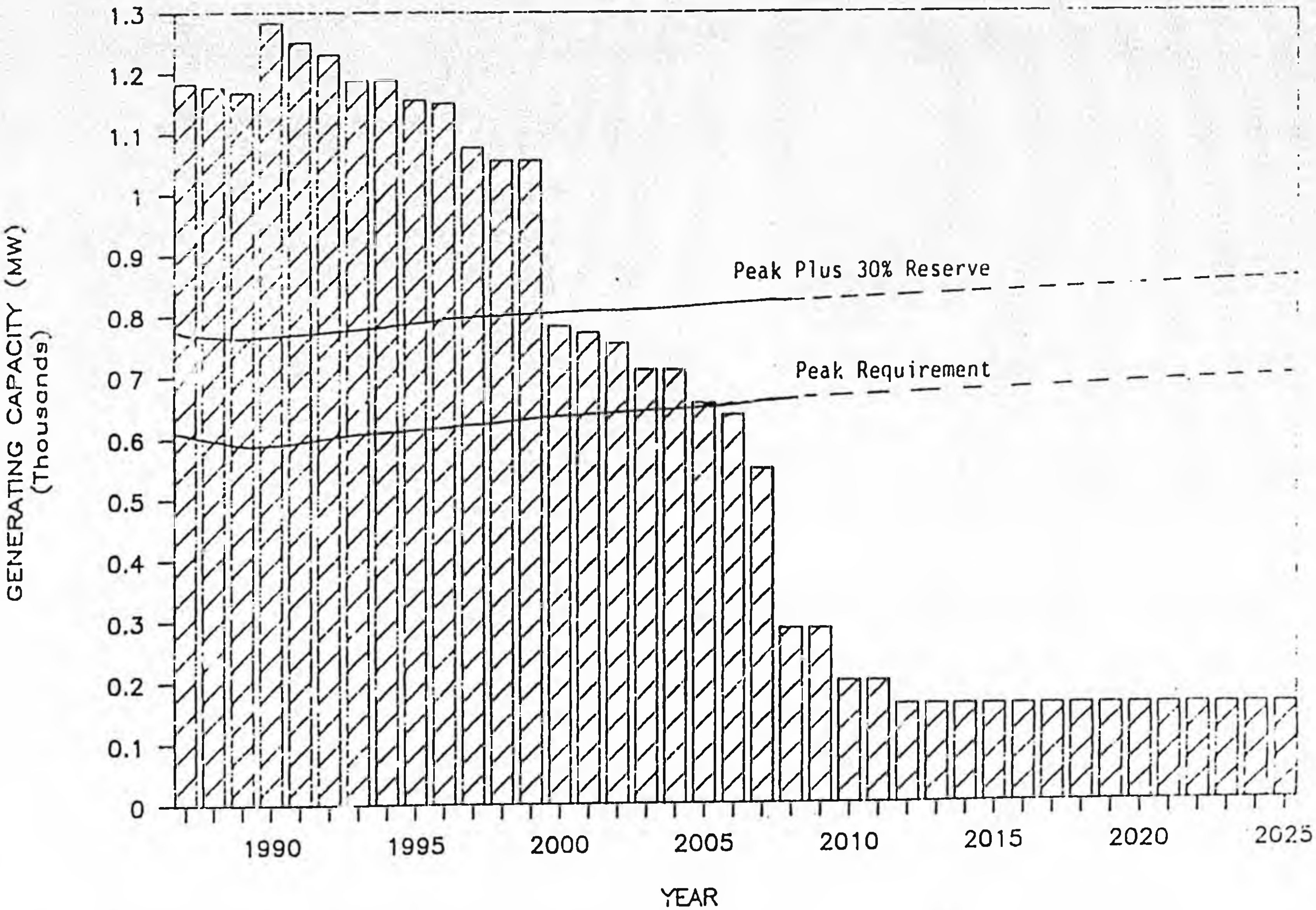
ALASKA LEGISLATURE COMMITTEE FILES 1987-1988 8672

4904 HRES RAILBELT ENERGY 470

FIGURE 2

GENERATING CAPACITY NET OF RETIREMENT

RAILBELT



Prepared by the House Research Agency, March 1987.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

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March 18, 1987

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay and Gretchen Keiser
Legislative Analysts

RE: Railbelt Energy Analysis
Research Request 87.114

As presented in the House Research Agency Railbelt Energy Analysis outline, this memorandum covers Railbelt energy demand and the Bradley Lake project feasibility analysis. The first section of the memorandum provides information on Railbelt energy demand and utility capacity. This discussion is followed by an examination of the Bradley Lake feasibility analysis prepared by the Division of Policy in the Governor's Office. The final section recalculates Bradley Lake net benefits based on revised projections of Railbelt energy demand and capacity requirements and other assumptions incorporated in the Division of Policy's analysis.

SUMMARY OF FINDINGS

- This analysis of Railbelt energy demand is based on an examination of projected peak demand, capacity reserve requirements, capacity retirement schedules, the Alaska Department of Revenue's statewide population forecast, and Public Utility Regulatory Policy Act (PURPA) facilities planned in the Railbelt area.[1] Because of the influence of population on energy demand, there is no basis for forecasting a near-term increase in energy consumption while population in the Railbelt is declining (page 3).

- Actual 1986 net generation and peak demand were seven percent less than APA projections. Our forecast, for the years 1987 through 2010, incorporates this initial decline in energy consumption. It

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[1]Public Utility Regulatory Policy Act (PURPA) electrical power production in this memorandum generally refers to small power production and cogeneration facilities as defined and regulated by Chapter 1 of the Federal Energy Regulatory Commission, PURPA of 1978.

also incorporates further reductions in energy demand as a result of near-term population declines. The APA forecast, prepared in 1985, has not been subsequently adjusted for lower actual use in 1986. The APA forecast for required production capacity overestimated required capacity by 12.1 percent in 1986 and is 33.9 percent above our adjusted forecast by the year 2001 (pages 3-6).

- For the Railbelt as a whole, existing electrical production capacity (plus PURPA generators) will satisfy peak and reserve requirements until the year 2000. There will be over 28 percent more capacity than required for reserve margins until 2000 as a result of: 1) past power plant construction based on earlier population growth projections; and 2) lower reserve requirements as a result of integrating stand-alone systems (pages 6-18).

- Following revisions to assumptions regarding the costs to complete Bradley Lake and the projected Cook Inlet gas prices and escalation rates, the Division of Policy's analysis concluded that Bradley Lake is still economically feasible and is likely to be less expensive than alternative gas generation over the 50-year period of analysis (pages 18-20).

- The division's assumptions regarding gas prices appear to be reasonable. However, we disagree with the division's fundamental assumption regarding future Railbelt energy demand and their conclusion that additional capacity will be needed by 1991. We believe the division's analysis addresses the issue as "which is the less expensive option to construct excess capacity?" instead of "what is the least cost means of meeting projected Railbelt demand for electrical power?" (page 20).

- Following revisions to assumptions regarding gas plant fuel efficiencies and cost to complete Bradley Lake, we recalculated the net savings of Bradley Lake under three scenarios. The base case scenario, which assumes (as the Division of Policy did) that new power is needed by 1991, projects Bradley Lake net savings of $86 million--virtually identical to those projected by the Division of Policy. Our second scenario, which delays Bradley Lake or gas plant construction until power is needed, indicates that Bradley Lake would not be economically feasible if completion of the project were delayed until Railbelt energy demand warranted new capacity in the late 1990s (pages 21-24).

- Our third scenario--which compares Bradley Lake if constructed as currently scheduled with a gas plant constructed when power is needed in the late 1990s--projects considerably lower Bradley Lake net savings of $36 million. The positive net savings indicate that the project should proceed, although from a public policy perspective, the relatively low net savings increase the risk that in retrospect we will have made a poor decision if forecast gas prices are only slightly lower than assumed (page 23).

- The analysis is sensitive to changes in other assumptions to varying degrees. The analysis is most sensitive to assumptions which directly affect annual fuel costs--including the gas turbine fuel efficiency assumption (pages 24-27).

RAILBELT ENERGY DEMAND AND CAPACITY REQUIREMENTS

This analysis of Railbelt energy demand is based on an examination of projected and peak demand, capacity reserve requirements, and retirement schedules that were developed by the Alaska Power Authority (APA). The demand projections and capacity retirement schedules were prepared by the APA based on estimates obtained from Railbelt utilities. In addition, we examined the Department of Revenue's (DOR) historic and forecast population numbers and information from the Alaska Public Utilities Commission (APUC) on Public Utility Regulatory Policy Act (PURPA) facilities planned in the Railbelt region.

Our analysis also looks at electrical energy demand and power plant capacity from a regional rather than individual utility standpoint. This perspective is used because the existing Alaska Intertie Agreement and proposed Bradley Lake Project Power Sales Agreement provide an interconnected, organizational framework and facilities for energy planning in the Railbelt as a region as opposed to stand-alone public utilities. Furthermore, the Railbelt Energy Fund is intended to provide energy services to residents of the region rather than to individual utilities in the Railbelt.

Energy Demand

In analyzing Railbelt energy demand, we reviewed historic net generation and the APA's projected demand (Attachment A). These trends were examined in light of historic and projected state population figures (Table 1) and actual 1986 net generation and peak demand (Table 2).[2] The historic energy generation and population figures, as well as numerous models of energy demand, indicate that population is a primary variable in determining energy demand levels. **Because of the influence of population on energy demand, there is no basis for forecasting a near-term increase in energy consumption while population in the Railbelt is declining.** We, therefore, adjusted the energy demand forecast to reflect this projected population decline.

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[2] The Alaska Department of Revenue historic and forecasted number of Permanent Fund Dividend check recipients is used as a proxy for state population trends.

TABLE 1
ALASKA STATE POPULATION* 1981 - 1999

YEAR	DIVIDEND RECIPIENTS (in thousands)
1981	430.1
1982	478.8
1983	486.8
1984	483.1
1985	520.9
1986	530.8
1987	527.2
1988	525.8
1989	528.1
1990	530.3
1991	532.5
1992	534.6
1993	536.8
1994	538.9
1995	541.1
1996	543.3
1997	545.5
1998	547.8
1999	549.9

* Based on the number of Permanent Fund dividend check recipients.

Source: Alaska Department of Revenue, March 1987.

Prepared by the House Research Agency, March 1987 (POP; 861217-29).

TABLE 2

PROJECTED* AND ACTUAL 1986 RAILBELT PEAK DEMAND AND CAPACITY AND RESERVE REQUIREMENTS.

CAPACITY REQUIREMENTS

UTILITY	PROJ. 1986	ACTUAL 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Anchorage																										
ML&P	164.0	143.0	141.6	141.1	141.7	142.3	143.0	143.7	144.4	145.1	145.9	146.6	147.3	148.1	148.8	149.6	150.3	151.1	151.8	152.6	153.3	154.1	154.9	155.5	156.4	157.2
CEA (retail)	191.3	130.6	178.8	178.3	179.0	179.7	180.6	181.5	182.4	183.3	184.2	185.1	186.1	187.0	187.9	168.9	189.8	190.8	191.7	192.7	193.6	194.6	195.6	196.6	197.5	[illegible]
MEA	90.3	91.5	90.5	90.3	90.7	91.0	91.5	91.9	92.4	92.9	93.3	93.8	94.3	94.7	95.2	95.7	96.2	96.7	97.1	97.6	98.1	98.6	99.1	99.6	100.1	[illegible]
Subtotal	445.6	415.1	410.9	409.7	411.4	413.0	415.1	417.1	419.2	421.3	423.4	425.5	427.7	429.8	432.0	434.1	436.3	438.5	440.7	442.9	445.1	447.3	449.5	451.8	454.1	[illegible]
Kenai Peninsula																										
HEA	79.0	68.4	67.7	67.5	67.8	68.1	68.4	68.7	69.1	69.4	69.8	70.1	70.5	70.8	71.2	71.5	71.9	72.3	72.6	73.0	73.3	73.7	74.1	74.4	74.8	[illegible]
SES	7.0	6.3	6.2	6.2	6.2	6.3	6.3	6.3	6.4	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	[illegible]
Subtotal	86.0	74.7	[illegible]	73.7	74.0	74.3	74.7	75.1	75.4	75.8	76.2	76.6	77.0	77.3	77.7	78.1	78.5	78.9	79.3	79.7	80.1	80.5	80.9	81.3	81.7	[illegible]
Fairbanks																										
FMUS	29.3	28.5	28.3	28.2	28.3	28.5	28.5	28.7	28.9	29.0	29.2	29.3	29.5	29.6	29.8	29.9	30.1	30.2	30.4	30.5	30.7	30.8	31.0	31.1	31.3	[illegible]
GVEA	85.8	85.2	84.3	84.1	84.4	84.8	85.2	85.6	86.0	86.5	86.9	87.3	87.8	88.2	88.7	89.1	89.5	90.0	90.4	90.9	91.4	91.8	92.3	92.7	93.2	[illegible]
Subtotal	[illegible]	113.8	112.7	112.3	112.8	113.2	113.8	114.4	114.9	115.5	116.1	116.7	117.2	117.8	118.4	119.0	119.6	120.2	120.8	121.4	[illegible]	122.6	123.2	123.9	124.5	[illegible]
TOTAL PEAK DEMAND	645.7	603.6	[illegible]	595.8	598.2	600.5	603.5	605.6	609.6	612.6	615.7	618.8	621.9	625.0	628.1	631.3	[illegible]	637.6	640.8	644.0	647.2	650.4	653.7	657.0	[illegible]	[illegible]
RESERVE REQUIREMENTS																										
Anchorage	----	124.5	123.3	122.9	123.4	123.9	124.5	125.1	125.8	126.4	127.0	127.7	128.3	128.9	129.6	130.2	130.9	131.5	132.2	132.9	133.5	134.2	134.9	135.5	136.2	[illegible]
Kenai	----	22.4	22.2	22.1	22.2	22.3	22.4	22.5	22.6	22.7	22.9	23.0	23.1	23.2	23.3	23.4	23.6	23.7	23.8	23.9	24.0	24.1	24.3	24.4	24.5	[illegible]
Fairbanks	----	34.1	33.8	33.7	33.8	34.0	34.1	34.3	34.5	34.7	34.8	35.0	35.2	35.4	35.5	35.7	35.9	36.1	36.2	36.4	36.6	36.8	37.0	37.2	37.3	37.5
TOTAL RESERVE REQUIREMENT	----	181.1	179.3	178.7	179.4	180.2	181.1	182.0	182.9	183.8	184.7	185.6	186.6	187.5	188.4	189.4	190.3	191.3	192.2	193.2	194.2	195.1	196.1	197.1	198.1	[illegible]
TOTAL SYSTEM CAPACITY REQUIREMENT		784.7	776.8	774.5	777.6	780.7	784.6	788.5	792.5	796.4	800.4	804.4	808.4	812.5	816.6	820.6	824.7	828.9	833.0	837.2	841.4	845.6	849.8	854.0	858.3	[illegible]
APA FORECAST		879.3	[illegible]	918.9	926.4	951.1	962.4	973.6	992.2	1004.3	1004.3	1004.3	1008.7	1022.8	1064.6	1084.6	1104.1	--	--	--	--	--	--	--	--	--
Percent Excess Demand in APA Forecast		12.1	16.6	18.6	19.1	21.8	22.7	23.5	25.2	26.1	25.5	24.8	24.8	25.9	30.4	32.2	33.9	--	--	--	--	--	--	--	--	--

* Based on APA and Railbelt utilities' forecast demand.

Source: Alaska Power Authority, Alaska Public Utilities Commission, Railbelt Utilities, Alaska Dept. of Revenue.

Prepared by the House Research Agency, March 1987 (Demand2; 861217-29).

Actual 1986 net generation and peak demand were seven percent below APA projections. We substituted actual 1986 energy usage for the APA forecast in Table 2. In subsequent years, population projections were used as an indicator of the direction and magnitude of changes in energy demand.[3] The Department of Revenue forecasts a decline in population between 1986 and 1989; the Alaska population is not expected to return to 1986 levels until approximately 1991.[4] Based on this forecast, Table 2 shows a similar decline in Railbelt energy demand for the years 1987 through 1989.

Beginning in 1990, demand increases proportionally to the slight 0.5 percent annual increase in population until the year 2000. This projection closely coincides with Chugach Electric Association's revised demand forecast of 0.55 percent annual growth as presented in the Division of Policy's feasibility analysis. Projected electrical energy demand for the years 1991 through 2010 is based on a 0.5 percent compounded growth rate.

Utility Capacity and Retirement Schedules

Information on current Railbelt standing capacity and retirement is presented in Tables 3 - 5 for the subregions of Anchorage, the Kenai Peninsula, and Fairbanks. These tables are identical to those prepared by the APA with the exception of the addition of three PURPA power plants planned in the Anchorage area and one PURPA power plant planned in the Fairbanks area. Plant retirement schedules have not been altered because the utilities believe these November 1985 Susitna hydroelectric project retirement projections continue to be valid.[5]

The utilities' retirement schedule of installed capacity is referred to as conditional retirement. It is the anticipated date that generating turbines require replacement or rebuilding. Conditional retirement is influenced by both physical and economic factors. Physical factors include the level of facility usage and the consequent "wearing out" of equipment. Because it is possible to completely or partially rebuild natural gas turbines, their retirement schedules can be incrementally adjusted. These conditional retirement dates can, therefore, be influenced significantly by economic and technological factors such as the price of natural gas and fuel efficiency of equipment.

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[3]Because the majority of the state's population resides in the Railbelt, we believe these statewide numbers are a reliable indicator of changes in the Railbelt population.

[4]The 1986 number is based on the number of residents who claimed a Permanent Fund Dividend check for that year. They could, however, have left the state before the end of calendar year 1986.

[5]Richard Emerman, Economist, Alaska Power Authority, Anchorage, personal communication, March 4, 1987.

TABLE 3
POWER PRODUCTION CAPACITY AND RETIREMENT IN ANCHORAGE

Unit name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
Eklutna	APAd	Hydro	30.0	----
AMLPCT#1	AMLP	NG	16.2	1990
AMLPCT#2	AMLP	NG	16.2	1990
AMLPCT#3	AMLP	NG	19.9	1991
AMLPCT#4	AMLP	NG	33.8	1992
AMLPCC#56	AMLP	NG	47.5	1999
AMLPCC#76	AMLP	NG	109.3	1999
AMLPCT#8	AMLP	NG	87.0	2009
BEL CT#1	CEA	NG	16.1	1994
BEL CT#2	CEA	NG	16.1	1994
BEL CT#3	CEA	NG	49.5	1999
BEL CT#4	CEA	NG	10.0	1996
BEL CT#5	CEA	NG	67.3	1999
BEL CC#68	CEA	NG	100.6	2007
BEL CC#78	CEA	NG	100.6	2007
INT CT#1	CEA	NG	14.3	1996
INT CT#2	CEA	NG	14.3	1996
INT CT#3	CEA	NG	19.9	1996
PURPA#1*	MSE	Peat	20.0	2025
PURPA#2*	MSV	WC	20.0	2025
PURPA#3**	SGI	Coal	50.0	2027

* Anticipated start-up date is 1990.
** Anticipated start-up date is 1992.

Legend:
APAd= Alaska Power Administration
AMLP= Anchorage Municipal Light and Power
CEA= Chugach Electric Association
MSE= MatSu Energy
MSV= MatSu Valley
SGI= SGI, Inc.
CT= Combustion Turbine
NG= Natural Gas
WC= Wood Chips

Source: Alaska Power Authority, February 1987; Alaska Public Utilities Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Anchorage; 861217-29).

TABLE 4
POWER PRODUCTION CAPACITY AND RETIREMENT ON THE KENAI PENINSULA

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
BERNCT#1	CEA	NG	8.9	1988
BERNCT#2	CEA	NG	18.4	1997
BERNCT#3	CEA	NG	27.2	2004
BERNCT#4	CEA	NG	27.2	2004
COOPER LAKE	CEA	Hydro	17.4	----
SOLDOTCT#1	AEG&T	NG	38.5	2011
SE[illegible]C#1-4	HEA	OIL	2.1	2000
SES[illegible]#1-3	SES	OIL	5.5	1995

Legend:
CEA= Chugach Electric Association
AEG&T= Alaska Electric Generation and Transmission Cooperative
HEA= Homer Electric Association
SES= Seward Electric System
CT= Combustion Turbine
NG= Natural Gas
IC= Internal Combustion

Source: Alaska Power Authority, February 1987; Alaska Public Utilities Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Kenai; 861217-29).

