

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 8672
970 SCOM44: HOUSE POWER ALTERNATIVES STUDY COMM. 1979-80 970

(d) The terms for a loan under (b)(1) of this section are as follows:

(1) the rate of interest is the same rate set for the bonds of the authority issued for the project;

(2) for a project which is not financed by bonds of the authority, the rate of interest is the average weekly rate of interest reported in the Weekly Bond Buyer for municipal revenue bonds for the 12 months preceding the loan application;

(3) the amount loaned may not exceed more than 20 percent of the original estimate of the cost of constructing the project other than the cost of debt service to redeem the bonds first issued for the project; and

(4) the owner of the project shall agree to repay a loan made under this section by the issuance of additional bonds or another method of financing within five years after the loan is made.

(e) The terms for a loan under (b)(2) of this section are as follows:

(1) the amount loaned may not exceed the debt service on bonds issued for the project for one year after the natural disaster and other expenses of the project which are determined necessary by the authority; and

(2) the rate of interest on the loan is the same rate set for the bonds issued to finance the project.

(f) The authority shall adopt regulations under AS 44.62 which prescribe the circumstances under which a project qualifies for a project completion loan under (b)(1) of this section. These regulations shall establish procedures for

(1) determining the costs of a project for which a loan may be made under this section; and

(2) audits which will avoid unexpected costs.

(g) The owner of a project for which bonds of the authority are issued for a purpose set out in (b) of this section is eligible for a debt assistance loan under AS 44.83.174.

* Sec. 2. AS 44.83.181(c)(3) is amended to read:

(3) an appropriation from the power project equity [GENERAL] fund

[(A) TO PAY DEBT SERVICE ON BONDS OR FOR OTHER PROJECT PURPOSES; OR

(B)] to reduce the amount of debt financing for the project;

* Sec. 3. AS 44.83.181(c)(4) is amended to read:

(4) a debt assistance loan under AS 44.83.175 [FROM THE GENERAL FUND];

* Sec. 4. AS 44.83.181(c)(7) is amended to read:

(7) a loan from [THE POWER PROJECT FUND (AS 44.83.170(a)), OR FROM] the renewable resources investment fund (AS 37.11.050); or

* Sec. 5. AS 44.83.185(a) is amended to read:

(a) The authority shall submit a feasibility study and plan of finance for a proposed new project to the legislature. When the report of the division of budget and management [EXAMINING THE FEASIBILITY STUDY AND PLAN OF FINANCE] is completed as required by AS 44.83.183 or 44.83.172(g), it shall be submitted to the legislature.

* Sec. 6. AS 44.83.185(c) is amended to read:

(c) The legislature shall consider and must approve all proposed new projects. However, approval by the legislature is not required if the new project is exempt under AS 44.83.187 and the owner of the project has not applied for an equity grant under AS 44.83.172. [EXCEPT PROPOSED NEW PROJECTS THAT ARE EXEMPT UNDER AS 44.83.187.] The legis-

1 lature may approve a proposed new project only by enacting law autho-
2 rizing that project.

3 * Sec. 7. AS 44.83.187(a)(1) is amended to read:

4 (1) requires an appropriation from the state general fund,
5 from the power project equity fund, or from the renewable resources
6 funds; or

7 * Sec. 8. AS 44.83.170 is repealed.
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Mark Withen

PUTTING VARIOUS HYDROPOWER COST FACTORS
INTO THEIR PROPER PERSPECTIVE

Elaboration of a memorandum prepared for
The Office of the Governor, State of Alaska,
January 14, 1981

By Arlon R. Tussing
February 26, 1981

PUTTING VARIOUS HYDROPOWER COST FACTORS
INTO THEIR PROPER PERSPECTIVE

Most recent debate over an Alaska hydropower-financing regime has concerned ---

- * the relative effect on electricity costs of financing with revenue bonds, general obligation bonds, and direct loans from the State treasury;
- * the impact of various financing schemes on project and statewide bond ratings, and the effect of those ratings on power costs; and
- * the total economic impact of different financing schemes on Alaskans when the consumer price of electricity and the treasury's potential earnings from other investments are both taken into account.

These are important questions, as the cost of electricity does depend powerfully on several financing variables. The table on page 3 compares the impact of several financial and non-financial factors on average electricity costs from an idealized Alaska hydroelectric project over the term of its financing, whether those costs are all paid by electricity consumers or paid in part by the state treasury. The upper part of the table shows that the impact of some of the financial variables --- specifically the choice between revenue and general obligation bonds, and revenue-bond ratings --- are relatively insignificant.

Comparing the financing variables on the upper part of the table to the planning, design, and management variables below shows that electric power costs tend to be less sensitive to financing methods in general than to the effects of over- or underbuilding, engineering errors, construction delays, and cost overruns --- all of them commonplace occurrences on major capital projects.

The risk and frequency of such cost-inflating events is not independent of the financing method, however. Large state capital grants, state general-obligation funding, state overrun or completion guarantees, or a statewide power-cost equalization policy could undermine the incentives of communities, utilities, or the Alaska Power Authority to forecast demand realistically, choose and design the right size and kind of projects, employ competent contractors, supervise them competently, and manage the projects efficiently.

The Washington Public Power Supply System [WPPSS or "Woops"] is a classic illustration of financial overassistance encouraging bad planning, mismanagement, engineering and construction incompetence, predatory behavior by construction unions, and worse. The result has been prolonged construction delays, tenfold or greater cost overruns, and a real possibility that the plants may never be licensed to generate power. The hypothetical instances of bad planning, delays, or overruns in the following table are, of course, far less serious than those that have afflicted WPPSS projects, so my contrast between financing and non-financing influences on electricity costs may be unrealistically conservative.

The table refers to the increase that each of the changes listed would cause in the project's average life-cycle electricity costs. These costs are measured by the total constant-dollar revenue required per kilowatt-hour of electricity sold, over 25 years of operation. The assumptions that were used throughout the table are shown in the technical notes that follow it; changing any of these assumptions would of course alter some of the numbers in the table, but we would expect the ranking of the factors to remain about the same.

PUTTING VARIOUS HYDROPOWER COST FACTORS
INTO THEIR PROPER PERSPECTIVE

The following table compares the sensitivity of hydropower costs to several financial, design, and construction variables.

Variable	Increases average life- cycle electric cost by
<u>Financial variables</u>	
1. Financing with A-rated revenue bonds rather than medium-grade G.O. bonds	0.4 percent
2. Financing with A-rated rather than AA-rated revenue bonds	2.4 percent
3. Loss of arbitrage	7.5 percent
4. Financing with medium rather than prime G.O. bonds	8.0 percent
5. 15-year instead of 30-year amortization	18.3 percent
6. Financing with AA (taxable) utility bonds rather than AA (tax-exempt) municipal bonds	44.1 percent
<u>Planning, design, and construction variables</u>	
7. Underbuilding based on a 3-percent expected load growth --- actual load growth 6 percent	21.0 percent
8. 25-percent cost overrun	25.0 percent
9. 3-year delay in start of construction	27.3 percent
10. 25-percent derating of plant	32.0 percent
11. 8 years instead of 5 years to complete	48.5 percent
12. 50-percent cost overrun	50.0 percent
13. Overbuilding based on 6-percent expected load growth --- actual load growth 3 percent	54.5 percent
14. 3-year delay in commissioning	65.1 percent
15. Overbuilding based on 6-percent expected load growth --- actual load growth zero	106.7 percent
16. Non-operability & abandonment	200.0 percent
17. Cases 11, 12, and 13 all apply	361.0 percent

NOTES

General: Average life-cycle electric cost is the total revenue required per kilowatt-hour sold, years 6 through 30 inclusive. Except where otherwise indicated, the construction period is 5 years with equal annual outlays; operating life and permanent financing are 25 years; project is hydro or other 100-percent fixed-cost technology; financing is 100 percent debt; interest rates are the same for construction and permanent financing. Interest cost is 10 percent unless otherwise indicated.

Any electricity supply shortfalls during years 6 to 15 that result from delays, derating, or underbuilding are made up by thermally-generated power. The unit cost of thermally-generated supplemental power is assumed to be twice the average life-cycle cost of power from the project in question (if it had been completed and operated according to design).

Interest rate figures are from Salomon Brothers Bond Market Roundup for the week ending January 9, 1981 [copy attached].

Financial Variables

1. A-rated 30-year electric revenue bonds at 10.25 percent vs. medium-grade 30-year G.O. bonds at 10.20 percent.
2. A-rated 30-year electric revenue bonds at 10.25 percent vs. AA-rated 30-year electric revenue bonds at 10.00 percent.
3. Medium-grade 30-year G.O. bonds at 10.20 percent vs. prime 30-year G.O. bonds at 9.40 percent.
4. 15-year prime G.O. bonds at 8.60 percent, amortized over 15 years, vs. 30-year prime G.O. bonds at 9.40 percent, amortized over 30 years.
5. Arbitrage here refers to the ability of the state to invest its surpluses in taxable securities at relatively high interest rates while its agencies or subdivisions continue to borrow at lower interest rates in tax-exempt bond markets. The IRS will disallow a federal tax exemption for state or municipal bonds that are clearly issued for arbitrage purposes (i.e., "to profit at the expense of the U.S. Treasury"). Row 5 compares the combined cost of power to consumers and the State treasury under two financing proposals presented to the Governor's office earlier in the year, one of which would, and one of which would not, permit the State to make offsetting investments in taxable securities markets. For details, see Tussing's January 23, 1981 memorandum to Governor Hammond, Appendix A.
6. AA-rated 30-year taxable utility bonds at 14.50 percent vs. AA-rated tax-exempt electric revenue bonds at 10.00 percent.

Planning, design, and construction variables

7. Plant is designed to reach optimum load factor after 10 years of operation at 3 percent annual load growth. At 6 percent annual growth the capacity constraint is reached in the third year of operation (year 6). The cost of supplementary thermal power generation through the tenth year of operation (year 15) is added to the total cost figure in determining life-cycle average cost.

8. Self-explanatory.

9. Construction outlays and operation are both delayed 3 years. Term of financing and life of project are unchanged. Additional cost is the difference between the cost of an added 3 years of thermal power generation and the unit cost of power from the project in question.

10. "Derating" is official recognition of the inability to attain design-capacity operation. The plant is designed to reach its optimum load factor after 10 years of operation, at 3 percent annual load growth. With 25-percent derating, the capacity constraint is reached in the first year of operation (year 6). Power shortfall for ten years is made up by thermal power generation.

11. Equal annual construction outlays are stretched out from 5 to 8 years but total is unchanged; amortization is reduced from 25 to 22 years. The cost of 3 years of thermal power generation is added to total costs in determining average costs.

12. Self-explanatory.

13. Plant is designed to reach optimum load factor after 10 years of operation, at 6 percent annual load growth. The higher unit cost reflects lower utilization rates caused by growth at only 3 percent.

14. Project is completed on schedule, but actual startup is delayed 3 years because of technical or licensing problems; amortization is reduced from 25 to 22 years. The cost of 3 years of thermal power generation is added.

15. Plant is designed to reach optimum load factor after 10 years of operation, at 6 percent annual load growth. Additional unit costs reflect lower utilization rates caused by lack of load growth.

16. Plant is completed but fails to operate or receive operating license. Demand must be met by thermal power generation.

17. Self-explanatory. $[1.485 \times 1.5 \times 1.545 = 4.61]$

Mark Withan

MEMORANDUM

14 February, 1981

To: Tom Singer
From: Arlon R. Tussing

Re: Power Project Equity Fund

-As we agreed earlier in the week, I have provided some draft language on the relation between grants from the Equity Fund and electric rates [subsection e]. In providing the groundwork for this specific language I began from the beginning and edited the preceding subsections.

Two changes are intended to improve the "equity" of the grant distribution: (c.2) provision for exclusion from the eligible resident population of persons [e.g., on floating fish processors or at Prudhoe Bay] who would not in fact be served by a utility project, and (c.1, c.4) deduction of the present value of previous interest subsidies granted by the Authority. To forestall litigation, (c.5) the Authority's determination on populations, prorationing, and the value of previous subsidies is made final.

The language on electric rates in (e) excludes the grant from a utility's rate base (where applicable) and provides otherwise that the grant must be used to effect lower rates as if it reduced a rate base. For utilities or others who are not under APUC jurisdiction, (e.3) permits the Authority to require rate reductions by contract as a condition of the grant. Rate reductions (e.2) must be in the form of lump-sum reductions in monthly bills and not reductions in unit prices (per kwh) in the case of even partially fossil-fired systems where such a rate structure would encourage fuel waste.

The delineation of eligible projects (f) has been cleaned up.

Edited legislative language for "An Act relating to the Alaska Power Authority, after Baldwin draft #2, dated 2/9/81. By Tussing, 13 February 1981

Sec. 44.83.172 POWER PROJECT EQUITY FUND (a) There is hereby established a Power Project Equity Fund (hereinafter the Equity Fund), which shall be separate from any other money or funds of the Authority.

(b) The Equity Fund shall consist of money appropriated by the Legislature and interest earned on money in the Equity Fund. The Commissioner of Revenue shall invest any surplus in the Equity Fund in the manner specified in AS 37.10.070.

(c) There is hereby authorized to be appropriated to the Equity Fund \$800,000,000, which shall be the only appropriation of State moneys to the Equity Fund. Any moneys remaining in the Equity Fund on December 31, 1985 shall be returned to the General Fund.

