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Table 5-1

KENAI-ANCHORAGE TRANSFERS WITH EXISTING LINE

BASE

	Assumptions		Economy Energy Transfer (GWh/yr) South ----> North			Economy Energy Transfer (GWh/yr) North ----> South			Transmission Loss (GWh/yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	123.8	118.1	110.2	142.3	135.0	172.3	29.3	28.1	30.7
		Middle	105.7	82.4	81.7	144.1	126.0	267.6	27.8	24.2	36.7
		High	93.5	85.3	82.8	131.6	123.1	287.4	25.6	24.2	38.6
	Middle	Low	115.6	118.0	110.1	142.3	156.0	172.3	28.6	30.0	30.7
		Middle	98.6	82.2	81.3	144.1	139.2	225.2	27.2	25.3	32.9
		High	81.6	84.6	82.4	132.5	133.8	215.8	24.7	25.0	32.2
	High	Low	115.6	117.7	110.0	160.7	156.0	172.3	30.2	30.0	30.7
		Middle	98.6	81.4	81.2	172.8	139.1	225.2	29.8	25.2	32.9
		High	81.6	82.0	82.1	151.1	133.8	216.6	26.3	24.8	32.2
Case 2	Low	Low	128.7	123.0	115.1	148.4	141.1	178.4	31.3	30.1	32.7
		Middle	110.6	87.3	86.6	150.2	132.1	273.7	29.8	26.2	38.7
		High	98.4	90.2	87.7	137.7	129.2	293.5	27.6	26.2	40.6
	Middle	Low	120.5	122.9	115.0	148.4	162.1	178.4	30.6	32.0	32.7
		Middle	103.5	87.1	86.2	150.2	145.3	231.3	29.2	27.3	34.9
		High	86.5	89.5	87.3	138.6	139.9	221.9	26.7	27.0	34.2
	High	Low	120.5	122.6	114.9	166.8	162.1	178.4	32.2	32.0	32.7
		Middle	103.5	86.3	86.1	178.9	145.2	231.3	31.8	27.2	34.9
		High	86.5	86.9	87.0	157.2	139.9	222.7	28.3	26.8	34.2

Table includes hydrothermal coordination adjustment.

5.5 NEW KENAI-ANCHORAGE LINE: ECONOMY ENERGY TRANSFER AND TRANSMISSION LOSS BENEFITS

5.5.1 Increased Kenai-Anchorage Transfers

The change in transfer levels due to the new Kenai-Anchorage line is shown in Table 5-2. Including the transfers for limiting part-load operation of thermal units, on average, transfer levels in 1994 from Kenai to Anchorage increase by about 113 GWh per year due to the new line. Transfers from Anchorage to Kenai in 1994 increase on average by about 147 GWh per year. Transfer losses decrease slightly with the new line.

5.5.2 Benefits of Increased Kenai-Anchorage Transfers

The annual savings associated with these increased transfers and reduced transmission losses are shown in Table 5-3. The annual average net savings vary between $2.0 and $2.9 million per year between 1994 and 2010. Over 90 percent of the benefits can be attributed to increased hydro-thermal coordination. There are small negative benefits associated with the change in transfer losses and a decrease in the gas royalty, however, the economy transfer benefits strongly outweigh the small losses.

The present value of these savings, discounted back to 1994 at a real rate of 4.5 percent, is shown in Table 5-4. The present value of these benefit categories average $43.4 million. As shown, the results for Case 1 and Case 2 do not differ significantly.

Table 5-2

CHANGE IN KENAI-ANCHORAGE TRANSFERS DUE TO THE NEW LINE

	Assumptions		Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
			South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	117.0	115.2	113.8	125.1	128.0	106.2	-2.4	-1.8	-4.1
		Middle	113.7	110.6	109.8	153.6	201.3	101.5	-0.6	3.2	-7.7
		High	111.3	111.9	109.7	142.9	226.8	143.6	-0.0	4.3	-6.9
	Middle	Low	114.9	115.3	114.1	125.1	107.0	106.2	-2.2	-3.6	-4.1
		Middle	112.6	110.8	111.6	167.5	188.1	143.8	0.2	2.0	-3.8
		High	110.4	112.6	114.8	191.9	230.5	214.6	2.5	4.0	-0.3
	High	Low	114.9	115.2	114.0	106.7	107.0	106.2	-3.8	-3.6	-4.1
		Middle	112.6	110.8	110.8	138.8	188.2	143.8	-2.3	2.1	-3.8
		High	110.4	112.7	112.6	173.3	230.5	213.8	0.9	4.2	-0.4
Case #2	Low	Low	112.1	110.3	108.9	119.0	121.9	100.1	-4.4	-3.8	-6.1
		Middle	108.8	105.7	104.9	147.5	195.2	95.4	-2.6	1.2	-9.7
		High	106.4	107.0	104.8	136.8	220.7	136.9	-2.0	2.3	-8.9
	Middle	Low	110.0	110.4	109.2	119.0	100.9	100.1	-4.2	-5.6	-6.1
		Middle	107.7	105.9	106.7	161.4	182.0	137.7	-1.8	0.0	-5.8
		High	105.5	107.7	109.9	185.8	224.4	208.5	0.5	2.0	-2.3
	High	Low	110.0	110.3	109.1	100.6	100.9	100.1	-5.8	-5.6	-6.1
		Middle	107.7	105.9	105.9	132.7	182.1	137.7	-4.3	0.1	-5.8
		High	105.5	107.8	107.7	167.2	224.4	207.7	-1.1	2.2	-2.4

Table includes hydrothermal coordination adjustemnt.

Table 5-3

ANNUAL TRANSFER BENEFITS DUE TO THE NEW KENAI-ANCHORAGE LINE

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	1.6	1.8	1.9	0.0	0.0	0.1	1.6	1.8	1.9
		Middle	1.6	1.8	1.9	0.0	-0.1	0.2	1.6	1.8	2.1
		High	1.5	1.8	2.0	0.0	-0.1	0.1	1.5	1.8	2.2
	Middle	Low	2.0	2.3	2.7	0.0	0.1	0.1	2.0	2.4	2.8
		Middle	2.1	2.5	2.9	-0.0	-0.0	0.1	2.1	2.5	3.0
		High	2.1	2.5	3.0	-0.1	-0.1	-0.0	2.0	2.4	3.0
	High	Low	2.2	2.8	3.6	0.1	0.1	0.1	2.3	2.9	3.7
		Middle	2.4	3.1	3.8	0.0	-0.1	0.1	2.4	3.0	3.9
		High	2.4	3.1	3.9	-0.0	-0.1	0.0	2.4	2.9	3.9
Case #2	Low	Low	1.5	1.8	1.8	0.0	0.0	0.1	1.6	1.8	1.9
		Middle	1.6	1.8	1.9	0.0	-0.0	0.2	1.6	1.8	2.1
		High	1.5	1.8	2.0	0.0	-0.1	0.2	1.5	1.7	2.2
	Middle	Low	2.0	2.3	2.7	0.1	0.1	0.1	2.0	2.4	2.8
		Middle	2.1	2.4	2.8	0.0	-0.0	0.2	2.1	2.4	3.0
		High	2.0	2.5	3.0	-0.0	-0.1	0.0	2.0	2.4	3.0
	High	Low	2.2	2.8	3.5	0.1	0.1	0.2	2.3	2.9	3.6
		Middle	2.3	3.0	3.7	0.1	-0.0	0.2	2.4	3.0	3.9
		High	2.3	3.0	3.8	0.0	-0.1	0.1	2.4	2.9	3.9

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer + Reduced Transmission Loss
4. Table includes hydrothermal coordination adjustemnt.

Table 5-4

PRESENT VALUE OF TRANSFER BENEFITS DUE TO NEW KENAI-ANCHORAGE LINE

Scenario	Assumptions: Fuel	Assumptions: Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Case #1	Low	Low	35.0	-2.1	-3.1	29.8
		Middle	35.7	-1.1	-3.4	31.2
		High	36.9	-1.3	-3.2	32.5
	Middle	Low	48.9	-2.9	-4.0	42.0
		Middle	51.7	-2.9	-4.6	44.3
		High	53.9	-4.5	-4.5	44.9
	High	Low	61.8	-3.6	-5.3	52.9
		Middle	65.4	-3.5	-5.7	56.3
		High	68.0	-5.5	-6.9	55.6
Case #2	Low	Low	35.2	-2.1	-3.1	30.0
		Middle	35.9	-1.1	-3.4	31.5
		High	37.2	-1.3	-3.2	32.7
	Middle	Low	49.3	-2.9	-4.1	42.3
		Middle	52.1	-3.0	-4.6	44.6
		High	54.3	-4.5	-4.5	45.2
	High	Low	62.3	-3.7	-5.3	53.3
		Middle	65.9	-3.6	-5.7	56.7
		High	68.5	-5.6	-6.9	56.0

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2033 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include hydrothermal coordination adjustment.

5.6 ECONOMY ENERGY TRANSFERS BETWEEN ANCHORAGE AND FAIRBANKS WITH EXISTING LINE

The system simulation indicates that nearly all transfers between Anchorage and Fairbanks flow from the south to the north. The cost differential between oil and gas reflected in the fuel price forecasts is the motivation for transfers between the two areas.

Fairbanks relies first upon its existing coal-fired capacity. In the absence of an intertie, Fairbanks would next rely upon existing oil-fired capacity. The availability of gas-fired capacity in Anchorage, combined with the price advantage of Cook Inlet gas with respect to oil, creates an opportunity for economy energy transfer savings. For example, the North Pole oil-fired combustion turbines in Fairbanks have a full-load heat rate of approximately 10,900 Btu/kWh. The gas-fired combustion turbines #3 and #5 at Beluga are somewhat less efficient at full load, with a heat rate of 12,691 Btu/kWh.

Based on the fuel oil and natural gas price forecasts adopted for 1994 in the low case and ignoring variable O&M costs (which are similar for these units), a variable generation cost of $33.47 per MWh is computed for the North Pole units compared with $18.05 per MWh for the Beluga units. Even after adding 15 percent transmission losses, the Beluga units would be 57 percent less expensive. In 1990, the estimated price differential between Fairbanks #4 fuel oil and Cook Inlet wellhead (Chugach) gas is $1.36, $1.95, and $2.26 per MBtu for the low, middle, and high fuel forecasts respectively (i.e., it is higher for the higher-priced scenarios). In addition, as time goes on, the differential within each forecast also increases to $2.09, $3.02, and $3.97 per MBtu for the three fuel forecast scenarios in 2010.

Table 5-5 shows the estimated transfer levels from Anchorage to Fairbanks over the existing line in the absence of any upgrade. These results are based on the transfers indicated by the Over/Under production simulation, net of adjustments calculated due to the North Pole constraint.[9] In the expected case in 1994, transfers from Anchorage to Fairbanks are estimated at about 471 GWh per year,[10] declining to about 418 GWh by 2010. Transmission losses associated with these transfers range from 74 to 57 GWh per year, averaging around 15 percent of transfers.

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9. Again, the North Pole constraint reduces the level of transfers that would otherwise be expected, because intertie purchases must be reduced substantially whenever a North Pole unit is started up.

10. The existing Anchorage-Fairbanks line has a transfer limit of 675 GWh per year (based on 77 MW x 8760 hours per year).

Table 5-5

ANCHORAGE-FAIRBANKS TRANSFERS WITH EXISTING LINE

BASE

Scenario	Assumptions: Fuel	Assumptions: Load	Economy Energy Transfer (GWh/yr) South ----> North 1994	2002	2010	North ----> South 1994	2002	2010	Transmission Loss (GWh/yr) 1994	2002	2010
Case 1	Low	Low	502.3	428.0	374.7	0.0	0.0	0.0	75.5	54.2	42.5
		Middle	509.5	406.4	421.7	0.0	0.0	0.0	77.9	50.7	55.7
		High	510.1	416.7	493.3	0.0	0.0	0.0	78.2	52.5	75.6
	Middle	Low	451.3	477.5	469.1	0.0	0.0	0.0	71.5	78.6	72.8
		Middle	443.6	475.8	444.3	0.0	0.0	0.0	69.6	76.9	63.7
		High	475.3	505.6	467.7	0.0	0.0	0.0	77.2	82.9	68.2
	High	Low	442.0	445.5	354.3	0.0	0.0	0.0	70.1	70.9	45.3
		Middle	433.1	394.8	343.4	0.0	0.0	0.0	68.1	57.9	39.8
		High	471.1	416.8	392.1	0.0	0.0	0.0	76.6	61.6	50.1
Case 2	Low	Low	502.3	428.0	374.7	0.0	0.0	0.0	75.5	54.2	42.5
		Middle	509.5	406.4	421.7	0.0	0.0	0.0	77.9	50.7	55.7
		High	510.1	416.7	493.3	0.0	0.0	0.0	78.2	52.5	75.6
	Middle	Low	451.3	477.5	469.1	0.0	0.0	0.0	71.5	78.6	72.8
		Middle	443.6	475.8	444.3	0.0	0.0	0.0	69.6	76.9	63.7
		High	475.3	505.6	467.7	0.[illegible]	0.0	0.0	77.2	82.9	68.2
	High	Low	442.0	445.5	354.3	0.[illegible]	0.0	0.0	70.1	70.9	45.3
		Middle	433.1	394.8	343.4	0.0	0.0	0.0	68.1	57.9	39.8
		High	47[illegible].1	416.7	392.1	0.0	0.0	0.0	76.6	61.6	50.1

Table includes North Pole adjustment.

5.7 AF100 LIMITED UPGRADE OF ANCHORAGE-FAIRBANKS LINE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS.

As described in Section 2, the AF100 limited upgrade consists of the addition of electrical equipment, primarily series capacitors and SVS, to allow a higher level of transfer over the existing line. Presently, the line is limited to 77 MW input at the Anchorage end. Assuming the existing Healy coal plant is operating, which is usually the case, approximately 62 MW can be received in Fairbanks. The limited upgrade would allow 110 MW to be input at the Anchorage end with approximately 84 MW received on the Fairbanks end.

5.7.1 Increased Anchorage-Fairbanks Transfers

Transfers without the limited upgrade are described in Section 5.6 and presented in Table 5-5. The change in transfer levels due to the limited upgrade of the Anchorage-Fairbanks intertie is shown in Table 5-6. On average, transfers from Anchorage to Fairbanks due to the AF100 are projected to increase by about 67 GWh per year in 1994 and by 106 GWh per year in 2010. Although the upgrade permits a higher level of transfers, it also results in higher transfer losses; transfer losses increase by about 22 GWh per year in 1994 and by 35 GWh per year in 2010.

5.7.2 Benefits of Increased Anchorage-Fairbanks Transfers

As shown in Table 5-7, the value of the increased Anchorage-Fairbanks transfers ranges from an average of nearly $1.0 million per year in 1994 to $2.8 million per year in 2010. The negative benefits associated with "reduced transmission losses" are netted out against the value of the increased transfers.

The present value of these savings discounted to 1994 at 4.5 percent is shown in Table 5-8. The benefit of the change in transmission losses is a loss of $15.4 million, which is strongly outweighed by the benefits of increased economy energy transfers (an average benefit of $42.7 million), primarily due to the removal of the North Pole constraint. The present value of the average net benefits in these categories is $31.8 million.

Table 5-6

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO THE LIMITED UPGRADE OF THE AF LINE TO 100 MW

	Assumptions		Change in Economy Energy Transfer (GWh/yr) South ----> North			North ----> South			Change in Transmission Loss (GWh/yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	160.9	144.9	163.1	0.0	0.0	0.0	52.3	46.4	57.8
		Middle	146.8	137.8	106.1	0.0	0.0	0.0	47.7	44.1	34.7
		High	146.4	167.3	93.9	0.0	0.0	0.0	46.9	54.1	31.0
	Middle	Low	23.0	18.7	73.7	0.0	0.0	0.0	7.4	6.1	24.0
		Middle	23.9	35.0	94.8	0.0	0.0	0.0	7.7	11.2	30.7
		High	25.4	56.9	151.8	0.0	0.0	0.0	8.2	18.3	49.1
	High	Low	23.0	15.3	62.3	0.0	0.0	0.0	7.4	4.9	20.3
		Middle	23.9	28.8	83.9	0.0	0.0	0.0	7.7	9.2	27.2
		High	25.4	45.8	127.0	0.0	0.0	0.0	8.2	15.0	41.1
Case #2	Low	Low	160.9	144.9	163.1	0.0	0.0	0.0	52.3	46.4	57.8
		Middle	146.8	137.8	106.1	0.0	0.0	0.0	47.7	44.1	34.7
		High	146.4	167.3	93.9	0.0	0.0	0.0	46.9	54.1	31.0
	Middle	Low	23.0	18.7	73.7	0.0	0.0	0.0	7.4	6.1	24.0
		Middle	23.9	35.0	94.8	0.0	0.0	0.0	7.7	11.2	30.7
		High	25.4	56.9	151.8	0.0	0.0	0.0	8.2	18.3	49.1
	High	Low	23.0	15.3	62.3	0.0	0.0	0.0	7.4	4.9	20.3
		Middle	23.9	28.8	83.9	0.0	0.0	0.0	7.7	9.2	27.2
		High	25.4	45.8	127.0	0.0	0.0	0.0	8.2	15.0	41.1

Table includes North Pole adjustment.

Table 5-7

ANNUAL TRANSFER BENEFITS DUE TO THE LIMITED UPGRADE OF THE AF LINE TO 100 MW

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	2.1	2.6	3.0	-0.8	-0.9	-1.2	1.2	1.8	1.9
		Middle	1.9	2.5	2.0	-0.8	-0.8	-0.7	1.1	1.7	1.2
		High	1.9	2.8	1.4	-0.7	-1.0	-0.7	1.1	1.8	0.8
	Middle	Low	0.4	0.4	2.0	-0.2	-0.2	-0.7	0.3	0.2	1.3
		Middle	0.5	0.8	2.6	-0.2	-0.3	-0.9	0.3	0.5	1.7
		High	0.5	1.2	3.9	-0.2	-0.5	-1.5	0.3	0.7	2.5
	High	Low	0.5	0.4	2.4	-0.2	-0.2	-0.8	0.3	0.3	1.6
		Middle	0.5	0.9	3.3	-0.2	-0.3	-1.1	0.3	0.6	2.2
		High	0.5	1.4	4.9	-0.2	-0.5	-1.7	0.3	0.9	3.2
Case #2	Low	Low	2.1	2.6	3.0	-0.8	-0.9	-1.2	1.2	1.8	1.9
		Middle	1.9	2.5	2.0	-0.8	-0.8	-0.7	1.1	1.7	1.2
		High	1.9	2.8	1.4	-0.7	-1.0	-0.7	1.1	1.8	0.8
	Middle	Low	0.4	0.4	2.0	-0.2	-0.2	-0.7	0.3	0.2	1.3
		Middle	0.5	0.8	2.6	-0.2	-0.3	-0.9	0.3	0.5	1.7
		High	0.5	1.2	3.9	-0.2	-0.5	-1.5	0.3	0.7	2.5
	High	Low	0.5	0.4	2.4	-0.2	-0.2	-0.8	0.3	0.3	1.6
		Middle	0.5	0.9	3.3	-0.2	-0.3	-1.1	0.3	0.6	2.2
		High	0.5	1.4	4.9	-0.2	-0.5	-1.7	0.3	0.9	3.2

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer
   + Reduced Transmission Loss
4. Table includes North Pole adjustment.

Table 5-8

PRESENT VALUE OF TRANSFER BENEFITS DUE TO THE LIMITED UPGRADE OF AF LINE TO 100 MW

Scenario	Assumptions: Fuel	Assumptions: Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Case #1	Low	Low	55.0	-20.2	6.1	40.9
		Middle	44.6	-16.4	5.3	33.5
		High	40.5	-16.8	5.6	29.3
	Middle	Low	25.4	-9.1	2.5	18.8
		Middle	33.6	-12.0	3.3	25.0
		High	51.1	-19.1	5.2	37.2
	High	Low	30.9	-10.3	2.9	23.4
		Middle	41.6	-14.0	3.9	31.5
		High	61.8	-21.1	5.9	46.6
Case #2	Low	Low	55.0	-20.2	6.1	40.9
		Middle	44.6	-16.4	5.3	33.5
		High	40.5	-16.8	5.6	29.3
	Middle	Low	25.4	-9.1	2.5	18.8
		Middle	33.6	-12.0	3.3	25.0
		High	51.1	-19.1	5.2	37.2
	High	Low	30.9	-10.3	2.9	23.4
		Middle	41.6	-14.0	3.9	31.5
		High	61.8	-21.1	5.9	46.6

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

5.8 AF138 INTERTIE: ECONOMY ENERGY AND TRANSMISSION LOSS BENEFITS

As described in Section 2, the AF138 option consists of the limited upgrade of the Anchorage-Fairbanks line to 100 MW and a new 138 KV intertie from Healy to Ft. Wainwright. With the existing line, 77 MW can be input in Anchorage and 62 MW received in Fairbanks. With the AF138 option, 120 MW can be input in Anchorage and 99 MW received in Fairbanks.

5.8.1 Increased Anchorage-Fairbanks Transfers

The change in transfer levels due to the new Anchorage-Faribanks 138 KV line is shown in Table 5-9. The average increase in transfer levels from Anchorage to Fairbanks due to the new intertie is on average 122 GWh per year in 1994 and 186 GWh per year in 2010. The transfer losses increase by an average 2 GWh in 1994 and by 23 GWh in 2010. These increases are a direct result of the increase in transfers across the lines.

5.8.2 Benefits of Increased Anchorage-Fairbanks Transfers

The annual savings associated with the increased Anchorage-Fairbanks transfers and reduced transmission losses are shown in Table 5-10. The expected annual net savings (adju d for transfer losses) rise from $2.0 million in 1994 to $4.3 million in 2010.

The present value of these savings discounted to 1994 at 4.5 percent is shown in Table 5-11. The present value of the average net benefits is $76.9 million. The benefits due to economy energy savings are $76.2 million; and the benefits due to increased gas royalty are $7.7 million. These benefits are offset by a loss of $7.0 million from increased transmission losses.

Approximately half of the total benefits can be traced to the removal of the North Pole constraint. In other words, the analysis indicates that the inability to provide small economical increments of power in Fairbanks, when needed at times of full intertie loading, is very costly.

