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it is more than offset by the increase in the net present value of benefits that result from extending the life of the lines. Thus, the net effect is to increase the benefit/cost ratio of the lines.

RELIABILITY BENEFITS

The reliability of an electrical system is important because the value of electric power exceeds the cost of producing the power. While the cost to a utility of an outage may be relatively small, the value to an industrial or commercial customer may be quite large. The proposed upgraded or new interties are expected to improve service reliability by reducing both the frequency and duration of customer outages.

The assessment of the value of improved system reliability requires an estimate of the outages that an intertie would avoid and the cost to customers of these avoided outages. Decision Focus estimated the impact of the interties on customer outages or unserved energy by analyzing the historical outages in the Railbelt area and the reduction in outages that could be attributed to new interties. For the cost of customer outages, DFI relied on research prepared for the Electric Power Research Institute.[9]

Decision Focus used similar methodology to calculate the reliability benefits for the AEA 230 KV study and the Railbelt utilities' 138 KV study. Benefits, however, increased from $14.0 million to $41.0 million for the Anchorage-Kenai line and from $1.4 million to $11.5 million for the Anchorage-Fairbanks lines as a result of the use of different estimates for the cost and amount of unserved energy. The increased value used to calculate the cost of unserved commercial and industrial sector unserved energy accounts for the majority of this increase.

In the AEA 230 KV study, DFI values unserved residential energy at $2.07/kilowatt hour (KWh) based on a study completed by Sangvhi in 1983. More recent surveys, reported in the 1989 EPRI study cited above, estimate residential outage costs ranging from $0.21/KWh to $9.91/KWh. Based on this more recent information, DFI assumed a cost of $5.00/KWh for residential

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[9] *The Value of Service Reliability to Customers*, EPRI Report EA-4494, prepared for EPRI by Criterion, Incorporated, San Diego, Ca. May 1986; L.V. Scott, "Ontario Hydro Surveys on Power Systems Reliability: Summary of Customer Viewpoints," compiled in *The Value of Service Reliability to Customers*, EPRI Report EA-4494, May 1986; *Customer Demand for Service Reliability: Existing and Potential Sources of Information*, prepared for EPRI By Laurits Christensen Associates, Madison, Wisconsin, May 1989; and A.P. Sanghvi, "Economic Costs of Electricity Supply Interruptions: U.S. and Foreign Experience," in *The Value of Service Reliability to Customers*, EPRI Report EA-4494, May 1986.

outages which is the midpoint of the range of results. This change more than doubles the residential sector's reliability benefits of the 138 KV line.

Similarly, the benefits of improved industrial and commercial reliability increased by a magnitude of two as a result of a different interpretation of results from surveys conducted by Ontario Hydro. Based on these surveys, Len Scott estimated the dollar per kilowatt hour cost of an outage assuming the electrical usage at the time of the outage was 75 percent of annual peak demand at the time of the outage, i.e., that the facilities were open and operating at the time of the outage.[10] This is an accurate interpretation of the survey data because the survey question asked for "the cost of an outage that occurs at 10 a.m. on a Friday morning in January."[11] In the original AEA 230 KV intertie analysis, DFI used Scott's data to calculate the cost of industrial and commercial sector unserved energy that could be avoided from the construction and/or upgrade of new interties.

In the 1989 EPRI reliability report, Christensen Associates present the results of the same Ontario Hydro surveys shown in the Scott report. In this 1989 report, Christensen Associates explicitly urge caution when using dollars per peak kilowatt hour of usage or dollars per average annual usage because their inappropriate application can lead to inaccurate results.[12] Based on a conversation with one of the Christensen analysts and without information regarding the actual survey question, DFI changed the formula for calculating the cost of unserved energy to reflect average annual demand rather than peak demand which is inconsistent with the survey question and thus the calculated cost of unserved energy. This change dramatically increased the value of industrial and commercial reliability benefits.[13] In light of information on the actual survey question, Decision Focus investigators acknowledged that the formula was misapplied in the utility 138 KV intertie study.[14] This results

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[10] L.V. Scott, May 1986.

[11] Dick Emerman, senior economist, Alaska Energy Authority, personal communication, January 10, 1990, based on his conversation with David Glyer, Laurits Christensen Associates, January 1990; Ginny Fay, personal communication with David Glyer, February 16, 1990.

[12] Laurits R. Christensen Associates, 1989, p. 2-14.

[13] The average annual or peak demand figure is in the denominator of the formula which is why dividing by average annual (a smaller number), gives a higher cost of unserved energy.

[14] Meeting with Decision Focus Incorporated principal investigators Salim Jabbour and Richard Fancher, Anchorage, January 30, 1990. The analysts, however, maintain that despite the misapplication of the formula, the result is correct.

in an overestimate of intertie benefits of the southern line by approximately $15 million and the northern line by approximately $5 million.

ECONOMY ENERGY TRANSFER AND HYDRO-THERMAL COORDINATION BENEFITS

Economy energy benefits are realized when an intertie allows energy to be transferred from a lower-cost area to displace energy that would otherwise be produced in a higher-cost area. Increases in transmission capacity can provide the opportunity for additional economy energy savings. According to Decision Focus's analysis, benefits between Anchorage and Fairbanks are primarily a result of disparities in power production costs in the two areas. Partially as a result of their conclusions regarding the optimal dispatch of Fairbanks power generating units (i.e., limited operation of the FMUS coal facility), peak demand in Fairbanks exceeds the transfer capacity of the current intertie. Therefore, the benefits of both the AF100 and AF138 are attributable to alleviating the capacity constraint of the current line. In contrast, the benefits of the new Kenai-Anchorage line are almost entirely the result of increased coordination of hydroelectric and thermal generating units.

In their study, DFI simultaneously analyzed economy energy and transmission loss savings using the Over/Under production simulation model.[15] A number of adjustments were subsequently made to the Over/Under results as follows:

- for the AF100 and AF138 options, an adjustment was made to account for the "North Pole operating constraint (explained below),"
- for the KA138 intertie, an adjustment was made to account for the increased transfer levels to replace the less efficient performance of partly loaded gas-fired turbines with Bradley Lake hydroelectric power, i.e., hydro-thermal coordination;
- and for all intertie options, an adjustment was made for the benefits from the collection of gas royalty and severance taxes.

These adjustments account for a substantial portion of the economy energy transfer benefits of the intertie and are discussed in the remainder of this section.

Economy Energy Transfers Between the Kenai Peninsula and Anchorage

While both Anchorage and the Kenai Peninsula have gas-fired generating units, Anchorage's units are more efficient. As a result, little or no economy energy

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[15] The Over/Under model is a long-term capacity expansion/production simulation model that was developed by DFI for the EPRI.

benefit can be gained from operating the gas units on the Kenai Peninsula. In addition, after the completion of the Bradley Lake hydroelectric project, the Kenai Peninsula will have substantial hydroelectric resources. The available hydroelectric resources over the course of the average year, however, will be less than the anticipated energy requirements on the Kenai Peninsula. Therefore, Kenai continues to be a net importer of energy from Anchorage.

The main component of expected transfers between Anchorage and the Kenai Peninsula is based on the optimal pattern of dispatch of energy from Bradley Lake. Bradley Lake has sufficient water storage capability to allow hydro energy production during the winter months in excess of Kenai Peninsula demand requirements. In addition, the Bradley and Cooper Lake facilities provide more power than needed to meet Kenai peak demand. Therefore, some of this excess capacity can be used to allow the turning off of less efficient, only partly loaded gas-fired turbines operating in the Anchorage area.

However, there are two major errors in DFI's analysis of hydro-thermal coordination benefits. The first is a calculation error which results in a $25 million overestimate of benefits. The error involves a fuel savings estimate in millions of Btu per hour of hydro-thermal reshaping located in Table A-6 on page A-8 of the utility 138 KV report. In the first column of Table A-6, the figure "356" should read "132" and the figure "125" should read "55."[16]

The second miscalculation results from using a constant rather than varying gas turbine heat rate across loading levels for calculating fuel savings for hydro-thermal coordination. Gas turbines operating at full load have their most optimal, efficient heat rates. As turbine loading is reduced, the heat rate increases (in Btu's per KWh). To accurately calculate fuel savings from turning off turbines in Anchorage, this varying heat rate efficiency needs to be taken into account. Use of a constant, 50 percent loaded, turbine heat rate overestimates the savings potential of the new intertie. This oversimplification results in an additional $4 million overestimate in benefits of the new Anchorage-Kenai intertie.[17]

A third problem with the hydro-thermal coordination benefits calculation is that it assumes that after the Bradley Lake project is completed and a new Anchorage-Kenai intertie is constructed, the electrical system will be optimally dispatched in order to capture the *potential* benefits of the system. If optimal dispatch does not occur, these benefits will be realized. Salim Jabbour, principal investigator, DFI, estimated that $3-$6 million in annual savings are currently available in the Railbelt if the system were optimally dispatched. In calculating potential benefits of a new intertie, DFI attempted

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[16] Richard Fancher of DFI confirmed this calculation error in Anchorage on January 30, 1990.

[17] Ibid.

to compare optimal systems with and without a new intertie. It is not clear, however, whether the effects of the currently suboptimal system are fully removed because data from actual utility dispatch patterns is used to determine which gas-fired unit would be shut off under hydro-thermal coordination, i.e., a 100 MW unit. The size of this unit, in turn, results in the capacity of the existing intertie being insufficient to turn off the unit. If, however, all of the units in Anchorage were optimally dispatched by one control center, it is likely that the unit identified to be the "marginal" unit to be shut off (from the historical utility data) would be smaller than 100 MW. If so, the current intertie capacity may be sufficient to shut off the unit.

The most significant problem with the hydro-thermal benefit category, however, is the assumption that these potential benefits would be realized through optimal utility dispatch in the Railbelt given the significant utility and ratepayer savings that are currently available but unrealized. There will be even less market incentive for the utilities to capture the potential new intertie benefits because the intertie will be financed by a state grant. Decision Focus investigators suggested that to increase the likelihood of capturing hydro-thermal coordination benefits, a condition of a state grant should be the development of a single utility dispatch control center in Anchorage for the southern Railbelt and one control center in Fairbanks for the northern Railbelt (the latter is currently the case).[18]

Economy Energy Transfers Between Anchorage and Fairbanks

In the system simulation conducted by DFI, nearly all transfers of power between Anchorage and Fairbanks flow from south to north because Anchorage gas-fired generation costs less than Fairbanks oil-fired power. Fairbanks first relies upon its existing coal-fired capacity. In the absence of an intertie, Fairbanks would next rely upon existing oil-fired generation capacity. An intertie allows the displacement of higher cost Fairbanks oil-fired generation with lower cost Anchorage gas-fired generation. Increased transmission line capacity allows Fairbanks to take advantage of increased economy energy transfers as Fairbanks electrical demand grows. Most (73 percent) of the benefits of the AF100 upgrade and the construction of a new Healy-Fairbanks 138 KV line result from increased economy energy transfers. However, these benefits are driven by three significant assumptions.

North Pole Operating Constraint. The first key assumption is the so-called "North Pole operating constraint." The North Pole operating constraint occurs because of the poor part-load performance of the Golden Valley Electric Association (GVEA) two 61 MW oil-fired combustion turbines located at North Pole. To be economically most efficient, the units must be operated above a

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[18] Meeting with Salim Jabbour and Richard Fancher, DFI, Anchorage, January 30, 1990.

minimum load level. When demand in Fairbanks for energy over the intertie exceeds the intertie capacity, one of the North Pole units must be started. Because the minimum economic level of operation of these units is relatively high, intertie purchases are reduced whenever a North pole unit is started, even if Fairbanks demand only minimally exceeds intertie capacity. The AF100 and AF138 projects would reduce or eliminate this North Pole constraint by allowing a higher level of energy transfer into Fairbanks from Anchorage. As a result, there would be fewer occasions for the North Pole units to be started.

There are three problems with the calculation of benefits from eliminating the North Pole operating constraints. The first is that the DFI North Pole calculation assumes that the Fairbanks Municipal Utility System (FMUS) 20 MW coal-fired Chena #5 unit is not operated before the North Pole units until after the intertie reaches its full capacity. This occurs most often under the lower fuel price scenarios when full-load heat rates of Fairbanks generating units are compared. In contrast, DFI's Over/Under simulation model shows the Chena #5 unit operating after the year 2002. In actuality, part-load heat rates indicate that the FMUS Chena #5 coal-fired unit should be dispatched before any part loading of North Pole units. In fact, FMUS baseloads the Chena #5 unit. This correction reduces the incremental benefits of the AF138 over the AF100 by approximately $3 million.

The second problem with the North Pole constraint analysis is that the Fairbanks load forecast used by DFI assumes that the Fairbanks utilities supply power to the military. In the Railbelt electrical demand forecast conducted for the AEA by the University of Alaska, Institute of Social and Economic Research (ISER), Scott Goldsmith indicated that the extent to which Fairbanks utilities will supply military power in the future is uncertain. As a result, the military load should be subjected to a sensitivity analysis--this was done in the AEA study. Because no sensitivity analysis was done in the utility 138 KV study to determine the impact of this assumption, economy energy benefits are overestimated. The frequency of the North Pole operating constraint would be reduced without the military demand.

The third problem with the benefits attributed to the North Pole constraint is that it does not take into consideration the current negotiations between GVEA and FMUS regarding the sale of FMUS' 20 MW oil-fired Chena #6 unit.[19] Currently, this unit is not operating because its location on the Chena River causes water quality problems from fuel storage and leakage. The cost estimate for moving the unit to GVEA's North Pole facility is approximately $2 million. Given the significant level of intertie benefits attributable to the North Pole

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[19] Information on this purchase was not considered in the utility 138 KV study because this information was not provided to DFI. The information was contained in North American Electric Reliability Council (NERC) filings submitted to the AEA by FMUS and GVEA.

operating constraint, moving a generator appears more cost effective than the construction of the new AF138. If each of the transactions were to be privately financed, it is doubtful that GVEA would construct a new power line rather than move an idle generator.

Fuel Price Differentials. As part of the Railbelt alternatives study, the AEA contracted with ICF, Inc. to analyze fuel costs in the Railbelt.[20] Based on the ICF analysis, the AEA developed fuel price forecasts and estimates of price differentials between major fuel types in the Railbelt--natural gas, fuel oil, and coal. Economy energy sales over electrical transmission lines are motivated by fuel price differentials because lower cost power is transmitted to regions with higher cost power.

In their utility 138 KV analysis, DFI made two significant departures from fuel price assumptions used in the earlier AEA 230 KV study. The first is changing the probability weighting of the fuel price forecasts. In the AEA study, the low, middle, and high fuel forecasts were given a 60, 30, and 10 percent probability weighting for calculating the potential benefits of the upgraded/new interties. In the utility 138 KV study, the fuel forecasts were given equally weighted probabilities (i.e., 33.3 percent each). The effect of this change in weighting is to increase the forecasted fuel prices and the benefits of economy energy sales to the southern line. As a result of the relative coal price differential, changing the fuel forecast probabilities lowered the economy energy benefits of the northern line (i.e., Fairbanks produced coal power replaces natural gas economy energy sales because of the higher price of natural gas). There was no justification given for changing the forecast probabilities.

The second change made in the utility 138 KV study was to remove the sensitivity analysis for fuel price differentials after the year 2010. In the ICF analysis, fuel prices were forecasted through the year 2010. The life of the intertie projects, however, extends beyond that time horizon. Therefore, assumptions about fuel price differentials must be made after the year 2010. One of the sensitivity analyses conducted was to collapse the price differential between Cook Inlet natural gas and Fairbanks fuel oil based on the sharply rising marginal cost of Cook Inlet gas reserves as gas is depleted.[21]

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[20] ICF Incorporated, *Fuel Price Outlooks: Crude Oil, Natural Gas, and Fuel Oil, Railbelt Intertie Reconnaissance Study*, Volume 4, prepared for the Alaska Power Authority, August 1988.

[21] Fuel price differentials and this sensitivity analysis is discussed at length in Appendix B of the DFI report prepared for the AEA. See especially pages B-4 and B-5.

The effect of this Cook Inlet natural gas price increase is to remove the price differential between Cook Inlet natural gas and Fairbanks fuel oil after the year 2015, which would significantly erode the calculated benefits of economy energy transfers from Anchorage to Fairbanks. This is especially true in the utility 138 KV study because the life of the new Healy-Fairbanks intertie was increased from 35 to 50 years. Given the uncertainty of this distant time horizon and the level of known reserves of Cool Inlet natural gas, a fuel price differential sensitivity analysis should be conducted; no justification was given for removing the analysis from the utility report.[22] Maintaining a fuel price differential between 2020 and 2043 overstates the net present value of the incremental benefits of the AF138 over the AF100 by about $10 million.

Gas Royalty Benefits. A benefit category that was not included in the AEA 230 KV study but was added to the utility 138 KV study is the benefits from increased gas royalties.[23] This cate[illegible] was added on the premise that the new Anchorage-Fairbanks intertie would [illegible] increased gas substitution for oil, and therefore, would increase Alaska's royalty and severance taxes. This benefit calculation assumes that the price of natural gas will increase less than inflation plus the discount rate. To the extent that this assumption is incorrect, the benefit calculation overestimates actual benefits.

According to DFI, the royalty benefit calculation is adjusted "in the later years when the gas supply is depleted." However, it appears that there is no adjustment made for increased gas prices as Cook Inlet gas is depleted. The increase in gas prices could more than offset any increase in the present value of gas royalties and severance taxes that results from moving these payments forward in time. In addition, if gas resources are depleted in the next 50 years as DFI indicates--based on ICF's analysis--then maintaining a constant fuel price differential between natural gas and fuel oil to calculate the benefits of economy energy sales is inconsistent.

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[22] Maintaining a constant fuel price differential also contradicts the statement made on page 5-3 of the utility 138 KV report regarding benefits from increased gas royalties. In this section, DFI states that "benefits from increased gas royalties are reduced in later years when the gas supply is depleted." Economic logic dictates that as Cook Inlet gas is depleted, its price will increase. This will, in turn, reduce or eliminate the price differential between Cook Inlet natural gas and Fairbanks fuel oil and thus, the benefits of increased economy energy sales over the intertie.

[23] Gas royalty and severance tax benefits were not included in the feasibility analysis for the existing state-owned and constructed Anchorage-Fairbanks intertie. Nor were foregone natural gas royalties and severance taxes calculated as a cost in the Bradley Lake hydroelectric project analysis. If they had been, even with the sunk costs and higher gas prices assumed in 1987, the project may not have been found economically feasible.

CAPACITY SHARING BENEFITS

Electric power system interconnections through transmission lines allow one or more areas to share generation capacity and/or reduce required generation reserve margins without compromising system reliability. New or upgraded interties can reduce future investment costs by deferring or avoiding the need for generation capacity. During the period of analysis, the Railbelt will have two areas (Kenai and Fairbanks) with capacity surpluses, while one area (Anchorage) will eventually have a capacity shortage. Capacity deferral benefits are possible through increased power transmission between the surplus and shortage areas. Decision Focus analyzed the potential benefits of both capacity deferral and avoidance. This section primarily reviews the benefits attributable to capacity deferment.

Decision Focus calculated capacity deferment benefits based on generation capacity retirement schedules and a 20-year life of new gas turbines as provided by the Railbelt utilities. According to a recent AML&P study,[24] they intend to retire two units in 1992 after 30 and 28 years of life, which makes the 20-year lifespan a questionable assumption. The use of the conservative 20-year life span results in an increase in capacity deferral benefits.

The new KA138 intertie results in capacity deferment benefits because it has a higher transfer capacity than the existing intertie. To calculate capacity deferment benefits, DFI models two transfer capacity cases for the existing intertie. In Case 1, the existing intertie transfers 75 MW of input and 60 MW of output (the difference is customer usage along the line and line transfer losses). In Case 2, the existing line transfers 90 MW of input and provides 75 MW of output. In their analysis, however, DFI erroneously modelled 88 MW of output for Case 2 which understated the benefits of the new intertie.

This understatement, however, is more than compensated by the considerable disagreement over the actual transfer capacity of the Anchorage-Kenai line. Two transfer capacities were modelled primarily because of this disagreement. The engineering consultant for the Alaska Energy Authority, PTI, indicates that the existing intertie can routinely transfer 90 MW input and 75 MW output.[25] However, this would be the upper transfer capability of the existing line in the absence of "technical fixes;" the line's transfer capacity continues to be the topic of considerable debate. To the extent that the existing line's transfer capacity can be increased, the capacity benefits of a new line are significantly eroded.

