CHAPTER 1
PURPOSE AND NEED

1.1 INTRODUCTION

The Southern Intertie Project is proposed as a system improvement project to increase the overall Railbelt electrical system reliability and transfer of energy capabilities between the Kenai Peninsula and Anchorage. The Project would consist of constructing a second electrical transmission line between the Kenai Peninsula and Anchorage (Figures 1-1 and 1-2). The voltage for the proposed transmission line is 138kV.

The Railbelt system is a power grid that electrically connects south-central Alaska from Homer to Fairbanks. The Railbelt service area is illustrated on Figure 1-3. There are three distinct regions—the interior area centered around Fairbanks; the Anchorage and Matanuska Valley area; and the Kenai Peninsula. Electric generation, transmission, and distribution within the Alaska Railbelt are currently provided by six utility companies, which compose the IPG, also referred to as the Railbelt Utilities. Members of the IPG include GVEA, Matanuska Electric Association, CEA, AML&P, HEA, and City of Seward.

GVEA, an IPG member and RUS borrower, plans to apply to RUS for financial assistance for its share of the proposed project. The RUS, an agency of the U.S. Department of Agriculture, is subject to the requirements of the NEPA, as amended (42 U.S.C. 4321-4346) and the CEQ Regulations for Implementing the Procedural Provisions of NEPA (40 CFR Parts 1500 through 1508). In accordance with RUS Environmental Policies and Procedures (7 CFR Part 1794), providing funding for the proposed project would constitute a major federal action that could significantly affect the quality of the human environment. Because of its potential involvement in the proposed project, RUS assumed responsibility as lead agency for the preparation of an EIS for the project as announced in the *Federal Register* on October 9, 1996.

A major portion of one of the alternative routes, the Enstar Route, traverses the KNWR, which is managed by the USFWS. The KNWR is a conservation system unit designated under ANILCA (Section 303 (4), PWOL, 96-487). Access for transportation and utility systems across conservation system units are governed by regulations (43 CFR Part 36) implementing Title XI of ANILCA. The USFWS is a cooperating agency for this EIS and is directly responsible for making a decision on the IPG application for a permit to construct the line through the KNWR under the requirements for the ANILCA. The permit application to use the Enstar Route was submitted to the USFWS in August 1999. The USACE, which may issue permits for the proposed project, is also serving as a cooperating agency on this EIS.

1.2 PROJECT BACKGROUND

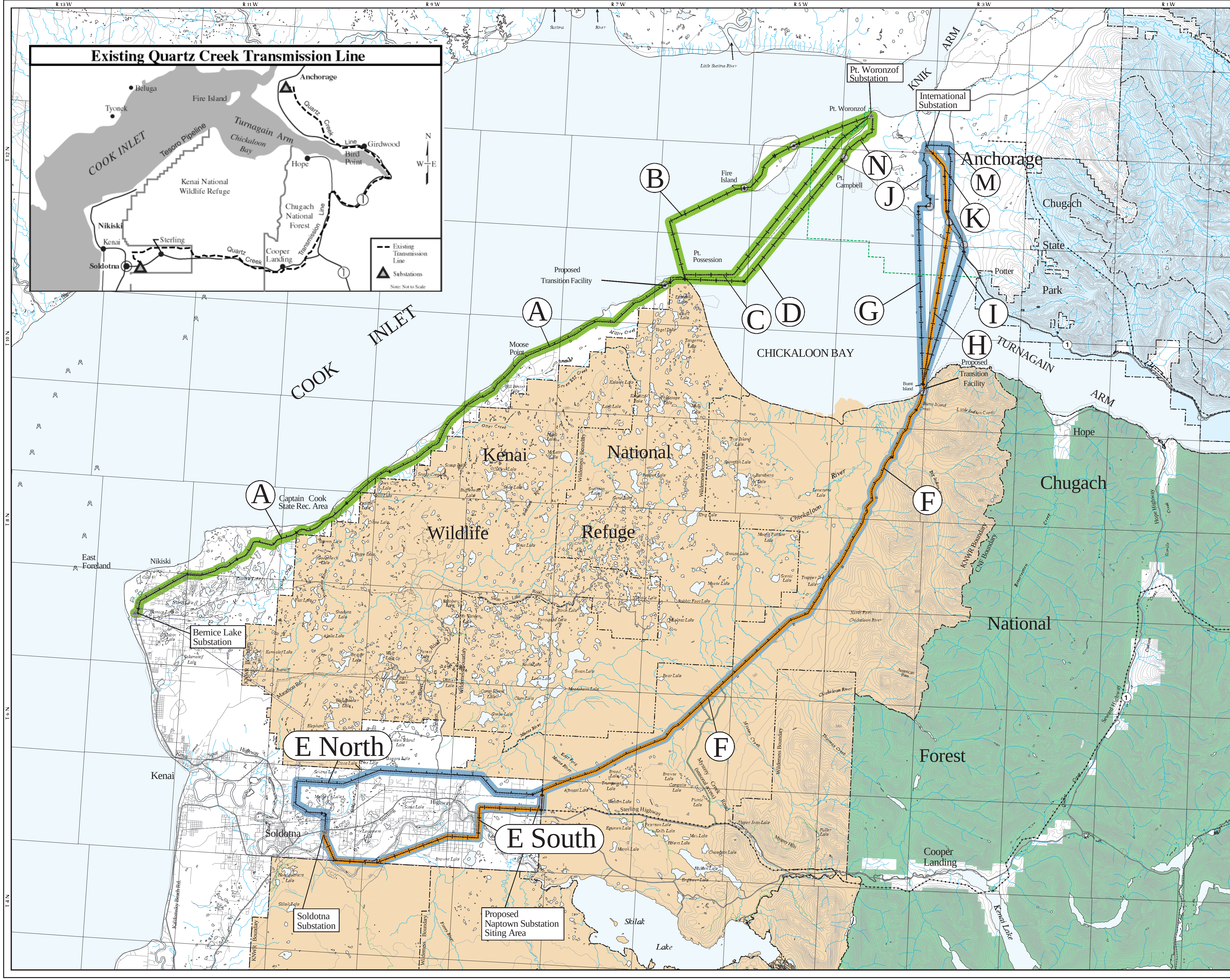
The Kenai Peninsula and Anchorage area are connected by one transmission line, known as the Quartz Creek 115kV transmission line. The Quartz Creek transmission line was originally constructed in 1960 to transmit power from CEA's Cooper Lake Hydroelectric Project to the Anchorage area. The need has grown for transmission line interconnections between load areas to efficiently utilize generating plants across the system, and reliably distribute that power to the load centers.

The Quartz Creek transmission line currently provides the sole path for coordinating the operation of generation on the Kenai Peninsula with Anchorage area generation (Figure 1-4). The line also is used to provide back-up power in the case of outages in the Anchorage area or on the Kenai Peninsula. The Quartz Creek transmission line is limited in electrical transfer capability and its ability to provide reliable back-up power during system outages. The line is subject to outages from ice, wind, and snow loading, and is routed across known and historically active avalanche areas. With the addition of the Bradley Lake Hydroelectric Project in 1991, the limitations of the Quartz Creek transmission line have not allowed the increased generating capacity from the Bradley Lake Project to be used to full potential. This has resulted in operation of the Railbelt electrical system in a less than optimum manner, and at higher costs than if a second line were to be constructed between the Kenai Peninsula and Anchorage.

The Bradley Lake Hydroelectric Project, owned by the State of Alaska, is located east of Homer on the south end of the Kenai Peninsula, and has a generating capacity of 120 MW. Power from the project is used by the Railbelt Utilities; the percentage shares in Bradley Lake are as shown in Table 1-1.

TABLE 1-1
PURCHASERS' PERCENTAGE SHARES OF BRADLEY LAKE CAPACITY AND OF ANNUAL PROJECT COSTS

Purchaser	Percentage Share (Percent)
Alaska Electric Generation and Transmission Cooperative, Inc. (representing Homer Electric Association and Matanuska Electric Association)	25.8
Chugach Electric Association, Inc.	30.4
Golden Valley Electric Association, Inc.	16.9
Municipality of Anchorage, d/b/a Municipal Light and Power	25.9
City of Seward Electric System	1.0
Total	100.0
Source: Power Sales Agreement for Bradley Lake Energy, December 8, 1987	



ALTERNATIVES STUDIED IN DETAIL SOUTHERN INTERTIE PROJECT FIGURE 1-1

Legend

- Applicant's Proposed Route
- Enstar Route Options
- Tesoro Route Options
- Chugach State Park
- Kenai National Wildlife Refuge
- Chugach National Forest
- Private, Borough, or State Selected Lands

Note: No-action alternative is shown in inset in upper left-hand corner of map.

Base Map Sources:
Municipality of Anchorage (1994).
Chugach National Forest (1995).
Kenai Peninsula Borough (1994).
USGS 1:63,360 and 1:25,000 Quads.
Contour Interval: 200 Feet
Contour Labeling in Feet

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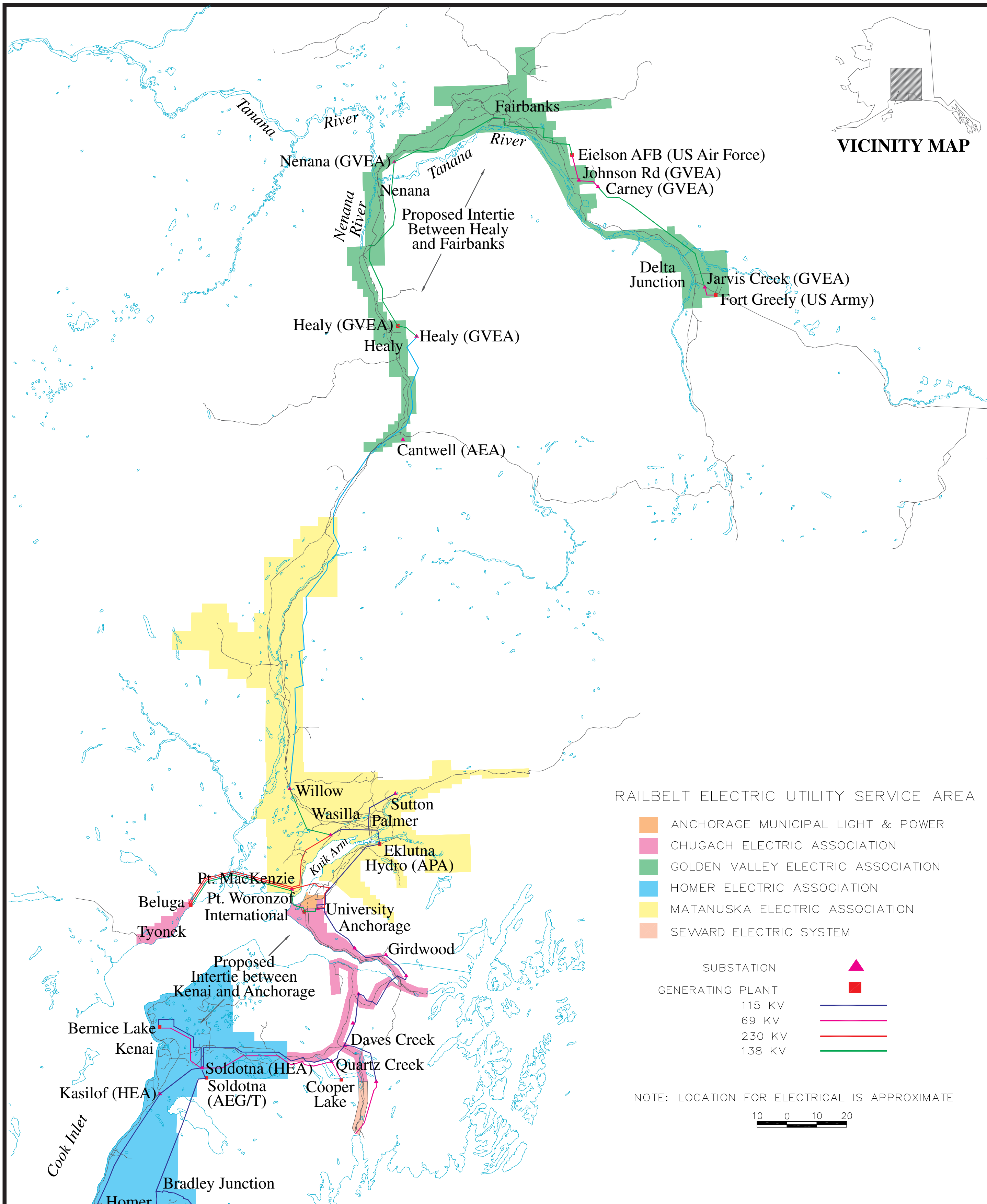
PROJECT VICINITY MAP

