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that the analysis assumes more advantageous siting of some new gas-fired capacity with the Intertie project in place. However, study constraints did not allow consideration of other possible siting benefits such as the impact of the Intertie on the viability of coal-fired generation or other large-scale projects.

The primary benefit categories that are quantified in the system modeling effort are economy interchange, reserve sharing, and system efficiency. All major assumptions and parameters for the study were provided to Lotus Consulting Group by the Power Authority.

Major Assumptions and Parameters

There are many assumptions that enter in to such an assessment, such as electricity demand forecasts and fuel price forecasts. For most of these assumptions, there are numerous values and trends that could be defined that fall within a range of reasonable possibilities. Yet single point estimates had to be selected for each of these assumptions because the time and dollar constraints did not permit review of multiple scenarios. The approach adopted for the study was to select values that were either suggested or agreed to by Railbelt utility representatives and that were judged by the Power Authority to be reasonable. These major assumptions and parameters are discussed below:

* Time Frame for the Analysis: System costs were modeled for the 30 year period from 1991 through 2020. Thirty years was selected as a conservative estimate of the economic life of the Intertie project. Although steel towers would be expected to last longer than 30 years, less durable elements of the Intertie project such as submarine cable may require renovation or replacement by that time. The initial year was set at 1991 because it would be difficult to complete the Intertie project prior to that time and because 1991 is expected to be the first full year of commercial operation for the Bradley Lake project.

* Fuel Price Forecasts: For an analysis of this type, the critical issue with regard to fossil fuel prices is not whether the absolute level of such prices is likely to increase, decrease, or remain the same, but rather what the price differentials are likely to be between different fuels delivered to different locations. For example, the economy interchange benefit of transmission capacity between Anchorage and Fairbanks is primarily based on the assumed differential between the price of natural gas in the Cook Inlet area and the price of fuel oil in the Fairbanks area. If the prices of those two fuels are competitive, there is little benefit in importing energy from one area to displace generation in the other area, whether or not the absolute level of prices is high or low. Conversely, a significant differential in price

can lead to a substantial benefit from economy interchange. Because the absolute level of fossil fuel prices is not central to the analysis, the approach adopted was to assume that the absolute level remains essentially constant in real terms (i.e. tracks the rate of inflation, no more and no less). This assumption was adopted for simplicity, and does not reflect any consideration by the State, the Power Authority, or the Railbelt utilities regarding the expected long-term outlook for fossil fuel prices in general.

Cook Inlet Natural Gas: Substantial gas-fired generating capacity exists in three distinct locations within the Cook Inlet area: the Beluga station on the west side of Cook Inlet, the Kenai Peninsula, and the Anchorage area itself. Because part of the Railbelt Intertie proposal consists of a new line between Anchorage and the Kenai Peninsula, and because reliable transmission already exists between Beluga and the Anchorage area, it is necessary to estimate the extent of any price differential for natural gas delivered to power plants in these three distinct locations. If a price differential exists, then the transmission proposal will produce benefit if it allows lower priced gas to be used to a greater extent.

The first step in estimating delivered price is to estimate the wellhead value. It is assumed for this analysis that the

wellhead value of natural gas is the same everywhere in the Cook Inlet area. A natural gas pipeline network is currently in place that extends from the Beluga field around Knik Arm to Anchorage, down to the Kenai Peninsula and then back across Cook Inlet to the vicinity of the Trading Bay field about 13 miles south of the Beluga station. In other words, with the exception of a short segment between Beluga and Trading Bay on the west side of the Inlet, a pipeline loop extends around the area linking the various major fields in the Cook Inlet region. The existence of this linkage supports the idea that the wellhead value of gas in one field is likely to be very much the same as the wellhead value of gas in another.

Natural gas for the Beluga generating station is obtained at the wellhead from the Beluga field through direct purchase from gas producers. Therefore, there is no charge for transporting the gas from the field to the plant. Natural gas for both Kenai Peninsula and Anchorage area plants is presently purchased from Enstar Natural Gas Company, which delivers gas to the plants through its pipeline system at a price that includes Enstar's gas acquisition cost and the cost of pipeline transportation. Based on discussion with an Enstar representative, it is estimated that the transportation cost component of the delivered price is currently \$.60 per MMBTU.

The utilities that currently operate gas-fired capacity on the Kenai Peninsula have expressed the expectation that gas in the future will be obtainable for their plants on the Kenai Peninsula at its wellhead value from suppliers other than Enstar. Consequently, it was assumed for this analysis that natural gas available to generating plants on the Kenai Peninsula will be priced at the assumed wellhead value (i.e. without a \$.60 per MMBTU transportation charge). In support of this assumption, it can be noted that the review of Bradley Lake economics issued by the State Office of Management and Budget (dated February 25, 1987) incorporates the same assumption that such gas will be available at its wellhead value.

For generating plants in the Anchorage area, it is assumed that future supplies of natural gas must still be delivered by pipeline at a price that includes a \$.60 per MMBTU transportation cost. Therefore, the approach adopted for the analysis was to assume the availability of natural gas both at Beluga and on the Kenai Peninsula at the wellhead value, but to assume that the price delivered to Anchorage area plants would equal the wellhead value plus \$.60 per MMBTU. Based on discussions with area utilities, it was assumed that the wellhead value is \$1.60 per MMBTU (implying a delivered price to Anchorage area plants of \$2.20 per MMBTU). These values were held constant in real terms throughout the period of

analysis. (1)

Fuel Oil in Fairbanks: It is necessary to estimate a fuel oil price in Fairbanks that is reasonably consistent with an assumed Cook Inlet natural gas price of \$1.60 at the wellhead. The judgment adopted for this analysis was that a Cook Inlet gas price of \$1.60 is roughly consistent with a long-run world oil price in the vicinity of \$20/barrel (in 1986 dollars). These magnitudes are supported in general by the observation that Cook Inlet wellhead values for natural gas were about \$2.30/MMBTU four years ago when the world oil price was approximately \$30/barrel. Since \$1.60 represents a reduction of about one-third, the oil price assumed to be consistent was reduced by about one-third.

Based on discussion with Fairbanks utility representatives, the assumed crude oil price of \$20/barrel was translated into an estimated fuel oil price of \$.48/gallon. That price, in turn, is equivalent to \$3.40/MMBTU. The analysis therefore assumes a long-run price differential between Cook Inlet natural gas at the wellhead and fuel oil available in Fairbanks of \$1.80/MMBTU (i.e. \$3.40 for fuel oil vs. \$1.60 for natural gas).

It is interesting to note that the feasibility study for the

existing Anchorage/Fairbanks intertie performed for the State in 1981 incorporated the assumption of a far greater differential between these two prices. Given a natural gas price of about \$1.60/MMBTU, the estimated fuel oil price assumed within that analysis was approximately \$9.00/MMBTU, a differential of \$7.40. This suggests that the estimated long-run price differential adopted for the current analysis may be conservative, as it is approximately one-fourth of the long-run differential previously estimated.

Coal in Fairbanks: As discussed below under the heading of "Expansion Plan," the scenario examined for this study involved a reduction in existing coal-fired capacity in the Fairbanks area from 45 MW today to a single 25 MW plant. The existing capacity consists of a 20 MW plant in Fairbanks that is scheduled for retirement in 2005 and a 25 MW minemouth plant at Healy that is assumed to be replaced in kind in 2002.

The current delivered price of coal to the 20 MW plant in Fairbanks is \$44.48/ton, or about \$2.85/MMBTU. The current minemouth price available to the Healy plant on long-term contract is \$1.30/MMBTU. The existing contract runs through 1994. For this analysis, it is assumed that a marginal price reduction will be negotiated for the Fairbanks plant yielding a delivered price of \$2.50/MMBTU until the plant is retired. For the Healy plant, it is assumed that the

price will remain at \$1.30/MMBTU (in 1986 dollars) through 1994, but will then increase to \$1.60/MMBTU in 1995 and remain constant in real terms thereafter. (2)

* Electricity Demand Forecast: Between 1965 and 1985, the average annual rate of increase in electricity demand in the Railbelt was 10.3%. Historical demand growth is shown in the table below:

Railbelt Utility Electric Energy Generation
(millions of kwh)

<u>Year</u>	<u>Southcentral Area</u>	<u>Fairbanks Area</u>	<u>Total Railbelt</u>
1965	367	120	487
1970	700	222	922
1975	1353	452	1805
1980	2112	440	2552
1985	2939	509	3448

During 1986, electric energy demand in the Railbelt was flat to declining. The most recent electricity demand forecasts

produced by the Railbelt utilities as of December 1986 reflect an expected average annual rate of demand growth of 1.5% over the long run. These utility forecasts were used for the present analysis, with the following three adjustments:

- 1) The utility forecasts cover the period 1987 - 2001. These forecasts were extended through the year 2020 by applying the average annual rate of increase indicated for the entire Railbelt through 2001. Because that average annual rate of increase was equal to 1.5%, the demand forecast used for this analysis reflects an average annual rate of increase of 1.5% for the entire period between 1987 and 2020.

- 2) The forecasts provided by Chugach Electric and its wholesale customers showed an anticipated dip in demand during the mid-1990s. This was based on an earlier assumption that rate shock would occur at that time due to the expiration of old Beluga gas contracts and the expectation that new gas prices would suddenly be encountered. Now, however, Chugach believes that rate shock can be avoided at that time by negotiating a gradual ramping in of the new price level. Consequently, the anticipated dip in demand has been leveled out for purposes of this analysis.

- 3) Though the military has historically generated its own power in the Fairbanks area, consideration is being given to the purchase of power from a local utility, which would result in substantial savings to the military according to the utility's estimates. The Fairbanks utility forecast has been adjusted upward to account for this alternative. Anticipated peak requirements have been increased by 30 MW as a result.

For major Railbelt studies in the past, specifically the Susitna and Bradley Lake feasibility studies, the Power Authority has produced its own electricity demand forecast in a two step process:

- 1) A forecast of employment, population, and households was generated by the Institute of Social and Economic Research (ISER) using their MAP econometric model. Assumptions provided to ISER by the Power Authority included oil price and State revenue scenarios.
- 2) These demographic forecasts were provided as inputs to the Railbelt Electricity Demand (RED) model maintained and operated by Battelle Pacific Northwest Laboratories in Richland, Washington. The demand forecast was an output of the RED model.

This modeling sequence was most recently authorized and funded by the Power Authority in 1985 in preparing a revision to the FERC license application for the Susitna project. The lowest oil price scenario specified as input to the modeling sequence was the forecast from Wharton Econometrics, which anticipated oil prices in 1985 dollars rising from \$24.80 in 1990 to \$31.30 in 2000, and then to \$40.70 in 2010. The average annual rate of electricity demand growth for the Railbelt that emerged from this scenario was 1.7%, a factor that reflected a substantial measure of anticipated, price-induced conservation. Higher oil price inputs resulted in similar long-term demand forecasts because the economic stimulus of higher prices was, in general, compensated by the effect of higher power costs in encouraging electric energy conservation through the price elasticity mechanism.

Implementation of the modeling sequence described above is time-consuming and costly, and could not have been accomplished within the constraints of the present analysis. Given the results of the modeling reported above from 1985 and the fact that electricity demand has grown at a far higher rate in the Railbelt during most of the last 25 years, an average annual rate of demand growth of 1.5% was judged to be reasonable.

* Expansion Plan: In order to model the costs of producing electricity for a future 30 year period, it is necessary to make assumptions regarding the retirement of existing generating units and the addition of new units both for replacement and for meeting anticipated load growth. A schedule of planned retirements was obtained from earlier Railbelt studies and reconfirmed with Railbelt utility representatives. The amount of new generating capacity that was assumed to be added to the system was based on the premise that a planning reserve margin of approximately 40% would be maintained in each of the three supply centers (i.e. Kenai Peninsula, Fairbanks, and Anchorage/Beluga) in the absence of any change in the existing transmission system. A planning reserve margin of 40% means that the amount of installed capacity exceeds the annual peak demand by 40%.

For most utilities in the lower 48 states, a planning reserve margin of 40% would be considered high. However, reserve margins in the Railbelt today are considerably higher than that, approximating 70% for the Railbelt as a whole. (3) Though Railbelt conditions warrant a relatively high level of reserves, it is generally agreed that evolution of the existing system has produced reserve margins today that are higher than necessary. Reserve margins for purposes of the analysis are therefore allowed to decline to a 40% level given the existing transmission system.

Transmission improvements can sometimes allow for additional sharing of reserves among regions and utilities, and consequently result in a reduction in the total amount of installed capacity required. For the present analysis, it is assumed that a new Anchorage/Kenai Peninsula line would have this effect but that an upgrade of the Anchorage/Fairbanks line would not.

For purposes of reserve planning, a given load center may rely on a transmission line from another area for a certain proportion of its reserves, but typically would not rely on the line for reserves that exceed the capacity of the largest installed unit operated within that load center. The existing Anchorage/Fairbanks intertie can now provide reliable access to 70 MW of capacity, an amount that approximates the size of the largest unit in the Fairbanks area. If the transfer capability of the line were increased to a full 350 MW, the line could be relied upon for significantly greater reserve capacity only if the size of the largest generating units in the Fairbanks area were significantly larger in the future.

In contrast, the proposed new line between Anchorage and the Kenai Peninsula would produce a far more reliable connection between these two areas than presently exists. As discussed in the report from Lotus Consulting Group, it was estimated

that the new Anchorage/Kenai Peninsula line would allow a reduction of installed reserves in the Anchorage/Beluga area from a 40% level to a 25% level, resulting in a reduction of installed capacity of approximately 100 MW relative to installed capacity required with the existing transmission system. The capacity expansion plan assumed for scenarios that include the new Anchorage/Kenai Peninsula line reflect this reduction in required installed capacity. (4)

Finally, the type and location of capacity additions had to be specified for the analysis. That specification was based primarily on the following three assumptions or principles:

- 1) The Bradley Lake project would be complete and operational throughout the analysis period.
- 2) The type of capacity additions should be consistent with the fuel price forecasts adopted for the analysis.
- 3) Within the constraints of reserve requirements and transmission capacity, new units should be located at sites that offer the lowest costs of operation.

The price level for natural gas adopted for this analysis is too low to permit effective penetration of the market by

coal-fired generation. As noted earlier, this does not constitute a conclusion by the Power Authority that expanded coal-fired generation in the Railbelt is implausible, but only that such expansion would be inconsistent with the fuel price scenario adopted for this specific analysis. The capacity "expansion plan" therefore entails a reduction of existing coal-fired capacity in the Fairbanks area from the current 45 MW to a single 25 MW plant at Healy. It is assumed that the Healy plant is replaced by a more efficient 25 MW coal-fired plant in the year 2002, which is the scheduled retirement date of the existing unit.

All other capacity additions besides Bradley Lake are assumed to consist of oil-fired combustion turbines in the Fairbanks area and natural gas-fired combustion turbines and combined cycle units in the southcentral area. Because the price of natural gas delivered to the power plant is assumed to be lower on the Kenai Peninsula than in the Anchorage area, it was further assumed for this analysis that the existing combined cycle capacity in the Anchorage area would be replaced by new combined cycle units on the Kenai Peninsula when the existing units are retired in scenarios that include the new Anchorage/Kenai Peninsula line. Those resulting production cost savings could not be realized in the "base case" because the existing transmission limitation would not allow that relocation of plant capacity to occur.

