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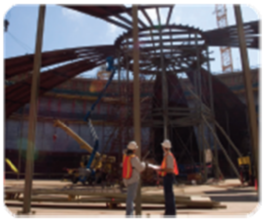



ALASKA RAILBELT ELECTRICAL GRID AUTHORITY (REGA) Study

Final Report

September 12, 2008

BLACK & VEATCH
Building a world of difference.

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In conducting our analysis and in forming the recommendations summarized in this report, Black & Veatch Corporation (Black & Veatch) has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilized in performing the analysis and developing our recommendations follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used, depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected. Such factors may include, but are not limited to, the ability of the Railbelt electric utilities and the State of Alaska to implement the recommendations and execute the implementation plan contained herein, the regional and national economic climate, and growth in the Railbelt region.

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Furthermore, readers of this report should understand that its focus is on the evaluation of alternative organizational structures for the reconfiguration of the generation and transmission functions of the Railbelt utilities. In completing its analysis, Black & Veatch evaluated alternative energy futures and developed prescriptive resource plans for each energy future considered. These prescriptive resource plans were developed to assist in the evaluation of alternative organizational paths. These prescriptive resource plans are not alternative integrated resource plans; as such, readers should not compare the prescriptive resource plans to each other nor should they draw any conclusions from this analysis as to what the optimal resource mix for the Railbelt over the next 30 years might include.

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- Chugach Electric Association
- City of Seward Electric System
- Golden Valley Electric Association
- Homer Electric Association
- Matanuska Electric Association

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"Alone we can do so little, together we can do so much."

Helen Keller

"Hope is not a strategy."

Anchorage Chamber of Commerce, *Findings and Conclusions about Alaska's Energy Crisis*

"Coming together is a beginning, staying together is progress, and working together is success."

Henry Ford

"The die is cast: electric prices are going up. Since a large percentage of the generating capacity currently operated by the utilities is ready for replacement we're at a point where long-term decisions that support lower power costs over time are critical."

Project Developer

"The long-term failure of the Railbelt utilities to deal with aging generation and other related energy issues suggests that there is insufficient motivation, economic or otherwise, to come together in a cooperative manner to solve industry problems."

Native Corporation Representative

"There is a lack of an over-riding vision and goals that aligns electrical production and energy security within a framework that is ecologically sustainable and equitable to all future generations."

Renewable Energy Advocate

"The bottom line is that in order for an energy plan to be effective, it has to have support and that has to come from the top down. When the Governor and the Legislature decide that energy is the number one priority in order to provide an economically stable State, it will attract business and people."

Financial Community Representative

"The economic stability of the State relies upon the Railbelt and consequently there has to be a substantive investment by the State in it so that the State attracts businesses and development."

Financial Community Representative

"Future results will not be different if we do not make different choices."

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SECTION 1 - EXECUTIVE SUMMARY

Black & Veatch was retained by the Alaska Energy Authority (AEA) to evaluate the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the Railbelt grid.

The stated objectives of the study were to:

- Identify and assess a list of options for the management, operation, access rules, ownership, resource planning, and regulatory structures of the Railbelt generation and transmission system.
- For certain agreed-upon options, further analyze and provide recommendations of possible alternative structures to manage and dispatch electric power throughout the Railbelt region.
- Provide a final work product for stakeholders and decision-makers to consider in planning how to meet the Railbelt region's energy needs over the next 30 years.

This report presents the results of this study, as well as our conclusions and recommendations, and an implementation plan for the development of a regional G&T entity.

Setting a Course for the Future

"When our children's children look at the decisions that we made, what will they think of us?"

The Railbelt generation, transmission, distribution infrastructure did not exist prior to the 1940s. At that time, citizens in separate areas within the Railbelt region joined together to form four cooperatives (Golden Valley Electric Association, GVEA; Matanuska Electric Association, MEA; Chugach Electric Association, CEA; and Homer Electric Association, HEA) and two municipal utilities (Anchorage Municipal Light & Power, ML&P; and the City of Seward Electric System, SES) to provide electric power to the consumers and businesses within their service areas. Collectively, these utilities are referred to as the Railbelt utilities.

"The Railbelt utilities have successfully worked together to improve the Bradley Lake Project. This upgrade has made the Railbelt system more reliable. The lesson here is that utilities can work cooperatively under a State/private partnership."

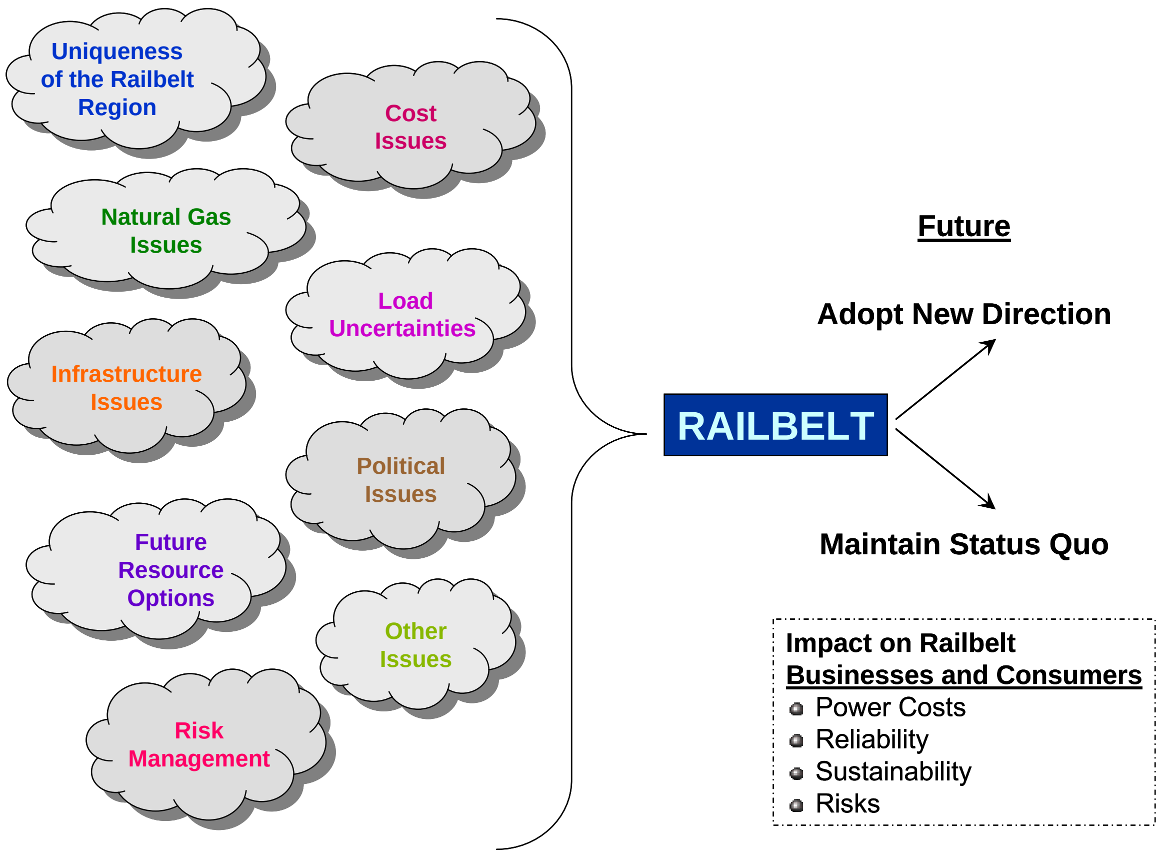
Utility Representative

The independent and cooperative decisions made over time by utility managers and Boards, as well as the State, in a number of areas have significantly improved the quality of life and business environment in the Railbelt. Examples include:

- **Infrastructure Investments** – the State and the Railbelt utilities have made significant investments in the region's generation and transmission infrastructure. Examples include the Alaska Intertie and Bradley Lake Hydroelectric Plant.
- **Gas Supply Investments and Contracts** – ML&P took a bold step when it purchased a portion of the Beluga River Gas Field, a decision that has produced a significant long-term benefit for ML&P's customers and others within the Railbelt. Additionally, Chugach was able to enter into attractive gas supply contracts. These decisions have resulted in low gas prices which have significantly offset the region's inability to achieve economies of scale in generation due to its small size.
- **Innovative Solutions** – GVEA's Battery Energy Storage System (BESS) is one example of numerous innovative decisions that have been made by utility managers and Boards to address issues that are unique to the Railbelt region.
- **Joint Operations and Contractual Arrangements** – over the years, the Railbelt utilities have joined together for joint benefit in terms of coordinated operation of the Railbelt transmission grid and have entered into contractual arrangements that have benefited each utility.

The evolution of the business and operating environments and changes in the mix of stakeholders, presents new dynamics for the way decisions must be made. These changing environments pose significant challenges for the Railbelt utilities and, indeed, all stakeholders. In fact, it is not an overstatement to say that the Railbelt is at a historical crossroad, not unlike the period of time when the Railbelt utilities were originally formed. The following graphic summarizes the key categories of issues currently facing the Railbelt utilities.

Figure 1 - Summary of Issues Facing the Railbelt Region



The following table provides a listing of the issues within each category shown in the graphic above. These issues are addressed in detail in Section 3.

Table 1 - Summary Listing of Issues Facing the Railbelt Region

Uniqueness of the Railbelt Region • Size and geographic expanse • Limited interconnections and redundancies • State versus Federal regulation	**Load Uncertainties** • Stable native growth • Potential major new loads	**Political Issues** • Historical dependence on State funding • Proper role for State
Cost Issues • Relative costs – Railbelt region versus other states • Relative costs – among Railbelt utilities • Economies of scale and scope	**Infrastructure Issues** • Aging generation infrastructure • Baseload usage of inefficient generation facilities • Operating and spinning reserve requirements	**Risk Management** • Need to maintain flexibility • Future fuel diversity • Aging infrastructure • Ability to spread regional risks
Natural Gas Issues • Historical dependence • Expiring contracts • Declining developed reserves and deliverability • Historical increase in gas prices • Potential gas supplies and prices	**Future Resource Options** • Acceptability of large hydro and coal • Carbon tax and other environmental restrictions • Optimal size and location of new generation and transmission facilities • Limited development – renewables • Limited development – DSM/energy efficiency programs	**Other Issues** • Aging workforce and ability to attract skilled employees • Reliability • Proposed ML&P/Chugach merger • Sustainability

The current situation facing the Railbelt utilities is the result of thousands of historic decisions, resulting in the electric systems as they exist today, as well as a number of factors (e.g., rising natural gas prices) that are outside the control of utility managers. We received significant comments related to the current issues facing the Railbelt region from not only the utilities themsleves, but also from the numerous non-utility stakeholders who met with the Black & Veatch project team or responded to our non-utility stakeholder input survey instrument. Throughout this report, we provide selected comments in sidebars that, when viewed in total, present a good general overview of the views of various stakeholders of the current Railbelt electric system situation.

"A long-range vision of sustainable and responsible electricity generation and transmission is needed. We are at a crossroads here in Alaska. Aging infrastructure, the lack of a robust transmission network, impressive natural resources, and the strong public and political concern regarding the effects of climate change have us balanced between polluting fuel sources of the past and clean fuel sources of the future."

Consumer Advocate

Given this widespread recognition of the changing regional conditions, this study was directed by the Alaska Legislature to assess whether reconfiguring the electric generation and transmission elements of the Railbelt region would produce benefits in terms of cost, efficiency and reliability.

Fortunately, the Railbelt region has a number of inherent advantages and significant natural resources that provide a solid basis for working through the challenges facing it. Additionally, the Railbelt region can learn from the experience of utilities elsewhere and there is no need to "reinvent the wheel."

"Quite frankly, we have studied the issues to death and only need to act. What is likely preventing implementation is the lack of leadership from management and decision-making from utility boards on a course of action."

Utility Representative

* * *

"There has been a lack of courage to make a decision and plan for the future without perfect knowledge which we all know does not exist."

Fuel Supplier

* * *

"High energy prices and reduced supplies are likely to damage the economy of South-central Alaska and have already damaged rural economies."

Anchorage Chamber of Commerce, *Findings and Conclusions about Alaska's Energy Crisis*

Decisions that need to be made over the next five years will set the foundation for the next 50 years. These decisions include:

- How best to address the significant issues and manage the risks facing the Railbelt region.
- Whether a regional generation and transmission entity will be formed to plan and develop new generation and transmission capacity for the Railbelt.
- The specifics of the State Energy Plan, and related policies, that is currently being developed in response to a directive from the Governor.
- The development of a regional Integrated Resource Plan (IRP) that will identify the optimal mix of utility investment in generation resources and transmission, and non-utility investments in conservation resources for the future.
- How the State will optimally deploy the abundant in-state resources, including hydroelectric, coal, renewables, and demand-side management (DSM)/energy efficiency programs to meet the needs of the citizens and businesses in the Railbelt region and throughout the State.
- Determine the best source(s) of financing, including potential State financial assistance, to minimze the costs that will be borne by Railbelt region citizens and businesses related to the capital investments that will be necessary to replace aging infrastructure and reliably meet the future electric needs of the region

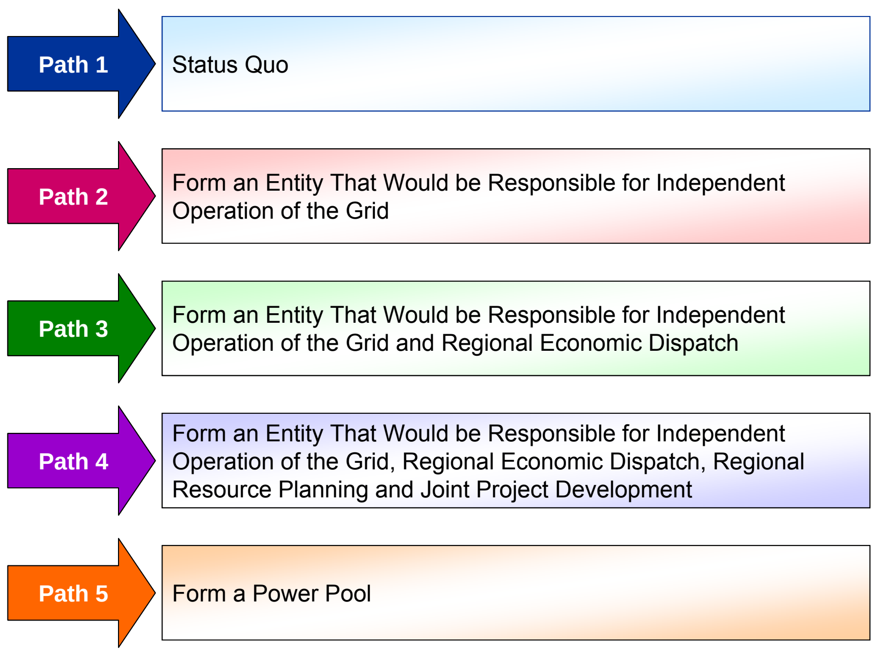
Taking a regional approach to economic dispatch, integrated resource planning, and project development will most likely lead to better results than the current situation of six individual decisions working separately to meet the needs of their residential and commercial customers, provided that the regional entity has the appropriate governance structure, and financial and technical expertise.

This study is not a State Energy Plan, nor is it an IRP; consequently, we do not answer the question as to what will be the future optimal resource mix. However, taking advantage of these resources, when chosen, will be easier with the implementation of the correct Railbelt generation and transmission organizational structure, which is the focus of this study.

Organizational Paths and Scenarios Evaluated

Based upon input from the Advisory Working Group that was formed to provide advice and help guide the Black & Veatch project team during the course of the project, five Organizational Paths were chosen for detailed evaluation. These Paths are shown in the following graphic and discussed below.

Figure 2 - Summary of Organizational Paths Evaluated



It should be noted that the following descriptions of Organizational Paths 2, 3, 4, and 5 are focused on the functional responsibilities of a new regional entity. In each case, the new regional entity could be a Joint Action Agency (JAA), G&T Cooperative, or State Agency/Corporation.

- **Path 1 – Status Quo**
  This Path assumes that the six Railbelt utilities continue to conduct business essentially in the same manner as now (i.e., six separate utilities with limited coordination and bilateral contracts between them), and it does not include the potential impact of the proposed ML&P/Chugach merger. This is, in essence, the "Base Case" and the other Paths will be compared to this Path for each of the Evaluation Scenarios considered.
- **Path 2 – Form an Entity That Would be Responsible for Independent Operation of the Grid**
  Under this Path, a new entity would be formed to independently operate the Railbelt electric transmission grid. Currently, the Railbelt utilities have three control centers (GVEA, Chugach and ML&P). The operations of these centers are coordinated (but generation is not fully economically dispatched on a regional basis) through the Intertie Operating Committee. This new entity would not perform regional economic dispatch, just the independent operation of the Railbelt transmission grid.

- **Path 3 – Form an Entity That Would be Responsible for Independent Operation of the Grid and Regional Economic Dispatch**
  This Path would expand upon this coordination through the formation of an organization that would be responsible for the joint economic dispatching of all generation facilities in the Railbelt. This Path, as well as the following two Paths, will require some additional investment in transmission transfer capability and supervisory control and data acquisition (SCADA)/telecommunications capabilities. This Path, and the following two Paths, would also require the development of operating and cost sharing agreements to guide how economic dispatching would occur and how the related costs and benefits would be allocated among the six Railbelt utilities.
- **Path 4 – Form an Entity That Would be Responsible for Independent Operation of the Grid, Regional Economic Dispatch, Regional Resource Planning, and Joint Project Development**
  This Path is similar to Path 3 except the scope of responsibilities of the new regional entity would be expanded to include regional integrated resource planning and the joint project development of new generation and transmission assets.
- **Path 5 – Form Power Pool**
  This entity would be responsible for the independent operation of the transmission grid, regional economic dispatch and regional resource planning. In that sense, it is similar to Path 4, except that the individual utilities would retain the responsibility for the development of future generation and transmission facilities.

As noted before, there are a significant number of issues and uncertainties facing the Railbelt utilities. One of the most significant issues related to the evaluation of alternative organizational structures for the reconfiguration of the Railbelt utilities relates to the future generation supply resource mix that will be implemented to replace the aging generation facilities and meet future load growth in the region.

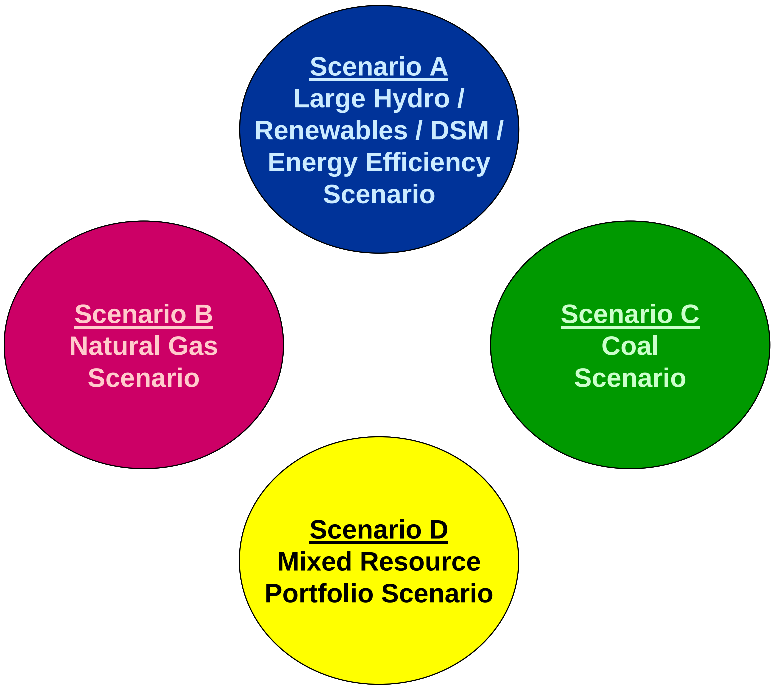
As a result, we developed the following four Evaluation Scenarios, which can be viewed as alternative energy futures for the Railbelt region. We analyzed the net impact of each Organizational Path under each of the four Evaluation Scenarios separately to determine the economic benefits of each Organizational Path, relative to each other. The intent was to determine if one Organizational Path was the most optimal alternative regardless of the energy future chosen by the region, or whether different Organizational Paths were optimal under different futures.

For each Evaluation Scenario, we developed prescriptive generation supply resource plans, which are representative resource plans to determine the economic benefits of each Organizational Path. These prescriptive resource plans are not the same as integrated resource plans for each Evaluation Scenario, which are optimal long-term resource plans given all considered factors.

Therefore, as noted earlier, it would be inappropriate to compare one Evaluation Scenario to another, as the resulting evaluation plans and power costs under the different Scenarios are not necessarily indicative of what they would be under an optimized integrated resource plan. They do, however, provide a solid foundation for the evaluation of the various Organizational Paths to each other under alternative futures.

These Evaluation Scenarios are shown in the following graphic and discussed below.

Figure 3 - Summary of Evaluation Scenarios



Note to the Readers of This Report

It is important to understand that the focus of this study is on the evaluation of alternative organizational structures for the reconfiguration of the generation and transmission functions of the Railbelt utilities. In completing this analysis, Black & Veatch evaluated alternative energy futures and developed prescriptive resource plans for each energy future considered. These prescriptive resource plans were developed to assist in the evaluation of alternative organizational paths. These prescriptive resource plans are not alternative integrated resource plans; as such, readers should not compare the prescriptive resource plans to each other nor should they draw any conclusions from this analysis as to what the optimal resource mix for the Railbelt over the next 30 years might include.

- **Scenario A – Large Hydro/Renewables/DSM/Energy Efficiency Scenario**
  This Scenario assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.
- **Scenario B – Natural Gas Scenario**
  In this Scenario, we assumed that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.
- **Scenario C – Coal Scenario**
  The central resource option in this Scenario is the addition of coal plants to meet the future needs of the region.
- **Scenario D – Mixed Resource Portfolio Scenario**
  In this Scenario, we assumed that a combination of large hydroelectric, renewables, DSM/energy efficiency programs, coal and natural gas resources is added over the next 30 years to meet the future needs of the region.

Existing and Future Resource Options

There are a variety of existing generation resources that are owned and operated by the Railbelt utilities, as well as a transmission grid that extends from the Fairbanks area down to the Kenai Peninsula. There are also a broad array of supply-side resource options, both traditional and renewable resources, and demand-side resources (i.e., DSM and energy efficiency programs), available to meet the future electrical needs of the Railbelt region. A description of these existing and future resource options are provided in Section 5.

Organizational Issues

This section provides an overview of the various organizational issues that relate to the formation of a new regional entity, including scope of responsibilities, tax and legal issues, regulatory oversight issues, required legislative actions, and so forth.

The formation of regional entities to focus on generation and transmission issues is a common practice throughout the country. Typically, the legal structure of the entities falls into one of the following four business models:

- State/Federal Power Authorities
- G&T Cooperatives
- Joint Action Agencies
- Regional Transmission Organizations (RTOs)/Independent System Operators (ISOs)

Within the not-for-profit segment of the industry, the G&T Cooperative and JAA and business models are the most common. State Power Authorities exist in a limited number of states. RTOs/ISOs are typically “super regional” organizations as they cover large regions (e.g., Texas or multiple states) in the lower-48 states, and investor-owned utilities (IOUs), G&T Cooperatives, JAAs, and State Power Authorities operate within the regions under their direction.

In Appendix B, we provide descriptions of a number of different organizations that currently exist within the U.S. that are similar to the types of organizations considered in this study, including:

- State/Federal Power Authorities
- G&T Cooperatives
- Joint Action Agencies
- Other Types of Regional Generation and Transmission Entities
- Centralized Energy Efficiency Organizations

Many other examples exist, but this summary provides a representative overview of these types of organizations.

Notwithstanding the experience that has been gained elsewhere with the formation of regional G&T entities, there are a number of organizational issues that need to be addressed if the Railbelt utilities and the State of Alaska are to successfully create such an entity. Specific categories of these organizational issues are identified in the following graphic. In addition, the subsequent table provides a listing of the issues within each category shown in the graphic below. These issues are addressed in detail in Section 6.

Figure 4 - Summary of Organizational Issues

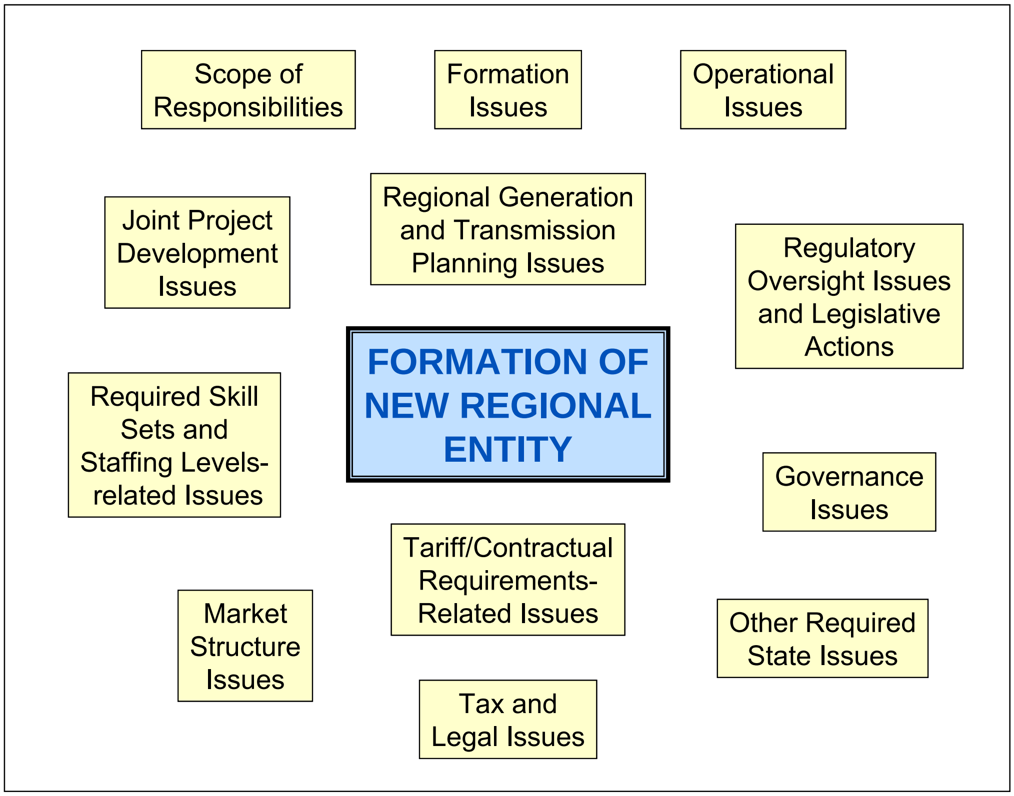


Table 2 - Summary of Organizational Issues

Scope of Responsibilities • Coordinated operation of the transmission grid • Regional economic dispatch • Regional resource planning • Joint project development	**Required Skill Sets and Staffing Levels-Related Issues** • Total staffing levels • Organizational structure • Strategy for transfer of existing employees • Recruiting and relocation strategy • Compensation program	**Tariff/Contractual Requirements-Related Issues** • Open access transmission tariff • Postage stamp of mileage-based rates • Contracts between individual parties
Formation Issues • Legal structure • Location • Transfer of existing assets and fuel supply contracts • Whether to adopt a "hold harmless" requirement • Transition period	**Tax and Legal Issues** • Ability to issue tax-exempt debt • Transfer of ownership of existing assets • Transfer of the City of Anchorage's ownership of gas reserves in the Cook Inlet • Governance	**Governance Issues** • Non-profit operation • Requirements for membership • Board representation • Formation of management committees • Meetings • Decision-making and approval process • Issuance of debt
Operational Issues • O&M responsibility • Consolidation of control centers • Required SCADA/ telecommunications investments • Determination of transmission voltage level and treatment of large customers currently served at transmission voltage levels	**Regulatory Oversight Issues and Legislative Actions** • Regional integrated resource plans • Joint project development • Fuel contracts • Cost/benefit allocation methodology • Transmission tariff • Annual reporting requirements	• Purchase of power, adherence to results of economic dispatch, regional planning process and joint project development • Termination of membership • Merger, consolidation or dissolution of regional entity • Indemnification of Directors, management personnel, employees and agents
Regional Generation and Transmission Planning Issues • Development of new coordinated planning processes • Requirement to follow results	**Other Required State Actions** • State Energy Plan and related issues	• Contracting • Rules, regulations and rate schedules
Joint Project Development Issues • All-in or opt-out option • Responsibility for project construction	**Market Structure Issues** • Required changes to market structure • Adoption of a competitive power procurement process	

Summary of Assumptions

The supply-side and demand-side resource assumptions that we used in our analysis are summarized in Section 7. This section also discusses the input assumptions that we used regarding the start-up and annual operating costs associated with each Organizational Path. Under the base case, we assumed that the new regional entity would be able to issue tax-exempt debt under each Organizational Path and Evaluation Scenario. As a sensitivity case, we also evaluated Organizational Path 4, for each Evaluation Scenario, under the assumption that the new regional entity would be required to issue taxable municipal bonds to finance the region's future generation and transmission assets.

Summary of Results

Power Cost Results

In this subsection, we summarize the economic results of our analysis of power costs under each of the alternative Organizational Paths for each of the Evaluation Scenarios. These results are discussed in more detail in Section 8.

The following table summarizes the average annual present worth savings in power costs, including both generation and transmission costs, for each Organizational Path and Evaluation Scenario. To calculate the average annual present worth figures shown in the tables in this Section, we discounted the 30-year stream of costs to a present worth value in 2009 using a discount rate of 6.0 percent. We then divided this value by 30 to calculate the average annual present worth value.

Table 3 - Average Annual Present Worth Power Cost Savings ($'000)

	Path 2	Path 3	Path 4	Path 5
Tax-Exempt Debt				
Scenario A	--	$10,688	$49,228	$49,228
Scenario B	--	$9,658	$19,341	$19,341
Scenario C	--	$13,104	$43,722	$43,722
Scenario D	--	$11,263	$40,740	$40,740
Taxable Debt				
Scenario A			$34,712	
Scenario B			$16,997	
Scenario C			$37,417	
Scenario D			$31,659	

The top half of the above table shows the average annual power cost savings associated with the formation of a new regional G&T entity, assuming that the entity would be able to finance future generation and transmission asset additions using tax-exempt debt. As can be seen, the most significant savings result from Organizational Paths 4 and 5. As previously discussed, the only difference between Paths 4 and 5 is that, under Path 5, the existing Railbelt utilities would remain responsible for the joint development of future generation and transmission facilities; the resulting power cost savings are the same for both Organizational Paths because we assumed that the investment decisions made by the individual utilities under the Path 5 power pool would align and track completely with the regional resource planning decisions made by the new regional entity.

As can be seen in the table above, there are not any power cost savings associated with Organizational Path 2. This is because Path 2 involves the coordinated operation of the Railbelt transmission grid by an independent entity; the only difference between Path 2 and the status quo (Organizational Path 1) is that the transmission grid operation function would be performed by an independent entity, as opposed to the existing Railbelt which are fulfilling this responsibility today. Hence, there is not any additional power costs savings associated with this Organizational Path.

Finally, the bottom half of this table shows the power costs savings under Organizational Path 4 assuming that taxable debt must be used to finance future generation and transmission asset additions. As can be seen, this sensitivity case results in lower average annual power cost savings, under each Evaluation Scenario, due to the additional financing costs associated with taxable debt relative to tax-exempt debt.

More detailed information regarding these power cost savings results are provided in Appendices C-F.

Organizational Cost Results

We developed a detailed estimate of the average annual present worth costs associated with the creation of a new regional entity for each of the alternative Organizational Paths. We also developed a 30-year estimate of the annual operating costs for each alternative organization, including the amortization of the start-up costs over the first five years of operations. A detailed discussion related to these cost estimates is provided in Section 7. These cost estimates do not include potential net cost savings at existing utilities.

The following table summarizes the resulting labor costs related to the start-up of each of the alternative Organizational Paths.

Table 4 - Estimated Start-up Costs – Labor

Category	Estimated Start-Up Labor Cost ($'000)			
	Path 2	Path 3	Path 4	Path 5
Provide Overall Program Management/Governance	$68	$168	$294	$199
Finalize Business Structure	96	193	353	243
Secure New Facility	80	121	167	133
Develop Business Policies, Processes and Procedures	78	113	207	159
Complete Operations Transition Planning	13	15	23	18
HR and Recruiting	57	82	252	104
Complete Operations and Economic Dispatch Transition	12	310	310	310
Complete Generation and Transmission Planning Transition	0	0	96	96
Develop IT Infrastructure	189	199	405	211
Develop Business Systems	166	511	652	511
Employee Training	67	88	176	105
Transition and Cutover Execution	76	82	110	82
Other	0	0	285	285
Subtotals	**$902**	**$1,882**	**$3,331**	**$2,457**
Out-of-Pocket Expenses (15%)	135	282	500	369
Contingency (25%)	259	541	958	706
Totals	**$1,296**	**$2,705**	**$4,788**	**$3,532**

In addition to labor costs, there are a number of non-labor costs that will be incurred during the start-up of a new regional entity. Therefore, the next step in the process was to develop cost estimates for each Organizational Path related to the following:

- Control center system enhancements

- Economic dispatch and resource planning software
- Transmission planning software
- Enterprise back-office systems
- Office equipment (e.g., furniture and printers)
- Servers and network infrastructure
- Telecommunications
- Desktop hardware and software

The following table summarizes the resulting non-labor start-up costs for each alternative Organizational Path.

Table 5 - Estimated Start-up Costs – Non-Labor

	Estimated Start-Up Non-Labor Cost ($'000)			
Category	**Path 2**	**Path 3**	**Path 4**	**Path 5**
Software Capital Investment				
Control Center	$0	$500	$500	$500
Economic Dispatch/Resource Planning	0	34	34	34
Transmission Planning	0	0	154	99
Enterprise Back-Office	100	200	200	200
Subtotals	**$100**	**$734**	**$888**	**$832**
Other				
Office Equipment	127	183	591	246
Servers	72	88	92	89
Network Infrastructure	27	35	62	41
Telecommunications	54	54	54	54
Desktop PCs	43	65	211	86
Subtotals	**$324**	**$425**	**$1,010**	**$515**
Totals	**$424**	**$1,159**	**$1,898**	**$1,348**

The following table summarizes the average annual administration and general (A&G) costs for each Organizational Path. As discussed previously, the total annual A&G costs include the following components:

- Five-year amortization of start-up labor and non-labor costs
- Total salaries and benefits
- Software licensing and maintenance costs
- Hardware maintenance and replacement
- Other non-labor costs (e.g., rent, office supplies, insurance and outside services)

Table 6 - Average Annual Present Worth A&G Costs ($'000)

Path 2	$1,272
Path 3	$2,459
Path 4	$6,545
Path 5	$3,132

The average annual A&G costs for Organizational Path 5 are lower than Path 4 because of lower start-up labor and non-labor costs, and lower annual operating costs due to lower staffing requirements.

More detailed information regarding these results is provided in Appendices C-F.

Net Savings

The following table provides an overall summary of the average annual present worth net savings (costs) under each Evaluation Scenario. In other words, this table shows the average annual present worth net savings, or increased costs, when both the power cost savings, shown in Table 3, and the annual A&G costs, shown in Table 6, are combined together.

Table 7 - Average Annual Present Worth Net Savings (Costs) Under Each Evaluation Scenario ($'000)

					Relative Path 4 Results	
Scenario	Path 2	Path 3	Path 4	Path 5	% Savings	Impact on Typical Monthly Residential Bill
Tax-Exempt Debt						
Scenario A	($1,272)	$8,229	$42,683	$46,097	10.9%	$11.50
Scenario B	($1,272)	$7,199	$12,795	$16,209	4.1%	$4.30
Scenario C	($1,272)	$10,645	$37,177	$40,591	10.8%	$11.30
Scenario D	($1,272)	$8,804	$34,195	$37,608	9.4%	$9.90
Taxable Debt						
Scenario A			$28,166		7.9%	$8.30
Scenario B			$10,452		3.6%	$3.70
Scenario C			$30,872		10.1%	$10.60
Scenario D			$25,114		7.5%	$7.90

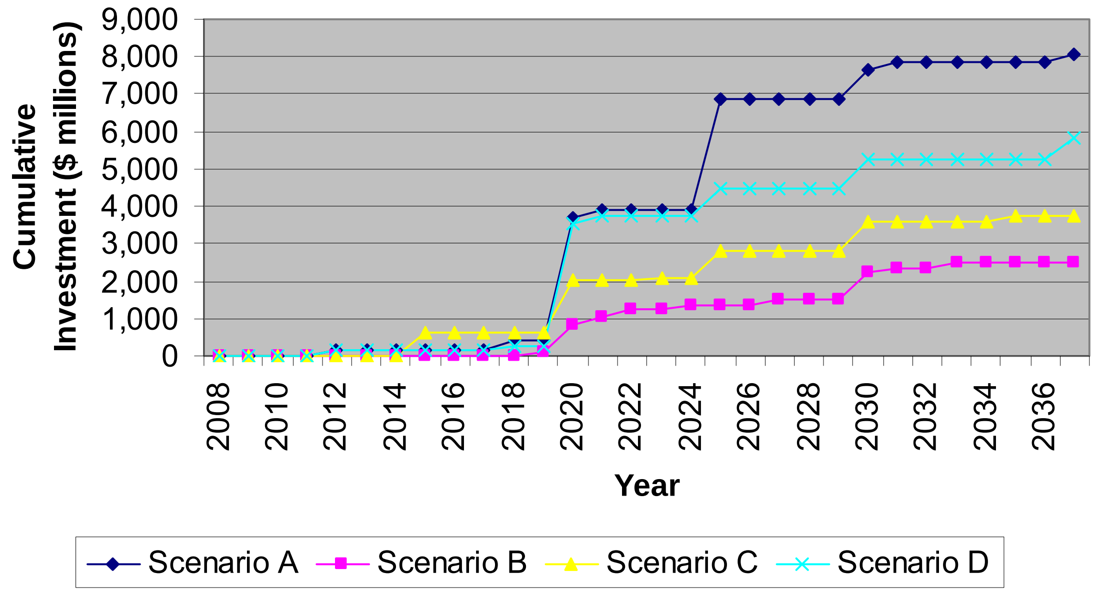
As can be seen in this table, Organizational Paths 4 and 5 offer the greatest net annual savings, and these savings are significant relative to the status quo (Organizational Path 1). While the net annual savings for Organizational Path 4 are less under the taxable debt sensitivity case, they are still significant. The above table also shows the percentage savings relative to the total power costs under each Organizational Path 4, as well as the resulting impact on typical monthly residential bills.

Cumulative Capital Requirements

The following figure shows the cumulative capital requirements over the next 30 years resulting from the generation and transmission expansion plans for each of the four Evaluation Scenarios. As can be seen, the future cumulative capital requirements range from $2.5 billion for Evaluation Scenario B to $8.1 billion for Scenario A. This graphic also shows the fact that these capital expenditures do not occur evenly over the 30-

year period. In developing this graph, we assumed that all of the capital expenditures associated with a specific project would occur in the initial year of commercial operation since we did not develop a detailed cash flow projection for each project. While this assumption is not reflective of reality since project construction costs occur over several years, this graphic does demonstrate that there are specific periods during the 30-year planning horizon during which capital requirements will be particularly high.

Figure 5 - Required Cumulative Capital Investment



Factors to Consider in Choosing Organizational and Legal Structure

In this subsection, we address several factors that need to be considered in making the decision to form a new regional G&T entity, the scope of responsibilities of that entity, and the legal form.

Path 4 Versus Path 5

Table 7 above also shows that, based on our economic analysis, Organizational Path 5 is slightly more cost effective than Path 4. Consequently, the net annual savings under Path 5 are shown to be greater than under Path 4. These incremental annual savings result from Path 5's lower annual A&G costs arising from the fact that the required size of a regional power pool is smaller (i.e., fewer staff and related costs) than for a fully functioning regional generation and transmission entity (i.e., Path 4). These incremental annual net savings under Path 5 may not, however, be realized for two reasons.

First, under Path 5, the existing utilities remain responsible for the development of their own future generation and transmission resources. This results in lower staffing requirements for the regional entity but, on the other hand, it means that the individuals at the existing utilities who are currently responsible for these activities would remain at the existing Railbelt utilities and, therefore, the Railbelt utilities would continue to incur the full payroll costs associated with these individuals. This was not fully reflected in our cost analysis. As a result, the incremental net annual savings of Path 5 would be less.

Additionally, we assumed that the power cost savings under Path 5 would be the same as Path 4. This, in essence, means that the decisions made by the individual Railbelt utilities regarding investments in future generation and transmission resources would completely align and track with the results of the regional resource planning process conducted by the regional entity. While incentives and penalties can be incorporated in the power pool's cost allocation methodology to induce the individual utilities to behave in this manner, there is no guarantee that this will happen. Hence, it is very possible that the actual power cost savings under Path 5 would, in fact, be less than under Path 4, and the resulting decrease in power cost savings could easily be greater than the savings in A&G costs under Path 5.

Therefore, we view Path 5 as more of a transition strategy towards the development of a fully functioning regional generation and transmission entity, not the ultimate optimal end-state for the region. We further believe that the region should move directly to the optimal end-state; therefore, we are not recommending the formation of a power pool, even as a transitional strategy.

Non-Economic Benefits Associated With Formation of a Regional Entity

There are a number of benefits associated with the creation of a fully functioning regional generation and transmission entity (i.e., a Path 4-type entity) that go beyond the economics that were modeled in our analysis. These additional benefits include the following:

- Economies of scale and coordination related to staffing. Examples include:
  - Better coordination is possible if all regional employees with generation and transmission responsibilities are part of one organization.
  - Depth of bench – it is easier to take advantage of the depth of everyone's skills and expertise when everyone works for one organization, and greater specialization can occur.
  - The concentration of staff increases the ability of the regional entity to keep abreast of new technologies (e.g., renewables) and industry trends.
  - The concentration of staff also increases the ability of the Railbelt region to develop and support the delivery of cost effective renewables and DSM/energy efficiency programs.
- The concentration of staff would likely lead to more sophisticated generation and transmission planning, resulting in better regional resource planning decisions.
- A regional entity, with rational regional planning, enables the region to identify and prioritize projects on a regional basis and it puts the State in a better position to evaluate, award and monitor funding.
- The formation of a regional entity could lead to a reduction in the required levels of reserve margins over time.
- A regional entity is better able to integrate non-dispatchable resources, such as wind and solar.
- With regard to project development, the concentration of staff within one organization increases the ability to make timely and effective mid-course corrections, as required.
- A regional entity is in a better position to manage risks which is particularly important given the current circumstances in the Railbelt region.
- A regional entity is more likely in a better position to compete in a competitive marketplace for human resources and to offset, somewhat, the impacts of an aging workforce.
- A regional entity could also result in other cost savings not captured in our economic modeling, including:
  - The region would need to develop only one regional Integrated Resource Plan, as opposed to three or more Integrated Resource Plans, every three to five years.
  - Legal and consulting expenses can be reduced as more issues are addressed on a regional basis versus on an individual utility basis.
  - Total staffing levels in certain areas on a regional basis can likely be reduced.
  - Better access to lower cost financing due to the overall financial strength of the regional entity relative to the six individual utilities.
- The formation of a regional entity can increase the flexibility of the region to respond to major events (e.g., a large load increase, such as a new or expanded mine).

- A regional entity would be in a better position to work with Enstar Natural Gas Company and the gas producers to address the region's energy issues in a more comprehensive manner.

Region's Ability to Finance the Future

As discussed previously, the region is facing very significant future capital investments over the next 30 years, ranging from $2.5 billion to $8.1 billion depending upon the future resource portfolio that the region selects. The following table provides some relative consolidated Railbelt utility statistics, based upon information provided in the utilities' annual reports, to highlight how significant of a challenge the region faces in terms of financing its future. It is clear that the total net electric plant of the region will increase very significantly. The outstanding total long-term obligations for all six existing Railbelt utilities is at the present time approximately $1.1 billion. Therefore, issuing debt to meet the future capital requirements of the region will increase the long-term obligations of the region a minimum of two times and possibly as much as seven times. This is further supported by the fact that the current "equity" of the six Railbelt utilities is slightly less than $0.6 billion.

Table 8 - Estimated Required Capital to Finance the Region's Future

Scenario	Required Capital Investment Over Next 30 Years – Path 4 *($'000,000)*
A – Hydro/Renewables/DSM	$8,070
B – Natural Gas	$2,475
C – Coal	$3,769
D – Mixed	$5,840

Combined Railbelt Utility Financial Information - 2007 *($'000,000)*

- Total Net Electric Plant $1,475
- Total Revenues $729
- Total Long-Term Obligations $1,081
- Total "Equity" $588

An important point to keep in mind is that regardless of whether the future required investment is $2.5 billion or $8.1 billion, that investment will need to be recovered through rates, thereby resulting in higher monthly bills for residential and commercial customers.

Value of State Financial Assistance

As a result of these very significant capital requirements and their resulting impact on rates, obtaining financial assistance from the State of Alaska will be very important. This assistance could come in a variety of forms, including grants and or loans. This type of assistance is the most direct way to minimize the impact on monthly electric bills as it lowers the amount of debt that would need to be raised from other sources of financing.

The following table shows the direct impact of State financial assistance per $1 billion of assistance versus financing the capital needs from the Railbelt utilities and recovering these financing costs from customers. We show the annual savings that would result under two cases: 1) the assistance is provided in the form of a grant, and 2) the assistance is provided in the form of a zero-interest loan. These annual savings are based on the potential reduction in annual financial carrying costs (7.86 percent in the case of a grant and 4.52 percent in the case of a zero-interest loan) associated with each $1 billion in avoided debt raised in the municipal bond market.

Table 9 - Value of State Financial Assistance (per $1 Billion of Assistance)

Form of Assistance	Annual Savings *($'000,000)*
Grant	$78.6
Zero-Interest Loan	$45.2

Value of Tax-Exempt Financing

The ability of a regional entity to issue tax-exempt debt would also have significant benefits. The amount of this benefit is a direct function of the region's "fuel future" in that the greater the up-front capital costs (e.g., development of a large hydroelectric or coal plant), the greater the savings. This is shown in the following table. The annual savings shown are based on an assumed 1.75 percent (175 basis points) difference between tax-exempt debt and taxable debt (the basis for this assumption is discussed in detail in Section 9).

Table 10 - Value of Tax-Exempt Financing

Scenario	Required Capital Investment Over Next 30 Years – Path 4 *($'000,000)*	Potential Annual Savings Associated With Tax-Exempt Financing (Assuming 175 Basis Point Differential) *($'000,000)*
A – Hydro/Renewables/DSM	$8,070	$141
B – Natural Gas	$2,475	$43
C – Coal	$3,769	$66
D – Mixed	$5,840	$102

This table shows the annual savings in interest payments based upon an assumed 1.75 percent (175 basis points) difference in the taxable interest rate and the tax-exempt interest rate. As can be seen, annual savings range from approximately $40 million to $140 million depending upon the region's future resource portfolio. We also show the resulting percentage savings in power costs, as well as the impact on typical monthly residential bills.

There are a number of issues and restrictions related to the regional entity's ability to issue tax-exempt debt. These issues are discussed in Section 6 and Appendix G. We have identified a few strategies for addressing these issues; these strategies are discussed in Section 9 and Appendix G.

> ***"Differences have created a situation in which the utilities are forced into an inter-dependent relationship in which their interests are not aligned. Creation of a regional grid authority or unified system operator would be a facilitating step toward greater cooperation between the entities by removing some of the issues of contention between them."***
>
> **Native Corporation Representative**

Conclusions and Recommendations

The following summarizes the overall organizational structure recommendations arising from the REGA Study.

- As shown in Figure 6, a new Railbelt regional entity with responsibility for generation and transmission operations and future ownership should be formed; the existing Railbelt utilities would retain the responsibility for providing traditional distribution services, such as moving power from transmission/distribution substations to individual customers, meter reading, turn-ons/offs, and responding to customer inquiries. More specifically, the functional responsibilities of this new regional entity should include:

- Independent, coordinated operation of the Railbelt electric transmission system
- Economic dispatch of the Railbelt region's generation facilities
- Railbelt region resource and transmission expansion planning
- Joint development of new generation and transmission facilities for the Railbelt region

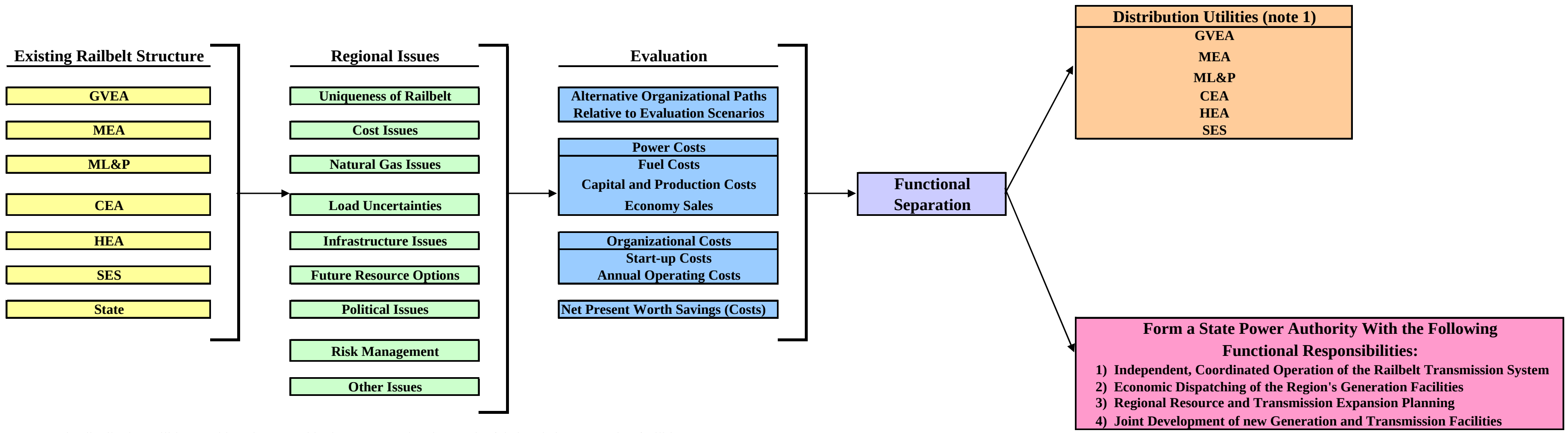
- To maximize the economic benefits associated with regionalization, the legal structure for this new regional entity should be a State Power Authority for the following reasons:
  - It is projected that the Railbelt region will need to issue new debt between $2.5 - $8.1 billion over the next 30 years to build new generation and transmission facilities to reliably serve the electric needs of citizens and businesses in the region. This level of investment, which is dependent upon the future generation resource options and transmission expansion projects chosen in a regional planning process, represents a significant challenge for the Railbelt region given its small size. Having the good faith and credit of the State supporting the regional entity will minimize the financial risks and result in a lower cost for debt.
  - State financial assistance, whether in the form of a grant(s) or low interest loan(s), would provide a significant benefit to the Railbelt region. This potential assistance represents the single most significant way to reduce the burden on Railbelt citizens and businesses associated with the financing of required generation and transmission investments.
  - It seems reasonable to conclude that the Governor and State Legislature would be more willing to provide some level of financial assistance to the Railbelt region if the new regional entity was formed as a State Power Authority, as opposed to a private business such as a G&T Cooperative.
  - In addition to potential State financial assistance, forming the new Railbelt regional entity in a manner that would allow it to issue tax-exempt debt would provide a significant economic benefit to the region. A State Power Authority is in a better position to be able to issue tax-exempt municipal debt, although significant restrictions exist that make this a challenge.
  - Generally speaking, a G&T Cooperative is unable to issue tax-exempt debt due to Internal Revenue Service (IRS) restrictions. A G&T Cooperative, as well as a State Power Authority, could obtain taxable debt through the Rural Utilities Service (RUS)/Federal Financing Bank (FFB) at favorable interest rates relative to the rates that are available in the taxable municipal bond market. However, RUS/FFB funding is subject to Congressional appropriations (approximately $3.2 billion in fiscal year (FY) 2008 for generation and transmission facilities) and the region would need to compete against other requests from cooperatives throughout the country. Additionally, RUS/FFB money is intended for rural communities; given that the majority of the Railbelt would not qualify as rural under the RUS/FFB rules, the amount of money that would be available from the RUS/FFB would be further restricted. As a result, the region will not be able to rely upon the RUS/FFB to meet all of its financing requirements. Furthermore, obtaining financing through the RUS/FFB can take up to two years with no assurance of success, and the resulting covenants are typically more restrictive than what can be negotiated in the municipal bond market. As a result, obtaining RUS/FFB financing is more risky than the municipal bond market.
  - If a State Power Authority is formed, it is very important that its Board of Directors and management team consists of individuals with substantive knowledge and understanding of the electric or energy

> ***"The economic stability of the State relies upon the Railbelt and consequently there has to be a substantive investment by the State in it so that the State attracts businesses and development."***
>
> **Financial Community Representative**

> ***"The State should do what the State does best; the utilities should do what the utilities do best."***
>
> **State Agency Representative**

industry, specifically generation and transmission, and consumer issues. Furthermore, the Board needs to be sufficiently insulated from State political cycles so that effective long-term planning and project development can occur. Without such industry expertise and independence, the Board and management team will not be able to effectively address the issues and risks facing the Railbelt region and manage the region's very substantial capital improvement program.

Figure 6 - Summary of Recommendations – Organizational Structure



Note 1: The distribution utilities would retain ownership, but not operational control, of their existing generation facilities.

Additional recommendations related to some of the organizational issues discussed in Section 6 are provided in the following table.

