenue measures, including reimposition of the income tax and transfer of Alaska Permanent Fund earnings to the General Fund for annual appropriations. These measures maintain the existing employment level in government but are not sufficient for expansion of government employment.

Toward the end of the century, the decline in petroleum revenues resulting from the depletion of the Prudhoe Bay field will become more pronounced, leading to a marked contraction in state and local government activity, which will continue through 2010. This is initially a period of slow growth, marked by a structural realignment of the economy as the public sector contracts absolutely as well as in percentage terms.

As this realignment continues, the economy eventually will enter what might be characterized as the post-Prudhoe Bay era. State and local governments are less dominant forces in the economy, and growth will be more closely related to private sector basic activities.

During this period, growth in population and the number of households will be primarily the result of natural increase. The annual addition of new jobs to the economy will be the growth in the labor supply resulting in net out-migration in many years. Because the average household size will continue its downward trend, the growth in the number of households will exceed that of population. The labor force participation rate will remain high so that the proportion of the population at work will stay relatively constant.

Table B.5.4.20 presents projections of several important components of the state's fiscal structure for the SHCA case, while Table B.5.4.21 presents the same information for the Composite case. These components include unrestricted general fund expenditures, the balance in the general fund, permanent fund dividends, state personal income tax revenues, level of outlays for subsidies, and the percentage of Permanent Fund earnings that are added to the general fund. Table B.5.4.20 shows that, based on the fiscal rules summarized in Section 5.3 above, dividends from the Permanent Fund continue to be disbursed through the year 1990 in the SHCA case, at which time the program is halted. A state personal income tax is reinstituted in the year 1992 in order to augment revenues. State subsidy programs are terminated after the year 1990, and reinvestment of Permanent Fund dividends ends after 1992. Table B.5.4.21 indicates that in the Composite case, maintenance of general fund expenditures requires the same actions, in the same years, as in the SHCA case.

However, while these fiscal measures are assumed to be implemented, petroleum revenues are projected to continue to provide a large share of state expenditures, accounting in the year 2010 for approximately 42 percent of total unrestricted general fund expenditures (those expenditures not funded by revenues dedicated to specific functions) in the SHCA case. Petroleum revenues constitute approximately 39 percent of unrestricted general fund expenditures in 2010 in the Composite case.

(i) Population (***)

Table B.5.4.22 presents SHCA case population projections for the state, Railbelt, Anchorage-Cook Inlet area, and Fairbanks-Tanana Valley area. The state population is forecast to increase by 30 percent. Railbelt population is projected to grow by approximately 33 percent between 1985, from 381,264 to 506,384. In the Railbelt, the Anchorage area is projected to grow by 34 percent, compared to the projected growth in Fairbanks of 27 percent. Table B.5.4.23 indicates that in the Composite case, growth rates would be 32, 34, and 26 percent in the Railbelt, Anchorage, and Fairbanks, respectively.

(ii) Employment (***)

The growth of employment in the SHCA case is shown on Table B.5.4.24. While statewide non-agriculture wage and salary employment is projected to grow by 33 percent during the next 25 years, total state employment is forecast to increase by only 29 percent. Again the Railbelt is projected to experience a higher employment increase, rising by 34 percent, with the Anchorage area growing by 35 percent compared to 29 percent growth in the Fairbanks area.

Table B.5.4.25. Total state employment is forecast to grow by 29 percent, while Railbelt growth is 33 percent over the same 25 year period. The Anchorage and Fairbanks areas are forecast to grow by 34 and 29 percent, respectively.

(iii) Households (***)

Table B.5.4.26 presents household projections for the SHCA case according to state total, the Railbelt, the Anchorage area, Fairbanks area, and statewide by age of head of household. Households are projected to increase faster than population. Statewide households are projected to increase by 37 percent by the year 2010, compared to a 39 percent increase in the Railbelt, a 40 percent rise in the Anchorage area, and a 34 percent increase in the Fairbanks area. Household growth in the Composite case is slightly lower than in the SHCA case, showing 36 percent growth in the state, 38 percent in the Railbelt, 40 percent in the Anchorage area, and 33 percent in the Fairbanks area. The figures are shown on Table B.5.4.27.

(c) Electric Power Demand (**)

(i) Households Served and Vacant Households (***)

The regional households projections obtained from the MAP model are used in the RED housing module to derive the number of households served by electric utilities and the number of vacant households. Tables B.5.4.28 and B.5.4.29 present the number of households served in the SHCA and Composite cases, respectively. Tables B.5.4.30 and B.5.4.31 present the number of vacant households by case. The residential module then computes the annual consumption per type of household based on the market saturation of appliances and the annual consumption per appliance.

(ii) Residential Electricity Use Per Household (***)

Table B.5.4.32 summarizes the average consumption per household before and after conservation adjustment and fuel substitution in the SHCA case. In the Anchorage area, the average consumption per household is expected to decrease from about 11,700 kWh in 1985 to 10,100 kWh in 2000, mainly due to the real increase of electricity price which will continue to cause some conversion from electric space heating to substitute fuels. After 2000, the consumption is expected to slowly increase to about 10,300 kWh in 2010, at an average annual growth rate of less than one percent. In the Fairbanks area, the average household consumption is expected to increase from 12,400 kWh in 1985 to 14,500 kWh in 2010, at an average annual growth rate of about one percent. This increase is due to the stabilization of electricity prices, while the prices of substitute fuels are increasing. The projected consumption per household in year 2000 is similar to the 1975 average consumption.

Table B.5.4.33 summarizes the average consumption per household in the Composite case. The use per household is essentially the same as for the SHCA case.

(iii) Business Use Per Employee (***)

The employment forecasts obtained from MAP are used in the RED Business Consumption module to derive the electric demand in the business (commercial-government-small industrial) sector. Table B.5.4.34 summarizes the business use per employee projections for the SHCA case. The consumption projections were obtained from a forecast of predicted floorspace per employee, and an econometrically derived electricity consumption per square foot, which is then adjusted for price effects. The floorspace per employee is expected to increase at the Anchorage historical rate until 2010, bringing square footage per employee close to the 1979 U.S. national average. As a result, in the Anchorage area, the average consumption per employee is expected to increase from about 8,700 kWh in 1980 to about 10,000 kWh in 2010, at an average annual rate of less than one percent. In the Fairbanks area, the consumption per employee is expected to increase from about 8,100 kWh in 1980 to 12,000 kWh in 2010, corresponding to an average annual growth rate of 1.3 percent.

As indicated in Table B.5.4.35, business electricity use per employee in the Composite case is expected to be similar.

Table B.5.4.36 provides a year by year projection of price-induced conservation and fuel switching for the two load centers in the SHCA case, while Table B.5.4.37 provides the same information for the Composite case. Tables B.5.4.38 and B.5.4.39 give a year by year breakdown of energy consumption projections for the residential, business (commercial-government-small industrial), miscellaneous, and large industrial sectors for the two load centers for the SHCA case. Tables B.5.4.40 and B.5.4.41 present the Composite case. The industrial sector includes projections of large industrial and military loads. Industrial loads were derived from estimates of industrial growth in the Kenai Peninsula. Military loads were derived from discussions with representatives at each military installation.

Finally, Tables B.5.4.42 and B.5.4.43 summarize the annual peak and energy demand projections for each load center and for the total system for the SHCA and Composite cases, respectively. In the SHCA case, the averge annual growth rate of electricity demand is expected to slowly decrease from about 1.5 percent during the period 1985-1990 to 0.6 percent during the period 1995-2000. After 2000, the demand is expected to increase at an average annual rate of 1.5 percent until 2005, and 2.7 percent for the period 2005-2010. In the Composite case, the rates of change are essentially the same.

5.4.3 - Forecast Comparison (***)

In addition to the SHCA and Composite cases, the Wharton case was carried through the MAP and RED models. The results are presented on Table B.5.4.44. Projections of population, households, energy demand, and peak demand are displayed in Figures B.5.4.2 through B.5.4.5 for all three cases.

As shown in Figure B.5.4.2, the Railbelt population is expected to increase from 381,300 in 1985 to 499,200 in the Wharton case and 506,400 in the SHCA case, for the year 2010. The corresponding number of households, shown in Figure B.5.4.3, would increase from 134,300 in 1985 to 184,000 or 187,000. Railbelt employment is expected to increase from 181,900 in 1985 to 240,300 under the Wharton case, and 243,200 in the SHCA case.

As shown on Figure B.5.4.4, the 2010 energy consumption would be between 4,900 and 5,100 GWh in all cases. The corresponding average annual growth rate over the period 1985-2010 would be approximately 1.7 percent. The peak demand shown in Figure

B.5.4.5, is expected to increase from 630 MW in 1985 to approximately 950 MW in 2010 in all three cases.

5.4.4 - Sensitivity Analysis (**)

Sensitivity analyses for a number of variables were conducted using the MAP, RED, and OGP models in order to determine the extent to which forecasts are affected by varying the values of selected input variables and parameters.

(a) MAP Model Sensitivity Tests (**)

The Susitna License Application as accepted by FERC in July 1983 (APA 1983) contained a summary of several MAP model sensitivity tests. At that time, input variables subjected to sensitivity testing included ten industrial development factors, tourism in Alaska, and four national economic variables, as well as a number of other parameters not reported in the License Application. The results indicated that of the variables tested, projections of households are most sensitive to mining employment, which includes petroleum production; military employment; tourism; growth in real wages; and growth in the consumer price index.

An additional set of tests was made during the autumn of 1984. The results of these tests are shown on Table B.5.4.45. The first three tests (TEST 0, 1, 2) investigated the effect of adding new and revised data such as updated population and wage and salary figures to the data base. Three tests (TESTS 3, 3S, 4) were undertaken to assess the sensitivity of model simulations to the econometric methods used to estimate the stochastic equation coefficients, and one test (TEST 5) redefined the form of the relationship between support industry gross product and income. Three tests (TEST 6, 6R, 6T) compared the effects of various petroleum corporate income tax levels, while one test (TEST 7) holds royalty, severance tax, and petroleum corporate income taxes constant. One test (TEST 8) assumes very high levels of petroleum revenues and petroleum employment. One test (TEST 9) determines the gross effect of Susitna construction on the state economy (without netting out the displaced economic activity associated with meeting Railbelt power demands by some other means).

Additionally, three tests (CTST 10A, 10B, 10D) gauged simulation sensitivity to varying certain state government policies, such as increasing the return on the Permanent Fund balance from 3 to 4 percent, combining no reintroduction of the income tax with perpetuation of the permanent fund dividend, and permanent elimination of the income tax alone.

One test (CTST 11) examined the combined effects on households of a decline in the labor force participation rate and a related change in average household size. Finally, four tests (TEST 9.82, 9.81, 9.80, 9.79) were made to determine how sensitive the support sector equations are to the extension of data series to termination points in 1982, 1981, 1980, and 1979.

The results indicate that the forecast of households is most sensitive to 1) high exogenous estimates of petroleum-related employment, and 2) a declining labor force participation rate accompanied by a declining average household size. The latter effect is large because changes in labor force participation are usually correlated with changes in household size, creating more households in a given population.

(b) RED Model Sensitivity Tests (**)

Sensitivity analyses were conducted for key variables, using the data files from the Uncertainty Module. These variables include (1) appliance saturations, (2) business consumption and the trend in square feet of business floorspace per employee, (3) own price elasticity, (4) cross price elasticity, (5) the lagged adjustment factor, and (6) load factors. The sensitivity analyses were carried out for the SHCA Case. The results are shown on Tables B.5.4.45 through B.5.4.49. Although these sensitivity tests were based on earlier RED Model runs using prices that are slightly different, the results are similar to the current cases.

Table B.5.4.45 summarizes the results obtained when appliance saturations were allowed to vary. Table B.5.4.9 presents a typical example of market saturation ranges which were used as input into the Uncertainty Module. The saturations were allowed to vary over their entire range (in some instances, ± 10 percent). As shown on Table B.5.4.45, the results on the overall energy demand are within 1 percent of the test case values.

The sensitivity analysis of the Business Sector was done by allowing the consumption rate parameter to vary within a range approximately corresponding to a 95 percent confidence interval. This resulted in a range of values within ± 20 percent of the mean value for the Anchorage-Cook Inlet area. As shown on Table B.5.4.46, the effects on the overall energy demand are within 20 percent of the test case values. Because of the lack of detailed historical data for the Fairbanks area, the range of the consumption parameter value was set by assumption and the results of the Monte Carlo test reflect this assumption.

Tables B.5.4.47 and B.5.4.48 present the results of the own-price and cross-price elasticities variations. The values of the parameters were allowed to vary within an assumed range of minus 16 percent to plus 40 percent for own price elasticity, plus or minus 100 percent for oil price elasticity, and plus or minus 40 percent for gas price elasticity. This roughly corresponds to a 95 percent confidence interval. The effects on the overall energy demand are within plus 5 percent to minus 20 percent of the test case values.

Finally, a sensitivity analysis was done for the peak demand, using the range of the annual load factors of the two load centers for the period 1970-1982. The results are presented in Table B.5.4.49. For the year 2010, the peak residential plus commercial demand would vary between 925 and 1187 MW, with a test case value of 1030 MW. No range has been specified for industrial demand; however, the total 2010 demand levels that would be forecast with 75 percent and 25 percent confidence are 1032 MW and 1212 MW, respectively, compared to the reference value of 1085.

(c) OGP Model Sensitivity Tests (**)

Sensitivity tests were also conducted for the OGP Model. The key variables other than petroleum price which were tested are base fuel price, discount rate, Watana construction cost, real coal price escalation and natural gas availability. The sensitivity analyses are described in Exhibit D.

5.4.5 - Comparison with Previous Forecasts (**)

Previous power demand forecasts have been used in earlier stages of the Susitna Hydroelectric Project studies. In 1980, the Institute for Social and Economic Research (ISER) prepared economic and accompanying end-use electric energy demand projections for the Railbelt. These forecasts were used in several portions of the feasibility study, including the development selection study. The forecast is shown on Table B.5.4.50.

In 1981 and 1982, Battelle Pacific Northwest Laboratories produced a series of load forecasts for the Railbelt. These forecasts were developed as a part of the Railbelt Alternatives

Study completed by Battelle under contract to the State of Alaska. Battelle's forecasts were based on updated economic projections prepared by ISER and some revised end-use models developed by Battelle which took into account price sensitivity and several other factors not included in the 1980 projections. The December 1981 Battelle forecast used in the optimization studies for the Watana and Devil Canyon developments is shown on Table B.5.4.50.

Another series of load forecasts was made to support the Susitna License Application as accepted by FERC in 1983 (APA 1983). The reference case forecast is shown on Table B.5.4.50. The reference case and other forecasts were made following the same procedures described in Section 5.3. They reflect an ongoing process of model refinement, plus the updating of underlying economic assumptions.

In addition to the forecasts made for the purpose of planning the Susitna Hydroelectric Project, the Railbelt utilities annually produce forecasts for their own respective markets. The sum of the current Railbelt utility forecasts is shown on Table B.5.4.50.

Table B.5.4.50 provides a summary comparison of these previous power market forecasts. While these forecasts are not precisely consistent in the definitions of the market area or in the assumptions relating to the current reference case, the comparison does provide an insight into the change in perception of future growth rates during the time that the various sets of forecasts were developed.

5.4.6 - Impact of Oil Prices on Forecasts (**)

The world price of oil is a significant factor in the Alaskan economy. As a consequence, world oil prices influence the demand for electric energy and other forms of energy. Although oil prices are important, there are many other economic, social, and political factors which affect future Alaskan economic trends and energy requirements.

Among the factors which mitigate the impact of declining oil prices on the level of economic activity in Alaska are the following:

- o Other basic industries, unrelated to petroleum, exist independent of the oil industry in Alaska and will continue to do so.

- o The presence of the petroleum industry in Alaska has already transformed the Alaska economy, creating an infrastructure and a degree of economic maturity that would not be undone if the oil industry declines in importance.

- The current level of petroleum producing activity in the state is relatively insensitive to oil price changes within a wide range, because continued operation of existing fields requires only sufficient revenue to cover low field operating costs. (Lower petroleum prices do, however, have a more dramatic impact on exploration and development of new fields).

- Diversion of a portion of past petroleum revenue into the State's Permanent Fund, plus reinvestment of Permanent Fund interest, has provided the state with a cushion against falling petroleum revenues in the future. Interest on the Permanent Fund could be channeled into the General Fund (as is assumed in the MAP model) to help maintain the level of operating and capital expenditures.

The impact of world oil prices on future economic conditions and electric energy and peak demands can therefore best be understood by reviewing the load forecasting procedure. First, a number of world oil price scenarios were used in the APR Model to generate various petroleum revenue projections. Because royalties and severance taxes are sensitive to changes in world oil prices, different petroleum revenue projections were obtained. Next, the projected petroleum revenues along with specified economic development assumptions and other variables were employed in the MAP Model to project economic factors such as households, state government expenditures, and employment. These economic factors were influenced by the various oil price growth rate assumptions, but were also influenced by other economic factors which tend to mitigate the impact of petroleum revenues alone. Finally, electric demand forecasts were produced using the RED Model. The RED Model employed the output of the MAP Model as well as other assumptions and input data. The fuel price data used in the RED Model for electricity, natural gas, and heating oil are affected by the growth rates assumed for world oil prices. An electric demand forecast was made for each world oil price scenario. This procedure resulted in the production of electric demand forecasts which incorporated all direct and indirect effects of a given timepath of world oil prices on electric demand in the Railbelt in a comprehensive and consistent manner. The range of electric demand forecasts reflects the overall impact of world oil prices as well as other key variables included in the separate models.

6 - FUTURE SUSITNA BASIN DEVELOPMENT (*)

Development of the proposed Susitna Hydroelectric Project would preclude further major hydroelectric development in the Susitna basin, with the exception of major storage projects in the Susitna basin headwaters. Although these types of plans have been considered in the past, they are neither active nor anticipated to be so in the foreseeable future.

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TABLES

TABLE B.1.3.1: POTENTIAL HYDROELECTRIC DEVELOPMENT

Site	Dam Proposed Type	Dam Height Ft.	Upstream Regulation	Capital Cost $ million (1980)	Installed Capacity (MW)	Average Annual Energy GWh	Economic[1] Cost of Energy $/1000 kWh (1980)	Source of Data
Gold Creek[2]	Fill	190	Yes	900	260	1,140	37	USBR 1953
Olson[2] (Susitna II)	Concrete	160	Yes	600	200	915	31	USBR 1953 KAISER 1974 COE 1975
Devil Canyon	Concrete	675	No Yes	830 1,000	250 600	1,420 2,980	27 17	This Study "
High Devil Canyon (Susitna I)	Fill	855	No	1,500	800	3,540	21	" "
Devil Creek[2]	Fill	Approx 850	No	-	-	-	-	-
Watana	Fill	880	No	1,860	800	3,250	28	"
Susitna III	Fill	670	No	1,390	350	1,580	41	"
Vee	Fill	610	No	1,060	400	1,370	37	"
Maclaren	Fill	185	No	530[4]	55	180	124	"
Denali	Fill	230	No	480[4]	60	245	81	"
Butte Creek[2]	Fill	Approx 150	No	-	40	130[3]	-	USBR 1953
Tyone[2]	Fill	Approx 60	No	-	6	22[3]	-	USBR 1953

1/ Includes AFDC, Insurance, Amortization, and Operation and Maintenance Costs.
2/ No detailed engineering or energy studies undertaken as part of this study.
3/ These are approximate estimates and serve only to represent the potential of these two damsites in perspective.
4/ Include estimated costs of power generation facility.

TABLE B.1.3.2: COST COMPARISONS

DAM		Capital Cost Estimate[2] (1980 $)				
		ACRES 1980		OTHERS		
Site	Type	Installed Capacity - MW	Capital Cost $ million	Installed Capacity - MW	Capital Cost $ million	Source and Date of Data
Gold Creek	Fill	-	-	260[1]	890	USRB 1968
Olson (Susitna II)	Concrete	-	-	190[1]	550	COE 1975
Devil Canyon	Fill	600	1,000	-	-	-
	Concrete Arch	-	-	776	630	COE 1975
	Concrete Gravity	-	-	776	910	COE 1978
High Devil Canyon (Susitna I)	Fill	800	1,500	700	1,480	COE 1975
Devil Creek	Fill	-	-	-	-	-
Watana	Fill	800	1,860	792	1,630	COE 1978
Susitna III	Fill	350	1,390	445	-	KAISER 1974
Vee	Fill	400	1,060	-	770	COE 1975
Maclaren	Fill	55	530	-		-
Denali	Fill	60	480	None	500	COE 1975

1/ Dependable Capacity

2/ Excluding Anchorage/Fairbanks transmission intertie, but including local access and transmission.

TABLE B.1.3.3: DAM CREST AND FULL SUPPLY LEVELS

Site	Staged Dam Construction	Full Supply Level - Ft.	Dam Crest Level - Ft.	Average Tailwater Level - ft.	Dam Height[1/] ft.
Gold Creek	No	870	880	680	290
Olson	No	1,020	1,030	810	310
Portage Creek	No	1,020	1,030	870	250
Devil Canyon - intermediate height	No	1,250	1,270	890	465
Devil Canyon - full height	No	1,450	1,470	890	675
High Devil Canyon	No	1,610	1,630	1,030	710
	No	1,750	1,775	1,030	855
Watana	Yes	2,000	2,060	1,465	680
	Stage 2	2,200	2,225	1,465	880
Susitna III	No	2,340	2,360	1,810	670
Vee	No	2,330	2,350	1,925	610
Maclaren	No	2,395	2,405	2,300	185
Denali	No	2,540	2,555	2,405	230

1/ To foundation level

TABLE B.1.4.1: CAPITAL COST ESTIMATE SUMMARIES SUSITNA BASIN DAM SCHEMES
(COST IN $MILLION 1980)

Item	Devil Canyon 1470 ft Crest 600 MW	High Devil Canyon 1775 ft Crest 800 MW	Watana 2225 ft Crest 800 MW	Susitna III 2360 ft Crest 330 MW	Vee 2350 ft Crest 400 MW	Maclaren 2405 ft Crest No power	Denali 2250 ft Crest No power
1) Lands, Damages & Reservoirs	26	11	46	13	22	25	38
2) Diversion Works	50	48	71	88	37	118	112
3) Main Dam	166	432	536	398	183	106	100
4) Auxiliary Dam	0	0	0	0	40	0	0
5) Power System	195	232	244	140	175	0	0
6) Spillway System	130	141	165	121	74	0	0
7) Roads and Bridges	45	68	96	70	80	57	14
8) Transmission Line	10	10	26	40	49	0	0
9) Camp Facilities and Support	97	140	160	130	100	53	50
10) Miscellaneous[1/]	8	8	8	8	8	5	5
11) Mobilization and Preparation	30	47	57	45	35	15	14
Subtotal	757	1137	1409	1053	803	379	333
Contingency (20%)	152	227	282	211	161	76	67
Engineering and Owner's Administration (12%)	91	136	169	126	96	45	40
TOTAL	1000	1500	1860	1390	1060	500	440

1/ Includes recreational facilities, buildings and grounds and permanent operating equipment.

TABLE B.1.4.2: RESULTS OF SCREENING MODEL

	Total Demand		Optimal Solution				First Suboptimal Solution				Second Suboptimal Soultion			
Run	Cap. MW	Energy GWh	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $ million	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $ million	Site Names	Max. Water Level	Inst. Cap. MW	Total Cost $ million
1	400	1750	High Devil Canyon	1580	400	885	Devil Canyon	1450	400	970	Watana	1950	400	980
2	800	3500	High Devil Canyon	1750	800	1500	Watana	1900	450	1130	Watana	2200	800	1860
							Devil Canyon	1250	350	710				
							TOTAL		800	1840				
3	1200	5250	Watana	2110	700	1690	High Devil Canyon	1750	800	1500	High Devil Canyon	1750	820	1500
			Devil Canyon	1350	500	800	Vee	2350	400	1060	Susitna III	2300	380	1260
			TOTAL		1200	2490	TOTAL		1200	2560	TOTAL		1200	2760
4	1400	6150	Watana	2150	740	1770	NO SOLUTION				NO SOLUTION			
			Devil Canyon	1450	660	1000								
			TOTAL		1400	2770								

TABLE B.1.4.3: INFORMATION ON THE DEVIL CANYON DAM AND TUNNEL SCHEMES

Item	Devil Canyon Dam	Tunnel Scheme 1	Tunnel Scheme 2	Tunnel Scheme 3	Tunnel Scheme 4
Reservoir Area (Acres)	7,500	320	0	3,900	0
River Miles Flooded	31.6	2.0	0	15.8	0
Tunnel Length (Miles)	0	27	29	13.5	29
Tunnel Volume (1000 Yd^3)	0	11,976	12,863	3,732	5,131
Compensating Flow Release (cfs)	0	1,000	1,000	1,000	1,000
Reservoir Volume (1000 Acre-feet)	1,100	9.5	--	350	--
Dam Height (feet)	625	75	--	245	--
Typical Daily Range of Discharge from Devil Canyon Powerhouse (cfs)	6,000 to 13,000	4,000 to 14,000	4,000 to 14,000	8,300 to 8,900	3,900 to 4,200
Approximate maximum daily fluctuations in Reservoir (feet)	2	15	--	4	--

TABLE B.1.4.4: DEVIL CANYON TUNNEL SCHEMES COSTS, POWER OUTPUT AND AVERAGE ANNUAL ENERGY

Stage	Installed Capacity (MW) Watana	Installed Capacity (MW) Devil Canyon Tunnel	Increase 1/ in Installed Capacity (MW)	Devil Canyon Average Annual Energy (GWh)	Increase 1/ in Average Annual Energy (GWh)	Tunnel Scheme Total Project Costs $ Million	Cost 3/ of Additional Energy 1 (mills/kWh)
STAGE 1:							
Watana Dam	800	---	---	---	---	---	---
STAGE 2:							
Tunnel:							
- Scheme 1	800	550	550	2,050	2,050	1980	42.6
- Scheme 2	70	1,150	420	4,750	1,900	2320	52.9
- Scheme 3 2/	850	330	380	2,240	2,180	1220	24.9
- Scheme 4	800	365	365	2,490	890	1490	73.6

1/ Increase over single Watana, 800 MW development 3250 GWh/yr
2/ Includes power and energy produced at re-regulation dam
3/ Energy cost is based on an economic analysis (i.e. using 3 percent interest rate)

TABLE B.1.4.5: CAPITAL COST ESTIMATE SUMMARIES TUNNEL SCHEMES
COSTS IN $MILLION 1980

Item		Two 30 ft dia tunnels		One 40 ft dia tunnel
Land and damages, reservoir clearing		14		14
Diversion works		35		35
Re-regulation dam		102		102
Power system		680		576
(a) Main tunnels	557		453	
(b) Intake, powerhouse, tailrace and switchyard	123		123	
Secondary power station		21		21
Spillway system		42		42
Roads and bridges		42		42
Transmission lines		15		15
Camp facilities and support		131		117
Miscellaneous		8		8
Mobilization and preparation		47		47
TOTAL CONSTRUCTION COST		1,137		1,015
Contingencies (20%)		227		203
Engineering, and Owner's Administration		136		122
TOTAL PROJECT COST		1,500		1,340

TABLE B.1.4.6: SUSITNA DEVELOPMENT PLANS

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

TABLE B.1.4.6 (Page 2 of 3)

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

TABLE B.1.4.6 (Page 3 of 3)

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

1_/ Allowing for a 3 year overlap construction period between major dams.

2_/ Plan 1.2 Stage 3 is less expensive than Plan 1.3 Stage 2 due to lower mobilization costs.

3_/ Assumes FERC license can be filed by June 1984, ie. 2 years later than for the Watana/Devil Canyon Plan 1.

TABLE B.1.5.1: SUSITNA ENVIRONMENTAL DEVELOPMENT PLANS (Page 1 of 3)

				Stage/Incremental Data			Cumulative System Data		
Plan	Stage	Construction	Capital Cost $ Millions (1980 values)	Earliest On-line Date1/	Reservoir Full Supply Level - ft.	Maximum Seasonal Draw-down-ft	Annual Energy Production Firm GWh	Avg. GWh	Plant Factor %
El.1	1	Watana 2225 ft 800MW and Re-Regulation Dam	1960	1993	2200	150	2670	3250	46
	2	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2860						
El.2	1	Watana 2060 ft 400MW	1570	1992	2000	100	1710	2110	60
	2	Watana raise to 2225 ft	360	1995	2200	150	2670	2990	85
	3	Watana add 400MW capacity and Re-Regulation Dam	230 2/	1995	2200	150	2670	3250	46
	4	Devil Canyon 1470 ft 400MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	3060						
El.3	1	Watana 2225 ft 400MW	1740	1993	2200	150	2670	2990	85
	2	Watana add 400MW capacity and Re-Regulation Dam	250	1993	2200	150	2670	3250	46
	3	Devil Canyon 1470 ft 400 MW	900	1996	1450	100	5520	6070	58
		TOTAL SYSTEM 1200MW	2890						

TABLE B.1.5.1 (Page 2 of 3)

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

TABLE B.1.5.1 (Page 3 of 3)

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

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

TABLE B.1.5.2: RESULTS OF ECONOMIC ANALYSES OF SUSITNA PLANS - MEDIUM LOAD FORECAST

Susitna Development Plan Inc.	On-line Dates Stages					Installed Capacity (MW) by Category in 2010					Total System Installed Capacity In	Total System Present Worth Cost	Remarks Pertaining to the Susitna Basin Development Plan
						Thermal			Hydro				
Plan No.	1	2	3	4	OGP5 Run Id. No.	Coal	Gas	Oil	Other	Susitna	2010-MW	$ Million 1/	
E1.1	1993	2000	--	--	LXE7	300	426	0	144	1200	2070	5850	
E1.2	1992	1995	1997	2002	L5Y9	200	501	0	144	1200	2045	6030	
E1.3	1993	1996	2000	--	L8J9	300	426	0	144	1200	2070	5850	
	1993	1996	--	--	L7W7	500	651	0	144	800	2095	6960	Stage 3, Devil Canyon Dam not constructed
	1998	2001	2005	--	LAD7	400	276	30	144	1200	2050	6070	Delayed implementation schedule
E1.4	1993	2000	--	--	LCK5	200	726	50	144	800	1920	5890	Total development limited to 800 MW
Modified E2.1	1994	2000	--	--	LB25	400	651	60	144	800	2055	6620	High Devil Canyon limited to 400 MW
E2.3 1/	1993	1996	2000	--	L601	300	651	20	144	1200	2315	6370	
	1993	1996	--	--	LE07	500	651	30	144	800	2125	6720	Stage 3, Vee Dam, not constructed
Modified E2.3	1993	1996	2000		LEB3	300	726	220	144	1300	2690	6210	Vee Dam replaced by Chakachamna Dam
3.1	1993	1996	2000	--	L607	200	651	30	144	1180	2205	6530	
Special 3.1	1993	1996	2000	--	L615	200	651	30	144	1180	2205	6230	Capital cost of tunnel reduced by 50 percent
E4.1	1995	1996	1998	--	LTZ5	200	576	30	144	1200	2150	6050	Stage 4 not constructed

1/ Adjusted to incorporate cost of re-regulation dam

TABLE B.1.5.3: RESULTS OF ECONOMIC ANALYSES OF SUSITNA PLANS - LOW AND HIGH LOAD FORECAST

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

Note: Incorporating load management and conservation

TABLE B.1.5.4: ANNUAL FIXED CARRYING CHARGES

Project Type	Economic Life - Years	Economic Parameters: Cost of Money %	Amortization %	Insurance %
Thermal - Gas Turbine (Oil Fired)	20	3.00	3.72	0.25
- Diesel, Gas Turbine (Gas Fired) and Large Steam Turbine	30	3.00	2.10	0.25
- Small Steam Turbine	35	3.00	1.65	0.25
Hydropower	50	3.00	0.89	0.10

FUEL COSTS AND ESCALATION RATES

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

TABLE B.1.5.5: SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS

Parameter	PLANT TYPE					
	COAL-FIRED STEAM			COMBINED CYCLE	GAS TURBINE	DIESEL
	500 MW	250 MW	100 MW	250 MW	75 MW	10 MW
Heat Rate (Btu/kWh)	10,500	10,500	10,500	8,500	12,000	11,500
<u>O&M Costs</u>						
Fixed O&M ($/yr/kW)	0.50	1.05	1.30	2.75	2.75	0.50
Variable O&M ($/MWh)	1.40	1.80	2.20	0.30	0.30	5.00
<u>Outages</u>						
Planned Outages (%)	11	11	11	14	11	1
Forced Outages (%)	5	5	5	6	3.8	5
Construction Period (yrs)	6	6	5	3	2	1
Start-up Time (yrs)	6	6	6	4	4	1
<u>Total Capital Cost</u> ($ million)						
Railbelt:	-	-	-	175	26	7.7
Beluga:	1,130	630	290	-	-	-
<u>Unit Capital Cost ($/kW)1/</u>						
Railbelt:	-	-	-	728	250	778
Beluga:	2,473	2,744	3,102	-	-	-

1/ Including AFDC at 0 percent escalation and 3 percent interest.

TABLE B.1.5.6: ECONOMIC BACKUP DATA FOR EVALUATION OF PLANS

Parameter	Total Present Worth Cost for 1981 - 2040 Period $ Million (% Total) Generation Plan With High Devil Canyon - Vee	Generation Plan With Watana - Devil Canyon Dam	Generation Plan With Watana - Tunnel	All Thermal Generation Plans
Capital Investment	2800 (44)	2740 (47)	3170 (49)	2520 (31)
Fuel	3220 (50)	2780 (47)	3020 (46)	5240 (64)
Operation and Maintenance	350 (6)	330 (6)	340 (5)	370 (5)
TOTAL:	6370 (100)	5850 (100)	6530 (100)	8130 (100)

TABLE B.1.5.7: ECONOMIC EVALUATION OF DEVIL CANYON DAM AND TUNNEL SCHEMES AND WATANA/DEVIL CANYON AND HIGH DEVIL CANYON/VEE PLANS

		Present Worth of Net Benefit ($ million) of Total Generation System Costs for the: Devil Canyon Dam over the Tunnel Scheme	Watana/Devil Canyon Dams over the High Devil Canyon/Vee Dams	Remarks
ECONOMIC EVALUATION:				
- Base Case		680	520	Economic ranking: Devil Canyon Dam scheme is superior to tunnel scheme. Watana/Devil Canyon Dam plan is superior to the High Devil Canyon Dam/Vee Dam plan.
SENSITIVITY ANALYSES:				
- Load Growth	Low	650	210	The net benefit of the Watana/Devil Canyon plan remains positive for the range of load forecasts considered. No change in ranking.
	High	N.A.	1040	
- Capital Cost Estimate		Higher uncertainty associated with tunnel scheme.	Higher uncertainty associated with H.D.C./Vee plan.	Higher cost uncertainties associated with higher cost schemes/plans. Cost uncertainty therefore does not affect economic ranking.
- Period of Economic Analysis	Period shortened to (1980 - 2010)	230	160	Shorter period of evaluation decreases economic differences. Ranking remains unchanged.
- Discount Rate	5% 8% (interpolated) 9%			
- Fuel Cost	80% basic fuel cost	As both the capital and fuel costs associated with the tunnel scheme and H.D.C./Vee Plan are higher than for Watana/Devil Canyon plan any changes to these parameters cannot reduce the Devil Canyon or Watana/Devil Canyon net benefit to below zero.		Ranking remains unchanged.
- Fuel Cost Escalation	0% fuel escalation 0% coal escalation			
- Economic Thermal Plant Life	50% extension 0% extension			

TABLE B.1.5.8: ENVIRONMENTAL EVALUATION OF DEVIL CANYON DAM AND TUNNEL SCHEME (Page 1 of 2)

Environmental Attribute	Concerns	Appraisal (Differences in impact of two schemes)	Identification of difference	Appraisal Judgment	Scheme judged to have the least potential impact: Tunnel	DC
Ecological:						
- Downstream Fisheries and Wildlife	Effects resulting from changes in water quantity and quality.	No significant difference between schemes regarding effects downstream of Devil Canyon.	------	Not a factor in evaluation of scheme.		
		Difference in reach between Devil Canyon dam and tunnel re-regulation dam.	With the tunnel scheme controlled flows between regulation dam and downstream powerhouse offers potential for anadromous fisheries enhancement in this 11 mile reach of the river.	If fisheries enhancement opportunity can be realized the tunnel scheme offers a positive mitigation measures not available with the Devil Canyon Dam scheme. This opportunity is considered moderate and favors the tunnel scheme. However, there are no current plans for such enhancement and feasibility is uncertain. Potential value is therefore not significant relative to additional cost of tunnel.	X	
Resident Fisheries:	Loss of resident fisheries habitat.	Minimal differences between schemes.	Devil Canyon Dam would inundate 27 miles of the Susitna River and approx. 2 miles of Devil Creek. The tunnel scheme would inundate 16 miles of the Susitna River.	Loss of habitat with dam scheme is less than 5% of total for Susitna mainstem. This reach of river is therefore not considered to be highly significant for resident fisheries and thus the difference between the schemes is minor and favors the tunnel scheme.	X	
Wildlife:	Loss of wildlife habitat.	Minimal differences between schemes.	The most sensitive wildlife habitat in this reach is upstream of the tunnel re-regulation dam where there is no significant difference between the scheme. The Devil Canyon Dam scheme in addition inundates the river valley between the two damsites resulting in a moderate increase in impacts to wildlife.	Moderate wildlife populations of moose, black bear, weasel, fox, wolverine, other small mammals and songbirds and some riparian cliff habitat for ravens and raptors, in 11 miles of river, would be lost with the dam scheme. Thus, the difference in loss of wildlife habitat is considered moderate and favors the tunnel scheme.	X	

TABLE B.1.5.8: (Page 2 of 2)

Environmental Attribute	Concerns	Appraisal (Differences in impact of two schemes)	Identification of difference	Appraisal Judgment	Scheme udged to have the least potential impact: Tunnel	Scheme udged to have the least potential impact: DC
Cultural:	Inundation of archeological sites.	Potential differences between schemes.	Due to the larger area inundated the probability of inundating archeological sites is increased.	Significant archeological sites, if identified, can probably be excavated. Additional costs could range from several hundreds to hundreds of thousands of dollars, but are still considerably less than the additional cost of the tunnel scheme. This concern is not considered a factor in scheme evaluation.	-	-
Land Use:	Inundation of Devil Canyon.	Significant difference Between schemes.	The Devil Canyon is considered a unique resource, 80 percent of which would be inundated by the Devil Canyon Dam scheme. This would result in a loss of both an aesthetic value plus the optential for white water recreation.	The aesthetic and to some extent the recreational losses associated with the development of the Devil Canyon Dam is the main aspect favoring the tunnel scheme. However, current recreational uses of Devil Canyon are low due to limited access. Future possibilities include major recrational development with construction of restaurants, marinas, etc. Under such conditions, neither scheme would be more favorable.	X	

OVERALL EVALUATION: The tunnel scheme has overall a lower impact on the environment.

TABLE B.1.5.9: SOCIAL EVALUATION OF SUSITNA BASIN DEVELOPMENT SCHEMES/PLANS

Social Aspect	Parameter	Tunnel Scheme	Devil Canyon Dam Scheme	High Devil Canyon/ Vee Plan	Watana/Devil Canyon Plan	Remarks
Potential non-renewable resource displacement	Million tons Beluga coal over 50 years	80	110	170	210	Devil Canyon Dam scheme potential higher than tunnel scheme. Watana/ Devil Canyon plan higher than High Devil Canyon/ Vee plan.
Impact state economy	--	All projects would have similar impacts on the state and local economy.				Essentially no difference between plans/schemes.
Impact on local economy	--	All projects would have similar impacts on the state and local economy.				
Seismic exposure	Risk of major structural failure	All projects designed to similar levels of safety.				
	Potential impact of failure on human life.	Any dam failures would effect the same downstream population.				
Overall Evaluation	1. Devil Canyon Dam superior to tunnel. 2. Watana/Devil Canyon superior to High Devil Canyon/Vee plan.					

TABLE B.1.5.10: ENERGY CONTRIBUTION EVALUATION OF THE DEVIL CANYON DAM AND TUNNEL SCHEMES

Parameter	Dam	Tunnel	Remarks
Total Energy Production Capability			
Annual Average Energy GWh	2850	2240	Devil Canyon dam annually develops 610 GWh and 540 GWh more average and firm energy respectively than the tunnel scheme.
Firm Annual Energy GWh	2590	2050	
% Basin Potential Developed[1/]	43	32	Devil Canyon scheme develops more of the basin potential.
Energy Potential Not Developed GWh	60	380	As currently envisaged, the Devil Canyon Dam does not develop 15 ft gross head between the Watana site and the Devil Canyon reservoir. The tunnel scheme incorporates additional friction losses in tunnels. Also the compensation flow released from re-regulation dam is not used in conjunction with head between re-regulation dam and Devil Canyon.

1/ Based on annual average energy. Full potential based on USBR four dam scheme.

TABLE B.1.5.11: OVERALL EVALUATION OF TUNNEL SCHEME AND DEVIL CANYON DAM SCHEME

ATTRIBUTE	SUPERIOR PLAN
Economic	Devil Canyon Dam
Energy Contribution	Devil Canyon Dam
Environmental	Tunnel
Social	Devil Canyon Dam (Marginal)
Overall Evaluation	Devil Canyon Dam scheme is superior <u>Tradeoffs made:</u> Economic advantage of dam scheme is judged to outweigh the reduced environmental impact associated with the tunnel scheme.

TABLE B.1.5.12: ENVIRONMENTAL EVALUATION OF WATANA/DEVIL CANYON AND HIGH DEVIL CANYON/VEE DEVELOPMENT PLANS (Page 1 of 2)

Environmental Attribute	Plan Comparison	Appraisal Judgment	Plan judged to have the least potential impact HDC/V	W/DC
Ecological:				
1) Fisheries	No significant difference in effects on downstream anadromous fisheries. HDC/V would inundate approximately 95 miles of the Susitna River and 28 miles of tributary streams, including the Tyone River. W/DC would inundate approximately 84 miles of the Susitna River and 24 miles of tributary streams, including Watana Creek.	Due to the avoidance of the Tyone River, lesser inundation of resident fisheries habitat and no significant difference in the effects on anadromous fisheries, the W/DC plan is judged to have less impact.		X
2) Wildlife a) Moose	HDC/V would inundate 123 miles of critical winter river bottom habitat. W/DC would inundate 108 miles of this river bottom habitat. HDC/V would inundate a large area upstream of Vee utilized by three sub-populations of moose that range in the northeast section of the basin. W/DC would inundate the Watana Creek area utilized by moose. The condition of this sub-population of moose and the quality of the habitat they are using appears to be decreasing.	Due to the lower potential for direct impact on moose populations within the Susitna, the W/DC plan is judged superior.		X
b) Caribou	The increased length of river flooded, especially upstream from the Vee damsite, would result in the HDC/V plan creating a greater potential division of the Nelchina herd's range. In addition, an increase in range would be directly inundated by the Vee reservoir.	Due to the potential for a greater impact on the Nelchina caribou herd, the HDC/V scheme is considered inferior.		X
c) Furbearers	The area flooded by the Vee reservoir is considered important to some key furbearers, particularly red fox. This area is judged to be more important than the Watana Creek area that would be inundated by the W/DC plan.	Due to the lesser potential for impact on furbearers the W/DC is judged to be superior.		X
d) Birds & Bears	Forest habitat, important for birds and black bears, exist along the valley slopes. The loss of this habitat would be greater with the W/DC plan.	The HDC/V plan is judged superior.	X	
Cultural:	There is a high potential for discovery of archeological sites in the easterly region of the upper Susitna basin. The HDC/V plan has a greater potential of affecting these sites. For other reaches of the river the difference between plans is considered minimal.	The W/DC plan is judged to have a lower potential effect on archeological sites.		X

TABLE B.1.5.12 (Page 2 of 2)

Environmental Attribute	Plan Comparison	Appraisal Judgment	Plan judged to have the least potential impact: HDC/V	W/DC
Aesthetic/ Land Use				
	With either scheme, the aesthetic quality of both Devil Canyon and Vee Canyon would be impaired. The HDC/V plan would also inundate Tsusena Falls.	Both plans impact the valley aesthetics. The difference is considered minimal.	-	-
	Due to construction at Vee damsite and the size of the Vee reservoir, the HDC/V plan would inherently create access to more wilderness area than would the W/DC plan.	As it is easier to extend access than to limit it, inherent access requirements were considered detrimental and the W/DC plan is judged superior. The ecological sensitivity of the area opened by the HDC/V plan reinforces this judgment.		X

OVERALL EVALUATION: The W/DC plan is judged to be superior to the HDC/V plan. (The lower impact on birds and bears associated with HDC/V plan is considered to be outweighed by all the other impacts which favor the W/DC plan.)

Notes: W = Watana Dam
DC = Devil Canyon Dam
HDC = High Devil Canyon Dam
V = Vee Dam

TABLE B.1.5.13: ENERGY CONTRIBUTION EVALUATION OF THE WATANA/DEVIL CANYON AND HIGH DEVIL CANYON/VEE PLANS

Parameter	Watana/ Devil Canyon	High Devil Canyon/Vee	Remarks
Total Energy Production Capability			
Annual Average Energy GWh	6070	4910	Watana/Devil Canyon plan annually develops 1160 GWh and 1650 GWh more average and firm energy, repectively, than the High Devil Canyon/Vee Plan.
Firm Annual Energy GWh	5520	3870	
% Basin Potential Developed 1/	91	81	Watana/Devil Canyon plan develops more of the basin potential
Energy Potential Not Developed GWh 2/	60	650	As currently conceived, the Watana/-Devil Canyon plan does not develop 15 ft of gross head between the Watana site and the Devil Canyon reservoir. The High Devil Canyon/Vee Plan does not develop 175 ft gross head between Vee site and High Devil reservoir.

Notes:

1/ Based on annual average energy. Full potential based on USBR four dam schemes.

2/ Includes losses due to unutilized head.

TABLE B.1.5.14: OVERALL EVALUATION OF THE HIGH DEVIL CANYON/VEE AND WATANA/DEVIL CANYON DAM PLANS

ATTRIBUTE	SUPERIOR PLAN
Economic	Watana/Devil Canyon
Energy Contribution	Watana/Devil Canyon
Environmental	Watana/Devil Canyon
Social	Watana/Devil Canyon (Marginal)
Overall Evaluation	Plan with Watana/Devil Canyon is superior Tradeoffs made: None

TABLE B.2.2.1: COMBINED WATANA AND DEVIL CANYON OPERATION

Watana Dam Crest Elevation (ft MSL)	Watana[1/] Cost ($ x 10^6)	Devil Canyon[1/] Cost ($ x 10^6)	Total Cost ($ x 10^6)	Average Annual Energy (GWh) Watana[2/] Alone	Average Annual Energy (GWh) Watana/Devil Canyon
2240 (2215 reservoir elevation)	4,076	1,711	5,787	3,542	6,809
2190 (2165 reservoir elevation)	3,785	1,711	5,496	3,322	6,586
2140 (2115 reservoir elevation)	3,516	1,711	5,227	3,071	6,264

1/ Estimated costs in January 1982 dollars, based on preliminary conceptual designs, including relict channel drainage blanket and 20 percent contingencies.

2/ Prior to year 2002

TABLE B.2.2.2: PRESENT WORTH OF PRODUCTION COSTS

Watana Dam Crest Elevation (ft MSL)	Present Worth of Production Costs[1/] ($ x 10^6)
2240 (reservoir elevation 2215)	7,123
2190 (reservoir elevation 2165)	7,052
2140 (reservoir elevation 2115)	7,084

1/ LTPW in January 1982 dollars

TABLE B.2.2.3: DESIGN PARAMETERS FOR DEPENDABLE CAPACITY AND ENERGY PRODUCTION

	Watana	Devil Canyon
Minimum stream flow[1] (monthly average, cfs)	570 (March 1950)	664 (March 1964)
Mean streamflow[1]	7,990	9,080
Maximum streamflow[1]	42,840 (June 1964)	47,816 (June 1964)
Evaporation	Approximately cancels precipitation and is neglected.	
Leakage	Negligible	Negligible
Critical streamflow for dependable capacity curve (Watana and Devil Canyon combined)	5,450 GWh annual potential recurrence frequency 1 in 32 years	
Area capacity curve	Figure B.3.2.1	Figure B.3.2.1
Hydraulic Capacity		
Flow (cfs) 1/2	1,775	1,895
full	3,550	3,790
best	2,900	3,100
Efficiency 1/2	87	87
full	91	91
best	94	94
Generator output (kW) 1/2	91,000	82,000
full	183,000	164,000
best	156,000	139,000
Tailwater rating curves	Figure B.4.2.3	Figure B.4.2.3

[1] Based on 32 years of streamflow data.

TABLE B.2.2.4: WATANA - MAXIMUM CAPACITY REQUIRED (MW)
OPTION 1 - THERMAL AS BASE

	CAPACITY (MW)		
Hydrological Year	1995	2000	2010***
1	743	762	838*
2	550	569	680
3	760	779	836*
4	749	768	836*
5	744	763	868*
6	763	782	832*
7	737	756	838*
8	771	790	836**
9	799**	818**	825*
10	563	582	683*
11	769	788	832*
12	784*	803	829*
13	773	792	832*
14	771	790	838*
15	745	764	844*
16	550	569	840*
17	745	764	836*
18	554	573	684*
19	771	790	832*
20	550	569	685*
21	550	569	678
22	550	569	672
23	784*	803	834*
24	747	766	838*
25	550	569	684
26	550	569	678
27	728	747	839*
28	550	569	675
29	785*	804	833*
30	550	569	678
31	787*	806	837*
32	754	773	839*

*Restricted by peak demand
**Maximum value
***Including Devil Canyon

TABLE B.2.2.5: WATANA - MAXIMUM CAPACITY REQUIRED (MW)
OPTION 2 - THERMAL AS PEAK

Hydrological Year	CAPACITY (MW)		
	1995	2000	2010*
1	575	575	838
2	382	382	389
3	592	592	839
4	581	581	836
5	576	576	868
6	595	595	832
7	569	569	838
8	603	603	836
9	631	631	825
10	395	365	391
11	601	601	832
12	616	616	829
13	605	605	832
14	603	603	838
15	577	577	844
16	382	382	840
17	577	577	836
18	386	386	392
19	603	603	832
20	382	382	393
21	382	382	386
22	382	382	380
23	616	626	834
24	579	579	838
25	382	382	392
26	382	382	386
27	560	560	839
28	382	382	383
29	617	617	833
30	382	382	387
31	619	619	837
32	586	586	839

*Including Devil Canyon

TABLE B.2.2.6: SUMMARY COMPARISON OF POWERHOUSES AT WATANA

Item	SURFACE ($000) 4 x 210 MW	UNDERGROUND ($000) 4 x 210 MW	UNDERGROUND ($000) 6 x 140 MW
Civil Works:			
Intakes	54,000	54,000	70,400
Penstocks	72,000	22,700	28,600
Powerhouse/Draft Tube	29,600	26,300	28,100
Surge Chamber	NA	4,300	4,800
Transformer Gallery	NA	2,700	3,400
Tailrace Tunnel	NA	11,000	11,000
Tailrace Portal	NA	1,600	1,600
Main Access Tunnels	NA	8,100	8,100
Secondary Access Tunnels	NA	300	300
Main Access Shaft	NA	4,200	4,200
Access Tunnel Portal	NA	100	100
Cable Shaft	NA	1,500	1,500
Bus Tunnel/Shafts	NA	1,000	1,200
Fire Protection Head Tank	NA	400	400
Mechanical - For Above Items	54,600	55,500	57,200
Electrical - For Above Items	37,400	37,600	41,200
Switchyard - All Work	14,900	14,900	14,900
TOTAL	262,500	246,200	277,000

TABLE B.2.3.1: DESIGN DATA AND DESIGN CRITERIA FOR FINAL REVIEW OF LAYOUTS

River Flows

Average flow (over 30 years of record):	7,860 cfs
Probable maximum flood (routed):	326,000 cfs
Maximum inflow with return period of 1:10,000 years:	156,000 cfs
Maximum 1:10,000-year routed discharge:	115,000 cfs
Maximum flood with return period of 1:500 years:	116,000 cfs
Maximum flood with return period of 1:50 years:	87,000 cfs
Reservoir normal maximum operating level:	2215 ft
Reservoir minimum operating level:	2030 ft

Dam

Type:	Rockfill
Crest elevation at point of maximum super elevation:	2240 ft
Height:	890 ft above foundation
Cutoff and foundation treatment:	Core founded on rock; grout curtain and down-stream drains
Upstream slope:	2.4H:1V
Downstream slope:	2H:1V
Crest width:	50 ft

Diversion

Cofferdam type:	Rockfill
Cutoff and foundation:	Slurry trench to bedrock
Upstream cofferdam crest elevation:	1585 ft
Downstream cofferdam crest elevation:	1475 ft
Maximum pool level during construction:	1580 ft
Tunnels:	Concrete-lined,
Final closure:	Mass concrete plugs
Releases during impounding:	6,000 cfs maximum via bypass to outlet structure

Spillway

Design floods:	Passes PMF, preserving integrity of dam with no loss of life Passes routed 1:10,000-year flood with no damage to structures
Main spillway - Capacity:	Routed 1:10,000-year flood with 5 ft surcharge
- Control structure:	Gated ogee crests
Emergency spillway - Capacity:	PMF minus 1:10,000 year flood
- Type:	Fuse plug

Power Intake	
Type:	Reinforced concrete
Number of intakes:	6
Draw-off requirements:	Multi-level corresponding to temperature strata
Drawdown:	185 feet
Penstocks	
Type:	Concrete-lined tunnels with downstream steel liners
Number of penstocks:	6
Powerhouse	
Type:	Underground
Transformer area:	Separate gallery
Control room and administration:	Surface
Access - Vehicle:	Rock tunnel
- Personnel:	Elevator from surface
Power Plant	
Type of turbines:	Francis
Number and rating:	6 x 170 MW
Rated net head:	690 ft
Design flow:	3,500 cfs per unit
Normal maximum gross head:	745 ft
Type of generator:	Vertical synchronous
Rated output:	190 MVA
Power factor:	0.9
Frequency:	60 HZ
Transformers:	13.8-345 kV, 3-phase
Tailrace	
Water passages:	2 concrete-lined tunnels
Surge:	Separate surge chambers
Average tailwater elevation (full generation):	1458 ft

Note: Certain design data and criteria have been revised since date of layout review. For current project parameters refer to Exhibit F, Preliminary Design Report.

TABLE B.2.3.2: EVALUATION CRITIERA

PRELIMINARY REVIEW	INTERMEDIATE REVIEW	FINAL REVIEW
Technical feasibility	Technical feasibility	Technical feasibility
Compatibility of layout with known geological and topographical site features	Compatibility of layout with known geological and topographical site features	Compatibility of layout with known geological and topographical site features
Ease of construction	Ease of construction	Ease of construction
Physical dimensions of component structures in certain locations	--	--
Obvious cost differences of comparable structures	Overall cost	Overall cost
Environmental acceptability	Environmental acceptability	Environmental impact

TABLE B.2.3.3: SUMMARY OF COMPARATIVE COST ESTIMATES

INTERMEDIATE REVIEW OF ALTERNATIVE ARRANGEMENTS
(January 1982 $ x 10^6)

	WP1	WP2	WP3	WP4
Diversion	101.4	112.6	101.4	103.1
Service Spillway	128.2	208.3	122.4	267.2
Emergency Spillway	-	46.9	46.9	-
Tailrace Tunnel	13.1	13.1	13.1	8.0
Credit for Use of Rock in Dam	(11.7)	(31.2)	(18.8)	(72.4)
Total Non-Common Items	231.0	349.7	265.0	305.9
Common Items	1643.0	1643.0	1643.0	1643.0
Subtotal	1874.0	1992.7	1908.0	1948.9
Camp & Support Costs (16%)	299.8	318.8	305.3	311.8
Subtotal	2173.8	2311.5	2213.3	2260.7
Contingency (20%)	434.8	462.3	442.7	452.1
Subtotal	2608.6	2773.8	2656.0	2712.8
Engineering and Administration (12.5%)	326.1	346.7	332.0	339.1
TOTAL	2934.7	3120.5	2988.0	3051.9

TABLE B.2.4.1: DEVIL CANYON - MAXIMUM CAPACITY REQUIRED (MW)

Hydrological Year	Capacity (MW) 2010 (Option 1 and 2)
1	544**
2	353
3	546
4	546
5	514
6	548
7	544
8	546
9	557
10	351
11	548
12	551
13	548
14	544
15	538
16	542
17	546
18	350
19	550
20	349
21	355
22	361
23	548
24	544
25	349
26	355
27	543
28	359
29	549
30	355
31	545
32	543

**Maximum Value

TABLE B.2.5.1: DESIGN DATA AND DESIGN CRITERIA FOR REVIEW OF ALTERNATIVE LAYOUTS

River Flows	
Average flow (over 30 years of record):	8,960 cfs
Probable maximum flood:	346,000 cfs
Max. flood with return period of 1:10,000 years:	165,000 cfs (after routing through Watana)
Maximum flood with return period of 1:500 years:	-
Maximum flood with return period of 1:50 years:	42,000 cfs (after routing through Watana)
Reservoir	
Normal maximum operating level:	1455 feet
Reservoir minimum operating level:	1430 feet
Area of reservoir at maximum operating level:	21,000 acres
Reservoir live storage:	180,000 acre-feet
Reservoir full storage:	1,100,000 acre-feet
Dam	
Type:	Concrete arch
Crest elevation:	1455 feet
Crest length:	-
Maximum height above foundation:	635 feet
Crest width:	20 feet
Diversion	
Cofferdam types:	Rockfill
Upstream cofferdam crest elevation:	960 feet
Downstream cofferdam crest elevation:	900 feet
Maximum pool level during construction:	955 feet
Tunnels:	Concrete-lined
Outlet structures:	Low-level structure with slide closure gate
Final closure:	Mass concrete plugs in line with dam grout curtain
Releases during impounding:	2,000 cfs min. via fixed-cone valves

TABLE B.2.5.1 (Page 2 of 2)

Spillway

Design floods:	Passes PMF, preserving integrity of dam with no loss of life
	Passes routed 1:10,000-year flood with no damage to structures
Service spillway - capacity:	45,000 cfs
- control structure:	Fixed-cone valves
- energy dissipation:	Five 108-inch diameter fixed-cone valves
Secondary spillway - capacity:	90,000 cfs
- control structure:	Gated, ogee crests
- energy dissipation:	Stilling basin
Emergency spillway - capacity: 1:10,000-year	pmf minus routed
	flood
- type:	Fuse plug

Power Intake

Type:	Underground
Transformer area:	Separate gallery
Access:	Rock Tunnel
Type of turbines:	Francis
Number and rating:	4 x 140 MW
Rated net head:	550 feet
Maximum gross head:	565 feet approx.
Type of generator:	Vertical synchronous
Rated output:	155 MVA
Power factor:	0.9

Note: Certain design data and criteria have been revised since date of layout review. For current project parameters refer to Exhibit F, Preliminary Design Report.

TABLE B.2.5.2: SUMMARY OF COMPARATIVE COST ESTIMATES

PRELIMINARY REVIEW OF ALTERNATIVE ARRANGEMENTS
(January 1982 $ X 10^6)

Item	DC1	DC2	DC3	DC4
Land Acquisition	22.1	22.1	22.1	22.1
Reservoir	10.5	10.5	10.5	10.5
Main Dam	468.7	468.7	468.7	468.7
Emergency Spillway	25.2	25.2	25.2	25.2
Power Facilities	211.7	211.7	211.7	211.7
Switchyard	7.1	7.1	7.1	7.1
Miscellaneous Structures	9.5	9.5	9.5	9.5
Access Roads & Site Facilities	28.4	28.4	28.4	28.4
Common Items - Subtotal	783.2	783.2	783.2	783.2
Diversion	32.1	32.1	32.1	34.9
Service Spillway	46.8	53.3	50.1	85.2
Saddle Dam	19.9	18.6	18.6	19.9
Non-Common/Items Subtotal	98.8	104.0	100.8	140.0
Total	882.0	887.2	884.0	923.2
Camp & Support Costs (16%)	141.1	141.9	141.4	147.7
Subtotal	1023.1	1029.1	1025.4	1070.9
Contingency (20%)	204.6	205.8	205.1	214.2
Subtotal	1227.7	1234.9	1230.5	1285.1
Engineering & Administration (12.5%)	153.5	154.3	153.8	160.6
Total	1381.2	1389.2	1384.3	1445.7

TABLE B.2.7.1: POWER TRANSFER REQUIREMENTS (MW)

Year	DEPENDABLE CAPABILITY Watana	Devil Canyon	Total Susitna	TRANSFER CAPABILITY Susitna to Anchorage	Susitna to Fairbanks	TRANSFER EXPECTED Sustina to Anchorage	Susitna to Fairbanks
1999	360	-	360	578	170	327	52
2005	360	600	960	1088	320	601	198
2012	1020	600	1620	1377	405	1245	276

TABLE B.2.7.2: SUMMARY OF LIFE CYCLE COSTS (1985 $ Million)[1/]

	TRANSMISSION ALTERNATIVE				
	1	2	3	4	5
Transmission Lines					
Capital	$220.12	$231.37	$188.18	$205.28	$223.72
Land Acquisition	26.70	29.64	25.76	28.70	26.59
Capitalized Annual Charges	181.56	191.25	153.17	166.57	180.95
Capitalized Line and Losses	75.66	77.70	91.97	93.85	61.05
Total Transmission Line Cost	$504.04	$529.96	$459.08	$494.40	$492.31
Switching Stations					
Capital	$168.62	$155.35	$190.43	$177.16	$224.79
Capitalized Annual Charges	181.06	167.53	204.19	190.66	242.85
Total Switching Station Cost	$349.69	322.88	394.19	367.82	467.64
TOTAL	$853.72	$852.84	$853.70	$862.22	$959.95

1/ This estimate is based on an Acres (1982). Subsequently, switching equipment for Devil Canyon was shifted to create Gold Creek switchyard. However, selection of alternative 2 did not change.

TABLE B.2.7.3: TECHNICAL, ECONOMIC, AND ENVIRONMENTAL CRITERIA USED IN CORRIDOR SELECTION

Type	Criteria	Selection
1. Technical		
- Primary	General Location	Connect with Intertie near Gold Creek, Willow, and Healy. Connect Healy to Fairbanks. Connect Willow to Anchorage.
	Elevation	Avoid mountainous areas.
	Relief	Select gentle relief.
	Access	Locate in proximity to existing transportation corridors to facilitate maintenance and repairs.
- Secondary	River Crossings	Minimize wide crossings.
2. Economical		
- Primary	Elevation	Avoid mountainous areas.
	Access	Locate in proximity to existing transportation corridors to reduce construction costs.
- Secondary	River Crossings	Minimize wide crossings.
	Timbered Areas	Minimize such areas to reduce clearing costs.
	Wetlands	Minimize crossings which require special designs.
3. Environmental		
- Primary	Development	Avoid existing or proposed developed areas.
	Existing Transmission Right-of-Way	Parallel.
	Land Status	Avoid private lands, wildlife refuges, parks.
	Topography	Select gentle relief.
- Secondary	Vegetation	Avoid heavily timbered areas.

TABLE B.2.7.4: ENVIRONMENTAL INVENTORY - SOUTHERN STUDY AREA (WILLOW TO ANCHORAGE/POINT MACKENZIE)

	Corridor Segment AB	BC	ADF	AEF	FC
Length (miles)	38	35	26	27	12
Number of Road Crossings	2 hwy (Rt. 3, Glenn), 6 light duty roads, 1 unimproved road, 2 trails, 1 railroad	4 hwy (Glenn, 4x), 3+ light duty roads, 7 unimproved roads, 1 trail, several railroads	1 hwy (Rt. 3), 3 tractor trails	1 hwy (Parks), 1 tractor trail	2 tractor trails
Number of River/ Creek Crossings	1 river, 17 creeks	4 rivers, 11 creeks	1 river, 6 creeks	1 river, 6 creeks	2 creeks
Topography	Willow (100'), crosses Willow Ck., follows Deception Ck. (1000') along ridge of Talkeetna Mts., s.e. into Palmer (200')	Palmer (200'), crosses Knik River to base at Chugach Mts. (500'), along Knik Arm (200'-300'), to Anchorage (200')	Willow (100'), s. along Susitna River plains (flat, wet area, with drier, raised levees, 200'-400'), to F at 150'	Willow (100'), s. along flat wet area (200'-400'), to F at about 150'	F at 150' along flats to C near sea level
Soils[1/]	Willow to near Palmer-S04, Palmer-E01	Palmer-E01, Knik Arm-EF1, S. of Eklutna to n. of Anchorage-S05, Anchorage - S04	Willow-S04, S. of Willow to F-S01	Near L. Susitna River - S05, Remainder-S04	Near F - S04, Near C - S01
Land Ownership/[2/] Status	A to s. of Willow Ck. Rd. crossing-mostly P, with some BAP and some SP;... to due n. of Wasilla-mainly SPTA;... to B-mostly P, with some BAP and SP	B to Knik R. - P; ... to Birchwood-mainly VS with some SPTA, P and BAP; Birchwood area-P; s.w. of Birchwood to near C'-U.S. Army Military Wdl.; C'-DATA VOID	Near A-P; route fairly even mix of BAP and SPTA; some P near Fish Ck; area surrounding L Susitna R - Susitna Flats Game Reguse; near F-SPTA	A, s. to Rainbow L.- mostly P, small parcels BAP; State selected Fed. parcel w. of Willow L.; s. to L. Susitna R. - Nancy Lake State Rec. Area; to F - mix of SPTA and BAP	F to 1 mi. s.-SPTA;... s. to Horseshoe L.-Pt. MacKenzie Agr. Sale; ... s. to C-mainly SPTA, some BAP
Existing/Proposed Developments	Ag. uses n. & w. of Palmer; ag/res. use near L. Susitna; proposed capital site; mixed res. area at Willow Ck.; Willow air strip; cabin near A	Urban uses in Anch.; passes through/near several communities: Eagle R, Birchwood, Eklutna, Chugiak, Peters Ck.	Red Shirt Lake-mixed residential use; near residential & recr. areas s.w. of Willow; Susitna Flats State Game Refuge	Mixed res. areas; lakes used to land float planes	Scattered residential/cabins on Horsehoe Lake; proposed ag. uses in area
Existing Rights-of-Way	Follows no known right-of-way for appreciable distance	Parallels trans. line Knik R. to Anch.; parallels Glenn Hwy. from Knik R. to Birchwood; parallels RR-Eagle to C'	Generally parallels a tractor trail	No known	Generally follows a tractor trail
Scenic Quality/ Recreation	Gooding L. - bird-watching; rec. trails e. of Willow-hunting, hiking, x-c skiing, dog sledding, snowmobiling, snowshoeing; rec. trail by Decep. Ck.- snowmobiling, dog sledding, fishing	Passes near 2 camping grounds; parallels Iditarod racing trail (x-c skiing, sledding, snowmobiling); birdwatching at Eklutna Flats and Matunuska River	X-c ski & snowmobile trails; recreation area s.w. of Willow	Mixed rec. areas; Nancy Lake State Rec. area; trails and multiple uses; may cross Goose Bay St. Game Refuge	May cross Susitna Flats State Wildlife Refuge
Cultural Resources[3/]	DATA VOID	DATA VOID	DATA VOID	DATA VOID	DATA VOID

TABLE B.2.7.4 (Page 2 of 2)

	Corridor Segment				
	AB	BC	ADF	AEF	FC
Vegetation[4]	Upland, mixed deciduous-conifer forests (birch-spruce) - open and closed mostly. Tall shrub (alder); some woodland black spruce; bogs along Deception Ck.	Deciduous forest (balsam poplar) along river, probably birch/spruce forests on uplands in most of area. DATA VOID	Higher grounds: Spruce-birch-poplar forests. Wet sedge grass bogs and black spruce forests prevalent in lower half	Upper half; mostly upland birch, spruce & aspen. Lower half: wet sedge-grass bogs and black spruce; some birch, spruce; aspen on higher ground	Spruce forests, spruce-birch forests, sedge-grass bogs and black spruce bogs
Fish Resources[5]	Willow Ck. - chinook salmon, grayling, burbot, longnose sucker, round whitefish, Dollar Varden, slimy sculpin; lake trout & rainbow trout in lakes; L. Susitna R. - king salmon; Decep. Ck. - king, pink salmon	Sockeye, chinook, pink, shum, coho salmon in large rivers; grayling burbot, longnose sucker, round whitefish, Dolly Varden, slimy sculpin, lake and rainbow trout in lakes & stream; salmon of particular significance in the Matanuska and Knik Rivers	Willow Ck. - chinook salmon; lake and rainbow trout possible in some lakes; also, in streams are grayling, bur bot, longnose sucker, round whitefish, Dolly Varden, slimy sculpin; Red Skirt L. - lake trout, sockeye salmon	Lakes may contain rainbow and lake trout; possibly grayling in the region	Lake may contain rainbow and lake trout; possibly grayling in the region
Birds[6]	DATA VOID	Waterfowl and shore bird nesting areas around Knik Arm and Eagle River Flats	Waterfowl and shore bird nesting in Willow Creek/ Delta Islands	Same as ADF	Waterfowl and shore bird migration route, feeding and nesting area
Furbearers[6]	DATA VOID	DATA VOID	DATA VOID	Same as ADF	Furbearer and small mammal summer/winter range
Big Game[6]	Except near Palmer-black bear summer range, moose winter/ summer range, migrating corridors and calving area; near A also brown bear summer range and feeding area	DATA VOID	Brown and black bear feeding moose winter/summer range and calving area	Same as ADF	Black bear summer range and feeding area; moose winter/ summer range, feeding and calving area

1/ Source: Unites States Department of Agriculture, Soil Conservation Service 1979. See Table B.43 for explanation of soil units.

2/ Source: CIRI/Holmes and Narver. 1980. P=Private, SPTA+State Patented or Tentatively Approved, SP=State Patented, BAP=Borough Approved or Patented.

3/ Coastal area probably has many sites, available literature not yet reviewed.

4/ Tall shrub=alder; low shrub=dwarf birch, and/or willow; open spruce=black (wet) cover, mixed forest=spruce-birch.

5/ Little data available. Source of information in this table: Alaska Department of Fish and Game 1978a.

6/ Little data available. Source of information in this table: Alaska Department of Fish and Game 1978b.

TABLE B.2.7.5: ENVIRONMENTAL INVENTORY - CENTRAL STUDY AREA (DAMSITES TO INTERTIE)

Corridor Segment	Approx. Length (Miles)	Approx. # Road Crossings	Approx. # River/Creek Crossings	Topography	Soils[a]	Land Ownership/Status[b]
AB	7	0	5 creeks	Moderate sloping s. rim of Susitna R. Valley; crosses deep ravine at Fog Ck. at about 2000' contour	SO15	VS
BC	18	0	8 creeks	2000' contour along s. rim of Susitna River; crosses 3 steep gorges	B, westward- SO15; near C - SO10	VS
CD	15	1+	1 river 4 creeks	Moderately sloping terrain; crosses Susitna R. near Gold Creek (800')	OS10	C to 1 1/2 mi. e. of Susitna R. - VS; Susitna R. to 1 1/2 mi. e. - SPTA; ... to D-P
BEC	23	0	8 creeks	Crosses moderate slopes around Stephan Lake; w., then n. to avoid deep ravine at Cheechako Ck., then follows s. rim of Susitna at about 2000'	B, westward - OS15; between B & C IU3; near C - SO10	VS except where corridor skirts Cheechako Ck. ravine, which is classified SS Suspended
AJ	18	0	11 creeks	A (about 2000') to 3500'; crosses deep ravine at Devil Ck. (2000'); goes by several ponds	A, westward - OS15; remainder, except J - OS16; near J - SO10	SS except at J and at A westward across Tsusena Ck., which are VS
JC	8	0	1 creek	J (2000'), s.w. through gently sloping High Lake area, to C at Devil Canyon (2000')	OS10	SS except at J and C which are VS
CF	15	0	2 creeks	Devil Canyon (<2000') west across 600' deep Portage Creek gorge; w. across gentle terrain to F (1200')	SO10	C to 1 1/2 mi. e. of Miami L. mainly VS with small parcel of SS; ... to F-P
AG	65	0	1 river 35 creeks	A (2000'), n. along Deadman Ck. to 3200'; crosses Brushkana drainage (at 3200'); drops to Nenana River (2400') and fairly flat terrain to G (2200')	Near A and along Denali Hwy. - OS15; through mts. - SO16	A - VS; n. of A to s.w. of Big L. - SS, ... to s. of Deadman L. - SPTA ... to Denali Hwy - Fed. D-1 Land; data void for 8 mi.; around G - Small Fed. Parcel

a. Source: United States Department of Agriculture, Soil Conservation Service 1979. See Table B.42 for explanation of soil units.

b. Source: CIRI/Holmes and Narver. 1980. P=Private, SPTA=State Patented or Tentatively Approved, SS=State Selection, VS=Village Selection.

TABLE B.2.7.5 (Page 2 of 6)

Corridor Segment	Approx. Length (Miles)	Approx. # Road Crossings	Approx. # River/Creek Crossings	Topography	Soils[a]	Land Ownership/Status[b]
AH	22	0	9 creeks	A (2000'), along Tsusena Ck. past Tsusena Butte; through mt. pass at 3600'	Near A - SO15; mt. base - SO16; mts. - RM1	A - VS; ... to n. of Tsusena Butte SS; data void beyond here
HI	21	0	15 creeks	H (3400') through mts.; along Jack R. drainage and Caribou Pass; to I at 2400'	Mts. - RM1; along hwy - SO15	I - VS; data void to east
HJ	23	0	13 creeks	H (3400') through mts. along Portage Ck. drainage, through pass at 3600' into Devil Creek drainage; to J at 2000'	Near J - SO16 mid elevations - SO17; mts. - RM1	J - VS; Devil Ck drainage - SS; data void beyond here

a. Source: United States Department of Agriculture, Soil Conservation Service 1979. See Table B.42 for explanation of soil units.

b. Source: CIRI/Holmes and Narver. 1980. P=Private, SPTA=State Patented or Tentatively Approved,

Corridor Segment	Fish Resources[a]	Birds	Furbearers	Big Game
AB	Fog Lakes - Dolly Varden, sculpin; Stephan Lake contains lake and rainbow trout, sockeye & coho salmon, whitefish, longnose sucker, graying; burbot	Potential raptor nesting habitat in Fog Creek area	Excellent fox and marten habitat; Fog Lakes support numerous beavers and muskrat; otters common	Supports large pop. of moose; wolves, wolverine and bear, (especially brown) common; caribou regularly use area
BC	Several small tributaries crossed, perhaps used by grayling	Potential raptor nesting habitat along Devil Canyon	Excellent fox and marten habitat	Area around Stephan Lake & Prairie Ck. supports large pop. of moose; wolves, wolverines, and some bear (especially brown) common; caribou regular users
CD	Same as BC	Potential raptor nesting habitat along Devil Canyon	Area around Devil Canyon has excellent fox and marten habitat	Moose, caribou, and bear habitat
BEC	Several small tributaries crossed, perhaps used by grayling, burbot	Potential raptor nesting habitat along Devil Canyon and along drainages upstream; Stephan Lake area important to waterfowl and migrating swans	Excellent fox and marten habitat, particularly around Stephan Lake	Same as AB
AJ	Dolly Verden; grayling in Tsusena Creek	Data void	Red fox denning sites, numerous beaver, muskrat and mink, especially around High Lake	Mouth of Tsusena Ck. important moose habitat; heavily used by black and brown bear
JC	Burbot; no data for High Lake	Potential raptor hab. by Devil Canyon; golden eagle nest along Devil Ck. s. of confluence of ck. from High Lake	Same as AJ	Important moose and bear habitat; data void
CF	Portage Creek has king, chinook, chum and pink salmon, grayling, burbot	Potential raptor habitat along lower Portage Ck. and from Portage Ck. mouth through Devil Canyon	Area between Parks Hwy and Devil Canyon supports numerous beaver, muskrat, and mink	Probably important moose wintering area area and black bear habitat; at least one wolf pack

a. Little data available. Sources of information in this table: Alaska Department of Fish and Game 1978a, Friese 1975, and Morrow 1980.

Corridor Segment	Fish Resources[a]	Birds	Furbearers	Big Game
AG	Dolly Varden; lakes - lake trout, grayling, white- fish; tributaries to Nenana River and Brushkana Creek n. of Deadman Mt., and Jack R. near Denali Hwy considered fish habitat	Waterfowl numerous at Deadman Lake; important bald eagle habitat by Denali Hwy and Nenana R. just w. of Monahan Flat; unchecked bald eagle nest along Deadman Ck., s.e. of Tsusena Butte	Population relatively low, although beaver, mink, fox present; Deadman Mt. to Denali Hwy - moderate pop. red fox	Probably important area for caribou, expecially in the north
AH	Dolly Varden; grayling	Known active bald eagle nest s.e. of Tsusena Butte	Population along Tsusena Ck. probably relatively low; with beaver, mink, and fox probably present	Data void
HI	Lake trout, Caribou Pass area; Jack River s. of Caribou Pass considered important fish habitat; data void	Data void	Data void	Data void
HJ	Portage Creek - king, chinook, chum, and pink salmon, grayling, burbot	Data void	Numerous beaver, muskrat, and mink around High Lake	Data void

a. Little data available. Sources of information in this table: Alaska Department of Fish and Game 1978a, Friese 1975, and Morrow 1980.

TABLE B.2.7.5 (Page 5 of 6)

Corridor Segment	Existing/Proposed Developments	Existing Rights-of-Way	Scenic Quality/Recreation	Cultural Resources	Vegetation[a]
AB	Cabins on Fog Lakes; planes use lakes	No known	Fog Lakes - high aesthetic quality; fishing in Fog Lakes	Arch. sites identified near Watana Dam site and w. shore of Stephan Lake; potential for more sites around Fog Lakes and Stephan Lake	Mostly woodland black spruce (wet); some low shrub
BC	Cabins and lodge on Stephan Lake	No known	Stephan Lake - high aesthetic quality	Arch. sites near Stephan Lake	Open and woodland spruce forests, low shrub, open and closed mixed forest in about equal amounts
CD	Follows proposed Susitna railroad extension; scattered cabins in Canyon/Gold Creek area	Old Corps trail, Gold Ck. to Devil Canyon	Scenic area; possible fishing	Hist. sites near Gold Ck.; data void	Mostly closed mixed forests
BEC	Cabins and lodge on Stephan Lake	No known	Stephan Lake - high aesthetic quality; major recreation area for fishing/boating/planes	See AB	Woodland spruce and bogs around Stephan Lake; low shrub, mat & cushion and sedge-grass tundra at upper end of Cheechako Ck. drainage; tall shrub (alder) and mixed forest along Cheechako Ck. and towards Devil Canyon

a. Tall shrub=alder; low shrub=dwarf birch, and/or willow; open spruce=black (wet) or white spruce, 25%-60% cover; woodland spruce=white or black spruce, 10%-25% cover, mixed forest=spruce-birch.

TABLE B.2.7.5 (Page 6 of 6)

Corridor Segment	Existing/Proposed Developments	Existing Rights-of-Way	Scenic Quality/Recreation	Cultural Resources	Vegetation[a]
AJ	Follows proposed Susitna access road from Tsusena Creek to High Lake; lodge at High Lake	No known	High Lake and other lakes - high aesthetic quality; fishing/hunting in Hight Lake area	Arch. sites at Portage Ck. and Susitna R. confluence and near Watana Dam site	Mostly low shrub, mat & cushion, sedge-grass tundra some tall shrub (alder)
JC	Generally follows proposed Susitna access rd.; lodge at High Lake	No known	Same as AJ	No Known arch. sites	Tall shrub (alder) shrub and open low mixed forest
CF	Mining claims, cabins in Portage Creek area	No known	Boating in Susitna; hunting, fishing, hiking	Arch. sites at Portage Ck.; hist. sites near Canyon	Open & closed mixed forest, tall shrub, low shrub
AG	Follows proposed Susitna access road from Watana to just s. of Deadman Mt.; occasional cabins; landing strip along Denali Hwy; airport near G	Parallels Denali Hwy beyond Brushkana Ck. drainage to G	Remote flat areas - high visibility; Deadman L. and Mt., Alaska Range - high aesthetic quality; fishing, float planes; major rec. areas by Brushkana and Nenana R., Drasher L.	Arch. sites along Deadman Ck.	Mostly low shrub in southern end; northern end - data void
AH	Cabins near Tsusena Butte	No Known	Tsusena Butte - aesthetic quality; major sheep hunting area	Arch. site n. of Tsusena Butte along Tsusena Ck.; data void	Low shrub, tall shrub, woodland spruce
HI	Cabins near Summit	No known	Major sheep hunting area; bird watching at Summit L.	Data void	Data void
HJ	Follows proposed Susitna access road along Devil Creek approx. 3 mi.; cabins along Devil Creek drainage	No known	Scenic drainage; Sheep hunting in n.	Data void	Mat & cushion sedge-grass tundra, tall shrub and open mixed forest in southern end

a. Tall shrub=alder; low shrub=dwarf birch, and/or willow; open spruce=black (wet) or white spruce, 25%-60% cover; woodland spruce=white or black spruce, 10%-25% cover, mixed forest=spruce-birch.

TABLE B.2.7.6: ENVIRONMENTAL INVENTORY - NORTHERN STUDY AREA
(HEALY TO FAIRBANKS)

	Corridor Segment AB	BC	BDC	AE	EDC	EF
Length (miles)	40	50	46	65	50	40
Number of Road Crossings	2 hwy (Park), 3 trails (1 winter), 2 unimproved rds., 1 railroad	Parks Highway, 1 winter trail	1 winter trail	1 hwy. (Parks), 1 trail	7 trails	Several roads in Fairbanks depending upon exact route; 3 trails
Number of River/ Creek Crossings	3 rivers, 15 creeks	1 river, 25 creeks	2 rivers, 29 creeks	1 river 50 creeks[1]	2 rivers, 22 creeks	2 rivers, 10 creeks, Salchaket Slough
Topography	Follows Nenana River north at 1000' to Browne-crosses River; n.w. to Clear MEWS at 500'	Clear MEWS (500') north across plain (400'), n.e. across Tanana River Valley to Ester (600')	Clear MEWS (500'), n.e. across plain to a point about 24 mi. due s. of Ester; n. across plain to Tanana R. (400') and n. to Ester	Up Healy Ck. to pass at 4500'; down Wood R. drainage to Japan Hills (1100'); steep mts.; valleys	Japan Hills (1100') n.w. on plain along Wood R.; through Wood R. Buttes area, n. across Tanana R.; n. to Ester	Japan Hills (1100') n. across plain to Tanana R. (500'); n. to Fairbanks
Soils[2/]	IR10	Near B-IR10; flats s. of Tanana River-IQ2; Tanana River-IQ3; Tanana R. to Ester-IR14	Near B-IR10, Remainder -IQ2	Near A-IR10; mt. base-IQ25; mt. area-RM1; near E-IR1	Near E-IR1; between E and open flats-IR10; open flats IQ2; Tanana R.-IQ3; Ester-IR14	Near E-IR1; s. section of flats-IR10; flats-IQ2; Fairbanks-IQ3
Land Ownership/[3/] Status	A to e. of Dry Ck.-small Fed. Parcel; ... to s. of Clear MEWS and at B-mostly SPTA, small parcels of P, small Fed. Nat. Allot. along Nenana R.; Clear MEWS area-parcel CIRI Selection, and U.S. Army Wdl. Land	B to 1-1/2 mi n. - SPTA; ... to s. to Tanana R.-SS; ...to Tanana R.-P; ...to crossing L. Goldstream Ck.-mostly SPTA; ...to Bonanza Ck. Crossing - SS; ...to near C-SP; remainder-DATA VOID	B area - SPTA; Fish Ck. to Tanana R.-data void remainder-SPTA, BAP with P at C and just n. of Tanana R.	A to Nenana R.-small Fed. Parcel; ...to e. of Gold Run-SPTA ... remainder-DATA VOID	Same as BDC north of the Tanana River	DATA VOID
Existing/Proposed Developments	Scattered residential and other uses along Parks Hwy; cabin near Browne; air strip at Healy	Scattered residential and other uses along Parks Hwy; cabin at Tanana R. crossing	Ft. Wainwright Mil. Reservation	Air strips-Healy and Cripple/Healy Cks. confluence; cabins-Cody Ck/Wood R., Snow Mt. Gulch	Ft. Wainwright Mil. Res.; Wood R. Butte VABM	Ft. Wainwright Mil. Res.; cabin-Wood R. crossing s. of Clear Butte
Existing Rights-of-Way	Generally parallels Parks Hwy, RR and trans. line-Healy to Browne	Follows w/in several mi. Parks Hwy, RR, and trans. line; more closely follows Parks Hwy. and trans. line and sled rd. n. of of Tanana R.	No known	Parallels small rd.-near Healy to Coal Ck.; small RR-Healy to Suntrana; trail at pass between Healy and Cody Cks.	No known	Parallels Bonnifield Trail -Clear Ck. Butte to Fairbanks; trans. line just s. of Fairbanks
Scenic Quality/ Recreation	Parks Hwy-scenic area; rafting, kayaking on Nenana R.	Parks Hwy-scenic area; hunting, fishing	Wide open flat-high visibility; snow-mobiling in flats s. of Fairbanks	Scenic quality data void; Healy Ck.-rafting area	Wide open flats-high visibility; snow-mobiling in flats s. of Fairbanks	Wide open flats-high visibility
Cultural Resources	Dry Ck. arch. site near Healy; good possibility for other sites; DATA VOID	Good possibility for arch. sites; DATA VOID	Good possibility for arch. sites; DATA VOID	Dry Ck. arch. site near Healy; few arch. sites in mountains; maybe near Japan Hills; DATA VOID	High possibility for arch. sites; DATA VOID	Arch. sites have been identified for the Ft. Wainwright and Blair Lakes areas

TABLE B.2.7.6 (Page 2 of 2)

	Corridor Segment AB	BC	BDC	AE	EDC	EF
Vegetation4/	Southern end-data void Northern end-low shrub, sedge-grass tundra	S. of Tanana River-wet old river floodplain, low shrub and sedge-grass bogs; Tanana R. crossing-willow and alder shrub types, white spruce, balsam poplar forests along river; n. of Tanana R. -open and closed deciduous (birch and aspen) forests on slopes, w/woodland spruce and bogs, low shrub, and wet sedge-grass on valley bottoms	Probably wet, low shrub, and sedge-grass, alder shrub, lowland spruce; n. of Tanana-upland deciduous forests	DATA VOID	Probably similar to BDC	Probably similar to EDC; wet
Fish Resources5/	Grayling, burbot, long-nose sucker, Dolly Varden, round white-fish, slimy sculpin	Grayling, burbot, long-nose sucker, Dolly Varden, round white-fish, slimy sculpin, salmon (coho, king, chum), sheefish; lake chub possible	Same as BC	Same as AB	Same as AB, lake chub possible	Same as BC with the exception of coho salmon, which is not recorded
Birds6/	Important golden eagle habitat near A	Prime peregrine habitat at Tanana R.; prime waterfowl habitat along Tanana R. s. of corridor	Near Totatlanika Ck. to Tanana R.-prime waterfowl habitat; near Wood R.-important raptor habitat; between D&C by Tanana R. -prime peregrine habitat	Important golden eagle habitat at A & along Healy Ck. s. of Usibelli Pk; prime peregrine habitat on Keevy Pk.	From Wood R. Buttes to n. of Tanana R.-prime waterfowl habitat; between D&C along the Tanana R.-prime peregrine habitat	N. of Blair Lake Air Force Range to the Tanana R.-prime waterfowl habitat; s. of Fairbanks along Tanana R.-prime bald eagle habitat
Furbearers6/	Prime habitat-15 mi. from Nenana to B	Prime habitat-from Clear MEWS across the Tanana	Prime habitat from B to across Tanana Rive	Prime habitat from E to the s. about 15 mi.	Prime habitat from E to just n. of Tanana River	Prime habitat from E to Tanana River
Big Game6/	From Nenana R. to B-prime moose and important black bear habitat; from A northward about 10 mi.-prime moose habitat	Clear MEWS to across Tanana R.-prime moose and important black bear habitat; n. of Bonanza Ck. Exp. Forest-prime black bear habitat	B to across Tanana R. -prime moose, important black bear habitat; Wood R. to just s. of the Tanana R.-prime black bear habitat	Usibelli to Japan Hills-prime moose & caribou habitat; between A & Mystic Mt.-prime sheep habitat; E to the s.-import. black bear habitat	E to just n. of Tanana R.-prime moose, important black bear habitat; Wood R. to just s. of Tanana R.-prime black bear	E to tanana R.-prime moose and important black bear habitat; Clear MEWS to Tanana R.-prime black bear habitat

1/ Assumes corridor is located on n. side of Healy Ck. for most of its length, n. side of Cody Ck., and n.w. side of Wood R.

2/ Source: United States Dept. of Agriculture, Soil Conservation Service 1979. See Table B.42 for explanation of soil units.

3/ Source: CIRI/Holmes and Narver. 1980. P=Private, SPTA=State Patented or Tentatively Approved; SP=State Patented; SS=State Selection, BAP=Borough Approved or Patented.

4/ Tall shrub=alder; low shrub=dwarf birch, and/or willow; open spruce=black (wet) or white spruce, 25%-60% cover; woodland spruce=white or black spruce, 10%-25% ccover; mixed forest=spruce-birch.

5/ Little data available. Sources of information in this table: Alaska Dept. of Fish and Game 1978a and Morrow 1980.

6/ Source: VanBallenberghe personal communication. Prime habitat=minimum amount of land necessary to provide sustained yield for that species; based upon knowledge of that species' needs from experience of ADF&G personnel. Important habitat=land which the ADF&G considers not as critical to a species as is Prime habitat but is valuable.

TABLE B.2.7.7: SOIL ASSOCIATIONS WITHIN THE PROPOSED TRANSMISSION CORRIDORS - GENERAL DESCRIPTION, OFFROAD TRAFFICABILITY LIMITATIONS (ORTL), AND COMMON CROP SUITABILITY (CCS)[a]

EF1 - Typic Gyofluvents - Typic Cryaquepts, loamy, nearly level

- Dominant soils of this association consist of well-drained, stratified, waterlaid sediment of variable thickness over a substratum of gravel, sand, and cobblestones. Water table is high in other soils, including the scattered muskegs. ORTL: Slight - Severe (wet; subject to flooding); CCS: Good - Poor (low soil temperature throughout growing season).

EO1 - Typic Cryorthents, loamy, nearly level to rolling

- This association occupies broad terraces and moraines; most of the bedrock is under thick deposits of very gravelly and sandy glacial drift, capped with loess blown from barren areas of nearby floodplains. Well-drained, these soils are the most highly developed agricultural lands in Alaska. ORTL: Slight; CCS: Good - Poor.

IQ2 - Histic Pergelic Cryaquepts - loamy, nearly level to rolling

- The dominant soils in this association are poorly drained, developed in silty material of variable thickness over very gravelly glacial drift. Most soils have a shallow permafrost table, but in some of the very gravelly, well-drained soils, permafrost is deep or absent. ORTL: Severe - Wet; CCS: Poor

IQ3 - Histic Pergelic Cryaquepts - Typic Cryofluvents, loamy, nearly level

- Soils of this association located in low areas and meander scars of floodplains are poorly drained silt loam or sandy loam; these are usually saturated above a shallow permafrost table. Soils on the natural levees along existing and former channels are well-drained, stratified silt loam and fine sand; permafrost may occur. ORTL: Severe (wet); CCS: Unsuitable (low temperature during growing season; wet) - Good (but subject to flooding).

IQ25 - Pergelic Cryaquepts - Pergelic Cryochrepts, very gravelly, hilly to steep

- Soils of this association occupying broad ridgetops, hillsides, and valley bottoms at high elevation are poorly drained, consisting of a few inches of organic matter, a thin layer of silt loam, under which is very gravelly silt loam; permafrost table is at a depth greater than 2 feet. In locations of hills and ridges above tree line these soils are well-drained. ORTL: Severe (wet, steep slopes); CCS: Unsuitable (wet; low soil temperature; short, frost-free period).

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a. Source: U.S. Department of Agriculture, Soil Conservation Service 1979. See Table B.43 for definitions for Offroad Trafficability Limitations and Common Crop Suitability.

IR1 - Typic Cryochrepts, loamy, nearly level to rolling

- On terraces and outwash plains, these soils are well-drained, having a thin mat of course organic matter over gray silt loam. In slight depressions and former drainage ways, these are moderately well-drained soils, having a thin organic mat over silt loam, with a sand or gravelly substratum. ORTL: Slight-Moderate; CCS: Good.

IR10 - Typic Cryochrepts, very gravelly, nearly level to rolling - Aeric Cryaquepts, loamy, nearly level to rolling

- Generally well- to moderately well-drained soils of terraces, outwash plains, and low moraines. Typically, these soils have a silt loam upper layer over gravelly soils. Pockets of poorly drained soils with a shallow permafrost table occupy irregular depressions. ORTL: Moderate - Severe (wet); CCS: Good - Poor (wet; low soil temperature throughout growing season; short, frost-free period).

IR14 - Alfic Cryochrepts, loamy, hilly to steep - Histic Pergelic Cryaquepts, loamy, nearly level to rolling

- On mid-slopes, these soils are well drained, of micaceous loess ranging to many feet thick over shattered bedrock of mica schist. Bottomland areas are poorly drained with a relatively thick surface of peatmoss. In these soils, permafrost ranges from 5-30 inches in depth. ORTL: Moderate - Severe (steep slope; wet); CCS: Poor (steep slopes; highly susceptible to erosion).

IU3 - Pergelic Cryumbrepts, very gravelly, hilly to steep - rough mountainous land

- On high alpine slopes and ridges close to mountain peaks, these soils have a thin surface mat of organic material beneath which is an 8 to 12-inch-thick, dark brown horizon formed in very gravelly or stony loam. This association also includes areas of bare rock and stony rubble on mountain peaks. ORTL: Severe (short, frost-free period) - Very Severe (steep slope); CCS: Unsuitable (short, frost-free period; shallow bedrock).

RM1 - Rough Mountainous Land

- Rough, mountainous land composed of steep, rocky slopes; icefields; and glaciers. Soils on lower slopes are stony and shallow over bedrock. Unsuitable for agriculture. Roads feasible only in major valleys.

SO1 - Typic Cryorthods, loamy, nearly level to rolling - Sphagnic Borofibrists, nearly level

- Low hills, terraces, and outwash plains have well-drained soils formed in silty loess or ash, over gravelly glacial till. Depressions have poorly drained, fibrous organic soils. ORTL: Slight - Very Severe; CCS: Good (on well-drained soils) - Unsuitable (wet organic soil).

S04 - Typic Cryorthods, very gravelly, nearly level to rolling - Sphagnic Borofibrists, nearly level

- Soils of nearly level to undulating outwash plains are well-drained to excessively well-drained, formed in a mantel of silty loess over very gravelly glacial till. Soils of the association located in depressions are very poorly drained, organic soils. ORTL: Slight - Very Severe; CCS: Good - Unsuitable (wet, organic).

S05 - Typic Cryorthods, very gravelly, hilly to steep - Sphagnic Borofibrists, nearly level

- On the hills and plains, these soils, formed in a thin metal of silty loess over very gravelly and stony glacial drift, are well drained and strongly acid. In muskegs, most of these soils consist of fibrous peat. ORTL: Severe (steep slope); CCS: Unsuitable (steep slopes; stones and boulders; short, frost-free season).

S010 - Humic Cryorthods, very gravelly, hilly to steep

- Generally, these are well-drained soils of foothills and deep mountain valleys, formed in very gravelly drift with a thin mantel of silty loess or mixture of loess and volcanic ash. These soils are characteristically free of permafrost except in the highest elevation. ORTL: Severe (steep slope); CCS: Poor - Unsuitable (low soil temperature throughout growing season; steep slopes).

S015 - Pergelic Cryorthods - Histic Pergelic Cryaquepts, very gravelly, nearly level to rolling

- On low moraine hills, these soils are well drained, formed in 10 to 20 inches of loamy material over very gravelly glacial drifts. On foot slopes and valleys, these soils tend to be poorly drained, with shallow permafrost table. ORTL: Slight - Severe (wet); CCS: Unsuitable (short, frost-free period; wet; stones and boulders).

S016 - Pergelic Cryorthods very gravelly, hilly to steep - Histic Pergelic Cryaquepts, loamy, nearly level

- On hilly moraines these soils are well-drained; beneath a thin surface of partially decomposed organic matter, the soils have spodic horizons developed in shallow silt loam over very gravelly or sandy loam. In valleys and long foot slopes, these are poorly drained soils, with a thick, peaty layer over a frost-churned loam or silt loam. Here, depth of permafrost is usually less than 20 inches below surface mat. ORTL: Severe (steep slope; wet); CCS: Unsuitable (short, frost-free period) - Poor (wet; low soil temperature).