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[24] Anchorage Municipal Light & Power, "Explanation and Support for Avoided Cost Tariff Proposed by ML&P," October 25, 1989, p. 8.

[25] PTI, "Kenai Export Limits With and Without a New Line With and Without Additional Compensation," PTI Report Number R106-89, November 30, 1989.

Another significant problem with the estimate of capacity deferment benefits results from the inconsistency between generation capacity retirement schedules used for the intertie analyses, and those provided to the AEA for a North American Electric Reliability Council (NERC) study, and for calculating utility avoided costs. Information on current Railbelt standing capacity and retirement of that capacity is presented in Tables 4 - 6 for the subregions of Anchorage, the Kenai Peninsula, and Fairbanks. These tables are based on utility system modelling used by DFI (Appendix F, AEA study). The same system modelling was used for both the AEA and utility studies (see Attachment B).

In this memorandum, the DFI information has been adjusted to account for the extension of the operating life of existing equipment. This life extension is based on utility information for 1) avoided cost hearings[26] and 2) the NERC survey identified above. Thus, the primary difference between DFI's capacity and retirement schedules and those in Tables 4 - 6 is that DFI assumes no capacity life extension, while according to the information presented for calculating avoided costs and provided to NERC, a considerable amount of life extension is anticipated. The generating units to be overhauled or rebuilt are identified as such in the tables. These tables assume one major rebuild that increases the life of the unit by 15 years. In addition, according to CEA's NERC report, the Bernice Lake #4 natural gas turbine is being moved to Anchorage in 1994 and, therefore, is reflected as such in these tables. Movement of this unit further reduces the capacity constraint of the existing Anchorage-Kenai intertie.

Figures 1 - 4 illustrate total installed capacity, capacity retirement, and forecasted low, middle, and high electrical power demand in the Railbelt and its subregions from 1994 through 2025. Information on installed capacity and retirement dates is from Tables 4 - 6. The energy demand forecasts are from the University of Alaska, Institute of Social and Economic Research analysis for the Railbelt intertie study.[27] The demand forecasts are peak demand and include a 30 percent reserve margin. According to Figure 1, under the high forecast the Railbelt will need no additional generating capacity until the year 2007; under the low demand forecast, no additional capacity will be needed

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[26] Under the Public Utilities Regulatory Policies Act of 1978 (PURPA), utilities must purchase power from independent qualifying facilities at their avoided energy costs which is defined as the cost of the next increment of power they would produce. There is inconsistency, however, between AML&P's avoided cost and NERC information. For AML&P retirements in the 1990s, NERC survey information was used.

[27] University of Alaska Anchorage, Institute of Social and Economic Research in collaboration with Adams, Morgenthaler, & Company, Inc.; Regional Economic Research, Inc.; and James E. McMahon; *Forecast of Electricity Demand in the Alaska Railbelt Region: 1988-2010;* prepared for the Alaska Power Authority, April 30, 1989.

until 2009. Anchorage will be short of capacity sometime between 2007 and 2009. This, however, does not take into consideration potential power sales from the Kenai Peninsula that will have ample capacity throughout the period of analysis.

Determining the value of capacity deferment first requires the calculation of the amount of capacity deferred through the retirement schedules described above. The second part of the calculation is the estimate of the cost of the capacity that is deferred. In their analysis, DFI estimates that the cost of deferred capacity is $51/KW/year. However, prior to 2007 when additional capacity is required in the Railbelt, the replacement cost of gas turbines overestimates the potential capacity sharing benefits because the cost of life extension is less than $51/KW/year. In their avoided cost proposal, AML&P suggests that gas turbines can be life extended for only the cost of fixed operation and maintenance, $13/KW/year, 74 percent less the $51/KW/year in the DFI study. While AML&P's cost estimate seems extremely low, it indicates that capacity can be acquired at considerably less than DFI's estimates. In the utility report, DFI acknowledges (p. 6-5) that the extent to which capacity is life-extended rather than replaced will reduce capacity sharing benefits.

TABLE 4
POWER PRODUCTION CAPACITY AND RETIREMENT IN ANCHORAGE

Unit name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
Eklutna	APAd	Hydro	30.0	----
AMLPCT#1	AMLP	NG	16	2015(a)
AMLPCT#2	AMLP	NG	16	2015(a)
AMLPCT#3	AMLP	NG	19	2015(a)
AMLPCT#4	AMLP	NG	33	2015(a)
AMLPCC#56	AMLP	NG	47	2015(b)
AMLPCC#76	AMLP	NG	109	2014(b)
AMLPCT#8	AMLP	NG	87	----
BEL CT#1	CEA	NG	17	2002
BEL CT#2	CEA	NG	17	2006
BEL CT#3	CEA	NG	55	2003
BEL CT#4	CEA	NG	9	1994
BEL CT#5	CEA	NG	66	2006
BEL CC#68	CEA	NG	101	2008
BEL CC#78	CEA	NG	101	2008
INT CT#1	CEA	NG	16	1996
INT CT#2	CEA	NG	16	1997
INT CT#3	CEA	NG	19	1997
INT CT#5	CEA	NG	25	----(c)

Notes:
(a) Units are repowered to 13,500 btu/kwh and life extended.
(b) Retrofitted and remains constant throughout the study period.
(c) This unit is moved in 1994 from the Kenai Peninsula to Anchorage.

Legend:
APAd= Alaska Power Administration
AMLP= Anchorage Municipal Light and Power
CEA= Chugach Electric Association
CT= Combustion Turbine
NG= Natural Gas

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989; and Anchorage Municipal Light & Power, "Explanation and Support for Avoided Cost Tariff Proposed by ML&P," October 25, 1989.

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

TABLE 5
POWER PRODUCTION CAPACITY AND RETIREMENT ON THE KENAI PENINSULA

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
BERNCT#1	CEA	NG	8	1994
BERNCT#2	CEA	NG	18	2006
BERNCT#3	CEA	NG	25	2019(a)
BERNCT#4	CEA	NG	25	2004(b)
COOPER LAKE	CEA	Hydro	17	----
SOLDOTCT#1	AEG&T	NG	39	----(a)
SELDIC#1-4	HEA	OIL	2.1	2015(a)
SESIC#1-3	SES	OIL	10.5	2010(a)
BRADLEY LAKE	AEA	Hydro	119	----

Legend:

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

Notes:
(a) Units are life extended and remain constant throughout analysis.
(b) This unit is moved to Anchorage in 1994.

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989.

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

TABLE 6
POWER PRODUCTION CAPACITY AND RETIREMENT IN FAIRBANKS

Unit Name	Unit Owner	Principal Fuel	Generating Capacity (MW)	Retirement Date
CHENST#1	FMUS	Coal	5	2001
CHENST#2	FMUS	Coal	2	2000
CHENST#3	FMUS	Coal	1.5	1995
CHENCT#4	FMUS	Oil	6	1987
CHENST#5	FMUS	Coal	20	2010
CHENCT#6	FMUS	Oil	26	2006
FMUSIC#1	FMUS	Oil	2.8	1992
FMUSIC#2	FMUS	Oil	2.8	1992
FMUSIC#3	FMUS	Oil	2.8	1995
HEALST#1	GVEA	Coal	25	2017(a)
HEALIC#2	GVEA	Oil	2.8	1997
NOPOCT#1	GVEA	Oil	61	2021(a)
NOPOCT#2	GVEA	Oil	61	2022(a)
ZENCT#1	GVEA	Oil	18	2016(a)
ZENCT#2	GVEA	Oil	18	2002
DSLIC#1-8	GVEA	Oil	14.7	2011

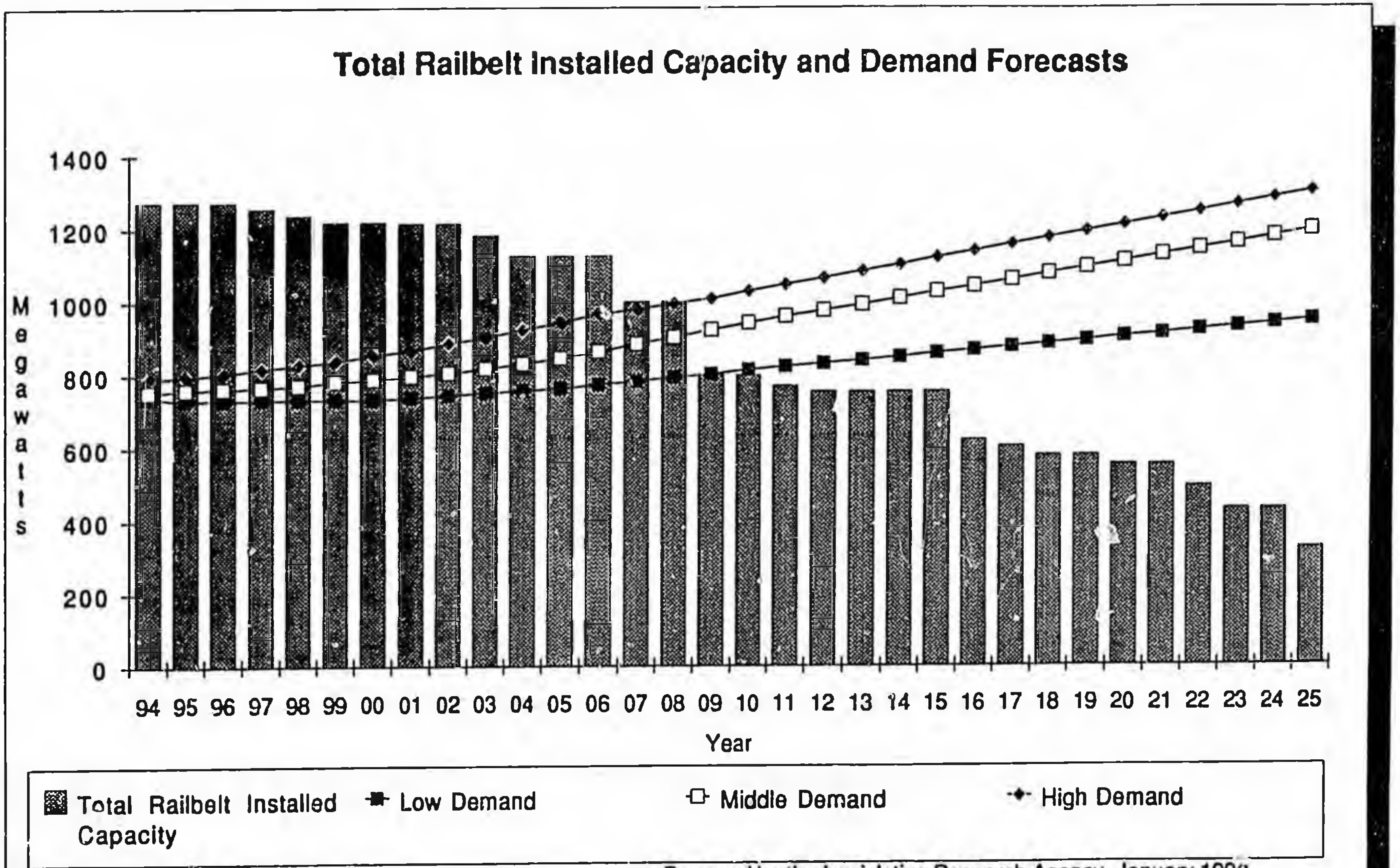
Legend:
FMUS= Fairbanks Municipal Electric Association
GVEA= Golden Valley Electric Association
ST= Steam Turbine
CT= Combustion Turbine
IC= Internal Comustion

Notes:
(a) Units are life extended and remain constant throughout the analysis.
*Chena Unit #4 Not Currently Operating; #6 possible sale to GVEA.

Source: Decision Focus Inc., "Railbelt Intertie Reconnaissance Study," prepared for the Alaska Power Authority, June 1989; Railbelt utility data submitted for North American Electric Reliabilty Council study, December 1989.

