SB
159-H

HOUSE COMMITTEE REPORT

(11)

Date referred: 4/24/87 FURTHER REFERRALS:

DATE: 4-28-87

The Finance Committee has considered SB 159

"An Act amending an appropriation to the Alaska Power Authority for the Bradley Lake Hydroelectric Project; and providing for an effective date."

RECOMMENDS:

[ ] replace with ______________ [ ] the same title

[ ] attached amendment(s) [ ] a new title

[X] do pass

[ ] do not pass

[ ] no recommendation

[ ] individual recommendations

[ ] additional referral to the ______________ Committee

ADOPTS: [X] House Finance letter of intent

ATTACHES NEW FISCAL NOTE(s):

[ ] fiscal impact

[ ] zero fiscal note

[ ] zero with analysis

[ ] same as previous fiscal note published ______

[ ] same as previous zero fiscal note published ______

SIGNING DO PASS:

Al Adams

Pat Pourchot

Ronald L. Larson

Mark Boyer

Steve Frank

Steve [illegible]

SIGNING OTHER RECOMMENDATIONS:

[illegible] - no rec

Kay Brown - DO NOT PASS

Mike Davis DO NOT PASS WITHOUT LETTER OF INTENT

Al Adams

Chairman's signature

Alaska State Legislature

HOUSE OF REPRESENTATIVES

Committee on Finance

Official Business

P.O. Box V
State Capitol
Juneau, Alaska 99811

HOUSE FINANCE COMMITTEE
LETTER OF INTENT
FOR
SENATE BILL 159

It is the intent of the Legislature that no additional encumbrances shall be made on funds appropriated for the Bradley Lake project until the utilities proposing to buy power from the project sign binding, unconditional, take or pay power sales agreements for one hundred percent of the production.

Al Adams

Al Adams, Chair
House Finance Committee

Introduced: 3/3/87
Referred: Finance

IN THE SENATE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

SENATE BILL NO. 159

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act amending an appropriation to the Alaska Power Authority for the Bradley Lake Hydroelectric Project; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. Section 3, ch. 128, SLA 1986, page 8, line 7, is amended to read:

	Appropriation Item	General Fund	Other Funds
Alaska Power Authority -- Bradley Lake Hydro-electric Project	$50,000,000	[$50,000,000]	<u>$50,000,000</u>

* Sec. 2. The funding source of this amended appropriation is the Railbelt Energy Fund (AS 37.05.153).

* Sec. 3. This Act takes effect immediately under AS 01.10.070(c).

STEVE COWPER
GOVERNOR

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

March 3, 1987

The Honorable Jan Faiks
President of the Senate
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Senator Faiks:

Under the authority of art. III, sec. 18, of the Alaska Constitution, I am transmitting a bill that amends an appropriation to the Alaska Power Authority -- ch. 128, SLA 1986, page 8, line 7, in the amount of $50,000,000 -- by changing the funding source from the general fund to the Railbelt Energy Fund (AS 37.05.153).

AS 37.05.153, the law outlining the purpose of the Railbelt Energy Fund, specifies that the legislature may appropriate money from the fund to assist in meeting railbelt energy needs. As the Bradley Lake Hydroelectric Project is designed to reduce the long-term cost of power to railbelt consumers, my Administration is recommending that funding for the project be appropriated from the Railbelt Energy Fund.

Sincerely,

Steve Cowper
Governor

4/28/87

LETTER OF INTENT
Senate Bill 159

House Finance Committee

No additional encumbrances shall be made on funds appropriated for the Bradley Lake project until the utilities proposing to buy power from the project sign binding, unconditional, take or pay power sales agreements for one hundred percent of the production.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

April 20, 1987

MEMORANDUM

TO: Representative Sam Cotten

gfor gffr gk.

FROM: Ginny Fay and Gretchen Keiser
Legislative Analyst

RE: Joint House and Senate Resources Hearing on Railbelt Energy
Research Request 87.259

You requested that we provide comments on testimony that was presented during the April 8, 1987 Joint House and Senate Resources Committees' meeting on Railbelt energy.

BENEFITS OF THE BRADLEY LAKE HYDROELECTRIC PROJECT AND INTERTIES

The "Railbelt Energy Plan" dated April 8, 1987 and some Railbelt utility managers have asserted that the House Research Agency (HRA) has conducted studies that "show positive benefits for Bradley Lake and the interties, even when considered on their own." The HRA is currently reviewing analyses conducted by the Alaska Power Authority (APA) on the Anchorage-Kenai and Anchorage-Fairbanks interties. We have not, however, completed our analysis. Therefore, we have not reached any conclusions regarding the net benefits of the interties at this time.

Although we have not completed our analysis of the interties, we have some comments regarding the testimony presented. The statement that the interties will provide $423 million in benefits is a bit misleading in that the figure is a simple sum of benefits. Standard presentation of this type of information is as the present value of net benefits (i.e., costs are subtracted from benefits after appropriate discounting). As calculated in the APA study, the present value of intertie benefits is approximately $205 million; the present value of costs is approximately $210 million. Therefore, the benefit-cost ratio for the intertie is close to one rather than greater than two as might have been inferred from the testimony.

The intertie economic feasibility analyses currently being conducted for the APA do not satisfy statutory requirements as provided in AS 44.83.177 and .183 or regulations 3 AAC 94.055-65 (Attachment A). Further, Senate

Bill 206 (Section 4)--which would exempt intertie projects from the reconnaissance, feasibility and financial studies; OMB review; and legislative approval requirements under AS 44.83.177-185--appears to be in direct contradiction with Finding No 3 of the "Report of the Railbelt Energy Council" dated January 24, 1987 (page 14). Finding No 3 states that "the burden of proof for making a compelling case for State participation in any project rests with the project sponsor(s) to include demonstrating that private financing is not feasible or available and that public policy considerations warrant financial assistance by the State."

Regarding the Bradley Lake Project, our March 18 memorandum concluded that, given sunk costs, the project would probably show net savings over the natural gas alternative for the 50-year period of analysis. We also concluded, however, that in order to more accurately project the benefits of the project, an analysis computing the projected costs of all power consumed in the Railbelt under additional scenarios would be required. Our memorandum analyzed only the economic **feasibility** of Bradley Lake versus one alternative based on costs of the projects; we did not perform a **benefit-cost analysis.** A benefit-cost analysis takes into consideration a wide spectrum of direct and indirect costs and benefits of a project and its alternatives. The present value of net benefits are then calculated to determine the desirablity of proceeding with a project.

Our analysis, as well as those of the APA and Division of Policy, merely compared the costs of Bradley Lake and the natural gas alternative--no assessment was made as to whether either of these options was the "best" alternative for consumers in the Railbelt. In our cost analysis, we concluded that the $85 million savings calculated by the Division of Policy answered the question "which is the less expensive option to construct excess capacity?" Given Railbelt energy supply and demand, we believe that the Railbelt utilities would not add generating capacity during the next decade if they were to bear the full cost of the projects. We believe that the scenario in which construction of a gas plant is delayed until 1998 offers a reasonable comparison of the gas/hydro alternatives. That scenario showed net savings of $36 million attributable to the Bradley Lake project.

A statement made a number of times during the committee hearing was that construction of the Bradley Lake Project and the interties will provide badly needed jobs in the Railbelt area. It should be noted, however, that these projects are capital intensive and provide relatively few jobs per dollar of expenditure. A Bonneville Power Administration Study found that high impact conservation programs create more jobs than would be created by building new power plants to generate an equivalent amount of energy.[1]

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[1]Bonneville Power Administration. "Electric Energy Conservation Study." Portland: 1976 (prepared by Skidmore, Owings & Merrill). "Energy, Jobs, and the Economy" by Richard Grossman and Gail Daneker (Alyson Publications, Inc.; 1979) provides additional information about energy programs and employment.

A comment was also made that the loss of royalties and severance and income taxes should be considered if Bradley Lake is built rather than the natural gas alternative. While we agree that these types of costs should be considered in a benefit-cost analysis, this income to the State would most likely be postponed (thus would have a lower present value) rather than be lost.

EFFECT OF THE INTERTIES ON RESERVE CAPACITY AND POWER COSTS

Comments during the committee meeting regarding required reserve capacity indicated that 30 - 40 percent reserve requirements were industry standards in the contiguous states and 60 - 70 percent was realistic for future planning in the Railbelt. To the contrary, a number of dockets have occurred in other states to remove capacity over a 20 percent margin from rate base calculations.[2] In addition, a number of professional journal articles also support a 20 percent reserve margin in other states.[3] On this basis, our Bradley Lake analysis used a 30 percent reserve margin. Based on our projections of demand, reserve margins in the Railbelt will probably exceed 60 percent until the late 1990s.

Has this been considered?

In addition, Tesoro Alaska Petroleum Company has recently contacted the Alaska Public Utilities Commission to commence cogeneration electrical production at the Nikiski refinery on the Kenai Peninsula. They expect to be able to produce all their own electricity as well as sell 20 - 40 megawatts (MW) of electricity.[4] This lower price energy will most likely add 40 to 60 MW to the excess capacity in the Railbelt.