Figure 1-2



RAILBELT UTILITIES SYSTEM
SOUTHERN INTERTIE PROJECT
FIGURE 1-3

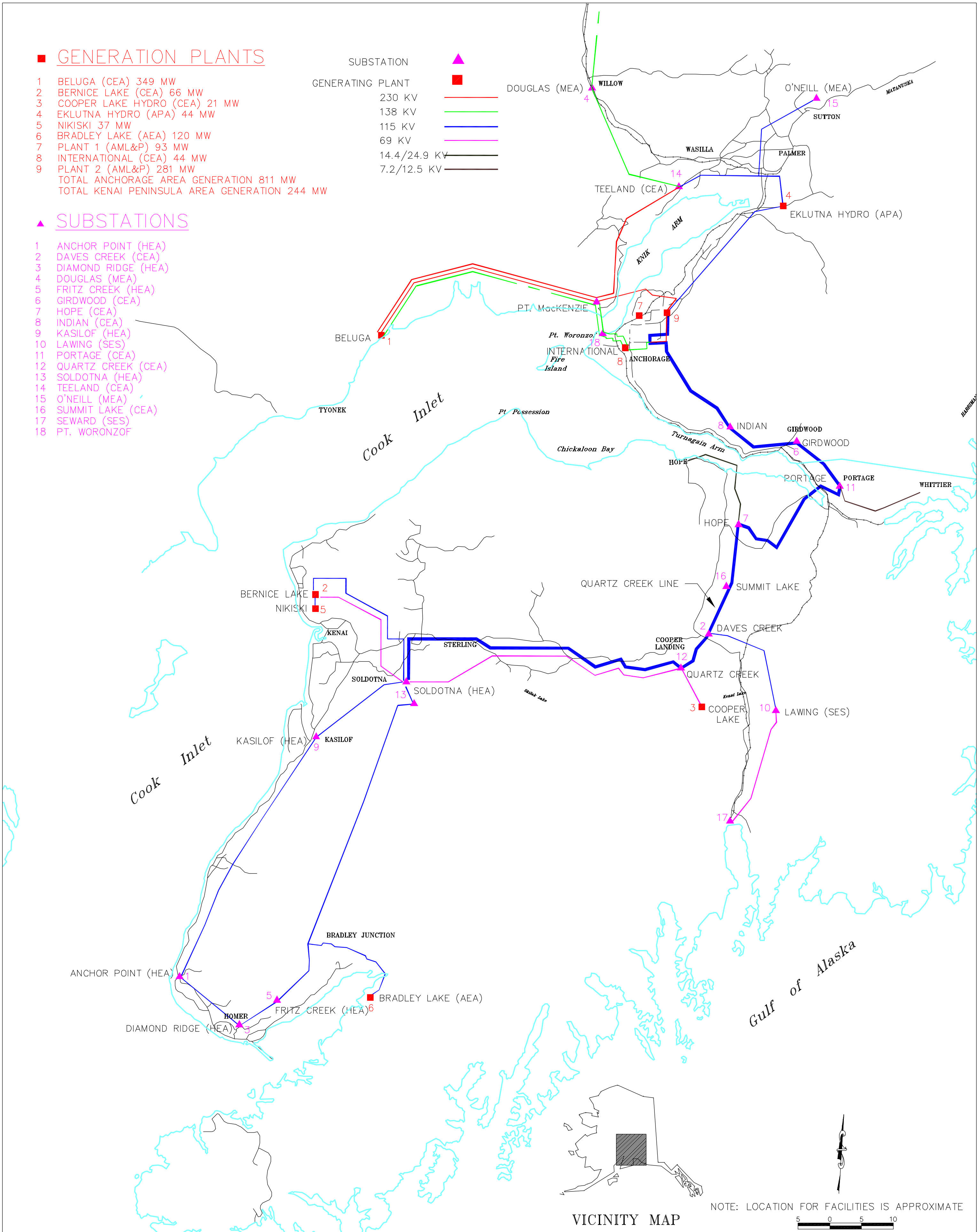

GENERATION PLANTS
1 BELUGA (CEA) 349 MW
2 BERNICE LAKE (CEA) 66 MW
3 COOPER LAKE HYDRO (CEA) 21 MW
4 EKLUTNA HYDRO (APA) 44 MW
5 NIKISKI 37 MW
6 BRADLEY LAKE (AEA) 120 MW
7 PLANT 1 (AML&P) 93 MW
8 INTERNATIONAL (CEA) 44 MW
9 PLANT 2 (AML&P) 281 MW
TOTAL ANCHORAGE AREA GENERATION 811 MW
TOTAL KENAI PENINSULA AREA GENERATION 244 MW
SUBSTATIONS
1 ANCHOR POINT (HEA)
2 DAVES CREEK (CEA)
3 DIAMOND RIDGE (HEA)
4 DOUGLAS (MEA)
5 FRITZ CREEK (HEA)
6 GIRDWOOD (CEA)
7 HOPE (CEA)
8 INDIAN (CEA)
9 KASILOF (HEA)
10 LAWING (SES)
11 PORTAGE (CEA)
12 QUARTZ CREEK (CEA)
13 SOLDOTNA (HEA)
14 TEELAND (CEA)
15 O'NEILL (MEA)
16 SUMMIT LAKE (CEA)
17 SEWARD (SES)
18 PT. WORONZOF
SUBSTATION
GENERATING PLANT
230 KV
138 KV
115 KV
69 KV
14.4/24.9 KV
7.2/12.5 KV
DOUGLAS (MEA)
WILLOW
O'NEILL (MEA)
MATANUSKA
SUTTON
WASILLA
PALMER
TEELAND (CEA)
EKLUTNA HYDRO (APA)
KNIK
ARM
PT. MacKENZIE
BELUGA
Pt. Woronzof
INTERNATIONAL
Fire Island
ANCHORAGE
TYONEK
Cook Inlet
Pt Possession
Chickaloon Bay
Turnagain Arm
INDIAN
GIRDWOOD
HOPE
PORTAGE
WHITTIER
QUARTZ CREEK LINE
SUMMIT LAKE
DAVES CREEK
BERNICE LAKE
NIKISKI
KENAI
STERLING
COOPER LANDING
SOLDOTNA
SOLDOTNA (HEA)
QUARTZ CREEK
Skilak Lake
Kenai Lake
COOPER LAKE
LAWING (SES)
KASILOF (HEA)
KASILOF
Cook Inlet
BRADLEY JUNCTION
ANCHOR POINT (HEA)
BRADLEY LAKE (AEA)
FRITZ CREEK (HEA)
HOMER
DIAMOND RIDGE (HEA)
Gulf of Alaska
VICINITY MAP
NOTE: LOCATION FOR FACILITIES IS APPROXIMATE
5 0 5 10

FIGURE 1-4

At the time the Power Sales Agreement[1] for the Bradley Lake energy was signed, it was recognized that additional transmission lines (interties) would be needed between the Kenai Peninsula and Fairbanks for system reinforcement and provide for the economical transfer of Bradley Lake power. The purchasers agreed to use their best efforts to obtain sufficient funding for the interties, as well as for the Bradley Lake Project.

In addition to the Power Sales Agreement, a transmission wheeling agreement[2] with CEA to transfer power from Bradley Lake north of the Kenai Peninsula over the Quartz Creek transmission line was executed as well. The wheeling agreement recognized the limitations of the Quartz Creek transmission line to accommodate the transfer of Bradley Lake power. The agreement contains the following specific points:

- delivery of Bradley Lake Power to the Purchasers requires transmission facilities
- construction of additional transmission facilities (northern and southern interties) was anticipated to reduce the effective cost to ratepayers for power from Bradley Lake
- additional transmission facilities had, at that time, not yet been funded
- under the circumstances, the Quartz Creek transmission line was/is the only transmission path, and that the wheeling agreement would be superseded if and when additional transmission facilities were constructed

The Kenai Peninsula Borough Comprehensive Plan also acknowledges that to fully utilize the Bradley Lake Project, additional transmission line upgrades are needed to carry power to Anchorage and Fairbanks.[3]

[1] Bradley Lake Hydroelectric Project, Agreement for the Sale and Purchase of Electric Power ("Power Sales Agreement") by and among The Alaska Power Authority, an agency of the State of Alaska ("Seller") and The Chugach Electric Association, Inc., The Golden Valley Electric Association, Inc., The Municipality of Anchorage d/b/a Municipal Light and Power, The City of Seward d/b/a Seward Electric System, and The Alaska Electric Generation and Transmission Cooperative, Inc. ("Purchasers") and The Homer Electric Association, Inc., and The Matanuska Electric Association, Inc. (Additional Parties), December 8, 1987.

[2] Bradley Lake Hydroelectric Project, Agreement for the Wheeling of Electric Power and for Related Services ("Services Agreement") by and among The Chugach Electric Association, Inc., The Homer Electric Association, Inc., The Golden Valley Electric Association, Inc., The Matanuska Electric Association, Inc., The Municipality of Anchorage d/b/a Municipal Light and Power, The City of Seward d/b/a Seward Electric System, and The Alaska Electric Generation and Transmission Cooperative, Inc., December 8, 1987.

[3] Kenai Peninsula Borough Comprehensive Plan, May 1992, page 3-39.