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

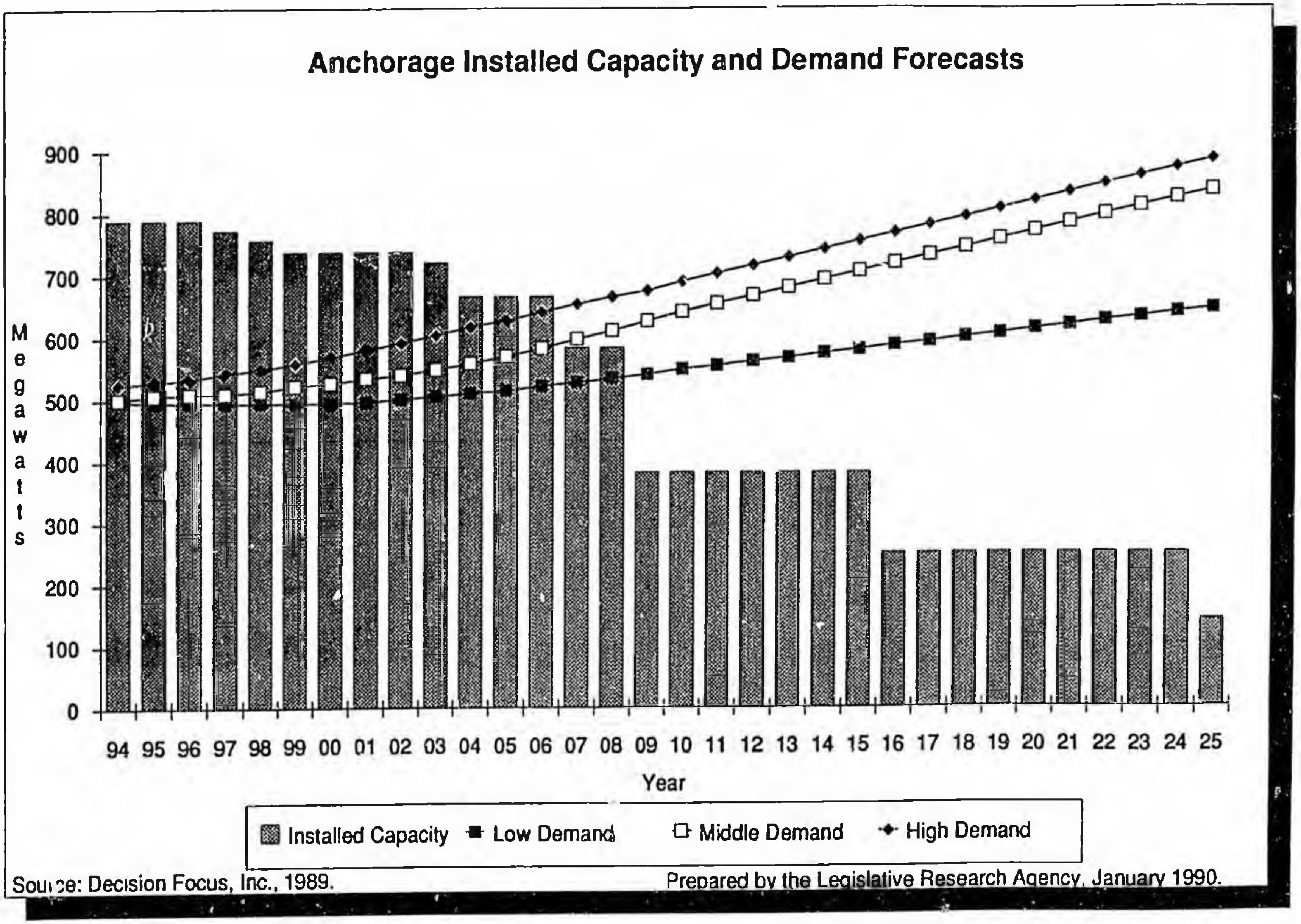
FIGURE 1


Total Railbelt Installed Capacity and Demand Forecasts

Source: Decision Focus Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

FIGURE 2

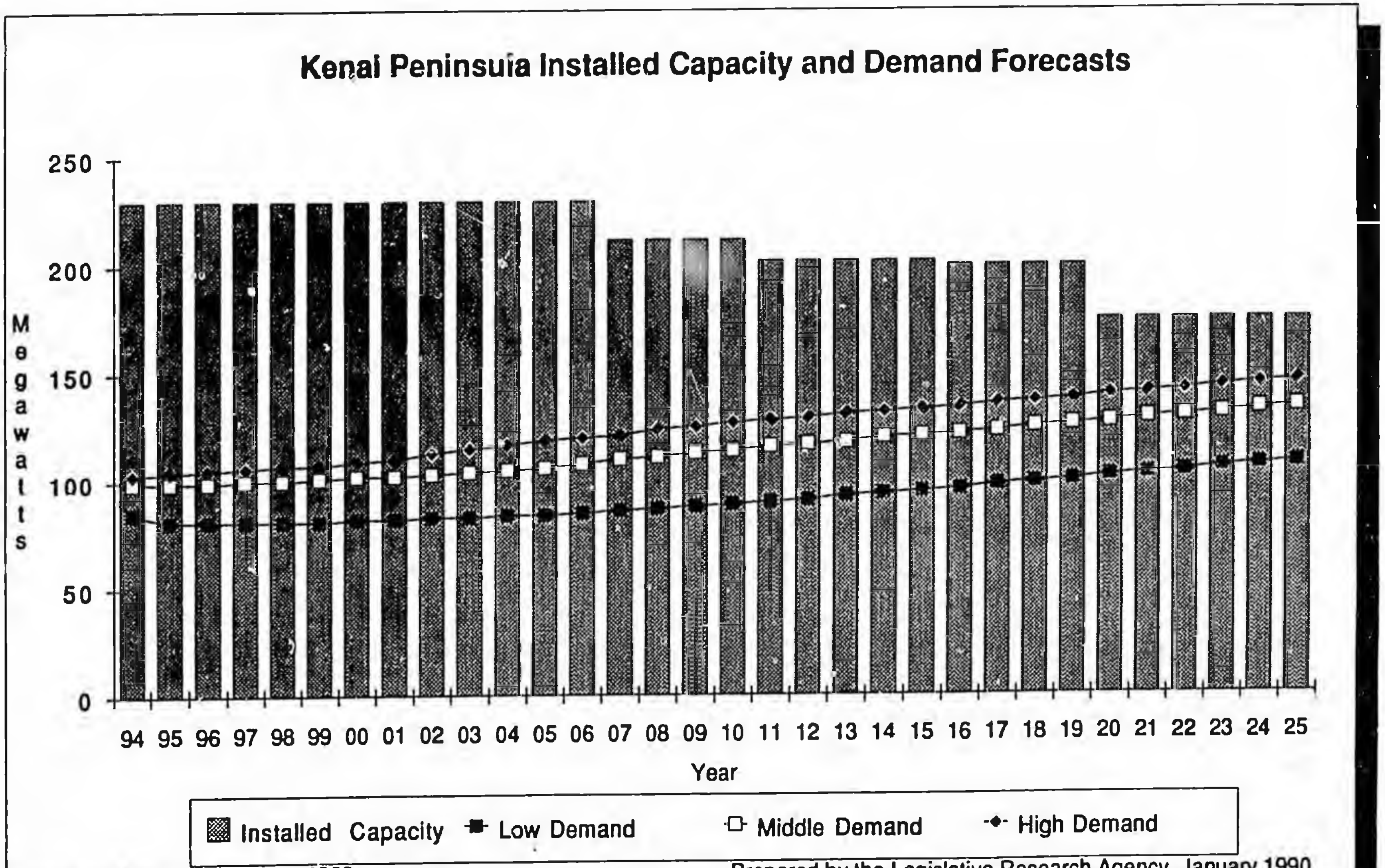


Anchorage Installed Capacity and Demand Forecasts

Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

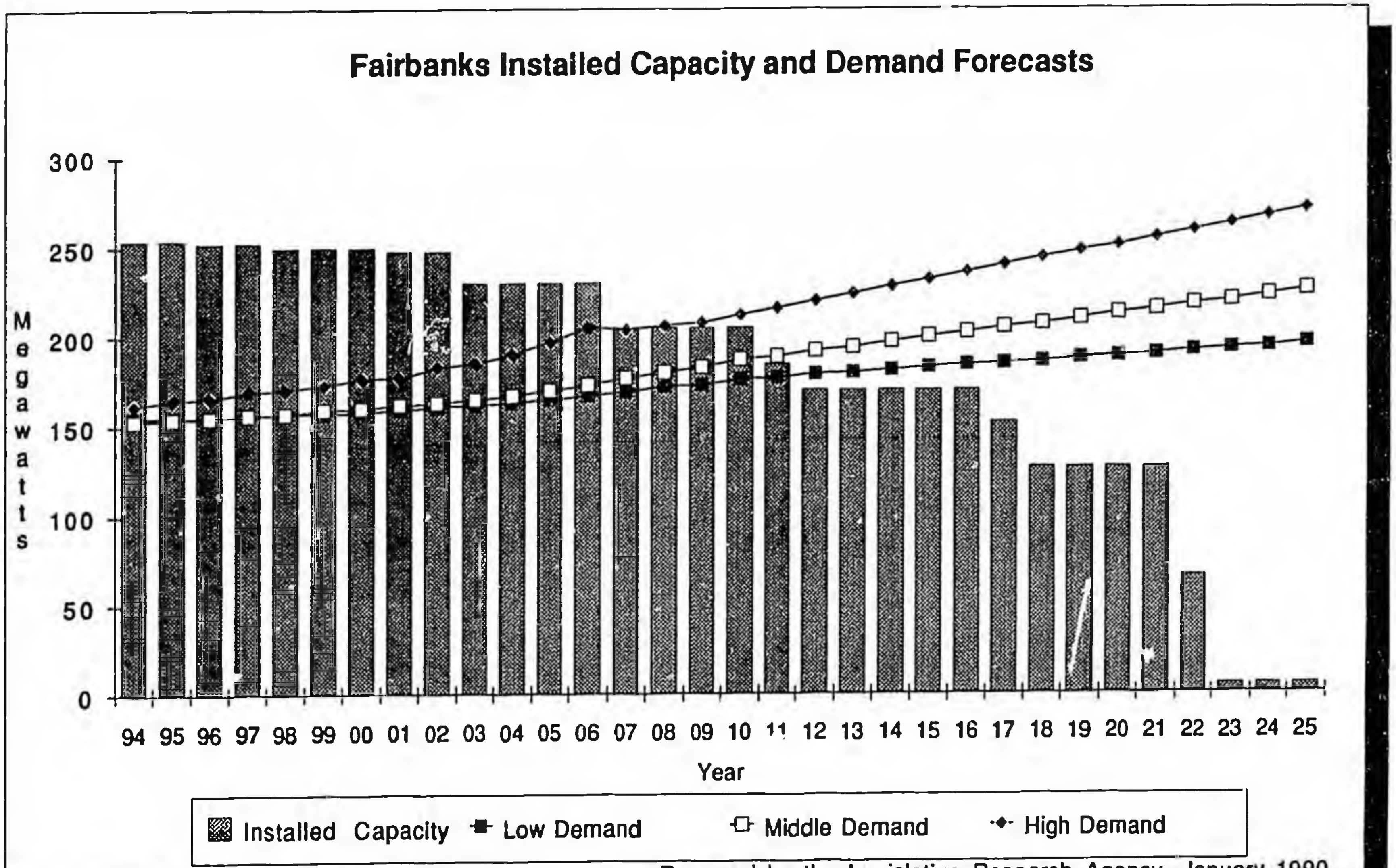
FIGURE 3



Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

FIGURE 4



Source: Decision Focus, Inc., 1989.

Prepared by the Legislative Research Agency, January 1990.

OPERATING OR SPINNING RESERVE SHARING

Operating or spinning reserves are the operating capacity that is not being used to serve the existing load. Instead, it is available to respond to a change in load. For example, a 40 MW unit that is serving a 20 MW load is providing 20 MW of load and 20 MW of spinning reserves. Operating or spinning reserves are used to respond to changes in customer demand and failures in the electric generation and/or transmission system. In this manner, operating reserves improve system reliability, but they also add to system costs. 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 spin in Anchorage because Bradley Lake spin is free while gas consumption makes thermal spin costly.

In their analysis, DFI estimates that the new 138 KV Anchorage-Kenai line would increase operating reserves sharing and result in $5.2 to $13.5 million in benefits. This is based on DFI examination of operating records of CEA, GVEA, and AML&P for 1988 which indicated that the cost of providing spinning reserves is between 7,000 and 11,000 Btu/KWh. Based on this review, DFI estimates the cost of spinning reserve to be 7,000 Btu/KWh. This cost of spinning reserves on a Btu per kilowatt hour basis was then applied to the gas turbine part-load operating cost data to calculate the total benefits attributable to a reduction in Anchorage gas-fired spinning reserves.

In two extensive meetings with Salim Jabbour, principal investigator, we asked DFI to verify the formula used to calculate the cost of spinning reserves because the formula used in a DFI report failed to produce accurate results.[28] While DFI was not able to substantiate their formula, they did acknowledge that Alan Mitchell's formula to calculate the cost of spinning reserves is correct.[29] Using Mr. Mitchell's formula, the cost of spinning reserves is 2,800 Btu/KWh. **This correction reduces the benefits of spinning reserve sharing to $2.1 to $5.4 million or an average of $3.6 million. This contrasts with DFI's estimated benefits of $5.2 to $13.5 million or an average of $9.4 million.** Details of these calculations are provided in Attachment C.

REDUCED MAINTENANCE COSTS

A new benefit category in the DFI utility study, which was not in the AEA study, is reduced maintenance costs of the existing Anchorage-Kenai intertie as a result of the construction of the new KA138 line. The present value of

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[28] Decision Focus, Inc., "Value of Bradley Lake Spinning Reserves," prepared for the Railbelt Utilities, October 6, 1989, p. 6.

[29] Alan Mitchell of Analysis North is the utility consumer advocate under contract to the state of Alaska.

reduced maintenance attributed to the new intertie is $5 million. The justification for these benefits is not described in the report and is based on information provided by the Chugach Electric Association to DFI. Given that CEA stands to benefit considerably from the state construction of the intertie, this reduced maintenance cost estimate should be reviewed by an independent party or AEA engineers in the course of their review of intertie construction cost estimates.

IMPACT OF THE HEALY CLEAN COAL DEMONSTRATION PROJECT ON INTERTIE BENEFITS

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

* * *

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 at this time. 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.

I hope this information answers your questions. If you have additional questions, please do not hesitate to call.

Attachments

ATTACHMENT A

Letter from Salim Jabbour, DFI, to Mike Kelly, GVEA regarding the Impact of the Healy Clean Coal Project on the 138KV Intertie Study

Valin

DECISION
FOCUS
INCORPORATED

[illegible] El Camino Real
Los Altos, California 94022
415 [illegible]

January 15, 1990

Mr. Michael P. Kelly
General Manager
Golden Valley Electric Association
P.O. Box 71249
Fairbanks, AK 99707

Dear Mike:

In response to your request, I am writing to provide you with my best professional judgement on how the Healy Coal Project (HCP) would affect the economic feasibility of the proposed 138 KV lines. The following discussion is based on four hours of work; no quantitative analysis was performed.

Impact of The HCP on The Economic Feasibility of The Southern Line

The HCP would affect the economic benefits of the proposed southern line through at least two of the categories identified in the December 1989 report.

> *Capacity Sharing.* The HCP would increase the capacity surplus in Fairbanks (assuming no power plants in the Fairbanks area are retired or mothballed because of the HCP). Capacity surplus in Fairbanks could be used by Anchorage (even without any new lines) to meet future capacity shortages in the Anchorage area. This would reduce Anchorage needs for capacity additions in the future and therefore reduce capacity sharing benefits due to the southern line.
>
> *Reliability.* The HCP could provide Anchorage with a source of energy in case of emergencies; therefore it could reduce outage durations and outage costs in Anchorage. The extent to which this is feasible depends on Fairbanks needs for power during an emergency in Anchorage and whether or not surplus capacity in the north is available for export to the Anchorage area. Therefore, it is possible that the HCP could reduce the reliability benefits of the proposed southern line.

Overall, the HCP is expected to reduce the benefits of the proposed southern line. It is estimated that the expected benefit to cost ratio would remain larger than one, i.e. the proposed southern line would remain cost effective. This assumes, of course, that all other assumptions remain unchanged.

Impact of The HCP on The Economic Feasibility of The Northern Line

The HCP would affect the economic benefits of the northern line primarily through its impact on energy transfers between Anchorage and Fairbanks. The benefits of the proposed northern line derive primarily from the Anchorage-Fairbanks energy transfers through the reduction in the transfer losses between the two areas, and the elimination of the constraint on the transfer capacity.

The HCP would reduce Fairbanks needs for imports from Anchorage, but would not significantly impact energy transfers over the Healy-Fairbanks corridor. Since most of the losses occur between Healy and Fairbanks, the HCP is expected to slightly reduce the transfer loss benefits of the proposed northern line.

However, since the combined capacity of the new HCP and GVEA's Healy plant exceeds the transfer capacity of the Healy-Fairbanks existing line, one could argue that the proposed northern line would allow increased economy transfers by eliminating this constraint (this argument assumes that transfers from HCP to Fairbanks are more optimal than transfers to Anchorage because Fairbanks has higher generation costs).

Overall, it is estimated that the HCP would not have a significant impact on the benefits of the northern line.

In conclusion, it seems that the HCP would not significantly impact the benefit to cost ratios of the proposed 138 KV interties. Based on this conclusion, I would not recommend a detailed re-evaluation of the interties.

Sincerely,

Salim Jabbour

Salim J. Jabbour
Vice President

ATTACHMENT B

DFI System Modelling Data (Appendix F) AML&P Avoided Cost Information and NERC Study Information

Table F-1

CAPACITY EXPANSION PLANS—RAILBELT, 1994-2010

Area	Utility	Unit	Unit Size (MW)	Retirement Schedule
Kenai		Bradley Lake	119	Stays constant
Kenai		Cooper Lake	17	Stays constant
Kenai	SES	ICE	10.5	Stays constant
Kenai	HEA	ICE	2.1	Stays constant
Kenai	HEA	Soldotna CT	39	Stays constant
Kenai	CEA	Bernice Lake CT #1	8	Retires before 1994
Kenai	CEA	Bernice Lake CT #2	18	Retires at end of 2006
Kenai	CEA	Bernice Lake CT #3	25	Stays constant
Kenai	CEA	Bernice Lake CT #4	25	Moves to International before 1994
Anchorage		Eklutna	30	Stays constant
Anchorage	MEA	No plants		
Anchorage	CEA	International CT #1	16	Retires at end of 1996
Anchorage	CEA	International CT #2	16	Retires at end of 1997
Anchorage	CEA	International CT #3	19	Retires at end of 1998
Anchorage	CEA	International CT #4	25(new)	Stays constant
Anchorage	CEA	International CT #5	40	Comes on-line at beginning of 2000 and stays constant
Anchorage	CEA	Beluga CT #1	17	Renewed until end of 2002
Anchorage	CEA	Beluga CT #2	17	Renewed until end of 2006
Anchorage	CEA	Beluga CT #3	55	Retires at end of 2003
Anchorage	CEA	Beluga CT #4	9	Retires before 1994
Anchorage	CEA	Beluga CT #5	66	Renewed to end of 2006
Anchorage	CEA	Beluga CC #6&8	101	Renewed to end of 2008, 51 MW retired at end of 2008, remaining 50 MW stays constant
Anchorage	CEA	Beluga CC #7&8	101	Renewed to end of 2008, 31 MW retires at end of 2008, drops to 50 MW in 2010
Anchorage	CEA	New CC	100	Comes on-line in 2003
Anchorage	CEA	New CT	100	Comes on-line in 2006
Anchorage	CEA	New CC	100	Comes on-line in 2008
Anchorage	AMLP	AMLP CT #1	16	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #2	16	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #3	19	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CT #4	33	Repowered to 13,500 Btu/kWh
Anchorage	AMLP	AMLP CC #5&6	47	Retrofitted and remains constant
Anchorage	AMLP	AMLP CC #7&6	109	Retrofitted and remains constant
Anchorage	AMLP	AMLP CT #8	87	Stays constant

Fairbanks	FMUS	ICE #1	2.8	Retires before 1994
Fairbanks	FMUS	ICE #2	2.8	Retires before 1994
Fairbanks	FMUS	ICE #3	2.8	Retires at end of 1996 but is assumed to remain constant because it will either be replaced or retrofitted
Fairbanks	FMUS	Chena ST #1	5	Stays constant
Fairbanks	FMUS	Chena ST #2	2	Retires at end of 2000
Fairbanks	FMUS	Chena ST #3	1.5	Retires at end of 1995
Fairbanks	FMUS	Chena ST #4		Cannot be operated (EPA)
Fairbanks	FMUS	Chena ST #5	20	Life extended to 2010
Fairbanks	FMUS	Chena ST #6	23	Retires at end of 2006
Fairbanks	GVEA	Healy ST #1	25	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Healy ICE #2	2.8	Retires at end of 1997
Fairbanks	GVEA	North Pole CT #1	61	Extended or replaced in kind, stays constant
Fairbanks	GVEA	North Pole CT #2	61	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Zender CT #1	18	Extended or replaced in kind, stays constant
Fairbanks	GVEA	Zender CT #2	18	Retires at end of 2002
Fairbanks	GVEA	ICEs	14.7	Stays constant
Copper Valley	CVEA	Solomon Gulch	12	Stays constant
Copper Valley	CVEA	Glenallen ICEs	10.4	Stays constant
Copper Valley	CVEA	Valdez ICEs	7.2	Stays constant

Notes:

1. Bradley Lake capacity = 114 MW delivered at Soldotna
2. For Fairbanks, it is assumed that either a 50-MW coal plant at Healy comes on-line in 1995 (coal case) or a 50-MW CT (oil- or gas-fired depending on availability of gas in Fairbanks) comes on-line in 2005 (all other cases).

EXPLANATION AND SUPPORT FOR AVOIDED COST TARIFF PROPOSED BY ML&P

The purpose of this document is to support the Avoided Cost tariff (No. later) submitted by the Municipality of Anchorage, doing business as Municipal Light and Power (ML&P). This document outlines the avoided cost methodology and Qualifying Facility (QF) rate formulas, that are included in the ML&P "Cogeneration avoided cost rate tariff" that ML&P intends to use with future Public Utility Regulatory Policies Act (PURPA) (16 USC 824a-3) resources or QFs greater than 100 kW. The methodology will be used to develop avoided costs for QFs on a case-by-case basis within this size range based on specific size and operating characteristics of proposed QFs. ML&P did not have a tariff or approved methodology on file with the Alaska Public Utilities Commission (APUC) for avoided costs of facilities greater than 100 kW when it was subject to APUC regulation.

The avoided cost methodology and QF rate formulas provide a generic method that can be used to determine rates for a variety of QFs. The rates satisfy the requirements of PURPA. The methodology will be used to develop a contract rate that is responsive to changes in ML&P's fuel costs and the rate of inflation throughout the term of a QF contract.

To calculate the avoided costs of ML&P a computer simulation was performed of the ML&P generation system. A set of computer models calculated the various costs to ML&P. The costs were calculated with and without cogeneration present, but with no costs assigned to the operation of the cogeneration facility. The difference in the annual cost between the two simulations was the costs (capital, fuel, cost of energy not served and operation and maintenance (O&M)) that ML&P would avoid by purchasing from a QF.

Therefore, ML&P has avoided capital costs, avoided fuel costs, avoided fixed O&M costs, avoided variable O&M costs, and avoided backup purchases during forced generation outages. These costs can be allocated to avoided energy or avoided capacity values. These avoided energy and capacity costs were then adjusted to remove the effects of inflation and natural gas prices. This resulted in a set of yearly energy and capacity avoided cost formulas.

In the analysis, the avoided energy costs are both dependent upon and correlate with future natural gas prices. The rate of inflation also has a direct effect upon ML&P's avoided capacity and energy costs. Because of the sensitivity to future prices, the final avoided costs have been developed as a formula of actual future prices. The payment by ML&P using such avoided cost formulas based upon actual natural gas and inflation values will more accurately forecast future avoided costs and should neither harm nor benefit the ultimate ratepayers. In other words, the use annual formulas will leave the ratepayers neutral as to whether ML&P uses its own resources or purchases from QFs.

In addition, how the size of a QF (10MW, 25MW and 50MW), how the QFs level of production (plant factor/availability), and how the year the QF goes on-line would impact ML&P's avoided costs were analyzed. These sensitivity analyses allowed us to determine the relative importance of the key parameters that affect ML&P's avoided costs and to suggest avoided cost rate formulas that ensure that the ratepayers are risk neutral.

The major elements of the studies to develop ML&P's avoided costs were: updating of the ML&P load forecast; modeling the ML&P generation system; verifying the computer models; converting avoided costs into avoided cost rate formulas; and developing standard contract language for use with future potential QFs.

I. LOAD FORECAST

How the Load Forecast Impacts Avoided Costs

The load forecast is used as an input in the computer simulation and modeling process. The annual peak demand in the load forecast is the principal factor determining when additional generation is required and, therefore, affects capacity cost payments. The energy load forecast also affects the mix of resources dispatched to meet load.

Why a Load Forecast was Prepared Now

The previous official ML&P forecast was published in June of 1986. The 1986 forecast was updated during 1988 to incorporate recent historical electric consumption information and current expectations as to the effects of reduced oil revenues on the State's economy into the utility's planning process. The most recent forecast is documented in a study titled Anchorage Municipal Light and Power Load Forecast 1988-2010." This study was finalized in September of 1988 and is included as an appendix to this document.

The last ML&P load forecast was updated because of the need to have consistent assumptions between generation avoided cost and load forecast models. The load forecast is a function of a number of economic and demographic variables, such as inflation rates, future gas and oil prices, etc. The latest estimates of these variables were incorporated into the generation avoided cost model to be consistent with the ML&P load forecast, even though the methodology and tariff are based upon actual natural gas prices and inflation rates rather than forecast prices.

Major Economic, Petroleum & Fiscal Assumptions

The electric forecast uses assumptions found in the economic forecasts of The Institute of Social and Economic Research (ISER), University of Alaska, Anchorage, as presented in its publication, "Economic and Demographic Projections for Southern Railbelt Electric Utilities," October 1987. ISER uses an econometric model to project key economic variables that are used for the electric forecast. ISER portrays a range of economic scenarios about the future course of the Anchorage and Alaskan economies.

For national economic trends, ISER forecasts assume consumer prices will rise at an annual rate of 5.4% in 1988 and 1989, 6.3% through 1994, 6.6% through 2000, and 6.8% thereafter. Growth in real average weekly earnings averages 1% annually. Growth in real per capita income averages 1.5% per year. The long run unemployment rate is estimated at 6.5%.

ISER expects the current Alaska recession to bottom out sometime in the 1990's, depending on whether low, medium, or high economic growth is assumed. In the low case, Anchorage non-agricultural employment is projected to drop to 95,055 in 1992 from the 1987 level of 98,100. The base case assumes employment in the Municipality will rise slightly to 99,168 in 1989. The high case assumes employment growth in 1989 to 99,896. Population, income, and other variables follow similar patterns, depending on the scenario for future growth.

The treatment of oil and gas prices is particularly difficult. If oil and gas prices are artificially high, then governmental economic activity in Alaska due to tax revenues will stimulate the use of electric energy in Anchorage. But similarly, costs of fuel at ML&P will be high, tending to raise electric rates and depressing the use of electricity in certain load segments. These combined effects in both loads and fuel prices impact avoided energy costs that ML&P faces.

World oil prices are projected by ISER in the low scenario to fall in real (1988) dollars, from an estimated $18 per barrel in 1988 by 1% per year through the 1990's. The base case foresees a 0.5% per year rise in oil prices. The high case envisages a rise to $21 per barrel in real terms by 1990 and a 2% annual increase thereafter.

Summary of Load Forecast Results

The medium and the high load forecasts were analyzed to determine avoided costs for ML&P. For the reasons discussed in Section III, the medium forecast represents the most probable estimate of the future and hence is the basis for developing ML&P's "avoided cost" annual formulas. The high forecast represents the case where energy costs are the highest and the need for additional capacity is the greatest. This forecast was used as the basis for a sensitivity analysis comparison.

The medium or mid-range forecast shows total annual ML&P energy requirements growing from about 830 GWh in 1988 to over 1112 GWh in 2010. Compound annual average growth rates for the mid-range forecast are 0.3% from 1987-1992; 1.0% from 1992-1997; and 1.8% from 1997-2010. Peak demand grows at comparable rates from 142 MW in 1988 to over 190 MW in 2010.