Table 5-9

CHANGE IN ANCHORAGE-FAIRBANKS TRANSFERS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

	Assumptions		Change in Economy Energy Transfer (GWh/yr)						Change in Transmission Loss (GWh/yr)		
			South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	222.3	229.5	259.7	0.0	0.0	0.0	26.6	33.1	39.7
		Middle	206.5	199.7	228.9	0.0	0.0	0.0	22.3	27.1	30.2
		High	238.0	232.5	218.0	0.0	0.0	0.0	29.3	37.2	24.2
	Middle	Low	137.6	20.5	102.4	0.0	0.0	0.0	1.0	-21.[illegible]	1.5
		Middle	124.9	39.1	146.9	0.0	0.0	0.0	-0.6	-17.0	11.6
		High	79.1	102.6	218.5	0.0	0.0	0.0	-11.3	-1.1	26.8
	High	Low	32.1	37.3	156.0	0.0	0.0	0.0	-16.1	-17.1	13.2
		Middle	32.0	90.3	176.3	0.0	0.0	0.0	-15.6	-4.0	20.7
		High	25.8	111.7	170.9	0.0	0.0	0.0	-20.0	0.2	19.5
Case #2	Low	Low	222.3	229.5	277.9	0.0	0.0	0.0	26.6	33.1	45.5
		Middle	206.5	199.7	245.1	0.0	0.0	0.0	22.3	27.1	35.4
		High	238.0	250.0	227.6	0.0	0.0	0.0	29.3	42.8	[illegible]7.3
	Middle	Low	137.8	20.6	103.1	0.0	0.0	0.0	1.0	-21.7	1.7
		Middle	124.9	39.2	148.0	0.0	0.0	0.0	-0.6	-17.0	12.0
		High	79.2	103.3	218.8	0.0	0.0	0.0	-11.2	-0.9	26.9
	High	Low	32.1	37.3	156.7	0.0	0.0	0.0	-16.1	-17.1	13.4
		Middle	32.0	90.3	177.4	0.0	0.0	0.0	-15.6	-4.0	21.1
		High	25.8	112.4	171.2	0.0	0.0	0.0	-19.9	0.5	19.6

Table includes North Pole adjustment.

Table 5-10

ANNUAL TRANSFER BENEFITS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

Assumptions			Increased Economy Energy Transfer (M$/Yr)			Reduced Transmission Loss (M$/Yr)			Net Transfer Benefits (M$/Yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case #1	Low	Low	3.3	3.8	4.6	-0.5	-0.6	-0.8	2.8	3.2	3.8
		Middle	3.0	3.6	4.3	-0.4	-0.5	-0.7	2.6	3.1	3.7
		High	3.1	4.3	4.6	-0.5	-0.7	-0.5	2.6	3.6	4.1
	Middle	Low	1.6	1.1	3.3	-0.0	0.5	-0.1	1.6	1.6	3.2
		Middle	1.6	1.6	4.4	0.0	0.4	-0.4	1.6	1.9	4.0
		High	1.4	2.5	6.0	0.2	-0.0	-0.9	1.6	2.5	5.1
	High	Low	1.3	1.4	4.2	0.3	0.4	-0.6	1.6	1.8	3.6
		Middle	1.3	2.1	5.7	0.3	0.0	-0.9	1.6	2.1	4.8
		High	1.3	2.8	7.1	0.4	-0.1	-0.9	1.7	2.7	6.2
Case #2	Low	Low	3.3	3.9	5.0	-0.5	-0.6	-1.0	2.8	3.2	4.1
		Middle	3.0	3.6	4.7	-0.4	-0.5	-0.8	2.6	3.1	3.9
		High	3.1	4.6	4.8	-0.5	-0.8	-0.6	2.6	3.8	4.2
	Middle	Low	1.6	1.1	3.3	-0.0	0.5	-0.1	1.6	1.6	3.2
		Middle	1.6	1.6	4.5	0.0	0.4	-0.5	1.6	1.9	4.0
		High	1.4	2.5	6.0	0.2	-0.0	-0.9	1.6	2.5	5.1
	High	Low	1.3	1.4	4.2	0.3	0.4	-0.6	1.6	1.8	3.6
		Middle	1.3	2.1	5.7	0.3	0.0	-0.9	1.6	2.1	4.8
		High	1.3	2.8	7.1	0.4	-0.1	-0.9	1.7	2.7	6.2

1. All values are in 1990 million dollars.
2. Positive reduced transmission losses are savings.
3. Net Transfer Benefits = Increased Economy Energy Transfer + Reduced Transmission Loss
4. Table includes North Pole adjustment.

Table 5-11

PRESENT VALUE OF TRANSFER BENEFITS DUE TO A SECOND HEALY-FAIRBANKS 138 KV LINE

Scenario	Assumptions: Fuel	Assumptions: Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Net Transfer Benefits
Case #1	Low	Low	84.9	-14.5	10.0	80.3
		Middle	82.7	-13.5	9.9	79.1
		High	87.8	-11.9	9.9	85.8
	Middle	Low	47.6	2.5	3.7	53.7
		Middle	61.7	-1.9	5.3	65.1
		High	83.8	-7.7	7.8	83.8
	High	Low	57.7	-1.2	6.3	62.7
		Middle	76.1	-5.6	7.7	78.1
		High	97.1	-6.7	8.6	99.0
Case #2	Low	Low	88.9	-15.8	10.3	83.4
		Middle	87.1	-15.0	10.4	82.5
		High	90.7	-13.0	10.2	88.0
	Middle	Low	47.7	2.4	3.7	53.8
		Middle	61.9	-2.0	5.3	65.2
		High	84.0	-7.8	7.8	83.9
	High	Low	57.8	-1.3	6.3	62.8
		Middle	76.4	-5.8	7.7	78.3
		High	97.2	-6.8	8.6	99.0

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5 %/yr)
2. Increased economy transfer and reduced transmission losses include North Pole adjustment.

Section 6

BENEFITS OF INCREASED CAPACITY SHARING

6.1 OVERVIEW

A new/upgraded intertie could allow two or more areas to share and/or increase sharing generation capacity. As a result, future investment in generation capacity could be deferred or avoided. This section describes the benefits of increased capacity sharing due to the proposed Kenai-Anchorage new intertie (KA138), the limited upgrade of the Anchorage-Fairbanks intertie (AF100), and the new Healy-Fairbanks intertie (AF138).

We start by presenting background concepts and graphical aids to introduce capacity-sharing benefits. This is followed by presentation of the Railbelt capacity surplus (expected mainly in Kenai and Fairbanks) and the Railbelt capacity shortage without new/upgraded interties (expected mainly in Anchorage). We then present the reduced Railbelt capacity shortage due to new/upgraded interties, dividing the reductions in shortage into deferral and avoidance categories. The total benefits of reduced Railbelt capacity shortage (i.e., benefits of capacity sharing) vary between $13.4 and $35.7 million for the KA138, $7.6 and $9.9 million for the AF100, and $16.3 and $18.2 million for the AF138.

6.2 CAPACITY SHARING BENEFITS

Two types of capacity-sharing benefits due to new/upgraded interties are discussed in detail in this section: capacity deferral and capacity avoidance. Although there may be other possible benefits (see Section 6.10), these two types appear to be the most important and the most readily quantified.

A new or upgraded intertie between two areas provides a vehicle for the sharing of energy resources, such that a deficiency in one area might be overcome through use of another area's resources. As is discussed in the following sections, the Railbelt will have a situation in the next decade where two areas (Kenai and Fairbanks) will have capacity surpluses, while another (Anchorage) will have a capacity shortage. Capacity deferral benefits are possible through increased transmission between the surplus and shortage areas.

Figure 6-1 shows how new interties would help defer needed capacity additions in Anchorage. The thick solid line reflects decreasing Anchorage available capacity for the period of 1994-2030, including retirements and excluding any new capacity. The thin solid line shows increasing capacity requirements, defined as load plus reserves, for the same period. Once capacity requirements become greater than available capacity, Anchorage would need to add capacity equaling that difference. The dashed line shows the capacity surplus available in Kenai and Fairbanks that is available to Anchorage through a new/upgraded intertie. The surplus in those areas is decreasing through time, and is reduced to zero before the end of the planning horizon; the impact of this temporary surplus is to delay, or *defer*, capacity additions in Anchorage. The shaded area shows benefits possible from the deferral of capacity additions, showing that deferral is only applicable when Anchorage has a capacity shortage.

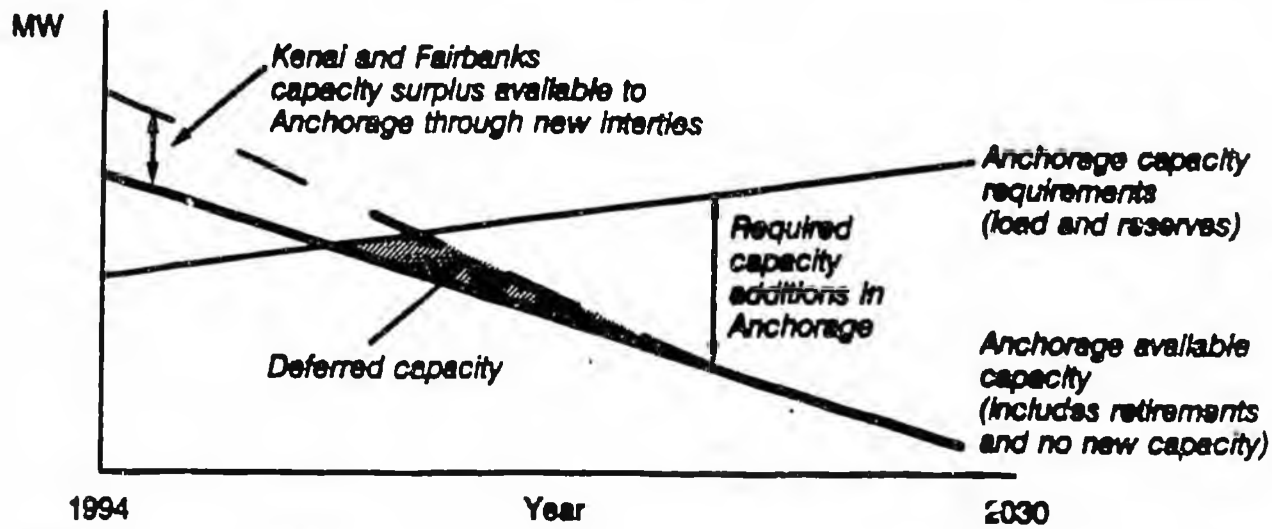


Figure 6-1. Capacity Deferral Benefits

The second type of capacity-sharing benefit possible from greater interconnection is capacity avoidance. This benefit is derived from the increase in reliability that the new or upgraded intertie provides to each area. The Railbelt utilities, like all utilities, set certain targets of reserve capacity margin to ensure sufficient delivery of power and energy. Such targets are generally a percentage of installed system capacity or load. A new/upgraded intertie provides another resource that a given area can rely on in the event of outages, unexpected loads, or other occurrences.

Figure 6-2 shows how one or more intertie could reduce capacity requirements. The solid line represents the capacity requirements of a given area. Including the intertie(s) will result in an additional resource that is available through the life of the intertie(s). The impact of the additional resource is a constant reduction in the capacity requirements of the area. If a shortage exists in this area (e.g. Anchorage) then this reduction contributes to an equivalent amount of *avoided* capacity additions.

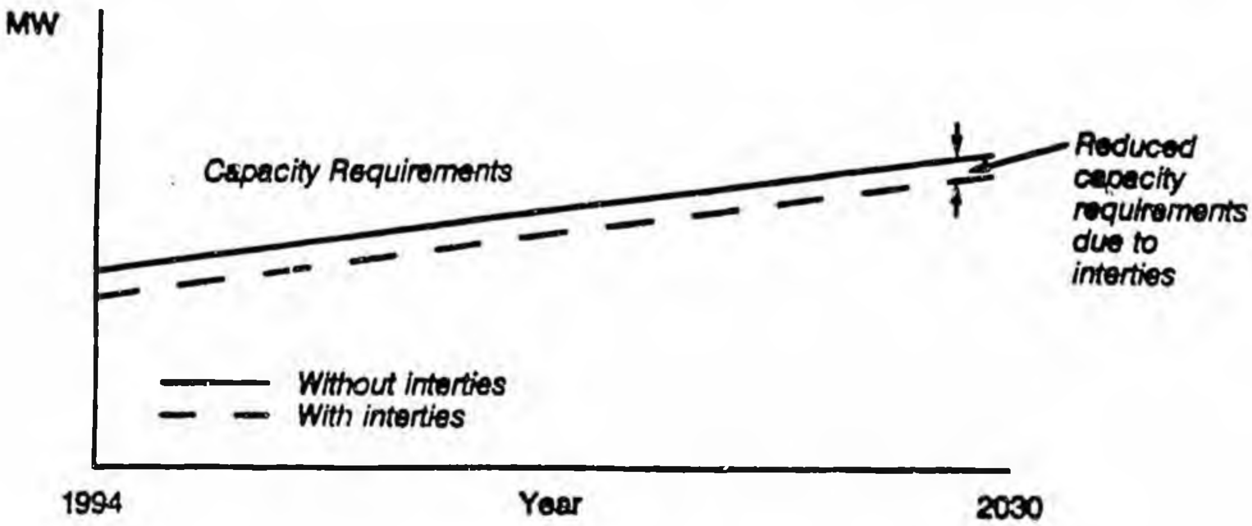


Figure 6-2. Reduced Capacity Requirements

Figure 6-3 builds on Figure 6-1, displaying the avoided capacity benefit for Anchorage, which reduces required capacity starting in the first year of shortage in the Anchorage area. The shaded benefits of the new/upgraded interties in Figure 6-3 are derived from deferred and avoided capacity additions *in the Anchorage area only.*

Figure 6-4 shows how increased interconnection between Kenai and Anchorage, and Fairbanks and Anchorage could impact the surplus areas, which could then be translated to a benefit for the capacity short area. As shown in Figure 6-1, Kenai and Fairbanks have surpluses available to Anchorage through the interties, corresponding to the difference between the thick solid line and the dashed line in Figure 6-4. Lower capacity requirements in Kenai and Fairbanks due to increased reliability, shown in Figure 6-2, further increases the surplus which will exist in Kenai and Fairbanks. This additional capacity surplus made available by Kenai and Fairbanks to Anchorage is the shaded portion of Figure 6-4. The result in Anchorage could be additional deferred capacity.

Figure 6-5 combines the two capacity-sharing benefits due to the proposed interties: avoided capacity and deferred capacity in Anchorage and additional surpluses in Kenai and Fairbanks, translating into additional deferred capacity in Anchorage (or alternatively, avoided new capacity in Fairbanks and Kenai).

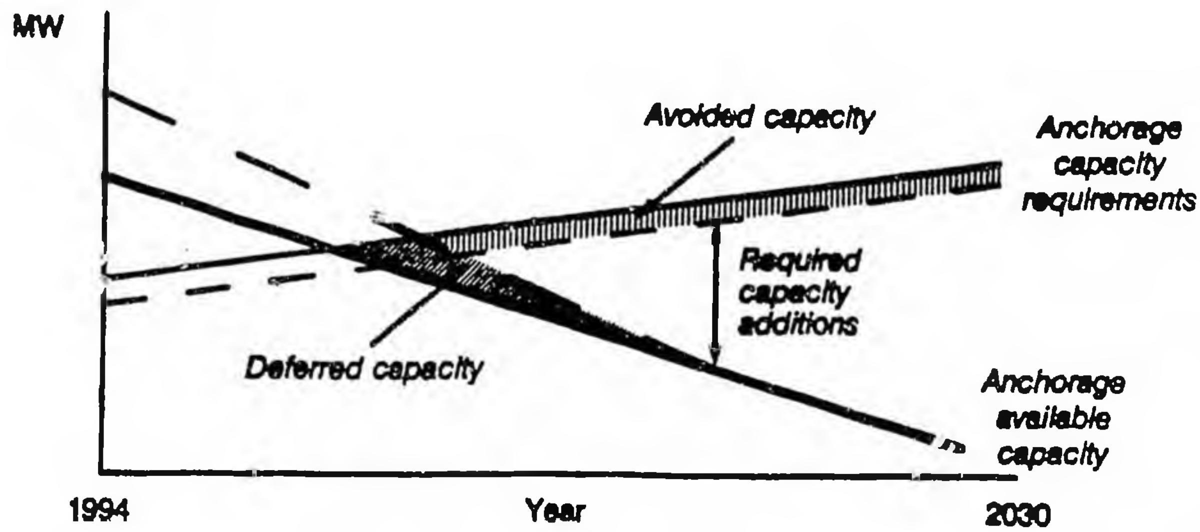
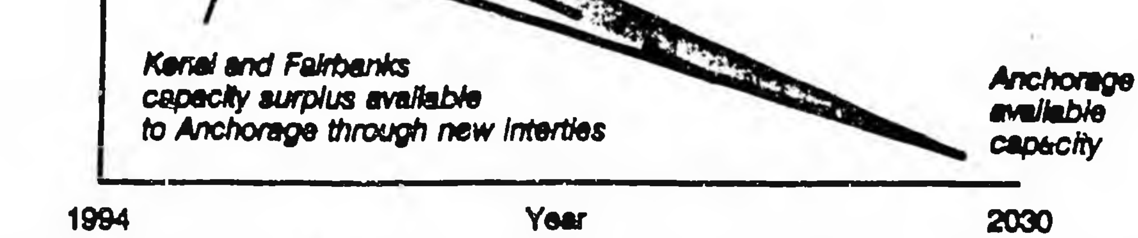


Figure 6-3. Avoided and Deferred Capacity Benefits



Lower capacity requirements in Kenai and Fairbanks would result in increased capacity surplus that can be shared with Anchorage

Figure 6-4. Increased Capacity Surplus From Lower Capacity Requirements

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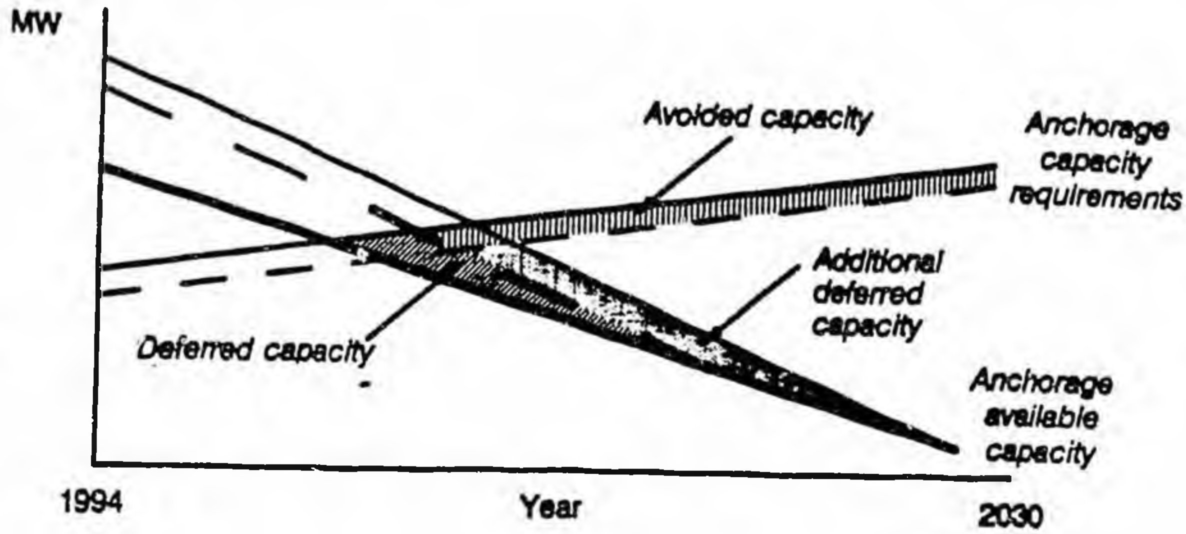

Figure 6-5. Total Capacity-Sharing Benefits

Capacity-sharing benefits due to the new/upgraded interties are integrated into a flow chart in Figure 6-6. Note that capacity-sharing benefits are not limited to capacity-short areas, since a surplus in one area can be used to alleviate shortages in other areas.

The following sections incorporate the concepts and benefits described in this section into a more detailed analysis of the capacity-sharing benefits of the proposed interties for the Railbelt.

6.3 RAILBELT CAPACITY SURPLUS

Capacity surplus is local generation capacity in excess of required generation capacity. Local generation capacity is here defined as existing local capacity minus local capacity retirements.[1] Required generation capacity is the sum of peak load and capacity reserve margin. Capacity reserve margin is a fraction of peak load. The following equations summarize the calculation of the capacity surplus.

Capacity Surplus = Local Capacity – Required Capacity
Required Capacity = Peak Load + Capacity Reserve Margin
Capacity Reserve Margin = Fraction x Peak Load

1. For this analysis, capacity retirements are assumed to occur as planned according to retirement schedules. If life extension or repowering of generating units were assumed instead, existing capacity surpluses would persist over a longer time period; and the benefits of capacity sharing via interties would be deferred and, as a result, reduced.