1.2.1 How the Existing System is Operated

The Alaska Intertie Agreement[4] provides the contractual umbrella under which the Railbelt Utilities and State of Alaska operate the interconnected electrical system. The Railbelt Utilities and State of Alaska constructed the initial intertie between Anchorage and Fairbanks to allow the participating utilities to improve system reliability and buy and sell power among themselves, in order to reduce the overall cost of operating the system. As noted above, the Quartz Creek transmission line, operated by CEA, currently provides the transmission line path connecting the Kenai Peninsula with Anchorage, and in turn with the Fairbanks area.

The existing Quartz Creek transmission line is limited to transferring 70 MW of power for a secure transfer. To allow full use of the Kenai Peninsula generation, the intertie secure transfer capacity needs to be increased to 125 MW. The Project would provide the increased transmission capacity to make these higher transfers possible in a secure manner.

Currently the existing system between the Kenai Peninsula and Anchorage is operated so as to maximize the transfers of economy energy, and coordinate the hydro and thermal generation resources on the Kenai Peninsula and in Anchorage, within the limitations of the existing Quartz Creek transmission line. As depicted on Figure 1-5, power flows in both directions, to and from the Kenai Peninsula and Anchorage.

The average variation of the import/export of power to the Kenai Peninsula is plus or minus 40 MW on a daily basis. During the day, when loads in the Anchorage area are high, hydropower is dispatched from the Kenai Peninsula to Anchorage to "shape" the overall generation so that thermal generation units in the Anchorage area operate near full load for maximum efficiency, which results in overall lower generation costs. At night when electrical loads are lower, the hydrogeneration is reduced to conserve the water in the reservoirs, while the thermal generation units continue to operate at the highest possible efficiency.

With the Project in service as a second transmission line interconnection between the Anchorage area and Kenai Peninsula, increased economy energy transfers and hydro-thermal coordination, currently limited by the existing single Quartz Creek transmission line, would be possible, and full advantage could be taken of the Bradley Lake hydro resource.

[4] Alaska Intertie Agreement, among The Alaska Power Authority, The Municipality of Anchorage d/b/a Municipal Light and Power, The Chugach Electric Association, Inc., The City of Fairbanks, Municipal Utilities System, The Golden Valley Electric Association, Inc., and The Alaska Electric Generation and Transmission Cooperative, Inc. of which The Homer Electric Association, Inc. and The Matanuska Electric Association, Inc. are members. December 23, 1985.

Hydroelectric resources are coordinated with thermal resources (hydro-thermal coordination) so that thermal resources such as gas-fired turbines at the Beluga Power Station can be operated at the highest possible efficiency, while using the hydro resources to "shape" the instantaneous system load requirements. The hydrothermal generation coordination process is illustrated on Figure 1-6[5].

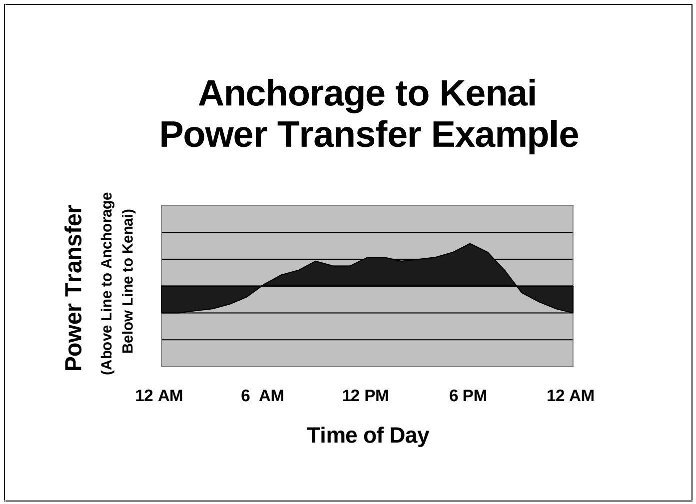


Figure 1-5

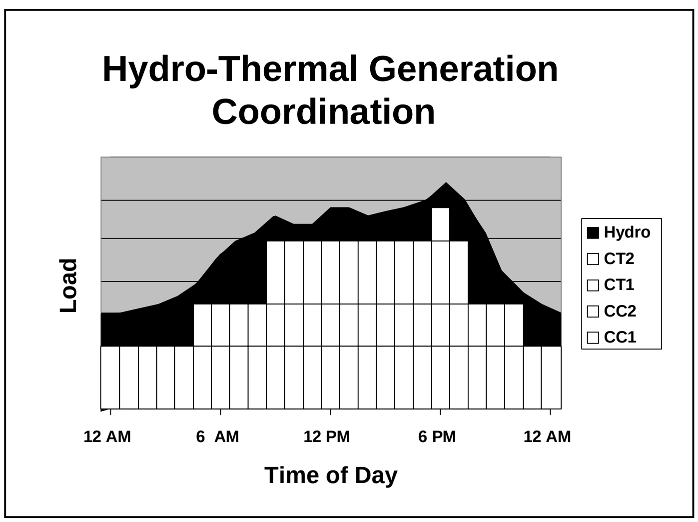


Figure 1-6

[5] On Figure 1-6, CT means combustion turbine, and CC means combined-cycle combustion turbine. Both are thermal generation resources.

1.2.2 Previous Studies

The purpose of and need for the Project have been studied extensively and confirmed repeatedly through numerous studies since 1987. A series of engineering, economic, and environmental studies have been conducted for the proposed Project to confirm its need and establish key cost and technical parameters, as shown in Table 1-2.

TABLE 1-2
REFERENCE NUMBERS FOR STUDIES ADDRESSING KEY PROJECT ISSUES*

Project Issue	Year Study Completed							
	1987	1989	1990	1991	1996	1997	1998	1999
System reliability	1	2,3,4	5	6,8			11,13	14
Increased transfer capacity	1	2,3,4	5	6	9	10	11,13	14
Economic utilization of available generation		2,3,4	5	6			11,13	14
System stability	1	2	5	6	9	10	13	14
Spinning reserves		2,3,4	5	6			11,13	14
Project costs	1	2,3,4		6,7	9		12	14
Project benefits		2,3,4		6			11	14
Environmental siting analysis	1				9			14
Transmission line losses	1	2,3,4		6	9	10	11	14
Maintenance costs		2,3,4					11,12	14

* See list of references for specific studies referenced by number in this table.

Initial Southern Intertie related studies included a cost estimate and corridor feasibility study by Power Engineers and Hart-Crowser (1987), and the *Alaska Power Authority (APA) Railbelt Intertie Reconnaissance Study* (1989).

Two of the key volumes included in the 1989 reconnaissance study were a *Benefit/Cost Analysis* (Decision Focus, Inc. [DFI] 1989a, and updated in December 1989b), and a *Reliability Assessment of the Railbelt Interconnected Electric Utility Systems* (NERC 1990).

The reconnaissance studies were summarized in the *Alaska Energy Authority (AEA) Railbelt Intertie Feasibility Study, Final Report, March 1991* (The APA became part of the AEA). The final report included updated cost estimates prepared by Dryden and LaRue (1991). This particular report was prepared to comply with the project review requirements contained in AS 44.83.181 for the northern and southern intertie projects identified in Ch. 208, Sec. 159, SLA 1990.

In 1995, Power Engineers and Dames & Moore (1996) prepared updated cost estimates and conducted an alternatives analysis and electrical system, environmental, and macro corridor studies. Completed in 1996, these studies took a fresh look at the electrical, cost, and environmental siting aspects of the Project. In 1997 and 1998, DFI reviewed and updated the value of the Project benefits (DFI 1998). In 1997 and 1998 the reliability assessment of the railbelt systems completed by NERC in 1990 also was updated by the NERC Reliability Assessment Subcommittee (August 1998). The balance of this chapter refers extensively to these detailed studies, and summarizes their pertinent conclusions. In 1998, Power Engineers updated the cost estimates for the Project (January 1998). In July 1999, the comprehensive Southern Intertie Project Environmental Analysis was completed (Power Engineers and Dames & Moore 1999).

1.2.3 System Planning and Operating Criteria

The Alaska interconnected system has grown in much the same way as interconnected systems in the lower 48 states, first as isolated systems, and then as an interconnected system to take advantage of capabilities in adjoining systems to provide mutual support. The Railbelt power grid allows the participating utilities to sell and buy power to and from each other, taking advantage of lower costs in other areas, and to provide back-up power to each other. In this manner, lower cost generation resources in adjacent areas can be utilized more fully and the cost of operating the system and procuring electricity can be minimized. The IPG was formed by the Railbelt Utilities to improve electric reliability and coordination within the Railbelt by working together to improve the interconnected system through intertie improvements and cooperative energy projects. The Southern Intertie is one of these cooperative projects.

The ASCC is an association of Alaska's electric power utilities. The ASCC reviews the Alaska interconnected system on a continuing basis to promote reliable system operation, through coordination between utilities in the planning and operation of the interconnected system. In 1991, as a result of discussions with NERC, ASCC adopted coordinated interconnection planning and operating criteria. The 12 operating criteria adopted are based on NERC planning guides for bulk electric system planning and are adapted specifically to Alaska. The NERC and ASCC criteria are shown in Table 1-3.

TABLE 1-3
ELECTRICAL UTILITY PLANNING CRITERIA

NERC Planning Guides[a]	ASCC Planning Criteria[b]
To the extent practicable, a balanced relationship is maintained among bulk electric system elements in terms of size of load, size of generating units and plants, and strength of interconnections. Application of this guide includes the avoidance of the following: ▪ excessive concentration of generating capacity in one unit, at one location, or in one area ▪ excessive dependence on any single transmission circuit, tower line, right-of-way, or transmission switching station ▪ excessive burdens on neighboring systems	1. Balance Among System Elements - A balanced relationship shall be maintained among bulk electric system elements so as to avoid excessive dependence on any one element.

