Alaska Energy Authority
Railbelt Transmission Plan
Economic Analysis

Project #15-0481

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1 Introduction

This report includes the findings of the economic studies completed to determine the future composition of the Railbelt transmission system.

Since the last draft report was issued in March 2014, new reliability and operating standards have been adopted by the Railbelt utilities, and new generation plants for all utilities have been commissioned. Additionally, the Railbelt utilities have spent considerable effort reviewing and updating the economic models used to simulate the Railbelt's cost of power production. As a result of the new standards, new power plants, and the utilities' work on the economic model; the transmission studies have been updated to reflect 2016 conditions, and the economic studies have been updated to use the latest economic models available from the utilities.

This portion of the Transmission Plan provides the data and results used to complete the economic analysis of the production cost simulations with and without the recommended system improvements. In addition to the Production Cost simulations, the report identifies other economic benefits that should be considered when the evaluations required by AKTPL-001-4 are completed.

This portion of the report is not intended to be a complete economic evaluation as it only included limited evaluation of each projects' benefits.

2 Executive Summary

Electric Power Systems (EPS) has completed an analysis to determine the recommended future transmission system in the Railbelt. The need for the transmission plan was driven by the changes in the Railbelt generation and transmission system since the completion of the 2010 Regional Integrated Resource Plan (RIRP) administered by the Alaska Energy Authority (AEA).

The recommended transmission system improves reliability and has the potential to mitigate future cost increases to Railbelt rate payers and allow significant energy transfers between different areas of the Railbelt system. Constraints to the use of Bradley Lake hydroelectric project energy are removed and the coordination of hydro and thermal generation resources throughout the Railbelt can be optimized. While the proposed reliability improvements are far from what would be required for a transmission system in the Lower 48, they do significantly improve the reliability and economics of the Railbelt and allow the utilities to pursue additional load and resource pooling options not possible with the existing transmission system. The proposed improvements allow increased use of variable renewable generation, such as wind and photovoltaic (PV) in the Railbelt system, which is currently near its limit of renewable resource penetration.

Most transmission improvements are typically justified by the cost of unserved energy, or the value of system reliability, and are rarely justified purely on hard economic benefits. However, the value of unserved energy was not factored into the benefit analysis of the proposed transmission improvements in this study. There is currently no uniform estimate of unserved energy throughout the Railbelt, nor are there available records or criteria to allow it to be equitably evaluated. Typically, in the Lower 48, these types of reliability improvements are required as part of the bulk power systems' mandate to meet NERC's and/or the transmission areas' reliability criteria. Projects are not evaluated solely in terms of the pure economic benefit of the project for fuel savings or reduced losses.

Since the issuance of the 2014 draft report, the utilities have made a significant effort in updating the economic model of the Railbelt to more accurately portray the system's operation, and some of the utilities are in active discussions on power pooling and its associated benefits. This study assumes the utilities will implement a fully pooled system prior to 2030. In addition to generation pooling, the study also assumed the utilities would maximize the benefit of hydro-thermal coordination prior to 2030, including the energy from the new Battle Creek project at Bradley Lake. The fuel savings possible from the new transmission system were measured from the baseline assumption that the existing transmission system was utilized to its greatest extent possible by implementing a fully pooled Railbelt system. The year 2030 was chosen for the study year as the final transmission improvements could be completed by that time. The power production cost of Railbelt generation was first estimated using a model of the fully pooled Railbelt in 2030.The cost of power production was then identified using the same fully pooled system with the new transmission system. Both simulations utilized hurdle rates of $1/MW to simulate a tight pool for all cases. The difference between the two simulations indicates the true value of the transmission system in reducing production costs for the Railbelt.

It is important to emphasize that the transmission benefits outlined in this report can only be realized following the construction of projects included in the study. Therefore, the true measure of each project's value is their net benefit to the Railbelt utilities and consumers, that is the economic benefit minus the cost of construction. It is also important to note that the impact these large construction projects would have on the State's economy are not estimated or included in the evaluations. The potential impact of these projects include design and construction using Alaskan labor, and an increased ability of the transmission system to serve additional loads or make use of renewable energy.

This report is not a mandate to construct these projects, but rather should be considered the first step in the transmission planning process outlined in the recently completed transmission planning standard, specifically AKTPL-001-4. Each of the projects must undergo further cost and benefit analysis prior to making the decision to construct each project. Some projects may be deemed feasible and constructed following the assessment and others may be put on hold until economic or other conditions warrant their construction.

As the projects are evaluated going forward, the value of unserved energy, the value of renewable energy, the value of future load-serving capability, the value of capacity sharing or deferral and the value of a significant reduction in greenhouse gasses should be computed and utilized in each projects' analysis. However, some of the projects are strictly reliability driven projects with little or very small hard economic benefits and can only be justified by more traditional transmission evaluation methods. These projects should be evaluated separately from the projects with large economic benefits.

The production cost runs for the existing system assumed the Anchorage-Kenai transmission line was available 100% of the time. However, in the last 10 years, the line has been out of service almost one month out of every year. If considered in the evaluations, the line outages would increase the production costs of the existing system and increase the benefits of the proposed transmission system.

