Southeast Alaska Intertie Study

Phase 1

FINAL REPORT

Prepared for

The Southeast Conference

Juneau, Alaska

by

D. HITTLE & ASSOCIATES, INC.
Engineers and Consultants

December 2003

Southeast Alaska Intertie Study

Phase 1

FINAL REPORT

December 12, 2003

Prepared for

The Southeast Conference

Juneau, Alaska

by

DHITTLE & ASSOCIATES, INC.
Engineers and Consultants

In association with:

Commonwealth Associates, Inc.
CH2M Hill, Inc.
Northstar Power Engineering
Poseidon Engineering, Ltd.

Southeast Alaska Intertie Study
Phase 1

Table of Contents

Section 6 – Power Supply Evaluation and Economic Analysis

Section 7 - Comparison of AC, HVDC and HVDC/VSC Technologies

List of Tables

List of Figures

Introduction and Conclusions

Introduction

Southeast Alaska is characterized by numerous islands, marine passages, mountains, and evergreen forests in a wet, relatively temperate climate. The combination of high precipitation levels and the mountainous terrain provides significant opportunity for hydroelectric generation. The mountainous, island environment, however, has limited the development of roads and other infrastructure systems, including electric transmission lines, to relatively confined areas surrounding the region's cities, towns and villages. Consequently, although significant hydroelectric power is available in some locations, the lack of power transmission facilities prevents its distribution to the region as a whole.

Electric service in Southeast Alaska is provided by community-based electric utilities that for the most part, are electrically isolated from each other. Essentially all electric power in the region is supplied by either hydroelectric power plants or diesel engine generators. Hydroelectric facilities provide the majority of the power requirement in Juneau, Ketchikan, Sitka, Petersburg, Wrangell, Skagway, Haines, Metlakatla, Craig and Klawock. In communities where hydroelectric power is not available, the reliance upon diesel generation has contributed to very high retail electric rates. Diesel power generation also involves a number of problems including dramatic fluctuations in fuel price, concerns with fuel handling, potential interruption in fuel delivery, air pollution and noise.

Economic activity in Southeast Alaska has traditionally been focused on logging, pulp manufacturing, fishing, seafood processing, mining, government and tourism. In recent years, activity in the timber industry has declined significantly with the closure of pulp mills in Ketchikan and Sitka and federal restrictions on logging in the Tongass National Forest. Lower cost electricity throughout the region has long been identified as an important element in attracting other commercial activities that could expand the economy in the future. As a result, the Southeast Conference has undertaken the evaluation of the costs and benefits associated with constructing transmission lines between various communities in Southeast Alaska.

The immediate purpose of a Southeast Alaska transmission system is to provide lower cost hydroelectric generation to communities where electric power is presently supplied with diesel generators. In the long term, an interconnected electric system in Southeast Alaska would potentially encourage the development of new hydroelectric plants on a regional, rather than a local community basis. With a larger connected load base, the initial cost of power from new hydroelectric plants might also be lower, providing cost savings to all utility customers. Further development and utilization of hydroelectric power in the region would also reduce air pollutant emissions.

In late January 2003, the Southeast Conference retained D. Hittle & Associates, Inc. (DHA) to conduct a study of a proposed Southeast Alaska transmission system (the "Intertie Study"). Since several studies of transmission systems in the region have been conducted in the past, the

Intertie Study serves to update the previous work as well as incorporate recent developments and other new information. In order to expedite the evaluation of certain interconnections, the Intertie Study has been separated into two phases as follows:

- Phase 1 – Evaluation of transmission interconnections between (a) Kake and Petersburg and, (b) Juneau, the Kennecott Mining Company - Greens Creek Mine (KMC-GC) on Admiralty Island and Hoonah.

- Phase 2 – Evaluation of a transmission system that interconnects all of the communities of Southeast Alaska.

This report summarizes the findings of Phase 1 of the Intertie Study. The findings of Phase 2 will be presented in a subsequent report. The primary objective of the Intertie Study is to estimate the costs and benefits associated with the proposed transmission interconnections. Benefits are essentially identified as the net savings in power production expenses resulting from the use of transmitted hydroelectric energy to offset diesel generation. Although the costs of operating and maintaining the transmission lines are included, construction costs are assumed to be grant funded and as such, do not factor in to the analysis of costs and benefits. The Southeast Conference has indicated that it, as well as other stakeholders, will pursue State and federal grants to fund the transmission systems. The cost of construction, however, has been reviewed as part of the Intertie Study.

The Intertie Study provides a feasibility assessment of the proposed transmission systems. If the Southeast Conference or other entities decide to pursue development of one or more of the transmission lines, additional study work will be needed as will actual design and permitting. There will also need to be various contracts for power purchases, operations, and maintenance and other commercial arrangements to be negotiated.

Phase 1 of the Intertie Study focuses solely on transmission lines between Juneau, KMC-GC and Hoonah (referred to as Southeast Intertie 1 or "SEI-1") and between Kake and Petersburg (referred to as Southeast Intertie 2 or "SEI-2"). SEI-1 will be used to transmit hydroelectric generation from Alaska Electric Light & Power (AEL&P) to KMC-GC and to the electric system of Tlingit-Haida Regional Electric Authority (THREA) in Hoonah. SEI-2 will be used to transmit hydroelectric generation from the Lake Tyee hydroelectric project owned by the Four Dam Pool Power Agency to THREA's service area in Kake. Both SEI-1 and SEI-2 have been studied in fairly significant detail in the recent past.

The tasks undertaken for Phase 1 of the Intertie Study, as they pertain to SEI-1 and SEI-2, are described as follows:

- Obtain and review previous studies of the transmission systems;

- Review the proposed routes of the transmission lines and provide adjustments as needed to reflect current information;

- Review previously developed estimated costs of constructing the transmission lines, and provide adjustments as needed to reflect current information;

- Review and define the necessary permitting requirements for the transmission lines and identify critical environmental and permitting issues;
- Estimate the costs and time required to obtain necessary permits to construct the transmission lines;
- Review issues and cost estimates associated with proposed submarine cables to be used in the transmission systems;
- Evaluate the use of newer direct current (dc) technologies for the transmission systems as compared to more traditional alternating current (ac) technologies;
- Estimate the annual costs of operating and maintaining the transmission systems;
- Estimate the annual deposit needed to establish a reserve fund for major repairs of the transmission systems;
- Forecast the energy requirements for Kake, Hoonah and KMC-GC;
- Estimate and compare the cost of power production in Kake, Hoonah and KMC-GC based on (1) the present power production system and (2) the interconnected systems;
- Summarize the results and conclusions of Phase 1 in a report.

It should be noted that a number of issues related to technical specifications for SEI-1 and SEI-2 have been identified that cannot be fully determined until the Phase 2 study is completed. For example, the size of conductors and cables that comprise the transmission systems may be different if the lines continue beyond Kake and Hoonah to Sitka, Angoon and other locations[1]. Exact specifications for the line components will be determined during final design, however, the assumptions used in the Phase 1 study are considered reasonable for evaluating the feasibility of the systems. Additional information with regard to SEI-1 and SEI-2, as needed, will be provided in the Phase 2 report.

Finally, the economic analysis conducted as part of the Intertie Study looked only at the cost of power production in the communities to be served by the proposed transmission systems. The cost of power production is typically the most significant component of an electric utility's revenue requirement; however, there are other costs that figure significantly into the basis for electric rates charged retail customers. Although the cost of power production may be reduced through alternative means of power supply, other costs may continue to keep retail rates at a high level. The State's Power Cost Equalization (PCE)[2] program also affects how much of the benefit

[1] The Southeast Alaska Intertie System, as proposed in previous studies, includes an interconnection between the northern and southern parts of the system. The previous studies have identified options for the north-south interconnection to be between Hoonah, Angoon, Sitka and Kake or between the Snettisham hydroelectric project and Kake.

[2] The Power Cost Equalization (PCE) program subsidizes retail electric rates for residential customers and public facilities in qualifying communities. The funding of the PCE program is granted by the State legislature on an

of lower production costs ultimately reach the electric consumer. Aside from the estimation of power production costs, the Intertie Study has not attempted to evaluate retail electric rates in Southeast Alaska.

Study Approach

Phase 1 of the Intertie Study relied upon the previous work of others in conjunction with new investigation and analysis. In this manner, prior studies and reports contributed significantly to the current study effort and in conjunction with the present study provide a much larger knowledge base than could be established with the Intertie study alone. The prior work reviewed includes transmission interconnection studies, power supply studies, hydroelectric generation feasibility studies, electric load forecasts and utility transmission design efforts. Because of the time and scope limitations for Phase 1 of the Intertie Study, the previous studies were relied upon most extensively with regard to technical and routing issues related to the proposed transmission systems. Much has changed in recent years with regard to transmission facilities in Southeast Alaska, and as a whole, the Intertie Study reflects a significant update to the previous studies.

In conducting Phase 1 of the Intertie Study, previous studies were obtained and reviewed, new information was gathered, and discussions were held with a number of utility, community, and government representatives. A feasibility level technical evaluation was conducted based on a review of previous studies, discussions with utility personnel familiar with the area and consideration of current utility practice. The technical review included consideration of the line route, system configuration, design criteria, and cost.

The proposed routes of SEI-1 and SEI-2 were reviewed but not significantly changed from those shown in previous preliminary design studies[3]. SEI-1, the Juneau – Greens Creek – Hoonah line, has been preliminarily configured by AEL&P in a manner consistent with AEL&P's existing system. The Intertie Study reviewed AEL&P's proposed plan and for the most part, made only minor adjustments to it. Some new effort was made on the routing and configuration of SEI-2 since it has not been evaluated in as much detail as SEI-1. Revised cost estimates have been developed for each of the two Interties.

A significant amount of new effort was conducted with regard to power supply analysis and the economic analysis of the Interties. This portion of the Intertie Study involved the projection of power requirements and the estimation of alternative power production costs. As with any analysis of this kind, a number of assumptions were made and it is important to note that the use of alternative assumptions could produce different results. A sensitivity analysis has been prepared, however, to provide a range of possible outcomes resulting from certain adjustments to the base assumptions.

In conducting the economic analysis for the Intertie Study, terms and conditions of existing contracts and agreements have been acknowledged to assure that the analysis appropriately

annual basis and no guarantees can be provided with regard to its continuation in the future. An endowment was created in 2002 using funds from the divestiture of the Four Dam Pool to fund a portion of the PCE program.

[3] The proposed routes are generally identified among the "potential power transmission corridors" in the 1997 Revision of the Tongass National Forest Land and Resource Management Plan.

models the commercial environment in which the Interties will operate. The question then becomes, is the Intertie economically justifiable from the perspective of the specific utilities that will be connected to it? Many transmission and power supply studies in the past have looked at economic viability from a regional or possibly even a "societal" basis.

Another significant difference in the Intertie Study compared to previous studies is that the capital costs (i.e. costs of planning, permitting, construction, financing, etc.) of the Intertie systems are not included in the evaluation of costs and benefits. It has been assumed[4] that the Interties will be grant funded and will have no capital recovery component associated with their future cost structure.

This study has been prepared in association with several other firms. Commonwealth Associates, Inc. was responsible for the review of overhead transmission routes and cost estimates; CH2M-Hill reviewed permitting requirements and prepared an estimate of the cost and time to obtain the necessary permits; Northstar Power Engineering prepared an evaluation of direct current (dc) transmission alternatives; and Poseidon Engineering Ltd. reviewed issues regarding the submarine cables to be used in the Interties. D. Hittle & Associates had primary responsibility for the power supply and economic analyses and for overall coordination of the study effort.

It should also be understood that the Intertie Study is a feasibility assessment. The technical information and cost estimates presented in this report are subject to change as more additional studies are conducted and more information is obtained. Actual design of the systems, if pursued in the future, will provide much more detailed specification of the system components, routes and configuration and allow for greater precision on estimating costs. The actual cost of constructing the system, however, will be subject to a number of factors including market conditions at the time bids for material and construction services are requested.

Previous Studies

Two previous studies have addressed the feasibility of developing an integrated electrical transmission intertie system for Southeast Alaska. Both SEI-1 and SEI-2 were addressed in these studies. The two previous overview studies were:

- The "*Southeast Alaska Transmission Intertie Study*" was prepared for the Alaska Energy Authority by Harza Engineering Company and dated October 1987. This study was an intensive effort that involved a significant amount of survey work in the field and evaluated transmission segments to most communities throughout the region extending from Skagway in the north to Ketchikan in the south[5]. The study consolidated much of the knowledge at the time regarding potential transmission routes and concluded: "…that a transmission system interconnecting many of the Southeast Alaska communities is technically and economically feasible".

[4] This assumption has been provided by the Southeast Conference.
[5] The 1987 Harza Study also included the evaluation of transmission interconnections to Whitehorse, Yukon Territory, Prince Rupert, British Columbia, and the proposed Quartz Hill molybdenum mine in the Misty Fiords National Monument south of Ketchikan.

- The "*Southeast Alaska Electrical Intertie System Plan*" was prepared for the Southeast Conference by Acres International and dated February 1997. The Acres study compiled information from previous studies and provided estimated costs and a time frame for the development of a Southeast Alaska Intertie system.

An Intertie from Juneau to Greens Creek Mine was addressed in the following study:

- *Greens Creek Transmission Line Planning Capital Cost Estimate*, prepared for the Alaska Energy Authority by R. W. Beck and Associates, Inc., December 1992.

An Intertie from Petersburg to Kake has been specifically addressed in three earlier studies starting in the early 1980's with the last being conducted in 1996. These studies were:

- *Transmission Intertie, Kake-Petersburg, A Reconnaissance Report*, prepared for the Alaska Power Authority by Robert W. Retherford Associates, January 1981.
- *Tyee-Kake Intertie Project, Detailed Feasibility Analysis, Volumes I and II* , prepared for the Alaska Power Authority by Ebasco, Inc., 1984.
- *Feasibility Study Kake-Petersburg Intertie*, prepared for the State of Alaska, Department of Community and Regional Affairs, Division of Energy by R. W. Beck, Inc., June 1996.

A number of other studies have been conducted in recent years evaluating power supply alternatives in Southeast Alaska. Several of these studies considered transmission interconnections with other communities as potential power supply alternatives to the extent that power could be obtained from generating facilities elsewhere. These studies were reviewed for basic information applicable to the Intertie Study. The studies include:

- *Thomas Bay Hydroelectric Project, Pre-Feasibility Assessment Report*, prepared for the City of Petersburg by Hosey & Associates, December 1985.
- *Juneau 20-Year Power Supply Plan Update,* prepared for Alaska Electric Light & Power, Alaska Energy Authority, Alaska Power Administration and Juneau Energy Advisory Committee by CH2M-Hill, August 1990.
- *Feasibility Study, Lake Tyee to Swan Lake Transmission Intertie*, prepared for the Alaska Energy Authority by R.W. Beck and Associates, Inc., June 1992.
- *Power Supply Planning Study,* prepared for Ketchikan Public Utilities by R.W. Beck, Inc., December 1996, updated in 1998.
- *Final Environmental Impact Statement, Swan Lake – Lake Tyee Intertie*, US Department of Agriculture-Alaska Region, Forest Service, August 1997.
- *Record of Decision, Swan Lake – Lake Tyee Intertie*, US Department of Agriculture, Forest Service-Alaska Region, August 1997.
- *Electric Resource Evaluation and Strategic Plan, 1997 Update*, prepared for the City and Borough of Sitka by R.W. Beck, Inc., September 1997.

- *Sitka-Kake-Petersburg, HVDC Intertie Study,* prepared for the City and Borough of Sitka by Dr. George Karady and F. Mike Carson, January 2000.
- *Four Dam Pool Hydroelectric Projects, Repair, Replacement and Reclamation Plan*, prepared for the Four Dam Pool Power Agency by D. Hittle & Associates, Inc., January 2002.

Status of Transmission Development in Southeast Alaska

Since completion of the 1987 Harza Study, there have been several follow-on studies of transmission interconnections in the region as indicated above. Further, some transmission interconnections have been constructed and another, the Swan – Tyee Intertie is being developed by Ketchikan Public Utilities (KPU) and is presently under construction. Alaska Power & Telephone Company (AP&T) constructed and began operating a submarine cable connection between Skagway and Haines in 1998. The State constructed an overhead transmission line between Craig and Klawock in 1988 and more recently, AP&T constructed a transmission interconnection between Craig and Thorne Bay on Prince of Wales Island.

The three AP&T interconnections are between AP&T-owned distribution centers and serve the purpose of expanding the load base to be served from AP&T's hydroelectric generating facilities, the Black Bear Lake project near Klawock and the Goat Lake project near Skagway. KPU is developing the Swan – Tyee Intertie to gain access to surplus generation at the Lake Tyee hydroelectric project. AEL&P has also performed preliminary studies and investigations with regard to the Juneau – Greens Creek – Hoonah Intertie in recent years.

The City of Ketchikan is serving as the Swan – Tyee Intertie owner, holding the necessary permits and licenses and administering the contracts for design, construction and material procurement[6]. The line is being designed by Washington Infrastructure Services, Inc. of Bellevue, Washington under a contract initially awarded to Raytheon Engineers & Constructors in 1995. Most of the design and permit application effort to date was undertaken and completed between 1995 and 1997. The need to arrange financing for construction and obtain necessary permits halted any further design work at the time. WIS continued to provide KPU with some periodic support of its design, including evaluation of alternative technologies, but did not restart its regular involvement with the design process until August 2002.

At the present time, design of the Swan – Tyee Intertie is essentially complete, all necessary permits have been obtained, approximately 18 miles of the right-of-way was cleared in 2002 and the procurement contract for the steel H-frame structures and foundation pile caps was awarded in December 2002. Bids for the primary construction contract are presently being solicited and it is expected that the remaining clearing and foundation survey work will be completed in 2003. Construction of the line is expected to be completed in mid-2005 at a total estimated cost of

[6] The City of Ketchikan and the Four Dam Pool Power Agency (FDPPA) are negotiating to transfer the Swan – Tyee Intertie project to the FDPPA. It is anticipated that the FDPPA will take ownership of the project upon its completion, if not sooner.

$76.5 million. The Swan – Tyee line in total will be approximately 57 miles in length and entirely of overhead construction with no submarine crossings. It will be constructed for 138-kV nominal voltage but will be operated initially at 69-kV.

AEL&P and others have conducted several evaluations of developing a transmission interconnection with the Kennecott Mining Company's Greens Creek Mine on Admiralty Island. In 1998, AEL&P provided certain power supply availability and costing information to Kennecott as part of an evaluation of power supply alternatives being conducted by Kennecott. Kennecott subsequently decided to expand it's on site generation capability at the mine site[7] rather than pursue an interconnection to AEL&P at the time. AEL&P has continued to investigate the feasibility of constructing a transmission line to Admiralty Island as part of an eventual interconnection to Hoonah[8]. Since the 1998 proposal to Kennecott, AEL&P has constructed a significant length of overhead 69-kV transmission line on northern Douglas Island as part of its overall system expansion plan. The transmission line on Douglas Island is a critical component in the interconnection with the Kennecott Greens Creek Mine and Hoonah. The Douglas Island transmission line is complete to within a short distance of the proposed landing site of the submarine cable crossing to Admiralty Island.

Conclusions

The following conclusions are offered with regard to Phase 1 of the Intertie Study. Although these conclusions are offered at this point in the report, it is important to understand the assumptions and other factors described in subsequent sections of this report that contribute to the conclusions.

1. Both the Juneau – Greens Creek – Hoonah Intertie and the Kake – Petersburg Intertie are technically feasible. Proposed routes for both Interties have been studied before and are generally identified in existing US Forest Service land use plans. Although two primary route alternatives have been identified for the Kake – Petersburg Intertie, the Southern route alternative has been and continues to be the preferred alternative from a cost and constructability perspective.

2. Forest Service roads exist along the majority of the length of the proposed routes. Construction of the Interties adjacent to these roads, to the extent possible, should provide for lower costs of construction and maintenance. Single wood pole structures are preferred for placement along roads.

3. The estimated costs of developing and constructing the Interties are $37.1 million and $23.1 million for the Juneau - Greens Creek - Hoonah line and the Kake – Petersburg line, respectively.

[7] Kennecott installed a 5,200 kW diesel-fired combustion turbine at the Greens Creek mine in 2000.
[8] AEL&P undertook its most recent investigations of the Juneau – Greens Creek – Hoonah transmission line, which involves two significant submarine cable crossings, as a follow-on to its involvement in 1999 with the replacement of the 138-kV submarine cables across Taku Inlet that are part of the Snettisham transmission line.

4. AEL&P has undertaken certain efforts to develop the Juneau – Greens Creek – Hoonah Intertie that should contribute to expediting the time required for development of this system. The total time required to develop and construct the Kake – Petersburg line is approximately four years, of which construction is estimated to require about two construction seasons.

5. Energy generation capability is projected to be available from the Four Dam Pool Power Agency's Lake Tyee hydroelectric project to sell to THREA for use in Kake if the Kake – Petersburg Intertie is constructed. A power sales contract will need to be negotiated between THREA and the Four Dam Pool Power Agency.

6. AEL&P will need to construct the Lake Dorothy hydroelectric project to have sufficient energy generation capability to supply KMC-GC and THREA's Hoonah service area over the proposed Intertie. AEL&P is presently in the process of obtaining necessary permits and approvals to develop the Lake Dorothy project.

7. Assuming that construction and development costs of the Interties are grant funded and that reasonable power supply contracts can be arranged, THREA and KMC-GC should be able to realize savings in their respective costs of power supply with the Interties when compared to continued diesel-fueled power generation.

8. The annual costs to operate, maintain and administer the Interties should be relatively minor and can be reasonably recovered through charges for transmission services or, bundled in with the delivered cost of power.

9. With the Interties, THREA may be able to offer economic incentive rates in Kake and Hoonah, with certain limitations, to encourage new commercial activity. The economic incentive rates could be tied to the cost of purchased power with a nominal margin.

10. A direct current (DC) transmission system is technically feasible for the Interties but is estimated to cost significantly more than a standard alternating current (ac) system.

Transmission Line Routes and Technical Characteristics

Introduction

Two separate transmission lines are being evaluated as part of Phase 1 of the Intertie Study. The Juneau – Greens Creek – Hoonah transmission line ("Southeast Intertie Line 1" or "SEI-1") will interconnect the Kennecott Greens Creek Mine (KMC-GC) on Admiralty Island and the community of Hoonah on Chicagof Island to the electric system of AEL&P. SEI-1 will be used to deliver hydroelectric power from AEL&P to the KMC-GC and to Hoonah, offsetting oil-fired generation in both of these locations.

The Petersburg - Kake transmission line ("Southeast Intertie Line 2" or "SEI-2") will interconnect the community of Kake on Kupreanof Island to the interconnected electric systems of Petersburg and Wrangell. Petersburg and Wrangell are connected to and purchase most of their respective power supplies from the Lake Tyee hydroelectric project owned by the Four Dam Pool Power Agency (FDPPA). SEI-2 will be used to transmit surplus hydroelectric power purchased from the FDPPA to THREA's electric system in Kake, thereby offsetting diesel generation in Kake.

Both SEI-1 and SEI-2 have been studied in the past by others and have fairly well identified routes and characteristics. The previously defined routes and design concepts have been reviewed and modified to reflect current information. This section of the report presents the findings of the technical review. The route descriptions, design concepts and general transmission line characteristics were used to prepare the cost estimates shown in Section 4 of the report.

Juneau – Greens Creek – Hoonah Transmission Line (SEI-1)

The 1992 Alaska Energy Authority study of the transmission interconnection to KMC-GC[9] addressed the line route and prepared a conceptual design and capital cost estimate for the proposed transmission line to KMC-GC. The proposed line was based on overbuilding the existing distribution facilities along the north end of Douglas Island with a new 69-kV line for a distance of approximately 8 miles. At the end of the existing distribution line, a new 7.8 mile-long, 69-kV line (with strength and space provisions for eventual distribution underbuild) was proposed to be constructed to Outer Point. At Outer Point, the proposed line was proposed to cross under Stevens Passage for 5.9 miles to Young Bay on Admiralty Island and then continue overhead to Hawk Inlet and on to the KMC-GC mine, a total overhead distance of 14 miles.

Since the 1992 study, AEL&P has completed construction of a 69-kV overhead line to Outer Point and has initiated various studies and preliminary design concepts and layouts for extending the line to Hoonah and KMC-GC.

[9] *Greens Creek Transmission Line Planning Capital Cost Estimate*, prepared for the Alaska Energy Authority by R. W. Beck and Associates, Inc., December 1992.