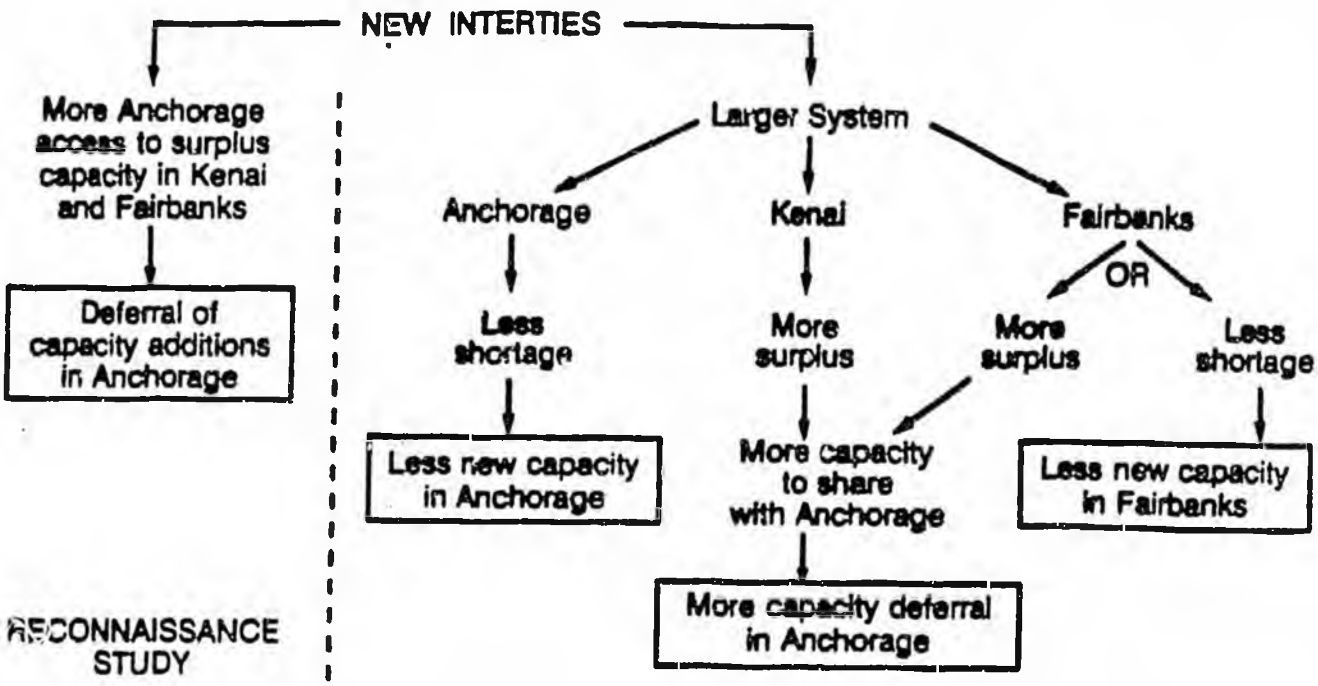

Figure 6-6. Capacity-Sharing Benefits for the Railbelt

According to the Alaska Intertie Agreement [1], the capacity reserve margin should be equal to thirty (30) percent of the annual peak load. Kenai is expected to have a capacity surplus of over 100 MW when Bradley Lake comes on line (expected in the fall of 1991); the Kenai surplus is expected to continue for at least 37 years.[2] Table 6-1 summarizes the Kenai capacity surplus for three load forecasts.[3]

The existing capacity in Fairbanks is also larger than the capacity requirements in Fairbanks. Fairbanks is expected to have a capacity surplus for the next 10 to 15 years depending on load growth. The current capacity surplus in Fairbanks is around 100 MW. Table 6-2 summarizes the Fairbanks capacity surplus for the period 1994-2028 for all three load forecasts.

2. The capacity surplus decreases over time as the load grows and as generation capacity is retired.

3. Load growth for 2011 through 2028 was based on the growth rate of the last five years of the load forecast, i.e., 2005 through 2010. This assumption had little impact on the capacity deferral benefits calculated in the following sections, since 2009 was the last year for which there was a capacity sharing benefit (refer to Sections 6.5 and 6.6).

Table [illegible]-1

KENAI CAPACITY SURPLUS (MW)*

	Load Growth		
Year	Low	Medium	High
1994	138	124	120
1995	139	121	116
1996	139	121	115
1997	139	120	114
1998	139	120	113
1999	139	119	113
2000	138	118	111
2001	138	118	1[illegible]0
2002	137	117	[illegible]7
2003	137	116	105
2004	136	115	103
2005	131	109	96
2006	130	107	95
2007	111	87	76
2008	110	86	73
2009	109	84	72
2010	68	43	30
2011	66	40	28
2012	65	39	27
2013	63	38	25
2014	62	36	24
2015	61	35	23
2016	60	34	22
2017	58	33	20
2018	57	31	19
2019	56	30	18
2020	54	29	16
2021	53	27	15
2022	52	26	14
2023	50	25	12
2024	49	23	11
2025	48	22	10
2026	47	21	9
2027	45	20	7
2028	44	18	6

*Based on a 30 percent planning reserve margin. Calculations assume that no Kenai capacity is moved to Anchorage.

Table 6-2

FAIRBANKS CAPACITY SURPLUS*

	Load Growth		
Year	Low	Medium	High
1994	90	92	83
1995	88	89	78
1996	81	81	70
1997	77	77	64
1998	76	76	62
1999	76	74	60
2000	68	66	49
2001	49	46	31
2002	4	2	0
2003	3	0	0
2004	2	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0

*Based on a 30 percent planning reserve margin.

Anchorage has a current capacity surplus of around 300 MW. However, because of planned capacity retirements and projected load growth, the Anchorage capacity surplus is expected to disappear as early as 1995. Capacity surplus in Kenai and Fairbanks is therefore expected to persist longer than capacity surplus in Anchorage. As a result, there will be no benefit from sharing the Anchorage capacity surplus with Kenai and Fairbanks, both of which will have their own local surplus longer than Anchorage will. However, there will be benefit realized from sharing the Kenai and Fairbanks surplus with Anchorage after a capacity shortage develops in Anchorage.

6.4 RAILBELT CAPACITY SHORTAGE WITHOUT NEW/UPGRADED INTERTIES

Capacity shortage is required generation capacity in excess of available capacity. For Kenai and Fairbanks, available capacity equals local capacity. For Anchorage, available capacity equals local capacity plus other capacity accessible through transmission lines. In other words, Anchorage can draw on surplus in Kenai and Fairbanks to alleviate an Anchorage shortage. However, neither Kenai nor Fairbanks can draw on surplus in Anchorage, for there is none when Kenai and Fairbanks experience shortages.

6.4.1 Kenai Capacity Shortage

Kenai is expected to have a capacity surplus until at least 2028. Table 6-3 illustrates the expected local capacity in Kenai between 1994 and 2028 and the corresponding capacity shortage, which is zero for all three load forecasts through the entire study period.

6.4.2 Fairbanks Capacity Shortage

Fairbanks is expected to have a capacity surplus for the next 10 to 15 years. Depending on the load forecast, Fairbanks is expected to start having a capacity shortage between 2002 and 2005. Table 6-4 illustrates the expected local capacity in Fairbanks between 1994 and 2028 and the corresponding capacity shortage for all three load forecasts.

Table 6-3

KENAI CAPACITY SHORTAGE

Year	Local Capacity (MW)	Load Growth : Low			Load Growth : Medium			Load Growth : High		
		Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	223	65	85	0	76	99	0	80	103	0
1995	220	62	81	0	76	99	0	80	104	0
1996	220	62	81	0	76	99	0	80	105	0
1997	220	62	81	0	77	100	0	82	106	0
1998	220	63	81	0	77	100	0	82	107	0
1999	220	63	81	0	78	101	0	83	107	0
2000	220	63	82	0	78	102	0	84	109	0
2001	220	63	82	0	79	102	0	85	110	0
2002	220	64	83	0	79	103	0	87	113	0
2003	220	64	83	0	[illegible]	104	0	88	115	0
2004	220	64	84	0	[illegible]	105	0	90	117	0
2005	215	65	84	0	82	106	0	91	119	0
2006	215	66	85	0	83	108	0	92	120	0
2007	197	66	86	0	84	110	0	93	121	0
2008	197	67	87	0	85	111	0	95	124	0
2009	197	68	88	0	87	113	0	96	125	0
2010	157	68	89	0	88	114	0	97	127	0
2011	156	69	90	0	89	116	0	98	128	0
2012	156	70	91	0	90	117	0	99	129	0
2013	156	71	93	0	91	118	0	100	131	0
2014	156	72	94	0	92	120	0	101	132	0
2015	156	73	95	0	93	121	0	102	133	0
2016	156	74	96	0	94	122	0	103	134	0
2017	156	75	98		95	123	0	104	136	0
2018	156	76	99	0	96	125	0	105	137	0
2019	156	77	100	0	97	126	0	106	138	0
2020	156	78	102	0	98	127	0	107	140	0
2021	156	79	103	0	99	129	0	108	141	0
2022	156	80	104	0	100	130	0	109	142	0
2023	156	81	106	0	101	131	0	110	144	0
2024	156	82	107	0	102	133	0	111	145	0
2025	156	83	108	0	103	134	0	112	146	0
2026	156	84	109	0	104	135	0	113	147	0
2027	156	85	111	0	105	136	0	114	149	0
2028	156	86	112	0	106	138	0	115	150	0

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Kenai = Kenai Capacity Requirement - Kenai Local Capacity

Table 6-4

FAIRBANKS CAPACITY SHORTAGE

Year	Local Capacity (MW)	Load Growth : Low			Load Growth : Medium			Load Growth : High		
		Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	245	119	155	0	118	153	0	125	162	0
1995	243	119	155	0	119	154	0	127	165	0
19[illegible]	236	119	155	0	119	155	0	128	166	0
1[illegible]	233	120	156	0	120	156	0	130	169	0
19[illegible]	233	121	157	0	121	157	0	132	171	0
1999	233	121	157	0	122	159	0	133	173	0
2000	226	121	158	0	123	160	0	136	177	0
2001	208	122	159	0	125	162	0	136	177	0
2002	165	124	161	0	126	163	0	141	183	18
2003	165	125	162	0	127	165	0	143	185	20
2004	165	126	163	0	129	167	2	146	190	25
2005	145	127	165	20	131	170	25	152	197	52
2006	61	128	167	106	133	173	112	157	205	144
2007	0	130	169	169	136	177	177	157	204	204
2008	0	132	172	172	139	180	180	158	206	206
2009	0	133	173	173	141	183	183	160	208	208
2010	0	135	176	176	143	187	187	163	212	212
2011	0	136	177	177	145	189	189	166	216	216
2012	0	137	179	179	147	192	192	169	220	220
2013	0	138	180	180	149	194	194	172	224	224
2014	0	139	181	181	151	197	197	175	228	228
2015	0	140	183	183	153	200	200	178	232	232
2016	0	141	184	184	155	202	202	181	236	236
2017	0	142	185	185	157	205	205	184	240	240
2018	0	143	186	186	159	207	207	187	244	244
2019	0	144	188	188	161	210	210	190	248	248
2020	0	145	189	189	163	213	213	193	251	251
2021	0	146	190	190	165	215	215	196	255	255
2022	0	147	192	192	167	218	218	199	259	259
2023	0	148	193	193	169	220	220	202	263	263
2024	0	149	194	194	171	223	223	205	267	267
2025	0	150	196	196	173	226	226	208	271	271
2026	0	151	197	197	175	228	228	211	275	275
2027	0	152	198	198	177	231	231	214	279	279
2028	0	153	199	199	179	233	233	217	283	283

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Fairbanks = Fairbanks Capacity Requirement - Fairbanks Local Capacity

6.4.3 Anchorage Capacity Shortage

While the existing capacity surplus in Anchorage may disappear as early as 1995, capacity shortages in Anchorage may not occur until 1996 or 1997. The reason for this time lag between capacity surplus and capacity shortage in Anchorage is the existing transmission lines that make surplus capacity in Kenai and Fairbanks accessible in Anchorage. A capacity shortage exists in Anchorage only if the Anchorage capacity requirements exceed the sum of the Anchorage local capacity and the capacity surplus in Kenai and Fairbanks accessible in Anchorage.

The Kenai capacity surplus that is accessible in Anchorage is the minimum of the Kenai capacity surplus and the capacity of the Kenai-Anchorage line. Two estimates of the current transfer limit on the Kenai-Anchorage line have been used to calculate the capacity shortage in Anchorage (and later to calculate benefits from the KA138). Case 1 assumes a 60 MW existing transfer limit, based on Anchorage delivery, while Case 2 uses 88 MW as the existing limit.

The Fairbanks capacity surplus that is accessible in Anchorage is the minimum of the Fairbanks capacity surplus and the capacity of the Anchorage-Fairbanks line (currently 62 MW, based on Anchorage delivery). Table 6-5 illustrates the expected local capacity in Anchorage between 1994 and 2028 and the corresponding capacity shortage for the three load forecasts.

6.5 CAPACITY DEFERRAL DUE TO NEW/UPGRADED INTERTIES

This section outlines the reductions in capacity shortages due to the proposed interties, accounting for the advantages of deferring capacity additions in one area through utilization of currently forecasted surpluses in other areas. Section 6.7 describes shortage reductions through capacity avoidance.

Due to some variability reported for the transfer limits of the existing and proposed interties, two cases corresponding to different transfer scenarios have been used to bound capacity deferral benefits of the new/upgraded interties.

Table 6-5

ANCHORAGE CAPACITY SHORTAGE—CASE 1

		Load Growth : Low			Load Growth : Medium			Load Growth : High		
Year	Local Capacity (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	633	383	498	0	386	502	0	404	525	0
1995	499	382	497	0	390	507	0	407	529	0
1996	379	381	495	0	392	510	9	411	534	33
1997	347	381	495	26	393	510	41	417	543	74
1998	328	380	494	44	396	515	65	423	550	101
1999	117	380	494	255	401	522	283	430	559	322
2000	117	380	494	255	405	527	288	438	569	343
2001	117	382	497	271	411	534	311	447	581	373
2002	117	385	501	320	416	540	361	455	592	415
2003	117	389	506	326	422	549	372	465	604	427
2004	117	393	511	332	430	559	382	475	618	441
2005	117	397	515	338	438	570	393	483	628	451
2006	117	401	522	345	448	583	406	494	642	465
2007	117	406	528	351	460	598	421	504	655	478
2008	117	411	534	357	471	612	435	513	666	489
2009	30	416	541	451	482	627	537	520	676	586
2010	5	422	549	484	494	642	594	532	691	656
2011	5	427	555	490	504	655	609	542	704	671
2012	5	432	562	497	514	668	624	552	717	685
2013	5	437	568	503	524	681	638	562	730	700
2014	5	442	575	510	534	694	652	572	743	714
2015	5	447	581	516	544	707	667	582	756	728
2016	5	452	588	523	554	720	681	592	769	743
2017	5	457	594	531	564	733	695	602	782	757
2018	5	462	601	539	574	746	710	612	795	771
2019	5	467	607	547	584	759	724	622	808	786
2020	5	472	614	554	594	772	738	632	821	800
2021	5	477	620	562	604	785	752	642	834	814
2022	5	482	627	570	614	798	767	652	847	828
2023	5	487	633	578	624	811	781	662	860	843
2024	5	492	640	586	634	824	795	672	873	857
2025	5	497	646	593	644	837	810	682	886	871
2026	5	502	653	601	654	850	824	692	899	886
2027	5	507	659	609	664	863	838	702	912	900
2028	5	512	666	617	674	876	853	712	925	914

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Anchorage = Anchorage Capacity Requirements
— Anchorage Local Capacity
— Surplus in Kenai and Fairbanks Accessible via Transmission Lines

Table 6-5

ANCHORAGE CAPACITY SHORTAGE—CASE 2

Year	Local Capacity (MW)	Load Growth : Low Load (MW)	Load Growth : Low Capacity Requir't (MW)	Load Growth : Low Capacity Shortage (MW)	Load Growth : Medium Load (MW)	Load Growth : Medium Capacity Requir't (MW)	Load Growth : Medium Capacity Shortage (MW)	Load Growth : High Load (MW)	Load Growth : High Capacity Requir't (MW)	Load Growth : High Capacity Shortage (MW)
1994	633	383	498	0	386	502	0	404	525	0
1995	499	382	497	0	390	507	0	407	529	0
1996	379	381	495	0	392	510	0	411	534	5
1997	347	381	495	0	393	510	13	417	543	46
1998	328	380	494	16	396	515	37	423	550	73
1999	117	380	494	227	401	522	255	430	559	294
2000	117	380	494	227	405	527	260	438	569	315
2001	117	382	497	243	411	534	283	447	581	345
2002	117	385	501	292	416	540	333	455	592	387
2003	117	389	506	298	422	549	344	465	604	399
2004	117	393	511	304	430	559	354	475	618	413
2005	117	397	515	310	438	570	365	483	628	423
2006	117	401	522	317	448	583	378	494	642	437
2007	117	406	528	323	460	598	393	504	655	463
2008	117	411	534	329	471	612	409	513	666	476
2009	30	416	541	423	482	627	513	520	676	574
2010	5	422	549	475	494	642	594	532	691	656
2011	5	427	555	484	504	655	609	542	704	671
2012	5	432	562	492	514	668	624	552	717	685
2013	5	437	568	500	524	681	638	562	730	700
2014	5	442	575	508	534	694	652	572	743	714
2015	5	447	581	515	544	707	667	582	756	728
2016	5	452	588	523	554	720	681	592	769	743
2017	5	457	594	531	564	733	695	602	782	757
2018	5	462	601	539	574	746	710	612	795	771
2019	5	467	607	547	584	759	724	622	808	786
2020	5	472	614	554	594	772	738	632	821	800
2021	5	477	620	562	604	785	752	642	834	814
2022	5	482	627	570	614	798	767	652	847	828
2023	5	487	633	578	624	811	781	662	860	843
2024	5	492	640	586	634	824	795	672	873	857
2025	5	497	646	593	644	837	810	682	886	871
2026	5	502	653	601	654	850	824	692	899	886
2027	5	507	659	609	664	863	838	702	912	900
2028	5	512	666	617	674	876	853	712	925	914

Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Anchorage = Anchorage Capacity Requirements
— Anchorage Local Capacity
— Surplus in Kenai and Fairbanks Accessible via Transmission Lines

6.5.1 Kenai-Anchorage New Intertie (KA138)

The new Kenai-Anchorage intertie would allow Anchorage to use the capacity surplus in Kenai without the 60 to 88 MW transfer limit that exists today.[4] The combined Kenai-Anchorage area would include the capacity resources of the two areas to meet the capacity requirements of the combined area, recognizing that the intertie might constrain some sharing of resources. The Kenai-Anchorage area could also rely on capacity surplus in Fairbanks to the extent that this surplus is less than the transfer capacity of the existing Anchorage-Fairbanks line (62 MW, based on Anchorage delivery). The KA138 line would therefore allow Anchorage to use the capacity surplus in Kenai up to the transfer limit of the line, and correspondingly reduce capacity shortages in Anchorage. Table 6-6 illustrates the capacity shortages in the Kenai/Anchorage combined area for all three load forecasts.

The capacity shortage in the Kenai/Anchorage combined area (case with new intertie) is less than or equal to the sum of the capacity shortages in the two areas (case without new intertie). For example, consider the situation in Anchorage for Case 1, where the existing transfer limit between Anchorage and Kenai is 60 MW. In Table 6-5 (Case 1), there is a 65 MW capacity shortage in Anchorage for the middle load growth forecast in 1998[5] and a 15 MW capacity shortage in the Anchorage/Kenai combined area (Table 6-6). Therefore, the new Kenai-Anchorage intertie would reduce the capacity shortage in 1998 by 50 MW (65 MW - 15 MW) for the middle load forecast. This reduced capacity shortage is due to the fact that the new intertie would allow Anchorage to use 110 MW of the 120 MW surplus in Kenai in 1998 (refer to Table 6-1); only 60 MW would be used without the new intertie. Table 6-7 illustrates the reduced Kenai/Anchorage capacity shortages due to the KA138. Note that the reductions never exceed the increase in the transfer limit (50 MW for Case 1, 22 MW for Case 2).

According to Table 6-7, the Kenai/Anchorage capacity shortages are reduced between 1996 and 2015; no capacity shortage reductions are identified after 2015. Therefore, these reduced shortages represent *deferred capacity additions* rather than *avoided capacity additions*. Avoided capacity additions could be accomplished since the KA138 could reduce the capacity reserve margin of the Kenai/Anchorage area; these reductions are outlined in Sections 6.7 and 6.8.

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4. The transfer limit for the new intertie would be 110 MW adjusted for transmission losses. The existing limit has been reported as both 60 MW and 88 MW, which constitute Case 1 and Case 2, respectively.

5. There is no capacity shortage in Kenai in 1998.

Table 6-6

KENAI/ANCHORAGE CAPACITY SHORTAGE

Year	Kenai/ Anchorage Capacity (MW)	Load Growth : Low Load (MW)	Low Capacity Requir't (MW)	Low Capacity Shortage (MW)	Load Growth : Medium Load (MW)	Medium Capacity Requir't (MW)	Medium Capacity Shortage (MW)	Load Growth : High Load (MW)	High Capacity Requir't (MW)	High Capacity Shortage (MW)
1994	856	448	582	0	462	601	0	484	629	0
1995	719	445	578	0	466	606	0	487	633	0
1996	599	443	576	0	468	609	0	491	639	0
1997	567	443	576	0	469	610	0	499	648	24
1998	548	442	575	0	473	615	15	505	657	51
1999	337	443	575	205	479	623	233	513	666	272
2000	337	443	576	205	484	629	238	521	678	293
2001	337	445	579	221	489	636	261	532	691	323
2002	337	449	584	270	495	643	311	542	705	368
2003	337	453	589	276	502	653	322	553	719	382
2004	337	457	594	282	511	664	332	566	735	398
2005	332	461	600	288	520	676	344	575	747	415
2006	332	467	607	295	531	691	359	586	762	430
2007	314	472	614	301	544	707	393	597	777	463
2008	314	478	621	307	556	723	409	608	790	476
2009	227	484	629	402	569	740	513	616	801	574
2010	162	490	637	475	582	756	594	629	818	656
2011	161	496	645	484	593	770	609	640	832	671
2012	161	502	653	492	604	785	624	651	846	685
2013	161	508	661	500	615	799	638	662	861	700
2014	161	514	669	508	626	813	652	673	875	714
2015	161	520	676	515	637	828	667	684	689	728
2016	161	526	684	523	648	842	681	695	904	743
2017	161	532	692	531	659	856	695	706	918	757
2018	161	538	700	539	670	871	710	717	932	771
2019	161	544	708	547	681	885	724	728	947	786
2020	161	550	715	554	692	899	738	739	961	800
2021	161	556	723	562	703	913	752	750	975	814
2022	161	562	731	570	714	928	767	761	989	828
2023	161	568	739	578	725	942	781	772	1004	843
2024	161	574	747	586	736	956	795	783	1018	857
2025	161	580	754	593	747	971	810	794	1032	871
2026	161	586	762	601	758	985	824	805	1047	886
2027	161	592	770	609	769	999	838	816	1061	900
2028	161	598	778	617	780	1014	853	827	1075	914

The Kenai/Anchorage Capacity (Second column) is the sum of the two area's capacities which, due to transmission limits, may not serve an equal amount of load.

Capacity requirements are based on a 30 percent capacity reserve margin.