The fuel usage with the proposed transmission system resulted in annual savings ranging from $34,752,000 per year for the low load cases to $83,040,000 per year for the high load cases, with the base case savings being $55,885,000 per year (in 2030 dollars). Fuel prices do not have a marked influence on the overall fuel savings, provided the difference between Fairbanks and Southcentral energy prices remain relatively stable. The wide range in system fuel savings is more a product of the uncertainty in utility load forecasts as opposed to ranges in the cost of fuel.

Historically, the Bradley Lake participants have received an average of 49,466 MWH/year of Bradley Lake energy when the project is operated at an output above 90 MW in order to avoid spilling water. That energy will be unavailable if the Kenai transmission constraints are enacted without mitigation. Further, the utilities have received 173,884 MWh/year of energy when Bradley Lake is operated at an output above 65 MW. The energy availability when Bradley is operated above 65 MW is at risk utilizing the existing transmission system. While the energy Bradley can produce when it is operated between 65 and 90 MW could be utilized by the utilities, it may not be utilized at a time that provides the same economic benefit as its historical use.

Since 2000, the Railbelt utilities have added various generation plants located within their own service territories to replace aging generation infrastructure. The capital costs of replacing these plants over the life of the transmission system was not included in the transmission benefits. At the earliest time the projects recommended in this plan could be completed, the newest plants in Fairbanks and Southcentral Alaska will be 25 and 15 years old, base-loaded plants on the Kenai will be approaching 50 years old for the frame 6 gas turbine and the base-loaded steam boiler will be 30 years old. All of these plants will be in the process of requiring replacement or significant refurbishment as the transmission projects are put in service. Without additional transmission improvements, generation planning will continue to be completed by individual utilities, located in geographically dispersed areas. Capacity sharing and deferral will be limited by the existing transmission system and customer rates will not be at their lowest possible level.

The economic benefit of improved reliability as measured by unserved energy, capacity deferral of individual utilities, and reservoir optimization of the Bradley Lake and Cooper Lake hydro plants, made possible with the improved transmission system, were not evaluated in this report.

Additional production cost simulations were completed to determine the sensitivity of the project benefits to several different conditions. These sensitivities included differing fuel prices in the Railbelt, LNG availability in the Fairbanks area, new units in the Fairbanks area, loss of existing load, and addition of new loads in the system. The sensitivity cases indicate that the availability of LNG at GVEA's North Pole and the construction of a new combined cycle unit and six 9 MW reciprocating engines at North Pole results in the lowest savings for the transmission system at $34,959,000/year (2030 $). However, this low level of savings can only be experienced after the large capital expenditure for LNG and a new power plant with additional generation installed at the North Pole facility. Absent this large capital expenditure, the next lowest sensitivity is the loss of 44 MW of load in the Fairbanks area and little or no load growth over the next 50 years, with an associated savings of $34,752,000/year (2030 $). Sensitivities in gas pricing do not have an appreciable impact on the base case savings. The retirement of Healy #1 and the Aurora plant in Fairbanks do not have an appreciable impact on the transmission benefits since the existing system can support additional non-firm sales.

The introduction of LNG into GVEA's North Pole plant, without an additional unit does not have an appreciable impact on the transmission benefits.

The only scenario where the benefit/cost ratio is less than 1.0 is the case where LNG is used for the new units, a new power plant and the existing power plant at North Pole.

A summary of the sensitivity cases is presented in the Table 2-3.

Table 2-3: Sensitivity Case

		Annual Production Costs - K$			Annual Savings - K$	
Scenario	Total Pool Load	Existing Transmission	Upgraded Transmission			
	Annual GWh	Full Pooling Non-Firm	Full Pooling		From Firm	From Non-Firm
		Transmission	Firm Transmission	Non-Firm Transmission	Transmission	Transmission
Adjusted Base Case	5202.7	508,524	452,639	452,274	55,885	365
High Load	5202.7 + 573.0	654,571	571,531	543,420	83,040	28,111
Low Load	5202.7 - 306.6	447,996	413,244	413,272	34,752	-28
Aurora & Healy 1 Retired	5202.7	563,792	473,618	472,950	90,175	668
LNG @ NPCC only	5202.7	501,622	452,601	452,424	49,021	177
High Fuel Cost	5202.7	692,556	638,244	638,026	54,312	218
Low Fuel Cost	5202.7	389,489	342,606	342,505	46,883	101
Re-Build of North Pole	5202.7	509,575	474,616	474,549	34,959	67

The range of benefit/cost ratios of the projects are seen in Table 2-4, where cost is in K$.