The high forecast projects total ML&P annual energy requirements growing from about 832 GWh in 1988 to over 1198 GWh in 2010. Compound annual average growth rates for the high-range forecast are 0.7% from 1987-1992; 1.7% from 1992-1997; and 2.0% from 1997-2010. Peak demand grows at comparable rates from 142 MW in 1988 to over 205 MW in 2010.

II. SYSTEM PLANNING APPROACH TO AVOIDED COST CALCULATIONS

General Approach

The method used to calculate avoided costs for ML&P was a two step process. First, computer models were used to simulate the generation costs for the ML&P system on an annual basis over the study horizon. As inputs to the computer models, economic and load data consistent with the medium forecast were used. Next, an assumed QF was forced into the resource generation dispatch stack for the years in question. The assumed QF was assigned no generation costs. The difference in total costs (capacity and energy) between the generation dispatch without the QF and with the QF then determined the annual avoided costs. The avoided costs were categorized into avoided energy and avoided capacity costs. This method produces a forecast of the cost to be avoided by inclusion of the QF within ML&P's generation mix.

Because the ML&P system does not require under current forecast loads and contract reserve margins any additional generation capacity until about 2015, the inclusion of a QF results only in avoided energy costs then. It is not until added generation capacity is required that avoided capacity costs are credited to the QF.

To provide independent verification of the modeling effort two comparisons were made. First, the results were carefully compared to current operational patterns of the ML&P system. Second, the results were compared to a medium term generation dispatch computer model used by the utility. Both comparisons confirmed the modeling results.

System Planning Approach as Viewed by Other Jurisdictions

The objective of the system planning or "differential revenue requirement" approach used by ML&P is to reflect anticipated system costs as precisely as possible in the avoided cost calculation. The system planning approach provides a higher degree of accuracy in determining avoidable costs than a "surrogate plant" or other approach can provide. This higher degree of accuracy is provided by examining a given utility's system closely. This allows the utility to determine with some precision at what point the utility will add a resource, what type of resource it will be, what the costs and generation characteristics the new resource will be, and what the cost differences would be for a QF alternative to the new resource.

Because the system planning approach most accurately calculates the costs that a utility can expect to avoid by purchasing power from a QF, it is accepted by the FERC (Preamble to 18 CFR Part 292, FERC Regulations Preambles 1977-1981, ¶30, 128 at p.30, 866) and best accomplishes the widely recognized goals of PURPA's avoided cost standard. That standard is designed to leave ratepayers indifferent as to whether their electric utility obtains power from its own resources or from a QF.

Why the Westinghouse Model was Chosen

The Westinghouse Generation Planning (WIGPLAN) computer model was used to perform the computer simulation. The WIGPLAN model is widely used in the electric utility industry and is one of the major planning models used to evaluate the needs for new generation. This model was previously used to analyze ML&P's generation needs and those of other electric utilities.

The prime reasons for the choice of this computer model were that: (1) it allows for long term (30-year) simulations; (2) through the Probabilistic Production Costing (PPC) module it can handle certain spinning reserve requirements and maintenance scheduling; and (3) the model's generation expansion section chooses the most cost-effective future resource to add for a particular utility's load characteristics. This capability includes analyzing the trade-offs between machines of varying efficiency, capital costs and fuel costs.

There are other advantages to the Westinghouse model. It will perform an economic dispatch of available units to simulate lowest cost operation that a utility would realize and it is able to evaluate resources whose heat rates vary as a function of generation level. This feature is important in the ML&P modeling since, if a QF facility is particularly large, it can force combined cycle units to operate in a simple cycle mode and require multiple machines to be operated below their most efficient load levels so that they can provide necessary spinning reserves.

One difficulty encountered in modeling the ML&P system was the inability of WIGPLAN to accurately commit resources in the dispatch simulation due to specific minimum loading and spinning reserve constraints.

This was resolved using a custom Lotus 1-2-3 spreadsheet program which defined the ability to commit the various combined cycle/ simple cycle combustion turbine (CT) options. The Lotus model analyzed whether certain units could be operated due to minimum generation and/or spinning reserve requirements for typical low and high load days by season and by year over the forecast period. This information was then fed into the Westinghouse model to determine optimal dispatch and hence the appropriate cost of energy and capacity for ML&P.

Proper Planning Horizon

To compute avoided costs it was necessary to determine the proper planning horizon. The Westinghouse program is capable of a 30-year planning horizon and the Load Forecast comes on approximate 20-year time horizon from 1988 to 2010. ML&P's last generation planning study covered a 10-year period.

Most load forecasts for electric utilities extend only 20 years. Many utilities regularly forecast on only a 5- to 10-year basis. The reason for this shorter horizon is that economic data projections can become very speculative after about 10 years. Population projections, which are a prime driver of load forecasts, tend to become highly speculative after 10 to 20 years due to the effects of migration and changes in fertility and mortality rates for various age groups.

The last ML&P generation study entitled <u>10-Year System Planning Study</u>, performed in July of 1985, adopted a 10-year planning horizon. A determination of the proper planning horizon should not be determined by amount of data available. A 30-year modeling study was performed to extend the study out far enough until there was a need for the next increment of capacity.

The most significant factors supporting a limited planning horizon are the volatility and impact of world oil prices on the Alaskan economy. Because of these factors, avoided costs have been calculated in a way which removes the risk of changes in oil prices and inflation rates from ratepayers. This can be approximated by the adoption of an avoided cost rate formula rather than an explicit avoided cost rate. The "heat rate" formula used to calculate an avoided energy rate is based on fuel costs at the time they are incurred. Fuel costs are determined monthly and based on the actual average cost of natural gas purchased by ML&P.

Similarly, because of the uncertainty associated with long-term purchase commitments, avoided capacity rates should not be locked in more than 20 years in advance of need by a utility. In addition to uncertainties about load growth, population growth and fuel prices, technological improvements are occurring in the CT generation manufacturing business. The lag time between introduction of technological changes in the aircraft industry and implementation of those changes in the power industry is around 10 years. Therefore, future advances in technology could significantly reduce avoided capacity costs 20 to 25 years hence.

Based on these considerations, the proper planning horizon for current ML&P avoided cost commitments has been identified as 10 to 20 years. While much can be done to minimize the nature of the speculation, technologies and industrial relationships can change dramatically in a twenty year time-frame.

Planning Horizon Considerations by Regulatory Agencies

The question of a proper avoided cost planning period has recently been addressed by several state commissions. The Idaho Commission issued Order No. 22636 on July 27, 1989 in Case No. U-1500-170, a generic proceeding on PURPA implementation. It reaffirmed the limitation of QF contracts to 20 year duration because of the types of uncertainties identified above (Order at p.77)

Similarly, the Oregon Public Utility Commission has found that avoided costs in PURPA contracts which looked reasonable less than ten years ago now appear to harm ratepayer interests. The California Energy Commission also has found that avoided cost rates projected out 20 years and levelized have created an over-commitment of QF resources that jeopardizes California utilities' ability to minimize costs to ratepayers through interference with economy energy transactions.

III. MAJOR MODELING ASSUMPTIONS AND DATA SOURCES

Consistency

Numerous assumptions were needed to model the generation resources. One primary goal was to provide a consistent set of assumptions. Specifically, the same fuel prices, inflation rates, and load levels used in the load forecast and forecast scenarios were incorporated in the WIGPLAN model.

Future Resource Options

The analysis was extended far enough in the future to evaluate imparts of new resources. This required an evaluation of resources alternatives which might be selected to meet local requirements. The principal resource choices were coal fired and CT technologies. The resource options were placed in the WIGPLAN program and the program used its "look ahead" capability to choose the most cost effective new form of generation when required.

To analyze future costs of CT technology a literature search was conducted. Because this technology is advancing rapidly, a variety of organizations were contacted for information. Future estimates of heat rates (9,224 BTU/ kWh LHV and 10,300 BTU/kWh HHV) are based on Electric Power Research Institute (EPRI) information and projections as to the size of future CT's (200 MW). Based on ML&P's current plans, this would take the form of a joint venture with another utility.

EPRI, manufacturers and trade associations were reluctant to estimate future prices of expected CT technology. Therefore, an analysis of economies of scale found in the turbine manufacturing process was performed. This analysis, when combined with information about plant costs specific to Alaska, resulted in an installed 1988 capital cost of $177/kW. A separate report is included as an appendix to this testimony which documents this information.

Coal fired power plant capital costs and heat rates used in the WIGPLAN model were taken from the EPRI Technical Assessment Guide information. Capital costs are estimated at $3,000 per kW in 1988 dollars. The heat rate for the coal plant was assumed to be 12,460 BTU/kWh.

Plant Retirements

ML&P's two oldest CT units are assumed to be retired in the year 1992. Units 1 and 2 were installed in 1962 and 1964 respectively. Units 1 and 2 have individual maximum capacities of about of 16.2 MW. Anchorage ML&P's share of Bradley Lake was modeled at about 23.3 MW of capacity starting in 1992. Because the model rarely used units 1 & 2 after Bradley Lake became operational, these units were assumed to be retired to save fixed O&M costs. Units 1 & 2 provide ML&P with substantial flexibility. The actual status of Units 1 & 2 can range from retirement, whenever Bradley Lake goes on line, to repowering if a need for new capacity develops.

CT unit 3 was assumed to be retired in 1996. This CT was added to the ML&P system in 1968. CT unit 3 was modeled with a capacity of about 19.8 MW. It was assumed that this unit would be kept on line until Bradley Lake had achieved maturity and its operation had been fully integrated into the ML&P system.

The primary modeling reason for the retirement of all three units was that with the addition of Bradley Lake, the ML&P system has more capacity and energy than it currently needs. Because these three oldest and smallest units have the "worst" or highest heat rates, the probability of use or dispatch drops with the addition of Bradley Lake. Retiring the units, therefore, represents an opportunity to save fixed O&M costs.

ML&P's other CT's are modern units installed in the 1970's and the 1980's. These units are being well maintained. ML&P's standard operation calls for annual to semiannual inspections and major overhauls approximately every 3 years. At these overhauls ML&P performs both a full inspection and destructive testing on selected (1 blade per row) hot rotating blades. In this way, the CT's are constantly checked and parts are replaced and upgraded. This program on modern CT's should result in an extended life expectancy. ** [Therefore, no other retirements were assumed for the study period. All the way through 2017 → 1980→ 2017

37 years

Existing Resource Physical Parameters

With respect to individual resources, model parameters were based on actual data, where possible, not empirical or theoretical assumptions. The first assumptions made were on the resources to be included in the generation modeling effort. Heat Rates or efficiencies for the CTs that ML&P operates were taken from actual test data performed by ML&P. The fuel rate (y) in MCF/hr was converted to a fuel consumption formula:

$$y = A + B\,(MW) + C\,(MW)^2 .$$

The coefficients for A, B, & C are shown in Table 1. Minimum and maximum generation output of the CTs was based on actual experience levels. Combined cycle units are committed to minimum operation of a full day, consistent with ML&P generation dispatch practices. This prevents unnecessary cycling and stress on the combined cycle units.

Similarly, O&M expenses were calculated from historic ML&P data, as were forced outage rates and maintenance requirements. Table 2 and Table 3 provide key physical parameters for the various CTs and hydro projects. These parameters were used as an input in the modeling effort.

Table 1
Resource Fuel & O&M Costs

	Fuel Consumption			O&M	
Unit	"A" MCF	"B" MCF/MW	"C" MCF/MW^2	Fixed $/kW	Var $/MWH
CT1	79	9.16	0.0476	10.41	6.75
CT2	76	8.50	0.0933	10.41	6.75
CT3	80	9.19	0.2310	10.41	6.75
CT4	160	7.83	0.0289	10.41	6.75
CT5	160	8.51	0.0159	12.27	0.81
CT7	160	9.60	0.0012	11.93	0.81
CT8	215	7.65	0.0196	9.54	0.81
CC5+6	168	6.74	0.0026	9.54	0.81
CC6+7	199	5.93	0.0080	9.54	0.81
Eklutna		(Hydro)		0.00	19.00
Bradley		(Hydro)		0.00	7.00

Table 2
Physical Resource Parameters

Unit	Year Added	Min (MW)	Summer Max (MW)	Winter Max (MW)	Forced Outage Rate %	Maint wks/ year
CT1	1962	5.0	14.0	16.2	21.4	8
CT2	1964	5.0	14.0	16.2	21.4	8
CT3	1968	5.0	17.7	19.8	21.4	8
CT4	1972	5.0	31.1	31.4	21.4	8
CT5	1974	10.0	33.8	35.1	4	11.7
CT7	1981	10.0	74.4	74.3	4	6
CT8	1984	10.0	77.7	86.5	4	6
CC5+6	1978	25.0	42.8	45.1	2	12.4
CC6+7	1981	35.0	99.4	99.3	2	7.5
Eklutna	1953	0.0			5	4
Bradley	1992	0.0			5	4

Table 3
Energy from Hydro Resources

Month	Eklutna MWH/week	Bradley Lake MWH/week
1	1713	2389
2	1795	2618
3	1635	2002
4	1401	1625
5	1501	1715
6	1646	1707
7	1751	1681
8	1760	1626
9	1709	1613
10	1754	2002
11	1810	2463
12	1935	2474

Installed reserve capacity requirements in the modeling are based on the formula established by contract among the interconnected Railbelt utilities. The contract requires that ML&P meet its annual system peak plus a minimum of a 30% reserve capacity requirement. The Alaska Intertie Agreement (Addendum No 1 Reserve Capacity and Operating Reserve Responsibility) was signed in December of 1985. The analysis assumes that additional generation

* is added when an ML&P reserve margin of 45% is reached. This provides a cushion in case abnormal weather or unexpected growth occurs so that generation can be added before the contract minimum is reached. The analysis also assumes that the Alaska Intertie Agreement remains in force for the study period.

Spinning reserves are also determined by the Intertie Agreement. ML&P spinning reserves are calculated by multiplying the largest unit of the total interconnected system times the largest ML&P unit on-line and then dividing that product by the sum of all interconnected utilities' largest units on-line. Historically, this spinning reserve requirement has worked out to average about 33% of total load for ML&P in the winter and about 41% in the summer.

The analysis also assumes that no economy energy sales or purchases occurred. In the interconnected Alaska power grid, economy energy sales are difficult to predict with certainty. In the past, sales have occurred at various quantities and prices. For the 20-year planning horizon, the Bradley Lake project will provide most of ML&P's traditional economy energy purchasers with energy having a low variable cost.

But allows cc to remain loaded.

Similarly, modest amounts of economy energy transactions would probably affect the "with" and "without" cogeneration scenarios equally. Modeling of other interconnected utilities with a multi-area model was beyond the scope of the studies supporting the proposed tariff and would require extensive data and forecasts from other utilities that probably are not available to ML&P. Furthermore, should economy energy sales dominate, the QF would probably contract directly with the buying utility because it would obtain the highest price.

Cogeneration Assumptions

For illustrative purposes to discuss the features of the tariff rates and the models, a number of assumptions were made about potential cogeneration resources. These assumptions were needed as inputs to the computer models. The analysis used a range of assumptions so that the tariff could provide avoided cost planning data to a broad range of QF developers.

The first major assumption was the size of a unit. Three examples, 10 MW, 25 MW and 50 MW, were used to quantify the impacts of alternate sizes. A 50 MW cogeneration unit was considered the upper limit. At 50 MW there were a number of minimum load and potential reserve problems that could occur on the ML&P system. A 50 MW or larger unit would need to have a variety of special scheduling-related operational constraints. Cogeneration units outside of the 100 kW to 50 MW range will require special analysis to calculate the appropriate annual coefficients to be used in determining avoided costs.

The sample analysis assumes that the cogeneration QF would come on-line in 1992. To test how the on-line date affects the avoided costs of ML&P, a scenario analysis using a 1998 on-line date was performed.

The cogeneration unit was also assumed to have a plant factor of 80% and would be capable of operating all year long except for a 30-day scheduled maintenance period. Every 5 years a 60-day maintenance period would be required. To test the plant factor assumption and create rates for other hypothetical facilities the plant factor of the QF was reduced to a 60% value.

To model these assumptions the QF unit's forced outage rate and scheduled usage below full output when capable are needed. It was also assumed that the unit would be at full production whenever possible. Accordingly, it was determined that the forced outage rate would be 6.58% for the 80% plant factor scenario.

Assumes when on on full? Lumped it into FOR

Using the 60% plant factor, while continuing to assume full production scheduling and minimal maintenance periods, results in a 26.58% forced outage rate. Although longer maintenance periods and a lower forced outage rate could have been chosen, the main purpose was to analyze sensitivity of avoided costs to the plant factor.

Maint is scheduled, & FOR is random, penalize plant.

It also assumed that the QF was within the Anchorage ML&P service area and, therefore, that the power delivered should not be reduced for transmission losses. These assumptions were used to develop a set of appropriate examples of avoided costs theoretically available to a resource developer. Actual rates will vary depending on the specific QF which is proposed.

Economic Factors

The principal economic factors used in the modeling were the fixed charge rate, a discount rate, A&G costs, and forecasts of fuel costs, inflation, CT capital inflation, and costs of energy not served.

A fixed charge rate of 18% was assumed. This fixed charge rate is based upon the Chugach/ML&P Unit 8 CT contract.

A discount rate of 9.92% was used in the calculations. This was the average cost of capital used in ML&P's most recent rate case.

Administrative and General (A&G) costs were not included in the avoided cost calculation because they are not avoided by a purchase from a QF. In fact, complexities associated with administering a large QF contract could result in higher A&G expenses. Therefore, inclusion of A&G expenses in the forecast avoided costs would be inappropriate.

A fuel forecast was also required as an input into the modeling programs and in the calculation of the tariff avoided cost coefficients, even though the tariff is based upon actual natural gas prices that occur in the future. The fuel forecast used is based on data derived from ISER and used in the load forecast.

Because oil and natural gas prices have a large impact on state tax revenues and economic activity as well as on the costs to the utility, a consistent set of assumptions was required. An element of the analysis was to calculate one set of avoided costs based on a "high" economic activity scenario. This high scenario contained high gas or fuel prices for ML&P. The fuel price data used in the analysis are contained within (Table 20 of Appendix A) of the attached load forecast document.

ML&P's avoided costs are highly dependent upon the future price of natural gas. Because of this dependance on actual prices it was necessary to review the ISER natural gas price forecast by comparison to another Alaska natural gas price forecast. As discussed elsewhere, ISER gas prices are used for purposes of forecasting loads and calculating avoided costs. The avoided costs are then adjusted to remove the ISER-based natural gas price, so that the final avoided cost rate formula uses ML&P's actual price of natural gas.

To review the ISER-based fuel cost forecasts used in the analysis, they were compared to gas prices calculated by the Alaska Power Authority in August of 1988. The mid-level gas forecast is a little bit lower from the 1993 to 2003 than the latest APA mid-range gas forecast. The high ISER-based gas forecast is just above the high APA forecast, and the low ISER-based gas forecast is just below the APA low gas forecast. Therefore, the range of analysis is close to and slightly broader than the APA gas forecast range. This independently confirms the range of gas price values used in the computer modeling.

Another computer data requirement is the rate of inflation. Just as the tariff uses actual natural gas prices rather than forecast values, it will use actual rates of inflation. The inflation forecast used in the computer modeling is consistent with the inflation forecast contained in the attached Load Forecast (Table 16 of Appendix A of the attached Load Forecast document.) This inflation forecast was also used to inflate CT capital costs. The analysis that discusses the use of a general inflation rate to escalate future CT capital costs is found in the attached report on CT technology.

The "cost of energy not served" is a method by which the WIGPLAN model calculates energy not available to meet load due to the probabilistic nature of forced outages and then evaluates this energy cost. It was assumed that ML&P could buy the extra energy from Chugach Electric Association at an existing contractual rate tied to the price of natural gas. In practice ML&P could either utilize this rate, make purchases in the economy energy market, borrow energy from another utility to be returned at a later date, or utilize its hydro storage contract options.

An approach was chosen that assumed the needed power would be purchased at the relatively high Chugach contract rate and overstates the value of energy not served which includes the avoided costs. The Chugach rate appears in the Chugach Electric Association Emergency Power Rate Schedule for Intertie with ML&P. The rate schedule includes a basic cost of 51.9 mills/kWh and a surcharge based on a percentage increase in current natural gas prices over a price of $1.6777/MCF applied to a reference price of 34.3 mills/kWh. This rate was estimated using the natural gas price forecast found in the Load Forecast and was applied to both the "with" and "without" computer simulations.