Capacity shortage, if any, for Kenai/Anchorage area = Kenai/Anchorage Capacity Requirements
— Kenai/Anchorage Capacity
— Surplus in Fairbanks Accessible via Existing Anchorage/Fairbanks Lines

Table 6-7

REDUCED KENAI/ANCHORAGE CAPACITY SHORTAGE DUE TO KENAI-ANCHORAGE NEW INTERTIE (MW)

	CASE 1				CASE 2		
	Load Growth				Load Growth		
Year	Low	Medium	High	Year	Low	Medium	High
1994	0	0	0	1994	0	0	0
1995	0	0	0	1995	0	0	0
1996	0	9	33	1996	0	0	5
1997	26	41	50	1997	0	13	22
1998	44	50	50	1998	16	22	22
1999	50	50	50	1999	22	22	22
2000	50	50	50	2000	22	22	22
2001	50	50	50	2001	22	22	22
2002	50	50	47	2002	22	22	19
2003	50	50	45	2003	22	22	17
2004	50	50	43	2004	22	22	15
2005	50	49	36	2005	22	21	8
2006	50	47	35	2006	22	19	7
2007	50	27	16	2007	22	0	0
2008	50	26	13	2008	22	0	0
2009	49	24	12	2009	21	0	0
2010	8	0	0	2010	0	0	0
2011	6	0	0	2011	0	0	0
2012	5	0	0	2012	0	0	0
2013	3	0	0	2013	0	0	0
2014	2	0	0	2014	0	0	0
2015	1	0	0	2015	0	0	0
2016	0	0	0	2016	0	0	0
2017	0	0	0	2017	0	0	0
2018	0	0	0	2018	0	0	0
2019	0	0	0	2019	0	0	0
2020	0	0	0	2020	0	0	0
2021	0	0	0	2021	0	0	0
2022	0	0	0	2022	0	0	0
2023	0	0	0	2023	0	0	0
2024	0	0	0	2024	0	0	0
2025	0	0	0	2025	0	0	0
2026	0	0	0	2026	0	0	0
2027	0	0	0	2027	0	0	0
2028	0	0	0	2028	0	0	0

6.5.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

The Anchorage-Fairbanks intertie upgrade would allow Anchorage to use the capacity surplus in Fairbanks without the 62 MW transfer limit that exists today.[6] For capacity planning purposes, Anchorage and Fairbanks could then be considered a single area; the load, capacity, and required capacity of the Anchorage/Fairbanks combined area would then be equal to the sum of the loads, capacities, and required capacities in the two areas. The Anchorage/Fairbanks area could also rely on capacity surplus in Kenai to the extent that this surplus is less than the transfer capacity of the existing Kenai-Anchorage line (60 MW for Case 1 and 88 MW for Case 2, based on Anchorage delivery). The AF100 upgrade would therefore allow Anchorage to fully use the capacity surplus in Fairbanks and correspondingly reduce capacity shortages in Anchorage. Table 6-8 illustrates the capacity shortages in the Anchorage/Fairbanks combined area for all three load forecasts.[7]

The capacity shortage in the Anchorage/Fairbanks combined area (case with intertie upgrade) is less than or equal to the sum of the capacity shortages in the two areas (case without the upgrade). For example, there is a 41 MW capacity shortage in Anchorage for the middle load growth forecast in 1997[8] and a 26 MW capacity shortage in the Anchorage/Fairbanks combined area. Therefore, the AF100 upgrade would reduce the capacity shortage in 1997 by 15 MW (41 MW - 26 MW) for the middle load forecast. This reduced capacity shortage is due to the fact that the intertie upgrade would allow Anchorage to fully use the 77 MW surplus in Fairbanks in 1998 (refer to Table 6-2); only 62 MW would be used without the new intertie. Table 6-9 illustrates the reduced Anchorage/Fairbanks capacity shortages due to the AF100 upgrade for the two cases of AF100 transfer limits.

According to Table 6-9, the Anchorage/Fairbanks capacity shortages are reduced between 1996 and 2000; no capacity shortage reductions are identified after 2000. Therefore, these reduced shortages represent *deferred capacity additions* rather than *avoided capacity additions*. Avoided capacity additions could be accomplished since the Anchorage-Fairbanks AF100 upgrade could reduce the capacity reserve margin of the Anchorage/Fairbanks area; these reductions are outlined in Sections 6.7 and 6.8.

6. The transfer limit of the upgraded intertie would be 84 to 87 MW adjusted for transmission losses. These two limits are used as Cases 1 and 2.

7. The Case 1 transfer limit of 60 MW for the existing KA line is assumed.

8. There is no capacity shortage in Fairbanks in 1998.

Table 6-8

ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE

Year	Anchorage-Fairbanks Capacity (MW)	Load Growth : Low Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : Medium Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)	Load Growth : High Load (MW)	Capacity Requir't (MW)	Capacity Shortage (MW)
1994	878	502	653	0	504	655	0	529	688	0
1995	742	502	652	0	509	661	0	533	694	0
1996	615	500	650	0	511	665	0	539	700	25
1997	580	501	651	11	513	666	26	547	711	71
1998	561	500	650	29	517	672	51	555	722	101
1999	350	501	651	241	523	680	270	563	732	322
2000	343	502	652	249	529	687	284	574	746	343
2001	325	505	656	271	535	696	311	583	758	373
2002	282	509	662	320	541	703	361	596	775	433
2003	282	514	668	326	549	714	372	607	789	447
2004	282	518	674	332	558	726	384	621	808	466
2005	262	524	681	359	569	740	418	635	825	503
2006	178	530	689	451	581	756	518	651	846	608
2007	117	536	697	520	596	774	597	661	859	682
2008	117	543	706	529	610	793	616	671	872	695
2009	30	550	714	624	624	811	721	680	884	794
2010	5	558	725	660	637	828	781	695	904	868
2011	5	564	733	668	649	844	799	708	921	887
2012	5	570	740	675	661	860	815	721	937	906
2013	5	576	748	683	673	875	832	734	954	924
2014	5	582	756	691	685	891	849	747	971	942
2015	5	588	764	699	697	906	866	760	988	960
2016	5	594	772	707	709	922	883	773	1005	978
2017	5	600	779	716	721	938	900	786	1022	997
2018	5	606	787	725	733	953	917	799	1039	1015
2019	5	612	795	734	745	969	934	812	1056	1033
2020	5	618	803	744	757	984	951	825	1073	1051
2021	5	624	811	753	769	1000	968	838	1090	1069
2022	5	630	818	762	781	1016	984	851	1106	1088
2023	5	636	826	771	793	1031	1001	864	1123	1106
2024	5	642	834	780	805	1047	1018	877	1140	1124
2025	5	648	842	789	817	1062	1035	890	1157	1142
2026	5	654	850	798	329	1078	1052	903	1174	1160
2027	5	660	857	807	841	1094	1069	916	1191	1179
2028	5	666	865	816	853	1109	1086	929	1208	1197

The Anchorage/Fairbanks Capacity (Second Column) is the sum of the two areas capacities which, due to transmission limits, may not serve an equal amount of load.
Capacity requirements are based on a 30 percent capacity reserve margin.
Capacity shortage, if any, for Anchorage/Fairbanks Area = Anchorage/Fairbanks Capacity Requirements
— Anchorage/Fairbanks Capacity
— Surplus in Kenai Accessible via Existing Kenai/Anchorage Lines

Table 6-9

REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE DUE TO ANCHORAGE/FAIRBANKS INTERTIE UPGRADE (MW)

CASE 1

Year	Load Growth Low	Load Growth Medium	Load Growth High
1994	0	0	0
1995	0	0	0
1996	0	9	8
1997	15	15	2
1998	14	14	0
1999	14	12	0
2000	6	4	0
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0

CASE 2

Year	Load Growth Low	Load Growth Medium	Load Growth High
1994	0	0	0
1995	0	0	0
1996	0	0	5
1997	0	13	2
1998	14	14	0
1999	14	12	0
2000	6	4	0
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
2012	0	0	0
2013	0	0	0
2014	0	0	0
2015	0	0	0
2016	0	0	0
2017	0	0	0
2018	0	0	0
2019	0	0	0
2020	0	0	0
2021	0	0	0
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	0	0	0

6.5.3 Healy-Fairbanks New Intertie (AF138)

The AF138 intertie would allow Anchorage and Fairbanks to reduce their capacity requirements by the same amount calculated for the Anchorage-Fairbanks AF100 upgrade; since the AF100 provides all the transfer capability needed to take advantage of capacity sharing between Anchorage to Fairbanks. Table 6-9 shows the reduced shortage for the Anchorage/Fairbanks area is always less than the increased transfer levels for the AF proposals. The increase in transfer limits for the AF138 provides no additional capacity deferral benefits beyond those calculated for the AF100.

6.6 BENEFITS OF CAPACITY DEFERRAL DUE TO NEW/UPGRADED INTERTIES

When capacity is needed, the Railbelt utilities would acquire additional capacity by repowering existing power plants, extending the life of existing power plants, or adding new power plants. The expected reduced capacity shortage due to the new/upgraded interties would allow the Railbelt to reduce the addition of capacity and therefore save capital costs. Cost savings are largest when the Railbelt can avoid adding a new plant; avoiding repowering or life extension of an existing power plant also leads to cost savings.

Since reduced capacity shortages are only temporary (refer to Sections 6.5.1 and 6.5.2), the resulting savings are cost deferrals rather than cost avoidances. Therefore, we assign savings for reduced capacity shortages during any given year based on the reduced capacity shortage in that year (refer to Tables 6-7 and 6-9) and the annual value of saved capacity. The annual value of saved capacity in any given year is calculated at $51 per kilowatt per year.[9]

6.6.1 Kenai-Anchorage New Intertie (KA138)

Using the calculated reduced Kenai/Anchorage capacity shortages (Table 6-7) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity deferral attributed to the KA138 line. Table 6-10 summarizes the results. The discounted value of all benefits between 1994 and 2028 is largest for the lowest load forecast and lowest for the highest load forecast; with higher loads, there is less surplus capacity available for sharing. At a discount rate of 4.5 percent per year, the benefits of capacity deferral due to the KA138 intertie vary between $18.91 million and $20.90 million for Case 1 and $6.67 million and $8.30 million for Case 2.

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9. Based on the levelized capital cost of a combustion turbine of $490 per kilowatt, and a fixed O&M of $13 per kilowatt per year. Levelization is for 20 years at 4.5 percent per year.

Table 6-10

BENEFITS OF REDUCED KENAI/ANCHORAGE CAPACITY SHORTAGE (million dollars)

	CASE 1				CASE 2		
	Load Growth				Load Growth		
Year	Low	Medium	High	Year	Low	Medium	High
1994	0.00	0.00	0.00	1994	0.00	0.00	0.00
1995	0.00	0.00	0.00	1995	0.00	0.00	0.00
1996	0.00	0.43	1.69	1996	0.00	0.00	0.26
1997	1.31	2.12	2.55	1997	0.00	0.68	1.12
1998	2.24	2.55	2.55	1998	0.80	1.12	1.12
1999	2.55	2.55	2.55	1999	1.12	1.12	1.12
2000	2.55	2.55	2.55	2000	1.12	1.12	1.12
2001	2.55	2.55	2.53	2001	1.12	1.12	1.11
2002	2.55	2.55	2.42	2002	1.12	1.12	0.99
2003	2.55	2.55	2.31	2003	1.12	1.12	0.89
2004	2.55	2.55	2.17	2004	1.12	1.12	0.75
2005	2.55	2.48	1.83	2005	1.12	0.97	0.41
2006	2.55	2.41	1.78	2006	1.12	0.91	0.36
2007	2.55	1.40	0.79	2007	1.12	0.00	0.00
2008	2.55	1.32	0.67	2008	1.12	0.00	0.00
2009	2.51	1.24	0.62	2009	1.07	0.00	0.00
2010	0.42	0.00	0.00	2010	0.00	0.00	0.00
2011	0.30	0.00	0.00	2011	0.00	0.00	0.00
2012	0.24	0.00	0.00	2012	0.00	0.00	0.00
2013	0.17	0.00	0.00	2013	0.00	0.00	0.00
2014	0.11	0.00	0.00	2014	0.00	0.00	0.00
2015	0.04	0.00	0.00	2015	0.00	0.00	0.00
2016	0.00	0.00	0.00	2016	0.00	0.00	0.00
2017	0.00	0.00	0.00	2017	0.00	0.00	0.00
2018	0.00	0.00	0.00	2018	0.00	0.00	0.00
2019	0.00	0.00	0.00	2019	0.00	0.00	0.00
2020	0.00	0.00	0.00	2020	0.00	0.00	0.00
2021	0.00	0.00	0.00	2021	0.00	0.00	0.00
2022	0.00	0.00	0.00	2022	0.00	0.00	0.00
2023	0.00	0.00	0.00	2023	0.00	0.00	0.00
2024	0.00	0.00	0.00	2024	0.00	0.00	0.00
2025	0.00	0.00	0.00	2025	0.00	0.00	0.00
2026	0.00	0.00	0.00	2026	0.00	0.00	0.00
2027	0.00	0.00	0.00	2027	0.00	0.00	0.00
2028	0.00	0.00	0.00	2028	0.00	0.00	0.00
NPV 3.0%	24.18	23.31	21.21	NPV 3.0%	9.62	8.23	7.41
NPV 4.5%	20.90	19.63	18.91	NPV 4.5%	8.30	7.29	6.67

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6.6.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Table 6-9) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings due to capacity deferral attributed to the AF100. Table 6-11 summarizes the results. At a discount rate of 4.5 percent per year, the benefits of capacity deferral due to the AF100 upgrade vary between $0.43 million and $2.20 million for Case 1 and $0.33 million and $1.75 million for Case 2.

6.6.3 Healy-Fairbanks New Intertie (AF138)

Because the AF100 upgrade and the AF138 intertie would lead to the same capacity shortage reductions, these calculations produce the same capacity deferral benefits. Those benefits are between $0.43 million and $2.20 million for Case 1 and $0.33 million and $1.75 million for Case 2.

6.7 CAPACITY AVOIDANCE DUE TO NEW/UPGRADED INTERTIES

The proposed interties make two significant contributions relevant for capacity-sharing benefits: access to another area's capacity and increased reliability.

The previous section presented reductions in capacity shortage in Anchorage due to the proposed interties by *accessing* surplus capacity in Kenai and Fairbanks (surplus areas) to defer capacity additions in Anchorage (shortage area). Capacity deferral benefits derive from capacity in surplus areas contributing to a target reserve margin for a shortage area.

The reserve margin of an electric power system is a function of desired system reliability, sizes of power plants, availability of power plants, and system size. A system reserve margin decreases with lower desired system reliability, smaller plants size, higher plants availability, and larger system size.

A new intertie leads to larger system sizes for interconnected areas and therefore would allow both areas to establish lower reserve margins, and/or add larger size units while keeping desired reliability unchanged. Lowering reserve margins leads to reduced capacity additions, i.e., capacity avoidance benefits.

Table 6-11

BENEFITS OF REDUCED ANCHORAGE/FAIRBANKS CAPACITY SHORTAGE (million dollars)

CASE 1

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.0
1995	0.00	0.00	0.00
1996	0.00	0.43	0.39
1997	0.74	0.77	0.11
1998	0.73	0.69	0.00
1999	0.72	0.63	0.00
2000	0.31	0.18	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	2.14	2.37	0.46
NPV 4.5%	1.99	2.20	0.43

CASE 2

	Load Growth		
Year	Low	Medium	High
1994	0.00	0.00	0.00
1995	0.00	0.00	0.00
1996	0.00	0.00	0.26
1997	0.00	0.68	0.11
1998	0.73	0.69	0.00
1999	0.72	0.63	0.00
2000	0.31	0.18	0.00
2001	0.00	0.00	0.00
2002	0.00	0.00	0.00
2003	0.00	0.00	0.00
2004	0.00	0.00	0.00
2005	0.00	0.00	0.00
2006	0.00	0.00	0.00
2007	0.00	0.00	0.00
2008	0.00	0.00	0.00
2009	0.00	0.00	0.00
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	0.00	0.00	0.00
2023	0.00	0.00	0.00
2024	0.00	0.00	0.00
2025	0.00	0.00	0.00
2026	0.00	0.00	0.00
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
NPV 3.0%	1.49	1.89	0.34
NPV 4.5%	1.37	1.75	0.33

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This section calculates the reductions in capacity reserve margin that could be made with the proposed interties and the associated avoidance of some capacity additions.[10] No estimate of economies of scale benefits is provided in this analysis,[11] due to lack of good data on economies of scale.

6.7.1 Equivalent Reliability Index

Many different measures of the reliability of a power system have been developed and used; they vary depending on the particular needs of the measurement. Loss of Load Probability (LOLP) has gained considerable use in the industry as a reasonably well-defined index of system reliability [2]. An Equivalent Reliability Index (ERI), based on the same concepts of LOLP, is defined and used here for evaluation of the new/upgraded interties.

Experience has shown that the mean and variance (the square of the standard deviation) of capacity availability represent, reasonably well, the distribution of availability for reliability purposes, and that the distribution can be approximated by the Normal or Gaussian distribution [2]. In reference [3], LOLP is calculated by evaluating the area under the capacity availability distribution from zero to a given load. This evaluation requires standardizing the variable and using a standard Normal table to evaluate the probability.

For example, the LOLP at a load of L, for a capacity availability mean M and standard deviation S, could be found from calculating the standard variable:

$$Z = (L - M)/S$$

and

LOLP = 0.5 – Area Under the Standard Normal Evaluated Between 0 and Z

The implication of the calculation for the following discussion is that a change in the capacity of the system results in changes to the mean and variance of the availability distribution. A system addition would result in a different level of load that could be served (or lost) for the same LOLP target.

Following the same rational, and assuming the capacity on outage to be normally distributed, the Equivalent Reliability Index (ERI) is a measure of the adequacy of the reserve margin to meet the level of outages.

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10. The section on reliability (Section 4) covered the benefits of the new/upgraded interties gained from the reduction in outages; impacts on capacity planning were not included in that analysis.

11. The inclusion of economies of scale benefits could only increase the benefits of capacity sharing.

$$ERI = (RM - m)/s,$$

where RM = Reserve Capacity Margin (MW)
m = Mean of Capacity on Outage (MW)
s = Standard Deviation of Capacity on Outage (MW)

A change in available capacity affects the mean and standard deviation of the capacity on outage. A new intertie, for instance, leads to a decrease in the standard deviation of the capacity on outages. This implies that the reserve margin could be adjusted downward for the decrease in the standard deviation of the capacity on outage, while holding the ERI constant.

6.7.2 Calculation of Avoided Capacity

The ERI is used as a measure of capacity adequacy, taking as input reserve margin and the distribution of capacity outages. Holding the ERI constant for evaluation of the cases with and without the interties, we calculate reductions in needed reserve margins due to the new/upgraded interties. New/upgraded interties result in reductions in reserve margins, since the impact of reliable additions is to decrease the standard deviation of the outage distribution (while slightly increasing the mean). Reductions in reserve margins lead to a fixed level of capacity avoidance for the area of interest.

A simulation of the capacity avoidance due to the new/upgraded interties used capacity and outage data for each generating unit in the Railbelt. A reserve load margin[12] of 30 percent, which is equivalent to a system reserve margin[13] of 23.08 percent, is assumed. Available generating resources for each area consist of those units most important for evaluation purposes; i.e., if a unit is to be retired in 1992, the unit is not included. The simulation assumes that the relationship between loads and resources remains constant through the study period so that the percent reserve margin stays constant.

The ERI is calculated, as described above, from the capacity on outage data. For each proposal, the amount of avoided capacity is calculated as the MW reduction in reserve margin, such that the ERI is held constant with the addition of the new intertie. Benefits of the avoided additions to capacity are then calculated by applying the same capacity value ($51/kW) as in the deferral analysis.

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12. Reserve load margin is the amount of available generating resources that exceeds forecasted load, calculated as a percent of the load.

13. System reserve margin is the amount of available generating resources that exceeds forecasted load, calculated as a percentage of the total available generating resources.

6.7.3 Kenai-Anchorage New Intertie (KA138)

The amount of avoided capacity additions in the Kenai/Anchorage area due to the KA138 ranges from 9.4 MW to 20.7 MW for each year in which shortages occur, which is the case after 1999. The low estimate is based on an existing transfer limit of 88 MW between Kenai and Anchorage, while the high estimate is based on an existing transfer limit of 60 MW.

6.7.4 Anchorage-Fairbanks Intertie Upgrade (AF100)

The amount of avoided capacity additions in the combined Anchorage/Fairbanks area, due to the AF100 line, ranges from 9.6 MW to 10.9 MW for each year in which shortages occur. The low estimate is based on a transfer limit of 84 MW for the AF100, while the high estimate corresponds to a transfer limit of 87 MW.

6.7.5 Healy-Fairbanks New Intertie (AF138)

The amount of avoided capacity additions in the combined Anchorage/Fairbanks area, due to the AF138 line, is 21.3 MW for each year of shortage conditions. This estimate is based on a transfer limit of 112 MW, after losses, for the AF138 between Anchorage and Fairbanks.

6.8 BENEFITS OF CAPACITY AVOIDANCE DUE TO NEW/UPGRADED INTERTIES

6.8.1 Kenai-Anchorage New Intertie (KA138)

Using the calculated reduced Kenai/Anchorage capacity shortages (Section 6.7.3) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity avoidance due to the KA138.[14]

The benefits are calculated for 1994-2033 at a discount rate of 4.5 percent per year; no benefits accrue for the years 1994-1998 since there are no forecasted capacity for this period in the Railbelt. The benefits of capacity avoidance due to the KA138 intertie vary between $14.8 million for Case 1 and $6.74 million for Case 2.

14. A 40-year lifetime has been estimated for the KA138.

6.8.2 Anchorage-Fairbanks Intertie Upgrade (AF100)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Section 6.7.4) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity avoidance due to the AF100.

The benefits are calculated for 1994-2043[15] at a discount rate of 4.5 percent per year; no benefits accrue for 1994-1998 since there are no forecasted capacity shortages for this period in the Railbelt.

The benefits of capacity avoidance due to the AF100 upgrade are between $7.16 million for Case 1 and $8.13 million for Case 2.

6.8.3 Healy-Fairbanks New Intertie (AF138)

Using the calculated reduced Anchorage/Fairbanks capacity shortages (Section 6.7.5) and the $51 per kilowatt per year value of saved capacity, we calculate the capital cost savings from capacity due to the AF138.

The benefits are calculated for 1994-2043[16] at a discount rate of 4.5 percent per year; no benefits accrue for 1994-1998 since there are no forecasted capacity shortages for this period in the Railbelt. The benefits of capacity avoidance due to the AF138 intertie are $15.97 million.

6.9 TOTAL CAPACITY-SHARING BENEFITS DUE TO NEW/UPGRADED INTERTIES

Total benefits of the new/upgraded interties are the sum of capacity deferral benefits (Section 6.6, Tables 6-10, 6-11) and capacity avoidance benefits (Sections 6.8.1, 6.8.2, 6.8.3). The total benefits for each new or upgraded intertie are shown in Table 6-12.