(d) (1) Grants for power projects. The Authority may make grants from the Equity Fund to Alaska utilities or other owners of proposed electrical generation projects that are eligible under subsection (f) of this section, in the amount of \$2,000 for each 1980 resident of the project's service area, less the value of any previous subsidy granted by the Authority for electrical generation projects serving the same service area.

(2) The Authority shall determine the 1980 resident population of each service on the basis of the 1980 decennial Census of the United States, but the resident population of a project's service area shall not include any person whose residence could not or would not in fact be served by electrical power from the project.

(3) Where the service areas of more than one utility or proposed project coincide or overlap, or where a proposed project will provide electricity to more than one service area, the Authority shall allocate any grant from the Equity Fund under this section among utilities or projects in proportion to the number of customers that are or would be served by ~~the~~ each utility or project.

(4) A direct loan granted by the Authority to a utility or other owner of an electrical generating project at a rate of interest lower than the market rate of interest shall be considered a subsidy for the purpose of paragraph (2). The value of any such interest subsidy is the difference between the actual interest cost of the direct loan and the market interest cost on an otherwise identical loan, reduced to present value at a discount rate equal to the market rate of interest. For the purposes of this paragraph, the market rate of interest is the rate of interest that the utility or project owner incurred or would have had to incur for revenue bond financing of the project subsidized by the direct loan.

(5) The Authority shall consult with all affected municipalities and utilities before apportioning any grant among utilities or projects under paragraph (3), but the judgment of the Authority shall be final with respect to the 1980 resident population of any service area, the apportionment of grants from the Equity Fund among service areas or projects, the market rate of interest, or the value of any previous subsidy. [Alternatively, you may want allow interested parties to contest the Authority's decisions on these matters, but only on the ground they are arbitrary and capricious.]

(e) (1) Rate reductions. A utility or other recipient of a grant from the Equity Fund under this section may use the proceeds of that grant only to pay a portion of the fixed capital costs of an electrical generation project. The amount of such a grant shall not become part of any utility's rate base, and shall result in a reduction of the rates charged and collected for electricity generated by the project by an amount no less than the reduction in the cost of interest and debt-amortization attributable to the grant.

(2) In any service area served in whole or in part by fossil-fuel or other thermal generating capacity (except for reserve generating capacity) the rate-reductions required under this subsection shall, insofar as practical, take the form of a lump-sum reduction in the monthly charge to each customer of the utility or project, and shall in no case take the form of a reduction of the rate per incremental unit of electricity.

(2) The Authority, as a condition of a grant under this section, may require any utility or other owner of a proposed generating project not subject to the rate-making jurisdiction of the Alaska Public Utilities Commission to execute a contract with the Authority providing for the rate-reductions required by this subsection.

(f) An electrical generation project shall be eligible for a grant under this section only if (1) it produces electricity from a renewable resource, (2) it is a cogeneration project or (3), in the judgment of the Authority, no alternative generation project using a renewable resource or cogeneration project is technically and economically feasible. For the purposes of this subsection, renewable resources include but are not necessarily limited to, hydro, wind, solar, and nuclear fusion energy.

Mark A. How

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526 Main Street • Juneau Alaska 99801 • (907) 586-1290

MEMORANDUM

28 February, 1981

To: Frances Ulmer, Director
Division of Policy Development and Planning

From: Arlon R. Tussing

Re: FINANCING ALTERNATIVE ENERGY PROJECTS (The Alaska Power Authority as technical and financial clearing-house for alternative energy, in place of the Alaska Energy Center).

On February 6, I provided at your request an outline of possible machinery and standards by which the Alaska Energy Center would help finance non-utility power projects, cogenerators, and conservation investments. Several commentators inside and outside of state government have since suggested that it would be better to give the Alaska Power Authority, rather than the Energy Center, the main responsibility for alternative energy financing.

Tom Singer has asked me to explain the case for giving the lead on alternative energy financing to the Power Authority, and to describe how the responsibilities of the Power Authority, the Energy Center and the APUC, would be reallocated under such an arrangement. I believe this issue to be as much a matter of political judgment as of economics or administrative efficiency, and I do not personally have a firm position on the question. Here, nevertheless, are the elements of the case for the Power Authority, followed by a revised statement of the program I offered on February 6.

My memorandum of that date proposed to establish the Energy Center as a

"one-window" service to assess the technical and economic viability of proposed alternative energy projects; to package State, federal, and private financing for such projects; to prepare and submit permit applications; to help deal with contractors, utilities, the APUC, and other regulatory bodies. APUC jurisdiction would be expanded to the extent necessary to implement the program . . .

page two

You are already familiar with the rationale for an independent state-sponsored institution committed to and with a vested interest in alternative energy, including decentralized electricity generation. The most substantial opposing arguments, however, are that

(1) the Power Authority already has related responsibilities and experience, while the Energy Center would have to begin a new program that overlaps the Authority's mission, entirely from scratch; that

(2) the new role proposed for the Energy Center would tend to overwhelm and compromise its research and development mission; that

(3) taking all responsibility for alternative energy, non-utility generation, cogeneration, and conservation away from the Power Authority would cement its identification with capital-intensive central-station generating technologies, and guarantee that there would be a permanent adversary relationship between the utilities and the Power Authority on the one hand, and the sponsors of alternative energy and the Energy Center on the other; and that

(4) the Power Authority could resolve most of the technical, rate, and other problems independent power producers and cogenerators will have with Alaska utilities (and vice versa) by negotiation and by means of contracts, without recourse to formal proceedings before the APUC or in the courts.

In the following revision of my February 6 outline, the institutional commitment to alternative energy is vested in a new Division [of Alternative Energy, Cogeneration, and Energy Conservation] in the Alaska Power Authority. The Division would be the one-window technical and financial service for non-utility power generators and cogenerators, giving them a somewhat expanded version of the services the Authority is now empowered to give the electric utilities.

The main focus of the Energy Center will remain alternative energy research and development, but it will cooperate financially and technically with the new Division of the Power Authority in alternative energy demonstration projects, and will play a general promotional and advocacy role for alternative energy. The legislation would specifically prohibit these activities on the part of the Power Authority with respect to both central-station and alternative energy technologies, projects, or plans.

ALASKA ALTERNATIVE ENERGY PROGRAM

ONE-WINDOW SERVICE. A newly-established line Division [of Alternative Energy, Cogeneration, and Energy Conservation]* in the Alaska Power Authority would become a one-window service for qualified applicants wanting to design, install, and finance certain alternative energy projects. The Division would have a separate budget line, with its operating expenses subject to annual legislative review and appropriation. It would have dedicated or revolving funds for all those purposes, and only those purposes, for which the the Authority has such funds for assistance to utility power projects.

A. Qualified applicants may include ---

1. households,
2. groups of households,
3. small businesses, and
4. municipalities.

B. Alternative energy projects may include ---

1. Self-sufficient power generation --- consumer-owned electrical generating facilities to serve consumers outside the service area of any existing utility, or not economic to connect to an existing utility;
2. "Opt-out" power generation --- consumer owned electrical generating facilities to serve consumers within the service area of an existing utility, but which would not be connected to the utility, despite the fact that the consumers are currently connected or are [in the opinion of the utility] economically feasible to connect;
3. Supplemental power generation --- consumer-owned electrical generating facilities to serve consumers who are or would be connected to an existing utility for backup or supplemental power;

* The ultimate name of the Division will have to be different. As the organization will surely be known by its initials, let us find something more acceptable than DAECEC.

4. Cogeneration --- commercial or industrial facilities that are or would be connected to an existing utility, and which produce electrical power as a by-product or joint product with some other commodity or service [e.g., industrial process steam];
5. Small power producers --- non-utility electrical generating facilities that are or would be connected to an existing utility, and which may or may not be cogenerators, producing power in whole or in part for sale to an existing utility; and
6. Energy conservation projects --- residential, small-commercial, or small-industrial consumer-owned investments in equipment or structural improvements that will create substantial energy savings.

C. Services provided by the Division regarding alternative energy projects include ---

1. Technical & economic feasibility assessments;
2. Comprehensive financial packaging, including assistance in getting federal loans, grants, and tax credits; private loans; and State loans and grants under this and other programs;
3. Preparing license and permit applications to local, state, and federal agencies, and representing applicants before permitting agencies; and
4. Assistance and representation in dealing with contractors, utilities, and the APUC and other regulatory bodies.

D. To be eligible, a project must ---

1. Be technically feasible and reliable --- of proved technology and design [*] of a type and scale appropriate to the location and service, and installed and serviced by responsible, competent parties;

* The Energy Center would have lead responsibility for financing alternative energy research and development projects. The Division would be permitted and encouraged to participate in financing and other arrangements for Energy Center-sponsored and assisted demonstration projects.

2. Be clearly cost-effective in terms of energy production or savings over its economic life --- even if it had no subsidy;
3. Be of undoubted net benefit to its owner(s) over its economic life, in terms of the value of energy produced or saved, as measured by lowest-cost alternative;
4. Generate sufficient cash flow in terms of revenues generated or payments avoided to cover its debt-service and operating and maintenance costs at all times, by a reasonable margin; and
5. Not result in higher energy costs to others.

E. State financial assistance through the Division ---

1. Will be complementary to financing from other sources, to the extent practical;
2. May include direct loans or partial guarantees for non-State financing;
2. May be subordinate to other financing;
3. Requires equity participation by the owner(s), including "sweat-equity" under specified circumstances;
4. May have a term no longer than the project's realistic useful life, or that of the uses or structure(s) it serves, whichever is less;
5. May have an escalating debt-service schedule intended to lower the project's early cash-flow requirements, to the extent permitted by a rate of increase in project's total debt-service requirements (including debt service from other sources) not exceeding 5 percent per year;
6. Shall carry an interest rate appropriate to the collateral or other security of the financing [See "H" below.]; and
7. Shall be a joint liability of the property (ies) served and on which the project is located.

G. Cash grants of the same per-capita amount as may be granted to Alaska utilities or central-station power projects under the proposed Equity Fund [\$2,000 per capita?]

1. May be granted for alternative energy projects not connected to a utility [self-sufficient and opt-out power generation projects]; but

2. A utility may require a connection charge equal to the unamortized portion of any such equity grant [on a ten-year amortization schedule] prior to making a connection to any property, or subsequent subdivision of any property, served by the project.

H. State loans and State-guaranteed loans shall be secured by appropriate means, and the interest rate or guarantee fee on such loans shall reflect the type and quality of the security. For example, the interest rate on loans secured by ---

1. The salvage or resale value of equipment shall be comparable to current Anchorage bank rates on machinery and equipment loans.
2. Property(ies) served by the project and/or on which the project is located shall be comparable to prevailing Anchorage rates on residential second deeds of trust.
3. A contract with a utility to which the property and facility are connected, shall be no comparable to recent revenue-bond rates on Authority-assisted central-station projects [See "J" below].

I. Costs incurred by the Division for technical and economic assessments, filing fees, appearances before regulatory bodies, and other specified costs directly attributable to a given alternative energy project financed in whole or in part by a State loan under this program, shall be reimbursed by the applicant, normally by an addition to the loan principal.

J. Debt service on State loans or financial packages arranged by the Authority under this program, for any alternative energy project connected to an existing utility, may be made a conditional liability of the utility and the Authority may require the utility to collect such debt-service charges as a surcharge on its regular billing(s) to property(ies) served by the project. Under a contract among the project owner(s), the Authority, and the utility, payment of the surcharge shall become a condition of continued utility service to the property or, more importantly, of service to any new customer on the property or any subdivision of it [*].

* The refusal or contractual inability of the utility to hook up or serve a new customer on the property can be a powerful incentive to clear up any delinquency, because it will make the property unsaleable. It is important that any such burden on a property be duly recorded.

RELATIONS BETWEEN THE DIVISION, THE ENERGY CENTER,
AND THE ALASKA PUBLIC UTILITIES COMMISSION

A. The Alaska Energy Center's role in this program, in addition to its established research and development function, would be ---

1. Promotional: to publicize established and practical alternative energy, cogeneration, and energy conservation technologies for Alaska, and this and other technical and financial assistance programs; and to encourage and assist Alaskans to participate in them;
2. Demonstration: to establish and fund, or participate with the Power Authority in establishing or funding first-generation demonstrations in Alaska of technologies and equipment proved elsewhere or in different applications [The two organizations are intended to have overlapping jurisdictions, and either would be allowed to take the lead or act alone on demonstration projects.];
3. Advocacy: to represent (at its discretion) the interests of alternative energy project owners or would-be owners, or to assist them in dealing with contractors, utilities, the Authority, the APUC, and other regulatory bodies.

B. Additional APUC jurisdiction. The APUC already has major responsibility regarding utility connections, charges, and payments to cogenerators and small power producers under PURPA, but APUC does not now generally have jurisdiction over rates and terms of service for municipal utilities, the Alaska Power Authority, or federal power projects.

The legislation establishing the Alaska Power Authority is explicit, however, that the Authority shall have no regulatory jurisdiction over electric utilities, and the Energy Center is certainly not a suitable regulatory body. Thus, any additional regulatory authority that implementation of this program may require should be in the APUC, but it is not obvious now just what additional jurisdiction and duties are necessary.