TABLE B.2.7.8: DEFINITIONS FOR OFFROAD TRAFFICABILITY LIMITATIONS AND COMMON CROP SUITABILITY OF SOIL ASSOCIATIONS[a] OFFROAD TRAFFICABILITY LIMITATIONS (ORTL)

Offroad Trafficability refers to cross-country movement of conventional wheeled and tracked vehicles, including construction equipment. Soil limitations for Offroad Trafficability (based on features of undisturbed soils) were rated Slight, Moderate, Severe, and Very Severe on the following bases:

- Slight

  Soil limitations, if any, do not restrict the movement of cross-country vehicles.

- Moderate

  Soil limitations need to be recognized but can generally be overcome with careful route planning. Some special equipment may be required.

- Severe

  Soil limitations are difficult to overcome, and special equipment and careful route planning are required. These soils should be avoided if possible.

- Very Severe

  Soil limitations are generally too difficult to overcome. Generally, these soils are unsuitable for conventional offroad vehicles.

COMMON CROP[b]
SUITABILITY (CCS)

Soils were rated as Unsuitable, Good, Fair, and Poor for the production of common crops on the following bases:

- Unsuitable

  Soil or climate limitations are generally too severe to be overcome. None of the common crops can be grown successfully in most years, or there is danger of excessive damage to soils by erosion if cultivation is attempted.

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a. Source: U.S. Department of Agriculture, Soil Conservation Service 1979.

b. The principal crops grown in Alaska--barley, oats, grasses for hay and silage, and potatoes--were considered in preparing ratings. Although only these crops were used, it is assumed that the ratings are also valid for vegetables and other crops suited to Alaskan soils.

- Good

Soil or climate limitations, if any, are easily overcome, and all of the common Alaskan crops can be grown under ordinary management practices. On soils of this group --

(a) Loamy texture extends to a depth of at least 18 inches (45 cm).

(b) Crop growth is not impeded by excessive soil moisture during the growing seasons.

(c) Damage by flooding occurs no more frequently than 1 year in 10.

(d) Slopes are dominantly less than 7 percent.

(e) Periods of soil moisture deficiency are rare, or irrigation is economically feasible.

(f) Damage to crops as a result of early frost can be expected no more frequently than 2 years in 10.

(g) The hazard of wind erosion is estimated to be slight.

- Fair

Soils or climate limitations need to be recognized but can be overcome. Common crops can be grown, but careful management and special practices may be required. On soils of this group --

(a) Loamy texture extends to a depth of at least 10 inches (25 cm).

(b) Periods of excessive soil moisture, which can impede crop growth during the growing season, do not exceed a total of 2 weeks.

(c) Damage by flooding occurs no more frequently than 2 years in 10.

(d) Slopes are dominantly less than 12 percent.

(e) Periods of soil moisture deficiency are infrequent.

(f) Damage to crops as a result of early frost can be expected no more frequently than 3 years in 10.

(g) There is no more than a moderate hazard of wind erosion.

- Poor

Soils or climate limitations are difficult to overcome and are severe enough to

make the use questionable. The choice of crops is narrow, and special treatment or management practices are required. In some places, overcoming the limitations may not be feasible. On soils of this group --

(a) Loamy texture extends to a depth of at least 5 inches (12 cm).

(b) Periods of excessive soil moisture during the growing season do not exceed a total of 3 weeks.

(c) Damage by flooding occurs no more frequently than 3 years in 10.

(d) Slopes are dominantly less than 20 percent.

(e) Periods of soil moisture deficiency are frequent enough to severely damage crops.

(f) Climatic conditions permit at least one of the common crops, usually grasses, to be grown successfully in most years.

TABLE B.2.7.9: ECONOMICAL AND TECHNICAL SCREENING SOUTHERN STUDY AREA (WILLOW TO ANCHORAGE/POINT MACKENZIE)

	(1) ABC'	(2) ADFC	(3) AEFC
- Length (miles)	73	38	39
- Max. Elev. (ft)	1400	400	400
- Clearing (miles) =			
Medium & Light	61	20	15
None	12	18	24
- Access (miles) =			
New Roads	20	0	12
4-Wheel	53	38	27
- Tower Construction*	329	180	176
- Rating:			
Economical	C	A	C
Technical	C	A	A

A = recommended corridor
C = acceptable but not preferred
F = unacceptable

* Approximate number of towers required for this corridor, assuming single-circuit line.

TABLE B.2.7.10: ECONOMICAL AND TECHNICAL SCREENING
CENTRAL STUDY AREA (DAM SITES TO INTERTIE)

	(1) ABCD	(2) ABECD	(3) AJCF	(4) ABCJHI	(5) ABECJHI	(6) CBAHI	(7) CEBAHI	(8) CBAG	(9) CEBAG	(10) CJAG	(11) CJAHI	(12) JACJHI	(13) ABCF	(14)* AJCD	(15) ABECF
- Length	40	45	41	77	82	68	75	90	95	91	69	70	41	41	45
- Max. Elevation, ft.	2500	3600	3500	4300	4300	4300	3500	3300	3600	3500	3800	3900	2500	3500	3600
- Clearing															
Medium & Light	38	30	26	18	30	20	27	45	37	40	55	17	39	26	35
None	2	15	15	59	50	48	46	45	60	51	14	53	2	15	10
- Access															
New Roads	28	31	12	58	49	44	53	44	49	13	27	44	41	5	45
4-Wheel	12	12	29	8	8	3	3	46	46	78	23	26	0	36	0
- Tower Construction*	180	203	185	347	369	306	338	405	428	410	311	315	185	185	203
- Rating:															
Economical	C	C	C	F	F	C	F	F	F	F	C	F	C	A	C
Technical	A	C	C	F	F	F	C	C	C	C	C	C	C	A	C

A = recommended
C = acceptable but not preferred
F = unacceptable

* Approximate number of towers required for this corridor, assuming single-circuit line.

TABLE B.2.7.11 ECONOMICAL AND TECHNICAL SCREENING NORTHERN STUDY AREA (HEALY TO FAIRBANKS)

	(1) ABC	(2) ABDC	(3) AEDC	(4) AEF
- Length	90	86	115	105
- Max. Elevation	1600	1600	4500	4500
- Clearing				
Medium & Light	48	50	40	50
None	42	36	75	55
- Access				
New Roads	0	0	54	42
4-Wheel	90	43	42	16
- Tower Construction*	405	387	518	473
- Rating:				
Economical	A	A	C	C
Technical	A	C	F	F

A = recommended
C = acceptable but not preferred
F = unacceptable

* Approximate number of towers required for this corridor, assuming single-circuit line.

TABLE B.2.7.12: SUMMARY OF SCREENING RESULTS

Corridor	Env.	Econ.	Tech.	Summary
	RATINGS			
- Southern Study Area				
(1) ABC'	C	C	C	C
(2) ADFC	A	A	A	A
(3) AEFC	F	C	A	F
- Cental Study Area				
(1) ABCD	C	C	A	C
(2) ABECD	F	C	C	F
(3) AJCF	C	C	C	C
(4) ABCJHI	F	F	F	F
(5) ABECJHI	F	F	F	F
(6) CBAHI	F	C	F	F
(7) CEBAHI	F	F	C	F
(8) CBAG	F	F	C	F
(9) CEBAG	F	F	C	F
(10) CJAG	F	F	C	F
(11) CJAHI	F	C	C	F
(12) JACJHI	F	F	C	F
(13) ABCF	C	C	C	C
(14) AJCD	A	A	A	A
(15) ABECF	F	C	C	F
- Northern Study Area				
(1) ABC	A	A	A	A
(2) ABDC	C	A	C	C
(3) AEDC	F	C	F	F
(4) AEF	F	C	F	F

A = recommended
C = acceptable but not preferred
F = unacceptable

TABLE B.2.7.13: ENVIRONMENTAL CONSTRAINTS - SOUTHERN STUDY AREA (WILLOW TO ANCHORAGE/POINT MACKENZIE)

	Corridor Segment 1 (ABC')	2 (ADFC)	3 (AEFC)
Length (miles)	73	38	39
Topography/Soils	Some soils with severe limitations to off road travel; some good agricultural soils	Most of route potentially wet, with severe limitations to off road travel; some good agricultural soils	Same as Corridor 2
Land Use	No existing ROW in AB; residential uses near Palmer; proposed capital site; much U.S. Military Wdl., Private, and Village Selection Land	Trail is only existing ROW; residential and recreational areas; Susitna Flats Game Refuge; agricultural land sale	No known existing ROW; recreational use areas, including Nancy Lakes; lakes used by float planes; agricultural land sale
Aesthetics	Iditarod Trail; trail paralleling Deception Ck.: Gooding L. birdwatching area; 5 crossings of Glenn Hwy, 1 crossing of Parks Hwy	Susitna Flats Game Refuge; Iditarod Trail; 1 crossing of Parks Hwy	Lake area south of Willow; Iditarod Trail; 1 crossing of Parks Hwy
Cultural Resources[1/]	Archeologic sites - DATA VOID	Archeologic sites - DATA VOID	Archeologic sites - DATA VOID
Vegetation	Wetlands along Deception Ck. and at Matanuska River crossing; extensive clearing in upland, forested areas needed	Extensive wetlands; clearing needed in forested areas	Extensive wetlands; clearing needed in forested areas
Fish Resources	5 river and 28 creek crossings; valuable spawning sites, especially salmon: Knik area, Matanuska area, DATA VOID	1 river and 8 creek crossings; valuable spawning sites, especially salmon: L. Susitna R., DATA VOID	1 river and 8 creek crossings; valuable spawning sites, especially salmon: L. Susitna R., DATA VOID
Wildlife Resources	Passes through or near waterfowl and shorebird nesting and feeding areas, and areas used by brown bear	Passes through or near waterfowl and shorebird nesting, feeding, and migration areas, and areas used by furbearers and brown bear	Same as Corridor 2
Environmental Rating[2/]	C	A	F

1/ Coastal area probably has many sites; available literature not yet reviewed.

2/ A = recommended; C = acceptable but not recommended; F = unacceptable

TABLE B.2.7.14: ENVIRONMENTAL CONSTRAINTS CENTRAL STUDY AREA (DAM SITES TO INTERTIE)

	Corridor Segment 1 (ABCD)	2 (ABECD)	3 (AJCF)	4 (ABCJHI)	5 (ABECJHI)
Length (miles)	40	45	41	77	82
Topography/Soils	Crosses several deep ravines; about 1000' change in elevation; some wet soils	Crosses several deep ravines; about 2000' change in elevation; some steep slopes; some wet soils	Crosses several deep ravines; about 2000' change in elevation; some steep slopes; some some wet soils	Crosses several deep ravines; >2000' change in elevation; routing above 4000'; steep slopes; some wet soils; shallow bedrock in mts.	Crosses several deep ravines; changes in elevation >2000'; routing above 4000'; steep slopes; some wet soils; shallow bedrock in mts.
Land Use	Little existing ROW except Corps Rd.; mostly Village Selection and Private Lands	Little existing ROW except Corps Rd. and at D; rec. and resid. areas; float plane areas; mostly Village Selection and Private Lands	No existing ROW except at F; rec. areas; float plane areas; mostly Village Selection and Private Land; resid. & rec. development in area of Otter L. and old sled road	No existing ROW; rec. areas isolated cabins; lakes used by float planes; much Village Selection Land	Same as corridor 4
Aesthetics	Fog Lakes; Stephan Lake	Fog Lakes; Stephan Lake; proposed railroad extension; high country (Prairie & Chulitna Ck. drainages) and viewshed of Alaska Range	Viewshed of Alaska Range & High Lake; proposed access road	Fog Lakes; Stephan Lake; proposed access road; viewshed of Alaska Range	Fog Lakes; Stephan Lake; High Lake; proposed access road; viewshed of Alaska Range
Cultural Resources	Archeologic sites near Watana dam site, Stephan Lake and Fog Lakes; DATA VOID from Gold Ck. to Devil Canyon; historic sites near the communities of Gold Creek and Canyon	Same as Corridor 1	Archeologic sites by Watana dam site, & near Portage Ck./Susitna R. Confluence; possible sites along Susitna R.; historic sites near communities of Gold Ck. and Canyon	Archeologic sites near Watana dam site, Stephan L. and Fog Lakes; possible sites along pass between drainages, DATA VOID between H and I	Same as Corridor 4
Vegetation	Wetlands in eastern third of corridor; extensive forest-clearing needed	Wetlands in eastern half of corridor; extensive forest-clearing needed	Forest-clearing needed in western half	Small wetland areas in JA area; extensive forest-clearing needed; DATA VOID	Wetlands in JA and Stephan Lake areas; extensive forest-clearing needed
Fish Resources	1 river and 17 creek crossings; valuable spawning areas, especially grayling: DATA VOID	1 river and 17 creek crossings; valuable spawning areas, especially grayling: DATA VOID	14 creek crossing; valuable spawning areas, especially grayling and salmon: Indian River, Portage Creek, DATA VOID	1 river and 42 creek crossings; valuable spawning areas, especially grayling	42 creek crossings; valuable spawning areas, especially grayling and salmon: DATA VOID
Wildlife Resources	unidentified raptor nest located on trib. to Susitna; passes through, habitat for: raptors, furbearers, wolves, wolverine, brown bear, caribou	Passes through habitat for: raptors, waterfowl, migrating swans, furbearers, caribou, wolves, wolverine, brown	Golden eagle nest along Devil Ck. near High L.; active raven nest on Devil Ck.; passes through habitat for: raptors, furbearers, wolves, brown bear	Golden eagle nest along Devil Ck. near High L.; caribou movement area; passes through habitat for: raptors, waterfowl, furbearers, wolves, wolverine, brown bear	Same as Corridor 4 with important waterfowl and migrating swan habitat at Stephan Lake
Environmental Rating[1/]	C	F	C	F	F

1/ A = recommended, C = acceptable but not recommended, F = unacceptable

TABLE B.2.7.14 (Page 2 of 3)

	Corridor Segment 6 (CBAHI)	7 (CEBAHI)	8 (CBAG)	9 (CEBAG)	10 (CJAG)
Length (miles)	68	73	90	95	91
Topography/Soils	Crosses several deep ravines; changes in elevation of about 1600'; routing above 4000'; steep slopes; some wet soils; shallow bedrock in mts.	Crosses several deep ravines; change in elevation of about 1600'; routing above 3000'; steep slopes; some wet soils; shallow bedrock in mts.	Crosses several deep ravines; change in elevation of about 1600'; routing above 3000'; steep slopes; some wet soils; shallow bedrock in mts.	Crosses several deep ravines; changes in elevation of about 1600'; routing above 3000'; steep slopes; some wet soils; shallow bedrock in mts.	Same as Corridor 8
Land Use	No known existing ROW; rec. areas and isolated cabins; float plane area; Susitna area and near I are Village Selection Lands	Same as Corridor 6	No existing ROW; rec. areas and isolated cabins; float plane areas; air strip and airport; much Village Selection and Federal Land	Same as Corridor 8	No existing ROW; rec. areas and isolated cabins; float plane areas; air strip and airport; mostly Village Selection and Federal Land
Aesthetics	Fog Lakes and Stephan Lake; Tsusena Butte; viewshed of Alaska Range	For Fog Lakes and Stephan Lake; high country (Prairie-Chunlina Cks.); Tsusena Butte; viewshed of Alaska Range	Fog Lakes; Stephan Lake; access road; scenic area of Deadman Ck.; viewshed of Alaska Range	Fog Lakes; Stephan Lake; proposed access road; high country (Prairie and Chunilna Cks.); Deadman Ck.; viewshed of Alaska Range	High Lakes area; proposed access road; Deadman Ck. drainage; viewshed at Alaska Range
Cultural Resources	Archeologic sites near Watana dam site, Fog Lakes & Stephan Lake; DATA VOID between H and I	Same as Corridor 6	Archeologic sites by near Watana dam site, Fog Lakes, Stephan Lake and along Deadman Ck.	Same as Corridor 8	Archeologic sites near Watana dam site and along Deadman Ck.
Vegetation	Extensive wetlands from B to near Tsusena Butte; extensive forest-clearing needed	Extensive wetlands in Stephan L., Fog Lakes Tsusena Butte areas; extensive forest-clearing needed	Wetlands between B and mountains; extensive forest-clearing needed	Wetlands in Stephan L./Fog Lakes areas; extensive forest-clearing needed	Small wetlands in JA area; extensive forest-clearing needed
Fish Resources	32 creek crossings; valuable spawning areas, especially grayling: DATA VOID	45 creek crossings; valuable spawning areas, especially grayling: DATA VOID	1 river and 43 creek crossings; valuable spawning areas, especially grayling: DATA VOID	1 river and 48 creek crossings; valuable spawning areas, especially grayling: DATA VOID	1 river and 47 creek crossings; valuable spawning areas, especially grayling: DATA VOID
Wildlife Resources	Bald eagle nest s.e. of Tsusena Butte; area of caribou movement; passes through habitat for: raptors, waterfowl, furbearers, wolves, wolverine, brown bear	Same as Corridor 6, with important waterfowl and migrating swan habitat at Stephan Lake	Important bald eagle habitat by Denali Hwy. & Deadman L.; unchecked bald eagle nest near Tsusena Butte; passes through habitat for: raptors, furbearers, wolves, wolverine, brown bear	Same as Corridor 8, with important waterfowl and migrating swan habitat at Stepahn Lake	Golden eagel nest along Devil Ck. near High Lake; unchecked bald eagel nest near Tsusena Butte; area of caribou movement; passes through habitat for: raptors, waterfowl, furbearers, brown bear
Environmental Rating	F	F	F	F	F

TABLE 8.2.7.14 (Page 3 of 3)

	Corridor Segment 11 (CJAHI)	12 (JA-CJHI)	13 (ABCF))	14 (AJCD)	15 (ABECF)
Length (miles)	69	70	41	41	45
Topography/Soils	Crosses several deep ravines; changes in elevation of about 1000'; routing above 3000'; steep slopes; some wet soils; shallow bedrock in mts.	Same as Corridor 11	Crosses several deep ravines; about 1000' change in elevation; some wet soils	Crosses deep ravine at Devil Ck.; about 2000' change in elevation; routing above 3000'; some steep slopes; some wet soils	Crosses several deep ravines; about 2000' change in elevation; some wet soils
Land Use	No existing ROW; rec. areas & isolated cabins; float plane areas; mostly Village Selection and Private Land	No existing ROW; rec. areas and isolated cabins; float plane area; mostly Village Selection and Private Land	No known existing ROW; except at F; rec. areas; float plane areas; resid. and rec. use near Otter L. and old sled rd.; isolated cabins; mostly Village Selection Land; some Private Land	Little existing ROW except Old Corps Rd. and at D; rec. areas; isolated cabins; much Village Selection land; some Private Land	No known existing ROW except at F; rec. areas; float plane areas; resid. and rec. use near Otter L. & old sled rd.; isolated cabins; mostly Village Selection land with some Private Land
Aesthetics	High Lakes area; proposed access road; viewshed of Alaska Range	High Lakes area; proposed access road; Tsusena Butte; viewshed of Alaska Range	Fog Lakes, Stephan L.	Viewshed of Alaska Range and High Lake; proposed access road	Fog Lakes; Stephan Lake; high country (Prairie and Chulina Cks. drainages); viewshed of Alaska Range
Cultural Resources	Archeologic sites near Watana dam site	Archeologic site near Watana dam site; possible sites along pass between drainages	Archeologic sites near Watana dam site, Portage Ck./Susitna R. confluence; Stephan L. and Fog Lakes; historic sites near communities of Canyon and Gold Ck.	Archeologic sites by Watana dam site, possible sites along Susitna R.; historic sites near communities of Canyon and Gold Ck.	Same as Corridor 13
Vegetation	Small wetland areas in JA area; some forest-clearing needed	Small wetland areas in JA area; fairly extensive forest-clearing needed	Wetlands in eastern third of corridor; extensive forest-clearing needed	Forest-clearing needed in western half	Wetlands in eastern half of corridor; extensive forest-clearing needed
Fish Resources	36 creek crossings; valuable spawning areas, especially grayling and salmon: DATA VOID	40 creek crossings; valuable spawning areas, especially grayling and salmon: DATA VOID	15 creek crossings; valuable spawning areas, especially grayling and salmon: Indian River, Portage Ck., DATA VOID	1 river and 16 creek crossings; valuable spawning areas, especially grayling: DATA VOID	15 creek crossings; valuable spawning areas, expecially grayling and salmon: Indian River, Portage Ck., DATA VOID
Wildlife Resources	Golden eagle nest along Devil Ck. near High Lake; bald eagle nest s.e. of Tsusena Butte; passes through habitat for: raptors, furbearers, brown bear	Golden eagle nest along Devil Ck. near High Lake; passes through habitat for: raptors, furbearers, wolves, brown bear	Unidentified raptor nest on tributary to Susitna; passes through habitat for: raptors, furbearers, wolves, wolverine, brown bear, caribou	Golden eagel nest in Devil Ck./High Lake area; active raven nest on Devil Ck.; passes through habitat for: raptors, furbearers, wolves, brown bear, caribou	Important waterfowl and migrating swan habitat at Stephan L.; passes through habitat for: raptors, waterfowl, furbearers, wolves, wolverine, brown bear, caribou
Environmental Rating	F	F	C	A	F

TABLE B.2.7.15: ENVIRONMENTAL CONSTRAINTS NORTHERN STUDY AREA (HEALY TO FAIRBANKS)

	Corridor Segment			
	1 (ABC)	2 (ABDC)	3 (AEDC)	4 (AEF)
Length (miles)	90	86	115	105
Topography/Soils	Some wet soils with severe limitations to off-road traffic	Severe limitations to off-road traffic in wet soils of the flats	Change in elevation of about 2500'; steep slopes; shallow bedrock in mts.; severe limitations to off-road traffic in the flats	Same as Corridor 3
Land Use	Air strip; residential areas and isolated cabins; some U.S. Military Withdrawal and Native land	No existing ROW n. of Browne; scattered residential and isolated cabins; airstrip; Fort Wainwright Military Reservation	No existing ROW beyond Healy/Cody Ck. confluence; isolated cabins; airstrips; Fort Wainwright Military Reservation	Airstrips; isolated cabins; Fort Wainwright Military Reservation
Aesthetics	3 crossings of Parks Hwy; Nenana R. - scenic area	3 crossings of Parks Hwy; high visibility in open flats	1 crossing of Parks Hwy.; high visibility in open flats	High visibility in open flats
Cultural Resources	Archeologic sites probable since there is a known site nearby; DATA VOID	Dry Creek archeologic site near Healy; possible sites along river crossings; DATA VOID	Dry Creek archeologic site near Healy; possible sites near Japan Hills and in the mts.; DATA VOID	Archeologic sites near Dry Creek and Fort Wainwright; possible sites near Tanana River; DATA VOID
Vegetation	Extensive wetlands; forest-clearing needed mainly north of the Tanana River	Probably extensive wetlands between Wood and Tanana Rivers; extensive forest-clearing needed n. of Tanana River	Probably extensive wetlands between Wood and Tanana Rivers; extensive forest-clearing needed n. of Tanana River; data lacking for southern part	Probably extensive wetlands between Wood and Tanana Rivers
Fish Resources	4 river and 40 creek crossings; valuable spawning sites: Tanana River, DATA VOID	5 river and 44 creek crossings; valuable spawning sites: Wood River, DATA VOID	3 river and 72 creek crossings; valuable spawning sites: Wood River, DATA VOID	3 river and 60 creek crossings; valuable spawning sites: Wood River, DATA VOID
Wildlife Resources 1/	Passes through or near prime habitat for: peregrines, waterfowl, furbearers, moose; passes through or near important habitat for: peregrines, golden eagles	Passes through or near prime habitat for: peregrines, waterfowl, furbearers; passes through or near important habitat for: golden eagles, other raptors	Passes through or near prime habitat for: peregrines, waterfowl, furburers, caribou, sheep; passes through or near important habitat for: golden eagles, brown bear	Passes through or near prime habitat for: peregrines, bald eagles, waterfowl, furbearers, caribou, sheep; passes through or near important habitat for: golden eagles, brown bear
Environmental Rating 1/	A	C	F	F

1/ Source: VanBallenberghe personal communication. Prime habitat = minimum amount of land necessary to provide a sustained yield for a species; based upon knowledge of that species' needs f rom eeperience of ADF&G personnel. Important habitat = land which ADF&G considers not as critical to a species as is Prime habitat, but is valuable.

2/ A = recommended, B = acceptable but not preferred, C = unacceptable

TABLE B.2.7.16: TECHNICAL, ECONOMIC AND ENVIRONMENTAL CRITERIA USED IN CORRIDOR SCREENING

<u>Technical</u>

Primary

- Topography
- Climate and Elevation
- Soils
- Length

Secondary

- Vegetation and Clearing
- Highway and River Crossings

<u>Economic</u>

Primary

- Length
- Presence of Right-of-Way
- Presence of Access Roads

Secondary

- Topography
- Stream Crossings
- Highway and Railroad Crossings

<u>Environmental</u>

Primary

- Aesthetic and Visual
- Land Use
- Presence of Existing Right-of-Way
- Existing and Proposed Development

Secondary

- Length
- Topography
- Soils
- Cultural Reservoir
- Vegetation
- Fishery Resources
- Wildlife Resources

Table B.3.1.1: PERTINENT DATA FOR GAGING STATIONS

Station Name	USGS Gage Number	Susitna River Mile	Drainage Area (mi^2)	Periods of Record: Streamflow (Continuous)[1]	Periods of Record: Water Quality[2]	Agency
Susitna River nr. Denali	15291000	290.8	950	5/57-9/66, 11/68-Present	1957-66, 1968-69, 1974-Present (6/30/82)	USGS
Susitna River nr. Cantwell (Vee Canyon)	15291500	223.1	4,140	5/61-9/72, 5/80-Present	1962-72, 1980-Present (7/27/82)	USGS
Susitna River nr. Cantwell (Vee Canyon)	-	223.1	4,140	-	1980-81	R&M Consult.
Susitna River nr. Watana Damsite	-	182.2[3]	5,180	8/80-Present	10/80-12/81	R&M Consult.
Susitna River at Gold Creek	15292000	136.6	6,160	6/49-Present	1949-58, 1962, 1967-68, 1974-Present (9/16/82)	USGS
Susitna River at Gold Creek	-	136.6	6,160	-	1980-Present (10/14/82)	R&M
Susitna River at Sunshine	15292780	83.9	11,100	5/81-Present	1971, 1975, 1977, 1981-Present (10/13/82)	
Susitna River at Susitna Station	15294350	25.8	19,400	10/74-Present	1955, 1970, 1975-Present (10/5/82)	USGS
Maclaren River nr. Paxson	15291200	259.8[4]	280	6/58-Present	1958-61, 1967-68, 1975	USGS
Chulitna River nr. Talkeetna	15292400	98.0[4]	2,570	2/58-9/72, 5/80-Present	1958-59, 1967-72, 1980-Present (6/3/82)	USGS
Talkeetna River nr. Talkeetna	15291500	97.0[4]	2,006	6/64-Present	1954, 1966-Present (10/14/82)	USGS
Skwentna River nr. Skwentna	15294300	28.0[5]	2,250	10/59-Present	1959, 1961, 1967-68, 1974-75, 1980-81	USGS
Yentna River nr. Susitna Station	15294345	28.0[4]	6,180	10/80-Present	1981-Present (8/11/82)	USGS

1/ All streamflow gage stations are currently active, however, flow data included in this document is through September 1981.
2/ "Present" in periods of record indicates station is active as of January 1983. A date after "Present" indicates the most recent data available.
3/ Watana continuous water quality monitor was installed at river mile 183.0.
4/ River mile at tributary's confluence with Susitna River.
5/ River mile at Yentna-Susitna confluence.

Source: USGS and R&M

TABLE B.3.1.2: USGS STREAMFLOW SUMMARY (cfs) (Water Years 1951 thru 1981)

Station		Denali	Cantwell	Gold Creek	Susitna	Maclaren	Chulitna	Talkeetna	Skwentna
Yrs. of Record		22+	12+	32	7	23+	16+	17+	22
Oct	Max	2,165	5,472	8,212	58,640	734	8,062	4,438	7,254
	Mean	1,187	3,236	5,757	35,694	421	4,916	2,562	4,492
	Min	528	1,638	3,124	19,520	249	2,898	1,450	1,929
Nov	Max	878	2,487	4,192	31,590	370	3,213	1,718	4,195
	Mean	528	1,514	2,568	16,289	189	2,075	1,180	1,930
	Min	290	780	1,215	9,933	95	1,480	765	678
Dec	Max	575	1,658	3,264	14,690	246	2,100	1,103	2,871
	Mean	344	1,053	1,793	9,794	127	1,494	836	1,320
	Min	169	543	866	6,000	49	1,000	556	624
Jan	Max	444	1,694	2,452	10,120	162	1,623	851	2,829
	Mean	257	896	1,463	8,417	100	1,299	680	1,117
	Min	119	437	724	6,529	44	974	459	600
Feb	Max	330	1,200	2,028	9,017	140	1,414	777	1,821
	Mean	215	761	1,243	7,665	87	1,115	573	952
	Min	81	426	723	5,614	42	820	401	600
Mar	Max	290	1,200	1,900	8,906	121	1,300	743	1,352
	Mean	195	711	1,123	6,842	78	988	512	839
	Min	42	429	713	5,368	41	738	380	600
Apr	Max	415	1,223	2,650	12,030	145	1,600	1,038	2,138
	Mean	232	883	1,377	8,350	87	1,176	603	1,110
	Min	43	465	745	6,233	50	700	422	607
May	Max	3,468	12,150	21,890	83,580	2,131	13,890	8,840	22,370
	Mean	2,092	8,044	13,277	64,896	823	8,634	4,336	8,755
	Min	629	1,915	3,745	48,670	208	2,355	2,145	1,635
June	Max	12,210	34,630	50,580	165,900	4,297	40,330	19,040	36,670
	Mean	7,261	18,808	27,658	123,447	2,886	22,527	11,619	19,137
	Min	4,647	9,909	15,500	90,930	1,751	17,390	5,207	10,650
July	Max	12,110	22,790	34,400	181,400	4,649	35,570	15,410	28,620
	Mean	9,600	17,431	24,383	141,300	3,216	27,047	10,974	17,811
	Min	6,756	12,220	16,100	115,200	2,441	20,820	7,080	11,670
Aug	Max	12,010	22,760	38,538	159,600	4,122	33,670	16,770	20,160
	Mean	8,246	15,252	21,996	118,973	2,633	22,749	9,459	13,535
	Min	3,919	6,597	8,879	91,360	974	11,300	3,787	7,471
Sept	Max	5,452	12,910	21,240	91,200	2,439	22,260	10,610	13,090
	Mean	3,300	7,971	13,175	71,239	1,138	11,544	5,369	8,156
	Min	1,822	3,376	5,093	48,910	470	6,704	2,070	3,783

Note: Sunshine and Yentna streamflow data were not included due to the brief period of record (approximately 1 yr).

Source: USGS

TABLE B.3.1.3: WATANA NATURAL MONTHLY FLOWS (CFS)

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1951	3299	1107	906	808	673	620	1302	11650	18518	19787	16478	17206	7734
1952	4593	2170	1501	1275	841	735	804	4217	25773	22111	17356	11571	7777
1953	6286	2757	1281	819	612	671	1382	15037	21470	17355	16682	11514	8035
1954	4219	1600	1184	1088	803	638	943	11697	19477	16984	20421	9166	7401
1955	3859	2051	1550	1388	1051	886	941	6718	24881	23788	23537	13448	8719
1956	4102	1588	1039	817	755	694	718	12953	27172	25831	19153	13194	9051
1957	4208	2277	1707	1373	1189	935	945	10176	25275	19949	17318	14841	8381
1958	6035	2936	2259	1481	1042	974	1265	9958	22098	19753	18843	5979	7770
1959	3668	1730	1115	1081	949	694	886	10141	18330	20493	23940	12467	8011
1960	5166	2214	1672	1400	1139	961	1070	13044	13233	19506	19323	16086	7954
1961	6049	2328	1973	1780	1305	1331	1965	13638	22784	19840	19480	10146	8603
1962	4638	2263	1760	1609	1257	1177	1457	11334	36017	23444	19887	12746	9833
1963	5560	2509	1709	1309	1185	884	777	15299	20663	28767	21011	10800	9278
1964	5187	1789	1195	852	782	575	609	3579	42842	20083	14048	7524	8263
1965	4759	2368	1070	863	773	807	1232	10966	21213	23236	17394	16226	8451
1966	5221	1565	1204	1060	985	985	1338	7094	25940	16154	17391	9214	7374
1967	3270	1202	1122	1102	1031	890	850	12556	24712	21987	26105	13673	9096
1968	4019	1934	1704	1618	1560	1560	1577	12827	25704	22083	14148	7164	8032
1969	3135	1355	754	619	608	686	1262	9314	13962	14844	7772	4260	4912
1970	2403	1021	709	636	602	624	986	9536	14399	18410	16264	7224	6115
1971	3768	2496	1687	1097	777	717	814	2857	27613	21126	27447	12189	8589
1972	4979	2587	1957	1671	1491	1366	1305	15973	27429	19820	17510	10956	8963
1973	4301	1978	1247	1032	1000	874	914	7287	23859	16351	18017	8100	7112
1974	3057	1355	932	786	690	627	872	12889	14781	15972	13524	9786	6314
1975	3089	1474	1277	1216	1110	1041	1211	11672	26689	23430	15127	13075	8403
1976	5679	1601	876	758	743	691	1060	8939	19994	17015	18394	5712	6835
1977	2974	1927	1688	1349	1203	1111	1203	8569	31353	19707	16807	10613	8233
1978	5794	2645	1980	1578	1268	1257	1408	11232	17277	18385	13412	7133	6992
1979	3774	1945	1313	1137	1055	1101	1318	12369	22906	24912	16671	9097	8184
1980	6150	3525	2032	1470	1233	1177	1404	10140	23400	26740	18000	11000	8908
1981	6632	3044	1790	1858	1592	1262	1641	14416	16739	27601	30542	11669	9985
1982	5700	2650	1863	1700	1234	898	1196	10879	21444	20445	13206	13890	7968
1983	5154	2132	1893	1797	1610	1427	1565	11672	20401	18761	20862	11192	8253
MAX	6632	3525	2259	1858	1610	1560	1965	15973	42842	28767	30542	17206	9985
MIN	2403	1021	709	619	602	575	609	2857	13233	14843	7772	4260	4912
MEAN	4567	2064	1453	1225	1035	936	1158	10625	22980	20747	18366	10875	8046

TABLE B.3.1.4: DEVIL CANYON NATURAL MONTHLY FLOWS (CFS)

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1950	5,758	2,405	1,343	951	736	670	802	10,491	18,469	21,383	18,821	7,951	7,482
1951	3,652	1,231	1,031	906	768	697	1,505	13,219	19,979	2,157	18,530	19,799	8,574
1952	5,222	2,539	1,758	1,484	943	828	879	7,990	30,014	24,862	19,647	13,441	8,884
1953	7,518	3,233	1,550	1,000	746	767	1,532	17,758	25,231	19,184	19,207	13,928	9,305
1954	5,109	1,921	1,387	1,224	930	729	1,131	15,286	23,188	19,154	24,072	11,579	8,809
1955	4,830	2,507	1,868	1,649	1,275	1,024	1,107	8,390	28,082	26,213	24,960	13,989	9,658
1956	4,648	1,789	1,207	922	893	852	867	15,979	31,137	29,212	22,610	16,496	10,551
1957	5,235	2,774	1,987	1,583	1,389	1,105	1,190	12,474	28,415	22,110	19,389	18,029	9,633
1958	7,435	3,590	2,905	1,792	1,212	1,086	1,437	11,849	24,414	2,163	21,220	8,689	8,808
1959	4,403	2,000	1,371	1,317	1,179	878	1,120	13,901	21,538	23,390	28,594	15,330	9,585
1960	6,061	2,623	2,012	1,686	1,340	1,113	1,218	14,803	14,710	21,739	22,066	18,930	9,025
1961	7,171	2,760	2,437	2,212	1,594	1,639	2,405	15,031	27,069	22,881	21,164	12,219	9,965
1962	5,459	2,544	1,979	1,796	1,413	1,320	1,613	12,141	49,680	24,991	22,242	14,767	10,912
1963	6,308	2,696	1,896	1,496	1,387	958	811	17,698	24,094	32,388	22,721	11,777	10,353
1964	5,998	2,085	1,387	978	900	664	697	4,047	47,816	21,926	15,586	8,840	9,244
1965	5,744	2,645	1,161	925	829	867	1,314	12,267	24,110	26,196	19,789	18,234	9,507
1966	6,497	1,908	1,478	1,279	1,187	1,187	1,619	8,734	30,446	18,536	20,245	10,844	8,663
1967	3,844	1,458	1,365	1,358	1,268	1,089	1,054	14,436	27,796	25,081	30,293	15,728	10,398
1968	4,585	2,204	1,930	1,851	1,779	1,779	1,791	14,982	29,462	24,871	16,091	8,226	9,129
1969	3,577	1,532	836	687	682	770	1,421	10,430	14,951	15,651	8,484	4,796	5,318
1970	2,867	1,146	810	757	709	772	1,047	10,722	17,119	21,142	18,653	8,444	7,012
1971	4,745	3,082	2,075	1,319	944	867	986	3,428	31,031	22,942	30,316	13,636	9,614
1972	5,537	2,912	2,313	2,036	1,836	1,660	1,566	19,777	31,930	21,717	18,654	11,884	10,152
1973	4,639	2,155	1,387	1,140	1,129	955	987	7,896	26,393	17,572	19,478	8,726	7,705
1974	3,491	1,463	997	843	746	690	949	15,005	16,767	17,790	15,257	11,370	7,114
1975	3,507	1,619	1,487	1,490	1,342	1,272	1,457	14,037	30,303	26,188	17,032	15,155	9,567
1976	7,003	1,853	1,008	897	876	825	1,261	11,305	22,814	18,253	19,298	6,463	7,655
1977	3,552	2,392	2,148	1,657	1,470	1,361	1,510	11,212	35,607	21,741	18,371	11,916	9,411
1978	6,936	3,211	2,371	1,868	1,525	1,481	1,597	11,693	18,417	20,079	15,327	8,080	7,715
1979	4,502	2,324	1,579	1,304	1,204	1,165	1,403	13,334	24,052	27,463	19,107	10,172	8,965
1980	6,900	3,955	2,279	1,649	1,383	1,321	1,575	11,377	26,255	30,002	20,196	12,342	9,936
1981	7,335	3,382	1,841	1,958	1,839	1,470	1,898	15,789	18,387	31,680	35,256	13,033	11,156
1982	6,384	3,270	2,207	2,086	1,559	1,094	1,574	12,490	24,439	22,877	14,536	16,427	9,079
1983	6,272	2,454	2,192	2,098	1,858	1,596	1,781	13,777	22,789	20,295	23,203	12,731	9,254
MAX	7,518	3,955	2,905	2,212	1,858	1,779	2,405	19,777	47,816	32,388	35,256	19,799	11,156
MIN	2,867	1,146	810	687	682	664	697	3,428	14,710	15,651	8,484	4,796	5,318
MEAN	5,374	2,402	1,693	1,415	1,202	1,074	1,324	12,404	25,821	23,025	20,600	12,420	9,063

TABLE B.3.1.5: GOLD CREEK NATURAL MONTHLY FLOWS (CFS)

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	ANNUAL
1950	6335	2583	1439	1027	788	726	870	11510	19600	22600	19880	8301	8032
1951	3848	1300	1100	960	820	740	1617	14090	20790	22570	19670	21240	9106
1952	5571	2744	1900	1600	1000	880	920	5419	32370	26390	20920	14480	9552
1953	8202	3497	1700	1100	820	820	1615	19270	27320	20200	20610	15270	10090
1954	5604	2100	1500	1300	1000	780	1235	17280	25250	20360	26100	12920	9682
1955	5370	2760	2045	1794	1400	1100	1200	9319	29860	27560	25750	14290	10256
1956	4951	1900	1300	980	970	940	950	17660	33340	31090	24530	18330	11473
1957	5806	3050	2142	1700	1500	1200	1200	13750	30160	23310	20540	19800	10384
1958	8212	3954	3264	1965	1307	1148	1533	12900	25700	22880	22540	7550	9476
1959	4811	2150	1513	1448	1307	980	1250	15990	23320	25000	31180	16920	10560
1960	6558	2850	2200	1845	1452	1197	1300	15780	15530	22980	23590	20510	9712
1961	7794	3000	2694	2452	1754	1810	2650	17360	29450	24570	22100	13370	10809
1962	5916	2700	2100	1900	1500	1400	1700	12590	43270	25850	23550	15890	11565
1963	6723	2800	2000	1600	1500	1000	830	19030	26000	34400	23670	12320	11073
1964	6449	2250	1494	1048	966	713	745	4307	50580	22950	16440	9571	9800
1965	6291	2799	1211	960	860	900	1360	12990	25720	27840	21120	19350	10169
1966	7205	2098	1631	1400	1300	1300	1775	9645	32950	19860	21830	11750	9432
1967	4163	1600	1500	1500	1400	1200	1167	15480	29510	26800	32620	16870	11219
1968	4900	2353	2055	1981	1900	1900	1910	16180	31550	26420	17170	8816	9811
1969	3822	1630	882	724	723	816	1510	11050	15500	16100	8879	5093	5596
1970	3124	1215	866	824	768	776	1080	11380	18630	22660	19980	9121	7591
1971	5288	3407	2290	1442	1036	950	1082	3745	32930	23950	31910	14440	10251
1972	5847	3093	2510	2239	2028	1823	1710	21890	34430	22770	19290	12400	10886
1973	4826	2253	1465	1200	1200	1000	1027	8235	27800	18250	20290	9074	8086
1974	3733	1523	1034	874	777	724	992	16180	17870	18800	16220	12250	7631
1975	3739	1700	1603	1516	1471	1400	1593	15350	32310	27720	18090	16310	10275
1976	7739	1993	1081	974	950	900	1373	12620	24380	18940	19800	6881	8189
1977	3874	2650	2403	1829	1618	1500	1680	12680	37970	22870	19240	12640	10109
1978	7571	3525	2589	2029	1668	1605	1702	11950	19050	21020	16390	8607	8195
1979	4907	2535	1681	1397	1286	1200	1450	13870	24690	28880	20460	10770	9489
1980	7311	4192	2416	1748	1466	1400	1670	12060	29080	32660	20960	13280	10748
1981	7725	3569	1915	2013	1975	1585	2040	16440	19300	33940	37870	13790	11961
1982	7463	3613	2397	2300	1739	1203	1783	13380	26100	24120	15270	17780	9800
1983	6892	2633	2358	2265	1996	1690	1900	14950	24510	21150	24500	13590	9926
MAX	8212	4192	3264	2452	2028	1900	2650	21890	50580	34400	37870	21240	11961
MIN	3124	1215	866	724	723	713	745	3745	15500	16100	8879	5093	5596
MEAN	5840	2589	1832	1527	1301	1156	1424	13425	27554	24337	21852	13340	9733

TABLE B.3.1.6: WEEKLY STREAMFLOW AT WATANA (CFS)1/

YEAR													
1950	802	774	779	869	876	791	559	512	576	558	523	656	628
	550	557	603	717	1,711	6,115	10,442	10,845	13,591	14,369	13,924	21,992	16,255
	15,877	17,953	19,631	21,345	21,448	19,853	18,160	14,972	11,275	8,096	9,178	6,205	6,282
	4,521	4,029	3,518	2,007	1,248	1,176	1,103	1,042	994	903	903	903	903
1951	828	812	812	812	757	667	667	667	641	618	618	6,189	618
	542	700	1,071	1,861	4,923	14,338	15,945	7,915	13,828	26,695	19,247	12,238	17,232
	18,464	21,682	20,740	19,074	17,891	14,413	15,312	14,985	21,048	24,531	15,237	15,738	15,226
	7,559	5,055	3,674	2,855	2,793	2,690	1,928	1,908	1,761	1,489	1,489	1,489	1,489
1952	1,329	1,299	1,299	1,299	1,069	819	819	819	784	730	730	730	730
	796	796	796	696	909	1,132	1,549	3,357	16,784	19,892	28,174	30,555	27,039
	23,526	16,714	21,361	23,150	30,727	19,888	15,618	11,855	13,935	15,561	10,522	9,086	12,430
	8,559	7,982	5,556	4,049	2,938	3,377	2,164	2,542	1,913	1,250	1,250	1,250	1,250
1953	880	820	820	820	722	598	498	598	606	678	678	678	678
	486	486	785	1,308	1,007	13,666	12,435	21,448	6,652	27,821	21,482	17,488	20,466
	17,377	15,695	17,070	17,745	20,931	17,859	14,312	14,731	17,519	14,058	12,806	10,679	9,299
	6,126	50,809	3,728	2,971	1,821	1,738	1,608	1,497	1,361	1,174	1,174	1,174	1,174
1954	1,120	1,099	1,099	1,099	1,099	982	794	794	794	716	630	630	630
	506	506	870	930	4,308	8,521	13,802	15,823	14,807	19,799	19,022	18,245	22,178
	19,307	15,396	14,981	14,981	24,614	20,049	20,049	20,049	18,930	11,256	9,676	9,025	6,621
	4,746	4,461	3,359	3,359	2,716	2,159	2,032	1,796	1,756	1,657	1,624	1,431	1,431
1955	1,546	1,561	1,338	1,249	1,179	1,052	1,052	949	979	879	879	879	879
	828	828	828	828	2,519	3,321	3,882	11,626	12,771	17,007	27,727	30,081	28,168
	29,660	24,776	19,124	22,869	20,805	19,270	19,771	24,039	34,146	17,921	13,691	11,128	10,015
	6,059	4,461	3,633	3,129	2,062	1,721	1,581	1,393	1,306	1,027	1,027	1,027	1,027
1956	848	810	810	810	809	750	750	750	739	689	689	689	689
	641	641	641	641	1,798	8,483	12,106	24,085	15,966	27,294	35,522	26,081	22,994
	24,335	26,536	26,799	26,153	24,666	22,446	29,285	16,173	13,792	11,446	16,046	15,637	11,446
	5,279	5,279	3,583	3,300	2,789	2,342	2,247	2,123	2,035	1,908	1,852	1,509	1,509
1957	1,399	1,378	1,378	1,378	1,310	1,193	1,193	1,193	1,079	920	920	920	920
	837	837	837	837	2,452	4,269	4,269	15,611	23,050	31,747	28,053	24,892	17,043
	19,864	18,252	20,463	22,198	17,659	17,664	17,568	16,111	17,894	14,143	15,435	15,008	16,474
	7,628	6,544	5,337	5,503	3,997	3,287	2,815	2,314	2,837	2,991	2,551	1,902	1,544

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YEAR													
1958	1,939	1,514	1,408	1,332	1,101	1,152	1,038	959	959	1,024	1,000	939	939
	950	1,063	1,153	1,398	3,001	5,917	8,267	15,742	16,842	24,642	24,642	21,247	19,363
	18,442	18,442	18,442	18,082	32,829	23,946	17,783	14,415	9,969	6,695	6,695	5,128	5,862
	4,604	5,050	3,865	2,689	2,392	2,068	1,760	1,352	1,215	797	879	1,375	1,375
1959	1,150	1,190	1,056	1,035	1,051	1,027	984	879	797	683	683	683	683
	666	666	952	999	1,891	2,951	12,694	17,856	14,298	20,496	15,311	18,247	20,418
	21,688	20,819	22,556	17,816	18,373	14,392	18,474	34,121	33,290	20,953	10,824	8,131	8,765
	8,534	5,896	3,243	4,051	2,692	2,292	2,194	2,064	1,962	1,656	1,656	1,656	1,656
1960	1,541	1,523	1,360	1,295	1,227	1,175	1,152	1,096	1,062	1,041	996	882	882
	694	694	910	945	4,703	6,668	12,886	20,055	29,716	11,838	12,275	12,710	13,971
	19,936	14,780	17,003	23,312	26,486	20,467	18,086	17,477	16,811	14,281	22,570	15,996	13,691
	9,778	7,102	5,050	3,678	2,753	2,516	2,319	2,958	2,118	2,126	2,985	1,833	1,833
1961	1,776	1,773	1,825	1,846	1,601	1,317	1,297	1,246	1,181	1,097	1,222	1,535	1,535
	1,617	1,617	1,783	1,811	5,580	10,306	17,835	16,989	15,795	14,578	23,810	29,749	24,996
	18,341	19,253	19,937	29,655	22,581	23,083	19,710	18,708	13,842	9,309	10,560	10,059	11,578
	8,304	3,663	3,663	3,663	2,910	2,187	2,187	2,187	2,967	1,742	1,742	1,742	1,742
1962	1,645	1,626	1,626	1,626	1,462	1,237	1,237	1,237	1,207	1,174	1,174	1,174	1,174
	1,336	1,335	1,335	1,335	3,165	3,896	10,571	15,580	25,042	25,502	49,464	42,296	29,941
	24,659	24,067	20,979	24,659	22,051	19,487	19,487	19,487	19,844	18,961	11,972	9,699	11,158
	7,677	5,856	5,094	4,603	3,273	2,427	2,427	2,427	2,243	1,684	1,684	1,684	1,684
1963	1,346	1,303	1,303	1,303	1,284	1,203	1,203	1,203	1,015	870	870	870	870
	680	680	680	2,138	2,871	16,185	26,173	29,395	20,039	20,039	20,039	20,039	20,039
	25,591	30,081	31,343	26,765	24,772	22,882	19,853	20,996	17,689	13,134	11,736	8,384	9,514
	7,204	6,067	4,963	3,760	2,277	2,937	1,803	1,489	1,454	1,358	1,311	1,038	1,038
1964	913	888	830	807	815	818	802	760	696	612	588	524	524
	588	588	637	646	524	521	699	1,548	17,791	66,753	45,845	38,257	27,669
	22,261	22,938	21,646	14,854	16,893	15,984	12,889	13,741	11,603	8,901	7,255	7,294	7,139
	5,814	6,596	4,258	3,387	2,593	2,408	2,383	2,656	1,708	1,175	1,047	952	952
1965	880	866	866	866	821	764	764	764	785	809	809	809	809
	1,050	1,050	1,324	1,370	1,702	4,582	7,973	14,365	28,598	18,020	19,249	18,396	27,076
	25,264	25,478	23,730	20,581	18,313	16,343	25,247	16,925	9,394	14,093	17,314	15,844	20,946
	10,948	6,087	2,852	2,359	2,043	1,676	1,481	1,412	1,361	1,265	1,223	1,174	1,129
1966	1,075	1,062	1,062	1,062	1,026	980	980	980	983	985	985	985	985
	1,091	1,091	1,432	1,490	2,210	2,873	5,322	10,202	16,017	37,660	26,954	22,768	19,214
	15,178	14,458	15,132	17,122	22,511	18,320	15,064	18,252	14,605	10,023	9,733	9,623	8,022
	5,525	3,605	2,802	1,896	1,290	1,192	1,192	1,192	1,173	1,119	1,119	1,119	1,119

TABLE B.3.1.6 (Page 3 of 5)

YEAR													
1967	1,105	1,106	1,106	1,106	1,077	1,037	1,037	1,037	965	882	882	882	882
	771	771	790	910	1,409	4,044	14,066	19,680	23,533	22,187	29,069	24,227	23,703
	17,634	16,574	24,423	28,466	21,665	20,177	44,290	24,653	16,555	23,511	13,875	10,087	8,761
	5,636	4,692	3,669	2,797	2,340	1,987	1,881	1,812	1,780	1,740	1,740	1,669	1,657
1968	1,633	1,634	1,634	1,611	1,552	1,561	1,561	1,561	1,561	1,560	1,560	1,560	1,560
	1,544	14,885	1,556	1,552	1,787	2,353	10,464	27,061	21,911	21,507	29,938	20,356	22,099
	24,724	22,504	21,723	20,991	18,327	16,541	13,759	12,436	11,024	9,099	9,115	5,821	5,903
	4,162	3,593	2,768	2,457	2,109	1,631	1,241	1,084	901	809	767	724	687
1969	658	640	598	598	598	587	599	630	630	655	673	709	732
	779	919	1,196	1,696	2,867	5,116	9,727	17,064	10,290	11,525	14,689	15,092	14,614
	13,051	16,518	16,974	14,188	11,668	12,201	6,318	5,126	4,792	5,256	4,595	3,939	3,781
	3,018	2,841	2,489	1,680	1,432	1,202	950	842	784	735	699	694	694
1970	656	656	628	617	618	628	589	589	589	605	616	645	645
	769	846	969	1,176	1,634	3,900	13,817	12,474	15,221	12,989	12,531	11,864	19,977
	22,089	16,855	18,059	17,267	21,606	18,880	14,586	16,486	11,350	9,396	7,477	7,616	4,850
	4,991	4,166	3,393	2,885	2,923	2,796	2,543	2,249	2,013	1,886	1,761	1,614	1,446
1971	1,328	1,188	1,080	950	880	821	746	746	730	716	716	716	716
	717	744	808	904	1,098	1,415	2,987	3,683	6,558	19,251	39,740	24,136	33,340
	21,395	21,771	25,092	16,325	20,943	38,945	34,819	21,362	16,880	19,170	12,233	9,251	9,174
	6,619	5,931	4,501	3,711	3,005	2,717	2,574	2,430	2,311	2,015	2,015	1,860	1,860
1972	1,790	1,642	1,642	1,642	1,643	1,528	1,465	1,464	1,403	1,416	1,351	1,351	1,329
	1,241	1,241	1,189	1,241	2,386	13,753	13,553	18,894	31,966	20,142	35,772	31,327	21,178
	22,096	22,084	19,683	16,050	18,343	19,674	18,045	18,653	12,473	11,598	15,857	11,686	6,032
	4,296	3,976	5,515	4,090	2,727	2,210	1,887	1,738	1,519	1,356	1,210	1,186	1,186
1973	1,051	1,026	1,026	1,026	1,035	1,008	1,008	1,008	929	868	868	868	868
	879	879	879	929	1,227	2,355	8,066	11,190	13,811	17,385	28,985	31,344	20,593
	18,980	18,143	13,728	14,810	15,752	18,754	14,942	19,441	20,593	11,210	7,823	6,605	6,133
	4,607	3,710	2,558	1,938	1,693	1,459	1,344	1,230	1,129	1,028	926	881	854
1974	816	811	778	765	745	707	694	662	663	648	636	605	605
	594	620	747	1,189	2,059	5,341	9,964	22,246	25,280	16,013	13,675	12,785	13,651
	14,383	17,865	16,395	15,766	14,730	15,504	13,265	10,498	14,244	13,395	7,511	6,590	11,410
	4,537	4,590	2,402	1,602	1,468	1,478	1,478	1,478	1,461	1,264	1,264	1,264	1,264
1975	1,270	1,203	1,203	1,203	1,200	1,123	1,123	1,081	1,051	1,040	1,040	1,040	1,040
	1,036	1,047	1,142	1,354	2,133	5,138	11,291	17,252	23,081	30,459	22,880	28,749	25,700
	23,413	25,455	24,131	22,076	20,265	16,199	15,474	13,658	11,762	9,359	15,849	14,847	14,301
	7,559	6,664	6,139	3,621	2,720	1,937	1,475	1,173	1,011	925	80	855	809

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YEAR													
1976	778	778	750	739	741	746	746	746	726	687	687	687	687
	644	675	839	1,402	3,440	9,778	9,397	9,828	11,375	23,100	24,887	17,525	16,928
	16,991	16,954	15,164	15,476	20,226	26,317	19,534	15,004	10,554	6,302	5,160	5,190	6,320
	3,729	3,045	2,903	2,576	2,139	1,963	1,839	1,736	2,097	1,902	1,722	1,583	1,462
1977	1,442	1,400	1,326	1,294	1,257	1,219	1,197	1,197	1,156	1,106	1,106	1,106	1,106
	1,149	1,149	1,211	1,272	1,314	2,267	8,205	12,588	19,531	29,414	38,954	31,928	28,489
	18,502	20,572	21,740	18,089	19,531	18,939	17,328	17,519	11,066	8,643	12,235	11,736	11,288
	8,782	6,882	6,046	4,510	3,355	2,862	2,578	2,392	2,223	2,108	2,015	1,955	1,808
1978	1,741	1,641	1,557	1,496	1,403	1,285	1,247	1,247	1,212	1,258	1,258	1,258	1,275
	1,251	1,251	1,251	1,322	3,355	11,862	16,195	10,959	11,660	13,979	19,417	16,614	20,703
	19,608	18,215	18,416	18,064	16,600	15,674	14,572	12,160	8,756	9,287	8,372	6,293	5,367
	4,195	4,701	3,796	2,849	2,736	2,368	1,774	1,558	1,502	1,483	1,349	1,214	1,170
1979	1,185	1,138	1,138	1,138	1,059	1,067	1,067	1,067	,989	1,113	1,113	1,113	1,113
	1,064	1,113	1,228	1,545	2,451	4,633	10,811	17,246	28,470	25,470	21,379	19,302	23,880
	22,832	22,584	27,495	28,100	21,732	20,356	15,431	13,993	12,415	7,911	7,704	11,339	10,260
	6,672	8,469	5,948	4,395	4,084	3,698	4,120	2,949	2,811	2,297	2,069	1,890	1,711
1980	1,607	1,535	1,451	1,379	1,345	1,285	1,224	1,176	1,175	1,177	1,177	1,177	1,177
	1,122	1,122	1,179	1,604	3,462	8,212	11,764	10,518	16,714	25,823	20,349	26,351	22,988
	26,281	26,663	38,137	25,275	28,150	19,051	18,006	16,331	11,948	8,723	9,329	15,679	11,706
	8,532	7,605	6,326	5,214	3,950	3,534	2,637	2,685	2,707	2,175	1,678	1,578	1,516
1981	1,448	1,584	1,961	2,118	2,142	1,911	1,594	1,265	1,190	1,194	1,274	1,297	1,314
	1,238	1,291	1,373	1,779	4,737	17,566	17,640	11,625	19,077	15,465	14,949	16,085	18,788
	14,090	33,261	32,516	29,007	31,168	30,077	38,871	30,803	20,647	15,158	12,220	10,197	9,485
	5,901	5,560	5,713	6,627	3,364	2,845	2,782	2,339	2,057	1,971	1,860	1,794	1,794
1982	1,697	1,695	1,695	1,695	1,729	1,662	1,212	,881	,767	,826	,826	,874	1,123
	,956	,956	1,057	1,403	2,641	6,274	11,618	15,603	17,916	21,638	18,090	23,883	23,173
	16,689	20,637	2,979	23,533	20,306	13,970	12,157	10,610	11,835	10,670	13,360	21,010	13,236
	7,782	6,119	4,982	2,921	2,384	2,252	2,137	1,997	1,944	1,850	1,850	1,850	1,965
1983	2,201	1,906	1,590	15,588	1,553	15,335	1,540	1,685	1,583	1,534	1,437	1,389	1,280
	1,185	1,208	1,411	,197	3,484	8,419	14,537	12,909	18,671	23,758	17,019	29,754	20,568
	22,463	19,352	16,152	17,431	17,935	22,829	21,149	18,683	22,728	15,528	9,607	8,465	11,118
	9,429	7,833	6,641	4,560	4,967	2,833	2,462	2,258	2,113	2,947	1,961	1,887	1,826

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MAX	2,201	1,906	1,971	2,118	2,142	1,911	1,650	1,685	1,583	1,560	1,560	1,560	1,560
	1,517	1,617	1,783	1,907	10,007	17,566	17,834	27,061	31,966	66,753	49,464	42,296	33,340
	29,660	33,261	32,516	29,007	32,829	38,945	44,209	34,121	34,145	24,531	22,570	21,010	20,946
	10,948	8,469	6,641	6,627	4,984	3,698	4,120	2,949	2,811	2,911	2,551	1,955	1,965
MIN	656	640	598	598	598	587	559	512	576	558	523	524	524
	486	486	603	641	524	521	699	1,548	6,558	11,525	12,275	11,864	13,651
	13,051	14,458	13,728	14,188	11,668	12,201	6,318	5,126	4,792	5,256	5,495	3,939	3,781
	3,018	2,841	2,402	1,602	12,248	1,176	950	842	787	735	699	694	687
MEAN	1,274	1,235	1,204	1,190	1,137	1,060	1,019	987	944	920	918	923	930
	906	925	1,043	1,232	2,792	6,260	19,667	14,705	18,439	22,802	24,502	23,194	21,895
	20,412	20,804	20,963	20,393	21,250	19,718	18,857	17,190	15,445	12,573	11,279	10,324	9,788
	6,392	5,356	4,235	3,403	2,650	2,264	2,027	1,868	1,748	1,556	1,482	1,405	1,370

1/ Flows are presented in standard weekly periods of seven days, beginning with week number one (Dec. 31 - Jan. 6) and continuing across at thirteen weeks per line. The 39th week is an eight day period (standard water week 52 [Sept. 23 - Sept. 30]) and the flow for this period is the total eight day flow divided by seven as used in the reservoir operation program. This flow in week 39 is the average flow multiplied by 1.143.

TABLE B.3.1.7: WEEKLY STREAMFLOW AT DEVIL CANYON (CFS)[1/]

YEAR													
1950	937	903	910	1,015	1,017	905	639	586	662	658	618	666	741
	645	653	707	841	2,073	7,412	12,653	13,142	16,482	16,076	15,579	24,604	18,186
	18,806	20,005	21,876	23,788	23,852	22,094	20,211	16,662	12,546	8,782	9,955	6,732	6,814
	5,002	4,460	3,893	2,221	1,390	1,308	1,227	1,159	1,105	1,029	1,029	1,029	1,029
1951	928	911	911	911	849	763	763	763	732	693	,693	,693	693
	632	812	1,247	2,166	5,578	16,270	18,094	8,982	15,694	28,723	20,708	13,168	18,542
	20,078	23,579	22,556	29,742	20,059	16,216	17,229	16,860	23,677	28,254	17,550	18,128	17,537
	8,578	5,735	4,169	3,240	3,275	3,051	2,256	2,231	2,060	1,744	1,744	1,744	1,744
1952	1,547	1,512	1,512	1,512	1,242	913	913	913	876	823	,823	,823	823
	865	865	865	865	1,070	1,348	1,844	3,994	19,808	23,151	32,788	35,561	31,470
	26,455	18,796	24,021	26,032	34,530	22,572	17,722	13,454	15,784	18,093	12,236	10,567	14,453
	10,249	9,557	6,653	4,848	4,640	3,958	2,537	3,109	2,241	1,518	1,518	1,518	1,518
1953	1,076	1,001	1,001	1,001	882	728	728	728	737	770	,770	,770	770
	515	515	833	1,384	11,682	16,151	14,696	25,346	19,715	32,683	25,237	20,543	24,040
	19,114	17,262	18,775	19,518	24,005	20,574	16,487	16,972	20,191	17,049	15,531	12,951	11,276
	7,420	6,152	4,514	3,597	2,199	2,085	1,928	1,796	1,633	1,374	1,374	1,374	1,374
1954	1,260	1,236	1,236	1,236	1,105	923	923	923	834	718	1,718	,718	718
	585	585	1,006	1,067	5,588	11,134	18,035	20,674	19,401	23,445	22,525	21,603	26,262
	21,613	17,237	16,771	16,771	29,010	23,623	23,623	23,623	22,350	14,288	12,282	11,456	8,406
	5,953	5,593	4,211	4,211	3,316	2,637	2,487	2,197	2,140	1,995	1,956	1,723	1,723
1955	1,838	1,855	1,589	1,483	1,401	1,280	1,280	1,280	1,153	1,010	1,010	1,010	1,010
	962	962	962	962	3,137	4,150	4,849	14,520	15,954	19,123	31,175	33,822	31,673
	32,794	27,394	21,145	25,282	22,103	20,433	20,965	25,488	36,191	18,609	14,219	11,555	10,400
	6,868	5,055	4,117	3,547	2,325	1,938	1,781	1,570	1,470	1,197	1,197	1,197	1,197
1956	958	913	913	913	914	892	892	892	879	849	,849	,849	849
	770	770	770	770	2,220	10,455	14,922	29,687	19,760	31,174	40,573	29,790	26,263
	27,406	29,885	30,181	29,454	29,030	26,510	23,956	19,099	16,306	14,339	20,101	19,588	14,339
	6,577	6,577	4,462	4,110	3,399	3,855	2,740	2,587	2,471	2,213	2,147	1,751	1,751
1957	1,614	1,588	1,588	1,588	1,590	1,396	1,396	1,396	1,263	1,088	1,088	1,088	1,088
	974	974	974	974	2,998	5,240	8,557	19,170	28,186	35,489	31,349	27,825	19,052
	21,995	20,209	22,658	24,581	19,970	19,771	19,663	18,031	19,953	17,237	18,813	18,292	20,076
	9,403	8,067	5,479	6,784	4,885	4,021	3,443	3,831	3,221	3,868	3,300	2,460	1,998

TABLE B.3.1.7 (Page 2 of 5)

YEAR													
1958	2,228	1,953	1,703	1,611	1,331	1,333	1,201	1,190	1,111	1,138	1,110	1,042	1,042
	1,071	1,198	1,299	1,575	3,551	7,050	9,849	18,752	20,003	2,116	27,116	23,381	21,304
	20,248	20,248	20,248	19,851	36,827	26,997	20,048	16,251	11,239	7,737	7,737	6,008	6,865
	5,540	4,873	4,662	3,236	2,770	2,388	2,035	1,563	1,405	985	1,086	1,699	1,699
1959	1,403	1,351	12,288	1,262	1,275	1,278	1,226	1,096	997	865	865	865	865
	831	831	1,187	1,246	2,471	4,043	17,266	24,455	19,652	23,860	17,822	21,239	23,769
	24,645	23,659	25,632	20,245	21,943	17,188	22,064	40,756	39,763	24,835	13,349	10,026	10,810
	10,007	6,913	3,803	4,751	3,192	2,716	2,599	2,444	2,322	1,995	1,995	1,995	1,995
1960	1,857	1,835	1,637	1,559	1,474	1,378	1,351	1,286	1,247	1,205	1,152	1,019	1,019
	790	790	1,035	1,077	5,345	7,566	14,617	22,750	23,524	13,128	13,610	14,093	15,491
	22,156	16,426	18,898	25,911	30,054	23,404	20,681	19,984	19,226	16,823	26,586	18,844	16,128
	11,591	8,418	5,986	4,360	3,269	2,981	2,749	2,439	2,508	2,534	2,583	2,271	2,271
1961	2,211	2,203	2,268	2,294	1,988	1,604	1,578	1,516	1,556	1,352	1,505	1,891	1,891
	1,996	1,996	2,201	2,235	6,581	12,101	20,940	19,947	18,628	17,325	28,298	35,357	29,708
	21,299	22,357	23,150	23,984	24,592	25,061	21,399	30,310	15,053	1,162	12,778	12,169	14,007
	9,801	4,324	4,324	4,324	3,274	2,458	2,458	2,458	2,321	1,960	1,960	1,960	1,960
1962	1,837	1,815	1,815	1,815	1,634	1,392	1,392	1,392	1,359	1,316	1,316	1,316	1,316
	1,486	1,486	1,486	1,486	3,391	4,173	11,325	16,690	26,822	28,876	56,010	47,891	33,902
	26,163	25,543	22,258	26,163	24,614	21,799	21,799	21,799	22,290	22,008	13,899	11,257	12,951
	8,737	6,653	5,797	5,238	3,522	2,607	2,607	2,607	2,410	1,872	1,872	1,872	1,872
1963	1,540	1,490	1,490	1,490	1,465	1,414	1,414	1,414	1,188	933	933	933	933
	693	693	693	693	2,460	3,320	18,714	30,261	34,055	23,383	23,383	23,383	23,383
	28,908	37,368	35,407	30,234	26,472	24,729	21,455	22,691	19,122	14,318	12,804	10,239	10,381
	8,327	7,011	5,636	4,347	2,658	2,374	2,100	1,736	1,690	1,576	1,523	1,205	1,205
1964	1,047	1,020	954	926	934	942	922	866	802	707	679	606	606
	674	674	730	740	590	604	809	1,790	20,029	74,483	51,153	42,687	30,872
	24,270	25,009	23,601	16,194	18,729	17,736	14,300	15,247	12,880	10,489	8,548	8,595	8,413
	7,044	7,883	5,159	4,104	2,914	2,687	2,659	2,963	1,906	1,271	1,133	1,030	1,030
1965	943	928	928	928	880	820	820	820	841	870	870	870	870
	1,115	1,115	1,406	1,454	1,899	5,130	8,925	16,084	31,961	20,514	21,916	29,042	30,826
	28,458	28,698	26,730	23,181	20,872	18,586	28,711	19,247	10,693	15,833	19,452	17,801	23,533
	13,634	7,579	3,550	2,937	2,500	2,042	1,804	1,721	1,656	1,554	1,503	1,442	1,388
1966	1,298	1,281	1,281	1,281	1,238	1,180	1,180	1,180	1,184	1,187	1,187	1,187	1,187
	1,317	1,317	1,731	1,800	2,714	3,540	6,557	12,569	19,703	4,411	15,369	26,668	22,505
	17,390	16,564	17,337	19,615	16,089	21,345	17,552	21,266	17,016	11,802	11,462	11,331	9,448
	6,487	4,350	3,288	2,227	1,568	1,446	1,446	1,446	1,422	1,361	1,361	1,361	1,361

YEAR													
1967	1362	1363	1363	1363	1325	1275	1275	1275	1188	1078	1078	1078	1078
	963	963	989	1138	1624	4649	16169	22624	207061	24918	32648	27290	26620
	20076	19995	27805	32408	25176	23505	51282	28599	19229	27035	15955	11597	10072
	6430	5353	4187	3191	2670	2265	2145	2064	2026	1969	1969	1888	1875
1968	1868	1869	1869	1842	1776	1779	1779	1779	1779	1779	1779	1779	1779
	1750	1684	1764	1883	2087	2748	12217	31597	25614	24621	34274	34753	25300
	27823	25325	24447	23623	20824	18816	15653	14145	12539	10453	10471	6687	5851
	4751	4102	3160	2805	2386	1844	1404	1229	1017	896	849	801	761
1969	731	711	663	663	663	660	673	607	707	735	755	796	822
	878	1036	1348	1912	3208	5726	10892	19104	11446	12312	15692	17191	15610
	13725	17372	17848	14921	12703	13327	6903	5598	5234	5924	5179	4441	4262
	3613	3401	2979	2011	1615	1349	1065	943	883	840	799	793	793
1970	780	781	748	735	735	739	693	693	693	698	711	745	745
	811	893	1021	1240	1833	4383	15525	14018	17146	15505	14957	14162	23845
	23076	19362	20745	19835	24759	21655	16732	18910	13021	10994	8748	8910	5677
	6293	5253	4279	3638	3621	3449	3138	2776	2486	2321	2166	1986	1779
1971	1597	1429	1298	1140	1059	999	908	908	889	865	865	865	865
	870	903	980	1096	1312	1700	2506	4424	7861	21610	44612	27094	37428
	23189	23596	27197	17694	23161	43006	38447	23577	18657	21459	13693	10354	10269
	7354	6590	5002	4124	3386	3056	2896	2735	2602	2389	2389	2205	2205
1972	2182	2001	2001	2001	2000	1885	1807	1807	1730	1718	1639	1639	1613
	1483	1483	1422	1483	2946	17070	16823	23452	39387	23332	41437	36288	24532
	24274	24261	21623	17632	19568	20953	19219	19865	13290	12589	17212	12685	6546
	4631	4286	5945	4490	2970	2408	2056	1894	1654	1511	1349	1321	1321
1973	1162	1134	1134	1134	1142	1142	1142	1142	1050	945	945	945	945
	949	959	959	1003	1329	2552	8737	12035	14974	19248	32089	34700	22798
	20385	19488	14744	15905	17030	20275	16155	21018	22260	12074	8425	7115	6604
	5275	4249	2930	2220	1835	1574	1450	1328	1218	1099	989	941	913
1974	876	870	835	822	798	765	751	717	718	714	700	666	666
	639	665	802	1279	2387	6225	11611	25921	29383	18190	15463	14457	15436
	16001	19887	18241	17539	16605	17493	14966	11844	16072	15586	8738	8830	13278
	5158	5126	2732	1822	1618	1622	1622	1622	1607	1479	1479	1479	1479
1975	1473	1394	1394	1394	1393	1365	1365	1313	1274	1272	1272	1272	1272
	1248	1260	1375	1630	2559	6184	13592	20770	27708	34462	25886	32526	29079

YEAR													
	26,155	28,436	26,957	24,660	22,789	18,242	17,426	15,380	13,252	10,858	18,386	17,223	16,589
	9,346	8,243	7,593	4,478	3,159	2,241	1,707	1,356	1,167	1,063	1,023	983	930
1976	920	921	888	875	875	880	880	880	856	822	822	822	822
	756	792	983	1,643	4,311	12,374	11,892	12,436	14,396	26,245	28,274	19,909	19,234
	18,276	18,235	17,385	17,831	21,250	27,600	20,486	15,736	11,079	7,164	5,867	5,902	7,183
	4,442	3,626	3,458	3,068	2,652	2,438	2,285	2,156	2,600	2,429	2,200	2,020	1,867
1977	1,772	1,720	1,629	1,590	1,543	1,487	1,461	1,461	1,415	1,355	1,355	1,355	1,355
	1,438	1,438	1,516	1,692	1,712	2,974	10,765	16,516	25,448	33,191	43,962	36,028	32,148
	20,430	22,716	24,005	19,973	21,372	20,695	18,935	19,143	12,101	9,714	13,751	13,190	12,685
	8,112	8,229	7,232	5,395	4,079	3,474	3,131	2,904	2,692	2,523	2,412	2,340	2,163
1978	2,060	1,942	1,843	1,770	1,663	1,548	1,503	1,503	1,460	1,478	1,478	1,478	1,498
	1,441	1,441	1,441	1,522	3,504	12,344	16,853	11,404	12,150	14,917	20,720	17,729	22,092
	21,324	19,810	20,028	19,646	18,935	17,917	16,659	13,901	10,010	10,516	9,480	7,126	6,077
	5,005	5,607	4,528	3,398	3,267	2,830	2,121	1,862	1,792	1,748	1,591	1,433	1,381
1979	1,359	1,306	1,306	1,306	1,212	1,218	1,218	1,218	1,126	1,169	1,169	1,169	1,169
	1,131	1,184	1,305	1,640	2,638	4,998	11,662	18,604	30,663	26,683	22,397	20,220	25,018
	25,082	24,811	30,205	30,868	24,867	23,326	18,838	16,043	14,232	8,834	8,606	12,663	11,459
	7,486	9,501	6,673	4,930	4,588	4,148	4,621	3,309	3,151	2,576	2,321	2,119	1,918
1980	1,801	1,722	1,628	1,547	1,507	1,440	1,372	1,319	1,320	1,321	1,321	1,321	1,321
	1,260	1,260	1,324	1,800	3,875	9,212	13,196	11,801	18,768	28,973	22,831	29,565	25,792
	29,501	29,933	31,585	28,372	31,440	21,402	20,230	18,346	13,413	9,786	10,465	17,592	13,134
	9,434	8,409	6,994	5,465	4,389	3,929	2,932	2,985	2,998	2,216	1,710	1,608	1,546
1981	1,525	1,775	2,066	2,232	2,262	2,240	1,868	1,484	1,391	1,391	1,484	1,510	1,529
	1,449	1,510	1,608	2,083	5,196	19,239	19,321	12,733	20,884	18,091	16,425	17,674	20,644
	16,157	38,138	37,283	33,258	36,067	34,704	44,852	35,541	23,832	16,893	13,620	11,366	10,573
	6,569	6,190	6,361	7,376	4,141	3,513	3,436	2,889	2,534	2,328	2,193	2,115	2,115
1982	2,084	2,083	2,083	2,083	2,106	2,111	1,542	1,119	982	1,001	1,001	1,060	1,363
	1,286	1,286	1,420	1,886	3,035	7,207	13,345	17,920	20,543	24,650	20,690	27,290	26,402
	18,710	23,136	23,521	26,386	22,303	15,386	13,388	11,684	13,035	12,548	15,713	24,712	15,566
	9,491	7,464	6,077	3,562	2,760	2,590	2,458	2,297	2,235	2,142	2,142	2,142	2,274
1983	2,569	2,225	1,974	1,854	1,813	1,769	1,902	1,942	1,821	1,710	1,602	1,548	1,427
	1,341	1,366	1,596	2,158	4,096	9,947	17,176	15,253	21,996	26,445	18,942	23,102	22,894
	24,232	20,875	17,423	18,801	19,944	25,388	23,520	20,778	25,284	17,691	19,046	9,644	12,669
	10,643	8,842	7,495	5,148	4,558	3,173	2,758	2,532	2,362	2,262	2,167	2,087	2,019

YEAR													
MAX	2,569	2,225	2,268	2,294	2,262	2,240	1,902	1,942	1,821	1,779	1,779	1,891	1,891
	1,996	1,996	2,201	2,235	11,682	19,239	20,940	31,597	39,387	74,483	56,010	47,891	37,428
	32,794	38,138	37,283	33,258	36,826	43,006	51,282	40,756	39,763	28,254	26,586	24,712	23,533
	13,634	9,557	7,593	7,376	4,885	4,148	4,621	3,309	3,221	3,868	3,300	2,460	2,274
MIN	,731	,711	,663	,663	,663	,660	,639	,586	,662	,658	,617	,606	,606
	,515	,515	,693	,693	,590	,604	,809	1,790	7,861	12,312	13,610	13,168	15,436
	13,725	16,426	14,744	14,921	12,703	13,327	6,903	5,598	5,234	5,924	5,179	4,441	4,262
	3,613	3,401	2,732	1,822	1,390	1,308	1,065	,943	,883	,840	,799	,793	,761
MEAN	1,489	1,442	1,404	1,388	1,324	1,248	1,199	1,160	1,190	1,066	1,064	1,070	1,079
	1,047	1,069	1,205	1,422	3,265	7,330	12,498	17,336	21,612	25,764	27,707	26,246	24,768
	22,653	23,106	23,303	22,673	23,875	22,124	21,222	19,348	17,375	14,496	13,016	11,929	11,304
	7,506	6,284	4,957	3,983	3,082	2,631	2,355	2,169	2,030	1,822	1,736	1,644	1,602

1/ Flows are presented in standard weekly periods of seven days, beginning with week number one (Dec. 31 - Jan. 6) and continuing across at thirteen weeks per line. The 39th week is an eight day period (standard water week 52 [Sept. 23 - Sept. 30]) and the flow for this period is the total eight day flow divided by seven as used in the reservoir operation program. This flow in week 39 is the average flow multiplied by 1.143.

TABLE B.3.1.8: WEEKLY STREAMFLOW AT GOLD CREEK (CFS)1/ (Page 1 of 5)

YEAR													
1950	1,014	979	986	1,100	1,100	971	689	629	710	711	666	720	801
	774	783	849	1,009	2,314	8,007	13,671	14,200	17,914	17,100	16,571	26,171	19,343
	19,957	21,229	23,214	25,243	25,100	23,129	21,157	17,443	13,171	9,263	10,500	7,100	7,186
	5,257	4,686	4,091	2,334	1,471	1,386	1,300	1,229	1,171	1,100	1,100	1,100	1,100
1951	980	960	960	960	900	820	820	820	786	740	740	740	740
	774	997	1,529	2,657	6,157	17,329	19,271	9,567	16,671	29,543	21,300	13,543	19,071
	20,729	24,343	23,286	21,414	21,429	17,614	18,714	18,314	25,600	30,057	18,671	19,286	18,657
	9,229	6,171	4,486	3,486	3,500	3,204	2,369	2,343	2,186	1,900	1,900	1,900	1,900
1952	1,643	1,600	1,600	1,600	1,343	1,000	1,000	1,000	,949	880	880	880	880
	920	920	920	920	1,191	1,514	2,071	4,486	21,929	24,814	35,143	38,114	33,729
	27,629	19,629	25,086	27,186	37,243	25,071	19,686	14,943	17,329	18,886	12,771	11,029	15,086
	11,143	10,390	7,233	5,271	5,000	4,257	2,729	3,343	2,429	1,700	1,700	1,700	1,700
1953	1,186	1,100	1,100	1,100	980	820	820	820	,820	820	820	820	820
	930	930	1,504	2,500	14,129	15,814	15,300	26,386	20,743	35,114	27,114	22,071	25,829
	20,229	18,271	19,871	20,657	25,643	21,857	17,514	18,029	21,500	18,786	17,114	14,271	12,426
	8,119	6,733	4,940	3,937	3,401	2,271	2,100	1,957	1,786	1,500	1,500	1,500	1,500
1954	1,329	1,300	1,300	1,300	1,171	1,000	1,000	1,000	,906	780	780	780	780
	870	870	1,496	1,600	6,743	12,286	19,900	22,814	21,571	25,457	24,457	23,456	28,514
	24,486	19,529	19,000	19,000	31,143	24,000	24,000	24,000	23,000	1,586	14,000	13,057	9,581
	6,500	6,109	4,500	4,500	3,686	3,000	2,829	2,500	2,414	2,200	2,157	1,900	1,900
1955	1,986	2,000	1,714	1,600	1,514	1,400	1,400	1,400	1,271	1,100	1,100	1,100	1,100
	1,200	1,200	1,200	1,200	3,557	4,500	5,247	15,743	17,429	20,329	33,143	35,957	33,671
	34,186	28,557	22,043	26,357	22,614	20,900	21,443	26,071	37,243	19,671	15,029	12,214	10,993
	7,236	5,327	4,339	3,737	2,486	2,100	1,929	1,700	1,586	1,300	1,300	1,300	1,300
1956	1,026	980	980	,980	976	970	970	970	957	940	940	940	940
	950	950	950	950	2,514	11,400	16,271	32,371	21,686	33,457	43,543	31,971	28,186
	29,057	31,686	32,000	31,229	31,429	28,771	26,000	20,729	17,714	16,000	22,429	21,857	16,000
	7,200	7,200	4,886	4,500	3,757	3,200	3,071	2,900	2,757	2,400	2,329	1,900	1,900
1957	1,729	1,700	1,700	1,700	1,614	1,500	1,500	1,500	1,371	1,200	1,200	1,200	1,200
	1,200	1,200	1,200	1,200	3,414	5,757	9,400	21,057	30,914	37,443	33,086	29,357	20,100
	23,214	21,329	23,914	25,943	20,957	20,943	20,829	19,100	21,143	19,814	29,643	20,071	20,029
	10,333	8,864	7,230	7,454	5,429	4,521	3,870	3,181	3,586	4,314	3,680	2,744	2,229

TABLE B.3.1.8 (Page 2 of 5)

YEAR													
1958	2,429	2,129	1,857	1,757	1,457	1,443	1,300	1,200	1,200	1,200	1,171	1,100	1,100
	1,200	1,343	1,457	1,766	3,990	7,883	11,014	20,971	22,056	28,000	28,000	24,143	22,000
	22,000	22,000	22,000	21,571	38,686	27,529	20,443	16,571	11,557	8,500	8,500	6,600	7,543
	3,991	5,271	5,043	3,500	2,986	2,600	2,214	1,700	1,529	1,100	1,214	1,900	1,900
1959	1,557	1,500	1,429	1,400	1,400	1,400	1,343	1,200	1,106	980	980	980	980
	1,000	1,000	1,429	1,500	2,857	4,543	19,400	27,486	22,329	26,029	19,443	23,171	25,929
	26,400	25,343	27,457	21,686	23,886	18,629	23,914	44,171	43,171	28,700	14,829	11,137	12,007
	10,714	7,400	4,071	5,086	3,486	3,000	2,871	2,700	2,557	2,200	2,200	2,200	2,200
1960	2,029	2,000	1,786	1,700	1,614	1,500	1,471	1,400	1,357	1,300	1,243	1,100	1,100
	1,100	1,100	1,443	1,500	5,857	7,600	14,686	22,857	24,286	14,357	14,886	15,415	16,943
	22,929	17,000	19,557	26,814	32,043	25,429	22,471	21,714	20,857	18,314	28,943	20,514	17,557
	12,529	9,100	6,471	4,714	3,586	3,300	3,043	2,700	2,757	2,900	2,843	2,500	2,500
1961	2,414	2,400	2,471	2,500	2,200	1,800	1,771	1,700	1,614	1,500	1,571	2,100	2,100
	2,500	2,500	2,657	2,800	7,229	12,714	22,000	20,957	19,814	18,971	30,986	38,714	32,529
	23,000	24,143	25,000	25,900	25,643	26,000	22,200	21,071	15,657	12,429	14,100	13,429	15,457
	10,429	4,600	4,600	4,600	3,514	2,700	2,700	2,700	2,529	2,100	2,100	2,100	2,100
1962	1,929	1,900	1,900	1,900	1,729	1,500	1,500	1,500	1,456	1,400	1,400	1,400	1,400
	1,700	1,700	1,700	1,700	3,700	4,500	12,214	1,800	28,471	30,286	58,743	50,229	35,557
	27,186	26,543	23,129	27,186	26,057	23,000	23,000	23,000	23,429	23,571	14,886	12,057	13,871
	9,150	6,976	6,071	5,486	3,700	2,800	2,800	2,800	2,571	2,000	2,000	2,000	2,000
1963	1,657	1,600	1,600	1,600	1,557	1,500	1,500	1,500	1,286	1,000	1,000	1,000	1,000
	830	,830	,830	,830	2,666	3,400	19,171	31,000	35,686	26,000	26,000	26,000	26,000
	31,143	40,257	38,143	32,571	27,800	25,143	21,814	23,071	19,543	15,143	13,543	10,829	10,979
	8,897	7,491	6,129	5,643	2,886	2,600	2,300	2,900	1,843	1,700	1,643	1,300	1,300
1964	1,129	1,100	1,029	1,000	1,000	1,000	,980	,930	,861	,770	,739	,660	,660
	710	,710	,770	,780	,866	1,043	1,400	3,099	28,990	75,029	51,529	43,000	31,100
	25,371	26,143	24,671	19,629	19,757	18,729	15,100	16,100	13,600	11,354	9,253	9,304	9,106
	7,677	8,591	5,623	4,473	3,080	2,836	3,807	3,129	2,033	1,370	1,221	1,110	1,110
1965	981	,960	,960	,960	,917	,860	,860	,860	,877	,900	,900	,900	,900
	1,180	1,180	1,489	1,540	2,011	5,386	9,371	16,886	33,643	21,971	23,471	22,429	33,014
	30,357	30,614	28,514	24,729	22,229	19,671	30,386	20,371	11,343	15,849	20,700	18,943	25,043
	15,086	8,387	3,929	3,250	2,764	2,264	2,000	1,907	1,829	1,714	1,557	1,590	1,530
1966	1,419	1,400	1,400	1,400	1,357	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
	1,500	1,500	1,971	2,050	3,014	3,886	7,200	13,800	21,657	47,686	34,129	28,829	24,329
	18,643	17,757	18,586	21,029	28,014	22,914	18,843	22,829	18,300	12,886	12,614	12,371	10,314
	6,990	4,687	3,544	2,400	1,729	1,600	1,600	1,600	1,571	1,500	1,500	1,500	1,500

YEAR													
1967	1,500	1,500	1,500	1,500	1,457	1,400	1,400	1,400	1,314	1,200	1,200	1,200	1,200
	1,100	1,100	1,129	1,300	1,743	4,929	17,143	23,986	28,829	26,571	34,814	29,014	28,386
	21,557	21,471	29,857	34,800	27,100	25,043	54,871	30,600	20,614	29,071	17,157	12,471	10,831
	6,851	5,703	4,460	3,400	2,857	2,429	2,300	2,214	2,171	2,100	2,100	2,014	2,000
1968	2,000	2,000	2,000	1,971	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
	1,871	1,800	1,886	2,014	2,243	2,943	13,086	33,843	27,543	26,457	36,829	37,343	27,186
	29,429	26,786	25,857	24,986	22,214	20,143	16,757	15,143	13,429	11,271	11,291	7,210	6,309
	5,061	4,370	3,366	2,987	2,543	1,971	1,500	1,314	1,086	950	900	850	807
1969	771	750	700	700	700	700	714	750	750	779	800	843	871
	957	1,129	1,471	2,086	3,400	6,013	11,434	20,057	12,069	12,800	16,314	17,871	16,229
	13,929	17,629	18,114	15,143	13,386	14,286	7,399	6,001	5,593	5,303	5,511	4,726	4,536
	3,940	3,709	3,249	2,193	1,714	1,429	1,129	1,000	936	900	857	850	850
1970	850	850	814	800	800	800	750	750	750	750	764	800	800
	850	936	1,071	1,300	1,943	4,614	15,343	14,757	18,129	16,971	19,671	15,500	26,100
	25,029	21,000	22,500	21,514	26,429	22,871	17,671	19,971	13,786	11,897	9,466	9,643	6,143
	7,017	5,857	4,771	4,057	4,000	3,800	3,457	3,057	2,743	2,571	2,400	2,200	1,971
1971	1,743	1,557	1,414	1,243	1,157	1,100	1,000	1,000	979	950	950	950	950
	964	1,000	1,086	1,214	1,457	1,900	2,800	4,943	8,714	22,857	47,186	28,657	39,586
	24,471	24,900	28,700	18,671	24,357	44,743	40,000	24,529	19,471	22,857	14,586	11,029	10,939
	7,744	6,939	5,267	4,343	3,600	3,257	3,086	2,914	2,771	2,600	2,600	2,400	2,400
1972	2,400	2,200	2,200	2,200	2,200	2,086	2,000	2,000	1,914	1,886	1,800	1,800	1,771
	1,700	1,700	1,629	1,700	3,386	19,571	19,286	26,886	44,243	24,471	43,457	38,057	25,729
	35,371	25,357	22,600	18,429	20,243	21,729	19,929	20,600	13,786	13,186	18,029	13,286	8,657
	4,786	4,429	6,143	4,557	3,114	2,543	2,171	2,000	1,743	1,600	1,429	1,400	1,400
1973	1,229	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,114	1,000	1,000	1,000	1,000
	1,000	1,000	1,000	1,057	1,400	2,686	9,200	12,671	15,714	20,214	33,700	36,443	23,943
	21,057	20,129	15,229	15,429	17,545	21,029	15,757	21,800	23,171	12,814	8,942	7,551	7,010
	5,636	4,539	3,130	2,371	1,914	1,643	1,514	1,386	1,271	1,143	1,029	979	950
1974	907	900	864	850	829	800	786	750	750	750	736	700	700
	700	729	879	1,400	2,571	6,586	12,286	27,429	31,357	19,557	16,700	15,614	16,671
	16,943	21,057	19,314	18,571	17,714	18,686	15,986	12,651	17,130	16,614	9,314	9,413	14,154
	5,503	5,469	2,914	1,943	1,700	1,700	1,700	1,700	1,686	1,600	1,600	1,600	1,600
1975	1,586	1,500	1,500	1,500	1,500	1,500	1,500	1,443	1,400	1,400	1,400	1,400	1,400
	1,400	1,414	1,543	1,829	2,843	6,857	15,071	23,029	30,500	36,400	27,343	34,357	30,714
	27,500	29,900	28,343	25,929	24,200	19,486	18,614	15,429	14,157	11,743	19,886	18,629	17,943
	10,286	9,071	8,357	4,929	3,429	2,457	1,871	1,486	1,271	1,143	1,100	1,057	1,000

TABLE B.3.1.8 (Page 4 of 5)

YEAR													
1976	1,000	1,000	964	950	950	950	950	950	929	900	900	900	900
	900	943	1,171	1,957	4,957	13,943	13,400	14,014	16,129	27,700	29,843	21,014	20,300
	19,329	19,286	18,386	18,857	21,714	27,714	20,571	15,800	11,183	7,729	6,330	6,367	7,750
	4,831	3,943	3,760	3,337	2,943	2,714	2,543	2,400	2,886	2,715	2,457	2,257	2,086
1977	1,957	1,900	1,800	1,757	1,700	1,629	1,600	1,600	1,557	1,500	1,500	1,500	1,500
	1,600	1,600	1,686	1,771	1,971	3,457	12,514	19,200	29,200	24,956	46,300	37,943	33,857
	21,714	24,143	25,514	21,229	22,286	21,329	19,514	19,729	12,514	10,363	14,671	14,071	13,534
	8,829	8,957	7,871	5,871	4,486	3,829	2,450	3,200	2,964	2,757	2,636	2,557	2,364
1978	2,236	2,107	2,000	1,921	1,807	1,700	1,650	1,650	1,600	1,600	1,600	1,600	1,621
	1,650	1,650	1,650	1,743	3,643	12,557	17,143	11,600	12,371	15,386	21,371	18,286	22,786
	22,314	20,729	20,957	20,557	20,214	19,114	17,771	14,829	10,686	11,214	10,109	7,599	6,481
	5,416	6,069	4,901	3,679	3,577	3,126	2,343	2,057	1,971	1,900	1,729	1,557	1,500
1979	1,457	1,400	1,400	1,400	1,300	1,300	1,300	1,300	1,200	1,200	1,200	1,200	1,200
	1,200	1,257	1,386	1,743	2,743	5,143	12,000	19,143	31,671	27,486	23,071	20,829	25,771
	26,371	26,086	31,757	32,457	26,514	24,800	20,029	17,057	15,171	9,447	9,203	13,543	12,254
	7,890	10,014	7,034	5,197	4,871	4,424	4,929	3,529	3,357	2,743	2,471	2,257	2,043
1980	1,914	1,829	1,729	1,643	1,600	1,529	1,457	1,400	1,400	1,400	1,400	1,400	1,400
	1,400	1,400	1,471	2,000	4,143	9,714	13,914	12,443	19,843	32,143	25,329	32,800	28,614
	31,343	31,800	33,557	30,143	33,014	23,200	21,929	19,886	14,457	10,570	11,304	19,000	14,186
	9,849	8,779	7,303	6,019	4,657	4,211	3,143	3,200	3,200	2,314	1,786	1,679	1,614
1981	1,571	1,829	2,129	2,300	2,329	2,414	2,014	1,600	1,500	1,500	1,600	1,629	1,650
	1,700	1,771	1,886	2,443	5,623	20,400	20,486	13,500	21,943	18,629	15,914	18,200	21,257
	17,829	42,086	41,143	36,700	38,600	31,657	46,729	37,029	24,971	17,986	14,500	12,100	11,256
	7,641	7,200	7,399	8,581	4,512	3,943	3,857	3,243	2,828	2,529	2,385	2,300	2,300
1982	2,300	2,300	2,300	2,300	2,314	2,357	1,721	1,250	1,100	1,100	1,100	1,164	1,497
	1,500	1,500	1,657	2,200	3,386	8,100	15,000	20,143	22,714	26,143	21,857	28,857	28,000
	19,500	24,114	24,514	27,500	23,657	16,629	14,471	12,629	14,014	13,486	16,886	26,557	28,000
	10,429	8,201	6,677	3,914	2,971	2,786	2,643	2,471	2,400	2,301	2,300	2,300	2,443
1983	2,771	2,400	2,129	2,000	1,957	1,900	2,043	2,086	1,957	1,814	1,700	1,643	1,514
	1,500	1,529	1,786	2,414	4,586	11,086	19,143	17,000	24,143	27,343	19,586	23,886	23,671
	25,371	21,857	18,243	19,686	21,014	26,586	24,629	21,757	26,529	18,957	11,729	10,334	13,574
	11,283	9,373	7,945	5,457	4,843	3,386	2,943	2,700	2,414	2,386	2,286	2,200	2,129

TABLE B.3.1.8 (Page 5 of 5)

YEAR													
MAX	2,271	2,400	2,471	2,500	2,329	2,414	2,043	2,086	1,957	1,900	1,900	2,100	2,100
	2,500	2,500	2,757	2,800	14,129	20,400	22,000	33,843	44,243	65,029	58,743	50,229	39,586
	34,186	42,086	41,143	36,700	38,686	44,743	54,871	44,171	43,171	30,057	28,943	26,557	25,043
	15,086	10,390	8,357	8,581	5,429	4,529	4,929	3,529	3,586	4,314	3,680	2,744	2,500
MIN	771	750	700	700	700	700	686	629	710	711	666	660	660
	700	710	770	780	866	1,043	1,400	3,099	8,714	12,800	14,886	13,543	16,229
	13,929	17,000	15,229	15,143	13,386	14,286	7,399	6,001	5,593	6,303	5,511	4,726	4,536
	3,940	3,709	2,914	1,943	1,471	1,386	1,129	1,000	,936	,900	,857	,850	,807
MEAN	1,607	1,554	1,412	1,494	1,427	1,354	1,300	1,258	1,204	1,151	1,149	1,157	1,167
	1,216	1,240	1,408	1,667	3,654	7,914	13,466	18,715	23,556	27,284	29,369	27,860	26,313
	23,987	24,491	24,708	24,031	25,294	23,320	22,387	20,411	18,377	15,621	14,039	112,871	12,129
	8,102	6,782	5,348	4,303	3,332	2,861	2,562	2,358	2,204	1,978	1,886	1,785	1,739

1/ Flows are presented in standard weekly periods of seven days, beginning with week number one (Dec. 31 - Jan. 6) and continuing across at thirteen weeks per line. the 39th week is an eight day period (standard water week 52 (Sept. 23 - Sept. 30) and the flow for this period is the total eight day flow divided by seven as used in the reservoir operation program. This flow in week 39 is the average flow multiplied by 1.143.