Table 2-4: Sensitivity Case Summaries

	Scenario	Debt Service	M & O Expense	Total Costs	Benefits	Benefit/Cost Ratio
	2030 dollars	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	
1	Base Case	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,427,333	1.62
2	High Load	$ 1,531,228	$ 588,609	$ 2,119,837	$ 4,805,687	2.27
3	Low Load	$ 1,531,228	$ 588,609	$ 2,119,837	$ 2,294,614	1.08
4	Aurora/Healy 1 Retired	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,389,772	1.60
5	LNG @NPCC only	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,072,960	1.45
6	High Fuel Cost	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,144,180	1.48
7	Low Fuel Cost	$ 1,531,228	$ 588,609	$ 2,119,837	$ 2,812,290	1.33
8	Re-build of North Pole	$ 1,531,228	$ 588,609	$ 2,119,837	$ 1,325,511	0.63

Note: All costs are discounted life cycle costs expressed in 2030

	Scenario	Debt Service	M & O Expense	Total Costs	Benefits	Benefit/Cost Ratio
	2015 dollars	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	
1	Base Case	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,534,109	1.62
2	High Load	$ 1,132,163	$ 435,207	$ 1,567,370	$ 3,553,240	2.27
3	Low Load	$ 1,132,163	$ 435,207	$ 1,567,370	$ 1,696,597	1.08
4	Aurora/Healy 1 Retired	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,506,338	1.60
5	LNG @NPCC only	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,272,092	1.45
6	High Fuel Cost	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,324,751	1.48
7	Low Fuel Cost	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,079,358	1.33
8	Re-build of North Pole	$ 1,132,163	$ 435,207	$ 1,567,370	$ 980,060	0.63

Note: All costs are discounted life cycle costs expressed in 2015

The recommended transmission plan meets the requirements of AKTPL-001-4 for system reliability and contingency evaluation. However, AKTPL-001-4 also requires each project to be evaluated in terms of reliability and costs to determine whether the project should be constructed. The evaluation required by the standard includes the costs identified in this report, but also requires the identification of all benefits, including the benefits not included in the scope of this project, such as generation capacity deferral, value of unserved energy, water management, additional green energy, firm fuel and energy deliveries for all utilities, and Bradley excess energy delivery.

It is recognized that both the costs and the benefits included in this report are estimates and that changes in assumptions can alter the conclusions and recommendations. There are many assumptions and changes that can be debated to decrease and increase both the costs and benefits of the recommended projects. The fuel savings presented in this study represent only a 7-15% savings in total 2030 fuel costs over the entire Railbelt. In formulation of RTOs and generation pooling in the lower 48, the US Department of Energy in its 2005 report to Congress estimated the reduction in power production costs that could be achieved through economic dispatch across various power pools ranged from 8-30%. In a 2013 DOE sponsored study for the Eastern Interconnection State's Planning Council and the National Association of Regulatory Utility Commissioners, it was determined that having transmission assets allowing the transfer of power between regions could result in a 10% decrease in capital costs of future generation and that transmission expansion can play a significant role in generation capacity planning. Considering the wide variations in Railbelt generation investment, this savings could appear even larger in the Alaskan grid in future years. Since the DOE study was completed in a transmission system with few transmission constraints, achieving 7-15% fuel savings in the Railbelt after relatively severe transmission constraints are relaxed appears significantly lower than savings indicated in national studies and results.

3 Production Cost Simulations

3.1 The Structure of the Model

The model employed for these analyses was the PROMOD IV® power system production modeling program, the core of which produces unit commitment and economic dispatch solutions. The particular configuration of PROMOD for this work included the Hourly Monte Carlo, (HMC), module to simulate generator forced outages and the Transmission Analysis Module, ("TAM"), to incorporate a branch-by-branch, bus-by-bus model of the transmission system being studied. The use of these two modules represents the generation dispatch by a set of deterministic hourly chronological values for each load, generation source and branch flow. This enables the program to produce an economic dispatch that respects line and interface flow limits, survives contingencies, as well as respecting the various system and generator constraints.

3.2 Assembling the Data

The data assembly for this configuration of PROMOD begins with importing, into the program, the "raw" file resulting from a PSS/E load flow run of the transmission system involved in the analysis. The power flow data is used by PROMOD to set up a bus-by-bus, branch-by-branch model of the system as part of its data.

System data is input to PROMOD to set up an organizational structure of areas, companies and pools and the relationships among them. In addition, there are included requirements for operating, spinning and regulation reserves for companies and/or pools.

The individual generation resources are "mapped" to their appropriate busbars in the transmission data, then the data describing the ownership, nature, operating characteristics and operating costs of each generating resource are loaded into the production modeling data Tables. Most operating data can vary on a monthly basis, but where necessary specific items can vary hourly or daily. This data includes fuels, emissions and non-fuel operation and maintenance costs.

Data defining a particular run is also input to the program and includes the nature of the run, the period involved and the outputs required. All of the data input up to this point is stored in a data file written in the program's portable file format, (".PFF").

Load data, including weekly peak load & energy and hourly load shape for each area is provided in a separate file, which is read into PROMOD at the time of execution. PROMOD converts this data into hour-by-hour Company loads that it "maps" to the load busses. Also read in at execution, is a file of information, (the EVENT file,) concerning the various line and interface flow limits and contingencies to be obeyed and considered in developing a least cost dispatch.

Because two different transmission systems were involved in this study, the existing transmission and the upgraded transmission, two different Transmission/Production datasets were created as described above, as well as two different Event files. Only one Load file was required.

3.3 Data Sources

EPS provided the PSS/E raw files for the two transmission systems, as well as a description of the reserve requirements and transmission flow limitations for the two cases.