* Transmission Limitations

As noted earlier, the existing transmission line between Anchorage and the Kenai Peninsula can typically deliver about 40 MW in Soldotna given a 55 MW input on the Anchorage end of the line, due to the demands of customers along the route (e.g. Seward, Girdwood, and others) and due to transmission losses. An additional demand of approximately 5 MW is presently anticipated to occur in Seward over the next 5 years as a result of the new maximum security prison and other industrial development. Consequently, the delivery capability of 40 MW is expected to decline to about 35 MW by 1991, and to decline further thereafter to the extent that demand continues to grow along that route. Consequently, it is assumed for this analysis that the actual transfer capability of the existing line in 1991 will be 35 MW, and that such capacity will decline to 24 MW by the year 2020.

In addition, the cost of energy imported over the specified transmission lines has been increased to reflect the cost of transmission losses. For example, if the transmission loss over a particular line were 5%, the effect of that loss would be to increase the cost of the delivered energy by 5%.

Transmission losses for both the existing Anchorage/Fairbanks and Anchorage/Kenai Peninsula interties have been assumed to be 10%. Transmission loss between the Beluga station and

Anchorage has been assumed at 2%. Transmission losses for the upgraded Anchorage/Fairbanks intertie have been assumed at 4%, while 2% losses were assumed for the new Anchorage/Kenai Peninsula intertie.

- * Inflation and Discount Rate: A zero inflation rate is assumed for the economic analysis, and all costs are consequently expressed in terms of constant 1986 dollars. The real discount rate used for the calculation of net present value is 3.5%. Both of these are consistent with analysis parameters previously adopted by the Power Authority.

Results of System Modeling

Four distinct scenarios were modeled by Lotus Consulting Group:

- 1) Base Case: No change in existing transmission system.
- 2) Anchorage/Kenai Peninsula Only: A new intertie between Anchorage and the Kenai Peninsula is assumed that can transfer up to 250 MW on a reliable basis. No other change in the transmission system is assumed.
- 3) Anchorage/Fairbanks Upgrade Only: The existing intertie between Anchorage and Fairbanks is upgraded from its

present transfer capability of 70 MW to a full capability of 350 MW. No other change in the transmission system is assumed.

- 4) Full Railbelt Intertie Proposal: Both of the transmission improvements described above are assumed: the Anchorage/Kenai Peninsula Intertie and the Anchorage/Fairbanks upgrade.

The benefits that were quantified in this analysis are defined as the reduction in system cost that occurs as a result of a given transmission improvement. For example, the quantified benefit of the full Railbelt Intertie proposal is defined as the difference in system cost between scenario #1 and scenario #4, i.e. the base case cost minus the system cost given the full Intertie proposal. As discussed in greater detail in the report from Lotus Consulting Group, the value of the benefits identified in the system modeling exercise are as follows:

	Sum of Benefits in 1986 Dollars <u>(millions)</u>	Net Present Value of Benefits* <u>(millions)</u>
Full Intertie Proposal	\$423.2	\$204.6
Anchorage/Kenai Only	209.4	102.2
Anchorage/Fairbanks Only	210.6	101.2

* The base year for the net present value calculation is 1987.

Approximately 25% of the identified value of the Anchorage/Kenai Peninsula intertie is attributable to an estimated 100 MW of capacity cost savings made possible by reserve sharing. The other 75% of value is due primarily to siting flexibility for new plant capacity and economy interchange. It should be noted that the entire output of the Bradley Lake project is absorbed by the system in every scenario, including the base case. The effect of the intertie project on Bradley Lake would be to increase the distribution, not the amount, of Bradley Lake power sales.

The identified value of the Anchorage/Fairbanks upgrade is due primarily to the increased displacement of oil-fired generation in the Fairbanks area by natural gas-fired generation from the southcentral area. The key factors that contribute to this estimate are the assumed differential between the natural gas price and the fuel oil price, and the assumed electricity demand forecast over the long run for the Fairbanks area.

Other Benefits

- * System Reliability: Strengthening the transmission links between load centers creates a more resilient interconnected system that is better able to recover from disturbances such as the loss of a major generating unit. The existing transmission links between Anchorage and the Kenai Peninsula

and between Anchorage and Fairbanks will result in a separation of the three areas from one another if a significant disturbance occurs. This will usually result in the loss of load in at least two of the three areas. This separation occurs precisely at the time when it is most important to maintain the connection between areas to enable generating reserves to be transported to the area where the disturbance has occurred.

A stronger interconnection between the three load centers would reduce the probability of islanding (where one area loses its interconnection with another area), and consequently reduce the probability or magnitude of an outage.

* Enhanced Competition Among Fuel Suppliers: Though the magnitude of this benefit to Railbelt consumers is particularly difficult to assess, it could be one of the most significant aspects of the Intertie project. An example might help to illustrate the potential. A conservative estimate of natural gas consumption for electric generation during the early years of the study period is 30 BCF per year. At \$1.60 per MMBTU, the cost of that gas in 1986 dollars would be \$48 million per year. If enhanced competition resulted in a reduction in the wellhead price of 5 cents per MMBTU, the annual savings in fuel cost would amount to about \$1.5 million per year. Extending that benefit over the 30 year study

period from 1991 through 2020, the total saving achieved in this manner would be \$45 million, with a present value of about \$24 million. Oil and coal suppliers would be faced with similar competitive pressures.

Comparison of Costs and Benefits

There are two routes that are presently under consideration for a new Anchorage/Kenai Peninsula intertie. The best construction cost estimates currently available are about \$76 million for one route and about \$96 million for the other route. Because the construction cost is not the only consideration in route selection, a decision on a preferred route has not yet been made. For purposes of this preliminary comparison of costs and benefits, a construction cost of \$86 million is assumed based on the average cost of the two routes.

A study aimed at careful development of a cost estimate for the Anchorage/Fairbanks upgrade is scheduled to take place during the month of April, 1987. Until that study is complete, the best figure available continues to be a rough estimate of \$100 million. Therefore, the construction cost of the full Railbelt Intertie proposal is assumed to be \$186 million (in 1986 dollars) for purposes of this comparison. Further, it is assumed that these costs would be spread over a two year construction period,

specifically that half of the cost would be incurred in 1989 and the other half in 1990.

The annual operations and maintenance (O&M) cost of a new Anchorage/Kenai Peninsula line has been estimated at 1.5% of the construction cost by the firm that performed the preliminary engineering and design of those alternatives. Applying that 1.5% factor to the estimated construction cost of the full Railbelt Intertie proposal yields an estimated annual O&M cost of about \$2.8 million (in 1986 dollars). For this comparison, it is therefore assumed that a \$2.8 million O&M cost is incurred for the full project for each year between 1991 and 2020.

The sum of the construction and O&M costs described above for the full Railbelt Intertie proposal is approximately \$270 million (in 1986 dollars) over the period 1989 through 2020. The present value of those costs is approximately \$210 million. (5)

The sum of the benefits identified in the modeling exercise is therefore approximately \$150 million higher (in 1986 dollars) than the sum of the estimated costs (i.e. \$423 million in benefits vs. \$270 million in costs). However, because most of the costs are incurred before most of the identified benefits are realized, the present value of costs and identified benefits are approximately the same. If the benefits not captured in the modeling exercise

were brought into this comparison, then the present value of benefits would exceed the present value of costs.

As stated earlier, the goal of this study was to produce an understanding of the benefits of both transmission proposals sufficient to judge whether they are promising with regard to economic feasibility criteria. On the basis of the analysis performed, it is concluded that the proposed transmission projects are capable of delivering economic benefits in excess of their costs, and consequently warrant further consideration.

FOOTNOTES

- (1) It is recognized that Chugach Electric Association, which operates the Beluga generating station, still has access to significant quantities of old gas at Beluga at prices in the vicinity of \$.30 per MMBTU. In the initial modeling runs performed for this study, the Beluga gas price (in 1986 dollars) was assumed to ramp up from \$1.04/MMBTU in 1991 to \$1.60/MMBTU in 2003, remaining constant at \$1.60 thereafter. The price prior to 2003 represented a blend of old and new gas with a declining proportion of old. It was assumed that gas at the blended price was available to generate power for economy sales to other utilities, though such sales to Anchorage Municipal Light and Power (AML&P) were limited by forcing the AML&P units to run. (AML&P operates most of the "Anchorage area" generating capacity.) The basis for this constraint was the Chugach policy of reserving its limited supply of old gas for the benefit of its own customers.

In the final modeling runs, however, the Beluga gas price (in 1986 dollars) was assumed to be \$1.60 in 1991 and to remain constant in real terms thereafter. By ignoring the declining quantities of old gas, production costs are overestimated for the early years of the study, but are

overestimated equally in the base case (with the existing transmission system) and in the alternate case (with the improved transmission system). The benefit of ignoring the old gas for purposes of the modeling is that the price of energy for economy sales from Beluga will always reflect the price of new gas at \$1.60, which is more realistic than the assumption used initially. By assuring that economy sales from Beluga will be based only on the new gas price, it became possible to remove the "must run" requirement for the AML&P units.

Further, the analysis incorporates the assumption that natural gas will be available in sufficient quantities at wellhead prices at Beluga and on the Kenai Peninsula, and at wellhead plus transportation in Anchorage, to meet all estimated demands at these locations through the year 2020. Variations regarding the natural gas supply assumption could produce alternative patterns of use for the proposed transmission projects.

- (2) The estimated increase in the minemouth price to \$1.60/MMBTU for the Healy plant in 1995 is based on the following observations:

- 1) The current minemouth price for coal paid by

Fairbanks Municipal Utility System is \$34.48 per ton, which is approximately \$2.20/MMBTU.

- 2) The current minemouth price for coal paid by the U.S. military at Fort Wainwright is \$31.79 per ton, which is approximately \$2.05/MMBTU.
 - 3) The prices noted above were recently negotiated, and suggest that the price of coal for the Healy power plant will be subject to upward pressure when the current contract expires. However, particularly as a result of the Anchorage/Fairbanks intertie, the extent of such increase will be limited by competition. The assumption of a moderate increase was therefore adopted in balancing these considerations.
- (3) The high existing reserve margins in the Railbelt are, in large part, due to the more hostile operating environment, the relatively large size of certain generating resources with respect to the loads of the individual systems, and the limited extent of interconnection among the utilities. Most of the existing generating capacity was installed prior to the construction of the Anchorage/Fairbanks intertie and also before the establishment of a high capacity interconnection

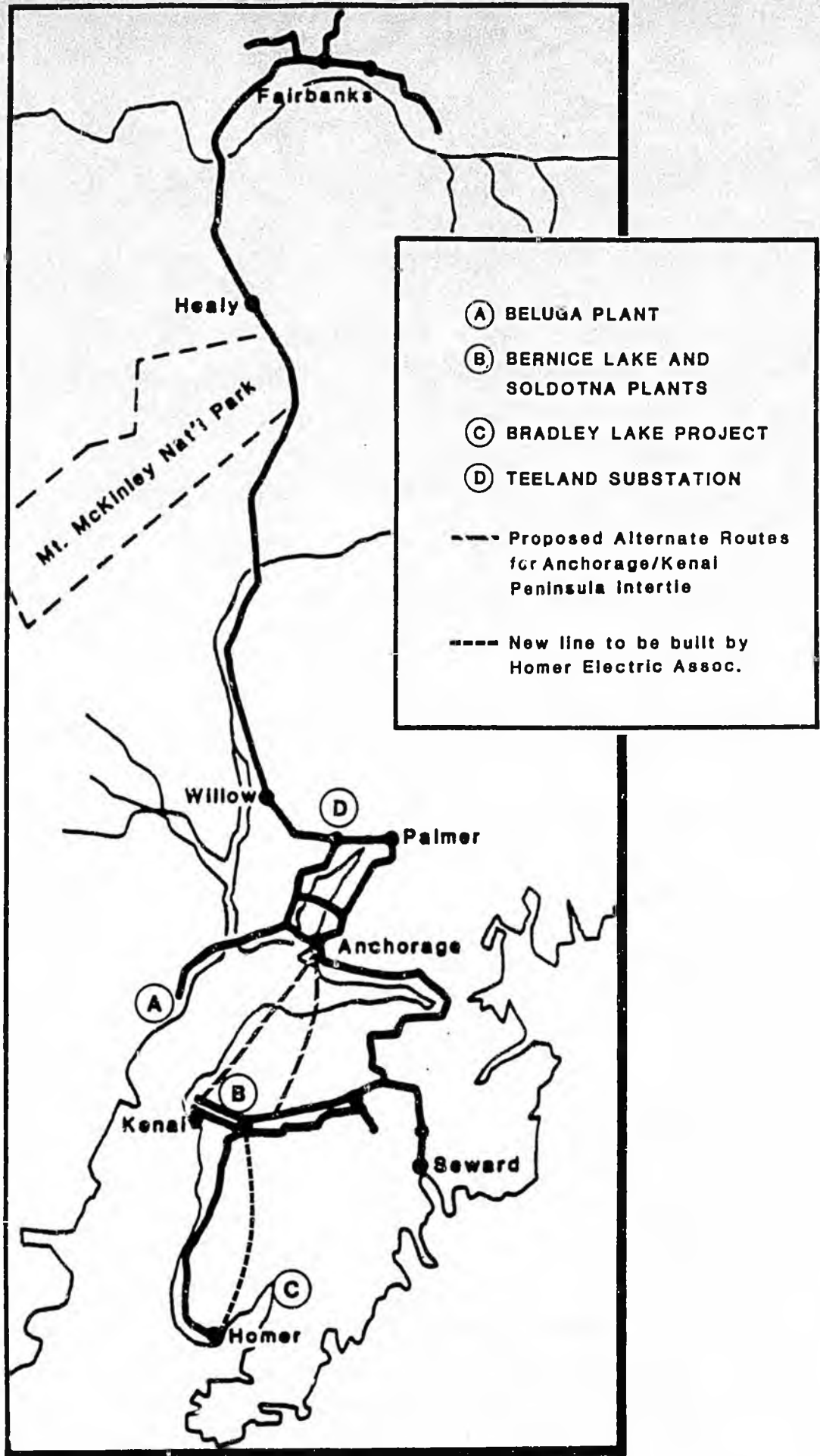
in Anchorage between Chugach Electric and Municipal Light and Power. Mild winters in recent years have also contributed to the appearance of high reserve margins.

(4) Although the reserve margins used in this analysis are considered reasonable for modeling purposes, actual reserve requirements may well depart from these general estimates according to the specific determinations and judgments of the utilities.

(5) For clarification, costs of the Intertie proposal were estimated as follows:

<u>YEAR</u>	<u>COST</u> <u>(Millions of 1986 Dollars)</u>	
1989	\$ 93.0	Construction
1990	93.0	Cost = \$186 million
1991	2.8	
1992	2.8	O&M Cost =
.	.	\$2.8 million / year
.	.	for 30 years
2020	<u>2.8</u>	
		(Net Present Value =
TOTAL	\$ 270.0	\$209.8 million)

Figure 1.



**Railbelt Transmission
Alternatives Assessment
Final Report**

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Prepared For

**The Alaska Power Authority
Anchorage, Alaska**

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Executive Summary

The Alaska Power Authority (APA) contracted with Lotus Consulting Group to evaluate the benefits of alternative transmission configurations within the Alaska Railbelt region. The multi-area study was conducted using Lotus Consulting Group's propriety software program UPLAN. Based on data supplied by APA, the model determined the savings in production costs and capacity deferrals associated with the specified improvements to the transmission network.

The sum of the benefits identified over the 30 year planning horizon is \$423 million (expressed in 1986 dollars), with a net present value of \$205 million dollars. This result was based on increasing the interconnection between the Kenai Peninsula and Anchorage from 35 MW to 250 MW, and between Anchorage and Fairbanks from 70 MW to 350 Mw. These improvements allow for increased purchase of economy energy and the relocation of future generating resources to the Kenai Peninsula to take advantage of favorably priced natural gas. In addition, by creating an opportunity for reserve sharing between the Kenai Peninsula and Anchorage, the improvements allow deferral of 100 MW of new installed capacity in the Anchorage area.