A working group representing the Authority, the Energy Center, and the APUC, would be established and charged to report through the Commissioner of Commerce to the 1982 Legislature its recommendations for enlargement or amendment of APUC jurisdiction, and other organizational or regulatory measures that might be necessary to implement this program. The issues on which the group shall report includes the need, if any, for enlarged jurisdiction to ---

1. Approve or determine rates and terms of service for standby service to supplemental power projects;
2. Approve or determine "avoided costs" for each utility, as defined under PURPA, and the rates and terms of service on which utilities must purchase or wheel power from cogenerators and small power producers;
3. Order utilities to connect properties served by alternative energy projects and to execute contracts with cogenerators and small power producers; and
4. Order utilities to contract with the Alaska Power Authority and owners of alternative energy projects for collection of debt-service on State-financed, guaranteed, or packaged loans [See "J" above.].

2-5-81

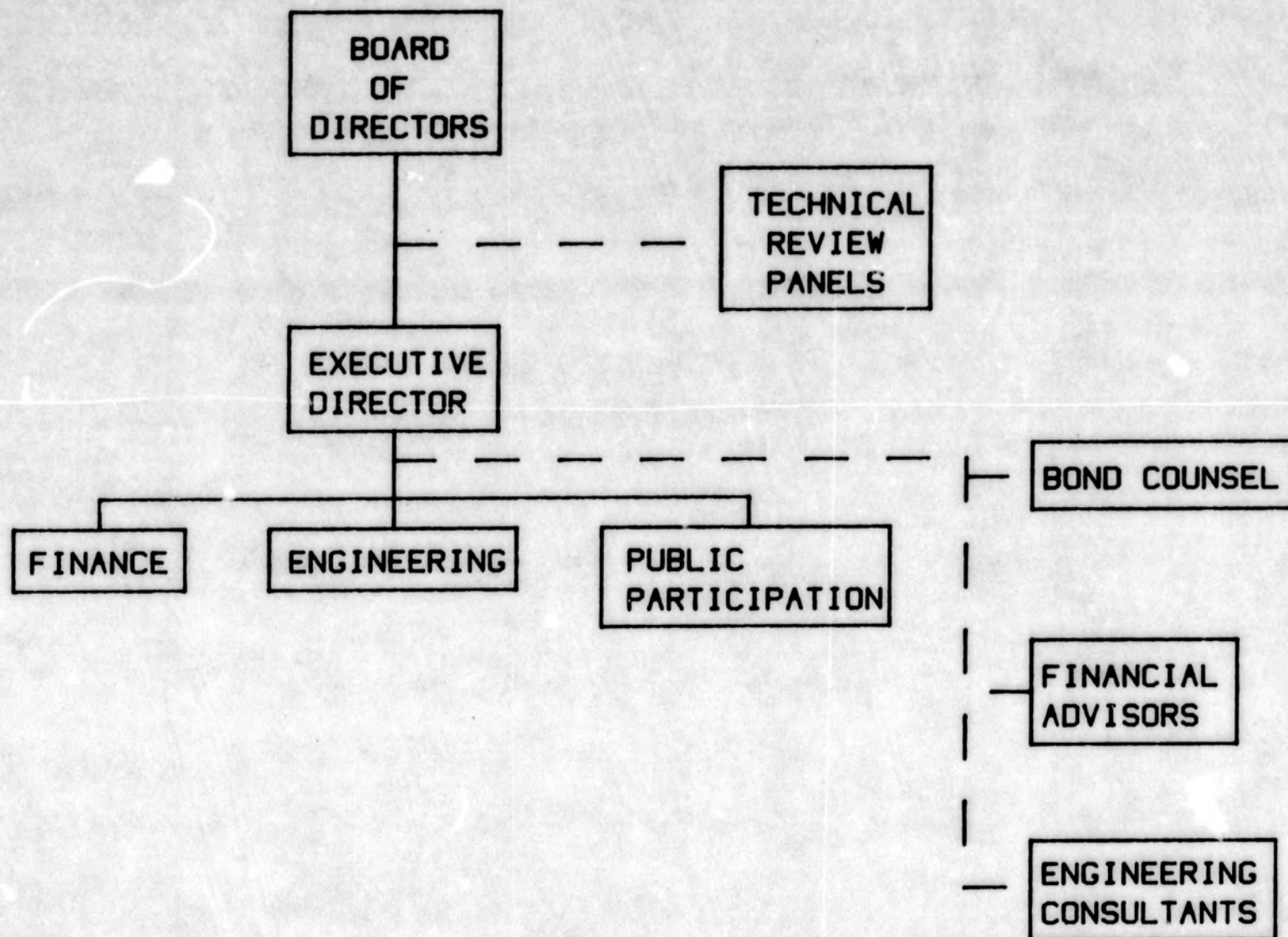
Tye. Dick Ballard

ALASKA POWER AUTHORITY

PURPOSE

Promote, develop and advance the general prosperity and economic welfare of the people of Alaska by providing a means of constructing, acquiring, financing and operating power production facilities limited to fossil fuel, wind power, tidal, geothermal, hydroelectric, or solar energy production and waste energy conservation facilities.

- o Financing
- o Feasibility Study Funding
- o Develop, Own and Lease
- o Develop, Own, Operate and Wholesale



ALASKA



• FAIRBANKS

• ANCHORAGE

• VALDEZ

HOMER

• DILLINGHAM

• KODIAK

• JUNE AU

SITKA

PETERSBURG

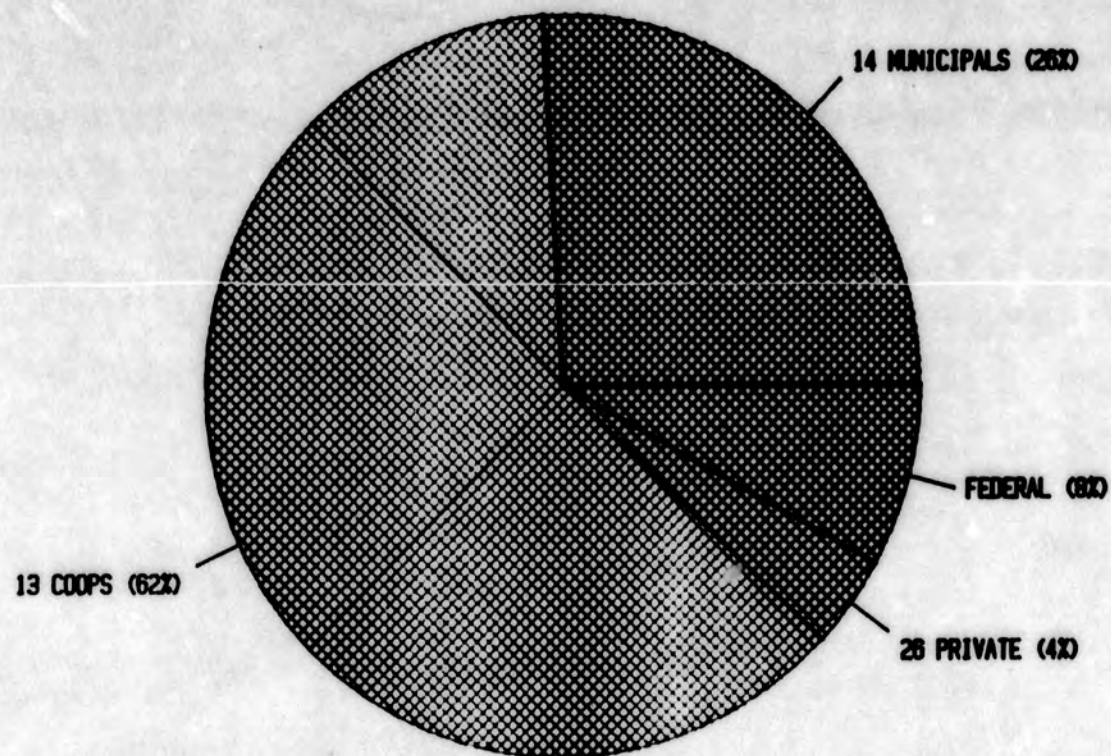
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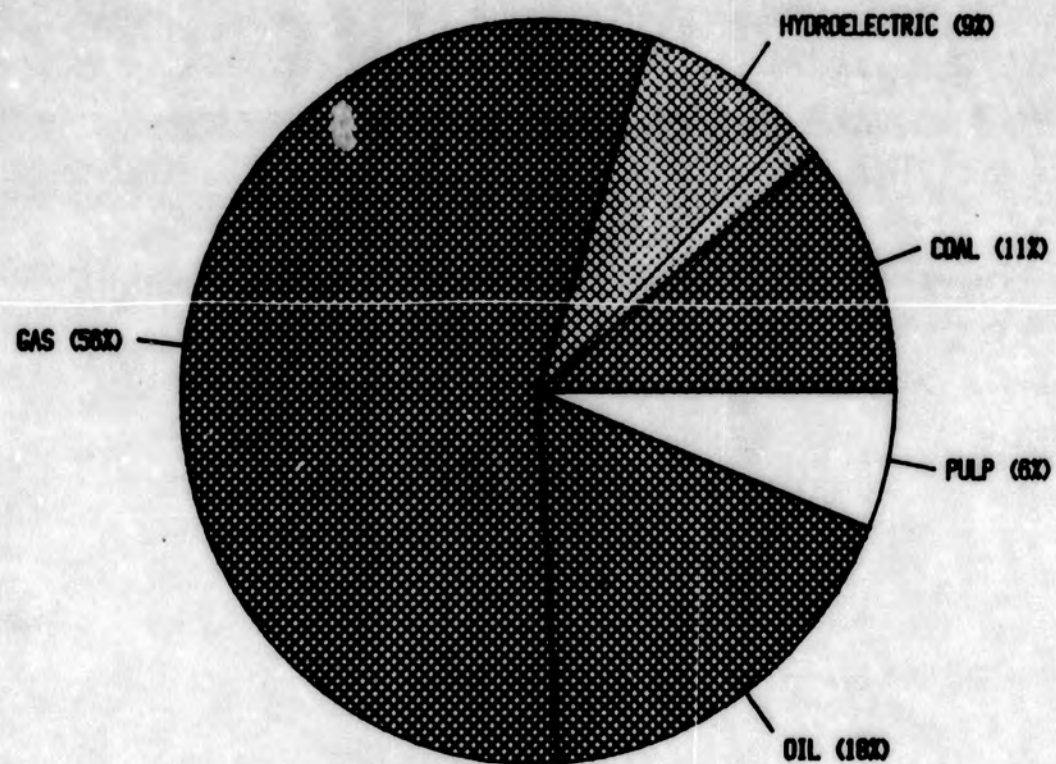
GENERATION BY TYPE OF UTILITY