With the exception of the fuel price data, the production data was mainly the result of the modeling process recently carried out with the utilities as part of the activities of their Economic Dispatch Group, ("EDG"). The exception being the updated transmission constraints produced by the new PSS/e model and the inclusion of transmission constraints between Healy and Fairbanks for the existing system that were omitted in the EDG model.

Because the EDG data was developed for the 2020 year, and this study was being performed for the year 2030, various cost items such as Variable O&M costs and Natural Gas transportation costs had to be escalated. The year-to-year escalation rates used for this task were the GDP deflators implicit in the Tables of the projected fuel price information found in the Energy Information Administration's, ("EIA's"), 2016 Annual Energy Outlook, ("AEO"), Reference Case.

The load projection used in the Base Case of this study was based on the EDG load projections, but were not as pessimistic. The lower load levels of the EDG study formed the low load case in this study. The non-mining load was escalated from 2020 to 2030 at very low rates, which were different for each company, and the Fort Knox mine was assumed to remain in production. The low load scenario in this study assumed Ft. Knox would close and the high load scenario assumed that the Livengood Mine would be developed by 2030 and the Fort Knox load would remain on the GVEA system.

The Fuel prices in the Base Case were derived from the 2020 EDG fuel prices with adjustments intended to remove the effect of current contracting and adjustments to include the price movements in the EIA 2016 AEO Reference Case. High and Low price projections made use of two other AEO cases, as recorded in Section 3.4 below. Discussions were also held with Mapco refinery to assess the probability of the current GVEA pricing structure remaining constant through the study period. Based on these discussions, it was determined that the GVEA fuel pricing could not be guaranteed through the life of this study and market costs for fuel was used.

Details of the Base Case and sensitivity runs developed in this study are in the following Section 3.4.

3.4 Base Case and Sensitivities

Eight Cases were developed to explore the value of the transmission upgrades in alternative future conditions. The alternatives were made up of various cases for loads, fuel costs and generation resources, as shown in Tables 5-1 and 5-2.

Table 5-1: Load Alternatives

Sensitivity	Load	Fuel Costs	Resources
Base Case	Base Case	Base Case	Base Case
High Load	High Load	Base Case	Base Case
Low Load	Low Load	Base Case	Base Case
Retire Old Coal	Base Case	Base Case	Ret. Aurora-Healy 1
LNG for NPCC	Base Case	Base Case	LNG for NPCC
High Fuel	Base Case	High Fuel Cost	Base Case
Low Fuel	Base Case	Low Fuel Cost	Base Case
Rebuild North Pole	Base Case	Base Case	Rebuild North Pole

3.5 Loads

Table 5-2: Load Sensitivities

		GWh					
Year 2020		**Railbelt**	**GVEA**	**MEA**	**ML&P**	**CEA/SES**	**HEA**
Base Case		5078.6	1467.9	782.0	1079.8	1283.9	465.1
Lower Load							
Sensitivity		4771.2	1160.5	782.0	1079.8	1283.9	465.1
Higher Load							
Sensitivity		5653.2	2042.5	782.0	1079.8	1283.9	465.1
Year 2030							
Base Case		**5175.4**	**1491.3**	**813.8**	**1090.6**	**1309.8**	**469.8**
Lower Load							
Sensitivity		**4868.0**	**1183.9**	**813.8**	**1090.6**	**1309.8**	**469.8**
Higher Load							
Sensitivity		**5750.0**	**2065.9**	**813.8**	**1090.6**	**1309.8**	**469.8**

Notes

1. The Lower Load sensitivity represents the loss of the GVEA Fort Knox mine load.
2. The Base Case load represents the retention of Fort Knox load
3. The Higher Load sensitivity represents the addition of the Livengood mine load to GVEA's load.
4. The remainder of GVEA's load is grown at a rate of 0.2 %/year.
5. MEA, ML&P, CEA/SES and HEA loads are grown at 0.4, 0.1, 0.2 and 0.1 %/year respectively.

3.6 Escalation

As a general escalation rate, used for cost items such as non-fuel operation and maintenance expense and natural gas transportation costs, the GDP deflator, used by the EIA in the 2016 AEO Reference Case, was chosen (Table 5-3).

Table 5-3: Escalation Rates

Year	GDP Deflator
2016	2.04
2017	2.04
2018	2.04
2019	2.04
2020	2.04
2021	2.06
2022	2.06
2023	2.06
2024	2.06
2025	2.06
2026	2.00
2027	2.00
2028	2.00
2029	2.00
2030	2.00

3.7 Fuel Prices – Base Case

The Base Case fuel prices were first developed for the year 2020 from the fuel prices contributed by the utilities. As far as possible, the effects of contract timing and short term special deals were removed from the individual utility projections. Commodity price changes beyond 2020 were derived for the individual fuels from the "Reference case" projections of the EIA's 2016 AEO. Table 5-4 shows Base Case projections for 2020 and 2030. NG delivery was escalated at the GDP deflator.