The system modeling further indicates that the identified benefits are attributable to each of the two transmission proposals in nearly equal proportions. Construction of only the new intertie between the Kenai Peninsula and Anchorage produced benefits with a net present value of \$102 million dollars, while the net present value of benefits identified for the Anchorage/Fairbanks upgrade considered separately were \$101 million dollars.

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1. Introduction

In this report, we describe the data and methodology used to estimate the economic benefits associated with an increase in the transfer capability of the intertie connecting the Anchorage, Fairbanks and Kenai Peninsula regions of the Alaska Railbelt. A 30-year base case and alternative cases with expanded transmission capacities were analyzed.

The Alaska Power Authority has identified the goal of the study as the assessment of the benefits from improving the transmission network to provide for the increased integration of the Railbelt region. The benefits captured in the system modeling described in this report accrue from the increased opportunity for economy interchange, reduced capacity requirements through reserve sharing and increased system efficiency due to reduced transmission losses.

This report consists of three major sections. The first section describes the methodological foundations of the study and the data and assumptions from which the base case simulations for the region were developed. This first section includes Chapters 1 through 4.

Chapters 5 and 6 make up the second major division of the report. These chapters describe the three alternative scenarios which were evaluated. For each scenario, the major assumptions made and results obtained are presented.

Chapter 7 presents the overall results of the Railbelt Transmission assessment and our conclusions concerning the results.

The report concludes with a set of appendices, in which listings of the major input and output data sets from the simulations are provided for reference, along with a description of the UPLAN planning model.

2. Overview of Methodology

The basic outline of the existing Railbelt system is shown schematically in Figure 1. The system as modeled consists of 3 supply/demand nodes connected by bidirectional interties with known transfer capacity. Within the area covered by each node, no transmission limitations exist. Each node is modeled to serve its own local demand from its own generating resources with first priority, and will supply economy energy to the network only from excess energy available after satisfying local demand.

Figure 2 shows a typical three system network. In this network, a *terminal node* is a node tied to exactly one other node: nodes A and C are terminal nodes. An *interior node* is a node connected to two other nodes: system B is the only interior node in this network. For each node, we need the supply, financial, and load shape data normally required to model the node as an isolated system.

For each scenario, we analyze the network iteratively, beginning each solution from an opposite terminal node. The method consists of the following steps:

- 1) Starting with a terminal node, estimate its potential economy energy exports to its connecting node, given the intertie capacity and the export demand shape as seen through the intertie. The net profile for sales demand is the minimum of either the intertie capacity limit or the load shape of the connected node.
- 2) Transform the resulting potential energy export to one or more equivalent, capacity-factor limited purchase resource units, and add the unit(s) to the supply resources of the interconnected interior node.

Figure 1. Existing Transmission Capacity

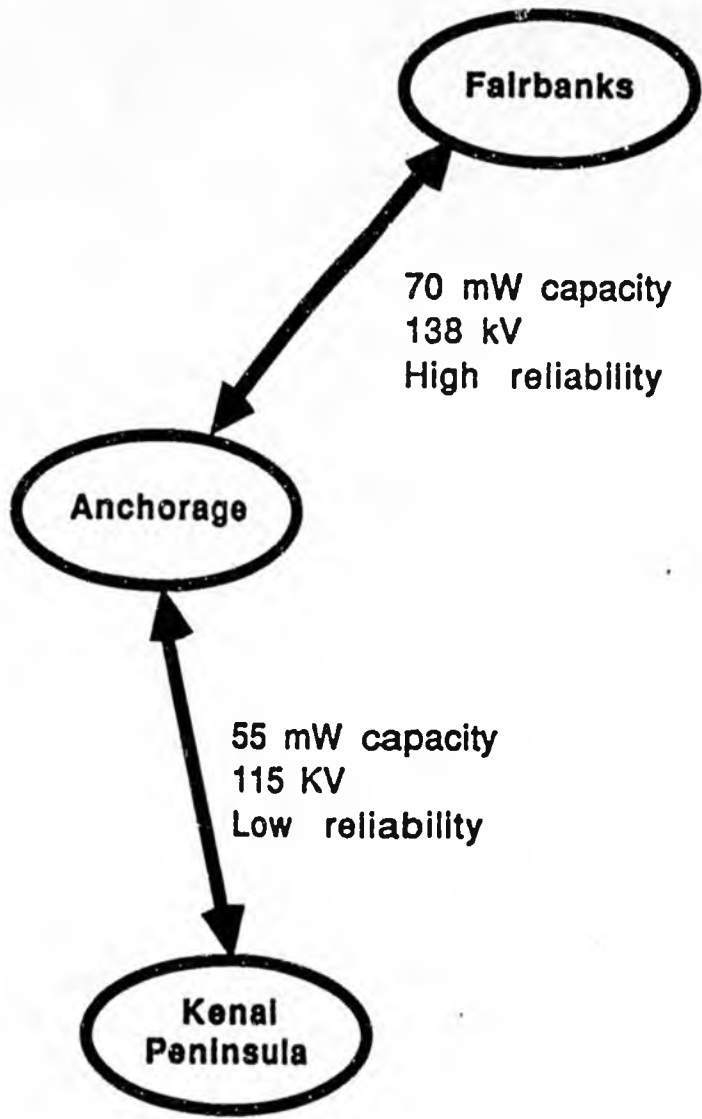
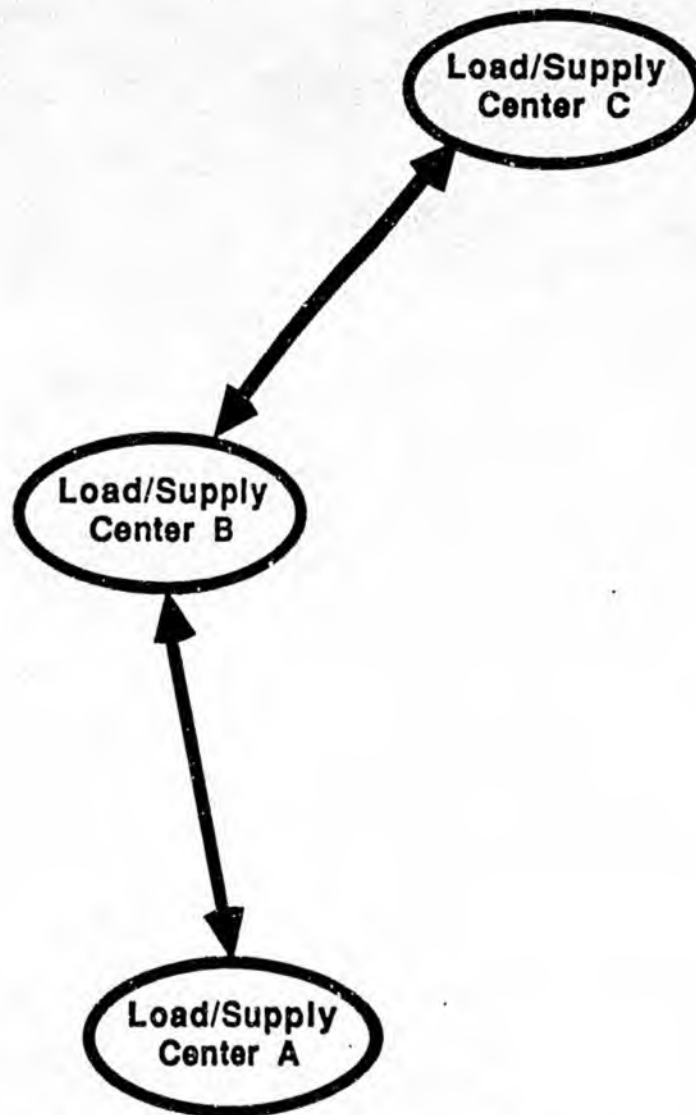


Figure 2. Simplified Network Topology



Interties are bidirectional, capacity-limited links with known transfer capacity

3) For the interior node, estimate its own production costs and potential exports to the next node, using its own generation and the purchase resources of the previous node. The potential exports will include any wheeled energy, ie. energy available from the previous node, not dispatched against the current node's native demand, and available for dispatch against the next node's net profile for sales demand.

4) Repeat step 3 for each interior node until the terminal node in the series is reached. For the terminal node, no potential export energy is estimated: its own production costs are estimated using the economy purchase units from the previous node.

5) Redo the analysis in the reverse direction, this time starting with final terminal node examined in the previous step. The final simulation in this series will estimate the own production costs of the original starting node analyzed in step 1, using available purchase resources from the other direction.

6) Compare the forward and the reverse solutions, and resolve any conflicts in intertie usage, either by repeating the process with the previous round of economy interchange data or revising the size and cost of the equivalent purchase economy units in the appropriate node.

For the network of Figure 2, the process would involve six production cost simulations. The following table shows the demands, supply systems, and results obtained from each of the six:

Case	Native Load	2nd Area Load	Supply Resources	Result
1	A	B	A	Potential exports from A (A*)
2	B	C	B + A*	1. B costs with A* purchases 2. Potential exports to C from A and B (B*)
3	C	none	C + B*	C costs with B* purchases
4	C	B	C	Potential exports from C (C*)
5	B	A	B + C*	1. B costs with C* purchases 2. Potential exports to A from B and C (B#)
6	A	none	A + B#	A costs with B# purchases

In general, another run for area B with potential purchase from both A and C may be necessary. In this study the operating costs of Fairbanks, which will be modeled as area C, are higher than anything in Anchorage and no sales will occur from Fairbanks to Anchorage.

The application of the methodology can be readily automated using the simulation capabilities of UPLAN. From the end-use demand model the net hourly load profile of the sales demand for the connecting node is constructed on a chronological basis. This profile is used in a two area monthly production simulation and UPLAN automatically determines the surplus energy and associated costs available for interchange. This information is converted into equivalent monthly constrained availabilities for economy purchase units in the connecting node to determine the area absorption.

3. DATA OVERVIEW

3.1 Supply Side Representation

General

Basic technical and operating data for all generating units was obtained from the Alaska Power Authority and is shown in the Appendix, Section 8.2.

Unit level cost data reported in 1985 dollars was escalated by 2% to yield 1986 base year dollars for study purposes. Maintenance outages were modeled using the APA values for planned outage rates, and the timing of unit maintenance followed that reported in earlier Alaska Power Authority studies.

The Anchorage supply center consists of all generating units operated by Anchorage Municipal Light and Power (AML), the Beluga and International units of Chugach Electric Association, and the Eklutna Hydro project of the Alaska Power Administration. For this study, all units were coordinated with the area requirements and dispatched on strictly economic ordering.

The Kenai Peninsula supply center includes the Bradley Lake and Cooper Lake hydro projects, and the thermal units at Soldotna, Seldovia, and Seward. It is assumed that the Bradley Lake unit will be available and on-line in 1991, and that it will operate at \$0 variable O&M costs.

The Fairbanks supply center includes all capacity owned by the Fairbanks Municipal Utility System and Golden Valley Electric Association. These units include Chena Units 5 and 6, FMUS IC units 1-3, Healy steam and IC units, and the North Pole, Zendher, and Diesel IC units operated by Golden Valley. It is assumed that the Chena units 1 through 4 will not be operated over the study period due to environmental constraints.

For the base case, planning reserve margin for all regions was established 40%. The Kenai center was modeled with commitment levels for fossil units to provide frequency control. This amounts to an operating reserve require of approximately 25 MW.

Fuel Prices

All prices, costs and revenues in the study are reported in 1986 constant dollars.

Wellhead gas prices are assumed identical throughout the Cook inlet area. A wellhead gas price of \$1.60/MMBTU is assumed, with no real escalation over the study period.

Delivered prices of gas are assumed to vary across the region. Gas delivered to Anchorage is priced at wellhead plus 60 cents/MMBTU for pipeline transportation. On the Kenai Peninsula and at Beluga, gas is priced wellhead.

Coal delivered to the Healy Station of GVEA is priced at \$1.30/MMBTU through 1994, and at \$1.60/MMBTU thereafter. Coal delivered to Fairbanks MUS is priced at \$2.50/MMBTU.

Fuel oil prices are chosen to be consistent with a crude oil price of \$20 per barrel. #4 Fuel oil is priced at \$3.40/MMBTU, and diesel fuel is priced at \$5.00/MMBTU for all sites except Seldovia, where diesel is priced at \$7.00/MMBTU.

3.2. Demand Side Representation

Fairbanks load center is modeled as the combined loads of Fairbanks Municipal Utility System and Golden Valley Electric Association. In addition, 30 MW was added to the Fairbanks peak load over the complete study period, 1991-

2020, with no change in Fairbanks load factor to accommodate the assumption that military loads in the future will be served by Fairbanks utilities.

Anchorage load center is modeled as the combined loads of Anchorage Municipal Light and Power, Chugach retail demand, and Matanuska demand.

The Kenai Peninsula load center is modeled as the combined loads of the City of Seward and the Homer Electric Association. To this is added an 8 MW incremental demand, representing northern Kenai Peninsula customers with demand characteristics identical to Anchorage demand. This increment is escalated at the same rate as AMLP demand.

Hourly load shapes were developed for two regions: Anchorage and Fairbanks. It is assumed that the hourly load shape of the Anchorage and Kenai Peninsula regions will be the same. Hourly loads were developed from information provided by APA for the years 1982 and 1983. Three distinct representative seasonal weekly load shapes were developed for each region: a winter shape, a summer shape, and a transitional Spring/Fall shape. These representative shapes were assigned to individual months, and adjusted to match the month-by-month peak and energy fractions reported in Table 8.3.1, Statement of Power Needs and Utilization, provided by the Power Authority.

For the 1991-2010 period, three separate annual load shapes were employed for each region. The first was used for the 1990-95 period, the second for 1996-2000 period, and the final for the 2001-2020 period.

Annual peak load and energy forecasts were based on Table 8.3.2 Total Railbelt Energy Requirements, which summarizes the load forecasts prepared by the Railbelt utilities. To estimate total busbar energy requirements, the system losses reported separately for Chugach Electric Association were rolled back into their reported sources on the basis of a 2.9% transmission loss associated with sales to Homer, Seward, and Matanuska, and 13.88% loss associated with retail sales.

Peak demand and energy estimates for the 1993 to 2000 period were adjusted from their tabulated values for Homer, Matanuska, and Chugach to reflect an unchanging year-to-year energy and peak demand forecast, rather than the sharp 1994-95 decline in peak and energy reported in Table 8.3.2.

For the period from 2002 to 2020, peak demand and energy are assumed to grow at the rate of 1.5% per year for all regions. The annual peak demand and energy forecast used in the analysis for all three regions are shown in Table 8.3.3 in the Appendix, Section 8.3.

3.3. Interconnection Representation: Base Case

As shown in Figure 1, the current capacity of the connection between Anchorage and the Kenai Peninsula is 55 MW. However, due primarily to the demands of customers along the route, the assumed transfer capability of the line from one end to the other is set at 35 MW in 1991. This capacity is assumed to decline from 35 MW to 24 MW over the 30 year study period due to the increasing requirement of the Seward area. The existing line from Anchorage to Fairbanks has a transfer capacity of 70 MW.

In addition to the capacity limitations, transmission losses were included. The transmission loss factors between the Kenai Peninsula and Anchorage and between Anchorage and Fairbanks are assumed to be 10% in the base case. Also, average transmission losses of 2% were assumed between Beluga and the Anchorage load center. These factors were used to increase the perceived cost of the purchase energy and factored into the valuation of the economic absorption of sales.