The existing AEL&P transmission line on Douglas Island is constructed for and operated at 69-kV. AEL&P has initially specified that SEI-1 will be operated at 69-kV. Submarine cables will be sized to accommodate reasonably expected power flow requirements. The AEL&P plan is based on transmitting a maximum of 60 MW between Juneau and Hawk Inlet and 30 MW between Hawk Inlet and Hoonah. This variance is due to the much higher power demand at KMC-GC, approximately 10 MW, compared to the load at Hoonah of around 2 MW. It is important to note that the section of SEI-1 between Hawk Inlet and the KMC-GC mine site is expected to be removed upon closure of the mine, a date that is uncertain but potentially somewhere between 10 and 15 years in the future.

Interconnection facilities will include submarine cable termination yards on Douglas Island, on Admiralty Island at Young Bay and Hawk Inlet, and at Spasski Bay on Chicagof Island approximately 3 miles east of Hoonah. The submarine cable termination yards will serve as the interface between overhead sections of the line and submarine cables. They will generally be located near the shoreline but behind existing treelines to limit visibility from the water. Other facilities include a new substation in Hoonah and a substation at the Greens Creek mine, both of which will connect to the existing electric systems in these locations.

Conceptual Line Route

The AEL&P proposed route for SEI-1 is shown in Figure 2-1 and described below:

Segment 1: *Juneau to Hawk Inlet*
(26.5 miles total, 9.5 miles submarine cable, 11 miles existing and 6 miles new overhead)

The Juneau to Hawk Inlet segment starts at the West Juneau Substation on Douglas Island. An existing 69-kV overhead line interconnects the substation with Outer Point a distance of approximately 11 miles[10]. At Outer Point a submarine cable termination yard is planned near the mouth of Peterson Creek. The termination yard will contain 69-kV disconnect switches, breakers, and reactors and risers that connect the overhead system to the submarine cable. The yard will be placed approximately 150 feet inland from the mean high water line.

Photo 1 – Young Bay boat dock to north (right) of proposed cable landing site.

The cable will be buried as it leaves the yard and for approximately 180

[10] It is expected that AEL&P will retain ownership of the existing transmission line between the West Juneau substation and the Outer Point submarine cable termination yard.

feet offshore from the mean high water line.

The submarine cable will extend 9.5 miles across Stephens Passage to a termination facility in Young Bay on Admiralty Island near, but south of the existing Greens Creek ferry dock. The termination yard at Young Bay will include a cable riser, a ground switch, lightning arrestors, disconnects, a station service transformer and connection to the overhead transmission line on Admiralty Island. The overhead line will essentially follow the existing road across Admiralty Island to a point on Hawk Inlet near the existing ore loading facility, a distance of about 6 miles. AEL&P plans to construct the overhead line using wood, single-pole structures and 336 kcmil ACSR conductor. A submarine cable termination yard on Hawk Inlet will provide the interface between the overhead line and the submarine cable heading to Hoonah. The Hawk Inlet yard will include breakers, disconnects, lightning arrestors and a 3-phase reactor bank.

The Greens Creek tap will be made at this point. In addition, AELP plans to install a 69/4.16-kV transformer at the Hawk Inlet yard to provide electric service to the Hawk Inlet loading dock facility owned and operated by KMC-GC. Except for the relatively minor electric load at the Hawk Inlet loading dock, there are no other electric loads to be served.

The overhead portion of the line will be located entirely within the Tongass National Forest to the north of the Admiralty Island National Monument boundary.

Segment 2: *Greens Creek Tap*
(9 miles new overhead)

Photo 2 – Aerial view of road to Greens Creek mine.

The Greens Creek Tap will originate at the Hawk Inlet submarine cable termination yard on Admiralty Island as a tap on the 69-kV overhead line from Juneau. The line will be used to transmit power directly to the KMC-GC mine and will traverse approximately 9 miles generally adjacent to the existing KMC-GC road to a location near the KMC-GC powerhouse. A substation will be needed at this point to provide power for delivery to the mine's local distribution system at 4.16-kV. In addition to a 69/4.16-kV transformer, the substation will also include breakers and voltage regulators to protect the AEL&P and Greens Creek electric systems and maintain adequate delivery voltage at the mine. The mine's generating units will be interconnected with the AEL&P system but will not generally be used at the same time as power is being delivered from Juneau.

This line segment is primarily located within the Admiralty Island National Monument. The line is expected to be dismantled and removed at the time the Greens Creek mine is permanently closed down.

Segment 3: *Hawk Inlet to Hoonah*
(28.5 miles total, 25 miles submarine cable, 3.5 miles overhead)

The Hawk Inlet to Hoonah segment will originate at the Hawk Inlet submarine cable termination yard on Admiralty Island as a continuation of the 69-kV line from Juneau. The cable termination yard will be located on the eastern shore approximately 2.75 miles up Hawk Inlet. The cable termination yard will be located just inland from the shoreline and the submarine cable will be buried as it leaves the yard and proceeds offshore.

Photo 3 – Hawk Inlet, looking northeast from near the inlet entrance to the KMC-GC ore terminal facility. Note the large tide flat to the right.

The total length of the submarine cable is estimated to be approximately 25 miles. The route identified by AEL&P is similar to the route indicated in the 1987 Southeast Alaska Intertie Study. It should also be noted that preliminary discussions with US Forest Service (USFS) representatives indicated a suggestion on the part of the USFS to bring the submarine cable ashore near Point Augusta on Chicagof Island and continue the line to Hoonah overland.

In the preliminary route identified by AEL&P, the cable will be brought ashore at Spasski Bay and connected to a submarine cable termination yard similar to the cable termination yard in Young Bay on Admiralty Island. The Spasski Bay cable termination yard will include 69-kV disconnect switches, a 3-phase reactor bank, lightning arrestors and risers to connect the cable to a 69-kV overhead line that proceeds to Hoonah. The overhead portion of the Hawk Inlet to Hoonah segment will connect the Spasski Bay submarine cable termination yard to a new substation to be constructed in Hoonah. The overhead line will be approximately 3.5 miles in length and will use single-pole structures and 336 kcmil ACSR conductor.

The Hoonah substation is expected to be constructed near the Hoonah powerhouse and will serve as the termination of SEI-1. The substation will include breakers, a disconnect switch and a 69/4.16-kV transformer to interconnect with the local distribution system in Hoonah. The low voltage side of the substation will connect to the 4.16-kV bus at the Hoonah powerhouse.

The overhead portion of the line west of Spasski Bay will be located on private lands and will extend cross-country from Spasski Bay for approximately 0.75 miles at which point the line will follow an existing road for 2.75 miles to the Hoonah substation. The last 1.75 miles before the substation will carry the existing distribution line as underbuild.

Photo 4 – USFS road heading east from just outside of Hoonah.

Overhead Transmission Line Design Concepts

Structure Type

It is expected that AEL&P's standard single wood pole design will be used for the overhead portion of SEI-1. Figure 2-2 depicts the general framing of this structure type. The line will generally be placed alongside existing roads and spans (the distance between poles) will be relatively short. This configuration will provide future maintenance advantages due to ease of access and smaller structures.

Physical Loading

Typical physical loading criteria and associated overload capacity factors used for overhead transmission line designs in Southeast Alaska at lower elevations consist of combinations similar to the following criteria. Load cases 1 and 2 are required by the National Electrical Safety Code (NESC) for design of overhead utility lines. Load cases 3, 4 and 5 are based on local utility experience. Although these load cases sound quite severe they do not appear to significantly change the design outcome and do not have a significant cost penalty. For structure strength, the Intertie Study has considered load cases 3, 4 and 5 in addition to the NESC required load cases for its feasibility assessment.

1. NESC Heavy - Method A.

   NESC Heavy loading consists of a 4 pounds per square foot (PSF) wind (40 MPH) applied to the structure and supported facilities with the conductors and cables coated by ½ inch radial ice which is assumed to weigh 57 pounds per cubic foot. For this case, conductor tensions are to be consistent with an ambient temperature of 0° Fahrenheit. Additionally, a constant of 0.3 pounds is to be added to the resultant of the wind and weight related loads (for the purpose of developing conductor design tensions only).

Overload Factors which are applicable to the NESC Heavy Method A load case applied to wood structures are 2.5 for wind related loads, 1.5 for weight related loads and 1.65 for wire tension related loads. When using these Overload Factors for wood, a strength reduction factor of 0.65 is to be used. Guys shall use a strength reduction factor of 0.9. The applicable Shape Factor is 1.0 for cylindrically shaped components, 1.6 for components with flat sides.

2. NESC Extreme Wind

   For structures which exceed, or support facilities which exceed a height of 60 feet above ground or water level, an extreme wind condition is to be considered.

   NESC Extreme Wind loading for the Juneau/Hoonah region is generally considered to be 100 MPH nominal design 3-second gust (NESC Figure 250-2b). In accordance with the NESC, conductor tensions are to be consistent with an ambient temperature of 60° F. In Southeast Alaska the temperature criteria has typically been based on 40° F. Overload Factors that are applicable to the NESC Extreme Wind load case are 1.0 for wind, weight and tension related loads. For wood structures evaluated using these Overload Factors, a strength reduction factor of 0.75 is used. Guys are to utilize a strength reduction factor of 0.9. The applicable Shape Factor is 1.0 for cylindrically shaped components and 1.6 for components with flat sides.

3. Extreme Ice

   The NESC Extreme Ice case is based on 1.5 inches radial ice (57 pounds per cubic foot) at 30° F with no wind. This load case would be applied with a 1.0 Overload Capacity factor for wood structures for wind, weight and tension related loads while using a strength reduction factor of 0.75 for wood and 0.9 for guys.

4. Extreme Combination ice and Wind

   This load case is based on 1 inch radial ice (57 pounds per cubic foot) at 0° F in combination with a 4 PSF (40 mph) wind. This load case would be applied with a 1.0 Overload Capacity factor for wood structures for wind, weight and tension related loads while using a strength reduction factor for wood of 0.9 and 1.0 for guys.

5. Combination Snow and Wind

   This load case assumes 2 inches radial snow (37 pounds per foot) at 30° F in combination with a 2.3 PSF (30 mph) wind. This load case would be applied with a 1.0 Overload Capacity factor for wood structures for wind, weight and tension related loads while using a strength reduction factor for wood of 0.75 and 0.9 for guys.

Foundations and Structure Support

The soils in Southeast Alaska vary from muskeg to rock and everything in between. However, for most of SEI-1, the line route will follow existing roads and it is anticipated that most of the poles will be located within the roadway fill material. In areas where the poles are in good soils but outside the roadway fill material, many pole foundations will have to be over-embedded due to a layer (3′ to 5′) of organic material. The feasibility design for this study is based on standard embedment depths plus an additional 4 ft. (10% of pole length + 6 ft.) for tangent structures in normal soils. Structures located in rock and guyed structures are assumed to be embedded at standard embedment (10% + 2 ft.). Pole structures located in muskeg can be stabilized using a wood raft at ground line with side guys or by construction of a foundation system using either driven H-piles or use of a culvert embedded at a depth required for lateral stability with placement of the pole inside the culvert.

Based on discussions with local utility personnel this study has assumed the following soil conditions for the overhead segments of SEI-1:

Young Bay to Hawk Inlet (6 miles)

- 80% in good soils or roadway fill
- 10% rock
- 10% muskeg

Greens Creek Tap (9 miles)

- 50% in good soils or roadway fill
- 50% rock

Spasski Bay to Hoonah (6.5 miles)

- 70% in good soils or roadway fill
- 10% in rock
- 20% in muskeg

A Linear Reference Diagram showing the type of soils, land ownership, road access and clearing requirements for SEI-1 is provided in Figure 2-3.

Electrical Clearances to Grade

Minimum clearances above grade for conductors are required by the NESC based on line voltage and land use under the line. The NESC required clearance must be maintained under either of two conditions: 1) the conductor sagging at its maximum operating temperature (120° F minimum), and 2) under the NESC Heavy loading district requirement of ½ inch radial ice at 30° F (without the 4 psf wind). The vertical clearance for 69-kV lines above roads and lands that can be traversed by trucks is 20.2 feet.

Engineering judgment should be used to determine if clearances in addition to the minimum required by NESC should be applied. This would apply to any specific area that may have access to unusually large vehicles or special conditions such as extreme snow depths. In addition to the basic clearance requirement, it is generally prudent to add a plotting margin (2 to 4 feet) to compensate for irregular terrain not identified in the survey, side hills, plotting errors, construction variables and other contingencies. For the purpose of the Intertie Study feasibility layout, the basic ground clearance has been assumed to be 25 feet minimum with the conductor temperature at 120° F final sag.

Conductor Selection

The conductor suggested by earlier studies and used for this feasibility review is a 336.4 kcmil 30/7 ACSR/AW (Oriole/AW). Sag/tension charts were developed for this conductor based on the following tension limit criteria:

- 15% Ultimate Rated Strength at -5° F initial
- 20% Ultimate Rated Strength at -5° F Final
- 50% Ultimate Rated Strength at NESC Heavy Loading Initial
- 75% Ultimate Rated Strength at Extreme ice (1.5 inch) Loading Initial
- 75% Ultimate Rated Strength at Extreme snow (2 inch) Loading Initial

Right-of-Way Clearance

Based on discussions with local utility personnel this study has assumed the following:

Young Bay to Hawk Inlet (6 miles)

Trees are not a major concern along this section of line. Trees have been removed immediately adjacent to the roadway and the remaining trees are not extremely tall. It is anticipated that a clearing width of approximately 50 feet will be required plus the removal of danger trees. It is anticipated that danger trees will need to be determined on a one by one basis based on risk assessment.

Greens Creek Tap (9 miles)

The steep terrain and the presence of trees along this segment make clearing an important consideration. Historically this segment has experienced considerable blow-down of trees. An overhead line can not withstand the impact of falling trees without considerable damage. It is recommended that trees that can strike the line if they fall be removed. For the feasibility review it has been assumed that the clearing width will be 75 feet along this section of line.

Spasski Bay to Hoonah (3.5 miles)

The first 0.75 miles from Spasski Bay towards Hoonah will extend through timber on private lands. It is recommended that trees that can strike the line if they fall be removed. This total width is estimated to be an average of 150 feet. At the point where the line starts to parallel the road the clearing width can be reduced to about 50 feet as long as selected danger trees farther from the line are removed also.

Raptor (Eagle) Protection

Southeast Alaska is home to many eagles and therefore the line design must consider raptor (eagle) protection. The electrical industry standard for raptor protection is currently based on "Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996". This publication suggests that 60 inches between conductor phases as well as 60 inches to all grounded parts will provide a safe design for large raptors such as eagles. The conductor phase spacing of most 69-kV lines exceeds this recommended dimension.

The distance from conductor to ground needs to be considered, however. A potential problem could exist in that the typical 69-kV insulator is only 36″ to 42″ in length and therefore, if the base of the insulator is grounded, a conductor to ground path would exist that does not meet this standard. The design considered in this report assumes that an overhead ground wire will not be required and line hardware will not be grounded or bonded. Although it should be noted that the base of the insulator, while not grounded, is electrically at a different potential and simultaneous contact with the phase conductor and the insulator base would likely be lethal.

This having been said, it can be argued that the 69-kV single pole design absent the ground wire meets the spirit of the raptor protection guidelines. It is also important to note that this design has been used by AEL&P at other locations without problems related to raptor fatalities. Historical performance is considered to have more significance, in this case, than the published guidelines.

Submarine Cables

Two separate submarine cable crossings will be needed for SEI-1. The first, between Douglas Island and Young Bay on Admiralty Island will be about 9.5 miles long and is a relatively straight-forward crossing. The second, between Hawk Inlet on Admiralty Island and Spasski Bay on Chicagof Island is much longer, approximately 25 miles, and involves much more significant depths.

AEL&P's preliminary design concept for the Douglas Island – Young Bay crossing provides for the use of a single-armored, 3-phase, dielectric submarine cable with bundled fiber optic communication lines. The bundled cable will be about 6 inches in diameter. Figure 2-3 provides a cross-section layout of a cable similar to that presently proposed for the crossing. The submarine cable will extend 9.5 miles across Stephens Passage to a termination facility in Young Bay on Admiralty Island south of the existing KMC-GC dock. From National Oceanic and Atmospheric Administration (NOAA) charts, it appears that the water depth in the vicinity of the crossing increases uniformly from 0 feet at the shoreline to 300 feet near the center of Stephens Passage.

A "Limited Topographic Survey" by R&M Engineering dated January 2003 was conducted along a proposed route for the submarine crossing of Stephens Passage. This survey shows a gradual increase in depth over the first 3000 feet to a depth between 200 and 250 feet. The depth remains between 200 and 250 feet until station 335+00 at which point the bottom begins a gradual decrease in depth until the shoreline is reached at station 487+00. The nautical charts show a bottom that consists of mud and shells with occasional large rocks near Outer Point. The remainder of the route appears to consist of mud, sand and pebbles all the way to Young Bay.

No evidence of steep terrain or large rocks, that might cause suspensions in the submarine cables, has been detected. However, a thorough submarine topographical survey and subsurface profile needs to be accomplished to determine the best route for the submarine cable. This will identify areas to be avoided such as shipwrecks, large rocks, rock outcroppings, etc., that could cause suspensions and damage to the cable. This survey could be conducted utilizing a multi-beam sonar system such as the Reson Seabat 8101. If deleterious conditions are suspected, additional information should be obtained with a side-scan sonar system.

Based on the information presently available, no obvious problems are anticipated with the cable installation between Douglas Island and Young Bay. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of at least 10 feet below Mean Lower Low Water. Either direct burial or placement in a duct with a thermal backfill may be utilized. The cable proposed by AEL&P should be entirely adequate for this portion of the project.

For the Hawk Inlet – Spasski Bay crossing, AEL&P has initially specified the use of both double armored and single-armored, 3-phase dielectric submarine cable. Figure 2-4 provides a cross-section diagram of the double-armored cable. Double-armored cable will be used in areas where more cable strength is needed, such as in areas with significant depth or where danger from ship anchors exists. The total length of the submarine cable is estimated to be approximately 25 miles. The Hawk Inlet submarine cable terminal yard is anticipated to be located immediately south of the KMC-GC docks. This puts the cable entry point midway between two communications cables. The power cable should be installed in a position to avoid crossing either of these existing cables.

Due to the ship traffic in Hawk Inlet, it is recommended that consideration be given to burying the cable all the way down Hawk Inlet to a point 600 to 800 feet southwest of Hawk Point. Based on a review of Hawk Inlet nautical charts, a machine such as the Nexan's CapJet should be adequate for trenching and burying of the cable.

From Hawk Inlet the cable route proceeds in a westerly direction North of Whitestone Harbor and Pullizzi Point, then into Spasski Bay. In the preliminary route identified by AEL&P, the Hawk Inlet – Spasski Bay submarine cable crosses Chatham Strait and continues reasonably close to the north shore of Chicagof Island to a point in Spasski Bay. At this point, the cable will be brought ashore and connected to a submarine cable termination yard similar to the cable termination yard in Young Bay on Admiralty Island.

The route identified by AEL&P is similar to the route indicated in the 1987 Southeast Alaska Intertie Study[11] for the Hawk Inlet to Hoonah interconnection. It should also be noted that preliminary discussions with USFS representatives indicated a suggestion on the part of the

[11] The Hawk Inlet to Hoonah connection was labeled Segment 14.1 in the referenced report. Alaska Power Authority, Southeast Alaska Transmission Intertie Study, Harza Engineering Company, October 1987. Note that a survey of this potential crossing location was not conducted as part of the 1987 Harza Study.

USFS to bring the submarine cable ashore near Point Augusta on Chicagof Island and continue the line to Hoonah overland.

Based on the information presently available, no obvious problems are anticipated with the cable installation. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of 10 feet below Mean Lower Low Water. Either direct burial or placement in a duct with a thermal backfill may be utilized.

Water depths of the Hawk Inlet – Spasski Bay crossing approach 2,100 feet (350 fathoms) and double armored cable should be considered for the deeper portions of the crossing. However, this decision normally rests with the cable manufacturer and installer, since knowledge regarding the tensioning equipment and the cable design itself (especially its weight in seawater) are required. The cable specified by AEL&P should be entirely adequate for this portion of the project.

Switchyards and Substations

Submarine cable termination yards will be needed on Douglas Island, on Admiralty Island at Young Bay and Hawk Inlet, and at Spasski Bay on Chicagof Island approximately 3 miles east of Hoonah. The submarine cable termination yards are expected to require areas of approximately 100 feet by 100 feet and will serve as the interface between overhead sections of the line and submarine cables. They will generally be located near the shoreline but behind existing treelines to limit visibility from the water. The termination yards will contain 69-kV disconnect switches, lightning arrestors and risers that connect the overhead system to the submarine cable. The disconnect switches allow for the electrical isolation of the cable for maintenance and testing. Other equipment, such as breakers and reactors, may also be needed to assure proper operation and protection of the interconnected electric system.

Other facilities include a new substation in Hoonah and a substation at the KMC-GC mine, both of which will connect to the existing electric systems in these locations. THREA's and KMC-GC's generating units will be interconnected with the AEL&P system but will not generally be used at the same time that power is being delivered from Juneau. The substation at the KMC-GC mine will include a 69/4.16-kV transformer to connect to the mine's primary distribution system. The cable termination yard at Hawk Inlet will be the location of the tap to the mine. In addition, AEL&P plans to install a 69/4.16-kV transformer at the Hawk Inlet cable termination yard to provide electric service to the Hawk Inlet loading dock facility owned and operated by KMC-GC.

The Hoonah substation is expected to be constructed near the Hoonah powerhouse and will serve as the termination of SEI-1. The substation is expected to include breakers, a disconnect switch and a 69/4.16-kV transformer to interconnect with the THREA distribution system in Hoonah. The low voltage side of the substation will connect to the 4.16-kV bus at the Hoonah powerhouse.

Power Flow Analysis

The long submarine cable and transmission line to Hoonah with a relatively small load at the end of the line could require the installation of certain devices and equipment to assure proper system operation. As part of this Intertie Study, a power flow analysis was conducted to determine if the high line charging associated with the submarine cables can cause high voltages at the end of the transmission system in Hoonah. The power flow analysis was also used to determine what would be needed to mitigate any over voltage conditions.

The analysis concluded that two 5-MVAr reactors at Hawk Inlet and one at Hoonah will help regulate the loads at Hoonah and Greens Creek under normal operating conditions. Under a single contingency condition (i.e. an outage of the 25 mile submarine cable), the second reactor at Hawk Inlet, located on the Greens Creek side of the circuit breaker, will provide voltage regulation for the loads at the mine. The analysis, conducted by Commonwealth Associates, Inc., is provided in Appendix A to this report.

Kake – Petersburg Transmission Line (SEI-2)

The Kake - Petersburg transmission line, "Southeast Intertie Segment 2" or "SEI-2" will interconnect the community of Kake on Kupreanof Island to the interconnected electric systems of Petersburg and Wrangell. Petersburg and Wrangell are connected to and purchase most of their respective power supplies from the Lake Tyee hydroelectric project owned by the Four Dam Pool Power Agency (FDPPA). SEI-2 will be used to transmit surplus hydroelectric power purchased from the FDPPA to THREA's electric system in Kake, thereby offsetting diesel generation in Kake.

At the present time, the City of Ketchikan is constructing a transmission line to interconnect its electric system with the Tyee-Wrangell-Petersburg (TWP) electric system. This new interconnection will provide Ketchikan with access to the surplus generation capability of the Lake Tyee hydroelectric project. Although Kake's power requirements from the Lake Tyee project will be subordinate to the requirements of Petersburg, Wrangell and Ketchikan, current forecasts indicate that sufficient energy should be available to supply Kake's load for several years in to the future.

SEI-2 transmission line has been studied in reasonable detail in the past, most recently in 1996 with a feasibility study prepared by R.W. Beck for the State of Alaska, Department of Community Affairs, Division of Energy (the "1996 Feasibility Study"). The 1996 Feasibility Study was a follow-on to the 1987 Southeast Alaska Transmission Intertie Study prepared for the Alaska Power Authority by the Harza Engineering Company (the "1987 Intertie Study").

Both the 1987 Intertie Study and the 1996 Feasibility Study identified two primary routes for the line. One alternative route goes to the north of the Petersburg Creek – Duncan Salt Chuck Wilderness Area, while the other route goes to the south of the Wilderness Area. In both of the previous studies, the southern route alternative was preferred because of its shorter length, lower estimated construction cost and generally lesser environmental impact. It is important to note, however, that detailed environmental studies will be needed to thoroughly identify the impacts of the alternative routes.

A number of US Forest Service roads have been built in the area where SEI-2 would most likely be located. These roads will facilitate construction and maintenance of the line by providing ground access to the area. In more remote regions, construction crews and materials are usually transported by helicopter which contributes to higher overall construction costs.

The 1996 Feasibility Study was intended to define the design and routing criteria, estimate costs, provide a brief environmental review and assess the economic and financial feasibility of an Intertie between Petersburg and Kake. It was based on a 3-phase AC overhead system with submarine crossings of major water bodies. The 1996 Feasibility Study included a review and summary of the earlier reports and included consideration of the Kake Coastal Management Program, Public Hearing Draft dated April 1984.