Table 11 - Summary of Recommendations - Formational Issues

Issue	Recommendation
Location	Anchorage Area
Transfer Ownership of Existing Assets	No
Establish "Hold Harmless" Requirement Regarding Allocation of Costs and Benefits of Regional Entity With Transition Plan	Yes
Transfer Selected Existing Employees	Yes
Extensive Expansion of Transmission Grid	Yes
Governance Structure	Depends on Legal Structure of Entity
Develop Open Access Transmission Tariff	Yes
Develop Generator Interconnection Standards	Yes
Develop Competitive Power Procurement Process	Yes (to provide Independent Power Producers an equal opportunity to compete)
Establish Postage-Stamp or Mileage-Based Rates	
Generation	Postage-Stamp Over Time
Transmission	Postage-Stamp
Regional Development of Renewables	Yes
Regional Development of DSM/Energy Efficiency Programs	Yes (in Close Coordination With Distribution Utilities to Tailor and Deliver Programs to Individual Service Territories)
RCA Oversight	No (due to the following reasons: 1) regional generation and transmission entities are typically not subject to state regulatory oversight, 2) the potential conflict when one state agency oversees another state agency, and 3) we do not believe that the benefits of regulation outweigh the incremental costs)
Elements of Integrated Resource/ Transmission Expansion Planning Process	
Consistency With State Energy Plan and Related Policies	Yes
Consistent Evaluation of Supply-Side and Demand-Side Resource Options	Yes
Interactive Analysis of Resource and Transmission Options	Yes
Economic Analysis of Replacement/Life Extension of Aging Generation Facilities	Yes
Innovative Rate Structures	Yes (in Coordination With Distribution Utilities)
Response to CO_2 and Other Environmental Restrictions	Yes
Re-evaluate Reserve Margin Targets	Yes
Public Participation	Yes

Next Steps and Implementation Plan

Next Steps

The following list of actions represents the next steps that need to be taken with regard to the formation of a new regional entity.

- The Railbelt utilities, in conjunction with the State, need to make the decision whether to form a new Railbelt regional entity and finalize the functional responsibilities of that entity. It is critical that this decision be made as soon as possible; the challenges confronting the Railbelt region require that action be taken now. Delay will only make the challenges greater and, if the regional entity is not formed now, decisions will need to be made by individual utilities and these decisions will not result in optimal results from a regional persepctive.
- A conclusive determination regarding the ability of the new regional entity to issue tax-exempt debt needs to be made and an appropriate strategy developed. The Railbelt utilities and the State should secure the services of one of more bond counsels and bond underwriters to support this effort.
- The legal form (i.e., State Power Authority, G&T Cooperative, or 63-20 Corporation) of the regional entity needs to be finalized.
- The Railbelt utilities and the State need to establish a transition management team to oversee the formation of the new entity.
- Required legislative actions should be introduced in the new legislative session, addressing the following:
    - Formation of the regional entity (including powers, legal form, governance structure, ability to purchase property, and selected bylaw requirements).
    - Modification of existing utilities' service territory certificates, as necessary.
    - Establishing direct privity with retail customers if the Retail Requirements Approach is adopted (the Retail Requirements Approach is discussed in Section 9).
    - Implementation of market structure changes (e.g., OATT and a competitive power procurement process).
    - Secure State financial assistance (e.g., grants or loans) for the development of regional generation and transmission infrastructure (based upon results of regional Integrated Resource Plan).
- Complete the formation of the new entity, including the following actions:
    - Establish utility/state implementation team
    - Determine need for outside assistance
    - Revise start-up implementation plan
- Develop initial regional Integrated Resource Plan and Transmission Expansion Plan. We have two important additional comments regarding the development of these two plans. *First*, it is very important that these initial regional plans be developed as soon as possible to identify the Railbelt region's future fuels strategy and transmission expansion program. *Second*, as part of this effort, a formal public participation process should be established, providing for transparency and broad participation by stakeholders throughout the process. The Hawaii Electric Company has such a public participation process in place which we believe provides a good example of how such a process should be established.
- The Railbelt utilities and the State need to determine how to finance the formation of the new regional entity, and develop a process to manage this seed money.
- Develop a methodology for the allocation of the costs and benefits associated with the regional entity during the recommended ten-year transition period, consistent with the hold-harmless philosophy.

Start-up Implementation Plan

The actual formation of a new Railbelt regional entity, once the decision is made to form such an entity, involves a significant number of actions. These actions, which are described in more detail in Section 10, have been grouped into the following categories:

- Overall Program Management/Governance
- Finalize Business Structure
- Secure New Facility
- Develop Business Policies, Processes and Procedures
- Complete Operations Transition Planning
- HR and Recruiting
- Complete Operations and Economic Dispatch Transition
- Complete Generation and Transmission Planning Transition
- Develop IT Infrastructure
- Develop Business Systems
- Employee Training
- Transition and Cutover Execution
- Other

Based upon experience elsewhere regarding the formation of similar entities, we believe that a 12-month start-up period, while a challenge, can be achieved. An overall implementation budget and schedule for the formation of the recommended regional entity are provided in Section 10.

SECTION 2 - PROJECT OVERVIEW AND REPORT OUTLINE

This section provides a historical backdrop for this report, along with a summery of the project's objectives, scope of work, and an overview of Black & Veatch's approach to the completion of this study. We also provide a summary of the stakeholder input process and discuss the role of the REGA Advisory Working Group. Finally, this section provides an overview of the models used and a description of the remaining sections of this report.

Historical Context and Background

Two similar studies have been completed for the Railbelt region in the past decade. The first study, "Power Pooling/Central Dispatch Planning Study," was completed in 1998 and the second study, "Railbelt Energy Study," was completed in 2004.

"Heard the one about the boiling frog? Sure you have. A frog is in a pot of water. The pot is placed on the stove. The frog is unconcerned for a while. Then it figures it can't handle the warmer water. It squirms as things get hot, but figures it's gotten along so far. And then it's boiled."

The first study was completed by Black & Veatch and was prepared for the Alaska Public Utilities Commission (APUC), which has since become the Regulatory Commission of Alaska (RCA), under contract with the Alaska Electric Generation and Transmission Cooperative, Inc. (AEG&T). In that study, Black & Veatch analyzed the potential benefits of a power pool with central dispatch among the Railbelt utilities. Black & Veatch evaluated the following three expansion cases: 1) the Individual Case, 2) the Pooled Case, and 3) the Joint Case. The Individual Case assumed that the status quo was maintained. The Pooled Case assumed that each utility would continue to meet its own capacity requirements, but that all of the regional generation assets would be centrally dispatched. The Joint Case assumed that the utilities jointly met capacity requirements and jointly dispatch all regional generation assets as if they were one utility.

The results of this study showed production and capital cost-related savings of $30.0 million over the 20-year planning horizon of the study, or 2.1%, for the Pooled Case relative to the Individual Case on a cumulative present worth (CPW) basis. For the Joint Case, the study showed CPW production and capital cost-related savings of $48.1 million, or 3.4%, relative to the Individual Case.

When the costs associated with the formation and operation of a "Railbelt Utility Operator," including equipment and staffing, were considered the net savings were reduced for the Pooled Case to $6.6 million, or 0.5%, and for the Joint Case to $24.7 million, or 1.7%.

The second study was completed by R.W. Beck and Ater Wynne and the objective of the study was to identify the combination of generation and transmission capital investments in the Railbelt region over a 30-year period (2004-2033) that would: 1) minimize future power supply costs, and 2) maintain current levels of power supply reliability. In this study, R.W. Beck/Ater Wynne identified alternative generation and transmission investment plans taking into account uncertainties regarding future loads, fuel prices, and resource options, assuming that the six Railbelt utilities act collectively. Results were shown for: 1) retirements, 2) reliability, 3) load-resource balances, 4) base case investment strategies, 5) effects of risk aversion on investment decisions, and 6) analysis of unique investment opportunities and sensitivity cases.

Project Scope of Work

The stated objectives of this study were to:

- Identify and assess a list of options for the management, operation, access rules, ownership, resource planning, and regulatory structures of the Railbelt generation and transmission system.
- For certain agreed-upon options, further analyze and provide recommendations of possible alternative structures to manage and dispatch electric power throughout the Railbelt region.
- Provide a final work product for stakeholders and decision-makers to consider in planning how to meet the Railbelt region's energy needs over the next 30 years.

> ***"We can talk this issue to death or we can get serious and begin to do something."***
>
> **Local Political Representative**
>
> * * * *
>
> ***"A unified system operator should manage the generating and transmission assets of the Railbelt. This could be through dispatch management or actual ownership. It should also plan and implement future generation asset acquisition for the Railbelt utilities, and manage fuel purchases and policies to encourage a robust supply and low price."***
>
> **Fuel Supplier**
>
> * * * *
>
> ***"The situation is near-dire now."***
>
> **Utility Representative**

The completion of this study including the following activities:

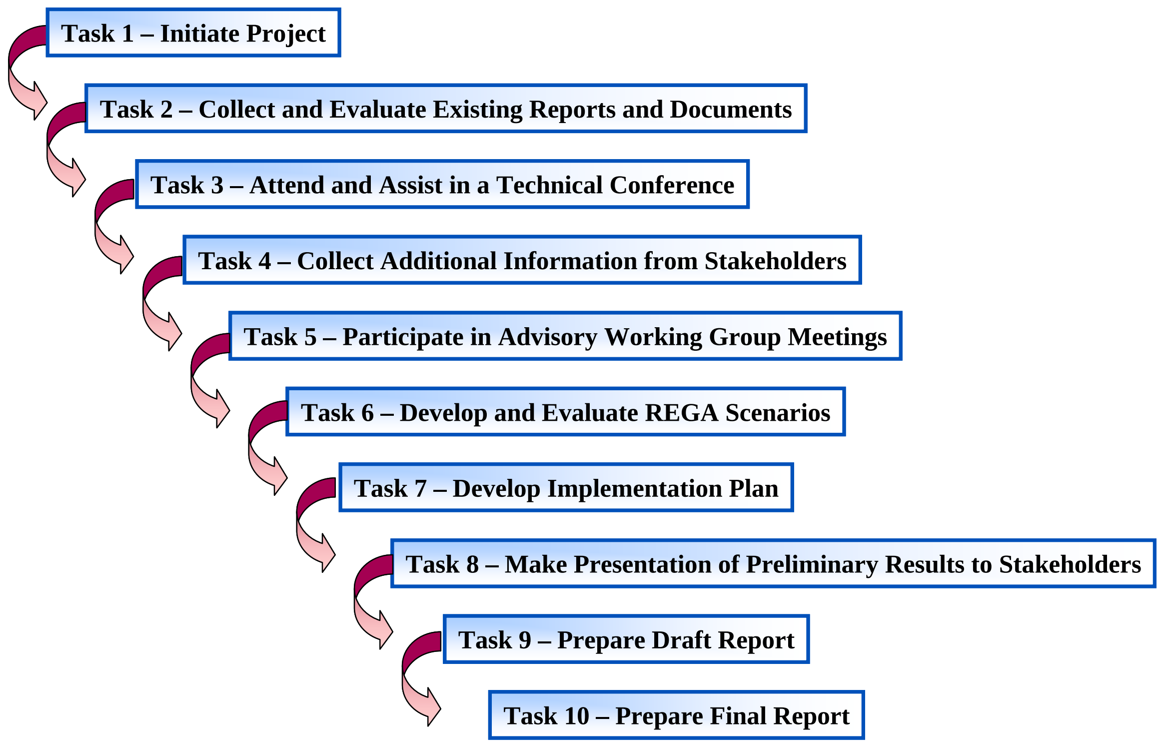
- Reviewing existing reports and available Railbelt electric system data, and conducting interviews and discussions with utilities and stakeholders.
- Reviewing available Railbelt utility modeling tools and capabilities, and providing additional modeling to provide a range of options supported by legal, regulatory, and economic analysis.
- Analyzing a range of scenarios and developing recommendations on whether and how the Railbelt electric system should be reconfigured to provide for a REGA.
- Assessing whether a REGA can be implemented cooperatively by utilities or whether a separate business entity is required.
- Identifying and considering all aspects of grid operation including procurement, ownership, control, management, and operation and maintenance.
- Determining whether economic dispatch should be through a pooled arrangement or through a separate entity.
- Assessing whether utilities should continue to develop service area-specific integrated resource plans, or should there be a single, regional integrated resource plan.
- Identifying any necessary changes in the market structure of the Railbelt region to implement the REGA.
- Understanding and considering the current regulatory regime under which utilities operate, including compliance with the RCA statutes and optional Federal Energy Regulatory Commission (FERC) rules under Orders Nos. 888 and 2000.
- Assessing whether the entity should be regulated by the RCA, what role the RCA should play in the regional planning, whether the regional plan should require RCA approval, and any state statutory and regulatory changes necessary for REGA implementation.
- Assessing whether all Railbelt utilities should be required to participate in and be bound by regional integrated resource planning decisions.
- Assessing whether investment decisions under the REGA should be subject to individual Railbelt utility Board of Director's approval.
- Developing an implementation plan for the most feasible scenarios, including specific implementation actions to be taken by utilities and stakeholders, including an implementation budget and schedule.

SECTION 2 - PROJECT OVERVIEW AND REPORT OUTLINE

Project Approach

The following graphic provides an overview of the approach that Black & Veatch took in the completion of this study.

Figure 7 - Project Approach Overview



Key activities for each of the project tasks is described below.

Task 1 – Initiate Project

Black & Veatch and key AEA management personnel held a general kick-off meeting, during which the following items were discussed:

Confirm project objectives and deliverables

- Discuss general strategic issues and considerations
- Identify joint AEA/Black & Veatch team members
- Discuss AEA management and staff involvement
- Discuss procedures for interacting with stakeholders
- Finalize project schedule

Task 2 – Collect and Evaluate Existing Reports and Documents

Black & Veatch developed two data requests for the Railbelt utilities to collect available resource material regarding Railbelt energy issues and resources. The utilities provided a significant amount of information in response to these data requests.

Task 3 – Attend and Assist in a Technical Conference

Black & Veatch worked closely with AEA personnel to organize, and participate in, a Technical Conference in November 2007. The purpose of this Technical Conference was to: 1) bring experts and stakeholders together to discuss important Railbelt issues, 2) inform stakeholders of the current status and condition of the Railbelt generation and transmission systems, and 3) develop public awareness of the issues surrounding the Railbelt grid. Approximately 120 people attended this Technical Conference.

Task 4 – Collect Additional Information From Stakeholders

Based on discussions during the Technical Conference and review of the data received from the Railbelt utilities, Black & Veatch collected additional information from Railbelt stakeholders regarding their plans and views towards implementation of a REGA. This data collection effort included a general survey instrument that was sent to all stakeholders that were invited to attend the Technical Conference. Black & Veatch also conducted interviews and used other sources to complete this data collection effort.

"The biggest issue is one of convergence: 1) declining Cook Inlet gas reserves, 2) increasing gas prices, 3) industrial users being driven out of the local gas market and either shifting to a new energy feedstock or looking at changing their business model, and 4) the six Railbelt electric utilities entrenched in a status quo of natural gas generation with a pricing structure that rewards high-volume usage and passes natural gas costs and future increases on to the consumer."

Renewable Energy Advocate

* * * *

"The utilities have basically been doing nothing and holding their breath hoping a miracle falls from the sky."

Fuel Supplier

Task 5 – Participate in Advisory Working Group Meetings

Black & Veatch participated in a series of five Advisory Working Group meetings to brief the group on progress, to solicit input on project issues, and to collect additional information.

Task 6 – Develop and Evaluate REGA Scenarios

Black & Veatch developed five feasible REGA organizational structures (Organizational Paths), complete with an assessment of the related costs and benefits under four differing resource scenarios (Evaluation Scenarios), and assessed the collective and individual impacts on the Railbelt utilities.

Task 7 – Develop Implementation Plan

Black & Veatch developed an implementation plan for the most feasible REGA scenario. This implementation plan includes:

- Narrative description of implementation tasks
- Pro forma budget defining implementation costs
- A implementation schedule organized by work activity

Task 8 – Make Presentation of Preliminary Results to Stakeholders

We prepared a presentation that summarized our preliminary results for presentation to stakeholders at a second Technical Conference in July 2008. The presentation also included our preliminary conclusions and recommendations, and it provided stakeholders the opportunity to provide comments, which were incorporated in the Draft Report.

Task 9 – Prepare Draft Report

Black & Veatch prepared a Draft Report and provided it to the AEA, which made it available to all stakeholders, for review and comment. This Draft Report included:

- An Executive Summary that summarized the study methodology, evaluation scenarios considered, assumptions used, and the recommended organizational structure for the REGA.
- A detailed analysis of five feasible alternative organizational structures, including the following for each structure:
  - Business structure
  - Market structures
  - Regulatory issues
  - Costs and issues related to power generation, transmission lines, and organizational formation and ongoing operations
- A comparative analysis of each alternative organizational structure relative to different energy futures.
- Preliminary implementation plans and schedules for the most feasible REGA organization(s).
- A bibliography.

"There is what I would call institutional neurosis. The individual utilities have established interconnected "fiefdoms" that have experienced differing levels of historical ego and control battles that have led to generational bitterness. Plus they have been operating in an isolated market that has not spurned innovative policies comparable to the lower-48 and some developing world markets."

Renewable Energy Advocate

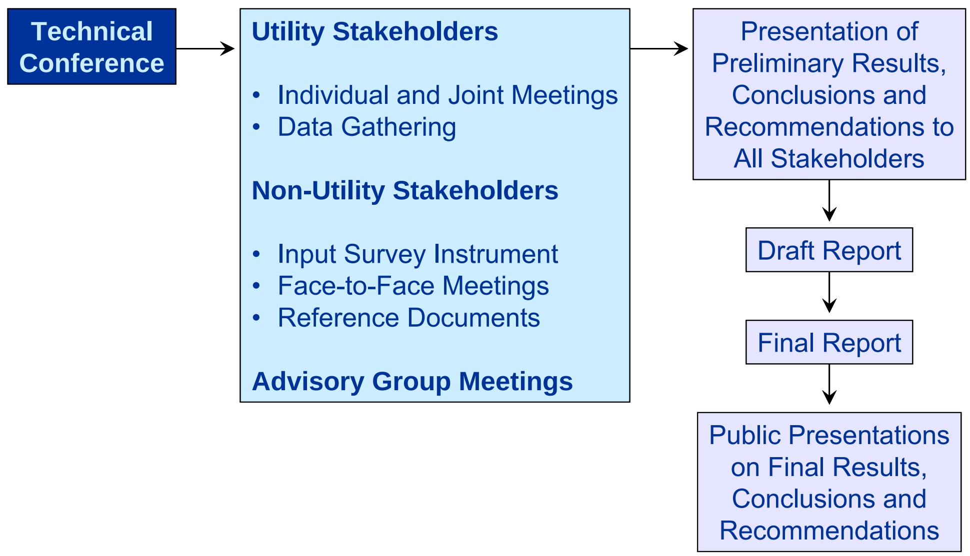
Task 10 – Prepare Final Report

Based upon comments received on the Draft Report, Black & Veatch developed this Final Report.

Stakeholder Input Process

One of the AEA's directives to Black & Veatch, related to the completion of this project, was to proactively solicit input from all of the Railbelt region's stakeholders. Elements of the stakeholder involvement process are summarized in the following graphic.

Figure 8 - Elements of Stakeholder Involvement Process



As the first element of this public participation process, the AEA held a two-day Technical Conference at the beginning of the project. The purpose of this conference was to enable a number of industry participants to provide their views regarding the broad array of issues confronting the Railbelt utilities. Approximately 120 individuals, including Black & Veatch project team members, participated in this conference.

Additionally, Black & Veatch provided non-utility stakeholders the opportunity to meet personally with Black & Veatch project team members; over 30 such meetings were held. These meetings were in addition to the meetings that Black & Veatch held with Railbelt utility representatives.

Furthermore, Black & Veatch sent an e-mail to all non-utility stakeholders that were on the first Technical Conference invitation list, prepared by the AEA, to provide them an opportunity to respond to specific questions that were included in a non-utility stakeholder input survey instrument. A copy of the survey instrument is provided in Appendix A. Black & Veatch received approximately 25 responses to this survey.

Additionally, all stakeholders were provided the opportunity to provide comments on our preliminary results, conclusions and recommendations before we developed the Draft Report. Stakeholders were also provided the opportunity to submit comments on the Draft Report.

Role of Advisory Working Group and Membership

Another important element of this project's stakeholder input process was the formation of an Advisory Working Group, assembled by the AEA, which provided input to the Black & Veatch/AEA project team throughout the study. This Group, which met five times during the course of the project, included the following members:

- Norman Rokeberg, Retired State of Alaska Representative, Chairman
- Jan Wilson, Regulatory Commission of Alaska
- Jim Sykes, Alaska Public Interest Group

- Chris Rose, Renewable Energy Alaska Project, Vice Chairman
- Brad Janorschke, Homer Electric Association
- Brian Newton, Golden Valley Electric Association
- Colleen Starring, Enstar Natural Gas Company
- Debra Schnebel, Scott Balice Strategies
- Kip Knudson, Tesoro
- Lois Lester, AARP
- Marilyn Leland, Alaska Power Association
- Mitch Little/Les Webber, Marathon Oil Company
- Nick Goodman, TDX Power, Inc.
- Steve Denton, Usibelli Coal Mine, Inc.
- Tony Izzo, TMI Consulting

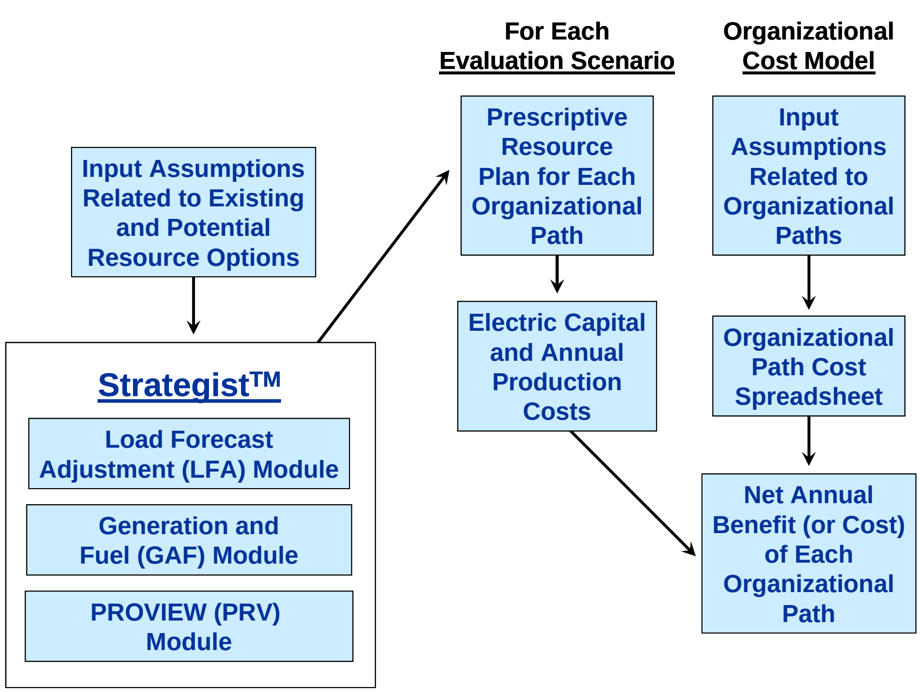
The Advisory Working Group provided input on a number of project-related issues, including

- Project objectives, scope, and approach
- Organizational Paths to be evaluated
- Evaluation Scenarios to be considered
- Input assumptions for each Evaluation Scenario
- Tax and legal issues
- Preliminary results, conclusions and recommendations
- Draft Report

Overview of Strategist™ and Organizational Cost Models

Black & Veatch primarily used two models to complete the necessary detailed cost analysis that led to our conclusions and recommendations. This is shown in the following graphic.

Figure 9 - Overview of Models



To model the production cost and capital cost impacts of the various Evaluation Scenarios under each of the Organizational Paths, Black & Veatch used Strategist™, which is an investment optimization model developed by New Energy Associates. Strategist™ is available for use as a least-cost resource optimization system to develop optimal portfolios of resources. In Strategist™, integrated resource screening and optimization is accomplished within a single system for demand- and supply-side analysis of all resource types.

Production costing models use two analytical modeling devices to assess costs. The process uses either a deterministic simulation or a probabilistic simulation of system operation. Both options produce reasonable cost estimates. The essential difference between the two models results from the treatment of forced outage rates (i.e., times when generation is not available on an unscheduled basis). The deterministic model spreads forced outages over the operating hours of the capacity by reducing the plant's output in every hour to reflect the equivalent availability. The probabilistic model uses a random draw to determine the times when the unit is unavailable based on the forced outage rate for the unit. In either case, the impacts of factors that influence production costs given unit characteristics are reflected in the modeling. Strategist™ uses both a deterministic and probabilistic approach. The deterministic approach is used in selecting the optimal expansion plans and the probabilistic approach is used in determining the production costs.

Strategist™ is comprised of several modules. A flexible control system ties the application modules together and automates data transfer from one module to another. A user interface allows users to interact with the Strategist™ database containing all inputs and outputs. Strategist's™ user interface includes features such as full-screen spreadsheet data entry/edit capability, on-line documentation, graphic display of data, program execution, and reporting.

Strategist™ consists of the following modules:

- **Load Forecast Adjustment (LFA) Module**
  The LFA module is a multi-purpose tool for creating and modifying load forecasts. Using the LFA module, a planner may address key issues related to future electricity or gas demand, and evaluate the impacts attributed to each defined customer group. Results from this analysis can be automatically transferred to other Strategist™ modules to determine production costs, system reliability, financing and revenue requirements, and a variety of other indicators affected by loads. The LFA module may be used in conjunction with the PROVIEW module to perform integrated demand/supply optimization.
- **Generation and Fuel (GAF) Module**
  The GAF module provides the production costs, system reliability indicators, fuel usage, and emissions information that are important in evaluating long-range system operating costs associated with particular generation plans. The GAF module simulates the effects on an electric utility of changes in operating characteristics, fuel prices and availability, contractual sale and purchase arrangements including economy interchange, and alternative generation resource plans. The GAF module will also dispatch and calculate interchange accounting for a multi-company system.
- **PROVIEW Module**
  The PROVIEW module is an automatic expansion planning module which can determine the optimal balanced supply-side and demand-side plan for a utility system under a prescribed set of constraints and assumptions. It enables planners to study a wide variety of long-range expansion planning options including alternative technologies, unit conversions, unit capacity sizes, load management, marketing and conservation programs, fuel costs, reliability limits, and financial constraints in order to develop a coordinated integrated plan which would be best suited for the utility. The PROVIEW module simulates the operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through marketing programs, and it examines the impact on the construction budget of building new units.

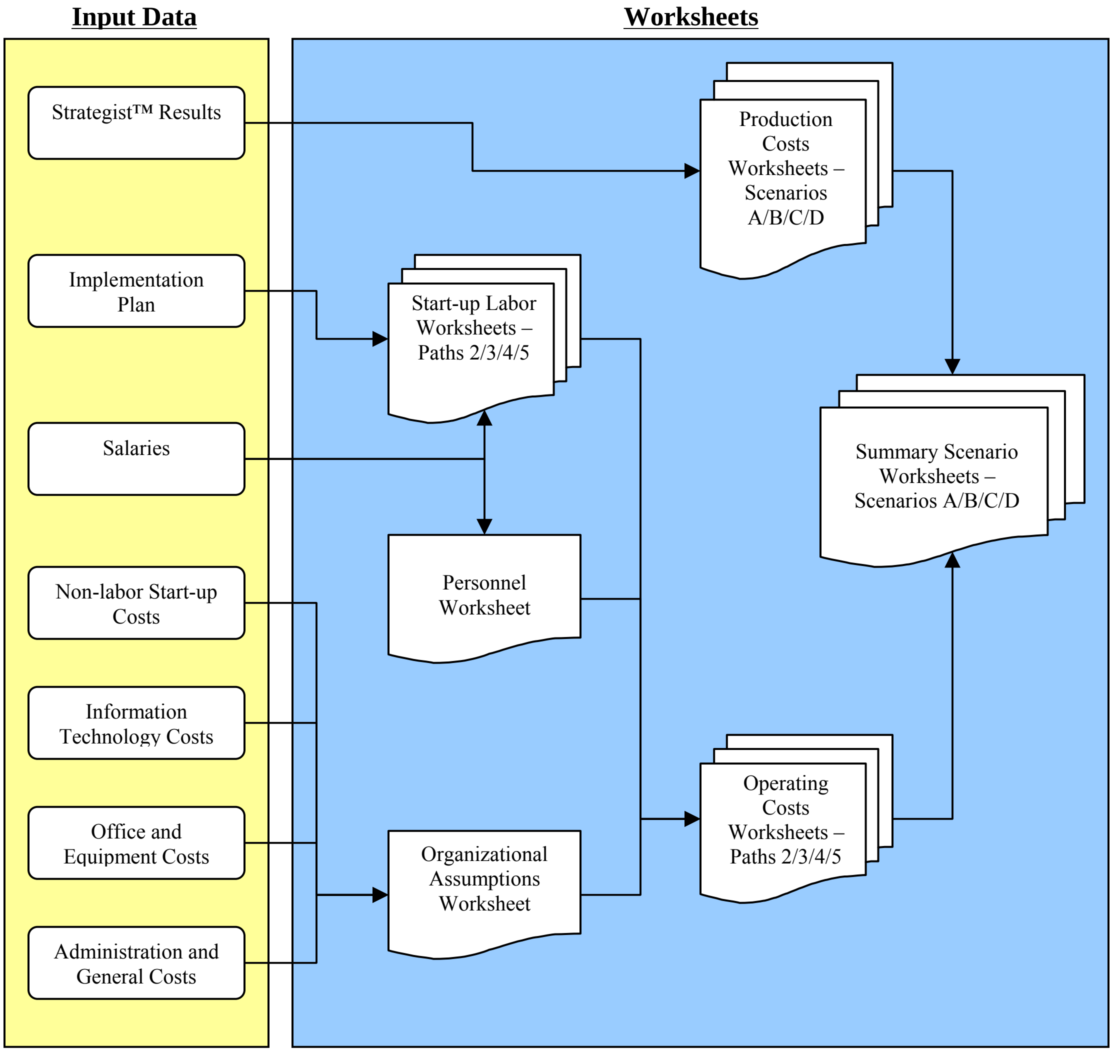
To estimate the costs associated with the formation and operation of a new entity under Organizational Paths 2, 3, 4, and 5, Black & Veatch developed detailed an Organizational Cost Model based upon the detailed implementation plans, which are discussed in Sections 7 and 10 of this report.

The Organizational Cost Model (note: a copy of this model is provided on the AEA web site) is an Excel-based workbook that summarizes a 30-year pro forma projection of the benefits and costs related to the formation of a new regional G&T entity. Its purpose is to: 1) document the detailed organizational cost assumptions, 2) detail the estimated Implementation Plan labor costs, 3) detail the estimated personnel requirements and total personnel costs, 4) summarize Strategist™ results, and 5) detail the estimated organizational operating costs for all Organizational Path under each Evaluation Scenario.

The following graphic shows the basic dataflow within the Organizational Cost Model, which consists of the following worksheets:

1. Organizational Assumptions Worksheet – this worksheet details the assumptions and non-labor costs for the new regional entity under each Path.
2. Start-up Labor Worksheets (Paths 2, 3, 4, and 5) – these worksheets detail the Implementation Plan and estimated level of effort for each activity for each Organizational Path.
3. Personnel Worksheet – this worksheet outlines the estimated required personnel (on a full-time equivalent basis) by position for the new regional entity under each Organizational Path and the total salary dollars required (note: salary figures for each position are not shown due to the confidential nature of this information).
4. Summary Scenario Worksheets (Scenarios A, B, C, and D) – these worksheets summarize the results of the production costs worksheets and the operating costs worksheets for each Evaluation Scenario. Each scenario worksheet contains the production and operating costs for each Organizational Path under the specific Evaluation Scenario, including the sensitivity analysis for taxable debt financing.
5. Production Costs Worksheets (Scenarios A, B, C, and D) – these worksheets summarize the 30-year pro forma results of the Strategist™ production cost model for each Evaluation Scenario and shows the net present value.
6. Operating Costs Worksheets (Paths 2, 3, 4, and 5) – these worksheets generate the 30-year pro forma costs from the single year costs in the Personnel, Start-up Labor and Organizational Assumptions Worksheets. Each worksheet summarizes the start-up and operating costs for each Organizational Path and shows the net present value.

Figure 10 - Organizational Cost Model



Report Outline

The remainder of this report contains the following sections:

Section 3 – Situational Assessment

This section provides an overview of the various issues currently facing the Railbelt utilities.

Section 4 – Organizational Paths and Evaluation Scenarios

In this section, we provide descriptions of the alternative Organizational Paths and Evaluation Scenarios that were analyzed during the course of this project.

Section 5 – Existing and Future Resource Options

This section includes a detailed summary of the generation and transmission assets that currently exist in the Railbelt region. We also provide information regarding future resource options that are available to meet the electric demand of residential and business customers in the Railbelt region.

Section 6 – Organizational Issues

This section provides an overview of the various organizational issues that are related to the formation of a new regional entity, including scope of responsibilities, tax and legal issues, regulatory oversight issues, required legislative actions, and so forth.

Section 7 – Summary of Assumptions

In this section, we provide an overview of the input assumptions that underlie our detailed analysis. These assumptions relate to existing generation and transmission assets, future generation and transmission resources, organizational formation and ongoing operations.

Section 8 – Summary of Results

This section provides a summary of the results of our detailed economic analysis, including generation and transmission costs, organizational costs, and net benefits.

Section 9 – Conclusions and Recommendations

In this section, we provide a summary of our conclusions arising from the results of this study and a detailed description of our recommendations regarding the reconfiguration of the Railbelt utilities.

Section 10 – Implementation Plan

In this final section of the report, we provide a detailed plan for the implementation of the recommended regional organizational structure.

This report also contains the following appendices:

Appendix A - Non-Utility Stakeholder Input Survey Instrument

This appendix provides the survey instrument that was sent to non-utility stakeholders to solicit input on the issues facing the Railbelt region.

Appendix B - Profiles of Example Regional Organizations

This appendix includes summary descriptions of some of the State and Federal Power Authorities, G&T Cooperatives, JAAs, and centralized energy efficiency organizations that exist throughout the country.

Appendix C – Scenario A Results

This appendix provides tables that summarize the results of Scenario A.

Appendix D – Scenario B Results

This appendix provides tables that summarize the results of Scenario B.

Appendix E – Scenario C Results

This appendix provides tables that summarize the results of Scenario C.

Appendix F – Scenario D Results

This appendix provides tables that summarize the results of Scenario D.

Appendix G – Tax-Exempt Bond Financing Options for Construction of a New Electric Generation and Transmission Facility to Serve the Railbelt

This appendix provides a detailed description of the issues associated with issuing tax-exempt debt and related strategies for dealing with these issues.

Appendix H – Bibliography

This appendix provides a listing of the reference documents that were reviewed as part of this study.

Appendix I – Public Comments Received on Draft Report

This appendix provides the public comments that were received on the Draft Report. Black & Veatch reviewed these comments and made numerous changes when finalizing this report to reflect those comments as appropriate.

SECTION 3 - SITUATIONAL ASSESSMENT

This section begins with an overview of the key issues facing the U.S. electric utility industry. This is followed by a discussion of current situation facing the Railbelt region.

U.S. Electric Industry Issues

The electric utility industry throughout the U.S. is facing a number of critical issues as shown in the sidebar on the right. These issues were identified as the result of a national survey of industry participants that was conducted by Black & Veatch in 2007.

"Big Ten Strategic Issues Facing the Power Industry

- *Aging/Inadequate Infrastructure*
- *Aging Workforce*
- *Security*
- *Reliability*
- *Environment*
- *Investment*
- *Technology*
- *Fuel Policy*
- *Market Structure*
- *Regulation*

"2007 Strategic Directions in the Electric Utility Industry," published by Black & Veatch Corporation, 2007

- **Aging/inadequate infrastructure** – like other industries, existing generation and transmission assets are deteriorating and, in many ways, are inadequate for today's and tomorrow's industry structure. Older assets also operate less efficiently than newer technologies.
- **Aging workforce** – the "baby boomers" are retiring in record numbers and there are not an adequate number of younger employees entering the industry to fully compensate for the resulting loss of skills and expertise.
- **Security** – from cyber attacks to terrorism, adequately protecting the industry's assets from intentional harm is an increasing challenge.
- **Reliability** – the reliability of the delivery of electricity has declined at the same time that the need for greater reliability has increased.
- **Environment** – the electric industry and the environment are, in many ways, two sides of the same coin and changing environmental regulations will continue to challenge the industry.
- **Investment** – significant investments are required in all aspects of the industry to "catch up" from past investment levels and to enable the industry to continue its movement to greater competition.
- **Technology** – technological developments present challenges in term of electricity demand as well as offer promising opportunities for the industry to address the challenges facing it.
- **Fuel policy** - developing a comprehensive fuel policy that takes new risks into account has become a major challenge for power producers and their customers.
- **Market structure** - the repeal of the Public Utility Holding Company Act, the creation of new types of companies in restructured markets, and the creation of new market structures have fundamentally changed, and will continue to change, the "rules of the game."
- **Regulation** - even after a decade of trying, regulators still need to develop firm boundaries between regulated and unregulated pricing, provide incentives that would cause electricity suppliers to act efficiently and on behalf of consumers, and signals that would bring in needed investment capital.

"The key issues facing the Railbelt electric utilities fall into four primary topics or categories: aging generation, heavy reliance on a single fuel source, a delicate transmission system, and conflicting interests of local utilities."

Native Corporation Representative

"The key issues of concern in the Railbelt electric utility market are easy to define and have been recognized for many years. To date, however, attempts to resolve those issues have been unsuccessful. Industry-driven progress in addressing these issues requires a champion with a clear vision for the future and the skills capable of rallying the forces of change necessary to re-shape the system."

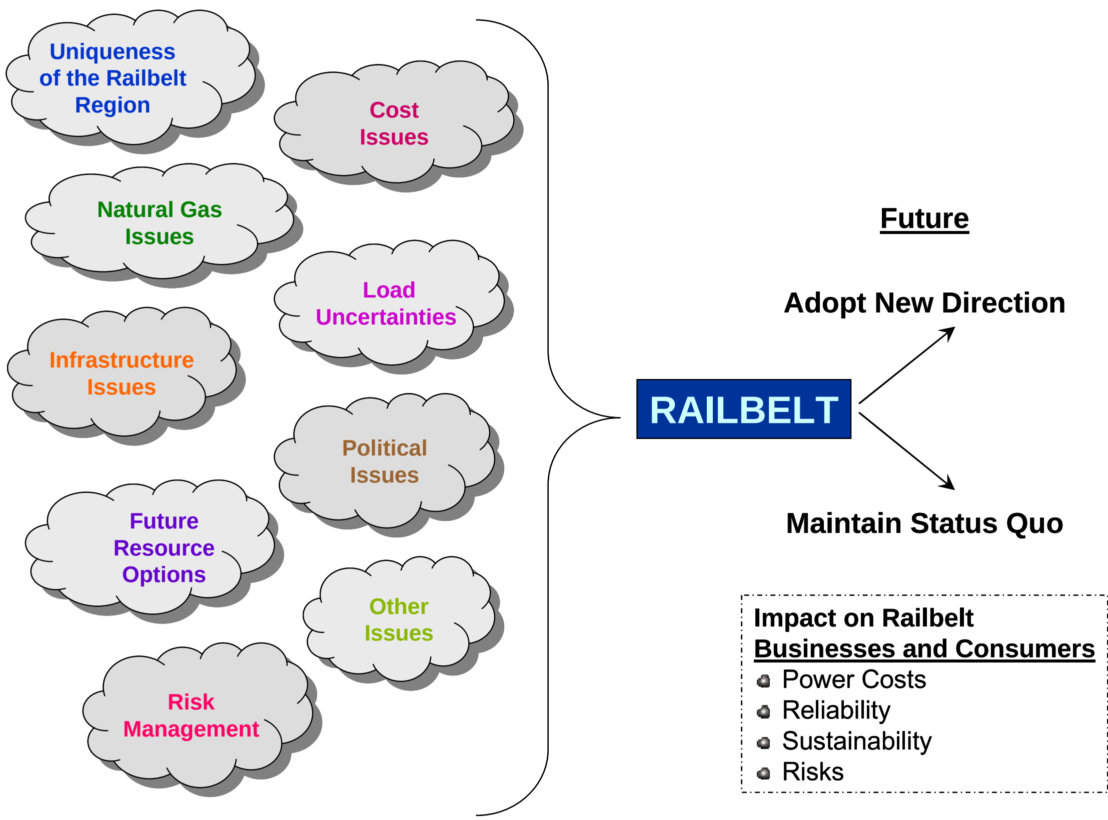
Native Corporation Representative

The current situation facing the Railbelt utilities is the result of thousands of historic decisions, resulting in the electric systems as they exist today, as well as a number of factors (e.g., rising natural gas prices) that are outside of the control of utility managers. We received significant comments related to the current issues facing the Railbelt region from not only the utilities themselves but also from the numerous non-utility stakeholders who met with the Black & Veatch project team or responded to our non-utility stakeholder input survey instrument. The information below regarding these issues are based, in part, on the utility and non-utility stakeholder comments we received.

Railbelt Issues

As shown in the following graphic, the Railbelt utilities are facing many of these same issues, as well as a number of additional issues that are specific to the Railbelt region.

Figure 11 - Summary of Issues Facing the Railbelt Region



Each of these issue categories is discussed below.

Uniqueness of the Railbelt Region

In comparison to the business and operating environment of the utility industry in the U.S., the Railbelt region is unique. The following presents a summary of the more significant issues that cause the uniqueness of the Railbelt region:

Issue	Description
Size and Geographic Expanse	First, the overall size of the Railbelt region is small when compared to other utilities or areas. The total peak load of all six utilities is approximately 875 MW. When compared to the peak loads of other utilities throughout the U.S., a combined “Railbelt utility” would still be relatively small. As an example, many electric utilities have single coal or nuclear plants that exceed 900 MW of capacity (based on Energy Information Administration, EIA, plant data, there are 100 generating units in the U.S. with nameplate capacity greater than 900 MW). This relative size, coupled with the geographic expanse and diversity of the Railbelt region, creates certain issues and affects the solutions available to the Railbelt utilities. There are, however, other municipal and cooperative utilities that face the same challenges of size and geographic diversity, and thus can provide directional guidance for the Railbelt regional solution.
Limited Interconnections and Redundancies	The Railbelt electric transmission grid has been described as a long straw, as opposed to the integrated, interconnected, and redundant grid that is in place throughout the lower-48 states. This characterization reflects the fact that the Railbelt electric transmission grid is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies. As a result of the lack of redundancies and interconnections with other regions, each Railbelt utility is required to maintain much higher generation reserve margins than elsewhere in order to ensure reliability in the case of a transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region.
State Versus Federal Regulation	Similar to utilities in most other regions of the country, the Railbelt utilities are under the regulatory oversight of a state regulatory agency, the RCA. However, unlike most other regions of the country, the Railbelt utilities are not under the oversight of the FERC.

Cost Issues

The following issues relate to the current cost structure of the Railbelt utilities.

Issue	Description
Relative Costs – Railbelt Region Versus Other States	Alaska has the seventh highest cost of any state based on the total cost per kWh, as shown in Table 12. Alaska's average retail rate was 12.8 cents per kWh; in comparison, Hawaii was the highest ranked state at 20.7 cents per kWh and Idaho was the lowest at 4.9 cents per kWh.
Relative Costs – Among Railbelt Utilities	ML&P's customers pay the lowest monthly electric bills in the region; GVEA's residential customers pay the highest monthly bills. Chugach, MEA, Seward and Homer are in the middle. Table 13 provides a comparison of the monthly electric bills paid by the residential, small commercial and large commercial customers of each of the six Railbelt utilities. Monthly bills are shown for residential customers assuming average monthly usage of 750 kWh based upon the rates of each Railbelt utility. Also shown are the monthly bills paid by small commercial (10,000 kWh average monthly usage) and large commercial (150,000 kWh average monthly usage) customers.
Economies of Scale and Scope	The Railbelt utilities have not been able to take full advantage of economies of scale and scope. With respect to scale economies, there are several reasons that the region has been limited by scale constraints. First, as previously noted, the combined peak load of the six Railbelt utilities is still relatively small. Second, the Railbelt transmission grid's lack of redundancies and interconnections with other regions has placed reliability-driven limits on the size of generation facilities that could be integrated into the Railbelt region. Third, the fact that each utility has developed their own long-term resource plans has led to less optimal results (from a regional perspective) relative to what could be accomplished through a rational, fully coordinated regional planning process. Finally, the existence of six separate utilities, and their small size on an individual utility basis, has restricted their ability to take advantage of economies of scale with regards to staffing and their skill sets. For example, the development of six separate programs to develop and deliver DSM and energy efficiency programs is a considerably more difficult challenge than would be the case if there was one Railbelt utility, or a combined regional entity, responsible for developing and delivering DSM and energy efficiency programs to residential and commercial customers throughout the Railbelt region. Scope economies arise when a single entity provides a range of different products and lowers per unit costs of all by spreading fixed costs over multiple product lines. Thus, scope economies exist for combination utilities providing multiple products and services including electricity, natural gas, security, internet, CATV, etc. Some municipal and cooperative utilities have expanded their service offerings to obtain scope economies.

Table 12 - Relative Cost per kWh (Alaska Versus Other States) 2006

Name	Average Retail Price (cents/kWh)	Name	Average Retail Price (cents/kWh)
Hawaii	20.72	North Carolina	7.53
Massachusetts	15.45	New Mexico	7.37
New York	15.27	Oklahoma	7.30
Connecticut	14.83	Alabama	7.07
Rhode Island	13.98	Illinois	7.07
New Hampshire	13.84	Iowa	7.01
Alaska	12.84	Arkansas	6.99
California	12.82	South Carolina	6.98
New Jersey	11.88	Minnesota	6.98
Maine	11.80	Tennessee	6.97
Vermont	11.37	Montana	6.91
District of Columbia	11.08	Kansas	6.89
Florida	10.45	Virginia	6.86
Texas	10.34	South Dakota	6.70
Delaware	10.13	Oregon	6.53
Maryland	9.95	Indiana	6.46
Nevada	9.63	Missouri	6.30
Pennsylvania	8.68	North Dakota	6.21
Mississippi	8.33	Washington	6.14
Louisiana	8.30	Nebraska	6.07
Arizona	8.24	Utah	5.99
Michigan	8.14	Kentucky	5.43
Wisconsin	8.13	Wyoming	5.27
Ohio	7.71	West Virginia	5.04
Georgia	7.63	Idaho	4.92
Colorado	7.61		

Source: Energy Information Administration, “State Electricity Profiles,” DOE/EIA-0348, November 2007.

Table 13 - Relative Monthly Electric Bills Among Alaska Railbelt Utilities

RESIDENTIAL	Fuel Adjustment	Regulatory Cost Charge	Energy Charge	Total Energy Charge	Customer Charge	Usage Factor (kWh)	Typical Bill	Railbelt vs. IOU Average	Railbelt vs. Cooperatives Average
GVEA	0.05903	0.000274	0.11153	0.170834	15	750	$143.13	173%	193%
Chugach	0.02478	0.000274	0.09282	0.117874	8.42	750	$96.83	117%	130%
MEA	0.03084	0.000274	0.09447	0.125584	5.65	750	$99.84	121%	134%
ML&P	-0.00655	0.000274	0.09476	0.088484	6.56	750	$72.92	88%	98%
Homer (North of Kachemak Bay)	0.00078	0.000274	0.12718	0.128234	11	750	$107.18	130%	144%
Homer (South of Kachemak Bay)	0.00078	0.000274	0.13056	0.131614	11	750	$109.71	133%	148%
City of Seward	NA	NA	NA	NA	NA	NA	NA	NA	NA
Average							**$104.93**		

SMALL COMMERCIAL	Fuel Adjustment	Regulatory Cost Charge	Energy Charge	Total Energy Charge	Customer Charge	Usage Factor (kWh)	Typical Bill	Railbelt vs. IOU Average
GVEA	0.05903	0.000274	0.10957	0.168874	20	10,000	$1,708.74	161%
Chugach	0.02478	0.000274	0.08001	0.105064	18.26	10,000	$1,068.90	100%
MEA	0.03084	0.000274	0.07677	0.107884	5.65	10,000	$1,084.49	102%
ML&P	-0.00655	0.000274	0.09182	0.085544	12.88	10,000	$868.32	82%
Homer (Non-demand metered)	0.00078	0.000274	0.1181	0.119154	24	10,000	$1,215.54	114%
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	10,000	$1,198.44	113%
City of Seward	NA	NA	NA	NA	NA	NA	NA	NA
Average							**$1,190.74**	

LARGE COMMERCIAL	Fuel Adjustment	Regulatory Cost Charge	Energy Charge	Total Energy Charge	Customer Charge	Demand Charge	Usage Factor (kWh)	Demand Usage (KW)	Typical Bill	Railbelt vs. IOU Average
GVEA	0.05903	0.000274	0.07835	0.137654	50	8.55	150,000	500	$24,973.10	175%
Chugach	0.02478	0.000274	0.0462	0.071254	58.85	11.65	150,000	500	$16,571.95	116%
MEA	0.03084	0.000274	0.06004	0.091154	13.37	4.85	150,000	500	$16,111.47	113%
ML&P	-0.00655	0.000274	0.05351	0.047234	44.15	11.85	150,000	500	$13,054.25	91%
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	6.73	150,000	500	$20,781.60	145%
City of Seward	NA	NA	NA	NA	NA	NA	NA	NA	NA	
Average									**$18,298.47**	

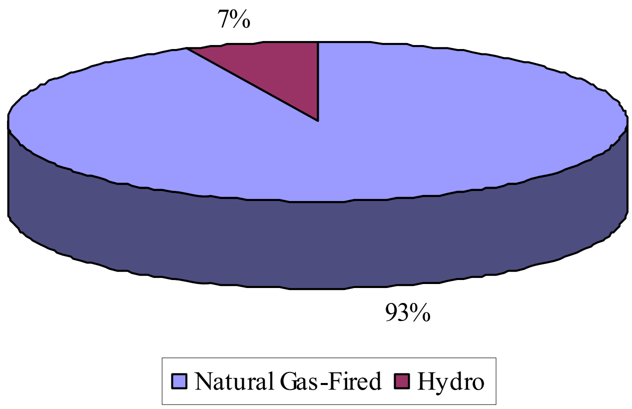
Natural Gas Issues

The Railbelt utilities use domestic natural gas as a significant generation fuel source and have done so for decades; the future ability of the Railbelt region to continue to rely on natural gas is in question.

Issue	Description
Historical Dependence	Natural gas has been the predominant source of fuel for electric generation used by the customers of ML&P, Chugach, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years. For example, Figure 12 shows the current dependence that Chugach (as well as MEA, Homer and Seward as a result of their full-requirements contracts with Chugach) has on natural gas-fired generation. ML&P has a similar level of dependence on natural gas.
Expiring Contracts	There are a number of inherent risks whenever a utility or region is so dependent upon one fuel source; risks with regard to prices, availability and deliverability. An additional risk faced by Chugach is the fact that its current gas supply contracts are expected to expire in the 2010-2012 timeframe, as shown in Figure 13. Chugach is currently working with its natural gas suppliers to renegotiate these contracts. Although those negotiations are have not been finalized, it is expected that future natural gas prices paid by Chugach will increase once the existing contracts expire.
Declining Developed Reserves and Deliverability	An additional problem faced by the Railbelt utilities, due to their dependence on natural gas, is the fact that existing developed reserves in the Cook Inlet are declining as well as the current deliverability of that gas. This is shown in Figure 14.

Issue	Description
	As can be seen in Figure 14, the population of the Anchorage, Mat-Su, and Kenai Peninsula areas has increased 170% since 1970. At the same time, known reserves in the Cook Inlet have declined by 80%. As a result, one prediction is that gas supplies from known reserves will meet less than one-half of the residential and commercial demand for heating and electricity by 2017. This will have a significant impact on all Railbelt utilities, including ML&P as its owned gas supply is experiencing the same dynamics. The predicted future supply versus demand balance for Cook Inlet gas is further detailed in Figure 15. Related to the decline in reserves is the decline in deliverability. Historically, deliverability of natural gas to electric generation facilities, and to residential and commercial customers in the Railbelt region for heating, was not a problem. However, deliverability is increasingly becoming an issue as the Cook Inlet gas fields age, reserves decline, and pressures drop. Consequently, the Railbelt region will not be able to continue its dependence upon natural gas in the future unless additional reserves are discovered in the Cook Inlet, new sources of supply become available from the North Slope, or an liquefied natural gas (LNG) import terminal is developed to supplement Cook Inlet supplies.
Historical Increase in Gas Prices	Railbelt residential and commercial customers are directly feeling the rise in natural gas prices that have occurred in recent years. These price increases are shown in Figure 16, which shows historical gas prices paid by Chugach. Figure 17 shows the resulting rise in Chugach's residential bills from 1994 to 2007. As can be seen, the fuel component of the customer's bill has increased significantly in recent years while the base rate component has remained roughly the same until the last year or so. With natural gas prices expected to continue increasing, Railbelt consumers and businesses will experience even greater electric prices in the future. Figure 18 provides additional details regarding how recent Cook Inlet gas prices compare to gas prices in other parts of the country. As can be seen, Cook Inlet prices are not as high as the national average but they have increased significantly in recent years and they are expected to continue to increase.
Potential Gas Supplies and Prices	Whether new gas supplies from the Cook Inlet become available or gas from the North Slope is brought to the Railbelt region, one reality can not be escaped: future gas supply prices will be higher. For additional gas supplies in the Cook Inlet to become available, prices will need to increase to encourage exploration. This results from the fact that oil and gas producers make investment decisions based upon expected returns relative to investment opportunities available elsewhere in the world. In the case of North Slope gas supplies, the cost, probability and timing of potential gas flows to the Railbelt region are unknown at this time. Nevertheless, given the construction lead times for a potential gas pipeline to provide gas from the North Slope, gas from that region is unlikely to be available for a number of years. Furthermore, if gas from the North Slope becomes available in the Railbelt region through either the Bullet or Spur Line, prices will be tied to market prices since potential natural gas flows to the Railbelt region will be just one of the competing demands for the available gas. Additionally, the pipeline transmission rates that will be paid to move gas to the Railbelt region will be significantly higher than the transportation rates that are imbedded in the delivered cost of gas from Cook Inlet suppliers under existing contracts.