TABLE B.3.1.9: SUMMARY OF ESTIMATED STREAMFLOW (cfs)

Station		Denali	Cantwell	Watana	Devil Canyon	Gold Creek[1/]	Sunshine[2/]	Susitna	Maclaren	Chulitna	Talkeetna	Skwentna
Oct	Max	2,165	5,472	6,632	7,518	8,212	20,837	58,640	734	8,062	4,891	7,254
	Min	528	1,638	2,403	2,867	3,124	8,176	13,476	249	2,380	1,451	1,929
	Mean	1,165	3,149	4,567	5,363	5,825	13,799	32,777	418	4,850	2,683	4,329
Nov	Max	878	2,487	3,525	3,955	4,192	8,795	31,590	370	3,213	1,721	4,195
	Min	192	780	1,021	1,146	1,215	4,020	8,251	95	1,480	765	678
	Mean	500	1,460	2,064	2,402	2,578	6,185	15,063	182	2,155	1,223	1,867
Dec	Max	575	1,658	2,259	2,905	3,264	6,547	14,690	246	2,100	1,203	2,871
	Min	146	543	709	810	866	2,675	5,753	49	1,000	556	624
	Mean	315	951	1,453	1,703	1,828	4,426	9,267	117	1,564	871	1,295
Jan	Max	651	1,694	1,858	2,212	2,452	5,216	10,120	162	1,681	940	2,829
	Min	85	437	619	687	724	2,228	6,365	44	974	459	600
	Mean	248	850	1,125	1,429	1,524	3,674	8,112	99	1,330	693	1,068
Feb	Max	422	1,200	1,610	1,858	2,028	4,664	9,413	140	1,414	777	1,821
	Min	64	426	602	682	723	2,095	5,614	42	820	392	490
	Mean	206	706	1,035	1,216	1,309	3,115	7,383	81	1,115	548	911
Mar	Max	290	1,273	1,560	1,779	1,900	3,920	8,906	121	1,354	743	1,352
	Min	42	408	575	644	713	1,972	5,271	36	770	285	522
	Mean	192	659	936	1,085	1,173	2,786	6,412	74	1,017	485	826
Apr	Max	415	1,702	1,965	2,405	2,650	5,228	13,029	145	1,883	1,075	2,138
	Min	43	465	609	697	745	2,233	4,613	50	700	385	607
	Mean	231	835	1,158	1,340	1,441	3,585	7,684	86	1,264	605	1,088
May	Max	4,259	13,751	15,973	19,777	21,890	43,121	88,470	2,131	21,902	8,840	22,370
	Min	629	1,915	2,857	3,428	3,745	10,799	28,713	208	2,355	2,140	1,635
	Mean	2,306	7,473	10,625	12,462	13,483	27,674	56,770	832	8,862	4,294	8,555
June	Max	12,210	34,630	42,842	47,814	50,580	116,152	165,900	4,297	40,330	19,040	40,356
	Min	4,647	9,909	13,233	14,710	15,500	40,702	73,838	1,751	15,297	5,207	10,650
	Mean	7,532	17,567	22,980	26,043	27,795	63,268	112,256	2,888	22,173	11,085	18,462
July	Max	12,110	22,790	28,767	32,388	34,400	85,600	181,400	4,649	35,570	17,079	28,620
	Min	6,756	12,220	14,843	15,651	16,100	45,226	92,511	2,441	20,781	7,080	11,670
	Mean	9,688	16,873	20,747	23,075	24,390	64,143	126,590	3,241	26,875	10,748	16,997
Aug	Max	12,010	22,760	30,542	35,256	37,870	84,940	159,600	4,122	33,670	16,770	20,590
	Min	3,919	6,597	7,772	8,484	8,879	25,092	80,891	974	11,300	3,787	7,471
	Mean	8,431	14,614	18,366	20,654	21,911	56,148	109,084	2,644	22,896	9,596	13,335
Sep	Max	6,955	12,910	17,206	19,799	21,240	54,110	107,700	2,439	22,260	10,610	13,371
	Min	1,194	3,376	4,260	4,796	5,093	14,320	37,592	470	6,704	2,070	3,783
	Mean	3,334	7,969	10,878	12,555	13,493	32,867	67,721	1,167	12,391	5,779	8,371
Ann	Max	3,651	7,962	9,985	11,254	11,961	28,262	63,159	1,276	11,419	5,400	10,024
	Min	2,127	4,159	4,912	5,352	5,596	14,431	38,030	693	6,110	2,249	4,939
	Mean	2,885	6,184	8,046	9,159	9,781	23,607	46,891	998	8,931	4,073	6,622

1/ Data for Gold Creek based on 34 years of recorded data (1950-1983). Missing Data for all other locations have been filled in as described in Harza-Ebasco's report (HE 1984b).

2/ ~~Sunshine discharge for WY1980 and Oct-Apr WY1981 were computed from Gold Creek, Talkeetna, and Chulitna~~ discharges for the same period.

TABLE B.3.1.10: INSTANTANEOUS PEAK FLOWS OF RECORD

Maclaren		Denali		Cantwell		Gold Creek	
Date	Flows (cfs)	Date	Flows (cfs)	Date	Flows (cfs)	Date	Flows (cfs)
8/11/71	9,260	8/10/71	38,200	8/10/71	55,000[2]	6/7/64	90,700
9/13/60	8,920	8/14-15/67	28,200	6/8/64	51,200	8/10/71	87,400
8/14/67	7,460	7/28/80	24,300	6/15/62[3]	46,800	6/17/72	82,600
7/18/63	7,300	8/4/76	22,100	6/17/72	44,700	6/15/62	80,600
6/16/72	7,070	8/9/81	23,200	8/14/67	38,800	8/15/67	80,200
8/10/81	6,650	7/12/75	21,700	7/18/63	32,000[4]	7/12/81	64,900
6/14/62	6,540	7/27/68	19,000	8/14/81	30,900	6/6/66	63,600
8/5/61	6,540					8/25/59	62,300

Notes: 1 Maximum daily flow from preliminary USGS data.
2 Estimated maximum daily flow based on discharge records at Denali and Gold Creek.
3 Approximate date.
4 Maximum daily flow.

Source: USGS

TABLE B.3.1.11: ESTIMATED EVAPORATION LOSSES - WATANA AND DEVIL CANYON RESERVOIRS

Month	WATANA STAGE III		DEVIL CANYON		Average Monthly Air Temperature (°C)		
	Pan Evaporation (inches)	Reservoir Evaporation (inches)	Pan Evaporation (inches)	Reservoir Evaporation (inches)	Watana1/	Devil Canyon2/	Talkeetna3/
Jan	0.0	0.0	0.0	0.0	- 2.5	- 4.5	-13.0
Feb	0.0	0.0	0.0	0.0	- 7.3	- 5.0	- 9.3
Mar	0.0	0.0	0.0	0.0	- 1.8	- 4.3	- 6.7
Apr	0.0	0.0	0.0	0.0	- 1.8	- 2.5	0.7
May	3.6	2.5	3.9	2.7	8.7	6.1	7.0
Jun	3.4	2.4	3.8	2.7	10.0	9.2	12.6
Jul	3.3	2.3	3.7	2.6	13.7	11.9	14.4
Aug	2.5	1.8	2.7	1.9	12.5	N/A	12.7
Sept	1.5	1.0	1.7	1.2	N/A	4.8	7.8
Oct	0.0	0.0	0.0	0.0	0.2	- 1.8	0.2
Nov	0.0	0.0	0.0	0.0	- 5.1	- 7.2	- 7.8
Dec	0.0	0.0	0.0	0.0	-17.9	-21.1	-12.7
Annual	14.3	10.0	15.8	11.1			

1/ Based on data - April 1980-June 1981
2/ Based on data - July 1980-June 1981
3/ Based on data - January 1941-December 1980

TABLE B.3.1.12: WATER APPROPRIATIONS WITHIN ONE MILE OF THE SUSITNA RIVER

LOCATION[1/]	ADL NUMBER	TYPE	SOURCE (DEPTH)	AMOUNT	DAYS OF USE
CERTIFICATE					
T19N R5W	45156	Single-family dwelling	well (?)	650 gpd	365
		general crops	same source	0.5 ac-ft/yr	91
T25N R5W	43981	Single-family dwelling	well (90 ft)	500 gpd	365
T26N R5W	78895	Single-family dwelling	well (20 ft)	500 gpd	365
	200540	Grade school	well (27 ft)	910 gpd	334
	209233	Fire station	well (34 ft)	500 gpd	365
T27N R5W	200180	Single-family dwelling	unnamed stream	200 gpd	365
		Lawn & garden irrigation	same source	100 gpd	153
	200515	Single-family dwelling	unnamed lake	500 gpd	365
	206633	Single-family dwelling	unnamed lake	75 gpd	365
	206930	Single-family dwelling	unnamed lake	250 gpd	365
	206931	Single-family dwelling	unnamed lake	250 gpd	365
PERMIT					
	206929	General crops	unnamed creek	1 ac-ft/yr	153
T30N R3W	206735	Single-family dwelling	unnamed stream	250 gpd	365
PENDING					
	209866	Single-family dwelling	Sherman Creek	75 gpd	365
		Lawn & garden irrigation	same source	50 gpd	183

[1/] All locations are referenced to the Seward Meridian.

TABLE B.3.2.1: RESERVOIR OPERATION LEVEL CONSTRAINTS

Reservoir	Normal Minimum Water Surface Elevation	Normal Maximum Water Surface Elevation	Maximum Flood Surcharge Elevation
Watana Stage I	1,850	2,000	2,014
Devil Canyon Stage II	1,405	1,455	1,456
Watana Stage III	2,065	2,185	2,193

TABLE B.3.2.2: STANDARD WATER WEEKS FOR ANY WATER YEAR N

WEEK NUMBER	FROM			TO			WEEK NUMBER	FROM			TO		
	day	month	year	day	month	year		day	month	year	day	month	year
1	1	Oct	n-1	7	Oct	n-1	27	1	Apr	n	7	Apr	n
2	8	Oct	n-1	14	Oct	n-1	28	8	Apr	n	14	Apr	n
3	15	Oct	n-1	21	Oct	n-1	29	15	Apr	n	21	Apr	n
4	22	Oct	n-1	28	Oct	n-1	30	22	Apr	n	28	Apr	n
5	29	Oct	n-1	4	Nov	n-1	31	29	Apr	n	5	May	n
6	5	Nov	n-1	11	Nov	n-1	32	6	May	n	12	May	n
7	12	Nov	n-1	18	Nov	n-1	33	13	May	n	19	May	n
8	19	Nov	n-1	25	Nov	n-1	34	20	May	n	26	May	n
9	26	Nov	n-1	2	Dec	n-1	35	27	May	n	2	Jun	n
10	3	Dec	n-1	9	Dec	n-1	36	3	Jun	n	9	Jun	n
11	10	Dec	n-1	16	Dec	n-1	37	10	Jun	n	16	Jun	n
12	17	Dec	n-1	23	Dec	n-1	38	17	Jun	n	23	Jun	n
13	24	Dec	n-1	30	Dec	n-1	39	24	Jun	n	30	Jun	n
14	31	Dec	n-1	6	Jan	n	40	1	Jul	n	7	Jul	n
15	7	Jan	n	13	Jan	n	41	8	Jul	n	14	Jul	n
16	14	Jan	n	20	Jan	n	42	15	Jul	n	21	Jul	n
17	21	Jan	n	27	Jan	n	43	22	Jul	n	28	Jul	n
18	28	Jan	n	3	Feb	n	44	29	Jul	n	4	Aug	n
19	4	Feb	n	10	Feb	n	45	5	Aug	n	11	Aug	n
20	11	Feb	n	17	Feb	n	46	12	Aug	n	18	Aug	n
21	18	Feb	n	24	Feb	n	47	19	Aug	n	25	Aug	n
22	25	Feb	n	3	Mar	n	48	26	Aug	n	1	Sep	n
23	4	Mar	n	10	Mar	n	49	2	Sep	n	8	Sep	n
24	11	Mar	n	17	Mar	n	50	9	Sep	n	15	Sep	n
25	18	Mar	n	24	Mar	n	51	16	Sep	n	22	Sep	n
26	25	Mar	n	31	Mar	n	52	23	Sep	n	30	Sep	n

TABLE B.3.2.3: SHCA LOAD FORECAST

	Net Generation at Plant 1/	
Year	Peak	Energy Requirement
	(MW)	(GWh)
1985	702	3,691
1986	713	3,747
1987	724	3,803
1988	735	3,861
1989	746	3,919
1990	757	3,978
1991	769	4,043
1992	782	4,110
1993	795	4,178
1994	808	4,247
1995	821	4,317
1996	826	4,341
1997	831	4,366
1998	836	4,392
1999	840	4,417
2000	845	4,442
2001	858	4,510
2002	871	4,579
2003	885	4,650
2004	898	4,721
2005	912	4,793
2006	937	4,923
2007	962	5,056
2008	988	5,193
2009	1,015	5,333
2010	1,042	5,478
2011	1,064	5,594
2012	1,087	5,712
2013	1,110	5,833
2014	1,133	5,957
2015	1,157	6,083
2016	1,182	6,212
2017	1,207	6,343
2018	1,232	6,478
2019	1,258	6,615
2020	1,285	6,755
2021	1,312	6,898
2022	1,340	7,044
2023	1,369	7,193
2024	1,398	7,345
2025	1,427	7,501

1/ Losses of 10 percent for transmission and distribution included. Net generation = Sales/(1-.10)

TABLE B.3.2.4: DISTRIBUTION OF RAILBELT MONTHLY ENERGY REQUIREMENT SHCA FORECAST

Month	Percent of Annual[1/]	Energy Load Year 2004	Energy Load Year 2025
		(GWh)	(GWh)
Jan	.107	505	803
Feb	.089	420	667
Mar	.089	420	667
Apr	.079	373	593
May	.072	340	540
Jun	.066	312	495
Jul	.068	321	510
Aug	.070	330	525
Sep	.073	345	548
Oct	.089	420	667
Nov	.095	449	713
Dec	.103	486	773
Totals	100.0	4721	7501

1/ Source: Based on Method of Indirect Averaging analysis of Railbelt hourly load data for 1982 and 1983.

TABLE B.3.2.5: EXISTING AND PLANNED RAILBELT HYDROELECTRIC GENERATION

Average Energy (GWh)

	Existing Plants[1/]			Proposed Plant	
Month	Eklutna	Cooper Lake	Sub-Total	Bradley[2/] Lake	Total
Jan	14	4	18	41	59
Feb	12	3	15	39	54
Mar	12	3	15	31	46
Apr	10	3	13	26	39
May	12	3	15	20	35
Jun	12	3	15	13	28
Jul	13	4	17	17	34
Aug	14	4	18	27	45
Sep	13	3	16	39	55
Oct	14	4	18	34	52
Nov	14	4	18	39	57
Dec	14	4	18	41	59
Total	154	42	196	367	563

Firm Energy (GWh)

	Existing Plants[1/]			Proposed Plant	
Month	Eklutna	Cooper Lake	Sub-Total	Bradley[2/] Lake	Total
Jan	13	4	17	41	58
Feb	12	3	15	39	54
Mar	9	3	12	31	43
Apr	10	3	13	26	39
May	11	3	14	20	34
Jun	8	2	10	13	23
Jul	9	3	12	13	25
Aug	8	2	10	13	23
Sep	9	3	12	14	26
Oct	9	3	12	29	41
Nov	8	2	10	39	49
Dec	12	3	15	41	56
Total	118	34	152	319	471

1/ Source: Acres (1982)

2/ Scheduled on-line in 1990

TABLE B.3.3.1: WEEKLY MINIMUM MEAN FLOWS AT GOLD CREEK FOR FLOW CASE E-VI

Water Week	Minimum Gold Creek Flow (cfs)	Water Week	Minimum Gold Creek Flow (cfs)
14	5,000	40	6,000
15	5,000	41	6,000
16	5,000	42	6,000
17	5,000	43	6,400(2)
18	5,000	44	11,100(3)
19	5,000	45	12,000
20	5,000	46	12,000
21	5,000	47	12,000
22	5,000	48	12,000
23	5,000	49	12,000
24	5,000	50	11,900(4)
25	5,000	51	7,400(5)
26	5,000	52	6,000(6)
27	5,000	1	5,000
28	5,000	2	5,000
29	5,000	3	5,000
30	5,000	4	5,000
31	5,700(1)	5	5,000
32	6,000	6	5,000
33	6,000	7	5,000
34	6,000	8	5,000
35	6,000	9	5,000
36	6,000	10	5,000
37	6,000	11	5,000
38	6,000	12	5,000
39	6,000	13	5,000

(1) 2 days at 5,000 cfs then 5 days at 6,000 cfs
(2) 5 days at 6,000, 1 day at 7,000, 1 day at 3,000 cfs
(3) 1 day each at 9,000, 10,000 and 11,000 and 4 days at 12,000 cfs
(4) 6 days at 12,000 cfs, 1 day at 11,000 cfs
(5) 1 day each at 10,000, 9,000, 8,000 and 7,000 cfs and 3 days at 6,000 cfs
(6) 8 days at 6,000 cfs

TABLE B.3.3.2: ECONOMIC ANALYSIS OF ENVIRONMENTAL FLOW CASES
SHCA FORECAST

Case	Cumulative Present Worth of System Costs 1/ (1996-2054) (million 1985 $)	Cumulative Present Worth Of Differential Mitigation Costs 2/ (1996-2054) (million 1985 $)	Cumulative Present Worth of Net System Costs (1996-2054) (million 1985 $)	Total Railbelt Installed Capacity in Year 2025 (MW)
P-1	4,811	25	4,836	2,105
A	4,813	25	4,838	2,105
E-VI	4,823	0	4,823	2,192
E-IV	4,830	0	4,830	2,192
C	5,120	11	5,131	2,279
E-V	5,490	-4	5,486	2,543
E-I	6,570	-7	6,563	2,855

1_/ Costs include production costs and costs for mitigation measures for E-VI flow requirements.

2_/ Costs represent differential costs to mitigate beyond E-VI flow requirements.

TABLE B.4.1.1: TRANSMISSION SYSTEM PERFORMANCE UNDER DOUBLE CONTINGENCY

Parameter	Acceptable Performance Criteria	System Configuration 1999	2005	2025
Highest Line Loading as % of Rating	114 1/	27 2/	58 2/	48 2/
Highest P.U. Voltage	1.10	1.05	1.05	1.05
Lowest P.U. Voltage				
On 345 kV	0.90	1.006	0.988	0.998
On 115 or 138 kV	0.90	0.986	0.963	0.964
Max. Differential Phase Angle	55°	16.5°	30.5°	30.2°

1/ Based on an estimated 14% overload capability over rated, assuming a 75% daily load factor.

2/ Based on thermal capability of conductor bundle.

TABLE B.4.2.1: GENERATING UNIT OPERATING CHARACTERISTICS

	Watana Stage I	Devil Canyon Stage II	Watana Stage III
Reservoir Elevation-ft			
Normal Maximum	2000	1455	2185
Average Operating	1955	1452	2145
December-January Operating	1915	1405	2110
Minimum Operating	1850	1405	2065
Unit Characteristics			
Number of Units	4	4	4/2 1/
Net Head-ft			
Design	590	590	590/680
Maximum Operating	537	600	719/719
Average Operating	490	597	680/680
December-January Operating	450	545	645/645
Minimum Operating	384	545	600/600
Generator Unit Output-MW			
Maximum Operating Head	125	175	200/200
Average Operating	110	170	185/185
December-January Operating Head	90	150	170/170
Minimum Operating Head	65	150	150/150
Dependable Plant Capability-MW (December-January Operating Head)	360	600	1020
Nominal Plant Capability-MW (Average Operating Head)	440	680	1110

1/ Stage I Units/Stage III Units

TABLE B.4.2.2: ENERGY PRODUCTION AND DEPENDABLE CAPACITY

	Watana Stage I		Watana I and Devil Canyon II		Watana III and Devil Canyon II		Not Limited by Load
	1999	2004	2005	2011	2012	2025	
Average Energy (GWh)		2,390	4,200	4,750	5,130	6,690	6,900
Firm Energy (GWh)		1,990	4,200	4,500	5,130	5,720	5,720
Dependable Capacity (MW)		300	790	805	1,500	1,520	1,620

TABLE B.5.2.1: INSTALLED CAPACITY OF ANCHORAGE-COOK INLET AREA (DECEMBER 1984)

			Natural Gas		
	Hydro	Diesel	Combustion Turbine	Steam Turbine	Total
Utilities1/					
Alaska Power Administration	30.0	0	0	0	30.0
Anchorage Municipal Light and Power	0	0	329.9	0	329.9
Chugach Electric Associaton	17.4	0	490.4	0	507.8
Homer Electric Association	0	2.1	0	0	2.1
Matanuska Electric Association	0	0	0	0	0
Seward Electric Association	0	5.5	0	0	5.5
Total	47.4	7.6	820.3	0	875.3
Military Installations2/					
Elmendorf AFB	0	2.1	0	31.5	33.6
Fort Richardson	0	7.2	0	18.0	25.2
Subtotal	0	9.3	0	49.5	58.8
Industrial Installations3/					
Industry	0	9.6	16.0	0	25.6
TOTAL	47.4	26.5	836.3	49.5	959.7

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

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

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

TABLE B.5.2.2: INSTALLED CAPACITY OF THE FAIRBANKS-TANANA VALLEY AREA (DECEMBER 1984)

	Diesel	Hydro	Oil Combustion Turbine	Coal Steam Turbine	Total
Utilities[1]					
Faribanks Municipal Utility System	8.4	0	32.2	28.6	69.2
Golden Valley Electric Association	17.3	0	157.8	25.0	200.1
University of Alaska	0	0	0	13.0	13.0
Subtotal	25.7	0	190.0	66.6	202.3
Military Installations[2]					
Eielson AFB	0	0	0	15.0	15.0
Fort Greeley	5.5	0	0	0	5.5
Fort Wainwright	0	0	0	22.0	22.0
Industrial Installations[3]					
Industry	2.8	0	0	0	2.8
TOTAL	34.0	0	190.0	103.6	327.6

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

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

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

TABLE B.5.2.3: EXISTING GENERATING PLANTS IN THE RAILBELT REGION (DECEMBER 1984)

Plant/Unit	Prime Mover	Fuel Type	Instal- lation Date	Retire- ment Date	Generating Capacity @ 30°F (MW)	Heat Rate @ Gen. Capacity (Btu/kWh)
			Alaska Power Administration			
Eklutna[1]	H	--	1955	2051	30.0	--
			Anchorage Municipal Light and Power			
Station #1[2] (b)						
Unit #1	SCCT	NG/O	1962	1990	16.2	15,329
Unit #2	SCCT	NG/O	1964	1990	16.2	15,329
Unit #3	SCCT	NG/O	1968	1991	19.9	14,089
Unit #4	SCCT	NG/O	1972	1992	33.8	13,901
Station #2						
Unit #56[3]	CCCT	NG/O	1979	1999	47.5	10,570
Unit #76[3]	CCCT	NG/O	1979	1999	109.3	9,365
Unit #8	SCCT	NG/O	1984	2009	87.0	12,000
			Chugach Electric Association			
Beluga						
Unit #1	SCCT	NG	1968	1994	16.1	16,100
Unit #2	SCCT	NG	1968	1994	16.1	16,100
Unit #3	SCCT	NG	1972	1999	49.5	12,800
Unit #4	SCCT	NG	1976	1996	10.0	17,500
Unit #5	SCCT	NG	1975	1999	67.3	12,400
Unit #68[4]	CCCT	NG	1976	2007	100.6	9,600
Unit #78[4]	CCCT	NG	1976	2007	100.6	9,600
Cooper Lake[5]						
Unit #1,2	H	--	1960	2051	17.4	--
International						
Unit #1	SCCT	NG	1965	1996	14.3	18,000
Unit #2	SCCT	NG	1968	1996	14.3	18,000
Unit #3	SCCT	NG	1970	1996	19.9	14,500
Bernice Lake						
Unit #1	SCCT	NG	1963	1988	8.9	17,300
Unit #2	SCCT	NG	1971	1997	18.4	14,500
Unit #3	SCCT	NG	1978	2004	27.2	13,700
~~Unit #4~~	~~SCCT~~	~~NG~~	~~1981~~	~~2004~~	~~27.2~~	~~13,700~~

TABLE B.5.2.3 (Page 2 of 4)

Plant/Unit	Prime Mover	Fuel Type	Installation Date	Retirement Date	Generating Capacity @ 30°F (MW)	Heat Rate @ Gen. Capacity (Btu/kWh)
			Homer Electric Association			
Seldovia						
Unit #1	D	O	1952	1990	0.3	14,998
Unit #2	D	O	1964	1994	0.6	12,006
Unit #3	D	O	1970	2000	0.6	12,006
Unit #4	D	O	1982	2012	0.6	12,006
			Seward Electric System			
SES						
Unit #1	D	O	1965	1990	1.5	15,000
Unit #2	D	O	1965	1990	1.5	15,000
Unit #3	D	O	1965	1995	2.5	15,000
			Military Installations - Anchorage Area			
Elmendorf AFB						
Total Diesel	D	O	1952	--	2.1	10,500
Total ST	ST	NG	1952	--	31.5	12,000
Fort Richardson						
Total Diesel	D	O	1952	--	7.2	10,500
Total Steam	ST	NG	1952	--	18.0	20,000
			Golden Valley Electric Association			
Healy Coal	ST	Coal	1967	2002	25.0	12,750
Healy Diesel	D	O	1967	1997	2.6	11,210
North Pole						
Unit #1	SCCT	O	1976	2006	60.9	9,500
Unit #2	SCCT	O	1977	2007	60.9	9,500

TABLE B.5.2.3: (Page 3 of 4)

Plant/Unit	Prime Mover	Fuel Type	Instal-lation Date	Retire-ment Date	Generating Capacity @ 30°F (MW)	Heat Rate @ Gen. Capacity (Btu/kWh)
Zendher						
GT1	SCCT	0	1971	2001	18.0	14,869
GT2	SCCT	0	1972	2002	18.0	14,869
Combined Diesel	D	0	1961-70	1991-2000	14.7	11,210
			University of Alaska - Fairbanks			
S1	ST	Coal	--	--	1.5	12,000
S2	ST	Coal	1980	--	1.5	12,000
S3	ST	Coal	--	--	10.0	12,000
			Fairbanks Municipal Utilities System			
Chena						
Unit #1	ST	Coal	1954	2000	5.1	15,968
Unit #2	ST	Coal	1952	2000	2.0	18,049
Unit #3	ST	Coal	1952	2000	1.5	18,091
Unit #4	SCCT	O	1963	1985	6.1	12,894
Unit #5	ST	Coal	1970	2005	20.0	14,236
Unit #6	SCCT	O	1976	2006	26.1	12,733
Diesel #1	D	O	1967	1992	2.8	12,128
Diesel #2	D	O	1968	1992	2.8	12,128
Diesel #3	D	O	1969	1992	2.8	12,128
			Military Installations - Fairbanks			
Eielson AFB						
S1, S2	ST	O	1953	--	2.50	--
S3, S4	ST	O	1953	--	6.25	--
Fort Greeley						
D1, D2, D3	D	O	--	--	3.0	10,500
D4, D5	D	O	--	--	2.5	10,500
Ft. Wainwright						
S1, S2, S3, S4	ST	Coal	1953	--	20	20,000
S5	ST	Coal	1953	--	2	--

Legend	H	-	Hydro
	D	-	Diesel
	SCCT	-	Simple cycle combustion turbine
	ST	-	Steam turbine
	CCCT	-	Combined cycle combustion turbine
	NG	-	Natural gas
	O	-	Distillate fuel oil

Notes

1/ Average annual energy production for Eklutna is 154 GWh.

2/ All AMLP SCCTs are equipped to burn natural gas or oil. In normal operation they are supplied with natural gas. All units have reserve oil storage for operation in the event gas is not available.

3/ Units #5, 6, and 7 are designed to operate as a combined-cycle plant. When simulated in this mode, they are modeled as two separate units with the characteristics shown. Thus, Units #5 and 7 are retired from "gas turbine operation" and added to "combined-cycle operation".

4/ Beluga Units #6, 7, and 8 operate as a combined-cycle plant. When simulated in this mode, they are modeled as two separate units with the characteristics shown. Thus, Units #6 and 7 are retired from "gas turbine operation" and added to "combined-cycle operation".

5/ Average annual energy production for Cooper Lake is 42 GWh.

TABLE B.5.2.4: MONTHLY DISTRIBUTION OF PEAK POWER DEMAND

	Anchorage - Cook Inlet Area			
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	88.5	100.0	100.0	100.0
February	87.4	92.5	88.0	90.2
March	78.4	82.1	80.5	81.3
April	69.4	76.5	72.8	74.6
May	60.9	63.5	65.3	64.4
June	58.5	60.5	62.5	61.5
July	58.5	61.4	62.1	61.8
August	59.2	62.9	64.4	63.6
September	66.8	72.9	72.6	72.8
October	80.1	90.6	81.0	85.8
November	88.0	95.8	84.7	90.2
December	99.2	93.7	93.6	93.6

	Fairbanks - Tanana Valley Area			
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	92.7	100.0	100.0	100.0
February	91.8	97.2	86.6	91.9
March	79.1	84.5	79.7	85.6
April	68.0	76.3	67.9	72.1
May	60.2	69.4	67.1	68.2
June	56.9	68.4	62.9	65.6
July	57.1	64.6	63.4	64.0
August	58.6	66.0	67.6	66.8
September	64.1	69.5	71.3	70.4
October	75.4	84.6	79.8	82.2
November	84.2	99.4	82.6	91.0
December	95.0	94.9	97.2	96.0

	Total Railbelt Area			
	Average 1976-1982	1982	1983	Average 1982-1983
	(%)	(%)	(%)	(%)
January	89.8	100.0	100.0	100.0
February	87.7	92.8	87.6	90.2
March	78.9	83.0	80.6	81.8
April	69.2	77.3	72.2	74.8
May	60.9	65.1	65.1	65.1
June	58.3	61.2	62.1	61.6
July	57.9	62.4	62.1	62.2
August	59.8	63.0	64.4	63.7
September	66.4	72.7	72.0	72.4
October	79.5	89.8	81.0	85.4
November	87.7	96.3	84.3	90.3
December	98.9	94.6	93.5	94.0

TABLE B.5.2.4 (Page 2 of 2)

	Anchorage - Cook Inlet Area			
	Average 1976-1982 (%)	1982 (%)	1983 (%)	Average 1982-1983 (%)
January	10.0	10.7	10.4	10.6
February	8.9	9.0	8.7	8.8
March	8.9	8.9	8.9	8.9
April	7.8	7.9	7.8	7.8
May	7.2	7.1	7.3	7.2
June	6.6	6.5	6.7	6.6
July	6.7	6.8	6.9	6.8
August	6.9	6.9	7.2	7.0
September	7.2	7.2	7.6	7.4
October	8.7	9.0	8.7	8.8
November	9.8	9.6	9.3	9.4
December	11.2	10.2	10.4	10.3

	Fairbanks - Tanana Valley Area			
	Average 1976-1982 (%)	1982 (%)	1983 (%)	Average 1982-1983 (%)
January	10.8	11.0	10.7	10.8
February	9.7	9.2	8.8	9.0
March	9.2	8.9	9.0	9.0
April	7.7	7.8	7.5	7.6
May	6.9	7.3	7.2	7.2
June	6.3	6.6	6.7	6.6
July	6.5	6.8	6.8	6.8
August	6.6	6.9	7.2	7.0
September	7.1	7.2	7.7	7.4
October	8.5	8.8	8.5	8.6
November	9.4	9.4	9.1	9.2
December	11.3	10.2	10.6	10.4

	Total Railbelt Area			
	Average 1976-1982 (%)	1982 (%)	1983 (%)	Average 1982-1983 (%)
January	10.2	10.7	10.5	10.6
February	9.1	9.0	8.8	8.9
March	9.0	8.9	8.9	8.9
April	7.8	7.9	7.8	7.8
May	7.1	7.2	7.2	7.2
June	6.5	6.5	6.7	6.6
July	6.7	6.8	6.9	6.8
August	6.8	6.9	7.2	7.0
September	7.2	7.2	7.6	7.4
October	8.7	9.0	8.7	8.8
November	9.7	9.6	9.2	9.4
December	11.2	10.2	10.4	10.3

Source: Data for 1976-1982 are taken from Alaska Electric Power Statistics 1960-1983, Alaska Power Administration (1984). Data for 1982 and 1983 are based on Applicant's evaluation of hourly load data provided by the Railbelt Utilities.

TABLE B.5.2.5: PROJECTED MONTHLY DISTRIBUTION OF PEAK AND ENERGY DEMAND PERCENTAGE OF ANNUAL DEMAND[1/]

	Total Railbelt Area	
	Peak (%)	Energy (%)
January	100.0	10.7
February	88.5	8.9
March	81.8	8.9
April	74.7	7.9
May	65.1	7.2
June	61.6	6.6
July	62.2	6.8
August	63.6	7.0
September	72.3	7.3
October	85.4	8.9
November	91.1	9.5
December	94.9	10.3

1/ Source: Based on Applicant's Method of Indirect Averaging analysis of Railbelt hourly load data for 1982 and 1983 provided by the Railbelt Utilities.

TABLE B.5.2.6: TYPICAL 24-HOUR LOAD DURATION RELATIONS

	TYPICAL WEEKDAY			TYPICAL WEEKEND DAY		
RANK	APRIL	AUGUST	DECEMBER	APRIL	AUGUST	DECEMBER
1	1.000	1.000	1.000	.945	.967	.943
2	.922	.957	.928	.916	.934	.925
3	.899	.947	.898	.899	.931	.914
4	.896	.938	.890	.877	.908	.912
5	.896	.933	.883	.864	.899	.899
6	.880	.916	.870	.858	.884	.889
7	.869	.912	.860	.857	.858	.884
8	.866	.910	.852	.856	.851	.857
9	.839	.902	.850	.853	.835	.856
10	.829	.871	.843	.841	.832	.846
11	.818	.867	.838	.833	.824	.835
12	.809	.841	.813	.822	.822	.831
13	.805	.823	.805	.807	.805	.826
14	.796	.810	.793	.803	.798	.802
15	.794	.767	.772	.801	.785	.783
16	.792	.744	.757	.747	.737	.730
17	.717	.723	.704	.735	.715	.721
18	.694	.709	.674	.697	.649	.714
19	.649	.613	.655	.657	.626	.674
20	.632	.609	.611	.638	.626	.663
21	.627	.584	.610	.630	.585	.661
22	.613	.579	.610	.621	.584	.627
23	.606	.577	.566	.612	.582	.602
24	.601	.575	.548	.586	.565	.571

Source: Based on Applicant's Method of Indirect Averaging analysis of Railbelt hourly load data for 1982 and 1983 provided by the Railbelt Utilities.

TABLE B.5.2.7: LOAD DIVERSITY IN THE RAILBELT

Railbelt Loads (MW) - January 6, 1982

UTILITY	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	Non-Coincident Peak
CEA	301.4	309.6	327.8	337.7	352.2	346.2	341.1	352.2
AMLP	109.0	107.0	117.0	114.5	116.0	112.0	107.0	117.0
GVEA	59.8	61.3	61.3	67.6	63.7	65.8	65.7	67.6
FMUS	26.0	26.2	26.1	25.6	24.0	23.5	22.5	26.2
TOTAL	496.2	506.1	532.2	545.4	555.9	547.5	536.3	563.0

$$\text{Diversity} = \frac{\text{Coincident Peak}}{\text{Non-coincident Peak}} = \frac{555.9}{563.0} = .987$$

Railbelt Loads (MW) - January 10, 1983

UTILITY	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	Non-Coincident Peak
CEA	335.2	331.7	354.8	370.0	372.3	370.1	360.5	372.3
AMLP	117.0	117.0	121.0	119.0	115.0	114.0	112.0	121.0
GVEA	65.3	67.9	72.2	71.8	70.7	70.2	70.1	72.2
FMUS	27.7	28.0	28.2	26.9	26.0	25.0	24.5	26.9
TOTAL	545.2	544.6	576.2	587.7	584.0	579.3	567.1	592.4

$$\text{Diversity} = \frac{\text{Coincident Peak}}{\text{Non-coincident Peak}} = \frac{587.7}{592.4} = .992$$

Source: Applicants evaluation of 1982 and 1983 hourly load data provided by Railbelt Utilities.

TABLE B.5.2.8: RESIDENTIAL AND COMMERCIAL ELECTRIC RATES[1/] ANCHORAGE-COOK INLET AREA JUNE 1985

Utility	Energy Used	Electric Rate: Fixed Rate	Electric Rate: Rate With Cost of Power Adjustment
Residential Rates (monthly)			
Anchorage Municipal Light & Power	Customer Charge	$ 4.50	
	All kWh	5.15 cents/kWh	5.99 cents/kWh
Chugach Electric Association, Inc.	Customer Charge	$ 5.49	—
	First 1500 kWh	6.00 cents/kWh	6.44 cents/kWh
	Over 1500 kWh	4.50 cents/kWh	4.94 cents/kWh
Commercial Rates (monthly)			
Anchorage Municipal Light & Power			
Small General Service 25 kW or less	Customer Charge	$ 8.24	—
	All kWh	6.24 cents/kWh	7.08 cents/kWh
Large General Service Over 25 kW	Customer Charge	$ 65.00	
	Demand Charge	$ 7.22 /kW	8.06 /kW
	All kWh	2.90 cents/kWh	3.74 cents/kWh
Exper. Time of Day	Customer Charge	$ 18.00	—
	7AM to 7PM	5.86 cents/kWh	6.70 cents/kWh
	7PM to 7AM To Amt. used 7AM to 7PM	2.41 cents/kWh	3.25 cents/kWh
	Excess of Amt. 7AM to 7PM	1.64 cents/kWh	2.48 cents/kWh
Chugach Electric Association, Inc. Small General Service 10 kW or Less	Customer Charge	$ 10.07	—
	All kWh	5.69 cents/kWh	6.13 cents/kWh
Large General Service Over 10 kW	Customer Charge	$ 30.51 cents	—
	Demand Charge	$ 7.93 /kW	—
	All	3.32 cents/kWh	3.76 cents/kWh
Sale for Resale	Customer Charge	$132.86	—
	All kWh	1.06 cents/kWh	1.41 cents/kWh
	Demand Charge		
	MEA	$ 14.73 /kW	—
	HEA	$ 14.23 /kW	—
	SES	$ 12.10 /kW	—

1/ Source: Alaska Public Utility Commission, Rates for Regulated Utilities as of June 14, 1985.

TABLE B.5.2.8 (Page 2 of 2)

Utility	Energy Used	Electric Rate: Fixed Rate	Electric Rate: Rate With Cost of Power Adjustment
Residential Rates (monthly)			
Homer Electric Assn., Inc.	Customer Charge	$ 14.74	—
	First 1000 kWh	6.44 cents/kWh	7.57 cents/kWh
	Over 1000 kWh	5.21 cents/kWh	6.34 cents/kWh
Matanuska Electric Assn., Inc.	Facility Charge	$ 10.00	—
	First 1300 kWh	7.51 cents/kWh	—
	Over 1300 kWh	5.81 cents/kWh	—
Seward Electric System 2/	Customer Charge	$ 20.08/22.28	—
	All kWh	8.08 cents/kWh	8.52 cents/kWh
Commercial Rates (monthly)			
Homer Electric Assn., Inc.			
Non-Demand Metered	Customer Charge	$ 29.48	—
	All kWh	6.44 cents/kWh	7.57 cents/kWh
Demand Metered	Customer Charge	$ 176.90	—
	Demand Charge (over 25 kW)	$ 4.30 /kW	—
	All kWh	5.02 cents/kWh	6.15 cents/kWh
Interruptible	Customer Charge	$ 176.90	—
	Demand Charge (over 25 kW)	$ 3.07 /kW	—
	All kWh	5.02 cents/kWh	6.15 cents/kWh
Matanuska Electric Assn., Inc.	Facility Charge	$ 25.00	—
	Demand Charge	$ 3.61 /kW	—
	All kWh	4.48 cents/kWh	—
Seward Electric System Small General Service 50 kW or Less	Customer Charge	$ 36.25/45.49	—
	All kWh	9.80 cents/kWh	10.24 cents/kWh
Large General Service Over 50 kW	Customer Charge	$ 36.25 cents/45.49	—
	Demand Charge	$ 28.31 /kW	—
	All kWh	2.59 cents/kWh	3.03 cents/kWh

1/ Source: Alaska Public Utility Commission, Rates for Regulated Utilities as of June 14, 1985.

2/ Source: City of Seward Resolution 85-55, May 15, 1985.

TABLE B.5.2.9: RESIDENTIAL AND COMMERCIAL ELECTRIC RATES[1/]
FAIRBANKS-TANANA VALLEY AREA JUNE 1985

Utility	Energy Used	Electric Rate: Fixed Rate	Electric Rate: Rate With Cost of Power Adjustment
Residential Rates			
Fairbanks Municipal Utilities System	Customer Charge	$ 8.00	-
	0-100 kWh	6.00 cents/kWh	-
	100-500 kWh	8.00 cents/kWh	-
	Over 500 kWh	7.00 cents/kWh	
Golden Valley Electric Assn.	Customer Charge	$10.00	$10.00
	First 500 kWh	11.25 cents/kWh	12.11 cents/kWh
	Over 500 kWh	9.50 cents/kWh	10.36 cents/kWh
Commercial Rates			
Fairbanks Municipal Utilities System	Customer Charge	$15.00	
	Demand Charge (Over 30kW)	$13.00/kW	
	First 500 kWh	10.00 cents/kWh	-
	500-1500 kWh	9.00 cents/kwh	-
	Over 15,000 kWh	6.00 cents/kwh	-
Golden Valley Electric Assn.			
General Service 50 kW or Less	Customer Charge	$20.00	
	0-4500 kWh	15.00 cents/kWh	15.86 cents/kWh
	4500-5000 kWh	11.10 cents/kWh	11.96 cents/kWh
	Over 5000 kWh	9.50 cents/kWh	10.36 cents/kWh
General Service Over 50 kW	Customer Charge	$40.00	
	Demand Charge	$ 6.25/kW	
	0-4500 kWh	11.36 cents/kWh	12.22 cents/kWh
	4500-10000 kWh	9.90 cents/kWh	10.76 cents/kWh
	10000-15000 kWh	9.34 cents/kWh	10.20 cents/kWh
	Over-15000 kWh	7.58 cents/kWh	8.44 cents/kWh

1/ Source: Alaska Public Utility Commission, Rates for Regulated Utilities as of June 14, 1985.

TABLE B.5.2.10: ANCHORAGE MUNICIPAL LIGHT AND POWER CUMULATIVE ENERGY CONSERVATION PROJECTIONS

	Energy Conservation in MWh/yr						
Program	1981	1982	1983	1984	1985	1986	1987
Weatherization	586	762	938	1,114	1,290	1,466	1,641
State Programs	879	1,759	2,199	2,683	3,078	3,518	3,737
Water Flow Restrictions	200	464	464	464	464	464	464
Water Heat Injection	3,922	3,922	3,922	3,922	3,922	3,922	3,922
Hot Water Heater Wrap	NA	NA	249	249	249	249	249
Street Light Conversion	0	555	1,859	3,307	4,788	6,306	7,861
Transmission Conversion	0	0	4,119	8,732	9,256	9,811	10,399
Boiler Pump Conversion	7,148	7,148	7,148	7,148	7,148	7,148	7,148
TOTAL	12,735	14,609	20,896	27,619	30,195	32,614	35,421
Increase From Previous Year %	NA	14.7	43.0	32.2	9.3	9.8	8.6

Source: AMLP, 1983

TABLE B.5.2.11: HISTORICAL ECONOMIC AND ELECTRIC POWER DATA

ITEM	Unit	1960	1965	1970	1975	1980	1982	1984
		YEAR						
State Oil and Gas Revenues to General Fund	($ million)	4.2	16.4	938.6	88.3	2,261.0	3,580.2	2,866.1
State General Fund Expenditures		n.a.	157.7	249.6	661.4	1,375.7	3,848.0	3,346.0
State Population		226,000	265,000	305,000	390,000	402,000	437,000	523,000
State Employment		94,000	110,000	133,000	198,000	211,000	232,000	264,000
Railbelt Employment		n.a.	74,000	89,000	130,000	132,000	154,000	n.a.
Railbelt Population		140,000	n.a.	200,000	n.a.	276,000	307,000	371,000
Railbelt Households		37,000	n.a.	54,000	n.a.	94,000	107,000	n.a.
Railbelt Electric Energy Generation	GWh							
Anchorage 1/		n.a.	367	700	1,353	2,105	2,446	2,667
Fairbanks 2/		n.a.	120	222	452	443	491	541
Total		n.a.	487	922	1,805	2,548	2,937	3,208

TABLE B.5.2.11 (Page 2 of 2)

ITEM	Unit	1960	1965	1970	1975	1980	1982	1984
		YEAR						
Railbelt Peak 3/ Demand	MW	n.a.	107	210	420	577	598	609
Railbelt Generation Capacity	MW	n.a.	n.a.	n.a.	n.a.	1,143	1,272	1,287

1/ AML&P, CEA, Alaska Power Administration
2/ FMUS, GVEA
3/ Alaska Electric Power Statistics 1960-1983, USDOE APAD. 1984 values taken from utility annual reports.

Sources: MAP Model Data Base; Federal Energy Regulatory Commission, Power System Statement; Alaska Power Administration, Unpublished Printouts, 1983.

TABLE B.5.2.12: MONTHLY LOAD DATA FROM ELECTRIC UTILITIES OF THE ANCHORAGE-COOK INLET AREA 1976-1983[1/]

	1976	1977	1978	1979	1980	1981	1982	1983[2/]
				NET ENERGY (GWh)				
January	161	163	197	209	221	202	265	266
February	151	144	168	210	182	188	220	222
March	147	165	173	185	186	187	216	225
April	127	143	150	162	157	170	192	200
May	117	131	141	146	146	154	177	184
June	103	118	130	132	137	148	159	171
July	108	118	132	136	141	156	167	176
August	111	123	132	138	144	157	169	182
September	121	128	139	142	152	164	175	193
October	145	159	169	168	177	197	221	221
November	154	194	191	179	202	218	234	236
December	172	217	209	238	259	234	250	265
ANNUAL	1,617	1,803	1,931	2,045	2,104	2,175	2,445	2,541
				PEAK DEMAND (MW)				
January	293	288	341	358	399	352	472	489
February	284	270	329	395	337	377	440	430
March	254	283	297	340	322	325	392	394
April	220	262	270	268	267	307	365	356
May	199	225	240	233	248	272	304	319
June	186	209	229	231	234	273	291	306
July	194	203	227	217	224	280	291	304
August	198	216	237	220	241	276	299	315
September	218	253	253	245	259	310	348	355
October	278	293	312	287	311	350	429	396
November	276	344	353	316	350	401	445	414
December	311	375	383	391	444	445	451	458
ANNUAL	311	375	383	395	444	445	472	489

1/ Includes total net generation by CEA, AMLP and APAD and sales to other utilities. (This equals total Railbelt area except MEA purchase from APAD - 5 MW by contract). Source: Alaska Power Administration, unpublished printouts, 1983.

2/ Applicant's evaluation of 1983 Railbelt utility hourly load data.

TABLE B.5.2.13: MONTHLY LOAD DATA FOR THE FAIRBANKS-TANANA VALLEY AREA 1976-1983[1/]

	1976	1977	1978	1979	1980	1981	1982	1983[2/]
				NET ENERGY (GWh)				
January	56	48	52	49	50	42	54	55
February	53	41	45	51	38	41	45	46
March	44	47	45	42	38	38	43	47
April	34	38	36	35	33	35	39	39
May	30	32	32	30	31	32	35	27
June	27	29	30	28	28	30	32	34
July	28	29	30	30	30	30	34	35
August	29	31	31	29	30	30	34	37
September	31	31	33	32	32	34	36	40
October	40	41	40	36	36	39	43	44
November	43	54	44	37	41	42	46	47
December	53	61	48	48	56	49	50	55
ANNUAL	468	482	466	447	443	442	491	516
				PEAK DEMAND (MW)				
January	101	88	96	89	95	80	94	100
February	100	87	95	101	75	88	92	87
March	82	86	82	81	70	68	82	80
April	65	73	71	66	60	65	73	68
May	55	60	58	56	56	65	67	67
June	50	56	58	54	54	60	63	63
July	54	54	55	56	56	59	61	64
August	53	56	55	57	59	61	71	68
September	60	65	63	60	61	66	70	72
October	82	79	72	67	71	72	82	80
November	84	102	86	72	76	78	89	83
December	97	118	84	88	95	93	89	98
ANNUAL	101	118	96	101	95	93	94	100

1/ Data for FMUS and GVEA including purchases. Source: Alaska Power Administration, unpublished printout, 1983.

2/ Applicant's evaluation of 1983 Railbelt utility hourly load data.

TABLE B.5.2.14: NET GENERATION BY RAILBELT UTILITIES
1976-1984
(GWh)

Utility	1976 1/	1977 1/	1978 1/	1979 1/	1980 1/	1981 1/	1982 1/	1983 2/	1984
Anchorage Municipal Light & Power	444.9	420.3	443.1	473.1	486.6	485.3	579.5	598.7	654.0
Chugach Electric Assn.	1,054.5	1,179.7	1,308.6	1,401.0	1,434.1	1,467.2	1,718.4	1,775.3	1873.7
Alaska Power Administration	118.0	203.6	180.1	171.1	184.3	223.2	147.9	149.5	139.2
Anchorage Cook Inlet Subtotal	1,617.4	1,803.6	1,931.8	2,045.2	2,105.0	2,175.7	2,445.8	2,523.5	2666.9
Fairbanks Municipal Utility System	123.3	128.5	124.7	124.7	125.6	126.1	140.7	139.1	140.2
Golden Valley Electric Association	344.7	353.5	341.5	322.9	317.7	316.9	350.3	364.4	401.4
Fairbanks Area Sub-total	468.0	481.7	466.2	447.6	443.3	443.0	491.1	503.5	541.4
Railbelt Total	2,085.4	2,285.3	2,398.0	2,492.8	2,548.3	2,618.7	2,936.9	3,027.0	3208.3

Note: Subtotals and total shown may differ from column totals due to rounding.

1/ Source: Alaska Power Administration, Unpublished Printouts, 1983.

2/ Alaska Electric Power Statistics 1960-1983, Alaska Power Administration, Sept. 1984.

TABLE B.5.3.1: COMPARISON OF RECENT FY 1985 PETROLEUM PRODUCTION REVENUE FORECASTS FROM PETREV (IN MILLIONS OF DOLLARS)

Percentage Less Than Cumulative Frequency Distribution[1]	9/1983 Forecast	12/1983 Forecast	3/1984 Forecast	6/1984 Forecast	9/1984 Forecast	12/1984 Forecast
0%	1,770	1,620	2,020	2,160	2,510	2,620
10%	2,340	2,190	2,430	2,430	2,650	2,690
20%	2,490	2,340	2,580	2,540	2,710	2,710
30%	2,650	2,510	2,700	2,620	2,740	2,730
40%	2,780	2,630	2,790	2,670	2,760	2,740
50%	2,870	2,740	2,880	2,710	2,790	2,750
60%	2,980	2,830	2,980	2,760	2,820	2,770
70%	3,111	2,980	3,070	2,810	2,850	2,790
80%	3,270	3,110	3,160	2,870	2,890	2,810
90%	3,480	3,330	3,340	2,970	2,940	2,840
100%	4,790	4,610	4,620	3,310	3,100	2,960
RANGE	3,020	2,990	2,600	1,150	590	340
MEAN	2,899	2,758	2,904	2,717	2,801	2,757

Source: Alaska Department of Revenue (1985)

1_/ Percentages represent probability that total petroleum production revenue will be less than the stated amount.

TABLE B.5.3.2: MAP MODEL VALIDATION
SIMULATION OF HISTORICAL
ECONOMIC CONDITIONS

Factor	Year	Observed Value	Estimated Value	Difference	Percent Difference
Non-Agricultural Wage and Salary Employment	1965	70,529	68,377	-2,152	-3.0
	1970	92,465	90,949	-1,516	-1.6
	1975	161,315	155,908	-5,407	-3.4
	1980	170,807	165,323	-5,484	-3.2
	1982	199,545	195,990	-3,555	-1.8
Wages and Salaries In Alaska (million nominal $)	1965	721	729	8	1.1
	1970	1,203	1,121	-82	-6.8
	1975	3,413	3,253	-160	-4.7
	1980	4,280	4,390	110	2.6
	1982	5,938	5,963	25	0.4
Personal Income In Alaska (million nominal $)	1965	827	814	-13	-1.6
	1970	1,388	1,276	-112	-8.1
	1975	3,455	3,212	-243	-7.0
	1980	5,152	5,393	241	4.7
	1982	7,384	7,437	53	0.7

Source: ISER (1985).

TABLE B.5.3.3: COMPARISON OF ACTUAL AND PREDICTED ELECTRICITY CONSUMPTION OF 1980-1983 (GWh)

	RED SHCA Case Output[1]	Red Adjusted[2]	Utility[3] Reported
Anchorage - Cook Inlet Area			
1980			
Residential	980	939	936
Business	903	903	915
Others	109	109	109
Total	1,992	1,951	1,960
1981			
Residential	1,034	1,030	916
Business	994	1,006	913
Others	117	117	139
Total	2,145	2,153	1,968
1982			
Residential	1,088	1,096	1,033
Business	1,084	1,101	1,009
Others	126	126	160
Total	2,298	2,323	2,202
1983			
Residential	1,142	1,069	1,059
Business	1,175	1,128	1,158
Others	135	135	97
Total	2,452	2,332	2,314
Fairbanks - Tanana Valley Area			
1980			
Residential	175	168	168
Business	234	234	239
Others	7	7	5
Total	417	408	412
1981			
Residential	193	186	159
Business	255	260	258
Others	7	7	4
Total	455	453	421

TABLE B.5.3.3 (Page 2 of 2)

	RED SHCA Case Output1/	Red Adjusted2/	Utility3/ Reported
Fairbanks - Tanana Valley Area (continued)			
1982			
Residential	210	204	178
Business	276	291	264
Others	7	7	4
Total	493	502	446
1983			
Residential	226	230	187
Business	297	323	269
Others	7	7	5
Total	530	560	461

1/ RED Model SHCA case run, August 1985.

2/ Two adjustments were made. First, residential space heat and automobile and truck engine block heater consumption was scaled by the actual number of heating degree-days compared to the normal heating degree days represented in the model. Second, the total use in both load centers was scaled for price effects using actual retail prices for electricity and estimated gas and oil prices for 1980-1983. Price effects were individually calculated for each year because the RED model contains data only for five year increments (i.e. 1980, 1985) and not for each intervening year. The scaling mechanism for price effects is fully documented in Scott, King and Moe 1985.

3/ Data from Alaska Power Administration, Alaska Electric Power Statistics, U.S. Department of Energy, Juneau, Alaska.
- o Sixth Edition, 1960-1980, August 1981.
- o Seventh Edition, 1960-1981, August 1982.
- o Eighth Edition, 1960-1982, August 1983.
- o Ninth Edition, 1960-1983, September 1984.

Industrial consumption was estimated as Homer Electric Association Large Commercial category, reported in Burns and McDonnell, 1983, p. D.19.

TABLE B.5.4.1: FORECASTS OF WORLD OIL PRICE APR MODEL (1985 $/bbl)

Year	Wharton	Composite	SHCA
1985	27.10	27.10	28.10
1990	24.80	26.50	27.70
1995	27.60	31.80	32.80
2000	31.30	38.10	41.00
2005	35.10	44.00	50.20
2010	40.70	51.00	61.50

Source: Exhibit D, Appendix D1

TABLE B.5.4.2: MAJOR VARIABLES AND ASSUMPTIONS APR MODEL

Name	Year	Value	
		Same Value in All Cases	
North Slope Oil Variables[1/]			
Production (mmbbl/day)	1985	1.69	
	2010	0.15	
Trans. & Quality Differential (1985 $/bbl)	1985	9.10	
	2010	4.27	
Prudhoe Bay Economic Limit Factor	1985	0.86	
	2010	0.65	
Average State Royalty Rate (%)	1985	12.5	
	2010	12.6	
Average Nominal Severance Tax Rate (%)	1985	15.0	
	2010	15.0	
North Slope Gas Variables[1/]			
Production (bcf/day)	1985	0.03	
	2010	0.18	
Price (1985 $/mcf)	1985	1.42	
	2010	3.33	
Cook Inlet Oil Variables[1/]			
Production (mmbbl/day)	1985	0.05	
	2010	0.00	
Cook Inlet Gas Variables[1/]			
Production (bcf/day)	1985	0.54	
	2010	0.58	
		Values Vary Between Cases	
		Composite	SHCA
Cook Inlet Gas Variables[2/]			
Price (1985 $/mcf)	2010	4.97	6.43

1/ Alaska Department of Revenue, APR Data Disk, 1985, except as noted

2/ See Exhibit D

TABLE B.5.4.3: VARIABLES AND ASSUMPTIONS
MAP MODEL

Symbol	Name	Year	Value	
			Same Value in All Cases	
EMAGRI	State Agricultural Employment (Employees)	1985	400	
		2010	1,223	
EMP9	State Mining Employment (Employees)	1985	10,391	
		2010	16,243	
EMCNX1	State High Wage Exog. Const. Emp. (Employees)	1985	2,891	
		2010	336	
EMCNX2	State Regular Wage Exog. Const. Emp. (Employees)	1985	218	
		2010	0	
EMT9X	State Exog. Transportation Emp. (Employees)	1985	1,116	
		2010	2,335	
EMMX1	State High Wage Manuf. Emp. (Employees)	1985	0	
		2010	0	
EMMX2	State Regular Wage Manuf. Emp. (Employees)	1985	11,129	
		2010	12,104	
EMFISH	State Fish Harvesting Emp. (Employees)	1985	7,608	
		2010	8,233	
EMGM	State Active Duty Military Emp. (Employees)	1985	21,818	
		2010	19,570	
EMGC	State Civilian Federal Emp. (Employees)	1985	17,907	
		2010	20,285	
TOURIST	Tourists Visiting Alaska (Visitors)	1985	810,000	
		2010	1,560,000	
GGRWEVS	U.S. Real Wage Growth/Year		.01	
UUS	U.S. Unemployment Rate		.06	
GRDIRPU	U.S. Real Per Capita Income Growth/Year		.015	
GRUSCPI	Price Level Growth/Year		.055	
RPBS	State Bonus Payment & Federal Shared Royalties Revenue (Million Nominal $)	1985	50.6	
		2010	82.0	
RPPS	State Petroleum Property Tax Revenue (Million Nominal $)	1985	107.4	
		2010	451.9	
RTCSPX	State Petroleum Corporate Tax (Million Nominal $)	1985	190.0	
		2010	44.9	
			Values Vary Between Cases	
			Composite	SHCA
RPTS	State Petroleum Production Tax Revenue (Million Nominal $)	1985	1372.0	1372.0
		2010	969.6	1191.3
RPRY	State Petroleum Royalty Revenue (Million Nominal $)	1985	1372.0	1372.0
		2010	1784.7	2207.3

TABLE B.5.4.4: SUMMARY OF MAP MODEL PROJECTION ASSUMPTIONS (SHCA AND COMPOSITE CASES)

ASSUMPTIONS COMMON TO BOTH CASES	DESCRIPTION[1/]
NATIONAL VARIABLES ASSUMPTIONS	
U.S. Inflation Rate	Consumer prices rise at 5.5 percent annually after 1985 [GRUSCPI].
Real Average Weekly Earnings	Growth in real average weekly earnings averages 1 percent annually [GRRWEUS].
Real Per Capita Income	Growth in real per capita income averages 1.5 percent annually after 1984 [GRDIRPU].
Unemployment Rate	Long-run rate of 6 percent [UUS].
INDUSTRY ASSUMPTIONS	
Trans-Alaska Pipeline	Operating employment remains constant at 990 through 2010 (TAP.F84).
North Slope Petroleum Production	Petroleum employment increases through the early 1990s to a peak of 4.6 thousand and subsequently tapers off gradually. Construction employment is eliminated by the late 1990s. This case presumes no significant change in current oil price trends (NSO.84B).
Upper Cook Inlet Petroleum	Employment in exploration and development of oil and gas in the Upper Cook Inlet area declines gradually beginning in 1983 by approximately 2.5 percent per year (UPC.F84).
OCS Development	Exploration and development activity grows through the mid-1990s and direct employment continues through the following decade at a slightly reduced level of approximately 7,000 (OCS.CM3(-3)).

ASSUMPTIONS COMMON TO BOTH CASES	DESCRIPTION[1]/
Oil Industry Headquarters	Oil company headquarters employment in Anchorage rises by 1,150 between 1983 and 1986 to remain at around 4,600 through 2010 (OHQ.F84).
Beluga Chuitna Coal Production	Development of 4.4 million ton/year mine for export beginning in 1990 provides total employment of 524 (BCL.04T(-4)).
Healy Coal Mining	Export of approximately 1 million tons of coal annually will add 25 new workers to current base of 100 by 1986 (HCL.84X).
U.S. Borax	The U.S. Borax mine near Ketchikan is brought into production with operating employment of 790 beginning in 1989 and eventually increasing to 1,020 (BXM.F84).
Greens Creek Mine	Production from the Greens Creek Mine on Admiralty Island results in employment of 150 people from 1988 through 2003 (GCM.F84).
Red Dog Mine	The Red Dog Mine in the Western Brooks Range reaches full production with operating employment of 428 by 1993 (RED.F84).
Other Mining Activity	Mining employment not included in special projects increases from current level at 1 percent annually (OMN.F84).
Agriculture	Moderate state support results in expansion of employment in agriculture by 4 percent per year (AGR.F83).
Logging and Sawmills	Employment expands to over 3,200 by 1990 before beginning to decline gradually to about 2,800 after 2000 (FLL.F84).
Pulp Mills	Employment declines at a rate of 1 percent per year after 1991 (FPU.F84).
Commercial Fishing - Nonbottomfish	Employment levels in traditional fisheries harvest remain constant at 7,500 through 2010 (TCF.F84).

ASSUMPTIONS COMMON TO BOTH CASES	DESCRIPTION[1/]
Commercial Fish Processing - Nonbottomfish	Employment in processing traditional fisheries harvests remains at the level of the average figure for the period 1978-1982, or around 7,300 (TFP.F84).
Commercial Fishing - Bottomfish	The total U.S. bottomfish catch expands at a constant rate to allowable catch in 2000, with Alaska resident harvesting employment rising to 733. Onshore processing capacity expands in the Aleutians and Kodiak census divisions to provide total resident employment of 971 by 2000 (BCF.F83).
Federal Military Employment	Employment declines at 1 percent per year, consistent with the long-term trend since 1960 (GFM.F84).
Light Army Division Deployment	A portion of a new Army division is deployed to Fairbanks and Anchorage beginning in 1986, augmenting active-duty personnel by 2,600 (GFM.JPR).
Federal Civilian Employment	Rises at 0.5 percent annual rate consistent with the long-term trend since 1960 (GFC.F84).
Tourism	Number of visitors to Alaska increases by 30,000 per year to over 1.3 million by 2010 (TRS.XXX).
State Hydroelectric Projects	Construction employment from Alaska Power Authority projects peaks at over 700 in 1990 for construction of several projects in Southcentral and Southeast Alaska (SHP.F83).
STATE PETROLEUM REVENUE ASSUMPTIONS	
Bonuses	Nominal average of past values net of major sales (SHC.B85).
Property Taxes	Aggregation of property taxes from specific petroleum activities based upon March 1985 Alaska Department of Revenue estimates (SHC.B85) and ISER estimates for OCS-related activities (OCS.CM3(-3)).

ASSUMPTIONS COMMON TO BOTH CASES	DESCRIPTION[1/]
Petroleum Corporate Income Tax	No change from current method of calculating tax base. Based upon March 1985 Alaska Department of Revenue estimates (SHC.B85).
Rents	Approximately constant at real current level [RPEN].
State Sharing of Federal Petroleum Revenues	Increasing $1 million annually in nominal dollars with two steps of $10 million each in the mid-1990s [RSFDNPX].
<u>STATE FISCAL BEHAVIOR ASSUMPTIONS</u>	
State Appropriations	If funds available, ceiling established by Constitutional Spending Limit; otherwise appropriations equal revenues [APGF].
Capital/Operations Split	Two-thirds operations if Spending Limit in effect; three-fourths operations otherwise [EXSPLITX].
General Obligation Bonds	Bonding occurs up to point where debt service is 5 percent of state revenues.
Municipal Capital Grants	Funding terminated in FY 1987 [RLTMCAP].
Permanent Fund/Other Appropriations in Excess of Spending Limit	None
Permanent Fund Principal	Continuous accumulation.
State Loan Programs	New capitalization terminated in FY 1991 [EXSUBSX].
Permanent Fund Dividend	Dividend terminated after FY 1990 distribution [EXPFDIST].
Use of Permanent Fund Earnings	Beginning in FY 1991, half of earnings transferred to General Fund; beginning in 1993, all earnings transferred to General Fund [EXPFTOGF].
Personal Income Tax	Personal income tax reinstated in CY 1992.

ASSUMPTIONS SPECIFIC TO EACH CASE	DESCRIPTION[1]
COMPOSITE CASE[2]	
State Petroleum Revenue Assumptions	
Severance Taxes	Based on 1985 "APA Average" world oil price projection used to drive Alaska Department of Revenue APR petroleum revenue model (AOF.B85).
Royalties	Based on 1985 "APA Average" world oil price projection used to drive Alaska Department of Revenue APR petroleum revenue model (AOF.B85).
SHERMAN CLARK CASE[3]	
State Petroleum Revenue Assumptions	
Severance Taxes	Based on 1985 Sherman Clark world oil price projection used to drive Alaska Department of Revenue APR petroleum revenue model (SHC.B85).
Royalties	Based on 1985 Sherman Clark world oil price projection used to drive Alaska Department of Revenue APR petroleum revenue model (SHC.B85).

1/ Codes in brackets are model variables. Codes in parentheses indicate ISER names for MAP Model SCEN case files. Industry and state petroleum revenue assumptions are incorporated into the scenario generator.

2/ Case HE53.3 with scenario S85.SUA3.

3/ Case HE53.1 with scenario S85.SUA3.

TABLE B.5.4.5: VARIABLES AND ASSUMPTIONS RED MODEL

Symbol	Name	SHCA and Composite Case Values	Source
Uncertainty Module			
	Fuel Price Forecast	Table B.5.4.6 and B.5.4.7	1983 Actual Data Combined with Escalation Rates
b,c,d	Housing Demand Coefficients	Table B.5.4.8	Battelle (1983)
SAT	Saturation of Residential Appliances	Table B.5.4.9	Battelle Northwest End Use Survey; Battelle (1983)
ESR, CEOSR, CEGSR	Price Adjustment Coefficients	Table B.5.4.10	Scott, King, and Moe (1985)
Housing Module			
THH	Regional Household Forecast	Table B.5.4.26 and B.5.4.27	MAP Output
HH	State Households by Age Group	Table B.5.4.26 and B.5.4.27	MAP Output
Residential Module			
HI	Households by Type of Dwellings	Table B.5.4.28 and B-5.4.29	Housing Module Output
AC	Average Consumption of Appliances	Table B.5.4.11	Battelle Northwest End Use Survey; Battelle (1983)

TABLE B.5.4.5 (Page 2 of 3)

Symbol	Name	SHCA and Composite Case Values	Source
FMS	Fuel Mode Split (Percentage of Appliances Using Electicity)	Table B.5.4.11	Battelle (1983)
AS	Initial Stock of Appliances	Table B.5.4.9 and B.5.4.11	Battelle (1983)
c	Growth in Electricity Use of Applicances	Table B.5.4.12	Battelle (1983) Scott, King and Moe (1985
d	Vintage Specific Survival Rate	Table B.5.4.13	Battelle (1983)
Business Consumption Module			
TEMP	Total Regional Employment	Table B.5.4.24 and B.5.4.25	MAP Output
a,b	Floorspace per Employee	Table B.5.4.14	Scott, King and Moe 1985
BETA, BBETA	Business Consumptions	Table B.5.4.14	Scott, King and Moe 1985
Program-Induced Conservation Module			
	Not used		
Miscellaneous Module			
VACHG	Vacant Housing	Table B.5.4.30 B.5.4.31	Battelle (1983)
vh	Consumption per Vacant Housing	300 kWh	Battelle (1983)

TABLE B.5.4.5 (Page 3 of 3)

Symbol	Name	SHCA and Composite Case Values	Source
Sl	Street Lighting Consumption	1.0 percent	Battelle (1983)
sh	Proportion of Households Having a Second Home	2.5 percent	Battelle (1983)
shkWh	Per Unit Second Home Consumption	500 kWh	Battelle (1983)
Peak Demand Module			
LF	Annual Load Factor		Exhibit D
	Fairbanks	60.0 percent	
	Anchorage	60.0 percent	

TABLE B.5.4.6: FUEL PRICE FORECASTS USED BY RED - SHCA CASE (1980 DOLLARS)

Year	Anchorage - Cook Inlet Area Residential	Anchorage - Cook Inlet Area Business	Fairbanks - Tanana Valley Area Residential	Fairbanks - Tanana Valley Area Business
	Heating Fuel Oil ($/MMBtu)			
1980	7.75	7.20	7.83	7.50
1985	6.45	5.87	6.51	6.18
1990	6.36	5.79	6.42	6.10
1995	7.53	6.85	7.60	7.22
2000	9.41	8.56	9.49	9.02
2005	11.52	10.49	11.63	11.05
2010	14.11	12.84	14.24	13.53
	Natural Gas ($/MMBtu)			
1980	1.73	1.50	12.74	11.29
1985	2.11	1.74	10.60	9.12
1990	2.44	2.06	10.45	8.98
1995	4.23	2.97	12.37	10.64
2000	5.13	3.86	15.46	13.29
2005	6.10	4.84	18.94	16.29
2010	7.37	6.11	23.19	19.95
	Electricity ($/kWh)			
1980	.037	.034	.095	.090
1985	.057	.047	.082	.072
1990	.065	.053	.075	.066
1995	.076	.062	.081	.071
2000	.101	.082	.104	.091
2005	.105	.086	.107	.094
2010	.107	.088	.111	.096

TABLE B.5.4.7: FUEL PRICE FORECASTS USED BY RED - COMPOSITE CASE
(1980 DOLLARS)

Year	Anchorage - Cook Inlet Area Residential	Business	Fairbanks - Tanana Valley Area Residential	Business
	Heating Fuel Oil ($/MMBtu)			
1980	7.75	7.20	7.83	7.50
1985	6.45	5.87	6.51	6.18
1990	6.31	5.74	6.37	6.05
1995	7.55	6.88	7.63	7.25
2000	9.07	8.25	9.15	8.69
2005	10.51	9.56	10.61	10.08
2010	12.18	11.09	12.30	11.68
	Natural Gas ($/MMBtu)			
1980	1.73	1.50	12.74	11.29
1985	2.11	1.74	10.60	9.12
1990	2.43	2.05	10.37	8.92
1995	4.11	2.85	12.43	10.69
2000	4.80	3.54	14.90	12.81
2005	5.46	4.20	17.27	14.86
2010	6.23	4.97	20.02	17.22
	Electricity ($/kWh)			
1980	.037	.034	.095	.090
1985	.057	.047	.082	.072
1990	.065	.053	.075	.066
1995	.071	.058	.077	.068
2000	.091	.074	.094	.082
2005	.105	.086	.107	.094
2010	.105	.086	.107	.095

TABLE B.5.4.8: HOUSING DEMAND COEFFICIENTS

Single Family		Multi Family		Mobile Homes	
Variable	Value	Variable	Value	Variable	Value
BA1	-0.303	CA1	0.225	DA1	0.068
BA2	-0.175	CA2	0.086	DA2	0.039
BA4	0.080	CA4	-0.090	DA4	0.014
B2S	0.182	C2S	-0.203	D2S	0.008
B3S	0.317	C3S	-0.280	D3S	-0.020
B4S	0.380	C4S	-3.352	D4S	-0.016

Note: These coefficients were used in the housing demand equations. A detailed explanation of these equations is presented in Battelle (1983).

Source: Battelle (1983).

TABLE B.5.4.9: EXAMPLE OF MARKET SATURATIONS OF APPLIANCES IN SINGLE-FAMILY HOMES FOR ANCHORAGE-COOK INLET AREA (PERCENT)

Year	Refrigerators Default	Refrigerators Range	Freezers Default	Freezers Range	Dishwashers Default	Dishwashers Range	Clothes Washers Default	Clothes Washers Range
1980	99.0	--	88.3	--	78.2	--	91.7	--
1985	99.0	98-100	90.0	85-95	85.0	80-90	92.0	90-94
1990	99.0	98-100	90.0	85-95	90.0	85-95	92.5	90-95
1995	99.0	98-100	90.0	85-95	90.0	85-95	93.7	91-96
2000	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98
2005	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98
2010	99.0	98-100	90.0	85-95	90.0	85-95	95.0	92-98

Year	Water Heater Default	Water Heater Range	Clothes Dryers Default	Clothes Dryers Range	Range (cooking) Default	Range (cooking) Range	Saunas Jacuzzis Default	Saunas Jacuzzis Range
1980	98.6	--	90.2	--	99.9	--	14.1	--
1985	98.8	95-100	91.2	88-94	100.0	99-100	16.3	13-19
1990	99.0	98-100	92.5	89-95	100.0	99-100	18.7	14-22
1995	99.0	98-100	93.7	90-96	100.0	99-100	21.0	16-26
2000	99.0	98-100	95.0	92-98	100.0	99-100	23.4	18-28
2005	99.0	98-100	95.0	92-98	100.0	99-100	25.7	20-30
2010	99.0	98-100	95.0	92-98	100.0	99-100	28.1	23-33

Note: A complete listing of market saturation data for single-family, multi-family, mobile-homes, and duplexes in Anchorage and Fairbanks is presented in Battelle (1983) and Scott, King and Moe (1985).

Source: Battelle 1983

TABLE B.5.4.10: PARAMETER VALUES IN RED MODEL PRICE ADJUSTMENT MECHANISM

	Residential Sector	Business Sector
Short-Run Elasticities		
Own-Price	-0.12	-0.15
Cross-Price		
Natural Gas	0.0225	0.0082
Oil	0.01	0.01
Long-Run Elasticities		
Own-Price	-0.40	-0.50
Cross-Price		
Natural Gas	0.075	0.027
Oil	0.033	0.033
Lagged Adjustment	0.700	0.700

Source: Scott, King, and Moe (1985).

TABLE B.5.4.11: PERCENT OF APPLIANCES USING ELECTRICITY AND AVERAGE ANNUAL ELECTRICITY CONSUMPTION, RAILBELT LOAD CENTERS, 1980

Appliance	Anchorage: Percentage Using Electricity SF	MH	DP	MF	Annual kWh Consumption	Fairbanks: Percentage Using Electricity SF	MH	DP	MF	Annual kWh Consumption
Space Heat (Existing Stock)										
Single Family	16.0	NA	NA	NA	32,850	9.7	NA	NA	NA	43,380
Mobile Home	NA	0.7	NA	NA	24,570	NA	0.0	NA	NA	33,210
Duplex	NA	NA	22.8	NA	21,780	NA	NA	11.7	NA	28,710
Multi-Family	NA	NA	NA	44.4	15,390	NA	NA	NA	14.8	19,080
Space Heat (New Stock)										
Single Family	10.9	NA	NA	NA	32,850	9.7	NA	NA	NA	43,380
Mobile Home	NA	0.7	NA	NA	24,570	NA	0.0	NA	NA	33,210
Duplex	NA	NA	15.0	NA	21,780	NA	NA	11.7	NA	28,710
Multi-Family	NA	NA	NA	25.0	15,390	NA	NA	NA	14.8	19,080
Water Heaters (Existing)	36.5	50.4	44.0	60.9	3,300	33.1	42.8	43.1	26.2	3,300
Water Heaters (New)	10.0	0.7	15.0	25.0	3,300	33.1	42.8	43.1	26.2	3,300
Clothes Dryers	84.3	88.1	81.3	86.6	1,032	96.2	94.6	94.4	100.0	1,032
Cooking Ranges	75.8	23.2	85.2	88.2	850	79.0	48.2	95.0	97.1	850
Sauna-Jacuzzis	93.5	100.0	93.7	81.8	2,000	61.8	100.0	60.8	100.0	2,000
Refrigerators	100.0	100.0	100.0	100.0	1,800	100.0	100.0	100.0	100.0	1,800
Freezers	100.0	100.0	100.0	100.0	1,342	100.0	100.0	100.0	100.0	1,342
Dishwashers	100.0	100.0	100.0	100.0	250	100.0	100.0	100.0	100.0	250
Additional										
Water Heating (Existing)	36.5	50.4	44.0	60.9	799	33.1	42.8	43.1	26.2	799
Water Heating (New)	10.0	0.7	15.0	25.0	799	33.1	42.8	43.1	26.2	799
Clothes Washers	100.0	100.0	100.0	100.0	90	100.0	100.0	100.0	100.0	90
Additional										
Water Heating (Existing)	36.5	50.4	44.0	60.9	1,202	33.1	42.8	43.1	26.2	1,202
Water Heating (New)	10.0	0.7	15.0	25.0	1,202	33.1	42.8	43.1	26.2	1,202
Miscellaneous	100.0	100.0	100.0	100.0	2,110	100.0	100.0	100.0	100.0	2,466

Source: Battelle (1983).

TABLE B.5.4.12: GROWTH RATES IN ELECTRIC APPLIANCE CAPACITY AND INITIAL ANNUAL AVERAGE CONSUMPTION FOR NEW APPLIANCES

Appliance	Average Annual kWh Consumption for New Appliances (1985) Anchorage	Fairbanks	Growth Rate in Electrical Capacity Post 1985 (annual)
Space Heat			
Single Family	40,000	43,380	0.005
Mobile Home	30,000	33,210	0.005
Duplex	26,600	28,710	0.005
Multi-Family	18,800	19,080	0.005
Water Heaters	3,475	3,475	0.000
Clothes Dryers	1,032	1,032	0.01
Cooking Ranges	1,250	1,250	0.01
Sauna-Jacuzzis	1,750	1,750	0.01
Refrigerators	1,560	1,560	0.01
Freezers	1,550	1,550	0.01
Dishwashers	230	230	--
Additional Water Heating	740	740	0.005
Clothes Washers	70	70	0.0
Additional Water Heating	1,050	1,050	0.005
Miscellaneous Appliances	2,160	2,536	1/

1/ Incremental growth of 80 kWh per customer in Anchorage 5-year period; 100 kWh in Fairbanks.

Source: Battelle (1983); Scott, King, and Moe (1985).

TABLE B.5.4.13: PERCENT OF APPLIANCES REMAINING IN SERVICE YEARS AFTER PURCHASE

	Years After Purchase					
	5	10	15	20	25	30
Old Appliances						
Space Heat (All)	90	80	60	30	10	00
Water Heaters	60	30	10	00	00	00
Clothes Dryers	80	60	30	10	00	00
Ranges - Cooking	60	30	10	00	00	00
Saunas-Jacuzzis	50	30	10	00	00	00
Refrigerators	80	60	30	10	00	00
Freezers	90	80	60	30	10	00
Dishwashers	60	30	10	00	00	00
Clothes Washers	60	30	10	00	00	00
New Appliances						
Space Heat (All)	89	73	56	42	30	10
Water Heaters	75	35	10	00	00	00
Clothes Dryers	100	75	35	10	00	00
Ranges - Cooking	75	35	10	00	00	00
Saunas-Jacuzzis	100	75	35	10	00	00
Refrigerators	100	75	35	10	00	00
Freezers	100	100	75	35	10	00
Dishwashers	75	35	10	00	00	00
Clothes Washers	75	35	10	00	00	00

Source: Battelle (1983), based upon Goldsmith and Huskey (1980).

TABLE B.5.4.14: RED BUSINESS SECTOR ELECTRICITY CONSUMPTION PARAMETERS

Variable	Anchorage - Cook Inlet		Fairbanks - Tanana Valley	
	Default Value	Range	Default Value	Range
Business Square Feet of Floorspace Per Employee 1/				
a_i	383.023	--	317.5622	--
b	5.811	--	5.8112	--
Business Consumption of Electricity 2/				
$BETA_i$	-2.2118	--	-.7980	--
$BBETA_i$	1.224	1.003-1.416	1.0	.826-1.081

1/ Equation is $STOCK_{it}=(a_i * b * t) * TEMP_{it}$

where:

$STOCK_{it}$ = Square feet of business floorspace, load center i, year t

a_i = intercept (1972 value) square footage per employee in each load center i, year t

b=growth rate parameter

t=forecast year (t=1,2, ...,38)

$TEMP_{it}$ =Total employment, load center i, year t

2/ Equation is $PRECON_{ik} = \exp [BETA_i + BBETA_i \times \ln (STOCK_{ik})]$

$PRECON_{ik}$ = Nonprice-adjusted business consumption (MWh), load center i , forecast period K

$BETA_i$ =parameter equal to regression equation intercept, load center i

$BBETA_i$ =percentage change in business consumption for a 1% change in stock (floorspace elasticity), load center i

$STOCK_{ik}$ square feet of business floorspace, load center i, forecast period k.

TABLE B.5.4.15: VARIABLES AND ASSUMPTIONS -- OGP MODEL ECONOMIC PARAMETERS

1. All Costs in January 1985 Dollars

2. Base Year for Present Worth Analysis: 1985

3. Analysis Periods:

   System Expansion: 1996-2025
   Annual Cost Extension: 2026-2054

4. Electrical Load Forecast: 1985 to 2025

5. Discount Rate: 3.5 percent

6. Inflation Rate: 0 percent

7. Economic Life of Projects:

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

8. Annual Fixed Carrying Charges

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

9. Susitna Project Construction Cost, $ million

Watana Stage I	2682
Devil Canyon Stage II	1394
Watana Stage III	1319
Total	5395

10. Susitna Annual Operation and Maintenance Cost, $ million

1999-2004	11.50
2005-2011	12.75
2012-2017	12.75
2018-2025	11.45

TABLE B.5.4.15 (Page 2 of 3)

THERMAL GENERATING PLANT PARAMETERS (1985 $)

Parameters	Coal 200 MW 1/	Combined Cycle 229 MW	Combustion Turbine 87 MW 2/
Heat Rate (Btu/kWh)	10,300	9,200	12,000
Earliest Availability	1992	1988	1988
O&M Costs			
Fixed O&M ($/kW/yr)	61.42	13.26	8.76
Variable O&M ($/MWh)	4.30	0.66	0.58
Outages			
Planned Outages (%)	8	7	3.2
Forced Outages (%)	5.7	8	8
Construction Period (yrs)	6	2	1
Startup Time (yrs)	3	2	1
Unit Capital Cost ($/kW)			
Beluga/Railbelt	2,593	650	386
Nenana	2,702	---	---
Unit Capital Cost ($/kW) 3/			
Beluga/Railbelt	2,877	673	393
Nenana	2,998	---	---

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

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

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

TABLE B.5.4.15 (Page 3 of 3)

FUEL PRICES (1985)

Year	SHCA Forecast: Coal Price: Nenana Delivered ($/MMBtu)	SHCA Forecast: Coal Price: Beluga Minemouth ($/MMBtu)	SHCA Forecast: Oil ($/bbl)	SHCA Forecast: Gas 2/ ($/MMBtu)	Composite Forecast: Coal Price: Nenana Delivered $/MMBtu	Composite Forecast: Coal Price: Beluga Minemouth $/MMBtu	Composite Forecast: Oil ($/bbl)	Composite Forecast: Gas 2/ ($/MMBtu)	Forecast 1/: Oil ($/bbl)	Forecast 1/: Gas 2/ ($/MMBtu)
1985	1.84	1.32	28.10	2.13	1.84	1.42	2710	1.98	27.10	1.97
1990	1.99	1.45	27.70	2.08	1.99	1.54	26.50	1.90	24.80	1.66
1995	2.14	1.60	32.80	2.80	2.14	1.65	31.80	2.65	27.60	2.05
2000	2.31	1.78	41.00	3.95	2.31	1.78	38.10	3.53	31.30	2.57
2010	2.69	2.13	61.50	6.83	2.69	2.19	51.00	5.37	40.70	3.89
2020	3.13	2.55	85.00	10.15	3.13	2.57	68.90	7.85	54.60	5.83
2030	3.64	3.30	96.00	11.70	3.64	3.08	75.00	8.70	73.40	8.84
2040	4.24	4.10	106.00	13.12	4.24	3.22	75.00	8.70	75.00	8.70
2050	4.94	5.12	117.00	14.67	4.94	3.74	75.00	8.70	75.00	8.70

1/ Composite forecast coal prices assumed for Wharton forecast.

2/ Includes 0.40 $/MMBtu charge for delivery.

TABLE B.5.4.16: SHCA CASE FORECAST SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1985	1990	1995	2000	2005	2010
World Oil Price (1985$/bbl)	28.10	27.70	32.80	41.00	50.20	61.50
Energy Price Used by RED (1980$)						
Heating Fuel Oil-Anchorage ($/MMBtu)	6.45	6.36	7.53	9.41	11.52	14.11
Natural Gas - Anchorage ($/MMBtu)	2.11	2.44	4.23	5.13	6.10	7.37
State Petroleum Revenues 1/ (Million Nominal $)						
Production Taxes	1,372	1,299	1,286	994	903	1191
Royalty Fees	1,372	1,826	2,031	1,983	1,912	2,207
State General Fund Expenditures (Million Nominal $)	3,665	3,773	5,692	5,831	6,387	7,762
State Population	536,525	563,923	597,969	632,655	657,639	699,607
State Employment	269,087	281,962	304,522	319,827	325,447	348,304
Railbelt Population	381,264	399,873	422,238	440,956	468,823	506,384
Railbelt Employment	181,885	189,109	201,168	210,611	222,663	243,163
Railbelt Total Number of Households	134,300	142,574	152,499	161,248	172,218	186,823
Railbelt Electricity Consumption 2/ (GWh)						
Anchorage	2,715	2,784	2,983	3,079	3,336	3,848
Fairbanks	608	797	902	919	978	1,081
Total	3,323	3,581	3,885	3,998	4,314	4,929
Railbelt Peak Demand (MW)	632	681	739	761	821	938

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, rents, and federal shared royalties.

2/ At customer level

TABLE B.5.4.17: COMPOSITE CASE FORECAST SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1985	1990	1995	2000	2005	2010
World Oil Price (1985$/bbl)	27.10	26.50	31.80	38.10	44.20	51.00
Energy Price Used by RED (1980$)						
Heating Fuel Oil-Anchorage ($/MMBtu)	6.45	6.31	7.56	9.07	10.51	12.18
Natural Gas - Anchorage ($/MMBtu)	2.11	2.43	4.11	4.80	5.46	6.23
State Petroleum Revenues 1/ (Million Nominal $)						
Production Taxes	1,372	1,224	1,238	913	783	970
Royalty Fees	1,372	1,717	1,953	1,819	1,650	1,785
State General Fund Expenditures (Million Nominal $)	3,665	3,610	5,280	5,586	6,009	7,131
State Population	536,525	562,317	595,023	628,969	653,542	695,215
State Employment	269,087	280,177	302,226	318,010	323,335	346,249
Railbelt Population	381,264	398,969	419,236	438,363	465,911	503,372
Railbelt Employment	181,885	187,967	199,116	209,340	221,172	241,761
Railbelt Total Number of Households	134,300	142,243	151,445	160,294	171,129	185,668
Railbelt Electricity Consumption 2/ (GWh)						
Anchorage	2,715	2,770	3,003	3,160	3,344	3,815
Fairbanks	608	793	907	943	981	1,073
Total	3,323	3,563	3,910	4,103	4,325	4,888
Railbelt Peak Demand (MW)	632	678	744	781	823	930

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, rents, and federal shared royalties.

2/ At customer level

TABLE B.5.4.18: SHCA CASE STATE PETROLEUM REVENUES (Million Nominal $)

Year	Royalties	Severance Taxes	Corporate Income Taxes	Property Taxes	Total Including Bonuses, Rents, and Federal Shared Royalties	Total to General Fund (Net of Permanent Fund Contri-bution)
1983	1437.900	1493.000	236.000	152.600	3420.600	3035.849
1984	1396.700	1392.400	265.100	131.000	3237.300	2875.100
1985	1372.000	1372.000	190.000	107.400	3092.000	2736.350
1986	1695.265	1627.469	242.100	102.900	3701.734	3269.417
1987	1828.607	1735.756	264.200	107.000	3970.563	3504.661
1988	1848.434	1453.355	274.100	116.523	3728.412	3257.303
1989	1863.817	1411.140	294.200	137.637	3743.794	3268.590
1990	1826.438	1299.429	304.000	144.649	3612.515	3146.406
1991	1894.220	1316.453	303.700	147.376	3701.749	3169.838
1992	1971.221	1337.337	291.700	140.725	3781.982	3228.621
1993	2054.794	1379.784	297.800	156.315	3912.693	3283.655
1994	2050.586	1355.180	268.100	165.402	3882.268	3254.192
1995	2030.882	1285.693	251.100	161.875	3783.550	3158.085
1996	2023.862	1247.807	235.200	206.137	3779.006	3152.047
1997	2046.940	1215.856	222.600	230.911	3783.307	3149.124
1998	2046.433	1167.739	200.700	270.521	3753.394	3119.063
1999	2008.302	1070.878	179.300	306.096	3633.576	3010.385
2000	1983.280	993.533	158.400	379.048	3584.261	2968.277
2001	1843.249	842.240	138.000	449.979	3345.468	2770.893
2002	1780.510	792.668	121.800	486.557	3254.535	2698.482
2003	1814.169	814.537	107.500	485.099	3295.304	2728.853
2004	1854.221	851.450	94.900	483.270	3358.841	2780.074
2005	1911.559	902.923	83.800	480.773	3455.055	2858.787
2006	1955.380	951.888	74.000	477.435	3536.702	2926.688
2007	2031.676	1025.718	65.300	473.079	3674.773	3041.570
2008	2035.953	1062.136	57.600	467.558	3703.246	3068.460
2009	2118.701	1112.038	50.900	460.572	3823.211	3163.300
2010	2207.310	1191.319	44.900	451.948	3977.478	3290.684

Source: MAP Model Output. Files HE53.1 and HER53.1. Variables: RPRY, RPTS, RTCSPX, RPPS, RP9S, and RP9SGF.

TABLE B.5.4.19: COMPOSITE CASE STATE PETROLEUM REVENUES (Million Nominal $)

Year	Royalties	Severance Taxes	Corporate Income Taxes	Property Taxes	Total Including Bonuses, Rents, and Federal Shared Royalties	Total to General Fund (Net of Permanent Fund Contribution)
1983	1437.900	1493.000	236.000	152.600	3420.600	3034.849
1984	1396.700	1392.400	265.100	131.000	3237.300	2875.100
1985	1372.000	1372.000	190.000	107.400	3092.000	2736.350
1986	1605.383	1544.257	242.100	102.900	3528.640	3118.794
1987	1729.298	1644.928	264.200	107.000	3780.426	3339.351
1988	1746.100	1375.635	274.100	116.523	3548.358	3102.833
1989	1757.513	1333.247	294.200	137.637	3559.597	3110.969
1990	1717.382	1224.391	304.000	144.649	3428.422	2989.576
1991	1790.046	1246.316	303.700	147.376	3527.438	3024.175
1992	1871.650	1271.800	291.700	140.725	3616.875	3090.896
1993	1960.157	1318.919	279.800	156.315	3756.291	3155.644
1994	1963.875	1299.419	268.100	165.402	3739.796	3137.733
1995	1953.026	1237.628	251.100	161.875	3657.629	3055.521
1996	1927.142	1189.558	235.200	206.137	3624.037	3026.994
1997	1930.842	1148.461	222.600	230.911	3599.814	3000.461
1998	1912.060	1092.759	200.700	270.521	3544.041	2950.022
1999	1858.931	993.055	179.300	306.096	3406.382	2828.002
2000	1818.815	912.904	158.400	379.048	3339.167	2772.522
2001	1669.401	764.645	138.000	449.979	3094.025	2571.604
2002	1593.035	711.232	121.800	486.557	2985.623	2485.812
2003	1603.990	722.449	107.500	485.099	2993.038	2489.641
2004	1620.013	746.507	94.900	483.270	3019.690	2511.186
2005	1650.406	782.548	83.800	480.773	3073.528	2555.605
2006	1667.140	815.027	74.000	477.435	3111.602	2588.060
2007	1710.077	867.402	65.300	473.079	3194.857	2658.134
2008	1690.615	886.851	57.600	467.558	3182.624	2651.439
2009	1736.014	916.641	50.900	460.572	3245.126	2700.022
2010	1784.688	969.571	44.900	451.948	3333.107	2773.100

Source: MAP Model Output Files HE53.3 and HER53.3. Variables: RPRY, RPTS, RTCSPX, RPPS, RP9S, and RP9SGF.

TABLE B.5.4.20: SHCA CASE STATE GOVERNEMENT FISCAL CONDITIONS (Million Nominal $)

Year	Unrestricted General Fund Expenditures	General Fund Balance	Permanent Fund Dividends	State Personal Income Tax	State Subsidy Programs	Percent of Permanent Fund Earnings to General Fund
1983	3499.489	2315.700	176.000	0.000	274.700	23.0
1984	3518.373	2041.822	193.917	0.000	250.000	0.0
1985	3664.836	1497.312	190.524	0.000	250.000	0.0
1986	3410.682	1712.316	238.049	0.000	250.000	0.0
1987	3736.196	1865.815	269.060	0.000	250.000	0.0
1988	3915.580	1611.859	291.666	0.000	250.000	0.0
1989	4150.453	1125.223	314.778	0.000	200.000	0.0
1990	3772.734	873.367	350.895	0.000	100.000	0.0
1991	4012.436	868.398	0.000	0.000	0.000	50.0
1992	4295.910	935.254	0.000	244.207	0.000	50.0
1993	4922.473	1304.047	0.000	494.410	0.000	100.0
1994	5736.023	993.992	0.000	557.415	0.000	100.0
1995	5692.410	739.742	0.000	609.495	0.000	100.0
1996	5663.820	604.469	0.000	651.376	0.000	100.0
1997	5611.551	623.102	0.000	691.349	0.000	100.0
1998	5708.297	640.164	0.000	745.909	0.000	100.0
1999	5750.297	646.602	0.000	804.565	0.000	100.0
2000	5831.277	666.785	0.000	865.454	0.000	100.0
2001	5802.555	659.980	0.000	925.312	0.000	100.0
2002	5833.957	668.094	0.000	974.152	0.000	100.0
2003	5970.074	695.758	0.000	1029.248	0.000	100.0
2004	6154.270	733.926	0.000	1096.306	0.000	100.0
2005	6386.668	778.551	0.000	1174.044	0.000	100.0
2006	6634.203	818.473	0.000	1261.026	0.000	100.0
2007	6927.227	862.113	0.000	1350.871	0.000	100.0
2008	7150.926	899.289	0.000	1446.110	0.000	100.0
2009	7421.859	964.199	0.000	1551.661	0.000	100.0
2010	7762.457	1039.770	0.000	1669.305	0.000	100.0

Source: MAP Model Output Files HE53.1 and HER53.1.
Variables: EXGFBM, BALGF9, EXTRNS, RTIS, EXSUBS, and EXPFTOGF.