1979 UTILITY GENERATION - 3,066 GWH



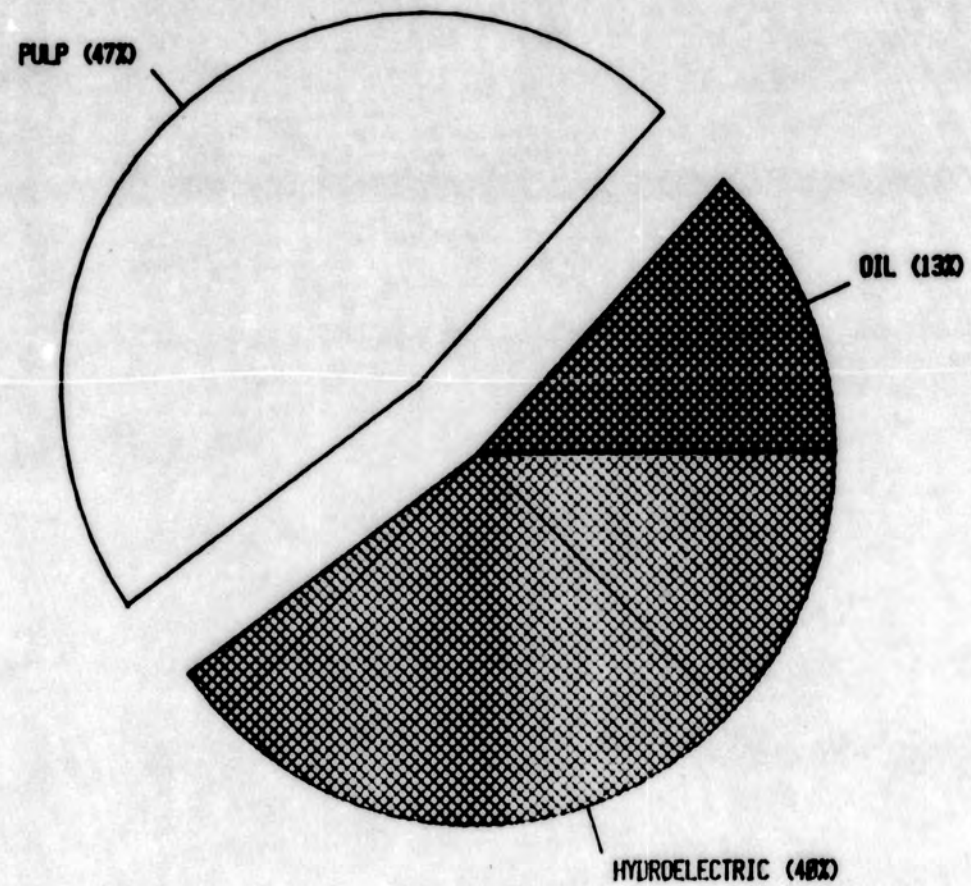
STATEWIDE GENERATION BY ENERGY SOURCE

1979 STATEWIDE GENERATION - 4,836 GWH



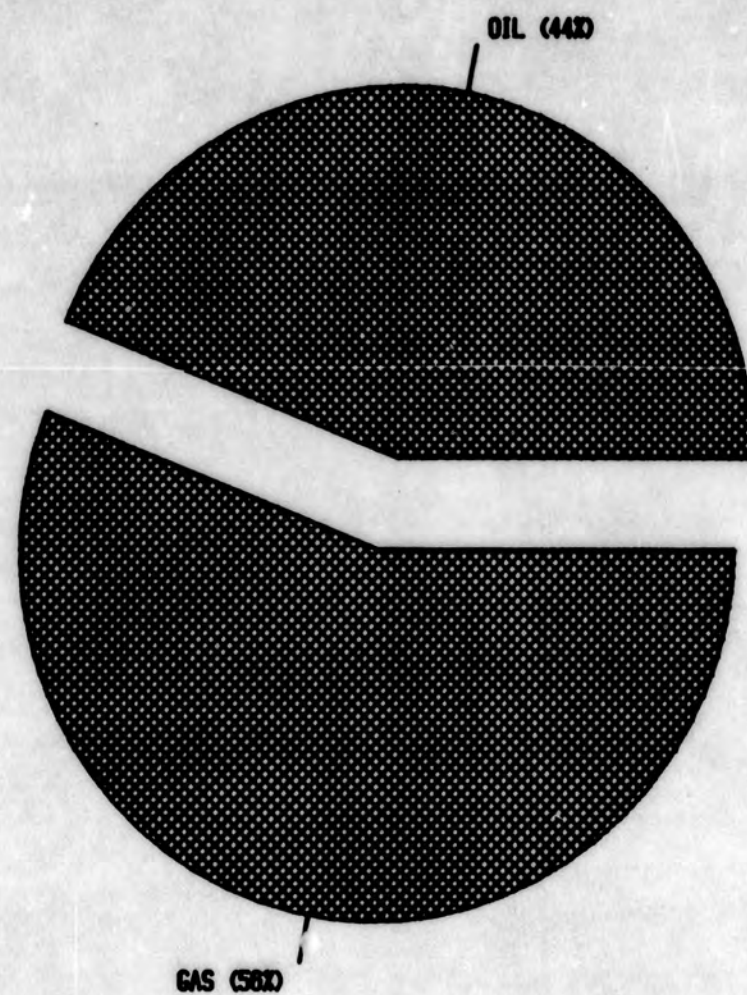
SOUTHEAST GENERATION BY ENERGY SOURCE

1979 SOUTHEAST GENERATION - 657 GWH



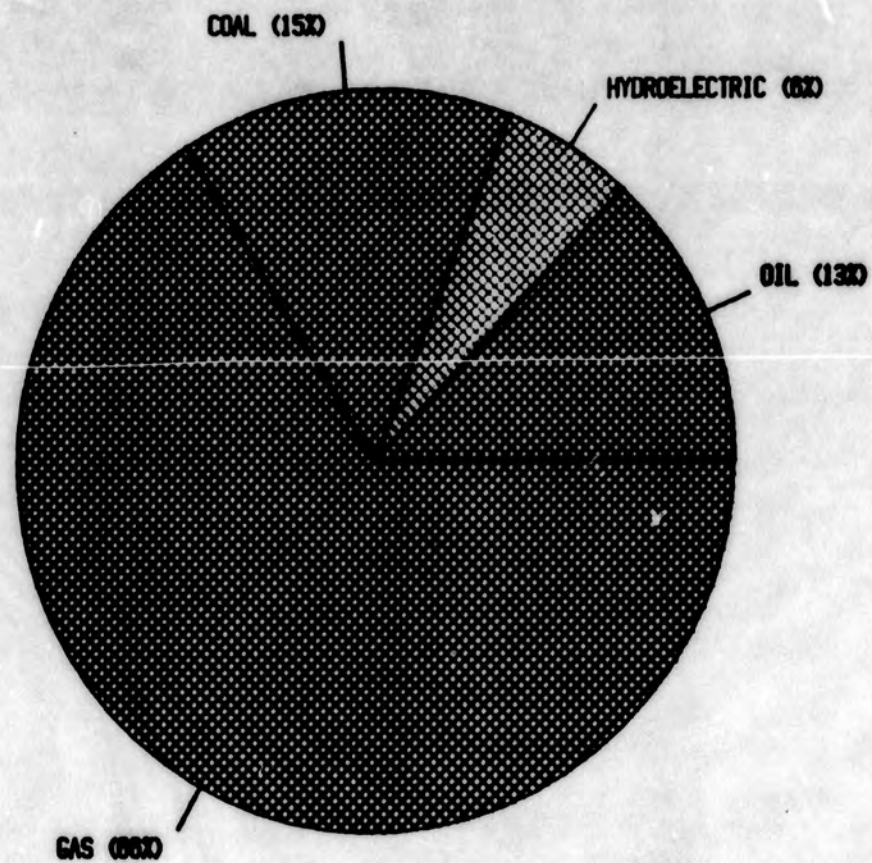
RURAL GENERATION BY ENERGY SOURCE

1979 RURAL GENERATION - 782 GWH



RAILBELT GENERATION BY ENERGY SOURCE

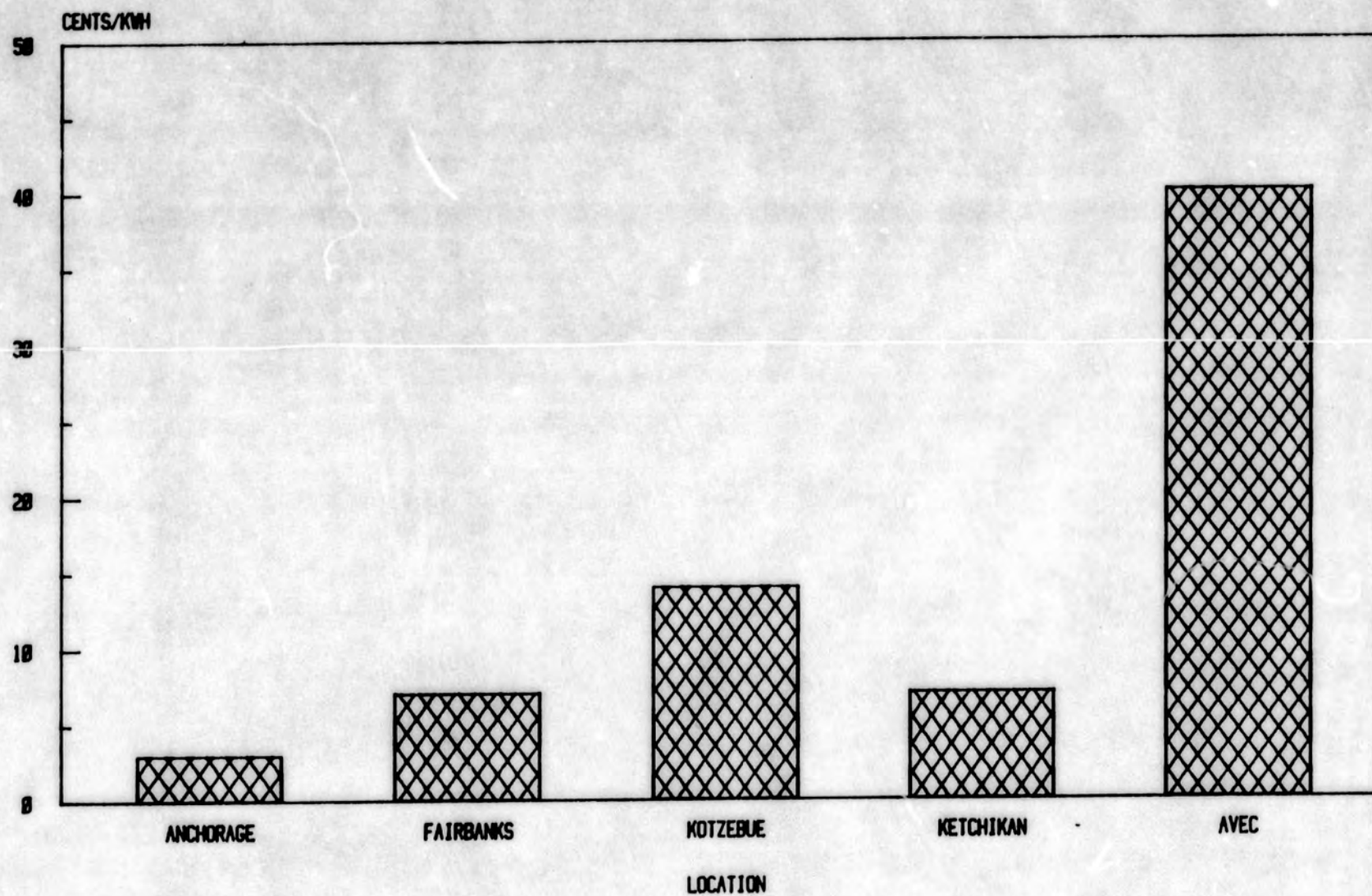
1979 RAILBELT GENERATION - 3,397 GWH



ALASKA FUEL COST TRENDS

	<u>PREVIOUS COST (YEAR)</u>	<u>CURRENT COST (YEAR)</u>	<u>ANNUAL RATE OF INCREASE</u>
HEALY COAL	\$4. 50/ton (1967)	\$14. 50/ton (1979)	10%
AVEC DIESEL OIL	\$0. 35/gal (1973)	\$1. 40/gal (1980)	22%
COOK INLET GAS	\$0. 15/mcf (1971)	\$1. 50/mcf (1980)	29%

COST OF POWER, 1980



ALASKA



• FAIRBANKS

• ANCHORAGE

• VALDEZ

Solomon Gulch

■ Lake Elva

• DILLINGHAM

• HOMER

Bradley Lake

• KODIAK

Terror Lake

• JUNE AU

PETERSBURG

SITKA

WRANGE L

• Tyee

• Lake

• Swan

KLAWOCK

Black Bear Lake

KETCHIKAN

NEAR TERM PROJECTS

SOLOMON GULCH HYDROELECTRIC PROJECT

LOCATION: Adjacent to the Alyeska Pipeline
Terminal at Valdez

MARKET: Valdez and Glennallen, population
approximately 6,000

TYPE: Rockfill dam at outlet of Solomon Lake,
auxiliary dam and spillway, penstock,
powerhouse, and 104 mile 115 KV trans-
mission line.

OUTPUT: 12 MW installed capacity
56,000,000 Kwh average annual energy

CAPITAL REQUIREMENTS: \$20,000,000 remaining

under way

Kod → David Neese

TERROR LAKE HYDROELECTRIC PROJECT

LOCATION: Kodiak Island

MARKET: Kodiak and the USCG station, service area
population approximately 8,000

TYPE: Rockfill dam at outlet of Terror Lake, four
small diversion dams, diversion channels
and shafts, power tunnel, powerhouse, 17
miles of 69 KV transmission line.

OUTPUT: 20 MW installed capacity
132,000,000 Kwh firm annual energy

CAPITAL REQUIREMENTS: $\$110,000,000 \div 20 = 5\frac{1}{2}$ mil/yr

Robt. Arnold - Ketchikan $\rightarrow$ Interest rate high -
Ted Ferry

SWAN LAKE HYDROELECTRIC PROJECT

LOCATION: 22 miles northeast of Ketchikan near
Carroll Inlet.

MARKET: Ketchikan, service area population 12,600

TYPE: 190 foot high thin arch concrete dam raising
the level of Swan Lake, with a power tunnel,
powerhouse, port facility, switchyard and 31
miles of 115 KV wood pole transmission lines.

OUTPUT: 22 MW installed capacity
67,000,000 Kwh of firm annual energy

CAPITAL REQUIREMENTS: \$110,000,000 with a State $\div 22$ $\$5,000,000$
contribution of \$18,000,000

(Port Director) — Dick Ballard — ① "2000/psm-45h" —
② of 15 mil, 1 yr delay, since voted, + cost
eroded 12+ mil.
③ "sub-subsat loan" won't work.

TYEE LAKE HYDROELECTRIC PROJECT

LOCATION: 40 miles southeast of Wrangell near
Bradfield Canal

MARKET: Petersburg and Wrangell, service area
population 6,400

TYPE: Lake tap of 1,370-foot elevation Lake Tyee,
power tunnel, surge tank, powerhouse, and 83
miles of 115 KV transmission lines.

OUTPUT: 30 MW installed capacity
133,000,000 Kwh of firm annual energy

CAPITAL REQUIREMENTS: \$60,000,000 with a State
contribution of \$15,000,000

GREEN LAKE HYDROELECTRIC PROJECT

LOCATION: 10 miles southeast of Sitka on the
Vodopad River.

MARKET: Sitka, service area population 8,800.

TYPE: 280-foot-high double-curvature, concrete-
arched dam at the outlet of existing
Green Lake, with a 1,910-foot-long power
tunnel, powerhouse, access roads,
substation and 8 miles of 69-KV wood pole
transmission lines.