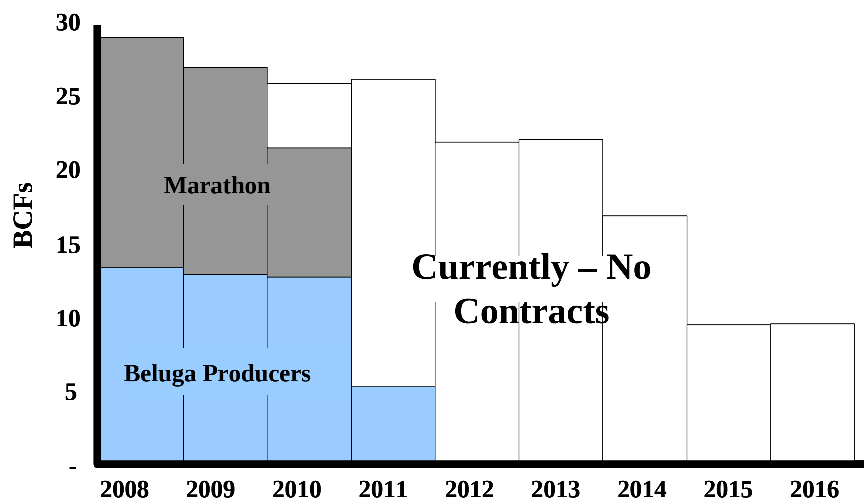
Figure 12 - Chugach's Reliance on Natural Gas



Total Power Produced in 2007: 2,628 gWh

Source: Chugach Electric Association.

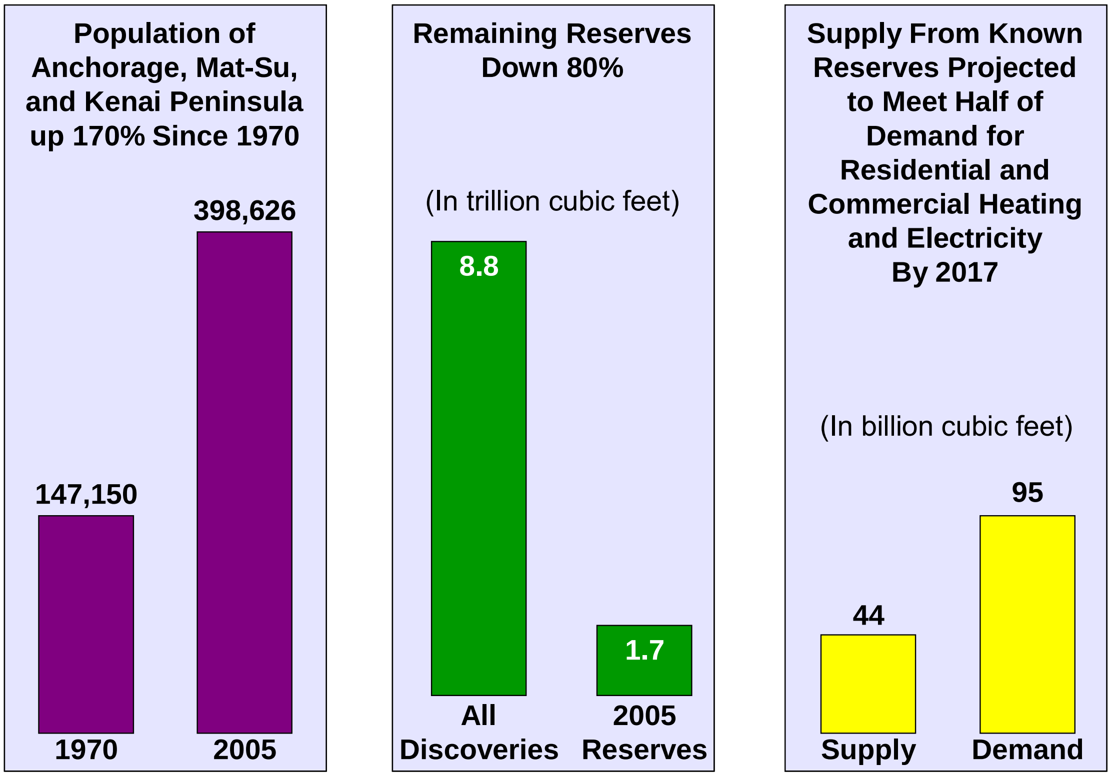
Figure 13 - Chugach's Gas Supply Outlook



Source: Chugach Electric Association.

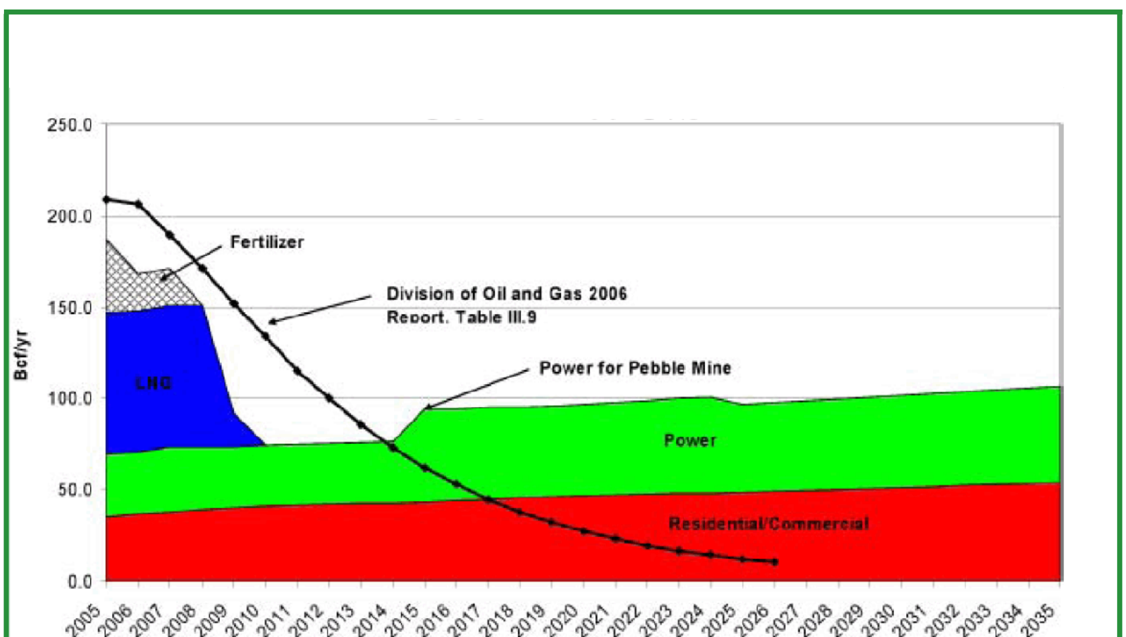
SECTION 3 - SITUATIONAL ASSESSMENT

Figure 14 - Overview of Cook Inlet Gas Situation



Source: Alaska Department of Labor, Alaska Division of Oil and Gas, and Science Applications International Corporation.

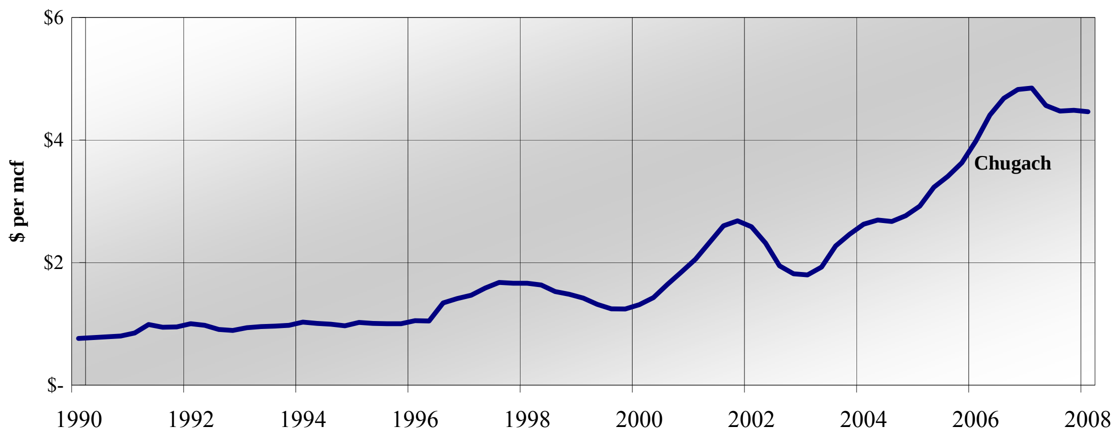
Figure 15 - Projected Supply and Demand for Cook Inlet Gas



Source: NETL/DOE Study (2006) and Division of Oil and Gas (2006)

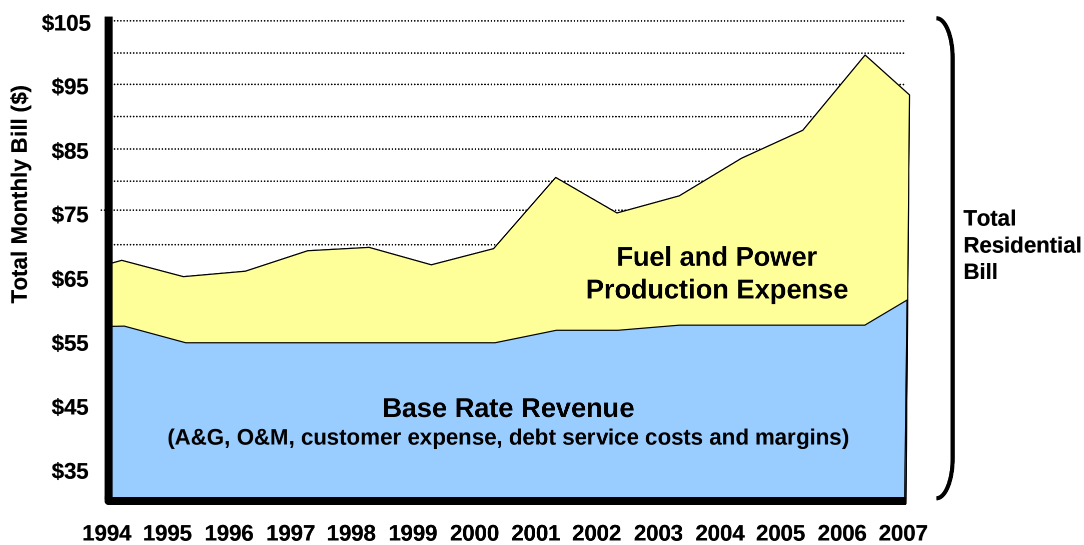
Note: the line in the graphic above depicts projected supplies and the colored sections depict projected demands.

Figure 16 - Historical Chugach Natural Gas Prices Paid



Source: Chugach Electric Association.

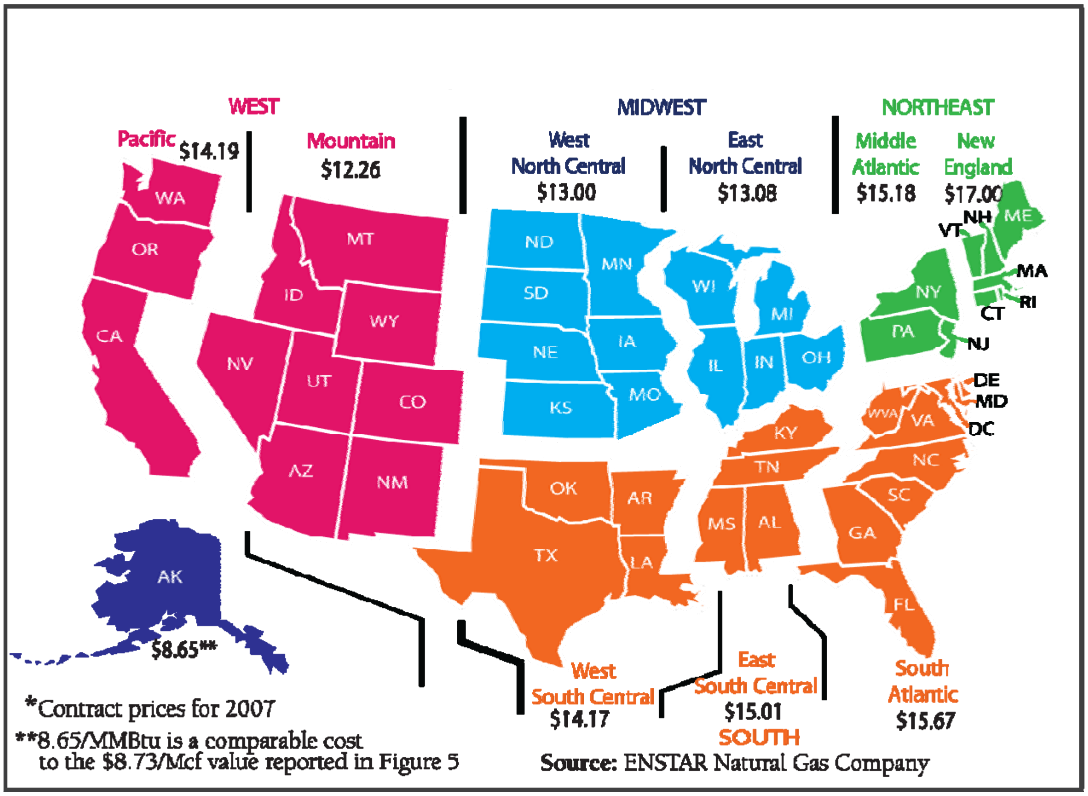
Figure 17 - Chugach Residential Bills Based on 700 kWh Consumption 1994 – 2007



* 1993 Residential Bill, adjusted for inflation. Source: US Dept. of Labor, Bureau of Labor Statistics (BLS), CPI-U, Anchorage.

Source: Chugach Electric Association.

Figure 18 - Prices of Natural Gas for Residential Customers (per Million Btu) - 2007



Load Uncertainties

Load uncertainties are always an issue of concern for electric utilities as they make investment decisions regarding which generation resources to add to their system.

Issue	Description
Stable Native Growth	With regard to native load growth (e.g., normal load growth resulting from residential and commercial customers), Railbelt utilities have experienced stable growth in recent years. This stable native load growth is expected to continue in the years ahead, absent significant economic development gains in the region.
Potential Major New Loads	There are, however, a number of potential significant load additions that could result from economic development efforts. These potential load additions could result from the development of new, or expansion of existing, mines (e.g., Pebble and Donlin Creek), continued military base realignment, and other economic development efforts. Additionally, there will likely be a significant increase in Railbelt population if the North Slope natural gas pipeline, and related Spur or Bullet Line, is built. Any significant growth in Railbelt electric loads will lead to increased stress on the ability of the region's utilities to meet demand, particularly if this demand has to be met by one utility. This is particularly true given the fact that a significant portion of the Railbelt's electric generation facilities are approaching their planned retirement dates. This is further discussed below.

Infrastructure Issues

The challenges faced by the Railbelt utilities are magnified by the aging nature of existing generation facilities in the region.

Issue	Description
Aging Generation Infrastructure	Approximately 48 percent of the existing generation capability within the Railbelt region is scheduled to be retired within 15 years. During this period, decisions relative to retirement, refurbishment, and life extension must be made. Replacing this capacity with more efficient capacity requires substantial new capital investment, offset by the lower cost of generation when plants incorporate lower fuel cost resources, such as coal.
Baseload Usage of Inefficient Generation Facilities	Another issue that is directly related to the aging nature of the existing Railbelt generation fleet is the fact that certain older, inefficient generation units are being used as baseload, or near-baseload, generation facilities, raising regional operating costs. Since the cost of energy production is a combination of fuel cost and heat rate, the combination of rising energy costs and more production from high heat rate units causes larger increases in the cost of energy. A simple example illustrates the compound nature of the problem. At a heat rate of 10,000 BTU/kWh and a gas cost of six dollars per Mcf, a kilowatt-hour costs six cents to produce. If the heat rate increases to 15,000BTU/kWh, that same kilowatt-hour now costs nine cents. As more high heat rate units operate more hours, the average cost of power increases even without a fuel cost increase. In addition, it is typical that as generation units mature past the mid-point of their average life there is a strong likelihood that heat rates will rise the further their age goes beyond the mid-point of expected life.
Operating and Spinning Reserve Requirements	Railbelt reliability procedures require spinning reserves equal to the largest operating unit and an operating reserve level of an additional 50% of the largest unit. In addition, the region's system target reserve margin is set at 30%. These reserve levels reflect the absence of interconnections, the relative operating impacts of limited resources and the necessity of maintaining reliability with the existing size of the system. Such high reserve margins affect total fuel and maintenance costs.

Future Resource Options

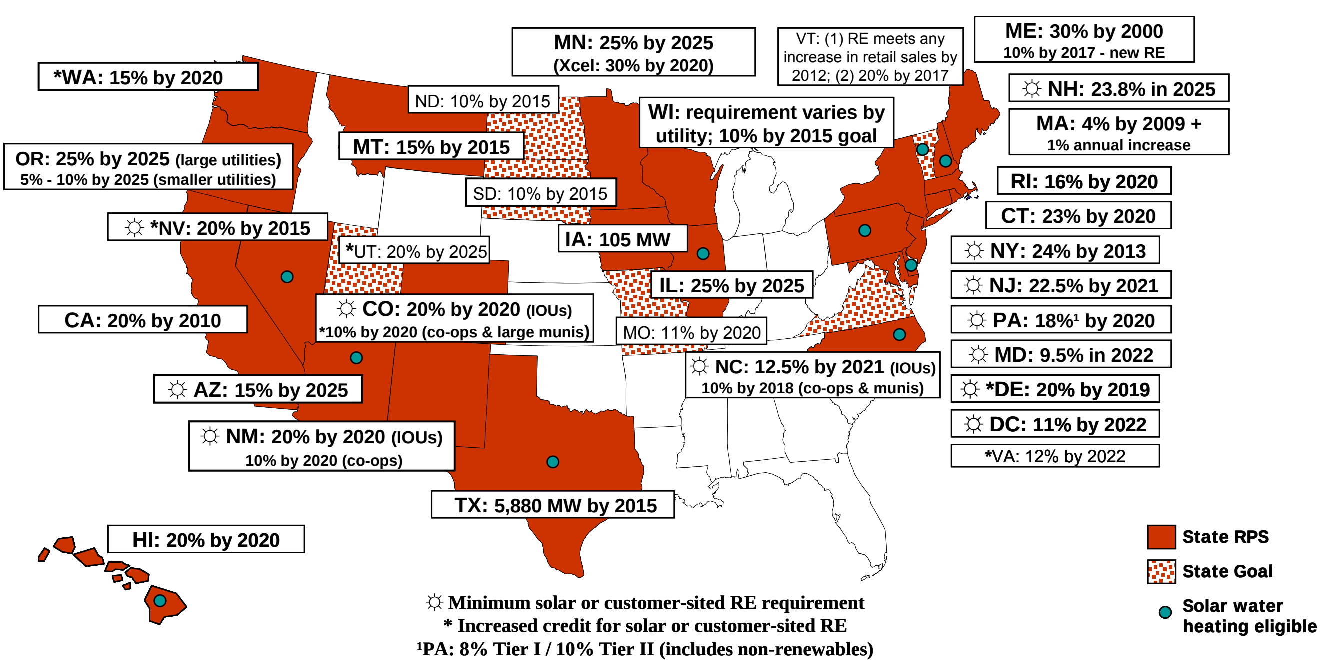
There are several issues regarding the future resource options that will be available to meet demand within the Railbelt region.

Issue	Description
Acceptability of Large Hydro and Coal	Much discussion has occurred in recent years about the future role that large hydroelectric and coal projects might play in meeting the electricity needs of the Railbelt region. Like other parts of the country and the world, the acceptability and economics of large hydroelectric and coal facilities are uncertain. As might be expected, we received different comments from various utility and non-utility stakeholders regarding the acceptability of these technologies. Resolving the acceptability issues, and other related economic and environmental issues, associated with large hydro and coal will require the active involvement of the Governor and Legislature, as well as the Railbelt utilities and other stakeholders.
Carbon Tax and Other Environmental Restrictions	Another uncertainty facing the Railbelt utilities relates to the restrictions on carbon emissions, and the related economic impact, that might be imposed by Federal and/or State legislation, as well as other environmental restrictions (e.g., mercury limits) that will impact the technical and economic feasibility of various generation technologies. In the case of the imposition of carbon taxes, there are a number of competing bills currently working their way through the Federal legislative process. These bills each have different targets for the reduction of carbon emissions, and each will result in different levels of carbon taxes and/or different costs for the capturing and sequestering of carbon emissions. Depending upon the form of Federal and/or State carbon legislation ultimately

Issue	Description
	enacted, the economics of fossil-fueled generation technologies could be significantly impacted.
Optimal Size and Location of New Generation and Transmission Facilities	Given the need to replace existing generation facilities and meet expected load growth, significant investments in new generation resources will be required. A very important issue that needs to be addressed by the Railbelt utilities is the optimal size and location of new generation and transmission facilities. This is, in fact, one of the factors driving the interest in the formation of a regional generation and transmission entity. When individual utilities make resource decisions that optimize the future resource mix for their own needs, the resulting regional resource mix will simply not be as optimal relative to the resource mix that would result from a regional planning process. Additionally, decisions that will be made with regard to improving and expanding the Railbelt electric transmission grid will have a direct bearing of determining the optimal size and location of future generation resources. The economics of new generation and its location includes the investment in transmission to deliver the generation to remote load centers. Further, optimal decisions require analysis of both generation and transmission costs across the interconnected grid.
Limited Development – Renewables	Renewable generation technologies represent a significant opportunity for the Railbelt utilities relative to replacing aging generation facilities and meeting future load growth. To date, the Railbelt utilities have developed renewable resource technologies to a very limited degree, relative to the technical potential of these resources as well as relative to the level of deployment of these technologies in other regions of the country. While this limited use of renewable resources may reflect the challenges of integrating such resources into a transmission constrained grid and managing the power fluctuations on an individual utility basis, enhanced transmission infrastructure and regional coordination may create additional opportunities for renewables as part of the portfolio of resources. The issue of integrating technologies having variable outputs, such as wind and solar, into a fossil-fueled grid presents substantial operational challenges including the determination of the optimal level of these resources. As evidence of the growing reliance on renewable resources throughout the country, Figure 19 shows those states that have adopted a Renewables Portfolio Standard (RPS). Typically, these programs call for renewables to represent a certain percentage of the overall resource mix of an individual utility or region by a certain point in time. It is important to note that these renewable resource standards raise the cost of power because the technologies used cost more than conventional generation. Given the high cost of power and absence of scale economies, any decision to mandate an RPS will likely increase power costs further for customers in the Railbelt region absent contributions from the State to buy down the costs of these resources. An important issue related to the implementation of renewable resources that needs to be addressed is whether the development of renewable resources should be accomplished by the individual Railbelt utilities or whether a regional approach would result in the more efficient and cost-effective deployment of these resources.
Limited Development – DSM/Energy Efficiency Programs	Similar to the comments above related to renewable resource technologies, the Railbelt utilities have limited experience with the planning, developing and delivering of DSM and energy efficiency programs. To date, the majority of efforts in the Railbelt region and the State as a whole have been focused on the implementation of home weatherization programs. These programs can significantly reduce the energy consumption within individual homes; however, given the limited saturation of electric space heating equipment and the general lack of air conditioning loads, the potential for DSM and energy programs are limited from the perspective of the Railbelt electric utilities.

Issue	Description
	Notwithstanding this, additional opportunities do exist in this area. Utilities in other states have demonstrated the ability to deliver DSM and energy efficiency programs that have substantively reduced peak loads and saved energy. Table 14 shows the top ten states with regard to the cumulative impact of electric energy efficiency programs through 2003. For comparative purposes, figures for Alaska and the U.S. average are also shown. As can be seen, three states (Connecticut, California and Washington) have cumulative savings in excess of 7.0 percent of total annual retail sales. For these states, the combination of long-term programs of 25 or more years, substantial investment in programs targeted at electric loads, and substantial benefits from large-scale programs targeted at significant end-use technologies such as space conditioning, provided opportunities for larger statewide savings. Alaska ranked 43rd based upon the results of this study. An implementation issue that needs to be addressed is whether the development and deployment of DSM and energy efficiency programs throughout the Railbelt region should be accomplished by the individual Railbelt utilities or whether a regional approach would result in more efficient and cost-effective deployment of these resources. Additionally, given the fact that the total monthly energy bills paid by residential and commercial customers in the Railbelt have increased significantly in recent years and given that natural gas is the predominant form of space heating within the majority of the Railbelt region, it may be appropriate for the electric utilities to work jointly with Enstar to develop DSM and energy efficiency programs that would be beneficial to both. This would create economies of scope for the region and reduces the delivery costs of DSM and energy efficiency programs.

Figure 19 - Established Renewables Portfolio Standards



Source: Database of State Incentives for Renewables & Efficiency (DSIRE)

Table 14 - Cumulative Impacts of Electric Efficiency Programs as a Percentage of Total Retail Sales 2003

Rank	State	Cumulative Annual Energy Savings as a Percentage of Annual Total Retail Sales
1	Connecticut	7.8%
2	California	7.5%
3	Washington	7.2%
4	Minnesota	6.7%
5	Rhode Island	6.2%
6	Oregon	6.0%
7	Massachusetts	5.8%
8	Vermont	4.8%
9	Wisconsin	4.4%
10	Montana	3.9%
43	Alaska	0.1%
	U.S. Average	**1.9%**

"Source: ACEEE's 3rd National Scorecard on Utility and Public Benefit Energy Efficiency Programs: A National Review and Update of State-Level Activity," Report U054, October 2005, pages 8 and 18.

Political Issues

The following political issues impact the current situation in the Railbelt region.

Issue	Description
Historical Dependence on State Funding	The Railbelt utilities have been dependent upon State funding for certain portions of the regional generation and transmission infrastructure, as well as for certain local infrastructure investments. Some of these investments have been made through the Railbelt Energy Fund; others have been direct appropriations by the Legislature. Regional State-funded infrastructure investments include the Alaska Intertie and Bradley Lake Hydroelectric Plant.
Proper Role for State	Historical State infrastructure-related investments have provided significant benefits to the residential and commercial customers in the Railbelt. Going forward, one question that needs to be answered is what the proper role of the State should be relative to the further development of the Railbelt region's generation and transmission infrastructure.

Risk Management

The following issues relate to risk management, which has become increasingly important for all utilities.

Issue	Description
Need to Maintain Flexibility	As previously discussed, the recent increase in natural gas prices highlights the dangers inherent with an over-reliance on one fuel source or generation technology. Just as investors rely on a portfolio of assets, it is important for utilities to develop a portfolio of assets to insure safe, reliable and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility.

Issue	Description
	In this context, maintaining flexibility has three dimensions. First, it is important to maintain organizational flexibility. In other words, the choice of a regional entity should be done in a manner that doesn't needlessly lock the region into one structure that cannot be modified, if necessary, to respond to future circumstances. The second dimension of flexibility relates to future generation resources and fuel supplies. A regional entity should be formed only if it is likely to enhance the region's ability to maintain and improve the region's resource asset portfolio flexibility. The third dimension of flexibility relates to the ability to adjust to changing State and Federal policies, whether they are related to a State Energy Plan, carbon emissions, support of the North Slope gas pipeline and the related Bullet or Spur Lines, and so forth. Resource decisions being made by utility managers are increasingly driven or influenced by energy policy makers. Again, if a regional entity is to be formed, it should enable the region to better maintain flexibility in the face of increasing energy policy uncertainties. In developing a State Energy Plan, it is important to bear in mind the issue of unintended consequences that haunts many well meaning policy initiatives. Reliance on both industry expertise and experience becomes a critical element for developing sound plans. One additional issue that needs to be addressed is how MEA and CEA will meet their loads once their power supply contracts with CEA expire.
Future Fuel Diversity	Fuel supply diversity inherently has value in terms of risk management. Simply stated, the greater a region's dependence upon one fuel source, the less flexibility the region will have to react to future price and availability problems. The abundance of local coal reserves, provides one source of fuel diversity and should be considered as an option to natural gas.
Aging Infrastructure	The fact that the generation and transmission infrastructure in the Railbelt region is aging, and that a significant percentage of the region's generation units are approaching the end of their expected lives, adds to the challenges facing utility managers. That represents the "half empty" view of the situation. The "half full" views leads one to a more positive perspective that the region has an unprecedented opportunity to diversify its resource mix and improve the overall efficiency of its generation fleet. To seize the opportunity, it must be recognized that generation and transmission projects have significant lead times and the process must start now rather than later. In addition, the State should develop policies designed to eliminate unreasonable barriers to the siting and construction of utility infrastructure.
Ability to Spread Regional Risks	The level of uncertainty facing the Railbelt region continues to grow, as do the risks attendant to utility operations. One important approach to risk management is to spread the risk to a greater base of investors and consumers so that the impact of those risks on individuals is reduced. Simply stated, the ability of the region to absorb the risks facing it is greater on a regional basis than it is on an individual utility basis.

Other Issues

There are some other important issues facing the Railbelt, including the following:

Issue	Description
Aging Workforce and Ability to Attract Skilled Employees	As noted earlier, the Railbelt utilities are faced with the realities of an aging workforce as are all utilities throughout the nation. There is simply not enough skilled labor and management talent entering the electric utility industry to offset the significant percentage of utility employees that will retire within the next 5 to 10 years. This reality adds to the

Issue	Description
	importance of achieving economies of scale with regard to staffing and skill sets. It will become increasingly harder for the Railbelt utilities, on an individual basis, to attract and retain the necessary staffing levels and skill sets to effectively address the challenges ahead. This is particularly true with regard to the development of new technologies (e.g., renewable resources), increasing customer services (e.g., expansion of DSM and energy efficiency programs), and more sophisticated risk management (e.g., managing the risks associated with market-based natural gas prices).
Reliability	Historically, the Railbelt utilities have done a good job of maintaining reliable electric service. Maintaining future reliability requires planning for additional generation and transmission, and replacing aging infrastructure.
Proposed ML&P/Chugach Merger	ML&P and Chugach are exploring the potential benefits of merging, or increasing the level of joint operations and project development. At the time that this study was completed, no final decisions have been made by the Anchorage City Council or the Chugach Board of Directors. Certainly, a decision to merge or consolidate ML&P and Chugach operations could be viewed as a step towards the formation of a regional entity; it could also prove to be an impediment in that it could be viewed as a competing proposal to, or reducing the net incremental benefits associated with, the formation of a region-wide entity.
Sustainability	Increasing demands are being placed on utility managers to conduct operations in as sustainable of a manner as possible. The underlying notion of good stewardship is a characteristic that is second nature to most utility Board members, managers, and employees; this is even more true within not-for-profit cooperatives and municipal utilities. Nothwithstanding this, the need to incorporate sustainability concepts more fully in future planning and operational decisions is a challenge that must be met by the Railbelt utilities.

SECTION 4 - ORGANIZATIONAL PATHS AND EVALUATION SCENARIOS

In this section, we provide descriptions of the alternative Organizational Paths that were evaluated during the course of this project and a summary of the Evaluation Scenarios that were analyzed.

Describe Each Organizational Path Evaluated

The following graphic summarizes the various organizational options that were available for consideration as part of this study. This table is intended to be inclusive of the primary options; there are other less relevant options and variations of the options shown in the table.

Table 15 - Summary of Organizational Options

	Railbelt Utilities							
		Consolidated						
Functional Area	Current Structure	Public Entity(ies)	Investor-Owned	Voluntary Agreements	JAA/G&T Cooperative	RTO/ISO	State Agency	Other
Generation Infrastructure								
Planning	✓	✓	✓	✓	✓		✓	
Project Development	✓	✓	✓	✓	✓		✓	✓
Operations	✓	✓	✓	✓	✓			✓
Transmission Infrastructure								
Planning	✓	✓	✓	✓	✓	✓	✓	
Project Development	✓	✓	✓	✓	✓	✓	✓	
Operations	✓	✓	✓	✓	✓	✓	✓	✓
Economic Dispatch		✓	✓	✓	✓	✓	✓	
Distribution	✓	✓	✓					
Customer Services								
DSM/Energy Efficiency Programs	✓	✓	✓	✓	✓		✓	✓
Other Services	✓	✓	✓					✓
Competitive Procurement								
Power Supplies	✓	✓	✓	✓	✓			
Fuel Supplies	✓	✓	✓	✓	✓			
Other Products and Services	✓	✓	✓	✓	✓			
Market Development	✓	✓	✓		✓	✓	✓	

On the left-hand side of this table, we have shown the primary functional areas, or requirements, involved in the provision of electric service. These functional areas include:

- **Generation Infrastructure**
  - **Planning** – planning of future generation resources (both traditional and renewables).
  - **Project Development** – development of new generation facilities.
  - **Operations** – day-to-day operations of existing and future generation facilities.
- **Transmission Infrastructure**
  - **Planning** – planning of future transmission grid expansions.
  - **Project Development** – development of new transmission assets.
  - **Operations** – day-to-day operations of the transmission grid to meet reliability, security, congestion management, and ancillary services requirements.

- **Economic Dispatch** – centralized economic dispatch of all generation resources within the Railbelt region.
- **Distribution** – provision of distribution services to move power from the transmission grid to individual businesses and residences (note: this is outside of the scope of this project but is included here for completeness sake).
- **Customer Services**
  - **DSM/Energy Efficiency Programs** – the provision of DSM and energy efficiency programs to customers.
  - **Other Services -** provision of other customer services (e.g., metering and customer call centers) (note: again, this is outside of the scope of this project but is included here for completeness sake).
- **Competitive Procurement**
  - **Power Supplies** – competitive solicitation of power supplies, either on an individual utility or regional basis.
  - **Fuel Supplies** – regional, competitive procurement of fuel supplies.
  - **Other Products and Services** – competitive procurement of other required products and services (e.g., procurement of power poles).
- **Market Development** – development and operation of a competitive power market.

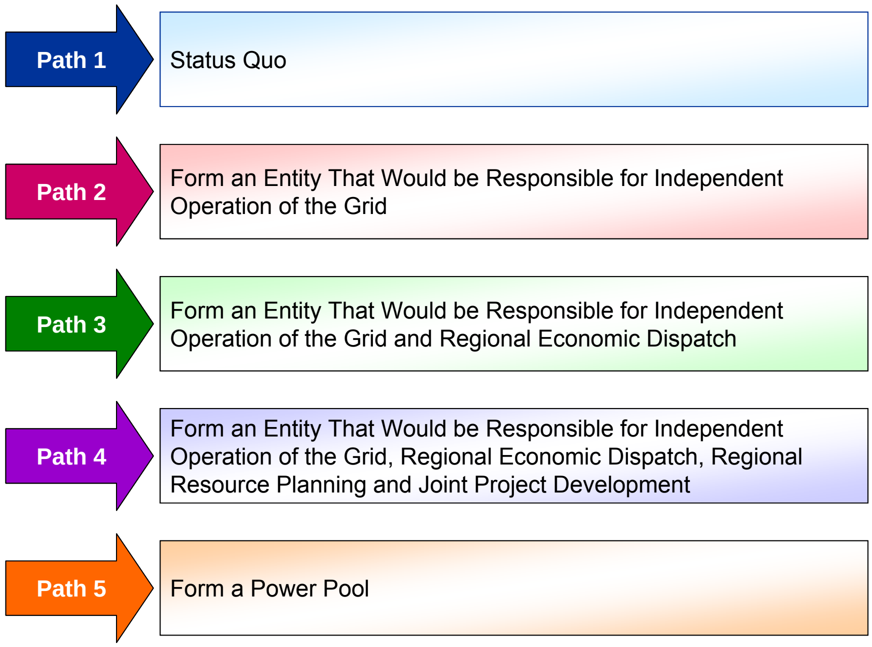
Going across the table, we show a number of potential organizational options for the provision of the functional requirements of electric service. These include:

- **Railbelt Utilities**
  - **Current Structure** – this represents the continuation of the current utility structure and functional operations provided by the Railbelt utilities.
  - **Consolidated Options** – these columns represent for-profit and not-for-profit consolidated organizational structures for the Railbelt utilities.
    - **Public Entity(ies)** – this organizational option involves the consolidation of the existing six utilities into one or more public utilities.
    - **IOU -** this option involves the consolidation of the existing six utilities into an IOU.
- **Voluntary Agreements** – this option involves maintaining the existing utility structure within the Railbelt region but entering into additional cooperative agreements.
- **JAA/G&T** – this option consists of the formation of a new JAA or G&T Cooperative.
- **RTO/ISO** – this option consists of the formation of a RTO or ISO.
- **State Agency** – this option involves expanding the responsibilities of an existing, or the formation of a new, State agency.
- **Other** – this includes other entities (e.g., independent power producers).

The check marks shown in the table indicate that the organizational option provides the specified functional requirements involved in the provision of electric service.

The task then became to determine which organizational options to evaluate further in detail. Based upon input from the Advisory Working Group, five organizational structures (herein referred to as Organizational Paths) were chosen for detailed evaluation. These chosen Paths are shown in the following graphic and discussed below.

Figure 20 - Summary of Organizational Paths Evaluated



It should be noted that the following descriptions of Organizational Paths 2, 3, 4, and 5 are focused on the functional responsibilities of a new regional entity. In each case, the new reginal entity could be a JAA, G&T Cooperative, or State Agency/Corporation.

- **Path 1 – Status Quo**
  This Path assumes that the six Railbelt utilities continue to conduct business essentially in the same manner as now (i.e., six separate utilities with limited coordination and bilateral contracts between them), and it does not include the potential impact of the proposed ML&P/Chugach merger. This is, in essence, the "Base Case" and the other Paths will be compared to this Path for each of the Evaluation Scenarios considered.
- **Path 2 – Form an Entity That Would be Responsible for Independent Operation of the Grid**
  Under this Path, a new entity would be formed to independently operate the Railbelt electric transmission grid. Currently, the Railbelt utilities have three control centers (GVEA, Chugach and ML&P). The operations of these centers are coordinated (but generation is not fully economically dispatched on a regional basis) through the Intertie Operating Committee. This new entity would not perform regional economic dispatch, just the independent operation of the Railbelt transmission grid.
- **Path 3 – Form an Entity That Would be Responsible for Independent Operation of the Grid and Regional Economic Dispatch**
  This Path would expand upon this coordination through the formation of an organization that would be responsible for the joint economic dispatching of all generation facilities in the Railbelt. This Path, as well as the following two Paths, will require some additional investment in transmission transfer capability and SCADA/telecommunications capabilities. This Path, and the following two Paths, would also require the development of operating and cost sharing agreements to guide how economic dispatching would occur and how the related costs and benefits would be allocated among the six Railbelt utilities.

- **Path 4 – Form an Entity That Would be Responsible for Independent Operation of the Grid, Regional Economic Dispatch, Regional Resource Planning, and Joint Project Development**
  This Path is similar to Path 3 except the scope of responsibilities of the new regional entity would be expanded to include regional integrated resource planning and the joint project development of new generation and transmission assets.
- **Path 5 – Form Power Pool**
  This entity would be responsible for the independent operation of the transmission grid, regional economic dispatch and regional resource planning. In that sense, it is similar to Path 4, except that the individual utilities would retain the responsibility for the development of future generation and transmission facilities.

The formation of an RTO/ISO was not chosen for detailed evaluation in this study. This decision was made for three reasons: 1) RTO/ISOs include additional functionality related to the facilitation of competitive electric markets with many power producers and load serving entities, 2) the geographical service territories of RTO/ISOs are significantly greater than the geographical size of the Railbelt region, and 3) the formation and annual operating costs of a fully-functioning RTO/ISO are too great to be economic given the relative small size of the Railbelt region. Consequently, the formation of a RTO/ISO is inappropriate for the Railbelt.

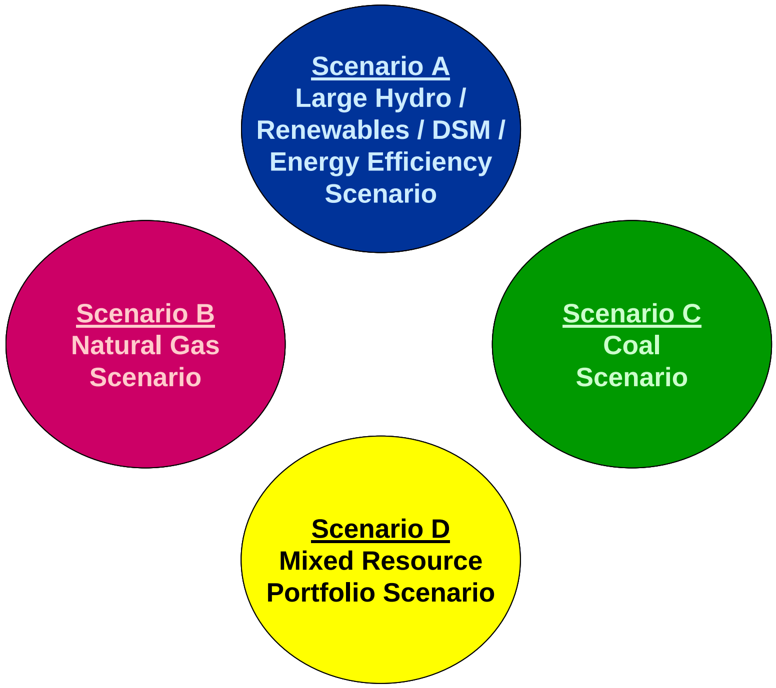
Description of Evaluation Scenarios

As has been discussed in previous sections of this report, there are a number of issues and uncertainties facing the Railbelt. These issues and uncertainties that impacted our analysis include, but are not limited to, the following:

- Future fuel supplies and costs.
- Load growth, military base realignment, economic development, and power exports.
- Aging generation and transmission assets and planned retirements.
- Future desirability and costs of major generation facilities (e.g., coal, nuclear, and hydro facilities).
- Impact of a major power project coming on-line in the Railbelt, such as a large hydropower project.
- Potential growth in non-utility generation (e.g., qualifying facilities, QFs, and independent power producrs, IPPs).
- Potential transmission system expansions.
- DSM/energy efficiency programs, renewables, and distributed generation resources - resource potential, relative economics, and policy-driven targets and growth.
- Environmental legislation (including carbon taxes), regulations and constraints.
- Financing – access to capital, costs, and tax implications.
- Outcome of proposed Chugach/ML&P merger, coordinated operations, and or joint project development.
- Future role of the State, AEA and AIDEA – expand, maintain or sell State-owned energy assets.

Our challenge was to convert this list of issues and uncertainties into a reasonable number of Evaluation Scenarios to be used in the assessment of each Organizational Path. To this end, we developed the four Evaluation Scenarios shown in the following figure, which can be viewed as alternative energy futures for the Railbelt region. We analyzed the net impact of each Organizational Path under each of the four Evaluation Scenarios separately to determine the economic benefits of each Organizational Path, relative to each other. The intent was to determine if one Organizational Path was the most optimal alternative regardless of the energy future chosen by the region, or whether different Organizational Paths were optimal under different futures.

Figure 21 - Summary of Evaluation Scenarios



For each Evaluation Scenario, we developed prescriptive generation supply resource plans, which are representative resource plans to determine the economic benefits of each Organizational Path. These prescriptive resource plans are not the same as integrated resource plans for each Evaluation Scenario, which are optimal long-term resource plans given all considered factors.

Therefore, as noted earlier, it would be inappropriate to compare one Evaluation Scenario to another, as the resulting evaluation plans and power costs under the different Scenarios are not necessarily indicative of what they would be under an optimized integrated resource plan. They do, however, provide a solid foundation for the evaluation of the various Organizational Paths to each other under alternative futures.

- **Scenario A -Large Hydro/Renewables/DSM/Energy Efficiency Scenario**
  This Scenario assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.
- **Scenario B - Natural Gas Scenario**
  In this Scenario, we assumed that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.
- **Scenario C - Coal Scenario**
  The central resource option in this Scenario is the addition of coal plants to meet the future needs of the region.
- **Scenario D - Mixed Resource Portfolio Scenario**
  In this Scenario, we assumed that a combination of large hydroelectric, renewables, DSM/energy efficiency programs, coal and natural gas resources is added over the next 30 years to meet the future needs of the region.

SECTION 5 - EXISTING AND FUTURE RESOURCE OPTIONS

This section includes a detailed summary of the generation and transmission assets that currently exist in the Railbelt region. We also provide a high-level overview of the supply-side and demand-side resource options that are available to meet the electric demand of residential and business customers in the Railbelt region.

Description of Existing Resources

Existing Generation Resources

This section contains a general description of the generation and transmission resources currently in use in the Railbelt region. The existing system data was provided by the Railbelt utilities in response to data requests by Black & Veatch. Black & Veatch reviewed the data and, where necessary, applied judgment to the data to obtain a consistent set of existing system data for planning purposes.

ML&P operates seven combustion turbines (Units 1-5, 7, and 8) between two power plants, which operate on natural gas, and one steam turbine (Unit 6), which derives its steam from un-fired heat recovery steam generators (HRSGs). Units 1, 2, and 4 are unavailable for commercial operation and are not considered in ML&P's approximate 400 MW of generating capability. Combustion turbines 5 and 7 have HRSGs, which allow them to operate in a combined cycle mode with the Unit 6 steam turbine. Unit 5 is frequently cycled when used in combined cycle or simple cycle mode. Unit 5 or Unit 7 may be operated in simple cycle mode when the steam turbine is unavailable. ML&P's existing thermal units are shown in the following table.

Table 16 - ML&P Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Anchorage ML&P - Plant 1	1*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	2*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	3	Natural Gas	32.0	n/a
Anchorage ML&P - Plant 1	4*	Natural Gas	34.1	n/a
Achorage ML&P - Plant 2	5	Natural Gas	37.4	n/a
Anchorage ML&P - Plant 2	5/6	Natural Gas	49.2	n/a
Anchorage ML&P - Plant 2	7	Natural Gas	81.8	2030
Anchorage ML&P - Plant 2	7/6	Natural Gas	109.5	2030
Anchorage ML&P - Plant 2	8	Natural Gas	87.6	2030
Anchorage ML&P - Plant 2	6	n/a	n/a	2030
* Denotes units not available for commercial operation				

CEA operates 13 combustion turbines between three power plants (Bernice 2-4, Beluga 1-7, and International 1-3) which operate on natural gas and one steam turbine (Beluga 8) which derives its steam from HRSGs. CEA's existing thermal units are shown below.

Table 17 - CEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Bernice	2	Natural Gas	19.0	2014
Bernice	3	Natural Gas	26.0	2014
Bernice	4	Natural Gas	22.5	2014
Beluga	1	Natural Gas	19.6	2011
Beluga	2	Natural Gas	19.6	2011
Beluga	3	Natural Gas	64.8	2014
Beluga	5	Natural Gas	68.7	2014
Beluga	6	Natural Gas	82.0	2020
Beluga	6/8	Natural Gas	108.5	2014
Beluga	7	Natural Gas	82.0	2021
Beluga	7/8	Natural Gas	108.5	2014
International	1	Natural Gas	14.1	2011
International	2	Natural Gas	14.1	2011
International	3	Natural Gas	18.5	2011

GVEA's generating capability of 277 MW is supplied by six generating facilities. The Healy Power Plant provides 27 MW, is coal-fired and located adjacent to the Usibelli Coal Mine. GVEA's 190 MW North Pole Power Plant is oil-fired and built next to the Flint Hills refinery. The oil-fired Zehnder Power Plant in Fairbanks can provide 36 MW. The Delta Power Plant (DPP), formerly the Chena 6 Power Plant can produce 25 MW. GVEA's existing thermal units are shown in the following table.

Table 18 - GVEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Zehnder	GT1	HAGO	17.7	2030
Zehnder	GT2	HAGO	17.7	2030
North Pole	GT1	HAGO	62.0	2017
North Pole	GT2	HAGO	64.0	2018
North Pole	GT3	NAPHTHA	52.0	2042
North Pole	ST4	STEAM	12.0	2042
Healy	ST1	Coal	26.7	2022
DPP	1	HAGO	24.9	2030

HEA owns the natural gas Nikiski combustion turbine. During the summer months it can produce a maximum of 35 MW, whereas in the winter it provides 39 MW. This unit is shown below.

Table 19 - HEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Nikiski	1	Natural Gas	39.0	n/a

Each of the utilities in the Railbelt region have full or partial ownership in existing hydroelectric generation facilities. The hydroelectric generation plants include Bradley Lake (a 120 MW hydroelectric plant with 90 MW of normally dispatchable capacity and 30 MW of spinning reserves), Eklutna Lake hydroelectric station (maximum capacity of 40 MW), and Copper Lake hydroelectric facility (20 MW of capacity). The following table gives the percent ownership, annual energy, and capacity for each utility for each of the hydroelectric plants.

Table 20 - Railbelt Hydroelectric Generation Plants

Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
MEA	13.8	50,508	12.4	3.7	16.7	27,388	6.7	0.0	0	0.0
HEA	12.0	41,139	10.8	3.2	0.0	0	0.0	0.0	0	0.0
CEA	30.4	111,269	27.4	8.2	30.0	49,200	12.0	100.0	50,000	20.0
GVEA	16.9	52,894	15.2	4.6	0.0	0	0.0	0.0	0	0.0
ML&P	25.9	90,333	23.3	7.0	53.3	87,412	21.3	0.0	0	0.0
SES	1.0	3,660	0.9	0.3	0.0	0	0.0	0.0	0	0.0
Total	100.0	349,803	90.0	27.0	100.0	164,000	40.0	100.0	50,000	20.0

The table below shows the resulting total capacity for each utility within the Railbelt region.

Table 21 - Railbelt Installed Capacity

Utility	Thermal Existing Capacity	Bradley Lake Capacity	Eklutna Lake Capacity	Cooper Lake Capacity	Total
MEA	0.0	12.4	6.7	0.0	19.1
HEA	39.0	10.8	0.0	0.0	49.8
CEA	504.0	27.4	12.0	20.0	563.4
GVEA	277.0	15.2	0.0	0.0	292.2
ML&P	278.0	23.3	21.3	0.0	322.6
SES	0.0	0.9	0.0	0.0	0.9
Total	1,098.0	90.0	40.0	20.0	1,248.0

Existing DSM/Energy Efficiency Programs

Savings from existing DSM/energy efficiency programs are included in the Railbelt utilities' load forecasts. In general, the Railbelt utilities' DSM/energy efficiency programs are educational in nature. Of the Railbelt utilities, GVEA has the most substantive set of DSM/energy efficiency programs with their Energy$ense suite of programs, consisting of the Builder$ense, Home$ense, and Business$ense programs.

The Builder$ense program is a rebate program that provides the following rebates to home builders.

- Lighting:
    - $25 rebate for interior hard-wired fluorescent lamp fixtures or compact fluorescent lamp fixtures.
    - $5 rebate for screw-in fluorescent light bulbs used in hard-wired light fixtures, such as track lighting or recessed fixtures.
    - $30 rebate for combination photocell/motion detectors for exterior light fixtures.
    - $75 rebate for high-pressure sodium (HPS) exterior light fixtures.
- Vehicle engine preheating plug-ins:
    - $40 rebate for the installation of a timer to control an exterior vehicle plug-in outlet.
    - $20 rebate for the installation of a switch to control an exterior vehicle plug-in outlet.
- Electric water heater:
    - $20 rebate for R-11+ insulating blankets installed on an electric water heater.
    - $75 rebate for the installation of timers that control electric water heater.

The Home$ense program is an audit program that provides the following benefits. During a Home$ense audit, participants receive:

- Education materials and best practices in energy efficiency and use.
- Up to 12 compact fluorescent lamps installed to replace incandescent bulbs.
- A refrigerator thermometer and coil cleaning brush.
- An adjustable weather-proof vehicle plug-in timer, if applicable.

In addition, if the house has a 220-volt hard-wired electric water heater, participants may also receive:

- An electric water heater insulating blanket.
- Up to 10 lineal feet of pipe wrap.
- Two faucet aerators.
- One low-flow shower head.

The Business$ense program is a commercial lighting program that provides up to a $20,000 rebate per customer. Rebates can be applied to the cost of the products and their installation. Rebates will not be applied toward consultation or design fees. Customers must contribute two years of anticipated electric bill savings toward the project cost. Rebates can be up to $1,000/kW, or 50% of the project cost, not to exceed $20,000 per project.

While ML&P has not yet implemented any DSM programs, Grimason Associates recently conducted a study and provided a report to ML&P, entitled *"Recommendations on Potential Energy Efficiency Incentives and Programs to be Offered by Municipal Light and Power."* This study identifies a wide range of DSM/energy efficiency programs and evaluates several strategies for the introduction of DSM/energy efficiency programs within ML&P's service territory.

"While the transmission system serving the population centers of Anchorage / Mat-Su is robust, the same cannot be said for communities closer to the north and south terminuses of the system."

Native Corporation Representative

The other Railbelt Utilities' existing DSM/energy efficiency programs consist primarily of audit programs and educational programs.

Existing Transmission Grid

For the Railbelt transmission system, the Railbelt Utilities are separated into three main load centers: northern, central, and southern. Within each load center, capacity and energy are assumed to flow freely without transmission constraints.

"While the resource potential for renewables is probably high in Alaska, the small number of generation units/plants and the current limitations of the Intertie (not a true grid) render the economic dispatch of wind-sourced power (in significant amounts) difficult if not nearly impossible."

Industry Consultant

GVEA's service area makes up the northern load center and is connected with 138 kV lines that flow through Delta Junction, Fairbanks, and Healy.