TABLE 5
POWER PRODUCTION CAPACITY AND RETIREMENT IN FAIRBANKS

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
CHENST#1	FMUS	Coal	5.1	2000
CHENST#2	FMUS	Coal	2.0	2000
CHENST#3	FMUS	Coal	1.5	2000
CHENCT#4	FMUS	Oil	6.1	1987
CHENST#5	FMUS	Coal	20.0	2005
CHENCT#6	FMUS	Oil	26.1	2006
FMUSIC#1	FMUS	Oil	2.8	1992
FMUSIC#2	FMUS	Oil	2.8	1992
FMUSIC#3	FMUS	Oil	2.8	1992
HEALST#1	GVEA	Coal	25.0	2002
HEALIC#2	GVEA	Oil	2.6	1997
NOPOCT#1	GVEA	Oil	60.9	2006
NOPOCT#2	GVEA	Oil	60.9	2007
ZENCT#1	GVEA	Oil	18.0	2001
ZENCT#2	GVEA	Oil	18.0	2002
DSLIC#1-8	GVEA	Oil	14.7	1996
PURPA#1**	AEM	WC	25.0	2025

*Chena Units #1-4 Not Currently Operating
** Anticipated start-up date is 1990.

Legend:
FMUS= Fairbanks Municipal Electric Association
GVEA= Golden Valley Electric Association
AEM= AEM, Inc.
ST= Steam Turbine
CT= Combustion Turbine
IC= Internal Comustion
WC= Waste Coal

Source: Alaska Power Authority, February 1987; Alaska Public Utility Commission, March 1987.

Prepared by the House Research Agency, March 1987 (Fairbanks; 861217-29).

In general, declines in energy demand tend to postpone the retirement of equipment because the facility is used less, thereby decreasing physical wear. In addition, declines in the price of natural gas reduce the overall cost of plant operation which reduces the desirability of capital investments that increase operational efficiency. The reverse would also be true--increased usage accelerates the physical wearing out of equipment and higher fuel costs makes investment in newer, more efficient equipment relatively more cost-effective than the incremental rebuilding of less efficient equipment. Because these retirement schedules are "moving targets", time constraints for this analysis prevent a thorough examination of these schedules.

The Railbelt generating capacity, net of retirement, was altered to include four planned PURPA facilities in the Railbelt area. Three of these plants (PURPA # 1 - 3, Table 3) are to be built in the Anchorage area; the fourth (PURPA # 1, Table 5) is to be built in the Fairbanks area. The APUC currently has dockets open for these facilities which are scheduled to come on line in approximately 1990. At least two of these PURPA facility corporations have entered into power sales discussions with utilities in the Railbelt.[6] Because of the stage of development of these plants, their estimated 115 megawatts of installed capacity was included in our capacity calculations.[7]

The APA's reserve capacity calculations were also adjusted in our analysis. Reserve capacity in the continental United States is usually set at 15 to 20 percent of peak demand for a totally integrated system (i.e., one which makes possible the sharing of capacity through transmission lines). The contiguous states are also divided into seven reliability councils which provide an organizational structure for the sharing of generating capacity. The ability to share power also allows the sharing of reserve capacity and results in the relatively small percentage of peak demand reserve capacity.

At the opposite end of the reserve capacity spectrum are stand-alone systems, which are common in Alaska. For smaller stand-alone systems such as a one-diesel generator in a rural community, 100 percent backup is not unusual. For larger communities with multiple generators which are not integrated with other power facilities, reserve capacity equal to the capacity of the largest single generator is the general rule. With the development of an integrated system through the construction of interties, the Railbelt has the ability to reduce required reserve capacity.[8]

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[6]Michael Travella, Utilities Engineer, Alaska Public Utilities Commission, personal communication, March 6, 1987.

[7]These electrical power generating facilities and the Federal Energy Regulatory Commission, Public Utilities Regulatory Policies Act of 1978 (PURPA) may warrant further analysis, which this agency can conduct upon request.

[8]Michael Travella, Utilities Engineer, Alaska Public Utilities Commission, personal communication, March 10, 1987.

All utilities in the Railbelt are currently connected via an intertie system (Figure 1). Following the completion of the Anchorage-Fairbanks intertie, the Alaska Intertie Agreement was signed in December 1985 by Chugach Electric Association, Alaska Municipal Light and Power, Golden Valley Electric Association, Fairbanks Municipal Utility System, and the Alaska Electrical Generation and Transmission Corporation. In this agreement, each utility agreed to a required 30 percent reserve margin. Based on this intertie agreement, the fact that the Railbelt is now an integrated system, and a comparison with national standards, we believe that a 30 percent reserve capacity margin is a reasonable and conservative reserve capacity margin. **This analysis, therefore, uses a 30 percent reserve requirement rather than the 40 percent used by the APA.**[9]

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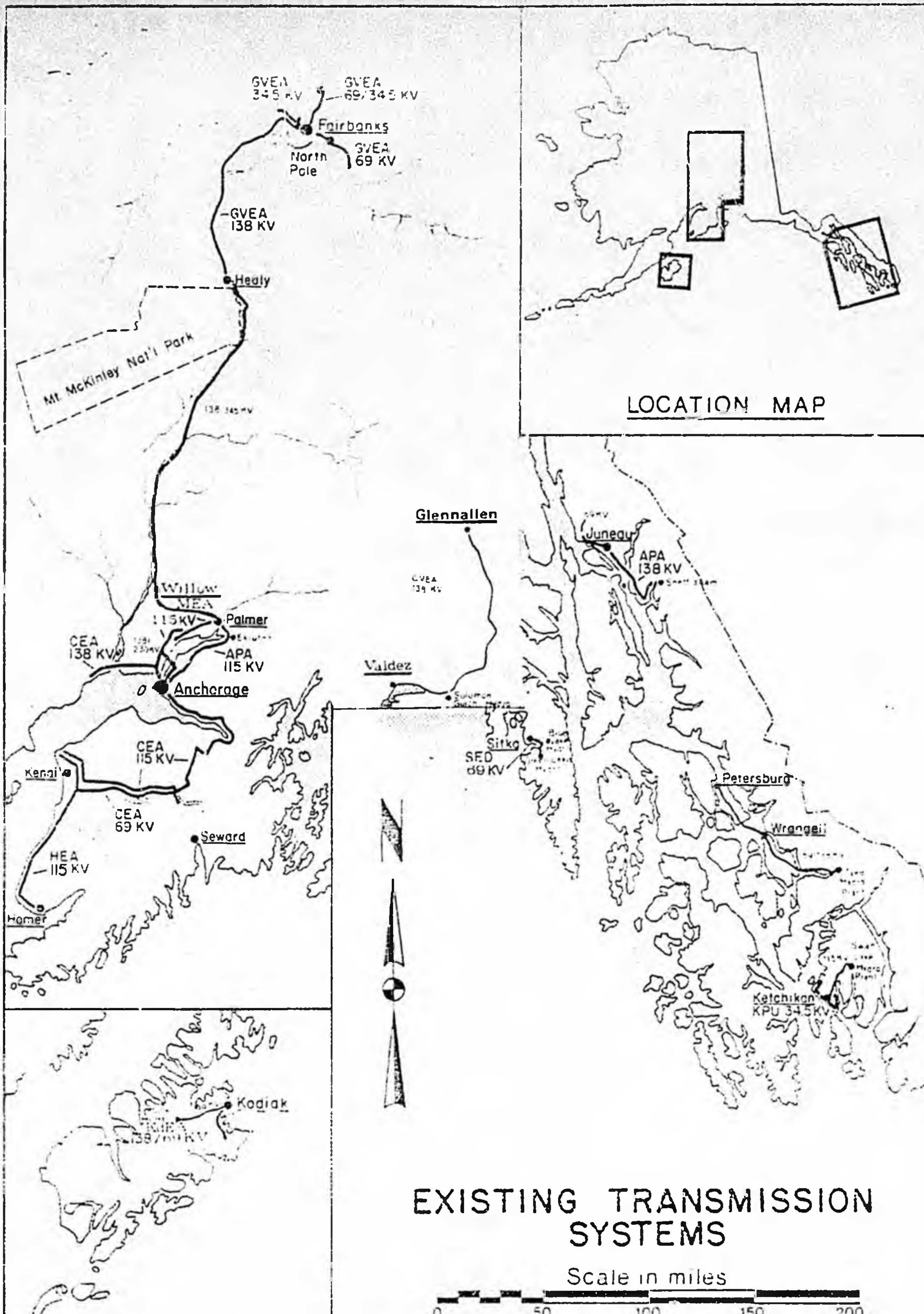
[9] Our analysis also calculated required reserve capacity on a subregional basis (i.e., Anchorage, Kenai, and Fairbanks). This implies that utilities in a subregion will share their reserve capacity via the ability to share power over interties. The APA used this same approach in their Railbelt energy requirements forecast (Table A.2, Attachment A).

FIGURE 1



Source: "Alaska Electric Power Statistics, 1960-1984," Alaska Power Authority, 1985.

Sept. 1985

Capacity vs. Demand

Combining our demand forecast with utility capacity and retirement schedules for the Railbelt and for the Anchorage, Kenai Peninsula, and Fairbanks subregions (Figures 2 - 5), the required schedules for additional capacity are apparent. For the Railbelt as a whole, existing capacity (plus planned PURPA generators) satisfies projected peak and reserve demand until the year 2000.[10] Electrical generation capacity exceeds required reserve by more than 28 percent until the year 2000 as a result of: 1) past plant construction based on earlier population growth projections; and 2) lower reserve requirements as a result of integrating stand-alone systems. Similarly for the Anchorage subregion, there is adequate capacity until the year 2000.[11] On the Kenai Peninsula, there is sufficient capacity until the year 2005; there is also substantial excess capacity until 1998. In the Fairbanks area, existing capacity can provide energy services until 2007. There will be approximately 65 percent excess capacity (over required reserve) in Fairbanks until 2003.[12]

A comparison of our demand analysis with APA's forecast (Table 2) shows that APA's forecast is 18.6 percent higher in 1988 and diverges to 33.9 percent higher in 2001. These differences occur primarily because the APA 1) does not take into account a decline in population and energy demand from 1986 through 1989 and 2) overestimates reserve capacity requirements. The implication of these results is that 90 megawatts of additional electrical generation capacity are not required in the Railbelt until the late 1990s.

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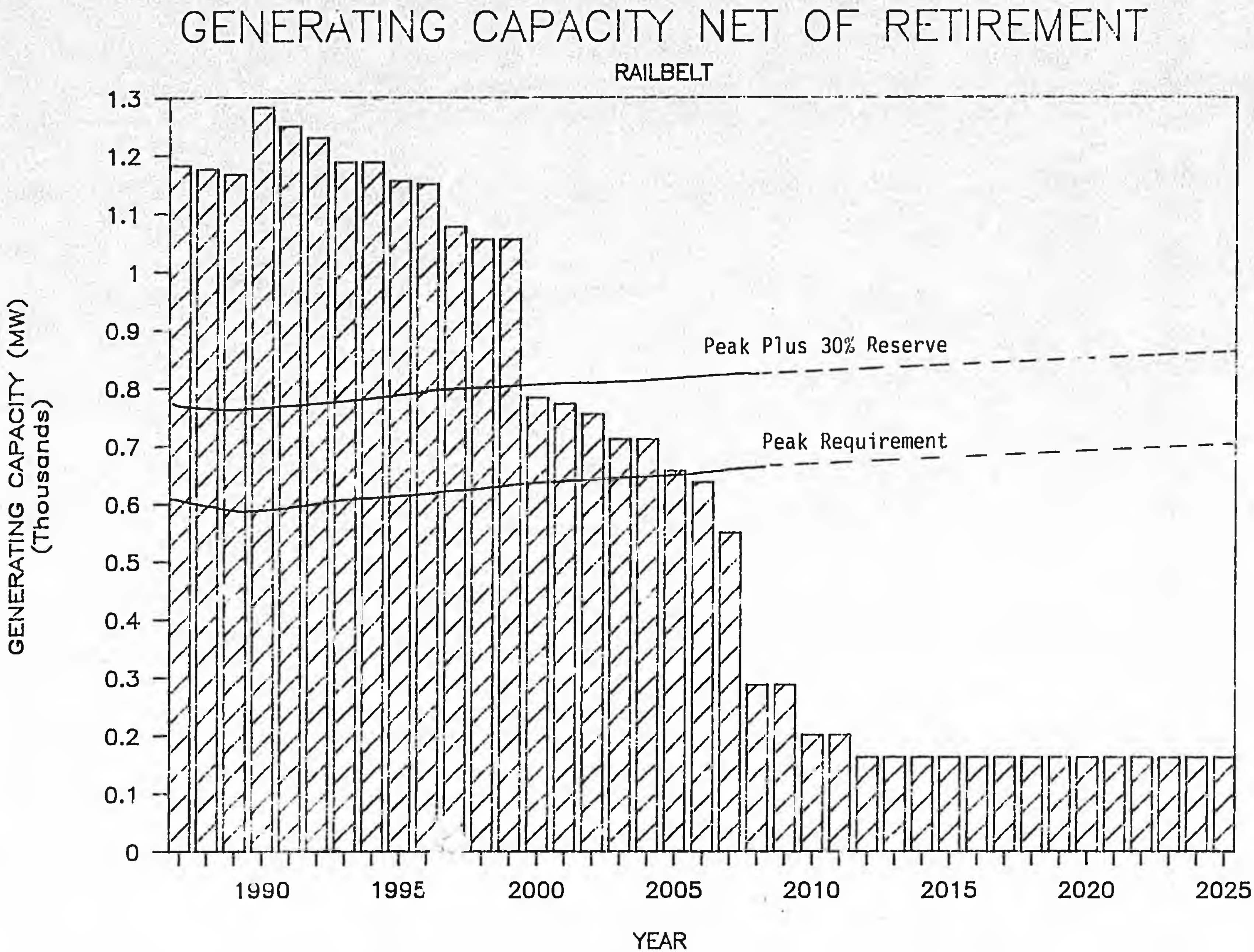
[10]Capacity is sufficient to meet projected Railbelt power requirements until 2000 even without the 115 MW expected to be generated by the PURPA power facilities.

[11]There is some discrepancy between the retirement dates for the two CEA 100.6 MW gas turbines. The APA schedule their retirement on a 30-year lifespan (2007) while CEA plans retirement in 1997 and 1999. Because of the excess production capacity in Anchorage and the rest of the Railbelt, however, this discrepancy does not alter the year 2000 result. If, however, PURPA power is not included, additional capacity would be required in 1998. In our benefit-cost analysis, we used the year 1998.

[12]Discussions with Chuck Canterbury, Fort Richardson, Public Affairs Office for the Alaska Division (March 11, 1987), indicate that the military has no intention of purchasing power from utilities in Fairbanks. They have purchased a small amount in the past to more conveniently service two buildings. In the past, until the decline in the price of fuel oil, GVEA has purchased military power.

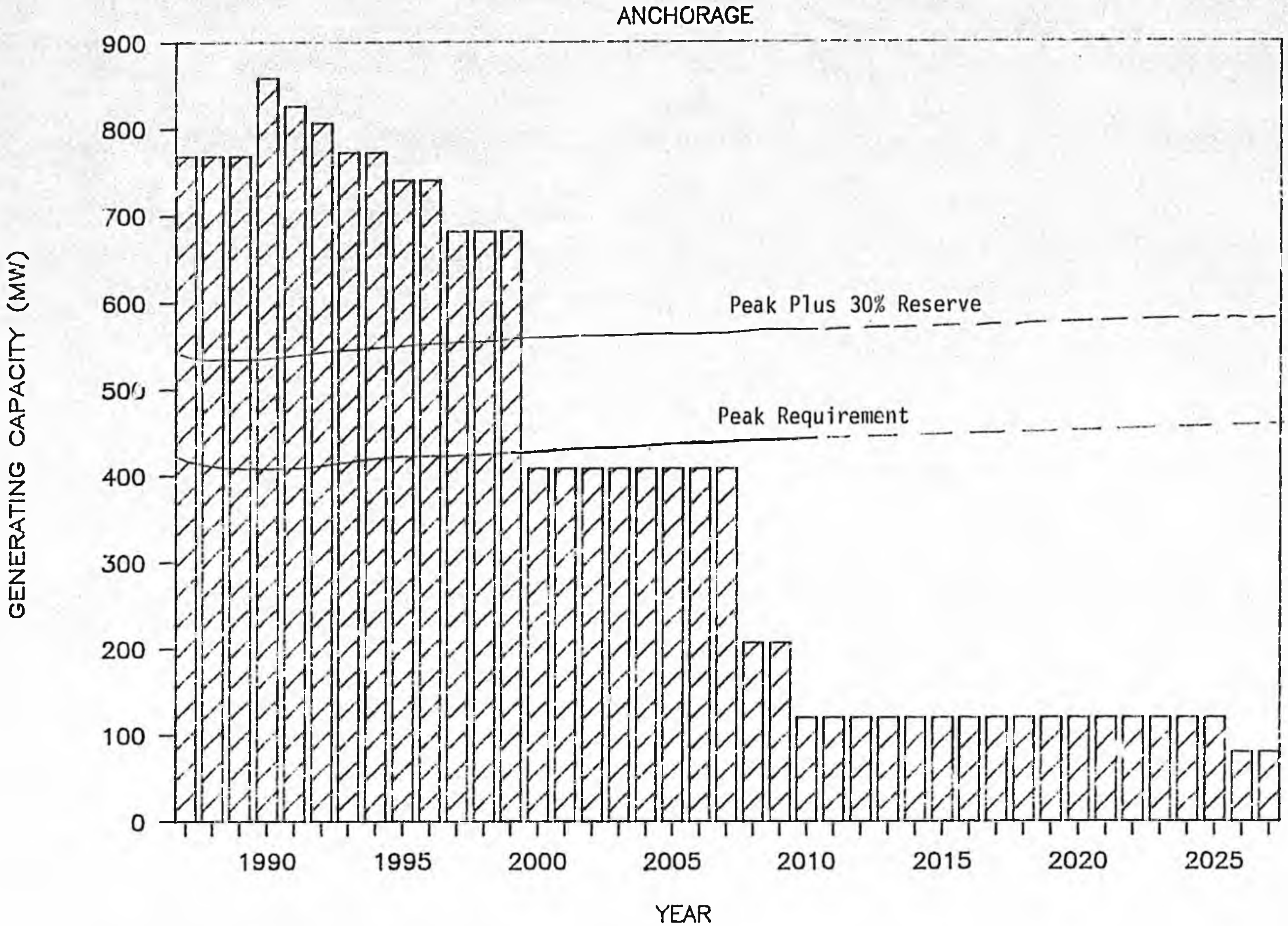
FIGURE 2



Prepared by the House Research Agency, March 1987.