There was also testimony presented that Golden Valley Electric Association (GVEA) had reduced its customer electric rate 25 percent based on economy energy sales over the intertie. The GVEA has not had a rate change docket open in five years, but did lower its adjustable fuel surcharge rate based on the reduction of the cost of fuel oil (obtained from MAPCO) since spring 1986.

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[2] Indiana Public Service Commission, Northern Indiana Public Service Co., Cause # 37458, June 19, 1985, p. 402; Pennsylvania Public Utility Commission, West Penn. Power Co., Docket # R-842651, August 28, 1985; Missouri Public Service Co., Kansas City Power and Light Co., Case # Eo-85-185 and EO-85-225, April 23, 1986.

[3] John Douglas, "System Reliablity: Seeing the Whole Picture," EPRI (Electric Power Research Institute) Journal, November 1986; 37th Annual Electrical Facility Forecast, Staff Report from the Electrical World Magazine, September 1986, p. 50; and Paul D. Ziemer, "Sound Public Policies are Needed for an Electric Future," Public Utilities Fortnightly, June 13, 1985.

[4] David Brown, Engineer Tesoro Refining Co., Kenai, Alaska, Personal communication, April 9, 1987.

POWER RATES UNDER BRADLEY LAKE OR THE GAS ALTERNATIVE

There was a presentation and discussion during the committee hearing regarding the point in the future when power rates under the gas alternative would begin to exceed the rates projected for Bradley Lake. It was stated that the crossover would occur roughly five to seven years into Bradley power production. Implicit in this timeframe is the assumption that the State makes an equity contribution on the order of $175 million for the Bradley Lake project, whereas the gas turbine alternative would be entirely bond financed. According to our March 18, 1987 analysis of the economic feasibility of the two alternatives--which assumed that costs for both alternatives would be bonded, thereby implicitly assuming no further State subsidy of Bradley Lake--the power rate crossover would occur in about 2004, or 14 years into Bradley power production.

Although the information presented at the hearing is probably representative of rate calculations for Bradley Lake, we caution you that the projected power rates under the two alternatives are quite sensitive to some of the underlying assumptions built into the model. Changing the long-term bond interest rate from eight to ten percent, for example, delays the crossover point roughly three years because of the proportionately greater impact on Bradley Lake debt service. On the other hand, if the heat rate for a new gas turbine is raised from 11,500 Btu/Kwh (assumed in our March 18 analysis) to 13,000, the crossover point would occur roughly two years earlier because greater fuel consumption would raise the gas power rates.

BRADLEY LAKE POWER SALES AGREEMENT

This section briefly clarifies a number of comments made during the committee hearing regarding the draft power sales agreement for Bradley Lake power. Under the power sales agreement (PSA), the Railbelt utilities would be accountable for up to $175 million in "recoverable construction costs" (Section 1 (dd); 2/12/87 draft). A long-term revenue bond would be issued by the APA, and the utilities would be responsible for the annual debt service (about $15.5 million for a 30-year, $175 million bond at eight percent). Under the draft PSA, the utilities and the State would share equally in savings if the Bradley Lake construction costs come in under $350 million. On the other hand, the State would be accountable for all excess costs above $350 million.

Contrary to what might have been inferred from testimony given during the hearing, the State would not recover its equity contribution of $175 million under the payment schedule proposed in the PSA. Section 24 of the PSA does provide for an "excess payment amount" to be paid by the utilities as part of the annual project costs once the 30-year bond has been retired. In effect, Railbelt electric customers' power rates will continue to reflect something close to the rates paid during the first 30 years when annual debt service of the bond is necessary. The PSA requires that the State establish a revolving loan fund for future Railbelt energy projects into which these annual excess payments would be deposited. From the perspective of the Railbelt electric customer, this proposal will probably offer little real benefit because their power rates will reflect either the annual excess payments into the revolving loan fund for new generating capacity, or new annual debt service to cover capital investment by the utilities for this same new capacity purchased without the loan fund.

The PSA establishes that, at a maximum, the excess payments would equal four cents/kwh of Bradley Lake power purchased by the utilities. Given that Bradley Lake is estimated to produce 369.2 million kilowatts each year, we calculate that the annual excess payment to a revolving loan fund would be at most about $14.8 million, beginning in 2021. If we take into account inflation over the intervening 34 years (projected at 4.5 percent for the period 1987 - 2021), the $14.8 million will be worth about $3.2 million in today's dollars. Because the payments would commence so far in the future, the net present value of a 20-year revenue stream (2021 - 2040) into the revolving loan fund (under the original 50-year power sales agreement) is estimated to be about $10 million.

STATEWIDE ENERGY EXPENDITURES

The concept of a statewide program for sharing in the expenditure of State energy dollars in the future was considered during the committee hearing. It was asserted that rural areas had not received an equitable share of State energy funds to date. Table 1 below summarizes our estimates of State energy appropriations for the period FY 77 - FY 86. On a strict urban-rural split, the urban areas of the state (as noted in Table 1) have received nearly three times the energy appropriations received by the rural areas on a per capita basis.

TABLE 1
ESTIMATED STATE ENERGY APPROPRIATIONS: FY 77 - FY 86

REGION	FY 85 POPULATION	TOTAL ESTIMATED APPROPRIATIONS	PER CAPITA
Urban	377,440	$1,549,600,000	$4,106
Rural	145,608	214,100,000	1,470
Railbelt			
w/R.E.Fd	376,136	709,500,000	1,886
w/o R.E.Fd	376,136	428,570,000	1,139
Four-Dam Pool	32,991	839,900,000	25,458
Unallocatable (statewide)	523,048	131,800,000	252
Total Statewide	523,048	1,895,300,000	3,624

Note: 1) Both grants and loans are included in appropriation totals.

2) Because of difficulties encountered in reconciling numerous legislative appropriation bills with agency records, these figures should be viewed as approximations which generally reflect energy expenditures in different regions of the State.

3) "Urban" includes the communities: Anchorage, Fairbanks, Juneau, Kenai, Ketchikan, Kodiak, Palmer, Petersburg, Seward, Sitka, Soldotna, Valdez, Wasilla and Wrangell.

4) Railbelt appropriations are estimated with and without the Railbelt Energy Fund of $281 million.

5) R. E. Fd = Railbelt Energy Fynd.

6) Four-Dam Pool communities include Kodiak, Port Lions, Valdez, Glennallen, Ketchikan, Wrangell and Petersburg.

Source: Rural Energy: An Overview of Programs and Policy, House Research Agency Report 85-C (February 1985) and appropriation updates.

The urban figure is somewhat misleading because it includes appropriations for the four-dam pool projects, which vastly exceed appropriations for rural or Railbelt projects on a per capita basis, as indicated in Table 1. If we compare rural and Railbelt per capita appropriations, rural residents have received about $400 less than Railbelt residents--assuming that the Railbelt Energy Fund (REF) is spent in the Railbelt. Without the REF, however, the Railbelt region will have received less per capita than rural Alaska over the 10-year period. As you are aware, a primary vehicle for equalizing statewide power rates presently is the Power Cost Equalization Program, which will represent about $95 per capita in FY 87 for rural residents.

COOK INLET GAS FOR POWER GENERATION

Comments were raised during the committee hearing regarding the long-term availability of Cook Inlet natural gas for power generation. It was asserted that gas production will decline unless new reserves are found--a serious concern on the planning horizon for utility management. As you may recall, our April 13, 1987 memorandum which examined the Cook Inlet gas situation concluded that known gas reserves would likely supply current end uses until approximately 2010. Further, we suggested that additional recoverable gas--likely to be discovered although in uncertain amounts--could supply Railbelt consumption for another 10 to 25 years, or longer.

Testimony was presented that Cook Inlet gas should be reserved for its "highest and best use"--presumedly space heating and power generation. The implication, of course, is that other uses--specifically LNG export and Ammonia-Urea production--should somehow be restricted. We believe that a public policy proposal is being confused with current and future market conditions in Cook Inlet. As our April 13 memorandum suggested, dwindling gas supplies at some point in the future would likely push contract prices upward. Nonregional use (LNG export and Ammmonia-Urea production) could decline as foreign customers seek cheaper products elsewhere or Cook Inlet producers seek more profitable gas contracts with Railbelt electric and space-heating utilities. Future market conditions would, in effect, reserve the gas for those end uses which are willing to pay--without any public policy intervention.

* * *

Please contact us if you have any questions regarding this information.