Table 5-4: Base Case Projections

Fuel Item	Location	2020 Price c/mmBTU	2030 Price c/mmBTU
Coal		397	485.4
NG - Commodity		750	1075
NG - Transportation	Beluga, Bernice, Nikiski	48.875	59.754
	Uklutna GS	50.0	61.129
	MLP, MLP2A	32.5	39.734
	Soldotna	66.175	80.904
	SPP	20.0	24.452
Naptha		1413	2207.7
ULSD	Most locations	1815	2818.8
	Delta, Small Diesels	1900	2950.8

3.8 Fuel Prices – Sensitivities

The source material for the High and Low Fuel Price sensitivities came from comparison Tables for three case projections that were part of the EIA's 2016 Annual Energy Outlook. The three cases were the Reference Case which was the basis for the Base Case Fuel Prices, the "Low Oil and Gas Resource and Technology Case," which provided the basis for the High Fuel Price sensitivity, and the "High Oil and Gas Resource and Technology Case," which provided the basis for the Low Fuel Price sensitivity. The 2030 prices for the sensitivities are shown in Table 5-5.

Table 5-5: 2030 Fuel Prices – c/mmBTU

Fuel Item	Location	Low Price Sensitivity	High Price Sensitivity
Coal		466.5	511.9
NG - Commodity		729.2	1665.9
NG - Transportation	As in Base Case		
Naptha		1725.7	2489.1
ULSD	Most locations	2203.3	3177.9
	Delta, Small Diesels	2306.5	3326.8

3.9 The Consistency of the Modeling

The original intent in performing the production cost simulation studies was to utilize the ProMod model developed by the Railbelt utilities as part of their studies on power pooling and unified system operator studies. Slater had recently performed dispatch analyses of the Railbelt System for the Utilities' Economic Dispatch Group, (EDG,) aimed at exploring the benefits of pooled operation in the 2020 year. Accordingly, it was advisable to show that the modeling for this study was consistent with the modeling in the EDG work.

However, after completing a benchmark study to show the model proposed for this study produced similar results to the work completed by the utilities, there were several major errors uncovered in the original model that formed the basis for the comparison. The errors are summarized as follows:

- The original model had no transmission constraint between Healy and Fairbanks, potentially allowing more transactions than were physically possible. The transmission constraints were inserted into the model for both the existing and proposed transmission system.
- GVEA's Fort Knox load was intended to be removed from the model, but the load was relocated to the Healy area and load in the Fairbanks area reduced to maintain the desired overall load. The result was that more load was served out of Healy and did not need to utilize the Healy – Fairbanks transmission system. This was corrected and the GVEA load was correctly modeled in the final simulations.
- The transmission constraints between Anchorage – Healy were incorrectly applied, artificially restricting transfers from south to north. The constraints were corrected and resulted in a significant increase in transfers to GVEA.

The final model has considerable changes that were not anticipated at the start of the project. We would encourage the utilities to take ownership of the model and update any system modifications within the model to continue to refine its accuracy.

3.10 Resource Sensitivities

In addition to the four sensitivities involving variation in system load and fuel costs, three sensitivities were examined which dealt with changes to generation resources. The first of these, "Retire Old Coal" made no changes to loads or fuel cost, but retired, prior to 2030, the two old coal fired resources, the Aurora Energy LLC units in the Fairbanks area and the GVEA Healy 1 unit. In this sensitivity, no generating capacity was added to replace the old coal capacity.

The second resource sensitivity involved changing the fuel for the North Pole combined cycle unit from Naptha to LNG shipped into Fairbanks. In this sensitivity, the price of the LNG was set at 1300 c/mmBTU in 2020, escalating to 1863.33 c/mmBTU in 2030.

The third resource sensitivity involved major changes to GVEA generation prior to 2030. The old coal units (Aurora and Healy 1) would be retired, along with the two old CT's at North Pole. A second combustion turbine would be added to the North Pole combined cycle unit, and six 9 MW Wartsila Diesel generators would also be installed at North Pole.

An new LNG supply is required to fuel all generation at the North Pole generating station. The cost of the LNG supply or the cost of the new generators and power plant are not included in this analysis.

3.11 Results of this Analysis

For each of the Base Case and seven sensitivities, two computer model runs were made. The first, "Existing Transmission – Full Pooling" was developed to simulate a fully pooled system with minimal hurdles between utilities. Although the utilities are far from this type of arrangement, this insures that any changes in production cost simulations are the result of the transmission improvements as opposed to the benefits of increased pooling. The hurdles were set at 1/MWh for commitment and $1/MWh for dispatch. These hurdle values don't represent any actual economic relationships among the utilities, but were set at these values to achieve the "full pool" behavior described above.

The third model run for each case, "Upgraded Transmission – Full Pooling," was set up the same way as the fully pooled model run, described above, except that the data bases, including EVENT files, were those created on the power flow data for the upgraded transmission. The differences between the runs were recorded as the benefits of the upgraded transmission.

Table 5-8 shows the production cost results for each modeled case, while Table 5-9 records the atmospheric emissions for each case, and Table 5-10 displays the transmission losses.