4. Base Case Development and Benchmarking

Generation capacity plans were developed for each supply center. It was assumed that the Anchorage area stations will retire their current capacities over the study period and expand the resources in keeping with the needs of the Anchorage area. For the Anchorage and Kenai Peninsula Regions, all new capacity consisted of gas-fired CTs and combined cycle units at \$400/KW and \$650/KW, respectively.

In Fairbanks it was assumed the current Healy unit will be replaced with a new coal-fired unit. All other new capacity for Fairbanks consisted of oil-fired CTs at \$400/KW.

For the period 1991-2020, the base case capacity was expanded to meet a reserve margin requirement of 40%.

Table 1 shows the supply resources used in the UPLAN simulations for the Kenai Peninsula. Table 2 shows the associated reserve margins over the planning horizon. Tables 3 and 4 show the same for Fairbanks and Tables 5 and 6 for Anchorage.

UPLAN was run for the 30 year planning period of 1991 to 2020 following the methodology of Chapter 2. The total production costs for each area and the region as a whole are shown in Table 7. Detailed results for four selected years from these simulations are shown in Tables 8 through 19. Tables 8 to 11 present the annual total and unit operations in the Fairbanks area for 1991, 1996, 2006 and 2015. Tables 12 to 15 show the same results for the Kenai Peninsula and Tables 16 to 19 for Anchorage. The simulation results were nominally compared to previous simulations produced by other A P A consultants, and are consistent within the differences in load and resource assumptions between the two runs.

In the base case results, Fairbanks is basically the main importer of energy. There is some interchange being conducted within the Anchorage area with

generation from Beluga serving some of the load belonging to AMLP thereby displacing the output of the AMLP units, but this interaction has not been quantified for this study.

5. Reserve Sharing

Prior to performing the final simulations for the complete 30 year planning study, a series of single year studies was done to evaluate the characteristics of the region. The main outcome of these studies was the setting of the reserve sharing level in the Anchorage-Kenai Peninsula region. The Anchorage expansion for the alternate case was revised to reflect reserve sharing between the Anchorage and the Kenai Peninsula regions.

The estimation methodology was to calculate the index of reliability for Anchorage and the Kenai Peninsula as isolated areas. The index of reliability used in UPLAN is Loss of Load Probability (LOLP) as reported in days/year. This statistic is calculated by determining the probability of the load exceeding the capacity during any hour of the simulation period. For this study, only a single year was evaluated: the year chosen was 2016. Tables 20 and 21 present the reliability simulation of these areas as isolated systems. The Anchorage area shows an index of reliability of 0.056 days per year. The Kenai Peninsula area has an index of reliability of 0.088 days per year. The joint reliability of the two isolated systems is therefore 0.144 days per year. Table 22 shows Anchorage/Kenai Peninsula as an interconnected area sharing reserves. By removing 110 MW of installed capacity from this combined system, the reliability index rises from 0.002 to 0.115 as shown in Table 23. This level is considered equivalent to the combination of the two isolated systems and no further capacity was removed. Note that all capacity removed from the expansion

plan was associated with the Anchorage area. This build-down corresponds to a 25% planning reserve margin in Anchorage.

6. Alternate Scenario Simulation Results

For the alternate cases, the intertie transfer capacities are set to 250 MW for the Anchorage/Kenai Peninsula line, and 350 MW for the Anchorage/Fairbanks line. The transmission loss factors were reduced from 10% to 2% for the Anchorage/Kenai Peninsula intertie and from 10% to 4% for the Anchorage/Fairbanks intertie. This is reflected in lower costs for the economy energy interchange and represents an additional potential benefit to the region.

In the alternate case, planning reserve margin for the Kenai Peninsula and Fairbanks areas are still modeled at 40%. However, the alternate case planning reserve margin for Anchorage was reduced to 25%, as discussed in the previous section. Table 24 shows the revised Anchorage supply resources for the alternate case. Table 25 presents the associated reserve margins.

Unit commitment for frequency control was discontinued on the Kenai Peninsula. It is assumed for purposes of this analysis that the replacement unit for Anchorage combined cycle capacity retired in 1999 is located on the Kenai Peninsula, where access is gained to natural gas priced at the assumed wellhead value. The Kenai Peninsula and Anchorage are modeled as a single, jointly dispatched supply/demand area with no effective transmission limitations in scenarios that include the new Anchorage/Kenai Peninsula line. (The single year run described earlier indicated that no significant transmission constraint existed in these alternative intertie cases and no change in the methodology described in Chapter 2 is necessary to achieve the same results. This results in a significant savings in computational requirements without any loss of accuracy. Although the installation of an additional

180 MW of combined cycle capacity on the Kenai Peninsula appears to create a surplus capacity of more than 250 MW during off-peak hours in the off-peak season, the capacity of the Kenai Peninsula hydro projects will be significantly discounted because of limited water availability at the same time. As a result, sufficient line capacity will be open during these time periods.)

UPLAN runs were made of the alternate case with increased tie lines and revised resources following the same procedure as the base case. Tables 26 through 33 show the detailed results for the four same years as are shown for the base case. Tables 26 to 29 present the production simulations for Fairbanks for 1991, 1996, 2006 and 2015. Tables 30 to 33 show the results for the Anchorage-Kenai areas as operated under the joint dispatch assumption for the same years.

By way of comparison, Table 34 shows the production simulation in the Fairbanks area for the year 2006 for the base case and the alternate case. In this year there is an operating savings of around 8.6 million dollars. This savings is achieved because of the increased availability of economy energy and the lower cost of the purchase power. Around 1 million dollars is gained from the lower average cost of purchase power and from the increased reliability provided by the larger intertie. However, the bulk of the savings (7.6 million) comes from the ability to import an additional 430 GWH at an incremental savings of about 18 \$/mwh.

The savings in the Anchorage-Kenai production costs are around 5.5 million dollars for the same year, 2006. Table 35 repeats the base case results for Anchorage and Kenai in 2006 for comparison to Table 32. The components of the savings are slightly more complicated to see. The dominant effect in the region is the availability of low cost energy out of the combined cycle unit located on the Kenai Peninsula and using wellhead gas for fuel. There is a savings of around 1 million dollars from relaxing the operating reserve requirement for frequency control and from the serving of some Kenai Peninsula load out of the new combined cycle unit at an incremental

savings of 3.5 \$/mwh. The remaining 4.5 million dollars savings occurs in the Anchorage area by having available an additional 1200 GWH of energy from the new combined cycle unit at an average production savings of around 3.8 \$/mwh.

Using the same assumptions of the alternate case, two additional studies were performed using UPLAN to evaluate the incremental benefits of the upgrading of each intertie separately. The results of these runs are similar to the alternate case and are contained in the Appendix.

7. Summary and Conclusions

Tables 36 through 38 show the complete comparisons of the various scenarios. Table 36 presents the production operating savings and capacity deferral savings between the base case and the alternate case. The capacity benefit is calculated by crediting the savings with the amortized capital costs of the deleted units over a 20 year period at a real interest rate of 3.5%. The units removed from the resource plan in the alternate case are the new 50 MW Beluga CT unit scheduled to be installed in 1994 and the new 50 MW AMLP CT unit scheduled for installation in 2007. This amounts to a savings of over 50 million dollars over the 30 year planning horizon. The savings in operating costs are 372.5 million dollars giving a total savings of 423 million dollars. The net present value of this savings discounted back to 1987 at a discount rate of 3.5% is 205 million dollars. Because no inflation was used in the study, these values are in 1986 dollars.

Table 37 shows the same comparative information for the savings achieved by upgrading only the Kenai Peninsula to Anchorage tie. The net present value of savings is 102 million dollars. Finally, Table 38 presents the savings from upgrading only the Anchorage to Fairbanks intertie. In this case, the net present value is 101 million dollars.

Table 1 - Kenai Supply Model

RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kenairsa.SPM-Kenai Supply Model

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
bern	bernice2	18	1	1971	26
bern	bernice3	27	1	1978	26
bern	bernice4	27	1	1981	23
brad	bradleyH	90	1	1990	65
coop	cooper H	18	1	1975	99
gtk	soldatCT	38	1	1985	25
sldi	seldic2	1	1	1964	99
sldi	seldic34	1	1	1970	99
ses	seward3	2	1	1965	99
ses	seward4	2	1	1985	99
ses	seward5	3	1	1986	99
ses	seward6	3	1	1990	99
new	new ct1	40	1	2004	20
new	new ct2	40	1	2010	20
new	new ct3	25	1	2014	25

Table 2 - Kenai Reserve Margins

Capacity and Reserve Margin

Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin	Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin
	(MW)	(MW)	Exc. Pur (%)	Inc. Pur (%)		(MW)	(MW)	Exc. Pur (%)	Inc. Pur (%)
1991	116	230	98.962	98.962	2006	130	198	52.191	52.191
1992	117	230	96.749	96.749	2007	132	198	49.886	49.886
1993	119	230	93.766	93.766	2008	135	198	47.103	47.103
1994	119	230	93.115	93.115	2009	136	198	45.588	45.588
1995	119	230	92.953	92.953	2010	138	200	44.823	44.823
1996	119	230	92.791	92.791	2011	140	200	42.653	42.653
1997	119	212	77.554	77.554	2012	142	200	40.548	40.548
1998	120	212	77.258	77.258	2013	144	200	38.504	38.504
1999	120	212	76.962	76.962	2014	147	225	53.479	53.479
2000	120	212	76.667	76.667	2015	149	225	51.210	51.210
2001	121	212	75.497	75.497	2016	151	225	49.007	49.007
2002	123	212	72.920	72.920	2017	153	225	46.771	46.771
2003	125	212	70.281	70.281	2018	156	225	44.602	44.602
2004	126	198	56.770	56.770	2019	158	225	42.495	42.495
2005	128	198	54.446	54.446	2020	160	225	40.362	40.362

Table 3 - Fairbanks Supply Model

RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:fairrsa.SPM-Fairbanks Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
Chen	ChenaST5	20	1	1970	35
Chen	ChenaST6	26	1	1976	30
Fmus	Fmusic 1	3	1	1967	25
Fmus	Fmusic 2	3	1	1967	25
Fmus	Fmusic 3	3	1	1967	25
Heal	HealyST1	25	1	1967	35
Heal	HealyIC2	3	1	1967	30
Nopo	NoPolCT1	61	1	1976	30
Nopo	NoPolCT2	61	1	1977	30
Zen	Zender 1	18	1	1971	30
Zen	Zender 2	18	1	1972	30
DslI	DslIC 1	2	1	1961	30
DslI	DslIC 2	2	1	1961	30
DslI	DslIC 3	2	1	1961	30
DslI	DslIC 5	3	1	1970	30

RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:fairrsa.SPM-Fairbanks Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
DslI	DslIC 6	3	1	1970	30
UAFI	UAFIC 7	3	1	1970	26
UAFI	UAFIC 8	3	1	1970	26
NewH	NewHeST1	25	1	2002	35
NewF	NEWFACT A	25	1	1992	30
NewF	NEWFACT B	25	1	2002	30
NewF	NEWFACT 1	25	1	1996	30
NewF	NEWFACT 2	25	1	1999	30
NewF	NEWFACT 3	25	1	2001	30
NewF	NEWFACT 4	50	1	2005	30
NewF	NEWFACT 5	70	1	2006	30
NewF	NEWFACT 6	70	1	2007	30
NewF	NEWFACT 7	30	1	2010	30
NewF	NEWFACT 8	30	1	2016	30

Table 4 - Fairbanks Reserve Margins

Capacity and Reserve Margin

Year	Peak Load (MW)	System Capacity (MW)	Reserve Margin Exc. Pur (%)	Reserve Margin Inc. Pur (%)	Year	Peak Load (MW)	System Capacity (MW)	Reserve Margin Exc. Pur (%)	Reserve Margin Inc. Pur (%)
1991	176	253	43.587	43.587	2006	237	331	39.899	39.899
1992	180	269	49.279	49.279	2007	240	340	41.844	41.844
1993	184	269	45.958	45.958	2008	243	340	39.975	39.975
1994	189	269	42.630	42.630	2009	246	340	38.155	38.155
1995	193	269	39.378	39.378	2010	249	370	48.416	48.416
1996	197	288	45.897	45.897	2011	253	370	46.477	46.477
1997	202	285	41.019	41.019	2012	256	370	44.588	44.588
1998	207	285	37.814	37.814	2013	259	370	42.692	42.692
1999	212	310	46.503	46.503	2014	263	370	40.791	40.791
2000	217	304	40.286	40.286	2015	266	370	38.941	38.941
2001	222	311	40.216	40.216	2016	270	400	48.258	48.258
2002	225	318	41.522	41.522	2017	273	400	46.306	46.306
2003	228	318	39.719	39.719	2018	277	400	44.404	44.404
2004	231	318	37.901	37.901	2019	281	400	42.501	42.501
2005	234	348	48.973	48.973	2020	285	400	40.598	40.598

Table 5 - Anchorage Supply Model

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
EKLU	EklutnaH	30	1	1955	99
AML P	Anc CT 1	16	1	1962	25
AML P	Anc CT 2	16	1	1964	25
AML P	Anc CT 3	20	1	1968	23
AML P	Anc CT 4	34	1	1972	20
AM C	Anc CC56	48	1	1979	20
AM C	Anc CC76	109	1	1979	20
AML P	Anc CT 8	87	1	1984	25
AML P	Anc CT 9	87	1	2050	38
Bel	BelugCT1	16	1	1968	26
Bel	BelugCT2	16	1	1968	26
Bel	BelugCT3	50	1	1972	27
Bel	BelugCT4	10	1	1976	20
Bel	BelugCT5	67	1	1975	24
BelC	BelgCC68	101	1	1976	31

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
belg	BelgCC78	101	1	1976	31
Int	IntnCT1	14	1	1965	31
Int	IntnCT2	14	1	1968	28
Int	IntnCT3	20	1	1970	26
NewC	New CC76	180	1	1999	25
NewB	NewBCT 3	50	1	1994	27
NewB	NewBCT 4	50	1	1996	27
NewB	NewBCT 5	67	1	1999	25
NewB	NewBCT 6	50	1	1999	25
NewB	NewBCC68	101	1	2007	31
NewB	NewBCC78	101	1	2007	31
NewC	New CT10	50	1	2007	25
NewC	New CT11	87	1	2009	25
NewC	New CT12	50	1	2015	25
NewC	New CT13	50	1	2018	25
NwBC	NewBCT14	50	1	2002	25
NwBC	NewBCT15	50	1	2011	25

Table 6 - Anchorage Reserve Margins

Capacity and Reserve Margin									
Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin		Year	Peak Load (MW)	System Capacity Exc. Pur (MW)	Reserve Margin	
			Exc. Pur (%)	Inc. Pur (%)				Exc. Pur (%)	Inc. Pur (%)
1991	459	717	56.209	56.209	2006	555	766	38.043	38.043
1992	464	683	47.325	47.325	2007	563	816	44.886	44.886
1993	474	683	44.245	44.245	2008	572	816	42.732	42.732
1994	484	701	44.835	44.835	2009	580	816	40.617	40.617
1995	486	701	44.209	44.209	2010	589	816	38.540	38.540
1996	488	693	42.037	42.037	2011	598	866	44.865	44.865
1997	490	693	41.313	41.313	2012	607	866	42.716	42.716
1998	494	693	40.312	40.312	2013	616	866	40.607	40.607
1999	499	716	43.631	43.631	2014	625	866	38.538	38.538
2000	506	716	41.502	41.502	2015	635	916	44.366	44.366
2001	515	716	39.002	39.002	2016	644	916	42.236	42.236
2002	523	766	46.519	46.519	2017	654	916	40.125	40.125
2003	531	766	44.338	44.338	2018	673	966	43.451	43.451
2004	539	766	42.221	42.221	2019	684	966	41.331	41.331
2005	547	766	40.113	40.113	2020	694	966	39.233	39.233