TABLE 1-3 (continued)
ELECTRICAL UTILITY PLANNING CRITERIA

NERC Planning Guides[a]	NERC Planning Guides[a]
The system is designed to withstand credible contingency situations.	2. Contingencies - Additions to the interconnected system shall be planned and designed to allow the interconnected system to withstand any credible contingency situation without excessive impact on the system voltages, frequency, load, power flows, equipment thermal loading, or stability.
Dependence on emergency support from adjacent systems is restricted to acceptable limits.	3. Emergency Support - Reserves shall be provided such that emergency support from adjacent systems is restricted to acceptable limits as determined by studies of the interconnected system.
Adequate transmission ties are provided to adjacent systems to accommodate planned and emergency power transfers.	4. Support From Adjacent Systems - Adequate transmission ties between adjacent systems shall be provided to accommodate planned and emergency power transfers.
Reactive power resources are provided that are sufficient for system voltage control under normal and contingency conditions, including support for a reasonable level of planned transfers and a reasonable level of emergency power transfer.	5. Reactive Power Resources - Each control area shall provide sufficient capacitive and inductive resources at proper levels to maintain system-steady state and dynamic voltages within established limits, including support for reasonable levels of planned and emergency power transfers.
Adequate margins are provided in both real and reactive power resources to provide acceptable dynamic response to system disturbances.	6. Real and Reactive Power Margins - Margins in both real and reactive power resources are provided for acceptable dynamic response to system disturbances.
Recording of essential system parameters is provided for both steady state and dynamic system conditions.	7. Recording System Parameters - Essential system parameters shall be recorded.
System design permits maintenance of equipment without undue risk to system reliability.	8. Reliability During Maintenance - System design shall allow for equipment maintenance without unduly degrading reliability.
Planned flexibility in switching arrangements limits adverse effects and permits reconfiguration of the bulk power transmission system to facilitate system restoration.	9. Switching Flexibility - Switching arrangements shall be provided to limit adverse effects and permit reconfiguration of the bulk power transmission system to facilitate system restoration.
Protective relaying equipment is provided to minimize the severity and extent of system disturbances and to allow for malfunctions in the protective relay system without undue risk to system reliability.	10. Protective Relaying - Provide sufficient relaying equipment such that the severity and extent of the system disturbances is minimized and that malfunctions in the protective relay system do not jeopardize system reliability.
Black start-up capability is provided for individual systems.	11. Black Start-up - Black start-up capability is to be provided for individual systems.
Fuel supply diversity is provided to the extent practicable.	12. Fuel Supply - Plans for generation additions shall consider fuel supply diversity.

[a] NERC Planning Guides as approved by NERC Engineering Committee on February 18, 1989. These planning guides describe the characteristics of a reliable bulk electric system. They are intended to provide guidance to the regional councils, subregions, pools, and/or individual systems in planning their bulk electric systems.

[b] ASCC Planning Criteria adopted by the ASCC on April 4, 1991.

These criteria have been developed based on the “lessons learned” from the construction and operation of the interconnected bulk power systems of North America, and are the industry accepted practices for planning and measuring the performance of bulk power interconnected systems. Based on these criteria, binding operating agreements between the Railbelt Utilities have been negotiated, and contractually govern the operation of the Alaska Railbelt interconnected system.

The Project has been planned and is proposed in accordance with these criteria. The Project would correct deficiencies in the existing interconnected system and is consistent with the ASCC criteria on system balance, contingencies, provision of emergency support, support from adjacent systems, reactive power resources, real and reactive power margins, reliability during maintenance, and switching flexibility.

1.3 PURPOSE AND NEED FOR THE PROJECT

This Project is needed because the existing Railbelt electrical system is deficient south of Anchorage. The studies that were conducted on the system identified several objectives that, if met, would correct the deficiencies and make the system run more economically and effectively. How this Project will meet those objectives is described below in more detail.

Specifically, the proposed Project would provide a second path for power to flow between the Kenai Peninsula and Anchorage and is needed to accomplish the following:

- increase the reliability of the interconnected Railbelt electrical system from the Kenai Peninsula to Fairbanks, and reduce the requirement for load shedding during system disturbances
- increase the power transfer capacity between the Kenai Peninsula and Anchorage area
- provide the capability to utilize the most economic generation mix available to reduce costs to consumers and to allow generation capacity in one area to support the load in the other area
- reduce area requirements for spinning reserve generation, thereby reducing operating costs and increasing the life-span of generation plants
- improve Railbelt electrical system stability
- reduce transmission line losses for power transfers and reduce maintenance costs
- provide adequate access to power entitlements from the Bradley Lake Hydroelectric Project for the utilities north of the Kenai Peninsula, and allow Bradley Lake generation to be more fully utilized

Table 1-4 shows how the Project, by meeting its objectives, would fulfill the ASCC criteria that currently are not fully being met. Following the table is a detailed discussion of each Project objective including its definition, the current system deficiency, how the Project would meet the deficiencies, and benefits from the Project.

1.3.1 Reliability

System Deficiency

System reliability depends on system components remaining in service. Typical system components that can fail and cause major outages are generation plants, transmission lines, power circuit breakers, and power transformers. Adding transmission lines to a system improves system reliability by providing multiple paths for the power to flow; thus, an outage of a single component does not completely disrupt the system.

The Quartz Creek transmission line has a history of outages due to wind, ice, snow, and avalanches. The reason for this is that the route traversed by the line passes through known areas of high avalanche activity and areas known for high winds, ice, and snow. The line route along the Turnagain Arm is subject to periodic high winds, and the narrow mountain valleys south of Portage also can “funnel” high winds into the line. The Turnagain Pass and Summit Lake areas are well known for ice and snow loading. Avalanche activity along the Turnagain Arm, Turnagain Pass, and Summit Lake areas expose the line to additional risk. Because of the very steep side slopes along Turnagain Arm and avalanche paths through the mountains, structure locations and alignments for the line are very limited. The line route and structure locations that exist today are not always the most desirable, but they are the best available.

A history of unscheduled outages for the Quartz Creek transmission line from 1975 through 2000 is shown in Table 1-5. Outage data are not available prior to 1975. Unscheduled outages are those outages that occur unexpectedly. Scheduled, or planned, outages are those outages that occur in a time and manner planned for by utilities to conduct repair and maintenance activities on the line or other system components. The average duration of an outage (for outages with known durations) is 20.8 hours, based on 52 of the total of 108 (48 percent) outages recorded.

Project Objectives	ASCC Criteria #1 System Balance	ASCC Criteria #2 Contingencies	ASCC Criteria #3 Emergency Support	ASCC Criteria #4 Support from Adjacent Systems	ASCC Criteria #5 Reactive Power Resources	ASCC Criteria #6 Real & Reactive Power Margins	ASCC Criteria #8 Reliability during Maintenance	ASCC Criteria #9 Switching Flexibility
Increase the reliability of the interconnected system	A second line would reduce excessive dependence on the Quartz Creek transmission line.	A second line would mitigate or eliminate the current impact of single contingency outages.	A second line would provide added system support in the event of outages.	A second line would allow planned and emergency power transfers to minimize outages.	A second line would provide access to overall system reactive support to minimize outages.	A second line would provide support to both areas improving dynamic response and system reliability.	A second line would allow for continued power transfers during maintenance activities, thereby maintaining reliability.	A second line would provide flexibility to maintain service reliability with switching on the Quartz Creek transmission line or a second line.
Increase the power transfer capacity between the Kenai Peninsula and Anchorage	Increased power transfers lessen dependence on the Quartz Creek transmission line.	Power transfers during outages of the Quartz Creek transmission line or a second line would not be interrupted, and increased support would be available for system-wide outages.	Increased power transfer would relieve transmission constraints during emergencies.	Two lines would provide increased ability to support adjoining areas.	Increased power transfer capability would provide increased access to reactive resources.	Increased power transfer capacity would improve system response to disturbances.	Increased power transfer capacity would provide flexibility in maintenance scheduling.	Increasing the power transfer capacities would make the timing and duration of switching more flexible.
Provide the capability to utilize the most economic generation mix to reduce costs	Generation can be shared in a more balanced and economical manner system-wide.	N/A	N/A	A second line would allow generation in adjacent systems to be utilized economically for planned and emergency conditions.	A second line would provide increased access to the most economic reactive resources at existing generation plants.	A second line would allow increased flexibility in assigning which generation provides spinning reserves, which could reduce costs.	The Project would allow economic dispatch of power to continue during system maintenance.	N/A
Improve overall system stability during disturbances	Adding a second line would reduce dependence on the Quartz Creek transmission line and would provide a loop feed to the Kenai Peninsula, thereby enhancing system stability.	A second line would enable the system to withstand Quartz Creek transmission line and other outages with higher power transfer, and would maintain system stability.	A second line would increase the level of support that can be provided during emergencies.	A second line would provide additional system-wide support during outage conditions, enhancing system stability.	A second line would provide better system-wide access to available reactive resources to enhance stability during disturbances.	A second line would provide better access to real and reactive resources during system disturbances to maintain stability.	A second line would allow continued support to adjacent areas during maintenance of the Quartz Creek transmission line and maintain stability during disturbances.	N/A
Reduce spinning reserve requirements	A second line would allow sharing of spinning reserve resources between areas, reducing overall spinning reserve requirements.	A second line would provide enhanced system-wide access to spinning reserve resources during disturbances, thereby reducing overall spinning reserve requirements.	A second line would allow increased spinning reserves to be provided from an adjacent area during emergencies, thereby reducing overall spinning reserve requirements.	Increased transmission capacity would allow an increased level of support from adjacent areas for planned and emergency conditions, thereby lowering overall spinning reserve requirements.	N/A	A second line would allow adequate real and reactive power resources to be provided on a system-wide basis instead of for each area, thereby reducing overall spinning reserve requirements.	A second line would allow flexibility in designating spinning reserves during maintenance activities, thereby reducing overall costs.	N/A
Reduce line losses and maintenance costs	N/A	N/A	A second line would allow maintenance to be more effectively scheduled during and as follow-up to emergencies.	A second line would provide support to adjacent systems through more timely maintenance and lowered line losses.	N/A	N/A	A second line would maintain service reliability and lower costs during maintenance of either line.	N/A
Increase access to power entitlements from the Bradley Lake Project and allow its generation to be more fully utilized	N/A	N/A	N/A	N/A	N/A	N/A	N/A	A second line would result in a reduction of maintenance costs because of increased flexibility in the timing and duration of switching.

TABLE 1-4
APPLICABLE ASCC
PLANNING AND OPERATING CRITERIA

TABLE 1-5 QUARTZ CREEK TRANSMISSIONLINE – UNSCHEDULED OUTAGES				
Year	**Total Outages Recorded**	**Outages with Known Durations**		
		Number of Outages	**Hours**	**Minutes**
1975	2	None	-	-
1976	3	None	-	-
1977	3	None	-	-
1978	3	3	5	43
1979	2	None	-	-
1980	11	3	88	21
1981	7	2	5	56
1982	7	4	8	38
1983	7	2	9	15
1984	2	2	22	47
1985	5	2	10	35
1986	4	3	107	54
1987	3	1	10	27
1988	10	6	7	11
1989	3	3	1	26
1990	4	4	16	55
1991	1	1	5	56
1992	2	1	2	56
1993	3	2	0	24
1994	2	2	0	32
1995	3	2	8	59
1996	6	2	0	6
1997	10	2	45	44
1998	0	0	0	0
1999	3	3	5	55
2000	2	2	733	52
Totals	108	52	1,081 hours, 30 minutes	
Summary				
Average outages per year - 4.2				
Source: Chugach Electric Association 1975-2001				

Eight of the outages included in the total of 108 outages during the period are listed as having been caused by avalanches. Further information on avalanche hazards can be found in Chapter 2. Based on discussions with CEA staff, the Quartz Creek transmission line was out of service for repairs due to these avalanches for approximately 10 days for each event. During these lengthy periods that the line is out of service, it is unavailable to function as an intertie between the Kenai Peninsula and Anchorage. The causes of the 108 outages, as recorded by CEA, are shown in Table 1-6. The highest number of outages is attributed to unknown causes. A review of the data indicates that the outage duration from an unknown cause varies from minutes, to 80+ hours, to not recorded. Because outage durations are only available for 52 of the 108 outages, it is not possible to definitively determine which cause is responsible for the most outage time.