Attachment

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

April 8, 1987

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay
Legislative Analyst

RE: Railbelt Energy Analysis
Research Request 87.114 (Supplemental Information)

As part of this agency's analysis of Railbelt energy, you requested that we provide additional information on cogeneration and small electrical power facilities that are covered under the Public Utilities Regulatory Policy Act (PURPA) of 1978. These facilities were generally referred to as PURPA generators in our memorandum of March 18. This memorandum initially covers the regulatory authority pursuant to PURPA and an overview of how these alternative energy regulations have affected electrical power generation in the United States. This is followed by a discussion of the potential effects of State financing of the Bradley Lake project on these types of facilities in the Railbelt. This includes a discussion of the role of the Alaska Public Utilities Commission (APUC) and Federal Energy Regulatory Commission (FERC) in the Bradley Lake Power Sales Agreement.

Regulatory Background and Authority

Precipitated by the Arab oil embargo in 1973 and further accentuated by the inability of pipelines to deliver natural gas to meet winter demands, legislation was proposed by President Carter to curb America's use of oil and gas. The legislation was designed to eliminate the country's dependence on foreign oil while simultaneously conserving "scarce" natural resources. The result of the administration's legislative package was the passage of the National Energy Acts which were signed into law by the President on November 9, 1978.[1]

Contained within the Public Utilities Regulatory Policy Act of 1978 (PURPA) were two sections regarding small power production and cogeneration.[2] The PURPA was designed to encourage conservation and efficiency in energy use, regulate wheeling of bulk power, and provide incentives for industrial cogenerators and small power producers.[3]

At present, small-scale renewable technologies are not a major factor in the nation's overall electricity supply, accounting for less than one-half of one percent of total generating capacity. Traditional utility forecasts of electricity supplies have not even included these resources in capacity planning.[4] Currently, with oil prices falling, renewable energy tax credits being phased out, and cutbacks in federal research and development support, there is a tendency to down play the future role of renewable technologies.[5] Market penetration of renewable technologies is growing, however, and most have attractive features--including short lead time, modular design characteristics, reduced environmental impacts, and inflation-proof fuel costs--that make them especially appropriate for deployment in today's uncertain utility planning environment.[6]

Although the portion of electrical power generation provided by cogeneration and small power facilities remains small, tremendous growth has occurred in the application of these technologies during the years since enactment of PURPA (Figure 1). Whether measured by the increase in total dollars expended on cogeneration equipment and related systems, by the number of applications for qualifying facility status filed with the Federal Energy Regulatory Commission (FERC), or by the increase in the nation's electrical capacity contributed by PURPA systems, it is clear that these facilities are beginning to contribute significantly to America's energy supply and have become an important factor in planning for the nation's energy needs to the year 2000.[7] Table 1 provides information regarding potential electrical power production by cogeneration.

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[2]Section 201, 92 Stat. 3134, 16 U.S.C. § 796(16) through (22), and §210, 92 Stat. 3144, 16 U.S.C. § 824a-3.

[3]Cogeneration is the sequential production of both electrical (or mechanical) energy and thermal energy from the same primary energy source.

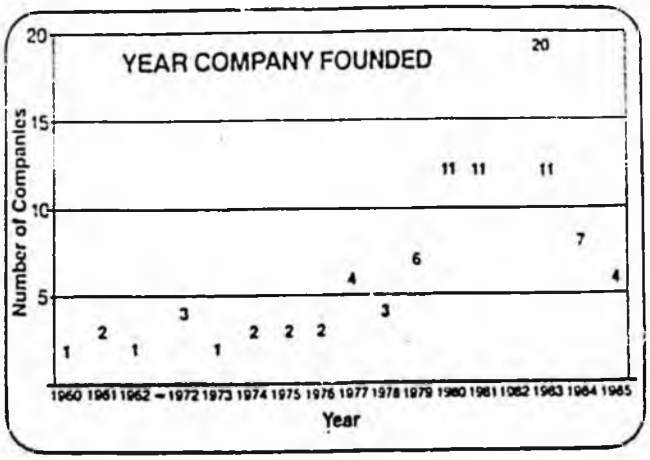
[4]The exception to this is California, which has adopted an avoided cost methodology for electrical capacity production.

[5]Scott A. Fenn, "Renewable Power Generation: Beyond the Shakeout," Public Utilities Fortnightly, November 13, 1986, p. 24.

[6]Ibid., p. 25.

[7]Michael J. Zimmer and Beverly E. Jones, "Cogeneration: Boon or Bane to Consumers?" Public Utilities Fortnightly, June 12, 1986, p. 23.

Figure 1



Source: Fenn, op. cit., p. 27

TABLE 1

Summary of Cogeneration Potential Compared to Current Capacity of Operating Power Plants as of 1983 (Megawatts)

STATE	POTENTIAL INSTALLED COGEN. CAPACITY (1)	TOTAL CURRENT INSTALLED ELEC. CAPACITY (2)	COGEN. AS A PERCENT OF TOTAL ELEC. CAPACITY
ALABAMA	1,017	19,199	5.30
ALASKA	185	1,444	12.81
ARIZONA	145	11,015	1.32
ARKANSAS	353	8,796	4.01
CALIFORNIA	3,944	39,821	9.90
COLORADO	135	6,501	2.08
CONNECTICUT	258	6,107	4.23
DELAWARE	188	2,053	9.16
DIST OF COLUMBIA	1	868	0.12
FLORIDA	1,016	31,893	3.19
GEORGIA	920	17,562	5.24
HAWAII	147	1,482	9.92
IDAHO	21	2,020	1.04
ILLINOIS	1,408	29,710	4.74
INDIANA	502	18,700	2.68
IOWA	482	8,815	5.47
KANSAS	583	9.488	6.14
KENTUCKY	534	15.965	3.34
LOUISIANA	3,258	15,495	21.01
MAINE	529	2,396	22.08
MARYLAND	410	9,816	4.18
MASSACHUSETTS	533	9,910	5.38
MICHIGAN	631	22,058	2.86
MINNESOTA	370	8,610	4.30
MISSISSIPPI	385	5,825	6.61
MISSOURI	271	15,720	1.72
MONTANA	0	3,219	0
NEBRASKA	217	5,895	3.68
NEVADA	5	4,564	0.11
NEW HAMPSHIRE	250	1,536	16.28
NEW JERSEY	1,418	13,785	10.29
NEW MEXICO	206	5,393	3.82
NEW YORK	2,126	32,043	6.64
NORTH CAROLINA	882	18,419	4.79
NORTH DAKOTA	221	3,828	5.77
OHIO	2,103	27,467	7.66
OKLAHOMA	475	12.560	3.78
OREGON	454	10,576	4.29
PENNSYLVANIA	2,512	34,824	7.21
RHODE ISLAND	82	270	30.35
SOUTH CAROLINA	960	12,316	7.79
SOUTH DAKOTA	0	2,432	0
TENNESSEE	654	18,188	3.60
TEXAS	5,110	57,615	8.87
UTAH	72	3,032	2.38
VERMONT	38	949	4.00
VIRGINIA	784	11.513	6.81
WASHINGTON	700	21.808	3.21
WEST VIRGINIA	260	15,156	1.72
WISCONSIN	1,241	10,721	11.58
WYOMING	308	5.920	5.20
TOTALS	39,344 MW	655,493 MW	6.00

SOURCES: (1) Dun & Bradstreet Technical Economic Services and TRW Energy Development Group, Prepared for U.S. Dept. of Energy, Industrial Cogeneration Potential (1980-2000) for Application of Four Commercially Available Prime Movers at the Plant Site (August 1984).

(2) As reported by all utilities to Department of Energy.

This growth in cogeneration and renewable energy facilities has not been achieved without some difficulties. The struggle often has involved a portion of the energy industry which could stand to gain the most from a cooperative partnership with these budding technologies--the electric utilities.[8] The suppliers and developers of these newer energy technologies have not been dominated by the traditional utility industry. The utility industry, with a few notable exceptions, has been content to allow nonutility companies to develop and serve as a proving ground for these high-risk new technologies. Development of renewable technologies is being carried out principally by a diverse group of nonutility developers ranging from multinational aerospace and petroleum companies to small, entrepreneurial firms founded on the work of a single investor.[9] One of the principal intents of PURPA was to facilitate the incorporation of these technologies into the electrical regulatory process and markets and thereby encourage their development.

The resistance of utilities is, in part, a result of a broader restructuring of the electrical production industry. Traditionally, electric utilities have enjoyed geographic monopolies under conditions of rapidly growing power consumption. The nationwide decline in growth of electrical demand, coupled with increased competition from unregulated industries (such as the producers of insulation and more efficient lighting systems) and other utilities marketing surplus power, has made the production of electricity a more competitive industry. Perhaps the most important new form of competition for electric utilities in the long run, however, is the emergence of nonutility power producers selling power to the grid under provisions of the PURPA.[10]

With the development of PURPA, Congress gave the FERC a mandate to prescribe rules as it determined necessary to encourage cogeneration and renewable power production. Those rules were to require electric utilities to offer to purchase electric energy from PURPA facilities (referred to as "qualifying facilities"). The regulations were to ensure that the rates for such purchases would be just and reasonable to the consumers of the electric utilities and in the public interest, would not discriminate against the PURPA facility, and would result in a rate which would require the utility's customers to pay no more than they would have paid for electricity had the utility produced the electricity or purchased it from another source.[11] Thus, the price a utility would pay for electricity produced by a qualifying facility would equal the utility's "avoided cost."