Table 7

Base Case Production Costs (Mill \$)

Year	Kenai	Anchor	Fairbnk	Total
1991	8.46	58.70	32.47	99.63
1992	8.61	58.98	33.60	101.19
1993	8.82	60.35	34.56	103.73
1994	8.86	60.67	34.88	104.41
1995	8.87	60.94	35.79	105.60
1996	8.88	59.87	36.21	104.96
1997	8.77	60.18	37.19	106.14
1998	8.79	60.62	38.19	107.60
1999	8.75	59.45	37.75	105.95
2000	8.78	60.31	38.87	107.96
2001	8.88	62.77	39.78	111.43
2002	8.84	63.79	38.87	111.50
2003	9.09	64.71	39.50	113.30
2004	8.34	65.63	40.14	114.11
2005	8.55	66.59	39.93	115.07
2006	8.76	67.56	40.36	116.68
2007	8.98	67.96	41.44	118.38
2008	9.26	68.97	42.20	120.43
2009	9.42	69.65	42.93	122.00
2010	9.31	70.65	43.84	123.80
2011	9.52	71.84	44.14	125.50
2012	9.73	72.90	44.92	127.55
2013	9.95	73.98	45.72	129.65
2014	10.41	75.06	46.51	131.98
2015	10.64	76.60	47.33	134.57
2016	10.86	77.72	48.43	137.01
2017	11.10	78.88	49.30	139.28
2018	11.33	81.68	50.24	143.25
2019	11.56	82.91	51.14	145.61
2020	11.80	84.16	52.09	148.05

Table 8 - 1991 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 1
 RNM file:c:FAIRALL.RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	937.66	PK Load (MW)	176.20	Fix O&M	4.78
Unserve	0.51			Variable	16.73
Net. Gen.	937.15			Unservd	0.05
Storage	0.00			Fuel	10.92
Total Gen	937.15	LOLP (Dys/Yr)	0.000	Total	32.47

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
HealyST1	91.10	199.52	835.97	3332.79	4168.76	20.89	
ChenaST5	56.92	99.72	65.12	3747.25	3812.37	38.23	
TIEPUR91	89.74	550.28	15697.81	0.00	15697.81	28.53	
NoPolCT1	15.95	85.23	124.18	3730.70	3854.88	45.23	
NoPolCT2	0.44	2.33	3.39	101.87	105.26	45.23	
ChenaST6	0.03	0.06	0.04	3.59	3.62	57.21	
Zender 1	0.01	0.01	0.01	0.67	0.68	57.16	
Zender 2	0.00	0.00	0.00	0.18	0.18	57.16	
HealyIC2	0.00	0.00	0.00	0.01	0.01	67.26	
UAFIC 7	0.00	0.00	0.00	0.01	0.01	67.26	
DslIC 5	0.00	0.00	0.00	0.01	0.01	67.26	
DslIC 6	0.00	0.00	0.00	0.00	0.01	67.26	
UAFIC 8	0.00	0.00	0.00	0.00	0.00	67.26	
Fmusic 1	0.00	0.00	0.00	0.00	0.00	89.69	
Fmusic 2	0.00	0.00	0.00	0.00	0.00	89.69	
Fmusic 3	0.00	0.00	0.00	0.00	0.00	89.69	

Table 9 - 1996 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 2
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1996: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1038.89	PK Load (MW)	197.40	Fix O&M	5.21
Unserve	0.22			Variable	16.15
Net Gen.	1038.67			Unserve	0.02
Storage	0.00			Fuel	14.84
Total Gen	1038.67	LOLP (Dys/Yr)	0.000	Total	36.21

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
HealyST1	91.10	199.52	835.98	4102.72	4938.70	24.75
ChenaSTE	67.79	118.76	77.55	4428.44	4505.99	37.94
TIEPUR96	93.45	573.06	15021.12	0.00	15021.12	26.21
NoPolCT1	26.48	141.48	206.13	6050.55	6256.68	44.22
NoPolCT2	1.08	5.76	8.40	252.25	260.65	45.23
NEWFACT A	0.03	0.06	0.03	2.47	2.51	41.70
NEWFACT 1	0.01	0.03	0.02	1.08	1.10	41.70
ChenaST6	0.00	0.00	0.00	0.17	0.17	57.21
Zender 1	0.00	0.00	0.00	0.03	0.03	57.16
Zender 2	0.00	0.00	0.00	0.01	0.01	57.16
HealyIC2	0.00	0.00	0.00	0.00	0.00	67.26
DslIC 5	0.00	0.00	0.00	0.00	0.00	67.26
DslIC 6	0.00	0.00	0.00	0.00	0.00	67.26

Table 10 - 2006 Base Case Production Operation in Fairbanks

Detail report:a:FRASE401.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL.RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FRASE401.SPM-fairbanks basea case supply 40% prn 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	3.75			Variable	15.58
Net Gen.	1227.11			Unservd	0.37
Storage	0.00			Fuel	20.26
Total Gen	1227.11	LOLP (Dys/Yr)	0.011	Total	40.36

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewHeST1	87.48	191.57	823.76	3024.46	3848.21	20.09
TIEPURO6	97.88	600.21	14231.02	0.00	14231.02	23.71
NoPoICT2	57.75	308.58	449.60	12027.15	12476.74	40.43
NEWFACT A	15.99	35.03	20.32	1440.44	1460.75	41.70
NEWFACT B	9.39	20.57	11.93	846.06	858.00	41.70
NEWFACT 1	6.25	13.69	7.94	563.05	570.99	41.70
NEWFACT 2	5.04	11.04	6.41	454.15	460.55	41.70
NEWFACT 3	4.38	9.59	5.56	394.30	399.86	41.70
NEWFACT 4	3.84	16.83	9.76	692.28	702.04	41.70
NEWFACT 5	3.26	19.99	11.60	822.21	833.81	41.70

Table 11 - 2015 Base Case Production Operation in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 4
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prn 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1385.37	PK Load (MW)	266.30	Fix O&M	4.56
Unserve	0.82			Variable	15.51
Net Gen.	1384.55			Unserve'd	0.08
Storage	0.00			Fuel	27.18
Total Gen	1384.55	LOLP (Dys/Yr)	0.028	Total	47.33

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	87.49	191.60	823.86	3024.80	3848.66	20.09
TIEPUR15	98.75	605.56	14347.54	0.00	14347.54	23.69
NEWFACT A	54.70	119.78	69.47	4925.81	4995.28	41.70
NEWFACT 8	46.05	100.85	58.49	4147.15	4205.64	41.70
NEWFACT 1	32.88	72.01	41.77	2961.43	3003.20	41.70
NEWFACT 2	26.33	57.66	33.44	2371.00	2404.44	41.70
NEWFACT 3	18.60	40.73	23.62	1674.85	1698.47	41.70
NEWFACT 4	12.66	55.44	32.16	2279.93	2312.09	41.70
NEWFACT 5	10.12	62.06	35.99	2551.90	2587.89	41.70
NEWFACT 6	9.12	55.90	32.42	2298.89	2331.31	41.70
NEWFACT 7	8.74	22.97	13.32	944.43	957.76	41.70

Table 12 - 1991 Base Case Production Operation in Kenai

Detail report: a:KBAS35LS.DTL 05-17-1987 Page 1
 RNM file: c:KENAALL .RNM-kenai load 1991-2020
 Supply file: c:kbas35ls.SPM-kenai with anc 35mw purch 10% prm loss penalty
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	596.25	PK Load (MW)	115.60	Fix O&M	3.70
Unserve	0.15			Variable	0.28
Net Gen.	596.10			Unreserved	0.02
Storage	0.00			Fuel	1.46
Total Gen	596.10	LQLP (Dys/Yr)	0.000	Total	8.46

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
soldatCT	51.90	172.76	247.05	4138.16	4385.20	25.38
bernice3	4.36	10.31	23.00	252.18	275.17	26.68
bernice4	1.23	2.91	6.50	71.23	77.73	26.68
bernice2	0.00	0.00	0.00	0.00	0.00	27.91
ANCPUR91	0.00	0.00	0.00	0.00	0.00	28.08
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.82	369.13	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 13 - 1996 Base Case Production Operation in Kenai

Detail report:a:KBAS35LS.DTL 03-17-1987 Page 2
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	615.33	PK Load (MW)	119.30	Fix O&M	3.70
Unserve	0.11			Variable	0.31
Net Gen.	615.22			Unservd	0.01
Storage	0.00			Fuel	4.86
Total Gen	615.22	LOLP (Dys/Yr)	0.000	Total	8.88

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost	
			Variable	Fuel Cost	Total	.\$/(MWH)	
soldatCT	56.67	188.64	269.76	4460.38	4730.14	25.07	
bernice3	5.19	12.26	27.35	299.91	327.26	26.68	
bernice4	1.77	4.19	9.33	102.35	111.68	26.68	
ANCPUR96	0.00	0.00	0.00	0.00	0.00	25.58	
bernice2	0.00	0.00	0.00	0.00	0.00	0.00	
seward3	0.00	0.00	0.00	0.00	0.00	0.00	
seward4	0.00	0.00	0.00	0.00	0.00	0.00	
seward5	0.00	0.00	0.00	0.00	0.00	0.00	
seward6	0.00	0.00	0.00	0.00	0.00	0.00	
seldic2	0.00	0.00	0.00	0.00	0.00	0.00	
seldic34	0.00	0.00	0.00	0.00	0.00	0.00	
bradleyH	46.82	369.14	0.00	0.00	0.00	0.00	
cooper H	25.99	40.98	0.00	0.00	0.00	0.00	

Table 14 - 2006 Base Case Production Operation in Kenai

Detail report: a:KBAS351.C.DTL 03-17-1987 Page 3
 RNM file: c:KENAALI .RNM-kenai load 1991-2020
 Supply file: c:kb351s.SPM-kenai with anc 35mw purch 40% prim loss penalty

SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS (M\$)	
Demand	670.56	PK Load (MW)	130.10	Fix O&M	3.32
Unserve	0.64			Variable	0.18
Net Gen.	669.92			Unservd	0.06
Storage	0.00			Fuel	5.20
Total Gen	669.92	LOLP (Dys/Yr)	0.000	Total	8.76

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
new ct1	65.89	230.88	133.91	4468.02	4601.94	19.93
soldatCT	8.76	29.17	41.71	735.80	777.50	26.66
ANCPUR06	0.01	0.02	0.51	0.00	0.51	23.78
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.79	368.90	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Table 15 - 2015 Base Case Production Operation in Kenai

Detail report:a:KBAS35LS.DTL 03-17-1987 Page 4
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	766.95	PK Load (MW)	148.80	Fix O&M	3.46
Unserve	0.76			Variable	0.21
Net Gen.	766.18			Unservd	0.08
Storage	0.00			Fuel	6.89
Total Gen	766.18	LOLP (Dys/Yr)	0.001	Total	10.64

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$(/MWH)
			Variable	Fuel Cost	Total	
new ct1	73.63	257.99	149.63	4992.65	5142.28	19.93
new ct2	22.58	79.12	45.89	1531.18	1577.07	19.93
new ct3	8.74	19.13	11.10	370.20	381.30	19.93
ANCPUR15	0.01	0.02	0.53	0.00	0.53	23.79
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.80	368.96	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Table 16 - 1991 Base Case Production Operation in Anchorage

Detail report:a:AK3540LS.DTL 03-17-1987 Page 1
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK351.AST.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	2516.97	PK Load (MW)	459.00	Fix O&M	11.60
Unserve	0.14			Variable	4.93
Net Gen.	2516.83			Unservd	0.01
Storage	0.00			Fuel	42.16
Total Gen	2516.83	LOLP (Dys/Yr)	0.003	Total	58.70

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
BelgCC78	78.70	696.27	995.66	10906.26	11901.93	17.09
BelgCC68	78.48	694.38	990.88	11145.99	12136.87	17.48
BelugCT3	75.72	331.65	473.26	6417.66	6890.93	20.78
BelugCT5	63.01	369.80	527.70	8386.41	8914.11	24.11
Anc CC76	24.98	238.48	1380.30	4914.37	6294.67	26.40
KENPUR91	6.45	19.77	524.49	0.00	524.49	26.53
BelugCT2	3.18	4.46	6.36	124.50	130.86	29.37
BelugCT1	2.24	3.14	4.49	87.64	92.13	29.37
BelugCT4	1.65	1.44	2.06	47.35	49.41	34.25
Anc CC56	0.83	3.51	20.32	92.97	113.29	32.27
Anc CT 8	0.13	0.99	5.74	30.59	36.32	36.65
Anc CT 4	0.01	0.04	0.26	1.81	2.06	46.43
IntnCT1	0.01	0.01	0.09	0.32	0.41	61.52
IntnCT2	0.00	0.00	0.05	0.18	0.23	61.52
IntnCT3	0.00	0.00	0.03	0.12	0.16	61.43
EklutnaH	58.18	152.89	0.00	0.00	0.00	0.00

Table 17 - 1996 Base Case Production Operation in Anchorage

Detail report:a:AK35401.S.DTL 03-17-1996 / Page 2
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SPM-anc w/ 35mw ken,pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	2684.08	PK Load (MW)	487.90	Fix O&M	10.69
Unserve	0.22			Variable	3.59
Net Gen.	2683.86			Unservd	0.02
Storage	0.00			Fuel	45.56
Total Gen	2683.86	LOLP (Dys/Yr)	0.045	Total	59.87

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
BelgCC78	78.68	696.11	995.44	10904.17	11899.61	17.09	
BelgCC68	78.61	695.53	992.53	11160.82	12153.35	17.47	
NewBCT 3	73.44	321.68	186.57	6349.66	6536.23	20.32	
NewBCT 4	67.88	297.32	172.45	5868.87	6041.31	20.32	
BelugCT3	54.94	240.62	343.36	4891.75	5235.11	21.76	
BelugCT5	32.27	189.39	270.27	4610.94	4881.20	25.77	
Anc CC76	8.65	82.61	478.15	1702.39	2180.54	26.40	
KENPUR96	1.61	4.95	131.56	0.00	131.56	26.60	
Anc CC56	0.52	2.21	12.78	58.46	71.23	32.27	
Anc CT 8	0.08	0.58	3.33	17.77	21.10	36.65	
EklutnaH	58.17	152.86	0.00	0.00	0.00	0.00	

Table 18 - 2006 Base Case Production Operation in Anchorage

Detail report:a:AK3540LS.DTL 03-17-1987 Page 3
 RNM file:c:ANGHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK3540LS.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3124.08	PK Load (MW)	554.90	Fix O&M	11.16
Unserve	1.38			Variable	3.00
Net Gen.	3122.70			Unserved	0.14
Storage	0.00			Fuel	53.27
Total Gen	3122.70	LOLP (Dys/Yr)	0.225	Total	67.56

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
BelgCC78	78.71	696.35	995.78	10907.50	11903.29	17.09
BelgCC68	78.70	696.31	993.64	11171.03	12164.67	17.47
NewBCT14	77.90	341.22	197.91	6603.28	6801.18	19.93
NewBCT 3	73.51	321.97	186.74	6355.46	6542.20	20.32
NewBCT 4	66.88	292.92	169.89	5781.94	5951.84	20.32
NewBCT 5	55.35	324.87	188.43	6412.72	6601.14	20.32
NewBCT 6	37.99	166.39	96.51	3284.40	3380.90	20.32
New CC56	12.67	53.28	30.90	1152.35	1183.25	22.21
New CC76	6.15	71.09	41.23	1537.51	1578.74	22.21
KENPUR06	1.12	3.43	84.45	0.00	84.45	24.61
Anc CT 8	0.25	1.94	11.24	59.92	71.15	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Table 19 - 2015 Base Case Production Operation in Anchorage