Table 5-8: Production Costs for Each Modeled Case

		Annual Production Costs - K$			Annual Savings - K$	
Scenario	**Total Pool Load**	**Existing Transmission**	**Upgraded Transmission**			
	Annual GWh	**Full Pooling Non-Firm Transmission**	**Full Pooling**		**From Firm Transmission**	**From Non-Firm Transmission**
			Firm Transmission	**Non-Firm Transmission**		
Adjusted Base Case	5202.7	508,524	452,639	452,274	55,885	365
High Load	5202.7 + 573.0	654,571	571,531	543,420	83,040	28,111
Low Load	5202.7 - 306.6	447,996	413,244	413,272	34,752	-28
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High Fuel Cost	5202.7	692,556	638,244	638,026	54,312	218
Low Fuel Cost	5202.7	389,489	342,606	342,505	46,883	101
Re-Build of North Pole	5202.7	509,575	474,616	474,549	34,959	67

Table 5-9: Transmission Losses for Different Cases

	Scenario	Debt Service	M & O Expense	Total Costs	Benefits	Benefit/Cost Ratio
	2030 dollars	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	
1	Base Case	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,427,333	1.62
2	High Load	$ 1,531,228	$ 588,609	$ 2,119,837	$ 4,805,687	2.27
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6	High Fuel Cost	$ 1,531,228	$ 588,609	$ 2,119,837	$ 3,144,180	1.48
7	Low Fuel Cost	$ 1,531,228	$ 588,609	$ 2,119,837	$ 2,812,290	1.33
8	Re-build of North Pole	$ 1,531,228	$ 588,609	$ 2,119,837	$ 1,325,511	0.63

Note: All costs are discounted life cycle costs expressed in 2030

	Scenario	Debt Service	M & O Expense	Total Costs	Benefits	Benefit/Cost Ratio
	2015 dollars	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	($/Yr x 10^-3)	
1	Base Case	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,534,109	1.62
2	High Load	$ 1,132,163	$ 435,207	$ 1,567,370	$ 3,553,240	2.27
3	Low Load	$ 1,132,163	$ 435,207	$ 1,567,370	$ 1,696,597	1.08
4	Aurora/Healy 1 Retired	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,506,338	1.60
5	LNG @NPCC only	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,272,092	1.45
6	High Fuel Cost	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,324,751	1.48
7	Low Fuel Cost	$ 1,132,163	$ 435,207	$ 1,567,370	$ 2,079,358	1.33
8	Re-build of North Pole	$ 1,132,163	$ 435,207	$ 1,567,370	$ 980,060	0.63

Note: All costs are discounted life cycle costs expressed in 2015

A Appendix: A Cost/Benefit Notes and Summary

A.1 Notes on Benefit/Cost Ratios

The costs completed for these projects were developed based on a 2015 cost basis using information supplied by various Railbelt utilities and conceptual designs for each project. The cost estimates are estimated to be +/- 20% of actual construction costs. The project costs were reviewed in 2015 and appear to be within the +/- 20% range of project construction costs.

The production cost benefits for the projects are simplified simulations based on one year of the project's operation. The identified benefits are assumed to be constant for the life of the project. The actual benefit of any project will vary over time as energy resources, load, transmission lines and operating practices change in the Railbelt.

The development of benefits for individual projects was not completed for this final phase of the study. The intent of this study was to develop a transmission plan compliant with the initial steps of AKTLP 1-4. Within that standard, once a project has been identified, additional studies and cost/benefit analysis is required prior to construction of the project.

The Benefit/Cost Analysis was completed in accordance with the guidelines of Circular A-94 "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs". It utilized a discount of 1.5% and a cost of debt of 4.0% and cost of O&M of 1.5%/year. The O&M assumed no benefit in O&M for the replacement of aged infrastructure.

The actual construction of the projects will consume 10-15 years and as such the construction sequence will have an impact on the benefits available for each project. Certain projects for instance, depend on other projects being constructed in order to obtain the identified benefits. For the feasibility level analysis completed in this study, it was assumed all projects were available in year one.

Benefits associated with capacity deferral allowed by an improved transmission system, improved hydro water management and efficiency, increased use of renewables, decrease in greenhouse gas emissions, value of unserved energy, Bradley Lake excess energy delivery, and the ability to contract for firm energy and fuel deliveries throughout the system are not included within the scope of this project, but should be included in the project evaluations completed for AKTPL-001-4.

A.2 Loss/Energy/Capacity

The following table summarizes the historical usage of Bradley Lake energy compared to the current use of the project.

Table A-1: Historically Displaced Energy

Historically Displaced Energy (MWh)				
	Annual MWh	Historical losses	Projected Losses	Difference
HEA energy	47,289	946	1,419	473
Northern users	193,973	3,879	21,337	17,458
Battle Creek - HEA	4,680	0	140	140
Battle Creek - Northern Users	34,320	0	3,775	3,775
Historically wheeled energy to Northern users (MWh)				
Wheeled energy	152,738	4,582	16,801	12,219
Total energy losses				34,065