15. A 50-year lifetime has been estimated for the steel tower construction proposed for the AF100.

16. A 50-year lifetime has been estimated for the steel tower construction proposed for the AF138.

Table 6-12

TOTAL CAPACITY-SHARING BENEFITS
(million dollars, 1990 dollars)

	Case 1			Case 2		
	Load			Load		
	Low	Mid	High	Low	Mid	High
KA138	35.7	34.4	33.7	15.0	14.0	13.4
AF100	9.2	9.4	7.6	9.5	9.9	8.5
AF138	18.0	18.2	16.4	17.3	17.7	16.3

6.10 REFERENCES

[1] Alaska Intertie Agreement, December 1985.

[2] R. Billinton, "Bibliography on the Application of Probability Methods in Power System Reliability," *IEEE Transactions*, vol. PAS-91, pp. 649-660, 1972.

[3] J. Stremel, "The Cumulant Method of Calculating LOLP," IEEE PES Summer Meeting, Paper A 79 506-7, 1979.

Section 7

OPERATING RESERVE SHARING

7.1 OVERVIEW

Operating reserves[1] respond to changes in customer demand and failures in the electric generation and transmission system. Operating reserves improve reliability, but they are often expensive. The hydroelectric capacity on the Kenai Peninsula may provide a less expensive source for some operating reserves that otherwise would be provided by thermal generating units in the Anchorage area.

The operating reserve savings depend on the following four factors:

1. The operating reserve requirements in Anchorage.
2. The cost of providing operating reserves from thermal plants in Anchorage.
3. The transmission capacity between Anchorage and Kenai.
4. The generating capability in Kenai.

All four factors are discussed in more detail in the following subsections. The addition of a new Kenai-Anchorage intertie would increase the savings due to operating reserve sharing by about $5.2 to $13.5 million.

Appendix A discusses the transfer of energy back and forth between Anchorage and Kenai to reshape thermal demands to their most efficient production profile. The reshaping of demands served by thermal power plants differs significantly from sharing operating reserves. Reshaping involves moving significant amounts of energy between Kenai and Anchorage and changing the timing of thermal generation in Anchorage. Sharing operating reserves on the other hand, does not involve any transfer of energy between areas, nor the changed timing of any generation. It does involve shifting energy production among Anchorage power plants.

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1. Throughout this report, the term "operating reserves" refers only to "spinning reserves." However, according to the Alaska Intertie Agreement, operating reserves include both spinning and non-spinning reserves. Non-spinning operating reserves were not considered in this analysis because they are projected to exceed requirements in all scenarios.

7.2 ANCHORAGE OPERATING RESERVE REQUIREMENT

The interconnection agreements and operating practices among the Railbelt utilities currently result in the provision of approximately 65 MW of operating reserve accessible in the Anchorage area. Limited amounts of this operating reserve can be provided from outside the Anchorage area. Based on the information available, we estimate it is feasible to transfer up to 30 MW of operating reserve from Kenai to Anchorage. These 30 MW result from the practice of distributing these reserves such that they are not all lost with a single event.

With a second Kenai-Anchorage line, it would be feasible to transfer more than 30 MW of operating reserve from Kenai to Anchorage. The existence of two lines would provide a backup link between Kenai and Anchorage in the event of a line failure so that operating reserves are not all lost. Based on our discussions with system dispatchers,[2] we estimate that a second line would allow the transfer of up to 50 MW of operating reserve from Kenai to Anchorage. The 50 MW results from allowing for 15 MW of operating reserves to be provided by thermal power plants in Anchorage; these 15 MW are necessary to provide load following in the Railbelt.

7.3 THE COST OF OPERATING RESERVES

In order to respond quickly to changing requirements, power plants providing operating reserves are operated at part load such that they can quickly increase or decrease their power output. This is expensive for thermal generating plants, in general and gas turbines in particular. Most of the operating reserve provided in the Anchorage area comes from gas turbines.

Appendix A provides more specific information about gas turbine part-load operating costs. For example, when the 66 MW Beluga #5 CT operates at a loading of 33 MW, its total operating cost (also called heat rate) is 15,012 Btu/kWh. At a loading of 33 MW, Beluga #5 provides 33 MW of spinning reserves (66 MW of rated capacity minus 33 MW of loaded capacity). When Beluga #5 is operated to provide spinning reserves,[3] the cost of providing spinning reserves is the difference between the total operating cost of Beluga #5 (i.e., 15,012 Btu/kWh) and the system marginal cost. The system marginal cost is typically 9,000 to 11,000 Btu/kWh (refer to Table A-2). Therefore, the cost of spinning reserves provided by Beluga #5 is estimated at 5000 Btu/kWh.

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2. Meetings between Salim J. Jabbour and system dispatchers at Golden Valley Electric Association, Chugach Electric Association, Alaska Municipal Light & Power on August 8, 9 and 10, 1989.

3. Operating Beluga #5 could have been avoided if it were not for the spinning reserves requirement.

A detailed examination of the operating records of CEA, GVEA, and AMLP for 1988 indicates that the cost of providing spinning reserves is between 7,000 and 11,000 Btu/KWh.[4] In this study, we estimate the cost of spinning reserves at 7,000 Btu/KWh.

7.4 KENAI-ANCHORAGE TRANSMISSION CAPACITY

The new intertie will be capable of transferring 150 MW from Kenai to Anchorage (110 MW delivered). Based on the analysis described in Appendix A, transmission capacity will not be a constraint on the transfer of 50 MW of operating reserve.

The existing line can transfer 60 MW (delivered) from Kenai to Anchorage in Case 1, and 88 MW (delivered under emergency conditions) in Case 2. Based on the analysis described in Appendix A, it is expected that there will be 26 MW of capacity available for the transfer of operating reserves in Case 1 and 29 MW in Case 2. Because this increment of capacity has very high losses (approximately 20 percent), it will be seldom utilized for economy transactions. Transferring operating reserve is ideal because it does not incur losses. Therefore the transmission capacity between Kenai and Anchorage will be a constraint on the transfer of operating reserves under the single line scenario.

7.5 KENAI GENERATING CAPABILITY

With the addition of Bradley Lake, hydroelectric capacity in Kenai will increase to 133 MW delivered to Soldotna. This hydroelectric capability is energy-limited such that its overall capacity factor is on the order of 35 percent. This means that on average, more than 80 MW of unused hydroelectric capacity exists because of limited energy. This is an ideal operating reserve application. The ability of Kenai hydroelectric plants (particularly Bradley Lake) to provide useful operating reserve has been studied recently.[5] These findings indicate that while Bradley Lake's response rate is not fast enough to provide spinning reserves, Bradley Lake would allow the Railbelt utilities to get increased spinning reserves out of the thermal units at minimal or no additional cost. Following is an excerpt from a PTI report that explains this concept:

4. Value of Bradley Lake Spinning Reserves, prepared by Decision Focus Incorporated, October 6, 1989.

5. Power Technologies Incorporated and Stone and Webster Engineering Corporation have been working on this issue for the Alaska Energy Authority.

Combustion turbines are typically rated based on a maximum allowable turbine exhaust gas temperature. CT ratings are usually established for a standard set of environmental operating conditions known as ISO conditions. ISO conditions refer to an ambient temperature of 59 degrees Fahrenheit, at normal sea-level atmospheric pressure and at a certain relative humidity. For ISO conditions, CT will typically have two ratings based on some defined value of turbine exhaust gas temperatures:

1) Base Rating
2) Peak Rating

The turbine exhaust gas temperature is a significant indicator of the amount of life expenditure that occurs in a CT due to erosion and fatigue of the internal turbine parts.

The base rating is the power rating at which a CT can operate for sustained periods of time and stay within what is considered to be a normal maintenance schedule and without severe or unusual degradation to the internal parts of the turbine. The peak rating is a power rating greater than the base rating at which a CT can operate for some limited period of time (hours), but which will cause greater than normal degradation of the internal parts of the turbine and will increase the frequency and necessity of maintenance.

Although not specified as a rating, CT have an emergency capability which is above the peak rating. This emergency capability may correspond to the maximum, physical fuel consumption capability of the turbine as allowed by the fuel control system. A CT can operate at this emergency capability for only a very limited period of time, and operation at such levels (for more than a few seconds consecutively) will result in severe degradation of the internal parts of the turbine and will require significant maintenance activity...

...Various operating strategies can be developed to obtain increased response capability from a CT. One could normally operate a CT at no more than its base rating level and, during below-normal frequency conditions, take advantage of the few seconds of temporary "above rated power" output which might occur before the controls reduce the output of the CT back to its base rating level. Conversely, one could normally strive to operate a CT at no more than its base rating level, but configure the controls of the CT to allow it to operate, on a sustained basis, up to its peak rating level. Thus, in response to a below-normal frequency condition, the governor could boost the output of the CT to the emergency capability (maximum fuel consumption) until the exhaust temperature controls bring the output back to the peak rating level. The CT could then be allowed to operate at the peak rating level until other generation was brought on-line or until the output of slower responding hydro or steam units could be increased. Thus, the latter strategy would provide more sustained reserve capability from a given combustion turbine than the first operating strategy. Further, provided that a CT was not allowed to remain at its peak rating level for inordinate amounts of time, severe degradation of the internal parts of the turbine could be minimized and excessive maintenance activity avoided.

By using the "peak rating strategy," utilities can get increased spinning reserves from operating combustion turbines. The increase in spinning reserves is the difference between the peak and base ratings of the turbines. While the "peak rating strategy" could be used without Bradley Lake, the strategy would provide spinning reserves only if combustion turbines are operated at peak loading during emergency situations, for several minutes, until a unit is brought on-line. According to the PTI report, this would reduce the economic life of the turbines. The impact of Bradley Lake would be to reduce the time during which the turbines would be operated at peak loading to less than 1 minute.

Therefore, we assume that Bradley Lake would allow the use of the "peak rating strategy" and provide additional spinning reserves. Assuming a 10 percent difference between the peak and base ratings[6] of thermal units, we estimate that Bradley would provide an additional 30 MW of spinning reserves in the summer and 50 MW in the winter.[7]

7.6 SAVINGS IN OPERATING RESERVE COSTS

The benefits of increased operating reserve sharing due to a second line between Kenai and Anchorage derive from increased intertie availability,[8] increased reliance on Kenai's spinning reserves in the winter,[9] and increased intertie transfer capability.[10] We estimate the annual benefits of increased operating reserve sharing between $400,000 and $1,200,000. The net present value of increased operating reserve sharing is between $5.2 million and $13.5 million[11] (see Table 7-1).

Table 7-1

NET PERCENT VALUE OF SAVINGS DUE TO INCREASED OPERATING RESERVE SHARING (million dollars, 1990 dollars)

Scenario	Fuel	Increased Intertie Availability	Increased Reliance On Kenai Reserves In Winter	Increased Intertie Transfer Capability	Total
Case 1	Low	3.70	0.62	3.35	7.67
	Mid	5.11	0.87	4.71	10.69
	High	6.37	1.10	6.00	13.47
Case 2	Low	3.70	0.62	0.84	5.16
	Mid	5.10	0.87	1.18	7.15
	High	6.38	1.10	1.50	8.98

6. Based on discussions with PTI and representatives of the Railbelt electric utilities.

7. Based on Railbelt loads.

8. Refer to discussion on scheduled maintenance of the 115 KV line in Section 2.

9. Refer to Section 7.5.

10. Refer to Section 7.4.

11. Savings are adjusted for reduced gas royalty.

Section 8

SUMMARY AND CONCLUSIONS

8.1 OVERVIEW

This section provides a summary of the overall cost-benefit results for each of the alternatives analyzed in this study. The costs and benefits that have been estimated in the previous sections are aggregated and compared. In accordance with the practice followed throughout this analysis, all costs and benefits are expressed in terms of 1990 dollars.

The costs and benefits of the following intertie proposals are summarized in this section:

1. A new Kenai-Anchorage 138 KV intertie
2. A limited upgrade of the Anchorage-Fairbanks line
3. A new Healy-Fairbanks 138 KV intertie

The following benefit categories are described:

1. Reliability
2. Economy Energy Transfer
3. Transmission Efficiency
4. State Revenue
5. Capacity Sharing
6. Operating Reserve Sharing

8.2 NEW KENAI-ANCHORAGE 138 KV INTERTIE

Table 8-1 shows the present value of costs and benefits for the new Kenai-Anchorage line in each of the categories identified in this analysis. Positive benefits are indicated for each scenario examined. The expected value of net economic benefits is between $27.8 million and $57.1 million. The expected benefit to cost ratio is between 1.32 and 1.77. The difference between the low and high estimates of benefit reflects both the difference between the high and low reliability benefit and the difference between the low and high capital costs. The high estimate of total costs includes a replacement cost of $9.5 million (net present value of a replacement cost of $22.9 million after 20 years of service) for the submarine cable.

Figure 8-1 displays net benefits for each scenario. Figure 8-2 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-1

NEW KENAI-ANCHORAGE INTERTIE: SUMMARY OF COSTS AND BENEFITS

	Assumptions		Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Increased Spinning Reserves Sharing Benefits	Total Benefits		Total Costs		Net Benefits		Benefit to Cost Ratio	
Scenario	Fuel	Load						Low	High	Low	High	Low	High	Low	High
Case #1	Low	Low	35.0	-2.1	-3.1	35.7	7.7	110.5	127.8	74.1	86.2	24.3	53.7	1.28	1.72
		Middle	35.7	-1.1	-3.6	34.4	7.7	110.7	127.9	74.1	86.2	24.5	53.8	1.28	1.73
		High	34.9	-1.3	-3.2	33.7	7.7	111.2	128.4	74.1	86.2	25.0	54.3	1.29	1.73
	Middle	Low	48.9	-2.9	-4.0	35.7	10.7	125.7	142.9	74.1	86.2	39.5	68.8	1.46	1.93
		Middle	51.7	-2.9	-4.6	34.4	10.7	126.7	143.9	74.1	86.2	40.5	69.8	1.47	1.94
		High	53.9	-4.5	-4.5	33.7	10.7	126.6	143.9	74.1	86.2	40.4	69.8	1.47	1.94
	High	Low	61.8	-3.6	-5.3	35.7	13.5	139.4	156.7	74.1	86.2	53.2	82.5	1.62	2.11
		Middle	65.4	-3.5	-5.7	34.4	13.5	141.5	158.7	74.1	86.2	55.3	84.6	1.64	2.14
		High	68.0	-5.9	-6.9	33.7	13.5	140.1	157.4	74.1	86.2	53.9	83.3	1.63	2.12
Case #2	Low	Low	35.2	-2.1	-3.1	15.0	5.2	87.6	104.8	74.1	86.2	1.4	30.7	1.02	1.41
		Middle	35.9	-1.1	-3.4	14.0	5.2	88.0	105.3	74.1	86.2	1.8	31.1	1.02	1.42
		High	37.2	-1.3	-3.2	13.4	5.2	88.6	105.8	74.1	86.2	2.4	31.7	1.03	1.43
	Middle	Low	49.3	-2.9	-4.1	15.0	7.2	101.8	119.1	74.1	86.2	15.6	44.9	1.18	1.61
		Middle	52.1	-3.0	-4.6	14.0	7.2	103.1	120.4	74.1	86.2	16.9	46.2	1.20	1.62
		High	54.3	-4.5	-4.5	13.4	7.2	103.2	120.4	74.1	86.2	17.0	46.3	1.20	1.62
	High	Low	62.3	-2.7	-5.3	15.0	9.0	114.6	131.8	74.1	86.2	28.4	57.7	1.33	1.78
		Middle	65.9	-3.6	-5.7	14.0	9.0	117.0	134.2	74.1	86.2	30.8	60.1	1.36	1.81
		High	68.5	-5.6	-6.9	13.4	9.0	115.7	133.0	74.1	86.2	29.5	58.9	1.34	1.79

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2033 discounted at 4.5%/yr)
2. Total benefits include:

Benefit	Low	High
Reliability benefits	32.33	49.58
Reduced maintenance costs of 115 KV line	5.00	5.00

3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes hydrothermal coordination adjustment.

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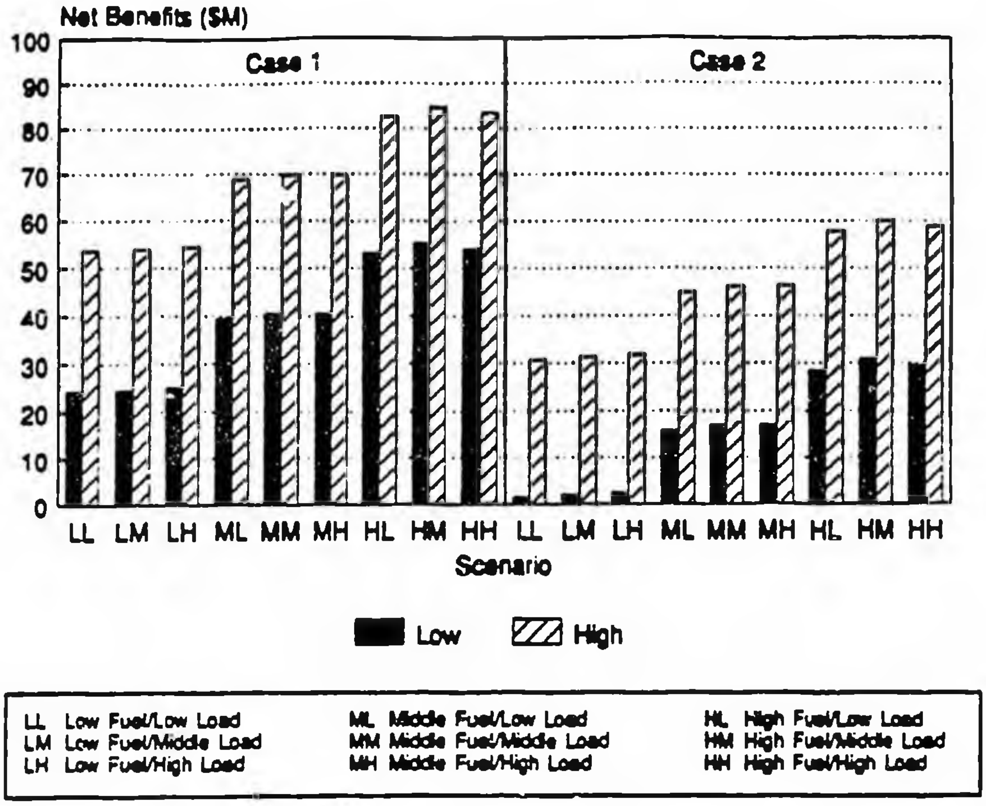
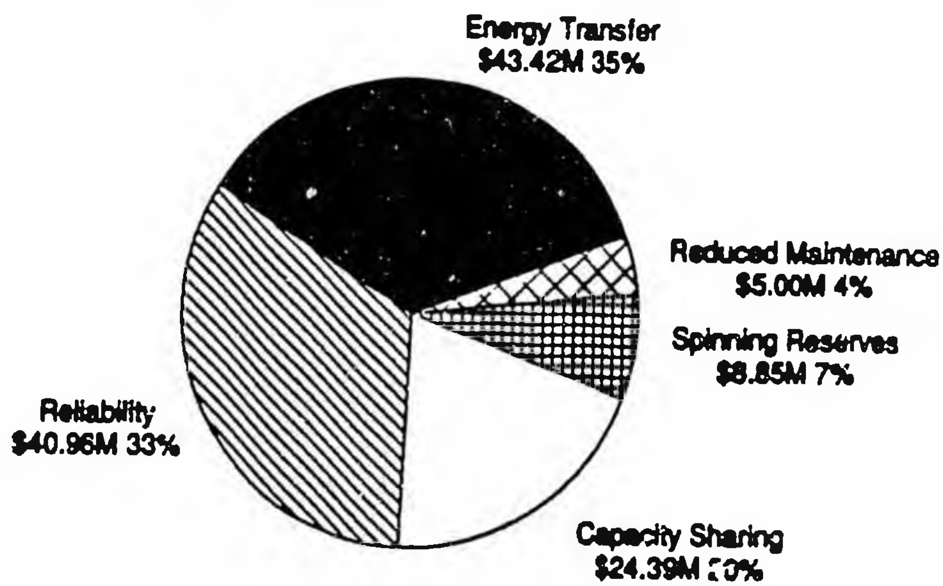


Figure 8-1. New Kenai-Anchorage Intertie: Net Benefits



Energy transfer includes transfer loss and gas royalty.
Average of all scenarios.

Figure 8-2. New Kenai-Anchorage Intertie: Breakdown of Expected Benefits

8.3 LIMITED UPGRADE OF THE ANCHORAGE-FAIRBANKS INTERTIE TO 100 MW

Table 8-2 shows the present value of costs and benefits for the limited Anchorage-Fairbanks upgrade to 100 MW. Positive benefits are indicated for each scenario examined. The expected value of net economic benefit is $35.5 million. The expected benefit to cost ratio is 4.45.