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[8]Ibid.

[9]Scott A. Fenn, "Renewable Power Generation: Beyond the Shakeout," p. 26.

[10]Ibid., p. 24.

[11]PURPA § 210(b), 16 U.S.C. § 824a-3(b).

Rates for electricity purchased from qualifying facilities (QF) by electric utilities based on avoided costs fall generally into two categories: capital costs and running or operating costs. The QF is entitled to a capacity payment when the utility can avoid the capital costs of building a new generating unit by purchasing electricity from the QF. Whether or not the utility must incur capital costs to supply the needs of its customers, the utility is expected to save operating costs when it purchases electricity from a QF instead of producing the electricity from its own plants. The operating cost savings are intended to be passed on to the QF in the form of energy payments.[12] The conditions under which capacity costs should be included in avoided costs calculations has been the source of considerable debate on both the state and federal utility regulatory level. The debate is a result of both the regulatory complexities of determining avoided costs and the balancing the interests of utilities, qualified facilities, and electric consumers.

Bradley Lake Project Financing and Power Sales Agreement

The PURPA requires a public utility to purchase electric power and energy from qualifying facilities at the utility's avoided cost. As mentioned above, these avoided costs are the cost a utility would avoid by purchasing power from a qualifying facility rather than generating power itself or purchasing the power elsewhere. As a result of the State subsidy of the Bradley Lake project, avoided cost calculations for the four planned Railbelt PURPA facilities can be expected to be lower than otherwise would be likely.

The developers of all four of the PURPA projects have filed complaints with the Alaska Public Utilities Commission (APUC) against the utility to which they seek to sell power.[13] Each complaint requests the APUC to determine the avoided cost the utility is required to pay to qualifying facilities under PURPA. The complaints, and particularly the SGI complaint, also seek to prohibit the utilities from making power purchases, such as from the Bradley Lake project, that would eliminate the need for power from the private project.

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[12] Robert D. Stewart, Jr., "The Law of Cogeneration in Oklahoma," Public Utilities Fortnightly, November 27, 1986, p. 24.

[13] The four private sector power projects proposed in the Railbelt include AEM Corp. with a 25 Mw "waste coal" project in Healy selling to GVEA; SGI, Inc. with a 50 Mw waste coal project selling to AML&P; Mat-SU Energy Corp. with 20 Mw peat facility selling to MEA; and Valley Energy Corp. with a 15 Mw project fired by wood chips selling output to MEA.

Under current State law--which requires the APUC to review wholesale power sales agreements--the significance of these filings are twofold. First, because the qualifying facilities have filed dockets prior to the APUC review of the Bradley Lake Power Sales Agreement, capital costs of the Bradley Lake project would be included in the calculation of avoided costs. The second factor, however, is that because the Bradley Lake project is the "competing" incremental power purchase, the avoided capital cost would be reduced to the extent that the State subsidizes the construction of Bradley Lake. Given the APUC's authority under the current State law, Bradley Lake capital costs would be included in the calculation of avoided costs for the qualifying facilities in the Railbelt.

If Senate Bill 22--which retroactively removes APUC's authority to review wholesale power sales agreements--is passed, a second scenario results in which Bradley Lake capital costs would not be included in the calculation of avoided costs for power purchases from qualified facilities. This is based on the assumption that the Railbelt utilities will have entered into the Bradley Lake Power Sales Agreement and will have no further need for electrical power generation capacity. Once a generating facility (e.g., Bradley Lake) has been constructed, its capital cost cannot be considered part of a utility's avoided costs.[14] After the completion of the Bradley Lake project, our analysis of Railbelt demand (see our March 18 memorandum) indicates that there will be no additional generating capacity requirements until approximately 1998. Therefore, there would be no avoided capital costs for PURPA facilities. Removal of capital costs in the avoided cost calculations can be expected to have a significant impact on the economic feasibility of planned PURPA generators in the Railbelt.

Avoided costs are calculated on an individual utility basis. If SSSB 22 is passed, only operating costs would be included in the calculation of avoided costs. Because of the complexities and the variability of factors influencing these avoided cost calculations (such as what portion of each utility's electrical generation and/or purchases is Bradley Lake power), it is difficult to estimate the affect of Bradley Lake power on avoided operating costs in the Railbelt. In a recent letter,[15] Ted Moninski, of the APUC, indicated that after the seven Railbelt utilities have signed a contract requiring them to purchase Bradley Lake power, the avoided operating cost to be paid to a qualified facility would most likely be the price of Bradley Lake power--providing the purchasing utility required

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[14]Even though Bradley Lake will not have been completed, the take or pay provision of the power sales agreement will commit the signing utilities to Bradley Lake generating capacity.

[15] T.S. Moninski II, letter to Rep. Kay Brown, March 31, 1987.

additional power.[16] The price at which the Alaska Power Authority sells electricity to the Railbelt utilities becomes the incremental cost for the purchase of additional power. If the utility had no power requirements in addition to Bradley Lake power, the avoided costs would probably be below the cost of Bradley Lake power.

The public financing of the Bradley Lake project would lower the cost of Bradley Lake power. A qualifying facility under private financing might not be able to provide power at the avoided cost resulting from the public financing of the Bradley Lake project. Economic theory suggests that private financing of and production from PURPA qualifying facilities will be less with public funding of the Bradley Lake project than without. **This implies that, ultimately, the State's financing of Bradley Lake will probably displace or delay at least a portion of private financing and construction of PURPA facilities in the Railbelt.** This is based on the assumption that the cost of Bradley Lake power would be considered the the incremental avoided cost.

It is unlikely that Bradley Lake capital costs would be excluded from avoided cost calculations, however, because the PURPA also requires the APUC to enforce the obligated, regulated utilities to purchase power from qualifying facilities at avoided cost. **Because this is a federal regulation, this aspect of the APUC's review of the Bradley Lake Power Sales Agreement cannot be eliminated by the Alaska State Legislature's removal of APUC's authority to review wholesale power sales agreements as proposed by SSSB 22.** If APUC authority is removed, affected parties would most likely petition the APUC under the federal statute. Ultimately, the qualifying facilities would have standing in federal district court and the matter would pass out of State jurisdiction to the FERC. It appears that **the State would retain the greatest level of control over the Bradley Lake Power Sales Agreements by not passing SSSB 22.**

While there are relatively few cases regarding the application of FERC regulations in a situation analogous to the Railbelt's Bradley Lake project and qualifying facilities, one similar ruling should be noted. In a docket pertaining to the Oglethorpe Power Corporation (RE81-56), the FERC decided that when a utility sells power at wholesale to utilities who in turn distribute electricity at retail, it may collectively excuse the individual retail utilities from the obligation to purchase power from the qualifying facilities and instead allow the obligation to fall upon the wholesale generation and transmission company. Under this FERC ruling, the Oglethorpe Power Corporation was required to purchase power and resell it. This ruling implies that as part of the Bradley Lake Power Sales Agreement, the Alaska Power Authority, as the wholesale distributor of electric power, could be required to purchase and resell power from qualifying facilities.

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[16] It is uncertain, however, why the APUC would consider Bradley Lake power to be the basis for determining avoided costs rather than any of the utilities' more expensive increments of power.

The Oglethorpe decision is founded on the idea that the FERC ought to enjoy considerable latitude in making sure that the goals of PURPA--the fostering and encouragement of cogeneration and small power production--will not be compromised. Thus, even though there is no specific PURPA provision or regulation allowing for a waiver of the obligation to purchase electricity from a QF, the FERC decided that such authority was implicit where necessary to accomplish the stated statutory objective. In Oglethorpe, that authority rested upon a catchall clause in PURPA allowing the FERC to adopt "such rules as it determines necessary" to encourage cogeneration development.[17]

In the case of Oglethorpe Power, the system was operated in such a way that it was economically practical for the central wholesale arm to coordinate all QF purchases rather than to incur the expense and inconvenience of requiring each retail utility to develop and install an administrative and engineering staff for QF purchase operations. Therefore, the system was allowed to concentrate QF purchases in one spot.[18]

It should be noted that small hydroelectric projects can be qualifying facilities under PURPA. The Bradley Lake project, however, exceeds the 80 Mw capacity limit.

I hope this information is useful. If you have additional question, please do not hesitate to contact me.

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[17] Bruce W. Rastford, "Pages from the Editor," Public Utilities Fortnightly, November 28, 1985, p. 4.

[18] Ibid.