Detail report:a:AK3540L.S.DT! 03-17-1987 Page 4
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SFM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3572.23	PK Load (MW)	634.50	Fix O&M	12.46
Unserve	1.77			Variable	3.88
Net Gen.	3570.45			Unservd	0.18
Storage	0.00			Fuel	60.08
Total Gen	3570.45	LOLP (Dys/Yr)	0.039	Total	76.60

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
NewBCC68	78.70	696.34	459.58	10907.41	11367.00	16.32
NewBCC78	78.71	696.36	459.60	10907.62	11367.22	16.32
NewBCT14	78.15	342.28	198.52	6623.71	6822.23	19.93
NewBCT15	77.50	339.45	196.88	6569.07	6765.96	19.93
NewBCT 3	73.33	321.17	186.28	6339.52	6525.80	20.32
NewBCT 4	68.44	299.76	173.86	5917.05	6090.92	20.32
NewBCT 5	58.44	343.00	198.94	6770.43	6969.37	20.32
NewBCT 6	44.41	194.53	112.83	3839.90	3952.73	20.32
KENPUR15	27.34	83.84	1838.16	0.00	1838.16	21.92
New CC56	9.95	41.85	24.27	905.14	929.41	22.21
New CC76	4.75	54.93	31.86	1188.06	1219.92	22.21
New CT10	0.46	2.01	1.17	53.46	54.62	27.19
New CT11	0.20	1.52	0.88	40.32	41.19	27.19
New CT12	0.11	0.50	0.29	13.40	13.69	27.19
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Table 21 - 2016 Production Operation in Anchorage
as an Isolated Area with 40% Reserves

Detail report:c:ANCH16 .DTL 03-18-1987 Page 1
 RNM file:c:anch16.RNM-anchorage 2016
 Supply file:c:ANCH .SPM-anchorage with 35 mw ken purchase units prm=40%
 SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3625.71	PK Load (MW)	644.00	Fix O&M	13.10
Unserve	0.17			Variable	2.16
Net Gen.	3625.54			Unservd	0.02
Storage	0.00			Fuel	71.19
Total Gen	3625.54	LOLP (Dys/Yr)	0.056	Total	86.47

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewBCC68	78.71	696.37	459.60	10952.68	11412.29	16.39
NewBCC78	78.71	696.36	459.59	10952.52	11412.11	16.39
NewBCT 3	78.17	342.40	198.59	6729.76	6928.35	20.23
NewBCT 5	77.31	453.76	263.18	8929.61	9192.79	20.26
NewBCT14	75.33	197.96	114.82	3906.59	4021.41	20.31
NewBCT15	73.44	160.83	93.28	3187.52	3280.80	20.40
NewBCT16	71.05	124.48	72.20	2481.31	2553.51	20.51
New CC56	69.94	294.08	170.56	8188.72	8359.29	28.43
New CC76	40.04	382.32	221.75	12036.34	12258.09	32.06
New CT10	15.73	68.89	39.96	2126.27	2166.23	31.44
New CT11	8.24	28.88	16.75	891.21	907.96	31.44
New CT12	3.85	16.86	9.78	520.22	530.00	31.44
New CT17	1.98	3.47	2.01	107.15	109.16	31.44
Anc CT 8	0.71	5.42	31.39	167.41	198.80	36.65
Anc CT 9	0.07	0.56	3.22	17.17	20.39	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Table 22 - 2016 Production Operation in Anchorage/Kenai
as a Joint Dispatch Area with 40% Reserves

Detail report:c:\ak16 .DTL 03-18-1987 Page 1
 RNM file:c:\ak16.RNM-anchorage and kenai 2016
 Supply file:c:\ANCH .SPM-anchorage with 35 mw ken purchase units prm=40%
 SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4475.84	PK Load (MW)	795.00	Fix O&M	16.64
Unserve	0.04			Variable	2.38
Net Gen.	4475.80			Unservd	0.00
Storage	0.00			Fuel	75.82
Total Gen	4475.80	LOLP (Dys/Yr)	0.002	Total	94.85

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
NewBCC68	78.70	696.34	459.58	10952.29	11411.88	16.39	
NewBCC78	78.70	696.32	459.57	10952.01	11411.57	16.39	
new ct1	83.81	220.25	127.75	4228.89	4356.64	19.78	
new ct2	83.81	308.35	178.84	5920.27	6099.12	19.78	
new ct3	83.77	322.87	187.26	6199.03	6386.29	19.78	
NewBCT 3	77.36	338.82	196.51	6667.39	6863.91	20.26	
NewBCT 5	76.11	446.69	259.08	8805.16	9064.24	20.29	
NewBCT14	73.82	194.01	112.53	3843.91	3956.43	20.39	
NewBCT15	71.65	156.92	91.01	3123.90	3214.91	20.49	
NewBCT16	66.15	115.90	67.22	2338.28	2405.50	20.75	
New CC56	54.53	229.29	132.99	6678.75	6811.74	29.71	
New CC76	17.27	164.88	95.63	5424.55	5520.18	33.48	
New CT10	3.18	13.92	8.08	429.72	437.80	31.44	
New CT11	1.37	4.79	2.78	147.80	150.58	31.44	
New CT12	0.54	2.37	1.37	73.15	74.53	31.44	
New CT17	0.25	0.44	0.25	13.53	13.78	31.44	
Anc CT 8	0.08	0.59	3.40	18.12	21.52	36.65	
Anc CT 9	0.00	0.04	0.22	1.17	1.39	36.65	
EklutnaH	58.18	152.91	0.00	0.00	0.00	0.00	
bradleyH	46.82	369.13	0.00	0.00	0.00	0.00	
cooper H	25.99	40.98	0.00	0.00	0.00	0.00	

**Table 23 - 2016 Production Operation in Anchorage/Kenai
as a Joint Dispatch Area with 110MW Reduction in Reserves**

Detail report:c:AK250 .DTL 03-18-1987 Page 1
 RNM file:c:ak16.RNM-anchor and kenai 2016
 Supply file:c:AK250 .SPM-reduced anchor reserve

SYSTEM REPORT FOR YEAR 2016

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4475.84	PK Load (MW)	795.00	Fix O&M	15.68
Unserve	0.08			Variable	2.42
Net Gen.	4475.76			Unserviced	0.01
Storage	0.00			Fuel	75.82
Total Gen	4475.76	LOLP (Dys/Yr)	0.115	Total	93.93

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
NewBCC68	78.70	696.30	459.56	10951.81	11411.37	16.39
NewBCC78	78.70	696.27	459.54	10951.45	11410.99	16.39
new ct1	83.81	220.24	127.74	4228.63	4356.37	19.78
new ct2	83.80	308.33	178.83	5919.92	6098.75	19.78
new ct3	83.76	322.85	187.25	6198.67	6385.92	19.78
NewBCT 3	77.35	338.80	196.50	6667.02	6863.52	20.26
NewBCT 5	76.10	446.67	259.07	8804.73	9063.80	20.29
NewBCT14	73.82	194.00	112.52	3843.72	3956.24	20.39
NewBCT15	71.65	156.91	91.01	3123.74	3214.75	20.49
NewBCT16	66.16	115.91	67.23	2338.43	2405.65	20.76
New CC56	54.56	229.40	133.05	6682.28	6815.33	29.71
New CC76	17.28	164.96	95.68	5427.40	5523.08	33.48
New CT12	3.18	13.92	8.08	429.70	437.78	31.44
Anc CT 8	0.96	7.30	42.23	225.19	267.42	36.65
Anc CT 9	0.12	0.92	5.33	28.44	33.77	36.65
EklutnaH	58.18	152.90	0.00	0.00	0.00	0.00
bradleyH	46.82	369.11	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 24 - Anchorage Supply Model with Reduced Reserves

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 1-15

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
EKLU	EklutnaH	30	1	1955	99
AML P	Anc CT 1	16	1	1962	25
AML P	Anc CT 2	16	1	1964	25
AML P	Anc CT 3	20	1	1968	23
AML P	Anc CT 4	34	1	1972	20
AM C	Anc CC56	48	1	1979	20
AM C	Anc CC76	109	1	1979	20
AML P	Anc CT 8	87	1	1984	25
AML P	Anc CT 9	87	1	2050	38
Bel	BelugCT1	16	1	1968	26
Bel	BelugCT2	16	1	1968	26
Bel	BelugCT3	50	1	1972	27
Bel	Bel gCT4	10	1	1976	20
Bel	BelugCT5	67	1	1975	24
BelC	BelgCC68	101	1	1976	31

RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:anchrsa.SPM-Anchorage Supply Model

Units 16-30

Unit ID	Unit Name	Size (MW)	Number of Units	Date Installed (Yrs.)	Unit Life (Yrs.)
belg	BelgCC78	101	1	1976	31
Int	IntnCT1	14	1	1965	31
Int	IntnCT2	14	1	1968	28
Int	IntnCT3	20	1	1970	26
NewC	New CC76	180	1	1999	25
*NewB	NewBCT 3	50	1	2999	27
NewB	NewBCT 4	50	1	1996	27
NewB	NewBCT 5	67	1	1999	25
NewB	NewBCT 6	50	1	1999	25
NewB	NewBCC68	101	1	2007	31
NewB	NewBCC78	101	1	2007	31
*NewC	New CT10	50	1	2999	25
NewC	New CT11	87	1	2009	25
NewC	New CT12	50	1	2015	25
NewC	New CT13	50	1	2018	25
NwBC	NewBCT14	50	1	2002	25
NwBC	NewBCT15	50	1	2011	25

Table 25 - Anchorage Reserve Margins with Reduced Reserves

Capacity and Reserve Margin

Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin	Year	Peak Load	System Capacity	Reserve Margin	Reserve Margin
	(MW)	Exc. Pur (MW)	Exc. Pur (%)	Inc. Pur (%)		(MW)	Exc. Pur (MW)	Exc. Pur (%)	Inc. Pur (%)
1991	459	717	56.209	56.209	2006	555	716	29.032	29.032
1992	464	683	47.325	47.325	2007	563	716	27.131	27.131
1993	474	683	44.245	44.245	2008	572	716	25.241	25.241
1994	484	651	34.504	34.504	2009	580	716	23.384	23.384
1995	486	651	33.923	33.923	2010	589	716	21.562	21.562
1996	488	643	31.789	31.789	2011	598	766	28.137	28.137
1997	490	643	31.117	31.117	2012	607	766	26.236	26.236
1998	494	643	30.188	30.188	2013	616	766	24.371	24.371
1999	499	666	33.601	33.601	2014	625	766	22.540	22.540
2000	506	666	31.621	31.621	2015	635	816	28.605	28.605
2001	515	666	29.295	29.295	2016	644	816	26.708	26.708
2002	523	716	36.955	36.955	2017	654	816	24.828	24.828
2003	531	716	34.916	34.916	2018	673	866	28.601	28.601
2004	539	716	32.937	32.937	2019	684	866	26.701	26.701
2005	547	716	30.968	30.968	2020	694	866	24.820	24.820

Table 26 - 1991 Alternate Case Production Operation in Fairbanks

Detail Report: a:FBAS250X.DTL 03-17-1987 Page 1
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	937.66	PK Load (MW)	176.20	Fix O&M	4.78
Unserve	0.94			Variable	17.93
Net Gen.	936.72			Unservd	0.09
Storage	0.00			Fuel	6.77
Total Gen	936.72	LOLP (Dys/Yr)	1.062	Total	29.58

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
HealyST1	85.70	187.68	786.40	3153.41	3939.81	20.99
ChenaST5	27.54	48.25	31.51	1883.32	1914.83	39.69
TIEPUR91	84.47	517.95	12922.94	0.00	12922.94	24.95
TibPUR91	5.87	144.07	4130.56	0.00	4130.56	28.67
NoPolCT1	5.28	28.22	41.12	1235.38	1276.50	45.23
NoPolCT2	1.49	7.95	11.58	347.89	359.47	45.23
ChenaST6	0.44	1.01	0.60	57.03	57.63	57.21
Zender 1	0.41	0.65	0.39	36.92	37.31	57.16
Zender 2	0.27	0.43	0.26	24.15	24.41	57.16
HealyIC2	0.21	0.06	0.33	3.43	3.76	67.26
UAFIC 7	0.20	0.05	0.31	3.22	3.53	67.26
DslIC 5	0.23	0.06	0.36	3.74	4.09	67.26
DslIC 6	0.25	0.07	0.38	4.04	4.43	67.26
UAFIC 8	0.26	0.07	0.40	4.19	4.59	67.26
Fmusic 1	0.26	0.07	1.60	4.56	6.16	89.69
Fmusic 2	0.26	0.07	1.58	4.51	6.09	89.69
Fmusic 3	0.25	0.07	1.54	4.41	5.95	89.69

Table 27 - 1996 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250%.DTL 03-17-1987 Page 2
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1038.89	PK Load (MW)	197.40	Fix O&M	5.21
Unserve	0.24			Variable	21.45
Net Gen.	1038.66			Unservd	0.02
Storage	0.00			Fuel	7.08
Total Gen	1038.66	LOLP (Dys/Yr)	0.295	Total	33.76

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$/ (MWH)
HealyST1	86.97	190.46	798.05	3932.84	4730.89	24.84
ChenaST5	26.50	46.42	30.32	1812.07	1842.39	39.69
TIEPUR96	89.41	548.24	14369.38	0.00	14369.38	26.21
TibPUR96	9.10	223.10	6208.87	0.00	6208.87	27.83
NoPolCT1	4.05	21.66	31.56	948.14	979.70	45.23
NoPolCT2	1.14	6.11	8.90	267.47	276.37	45.23
NEWFCT A	0.49	1.07	0.62	44.04	44.66	41.70
NEWFCT 1	0.33	0.72	0.42	29.49	29.90	41.70
ChenaST6	0.20	0.45	0.26	25.22	25.48	57.21
Zender 1	0.14	0.23	0.14	12.82	12.95	57.16
Zender 2	0.09	0.14	0.09	8.16	8.25	57.16
HealyIC2	0.07	0.02	0.11	1.13	1.24	67.26
Ds1IC 5	0.06	0.02	0.10	1.03	1.13	67.26
Ds1IC 6	0.07	0.02	0.10	1.09	1.20	67.26

Table 28 - 2006 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250X.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	0.02			Variable	24.17
Net Gen.	1230.84			Unservd	0.00
Storage	0.00			Fuel	3.49
Total Gen	1230.84	LOLP (Dys/Yr)	0.030	Total	31.81

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total	Total Cost \$/(MWH)
			Variable	Fuel Cost		
NewHeST1	86.38	189.17	813.42	2989.27	3802.69	20.10
TIEPURO6	96.75	593.30	12993.31	0.00	12993.30	21.90
TibPURO6	17.80	436.56	10350.95	0.00	10350.95	23.71
NoPolCT2	1.36	7.26	10.58	317.87	328.45	45.23
NEWFACT A	0.46	1.02	0.59	41.82	42.41	41.70
NEWFACT B	0.37	0.82	0.48	33.75	34.23	41.70
NEWFACT 1	0.30	0.65	0.38	26.60	26.98	41.70
NEWFACT 2	0.23	0.51	0.29	20.87	21.16	41.70
NEWFACT 3	0.18	0.40	0.23	16.45	16.68	41.70
NEWFACT 4	0.13	0.59	0.34	24.06	24.40	41.70
NEWFACT 5	0.09	0.57	0.33	23.34	23.67	41.70