TABLE B.5.4.21: COMPOSITE CASE STATE GOVERNMENT FISCAL CONDITIONS (Million Nominal $)

Year	Unrestricted General Fund Expenditures	General Fund Balance	Permanent Fund Dividends	State Personal Income Tax	State Subsidy Programs	Percent of Permanent Fund Earnings to General Fund
1983	3499.489	2315.700	176.000	0.000	274.700	23.0
1984	3518.373	2041.822	193.917	0.000	250.000	0.0
1985	3664.836	1497.312	190.524	0.000	250.000	0.0
1986	3497.226	1475.323	237.954	0.000	250.000	0.0
1987	3519.947	1662.631	268.661	0.000	250.000	0.0
1988	3907.627	1246.773	290.727	0.000	250.000	0.0
1989	4133.516	591.129	313.038	0.000	200.000	0.0
1990	3610.305	303.882	348.073	0.000	100.000	0.0
1991	3810.986	303.789	0.000	0.000	0.000	50.0
1992	4104.195	370.859	0.000	242.797	0.000	50.0
1993	4943.199	526.613	0.000	493.807	0.000	100.0
1994	5215.172	538.273	0.000	555.853	0.000	100.0
1995	5279.566	529.848	0.000	604.697	0.000	100.0
1996	5344.398	537.188	0.000	645.287	0.000	100.0
1997	5422.613	553.246	0.000	685.799	0.000	100.0
1998	5498.207	566.367	0.000	741.467	0.000	100.0
1999	5522.371	569.859	0.000	800.179	0.000	100.0
2000	5585.840	586.949	0.000	860.942	0.000	100.0
2001	5547.316	578.715	0.000	920.752	0.000	100.0
2002	5562.297	583.645	0.000	969.491	0.000	100.0
2003	5669.082	605.258	0.000	1024.249	0.000	100.0
2004	5818.734	635.445	0.000	1090.747	0.000	100.0
2005	6009.129	671.547	0.000	1167.367	0.000	100.0
2006	6207.797	706.578	0.000	1252.621	0.000	100.0
2007	6446.035	745.398	0.000	1341.272	0.000	100.0
2008	6627.434	777.578	0.000	1436.832	0.000	100.0
2009	6850.598	830.434	0.000	1543.331	0.000	100.0
2010	7130.594	889.020	0.000	1660.639	0.000	100.0

Source: MAP Model Output Files HE53.3 and HER53.3.
Variables: EXGFBM, BALGF9, EXTRNS, RTIS, EXSUBS, and EXPFTOGF.

TABLE B.5.4.22: SHCA CASE POPULATION (thousands)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1983	510.484			
1984	527.453	374.240	301.002	73.238
1985	536.525	381.264	307.278	73.987
1986	549.371	391.208	311.344	79.864
1987	551.850	390.471	310.969	79.503
1988	553.178	391.972	312.366	79.607
1989	560.657	397.279	317.269	80.011
1990	563.923	399.873	320.000	79.874
1991	567.837	402.244	321.868	80.376
1992	569.795	401.942	321.495	80.447
1993	576.465	406.349	324.935	81.414
1994	589.708	417.667	334.396	83.272
1995	597.969	422.238	338.649	83.590
1996	603.645	419.442	336.577	82.865
1997	607.509	423.985	340.597	83.388
1998	616.940	422.667	339.905	82.763
1999	623.645	432.981	348.769	84.213
2000	632.655	440.956	355.751	85.206
2001	638.154	450.147	363.651	86.496
2002	641.315	452.291	365.571	86.721
2003	645.454	457.491	370.066	87.425
2004	651.059	462.966	374.809	88.157
2005	657.639	468.823	379.953	88.870
2006	665.142	475.693	385.946	89.747
2007	672.362	482.381	391.752	90.630
2008	680.226	489.354	397.903	91.452
2009	689.099	497.095	404.682	92.414
2010	699.607	506.384	412.734	93.651

Source: MAP Model Output Files HE53.1 and HER53.1.
Variables: POP, P.IR, P.AG, and P.FG.

TABLE B.5.4.23: COMPOSITE CASE POPULATION (thousands)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1983	510.484			
1984	527.453	374.240	301.002	73.238
1985	536.525	381.264	307.278	73.987
1986	550.839	391.606	311.573	80.033
1987	551.434	389.888	310.504	79.385
1988	552.191	390.945	311.520	79.426
1989	559.888	396.563	316.673	79.891
1990	562.317	398.969	319.317	79.653
1991	565.875	401.077	320.956	80.122
1992	567.640	400.610	320.444	80.166
1993	576.155	405.522	324.154	81.369
1994	587.631	415.703	332.791	82.913
1995	595.023	419.236	336.150	83.086
1996	599.708	416.280	334.018	82.262
1997	603.835	421.303	338.419	82.884
1998	613.332	420.115	337.833	82.282
1999	619.991	430.404	346.681	83.723
2000	628.969	438.363	353.654	84.709
2001	634.505	447.581	361.579	86.003
2002	637.662	449.725	363.500	86.226
2003	641.739	454.889	367.968	86.922
2004	647.234	460.295	372.658	87.638
2005	653.542	465.911	377.608	88.303
2006	660.673	472.421	383.303	89.118
2007	667.716	478.976	388.991	89.986
2008	675.723	486.141	395.288	90.854
2009	684.784	494.124	402.265	91.859
2010	695.215	503.372	410.295	93.077

Source: MAP Model Output Files HE53.3 and HER53.3.
Variables: POP, P.IR, P.AG, and P.FG.

TABLE B.5.4.24: SHCA CASE EMPLOYMENT
(thousands)

Year	State Non-Ag Wage and Salary	State Total	Railbelt Total	Greater Anchorage Total	Greater Fairbanks Total
1983	213.243	254.642			
1984	222.290	264.038	179.069	142.623	36.446
1985	227.237	269.087	181.885	145.242	36.643
1986	230.977	275.622	186.029	146.478	39.551
1987	230.747	275.175	184.430	145.319	39.112
1988	231.062	275.298	185.665	146.309	39.356
1989	237.587	282.046	189.091	149.379	39.712
1990	237.706	281.962	189.109	149.717	39.392
1991	239.485	283.649	190.640	150.843	39.797
1992	239.117	283.060	190.715	150.751	39.964
1993	244.731	288.840	192.612	152.380	40.232
1994	256.670	301.365	198.950	157.805	41.145
1995	259.797	304.522	201.168	159.816	41.352
1996	260.901	305.539	201.285	159.853	41.433
1997	260.388	304.849	201.764	160.386	41.378
1998	267.445	312.240	203.778	162.172	41.606
1999	269.222	314.032	206.967	164.989	41.978
2000	274.802	319.827	210.611	168.225	42.386
2001	275.004	319.843	213.426	170.652	42.773
2002	273.982	318.556	214.858	171.710	43.148
2003	274.888	319.326	216.952	173.465	43.487
2004	277.481	321.894	219.582	175.696	43.886
2005	280.995	325.447	222.663	178.343	44.320
2006	285.102	329.634	226.402	181.529	44.873
2007	288.438	333.002	230.098	184.620	45.479
2008	292.451	337.094	233.656	187.694	45.961
2009	297.192	341.965	237.800	191.240	46.561
2010	303.306	348.304	243.163	195.767	47.396

Source: MAP Model Output Files HE53.1 and HER53.1.
Variables: EM97, EM99, M.IR, M.AG, and M.FG.

TABLE B.5.4.25: COMPOSITE CASE EMPLOYMENT (thousands)

Year	State Non-Ag Wage and Salary	State Total	Railbelt Total	Greater Anchorage Total	Greater Fairbanks Total
1983	213.243	254.642			
1984	222.290	264.038	179.069	142.623	36.446
1985	227.237	269.087	181.885	145.242	36.643
1986	232.708	277.462	187.016	147.205	39.812
1987	229.835	274.206	183.619	144.679	38.940
1988	229.786	273.942	184.560	145.424	39.136
1989	236.797	281.206	188.419	148.836	39.583
1990	236.028	280.177	187.967	148.837	39.130
1991	237.719	281.771	189.426	149.896	39.530
1992	237.420	281.254	189.540	149.833	39.707
1993	245.445	289.600	192.846	152.501	40.345
1994	254.997	299.584	197.462	156.611	40.851
1995	257.641	302.226	199.116	158.141	40.975
1996	258.035	302.488	198.978	158.013	40.965
1997	258.304	302.631	200.169	159.111	41.059
1998	265.601	310.276	202.399	161.068	41.330
1999	267.451	312.145	205.644	163.933	41.712
2000	273.096	318.010	209.340	167.212	42.128
2001	273.398	318.132	212.230	169.700	42.530
2002	272.404	316.875	213.684	170.776	42.908
2003	273.268	317.600	215.750	172.510	43.240
2004	275.770	320.071	218.317	174.692	43.625
2005	279.013	323.335	221.172	177.159	44.013
2006	282.796	327.176	224.621	180.110	44.511
2007	286.091	330.500	228.281	183.167	45.115
2008	290.405	334.912	232.107	186.452	45.655
2009	295.394	340.048	236.489	190.190	46.299
2010	301.379	346.249	241.761	194.650	47.111

Source: MAP Model Output Files HE53.3 and HER53.3.
Variables: EM97, EM99, M.IR, M.AG, and M.FG.

TABLE B.5.4.26: SHCA CASE HOUSEHOLDS (thousands)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1983	171.664			
1984	178.150	131.373	106.128	25.246
1985	181.869	134.300	108.704	25.596
1986	186.311	137.863	110.118	27.745
1987	187.702	138.002	110.306	27.696
1988	188.676	138.830	111.035	27.795
1989	191.754	141.253	113.204	28.050
1990	193.379	142.574	114.496	28.079
1991	195.217	143.725	115.402	28.322
1992	196.374	143.962	115.544	28.418
1993	199.139	146.003	117.144	28.859
1994	204.155	150.409	120.808	29.601
1995	207.471	152.499	122.694	29.805
1996	209.895	152.187	122.509	29.678
1997	211.690	154.032	124.123	29.909
1998	215.375	154.385	124.544	29.841
1999	218.129	158.106	127.737	30.369
2000	221.663	161.248	130.468	30.780
2001	223.997	164.568	133.316	31.252
2002	225.523	165.607	134.220	31.388
2003	227.368	167.646	135.968	31.677
2004	229.700	169.862	137.871	31.991
2005	232.357	172.218	139.921	32.298
2006	235.322	174.930	142.268	32.662
2007	238.186	177.555	144.530	33.026
2008	241.264	180.289	146.923	33.366
2009	244.679	183.289	149.533	33.756
2010	248.645	186.823	152.580	34.243

Source: MAP Model Output Files HE53.1 and HER53.1.
Variables: HH, HH.IR, HH.AG, and HH.FG.

Year	Total	Head Younger Than 25	Head 25-29	Head 30-54	Head Older Than 54
1983	171.664	21.132	29.622	96.310	24.600
1984	178.150	21.394	30.205	100.802	25.749
1985	181.869	21.155	30.102	103.790	26.822
1986	186.311	21.134	30.299	106.954	27.923
1987	187.702	20.623	29.714	108.371	28.994
1988	188.676	20.138	29.106	109.340	30.092
1989	191.754	20.099	29.134	111.210	31.311
1990	193.379	19.837	28.828	112.204	32.510
1991	195.217	19.661	28.641	113.167	33.748
1992	196.374	19.406	28.331	113.652	34.985
1993	199.139	19.459	28.500	114.876	36.303
1994	204.155	19.879	29.282	117.269	37.725
1995	207.471	19.973	29.599	118.806	39.093
1996	209.895	19.919	29.690	119.851	40.435
1997	211.690	19.781	29.639	120.513	41.757
1998	215.375	19.969	30.117	122.137	43.152
1999	218.129	19.992	30.346	123.285	44.506
2000	221.663	20.139	30.792	124.848	45.885
2001	223.997	20.086	30.918	125.785	47.206
2002	225.523	19.923	30.850	126.266	48.484
2003	227.368	19.835	30.897	126.878	49.758
2004	229.700	19.833	31.097	127.738	51.032
2005	232.357	19.879	31.394	128.784	52.299
2006	235.322	19.964	31.776	130.024	53.557
2007	238.186	20.021	32.128	131.246	54.791
2008	241.264	20.102	32.533	132.616	56.014
2009	244.679	20.221	33.019	134.208	57.231
2010	248.645	20.403	33.638	136.149	58.454

Source: MAP Model Output Files HE53.1 and HER53.1.
Variables: HH, HH24, HH25.29, HH30.54, and HH55.

TABLE B.5.4.27: COMPOSITE CASE HOUSEHOLDS (thousands)

Year	State	Railbelt	Greater Anchorage	Greater Fairbanks
1983	171.664			
1984	178.150	131.373	106.128	25.246
1985	181.869	134.300	108.704	25.596
1986	186.818	138.028	110.217	27.811
1987	187.561	137.805	110.150	27.655
1988	188.337	138.473	110.742	27.732
1989	191.489	141.002	112.995	28.007
1990	192.825	142.243	114.246	27.997
1991	194.538	143.298	115.070	28.228
1992	195.626	143.476	115.162	28.314
1993	199.021	145.716	116.871	28.845
1994	203.432	149.716	120.244	29.473
1995	206.446	151.445	121.819	29.626
1996	208.526	151.059	121.599	29.460
1997	210.404	153.061	123.337	29.724
1998	214.106	153.453	123.790	29.663
1999	216.838	157.162	126.975	30.187
2000	220.355	160.294	129.699	30.595
2001	222.696	163.619	132.552	31.067
2002	224.215	164.654	133.452	31.202
2003	226.033	166.675	135.188	31.487
2004	228.321	168.862	137.068	31.794
2005	230.879	171.129	139.047	32.083
2006	233.710	173.712	141.287	32.425
2007	236.506	176.284	143.502	32.782
2008	239.624	179.076	145.939	33.138
2009	243.096	182.154	148.613	33.542
2010	247.029	185.668	151.648	34.021

Source: MAP Model Output Files HE53.3 and HER53.3.
Variables: HH, HH.IR, HH.AG, and HH.FG.

TABLE B.5.4.27 (Page 2 of 2)

Year	Total	Head Younger Than 25	Head 25-29	Head 30-54	Head Older Than 54
1983	171.664	21.132	29.622	96.310	24.600
1984	178.150	21.394	30.205	100.802	25.749
1985	181.869	21.155	30.102	103.790	26.822
1986	186.818	21.222	30.431	107.222	27.943
1987	187.561	20.589	29.668	108.315	28.989
1988	188.337	20.075	29.012	109.170	30.080
1989	191.489	20.056	29.066	111.065	31.302
1990	192.825	19.751	28.689	111.896	32.489
1991	194.538	19.563	28.480	112.774	33.721
1992	195.626	19.307	28.164	113.204	34.952
1993	199.021	19.473	28.509	114.748	36.292
1994	203.432	19.787	29.133	116.826	37.686
1995	206.446	19.839	29.380	118.190	39.037
1996	208.526	19.741	29.395	119.030	40.360
1997	210.404	19.632	29.385	119.709	41.678
1998	214.106	19.833	29.882	121.325	43.065
1999	216.838	19.860	30.119	122.450	44.409
2000	220.355	20.010	30.573	123.996	45.775
2001	222.696	19.964	30.712	124.934	47.086
2002	224.215	19.804	30.650	125.410	48.351
2003	226.033	19.714	30.698	126.010	49.611
2004	228.321	19.709	30.892	126.850	50.870
2005	230.879	19.744	31.170	127.846	52.119
2006	233.710	19.813	31.523	129.015	53.358
2007	236.506	19.867	31.866	130.199	54.575
2008	239.624	19.960	32.290	131.590	55.784
2009	243.096	20.092	32.799	133.217	56.988
2010	247.029	20.272	33.414	135.148	58.195

Source: MAP Model Output Files HE53.3 and HER53.3.
Variables: HH, HH24, HH25.29, HH30.54, and HH55.

TABLE B.5.4.28: SHCA CASE FORECAST
NUMBER OF HOUSEHOLDS SERVED

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
Anchorage-Cook Inlet Area					
1980	35,473	20,314	8,230	7,486	71,503
1985	57,487	26,204	13,233	8,567	105,492
1990	61,250	27,558	14,017	8,460	111,284
1995	65,723	30,308	15,119	8,333	119,483
2000	69,849	33,196	16,193	8,019	127,256
2005	74,870	35,738	17,493	8,607	136,708
2010	81,469	39,268	19,227	9,403	149,367
Fairbanks-Tanana Valley Area					
1980	7,220	5,287	1,189	1,617	15,313
1985	10,646	6,348	2,130	1,881	21,004
1990	11,521	7,960	2,209	2,375	26,064
1995	13,619	7,841	3,001	2,339	26,800
2000	14,470	7,703	3,302	2,298	27,773
2005	15,791	7,549	3,695	2,252	29,287
2010	16,962	8,049	4,019	2,202	31,231

TABLE B.5.4.29: COMPOSITE CASE FORECAST
NUMBER OF HOUSEHOLDS SERVED

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
Anchorage-Cook Inlet Area					
1980	35,473	20,314	8,230	7,486	71,503
1985	57,487	26,204	13,233	8,567	105,492
1990	61,123	27,468	13,984	8,460	111,035
1995	65,254	30,012	15,007	8,333	118,606
2000	69,431	32,990	16,095	7,970	126,486
2005	74,397	35,505	17,381	8,552	135,835
2010	80,963	39,022	19,107	9,345	148,437
Fairbanks-Tanana Valley Area					
1980	7,220	5,287	1,189	1,617	15,313
1985	10,646	6,348	2,130	1,881	21,004
1990	11,458	7,960	2,193	2,375	23,986
1995	13,700	7,841	2,742	2,339	26,621
2000	14,413	7,703	3,172	2,298	27,587
2005	15,630	7,549	3,640	2,252	29,071
2010	16,841	7,975	3,991	2,202	31,008

TABLE B.5.4.30: SHCA CASE FORECAST
NUMBER OF VACANT HOUSEHOLDS

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
Anchorage-Cook Inlet Area					
1980	5,089	7,666	1,991	1,463	16,209
1985	632	1,496	146	292	2,566
1990	674	1,488	154	289	2,605
1995	723	1,637	166	284	2,810
2000	768	1,793	178	448	3,187
2005	824	1,930	192	284	3,230
2010	896	2,121	212	310	3,539
Fairbanks-Tanana Valley Area					
1980	3,653	3,320	986	895	8,854
1985	118	2,173	24	606	2,921
1990	127	454	24	81	686
1995	150	448	33	80	710
2000	159	440	36	78	714
2005	174	431	41	77	722
2010	187	435	44	75	740

TABLE B.5.4.31: COMPOSITE CASE FORECAST
NUMBER OF VACANT HOUSEHOLDS

Year	Single Family	Multifamily	Mobile Homes	Duplexes	Total
Anchorage-Cook Inlet Area					
1980	5,089	7,666	1,991	1,463	16,209
1985	632	1,496	146	292	2,566
1990	672	1,483	154	289	2,598
1995	718	1,621	165	284	2,788
2000	764	1,782	177	497	3,219
2005	818	1,917	191	282	3,209
2010	891	2,107	210	308	3,516
Fairbanks-Tanana Valley Area					
1980	3,653	3,320	986	895	8,854
1985	118	2,173	24	606	2,921
1990	126	454	24	81	686
1995	151	448	30	80	708
2000	159	440	35	78	712
2005	172	431	40	77	720
2010	185	431	44	75	735

TABLE B.5.4.32: SHCA CASE FORECAST
RESIDENTIAL ELECTRICITY USE PER HOUSEHOLD
(kWh)

Year	Before Conservation Adjustment and Fuel Substitution Small Appliances	Large Appliances	Space Heat	Total	After Adjustment Total
Anchorage-Cook Inlet Area					
1980	2,110	6,501	5,089	13,699	--
1985	2,190	6,098	4,636	12,923	11,689
1990	2,270	6,073	4,569	12,912	10,794
1995	2,350	6,178	4,505	13,033	10,551
2000	2,430	6,418	4,443	13,291	10,083
2005	2,510	6,676	4,407	13,593	10,021
2010	2,590	6,887	4,431	13,908	10,298
Fairbanks-Tanana Valley Area					
1980	2,466	5,740	3,314	11,519	--
1985	2,566	6,180	3,372	12,118	12,410
1990	2,666	6,529	3,471	12,667	12,385
1995	2,766	6,863	3,514	13,143	13,995
2000	2,866	7,165	3,626	13,657	13,857
2005	2,966	7,427	3,711	14,104	14,051
2010	3,066	7,608	3,791	14,466	14,465

TABLE B.5.4.33: COMPOSITE CASE FORECAST
RESIDENTIAL ELECTRICITY USE PER HOUSEHOLD
(kWh)

Year	Before Conservation Adjustment and Fuel Substitution Small Appliances	Large Appliances	Space Heat	Total	After Adjustment Total
Anchorage-Cook Inlet Area					
1980	2,110	6,501	5,089	13,699	--
1985	2,190	6,098	4,636	12,923	11,689
1990	2,270	6,073	4,569	12,911	10,790
1995	2,350	6,176	4,504	13,030	10,710
2000	2,430	6,419	4,444	13,293	10,390
2005	2,510	6,675	4,407	13,592	10,079
2010	2,590	6,886	4,431	13,907	10,220
Fairbanks-Tanana Valley Area					
1980	2,466	5,740	3,314	11,519	--
1985	2,566	6,180	3,372	12,118	12,410
1990	2,666	6,528	3,471	12,665	13,405
1995	2,766	6,860	3,552	13,178	14,207
2000	2,866	7,165	3,640	13,671	14,279
2005	2,966	7,426	3,714	14,105	14,148
2010	3,066	7,609	3,791	14,466	14,439

TABLE B.5.4.34: SHCA CASE FORECAST
BUSINESS ELECTRICITY USE PER EMPLOYEE
(kWh)

	Before Conservation Adjustment and Fuel Substitution		After Adjustments	
Year	Anchorage-Cook Inlet Area	Fairbanks-Tanana Valley Area	Anchorage-Cook Inlet Area	Fairbanks-Tanana Valley Area
1980	8,672	8,086	8,672	8,086
1985	10,123	8,731	9,153	9,278
1990	10,988	9,377	9,104	10,561
1995	11,968	10,022	9,288	11,322
2000	12,945	10,667	9,077	11,204
2005	13,975	11,313	9,310	11,427
2010	15,157	11,958	9,997	12,003

TABLE B.5.4.35: COMPOSITE CASE FORECAST
BUSINESS ELECTRICITY USE PER EMPLOYEE
(kWh)

Year	Before Conservation Adjustment and Fuel Substitution: Anchorage-Cook Inlet Area	Before Conservation Adjustment and Fuel Substitution: Fairbanks-Tanana Valley Area	After Adjustments: Anchorage-Cook Inlet Area	After Adjustments: Fairbanks-Tanana Valley Area
1980	8,672	8,086	8,672	8,086
1985	10,123	8,731	9,153	9,278
1990	10,973	9,377	9,089	10,557
1995	11,940	10,022	9,450	11,473
2000	12,927	10,667	8,833	11,632
2005	13,954	11,313	9,417	11,587
2010	15,138	11,958	9,996	11,989

TABLE B.5.4.36: SHCA CASE FORECAST
SUMMARY OF PRICE EFFECTS
(GWh)

Year	Anchorage-Cook Inlet Area: Residential Sector: Own-Price Reduction	Anchorage-Cook Inlet Area: Residential Sector: Cross-Price Reduction	Anchorage-Cook Inlet Area: Business Sector: Own-Price Reduction	Anchorage-Cook Inlet Area: Business Sector: Cross-Price Reduction	Fairbanks-Tanana Valley Area: Residential Sector: Own-Price Reduction	Fairbanks-Tanana Valley Area: Residential Sector: Cross-Price Reduction	Fairbanks-Tanana Valley Area: Business Sector: Own-Price Reduction	Fairbanks-Tanana Valley Area: Business Sector: Cross-Price Reduction
1985	137.6	-7.4	138.4	2.5	9.2	-3.0	22.4	-2.4
1990	257.1	-21.4	282.0	0.0	23.7	-5.8	51.0	-4.4
1995	376.2	-79.7	449.2	-20.8	26.3	-3.5	56.5	-2.7
2000	556.9	-148.6	707.0	-56.4	1.6	4.0	20.6	2.2
2005	708.4	-220.2	933.9	-101.9	21.5	-20.0	-3.5	8.8
2010	854.0	-314.8	1176.9	-166.6	0.6	-0.6	-12.0	14.1

TABLE B.5.4.37: COMPOSITE CASE FORECAST
SUMMARY OF PRICE EFFECTS
(GWh)

Year	Anchorage-Cook Inlet Area				Fairbanks-Tanana Valley Area			
	Residential Sector		Business Sector		Residential Sector		Business Sector	
	Own-Price Reduction	Cross-Price Reduction	Own-Price Reduction	Cross-Price Reduction	Own-Price Reduction	Cross-Price Reduction	Own-Price Reduction	Cross-Price Reduction
1985	137.6	-7.4	138.4	2.5	9.2	-3.0	22.4	-2.4
1990	256.4	-20.9	279.9	0.5	23.6	-5.9	50.6	-4.4
1995	351.6	-76.5	412.9	-19.1	30.8	-3.4	62.2	-2.7
2000	505.2	-138.0	634.6	-50.0	13.7	3.1	39.1	1.5
2005	671.5	-194.4	889.6	-85.8	-7.6	8.8	5.5	6.6
2010	811.0	-263.5	1,135.6	-135.0	0.4	0.4	-9.3	10.8

TABLE B.5.4.38: SHCA CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS
ANCHORAGE-COOK INLET AREA
(GWh)

Year	Residential Requirements	Business Requirements	Miscellaneous Requirements	Indust./Military Requirements	Total Requirements
1985	1,233	1,329	28	124	2,715
1990	1,201	1,363	28	192	2,784
1995	1,261	1,484	30	208	2,983
2000	1,283	1,527	31	238	3,079
2005	1,370	1,660	33	273	3,336
2010	1,538	1,957	38	315	3,848

TABLE B.5.4.39: SHCA CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS
FAIRBANKS-TANANA VALLEY AREA
(GWh)

Year	Residential Requirements	Business Requirements	Miscellaneous Requirements	Indust./Military Requirements	Total Requirements
1985	261	340	7	0	608
1990	323	416	8	50	797
1995	375	468	9	50	902
2000	385	475	9	50	919
2005	412	506	10	50	978
2010	452	569	11	50	1,081

TABLE B.5.4.40: COMPOSITE CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS
ANCHORAGE-COOK INLET AREA
(GWh)

Year	Residential Requirements	Business Requirements	Miscellaneous Requirements	Indust./Military Requirements	Total Requirements
1985	1,233	1,329	28	124	2,715
1990	1,198	1,353	28	192	2,770
1995	1,270	1,494	30	208	3,003
2000	1,314	1,577	31	238	3,160
2005	1,369	1,668	33	273	3,344
2010	1,517	1,946	38	315	3,815

TABLE B.5.4.41: COMPOSITE CASE FORECAST
BREAKDOWN OF ELECTRICITY REQUIREMENTS
FAIRBANKS-TANANA VALLEY AREA
(GWh)

Year	Residential Requirements	Business Requirements	Miscellaneous Requirements	Indust./Military Requirements	Total Requirements
1985	261	340	7	0	608
1990	322	413	8	50	793
1995	378	470	9	50	907
2000	394	490	10	50	943
2005	411	510	10	50	981
2010	448	565	11	50	1,073

TABLE B.5.4.42: SHCA CASE END USE FORECAST
PROJECTED PEAK AND ENERGY DEMAND

Year	Anchorage-Cook Inlet Area Energy (GWh)	Anchorage-Cook Inlet Area Peak (MW)	Fairbanks-Tanana Valley Area Energy (GWh)	Fairbanks-Tanana Valley Area Peak (MW)	Total System Area Energy (GWh)	Total System Area Peak at 60% Load Factor (MW)
1985	2,715	517	608	116	3,322	632
1990	2,784	530	797	152	3,580	681
1995	2,983	568	902	172	3,885	739
2000	3,079	586	919	175	3,998	761
2005	3,336	635	978	186	4,314	821
2010	3,848	732	1,081	206	4,930	938

TABLE B.5.4.43: COMPOSITE CASE END USE FORECAST PROJECTED PEAK AND ENERGY DEMAND

Year	Anchorage-Cook Inlet Area Energy (GWh)	Anchorage-Cook Inlet Area Peak (MW)	Fairbanks-Tanana Valley Area Energy (GWh)	Fairbanks-Tanana Valley Area Peak (MW)	Total System Area Energy (GWh)	Total System Area Peak at 60% Load Factor (MW)
1985	2,715	517	608	116	3,322	632
1990	2,770	527	793	151	3,563	678
1995	3,003	571	907	173	3,910	744
2000	3,160	601	943	179	4,104	781
2005	3,344	636	981	187	4,325	823
2010	3,815	726	1,073	204	4,889	930

TABLE B.5.4.44: WHARTON CASE FORECAST SUMMARY OF INPUT AND OUTPUT DATA

Item Description	1985	1990	1995	2000	2005	2010
World Oil Price (1985$/bbl)	27.10	24.80	27.60	31.30	35.10	40.70
Energy Price Used by RED (1980$)						
Heating Fuel Oil-Anchorage ($/MMBtu)	6.45	5.90	6.58	7.45	8.35	9.68
Natural Gas - Anchorage ($/MMBtu)	2.10	2.35	3.65	4.05	4.46	5.08
State Petroleum Revenues 1/ (Million Nominal $)						
Production Taxes	1,372	1,113	1,033	720	601	751
Royalty Fees	1,372	1,556	1,622	1,423	1,253	1,364
State General Fund Expenditures (Million Nominal $)	3,665	3,806	4,701	4,944	5,335	6,379
State Population	536,525	559,621	583,589	618,952	645,298	688,969
State Employment	269,087	278,012	293,298	313,683	320,030	344,017
Railbelt Population	381,264	394,631	410,458	431,301	460,071	499,187
Railbelt Employment	181,885	185,257	192,530	206,302	218,848	240,312
Railbelt Total Number of Households	134,300	140,751	148,302	157,679	168,895	183,964
Railbelt Electricity Consumption (GWh)						
Anchorage	2,714	2,721	2,946	3,260	3,576	3,964
Fairbanks	608	786	893	971	1,047	1,117
Total	3,322	3,507	3,838	4,231	4,623	5,081
Railbelt Peak Demand (MW)	632	667	730	805	880	967

1/ Petroleum revenues also include corporate income taxes, oil and gas property taxes, lease bonuses, rents, and federal shared royalties.

TABLE B.5.4.45: RESULTS OF RED MODEL SENSITIVITY TEST ON APPLIANCE SATURATIONS

	Total Electricity Requirements Without Large Industrial		
	1990 (GWh)	2000 (GWh)	2010 (GWh)
Anchorage-Cook Inlet Area			
Maximum1/	2,681	3,186	3,918
25% GE	2,673	3,179	3,910
Mean	2,670	3,173	3,904
50% GE	2,669	3,173	3,905
75% GE	2,667	3,167	3,900
Minimum	2,663	3,164	3,890
Std Dev	4.82	6.8	7.4
Test Case	2,673	3,174	3,901
Fairbanks-Tanana Valley Area			
Maximum1/	721	897	1,117
25% GE	720	896	1,116
Mean	719	894	1,114
50% GE	719	896	1,114
75% GE	718	894	1,113
Minimum	717	892	1,110
Std Dev	1.0	1.4	2.0
Test Case	719	895	1,113

1/ Maximum = maximum simulation value.
25% GE = 25 percent of simulation values were greater than or equal to table value.
Mean = mean value of all simulations.
50% GE = 50 percent of simulation values were greater than or equal to table value.
75% GE = 75 percent of simulation values were equal to or greater than table value.
Minimum = minimum simulation value.

TABLE B.5.4.46: RESULTS OF RED MODEL SENSITIVITY TEST ON BUSINESS SECTOR CONSUMPTION INTENSITY[1/]

	Total Electricity Requirements Without Large Industrial		
	1990 (GWh)	2000 (GWh)	2010 (GWh)
Anchorage-Cook Inlet Area			
Maximum[2/]	3,180	3,804	4,717
25% GE	2,826	3,364	4,147
Mean	2,653	3,149	3,870
50% GE	2,545	3,016	3,697
75% GE	2,119	2,488	3,019
Minimum	2,663	3,164	3,890
Std Dev	276.32	342.7	442.2
Test Case	2,673	3,174	3,901
Fairbanks-Tanana Valley Area			
Maximum[1/]	775	965	1,203
25% GE	729	907	1,129
Mean	712	886	1,102
50% GE	712	887	1,103
75% GE	696	867	1,078
Minimum	661	823	1,020
Std Dev	32.0	40.0	51.4
Test Case	719	895	1,113

1/ Coefficient of demand per square foot.

2/ Maximum = maximum simulation value.
25% GE = 25 percent of simulation values were greater than or equal to table value.
Mean = mean value of all simulations.
50% GE = 50 percent of simulation values were greater than or equal to table value.
75% GE = 75 percent of simulation values were equal to or greater than table value.
Minimum = minimum simulation value.

TABLE B.5.4.47: RESULTS OF RED MODEL SENSITIVITY TEST ON OWN PRICE ELASTICITIES

	Total Electricity Requirements Without Large Industrial 1990 (GWh)	2000 (GWh)	2010 (GWh)
Anchorage-Cook Inlet Area			
Maximum1/	2,720	3,283	4,093
25% GE	2,641	3,138	3,843
Mean	2,621	3,077	3,745
50% GE	2,635	3,072	3,726
75% GE	2,591	3,021	3,659
Minimum	2,528	2,903	3,453
Std Dev	50.82	96.2	160.6
Test Case	2,673	3,174	3,901
Fairbanks-Tanana Valley Area			
Maximum1/	736	911	1,137
25% GE	729	905	1,128
Mean	724	900	1,117
50% GE	724	902	1,119
75% GE	720	894	1,108
Minimum	713	887	1,091
Std Dev	6.0	7.1	13.3
Test Case	719	895	1,113

1/ Maximum = maximum simulation value.
25% GE = 25 percent of simulation values were greater than or equal to table value.
Mean = mean value of all simulations.
50% GE = 50 percent of simulation values were greater than or equal to table value.
75% GE = 75 percent of simulation values were equal to or greater than table value.
Minimum = minimum simulation value.

TABLE B.5.4.48: RESULTS OF RED MODEL SENSITIVITY TEST ON CROSS PRICE ELASTICITIES TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

	1990 (GWh)	2000 (GWh)	2010 (GWh)
A. 0.1 Cross-Price Elasticities			
Anchorage-Cook Inlet Area			
Maximum 1/	2,690	3,183	3,965
25% GE	2,676	3,178	3,931
Mean	2,672	3,175	3,907
50% GE	2,672	3,175	3,911
75% GE	2,666	3,172	3,893
Minimum	2,656	3,165	3,838
Std Dev	9.5	5.1	36.0
Test Case	2,673	3,174	3,901
Fairbanks-Tanana Valley Area			
Maximum 1/	723	898	1,132
25% GE	720	896	1,122
Mean	718	895	1,115
50% GE	719	896	1,116
75% GE	717	895	1,111
Minimum	714	892	1,095
Std Dev	2.5	1.5	10.4
Test Case	719	895	1,113
B. Gas Cross-Price Elasticities			
Anchorage-Cook Inlet Area			
Maximum 1/	2,699	3,279	4,101
25% GE	2,684	3,219	3,981
Mean	2,675	3,180	3,911
50% GE	2,676	3,184	3,914
75% GE	2,670	3,162	3,870
Minimum	2,638	3,024	3,649
Std Dev	15.8	64.7	120.6
Test Case	2,673	3,174	3,901

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	1990 (GWh)	2000 (GWh)	2010 (GWh)
Fairbanks-Tanana Valley Area			
Maximum1/	726	896	1,134
25% GE	720	896	1,122
Mean	719	895	1,114
50% GE	719	895	1,115
75% GE	717	895	1,110
Minimum	713	891	1,086
Std Dev	3.4	1.6	12.7
Test Case	719	895	1,113

TABLE B.5.4.49: RESULTS OF RED MODEL SENSITIVITY TEST ON ANNUAL LOAD FACTOR TOTAL ELECTRICITY REQUIREMENTS WITHOUT LARGE INDUSTRIAL

	1990 (MW)	2000 (MW)	2010 (MW)
Anchorage-Cook Inlet Area			
Maximum1/	620	733	890
25% GE	604	695	843
Mean	560	646	790
50% GE	556	648	795
75% GE	531	604	754
Minimum	489	573	708
Std Dev	40.4	50.2	49.5
Test Case	548	650	799
Fairbanks-Tanana Valley Area			
Maximum1/	196	241	297
25% GE	184	223	279
Mean	171	207	254
50% GE	177	210	253
75% GE	156	195	234
Minimum	146	174	217
Std Dev	16.1	19.1	24.5
Test Case	149	186	231

1/ Maximum = maximum simulation value.
25% GE = 25 percent of simulation values were greater than or equal to table value.
Mean = mean value of all simulations.
50% GE = 50 percent of simulation values were greater than or equal to table value.
75% GE = 75 percent of simulation values were equal to or greater than table value.
Minimum = minimum simulation value.

TABLE B.5.4.50: LIST OF PREVIOUS RAILBELT PEAK AND ENERGY DEMAND FORECASTS (MEDIUM SCENARIO)

	ISER 1980 Forecast 1/		Battelle 1981 Forecast 2/		Reference Case Forecast 3/		Utility 1985 Forecast 4/	
Year	Peak Demand (MW)	Energy Demand (GWh)	Peak Demand (MW)	Energy Demand (GWh)	Peak Demand (MW)	Energy Demand (GWh)	Peak Demand (MW)	Energy Demand (GWh)
1985	---	---	---	---	---	---	685	3,610
1990	735	4,030	892	4,456	777	3,737	869	4,584
1995	934	5,170	983	4,922	868	4,171	971	5,135
2000	1,175	6,430	1,084	5,469	945	4,542	1,085	5,725 5/
2005	1,380	7,530	1,270	6,428	1,059	5,093	NA	NA
2010	1,635	8,940	1,537	7,791	1,217	5,858	NA	NA

1/ Acres American 1982, Volume 1, Table 5.6. Includes 30 percent of military loads, and excludes industrial self-supplied electricity.

2/ Acres American 1982, Volume 1, Table 5.7. Excludes military and industrial self-supplied electricity.

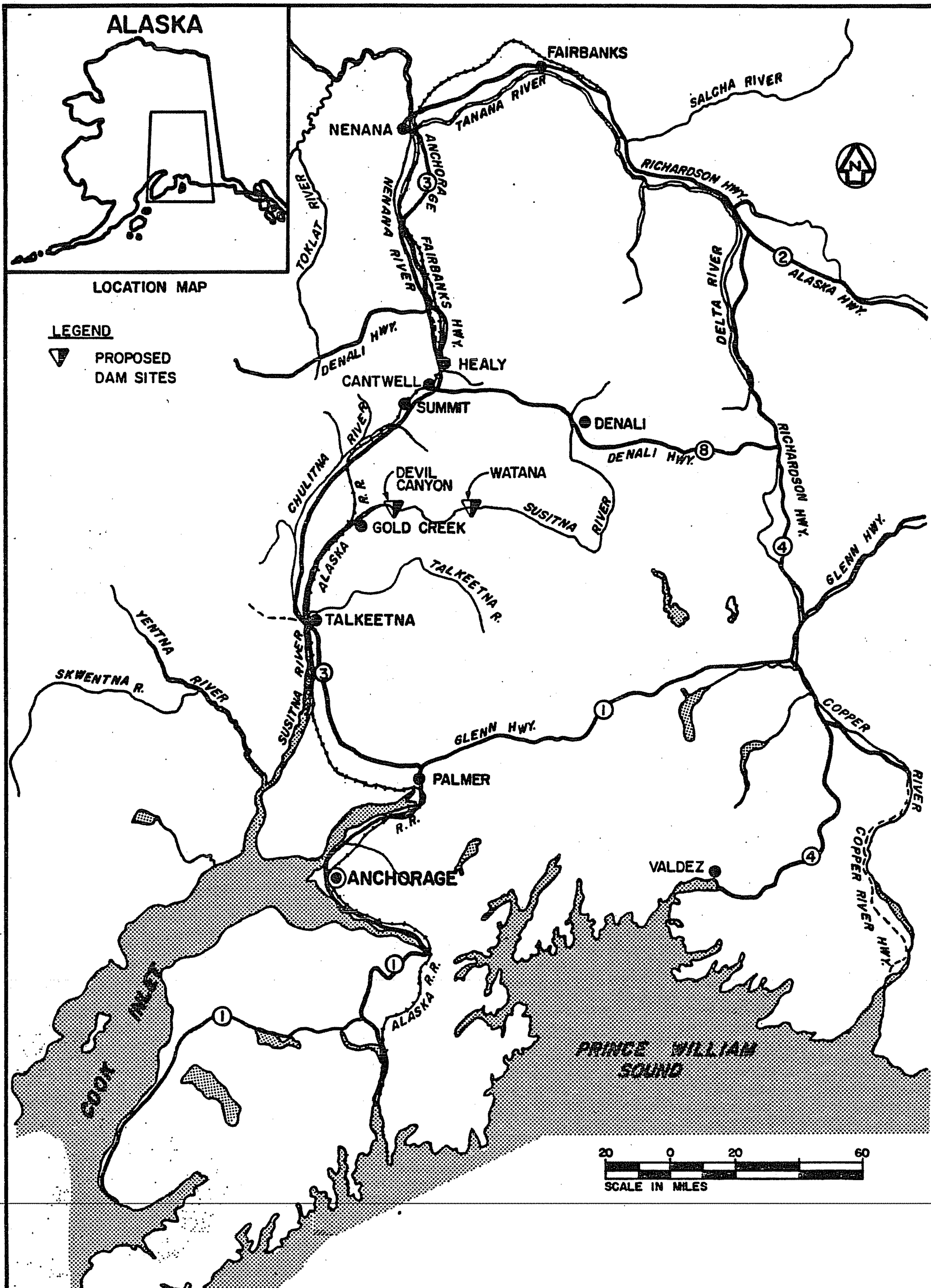
3/ APA 1983, Table B.117. Excludes 30 percent of military loads, and excludes industrial self-supplied electricity.

4/ APA 1985, Table 1.

5/ Energy and peak demand in the year 2000 were computed by extrapolation, based on the annual growth rate in the last year of each utility's forecast period.

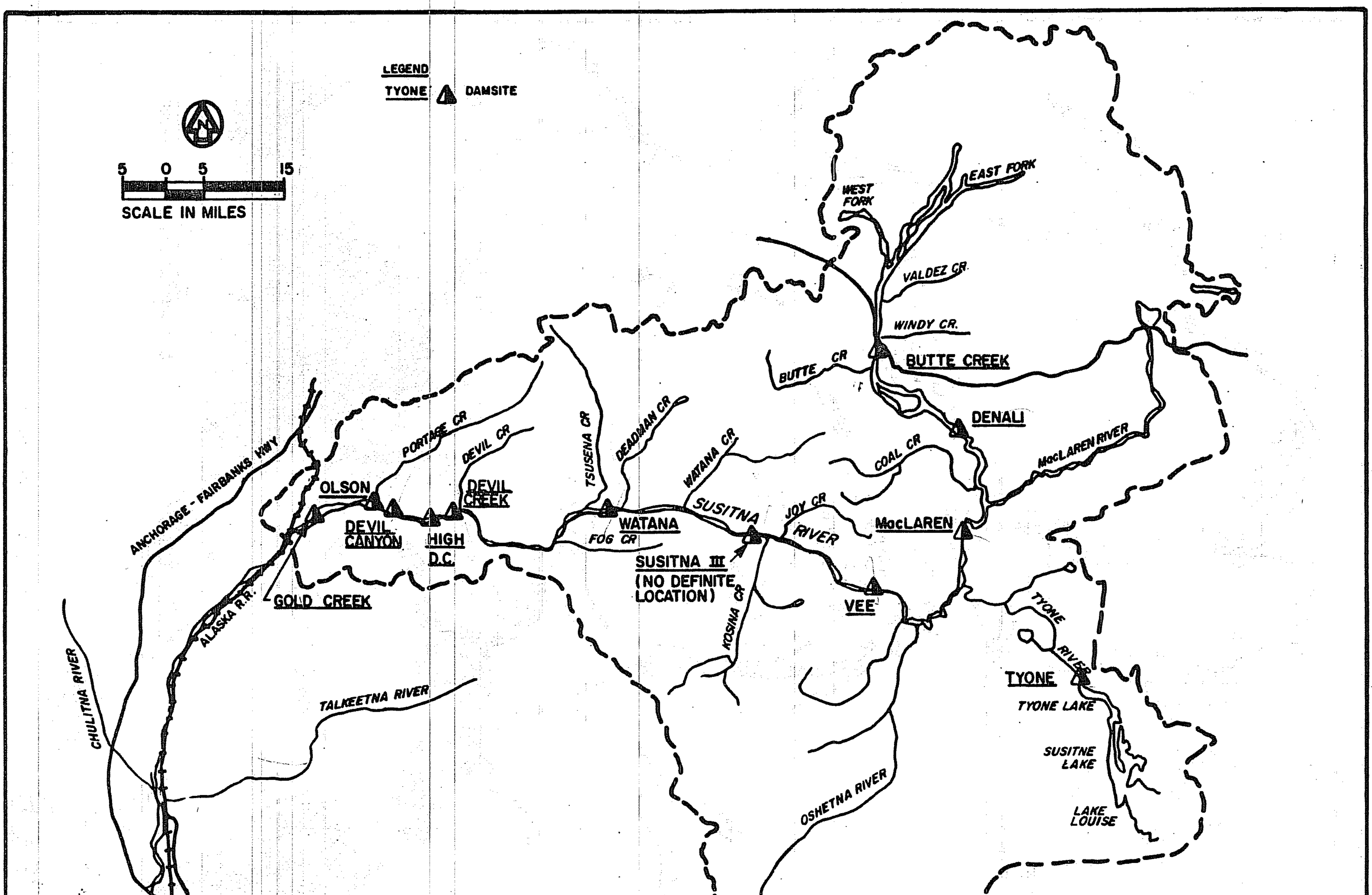
Note: The ISER, Battelle, and Reference Case forecasts are for end-use demand, and should be increased for transmission and distribution losses. Net generation = sales/(1-l).

FIGURES



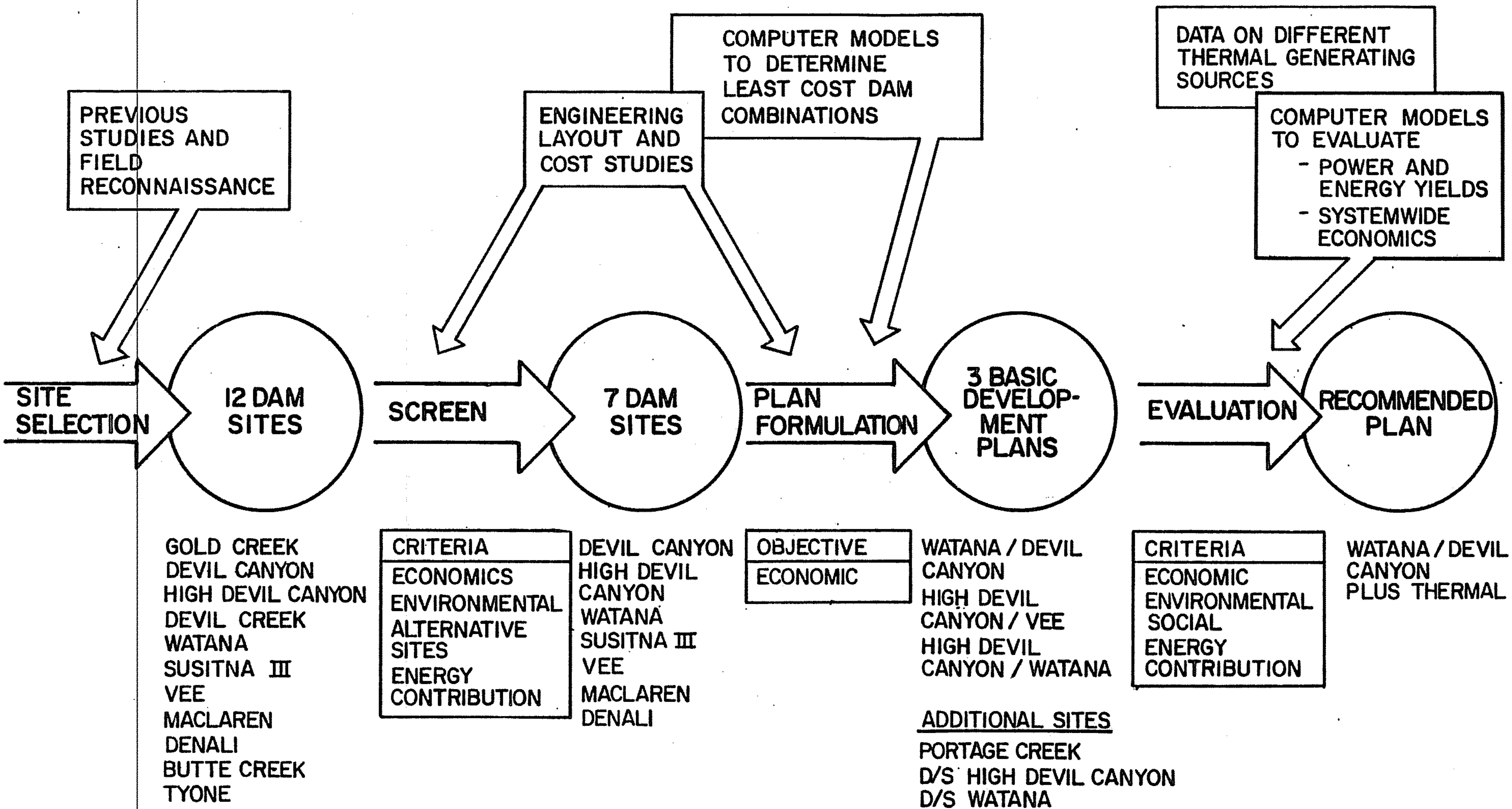
LOCATION MAP

FIGURE B.1.1.1



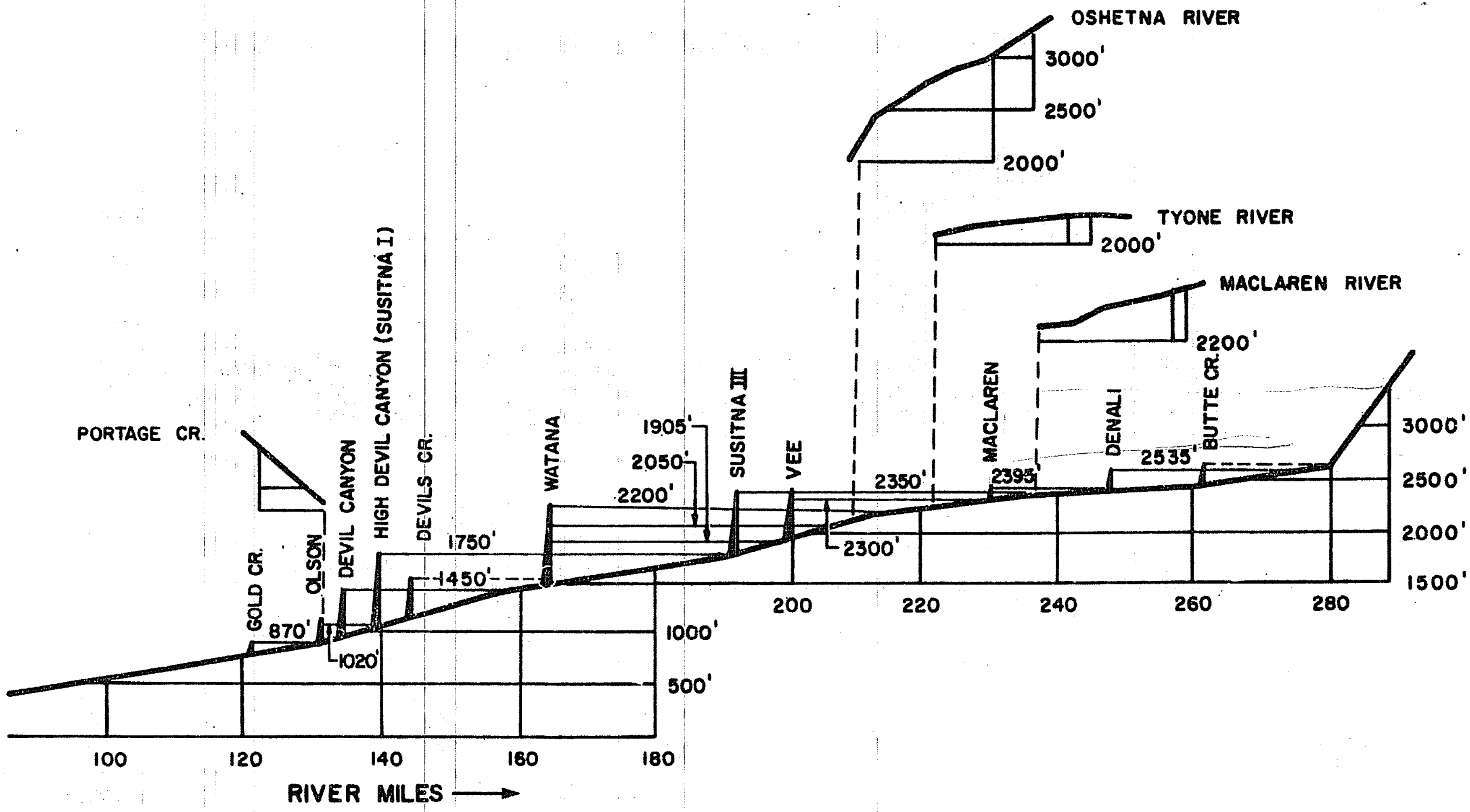
DAMSITES PROPOSED BY OTHERS

FIGURE B.1.1.2



SUSITNA BASIN PLAN FORMULATION AND SELECTION PROCESS

FIGURE B.1.2.1



PROFILE THROUGH ALTERNATIVE SITES

FIGURE B.1.3.1

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

LEGEND

COMPATIBLE ALTERNATIVES

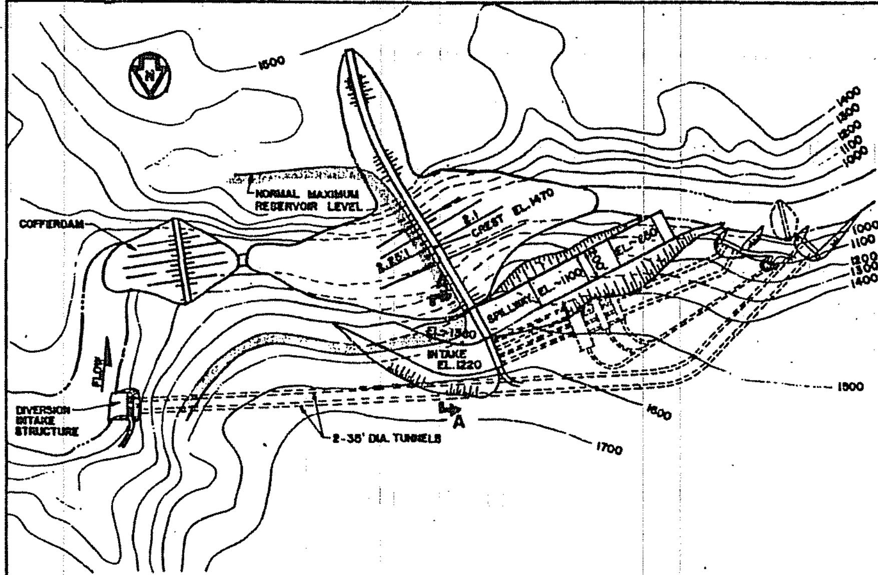
MUTUALLY EXCLUSIVE ALTERNATIVES

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

VALUE IN BRACKET REFERS TO APPROXIMATE DAM HEIGHT.