TABLE 1-6 QUARTZ CREEK TRANSMISSION LINE – CAUSES OF UNSCHEDULED OUTAGES Chugach Electric Association Outage Records		
Cause of Outage	**Total Outages Recorded**	**Percent of Total Outages**
Unknown	35	32
Line Faults (various causes)	26	24
Human Error	12	11
Equipment Failure	12	11
Severe Storms	9	8
Avalanches	8	7
Winds	4	4
Trees	2	2
Total Outages	108	100

While the capability and reliability of the Quartz Creek transmission line between the Anchorage and Kenai areas are limited, the line is still an important part of the interconnected system. As an intertie between the two generation areas, the line is a factor in providing electrical service to all of the Railbelt customers from the Kenai Peninsula to Fairbanks. In addition to acting as an intertie between the two areas, the line also provides electrical service to consumers along the line route in Indian, Girdwood, Portage, Whittier, Hope, Summit Lake, Dave's Creek, and Cooper Landing. The City of Seward is also served from the Quartz Creek transmission line. Table 1-7 provides a summary of the number of customers in the Railbelt by region, and those more directly affected by the performance of the line in Anchorage, along the line route, and on the Kenai Peninsula.

TABLE 1-7 RAILBELT ELECTRICAL UTILITY CUSTOMERS (number of electric meters)			
Region	**Serving Utility**	**Number of Customers (approximate)**	**Total Customers by Region**
Fairbanks	Golden Valley Electric Association/Fairbanks Municipal Utilities System	38,000	38,000
Anchorage	Anchorage Municipal Light and Power	30,000	144,700
	Chugach Electric Association	67,500	
	Matanuska Electric Association	39,200	
Quartz Creek Transmission Line Route	Chugach Electric Association	2,000	4,400
	Seward Electric Association	2,400	
Kenai Peninsula Lowlands	Homer Electric Association	23,000	23,000
Total Railbelt Electrical Customers (meters) as of 2001			**210,100**

In the event of a total system blackout, though such an occurrence is unlikely, 210,100 customers would be without power. For outages affecting only the customers along the Quartz Creek transmission line route and on the Kenai Peninsula, 27,400 customers would be without power. For those situations requiring load shedding[6] in the Anchorage area, a percentage of those customers would be affected as well, depending on the degree of load shed to maintain system stability during a disturbance. For an interruption of the Quartz Creek transmission line where the system remains stable, the 4,400 customers along the line route would still experience a power outage. A discussion of the number of outages that would be avoided and the unserved energy that would be saved with construction of a new transmission line is included below under the reliability benefits section.

NERC conducted reliability assessments of the Railbelt system in 1990, with an update in 1998 (August 1998). Both the 1990 reliability assessment and the 1998 update reached the same conclusion regarding the Southern Intertie Project: that it is needed to improve overall system reliability and reduce load shedding due to outages of the existing Quartz Creek transmission line.

NERC also concluded that the existing Quartz Creek transmission line poses a significantly higher than traditional reliability risk for system-wide blackouts due to single contingency outages. In terms of traditional reliability criteria (a system must be able to withstand an outage of any single component), the proposed Project is needed to help improve the reliability of the electric supply to the Kenai Peninsula and Anchorage and Fairbanks areas (NERC 1990).

Power Technologies, Inc., in their 1989 study on Kenai Peninsula power export limits, concludes that at 70 MW power transfer, “the Kenai Peninsula-Anchorage transmission line operation goes beyond the Railbelt practice of lean system design. Nowhere in the Railbelt is so much resource so critically dependent on stability aids and a single line…. A new line from the Kenai Peninsula area to Anchorage would provide Kenai Peninsula-Anchorage interconnection reliability at least on a par with most of the remainder of the Railbelt electrical system” (AEA 1991).

Improved Reliability

The construction of the Project between Anchorage and the Kenai Peninsula would not only provide a parallel path to the existing Quartz Creek interconnection, but also would make the Kenai Peninsula system more of a loop arrangement. Construction of the Project would provide the second path needed to improve the reliability of the overall system. NERC offers the following observations (NERC 1990):

- A second transmission line interconnection from the Kenai Peninsula to the Anchorage area would improve reliability by preventing the shedding of consumer load if the

[6] Load shedding is discussed in more detail in the section on system stability.

existing interconnection line trips (with the possible exception of those times when the Kenai Peninsula generation is operated in anticipation of loss of the existing tie).

- NERC recognized that when Bradley Lake came into service, reliability would suffer without a second interconnection line. That is, the second line between the Kenai Peninsula and Anchorage area is necessary to support Bradley Lake and help reliably distribute the Bradley Lake capacity to the purchasing systems, minimize blackouts in the Kenai Peninsula, and minimize under-frequency load shedding in the Fairbanks and Anchorage areas.

Subsequent to gaining operating experience with the Bradley Lake Project as part of the available generation pool, adjustments to system operations have been necessary to maintain system reliability and minimize outages. The following two operational changes were implemented to mitigate load shedding and outages due to trips of the Quartz Creek transmission line:

- The existing Quartz Creek 115kV transmission line is operated at zero energy flow in anticipation of possible outages an average of 20 days per year in the winter due to storms, and 20 days during the summer due to construction along the line route. This is an inefficient way of operating the system because during the period the line is not transferring electrical power between the Kenai Peninsula and Anchorage area, higher cost alternate generation sources must be used. The Project would allow power transfers to continue even during poor weather/construction conditions, since the Project provides a second line to continue the power transfers during an outage of the existing line.

- Because of the power transfer limitations of the existing Quartz Creek transmission line, current practice is to maintain a minimum thermal generation of 25 MW on the Kenai Peninsula to support the Kenai Peninsula system in the event of a system disturbance and prevent a blackout of the Kenai Peninsula (CEA 1997).

Neither of these two operational constraints would be necessary if the Project were constructed. The costs of these two practices are discussed in Section 1.3.4, System Stability.

Benefits

Reliability is important because the value of electric power exceeds the cost of producing the power. The cost to a utility of an outage in terms of lost sales may be small, while the cost of that same outage to an industrial or commercial consumer may be very large. Depending on the type of customer, outage costs will vary. For example, expensive machinery or process functions may be damaged by an outage for large industrial customers, or a retailer may see his/her shop emptied when the lights go out, but residential customers might only have to defer recreational or household activities.

The number, magnitude, and duration of consumer outages determine reliability. Reliability benefits occur if consumer outages are reduced as a direct consequence of constructing a new transmission line. The proposed Project is expected to reduce both the frequency and duration of generation and transmission related outages (i.e., outages related to unexpected loss of generating units or the existing Quartz Creek transmission line) (DFI 1998).

As part of the DFI studies completed in 1989, a detailed evaluation of Railbelt customer outages attributable to causes associated with the Quartz Creek transmission line was completed. The DFI studies evaluated the outages to determine the benefits derived from eliminating outages due to the Quartz Creek transmission line, which are essentially the same as the cost of the outages to consumers in the Railbelt.

The value associated with avoiding an outage can be measured by the value of the unserved energy resulting from an outage. Unserved energy is the electric energy that would have been demanded by the customer if the customer were not subjected to the outage. The value of unserved energy is different for residential customers than for commercial/industrial customers, and also varies with the duration of the outage. The duration, or how long an outage lasts, is important because as duration increases, the total cost of the outage to a customer increases.

DFI's study included a detailed analysis of the Railbelt Utilities and a number of industry studies to determine the value of a kilowatt hour (kWh) of unserved energy[7]. Based on the distribution by customer class and duration, the average value of each kWh of unserved energy avoided as a result of the Project is about $21 in 1997 dollars (DFI 1998).

The amount of unserved energy saved and outages avoided as a result of construction of the Project were also determined in the DFI studies. The DFI studies calculated that the Project would reduce unserved energy on the Kenai Peninsula by an average of 82.3 megawatt hours (MWh) per year, an average of 45.0 MWh/year in Anchorage, and avoid one to two outages per year of 30 MW and one-hour duration (DFI 1989a).

The value of the avoided outages and unserved energy is the value of the reliability to be gained from construction of the Project. Based on the detailed analysis documented in the studies, the value of the reliability benefits to be gained from construction of the Project as calculated by DFI in the 1998 update report is $49.4 million (1997 dollars).

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[7] References cited in the DFI December 1989 study include:
[1] "Value of Service Reliability to Customers," Electric Power Research Institute (EPRI) Report EA-4494, prepared for EPRI by Criterion, Incorporated, San Diego, CA, May 1986.
[2] L.V. Scott, "Ontario Hydro Surveys on Power Systems Reliability: Summary of Customer Viewpoints," compiled in *The Value of Service Reliability to Customers*, EPRI Report EA-4494, May 1986.
[3] "Customer Demand for Service Reliability: Existing and Potential Sources of Information," prepared for EPRI by Laurits Christensen Associates, Madison, Wisconsin, May 1989.
[4] A. P. Sanghvi, "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience," *The Value of Service Reliability to Customers,* EPRI, EA-4494, May 1986.

A review of some of the significant factors associated with the system and selected outage data since the DFI studies were completed indicates that the electrical load on the system has grown and system operational practices have changed, but are not substantially different than when the studies were conducted. For example, since that time, the electrical load growth on the system has exceeded the earlier forecasts. In the 1998 DFI update, the load forecasts for the system from the earlier studies were compared with current forecasts. The current load forecasts for the Kenai Peninsula and Fairbanks area exceed the forecasts from the earlier study, and the load forecast for Anchorage is at the high end of the projections forecast at that time (Table 1-8).

TABLE 1-8
COMPARISON OF PEAK DEMAND FORECASTS FOR 2010 (MW)

	Anchorage	Kenai	Fairbanks
1989 Study			
Low	403	75	143
Mid	474	96	151
High	511	106	171
1998 Update Study			
Update	509	128	256

Source: DFI 1989a, 1998

Also, the interconnected system is essentially unchanged from a transmission viewpoint. The proposed transmission system improvements, including the Northern and Southern Intertie projects, have not been constructed. However, the two operational practices previously identified have helped to improve system reliability.

In the DFI studies, HEA was recorded as having about two outage hours per year per customer from power supply outages. Homer tracks outages in accordance with RUS guidelines. RUS Form 7 outage data supplied by HEA for the years 1988 to 2000 are shown in Table 1-9. RUS minimum goals for average annual service interruptions per customer are that interruptions should not exceed one hour per consumer per year for power supply and five hours per year from all causes.