Table 29 - 2015 Alternate Case Production Operation in Fairbanks

Detail report:a:FBAS250X.DTL 03-17-1987 Page 4
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks

SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1385.37	PK Load (MW)	266.30	Fix O&M	4.56
Unserve	0.00			Variable	27.72
Net Gen.	1385.37			Unservd	0.00
Storage	0.00			Fuel	3.02
Total Gen	1385.37	LOLP (Dys/Yr)	0.000	Total	35.30

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total	Total Cost \$/(MWH)
			Variable	Fuel Cost	Total		
NewHeST1	87.49	191.60	823.89	3024.89	3848.78	20.09	
TIEPUR15	98.76	605.58	12959.42	0.00	12959.42	21.40	
TibPUR15	23.98	588.19	13934.18	0.00	13934.18	23.69	
NEWFACT A	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT B	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 1	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 2	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 3	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 4	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 5	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 6	0.00	0.00	0.00	0.00	0.00	41.70	
NEWFACT 7	0.00	0.00	0.00	0.00	0.00	41.70	

Table 30 - 1991 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 1
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 1991

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3113.18	PK Load (MW)	574.62	Fix O&M	15.30
Unserve	0.30			Variable	3.88
Net Gen.	3112.88			Unservd	0.03
Storage	0.00			Fuel	47.04
Total Gen	3112.88	LOLP (Dys/Yr)	0.000	Total	66.24

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000			Total Cost \$/(MWH)
			Variable	Fuel Cost	Total	
BelgCC78	78.71	696.38	995.82	10907.93	11903.75	17.09
BelgCC68	78.70	696.30	993.63	11170.91	12164.53	17.47
BelugCT3	80.71	353.52	504.47	6781.42	7285.89	20.61
BelugCT5	76.77	450.57	642.96	9762.72	10605.68	23.54
soldatCT	56.22	187.14	267.61	4226.11	4493.72	24.01
bernice3	32.77	77.50	172.82	1820.14	1992.96	25.72
bernice4	17.52	41.43	92.40	1001.00	1093.40	26.39
bernice2	10.86	17.12	38.19	436.87	475.05	27.74
Anc CC76	2.97	28.35	164.11	686.42	850.53	30.00
BelugCT2	0.42	0.58	0.83	16.33	17.16	29.37
BelugCT1	0.26	0.37	0.53	10.27	10.79	29.37
BelugCT4	0.18	0.15	0.22	5.06	5.28	34.25
Anc CC56	0.08	0.32	1.86	10.56	12.42	38.69
Anc CT 8	0.01	0.06	0.37	1.98	2.35	36.65
Anc CT 4	0.00	0.00	0.01	0.07	0.08	46.43
IntnCT1	0.00	0.00	0.00	0.01	0.01	61.52
IntnCT2	0.00	0.00	0.00	0.00	0.01	61.52
IntnCT3	0.00	0.00	0.00	0.00	0.00	61.43
seward3	0.00	0.00	0.00	0.00	0.00	116.76
seward4	0.00	0.00	0.00	0.00	0.00	116.76
seward5	0.00	0.00	0.00	0.00	0.00	116.76
seward6	0.00	0.00	0.00	0.00	0.00	116.76
seldic2	0.00	0.00	0.00	0.00	0.00	135.24
seldic34	0.00	0.00	0.00	0.00	0.00	135.24
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00
bradleyH	46.82	369.16	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 31 - 1996 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTI 03-17-1987 Page 2
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 1996

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3299.46	PK Load (MW)	607.27	Fix O&M	13.96
Unserve	0.20			Variable	3.77
Net Gen.	3299.26			Unreserved	0.02
Storage	0.00			Fuel	50.56
Total Gen	3299.26	LOLP (Dys/Yr)	0.008	Total	68.32

Unit Name	Capacity Factor	Energy (GWH)	Cost in \$1,000		Total Cost	
			Variable	Fuel Cost	Total	\$(/MWH)
BelgCC78	78.71	696.37	995.80	10907.72	11903.52	17.09
BelgCC68	78.70	696.35	993.69	11171.43	12165.12	17.47
NewBCT 4	77.67	340.21	197.32	6715.43	6912.75	20.32
BelugCT3	77.80	340.76	486.27	6568.53	7054.80	20.70
BelugCT5	69.99	410.79	586.20	9236.52	9822.72	23.91
soldatCT	42.49	141.44	202.26	3276.18	3478.45	24.59
bernice3	21.06	49.80	111.06	1196.76	1307.83	26.26
bernice4	13.48	31.87	71.08	776.57	847.64	26.59
bernice2	6.19	9.75	21.75	250.51	272.26	27.91
Anc CC76	1.87	17.84	103.28	431.99	535.27	30.00
Anc CC56	0.19	0.82	4.74	26.93	31.67	38.69
Anc CT 8	0.03	0.19	1.12	5.95	7.06	36.65
seward3	0.00	0.00	0.00	0.07	0.08	116.76
seward4	0.00	0.00	0.00	0.07	0.08	116.76
seward5	0.00	0.00	0.01	0.10	0.10	116.76
seward6	0.00	0.00	0.00	0.09	0.09	116.76
seldic2	0.00	0.00	0.01	0.02	0.03	135.24
seldic34	0.00	0.00	0.01	0.02	0.03	135.24
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00
bradleyH	46.82	369.15	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 32 - 2006 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 3
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prm 2
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3794.58	PK Load (MW)	685.00	Fix O&M	14.03
Unserve	2.11			Variable	3.06
Net Gen.	3792.48			Unservd	0.21
Storage	0.00			Fuel	53.44
Total Gen	3792.48	LOLP (Dys/Yr)	0.787	Total	70.74

Unit Name	Capacity Factor	Energy (GWH)	Variable Cost	Fuel Cost	Total Cost	Total Cost \$/(MWH)
New CC76	81.76	1289.27	747.78	20386.06	21133.83	16.39
BelgCC78	78.60	695.38	994.39	10894.95	11889.34	17.10
BelgCC68	75.04	663.92	947.42	10741.97	11689.39	17.61
NewBCT14	61.11	267.65	155.24	5179.50	5334.73	19.93
newKct1	46.76	163.86	95.04	3171.02	3266.06	19.93
NewBCT 4	13.98	61.24	35.52	1208.87	1244.39	20.32
NewBCT 5	8.77	51.48	29.86	1016.21	1046.07	20.32
NewBCT 6	5.62	24.64	14.79	486.27	500.56	20.32
soldatCT	1.94	6.46	9.24	163.09	172.33	26.66
Anc CT 8	0.70	5.34	30.92	164.88	195.80	36.65
seward3	0.25	0.04	0.26	4.90	5.16	116.76
seward4	0.25	0.04	0.25	4.83	5.09	116.76
seward5	0.24	0.06	0.37	6.96	7.33	116.76
seward6	0.23	0.06	0.35	6.56	6.91	116.76
seldic2	0.22	0.02	0.75	1.81	2.56	135.24
seldic34	0.21	0.02	0.73	1.76	2.49	135.24
EklutnaH	58.18	152.90	0.00	0.00	0.00	0.00
bradleyH	46.82	369.11	0.00	0.00	0.00	0.00
cooper H	25.99	40.98	0.00	0.00	0.00	0.00

Table 33 - 2015 Alternate Case Production Operation in Anchorage/Kenai Joint Area

Detail report:a:AKJOINTL.DTL 03-17-1987 Page 4
 RNM file:c:JOINTALL.RNM-anchorage/kenai joint load
 Supply file:c:AKJOINTL.SPM-joint anc/kenai dispatch newcc76 in kenai 40% prn 2

SYSTEM REPORT FOR YEAR 2015

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	4339.12	PK Load (MW)	783.30	Fix O&M	15.05
Unserve	0.78			Variable	2.30
Net Gen.	4338.34			Unservd	0.08
Storage	0.00			Fuel	63.50
Total Gen	4338.34	LOLP (Dys/Yr)	0.435	Total	80.92

Unit Name	Capacity Factor	Energy (GWH)	Variable	Cost in \$1,000	Fuel Cost	Total	Total Cost \$/(MWH)
NewBCC68	78.69	696.21	459.50	10905.68	11365.18	16.32	
NewBCC78	78.69	696.22	459.51	10905.78	11365.29	16.32	
New CC76	81.38	1283.20	744.26	20307.02	21051.28	16.41	
NewBCT14	72.48	317.44	184.12	6143.15	6327.27	19.93	
NewBCT15	69.06	302.50	175.45	5854.06	6029.51	19.93	
newKct1	55.42	194.18	112.63	3757.85	3870.48	19.93	
newKct2	37.86	132.66	76.94	2567.30	2644.24	19.93	
newKct3	26.32	57.64	33.43	1115.38	1148.81	19.93	
NewBCT 4	9.02	39.52	22.92	780.08	803.01	20.32	
NewBCT 5	5.62	32.99	19.14	651.26	670.39	20.32	
NewBCT 6	3.57	15.64	9.07	308.72	317.79	20.32	
New CT11	0.71	5.44	3.15	144.68	147.83	27.19	
New CT12	0.36	1.60	0.93	42.45	43.38	27.19	
seward3	0.15	0.03	0.15	2.86	3.01	116.76	
seward4	0.14	0.02	0.15	2.77	2.92	116.76	
seward5	0.14	0.04	0.21	3.95	4.16	116.76	
seward6	0.13	0.03	0.19	3.70	3.89	116.76	
seldic2	0.12	0.01	0.42	1.01	1.43	135.24	
seldic34	0.12	0.01	0.41	0.98	1.39	135.24	
EklutnaH	58.18	152.89	0.00	0.00	0.00	0.00	
bradleyH	46.81	369.08	0.00	0.00	0.00	0.00	
cooper H	25.99	40.97	0.00	0.00	0.00	0.00	

Table 34 - Comparison of 2006 Results in Fairbanks

Detail report:a:FBASE40L.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE40L.SPM-fairbanks basea case supply 40% prm 25 mw healy @97
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	3.75			Variable	15.58
Net Gen.	1227.11			Unservd	0.37
Storage	0.00			Fuel	20.26
Total Gen	1227.11	LOLP (Dys/Yr)	0.011	Total	40.36

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
NewHeST1	87.48	191.57	823.76	3024.46	3848.21	20.09
TIEPURO6	97.88	600.21	14231.02	0.00	14231.02	23.71
NoPolCT2	57.75	308.58	449.60	12027.15	12476.74	40.43
NEWFACT A	15.99	35.03	20.32	1440.44	1460.75	41.70
NEWFACT B	9.39	20.57	11.93	846.06	858.00	41.70
NEWFACT 1	6.25	13.69	7.94	563.05	570.99	41.70
NEWFACT 2	5.04	11.04	6.41	454.15	460.55	41.70
NEWFACT 3	4.38	9.59	5.56	394.30	399.86	41.70
NEWFACT 4	3.84	16.83	9.76	692.28	702.04	41.70
NEWFACT 5	3.26	19.99	11.60	822.21	833.81	41.70

Detail report:a:FBAS250X.DTL 03-17-1987 Page 3
 RNM file:c:FAIRALL .RNM-fairbanks native demand 1991-2020: +30 MW
 Supply file:c:FBASE250.SPM-rsa model of fairbanks
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	1230.86	PK Load (MW)	236.60	Fix O&M	4.14
Unserve	0.02			Variable	24.17
Net Gen.	1230.84			Unservd	0.00
Storage	0.00			Fuel	3.49
Total Gen	1230.84	LOLP (Dys/Yr)	0.030	Total	31.81

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
NewHeST1	86.38	189.17	813.42	2989.27	3802.69	20.10
TIEPURO6	96.75	593.30	12993.31	0.00	12993.30	21.90
TibPURO6	17.80	436.56	10350.95	0.00	10350.95	23.71
NoPolCT2	1.36	7.26	10.58	317.87	328.45	45.23
NEWFACT A	0.46	1.02	0.59	41.82	42.41	41.70
NEWFACT B	0.37	0.82	0.48	33.75	34.23	41.70
NEWFACT 1	0.30	0.65	0.38	26.60	26.98	41.70
NEWFACT 2	0.23	0.51	0.29	20.87	21.16	41.70
NEWFACT 3	0.18	0.40	0.23	16.45	16.68	41.70
NEWFACT 4	0.13	0.59	0.34	24.06	24.40	41.70
NEWFACT 5	0.09	0.57	0.33	23.34	23.67	41.70

Table 35 - Comparison of 2006 Results in Anchorage and Kenai

Detail report:a:AK3540LS.DTL 03-17-1987 Page 3
 RNM file:c:ANCHALL .RNM-anchorage load 1991-2020
 Supply file:c:AK35LAST.SPM-anc w/ 35mw ken pur 10% penalty prm 40% 2% beluga p
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	3124.08	PK Load (MW)	554.90	Fix O&M	11.16
Unserve	1.38			Variable	3.00
Net Gen.	3122.70			Unservd	0.14
Storage	0.00			Fuel	53.27
Total Gen	3122.70	LOLP (Dys/Yr)	0.225	Total	67.56

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
BelgCC78	78.71	696.35	995.78	10907.50	11903.29	17.09
BelgCC68	78.70	696.31	993.64	11171.03	12164.67	17.47
NewBCT14	77.90	341.22	197.91	6603.28	6801.18	19.93
NewBCT 3	73.51	321.97	186.74	6355.46	6542.20	20.32
NewBCT 4	66.88	292.92	169.89	5781.94	5951.84	20.32
NewBCT 5	55.35	324.87	188.43	6412.72	6601.14	20.32
NewBCT 6	37.99	166.39	96.51	3284.40	3380.90	20.32
New CC56	12.67	53.28	30.90	1152.35	1183.25	22.21
New CC76	6.15	71.09	41.23	1537.51	1578.74	22.21
KENPUR06	1.12	3.43	84.45	0.00	84.45	24.61
Anc CT 8	0.25	1.94	11.24	59.92	71.15	36.65
EklutnaH	58.19	152.92	0.00	0.00	0.00	0.00

Detail report:a:K8AS35LS.DTL 03-17-1987 Page 3
 RNM file:c:KENAALL .RNM-kenai load 1991-2020
 Supply file:c:kbas35ls.SPM-kenai with anc 35mw purch 40% prm loss penalty
 SYSTEM REPORT FOR YEAR 2006

ENERGY (GWH)		RELIABILITY		COSTS(M\$)	
Demand	670.56	PK Load (MW)	130.10	Fix O&M	3.32
Unserve	0.64			Variable	0.18
Net Gen.	669.92			Unservd	0.06
Storage	0.00			Fuel	5.20
Total Gen	669.92	LOLP (Dys/Yr)	0.000	Total	8.76

Unit Name	Capacity Factor	Energy (GWH)	Variable	Fuel Cost	Total	Total Cost \$/(MWH)
new ct1	65.89	230.88	133.91	4468.02	4601.94	19.93
soldatCT	8.76	29.17	41.71	735.80	777.50	26.66
ANCPUR06	0.01	0.02	0.51	0.00	0.51	23.78
seward3	0.00	0.00	0.00	0.00	0.00	0.00
seward4	0.00	0.00	0.00	0.00	0.00	0.00
seward5	0.00	0.00	0.00	0.00	0.00	0.00
seward6	0.00	0.00	0.00	0.00	0.00	0.00
seldic2	0.00	0.00	0.00	0.00	0.00	0.00
seldic34	0.00	0.00	0.00	0.00	0.00	0.00
bradleyH	46.79	368.90	0.00	0.00	0.00	0.00
cooper H	25.98	40.96	0.00	0.00	0.00	0.00