FIGURE 3

GENERATING CAPACITY NET OF RETIREMENT

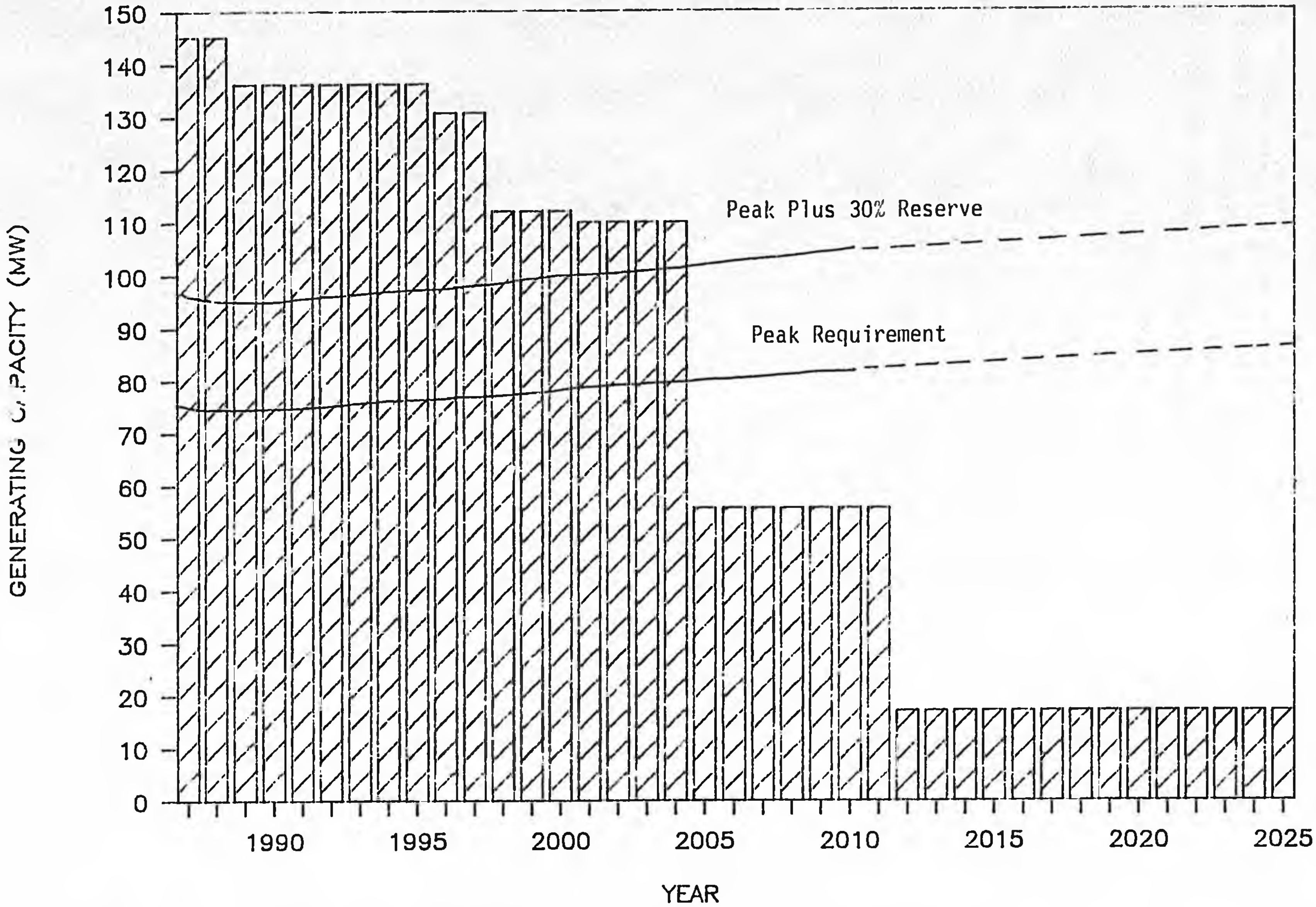


Prepared by the House Research Agency, March 1987

FIGURE 4

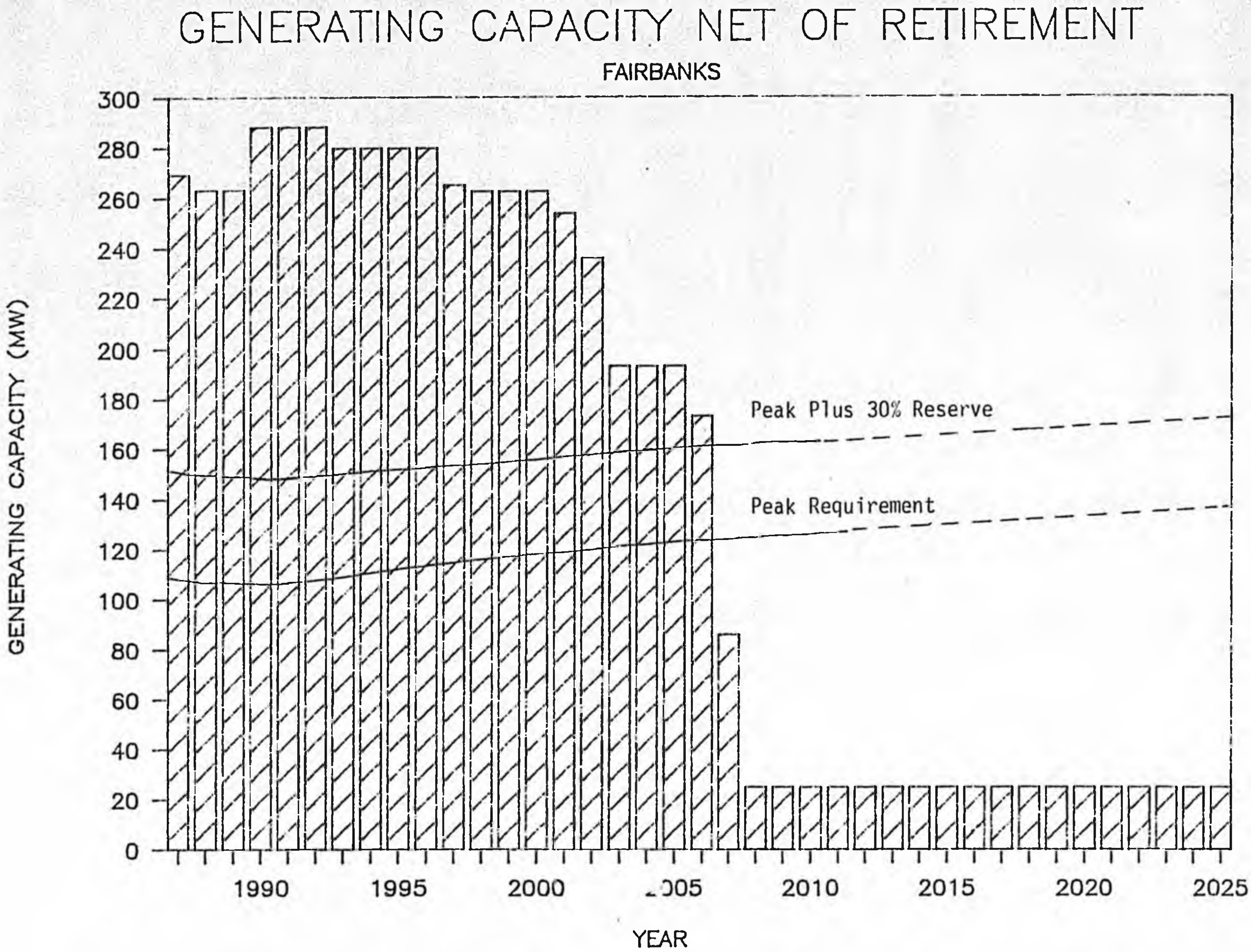
GENERATING CAPACITY NET OF RETIREMENT

KENAI



Prepared by the House Research Agency, March 1987.

FIGURE 5



Prepared by the House Research Agency, March 1987.

The feasibility analysis of the Division of Policy was based on the assumption that additional increments of generation capacity are necessary in 1991. Our examination of the Bradley Lake project economic feasibility refers to the scenario under this assumption as the "base case." As a result of our energy demand analysis, we also consider two other options as follows: 1) delaying both the Bradley Lake project and the construction of alternative natural gas facilities until they are needed in 1998; and 2) completing the Bradley Lake project as currently scheduled, while delaying gas plant construction until 1998.

Our capacity and demand analysis does not take into account the potential for further energy demand reductions through load management, more efficient use of energy, technological improvements, and energy conservation. It is likely that future capacity construction could be delayed past the year 2000 through improved energy management and utilization. This, however, would be unlikely if the State subsidizes capacity construction because the subsidization of power production and consumption often results in the inappropriate or wasteful use of energy resources.

ECONOMIC FEASIBILITY OF BRADLEY LAKE: THE DIVISION OF POLICY'S ANALYSIS

In this section, we review the February 25, 1987 feasibility analysis prepared by Jack Kreinheder of the Division of Policy (DP) in the Governor's Office. The DP analysis was directed toward the decision of whether to complete the Bradley Lake project at its marginal cost--defined as the total project cost less costs incurred or obligated to date [sunk costs]--or to suspend or abandon the project and pursue gas generation or other alternatives. As indicated by DP, a marginal cost analysis is appropriate at this time because the Bradley Lake sunk costs could not be applied toward gas generation if Bradley were terminated; the gas generation alternative would have to be constructed from scratch.

Simply put, the analysis compares the cost to complete Bradley Lake with the cost of providing the equivalent 90 megawatts of power under a gas generation alternative.[13] Costs in both cases are presented in 1986 dollars. The analysis assumes that a 90 MW gas turbine alternative would be constructed in 1989 and 1990 if Bradley Lake were not completed. The net benefits of finishing Bradley Lake are expressed as savings in millions of 1986 dollars, once the costs of the gas alternative have been subtracted from the Bradley Lake costs.

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[13]The Division of Policy analysis revises an August 1986 Stone and Webster Engineering feasibility prepared for the Alaska Power Authority (APA). The DP incorporated different assumptions for Bradley Lake costs and natural gas prices and calculated net benefits using the APA's model.

The DP concluded that Bradley Lake "is still economically feasible and that completing the project is likely to provide lower long-term power costs than alternative gas generation." However, the projected net benefits of Bradley Lake are much lower than those calculated under earlier analyses, primarily because of the dramatic decline in current and projected Cook Inlet natural gas prices. The key assumptions underlying DP's conclusion are discussed below.

Costs to complete Bradley Lake. The costs of the Bradley Lake project have been adjusted downward to take into account the following:

- **sunk costs estimated at roughly $75 million**, including $45 million already spent on the project and $30 million as a midpoint estimate of project termination expenses and site restoration costs which would be required by FERC if Bradley Lake were terminated;

- **projected savings of $28 million on the total construction cost** due to lower inflation and lower construction costs. The Alaska Power Authority's preliminary revised cost estimate for Bradley Lake is $328 million, compared with the original 1983 estimate of $356 million; and

- **estimated savings of $30 million in financing costs** because of the APA's use of short-term, variable rate notes, coupled with arbitrage earnings on the reinvestment of the note proceeds.

The above items result in a $133 million reduction in the cost of completing Bradley Lake. As DP's analysis indicates, the original project costs of $408 million ($356 million construction + $52 million financing costs) can be reduced by almost one-third to a cost of about $275 million to complete Bradley Lake.

Cook Inlet Natural Gas Prices. As you are aware, natural gas prices have declined dramatically since the original 1983 Stone and Webster Engineering feasibility analysis of the Bradley Lake project. Gas received under Enstar's 1982 gas contract--which ties the gas price to the price of fuel oil at Tesoro's Nikiski refinery--has declined 37 percent from $2.32/mcf (in 1982) to $1.47/mcf (in January 1987). As indicated in the Division of Policy's analysis, the key questions are: 1) what is the likely price of gas under new Cook Inlet gas contracts; and 2) what is the most probable rate, or range of rates, at which gas prices will increase in the future.

The DP analysis calculated Bradley Lake net savings under a range of base gas prices ($1.10 to $1.70/mcf) and a range of real price escalation rates (0 to 2 percent).[14] Chugach Electric Association (CEA) recently paid $1.70/mcf in short-term contracts with Beluga field producers; the consensus places the upper limit for the base price of new gas supplies at $1.70/mcf. The DP suggests that a base price of $1.50/mcf appears to be a good mid-range figure. With respect to real escalation rates, views vary but the DP analysis referenced forecasts of gas prices by the Department of Revenue and CEA. According to Revenue's December 1986 petroleum revenue forecast, Cook Inlet gas prices are expected to track crude oil prices, which assume an average 2.0 percent real escalation rate between 1987 and 2003. The CEA's gas price forecasts are fairly close to Revenue's.

In summary, the DP analysis calculated a series of projected net benefits which incorporate the lower cost to complete Bradley Lake as well as a range of base gas prices under real escalation rates ranging from 0 to 2 percent. Attachment B presents the DP projections of net savings; the economic feasibility of Bradley Lake (even under the lower cost estimate) remains very sensitive to gas prices and their rate of escalation. For example, at a base price of $1.60/mcf and two percent real escalation, Bradley Lake is estimated to be $85 million cheaper in 1986 dollars than the gas alternative. At a one percent real escalation rate and a base price of $1.60/mcf, however, Bradley net savings drop by about $55 million. As noted by the division, each 10 cent/mcf change in base gas prices alters the Bradley net savings by about $15 million. Despite the uncertainties, the division concludes that "...current gas price forecasts by the Department of Revenue and Chugach Electric suggest that Bradley Lake is still likely to be less expensive than [alternative] gas generation over the 50 year period of analysis."

A REEXAMINATION OF BRADLEY LAKE NET SAVINGS UNDER KEY ENERGY ASSUMPTIONS

Based on our review of the above analysis, we conclude that the Division of Policy's assumptions regarding the base gas prices and projected escalation rates appear reasonable. However, we question the division's fundamental assumption regarding future Railbelt energy demand and the timing of installation of additional capacity. Our analysis of Railbelt energy demand and capacity requirements indicates that, even without Bradley Lake, new gas

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[14]The Division of Policy analysis does not add a delivery charge to the wellhead price of gas; it assumes that new gas generation will be located near a producing field (e.g., the Bernice Lake substation near Marathon's Steelhead platform). A 40 cent/mcf delivery charge (used in the August 1986 Stone and Webster feasibility) would increase costs of the gas alternative and enhance the projected net benefits of Bradley Lake by about $65 million.

generation will probably not be needed until the late 1990s. This conclusion stems from: 1) lower near-term energy demand forecasts due to population declines; and 2) lower reserve capacity requirements because of existing regional interties. In light of this conclusion, we believe that the division's analysis must be reexamined.

In this section, we first present our analysis of Bradley Lake net benefits, expressed as savings, under three scenarios:[15]

1. The base case incorporates the Division of Policy's implicit assumption that 90 MW of additional gas generation will be needed in 1991 if Bradley Lake is not completed. We altered the division's cost to complete Bradley Lake to be $283 million--the revised construction cost of $328 million minus the $45 million already spent on construction. If the decision were made to abandon Bradley Lake and proceed with gas generation, the cost of the gas alternative would include the estimated $30 million in Bradley Lake termination and site restoration costs.

2. Assuming that 90 MW of new power is not needed until the late 1990s, the second scenario provides a comparison of Bradley Lake and the gas alternative if construction of both were delayed and power commenced in 1998. The cost to complete Bradley Lake includes expenses to mothball the project in 1987 and reactivate the project in the mid-1990s. As above, the gas alternative includes the cost of termination and site restoration at Bradley Lake as well as gas plant construction costs in 1996-97. Since neither project would begin producing power until 1998 under this scenario, we extend the period of analysis until the year 2048 in order to provide a 50-year period of costs for analysis.

3. The third scenario assumes that the Bradley Lake project is completed under the current schedule at an estimated cost of $283 million. However, we believe that the decision to complete Bradley Lake must be weighed against alternative gas generation which would be constructed later in the 1990s and begin producing power in 1998 when it was needed. While this feasibility analysis does not provide a year-for-year comparison, it does present a calculation of today's decision to complete Bradley Lake. In effect, this scenario calculates the merits of the public policy decision to proceed with Bradley Lake.

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[15] Detailed tables for each of these scenarios are included in Attachment C.

Base Case Scenario. Based on an analysis of Chugach Electric Association's projections, the Division of Policy concluded that new gas generation will likely be installed by 1990 if Bradley Lake were not completed. Under this scenario, Chugach Electric indicates that a new 87 MW gas plant would likely be constructed and become part of the base load capacity, thereby delegating older, less fuel efficient turbines to peak loading.[16]

We recalculated the net present costs of Bradley Lake and the gas generation alternative under this base case of power needed (from either source) by 1991. In the process of verifying the APA/DP model, we made slight modifications to the spreadsheet formulas but did not alter the analytical approach. Our base case scenario, however, incorporates two notable changes in underlying assumptions. First, we believe that the gas generation's fuel efficiency should reflect the effective heat rate of a new gas turbine (approximately 11,500 Btu/kwh), rather than the 13,000 Btu/kwh rate used in the APA/DP model. It is appropriate to compare "new" Bradley Lake power with power produced at the fuel efficiency of a new turbine, rather than under a blended, less efficient rate (of 13,000 Btu/kwh) based on the combined use of new and old turbines.

The second change incorporated into the APA/DP model was to alter the cost to complete Bradley Lake to equal $283 million. This represents the preliminary revised construction cost ($328 million) minus the expenses to date ($45 million). If the decision were made to terminate Bradley Lake, an estimated $30 million in termination and site restoration expenses would be incurred in order to then proceed with the gas generation alternative. We, therefore, include these Bradley Lake termination and site restoration costs as a cost to the gas alternative.

As shown in Table 6, the **Bradley Lake net savings under our base case scenario equal $85.8 million--virtually the same as those presented by the Division of Policy.** The cost savings gained through greater gas turbine fuel efficiencies incorporated into our base case are cancelled by the termination and site restoration costs added to the gas alternative if the decision were made to abandon Bradley and proceed with gas generation.

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[16] Tom Martin, Director of Planning, Chugach Electric Association, personal communication, March 9, 1987.

TABLE 6
BRADLEY LAKE NET SAVINGS UNDER VARIOUS SCENARIOS
(Million $)

SCENARIO	NET PRESENT COST: GAS ALTERNATIVE	NET PRESENT COST: BRADLEY LAKE	BRADLEY LAKE NET SAVINGS
I. Base Case w/Power in 1991	$330.4	$244.6	$85.8
IA. Base Case under Revised Demand Forecast	315.7	229.9	85.8
II. Construction Delay w/Power in 1998	280.6	406.7	(126.0)
III. Bradley Lake now vs Gas Plant in 1998	280.6	244.6	36.0

Note: All scenarios assume a base price of $1.60/mcf; zero delivery charge; 2.0 percent escalation rate; 11,500 Btu/kwh heat rate; 4.5 percent inflation; and $400/kw gas plant construction costs.

The base case scenario incorporates the flawed assumption that 90 MW of additional power will be needed in 1991. Our demand analysis concludes, instead, that an additional increment of production capacity will not be needed until the late-1990s. Therefore, the construction of either Bradley Lake or the gas alternative would result in the early retirement of existing generation capacity. It is assumed that Bradley Lake or a new, more efficient gas turbine would result in lower costs through the displacement of older, less efficient gas generation production. Because the cost reductions are the same for both types of new power, Bradley Lake net savings do not change for this base case under revised demand forecast scenario (Table 6). The net present costs, however, decline by roughly $15 million for both Bradley Lake and the gas alternative.

Delay Construction Scenario. The net savings of Bradley Lake become negative under our second scenario in which construction of both Bradley Lake and the gas plant alternative are delayed several years until Railbelt energy demand catches up with existing capacity and new generating capacity is warranted. As shown in Table 6, the net present cost of Bradley Lake (if construction were delayed until 1994-1997) nearly doubles from $245 million in our base case to $407 million.

Under this scenario, we assume Bradley Lake construction costs of $415 million during the period 1994-97 [i.e., the 1987 estimated cost to complete Bradley of $283 million inflated at 4.5 percent annually plus an estimated $30 million in additional expenses (administration, licensing, and contracting). We estimate that the project would require $554 million in long-term taxable bonds, issued in 1993 at 10 percent interest, in order to cover construction costs as well as four years of debt service payments prior to project revenues commencing in 1998. Bradley Lake costs would increase dramatically due to the loss of the favorable short-term financing presently in place. On the other hand, the net present cost of the gas alternative drops if construction is delayed--primarily because fuel savings during the period of delay more than offset the gas plant's increased financing costs (which are relatively minor compared with those for Bradley Lake).[17] As shown in Table 6, the Bradley Lake net savings under this scenario are projected to be a negative $126 million. **On the basis of this analysis, it does not appear to be economically feasible to delay Bradley Lake and reactivate the project in the mid-1990s.**

Bradley Lake in 1991 vs Delayed Gas Construction Scenario. Our third scenario calculates the net present cost of Bradley Lake constructed under the current schedule and the net present cost of the gas plant alternative if it were delayed until needed. The net savings to be gained from completing Bradley Lake decline to about $36.0 million. From a public policy perspective, we suggest that this scenario presents a mathematical formulation of the real question: What is the benefit (or cost) of proceeding with Bradley Lake at this time, despite forecasts which suggest that the project is not needed for several years? **Based on this analysis, the positive net savings of Bradley Lake indicate that the project should proceed. However, the net savings are not outstanding--and in retrospect could become marginal or negative if gas base prices and/or price escalation rates are lower than assumed.**

Net Savings under Various Assumptions

We recalculated the net savings projected for the Bradley Lake project under varying assumptions (gas plant construction costs, turbine heat rate, inflation rate, and discount rate) in order to determine the sensitivity of the analysis to changes in these assumptions. Table 7 summarizes the net savings as these assumptions are varied under the base case scenario and the "Bradley Lake now vs. delayed gas construction" scenario which we believe to be most accurate representation of the current public policy choice.

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[17] We assume that gas plant construction in the mid-1990s would be financed by taxable revenue bonds at a 10 percent interest rate. The 10 percent interest rate was assumed for delayed gas plant construction in both the second and third scenarios.

TABLE 7
BRADLEY LAKE NET SAVINGS UNDER VARYING ASSUMPTIONS
(Millions $)

SCENARIO/ASSUMPTION	NET PRESENT COST: GAS ALTERNATIVE	NET PRESENT COST: BRADLEY LAKE	BRADLEY LAKE NET SAVINGS
Scenario I: Base Case w/ Power in 1991	$330.4	$244.6	$85.8
Construction Costs of $350/kw	325.0	244.6	80.4
Heat Rate of 13,000 Btu/kwh	359.9	244.6	115.2
Inflation Rate at 5.0 percent	327.9	231.5	96.4
Discount Rate			
3.0 percent	369.3	264.0	105.2
4.0 percent	297.4	227.2	70.2
12.0 percent	100.8	88.5	12.3
Scenario III: Bradley Lake now vs Gas Plant in 1998	280.6	244.6	36.0
Construction Costs of $350/kw	275.1	244.6	30.5
Heat Rate of 13,000 Btu/kwh	304.5	244.6	59.9
Inflation Rate of 5.0 percent	278.4	231.5	46.8
Discount Rate			
3.0 percent	318.8	264.0	54.8
4.0 percent	248.4	227.2	21.2
5.0 percent	197.8	197.4	0.5

Note: Both scenarios assume a base gas price of $1.60/mcf; zero delivery charge; 2.0 percent escalation rate; 11,500 Btu/kwh heat rate; 4.5 percent inflation; and $400/kw gas plant construction costs.