ALASKA STATE LEGISLATURE
HOUSE OF REPRESENTATIVES
RESEARCH AGENCY

P.O. Box Y, State Capitol
Juneau, Alaska 99811-3100
Mail Stop 3100
(907) 465-3991

March 24, 1987

MEMORANDUM

TO: Representative Sam Cotten

FROM: Ginny Fay and Gretchen Keiser
Legislative Analysts

RE: **Railbelt Energy Analysis**
Research Request 87.114 (Supplemental Information)

This memorandum clarifies our Bradley Lake feasibility analysis and briefly addresses a number of questions raised during yesterday's briefing on Railbelt energy issues.

BRADLEY LAKE FEASIBILITY ANALYSIS

The net savings calculations in our March 18, 1987 memorandum correctly compare the annual production of 369 gigawatt hours (gwh) from Bradley Lake (operating at an annual effective capacity of about 42 megawatts) with 369 gwh annual production from a 87 megawatt (MW) gas plant (operating at an equivalent effective capacity of roughly 41 MW). In other words, the model adjusts the gas plant output to match the projected power production from Bradley Lake.

It could be argued that a 40 MW gas turbine operating at full capacity could provide roughly the equivalent amount of energy as a larger turbine operating at 47 percent capacity. If we substitute a smaller gas turbine for the gas generation alternative under our scenario III (Bradley Lake constructed as scheduled compared with gas plant in operation in 1998), the Bradley Lake net savings decline from $36 million to $3 million (see Attachment A). However, we do not believe that installation of a 40 MW gas turbine in the late 1990s is a realistic alternative because it would be insufficient to meet projected Railbelt demand after about 2002. In fact, installation of a 87 MW gas plant in the late 1990s would also be insufficient to meet projected Railbelt energy demand beyond 2002 (see Attachment B).

Our demand forecast suggests that Bradley Lake power is unnecessary until the late 1990s. At that time, Bradley Lake power would provide sufficient power to postpone the installation of additional generation facilities for roughly five years. To reiterate a point made in our previous memorandum, our analysis answers the question asked: Bradley Lake will probably produce an increment of energy production more cheaply than a gas alternative over the 50-year period of analysis. We have not, however, answered what we believe to be the more appropriate question of "what is the least cost means of meeting the projected Railbelt demand for electrical power?" Addressing this question is more likely to ensure lower power rates for the Railbelt electric consumers.

CONTRACT TERMINATION AND SITE RESTORATION COSTS IF BRADLEY LAKE IS CANCELLED

If the Bradley Lake project were cancelled, approximately $30 million in termination and site restoration costs would be incurred. The question raised during the briefing was whether these costs should be attributed to Bradley Lake or the gas generation alternative in the feasibility analysis. We believe (and our analysis assumes) that the termination and site restoration costs should be calculated as an expense of the gas alternative because these costs would be incurred only if the decision were made to proceed with the gas alternative rather than complete Bradley Lake. On the other hand, if the State completes Bradley Lake, these costs would not be incurred.

THE FEASIBILITY OF THE PROPOSED INTERTIES

A number of questions were raised during the briefing regarding the Kenai-Anchorage and Anchorage-Fairbanks interties--specifically with respect to the proposed coupling of the Bradley Lake project with State funding for the construction and/or upgrade of these interties. While we acknowledge the importance of a review and analysis of the proposed interties, we would like to point out that our present analysis was directed toward answering the question of which alternative (Bradley Lake or a gas turbine) provides power less expensively over a 50-year period of analysis. We are now examining the intertie proposals as part of this series of memorandums we are preparing on Railbelt energy issues. We intend to integrate transmission requirements into our overall analysis of Bradley Lake and the gas generation alternative.

OTHER ISSUES

You requested that we examine two additional issues which are pertinent to the legislature's consideration of Railbelt energy projects. The issues were:

- cost estimates for site restoration which would be required by the FERC if Bradley Lake were terminated; and

- the long-term availability of natural gas in Cook Inlet for gas-fired power generation.

We will provide information regarding these issues shortly in a subsequent memorandum.

* * *

Please contact us if you have any questions.

ATTACHMENT A

TABLE A.1 DELAY OF GAS GENERATION ALTERNATIVE/WITH INSTALLATION OF A 40 MW GAS TURBINE
BRADLEY LAKE NET SAVINGS ANALYSIS

ANALYSIS PARAMETERS	
Cash Flow for Base Construction Cost:	
1987	0%
1988	0%
1989	0%
1990	0%
1991	0%
1992	0%
1993	0%
1994	0%
1995	0%
1996	50%
1997	50%
Load Factor:	100%
Annual Energy (gwh):	369.2
Transmission Cost ($1986 Millions):	$0.0
BRADLEY LAKE	
Cost to Complete:	$283.0
Debt Service (30 yr):	$25.1
NP COST GAS	$217.6
+ term & site restoration	$30.0
NP COST GAS	$247.6
NP COST BRADLEY	$244.6
NET SAVINGS BRADLEY	$3.0

YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
2016		1.0	0.5	0.5	12.3	14.2	3.9	2.90	2.0	6.7	8.7
2017		0.9	0.5	0.5	12.6	14.4	3.9	2.96	2.0	6.4	8.4
2018		0.9	0.5	0.5	12.8	14.7	4.0	3.02	2.0	6.1	8.1
2019		0.8	0.5	0.5	13.1	14.9	4.0	3.08	2.0	5.9	7.9
2020		0.8	0.5	0.5	13.3	15.1	4.1	3.14	2.0	5.6	7.6
2021		0.8	0.5	0.5	13.6	15.3	4.2	3.20	2.0		2.0
2022		0.7	0.5	0.5	13.9	15.6	4.2	3.26	2.0		2.0
2023		0.7	0.5	0.5	14.1	15.8	4.3	3.33	2.0		2.0
2024		0.7	0.5	0.5	14.4	16.1	4.4	3.40	2.0		2.0
2025		0.6	0.5	0.5	14.7	16.3	4.4	3.46	2.0		2.0
2026		0.6	0.5	0.5	15.0	16.6	4.5	3.53	2.0		2.0
2027		0.6	0.5	0.5	15.3	16.9	4.6	3.60	2.0		2.0
2028		0.6	0.5	0.5	15.6	17.1	4.6	3.68	2.0		2.0
2029		0.5	0.5	0.5	15.9	17.4	4.7	3.75	2.0		2.0
2030		0.5	0.5	0.5	16.2	17.7	4.8	3.82	2.0		2.0
2031		0.5	0.5	0.5	16.6	18.0	4.9	3.90	2.0		2.0
2032		0.5	0.5	0.5	16.9	18.3	5.0	3.98	2.0		2.0
2033		0.5	0.5	0.5	17.2	18.7	5.1	4.06	2.0		2.0
2034		0.4	0.5	0.5	17.6	19.0	5.1	4.14	2.0		2.0
2035		0.4	0.5	0.5	17.9	19.3	5.2	4.22	2.0		2.0
2036		0.4	0.5	0.5	18.3	19.7	5.3	4.31	2.0		2.0
2037		0.4	0.5	0.5	18.7	20.0	5.4	4.39	2.0		2.0
2038		0.4	0.5	0.5	19.0	20.4	5.5	4.48	2.0		2.0
2039		0.4	0.5	0.5	19.4	20.7	5.6	4.57	2.0		2.0
2040		0.3	0.5	0.5	19.8	21.1	5.7	4.66	2.0		2.0