Combined Cycle Availability and Commitment Model

A Lotus 1-2-3 computer model was created to determine for each season of each year which resources could be committed to load and scheduled consistent with economic dispatch, spinning reserve, and unit operation limitations. Typical high and low seasonal daily load shapes were analyzed. The results of the analysis provided the years and seasons in which ML&P's newer units could be operated in either combined or simple cycle mode without violating certain constraints. The principal constraints were: 1) economic dispatch; 2) combined cycle units must be run a full 24 hours, not cycled on and off daily; 3) the contract hydro resources must be fully utilized; 4) contract spinning reserve requirements must be met for all hours of operation; and, 5) when the cogeneration QF is operational its energy must be used in the ML&P system.

The resulting information on which units could be run at which times was used as input into the Westinghouse WIGPLAN model. Therefore, the combined cycle availability and commitment model and the spinning reserve model was run for each sensitivity case.

The results of this model were carefully compared to current operational patterns of the ML&P system and to medium term generation dispatch models used by the utility. This provided an independent verification of the model results, and an assessment of the limitations of the Lotus 1-2-3 model results as an input to the WIGPLAN program. The model results compared well to current practice and the medium-term generation dispatch model.

Verification of the Modeling Effort

To verify the WIGPLAN model results, two methods of cross checking were utilized. First, the WIGPLAN results were checked against recent historic data on fuel costs and hours of generation by machine. The WIGPLAN results agreed with the 1988 historical values. Second, ML&P staff choose a future year (1992) and independently calculated the generation costs and unit operation hours using a different computer program, the Powersym Plus model. This computer model is used by ML&P for analysis of optimal scheduling of its resources. The independent calculation of 1992 conditions with the use of this model confirmed the accuracy of the WIGPLAN results.

IV. RESULTS OF MODELING AVOIDED COSTS

Overview of Results

To determine an example of the avoided costs of ML&P for a specific QF, the results of two WIGPLAN computer modeling runs were subtracted. The best estimate of the costs ML&P would avoid by a firm power purchase from a 50MW, 80% plant factor, QF added in 1992 are detailed in Table 4.

The avoided costs are categorized as avoided capacity and avoided energy costs. There are no avoided capacity benefits until the year 2015, over two decades after the QF is assumed to be added.

Similarly, avoided energy benefits are relatively low because including the QF in ML&P's resource stack creates inefficiencies. Specifically, without the QF, ML&P can utilize its extremely fuel efficient combined cycle plants (units 5/6 and 6/7.) With a 50MW QF, the combined cycle plants would be shut down because of minimum load and cycling or operating requirements on combined cycle operation. This would force ML&P to use less fuel efficient units (i.e., higher heat rate units) to serve customers' needs above those met by the QF.

But economy E solves this & dispatching.

Formula Results

Table 4 presents the formula coefficients for the analysis of a 50MW, 80% plant factor, 1992 firm power QF. Tables 5 through 8 contain formula coefficients for the other sample facilities quantified in the scenario analysis.

This formula representation of avoided costs in constant 1988 dollars is the most appropriate way to calculate avoided costs. Use of the formula makes the avoided costs of ML&P accurately reflect inflation, fuel prices and amounts of energy produced by a QF. The formula makes the avoided costs less dependent on future uncertainty. In this way the risks of speculation associated with inflation and natural gas prices are not forced upon the ratepayers of ML&P.

Tables 4 through 8 contain columns labaled "A" and "B". These columns represent annual coefficients used in the sample energy avoided cost formulas. The "A" coefficient or term relates to fuel. It is determined by taking the difference in fuel costs and energy not served costs between the "with" and "without" cogeneration computer runs, then dividing that difference by the cogenerated energy and then dividing by the current fuel price. The "B" term is the difference in variable O&M costs between the "with" and "without" cogeneration computer runs, then divided by the cogenerated energy and then divided by the amount of inflation since 1988. The formula for calculating avoided energy costs from Tables 4 through 8 is of the form:

Energy Rate ($/MWh)= (Nat. Gas P * A) + (B * O&M Inflation)

To determine the monthly capacity cost coefficient, the difference in annual capital costs and the difference in annual fixed O&M costs between the "with" and "without" cogeneration computer runs was first determined. Those differences were then divided by 12 months and by the size of the QF unit. Capacity costs can be calculated as:

Avoided capacity Rate ($/kW-Month) = Monthly Capacity Cost Coefficient * Inflation from 1988

Sensitivity Analysis Results

To supplement the example found in Table 4 and present a range of information on avoidable costs potentially available to a QF developer, some of the major QF assumptions were tested for sensitivity. It was necessary to evaluate the impact of QF size, commercial operation date and plant factor. It was also necessary to evaluate the impact of a "high economic" activity and hence a "high load" scenario on ML&P's avoided costs. This section of the report reviews the distinct scenarios and discusses the corresponding Tables of coefficients created from the computer models.

The first sensitivity analysis involved reducing the plant factor of the QF from 80% to 60%. The annual avoided capacity and energy formula coefficient results of this analysis are found in Table 5.

The second sensitivity analysis was to extended the QF commercial operation date from 1992 to 1998. These results are found in Table 6. It should be noted that the values are identical to those of the case presented in Table 4 except for the years between 1992 and 1997.

The third sensitivity analysis was to reduce the size of the QF from 50MW to 25MW. A fourth further reduced the size to 10MW. The results of these two analyses of size are contained in Table 7.

The fifth and final sensitivity analysis calculated ML&P's avoided costs under a "high economic" activity scenario. The results are contained in Table 8.

Conclusions from Modeling

It is clear from all of the scenario analyses that ML&P does not need additional capacity at this time. Therefore, there are no avoided capacity costs for the immediate future. The avoided energy costs also demonstrate that a 50MW cogeneration facility would cause inefficiency in ML&P's operation.

The sensitivity analysis shows that avoided costs are a function of the QF unit's size and plant factor. The avoided costs are also a function of ML&P's loads, future inflation and future gas prices. Because these factors affect avoided costs, rates paid to a QF should reflect as many of these factors as possible.

Avoided Capacity Rates

Because capacity is not needed on the ML&P system before the year 2015, entering a contract that requires payment of an avoided capacity rate at this time is inappropriate. There are three reasons why contracting to pay an avoided capacity rate would place an unfair risk on ML&P's ratepayers.

First, a contractual capacity rate would be zero until the year 2015 because no capacity costs could be avoided until then. Due to the level of uncertainty about load, resource and cost projections, a 20-year term is the maximum appropriate length for a contract. Therefore, a 20-year contract would set the avoided capacity rate at zero for the life of the contract. A non-zero capacity rate could be established only if the contract exceeded 25 years.

Second, the technology of CTs is changing. Based upon existing information the capacity cost of the next generation of CT technology was extrapolated. However, before the year 2015 more than one generation of improvement in CT technology could occur, probably lowering ML&P's avoided capacity costs more than modeled. Therefore, to establish contract avoided capacity costs now would limit the ability of ML&P's ratepayers to recognize the financial benefits of technological change.

Finally, an avoided capacity rate is also inappropriate at this time because ML&P does not need capacity. Utility regulation and rates should promote economic principles. To set a rate that encourages the development of additional capacity when it is not needed is an inappropriate use of funds and economic resources.

Even though it is inappropriate to contractually establish an avoided capacity rate at this time, it is appropriate to discuss how such a rate might be determined and when. ML&P proposes to use a methodology similar to that described in this document to determine avoided capacity cost coefficients. These cost coefficients would then be used as the basis for a contract capacity rate in terms of $/kW-month of firm capacity.

As a normal part of ML&P's planning process, it reviews its needs for future capacity. In the future, ML&P will update this avoided cost filing as appropriate to calculate avoided capacity cost coefficients, and propose avoided capacity rates for firm power QFs.

Avoided Energy Rates

ML&P's avoided energy rates are based upon the coefficients in the previous section. These coefficients are representative of, or examples calculated to simulate, certain specific QF characteristics. The avoided energy cost coefficients in Tables 4 through 7 can be used to calculate a spectrum of avoided energy rates. The purpose of the methodology proposed and this explanation is to provide a set of avoided energy rates that may assist in the decision making process for a variety of prospective QF developers.

To qualify for these particular avoided energy rates, a QF must meet the operational and size parameters associated with the computer model assumptions that created Tables 4 through 7. QFs with different characteristics probably will not qualify for the particular avoided energy costs presented. Such QFs will require an individualized analysis of the effects on the ML&P system and hence different avoided energy costs. The model is available for developing the specific coefficients.

Under a formula approach, avoided energy rates are more predictable than avoided capacity rates because energy rates are principally based on heat rates of existing CTs. A formula rate which takes account of actual natural gas prices, inflation, and the firm energy generated by a QF is the most appropriate method of setting avoided energy rates. Such a rate is neutral from the ratepayers' perspective toward these factors and has a higher probability of accurately representing ML&P's actual avoided energy costs at the time the power is delivered. However, prior to defining the avoided energy rate, the methods of determining natural gas prices and inflation rates must be defined.

ML&P currently purchases all of its natural gas from ENSTAR. It is proposed that ML&P calculate its average price of natural gas purchased on a monthly basis for use in its CTs. This method of calculating natural gas prices would allow ML&P to incorporate the average actual gas cost for each month in its avoided energy cost payments to a QF for that month.

The impact of inflation on avoided energy costs goes beyond fuel price changes. Inflation also affects ML&P's variable O&M costs. Therefore, as a proxy for variable O&M inflation, the ratio of the most recent Anchorage CPI to the 1988 annual Anchorage CPI should be used to adjust the "B" term (the variable O&M component.) Because the O&M component of avoided costs is relatively small compared to the fuel-related component, or the "A" term, no "true up" to account for the lag between when the CPI is available and the period it covers is proposed. Using the Anchorage CPI or its successor as the proxy for variable O&M inflation is administratively convenient. The CPI is widely applied and independently calculated.

The following sample calculation of an avoided energy rate for a firm power QF is a function of many QF operating assumptions. With the coefficients found in Table 4, the principal assumptions are 1) that the QF is a 50MW unit, with an 80% plant factor, with commercial operation in 1992, and 2) that the QF delivers firm energy directly to ML&P's transmission grid without significant losses. For such a QF, ML&P would pay on a monthly basis for energy generated using the following avoided energy rate formula:

Energy Rate (\$/MWh)= (Nat. Gas P * A) + (B * O&M Inflation)

where: Nat. Gas P, is ML&P's average price (\$/MCF) of natural gas purchased for use in its CTs calculated on a monthly basis.

O&M Inflation, is the most recently released monthly Anchorage Alaska CPI divided by the 1988 annual Anchorage CPI.

A and B are the annual fuel efficiency (MCF/MWh) and variable O&M, (\$/MWh) avoided energy coefficients found in Table 4.

Estimating the Avoided Cost for a Cogeneration Plant Not Simulated

Visual comparison of the A and B coefficients from one table to the next indicates that the avoided costs do not vary linearly as the size of the cogeneration plant changes. The actual coefficients to be included in a contract will be determined by re-running the computer model using the specific cogenerator parameters. This computer simulation would cost about \$2,500. To determine the economic feasibility of a cogeneration project which is smaller than 50 MW, the avoided cost payments to a cogenerator should be estimated using the following method.

The A and B coefficients are looked up in the tables (Attachment 2) for the next larger and smaller cogenerator capacities from the desired cogenerator size (*i.e.*, look up 25 and 50 MW for proposed 40 MW cogenerator. For each year the A coefficient is multiplied by the annual energy output of the smaller, simulated cogenerator to produce the avoided gas purchase by ML&P. For each year the B coefficient is multiplied by the annual energy output of the smaller, simulated cogenerator to produce the avoided variable O&M cost in 1988 dollars. Similarly, the avoided gas purchases and avoided variable O&M costs are determined for the larger, simulated cogenerator. The avoided gas purchases and avoided variable O&M costs are translated into yearly payments to the simulated cogenerators using either the fuel price escalation and CPI inflation rates used in the computer model or supplied by the proposed cogenerator. Then the payments to the proposed cogenerator can be interpolated to give an estimate of the avoided cost payments. Since the change is not linear with cogenerator capacity, the interpolation is only an estimate with the simulated curves on either side providing an absolute bound on the avoided cost payments. The following graph represents a three dimensional picture of the avoided cost payments as a function of capacity assuming no increase in fuel prices and no inflation.

V. CONCLUSION

For the reasons stated in this document ML&P adopts the avoided cost rates described in this "Explanation and Support" document as reasonable and conformance with applicable requirements of PURPA.

Table 4
Sample Avoided Cost Coefficients
for a 50MW QF with a 1992 start date
and an 80% Plant Factor

Year	Avoided Capacity Cost ($/KW-month) (1988 $)	Avoided Energy Costs A (mcf/MWh)	Avoided Energy Costs B ($/MWh) (1988 $)
1992	0.0000	7.4603	0.8480
1993	0.0000	7.2817	0.8437
1994	0.0000	7.1025	0.8476
1995	0.0000	6.9340	0.8482
1996	0.0000	6.8393	0.8496
1997	0.0000	6.7616	0.8408
1998	0.0000	9.8255	0.8421
1999	0.0000	9.8468	0.8435
2000	0.0000	9.8335	0.8447
2001	0.0000	9.8336	0.8468
2002	0.0000	9.8149	0.8485
2003	0.0000	9.8094	0.8507
2004	0.0000	9.8068	0.8532
2005	0.0000	9.7058	0.8538
2006	0.0000	9.6950	0.8586
2007	0.0000	9.8030	0.8707
2008	0.0000	9.8796	0.8821
2009	0.0000	10.2799	0.9181
2010	0.0000	10.4907	0.9270
2011	0.0000	10.4910	0.9348
2012	0.0000	10.2872	0.9392
2013	0.0000	9.9848	0.9388
2014	0.0000	10.6250	0.9401
2015	6.9019	11.4226	0.7583
2016	6.5964	11.3624	0.7525
2017	6.3094	11.2449	0.7449

Sample calculation for 1995

assumed average monthly ML&P natural gas price = $3.1568/MCF
assumed 1995 CPI = 441.8, 1988 CPI = 299.8
Avoided Energy = ($3.1568 * 6.9340) + ($0.8482*441.8/299.8)
= 23.14 mills/kWh (in 1995 $)
Avoided Capacity = ($0.00 * 441.8/299.8)
0.00 $/kW-month (in 1995 $)

Sample calculation for 2015

assumed average monthly ML&P natural gas price = $11.7872/MCF
assumed 2015 CPI = 1492.8 1988 CPI = 299.8
Avoided Energy = ($11.7872 * 11.4226) + ($0.7583*1492.8/299.8)
= 138.42 mills/kWh (in 2015 $)
Avoided Capacity = ($ 6.9019 * 1492.8/299.8)
= 34.37 $/kW-month (in 2015 $)

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1901-0286
Expires 7/31/90

PROCEDURES MANUAL FOR COMPLETING THE VOLUNTARY COORDINATED REGIONAL BULK POWER SUPPLY PROGRAM REPORT
(IE-411)

This report, which continues the annual series of reports initiated in 1970 under FPC Order 383-2, is voluntary under P.L. 66-280, the Federal Power Act, P.L. 95-91, the Department of Energy Organization Act, and P.L. 93-275, the Federal Energy Administration Act of 1974.

The information collected by this report is not regarded as confidential and will not be treated as such.

U.S. Department of Energy
Assistant Secretary
for International Affairs
and Energy Emergencies
Office of Deputy Assistant Secretary
for Energy Emergencies

Item 3-A Revised 9-88
IE-411 (9-87)

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES & REMOVALS

In this item, report all generating capacity installations, removals, and equipment upratings and deratings projected for the 10 year period after the beginning of the reporting calendar year. For hydro units state the basis of the reported capacity (adverse hydro, average hydro or other).

This data shall be listed in a single composite table for the Council, or for each Reporting Party identified in this report. The capacity changes should be grouped according to the calendar year in which they are projected to occur.

Use the same method of reporting joint ownership as in Item 2-A.

To facilitate reporting, the following abbreviations are to be used:

Column 01:	Identify each utility by the same 4 character letter codes used in Item 2-A.
Column 03:	Give the location of each generating station. Use FIPS state and county codes as in Item 2-A.
Column 04:	Identify the type of unit using the same code as Item 2-A.
Columns 05 & 06:	Net capacity expected under normal conditions for the season shown, when using the primary fuel.
Columns 07 & 09:	Identify the type of fuel using the same codes as in Item 2-A.
Columns 08 & 10:	Identify the principal methods of transporting fuel to the plant site using the same codes as in Item 2-A.
Column 11:	Show the month or season and year that the unit is projected to be included, removed, or rerated as a normal operating resource.
Column 12:	Indicate footnotes as necessary.

Column 13: Show the status of projected changes as follows:

P	Planned for installation but not utility-authorized.
L	Regulatory approval pending. Not under construction.
T	Regulatory approval received but not under construction.
U	Under construction, less than approximately 50% completed.
V	Under construction, more than approximately 50% completed.
A	Generating unit capability increased (rerated or relicensed).
D	Generating unit capability decreased (rerated or relicensed).
M	Generating unit put in deactivated shutdown status.
S	Generating unit returned to service from deactivated shutdown status.
R	Generating unit permanently removed from any service.
X	None of the above. See footnote referred to in Column 12. If a lengthy explanation is needed use Item 7 in addition to the footnote.

Department of Energy Form EB-411
ITEM 2B

Station Name	Net Capacity - MW (2)			Primary Fuel		Alternate Fuel				
	Unit Type	Summer 60 F	Winter 30 F	Fuel Type	Trans Method	Fuel Type	Trans Method	Effective Date	Notes	Status
Beluga 4	gt	8.1	8.7	ng	pl	na	na	6 / 1994		r
IGT 1	gt	13.8	15.1	ng	pl	oil	tk	6 / 1996		r
IGT 2	gt	13.8	15.1	ng	pl	oil	tk	6 / 1997		r
IGT 3	gt	16.7	18.5	ng	pl	oil	tk	6 / 1998		r
IGT 4	gt	24.5	27.5	ng	pl	oil	tk	6 / 1995	4 moved	p
Bernice 4	gt	24.5	27.5	ng	pl	oil	tk	6 / 1994	4 moved	r
Bernice 1	gt	7.7	7.8	ng	pl	oil	tk	6 / 1992		r

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C [illegible]

COUNCIL________________

REPORTING PARTY________________

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System	Station Name/Unit No.	Loc.	Unit Type
01	02	03	04

Net Capacity-MW Summer/	Winter	Primary Fuel Fuel Type	Primary Fuel Transp. Method	Alternate Fuel Fuel Type	Alternate Fuel Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13

Chugach Electric
ASSOCIATION, INC.

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ALASKA ENERGY AUTHORITY

CEA Form 514

Chugach Electric Association Inc.
5601 Minnesota Drive
P.O. Box 196300
Anchorage, Alaska 99519-6300
(907) 563-7494

VIA COURIER

Letter Of Transmittal

To: Alaska Energy Authority
701 East Tudor Road
Anchorage, Alaska

Date: 12/13/89

Job No:

Attn: Penny L. Haldane

Re: Request of 11/15/89 Independent Reliability Assessment on the Railbelt

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COUNCIL ASCC

REPORTING PARTY MLP

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System 01	Station Name/Unit No. 02	Loc. 03	Unit Type 04
AMLP	Plant 1		
	Plant 2		

Net Capacity-MW Summer	Net Capacity-MW Winter	Primary Fuel: Fuel Type	Primary Fuel: Transp. Method	Alternate Fuel: Fuel Type	Alternate Fuel: Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13
							NO changes	
							No change	

See RAS -02

COUNCIL ____________

REPORTING PARTY GVEA

ITEM [illegible]

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System	Station Name/Unit No.	Loc.	Unit Type
01	02	03	04
GVEA	NORTH Pole 03	NP	GT

Net Capacity-MW Summer	Net Capacity-MW Winter	Primary Fuel: Fuel Type	Primary Fuel: Transp. Method	Alternate Fuel: Fuel Type	Alternate Fuel: Transp. Method	Effective Date	Notes	Status
05	06	07	08	09	10	11	12	13
20	~~25~~ 24	FO4	PL	FO2	PL	1991		(X) PRESENTLY NEGOTIATED PURCHASE.