The 1996 Feasibility Study did not include any field work or visits to the project area and relied solely on work from previous studies tempered with consultation and input from local utility, and various State, federal and local governmental agency personnel. Earlier reports which included site reviews were the 1984 Ebasco[12] and 1987 Intertie Study reports. The 1984 Ebasco study included fairly extensive field work and analysis of construction conditions for a Petersburg to Kake Intertie and included a number of drawings highlighting features along suggested routes. The 1984 Ebasco report provides a reasonable description of the terrain and soils along the preferred Southern route.

Changes have occurred since the 1984 Ebasco report relative to the number of logging roads and the amount of logging and clearing that will be required along the route. The 1984 Ebasco report suggested a floating camp in the Duncan Canal area with material hauling using helicopters in the roadless section of the route, a distance at the time of approximately 20.5 miles. The roadless section of the route has now been reduced to approximately 13 miles.

The 1987 Intertie Study report included bathymetric surveys of the proposed submarine cable crossings and included a compilation of public and agency comments, but the comments addressed the entire Southeast Alaska Intertie system and did not necessarily focus on SEI-2.

All of the earlier studies concluded that the southern route was preferred, absent detailed environmental analysis. The 1996 Feasibility Study concluded: "…the southern route is preferred based on public comment, agency comment, previous study findings, and engineering and environmental judgment." All of the earlier reports emphasized the need to conduct environmental studies prior to selection of a specific route.

---

[12] *Tyee-Kake Intertie Project, Detailed Feasibility Analysis, Volumes I and II*, prepared for the Alaska Power Authority by Ebasco, Inc., 1984.

The present Intertie Study has focused primarily on the Southern Route Alternative based on the conclusions and recommendations outlined in the 1996 Feasibility Study regarding the preferred routing.

Conceptual Line Route

The earliest study of SEI-2 conducted in 1981 reviewed four route alternatives which were narrowed to two, the Northern and the Southern. The other two routes, located between the Northern and Southern routes, were abandoned because they passed through the Petersburg Creek Duncan Salt Chuck Wilderness Area and other environmentally sensitive zones. The same reasons for not considering these other routes are still valid today.

The 1996 Feasibility Study reviewed the Northern Route (59.9 miles total; 59.0 Overhead plus one submarine crossing of 0.9 miles in length) and a Southern Route (46.7 miles total; 44.7 miles overhead plus two submarine crossings, 0.9 and 1.1 miles in length, respectively).

This Intertie Study generally follows the preferred routing outlined in the 1996 Feasibility Study for the Southern Route Alternative with the following routing modifications:

- The alignment has been shifted to bring the line closer to existing logging roads. This has introduced more angle structures and has lengthened the line distance, however it will make access easier both during construction and for future maintenance. It should also lessen right-of-way clearing costs.
- The tap point near Petersburg is not as close to the proposed Wrangell Narrows submarine cable termination point as indicated in the earlier report and routing of the line is now assumed to follow the Highway for a short distance resulting in an additional 0.5 miles of line length between the tap and the Wrangell Narrows cable termination yard.

The routes shown in the 1996 Feasibility Study and in this report are general in nature. A specific alignment will be selected during the preliminary design effort after site field work is conducted to verify and take advantage of the existing road system, clear-cut areas, avoidance of muskeg/rock areas and to mitigate environmental impacts. A map showing the two primary route alternatives for SEI-1 is provided as Figure 2-4.

Route Description (SEI-2 Southern Route Alternative)

The proposed route of the Southern Alternative begins at a tap of the 69-kV FDPPA transmission system connecting the Lake Tyee hydroelectric project to Wrangell and Petersburg. The tap point and the east terminal of the Wrangell Narrows submarine crossing is proposed to be in the vicinity of the former Alaska Experimental Fur Farm, about 5 miles south of Petersburg. The Forest Service operates a warehouse at this location. For estimating purposes it has been assumed that the new single wood-pole line will tap the existing Lake Tyee-Petersburg 69-kV line at a new Petersburg Tap 69-kV switchyard, extend east crossing Mitkof Highway and then parallel the highway to the east submarine terminal structure location near the Fur Farm. The overhead line distance between the tap point and the submarine cable termination point is about 1.0 mile based on following the highway.

The new Petersburg Tap Switchyard will include two 69-kV disconnect switches toward Lake Tyee and Petersburg, one 69-kV circuit breaker toward the new 69-kV line, and protection control, supervisory communications, and 69-kV metering equipment for power to be purchased from the FDPPA. A submarine cable termination structure, comprised of lightning arresters and a steel-pole riser for the overhead-to-underground transition, will be constructed near the shoreline but sufficiently inland to limit its visibility from the water and to stay above the tidal zone. The cable will be buried for some distance offshore.

Photo 5 – Looking west across Wrangell Narrows towards the log transfer facility.

The submarine cable will extend approximately 0.6 mile across Wrangell Narrows to a proposed point just south of the Tonka log transfer facility on the west side of the Narrows. Another submarine cable termination structure consisting of lightning arresters and a steel-pole riser, will be located a short distance inland from the shoreline. The overhead line leaving the cable termination structure is proposed to use single-wood pole structures and will generally follow the route of Forest Service Road 6350 to Duncan Canal. A 1.1 mile submarine cable crossing of Duncan Canal is proposed between points located about 1.75 miles south of the mouth of Mitchell Slough on the east and about 2.5 miles south of Indian Point on the west side of Duncan Canal.

Submarine cable termination facilities consisting of steel-pole risers will be located on both sides of Duncan Canal. From the submarine cable termination structure on the west side of Duncan Canal, the single-wood pole overhead line will proceed in a northwesterly direction to the drainage basin just south of the Taylor Creek basin. At this point, the line will turn more to the west and generally follow the creek until it reaches Forest Service Road 45808 which could perhaps be extended easterly to support this project. The line is then expected to follow the general route of this road and Forest Service Roads 6328, 6314 and 6040 to Kake.

A 69/12.47-kV substation will be constructed in Kake to interconnect the new 69-kV line with the local distribution system. The new substation can be located at several locations. For purposes of this study the location has been proposed to be at the Kake power plant site. An alternate location would be about southwest of the Kake airport runway. This location eliminates the need to build the transmission line through Kake itself and could also serve as a point of departure for an eventual submarine cable to Baranof Island and the Sitka electric system. The proposed location is approximately 1.60 miles longer and requires rebuilding the existing distribution along the route.

The substation will include a 2500 kVA step-down transformer, a 12-kV recloser, three single-phase voltage regulators, relaying and supervisory communications equipment.

The total length of SEI-2 is 51.6 miles of which 49.9 miles is overhead and 1.7 miles is submarine cable. A series of plot profile layouts showing the entire length of SEI-2 with estimated pole placement is provided in Appendix B.

System Voltage

The 1996 Feasibility Study considered two alternatives for the voltage of the Kake – Petersburg transmission line as follows: (1) a 34.5-kV system initially operated at 24.9-kV, and (2) a 69-kV system that would be upgradeable to 138-kV.

1996 Feasibility Study - 24.9/34.5 kV Option

The 1996 Feasibility Study concluded that a 24.9-kV transmission line would be the minimum voltage level that could reliably support the Kake forecasted load. A 24.9-kV system, however, would not provide for future flexibility for sudden increases in load growth and it was recommended that the line be constructed at 34.5 kV standards and initially operated at 24.9-kV. The incremental cost to construct an overhead line to 34.5-kV standards versus 24.9-kV standards, using the same basic design concept was estimated to be 2%. The 24.9/34.5-kV line was to have been connected to the 24.9-kV bus in the existing Petersburg substation. If in the future the line was converted to 34.5 kV it would only require transformation in Petersburg and modification of transformation in Kake.

1996 Feasibility Study - 69/138 kV Option

The 1996 Feasibility Study concluded that the Kake load could be served even under a high growth scenario with a 69-kV line and the only reason for making the line upgradeable to 138-kV would be if the line were to be needed as part of a larger, regional transmission system. The incremental cost to construct an overhead line to 138-kV standards versus 69-kV standards, using the same basic design was estimated at the time of the 1996 Feasibility Study to be 10%-20% higher. The 69/138-kV option presented in the 1996 Feasibility Study included a new switching station near the Petersburg Tap point. The switching station included a circuit breaker with isolating switches, revenue metering equipment, underground power cable terminations and associated surge arresters. The connection to the Kake system was through a 1,000/1,500 KVA step-down transformer located in a new substation located near the power plant in Kake.

Current Study - 69 kV Option

The current Intertie Study has focused on a 69-kV option although additional confirmation of this specification should be made as part of future study and design efforts. Reasons for the 69-kV specification at the present time are:

- The Lake Tyee – Petersburg transmission line is operated at 69-kV so a tap of this line would not require any transformation.
- A 69-kV line is more than adequate to support the present and anticipated load in Kake and could also transmit a significant amount of power as a part of a more extensive regional transmission system.
- A 69-kV line can be constructed using single-pole structures, saving considerable expense when compared to 138-kV H-frame structures specified in the 1996 Feasibility Study.
- There is insufficient space on the existing Lake Tyee – Petersburg poles to attach another transmission line, as was considered for the 24.9/34.5-kV alternative in the 1996 Feasibility Study. The use of the existing poles, rather than install new structures, was one of the expected cost saving provisions of the lower voltage option.

Overhead Transmission Line Design Concepts

Conceptual Design

In the 1996 Feasibility Study, the 24.9/34.5-kV option was proposed to use a single wood pole structure with horizontal line post insulators assumed (the report did not identify) to be applied at spans in the range of 350 to 400 ft. The conductor considered was 266.8 kcmil ACSR. The 69/138-kV option proposed to use a wood H-Frame structure as the basic tangent structure, with average span length estimated at approximately 800 feet, and 336 kcmil ACSR conductor.

The conceptual design envisioned for the Intertie Study would use single wood pole, 69-kV structures with a vertical post insulator combined with horizontal post insulators. This design will be able to take advantage of existing roads for construction and maintenance and has been used successfully used for other transmission applications elsewhere in Alaska. The average span length is estimated to be 350 to 400 feet. The only segments of SEI-2 which are considered a candidate for H-frame long span construction are where no roads presently exist, the 12 mile segment west and the 1 mile segment east of Duncan canal. The conductor considered is 336.4 kcmil 30/7 ACSR/AW "Oriole/AW".

Structure Type

The 1996 Feasibility Study was based on using wood H-frame type structures for the 69/138 kV line. This H-Frame design concept was used successfully on the cross-country portion of the Ketchikan Swan Lake 115-kV line and has the advantage of allowing long span construction which can be used to advantage to avoid poor soil areas and for spanning large ravines. However, many 69-kV lines in Southeast Alaska have been constructed on single wood pole structures, particularly when the lines can follow existing roads.

The Petersburg to Kake line route is not as rugged as Ketchikan's Swan Lake line and the opportunity exists to follow logging roads for much of its length (the roadless section is approximately 25% of the line length). Following existing roads will provide access advantages during construction and will minimize the need for clearing. A short span road-side power line will also provide future maintenance advantages due to easy access and smaller structures. For the above reasons this study has selected a single wood pole design, reference Figure 2-2.

Physical Loading

Typical physical loading criteria and associated overload capacity factors used for overhead transmission line designs in Southeast Alaska at lower elevations consist of combinations similar to the following criteria. Load cases 1 and 2 are required by the National Electrical Safety Code (NESC) for design of overhead utility lines. Load cases 3, 4 and 5 are based on local utility experience. Although these load cases sound quite severe they do not appear to significantly change the design outcome and do not have a significant cost penalty. For structure strength, the Intertie Study has considered load cases 3, 4 and 5 in addition to the NESC required load cases for its feasibility assessment. (A description of the load cases is provided for SEI-1, above.)

Foundations and Structure Support

The soils in Southeast Alaska vary from muskeg to rock and everything in between. Earlier field work has indicated that much of the Southern route of SEI-2 is glacial till and colluvial, acceptable for standard direct embedment foundations. The 1987 Intertie Study was based on cross-country construction and the report estimated the mix of soils at 75/15/10 percent for normal, rock and muskeg soils, respectively. However, even in the areas considered normal the top 3 feet to 5 feet of material is organic and has essentially no lateral strength capability.

The feasibility design for this Intertie Study is based on standard embedment depths plus an additional 4 feet (10% of pole length + 6 feet) for tangent structures in normal soils. Structures located in rock and guyed structures are assumed to be embedded at standard embedment depths (10% + 2 feet). Pole structures located in muskeg can be stabilized using a wood raft at ground line with side guys or by construction of a foundation system using either driven H-piles or by using a culvert embedded at a depth required for lateral stability and the pole placed inside the culvert.

It is anticipated that with short-span construction generally following the roads that SEI-2 will follow, the mix of soils will be about the same as suggested in the 1987 Intertie Study report, 75/15/10 percent for normal, rock and muskeg soils.

Most sites will require imported granular backfill hauled to the site. Poles that are located off the road by more than 20 feet will require an access work pad created by extending the road fill to the site. Where the distance from the road makes this impractical, temporary lagging would be used to gain access to the site during construction. If the distance is extreme, helicopter access would be considered. In the roadless sections near Duncan Canal, it is assumed a staging area would be constructed and access to structure sites would be by helicopter.

A Linear Reference Diagram showing the type of soils, land ownership, road access and clearing requirements for SEI-2 is provided in Figure 2-5.

Electrical Clearances to Grade

Minimum clearances above grade for conductors are required by the NESC based on line voltage and land use under the line. The NESC required clearance must be maintained under either of two conditions: 1) the conductor sagging at its maximum operating temperature (120° F minimum), and 2) under the NESC Heavy loading district requirement of ½ inch radial ice at 30° F (without the 4 psf wind). The vertical clearance for 69-kV lines above roads and lands that can be traversed by trucks is 20.2 feet.

Engineering judgment should be used to determine if clearances in addition to the minimum required by NESC should be applied. This would apply to any specific area that may have access to unusually large vehicles or special conditions such as extreme snow depths. In addition to the basic clearance requirement, it is generally prudent to add a plotting margin (2 to 4 feet) to compensate for irregular terrain not identified in the survey, side hills, plotting errors, construction variables and other contingencies. For the purpose of the Intertie Study feasibility layout, the basic ground clearance has been assumed to be 25 feet minimum with the conductor temperature at 120° F final sag.

Conductor Selection

The conductor suggested by earlier studies and used for this feasibility review is a 336.4 kcmil 30/7 ACSR/AW (Oriole/AW). Sag/tension charts were developed for this conductor based on the following tension limit criteria:

- 15% Ultimate Rated Strength at -5° F initial
- 20% Ultimate Rated Strength at -5° F Final
- 50% Ultimate Rated Strength at NESC Heavy Loading Initial
- 75% Ultimate Rated Strength at Extreme ice (1.5 inch) Loading Initial
- 75% Ultimate Rated Strength at Extreme snow (2 inch) Loading Initial

Right-of-Way Clearance

Right-of-way width is often established based on conductor blowout. However, essentially the entire line length of SEI-2 is undeveloped and therefore blowout of the conductor is not a consideration. Clearing and maintaining of the right-of-way will be a major cost item during initial construction and for future maintenance. This issue requires a compromise between the initial cost of removing danger trees and the amount of maintenance that will be required on an annual basis and following extreme weather conditions.

Reliability of the line will be of major concern to the local utilities. The line will be designed to withstand anticipated extreme weather conditions, however, it will not be designed to withstand the impact of falling trees. In the areas where tall trees exist, reliability of the line is directly related to the extent of clearing. From strictly a reliability standpoint any tree that could potentially strike the line when falling should be removed. Based on the fact that some line sections will be located in areas where there are 100′ to 150′ tall trees, the width of clearing would calculate to be upwards of 300 feet.

Where the line is placed near roads the road itself will provide approximately 50′ of cleared width on the roadside. Also, much of the area along the route of SEI-2 has been clear-cut in the recent past. Areas that have been clear-cut, even as long as 35 years ago, have much shorter trees, often less that 40 feet in height.

Based on an objective of minimizing future maintenance costs suggested clearing criteria for SEI-2 would be to:

- Cut all trees within 50′ from centerline. Low growing brush would not be cut.
- Cut all brush in the immediate vicinity of structures.
- Remove all trees that could strike the line if they fall.

Raptor (Eagle) Protection

Southeast Alaska is home to many eagles and therefore the line design must consider raptor (eagle) protection. The electrical industry standard for raptor protection is currently based on "Suggested Practices for Raptor Protection on Power Lines: The State of the Art in 1996". This publication suggests that 60 inches between conductor phases as well as 60 inches to all grounded parts will provide a safe design for large raptors such as eagles. The conductor phase spacing of most 69-kV lines exceeds this recommended dimension.

The distance from conductor to ground needs to be considered, however. A potential problem could exist in that the typical 69-kV insulator is only 36″ to 42″ in length and therefore, if the base of the insulator is grounded, a conductor to ground path would exist that does not meet this standard. The design considered in this report assumes that an overhead ground wire will not be required and line hardware will not be grounded or bonded. Although it should be noted that the base of the insulator, while not grounded, is electrically at a different potential and simultaneous contact with the phase conductor and the insulator base would likely be lethal.

This having been said, it can be argued that the 69-kV single pole design absent the ground wire meets the spirit of the raptor protection guidelines. It is also important to note that this design has been used by AEL&P at other locations without problems related to raptor fatalities. Historical performance is considered to have more significance, in this case, than the published guidelines.

Submarine Cables

Two separate submarine cable crossings will be needed for SEI-2. The first, crosses Wrangell Narrows about five miles south of Petersburg and is slightly less than one mile in length. Tide movements are indicated to be very limited at this location and the waters are generally calm. The second crossing is about 1.25 miles in length and crosses Duncan Canal between points about 1.75 miles south of the mouth of Mitchell Slough on the east and about 2.5 miles south of Indian Point on the west side of Duncan Canal.

From NOAA charts the water depth at the Wrangell Narrows crossing appears to increase uniformly from 0 feet at the shoreline to 110 feet near the center of Wrangell Narrows. The nautical charts show a bottom that consists of mud and rocks. No evidence of steep terrain or large rocks, that might cause suspensions in the submarine cables, has been detected. However, a thorough submarine topographical survey and subsurface profile needs to be accomplished to determine the best route for the submarine cable. This will identify areas to be avoided such as shipwrecks, large rocks, rock outcroppings, etc., that could cause suspensions and damage to the cable. This survey may be conducted utilizing a multi-beam sonar system such as the Reson Seabat 8101. If deleterious conditions are suspected, additional information should be obtained with a side-scan sonar system.

Based on the information presently available, no obvious problems are anticipated with the cable installation at Wrangell Narrows. The cable should be buried approximately 1 meter in depth at both shores, out to a depth of 10 feet below Mean Lower Low Water (MLLW). Either direct burial or placement in a duct with a thermal backfill may be utilized. Due to the large amount of boat traffic through Wrangell Narrows, burial for the entire length is recommended.

The water depth at the location of the Duncan Canal crossing is approximately 100 feet at maximum. No particular problems are anticipated with this crossing except that the timing of placing the cable should be coordinated so as not to interfere with the crabbing season in the Canal.

Both of these submarine crossings were surveyed as part of the 1987 Intertie Study[13]. Findings related to these surveys are:

> "The crossing on Plate 5 [Wrangell Narrows] is a bowl-shaped depression as deep as 110 feet. Most of the alignment is soft bottomed except the eastern approach to Mitkof Island. Slopes on the east approach vary between 10:1 (6°) and 2:1 (27°) whereas those in the west approaching the Lindenberg Peninsula of Kupreanof Island are more gentle, varying between 14:1 (4°) and 3:1 (18°). There do not appear to be any obstacles to construction at this crossing. Wrangell Narrows is a busy thoroughfare for ship traffic, both commercial and recreational. Tanner crab fishing occurs from mid-January to mid-February and salmon trolling lasts from May through the first week in June."

> "Crossing 6.5 [Duncan Canal], Plate 6, is bowl-shaped in cross section with a fairly gentle west approach to Kupreanof Island, 11:1 (5°), and a steeper approach to the Lindenberg Peninsula, 6:1 (9°). Echograms indicate the crossing is probably floored by soft sediments and its deepest point is approximately 100 feet. The very near shore parts of the approach sounded with lead line may be hard bottom. There are no submarine cables in Duncan Canal. Construction in Duncan Canal may be delayed if emplacement is planned during the commercial crab fishing season. Dungeness crab fishing season is split with a summer season from May through September, and a winter season from October through January."

Cables to be used for the SEI-2 submarine crossings would be similar to the crossing between Douglas Island and Young Bay as described for SEI-1, above. The cable would be a single-armored, 3-phase, dielectric submarine cable with potentially bundled fiber optic communication

[13] Crossings 6.1 and 6.5, Appendix A, Transmission Line Submarine Crossings – Oceanography/Meteorology, Alaska Power Authority, Southeast Alaska Transmission Intertie Study, Harza Engineering Company, October 1987. Note that the eastern landing of the Wrangell Narrows crossing as surveyed for the 1987 study appears to be slightly north of the presently defined location.

lines. The bundled cable will be about 6 inches in diameter, however, the exact cable specification will not be known until it is known whether or not further interconnections will be made to SEI-2 to load centers beyond Kake. Additional cable specification will occur during the design of SEI-2. It is expected that both the Wrangell Narrows and the Duncan Canal crossings would be placed at essentially the same time with the same cable laying equipment.

Switchyards and Substations

Submarine cable termination yards will be needed on both ends of the Wrangell Narrows and the Duncan Canal crossings. The submarine cable termination yards are expected to require relatively small areas that will serve as the interface between overhead sections of the line and submarine cables. They will generally be located near the shoreline but behind existing treelines to limit visibility from the water. The termination yards will contain lightning arrestors and risers that connect the overhead system to the submarine cable. Disconnect switches would also be installed to allow for the electrical isolation of the cable for maintenance and testing. A switchyard will also be needed at the tap point of the Lake Tyee – Petersburg transmission line. This switchyard will include circuit breakers, disconnect switches, other protective and control equipment and would most likely be the location of revenue metering for the power to be delivered to THREA's Kake system.

Other facilities include a new substation which will connect to the existing electric system in Kake. THREA's generating units will be interconnected with the TWP system but will not generally be used at the same time that power is being delivered from Lake Tyee. The Kake substation is expected to be constructed near the Kake powerhouse and will serve as the termination of SEI-2. The substation is expected to include breakers, a disconnect switch and a 69/12.47-kV transformer to interconnect with the THREA distribution system in Kake. The low voltage side of the substation will connect to the 12.47-kV bus at the Hoonah powerhouse.

Permitting Requirements and Environmental Issues Overview

Introduction

A review of permitting requirements and environmental issues with regard to the development and construction of SEI-1 and SEI-2 was conducted as part of the Intertie Study. This review produced a summary of environmental documents, studies, and permits needed to implement the Interties and developed a cost estimate and an estimated schedule related to the permitting activities. The information presented in this section was gathered from conversations with federal, state and local agencies and from various web sites.

Table 3-1 and Table 3-2, at the end of this section, lists the individuals and agencies contacted as part of this review. Table 3-3 provides a tabularized summary of environmental documents, studies, and permits needed to implement the proposed project. A cost estimate and an estimated schedule that captures these activities is provided in Table 3-4 and Table 3-5 for SEI-1 and SEI-2, respectively.

Federal Agency Involvement

US Forest Service

Following is a description of the proposed project lands relative to the U.S. Forest Service (USFS) Tongass Forest Land and Resource Management Plan (LRMP) (USFS 1997 and revised map 1999). The required environmental documentation and permitting activities are based on the location and designated land use of the proposed alignment. Separate documents and permits would be required for each different project or segment.

SEI-1: Juneau—Greens Creek—Hoonah

The maximum length of corridor that would be within the USFS lands is approximately 14 miles or 27 percent of the entire corridor. The 6-mile section from Young Bay to the Greens Creek mine road and on to Hawk Inlet as well as the 8-mile section to the mine itself are located on Admiralty Island within the Tongass National Forest within an existing Transportation and Utility System (TUS) “window”. This “window” is an area potentially available for the location of a utility corridor as identified in the LRMP (USFS 1997). The USFS has identified these windows in areas where effects on other resources are recognized, resource protection can be provided, and the existing resource uses and activities will not conflict with the proposed project. The proposed location along an existing road is also consistent with the USFS directive to accommodate new transportation or utility proposals within existing corridors, to the maximum extent feasible.