The Division of Policy's analysis assumed that construction costs for a gas plant would run $400/kw (in 1986 dollars). The range of construction costs is apparently estimated at $350 to $450/kw, based on construction costs experienced by Alaska Electric Generation & Transmission and Anchorage Municipal Light & Power during the past few years. Lowering the cost assumption to $350/kw, however, has a fairly insignificant effect on the cost analysis. Under either scenario, the present cost of the gas alternative would be about $5.5 million lower at a construction cost of $350/kw.

As noted previously, we assumed a new gas turbine fuel efficiency ("heat rate") of 11,500 Btu/kwh in our three scenarios. On the other hand, the APA/DP model assumed a heat rate of 13,000 Btu/kwh to reflect newer gas turbines at 11,500 Btu/kwh (effective rate) operating as base capacity coupled with older, less existing turbines at 15,000-16,000 operating only when demand peaks. As shown in Table 7, using this higher, "blended" heat rate increases the fuel consumption under the gas alternative in both scenarios significantly and enhances the Bradley Lake net savings. The net savings analysis is very sensitive to the gas turbine fuel efficiency and other assumptions which directly affect annual fuel costs.

Annual Inflation Rate. The APA/DP model assumed 4.5 percent annual inflation over the 50-year period of analysis. In the January 1987 Revenue Sources report, the Department of Revenue projected an inflation rate of 3.89 percent in FY 87, 4.58 percent in FY 88-FY 92, 5.23 percent in FY 93 - FY 97, and 5.42 percent thereafter. If we substitute an annual inflation rate of 5.0%, the Bradley Lake net savings under both scenarios in Table 7 increase by about $11 million. Higher inflation rates lower the net present costs of both the gas alternative and Bradley Lake. However, higher inflation favors Bradley Lake to a greater extent because most of Bradley Lake's annual costs are fixed debt service payments, which (in 1986 dollars) become cheaper in the future. In contrast, a smaller portion of the gas alternative's annual costs are fixed.

The Discount Rate. In order to calculate the net present cost during the 50-year period of analysis, one must employ a discount rate which adjusts future cash flows to a value in current dollars. The APA/DP model employed a discount rate of 3.5 percent, which is apparently the discount rate routinely used by the U.S. Army Corps of Engineers to reflect the historic real cost of government spending.

The gas alternative operational costs are higher in later years (even when adjusted to 1986 dollars) because gas prices are assumed to escalate at a real rate of 2.0 percent, whereas Bradley Lake costs (in 1986 dollars) decline over the period of analysis. A lower discount rate emphasizes the relative weight of future costs and enhances the outlook of Bradley Lake. For example, under both scenarios shown in Table 7, Bradley Lake net savings increase by about $19 million when the discount rate is reduced to 3.0 percent.

On the other hand, a **higher discount rate** tends to lower the net savings of Bradley Lake because it deemphasizes future expenditures. For example, a discount rate of 4.0 percent lowers the net savings of Bradley Lake in both scenarios by about $15 million. The sensitivity of the analysis to the discount rate becomes particularly significant when Bradley Lake's net savings are relatively low--as under the third scenario. A discount rate of 5.0 percent under this scenario produces zero net savings, whereas a 12.0 percent discount rate under the base case still results in a positive net benefit (see Table 7). The analysis indicates, however, that the net savings of Bradley Lake remain positive under discount rates within a reasonable range of 3.0 to 4.0 percent.

CONCLUSION

It has been stated that Bradley Lake was not conceived as an emergency power project needed to meet Railbelt energy demand. Instead, it was intended to provide the Railbelt with an alternate power source free from the vagaries of fossil fuel price escalation. As the price of natural gas has declined, however, the projected net savings of the Bradley Lake project have eroded considerably. Our analysis indicates that the public policy choice today is to either proceed with Bradley Lake as currently scheduled or abandon the project. Delaying Bradley for several years--so that Railbelt energy demand could "catch up" with capacity--would be too costly relative to a less expensive gas alternative.

If the Bradley Lake project is to be completed as scheduled, we conclude that it will probably provide net savings over the 50-year period of analysis. However, in order to more accurately project the benefits of the projects, we believe that an **analysis computing the actual cost of all power consumed in the Railbelt under the different** scenarios would be required. However, this type of analysis would require a great deal of data-gathering from the seven Railbelt utilities, the APUC, and the APA. The time-consuming nature and inherent difficulties of this type of analysis probably explain why it has not already been conducted.

At this time, we reiterate our conclusion that the Bradley Lake project will probably produce power more cheaply than gas generation over the 50-year period we analyzed. Nevertheless, the net savings are certainly less than the proposed State contribution of roughly $164 million.[18] Furthermore, the analysis is extremely sensitive to natural gas prices and their escalation. Because the projected net savings of Bradley Lake are now relatively low, there is a high risk that its completion would be a poor public policy decision if gas prices prove to be only slightly lower than assumed. **The public risk grows considerably greater as the net savings projected for Bradley Lake decline.** Beyond the initial State cash contribution, the Railbelt electric customers will ultimately bear the costs of today's decision regarding Bradley Lake power.

Attachments

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[18] The State contribution assumes the revised cost of $328 million minus $164 million (one-half of $328 million) to be contributed by Railbelt utilities.

ATTACHMENT A

TABLE A.1

NET GENERATION OF ALASKA RAILBELT UTILITIES, 1976 - 1986

UTILITY	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Anchorage Municipal Light & Power (AMLP)	444.9	420.3	443.1	473.1	486.6	485.3	579.5	592.5	654.0	934.4	938.6
Chugach Electric Association (CEA)	1,054.5	1,179.7	1,308.6	1,401.0	1,434.1	1,467.7	1,718.4	1,781.8	1873.3	1,859.3	1,692.3
Alaska Power Administration (APAD)	118.0	203.5	180.1	171.1	184.3	222.7	147.9	149.9	164.6	150.0	154.8
Anchorage-Cook Inlet Subtotal	1,617.4	1,803.6	1,931.8	2,045.2	2,105.0	2,175.7	2,445.8	2,524.2	2,691.9	2,943.7	2,785.7
Fairbanks Municipal Utility System (FMUS)	123.3	128.5	124.7	124.7	125.6	126.1	140.7	146.9	140.2	101.0	96.8
Golden Valley Electric Association (GVEA)	344.7	353.5	341.5	322.9	317.7	316.9	350.3	346.2	401.1	408.0	420.6
Fairbanks Area Subtotal	468.0	481.7	466.2	447.6	443.3	443.0	491.1	493.1	541.3	509.0	517.4
RAILBELT TOTAL	2,085.4	2,285.3	2,398.0	2492.8	2,548.3	2,618.7	2,936.9	3,017.3	3,233.2	3,452.7	3,303.1

Source: Alaska Power Authority, "Alaska Electric Power Statistics, 1960-1985,"; Railbelt Utilities.

Prepared by the House Research Agency, March 1987 (Demand; 861217-29).

Table A2

TOTAL RAILBELT
ENERGY REQUIREMENTS

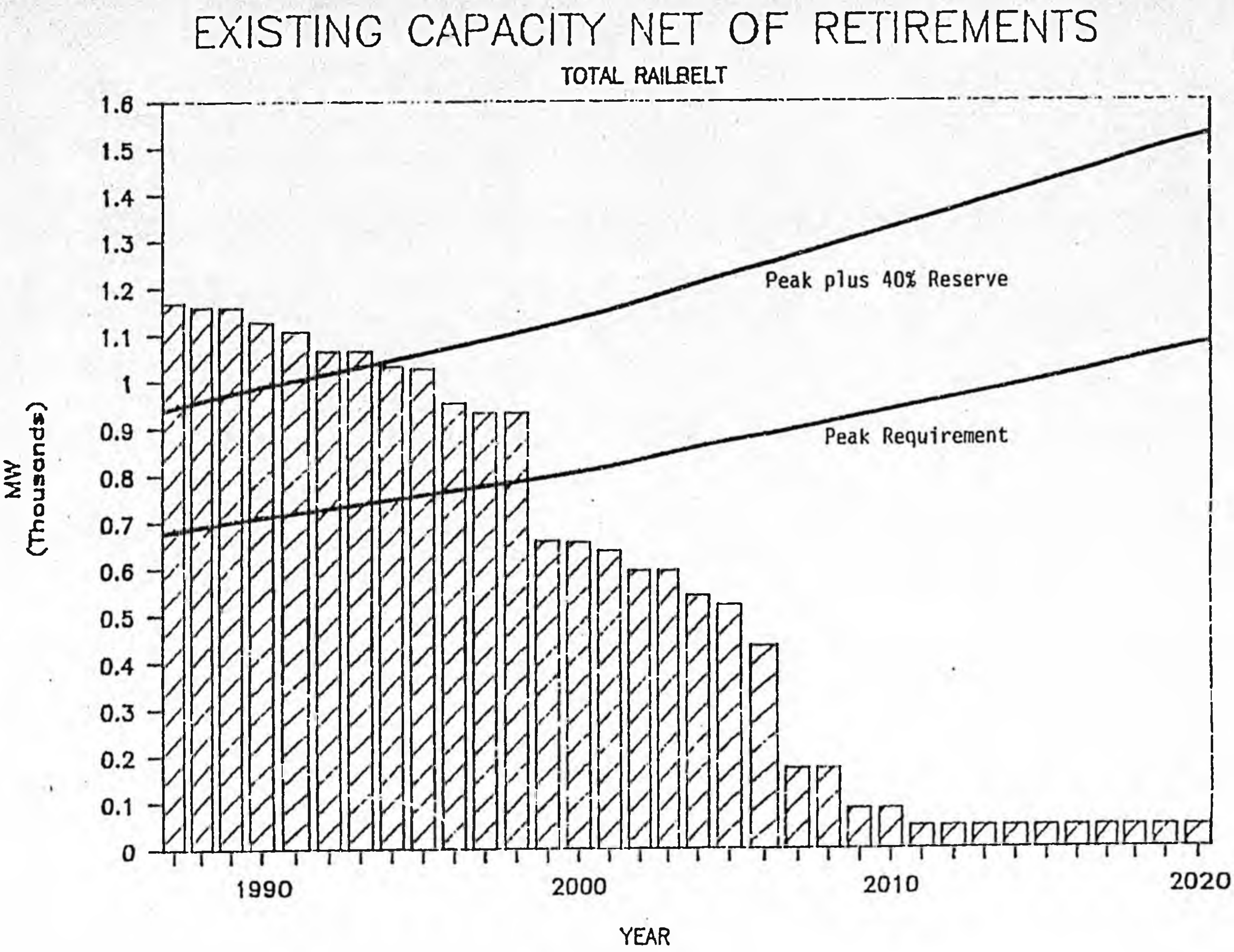
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
ANCHORAGE MUNICIPAL LIGHT AND POWER	851.8	861.6	865.7	891.7	882.1	826.3	872.6	913.4	934.5	915.3	954.8	969.0	987.0	1,011.6	1,037.6	1,064.1
CHUGACH ELECTRIC ASSOCIATION (RETAIL)	933.7	976.9	978.2	968.3	1,000.1	976.0	1,016.7	1,046.5	1,046.6	928.3	1,009.9	1,020.4	1,033.3	1,049.7	1,068.8	1,091.2
HOMER ELECTRIC ASSOCIATION	386.7	391.7	391.7	396.7	376.5	417.2	427.2	432.2	412.2	401.6	412.2	417.2	417.2	422.2	427.2	432.2
MATANUSKA ELECTRIC ASSOCIATION	478.1	475.2	474.0	474.5	425.9	432.7	433.7	412.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
CITY OF SEWARD	34.9	36.9	41.2	43.4	45.6	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
SYSTEM LOSSES	155.7	161.8	162.1	163.7	163.4	164.3	167.5	172.0	172.3	165.3	167.3	169.1	171.0	173.9	177.1	180.9
TOTAL (CEA)	1909.2	2010.5	2017.2	2046.7	2011.5	2054.1	2091.7	2141.2	2150.2	2003.7	2110.9	2136.1	2154.9	2197.8	2234.9	2284.0
FAIRBANKS MUNICIPAL UTILITY SYSTEM	165.2	172.9	171.6	176.3	179.9	185.3	187.0	192.8	196.6	200.5	204.5	208.6	212.8	217.0	221.4	225.8
GOLDEN VALLEY ELECTRIC ASSOCIATION	501.5	521.0	541.2	562.2	577.3	592.7	608.6	624.9	641.7	658.9	676.5	694.6	713.2	732.3	752.0	772.1
HOMER ELECTRIC ASSOCIATION	420.0	425.0	425.0	430.0	454.3	495.0	505.0	510.0	490.0	479.4	490.0	495.0	495.0	500.0	505.0	510.0
CHUGACH ELECTRIC ASSN	386.7	391.7	391.7	396.7	376.5	417.2	427.2	432.2	412.2	401.6	412.2	417.2	417.2	422.2	427.2	432.2
KENAI	33.3	33.3	33.3	33.3	77.8	77.8	77.8	77.9	77.8	77.8	77.6	77.8	77.8	77.8	77.8	77.8
MATANUSKA ELECTRIC ASSN (TOTAL)	478.1	475.2	474.0	474.5	479.2	486.0	487.0	496.1	523.6	524.6	525.4	532.8	536.4	549.5	563.7	580.9
CHUGACH ELECTRIC ASSN	478.1	475.2	474.0	474.5	425.9	432.7	433.7	412.8	470.3	471.3	472.1	479.5	483.1	496.2	510.4	527.6
KENAI (BRADLEY LAKE)	0.0	0.0	0.0	0.0	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3	53.3
CITY OF SEWARD	34.9	34.9	41.2	43.4	45.4	46.0	46.7	47.7	48.8	49.2	49.5	49.9	50.3	50.9	51.5	52.2
TOTAL	3,559.9	3,652.3	3,687.0	3,720.2	3,781.9	3,851.6	3,913.0	4,003.4	4,054.1	4,021.5	4,077.9	4,138.5	4,199.0	4,294.9	4,377.0	4,477.2

CAPACITY REQUIREMENTS

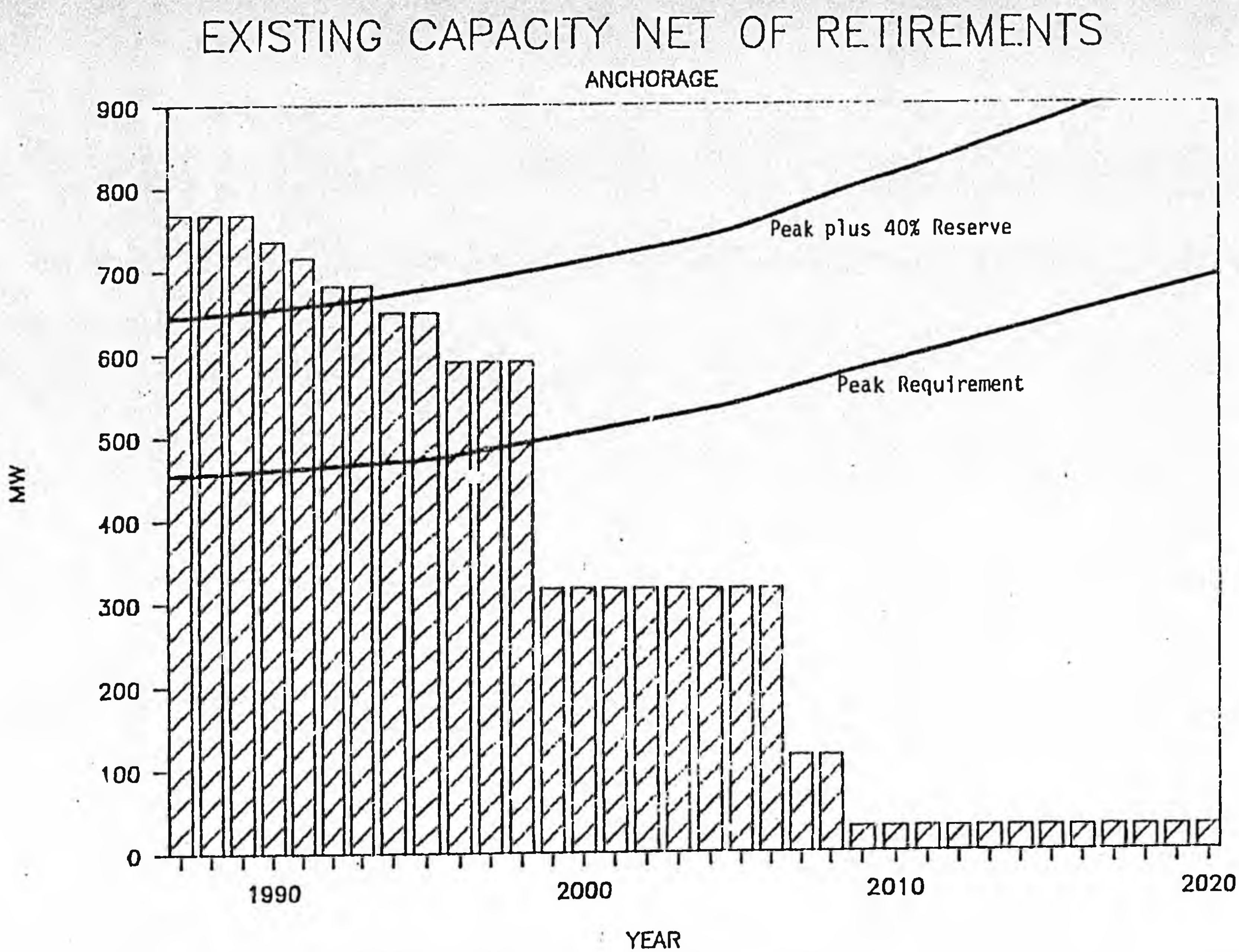
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
PEAK DEMAND																
ANCHORAGE MUNICIPAL LIGHT AND POWER	164.0	166.7	166.9	166.2	166.3	167.1	168.2	172.1	176.1	178.1	[illegible]	182.4	185.9	190.3	195.4	200.2
CHUGACH ELECTRIC ASSOCIATION *Retail*	191.3	198.4	197.0	197.4	198.1	195.6	193.0	202.2	200.6	191.3	[illegible]	175.6	158.0	201.2	204.8	209.1
FAIRBANKS MUNICIPAL UTILITY SYSTEM	29.3	30.0	30.6	31.2	32.1	33.4	34.4	35.4	36.5	37.6	38.7	39.9	41.1	42.3	43.6	44.9
GOLDEN VALLEY ELECTRIC ASSOCIATION	85.8	92.3	99.4	107.0	109.8	112.8	115.8	118.9	122.1	125.4	128.7	132.2	135.7	139.3	143.1	146.9
HOMER ELECTRIC ASSOCIATION	79.0	81.0	81.5	84.0	87.0	95.0	96.0	97.0	93.0	92.0	93.0	94.0	95.0	96.0	97.0	97.5
MATANUSKA ELECTRIC ASSOCIATION	90.3	94.9	96.5	93.6	95.5	96.4	97.5	99.3	105.8	94.9	95.7	96.5	97.0	97.5	99.7	101.2
SEWARD	7.0	7.0	10.0	11.0	12.4	12.5	12.7	13.3	13.6	13.7	13.8	13.9	14.0	14.1	14.2	14.3
TOTAL SYSTEM PEAK	646.7	670.3	681.9	690.4	701.2	712.8	722.6	738.2	747.7	733.0	743.3	754.4	765.7	780.9	797.7	814.1
RESERVE REQUIREMENTS																
ANCHORAGE AREA	133.2	138.0	138.1	137.2	138.0	137.7	139.1	142.1	144.8	139.3	140.7	142.4	144.3	146.8	150.0	153.1
FAIRBANKS AREA	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	85.9	85.9	85.9
KENAI PENINSULA	38.0	38.0	38.0	38.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0	51.0
TOTAL RESERVE REQUIREMENT	232.6	235.9	237.0	236.1	249.9	249.6	251.0	254.0	256.7	251.2	252.6	254.3	255.2	283.7	295.9	290.1
TOTAL SYSTEM CAPACITY REQUIREMENT	879.3	907.2	918.9	926.4	951.1	962.4	973.6	992.2	1,004.3	984.1	995.9	1,006.7	1,022.8	1,064.6	1,064.6	1,104.1