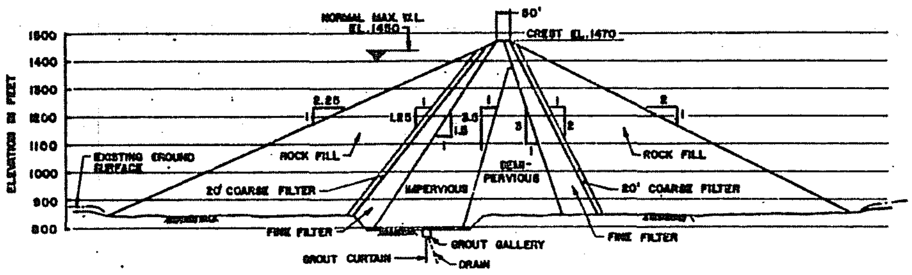
MUTUALLY EXCLUSIVE DEVELOPMENT ALTERNATIVES

FIGURE B.1.3.2



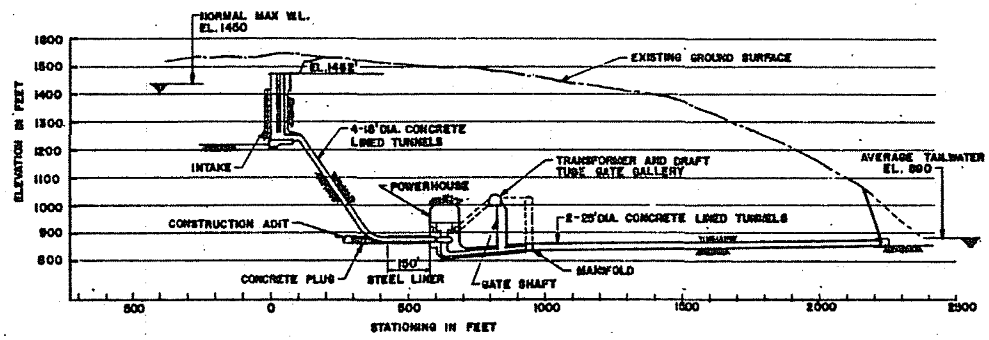
GENERAL ARRANGEMENT

SCALE: A



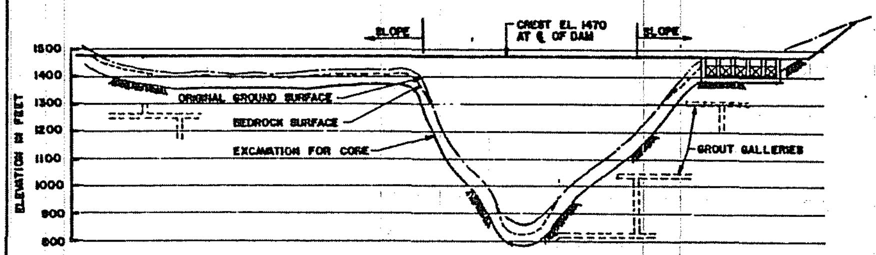
SECTION THRU DAM

SCALE: B



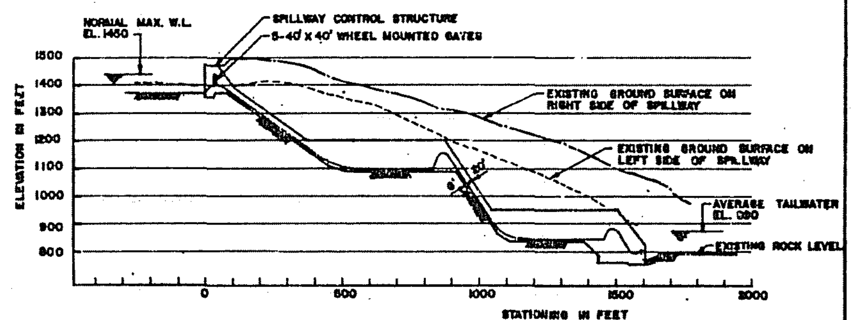
POWER FACILITIES PROFILE

SCALE: B



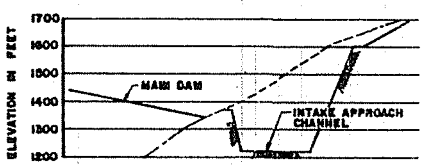
LONGITUDINAL SECTION THRU ℄ OF DAM

SCALE: B



SPILLWAY PROFILE

SCALE: B



SECTION A-A

SCALE: B

SCALE A 0 400 800 FEET

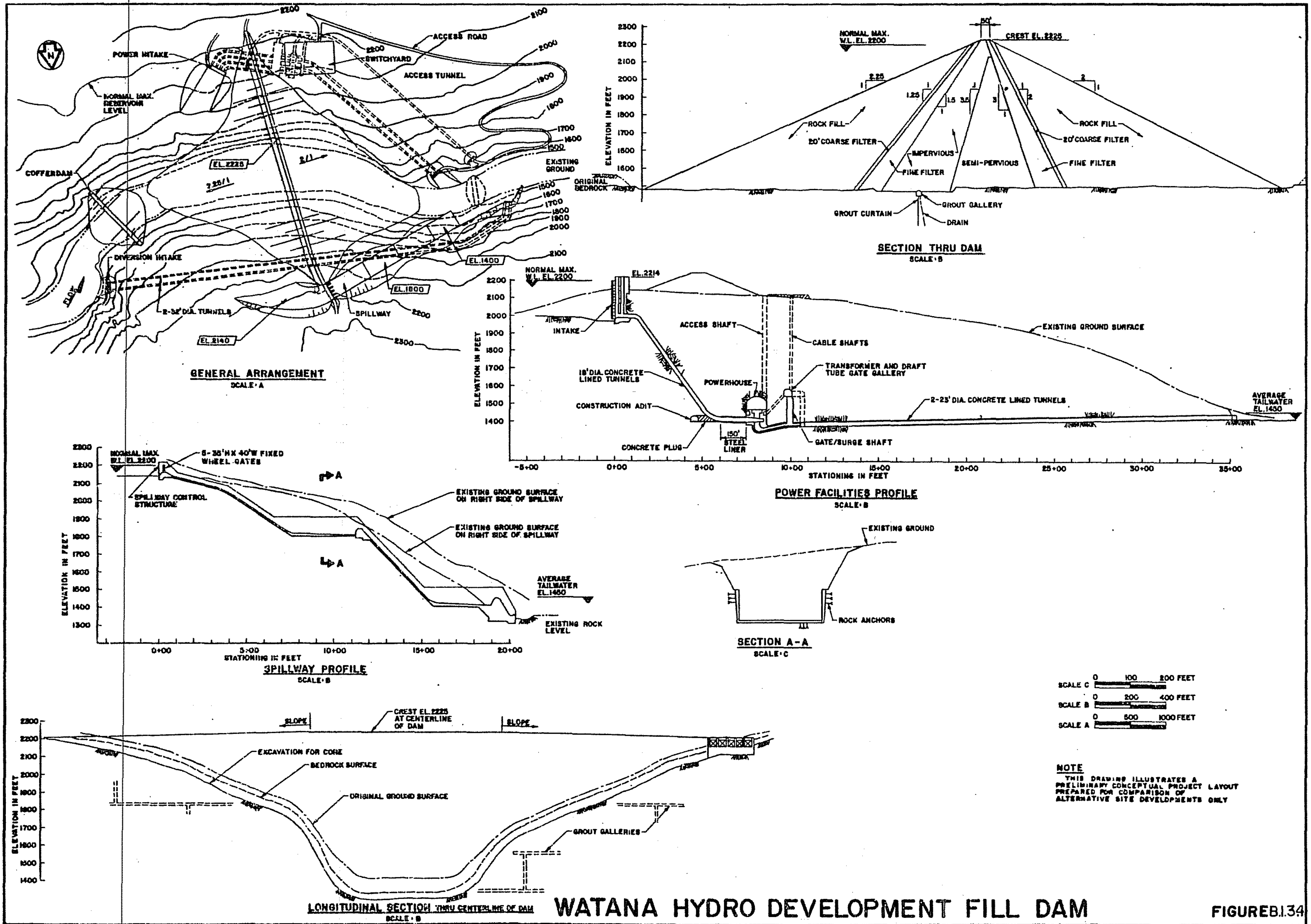
SCALE B 0 200 400 FEET

NOTE

THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

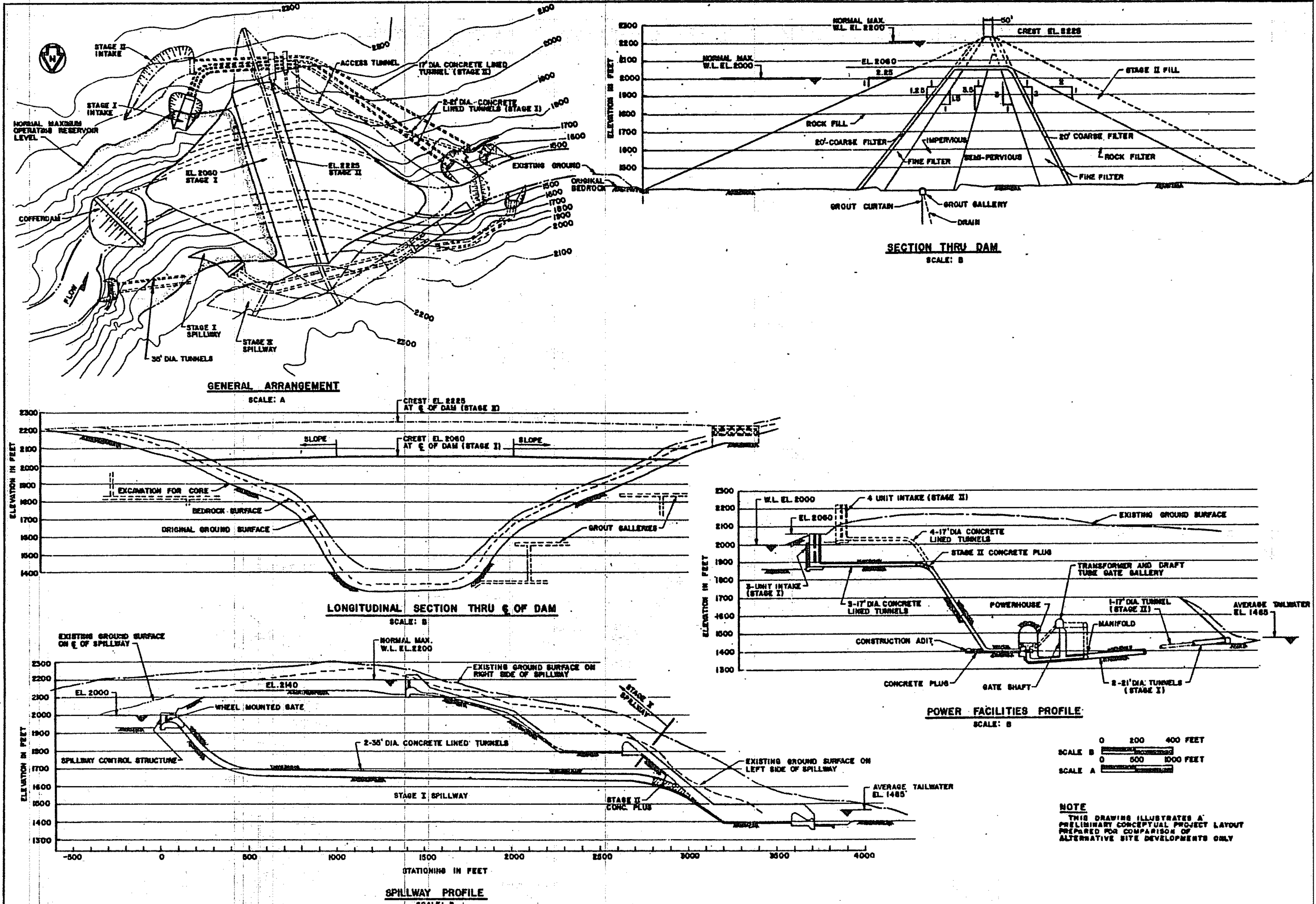
DEVIL CANYON HYDRO DEVELOPMENT FILL DAM

FIGURE B.1.3.3



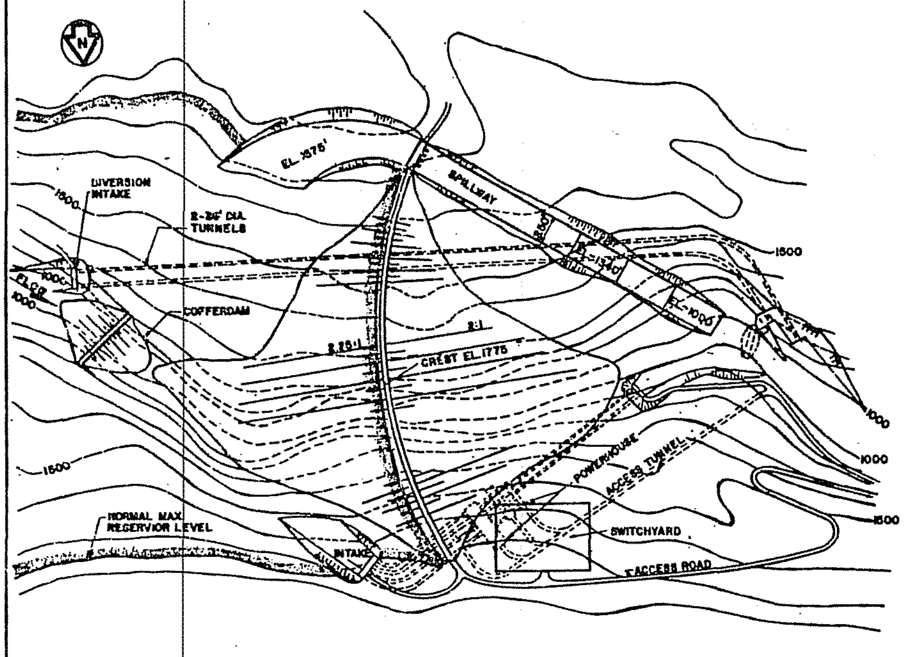
WATANA HYDRO DEVELOPMENT FILL DAM

FIGURE B.1.34



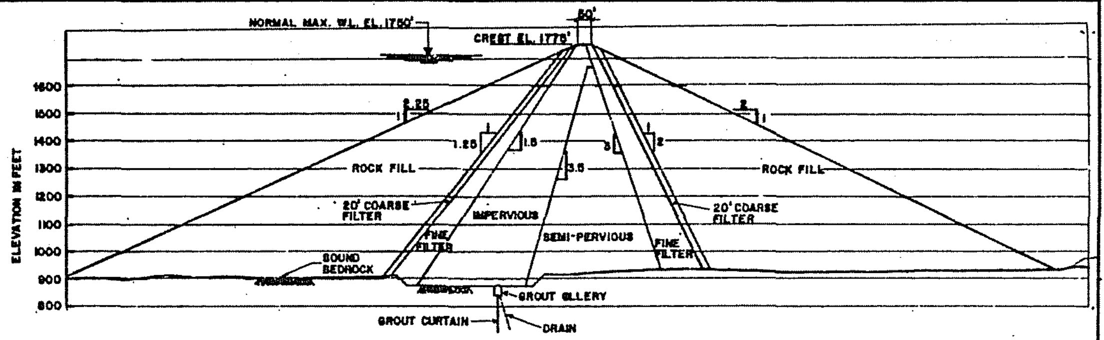
WATANA STAGED FILL DAM

FIGURE B.1.3.5



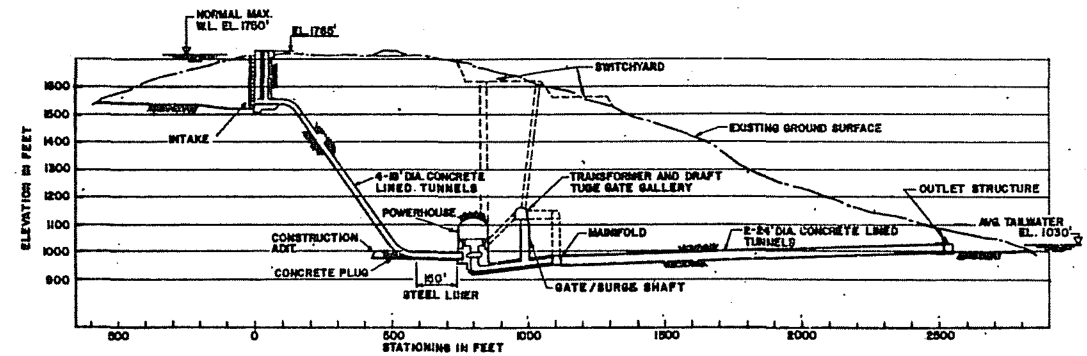
GENERAL ARRANGEMENT

SCALE : A



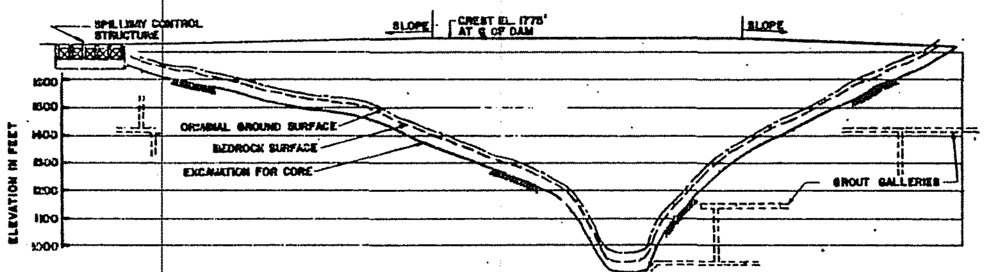
SECTION THRU DAM

SCALE : B



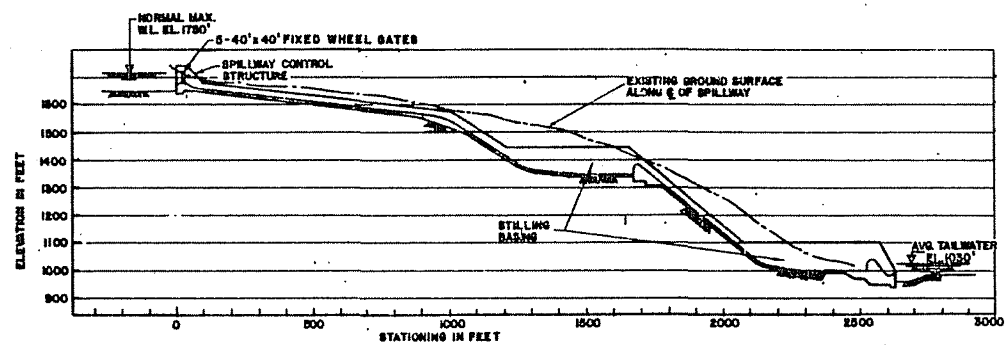
POWER FACILITIES PROFILE

SCALE : B



LONGITUDINAL SECTION THRU ℄ OF DAM

SCALE : B



SPILLWAY PROFILES

SCALE : B

SCALE A 0 400 800 FEET

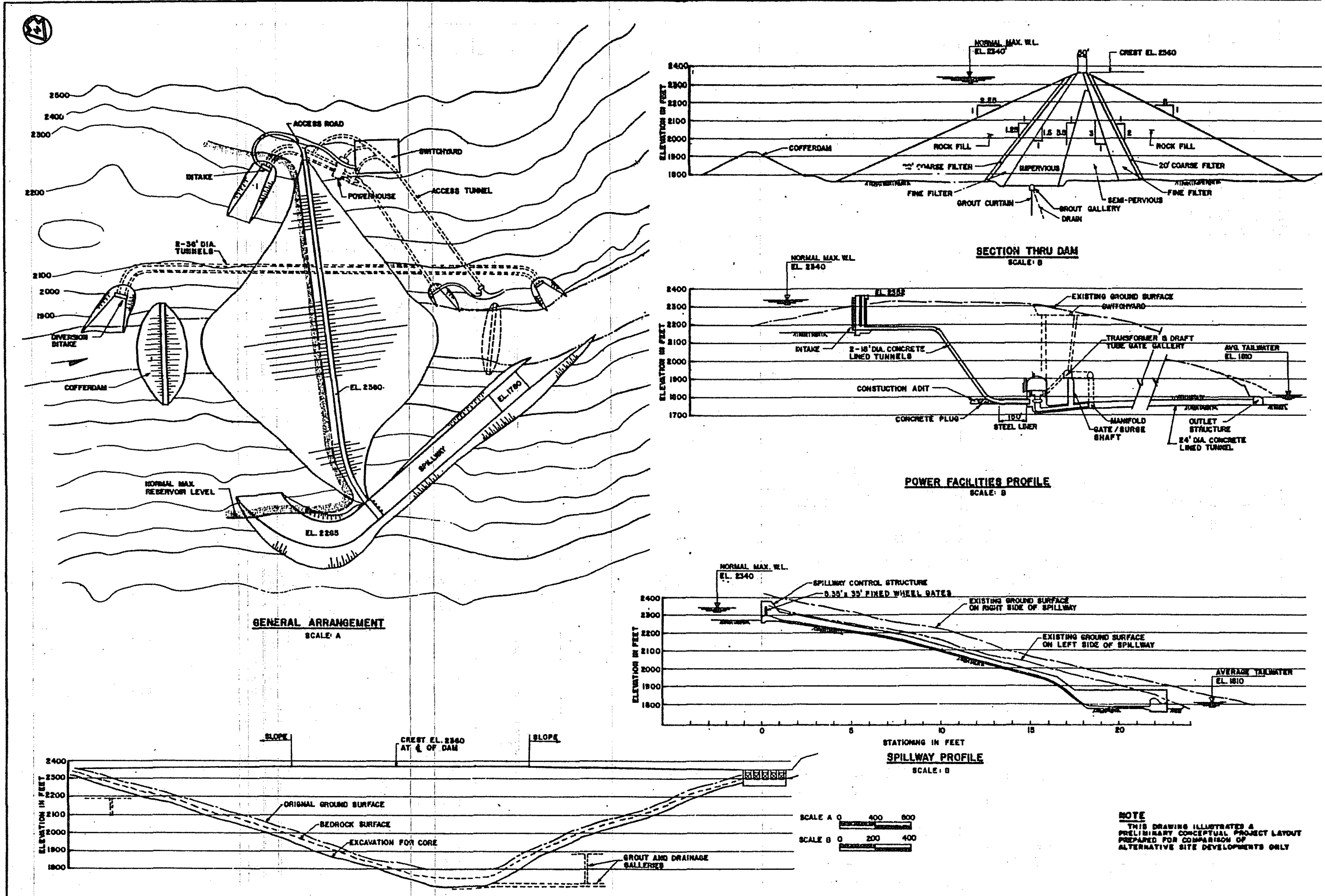
SCALE B 0 200 400 FEET

NOTE

THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

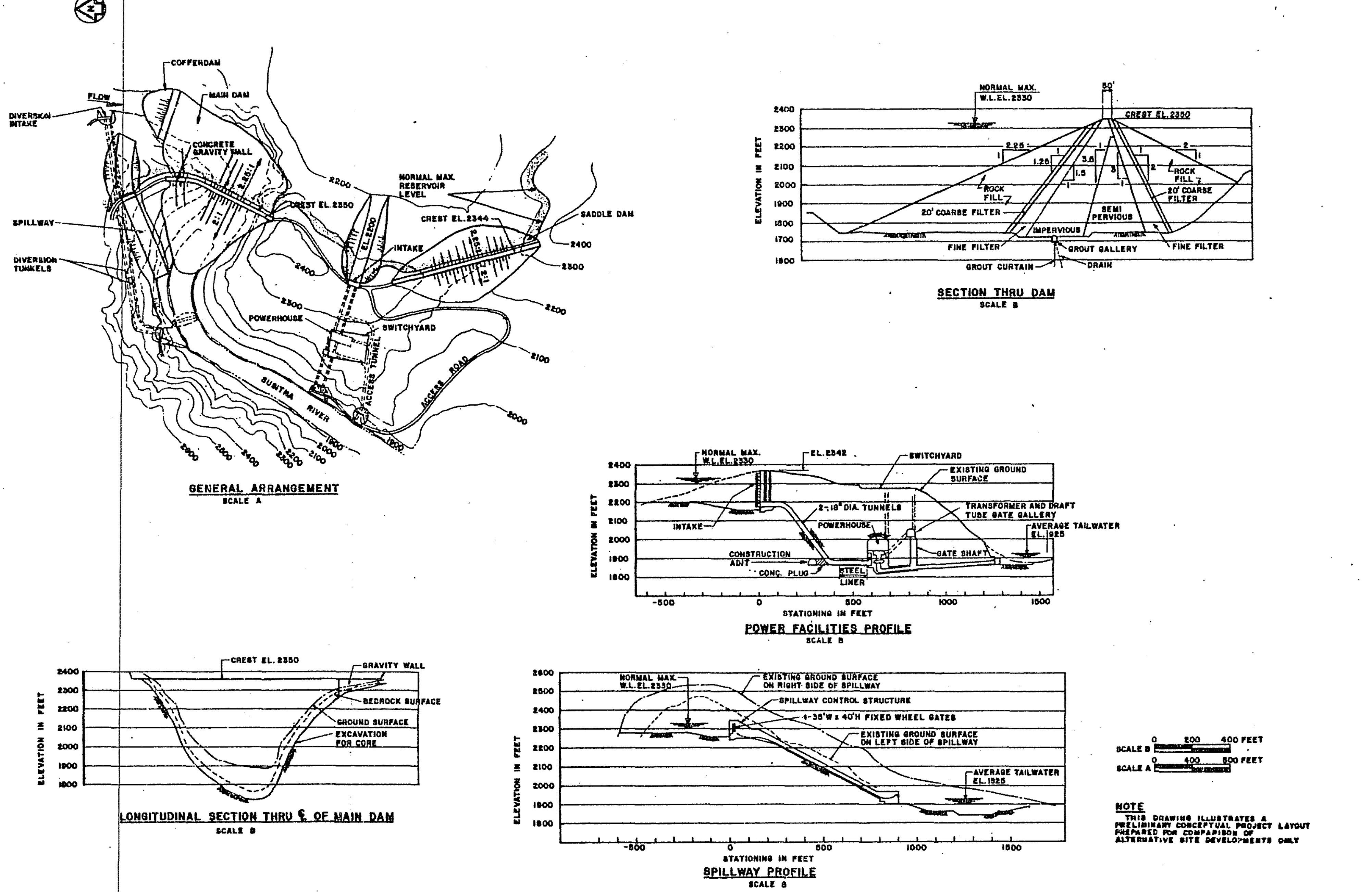
HIGH DEVIL CANYON HYDRO DEVELOPMENT

FIGURE B.1.3.6



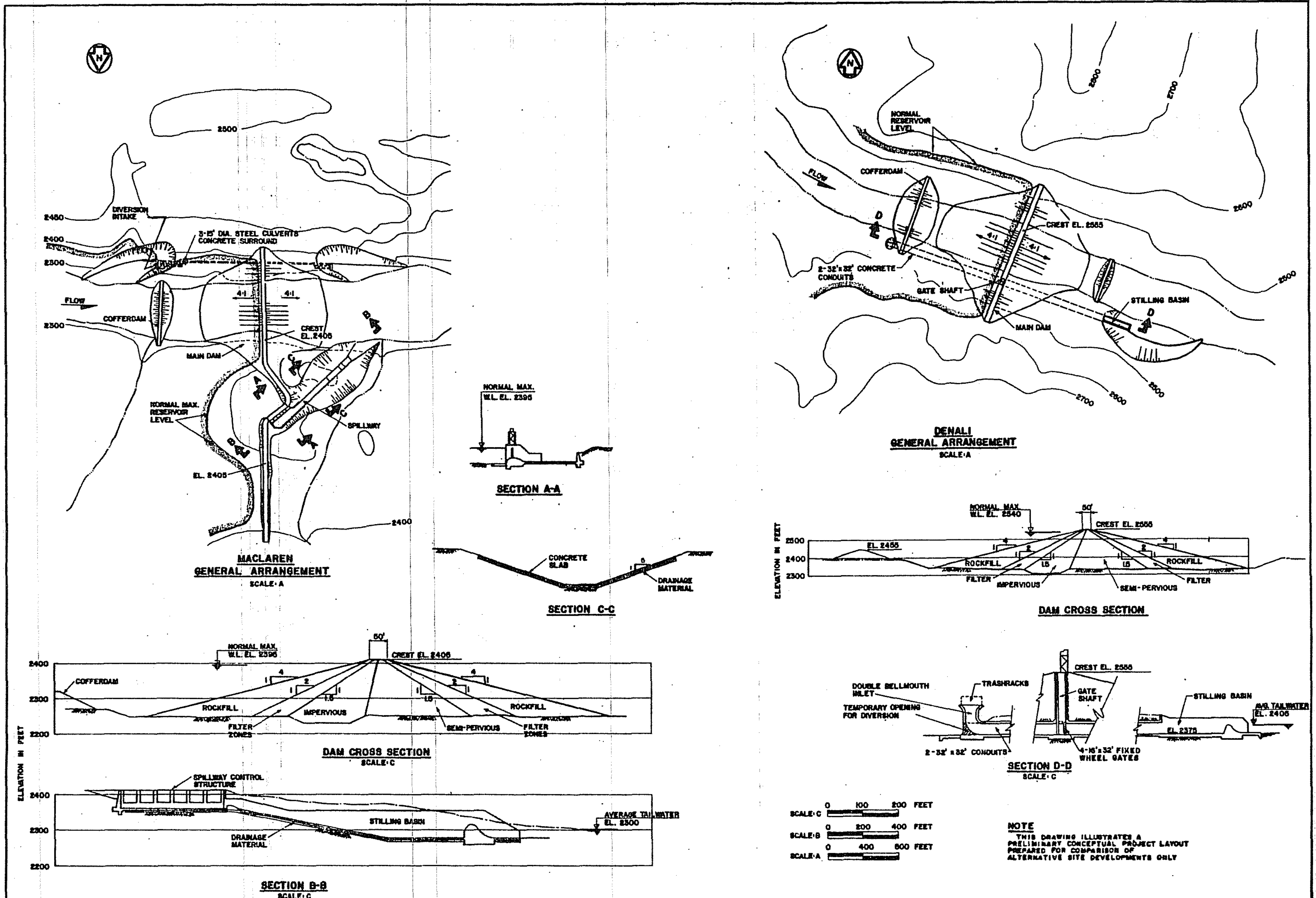
SUSITNA III HYDRO DEVELOPMENT

FIGURE B.1.3.7



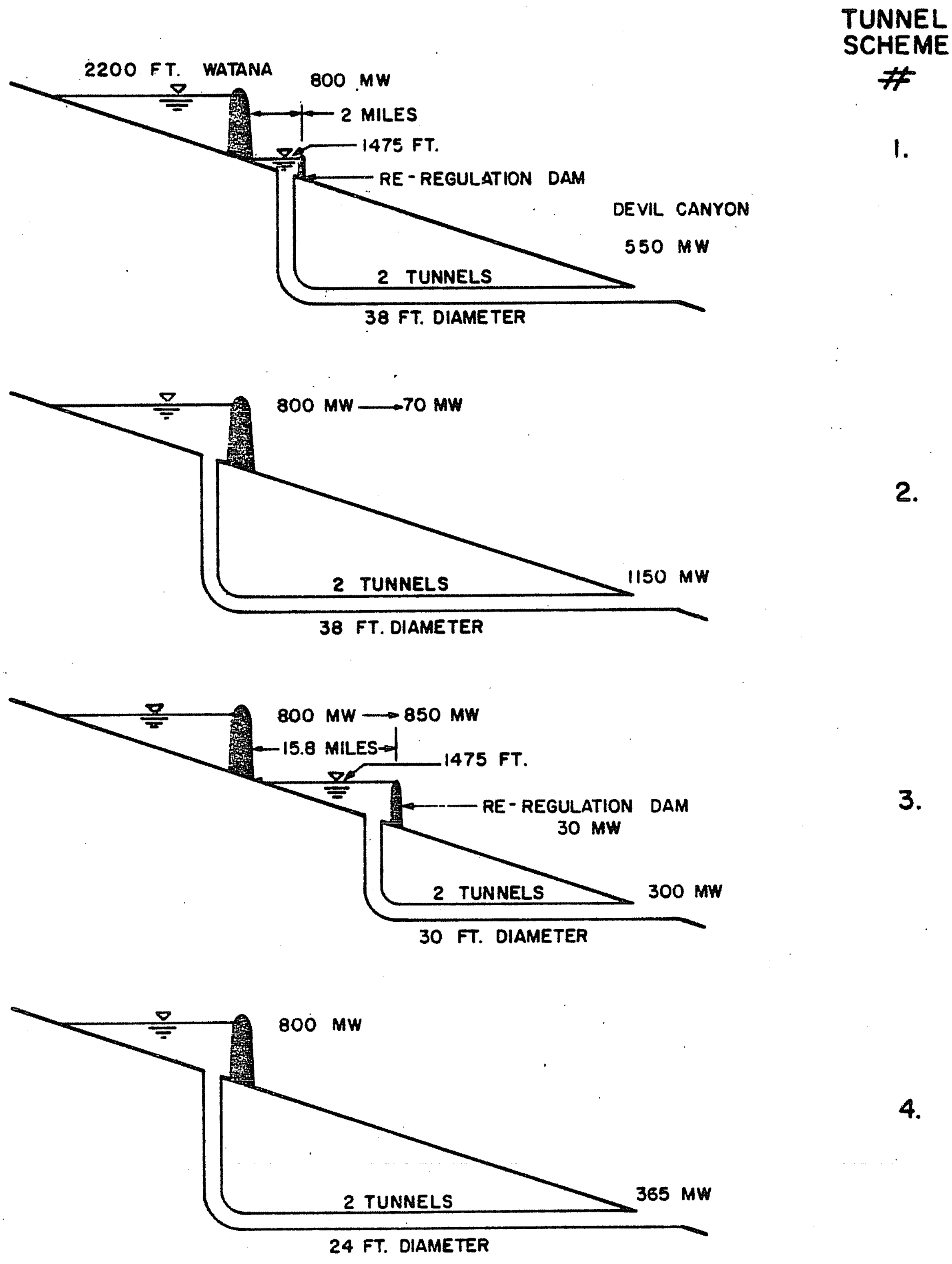
VEE HYDRO DEVELOPMENT

FIGURE B.1.3.8



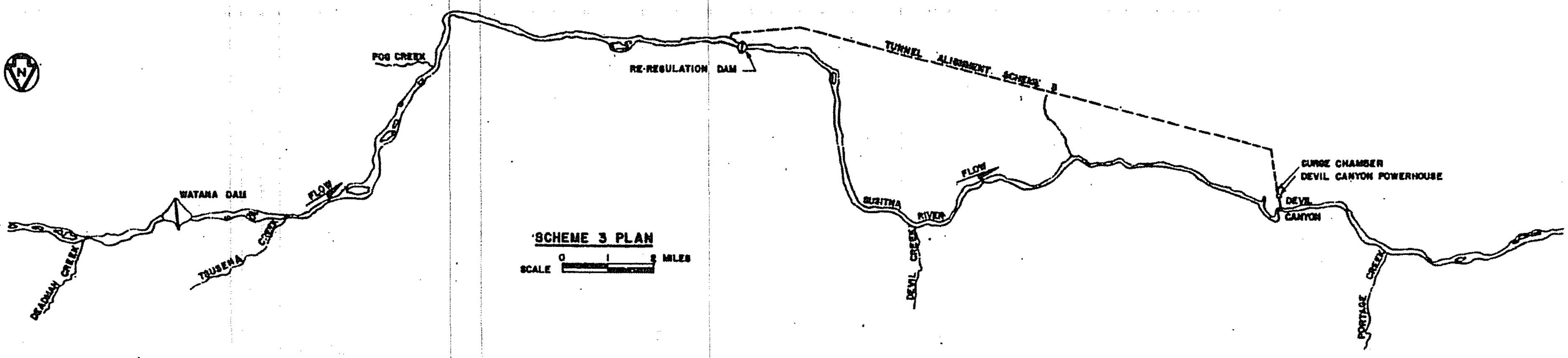
DENALI & MACLAREN HYDRO DEVELOPMENTS

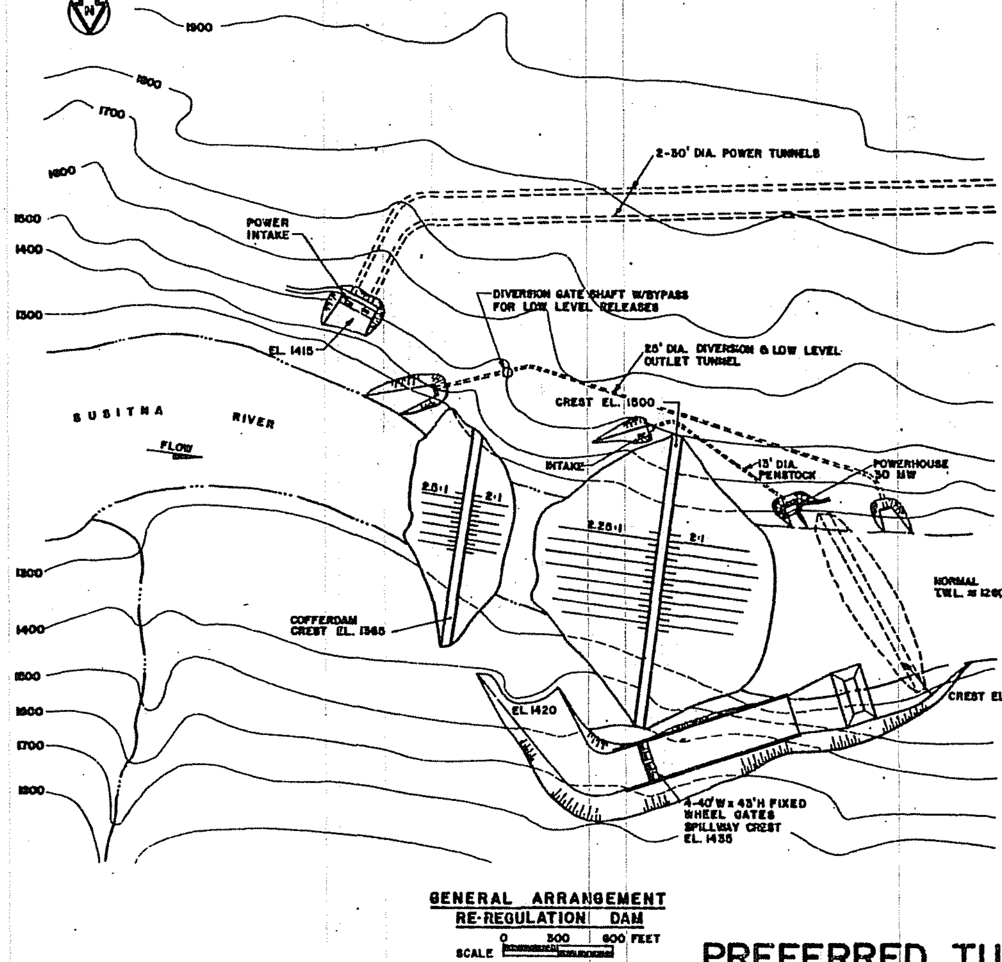
FIGURE B.1.3.9

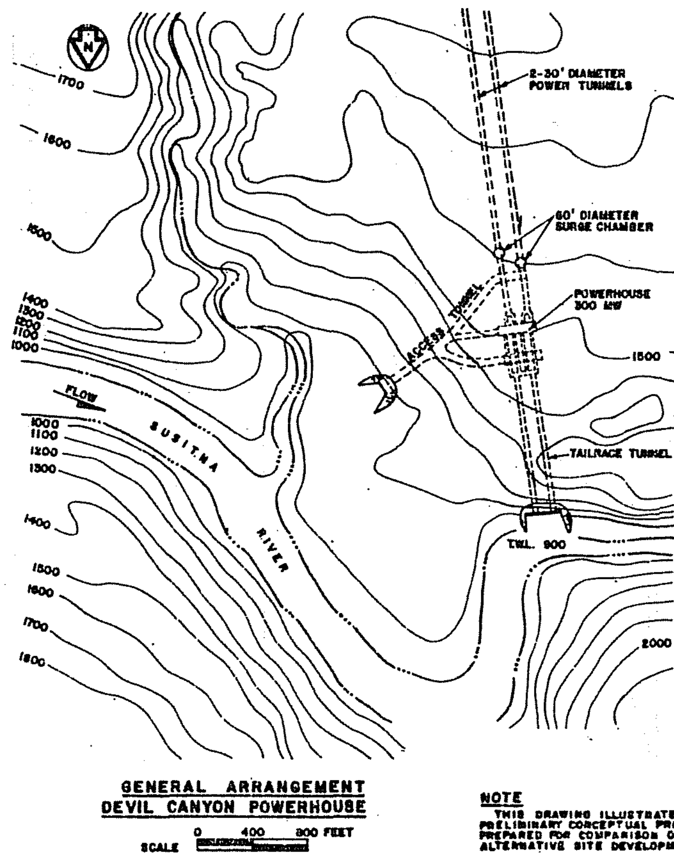


SCHEMATIC REPRESENTATION
OF CONCEPTUAL TUNNEL SCHEMES

FIGURE B.1.4.1



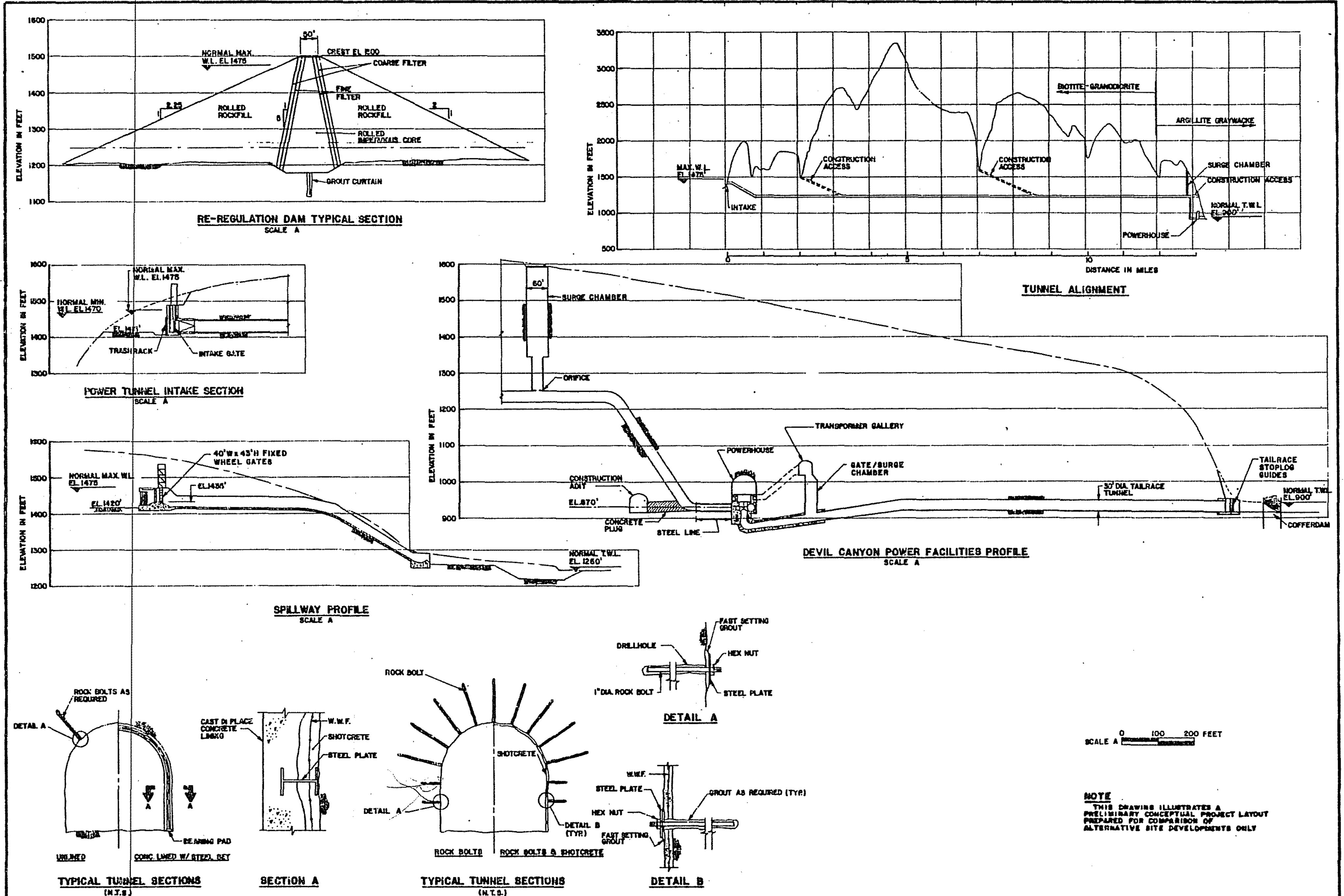




NOTE
THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

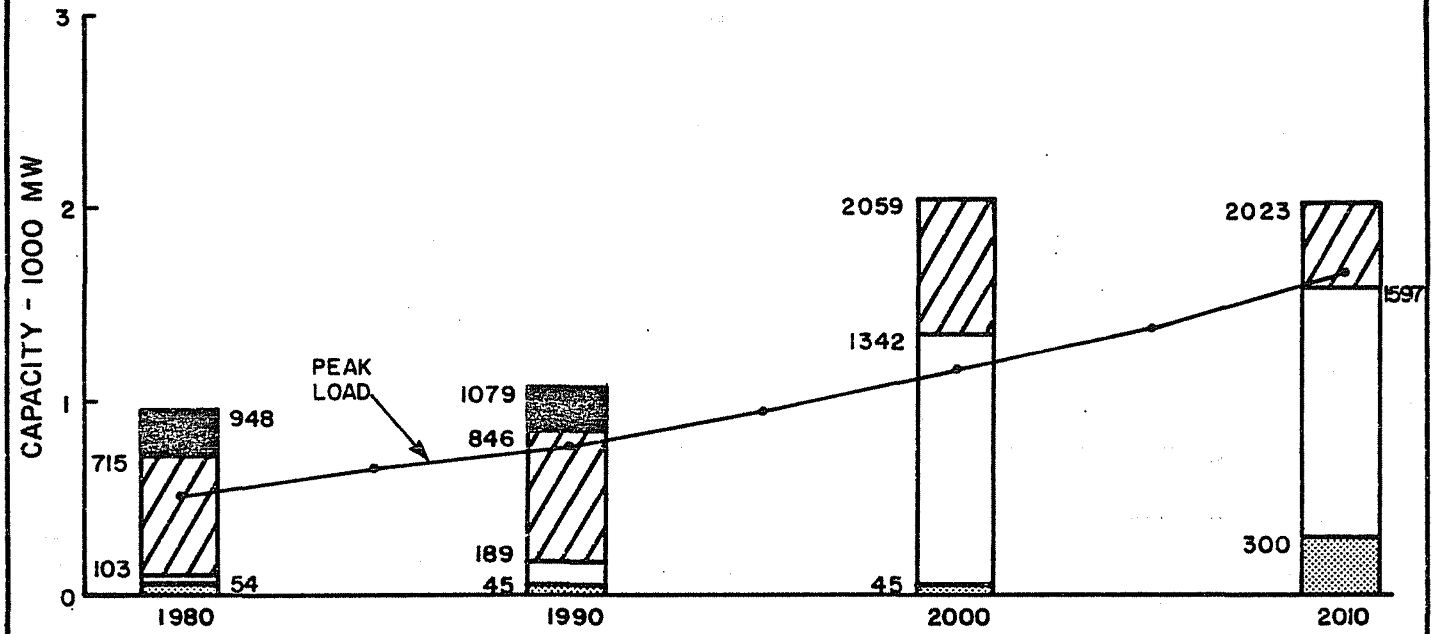
PREFERRED TUNNEL SCHEME 3 PLAN VIEW

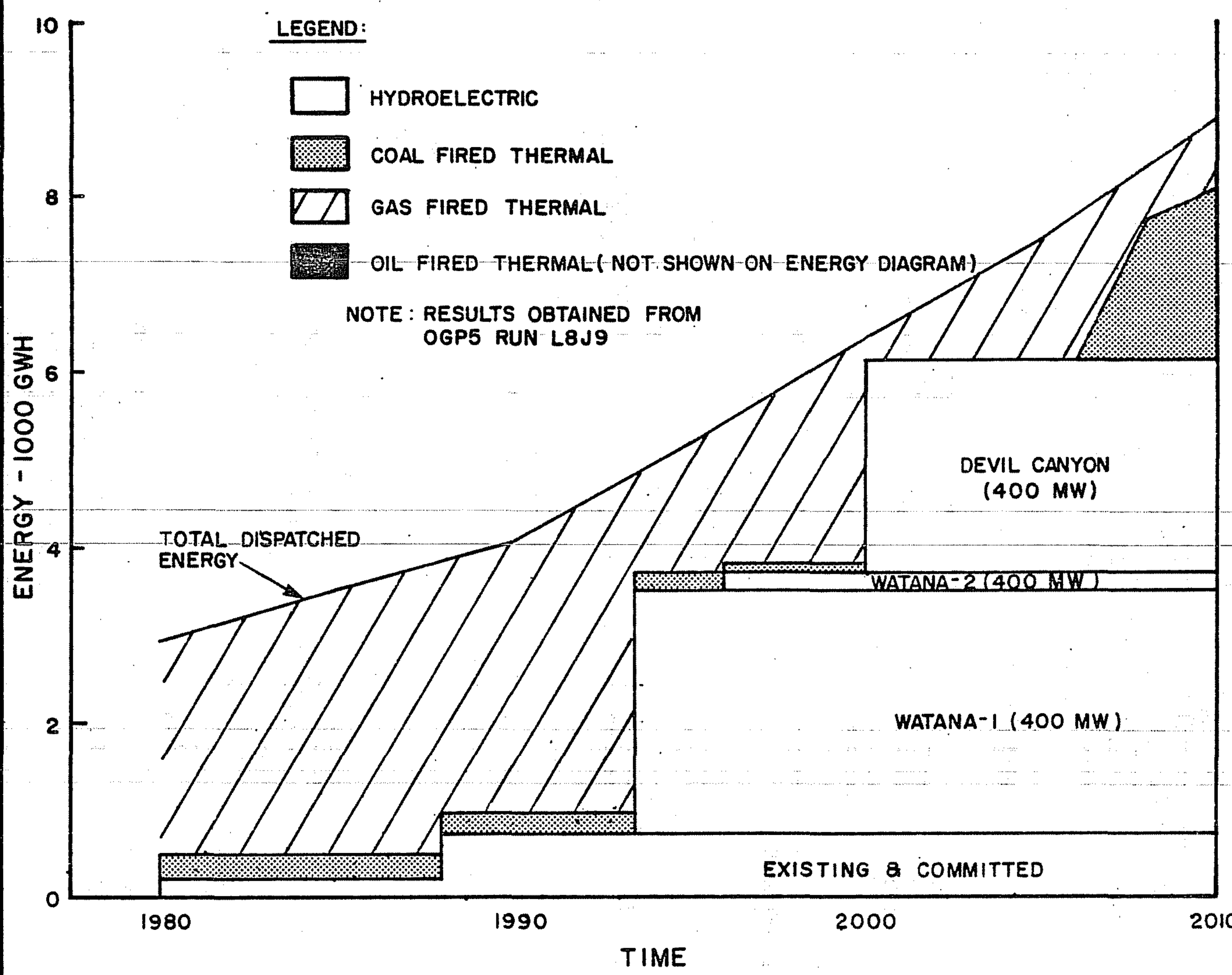
FIGURE B.1.4.2



PREFERRED TUNNEL SCHEME 3 SECTIONS

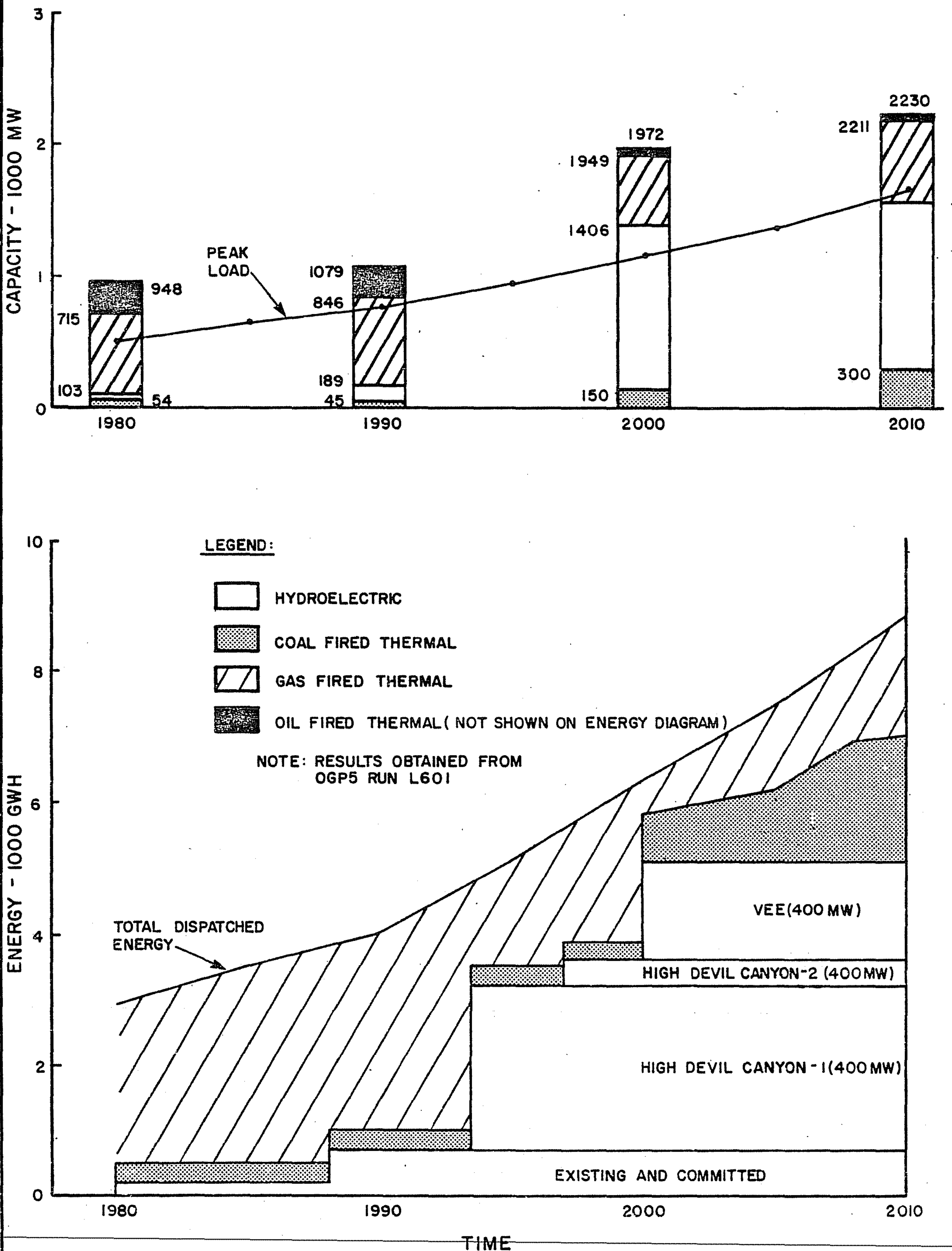
FIGURE B.1.4.3





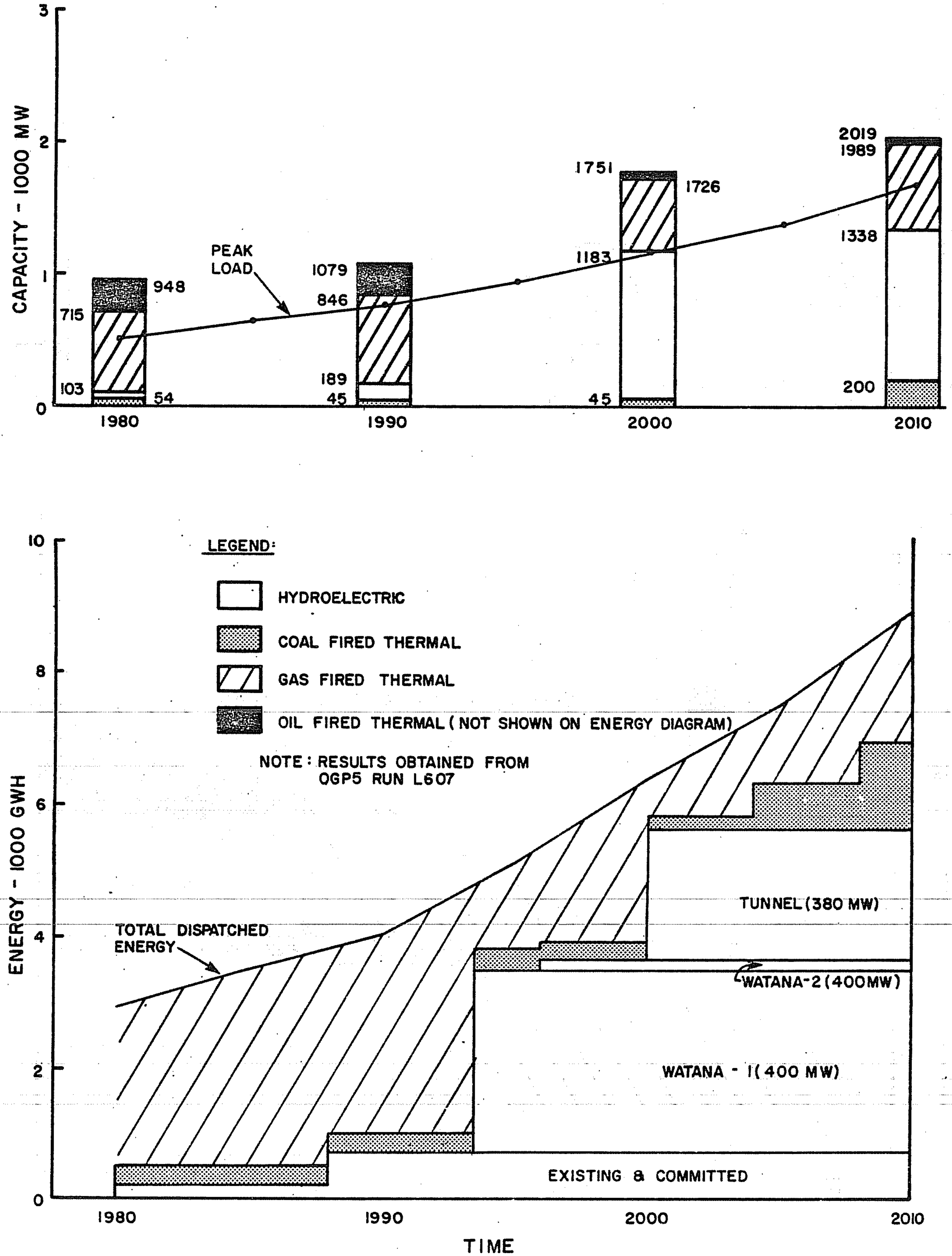
GENERATION SCENARIO WITH SUSITNA PLAN E1.3
-MEDIUM LOAD FORECAST-

FIGURE B.1.5.1



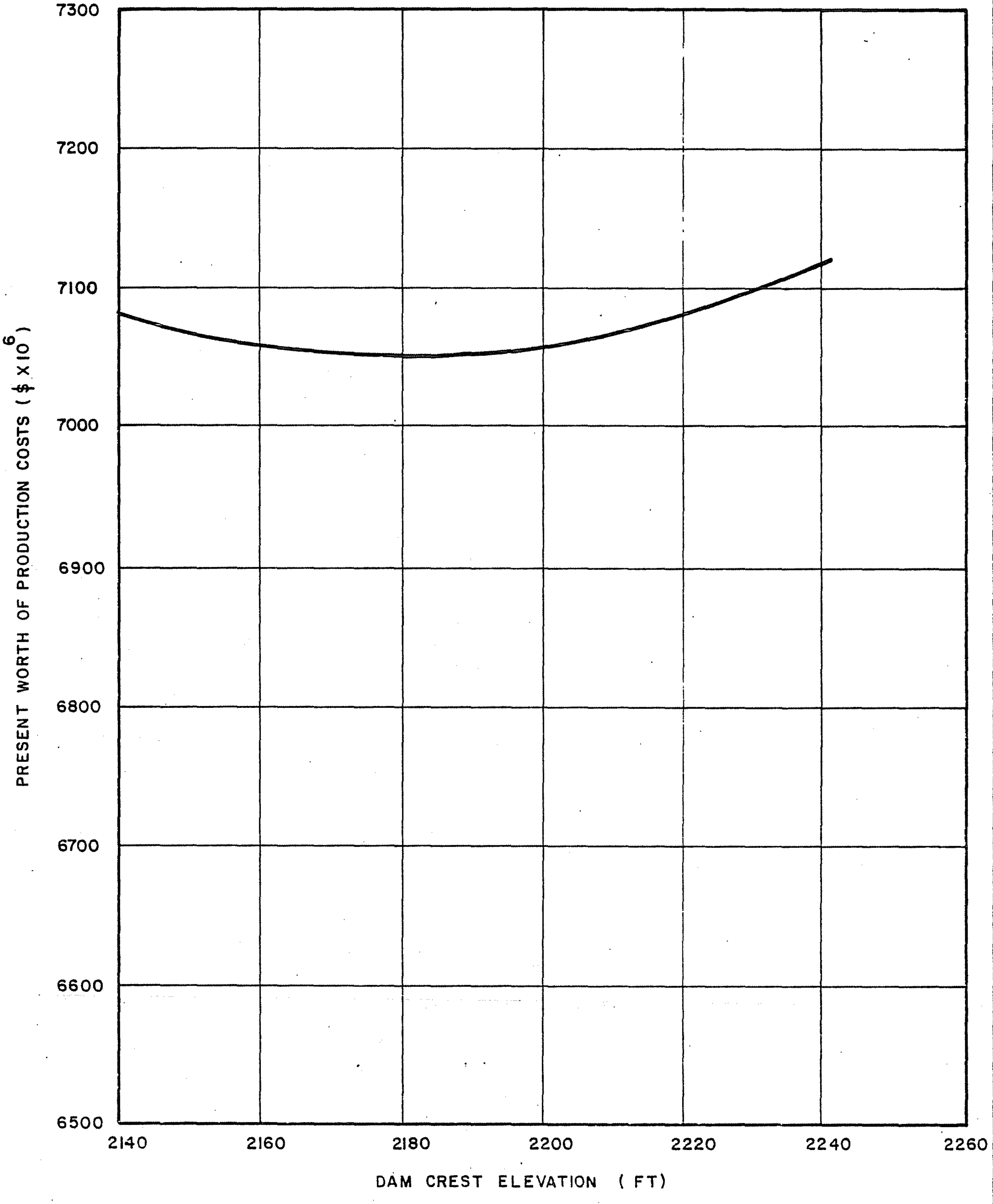
GENERATION SCENARIO WITH SUSITNA PLAN E 2.3
- MEDIUM LOAD FORECAST -

FIGURE B.1.5.2



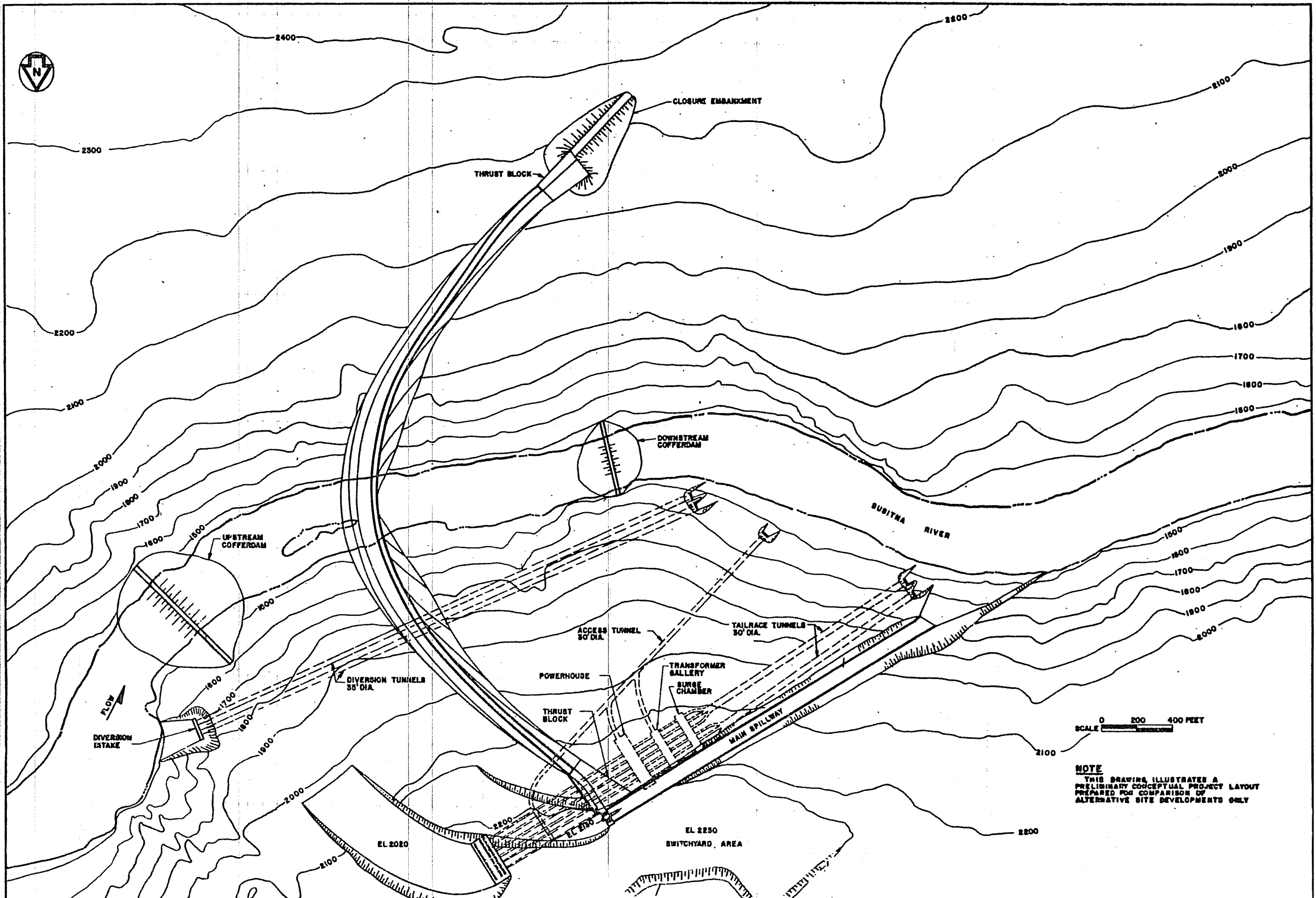
GENERATION SCENARIO WITH SUSITNA PLAN E3.1
- MEDIUM LOAD FORECAST -

FIGURE B.1.5.3



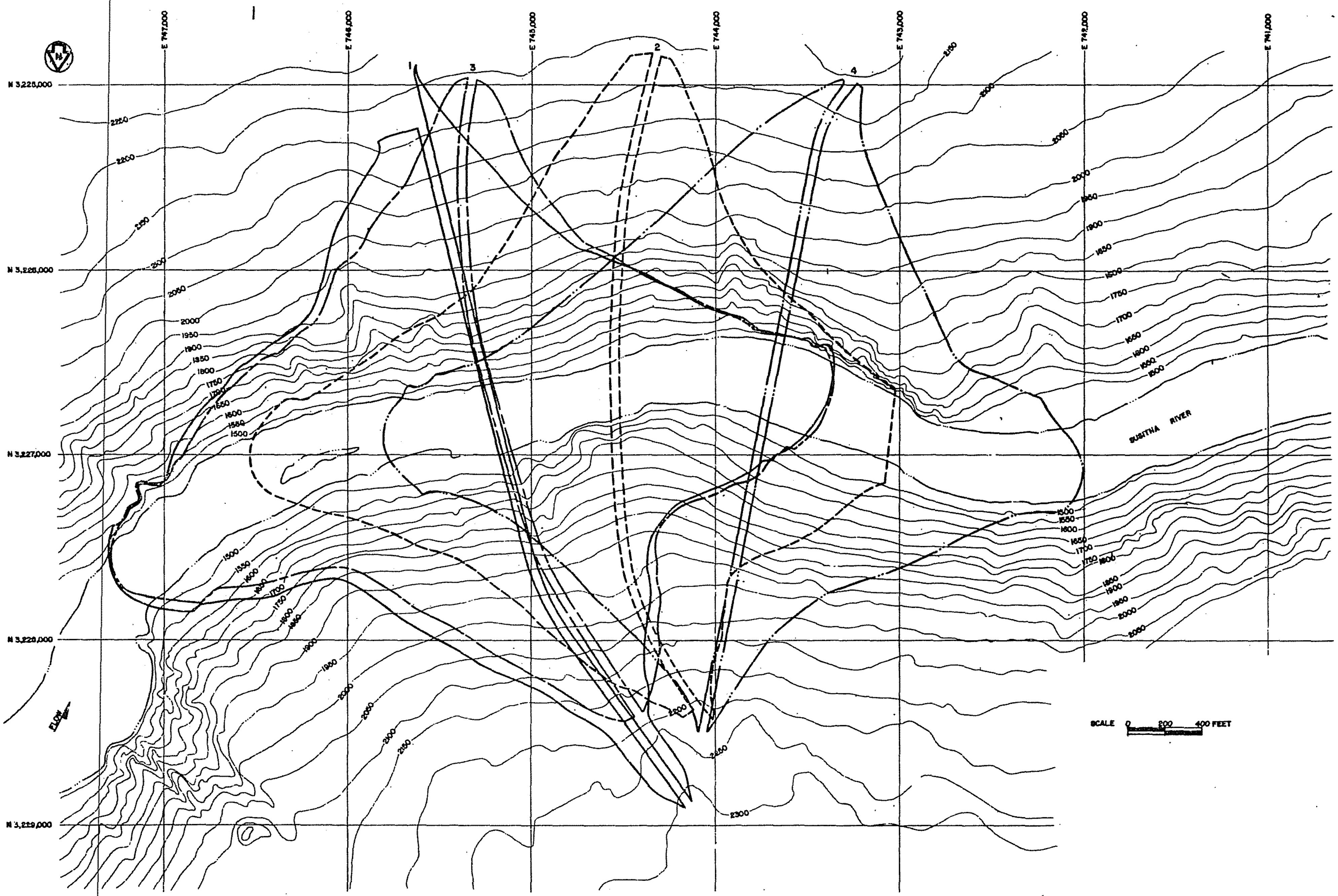
WATANA RESERVOIR
DAM CREST ELEVATION / PRESENT WORTH OF PRODUCTION COSTS

FIGURE B.2.2.1



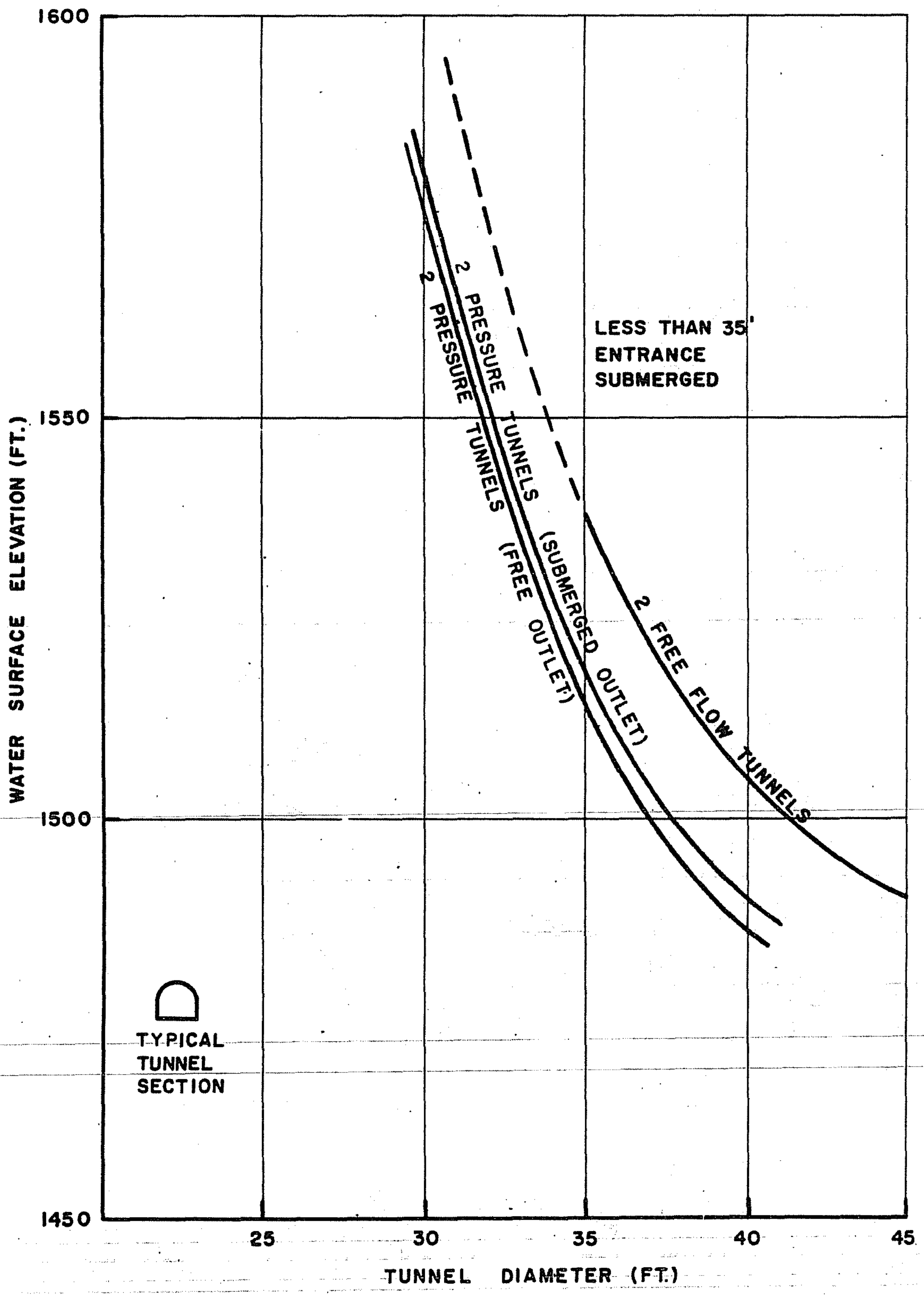
WATANA-ARCH DAM ALTERNATIVE

FIGURE B.2.2.2



WATANA ALTERNATIVE DAM AXES

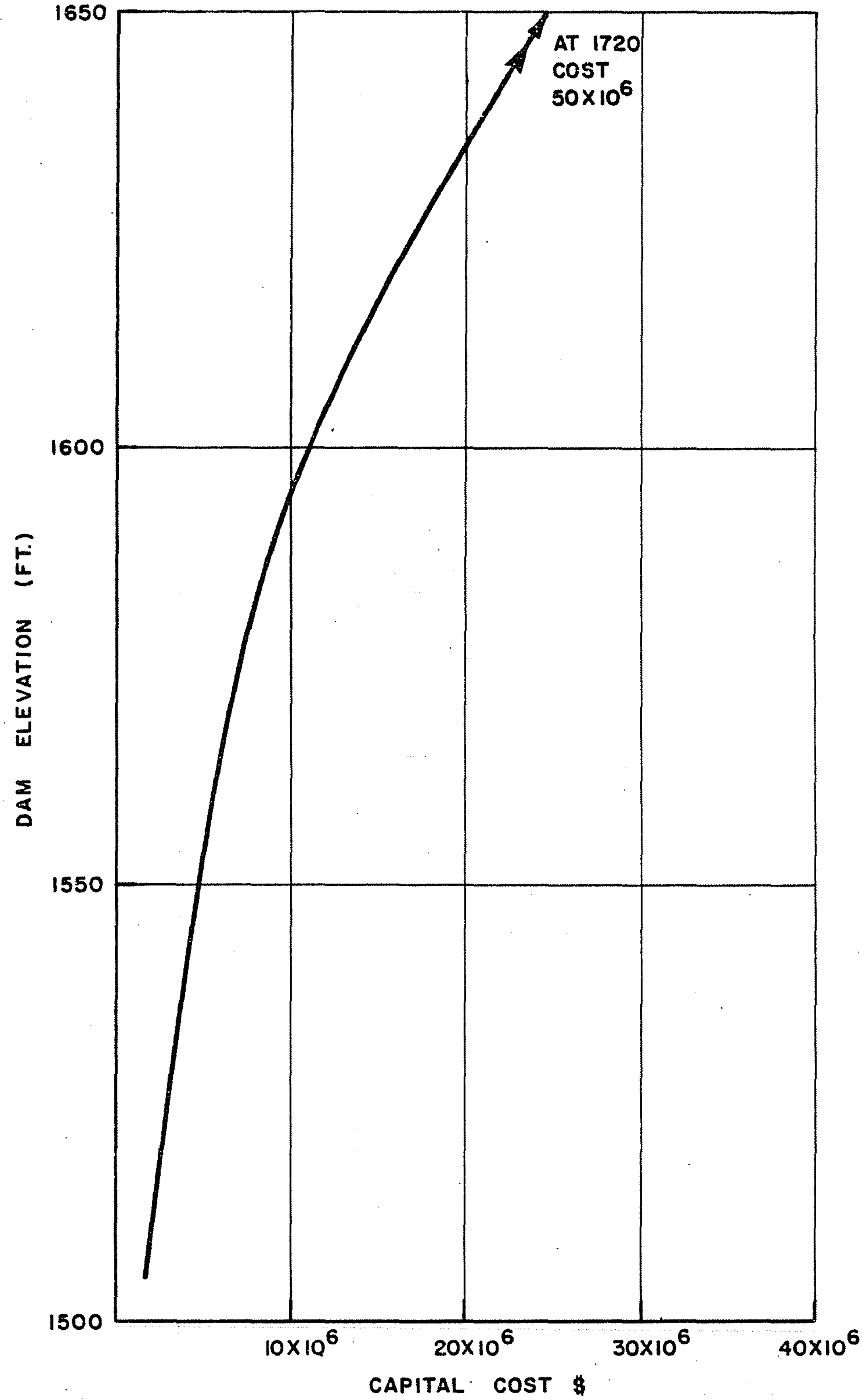
FIGURE B.22



NOTE
FOR 80,000 CFS

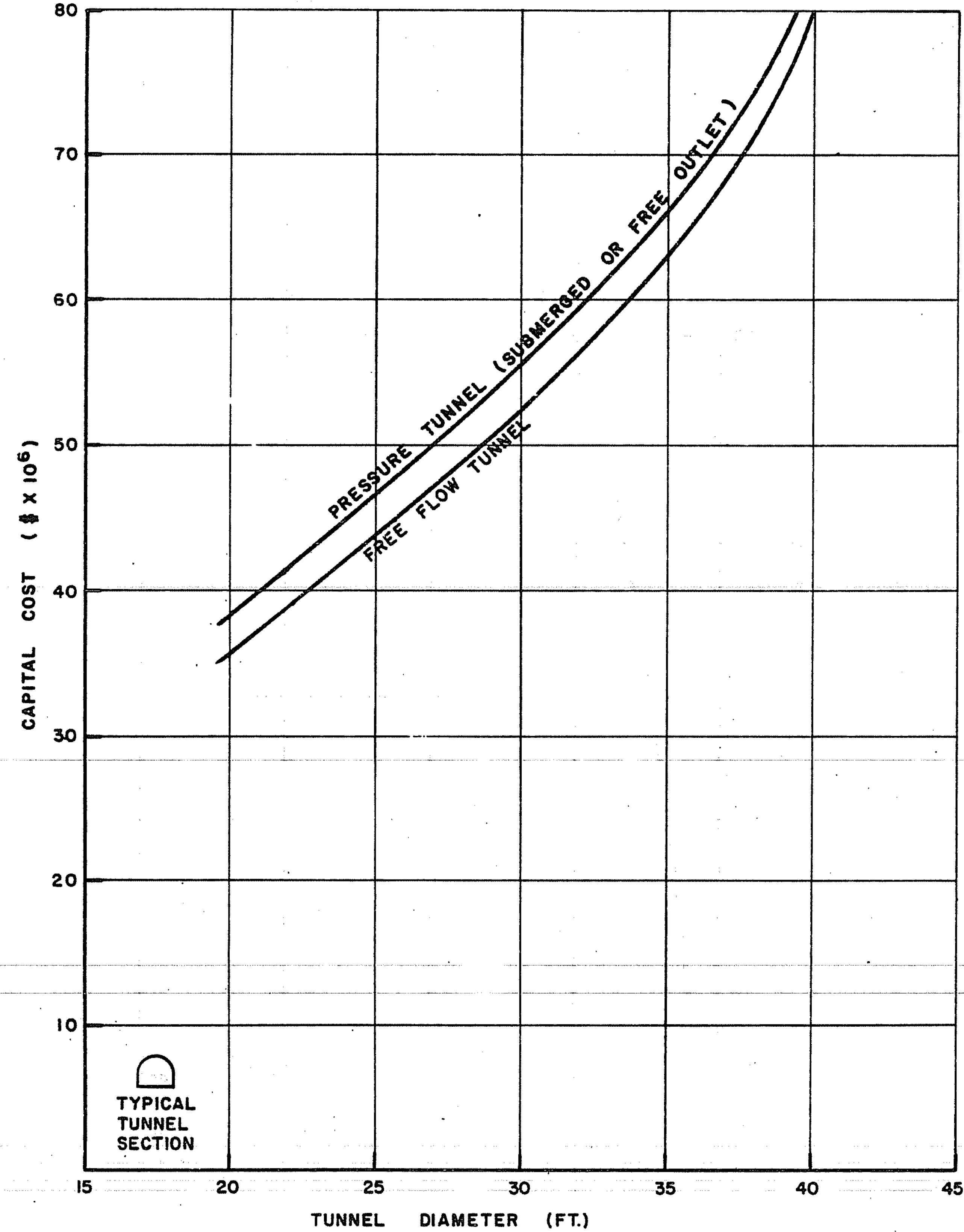
WATANA DIVERSION
HEADWATER ELEVATION/TUNNEL DIAMETER

FIGURE B.2.24



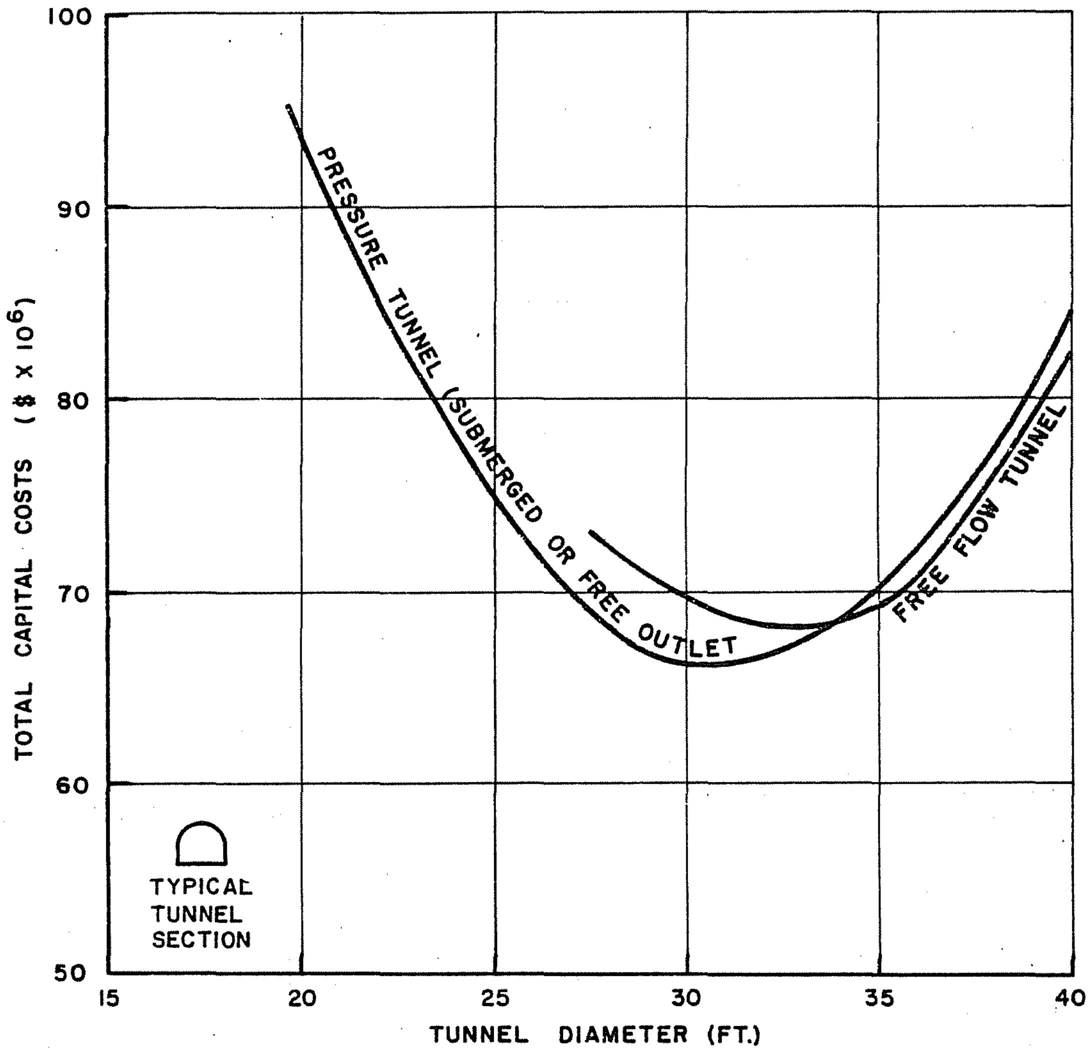
WATANA DIVERSION
UPSTREAM COFFERDAM COSTS

FIGURE B.2.25



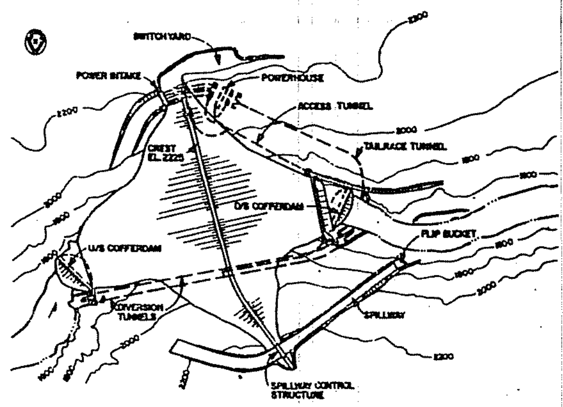
WATANA DIVERSION
TUNNEL COST/ TUNNEL DIAMETER

FIGURE B.2.2.6

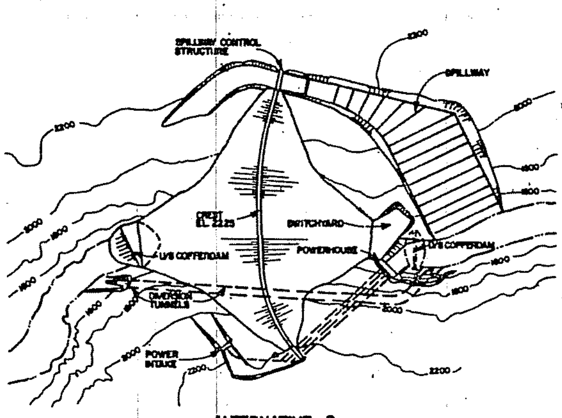


WATANA DIVERSION
TOTAL COST/TUNNEL DIAMETER

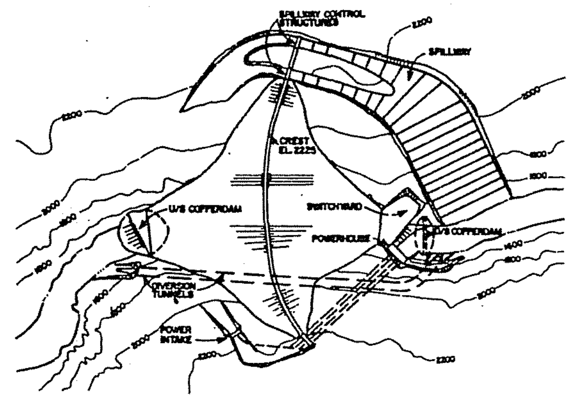
FIGURE B.2.2.7



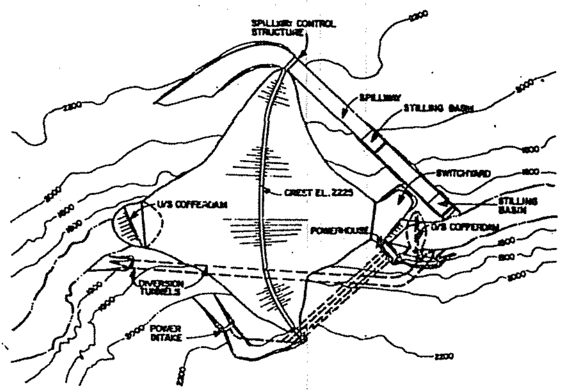
ALTERNATIVE 1



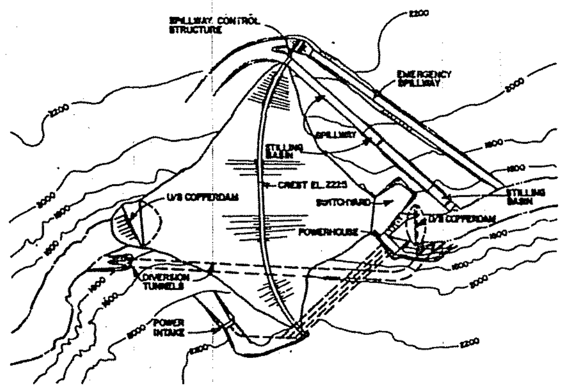
ALTERNATIVE 2



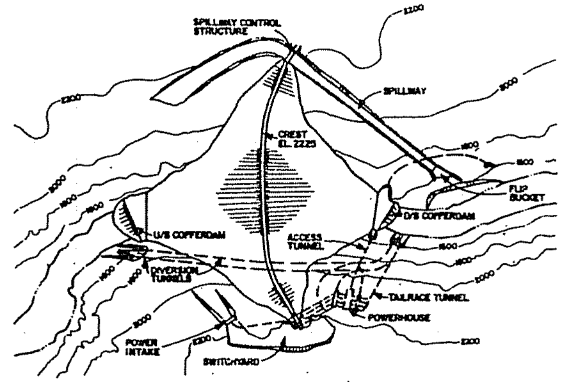
ALTERNATIVE 2A



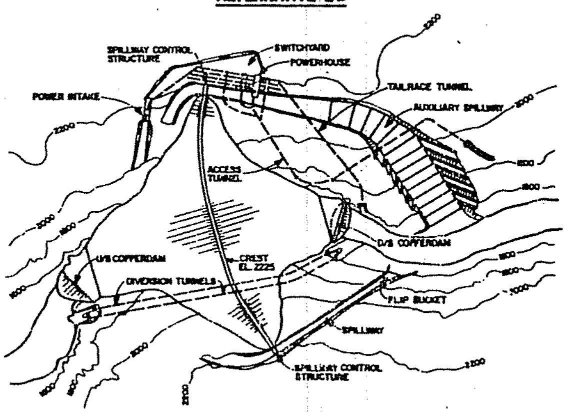
ALTERNATIVE 2B



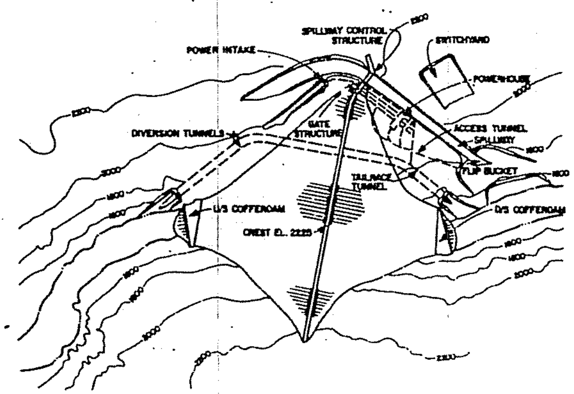
ALTERNATIVE 2C



ALTERNATIVE 2D



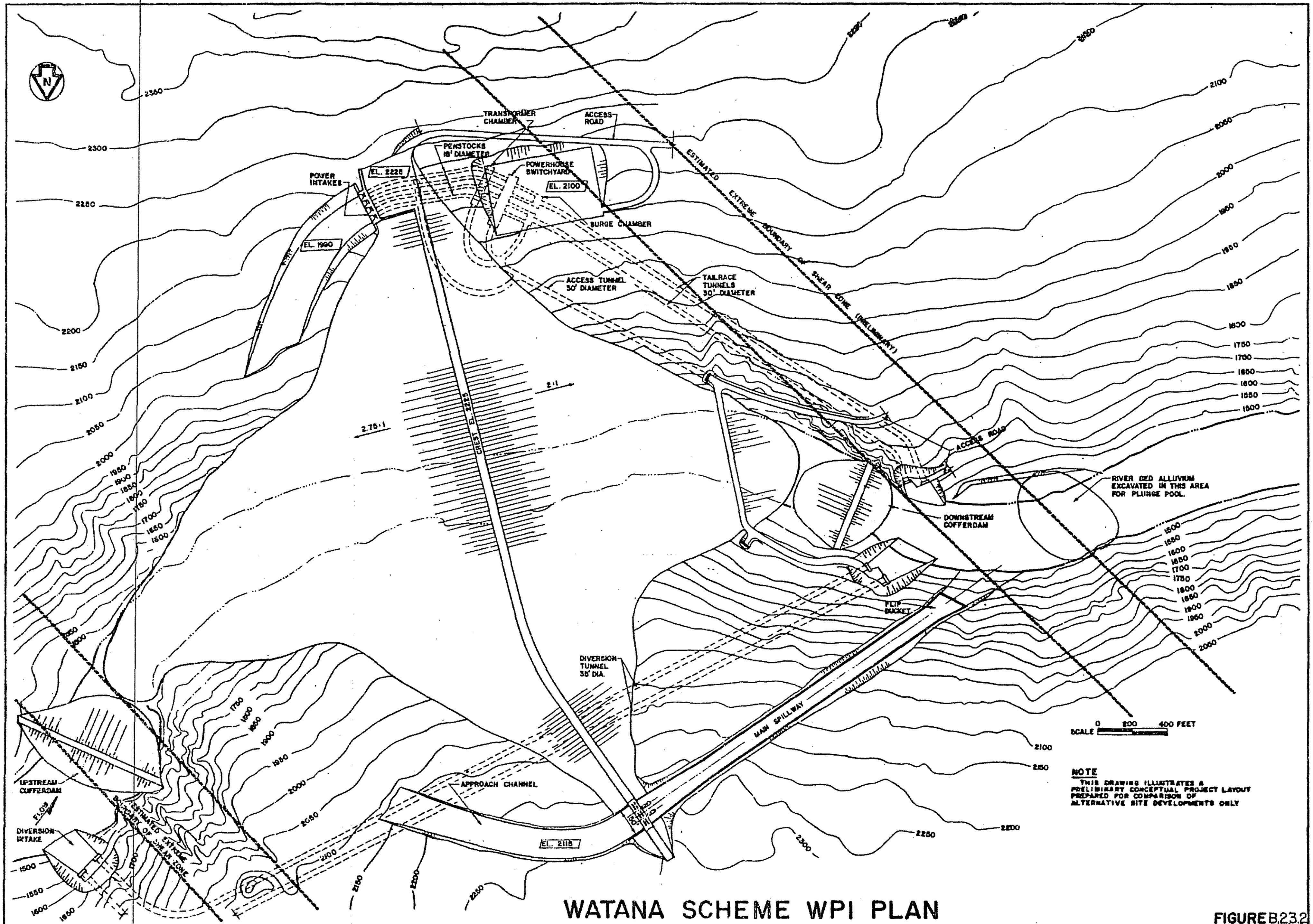
ALTERNATIVE 3



ALTERNATIVE 4

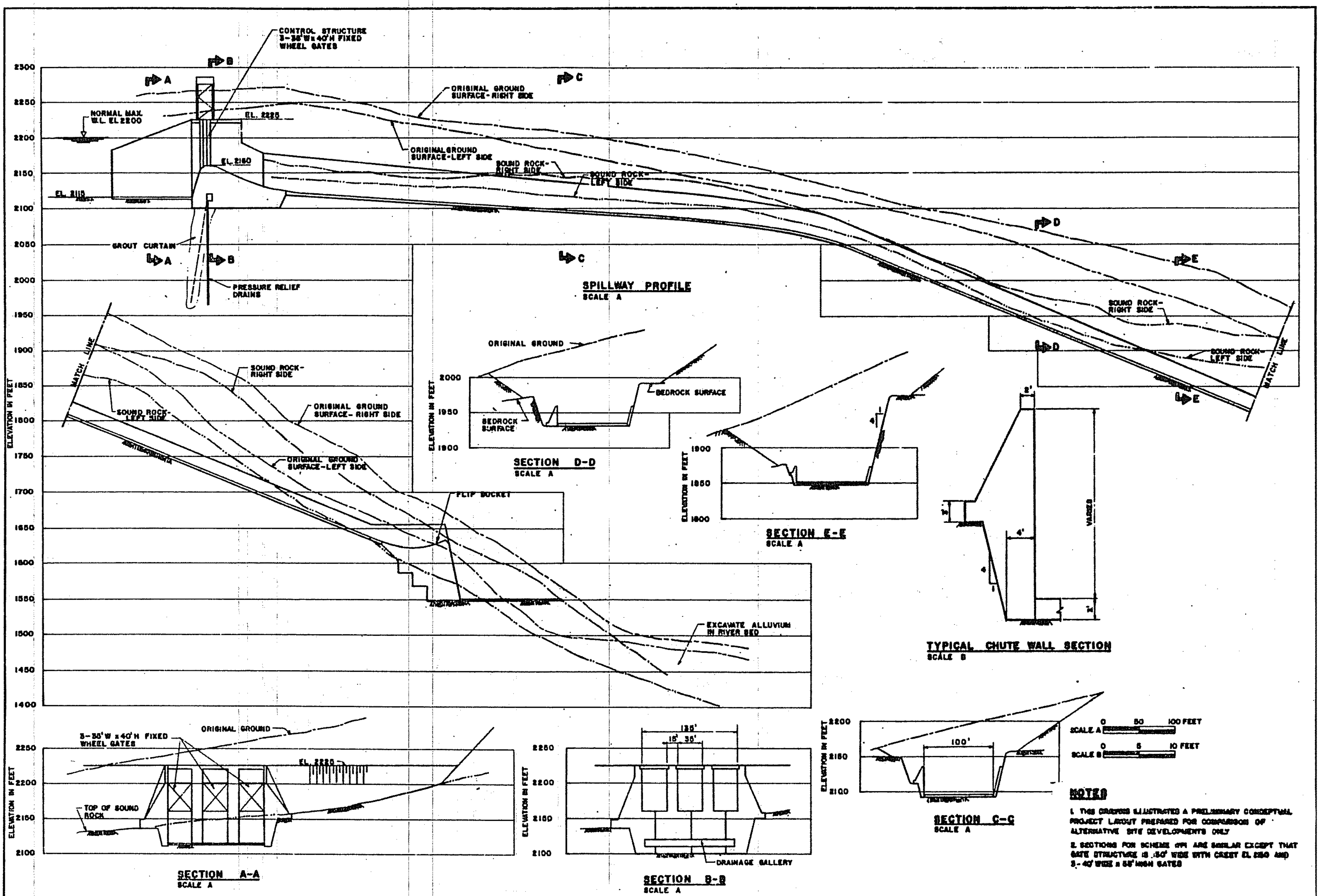
WATANA PRELIMINARY SCHEMES

FIGURE B.231



WATANA SCHEME WPI PLAN

FIGURE B.2.3.2



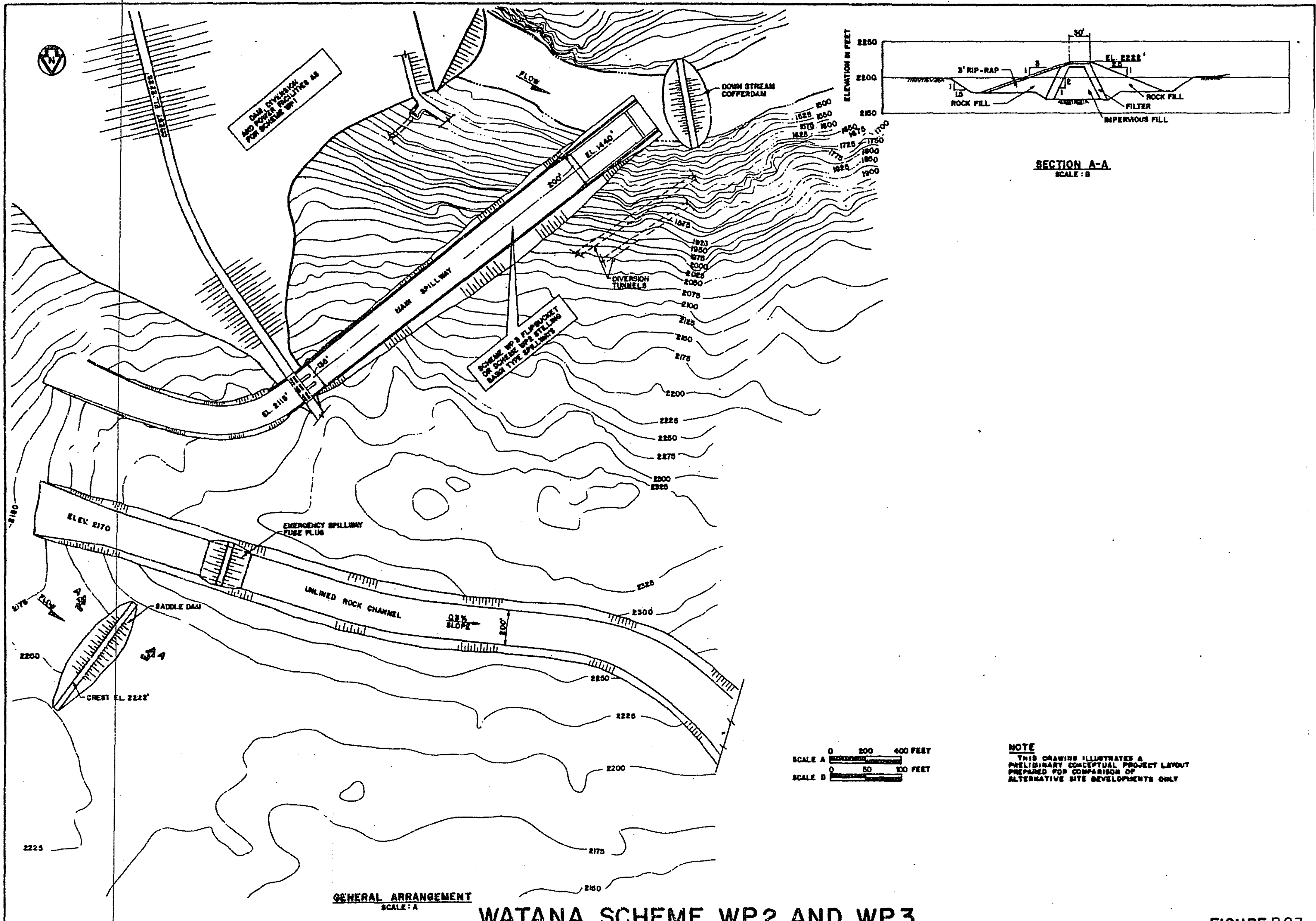
WATANA SCHEME WP3 SECTIONS

FIGURE B.2.3.3

NOTES

1. THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

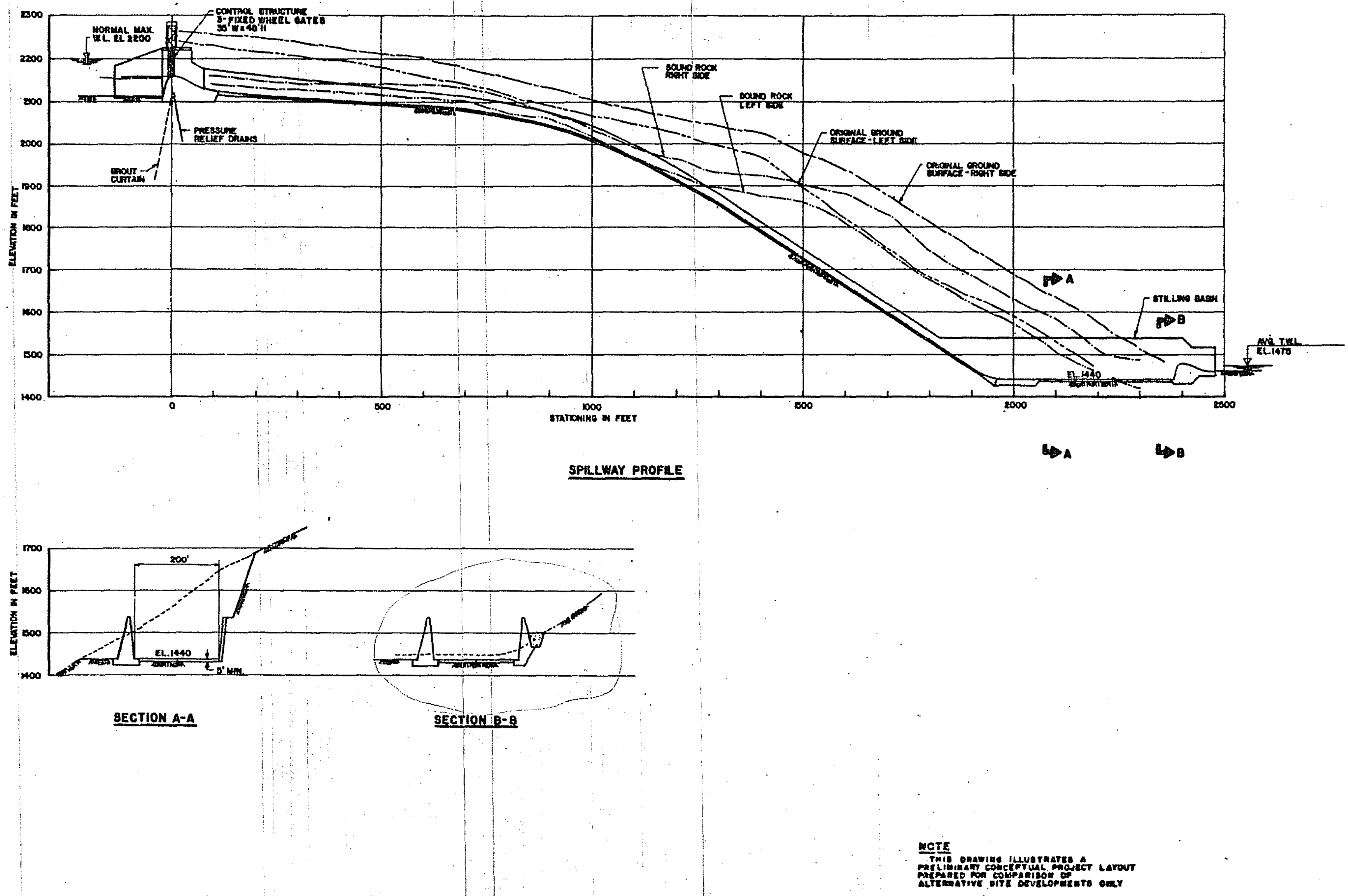
2. SECTIONS FOR SCHEME WP1 ARE SIMILAR EXCEPT THAT GATE STRUCTURE IS 150' WIDE WITH CREST EL 2150 AND 3-40' WIDE x 58' HIGH GATES



NOTE
THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

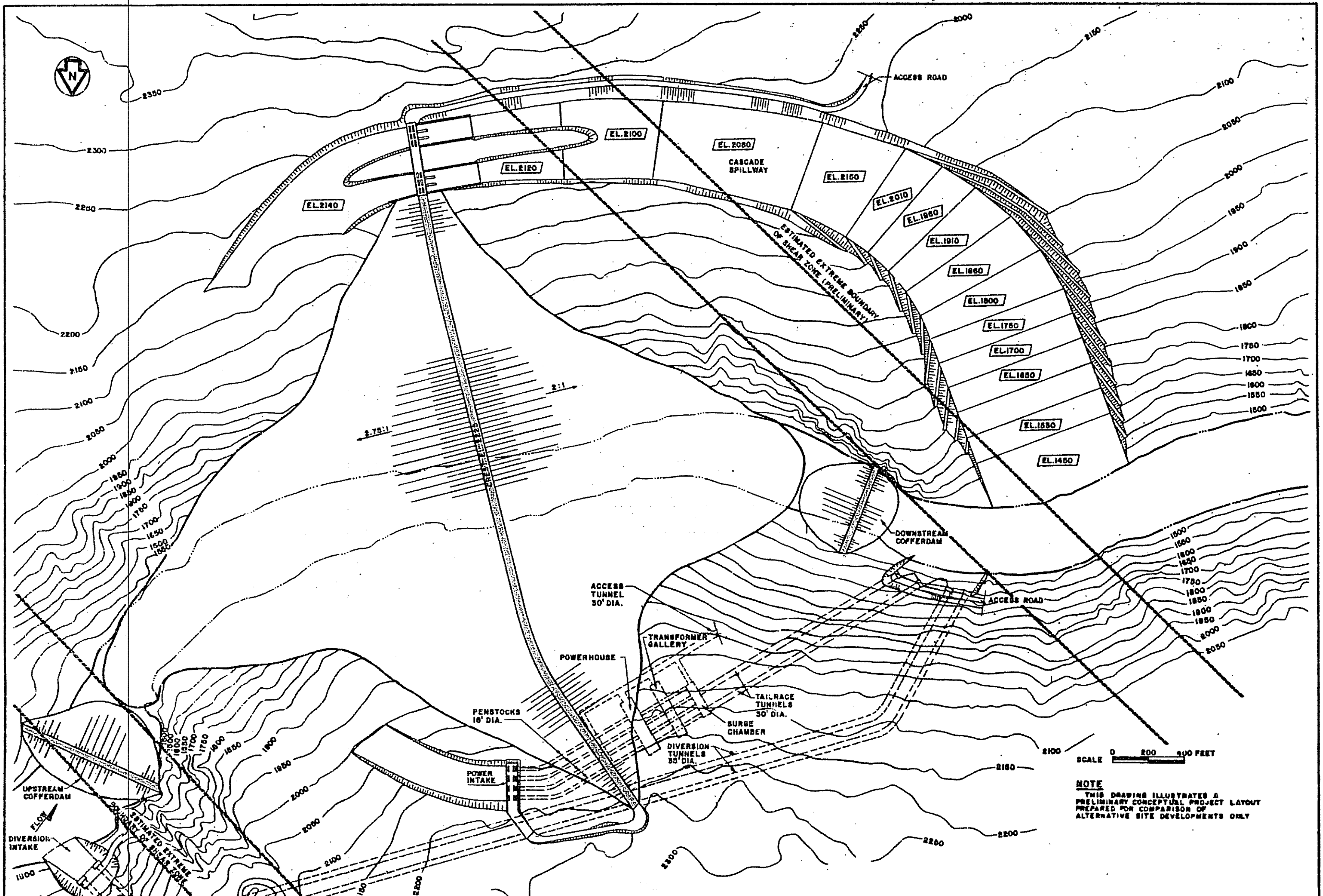
WATANA SCHEME WP2 AND WP3

FIGURE B.2.3



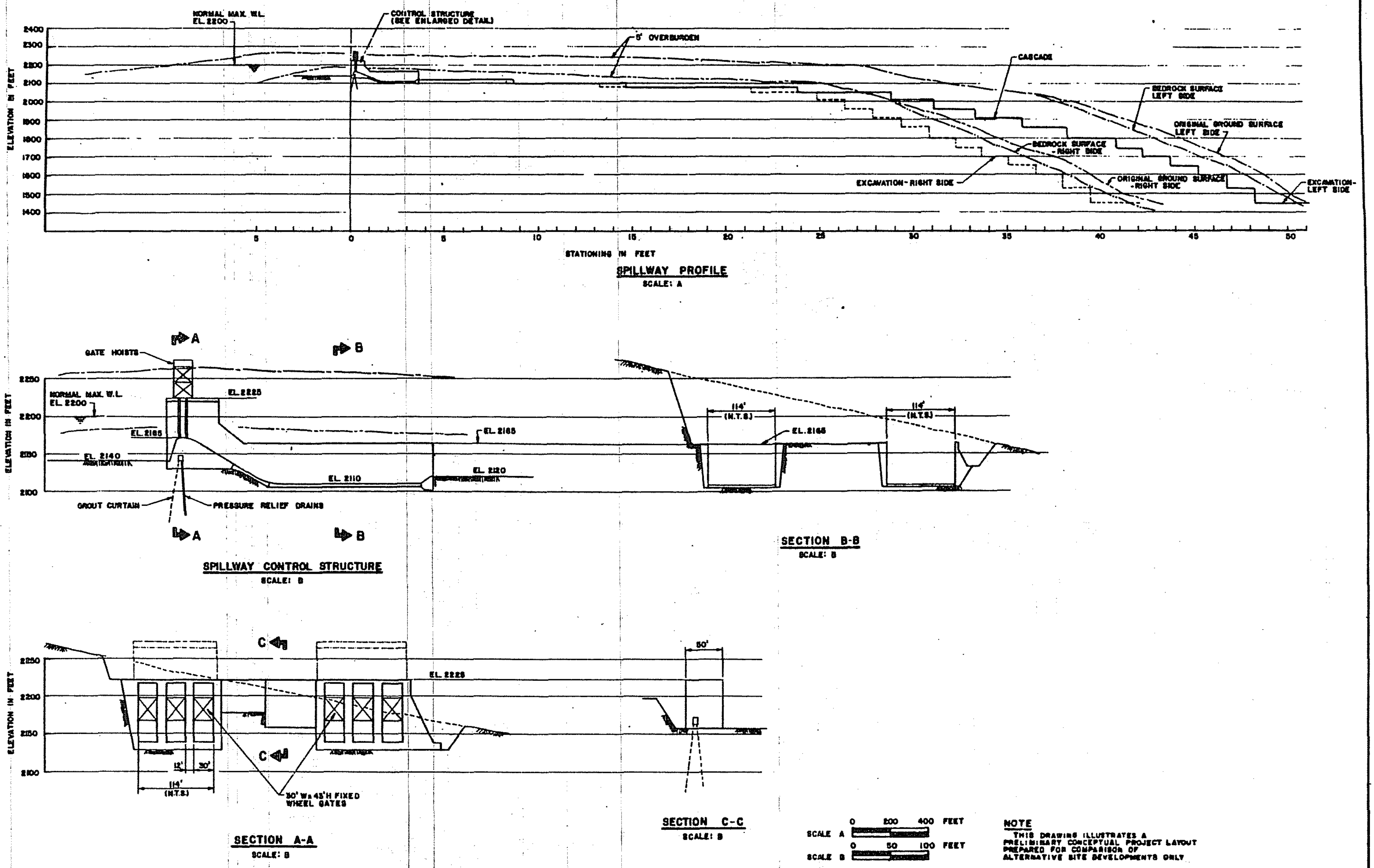
WATANA SCHEME WP2 SECTIONS

FIGURE B.2.35



WATANA SCHEME WP4 PLAN

FIGURE B2.36

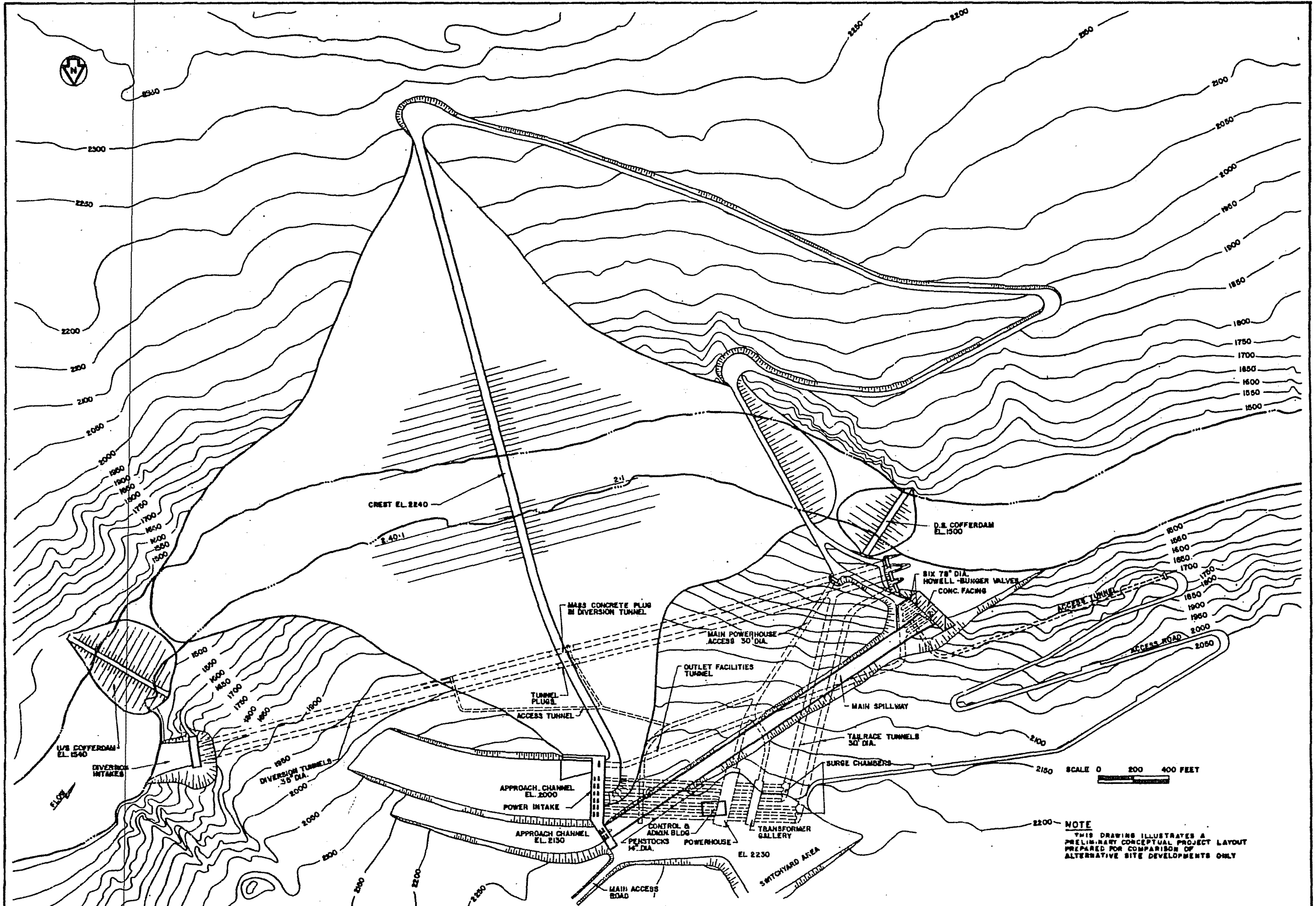


NOTE

THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

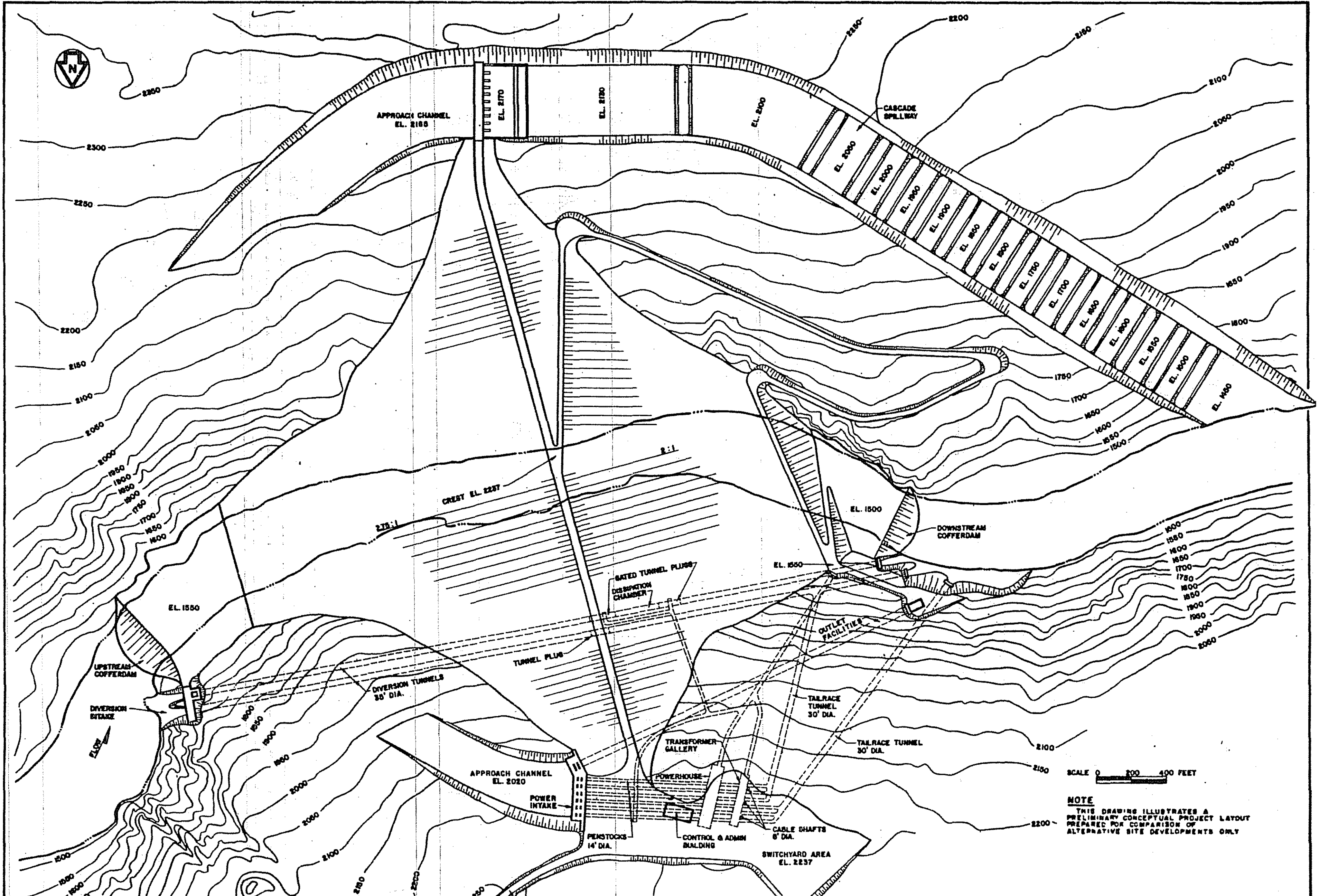
WATANA SCHEME WP4 SECTIONS

FIGURE B.2.3.7



WATANA SCHEME WP3A

FIGURE B.2.3.8



WATANA SCHEME WP4A

FIGURE B.2.3.9

WATANA DAM STAGE I

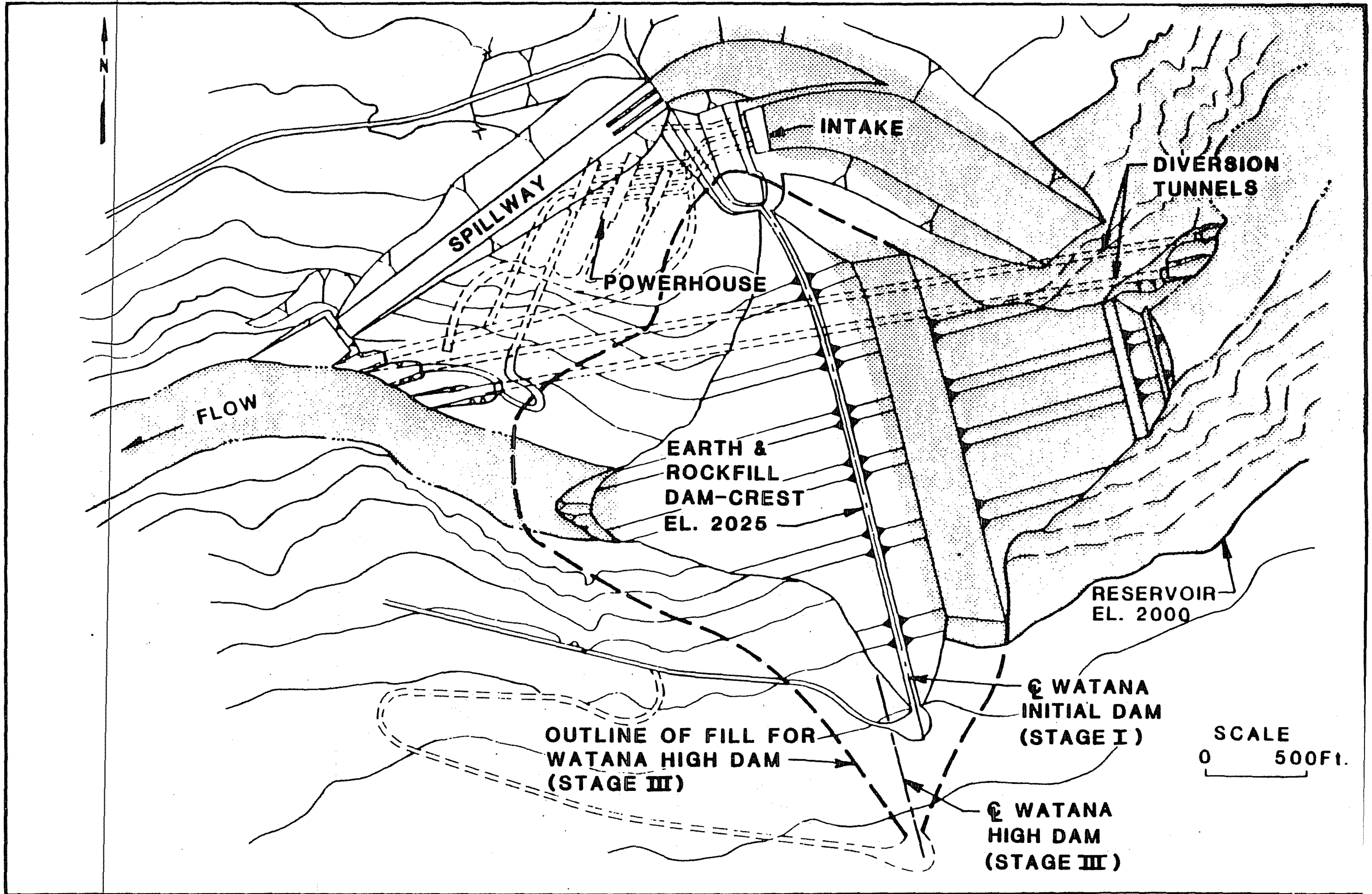


FIGURE B.2.3.10

DEVIL CANYON DAM STAGE II

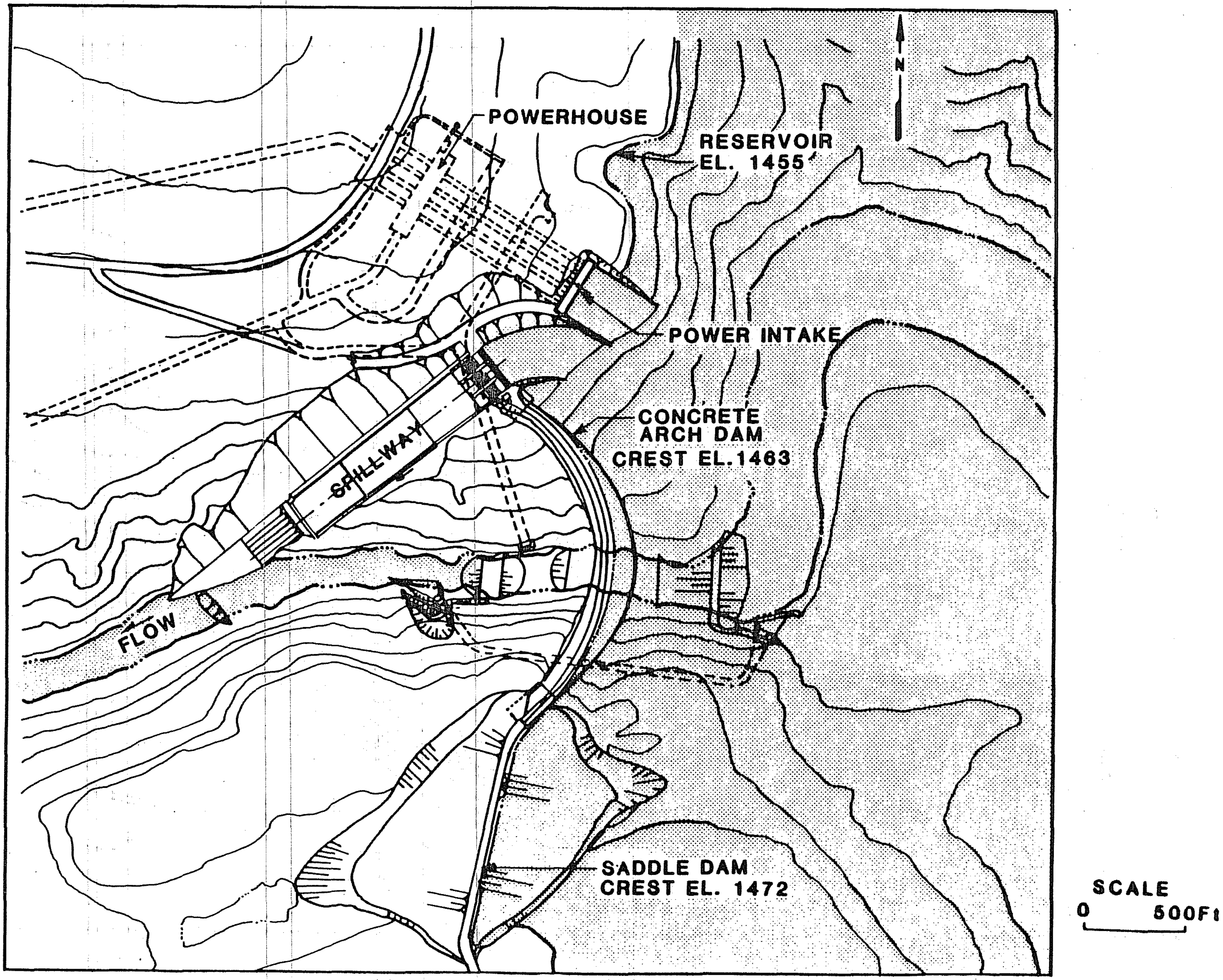


FIGURE B.2.3.11

WATANA DAM STAGE III

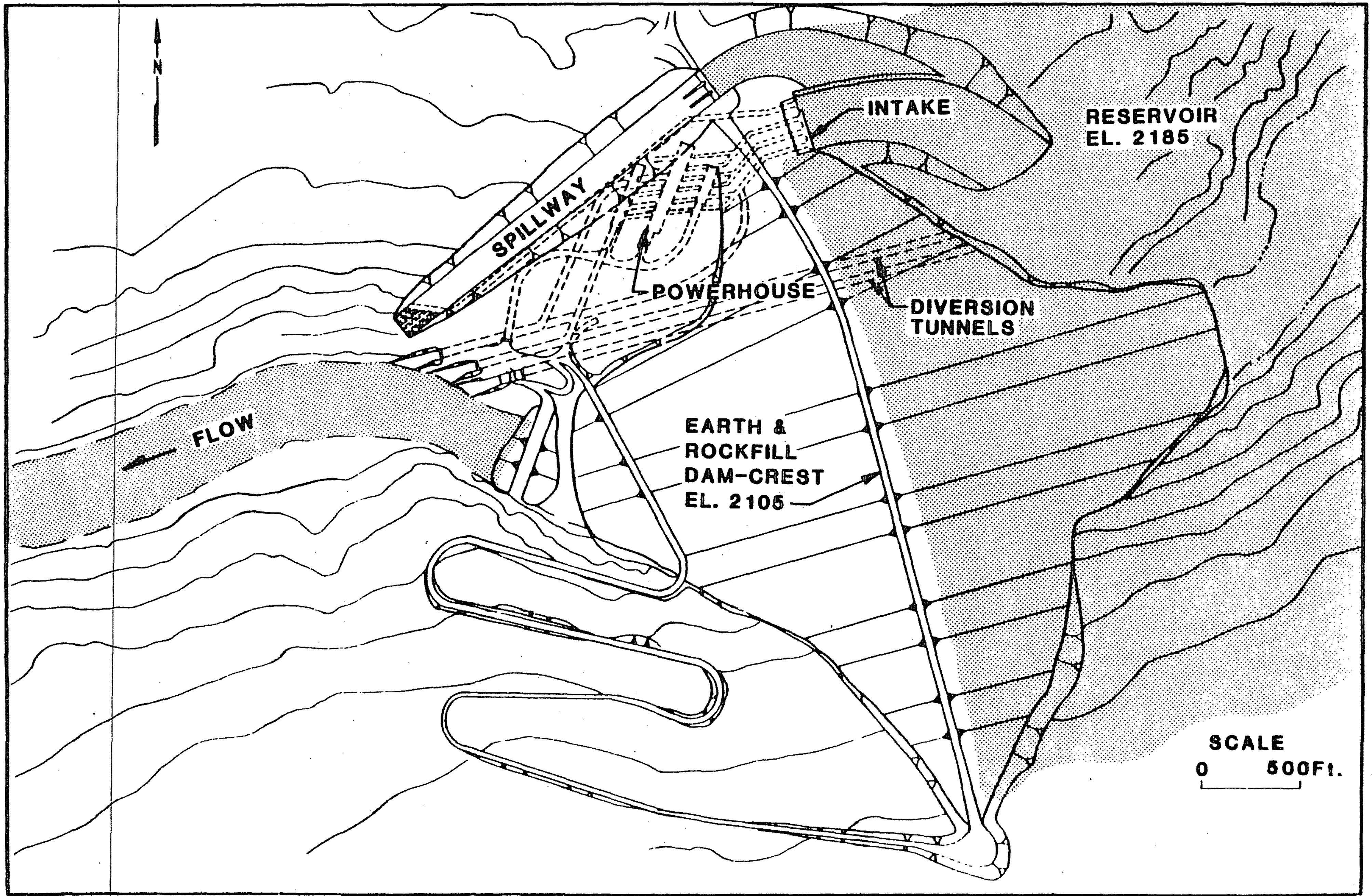
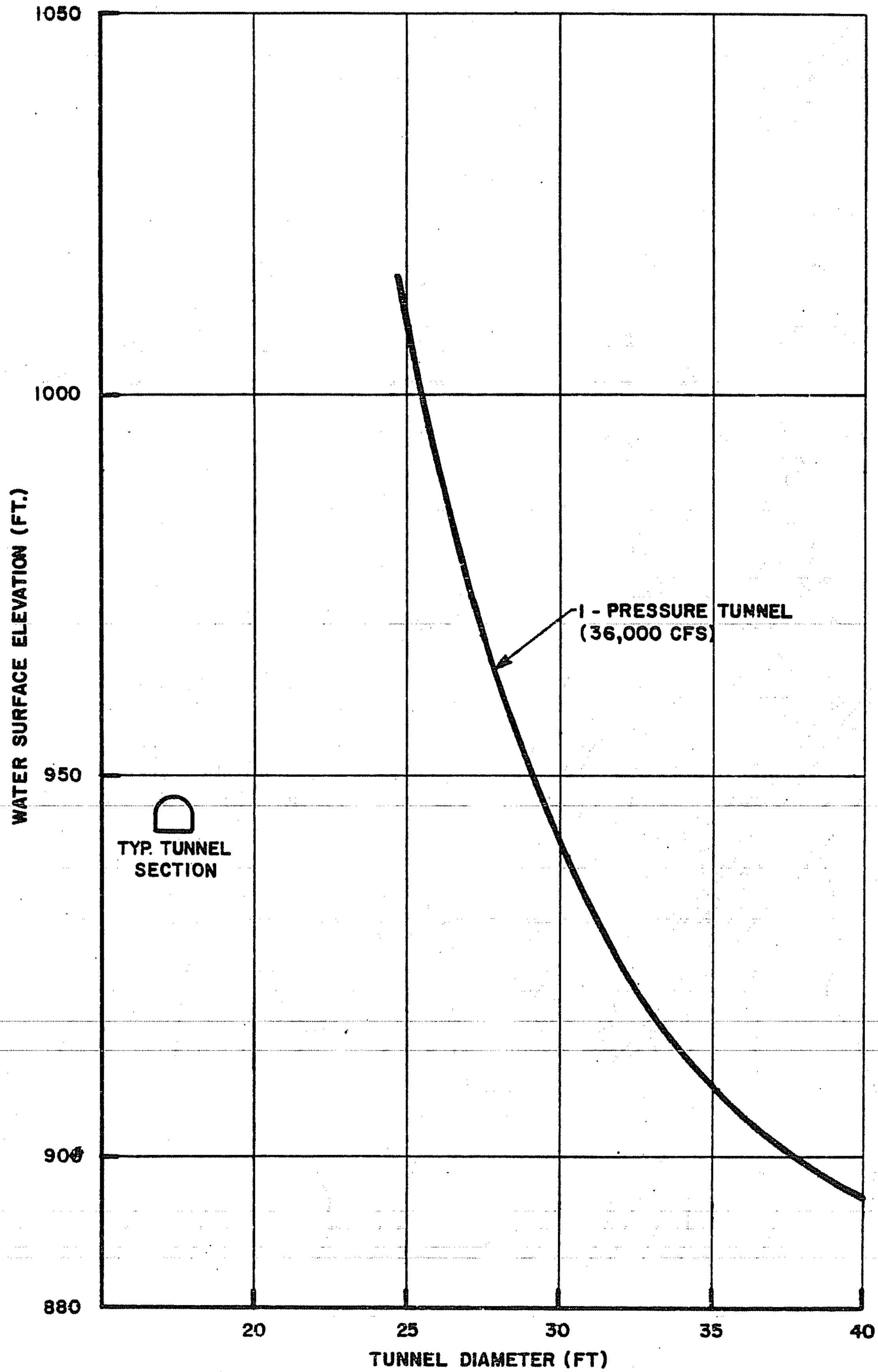
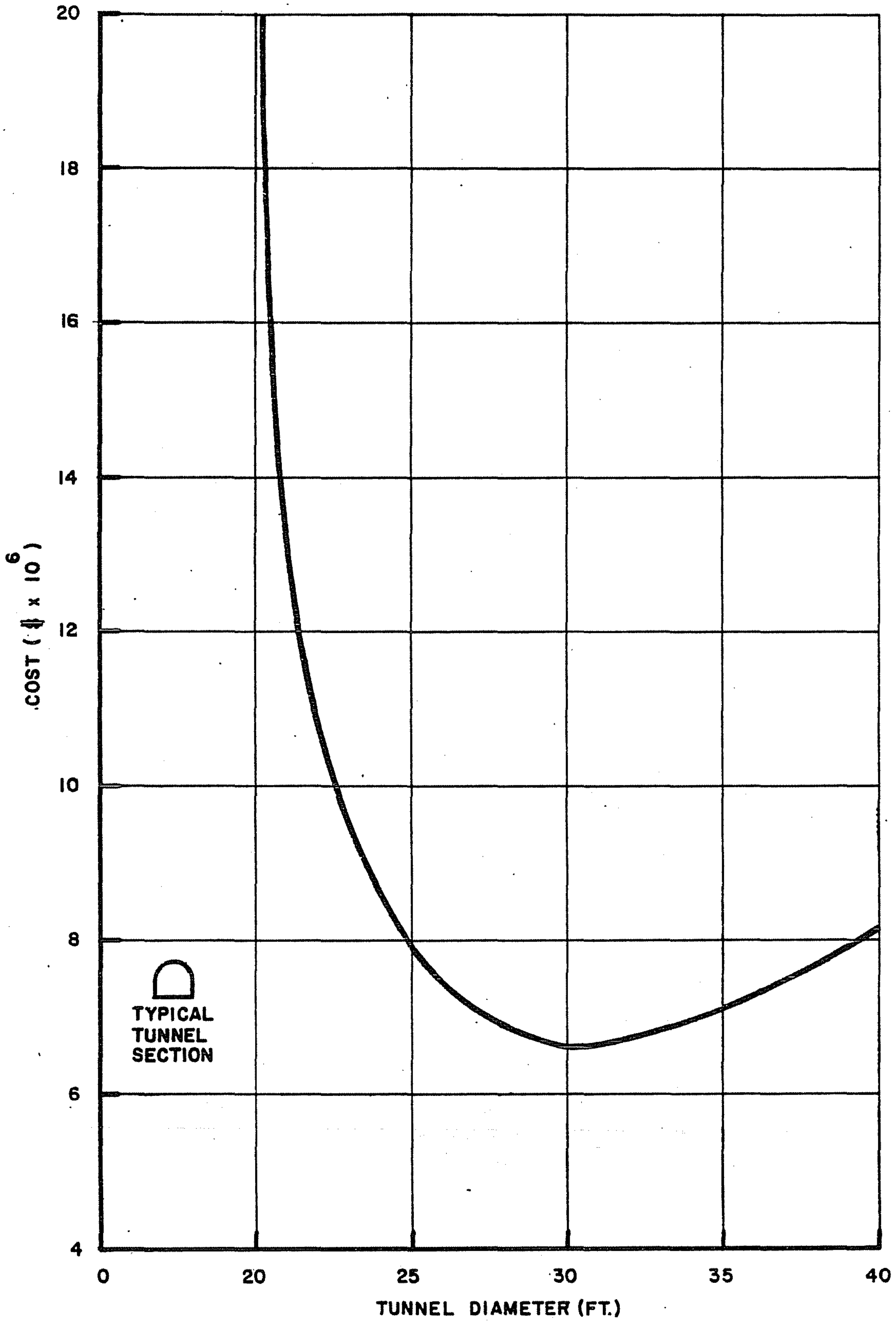


FIGURE B.2.3.12



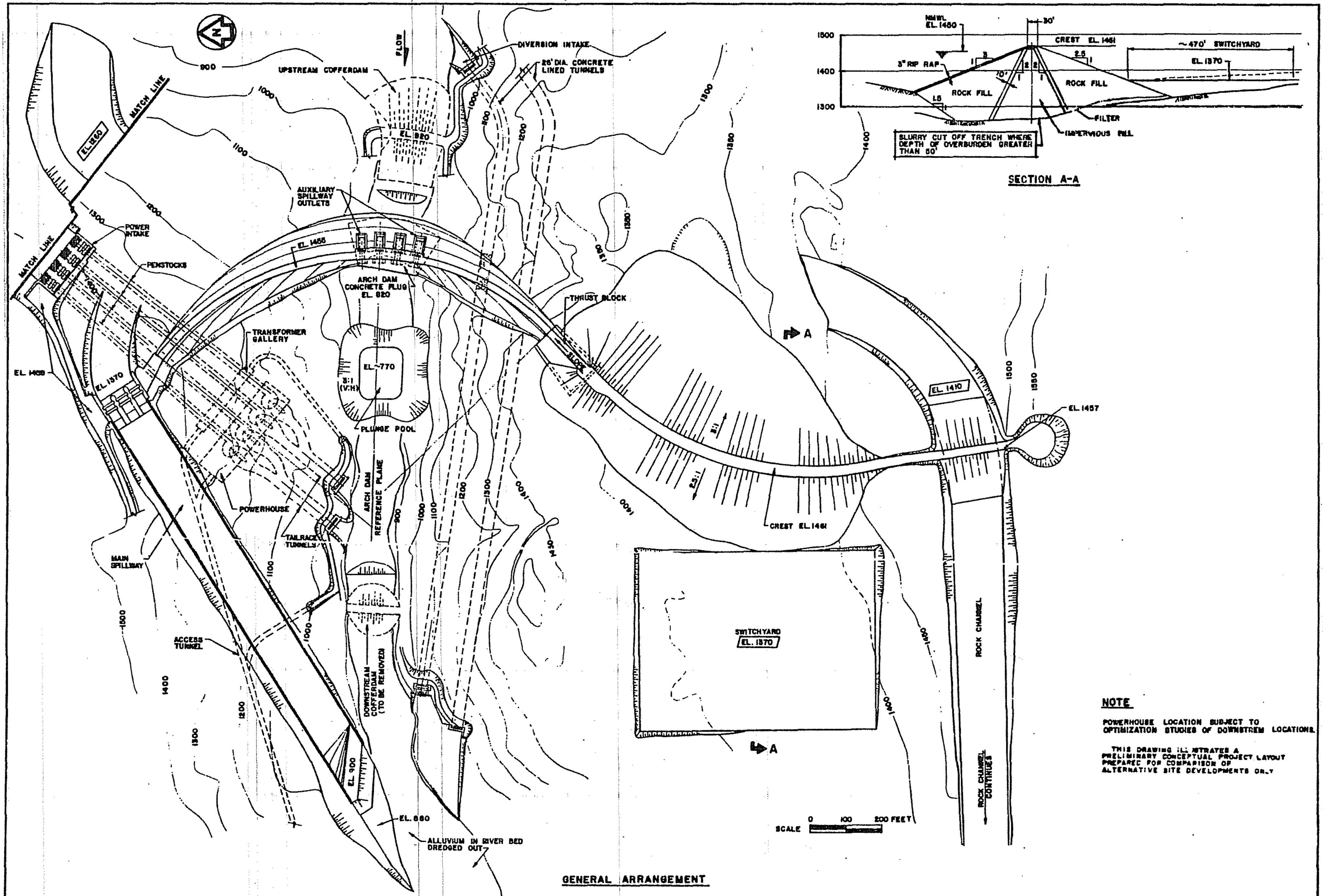
DEVIL CANYON DIVERSION
HEADWATER ELEVATION/TUNNEL DIAMETER

FIGURE B2.4.1



DEVIL CANYON DIVERSION
TOTAL COST/TUNNEL DIAMETER

FIGURE B.2.4.2



NOTE

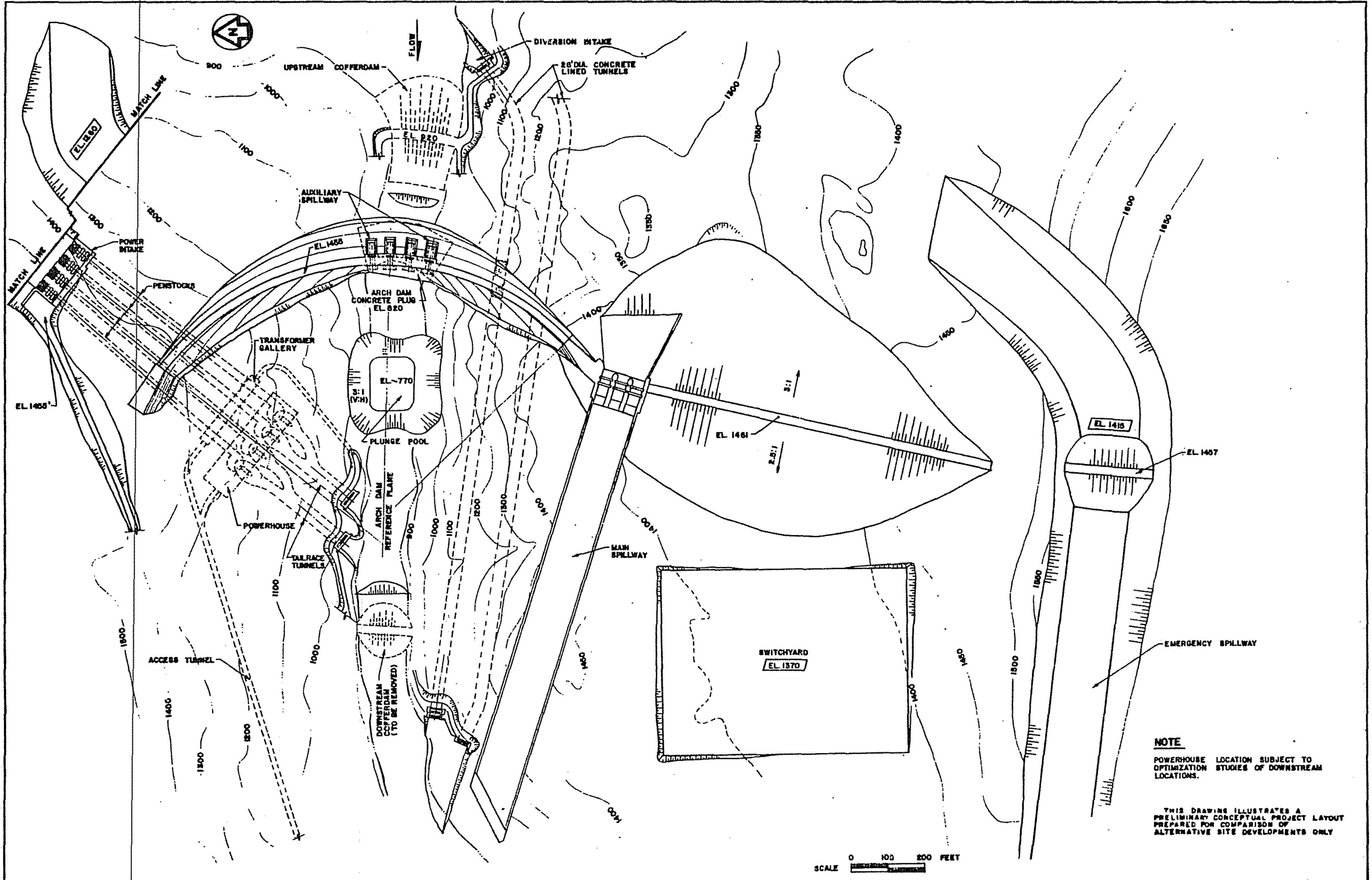
POWERHOUSE LOCATION SUBJECT TO OPTIMIZATION STUDIES OF DOWNSTREM LOCATIONS.

THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

GENERAL ARRANGEMENT

DEVIL CANYON SCHEME DCI

FIGURE B.2.5.1



NOTE

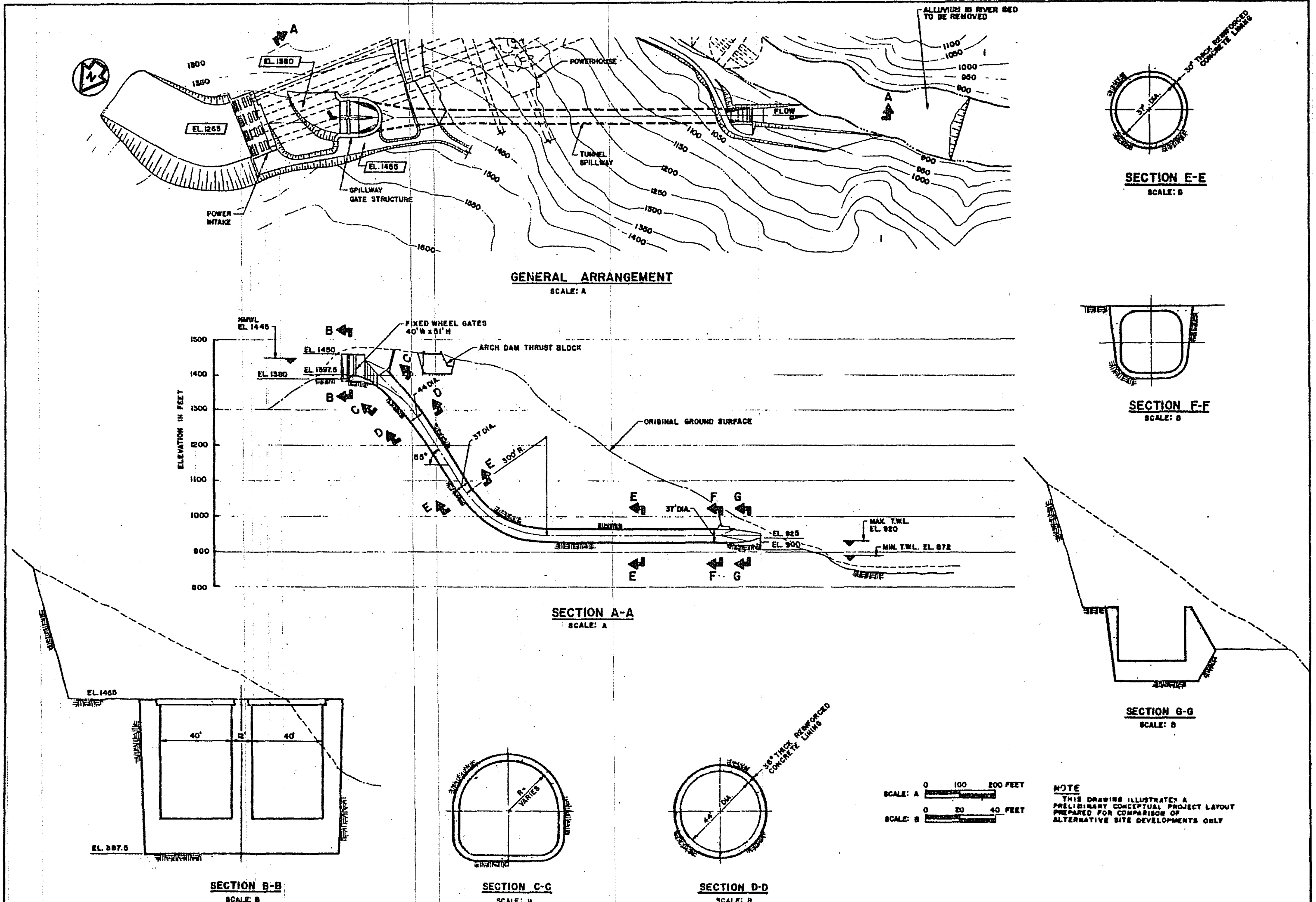
POWERHOUSE LOCATION SUBJECT TO OPTIMIZATION STUDIES OF DOWNSTREAM LOCATIONS.

THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

GENERAL ARRANGEMENT

DEVIL CANYON SCHEME DC2

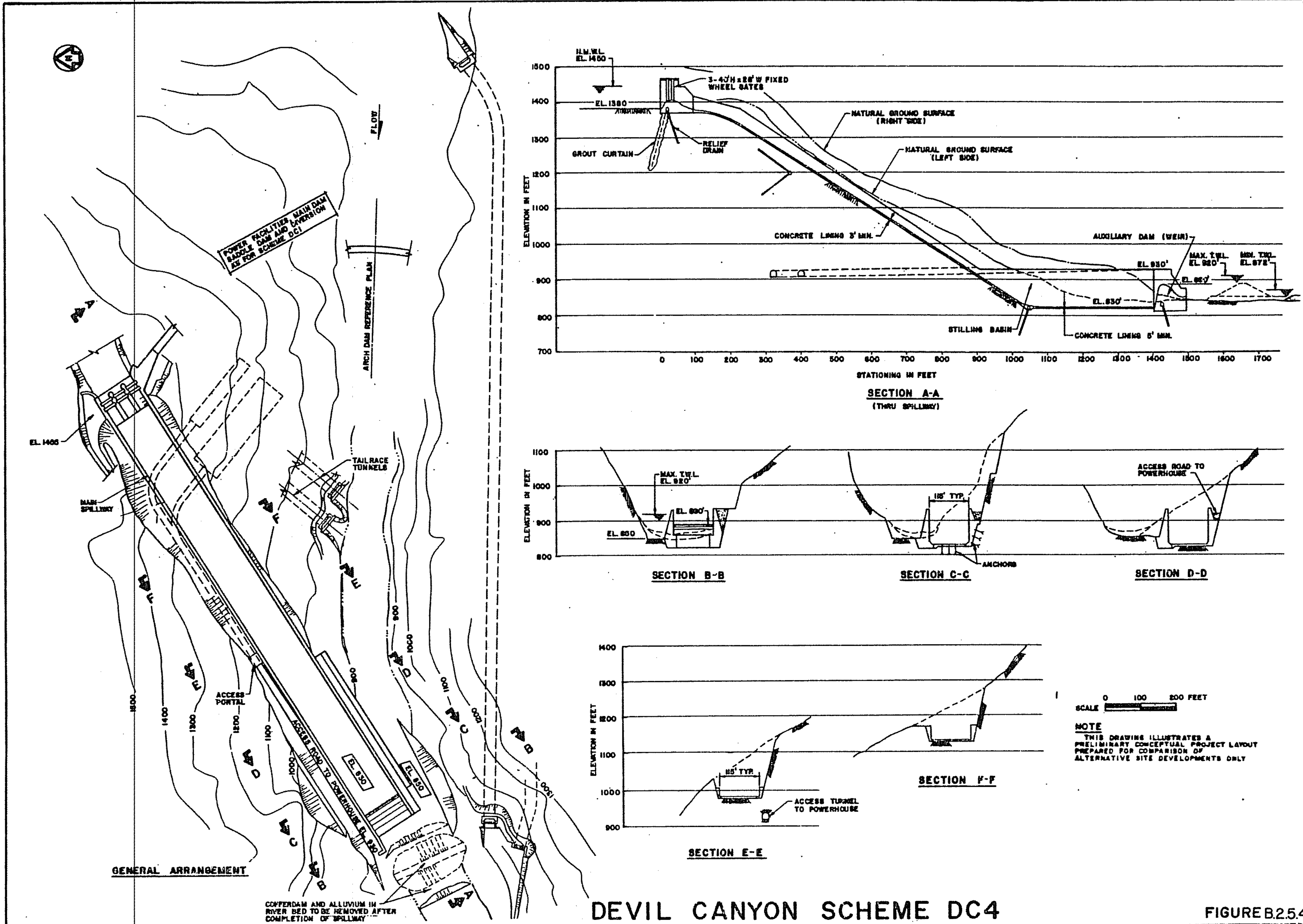
FIGURE B.2.5.2



NOTE
THIS DRAWING ILLUSTRATES A PRELIMINARY CONCEPTUAL PROJECT LAYOUT PREPARED FOR COMPARISON OF ALTERNATIVE SITE DEVELOPMENTS ONLY

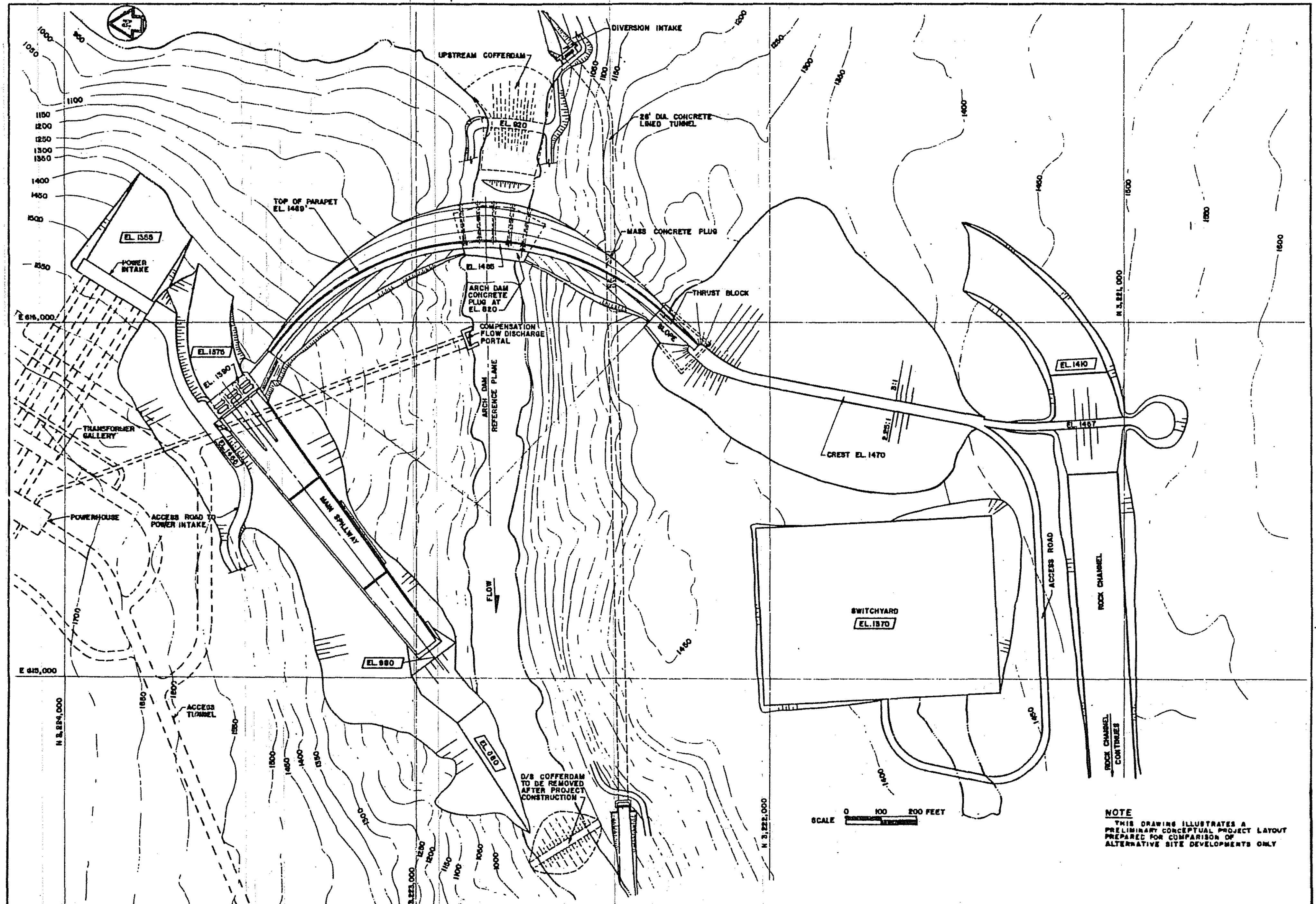
DEVIL CANYON SCHEME DC3

FIGURE B.2.5.3



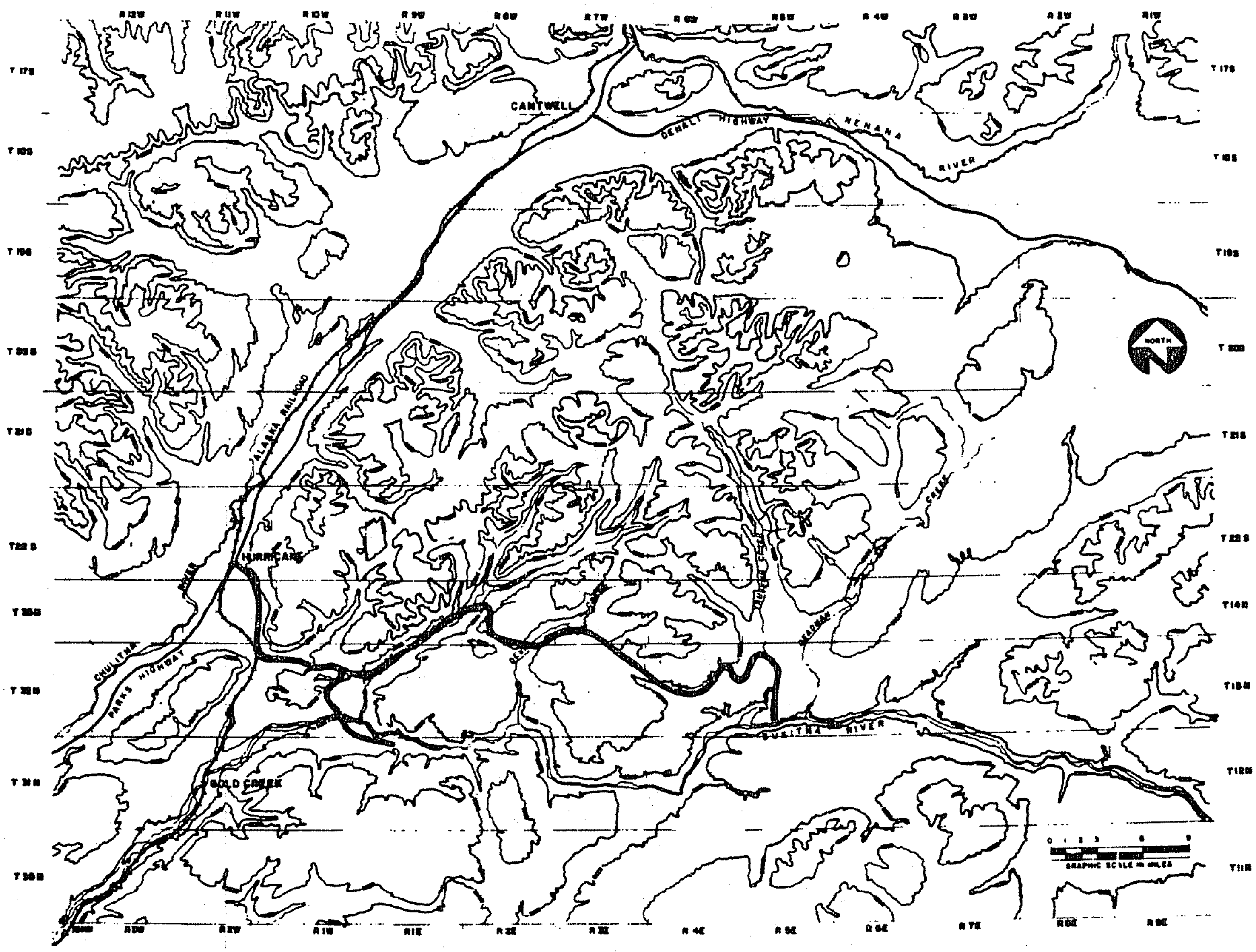
DEVIL CANYON SCHEME DC4

FIGURE B.2.5.4



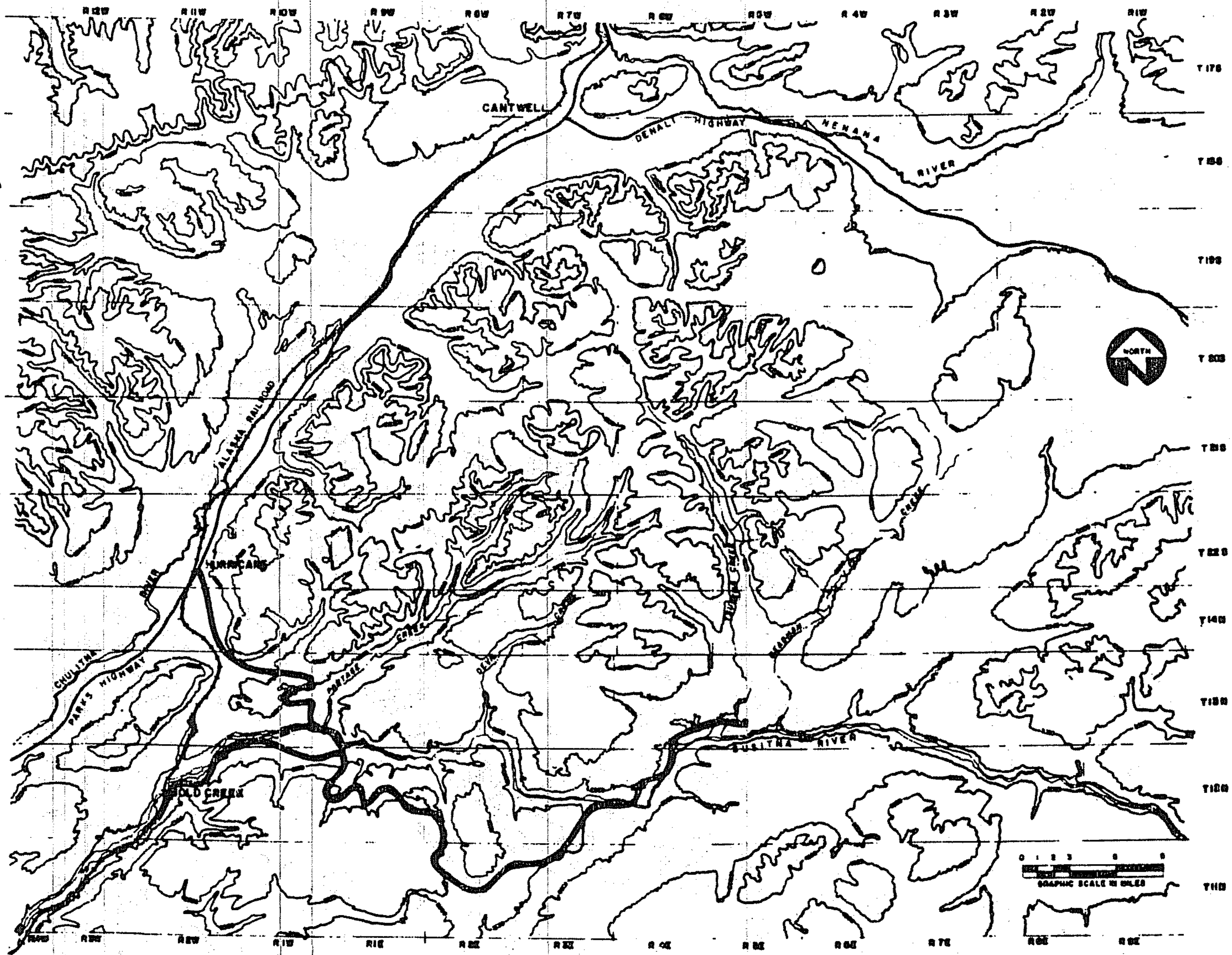
DEVIL CANYON SELECTED SCHEME

FIGURE B.2.55



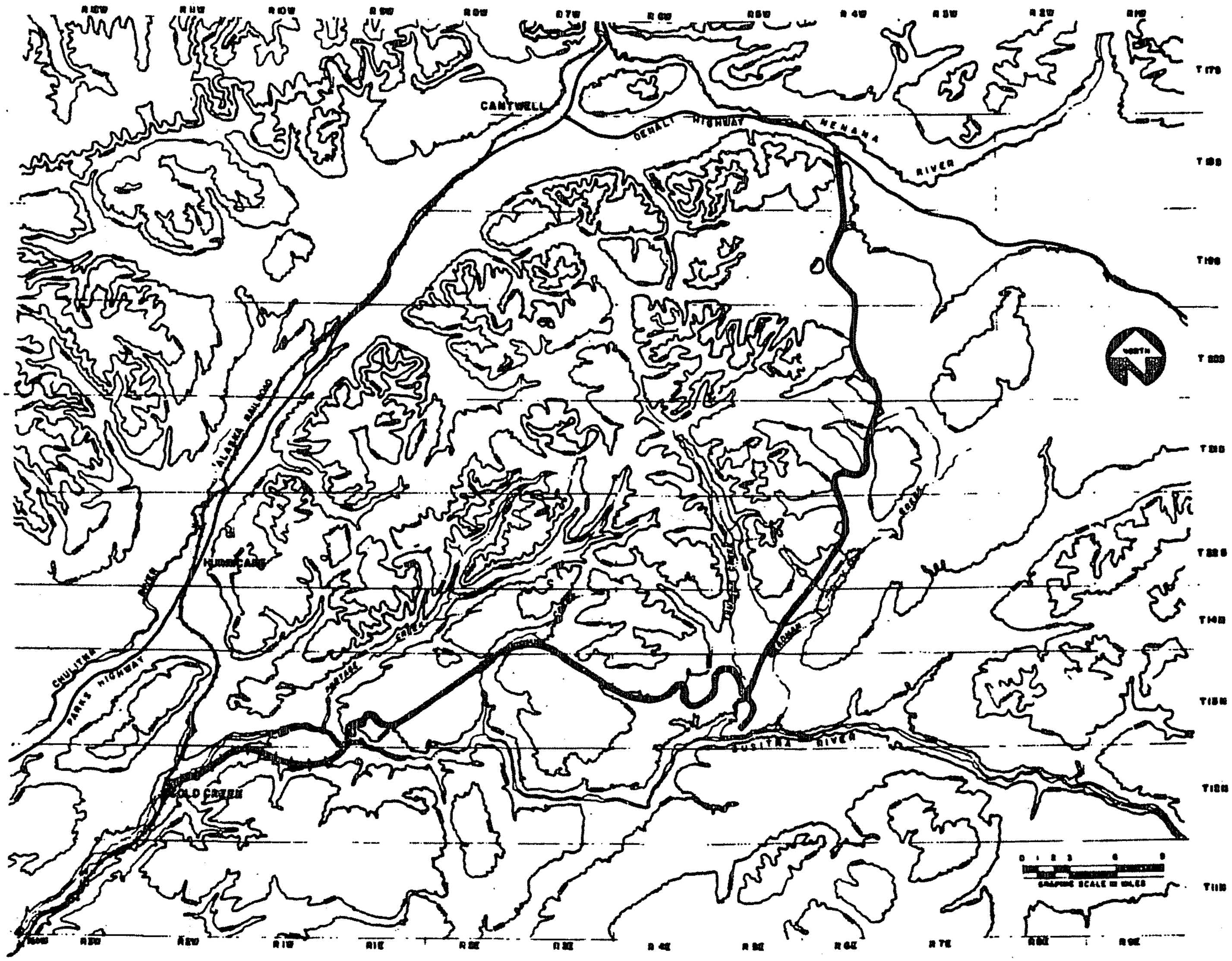
ACCESS PLAN 13 (NORTH)
SUSITNA HYDROELECTRIC PROJECT
ALTERNATIVE ACCESS PLAN

FIGURE B.2.6.2



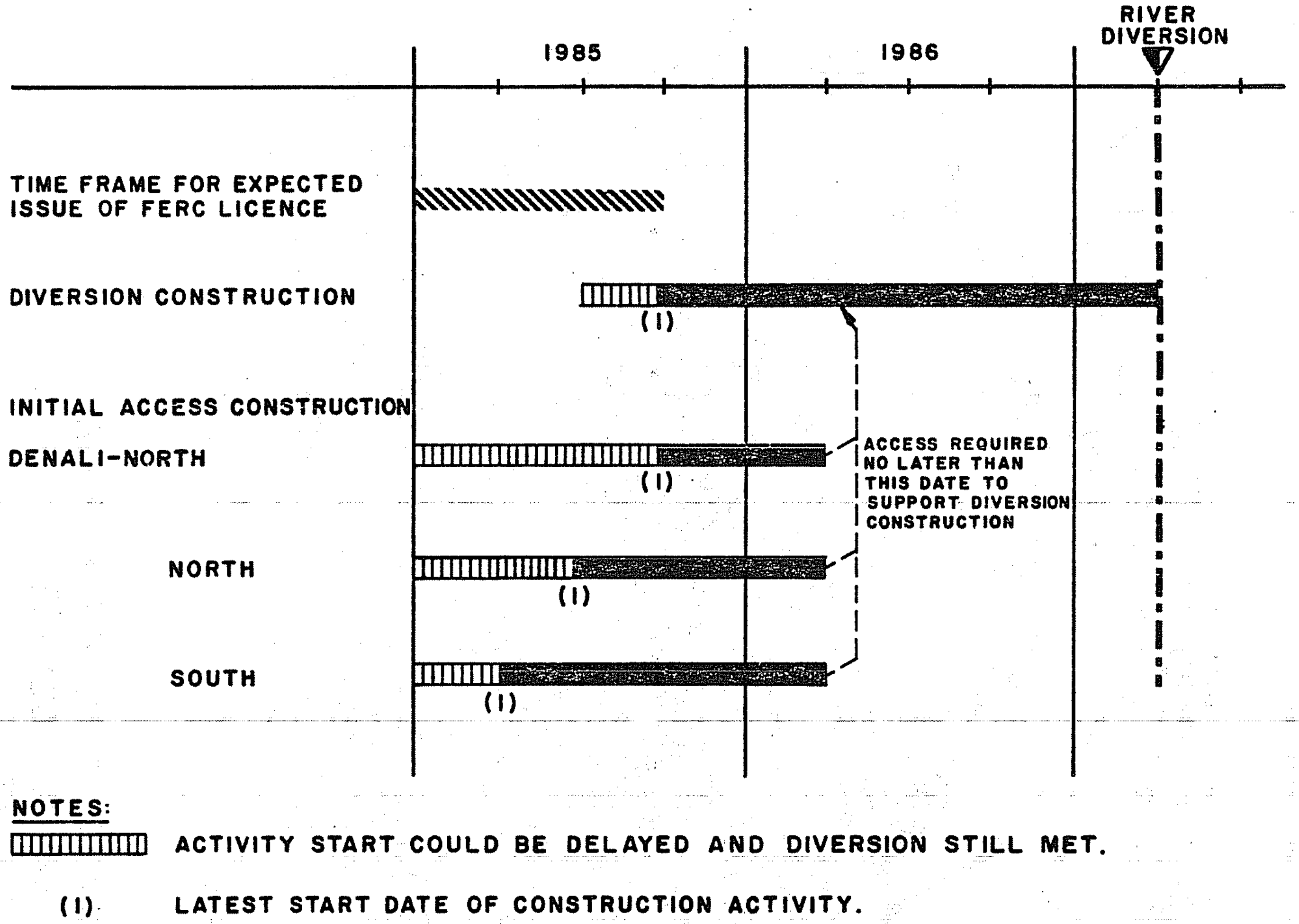
ACCESS PLAN 16 (SOUTH)
SUSITNA HYDROELECTRIC PROJECT
ALTERNATIVE ACCESS PLAN

FIGURE B.263



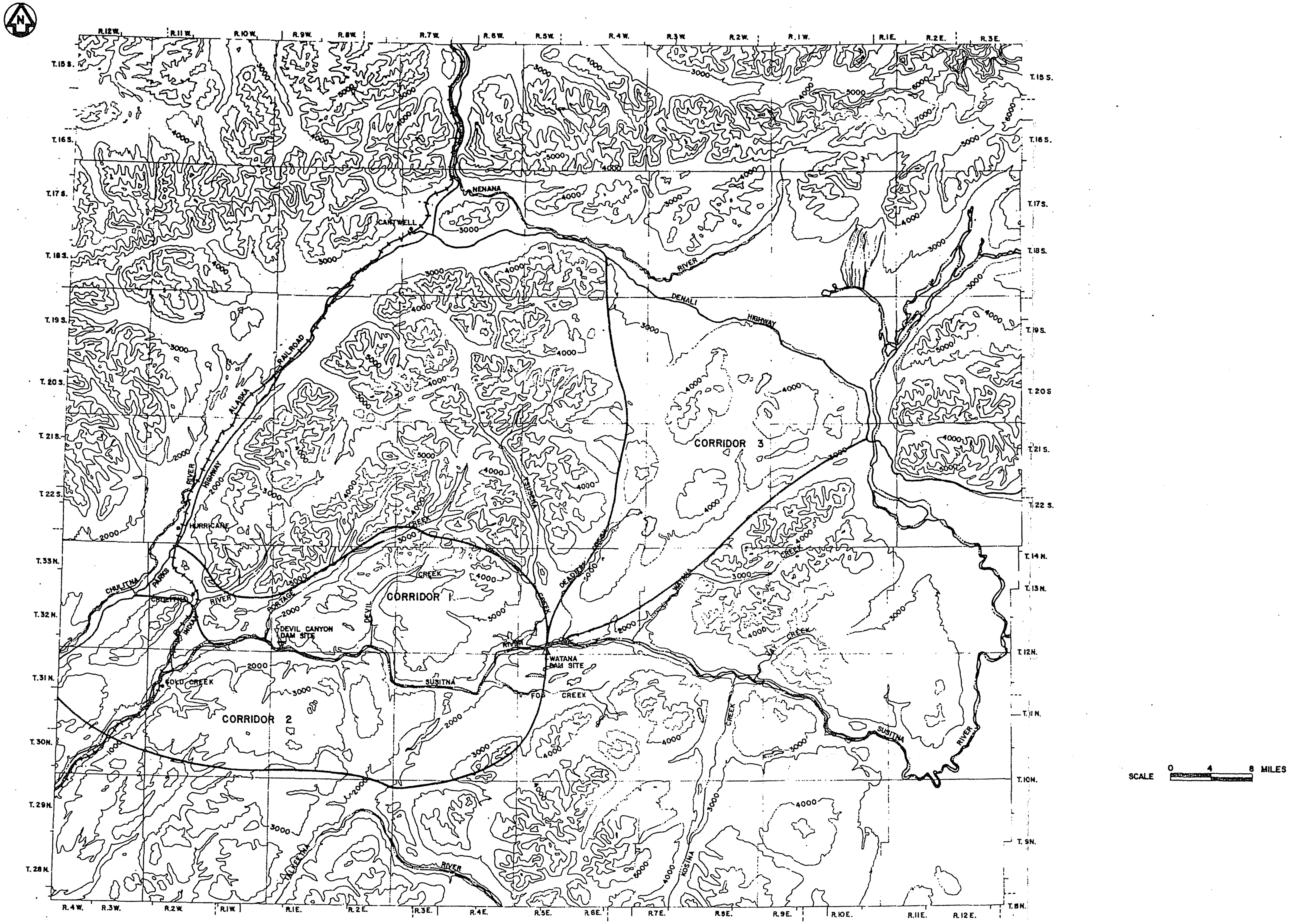
ACCESS PLAN 18 (PROPOSED)
SUSITNA HYDROELECTRIC PROJECT
ALTERNATIVE ACCESS PLAN

FIGURE B.2.64



SCHEDULE FOR ACCESS AND DIVERSION

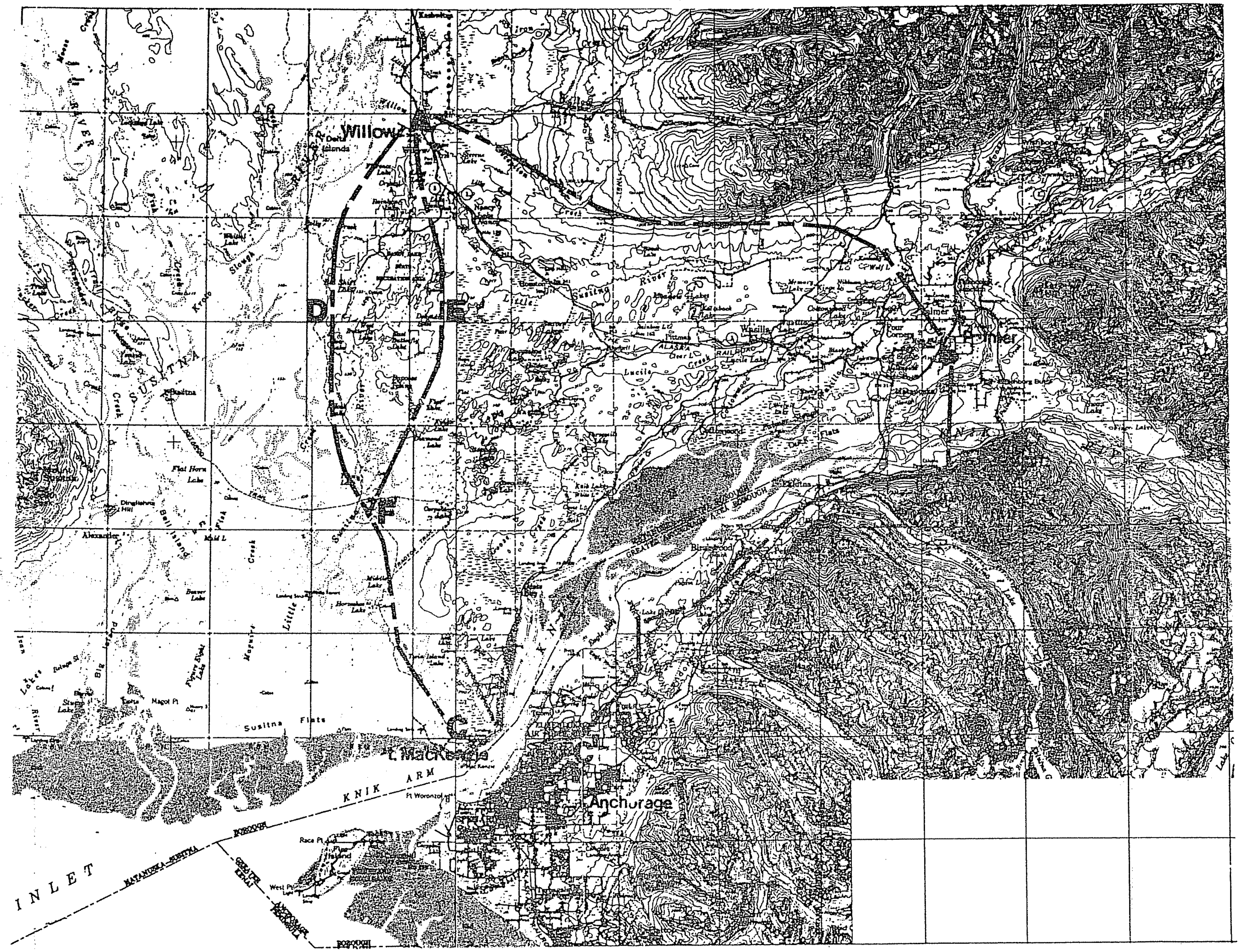
FIGURE B.2.6.5

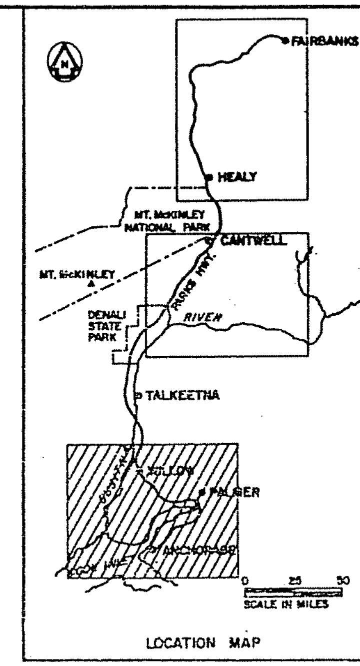


REFERENCE: BASE MAP FROM USGS, 1:250,000
HEALY, ALASKA
TALKEETNA MOUNTAINS, ALASKA

ALTERNATIVE ACCESS CORRIDORS

FIGURE B.2.6.1





LEGEND

STUDY CORRIDOR

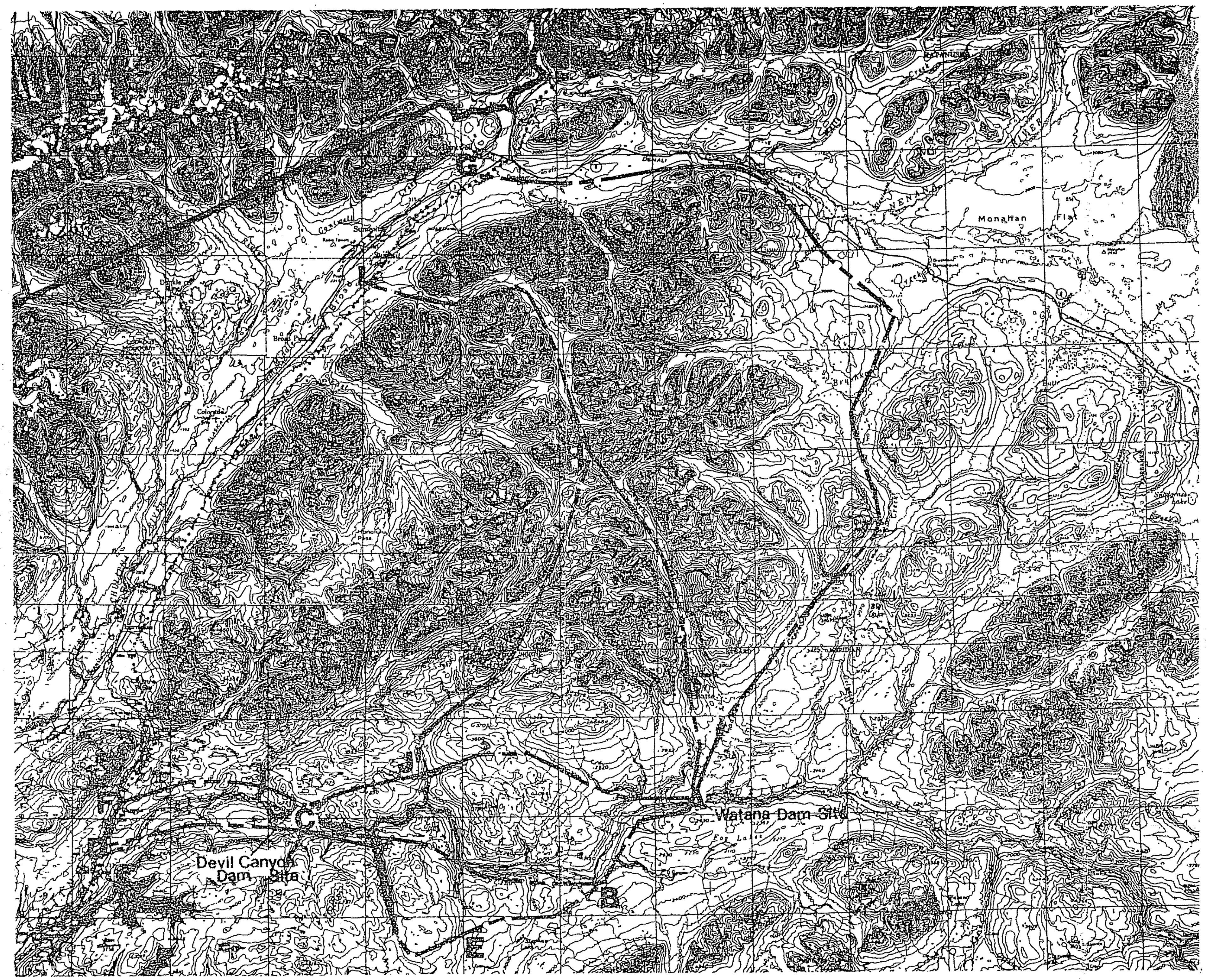
INTERTIE (APPROXIMATE)

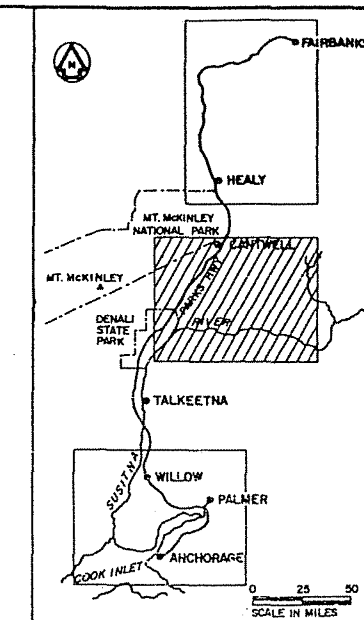
0 5 10

SCALE IN MILES

ALTERNATIVE TRANSMISSION LINE CORRIDORS
SOUTHERN STUDY AREA

FIGURE B.2.7.1





LOCATION MAP

LEGEND

STUDY CORRIDOR

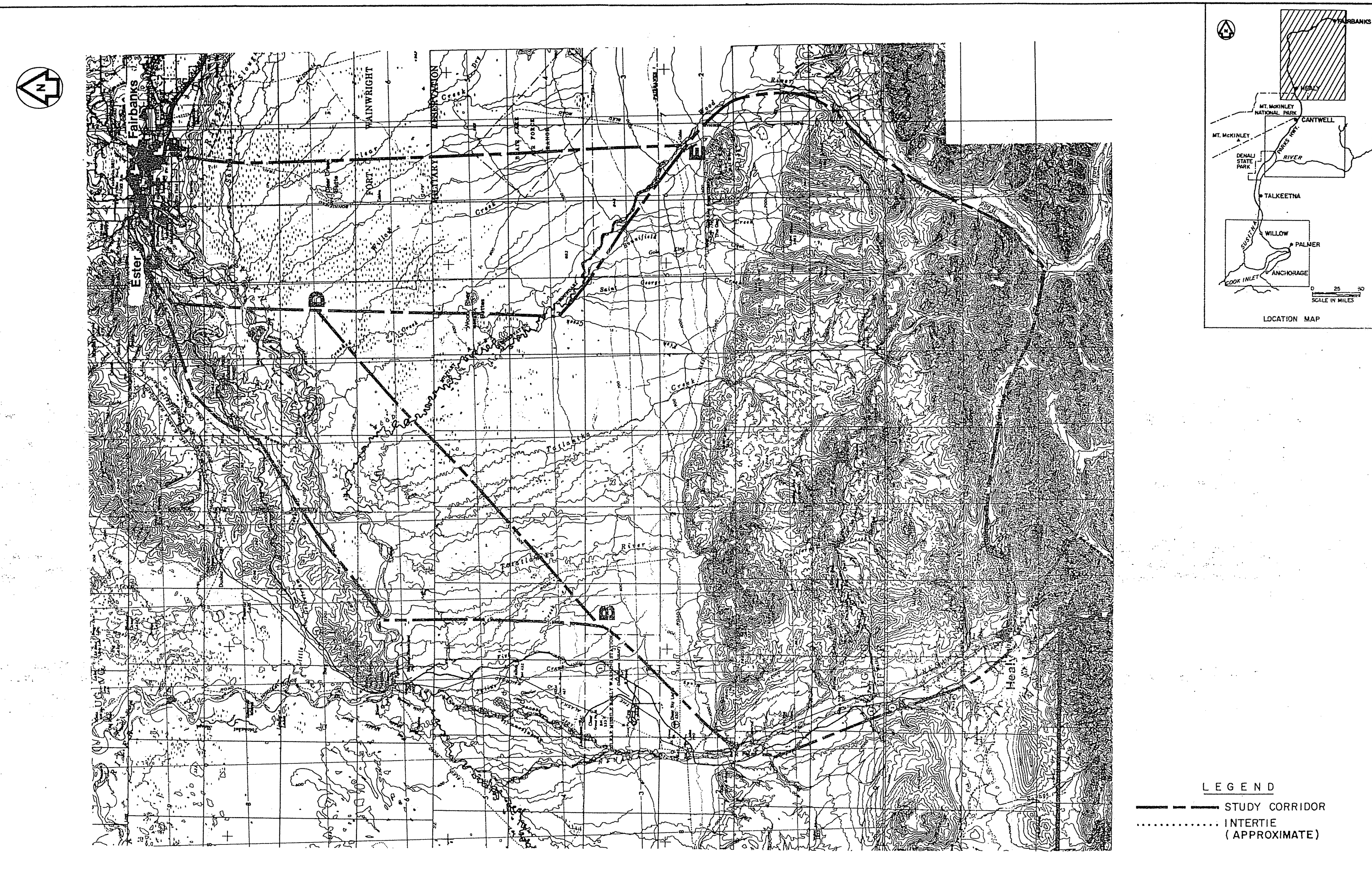
INTERTIE (APPROXIMATE)

0 5 10

SCALE IN MILES

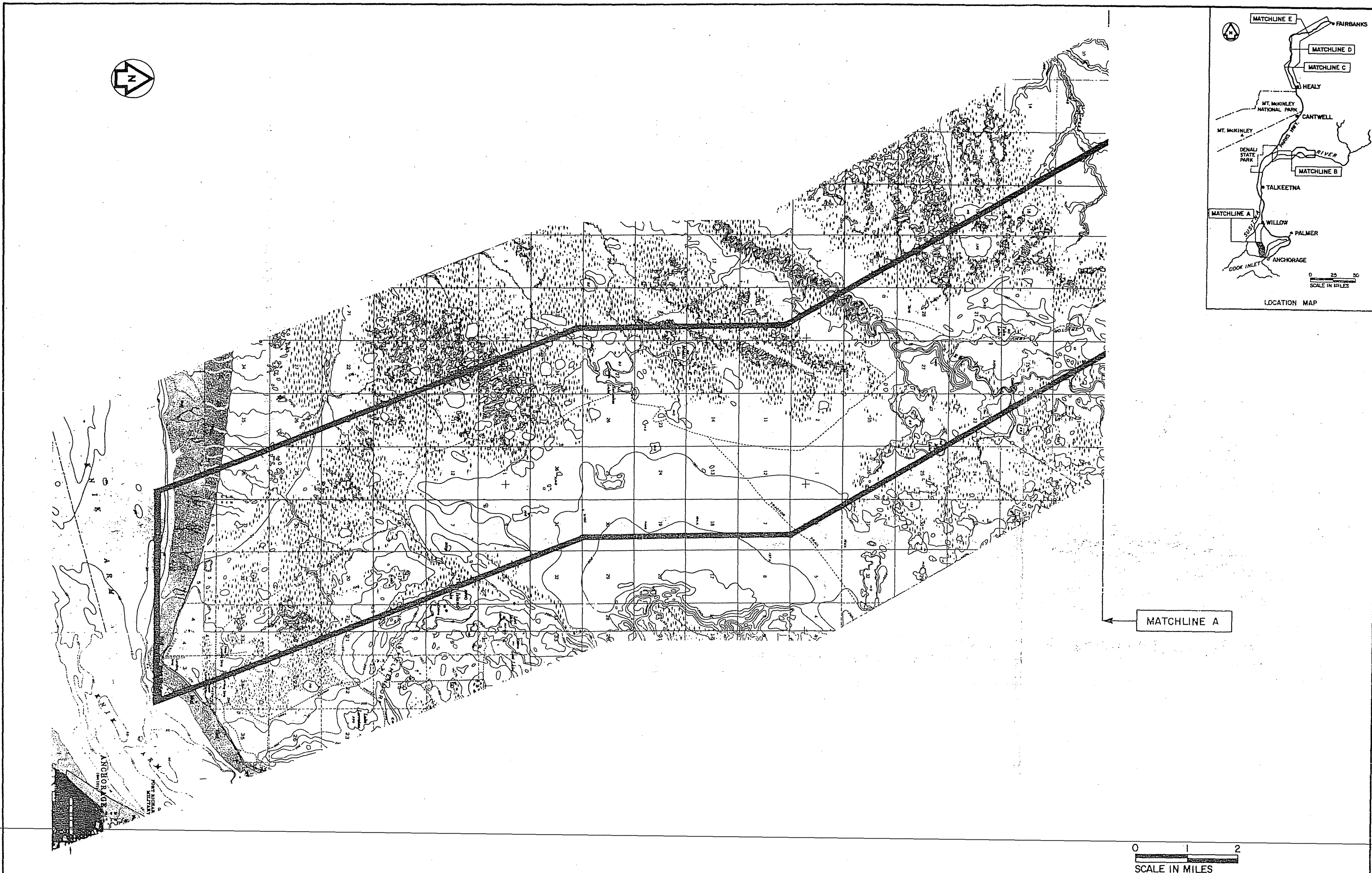
ALTERNATIVE TRANSMISSION LINE CORRIDORS
CENTRAL STUDY AREA

FIGURE B.2.7.2



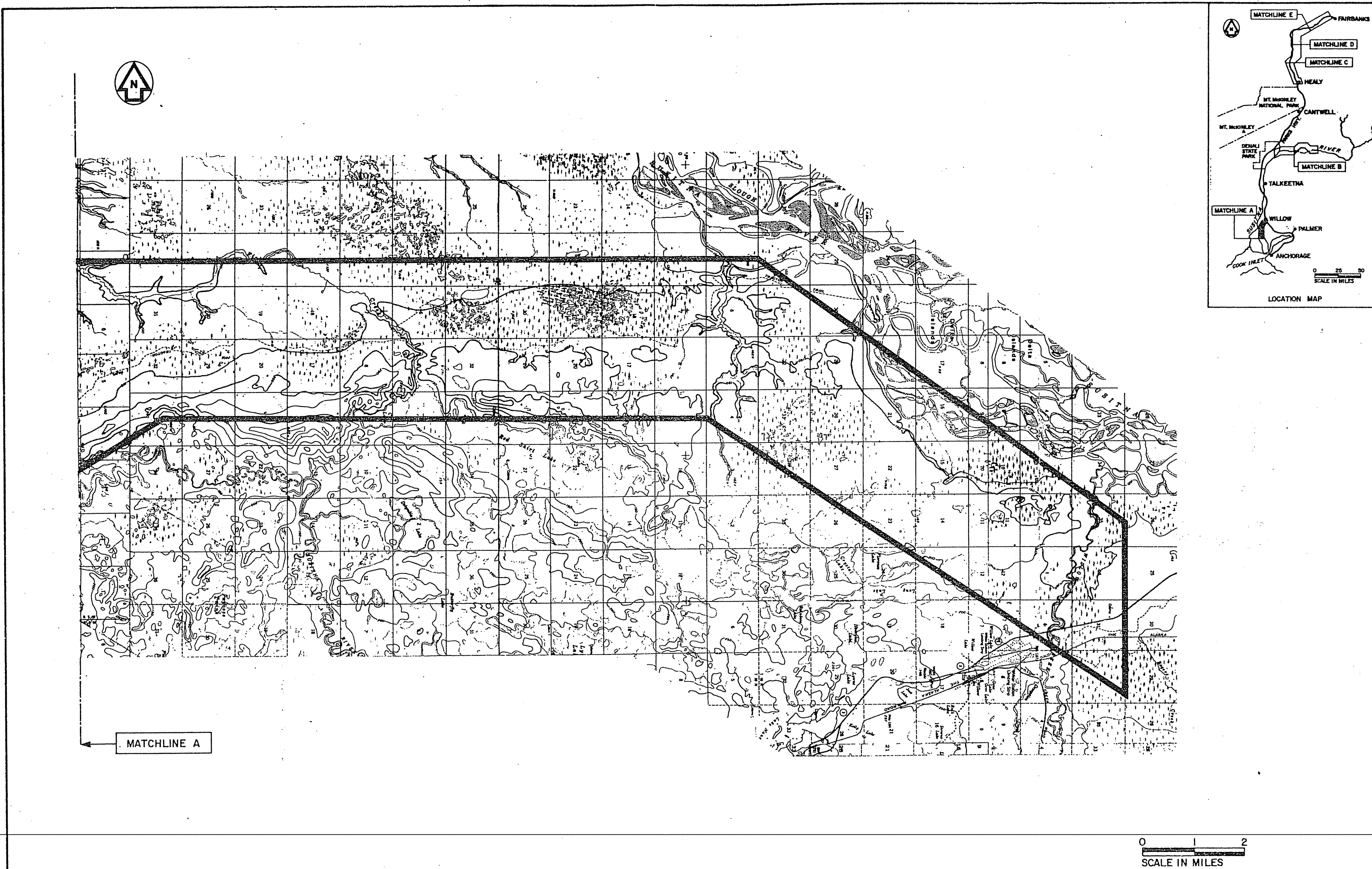
ALTERNATIVE TRANSMISSION LINE CORRIDORS
NORTHERN STUDY AREA

FIGURE B.2.7.3



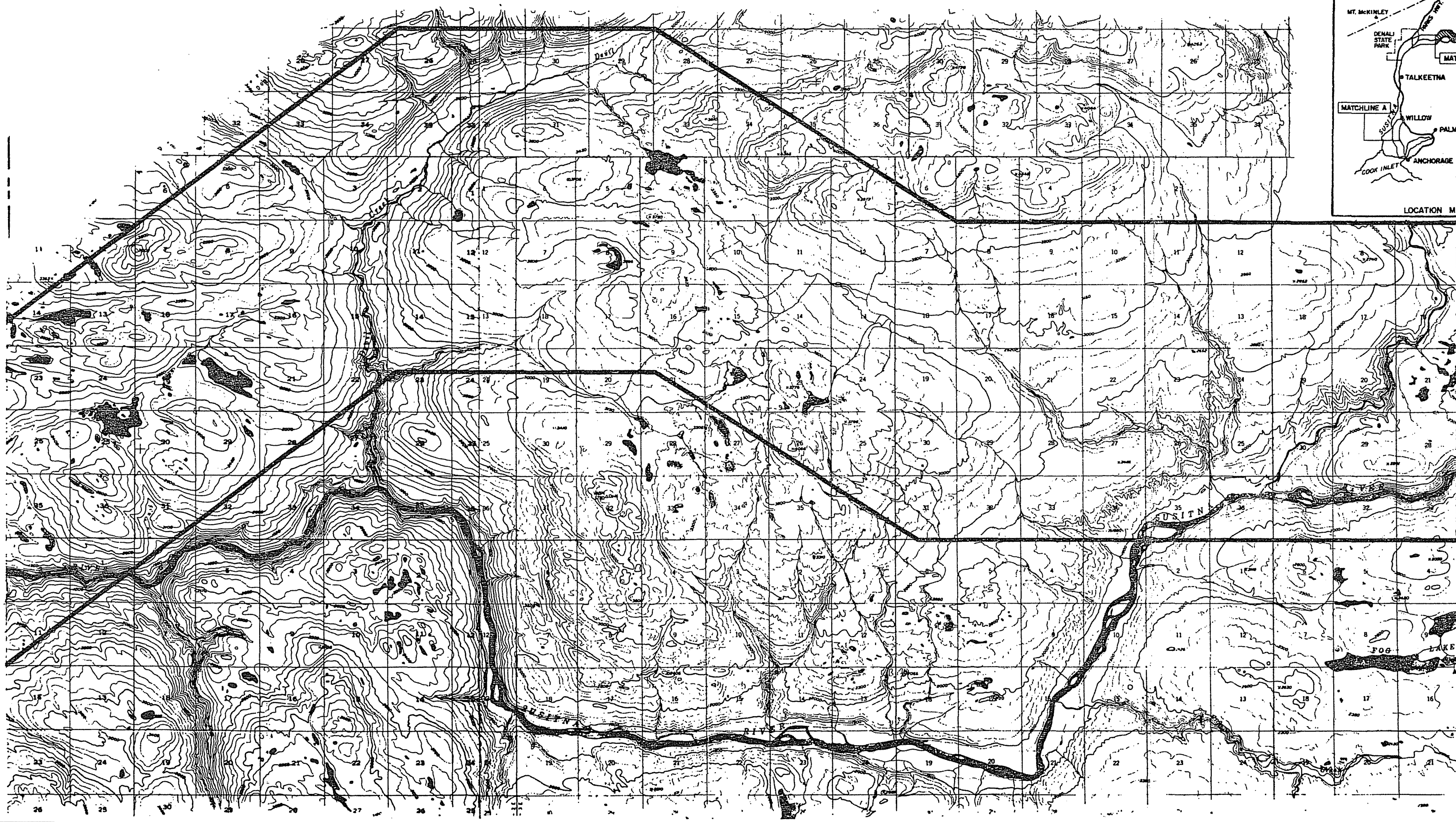
RECOMMENDED TRANSMISSION CORRIDOR
SOUTHERN STUDY AREA

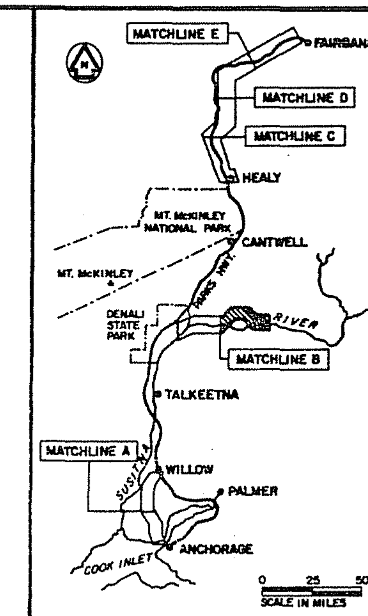
FIGURE B.2.74



RECOMMENDED TRANSMISSION CORRIDOR
SOUTHERN STUDY AREA

FIGURE B2.7.5





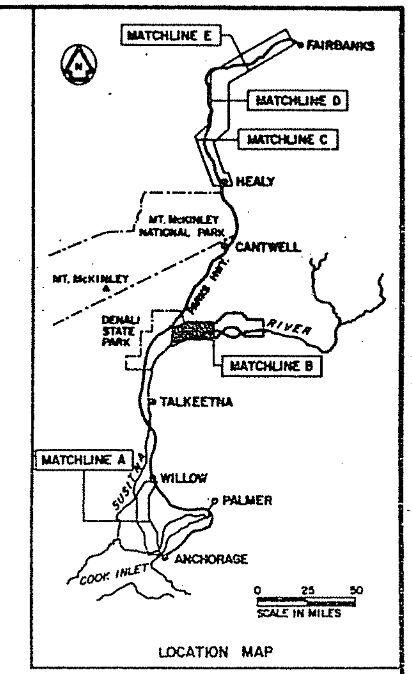
LOCATION MAP

0 1 2
SCALE IN MILES

MATCHLINE B

RECOMMENDED TRANSMISSION CORRIDOR
CENTRAL STUDY AREA

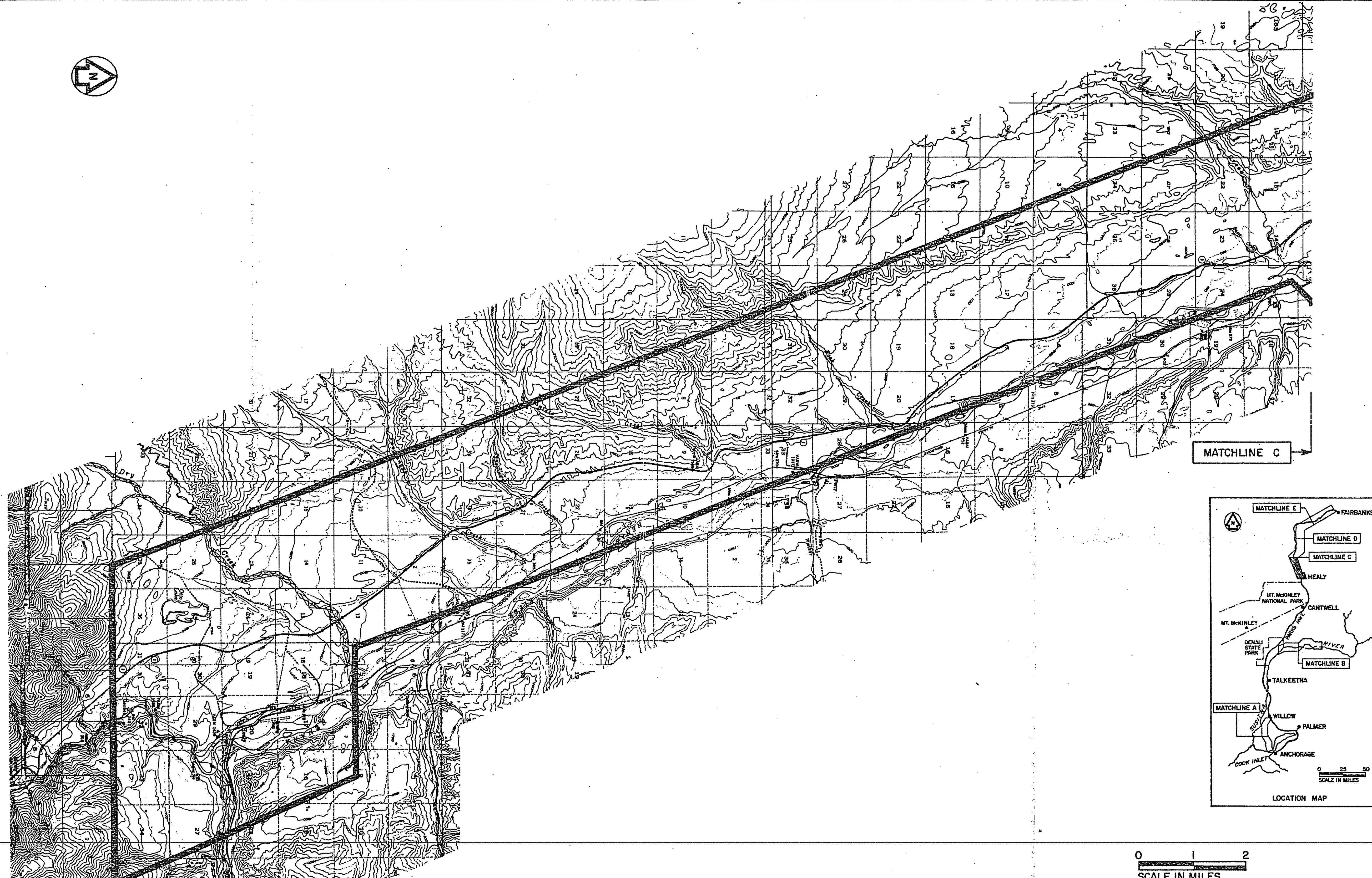
FIGURE B.2.7.6



0 1 2
SCALE IN MILES

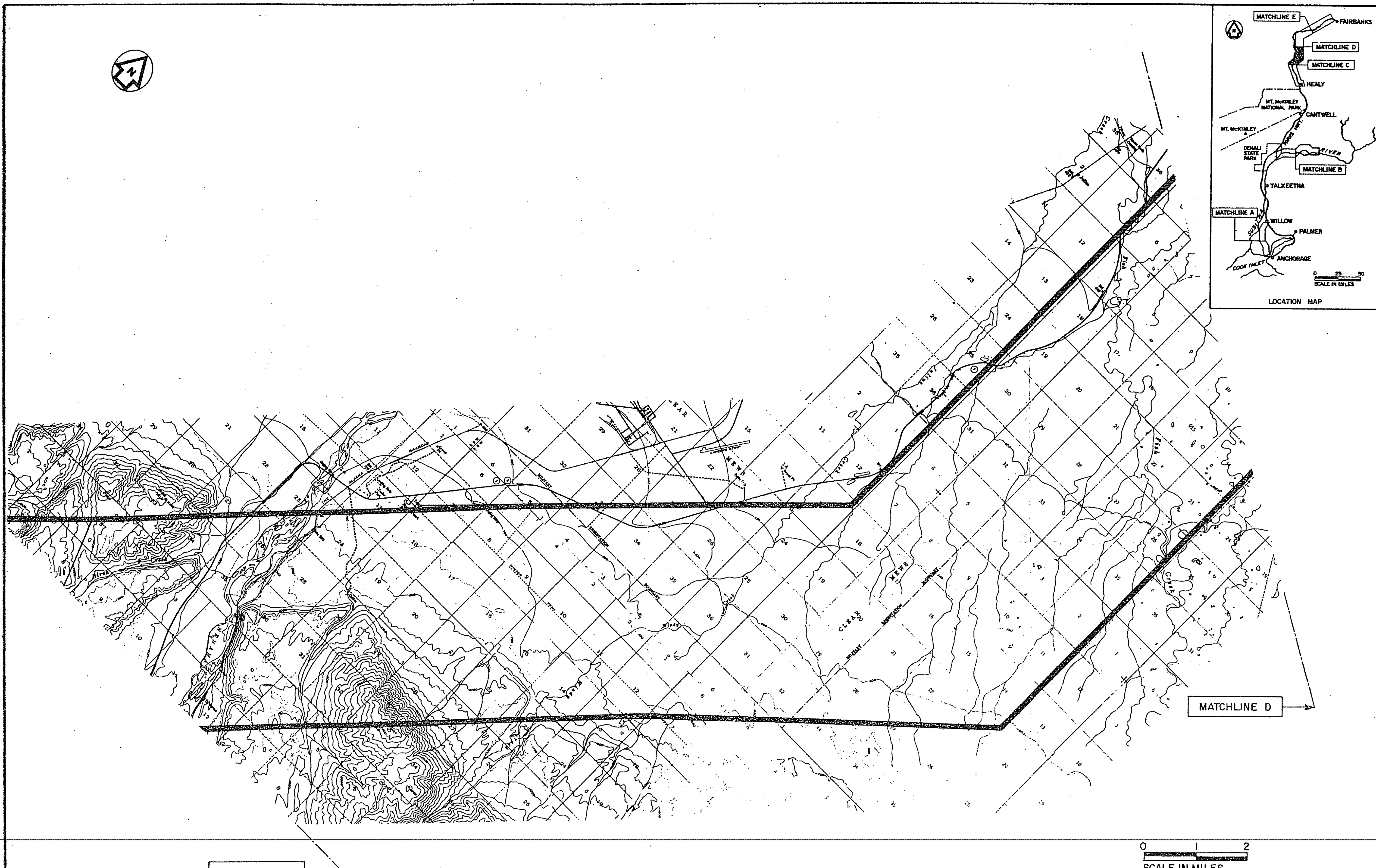
RECOMMENDED TRANSMISSION CORRIDOR
CENTRAL STUDY AREA

FIGURE B.277



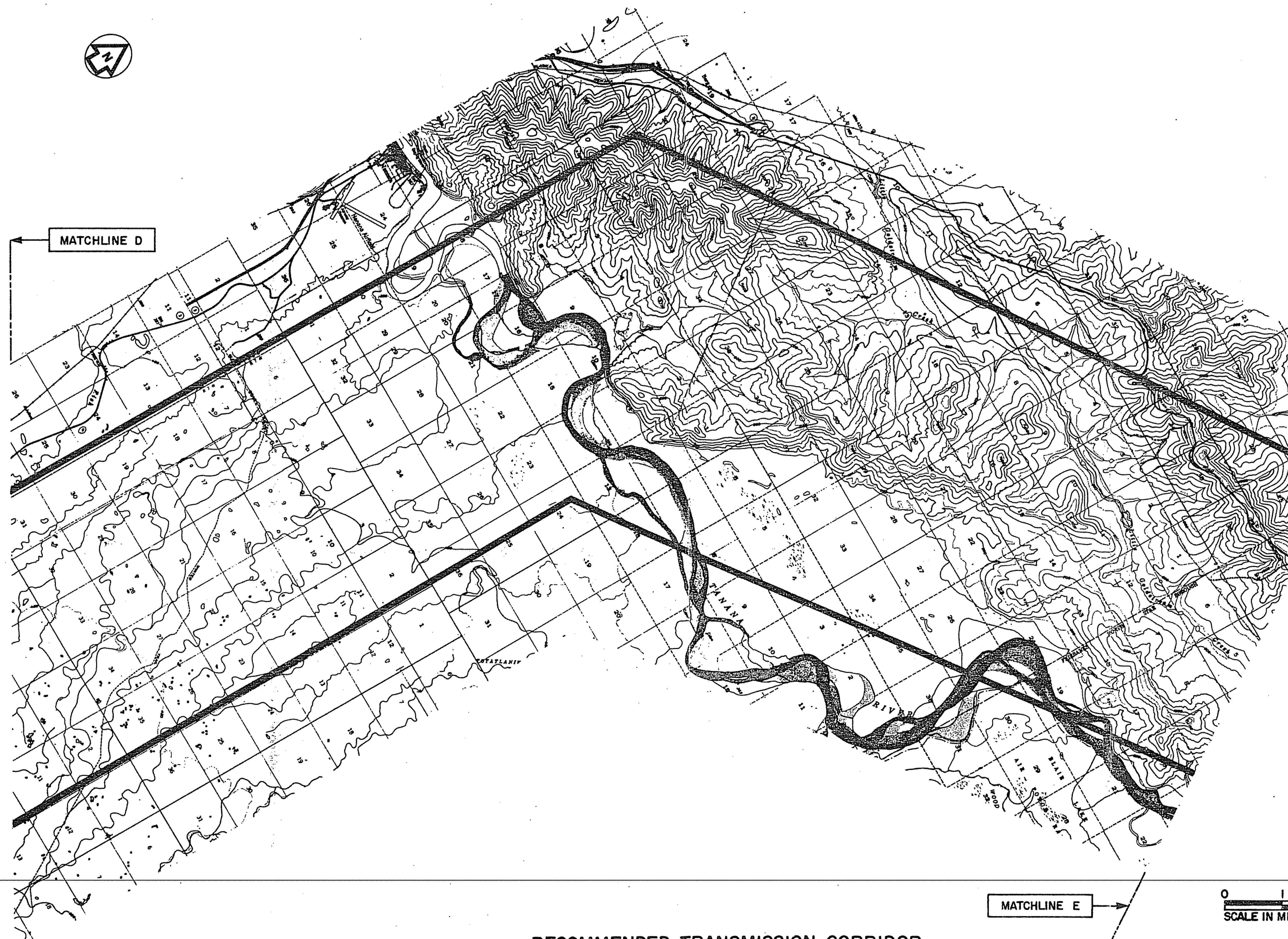
RECOMMENDED TRANSMISSION CORRIDOR
NORTHERN STUDY AREA

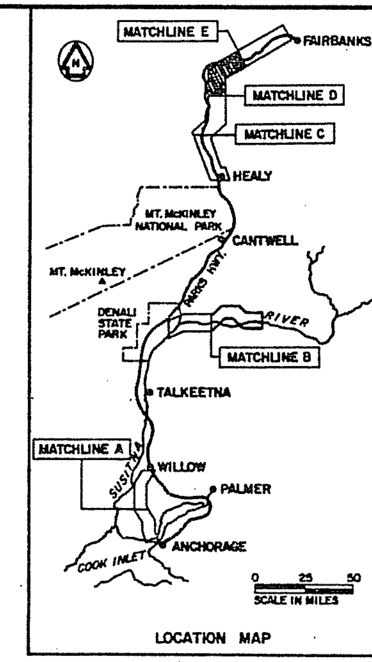
FIGURE B.2.78



RECOMMENDED TRANSMISSION CORRIDOR
NORTHERN STUDY AREA

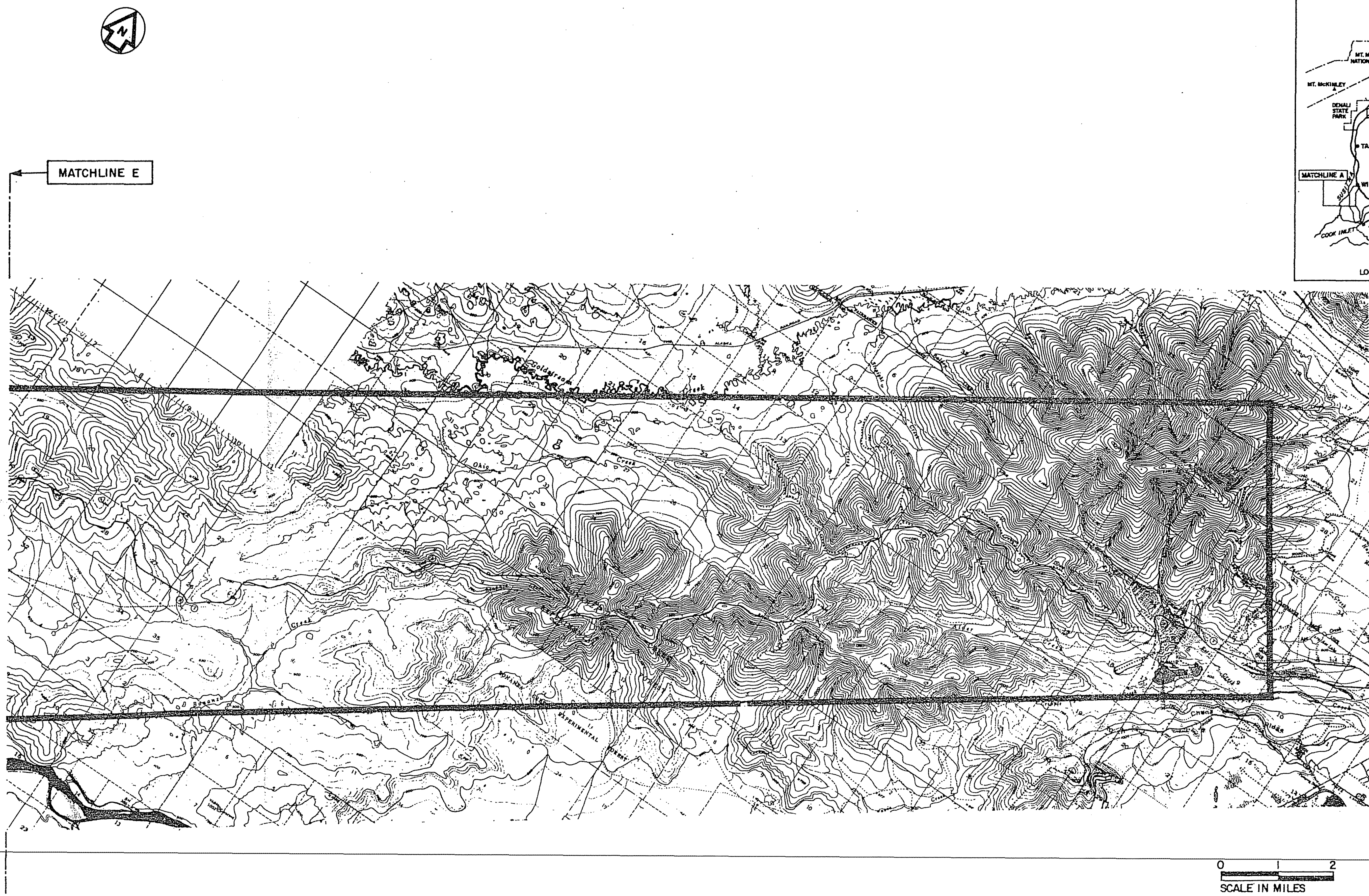
FIGURE B.2.7.9

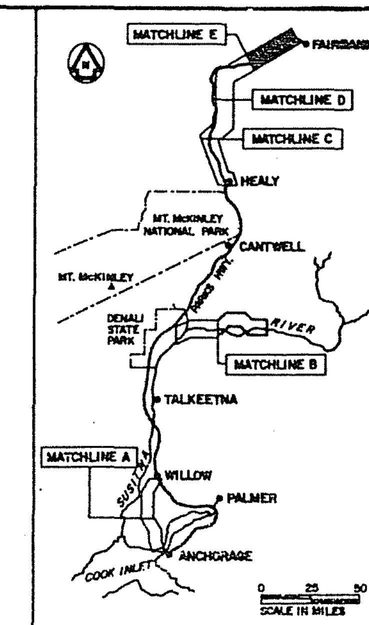




RECOMMENDED TRANSMISSION CORRIDOR
NORTHERN STUDY AREA

FIGURE B.2.7.10

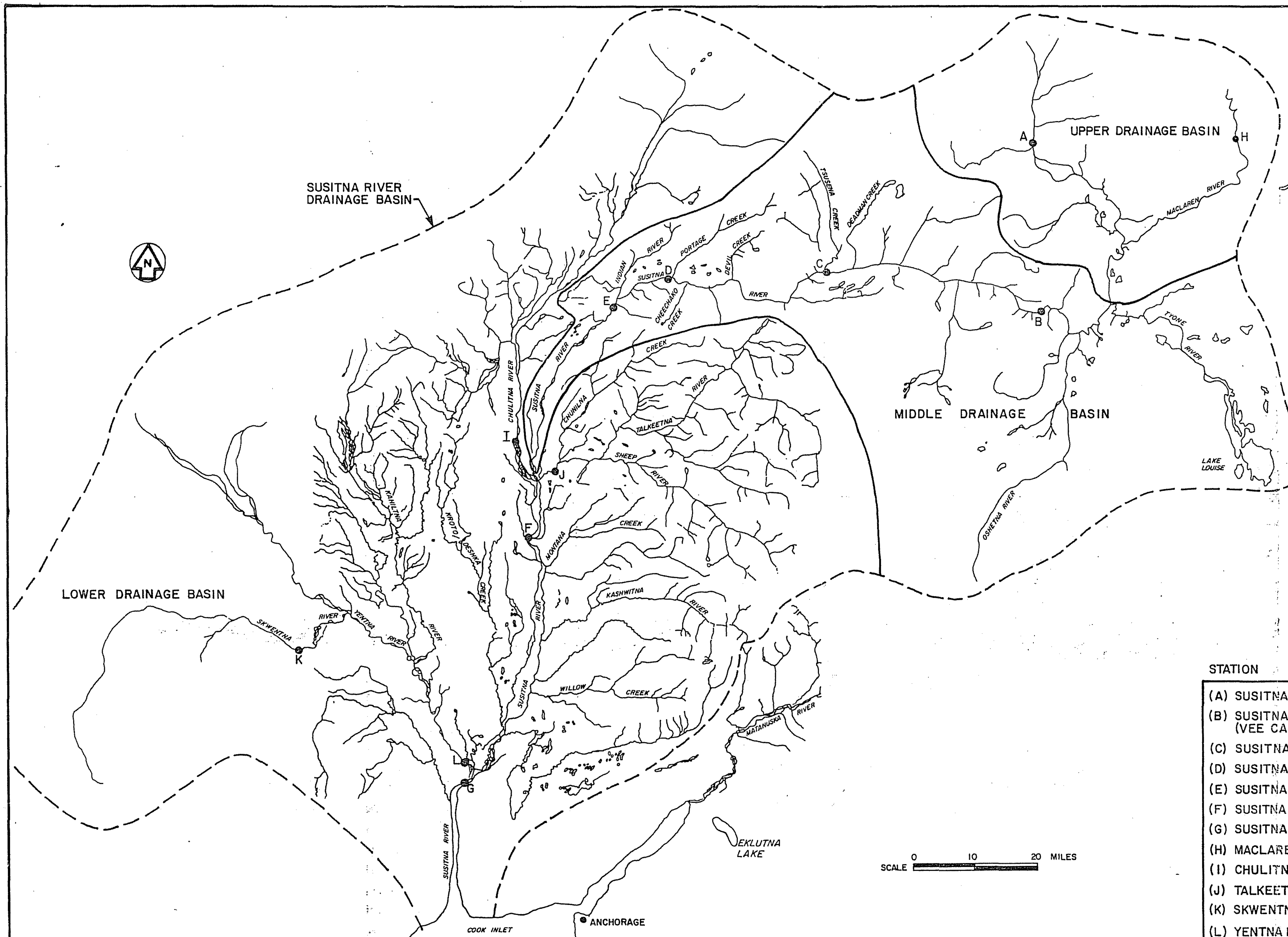




LOCATION MAP

RECOMMENDED TRANSMISSION CORRIDOR
NORTHERN STUDY AREA

FIGURE B.2.7.11



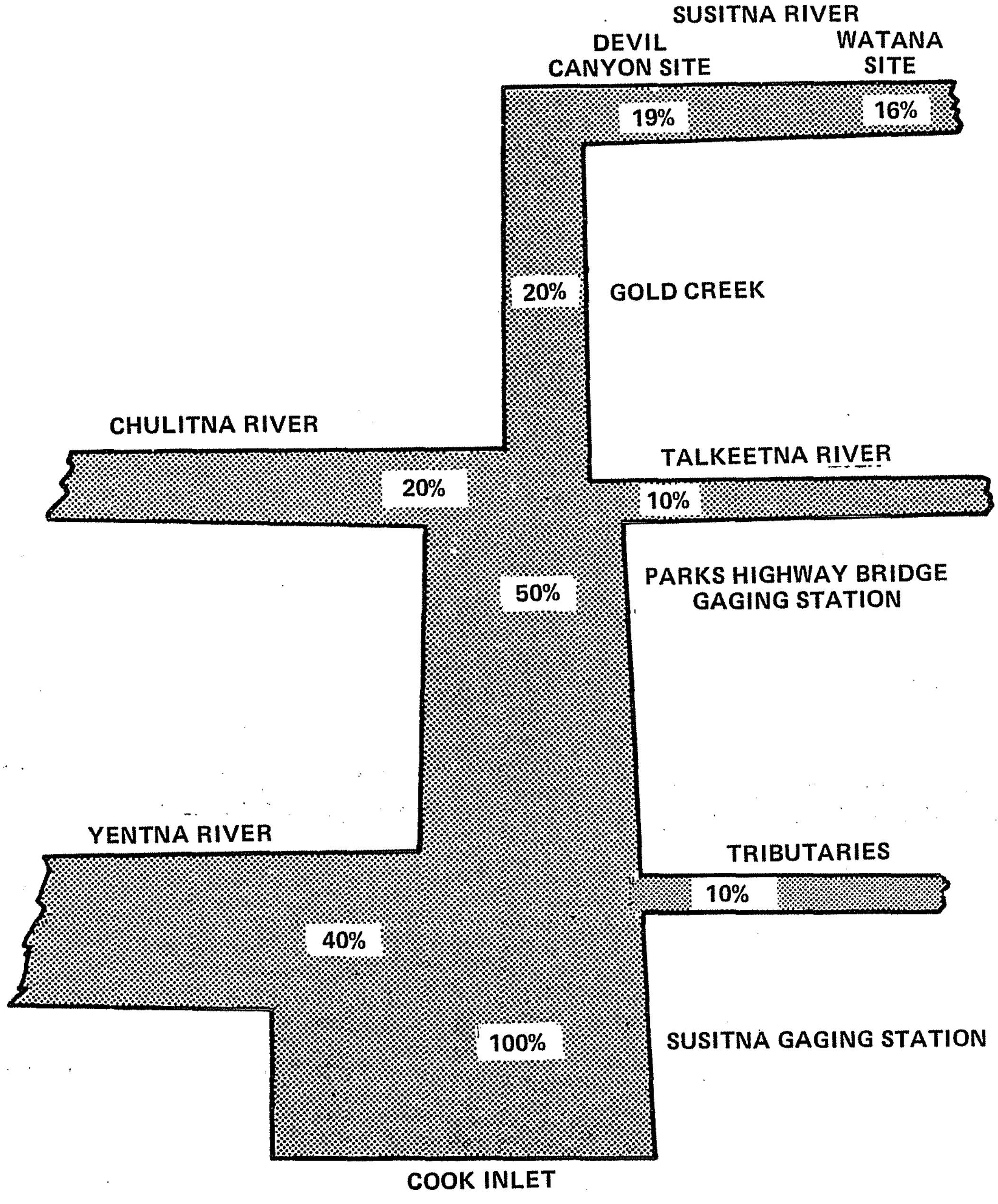
NOTES:

1. CONTINUOUS WATER QUALITY MONITOR INSTALLED.
2. DATA COLLECTION(JUL-SEP 1981 AND JUN-SEP 1982.)
3. THE LETTER BEFORE EACH STATION NAME IN THE TABLE IS USED ON THE MAP TO MARK THE APPROXIMATE LOCATION OF THE STATIONS.