OUTPUT: 16.5 MW installed capacity
64,900,000 KWh average annual energy

CAPITAL REQUIREMENTS: Total \$62,000,000 with a
State contribution of
\$8,200,000. Remaining
requirements of \$5,000,000.

SNETTISHAM HYDROELECTRIC PROJECT

LOCATION: 28 miles southeast of Juneau on the
Speel Arm of Port Snettisham

MARKET: Juneau and Douglas, service area
population 23,000.

TYPE: The Crater Lake phase will include a
lake tap, 7,800-foot-long power tunnel
and penstock, access road and third
generator in the existing powerhouse.

OUTPUT: 27 MW installed capacity

CAPITAL REQUIREMENTS: \$70,000,000 ÷ 27 = \$

POWER CREEK HYDROELECTRIC PROJECT

LOCATION: 7 miles northeast of Cordova

MARKET: Cordova, population approx. 2,500.

TYPE: 80-foot-high concrete dam, intake, 8,000 foot-long penstock, powerhouse, and 6 miles of transmission line. Run-of-river project.

OUTPUT: 5 MW installed capacity
32,000,000 KWh average annual energy

CAPITAL REQUIREMENTS: \$51,000,000

SCAMMON BAY HYDROELECTRIC PROJECT

LOCATION: Spring-fed stream at Scammon Bay.

MARKET: Scammon Bay, population 200.

TYPE: 8-foot rock-filled gabion dam, intake structure 3,500-foot-long penstock, and powerhouse. Run-of-river project.

OUTPUT: 150 KW installed capacity
529,000 KWh average annual energy

CAPITAL REQUIREMENTS: \$2,100,000

SMALL HYDROELECTRIC PROJECTS

- LOCATION:** Streams located near population centers and in areas of relatively high precipitation and topographical relief. Regional studies of small-scale hydroelectric potential have been completed for Southeast Alaska, Kodiak Island, Alaska Peninsula, Aleutian Islands, Southwest Alaska, and AVEC villages.
- TYPE:** Generally run-of-river projects providing replacement energy as available.
- OUTPUT:** Typically 100 KW to 1 MW installed capacity
- COST:** Typically \$5,000-15,000 per installed KW

PORT LIONS HYDROELECTRIC PROJECT

LOCATION: On Port Lions River at Kizhuyak Bay
on Kodiak Island

MARKET: Port Lions, population 250.

TYPE: 7-foot-high sheet pile forebay dam,
upstream storage dam, 2,100 feet of
steel penstock, and powerhouse.
Run-of-river project.

OUTPUT: 180 KW installed capacity
715,000 KWh average annual energy

CAPITAL REQUIREMENTS: \$1,500,000

Communities that exhibit the potential for
economic small-scale hydroelectric development:

Chignik Bay	Atka	Ouzinkie	Kaltag
Chignik Lagoon	Nikolski	Port Lions	Kiana
Chignik Lake	False Pass	Larsen Bay	Shungnak
Perryville	Unalaska	Ambler	Togiak
Ivanoff Bay	Akhiok	Elim	Angoon
Cold Bay	Karluk	Goodnews Bay	Tenekee Springs
King Cove	Old Harbor	Grayling	Gustavus

BLACK BEAR LAKE HYDROELECTRIC PROJECT

LOCATION: 8 miles east of Klawock on Prince of
Wales Island

MARKET: Klawock, Craig, and Hydaburg, service
area population 1,200 year-round.

TYPE: 28-foot bin wall and rockfill dam at outlet
of Black Bear Lake, penstock, powerhouse,
and 52 miles of 23 KV transmission line.

OUTPUT: 5 MW installed capacity
22,000,000 Kwh firm annual energy

CAPITAL REQUIREMENTS: \$30,000,000

BRADLEY LAKE HYDROELECTRIC PROJECT

LOCATION: At the head of Kachemak Bay near Homer
on the Kenai Peninsula

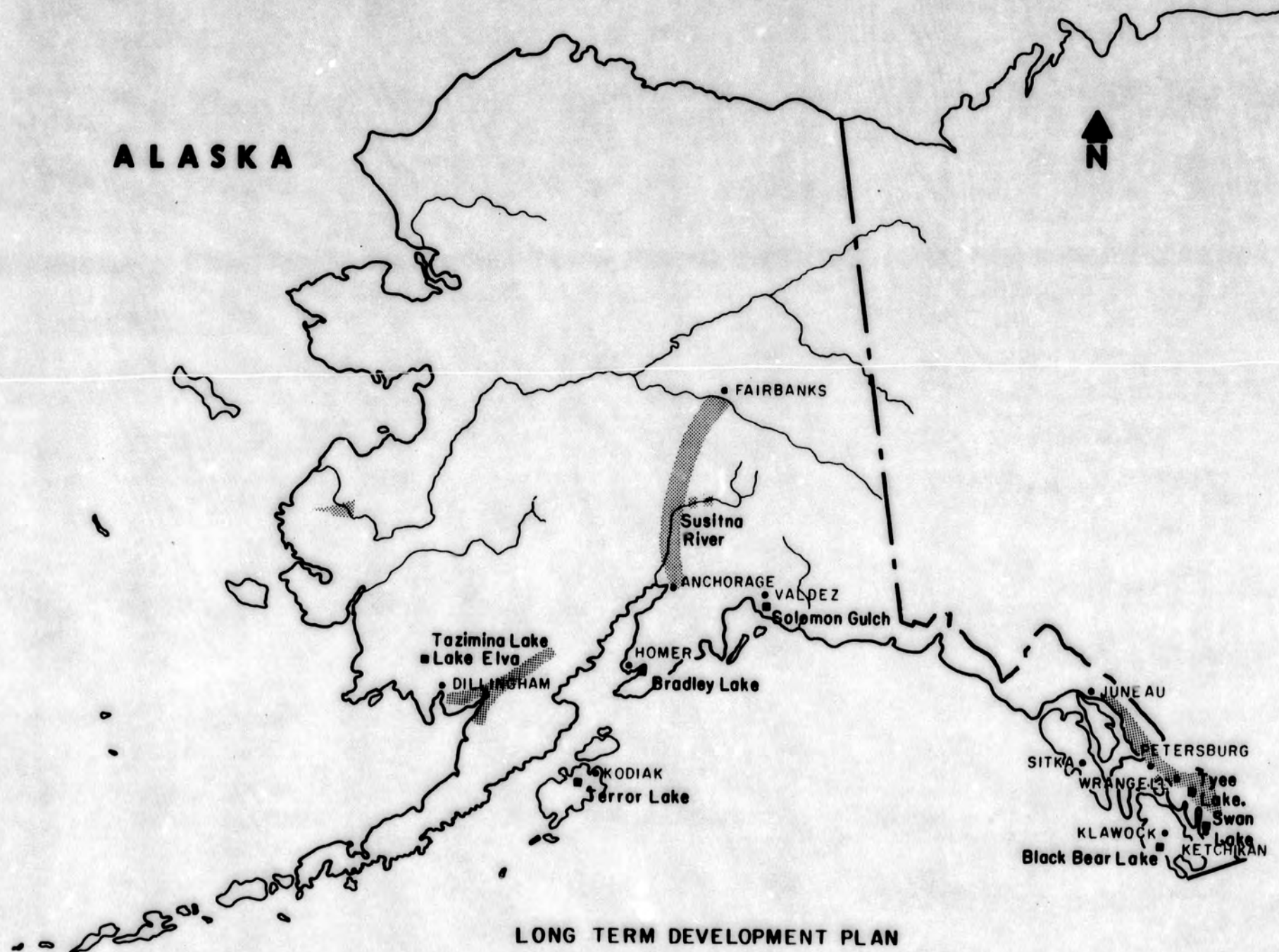
MARKET: Kenai Peninsula and perhaps Anchorage.
Kenai Peninsula population 22,000.

TYPE: 100-foot concrete gravity dam at the outlet
of Bradley Lake, diversion channels, lake
tap, power tunnel, underground powerhouse,
switchyard, and 10 miles of 115 KV wood pole
transmission line.

OUTPUT: 70 MW installed capacity
306,000,000 Kwh firm annual energy

CAPITAL REQUIREMENTS: \$200,000,000

ALASKA



TAZIMINA HYDROELECTRIC PROJECT AND INTERTIE

LOCATION: North of Lake Iliamna on the west side
of Cook Inlet

MARKET: Fifteen communities in the Bristol Bay
Region

TYPE: Earthfill 38-foot forebay dam, earthfill
45-foot storage dam, penstock, powerhouse,
access road and 181 miles of 138 KV trans-
mission line.

OUTPUT: 18 MW installed capacity (first stage)
79,000,000 Kwh firm annual energy

CAPITAL REQUIREMENTS: \$80,000,000

WEST CREEK HYDROELECTRIC PROJECT

LOCATION: West Creek in the vicinity of Skagway

MARKET: Skagway and Haines, market area
population 2,400.

TYPE: 107-foot-high concrete dam, 11,000-foot-
long power tunnel, surge tank, powerhouse
and transmission facilities.

OUTPUT: 5.4 MW installed capacity
27,000,000 KWh average annual energy

CAPITAL REQUIREMENTS: \$55,000,000

SOUTHEAST INTERTIE

LOCATION: Southeast Alaska

MARKET: Juneau, Petersburg, Wrangell, Ketchikan
and intermediate communities

TYPE: Interconnection of major hydroelectric
facilities (Snettisham, Tyee and Swan)
and adjacent load centers.

PURPOSE: Reliability and exchange of economy
energy.

RAILBELT INTERTIE

LOCATION: Southcentral Alaska

MARKET: Anchorage and Fairbanks

TYPE: Interconnection of existing systems at
138 KV

PURPOSE: Reserve sharing and economy energy
exchange

CAPITAL REQUIREMENTS: \$55,000,000

Dave Hutchings

SB 25 + 26 (Keytulla)

- ① Low int. financing
- ② Unified state-wide prog.
- ③ adequate funding
- ④ Fund @ today's cost (income to bal. inflation)
- ⑤ \$ for un-feasible projects stay in area.

SUSITNA HYDROELECTRIC PROJECT

LOCATION: Upper Susitna River NE of Talkeetna between Anchorage and Fairbanks

MARKET: Fairbanks, Anchorage, Matanuska Valley, Kenai Peninsula

TYPE: 810-foot rockfill dam and powerhouse at Watana (first stage)

635-foot concrete gravity dam and powerhouse at Devil Canyon (second stage)

364 miles 345 KV transmission line

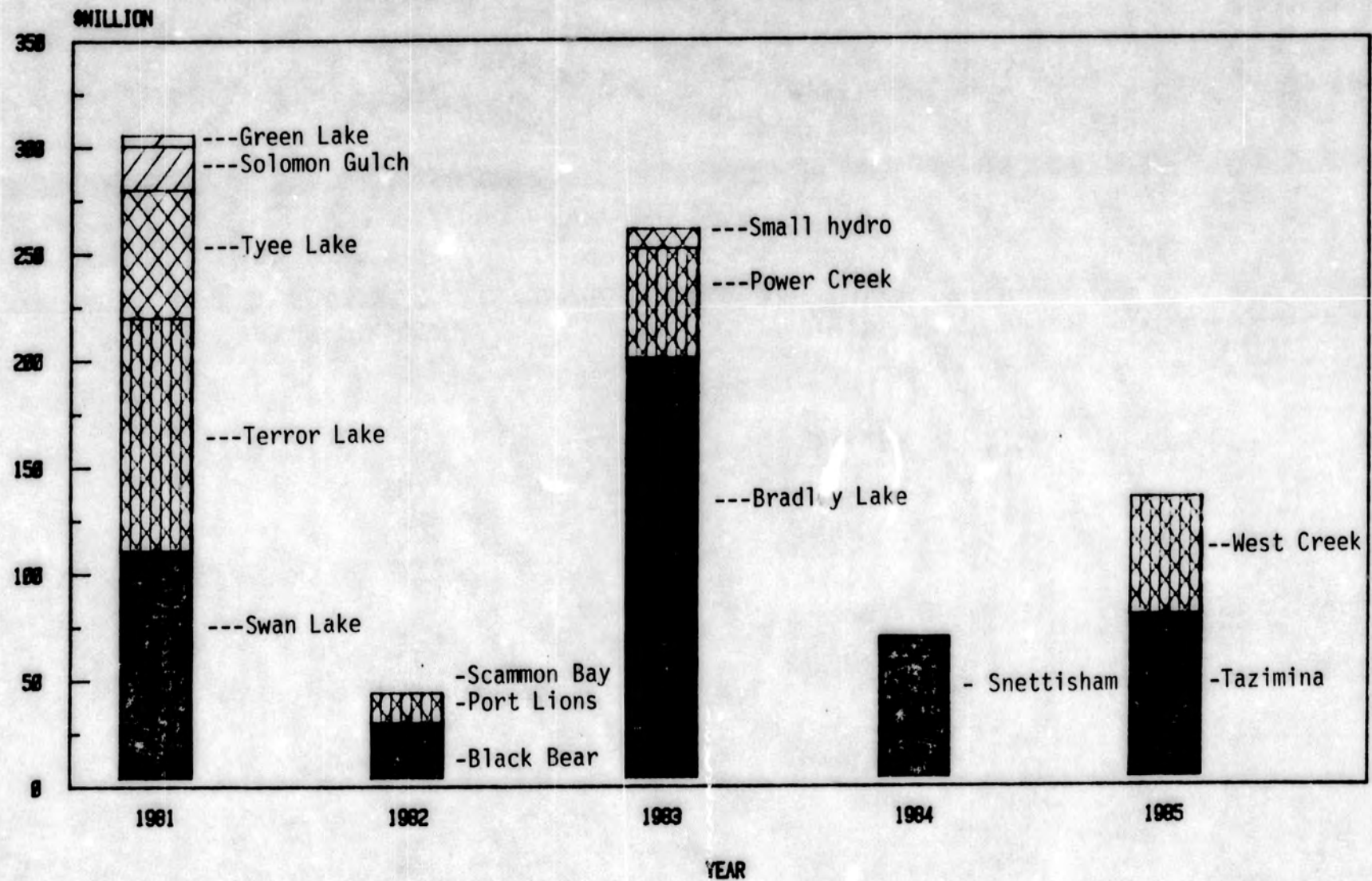
FIRST STAGE OUTPUT: 700 MW installed capacity
3,100,000,000 Kwh firm annual energy