Figure 8-3 displays the net benefits estimated for each scenario. Figure 8-4 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-2

ANCHORAGE-FAIRBANKS UPGRADE TO 100 MW: SUMMARY OF COSTS AND BENEFITS

Scenario	Assumptions Fuel	Assumptions Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case #1	Low	Low	55.0	-20.2	6.1	9.2	55.0	10.3	44.7	5.34
		Middle	44.6	-16.4	5.3	9.4	47.9	10.3	37.6	4.65
		High	40.5	-16.8	5.6	7.6	41.9	10.3	31.6	4.07
	Middle	Low	25.4	-9.1	2.5	9.2	33.0	10.3	22.7	3.20
		Middle	33.6	-12.0	3.3	9.4	39.4	10.3	29.0	3.82
		High	51.1	-19.1	5.2	7.6	49.9	10.3	39.5	4.84
	High	Low	30.9	-10.3	2.9	9.2	37.6	10.3	27.3	3.65
		Middle	41.6	-14.0	3.9	9.4	45.9	10.3	35.6	4.46
		High	61.8	-21.1	5.9	7.6	59.2	10.3	48.9	5.74
Case #2	Low	Low	55.0	-20.2	6.1	9.5	55.4	10.3	45.1	5.37
		Middle	44.6	-16.4	5.3	9.9	48.4	10.3	38.1	4.70
		High	40.5	-16.8	5.6	8.5	42.8	10.3	32.5	4.15
	Middle	Low	25.4	-9.1	2.5	9.5	33.3	10.3	23.0	3.23
		Middle	33.6	-12.0	3.3	9.9	39.9	10.3	29.6	3.87
		High	51.1	-19.1	5.2	8.5	50.7	10.3	40.4	4.92
	High	Low	30.9	-10.3	2.9	9.5	38.0	10.3	27.7	3.68
		Middle	41.6	-14.0	3.9	9.9	46.5	10.3	36.2	4.51
		High	61.8	-21.1	5.9	8.5	60.1	10.3	49.8	5.83

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 5.04 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

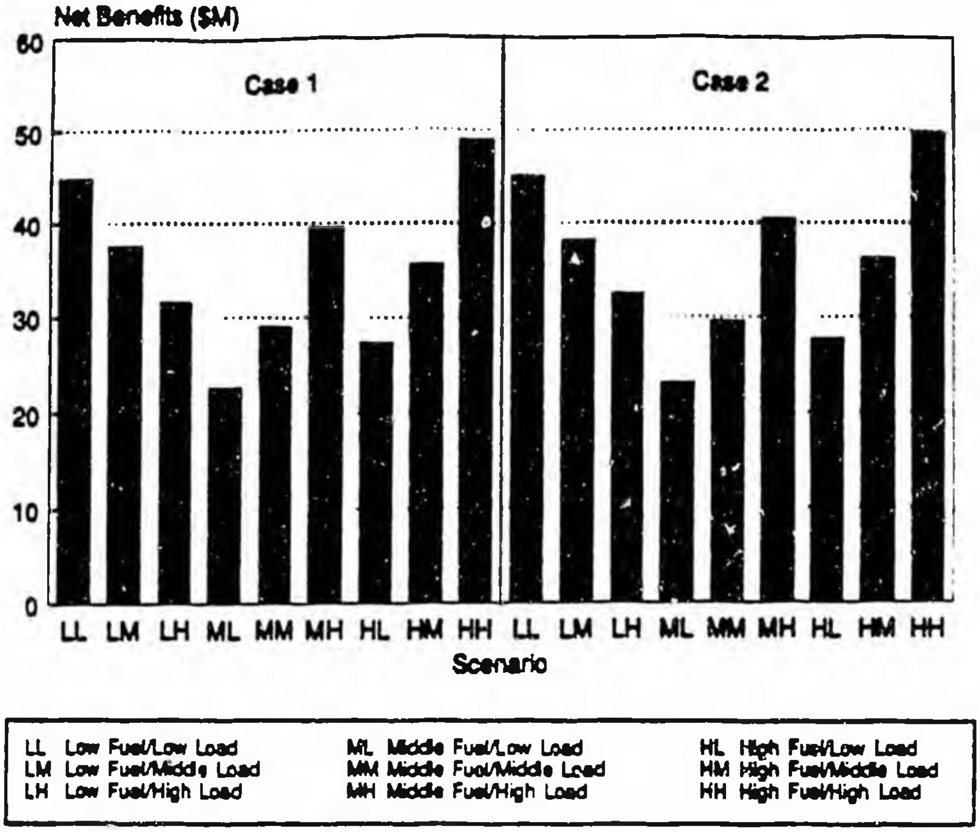


Figure 8-3. Anchorage-Fairbanks Upgrade to 100 MW: Net Benefits

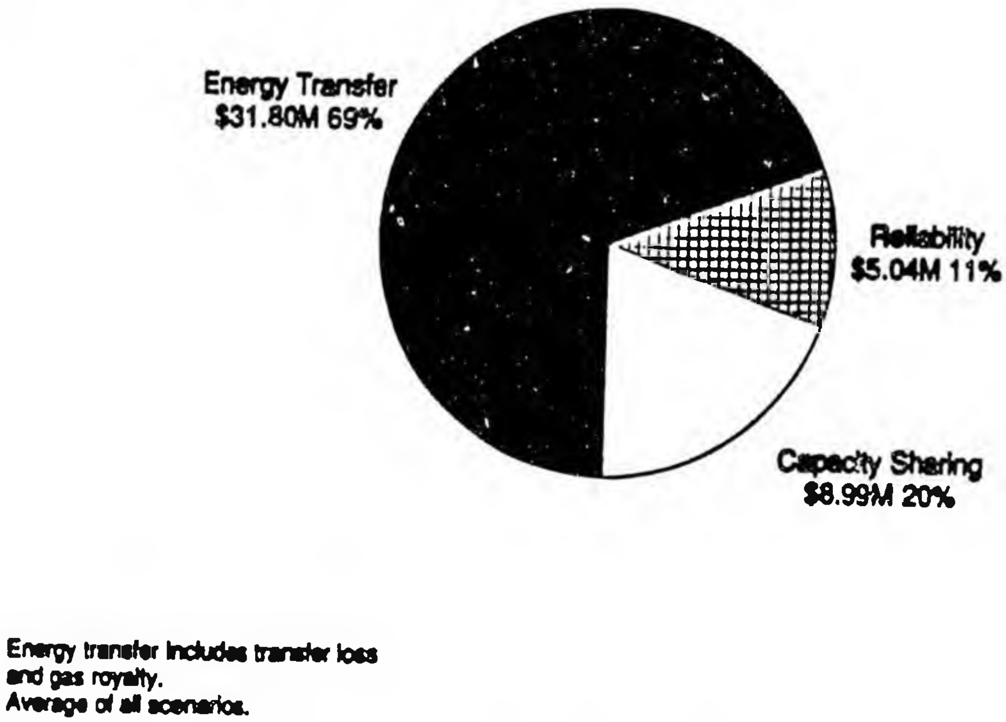


Figure 8-4. Anchorage-Fairbanks Upgrade to 100 MW: Breakdown of Expected Benefits

8.4 HEALY-FAIRBANKS INTERTIE

Table 8-3 shows the present value of costs and benefits for the Healy-Fairbanks Northern intertie. Positive benefits are indicated for each scenario examined. The expected value of economic benefit is $41.2 million. The expected benefit to cost ratio is 1.64.

Figure 8-5 displays the net benefits estimated for each scenario. Figure 8-6 shows the relative contribution of each benefit category to the total expected benefits.

Table 8-3

HEALY-FAIRBANKS NORTHERN INTERTIE: SUMMARY OF COSTS AND BENEFITS

Scenario	Assumptions: Fuel	Assumptions: Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case #1	Low	Low	84.9	-14.5	10.0	18.0	109.8	64.6	45.3	1.70
		Middle	82.7	-13.5	9.9	18.2	108.8	64.6	44.3	1.69
		High	87.8	-11.9	9.9	16.4	113.7	64.6	49.1	1.76
	Middle	Low	47.6	2.5	3.7	18.0	83.2	64.6	18.6	1.29
		Middle	61.7	-1.9	5.3	18.2	94.8	64.6	30.2	1.47
		High	83.8	-7.7	7.8	16.4	111.8	64.6	47.2	1.73
	High	Low	57.7	-1.2	6.3	18.0	92.2	64.6	27.6	1.43
		Middle	76.1	-5.6	7.7	18.2	107.8	64.6	43.2	1.67
		High	97.1	-6.7	8.6	16.4	126.9	64.6	62.3	1.97
Case #2	Low	Low	88.9	-15.8	10.3	17.3	112.2	64.6	47.7	1.74
		Middle	87.1	-15.0	10.4	17.7	111.7	64.6	47.2	1.73
		High	90.7	-13.0	10.2	16.3	115.8	64.6	51.3	1.79
	Middle	Low	47.7	2.4	3.7	17.3	82.6	64.6	18.1	1.28
		Middle	61.9	-2.0	5.3	17.7	94.5	64.6	29.9	1.46
		High	84.0	-7.8	7.8	16.3	111.7	64.6	47.2	1.73
	High	Low	57.8	-1.3	6.3	17.3	91.7	64.6	27.1	1.42
		Middle	76.4	-5.8	7.7	17.7	107.5	64.6	43.0	1.67
		High	97.2	-6.8	8.6	16.3	126.8	64.6	62.3	1.96

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 11.52 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

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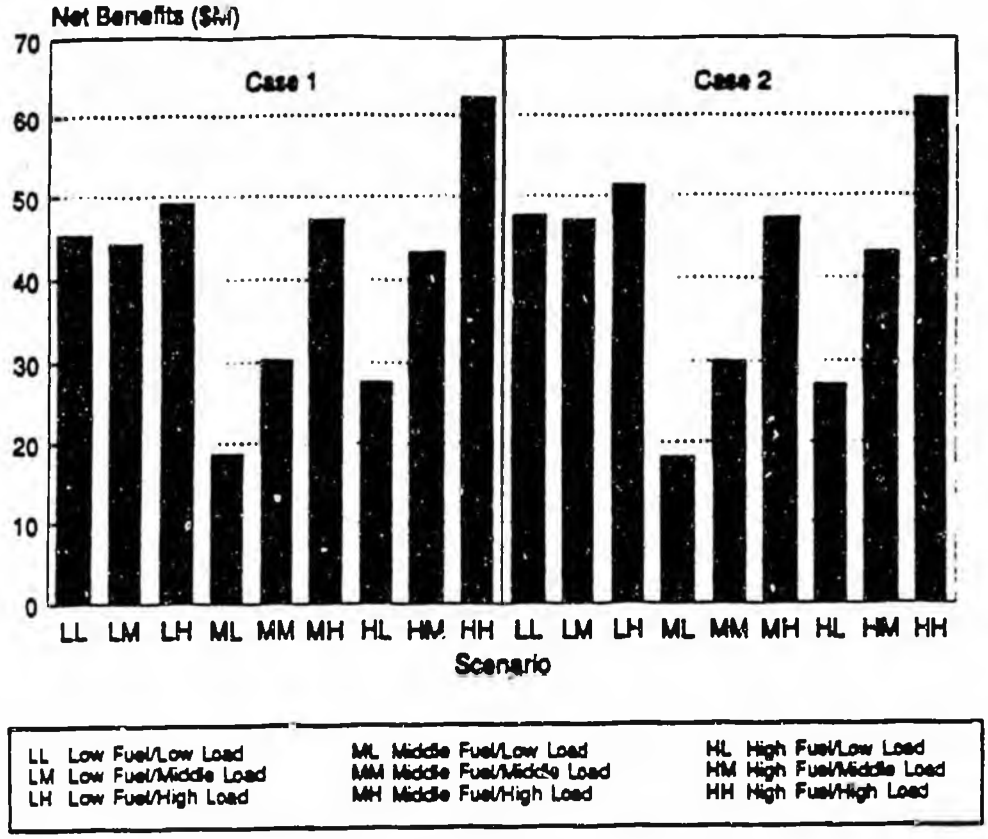

Figure 8-5. Healy-Fairbanks Northern Intertie: Net Benefits

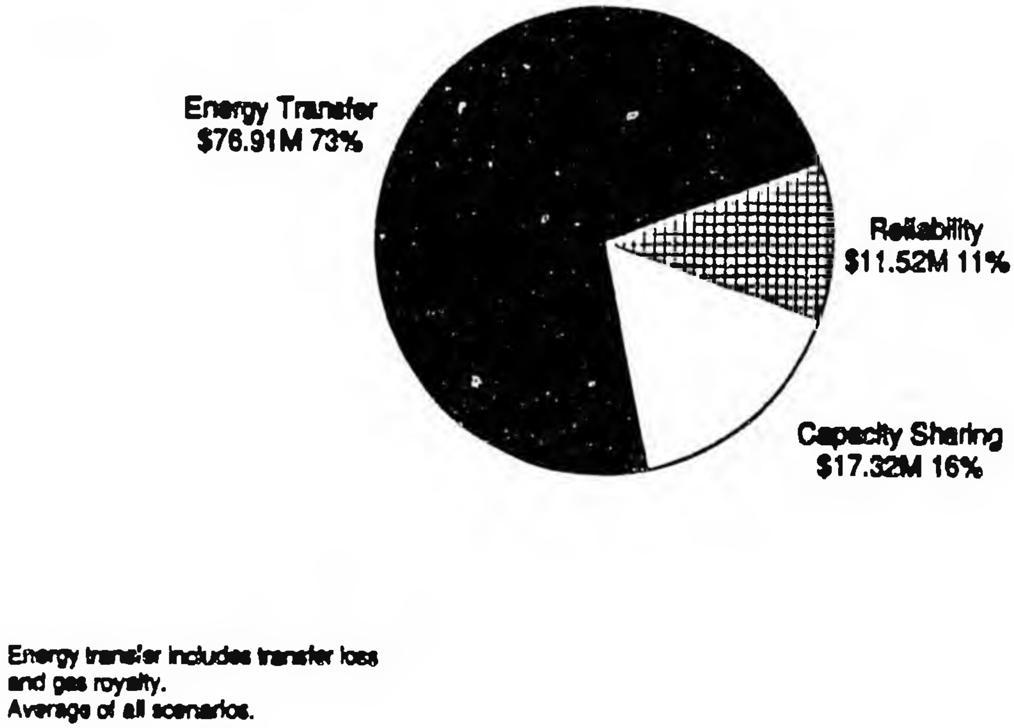

Figure 8-6. Healy-Fairbanks Northern Intertie: Breakdown of Expected Benefits

Table 8-4 shows the present value of the incremental costs and benefits for the Healy-Fairbanks northern intertie. All costs and benefits presented in Table 8-4 are incremental over corresponding costs and benefits of the limited upgrade of the Anchorage-Fairbanks line. The expected value of incremental net economic benefits is $5.7 million. The expected incrremental benefit to cost ratio is 1.1. Most of the examined scenarios show positive incremental net benefits; only three scenarios (all with low load forecasts) show small negative incremental net benefits.

Figure 8-7 displays the incremental net benefits estimated for each scenario. Figure 8-8 shows the relative contribution of each benefit category to the total expected incremental benefits.

Table 8-4

HEALY-FAIRBANKS NORTHERN INTERTIE: SUMMARY OF COSTS AND BENEFITS (INCREMENTAL OVER THE LIMITED UPGRADE OF THE ANCHORAGE-FAIRBANKS LINE)

Paste Table 8-4, reduced, here.

Scenario	Assumptions: Fuel	Assumptions: Load	Increased Economy Energy Transfer	Reduced Trans. Losses	Increased Gas Royalty	Increased Capacity Sharing Benefits	Total Benefits	Total Costs	Net Benefits	Benefit to Cost Ratio
Case 1	Low	Low	29.9	5.7	3.9	8.8	54.8	54.2	0.5	1.01
		Middle	38.1	2.9	4.7	8.8	60.9	54.2	6.7	1.12
		High	47.3	4.9	4.3	8.8	71.8	54.2	17.5	1.32
	Middle	Low	22.1	11.6	1.2	8.8	50.2	54.2	-4.0	0.93
		Middle	28.1	10.1	2.0	8.8	55.4	54.2	1.2	1.02
		High	32.7	11.4	2.6	8.8	61.9	54.2	7.7	1.14
	High	Low	26.8	9.0	3.4	8.8	54.5	54.2	0.3	1.01
		Middle	34.4	8.3	3.8	8.8	61.8	54.2	7.6	1.14
		High	35.3	14.4	2.7	8.8	67.7	54.2	13.4	1.25
Case 2	Low	Low	33.9	4.4	4.2	7.8	56.8	54.2	2.6	1.05
		Middle	42.5	1.5	5.1	7.8	63.3	54.2	9.1	1.17
		High	50.2	3.8	4.6	7.8	73.0	54.2	18.8	1.35
	Middle	Low	22.3	11.5	1.2	7.8	49.3	54.2	-4.9	0.91
		Middle	28.3	10.0	2.0	7.8	54.6	54.2	0.4	1.01
		High	32.8	11.3	2.6	7.8	61.0	54.2	6.8	1.12
	High	Low	27.0	8.9	3.4	7.8	53.7	54.2	-0.6	0.99
		Middle	34.8	8.2	3.8	7.8	61.1	54.2	6.8	1.13
		High	35.4	14.3	2.7	7.8	66.7	54.2	12.5	1.23

Notes:

1. All values are in 1990 million dollars (present value for 1994 through 2043 discounted at 4.5%/yr).
2. Total benefits include a reliability benefit of 5.48 million dollars.
3. Total costs include capital costs and O&M costs.
4. Net Benefits = Total Benefits - Total Costs.
5. Table includes North Pole adjustment.

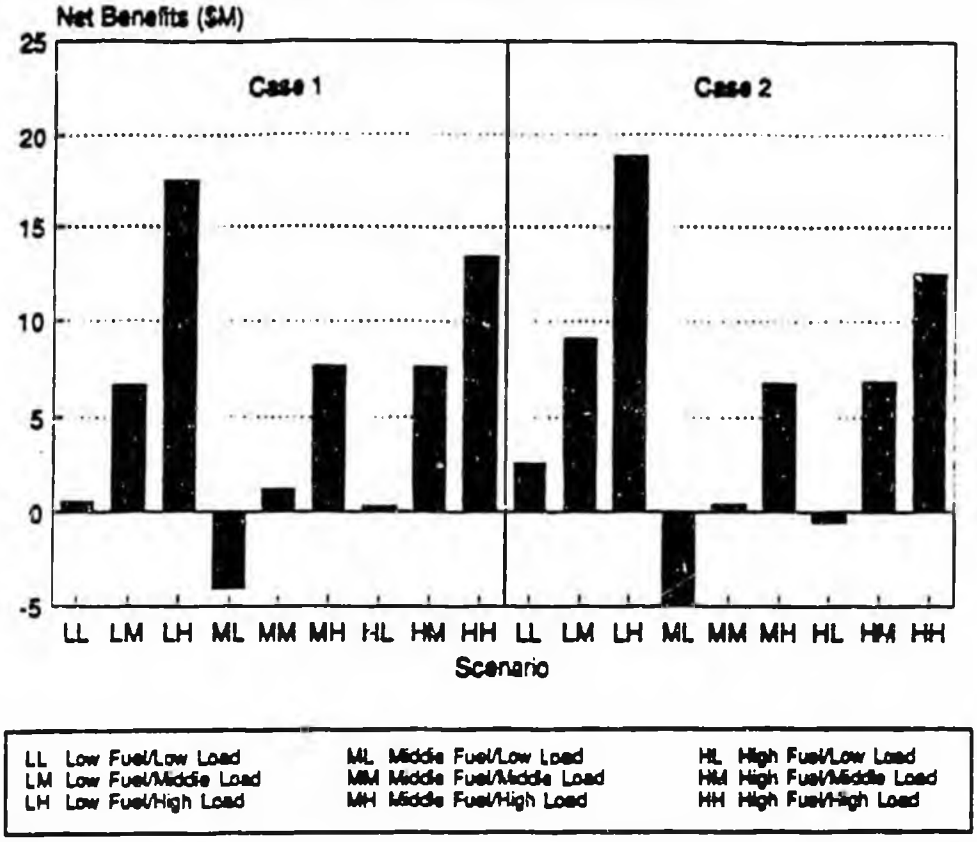

Figure 8-7. Healy-Fairbanks Northern Intertie: Net Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

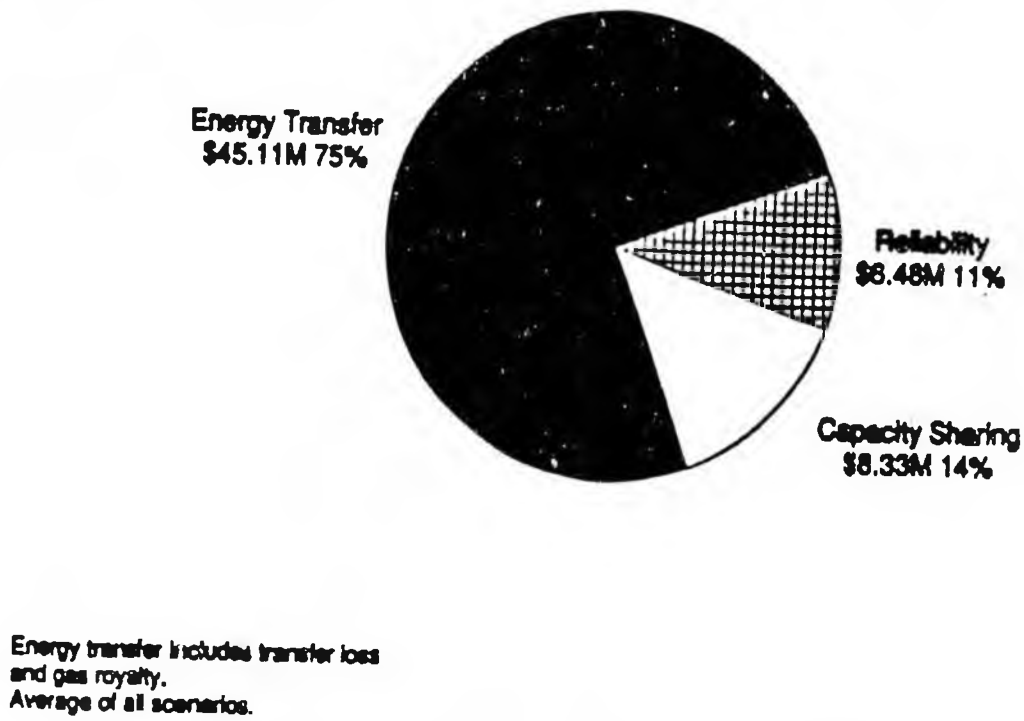

Figure 8-8. Healy-Fairbanks Northern Intertie: Breakdown of Expected Benefits (Incremental Over the Limited Upgrade of the Anchorage-Fairbanks Line)

Appendix A

BENEFITS OF INCREASED HYDRO-THERMAL COORDINATION

The efficiency of thermal generation depends on the output level of the power plant. Thermal power plants typically operate most efficiently at or near full loading. While dispatchers try to achieve the least-cost operation, the electric demand often does not match the most efficient power-plant operating level of output. Coordination between two or more areas allows a more efficient use of generation resources. For example, hydroelectric generation in Kenai can be utilized to increase the generating efficiency of the thermal power plants in Anchorage. By adjusting the output level of hydroelectric generation in Kenai, the demand served by Anchorage thermal power plants can be reshaped by either adding to or subtracting from the natural Anchorage electric demand. By properly reshaping the demand served by Anchorage generation, more efficient output levels of the Anchorage thermal power plants can be obtained, therefore, savings in operating costs can be achieved. Much of these savings, called benefits of hydro-thermal coordination, are the result of Bradley Lake; however, a new Kenai-Anchorage intertie could increase these savings by increasing the coordination capability between the Kenai hydro and the Anchorage thermal systems. The realized savings, called benefits of increased hydro-thermal coordination, depend on the following four factors:

1. Savings from reshaping Anchorage thermal generation
2. Transmission capacity between Anchorage and Kenai
3. Transmission losses
4. Flexible, low-cost generating capability in Kenai.

All of these are discussed in more detail in the following subsections. Approximately $1.4 million to $3.4 million (in 1990 dollars) of annual benefits accrue to the new intertie. These benefits result from increased economy transfers due to the new intertie's higher transfer capability and lower transmission losses.