The northern and the central load centers are interconnected via the Alaska Intertie, and the Healy-Fairbanks and Teeland-Douglas transmission lines. The Alaska Intertie is a 345 kV (operated at 138 kV), 170 mile transmission line that is owned by the AEA and runs between the Douglas and Healy substations. The Healy-Fairbanks transmission line is a 230 kV, 90-mile transmission line from the Healy to the Wilson substations which delivers power from the Alaska Intertie directly into the city of Fairbanks. Another 138 kV transmission line also runs from Healy to Nenana to Goldhill and delivers power to Fairbanks. The 138 kV, 20-mile Douglas-Teeland transmission line stretches between the Douglas and Teeland substations and connects the southern portion of the Alaska Intertie to the central load center.

The transfer capability of the Alaska Intertie and Healy-Fairbanks transmission lines is assumed to be 75 MW and 140 MW, respectively.

The central load center consists of MEA's, ML&P's, and CEA's service territories. MEA serves customers down the southern half of the intertie and south of the intertie through the towns of Wasilla and Palmer. ML&P serves the load of the residents of Anchorage. CEA serves some residents of Anchorage along with the area south of Anchorage and into the northern portion of the Kenai Peninsula.

The central and southern load centers are connected via a 135-mile, 115 kV transmission line which connects the Chugach system to that of the Kenai Peninsula. The transfer capability of the southern intertie is assumed to be 75 MW.

The southern load center consists of SES and HEA's service territories. SES serves the customers of the city of Seward. The HEA service area includes the cities of Homer and Soldotna.

Figure 22 shows the Railbelt transmission lines and Figure 23 shows the region's three load centers and the existing transfer capability.

"There is little or no talk about further improving the existing Intertie's capacity and reliability to permit increased power deliveries from alternative proven fuel reserves such as Healy coal and prospective natural gas reserves. Increasing these capacities in both directions can relieve the power cost escalation now occurring along the entire Railbelt's corridor."

Industry Consultant

"The Intertie's ability to offset natural gas consumption for electrical generation could alleviate the Anchorage Bowl's current reserve depletion issues for many years to come."

Industry Consultant

Figure 22 - Generation, Transmission, and Distribution Facilities

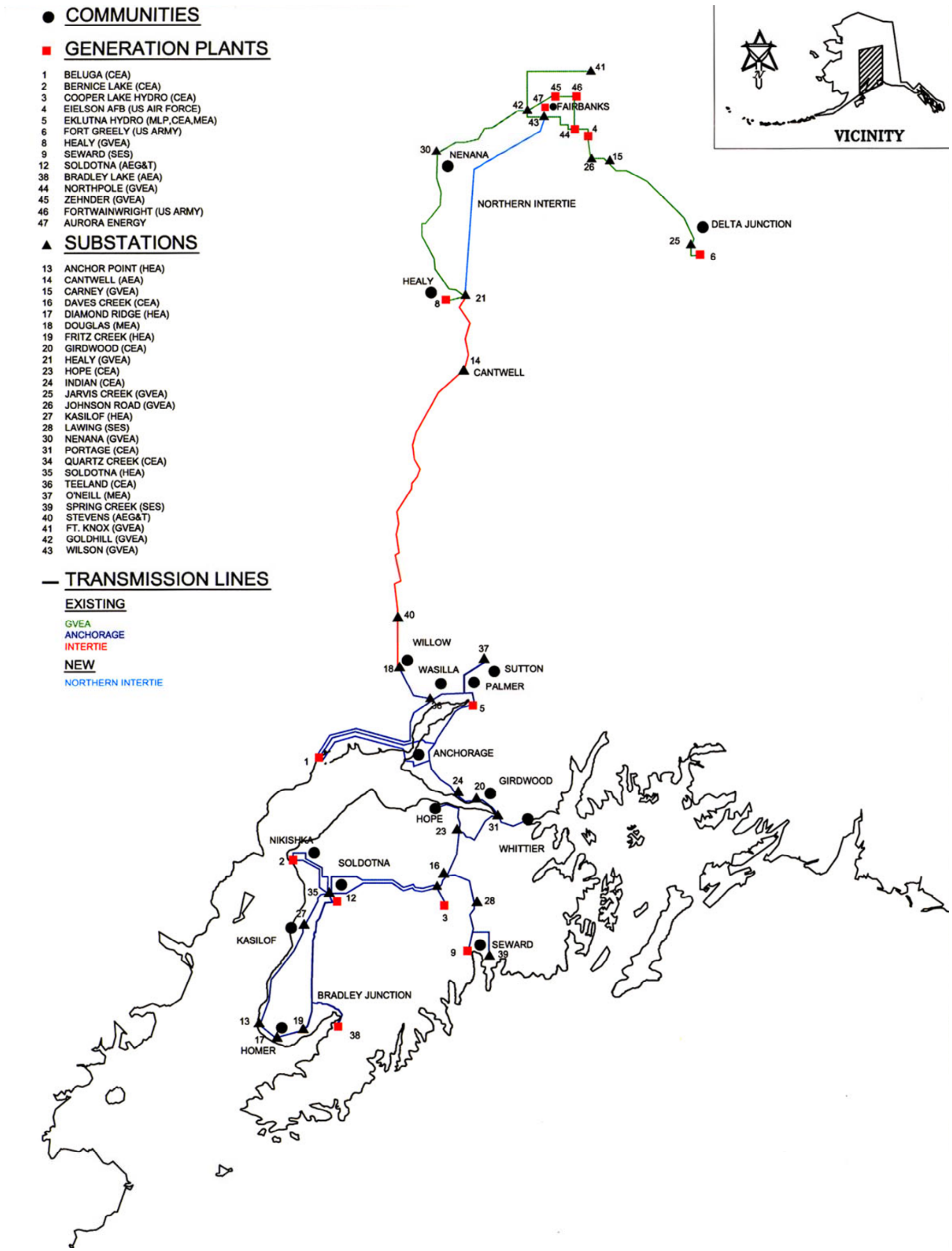
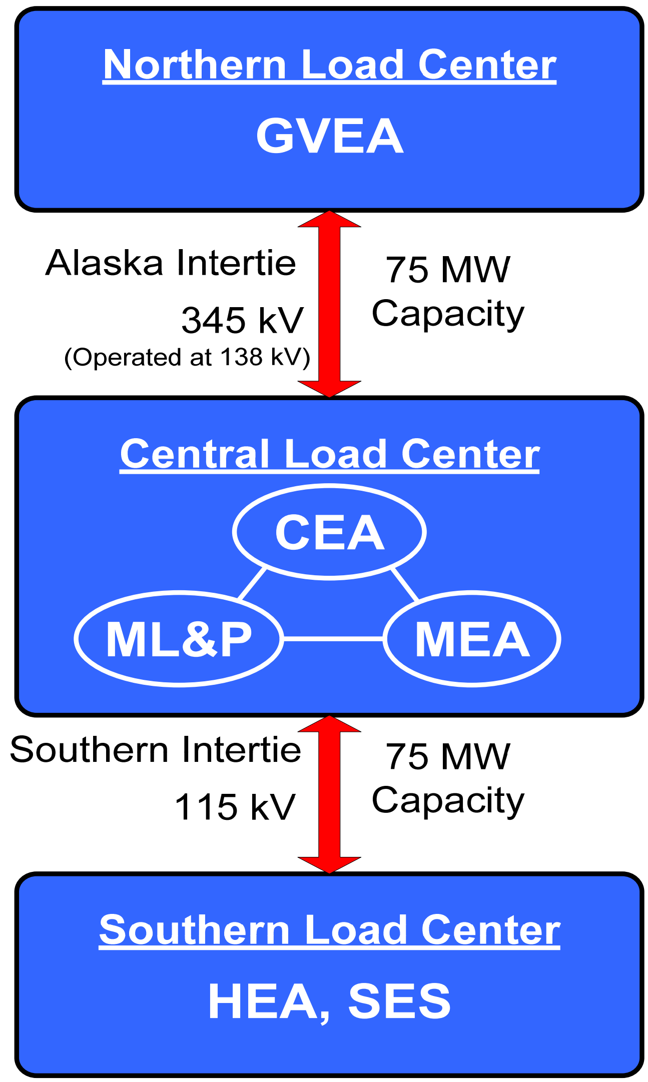


Figure 23 - Existing Load Centers as Modeled



The Alaska Intertie

The Alaska Intertie is a 170-mile long, 345 KV transmission line between Willow and Healy that is owned by the AEA. The Intertie was built in the mid-1980s with State of Alaska appropriations totaling $124 million. There is no outstanding debt associated with this asset.

The Intertie is one of a number of transmission segments that, when connected together, can move power throughout the network from Delta, through Fairbanks to Anchorage down to the southern most limit at Seldovia. This interconnected system of utilities, tied together with the Intertie is collectively termed the "Railbelt Electric Grid System."

The operation of the Intertie is governed by an agreement that was negotiated in 1985 between the predecessor of AEA, the Alaska Power Authority (APA), and four utility participants: ML&P, CEA, GVEA, and AEG&T Cooperative, Inc. All of the utility participants are connected to the Intertie and can move power on and off the Intertie.

For example, GVEA uses the Intertie to purchase non-firm economy energy from ML&P and CEA. As another example, the Railbelt Electric Grid System is used to transfer power from the Bradley Lake Hydroelectric Plant, which is located east of Homer just below the glacier-fed Bradley Lake. Each of the Railbelt utilities has rights for a specified percentage of the power output from Bradley Lake. GVEA owns a portion of the capacity and energy available from Bradley Lake, and it transmits this power north to its service area over the AEA Intertie.

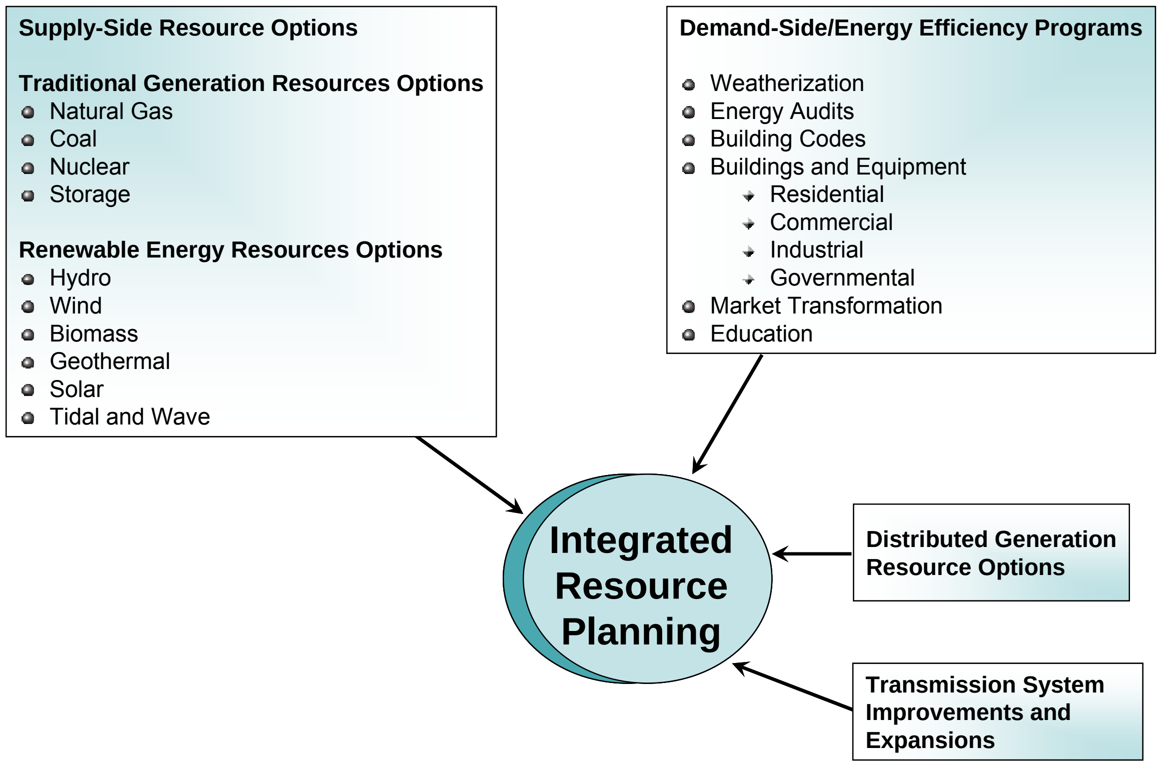
Both functional operation of the transmission line, as well as arrangements for the collection of and expenditure of annual operations and maintenance funds, are a part of this agreement. The agreement also specifies a governance structure that consists of representatives from the participating utilities and AEA.

The agreement specifies, through interconnection terms and conditions, how utilities are allowed access to the Intertie. Each utility is required to maintain a certain level of spinning reserve to preserve the reliability of electrical supply throughout the network. AEA is in the process of renegotiating this agreement with interested Railbelt Grid utilities.

Available Supply-Side and Demand-Side Resource Options

The following graph provides a high-level summary of the various supply-side and demand-side resource options that are available for meeting the future electric needs of the Railbelt.

Figure 24 - Available Supply-Side and Demand-Side Resource Options



Traditional Generation Resource Options

There are a number of traditional supply-side resource options available to the Railbelt region. These include:

Simple Cycle Combustion Turbines

Combustion turbine generators (CTGs) are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000º F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a “simple cycle” power plant.

“The major risk is the supply of natural gas and its price for the next ten years for heating and electrical generation.”

Financial Community Representative

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacities. Combustion turbine technology also provides rapid start-up and modularity for ease of maintenance. The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies.

Examples of available simple cycle combustion turbines include:

- GE 6B (MS6001B) simple cycle
- GE LMS100 simple cycle
- GE LM6000 simple cycle

Combined Cycle Combustion Turbines

Combined cycle power plants use one or more CTGs and one or more steam turbine generators (STGs) to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. High power steam is produced when the hot exhaust gas from the CTG is passed through a HRSG. The high pressure steam is then expanded through a steam turbine, which spins an electric generator.

"Major risks include running out of natural gas for generation, building new generation plants before existing plants wear out, and the ability to upgrade the transmission grid so that it is reliable."

State Agency Representative

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements because of added plant complexity.

The 1x1 combined cycle generating unit includes one CTG, one HRSG, and one STG. The 2x1 combined cycle generating unit includes two CTGs, two HRSGs, and one STG. The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG.

Examples of available combined cycle combustion turbines include:

- 1x1 GE 6FA (MS6001FA) combined cycle
- 2x1 GE 6FA (MS6001FA) combined cycle

"Coal makes sense, but hydro is better."

Industry Consultant

Pulverized Coal

Coal is the most widely used fuel for the production of power in the U.S., and most coal burning power plants use pulverized coal boilers. Pulverized coal units have the advantage of utilizing a proven technology with a very high reliability level. Pulverized coal units are relatively easy to operate and maintain. In a pulverized coal power plant, coal is ground to the texture of flour and blown into a boiler where it burns. A network of tubes circulates water through the boiler. The heat from the fireball caused by the burning coal makes steam. The super-heated steam is directed at the blades of the STG to make electricity.

"In my opinion, a bullet line from the North Slope is our greatest opportunity. It will provide energy for both electric and home heating loads and offer economic activity for industrials and future large mine projects such as Pebble."

Utility Representative

"The major future risk is over dependence on natural gas. Natural gas is a great fuel but overdependence on anything is extremely risky. All risk is currently born by ratepayers. A diversified portfolio is necessary to spread risk."

Project Developer

"A major opportunity exists to pursue new clean coal technologies, to build generation that uses stable fuel supplies and much more efficient generation, while also meeting future possible carbon tax issues."

State Agency Representative

"We all know the acceptability issues of coal and nuclear as we see them in the media. Place the questions to the voters in the form of an initiative ballot if you really want to know the true opinion of Alaskans – you may be surprised."

Industry Consultant

"True energy security means distributed generation systems based on geothermal and renewable resources. In the near-term we should utilize natural gas resources as a bridge to renewables, including geothermal."

Renewable Energy Advocate

"We believe the prospects for distributed generation are excellent given Alaska's Railbelt interconnected load/distance ratios."

Industry Consultant

Renewable Energy Resource Options

There are a number of renewable resources that can be part of the Railbelt's future resource mix. These resources include:

- Hydroelectric
- Wind
- Biomass
- Geothermal
- Solar
- Ocean (Tidal and Wave)

Each of the potential resources is discussed briefly below. These descriptions are based, in large part, on the AEA's *Renewable Energy Atlas of Alaska*.

Hydroelectric

Hydroelectric power is currently the State's largest source of renewable energy, responsible for approximately 24 percent of the State's electrical energy. In 2007, 27 hydro projects provided power to Alaska utility customers, ranging in size from the 105 kW Akutan hydro project in the Aleutians to the 126 MW State-owned Bradley Lake project near Homer.

Many of the State's developed hydro resources are located near communities in South central, the Alaska Peninsula, and Southeast.

Hydro projects include those that involve storage, both with and without dam construction, and smaller "run-of-river" projects.

A number of potential hydro projects exist within or near the Railbelt region, including the Susitna and Chakachamna projects.

Wind

Alaska has abundant wind resources suitable for power development. Much of the best wind sites are located in the western and coastal portions of the State. The wind in these regions tends to be associated with strong high and low pressure systems and related storm tracks.

National Renewables Cooperative Organization (NRCO)

"It was recently announced that a number of electric cooperatives are joining together to form a National Renewables Cooperative Organization to develop renewable energy projects. This organization is viewed as an opportunity to pool the resources and efforts of the cooperatives into a single national program. This program is in response to the fact that 26 states have already adopted renewable energy mandates and Congress is debating whether to adopt a national renewable portfolio standard. Generation and transmission cooperatives, unaffiliated distribution cooperatives, and partial requirements cooperatives that have the legal ability to participate in the wholesale market are eligible for membership in the NRCO. The structures and rules for the NRCO are still being developed. Sunflower Electric Power Corporation, Tri-State Generation & Association, Inc., and Basin Electric Power Cooperative are among NRCO's founding members.

Wind power technologies being used or planned in Alaska range from small wind chargers at off-grid homes or remote camps, to medium-sized machines displacing diesel fuel in isolated village wind-diesel hybrid systems, to large turbines greater than 1 MW. On the Railbelt, several of the utilities are examining wind power projects, including the proposed Fire Island and Eva Creek projects.

Biomass

Alaska's primary biomass fuels are wood, sawmill wastes, fish byproducts, and municipal waste. For example, wood is currently used for space heating throughout the State. Recent increases in oil and natural gas prices have increased the interest in using sawdust and wood wastes as fuel for lumber drying, space heating and small-scale power production.

Eielson Air Force Base densifies paper separated from the local waste stream and then co-fires the resulting cubes at the base's coal-fired power plant, providing up to 1.5 percent of the base's heat and power.

Energy recovery from Anchorage landfill gas is viable, according to a report prepared in 2005 for the Municipality of Anchorage. According to this study, this gas could be used to heat nearby military or school facilities or be converted to 2.5 MW of electrical power.

"In my mind the development of renewables is probably the only way we are going to be able to stabilize our electrical rates. Hydroelectric development has the potential to provide all or almost all of our electrical needs if someone would ever have the foresight to develop it."

Financial Community Representative

Geothermal

Alaska has four distinct geothermal resource regions: 1) the Interior hot springs, 2) the Southeast hot springs, 3) the Wrangell Mountains, and 4) the Ring of Fire volcanoes. The Interior and Southeast hot springs are low- to moderate-temperature geothermal systems with surface expression as hot springs. The Wrangell Mountains consists of several active volcanoes that may have geothermal energy development potential. The Ring of Fire hosts high-temperature hydrothermal systems.

Three large-scale geothermal electric power generation projects have been proposed in Alaska: 1) the Mt. Makushin project to provide power to the City of Unalaska, 2) the Akutan project to provide power to the City of Akutan, and 3) the Mt. Spurr project to provide power to the Railbelt region.

In the Interior, the Chena Hot Springs Resort is an example of the diverse use of geothermal energy. The resort has installed the first geothermal power plant in Alaska, including two 200 kW organic Rankine cycle generators. In addition to the electric power plant, the Chena Resort uses its geothermal resources for outdoor baths, district heating, swimming pool heating, refrigeration, and to provide heat and carbon dioxide to its greenhouses.

"New technologies and the potential for energy efficiency, renewables, and pricing are emerging constantly, but Alaska seems stuck in the 1960s with ideas far outdated. RCA action and a push from the Governor would help."

State Agency Representative

Solar

Alaska's northern location presents the challenge of minimal solar energy during the long winter when energy demand is greatest; notwithstanding this, solar energy is used for space heating (i.e., passive solar design) and off-grid power generation. "Active solar" heating systems use pumps or fans to move energy to a point of use, such as a domestic hot water tank. The State's largest utility-connected photovoltaic power system is in the remote community of Lime Village, which can generate up to 12 kW.

"Renewables offer the best opportunity. A mix of renewables and natural gas generation will serve the ratepayers best over time."

Project Developer

Significant utility-scale solar generation is unlikely in Alaska due to high capital costs and low yearly solar power output.

Ocean (Tidal and Wave)

Alaska has 34,000 miles of coastline, more than all other states combined. As a result, there is interest in harvesting energy from the ocean. Ocean energy falls into three general categories: 1) ocean thermal energy conversion (OTEC), 2) tidal energy, and 3) wave energy.

OTEC applications are limited to tropical areas and are not suitable for development in Alaska. That leaves tidal and wave energy, although the technologies for exploiting these potential resources are not yet commercially available.

Tidal energy is a concentrated form of the gravitational energy exerted by the moon and, to a lesser extent, the sun. This energy can be converted into electricity by using dams that force water through turbines at high and low tidal stages, or by underwater turbines that are turned by tidal flow.

In 2006, the Electric Power Research Institute (EPRI), in partnership with the AEA, CEA, and ML&P, completed a tidal energy study at Cairn Point on Knik Arm. The study showed that an estimated 17 MW of power could be generated using tidal energy. Since the report, FERC has issued eight preliminary tidal energy permits to energy developers for Alaska projects.

Wave energy is the result of wind acting on the ocean surface. Alaska has one of the best wave resources in the world; the total wave power flux on southern Alaska's coast alone is estimated at 1,250 TWh, or almost 300 times the amount of electricity that Alaskans use every year. As with other renewable energy sources in Alaska, a challenge to using wave energy is the lack of energy demand near the resource.

"Alaska has a wealth of hydroelectric alternatives within the State but the Governor and the Legislature have not been able to look at the long-term (i.e., they see only a four-year term as a Governor and two to three years as a Legislator). Until they get rid of their short-term mentality, the hydroelectric potential that the State has will continue to go undeveloped."

Financial Community Representative

"Alaska has a vast potential for dispatchable renewable energy projects. The transition to renewable energy technologies will help buffer the Railbelt from increasing fossil fuel costs."

Source: Consumer Advocate

"Natural gas should be used as the bridging fuel as we develop systems based upon geothermal and renewable resources."

Renewable Energy Advocate

"The increased viability and growth of wind generation world-wide is well documented. What is lacking now is a strong standard bearer that can get beyond the view that, for many years in this State, has pegged anyone wanting to save energy or promote renewables as a "greeny" without seeing the bottom-line benefits."

Renewable Energy Advocate

"Conservation is job one and the cheapest alternative."

Renewable Energy Advocate

"With big picture planning, renewable energy could fuel the grid, with long-term rates held in place, drawing big enterprises, like Google or Microsoft, who want flat-rate green power long into the future."

State Agency Representative

"Small-scale hydro, wind, and solar generators could allow Alaska residents to harness viable renewable resources with advancing and increasingly cheaper technologies, without incurring fuel costs."

Source: Renewable Energy Advocate

Demand-Side Management/Energy Efficiency Resource Options

There are numerous potential DSM/energy efficiency measures and programs that can assist customers reduce their annual energy consumption and peak demands. Some of these measures and programs include:

On-Site Energy Audit Programs

Energy audit programs provide customers the opportunity to gain an understanding of why they consumed their billed energy. The customer receives advice on ways to conserve and reduce their bills, and may also be advised on the feasibility of installing more insulation or more energy efficient appliances.

On-Line Energy Audits

On-line energy audits have become a popular DSM/energy efficiency solution, and can be easily accessed from the utility's web site. These are "do-it-yourself" types of energy audits, using an evaluation framework developed by the utility.

Load Management Programs

Load management programs are intended for customers who have electric water heaters, central air conditioning units, and central heating units. The programs allow the utility to interrupt non-critical electric services for certain specified amounts of time during peak utility system demand hours.

Energy Saving Tips

Advice on energy conservation is made available from utility staff and or literature provided by the utility. For example, in addition to distributing traditional pamphlets, bill inserts and web site information, the utility works with local schools to promote conservation among students. Additional programs include: monthly newsletters, energy conservation calendars, energy tips brochures, and local radio advertisements.

Appliance and Other Rebates

Rebates can be made available to residential and small commercial customers to upgrade to more efficient heating, ventilation, and air conditioning (HVAC) equipment. Additionally, rebates can also be offered to provide an incentive for customers to install residential attic insulation to prevent heat and cooling loss. Possible other rebate programs include customer rebates for: duct leak repair, annual HVAC maintenance, and light-emitting diode (LED) exit signs in buildings.

Load Profiling for Commercial Customers

Recording meters can be provided to allow commercial customers to monitor their electrical consumption. Commercial customers can also request monthly reports from the utility of their consumption profile.

Retrofit Programs

Qualifying customers and homes can apply for assistance in having their home remodeled with additional insulation and weatherization. An energy audit is usually necessary to determine if the requested home is qualified for such assistance. If the audit results in qualifying the home, a grant can be

"There are major opportunities for load reduction through education campaigns, incentives to use non-peak power, providing energy efficient light bulbs, etc."

Consumer Advocate

"Demand-side management will be the fastest route to cost and energy savings; Statewide, energy conservation and energy efficiencies measures should be aggressively pursued."

Consumer Advocate

"There are some economic benefits to DSM. However these are small. It is unlikely that DSM would make a substantial deferral of generation investment possible."

Project Developer

"The current rate structures seem to hinder efficiency and conservation measures and reward higher volume."

Renewable Energy Advocate

"Energy efficiency has never been considered for use along the Railbelt, and is largely underutilized. Much could be done in that area."

State Agency Representative

provided to the homeowner through the utility or some other program, such as the program offered by the Alaska Housing Finance Corporation.

Compact Fluorescent Bulbs (CFLs)

CFLs can be provided by the utility free of charge, or at a discounted rate to its customers. In most cases the CFLs use nearly 75% less electricity than an incandescent bulb, helping to effectively reduce the energy demand due to lighting.

ENERGY STAR® Program

The ENERGY STAR® program, which is backed by the U.S. Environmental Protection Agency and Department of Energy, provides strategies and tools to help utilities promote different energy-saving campaigns. Utilities participate in the ENERGY STAR® program by including links on their web sites, posters and displays in their lobbies, as well as providing other promotional materials to their customers on ENERGY STAR® programs, appliances, conservation tools, and other features.

"Demand-side management and energy efficiency programs are vastly underutilized in the Railbelt, especially by utilities."

State Agency Representative

SECTION 6 - ORGANIZATIONAL ISSUES

This section provides an overview of the various organizational issues that are related to the formation of a new regional entity, including scope of responsibilities, tax and legal issues, regulatory oversight issues, required legislative actions, and various other factors.

Experience with Other Business Models

The formation of regional entities to focus on generation and transmission issues is a common practice throughout the country. Typically, the legal structure of the entities falls into one of the following four business models:

- State/Federal Power Authorities
- Joint Action Agencies
- G&T Cooperatives
- RTOs/ISOs

"Splitting off generation and transmission from distribution makes a lot of sense. Some way to stop the feuds between the utilities and get at least the generation side working together is required."

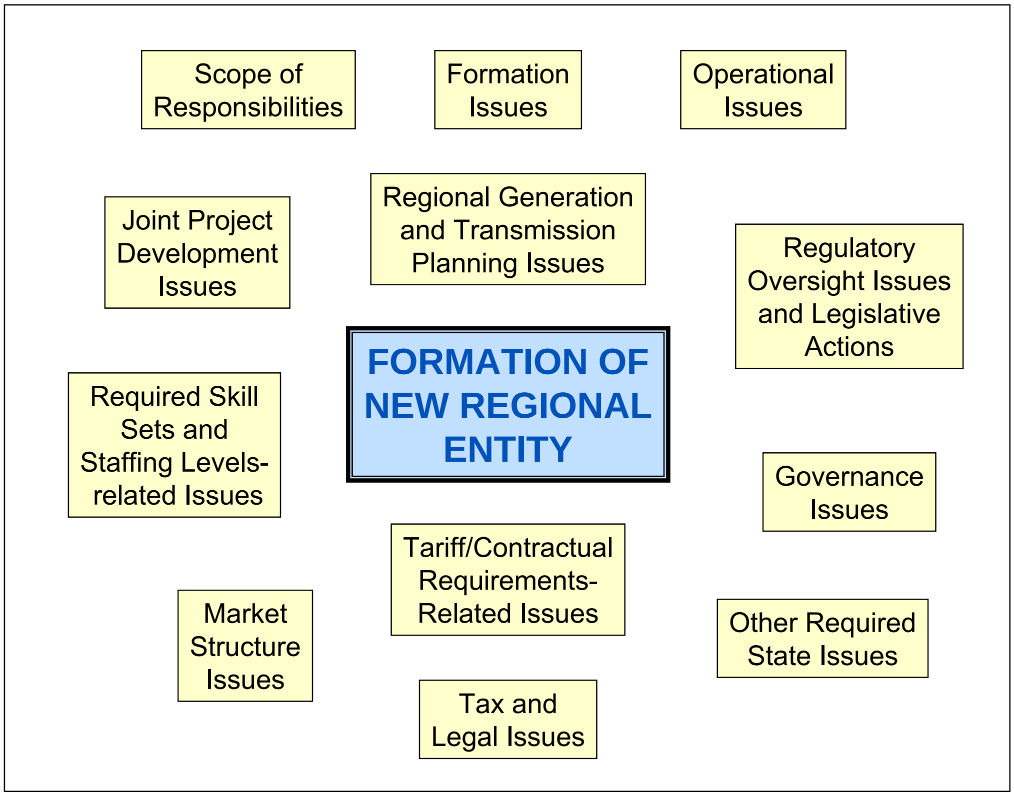
State Agency Representative

Within the not-for-profit segment of the industry, the G&T Cooperative and JAA business models are the most common. State Power Authorities exist in a limited number of states. RTOs/ISOs are typically "super regional" organizations as they cover large regions (e.g., Texas or multiple states) in the lower-48 states, and IOUs, G&T Cooperatives, JAAs, and State Power Authorities operate within the regions under their direction.

In Appendix B, we provide descriptions of a number of State and Federal Power Authorities, G&T Cooperatives, JAAs, and other types of regional G&T organizations that currently exist within the U.S. Many other examples exist but this summary provides a representative overview of these types of organizations.

Notwithstanding the experience that has been gained elsewhere with the formation of regional G&T entities, there are a number of organizational issues that need to be addressed if the Railbelt region is to successfully create such an entity. Specific categories of these organizational issues are identified in the following graphic.

Figure 25 - Summary of Organizational Issues



Each category of organizational issues is discussed below.

Scope of Responsibilities

The first important issue that must be addressed is to determine the specific scope of responsibilities for the new entity. Based on the Organizational Paths for the new regional entity that were chosen for evaluation, the most narrowly-defined scope of responsibilities would be the independent and coordinated operation of the grid (Coordinated Grid Operations). The next increment in scope of responsibility is conducting regional economic dispatch (Economic Dispatch). Finally, the last increments to be added to the scope of responsibility for a new regional entity is to provide regional integrated resource planning (Regional Integrated Resource Planning) and, finally, joint project development (Joint Project Development). This hierarchy of responsibilities is reflected in how the Organizational Paths evaluated in this study were constructed.

The following table further defines the operational scope for each of the four increments identified above.

Definitions

Coordinated Grid Operations – relates to the coordinated operations of the transmission grid to ensure the reliability of electric service throughout the region.

Economic Dispatch – involves the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.

Regional Integrated Resource Planning - a planning process for electric utilities that evaluates many different generation and transmission supply-side and demand-side options for meeting future electricity demands and selects the optimal mix of resources that minimizes the cost of electricity supply while meeting reliability needs and other objectives.

Joint Project Development – involves the coordinated development of future generation and transmission projects by multiple parties for the joint benefit of all participants.

"The central issues with all forms of collectivization are the allocation of costs and governance. It is easy enough to dispatch jointly for minimum cost, but how do you decide who pays what, particularly if the allocation of costs or payments is a function of the dispatch?"

Utility Representative

"An entity that would take on power supply for all utilities would have the greatest benefit. They could undertake the planning and joint project development, as well as undertake the dispatch function."

Utility Representative

* * *

"Our system is way too small for there to be three or more dispatch centers, planning processes, etc. If it were within one organization, I believe they would be able to reduce their costs overall and hopefully meet all of the needs of the Railbelt."

Financial Community Representative

* * *

"The formation and implementation of a single entity (e.g., a G & T cooperative or as the AEA) would allow for a single voice to be heard by Legislators in Juneau on major projects that needed equity capital to get them off the ground. Additionally, our Congressional delegation has repeated asked for a single voice to be developed by the Railbelt utilities so that a single priority list could be worked on."

Financial Community Representative

SECTION 6 - ORGANIZATIONAL ISSUES

Formation Issues

There are several issues specific to the start-up formation of a new regional entity. These issues include:

Issue	Description
Legal Structure	Should the new entity be a JAA, G&T Cooperative or State Agency/Corporation?
Location	Should the new regional entity be located in Anchorage, Fairbanks, or elsewhere?
Transfer of Existing Assets and Fuel Supply Contracts	Determine whether the ownership, or just some level of dispatch control, of existing assets should be transferred to the new entity.
Whether to Adopt a "Hold Harmless" Requirement	Should a rule be adopted whereby the formation of the new entity cannot harm any groups of existing customers? Adopting such a rule is common when these types of regional entities are formed. To meet this criteria, it is often necessary to develop a mechanism to fairly allocate the benefits of the type of entity to all customers within a region; this allocation methodology is usually put in place for some defined period of time.
Transition Period	Related to the issue above is the question of how long the transition period should be until the final cost/benefit allocation methodology is enacted?

Operational Issues

Operational issues that need to be addressed include the following:

Issue	Description
O&M Responsibility	Who will have responsibility for the ongoing operation and maintenance of the Railbelt region's generation and transmission assets and where will the line be drawn between transmission and local distribution facilities, the new regional entity or the existing six Railbelt utilities, or a combination?
Consolidation of Control Centers	The Railbelt region currently has three control centers, which are operated by GVEA, ML&P and CEA. If a regional entity is formed, is there a continued need to have three control centers or can they be consolidated into two centers (i.e., one primary and one back-up center)?
Required SCADA/Telecommunications Investments	To fully enable regional economic dispatch, certain investments in SCADA and telecommunications equipment will be required.
Determination of Transmission Voltage Level and Treatment of Large Customers Currently Served at Transmission Voltage Levels	Should a regional entity be formed, it will be important to make a determination as to which voltages will be considered transmission and which voltages are distribution. Additionally, it will be necessary to determine how to handle large customers which are currently served at transmission voltage levels.

Regional Generation and Transmission Planning Issues

One of the potential responsibilities of a new regional entity would be to periodically develop regional resource and transmission expansion plans. The scope and complexity of the planning process may vary from advisory plans related to new generation and transmission capacity requirements to fully integrated resource plans for the region. To achieve this, the following issues will need to be addressed:

Issue	Description
Development of New Coordinated Planning Processes	New regional generation and transmission planning processes will need to be developed and implemented requiring the full cooperation of the six independent utilities.
Requirement to Follow Results	It will need to be determined whether all six Railbelt utilities will be required to abide by the results of the regional planning process or whether they will have the option to continue to pursue their own future direction.

Joint Project Development Issues

There are several issues related to joint project development that need to be addressed, including:

Issue	Description
All-In or Opt-Out Option	Will all six Railbelt utilities, which join the regional entity (and any other utilities that might join later), be required to participate in future generation and transmission projects that result from a regional resource planning process, or will they have the option to decide which projects they will participate in and which projects they will not?
Responsibility for Project Construction	Will the new regional entity have the responsibility for the construction of future generation and transmission projects, or will the existing six utilities retain this responsibility?

Required Skill Sets and Staffing Levels-Related Issues

There are several staffing-related issues associated with the formation of a new regional entity, including the following:

Issue	Description
Total Staffing Levels	Determining the required level of staffing within the new entity to meet its functional responsibilities.
Organizational Structure	Developing an appropriate organizational structure to align staffing with functional responsibilities.
Strategy for Transfer of Existing Employees	Determining how many of the existing employees of the six Railbelt utilities should be candidates for transfer to the new regional entity and developing a strategy for encouraging those employees to transfer.
Recruiting and Relocation Strategy	To fill remaining positions, a strategy needs to be developed to recruit and relocate additional employees.
Compensation Program	The development of an overall compensation structure and benefits package for the new entity.

Tax and Legal Issues

Certain tax and legal issues need to be addressed related to the formation of a new regional entity. These issues include:

Issue	Description
Ability to Issue Tax-Exempt Debt	This is a very important issue given the magnitude of generation and transmission investments that need to be made within the Railbelt region over the next 30 years. There are two categories of tax-exempt bonds: government obligations and private activity bonds. Both categories contain their own restrictions regarding how the bond proceeds can be used by the issuing entity. The fact that the Railbelt utilities include four cooperatives complicates this issue. This is discussed further immediately following this table.
Transfer of Ownership of Existing Assets	Legal restrictions exist related to the transfer of the ownership of existing assets to a new entity. For example, in the cases of Chugach and GVEA related to the sale, lease or other disposition of more than 15 percent of its total assets, its bylaws require an affirmative vote of members constituting not less than two-thirds of the members voting, where the number of members voting also constitutes a majority of all members of the Chugach Association; the only exception to this requirement is that if the disposition of assets is to another cooperative or the State of Alaska, such disposition must be approved by a majority of the members voting in an election in which at least 10% of the members vote.
Transfer of the City of Anchorage's Ownership of Gas Reserves in the Cook Inlet	The City of Anchorage's ownership in Cook Inlet gas reserves was financed using tax-exempt bonds. As a result, the use of this gas is limited to the generation of electricity in ML&P-owned generation facilities.
Governance	As a practical matter, for the new entity to rely on tax-exempt debt to finance a large percentage of future infrastructure investments, it will need to be formed as a public entity. This has implications related to governance because the required structure for the Board of Directors for a public entity is different than how Boards are typically established for JAAs or G&T Cooperatives.

As noted in the table above, there are a number of issues related with tax-exempt financing, which are summarized below; a more detailed discussion of each of these issues is provided in Appendix G.

There are differences between government obligations that are not private activity bonds (government obligations) and government obligations that are private activity bonds (private activity bonds). Tax-exempt bond financing can be done with both government obligations and private activity bonds. The following summarizes the differences between the two types of bonds:

- **Government Obligations**
  - Generally, government obligation bonds must be issued by either a state or municipal government.
  - The advantages of government obligations that are not private activity bonds are: 1) they are presumed to be tax-exempt unless the government issuer does something to cause them to be taxable, and 2) they are not subject to the alternative minimum tax.
  - The ability of a regional public entity to issue tax-exempt debt and sell power to electric cooperatives or other private entities, or purchase their assets is generally limited by tax law; electric cooperatives generally don't have a way of directly participating in the benefits of a regional public entity's tax-exemption.
  - A government obligation bond becomes a private activity bond if:
    - More than 5% of the proceeds of the bonds are used to provide a facility that is used in the trade or business of a person that is not a governmental entity (the "private use test"), <u>and</u>

        - More than 5% of the money that will be used to pay the bonds is derived from a private business source (the "private security test").
    - Management contracts (e.g., a contract between the issuer and a private utility under which the private utility agrees to provide certain services to the issuer) can also cause a government obligation to become a private activity bond.
- **Private Activity Bonds**
    - Private activity bonds are taxable unless there is a specific Internal Revenue Code provision that permits it to be tax-exempt. In the case of an electric output facility, for a private activity bond to be tax-exempt:
        - The facility can be used to provide electricity to no more than two contiguous counties (boroughs in Alaska) or one county and one contiguous city (the "two county rule"), and.
        - The user of the facility must have provided electric service in the area that the facility will serve since at least January 1, 1997 or be a successor to such an entity (the "sunset rule").
    - The alternative minimum tax applies to private activity bonds, but not government obligation bonds. This makes the tax exemption less valuable because the alternative minimum tax applies a tax to these bonds for certain investors even though the bonds are otherwise tax-exempt. In this sense, private activity bonds are not exactly taxable and not exactly tax-exempt.
    - Private activity bonds are subject to each state's annual private activity bond cap (for Alaska, approximately $262 million). This restriction does not apply to government obligation bonds.
- **Provisions Applicable to All Tax-Exempt Bonds**
  In addition to the above, there are a number of provisions that the Internal Revenue Code imposes on all tax-exempt bonds, whether government obligations or private activity bonds.
    - No tax-exempt bonds may be federally guaranteed.
    - Tax-exempt bonds can be used to reimburse expenditures that were incurred before the issuance of the bonds only if the expenditures to be reimbursed occurred not more than 60 days before the issuer adopts an "official intent." The "official intent" can be made in any reasonable form, but usually the Board of Directors of the issuer adopts a resolution for this purpose.
    - Tax-exempt bonds are subject to arbitrage and arbitrage rebate provisions of the Internal Revenue Code and regulations.

What is the significance of turning a government obligation into a private activity bond? Most importantly, while a government obligation is tax-exempt unless the issuer does something that causes the bond to become taxable, a private activity bond is taxable unless there is a specific Internal Revenue Code provision that permits it to be tax-exempt. The Internal Revenue Code does permit private activity bonds that are used to finance electric output facilities to be tax-exempt, but only if certain conditions are satisfied. Specific strategies for addressing these issues are discussed in Section 9.

Regulatory Oversight Issues and Legislative Actions

The following issues relate to the regulatory oversight of the new regional entity, as well as legislative actions that need to be taken to facilitate the formation of a new entity:

Issue	Description
Regional Integrated Resource Plans	Will the RCA have the authority to review and approve the regional integrated resource plans that are developed by the regional entity?
Joint Project Development	Will the RCA have the authority to review and approve specific generation and transmission projects that are developed by the new regional entity, including the determination of need, the approval of the costs to be recovered from customers, and overall siting authority?
Fuel Contracts	Will the RCA have the authority to review and approve the fuel supply contracts that are entered into by the regional entity?
Cost/Benefit Allocation Methodology	Will the RCA have the authority to review and approve the methodology used by the regional entity to allocate the costs and benefits of regionalization to each of the six existing utilities?
Transmission Tariff	Will the new regional entity develop a transmission tariff to define the terms, conditions, and rates for transmission service and will the RCA have the authority to review and approve this tariff?
Annual Reporting Requirements	What annual reporting requirements should be established to enable the RCA and other parties to monitor the performance of the regional entity?

Other Required State Actions

Other State actions required to facilitate the achievement of the benefits of regionalization include:

Issue	Description
State Energy Plan and Related Policies	The Governor has directed that a State Energy Plan be developed. Her administration is also addressing other related issues such as climate change. A new regional entity will play an important role in the implementation of the policies resulting from these initiatives.

Market Structure Issues

The following market structure issues need to be addressed in the formation of a new regional generation and transmission entity:

Issue	Description
Required Changes to Market Structure	Should any changes to the existing Railbelt market structure be implemented to enable IPPs to participate in the market?
Adoption of a Competitive Power Procurement Process	Should the regional entity be required to develop and implement a competitive power procurement process whereby utility- and IPP-proposed projects are evaluated on a consistent basis?

Tariff/Contractual Requirements-Related Issues

The following issues relate to the development of an Open Access Transmission Tariff (OATT) and other contracts upon formation of the new regional entity to allow other non-utility sources of generation.

Issue	Description
Open Access Transmission Tariff	An OATT will need to be developed by the regional entity to define the terms, conditions, and rates for transmission service, and the requirements and standards for the interconnection of non-utility generation resources including contributions in aid of construction.
Postage Stamp or Mileage-Based Rates	A decision will need to be made as to whether the rates for transmission service will be postage stamp rates (i.e., everyone pays the same rates regardless of location) or will be mileage-based (i.e., rates vary by location). In addition, it will be necessary to address the determination of rates for power supply and ancillary services including line losses.
Contracts Between Individual Parties	A decision will need to be made as to whether the six existing Railbelt utilities will be allowed to continue to enter into bilateral contractual agreements related to power supply among them, outside of the regional entity, or whether all such power supply agreements must be with the regional entity.

Governance Issues

There are a number of issues related to governance and the development of bylaws for the new regional entity. These issues include, but are not limited to, the following:

Issue	Description
Non-Profit Operation	Provisions for ensuring that the new entity is operated on a non-profit basis.
Requirements for Membership	Specified requirements for membership, both at the time of formation as well as in the future, including any size threshold, application requirements and approval criteria. Additionally, specifications of the requirements under which transfer of membership (e.g., to successor organizations) would be permitted.
Board Representation	Specifying the number of Board members from the utilities and whether the Board members will be management personnel or Board representatives of each utility. Also, specifying provisions related to representation of the State of Alaska and/or outside parties on the Board, as well as the identification of any required qualifications and powers of Board members, compensation for Board involvement, voting provisions and the identification of officers and their respective roles and responsibilities.
Formation of Management Committees	Identification of any management committees that will be formed to support the operations of the Board, along with the specification of the roles, responsibilities, and membership of those committees.
Meetings	Provisions for annual, monthly and special Board meetings, as well as committee meetings, including meeting notifications, quorum requirements, and open meetings requirements.
Decision-Making and Approval Process	Identification of the types of decisions that require Board and/or management committee approval and the specification of the percentage of votes required for approval.
Issuance of Debt	Provisions that require Board approval to enable the regional entity to issue debt or assume any other financial obligations and whether RCA approval is required.

Issue	Description
Purchase of Power, Adherence to Results of Economic Dispatch, Regional Planning Process and Joint Project Development	Specification of the responsibilities of the utilities with regard to purchasing power from the regional entity, and abiding by the decisions of the regional entity with regard to economic dispatch, regional resource planning and joint project development.
Termination of Membership	Specifying the conditions under which a utility can terminate their participation in the regional entity, including required notice provisions and related approval process.
Merger, Consolidation or Dissolution of Regional Entity	Specifying the conditions under which the regional entity can be merged, consolidated or dissolved including any restrictions regarding the period of time before such action can be taken. Also, specification of how the assets, property, debts and other liabilities of the regional entity will be dissolved if such action is taken.
Indemnification of Directors, Management Personnel, Employees, and Agents	Providing, under certain circumstances, for indemnification of present and former Directors, management personnel, employees and agents for their acts or omissions during the course of their official responsibilities.
Contracting	Provisions under which the regional entity can enter into contractual arrangements and the required approval process for such contracts.
Rules, Regulations and Rate Schedules	Provisions for the development of rules, regulations and rate schedules, related to the management, administration and regulation of the business and affairs of the regional entity.

SECTION 7 - SUMMARY OF ASSUMPTIONS

In this section, we provide an overview of the input assumptions that underlie our detailed analysis of the various Organizational Paths and Evaluation Scenarios. These assumptions relate to existing generation and transmission assets, future generation and transmission resources, as well as organizational formation and ongoing operations.

Existing System Data

Our detailed evaluation of power costs was conducted over a forward looking 30-year evaluation period between 2008 through 2037 (since the new regional entity would not begin operations until 2009, we adjusted these 2008-2037 power cost values to 2009-2038 to make the time horizon consistent to the estimated organizational costs). Accordingly the Railbelt utilities needed to provide this information for the same period for their systems. The evaluations of each Organizational Path and Evaluation Scenario were conducted in nominal dollars with the annual costs discounted to 2009 dollars for comparison using various discount rates, which were selected to represent the range of discount rates that could be considered reasonable for the Railbelt utilities. The specific discount rates used were 6.0 percent, 8.0 percent, 10.0 percent, and 15.0 percent, with 6.0 percent used as the base case. For evaluation purposes, a general inflation and escalation rate of 3.0 percent has been assumed.

Fixed charge rates were developed for new capital additions based on the cost of capital for each utility for new generating unit additions. A joint fixed charge rate was used based for the joint commitment, dispatch, and planning path. The joint fixed charge rate was based on the assumption of being able to obtain taxable and tax-exempt financing, and further assumed 100 percent debt. The assumed cost of capital and fixed charge rates are presented in the following table. In developing the cost of capital assumptions, financial advisors were consulted and a general consensus developed for purposes of estimating the cost of capital for evaluation purposes. MEA, HEA, and CEA were assumed to use National Rural Utilities Cooperative Finance Corporation (CFC) financing with an interest rate of 6.75 percent. GVEA was assumed to use RUS financing with an interest rate of 5.0 percent. ML&P was assumed to use tax-exempt municipal bond financing with an interest rate of 5.0 percent. The tax-exempt joint paths were assumed to have an interest rate of 5.0 percent and the taxable joint paths were assumed to have an interest rate of 6.75 percent. Fixed charge rates were developed only considering principle and interest for financing terms of 20, 25, and 30 years based on the expected financing lifetimes of the various alternatives.

Table 22 - Cost of Capital and Fixed Charge Rates

		Fixed Charge Rate (%) Financing Terms (Years)		
Utility	Cost of Capital (%)	20	25	30
MEA	6.75	9.26	8.39	7.86
HEA	6.75	9.26	8.39	7.86
CEA	6.75	9.26	8.39	7.86
GVEA	5.00	8.02	7.10	6.51
ML&P	5.00	8.02	7.10	6.51
Joint Tax-Exempt	5.00	8.02	7.10	6.51
Joint Taxable	6.75	9.26	8.39	7.86

A load forecast was developed for each utility through the end of the study period based on the load forecasts provided by the utilities. The load forecast includes consideration of existing DSM and conservation programs, but does not include future plans for additional DSM and conservation. The table below presents the load forecast for each utility from 2008 through 2037.

Table 23 - Railbelt Load Forecast for Evaluation (2008 – 2037)

Year	Utility Peak Demand (MW)					
	ML&P	CEA	GVEA	HEA	MEA	SES
2008	158	477	230	81	141	10
2010	168	489	237	78	149	10
2015	172	272	218	80	172	11
2020	177	285	226	80	186	12
2025	180	296	234	81	201	12
2030	185	307	243	82	216	13
2035	189	319	252	83	231	14
2037	191	324	256	84	237	14

For consistency purposes, a single reference fuel price forecast was developed and used for all of the utilities in this analysis. The fuel price forecast reflects the general inflation rate of 3.0 percent and fuel prices are on a $/MMBtu basis. Henry Hub spot natural gas prices were taken from the EIA *2008 Annual Energy Outlook* (AEO) projections and used as a starting point to forecast the price of natural gas. Natural gas is assumed to be available from the North Slope in 2020. Natural gas from the North Slope is assumed to be at a $2.00/MMBtu discount to Henry Hub, but transportation costs to the central and southern portions of the Railbelt will offset that discount. ML&P owns gas in the Beluga River Unit (BRU) gas fields. Projected prices and volumes for BRU gas were provided by ML&P. Coal price forecasts were developed by escalating the given price per ton annually at two-thirds (66 percent) the general inflation rate (2.0 percent). Average crude wellhead prices for the lower 48 states were taken from the EIA's *2008 Annual Energy Outlook* and used as a starting point for developing heavy atmospheric gas oil (HAGO) and naphtha fuel price forecasts. Distillate fuel oil prices were based on the EIA's 2008 AEO distillate fuel oil price forecast. These fuel cost projections are shown in the following table.

Table 24 - Fuel Price Reference Forecast ($/MBtu)

Year	Henry Hub Natural Gas	Coal	HAGO	Naphtha	Distillate Fuel Oil
2008	7.67	2.59	17.33	18.75	18.41
2009	8.03	2.67	17.91	19.40	15.57
2010	7.77	2.75	17.65	19.00	15.33
2011	7.61	2.83	17.49	18.73	14.98
2012	7.61	2.92	17.06	18.13	14.56
2013	7.58	3.01	16.60	17.49	14.17
2014	7.58	3.10	16.26	17.00	14.26
2015	7.65	3.19	15.85	16.41	13.93
2016	7.82	3.29	15.46	15.85	13.79
2017	8.16	3.38	15.87	16.25	14.22
2018	8.51	3.49	16.04	16.36	14.85
2019	8.89	3.59	16.60	16.96	15.53
2020	9.00	3.70	17.04	17.40	16.18

Year	Henry Hub Natural Gas	Coal	HAGO	Naphtha	Distillate Fuel Oil
2021	9.06	3.81	17.69	18.08	16.83
2022	9.55	3.92	18.38	18.82	17.54
2023	10.05	4.04	19.14	19.63	18.41
2024	10.64	4.16	19.82	20.35	19.38
2025	11.21	4.29	20.72	21.35	20.33
2026	11.84	4.42	21.72	22.44	21.41
2027	12.29	4.55	22.70	23.52	22.40
2028	13.15	4.69	23.83	24.77	23.47
2029	13.93	4.83	24.79	25.81	24.68
2030	14.68	4.97	25.69	26.78	25.83
2031	15.48	5.12	26.80	27.99	27.07
2032	16.34	5.27	27.95	29.25	28.37
2033	17.24	5.43	29.15	30.58	29.73
2034	18.18	5.59	30.41	31.96	31.15
2035	19.18	5.76	31.72	33.40	32.65
2036	20.24	5.94	33.09	34.92	34.21
2037	21.35	6.11	34.52	36.50	35.85

ML&P has an ownership interest in the BRU natural gas fields and, as a result, has natural gas available at below market prices. These prices and the volume of gas available are confidential and, as such, are not presented in this report. Production from the Beluga River natural gas field is projected to decrease over time. Likewise, that information is also confidential and not presented in this report. For evaluation purposes, the confidential price projections and annual volumes available are modeled in the production costing runs. For purposes of economy transactions, ML&P has limited the use of BRU gas for economy sales to 1 BCF per year.