Alaska Power Authori
January 1987

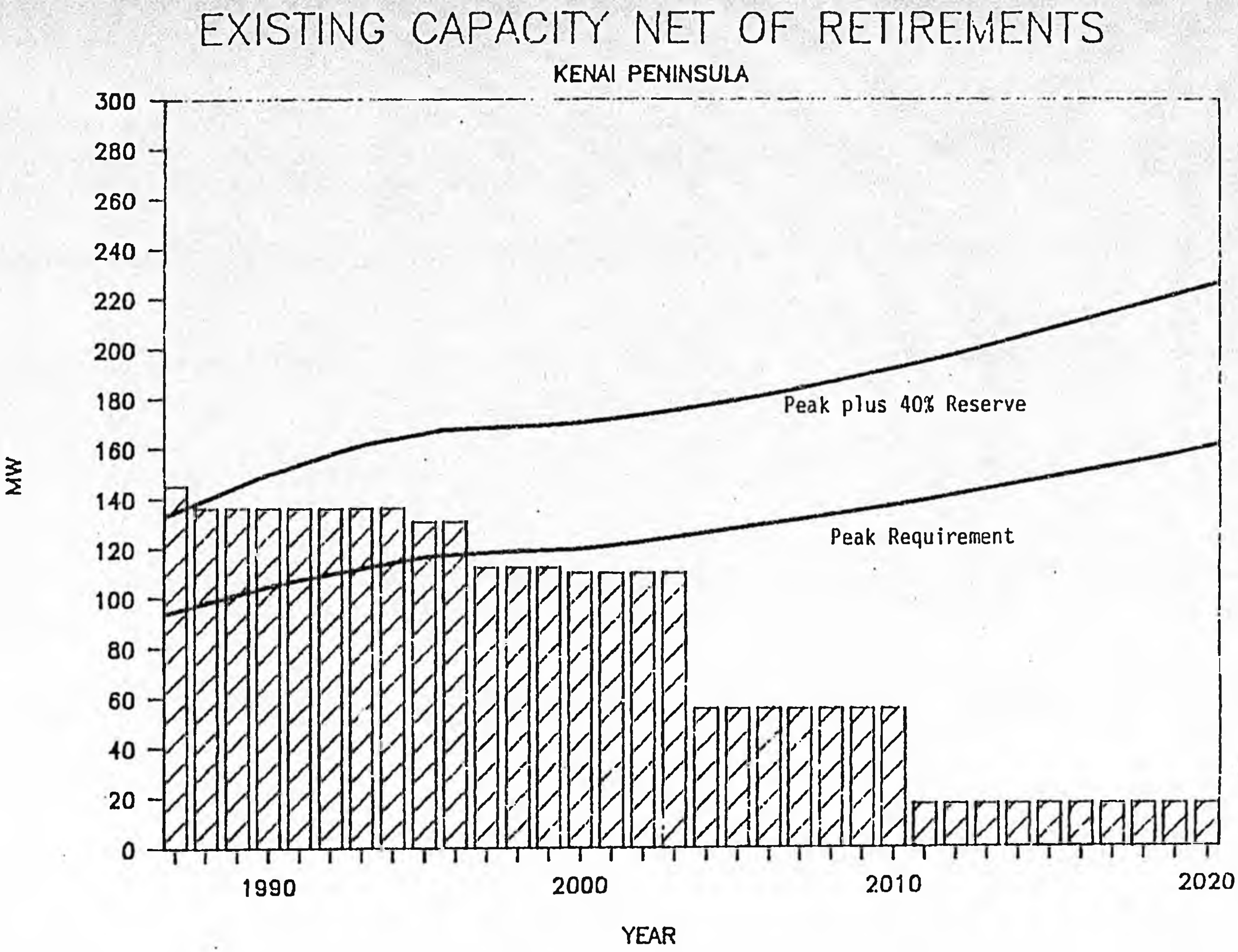
Note: This forecast is being used for: Preliminary Economic Assessment of Railbelt Transmission Alternatives



Prepared by the Alaska Power Authority, February 1987.



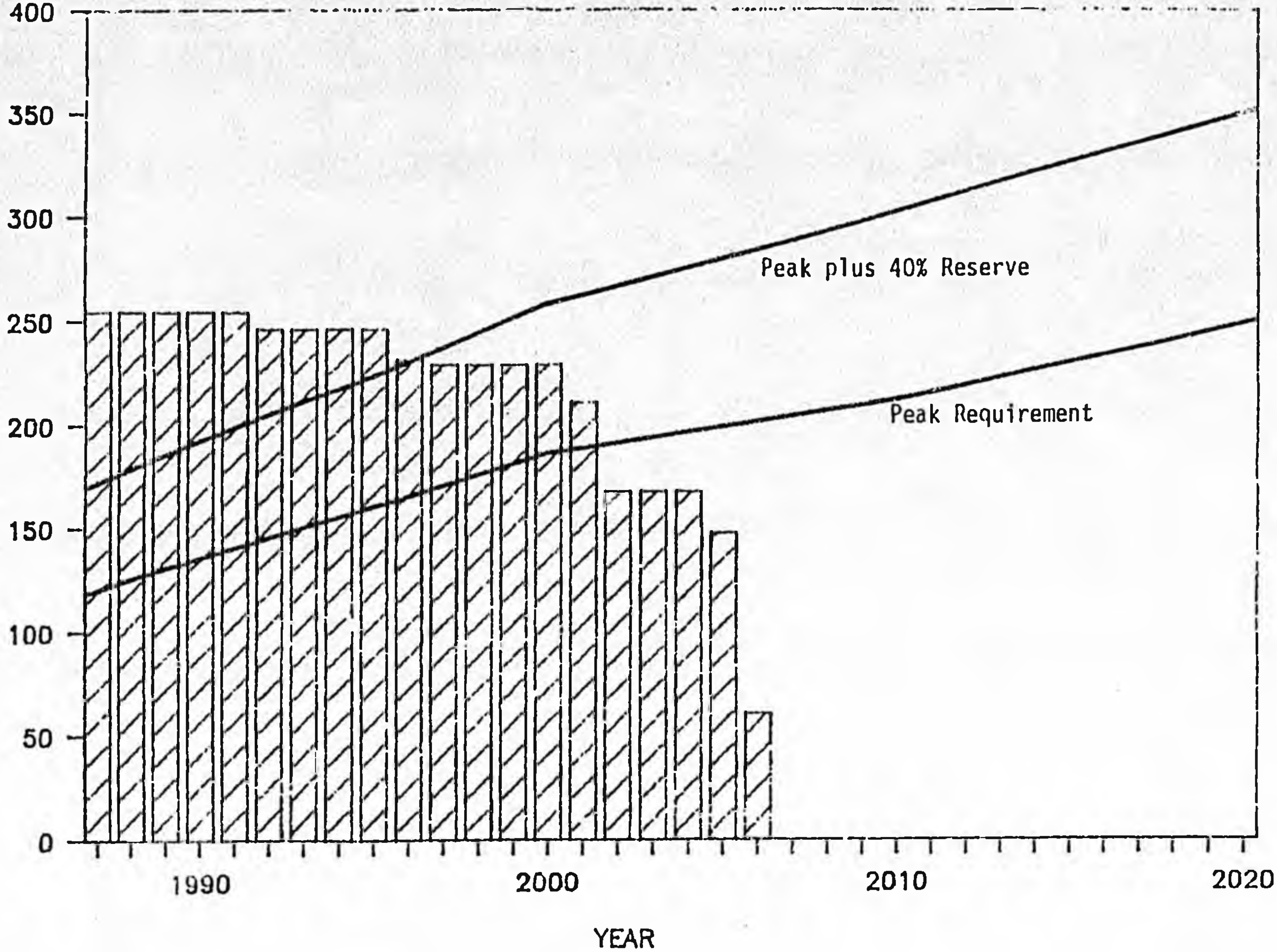
Prepared by the Alaska Power Authority, February 1987.



Prepared by the Alaska Power Authority, February 1987.

EXISTING CAPACITY NET OF RETIREMENTS

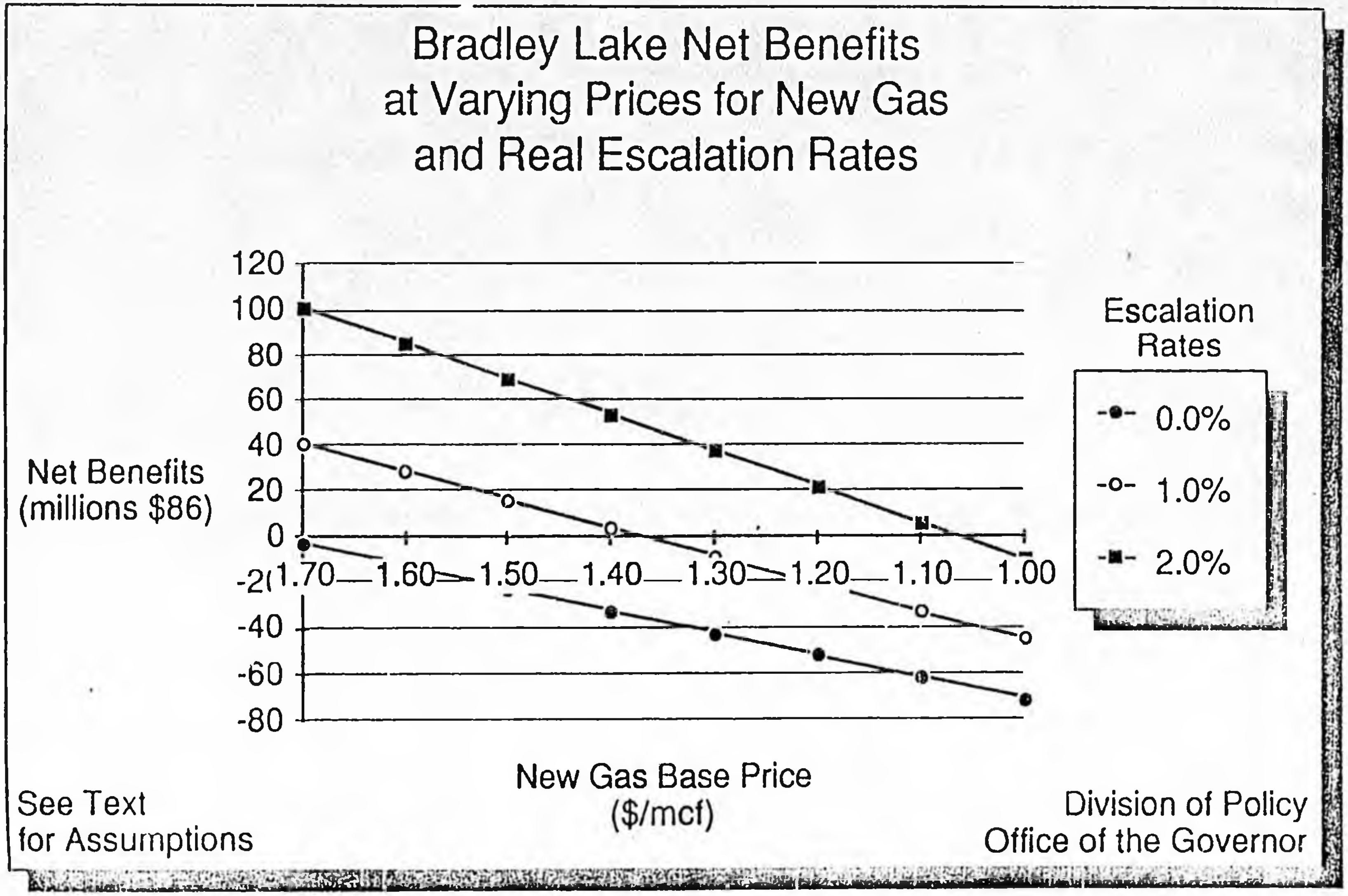
FAIRBANKS



Prepared by the Alaska Power Authority, February 1987.

ATTACHMENT B

FIGURE 1


Bradley Lake Net Benefits
at Varying Prices for New Gas
and Real Escalation Rates
Net Benefits
(millions $86)
120
100
80
60
40
20
0
-20
-40
-60
-80
1.70
1.60
1.50
1.40
1.30
1.20
1.10
1.00
New Gas Base Price
($/mcf)
Escalation
Rates
0.0%
1.0%
2.0%
See Text
for Assumptions
Division of Policy
Office of the Governor

ATTACHMENT C

TABLE C.1 BASE CASE SCENARIO:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($36 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Base Capital Cost Excluding IDC													
($1986/net kw):	$400												
		1987	0.0							$1.63			
Capacity (net kw):	90,000	1988	0.0							1.66			
		1989	18.0							1.70			
Construction Period (years):	2	1990	18.0	4.1						1.73			
Total Bonds:	$48.6	1991		4.0	1.0	0.5	7.5	13.0	3.5	1.77	2.0	20.2	22.2
Bond Term (yrs):	20	1992		3.8	1.0	0.5	7.7	13.0	3.5	1.80	2.0	19.3	21.3
Long-Term Interest Rate:	8.0%	1993		3.6	1.0	0.5	7.8	13.0	3.5	1.84	2.0	18.5	20.5
Bond Payment (1989$):	$4.9	1994		3.5	1.0	0.5	8.0	13.0	3.5	1.87	2.0	17.7	19.7
		1995		3.3	1.0	0.5	8.1	13.0	3.5	1.91	2.0	16.9	18.9
Inflation Rate:	4.5%	1996		3.2	1.0	0.5	8.3	13.0	3.5	1.95	2.0	16.2	18.2
Reinvest Rate:	6.0%	1997		3.0	1.0	0.5	8.4	13.0	3.5	1.99	2.0	15.5	17.5
Discount Rate:	3.5%	1998		2.9	1.0	0.5	8.6	13.1	3.5	2.03	2.0	14.8	16.8
		1999		2.8	1.0	0.5	8.8	13.1	3.6	2.07	2.0	14.2	16.2
		2000		2.7	1.0	0.5	9.0	13.2	3.6	2.11	2.0	13.6	15.6
		2001		2.6	1.0	0.5	9.1	13.2	3.6	2.15	2.0	13.0	15.0
Fixed O&M Cost		2002		2.4	1.0	0.5	9.3	13.3	3.6	2.20	2.0	12.4	14.4
($1986/kw/yr):	$11.25	2003		2.3	1.0	0.5	9.5	13.4	3.6	2.24	2.0	11.9	13.9
		2004		2.2	1.0	0.5	9.7	13.5	3.6	2.29	2.0	11.4	13.4
Variable O&M Cost		2005		2.1	1.0	0.5	9.9	13.6	3.7	2.33	2.0	10.9	12.9
($1986/kwh):	$0.0014	2006		2.1	1.0	0.5	10.1	13.7	3.7	2.38	2.0	10.4	12.4
		2007		2.0	1.0	0.5	10.3	13.8	3.7	2.43	2.0	10.0	12.0
New Turbine Heat Rate		2008		1.9	1.0	0.5	10.5	13.9	3.8	2.47	2.0	9.5	11.5
(BTU/kwh):	11,500	2009		1.8	1.0	0.5	10.7	14.0	3.8	2.52	2.0	9.1	11.1
		2010		1.7	1.0	0.5	10.9	14.2	3.8	2.57	2.0	8.7	10.7
Wellhead Gas Price		2011		1.6	1.0	0.5	11.1	14.3	3.9	2.62	2.0	8.4	10.4
($1986/MMBTU):	$1.60	2012		1.6	1.0	0.5	11.4	14.5	3.9	2.68	2.0	8.0	10.0
Gas Delivery ($86):	$0.00	2013		1.5	1.0	0.5	11.6	14.6	4.0	2.73	2.0	7.7	9.7
Real Wellhead Price		2014		1.4	1.0	0.5	11.8	14.8	4.0	2.79	2.0	7.3	9.3
Escalation Rate:	2.0%	2015		1.4	1.0	0.5	12.1	15.0	4.1	2.84	2.0	7.0	9.0
		2016		1.3	1.0	0.5	12.3	15.2	4.1	2.90	2.0	6.7	8.7

TABLE C.1 BASE CASE SCENARIO:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Cash Flow for Base		2017		1.3	1.0	0.5	12.6	15.3	4.2	2.96	2.0	6.4	8.4
Construction Cost:		2018		1.2	1.0	0.5	12.8	15.5	4.2	3.02	2.0	6.1	8.1
1987	0%	2019		1.2	1.0	0.5	13.0	15.7	4.3	3.08	2.0	5.9	7.9
1988	0%	2020		1.1	1.0	0.5	13.3	16.0	4.3	3.14	2.0	5.6	7.6
1989	50%	2021		1.1	1.0	0.5	13.6	16.2	4.4	3.20	2.0		2.0
1990	50%	2022		1.0	1.0	0.5	13.9	16.4	4.4	3.26	2.0		2.0
		2023		1.0	1.0	0.5	14.1	16.6	4.5	3.33	2.0		2.0
		2024		0.9	1.0	0.5	14.4	16.9	4.6	3.40	2.0		2.0
		2025		0.9	1.0	0.5	14.7	17.1	4.6	3.46	2.0		2.0
Load Factor:	47%	2026		0.9	1.0	0.5	15.0	17.4	4.7	3.53	2.0		2.0
Annual Energy (gwh):	369.2	2027		0.8	1.0	0.5	15.3	17.6	4.8	3.60	2.0		2.0
Transmission Cost		2028		0.8	1.0	0.5	15.6	17.9	4.9	3.68	2.0		2.0
($1986 Millions):	$0.0	2029		0.7	1.0	0.5	15.9	18.2	4.9	3.75	2.0		2.0
		2030		0.7	1.0	0.5	16.2	18.5	5.0	3.82	2.0		2.0
BRADLEY LAKE		2031		0.7	1.0	0.5	16.6	18.8	5.1	3.90	2.0		2.0
Cost to Complete:	$283.0	2032		0.7	1.0	0.5	16.9	19.1	5.2	3.98	2.0		2.0
Debt Service (30 yr):	$25.1	2033		0.6	1.0	0.5	17.2	19.4	5.3	4.06	2.0		2.0
		2034		0.6	1.0	0.5	17.6	19.7	5.3	4.14	2.0		2.0
NP COST GAS	$300.4	2035		0.6	1.0	0.5	17.9	20.0	5.4	4.22	2.0		2.0
+ term & site restoration	$30.0	2036		0.5	1.0	0.5	18.3	20.4	5.5	4.31	2.0		2.0
NP COST GAS	$330.4	2037		0.5	1.0	0.5	18.7	20.7	5.6	4.39	2.0		2.0
		2038		0.5	1.0	0.5	19.0	21.1	5.7	4.48	2.0		2.0
NP COST BRADLEY	$244.6	2039		0.5	1.0	0.5	19.4	21.4	5.8	4.57	2.0		2.0
NET SAVINGS BRADLEY	$85.8	2040		0.5	1.0	0.5	19.8	21.8	5.9	4.66	2.0		2.0

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Newbragas; 861217-29).