STATION	STREAMFLOW GAGING	CREST STAGE GAGE	STAFF GAGE	WATER QUALITY	WATER TEMPERATURE	SEDIMENT DISCHARGE	BEDLOAD SAMPLING[2]	CLIMATE
(A) SUSITNA RIVER NEAR DENALI	X		X		X	X		X
(B) SUSITNA RIVER NEAR CANTWELL (VEE CANYON)	X		X	X	X	X		
(C) SUSITNA RIVER NEAR WATANA DAMSITE	X	X		X[1]	X			X
(D) SUSITNA RIVER NEAR DEVIL CANYON		X	X					X
(E) SUSITNA RIVER AT GOLD CREEK	X			X	X	X	X	
(F) SUSITNA RIVER NEAR SUNSHINE	X				X	X	X	
(G) SUSITNA RIVER AT SUSITNA STATION	X			X	X	X		
(H) MACLAREN RIVER NEAR PAXSON	X							
(I) CHULITNA RIVER NEAR TALKEETNA	X				X	X	X	
(J) TALKEETNA RIVER NEAR TALKEETNA	X			X	X	X	X	
(K) SKWENTNA RIVER NEAR SKWENTNA	X			X	X	X		X
(L) YENTNA RIVER NEAR SUSITNA STATION	X				X	X		

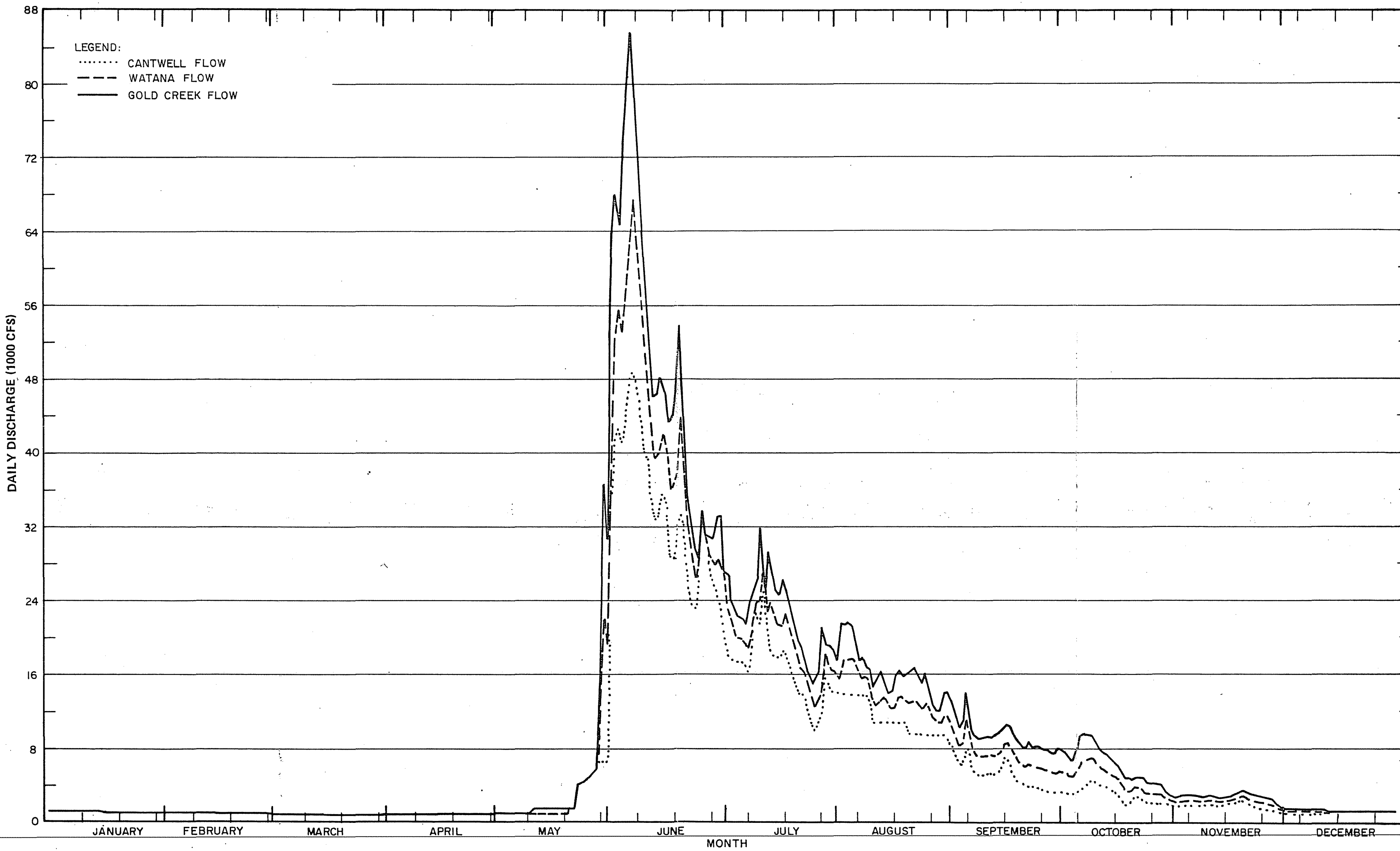
STREAMFLOW GAGING AND WATER QUALITY MONITORING STATIONS

FIGURE B.3.1.1



AVERAGE ANNUAL FLOW DISTRIBUTION WITHIN THE SUSITNA RIVER BASIN

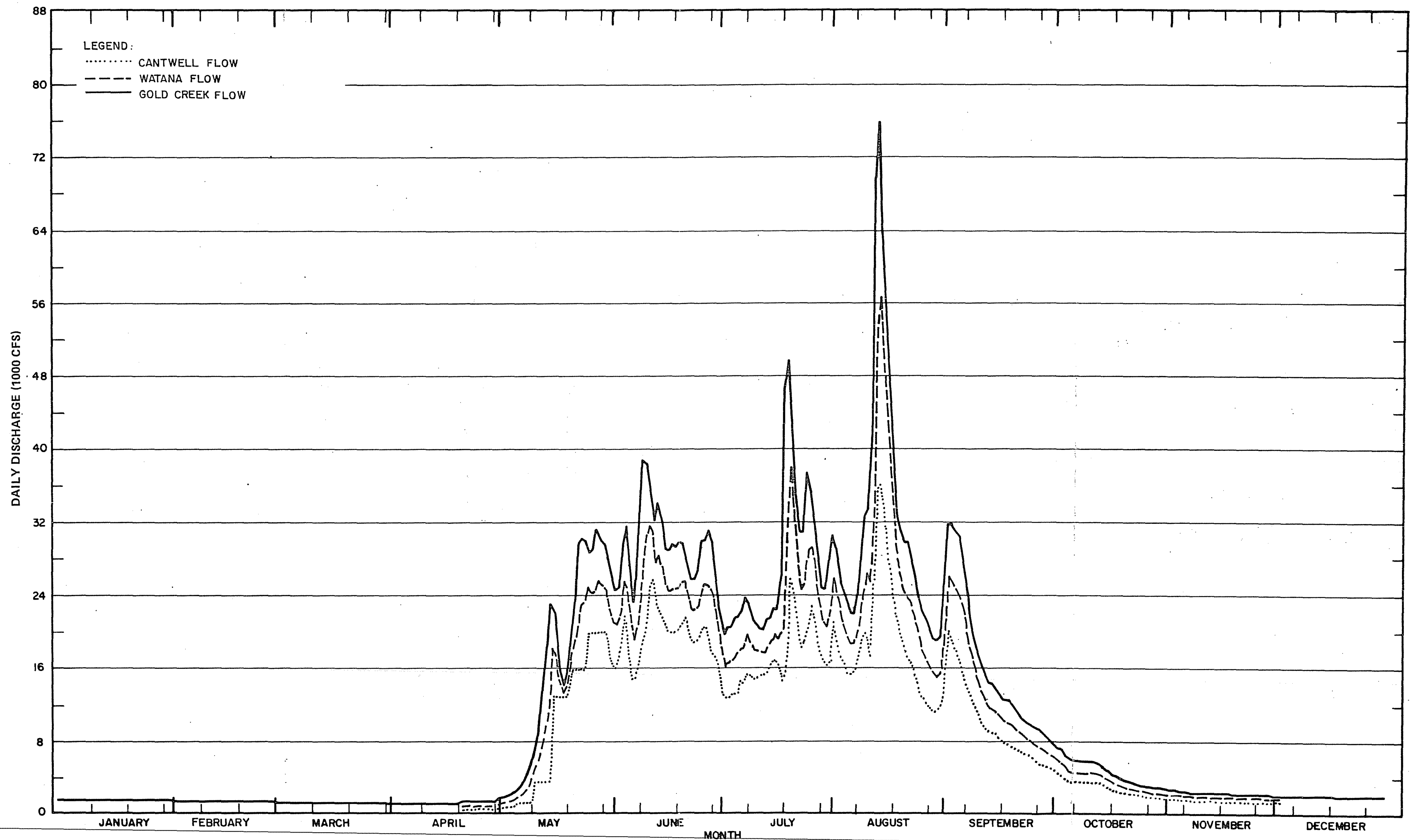
FIGURE B.3.1.2



NOTE:
TIME SCALE IS IN INCREMENTS OF 10 DAYS.

DAILY DISCHARGE HYDROGRAPHS
1964 NATURAL FLOWS
CANTWELL, WATANA AND GOLD CREEK

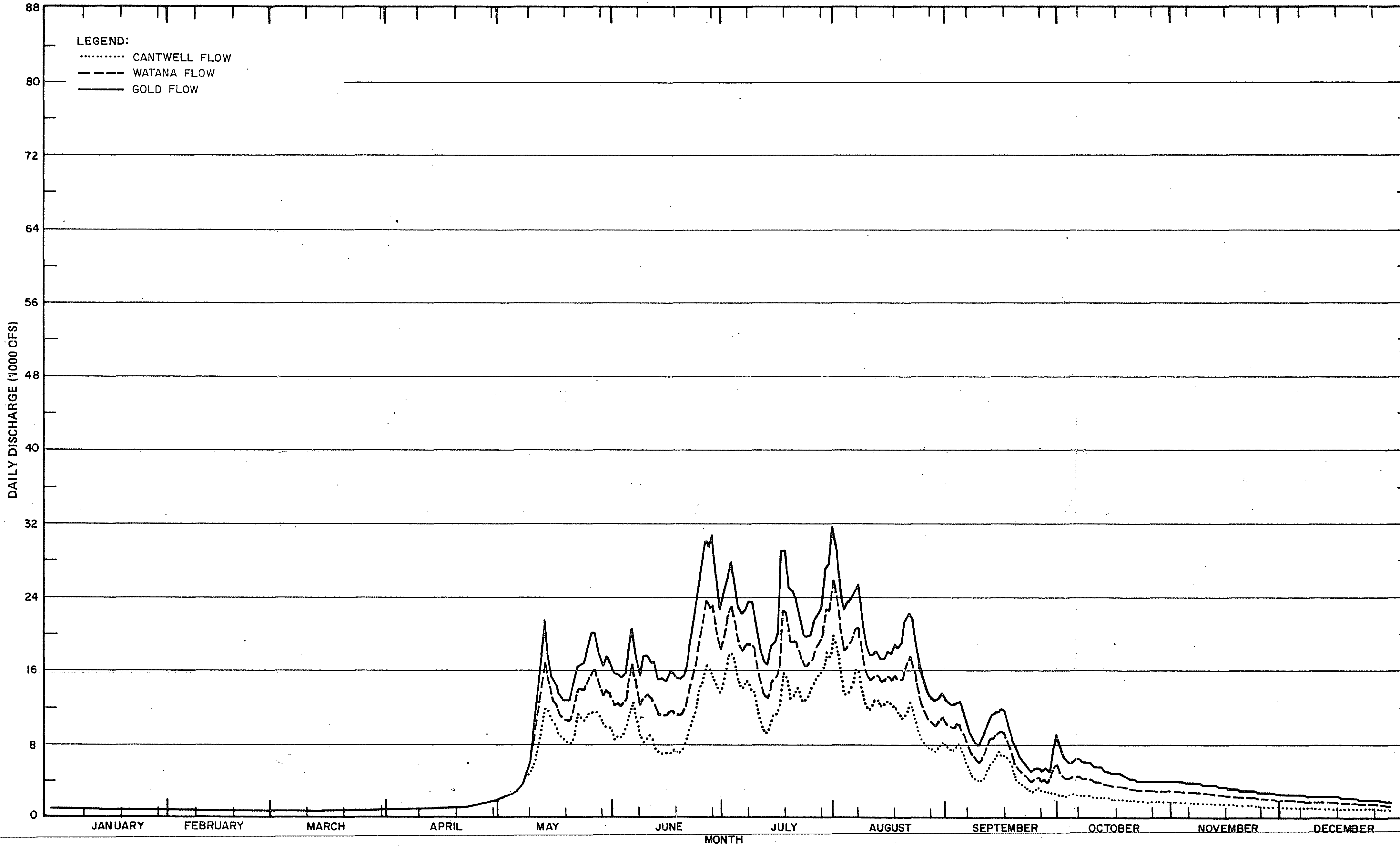
FIGURE B.3.1.3



NOTE:
TIME SCALE IS IN INCREMENTS OF 10 DAYS.

DAILY DISCHARGE HYDROGRAPHS
1967 NATURAL FLOWS
CANTWELL, WATANA AND GOLD CREEK

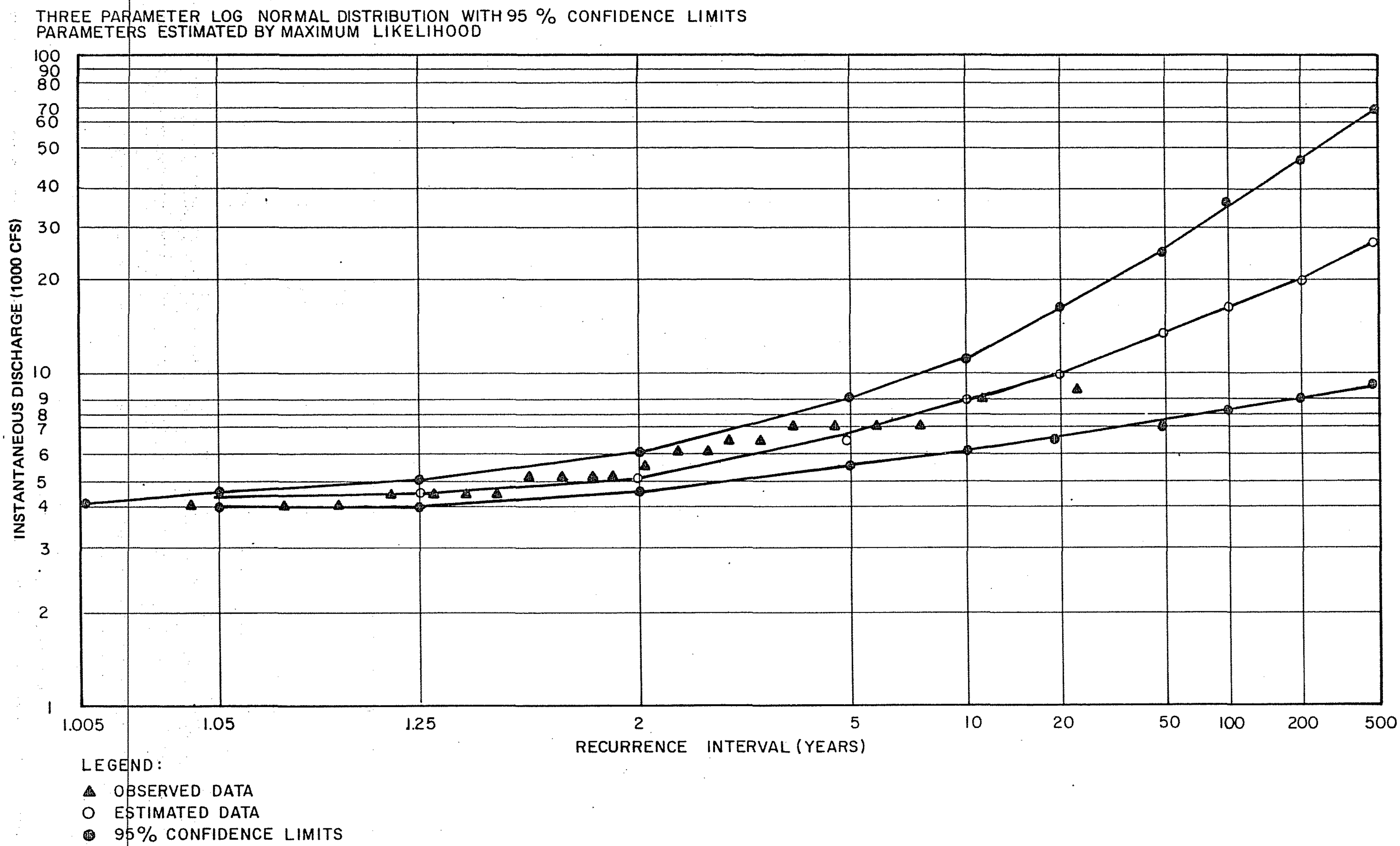
FIGURE B.3.1.4



NOTE:
TIME SCALE IS IN INCREMENTS OF 10 DAYS.

DAILY DISCHARGE HYDROGRAPHS
1970 NATURAL FLOWS
CANTWELL, WATANA AND GOLD CREEK

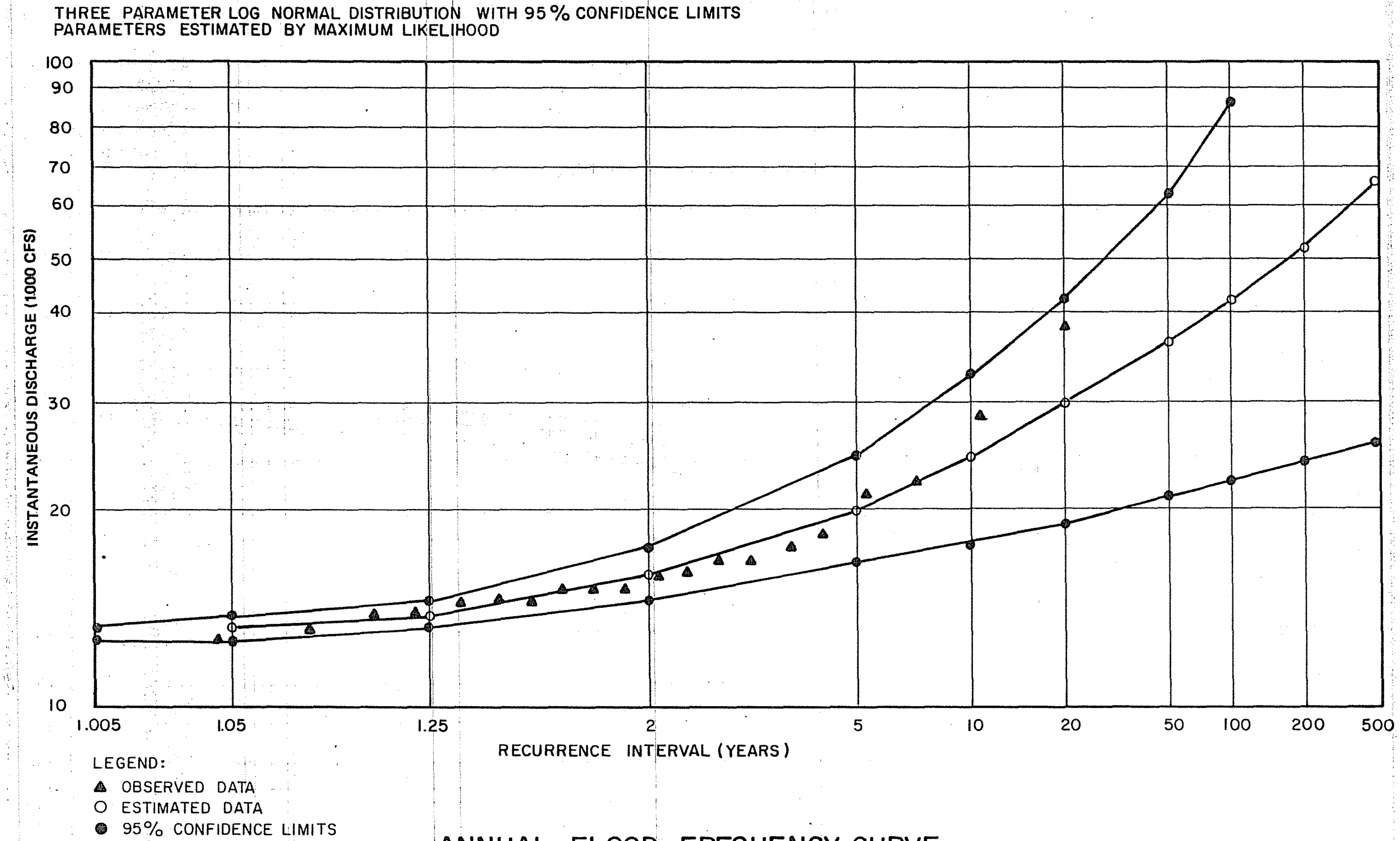
FIGURE B.3.1.5



ANNUAL FLOOD FREQUENCY CURVE
MACLAREN RIVER NEAR PAXSON

FIGURE B.3.1.6

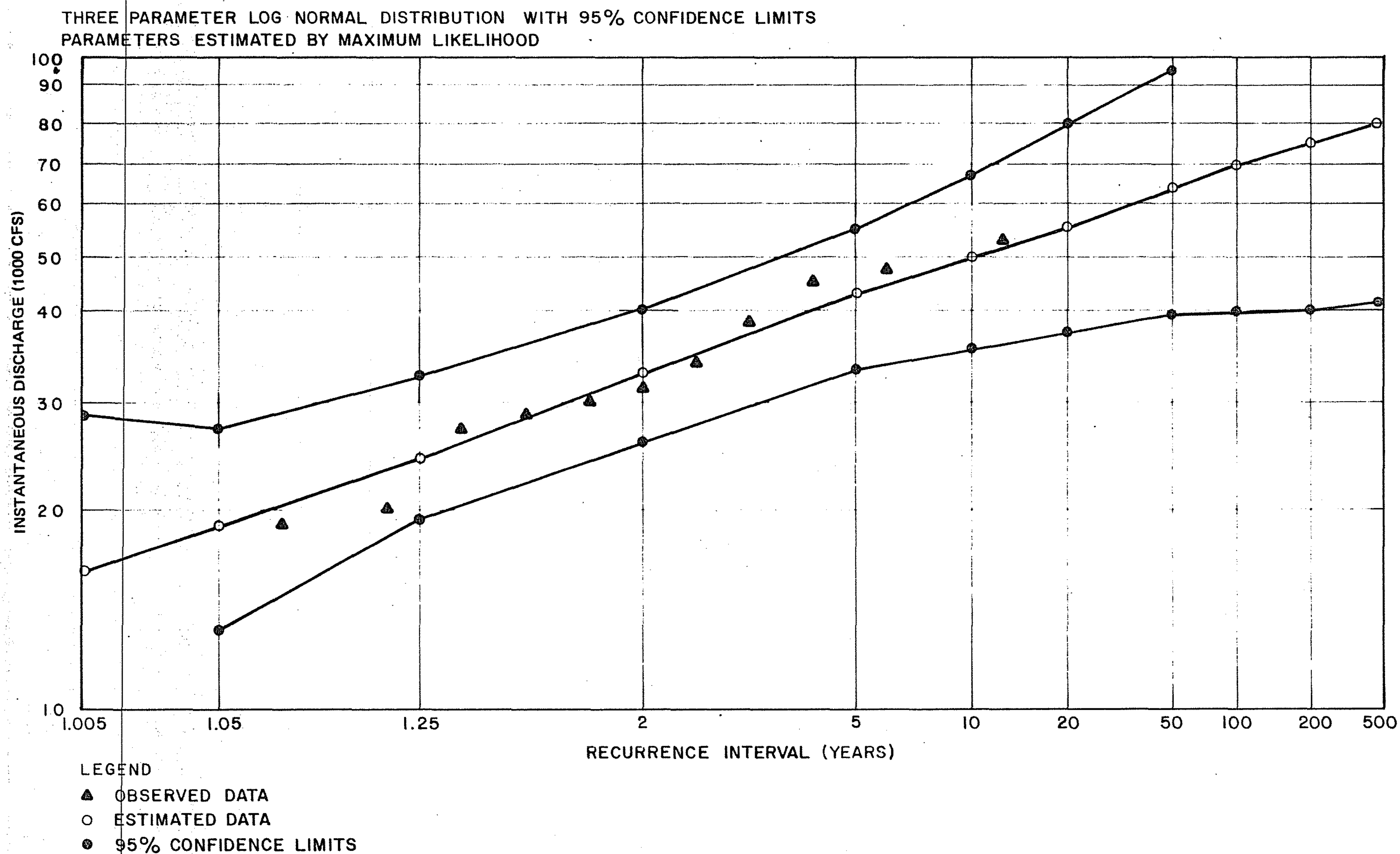
SOURCE: R & M 1981



ANNUAL FLOOD FREQUENCY CURVE
SUSITNA RIVER NEAR DENALI

FIGURE B.3.1.7

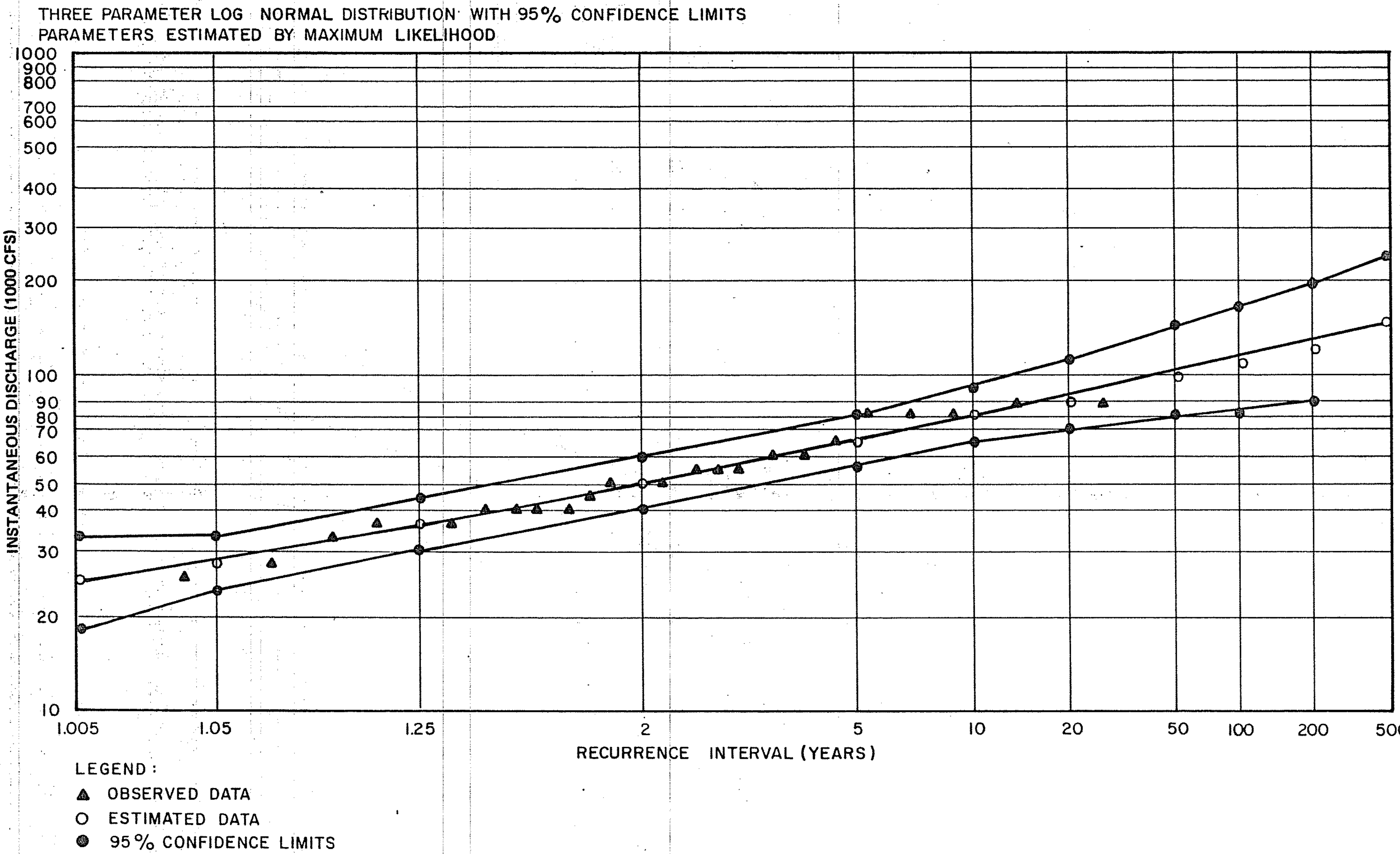
SOURCE: R & M 1981



ANNUAL FLOOD FREQUENCY CURVE
SUSITNA RIVER NEAR CANTWELL

FIGURE B.3.1.8

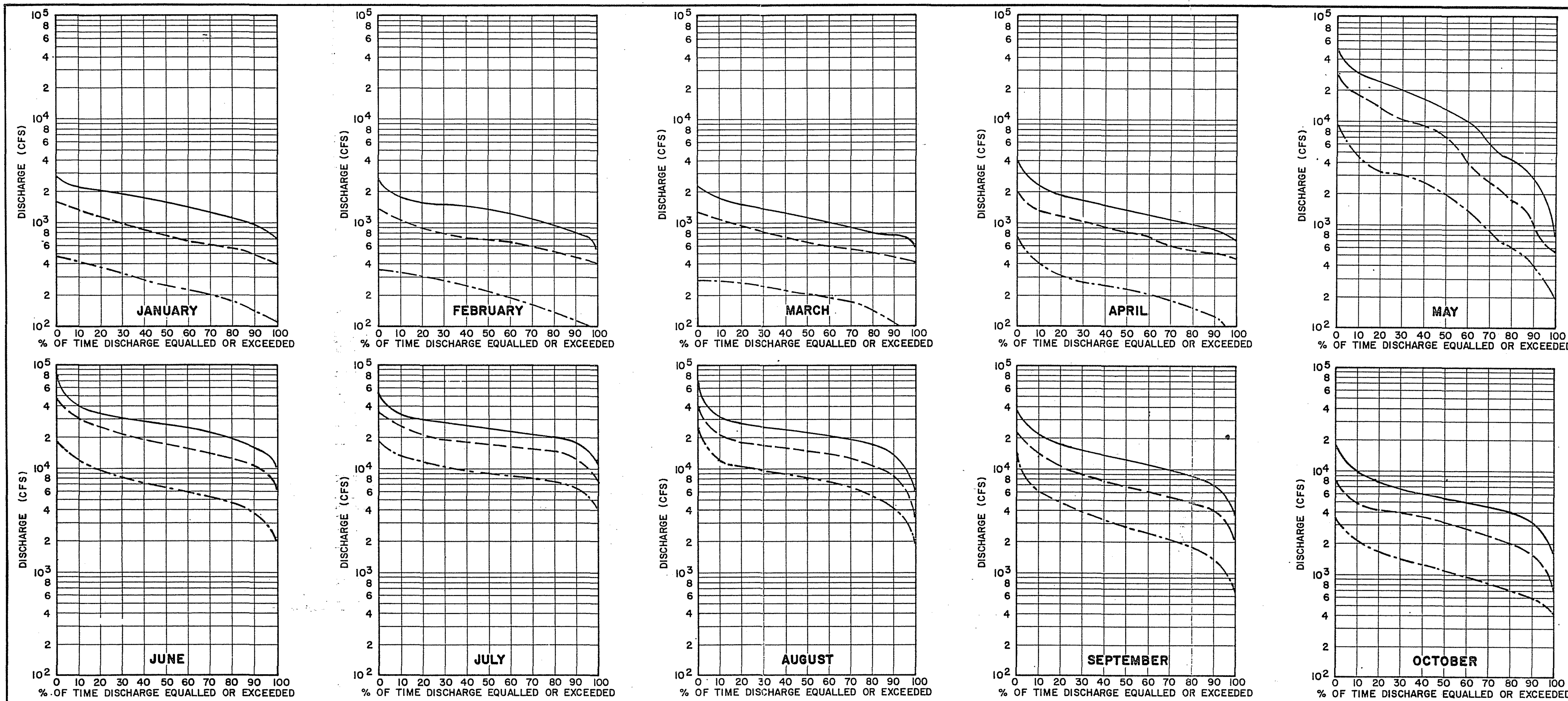
SOURCE: R & M 1981

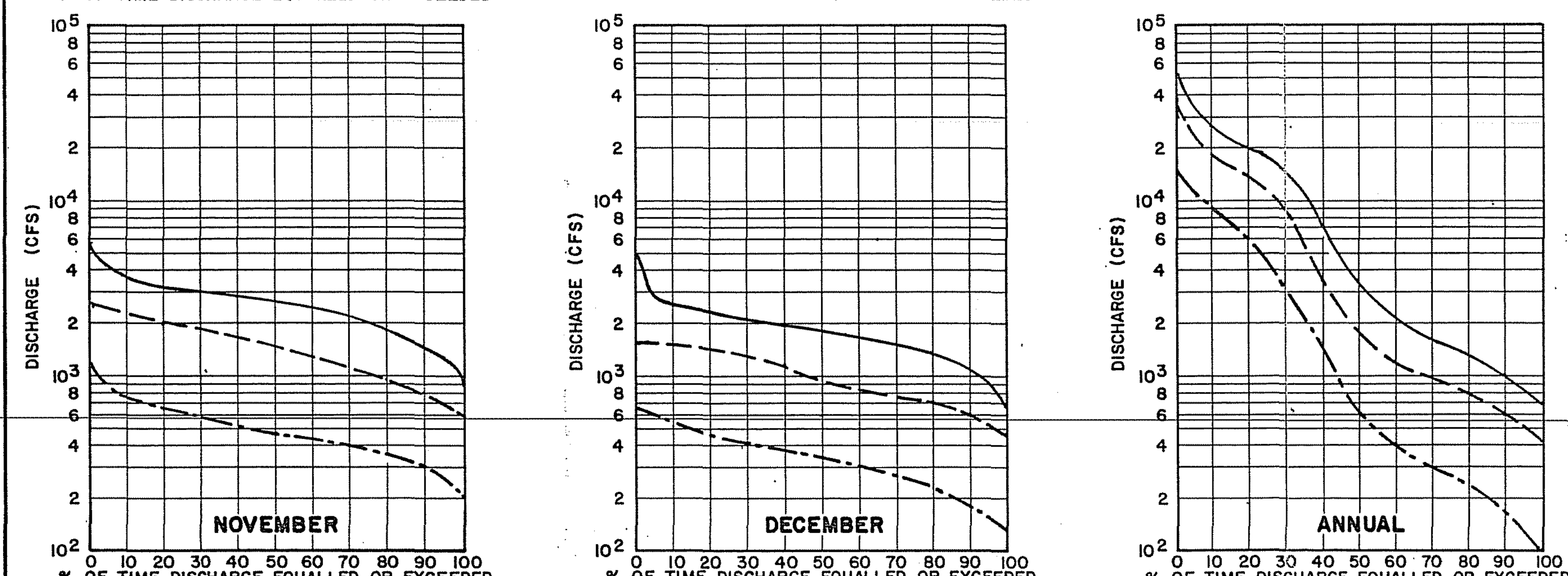


ANNUAL FLOOD FREQUENCY CURVE
SUSITNA RIVER AT GOLD CREEK

FIGURE B.3.1.9

SOURCE: R & M 1981





NOTES:

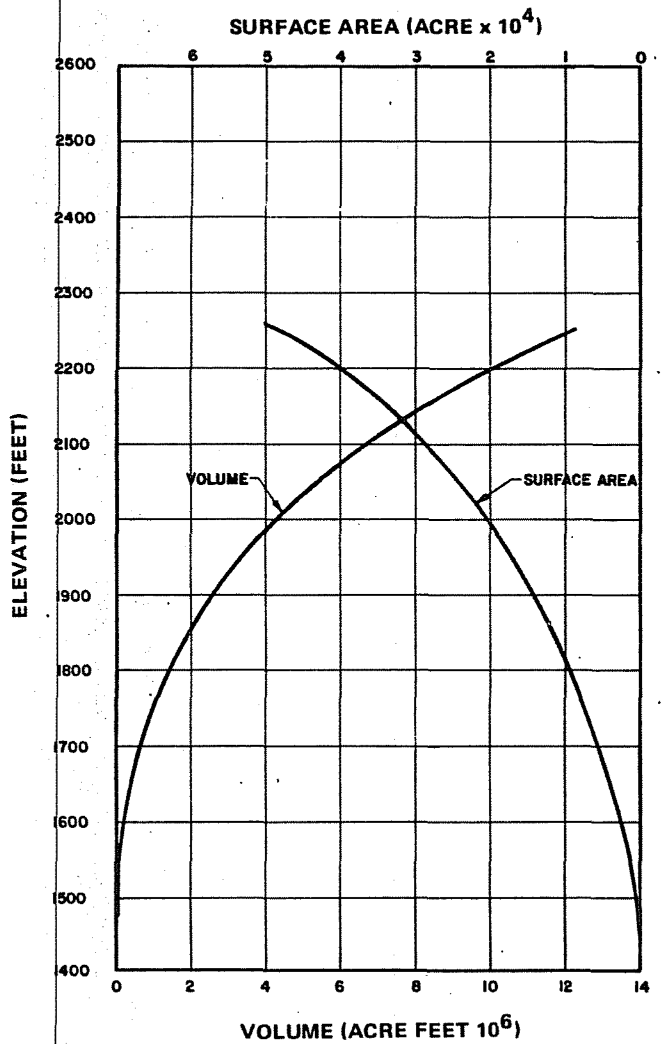
1. FLOW DURATION CURVES BASED ON MEAN DAILY FLOWS.
2. PERIODS OF RECORD:
   DENALI: MAY 1957 - SEP 1966, NOV 1968 - SEP 1981
   CANTWELL: MAY 1961 - SEP 1972, MAY 1980 - SEP 1981
   GOLD CREEK: AUG 1949 - SEP 1981

LEGEND:

——— GOLD CREEK
— — — CANTWELL
—·—·— DENALI

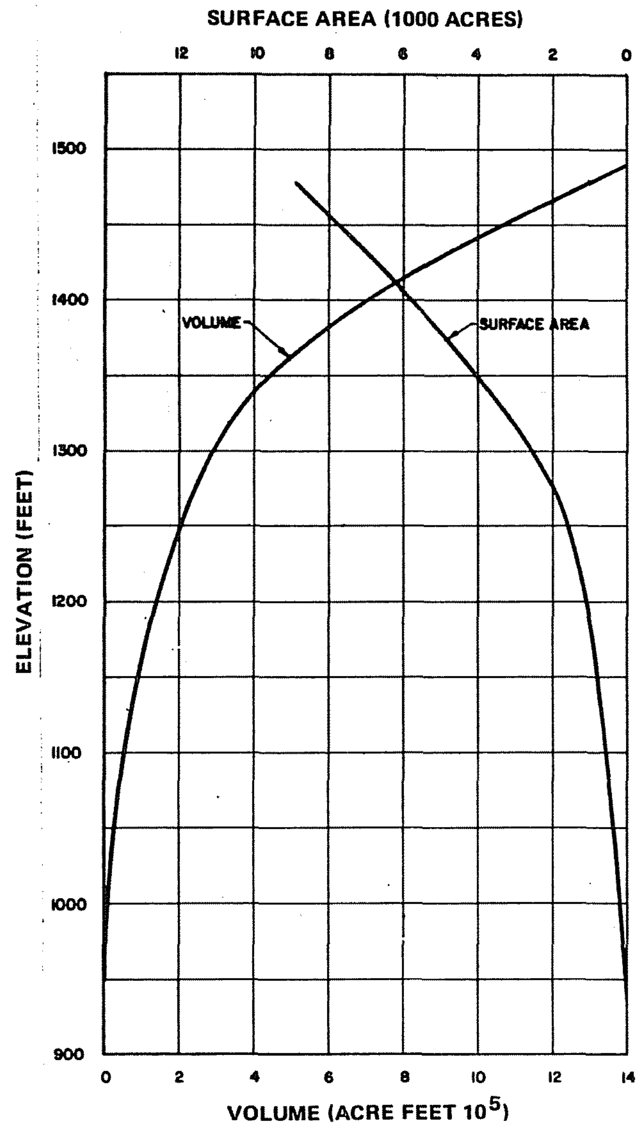
MONTHLY AND ANNUAL
FLOW DURATION CURVES
SUSITNA RIVER NEAR DENALI
SUSITNA RIVER NEAR CANTWELL
SUSITNA RIVER AT GOLD CREEK

FIGURE B.3.1.10



RESERVOIR VOLUME AND SURFACE AREA

WATANA

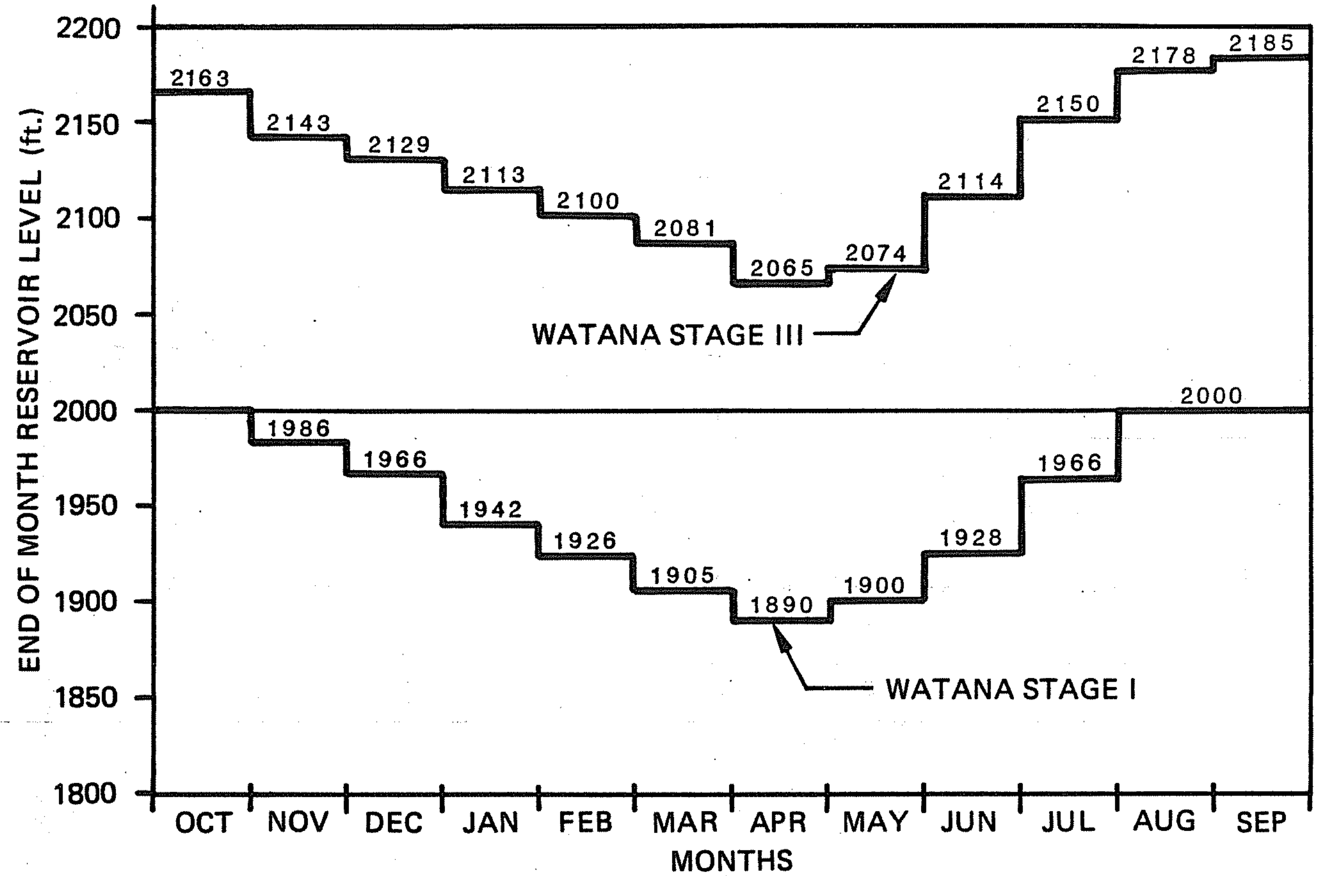


RESERVOIR VOLUME AND SURFACE AREA

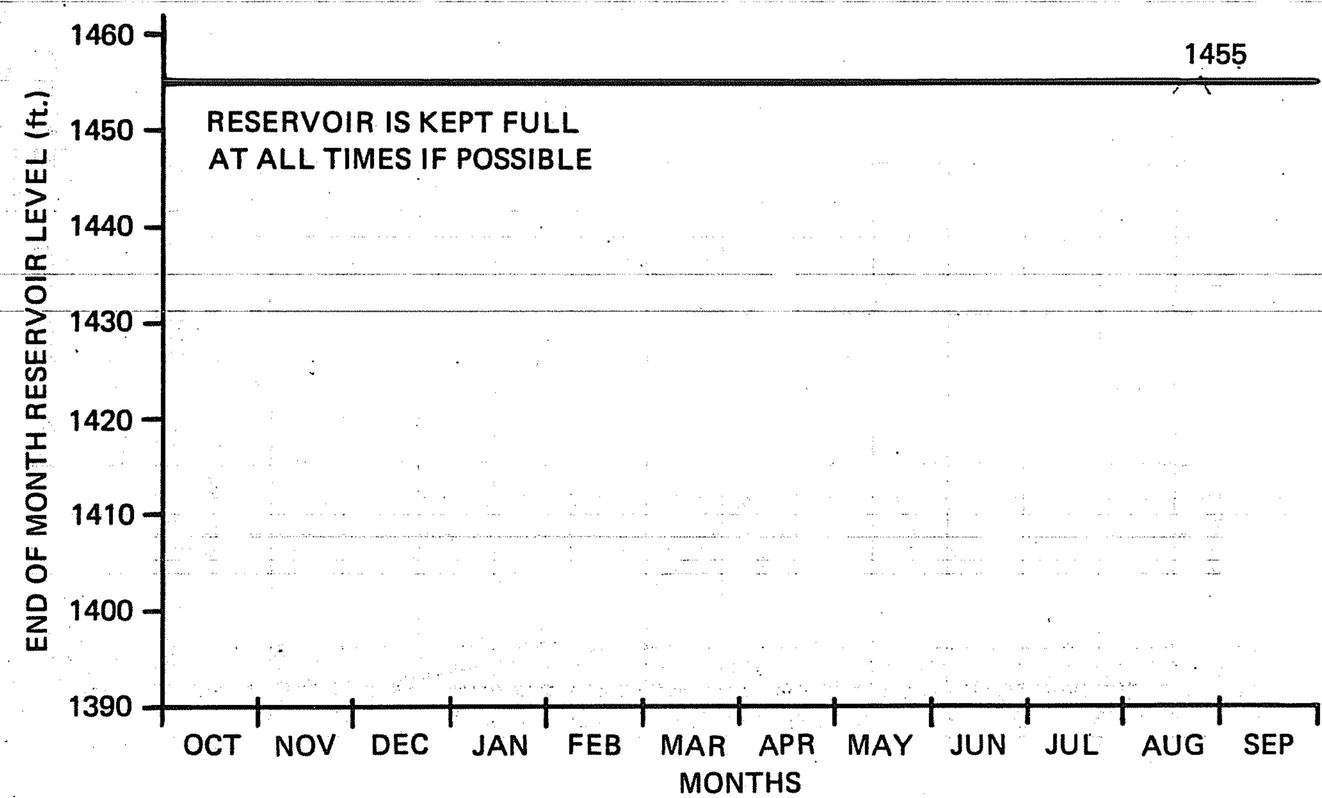
DEVIL CANYON

RESERVOIR AREA AND VOLUME VERSUS ELEVATION, WATANA AND DEVIL CANYON

FIGURE B.3.2.1



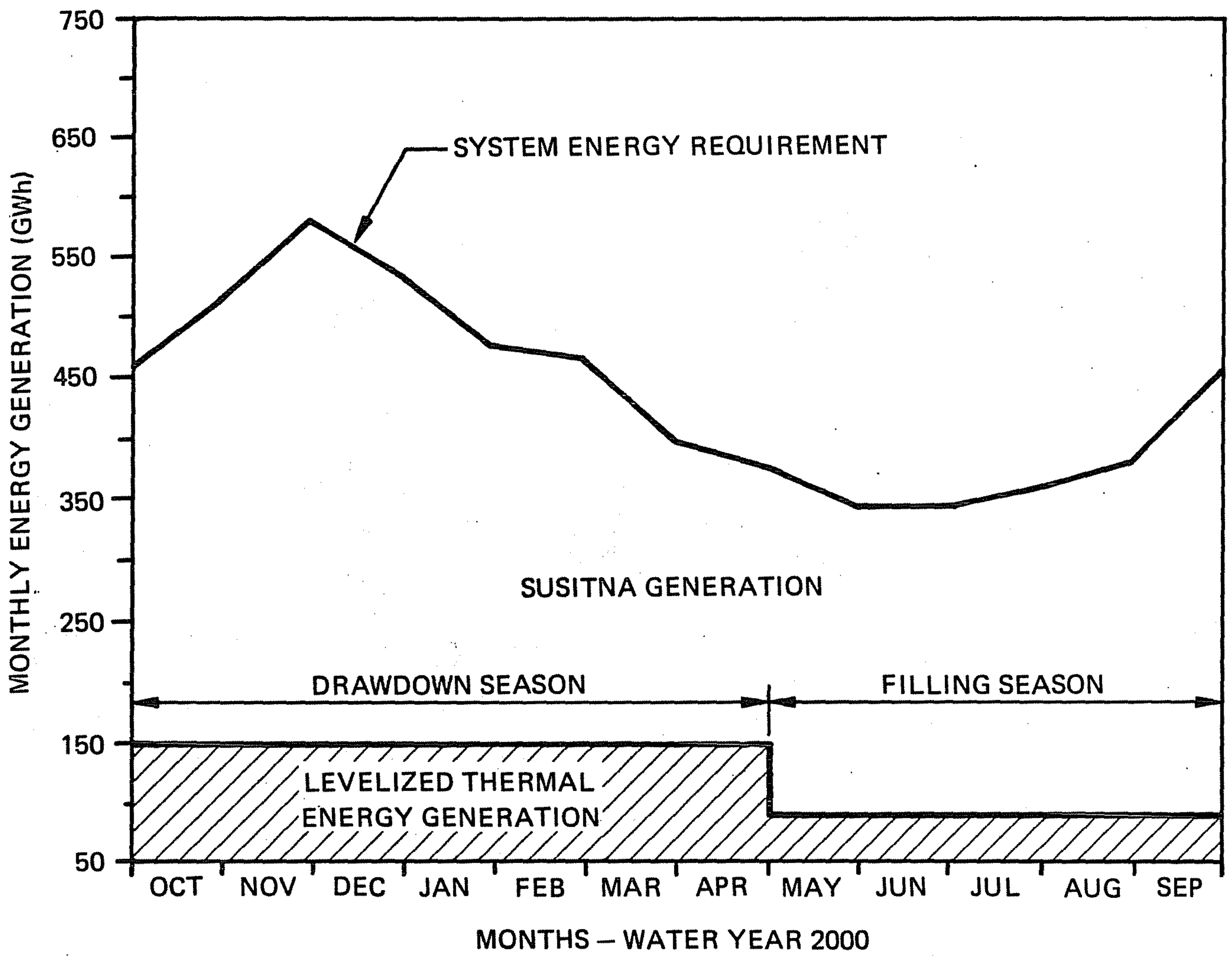
WATANA STAGE I AND STAGE III RESERVOIRS



DEVIL CANYON RESERVOIR

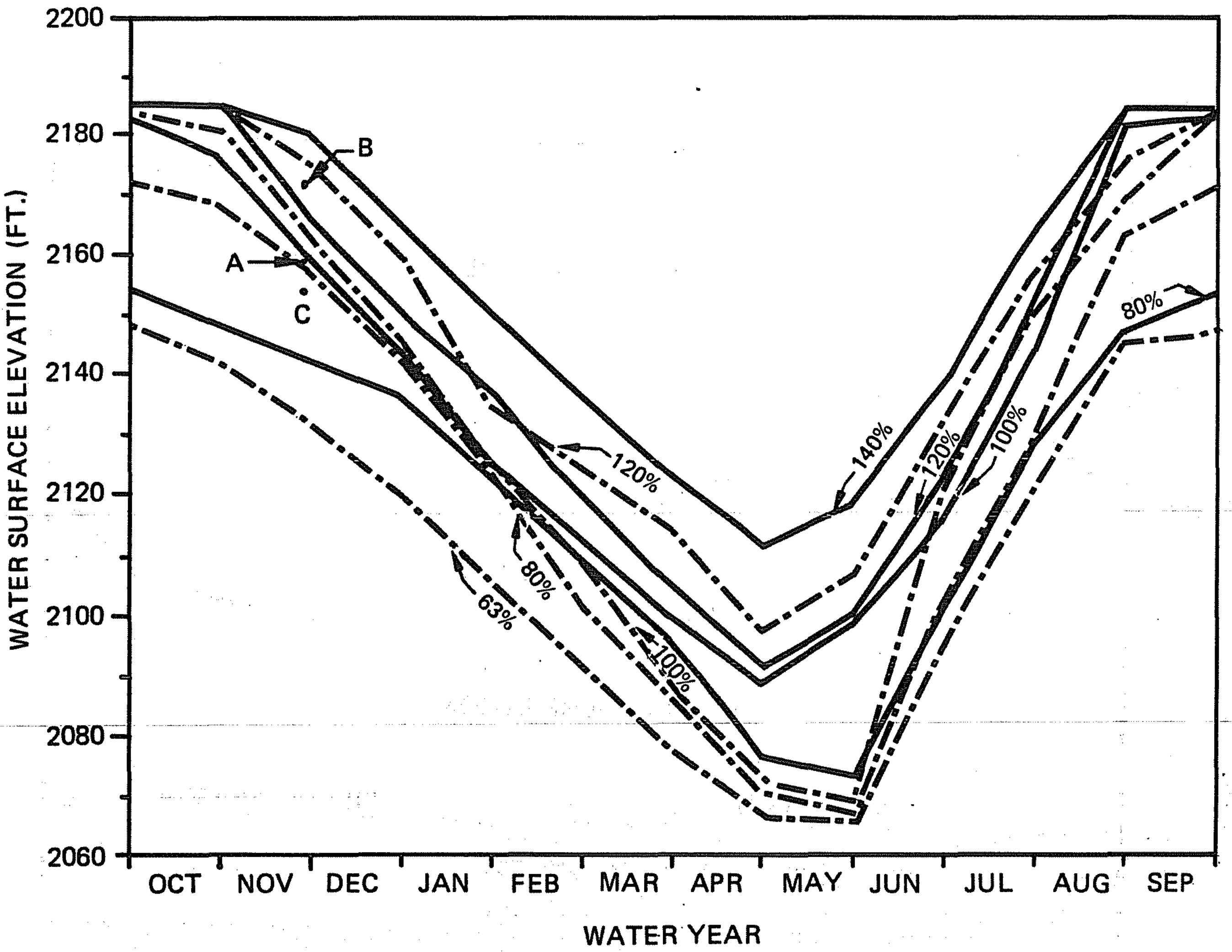
MONTHLY RULE CURVE ELEVATIONS

FIGURE B.3.2.2



LEVELIZED THERMAL ENERGY GENERATION

FIGURE B.3.2.3



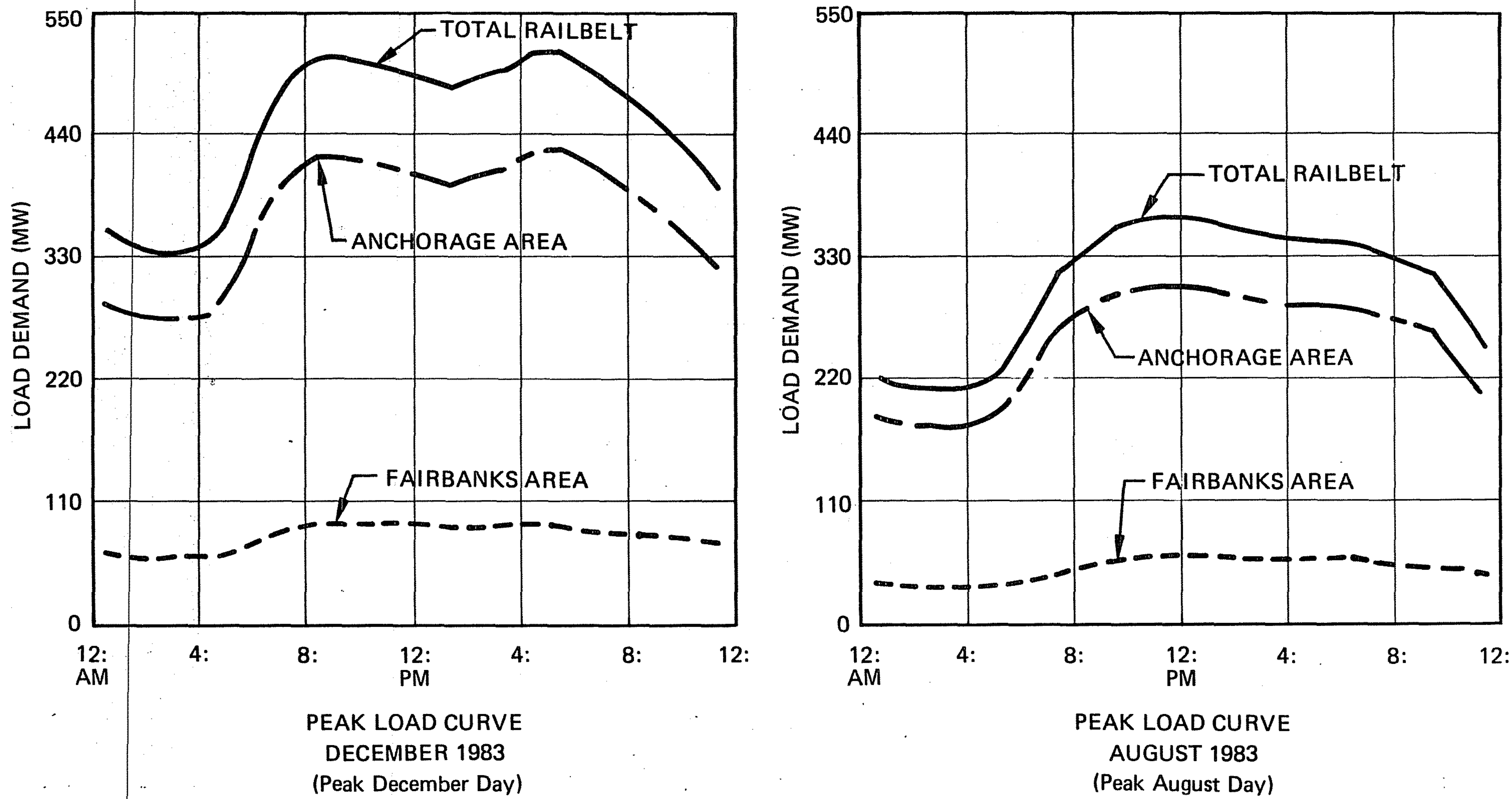
LEGEND:

CURVE FOR INCREASING RATE OF POWERHOUSE RELEASE

CURVE FOR DECREASING RATE OF POWERHOUSE RELEASE

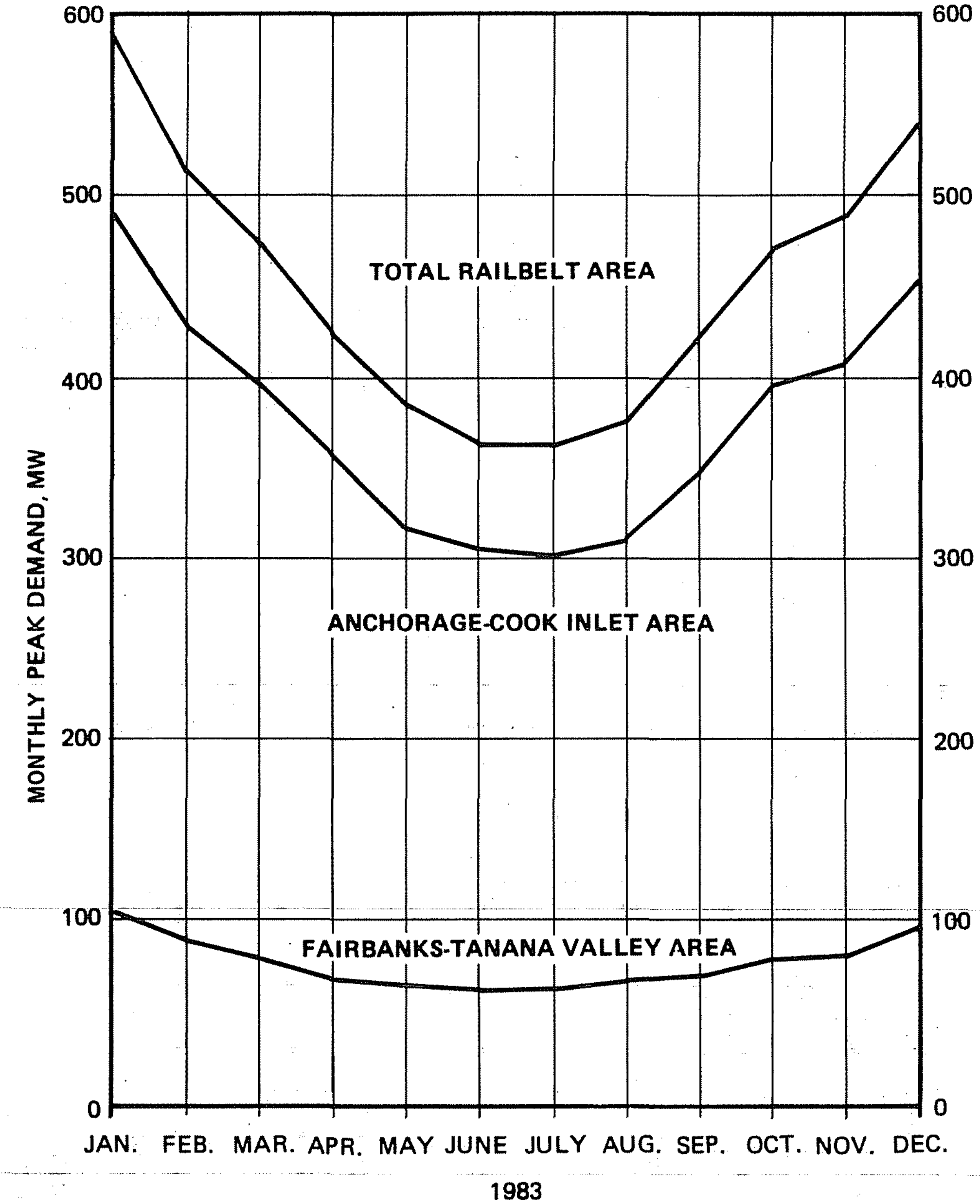
WATANA OPERATING GUIDE CURVES

FIGURE B.3.2.4



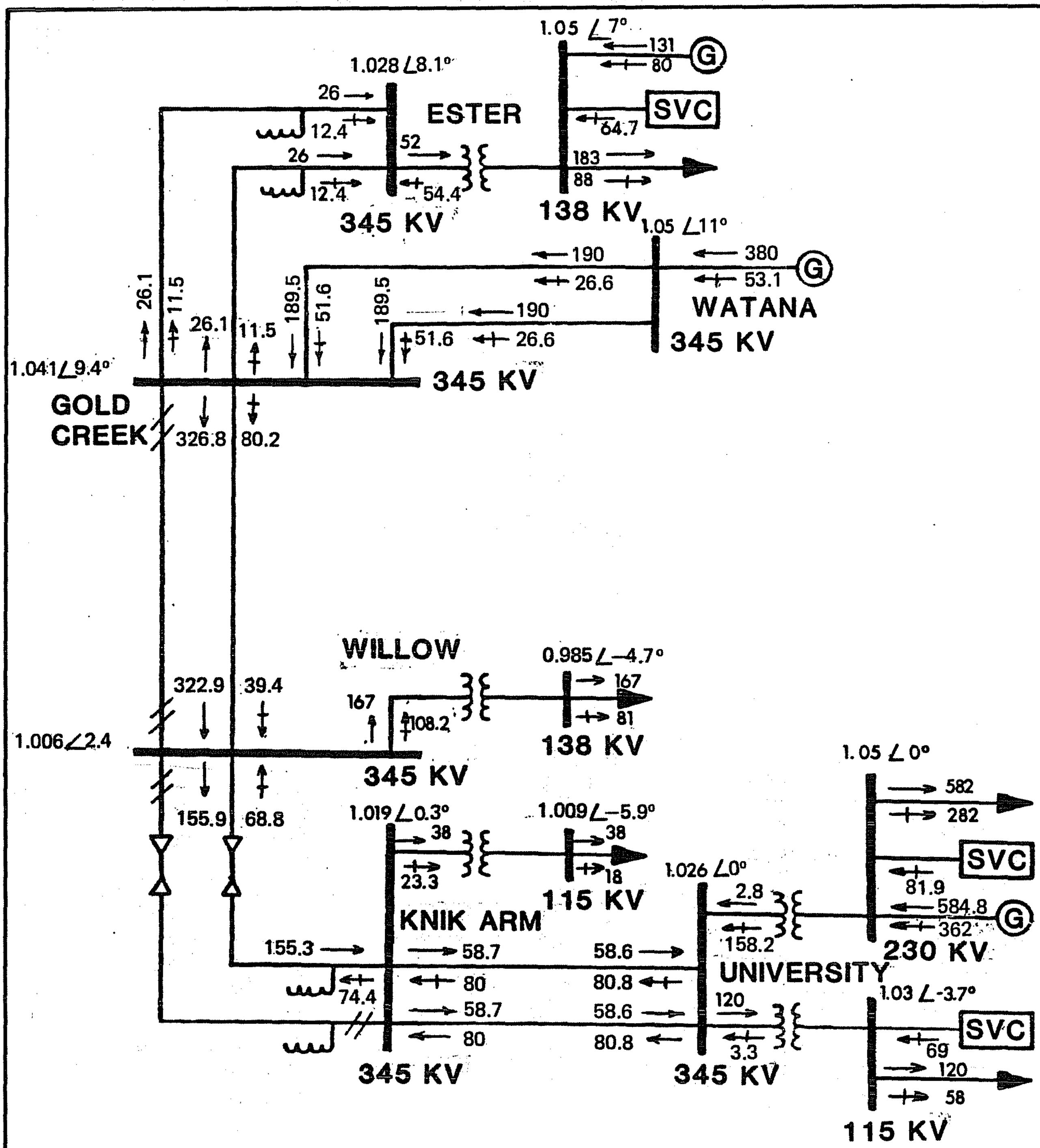
TYPICAL LOAD VARIATION IN ALASKA RAILBELT SYSTEM

FIGURE B.4.1.1



MONTHLY LOAD VARIATION FOR RAILBELT AREA

FIGURE B.4.1.2



1999 APPROXIMATE PEAK LOAD, DOUBLE CONTINGENCY

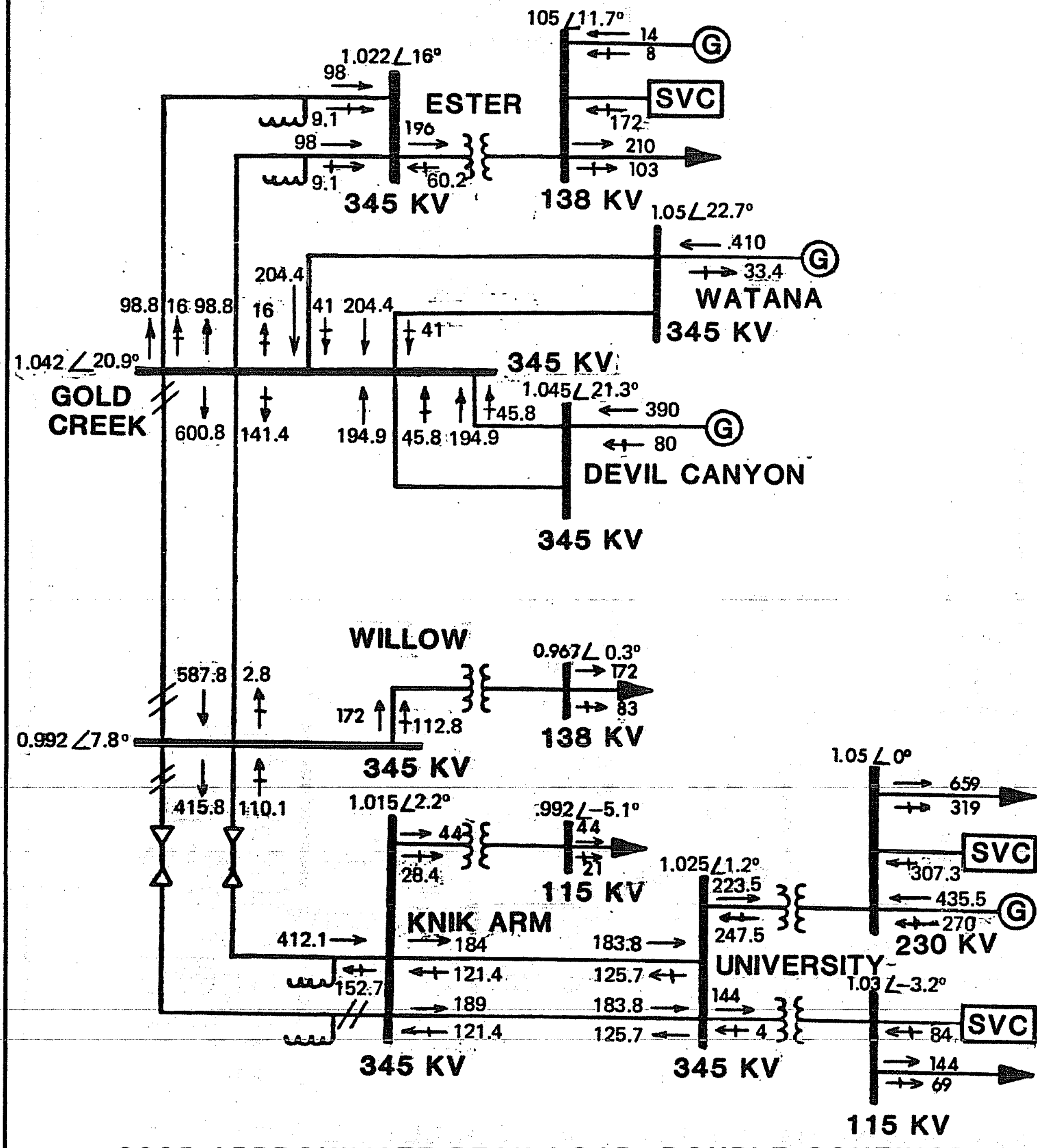
LEGEND

- REAL POWER (MW)
- REACTIVE POWER (MVAR)
- 1.00∠0.00 VOLTAGE IN PER UNIT & ANGLE IN DEGREES
- LOCAL LOAD
- G GENERATOR
- SVC STATIC VAR COMPENSATOR
- O/N TL TO U/W CABLE

ANCHORAGE-FAIRBANKS TRANSMISSION RELIABILITY EVALUATION

1999 INTERCONNECTED SYSTEM

FIGURE B.4.1.3



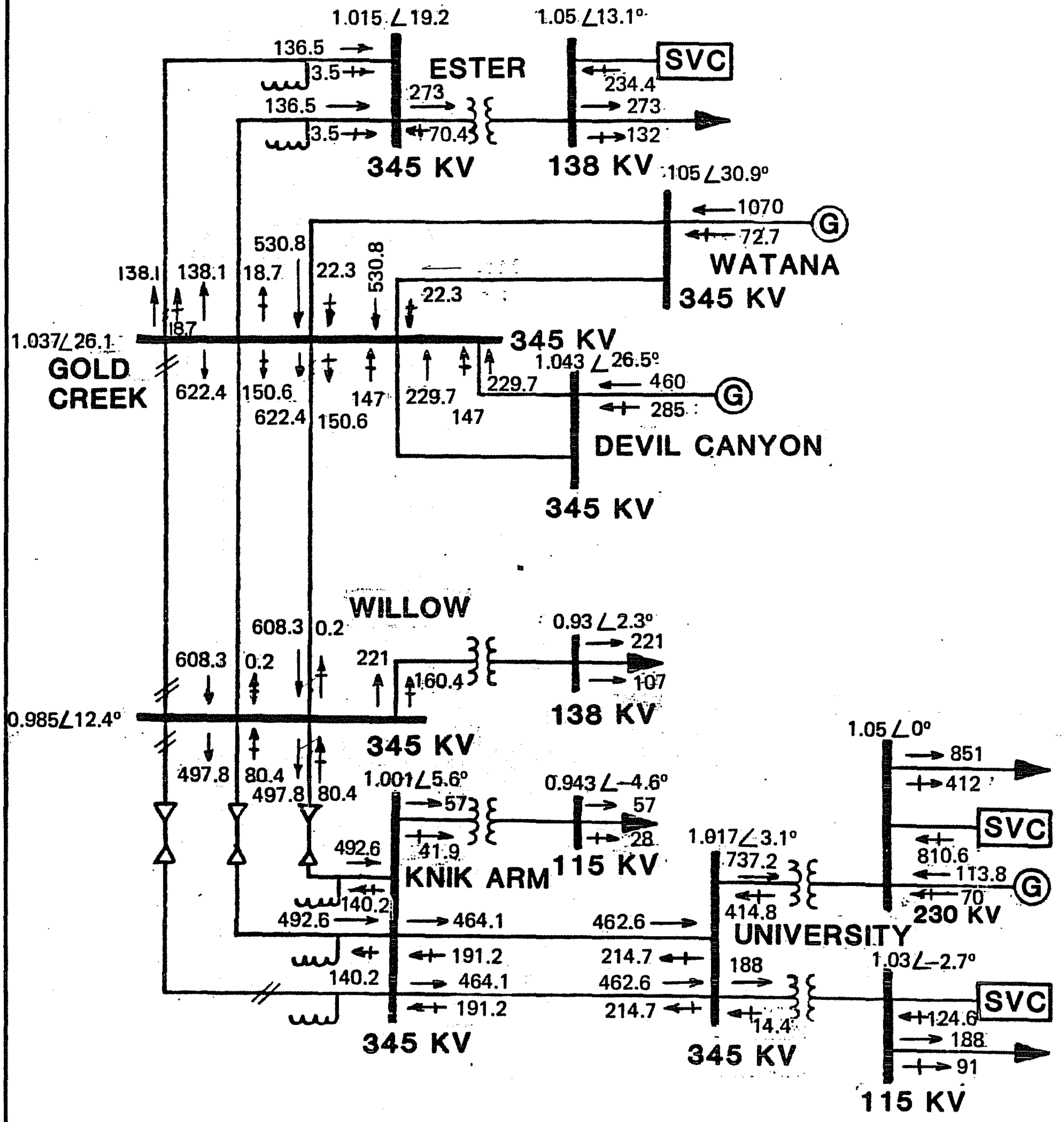
2005 APPROXIMATE PEAK LOAD, DOUBLE CONTINGENCY

LEGEND

- REAL POWER (MW)
- REACTIVE POWER (MVAR)
- 1.00∠0.00 VOLTAGE IN PER UNIT & ANGLE IN DEGREES
- LOCAL LOAD
- (G) GENERATOR
- SVC STATIC VAR COMPENSATOR
- O/N TL TO U/W CABLE

ANCHORAGE-FAIRBANKS TRANSMISSION RELIABILITY EVALUATION

2005 INTERCONNECTED SYSTEM FIGURE B.4.1.4



2025 APPROXIMATE PEAK LOAD, DOUBLE CONTINGENCY

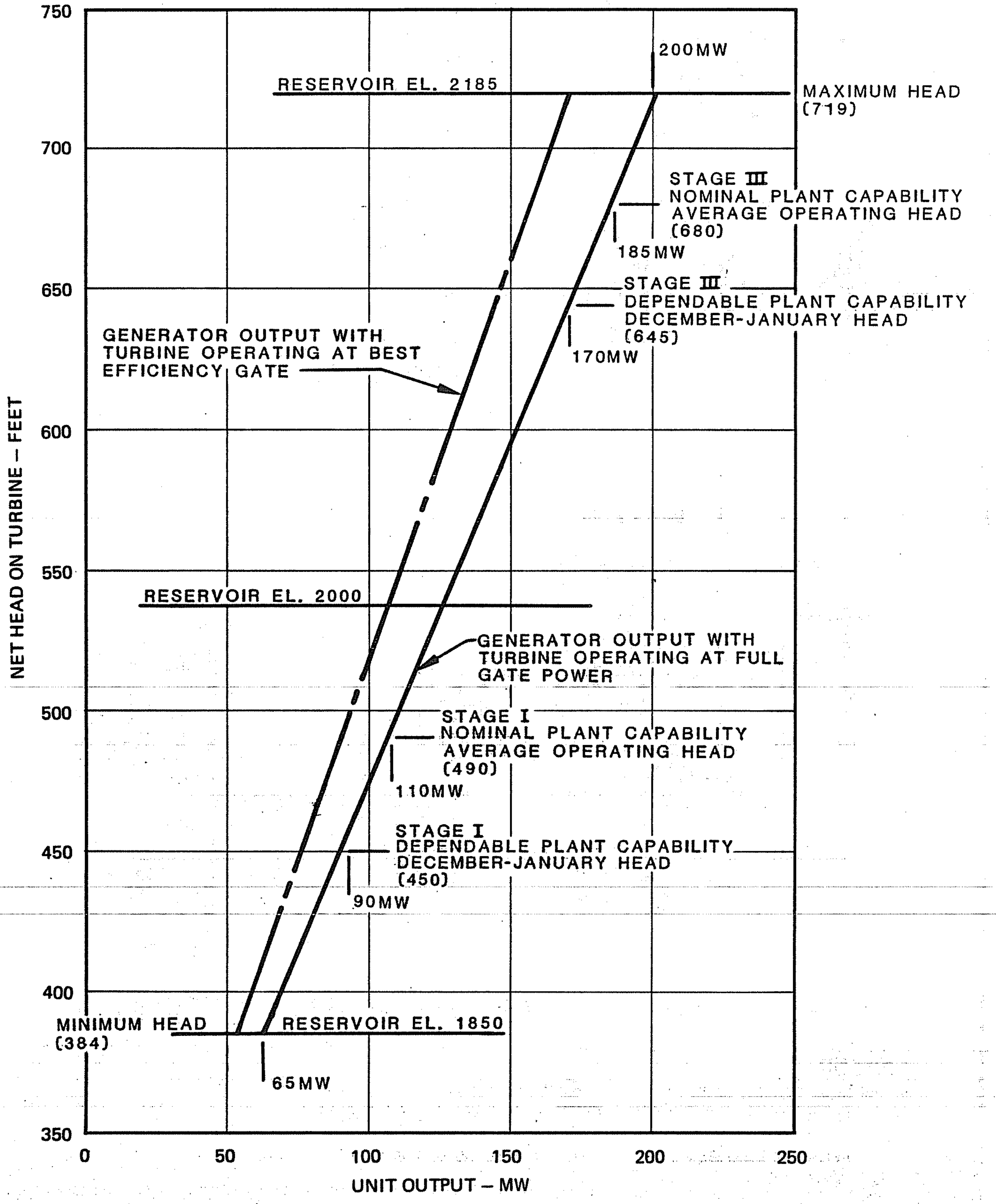
LEGEND

- REAL POWER (MW)
- REACTIVE POWER (MVAR)
- 1.00/0.00 VOLTAGE IN PER UNIT & ANGLE IN DEGREES
- LOCAL LOAD
- (G) GENERATOR
- SVC STATIC VAR COMPENSATOR
- O/N TL TO U/W CABLE

ANCHORAGE-FAIRBANKS TRANSMISSION RELIABILITY EVALUATION

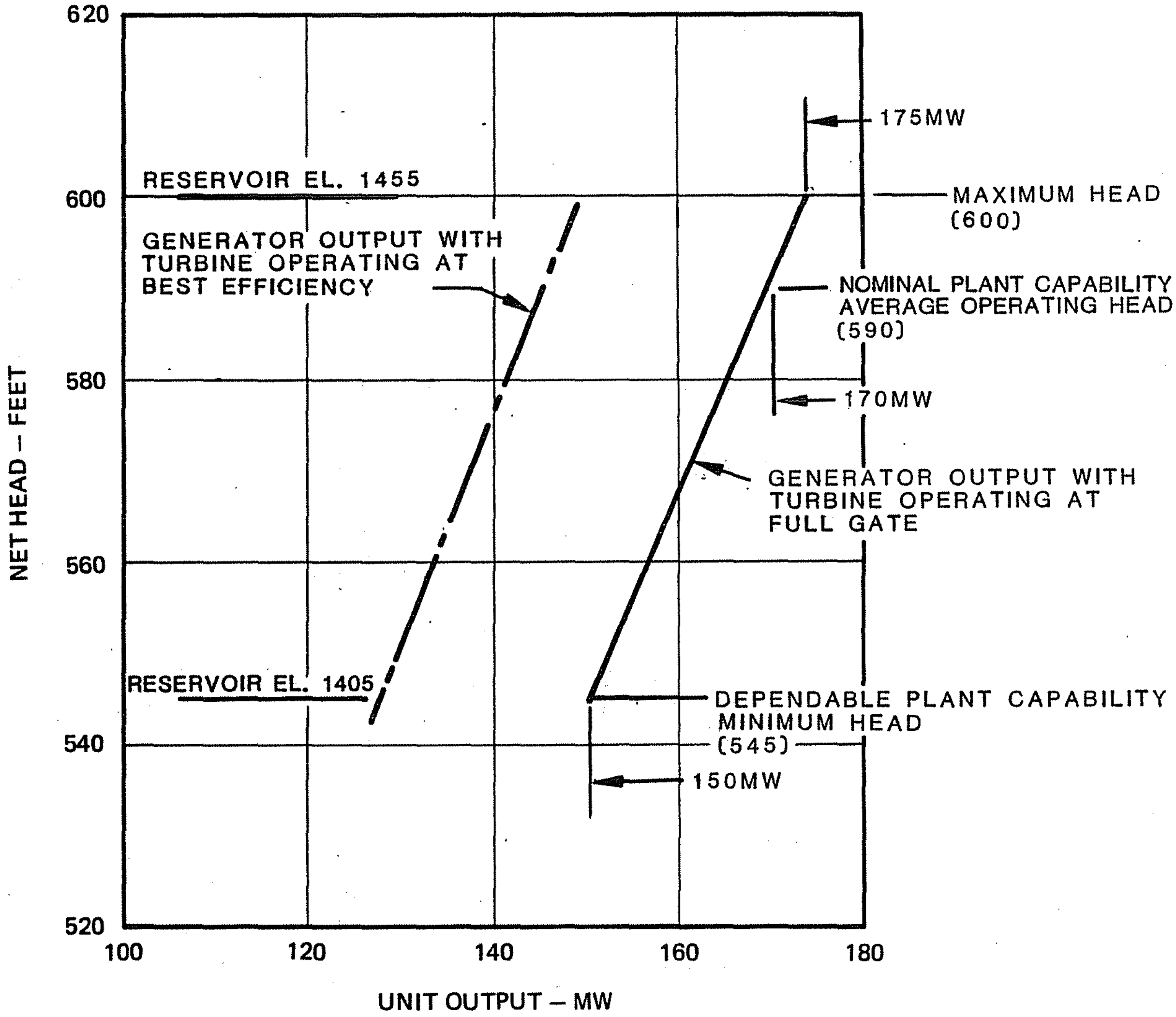
2025 INTERCONNECTED SYSTEM

FIGURE B.4.1.5



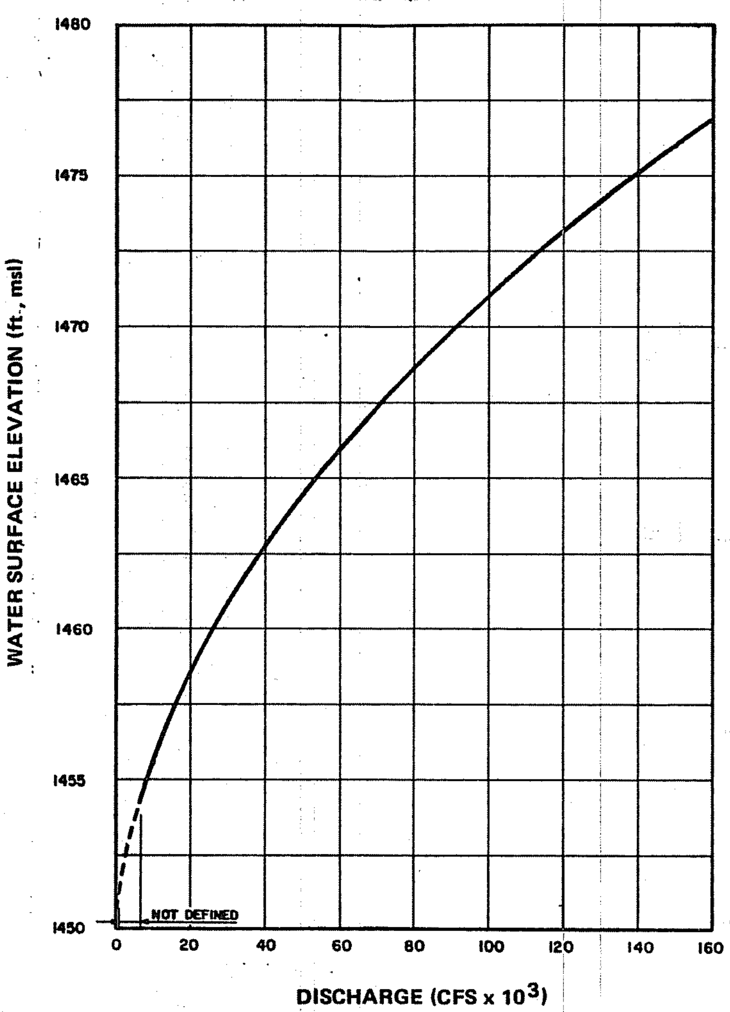
WATANA UNIT OUTPUT

FIGURE B.4.2.1



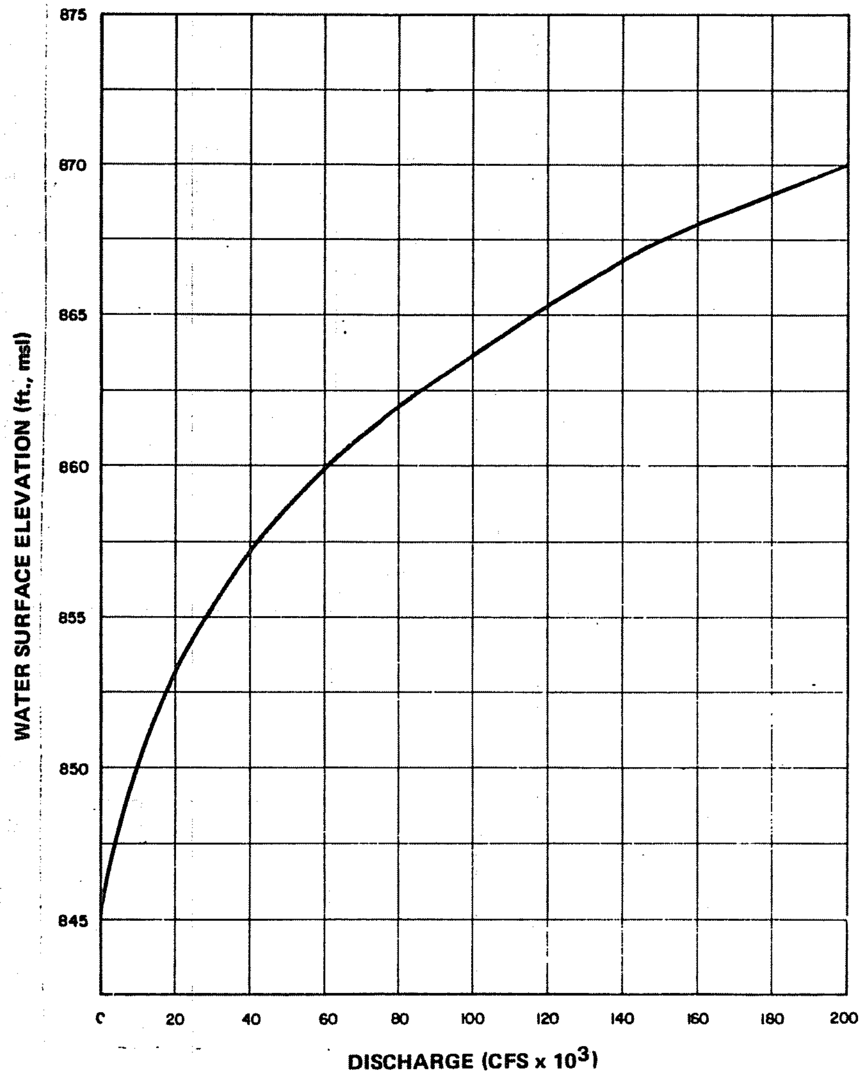
DEVIL CANYON UNIT OUTPUT

FIGURE B.4.2.2



TAILWATER RATING

WATANA

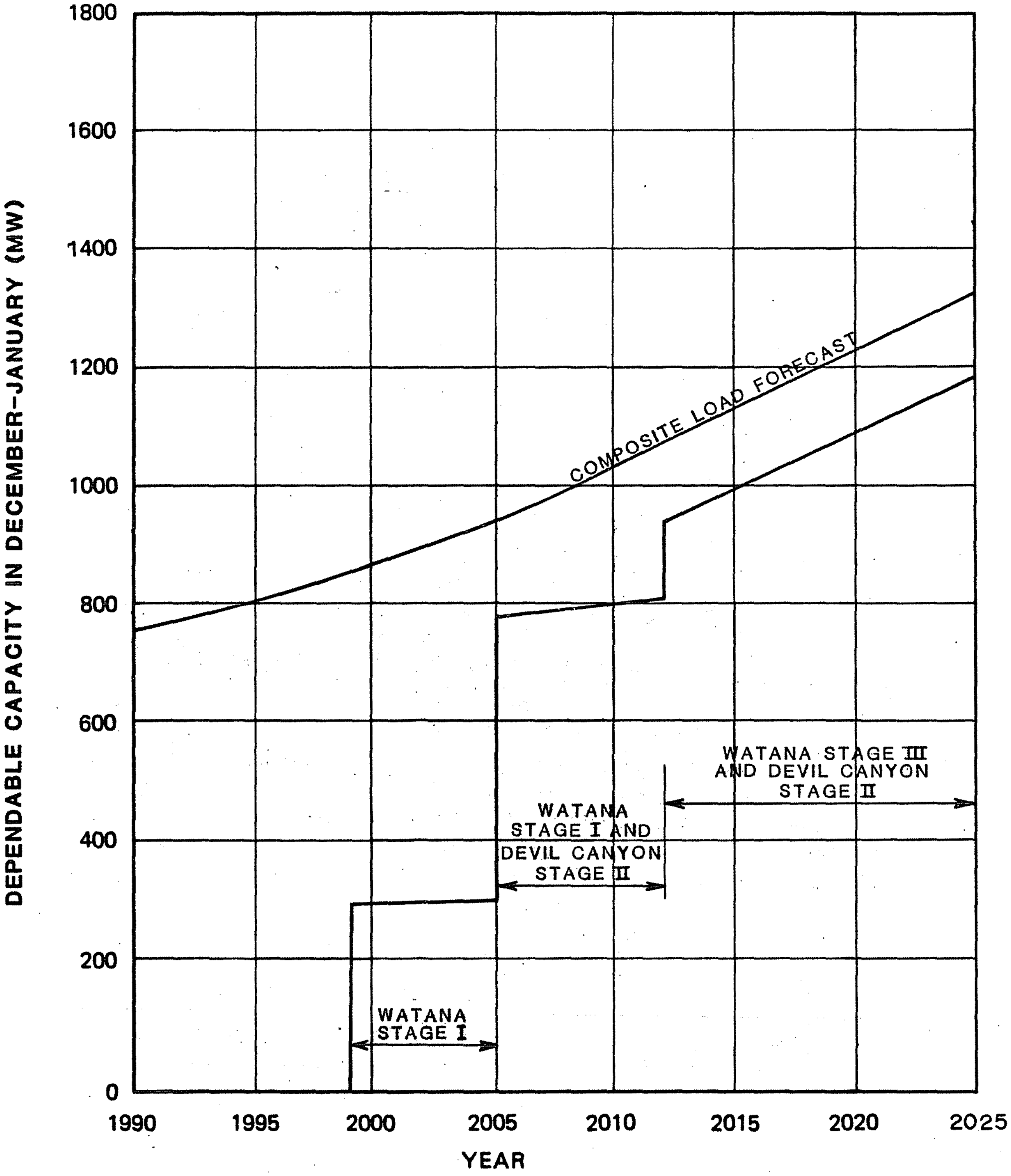


TAILWATER RATING

DEVIL CANYON

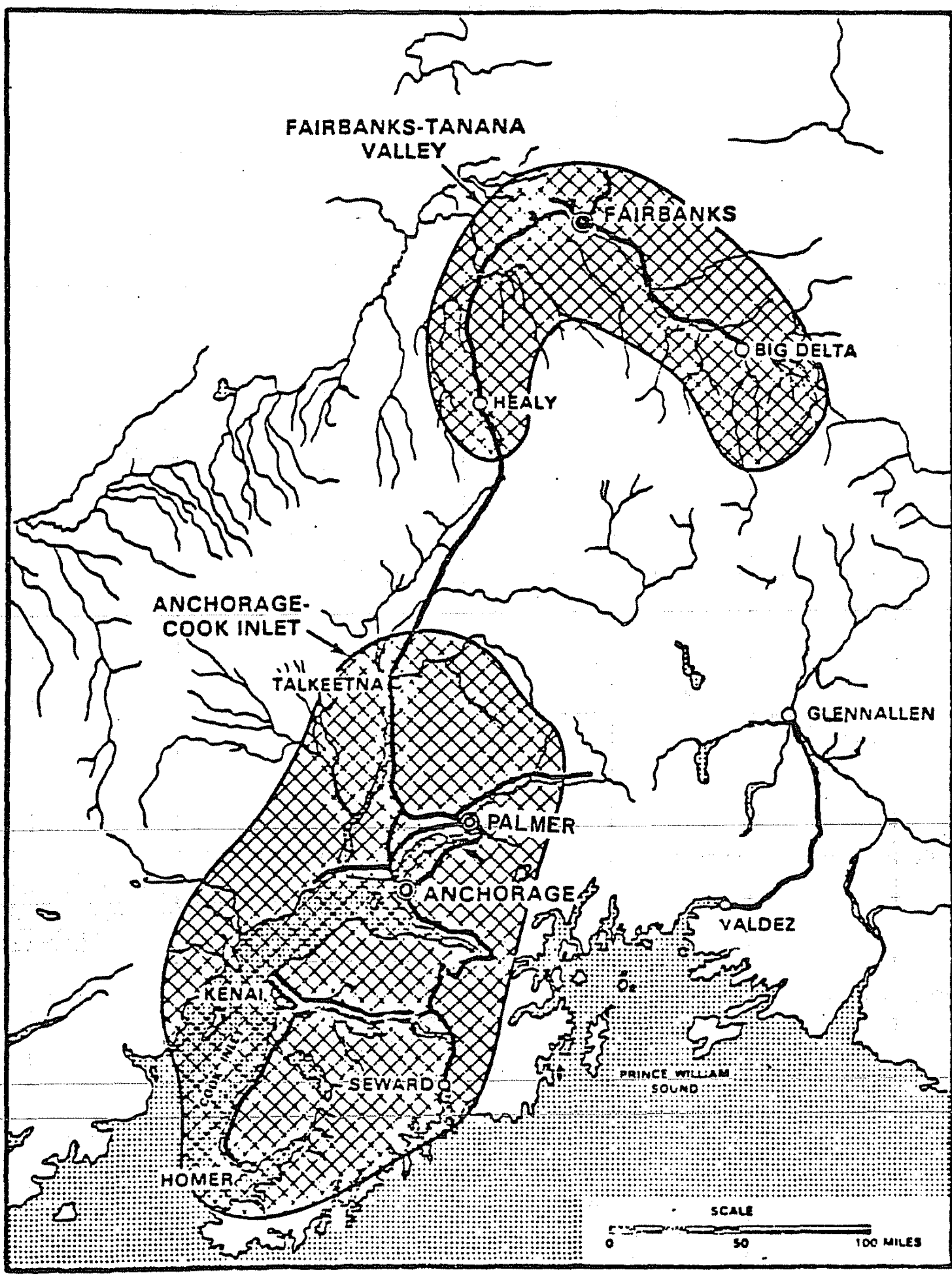
WATANA AND DEVIL CANYON TAILWATER RATING CURVES

FIGURE B.4.2.3



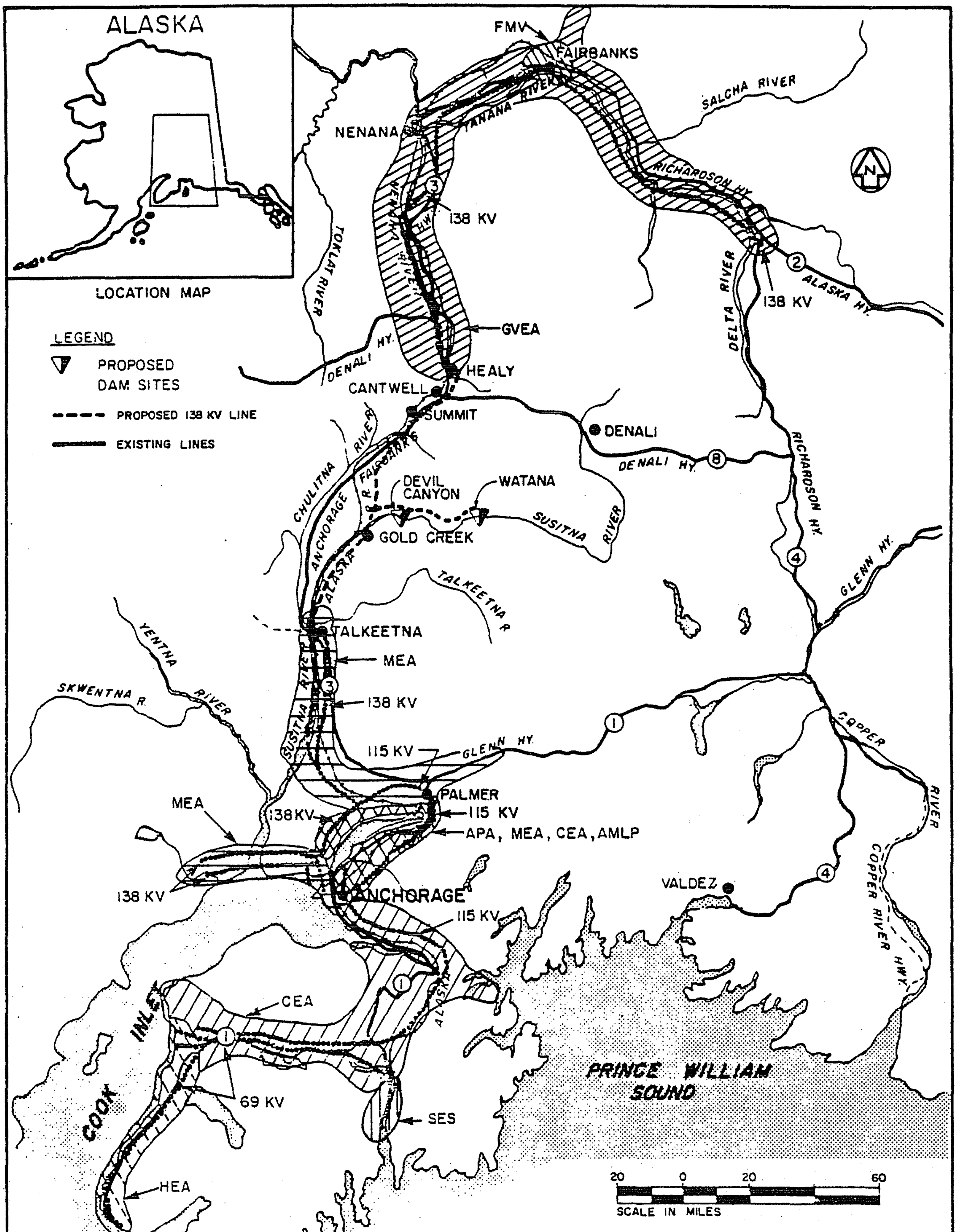
SUSITNA DEPENDABLE CAPACITY

FIGURE B.4.2.4



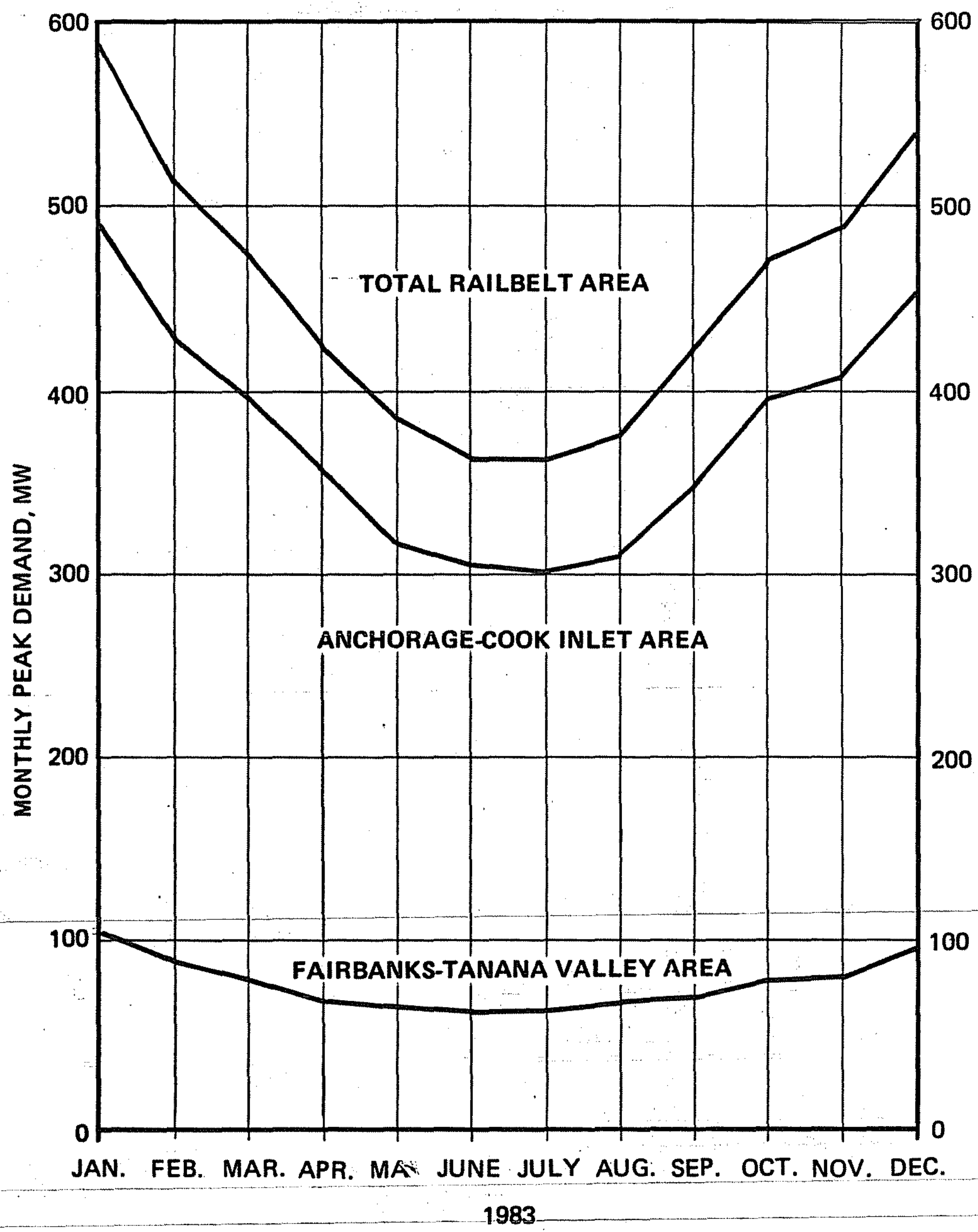
RAILBELT AREA OF ALASKA
SHOWING ELECTRICAL LOAD CENTERS

FIGURE B.5.2.1



LOCATION MAP SHOWING
TRANSMISSION SYSTEMS

FIGURE B.5.2.2



MONTHLY LOAD VARIATION FOR RAILBELT AREA

FIGURE B.5.2.3

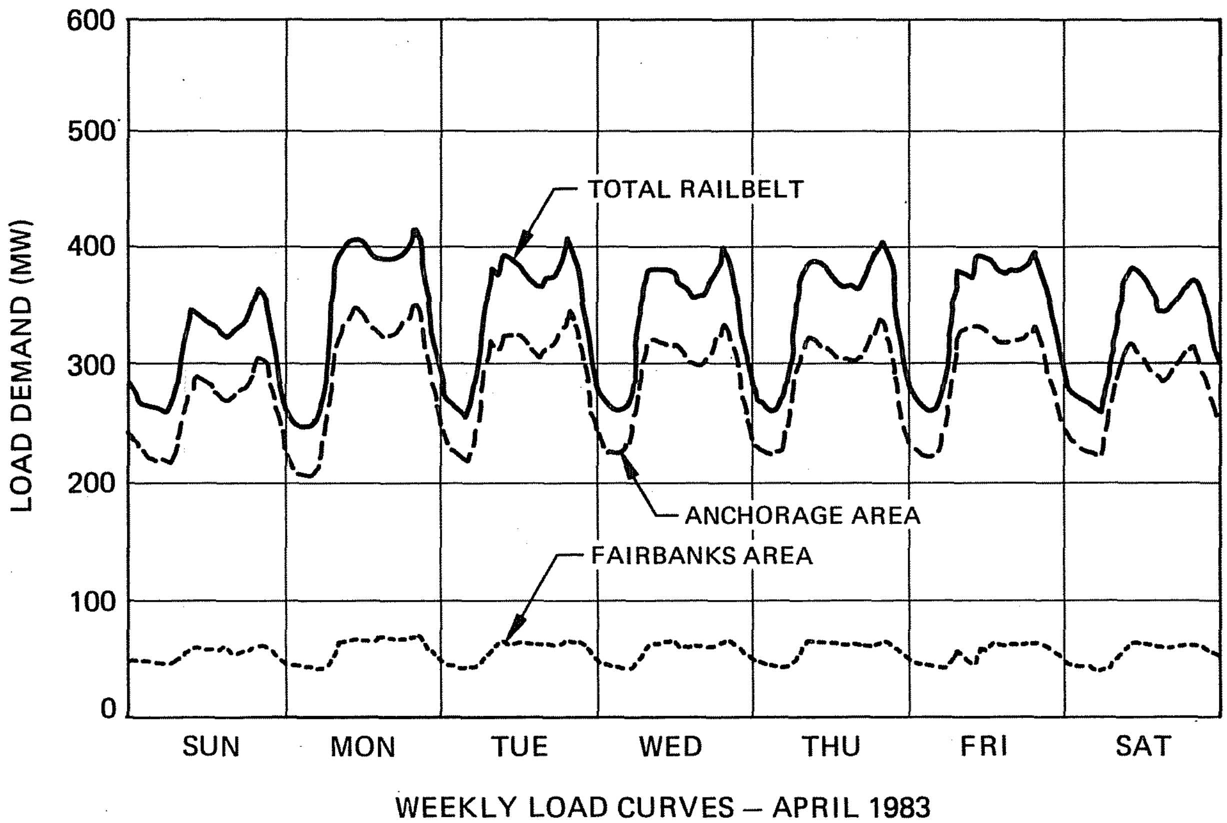
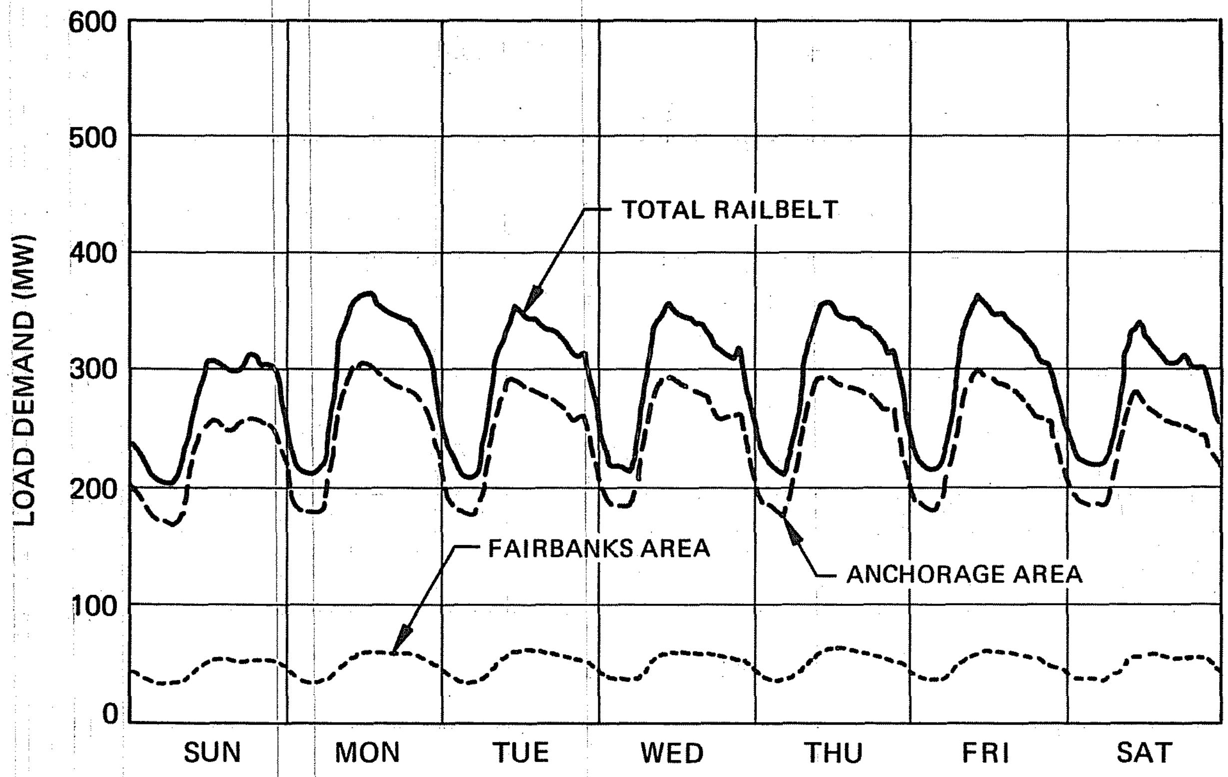