12/13 GVEA

COUNCIL ____________

REPORTING PARTY FMUS

ITEM 2-B

FUTURE GENERATING CAPACITY INSTALLATIONS, CHANGES AND REMOVALS
(For the Ten-Year Period After the Beginning of the Reporting Calendar Year)

System 01	Station Name/Unit No. 02	Loc. 03	Unit Type 04
FMUS	CHENA #6		GT

Primary Fuel				Alternate Fuel				
Net Capacity-MW Summer/ Winter 05 / 06		Fuel Type 07	Transp. Method 08	Fuel Type 09	Transp. Method 10	Effective Date 11	Notes 12	Status 13
20	23.6	FO2	TR			1990		R. = removal

SEE RAS r02

it

.23 before 91

combustion turbine Oil { 0 after 91

Other activity 0 till 91 23 after 91

what is happening –

should there be 2 entries here ??

~~What about~~ ~~[illegible]~~

FMUS

ATTACHMENT C

Spinning Reserve Cost Calculations

A Review of "Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"

Funded by

Department of Commerce and Economic Development
Contract ASPS 90-028: Utility Consumer Representation

Prepared by

Alan Mitchell

Analysis North
911 W. 8th Avenue, Suite 204
Anchorage, AK 99501
907-272-3425

Report AN-90-1

February 14, 1990

fixed amount of gas must be burned per hour to turn the turbine even when no electricity is produced. As the loading on the turbine increases, this hourly "friction overhead" cost can be spread over more and more kWh produced, reducing the average fuel cost per kWh. Often, however, several units must be deliberately kept on at relatively low loading levels in order to provide spinning reserve. The *cost of spin*, then, is the difference between the low cost of providing *energy alone* from a few highly loaded turbines and the higher cost of providing *energy plus spin* from more turbines operating at lower loads. One can also think of the cost of spin as the cost of the extra "friction overhead" introduced by having more turbines spinning without any more kWh over which to spread these fixed costs.

The KA intertie allows the free spin from Bradley Lake to be available to the Anchorage load center. Economic benefit results from the substitution of this free spin for costly spin from Anchorage thermal units. DFI found that the present value of this benefit (after averaging across cases) is $8.9 million.

2.4.1 Quantified Errors

The Cost of Spin is Calculated Incorrectly

To calculate the benefits of using more free spin from Bradley Lake, one must estimate *how much spin* substitution can occur and *how costly* is the thermal spin displaced. We first dispute the derivation of the cost of the displaced spin from thermal units. We argue that the calculation *method* is wrong, not the input assumptions. We present the argument by first deriving a general formula for the cost of spin. We show how this formula produces the right answer when applied to a simple example presented by DFI in a report for the Railbelt utilities. We then discuss why DFI's formula for the cost of spin is wrong and verify that it produces the wrong answer when applied to the same simple example. Finally, we apply our formula to heat rate data for Railbelt thermal generation units to estimate the correct cost of spin and adjust accordingly the spinning reserve benefits that DFI attributes to a new Kenai-Anchorage intertie.

The Cost of Spin: a Simple Example

The principles behind the calculation of the cost of spin are best introduced by means of the following simple example, which is reproduced from page 6 of the DFI report "Value of Bradley Lake Spinning Reserves" (October 6, 1989), prepared for the Railbelt Utilities. This example prefaced their actual analysis of the cost of spin in the Railbelt. Suppose a system of five 100 MW thermal generators is running such that:

Total capacity of operating turbines:	500 MW
Total load on system:	- 400 MW
Available operating reserve (spin):	100 MW
Number of operating turbines:	5

Loading level (L) of each turbine: 80%, i.e. 80 MW
Average Heat Rate at L = 80% : 12,000 Btu/kWh
Incremental Heat Rate from 80% to 100%: 2,000 Btu/kWh
(this is the incremental rate implied by DFI's example but is very low for actual generation units)

Now suppose that 100 MW of free spin becomes available from a hydro unit. It is now possible to shut down one unit completely and still serve the 400 MW load by running the four remaining units at full load. The cost savings from this rearrangement are easily calculated:

Gas saved by shutting down one unit: 80 MW * 12 MBtu/MWh = 960 MBtu/hr
Gas used by additional loading on remaining 4 units: 4 * 20 MW * 2 MBtu/MWh = 160 MBtu/hr
Net gas savings from eliminating 100 MW thermal spin: 960 MBtu/hr - 160 MBtu/hr = 800 MBtu/hr
Net gas savings per unit of spin eliminated: (800 MBtu/hr)/(100 MW) = 8 MBtu/MWh = 8,000 Btu/kWh

The cost savings from reducing the spin in this example is amount of fuel savings that occurs by rearranging the system as described (800 MBtu/hr), divided by the spin reduction, 100 MW. The answer above, 8,000 Btu/kWh-spin, the same answer arrived at by DFI in their Bradley Lake spinning reserve report.

A General Expression for the Cost of Spin

Using this simple example as a pattern, it is possible to derive a general expression for the cost of spin. Define the following variables (values in parentheses are from the example above):

L = *The loading level in % of the generation unit turned off to reduce spin (0.8).*

U = *The size of generation unit being turned off to reduce spin (100,000 kW).*

A_L = *The average heat rate of the unit being turned off, for loading level L (12,000 Btu/kWh).*

M = *The incremental heat rate of the units that pick-up the generation loss caused by shutting off the unit (2,000 Btu/kWh).*

The amount of reduced spin in the system is U. The load on the system remains constant while U kW of generation is turned off. Therefore, the reduction in spin must be U.

(1) Reduced Spin = U

The change in gas use can be thought of as consisting of two components. First, shutting the unit off causes a reduction in gas use of:

$$(2)\ \textit{Reduced gas use because of shutting unit off} = U \times L \times A_L$$

However, the remaining units must make up for the lost generation:

$$(3)\ \textit{Increase in gas use because of loading up remaining units} = U \times L \times M$$

The net decrease in gas use is found by subtracting (3) from (2):

$$(4)\ \textit{Net Decrease in Gas Use} = U \times L \times A_L - U \times L \times M = U \times L \times (A_L - M)$$

The net gas decrease per unit of spin is derived by dividing (4) by (1):

$$(5)\ \textit{Gas Decrease per Unit of Spin Reduced (Btu/kWh-spin)} = L \times (A_L - M)$$

We can further verify the formula by applying it directly to the DFI example presented above. The turbine being shut-off is 80% loaded, and its heat rate at 80% loading is 12,000 Btu/kWh. The incremental heat rate of the rest of turbines that make-up for the lost generation is 2,000 Btu/kWh (this is the incremental heat rate implied by the figures in the example but is very low for real-world generation units). Applying our formula for the cost of spin:

$$\textit{Cost of Spin} = 0.80 \times (12{,}000\ \textit{Btu/kWh} - 2{,}000\ \textit{Btu/kWh})$$

$$\textit{Cost of Spin} = 8{,}000\ \textit{Btu/kWh-spin}$$

This formula for the cost of spin gives the correct answer in the example.

Why DFI's formula for the Cost of Spin is Incorrect

After completing the simple numeric example in the Bradley Lake spinning reserve report, DFI states on page 7 that cost of spinning reserves is:

$$\textit{Cost of Spin} = (A_L - M) \times \frac{P}{PMAX - P}$$

where,

P = *Power Output of Unit*
$PMAX$ = *Unit Size*

To express this formula using the variable names above, note that $P = U \times L$ and $PMAX = U$:

$$Cost\ of\ Spin = (A_L - M) \times \frac{L}{1 - L}$$

DFI does not apply this formula to their introductory example in the report. When it is applied to the example, it produces the incorrect answer of 40,000 Btu/kWh-spin, not the correct answer of 8,000 Btu/kWh-spin:

$$Cost\ of\ Spin = (12{,}000\ Btu/kWh - 2{,}000 Btu/kWh) \times \frac{0.8}{1 - 0.8} = 40{,}000\ Btu/kWh\text{-}spin$$

This formula also produces impossible results when turbines near full loading are analyzed. As L approaches 1, the cost of spin approaches infinity, according to this formula. This is clearly not correct.

DFI claimed at the 1/30/90 Review Meeting that they actually performed their analysis of the cost of spin in the Railbelt with a different, somewhat more general formula. We now show that the derivation of this formula is also incorrect. Also, the more general expression when applied to short period of time produces the $(A_L - M) \times L/(1-L)$ formula, which we have already shown to be incorrect.

DFI's more general expression is:

$$Fuel\ Use = \lambda \times (Energy\ kWh) + \mu \times (Spin\ kWh)$$

where,

λ = *Cost of Energy, Btu/kWh*
μ = *Cost of Spin, Btu/kWh-spin*

This expression is a simple statement that the total fuel cost during a particular period of time equals the cost of energy times the amount of energy generated plus the cost of spin times the amount of spin generated over that time period. The expression does not allow one to calculate the cost of spin over the time period unless some assumption is made for λ, the cost of energy.

In DFI's empirical analysis of the Railbelt generation system, the assumption was made that λ is the incremental heat rate of the generation system, i.e. $\lambda = M$. This is the error in the derivation. Assuming that all energy is produced at the system incremental heat rate is incorrect. In order to get any energy at all from the system, a turbine must be turned on, and the fixed frictional loss of a spinning turbine must be incurred. The cheapest that energy can come out of the system is by fully loading turbines and spreading the frictional loss over the largest amount of kWh.

The assumption that the cost of energy equals the system incremental heat rate is equivalent to assigning *all* the fixed frictional loss in the system to the production of spin, and *none* to the production of energy. It is clear why this formula has problems when attempting to determine the cost of spin for turbines near full load. As a turbine approaches full load, the amount of spin decreases towards zero. DFI's formula still assigns all of the fixed frictional loss of the turbine to the cost of this spin. The cost per unit of spin becomes infinite as the turbine approaches full load because the divisor, the amount of spin, approaches zero.

We now show that DFI's more general expression produces the formula $(A_L - M) \times L/(1-L)$ when applied to a short period of time. We apply the expression to a turbine whose loading characteristics do not change over a one hour time period. Using our previous variables, the amount fuel used over that one hour period is $U \times L \times A_L$. The amount of energy produced is $U \times L$, and the amount of spin produced is $U \times (1 - L)$. Once again, DFI's assumption in the Railbelt analysis is that $\lambda = M$. Making these substitutions gives the equation:

$$U \times L \times A_L = M \times U \times L + \mu \times U \times (1 - L)$$

which simplifies to:

$$\mu = (A_L - M) \times \frac{L}{1 - L} = \textit{Cost of Spin}$$

We have already shown that this formula produces an incorrect answer when applied to a simple numeric example and produces an impossible answer when applied to turbines near full load.

Applying the Correct Formula to the Railbelt Data

We now apply our formula for the cost of spin, $L \times (A_L - M)$, to heat rate data of Anchorage/Kenai thermal units to estimate an average cost of spin. Table 3 summarizes the calculation. The units are arranged in their dispatch order, according to data provided by DFI in Appendix F of the AEA Recon report. We do not analyze units beyond the Beluga CT #1 unit, because the (load + spin) that can be served by the analyzed set of units is approximately 550 MW. This capability combined with the Railbelt Hydro capacity will serve the bulk of the load through the analysis period, if optimal economic dispatch occurs.

When determining the cost of spin for a particular unit, it is necessary to make an assumption about that unit's loading and make an assumption about the incremental heat rate of the rest of the system. We test two different assumptions about the unit loading, 50% and 75% (our heat rate data source did not have heat rates at 25% load). The results are not very sensitive to this assumption. For the system incremental heat rate, we use the 50-75% incremental heat

Table 3 - Cost of Spin for Kenai/Anchorage Thermal Generation Units

Unit	Size MW	50% HR	75% HR	100% HR	Increm HR 50-75%	Spin Cost 50% Ld	Spin Cost 75% Ld
Bel CC #78	101	10,981	9,831	9,391	7,531	Never	Marginal
Bel CC #68	101	10,981	9,831	9,391	7,531	Never	Marginal
AMLP CC #76	109	10,017	9,018	8,628	7,020	1,243	1,115
Bel CT #5	67	15,012	13,448	12,963	10,320	3,996	4,821
Bel CT #3	50	14,822	13,228	12,800	10,039	2,251	2,181
Bern CT #3	27	15,284	14,082	13,700	11,673	2,623	3,032
Bern CT #4	27	15,284	14,082	13,700	11,678	1,803	1,803
AMLP CC #56	48	13,802	11,500	10,365	6,896	1,062	(134)
Bel CT #1	16	17,119	15,602	15,314	12,568	5,112	6,530
						2,584	2,764
						Btu/kWh-spin	

NOTES: Heat rate data from "Railbelt Intertie Proposal Preliminary Economic Assessment", March 1987, Alaska Power Authority, and from "Explanation and Support for Avoided Cost Tariff Proposed by ML&P", MLP, 1989. Data from APA report for Beluga CT #3 was scaled up to match the DFI assumption of a 12,800 Btu/kWh full-load heat rate for the unit. The anomalous results for the Cost of Spin for the AMLP units are due to the fact that they are placed in the dispatch order according to their heat rate times their fuel cost/kWh plus variable O&M. Since AMLP pays a higher price for natural gas, they are placed behind less efficient Chugach units. For this societal resource cost analysis, there is no difference in cost between AMLP and Chugach gas; thus, it is justified to consider the cost of spin in terms of Btus/kWh-spin, without regard to fuel price.

rate of the unit one prior in the dispatch order. In an optimally dispatched system, it is likely that this unit will be the unit that picks up the lost generation caused by shutting off the final unit (units prior to this one are likely to have lower incremental heat rates, and therefore will operating at or near full load).

Adjusting DFI's Result to Arrive at the Correct Operating Reserve Benefit for a New Intertie

The average cost of spin for the units shown is 2,600 Btu/kWh-spin with the 50% loading assumption, and 2,800 Btu/kWh-spin for the 75% loading assumption. For our adjustment of the DFI spinning reserve benefit result, we choose the higher of the two estimates, favoring the new intertie. The average of the Case 1 and Case 2 operating reserve benefit as calculated by DFI is $8.9 million. DFI based this calculation on a cost of operating reserves of 7,000

Btu/kWh-spin (increased from 5,000 Btu/kWh-spin in the AEA Recon report). The followi expression adjusts the DFI result to correspond to our estimate of the cost of operating reserv of 2,800 Btu/kWh-spin:

$$\textit{Corrected Operating Reserve Benefit} = \$8.9\ \textit{million} \times \frac{2{,}800\ Btu/kWh\text{-}spin}{7{,}000\ Btu/kWh\text{-}spin}$$

$$\textit{Corrected Operating Reserve Benefit} = \$3.6\ \textit{million}$$

This adjustment lowers the present value operating reserve benefits of the new Kenai-Anchorag intertie by $5.3 million.

2.4.2 Unquantified Disputes

Case 1 Results use Too Low of a Transfer Capacity for the Existing Intertie

DFI analyzes two cases when calculating operating reserve benefits. Case 1 assumes that the transfer capacity of the existing intertie for the purposes of operating reserves access is 70 MW input and 61 MW output. Case 2 assumes 90 MW input and 75 MW output. In the Case 1 analysis, the operating reserve benefit of the new intertie is $10.6 million, and the result for Case 2 is $7.1 million.

Sharing operating reserves only involves transferring energy over the intertie during periods of emergencies when the operating reserves are called on. There are no routine transfers of energy associated with sharing operating reserves. Therefore, the most accurate transfer rating of the intertie to use in the calculation is the emergency transfer limit, not the secure transfer limit. The Kenai-Anchorage intertie question is simplified, however, because the Alaska Energy Authority technical consultant states that emergency *and* the secure transfer limit for the existing line will be 90 MW input, 75 MW output after the planned line compensation is installed ["Kenai Export Limits With and Without a New Line, With and Without Additional Compensation", Power Technologies Inc., November 30, 1989, page 5]. We see little justification for incorporating the Case 1 results (70 MW input, 61 MW output) into the expected benefit calculation of the new line.

There has been some dispute concerning PTI's calculation of the *secure* export limit of the existing Kenai-Anchorage line. This calculation is complex because it involves simulating the response of the system to various faults (short-circuits) occurring on the system of transmission lines. A transfer limit is considered secure if the system can "survive" after such faults.

The emergency transfer limit, however, is a much more straight-forward calculation. Simulation of faults is not involved, because the probability of a fault occurring during a period when a transmission line is being relied on for emergency purposes is very low. In the case of

A Review of

"Economic Feasibility of the Proposed 138 kV Transmission Lines In the Railbelt"

February 1990

Analysis North **Report AN-90-1**

Analysis North
Alaska's Utility Consumer Advocate
911 West 8th Avenue, Suite 204 Anchorage, Alaska 99501 907-272-3425

February 14, 1990

Dear Report Recipient:

Enclosed is our review of the Railbelt utilities' cost/benefit analysis of new 138 kV (kilovolt) electrical transmission lines for the Railbelt. The utilities propose to fund these transmission lines through a $125 million grant from the state's Railbelt Energy Fund. The utilities' analysis cost $250,000 and was performed by Decision Focus Inc. The report is available from the Alaska Rural Electric Cooperative Association (phone: 276-3235 in Anchorage).

Our review of this analysis was funded by a Utility Consumer Representation contract from the Department of Commerce and Economic Development. We undertook the review in an attempt to improve the quality of information being presented concerning these potential utility projects.

The utilities' study finds that a new Kenai-Anchorage 138 kV line, a limited upgrade of the Anchorage-Fairbanks line, and a new Healy-Fairbanks 138 kV line are cost-effective, with benefit to cost ratios of approximately 1.6, 4.4, and 1.1 respectively. Our review agrees that the limited Anchorage-Fairbanks upgrade is cost-effective, but substantially disagrees with the conclusions concerning the Kenai-Anchorage line and the Healy-Fairbanks line. We believe that more reasonable benefit/cost estimates for the projects are 0.6 - 0.8, indicating insufficient benefits to justify their construction.

Our disagreement stems from disputes concerning the input assumptions, methods, and arithmetic used in the utilities' analysis. Details of these disputes are provided in the enclosed report.

Should you have any questions concerning this review, please call us.

Sincerely yours,

Alan Mitchell

Alan Mitchell
Utility Analyst

A Review of
"Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"

Funded by

Department of Commerce and Economic Development
Contract ASPS 90-028: Utility Consumer Representation

Prepared by

Alan Mitchell

Analysis North
911 W. 8th Avenue, Suite 204
Anchorage, AK 99501
907-272-3425

Report AN-90-1

February 14, 1990

Table of Contents

1. Introduction and Executive Summary

This report reviews the *"Economic Feasibility of the Proposed 138 kV Transmission Lines in the Railbelt"* prepared by Decision Focus Inc. (DFI) for the Railbelt utilities. A review was done of most, but not all, of the benefit categories for the proposed 138 kV line between Anchorage and Kenai. Because of time constraints and the large number of areas of dispute with the Kenai-Anchorage analysis, a less thorough review of the Healy-Fairbanks line was completed. A summary of the conclusions of the Healy-Fairbanks line review is presented here, but detailed support for the conclusions is not provided.

We appreciate the promptness with which our data requests and questions were responded to by DFI. This facilitated the completion of our review.

Kenai-Anchorage 138 kV Intertie

The DFI analysis presents the costs and benefits of an additional transmission line between Anchorage and Kenai.[1] We identified 4 major errors in the methods and computations used in the analysis. These are not disputes concerning the input assumptions used in the analysis, which will always differ between analysts. These are errors in how the input assumptions were used to calculate the final estimate of intertie benefits. Correcting these errors lowers the present value benefits of the new intertie from DFI's estimate of $123 million (1990 dollars) to $65 million.

In addition, we dispute a number of the input assumptions used in the analysis. Although not all of our disputes argue for lower benefits, we believe that more reasonable input assumptions would lower the estimated benefits of the 138 kV intertie further. The Alaska Energy Authority analysis of a more capable 230 kV intertie between Anchorage and Kenai showed benefits of $51 million, present value.[2] This analysis was also performed by DFI. We believe that a more accurate analysis of the 138 kV option would show its benefits to be equal to or less than this value.

The benefit estimates for the 138 kV intertie need to be compared to the costs of the intertie. Two cost estimates were presented in the 138 kV analysis, both assuming use of the Enstar route through the Kenai Moose Range.[3] One estimate assumed a 40 year life of the

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[1] The existing line will remain operational even if the new line is built. It is necessary to serve customers along its route.