ULTIMATE OUTPUT: 1,392 MW installed capacity
6,100,000,000 Kwh firm annual energy

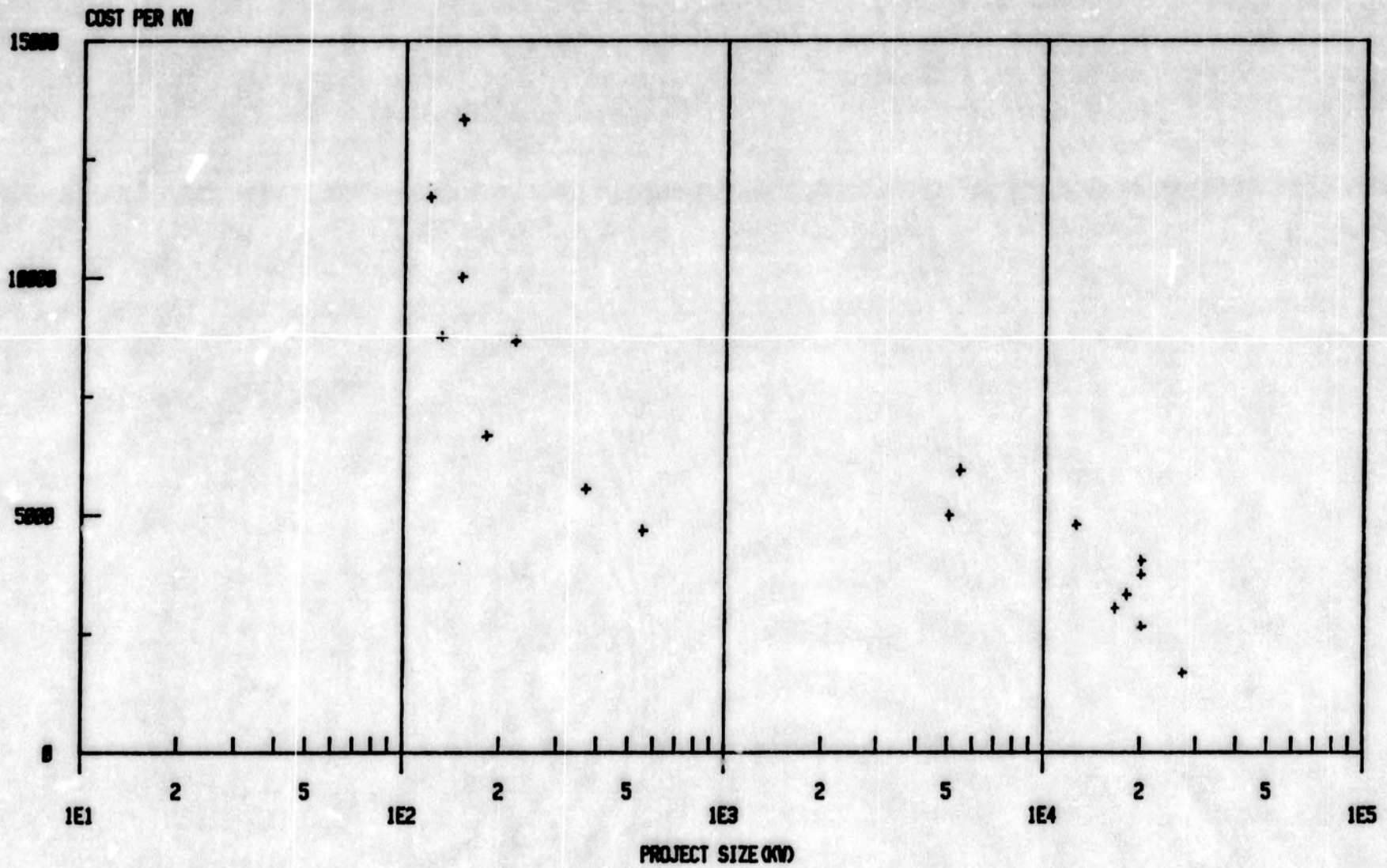
COST ESTIMATE (October 1978): \$ 2.5 billion $\div 1392 = \$1,817,529$

ESTIMATE OF CAPITAL REQUIREMENTS

(EXCLUDING SUSITNA)

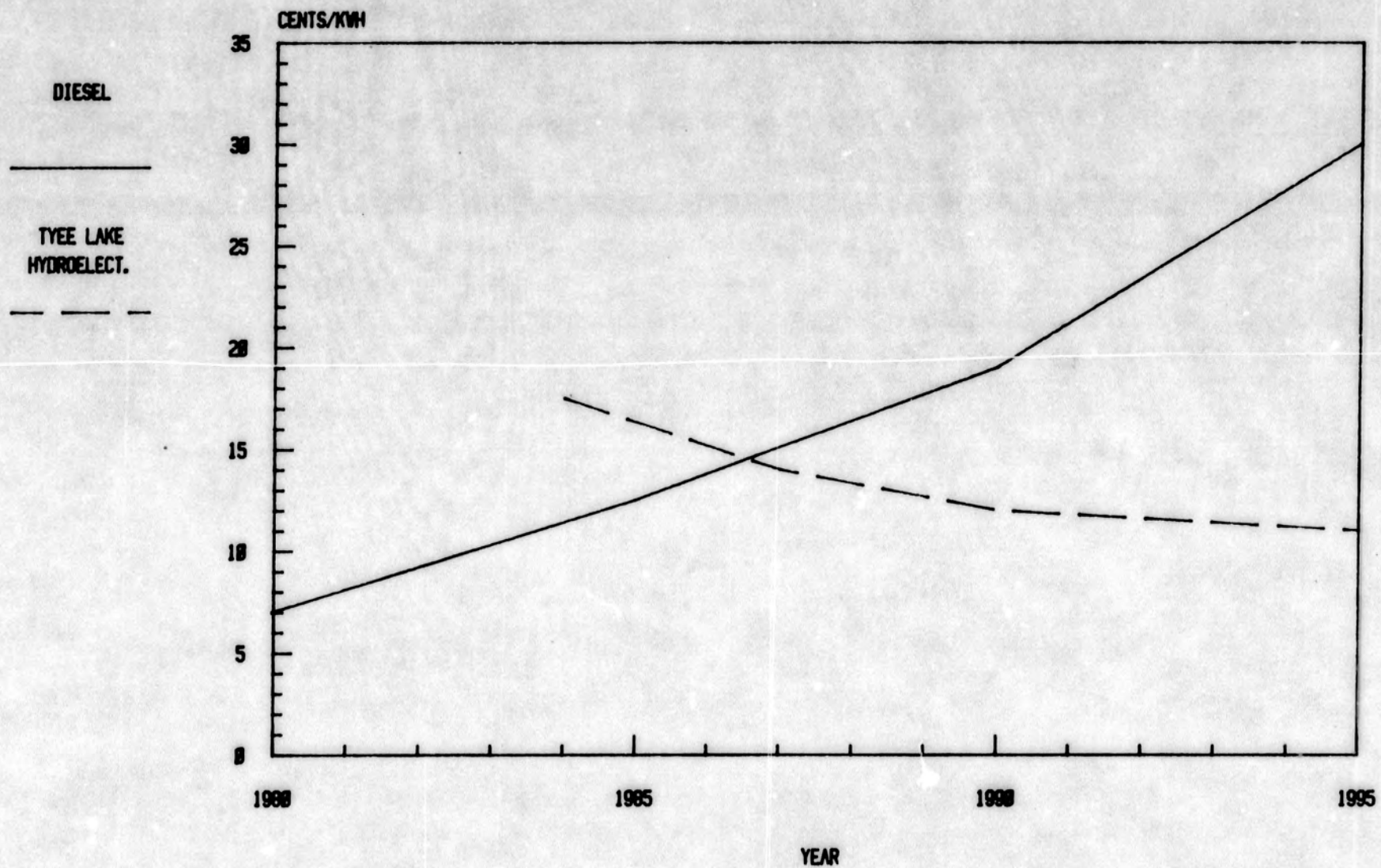


RELATIONSHIP OF COST TO SIZE



TYPICAL COST OF POWER OUTLOOK

BUSBAR COST



FINANCING ALTERNATIVES

- POWER AUTHORITY REVENUE BONDS
- STATE GENERAL OBLIGATION BONDS
- REVENUE BONDS WITH STATE GUARANTEES
- STATE GENERAL FUND LOAN
(EQUITY INVESTMENT)
- STATE GENERAL FUND APPROPRIATION
 - debt service payment
 - reduction of bondable costs
- NON-STATE ASSISTANCE
 - Federal (REA & FFB)
 - CFC

Introduced: 3/19/81
Referred: State Affairs

1 IN THE HOUSE

BY ROGERS AND BUCHHOLDT

2 SPONSOR SUBSTITUTE FOR HOUSE BILL NO. 9

3 IN THE LEGISLATURE OF THE STATE OF ALASKA

4 TWELFTH LEGISLATURE - FIRST SESSION

5 A BILL

6 For an Act entitled: "An Act relating to departments and programs of state
7 government which are concerned with energy; and provid-
8 ing for an effective date."

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

10 * Section 1. AS 37.12.125(6) is amended to read:

11 (6) "renewable resource" means

12 (A) non-human living organisms;

13 (B) natural components of the environment, including
14 the air, land, and water; [AND]

15 (C) energy systems which are naturally recurring or
16 replenished; and

17 (D) energy conservation.

18 * Sec. 2. AS 43.20.037(d)(1)(B)(ii) is amended to read:

19 (ii) a method of architectural design and construc-
20 tion which provides for the collection, storage and use of
21 direct radiation from the sun or which provides for the re-
22 tention of heat by the use of an amount or quality of insula-
23 tion which exceeds the amount or quality of insulation re-
24 quired by building performance standards adopted by the
25 Department of Transportation and Public Facilities under
26 AS 44.42.020(14); and

27 * Sec. 3. AS 44.33.020 is amended by adding a new paragraph to read:

28 (25) develop and administer a village energy conservation
29 program for the benefit of the people of rural areas of the state,

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED
AS A UNIT IN THE ORIGINAL DOCUMENT.

A.T. 1/9/81

INCOMPLETE

1. Two related problems --- financing and rates: In much if not most of Alaska, the lowest-cost power source in the long run is hydropower or some other capital-intensive technology. But the front-end costs of hydro projects, for example, may well exceed the funds that sponsors (individual Alaska utilities, the Alaska Power Authority, or others) could borrow in private capital markets on the strength of their own assets or assured revenues.

Even where the sponsors are able to finance hydro or other capital-intensive generating projects conventionally, moreover, private lenders are likely to insist on debt-service schedules and ratemaking arrangements that would cause consumer prices for electricity from the new project to exceed the life-cycle average cost of that power by several times.

2. The solution --- generally. Alaska's large cash balances allow the State to assist generating project sponsors ---

(a) to finance hydro and other highly capital-intensive generating technology at lower capital costs than most sponsors could obtain independently (if indeed they could finance their preferred projects at all), and at the same time

(b) to "levelize" the consumer price of electricity so that today's ratepayers can share the long-term benefits created by the new projects.

3. Three methods of State assistance. In order to assure financing of capital-intensive electrical generating projects at a reasonable cost, and to levelize consumer prices over time, three general methods are available to Alaska:

(a) State guarantees of all or part of the project debt, to make it marketable despite the financial weakness of the project and/or the sponsors;

(b) Direct State purchases of all or part of the project debt, despite the risks to the State attendant on the financial weakness of the project and/or the sponsors; and

(c) State bridging grants or loans to fill part of the gap between the long-term cost of electricity and the assured revenues the project or its sponsors must have in its early years in order to finance it conventionally.

4. The three methods are equivalent. These three methods are precisely identical in principle. Any one of them can be used to support or substitute for any specified part (say, 50 percent) of the project debt, while permitting the balance to be sold in the private revenue-bond market.

Any one of the three methods (or a combination of two or more) can be used to set first-year debt-service revenue requirements (and thus first-year electric rates) over a wide range of possible levels. In each case the State's willingness to accept financial risks that the private market, the utilities, or the ratepayers can not or will not accept is an implicit "subsidy", which makes financing possible under more acceptable terms than could otherwise be obtained on the private market.