Spinning reserve requirements for the Railbelt utilities are based on the largest unit on line. ML&P, CEA, GVEA, and HEA share that spinning reserve requirement in relation to their largest units on line. The current allocation of spinning reserves is presented in the following table. Spinning reserve requirements were adjusted when larger units were added for the scenarios. Non-spinning operating reserves are half of the spinning reserves.

Table 25 - Railbelt Spinning Reserve Requirements

Utility	Largest Unit	Capacity (MW)	Percentage of Largest Unit	Spinning Reserve Requirement (MW)
ML&P	Plant 2, Units 7-6	109.6	34.3	37.5
CEA	Beluga 7/8	108.6	34.0	37.2
GVEA	North Pole 2	62.6	19.6	21.4
HEA	Nikiski	39.0	12.2	13.4
Total		319.5	100.1	109.5

The Railbelt's capacity requirements are increasing over time due to load growth and retirements. The following table compares each utility's capacity to the reserves required to maintain a 30 percent reserve margin assuming the planned units retirements occur as scheduled. To the extent that planned retirements are postponed through refurbishment of existing units, the requirement for new capacity may be postponed.

Table 26 - Railbelt Capacity Requirements (2008 – 2037)

Year	Utility Excess/(Deficit) to Maintain 30 Percent Reserve					Total (MW)
	ML&P	CEA	GVEA	HEA[1]	MEA[2]	
2008	118	303	14	--	--	435
2010	105	297	6	--	--	408
2015	99	(253)	83	(54)	(205)	(330)
2020	93	(258)	(75)	(54)	(223)	(517)
2025	89	(428)	(112)	(56)	(242)	(749)
2030	82	(435)	(123)	(57)	(262)	(795)
2035	(130)	(441)	(195)	(58)	(281)	(1105)
2037	(132)	(443)	(200)	(59)	(289)	(1123)

(1) HEA currently is a full-requirements customer of CEA unitl Dec. 31, 2013

(2) MEA currently is a full-requirements customer of CEA unitl Dec. 31, 2014

The Railbelt Utilities make economy transactions based on numerous bilateral contracts subject to the existing transmission limitations. In general, the lack of natural gas for generation in GVEA's service area results in higher costs for GVEA than for the central load center, which has access to natural gas. As a result, the majority of economy transactions are based on economy sales to GVEA. For evaluation purposes for Organizational Paths 1 and 2, Strategist™ has modeled economy sales whenever they can be made with a margin of $15/MWh subject to the transmission constraints.

For modeling purposes, two major transmission upgrades were assumed for commercial operation in 2020. The Alaska Intertie currently operates at 138 kV. It was assumed that this segment would be upgraded to 230 kV. An additional 230 kV transmission line was also assumed to be constructed. This will require upgrades at the four substations along the Alaska Intertie transmission line. After the upgrades, the transfer capability will be about 250 MW.

A southern intertie is assumed to be constructed parallel to the current Quartz Creek transmission line, connecting the central and southern load centers. The transmission line will be approximately 135 miles in length and have a 230 kV rating. Adding this transmission line will increase the transfer capabilities between the southern and central load centers from 75 MW to 200 MW.

Several bills to regulate emissions of greenhouse gases (including carbon dioxide, methane, nitrous oxide, and fluorinated gas) have been proposed in the 110th US Congress. In response to a request from Senators Lieberman and Warner, the EIA developed an analysis entitled *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007,* which was published in April 2008. EIA projected carbon dioxide (CO_2) emission allowance prices were provided through the year 2030. The table below presents the CO_2 emission allowance prices used for modeling purposes. Data beyond 2030 has been extrapolated through 2037 using the average annual escalation during the last five years from 2026-2030. The CO_2 emission allowance prices were used for all Evaluation Scenarios.

Table 27 - Carbon Dioxide Emission Allowance Price Forecast

Year	$/ton
2008	-
2010	-
2015	27.44
2020	43.47
2025	69.15
2030	110.33
2035	141.69
2037	175.33

Supply-Side Alternatives Considered

This section characterizes the supply-side technologies that were considered for capacity resource additions. These alternatives include conventional, emerging, and renewable technologies. Estimated performance characteristics, emissions profiles, capital and operating costs, and availability are presented.

Cost and performance estimates have been estimated for several conventional thermal generation technologies that are proven, commercially available, and widely used in the power industry. The conventional technologies considered include simple cycle combustion turbines, combined cycle configurations, and sub-critical pulverized coal units. Additionally, cost and performance estimates were estimated for the GE LMS100 simple cycle combustion turbine, which may be considered an emerging technology.

The cost and performance estimates for conventional and emerging alternatives were developed by Black & Veatch based on a combination of estimates developed specifically for clients in Alaska, and estimates for projects in other regions of the U.S. that were adjusted for costs and conditions in Alaska. Capital costs were adjusted to 2008 dollars based on recent Black & Veatch estimates and actual project costs for equipment, materials, and labor reflecting the recent increases in costs for power plants. Performance estimates were based on specific projects in Alaska or other projects and adjusted for ambient conditions in Alaska.

Renewable energy technologies are diverse; as previously discussed, they include wind, solar, biomass, biogas, geothermal, hydroelectric, and ocean energy. The field is rapidly expanding from occupying niche markets to making meaningful contributions to the world’s electricity supply. This trend is driven by two major factors ─ subsidies and mandates.

For the purpose of this study, wind and hydroelectric are the only two renewable technologies assumed for future generation resource additions. These two resource options were included in both Evaluation Scenarios 1 and 4. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and a literature review; the generic cost estimates for renewable technologies developed by Black & Veatch included consideration of specific projects in Alaska, where available, and numerous other projects with costs adjusted for Alaska. Capital costs are in 2008 dollars and reflect the total project cost, including direct and indirect costs.

The following table shows the unit characteristics assumed for the conventional and emerging technologies; it should be noted that the options shown in the following table are representative but not exhaustive. Resource additions in Evaluation Scenario 2 were based on the natural gas alternatives shown below; additionally, they were used as “filler” resources in Evaluation Scenarios 1, 3, and 4 to match total generation to peak demands after other resource options were included. Coal was the primary resource addition in Evaluation Scenario 3.

Table 28 - Conventional and Emerging Technology Unit Characteristics (All Costs in 2008 Dollars)

Name	Net Output (MW)	Total Cost ($millions)	Primary Fuel	Forced Outage Rate (%)	Full Load Net Heat rate (Btu/kWh) HHV	Annual Scheduled Maintenance (Days/Yr)	CO_2 Emission Rate (lb/MMbtu)
GE 6B Simple Cycle	42.1	52.8	Natural Gas	2.0%	12,270	10	115
GE LMS100 Simple Cycle	98.8	123.4	Natural Gas	2.0%	8,260	10	115
GE LM6000 Simple Cycle	43.0	74.0	Natural Gas	2.0%	9,020	10	115
1x1 GE 6FA Combined Cycle	116.0	253.8	Natural Gas	3.0%	7,300	14	115
2x1 GE 6FA Combined Cycle	235.0	402.5	Natural Gas	4.0%	7,160	17	115
Sub-critical Pulverized Coal	100.0	462.4	Coal	5.0%	10,140	21	211

For the purpose of this study, wind generation project were assumed to be installed in 50 MW blocks. The wind generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimated total installed cost for the wind generation was $2,500/kW in 2008 dollars. The estimated annual capacity factor was 35 percent. The estimated fixed O&M costs were $18.00/kW-year in 2008 dollars. Ten (10) percent of the net capacity of the wind generation was assumed to contribute to the planning reserve margins. Transmission losses to deliver the wind generation to the transmission system are assumed to be 3.0 percent.

For the purpose of this study, large hydroelectric generation projects were assumed to be installed in 300 MW blocks. Each hydroelectric project was assumed to have four hydroelectric turbines, each with 75 MW capacity. The hydroelectric generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimate total installed cost for the hydroelectric projects was $5,600/kW in 2008 dollars. The estimated fixed O&M and variable O&M costs were $7.50/kW-year and $6.00/MWh, respectively in 2008 dollars. Transmission losses to deliver the hydroelectric generation to the transmission system were assumed to be 3.0 percent.

Demand-Side and Energy Efficiency Alternatives Considered

DSM and energy efficiency alternatives were assumed to cost $120/MWh. DSM/energy efficiency programs are assumed to commence at the rate of 0.5 percent of net electric load (NEL) each year beginning in 2015 and continue until 5.0 percent of NEL for load is met by DSM/energy efficiency programs.

The cost and level of DSM/energy efficiency programs were estimated by Black & Veatch based on a review of specific plans and studies for the Railbelt utilities, as well as DSM/energy efficiency program experience in the lower-48 states. The cost and level of DSM/energy efficiency programs reflect the actual situation facing the Railbelt utilities. One of the more significant factors included is the relatively low use per customer for the Railbelt utilities compared to utilities in the lower-48 states.

Organizational Formation and Ongoing Operations Costs

In this subsection, we summarize the assumptions used to estimate the start-up costs associated with the formation of a new regional entity, as well as the ongoing annual A&G costs.

Start-up Formation Costs

As the first step is developing an estimate of the start-up costs, we developed a detailed implementation plan for each alternative Organizational Path. Each of these implementation plans included a detailed listing of tasks in each of the following categories:

- Program management/governance
- Business structure
- New facility
- Business policies, processes, and procedures
- Transition planning
- HR and recruiting
- Operations and economic dispatch transition
- Generation and transmission planning transition
- IT infrastructure
- Business systems
- Employee training
- Transition and cutover
- Other

For each category identified above, we:

- Estimated the total number of days required to complete
- Estimated the breakdown of effort between utility personnel (management and staff) and outside contractors (including consulting and legal assistance)
- Estimated the total level of effort (days) for each category of utility personnel and contractors
- Estimated and applied a daily cost for each category of utility personnel and outside contractors
- Calculated the total start-up labor cost using the above factors

The following table summarizes the resulting level of effort related to the start-up of each of the alternative Organizational Paths.

Table 29 - Estimated Start-up Level of Effort

Category	Estimated Start-Up Level of Effort (Days)			
	Path 2	Path 3	Path 4	Path 5
Provide Overall Program Management/Governance	67	147	257	160
Finalize Business Structure	62	126	232	158
Secure New Facility	56	84	116	92
Develop Business Policies, Processes and Procedures	57	82	151	116
Complete Operations Transition Planning	10	12	19	15
HR and Recruiting	91	135	442	176
Complete Operations and Economic Dispatch Transition	16	314	315	313
Complete Generation and Transmission Planning Transition	0	0	86	86
Develop IT Infrastructure	125	131	276	139
Develop Business Systems	106	328	418	328
Employee Training	55	73	144	87
Transition and Cutover Execution	50	54	72	54
Other	0	0	196	196
Totals	**695**	**1,486**	**2,724**	**1,920**
Allocation of Effort				
Contractor Management	17%	17%	16%	18%
Contractor Staff	39%	38%	35%	37%
Subtotals	56%	55%	51%	55%
Utility Senior Management	18%	15%	17%	15%
Utility Staff	26%	30%	32%	30%
Subtotals	44%	45%	49%	45%
Totals	100%	100%	100%	100%

The following table summarizes the resulting labor costs related to the start-up of each of the alternative Organizational Paths.

Table 30 - Estimated Start-up Costs – Labor

Category	Estimated Start-Up Labor Cost ($'000)			
	Path 2	**Path 3**	**Path 4**	**Path 5**
Provide Overall Program Management/Governance	$68	$168	$294	$199
Finalize Business Structure	96	193	353	243
Secure New Facility	80	121	167	133
Develop Business Policies, Processes and Procedures	78	113	207	159
Complete Operations Transition Planning	13	15	23	18
HR and Recruiting	57	82	252	104
Complete Operations and Economic Dispatch Transition	12	310	310	310
Complete Generation and Transmission Planning Transition	0	0	96	96
Develop IT Infrastructure	189	199	405	211
Develop Business Systems	166	511	652	511
Employee Training	67	88	176	105
Transition and Cutover Execution	76	82	110	82
Other	0	0	285	285
Subtotals	**$902**	**$1,882**	**$3,331**	**$2,457**
Out-of-Pocket Expenses (15%)	135	282	500	369
Contingency (25%)	259	541	958	706
Totals	**$1,296**	**$2,705**	**$4,788**	**$3,532**

These implementation plans are discussed in greater detail in Section 10.

In addition to labor costs, there are a number of non-labor costs that will be incurred during the start-up of a new regional entity. Therefore, the next step in the process was to develop cost estimates for each Organizational Path related to the following:

- Control center system enhancements
- Economic dispatch and resource planning software
- Transmission planning software
- Enterprise back-office systems
- Office equipment (e.g., furniture and printers)
- Servers and network infrastructure
- Telecommunications
- Desktop hardware and software

The following table summarizes the resulting non-labor start-up costs for each alternative Organizational Path.

Table 31 - Estimated Start-up Costs – Non-Labor

Category	Estimated Start-Up Non-Labor Cost ($'000)			
	Path 2	Path 3	Path 4	Path 5
Software Capital Investment				
Control Center	$0	$500	$500	$500
Economic Dispatch/Resource Planning	0	34	34	34
Transmission Planning	0	0	154	99
Enterprise Back-Office	100	200	200	200
Subtotals	**$100**	**$734**	**$888**	**$832**
Other				
Office Equipment	127	183	591	246
Servers	72	88	92	89
Network Infrastructure	27	35	62	41
Telecommunications	54	54	54	54
Desktop PCs	43	65	211	86
Subtotals	**$324**	**$425**	**$1,010**	**$515**
Totals	**$424**	**$1,159**	**$1,898**	**$1,348**

Annual A&G Costs

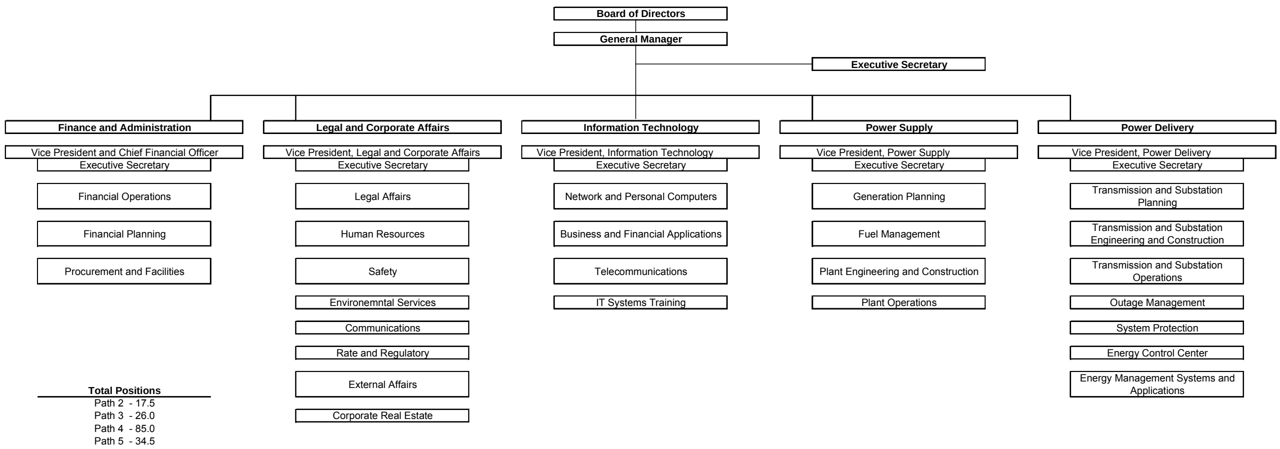
The first step in developing estimates of the 30-year annual A&G costs for each Organizational Path was to develop a prototype organizational chart. We then developed an estimate of the required number of positions in each of the following areas for each Organizational Path:

- General Manager's office
- Finance and administration
- Legal and corporate affairs
- Information technology
- Power supply
- Power delivery

We then estimated salary levels for each position and developed estimates of the number of transferred employees for each Organizational Path.

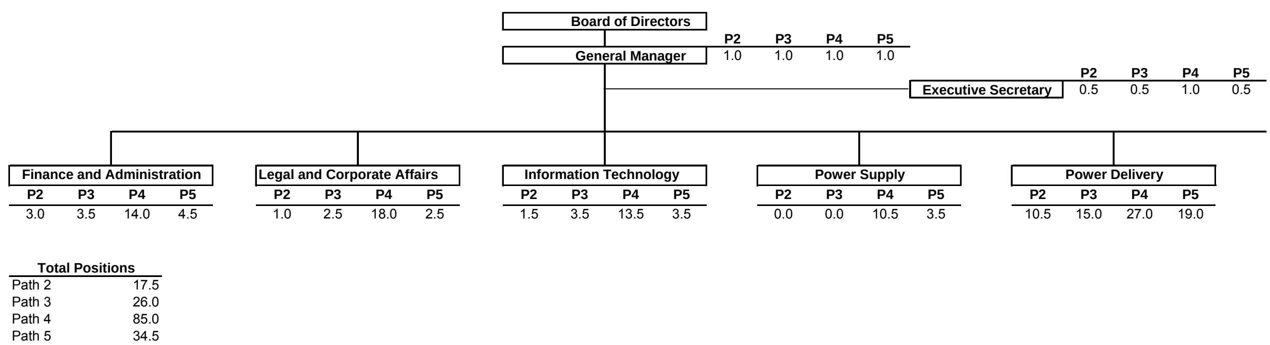
The following graphic shows the general organizational chart that would apply to each Organizational Path. Also shown is the total number of positions for each Path.

Figure 26 - Organizational Chart



The following graphic summarizes the total number of positions in each functional area for each Organizational Path.

Figure 27 - Number of Positions by Department



Next, we developed annual estimates for each Organizational Path related to the following:

- Five-year amortization of start-up labor and non-labor costs
- Total salaries and benefits
- Software licensing and maintenance costs
- Hardware maintenance and replacement
- Other non-labor costs (e.g., rent, office supplies, insurance and outside services)

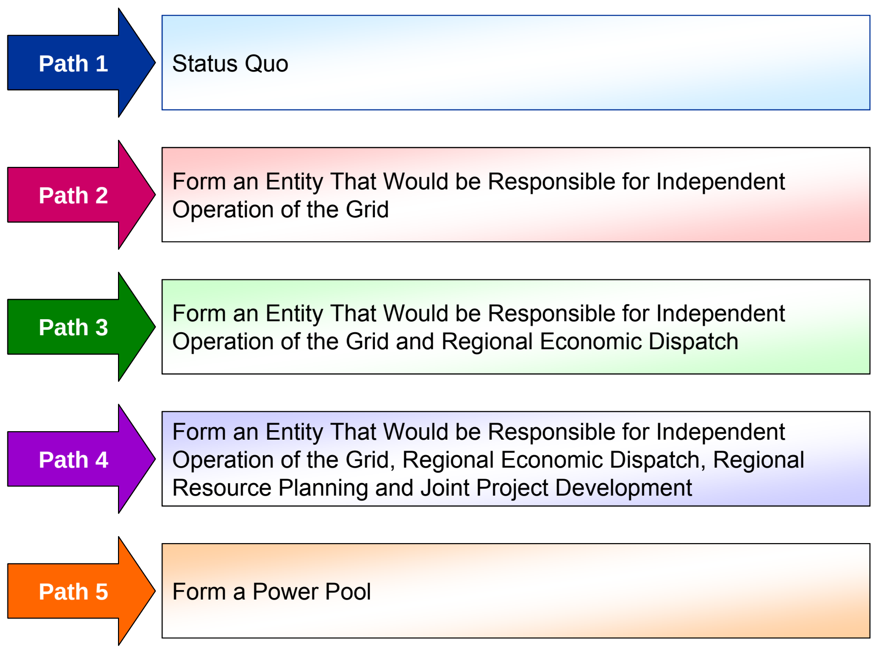
The resulting annual A&G costs are summarized in Section 8.

SECTION 8 - SUMMARY OF RESULTS

This section provides a summary of the results of our detailed economic analysis, including generation and transmission costs, organizational costs, and net benefits.

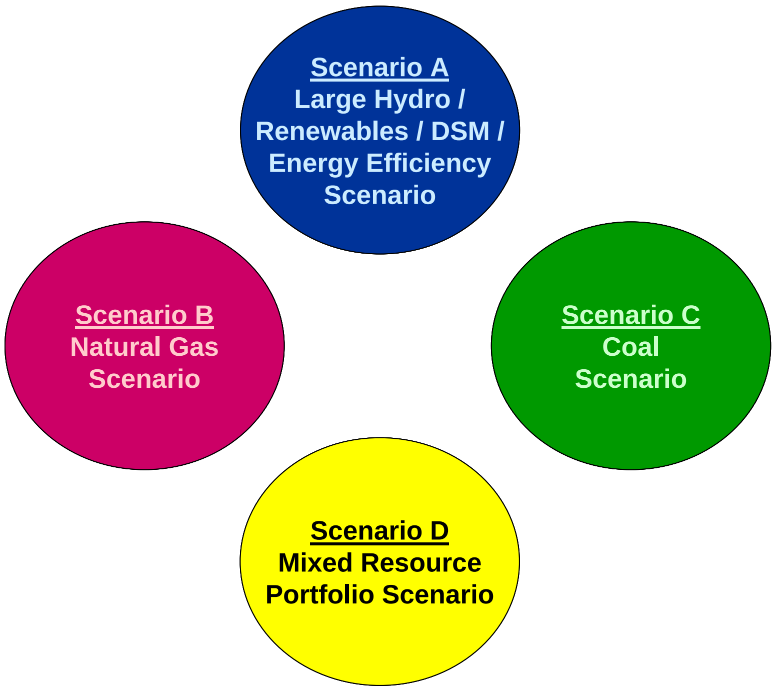
As previously discussed, we evaluated each of the five alternative organizational structures shown in the following graphic.

Figure 28 - Summary of Organizational Paths Evaluated



These five alternative Organizational Path structures were evaluated under each of the following four Evaluation Scenarios.

Figure 29 - Summary of Scenarios Evaluated



Power Cost Results

In this subsection, we summarize the economic results of our analysis of power costs under each of the alternative Organizational Paths for each of the Evaluation Scenarios. This analysis was based upon the following:

- The power cost model, Strategist™, which is described in Section 2.
- The cost and performance characteristics of the region's existing generation and transmission assets, as described in Section 5.
- The cost and performance characteristics of various resources that could be added to the region's resource portfolio, as described in Section 6.

Under the base case, we assumed that the new regional entity would be able to issue tax-exempt debt under each Organizational Path and Evaluation Scenario. As a sensitivity case, we also evaluated Organizational Path 4, for each Evaluation Scenario, under the assumption that the new regional entity would be required to issue taxable municipal bonds to finance the region's future generation and transmission assets.

The following table summarizes the average annual present worth savings in power costs, including both generation and transmission costs, for each Organizational Path and Evaluation Scenario. To calculate the average annual present worth figures shown in the tables in this Section, we discounted the 30-year stream of costs to a present worth value in 2009 using a discount rate of 6.0 percent. We then divided this value by 30 to calculate the average annual present worth value.

Note to the Readers of This Report

It is important to understand that the focus of this study is on the evaluation of alternative organizational structures for the reconfiguration of the generation and transmission functions of the Railbelt utilities. In completing this analysis, Black & Veatch evaluated alternative energy futures and developed prescriptive resource plans for each energy future considered. These prescriptive resource plans were developed to assist in the evaluation of alternative organizational paths. These prescriptive resource plans are not alternative integrated resource plans; as such, readers should not compare the prescriptive resource plans to each other nor should they draw any conclusions from this analysis as to what the optimal resource mix for the Railbelt over the next 30 years might include.

Table 32 - Average Annual Power Cost Savings
($'000)

	Path 2	Path 3	Path 4	Path 5
Tax-Exempt Debt				
Scenario A	--	$10,688	$49,228	$49,228
Scenario B	--	$9,658	$19,341	$19,341
Scenario C	--	$13,104	$43,722	$43,722
Scenario D	--	$11,263	$40,740	$40,740
Taxable Debt				
Scenario A			$34,712	
Scenario B			$16,997	
Scenario C			$37,417	
Scenario D			$31,659	

The top half of the above table shows the average annual power cost savings associated with the formation of a new regional G&T entity, assuming that the entity would be able to finance future generation and transmission asset additions using tax-exempt debt. As can be seen, the most significant savings result from Organizational Paths 4 and 5. As previously discussed, the only difference between Paths 4 and 5 is that, under Path 5, the existing Railbelt utilities would remain responsible for the joint development of future generation and transmission facilities; the resulting power cost savings are the same for both Organizational Paths because we assumed that the investment decisions made by the individual utilities under the Path 5 power pool would align and track completely with the regional resource planning decisions made by the new regional entity.

As can be seen in the table above, there are not any power cost savings associated with Organizational Path 2. This is because Path 2 involves the coordinated operation of the Railbelt transmission grid by an independent entity; the only difference between Path 2 and the status quo (Organizational Path 1) is that the transmission grid operation function would be performed by an independent entity, as opposed to the existing Railbelt which are fulfilling this responsibility today. Hence, there is not any additional power costs savings associated with this organizational Path.

Finally, the bottom half of this table shows the power costs savings under Organizational Path 4 assuming that taxable debt must be used to finance future generation and transmission asset additions. As can be seen, this sensitivity case results in lower average annual power cost savings, under each Evaluation Scenario, due to the additional financing costs associated with taxable debt relative to tax-exempt debt.

More detailed information regarding these power cost savings results are provided in Appendices C-F.

Organizational Cost Results

As discussed in Section 7, we developed a detailed estimate of the average annual present worth costs associated with the creation of a new regional entity for each of the alternative Organizational Paths. We also developed a 30-year estimate of the annual operating costs for each alternative organization, including the amortization of the start-up costs over the first five years of operations.

The following table summarizes the average annual A&G costs for each Organizational Path. As discussed previously, the total annual A&G costs include the following components:

- Five-year amortization of start-up labor and non-labor costs

- Total salaries and benefits
- Software licensing and maintenance costs
- Hardware maintenance and replacement
- Other non-labor costs (e.g., rent, office supplies, insurance and outside services)

These cost estimates do not include potential net cost savings at existing utilities.

Table 33 - Average Annual Present Worth A&G Costs ($'000)

Path 2	$1,272
Path 3	$2,459
Path 4	$6,545
Path 5	$3,132

More detailed information regarding these results is provided in Appendices C-F.

Net Savings

The following table provides an overall summary of the average annual present worth net savings (costs) under each Evaluation Scenario. In other words, this table shows the average annual present worth net savings, or increased costs, when both the power cost savings, shown in Table 32, and the annual A&G costs, shown in Table 33, are combined together.

Table 34 - Average Annual Present Worth Net Savings (Costs) Under Each Evaluation Scenario ($'000)

					Relative Path 4 Results	
Scenario	Path 2	Path 3	Path 4	Path 5	% Savings	Impact on Typical Monthly Residential Bill
Tax-Exempt Debt						
Scenario A	($1,272)	$8,229	$42,683	$46,097	10.9%	$11.50
Scenario B	($1,272)	$7,199	$12,795	$16,209	4.1%	$4.30
Scenario C	($1,272)	$10,645	$37,177	$40,591	10.8%	$11.30
Scenario D	($1,272)	$8,804	$34,195	$37,608	9.4%	$9.90
Taxable Debt						
Scenario A			$28,166		7.9%	$8.30
Scenario B			$10,452		3.6%	$3.70
Scenario C			$30,872		10.1%	$10.60
Scenario D			$25,114		7.5%	$7.90

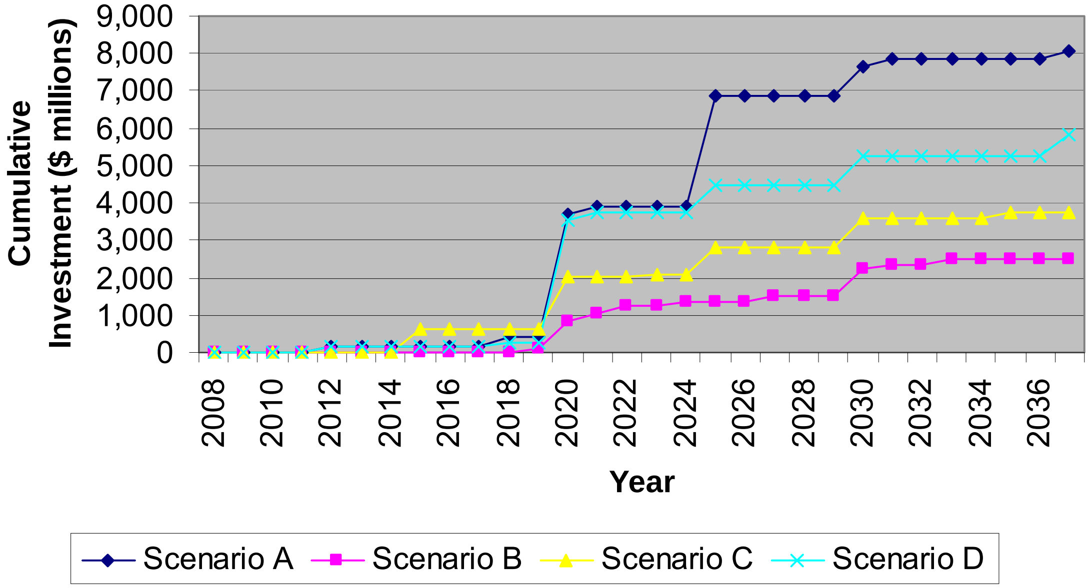
As can be seen in this table, Organizational Paths 4 and 5 offer the greatest net annual savings, and these savings are significant relative to the status quo (Organizational Path 1). While the net annual savings for Organizational Path 4 are less under the taxable debt sensitivity case, they are still significant.

The above table also shows the percentage savings relative to the total power costs under Organizational Path 4, as well as the resulting impact on typical monthly residential bills.

Cumulative Capital Requirements

The following figure shows the cumulative capital requirements over the next 30 years resulting from the generation and transmission expansion plans for each of the four Evaluation Scenarios. As can be seen, the future cumulative capital requirements range from $2.5 billion for Evaluation Scenario B to $8.1 billion for Scenario A. This graphic also shows the fact that these capital expenditures do not occur evenly over the 30-year period. In developing this graph, we assumed that all of the capital expenditures associated with a specific project would occur in the initial year of commercial operation since we did not develop a detailed cash flow projection for each project. While this assumption is not reflective of reality, since project construction costs occur over several years, this graphic does demonstrate that there are specific periods during the 30-year planning horizon during which capital requirements will be particularly high.

Figure 30 - Required Cumulative Capital Investment



SECTION 9 - CONCLUSIONS AND RECOMMENDATIONS

This section provides a summary of our conclusions and a detailed description of our recommendations regarding the reconfiguration of the Railbelt utilities, based upon the results of this study, as discussed in Section 8.

Conclusions

We have organized our conclusions into the following four subsections:

- Selection of Path 4
- Issues Associated With Selection of Specific Legal Form
- Strategies for Issuing Tax-Exempt Financing
- Summary Evaluation of Alternative Legal Structure

Selection of Path 4

There are clear benefits to the Railbelt region if a new regional G&T entity is formed. Organizational Paths 4 and 5 using tax-exempt debt clearly provide the most significant average annual present worth net savings under each of the four Evaluation Scenarios considered. This is shown in the following table. As noted earlier, these net savings include power costs (including generation and transmission costs), the amortization of organizational start-up costs, and annual organizational A&G costs for each Organizational Path under each Evaluation Scenario.

Table 35 - Average Annual Present Worth Net Savings (Costs) Under Each Evaluation Scenario ($'000)

					Relative Path 4 Results	
Scenario	Path 2	Path 3	Path 4	Path 5	% Savings	Impact on Typical Monthly Residential Bill
Tax-Exempt Debt						
Scenario A	($1,272)	$8,229	$42,683	$46,097	10.9%	$11.50
Scenario B	($1,272)	$7,199	$12,795	$16,209	4.1%	$4.30
Scenario C	($1,272)	$10,645	$37,177	$40,591	10.8%	$11.30
Scenario D	($1,272)	$8,804	$34,195	$37,608	9.4%	$9.90
Taxable Debt						
Scenario A			$28,166		7.9%	$8.30
Scenario B			$10,452		3.6%	$3.70
Scenario C			$30,872		10.1%	$10.60
Scenario D			$25,114		7.5%	$7.90

Path 4 Versus Path 5

As can be seen in the table above, Organizational Path 5 is slightly more cost effective than Path 4. Consequently, the net annual savings under Path 5 are shown to be greater than under Path 4. These incremental annual savings result from Path 5's lower annual A&G costs arising from the fact that the required size of a regional power pool is smaller (i.e., fewer staff and related costs) than for a fully functioning regional generation and transmission entity (i.e., Path 4). These incremental annual net savings under Path 5 may not, however, be realized for two reasons.

First, under Path 5, the existing utilities remain responsible for the development of their own future generation and transmission resources. This results in lower staffing requirements for the regional entity but, on the other hand, it means that the individuals at the existing utilities who are currently responsible for these activities would remain at the existing Railbelt utilities and, therefore, the Railbelt utilities would continue to incur the full payroll costs associated with these individuals. This was not fully reflected in our cost analysis. As a result, the incremental net annual savings of Path 5 would be less.

Additionally, we assumed that the power cost savings under Path 5 would be the same as Path 4. This, in essence, means that the decisions made by the individual Railbelt utilities regarding investments in future generation and transmission resources would completely align and track with the results of the regional resource planning process conducted by the regional entity. While incentives and penalties can be incorporated in the power pool's cost allocation methodology to induce the individual utilities to behave in this manner, there is no guarantee that this will happen. Hence, it is very possible that the actual power cost savings under Path 5 would, in fact, be less than under Path 4, and the resulting decrease in power cost savings could easily be greater than the savings in A&G costs under Path 5.

Therefore, we view Path 5 as more of a transition strategy towards the development of a fully functioning regional generation and transmission entity, not the ultimate optimal end-state for the region. We further believe that the region should move directly to the optimal end-state; therefore, we are not recommending the formation of a power pool, even as a transitional strategy.

Improving the Economics of Path 4

We used conservative assumptions in our organizational cost estimate (i.e., we tried to present the worst case scenario in terms of the start-up and annual operating costs associated with the formation of a new regional entity). As a result, there are several ways that the start-up and annual operating costs could be reduced, thereby improving the overall economics of Path 4. Specifically, Black & Veatch did not assume:

- Any savings at the existing utilities resulting from greater coordination; in fact, such savings are possible. As an example, the formation of a regional entity is likely to result in greater coordination of maintenance activities throughout the Railbelt region. This increased coordination would increase the net savings associated with the formation of a regional generation and transmission entity.
- That the new entity would staff up rapidly which would have reduced the total start-up labor costs. As the regional entity adds staff, those individuals can take on additional responsibilities related to the formation of the new entity. Quickly adding staff to the new regional entity could reduce the level of consulting and legal assistance that we assumed would be required to form the new entity, thereby potentially reducing overall start-up costs.
- That any of the existing Railbelt utilities' business systems, policies, and procedures would be transferred to the new regional entity. As with any new organization, the new regional entity will need to develop business systems, policies and procedures. Potential savings could occur if some of these systems, policies or procedures were, in fact, transferred to the new regional entity, and then modified to meet its own unique needs.
- Any savings from the consolidation of the three existing control centers. We recommend that the three control centers be consolidated into two centers, one primary and one back-up. Such consolidation most likely would result in some savings that we did not include in our analysis; based on discussions with utility representatives, these potential savings are not expected to be significant.

Non-Economic Benefits Associated With Formation of a Regional Entity

There are a number of benefits associated with the creation of a fully functioning regional generation and transmission entity (i.e., a Path 4-type entity) that go beyond the economics that were modeled in our analysis. These additional benefits include the following:

- Economies of scale and coordination related to staffing. Examples include:
    - Better coordination is possible if all regional employees with generation and transmission responsibilities are part of one organization.

- Depth of bench – it is easier to take advantage of the depth of everyone's skills and expertise when everyone works for one organization, and greater specialization can occur.
- The concentration of staff increases the ability of the regional entity to keep abreast of new technologies (e.g., renewables) and industry trends.
- The concentration of staff also increases the ability of the Railbelt region to develop and support the delivery of cost effective renewables and DSM/energy efficiency programs.

- The concentration of staff would likely lead to more sophisticated generation and transmission planning, resulting in better regional resource planning decisions.
- A regional entity, with rational regional planning, enables the region to identify and prioritize projects on a regional basis and it puts the State in a better position to evaluate, award and monitor funding.
- The formation of a regional entity could lead to a reduction in the required levels of reserve margins over time.
- A regional entity is better able to integrate non-dispatchable resources, such as wind and solar.
- With regard to project development, the concentration of staff within one organization increases the ability to make timely and effective mid-course corrections, as required.
- A regional entity is in a better position to manage risks which is particularly important given the current circumstances in the Railbelt region.
- A regional entity is more likely in a better position to compete in a competitive marketplace for human resources and to offset, somewhat, the impacts of an aging workforce.
- A regional entity could also result in other cost savings not captured in our economic modeling, including:
    - The region would need to develop only one regional Integrated Resource Plan, as opposed to three or more Integrated Resource Plans, every three to five years.
    - Legal and consulting expenses can be reduced as more issues are addressed on a regional basis versus on an individual utility basis.
    - Total staffing levels in certain areas on a regional basis can likely be reduced.
    - Better access to lower cost financing due to the overall financial strength of the regional entity relative to the six individual utilities.
- The formation of a regional entity can increase the flexibility of the region to respond to major events (e.g., a large load increase, such as a new or expanded mine).
- A regional entity would be in a better position to work with Enstar Natural Gas Company and the gas producers to address the region's energy issues in a more comprehensive manner.

Issues Associated With Selection of Specific Legal Form

In this subsection, we will discuss the following issues that relate to the choice of the specific legal form for the formation of a regional Path 4-type entity. It is clear that the formation of a new regional entity will result in significant benefits. The question then becomes whether the new entity should be a State Power Authority, G&T Cooperative, or some other legal form. We believe that there are a number of factors that should be considered in making the decision as to which legal form to select. The following discussion addresses what we consider the most significant factors regarding this choice.

- Examples of Alternative Business Structures
- Region's Ability to Finance the Future
- Value of State Financial Assistance
- Value of RUS/FFB Financing
- Value of Tax-Exempt Financing
- Overall Summary of Issues Associated With the Selection of Specific Legal Form

Examples of Alternative Business Structures

The formation of a regional generation and transmission entity, whether it be a State Power Authority or G&T Cooperative, is not a new concept; numerous examples of such organizations exist throughout the country. The following table provides a list of selected State/Federal Power Authorities and G&T Cooperatives that have been established in other regions of the country.

Table 36 - Example Regional Generation and Transmission Entities

State/Federal Power Authorities	G&T Cooperatives
• New York Power Authority	• Alabama Electric Cooperative
• Long Island Power Authority	• Associated Electric Cooperative, Inc.
• Bonneville Power Administration	• Basin Electric Cooperative
• Tennessee Valley Authority	• Buckeye Power, Inc.
• Under Consideration:	• Dairyland Power Cooperative
♦ Connecticut	• East Kentucky Power Cooperative
♦ Illinois	• Hoosier Energy Cooperative
♦ New Jersey	• South Mississippi Electric Power
♦ Rhode Island	• Western Farmers Electric Cooperative

In Appendix B, we provide descriptions of a number of different organizations that currently exist within the U.S. that are similar to the types of organizations considered in this study, including:

- State/Federal Power Authorities
- G&T Cooperatives
- Joint Action Agencies
- Other Types of Regional Generation and Transmission Entities
- Centralized Energy Efficiency Organizations

In the formation of a new regional G&T entity, the State can benefit from the experience and lessons learned of others throughout the country and that is why we have considered them as part of this study.

Region’s Ability to Finance the Future

As discussed previously, the region is facing very significant future capital investments over the next 30 years, ranging from $2.5 billion to $8.1 billion depending upon the future resource portfolio that the region selects. The following table provides some relative consolidated Railbelt utility statistics, based upon information provided in the utilities’ annual reports, to highlight how significant of a challenge the region faces in terms of financing its future. It is clear that the total net electric plant of the region will increase very significantly. The outstanding total long-term obligations for all six existing Railbelt utilities is at the present time approximately $1.1 billion. Therefore, issuing debt to meet the future capital requirements of the region will increase the long-term obligations of the region a minimum of two times and possibly as much as seven times. This is further supported by the fact that the current “equity” of the six Railbelt utilities is slightly less than $0.6 billion.

Table 37 - Estimated Required Capital to Finance the Region's Future

Scenario	Required Capital Investment Over Next 30 Years – Path 4 *($'000,000)*
A – Hydro/Renewables/DSM	$8,070
B – Natural Gas	$2,475
C – Coal	$3,769
D – Mixed	$5,840

Combined Railbelt Utility Financial Information - 2007 *($'000,000)*

- Total Net Electric Plant $1,475
- Total Revenues $729
- Total Long-Term Obligations $1,081
- Total "Equity" $588

An important point to keep in mind is that regardless of whether the future required investment is $2.5 billion or $8.1 billion, that investment will need to be recovered through rates, thereby resulting in higher monthly bills for residential and commercial customers.

Value of State Financial Assistance

As a result of these very significant capital requirements and their resulting impact on rates, obtaining financial assistance from the State of Alaska will be very important. This assistance could come in a variety of forms, including grants and or loans. This type of assistance is the most direct way to minimize the impact on monthly electric bills as it lowers the amount of debt that would need to be raised from other sources of financing.

The following table shows the direct impact of State financial assistance per $1 billion of assistance versus financing the capital needs from the Railbelt utilities and recovering these financing costs from customers. We show the annual savings that would result under two cases: 1) the assistance is provided in the form of a grant, and 2) the assistance is provided in the form of a zero-interest loan. These annual savings are based on the potential reduction in annual financial carrying costs (7.86 percent in the case of a grant and 4.52 percent in the case of a zero-interest loan) associated with each $1 billion in avoided debt raised in the municipal bond market.

Table 38 - Value of State Financial Assistance (per $1 Billion of Assistance)

Form of Assistance	Annual Savings *($'000,000)*
Grant	$78.6
Zero-Interest Loan	$45.2

"Where the State could get involved is the installation of infrastructure. We often speak of transmission as highways that carry energy. Social planners know that where roads go economic activity follows. If the State were to make infrastructure funding available, private investment could be attracted for hydro projects such as the Chakachamna hydro project."

Project Developer

"I believe the State of Alaska has a vested interest in future matters of the Railbelt utilities from a "maximum benefit" perspective, an economic stability perspective, a military security perspective, and a public heating/electrical crisis management perspective."

Renewable Energy Advocate

"The major hurdle for any type of development is cash equity in the project and the appropriate amount of financing that would allow a stabilized rate that the utility and the customer can rely upon. The only way that I see that happening is with some major involvement and buy-in by the State of Alaska and that must include the Governor's Office and the Legislature."

Financial Community Representative

Value of RUS/FFB Financing

One source of financing for a Path 4-type entity available to the region is the United States Department of Agriculture's (USDA) Rural Development Electric Program. This program, which is administered through the RUS, makes loans and loan guarantees to finance the construction of electric distribution, transmission and generation facilities, including system improvements and replacements required to furnish and import electric service in rural areas, for demand-side management and energy conservation programs, and for on- and off-grid renewable energy systems.

"I suggest that the State get involve in a major way to implement infrastructure to support the electrical system in the State. The reason being that without it, there is no economic development in the State and consequently no reason for people to come here or stay here."

Financial Community Representative

Under this program, loans are made to corporations; states; territories and subdivisions; and agencies such as municipalities, public utility districts, and cooperatives; non-profit, limited-dividend, or mutual associations that provide retail electric service to rural areas or supply the power needs of distribution borrowers in rural areas. USDA Rural Development also provides financial assistance to rural communities with extremely high energy costs to acquire, construct, extend, upgrade, and otherwise improve energy generation, transmission, or distribution facilities. USDA Rural Development services approximately 700 active electric borrowers in 47 states.

Guaranteed loans are provided by USDA Rural Development primarily through the FFB, CFC, and the National Bank for Cooperatives (CoBank). The FFB is an agency within the Treasury Department, providing funding in the form of loans for various government lending programs, including the guaranteed loan program. FFB loans are guaranteed by the USDA and are available to all electric utilities that meet certain requirements. FFB interest rates are fixed to the prevailing cost of money to the United States Treasury, plus an administrative fee of one-eighth of one percent. Under this program, loans are executed by the borrower and FFB, CFC, or CoBank, with payment of principal and interest guaranteed by USDA. CFC and CoBank rates are negotiated between the lender and the borrower.

Important elements of this financing source include:

- Attractive interest rate, set at the Treasury rate plus 1/8 percent; historically, this rate has been slightly greater than the tax-exempt municipal rate for similar credit ratings.
- RUS/FFB financing is capped, through Congressional appropriations, at a level that will make it difficult for the region to rely solely on this source:
  - The current appropriation is $6.6 billion, including $3.2 billion for generation- and transmission-related investments.
  - Over the past 30 years, the average level of total appropriation has been $1.85 billion.
- RUS/FFB money is intended for rural communities; given that the majority of the Railbelt region would not qualify as rural under the RUS/FFB rules, the amount of money that would be available from the RUS/FFB would be further restricted.
- RUS/FFB currently has a technology preference related to renewables, including hydroelectric facilities.
- RUS/FFB financing is available to both a State Power Authority and G&T Cooperative.

Based upon the above, the RUS/FFB represents one potential source of financing for the future; however, this source cannot be relied upon to provide all of the financing that will be needed to meet the future needs of the region.

Value of Tax-Exempt Financing

As previously discussed, the ability of a regional entity to issue tax-exempt debt would also have significant benefits. The amount of this benefit is a direct function of the region's "fuel future" in that the greater the up-front capital costs (e.g., development of a large hydroelectric or coal plant), the greater the savings. This is shown in the following table.

Table 39 - Value of Tax-Exempt Financing

Scenario	Required Capital Investment Over Next 30 Years – Path 4 *($'000,000)*	Potential Annual Savings Associated With Tax-Exempt Financing (Assuming 175 Basis Point Differential) *($'000,000)*
A – Hydro/Renewables/DSM	$8,070	$141
B – Natural Gas	$2,475	$43
C – Coal	$3,769	$66
D – Mixed	$5,840	$102

This table shows the annual savings in interest payments based upon an assumed 1.75 percent (175 basis points) difference in the taxable interest rate and the tax-exempt interest rate. As can be seen, annual savings range from approximately $40 million to $140 million depending upon the region's future resource portfolio. We also show the resulting percentage savings in power costs, as well as the impact on typical monthly residential bills.

In a perfect world, the interest rate applicable to a tax-exempt bond would, at least, approximate the rate applicable to a taxable bond with similar maturity and similar security, but the interest rate would be lower to reflect the value to the bondholder of not having to pay federal income tax on the interest earned on the tax-exempt bond. Of course, in the real world, the difference between taxable and tax-exempt interest rates varies from day to day and from bond issue to bond issue. It is a matter that is affected by a wide variety of factors.

There is no generally applicable spread between taxable and tax-exempt rates. It is generally true that tax-exempt rates are lower than taxable rates (assuming all other factors, such as those discussed below, are identical), but there is no specific guideline that can be relied on at all times. Nevertheless, historical experience has shown that a 1.5 percent to 2.0 percent (or 150 to 200 basis points) differential is a good general guideline. Accordingly, that is why we have assumed the 175 basis point mid-point as an average differential for purposes of this study.

The most significant factor that pertains to the interest rate that would apply to a given tax-exempt financing on any given day, beyond the general difference between the taxable and tax-exempt bond markets, is the security for the particular bond issuance. This is where ratings are particularly important. The rating agencies (Standard & Poor's, Moody's, and Fitch) assess the financial strength of the issue and assign a rating that is meant to reflect that strength. The strongest rating is AAA (or Aaa, in the case of Moody's). Minimum investment grade ratings (i.e., minimum ratings that will qualify a bond for being purchased by managers of large investment funds) are no lower than the B category. So-called "junk bonds" carry the highest interest rates because of the perceived security risk involved and are generally rated (if rated at all) in the C category or below. On any given day of issuance, the higher the rating assigned to the bond, the lower the likely interest rate applicable to it. Conversely, a lower rating should result in a higher interest rate. If all other factors are equal, one would expect that two bonds with equal ratings would trade at identical interest rates on a given day. Again, the real world intercedes, and on any given day two bonds with identical ratings will not necessarily bear the same interest rate even if other factors (e.g., the type of bond, the terms of the bond, the particular issuer, and others) are substantially the same.

Another aspect of the security for the bonds is the financial strength of the issuer and the financial strength of the issuer's project or program. This is the reason that the official statement (or other offering document) for a series of bonds usually goes into some detail in discussing the issuer of the bonds, the project or program being financed with proceeds of the bonds, the source of money expected to be used to repay the bonds, and other matters relating to the financial backing for the bonds.

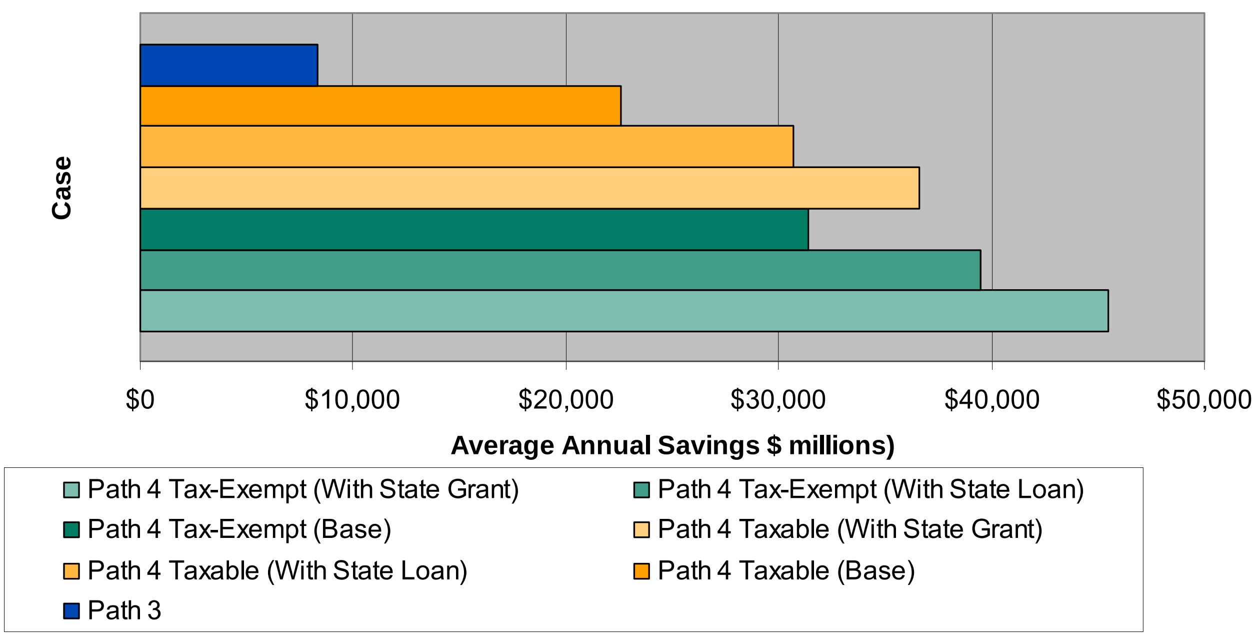
Overall Summary of Issues Associated With the Selection of Specific Legal Form

The discussion above was intended to highlight the significant challenges facing the region in terms of financing the future and to discuss the value of, and challenges associated with, State financial assistance, RUS/FFB financing, and tax-exempt financing.

Given the magnitude of the required future capital investments, Black & Veatch believes that minimizing the costs associated with financing the future is a critical objective and should have a direct impact on the choice of the legal form (i.e., State Power Authority, G&T Cooperative, or another form) for the new regional entity.

The purpose of the following graphic is to summarize the importance of State financial assistance and tax-exempt financing.

Figure 31 - Summary of Potential Savings



First, the graphic above shows how the savings associated with Organizational Path 3 compared to various estimates of the savings associated with Path 4. As can be seen, Path 4, regardless of the source of financing, provides significant incremental savings relative to Path 3.

The following cases are shown for Path 4:

- **Taxable (Base)** – the savings shown are based upon our detailed analysis of Path 4 assuming financing with taxable debt.
- **Taxable (With State Loan)** – these are the savings resulting from a $1.0 billion zero-interest loan from the State and taxable debt for the rest of the required financing.
- **Taxable (With State Grant)** – these are the savings resulting from a $1.0 billion grant from the State and taxable debt for the rest of the required financing.
- **Non-taxable (Base)** – the savings shown are based upon our detailed analysis of Path 4 assuming financing with tax-exempt debt.
- **Non-taxable (With State Loan)** – these are the savings resulting from a $1.0 billion zero-interest loan from the State and tax-exempt debt for the rest of the required financing.
- **Non-taxable (With State Grant)** – these are the savings resulting from a $1.0 billion grant from the State and tax-exempt debt for the rest of the required financing.

This graphic shows that State financial assistance provides the greatest direct benefit; the savings shown would increase proportionally if the level of State financial assistance, either in the form of a grant or low-interest loan, is greater than $1 billion. The graphic also shows the significant benefits that will result if the new regional entity is able to issue tax-exempt debt.

Strategies for Issuing Tax-Exempt Financing

While the potential benefits of tax-exempt financing are significant, so are the challenges associated with meeting the specific restrictions of the Internal Revenue Code and regulations. These challenges are summarized in Section 6 and are discussed in detail in Appendix G. Since the operations of the new regional entity would exceed two counties (boroughs in Alaska) and it would not satisfy the sunset rule, private activity bonds are not available for tax-exempt financing (unless a special permission is obtained through passage of a federal law). To obtain tax-exempt financing for future generation and transmission resources that are built by the new regional entity, the bonds would need to be government obligations bonds.

There are a limited number of potential solutions to enable the regional entity to issue tax-exempt government obligation bonds, including:

- Retail Requirements Approach (in Appendix G, this is referred to as the “Pirog/Boness Approach”)
- 63-20 Corporation
- Alaska Railbelt Corporation
- Tax Exemption Through an Act of Congress (e.g., Bradley Lake Hydroelectric Plant)

“The solution probably lies in increasing the mission and authority of the regulatory commission so they can engage in practices that facilitate the energy policy goals. Chief in these new roles would be proactive and future focused rate making actions and approvals for new generation projects.”