TABLE C.2 BASE CASE SCENARIO UNDER REVISED DEMAND FORECAST:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	FUEL SAVINGS ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Base Capital Cost Excluding IDC														
($1986/net kw):	$400													
		1987	0.0								$1.63			
Capacity (net kw):	90,000	1988	0.0								1.66			
		1989	18.0								1.70			
Construction Period (years):	2	1990	18.0	4.1							1.73			
Total Bonds:	$48.6	1991		4.0	1.0	0.5	7.5	2.6	10.4	2.8	1.77	2.0	20.2	19.6
Bond Term (yrs):	20	1992		3.8	1.0	0.5	7.7	2.7	10.3	2.8	1.80	2.0	19.3	18.6
Long-Term Interest Rate:	8.0%	1993		3.6	1.0	0.5	7.8	2.7	10.3	2.8	1.84	2.0	18.5	17.8
Bond Payment (1989$):	$4.9	1994		3.5	1.0	0.5	8.0	2.8	10.2	2.8	1.87	2.0	17.7	16.9
		1995		3.3	1.0	0.5	8.1	2.8	10.2	2.7	1.91	2.0	16.9	16.1
Inflation Rate:	4.5%	1996		3.2	1.0	0.5	8.3	2.9	10.1	2.7	1.95	2.0	16.2	15.3
Reinvest Rate:	6.0%	1997		3.0	1.0	0.5	8.4	2.9	10.1	2.7	1.99	2.0	15.5	14.6
Discount Rate:	3.5%	1998		2.9	1.0	0.5	8.6		13.1	3.5	2.03	2.0	14.8	16.8
		1999		2.8	1.0	0.5	8.8		13.1	3.6	2.07	2.0	14.2	16.2
		2000		2.7	1.0	0.5	9.0		13.2	3.6	2.11	2.0	13.6	15.6
		2001		2.6	1.0	0.5	9.1		13.2	3.6	2.15	2.0	13.0	15.0
Fixed O&M Cost		2002		2.4	1.0	0.5	9.3		13.3	3.6	2.20	2.0	12.4	14.4
($1986/kw/yr):	$11.25	2003		2.3	1.0	0.5	9.5		13.4	3.6	2.24	2.0	11.9	13.9
		2004		2.2	1.0	0.5	9.7		13.5	3.6	2.29	2.0	11.4	13.4
Variable O&M Cost		2005		2.1	1.0	0.5	9.9		13.6	3.7	2.33	2.0	10.9	12.9
($1986/kwh):	$0.0014	2006		2.1	1.0	0.5	10.1		13.7	3.7	2.38	2.0	10.4	12.4
		2007		2.0	1.0	0.5	10.3		13.8	3.7	2.43	2.0	10.0	12.0
New Turbine Heat Rate		2008		1.9	1.0	0.5	10.5		13.9	3.8	2.47	2.0	9.5	11.5
(BTU/kwh):	11,500	2009		1.8	1.0	0.5	10.7		14.0	3.8	2.52	2.0	9.1	11.1
		2010		1.7	1.0	0.5	10.9		14.2	3.8	2.57	2.0	8.7	10.7
Wellhead Gas Price		2011		1.6	1.0	0.5	11.1		14.3	3.9	2.62	2.0	8.4	10.4
($1986/MMBTU):	$1.60	2012		1.6	1.0	0.5	11.4		14.5	3.9	2.68	2.0	8.0	10.0
Gas Delivery ($86):	$0.00	2013		1.5	1.0	0.5	11.6		14.6	4.0	2.73	2.0	7.7	9.7
Real Wellhead Price		2014		1.4	1.0	0.5	11.8		14.8	4.0	2.79	2.0	7.3	9.3
Escalation Rate:	2.0%	2015		1.4	1.0	0.5	12.1		15.0	4.1	2.84	2.0	7.0	9.0
		2016		1.3	1.0	0.5	12.3		15.2	4.1	2.90	2.0	6.7	8.7

TABLE C.2 BASE CASE SCENARIO UNDER REVISED DEMAND FORECAST:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	FUEL SAVINGS ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Cash Flow for Base		2017		1.3	1.0	0.5	12.6		15.3	4.2	2.96	2.0	6.4	8.4
Construction Cost:		2018		1.2	1.0	0.5	12.8		15.5	4.2	3.02	2.0	6.1	8.1
1987	0%	2019		1.2	1.0	0.5	13.1		15.7	4.3	3.08	2.0	5.9	7.9
1988	0%	2020		1.1	1.0	0.5	13.3		16.0	4.3	3.14	2.0	5.6	7.6
1989	50%	2021		1.1	1.0	0.5	13.6		16.2	4.4	3.20	2.0		2.0
1990	50%	2022		1.0	1.0	0.5	13.9		16.4	4.4	3.26	2.0		2.0
		2023		1.0	1.0	0.5	14.1		16.6	4.5	3.33	2.0		2.0
		2024		0.9	1.0	0.5	14.4		16.9	4.6	3.40	2.0		2.0
		2025		0.9	1.0	0.5	14.7		17.1	4.6	3.46	2.0		2.0
Load Factor:	47%	2026		0.9	1.0	0.5	15.0		17.4	4.7	3.53	2.0		2.0
Annual Energy (gwh):	369.2	2027		0.8	1.0	0.5	15.3		17.6	4.8	3.60	2.0		2.0
Transmission Cost		2028		0.8	1.0	0.5	15.6		17.9	4.9	3.68	2.0		2.0
($1986 Millions):	$0.0	2029		0.7	1.0	0.5	15.9		18.2	4.9	3.75	2.0		2.0
		2030		0.7	1.0	0.5	16.2		18.5	5.0	3.82	2.0		2.0
BRADLEY LAKE		2031		0.7	1.0	0.5	16.6		18.8	5.1	3.90	2.0		2.0
Cost to Complete:	$283.0	2032		0.7	1.0	0.5	16.9		19.1	5.2	3.98	2.0		2.0
Debt Service (30 yr):	$25.1	2033		0.6	1.0	0.5	17.2		19.4	5.3	4.06	2.0		2.0
		2034		0.6	1.0	0.5	17.6		19.7	5.3	4.14	2.0		2.0
NP COST GAS	$285.7	2035		0.6	1.0	0.5	17.9		20.0	5.4	4.22	2.0		2.0
+ term & site restoration	$30.0	2036		0.5	1.0	0.5	18.3		20.4	5.5	4.31	2.0		2.0
NP COST GAS	$315.7	2037		0.5	1.0	0.5	18.7		20.7	5.6	4.39	2.0		2.0
		2038		0.5	1.0	0.5	19.0		21.1	5.7	4.48	2.0		2.0
NP COST BRADLEY	$229.9	2039		0.5	1.0	0.5	19.4		21.4	5.8	4.57	2.0		2.0
NET SAVINGS BRADLEY	$85.8	2040		0.5	1.0	0.5	19.8		21.8	5.9	4.66	2.0		2.0

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas1; 861217-29).

TABLE C.3 DELAY OF BRADLEY LAKE AND GAS GENERATION ALTERNATIVE:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)	REAL RATE cents/Kwh
Base Capital Cost Excluding IDC														
($1986/net kw):	$400													
		1987	0.0							$1.63				
Capacity (net kw):	90,000	1988	0.0							1.66				
		1989	0.0							1.70				
Construction Period (years):	2	1990	0.0							1.73				
Total Bonds:	$69.3	1991	0.0							1.77				
Bond Term (years):	20	1992	0.0							1.80				
Long-Term Interest Rate:	10.0%	1993	0.0							1.84				
Bond Payment (1997$):	$8.1	1994	0.0							1.87		41.3	41.3	11.2
		1995	0.0							1.91		39.5	39.5	10.7
Inflation Rate:	4.5%	1996	18.0							1.95		37.8	37.8	10.2
Reinvest Rate:	6.0%	1997	18.0	5.0				5.0	1.4	1.99		36.2	36.2	9.8
Discount Rate:	3.5%	1998		4.8	1.0	0.5	8.6	14.9	4.0	2.03	2.0	34.6	36.6	9.9
		1999		4.6	1.0	0.5	8.8	14.9	4.0	2.07	2.0	33.2	35.2	9.5
Fixed O&M Cost		2000		4.4	1.0	0.5	9.0	14.9	4.0	2.11	2.0	31.7	33.7	9.1
($1986/kw/yr):	$11.25	2001		4.2	1.0	0.5	9.1	14.9	4.0	2.15	2.0	30.4	32.4	8.8
		2002		4.0	1.0	0.5	9.3	14.9	4.0	2.20	2.0	29.1	31.1	8.4
Variable O&M Cost		2003		3.9	1.0	0.5	9.5	14.9	4.0	2.24	2.0	27.8	29.8	8.1
($1986/kwh):	$0.0014	2004		3.7	1.0	0.5	9.7	14.9	4.0	2.29	2.0	26.6	28.6	7.7
		2005		3.5	1.0	0.5	9.9	15.0	4.0	2.33	2.0	25.5	27.5	7.4
New Turbine Heat Rate		2006		3.4	1.0	0.5	10.1	15.0	4.1	2.38	2.0	24.4	26.4	7.1
(BTU/kwh):	11,500	2007		3.2	1.0	0.5	10.3	15.1	4.1	2.43	2.0	23.3	25.3	6.9
		2008		3.1	1.0	0.5	10.5	15.1	4.1	2.47	2.0	22.3	24.3	6.6
		2009		3.0	1.0	0.5	10.7	15.2	4.1	2.52	2.0	21.3	23.3	6.3
Wellhead Gas Price		2010		2.8	1.0	0.5	10.9	15.3	4.1	2.57	2.0	20.4	22.4	6.1
($1986/MMBTU):	$1.60	2011		2.7	1.0	0.5	11.1	15.4	4.2	2.62	2.0	19.6	21.6	5.8
Gas Delivery ($86):	$0.00	2012		2.6	1.0	0.5	11.4	15.5	4.2	2.68	2.0	18.7	20.7	5.6
Real Wellhead Price		2013		2.5	1.0	0.5	11.6	15.6	4.2	2.73	2.0	17.9	19.9	5.4
Escalation Rate:	2.0%	2014		2.4	1.0	0.5	11.8	15.7	4.3	2.79	2.0	17.1	19.1	5.2
		2015		2.3	1.0	0.5	12.1	15.9	4.3	2.84	2.0	16.4	18.4	5.0

TABLE C.3 DELAY OF BRADLEY LAKE AND GAS GENERATION ALTERNATIVE:
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)	REAL RATE cents/Kwh
Cash Flow for Base		2016		2.2	1.0	0.5	12.3	16.0	4.3	2.90	2.0	15.7	17.7	4.8
Construction Cost:		2017		2.1	1.0	0.5	12.6	16.2	4.4	2.96	2.0	15.0	17.0	4.6
1987	0%	2018		2.0	1.0	0.5	12.8	16.3	4.4	3.02	2.0	14.4	16.4	4.4
1988	0%	2019		1.9	1.0	0.5	13.1	16.5	4.5	3.08	2.0	13.7	15.7	4.3
1989	0%	2020		1.8	1.0	0.5	13.3	16.7	4.5	3.14	2.0	13.2	15.2	4.1
1990	0%	2021		1.7	1.0	0.5	13.6	16.9	4.6	3.20	2.0	12.6	14.6	4.0
1991	0%	2022		1.7	1.0	0.5	13.9	17.1	4.6	3.26	2.0	12.0	14.0	3.8
1992	0%	2023		1.6	1.0	0.5	14.1	17.3	4.7	3.33	2.0	11.5	13.5	3.7
1993	0%	2024		1.5	1.0	0.5	14.4	17.5	4.7	3.40	2.0		2.0	0.5
1994	0%	2025		1.5	1.0	0.5	14.7	17.7	4.8	3.46	2.0		2.0	0.5
1995	0%	2026		1.4	1.0	0.5	15.0	17.9	4.9	3.53	2.0		2.0	0.5
1996	50%	2027		1.3	1.0	0.5	15.3	18.2	4.9	3.60	2.0		2.0	0.5
1997	50%	2028		1.3	1.0	0.5	15.6	18.4	5.0	3.68	2.0		2.0	0.5
		2029		1.2	1.0	0.5	15.9	18.7	5.1	3.75	2.0		2.0	0.5
Load Factor:	47%	2030		1.2	1.0	0.5	16.2	18.9	5.1	3.82	2.0		2.0	0.5
Annual Energy (gwh):	369.2	2031		1.1	1.0	0.5	16.6	19.2	5.2	3.90	2.0		2.0	0.5
Transmission Cost		2032		1.1	1.0	0.5	16.9	19.5	5.3	3.98	2.0		2.0	0.5
($1986 Millions):	$0.0	2033		1.0	1.0	0.5	17.2	19.8	5.4	4.06	2.0		2.0	0.5
		2034		1.0	1.0	0.5	17.6	20.1	5.4	4.14	2.0		2.0	0.5
BRADLEY LAKE		2035		0.9	1.0	0.5	17.9	20.4	5.5	4.22	2.0		2.0	0.5
Cost to Complete:	$415.1	2036		0.9	1.0	0.5	18.3	20.7	5.6	4.31	2.0		2.0	0.5
Construction (years):	4	2037		0.9	1.0	0.5	18.7	21.0	5.7	4.39	2.0		2.0	0.5
Total Bonds:	$553.9	2038		0.8	1.0	0.5	19.0	21.4	5.8	4.48	2.0		2.0	0.5
Debt Service (30 yr):	$58.8	2039		0.8	1.0	0.5	19.4	21.7	5.9	4.57	2.0		2.0	0.5
		2040		0.8	1.0	0.5	19.8	22.1	6.0	4.66	2.0		2.0	0.5
NP COST GAS	$250.6	2041		0.7	1.0	0.5	20.2	22.4	6.1	4.75	2.0		2.0	0.5
+ term & site restoration	$30.0	2042		0.7	1.0	0.5	20.6	22.8	6.2	4.85	2.0		2.0	0.5
NP COST GAS	$280.6	2043		0.7	1.0	0.5	21.0	23.2	6.3	4.95	2.0		2.0	0.5
		2044		0.6	1.0	0.5	21.4	23.6	6.4	5.05	2.0		2.0	0.5
NP COST BRADLEY	$406.7	2045		0.6	1.0	0.5	21.9	24.0	6.5	5.15	2.0		2.0	0.5
NET SAVINGS BRADLEY	($126.0)	2046		0.6	1.0	0.5	22.3	24.4	6.6	5.25	2.0		2.0	0.5
		2047		0.6	1.0	0.5	22.7	24.8	6.7	5.35	2.0		2.0	0.5
		2048		0.5	1.0	0.5	23.2	25.3	6.8	5.46	2.0		2.0	0.5

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas3; 861217-29).

TABLE C.4 DELAY OF GAS GENERATION ALTERNATIVE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Base Capital Cost Excluding IDC													
($1986/net kw):	$400												
		1987	0.0							$1.63			
Capacity (net kw):	90,000	1988	0.0							1.66			
		1989	0.0							1.70			
Construction Period (years):	2	1990	0.0							1.73			
Total Bonds:	$69.3	1991	0.0							1.77	2.0	20.2	22.2
Bond Term (years):	20	1992	0.0							1.80	2.0	19.3	21.3
Long-Term Interest Rate:	10.0%	1993	0.0							1.84	2.0	18.5	20.5
Bond Payment (1997$):	$8.1	1994	0.0							1.87	2.0	17.7	19.7
		1995	0.0							1.91	2.0	16.9	18.9
Inflation Rate:	4.5%	1996	18.0							1.95	2.0	16.2	18.2
Reinvest Rate:	6.0%	1997	18.0	5.0				5.0	1.4	1.99	2.0	15.5	17.5
Discount Rate:	3.5%	1998		4.8	1.0	0.5	8.6	14.9	4.0	2.03	2.0	14.8	16.8
		1999		4.6	1.0	0.5	8.8	14.9	4.0	2.07	2.0	14.2	16.2
		2000		4.4	1.0	0.5	9.0	14.9	4.0	2.11	2.0	13.6	15.6
Fixed O&M Cost ($1986/kw/yr):	$11.25	2001		4.2	1.0	0.5	9.1	14.9	4.0	2.15	2.0	13.0	15.0
		2002		4.0	1.0	0.5	9.3	14.9	4.0	2.20	2.0	12.4	14.4
		2003		3.9	1.0	0.5	9.5	14.9	4.0	2.24	2.0	11.9	13.9
Variable O&M Cost ($1986/kwh):	$0.0014	2004		3.7	1.0	0.5	9.7	14.9	4.0	2.29	2.0	11.4	13.4
		2005		3.5	1.0	0.5	9.9	15.0	4.0	2.33	2.0	10.9	12.9
New Turbine Heat Rate		2006		3.4	1.0	0.5	10.1	15.0	4.1	2.38	2.0	10.4	12.4
(BTU/kwh):	11,500	2007		3.2	1.0	0.5	10.3	15.1	4.1	2.43	2.0	10.0	12.0
		2008		3.1	1.0	0.5	10.5	15.1	4.1	2.47	2.0	9.5	11.5
		2009		3.0	1.0	0.5	10.7	15.2	4.1	2.52	2.0	9.1	11.1
Wellhead Gas Price		2010		2.8	1.0	0.5	10.9	15.3	4.1	2.57	2.0	8.7	10.7
($1986/MMBTU):	$1.60	2011		2.7	1.0	0.5	11.1	15.4	4.2	2.62	2.0	8.4	10.4
Gas Delivery ($86):	$0.00	2012		2.6	1.0	0.5	11.4	15.5	4.2	2.68	2.0	8.0	10.0
Real Wellhead Price		2013		2.5	1.0	0.5	11.6	15.6	4.2	2.73	2.0	7.7	9.7
Escalation Rate:	2.0%	2014		2.4	1.0	0.5	11.8	15.7	4.3	2.79	2.0	7.3	9.3
		2015		2.3	1.0	0.5	12.1	15.9	4.3	2.84	2.0	7.0	9.0

TABLE C.4 DELAY OF GAS GENERATION ALTERNATIVE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COS ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Cash Flow for Base		2016		2.2	1.0	0.5	12.3	16.0	4.3	2.90	2.0	6.7	8.7
Construction Cost:		2017		2.1	1.0	0.5	12.6	16.2	4.4	2.96	2.0	6.4	8.4
1987	0%	2018		2.0	1.0	0.5	12.8	16.3	4.4	3.02	2.0	6.1	8.1
1988	0%	2019		1.9	1.0	0.5	13.1	16.5	4.5	3.08	2.0	5.9	7.9
1989	0%	2020		1.8	1.0	0.5	13.3	16.7	4.5	3.14	2.0	5.6	7.6
1990	0%	2021		1.7	1.0	0.5	13.6	16.9	4.6	3.20	2.0		2.0
1991	0%	2022		1.7	1.0	0.5	13.9	17.1	4.6	3.26	2.0		2.0
1992	0%	2023		1.6	1.0	0.5	14.1	17.3	4.7	3.33	2.0		2.0
1993	0%	2024		1.5	1.0	0.5	14.4	17.5	4.7	3.40	2.0		2.0
1994	0%	2025		1.5	1.0	0.5	14.7	17.7	4.8	3.46	2.0		2.0
1995	0%	2026		1.4	1.0	0.5	15.0	17.9	4.9	3.53	2.0		2.0
1996	50%	2027		1.3	1.0	0.5	15.3	18.2	4.9	3.60	2.0		2.0
1997	50%	2028		1.3	1.0	0.5	15.6	18.4	5.0	3.68	2.0		2.0
		2029		1.2	1.0	0.5	15.9	18.7	5.1	3.75	2.0		2.0
Load Factor:	47%	2030		1.2	1.0	0.5	16.2	18.9	5.1	3.82	2.0		2.0
Annual Energy (gwh):	369.2	2031		1.1	1.0	0.5	16.6	19.2	5.2	3.90	2.0		2.0
Transmission Cost		2032		1.1	1.0	0.5	16.9	19.5	5.3	3.98	2.0		2.0
($1986 Millions):	$0.0	2033		1.0	1.0	0.5	17.2	19.8	5.4	4.06	2.0		2.0
		2034		1.0	1.0	0.5	17.6	20.1	5.4	4.14	2.0		2.0
BRADLEY LAKE		2035		0.9	1.0	0.5	17.9	20.4	5.5	4.22	2.0		2.0
Cost to Complete:	$283.0	2036		0.9	1.0	0.5	18.3	20.7	5.6	4.31	2.0		2.0
Debt Service (30 yr):	$25.1	2037		0.9	1.0	0.5	18.7	21.0	5.7	4.39	2.0		2.0
		2038		0.8	1.0	0.5	19.0	21.4	5.8	4.48	2.0		2.0
NP COST GAS	$250.6	2039		0.8	1.0	0.5	19.4	21.7	5.9	4.57	2.0		2.0
+ term & site restoration	$30.0	2040		0.8	1.0	0.5	19.8	22.1	6.0	4.66	2.0		2.0
NP COST GAS	$280.6												
NP COST BRADLEY	$244.6												
NET SAVINGS BRADLEY	$36.0												

NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (Bradgas2; 861217-29).

HOUSE RESEARCH
RAILBELT ENERGY ANALYSIS

	Completion Date
I) Railbelt Energy Demand	March 18, 1987
A) Projected Railbelt Electrical Demand B) Demand for Bradley Lake Power C) Existing Installed Capacity and Retirement Schedules in Light of Current Revised Demand Forecasts.	
II) Bradley Lake Project	March 18, 1987
A) Examination of OMB's Feasibility Analysis B) Economic Feasibility Compared to Gas Alternative	
III) PURPA Generating Facilities	April 9, 1987
A) Regulatory background B) Bradley Lake Project Financing and Power Sales Agreements	
IV) Additional Issues	
A) Long-Term Gas Availability for Power Generation	April 10, 1987
B) Bradley Lake Restoration Requirements by FERC	
V) Transmission Lines	May 1, 1987
A) Kenai-Anchorage Transmission Line: 1) Current and Projected Electrical Demand in Kenai and Anchorage 2) Power Displacement: Generating Capacity 3) Existing Line Reliability and Upgradability 4) Natural Gas Price Differential Between Kenai and Anchorage 5) Cost of Four Alternate Routes	

Completion Date

B) Anchorage-Fairbanks Intertie — May 1, 1987

1) Current and Projected Electrical Demand in Anchorage and Fairbanks
2) Current Intertie Usage/Revenue Sharing/Reliability
3) Impact of Fuel Oil Prices on Intertie Usage

C) Review/Critique Alaska Power Authority Transmission Lines Analyses — May 1, 1987

D) Cost/Benefit Analyses for Transmission Lines — May 1, 1987

1) Anchorage-Kenai
   a) No change
   b) Upgrade existing line
   c) New line

2) Anchorage-Fairbank
   1) No change
   2) Total upgrade
   3) Upgrade sections over time

VII) **Financing Mechanisms for Bradley Lake and Transmission Lines** — May 1, 1987

A) Identify Existing Funding Sources

1) Railbelt Energy Fund
2) Accrued Interest
3) Remainder of Bradley Appropriations
4) Bond Market

B) Financing Scenarios

1) Examine various financing mechanisms with respect to State contribution, consumer rates, and the long-term integrity of a Railbelt Energy Fund
2) Bradley Lake Project Only
   a) Utilities pay $175 million bond, State pays remainder
   b) State contributes larger subsidy
   c) Four-dam pool loan concept
3) Bradley Lake Plus Kenai and/or Fairbanks Intertie(s)
   a) Spend all of Railbelt Energy Fund

   .