Base Case vs. Alternate Case - Savings in Production Cost & Capacity

Year	-----Base Case-----				-----Alternate Case-----			Operating Savings	Capital Savings	Total Savings
	Kenai	Anchor	Fairbnk	Total	Ken/Anch	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	66.24	29.58	95.82	3.81	0	3.81
1992	8.61	58.98	33.60	101.19	66.67	30.49	97.16	4.03	0	4.03
1993	8.82	60.35	34.56	103.73	68.24	31.34	99.58	4.15	1.41	5.56
1994	8.86	60.67	34.88	104.41	69.36	33.02	102.38	2.03	1.41	3.44
1995	8.87	60.94	35.79	105.60	69.68	33.77	103.45	2.15	1.41	3.56
1996	8.88	59.87	36.21	104.96	68.32	33.76	102.08	2.88	1.41	4.29
1997	8.77	60.18	37.19	106.14	68.55	34.80	103.35	2.79	1.41	4.20
1998	8.79	60.62	38.19	107.60	69.04	35.21	104.25	3.35	1.41	4.76
1999	8.75	59.45	37.75	105.95	62.48	31.39	93.87	12.08	1.41	13.49
2000	8.78	60.31	38.87	107.96	63.28	32.14	95.42	12.54	1.41	13.95
2001	8.88	62.77	39.78	111.43	65.56	33.13	98.69	12.74	1.41	14.15
2002	8.84	63.79	38.87	111.50	66.71	31.73	98.44	13.06	1.41	14.47
2003	9.09	64.71	39.50	113.30	67.77	32.09	99.86	13.44	1.41	14.85
2004	8.34	65.63	40.14	114.11	68.51	32.14	100.65	13.46	1.41	14.87
2005	8.55	66.59	39.93	115.07	69.61	31.51	101.12	13.95	1.41	15.36
2006	8.76	67.56	40.36	116.68	70.74	31.81	102.55	14.13	2.81	16.94
2007	8.98	67.96	41.44	118.38	70.79	32.54	103.33	15.05	2.81	17.86
2008	9.26	68.97	42.20	120.43	72.06	33.60	105.66	14.77	2.81	17.58
2009	9.42	69.65	42.93	122.00	72.81	33.60	106.41	15.59	2.81	18.40
2010	9.31	70.65	43.84	123.80	73.86	34.00	107.86	15.94	2.81	18.75
2011	9.52	71.84	44.14	125.50	75.32	33.44	108.76	16.74	2.81	19.55
2012	9.73	72.90	44.92	127.55	76.58	34.39	110.97	16.58	2.81	19.39
2013	9.95	73.98	45.72	129.65	77.85	34.74	112.59	17.06	2.81	19.87
2014	10.41	75.06	46.51	131.98	79.25	34.54	113.79	18.19	1.41	19.60
2015	10.64	76.60	47.33	134.57	80.92	35.30	116.22	18.35	1.41	19.76
2016	10.86	77.72	48.43	137.01	82.24	36.31	118.55	18.46	1.41	19.87
2017	11.10	78.88	49.30	139.28	83.59	37.33	120.92	18.36	1.41	19.77
2018	11.33	81.68	50.24	143.25	86.48	37.89	124.37	18.88	1.41	20.29
2019	11.56	82.91	51.14	145.61	87.89	38.63	126.52	19.09	1.41	20.50
2020	11.80	84.16	52.09	148.05	89.35	39.85	129.20	18.85	1.41	20.26
Total								372.50	50.66	423.16
NPV 1987								178.53	26.14	204.67

Table 36 - Year by Year Results

Base Case vs. Kenai-Anchor Tie Only Case - Savings in Production Cost & Capacity

Year	I-----Base Case-----I				I---Ken-Anc Only Case---I			Operating Savings	Capital Savings	Total Savings
	Kenai	Anchor	Fairbnk	Total	Ken/Anch	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	66.24	31.76	98.00	1.63	0	1.63
1992	8.61	58.98	33.60	101.19	66.67	32.85	99.52	1.67	0	1.67
1993	8.82	60.35	34.56	103.73	68.24	33.79	102.03	1.70	1.41	3.11
1994	8.86	60.67	34.88	104.41	69.36	34.89	104.25	0.16	1.41	1.57
1995	8.87	60.94	35.79	105.60	69.67	35.79	105.46	0.14	1.41	1.55
1996	8.88	59.87	36.21	104.96	68.32	36.58	104.90	0.06	1.41	1.47
1997	8.77	60.18	37.19	106.14	68.54	37.59	106.13	0.01	1.41	1.42
1998	8.74	60.62	38.19	107.60	69.03	38.57	107.60	0.00	1.41	1.41
1999	8.75	59.45	37.75	105.95	62.47	37.00	99.47	6.48	1.41	7.89
2000	8.78	60.31	38.87	107.96	63.27	38.10	101.37	6.59	1.41	8.00
2001	8.88	62.77	39.78	111.43	65.57	38.90	104.47	6.96	1.41	8.37
2002	8.84	63.79	38.87	111.50	66.72	38.23	104.95	6.55	1.41	7.96
2003	9.09	64.71	39.50	113.30	67.76	38.86	106.62	6.68	1.41	8.09
2004	8.34	65.63	40.14	114.11	68.51	39.34	107.85	6.26	1.41	7.67
2005	8.55	66.59	39.93	115.07	69.61	39.13	108.74	6.33	1.41	7.74
2006	8.75	67.56	40.36	116.68	70.75	39.52	110.27	6.41	2.81	9.22
2007	8.98	67.96	41.44	118.38	70.79	40.62	111.41	6.97	2.81	9.78
2008	9.26	68.97	42.20	120.43	72.06	41.36	113.42	7.01	2.81	9.82
2009	9.42	69.65	42.93	122.00	72.81	42.03	114.84	7.16	2.81	9.97
2010	9.31	70.65	43.84	123.80	73.86	42.87	116.73	7.07	2.81	9.88
2011	9.52	71.84	44.14	125.50	75.32	43.42	118.74	6.76	2.81	9.57
2012	9.73	72.90	44.92	127.55	76.58	44.16	120.74	6.81	2.81	9.62
2013	9.95	73.98	45.72	129.65	77.85	44.93	122.78	6.87	2.81	9.68
2014	10.41	75.06	46.51	131.98	79.25	45.60	124.85	7.13	1.41	8.54
2015	10.64	76.60	47.33	134.57	80.92	46.37	127.29	7.28	1.41	8.69
2016	10.86	77.72	48.43	137.01	82.24	47.42	129.66	7.35	1.41	8.76
2017	11.10	78.88	49.30	139.28	83.59	48.24	131.83	7.45	1.41	8.86
2018	11.33	81.68	50.24	143.25	86.48	49.10	135.58	7.67	1.41	9.08
2019	11.56	82.91	51.14	145.61	87.90	49.96	137.86	7.75	1.41	9.16
2020	11.80	84.16	52.09	148.05	89.35	50.85	140.20	7.85	1.41	9.26
Total								158.75	50.66	209.41
NPV 1987								76.10	26.14	102.24

Table 37 - Year by Year Results

Base Case vs. Anchorage-Fairbanks Tie Only Case - Savings in Production Cost & Capacity

Year	I-----Base Case-----I				I-----Anchor-Fairbanks Case----I				Operating Savings	Cap Sav	Total Savings
	Kenai	Anchor	Fairbnk	Total	Kenai	Anchor	Fairbnk	Total			
1991	8.46	58.70	32.47	99.63	8.46	58.70	30.53	97.69	1.94	0	1.94
1992	8.61	58.98	33.60	101.19	8.61	58.98	31.49	99.08	2.11	0	2.11
1993	8.82	60.35	34.56	103.73	8.82	60.35	32.31	101.48	2.25	0	2.25
1994	8.86	60.67	34.88	104.41	8.86	60.66	32.40	101.92	2.49	0	2.49
1995	8.87	60.94	35.79	105.60	8.87	60.93	33.16	102.96	2.64	0	2.64
1996	8.88	59.87	36.21	104.96	8.88	59.87	33.01	101.76	3.20	0	3.20
1997	8.77	60.18	37.19	106.14	8.77	60.17	33.76	102.70	3.44	0	3.44
1998	8.79	60.62	38.19	107.60	8.79	60.62	34.53	103.94	3.66	0	3.66
1999	8.75	59.45	37.75	105.95	8.75	59.45	32.60	100.80	5.15	0	5.15
2000	8.78	60.31	38.87	107.96	8.78	60.31	33.44	102.53	5.43	0	5.43
2001	8.88	62.77	39.78	111.43	8.88	62.77	34.33	105.98	5.45	0	5.45
2002	8.84	63.79	38.87	111.50	8.84	63.79	32.71	105.34	6.16	0	6.16
2003	9.09	64.71	39.50	113.30	9.09	64.72	33.18	106.99	6.31	0	6.31
2004	8.34	65.63	40.14	114.11	8.34	65.63	33.59	107.56	6.55	0	6.55
2005	8.55	66.59	39.93	115.07	8.55	66.58	32.42	107.55	7.52	0	7.52
2006	8.76	67.56	40.36	116.68	8.76	67.55	32.85	109.16	7.52	0	7.52
2007	8.98	67.96	41.44	118.38	8.98	67.96	33.41	110.35	8.03	0	8.03
2008	9.26	68.97	42.20	120.43	9.26	68.97	33.97	112.20	8.23	0	8.23
2009	9.42	69.65	42.93	122.00	9.42	69.64	34.38	113.44	8.56	0	8.56
2010	9.31	70.65	43.84	123.80	9.31	70.65	35.08	115.04	8.76	0	8.76
2011	9.52	71.84	44.14	125.50	9.52	71.84	34.66	116.02	9.48	0	9.48
2012	9.73	72.90	44.92	127.55	9.73	72.90	35.13	117.81	9.74	0	9.74
2013	9.95	73.98	45.72	129.65	9.95	73.98	35.73	119.65	10.00	0	10.00
2014	10.41	75.06	46.51	131.99	10.41	75.06	36.26	121.73	10.25	0	10.25
2015	10.64	76.60	47.33	134.57	10.64	76.60	36.87	124.11	10.46	0	10.46
2016	10.86	77.72	48.43	137.01	10.86	77.72	37.72	126.30	10.71	0	10.71
2017	11.10	78.88	49.30	139.28	11.10	78.88	38.51	128.49	10.79	0	10.79
2018	11.33	81.68	50.24	143.25	11.33	81.68	39.21	132.22	11.03	0	11.03
2019	11.56	82.91	51.14	145.61	11.56	82.91	39.87	134.34	11.27	0	11.27
2020	11.80	84.16	52.09	148.05	11.80	84.17	40.62	136.59	11.46	0	11.46
Total									210.59	0	210.59
NPV 1987									101.17	0	101.17

Table 38 - Year by Year Results

8. Appendices:

8.1. Description of the UPLAN Model

UPLAN

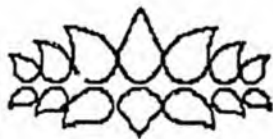
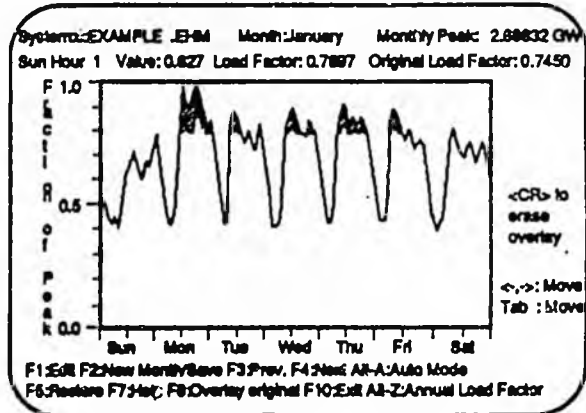
The Electric Utility Planning System

An Integrated Utility Planning Model

Major Features:

- *Supply-Side Planning*
- *Demand-Side Management*
- *Financial Planning*
- *Uncertainty Simulation*

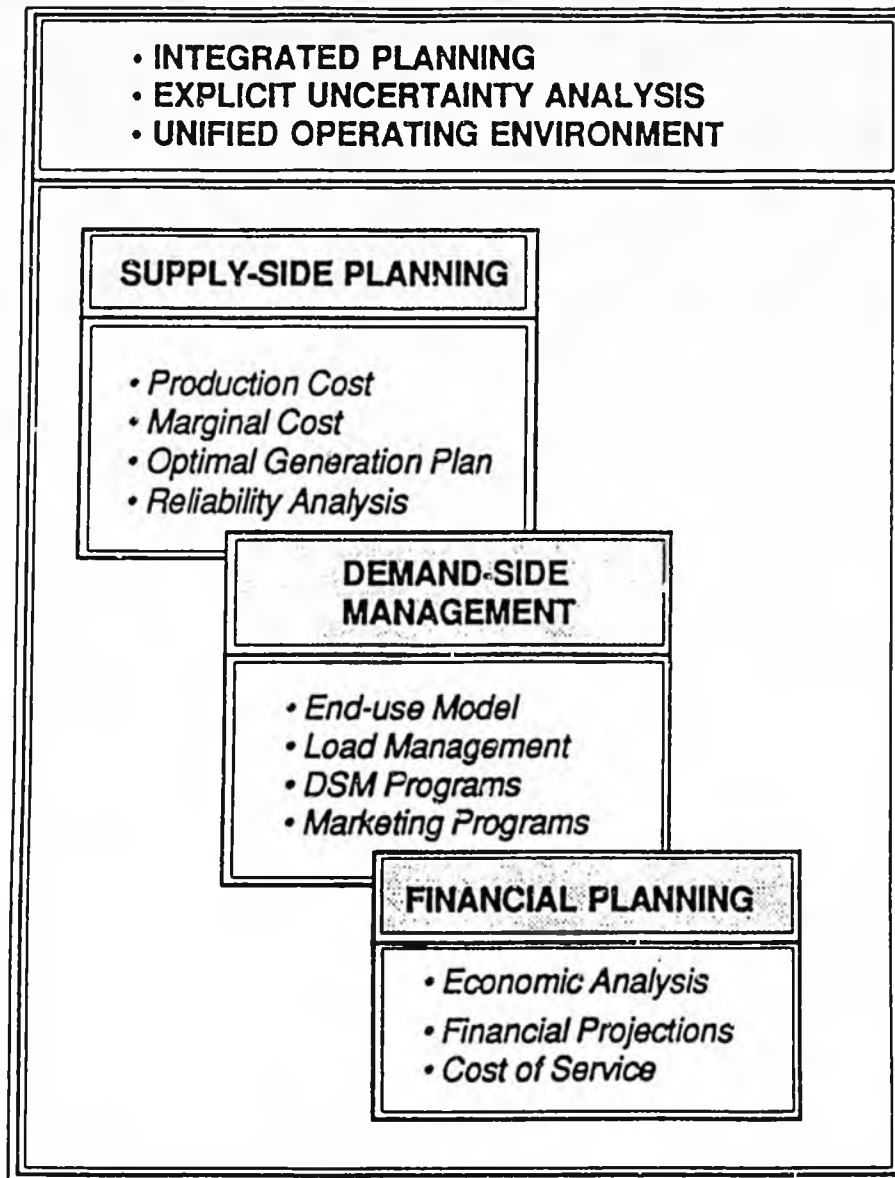
IBM PC/XT/AT/3270- or compatibles.



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The Electric Utility Planning System



Features:

- State-of-the-art utility planning system
- Fast, accurate and flexible
- Window-based, menu-driven environment
- Integrated workstation (IBM PC/XT/AT/3270PC/AT)
- Powerful batch interactive processing