Table A-2: Left intentionally blank

Table A-3: Kenai Loss Analysis

Kenai Loss Analysis						
Values			Line Losses / Bus Angles			
			Bradley Output			
			90		120	
From Bus	To Bus	Ckt ID	base	upgraded	base	upgraded
University	Indian	1	1.0	0.3	1.8	0.5
Indian	Girdwood	1	0.6	0.2	1.2	0.3
Girdwood	Portage	1	0.5	0.2	1.0	0.4
Portage	Hope	1	1.4	0.4	2.6	0.7
Hope	Daves Creek	1	1.3	0.3	2.2	0.6
Daves Creek	Quartz Creek	1	0.7	0.2	1.1	0.3
Quartz Creek	XFMR	1	no line	0.0	no line	0.0
Quartz Creek	Soldotna	1	3.7	1.0	6.7	1.8
Quartz Creek	Soldotna	2	no line	1.0	no line	1.8
Subotal: University - Soldotna			9.2	3.4	16.7	6.2
Soldotna	Bradley Lake	1	2.2	0.8	4.2	1.5
Soldotna	Bradley Lake	2	no line	0.8	no line	1.5
Subtotal: Soldotna - Bradley Lake			2.2	1.5	4.2	3.0
Soldotna	Thompson	1	0.0	0.0	0.0	0.0
Thompson	Kasilof	1	0.0	0.0	0.2	0.0
Kasilof	Anchor Pt	1	0.4	0.1	1.0	0.3
Anchor Pt	Diamond Ridge	1	0.2	0.1	0.4	0.1
Diamond Ridge	Fritz Crk	1	0.2	0.1	0.3	0.1
Fritz Crk	Bradley Lk	1	0.7	0.4	1.1	0.6
Subtotal: Soldotna - Bradley Lake			1.6	0.7	3.0	1.1
Total: University - Bradley Lake (All Lines)			12.9	5.6	23.9	10.3
Reduction of losses			7.3		13.6	
Kenai tie flow			77.6	81.5	100.2	107.6
SPP 138 kV angle			-3.4	-2.7	-8.8	-7.3
University 138 kV angle			-3.9	-3.1	-9.2	-7.7
Bradley Lake 115 kV angle			39.5	20.2	51.5	24.0
Angle Difference Bradley Lake - SPP			42.9	22.9	60.3	31.3
Reduction of angle			20.0		28.9	

Notes:

Cooper Lake unit 1 online, at 9.8 MW
Cooper Lake unit 2 online, at 9.8 MW
only changes are Bradley Lake output
swing bus at Beluga 7
tie flow measured on Dave's Creek - Hope line
HEA taking 14.4 MW of Bradley Lake

B Appendix B: Economic Analysis Sensitivity

		Annual Production Costs - K$			Annual Savings - K$	
Scenario	Total Pool Load	Existing Transmission	Upgraded Transmission			
	Annual GWh	Full Pooling Non-Firm	Full Pooling		From Firm	From Non-Firm
		Transmission	Firm Transmission	Non-Firm Transmission	Transmission	Transmission
Adjusted Base Case	5202.7	508,524	452,639	452,274	55,885	365
High Load	5202.7 + 573.0	654,571	571,531	543,420	83,040	28,111
Low Load	5202.7 - 306.6	447,996	413,244	413,272	34,752	-28
Aurora & Healy 1 Retired	5202.7	563,792	473,618	472,950	90,175	668
LNG @ NPCC only	5202.7	501,622	452,601	452,424	49,021	177
High Fuel Cost	5202.7	692,556	638,244	638,026	54,312	218
Low Fuel Cost	5202.7	389,489	342,606	342,505	46,883	101
Re-Build of North Pole	5202.7	509,575	474,616	474,549	34,959	67

Adjusted Base Case -Base Case plus Updates to HEA (Increase Load by 6%, adjustment to Soldotna, Import limit changed to 18 MW (Existing Transmission))

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	508,524	452,639	452,274	55,885	365	0.0	0.0	0.0	8.1	0.0	0.0
GVEA	211,298	184,798	184,687	26,501	110	371.0	587.2	589.3	33.4	0.0	0.0
MEA	79,051	71,639	71,556	7,412	83	-128.0	-112.6	-113.4	219.4	23.9	22.0
ML&P	62,770	50,278	50,090	12,492	188	-482.5	-470.2	-471.3	0.0	0.0	0.0
CEA + SES	103,013	103,065	103,094	-52	-29	108.3	115.3	115.6	0.0	0.0	0.0
HEA	52,392	42,858	42,846	9,534	12	131.4	-119.8	-120.3			
									371.1	587.3	589.4
									-0.1	-0.1	-0.1

High Load

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	654,571	571,531	543,420	83,040	28,111	0.0	0.0	0.0	87.6	9.0	0.0
GVEA	371,304	328,090	306,438	43,214	21,652	426.6	923.7	1,124.9	271.5	47.0	0.9
MEA	73,853	60,051	60,744	13,802	-693	-177.3	-300.7	-307.9	401.1	215.9	81.2
ML&P	54,277	40,421	37,192	13,856	3,229	-480.0	-586.3	-692.6	2.4	0.0	0.0
CEA + SES	102,419	103,509	105,403	-1,090	-1,894	108.2	112.7	114.3	5.2	0.0	0.0
HEA	52,719	39,461	33,643	13,258	5,817	122.5	-149.4	-238.9			
									426.6	923.7	1,124.9
									0.0	0.0	0.0