   .

   z) Railbelt Fund as a revolving loan fund to pay for tranmission lines over time

HOUSE RESEARCH
RAILBELT ENERGY ANALYSIS

		Completion Date
I)	**Railbelt Energy Demand**	March 18, 1987
	A) Projected Railbelt Electrical Demand B) Demand for Bradley Lake Power C) Existing Installed Capacity and Retirement Schedules in Light of Current Revised Demand Forecasts.	
II)	**Bradley Lake Project**	March 18, 1987
	A) Examination of OMB's Feasibility Analysis B) Economic Feasibility Compared to Gas Alternative	
III)	**PURPA Generating Facilities**	April 9, 1987
	A) Regulatory background B) Bradley Lake Project Financing and Power Sales Agreements	
IV)	**Additional Issues**	
	A) Long-Term Gas Availability for Power Generation	April 10, 1987
	B) Bradley Lake Restoration Requirements by FERC	
V)	**Transmission Lines**	May 1, 1987
	A) Kenai-Anchorage Transmission Line: 1) Current and Projected Electrical Demand in Kenai and Anchorage 2) Power Displacement: Generating Capacity 3) Existing Line Reliability and Upgradability 4) Natural Gas Price Differential Between Kenai and Anchorage 5) Cost of Four Alternate Routes	

Completion Date

B) Anchorage-Fairbanks Intertie — May 1, 1987
- 1) Current and Projected Electrical Demand in Anchorage and Fairbanks
- 2) Current Intertie Usage/Revenue Sharing/Reliability
- 3) Impact of Fuel Oil Prices on Intertie Usage

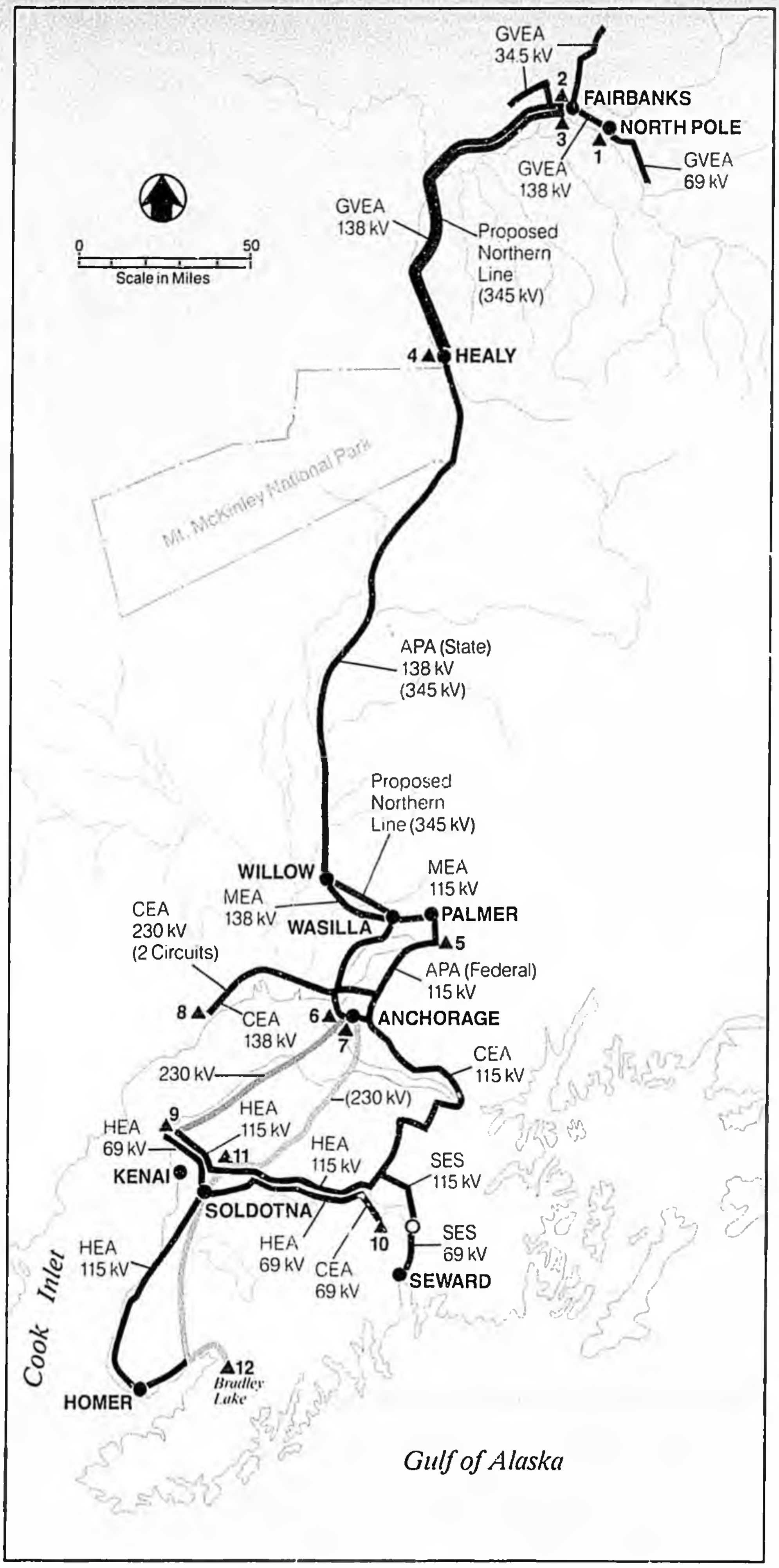
C) Review/Critique Alaska Power Authority Transmission Lines Analyses — May 1, 1987

D) Cost/Benefit Analyses for Transmission Lines — May 1, 1987
- 1) Anchorage-Kenai
  - a) No change
  - b) Upgrade existing line
  - c) New line
- 2) Anchorage-Fairbank
  - 1) No change
  - 2) Total upgrade
  - 3) Upgrade sections over time

VII) Financing Mechanisms for Bradley Lake and Transmission Lines — May 1, 1987

A) Identify Existing Funding Sources
- 1) Railbelt Energy Fund
- 2) Accrued Interest
- 3) Remainder of Bradley Appropriations
- 4) Bond Market

B) Financing Scenarios
- 1) Examine various financing mechanisms with respect to State contribution, consumer rates, and the long-term integrity of a Railbelt Energy Fund
- 2) Bradley Lake Project Only
  - a) Utilities pay $175 million bond, State pays remainder
  - b) State contributes larger subsidy
  - c) Four-dam pool loan concept
- 3) Bradley Lake Plus Kenai and/or Fairbanks Intertie(s)
  - a) Spend all of Railbelt Energy Fund
  - .
  - .
  - z) Railbelt Fund as a revolving loan fund to pay for tranmission lines over time



Railbelt Generation and Transmission Systems

LEGEND

- Community
- Generation Station
- 2 — Generation Station Identification Number
- 230 kV — Line Capacity
- Line Capacity Change
- Northern Line (Proposed)
- Fritz Creek Transmission Line (Proposed)
- Enstar Gas Pipeline Route (Proposed)
- Tesoro Products Line Route (Proposed)
- Transmission Line Route (Existing)

Prepared by ARECA

1. Oil Fired Generation — 121.8 mW — Golden Valley Electric Association — North Pole
2. Oil Fired Generation — 40.6 mW — Fairbanks Municipal Utilities System — Fairbanks
   Coal Fired Generation — 28.6 mW — Fairbanks Municipal Utilities System — Fairbanks
3. Oil Fired Generation — 51 mW — Golden Valley Electric Association — Fairbanks
4. Coal Fired Generation — 25 mW — Golden Valley Electric Association — Healy
5. Hydroelectric Generation — 30 mW — Alaska Power Administration (Federal) — Eklutna
6. Natural Gas Generation — 330 mW — Anchorage Municipal Light & Power — Anchorage
7. Natural Gas Generation — 49.4 mW — Chugach Electric Association — Anchorage
8. Natural Gas Generation — 360 mW — Chugach Electric Association — Beluga
9. Natural Gas Generation — 81.7 mW — Chugach Electric Association — Bernice Lake
10. Hydroelectric Generation — 17.4 mW — Chugach Electric Association — Cooper Lake
11. Natural Gas Generation — 38.5 mW — Alaska Electric Generation & Transmission — Soldotna
12. Hydroelectric Generation — 90 mW — Alaska Power Authority (State) — Bradley Lake

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* ORIGINAL                                                  *
* SENT:            04/08/87  TIME: 13:36                    *
* FROM:            LIQC[redacted]                           *
* SUBJECT:         S RES   ELECTRIC                         *
* PRINT DATE:      04/08/87  TIME: 13:36                    *
*                                                           *
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GLENN,
OUR PARTICIPANT, [redacted] OF M.E A., WILL BE ARRIVING AROUND 3:00PM. JUST WANTED TO LET YOU KNOW IN CASE YOU NEEDED TO PASS THAT INFO ON TO THE CHAIR. WE WILL DIAL IN AS SOON AS HE ARRIVES.
MARY - MATSU

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*************************************************************
*                                                           *
* DELIVER TO: LTCCGTG                                       *
*                                                           *
*                                                           *
* ORIGINAL                                                  *
* SENT:            04/08/87  TIME [redacted]:49             *
* FROM:            LT[redacted]  FAIRBANKS                  *
* SUBJECT:         4/8 SRES SB 205 206, HB 120              *
* PRINT DATE:      04/08/87  TIME: 13:49                    *
*                                                           *
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DATE: ___APRIL 8, 1987___
SITE: ___FAIRBANKS___
SPONSOR: ___SENATE RESOURCES___
SUBJECT: ___SB 205, SB 206, HB 120___
MODERATOR: ___FRAN___

****

TESTIFY:

NAME\REPRESENTING	ADDRESS	PHONE:#

****

OBSERVE:

NAME\REPRESENTING	ADDRESS	PHONE #
1. [redacted]		

****

Official Business

COMMITTEE: SENATE - HOUSE RESOURCES

DATE: MARCH 8, 1987

Subject of meeting:

SB 206

ALASKA POWER AUTHORITY BONDING

SIGN-IN

NAME	ADDRESS	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY?
JACK KREINHEDER			Division of Policy Governor's Office	Yes - SB 206

Official Business

COMMITTEE:

DATE:

SIGN-IN

Subject of meeting:

NAME	ADDRESS	PHONE	REPRESENTING	DO YOU WANT TO TESTIFY ?

TELECONFERENCE PARTICIPATION

SPONSOR ______________________

DATE/TIME ______________________

SUBJECT ______________________

LIO

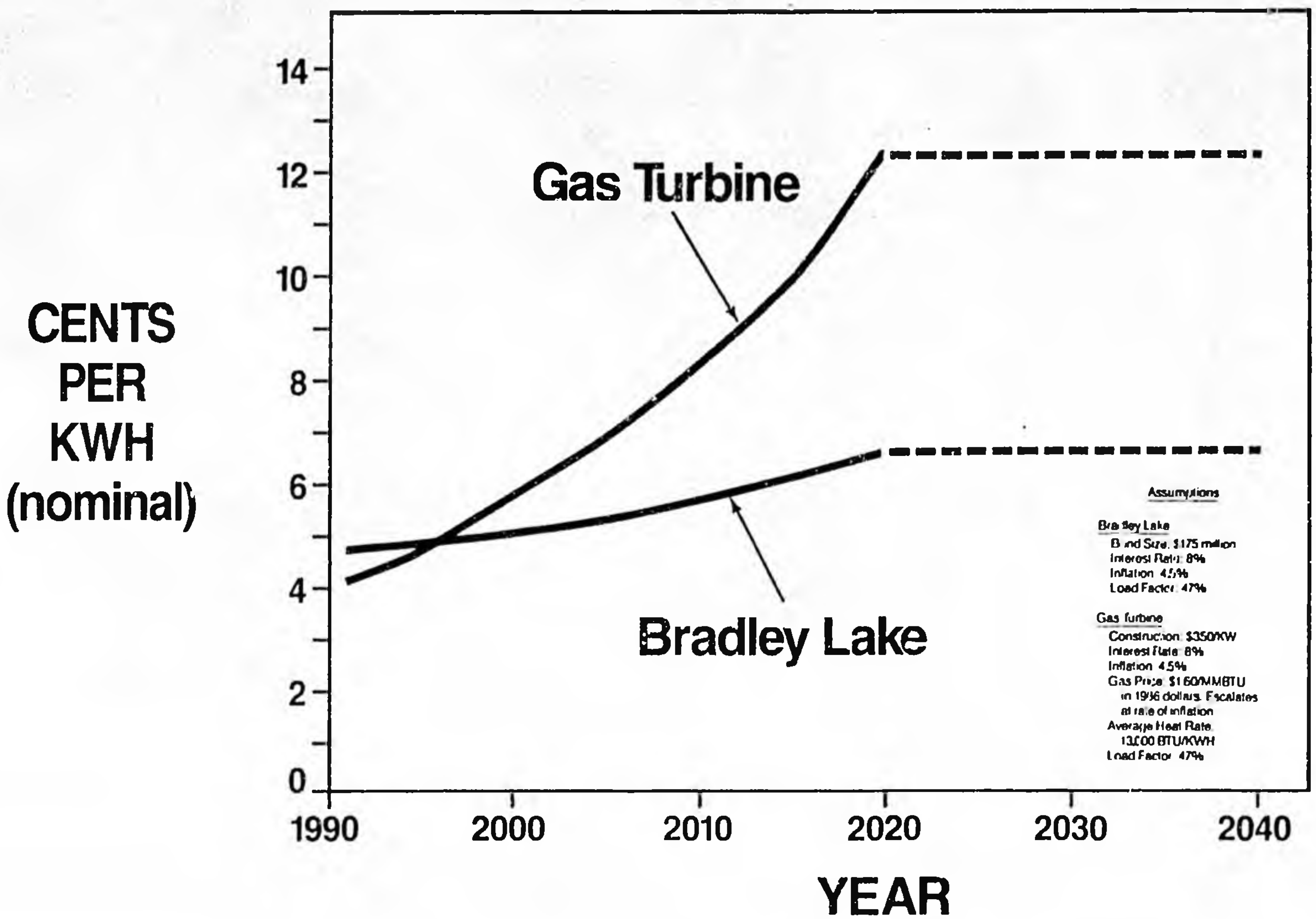
ANCHORAGE ✓ 2 observers; 2 to testify — Jeff Bohman, Bob Roggerd	PETERSBURG*
BARROW*	SITKA
BETHEL	SOLDOTNA
DELTA JUNCTION*	VALDEZ*
DILLINGHAM*	
	LTC
FAIRBANKS Fred Pratt	FT. YUKON
	GALENA
GLENNALLEN*	HOMER
JUNEAU	NAKNEK
KETCHIKAN	NEWHALEN
	SAINT PAUL
KODIAK	SAND POINT
KOTZEBUE*	TOGIAK
	UNALASKA
MAT-SU (will join @ 3:00pm) Bruce Scott	WRANGELL
NOME*	SEWARD (Not online)

VTS'S ON BACK

* SESSION ONLY

10/86

BRADLEY LAKE vs. GAS TURBINE PROJECTED RATES



CORRECTION

THIS DOCUMENT
HAS BEEN REPHOTOGRAPHED
TO ASSURE LEGIBILITY

TELECONFERENCE PARTICIPATION ____________ SPONSOR ____________

DATE/TIME ____________ SUBJECT ____________

LIO

ANCHORAGE ✓ *2 observers; 2 to testify — Jeff Bohman, Bob Roggard*	PETERSBURG*
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	GALENA
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MAT-SU *(will join @ 3:00PM) Bruce Scott*	UNALASKA
	WRANGELL
NOME*	*SEWARD (not online)*

VTS'S ON BACK

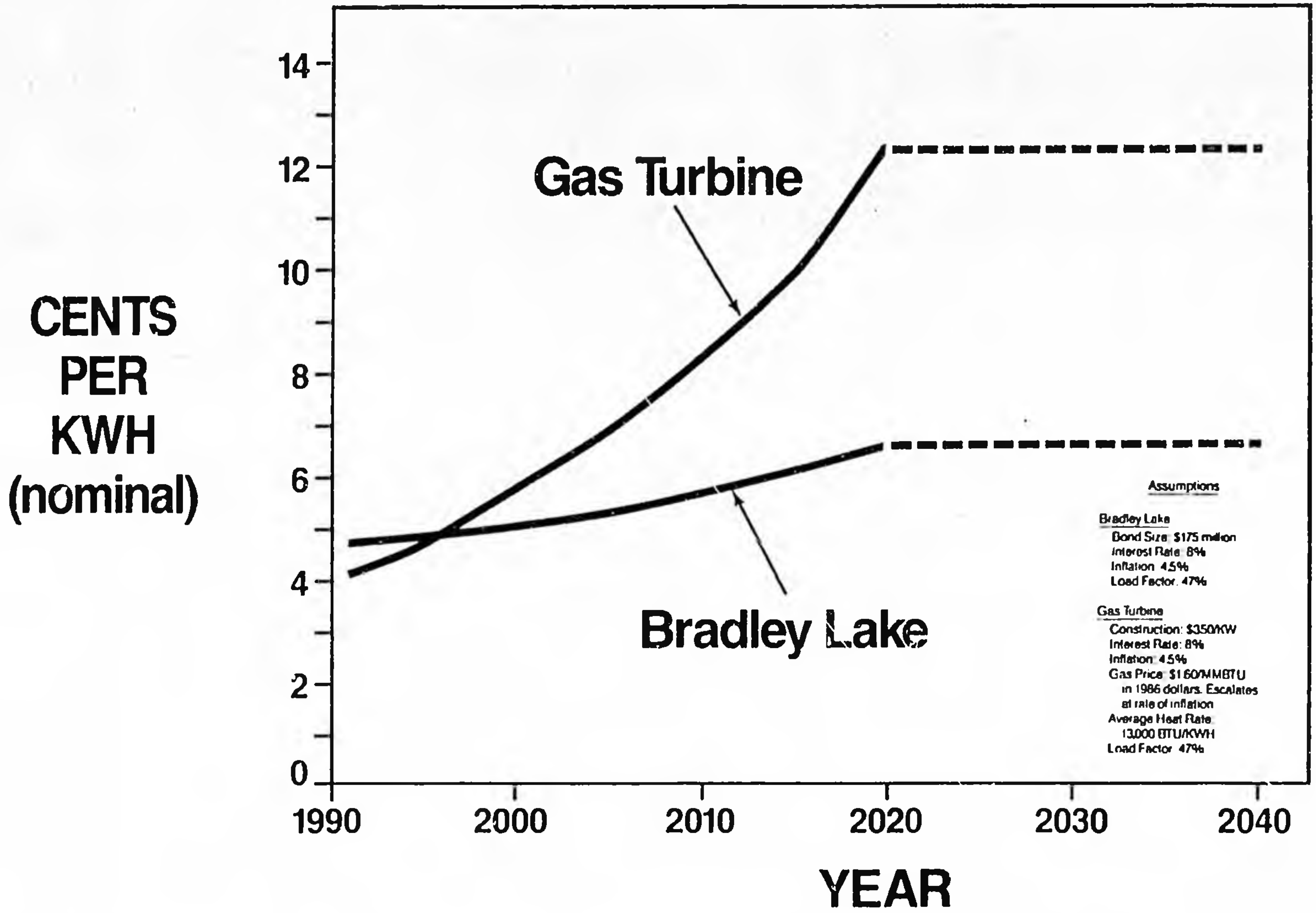
* SESSION ONLY

10/86

VTS

AMB - AMBLER		KLA - KLAWOCK	
ANA - ANAKTUVIK PASS		MEN - MENTASTA	
AND - ANDERSON		MET - METLAKATLA	
ANG - ANGOON		NEN - NENANA	
CAN - CANTWELL		NIK - NIKISKI	
CHS - CHISTOCHINA		NOR - NOORVIK	
CHI - CHITINA		NOT - NORTH TONSINA	
COP - COPPER CENTER		NOW - NORTHWAY	
COR - CORDOVA		PEL - PELICAN	
CRA - CRAIG		PTH - POINT HOPE	
DOT - DOT LAKE		SAV - SAVOONGA	
EAG - EAGLE		SLW - SELAWIK	
GAK - GAKONA		SEW - SEWARD	
GAM - GAMBELL		SHS - SHISHMAREF	
HNS - HAINES		SKG - SKAGWAY	
HEA - HEALY		SLA - SLANA	
HOO - HOONAH		TOK - TOK	
HPB - HOOPER BAY		OOK - TOOKSOOK BAY	
HYD - HYDABURG		UNK - UNALAKLEET	
KAK - KAKE		WAI - WAINWRIGHT	
KAT - KAKTOVIK		YAK - YAKUTAT	
KEN - KENNY LAKE			

BRADLEY LAKE vs. GAS TURBINE PROJECTED RATES



-- Graph Tape 461

BRADLEY LAKE PROJECT

TOTAL COST IF TERMINATED

Expenditures Through March 31, 1987	$	52.4 million
Additional Expenditure Through May 1987		5.0 million
Contract Termination Costs		4.4 million
Site Restoration Cost		8.0–33.0 million
TOTAL		$ 69.8–94.8 million

LeResche
#2

tape #576

Alaska Power Authority

RAILBELT INTERTIE BENEFITS

Quantified

- Economy Interchange
- Reserve Sharing
- System Efficiency
- Siting Flexibility for New Plants

Not Quantified

- System Reliability
- Increased Utility Coordination
- Distribution of Bradley Lake Benefits
- Enhanced Competition Among Fuel Suppliers

LeResche #3 Tape # 657

Alaska Power Authority

RAILBELT INTERTIE

COSTS AND BENEFITS

(Expressed in 1986 Dollars)

	Estimated Benefits	Estimated Costs
Full Intertie Proposal	$ 423 million	$ 270 million
Anchorage to Kenai Peninsula Only	209 million	125 million
Anchorage to Fairbanks Only	211 million	145 million

Note: Costs include operations and maintenance for 30 years

****
*   TELECOPY COVER LETTER   *
****

DATE 4-8-87

TIME 10:35 am.