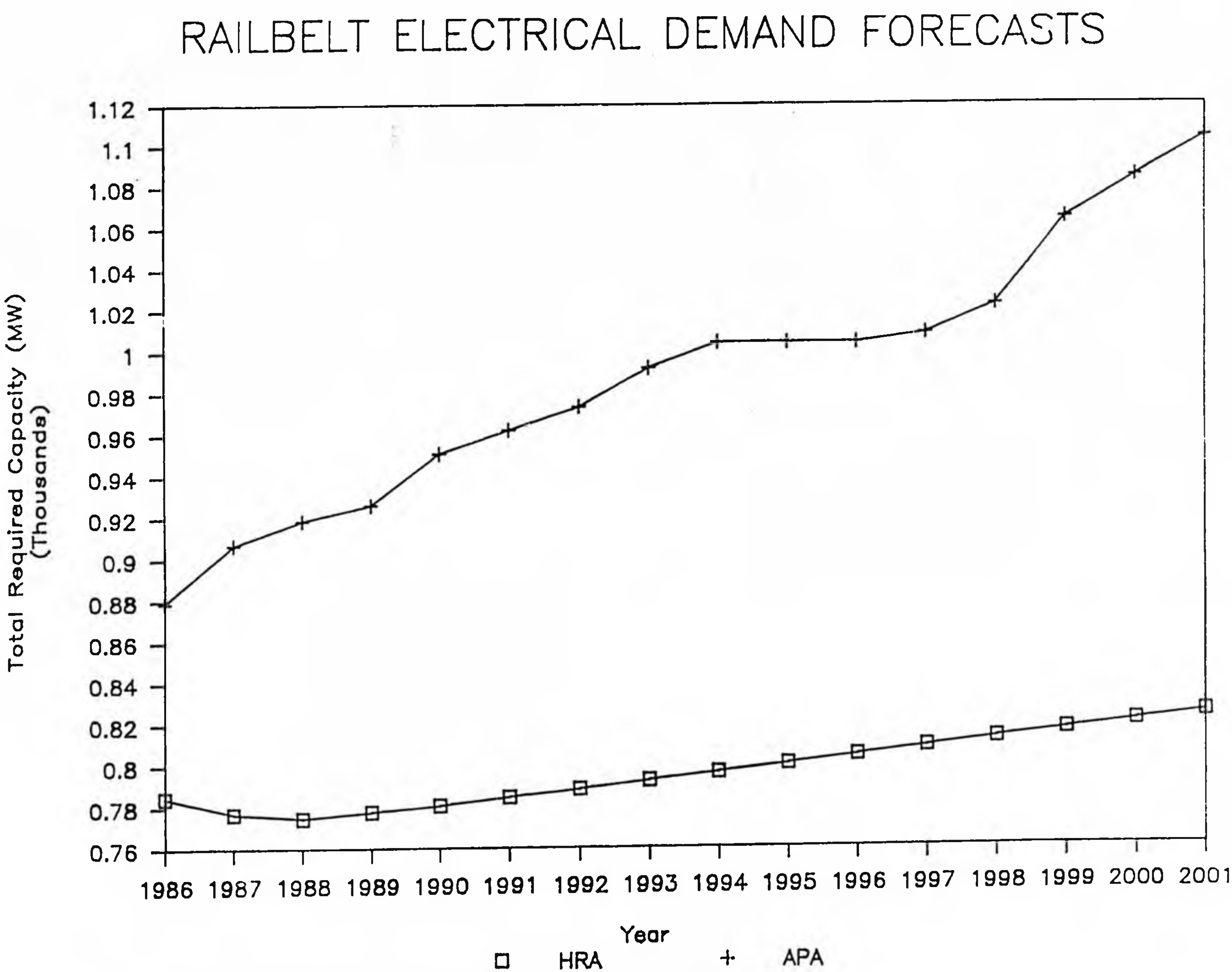
NOTE: The analysis is based on a model originally developed by the Alaska Power Authority.

Prepared by the House Research Agency, March 1987 (40MWgas; 870109-02).

TABLE A.1 DELAY OF GAS GENERATION ALTERNATIVE/WITH INSTALLATION OF A 40 MW GAS TURBINE
BRADLEY LAKE NET SAVINGS ANALYSIS

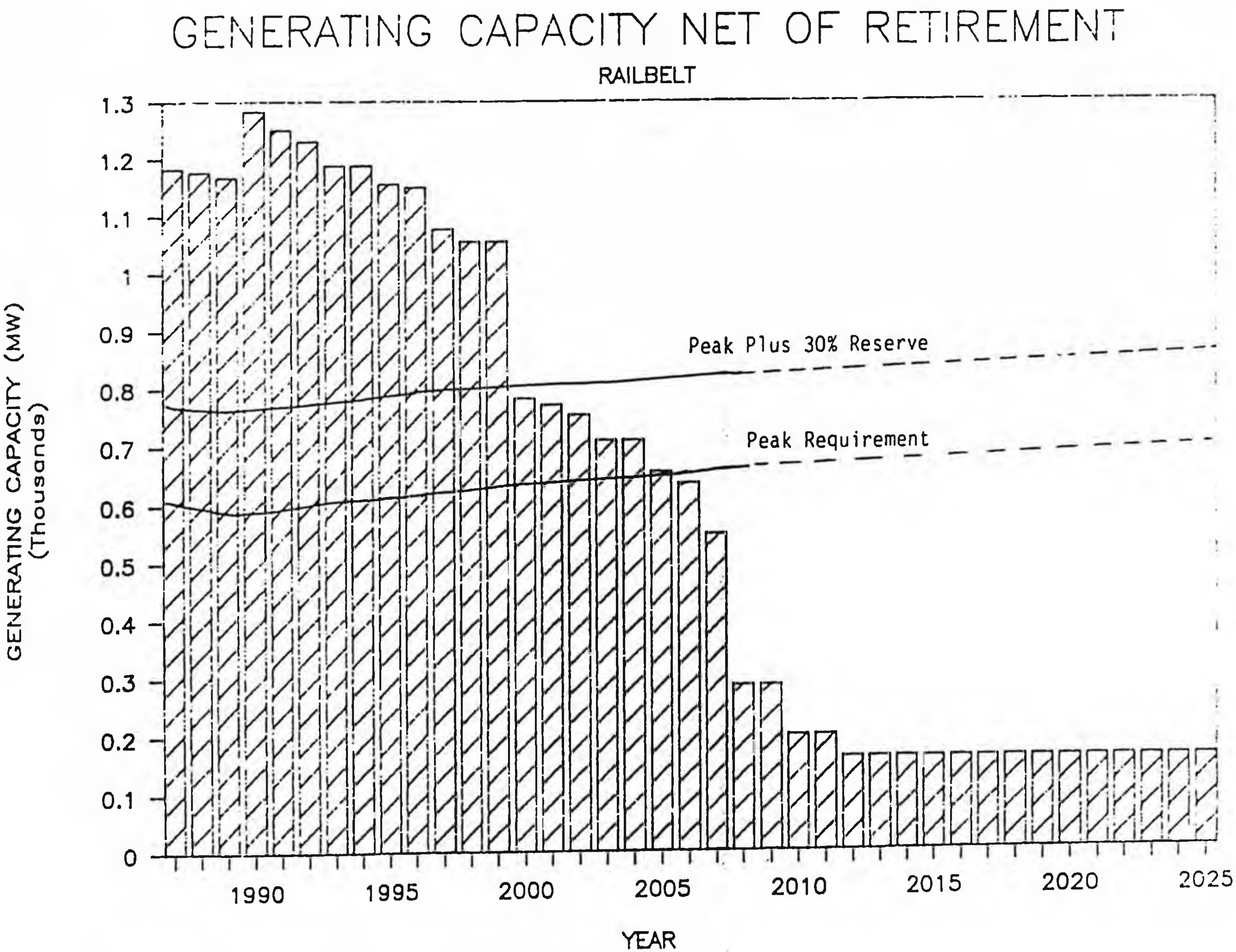
ANALYSIS PARAMETERS		YEAR	CAPITAL COST ($86 MLN)	DEBT SERVICE ($86 MLN)	FIXED O&M ($86 MLN)	VARIABLE O&M ($86 MLN)	FUEL COST ($86 MLN)	TOTAL COST ($86 MLN)	REAL RATE (C/KWH)	REAL WELLHEAD GAS PRICE ($86/MMBTU)	BRADLEY O&M ($86 MLN)	BRADLEY DS ($86 MLN)	TOTAL BRADLEY ($86 MLN)
Base Capital Cost Excluding IDC													
($1986/net kw):	$400												
		1987	0.0							$1.63			
Capacity (net kw):	40,000	1988	0.0							1.66			
		1989	0.0							1.70			
Construction Period (years):	2	1990	0.0							1.73			
Total Bonds:	$30.8	1991	0.0							1.77	2.0	20.2	22.2
Bond Term (years):	20	1992	0.0							1.80	2.0	19.3	21.3
Long-Term Interest Rate:	10.0%	1993	0.0							1.84	2.0	18.5	20.5
Bond Payment (1997$):	$3.6	1994	0.0							1.87	2.0	17.7	19.7
		1995	0.0							1.91	2.0	16.9	18.9
Inflation Rate:	4.5%	1996	8.0							1.95	2.0	16.2	18.2
Reinvest Rate:	6.0%	1997	8.0	2.2				2.2	0.6	1.99	2.0	15.5	17.5
Discount Rate:	3.5%	1998		2.1	0.5	0.5	8.6	11.7	3.2	2.03	2.0	14.8	16.8
		1999		2.0	0.5	0.5	8.8	11.8	3.2	2.07	2.0	14.2	16.2
		2000		2.0	0.5	0.5	9.0	11.9	3.2	2.11	2.0	13.6	15.6
Fixed O&M Cost ($1986/kw/yr):	$11.25	2001		1.9	0.5	0.5	9.1	12.0	3.2	2.15	2.0	13.0	15.0
		2002		1.8	0.5	0.5	9.3	12.1	3.3	2.20	2.0	12.4	14.4
		2003		1.7	0.5	0.5	9.5	12.2	3.3	2.24	2.0	11.9	13.9
Variable O&M Cost ($1986/kwh):	$0.0014	2004		1.6	0.5	0.5	9.7	12.3	3.3	2.29	2.0	11.4	13.4
		2005		1.6	0.5	0.5	9.9	12.4	3.4	2.33	2.0	10.9	12.9
New Turbine Heat Rate		2006		1.5	0.5	0.5	10.1	12.6	3.4	2.38	2.0	10.4	12.4
(BTU/kwh):	11,500	2007		1.4	0.5	0.5	10.3	12.7	3.4	2.43	2.0	10.0	12.0
		2008		1.4	0.5	0.5	10.5	12.8	3.5	2.47	2.0	9.5	11.5
		2009		1.3	0.5	0.5	10.7	13.0	3.5	2.52	2.0	9.1	11.1
Wellhead Gas Price		2010		1.3	0.5	0.5	10.9	13.2	3.6	2.57	2.0	8.7	10.7
($1986/MMBTU):	$1.60	2011		1.2	0.5	0.5	11.1	13.3	3.6	2.62	2.0	8.4	10.4
Gas Delivery ($86):	$0.00	2012		1.2	0.5	0.5	11.4	13.5	3.7	2.68	2.0	8.0	10.0
Real Wellhead Price		2013		1.1	0.5	0.5	11.6	13.7	3.7	2.73	2.0	7.7	9.7
Escalation Rate:	2.0%	2014		1.1	0.5	0.5	11.8	13.8	3.8	2.79	2.0	7.3	9.3
		2015		1.0	0.5	0.5	12.1	14.0	3.8	2.84	2.0	7.0	9.0

ATTACHMENT B



Prepared by the House Research Agency, March 1987.