TABLE 1-9
HEA ANNUAL OUTAGE HOURS PER CONSUMER
FIVE-YEAR AVERAGES

Year	Power Supply	Storm	Prearranged	Other	Total
1988 – 1992	2.68	2.63	0.12	2.79	8.22
1989 – 1993	1.80	2.81	0.09	2.59	7.29
1990 – 1994	1.60	3.01	0.09	2.33	7.03
1991 – 1995	1.41	2.22	0.10	2.18	5.91
1992 – 1996	1.01	2.04	0.08	1.73	4.86
1993 – 1997	0.98	1.44	0.04	1.71	4.17
1994 - 1998	0.66	1.33	0.04	1.63	3.66
1995 - 1999	0.41	1.24	0.04	1.61	3.30
1996 - 2000	0.24	1.36	0.03	1.21	2.83

Power supply outages are those associated with outages of generation, transmission, or load shedding to maintain system stability. A review of the power supply outage rate for HEA shows improvement since 1988. Contributing to this improvement are the operational practices developed in the last few years. These practices were not anticipated as being required when the 1989 studies were completed, before the Bradley Lake Project came into service in 1991, but have clearly been effective in helping to reduce the number of system outages.

1.3.2 Power Transfer Capability

System Deficiency

The secure power transfer between the Kenai Peninsula and Anchorage area is currently limited to 70 MW over the existing Quartz Creek transmission line (Power Engineers, Inc. 1996a). This limitation prevents the Railbelt Utilities from taking full advantage of the available generation on the Kenai Peninsula to maximize potential benefits from economy energy transfers.

Increased Power Transfer Capacity

The capability for increased secure power transfers between the Kenai Peninsula and Anchorage area would allow the Railbelt generation to be provided at a lower cost to consumers. Construction of the Project would cause the secure power transfer between the Kenai Peninsula and Anchorage to increase from 70 MW to 125 MW.

Benefits

The economy energy benefits accruing from the Project would be primarily due to disparities in marginal power production costs in the two areas, and because the optimal power flow across the existing Quartz Creek transmission line exceeds its present capacity. This would result in increased hydrothermal coordination[8] between the Bradley Lake and Copper Lake hydroelectric generation on the Kenai Peninsula and the thermal generation in the Anchorage area.

The value of these benefits has been studied and evaluated in detail (DFI 1989a, 1998). DFI calculated that on average, transfer levels from the Kenai Peninsula to Anchorage would increase by 113 gigawatt hours (GWh)/year, and by 147 GWh/year from Anchorage to the Kenai Peninsula due to the availability of the second line. The value of these benefits, which can also be viewed as cost savings, were calculated to be $37.8 million (1997 dollars) (DFI 1989a, 1998).

[8] Hydro-thermal coordination is the operation of hydro and thermal generation resources in a way that results in overall lower system operating costs.

1.3.3 Economic Generation

System Deficiency

Standard utility practice is to determine generation requirements and operate individual generation plants in a mix so as to meet the instantaneous demand for power and produce the least cost power. The present limitation on power transfers between the Kenai Peninsula and Anchorage area results in a more expensive mix of power being generated from the existing power plants to supply the load than if the Project were in service.

NERC concluded in their reliability assessment study that the existing single line transmission interconnections between the Kenai Peninsula and Anchorage area (the Quartz Creek transmission line) and between the Anchorage and Fairbanks areas constrain the sharing of generation between and among load centers and pose a significantly higher than traditional reliability risk for system-wide blackouts due to single contingency outages[9] (NERC 1990). This is particularly the case for generation at the Bradley Lake Project. Use of the generation at Bradley Lake in the north is limited by the 70 MW secure transfer level over the existing Quartz Creek transmission line.

Improved Economic Generation

The proposed Project would allow the Kenai Peninsula, Anchorage, and areas to the north to share the generation capacity more efficiently in each area and throughout the Railbelt. Increased transmission capacity allows one area to rely more heavily on generation capacity in another area, for capacity as well as for energy. For the Railbelt, the Project would allow Anchorage and Fairbanks to rely on a greater portion of the Kenai Peninsula generation capacity surplus for meeting capacity requirements, thus deferring the need to build new generation capacity.

Benefits

The Project would produce the following three types of benefits from capacity sharing, resulting in reduced costs for the generation of power:

- As load grows in a region, enough generation capacity must be available to meet the peak load in that region plus a required generation reserve margin, in case of system outages. Increased transmission line capacity and reliability increases access to surplus generation capacity in other regions, thus making it possible to defer capacity additions.

- The more interconnected a system, the lower the reserve margin that is required to provide the same level of reliability. Increasing transmission capacity increases the level

[9] A single contingency outage occurs with the loss of any one system component. A double contingency outage occurs with the loss of two system components during the same event.

of interconnectedness for the Railbelt, allowing utilities to permanently avoid or indefinitely postpone some capacity additions that would have been needed to maintain the desired reserve margin.

- Construction of the Project would allow the Railbelt Utilities to take advantage of the increased interconnectedness of the system by allowing them to share generation capacity, lines, and facilities more readily between areas, and so reduce the overall costs of producing and delivering power throughout the system.

The value of capacity sharing benefits were calculated by DFI in the 1989 study. As part of the update report (DFI 1998), DFI compared the load projections used in the 1989 study to current load projections for the same regions, as shown in Table 1-8.

DFI concluded in their 1998 update that the new forecasts for Anchorage and the Kenai Peninsula were somewhat higher than the previous 1989 forecasts, but not substantially. While the new forecast for the Fairbanks area is substantially higher, this has little impact on the economics of the Southern Intertie Project, because of the transmission limitations between Anchorage and Fairbanks (DFI 1998).

Demand growth, along with available capacity, determines the timing of any capacity sharing benefits. Demand tends to grow over time while, unless new generating units are installed, capacity holds steady or shrinks somewhat due to de-rating or retirement of older units. Therefore, capacity sharing benefits tend to first grow over time as the deficiency is eliminated in a relatively capacity-poor region, then fall as surplus disappears in the relatively capacity-rich regions.

The capacity sharing benefit in a year is the amount of capacity avoided or deferred in the year, measured in kilowatt-years, multiplied by the cost of a kilowatt-year of capacity. The cost of a kilowatt-year of capacity is composed of the annualized fixed cost of a new combustion turbine, including both the installed capital cost and fixed operation and maintenance cost. Costs for combustion turbines were reviewed and updated (DFI 1998). It was determined that a kilowatt-year of capacity is currently valued at $55 per kilowatt-year, in 1997 dollars. The new value is about 15 percent lower than the value calculated in the 1989 study.

The amount of capacity avoided or deferred and calculation of the resultant benefits (or cost savings) has been calculated by DFI. This was accomplished by determining the capacity avoidance and deferrals over time, accounting for the 30 percent of annual peak load reserve criterion stipulated in the Alaska Intertie Agreement (Addendum No. 1, page 1-2), and then applying the value of the capacity to determine the value of the benefits (DFI 1989b, 1998). In this manner a value for capacity sharing benefits for the Project was calculated to be $20.9 million (1997 dollars).

1.3.4 System Stability

System Deficiency

The existing Quartz Creek transmission line is limited to a 70 MW power transfer for secure or stable system operation. Under certain system configurations and power flows, when the existing Quartz Creek transmission line experiences an interruption, it is necessary to implement automatic load shedding schemes to immediately reduce the overall system load, so that the loads on the remaining generators and transmission lines are reduced to a level where the system will remain stable, and a system-wide blackout is prevented.

With the Bradley Lake Project on line, outages to the Kenai Peninsula due to instability from trips of the Quartz Creek transmission line during exports to the north were identified as potential problems (DFI 1989a). Subsequent to Bradley Lake coming on line, and based on operational experience to minimize instability from Quartz Creek transmission line trips, two previously discussed operational changes were implemented to mitigate load shedding and outages due to trips of the Quartz Creek transmission line. The present worth of the cost of reducing power transfers over the Quartz Creek transmission line to near zero during adverse weather conditions and summer construction has been calculated to be $11.4 million in 1997 dollars (DFI 1998).

The present worth of the cost of maintaining generation on line on the Kenai Peninsula at all times to provide spinning reserves has been calculated to be $10.7 million in 1997 dollars (DFI 1998). The benefit of the Project would be of the same value, since the need for these practices would be eliminated.

The Railbelt Utilities have been collecting information on overall system “deviations” as noted by a frequency swing of more than 0.1 Hertz from the normal 60-Hertz operating frequency. These events are summarized in Table 1-10 for 1993 through 2000.

TABLE 1-10
RAILBELT SYSTEMS
FREQUENCY DEVIATION AND LOAD SHEDDING EVENTS

Year	Number of Events	Number of Events with Load Shedding
1993	134	27
1994	128	9
1995	71	5
1996	121	4
1997	110	19
1998	145	9
1999	102	6
2000	69	10

Source: CEA 2001

Improved System Stability

The Project would enhance the stability performance of the Railbelt system by providing a second path for power to flow in the event of an interruption of the existing Quartz Creek transmission line, and would reduce the need for the implementation of load shedding schemes during system disturbances by increasing the secure power transfer between the Kenai Peninsula and Anchorage from 70 MW to 125 MW. The Quartz Creek transmission line is only one component of the integrated Railbelt electrical system. The addition of a second line between the Kenai Peninsula and Anchorage would support the system in Anchorage and areas to the north in the event of system disturbances in those areas (Power Engineers 1996a). Also, the system would be able to withstand a single contingency outage of the Quartz Creek transmission line while remaining stable for a 125 MW power transfer.

Benefits

The benefits of this enhanced stability would be evidenced in the increased reliability of the overall system and in the reduction of load shedding and system outages. The Project also would eliminate the need to maintain a minimum of 25 MW of generation on the Kenai Peninsula and to reduce the power transfer over the Quartz Creek transmission line to zero during adverse weather conditions and summer construction. As noted in the reliability discussion, the DFI studies estimated that the Project would reduce unserved energy on the Kenai Peninsula by an average of 82.3 MWh/year, an average of 45.0 MWh/year in Anchorage, and avoid one to two load shedding outages per year of 30 MW and one hour of duration. The value of the benefits due to increased system stability are accounted for in the reliability benefits of the Project.

1.3.5 Spinning Reserves

System Deficiency

Spinning reserves respond to changes in consumer demand and failures in the generation and transmission system. Spinning reserves improve reliability, but they are often expensive because some generation units must be operated partially loaded. The hydroelectric capacity at Bradley Lake on the Kenai Peninsula could provide a less expensive source for spinning reserves that otherwise would be provided by thermal generating units in the Anchorage area. Current operating practices and agreements among the Railbelt Utilities result in the provision of approximately 65 MW of operating reserve accessible in the Anchorage area (DFI 1989b). Limited amounts of this spinning reserve can be provided from outside the Anchorage area. Transmission capacity between Kenai Peninsula and Anchorage is a constraint on the transfer of spinning reserves between areas with only the single Quartz Creek transmission line in service.

Sharing and Reducing the Overall Need for Spinning Reserves

Construction of the Project would allow increased access to spinning reserves, so that spinning reserves for the system could be provided from the most appropriate generation source. This would reduce overall spinning reserve requirements.