Any of the three methods can be structured so as to recapture from ratepayers the whole value of that subsidy --- or any part of it --- over the life of the power project in question. Any of the three methods is compatible with some form of external "market test" of project viability, but each of them is vulnerable to being turned into a permanent subsidy or into an incentive for pyramid-building and gold-plating.

5. Differences in implications. The three approaches may differ significantly in ---

(a) their influence on the interest cost of external debt,

(b) the State's benefits from "arbitrage" (the ability to borrow for power projects at lower interest rates in the tax-exempt bond market, while investing surplus state revenues at higher rates in taxable securities),

(c) the time at which the financial risk to the State is greatest,

(d) the value of state funds or other assets that are immobilized for the duration of the project financing,

(e) the Constitutional and legal prerequisites, and

(f) organizational feasibility and administrative complexity.

The specific design of a financing project, however, is likely to have more influence on most of these factors than the choice between the three general methods.

6. Putting the various cost factors into proper perspective Not all of the considerations listed in 5 are of equal significance. Too much of the recent debate within State government in Alaska has centered on the ratings and interest cost for various kinds of debt. The Bank of America team, for example, placed great weight on the proposition that the interest cost of general obligation (G.O.) bonds is always cheaper than for otherwise-equivalent revenue bonds, collateralized or not.

Some financial experts disagreed with B of A, but what is significant is how little difference this issue, per se, seems to make. The table appended to this memorandum shows that the choice between revenue-bond and G.O.-bond financing makes only a 0.4 percent (four-tenths of one percent) difference in the average electricity cost over the 25-year operating life of a hydro project, all other things being equal.

ERIC E. WOHLFORTH
ROBERT B. FLINT
TIMOTHY G. MIDDLETON
PETER ARGETSINGER
W. J. PAT SORSEY



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276-6401

December 24, 1980

Hon. Jay Hammond
Governor, State of Alaska
Pouch A
Juneau, Alaska 99811

Dear Governor Hammond:

By direction of the Alaska Power Authority I have analyzed the paper submitted to you by Arlon Tussing on November 10, 1980, entitled "A new approach to Electric Power Project Financing" and the paper submitted by the Bank of America dated December 19, 1980 entitled "Proposed Alternative Power Financing Strategy".

1. As Bank of America letter states it, the Guaranty Fund as outlined by Mr. Tussing would be "illegal" under IRS arbitrage regulations. This means that under Internal Revenue Service Ruling 80-13 Bonds issued by the State or the Power Authority secured by a pledged fund of equal size to the bond issue would result in loss of tax exemption for the bond issue unless the yield on fund investments were limited to the bond yield. Under this Revenue Ruling and the sections of the Code cited therein the maximum amount of a pledged fund is 15% of the original face amount of the bonds issued.

2. Mr. Tussing states that lenders almost always insist on a straight line amortization schedule for the revenue bonds of project financed utility developments (page 16, Tussing Memorandum). For some reason Mr. Tussing ignores, as does the Bank of America the only large recently completed Electric Revenue Bond financing in the State, namely the \$54 million Municipal Utilities Revenue Bond Issue of the City and Borough of Sitka sold on June 14, 1979. This bond issue is typical of electric revenue bond issues in that the bonds mature in 40 years on a level debt service basis after completion of the project. (See page A-17 of the Official Statement where it is stated that at an assumed 7 1/2% interest rate on the bonds there would be approximately level debt service over 36 years).

You may be assured that 25 to 40 year, level debt service bond issues are typical of hydro electric tax exempt bond issues.

3. The issue then is not "levelizing" rates as is stated by Mr. Tussing but rather the two separate issues of the correct means of

reducing power rates and then the correct means of providing for an equitable repayment or recapture of a State subsidy necessary to reduce power rates. Again reference to page A-17 of the Sitka Official Statement shows that rates in that City are "levelized" from 1983 through 1988 at approximately 6.4 cents.

4. It is clear that either issuing general obligation bonds of the State as in the Bank of America Memorandum or bonds fully collateralized by funds of the State (which unfortunately would not be tax exempt bonds unless investments of the fund were limited to the bond rate) would reduce power financing costs. In both cases the required extra coverage of 25% or 35% could be eliminated and rates reduced. However, the memoranda do not show how interest sensitive power costs are to rates in terms of actual case examples of power financing. For example, both Table 4 and 5 of Mr. Tussing's Memorandum assume that interest during the first several years of the project would be paid from rates charged to the consumer rather than capitalized from the bond issue as is typical in revenue bond power financings. The Bank of America implies that general obligation bonds would permit scheduling of bond principal only after construction. It typically is so scheduled in revenue bond construction projects. The Bank talks of "traditional level" principal payments. The traditional repayment schedule is level debt service after construction.

5. The Bank of America Memorandum does not allude to the fact that any guaranty of the State by bonds would require voter approval. Clearly, a State guarantee of debt would enhance the credit rating on the bonds and reduce interest costs. The Bank of America Memorandum does not indicate the interest rate savings to the State which would be produced by the general obligation bonds as opposed to revenue bonds. The Bank of America Memorandum states that a State guaranty would eliminate the need for funded interest during construction, a debt service reserve account and an excess debt service coverage requirement. Of course capitalized interest can be eliminated if the State pays it from general revenue and the elimination of a debt service reserve account is not necessarily cost effective since such account may be funded with bond proceeds which may be invested on an unlimited yield under existing Internal Revenue Service Regulations if limited in size to 15 percent of the bond issue.

6. The "trade-off" for elimination of an excess debt service coverage requirement which, together with the lower interest cost of general obligation bonds, is the key to reduced power costs under the Bank of America Memorandum will be compensated for by a "up-front guaranty fee" for the risk the State would be assuming. The same bond guaranty fee is a feature of the Tussing Memorandum. Mr. Tussing states on page 12 that if the State relieves lenders of all or a part of the usual financing risks to reduce debt service coverage requirements, or to prolong the repayment of principal, the resulting cost to the State can be measured or at least estimated. He further

states "this cost incurred by the State is a part of the true cost of power from the new project and ought to be born by the consumers through a guaranty fee added to bond interest rates".

Neither memorandum quantifies the amount of the bond guaranty fee. Given an efficient market the estimate of assumed additional risks of the State which, if the bonds were revenue bonds, would be extracted by investors in the additional coverage requirement would be equal to the cost to the consumer of the additional coverage requirement. The Bank of America would capitalize the bond guaranty fee from bond proceeds for each individual project and provide for its repayment by consumers in latter years rates.

Without an actual case based on assumptions of borrowing costs and rate levels it is difficult to determine whether such a plan is equitable or feasible or what its effect on power consumers would be.

Recapture of subsidy is a separate determination from a plan of finance. The Bank of America plan of finance simply provides for the optimum bondholder security, namely general obligation bonds and a compensating Energy Development Fund as an accounting device for subsidy payment and recapture. The Energy Development Fund is not pledged to the bonds although it will pay interest during construction.

The Fund would receive a guaranty fee initially "to compensate its [the State's] willingness to absorb the risks of default". What would be the amount of the fee?

The Fund would pay interest during construction on the bonds.

The Fund would receive payments from consumers in latter years when level rates produce excess earnings.

It is submitted that this subsidy payment and recapture mechanism does not require a fund but merely an accounting formula and legislative enactment.

Subsidy costs and repayment methods can be provided under any plan of finance. The issue is the correct plan of finance to reduce power costs. A separate issue is a means of recapturing the subsidy required to reduce power costs.

7. Finally the Bank of America cites as a reason for the issuance of general obligation bonds the increased market capability due to the ability of banks to underwrite such issues. The benefits of commercial bank underwriting long term power debt are not quantifiable since such

Hon. Jay Hammond
December 24, 1980
Page 4

debt has typically been issued on a revenue bond basis with banks prohibited from underwriting.

Very truly yours,

WOHLFORTH & FLINT

By Eric E. Wohlforth
Eric E. Wohlforth

EEW/amP

cc: Ms. Francis A. Ulmer, Director
Div. of Policy Development &
Planning

Mr. Ron Lehr, Division of
Budget and Management

Lt. Governor Terry Miller

RECEIVED
DEC 23 1980

POLICY DEVELOPMENT
& PLANNING

ALASKA POWER AUTHORITY

MEMORANDUM

MEMO TO: Fran Ulmer
Div. of Policy Dev. & Planning

DATE: December 24, 1980

FROM: Eric P. Yould *EPY*
Executive Director
Alaska Power Authority

SUBJECT: Comments on Arlon Tussing's
Memorandum

Provided below are comments on Arlon Tussing's Memorandum: A New Approach to Electric Power Project Financing. Actually, I am gratified to see that Mr. Tussing realizes the complexity of financing projects in Alaska and the benefits of hydroelectric project development. Mr. Tussing confirms many concepts the Power Authority has supported for some time. However, the paper is an academic treatment of a real problem that requires innovative solutions that are both practical and in the best interest of the State. Mr. Tussing's paper, being so academic, has certain weaknesses that must be addressed.

1. Mr. Tussing's proposal for a Guarantee Fund would most likely be contrary to the IRS regulations on arbitrage and investments earnings of the fund would have a restricted yield.
2. Levelized debt service is the preferred schedule for repayment of principal and interest for capital intensive revenue financed projects. I am somewhat surprised that Mr. Tussing was not aware of this.
3. A Guarantee Fund would not necessarily eliminate debt service coverage requirements unless it was a large fund with a strong guarantee, which as mentioned in (1) above would likely be restricted by the IRS. Another aspect of the coverage requirement is that coverage revenues are generally used for operation and maintenance of the utility systems once debt service payment is assured. This is recognized by both the utility and the bond investor. The utility must collect revenue to insure proper operation and maintenance of the system, and the investor wants revenues collected for this purpose to help insure the continued operation of the financed project for its useful life. Therefore, elimination of coverage requirements will not always be in the interest of either the utility customers or the bond investor. It only impacts negatively when coverage requirements are excessive. In fact, elimination of debt service coverage would probably not reduce retail rates to consumers since the utility would have to maintain an adequate revenue stream anyway in order to provide for utility operation and maintenance. Consequently, there is little if any benefit to eliminating a reasonable debt coverage.
4. Advance payments for future inflation is a characteristic of any levelized debt service schedule in financing a capital intensive project. It cannot be resolved without refunding of early maturity debt and thereby either lengthening the debt repayment schedule or increasing the debt service in the latter years of the schedule. This in some respects eliminates one of the most desirable aspects of financing and operating a capital intensive alternative energy project. His technique is not generally accepted in the municipal market and it would carry an interest penalty. However, if it were accepted, it would largely eliminate the subsidy issue.

Fran Ulmer
December 24, 1980
Page 2

5. Underutilization of capacity is a major factor in power project financing in Alaska which must be addressed. The method used by Mr. Tussing to correct for this problem is the same as for adjusting for inflation in (4) above. The concept is desirable, however, it is most difficult to put into practice. The most effective way for the state to assist in correcting this problem is to provide more assistance in financing projects in return for more control of the projects and control over rate setting for the sale of project power to insure an adequate return to the state over the useful life of the project.

The following are a few comments on the Proposed Alternative Power Financing Strategy from Bank of America,

1. Page 1. Revenue Bonds carrying a full faith and credit guarantee would require voter approval and could impact to some degree the State's credit and ability to insure General Obligation debt in the future. Voter approval is not timely for immediate projects which should be financed, and if it were to be requested, it should be for a large authorization for possible projects statewide.
2. Page 2. Debt service schedules for long term capital intensive power project financing are levelized with increasing principal and declining interest payments. Consequently, there is no benefit to be gained by this proposal.
3. Page 3. Periodic payments to consumers would be subject to taxation. However, payments to utilities to achieve the same purpose which are structured similar to the Power Production Assistance Program would not have this problem.
4. Page 4. A State guarantee would not eliminate the need for funded interest during construction, since the IDC would have to be paid by the utility or the state from some source.

In conclusion, the Bank of America financing strategy, as the Tussing Memorandum, represents advice on investment banking issues from sources that are not experienced in the long term public power financing market. While I believe that both the Tussing and Bank of America efforts are sincere attempts to establish an equitable power financing program, their ideas are generally unworkable nor do they ameliorate the debt service burdens during the earlier years of a hydropower project's life.

We look forward to meeting with you and your representatives on December 29th to discuss these ideas, and others that we believe are workable.

cc: Governor Hammond
Terry Miller
Ron Lehr

ARLON R. TUSSING & ASSOCIATES / 880 H St., Suite No. 210, Anchorage, Alaska 99501

23 January, 1981

To: Frances Ulmer
From: Arlon R. Tussing

Re: POWER PROJECT FINANCING ALTERNATIVES

The enclosed is a revised copy of my January 21 memorandum to Governor Hammond. This version corrects some typos and contains a few stylistic improvements.

The revised version also reflects a recalculation of the interest cost comparison between direct State loans and the loan guarantee plus rate relief fund approach. The new figures are somewhat more favorable to Ron Lehr's approach but not sufficiently so to affect my recommendations.