FIGURE 2



Prepared by the House Research Agency, March 1987.

Steve Cowper, Governor

Alaska Power Authority

State of Alaska

April 17, 1987

The Honorable Virginia Collins
Alaska State Representative
Alaska House of Representatives
Post Office Box V
Juneau, Alaska 99811

Dear Representative Collins:

Thank you for your letter dated March 31, 1987, requesting our reply to the correspondence from Mr. Dale Teel of the Enstar Natural Gas Company. Our remarks are presented below for each of the critical statements made by Enstar:

Enstar Statement 1 (a) : APA is in error on the present and probable future price of natural gas.

The feasibility study performed by Stone and Webster for APA and released in 1984 evaluated the project on the basis of two distinct natural gas price forecasts shown below:

Natural Gas Price Forecasts: Wellhead Values
From 1984 Bradley Lake Feasibility Study
(1983 dollars per MMBTU)

Year	Reference Case	Sensitivity Case
1985	$ 2.16	$ 2.13
1995	3.18	2.23
2005	4.27	2.16
2015	5.60	2.16
2025	6.83	2.16
2035	7.73	2.16

The project was found to be economically feasible in both the reference case and the sensitivity case.

The Federal Energy Regulatory Commission (FERC) released its own evaluation of the project in September 1985 based on the following

8799/691(1)

natural gas price forecast:

Natural Gas Price Forecast: Wellhead Value
From 1985 FERC Project Evaluation
(1982 dollars per MMBTU)

Year	Price
1985	$ 1.99
1990	1.99
1995	2.19
2000	2.42
2010	3.26
2020	5.58

The FERC evaluation also found the project to be economically feasible.

In December 1982, the Enstar Natural Gas Company entered into contracts for the purchase of significant quantities of gas priced initially at $2.32 per MMBTU. The purchase price is adjusted annually based on changes in the price of fuel oil. As a result of these adjustments and the behavior of oil prices, the purchase price has now declined below $2.00. Although the long run price forecast of Cook Inlet natural gas will always be an area of uncertainty, the price level negotiated by Enstar in December 1982 confirms at a minimum that the long run forecast for the sensitivity case in the feasibility study is reasonable.

More recent updates of Bradley Lake economics have not been based on a particular natural gas price forecast, but instead have presented simple comparisons based on a wide range of possible natural gas price trajectories. All of these more recent comparisons performed by APA begin with an assumed base price of Cook Inlet natural gas of $1.60 per MMBTU at the wellhead.

Enstar Statement 1 (b) : APA is in error on gas usage (i.e. efficiency) of gas-fired generating plants.

The "full load" heat rates assumed in the 1984 feasibility study were: 8,000 BTU/KWH for a 200 MW gas-fired combined cycle plant, and 12,200 BTU/KWH for a 70 MW gas-fired combustion turbine. A "full load" heat rate refers to the maximum efficiency of a unit operating at full capacity. Efficiency is reduced for units operating at less than full capacity. The combined cycle heat rate noted above reflects greater efficiency than has been reported for any existing combined cycle plant in the Railbelt. The combustion turbine heat rate noted above reflects a slightly lower level of efficiency than has been reported at "full load" for the newest combustion turbine of comparable size installed in the Railbelt.

The methodology of the 1984 feasibility study was to model the development and operation of the entire Railbelt system with and without Bradley Lake in order to determine the impact of the project on total system costs. Subsequently, requests were conveyed to APA staff to produce a highly simplified update of Bradley Lake economics. It was determined that the most easily understood approach to these requests was to set up a simple comparison of Bradley Lake costs with the costs of duplicating Bradley Lake's output characteristics using a natural gas-fired generating unit. The type of unit selected for this comparison was a gas-fired combustion turbine because, unlike combined cycle units, a combustion turbine can be operated to produce the same pattern of output as Bradley Lake.

The value of the Bradley Lake project is maximized by operating it as a peaking unit (i.e. concentrating its output during periods of peak power demand), and it is intended that the project be operated in that manner. A combined cycle unit, though more efficient than a combustion turbine, is designed for base load applications and is not capable of effective operation as a peaking unit. Because a combustion turbine can readily duplicate the output characteristics of Bradley Lake while a combined cycle unit cannot, any simple comparison between Bradley Lake and a natural gas-fired generator should be based on the costs of operating a combustion turbine.

The cost comparison produced in August 1986 was based on a combustion turbine with an assumed average "heat rate" of 12,000 BTU/KWH. That level of efficiency is approximately equal to the maximum efficiency reported for the newest combustion turbine installed in the Railbelt, operating at full capacity. A number of subsequent comparisons performed by APA and others are based on an assumed average heat rate of 13,000 BTU/KWH. The reason for this is that the combustion turbine would not be operated at full capacity (and, therefore, at maximum efficiency) at all times, but rather would produce a variable pattern of output reflecting less than full capacity operation during much of the year. An estimate of average efficiency throughout the year has therefore been substituted in these later comparisons for an estimate of maximum efficiency.

Enstar Statement 1 (c) : APA is in error on capital cost of gas-fired generators.

Capital cost estimates for natural gas-fired generators were developed for the Railbelt Electric Power Alternatives Study prepared by Battelle Pacific Northwest Laboratories in 1982 on contract to the Office of the Governor, Division of Policy Development and Planning. The Battelle estimates from that study are as follows:

Capital Cost of Gas-Fired Generators
From Battelle, 1982 Railbelt Alternatives Study
(1980 dollars)

70 MW Combustion Turbine	$560 per KW
200 MW Combined Cycle	$920 per KW

These estimates from the Battelle study were used in the 1984 Bradley Lake feasibility study after adjusting for inflation.

The Bradley Lake economic update issued in August 1986 used a capital cost estimate of $484 per KW (in 1986 dollars) for a combustion turbine, based on the actual cost of installing the new combustion turbine located at Soldotna. It has been noted that the cost of installing the Soldotna unit included a significant measure of site preparation expense that would usually not be incurred. As a result, the most recent comparisons of Bradley Lake costs with the costs of building and operating a combustion turbine have used capital cost estimates of $350 to $400 per KW (in 1986 dollars).

Enstar Statement 2 : APA has not evaluated the loss of State revenue that would occur as a result of reduced natural gas sales.

The Bradley Lake project will help to extend the life of Cook Inlet gas supplies, but will not reduce the aggregate amount of such gas consumed over time. The effect on State revenues would be to help stretch them out over a somewhat longer time period, not to reduce the total amount received. To the extent that resource prices increase over time, the total amount of State revenue from the sale of these resources would be increased.

Enstar Statement 3 (a) : Completing Bradley Lake now would seriously drive Railbelt electric rates upward.

It is presently anticipated that the price of Bradley Lake output in its initial year of operation will be approximately 5.0 cents per kwh. If all of the project's output were sold to Chugach Electric Association and Homer Electric Association, it is estimated that retail rates in that initial year would be approximately 2% to 4% higher than they would otherwise be. If all seven Railbelt utilities participate in purchasing Bradley Lake output, the magnitude of retail rate impact in the initial year would be reduced by approximately half.

Over the long term, Bradley Lake rates will be highly resistant to inflation because the dominant cost element is fixed annual debt service. Though rates from Bradley Lake would be stable over time, rates for gas-fired generation are expected to increase at least as much as the rate of inflation. The purchasing utilities have expressed the expectation that Bradley Lake rates will equal gas-fired rates within the first five to ten years of project operation. Since the project is expected to produce power for perhaps 100 years before requiring major renovation of its primary structures, Bradley Lake rates are expected to be less expensive than the gas-fired alternative for 90 to 95 years following the crossover point. The long run cost savings and rate stability of conventional hydroelectric technology is the essential basis for the project's appeal to the purchasing utilities.

Enstar Statement 3 (b) : Completing Bradley Lake now would drive Railbelt gas rates upward because of Enstar's take or pay gas contracts executed in 1982.