This corridor "window" is within land designated for use as Semi-remote Recreation. That use designation is based on the following description:

> "Provide for recreation and tourism in natural-appearing settings where opportunities for solitude and self-reliance are moderate to high." (USFS LRMP Map; 1997 Revision, modified April 1999)

The Management Prescription associated with Semi-Remote Recreation (SM) requires that the "Partial Retention Visual Quality Objective (VQO Partial Retention)" be applied to developments, facilities, or structures. The standards and guidelines require that design activities shall be subordinate to the landscape character of the area.

The transmission line to the Greens Creek Mine will be in Non-Wilderness Monument Land, also within the corridor window. The standards and guidelines are similar to that of the Semi-Remote Recreations, however, there will need to be provisions to remove the line following closure of mining activities.

Environmental Documentation Requirements

The USFS will require some National Environmental Policy Act (NEPA) environmental documentation process. The project route within USFS land is within a designated road/utility corridor and will be built following the standards and conditions defined by the LRMP. At this time, it appears that an Environmental Assessment (EA) may be adequate documentation to make a determination of Finding of No Significant Impact (FONSI). However, because the component on Admiralty Island is necessary to provide service to Hoonah, the USFS will require the documentation be inclusive of the entire route. They will only have decision-making authority over the portion on USFS lands. The process would begin with a submittal of an application for a Special-Use Authorization.

As with the Swan Lake-Lake Tyee transmission project currently under construction, the project proponent would fund the administration of the EA development and contract out technical analyses and document preparation. Completion of an EA is possible within one year and associated costs could be less than $250,000, excluding marine surveys of submarine cable trenching areas.

There are two issues:

1. Does the line need to cross USFS land at all? Providing energy to Greens Creek Mine is one purpose but this will require documentation to justify the need. Cost could also be used to a certain extent. Cost comparison between the proposed route versus a submarine cable from Douglas Island to Hawk Inlet and/or Spasski Bay will likely be required.

2. Scenery impacts from placing overhead transmission lines within the viewshed. The USFS would expect an analysis of the use of a buried cable as an alternative to prevent any change of viewshed. The semi-remote wilderness land use does not preclude overhead lines that are built to blend into the surrounding scenery.

Permitting and Fees

Following is a list of permits, fees, and requirements that would be needed following conclusion of the NEPA process:

Special Use Authorization - Application information and form can be found at the following web site: http://www.fs.fed.us/recreation/permits/. Prior to submittal of the form, a pre-application is required. During that meeting, USFS staff will discuss the proposed action, potential conflicts, application procedures, probable time frames, fees and bonding requirements, and what other agency coordination may be called for.

Construction Permit - This is a 5-year permit with a posted bond in the amount necessary to return the disturbances should the project fail.

Timber "disposal" costs - The value of the timber that would be removed would be assessed by the USFS. The removal of timber could be by the USFS or by a third party. The project proponent would be responsible for paying for the value of the timber.

Easement Fee - This is a long-term (50 years or what ever is negotiated) lease of the easement. The amount of the one-time fee is 5 percent of the fair market value of the land. The alignment would need to be appraised to determine the fair market value to use in fee calculation.

SEI-2: Petersburg—Kake

Two alternatives are under consideration, the Northern Route (59.9 miles) and Southern Route (46.7 miles). These routes are primarily within the Tongass National Forest and both have been identified as corridor "windows" available for roads and utilities. Land designations along these routes are primarily within Intensive Development and Moderate Development categories. The northern route also crosses an "Old-Growth Forest" area.

Environmental Documentation Requirements

Preliminary discussions with the USFS indicate that an environmental impact statement (EIS) would be required to evaluate the Petersburg to Kake utility corridor. Issues necessary to cover include a defensible Purpose and Need Statement, alternatives under evaluation including the No Action alternative, affected environment, environmental consequences, and secondary and cumulative impacts. The major issues are expected to be similar to those identified in the Swan Lake-Lake Tyee Intertie project such as overhead lines within migratory bird flyways, viewsheds, transmission line right-of-way clearing and maintenance, and construction road.

The process would begin with a submittal of an application for a Special-Use Authorization. As with the Swan Lake-Lake Tyee project, the project proponent would fund the administration of the NEPA environmental documentation process and contract out technical analyses and document preparation.

The length of time necessary for completion of the NEPA documentation and signing of a Record of Decision (ROD) will depend on the project alignment and proposed type of line (overhead versus submarine) and proposed construction methods. Lessons learned from the Swan Lake-Lake Tyee Intertie project allow the filing for SEI-2 to incorporate appropriate mitigation in the original proposals, lessening the impacts and agency requirements. One of those issues was limiting the need for construction roads by using helicopters to place transmission poles. Additionally, preliminary agency comments regarding the Swan Lake-Lake Tyee project submitted in 1995 also identified issues of concern (e.g., an overhead line across Duncan Canal) that have been incorporated into the current proposal. Using a trenched submarine cable at that location will address that concern.

An optimistic estimate for completion of the NEPA process is 12 to 24 months. Costs associated with impact analyses and document preparation for this sized project can range between $700,000 to $1,000,000 depending on the technical analyses needed and amount of controversy.

Permitting and Fees

The same permits and fees would be required for SEI-2 as listed above for SEI-1.

US Army Corps of Engineers (COE)

US Army Corps of Engineers permits would be associated with two components of the project. These components are part of both the Juneau—Hoonah and Petersburg—Kake segments.

> Component 1 – Submarine Cable: COE has jurisdiction over areas between the high tide line and mean high water (Section 404—coastal wetlands and tidal zone) and below mean high water within navigable waters (Section 10).
>
> Component 2—Freshwater Wetlands: COE has jurisdiction over areas between ordinary high water and the upland edge of wetland (Section 404 if not navigable, shared with Section 10 if navigable).

While there is a nationwide permit for Utility Line Activity (NWP # 12), our contact at COE, Mr. Leeds was uncertain whether or not this would apply to the Southeast Intertie projects (see Note 1 of NWP #12 attached). He will check in with this and let us know.

Nevertheless, the permitting process through the COE will be relatively simple provided the required documentation and drawings are provided. Section 10 (all structures and work in navigable waters) and Section 404 (disposal of dredged or fill material in waters of the U.S. including wetlands) permits will be necessary. Mr. Leeds estimates that it would be a 2 to 4 month process. NEPA would not be required from the COE. See the following web site: www.poa.usace.army.mil/reg/default.htm.

Permit applications would be routed to NMFS, USFWS, and EPA as well as appropriate State agencies (DNR, DFG, and DGC) for review. For this project, the COE would include notification of National Oceanic and Atmospheric Administration (NOAA) and National Ocean Service (NOS) for charting the utility line to protect navigation.

Costs associated with this permit application are related to preparation of the permit drawings. Most of these drawings would be a part of normal document preparations so additional costs would be minimal.

Because construction activities might affect shorelines, rivers or streams through run-off, which may contain pollutants such as sediments, a Short Term Variance from Water Quality Standards (Section 401 Water Quality Certification) may be needed. The COE would process this request to ADEC as part of its Section 10 and Section 404 permit process.

U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS)

These agencies are responsible for protection of listed species, critical habitat, and essential fish habitat. They do not have permitting authority, however, federal actions and issued permits must comply with the Endangered Species Act and the Magnuson-Stevens Act Provisions for Essential Fish Habitat (EFH). Based on prior agency correspondence (1995) and recent conversations with NMFS and USFWS staff, there are two primary issues:

- Potential impacts on bald eagles/raptors and migrating waterfowl from overhead transmission lines

- Potential impacts on essential fish habitat if it exists along shorelines where submarine cables would be placed.

NMFS review and concurrence of COE Section 10 and 404 permits would allow NMFS to request information about the shoreline affected. Simple marine habitat characterizations at each submarine cable trenching location would be adequate to provide NMFS with the information it needs to determine if EFH is affected.

Eelgrass may occur in the shallow subtidal zone at any of the submarine cable locations. Eelgrass is a known important habitat for many fish, including juvenile salmonids, and crab. NMFS indicated that because the cables would be buried, long-term eelgrass loss would not be expected. If eelgrass did occur at the cable site, NMFS would expect that the construction would include careful removal of the eelgrass turions and replanting after filling in the trench. A monitoring program would also be expected to ensure the replanting was successful.

The NEPA process carried out by the USFS will include review and comments from FWS and NMFS. For SEI-1, this is expected to be limited to Admiralty Island because of the size of the USFS land involved. Overhead transmission lines from Spasski Bay to Hoonah may not require federal permits or approval.

Early communications will be needed with the FWS and NOAA/NMFS to request information regarding protected species present and a list of their concerns. A Biological Assessment may be needed for any such identified species. Early informal discussions indicated that there are no species of special concern within the project area. Therefore, we expect an Informal Consultation to be adequate for both projects.

There will be some additional discussions and conditions applied to protect raptors because bald eagles do occur in both areas. However, standard construction and designs are now available to mitigate for potential impacts to raptors.

US Environmental Protection Agency (EPA)

Construction of both SEI-1 and SEI-2 could disturb, in total, 5 acres or more of natural upland vegetation. If that is the case, a construction storm water pollution prevention plan must be prepared and approval given by the EPA to operate under the Federal Storm Water General Permit. Alaska also requires that site-specific plans be submitted to the Department of Environmental Conservation (ADEC) for approval before the project is started.

U.S. Coast Guard

The Aids to Navigation and Waterways Management Branch will review final locations of any approved submarine cables. They would be notified by the ACOE through the Section 10 permit process. The Coast Guard would then process the information to be added to NOAA Charts and pass on information to appropriate groups.

Federal Energy Regulatory Commission (FERC) - Electric Power Regulation

The proposed projects are within the State of Alaska and, therefore, the transmission line is not under the jurisdiction of FERC. FERC approves rates for wholesale electric sales of electricity and transmission in interstate commerce for private utilities, power marketers, power pools, power exchanges and independent system operators. Again, this project is not an "interstate commerce" issue so FERC approval or permitting will not be required.

State of Alaska Agencies

There are several agencies or departments within the State of Alaska who will have an approval / permitting authority for components of the proposed Interties. Because this project may affect coastal resources and needs both federal and state permits and approvals, the Alaska Coastal Zone Management Program will be involved to ensure that the project is consistent with local coastal zone management programs and policies. The consistency review process is currently initiated and directed through the Department of Governmental Coordination (DGC). The DGC reviews the project and makes sure that all applicable state, federal, and local agencies are included in project or permit reviews.

Recent proposed legislation may alter how the DGC and Coastal Zone Management Programs work to review and determine project consistency. While the exact process that will be in place at the time these projects are presented for permits and approvals, the regulations pertaining to and the intent of the CZMP will continue into the foreseeable future.

Coastal Zone Management Program

Projects in or affecting the coastal areas of Alaska are reviewed by multiple agencies using a system called the "project consistency review", based on the Alaska Coastal Management Program (ACMP). The DGC implements this review process. The local district coastal zone coordinators, state, and federal agencies are provided project documents for review to determine if the project is consistent with the standards of the ACMP and enforceable policies of approved district coastal management programs. For SEI-1, there are two coastal zone districts, the Juneau District and the Hoonah District. For SEI-2, there are also two districts, the Kake District and the Petersburg District.

The DGC offers a pre-application review process that can consist of a meeting format or the proponent can submit project description and related materials for DGC to distribute to the reviewers for their early review. Completion of a Coastal Project Questionnaire and providing adequate project descriptions will begin this coordination. Through this process, the applications can be submitted in a more complete form to speed up the review process. See the web site: http://www.gov.state.ak.us/dgc/Projects/pcpq.html for more information.

Department of Natural Resources

The Department of Natural Resources (DNR) will issue easement permits for all State lands. Those lands include the tidal and subtidal waters where submarine cables would be placed. The permit or easement application will require a $100 filing fee per crossing and an annual lease of that public land. The price of the lease will depend on the location. It takes about 6 months to receive the easement permit and it requires survey data.

Upon completion of the ACMP and NEPA processes, DNR will issue an early entry permit that will allow the collection of survey data needed for finalization of the permits.

Department of Fish and Game

The Department of Fish and Game (ADFG) issues underground salmon stream crossing permits only. Based on the information available at this time, no such stream crossings are proposed within either Intertie segment. ADFG will review the process through the ACMP consistency review. The COE permit application will need to include the construction methodologies and areas that would be affected during construction. Through the COE permitting process, ADFG will review and apply conditions on how construction is to be conducted. If there are impacts to salmon streams, ADFG would need to be identified, either prior to the permit process (with mitigation incorporated) or by the agencies who would require mitigation. Mitigation can be in the form of seasonal constraints, construction methods, or actual denial of permits until proper mitigation can be incorporated.

Department of Transportation & Public Facilities

The Department of Transportation and Public Facilities (DOTPF) will require a utility permit application for those lines that will be within a DOTPF right of way. Separate permits will be needed for each right of way. Accompanying permit applications, the DOTPF will need project plans, profiles and staking sheets. The permit costs are $400 per permit plus $0.25/lineal foot to a maximum of $2,500.

At this time, SEI-1 would require two permits, one associated with lines along the Douglas Highway and one for the Hoonah Airport Road. SEI-2 would require permits associated with the Mitkof Highway and local Kake roads.

State Historic Preservation Officer (SHPO)

Section 106 of the National Historic Preservation Act (NHPA) requires review of any project funded, licensed, permitted, or assisted by the federal government for impact on significant historic properties. The agencies must allow the State Historic Preservation Officer and the Advisory Council on Historic Preservation (ACHP), a federal agency, to comment on a project. The Alaska Historic Preservation Act contains a provision similar to Section 106 which mandates that any project with state involvement be reviewed in a similar manner. See (http://www.dnr.state.ak.us/parks/oha_web/sec106~1.htm).

The Intertie alignments and project description (including construction and operation) will need to be submitted to the SHPO to determine if there are known historic or cultural resources within the alignment vicinity that could be affected by the projects. Additionally, a certified historic and cultural resource specialist should evaluate the alignment through a records search and field study specifically in areas that would be affected by transmission pole and submarine cable construction.

This type of analysis would take approximately 3 months including fieldwork. During construction, the SHPO might require that a cultural resource specialist be present during groundwork to observe and alert the construction crew if cultural resources are uncovered.

Department of Environmental Conservation (ADEC)

The ADEC will issue the water quality certificate as part of the COE Section 10 and 404 permit process. This will cover the construction methods to use to avoid/minimize water quality degradation and will permit the temporary water quality exceedences expected.

Local City Requirements

Four cities would be involved in some transmission line construction or use for both projects: City and Borough of Juneau, Hoonah, Kake, and Petersburg.

City and Borough of Juneau

Information is coming from Nathan Bishop of Community Development (907-586-5709).

Hoonah

According to Keith Bettridge, City Administrator and Coastal Zone District Coordinator, Hoonah has no building or structural permitting/review process. They would verify that the transmission line would be appropriate to the zoning once the final alignment was determined. From what he understands now, there would be no zoning issues. As for the Coastal Zone consistency review, the Hoonah district is limited to the city limits and there does not seem to be any problem with this proposed project. There is support for this project in the community.

Petersburg

The City of Petersburg would require no permit for construction of either alternative transmission line or termination yard. At a minimum, for the northern route, the City would review the plans for the termination yard within the city but no fee would be charged. There is support for this project in the community.

Kake

Messages were left with the City.

Other Stakeholders

In addition to Alaska State and US Federal agencies, Native Alaskan tribes and corporations must be consulted on projects that might affect them. Should any tribal property be involved, the proponent will need to negotiate for the purchase or rights to use that property. The following are entities that the proponent must contact for their comments and concerns:

- Sealaska Corp.
- Kake Tribal Corporation
- Goldbelt, Inc.
- Shee Atika, Inc.

TABLE 3-1
List of Contacts – Juneau-Greens Creek-Hoonah Transmission Line

Type	Last Name	First	Address 1	City	State	Zip	Title	Organization	Phone
phone	Bettridge	Keith	P.O. Box 360	Hoonah	AK	99829	Hoonah Coastal District Coordinator and City Manager	Alaska Coastal Zone Management	907-945-3663
	Bittner	Judith E.	550 W. 7th Ave., Suite 1310	Anchorage	AK	99501-3565	State Historic Preservation Officer	Alaska Department of Natural Resources	269-8721
	Enriquez	Richard	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801		U.S.Fish and Wildlife Service	586-7076
phone	Jacobson	Mike	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801	Eagle Management Specialist	U.S. Fish and Wildlife Service	586-7333
phone	Hanson	Shannon	P.O. Box 898	Anchorage	AK	99506-0898	Regulatory Branch	U.S.Army District-Alaska Corps of Engineers	1-800-478-2712
phone	Rothchild	Steve	P.O. Box 25517	Juneau	AK	99801	Seventeenth Coast Guard District	U.S. Coast Guard	463-2263
	Heumann	Katharine	302 Gold Street, Suite 202 PO Box 110030	Juneau	AK	99801-0030	District Program Coordinator	Division of Governmental Coordination	465-3529
	Jen	Mark	222 W. 7th Ave. #19	Anchorage	AK	99513-7588	Alaska Operations Office/Anchorage	U.S.Environmental Protection Agency	271-3411
phone	Leeds	John	8800 Glacier Hwy	Juneau	AK	99801	Field Office	U.S. Army District-Alaska Corps of Engineers	790-4490
	Matter	Paul	P.O. Box 135	Hoonah	AK	99829	Hoonah District Ranger	U.S. Forest Service	907.945.3631
phone	Grantham	Patty	P.O. Box 1328	Petersburg	AK	99833	Tongass National Forest, Petersburg Ranger	U.S. Forest Service	907-772-5900
phone	Baldwin	Sara	8461 Old Dairy Road	Juneau	AK	99801	Tongass National Forest	U.S. Forest Service	790-7443
meeting	Thomas	Lorraine	8461 Old Dairy Road	Juneau	AK	99801	Tongass National Forest	U.S. Forest Service	586-8800
phone	Rogers	Dennis	204 Siginaka Way	Sitka	AK	99835	Tongass National Forest--NEPA Coordinator	U.S. Forest Service	907-747-6671
	Payne	P. Michael	P.O. Box 021668	Juneau	AK	99802-1668		National Marine Fisheries	
phone	Powell	Jim	410 Willoughby Ave	Juneau	AK	99801	Water Quality Certification	Alaska Department of Environmental Cons.	465-5321
	Scott	Brady	400 Willoughby Avenue	Juneau	AK	99801-1724	Division of Land, Southeast Region	Alaska Department of Natural Resources	465-3400
phone	Cohen	David	400 Willoughby Avenue	Juneau	AK	99801-1724	Division of Land, Southeast Region	Alaska Department of Natural Resources	
phone/ meeting	Shaw	Linda	P.O. Box 021668	Juneau	AK	99802-1668		National Marine Fisheries	586-7510
	Woods	Theresa	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801	Field Supervisor	U.S.Fish and Wildlife Service	
phone	Schrader	Carl		Juneau	AK		SE Habitat	Alaska Fish and Game Department	907-465-4287
phone	Gustafson	Jack		Ketchikan	AK		Ketchikan Habitat	Alaska Fish and Game Department	907-225-2027
phone	Bishop	Nathan	155 South Seward Street	Juneau	AK	99801	Department of Community Development	City and Borough of Juneau	907-586-5709

TABLE 3-2
List of Contacts – Kake-Petersburg Transmission Line

Type	Last Name	First	Address 1	City	State	Zip	Title	Organization	Phone
phone	Luczak	Leo	P.O.Box 329	Petersburg	AK	99833	Community Development Director/Coastal Zone	City of Petersburg	772-4533
	Bittner	Judith E.	550 W. 7th Ave., Suite 1310	Anchorage	AK	99501-3565	State Historic Preservation Officer	Alaska Department of Natural Resources	269-8721
	Enriquez	Richard	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801		U.S.Fish and Wildlife Service	586-7076
phone	Jacobson	Mike	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801	Eagle Management Specialist	U.S. Fish and Wildlife Service	586-7333
phone	Hanson	Shannon	P.O. Box 898	Anchorage	AK	99506-0898	Regulatory Branch	U.S.Army District-Alaska Corps of Engineers	1-800-478-2712
phone	Rothchild	Steve	P.O. Box 25517	Juneau	AK	99801	Seventeenth Coast Guard District	U.S. Coast Guard	463-2263
phone	Heumann	Katharine	302 Gold Street, Suite 202 PO Box 110030	Juneau	AK	99801-0030	District Program Coordinator	Division of Governmental Coordination	465-3529
	Jen	Mark	222 W. 7th Ave. #19	Anchorage	AK	99513-7588	Alaska Operations Office/Anchorage	U.S.Environmental Protection Agency	271-3411
phone	Leeds	John	8800 Glacier Hwy	Juneau	AK	99801	Field Office	U.S. Army District-Alaska Corps of Engineers	790-4490
phone	Grantham	Patty	P.O. Box 1328	Petersburg	AK	99833	Tongass National Forest, Petersburg Ranger	U.S. Forest Service	907-772-5900
phone	Baldwin	Sara	8461 Old Dairy Road	Juneau	AK	99801	Tongass National Forest	U.S. Forest Service	790-7443
meeting	Thomas	Lorraine	8461 Old Dairy Road	Juneau	AK	99801	Tongass National Forest	U.S. Forest Service	586-8800
phone	Rogers	Dennis		Sitka	AK		Tongass National Forest--Sitka Ranger district	U.S. Forest Service	907-747-6671
	Payne	P. Michael	P.O. Box 021668	Juneau	AK	99802-1668		National Marine Fisheries	
phone	Powell	Jim	410 Willoughby Ave	Juneau	AK	99801	Water Quality Certification	Alaska Department of Environmental Conservation	465-5321
phone	Cohen	David	400 Willoughby Avenue	Juneau	AK	99801-1724	Division of Land, Southeast Region	Alaska Department of Natural Resources	
phone/meet	Shaw	Linda	P.O. Box 021668	Juneau	AK	99802-1668		National Marine Fisheries	586-7510
	Woods	Theresa	3000 Vintage Park Blvd, Suite 201	Juneau	AK	99801	Field Supervisor	U.S.Fish and Wildlife Service	
phone	Cariello	Jim	P.O. Box 667	Petersburg	AK	99833	Area Habitat Biologist	Alaska Department of Fish and Game	
phone	Gustafson	Jack		Ketchikan	AK		Ketchikan Habitat	Alaska Department of Fish and Game	907-225-2027
phone			P.O. Box 500	Kake	AK	99830		City of Kake	907-785-3804

TABLE 3-3 (Page 1 of 2)
Summary of Agency Requirements and Associated Costs

Agency/ Requirement	Description	Associated Cost
Federal Agencies		
Federal Energy Regulatory Commission	**Electric Power Regulation** Approve interstate wholesale rate for distribution. Not applicable to proposed project	**NA**
U.S. Army Corp of Engineers: Section 10 Permit Section 404 Permit Other	**Authority to regulate work in waters of the U.S.** Permit and condition work in navigable waters Permit and condition work in wetlands Notify NOAA and NOS of underwater cables	**Permitting costs only, no NEPA process required** Costs will be associated with meetings with the Corps staff, preparation of and finalization of permit drawings, mitigation measures required by NMFS and/or USFWS
U.S. Forest Service Special Use Authorization Construction Permit Easement Fee Timber sales	**Permission to Work in the Tongass National Forest** Through the NEPA process, USFS will evaluate purpose and need of project, evaluate potential impacts, select the alternative, and condition the project. 5-year permit to construct. Bonding required. Long-term lease (50 years) Purchase of timber that would be removed by project	**The major costs would be:** Preparation of needed NEPA documents and funding for USFS administration of those processes Bonding amount equivalent to cost to restore forest. 5 percent of fair market value. USFS would appraise land value USFS or third party would appraise and harvest.
U.S. Fish and Wildlife Service	**Authority to uphold Endangered Species Act** Might require Biological Assessment (BA) if deemed needed. Review and condition federal permit applications	Costs might be needed to do BA or for mitigation or monitoring, no major issues identified at this time.
NOAA/ National Marine Fisheries Service	**Authority to uphold Endangered Species Act and Magnuson-Stevens Act (EFH)** Might require BA if deemed needed.	Costs might be needed to do BA or for mitigation or monitoring, costs for marine habitat survey and report.
U.S. Environmental Protection Agency	**Clean Water Act—Storm Water Quality**	Construction Storm Water Pollution Prevention Plan
U.S. Coast Guard	**Update Navigation Charts**	No additional costs