Fuel Supplier

* * *

“All of these things will be developed appropriately, either by utilities or by customers, if the prices are appropriate, and they will not be developed appropriately if the prices are not appropriate. Our suggestion, therefore, is to concentrate on ways to get the prices right.”

Utility Representative

* * *

“The regulatory environment is inconsistent and reactive, thus increasing business risks and reducing reliability and consistency.”

Anchorage Chamber of Commerce, Findings and Conclusions About Alaska’s Energy Crisis

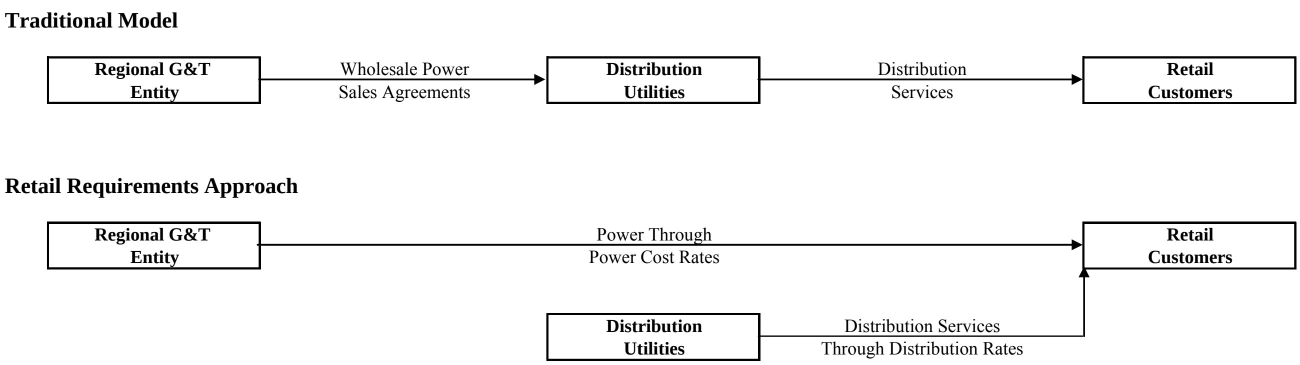
Each of these strategies are discussed below.

Retail Requirements Approach

Under the Revenue Requirements Approach, a public corporation of the State would be created (or the Alaska Energy Authority could be legislatively retrofitted) to issue bonds to finance the construction of future generation and transmission assets and own these assets. The Railbelt utilities would continue to provide traditional distribution services, such as moving power from transmission/distribution substations to individual customers, meter reading, turn-ons/offs, responding to customer inquiries, etc.; however, the public corporation would sell the electricity generated by the new generation facilities directly to retail consumers on a "requirements" basis. There would be no minimum purchase obligation and there would be no power sales agreement with any of the cooperative utilities, as discussed below. Since this arrangement would not result in private business use of the facilities, the bonds would not pass the private business use test and, thereby, they would remain government obligations and not private activity bonds. It is worth noting that this strategy is being considered as part of the Chugach/ML&P merger discussions.

This approach is summarized in the following graphic and discussed below.

Figure 32 - Overview of Retail Requirements Approach



Under the Retail Requirements Approach:

- A public entity would be formed to:
  - Determine which generation and transmission assets to add in the future
  - Oversee the development, and fully or partially finance these asset additions
- The regional public entity would finance a sole or undivided ownership interest in future generation and transmission facilities using tax-exempt debt, and:
  - Supply its governmental customers (i.e., ML&P and SES) on a wholesale basis
  - Sell directly to the retail customers of the electric cooperatives.

  It should be noted that two of the existing Railbelt utilities are publicly-owned municipal entities. As such, the State Power Authority could sell electricity to these utilities for distribution by these utilities to their customers. The sale of electricity from one governmental entity to another does not create private business use.
- The existing utilities would continue to serve their customers with electricity generated by their own facilities. The electricity generated by the public corporation's facility would supplement the existing utilities' electricity. The public corporation would enter into contracts with the existing utilities for the use of their distribution systems and for billing services.

- The question of how the regional public entity would sell to retail customers in an electric cooperative's service territory raises a number of policy and practical questions (for example, the cooperatives are regulated by the RCA and would probably require amendments to their Certificate of Public Convenience and Necessity, CPCN, to permit such a sale).
- The power generated by the regional public entity would be dispatched and distributed throughout the region using the distribution lines of the existing utilities:
  - The regional public entity would be in direct privity with each retail cooperative customer by individual contract, tariff or statutory provision.
  - The existing cooperatives would not take "ownership" of the power generated by the regional entity.
  - Each cooperative retail customer would be required to take power only to the extent that it has requirements and would only be obligated to pay for the power it takes.
  - Each cooperative retail customer would have a separate line item on their bills to pay for the power from the regional entity.
  - Each cooperative retail customer would receive a ratable amount of power from the regional entity with the remainder of their power coming from their existing utility.
  - The existing cooperatives would act in the capacity as a limited agent of the regional entity in billing, collecting monies from retail customers, and holding such monies in trust for the benefit of the regional entity.
  - The existing cooperatives would also distribute the power over their distribution lines and charge a separate charge for such service.
  - A monthly settlements process would be established.
- As a variation of the above, the existing utilities would enter into power sales contracts with the regional public entity, under which all of the generation from their existing generation assets would be sold to the regional entity, pooled together with other power supplies, and then resold (at cost) to retail customers using the existing utilities' distribution lines and services.

The advantage of this approach is that it is currently available for use under present Internal Revenue Code provisions. The disadvantage is that it requires that a new entity be given access to at least the private utilities' service areas to provide electricity directly to those private utilities' customers. Moreover, to maintain its status as a true public entity, which is essential to this approach, the Board of Directors of the public authority could not be controlled by the Railbelt utilities. This is understandably a matter of concern to the utilities.

63-20 Corporation

This concern over control of the new regional entity can be mitigated somewhat through the use of a 63-20 Corporation. In Revenue Ruling 63-20, the Internal Revenue Service set forth conditions under which private corporations may issue tax-exempt bonds on behalf of state and municipal governments. These corporations have become known as 63-20 Corporations. The conditions set forth in Revenue Ruling 63-20 include the following:

- The corporation must be formed under the general non-profit corporation law of a state for the purpose of stimulating industrial development within a political subdivision of the State.
- The corporation must engage in activities which are essentially public in nature.
- The corporation must be an entity which is not organized for profit.
- The corporate income must not insure to any private person.
- The state or political subdivision thereof must have a beneficial interest in the corporation while the indebtedness remains outstanding and it must obtain full legal title to the property of the corporation with respect to which the indebtedness was incurred upon retirement of such indebtedness.

- The requirement that the governmental unit must have a beneficial interest in the corporation while the indebtedness remains outstanding will be met if one of the following three requirements is satisfied:
  - The governmental unit has exclusive beneficial possession and use of a portion of the property financed by the obligations and additions to that property equivalent to 95 percent or more of its fair rental value for the life of the obligations; or
  - Both of the following are satisfied:
    - The non-profit corporation has exclusive beneficial possession and use of a portion of the property financed by the obligations, and any additions to that property, equivalent to 95 percent or more of its fair rental value for the life of the obligations; and
    - The governmental unit on whose behalf the non-profit corporation is issuing the obligations: 1) appoints or approves the appointment of at least 80 percent of the members of the governing Board of the corporation, and 2) has the power to remove, for cause, either directly or through judicial proceedings, any member of the governing Board and appoint a successor; or
  - The governmental unit has the right, at any time, to obtain unencumbered fee title and exclusive possession of the property financed by the obligations, and any additions to that property, by: 1) placing into escrow an amount that will be sufficient to defease the obligations, and 2) paying reasonable costs incident to the defeasance. However, the governmental unit, at any time before it defeases the obligations, may not agree or otherwise be obligated to convey any interest in the property to any person for any period extending beyond or beginning after the unit defeases the obligations. In addition, generally the unit may not agree or otherwise be obligated to convey a fee interest in the property to any person who was a user of the property, or a related person, before the defeasance within 90 days after the unit defeases the obligations.
- The requirement that the governmental unit must obtain full legal title to the property of the corporation with respect to which the indebtedness was incurred upon retirement of the indebtedness will be met if:
  - The obligations of the non-profit corporation are issued on behalf of no more than one governmental unit and unencumbered fee title to the property will vest solely in that governmental unit when the obligations are discharged.
  - All of the original proceeds and investment proceeds of the obligations are used to provide tangible real or tangible personal property.
  - The governmental unit obtains, upon discharge of the obligations, unencumbered fee title and exclusive possession and use of the property financed by the obligations, including any additions to the property, without demand or further action on its part.
  - Before the obligations are issued, the governmental unit adopts a resolution stating that it will accept title to the property financed by the obligations, including any additions to that property, when the obligations are discharged.
  - The indenture or other documents under which the obligations are issued provide that any other obligations issued by the non-profit corporation either to make improvements to the property or to refund a prior issue of the non-profit corporation's obligations will be discharged no later than the latest maturity date of the original obligations, regardless of whether the original obligations are callable at an earlier date. In addition, the maturity date of the original obligations or any other obligations issued by the non-profit corporation with respect to the property may not be extended beyond the latest maturity date of the original obligations, regardless of whether the original obligations are callable at an earlier date. If the governmental unit has the beneficial interest described above, the obligations need not meet the requirements of this bullet.
  - The proceeds of fire or other casualty insurance policies received in connection with damage to or destruction of the property financed by the obligations will, subject to the claims of the holders of

the obligations: 1) be used to reconstruct the property, regardless of whether the insurance proceeds are sufficient to pay for the reconstruction, or 2) be remitted to the governmental unit.

- A reasonable estimate of the fair market value of the property on the latest maturity date of the obligations, regardless of whether the obligations are callable at an earlier date, is equal to at least 20 percent of the original cost of the property financed by the obligations, and a reasonable estimate of the remaining useful life of the property on the latest maturity date of the obligations is the longer of one year or 20 percent of the originally estimated useful life of the property financed by the obligations.

- The corporation must have been approved by the state or a political subdivision thereof, either of which must also have approved the specific obligations issued by the corporation.

Assuming that the requirements of Revenue Ruling 63-20, as amplified by Revenue Procedure 82 26, are met, the Retail Requirements Approach could be implemented through a non-profit corporation with a Board of Directors controlled by the utilities involved. Instead of having bonds issued, and the facility owned, by a State Power Authority, the 63-20 Corporation could issue the bonds, and own and operate the facility.

Alaska Railroad Corporation

A very special circumstance exists with the Alaska Railroad Corporation. The federal act that transferred ownership of the railroad from the federal government to the State of Alaska stipulated that bonds issued by the Alaska Railroad Corporation would be treated as government obligations and would never be treated as private activity bonds. With this special power, the Alaska Railroad Corporation could issue bonds to finance the construction of a generation and transmission facility, and the bonds would be tax-exempt government obligations and would not be private activity bonds. Theoretically, this would apply even if the facility financed with the bonds were owned by one or more of the utilities.

The State law that governs the Alaska Railroad Corporation requires the enactment of special legislation before the Alaska Railroad Corporation may issue any bonds. As a result of this State law limitation, the corporation could not issue bonds to build a generation and transmission facility until after enactment of State authorizing legislation. This imposes the time constraint of waiting for the process of passage of a State law to be completed.

In addition to requiring State legislation, involving the use of the Railroad's special power will require seeking a ruling from the Internal Revenue Service to confirm that the power actually applies to this situation. Bringing this question to the attention of the Internal Revenue Service could very well result in an effort to close the Railroad's special power. This, then, becomes a political question of what is the best use of the Railroad's power assuming that there is at least a chance that it will only be able to be used once before the federal law is changed to eliminate the power.

Tax Exemption Through an Act of Congress

Other than using the Retail Requirements Approach (through a State Power Authority or through a 63-20 Corporation) or using the Alaska Railroad Corporation, the present federal tax laws and regulations provide no realistic avenue for tax-exempt financing of future generation and transmission assets. Pursuit of tax-exempt financing without using one of these two approaches would require obtaining special federal legislative permission. This has been done at least twice in Alaska for electric generation facilities.

The Bradley Lake Hydroelectric Project received a special exemption from the two-county rule in 1984. In 1995, the Snettisham Hydroelectric Project received a special exemption from the rule that requires rehabilitation expenditures to be made when tax-exempt private activity bond proceeds are used to acquire existing property. A special exemption from the two-county rule and the sunset rule for a new generation and transmission facility would permit such a facility to be financed with tax-exempt private activity bonds.

The difficulty in obtaining a special federal exemption for bonds to finance the proposed generation and transmission facility is Congress' scoring rule. Before any tax reduction measure can be enacted, Congress now requires that a corresponding measure be enacted to balance the loss of revenue to the Federal Treasury Department. This scoring requirement did not exist when the Bradley Lake exemption was granted in 1984. The scoring requirement was in place in 1995 when Snettisham received its special exemption; however, the exemption for Snettisham was granted in connection with the sale of the Snettisham facility from the federal government to the Alaska Energy Authority.

Summary Evaluation of Alternative Legal Structures

The most readily available and viable tax-exempt bond option available to the new regional entity for the financing of future generation and transmission facilities to serve the Railbelt area of Alaska is the Retail Requirements Approach. It has the advantage of being immediately available and involving the lowest interest rate kind of bonds without the need for involvement from either Congress or the Internal Revenue Service. On the other hand, it will require State legislation and it requires that customers of at least the private utilities be served directly (i.e., not through the cooperatives) by the new regional entity. If it is a State Power Authority that issues the bonds, the control over the State Power Authority will be in the hands of the State government.

The Retail Requirements Approach could be modified by using a 63-20 Corporation, which could provide a greater level of control over the regional entity by the utilities. This would still require State legislation, but it could give the utilities greater control while the initially issued bonds are still outstanding.

An alternative is to seek bond financing from the Alaska Railroad Corporation. This will also require State legislation. Further, it will require requesting a ruling from the Internal Revenue Service and, in so doing, will bring the Alaska Railroad Corporation's special bonding power to the attention of the Internal Revenue Service. This introduces the political question of finding the best use of the Railroad's power considering the possibility that it could be the only use before the power is eliminated. The advantages of this approach are that: 1) it can be used to finance a facility owned by the utilities, 2) it does not require any other entity to provide electric service directly to the utilities' customers, and 3) it also involves the use of the lowest interest rate kind of bonds.

Finally, special federal legislation can be sought through the Alaska congressional delegation. Such federal legislation could permit ownership of the facility by the utilities without a new entity providing service to the utilities' customers. Most likely, the special exemption would still leave the bonds as private activity bonds; so, this approach would probably not involve the lower interest rates generally available to government obligations that are not private activity bonds. Also, this approach would have to address the congressional scoring requirement.

The following table provides a comparison of the alternative legal forms for the regional entity relative to certain criteria, including the discussion above regarding tax-exempt financing, as well as other considerations.

Table 40 - Comparison of Alternative Legal Forms

Criteria	Organizational Form				
			State Power Authority		
	G&T Cooperative	63-20 Corporation	Retail Requirements Approach	Alaska Railroad Corporation	Congressional Tax Exemption
Core Function	Yes	Yes	Yes	No	Yes
Ability to Issue Tax-Exempt Debt	No	Yes, With Restrictions	Yes, With Restrictions	Yes, With Restrictions	Yes, With Restrictions
Risks Associated With Ability to Issue Tax-Exempt Debt	Not Applicable	Limited	Limited	Moderate	Significant
State Oversight Related to State Financial Assistance	Depends on Number of Voting State Representatives on Board of Directors	Depends on Number of Voting State Representatives on Board of Directors	Greatest	Greatest	Greatest
Overall Strength of Organizational Structure, Board and Management Team	Greatest	Depends Upon Level of Board/Management Energy Expertise	Depends Upon Level of Board/Management Energy Expertise	Current Board/Management Lacks Energy Expertise	Depends Upon Level of Board/Management Energy Expertise
Potential Impact of Changing State Political Environment	Limited	Limited	Potentially Significant, Depending Upon Level of Board Independence	Potentially Significant, Depending Upon Level of Board Independence	Potentially Significant, Depending Upon Level of Board Independence
Flexibility	Greatest	Some Limitations	Potential Limitations	Potential Limitations	Potential Limitations
Ability to Spread Risks	Significant	Significant	Greatest	Greatest	Greatest
Direct Customer-Owned Control	Moderate	Moderate	Limited	Limited	Limited
Ability to Fund Large Projects	Moderate	Significant	Greatest	Greatest	Greatest

As shown in the table above, the generation and transmission functions of the new regional entity would be a core function for each of the alternative legal forms, except in the case of the Alaska Railroad Corporation. As has been discussed above, a G&T Cooperative would not be able to issue tax-exempt debt; under the other legal forms, the regional entity could issue tax-exempt debt, albeit with restrictions.

The risk associated with raising tax-exempt debt is limited in the case of the 63-20 Corporation and the Retail Requirements Approach, as both forms are known to qualify for tax-exempt status. This risk increases in the case of the Alaska Railroad Corporation and becomes significant relative to obtaining a Congressional tax exemption.

The next criteria in the table relates to the level of State oversight inherent with each legal form, which could have a direct impact on the willingness of the State to provide financial assistance. As can be seen, all three variations shown for the State Power Authority offers the greatest level of State oversight. This level of oversight is less for a 63-20 Corporation, and even less for a G&T Cooperative.

Next is the issue of the overall strength of the organizational structure, Board and management team. The G&T Cooperative ranks highest under this criteria because of the cumulative expertise of the likely members of the Board and management team, assuming that these individuals will come from the existing Railbelt utilities. The strength of the other legal forms relative to this criteria will depend upon the level of energy industry expertise of the individuals that comprise the entity's Board and management team.

The next criteria shows that the G&T Cooperative and 63-20 Corporation forms are the most insulated against the potential impacts of changes in the State political environment. Similarly, the G&T Cooperative legal form provides the greatest organizational flexibility.

All legal forms provide a solid foundation for spreading risks across the region. The State Power Authority offers the greatest strength relative to this criterion.

With regard to customer control of the new regional entity, the G&T Cooperative and 63-20 Corporation offer an advantage. The existing Railbelt utilities each provide local citizens and customers with the opportunity to directly influence decisions. This level of control and influence is lessened in the case of a regional G&T Cooperative or 63-20 Corporation, and is lessened even more in the case of a State Power Authority.

Finally, with regard to the ability of the regional entity to fund large projects, the State Power Authority is ranked the highest, followed by a 63-20 Corporation and then by a G&T Cooperative.

Recommendations

The following summarizes the overall recommendations arising from this study, broken down into the following three categories:

- Recommendations Related to Organizational and Legal Structure Recommendations
- Recommendations Related to Organizational Issues
- Recommendations Related to the Issues Identified in the AEA Request-for-Proposals

Recommendations Related to Organizational and Legal Structure

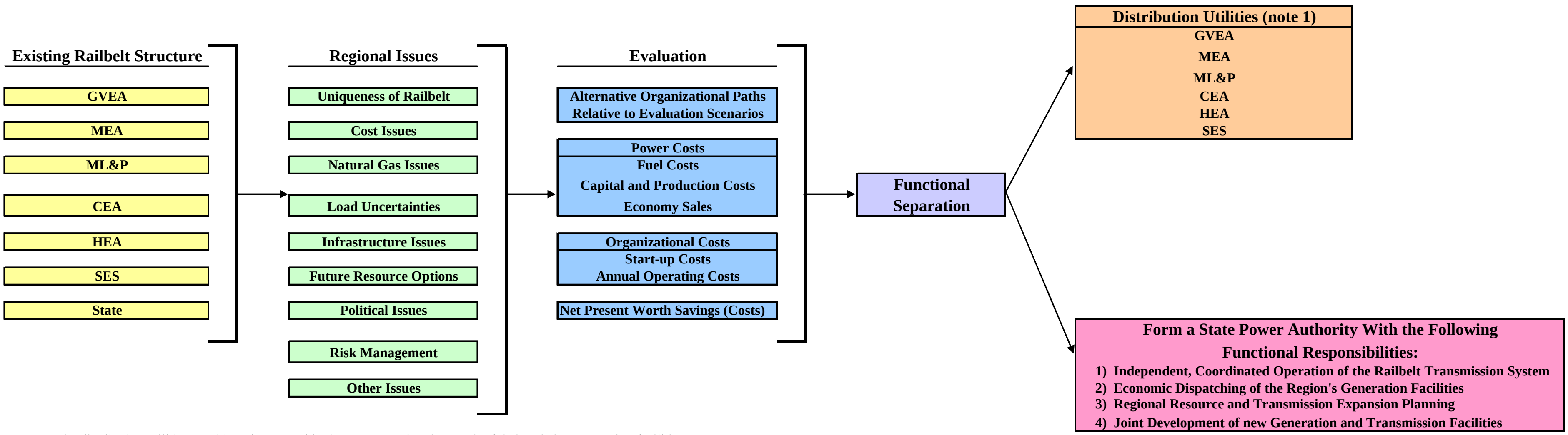
The following summarizes our recommendations with regard to the structure of the new regional entity.

- As shown in Figure 33, a new regional entity with responsibility for generation and transmission operations and future ownership should be formed; the existing Railbelt utilities would retain the responsibility for providing traditional distribution services, such as moving power from transmission/distribution substations to individual customers, meter reading, turn-ons/offs, and responding to customer inquiries. More specifically, the functional responsibilities of this new regional entity should include:
    - Independent, coordinated operation of the Railbelt electric transmission system
    - Economic dispatch of the Railbelt region's generation facilities
    - Railbelt region resource and transmission expansion planning
    - Joint development of new generation and transmission facilities for the Railbelt region
- To maximize the economic benefits associated with regionalization, the legal structure for this new regional entity should be a State Power Authority for the following reasons:
    - It is projected that the Railbelt region will need to fund between $2.5 - $8.1 billion of new capital investment over the next 30 years to build new generation and transmission facilities to reliably serve the electric needs of citizens and businesses in the region. This level of investment, which is dependent upon the future generation resource options and transmission expansion projects chosen in a regional planning process, represents a significant challenge for the Railbelt region given its small size. Having the good faith and credit of the State supporting the regional entity will minimize the financial risks and result in a lower cost for debt.
    - State financial assistance, whether in the form of a grant(s) or low interest loan(s), would provide a significant benefit to the Railbelt region. This potential assistance represents the single most significant way to reduce the burden on Railbelt citizens and businesses associated with the financing of required generation and transmission investments.
    - It seems reasonable to conclude that the Governor and State Legislature would be more willing to provide some level of financial assistance to the Railbelt region if the new regional entity was formed as a State Power Authority, as opposed to a private business such as a G&T Cooperative.
    - In addition to potential State financial assistance, forming the new Railbelt regional entity in a manner that would allow it to issue tax-exempt debt would provide a significant economic benefit to the region. A State Power Authority is in a better position to be able to issue tax-exempt municipal debt, although restrictions exist that make this a challenge.
    - Generally speaking, a G&T Cooperative is unable to issue tax-exempt debt due to Internal Revenue Code restrictions. A G&T Cooperative, as well as a State Power Authority, could obtain taxable debt through RUS/FFB at favorable interest rates relative to the rates that are available in the taxable municipal bond market. However, RUS/FFB funding is subject to Congressional appropriations (approximately $3.2 billion in FY2008 for generation and transmission facilities) and the region would need to compete against other requests from cooperatives throughout the country. Additionally, RUS/FFB money is intended for rural communities; given that the majority of the

Railbelt region would not qualify as rural under the RUS/FFB rules, the amount of money that would be available from the RUS/FFB would be further restricted. As a result, the region will not be able to rely upon the RUS/FFB to meet all of its financing requirements. Furthermore, obtaining financing through the RUS/FFB can take up to two years with no assurance of success, and the resulting covenants are typically more restrictive than what can be negotiated in the municipal bond market. As a result, obtaining RUS/FFB financing is more risky than the municipal bond market.

- If a State Power Authority is formed, it is very important that its Board of Directors and management team consists of individuals with substantive knowledge and understanding of the electric or energy industry, specifically generation and transmission, and consumer issues. Furthermore, the Board needs to be sufficiently insulated from State political cycles so that effective long-term planning and project development can occur. Without such industry expertise and independence, the Board and management team will not be able to effectively address the issues and risks facing the Railbelt region and manage the region's very substantial capital improvement program.

Figure 33 - Summary of Recommendations – Organizational Structure



Note 1: The distribution utilities would retain ownership, but not operational control, of their existing generation facilities.

Recommendations Related to Organizational Issues

The following summarizes our recommendations regarding the various organizational issues that were discussed in Section 6.

Scope of Responsibilities

Functional Responsibility	New Regional Entity
Coordinated Operation of the Transmission Grid	✓
Regional Economic Dispatch	✓
Regional Resource Planning	✓
Joint Project Development	✓

Formation Issues

Issue	Recommendations
Legal Structure	Form as a State Power Authority.
Location	Anchorage area, due to: • Centralized location • Concentration of skilled workforce • Location of majority of total regional load.
Transfer of Existing Assets and Fuel Supply Contracts	Ownership of existing assets – no. Dispatch and operational control of existing assets – yes.
Whether to Adopt a "Hold Harmless" Requirement	Yes; this is a matter of fairness and equity to stakeholders.
Transition Period	To move to average regional rates over time, consistent with hold harmless philosophy. With regard to regional transmission facilities, there is a need to develop a cost/benefit allocation methodology as part of the OATT. Existing generation facilities - fully regionalized rates by end of 10 years. Future generation facilities - costs regionalized immediately.

Operational Issues

Issue	Recommendations
O&M Responsibility	Existing generation and transmission facilities: • Initially, keep O&M responsibility with existing utilities • Utilities to develop a plan to transition O&M responsibilities to the new regional entity as soon as practical. Future generation and transmission facilities - regional entity.
Consolidation of Control Centers	Consolidate three existing control centers (GVEA, ML&P and CEA) into two control centers, one primary (either ML&P or CEA) and one back-up (GVEA), using existing systems and equipment to the extent possible.
Required SCADA/Telecommunications Investments	Limited expansion of existing systems that are in place.
Determination of Transmission Voltage Level and Treatment of Large Customers Currently Served at Transmission Voltage Levels	The new regional entity will need to make a determination regarding what will be the point of demarcation between transmission and distribution voltage levels. Additionally, the new entity will need to work with the Railbelt utilities to determine how to handle those large customers which are currently served at transmission voltage levels.

Regional Generation and Transmission Planning Issues

Issue	Recommendations
Development of New Coordinated Planning Processes	A new regional generation and transmission planning process needs to be developed, based on best practices, to provide a consistent approach to resource planning.
Requirement to Follow Results	Regional entity would take the lead in the development of future generation and transmission facilities.

Joint Project Development Issues

Issue	Recommendations
All-In or Opt-Out Option	New entity will make regional resource planning decisions and take the lead in the development of future generation and transmission facilities with all existing utilities sharing in the related costs.
Responsibility for Project Construction	Regional entity would take the lead in the development of future generation and transmission facilities.

Required Skill Sets and Staffing Levels-Related Issues

Issue	Recommendations
Total Staffing Levels	Black & Veatch's estimate of the required staffing levels for a Path 4-type entity was previously discussed in Section 7.
Organizational Structure	Black & Veatch's proposed organizational structure for a Path 4-type entity was previously discussed in Section 7.
Strategy for Transfer of Existing Employees	Utilities, collectively and individually, need to develop a strategy related to the transfer of existing employees to the new regional entity; this strategy should: 1) identify the total

Issue	Recommendations
	number of employees to be transferred, 2) identify specific employees to be transferred, 3) develop an overall compensation structure and benefits package, 4) retain each transferred employee's tenure relative to the benefits package, and 5) specify the relocation package to be offered to each transferred employee. It would be a mistake to form a new regional entity without transferring a substantive number of employees, due to: • The transfer of functional responsibilities to the new regional entity • The need to transfer regional, institutional knowledge to the new entity.
Recruiting and Relocation Strategy	The utilities will need to develop a strategy to make accepting a transfer attractive to existing employees and to recruit other employees to the new entity.
Compensation Program	It is common practice, in similar cases, to develop a compensation program for a new regional entity that is equal to or greater than existing compensation programs to provide existing employees with an incentive to transfer to the new entity. Union issues will need to be addressed in the formation of the new regional entity.

Tax and Legal Issues

Issue	Recommendations
Ability to Issue Tax-Exempt Debt	The ability of the new regional entity to issue tax-exempt debt would provide a significant economic benefit to the Railbelt region; as previously discussed, achieving this is a challenging issue and the utilities and the State of Alaska will need to further investigate this issue as the new regional entity is formed.
Transfer of Ownership of Existing Assets	Ownership of existing assets should remain with the existing utilities to: • Protect ML&P against the potential loss of its tax-exempt financing status • Eliminate the need to refinance the existing debt of existing utilities.
Transfer of the City of Anchorage's Ownership of Gas Reserves in the Cook Inlet	Under Internal Revenue Code regulations, ML&P's existing gas reserves, which were financed using tax-exempt debt, must be used within ML&P's generation facilities; therefore, ownership of existing assets should remain with the existing utilities.
Governance	As a public entity, the majority of the Board of Directors would need to be independent of the existing Railbelt utilities.

Regulatory Oversight Issues and Legislative Actions

Issue	Recommendations
Regional Integrated Resource Plans	RCA oversight limited to investigation of filed complaints. We conclude this for the following reasons: 1) regional generation and transmission entities are typically not subject to state regulatory oversight, 2) the potential conflict when one state agency oversees another state agency, and 3) we do not believe that the benefits of regulation outweigh the incremental costs.
Joint Project Development	RCA oversight limited to investigation of filed complaints.
Fuel Contracts	RCA should retain the responsibility for reviewing and approving fuel contracts related to existing generation facilities. For new generation facilities - RCA oversight limited to investigation of filed complaints.

Issue	Recommendations
Cost/Benefit Allocation Methodology	With regard to regional transmission facilities, there is a need to develop a cost/benefit allocation methodology as part of the OATT. Existing generation facilities - fully regionalized rates by end of 10 years. Future generation facilities – costs regionalized immediately.
Transmission Tariff	An OATT should be developed, with rates based on common industry standards and modeled after the FERC pro forma OATT with appropriate modifications to reflect Railbelt circumstances. Annual revenue requirement calculations should be based upon a formulaic rate structure that would be included in the OATT.
Annual Reporting Requirements	Additional annual reporting requirements should not be established.

"AEA and AIEDA can assist our resource development through the identification of renewable energy projects and the means to fund such projects. The RCA should not falter when it comes to enforcing our Governor's "mandate" to the utilities nor should it falter when enforcing the regulations by which the utilities are governed. The Palin administration should continue to show leadership on energy matters."

Consumer Advocate

"A State net-metering law would go a long way to encouraging distributed generation."

Renewable Energy Advocate Consultant

"Legislators could instill improvements in open-access and more accurate filings of "avoidable cost" rate filings."

Industry Consultant

"In general, open access to the State's natural resources, transmission infrastructure, and monopolized load centers needs to be legislatively improved to improve competition."

Industry Consultant

Other Required State Actions

Issue	Recommendations
State Energy Plan and Related Policies	The regional Integrated Resource Plan and Transmission Expansion Plan developed by the regional entity should be developed consistent with the State Energy Plan, which is under development, and related policies.

"I believe the State, through the AEA, should play a major role in matters affecting Railbelt utilities and their customers. It should expand its ownership and/or control of primary assets in the Railbelt to best serve all Railbelt consumers. The State should also encourage the private sector to compete for providing the new generation needs for the Railbelt."

Project Developer

"The State should aggressively work with all energy market players to determine the most viable and economic potential energy sources, work with a G&T entity to plan and fund infrastructure accordingly, and work with the RCA to write statutes and regulations that enable "safe, reliable and least-cost" power. The State should also work with the RCA to create incentives for residential, commercial and industrial energy efficiency and conservation education and measures."

Renewable Energy Advocate

"In a state as diverse, scattered, and sparse as Alaska is, the State has an extremely important role to play. It can provide seed money, bonds, training, educational development, incentives and goals that will provide a better energy future for all of us."

Consumer Advocate

Market Structure Issues

Issue	Recommendations
Required Changes to Market Structure	The Railbelt utilities are currently in the process of developing regional generator interconnection standards; these standards should be finalized and implemented. The OATT to be developed by the new regional entity should apply also to projects developed by IPPs.
Adoption of a Competitive Power Procurement Process	A competitive power procurement process should be developed by the regional entity that will establish a "level playing field" for IPP-proposed projects.

"In general, open access to the State's natural resources, transmission infrastructure, and monopolized load centers needs to be legislatively improved to improve competition."

Industry Consultant

"A small market in Alaska makes IPP development difficult."

Utility Representative

"I do not see IPP as a solution to the Railbelt problems; in fact I see any involvement by them as another hindrance in putting in place a real solution. Their motive is not to stabilize rates for the consumer or to work on behalf of the consumer."

Financial Community Representative

Tariff/Contractual Requirements-Related Issues

Issue	Recommendations
Open Access Transmission Tariff	An OATT should be developed, with rates based on common industry standards and modeled after the FERC pro forma OATT with appropriate modifications to reflect Railbelt circumstances. Annual revenue requirement calculations should be based upon a formulaic rate structure that would be included in the OATT.
Postage Stamp or Mileage-Based Rates	Generation-related costs – over time, move to postage rates. Transmission-related costs – postage rates.
Contracts Between Individual Parties	Existing contracts – retain as is, unless they can be transferred to the new regional entity and there is a benefit. New contracts - not allowed.

Governance Issues

Issue	Recommendations
Non-Profit Operation	Yes.
Requirements for Membership	Rules for participation would need to be established.
Board Representation	As a public entity, the majority of the Board of Directors would need to be independent of the existing utilities.
Formation of Management Committees	Yes (e.g., finance, planning, operations, and joint project development whenever a new project is under development).
Meetings	Annual and monthly Board meetings with public notification requirement. Special meetings as required.
Decision-Making and Approval Process	Management committees develop analysis and recommendations under the Board's and their own direction. Need clear definition of the nature and financial size of decisions that require Board approval and which decisions can be made by management committees.
Issuance of Debt	Any issuance of debt must be approved by Board.
Purchase of Power, Adherence to Results of Economic Dispatch, Regional Planning Process and Joint Project Development	All utilities required to adhere to the economic dispatch, regional planning, and project development decisions made by the regional entity.
Termination of Membership	Provisions need to be specified in bylaws (including length of notice and repayment of debt).
Merger, Consolidation or Dissolution of Regional Entity	Provisions need to be specified in bylaws.

Issue	Recommendations
Indemnification of Directors, Management Personnel, Employees, and Agents	Provisions need to be specified in bylaws.
Contracting	Provisions need to be specified in bylaws.
Rules, Regulations and Rate Schedules	Provisions need to be specified in bylaws.

Recommendations Related to the Issues Identified in the AEA Request-for-Proposals

The following summarizes our recommendations related to the specific issues that were identified in the original Request-for-Proposals.

Issue	Recommendations
Identify any State Statutory and Regulatory Changes Necessary for REGA Implementation	The following issues would require State statutory changes: • Formation of regional entity (including powers, legal form, governance structure, ability to purchase property, and selected bylaw requirements) • Modification of existing utilities' service territory certificates, as necessary • Establish direct privity with retail customers if the Retail Requirements Approach is adopted • Implementation of market structure changes (e.g., OATT and competitive power procurement process) • State financial assistance (e.g., grants or loans) for the development of regional generation and transmission infrastructure (based upon the results of the regional Integrated Resource Plan, once completed).
Identify Required Changes in the Regulatory Regime Under Which Utilities Operate (Including Compliance with RCA Statutes, Consideration of the Optional FERC Rules Under Order 888, and FERC Order 2000) and Determine Whether the Entity Should be Regulated by the RCA	New regional entity should not be under the jurisdiction of FERC or the RCA. We conclude this for the following reasons: 1) regional generation and transmission entities are typically not subject to state regulatory oversight, 2) the potential conflict when one state agency oversees another state agency, and 3) we do not believe that the benefits of regulation outweigh the incremental costs.
Determine What Role the RCA Should Play in Regional Planning and Whether the Regional Plan Should Require RCA Approval	RCA oversight limited to investigation of filed complaints.
Deteremine the Appropriate Relationship of the REGA to Serving Utilities	Regional entity has generation and transmission functional responsibilities and sells power to distribution utilities (or directly to their retail customers); also, perhaps, work with distribution utilities on matters of significant regional importance (e.g., development of DSM/energy efficiency programs). Existing Railbelt utilities would retain the responsibility for providing distribution services to their customers.

Issue	Recommendations
Determine Whether Economic Dispatch Should be Through a Pooled Arrangement or Through a Separate Entity	Separate entity.
Determine Whether Utilities Should Continue to do Service Area-Specific Integrated Resource Planning, or Whether There Should be a Single Regional IRP	The regional entity would be responsible for the development of one regional Integrated Resource Plan on a periodic basis (e.g., every three years).
Determine Whether all Railbelt Utilities Should be Required to Participate in and be Bound by the Regional Integrated Resource Planning Decisions	Yes, once the regional Integrated Resource Plan is approved by the regional entity's Board of Directors.
Determine Whether Investment Decisions Under a REGA Should be Subject to Individual Utility Board of Director's Approval	No, decisions would be made by the regional entity's Board of Directors.
Identify any Required Changes to Market Structure	Need to develop: • Regional generator interconnection standards • Competitive power procurement process executed by regional entity • OATT.
Determine Whether the REGA Should Consider Future Sources of Generation That Could be Provided by IPPs and, if Yes, What New System Operating Rules Would be Necessary to Allow Access to These Power Sources by Utilities in Need of Future Generation	A competitive power procurement process should be developed by the regional entity that will establish a "level playing field" for IPP-proposed projects.
Determine Whether Open-Access Tariffs Should be Required for All Transmission Lines in the Railbelt to Allow IPPs to Transmit Power to Customers	An OATT should be developed, with rates based on common industry standards and modeled after the FERC pro forma OATT with appropriate modifications to reflect Railbelt circumstances. Annual revenue requirement calculations should be based upon a formulaic rate structure that would be included in the OATT.

Issue	Recommendations
Determine the Effect That the Availability of Generation Fuels Have on the Future Functional Needs of the Railbelt Electrical Grid	The scenario analysis completed during this project has lead to the identification of the best organizational structure. Determining the effect that the availability of generation fuels will have on future resource planning decisions will need to be made in the context of the development of a regional Integrated Resource Plan.
Identify any Required Changes in Utility Management Responsibilities for Procurement of Additional Generation Under REGA	The regional entity will assume the responsibility for the procurement of additional generation resources.

SECTION 10 - NEXT STEPS AND IMPLEMENTATION PLAN

In this final section of the report, we discuss the next steps to be taken and provide a detailed plan for the implementation of the recommended regional organizational structure.

Next Steps

The following list of actions represents the most immediate steps that need to be taken with regard to the formation of a new regional entity.

> ***"The AEA could (maybe should) be strengthened. The State will need some sort of facilitator, and maybe enforcer, to take the concept of a Railbelt G&T from idea to implementation. I do not have any confidence that the utilities will do it on their own. The AEA could also be valuable in planning and evaluating infrastructure requirements for the Railbelt and Statewide."***
>
> **Fuel Supplier**

- The Railbelt utilities, in conjunction with the State, need to make the decision whether to form a new Railbelt regional entity and finalize the functional responsibilities of that entity. It is critical that this decision be made as soon as possible; the challenges confronting the Railbelt region require that action be taken now. Delay will only make the challenges greater and, if the regional entity is not formed now, decisions will need to be made by individual utilities and these decisions will not result in optimal results from a regional perspective.
- A conclusive determination regarding the ability of the new regional entity to issue tax-exempt debt needs to be made and an appropriate strategy developed. The Railbelt utilities and the State should secure the services of one or more bond counsels and bond underwriters to support this effort.
- The legal form (i.e., State Power Authority, G&T Cooperative, or 63-20 Corporation) of the regional entity needs to be finalized.
- The Railbelt utilities and the State need to establish a transition management team to oversee the formation of the new entity.
- Required legislative actions should be introduced in the new legislative session, addressing the following:
  - Formation of the regional entity (including powers, legal form, governance structure, ability to purchase property, and selected bylaw requirements).
  - Modification of existing utilities' service territory certificates, as necessary.
  - Establishing direct privity with retail customers if the Retail Requirements Approach is adopted.
  - Implementation of market structure changes (e.g., OATT and a competitive power procurement process).
  - Secure State financial assistance (e.g., grants or loans) for the development of regional generation and transmission infrastructure (based upon results of the regional Integrated Resource Plan, once completed).
- Complete the formation of the new entity, including the following actions:
  - Establish utility/state implementation team.
  - Determine need for outside assistance.
  - Revise start-up implementation plan.
- Develop initial regional Integrated Resource Plan and Transmission Expansion Plan. We have two important additional comments regarding the development of these two plans. First, it is very important that these initial regional plans be developed as soon as possible to identify the Railbelt region's future fuels strategy and transmission expansion program. Second, as part of this effort, a formal public participation process should be established, providing for transparency and broad participation by stakeholders throughout the process. The Hawaii Electric Company has such a public participation process in place which we believe provides a good example of how such a process should be established.
- The Railbelt utilities and the State need to determine how to finance the formation of the new regional entity, and develop a process to manage this seed money.

- Develop a methodology for the allocation of the costs and benefits associated with the regional entity during the recommended ten-year transition period, consistent with the hold harmless philosophy.

Start-up Implementation Plan

The actual formation of a new Railbelt regional entity, once the decision is made to form such an entity, involves a significant number of actions. These actions have been grouped into the following categories:

- **Overall Program Management/Governance**
  - Provide overall program management
  - Provide utility management/Board oversight
  - Provide administrative support
  - Manage formation seed money
- **Finalize Business Structure**
  - Finalize organizational roles and responsibilities
  - Finalize legal form
  - Form Board of Directors and related committees
  - Develop initial guiding principles
  - Develop bylaws
  - Complete legal formation requirements
  - Develop OATT and other required contracts
  - Modify existing contracts, as required
  - Develop strategy for establishing management team
  - Implement required legislative and regulatory changes
- **Secure New Facility**
  - Identify building requirements
  - Complete initial layout design
  - Secure and evaluate build/lease proposals
  - Make build/lease decision
  - Manage facility build out
- **Develop Business Policies, Processes and Procedures,** including:
  - Systems operations
  - Planning and engineering
  - Legal and HR
  - Financial and corporate services
  - IT operations
  - Finance and accounting
  - Payroll and benefits
  - Web site
  - Document management
- **Complete Operations Transition Planning**
  - Complete transition planning
  - Plan, mobilize and manage transition program
- **HR and Recruiting**
  - Implement HR policies and procedures
  - Recruit new employees and transfer existing employees

Start-up Implementation Plan Categories

- *Overall Program Management/Governance*
- *Finalize Business Structure*
- *Secure New Facility*
- *Develop Business Policies, Processes, and Procedures*
- *Complete Operations Transition Planning*
- *HR and Recruiting*
- *Complete Operations and Economic Dispatch Transition*
- *Complete Generation and Transmission Planning Transition*
- *Develop IT Infrastructure*
- *Develop Business Systems*
- *Employee Training*
- *Transition and Cutover Execution*
- *Other*

- **Complete Operations and Economic Dispatch Transition**
  - Identify operations to be transferred
  - Rationalize and consolidate existing control centers
  - Identify and implement required SCADA/telecommunications system enhancements
  - Deliver system operations applications
  - Develop databases and displays
- **Complete Generation and Transmission Planning Transition**
  - Establish planning methodology and criteria
  - Develop generation planning applications
  - Develop transmission planning applications
- **Develop IT Infrastructure**
  - Select vendor(s)
  - Deliver and support interim IT infrastructure development efforts
  - Develop IT infrastructure
  - Build IT infrastructure – primary and back-up sites, network and desktops
  - Manage system infrastructure build out
  - Deploy desktop and support
  - Manage procurement
  - Plan and manage data security
  - Test IT infrastructure
  - Provide database and system administration support across organization
- **Develop Business Systems,** including:
  - Financial and accounting systems
  - Payroll and benefits systems
  - Web site
  - Document management system
  - Technical architecture
  - Settlement and billing systems
  - Performance and volume test
  - Process and training development
- **Employee Training,** including:
  - Systems operations
  - Planning and engineering
  - Legal and HR
  - Financial and corporate services
  - IT operations
  - Finance and accounting
  - Payroll and benefits
  - Web site
  - Document management
- **Transition and Cutover Execution**
  - Complete operational trial
  - Coordinate and manage go-live activities

- **Other**
  - Develop initial regional Integrated Resource Plan
  - Develop initial regional Transmission Expansion Plan

As discussed earlier, Black & Veatch developed a detailed work plan and an estimate of the required level of effort required to form the new regional generation and transmission entity. This detailed work plan is included as part of this project's detailed work papers, and the resulting level of effort and start-up labor and non-labor costs were summarized in Section 7.

Start-up Implementation Budget

The following table summarizes the start-up budget for the formation of the new regional entity (i.e., the costs to achieve "Day 1 operations"), based upon the categories of activities listed above.

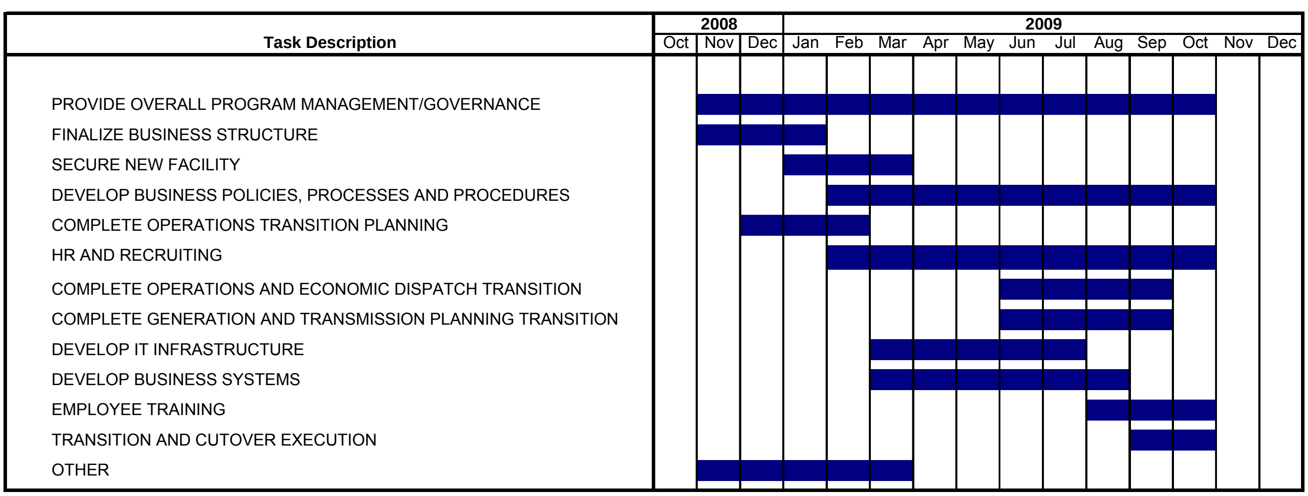
Table 41 - Implementation Budget
($'000)

Category	Path 4
Labor Costs	$4,788
Non-Labor Costs	$1,898
Total Start-up Costs	$6,686

Start-up Implementation Schedule

The following graphic provides an implementation schedule related to the formation of the new regional entity.

Figure 34 - Implementation Schedule



APPENDIX A - NON-UTILITY STAKEHOLDER INPUT SURVEY INSTRUMENT

Appendix A
Non-Utility Stakeholder Input Survey Instrument

1. In your view, what are the key issues and uncertainties regarding the future of the Railbelt electrical grid?

2. What are the major future risks (e.g., loads, generation, technology, fuel supplies, etc.) facing the Railbelt utilities?

3. What are the major future opportunities (e.g., loads, generation, technology, fuel supplies, etc.) available to the Railbelt utilities?

4. It was mentioned during the Technical Conference that there have been previous studies of the Railbelt, but they are all "sitting on the shelf." What was lacking in those studies that caused them to not be implemented?

5. What are the key elements that would make this study more valuable, successful and/or more likely to be implemented as compared to previous studies?

6. What material changes (e.g., generation, loads, transmission, costs, new projects, etc.) have occurred since previous studies that you believe could affect the results of this study? In your view, what actions have been taken by the Railbelt utilities, or other parties, since the previous studies? What actions have been successful, which have been unsuccessful?

7. How acceptable or desirable are coal and nuclear generation plants within the State? In your view, what are the major issues and challenges associated with the future use of coal and nuclear?

8. What carbon-related restrictions, taxes or fees should be established in Alaska?

9. What are your views regarding the resource potential and economics of demand-side management/energy efficiency programs within the Railbelt?

10. What are your views regarding the resource potential and economics of renewable energy technologies within the Railbelt?

11. What are your views regarding the resource potential for, and economics of, distributed generation programs within the Railbelt?

12. What are your views regarding the potential and economics of green pricing programs within the Railbelt?

13. Are there any market, legislative, or regulatory hurdles that negatively affect investments in energy efficiency and demand-side management programs, distributed generation technologies, renewable resources, and green pricing? If so, do you have any suggestions regarding how these hurdles should be addressed?

14. Are there any market, legislative, or regulatory hurdles that negatively affect the development of independent power projects? If so, do you have any suggestions regarding how these hurdles should be addressed?

15. If a separate organization was created to manage unified system operations of the Railbelt Electric Grid, what do you think its main responsibilities should be?

16. What are your views regarding the costs, benefits and shortcomings of joint economic dispatch, regional integrated resource planning, joint project development and investment, and the formation of a power exchange, Independent System Operator and/or Regional Transmission Organization?

17. Please identify any business models related to joint economic dispatch; regional integrated planning; or joint power project development and delivery of energy efficiency and/or renewables programs, etc., which you believe should be considered. Please identify specific examples where possible.

18. What role do you believe the State, and agencies such as the Alaska Energy Authority, should play in the future related to matters affecting the Railbelt utilities and their customers? In particular, do you believe that the State should expand or dispose of its ownership and/or control of primary energy assets in the Railbelt?

19. Please provide any additional comments you might have.

APPENDIX B - PROFILES OF EXAMPLE REGIONAL ORGANIZATIONS

Appendix B
Profiles of Example Regional Organizations

This appendix provides summary descriptions of selected existing regional entities grouped into the following categories:

- State/Federal Power Authorities
- G&T Cooperatives
- Joint Action Agencies
- Other types of regional generation and transmission organizations
- Centralized energy efficiency organizations

Profiles of Example State/Federal Power Authorities

Bonneville Power Administration (BPA)

BPA, headquartered in Portland, Oregon, is a federal agency under the U.S. Department of Energy. BPA was established in 1937 and serves the Pacific Northwest through operating an extensive electricity transmission system and marketing wholesale electrical power at cost from federal dams, one non-federal nuclear plant and other nonfederal hydroelectric and wind energy generation facilities. BPA aims to be a national leader in providing high reliability, low rates consistent with sound business principles, responsible environmental stewardship and accountability to the region.

BPA provides about half the electricity used in the Northwest and operates over three-fourths of the region's high-voltage transmission.

While BPA is part of the Department of Energy, it is not tax-supported through government appropriations. Instead, BPA recovers all of its costs through sales of electricity and transmission and repays the U.S. Treasury in full with interest for any money it borrows.

System Data

- Service area size (square miles): 300,000
- Transmission line (circuit miles): 15,190
- BPA substations: 259
- Employees (FTE): 2,896

BPA Customers

- Cooperatives: 57
- Municipalities: 42
- Public utility districts: 29
- Federal agencies: 7
- Investor-owned utilities: 6
- Direct-service industries: 4
- Port districts: 1
- Tribal: 2
- Power marketers: 87
- Transmission customers: 339

Board of Directors
BPA does not have a Board of Directors. The organization consists of just an executive management team, that consists of the following:

- Administrator
- Deputy Administrator
- Chief Operating Officer
- Senior Vice President – Power Services
- Senior Vice President – Transmission Services
- Executive Vice President General Counsel
- Executive Vice President Internal Business Systems
- Executive Vice President CFO

Long Island Power Authority (LIPA)

Overview
In May of 1998, LIPA became Long Island, New York's primary electric service provider, operating as a non-profit entity. As a not-for-profit municipal electric utility, LIPA seeks to recover only enough money from its customers to cover its operating costs, maintain reserve accounts as required by good business practices, and for emergencies such as damage caused by a severe storm.

System Data

- Electric revenues: $3.54 billion
- Customers: 1.1 million
- Square miles of service territory: 1,230

Board of Directors
The LIPA organization consists of a Board of Trustees with a total of 13 members. The Chairman and Vice Chairman are appointed by the State Governor of New York. All remaining board members are either appointed by the State Governor, Senate Majority Leader, or Speaker of the Assembly. These members are also placed into four separate committees: Personnel & Compensation Committee, Finance & Audit Committee, Energy Efficiency and Environmental Committee and Governance Committee.

New York Power Authority (NYPA)

Overview
NYPA is America's largest state-owned power organization. It provides some of the lowest-cost electricity in New York State. They sell power to government agencies; to community-owned electric systems and rural electric cooperatives; to job-producing companies; to private utilities for resale—without profit—to their customers; and to neighboring states, under federal requirements.

The Power Authority has a long history. Governor Franklin D. Roosevelt established New York's model for public power through legislation signed in 1931. This effort to secure public control of New York's hydropower resources was the result of a bipartisan effort that began with Governor Charles Evans Hughes in 1907.

Today, the Power Authority serves as a non-profit, public-benefit energy corporation that does not use any tax revenue or state credit. NYPA finances construction of their projects through bond sales to private investors, repaying bondholders with proceeds from their operations.