[2] "Railbelt Intertie Reconnaissance Study, Benefit/Cost Analysis", prepared by Decision Focus Inc. for the Alaska Energy Authority, June 1989.

[3] In the Alaska Energy Authority analysis of the 230 kV alternative, a more expensive alternate route along the Tesoro right of way was also costed.

proposed submarine cable under Turnagain Arm. The present value cost of this estimate is $74 million. A second cost estimate assumes a 20 year life for the submarine cable (slightly more than the 15 year life actually experienced by Chugach Electric's Cook Inlet submarine cables). This cost estimate is $86 million, present value.

Benefits of 138 kV Kenai-Anchorage Line are Less than Costs

If the benefits of the 138 kV Kenai-Anchorage intertie are $51 million or less, as we expect, the benefit to cost ratio of project will be less than 0.69 ($51 million divided by low cost estimate of $74 million). Even using the $65 million benefit estimate, derived from correcting only 4 major method errors in the 138 kV analysis, the benefit to cost ratio of the project will be 0.88 or 0.76, depending on the cost estimate used.

4 Major Errors Quantified

Figure 1 summarizes the magnitudes of 4 major method errors that were found in the DFI Kenai-Anchorage Intertie analysis:

- A computation error was found in the calculation of the hydro-thermal coordination benefits of the new intertie.[4] DFI has agreed to the existence of the error. The error overstates the Energy Transfer benefits of the new intertie by $25 million, present value.
- The existing intertie causes power outages when it fails while transferring energy between Anchorage and Kenai. The study claims that these power outages cost customers $32 - $50 million, which will be avoided if a new intertie is built. However, the analysis fails to recognize that these outage costs can also be avoided without the construction of a new intertie by giving up the energy transfers that cause the outages. These transfers are only worth $17 million according to DFI's analysis. The $17 million transfer benefit sets a logical cap on the reliability benefits of the new intertie. This cap lowers the reliability benefit estimate of the new intertie by $24 million.
- An incorrect formula for computing the cost of spinning reserve overstates the benefits of increased access to Bradley Lake spinning reserve by $5.3 million.
- An unnecessary simplification of the hydro-thermal benefit calculation overstates the hydro-thermal benefits of the new intertie by $3.7 million.

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[4] Hydro-thermal coordination is a method for coordinating the hydro generation on the Kenai peninsula with the thermal generation in Anchorage so as to minimize the excessive part-load operation of the thermal generation.

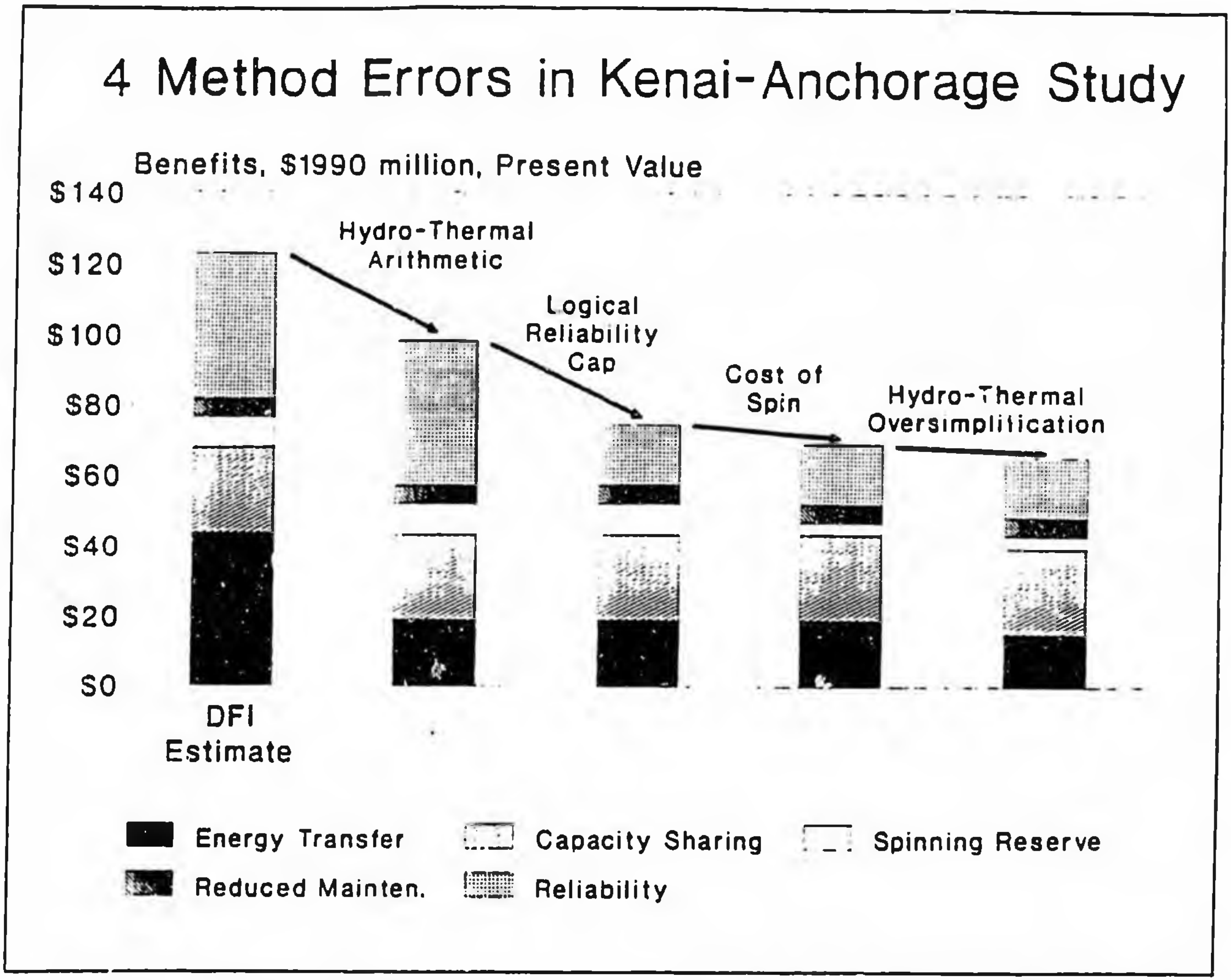

Figure 1 - Changes to Kenai-Anchorage Benefit Estimate due to 4 Major Method Errors. No other disputes are quantified in the displayed benefit adjustments.

Unquantified Areas of Dispute

In addition to the errors listed above, a number of unreasonable input assumptions tend to bias the project benefits upwards, including:

- The calculation of the increased energy transfer benefits of the new intertie assumes with certainty that a system for optimally coordinating generators will exist. Such a system does not exist now and may never exist.

- The hydro-thermal coordination regime modeled in the analysis appears is suboptimal. A more optimal regime makes better use of the existing intertie and depends far less on a new intertie for the creation of economic benefit.

- The capacity benefits provided by the new intertie are valued at the full cost of new generation capacity, despite the statement by Railbelt utilities that new capacity will be acquired through relatively cheap life-extension of existing plants.

Healy-Fairbanks 138 kV Intertie

AF100 Limited Upgrade Project Has Benefits Substantially in Excess of Costs

The northern interties analyzed in the report consist of two different projects. The AF100 intertie involves adding compensation equipment to the existing Anchorage-Fairbanks line to increase its transfer capacity. The DFI analysis finds this project to have a cost of $10 million and benefits of $46 million, present value. Most of the benefits of the project involve the solution of an operating constraint called the "North Pole Constraint". The analysis assumes that if the AF100 intertie is not built, the North Pole constraint will not be solved by some alternative means. Such an assumption inflates the benefits of the AF100; however, we believe that use of a more reasonable assumption in the analysis would still show positive net economic benefits for the AF100 project.

The Additional Benefits Achieved by the 138 kV Healy-Fairbanks Line, Over and Above the AF100 Option, are Probably Less than the Additional Costs

The second project analyzed is an additional 138 kV line between Healy and Fairbanks. The relevant question is whether the additional ("incremental") benefits of the line--over and above the benefits that will be provided by the cost-effective AF100 option--justify the additional costs of the line.[5] Advocates of this project often combine its benefits and costs with the AF100 project. The substantial benefits of the AF100 project disguise the marginal economic merit of the Healy-Fairbanks line when packaged together. Table 1 shows the estimates of *incremental* benefits and costs provided by DFI.

We believe it is probable that the incremental benefits of the Healy-Fairbanks line will be *less* than the incremental costs, because optimistic assumptions are used in the determination of the benefits.

Table 1 - DFI's Estimate of the Incremental Benefits and Costs of the Healy-Fairbanks Line

DFI's Incremental Benefits and Costs of Healy-Fairbanks Line
Millions of 1990 $, Present Value

Incremental Benefits	
Energy Transfer	
Reduced North Pole Constraint	$ 5.8
Other Economy Energy	$ 39.3
Capacity Sharing	$ 8.3
Reliability	$ 6.5
	====
TOTAL	**$ 59.9**
Incremental Costs	**$ 54.2**

---

[5] The Healy-Fairbanks line requires that AF100 option also be built.

Analysis Assumes Sending Gas-Generated Electricity from Anchorage to Fairbanks will Produce Substantial Benefit for the Next 54 years

The energy transfer benefits of the line are derived from substituting more gas-fired electricity from Anchorage for oil-fired electricity in Fairbanks, and from incurring less transmission losses on those substitutions. These substitutions are assumed to occur over the 50 year life of the intertie (1994 - 2043). Any one of at least three events could dramatically reduce the benefits of such substitutions:

- A gas pipeline from the North Slope through Fairbanks could supply natural gas directly to Fairbanks generators, avoiding the need for the intertie.
- A gas pipeline from Anchorage to Fairbanks would also avoid the need for the intertie. The Alaska Energy Authority analysis of the intertie projects also looked at the costs and benefits of an Anchorage-Fairbanks gas pipeline. The analysis found the benefits of the pipeline to substantially exceed the costs.
- A decrease or elimination of the price advantage of Cook Inlet natural gas over Fairbanks oil will reduce the benefits of the intertie. The ICF-Lewin Energy Group analyzed fuel prices in the Railbelt as part of the AEA Intertie Recon analysis.[6] They concluded that depletion of Cook Inlet gas reserves would force Cook Inlet gas prices up near the year 2015, less than half way through the life of the Healy-Fairbanks line. This projection was not incorporated in the fuel price forecasts used in the 138 kV analysis. Doing so would lower the benefits of the line by roughly $10 million.

Analysis Assumes 20 MW FMUS Coal Plant will Not Run in Low Fuel Price Scenario

In determining the benefits of reducing the North Pole operating constraint, it was assumed that after the intertie is fully loaded, the North Pole oil units would be turned on next. A part-load efficiency analysis shows that turning on the Chena 20 MW coal plant is less costly than running the North Pole units. Changing this assumption would reduce the North Pole benefits of the Healy-Fairbanks intertie by approximately $3 million.

Capacity Sharing Analysis Based on High Increase in Transfer Capacity

The 138 kV analysis assumes that the Healy-Fairbanks intertie increases the emergency transfer capability over the AF100 by about 26 MW after losses, in both the Anchorage to Fairbanks direction and in the Fairbanks to Anchorage direction. The technical consultant for the intertie projects, Power Technologies Inc., claims that the increased emergency transfer level

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[6] "Fuel Price Outlook for The Alaska Railbelt Region: Oil and Natural Gas", performed by the ICF-Lewin Energy Group for the Alaska Energy Authority, June 1988.

is about 16 MW from Anchorage to Fairbanks[7] and 10 MW from Fairbanks to Anchorage.[8] Using PTI's figures will substantially lower the incremental capacity transfer benefits of the Healy-Fairbanks line. Also, the effective capacity provided by the intertie was valued at the cost of new capacity, ignoring relatively cheap life extension options.

Reliability Benefits are Based on High Customer Outage Costs

The reliability benefits of the line are determined by estimating the number of power outages avoided by the line and assigning a value to the avoidance of those outages. The cost of the outages was determined from an unrealistic interpretation of a survey performed by Ontario Hydro. This is discussed in more detail in section 2.7.2.

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[7] "Secure and Emergency Transfers from Anchorage to Fairbanks", Power Technologies Inc., October 31, 1989.

[8] Personal Communication with Harrison Clark, Power Technologies Inc., January 29, 1990.

2. Kenai-Anchorage Intertie

2.1 Comparison With AEA 230 kV Study

Table 2 - Comparison of Kenai-Anchorage Intertie Analyses. For both the AEA 230 kV analysis and the Utility 138 kV analysis, the Low and high benefit estimates are averaged.

Kenai-Anchorage Intertie Analyses
Costs and Benefits are Present Value, Millions of 1990 $

Benefit/Cost Category	AEA 230 kV Analysis	Utility 138 kV Analysis	138 kV 4 Method Errors Corrected
INTERTIE COST			
Enstar Route			
w/o Submarine Replacement	$113	$74	$74[1]
w/ Submarine Replacement	NA	$86	$86[1]
Tesoro Route			
w/o Submarine Replacement	$137	NA	NA
w/ Submarine Replacment	NA	NA	NA
BENEFIT CATEGORIES			
Energy Transfer Benefits			
Hydro-Thermal Coordination	$14.3	$37.5	$ 9.1
Other Economy Energy	$ 4.8	$ 5.9	$ 5.9[2]
Operating Reserve Benefits	$ 0.8	$ 8.9	$ 3.6
Capacity Sharing Benefits	$11.8	$24.4	$24.4[2]
Stability Cost Savings	$ 3.1	$ 0.0	$ 0.0
Maintenance Cost Savings	$ 0.0	$ 5.0	$ 5.0[2]
Reliability Benefits[3]	$ 15.5	$41.0	$17.0
TOTAL BENEFITS	**$ 51**	**$123**	**$ 65**

NOTES:

[1] - The cost estimates were not reveiwed in this report.

[2] - Leaving these benefit estimates unchanged does not constitute endorsement. Substantial concerns about the assumptions and methods used to produce the estimates are discussed in the text, but are not quantified. This column only shows the change in benefit estimates derived from correcting 4 major method errors in the analysis.

[3] - Reliability benefits will not be reflected in electric rates. These are costs and inconveniences avoided by reducing the number and extent of customer power outages.

Table 2 compares the results from the Railbelt Utility 138 kV Kenai-Anchorage analysis with the 230 kV Kenai-Anchorage analysis prepared for the Alaska Energy Authority. Also included in the table is the utility benefit estimate for the 138 kV Kenai-Anchorage line adjusted for the 4 major method errors described in the Executive Summary. None of the unquantified disputes discussed in the rest of the report are factored into this benefit estimate. All benefits and costs are expressed in 1990 dollars (the AEA 230 kV study used 1987 dollars--these were converted).

Gross Benefits for the 138 kV Analysis Exceed the Gross Benefits for the 230 kV Analysis, Indicating Changed Assumptions

If a consistent analysis of both a 230 kV intertie and a 138 kV alternative were done, the 230 kV intertie would show more gross benefits (before subtracting costs). This is because the 230 kV intertie has higher transfer capacity, lower losses, and equal reliability--the three parameters that are important in assessing the benefits of an intertie. The fact that Table 1 shows that the *138 kV* option has larger benefits than the 230 kV option indicates that the two analyses were not consistent. The assumptions used in the 138 kV study were more favorable to the construction of a new intertie.

Some of the assumptions that were changed between the Kenai-Anchorage 230 kV analysis and the 138 kV analysis were:

General Assumptions

- When averaging the benefits across the different fuel price and load forecast scenarios, all scenarios were weighted equally in the 138 kV analysis. In the 230 kV analysis, certain scenarios had more weight than others. Most significantly, the fuel price probabilities in the 230 kV study were Low - 60%, Mid - 30%, High - 10%. Re-weighting the cases caused the benefits of the 138 kV Kenai-Anchorage analysis to increase (~$7 million), while Healy-Fairbanks intertie benefits were approximately unchanged.

- In the 138 kV analysis, any changes in gas royalty payments to the state were counted as costs or benefits in the analysis. If a project causes gas use to increase, an increased gas royalty benefit is attributed to the project. The opposite holds for a gas decrease. This change decreased the benefits of the Kenai-Anchorage line (~$4.5 million), since the line decreases gas use, and increased the benefits of the Healy Fairbanks line (incremental benefits + $3.2 million), since it increases gas use.

- The lifetime of the new Kenai-Anchorage intertie was assumed to be 35 years in the 230 kV analysis and 40 years in the 138 kV analysis. This increases the present value benefits of intertie since benefits are added up over a longer time period. Because of ongoing operation and maintenance costs, present value costs are also increased, but not enough to cancel the benefit increase.

- In the 230 kV analysis, the existing Kenai-Anchorage intertie was assumed to be unavailable for transfers for two weeks per year. In the 138 kV analysis, the existing intertie was assumed to be unavailable for transfer for approximately 3 months per year during a 13 year rebuilding period, and 1 month per year thereafter. This assumption increases the benefits of a new intertie because the new intertie captures the benefits lost by the existing intertie during these periods of unavailability.

- In the 138 kV analysis, two cases with different assumptions about the transfer capacity of the existing intertie were analyzed: Case 1 - 70 MW Input / 61 MW Output, and Case 2 - 90 MW Input / 75 MW Output. In the 230 kV analysis, only Case 1 was analyzed. The addition of the second case in the 138 kV analysis reduced the benefits of the new Kenai-Anchorage line.

Intertie Costs

- Because the 138 kV interties will be built at a lower voltage, the capital cost will be less than the 230 kV alternatives. The costs were re-estimated by the same firms that provided the 230 kV estimates for the AEA study.

- In the 138 kV analysis, no cost estimates were provided for the more expensive Tesoro route, which must be used if the intertie is not granted a right-of-way along the Enstar natural gas pipeline through the Kenai Moose Range.

- The 138 kV analysis presented a cost estimate that involved replacement of the Turnagain Arm submarine cable after 20 years. This sensitivity case was not presented in the 230 kV study.

- The maintenance cost estimates for the Kenai-Anchorage line were decreased in the 138 kV study. In the 230 kV study, maintenance costs were assumed to be 1.5% of capital cost per year for the entire line. In the 138 kV study, the maintenance cost of the aerial portion of the line was dropped to 0.5% of capital cost per year. The maintenance of the submarine cable under Turnagain Arm was assumed to still have a 1.5%/year maintenance cost.

New or Deleted Benefit Categories

- In the 138 kV study, it was assumed that the existence of a new intertie would allow Chugach to defer maintenance on the existing intertie. The deferral was assumed to provide a $5 million present value benefit. This benefit was not attributed to the new intertie in the 230 kV study.

- In the 230 kV analysis, the new KA intertie was assumed to reduce the capital cost of the stability system for Bradley Lake by approximately $3.1 million. Since the stability system is now designed for use with the existing intertie, the stability system is considered a sunk cost. Thus, in the 138 kV analysis, no benefit was attributed to the new intertie for reduced stability system cost.

Energy Transfer Benefits

- In the 138 kV study, the hydro-thermal coordination benefit calculation was performed in more detail. The new calculation method produced a dramatically higher benefit estimate (+ $23 million) than determined in the 230 kV analysis. However, we show later in the report that an arithmetic error was the source of much of the increase.

Operating Reserve (Spin) Benefits

- In the 230 kV analysis, Bradley Lake was assumed to provide the same amount of operating reserve (30 MW) both with and without a new intertie. In the 138 kV analysis, it was assumed that Bradley could be relied on for more spin if a new intertie were present (50 MW vs. 30 MW). Thus, the benefits of the new intertie were increased.

- The cost of providing spin from thermal generation units was assumed to be higher in the 138 kV analysis than in the 230 kV analysis. This increased the operating reserve benefits of the new intertie.

Capacity Sharing Benefits

- In the 230 kV analysis, the capacity sharing benefits of the Kenai-Anchorage line were related to its ability to tap excess capacity on the Kenai peninsula for emergency use in Anchorage. In the 138 kV analysis, this same benefit was addressed, but it was also assumed that the new intertie would allow the reduction of the required capacity reserve margin in the Kenai and Anchorage load centers. This assumption increased the benefits of the new intertie.

Reliability Benefits

- The assumption concerning the costs suffered by customers due to power outages was increased substantially from the 230 kV analysis to the 138 kV analysis. The Ontario Hydro survey that supplied the estimate for commercial customers was interpreted in a new way that caused the costs to more than double. New surveys were examined to determine a new cost for residential outages. The surveys relied upon gave estimates more than double those used in the 230 kV analysis.