TABLE 3-3 (Page 2 of 2)
Summary of Agency Requirements and Associated Costs

State of Alaska Agencies		
Coastal Zone Management Program	Authorized to review action against local coastal zone management plan. Division of Governmental Coordination distributes documents and consolidates comments and conditions.	Costs associated with permit and environmental documentation preparation, pre-submittal meeting, and potential subsequent conditions.
Department of Natural Resources	Easements across state lands including shorelines and subtidal areas. Early entry permit (valid for 1 year prior to construction) Right-of-Way Permit	Costs: $100 filing fee for each easement plus Annual ROW lease based on location.
Department of Fish and Game	**Title 16 Fish Habitat Permits** Fishway Act and Anadromous Fish Act	Because projects do not propose to work within any catalogued anadromous streams, fish habitat permits would not be needed. Seasonal constraints to construction of submarine cables would be enforced.
Department of Transportation & Public Facilities	**Utility permit** Permit application for lines within a DOT right of way.	$400 per permit plus $0.25/lineal foot to a maximum of $2,500.
State Historic Preservation Officer	Section 106 of the National Historic Preservation Act	Costs of an analysis of the presence or potential presence of cultural or historic sites including a records search and field investigation. Oversight during construction may be required if high potential is found.
Department of Environmental Conservation	Clean Water Act; Temporary Water Quality Certification	No additional costs except for implementation of BMP during construction
Local Governments		
City and Borough of Juneau		
Hoonah	Zoning review is the only area that the city of Hoonah would conduct.	None
Kake		
Petersburg	Only review if termination yard is within city limits.	None

TABLE 3-4
Summary of Estimated Costs and Schedule for Permitting and Environmental Processes
Juneau – Greens Creek – Hoonah Transmission Line

Agency/ Requirement	Description	Associated Cost Item	Estimated cost	Estimated Schedule Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12
Federal Requirements															
Federal Energy Regulatory Commission	NA	NA	NA												
U.S. Army Corp of Engineers:		Costs will be associated with meetings with the Corps staff, preparation of and finalization of permit drawings, mitigation measures required by NMFS and/or USFWS													
	Section 10 Permit	Permitting costs only, no NEPA process required	$20 - 25K												
	Section 404 Permit	Permit preparation	$5 - 7K												
		COE Review period	Na												
		Public Review period	Na												
	Notify NOAA and NOS of underwater cables	None	NA												
U.S. Forest Service	Special Use Authorization	Apply for Special Use Authorization													
		Preparation of needed NEPA document (EA) and funding for FS administration of those processes	$250 - 350K												
		Biological Assessment	$8 - 15K												
		Marine Habitat survey	$75 - 80 K												
		Expenses	$30 - 50K												
	Construction Permit	Bonding amount equivalent to cost to restore forest.	unknown												
	Easement Fee	5 percent of fair market value. FS would appraise land value	unknown												
	Timber sales	FS or third party would appraise and harvest.	unknown												
U.S. Fish and Wildlife Service	Endangered Species Act	Consultation if needed, no issues anticipated at this time	NA												
		Biological Assessment	see above												
NOAA/ National Marine Fisheries Service	Endangered Species Act & Magnuson-Stevens Act	Costs for marine habitat survey; additional funds might be needed for mitigation or monitoring, no major issues identified at this time.													
		Marine Habitat survey	see above												
		Mitigation/Monitoring Plan	$15 - 20K												
		Eelgrass transplanting during construction	$60 - 80K												
		Expenses	$25 - 30K												
		Monitoring per event (2 in 5 years)	$15 - 20K												
U.S. Environmental Protection Agency	Clean Water Act--Storm water pollution prevention plan	Prepare Construction Storm Water Pollution Prevention Plan	$5K												
U.S. Coast Guard	Navigation issues/charts.	No additional costs	NA												
Alaska State Requirements															
Coastal Zone Management Program	DGC process for consistency review	Pre-application meeting	$5 - 8K												
		Parallel review of COE + permits													
Department of Natural Resources	Permit Applications		$5K												
	Early entry permit (valid for 1 year prior to construction)	$100 / entry filing fee	4 cable crossings; $400												
	Right-of-Way Permit	Annual lease fee dependent on locations	?												
Department of Fish and Game	Title 16 Fish Habitat Permits	Not needed at this time	NA												
Department of Transportation & Public Facilities	Utility permit	$400 per permit plus $0.25/lineal foot to a maximum of $2,500.	$2.5K												
State Historic Preservation Officer	Section 106 review	Certified professional to conduct records review and field investigation on all project lands	$15 - 20K												
Department of Environmental Conservation	Section 401 Water Quality Certification	No extra costs--part of COE permit process	NA												

Subtotal	**$536 - 734 K**
Contingency at 25%	**$134 - 184 K**
Total Estimated Costs	**$770 - 918 K**

= Permitting Activity

= Technical study

TABLE 3-5
Summary of Estimated Costs and Schedule for Permitting and Environmental Processes
Kake - Petersburg Transmission Line

Agency/ Requirement	Description	Associated Cost Item	Estimated cost	Estimated Schedule Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9	Q10	Q11	Q12
Federal Requirements															
Federal Energy Regulatory Commission	NA	NA	NA												
U.S. Army Corp of Engineers:		Costs will be associated with meetings with the Corps staff, preparation of and finalization of permit drawings, mitigation measures required by NMFS and/or USFWS													
	Section 10 Permit	Permitting costs only, no NEPA process required	$20 - 25K												
	Section 404 Permit	Permit preparation	$30 - 60 K												
		COE Review period	Na												
		Public Review period	Na												
	Notify NOAA and NOS of underwater cables	None	NA												
	Special Use Authorization	Apply for Special Use Authorization													
U.S. Forest Service		Preparation of needed NEPA document (EA) and funding for FS administration of those processes	$700 - 1,000 K												
		Biological Assessment	$30 - 50K												
		Marine Habitat survey	$70 - 80K												
		Expenses	$30 - 50K												
	Construction Permit	Bonding amount equivalent to cost to restore forest.	unknown												
	Easement Fee	5 percent of fair market value. FS would appraise land value	unknown												
	Timber sales	FS or third party would appraise and harvest.	unknown												
U.S. Fish and Wildlife Service	Endangered Species Act	Consultation if needed, no issues anticipated at this time	NA												
		Biological Assessment	see above												
NOAA/ National Marine Fisheries Service	Endangered Species Act & Magnuson-Stevens Act	Costs for marine habitat survey; additional funds might be needed for mitigation or monitoring, no major issues identified at this time.													
		Marine Habitat survey	see above												
		Mitigation/Monitoring Plan	$15 - 20K												
		Eelgrass transplanting during construction	$60 - 80K												
		Expenses	$50 - 75K												
		Monitoring per event (2 in 5 years)	$15 - 20K												
U.S. Environmental Protection Agency	Clean Water Act--Storm water pollution prevention plan	Prepare Construction Storm Water Pollution Prevention Plan	$5K												
U.S. Coast Guard	Navigation issues/charts.	No additional costs	NA												
Alaska State Requirements															
Coastal Zone Management Program	DGC process for consistency review	Pre-application meeting													
		Parallel review of COE + permits													
Department of Natural Resources	Early entry permit (valid for 1 year prior to construction)	$100 / entry filing fee	4 cable crossings; $400												
	Right-of-Way Permit	Annual lease fee dependent on locations	?												
Department of Fish and Game	Title 16 Fish Habitat Permits	Not needed at this time	NA												
Department of Transportation & Public Facilities	Utility permit	$400 per permit plus $0.25/lineal foot to a maximum of $2,500.	$2.5K												
State Historic Preservation Officer	Section 106 review	Certified professional to conduct records review and field investigation on all project lands	$30 - 40K												
Department of Environmental Conservation	Section 401 Water Quality Certification	No extra costs--part of COE permit process	NA												

Subtotal	**$1.06 - 1.51 M**
Contingency at 25%	**$264 - 377 K**
Total Estimated Costs	**$1.32 - 1.89 M**

= Permitting Activity

= Technical study

Estimated Costs of Construction

Introduction

The costs to develop and construct the Interties have been estimated. The cost estimate for SEI-1, the Juneau – Greens Creek – Hoonah transmission line is based significantly on the preliminary estimate of this system as previously prepared by AEL&P. The cost estimate for SEI-2, the Kake – Petersburg line, is based on information from previous reports adjusted as appropriate for changed conditions. Although the cost of each line has been estimated separately, the same fundamental costing basis has been used for both systems.

The estimated costs of the Interties as provided in this report include all estimated costs of engineering and design, permitting, materials, equipment and construction. Primary components of each line (e.g. overhead lines, submarine cables) are identified separately in the cost estimate. Since the configuration of the Interties used as the basis for the cost estimate is still very preliminary, a contingency factor of 20% has been applied to all costs. As design proceeds and more precision can be used in estimating the costs, the contingency included in the total cost estimate can possibly be lowered. In any major project of this type, however, the actual cost of construction can very significantly from the engineer's estimate due to market conditions for the materials and services needed at the time of procurement. As an example, the cost of submarine cable is potentially on the rise at the present time because of a recent reduction in the number of cable manufacturers.

The cost estimates included in this report are based on the routing and technical information described in Section 2. Primary characteristics of the line are 69-kV, single-pole construction alongside existing roads where available. Submarine crossings are to be made with single 3-phase, dielectric cables with armor and potentially with fiber-optic communication lines bundled in. It is expected that the owner of the Interties will contract for all services of permitting, design, construction and construction management related to the Interties. The estimated costs of these services are included in the total cost estimate.

Juneau – Greens Creek – Hoonah (SEI-1)

AEL&P has recently developed a cost estimate for SEI-1 based on AEL&P's preliminary design for this system. The cost estimate is based on AEL&P's experience with constructing transmission lines elsewhere in its service area and other information. AEL&P solicited information on the cost of submarine cables shortly after completing the Taku Inlet submarine crossing in 2000. In preparing its cost estimate, AEL&P essentially presumed that it would serve as the project manager on the project.

We have reviewed AEL&P's cost estimate and have prepared a revised estimate that incorporates some adjusted costing information. The cost estimate for SEI-1 is shown in Table 4-1. It should be noted that Table 4-1 does not include the cost of removing the overhead line between Hawk Inlet and the Greens Creek mine upon the eventual closure of the mine. AEL&P has estimated that the cost to remove the line would be about $250,000 at today's cost level. It should also be noted that the cost of the substation that will be needed at the Greens Creek mine to take delivery of power at 69-kV over SEI-1, has not been included in Table 4-1. The new substation at the mine will be constructed and financed by either AEL&P or KMC-GC and as such, is not included as a component of SEI-1.

TABLE 4-1 (Page 1 of 2)
Estimated Cost of Project Development and Construction
Juneau – Greens Creek – Hoonah Transmission Line

		Estimated Cost
Overhead Lines		
Poles	$	815,700
Framing		701,500
Guys and Anchors		262,900
Conductor		812,400
Fiber Optic Cable - 48 strands		195,400
Foundations and work pads		263,700
Distribution transformer		122,500
Special Transportation and Helicopters		500,000
Staging area		65,000
Subtotal	$	3,739,100
Clearing		
Heavy Timber, Clearing w/Timber Credit	$	-
Light Clearing		223,010
Subtotal	$	223,010
Submarine Cable - Outer Pt. - Young Bay		
Cable - 3Φ bundled, Single Armor, 240mm^2	$	3,151,900
Fiber Optic System - 48 strands		200,600
Installation		406,400
Mob/Demob		605,000
Subtotal	$	4,363,900
Submarine Cable - Hawk Inlet - Spasski Bay		
Cable - 3Φ bundled, S/D Armor, 120mm^2	$	7,817,800
Fiber Optic System - 48 strands		549,100
Installation		745,200
Mob/Demob		865,000
Subtotal	$	9,977,100
Submarine Cable Term. Yards (Four) - Subtotal		
Site Prep, Foundations	$	220,000
Ground Grid and Fencing		90,000
Structures, Lightning Arrestors		240,000
Cable Terminations		96,000
Cathodic Protection		240,000
Shunt Reactor, Disconnect		360,000
Circuit Breakers, Relaying		360,000
Revenue Metering		80,000
SCADA, Other		340,000
Subtotal	$	2,026,000

TABLE 4-2 (Page 2 of 2)
Estimated Cost of Project Development and Construction
Juneau – Greens Creek – Hoonah Transmission Line

Hoonah Substation		
Civil Site Prep & Foundations	$	120,000
Ground Grid and Fencing		45,000
Bus Works		26,000
Control Cable and Conduit		20,000
SCADA and Control Interface		40,000
Fuses/Switches		40,000
Transformer - 69/4.16-kV, 5 MVA, Relaying, LA, etc.		120,000
Voltage Regulators/Bypass Switches		46,000
Recloser/Disconnect Switch		34,000
Relaying PT		36,000
SS and Battery		40,000
Shunt Reactor		180,000
Installation Labor		80,000
Subtotal	$	827,000
Total Direct Costs	$	21,156,110
Indirect Costs		
Alignment Definition and Prelim. Engineering	$	100,000
Alignment Survey		220,000
Final Engineering		975,000
Permitting		735,000
Structure Staking		90,000
Geotechnical Surveys - Overhead		50,000
Geotechnical Surveys - Cable		200,000
Material and Equipment Delivery		4,000,000
Mobilization (6% of Direct Costs less Sub. Cable)		409,000
Construction Management (7% of Direct Costs)		1,481,000
Owners Administration (7% of Direct Costs)		1,481,000
Subtotal - Indirect Costs	$	9,741,000
Contingency - 20%		6,179,000
Total Project Cost	$	37,076,110

As shown in Table 4-1, the total estimated cost of SEI-1 is $37.1 million. This is slightly higher than AEL&P's estimated cost of approximately $35 million. A significant cost item in the table above is the estimated cost of material delivery. The amount shown is based on the estimated cost of loading the 25-mile long submarine cable on the cable laying ship and transportation from Europe to the project site. It should be noted, that the estimated permitting cost shown in Table 4-1 is based on the high end estimate provided in Table 3-4.

Kake – Petersburg Intertie (SEI-2)

A cost estimate for the Southern Route Alternative of SEI-2 has been prepared. This estimate includes the costs of labor and materials for the design, permitting and construction of the overhead line, estimated to be 49.5 miles in length, and the two submarine crossings of Wrangell Narrows and Duncan Canal which are essentially two miles in combined length. As indicated in Section 2 of this report, SEI-2 is specified at 69-kV with single wood pole structures. To the extent possible, poles are to be located adjacent to existing USFS roads. Road access will be an important consideration in the estimated costs for SEI-2.

The total estimated costs for SEI-2 are shown in Table 4-2. As indicated for SEI-1, the estimated cost for permitting activities is midway between the low and high estimates provided in Table 3-5. A contingency of 20% has been applied to all costs shown in Table 4-2.

TABLE 4-2 (Page 1 of 2)
Estimated Cost of Project Development and Construction
Kake - Petersburg Transmission Line

		Estimated Cost
Overhead Line		
Poles	$	2,255,600
Framing		1,740,600
Guys and Anchors		547,600
Conductor		2,188,700
Fiber Optic Systems		653,400
Foundations and work pads		1,331,400
Distribution transfer		140,000
Special Helicopter Assistance		976,500
Staging area, Duncan Canal		65,000
Subtotal	$	9,898,800
Clearing		
Heavy Timber, Clearing w/Timber Credit	$	1,668,000
Light Clearing		120,000
Subtotal	$	1,788,000
Submarine Cable		
Cable - 3Φ bundled, Single Armor, 120mm^2	$	522,100
Fiber Optic System		26,400
Installation		458,400
Cathodic Protection		120,000
Mob/Demob		610,000
Subtotal	$	1,736,900
Petersburg Tap Switchyard		
Civil Site Prep & Foundations	$	80,000
Ground Grid and Fencing		30,000
Bus Works		34,000
Control Cable and Conduit		36,000
SCADA and Control Interface		35,000
Sectionalizing Switch (2)		63,000
Breaker & CT		100,000
Relaying, PT		36,000
Revenue Metering		40,000
Shunt Reactor and Disc SW		-
Subtotal	$	454,000
Submarine Cable Termination Yards (4)		
Support Structures, Foundations	$	160,000
Cable Terminations		96,000
Lightning Arresters		120,000
Subtotal	$	376,000

TABLE 4-2 (Page 2 of 2)
Estimated Cost of Project Development and Construction
Kake - Petersburg Transmission Line

Kake Substation		
Civil Site Prep & Foundations	$	120,000
Ground Grid and Fencing		45,000
Bus Works		34,000
Control Cable and Conduit		36,000
SCADA and Control Interface		40,000
Fuses/Switches		40,000
Transformer -69/12.5-kV, 2.5 MVA, Relaying, LA, etc		110,000
Voltage Regulators/Bypass Switches		34,000
Recloser/Disconnect Switch		34,000
Relaying PT		36,000
Installation Labor		80,000
SS and Battery		40,000
Subtotal	$	649,000
Total Direct Costs	$	14,902,700
Indirect Costs		
Alignment Definition and Prelim. Engineering	$	200,000
Alignment Survey		125,000
Final Engineering		600,000
Permitting		1,300,000
Structure Staking		125,000
Geotechnical Surveys		90,000
Mobilization (3% of Direct Costs less Sub. Cable)		395,000
Construction Management (5% of Direct Costs)		745,000
Owners Administration (5% of Direct Costs)		745,000
Subtotal - Indirect Costs	$	4,325,000
Contingency - 20%		3,846,000
Total Project Cost	$	23,073,700

Example Project Development Schedule

Introduction

The Intertie construction cost estimates provided in Section 4 include the estimated costs of several activities prior to actual construction. Included among these activities are preliminary design, geotechnical surveys, permitting and environmental studies, and final design. The actual time required to perform these activities and when they would be performed will depend on a number of factors. An example development schedule has been prepared to indicate what activities would be performed and what the activity duration would be for development of the Kake – Petersburg Intertie. The Juneau – Greens Creek – Hoonah Intertie would require a similar process, however, its development to date has been directed by AEL&P and would be expected to follow the development process associated with other AEL&P projects.

An integral part of the development of any project requiring a significant degree of grant funding is the pursuit and approval of funding sources. The time required for this effort cannot be reliably predicted. In addition, there will be a number of permits and approvals needed to construct the Interties as indicated in Section 3 of this report. The time required to obtain the necessary permits is often influenced by the degree of public support or opposition to the projects. Further, various commercial arrangements will be needed to allow for the effective utilization of the Interties. Such arrangements would include power sales agreements and contracts.

Permitting and Environmental Studies

The expected time requirement for permitting activities and environmental studies is shown in Section 3 of this report. The estimated duration of these activities is shown in Table 3-4 for SEI-1 and in Table 3-5 for SEI-2. The preparation of certain information needed in the permitting process, such as route diagrams and technical descriptions, will necessitate that certain engineering work be accomplished fairly early in the process. As shown in Table 3-5, the expected duration of permitting activities for SEI-2 is approximately two years. In order to expedite the development process, it would be recommended that preliminary engineering and route alignment activities be conducted concurrently with early permitting work and environmental studies.

Engineering Related Activities

The project development approach outlined below is based upon construction being undertaken by a contractor(s) using plans and technical specifications prepared by an engineering firm experienced with overhead transmission line design. Major equipment and materials would be obtained by the Intertie owner with installation performed by a construction contractor. An engineering firm, working as the Owner's Project Engineer would manage and oversee specialty engineering services. Various activities related to the engineering function of project development are described in the following paragraphs.

Selection of Project Team

Typically owners select a Project Manager (with appropriate experience) and contract with specialty firms to provide the required services. Engineering and related specialty areas include:

- Project Management
- Preliminary and Final Engineering
- Engineering survey
- Geotechnical Investigations
- Easements, Land Rights, property survey
- Logging and Clearing Specialist
- Construction Specialist

The engineering team would be charged with developing and implementing a detailed work plan, schedule and budget to accomplish the Project on schedule and within budget.

Alignment Definition

One of the first tasks required to move the Project forward will be to refine the conceptual design and the selected route. Construction, operation and maintenance issues will be discussed in detail with the owner and the owner's operating personnel to identify project requirements.

During this phase a transmission line design engineer and other specialists would initiate a detailed review of the route identifying any routing concerns or route improvements. This work will require coordination with the environmental and permitting specialist knowledgeable with the area. Incorporating input from the various specialists, a specific alignment will be selected. Selection of the specific alignment will consider:

- Specific site locations of Tap, Substation, Submarine Crossings
- Alignment of logging road
- Location of clear-cuts, size of trees
- Location of Muskeg
- Terrain elevation differences
- Environmental or cultural avoidance areas
- Location of eagle trees
- Location of good soils for structure stability
- Visual Concerns

Engineering Survey

An engineering survey will be obtained once a specific alignment is identified in the field and tied down with specific coordinates. The engineering survey will locate physical features in plan and determine elevations along the alignment within the defined corridor. Plan/profile drawings will be developed from the field survey.

There are several types of surveying methods which could be utilized on a project such as the Interties. One which may prove economical while also providing great flexibility in allowing adjustments during preliminary design without requiring follow-up visits for additional surveys is LIDAR (Light Detection and Ranging).

LIDAR, in summary, uses a laser and receivers mounted generally on a helicopter to scan an area from low altitude and collect survey data. The helicopter has airborne global positioning system (GPS) capability and also ties into ground stations established at about every 25 mile radius. The laser sends out several thousand pulses per second and the returns are collected by the receivers mounted on outriggers.

The data is collected as a series of X,Y,Z points tied to a reference grid such as State Plain Coordinates. The huge amount of data collected in the field is filtered and reduced into separate files such as ground, existing structures, existing wires and vegetation. These files can then be imported into design programs such as PLS-Cadd. In PLS-Cadd, the designer can create a surface wire-frame model from which profiles can be cut once the alignment is established. Because of the very dense coverage, (points are separated by a couple of feet within a 200′ to 1,000′ wide corridor) the surface model will result in very precise profiles. Refinements may be made to enhance the alignment following a review of the plan/profile drawings.

Preliminary Engineering

The objective of the preliminary design task is to finalize design criteria and to complete sufficient design calculations to determine the general layout and sizing of major facility components. Preliminary engineering will proceed simultaneously with the alignment definition phase. The preliminary design phase will include additional system studies and discussions with the owner's operating personnel to refine and determine:

- System protection plan
- 1-lines of system
- Equipment and conductor sizes
- Voltage drop and power flow
- Appropriate insulation
- Need for reactors

Preliminary engineering will also determine all of the detail design parameters and will result in issuance of a Basis of Design documenting design requirements such as:

- Codes and Standards

- Clearance requirements (horizontal and vertical)
- Conductor tension limits
- Sag/tension data
- Physical loading requirements
- Overload capacity factors
- Grounding requirements
- Clearing requirements
- Right-of-way constraints
- Framing requirements
- Guy and anchor requirements

An important element of the preliminary engineering task will be to develop an updated cost estimate for the project based on the information obtained and engineering work performed. Certain issues uncovered during preliminary engineering and the investigations preceding it could alter the approach ultimately determined to be the most viable for eventual implementation. An example of this could be whether or not long aerial crossings of water bodies could be more advantageously undertaken than submarine cable crossings. An updated cost estimate for the project will help decision makers determine more precise funding requirements.

Geotechnical Investigations

Subsurface soils investigations will be required at the major equipment locations (substation, termination locations and tap points). Experienced geotechnical personnel will review the entire route and observe road cuts and perform excavation of test pits along the route. Using the data collected tempered with experience, a subsurface profile will be developed identifying the subsurface profile and key avoidance areas.

Final Design

Final design will involve the completion and documentation of design calculations, special analysis, development of construction drawings, development of construction and material specifications, and development of final material lists. During final design, specific pole locations, framing, pole size, guy leads and anchor types will be determined for each structure along the alignment. Locations will be staked and field reviewed. At the major equipment locations, structures, foundations, grounding, and fencing will be sized and designed as appropriate.

Initiate Construction and Material Procurement Contracts

This function would involve the preparation of bid documents and specifications for vendors and suppliers to base bids for materials and construction services. Much of the material needed for the overhead portions of the Intertie can be obtained relatively quickly. The submarine cables would require a longer lead time and in particular, delivery of the cables and arranging for installation could require more than a year. Flexibility in the schedule with regard to the cable procurement could significantly affect the delivered and installed cost of the cable.

In general, it is expected that the procurement of materials and construction services would be conducted through the solicitation of bids and award of contracts to vendors and contractors early in the year in which construction is expected to commence. The first year of construction activity is not expected to require significant material deliveries so a full year of lead time on material manufacturing and delivery would be allowed for in the schedule.

Construction Activities

A two-year construction duration is expected for SEI-2. The major activities to be undertaken in each year are as follows:

Year 1

- Alignment clearing
- Construction of work pads, as required
- Construction of other key components, as appropriate

Year 2

- Line construction
- Installation of submarine cables
- Substation and switchyard construction

The actual time required to install the submarine cables is quite short, possibly just a few days. As such, they can be installed at anytime in the second year of the construction period, potentially at the very end of the process just before energization of the line.

Total Project Development Schedule

Assuming that funding were available, or at least reasonably assured, and arrangements needed to proceed with the Interties were approved[14], it is estimated that a four year development and construction schedule could be accomplished for SEI-2.