NYPA serves the following customers:

- Over 700 businesses and industrial customers
- 115 government entities in New York City and Westchester County
- 47 municipal and four rural cooperative electric systems, municipal and utility service agencies
- Public Agencies in seven neighboring states
- The state's six investor-owned utilities all purchase NYPA electricity which they sell to their customers
- 188 non-profit health-care, educational and cultural institutions across the state including museums, colleges and universities and hospitals

System Data

- Operating revenues: $2.96 billion
- Net assets: $2.27 billion
- 18 generating facilities - hydropower and fossil-fueled
- More than 1,400 circuit-miles of transmission lines

Board of Directors

The NYPA organization consists of a Board of Trustees with a total of seven members. The Chairman of the board is elected by fellow trustees. Remaining board members are either selected by others on the panel, or in most cases is nominated by the State Governor and then approved by that New York State Senate. Trustees have a term of five years and can be re-appointed by the Governor.

Santee Cooper (aka, South Carolina Public Service Authority)

Overview

Santee Cooper, also known as the South Carolina Public Service Authority, is South Carolina's state-owned electric and water utility. The Santee Cooper Regional Water System began commercial operation in October 1994, treating water from Lake Moultrie as the source of water to customers served by the Moncks Corner Public Works Commission, city of Goose Creek, Summerville Commissioners of Public Works and Berkeley County Water and Sanitation Authority. Today, 125,000 end-users are the beneficiaries of this stable supply of one of life's most precious commodities.

System Data

- Serves over 155,000 residential and commercial electric customers in Berkeley, Georgetown and Horry counties.
- Generate the power distributed by the state's 20 electric cooperatives to more than 625,000 customers in all 46 counties.
- More than 1.8 million South Carolinians receive their power directly or indirectly from Santee Cooper.

Tennessee Valley Authority (TVA)

Overview

The Tennessee Valley Authority is a federal corporation and the nation's largest public power company. As a regional development agency, TVA supplies affordable, reliable power, supports a thriving river system, and stimulates sustainable economic development in the public interest. TVA operates fossil-fuel, nuclear, and hydropower plants, and also produces energy from renewable sources. It manages the nation's fifth-largest river system to minimize flood risk, produce power, maintain navigation, provide recreational opportunities, and protect water quality in the 41,000-square-mile watershed.

TVA operates in 7 states: Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee and Virginia.

TVA has revenues of over $9 billion a year from sales to its three customer groups. It receives no public tax dollars but finances all of its programs, including those for environmental protection, integrated river management, and economic development, through power sales and the sale of bonds in the financial markets. The total amount of outstanding bonds and banknotes represents TVA's debt. All of its programs are paid for with power revenues.

TVA consists of a nine-member TVA Board of Directors which sets policy and strategy for TVA. The members are nominated by the President and confirmed by the U.S. Senate to serve five-year terms.

System Data

- Provides wholesale power to 159 municipal and cooperative power distributors, and by directly serving 53 large industries and government installations in the Valley.
- Transmission system serves some 8.7 million residents in an 80,000-square-mile area spanning portions of seven states
- Supplies the electricity needs of 8.7 million people
- Eleven coal-fired plants, 15,075 megawatts
- Six combustion turbine plants, 6,003 megawatts
- Three nuclear plants, 6,900 megawatts
- Twenty-nine hydroelectric dams
- One pumped-storage plant

Board of Directors

In accordance with the TVA Act, the Board of Directors consists of nine members appointed by the President of the United States by and with the advice and consent of the United States Senate. The Board of Directors selects one of its members to serve as Chairman of the Board.

Profiles of Example G&T Cooperatives

Alabama Electric Cooperative (PowerSouth)

Overview

PowerSouth Energy Cooperative, headquartered in Andalusia, Alabama, is a G&T cooperative that provides the wholesale power needs of 20 distribution members — 16 electric cooperatives and four municipal electric systems — in Alabama and northwest Florida. PowerSouth provides electric energy to nearly 400,000 consumers in 39 Alabama counties and 10 Florida counties. The company was known as Alabama Electric Cooperative prior to January 1, 2008.

PowerSouth has a combined generating capacity of more than 1,600 MWs, from their six generating facilities throughout Alabama. The generating mix consists of natural gas, coal, and hydroelectric facilities. PowerSouth also utilizes long-term purchased power agreements with other utilities to ensure an economic and reliable power supply for our members.

PowerSouth's distribution members vary in size, number of employees and service area characteristics. While PowerSouth's distribution members serve primarily rural areas, the service areas of some extend into rapidly expanding suburban areas.

Board of Directors

PowerSouth is owned by its 20 distribution members, who govern and set policy through a 40-member Board of Trustees composed of two voting delegates from each distribution system. The President and Chief Executive Officer and his staff carry out the daily management of PowerSouth.

PowerSouth has five operating divisions: Power Delivery, Power Supply, Financial Services, External Affairs, and Legal & Corporate Affairs.

System Data

Transmission Lines in Service:

- 46 kV – 681 miles
- 115 kV - 1,350 miles
- 230 kV – 183 miles
- Total - 2,214 miles

Substations (PowerSouth and Member-owned): 283

Employees: 554

Total consumers served: 397,129

Financial Data ($'000):

- Assets: $1,217,120
- Net Sales: $617,661
- Net Margins: $14,427

Sales Composition:

- Distribution Cooperatives: 84%
- Municipalities: 6%
- Other: 10%

Arkansas Electric Cooperative Corporation (AECC)

Overview

AECC is based in Little Rock and provides power for about 460,000 members of Arkansas' 17 electric distribution cooperatives. AECC has assets of about $1.1 billion and annual energy sales of about $468 million. AECC provides power to its 17 electric distribution cooperative members through its diverse generation assets, which include three hydroelectric plants; three natural gas/oil-fired plants and two natural gas-fired-only plants. AECC also co-owns portions of three coal-fired plants.

AECC was created in 1949 to provide Arkansas' distribution cooperatives with a reliable and affordable power supply. At the time, the cooperatives were faced with rising electricity costs and shrinking power supplies. Although the cooperatives had built their own distribution systems they had not built power plants and were prohibited by state law from doing so.

System Data

- Generation resources: 2,977 MW
- Annual energy sales: 11.6 million MWh
- Operating revenues: $518 million
- Assets: $1.13 billion
- Employees: 212

Associated Electric Cooperative, Inc. (AECI)

Overview

AECI is owned by and provides wholesale power to six regional and 51 local electric cooperative systems in Missouri, northeast Oklahoma and southeast Iowa that serve more than 850,000 customers. AECI was formed in 1961.

The transmission system owned by AECI and the six G&T cooperatives that are members of AECI enables it to buy power when needed to serve members and to sell its excess generation which brings in additional revenue.

AECI is governed by 12 Board members, who are elected to serve and represent AECI's six owner G&T cooperatives.

Three-Tier-System

Associated and its member systems are tied together in a unique, three-tiered system of generation, transmission and distribution cooperatives. Each tier is committed to the others through all-requirements contracts. These contracts ensure that Associated will provide a wholesale power supply to meet members' needs, and that member systems will buy all their power supply from Associated.

The system's top tier is made up of 51 distribution cooperatives in Missouri, southern Iowa and northeast Oklahoma. These distribution cooperatives provide electric service directly to consumer-members, including businesses, farms and households.

At the second level of the system are the six regional G&T cooperatives that transmit Associated's power to the 51 distribution cooperatives. These G&T cooperatives serve six geographical areas of Missouri, southern Iowa and northeast Oklahoma. These G&Ts work on a regional level as construction agents and also own and maintain all electrical systems above 161-kilovolt. At one time the G&Ts not only transmitted the power to their member distribution cooperatives, but they also had all of the responsibility for generating and/or purchasing it as well.

In 1961 the six G&Ts joined to form the system's third tier, AECI, which was subsequently given the responsibilities for generation and power procurement, leaving transmission as the primary responsibility of the G&Ts.

Basin Electric Cooperative

Overview

Basin Electric's core business is generating and delivering electricity to wholesale customers, primarily to member systems. It is one of the largest electric G&T cooperatives in the United States. Its service territory spans 430,000 square miles from the Canadian to the Mexican border (KMH to verify). Basin Electric consists of 125 member systems distributing electricity to 2.5 million consumers in parts of North Dakota, South Dakota, Wyoming, Colorado, Minnesota, Iowa, Nebraska, Montana, and New Mexico.

In 1961, Upper Midwest rural electric cooperatives incorporated Basin Electric to plan, design, construct and operate generation and transmission facilities required to meet future electricity needs of their member-owners. Today, Basin Electric's members distribute electricity to 2.5 million customers.

Basin Electric owns 2,595 MW and operates 3,508 MW of electric generating capacity of which 953 MW is for participants of the Missouri Basin Power Project (MBPP), and 80 MW is jointly owned by Basin Electric and its Class D member, Corn Belt Power Cooperative in Humboldt, Iowa. Its electric generation facilities are located in North Dakota, South Dakota, Wyoming and Iowa.

Basin Electric has eight subsidiaries, including two major subsidiaries, Dakota Gasification Company and Dakota Coal Company. Basin Electric and its subsidiaries employ more than 1,800 employees.

Basin Electric has a 10-member Board of Directors elected by the system membership. The directors have been elected to the boards of their local distribution systems and then, with the exception of Districts 9 and 10, to their respective intermediate G&T cooperative systems.

Basin Electric is a not-for-profit cooperative; as such any electric revenues in excess of cost of service, referred to as margins, are returned to its members on a patronage basis. Such margins are often retained for a period to provide working capital.

The qualifications for membership and the rights and obligations of the four classes of membership (Class A, Class B, Class C and Class D) are provided by law and established in the corporate bylaws.

Three-Tier System

Basin Electric is part of a three-tier delivery system. It sells wholesale power to its Class A members and others. The Class A members sell power to their distribution cooperatives (Basin Electric classifies distribution cooperatives as Class "C" members) who, in turn, sell power to retail customers. There are also special membership categories entitled Class B and Class D.

Buckeye Power, Inc.

In 1959, Ohio's electric cooperatives formed Buckeye Power. It was established as a statewide G&T cooperative with the objective of obtaining a power-producing facility.

Three years later, representatives of Buckeye Power and American Electric Power (AEP), parent company of Ohio Power, started discussions about working together. The final agreement to build the Cardinal Station was announced Oct. 28, 1963. It provided that Buckeye Power and Ohio Power would join to build the 1,200 MW facility, which at the time made it the world's largest and most efficient coal-fired power plant. AEP would build and operate the station and each company would own one of the 600 MW units. Buckeye's surplus capacity would be made available to Ohio Power at cost through a banked power agreement, under which Buckeye is able to buy back the capacity as it needs it.

Cardinal Unit 2 went on line in July 1967 and almost a year later, it became the property of Buckeye Power. Buckeye's share of the project cost was $62 million, all financed without federal REA funds.

As the population of the state continued to grow in the 1960s and 1970s, so did the demand for electricity. In 1977, Buckeye added Cardinal Unit 3 to its inventory, adding another 630 MW of capacity.

Today, there are 25 electric distribution cooperatives serving members in Ohio.

Dairyland Power Cooperative

With headquarters in La Crosse, Wisconsin, Dairyland Power Cooperative is a G&T cooperative that provides the wholesale electrical requirements and other services for 25 electric distribution cooperatives and 19 municipal utilities in the Upper Midwest. In turn, these cooperatives and municipals deliver the electricity to consumers, meeting the energy needs of nearly 600,000 people.

In 1938, 10 northern Wisconsin electric cooperatives created the Wisconsin Power Cooperative and Tri-State Power Cooperative was formed by five southern Wisconsin electric cooperatives. In 1941, Tri-State and Wisconsin Power Cooperative merged to create Dairyland Power Cooperative.

Today, Dairyland's generating stations, which include coal, hydroelectric, natural gas, landfill gas, and animal waste) have more than 1,100 MW capacity. It delivers electricity via more than 3,100 miles of transmission lines and nearly 300 substations located throughout the system's 44,500 square mile service area.

Dairyland's service area encompasses 62 counties in Wisconsin, Minnesota, Iowa and Illinois. The following provides additional information regarding Dairyland's operations:

- Dairyland member systems: 25
- Total member-consumer meters: 255,745
- Municipal customers: 19
- Approximate population served: 575,000
- Peak demand: 887 MW
- Power sales: 6.12 billion kWh
- Total operating revenue: $284 million
- Margins: $11.8 million
- Total assets: $946 million
- Owned generation capacity:
  - Coal: 979 MW
  - Hydroelectric: 24 MW
  - Natural gas/oil: 94 MW
- Other generation capacity:
  - Landfill gas: 11 MW
  - Manure digesters: 2 MW
  - Wind: 18 MW
  - Diesel: 92 MW
- Miles of transmission line: 3,111
- Substations: 294
- Employees: 599

East Kentucky Power Cooperative (EKPC)

Overview

In 1941 Kentuckians launched several not-for-profit distribution cooperatives. They got together and formed EKPC to make and supply the energy that these distribution cooperatives needed.

The member cooperatives set up EKPC as a not-for-profit G&T cooperative with headquarters in Winchester, Kentucky. EKPC's purpose is to generate energy and transmit it to cooperatives that distribute it to retail customers. Today, EKPC provides wholesale energy and services to 16 distribution cooperatives through power plants and more than 2,800 miles of transmission lines. The distribution cooperatives supply energy to 503,000 Kentucky homes, farms, businesses and industries across 87 counties.

Each of the 16 distribution cooperatives own EKPC and they have representatives on EKPC's board.

System Facts

EKPC supplies electricity through three coal-fired stations: H.L. Spurlock Power Station located near Maysville; John Sherman Cooper Power Station located near Somerset; and William C. Dale Power Station, located near Winchester.

There are also natural gas combustion turbines at J.K. Smith Station, located in Trapp, near Winchester.

EKPC also obtains about 170 MW of hydroelectric power through arrangements with Laurel and Wolf Creek dams and the federal Southeastern Power Administration.

Hoosier Energy Rural Electric Cooperative, Inc.

Hoosier Energy is a G&T cooperative providing wholesale electric power and services to 17 member electric distribution cooperatives in 48 central and southern Indiana counties and it provides electricity and related services to nearly 700,000 residents, businesses, industries and farms in a 15,000 square mile service territory in the southern half of Indiana.

With headquarters in Bloomington, Indiana, Hoosier Energy operates two coal-fired electric power production facilities: the 1,070 MW Merom Generating Station and the 250 MW Ratts Generating Station. Additionally, Hoosier owns a 174 MW peaking plant at Worthington and a 258 MW natural gas-fired generating facility, located on a 50 acre site between Bedford and Mitchell in Lawrence County.

High-voltage electric power is delivered over a system of 1,400 miles of transmission lines, 14 primary substation facilities and more than 200 distribution substations and delivery points.

KAMO Electric Cooperative, Inc.

KAMO, with headquarters in Vinita, Oklahoma, is a G&T cooperative serving 17 member distribution cooperatives in northeast Oklahoma and southwest Missouri. KAMO is one of six G&T utilities that own Associated Electric Cooperative, Inc. (AECI). AECI provides the capacity and energy needs for KAMO and the other five G&Ts.

KAMO's annual sales to members exceed 5,000,000 MWhs, which represents approximately 290,000 member-owners.

South Mississippi Electric Power Association

South Mississippi Electric is a non-profit G&T cooperative which generates, transmits and sells electric energy on a wholesale basis to 11 member distribution cooperatives. These 11 member systems own and maintain approximately 54,500 miles of distribution line and provide service to more than 405,000 meters in 56 counties in Mississippi.

In 1941 there were 24 cooperatives formed within the state. With no generating facilities, the rural distribution cooperatives purchased wholesale power from investor-owned utilities. The differing philosophies between the non-profit distribution cooperatives and the profit-oriented, investor-owned utilities led to the formation of South Mississippi Electric Power Association.

In April 1941, seven electric power associations chartered South Mississippi Electric. The Association employs more than 290 employees.

The base load generating fleet of South Mississippi Electric includes a coal-fired plant near Purvis and a 10 percent undivided interest in the Grand Gulf Nuclear Station in Port Gibson. Gas- and/or fuel oil-fired generation equipment includes units near Moselle and a total of eight combustion turbine units located at Sylvarena, Silver Creek, Benndale, and Paulding, utilized as generating capacity to meet peak demand.

Western Farmers Electric Cooperative (WFEC)

In existence for over 65 years, WFEC has grown into Oklahoma's largest locally-owned power supply system. WFEC is a G&T cooperative that provides essential electric service to 19 member-owner cooperatives, Altus Air Force Base, and other power users.

WFEC was organized in 1941 when western Oklahoma rural electric distribution cooperatives were unable to secure an adequate power supply at rates the farmers and rural industrial developers could afford.

The incorporators provided for individual rural electric distribution cooperatives to petition for membership. On April 25, 1941, the cooperative approved the membership of six cooperatives. These six members were joined by four other cooperatives later that year. Eight eastern Oklahoma rural electric distribution cooperatives joined WFEC in 1968, bringing the total number of member-owners to 19.

With three generating plants located at Mooreland, Anadarko and Hugo, WFEC has total power capacity of more than 1,400 MWs when the purchased hydropower is included. Today WFEC supplies the electrical needs of more than two-thirds of rural Oklahoma.

Profiles of Example Joint Action Agencies

American Municipal – Ohio (AMP-Ohio)

States: Ohio, Pennsylvania, West Virginia, Virginia and Michigan
Year Established: 1971
Number of Members: 81
Member Types: 81 public power communities in Ohio, 27 in Pennsylvania, two in West Virginia, four in Virginia and seven in Michigan

Organizational Structure
The AMP-Ohio Board of Trustees consists of 16 communities. Eight of these trustee communities are selected by their fellow public power communities in each of eight service areas of the organization. The other eight are elected at large. Various Board of Trustees committees concentrate on vital functions of the organization. Current committees include: Baseload Generation, Board Oversight, By-laws Review, Finance, Generation/Clean Air, Gorsuch Station Project, Green Power Development, Joint Ventures Oversight, Legislative, Member Services, Mutual Aid, Nominating, Non-electric, Personnel, Policy, Power Supply and Generation, Scholarship, and Transmission/RTO.

Coordination Efforts
AMP-Ohio has a control center that on a daily basis manages the full load requirements of the Northeast AMP-Ohio Service Group, Northwest AMP-Ohio Service Group and 11 members of the Western AMP-Ohio Service Group. The center also performs the same duties for individual cities in Ohio and Pennsylvania. Power coordinators also remotely operate the distributed generation units of AMP-Ohio and three joint ventures as needed. Through its SCADA Department, AMP-Ohio can also provide supervisory control and data acquisition services for member communities that are installing, upgrading or performing maintenance on their own systems.

Blue Ridge Power Agency (BRPA)

State: Virginia
Year Established: 1988
Number of Members: 10
Member Types: Seven municipalities, one state institution and two electric cooperatives

Organizational Structure

BRPA operates under the direction of its Board of Directors, to which each member appoints one Director and one or more Alternate from its organization. The ultimate goal of the organization is to pursue activities that will insure the most reliable and lowest cost wholesale electric power supplies possible for its members.

Coordination Efforts

BRPA provides a number of services to its wholesale and/or retail power supply, energy and transmission services and/or facilities procurement, contract negotiation, contract administration, consolidated billing, state and federal regulatory support and litigation, state and federal legislation, and joint purchasing.

Delaware Municipal Electric Corp. (DEMEC)

State: Delaware
Year Established: 1979
Number of Members: 9
Member Types: Municipal utilities

Organizational Structure

DEMEC is governed by a nine-member Board of Directors, with one director from each of the nine member municipal electric utilities. The responsibility for day-to-day operations of the Agency resides with a President appointed by the Board. The President directs the efforts of staff members and various contractors in place to meet the service requirements of the members.

Coordination Efforts

In addition to power supply, DEMEC provides legal and technical consulting services to its members, as well as representation in the federal and regional arenas regarding electric industry regulation and operation. DEMEC also provides its members with the benefits of joint and combined buying power and negotiating strength. It also assists member utilities in customer retention, economic development, customer education, system improvements and technical information sharing efforts for improved operating efficiency in their individual systems.

Florida Municipal Power Agency (FMPA)

State: Florida
Year Established: 1978
Number of Members: 30
Member Types: Municipal electric utilities

Organizational Structure

Each member appoints one representative to FMPA's Board of Directors, which governs the Agency's activities. Due to the diverse needs of the 30 municipal electric systems, FMPA was established as a project-oriented agency. Under this structure, each member has the option whether or not to participate in a project. Members may join more than one project; however, each project is independent from the others, so no revenues or funds available from one project can be used to pay the costs of another project.

Coordination Efforts

FMPA has five power supply projects and one pooled financing project. The Agency supplies all the power needs for 15 of its members and some of the power needs for five of its members. Some members do not currently participate in a project. FMPA supplies more than 40% of its members' power needs. They also offer additional members services, including: joint purchase and contract services, safety-related services, environmental services, energy conservation and customer service programs, T&D-related services, as well as training and workshops, information systems services, and utility rate services.

Illinois Municipal Electric Agency (IMEA)

States: Illinois
Number of Members: 31
Member Types: Municipalities that own and operate their own electric generation and/or distribution system

Organizational Structure

IMEA is governed by a Board of Directors, with one director representing each member community. The Board members are appointed by the mayors and confirmed by the individual municipal governing bodies. An Executive Board is elected annually from the full board. The Executive Board's job is to review policies and make recommendations to the full board for its consideration. A professional staff handles day-to-day operations.

Coordination Efforts

IMEA's primary function is to provide power supplies to its members. IMEA also provides engineering, communications, and economic development services, including engineering consultation, state and federal legislative lobbying, load retention and new business location services, and various communications programs.

Indiana Municipal Power Agency (IMPA)

State: Indiana
Year Established: 1980
Number of Members: 51
Member Types: Cities and towns that operate their own electric distribution systems and purchase generation and transmission service from IMPA

Organizational Structure

IMPA consists of a Management Team and Board of Commissioners. There are also are staff members that coordinate the following areas: Power System Coordination, Planning Engineering & Operations, Finance, and Member Services and Administration.

Coordination Efforts

IMPA provides its member systems with generation and transmission services, as well as power supply planning, engineering, economic development, government relations and communications services. IMPA uses a portfolio of generating resources to meet the power supply needs of its member systems. This includes a combination of IMPA- and member-owned generation with long-term, firm power purchases and some seasonal market purchases.

Louisiana Energy Power Authority (LEPA)

State: Louisiana
Year Established: 1979
Number of Members: 18
Member Types: Consists of Louisiana cities and towns, each maintaining its own independent municipal power system

Organizational Structure
LEPA has a Board of Directors that consists of 18 individuals, one from each member, and a staff of 12.

Coordination Efforts
Since 1989, LEPA has entered into all-requirements power contracts with many of its members and has coordinated the operation of its generation and transmission system through the use of a Energy Control Center.

Massachusetts Municipal Wholesale Electric Company (MMWEC)

State: Massachusetts
Year Established: 1969
Number of Members: 25
Member Types: Of the 40 municipal utilities in Massachusetts, 25 are Members of MMWEC and 28 are MMWEC project participants

Organizational Structure
MMWEC is governed by a 12-member Board of Directors. Seven of the directors are managers or commissioners of MMWEC Member utilities elected by the membership. Two directors are appointed by the Governor of Massachusetts, and three representatives are appointed by the governing bodies of the towns of Hampden, Ludlow and Wilbraham to vote on matters affecting their respective towns.

Coordination Efforts
MMWEC provides wholesale power supply, financial and other services to its members. It also provides numerous power supply-related services, including power supply forecasting and planning, project and contract development, power supply and demand management, and a range of services facilitating municipal utility participation in wholesale power markets. MMWEC also provides a variety of financial services, including bond issuance, money management, treasury, accounting and budgeting services. Other services include engineering and project operations, risk management, information systems and business services, as well as legal, regulatory and litigation support.

Michigan Public Power Agency (MPPA)

State: Michigan
Year Established: 1978
Number of Members: 14
Member Types: Municipal electric utilities

Organizational Structure
MPPA’s Board of Commissioners consists of one representative and up to two alternates from each member city. They are appointed by their respective municipal utility.

Coordination Efforts
MPPA provides economic benefits to its 14 municipal members and is involved in joint ownership of electrical generating plants and transmission facilities, as well as the pooling of utility resources.

Missouri River Energy Services (MRES)

States: Iowa, Minnesota, North Dakota and South Dakota
Year Established: 1965
Number of Members: 60
Member Types: Local electric utilities

Organizational Structure
MRES is governed by a 13-member Board of Directors who are elected by and from the ranks of our member representatives.

Coordination Efforts
MRES provides energy supplies to its members and associates, as well as the following additional services: review of engineering work, large retail customer retention and marketing programs, new business opportunities coordination, retail rate studies, Integrated Resource Plan preparation, distribution maintenance services, cost unbundling services, participation and intervention in pertinent state and federal cases, load forecasting, long-term power and energy planning, transmission services and contract negotiations, training and education, and active monitoring and advocacy of relevant state and national legislation.

Additional Information
MRES was the first multi-state joint action agency, and the third overall, to be established in the United States.

Northern California Power Agency (NCPA)

State: California
Year Established: 1968
Number of Members: 17 member communities and districts in northern and central California
Member Types: Municipalities, rural electric cooperatives, irrigation districts and other publicly-owned entities interested in the purchase, aggregation, scheduling and management of electrical energy

Organizational Structure
NCPA is organized into four separate business units: Power Management, Generation Services, Finance & Administrative Services, and Legislative & Regulatory.

Coordination Efforts
NCPA provides scale and skill economies devoted to the purchase, generation, transmission, pooling and conservation of electrical energy and capacity for its members. With the onset of electric utility restructuring, the Agency has become a primary supplier of power scheduling and interchange management services to power marketers and public agencies.

Additional Information
Following the passage of Assembly Bill 1890 in 1996, all California utilities were required to set aside a portion of their gross revenues for various community and environmental programs, including renewable energy programs. Every single one of NCPA's members' local governing bodies has adopted Renewable Portfolio Standards (RPS) that are tailored to their individual communities.

Piedmont Municipal Power Agency (PMPA)

State: South Carolina
Year Established: 1979
Number of Members: 10
Member Types: Municipal utilities

Organizational Structure
PMPA is governed by a Board of Directors, which consists of one director and one alternate from each member that are appointed by the elected city councils or utility commissions governing the local utilities.

Coordination Efforts

PMPA provides wholesale electric service to its Members primarily through a 25 percent ownership interest in the Catawba Nuclear Station, located in York County, South Carolina. PMPA also provides its Member utilities with other services such as PowerPartners, which is a DSM program that helps to postpone the need for building new generating facilities. PMPA also provides a forum for collaborative, long-range planning that benefits its Member utilities and legislative support.

Southern California Power Authority (SCPA)

State: California
Year Established: 1980
Number of Members: 12
Member Types: 11 municipal utilities and 1 irrigation district

Organizational Structure

The SCPPA Board of Directors consists of three committees: 1) Finance Committee, which is responsible for reviewing all financial matters that come before the Board, 2) Public Benefits Committee, which serves as an association of SCPPA member utility staff in charge of public benefits fund administration, pursuant to Assembly Bill 1890, and 3) Magnolia Coordinating Committee, which consists of representatives of the Magnolia Project participants and is responsible for governing the Project, through the approval of budgets, construction and operating plans and major contracts. The recently completed Magnolia Power Project is a clean, high-efficiency, combined-cycle unit on three acres of the Burbank Water & Power generating station complex adjacent to Magnolia Boulevard.

Coordination Efforts

SCPPA was formed to finance the acquisition of generation and transmission resources for its members. Currently, SCPPA has three generation projects and three transmission projects, which bring power from Arizona, New Mexico, Utah, and Nevada. SCPPA members deliver electricity to approximately two million customers over an area of 7,000 square miles. SCPA's role has evolved over the years to include legislative advocacy at the state and national levels, and cooperative efforts to reduce member costs and improve efficiency.

Profiles of Other Types of Regional Generation and Transmission Organizations

American Transmission Company (ATC)

ATC started business in January 2001 as the first multi-state, transmission-only utility in the United States solely focused on transmission.

ATC was formed as a result of the provisions of the Reliability 2000 legislation contained in Wisconsin Governor Tommy Thompson's 1999-2001 budget. Under the new law, major Midwest utilities were encouraged to combine their high-voltage transmission lines and related facilities to form an independent transmission company. ATC manages the systems, develops solutions for reliability challenges, and provides fair and open access to transmission facilities.

The formation of ATC was made possible by a combination of 28 utilities, municipalities, municipal electric companies and electric cooperatives from Wisconsin, Michigan and Illinois that have invested transmission assets or money for an ownership stake in ATC and are now equity owners in ATC.

ATC provides high voltage transmission service to utilities and retail electric cooperatives. ATC does not own distribution or generation facilities, which remain with the participating utility companies, who obtain transmission service from ATC.

ATC is also a transmission-owning member of the Midwest Independent System Operator (MISO) and the Mid-American Interconnected Network (MAIN).

ATC is regulated by FERC for rates and tariff, and regulated by the states of Michigan, Illinois and Wisconsin for siting transmission infrastructure.

ATC operates the electric transmission system from two system operations centers. From these centers, they monitor and operate the flow of electricity over 9,081 miles of transmission lines and through 480 electric substations in its service area.

ElectriCities

Overview
ElectriCities is a not-for-profit government service organization formed back in 1965 to protect the interests of public power customers, and to provide a unified voice to speak out in the North Carolina legislature. Electricities is financed through membership fees and dues, as well as through rate and service revenue and tuition from training programs and workshops.

ElectriCities is a service organization, not a power supplier. Fifty-one of its members receive their electricity from their participation in one of the State's two Power Agencies (North Carolina Municipal Power Agency Number 1, NCMPA1, and North Carolina Eastern Municipal Power Agency, NCEMPA). Other members purchase power from investor-owned utilities such as Duke Power and Carolina Power & Light or from other power suppliers like the cooperatives.

ElectriCities provides management services to both Power Agencies, a sharing arrangement that prevents duplication in costs, including: 1) representation and advocacy for the members and their customers in the legislative and regulatory processes, and 2) information, expertise and other resources that enhance the members' ability to meet or exceed the expectations of the communities they serve.

The Power Agencies provide: 1) economic and reliable generation and transmission services that enable the members to meet the needs of their customers, and 2) additional opportunities that enhance the Members' ability to provide excellent services to their customers.

Board of Directors
ElectriCities is governed by a 14-member board of directors elected by the membership. The Board consists of 12 members from Power Agency cities and two from cities not affiliated with the power agencies.

International Transmission Company (ITC)

ITC is in the business of transmitting high-voltage electricity throughout southeastern Michigan, supplying the gateway for energy delivery to the Midwest and Canada. ITC began operations in March 2003.

ITC's service territory covers approximately 7,600 square miles throughout 13 counties in Michigan, including the metropolitan areas of Detroit and Ann Arbor, which have a population of approximately 4.9 million. ITC's facilities include approximately 2,700 circuit miles of overhead and underground transmission lines, 17,000 towers and poles, and 155 stations and substations connecting our facilities. ITC also owns and manages the Michigan Electric Power Coordination Center (MEPCC) located in Ann Arbor, Michigan. Corporate headquarters is located in Novi, Michigan.

History
In 1994, the Michigan Public Service Commission (MPSC) issued an order outlining a limited program that would allow customers to choose alternate suppliers of generation for the territories covered by Detroit

Edison and Consumers Energy. This was the first step towards implementing electric retail choice in Michigan.

Two years later, FERC issued Order No. 888, directing utilities to file OATTs, breaking the host utility's monopoly on the transmission system and allowing any electric marketer to use the host utility's transmission lines for a cost-based fee.

Later that year, Detroit Edison and Consumers Energy, which had been working in partnership through the MEPCC, applied for and received approval from FERC for a joint OATT. This ensured that only a single rate would be charged for transmission throughout most of Michigan's Lower Peninsula.

In November 1999, ITC was created as an independently functioning business unit within Detroit Edison. This was the first step in the formation of a truly independent, stand-alone transmission company. In May 2000, ITC, Detroit Edison and DTE Energy filed a joint application with FERC, seeking permission to transfer all jurisdictional transmission assets from Detroit Edison to ITC. This permission was granted in June 2000.

In June 2001, ITC began operations as a wholly-owned subsidiary of DTE Energy. In December of that year, ITC joined the MISO, a FERC-approved regional transmission organization.

In December 2002, DTE announced an agreement to sell ITC to affiliates of Kohlberg Kravis Roberts & Co. (KKR) and Trimaran Capital Partners L.L.C. for $610 million. The FERC order approving this sale was issued in February 2003.

In April 2004, ITC became a stand-alone transmission company following the sale of transmission assets from DTE Energy.

Recently, ITC's parent company, ITC Holdings Corp., acquired the Michigan Electric Transmission Company, LLC (METC). Together, ITC and METC will have responsibility over majority of the transmission system in Michigan's Lower Peninsula and for improving the transmission infrastructure.

Lower Colorado River Authority (LCRA)

Overview

LCRA plays a variety of roles in Central Texas: delivering electricity, managing the water supply and environment of the lower Colorado River basin, developing water and wastewater utilities, providing public recreation areas, and supporting community and economic development.

LCRA is a conservation and reclamation district created by the Texas Legislature in 1934. It has no taxing authority and operates solely on utility revenues and fees generated from supplying energy, water and community services.

System Data

- Electric service area: 29,809 square miles, covering all or part of 53 counties
- More than 3,300 miles of transmission lines
- Manages water supplies along a 600-mile stretch
- Operates six dams on the Colorado River
- Regulates water discharges to manage floods, and releases water for sale to municipal, agricultural and industrial users
- Owns or operates 16,614 acres of parks and recreational areas

Utah Associated Municipal Power Systems (UAMPS)

Utah Associated Municipal Power Systems is a governmental cooperative of municipalities, service districts, and political subdivisions that own their own public power systems. The Cooperative works to pool electrical energy resources to provide power to the various public power customers such as businesses and residents of the member utilities.

The UAMPS membership represents 52 members from Utah, Arizona, California, Idaho, Nevada, New Mexico and Oregon.

Nebo Power Station is owned by UAMPS and is a combined cycle natural gas fired 140 MW plant in Payson, Utah. UAMPS uses a variety of sources to meet the demand of its members with electrical supply. These include coal fired electrical plants, wind turbine electrical farms, hydroelectric power, and the Association's Nebo Power Station a natural gas combined cycle electrical plant.

Vermont Electric Power Company (VELCO)

Overview

VELCO the nation's first ever "transmission only" company, was formed in 1956 as the most efficient solution for moving newly available St. Lawrence power into Vermont. In response to rising demand for services and the oil embargo of the early seventies, VELCO's role grew to include acting as the agent for out-of state power contracts for all of Vermont's utilities.

Assuming this responsibility saved money and substantially increased reliability through newly interconnected operations. Later, VELCO was specifically tasked to serve as the representative of Vermont's combined utilities at what was the precursor to today's ISO-New England. VELCO gave these utilities a voice where individually they would never have been heard.

Lastly, it was VELCO's construction of a new converter in Highgate that made interconnected operations with Hydro Quebec a possibility and so played a role in securing the HQ power contract.

System Data

The initial 224-mile 115 kV VELCO system was placed in service in September 1958. Since that time, VELCO has expanded its facilities and services as required by the needs of its participants and the evolution of the industry. Currently, its transmission system consists of:

- 610 miles of transmission lines
- 34 substations
- 200 MW back-to-back HVDC converter; to monitor and control this system VELCO uses an extensive fiber optic communication network
- 558 miles owned by VT TRANSCO, LLC
- 52 miles VETCO (HVDC)
- Highgate converter, jointly owned by several Vermont utilities. (Burlington Electric Department, Central Vermont Public Service Corp., Citizens Utilities, Green Mountain Power Corp., Rochester Electric Light & Power Co., Vermont Public Power Supply Authority and Village of Johnson Electric Light Department); the so called Highgate Joint Owners.

VT Transco, LLC

VT Transco, LLC was officially established on June 30, 2006 as a limited liability company formed by VELCO and Vermont's distribution companies, and owns Vermont's high-voltage electric transmission system. VELCO is the manager of the LLC, and in that capacity, operates and maintains Vermont's electric transmission system, as it has for fifty years.

Profiles of Example Centralized Energy Efficiency Organizations

New Jersey Clean Energy Program™

New Jersey's Clean Energy Program™, administered by the New Jersey Board of Public Utilities (BPU), promotes increased energy efficiency and the use of clean, renewable sources of energy including solar, wind, geothermal, and sustainable biomass. The program offers financial incentives, programs, and services for residential, commercial, and municipal customers.

In 2003, the BPU established a Clean Energy Council (CEC) comprised of a cross-section of government and industry representatives, energy experts, public interest groups, and academicians to engage stakeholders in the New Jersey Clean Energy Program's™ development and to advise the BPU on its administration. The Council provides input to the BPU regarding the design, budgets, objectives, goals, administration, and evaluation of the program. The Council is organized into three committees: 1) Energy Efficiency, 2) Renewable Energy, and 3) Outreach and Education.

The Office of Clean Energy (OCE), while serving as administrator of New Jersey's Clean Energy Program™, is assisted by Market Managers for the Residential, Commercial & Industrial, and Renewable Energy Programs. The OCE's Clean Energy Council is organized into three committees: 1) Energy Efficiency, 2) Renewable Energy, and 3) Marketing and Communications.

New York State Energy Research and Development Authority (NYSERDA)

NYSERDA is a public benefit corporation created in 1975 through the reconstitution of the New York State Atomic and Space Development Authority. NYSERDA's earliest efforts focused solely on research and development with the goal of reducing the State's petroleum consumption. Subsequent research and development projects focused on topics including environmental effects of energy consumption, development of renewable resources, and advancement of innovative technologies.

Currently, NYSERDA is primarily funded by state customers through the System Benefits Charge (SBC), which was established on May 20, 1996. These SBC funds were allocated towards energy-efficiency programs, research and development initiatives, low-income energy programs, and environmental disclosure activities. Part of this funding went into the creation of New York Energy Smart℠ which helps to maintain momentum for the State's efforts to develop competitive markets for energy efficiency; demand management; outreach and education services; research, development, and demonstration; low-income services; and to provide direct economic and environmental benefits to New York citizens and businesses. The SBC has been extended through June 30, 2011.

NYSERDA is governed by a Board consisting of 13 members, including the Commissioner of the Department of Transportation, the Commissioner of the Department of Environmental Conservation, the Chair of the Public Service Commission, and the Chair of the Power Authority of the State of New York. The remaining nine members are appointed by the Governor of the State of New York with the advice and consent of the Senate and include, as required by statute, an engineer or research scientist, an economist, an environmentalist, a consumer advocate, an officer of a gas utility, an officer of an electric utility, and three at-large members.

NYSERDA administers the New York Energy Smart℠ program, which is designed to support certain public benefit programs during the transition to a more competitive electricity market. Some 2,700 projects in 40 programs are funded by a charge on the electricity transmitted and distributed by the State's investor-owned utilities. The New York Energy Smart℠ program provides energy efficiency services, including those directed at the low-income sector, research and development, and environmental protection activities.

NYSERDA's other responsibilities include:

- Conducting a multifaceted energy and environmental research and development program to meet New York State's diverse economic needs.
- Making energy more affordable for residential and low-income households.
- Helping industries, schools, hospitals, municipalities, not-for-profits, and the residential sector, including low-income residents, implement energy efficiency measures.
- Providing objective, credible, and useful energy analysis and planning to guide decisions made by major energy stakeholders in the private and public sectors.
- Managing the Western New York Nuclear Service Center at West Valley, including: 1) overseeing the State's interests and share of costs at the West Valley Demonstration Project, a federal/State radioactive waste clean-up effort, and 2) managing wastes and maintaining facilities at the shut-down State-Licensed Disposal Area.
- Coordinating the State's activities on nuclear energy matters including the regulation of radioactive materials, and monitoring low-level radioactive waste generation and management in the State.
- Financing energy-related projects, reducing costs for customers.

Oregon Energy Trust

Energy Trust of Oregon, Inc., began operation in March 2002, and is charged by the Oregon Public Utility Commission (OPUC) with: 1) investing in cost-effective energy conservation, 2) helping to pay the above-market costs of renewable energy resources, and 3) encouraging energy market transformation in Oregon.

Energy Trust funds come from a 1999 energy restructuring law, which required Oregon's two largest investor-owned utilities to collect a three percent "public purposes charge" from their customers. The law also dedicated a separate portion of the public-purpose funding to energy conservation efforts in low-income housing energy assistance and K-12 schools.

The law authorized the OPUC to direct these funds to a non-governmental entity for investment. Energy Trust was organized as a nonprofit organization for this purpose. Energy Trust organized as a nonprofit corporation and entered into a November 2001 grant agreement with the OPUC to guide Energy Trust's electric energy work. The grant agreement was developed with extensive input from key stakeholders and interested parties, and has been amended several times since 2001.

In addition to its work under the 1999 energy restructuring law, the Energy Trust administers gas conservation programs for residential and commercial customers of NW Natural Gas and Cascade Natural Gas Corporation, and select programs for the residential customers of Avista Corporation in Oregon.

APPENDIX C - SCENARIO A RESULTS

Year	CEA	GVEA	HEA	MEA	MLP	Path 4 Taxable	Path 4 Non Taxable
	Paths 1,2, and 3					Path 4	
2008		GE LM6000 SC (1) 43.0 MW (Capital Cost $74.0 Million)					
2009		GE LM6000 SC (1) 43.0 MW (Capital Cost $76.2 Million)					
2010							
2011							
2012	Wind (1) 13.4 MW (Capital Cost $71.3 Million)	Wind (1) 13.0 MW (Capital Cost $70.2 Million)	Wind (1) 4.6 MW (Capital Cost $46.8 Million)	Wind (1) 8.3 MW (Capital Cost $57.1 Million)	Wind (1) 10.7 MW (Capital Cost $64.0 Million)	Wind (1) 50.0 MW (Capital Cost $174.5 Million)	Wind (1) 50.0 MW (Capital Cost $174.5 Million)
2013							
2014							
2015				GE LMS100 SC (2) 197.6 MW (Capital Cost $294.7 Million)			
2016							
2017							
2018	GE LM6000 SC (1) 43.0 MW (Capital Cost $99.4 Million); Wind (1) 13.4 MW (Capital Cost $44.8 Million)	Wind (1) 13.0 MW (Capital Cost $43.5 Million)	Wind (1) 4.6 MW (Capital Cost $15.6 Million)	Wind (1) 8.3 MW (Capital Cost $27.9 Million)	Wind (1) 10.7 MW (Capital Cost $36.1 Million)	GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $99.4 Million); Wind (1) 50.0 MW (Capital Cost $168.0 Million)	GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $99.4 Million); Wind (1) 50.0 MW (Capital Cost $168.0 Million)
2019		GE 6B SC (1) 42.1 MW (Capital Cost $73.1 Million)					
2020	Hydro (1) 80.1 MW (Capital Cost $782.4 Million)	Hydro (1) 77.7 MW (Capital Cost $763.2 Million)	Hydro (1) 27.9 MW (Capital Cost $365.1 Million)	Hydro (1) 49.8 MW (Capital Cost $540.4 Million)	Hydro (1) 64.5 MW (Capital Cost $657.2 Million)	Hydro (1) 300 MW (Capital Cost $2537.9 Million)	Hydro (1) 300 MW (Capital Cost $2537.9 Million)
2021						GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $217.3 Million)	GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $217.3 Million)
2022	GE LMS100 SC (1) 98.8 MW(Capital Cost $186.7 Million)						
2023							
2024							
2025	Hydro (1) 80.1 MW (Capital Cost $907.0 Million)	Hydro (1) 77.7 MW (Capital Cost $884.7 Million)	Hydro (1) 27.9 MW (Capital Cost $423.3 Million)	Hydro (1) 49.8 MW (Capital Cost $626.4 Million)	Hydro (1) 64.5 MW (Capital Cost $761.8 Million)	Hydro (1) 300 MW (Capital Cost $2942.1 Million)	Hydro (1) 300 MW (Capital Cost $2942.1 Million)
2026		GE LMS100 SC (1) 98.8 MW (Capital Cost $210.1 Million)		GE 6B SC (1) 42.1 MW (Capital Cost $89.9 Million)			
2027							
2028							
2029							
2030		GE 6B SC (1) 42.1 MW (Capital Cost $101.2 Million)			GE LMS100 SC (1) 98.8 MW (Capital Cost $236.4 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)
2031		GE 6B SC (1) 42.1 MW (Capital Cost $104.2 Million)				GE LMS100 SC (1) 98.8 MW in GVEA (Capital Cost $243.5 Million)	GE LMS100 SC (1) 98.8 MW in GVEA (Capital Cost $243.5 Million)
2032							
2033							
2034							
2035				GE LMS100 SC (2) 197.6 MW (Capital Cost $548.2 Million)			
2036							
2037				GE 6B SC (1) 42.1 MW (Capital Cost $124.4 Million)		1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $195.8 Million)	1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $195.8 Million)
Subtotal Capital Cost (Millions $)	$2,091.6	$2,400.4	$850.8	$2,309.0	$1,755.5	$7,349.7	$7,349.7

Scenario A — Path 1 Through Path 4 Expansion Plans

Northern and Southern Intertie Upgrades (Million $) - $720.0

Scenario A
Path 1 Through Path 4 Total Costs and Savings Comparison

Year	Path 1 Total Cost Nominal $000	Path 2 Total Cost Nominal $000	Path 3 Total Cost Nominal $000	Path 4 Tax Exempt Total Cost Nominal $000	Path 4 Taxable Total Cost Nominal $000	Path 2 Savings Nominal $000	Path 3 Savings Nominal $000	Path 4 Tax Exempt Savings Nominal $000	Path 4 Taxable Savings Nominal $000
2008	373,799	373,799	363,359	355,972	355,972	-	10,439	17,827	17,827
2009	466,416	466,416	430,980	426,394	426,394	-	35,436	40,022	40,022
2010	403,819	403,819	391,922	376,803	376,803	-	11,897	27,016	27,016
2011	462,600	462,600	427,015	421,814	421,814	-	35,584	40,786	40,786
2012	480,262	480,262	461,775	433,570	435,734	-	18,487	46,692	44,528
2013	520,130	520,130	458,264	436,539	438,702	-	61,867	83,591	81,428
2014	452,305	452,305	442,286	413,742	415,905	-	10,019	38,563	36,400
2015	458,959	458,959	439,736	460,338	462,502	-	19,222	(1,380)	(3,543)
2016	476,257	476,257	460,342	414,081	416,244	-	15,915	62,177	60,013
2017	522,000	522,000	476,795	492,495	494,658	-	45,205	29,505	27,342
2018	546,169	546,169	529,154	485,459	490,957	-	17,015	60,710	55,212
2019	607,061	607,061	555,104	519,736	525,234	-	51,957	87,326	81,827
2020	863,418	863,418	843,841	717,426	757,186	-	19,577	145,992	106,233
2021	857,873	857,873	843,925	749,983	792,478	-	13,948	107,890	65,395
2022	919,854	919,854	913,215	784,741	827,237	-	6,638	135,112	92,617
2023	945,752	945,752	935,753	830,614	873,110	-	9,999	115,138	72,642
2024	997,795	997,795	997,281	869,391	911,887	-	514	128,403	85,908
2025	1,265,038	1,265,038	1,248,987	1,092,196	1,174,409	-	16,050	172,842	90,628
2026	1,339,195	1,339,195	1,317,233	1,117,193	1,199,407	-	21,962	222,002	139,789
2027	1,376,235	1,376,235	1,354,691	1,181,884	1,264,097	-	21,545	194,352	112,138
2028	1,415,327	1,415,327	1,391,080	1,201,188	1,283,401	-	24,247	214,139	131,926
2029	1,467,498	1,467,498	1,442,371	1,294,284	1,376,498	-	25,127	173,213	91,000
2030	1,528,042	1,528,042	1,514,637	1,292,644	1,385,218	-	13,405	235,397	142,824
2031	1,610,005	1,610,005	1,593,744	1,375,590	1,471,240	-	16,262	234,415	138,766
2032	1,661,839	1,661,839	1,646,419	1,423,496	1,519,146	-	15,420	238,343	142,694
2033	1,731,119	1,731,119	1,715,464	1,490,362	1,586,011	-	15,656	240,758	145,108
2034	1,793,167	1,793,167	1,775,566	1,546,332	1,641,982	-	17,602	246,836	151,186
2035	1,908,704	1,908,704	1,893,374	1,631,721	1,727,370	-	15,330	276,983	181,333
2036	1,982,586	1,982,586	1,964,757	1,697,311	1,792,961	-	17,829	285,275	189,625
2037	2,110,632	2,110,632	2,090,722	1,820,211	1,918,144	-	19,910	290,421	192,488
Cumulative Present Worth Savings Based on 6.0 percent Discount Rate:						-	309,074	1,362,386	967,625
Cumulative Present Worth Savings Based on 8.0 percent Discount Rate:						-	257,628	992,948	725,158
Cumulative Present Worth Savings Based on 10.0 percent Discount Rate:						-	219,034	744,552	559,770
Cumulative Present Worth Savings Based on 15.0 percent Discount Rate:						-	156,095	407,011	328,590

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
1	*Path 1 - Status Quo*									
2										
3	**Economic Production Model**									
4										
5	Fuel Cost	395,591	330,856	374,392	267,994	294,229	474,489	749,729	12,704,555	5,150,291
6										
7	Capital and Production Cost	180,488	190,389	192,913	379,225	637,099	1,125,413	1,631,996	24,127,857	8,140,037
8	Sales	(109,663)	(117,425)	(104,705)	(188,260)	(124,502)	(128,453)	(327,686)	(4,626,985)	(1,922,916)
9										
10	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
11	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
12										
13	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**458,959**	**863,418**	**1,528,042**	**2,110,632**	**33,280,689**	**11,700,062**
14										
15	**Organizational Costs**									
16										
17	Start-up Costs									
18	Implementation Plan	-	-	-	-	-	-	-	-	-
19	Capital Investment	-	-	-	-	-	-	-	-	-
20	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
21	Subtotal - Start-up Costs	-	-	-	-	-	-	-	-	-
22										
23	Operating Costs									
24	Direct Labor	-	-	-	-	-	-	-	-	-
25	Transferred Employee Salaries	-	-	-	-	-	-	-	-	-
26	Net Incremental Direct Labor	-	-	-	-	-	-	-	-	-
27										
28	Pension and Benefits	-	-	-	-	-	-	-	-	-
29										
30	Annual Licensing and Fees	-	-	-	-	-	-	-	-	-
31	Annual Maintenance / Hardware Replacement	-	-	-	-	-	-	-	-	-
32	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
33	Subtotal - Operating Costs	-	-	-	-	-	-	-	-	-
34										
35	**Subtotal Organizational Costs**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	-	**-**
36										
37	**Grand Total**	**466,416**	**403,819**	**462,600**	**458,959**	**863,418**	**1,528,042**	**2,110,632**	**33,280,689**	**11,700,062**
38										

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
39	*Path 2 - Independent Operation of the Railbelt Grid*									
40										
41	**Economic Production Model**									
42										
43	Fuel Cost	395,591	330,856	374,392	267,994	294,229	474,489	749,729	12,704,555	5,150,291
44										
45	Capital and Production Cost	180,488	190,389	192,913	379,225	637,099	1,125,413	1,631,996	24,127,857	8,140,037
46	Sales	(109,663)	(117,425)	(104,705)	(188,260)	(124,502)	(128,453)	(327,686)	(4,626,985)	(1,922,916)
47										
48	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
49	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
50										
51	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**458,959**	**863,418**	**1,528,042**	**2,110,632**	**33,280,689**	**11,700,062**
52										
53	**Organizational Costs**									
54										
55	Start-up Costs									
56	Implementation Plan	67	267	267	-	-	-	-	1,335	1,077
57	Capital Investment	5	21	21	-	-	-	-	103	83
58	Other Non-labor Costs	17	67	67	-	-	-	-	332	268
59	Subtotal - Start-up Costs	89	354	354	-	-	-	-	1,770	1,428
60										
61	Operating Costs									
62	Direct Labor	450	1,854	1,910	2,149	2,491	3,349	4,242	84,282	33,368
63	Transferred Employee Salaries	225	927	955	1,075	1,246	1,674	2,121	42,142	16,684
64	Net Incremental Direct Labor	225	927	955	1,075	1,246	1,674	2,121	42,140	16,684
65										
66	Pension and Benefits	90	371	382	430	498	670	848	16,856	6,674
67										
68	Annual Licensing and Fees	19	19	20	22	24	31	38	815	337
69	Annual Maintenance / Hardware Replacement	34	34	35	80	90	116	141	2,866	1,116
70	Other Non-labor Costs	657	674	690	762	862	1,104	1,345	28,849	11,918
71	Subtotal - Operating Costs	1,024	2,025	2,082	2,368	2,721	3,594	4,493	91,527	36,728
72										
73	**Subtotal Organizational Costs**	**1,113**	**2,379**	**2,436**	**2,368**	**2,721**	**3,594**	**4,493**	**93,297**	**38,156**
74										
75	**Grand Total**	**467,529**	**406,198**	**465,035**	**461,326**	**866,139**	**1,531,636**	**2,115,124**	**33,373,986**	**11,738,218**
76										

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
77	*Path 3 - Independent Operation of the Railbelt Grid and Regional Economic Dispatch*									
78										
79	**Economic Production Model**									
80										
81	Fuel Cost	359,284	318,911	337,895	248,928	276,309	460,636	729,712	12,076,227	4,831,604
82										
83	Capital and Production Cost	166,746	202,248	174,300	331,925	677,043	1,121,283	1,504,387	23,800,307	8,107,162
84	Sales	(95,050)	(129,236)	(85,180)	(141,117)	(166,104)	(123,874)	(199,969)	(4,304,640)	(1,891,999)
85										
86	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
87	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
88										
89	**Subtotal - Economic Production Model**	**430,980**	**391,922**	**427,015**	**439,736**	**843,841**	**1,514,637**	**2,090,722**	**32,647,156**	**11,379,416**
90										
91	**Organizational Costs**									
92										
93	Start-up Costs									
94	Implementation Plan	139	557	557	-	-	-	-	2,787	2,248
95	Capital Investment	37	148	148	-	-	-	-	741	597
96	Other Non-labor Costs	22	87	87	-	-	-	-	436	352
97	Subtotal - Start-up Costs	198	793	793	-	-	-	-	3,963	3,197
98										
99	Operating Costs									
100	Direct Labor	626	2,578	2,655	2,989	3,465	4,657	5,899	117,206	46,402
101	Transferred Employee Salaries	250	1,031	1,062	1,195	1,386	1,863	2,360	46,882	18,561
102	Net Incremental Direct Labor	375	1,547	1,593	1,793	2,079	2,794	3,539	70,323	27,841
103										
104	Pension and Benefits	150	619	637	717	832	1,118	1,416	28,130	11,137
105										
106	Annual Licensing and Fees	505	521	536	604	702	951	1,217	24,265	9,784
107	Annual Maintenance / Hardware Replacement	39	40	41	100	113	145	177	3,589	1,394
108	Other Non-labor Costs	1,126	1,154	1,183	1,305	1,477	1,891	2,304	49,422	20,416
109	Subtotal - Operating Costs	2,196	3,880	3,990	4,520	5,202	6,899	8,653	175,729	70,572
110										
111	**Subtotal Organizational Costs**	**2,394**	**4,673**	**4,783**	**4,520**	**5,202**	**6,899**	**8,653**	**179,692**	**73,769**
112										
113	**Grand Total**	**433,374**	**396,595**	**431,798**	**444,256**	**849,044**	**1,521,535**	**2,099,375**	**32,826,848**	**11,453,185**
114										

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
115	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Tax-Exempt)*									
116										
117	**Economic Production Model**									
118										
119	Fuel Cost	368,643	318,950	346,714	328,087	281,968	440,650	673,526	12,276,450	5,015,934
120										
121	Capital and Production Cost	162,776	205,298	172,510	215,685	567,651	1,176,870	1,480,658	22,162,017	7,335,167
122	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(188,785)	(381,468)	(390,566)	(6,695,934)	(2,460,532)
123										
124	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
125	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
126										
127	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**460,338**	**717,426**	**1,292,644**	**1,820,211**	**28,817,796**	**10,223,219**
128										
129	**Organizational Costs**									
130										
131	Start-up Costs									
132	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
133	Capital Investment	45	180	180	-	-	-	-	899	725
134	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
135	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
136										
137	Operating Costs									
138	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
139	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
140	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
141										
142	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
143										
144	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
145	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
146	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
147	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
148										
149	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
150										
151	**Grand Total**	**431,480**	**388,711**	**434,026**	**472,603**	**731,565**	**1,311,444**	**1,843,835**	**29,301,876**	**10,419,580**
152										

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
153	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Taxable)*									
154										
155	**Economic Production Model**									
156										
157	Fuel Cost	368,643	318,950	346,714	328,087	281,968	440,650	673,526	12,276,450	5,015,934
158										
159	Capital and Production Cost	162,776	205,298	172,510	217,848	607,410	1,269,443	1,578,590	23,669,139	7,770,665
160	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(188,785)	(381,468)	(390,566)	(6,695,934)	(2,460,532)
161										
162	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
163	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
164										
165	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**462,502**	**757,186**	**1,385,217**	**1,918,144**	**30,324,917**	**10,658,717**
166										
167	**Organizational Costs**									
168										
169	Start-up Costs									
170	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
171	Capital Investment	45	180	180	-	-	-	-	899	725
172	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
173	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
174										
175	Operating Costs									
176	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
177	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
178	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
179										
180	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
181										
182	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
183	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
184	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
185	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
186										
187	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
188										
189	**Grand Total**	**431,480**	**388,711**	**434,026**	**474,766**	**771,324**	**1,404,017**	**1,941,767**	**30,808,997**	**10,855,079**
190										

Scenario A - Large Hydro/Renewables/DSM/Energy Efficiency Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
191	*Path 5 - Power Pool*									
192										
193	**Economic Production Model**									
194										
195	Fuel Cost	368,643	318,950	346,714	328,087	281,968	440,650	673,526	12,276,450	5,015,934
196										
197	Capital and Production Cost	162,776	205,298	172,510	215,685	567,651	1,176,870	1,480,658	22,162,017	7,335,167
198	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(188,785)	(381,468)	(390,566)	(6,695,934)	(2,460,532)
199										
200	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
201	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
202										
203	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**460,338**	**717,426**	**1,292,644**	**1,820,211**	**28,817,796**	**10,223,219**
204										
205	**Organizational Costs**									
206										
207	Start-up Costs									
208	Implementation Plan	182	728	728	-	-	-	-	3,638	2,935
209	Capital Investment	42	168	168	-	-	-	-	842	679
210	Other Non-labor Costs	26	106	106	-	-	-	-	529	427
211	Subtotal - Start-up Costs	250	1,002	1,002	-	-	-	-	5,008	4,040
212										
213	Operating Costs									
214	Direct Labor	837	3,448	3,551	3,997	4,634	6,228	7,890	156,763	62,063
215	Transferred Employee Salaries	335	1,379	1,421	1,599	1,854	2,491	3,156	62,705	24,825
216	Net Incremental Direct Labor	502	2,069	2,131	2,398	2,780	3,737	4,734	94,058	37,238
217										
218	Pension and Benefits	201	828	852	959	1,112	1,495	1,894	37,623	14,895
219										
220	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
221	Annual Maintenance / Hardware Replacement	41	42	43	112	127	163	199	2,210	1,560
222	Other Non-labor Costs	1,441	1,477	1,514	1,671	1,890	2,420	2,949	13,621	26,131
223	Subtotal - Operating Costs	2,707	4,953	5,093	5,764	6,633	8,794	11,026	223,950	89,906
224										
225	**Subtotal Organizational Costs**	**2,957**	**5,954**	**6,095**	**5,764**	**6,633**	**8,794**	**11,026**	**228,959**	**93,946**
226										
227	**Grand Total**	**429,351**	**382,757**	**427,909**	**466,102**	**724,060**	**1,301,438**	**1,831,237**	**29,046,754**	**10,317,165**
228										

* Note: The total and NPV columns sum the entire 30-year cash flow.