A.1 SAVINGS FROM RESHAPING ANCHORAGE THERMAL GENERATION

The efficiency of thermal power plants changes over the range of power-plant output.[1] For example, Table A-1 lists performance data for the Beluga CT #5.

Table A-1

OPERATING PERFORMANCE OF BELUGA CT #5

Output (MW)	Percent of Maximum	Heat Rate (Btu/kWh)	Fuel Use (MBtu/hr)
33	50	15012	495.4
66	100	12963	855.6

Source: [1]

Ignoring transmission losses for the moment, if Beluga CT #5 needed to operate at 50 percent loading to serve Anchorage local demand, the Kenai hydro energy could meet the demand half the time and Beluga CT #5 could operate at 100 percent loading the other half of the time. When Beluga CT #5 operates at full output, half of its energy would be transferred to Kenai. At the end of this half-on/half-off cycle of Beluga CT #5, the Kenai hydroelectric energy and Beluga CT #5 total electric generation would be unaffected, but the energy transfer between Kenai and Anchorage would have increased by 396 MWh in each direction; Figure A-1 illustrates the process.

During this cycle, the cost of thermal generation would be significantly reduced. For example, from Table A-1 one can calculate that operating Beluga CT #5 at 50 percent loading for 24 hours requires 11,890 MBtu. Operating Beluga CT #5 at 100 percent loading for 12 hours generates an equivalent amount of electricity but only requires 10,267 MBtu. Fuel savings of 1623 MBtu (i.e., 11,890 MBtu minus 10,267 MBtu) are realized by reshaping 396 MWh of energy. On a per unit of energy reshaped (i.e. thermal generation shifted through time) basis, this amounts to 4,098 Btu/kWh (i.e., 1,623 MBtu divided by 396 MWh.) As the calculation below illustrates, this saving is equivalent to the difference between the heat rate at 50 percent loading and the incremental heat rate between 50 percent loading and 100 percent loading:

Total heat rate at 50% loading	15,012 Btu/kWh
Incremental heat rate between 50% and 100% loadings	10,914[2] Btu/kWh
Difference	4,098 Btu/kWh

1. The efficiency of a thermal power plant is typically measured in terms of fuel input requirements per unit of electric output, called heat rates. Efficiency increases with reduced heat rates, i.e., with reduced fuel input per unit of electric output.

2. Using the values in Table A-1: (885.6 - 495.4)MBtu/(66 - 33)MW = 10.914 MBtu/MWh or 10,914 Btu/kWh.

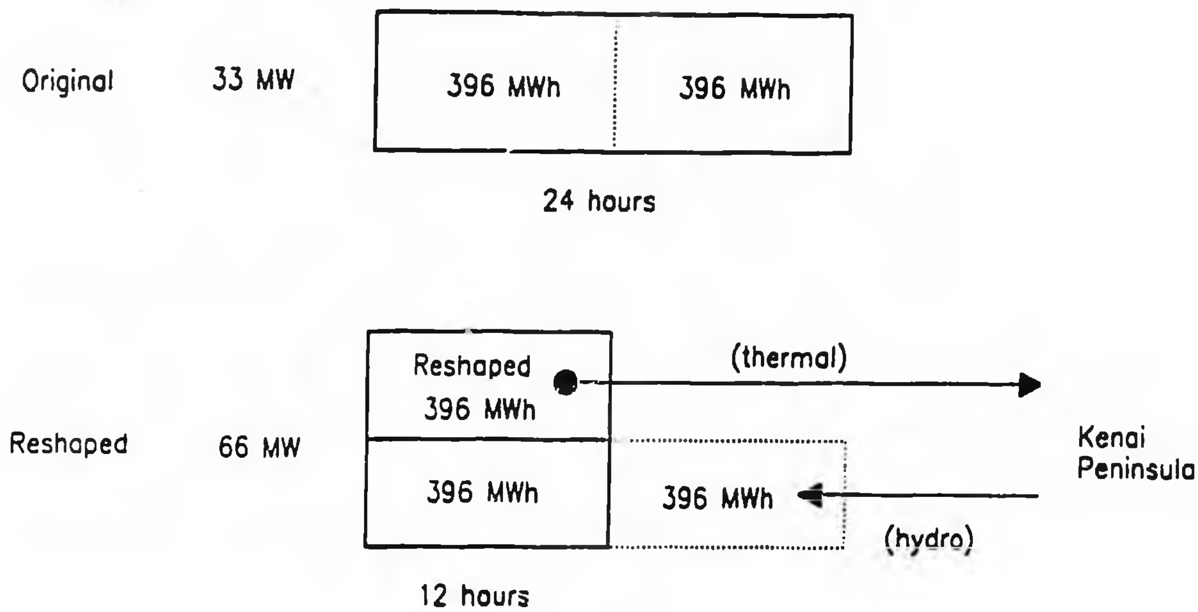

Figure A-1. Reshaping Thermal Energy Generation

The most expensive or marginal generating units in operation are the likely candidates for thermal energy generation reshaping. Table A-2 lists the heat rate performance characteristics for these units in Anchorage. In terms of the difference between the total heat rate at 50 percent output and the incremental heat rate between 50 percent and 100 percent output, Beluga CT #5 with a value of 4098 Btu/kWh is representative of this group. Therefore, the magnitude of savings illustrated in the previous example would generally carry over to results based on the complete set of representative units enumerated in Table A-2.

Reshaping thermal energy production will be applied to the marginal unit or the unit loaded last. We estimate the marginal units relative likelihood based on the unit's technology. The production simulation results indicate that combined cycles (CC) technology will be the marginal operating technology in Anchorage approximately 75 percent of the time; and gas turbine or combustion turbine (CT) technology will be marginal the remaining 25 percent of the time. We also distinguish between two "classes" of CC units: a 50 MW class (represented by AMLP #56 CC) and a 100 MW class (represented by Beluga CC #8).

Table A-2

HEAT RATE PERFORMANCE CHARACTERISTICS OF SELECTED ANCHORAGE AREA GENERATING UNITS

(1) Name	(2) Full Output (MW)	(3) Total Heat Rate @ 50% Output (Btu/kWh)	(4) Incremental Heat Rate 50% to 100% of Output (Btu/kWh)	(5) Col (3) Minus Col (4)
Beluga CC #8	101	10,981	7,801	3,180
AMLP CC #56	47	13,700	8,718	4,982
Beluga CT #3	55	13,136	9,552	3,584
AMLP CT #8	87	14,029	9,591	4,438
Beluga CT #5	66	15,012	10,914	4,098
AMLP CT #4	33	18,475	9,372	9,148

Source: [1]

Based on our examination of the production simulation results, we estimate that when the combined cycle is the marginal technology, about half the time the 50 MW class would be marginal; during the other half the larger 100 MW class combined cycle would be marginal. If gas turbine technology is marginal, we assessed the relative probability of the various units being marginal based primarily on their relative sizes.

Table A-3 lists the technology, representative units, and probability that a representative unit is the marginal unit in Anchorage before applying the hydro-thermal coordination.

Table A-3

MARGINAL UNIT IN ANCHORAGE BEFORE APPLYING HYDRO-THERMAL COORDINATION

Technology	Fraction of Time	Representative Unit	Fraction of Time
Combined Cycle	75%	Beluga #8 (100 MW class)	37.5%
		AMLP #56 (50 MW class)	37.5%
Gas Turbine	25%	Beluga #3	5%
		AMLP #8	9%
		Beluga #5	8%
		AMLP #4	3%

The amount of thermal demand which must be reshaped in order to affect hydro-thermal coordination benefits depends on which thermal unit in Anchorage is marginal before applying hydro-thermal coordination, and what the loading on that unit would otherwise be. Take, for example, a 100 MW class combined cycle unit. Given that such a unit is marginal, we conclude that the demand placed on this unit is uniformly distributed between its minimum and maximum loadings.[3] We reached the conclusion of uniform distribution because, given that a unit is the marginally committed unit, its loading above minimum will vary randomly based on temperature and other random events that affect electric demand. Figure A-2 illustrates a cumulative probability distribution of this assessment. This figure illustrates that given that the unit is marginal, there is a 100 percent probability that the loading is less than 100 MW and 0 percent probability that the loading is less than 25 MW. This figure also illustrates other likelihoods, for example the probability of a loading between 50 MW and 75 MW is 33 percent. This characteristic is important in determining how often sufficient transfer capability exists in the Kenai-Anchorage intertie to realize hydro thermal coordination. We return to this issue after defining the transmission capabilities.

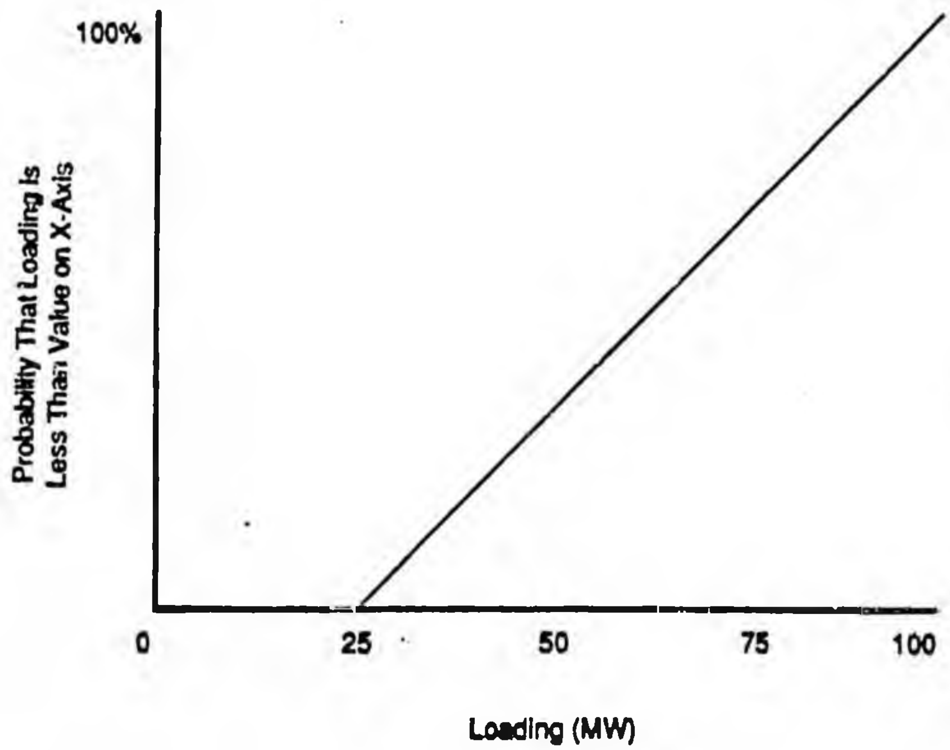

Figure A-2. Loading of a Marginal 100 MW Class Combined Cycle

3. For the 100 MW class combined cycle, we assume a 25 MW minimum load.

A.2 KENAI-ANCHORAGE TRANSMISSION LOSSES AND CAPACITY

Transmission losses and transfer capacity interact to affect the savings of reshaping. First, we review the impact of losses. Second, we discuss the impact of capacity constraints. Then we review the 100 MW combined-cycle class in detail.

Transmission losses reduce the benefits of reshaping thermal generation because they increase the required amount of input energy transfer and limit the potential for economic energy transfer between areas. The performance of the proposed 138 KV line and the existing 115 KV[4] line is listed in Table A-4. For the existing line, transmission losses are 8.9 percent for the first 40 MW and an incremental 16.6 percent for the second 20 MW, with still greater losses for higher loadings. We will use 8.9 percent losses as an example now. In order to have 1.0 MWh for reshaping in Anchorage, 1.098 MWh (1.0 MWh/(100% - 8.9%)) must be generated in Kenai. Furthermore, to return this 1.087 MWh to Kenai,[5] 1.2049 MWh (1.098 MWh/(100% - 8.9%)) must be generated in Anchorage. The right-most column in Table A-4 lists the reshaping energy requirement, i.e., the energy required to be generated in Anchorage to allow the reshaping of 1 MWh in Anchorage. It is possible that the losses can be so great as to prevent economical reshaping.

Table A-4

KENAI-ANCHORAGE TRANSMISSION LINE PERFORMANCE

	Input Range (MW)	Incremental Losses[a] (%)	Average Losses[a] (%)	Output Range (MW)	Reshaping Energy Requirement (MWh/MWh)
With a second 138 KV line	0-60	4.2	4.2	0-57	1.09
	60-90	10.2	6.2	57-84	1.14
	90-100	13.2	6.9	84-93	1.15
	100-120	15.2	3.3	93-110	1.19
	120-155	18.6	10.6	110-139	1.25
Existing 115 KV line	0-40	8.9	8.9	0-36	1.20
	40-60	16.6	11.5	36-53	1.28
	60-70	19.2	12.6	53-61	1.31
	70-90	28.7	16.2	61-75	1.42

a. Refer to Section 3.

4. The performance of the 115 KV line is shown up to 90 MW input; however, there is uncertainty concerning the ability of the line to accept more than 70 MW input.

5. Figure A-1 illustrates that the Kenai hydro-energy would be used for reshaping thermal energy generation in Anchorage. Since Kenai hydro-energy is less than the energy requirements in Kenai for all load forecasts, any Kenai hydro-energy transferred to Anchorage would have to be replaced by transferring back energy generation from Anchorage or with additional thermal generation in Kenai. Much of the time it is most economical to generate this thermal energy in Anchorage and transmit it to Kenai.

Reshaping thermal energy in Anchorage may also be limited by the total line transfer capability. If 100 MW combined cycle is marginal, it may be loaded between 25 MW and 100 MW as illustrated in Figure A-2. With the 138 KV line, any such loading can be accommodated; the existing 115 KV line alone has sufficient capability to reshape this unit only if its output is less than 61 MW or 75 MW depending on the transfer capacity of the 115 KV line.

We next explain how the transmission losses and transfer limits interact to determine what savings are possible given that a specific unit is marginal. Table A-5 lists the results for 100 MW class combined cycles. In the first full column from the left, this table shows the different performance ranges described in the previous table. The next column to the right lists the probability that reshaping falls within a specified range of transmission performance. These probabilities are calculated using the information illustrated in Figure A-2. This listing confirms that the 138 KV line can serve all reshaping demands while the 115 KV line cannot serve reshaping demands for this type of generating unit 32.7 percent of the time (i.e., above 75 MW). The next column to the right describes the savings obtained by reshaping. These values are calculated by substracting from 10,981 Btu/kWh, 7,801 Btu/kWh times the energy ratio shown in the right-most column in Table A-4. As one goes down this column for a transmission alternative, the savings decrease per kilowatthour reshaped because of increased losses. Note that while it may be possible to transfer up 75 MW output with the existing 115 KV line it is uneconomical to reshape above 61 MW. The next column to the right indicates the average loading one would expect given the transmission system is operating within that performance range. Therefore, the savings would be that loading (converted to kilowatts) times the savings in column to the left.[6]

The average range loading of the line for reshaping listed in Table A-5 is also useful in the calculation of unused line transfer capacity which could be used for spinning reserve transfers. The line capacity available to transfer spinning reserve is listed in the right-most column. Spinning reserve transfers are also limited by generation considerations. When the 100 MW class combined cycle unit is the reshaped unit, the calculations show that the 138 KV line always has enough unused capability to transfer 30 MW of spinning reserve and can transfer 50 MW of spinning reserve 90.8 percent of the time. The remaining 9.2 percent of the time it is limited to 42 MW.

The calculations summarized here for the 100 MW class combined cycle were repeated for all the generating units listed in Table A-1. The results for each specific unit were weighted by their respective probability of being the marginal unit. With the second 138 KV line, there would be enough capacity to transfer 49.7 MW (on average) of spinning reserves. On the other hand, the 115 KV line desiring to transfer 30 MW

6. For example, for the first row in this table, the savings would be 2,481 Btu/kWh times an average loading of 41,000 kw or 101 million Btus/hour. The results for the complete unit would be obtained weighting these savings by the probabilities that the loading is within that range.

of spinning reserve only has enough unused line capacity to transfer 28.7 MW (on average) if the output rating of the line is 75 MW and 23 MW (on average) if the output rating is 61 MW. Table A-6 summarizes the savings from hydrothermal coordination averaged across all unit loadings and all units.

Table A-5

PARAMETERS FOR 100 MW CLASS COMBINED CYCLE AS THE RESHAPED THERMAL UNIT

	Line Output Range (MW)	Probability of Loading in Range	Reshaping Savings (Btu/kWh)	Average Range Loading (MW)	Average Line Capacity and Output Available for Spinning Reserve (MW)	
With a second 138 KV line	0-57	43.3%	2481	41	98	
	57-84	35.9%	2115	71	68	
	84-93	11.6%	1981	89	50	
	93-110	9.2%	1707	97	42	
		100.0%				
Existing 115 KV line					75 max	61 max
	0-36	15.3%	1581	31	44	30
	36-53	22.2%	1028	45	30	16
	53-61	10.8%	775	57	18	4
	61-75	19.0%	0		75	61
	unit loading too big for line	32.7%	0		75	61
		100.0%				

Table A-6

HOURLY AVERAGE HYDRO-THERMAL COORDINATION SAVINGS

	Fuel Savings (million Btu per hour of reshaping)	Average Line Capacity Remaining for Spinning Reserve Use (MW)[7]
New 138KV line	356	50
Existing 115KV line		
Limited to 75 MW input	125	29
Limited to 90 MW input	128	26

7. Calculation assumes that maximum spinning reserves are limited to 50 MW (actually 49.7 MW) for the 138 KV line and to 30 MW for the 115 KV line.

A.3 KENAI GENERATING CAPABILITY

Reshaping Anchorage thermal generation with imported Kenai hydroelectric generation requires sufficient amounts of efficient generating capacity on the Kenai Peninsula. With the addition of Bradley Lake, Kenai hydroelectric generation delivered to Soldotna will increase from 17 MW to 133 MW.[8] Since Kenai's load rarely exceeds 70 MW,[9] Kenai generating capability will seldom limit transactions on the existing 60 MW interconnection to Anchorage.

The new intertie's capacity is higher and as a result more capability in Kenai will sometimes be required. Thus, if the need for Kenai generation in Anchorage exceeded the capabilities of Kenai hydroelectric generation, either thermal generation in Kenai would be necessary or the reshaping or spinning reserve demand would not be served.[10] We have analyzed these circumstances and concluded that the vast majority of the time in which greater generation is required in Kenai, the efficient gas turbines in Kenai will be sufficient and economic in meeting these increased generating requirements. Note that some of the most efficient gas turbines in the Railbelt are located on the Kenai Peninsula.

A.4 FREQUENCY OF TRANSACTIONS

Transactions to reshape Anchorage thermal generation should occur a substantial amount of the time. Our analysis assumes that these transactions would occur about 90 percent of the time, absent transmission constraints. As a result, reshaping occurs approximately 4,000 kilowatthours per year.[11]

With only the existing Kenai-Anchorage transmission line, other uses may preclude these reshaping transactions. We estimate that other uses will block reshaping on the existing line another 500 hours per year. This is principally a consequence of the need to substantially rebuild the existing line as described in Appendix B.

---

8. Based on 114 MW of Bradley Lake energy delivered to Soldotna.

9. Kenai's current load exceeds 70 MW approximately less than 5 percent of the time; it exceeds 60 MW less than 25 percent of the time.

10. Hydro-thermal coordination is an economy-type transaction and as such unserved demand does not affect reliability. Instead unserved demand refers to unavailable economic savings.

11. To reshape a thermal generating unit in Anchorage requires approximately two hours of transfer between Kenai and Anchorage (see Figure A-1). The 4,000 annual hours results from (90%) * (8764 hours per year) / (2 hours use of transmission per hour of reshaping) = 3943.8 hours reshaped per year.

A.5 BENEFITS OF NEW KENAI-ANCHORAGE LINE

Table A-7 shows that, with the existing line, the thermal energy transfers between Kenai and Anchorage would be around 91 to 98 GWh per year. Table A-8 shows that these transfers would increase by 104 to 110 GWh per year with the new line. The net benefits of these increased transfers are around 1.4 to 3.4 million dollars per year and are listed in Table A-9.

Table A-7

KENAI-ANCHORAGE TRANSFERS DUE TO HYDRO-THERMAL COORDINATION WITH EXISTING INTERTIE

			Thermal Energy Reshaping Transfers (GWh/yr)						Associated Transmission Loss (GWh/yr)		
			South	---->	North	North	---->	South			
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
	Middle	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
	High	Low	81	81	81	92	92	92	21	21	21
		Middle	81	81	81	92	92	92	21	21	21
		High	81	81	81	92	92	92	21	21	21
Case 2	Low	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23
	Middle	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23
	High	Low	86	86	86	98	98	98	23	23	23
		Middle	86	86	86	98	98	98	23	23	23
		High	86	86	86	98	98	98	23	23	23

Table A-8

NET INCREASE (DECREASE) IN KENAI-ANCHORAGE HYDRO-THERMAL COORDINATION TRANSFERS DUE TO THE NEW 138KV INTERTIE

			Increase in Thermal Energy Reshaping Transfers (GWh/yr)						Change in Transmission Associated Loss (GWh/yr)		
			South ----> North			North ----> South					
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
	Middle	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
	High	Low	110	110	110	110	110	110	1	1	1
		Middle	110	110	110	110	110	110	1	1	1
		High	110	110	110	110	110	110	1	1	1
Case 2	Low	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1
	Middle	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1
	High	Low	105	105	105	104	104	104	-1	-1	-1
		Middle	105	105	105	104	104	104	-1	-1	-1
		High	105	105	105	104	104	104	-1	-1	-1

Table A-9

NET BENEFITS OF INCREASED HYDRO-THERMAL COORDINATION DUE TO THE NEW KENAI-ANCHORAGE INTERTIE
(million dollars, 1990 dollars)

			Increased Transfer Benefits (M$/yr)			Reduced Transmission Loss (M$/yr)			Net Benefits (M$/yr)		
Scenario	Fuel	Load	1994	2002	2010	1994	2002	2010	1994	2002	2010
Case 1	Low	Low	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
		Middle	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
		High	1.43	1.60	1.79	-0.01	-0.01	-0.02	1.42	1.59	1.78
	Middle	Low	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
		Middle	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
		High	1.81	2.17	2.60	-0.02	-0.02	-0.02	1.79	2.15	2.57
	High	Low	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
		Middle	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
		High	2.08	2.65	3.39	-0.02	-0.02	-0.03	2.06	2.63	3.36
Case 2	Low	Low	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
		Middle	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
		High	1.39	1.56	1.75	0.01	0.02	0.02	1.41	1.58	1.76
	Middle	Low	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
		Middle	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
		High	1.76	2.11	2.53	0.02	0.02	0.02	1.77	2.13	2.55
	High	Low	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33
		Middle	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33
		High	2.02	2.58	3.30	0.02	0.03	0.03	2.04	2.61	3.33

A.7 REFERENCE

[1] Alaska Power Authority, Railbelt Intertie Proposal Preliminary Economic Assessment, March 1987, p. 8.2.11.