DFI has estimated that approximately 30 MW of spinning reserve can be transferred from the Kenai Peninsula to Anchorage over the existing line. This transfer of spinning reserves results from the practice of distributing these reserves such that they are not all lost with a single event. With a second line in service, it is estimated that up to 50 MW of spinning reserves could be transferred from the Kenai Peninsula to Anchorage (DFI 1996).

Benefits

The benefits of increased spinning reserve sharing in the interconnected Railbelt system resulting from construction of the Project would be realized through lower generation costs. In addition, because existing generation resources can be shared more readily with a second line in service, system generation can be operated fewer hours overall, resulting in longer service life from existing power plants. These benefits accrue as a result of the additional 20 MW of spinning reserves that can be transferred to Anchorage from the Kenai Peninsula, and on this basis DFI calculated a $9.3 million (1997 dollars) benefit over the life of the Project.

1.3.6 <u>Line Losses and Maintenance</u>

System Deficiency

Electrical system studies by Power Engineers (1996a) indicate that line losses for the existing Quartz Creek intertie are calculated to be 7 MW (10 percent) for a 70 MW power transfer. Line losses are completely dependent on the current flow and the resistance of the line conductors and increase by the square of the current (e.g., if the current doubles, the losses increase by a factor of four).

Maintenance costs on the existing Quartz Creek transmission line are higher than they would be if the Project were constructed. Currently, because the existing line is the only path between the Kenai Peninsula and Anchorage, it is difficult to schedule outages for maintenance. Also, regardless of whether or not the Project is constructed, the existing line is scheduled for incremental line reconstruction over a multi-year period to replace aging facilities. Removing the line from service for reconstruction and to conduct maintenance activities requires additional generation to be operated both on the Kenai Peninsula and in the Anchorage area to support the load and provide the necessary spinning reserves. This additional generation on line increases overall system operating costs. In addition, the scheduling of construction crews to conduct the maintenance and reconstruction activities is restricted in the timing and duration available to conduct the maintenance, also resulting in increased costs.

Reduced Line Losses and Increasing Flexibility to Schedule Maintenance

Construction of the Project would reduce transmission system losses. With both the Project and the existing Quartz Creek transmission line in service, the secure transfer limit would increase from 70 MW to 125 MW, while losses would decrease to 5 MW (4 percent) at the higher 125 MW transfer level.

With the Project in service as a second path between Anchorage and the Kenai Peninsula, reconstruction and maintenance activities can be scheduled independently of generation resources, increasing flexibility in maintenance scheduling and reducing costs.

Benefits

While these benefits compose a smaller portion of the overall benefits of the Project, cost savings due to reduced line losses and more efficient scheduling of outages for maintenance and reconstruction activities would be realized through construction of the Project. The value of the benefits realized through reduced transmission losses are included as part of the economy energy transfer benefits. The present value of the benefits realized from the greater flexibility in scheduling and carrying out maintenance and reconstruction activities was calculated by DFI (1989a, 1998) to be $4.0 million in 1997 dollars.

1.3.7 Bradley Lake

The Bradley Lake Hydroelectric Project came into service in 1991, and since that time has provided an additional generation resource to the Railbelt system. With respect to Bradley Lake, construction of the Project to provide a second transmission line path with an increased secure transfer capability from 70 MW to 125 MW between the Kenai Peninsula and Anchorage would accomplish the following:

- allow Bradley Lake to increase system reliability by providing additional spinning reserves to support the system north of the Kenai Peninsula during disturbances and maintain system stability
- allow Bradley Lake to be more fully utilized to provide additional hydro-thermal coordination benefits with the thermal generating units in the Anchorage area through increased economy energy transfers

- allow the system increased access to Bradley Lake to share generation capacity with the areas north of the Kenai Peninsula, by adding flexibility to allocate the capacity of Bradley Lake to meet load, and making it possible to defer generation capacity additions to the system

- allow the utilities north of the Kenai Peninsula full access to and the benefit of their shares of the power generated by Bradley Lake

Construction of the Project would fulfill the need for additional transmission facilities that were recognized by the State of Alaska and Railbelt Utilities when the Bradley Lake Project was constructed, and would allow Bradley Lake to contribute its full potential to the system. The benefits resulting from utilizing Bradley Lake to its full potential are included in the overall benefits calculated for the Project (DFI 1998).

1.4 PROJECT BENEFITS AND COSTS

The benefits from construction and operation of the Project have been studied and evaluated in detail by DFI (1989a), AEA (1991), and were updated by DFI (DFI Aeronomics) in 1998. This section describes the overall benefits that would result from construction of the Project and also details estimated Project construction and life cycle costs.

Because the interconnected system operates in an integrated manner, benefits from the Project have been evaluated by reviewing the effect of the Project on the overall system. Determination of a meaningful allocation of Project benefits to each of the members of the IPG is not practical. Each of the utilities has different rate structures, power purchase agreements, and operating agreements in effect. As the Railbelt Utilities transact business among themselves and their customers, agreements and rates can and do change. As a result, any allocation of Project benefits would quickly become out of date. The benefits as presented therefore accrue to the overall system and the IPG as a whole.

The December 1989 DFI report focused on the benefits of the Project, and evaluated benefits for the Project in several different categories. The 1998 update focused on the key data values underlying the estimates and determined how the data values have changed. An update of the Project benefits analysis was completed because several factors affecting the value of the benefits (or cost savings) have changed since the 1989 study. These factors include the following:

1. Projected fossil fuel prices are substantially lower now, in real terms.

2. The price of new combustion turbine generating units has dropped, in real terms.

3. A number of existing Railbelt generating units that had been scheduled to be retired by the turn of the century or soon after have had their planned operating lives extended.

4. The Bradley Lake Project on the Kenai Peninsula started operating in 1991.

As part of the 1998 update study, the effect of each of these factors on the value of the Project benefits was evaluated and the benefit calculations updated. In addition, all of the values were converted to 1997 dollars for comparison with current cost estimates for the Project (DFI 1998). Table 1-11 summarizes the benefit categories and the updated present worth of the benefits resulting from the analysis.

TABLE 1-11
NET PRESENT WORTH OF BENEFITS FOR THE PROJECT

Category	Updated Value (millions of 1997 $)
Capacity sharing	$20.9
Economy energy transfer	$37.8
Reliability	$49.4
Spinning reserve sharing	$9.3
Reduced line maintenance	$4.0
Avoid minimum CT generation on Kenai (*)	$10.7
Avoid not loading line during bad weather/construction (*)	$11.4
Total	$143.5

Notes:
1. Present worth in 2004, the first year of operation for the Project.
2. All present values calculated using discount rate of 4.5 percent, as recommended by AEA.
3. Economy energy transfer includes transmission losses and gas royalties.
* Asterisks indicate benefits not considered in 1989 due to different assumptions for system operating parameters prior to completion of the Bradley Lake Hydroelectric Project.

Since the 1998 update study was completed there have been two additional changes in the factors affecting the value of the benefits. However, these changes do not substantially impact the value of the overall benefits of the project. First, fossil fuel (natural gas) prices have risen this past year, negating some of the earlier decline in prices mentioned above. This rise in gas prices would have the effect of increasing the overall value of the benefits from the Project. Second, the Soldotna combustion turbine has been moved to the Nikiski Fertilizer Plant and is now operated in a cogeneration mode. The Soldotna unit has partially supplied the requirement for a minimum of 25 MW of generation on the Kenai Peninsula as discussed in previous sections. Operation of the unit in a cogeneration mode tends to lower the cost of providing the 25 MW minimum generation requirement, but not substantially.

AEA also evaluated the benefits of the Project based on DFI's quantitative analysis, and from the point of view of accepted industry practice and compliance with NERC and ASCC criteria for planning and operation of the Alaska interconnected system. While AEA noted that there can be a wide range of benefit values associated with the Project, based on the qualitative and quantitative analyses conducted for the Project, the life cycle benefits of the Project will exceed the costs, and the Project is needed and should be constructed (AEA 1991).

It is important to note that the value of the benefits from the Project can also be viewed as cost savings. If the Project is not constructed, the unrealized benefits would continue to be part of the overall cost of producing electricity, and those costs would be reflected in the rates for electricity paid by consumers.

1.4.1 Construction and Life Cycle Costs

The construction costs for the Project were estimated by Power Engineers, Inc. in 1996 and were updated in 1997 and 1998 (Power Engineers 1998) to reflect the potential facility requirements identified as part of the current siting studies being conducted for the EIS for the Project. The updated cost study also determined the present value of the operation and maintenance and submarine cable replacement costs over the 40-year project life. The results of this study are summarized in Table 1-12. For a description of the routes see Chapter 2, Sections 2.6.2 and 2.6.3.

TABLE 1-12
SUMMARY OF BENEFITS AND COSTS
(millions of 1997 dollars)

	Tesoro Route (Route Options A, D, N)	Enstar Route (Route Options E South, F, H, K)
Constructed cost	$99.5	$90.2
Present worth* of operation and maintenance costs	$4.3	$6.1
Present worth of cable replacement costs	$10.7	$3.3
Total life cycle cost	$114.5	$99.6
Present worth of project benefits	$143.5	$143.5
Benefit/cost ratio	1.25	1.44
Adjusted** benefit/cost ratio range	2.12	2.72

* A discount rate of 4.5 percent was used as recommended by the AEA based on the long-term real cost of money (AEA March 1991).

** The adjusted benefit/cost ratio is calculated by subtracting the $46.8 million state grant funding for the Project from the constructed cost and dividing into the benefit value.

1.4.2 Construction Cost

To determine the construction cost for the Project, conceptual designs were prepared for each aspect of the Project and are documented in the *Power Engineers Cost Summary Report* (Power Engineers 1998). Determination of the construction costs included specifying typical overhead line structure types by line segment depending on expected weather and terrain conditions, and preparing preliminary layouts for the substation and cable transition stations. For the underground and submarine cable installations, typical cable sizes and installation techniques, along with land and submarine ground or bottom conditions, were reviewed as well. Where appropriate, vendor quotations for materials were obtained and combined with historical prices from actual projects. Estimated costs for the submarine cable and installation were compared to the actual bids received by CEA (January 1998) for replacement of their Knik Arm cables. Also included in the estimate were both winter and summer construction, and air support for transportation of personnel and materials.

Operation and Maintenance Costs

Annual operation and maintenance costs were determined based on a typical program of annual maintenance for each type of facility, and the present worth was calculated over the life of the Project.

Submarine Cable Replacement Costs

Based on its experience with submarine cables installed in the Knik Arm since 1967, CEA determined typical replacement intervals for submarine cables in that environment. The replacement intervals depend on whether the submarine cable is installed in an embedded or non-embedded configuration. The non-embedded configuration, in which the double-armored submarine cable is simply laid on the bottom, is used in locations where it is not practical to embed the cable. In the embedded configuration, the cable is physically buried in the bottom using special equipment. Based on discussions with CEA personnel, cable laying contractors experienced with conditions in the Knik and Turnagain arms, and bottom and side scan sonar surveys conducted along the proposed marine routes during the summer of 1996, appropriate replacement intervals for the Southern Intertie submarine cable were determined. The cable replacement schedule for the non-embedded cables on the Tesoro Route is to replace two single-phase cables or one three-phase cable twice during the Project life (years 17 and 34), depending on the type of cable initially installed. For the Enstar Route, the cable can be embedded for the entire distance and the cable replacement schedule for this route is one single-phase cable or one three-phase cable once during the Project life (year 30). The present worth of the cable replacement costs, based on the cable replacement schedule, was included in the total life cycle costs of the Project for both the Tesoro or Enstar routes.