[14] In addition to the formation and approval of an ownership organization to be established by the Southeast Conference, other approvals will be needed from THREA's board and the Four Dam Pool Power Agency related to SEI-2. For SEI-1, approvals will be needed from THREA, AEL&P and the Regulatory Commission of Alaska (RCA). These approvals are in addition to the necessary approvals from local, State and federal agencies and other stakeholders as described in Section 3 of this report.

Power Supply Evaluation and Economic Analysis

Power Supply Evaluation

Overview

Hydroelectric generating facilities and diesel generators provide nearly all of the electric power generation in Southeast Alaska[15]. Elsewhere in Alaska, natural gas and coal are used to provide a significant portion of the electrical power supply; however, these fuels are not commercially available in Southeast Alaska. The State and federal government, as well as certain communities and utilities have developed the existing hydroelectric generating plants in Southeast Alaska.

Hydroelectric facilities require specific site conditions and generally have high initial development costs. The effective costs of hydroelectric development can be made even higher by the need to construct projects larger than the present electric loads require. This can create a surplus energy generation capability from hydroelectric plants, sometimes for a significant length of time.

The availability of diesel fuel, the ease of installing diesel generators in a wide range of capacities and relatively low initial costs have made diesel engine generators the generator of choice in most remote locations including Southeast Alaska. The operating and maintenance (O&M) expenses associated with diesel generators, however, often make them more costly than hydroelectric generation plants in the long run. Potential interruptions in fuel delivery, the susceptibility of fuel prices to wide variation, noise and air pollution issues are other negative aspects of diesel generation. Where available, hydroelectric generation is typically preferred to diesel generation.

The primary purpose of the Southeast transmission system will be to transmit power generated at lower-cost hydroelectric generation facilities to communities where diesel generation is the principal source of power supply. At the present time, some additional hydroelectric energy capability is available at both the Four Dam Pool Power Agency's Lake Tyee project and the State's Snettisham project. With a transmission system that creates a larger electric load base, fuller utilization of the capability of these projects can be accomplished. Further, new hydroelectric generation projects can be more effectively developed in the future.

The electric power requirements of all the load centers involved with the Intertie segments are important to the evaluation of Intertie feasibility. Projections of power requirements have been compiled for Kake, Petersburg, Wrangell, and Ketchikan, all of which currently rely upon the output of the Lake Tyee project or will be connected to Lake Tyee through the construction of new transmission facilities. Power requirement projections have also been compiled for

[15] AEL&P and KMC-GC use oil-fired combustion turbines for a portion of their power supply requirement. In the past, pulp mills in Ketchikan and Sitka used production waste materials as a boiler fuel to drive steam turbines.

AEL&P, the Kennecott Mining Company - Greens Creek Mine (KMC-GC) and Hoonah, all of which will use power from the Snettisham and Lake Dorothy projects.

The Intertie segments will be used to transmit hydroelectric energy that is either surplus to the needs of the utility systems currently interconnected with the hydroelectric plants or from new hydro plants. Consequently, it is important to evaluate the availability of the surplus generation and identify potential new hydroelectric resources that can be developed to economically provide additional energy to the interconnected systems, as needed, in the future. Although transmission lines are generally very reliable, power deliveries over the Intertie segments will need to be considered interruptible. As such, Hoonah, Kake and KMC-GC will need to retain local generation sufficient to supply loads if the transmission lines are down due to unplanned outages or maintenance.

It is also important to note the commercial and contractual arrangements that are in place that could potentially limit the availability of power resources for sale to other utility systems. For example, the Lake Tyee project is owned and operated by the Four Dam Pool Power Agency and its output is sold to Petersburg and Wrangell pursuant to the Four Dam Pool Power Sales Agreement. Petersburg, Wrangell and eventually Ketchikan when it is interconnected, will always have first priority to the output of the Lake Tyee Project pursuant to the Power Sales Agreement. AEL&P is a regulated investor-owned utility with an obligation to provide a return to its shareholders. Any sale of power from AEL&P's resources will need to acknowledge the rate structure that AEL&P has in place.

Power Requirements

Electric power requirements have been projected for the load centers for a ten-year projection period. For the THREA served communities, Kake and Hoonah, the power requirement projections are based on assumed growth rates applied to recently experienced loads. Explicit adjustments have been made for new large loads. Power requirements for Ketchikan, Petersburg and Wrangell have been compiled from previously prepared Four Dam Pool planning studies. AEL&P has provided projections of its power requirements. KMC-GC has also provided estimates of its current power requirements and expectations of changes to the present load amount. The existing loads of the communities, utilities and KMC-GC are shown in Table 6-1.

TABLE 6-1
2002 Energy Loads (MWh)

	Energy Sales (MWh)				
	Firm	Non-Firm [1]	Total	Energy Reqs. [2] (MWh)	Peak (kW)
AEL&P	296,035	14,139	310,174	326,803	-
THREA - Hoonah	3,296	865	4,161	4,557	780
Greens Creek [3]	55,845	-	55,845	55,845	8,000
Petersburg	36,617	-	36,617	41,644	8,880
Wrangell	20,150	5,079	25,229	25,742	3,070
Ketchikan	147,505	-	147,505	153,972	26,300
THREA - Kake	2,594	1,370	3,964	4,291	1,016

[1] Interruptible or non-firm energy sales that can be curtailed under certain circumstances.
[2] Energy requirements are the summation of total generation and total power purchases.
[3] Estimated.

The basis for and assumptions used in preparing the projected power requirements for each of the load centers are described in the following paragraphs.

Alaska Electric Light & Power

AEL&P has developed a forecast of its energy sales and total energy requirements for a 20-year period. The forecast includes sales to AEL&P's retail residential, commercial and public facility customers as well as non-firm sales that are dependent on the availability of surplus hydroelectric generation[16]. Non-firm energy sales are primarily to AEL&P's dual fuel customers and to cruise ships equipped to connect to shore-based power generation. AEL&P is projecting its total energy requirement to increase from 340,000 MWh in 2003 to 403,000 MWh in 2023, representing an average annual growth rate of 0.85%. AEL&P indicates that its forecast reflects a trend towards lower residential electric heating usage in Juneau than had been experienced in the past.

Kennecott Mining Company - Greens Creek Mine

The KMC-GC mine located on Admiralty Island uses electric power for mining operations and also for electric loads at the Hawk Inlet and Young Bay dock facilities. None of these loads are interconnected with each other and separate generation systems are needed at each location. The mine load averages approximately 6 MW throughout the day and the peak load is about 7.5 MW. The loads at the Hawk Inlet powerhouse average about 370 kW but can increase to 500 kW when loading a ship. The load at Young Bay is relatively small and insignificant.

[16] Hydroelectric generation can vary from year to year depending on local precipitation. In dryer years, the amount of hydroelectric generation surplus to the needs of AEL&P's retail customer base is lower than in normal years.

KMC-GC does not expect significant changes in its electric power requirements in the future. Ventilation improvements and additional loads at the grinding plant could in total increase the overall power requirement by about 500 kW. The expected remaining operating life of the facility is estimated by KMC-GC to be approximately 10 years, subject to exploration success, metal prices and other factors. The projected power requirements for KMC-GC are summarized in Table 6-2.

TABLE 6-2
Kennecott Greens Creek Mine
Projected Energy Loads and Capacity Requirements

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh)						
Mine Load	52,560	52,560	54,662	54,662	56,064	56,064
Hawk Inlet	2,628	2,628	2,628	2,628	2,628	2,628
Total Energy Requirements	55,188	55,188	57,290	57,290	58,692	58,692
Peak Demand (kW) [1]	8,000	8,000	8,300	8,300	8,500	8,500
Loadfactor [2]	78.8%	78.8%	78.8%	78.8%	78.8%	78.8%

[1] Includes estimated present peak demand of 7,500 kW at the mine and 500 kW at Hawk Inlet. Assumes an increase of 500 kW by 2007.

[2] Ratio of average demand to peak demand on an annual basis.

Hoonah

Electric service is provided to the residents and businesses of Hoonah by THREA. In 2002, there were 342 residential customers, 69 commercial customers and 22 public facility customers in Hoonah. Average monthly energy consumption of 460 kWh per residential customer is significantly lower than that experienced in the three largest cities in Southeast Alaska, Juneau, Ketchikan and Sitka where average monthly energy consumption is 837 kWh, 860 kWh and 966 kWh, respectively[17]. The low residential energy consumption is a reflection of the high retail cost of power, which averaged 35.4 cents per kWh[18] in 2002 to residential customers in Hoonah. Commercial rates are also in this range and undoubtedly function to significantly limit electrical consumption by commercial customers.

Over the past three years there has been a significant reduction in energy sales to the three interruptible customers in Hoonah, all of which have the ability of generating some or all of their total power needs on their own. Retail rates are approximately 18 cents per kWh for interruptible sales. THREA indicates that the change in retail sales was primarily a result of the closure of the Whitestone Logging camp in August 2001. The high retail cost of power has contributed to self generation by certain large commercial electric users in Hoonah. THREA

[17] Based on 2002 sales data for Juneau and Sitka and 2001 sales data for Ketchikan.

[18] The effective electricity rate to THREA's residential customers was lowered by the State's Power Cost Equalization (PCE) program to approximately 22 cents per kWh in 2001 for the first 500 kWh purchased each month. Although the PCE program provides a significant subsidization of residential power costs, it also provides an incentive to limit power consumption. It should also be noted that the funding of the PCE program is granted by the State legislature on an annual basis and no guarantees can be provided with regard to its continuation in the future.

offers an interruptible power sales rate to large customers with self-generating capability that is substantially lower than the regular commercial rate.

The number of residential electric customers served by a utility is typically related to the area population, available housing and per capita income, among other factors. The population of Hoonah in 2002 was reported to be approximately 860. Projections made by the Alaska State Department of Labor in 1998 indicate an average annual change in population of -1.34% to 0.24% for the Skagway-Hoonah-Angoon census area for the period 2003 through 2008[19]. Long-term population change through 2018 provided in the Labor Department's report is in the same general range. Recent sales information from THREA indicates that total residential customers served and average residential energy sales have remained relatively constant the past three years.

A new commercial development at Cannery Point near Point Sophia is presently under construction. The Point Sophia development involves the restoration and transformation of an old cannery into a tourist attraction and the installation of a number of other shore-based tourist activities for cruise ship passengers. The development is scheduled to begin operation in May 2004 and when fully developed, will entertain three to four cruise ship visits per week during the tourist season. Passengers will be lightered to shore in 2004; however, a dock facility is presently planned for completion in 2005. The Point Sophia development is estimated to employ upwards of 250 people during the tourist season when fully developed.

THREA's distribution lines do not extend to the development at the present time and initially, on-site diesel generation will be used to supply the Point Sophia power supply requirement. The electric power requirement is presently estimated to be approximately 500 kW beginning in 2004 with annual energy requirements estimated to be approximately 2,650 MWh. THREA is in the process of obtaining grant funds to extend its distribution system to Point Sophia and is planning to serve the new load. The Point Sophia development should somewhat stimulate the local economy in Hoonah resulting in higher electric loads among THREA's residential and commercial rate classes than would be experienced otherwise. A new subdivision with approximately 30 residential lots is presently under development in Hoonah.

For the purpose of this analysis, the number of residential, commercial and public facility customers served in Hoonah have been assumed to increase at an average annual rate of 2% per year through 2007 and at 1% per year thereafter. The period of higher growth is during the time when the Point Sophia development will begin operation. Energy use per account is assumed to increase at 0.5% to 1.0% per year. If the Intertie and other factors[20] contribute to the lowering of THREA's retail rates, electric consumption could increase even further. In addition, the Point Sophia development is assumed to increase local loads by 500 kW beginning in 2004 for the development itself, with further increases to 1,000 kW by 2008. There may also be opportunities to sell additional energy to customers that may be using their own generators at the present time, however, the amount of energy that this would represent is not known at the present time.

[19] References to population projections are from Alaska Economic Trends, September 1998.
[20] THREA is pursuing restructuring of its debt repayment which could contribute to lower retail rates.

With the Intertie, THREA may be able to offer an economic incentive power sales rate to new commercial/industrial customers that might encourage economic development in the Hoonah area and increase energy sales. The economic incentive rate would be tied to the incremental cost of purchased power over the Intertie and could be significantly lower than THREA's current interruptible rate. The impact of an economic incentive rate on Hoonah energy sales cannot be predicted and consequently, are not reflected in the analysis at the present time.

The projected power requirements for Hoonah are summarized in the following table.

TABLE 6-3
THREA – Hoonah Service Area
Projected Energy Loads and Capacity Requirements

	Historical			Projected					
	2000	2001	2002	2003	2004	2005	2006	2007	2012
Energy Sales (MWh)									
Residential	1,954	1,980	1,876	1,911	1,969	2,029	2,089	2,150	2,369
Commercial	868	881	795	811	827	844	860	877	962
Interruptible [1]	2,379	1,735	865	874	2,207	2,879	3,550	3,559	3,605
Public Facilities	677	667	626	638	657	676	696	717	787
Other	-	-	-	-	-	-	-	-	-
Total Sales	5,877	5,264	4,161	4,234	5,661	6,427	7,195	7,303	7,724
Increase % [2]		-10.4%	-20.9%	1.7%	33.7%	13.5%	12.0%	1.5%	1.0%
Station Service/Own Use	69	56	46	47	63	72	80	82	86
Street Lights	63	64	64	64	64	64	64	64	64
Losses	305	300	286	277	369	419	468	475	503
Total Generation (MWh)	6,314	5,684	4,557	4,622	6,157	6,982	7,807	7,924	8,377
Loss % of Gen. [3]	4.8%	5.3%	6.3%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
Peak Demand (kW)	1,120	1,160	780	879	1,171	1,328	1,485	1,508	1,594
Loadfactor [4]	64.4%	55.9%	66.7%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%

[1] Assumes the Point Sophia development will begin operation in 2004 and increase electrical consumption to 2,650 MWh per year by 2006.

[2] Increase in total sales over previous year.

[3] Distribution losses and energy unaccounted for. Projected losses based on recent experience.

[4] Ratio of average demand to peak demand on an annual basis. Projected loadfactor based on recent experience.

Petersburg and Wrangell

Petersburg and Wrangell are both municipally owned electric utilities interconnected with each other by the Lake Tyee transmission line. Petersburg Municipal Power & Light owns and operates the Blind Slough hydroelectric project and purchases its remaining power supply needs from the Lake Tyee project. Wrangell Municipal Light & Power purchases essentially all of its power supply from Lake Tyee. Electric loads in Petersburg and Wrangell have been projected recently with regard to studies of the Tyee-Swan Intertie. Loads in Petersburg are assumed to increase at average annual rates of 1.0%, 0.5% and 2.0% for medium, low and high forecast scenarios, respectively. Loads in Wrangell are assumed to increase at average annual rates of 0.3%, 0.0% and 1.0% for medium, low and high forecast scenarios, respectively. In addition, the low forecast scenario for Wrangell assumes that the Wrangell Forest Products mill, a 5,000 MWh per year load, closes its operation.

Forecasted loads for Wrangell and Petersburg are summarized in the following Table.

TABLE 6-4
Petersburg and Wrangell
Projected Energy Requirements – Medium Growth Scenario

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh)						
Petersburg [1]	41,410	41,824	42,242	42,664	43,091	45,289
Wrangell [2]	26,045	26,150	26,256	26,362	26,469	27,010
Total	67,455	67,974	68,498	69,026	69,560	72,299
Less: Petersburg Hydro [3]	(11,500)	(11,500)	(11,500)	(11,500)	(11,500)	(11,500)
Less: Minimal Diesel [4]	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)	(1,500)
Net Requirement on Tyee [5]	54,455	54,974	55,498	56,026	56,560	59,299

1 Assumes average growth in energy requirements of 1% per year.
2 Assumes average growth in energy requirements of 0.5% per year and continued operation of the Silver Bay sawmill.
3 Estimated average annual generation from PMP&L's Blind Slough hydroelectric project.
4 Estimated diesel generation needed for backup and maintenance purposes.
5 Projected net energy requirement of PMP&L and WML&P on the Lake Tyee hydroelectric project.

Ketchikan

Ketchikan Public Utilities (KPU), a municipally owned electric utility, is the second largest electric utility system in Southeast Alaska. KPU obtains the majority of its power supply from KPU-owned hydroelectric projects and the Swan Lake project, a Four Dam Pool Power Agency project. In most years, KPU's electric loads exceed the available hydroelectric generation capability and diesel generators must be used to supply the net power requirement. KPU is presently constructing the Swan-Tyee Intertie to gain access to the surplus generation capability of the Lake Tyee project[21]. The electric requirements of KPU will affect the net generation available to Kake from the Lake Tyee project.

Following the closure of the Ketchikan Pulp Company pulp mill power plant in 1997, KPU's total energy sales increased with the sale of power to the Gateway Forest Products sawmill. The sawmill closed at the end of 2001 and KPU saw a decrease in total energy sales. Electric loads are assumed to increase at average annual rates of 1.1%, 0.3% and 2.2% for base, low and high forecast scenarios, respectively. KPU's forecasted electric requirements are summarized in the following table.

21 The City of Ketchikan and the Four Dam Pool Power Agency (FDPPA) are presently negotiating to transfer the Swan – Tyee Intertie project to the FDPPA.

TABLE 6-5
Ketchikan Public Utilities
Projected Energy Requirements – Medium Growth Scenario

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh) [1]	153,972	155,666	157,378	159,109	160,859	169,903
Less: KPU Hydro [2]	(68,460)	(68,460)	(68,460)	(68,460)	(68,460)	(68,460)
Less: Swan Lake [3]	(68,108)	(68,585)	(69,065)	(69,401)	(69,725)	(70,668)
Net Requirement [4]	17,404	18,621	19,853	21,248	22,674	30,775

1 Assumes average growth in energy requirements of 1.1% per year.
2 Estimated annual energy generation from KPU-owned hydroelectric projects assuming average precipitation levels.
3 Estimated annual generation from the Swan Lake hydroelectric project assuming average precipitation levels. Average energy usage is expected to increase somewhat as the KPU load increases.
4 Projected net energy requirement to be provided from diesel generation, new hydro project generation or the Lake Tyee hydroelectric project, assuming the Swan-Tyee Intertie is constructed.

Kake

Electric service is provided to the residents and businesses of Hoonah by THREA. In 2002, there were 280 residential customers, 60 commercial customers and 12 public facility customers in Kake. Average monthly energy consumption of 450 kWh per residential customer is significantly lower than that experienced in the three largest cities in Southeast Alaska, Juneau, Ketchikan and Sitka where average monthly energy consumption is 837 kWh, 860 kWh and 966 kWh, respectively[22]. The low residential energy consumption is a reflection of the high retail cost of power, which averaged 35.5 cents per kWh[23] in 2002 to residential customers in Hoonah. Commercial rates are also in this range and undoubtedly function to significantly limit electrical consumption by commercial customers.

Although the number of residential customers served in Kake has decreased somewhat the past two years, total energy sales have increased each year mostly due to increased sales of interruptible energy. The interruptible energy sales rate in Kake is approximately 17 cents per kWh. THREA indicates that the increase in interruptible sales is due to increasing power requirements at Kake Foods.

For the purpose of this analysis, the number of residential, commercial and public facility customers served in Kake has been assumed to increase at an average annual rate of 1% per year. Energy use per account is assumed to increase at 0.5% to 1.0% per year. If the Intertie and other factors[24] contribute to the lowering of THREA's retail rates, electric consumption could increase

22 Based on 2002 sales data for Juneau and Sitka and 2001 sales data for Ketchikan.
23 The effective rate to residential customers was lowered by the State's Power Cost Equalization (PCE) program to approximately 22 cents per kWh in 2001 for the first 500 kWh purchased each month. Although the PCE program provides a significant subsidization of residential power costs, it also provides an incentive to limit power consumption to 500 kWh per month or less. It should also be noted that the funding of the PCE program is granted by the State legislature on an annual basis and no guarantees can be provided with regard to its continuation in the future.
24 THREA is pursuing restructuring of its debt repayment which could contribute to lower retail rates.

even further. There may also be opportunities to sell additional energy to customers that may be using their own generators at the present time, however, the amount of energy that this would represent is not known at the present time.

With the Intertie, THREA may be able to offer an economic incentive power sales rate to new commercial/industrial customers that might encourage economic development in the Kake area and increase energy sales. The economic incentive rate would be tied to the incremental cost of purchased power over the Intertie and could be significantly lower than THREA's current interruptible rate. The impact of an economic incentive rate on Kake energy sales cannot be predicted and consequently, are not reflected in the analysis at the present time.

The projected power requirements for Kake are summarized in the following table.

TABLE 6-6
THREA – Kake Service Area
Projected Energy Loads and Capacity Requirements

	Historical			Projected					
	2000	2001	2002	2003	2004	2005	2006	2007	2012
Energy Sales (MWh)									
Residential	1,600	1,588	1,498	1,529	1,561	1,593	1,626	1,659	1,823
Commercial	924	931	886	891	895	899	904	908	932
Interruptible [1]	697	934	1,370	1,397	1,425	1,454	1,483	1,498	1,574
Public Facilities	384	343	210	214	221	229	237	245	268
Other	-	-	-	-	-	-	-	-	-
Total Sales	3,605	3,796	3,964	4,031	4,102	4,175	4,249	4,309	4,597
Increase % [2]		5.3%	4.4%	1.7%	1.8%	1.8%	1.8%	1.4%	1.1%
Station Service/Own Use	44	58	62	58	59	60	61	62	66
Street Lights	77	80	80	80	80	80	80	80	80
Losses	194	244	185	219	223	227	231	234	250
Total Generation (MWh)	3,920	4,178	4,291	4,388	4,464	4,542	4,621	4,685	4,993
Loss % of Gen. [3]	4.9%	5.8%	4.3%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Peak Demand (kW)	1,036	1,000	1,016	1,044	1,062	1,080	1,099	1,114	1,187
Loadfactor [4]	43.2%	47.7%	48.2%	48.0%	48.0%	48.0%	48.0%	48.0%	48.0%

[1] Assumes interruptible sales will increase at 2% per year through 2007 and at 1% per year thereafter.
[2] Increase in total sales over previous year.
[3] Distribution losses and energy unaccounted for. Projected losses based on recent experience.
[4] Ratio of average demand to peak demand on an annual basis. Projected loadfactor based on recent experience.

Estimated Maximum Transmission Capacity at Hawk Inlet

For the purpose of defining the capacity of the first segment of SEI-1 between Juneau and Hawk Inlet, the future energy and capacity loads at Hawk Inlet have been estimated using information presented in this report as well as in the Phase 2 report. As the plan presently exists, Hawk Inlet will serve as the termination point for submarine cables that would eventually extend to Hoonah, Gustavus, Excursion Inlet, Angoon, Tenakee Springs and Sitka. The cable to Hoonah would potentially serve Gustavus and Excursion Inlet and also serve Sitka in the event that an overland transmission route to Sitka were to be developed. The preferred route to Sitka is presently a separate submarine cable from Hawk Inlet to Warm Springs Bay on Baranof Island with an intermediate landing in Angoon.

The hydroelectric capacity in Sitka currently exceeds the forecasted demand for the next 25 years, however, energy requirements are such that energy generation beyond the capability of the existing hydroelectric system will be needed in around 15 years. Except for Sitka, power deliveries over the Intertie system out of Hawk Inlet will be expected to regularly supply the full power requirement of each load center. Beyond Sitka, the Intertie system will interconnect with Kake and the Tyee-Swan region. It is not expected that the power flows out of Hawk Inlet will be used to regularly supply power to load centers beyond Sitka.

Based on the foregoing, the following table summarizes the estimated capacity requirements of the Intertie system at Hawk Inlet, excluding loads at the KMC-GC mine. The forecasted loads are assumed to increase over time at approximately 1% per year. For planning purposes, the demand shown for Sitka assumes that the 18,000-kW Green Lake hydroelectric project is offline. Since the exact timing of Intertie development is not known at the present time, the forecasted loads in the following table are shown for several example years.

TABLE 6-7
Estimated Power Demands at Hawk Inlet
With SEI-1 and Eventual Connection to Sitka

	2010	2020	2030
Maximum Demand at Hawk Inlet (kW)			
Hoonah	1,700	1,870	2,060
Gustavus/Excursion	2,390	2,790	3,200
Angoon	490	590	690
Tenakee Springs	91	101	111
Sitka (w/o Green Lake)	18,000	18,000	18,220
Total	22,671	23,351	24,281

As shown, the maximum load is estimated to be approximately 25 MW. Allowing for a new mining load or other large load, the demand could increase to an estimated 35 MW. This demand allows for significant transmission capacity to Sitka which under normal operating conditions, would not be needed. It is also important to acknowledge that if Sitka were to develop the 20-MW Takatz Lake hydroelectric project, the Intertie capacity could be needed for transmission north to Juneau. Combined with an estimated future demand of 17 MW at KMC-GC, the capacity of the Juneau – Hawk Inlet segment of SEI-1 should be no less than 52 MW, or about 58 MVa at a 0.9 power factor.