Mr. Teel states that the 1982 contracts were executed "when Enstar concluded that Bradley Lake was not economically viable." There is an implication in this statement that Enstar would not have committed to the take or pay provisions if the company believed that the Bradley Lake project would be built. However, there was every reason to believe at that time that the project would be built, and a strategy based on the project's eventual abandonment would have been imprudent at best.

Though world oil prices in 1982 had receded somewhat from their high water mark of the previous year, they were still holding in the $30 per barrel range and were generally expected to resume their upward climb following a period of market readjustment. As late as June 1983, the State revenue forecast (at the 50th percentile level) anticipated that petroleum production revenues would amount to approximately $3.0 billion per year through the end of the century, despite the expected decline in Prudhoe Bay production levels. It was the 1982 State Legislature that authorized the transfer of the project from federal to State sponsorship, clearly with the intention of pursuing its construction with the benefit of State oil revenue. (The U.S. Army Corps of Engineers had found the project to be economically feasible in 1978, prior to the run-up of oil prices in 1979 and

1980, but was not proceeding with construction at that time due to limited federal funding.) There was every indication in 1982 that the State had the desire and capability of building the Bradley Lake hydro project at an estimated construction cost of $300 million (in 1983 dollars).

During 1985, natural gas-fired generation supplied about 93.5% of the electric energy requirements of the southern Railbelt area. The remaining 6.5% was supplied by the Eklutna and Cooper Lake hydro projects. Had Bradley Lake been operational and reserved for use by the southern Railbelt, natural gas-fired generation would have supplied about 81% of these requirements, with hydro contributing the remaining 19%. It is correct that Enstar's take or pay provisions have not been a subject of review within the Bradley Lake feasibility evaluations. However, it would not be appropriate to deprive consumers of the improved supply diversity that Bradley Lake would provide in a generation system that is (and will continue to be) dominated by natural gas, as a result of contracts executed by Enstar in full knowledge of the Bradley Lake project and the probability that it would be built.

In addition, the implication that these contracts are irrevocable is highly questionable. In recent years throughout the nation, dozens of long term gas contracts have been voided due to changing market conditions.

Enstar Statement 4 : The opportunity value of State equity in Bradley Lake would be lost.

State funds that have either been spent or irrevocably committed to the Bradley Lake project have been estimated in the range of $70 million to $95 million, depending on site restoration costs that would be required in the event of project termination. Terminating the project would result in the loss of that investment. The "opportunity value" of the remaining State contribution to the project depends on what the alternative use of those funds would be.

Enstar Statement 5 : None of the studies take into consideration the $100 million to $200 million to be spent on transmission systems.

The Bradley Lake feasibility study accounts for the cost of connecting the project with the Kenai Peninsula transmission system. All of the project's output can be absorbed on the Kenai Peninsula, and the project's economic feasibility has been established on the basis of no additional transmission requirements. The Railbelt utilities seek additional transmission upgrades for a variety of reasons, one of which is to facilitate the distribution of Bradley Lake benefits to consumers north of the Kenai Peninsula.

We agree that a project such as Bradley Lake merits careful evaluation. Consideration of the Bradley Lake project by State and federal agencies goes back over 30 years. During the past ten years, such consideration has included the following:

1) 1978: U.S. Army Corps of Engineers feasibility study.

2) 1984: Alaska Power Authority feasibility study.

3) 1985: Office of Management and Budget (OMB) review of APA feasibility study.

4) 1985: Federal Energy Regulatory Commission (FERC) review of APA feasibility study.

5) 1987: OMB reevaluation of Bradley Lake economics.

6) 1987: House Research Agency review of Bradley Lake economics.

Each of these studies and evaluations has concluded that construction of the project should proceed. Further, the Railbelt utilities have consistently supported its construction.

Please let me know if you desire additional information.

Sincerely,

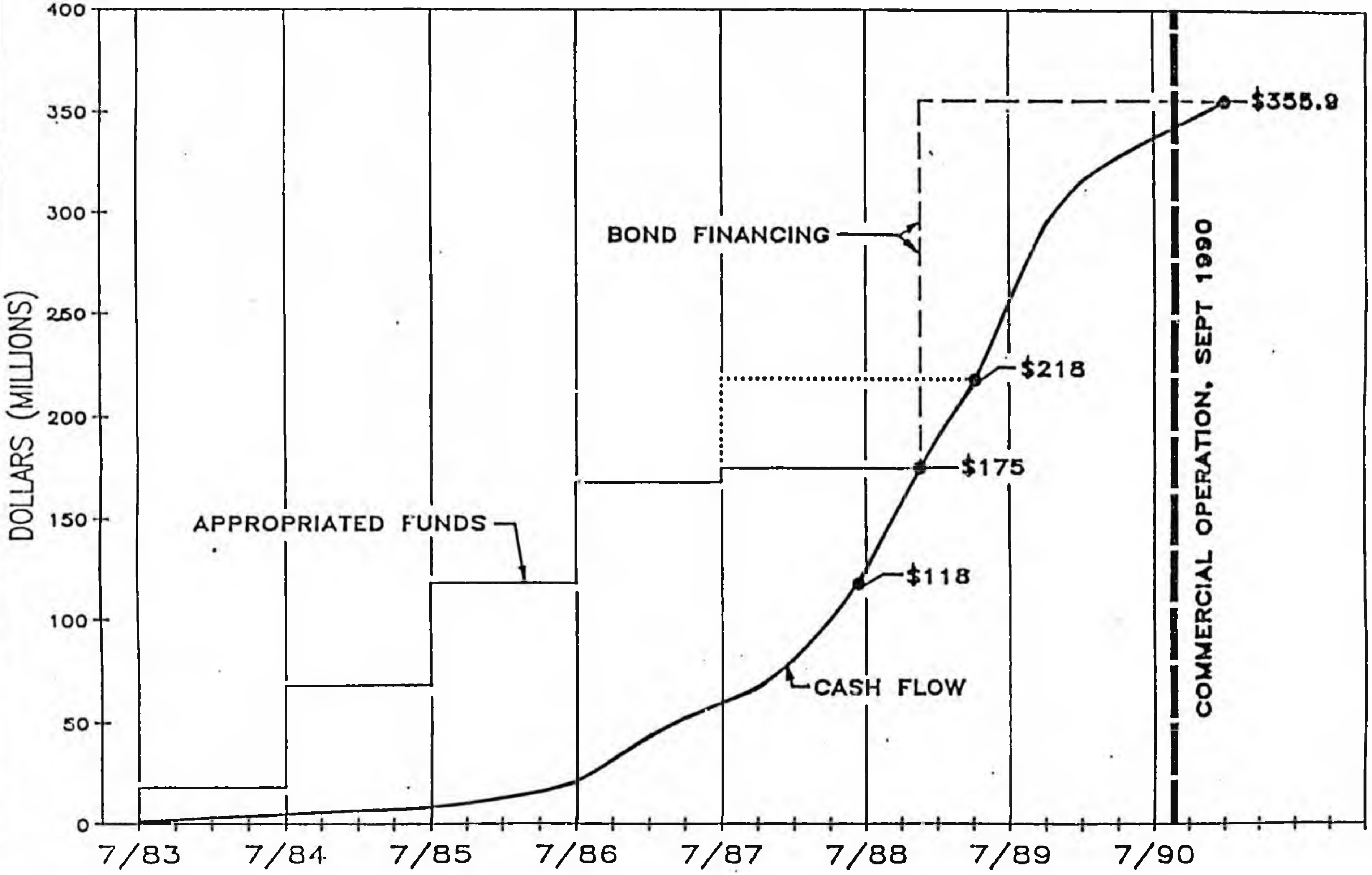
Brent N. Petrie for

Robert E. LeResche
Executive Director

RE:REL:it

8799/591(7)

ALTERNATE #2
CASH FLOW



BRADLEY LAKE HYDROELECTRIC PROJECT, MARCH 1987

BRADLEY LAKE PROJECT

TOTAL COST IF TERMINATED

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

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Introduced: 3/3/87
Referred: Finance

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IN THE SENATE

BY THE RULES COMMITTEE BY REQUEST OF THE GOVERNOR

SENATE BILL NO. 159

IN THE LEGISLATURE OF THE STATE OF ALASKA

FIFTEENTH LEGISLATURE - FIRST SESSION

A BILL

For an Act entitled: "An Act amending an appropriation to the Alaska Power Authority for the Bradley Lake Hydroelectric Project; and providing for an effective date."

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:

* Section 1. Section 3, ch. 128, SLA 1986, page 8, line 7, is amended to read:

	Appropriation Item	General Fund	Other Funds
Alaska Power Authority -- Bradley Lake Hydro-electric Project	$50,000,000	[$50,000,000]	$50,000,000

* Sec. 2. The funding source of this amended appropriation is the Railbelt Energy Fund (AS 37.05.153).

* Sec. 3. This Act takes effect immediately under AS 01.10.070(c).