FIGURE B.5.2.4

Page 1 of 3



WEEKLY LOAD CURVES – AUGUST 1983

FIGURE B.5.2.4
Page 2 of 3

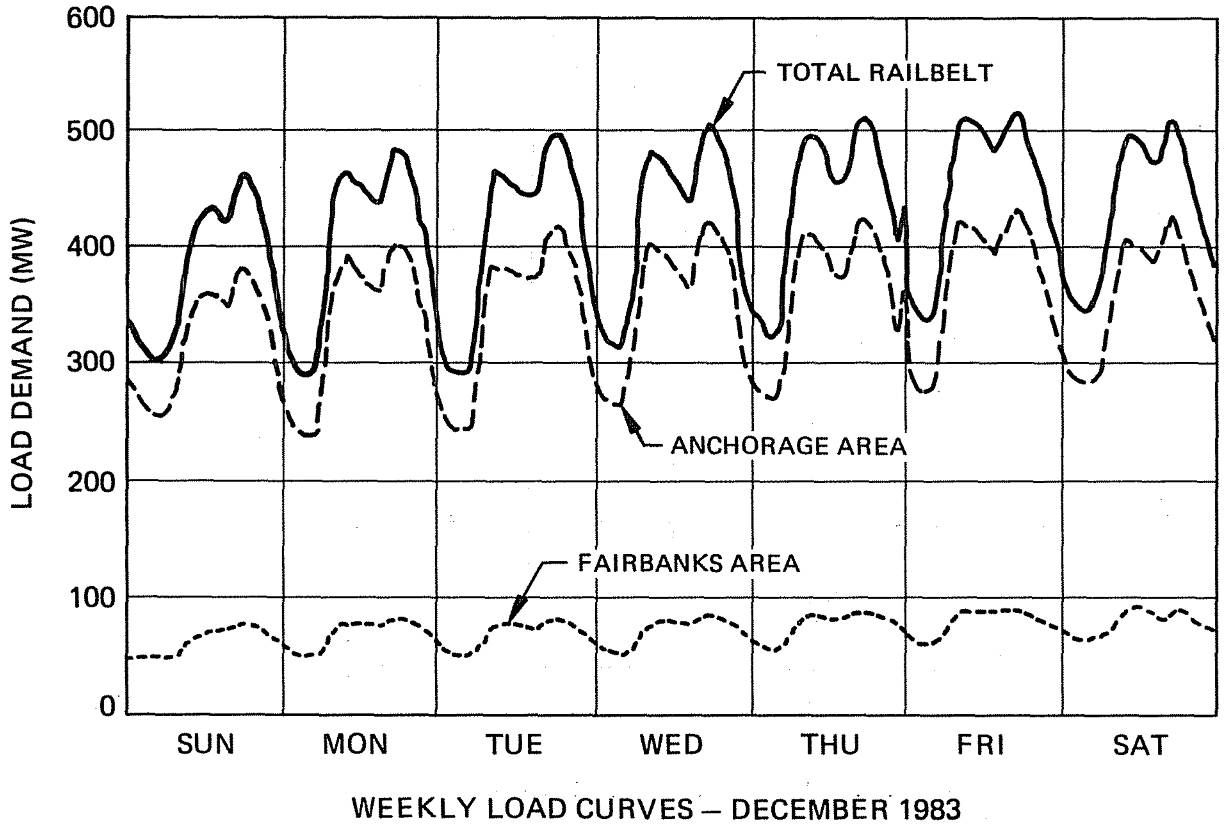
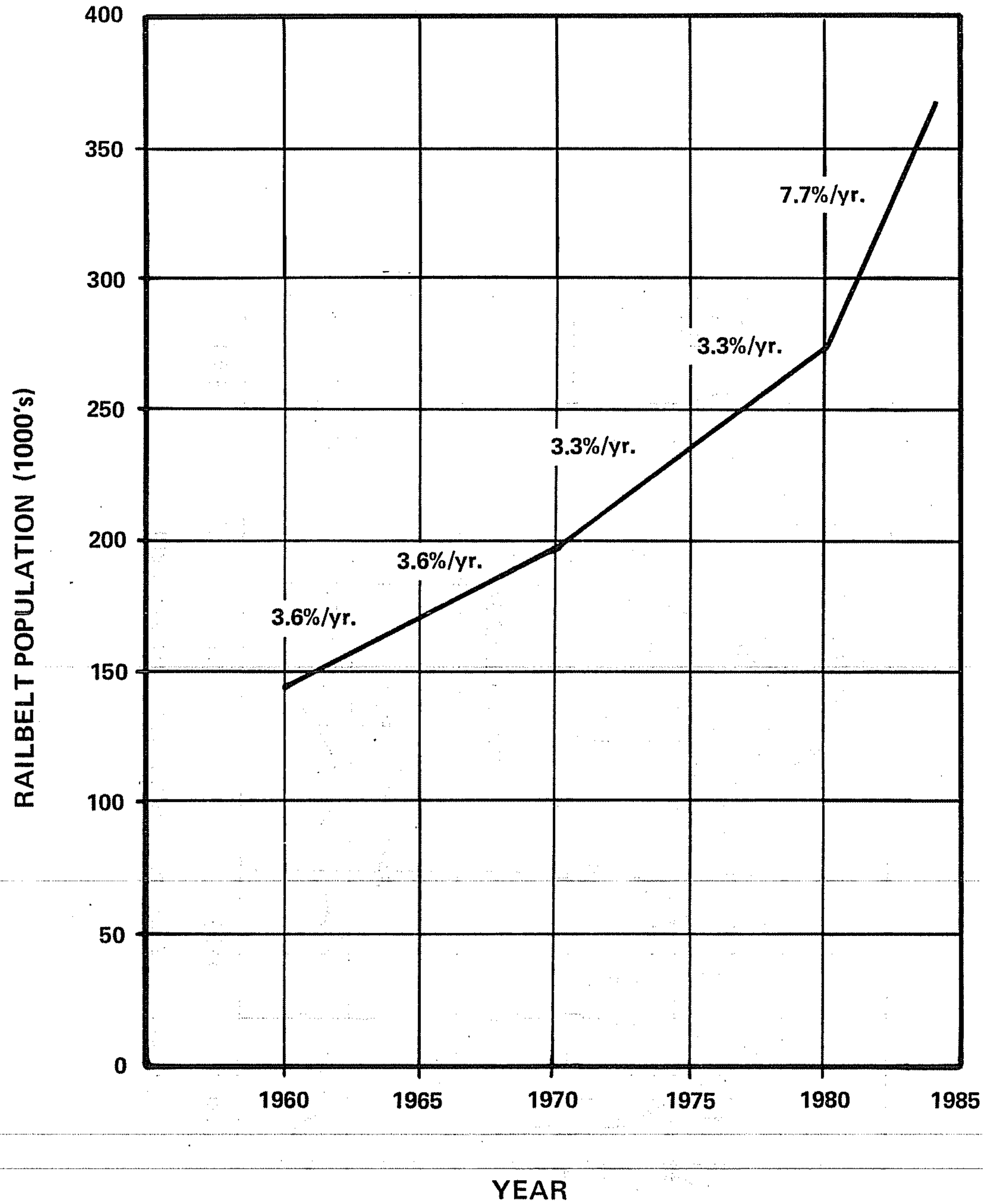
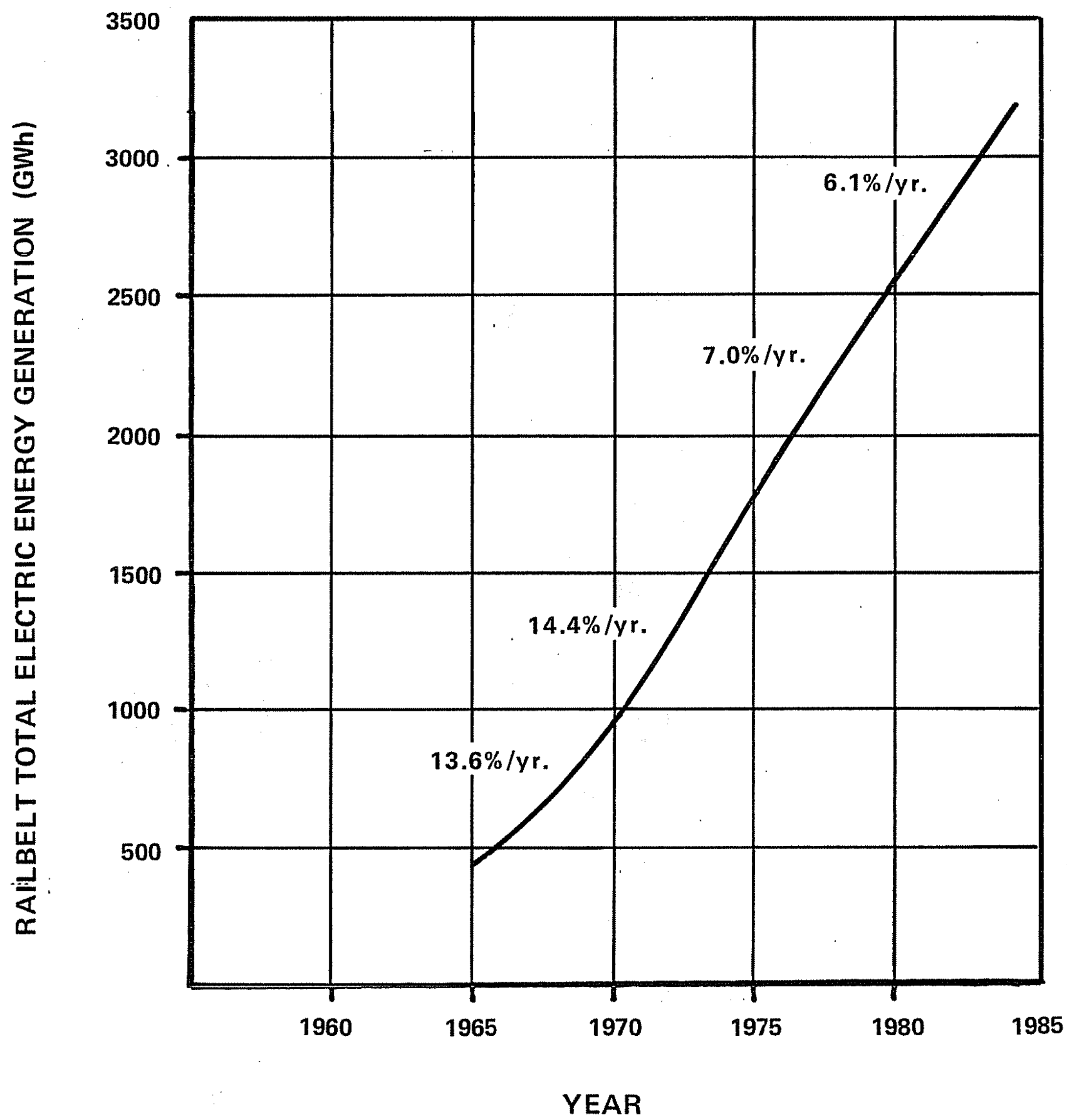


FIGURE B.5.2.4
Page 3 of 3



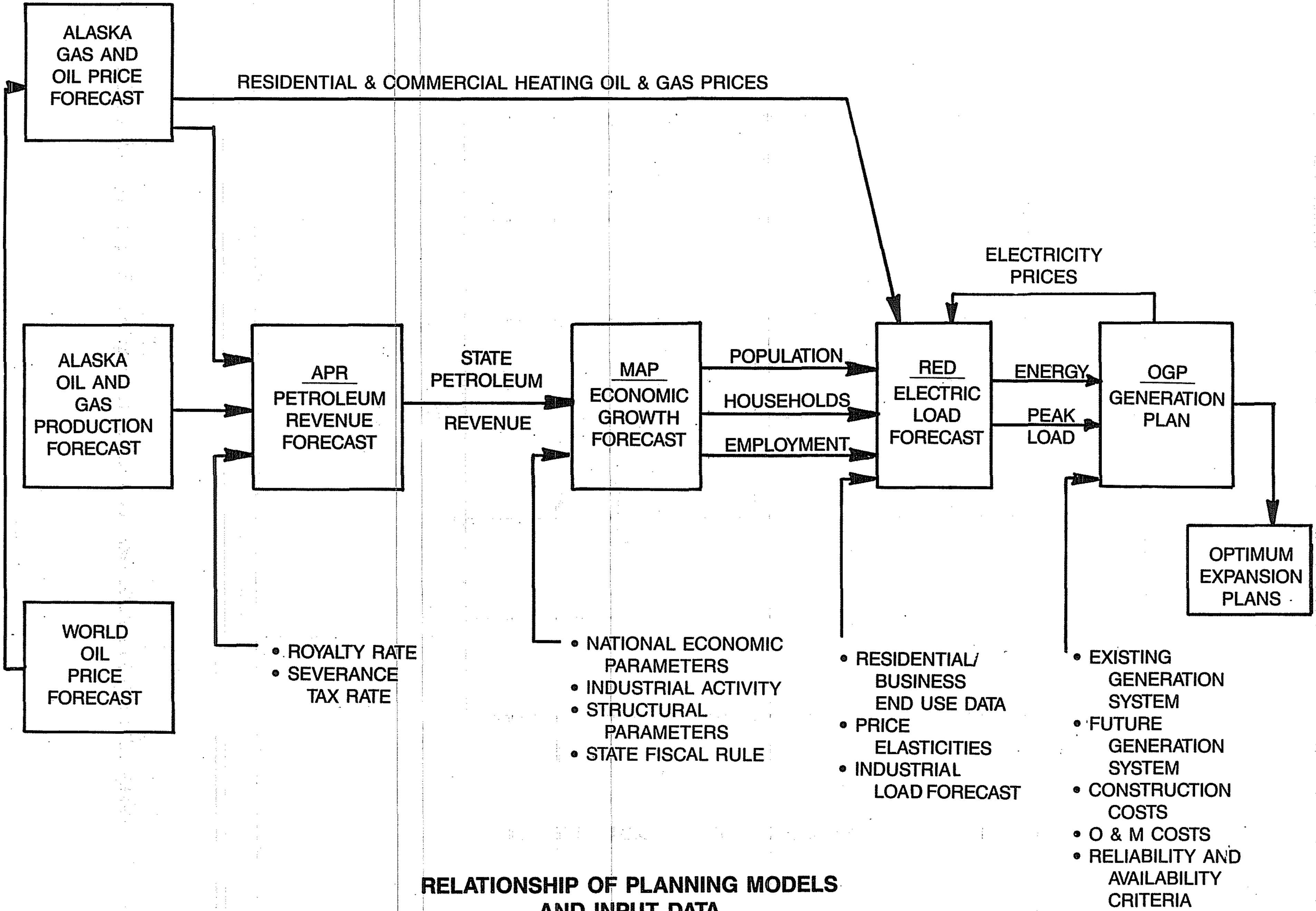
HISTORICAL POPULATION GROWTH

FIGURE B.5.2.5



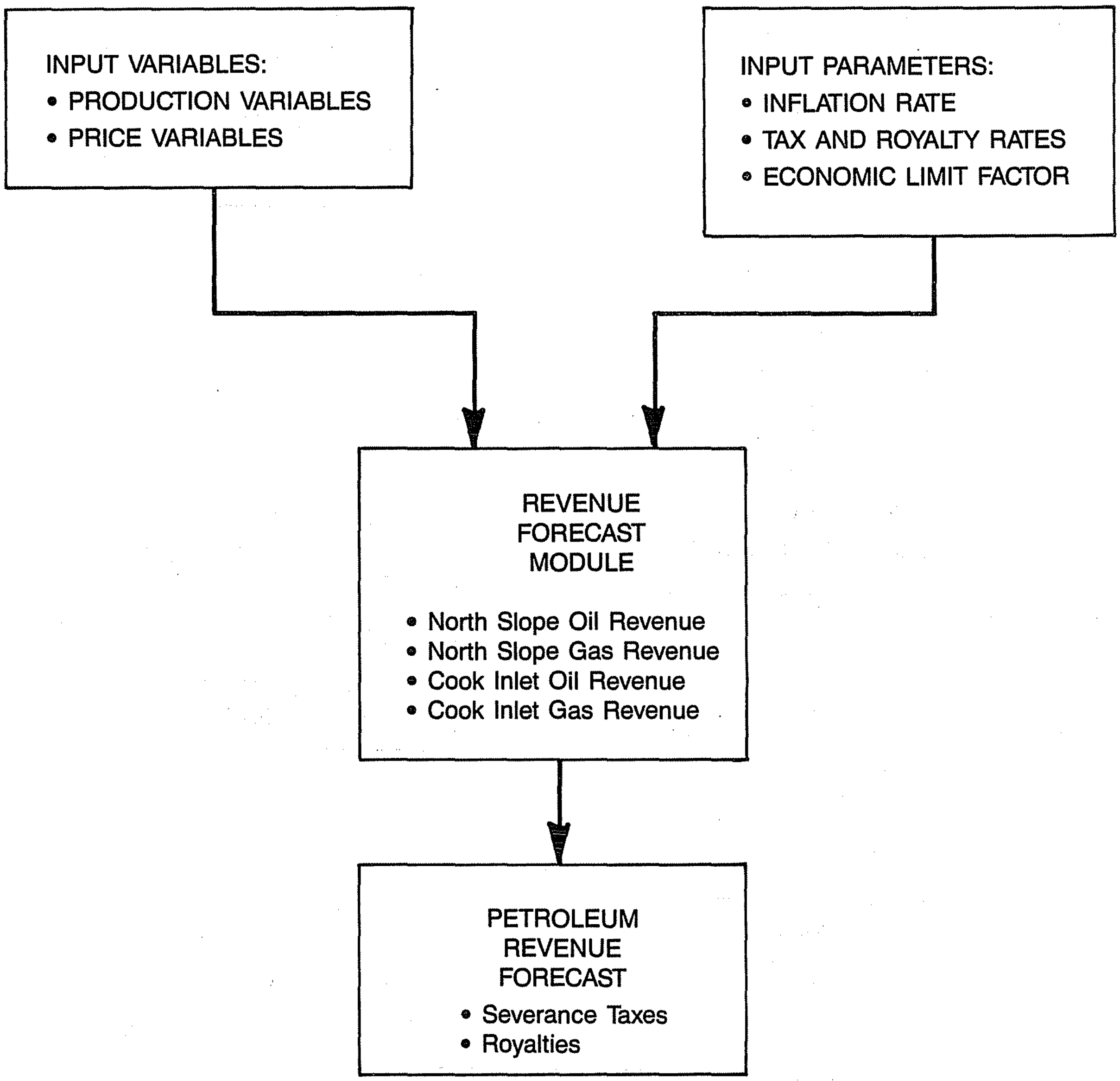
HISTORICAL GROWTH IN UTILITY NET GENERATION

FIGURE B.5.2.6



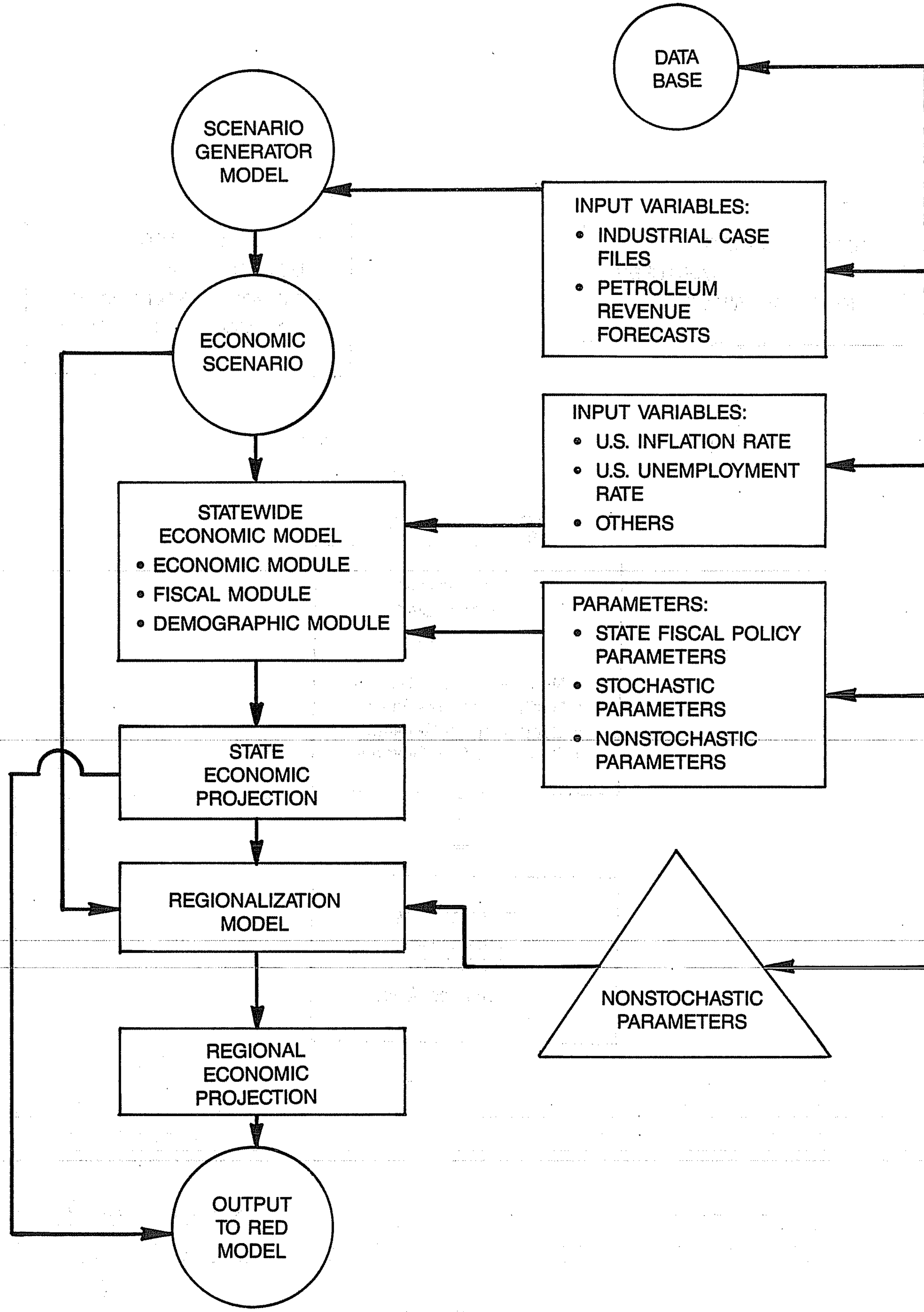
RELATIONSHIP OF PLANNING MODELS AND INPUT DATA

FIGURE B.5.3.1



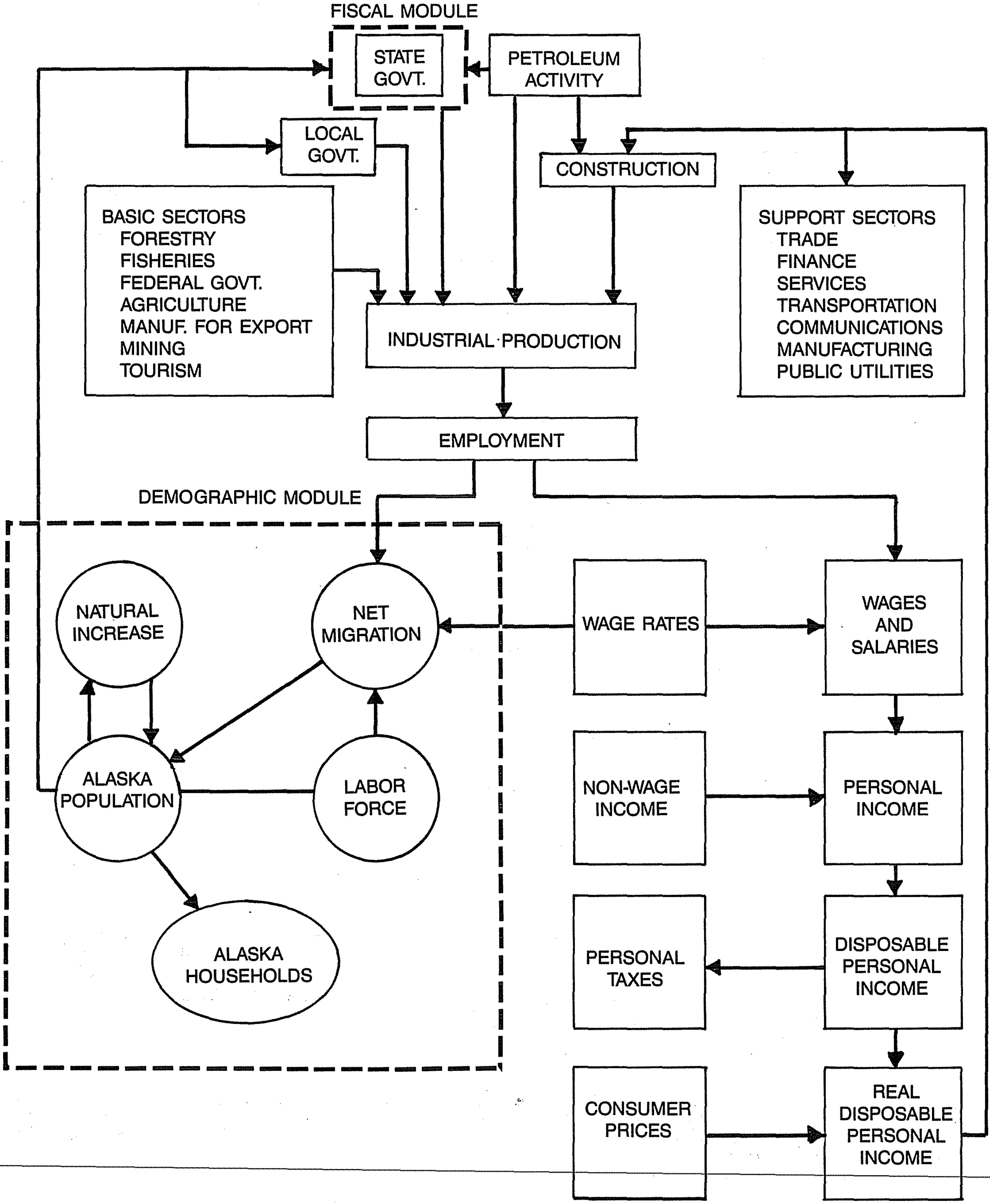
ALASKA PETROLEUM REVENUE SENSITIVITY (APR) MODEL STRUCTURE

FIGURE B.5.3.2



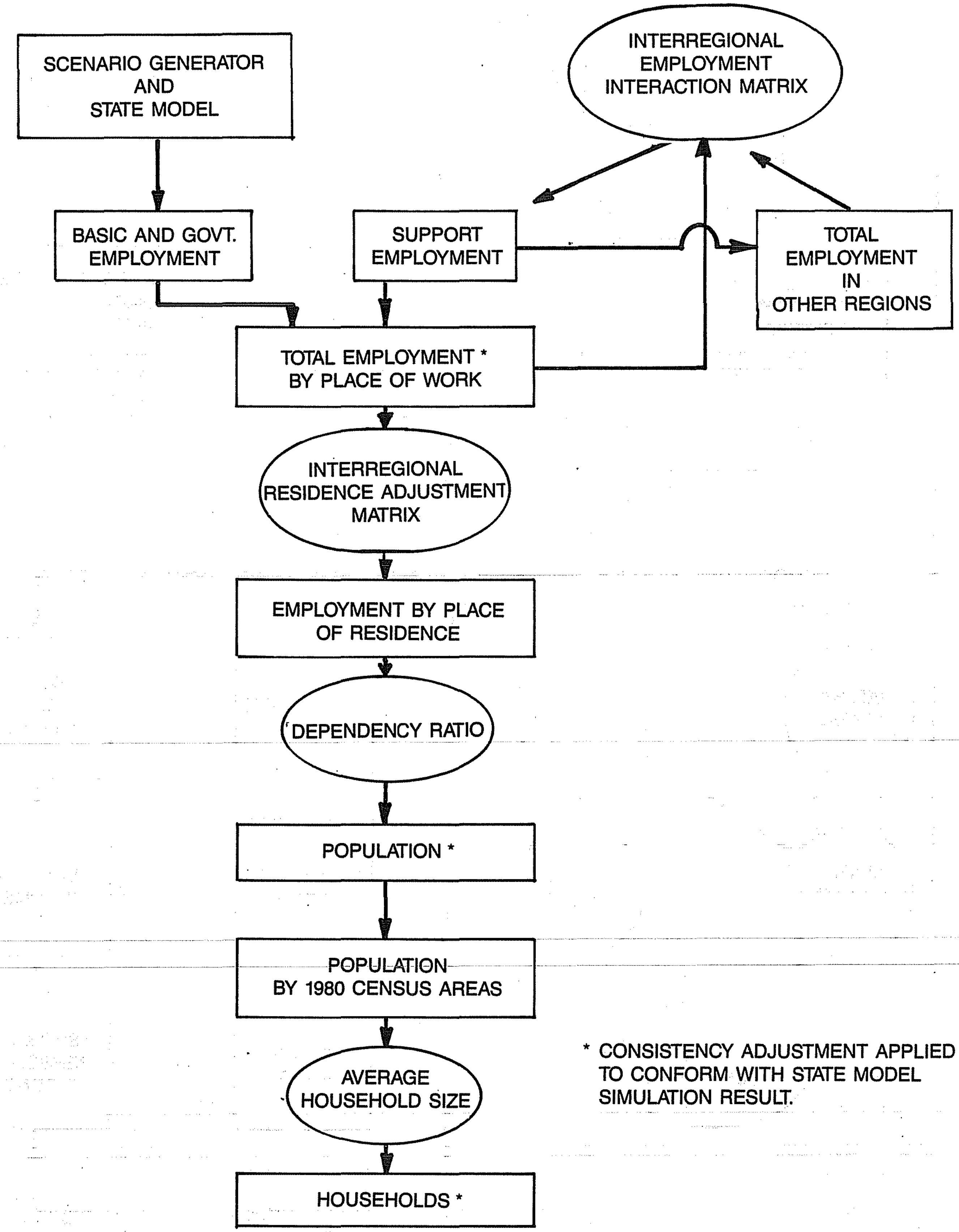
MAP MODEL SYSTEM

FIGURE B.5.3.3



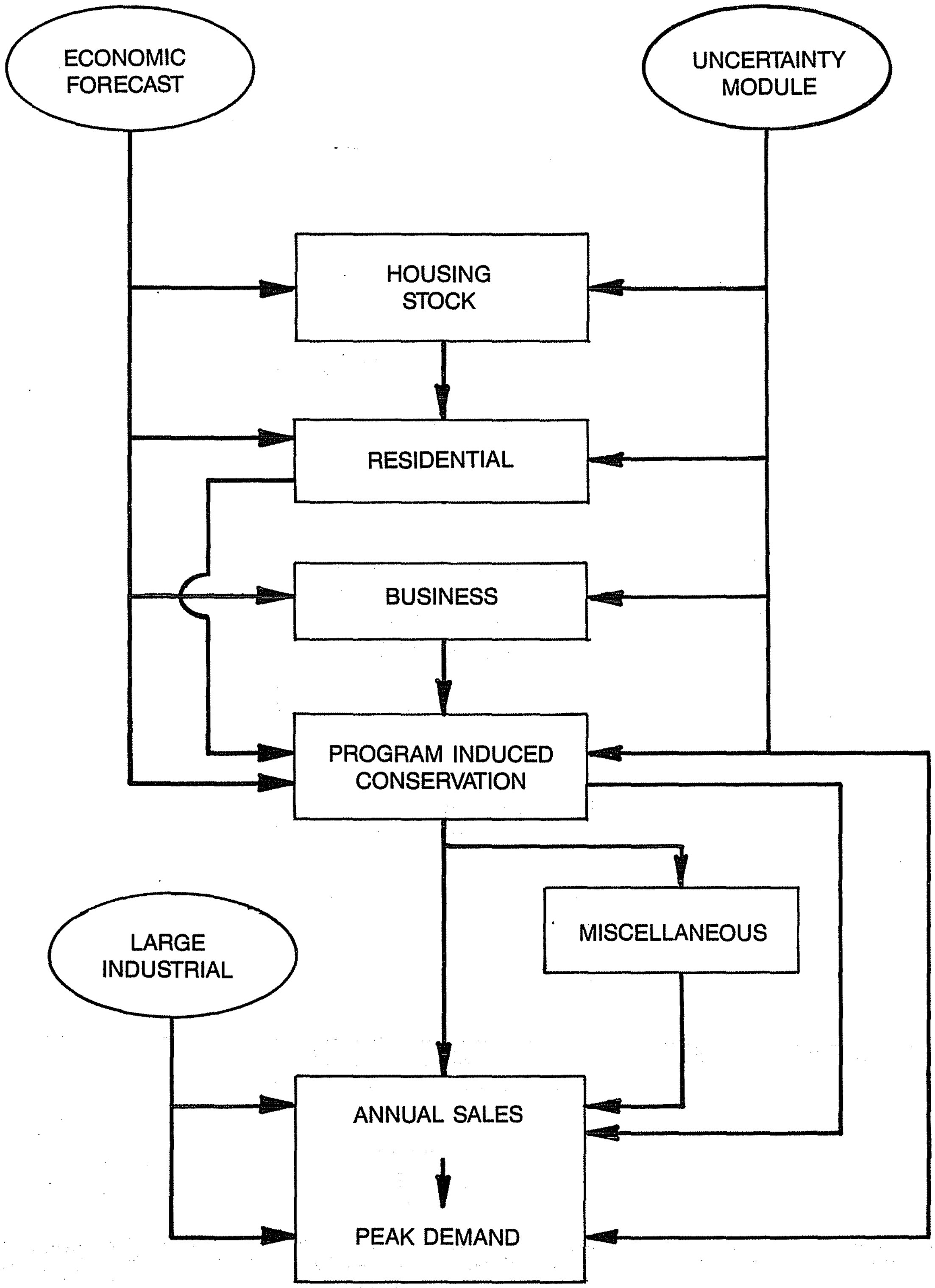
MAP ECONOMIC SUB-MODEL STRUCTURE

FIGURE B.5.3.4



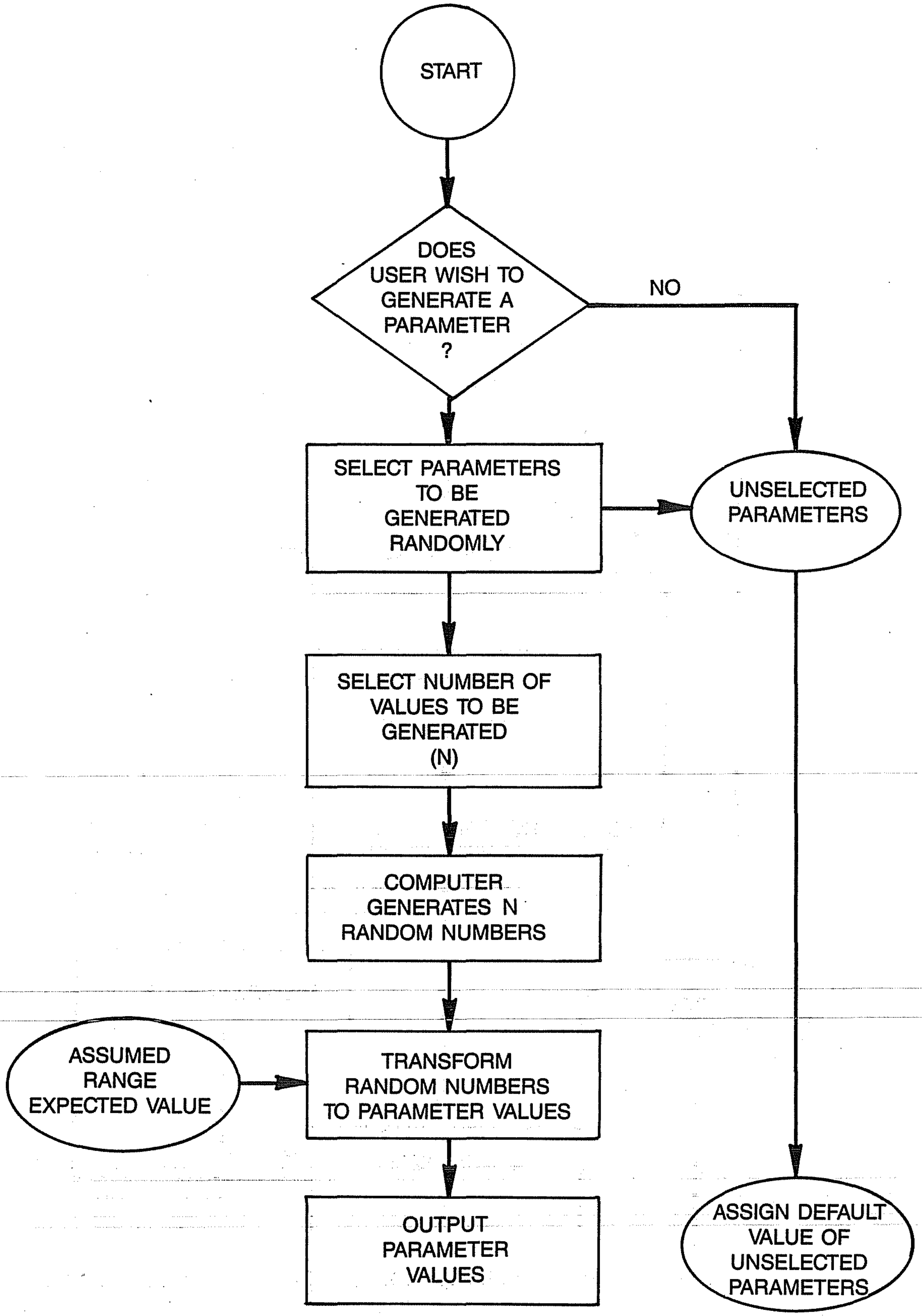
MAP REGIONALIZATION SUB-MODEL STRUCTURE

FIGURE B.5.3.5



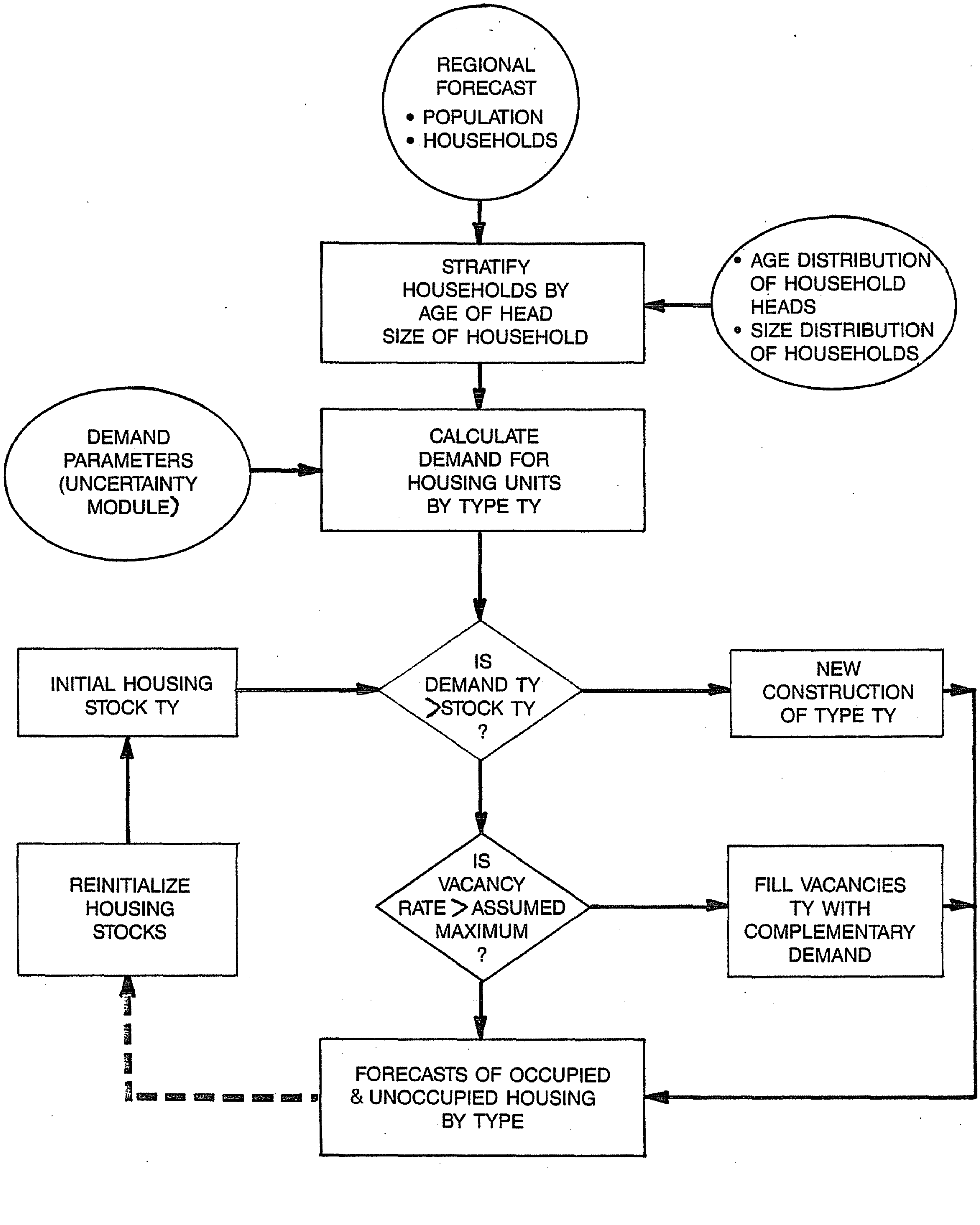
RED INFORMATION FLOWS

FIGURE B.5.3.6



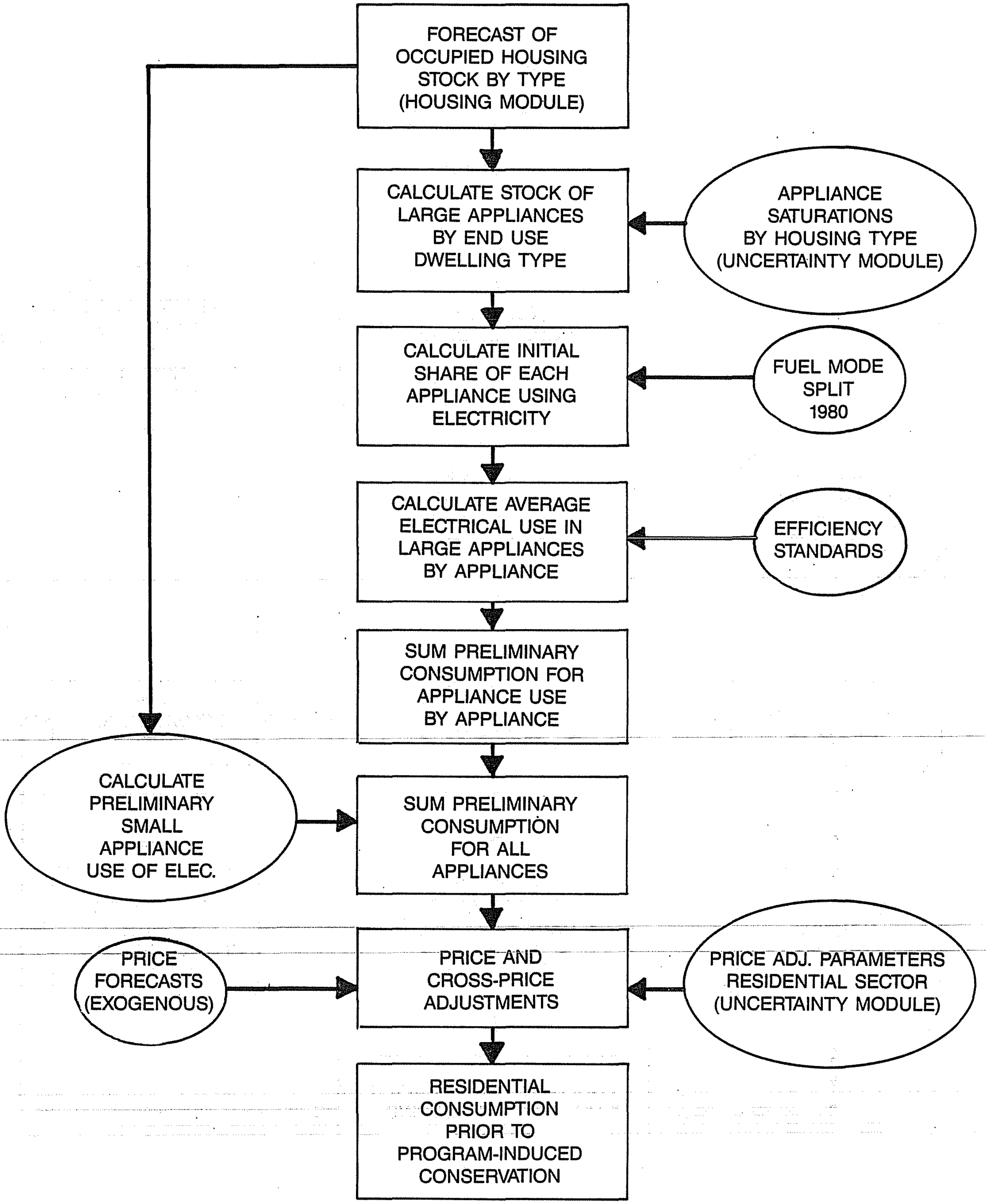
RED UNCERTAINTY MODULE

FIGURE B.5.3.7



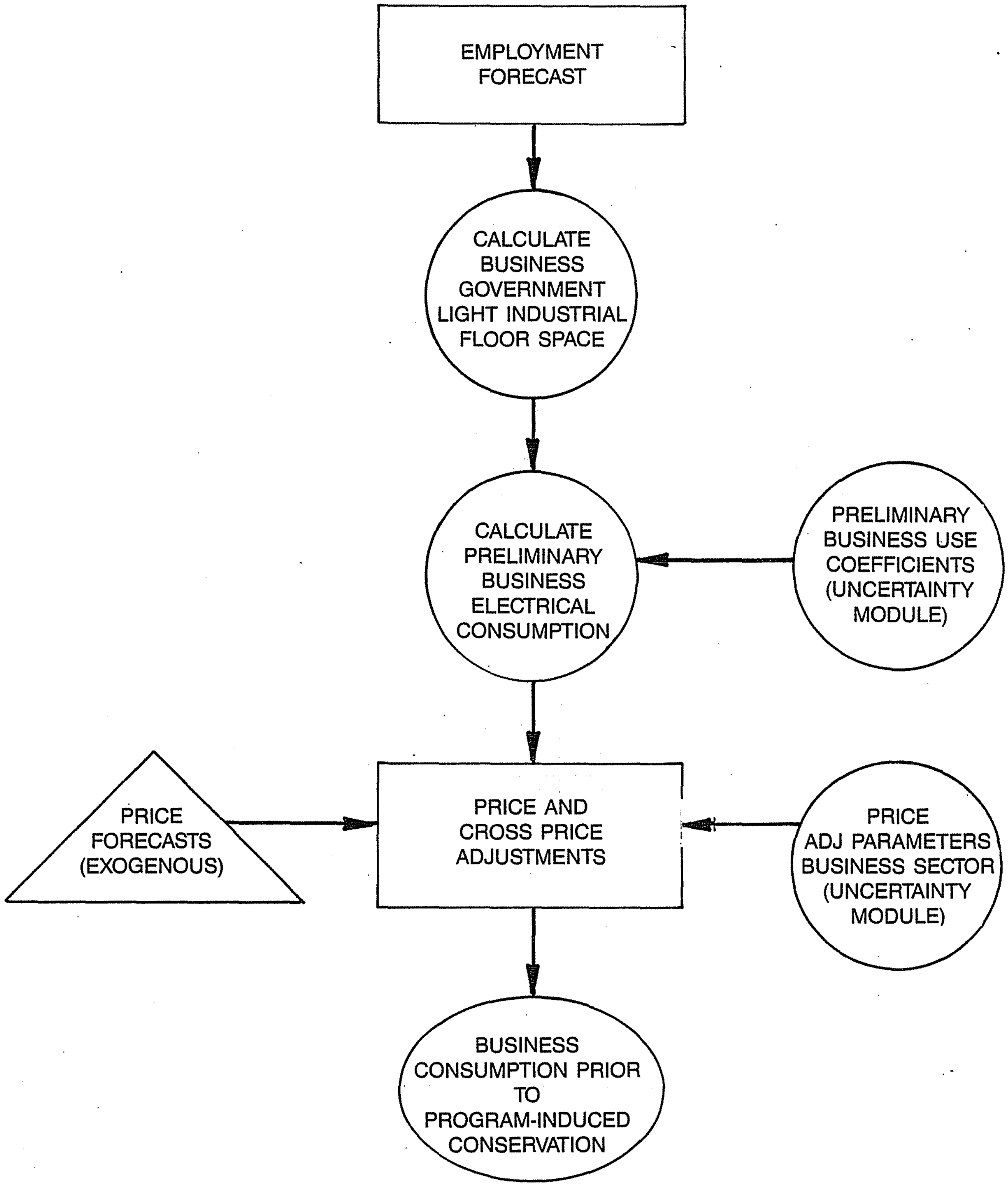
RED HOUSING MODULE

FIGURE B.5.3.8



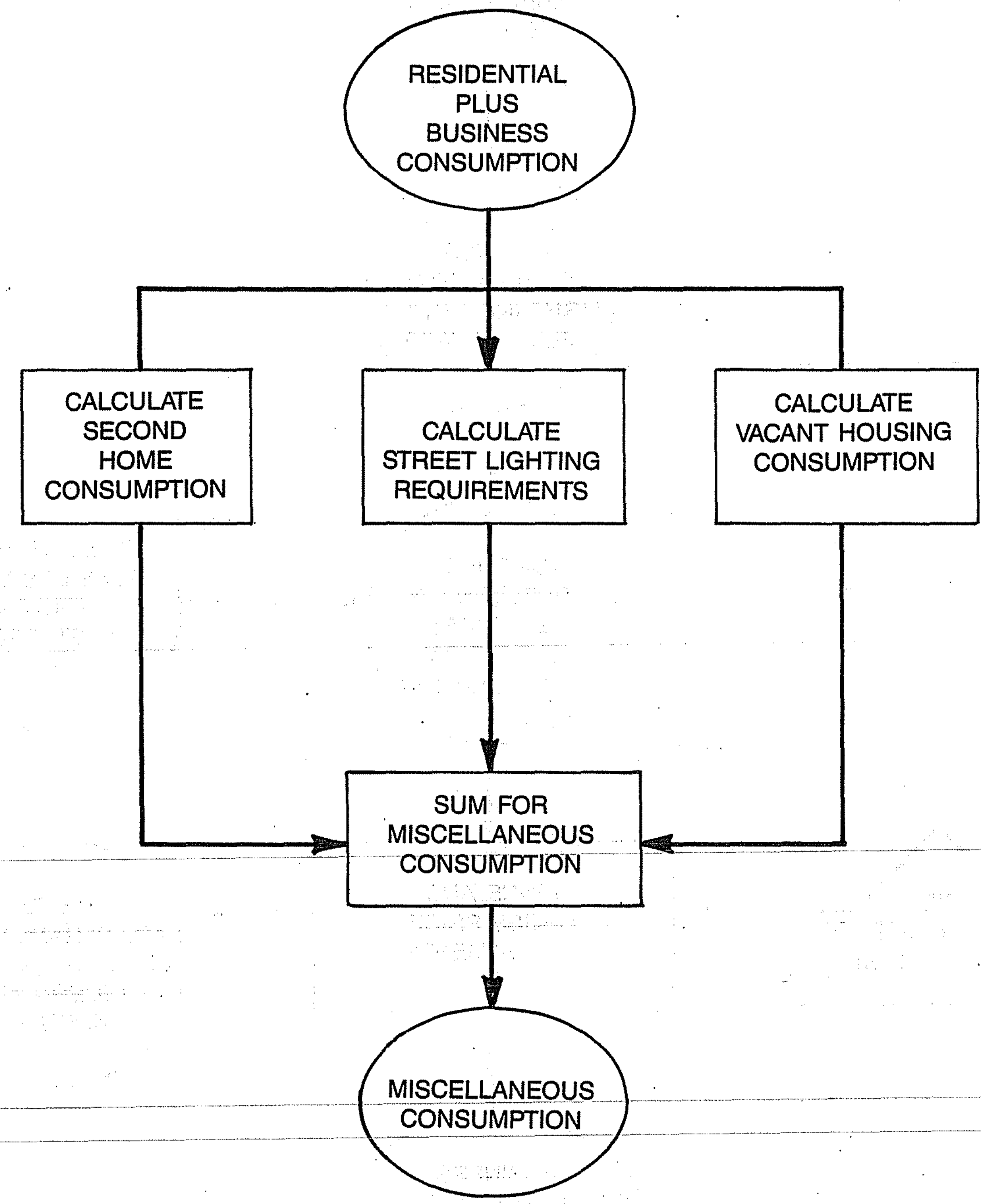
RED RESIDENTIAL CONSUMPTION MODULE

FIGURE B.5.3.9



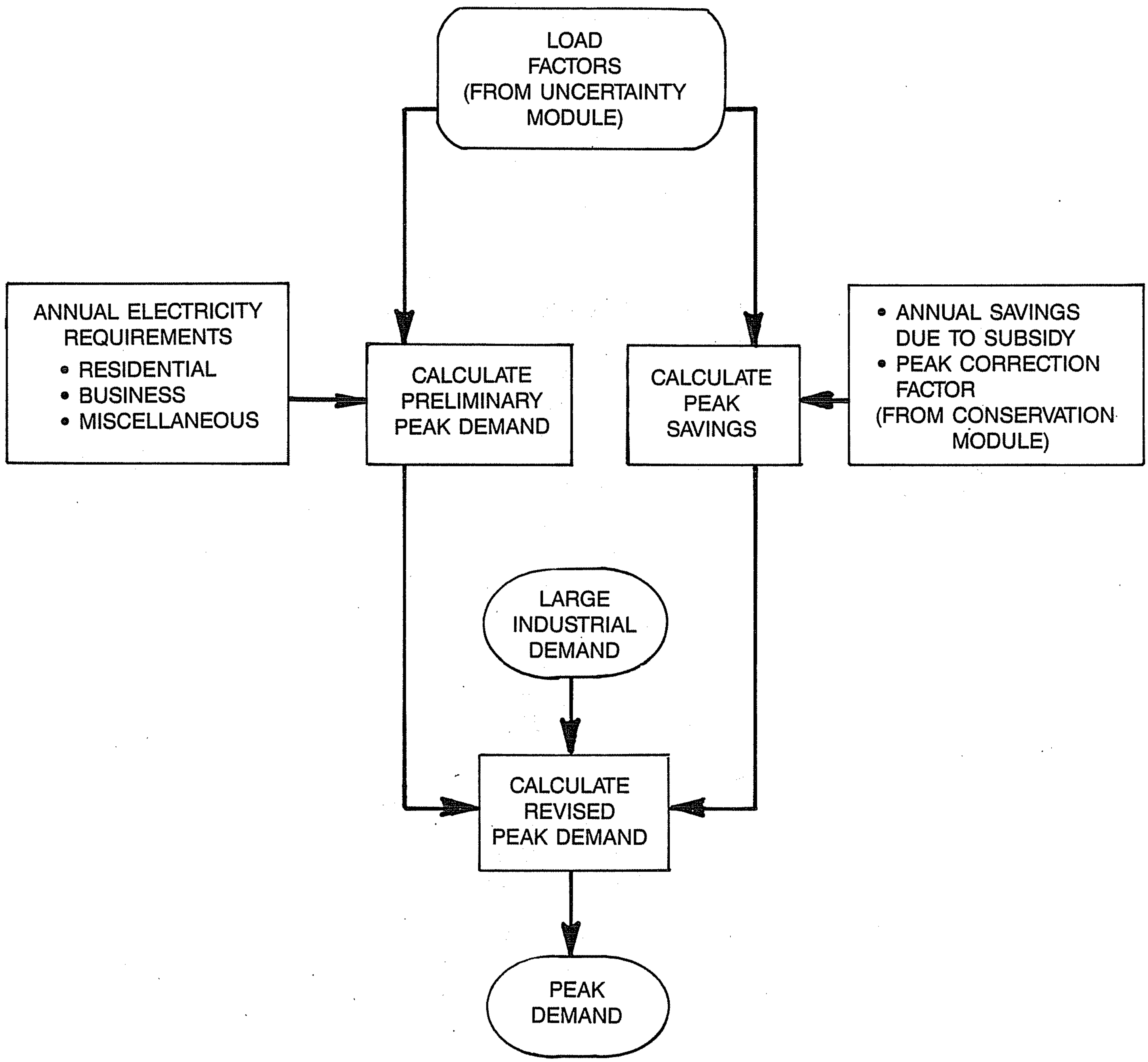
RED BUSINESS CONSUMPTION MODULE

FIGURE B.5.3.10



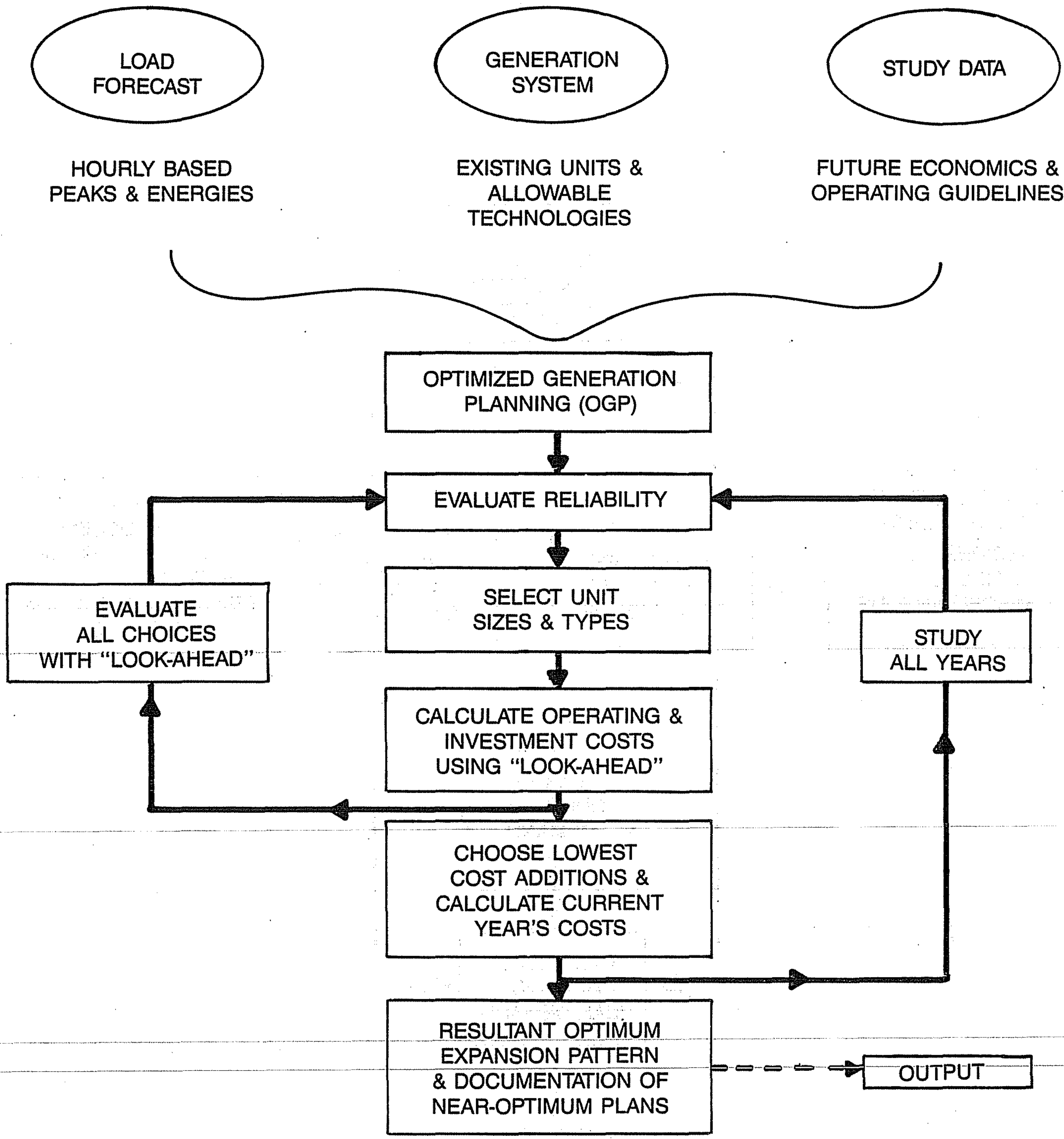
RED MISCELLANEOUS CONSUMPTION MODULE

FIGURE B.5.3.11



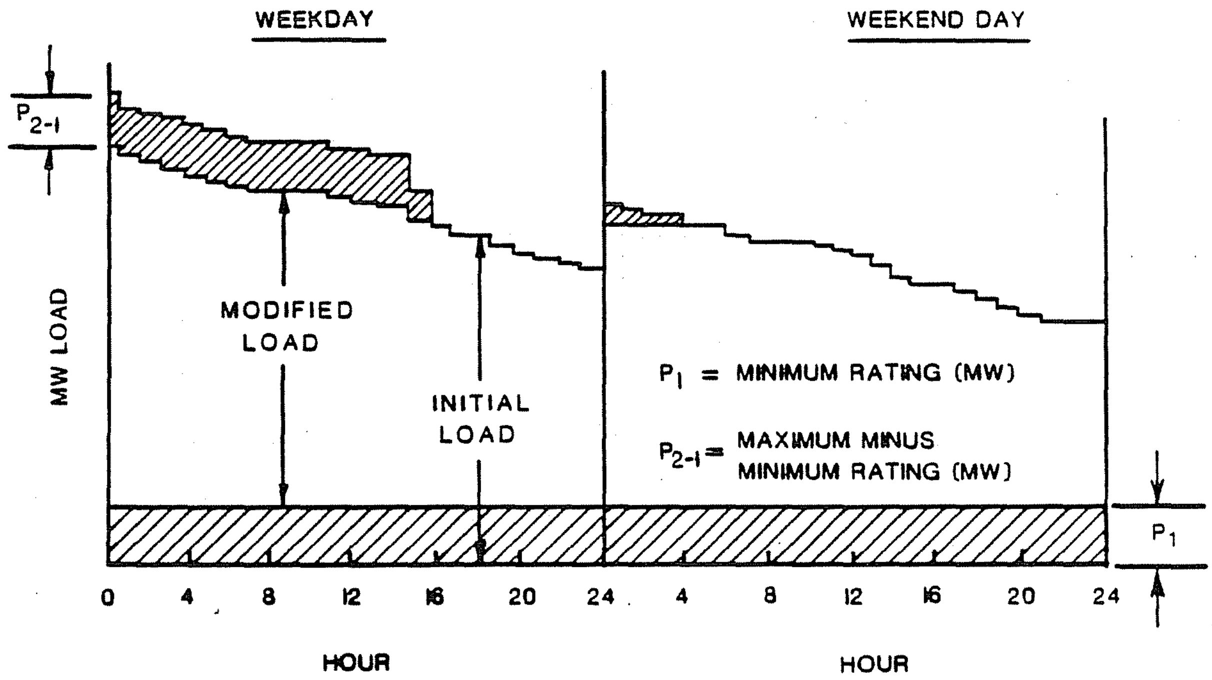
RED PEAK DEMAND MODULE

FIGURE B.5.3.12



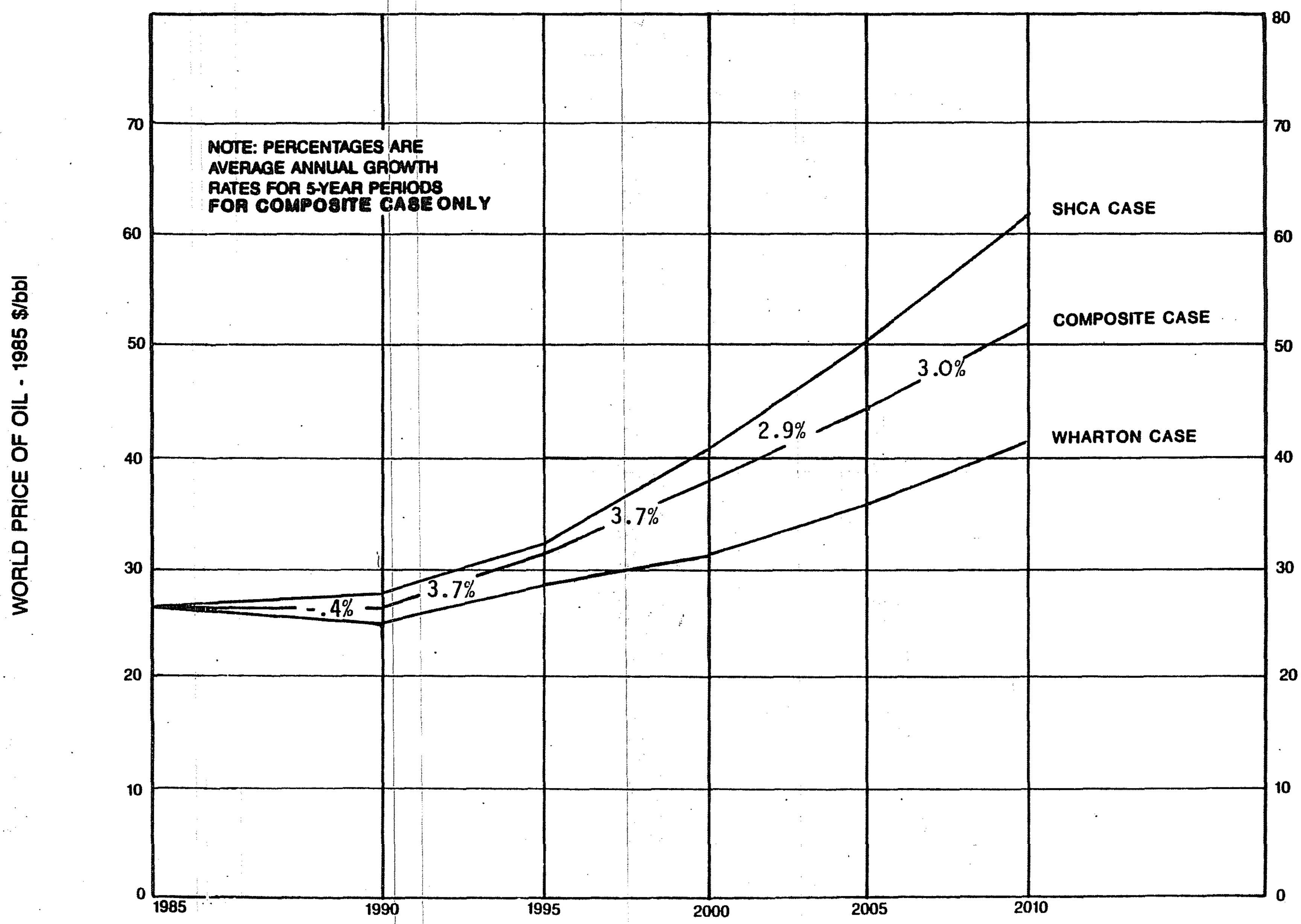
OPTIMIZED GENERATION PLANNING (OGP) PROGRAM INFORMATION FLOWS

FIGURE B.5.3.13



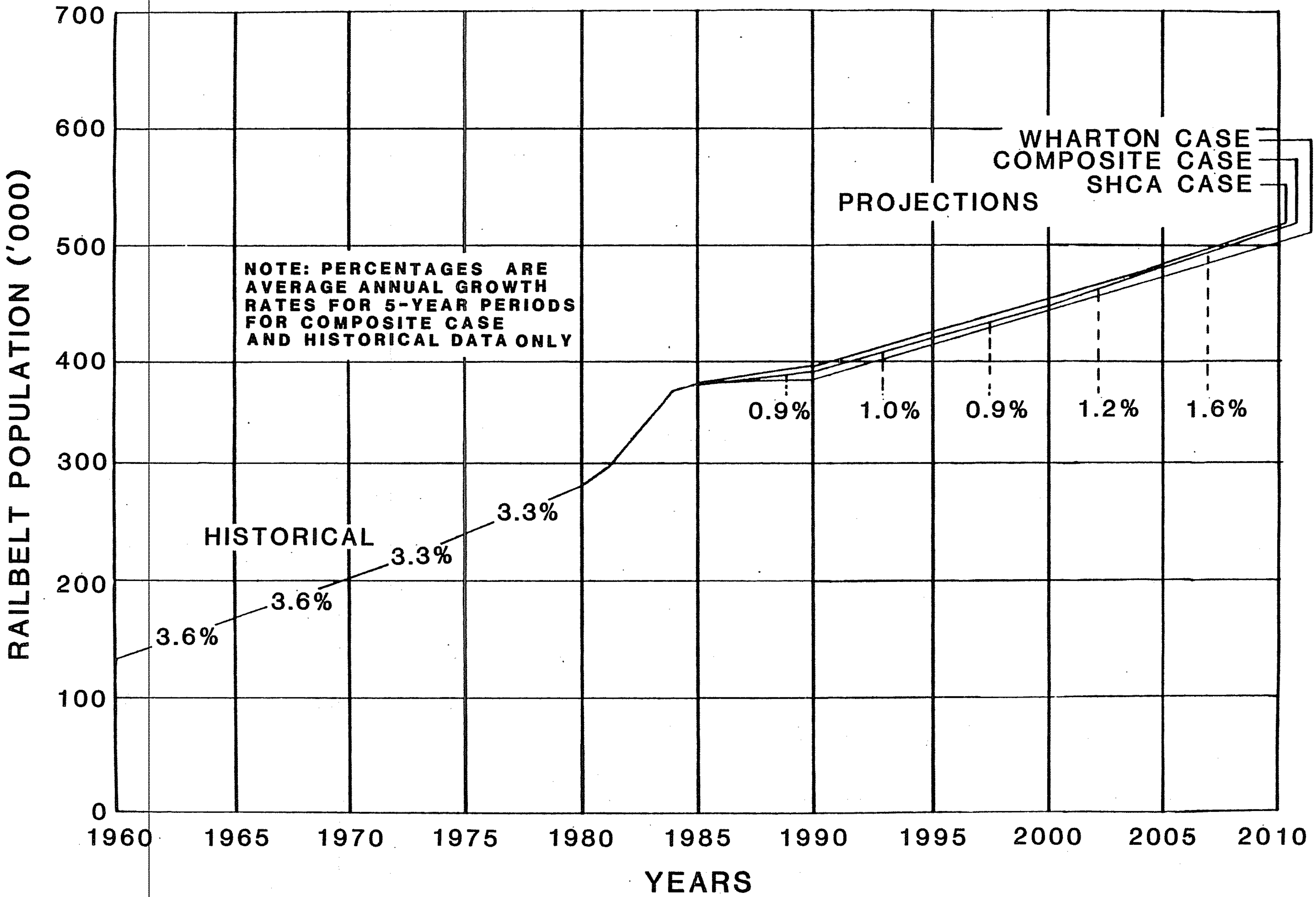
OPTIMIZED GENERATION PLANNING
EXAMPLE OF CONVENTIONAL HYDRO OPERATIONS

FIGURE B.5.3.14



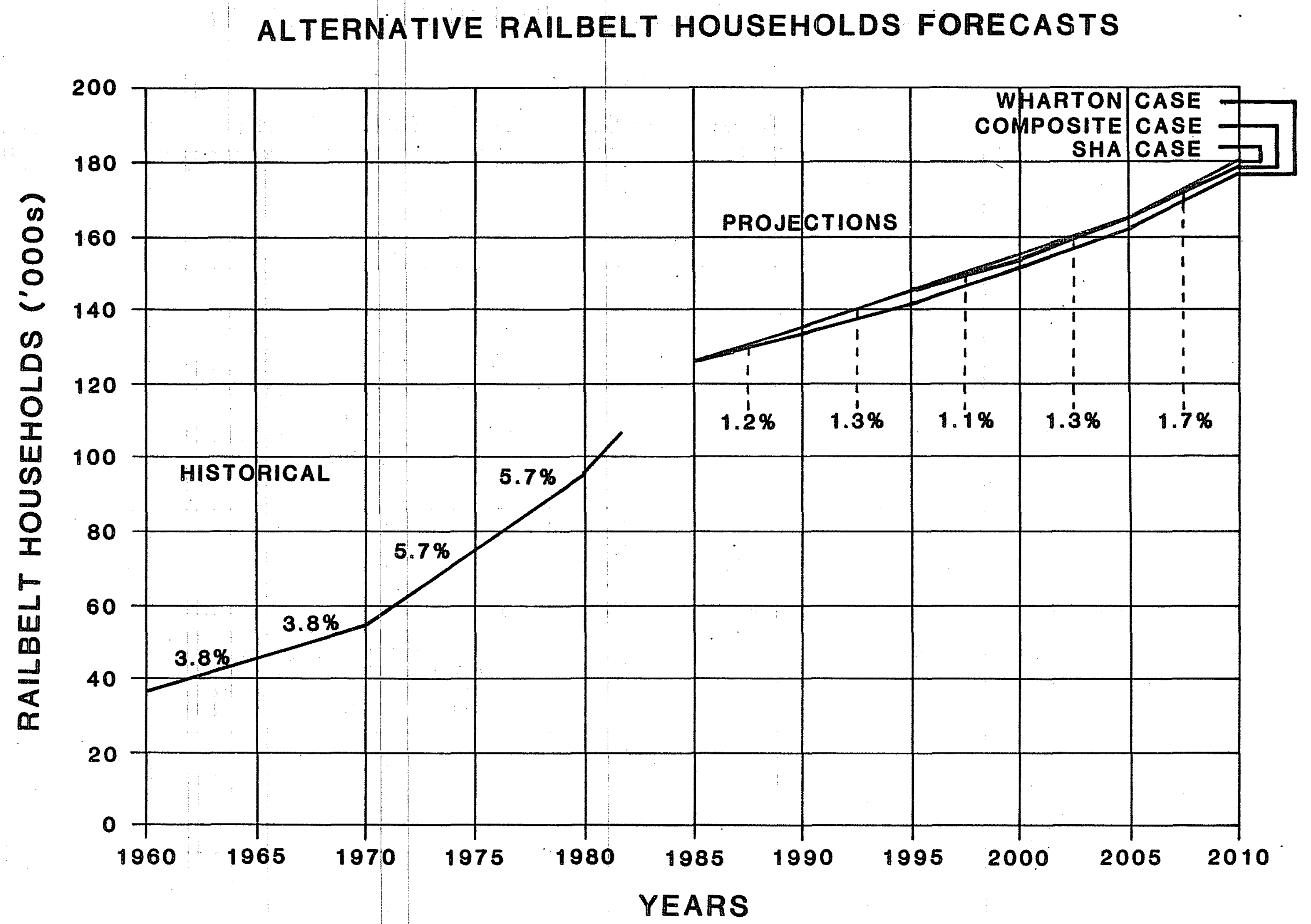
ALTERNATIVE OIL PRICE PROJECTIONS - $/bbl (1985 $)

FIGURE B.5.4.1



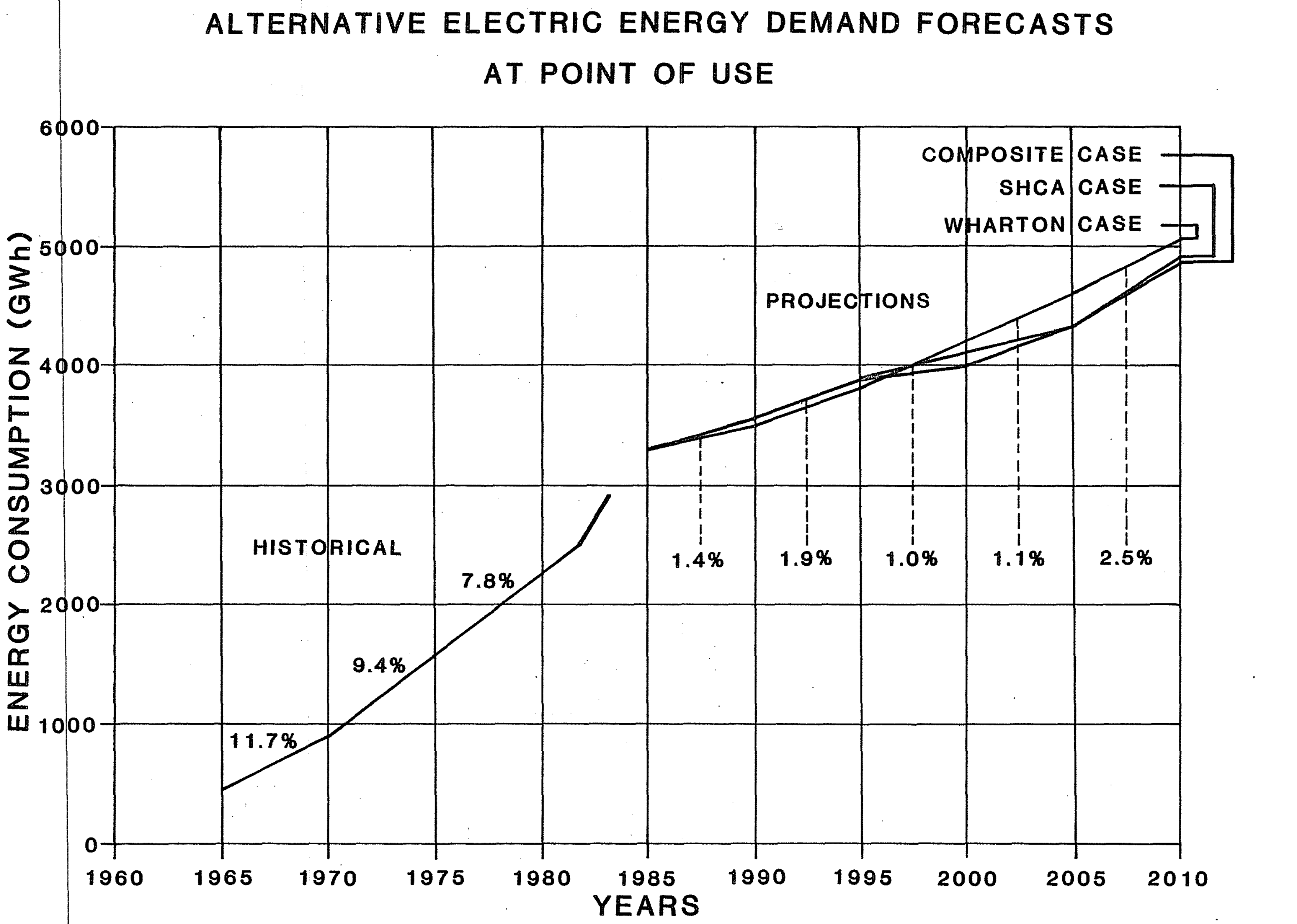
ALTERNATIVE RAILBELT POPULATION FORECASTS

FIGURE B.5.4.2



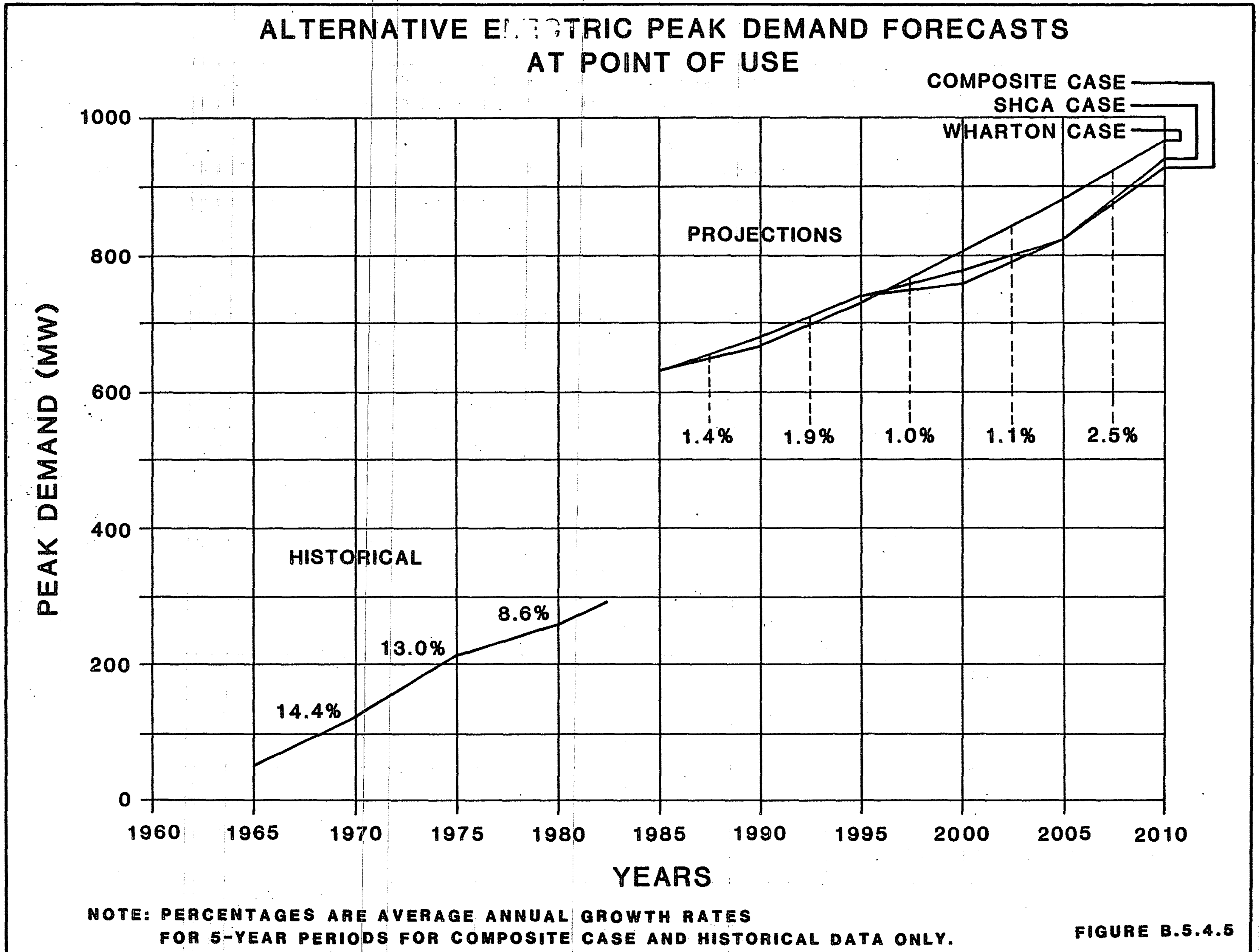
NOTE: PERCENTAGES ARE AN AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS FOR COMPOSITE CASE AND HISTORICAL DATA ONLY.

FIGURE B.5.4.3



NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES FOR 5-YEAR PERIODS FOR COMPOSITE CASE AND HISTORICAL DATA ONLY.

FIGURE B.5.4.4



ALTERNATIVE ELECTRIC PEAK DEMAND FORECASTS
AT POINT OF USE
COMPOSITE CASE
SHCA CASE
WHARTON CASE
PROJECTIONS
HISTORICAL
PEAK DEMAND (MW)
1000
800
600
400
200
0
1.4%
1.9%
1.0%
1.1%
2.5%
14.4%
13.0%
8.6%
1960
1965
1970
1975
1980
1985
1990
1995
2000
2005
2010
YEARS
NOTE: PERCENTAGES ARE AVERAGE ANNUAL GROWTH RATES
FOR 5-YEAR PERIODS FOR COMPOSITE CASE AND HISTORICAL DATA ONLY.

FIGURE B.5.4.5