Availability of Hydroelectric Generation

Based on the foregoing projections of power requirements and the generating capabilities of the existing hydroelectric facilities, the net hydroelectric generation available for sale to Kake, Hoonah and KMC-GC can be determined. It is important to note that hydroelectric generation capability is shown as an annual average. Actual generation can vary significantly from year to year based on local precipitation and other factors.

AEL&P

AEL&P owns and operates several hydroelectric projects and purchases the full output of the State-owned Snettisham hydroelectric project. Generally, hydroelectric generation is sufficient to meet the full power supply requirement of AEL&P's customers. Oil-fired combustion turbines and diesel generators are used to supplement hydroelectric generation when needed.

AEL&P has indicated that hydroelectric generation at the present time is limited and is insufficient to supply KMC-GC and Hoonah. Consequently, it will be necessary to construct the Lake Dorothy hydroelectric project before contractual commitments can be made to either KMC-GC or THREA. AEL&P is in the process of permitting and designing the Lake Dorothy project. Construction could begin as early as 2004 and will require about three years to complete the project. Phase 1 of the Lake Dorothy project, also called Bart Lake, is estimated to provide 75,000 MWh[25] on an average annual basis. Phase 2, which is not currently scheduled for construction, would provide total energy generation of 169,000 MWh annually for Phase 1 and Phase 2 combined. The following table summarizes AEL&P's hydroelectric energy resources and the estimated energy available.

TABLE 6-8
AEL&P Hydroelectric Generating Resources
And Available Energy (MWh)

	2003	2004	2005	2006	2007	2012
Hydroelectric Resources [1]						
AEL&P Hydro	59,000	59,000	59,000	59,000	59,000	59,000
Snettisham	294,000	294,000	294,000	294,000	294,000	294,000
Lake Dorothy [2]	-	-	-	-	75,000	75,000
Total Resources	353,000	353,000	353,000	353,000	428,000	428,000
Energy Requirements [3]						
Firm Sales	298,167	300,438	302,620	305,538	308,619	327,246
Non-firm Sales [4]	22,568	23,657	24,657	24,657	24,657	24,657
Losses and Own Use	19,197	19,405	19,564	19,710	19,864	20,795
Total Energy Requirements	339,932	343,500	346,841	349,905	353,140	372,698
Net Hydro Energy Available [5]	13,068	9,500	6,159	3,095	74,860	55,302

[1] As provided by AEL&P based on average water conditions. Net of transmission losses and station service.
[2] Phase 1, Bart Lake estimated average annual energy generation capability.
[3] As provided by AEL&P.
[4] Estimated energy sales to "dual-fuel" customers and cruise ships supplied with shore-based power, contingent upon availability of hydroelectric generation.
[5] Estimated average annual energy generation available to KMC-GC and Hoonah.

As shown in the previous table, under average water conditions, AEL&P has relatively limited amounts of surplus hydroelectric energy available without the Lake Dorothy project if AEL&P is

[25] Firm annual energy output is estimated at 68,000 MWh.

to supply its own retail loads and committed non-firm loads. Without the Lake Dorothy project, the total hydroelectric energy generation capability available to AEL&P is 353,000 MWh under average water conditions. The annual energy generation capability would only be 295,000 MWh under low water conditions. As a result, under low water conditions, AEL&P would not be able to supply all of its loads with hydroelectric generation and would need to use oil-fired generation to fully supply its power requirement.

Lake Tyee Project

The generating capability of the 20-MW Lake Tyee project is presently committed to Petersburg and Wrangell. The Swan-Tyee transmission Intertie, currently under construction, will provide Ketchikan with access to generation from the Lake Tyee project that is surplus to the needs of Petersburg and Wrangell. Several estimates of the annual energy capability of the Lake Tyee project have been developed in the past; however, the loads connected to the project have never been large enough to evaluate how well the estimates compare with actual performance. Generally, it has been estimated that under average water conditions, the annual energy generation capability of the project is about 129,000 MWh. Based on actual experience and the knowledge of individuals familiar with the operation of the project, the average annual energy generation could be as low as 110,000 MWh per year.

Hydroelectric generation is highly variable from year to year depending on local precipitation and other environmental conditions. As previously indicated, the average annual estimated energy generation capability of the Lake Tyee project is 129,000 MWh. Under dry, low water conditions[26], the energy generation is estimated to be 112,700 MWh whereas it could be as high as 154,800 MWh.

The following table summarizes the energy generation available from the Lake Tyee project assuming average annual energy generation of 120,000 MWh from the project.

TABLE 6-9
Estimated Hydroelectric Energy Generation
From the Lake Tyee Project – Medium Growth, Average Water
(MWh)

	2003	2004	2005	2006	2007	2012
Lake Tyee Generation [1]	120,000	120,000	120,000	120,000	120,000	120,000
Energy Requirements [2]						
Petersburg/Wrangell	54,455	54,974	55,498	56,026	56,560	59,299
Ketchikan	17,404	18,621	19,853	21,248	22,674	30,775
Net Energy Available [3]	48,141	46,405	44,649	42,726	40,766	29,926

[1] Assumed generation for purpose of this analysis. Actual generation will vary from year to year.
[2] Based on medium growth scenario, see Tables 6-4 and 6-5.
[3] Estimated annual generation from the Lake Tyee project available to Kake.

[26] Alternative energy generation estimates are typically derived using the lowest and highest measured streamflow data of record at the project location.

As shown in the previous table, the net energy generation available from the Lake Tyee project in 2007 is 40,766 MWh assuming average water conditions and medium load growth in Petersburg, Wrangell and Ketchikan. This is more than enough needed to meet the energy requirement of 4,685 MWh in Kake in the same year. By 2012, available energy from Lake Tyee is 29,926 MWh and, as loads continue to increase in Petersburg, Wrangell and Ketchikan, the available energy from Lake Tyee will continue to decline. Further, in dryer than average conditions, the available energy from Lake Tyee will be less than shown in Table 6-8, potentially by as much as 20,000 MWh in any particular year. If energy generation is not available from Lake Tyee, THREA will need to use its diesel generators in Kake to supply the necessary power requirement. As loads continue to grow in the interconnected region, however, new hydroelectric generation facilities could be constructed. The cost of power from these new facilities will potentially be higher than the cost of power from the Lake Tyee project.

Potential New Hydroelectric Generation Facilities

A number of new hydroelectric projects have been studied that could serve the Petersburg, Wrangell, Ketchikan, Kake, Hoonah and Juneau areas. Costs of these projects, as well as other factors including location, generating capacity, interconnected loads and the availability of better alternatives have precluded development of these projects. The development of a transmission interconnection system could make development of some of these projects economically and technically feasible at some later date. Hydroelectric projects that have been identified, the community they are closest to, and their estimated capacity and annual energy generation, include the following:

- Whitman Lake – Ketchikan; 4.6 MW, 19,600 MWh annually
- Connell Lake – Ketchikan; 1.9 MW, 11,640 MWh
- Lake Grace – Ketchikan; diversion to Swan Lake project, 72,200 MWh annually
- Mahoney Lake – Ketchikan; 9.6 MW, 45,600 MWh annually
- Lake Tyee Third Turbine – Petersburg/Wrangell; 10 MW, 1,000 MWh annually
- Thomas Bay Project (Swan Lake, Ruth Lake) – Petersburg; 40 MW, 274,000 MWh
- Sunrise Lake – Wrangell; 4 MW; 12,200 MWh
- Anita - Kunk Lake – Wrangell; 8 MW, 28,200 MWh annually
- Virginia Lake – Wrangell; 12 MW, 42,700 MWh annually
- Thoms Lake – Wrangell; 7.3 MW, 25,600 MWh annually
- Lake Dorothy, Phase 1 (Bart Lake) – Juneau, 15 MW, 75,000 MWh annually
- Lake Dorothy, Phase 2 – Juneau; 32 MW, 94,000 MWh annually

In addition to the Lake Dorothy Project, AEL&P has evaluated rehabilitation and expansion of existing hydroelectric facilities in the Juneau area.

Recently, the City of Hoonah has investigated the feasibility of two small hydroelectric projects. A report in June 2002 by Hydro West, Inc. provided basic information on the Gartina Falls project and the Water Supply Creek project, both of which would have a generating capacity of 600 kW each. The Gartina Falls project would provide an estimated 1,900 MWh per year and the Water Supply Creek project would provide an estimated 1,800 MWh per year. The estimated cost of the Gartina Falls project is $3.75 million while the Water Supply Creek project would cost an estimated $3.1 million. Based on assumed 50% grant funding and 50% funding with 0% interest rate loans[27], the estimated cost of energy from the two projects is 6.0 cents per kWh and 5.6 cents per kWh for the Gartina Falls and Water Supply Creek projects, respectively. The cost of power from these projects would be significantly higher if grant funding were not available.

Neither the Gartina Falls nor Water Supply Creek projects are preliminarily considered to have significant fish habitat impacts. The Water Supply Creek project site is above the anadromous fish barrier, which is Gartina Falls. There are deep pools at the base of Gartina Falls that are considered important for fish holding. The costs, above, include estimated amounts for mitigation of this issue, however, Hydro West indicates that additional study will be needed to fully identify all environmental issues with the projects.

Use of Oil-Fired Generating Facilities

Although it has been indicated that only hydroelectric generation would be transmitted over the Interties, power generated at diesel power plants could be transmitted just as well. The use of diesel generators from outside the local community, however, would need to acknowledge the additional cost associated with transmission losses as well as the cost differential between surplus hydroelectric power and diesel generation. In some cases, it could be less costly to purchase out-of-area diesel generation than run local generators. This will need to be factored in to the contracts for power supply services.

Economic Analysis of Interties

Introduction and Assumptions

An economic analysis has been conducted to determine if the benefits to be realized with the Intertie segments are greater than the costs of operating the Interties and purchasing power from hydroelectric resources. Benefits will be achieved through the offset of diesel generation costs at Kake, Hoonah and KMC-GC. Costs related to the Interties are direct costs of operations and maintenance (O&M), certain incremental administrative costs of the Intertie owner and the costs of purchasing power from AEL&P and the Four Dam Pool to serve the Kake, Hoonah and KMC-GC loads.

In preparing this analysis, several assumptions have been made. The most significant of these assumptions are:

- Capital costs of the Intertie systems are to be grant funded meaning that there will be no capital recovery component associated with the Interties. Note that the cost of a new

[27] These favorable financing assumptions were made by Hydro West in its evaluation of the projects for the City of Hoonah based on recent grant activity observed by Hydro West in Southeast Alaska. If grant funding is not available, the annual cost of power from the projects would most likely be significantly higher.

substation at KMC-GC is not included in the costs of the Intertie. It is presumed, per AEL&P, that the substation would be funded by either AEL&P or KMC-GC.

- Base year delivered fuel prices are $1.20 per gallon in Kake, $1.10 at KMC-GC and $1.35 per gallon in Hoonah[28]. It must be acknowledged that fuel prices are highly variable and subject to radical changes.
- Fuel costs, O&M and A&G costs will escalate at the assumed annual inflation rate of 2.5% per year.
- Existing generation capacity will be maintained for emergency backup in Kake, Hoonah and KMC-GC. Resulting net O&M costs will be significantly lower than if the generating units were operated to supply full load.
- The agency serving as owner of the Interties[29] will contract with others to provide maintenance on the Intertie systems. Administrative costs associated with ownership and operation of the Interties will be minimal.
- A reserve fund will be established to collect monies for major maintenance and repairs in the future. The reserve fund will also serve as a self-insurance fund since transmission lines are generally not insurable.
- The cost of purchased power from AEL&P will be inclusive of all transmission and delivery charges to the point of delivery, expected to be either at the submarine termination yard on Douglas Island or at KMC-GC and Hoonah.
- Energy losses over the Interties will be 2% of the transmitted power to KMC-GC and 4% to Kake and Hoonah.

The economic analysis estimates the power production costs for each service area that will be offset if the Interties are constructed. These "benefits" are then compared to the costs of power purchases and Intertie operation to determine if the benefits of the Interties exceed the costs. It is expected that each Intertie will need to show positive benefits. To protect the interests of electric consumers, the total costs incurred by the local utility systems, on a case-by-case basis, must be lower with the Interties than without to show economic justification for the Interties.

It should be noted that costs of operation that are the same with or without the Interties are not included in the analysis. Examples of these costs are capital recovery on existing generation plant and fixed O&M charges.

Projected Cost of Existing Diesel Generation

THREA owns and operates diesel generators in Kake and Hoonah to supply the full power supply requirement of these communities. Total installed generation capacity is 2,585 kW in Kake and 2,455 kW in Hoonah. Each community has three generating units. The principal cost

[28] THREA's actual cost of generation fuel for its entire system averaged approximately $1.23 per gallon in 2001 and $1.00 per gallon in 2002. Fuel costs have increased substantially in early 2003 over costs experienced in 2002.

[29] The Southeast Conference has indicated that it will not serve as owner of the Interties. More investigation of potential ownership structures will be included in the Phase 2 Intertie Study.

in operating the diesel generators is the cost of fuel, which represented approximately 55% of the total power production costs in THREA's system over the past three years.

KMC-GC operates a 5,200-kW oil-fired Solar turbine along with three 2,200-kW Ruston diesel generators and two Caterpillar 3516 1,825-kW diesel generators at the mine. Four Caterpillar 3406 diesel generators with a total capacity of 836 kW are operated at the Hawk Inlet ore loading facility and a 30-kW generator is located at the Young Bay dock.

Without the need to operate their diesel generators except in emergency situations, THREA and KMC-GC should be able to reduce the O&M costs of the units. The need for maintenance activities, lubricants and other consumables will be substantially reduced and maintenance and operating personnel can be assigned to other activities. Based on a review of THREA's production costs, it is estimated that the variable O&M cost[30] is about 3.0 cents per kWh. The variable O&M cost for the operation of KMC-GC's power generation system is estimated to be about 1.5 cents per kWh. KMC-GC presently has a staff of four to operate its powerplant and also pays a monthly fee for a maintenance contract on the Solar turbine. Further, KMC-GC also incurs costs to transport fuel from storage tanks at Hawk Inlet to the powerplant at the mine. Since it will be necessary to maintain backup generation in Hoonah, Kake and KMC-GC with the Interties, some power production O&M costs will continue to be incurred.

In addition to the offset of fuel and O&M costs, with the Interties both THREA and KMC-GC will benefit from the extension in operating life of their existing generators. Without the Interties, continued regular operation of the existing generators would require their eventual replacement or major overhaul. For the purpose of this analysis, it is assumed that without the Intertie, KMC-GC will replace one of its 2,200-kW diesel generators in five years (2008) and one in 2010 at a cost of $500 per kW. With the Intertie, the cost of these new generators would be avoided. THREA has indicated that if the Intertie to Hoonah is not constructed, it will likely need to install a 1,000-KW generator in Hoonah as a replacement for an older unit. The estimated cost of the new generator is $400,000.

The cost of generation fuel is a critical factor in the cost of power production for THREA and KMC-GC. Fuel prices in Kake in early March 2003 were reported at $1.59 per gallon, significantly higher than the average fuel price of $0.90 per gallon incurred in 2002 and $1.07 per gallon in 2001. Fuel prices in Hoonah typically average 20-30 cents more per gallon than in Kake[31]. KMC-GC is estimated to incur fuel prices based on a negotiated margin over a standard fuel price index. This should result in fuel prices at KMC-GC somewhat lower than those in Kake. It is not expected that diesel fuel prices will stay at the current high level, however, it is not expected that they will necessarily decrease to price levels experienced in 2002. Consequently, for the purpose of this analysis, the price of diesel fuel has been assumed to be $1.20 per gallon in Kake, $1.10 at KMC-GC and $1.35 per gallon in Hoonah. Fuel prices are further assumed to increase over time at the assumed rate of general inflation, 2.5% per year.

[30] Power production costs are often characterized as variable, those costs that are directly associated with each unit of operation, and fixed, costs that are not avoidable. The costs of operations personnel are considered fixed for THREA's Kake and Hoonah service areas.
[31] THREA operates fuel storage tanks in Kake and Angoon that allow for barge deliveries of fuel in large enough quantities to obtain lower prices. Near daily truck deliveries of fuel are needed in Hoonah causing higher prices.

The following tables show the projected variable cost of power production over the next ten years at Hoonah, KMC-GC and Kake, based on continued use of oil-fired generation. It is important to note that the variable cost of production is not the full cost of power production, but rather is the cost that could be directly avoided if the Interties were constructed.

TABLE 6-10
Projected Variable Cost of Power Production with Diesel Generation
THREA – Hoonah Service Area

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh) [1]	4,622	6,157	6,982	7,807	7,924	8,377
Fuel Price ($/gallon) [2]	$ 1.35	$ 1.38	$ 1.42	$ 1.45	$ 1.49	$ 1.69
Power Production Cost ($000)						
Fuel Cost [3]	$ 430	$ 588	$ 683	$ 783	$ 814	$ 974
Variable O&M [4]	139	189	220	252	262	314
Subtotal	$ 569	$ 777	$ 903	$ 1,035	$ 1,076	$ 1,288
Replacement Cost [5]	-	-	32	32	32	32
Total Production Cost	$ 569	$ 777	$ 935	$ 1,067	$ 1,108	$ 1,320
(¢/kWh)	12.3	12.6	13.4	13.7	14.0	15.8

1 See Table 6-3.
2 Assumes increase in fuel price at the assumed annual rate of general inflation
3 Based on average fuel usage of 14.5 kWh per gallon.
4 Estimated variable O&M cost of 3.0 cents per kWh based on THREA identified production cost items of miscellaneous power generation expenses, generator overhaul and maintenance expenses, maintenance supervision and maintenance salaries and miscellaneous. Does not include generation salaries and costs associated with maintenance of structures. Assumed to increase annually at the assumed rate of general inflation.
5 Based on estimated cost of new 1,000 kW diesel generator to replace older generating unit. Annual payment assumes a $400,000 loan at a 5% interest rate and a 20-year repayment period.

TABLE 6-11
Projected Variable Cost of Power Production with Diesel Generation
THREA – Kake Service Area

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh) [1]	4,388	4,464	4,542	4,621	4,685	4,993
Fuel Price ($/gallon) [2]	$ 1.20	$ 1.23	$ 1.26	$ 1.29	$ 1.32	$ 1.50
Power Production Cost ($000)						
Fuel Cost [3]	$ 384	$ 401	$ 418	$ 436	$ 453	$ 546
Variable O&M [4]	132	137	143	149	155	187
Subtotal	$ 516	$ 538	$ 561	$ 585	$ 608	$ 733
Replacement Cost [5]	-	-	-	-	-	-
Total Production Cost	$ 516	$ 538	$ 561	$ 585	$ 608	$ 733
(cents/kWh)	11.8	12.1	12.4	12.7	13.0	14.7

1 See Table 6-6.
2 Assumes increase in fuel price at the assumed annual rate of general inflation

[3] Based on average fuel usage of 13.7 kWh per gallon.

[4] Estimated variable O&M cost of 3.0 cents per kWh based on THREA identified production cost items of miscellaneous power generation expenses, generator overhaul and maintenance expenses, maintenance supervision and maintenance salaries and miscellaneous. Does not include generation salaries and costs associated with maintenance of structures. Assumed to increase annually at the assumed rate of general inflation.

[5] No replacement of generation plant is expected in Kake for the foreseeable future.

TABLE 6-12
Projected Variable Cost of Power Production with Oil-Fired Generation
Kennecott Greens Creek Mine

	2003	2004	2005	2006	2007	2012
Energy Requirements (MWh) [1]	55,188	55,188	57,290	57,290	58,692	58,692
Fuel Price ($/gallon) [2]	$ 1.10	$ 1.13	$ 1.16	$ 1.18	$ 1.21	$ 1.37
Power Production Cost ($000)						
Fuel Cost [3]	$ 5,059	$ 5,185	$ 5,517	$ 5,655	$ 5,939	$ 6,719
Variable O&M [4]	828	849	903	925	972	1,099
Subtotal	$ 5,887	$ 6,034	$ 6,420	$ 6,580	$ 6,911	$ 7,818
Replacement Cost [5]	-	-	-	-	-	224
Total Production Cost	$ 5,887	$ 6,034	$ 6,420	$ 6,580	$ 6,911	$ 8,042
(¢/kWh)	10.7	10.9	11.2	11.5	11.8	13.7

[1] See Table 6-2.

[2] Assumes increase in fuel price at the assumed annual rate of general inflation.

[3] Based on average fuel usage of 12.0 kWh per gallon.

[4] Estimated variable O&M cost of 1.5 cents per kWh, increased annually at the assumed rate of general inflation.

[5] Assumes replacement of 2,200 kW diesel generators in 2008 and 2010 at a cost of $500 per kW. Annual cost based on levelized capital recovery at a 7% interest rate and a 20-year repayment period.

Intertie Annual Costs

The transmission systems to be constructed will require regular efforts to inspect the system condition and make necessary repairs. Generally, these activities will be relatively minor, particularly for a new system. Structures, guys, insulators, conductors and submarine cable terminations will need to be inspected visually and a program to regularly clear trees and brush from the right of way will need to be established. It is expected that the Southeast Conference, as owner of the Interties, will contract out the regular inspection and maintenance activities to local utilities or other providers of this kind of service. The estimated annual O&M costs for the Interties are as follows:

TABLE 6-13

**Juneau-Greens Creek-Hoonah Intertie
Estimated Annual O&M Costs**

Tree Trimming	$	20,000
Overhead Line Inspections		15,000
Regular Repairs/Replacements		50,000
Submarine Terminal Inspections		15,000
Switchyard Maintenance		25,000
Miscellaneous		15,000
Subtotal	$	140,000
Contractor Fee [1]		25,000
Total	$	165,000
Unit Cost (¢/kWh) [2]		0.25

[1] Administrative and other overhead costs of contractor expected to be retained to provide O&M services for the Intertie and related facilities.

[2] Unit cost of O&M assuming combined energy sales of 66,600 MWh to KMC-GC and Hoonah.

TABLE 6-14

**Kake-Petersburg Intertie
Estimated Annual O&M Costs**

Tree Trimming	$	45,000
Overhead Line Inspections		20,000
Regular Repairs/Replacements		35,000
Submarine Terminal Inspections		15,000
Switchyard Maintenance		10,000
Miscellaneous		20,000
Subtotal	$	145,000
Contractor Fee [1]		25,000
Total	$	170,000
Unit Cost (¢/kWh) [2]		3.6

[1] Administrative and other overhead costs of contractor expected to be retained to provide O&M services for the Intertie and related facilities.

[2] Unit cost of O&M assuming energy sales of 4,685 MWh to Kake.

The agency or organization that owns the Interties, will incur certain expenses related to policy oversight, accounting, general administration and management. Some of these costs would not necessarily be incurred to the same extent if the Interties were owned and administered by a utility or other entity presently in an electric service type business. The following table provides the estimated Intertie related administrative costs assuming both the Kake – Petersburg and the Juneau – Greens Creek – Hoonah Interties are constructed and administered by the same agency.

TABLE 6-15
Estimated Annual Intertie Administrative Costs [1]

Management [2]	$ 60,000
Legal Fees	15,000
Permit Overview	10,000
Insurance [3]	30,000
Accounting/Billing	30,000
Legislative Affairs	10,000
Travel Expenses	15,000
Miscellaneous	20,000
Total	$ 190,000
Unit Cost (¢/kWh) [4]	0.27

[1] Assumes a common agency or organization owns and administers the two Interties.
[2] Based on allocated cost of part-time manager.
[3] Assumed cost of insurance on switchyards and related facilities.
[4] Unit cost assuming combined energy sales of 71,300 MWh to Kake, KMC-GC and Hoonah.

Intertie O&M and administrative costs are expected to be recovered through charges to each of the Intertie users that are directly proportional to the power transmitted. The charges could be included as part of the wholesale cost of power. For the purpose of this study, the O&M costs for each Intertie are assumed to be charged only to the users of that Intertie. For example, the O&M costs of the Kake – Petersburg Intertie are allocated solely to THREA's operation in Kake. The O&M costs for the Juneau – Greens Creek – Hoonah Intertie are allocated to both KMC-GC and Hoonah based on the percentage of total energy estimated to be transmitted to each load center. The unit O&M cost shown in Table 6-13 for the Kake – Petersburg Intertie is much higher than the unit O&M cost shown in Table 6-14 because estimated energy sales to KMC-GC and Hoonah are significantly greater than to Kake. The administrative costs are allocated to KMC-GC, Kake and Hoonah in proportion to the energy estimated to be delivered to each of these load centers.