PLEASE DELIVER THE FOLLOWING PAGES TO:

Name: REP. SAM COTTON AND REP. PAT POURCHOT

Telecopier Number: 586-9548

FROM: JANET L. VEO
6133 E. 12th
Anchorage, AK. 99504

TRANSMITTING 7 PAGES
(INCLUDING THIS COVER PAGE)

IF TRANSMISSION IS NOT COMPLETE,
PLEASE CALL: (907) 564-6452

RE: Senate Resources Joint Meeting on Railbelt Energy
April 8, 1987 at 1:30 pm.

DATE: April 8, 1987

TO: Rep. Pat Pourchot
Rep. Sam Cotton

FROM: Janet L. Veo
6133 East 12th
Anchorage, AK 99504

Today at 1:30 pm, Capitol 516 a joint meeting with Senate Resources is meeting on Railbelt Energy. I have serious concerns regarding the Bradley Lake Hydroelectric Project and Anchorage/Fairbanks and Anchorage/Kenai interties and request that the railbelt utilities and the Alaska Power Authority (APA) be questioned on some of the following points. Before I proceed with these questions I would like to provide a brief overview.

Final Bradley Lake power sales agreements were before the Alaska Power Authority Board for approval on February 27, 1987. There documents were pulled from the agenda because a conditional letter was attached which required APA to build the Anchorage/Kenai Intertie and upgrade the Anchorage/ Fairbanks intertie at a cost of $200 million. On March 13, 1987 at the Alaska Power Authority Board meeting,Bob LeResch, Executive Director of APA, reported that the utilities would wait to sign the Bradley Lake power sales agreements after approaching the legislature for funding from the Railbelt Energy Fund. Since that date legislation has been introduced to remove any obstacles which may delay approval of the power sales agreements and completion of the interties. I believe this legislation is not in the interest of the consumer and cititzens of this state. The legislation I refer to is:

> SSSB 22, Sec. 2 which exempts the APA from the Alaska Public Utility Commission's (APUC) oversight with respect to wholesale power agreements. Reference the attached testimony.
>
> SB 206, Sec. 2 (2) expempts APA from proving that the interties are economically feasible and in the best interest of the citizens. The interties is would be the largest power project to date and would not be required to prove economic viability.

My concerns and the questions I would hope you would ask the railbelt utilites and the Alaska Power Authority are as follows:

1. How do the uitilites intend to use the regional grid (i.e., Anch/Kenai and Anch/Fai interties) and are there

any agreements in place to assure usage?

2. What organizational structure or document is in place to assure economy energy? This is to say the cheapest energy from avaliable sources. Cheap energy occurs due to differances in prices, systems and generating units.

   Is Chugach willing to pass on their low cost gas contracts to the power grid for the benefit of other utilities?

   Is there central or coordinated dispatch to make low cost energy avaliable among the utilities?

3. Why haven't the utilites made better use of the existing Anchorage/Fairbanks intertie? See the attached schedule of the 1986 Anchorage Fairbanks usage.

I would appreciate your careful review before the Legislature acts on questions regarding Bradley Lake and the specifically the interties. The concerns I express are on behalf of myself as a citizen and Anchorage area consumer. If you have any questions you may reach me at the following telephone numbers.

Day Telephone: (907) 564-6482
Evening Telephone: (907) 338-2974

Sincerely,

Janet L. Veo

Janet L. Veo

TESTIMONY ON SSSB 22 - TO FINANCE COMMITTEE

APRIL 7, 1987

My name is Janet L. Veo. I reside at 6133 East 12th, Anchorage, AK. The testimony I am presenting is on behalf of myself as a private citizen.

I oppose passage of Sponsor Subsititute Senate Bill 22, Section 2 (AS 42.05.431(c)). Exemption of the Alaska Power Authority from the Alaska Public Utilities Commission's oversight with respect to wholesale power sales contracts is not in the best interest of the consumer. I believe that the Bradley Lake Hydroelectric Project and the Anchorage/Kenai and Anchorage/Fairbanks transmission interties will significantly increase my cost of power as well as my cost of natural gas from Enstar for the next ten to fifteen years.

I want to give a concrete example of why I believe the Alaska Power Authority will not protect my interests as a consumer. The Alaska Power Authority has demonstrated its willingness to bypass statutory and regulatory requirements for public input as evidenced in their actions with respect to Bradley Lake and the interties. By virtue of the proposed power sales agreements, the Alaska Power Authority has contractually linked Bradley Lake and the interties as one project. The Alaska Power Authority has failed to go through the statutory process as set forth in AS 44.83.177 through AS 44.83.187 and their own regulations.

To my knowledge, the Alaska Power Authority has not held any meetings expressly for the purpose of informing the public or for providing the opportunity for public comment regarding the interties. In fact, the Letter Agreement that spells out the conditions that would lead to execution of the power sales agreements is not available to the public. I requested copies of the proposed wholesale power sales agreements and the conditional letter agreement prior to the February 27, 1987, APA board meeting. These documents were before the Alaska Power Authority Board for final approval. I was denied copies by APA's Director of Finance. The reason given was that these documents were not signed. Furthermore, none of the power sales contract negotiation sessions with the utilities were published in the local newspaper for public notice. These measures have precluded any meaningful opportunity for public comment on the process leading up to final power sales agreements.

Alaska Power Authority stated in their board meeting of March 13, 1987, that they would proceed with construction of Bradley Lake once they have signed power sales agreements. The power sales agreements are contigent upon the utilities receiving funding by the legislature for the interties. With respect to the interties, the Alaska Power Authority has not completed a reconnaissance study which requires the opportunity for public input, it has not held public comment meetings, it has not evaluated economic alternatives, it has not received Office of Budget and Management review and approval, nor has it completed a feasibility study and finance plan. Despite this, the Alaska Power Authority contractually committed itself to constructing the interties.

All wholesale power sales contracts by the Alaska Power Authority should be approved by the Alaska Public Utilities Commission before such agreements are finalized. Municipal ratepayers and cooperative members are one and the same. Any after-the-fact disallowance of Alaska Power Authority related costs of these entities is rendered meaningless unless Alaska Public Utilities Commission approval is obtained prior to final contracts. Repeatedly the Alaska Power Authority has refused to include the public in planning for the interties either as a stand alone project or as a newly reconfigured Bradley Lake/Intertie Project. Should the Alaska Public Uitlities Commission not have oversight, the public will not be represented in the decision making process. I as a consumer will not have any protection from excessive costs and unwise decisions made by the Alaska Power Authority or the utilities. I strongly oppose passage of Sponsor Substitute Senate Bill 22, Section 2 (AS 42.05.431 (c)).

I thank you for your time and consideration of this matter.

ANCHORAGE FAIRBANKS INTERTIE

Month	GOLDEN VALLEY ELECTRIC (GWH) Estimated Takes	Actual Takes	MUS (GWH) Estimated Takes	Actual Takes
1986				
January	22.2	23.7		
February	22.0	18.0		
March	19.0	16.0		
April	17.9	10.6	Not available.	
May	15.0	0.4		
July	16.5	0.1		
December	25.5	0.4		
1987				
January	25.0	3.4	1.1	0.0
1986	73.5			
July '86 - Jan '87	140.0	7.5	11.0	0.1

Golden Valley is the main Anch/Fai intertie purchaser. The amount MUS takes is negligible.

Annual Line Capacity	613.2 Gwh		
GVE 1986 Takes	73.5 Gwh	=	12% of total capacity available
Jan - Apr '86 Takes	68.3 Gwh	=	93% of GVE '86 takes
May - Dec '86 Takes	5.2 Gwh	=	7% of GVE '86 takes

The decline in electrical takes from Anchorage by GVE occurred due to low low cost fuel oil in Fairbanks compared to Anchorage electrical prices.

Above data provided by Dick Emmermon, APA economist.

NOTE: There is no operating agreement in place for the proposed interties. An agreement should accompany the power sales agreements spelling out takes, payments of operating costs, maintenance, etc.

Alaska Power Authority

Railbelt Intertie Proposal

Preliminary Economic Assessment

March 1987

RAILBELT INTERTIE PROPOSAL

PRELIMINARY ECONOMIC ASSESSMENT

Summary and Conclusions

A contract for $25,000 was issued by the Alaska Power Authority to Lotus Consulting Group, an electric utility consulting firm based in California, for a preliminary assessment of economic benefits associated with two proposed transmission projects: upgrade of the existing Anchorage/Fairbanks intertie and construction of a new Anchorage/Kenai Peninsula intertie. Presented below is an overview of the issue, a summary of the benefit assessment undertaken by Lotus Consulting Group, discussion of other associated benefits that are not captured in that assessment, and a comparison of benefits with estimated project costs. The report prepared by Lotus Consulting Group is attached.

On the basis of the analysis performed, it is concluded that the proposed transmission projects are capable of delivering economic benefits in excess of their costs, and consequently warrant further consideration. The primary benefit categories that are quantified in the analysis are economy interchange, reserve sharing, system efficiency and, to a partial extent, siting flexibility for new generating plants. Other benefits that are not quantified include improved system reliability, increased utility coordination, distribution of Bradley Lake benefits, and enhanced competition among fuel suppliers.

The sum of the benefits identified in the system modeling performed by Lotus Consulting Group is approximately $150 million higher (in 1986 dollars) than the sum of the estimated costs. However, because most of the costs are incurred before most of the identified benefits are realized, the present value of costs and identified benefits are approximately the same. If the benefits not captured in the system modeling were brought into the comparison, then the present value of benefits would exceed the present value of costs.

Background and Purpose of the Study

A Request for Proposal (RFP) was issued by the Power Authority for a feasibility study of the Anchorage/Kenai Peninsula intertie in August 1986. The anticipated cost of that study is approximately $300,000, with the State contributing half of the funding and the Railbelt utilities contributing the other half. The firm that won the contract included $10,000 within its proposed budget to perform the economic cost/benefit part of the evaluation. However, despite its superior qualifications to perform other elements of the analysis such as engineering, design, and cost estimation, that firm failed to demonstrate adequate ability regarding the estimation of economic benefits. As a result, that component of the project was deleted from the scope of work, and a decision was made by the Power Authority to pursue that analysis separately.

During the same period of time, the Railbelt Energy Council was formulating its proposal for the State to upgrade the existing Anchorage/Fairbanks intertie as well as construct a new Anchorage/Kenai Peninsula line. It became apparent that the economic merits of both transmission proposals would become a subject of interest during the 1987 legislative session. Consequently, the Power Authority decided to consolidate the economic assessment of both proposals within a single contract, and to aim for completion of that assessment as early as possible in the 1987 session. State funding in the amount of $25,000 was identified for the effort, an RFP was developed in November 1986, and a contract was awarded to Lotus Consulting Group on December 31, 1986.

A highly detailed analysis of each alternative is not possible within the funding and time constraints that characterized this effort. The goal of the study, explicitly stated in the RFP, was to produce an understanding of the benefits of both transmission proposals sufficient to judge whether they are promising with regard to economic feasibility criteria.

Existing Generation and Transmission System

For the following discussion, it may be helpful to refer to the simplified Railbelt transmission map shown in Figure 1.

On the Kenai Peninsula, existing generating capacity consists primarily of natural gas units at Bernice Lake and Soldotna totaling about 120 MW, and a hydroelectric facility at Cooper Lake of about 17 MW. The natural gas units are currently used primarily for reserve capacity and winter peaking requirements. Most of the electric energy currently consumed on the Kenai Peninsula is generated at the Beluga station and brought south over the existing transmission line. For the intertie economic study, it is assumed that the Bradley Lake project is operational throughout the period of analysis.

The existing transmission line between Anchorage and the Kenai Peninsula is owned by Chugach Electric Association, is constructed for operation at 115 KV and has a rated transfer capability of 55 MW. However, due to the demand of customers along the route and also due to significant line losses, it is estimated that only

40 MW can be assumed for delivery in Soldotna given a 55 MW input on the Anchorage end of the line. In addition, the line is subject to avalanche and weather induced outages, and as a result its reliability is a continuing concern. It is primarily for that reason that generating capacity has been installed on the Kenai Peninsula sufficient to meet its own peak requirements even though most of the annual energy is imported from the north. The existing transmission line should not be considered an adequate interconnection for purposes of future generation capacity expansion.

In the Anchorage/Beluga area, installed generating capacity totals about 768 MW, all of which consists of natural gas-fired units except for the 30 MW hydroelectric facility at Eklutna. Of the total gas-fired capacity, approximately 360 MW is located at the Beluga station on the west side of Cook Inlet. Sufficient transmission capability currently exists between the Beluga station and the Anchorage load center to permit moderate expansion of generating capacity at Beluga without encountering transmission constraints. The transmission system of Chugach Electric Association extends north to the Teeland substation, which is identified at the northern end of Knik Arm in Figure 1.

The intertie between Teeland substation and Fairbanks consists of three segments: approximately 25 miles of line between Teeland and Willow owned by Matanuska Electric Association, approximately 170 miles of line between Willow and Healy owned by the Alaska Power Authority, and approximately 100 miles of line between Healy and Fairbanks owned by Golden Valley Electric Association. The entire circuit from Teeland to Fairbanks is currently operated at 138 KV and has a transfer capability of 70 MW.

In the Fairbanks area, installed capacity currently operated by the local utilities consists primarily of oil-fired units totaling about 200 MW and coal-fired units totaling about 45 MW. Of the total coal-fired capacity, 25 MW is located at Healy. Because the transmission line owned by Golden Valley Electric Association between Healy and Fairbanks can accommodate power transfers up to 95 MW, the coal-fired unit at Healy can operate at full capacity and still allow transfers between Anchorage and Fairbanks of up to 70 MW.

Railbelt Intertie Proposal

There are two components of the Railbelt Intertie proposal put forward by the Railbelt Energy Council:

1) Upgrade of the existing Anchorage/Fairbanks intertie;

2) Construction of a new Anchorage/Kenai Peninsula intertie.

The portion of the Anchorage/Fairbanks intertie built by the Power Authority is constructed for operation at 345 KV. However, the line is currently operated at 138 KV due to transmission constraints at both ends of the Power Authority line, i.e. south of Willow and north of Healy. By upgrading the circuit where these constraints exist, the intertie could be operated at a full 345 KV which would increase the power transfer capability between Anchorage and Fairbanks from 70 MW to approximately 350 MW. For purposes of the economic analysis, it was assumed that upgrade of the Anchorage/Fairbanks intertie would allow a full 350 MW to be transferred over the line.

It is expected that a new Anchorage/Kenai Peninsula intertie would be constructed for operation at 230 KV, and that the full power transfer capability of that line would be approximately 250 MW. For purposes of the economic analysis, it was assumed that a new line would provide a reliable interconnection that would permit transfers up to 250 MW.

Categories of Benefit

There are several types of benefits that would be associated with the proposed Railbelt Intertie project:

* Economy Interchange: These are the savings that are produced

when a transmission project allows lower cost generation produced in one area to displace higher cost generation produced in another area. Examples of this would occur when the cost of oil-fired generation in Fairbanks exceeds the cost of natural gas-fired generation in the Cook Inlet area, or when the cost of gas-fired generation in Anchorage exceeds the cost of gas-fired generation on the Kenai Peninsula. Another example would occur if the cost of coal-fired generation in the Interior fell below the cost of generation in the Southcentral area.

* Reserve Sharing: These are the savings that are produced when a transmission project allows one or more utilities to forego building or maintaining a certain amount of reserve capacity by relying instead on reserves available elsewhere in the interconnected system. An example of this would occur if a reliable interconnection were built between Anchorage and the Kenai Peninsula. The total installed capacity needed to meet reserve requirements for both areas would be reduced as a result.

* Siting Flexibility for New Generating Plants: Improved transmission allows greater flexibility in siting new plants wherever the costs of operation, including the costs of fuel, are lowest. For example, if natural gas is available on the Kenai Peninsula at a significant savings relative to the price

of natural gas delivered to Anchorage, then siting new plants on the Kenai Peninsula rather than the Anchorage area would reduce system costs. A firm interconnection would allow that to occur. Other examples would be the possible future construction of a major coal-fired power plant or hydro project in the Railbelt. Improved transmission would allow such a plant to be built anywhere near the grid (e.g. Beluga, Matanuska Valley, Healy, Nenana) and still serve all of the major Railbelt load centers.

* System Reliability: An improved transmission system can substantially reduce the number and extent of power outages. For example, the existing Anchorage/Fairbanks intertie made it possible for electricity demand in the Mat-Su Valley to be served from the Fairbanks area when service from Anchorage was interrupted during a recent incident. A new intertie between Anchorage and the Kenai Peninsula would produce a far more reliable connection between these two areas than currently exists, and would result in a reduction in the number and extent of power outages, particularly on the Kenai Peninsula.

* System Efficiency: Transmission losses are reduced in higher voltage circuits. Power transfers between Anchorage and Fairbanks presently suffer losses on the order of 10% at 138 KV. For the economic study, it is assumed that such losses would be reduced to 4% at 345 KV (i.e. a reduction in

losses of 60%). Similarly, it is assumed in the economic study that losses over the existing Anchorage/Kenai Peninsula line are 10%, but that losses over a new 230 KV line would be reduced to 2% (i.e. a reduction in losses of 80%).

* Increased Utility Coordination: It is generally agreed that the interests of Railbelt consumers would be served through increased integration of planning and operations among the seven Railbelt utilities. Strengthening the transmission network that links these utilities together would enhance the evolution of a more coordinated utility structure. Further, such improved linkage would facilitate the sharing of costs among all the utilities for future generation projects that may be economically attractive but which exceed the financial resources of any single utility or community.

* Distribution of Bradley Lake Benefits: The Railbelt Intertie project would facilitate the distribution of Bradley Lake benefits throughout the Railbelt by providing each of the seven utilities with direct access to project output over reliable transmission facilities.

* Enhanced Competition Among Fuel Suppliers: By improving the access of all seven utilities to energy sources throughout the Railbelt, the competition among those sources to supply utility requirements would be enhanced. Because each utility

would have a broader range of energy supply alternatives, the bargaining position of each utility with respect to potential fuel suppliers would be strengthened. The interests of consumers would be served by this improved position.

Study Methodology and Limitations

Lotus Consulting Group was directed to estimate the production costs of the Railbelt system for the period 1991 - 2020 with and without the proposed Railbelt Intertie. A computerized production cost simulation model was used for the analysis. Because the costs of construction and maintenance of the Intertie project were not defined at the time the economic analysis was undertaken, no estimate of those costs was included. The work performed by Lotus Consulting Group therefore sheds light only on the benefit side of the ledger. It is necessary to go beyond the Lotus study in order to compare total benefits with estimated costs.

Of the various benefit categories noted above, there are several that are not accounted for in any way within the Lotus study, specifically the benefits of improved system reliability, increased utility coordination, distribution of Bradley Lake benefits, and enhanced competition among fuel suppliers. The benefit of siting flexibility for new generating plants is partially accounted for in