Appendix B

MODELING ASSUMPTIONS

This appendix summarizes the significant modeling assumptions used in the evaluation of the economy energy and transmission loss benefits of the three alternative intertie proposals. Unless otherwise noted in this Appendix or in this report, all assumptions used in the Reconnaissance Study are used in this analysis.

B.1 COSTS AND BENEFITS

All fixed and variable costs, fuel prices, and benefits are reported in 1990 dollars. The price inflators used to convert the 1987 prices in the Reconnaissance Study to 1990 dollars are based on the GNP price inflator as reported in the *Survey of Current Business*, July 1989.[1] Table B-1 shows the price inflators assumed for the years 1987 to 1990.

For the evaluation of the present value of future costs and benefits, we assume a discount rate of 4.5 percent, as established by APA.

Table B-1

PRICE INFLATORS

Year	GNP Inflator
1987-1988	3%
1988-1989	3%
1989-1990	4.5%

B.2 FUEL PRICE FORECASTS

The fuel price forecasts used in this analysis are the same forecasts used in the Reconnaissance Study. In this analysis, however, well-head gas prices are assumed everywhere, and all transportation charges have been removed.[2]

1. "Survey of Current Business," U.S. Department of Commerce: Bureau of Economic Analysis, Volume 69, Number 6, July 1989, p. 89.

2. Refer to Appendix B of the Reconnaissance Study.

B.3 LOAD FORECASTS

The load forecasts are the same forecasts used in the Reconnaissance Study with no changes.[3]

B.4 BERNICE LAKE UNIT

We assume that the Bernice Lake unit will stay in Kenai.

B.5 SOLDOTNA

The Soldotna plant is assumed to have the same operating and maintenance costs as Bernice Lake.

B.6 RECONSTRUCTION OF THE EXISTING KENAI-ANCHORAGE 115 KV LINE

The existing Kenai-Anchorage line is scheduled for incremental line replacement between the years 1994 and 2007.[4] In modeling the transfers across the existing line, we have adjusted the intertie availability to account for this scheduled maintenance. Table B-2 shows the estimated number of days of scheduled maintenance and the corresponding availability assumed for the existing line. We assume four months of winter and eight months of summer.

The KA138 proposal allows for a second line between Kenai and Anchorage that would make the deferral of some of the scheduled maintenance possible. The deferred replacement of the existing line is estimated to result in a reduction of lifetime maintenance costs of $5 million.

Table B-2

RECONSTRUCTION PLAN OF THE EXISTING KENAI-ANCHORAGE 115 KV LINE

	Maintenance Days		Line Availability	
Years	Summer	Winter	Summer	Winter
1994-2007	85	14	65	88
2008-2033	14	14	95	88

3. Refer to Appendix C of the Reconnaissance Study.

4. Letter from Gerald Mackey, Planning Engineer, Chugach Electric Association, to Salim Jabbour, Decision Focus Incorporated, dated September 5, 1989.

Alaska State Legislature

HOUSE RESOURCES COMMITTEE

P.O. Box V
State Capitol
Juneau, Alaska 99811
(907) 465-3715

HOUSE RESOURCES COMMITTEE
OVERVIEW: PROPOSED 138 KV TRANSMISSION LINE
February 22, 1990
3:30 - 5:00

Salim Jabbour, Vice President, Decision Focus Inc.

Mike Kelly, General Manager, Golden Valley Electric Ass.

Ginny Fay, Analyst, Legislative Research Agency

Alan Mitchell, Analysis North

Bob LeResche, Executive Director, Alaska Energy Authority

Alaska State Legislature

Legislative Research Agency

P.O. Box Y
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February 19, 1990

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay
Legislative Analyst

RE: Review of the Economic Feasibility Study of the Railbelt Utilities' Proposed 138 Kilovolt Electrical Interties
Research Request 90.165

You requested this agency to review the *Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt* report which was recently prepared for the Railbelt electric utilities[1] by Decision Focus Incorporated (DFI). This same firm prepared the *Railbelt Intertie Reconnaissance Study: Benefit/Cost Analysis* for the Alaska Energy Authority (this study is referred to as the AEA study in this memorandum). The AEA study (completed June 1989) was conducted to determine the economic feasibility of 230 kilovolt (KV) electrical interties between Anchorage and the Kenai Peninsula, and Anchorage and Fairbanks, and their alternatives as required by state statute (AS 44.83.177). Because the 230 KV lines were not found to be economically feasible (i.e., they have benefit/cost ratios less than one), the Railbelt utilities proposed lower capacity transmission lines and hired DFI to analyze their economic feasibility.[2] The downsized 138 KV interties would be constructed between Kenai and Anchorage (southern line) and between Healy and Fairbanks (northern line). The northern line proposal also includes a limited upgrade of the existing Anchorage-Fairbanks line (limited AF100).

This memorandum reviews the major economic benefit categories of the 138 KV study--reliability, economy energy transfer, capacity sharing, and spinning reserve sharing. As a result of time constraints, however, this should not be considered a comprehensive review.

---

[1]The Railbelt electric utilities include Anchorage Municipal Light & Power (AML&P), Chugach Electric Association (CEA), Fairbanks Municipal Utility System (FMUS), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), and Matanuska Electric Association (MEA).

[2]Without AEA board action, however, the 138 KV intertie study does not constitute a statutorily required feasibility study because it was not conducted on the behalf of the state.

SUMMARY

Description and Costs of the Proposed Interties

The proposed new intertie between Anchorage and the Kenai Peninsula (KA138) is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. This route was the less expensive alternative of the two routes analyzed in the AEA study. The capital cost of the KA138 proposal is estimated at $64.1 - $65.6 million (Table 1). The limited Anchorage-Fairbanks 100 KV upgrade (AF100) is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the AEA study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW. The capital cost of the AF100 upgrade is estimated at $9.4 million in 1990 dollars (Table 1). The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The total capital cost of the proposal is $58.7 million (Table 1). This memorandum does not review the projects' cost estimates which should also receive independent review or review by AEA engineers.

Benefits of the Anchorage-Kenai Peninsula 138 KV Intertie

Decision Focus identifies five major categories of benefits for the southern intertie--reliability; economy energy transfer, which includes hydroelectric and thermal unit coordination; capacity sharing; spinning reserve sharing; and reduced maintenance costs on Chugach Electric Association's existing intertie. The total estimated benefit value for these categories is $123 million, which is approximately $72 million more than the benefit value estimated for the Anchorage-Kenai 230 KV line in the AEA study (Table 2).

Review of the DFI KA138 KV study, however, indicates that the benefits are overstated. Four major errors were made in calculating benefits of the southern line:

- The value of reliability benefits increased from $15.7 million to $41.0 million for the southern line as a result of the use of different estimates for the value of unserved residential, and commercial and industrial energy. The increase in the value of commercial and industrial unserved energy resulted from a misapplication of survey data which overestimated these benefits by approximately $20 million in present value. The calculation method and results of the AEA 230 KV study are more accurate (pp. 10-12).

- A computation error was found in the calculation of the benefits of hydro-thermal coordination benefits of the new intertie. Hydro-thermal coordination allows partly loaded, less efficient thermal generating capacity in Anchorage to be turned off and replaced with

Bradley Lake hydroelectric generation capacity on the Kenai Peninsula. Decision Focus, Inc. has recognized this computation error, which overstates economy energy transfer benefits of the new intertie by $25 million in present value (pp. 12-14).

- A second calculation error in the hydro-thermal benefit calculation results from using a constant rather than varying gas turbine heat rate across turbine loading levels for calculating fuel savings. This oversimplification results in an additional $4 million in benefits of the new Anchorage-Kenai line (p. 13).

- Operating or spinning reserves are the operating capacity that is not used to serve the existing load, but instead is available to respond quickly to changes in load or electrical demand. The operating reserve benefit of upgrading the Anchorage-Kenai intertie results from the substitution of operating reserve from the Bradley Lake hydroelectric project for gas-fired spinning reserves in Anchorage, because Bradley Lake spin is free while gas consumption makes thermal spin costly. Decision Focus estimates the value of this benefit category at $5.2 to $13.5 million, but a correction in the formula used to calculate these benefits reduces the value of operating reserve sharing to $2.1 to $5.4 million (p. 28).

In addition to these quantified corrections to the benefit calculation, the net benefits of the southern line were substantially increased in the utility study as a result of changes in assumptions regarding 1) operating and maintenance costs of the new line (p. 9); 2) economic life of the new intertie (pp. 9-10); and 3) reduced maintenance costs of the existing CEA line (pp. 28-29). Assumptions about electrical system optimal dispatch (pp. 13-14) and capacity sharing and retirement schedules (pp. 18-27) also result in the overestimate of benefits in the analysis. The DFI 138 KV study does not provide adequate justification for these changes in assumptions. Given our time constraints, we have not made corrections to these benefit categories have not been quantified. To do so would further reduce the estimated benefits.

Benefits of the Limited Anchorage-Fairbanks 100 KV Upgrade and Full 138 KV Line

In its analysis, DFI identifies three benefit categories for the northern intertie upgrade and a new 138 KV line between Healy and Fairbanks--reliability, economy energy transfer, and capacity sharing. Benefits to the limited AF100 upgrade changed relatively little between the AEA 230 KV study and the utility 138 KV study (Table 3). However, the incremental benefits of the new 138 KV line are overestimated as a result of three major assumptions:

- Reliability benefits are overestimated for the northern line as a result of the same misapplication of the value of commercial and industrial unserved energy described for the southern line (pp. 10-12).

- The North Pole operating constraint accounts for the majority of northern intertie economy energy benefits but assumptions regarding generating unit dispatch overestimate these benefits by $3 million. In addition, economy energy benefits are overestimated as a result of dropping fuel price differential and military load sensitivity analyses in the utility 138 KV study that were conducted in the AEA study (pp. 14-18).

- In addition to these quantified corrections to benefit calculations, benefits are overestimated as a result of assumptions regarding capacity sharing and retirement schedules (pp. 18-22).

If the construction of the Healy clean coal demonstration project is funded, benefits of the interties should be recalculated. A recent letter by DFI (Attachment A) indicates that while the Healy facility would not significantly affect the benefits of the northern line, it would reduce the reliability and capacity sharing benefits of southern intertie (p. 29).

In conclusion, based on this limited review, there appear to be significant errors in computations and unjustified changes in assumptions in the recently completed Decision Focus 138 KV study. While the limited AF100 upgrade appears to continue to have a benefit/cost ratio above one, the construction of either a new southern or northern line does not appear to be economically justifiable when the errors are corrected. For the Anchorage-Kenai Peninsula 138 KV intertie, our review of benefits indicates that maximum benefits are approximately $68 million. In contrast, DFI calculated benefits of $122.7 million (Table 2). For the Anchorage-Fairbanks fully upgraded 138 KV line, we calculated maximum incremental benefits over the limited upgrade of $45.4 million while DFI estimated these benefits at $59.9 million (Table 3). It is clear that had the 138 KV lines been analyzed under the same assumptions as those used in the AEA 230 KV study, the 138 KV lines would not have been found economically feasible. A decision to proceed with these 138 KV intertie projects would be based on the political rather than economic merits of the projects.

TABLE 1
ESTIMATED COSTS AND BENEFITS OF THE PROPOSED 138 KV ELECTRICAL INTERTIES
FROM THE DFI 138KV INTERTIE STUDY
(millions $ 1990)

	Estimated Cost(a)	Estimated Benefits(b)	Benefit to Cost Ratio
New Anchorage-Kenai Intertie	74 to 86 (c)	114 to 131	1.3 to 1.8
Limited Upgrade Anchorage-Fairbanks Intertie	10	46	4.4
Healy-Fairbanks Intertie			
Total	64	106	1.6
Incremental(d)	54	60	1.1

Notes:
a: Includes both capital and operation and maintenance (O&M) costs; assumes lower cost Enstar route, not Tesoro route.
b: Present value of total benefits between 1994 and 2033 for the Kenai-Anchorage line and between 1994 and 2043 for the Anchorage-Fairbanks upgrade and Healy-Fairbanks line.
c: Includes replacement of submarine cable after 20 years of service.
d: Incremental over the limited upgrade of the Anchorage-Fairbanks line.

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989; Anchorage-Kenai cost estimates were prepared by Powers Engineers for the Chugach Electric Association; and Anchorage-Fairbanks cost estimate was prepared by Harza Engineering Company for the Golden Valley Electric Association.

Prepared by the Legislative Research Agency, February 1990 (90-165a).

TABLE 2
COMPARISON OF BENEFITS AND ASSUMPTIONS OF THE ALASKA ENERGY AUTHORITY 230 KV INTERTIE AND THE PROPOSED UTILITY 138 KV INTERTIES STUDIES--ANCHORAGE-KENAI PENINSULA INTERTIE
(millions $ 1990)

BENEFIT CATEGORY	BENEFIT VALUE(a) AEA/230 KV	BENEFIT VALUE(a) 138 KV	DIFFERENCE	PARTIALLY CORRECTED BENEFIT VALUE*	ASSUMPTIONS CHANGED
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					Weighted probabilities: 60/30/10 for high/medium/low fuel and load growth forecast in reconnaissance study changed to even weighted probabilities in 138 KV study.
Royalties Netted Out					Assumes that the price of gas will increase less than inflation and the discount rate, i.e., better off to have royalties now than in the future.
Fuel Price Differential Extended thru Year 40					Ignores ICF study for AEA which indicates that gas production costs and prices are likely to escalate after year 17 of the analysis. This implies convergence of oil and gas prices after 2010.
RELIABILITY	15.7	41.0	25.3	20.0	Increased value of commercial and industrial unserved energy- different interpretation of data.
INCREASED ENERGY TRANSFER					Contains a $25 million mathematical error; hydro-thermal coordination accounts for 90 percent ($40 million) of benefits; assumes an optimally dispatched system; in contrast, currently $3-6 million annual benefit potential from improved system dispatch (without a new intertie) and unutilized hydro-thermal coordination with the Eklutna Dam.
Hydro-Thermal Coordination(c)	22.5	37.5	15.0	9.1	
Other Economy Energy	0.0	5.9	5.9	5.9	
INCREASED CAPACITY SHARING*	12.0	24.4	12.4	24.4	Based on book-life retirement and capacity shortage in the mid-1990s; recent avoided cost dockets and utility data indicate life extension plans to 2000-2015.
INCREASED SPINNING RESERVE SHARING	0.8	8.9	8.1	3.6	Improved access to Kenai excess capacity for reserves; assumes gas generation in use on Kenai and no life extension of Anchorage gas units.
REDUCED MAINTENANCE COSTS*	0.0	5.0	5.0	5.0	Reduced costs for Chugach Electric's existing intertie.
TOTAL	51.0	122.7	71.7	68.0	
BENEFIT:COST RATIO(b)	0.5	1.6		0.9	

Notes: *Corrected benefit values are adjusted primarily for mathematical errors and do not include all quantifiable adjustments such as those for capacity sharing, reduced maintenance costs, and changes in fuel price assumptions. The corrected benefit total should be viewed as a maximum.
(a) based on average benefit values
(b) based on average benefit and cost value
(c) For the 230KV study, this category includes increased stability and energy transfer, and reduced transmission.

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165b).

TABLE 3
COMPARISON OF BENEFITS AND ASSUMPTIONS OF THE ALASKA ENERGY AUTHORITY 230 KV INTERTIE AND THE PROPOSED UTILITY 138 KV INTERTIES STUDIES--ANCHORAGE-FAIRBANKS INTERTIE
(millions $ 1990)

BENEFIT CATEGORY	BENEFIT VALUE(a) AEA/230 KV	BENEFIT VALUE(a) 138 KV	DIFFERENCE	PARTIALLY CORRECTED BENEFIT VALUE*	ASSUMPTIONS CHANGED
LIMITED 100 KV UPGRADE					
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					Weighted probabilities: 60/30/10 for high/medium/low fuel and load growth forecast in AEA study changed to even weighted probabilities in 138 KV study. No military load sensitivity analysis.
Royalties Netted Out					Assumes that the price of gas will increase less than inflation and the discount rate, i.e., better off to have royalties now than in the future.
Fuel Price Differential Extended thru Year 50					Ignores ICF study for AEA which indicates that gas production costs and prices are likely to escalate after year 17 of the analysis. This implies convergence of oil and gas prices after 2010.
RELIABILITY	0.0	5.0	5.0		Used higher numbers for the cost and amount of unserved energy during outages.
ECONOMY ENERGY TRANSFER & REDUCED TRANSMISSION LOSSES	43.0	31.8	(11.2)		Price of coal is assumed constant over the extended 50-year period of analysis Fairbanks coal generation displaces a portion of gas-fired economy energy sales over the intertie from Anchorage.
CAPACITY SHARING	1.2	9.0	7.8		Based on book-life retirement and capacity shortage in the mid-1990s; recent avoided cost dockets and utility data indicate life extension plans to 2000-2015.
TOTAL	44.2	45.8	1.6		
BENEFIT:COST RATIO(b)	3.9	4.4			
FULL INTERTIE UPGRADE					Same assumption changes as limited upgrade.
FUEL PRICES					
Fuel & Load Forecast Probabilities Changed					
Royalties Netted Out					
Fuel Price Differential Extended thru Year 50					
RELIABILITY		6.5		4.0	
ECONOMY ENERGY TRANSFER & REDUCED TRANSMISSION LOSSES		45.1		33.1	This benefit category is reduced $12 million to correct for the fuel price differential assumption and the North Pole operating constraint.
CAPACITY SHARING		8.3		8.3	
TOTAL		59.9		45.4	
BENEFIT:COST RATIO(b)		---			
INCREMENTAL B:C RATIO(b)		1.1		0.8	

Notes: *Corrected benefit values are adjusted primarily for some input assumptions and do not include all quantifiable adjustments such as those for capacity sharing, reduced maintenance costs, and changes in fuel price assumptions. Benefits of the AF138 are incremental above the AF100. The corrected benefit total should be viewed as a maximum.
(a) based on average benefit values.
(b) based on average benefit and cost value

Source: Decision Focus Inc., "Economic Feasibility of the Proposed 138 KV Transmission Lines in the Railbelt," December 1989.

Prepared by the Legislative Research Agency, February 1990 (90-165c).

DESCRIPTIONS AND COSTS OF THE PROPOSED INTERTIES

New Intertie between Anchorage and the Kenai Peninsula (KA138 Intertie)

The KA138 line is a 138 KV version of the 230 KV line between Kenai and Anchorage along the Enstar route. This route was the less expensive alternative of the two routes analyzed in the AEA study. The line is comprised of three segment types: steel and wood pole overhead lines, underground cables, and a submarine cable through Turnagain Arm. Additions to the Huffman and International Substations have been considered as design options for the substation in Anchorage.

The capital cost of the KA138 proposal, with the Huffman Substation option and a 15 percent contingency, is estimated at $64.1 million in 1990 dollars. The capital cost of the proposal, with the International Substation option and a 15 percent contingency, is estimated at $65.6 million in 1990 dollars (Table 1).[3]

Limited Upgrade of the Anchorage-Fairbanks Intertie (AF100 Upgrade)

The AF100 upgrade is the same proposal for a limited upgrade of the intertie between Anchorage and Fairbanks previously considered in the AEA study. The upgrade consists of new static VAR systems and series capacitors that will increase the capacity of the current line by 30 MW. The capital cost of the AF100 upgrade, with a 15 percent contingency, is estimated at $9.4 million in 1990 dollars (Table 1).[4]

New Intertie Between Healy and Fairbanks (AF138 Intertie)

The AF138 proposal is comprised of the limited upgrade of the Anchorage-Fairbanks intertie coupled with a new 138 KV line from Healy to Ft. Wainwright. The proposed 138 KV line between Healy and Fort Wainwright is a steel-structure line that will reduce the transmission losses on the line between Healy and Fairbanks, and will increase the transfer capability between Anchorage and Fairbanks.

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[3]Both of these cost estimates were prepared by Power Engineers Incorporated for CEA in April, 1989.

[4]Decision Focus Incorporated, *Railbelt Intertie Reconnaissance Study, Benefit/Cost Analysis*, prepared for the Alaska Power Authority, June 1989.

The capital cost of the 138 KV line and terminal substations, with a 15 percent contingency, is estimated to be $49.3 million in 1990 dollars.[5] Including the capital cost of the limited upgrade ($9.4 million in 1990 dollars), the total capital cost of the proposal is $58.7 million (Table 1).

This memorandum does not review the projects' cost estimates which should also receive independent review or review by AEA engineers.

Operating and Maintenance Cost of the Proposed Interties

The variable costs of an intertie are the annual operating and maintenance costs that are associated with the operation of the line. These costs are typically expressed as a percentage of the capital cost of the line. In the AEA 230 KV study, as well as the previous intertie upgrade analysis[6] and the analyses for the construction of the existing Anchorage-Healy intertie, the variable cost of each line was estimated as 1.5 percent of capital cost. The accepted industry standards for calculating these costs are 0.5 to 1.5 percent. Because of Alaska's harsh climate and higher cost of living, the 1.5 percent estimate has previously been used in Alaska. In the 138 KV study, the variable costs of the Anchorage-Fairbanks and the Anchorage-Kenai lines were reduced to 0.5 and 1.0 percent, respectively, based on Railbelt utility input and that of engineering consultants.[7] The effect of this change is to reduce costs and thus, increase the benefit/cost ratio.

Economic Life of the Interties

The planning horizon of the study is set equal to the expected economic life of each intertie. The AEA 230 KV study assumes that the economic life of each of the proposed lines is 35 years. The Railbelt utilities indicated that the life of a line could be as long as 50 years. Based on DFI personal communications, the life of the 138 KV lines were changed to 50 and 40 years for the Anchorage-Fairbanks and Anchorage-Kenai lines, respectively.[8] While this change increases the net present value of the variable cost of the lines,

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[5]The estimate was prepared by Harza Engineering Company for GVEA, April 5, 1989.

[6]Lotus Consulting Group, *Railbelt Intertie Proposal: Preliminary Economic Assessment*, prepared for the Alaska Power Authority, March 1987.

[7]Harza Engineering Company; Flynn & Associates; and Power Engineers--see page 2-3 of the 138 KV study for more details.

[8]See Decision Focus Incorporated, December 1989, p. 2-5 for more detailed information on assumptions regarding the economic life of interties.