Life cycle costs are the sum of the constructed cost, plus the present worth over the Project life of the operation and maintenance and cable replacement costs. The present worth of the Project benefits is the total from Table 1-11. Benefit/cost ratios are calculated for the Tesoro and Enstar routes as shown in Table 1-12.

1.5 SCOPING AND PUBLIC INVOLVEMENT

1.5.1 Process Summary

The environmental review process for the Southern Intertie Project began with a Route Selection Study in 1995. Initially, the Applicant’s consultants contacted agencies and organizations having jurisdiction and/or specific interest in the Project. The purpose was to inform them about the

Project, verify the status and availability of environmental data, and request data and comments on the route selection process. Additional contacts were made throughout the process to clarify or update information. The resulting documentation is contained in the *Southern Intertie Project Route Selection Study Phase 1 - Environmental Section Report* that was submitted to RUS in June 1996. A series of agency and interagency meetings as well as two public meetings (January and February 1996) were also conducted.

The NEPA process for the Southern Intertie Project began with the publication of a Notice of Intent in the *Federal Register* by the RUS in October 1996. The notice announced the intent of RUS to prepare an EIS for the Project and the schedule for the three public scoping meetings. Three public scoping meetings were conducted in November 1996—Anchorage on November 12, Cooper Landing on November 13, and Soldotna on November 14. In addition to the public scoping meetings, RUS conducted an interagency meeting on November 6, 1996 in Anchorage. The purpose of the meeting was to (1) invite the participation of other federal, state, and local agencies; and (2) solicit comments and/or concerns regarding issues that should be addressed in the EIS. Nine agencies were represented at the meeting. Two community working groups (CWG) were also assembled in 1997, one on the Kenai Peninsula and the other in Anchorage. Each group met five times at key milestones during the process. Additional information on the public involvement process is contained in Chapter 4.

1.5.2 Analysis of Issues

The applicability and importance of the issues identified during the scoping and public involvement process varied among the regions that comprise the Project area. Issues related to purpose and need, and right-of-way limitations and restrictions are applicable to each region.

In Anchorage, the key issues reflect the urban setting and the Municipality of Anchorage's orientation towards recreation, tourism, and visual quality. Input from the Anchorage CWG and Municipal Planning Department emphasized the importance of visual quality to communities throughout the Municipality.

The Chugach Mountains, including Chugach State Park and Chugach National Forest, present a wide range of issues, including rural land use, recreation, tourism, public land management, watershed management, visual resources, biology, cultural resources, and avalanche hazards. For example, views from the Seward Highway, a National Scenic Byway, forest recreation areas, and Cooper Landing have been identified as significant issues to the Project by the agencies and the Kenai Peninsula CWG. Crossing Kenai Lake and the associated visual and possible watershed impacts also have been identified as key issues. The avalanche hazard associated with Chugach Mountains is a fundamental issue related to the purpose and need for the Project.

Submarine cables crossing the Turnagain Arm encounter both environmental and engineering constraints within the marine environment. The environmental sensitivity of the coastal wetlands associated with the Anchorage Coastal Wildlife Refuge (ACWR) and Chickaloon Flats has been identified as a key issue. Engineering issues include risk of failure and potential for embedding the cable due to ocean currents and boulders, gravel, and trenches on the ocean floor.

The key issues for the Kenai Lowlands are urban and rural land use, recreation and tourism, public land management, watershed management, visual resources, and biological resources. For example, existing and planned development in the Nikiski and Soldotna areas, recreation along the Kenai River, wildlife management in the KNWR, and views of the Aleutian and Alaskan ranges across Cook Inlet represent the broad range of public concerns. A separate listing of the issues and a summary of the comments received concerning each issue is presented in Chapter 4.

1.6 DECISIONS TO BE MADE

1.6.1 Rural Utilities Service

The RUS decision will be the identification of a preferred route and whether to provide financial assistance to participating RUS borrowers.

1.6.2 U.S. Fish and Wildlife Service

The USFWS decision will be whether to issue a right-of-way permit to IPG to construct and operate the proposed facilities on lands within the KNWR. The decision will be made in accordance with the requirements of Title XI of ANILCA for access by transportation and utility systems across conservation system units in Alaska. The USFWS must also meet its responsibilities under the National Wildlife Refuge System Administration Act of 1966 [(NWRSAA) (16 U.S.C. 668dd)], as amended, which stipulates that proposed refuge uses undergo a compatibility determination, as described below.

Compatibility Determination

The NWRSAA, as amended, requires that the Secretary of the Interior, before permitting any use of a national wildlife refuge, must determine that the use is compatible with the purposes for which the refuge was established, and with the mission of the NWRS. ANILCA [Section 304(b)] adopted the compatibility standard and requirement of the NWRSAA. The ANILCA Title XI process also provides that applicable law shall apply with respect to the authorization and administration of transportation or utility systems across conservation units, and includes a determination of compatibility with the unit's purposes as one of the criteria an agency must consider when reviewing a right-of-way application.

A compatible use is defined as a proposed or existing wildlife-dependent recreational use, or any other use of a national wildlife refuge, that, based on sound professional judgment, will not materially interfere with or detract from the fulfillment of the NWRS mission or the purpose(s) of the national wildlife refuge. The proposed construction of the Southern Intertie Project across KNWR must be found to be compatible to be permitted. If the proposed project is found to be not compatible, it cannot be legally permitted.

A compatibility determination will be prepared by the USFWS following public review and comment on the draft project EIS. Public comments received during the review will be used in the compatibility determination process. The compatibility determination is a decision document that is not subject to appeal; however, a finding of "not compatible" which by itself, or combined with other factors, results in a denial of the right-of-way permit application, may be appealed to the President following ANILCA Title XI procedures. The President, if receiving an appeal, would have four months to decide whether the proposed utility system would be compatible with the purposes for which the Refuge was established.

In providing comment to the USFWS to assist in the preparation of the compatibility determination, the public should focus on providing information on how they believe that the proposed project would impact the Refuge's ability to meet its mandated purposes and the mission of the NWRS. KNWR purposes, as established by ANILCA, include (1) to conserve fish and wildlife populations and habitats in their natural diversity including, but not limited to, moose, bears, mountain goats, Dall sheep, wolves and other furbearers, salmonids and other fish, waterfowl and other migratory and nonmigratory birds; (2) to fulfill the international treaty obligations of the United States with respect to fish and wildlife and their habitats; (3) to ensure, the maximum extent practicable and in a manner consistent with the first purpose, water quality and necessary water quantity within the refuge; (4) to provide in a manner consistent with the first and second purpose, opportunities for scientific research, interpretation, environmental education, and land management training; and (5) to provide, in a manner compatible with the four previous purposes, opportunities for fish and wildlife-oriented recreation. In addition, the purposes of the Wilderness Act are supplemental to Refuge purposes for designated Wilderness Areas. The purposes of the Wilderness Act are to secure an enduring resource of wilderness, to protect and preserve the wilderness character of areas within the National Wilderness Preservation System, and to administer the wilderness system for the use and enjoyment of the American people in a way that will leave the areas unimpaired for future use and enjoyment of wilderness. The Wilderness Act purposes only apply to those lands specifically designated as wilderness, but proposed uses outside of wilderness that may impact wilderness purposes inside designated areas, must be evaluated as part of the compatibility determination process. Finally, the NWRS mission, as stated in the NWRSAA is "To administer a national network of lands and waters for the conservation, management, and where appropriate, restoration of the fish, wildlife, and plant resources and their habitats within the United States for the benefit of present and future generations of Americans."

The compatibility determination will be completed subsequent to the public review of the DEIS. Information obtained in the DEIS about the Enstar Route (across the Refuge), and the environmental consequence of the proposed action, can be used by the public in making their comments to address how they believe such activities would impact the Refuge's ability to meet its purposes and the system mission. These comments may be included along with other general comments on the DEIS to the RUS under the guidance provided on submitting comments in this document. Comments regarding solely the compatibility determination may also be sent directly to Refuge Manager, Kenai National Wildlife Refuge, P.O. Box 2139, Soldotna, Alaska 99669; or faxed to (907) 262-3599. It is unnecessary to send comments to both the Refuge Manager and RUS. Any comments regarding compatibility sent directly to the Refuge Manager must be submitted within the same time frame as required for all comments on the DEIS sent to the RUS.

The Refuge Manager, after reviewing the public comments, will complete the compatibility determination using sound professional judgment to reach conclusions that are consistent with principles of sound fish and wildlife management and administration, available science and information, and applicable laws. The Refuge Manager must consider not only the direct impacts of a use but also the indirect impacts associated with the use and the cumulative impacts of the use when conducted in conjunction with other existing or planned uses of the Refuge, and uses of adjacent lands or waters that may exacerbate the effects of a Refuge use. The compatibility determination will be included in the Record of Decision supporting the USFWS's final action on the right-of-way application.

More information about KNWR can be obtained at http://Kenai.fws.gov/, and for the refuge compatibility determination process, at http://www.r7.fws.gov/compatibility/index.html.

1.6.3 U.S. Army Corps of Engineers

Regardless of which routing alternatives are selected, certain construction activities will require permits from the USACE. The USACE decision will be whether to issue those permits.

The USACE decision whether to issue a permit will be based on an evaluation of the probable impacts of the proposed activity and its intended use on the public interest. The benefits that reasonably may be expected to accrue from the proposal must be balanced against its reasonably foreseeable detriments. The decision whether to authorize a proposal, and if so, the conditions under which it will be allowed to occur, are therefore determined by the outcome of the general balancing process.

This permit will be issued or denied under the following authorities:

- Perform work in or affecting navigable waters of the United States – Section 10 Rivers and Harbors Act 1899 (33 U.S.C. 403)

- Discharge dredged or fill materials into waters of the United States – Section 404 Clean Water Act (33 U.S.C. 1344), including public interest review considering the guidelines set forth under Section 404(b) of the Clean Water Act (40 CFR 230)

- Transportation and utility systems in, across, and access into, Conservation Systems Units in Alaska under ANILCA (43 CFR Part 36)

Concurrent with the publication of the DEIS, the USACE has issued a Public Notice of Application for Permit (see Volume II, Appendix F). This notice is intended to solicit comments from the public; federal, state, and other local agencies and officials; Indian tribes; and other interested parties in order to consider and evaluate the impacts of this proposed activity. Any comments received will be considered by the USACE to determine whether to issue, modify, condition, or deny a permit for this proposal.