We discuss some of these changes in the following sections.

2.2 Costs, Intertie Availability

We were unable to review the capital or operating cost estimates provided for the 138 kV intertie, although we believe that they do deserve independent scrutiny. In the process of review, it should be determined whether interest during construction was included in the cost estimate, because the DFI analysis did not adjust the costs for this factor. Also, the question of whether the Turnagain Arm submarine cable will need to be replaced is a critical issue. Is there sufficient evidence indicating that a new submarine cable in Turnagain Arm will last more than the 15 year life experienced by Cook Inlet submarine cables?

The Existing Intertie is Assumed to be Unavailable for Transfers for Substantial Periods of the Year

DFI made the assumption in this analysis that the existing intertie will be unavailable for transfers for 99 days per year (3 + months) for the period 1994-2007 because of rebuilding, and 28 days per year for the years thereafter [page B-2, 138 kV Study]. This assumption comes directly from Chugach Electric, and should be reviewed by someone with expertise in utility construction. One version of the assumption appeared first in the final two months of the AEA Recon study. Chugach stated that existing intertie would be unavailable due to maintenance for 2 months every year from 1994 through 2004. From 2005 on, the intertie would be unavailable for one month per year. DFI did a quick analysis to see what the effects of the assumption would be, but did not include the impacts in the formal benefit estimate for the new line. The unavailability asssumptio was included in the 138 kV analysis, and the two month per year figure was increased to over three months per year.

We question whether it is optimal to extend the rebuilding of the existing intertie over such a long period of time. We also question why the fully rebuilt intertie will continue to experience one month per year of unavailability. The current unavailability of the existing intertie is not that long. Assuming a high level of unavailability increases the estimated benefits of a new intertie.

2.3 Energy Transfer Benefits

The Energy Transfer benefits of the KA intertie are cost savings that arise when it is cheaper to import electric energy than to produce it locally. The DFI analysis identifies two types of transfers which can effect such savings.

One type of transfer allows more efficient generation in one area to displace less efficient generation in another (there are no assumed natural gas price differences between the Kenai and Anchorage areas). The Over-Under production cost model was used to identify the savings attributable to a new intertie because of additional transfers and a reduction in transmission losses associated with the transfers. DFI concludes that the present value of this type of energy transfer benefit is about $6 million. The cost saving transfers that occur are almost entirely due to a flow of energy *from Anchorage to Kenai*, despite the existence of Bradley Lake on the Kenai Peninsula. The annual energy requirement in Kenai exceeds the hydro energy available. The modeling found that the optimal use of the hydro energy was in serving the local Kenai load. The model also found that serving the Kenai load in excess of the available hydro energy was most efficiently done by sending energy south over an intertie from Anchorage to Kenai.

The second type of transfer, called hydro-thermal coordination, essentially allows thermal generators to be run at higher average loading levels where they perform more efficiently. This opportunity arises from the fact that the Bradley Lake hydro project presumably can supply energy with equal efficiency over its full range of output, while a thermal generation unit (e.g. combustion turbine) requires substantially more fuel to produce kWh at low loadings than it does to produce kWh at high loadings. Hydro-thermal coordination involves transferring energy back and forth between the Anchorage and Kenai areas in a way that eliminates the excessive part-loading of thermal generation units in Anchorage (some part-loading, i.e. operating reserve, is required for reliability protection). The load served by means of such transfers is said to be *reshaped*. The scheme requires an intertie because there is very little thermal generation that occurs on the Kenai Peninsula. The coordination scheme suggested also involves no net increase in the amount of generation that occurs in the Kenai area. All exports of energy from Kenai for the purpose of hydro-thermal coordination are balanced by an equivalent pay-back of energy at another time from the Anchorage thermal units.

2.3.1 Quantified Errors

Computation error overstates hydro-thermal gas savings by $25 million

A computation error overstates the benefits of hydro-thermal coordination by $24.7 million. DFI has agreed that there is an error (Review meeting, 1/30/90). The error does *not* arise from the method or input assumptions used in the calculation; rather, the final result simply does not agree with the described method and input assumptions. DFI states that with a new intertie, 356 MBtu of gas savings will occur per hour of reshaping (p. A-8, 138 kV). The comparable figure stated for the existing intertie is 126 MBtu/hour. When the calculation is performed correctly, the results are 132 MBtu/hour for the new intertie and 55 MBtu/hour for the existing, under the Case 1 scenario. (We only performed the calculation for Case 1, the case that produces the maximum benefits for the new intertie.) The corrected calculation is presented in Appendix A.

To adjust the hydro-thermal benefits for this computation error, we multiply the DFI hydro-thermal benefit estimate by the ratio of the correct gas savings to the erroneous gas savings. Since reshaping is assumed to occur for 4,000 hours/year with the new intertie and

3.500 hours/year with the existing intertie, the corrected hydro-thermal benefit estimate is:

$$\textit{Corrected Estimate} = \$37.5 \times \frac{132\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 55\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}{356\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 126\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}$$

$$\textit{Corrected Estimate} = \$12.8\ \textit{million}$$

Method error overstates hydro-thermal savings by additional $3.7 million

An oversimplification in the hydro-thermal calculation method further overstates the coordination benefits by $3.7 million. DFI does not dispute the existence of the oversimplification (Review meeting, 1/30/90), although they have not provided their numeric correction. The reshaping savings per kWh reshaped for a thermal unit at any particular loading level L are:

$A_L - (M \times R)$, where

A_L is the average heat rate of the unit at loading level L,
M is the incremental heat rate of the unit measured from loading level L to 100% loading,
R is the reshaping energy requirement as defined by DFI on page A-6 of the 138 kV study.

In performing the calculation, DFI assumed that the average heat rate of the thermal unit is constant and equal to the average heat rate at 50% load. This assumption is highly inaccurate. The average heat rate varies substantially across loadings, rising rapidly at low loading levels. Thus, at low loadings production of energy is very inefficient and reshaping savings per kWh are correspondingly large. At high loadings the generator runs efficiently and savings available from reshaping are correspondingly small.

The assumption of a constant average heat rate discounts the benefits of reshaping at low loading levels, where the existing intertie performs nearly as well as the new intertie. The constant heat rate assumption inflates the benefits of reshaping at higher loading levels, levels where the new intertie shows its reshaping advantage. Therefore, by assuming a constant heat rate across loading levels, DFI overstates the benefits from the new intertie.

We quantified the magnitude of the overstatement by performing the hydro-thermal calculation allowing the heat rate to realistically vary across loading levels. No additional inputs beyond the DFI inputs were needed for the calculation. We used the same turbine characteristics and fractions of the year that each turbine was marginal. We used an assumption of constant incremental heat rates (as DFI implicitly did) to determine average heat rates at various loading levels. The calculation is presented in Appendix B.

The correct calculation shows that the average reshaping savings for the new intertie are 107 MBtu/hour, and the reshaping savings for the existing intertie are 54 MBtu/hour. The following procedure adjusts the original DFI hydro-thermal benefit estimate result to one that has no arithmetic error and incorporates the varying average heat rate assumption:

DFI Estimate = $37.5 *million*

$$\text{Corrected Estimate} = \$37.5 \times \frac{107\ MBtu/hr \times 4{,}000\ hours\ -\ 54\ MBtu/hr \times 3{,}500\ hours}{356\ MBtu/hr \times 4{,}000\ hours\ -\ 126\ MBtu/hr \times 3{,}500\ hours}$$

Corrected Estimate = $9.1 *million*

Summary of quantified hydro-thermal errors

The net result of these two corrections is that the hydro-thermal benefits of the new intertie as stated by DFI are reduced by $28.4 million, from a present value of $37.5 million to $9.1 million.

2.3.2 Unquantified Disputes

The Energy Transfer Benefits of the New Intertie Assumes an Optimal Dispatch Regime, Which Does Not Exist

Both the economy energy benefits calculated through the Over-Under modeling process and the hydro-thermal coordination benefits require coordinated and optimal dispatch across the Railbelt utilities with generation resources. It is clear that this dispatch system is not currently in place. DFI has claimed that there is $3 - $6 million per year of inefficiency in the current system due to suboptimal dispatch ($50 - $100 million, present value). If the system is never developed, a substantial portion of these benefits will not materialize. The benefits in the DFI analysis were not reduced to account for the probability that optimal coordination and dispatch may not occur.

Hydro-Thermal Coordination using Eklutna Lake is Not Considered

DFI did not address the potential to perform some hydro-thermal reshaping with the 30 MW Eklutna plant located in the Anchorage area. If reshaping is possible with this plant, a larger fraction of the ultimate reshaping potential could be obtained with the existing intertie combined with Eklutna, thus reducing the benefits of the new intertie.

Suboptimal Coordination Plan Inflates Intertie Benefits

We also believe that the hydro-thermal coordination regime modeled by DFI is a sub-optimal one. A simplified example of DFI's hydro-thermal scheme is graphically depicted in the top part of Figure 2. The figure is meant to show the simplified operating regime of one particular Anchorage thermal unit. Absent hydro-thermal coordination, the unit would turn on at time t1 and its loading would increase to follow the load until it reached maximum loading at time t2. It would remain at maximum loading until time t3 when it once again becomes the marginal unit. Its output decreases until it turns off at time t4.

With the type of hydro-thermal coordination modeled by DFI, turning on the thermal unit is delayed until time t2. Between t1 and t2, Kenai hydro energy is imported over the intertie to meet the (Load + Spin) requirements in Anchorage. The thermal unit is started at t2 when it can be fully loaded, and imports are ceased. At time t3, when the thermal unit would normally start unloading, its output is maintained at full load. The power in excess of Anchorage (Load + Spin) requirements is exported back to Kenai to reimburse for the previous imports.

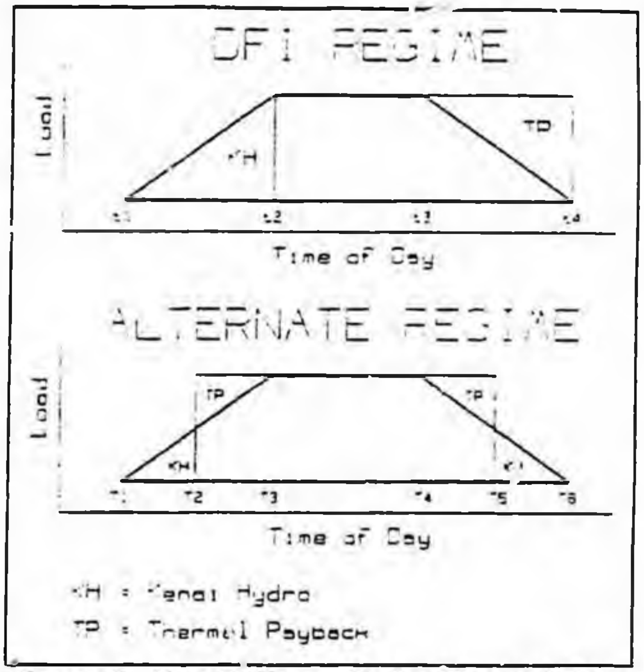

Figure 2 - Two Different Hydro-Thermal Coordination Regimes

An alternative hydro-thermal coordination regime is shown in the lower half of Figure 1. This method achieves the same objective as the DFI regime: it allows all energy produced by the thermal unit to be produced while operating at full load. However, the alternative method requires less energy transfer over the intertie, and it reduces the peak demand on the intertie for the purposes of reshaping. In doing so, it reduces transmission losses relative to the DFI method, and it reduces the periods when the reshaping requirements exceed the capacity of the intertie.

The alternative method involves importing Kenai energy when the thermal unit would otherwise be at low loadings and paying that energy back when the thermal unit would otherwise be at high loadings ("otherwise" meaning absent hydro-thermal coordination). The figure shows the Kenai import and thermal payback periods for this type of hydro-thermal regime applied to the simple example.

Had this regime been modeled when calculating the increased hydro-thermal benefits of the new intertie, the new intertie's benefits would have been less. With such a regime, the capacity constraint of the existing intertie would rarely be a problem. Further, the higher losses of the existing intertie would be less of a problem, since the average transfer required to perform the reshaping is less with this regime.

2.4 Operating Reserve (Spin) Cost Savings

Operating Reserve, or spin, is the amount of additional generating capacity which is instantly available to meet an increase in load. Spin from the Bradley Lake Hydroelectric project is essentially free, but spin from thermal units is costly. To create spin using a thermal unit, a fixed amount of gas must be burned per hour to turn the turbine even when no electricity is produced. As the loading on the turbine increases, this hourly "friction overhead" cost can be spread over more and more kWh produced, reducing the average fuel cost per kWh. Often, however, several units must be deliberately kept on at relatively low loading levels in order to provide spinning reserve. The *cost of spin*, then, is the difference between the low cost of providing *energy alone* from a few highly loaded turbines and the higher cost of providing *energy plus spin* from more turbines operating at lower loads. One can also think of the cost of spin as the cost of the extra "friction overhead" introduced by having more turbines spinning without any more kWh over which to spread these fixed costs.

The KA intertie allows the free spin from Bradley Lake to be available to the Anchorage load center. Economic benefit results from the substitution of this free spin for costly spin from Anchorage thermal units. DFI found that the present value of this benefit (after averaging across cases) is $8.9 million.

2.4.1 Quantified Errors

The Cost of Spin is Calculated Incorrectly

To calculate the benefits of using more free spin from Bradley Lake, one must estimate *how much spin* substitution can occur and *how costly* is the thermal spin displaced. We first dispute the derivation of the cost of the displaced spin from thermal units. We argue that the calculation *method* is wrong, not the input assumptions. We present the argument by first deriving a general formula for the cost of spin. We show how this formula produces the right answer when applied to a simple example presented by DFI in a report for the Railbelt utilities. We then discuss why DFI's formula for the cost of spin is wrong and verify that it produces the wrong answer when applied to the same simple example. Finally, we apply our formula to heat rate data for Railbelt thermal generation units to estimate the correct cost of spin and adjust accordingly the spinning reserve benefits that DFI attributes to a new Kenai-Anchorage intertie.

The Cost of Spin: a Simple Example

The principles behind the calculation of the cost of spin are best introduced by means of the following simple example, which is reproduced from page 6 of the DFI report "Value of Bradley Lake Spinning Reserves" (October 6, 1989), prepared for the Railbelt Utilities. This example prefaced their actual analysis of the cost of spin in the Railbelt. Suppose a system of five 100 MW thermal generators is running such that:

Total capacity of operating turbines:	500 MW
Total load on system:	- 400 MW
Available operating reserve (spin):	100 MW
Number of operating turbines:	5

Loading level (L) of each turbine:	80%, i.e. 80 MW
Average Heat Rate at L = 80% :	12,000 Btu/kWh
Incremental Heat Rate from 80% to 100%:	2,000 Btu/kWh

(this is the incremental rate implied by DFI's example but is very low for actual generation units)

Now suppose that 100 MW of free spin becomes available from a hydro unit. It is now possible to shut down one unit completely and still serve the 400 MW load by running the four remaining units at full load. The cost savings from this rearrangement are easily calculated:

Gas saved by shutting down one unit:	80 MW * 12 M Btu/MWh = 960 MBtu/hr
Gas used by additional loading on remaining 4 units:	4 * 20 MW * 2 MBtu/MWh = 160 MBtu/hr
Net gas savings from eliminating 100 MW thermal spin:	960 MBtu/hr - 160 MBtu/hr = 800 MBtu/hr
Net gas savings per unit of spin eliminated:	(800 MBtu/hr)/(100 MW) = 8 MBtu/MWh = 8,000 Btu/kWh

The cost savings from reducing the spin in this example is amount of fuel savings that occurs by rearranging the system as described (800 MBtu/hr), divided by the spin reduction, 100 MW. The answer above, 8,000 Btu/kWh-spin, the same answer arrived at by DFI in their Bradley Lake spinning reserve report.

A General Expression for the Cost of Spin

Using this simple example as a pattern, it is possible to derive a general expression for the cost of spin. Define the following variables (values in parentheses are from the example above):

L = *The loading level in % of the generation unit turned off to reduce spin (0.8).*

U = *The size of generation unit being turned off to reduce spin (100,000 kW).*

A_L = *The average heat rate of the unit being turned off, for loading level L (12,000 Btu/kWh).*

M = *The incremental heat rate of the units that pick-up the generation loss caused by shutting off the unit (2,000 Btu/kWh).*

The amount of reduced spin in the system is U. The load on the system remains constant while U kW of generation is turned off. Therefore, the reduction in spin must be U.

$$(1)\ \textit{Reduced Spin} = U$$

The change in gas use can be thought of as consisting of two components. First, shutting the unit off causes a reduction in gas use of:

$$(2)\ \textit{Reduced gas use because of shutting unit off} = U \times L \times A_L$$

However, the remaining units must make up for the lost generation:

$$(3)\ \textit{Increase in gas use because of loading up remaining units} = U \times L \times M$$

The net decrease in gas use is found by subtracting (3) from (2):

$$(4)\ \textit{Net Decrease in Gas Use} = U \times L \times A_L - U \times L \times M = U \times L \times (A_L - M)$$

The net gas decrease per unit of spin is derived by dividing (4) by (1):

$$(5)\ \textit{Gas Decrease per Unit of Spin Reduced (Btu/kWh-spin)} = L \times (A_L - M)$$

We can further verify the formula by applying it directly to the DFI example presented above. The turbine being shut-off is 80% loaded, and its heat rate at 80% loading is 12,000 Btu/kWh. The incremental heat rate of the rest of turbines that make-up for the lost generation is 2,000 Btu/kWh (this is the incremental heat rate implied by the figures in the example but is very low for real-world generation units). Applying our formula for the cost of spin:

$$\textit{Cost of Spin} = 0.80 \times (12{,}000\ \textit{Btu/kWh} - 2{,}000\ \textit{Btu/kWh})$$

$$\textit{Cost of Spin} = 8{,}000\ \textit{Btu/kWh-spin}$$

This formula for the cost of spin gives the correct answer in the example.

Why DFI's formula for the Cost of Spin is Incorrect

After completing the simple numeric example in the Bradley Lake spinning reserve report, DFI states on page 7 that cost of spinning reserves is:

$$\textit{Cost of Spin} = (A_L - M) \times \frac{P}{PMAX - P}$$

where,

P = *Power Output of Unit*
PMAX = *Unit Size*

To express this formula using the variable names above. note that P = U × L and PMAX = U:

$$\text{Cost of Spin} = (A_L - M) \times \frac{L}{1 - L}$$

DFI does not apply this formula to their introductory example in the report. When it is applied to the example. it produces the incorrect answer of 40.000 Btu/kWh-spin. not the correct answer of 8.000 Btu/kWh-spin:

$$\text{Cost of Spin} = (12.000\ Btu/kWh - 2,000 Btu/kWh) \times \frac{0.8}{1 - 0.8} = 40,000\ Btu/kWh\text{-}spin$$

This formula also produces impossible results when turbines near full loading are analyzed. As L approaches 1. the cost of spin approaches infinity. according to this formula. This is clearly not correct.

DFI claimed at the 1/30/90 Review Meeting that they actually performed their analysis of the cost of spin in the Railbelt with a different. somewhat more general formula. We now show that the derivation of this formula is also incorrect. Also. the more general expression when applied to short period of time produces the $(A_L - M) \times L/(1-L)$ formula. which we have already shown to be incorrect.

DFI's more general expression is:

$$\text{Fuel Use} = \lambda \times (\text{Energy kWh}) + \mu \times (\text{Spin kWh})$$

where,

λ = *Cost of Energy, Btu/kWh*
μ = *Cost of Spin, Btu/kWh-spin*

This expression is a simple statement that the total fuel cost during a particular period of time equals the cost of energy times the amount of energy generated plus the cost of spin times the amount of spin generated over that time period. The expression does not allow one to calculate the cost of spin over the time period unless some assumption is made for λ, the cost of energy.

In DFI's empirical analysis of the Railbelt generation system. the assumption was made that λ is the incremental heat rate of the generation system. i.e. $\lambda = M$. This is the error in the derivation. Assuming that all energy is produced at the system incremental heat rate is incorrect. In order to get any energy at all from the system. a turbine must be turned on. and the fixed frictional loss of a spinning turbine must be incurred. The cheapest that energy can come out