Low Load

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	447,996	413,244	413,272	34,752	-28	0.0	0.0	0.0	1.3	0.0	0.0
GVEA	141,817	129,547	129,518	12,270	29	175.7	291.2	291.3	5.8	0.0	0.0
MEA	81,227	75,188	75,300	6,039	-113	-3.0	103.2	104.5	128.2	5.6	5.5
ML&P	70,303	60,088	60,071	10,215	17	-437.3	-430.4	-432.6	0.0	0.0	0.0
CEA + SES	102,737	102,990	102,966	-253	24	116.5	122.6	122.6	0.0	0.0	0.0
HEA	51,912	45,432	45,418	6,481	14	148.1	-86.5	-85.8			
									188.6	299.5	299.6
									-12.9	-8.3	-8.3

Aurora & Healy 1 Retired

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	563,792	473,618	472,950	90,175	668	0.0	0.0	0.0	47.3	0.3	0.0
GVEA	278,296	229,209	227,321	49,087	1,888	450.3	963.1	960.7	128.7	0.8	0.0
MEA	74,606	59,532	60,471	15,075	-939	-187.4	-319.4	-311.7	399.3	56.9	60.4
ML&P	56,511	41,239	41,320	15,273	-81	-490.9	-596.4	-602.7	0.3	0.0	0.0
CEA + SES	102,499	103,956	103,986	-1,457	-30	106.8	111.8	112.1	0.3	0.0	0.0
HEA	51,880	39,683	39,852	12,197	-169	121.1	-159.1	-158.4			
									450.3	963.1	960.7
									0.0	0.0	0.0

LNG @ NPCC only

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	501,622	452,601	452,424	49,021	177	0.0	0.0	0.0	7.6	0.0	0.0
GVEA	203,596	182,144	182,062	21,452	82	366.2	577.5	578.8	32.9	0.0	0.0
MEA	78,943	72,139	72,262	6,804	-123	-131.8	-109.5	-108.3	224.6	33.4	32.2
ML&P	63,242	51,696	51,733	11,546	-37	-475.9	-466.8	-466.9	0.0	0.0	0.0
CEA + SES	103,317	103,144	103,118	173	26	108.8	114.8	115.4	0.0	0.0	0.0
HEA	52,524	43,478	43,249	9,046	229	132.6	-115.9	-118.9			
									366.3	577.6	578.9
									-0.1	-0.1	-0.1

High Fuel Cost

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	692,556	638,244	638,026	54,312	218	0.0	0.0	0.0	15.7	0.1	0.0
GVEA	239,288	212,533	212,321	26,754	213	343.7	568.4	568.8	36.0	1.0	0.9
MEA	116,873	109,544	109,581	7,329	-37	-135.3	-121.9	-121.6	234.1	40.8	40.6
ML&P	104,275	91,762	91,794	12,513	-32	-457.0	-460.6	-461.0	0.0	0.0	0.0
CEA + SES	153,868	155,064	155,032	-1,197	32	114.4	116.2	116.3	0.0	0.0	0.0
HEA	78,253	69,342	69,299	8,912	43	134.3	-102.3	-102.7			
									344.1	568.5	568.9
									-0.4	-0.1	-0.1

Low Fuel Cost

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	389,489	342,606	342,505	46,883	101	0.0	0.0	0.0	5.8	0.0	0.0
GVEA	178,218	156,182	156,095	22,036	87	383.2	601.6	601.7	33.1	0.0	0.0
MEA	58,305	51,937	52,114	6,368	-177	-121.0	-108.3	-105.7	220.1	15.4	15.3
ML&P	42,711	32,443	32,360	10,267	84	-495.5	-482.4	-484.4	0.0	0.0	0.0
CEA + SES	73,223	72,763	72,748	460	15	102.2	114.1	114.3	0.0	0.0	0.0
HEA	37,033	29,281	29,188	7,752	93	131.0	-125.0	-126.0			
									383.3	601.6	601.7
									-0.1	0.0	0.0

Re-Build of North Pole (New Units & LNG)

	Annual Production Costs - K$			Annual Savings - K$		Net Purchases - GWh			GVEA CC, CT, Transactions - GWh		
	Existing Transmission	Upgraded Transmission	Upgraded Transmission	From Upgraded	From Transmision	Existing Transmission	Upgraded Transmission	Upgraded Transmission	Existing Transmission	Upgraded Transmission	Upgraded Transmission
	Full Pooling	Full Pooling	Full Pooling	Transmission	Constraints	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling	Full Pooling
	Existing Constraints	Proposed Constraints	Unconstrained			Existing Constraints	Proposed Constraints	Unconstrained	Existing Constraints	Proposed Constraints	Unconstrained
System	509,575	474,616	474,549	34,959	67	0.0	0.0	0.0	159.1	16.3	16.4
GVEA	215,732	208,175	208,148	7,557	27	410.9	781.6	781.1			
MEA	77,672	68,204	68,246	9,468	-42	-185.1	-283.6	-283.9	457.1	216.0	216.4
ML&P	62,082	52,604	52,608	9,479	-4	-462.6	-472.0	-471.6	0.0	0.0	0.0
CEA + SES	102,569	103,214	103,198	-645	16	107.0	112.9	114.2	0.1	0.0	0.0
HEA	51,520	42,420	42,350	9,100	70	129.7	-138.8	-139.6			