I have calculated and included in this version the net interest cost to the State under the repayment formula included in Eric Wohlforth's draft legislation. Deferring amortization of the State loan until after retirement of other project debt would result in a significant loss of potential revenue to the State --- a present value equivalent to about 29 percent of the original loan principal. I do not believe that a loss of this size is acceptable or necessary to achieve acceptable electric rates.

enc

23 January, 1981

To: Governor Hammond
Via: Frances Ulmer
From: Arlon R. Tussing

Re: POWER PROJECT FINANCING ALTERNATIVES

1. State guarantees vs. subordinated loans. In a November 19 memorandum to you, I proposed a State loan-guarantee program to lower initial rates on hydroelectric projects that is almost identical to the one Ron Lehr presented last week. Discussions with Power Authority and Bank of America people, Eric Wohlforth, Sterling Gallagher, and others have convinced me, however, that the guarantee approach carries unacceptable risks and may not even be workable.

The alternative proposal using direct State loans is essentially a modification of an approach that the Power Authority has already implemented successfully for Sitka's Green Lake project. Its specifics reflect suggestions by Terry McGuire of the Power Authority, Eric Wohlforth, and me. In my judgment, this approach is superior to using State loan guarantees plus a rate-relief fund.

The two methods of State assistance have precisely the same purposes and economic effects, and either method can be structured to yield any desired level of initial electric rates, and any desired allocation of costs and risks between the ratepayers and the State treasury. Either is compatible with a project-by-project vote of the people, or with an overall program authorization. The differences are significant, however:

a. Interest costs. Theoretically, the use of tax-exempt G.O. bonds should result in lower net interest costs, mainly because the State funds that would otherwise be committed to a direct loan could be invested in taxable securities at a higher rate of return. This is Ron Lehr's chief argument for preferring guaranteed loans and a rate relief fund over direct loans from the State.

Eric Wohlforth and the Power Authority argued last week that the loan-guarantee approach would not result in lower net interest costs (or, what is the same thing, higher net earnings for State funds). I believe that Ron Lehr is probably right in principle, provided his scheme is workable. In Appendix A's illustrative case, the difference amounts to 7.5 percent of total costs. In my judgment, however, this saving is overshadowed by other considerations:

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b. Arbitrage. The Internal Revenue Service may determine that State-guaranteed bonds coupled with a rate relief fund as provided in Ron Lehr's plan is an illegal "arbitrage" scheme --- a device to borrow money in tax-exempt bond markets and invest it in taxable securities in order to "profit at the expense of the U.S. Treasury."

The experts we have heard disagree about how likely it is the IRS would actually condemn this plan, but arbitrage is in fact its chief purpose and its chief merit. What is clear is that we have no way of knowing how the IRS would actually rule, except after authorizing and preparing a specific bond offering.

c. Marketability. Thirty and 40-year electric revenue bonds are commonplace, but G.O. bonds with a maturity of more than 20 years may not be marketable in today's markets. Having to amortize the project debt in (say) 20 years instead of 30 would itself offset any interest-cost advantage from the guaranteed-loan approach.

On first impression it seems incredible that a bond with two sources of repayment should be harder to market than a bond with only one, but specialists from several investment houses have told me that this is indeed the case. See appendix B for an explanation.

d. Bond ratings. The State's G.O.-bond rating is sensitive to the volume of Alaska State and local G.O. bonds outstanding. Three hundred million or so dollars in general obligation debt to finance power projects in Alaska would not be likely to have any effect on the State's rating. But if general fund guarantees and a rate relief fund are chosen now to finance smaller projects, it may be difficult to deny the same treatment to the Susitna project, whose debt may be large enough to affect all of Alaska's bond ratings. This development could of course wipe out any interest-cost advantage from using the guarantee approach.

Just as with the marketability risk, it seems preposterous that using the kind of "double-barreled" bond guarantee proposed by Ron can not get around the danger of lowered ratings. Illogical or not, however, the problem is a real one. [See appendix B for an explanation.] And just as we found with respect to the "arbitrage" problem, experts differ on how much risk there actually is to the State's ratings, but once again the danger cannot be measured with any confidence until it is too late.

e. Simplicity. The subordinated loan scheme that the Power Authority and I endorse is simple: It requires only two kinds of debt to provide any desired time-profile of electric rates. Appendix A illustrates a financing that consists of \$9.1 million in conventional revenue bonds at 10 percent interest, and an \$9.1 million subordinated loan from the State at about 12 percent. Deferring debt-service on the State loan reduces the first-year fixed cost of electricity by half.

The guarantee plan, in contrast, requires three tiers of debt in order to obtain the same electric rate profile. Financing would consist of (a) \$9.1 million in conventional revenue bonds, (b) \$9.1 million in collateralized revenue bonds or G.O. bonds, and (c) nine annual loans of \$.09 to \$1.0 million each from the rate relief fund to make up the difference between the utility's revenues and scheduled debt service on the revenue and G.O. bonds. The rate relief fund would need an initial capital appropriation of at least \$3.47 million in order to provide these annual loans out of interest and retirement of its investments.

In contrast to the guarantee approach, the simplicity of direct loans would permit an exactly parallel scheme to be adopted for non-utility power projects. (I still owe you a proposal for such a program, which would probably be in AIDA rather than in the Power Authority.)

The direct loan approach is easier to design, easier to administer, and easier to explain to legislators, the public, and (most importantly) investors.

2. Capital subsidies. Either direct State loans or loan guarantees plus a rate relief fund can serve as an alternative to subsidies, because either one of them can bring the initial cost of electricity from capital-intensive generating projects down to acceptable levels. I personally see no more reason for the State to subsidize electricity as such than to subsidize beer, oranges, or shotguns.

If the State cannot avoid granting new subsidies, however --- perhaps because direct appropriations and interest-rate subsidies have already been granted to some communities --- Ron Lehr's suggestion of a once-and-for-all capital subsidy of \$1,000 per capita is one of the most elegant ideas around.

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This per-capita subsidy plan is one way of transferring oil wealth to the people in a very broad, egalitarian manner. It doesn't seem to confront any State or Federal Constitutional issues, and the benefits are not taxable. Restricting the grant to capital projects and to renewable energy, however, would deny its benefits to exactly those people who need State relief most desperately --- residents of isolated bush communities who have no alternative to diesel power for the foreseeable future.

The grant principal should, rather, be eligible for use on new capital investments either on hydro and other renewable energy or on conservation. Utilities, communities, or isolated groups that had no immediate prospect for such investments, however, could be allowed to invest their grant money, and to use only its earnings for fuel or other operating costs.

The earnings on the subsidy, whether invested in generating equipment or securities, should not be used to reduce rates per kilowatt-hour --- particularly in thermal-powered systems. Such a unit-price subsidy encourages people to consume more electricity than they otherwise would because they don't have pay its full cost. Rather, utilities should be required to distribute the subsidy benefits in the form of a flat monthly credit per customer. (Say, \$10 per month less on each bill, rather than 4 cents less per kilowatt-hour.)

3. Popular vote. According to Alaska's Constitution, a general obligation bond issue requires a vote of the people, but any legislation authorizing or appropriating funds for direct State loans could easily provide for a referendum, either for the program as a whole or for each project.

You have made a strong case for a popular vote where the wealth of all Alaskans would be used to subsidize power projects that benefit only a part of the population. If the State's power financing program is designed (as we have proposed) so that the ratepayers reimburse the State at market rates for any money it lends and for any financial risks it bears, the case for a vote is less compelling.

Which kind of vote to require, however, is a real dilemma under either type of program: a project-by-project referendum invites citizens to vote only for the projects in their own region, and against all the others. A referendum that encompasses projects in all parts of the State is almost certain to pass and to carry along with it poorly-selected as well as deserving projects. I don't know the way out of this dilemma.

APPENDIX A

Cash-flow comparison of loan-guarantee plus rate relief fund
and State subordinated loans.

Explanation of table. The table on page 8 compares otherwise equivalent plans for reducing initial electricity rates from a new hydroelectric project. For simplicity, only post-construction debt is considered. The initial debt figure of \$18.154 million was chosen because it results in a levelized annual debt service of \$2 million over 25 years at 10 percent.

Guaranteed loans plus rate relief fund. In the financing plan that uses a guaranteed loan plus a rate relief fund, the utility sells \$18.154 million in level debt-service 25-year serial bonds at an effective rate of 10 percent. [The January 8, 1981 yield on 30-year AA electric revenue bonds was 10.00 percent; the yield on medium-grade 30-year G.O. bonds was 10.20 percent, and on prime 30-year G.O. bonds 9.40 percent.]

The rate relief fund lends the utility just enough to cover the revenue deficiency shown in column 3 for years 1 through 9. The fund then recovers these loans plus 12-percent interest [reflecting the greater financial risk of these loans compared to the senior bonds] from the utility's surplus revenues in years 10 through 25.

Starting with a \$1 million first-year debt-service requirement, rather than \$2 million, load growth and inflation together will safely support a revenue increase at 8.522 percent per year without increases in real rates per kilowatt-hour. This is the rate of escalation needed to pay off the same \$18.154 million debt in just 25 years with the assistance of the rate relief fund.

A rate relief fund of \$3.467 million, invested in U.S. Treasury issues of the maturities shown in column 5, and the [January 8] yields shown in column 6, would allow the interest earnings and retirement of bonds at maturity to cover the revenue deficits shown in column 3. The rate relief fund would earn a discounted cash-flow (DCF) rate of return on its investments in U.S. Treasury certificates of 12.69 percent, and the combination of these investments and the loan to the State would yield a DCF return of 12.13 percent on the original \$3.647 million over the 25-year term of the loan.

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Direct State loans. In the alternative financing plan, conventional level debt-service revenue bonds at 10 percent provide \$9.077 million, half of the total (post-construction) capital at 10 percent interest, and require \$1 million in annual revenues for 25 years. The other \$9.077 is a subordinated loan from the State.

The revenue and rate profiles are the same as for the guaranteed loan and rate relief fund, as shown in column (1). The State thus receives debt service on the schedule shown in column 8. Because this example was designed to result in the same revenue stream and hence the same electric rates under both plans, the DCF rate of return to the State on a direct loan would be somewhat less — 10.93 percent — than the 12.13 percent it would earn on the smaller appropriation to the rate relief fund.

Interest cost comparison. The stream of debt service payments on the direct State loan, shown in column 8, has a present value of \$7.713 million at a discount rate of 12.13 percent. This would be the rate of return on the State's investment under the loan guarantee approach, and is a reasonable proxy for the opportunity cost of the money committed to the direct loan. The lower interest earnings on an outlay of \$9.077 million thus have a present cost to the State of \$1.364 million, or 7.5 percent of the \$18.154 million total project cost.

The loss of arbitrage earnings with a present value of \$1.364 is more impressive, however, if it is compared with the \$9.077 million subordinated loan. By this way of reckoning, the State would lose 15.0 percent of the value of its investment by passing up the opportunity to invest its funds in one, high-interest securities market and to borrow in another, lower-interest market. Even so, I do not believe that this potential gain would be worth the added complexity and the risks described elsewhere in this paper.

The Power Authority Proposal. The \$1.346 million loss-of-earnings figure above is based upon a repayment schedule for the direct State loan that coincides with the 25-year term of the conventional revenue bonds. If repayment of principal on the State's loan were deferred until revenue bonds were paid off, however, as proposed by the Power Authority, the effective cost to the State would be much higher.

At the same effective interest rate as in Appendix A (10.93 percent), the payment schedule contemplated in Eric Wohlforth's January 14 draft legislation would have a present value of only \$6.308 million. The present cost of the State's earnings loss would thus be \$2.709 million, 14.9 percent of the project cost, and 29.8 percent of the original loan.

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Beating the market? At least one member of the Governor's staff has argued that calculations like the foregoing are misleading, because the State can invest the rate relief fund and its general fund balances in taxable industrial bonds, for example, at considerably better yields than for U.S. Treasury bonds.

It is a truism that the State can always find higher-interest-rate investments than government bonds. Twenty-year U.S. bonds had a yield of 12.20 percent during the first week of January, and 30-year bonds 11.88 percent. During the same period, long-term AAA utility bonds had yields from 11.31 to 14.00 percent, and long-term A utilities 13.33 to 15.00 percent. Yields on long-term AAA industrial bonds were 11.98 to 12.50 percent, and A industrials earned 12.87 to 13.50 percent.

It does not follow from these rate spreads that the State can actually expect to earn a higher rate of return over the long run than the rate on government bonds. That supposition ignores the reason that industrial and private utility bonds have higher market rates of interest than U.S. governments.

The spread in rates between different securities of the same term reflects the consensus of investors regarding the risk of loss. In principle, the interest premiums for private utility and industrial bonds over risk-free investments like U.S. Treasury debt should be just enough that their total earnings --- net of losses --- will be exactly the same over the long run, given a sufficiently diversified portfolio of non-government securities.

Compare, for example, a typical portfolio of industrial bonds acquired ten or fifteen years ago, after allowance for Chrysler, Penn Central, Equity Funding, Youngstown Sheet and Tube, and Kaiser Steel. The actual earnings on that portfolio might have been higher than a comparable portfolio of U.S. Treasury issues acquired at the same time --- and it might have been lower. In either case, however, the difference could not have been predicted when the investment was made, and the market prices of the various securities at that time reflected the assumption that there would be no difference.

The yield on U.S. treasury bonds is thus the highest interest rate the State can COUNT ON earning.

COMPARISON OF
LOAN GUARANTEE PLUS RATE RELIEF FUND (Lehr)
vs.
STATE SUBORDINATED LOANS (APA-Tussing)

[illegible]