In addition to O&M and administrative costs, a charge related to the accrual of reserve funds to pay for major repairs to the Interties should be included in the costs charged to the Intertie users. These costs are not expected to be significant in the early years of Intertie operation and are in lieu of a depreciation charge. The reserve fund charge is also a means for "self-insuring" the Interties since transmission lines are generally not insurable.

As a basis for the amount of this repair and replacement (R&R) reserve that should be established, the estimated cost of a major repair or replacement of a significant system component can be used. It can also be reasonably assumed that with a new system, the timing of such a major repair or replacement would be several years in the future. For the Kake – Petersburg line, a reserve requirement of $1.0 million has been estimated while a $2.5 million reserve is estimated for the Juneau – Greens Creek – Hoonah line. Since these reserve amounts are based on the cost of a major submarine cable repair, a larger reserve is estimated to be needed on the Juneau – Greens Creek – Hoonah line because of the longer cables involved in this system. Annual deposits of $46,000 and $116,000 per year for the two Interties, respectively, would be needed to build up the reserve fund balance to these amounts within 15 years with accrued interest at 5% per year.

Cost of Purchased Power

With the Interties, power will be purchased from AEL&P and purchased directly by KMC-GC and THREA for use in Hoonah[32]. Power will be purchased from the Four Dam Pool Power Agency and purchased by THREA for use in Kake. Power to be purchased from AEL&P will be priced at a rate that includes delivery charges to Outer Point on Douglas Island, the origin of the Juneau-Greens Creek-Hoonah Intertie. It is not expected that AEL&P will dedicate any particular generating resource to KMC-GC or THREA but rather, will guarantee a quantity of energy at a price that recovers AEL&P's cost of production and assures that AEL&P's existing customers are not negatively impacted. Power purchases from AEL&P are expected to be tied to hydroelectric generation surplus to the needs of AEL&P's retail customers and existing non-firm commitments. With the development of the Lake Dorothy project, power deliveries to KMC-GC and Hoonah will essentially be firm.

In the event that hydroelectric generation is insufficient to supply AEL&P's full retail and interruptible load at any point in time, all or a portion of the deliveries to KMC-GC and Hoonah could be temporarily curtailed. On-site generation in KMC-GC and Hoonah would be needed to supply the local power requirement under this circumstance or alternatively, energy generated at AEL&P's oil-fueled generators could be used. If AEL&P needs to operate diesel generators to supply Hoonah or KMC-GC, there would need to be a surcharge applied to the base price for energy purchases.

AEL&P has indicated that it will need to develop the Lake Dorothy hydroelectric project in order to supply the power requirement of KMC-GC and Hoonah. Consequently, the cost of power to be purchased by KMC-GC and Hoonah from AEL&P will be tied to the cost of power from the Lake Dorothy project. Discussions with AEL&P indicate that an exact price for the power to be sold to KMC-GC and THREA is not available. A price range has been determined, however, and for purposes of this analysis a rate of 8.5 cents per kWh is considered a reasonable estimate. AEL&P is presently pursuing development of the Lake Dorothy project and has filed a permit application with the Federal Energy Regulatory Commission (FERC). Construction of the project could begin in 2004 at the earliest and would require about three years to complete.

[32] It is expected that AEL&P will contract directly with KMC-GC and THREA and that there will be no intermediate purchase by the Intertie owner/administrator. In this circumstance, AEL&P would most likely collect an additional amount over the cost of power supply to pay for the incremental Intertie costs. This additional amount could be bundled in to the power sales rate or could be an explicit transmission charge or "wheeling" fee.

Power to be purchased from the Four Dam Pool Power Agency (FDPPA) by THREA for delivery to Kake will also be interruptible. At the present time, the Four Dam Pool firm power rate is 6.8 cents per kWh. This rate could increase somewhat in the future but is expected to remain relatively constant for the next few years. Discussions with FDPPA management indicate that power could be sold to THREA at a rate that is potentially lower than the firm power sales rate because of the possibility of interruption in availability[33]. For purposes of this study, it has been assumed that power can be purchased from the Four Dam Pool at 4.0 cents per kWh through 2011, increasing by 0.5 cents per kWh in 2012 and every five years thereafter. This cost would include delivery charges to Petersburg[34].

Estimated Savings with the Intertie

Based on the foregoing, the cost of power to THREA and KMC-GC with the Interties has been projected. This cost includes the cost of purchased power and the allocated costs of Intertie O&M and administration to each line. The costs with the Intertie have then been compared to the costs without the Intertie to determine the net savings to THREA and KMC-GC associated with the Intertie. The cost of power with the Intertie and the estimated savings in each load center are shown on an annual basis in the following tables assuming that the Interties are constructed and begin operation in 2007. In Table 6-15 and Table 6-16, the KMC-GC mine is assumed to remain in operation through 2016. With the closure of the mine, THREA will need to cover the full operating cost of the Intertie.

TABLE 6-16

Projected Cost of Power and Savings with the Intertie
THREA – Hoonah Service Area

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	7,924	8,015	8,106	8,199	8,293	8,377	8,783
Energy Purchased (MWh) [2]	8,241	8,336	8,431	8,527	8,625	8,712	9,134
Purchased Power Price (¢/kWh) [3]	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 700	$ 709	$ 717	$ 725	$ 733	$ 740	$ 776
Intertie O&M [5]	23	23	24	25	26	27	242
Intertie A&G [6]	24	25	26	27	28	29	174
Intertie R&R [7]	14	14	14	14	14	14	116
Total Annual Costs with Intertie	$ 761	$ 771	$ 781	$ 791	$ 801	$ 810	$ 1,308
Unit Cost (¢/kWh) [8]	9.6	9.6	9.6	9.6	9.7	9.7	14.9
Savings with Intertie ($000) [9]	$ 347	$ 377	$ 408	$ 440	$ 475	$ 510	$ 251
Savings (¢/kWh) [10]	4.2	4.5	4.8	5.2	5.5	5.9	2.7
Breakeven Cost of Power (¢/kWh) [11]	12.7	13.0	13.3	13.7	14.0	14.3	11.2

[1] See Table 6-3.

[33] As indicated previously and shown in Table 3-8, it is expected that the full power requirement of Kake can regularly be supplied from the Lake Tyee project for several years to come, but cannot be fully guaranteed.

[34] Energy losses from Lake Tyee to the Kake Intertie tap point near Petersburg are also expected to be effectively included in the power sales rate. Since the metering point for power sales to Kake is to be at the tap point, energy losses between the tap point and Kake will need to be included as a cost to THREA.

[2] Includes estimated transmission losses of 4% between Juneau and Hoonah.
[3] Estimated price of power purchased from AEL&P.
[4] Estimated cost of power purchased from AEL&P.
[5] Intertie O&M cost as shown in Table 6-12 allocated to THREA based on percentage of total sales over the Intertie. Assumes O&M costs increase annually at the assumed rate of general inflation.
[6] Intertie A&G cost as shown in Table 6-14 allocated to THREA based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
[7] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost allocated to THREA based on percentage of sales over the Juneau – Greens Creek – Hoonah Intertie.
[8] Total Annual Costs divided by Total Energy Requirement.
[9] Total Production Cost for the diesel generation case (see Table 6-9) less Total Annual Costs with Intertie.
[10] Savings with Intertie divided by Total Energy Requirements.
[11] Estimated price for purchased power over the Intertie, exclusive of transmission related charges, that could be paid and produce no annual savings.

As shown in Table 6-15, the estimated savings to THREA in 2007, the first year of Intertie operation is $347,000. Table 6-15 also shows that the average charge for electric service in Hoonah could potentially be reduced by 4.2 cents per kWh with the Intertie[35]. Annual savings with the Intertie are expected to increase each year primarily due to assumed increases in the cost of diesel fuel that the Intertie will offset. In 2017, the first year after the assumed closure of the KMC-GC mine, the revenue recovery obligations of THREA increase and the savings decrease. The cumulative present value to mid-2003 of the estimated annual savings to THREA with the Intertie for the 20-year period, 2007 through 2026 is $4.67 million, assuming a 5% discount rate[36].

A significant benefit to THREA with the Intertie will be the ability to establish economic incentive rates for new large commercial/industrial electric consumers. As long as regular retail energy sales remain relatively stable in Hoonah, the fixed costs of THREA's distribution system and the Intertie will be recovered through normal rates. Consequently, an economic incentive rate based on the incremental cost of purchased power (8.5 cents per kWh in the above table) plus a nominal margin could be established. This rate would need to be negotiated on a case by case basis and should have a time limit to it (e.g. 5-10 years), but could be used to attract new commercial activity to the Hoonah area.

[35] Due to the effects of the State Power Cost Equalization program, any savings in THREA's cost of power due to the Intertie would not necessarily show up in reductions in the effective charges for residential electric service. Rather, the amount of subsidy from PCE provided to THREA would be reduced.
[36] The discount rate for THREA is based on THREA's cost of capital, which is generally a relatively low interest rate of 5%.

TABLE 6-17

Projected Cost of Power and Savings with the Intertie
Kennecott Greens Creek Mine

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	58,692	58,692	58,692	58,692	58,692	58,692	-
Energy Purchased (MWh) [2]	59,866	59,866	59,866	59,866	59,866	59,866	-
Purchased Power Price (¢/kWh) [3]	8.5	8.5	8.5	8.5	8.5	8.5	-
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ 5,089	$ -
Intertie O&M [5]	164	168	171	176	180	184	-
Intertie A&G [6]	176	180	184	188	193	197	-
Intertie R&R [7]	102	102	102	102	102	101	-
Total Annual Costs with Intertie	$ 5,531	$ 5,539	$ 5,546	$ 5,555	$ 5,564	$ 5,571	$ -
Unit Cost (¢/kWh) [8]	9.4	9.4	9.4	9.5	9.5	9.5	-
Savings with Intertie ($000) [9]	$ 1,380	$ 1,656	$ 1,826	$ 2,110	$ 2,288	$ 2,471	$ -
Savings (¢/kWh) [10]	2.3	2.8	3.1	3.5	3.8	4.1	-
Breakeven Cost of Power (¢/kWh) [11]	10.8	11.3	11.6	12.0	12.3	12.6	-

[1] See Table 6-2.
[2] Includes estimated transmission losses of 2% between Juneau and the KMC-GC mine.
[3] Estimated price of power purchased from AEL&P.
[4] Estimated cost of power purchased from AEL&P.
[5] Intertie O&M cost as shown in Table 6-12 allocated to KMC-GC based on percentage of total sales over the Intertie. Assumes O&M costs increase annually at the assumed rate of general inflation.
[6] Intertie A&G cost as shown in Table 6-14 allocated to KMC-GC based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
[7] Annual deposit to Intertie R&R fund to establish a $2.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost allocated to KMC-GC based on percentage of sales over the Juneau – Greens Creek – Hoonah Intertie.
[8] Total Annual Costs divided by Total Energy Requirement.
[9] Total Production Cost for the diesel generation case (see Table 6-11) less Total Annual Costs with Intertie.
[10] Savings with Intertie divided by Total Energy Requirements.
[11] Estimated price for purchased power over the Intertie, exclusive of transmission related charges, that could be paid and produce no annual savings.

As shown in Table 6-16, the estimated savings to KMC-GC in 2007, the first year of Intertie operation is $1,380,000. Annual savings with the Intertie are expected to increase each year primarily due to assumed increases in the cost of fuel that the Intertie will offset. The cumulative present value to mid-2003 of the estimated annual savings to KMC-GC with the Intertie for the ten-year period, 2007 through 2016 is $11.0 million, assuming an 8% annual discount rate.

TABLE 6-18

Projected Cost of Power and Savings with the Intertie
THREA – Kake Service Area

	2007	2008	2009	2010	2011	2012	2017
Energy Requirements (MWh) [1]	4,685	4,747	4,811	4,874	4,938	4,993	5,278
Energy Purchased (MWh) [2]	4,873	4,937	5,003	5,069	5,135	5,192	5,489
Purchased Power Price (¢/kWh) [3]	4.0	4.0	4.0	4.0	4.0	4.5	5.0
Annual Costs with Intertie ($000)							
Purchased Power [4]	$ 195	$ 197	$ 200	$ 203	$ 205	$ 234	$ 274
Intertie O&M [5]	195	200	205	210	215	221	250
Intertie A&G [6]	14	15	15	16	17	17	105
Intertie R&R [7]	46	46	46	46	46	46	46
Total Annual Costs with Intertie	$ 450	$ 458	$ 466	$ 475	$ 483	$ 518	$ 675
Unit Cost (¢/kWh) [8]	9.6	9.6	9.7	9.7	9.8	10.4	12.8
Savings with Intertie ($000) [9]	$ 158	$ 173	$ 190	$ 206	$ 224	$ 215	$ 204
Savings (¢/kWh) [10]	3.2	3.5	3.8	4.1	4.4	4.1	3.7
Breakeven Cost of Power (¢/kWh) [11]	7.2	7.5	7.8	8.1	8.4	8.6	8.7

1 See Table 6-6.
2 Includes estimated transmission losses of 4% between Petersburg and Kake.
3 Estimated price of power purchased from the Four Dam Pool Power Agency.
4 Estimated cost of power purchased from the Four Dam Pool Power Agency.
5 Intertie O&M cost as shown in Table 6-13 fully allocated to THREA. Assumes O&M costs increase annually at the assumed rate of general inflation.
6 Intertie A&G cost as shown in Table 6-14 allocated to THREA based on percentage of total sales over both Interties. Assumes A&G costs increase annually at the assumed rate of general inflation.
7 Annual deposit to Intertie R&R fund to establish a $1.5 million balance in 15 years with accrued interest at an assumed 5% interest rate. Cost is fully allocated to THREA.
8 Total Annual Costs divided by Total Energy Requirement.
9 Total Production Cost for the diesel generation case (see Table 6-10) less Total Annual Costs with Intertie.
10 Savings with Intertie divided by Total Energy Requirements.
11 Estimated price for purchased power over the Intertie that could be paid and produce no annual savings.

As shown in Table 6-17, the estimated savings to THREA in 2007, the first year of Intertie operation is $158,000. Annual savings with the Intertie are expected to increase each year primarily due to assumed increases in the cost of fuel that the Intertie will offset. The cumulative present value to mid-2003 of the estimated annual savings to KMC-GC with the Intertie for the 20-year period, 2007 through 2026 is $2.49 million, assuming a 5% annual discount rate.

Compared to the savings shown related to the Juneau – Greens Creek – Hoonah Intertie, the annual savings shown for the Kake – Petersburg Intertie are much less due to the need to allocate the operating costs of this Intertie over a much smaller load base in Kake than the combined Greens Creek – Hoonah load.

A significant benefit to THREA with the Intertie will be the ability to establish economic incentive rates for new large commercial/industrial electric consumers. As long as regular retail energy sales remain relatively stable in Kake, the fixed costs of THREA's distribution system and the Intertie will be recovered through normal rates. Consequently, an economic incentive rate based on the incremental cost of purchased power (4.0 cents per kWh in the above table) plus a nominal margin could be established[37]. This rate would need to be negotiated on a case by case basis and should have a time limit to it (e.g. 5-10 years), but could be used to attract new commercial activity to the Kake area.

The savings estimated for THREA's Hoonah and Kake service areas could, but would not necessarily be transferred directly through to a reduction in rates for electric service in Kake and Hoonah. THREA presently charges the same rates for all of its service areas[38] based on the combined costs of the entire system. The estimation of THREA's power rates is beyond the scope of this study. The State's Power Cost Equalization program would also affect how much of the Intertie provided savings would be realized by residential consumers in Kake and Hoonah[39]. The PCE program is funded each year by the State legislature and its funding magnitude as well as its continuation is uncertain.

Sensitivity of Results to Alternative Assumptions

As previously indicated, a number of assumptions have been made in preparing the comparative economic analysis used to determine the benefits of the Interties. Principal among the variables with significant impact on the results are load growth in Kake and Hoonah, future diesel fuel prices and future inflation. Alternative assumptions for these variables could potentially produce significantly different results. The following table provides a comparison of the estimated savings with the Interties using alternative assumptions. For each of the alternative cases in Table 6-18, it is important to note that only the specifically identified assumption is changed. All other assumptions remain the same as provided in the base case.

[37] The Four Dam Pool Power Agency would also need to be involved in any discussions of additional energy purchases for economic incentive purposes.

[38] THREA has indicated that it may need to establish rates in each service area based on the cost of service in the respective areas, at the request of the Regulatory Commission of Alaska (RCA).

[39] Essentially, the PCE program provides a subsidy to residential electric consumers. The amount of the subsidy is based on the local cost of power production. According to the program formula, if the cost of power production decreases, as it does when fuel prices drop, the magnitude of the subsidy would also decrease. The amount of the subsidy is also a function of the legislatively approved contribution to the program each year.

TABLE 6-19

Comparison of Savings using Alternative Assumptions
Cumulative Present Value of Intertie Savings [1]
($000)

Case	THREA - Hoonah Service Area	KGCM	THREA - Kake Service Area
Base Case [2]	$ 4,669	$ 10,974	$ 2,491
No Load Growth [3]	$ 1,665	$ 10,837	$ 1,424
Low Fuel Cost [4]	$ 3,424	$ 5,100	$ 1,435
High Fuel Cost [5]	$ 6,202	$ 13,622	$ 3,361
High Inflation [6]	$ 6,439	$ 14,210	$ 3,089

[1] Estimated cumulative present value savings of Intertie benefits between 2007 and 2026 to July 2003. Assumes discount rates of 5% for THREA and 8% for KMC-GC.
[2] Based on assumptions used in Tables 6-15, 6-16 and 6-17.
[3] Assumes loads in Hoonah and Kake do not increase beyond current, 2003 levels.
[4] Assumes 2003 fuel cost of $1.20, $0.90 and $1.00 for Hoonah, KMC-GC and Kake, respectively, escalated at the assumed annual rate of general inflation.
[5] Assumes 2003 fuel cost of $1.35, $1.10 and $1.20 for Hoonah, KMC-GC and Kake, respectively, escalated at 3.5% per year (i.e. 1% above the assumed annual rate of general inflation.) Note that the 2003 fuel costs assumed in this case are the same as used in the Base Case.
[6] Assumes 4.5% annual inflation applied to all O&M and A&G costs. Fuel costs are assumed to increase at 3.5% annually, (i.e. 1% below the assumed annual rate of general inflation).

Comparison of AC, HVDC and HVDC/VSC Technologies

Introduction

A study was conducted by Northstar Power Engineering and George Karady, Phd. of Arizona State University to evaluate the use of alternative energy transmission technologies for the Interties. Their complete report on the subject is included as Appendix E to this report. Following is an excerpted summary of the report and its findings.

The objective of the present study is the identification of the most advantageous transmission system for the Intertie. The technical problem is that the interconnection is between islands and requires submarine cables. In an alternating current (AC) system, the capacitive current limits the length of a submarine cable to about 40-50 miles. This problem can be eliminated by using direct current (DC) energy transmission. A DC system eliminates the capacitive charging current of the cable and permits long submarine cable routes.

Another advantage is that the DC system capacity is significantly larger than an AC system when cables are used. However, a DC system requires converters at both ends, which increases the initial investment. Another problem is that most operating HVDC systems are designed for point-to-point transmission. Recent development of new high power transistors (IGBTs) and the advancement of voltage source converter (VSC) technology have produced the HVDC with VSC transmission system. This has opened new areas for the use of DC transmission. These developments suggest that DC transmission or the combination of AC and DC transmission could be considered for the Southeast Alaska Intertie.

The available energy transmission methods are:

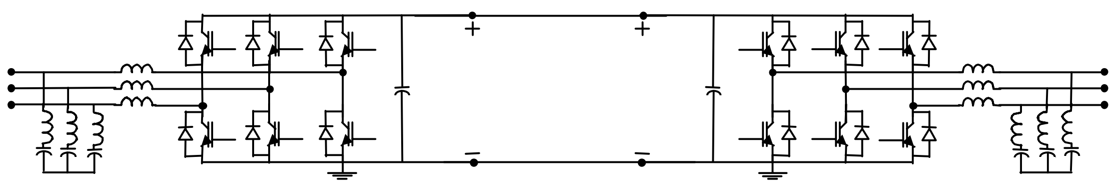
1) AC transmission using 69 kV transmission line
2) Combination of AC and traditional DC transmission
3) DC transmission with VSCs
4) Combination of AC and DC transmission with VSCs

HVDC and HVDC/VSC Options

A HVDC station requires considerable land because the transformers, filters and phase correction capacitors are placed outdoors. The valves and control equipment are placed in a closed air-conditioned/heated building. The completely enclosed system requires a large building and is prohibitively expensive.

A HVDC system with VSCs contains two converters. It can transfer energy in both directions. One of the converters operates as a PWM rectifier the other as an inverter. The rectifier can be controlled to operate close to unity power factor. The inverter can produce AC power with the required power factor. Typical losses claimed by ABB for two converters are 5%. Figure 7-1 shows the concept of a point-to-point energy transmission system.

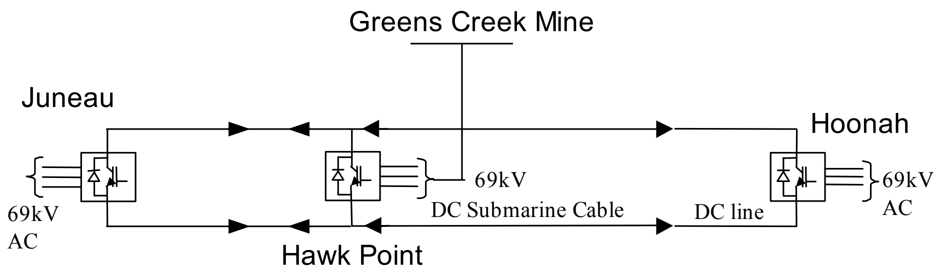
FIGURE 7-1
DC System with Voltage Source Converters (VSC)



The system is very simple and requires only a few components. The major components are the AC filters, DC capacitance, AC reactors, converters and the DC line or cable. The converter can be controlled remotely via a dial up telephone line. The system at the AC side is protected by standard circuit breakers. The converters can be energized separately.

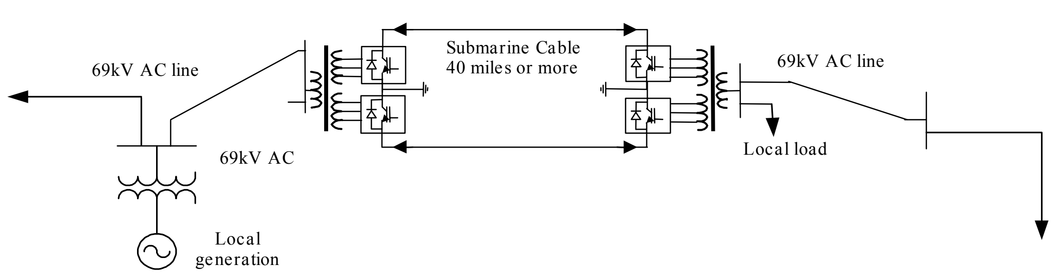
The total DC system with voltage source converters is a viable option. This system requires 3 converters as shown in Figure 7-2.

FIGURE 7-2
Conceptual DC System for SEI-1



The combined AC and DC system is built with standard AC 69-kV transmission lines and point-to-point DC transmission at a long submarine (30 miles or more) crossing. The concept of this system is shown in Figure 7-3.

FIGURE 7-3
Concept of Combined AC and DC System with Voltage Source Converters (VSC)



The preliminary cost estimates show that minimization of the number of converters will reduce the cost of the system. Because of the low level of load, the most advantageous system is the combined AC and DC system. Utilities have extensive operating experience with the existing 69 kV AC system, which suggests the use of a DC system with VSCs only at the long submarine crossing as a point-to-point transmission system.

Cost Issues

The combined AC and DC system uses 69-kV AC transmission and a dedicated DC link between Hawk Point and Hoonah. The DC cable system would require two separate cables or a bipolar system. The cost of the DC cable would be less than the cost of the bundled 3-phase AC cable on a cost per unit basis. The need for two cables, however, would increase the cost of the DC system. In addition, the DC system would need VSCs at each end of the system. Each VSC for the Hawk Inlet – Hoonah system, one in Hawk Inlet and one at Hoonah, is estimated to cost $3.2 million. The cost of the VSCs would not be required for a standard AC system. The combined AC-DC system for SEI-1 is a feasible but expensive solution.

A cost estimate has also been prepared for an HVDC system for the Kake – Petersburg line. The cost estimate is based on a system using submarine and underground cables for the entire length of the line. Where USFS roads exist, the underground cable would be plowed in to roads. As with the DC system described for SEI-1, VSCs would be needed at both ends of the system at an estimated cost of approximately $3.2 million each.

The total estimated direct cost of the HVDC system between Kake and Petersburg is $29.9 million. This compares to the estimated direct costs for the AC system of $23.1 million as shown in Table 4-2.