APPENDIX D - SCENARIO B RESULTS

Scenario B
Path 1 Through Path 4 Expansion Plans

	Paths 1, 2, and 3					Path 4	
Year	CEA	GVEA	HEA	MEA	MLP	Taxable	Non Taxable
2008		GE LM6000 SC (1) 43.0 MW (Capital Cost $74.0 Million)					
2009		GE LM6000 SC (1) 43.0 MW (Capital Cost $76.2 Million)					
2010							
2011							
2012							
2013							
2014							
2015				GE LMS100 SC (2) 197.6 MW (Capital Cost $303.5 Million)			
2016							
2017							
2018	GE LMS100 SC (1) 98.8 MW (Capital Cost $165.8 Million)						
2019		GE LMS100 SC (1) 98.8 MW (Capital Cost $170.8 Million)				1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $115.0 Million)	1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $115.0 Million)
2020							
2021				GE 6B SC (1) 42.1 MW (Capital Cost $77.5 Million)		GE LMS100 SC (1) 98.8 MW in MEA (Capital Cost $181.2 Million)	GE LMS100 SC (1) 98.8 MW in MEA (Capital Cost $181.2 Million)
2022	GE LMS100 SC (1) 98.8 MW (Capital Cost $186.7 Million)					GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $223.9 Million)	GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $223.9 Million)
2023							
2024						GE LM6000 SC (1) 43.0 MW in GVEA (Capital Cost $118.7 Million)	GE LM6000 SC (1) 43.0 MW in GVEA (Capital Cost $118.7 Million)
2025							
2026							
2027						GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $129.8 Million)	GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $129.8 Million)
2028		1X1 GE 6FA CC (1) 116.0 MW (Capital Cost $458.4 Million)					
2029							
2030					GE LMS100 SC (1) 98.8 MW (Capital Cost $236.4 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)
2031		GE 6B SC (1) 42.1 MW (Capital Cost $104.2 Million)				GE 6B SC (1) 42.1 MW in GVEA (Capital Cost $104.2 Million)	GE 6B SC (1) 42.1 MW in GVEA (Capital Cost $104.2 Million)
2032				GE 6B SC (1) 42.1 MW (Capital Cost $107.3 Million)			
2033						GE 6B SC (1) 42.1 MW in GVEA (Capital Cost $110.6 Million)	GE 6B SC (1) 42.1 MW in GVEA (Capital Cost $110.6 Million)
2034							
2035				GE LMS100 SC (2) 197.6 MW (Capital Cost $548.2 Million)			
2036							
2037					GE LM6000 SC (1) 43.0 MW (Capital Cost $174.4 Million)		
Subtotal Capital Cost (Millions $)	$352.5	$883.6	$0.0	$1,036.5	$410.8	$1,754.6	$1,754.6

Northern and Southern Intertie Upgrades (Millions $) - $720.0

Scenario B Path 1 Through Path 4 Total Costs and Savings Comparison									
Year	Path 1 Total Cost Nominal $000	Path 2 Total Cost Nominal $000	Path 3 Total Cost Nominal $000	Path 4 Tax Exempt Total Cost Nominal $000	Path 4 Taxable Total Cost Nominal $000	Path 2 Savings Nominal $000	Path 3 Savings Nominal $000	Path 4 Tax Exempt Savings Nominal $000	Path 4 Taxable Savings Nominal $000
2008	373,798	373,798	363,359	355,971	355,971	-	10,439	17,827	17,827
2009	466,416	466,416	430,980	426,394	426,394	-	35,436	40,022	40,022
2010	403,819	403,819	391,922	376,803	376,803	-	11,897	27,016	27,016
2011	462,600	462,600	427,015	421,814	421,814	-	35,584	40,786	40,786
2012	455,609	455,609	436,209	421,024	421,024	-	19,400	34,585	34,585
2013	496,274	496,274	434,261	425,314	425,314	-	62,013	70,960	70,960
2014	426,402	426,402	415,815	400,277	400,277	-	10,587	26,124	26,124
2015	431,939	431,939	411,413	444,381	444,381	-	20,526	(12,441)	(12,441)
2016	446,305	446,305	428,515	397,619	397,619	-	17,790	48,686	48,686
2017	489,759	489,759	443,846	469,330	469,330	-	45,913	20,429	20,429
2018	498,826	498,826	484,102	452,063	452,063	-	14,724	46,763	46,763
2019	568,799	568,799	510,264	496,796	498,138	-	58,536	72,003	70,662
2020	597,054	597,054	588,091	542,705	544,046	-	8,963	54,349	53,008
2021	606,102	606,102	604,623	577,585	581,216	-	1,479	28,517	24,886
2022	680,155	680,155	677,092	620,533	626,981	-	3,062	59,622	53,173
2023	704,974	704,974	699,944	656,317	662,765	-	5,030	48,657	42,209
2024	753,286	753,286	758,528	713,511	721,455	-	(5,242)	39,775	31,831
2025	791,952	791,952	782,668	763,761	771,704	-	9,285	28,192	20,248
2026	847,209	847,209	825,159	806,721	814,664	-	22,050	40,488	32,545
2027	886,180	886,180	866,268	868,873	878,450	-	19,912	17,307	7,730
2028	953,009	953,009	931,852	909,315	918,892	-	21,157	43,695	34,118
2029	1,008,760	1,008,760	988,397	990,306	999,883	-	20,363	18,453	8,876
2030	1,063,555	1,063,555	1,055,684	1,015,429	1,035,366	-	7,872	48,126	28,189
2031	1,150,620	1,150,620	1,140,814	1,107,626	1,128,878	-	9,807	42,995	21,742
2032	1,222,195	1,222,195	1,213,317	1,155,781	1,177,034	-	8,878	66,415	45,162
2033	1,298,376	1,298,376	1,289,861	1,249,242	1,271,891	-	8,515	49,135	26,485
2034	1,368,216	1,368,216	1,358,210	1,309,322	1,331,971	-	10,006	58,894	36,245
2035	1,493,904	1,493,904	1,485,194	1,412,500	1,435,149	-	8,710	81,404	58,755
2036	1,576,684	1,576,684	1,566,464	1,482,113	1,504,762	-	10,220	94,571	71,921
2037	1,716,554	1,716,554	1,705,921	1,621,518	1,644,168	-	10,633	95,036	72,386
Cumulative Present Worth Savings Based on 6.0 percent Discount Rate:						-	281,439	548,662	486,063
Cumulative Present Worth Savings Based on 8.0 percent Discount Rate:						-	239,142	434,873	393,947
Cumulative Present Worth Savings Based on 10.0 percent Discount Rate:						-	206,538	354,381	327,199
Cumulative Present Worth Savings Based on 15.0 percent Discount Rate:						-	151,266	234,121	223,688

Scenario B - Natural Gas Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
1	*Path 1 - Status Quo*									
2										
3	**Economic Production Model**									
4										
5	Fuel Cost	395,591	330,856	374,392	271,403	306,617	564,887	883,027	14,337,719	5,600,757
6										
7	Capital and Production Cost	180,487	190,389	192,913	347,559	311,972	466,515	891,336	12,748,234	4,756,032
8	Sales	(109,662)	(117,425)	(104,705)	(187,023)	(78,128)	(24,439)	(114,401)	(2,579,127)	(1,348,443)
9										
10	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
11	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
12										
13	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**431,939**	**597,054**	**1,063,555**	**1,716,554**	**25,582,088**	**9,340,995**
14										
15	**Organizational Costs**									
16										
17	Start-up Costs									
18	Implementation Plan	-	-	-	-	-	-	-	-	-
19	Capital Investment	-	-	-	-	-	-	-	-	-
20	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
21	Subtotal - Start-up Costs	-	-	-	-	-	-	-	-	-
22										
23	Operating Costs									
24	Direct Labor	-	-	-	-	-	-	-	-	-
25	Transferred Employee Salaries	-	-	-	-	-	-	-	-	-
26	Net Incremental Direct Labor	-	-	-	-	-	-	-	-	-
27										
28	Pension and Benefits	-	-	-	-	-	-	-	-	-
29										
30	Annual Licensing and Fees	-	-	-	-	-	-	-	-	-
31	Annual Maintenance / Hardware Replacement	-	-	-	-	-	-	-	-	-
32	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
33	Subtotal - Operating Costs	-	-	-	-	-	-	-	-	-
34										
35	**Subtotal Organizational Costs**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
36										
37	**Grand Total**	**466,416**	**403,819**	**462,600**	**431,939**	**597,054**	**1,063,555**	**1,716,554**	**25,582,088**	**9,340,995**
38										

Scenario B - Natural Gas Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
39	*Path 2 - Independent Operation of the Railbelt Grid*									
40										
41	**Economic Production Model**									
42										
43	Fuel Cost	395,591	330,856	374,392	271,403	306,617	564,887	883,027	14,337,719	5,600,757
44										
45	Capital and Production Cost	180,487	190,389	192,913	347,559	311,972	466,515	891,336	12,748,234	4,756,032
46	Sales	(109,662)	(117,425)	(104,705)	(187,023)	(78,128)	(24,439)	(114,401)	(2,579,127)	(1,348,443)
47										
48	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
49	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
50										
51	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**431,939**	**597,054**	**1,063,555**	**1,716,554**	**25,582,088**	**9,340,995**
52										
53	**Organizational Costs**									
54										
55	Start-up Costs									
56	Implementation Plan	67	267	267	-	-	-	-	1,335	1,077
57	Capital Investment	5	21	21	-	-	-	-	103	83
58	Other Non-labor Costs	17	67	67	-	-	-	-	332	268
59	Subtotal - Start-up Costs	89	354	354	-	-	-	-	1,770	1,428
60										
61	Operating Costs									
62	Direct Labor	450	1,854	1,910	2,149	2,491	3,349	4,242	84,282	33,368
63	Transferred Employee Salaries	225	927	955	1,075	1,246	1,674	2,121	42,142	16,684
64	Net Incremental Direct Labor	225	927	955	1,075	1,246	1,674	2,121	42,140	16,684
65										
66	Pension and Benefits	90	371	382	430	498	670	848	16,856	6,674
67										
68	Annual Licensing and Fees	19	19	20	22	24	31	38	815	337
69	Annual Maintenance / Hardware Replacement	34	34	35	80	90	116	141	2,866	1,116
70	Other Non-labor Costs	657	674	690	762	862	1,104	1,345	28,849	11,918
71	Subtotal - Operating Costs	1,024	2,025	2,082	2,368	2,721	3,594	4,493	91,527	36,728
72										
73	**Subtotal Organizational Costs**	**1,113**	**2,379**	**2,436**	**2,368**	**2,721**	**3,594**	**4,493**	**93,297**	**38,156**
74										
75	**Grand Total**	**467,528**	**406,198**	**465,035**	**434,307**	**599,775**	**1,067,150**	**1,721,047**	**25,675,385**	**9,379,151**
76										

Scenario B - Natural Gas Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
77	*Path 3 - Independent Operation of the Railbelt Grid and Regional Economic Dispatch*									
78										
79	**Economic Production Model**									
80										
81	Fuel Cost	359,283	318,911	337,895	250,984	297,416	555,125	869,204	13,787,399	5,303,720
82										
83	Capital and Production Cost	166,746	202,248	174,300	302,658	372,556	606,003	1,016,606	14,949,400	5,382,095
84	Sales	(95,050)	(129,236)	(85,180)	(142,229)	(138,474)	(162,036)	(236,482)	(4,753,714)	(1,967,208)
85										
86	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
87	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
88										
89	**Subtotal - Economic Production Model**	**430,980**	**391,922**	**427,015**	**411,413**	**588,091**	**1,055,684**	**1,705,921**	**25,058,347**	**9,051,256**
90										
91	**Organizational Costs**									
92										
93	Start-up Costs									
94	Implementation Plan	139	557	557	-	-	-	-	2,787	2,248
95	Capital Investment	37	148	148	-	-	-	-	741	597
96	Other Non-labor Costs	22	87	87	-	-	-	-	436	352
97	Subtotal - Start-up Costs	198	793	793	-	-	-	-	3,963	3,197
98										
99	Operating Costs									
100	Direct Labor	626	2,578	2,655	2,989	3,465	4,657	5,899	117,206	46,402
101	Transferred Employee Salaries	250	1,031	1,062	1,195	1,386	1,863	2,360	46,882	18,561
102	Net Incremental Direct Labor	375	1,547	1,593	1,793	2,079	2,794	3,539	70,323	27,841
103										
104	Pension and Benefits	150	619	637	717	832	1,118	1,416	28,130	11,137
105										
106	Annual Licensing and Fees	505	521	536	604	702	951	1,217	24,265	9,784
107	Annual Maintenance / Hardware Replacement	39	40	41	100	113	145	177	3,589	1,394
108	Other Non-labor Costs	1,126	1,154	1,183	1,305	1,477	1,891	2,304	49,422	20,416
109	Subtotal - Operating Costs	2,196	3,880	3,990	4,520	5,202	6,899	8,653	175,729	70,572
110										
111	**Subtotal Organizational Costs**	**2,394**	**4,673**	**4,783**	**4,520**	**5,202**	**6,899**	**8,653**	**179,692**	**73,769**
112										
113	**Grand Total**	**433,374**	**396,595**	**431,798**	**415,933**	**593,293**	**1,062,582**	**1,714,574**	**25,238,038**	**9,125,025**
114										

Scenario B - Natural Gas Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
115	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Tax-Exempt)*									
116										
117	**Economic Production Model**									
118										
119	Fuel Cost	368,642	318,950	346,714	329,796	308,358	528,600	846,170	13,940,131	5,463,091
120										
121	Capital and Production Cost	162,776	205,298	172,510	196,848	348,347	746,618	1,186,714	15,901,842	5,421,429
122	Sales	(105,025)	(147,445)	(97,410)	(82,263)	(170,593)	(316,382)	(467,958)	(6,760,585)	(2,456,393)
123										
124	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
125	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
126										
127	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**444,381**	**542,705**	**1,015,429**	**1,621,518**	**24,156,649**	**8,760,777**
128										
129	**Organizational Costs**									
130										
131	Start-up Costs									
132	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
133	Capital Investment	45	180	180	-	-	-	-	899	725
134	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
135	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
136										
137	Operating Costs									
138	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
139	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
140	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
141										
142	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
143										
144	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
145	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
146	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
147	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
148										
149	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
150										
151	**Grand Total**	**431,479**	**388,711**	**434,026**	**456,645**	**556,843**	**1,034,229**	**1,645,142**	**24,640,729**	**8,957,138**
152										

Scenario B - Natural Gas Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
153	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Taxable)*									
154										
155	**Economic Production Model**									
156										
157	Fuel Cost	368,642	318,950	346,714	329,796	308,358	528,600	846,170	13,940,131	5,463,091
158										
159	Capital and Production Cost	162,776	205,298	172,510	196,848	349,688	766,554	1,209,364	16,171,952	5,491,727
160	Sales	(105,025)	(147,445)	(97,410)	(82,263)	(170,593)	(316,382)	(467,958)	(6,760,585)	(2,456,393)
161										
162	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
163	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
164										
165	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**444,381**	**544,046**	**1,035,366**	**1,644,168**	**24,426,758**	**8,831,076**
166										
167	**Organizational Costs**									
168										
169	Start-up Costs									
170	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
171	Capital Investment	45	180	180	-	-	-	-	899	725
172	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
173	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
174										
175	Operating Costs									
176	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
177	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
178	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
179										
180	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
181										
182	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
183	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
184	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
185	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
186										
187	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
188										
189	**Grand Total**	**431,479**	**388,711**	**434,026**	**456,645**	**558,184**	**1,054,165**	**1,667,791**	**24,910,838**	**9,027,437**
190										

Scenario B - Natural Gas Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
191	*Path 5 - Power Pool*									
192										
193	**Economic Production Model**									
194										
195	Fuel Cost	368,642	318,950	346,714	329,796	308,358	528,600	846,170	13,940,131	5,463,091
196										
197	Capital and Production Cost	162,776	205,298	172,510	196,848	348,347	746,618	1,186,714	15,901,842	5,421,429
198	Sales	(105,025)	(147,445)	(97,410)	(82,263)	(170,593)	(316,382)	(467,958)	(6,760,585)	(2,456,393)
199										
200	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
201	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
202										
203	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**444,381**	**542,705**	**1,015,429**	**1,621,518**	**24,156,649**	**8,760,777**
204										
205	**Organizational Costs**									
206										
207	Start-up Costs									
208	Implementation Plan	182	728	728	-	-	-	-	3,638	2,935
209	Capital Investment	42	168	168	-	-	-	-	842	679
210	Other Non-labor Costs	26	106	106	-	-	-	-	529	427
211	Subtotal - Start-up Costs	250	1,002	1,002	-	-	-	-	5,008	4,040
212										
213	Operating Costs									
214	Direct Labor	837	3,448	3,551	3,997	4,634	6,228	7,890	156,763	62,063
215	Transferred Employee Salaries	335	1,379	1,421	1,599	1,854	2,491	3,156	62,705	24,825
216	Net Incremental Direct Labor	502	2,069	2,131	2,398	2,780	3,737	4,734	94,058	37,238
217										
218	Pension and Benefits	201	828	852	959	1,112	1,495	1,894	37,623	14,895
219										
220	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
221	Annual Maintenance / Hardware Replacement	41	42	43	112	127	163	199	2,210	1,560
222	Other Non-labor Costs	1,441	1,477	1,514	1,671	1,890	2,420	2,949	13,621	26,131
223	Subtotal - Operating Costs	2,707	4,953	5,093	5,764	6,633	8,794	11,026	223,950	89,906
224										
225	**Subtotal Organizational Costs**	**2,957**	**5,954**	**6,095**	**5,764**	**6,633**	**8,794**	**11,026**	**228,959**	**93,946**
226										
227	**Grand Total**	**429,351**	**382,757**	**427,909**	**450,144**	**549,338**	**1,024,223**	**1,632,544**	**24,385,607**	**8,854,723**
228										

* Note: The total and NPV columns sum the entire 30-year cash flow.

APPENDIX E - SCENARIO C RESULTS

Scenario C
Path 1 Through Path 4 Expansion Plans

Year	Paths 1, 2, and 3					Path 4	
	CEA	GVEA	HEA	MEA	MLP	Taxable	Non Taxable
2008		GE LM6000 SC (1) 43.0 MW (Capital Cost $74.0 Million)					
2009		GE LM6000 SC (1) 43.0 MW (Capital Cost $76.2 Million)					
2010							
2011							
2012							
2013							
2014							
2015	Coal (1) 26.7 MW (Capital Cost $204.9 Million)	Coal (1) 25.9 MW (Capital Cost $200.6 Million)	Coal (1) 9.3 MW (Capital Cost $111.4 Million)	GE LMS100 SC (2) 197.6 MW (Capital Cost $303.5 Million); Coal (1) 16.6 MW (Capital Cost $150.6 Million)	Coal (1) 21.5 MW(Capital Cost $176.8 Million)	Coal (1) 100MW (Capital Cost $598.3 Million)	Coal (1) 100MW (Capital Cost $598.3 Million)
2016							
2017							
2018	GE LM6000 SC (1) 43.0 MW (Capital Cost $99.4 Million)						
2019							
2020	Coal (1) 26.7 MW (Capital Cost $237.5 Million)	Coal (1) 25.9 MW (Capital Cost $232.5 Million)	Coal (1) 9.3 MW (Capital Cost $129.1 Million)	Coal (1) 16.6 MW (Capital Cost $174.6 Million)	Coal (1) 21.5 MW (Capital Cost $205.0 Million)	Coal (1) 100MW (Capital Cost $693.6 Million)	Coal (1) 100MW (Capital Cost $693.6 Million)
2021	GE 6B SC (1) 42.1 MW (Capital Cost $77.5 Million)						
2022	GE 6B SC (1) 42.1 MW (Capital Cost $79.9 Million)						
2023						GE 6B SC (1) 42.1 MW in MEA (Capital Cost $79.9 Million)	GE 6B SC (1) 42.1 MW in MEA (Capital Cost $79.9 Million)
2024							
2025	Coal (1) 26.7 MW (Capital Cost $192.7 Million)	Coal (1) 25.9 MW (Capital Cost $186.9 Million)	Coal (1) 9.3 MW (Capital Cost $67.0 Million)	Coal (1) 16.6 MW (Capital Cost $119.8 Million)	Coal (1) 21.5 MW (Capital Cost $155.0 Million)	Coal (1) 100MW (Capital Cost $721. 5 Million)	Coal (1) 100MW (Capital Cost $721.5 Million)
2026							
2027							
2028		GE LMS100 SC (1) 98.8 MW (Capital Cost $222.9 Million)					
2029							
2030					GE LM6000 SC (1) 43.0 MW (Capital Cost $141.8 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)	2x1 GE 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)
2031		1x1 NP CC Repwr (1) 64 MW (Capital Cost $164.0 Million)					
2032							
2033							
2034				GE 6B SC (1) 42.1 MW (Capital Cost $113.9 Million)			
2035				GE LMS100 SC (2) 197.6 MW (Capital Cost $548.2 Million)		1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $184.6 Million)	1x1 NP CC Repwr (1) 64.0 MW in GVEA (Capital Cost $184.6 Million)
2036		GE 6B SC (1) 42.1 MW (Capital Cost $120.8 Million)					
2037							
Subtotal Capital Cost (Millions $)	$891.9	$1,277.9	$307.5	$1,410.6	$678.6	$3,049.1	$3,049.1

Northern and Southern Intertie Upgrades (Millions $) - $720.0

Scenario C
Path 1 Through Path 4 Total Costs and Savings Comparison

Year	Path 1 Total Cost Nominal $000	Path 2 Total Cost Nominal $000	Path 3 Total Cost Nominal $000	Path 4 Tax Exempt Total Cost Nominal $000	Path 4 Taxable Total Cost Nominal $000	Path 2 Savings Nominal $000	Path 3 Savings Nominal $000	Path 4 Tax Exempt Savings Nominal $000	Path 4 Taxable Savings Nominal $000
2008	373,532	373,532	363,359	355,971	355,971	-	10,173	17,561	17,561
2009	466,238	466,238	430,980	426,394	426,394	-	35,259	39,845	39,845
2010	403,643	403,643	391,922	376,803	376,803	-	11,721	26,841	26,841
2011	462,450	462,450	427,015	421,814	421,814	-	35,434	40,636	40,636
2012	455,019	455,019	436,209	421,024	421,024	-	18,810	33,995	33,995
2013	496,225	496,225	434,261	425,314	425,314	-	61,964	70,911	70,911
2014	426,726	426,726	415,815	400,277	400,277	-	10,911	26,448	26,448
2015	487,408	487,408	461,070	434,821	442,899	-	26,338	52,587	44,509
2016	501,956	501,956	486,220	418,073	426,151	-	15,736	83,883	75,805
2017	524,721	524,721	493,388	472,595	480,672	-	31,333	52,127	44,049
2018	551,824	551,824	534,719	457,681	465,758	-	17,105	94,143	86,065
2019	586,051	586,051	538,608	486,668	494,745	-	47,444	99,384	91,306
2020	719,028	719,028	695,313	587,631	605,073	-	23,715	131,396	113,955
2021	726,207	726,207	707,134	604,116	621,557	-	19,073	122,091	104,649
2022	791,667	791,667	777,923	651,133	668,575	-	13,744	140,534	123,092
2023	810,976	810,976	790,473	691,736	710,217	-	20,502	119,239	100,758
2024	871,802	871,802	857,897	739,849	758,330	-	13,905	131,953	113,472
2025	947,460	947,460	919,864	811,068	839,288	-	27,596	136,393	108,172
2026	994,950	994,950	957,363	846,602	874,822	-	37,587	148,348	120,128
2027	1,038,539	1,038,539	1,001,569	904,083	932,303	-	36,970	134,457	106,236
2028	1,098,013	1,098,013	1,063,751	939,805	968,025	-	34,262	158,208	129,987
2029	1,156,902	1,156,902	1,119,408	1,021,850	1,050,071	-	37,494	135,052	106,832
2030	1,212,390	1,212,390	1,182,680	1,081,600	1,120,180	-	29,710	130,790	92,210
2031	1,305,425	1,305,425	1,273,902	1,146,607	1,185,187	-	31,524	158,819	120,238
2032	1,370,568	1,370,568	1,337,953	1,210,141	1,248,721	-	32,616	160,427	121,847
2033	1,451,246	1,451,246	1,416,769	1,282,778	1,321,358	-	34,477	168,468	129,887
2034	1,540,873	1,540,873	1,504,798	1,355,483	1,394,063	-	36,075	185,390	146,810
2035	1,675,650	1,675,650	1,636,561	1,465,136	1,505,868	-	39,089	210,514	169,782
2036	1,778,562	1,778,562	1,738,940	1,549,103	1,589,835	-	39,621	229,458	188,726
2037	1,912,745	1,912,745	1,868,854	1,674,171	1,714,903	-	43,891	238,574	197,842
Cumulative Present Worth Savings Based on 6.0 percent Discount Rate:						-	373,252	1,214,798	1,043,040
Cumulative Present Worth Savings Based on 8.0 percent Discount Rate:						-	299,660	906,956	787,971
Cumulative Present Worth Savings Based on 10.0 percent Discount Rate:						-	246,936	695,591	611,522
Cumulative Present Worth Savings Based on 15.0 percent Discount Rate:						-	166,649	397,882	359,665

Scenario C - Coal Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
1	*Path 1 - Status Quo*									
2										
3	**Economic Production Model**									
4										
5	Fuel Cost	395,413	330,656	374,241	249,851	271,578	440,064	669,177	11,753,983	4,876,204
6										
7	Capital and Production Cost	180,680	192,062	193,016	378,079	489,150	719,723	1,307,366	18,094,718	6,356,597
8	Sales	(109,855)	(119,075)	(104,807)	(140,521)	(98,293)	(3,990)	(120,392)	(2,245,953)	(1,248,615)
9										
10	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
11	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
12										
13	**Subtotal - Economic Production Model**	**466,238**	**403,643**	**462,450**	**487,408**	**719,028**	**1,212,390**	**1,912,745**	**28,678,010**	**10,316,835**
14										
15	**Organizational Costs**									
16										
17	Start-up Costs									
18	Implementation Plan	-	-	-	-	-	-	-	-	-
19	Capital Investment	-	-	-	-	-	-	-	-	-
20	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
21	Subtotal - Start-up Costs	-	-	-	-	-	-	-	-	-
22										
23	Operating Costs									
24	Direct Labor	-	-	-	-	-	-	-	-	-
25	Transferred Employee Salaries	-	-	-	-	-	-	-	-	-
26	Net Incremental Direct Labor	-	-	-	-	-	-	-	-	-
27										
28	Pension and Benefits	-	-	-	-	-	-	-	-	-
29										
30	Annual Licensing and Fees	-	-	-	-	-	-	-	-	-
31	Annual Maintenance / Hardware Replacement	-	-	-	-	-	-	-	-	-
32	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
33	Subtotal - Operating Costs	-	-	-	-	-	-	-	-	-
34										
35	**Subtotal Organizational Costs**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
36										
37	**Grand Total**	**466,238**	**403,643**	**462,450**	**487,408**	**719,028**	**1,212,390**	**1,912,745**	**28,678,010**	**10,316,835**
38										

Scenario C - Coal Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
39	*Path 2 - Independent Operation of the Railbelt Grid*									
40										
41	**Economic Production Model**									
42										
43	Fuel Cost	395,413	330,656	374,241	249,851	271,578	440,064	669,177	11,753,983	4,876,204
44										
45	Capital and Production Cost	180,680	192,062	193,016	378,079	489,150	719,723	1,307,366	18,094,718	6,356,597
46	Sales	(109,855)	(119,075)	(104,807)	(140,521)	(98,293)	(3,990)	(120,392)	(2,245,953)	(1,248,615)
47										
48	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
49	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
50										
51	**Subtotal - Economic Production Model**	**466,238**	**403,643**	**462,450**	**487,408**	**719,028**	**1,212,390**	**1,912,745**	**28,678,010**	**10,316,835**
52										
53	**Organizational Costs**									
54										
55	Start-up Costs									
56	Implementation Plan	67	267	267	-	-	-	-	1,335	1,077
57	Capital Investment	5	21	21	-	-	-	-	103	83
58	Other Non-labor Costs	17	67	67	-	-	-	-	332	268
59	Subtotal - Start-up Costs	89	354	354	-	-	-	-	1,770	1,428
60										
61	Operating Costs									
62	Direct Labor	450	1,854	1,910	2,149	2,491	3,349	4,242	84,282	33,368
63	Transferred Employee Salaries	225	927	955	1,075	1,246	1,674	2,121	42,142	16,684
64	Net Incremental Direct Labor	225	927	955	1,075	1,246	1,674	2,121	42,140	16,684
65										
66	Pension and Benefits	90	371	382	430	498	670	848	16,856	6,674
67										
68	Annual Licensing and Fees	19	19	20	22	24	31	38	815	337
69	Annual Maintenance / Hardware Replacement	34	34	35	80	90	116	141	2,866	1,116
70	Other Non-labor Costs	657	674	690	762	862	1,104	1,345	28,849	11,918
71	Subtotal - Operating Costs	1,024	2,025	2,082	2,368	2,721	3,594	4,493	91,527	36,728
72										
73	**Subtotal Organizational Costs**	**1,113**	**2,379**	**2,436**	**2,368**	**2,721**	**3,594**	**4,493**	**93,297**	**38,156**
74										
75	**Grand Total**	**467,351**	**406,022**	**464,885**	**489,776**	**721,749**	**1,215,984**	**1,917,237**	**28,771,306**	**10,354,992**
76										

Scenario C - Coal Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
77	*Path 3 - Independent Operation of the Railbelt Grid and Regional Economic Dispatch*									
78										
79	**Economic Production Model**									
80										
81	Fuel Cost	359,283	318,911	337,895	224,854	252,511	404,674	597,851	10,802,472	4,480,153
82										
83	Capital and Production Cost	166,746	202,248	174,300	392,700	646,564	1,118,223	1,921,271	25,612,979	8,489,737
84	Sales	(95,050)	(129,236)	(85,180)	(156,484)	(260,355)	(396,811)	(706,862)	(9,720,499)	(3,378,821)
85										
86	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
87	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
88										
89	**Subtotal - Economic Production Model**	**430,980**	**391,922**	**427,015**	**461,070**	**695,313**	**1,182,680**	**1,868,854**	**27,770,213**	**9,923,718**
90										
91	**Organizational Costs**									
92										
93	Start-up Costs									
94	Implementation Plan	139	557	557	-	-	-	-	2,787	2,248
95	Capital Investment	37	148	148	-	-	-	-	741	597
96	Other Non-labor Costs	22	87	87	-	-	-	-	436	352
97	Subtotal - Start-up Costs	198	793	793	-	-	-	-	3,963	3,197
98										
99	Operating Costs									
100	Direct Labor	626	2,578	2,655	2,989	3,465	4,657	5,899	117,206	46,402
101	Transferred Employee Salaries	250	1,031	1,062	1,195	1,386	1,863	2,360	46,882	18,561
102	Net Incremental Direct Labor	375	1,547	1,593	1,793	2,079	2,794	3,539	70,323	27,841
103										
104	Pension and Benefits	150	619	637	717	832	1,118	1,416	28,130	11,137
105										
106	Annual Licensing and Fees	505	521	536	604	702	951	1,217	24,265	9,784
107	Annual Maintenance / Hardware Replacement	39	40	41	100	113	145	177	3,589	1,394
108	Other Non-labor Costs	1,126	1,154	1,183	1,305	1,477	1,891	2,304	49,422	20,416
109	Subtotal - Operating Costs	2,196	3,880	3,990	4,520	5,202	6,899	8,653	175,729	70,572
110										
111	**Subtotal Organizational Costs**	**2,394**	**4,673**	**4,783**	**4,520**	**5,202**	**6,899**	**8,653**	**179,692**	**73,769**
112										
113	**Grand Total**	**433,374**	**396,595**	**431,798**	**465,590**	**700,515**	**1,189,578**	**1,877,507**	**27,949,905**	**9,997,487**
114										

Scenario C - Coal Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
115	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Tax-Exempt)*									
116										
117	**Economic Production Model**									
118										
119	Fuel Cost	368,642	318,950	346,714	266,732	253,604	398,508	629,412	11,465,792	4,705,676
120										
121	Capital and Production Cost	162,776	205,298	172,510	318,970	555,309	1,210,811	1,852,624	23,958,078	7,822,805
122	Sales	(105,025)	(147,445)	(97,410)	(150,881)	(277,874)	(584,312)	(864,458)	(11,520,607)	(3,855,959)
123										
124	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
125	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
126										
127	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**434,821**	**587,631**	**1,081,599**	**1,674,171**	**24,978,524**	**9,005,172**
128										
129	**Organizational Costs**									
130										
131	Start-up Costs									
132	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
133	Capital Investment	45	180	180	-	-	-	-	899	725
134	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
135	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
136										
137	Operating Costs									
138	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
139	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
140	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
141										
142	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
143										
144	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
145	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
146	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
147	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
148										
149	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
150										
151	**Grand Total**	**431,479**	**388,711**	**434,026**	**447,085**	**601,770**	**1,100,399**	**1,697,794**	**25,462,604**	**9,201,533**
152										

Scenario C - Coal Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
153	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Taxable)*									
154										
155	**Economic Production Model**									
156										
157	Fuel Cost	368,642	318,950	346,714	266,732	253,604	398,508	629,412	11,465,792	4,705,676
158										
159	Capital and Production Cost	162,776	205,298	172,510	327,048	572,751	1,249,391	1,893,356	24,584,683	8,011,961
160	Sales	(105,025)	(147,445)	(97,410)	(150,881)	(277,874)	(584,312)	(864,458)	(11,520,607)	(3,855,959)
161										
162	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
163	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
164										
165	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**442,899**	**605,073**	**1,120,180**	**1,714,903**	**25,605,129**	**9,194,327**
166										
167	**Organizational Costs**									
168										
169	Start-up Costs									
170	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
171	Capital Investment	45	180	180	-	-	-	-	899	725
172	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
173	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
174										
175	Operating Costs									
176	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
177	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
178	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
179										
180	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
181										
182	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
183	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
184	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
185	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
186										
187	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
188										
189	**Grand Total**	**431,479**	**388,711**	**434,026**	**455,163**	**619,211**	**1,138,979**	**1,738,526**	**26,089,209**	**9,390,688**
190										

Scenario C - Coal Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
191	*Path 5 - Power Pool*									
192										
193	**Economic Production Model**									
194										
195	Fuel Cost	368,642	318,950	346,714	266,732	253,604	398,508	629,412	11,465,792	4,705,676
196										
197	Capital and Production Cost	162,776	205,298	172,510	318,970	555,309	1,210,811	1,852,624	23,958,078	7,822,805
198	Sales	(105,025)	(147,445)	(97,410)	(150,881)	(277,874)	(584,312)	(864,458)	(11,520,607)	(3,855,959)
199										
200	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
201	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
202										
203	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**434,821**	**587,631**	**1,081,599**	**1,674,171**	**24,978,524**	**9,005,172**
204										
205	**Organizational Costs**									
206										
207	Start-up Costs									
208	Implementation Plan	182	728	728	-	-	-	-	3,638	2,935
209	Capital Investment	42	168	168	-	-	-	-	842	679
210	Other Non-labor Costs	26	106	106	-	-	-	-	529	427
211	Subtotal - Start-up Costs	250	1,002	1,002	-	-	-	-	5,008	4,040
212										
213	Operating Costs									
214	Direct Labor	837	3,448	3,551	3,997	4,634	6,228	7,890	156,763	62,063
215	Transferred Employee Salaries	335	1,379	1,421	1,599	1,854	2,491	3,156	62,705	24,825
216	Net Incremental Direct Labor	502	2,069	2,131	2,398	2,780	3,737	4,734	94,058	37,238
217										
218	Pension and Benefits	201	828	852	959	1,112	1,495	1,894	37,623	14,895
219										
220	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
221	Annual Maintenance / Hardware Replacement	41	42	43	112	127	163	199	2,210	1,560
222	Other Non-labor Costs	1,441	1,477	1,514	1,671	1,890	2,420	2,949	13,621	26,131
223	Subtotal - Operating Costs	2,707	4,953	5,093	5,764	6,633	8,794	11,026	223,950	89,906
224										
225	**Subtotal Organizational Costs**	**2,957**	**5,954**	**6,095**	**5,764**	**6,633**	**8,794**	**11,026**	**228,959**	**93,946**
226										
227	**Grand Total**	**429,351**	**382,757**	**427,909**	**440,585**	**594,265**	**1,090,393**	**1,685,197**	**25,207,483**	**9,099,118**
228										

* Note: The total and NPV columns sum the entire 30-year cash flow.

APPENDIX F - SCENARIO D RESULTS

Scenario D Path 1 Through Path 4 Expansion Plans							
	Paths 1, 2, and 3					Path 4	
Year	CEA	GVEA	HEA	MEA	MLP	Taxable	Non Taxable
2008		GE LM6000 SC (1) 43.0 MW (Capital Cost $74.0 Million)					
2009		GE LM6000 SC (1) 43.0 MW (Capital Cost $76.2 Million)					
2010							
2011							
2012	Wind (1) 13.4 MW (Capital Cost $71.3 Million)	Wind (1) 13.0 MW (Capital Cost $70.2 Million)	Wind (1) 4.6 MW (Capital Cost $46.8 Million)	Wind (1) 8.3 MW (Capital Cost $57.1 Million)	Wind (1) 10.7 MW (Capital Cost $64.0 Million)	Wind (1) 50.0 MW (Capital Cost $174.5 Million)	Wind (1) 50.0 MW (Capital Cost $174.5 Million)
2013							
2014							
2015	Coal (1) 26.7 MW (Capital Cost $204.9 Million)	Coal (1) 25.9 MW (Capital Cost $200.6 Million)	Coal (1) 9.3 MW (Capital Cost $111.4 Million)	GE LMS100 SC (2) 197.6 MW (Capital Cost $303.6 Million); Coal (1) 16.6 MW (Capital Cost $150.6 Million)	Coal (1) 21.5 MW(Capital Cost $176.8 Million)		
2016							
2017							
2018	GE LM6000 SC (1) 43.0 MW (Capital Cost $99.4 Million); Wind (1) 13.4 MW (Capital Cost $44.8 Million)	Wind (1) 13.0 MW (Capital Cost $43.5 Million)	Wind (1) 4.6 MW (Capital Cost $15.6 Million)	Wind (1) 8.3 MW (Capital Cost $27.9 Million)	Wind (1) 10.7 MW (Capital Cost $36.1 Million)	GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $99.5 Million)	GE LM6000 SC (1) 43.0 MW in MEA (Capital Cost $99.5 Million)
2019		GE 6B SC (1) 42.1 MW (Capital Cost $73.1 Million)					
2020	Hydro (1) 80.1 MW (Capital Cost $782.4 Million); Coal (1) 26.7 MW (Capital Cost $237.5 Million)	Hydro (1) 77.7 MW (Capital Cost $763.2 Million) ; Coal (1) 25.9 MW (Capital Cost $232.5 Million)	Hydro (1) 27.9 MW (Capital Cost $365.1 Million); Coal (1) 9.3 MW (Capital Cost $129.1 Million)	Hydro (1) 49.8 MW (Capital Cost $540.4 Million); Coal (1) 16.6 MW (Capital Cost $174.6 Million)	Hydro (1) 64.5 MW (Capital Cost $657.2 Million); Coal (1) 21.5 MW (Capital Cost $205.0 Million)	Hydro (1) 300 MW (Capital Cost $2537.9 Million)	Hydro (1) 300 MW (Capital Cost $2537.9 Million)
2021						GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $217.3 Million)	GE LM6000 SC (2) 86.0 MW in MEA (Capital Cost $217.3 Million)
2022	GE LMS100 SC (1) 98.8 MW (Capital Cost $186.7 Million)						
2023							
2024							
2025	Hydro (1) 80.1 MW (Capital Cost $907.0 Million); Coal (1) 26.7 MW (Capital Cost $192.7 Million)	Hydro (1) 77.7 MW (Capital Cost $884.7 Million); Coal (1) 25.9 MW (Capital Cost $186.9 Million)	Hydro (1) 27.9 MW (Capital Cost $423.3 Million); Coal (1) 9.3 MW (Capital Cost $67.0 Million)	Hydro (1) 49.8 MW (Capital Cost $626.4 Million); Coal (1) 16.6 MW (Capital Cost $119.8 Million)	Hydro (1) 64.5 MW (Capital Cost $761.8 Million); Coal (1) 21.5 MW (Capital Cost $155.0 Million)	Coal (1) 100.0 MW (Capital Cost $721.5 Million)	Coal (1) 100.0 MW (Capital Cost $721.5 Million)
2026							
2027							
2028		GE LMS100 SC (1) 98.8 MW (Capital Cost $222.9 Million)					
2029							
2030					GE LM6000 SC (1) 43.0 MW (Capital Cost $141.8 Million)	GE 2X1 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)	GE 2X1 6FA CC (1) 235.0 MW in CEA (Capital Cost $771.2 Million)
2031		GE 6B SC (1) 42.1 MW (Capital Cost $104.2 Million)					
2032							
2033							
2034							
2035				GE 1X1 6FA CC (1) 116.0 MW (Capital Cost $563.8 Million); GE LMS100 SC (1) 98.8 MW(Capital Cost $274.1 Million)			
2036							
2037						GE LMS100 (1) 98.8 MW in GVEA (Capital Cost $290.8 Million)	GE 1X1 6FA CC (1) 116.0 MW in GVEA (Capital Cost $598.1 Million)
Subtotal Capital Cost (Millions $)	$2,726.7	$2,932.0	$1,158.3	$2,838.3	$2,197.7	$4,812.7	$5,120.0

Northern and Southern Intertie Upgrades (Millions $) - $720.0

Scenario D Path 1 Through Path 4 Total Costs and Savings Comparison									
Year	Path 1 Total Cost Nominal $000	Path 2 Total Cost Nominal $000	Path 3 Total Cost Nominal $000	Path 4 Tax Exempt Total Cost Nominal $000	Path 4 Taxable Total Cost Nominal $000	Path 2 Savings Nominal $000	Path 3 Savings Nominal $000	Path 4 Tax Exempt Savings Nominal $000	Path 4 Taxable Savings Nominal $000
2008	373,799	373,799	363,359	355,972	355,972	-	10,439	17,827	17,827
2009	466,416	466,416	430,980	426,394	426,394	-	35,436	40,022	40,022
2010	403,819	403,819	391,922	376,803	376,803	-	11,897	27,016	27,016
2011	462,600	462,600	427,015	421,814	421,814	-	35,584	40,786	40,786
2012	478,524	478,524	460,037	431,832	433,996	-	18,487	46,692	44,528
2013	520,130	520,130	458,264	436,539	438,702	-	61,867	83,591	81,428
2014	452,305	452,305	442,286	413,742	415,905	-	10,019	38,563	36,400
2015	458,959	458,959	439,736	460,338	462,502	-	19,222	(1,380)	(3,543)
2016	476,257	476,257	460,342	414,081	416,244	-	15,915	62,177	60,013
2017	522,000	522,000	476,795	492,495	494,658	-	45,205	29,505	27,342
2018	532,447	532,447	515,047	473,543	476,958	-	17,400	58,904	55,489
2019	594,451	594,451	542,438	506,465	509,880	-	52,014	87,986	84,571
2020	850,414	850,414	830,680	705,844	743,520	-	19,734	144,570	106,894
2021	845,250	845,250	831,156	739,445	779,857	-	14,093	105,805	65,393
2022	908,504	908,504	901,952	774,754	815,167	-	6,552	133,750	93,338
2023	934,457	934,457	924,576	822,392	862,804	-	9,882	112,065	71,653
2024	986,928	986,928	986,218	859,669	900,081	-	710	127,259	86,847
2025	1,063,548	1,063,548	1,051,320	931,294	981,446	-	12,228	132,254	82,101
2026	1,114,375	1,114,375	1,090,277	976,322	1,026,475	-	24,098	138,053	87,901
2027	1,154,740	1,154,740	1,131,289	1,025,692	1,075,844	-	23,451	129,048	78,896
2028	1,215,862	1,215,862	1,190,163	1,063,485	1,113,637	-	25,699	152,377	102,224
2029	1,270,010	1,270,010	1,244,118	1,137,638	1,187,790	-	25,892	132,372	82,220
2030	1,321,964	1,321,964	1,301,310	1,179,742	1,240,254	-	20,654	142,222	81,710
2031	1,409,441	1,409,441	1,384,580	1,243,804	1,304,316	-	24,861	165,636	105,124
2032	1,465,159	1,465,159	1,441,632	1,297,640	1,358,152	-	23,527	167,519	107,007
2033	1,541,357	1,541,357	1,516,005	1,367,133	1,427,645	-	25,352	174,223	113,711
2034	1,609,185	1,609,185	1,581,989	1,430,531	1,491,042	-	27,196	178,654	118,142
2035	1,729,213	1,729,213	1,706,688	1,521,299	1,581,811	-	22,525	207,913	147,401
2036	1,810,219	1,810,219	1,784,456	1,594,802	1,655,313	-	25,763	215,418	154,906
2037	1,928,576	1,928,576	1,901,576	1,729,468	1,717,665	-	27,001	199,109	210,912
Cumulative Present Worth Savings Based on 6.0 percent Discount Rate:						-	324,172	1,137,193	871,813
Cumulative Present Worth Savings Based on 8.0 percent Discount Rate:						-	266,968	847,000	662,861
Cumulative Present Worth Savings Based on 10.0 percent Discount Rate:						-	224,881	648,717	518,849
Cumulative Present Worth Savings Based on 15.0 percent Discount Rate:						-	158,002	371,688	313,684

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
1	*Path 1 - Status Quo*									
2										
3	**Economic Production Model**									
4										
5	Fuel Cost	395,591	330,856	374,392	267,994	295,377	454,321	687,288	12,264,054	5,049,269
6										
7	Capital and Production Cost	180,488	190,389	192,913	379,225	620,812	1,084,896	1,770,285	24,169,418	8,051,673
8	Sales	(109,663)	(117,425)	(104,705)	(188,260)	(122,367)	(273,845)	(585,589)	(7,053,047)	(2,501,851)
9										
10	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
11	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
12										
13	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**458,958**	**850,414**	**1,321,964**	**1,928,576**	**30,455,687**	**10,931,741**
14										
15	**Organizational Costs**									
16										
17	Start-up Costs									
18	Implementation Plan	-	-	-	-	-	-	-	-	-
19	Capital Investment	-	-	-	-	-	-	-	-	-
20	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
21	Subtotal - Start-up Costs	-	-	-	-	-	-	-	-	-
22										
23	Operating Costs									
24	Direct Labor	-	-	-	-	-	-	-	-	-
25	Transferred Employee Salaries	-	-	-	-	-	-	-	-	-
26	Net Incremental Direct Labor	-	-	-	-	-	-	-	-	-
27										
28	Pension and Benefits	-	-	-	-	-	-	-	-	-
29										
30	Annual Licensing and Fees	-	-	-	-	-	-	-	-	-
31	Annual Maintenance / Hardware Replacement	-	-	-	-	-	-	-	-	-
32	Other Non-labor Costs	-	-	-	-	-	-	-	-	-
33	Subtotal - Operating Costs	-	-	-	-	-	-	-	-	-
34										
35	**Subtotal Organizational Costs**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
36										
37	**Grand Total**	**466,416**	**403,819**	**462,600**	**458,958**	**850,414**	**1,321,964**	**1,928,576**	**30,455,687**	**10,931,741**
38										

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
39	*Path 2 - Independent Operation of the Railbelt Grid*									
40										
41	**Economic Production Model**									
42										
43	Fuel Cost	395,591	330,856	374,392	267,994	295,377	454,321	687,288	12,264,054	5,049,269
44										
45	Capital and Production Cost	180,488	190,389	192,913	379,225	620,812	1,084,896	1,770,285	24,169,418	8,051,673
46	Sales	(109,663)	(117,425)	(104,705)	(188,260)	(122,367)	(273,845)	(585,589)	(7,053,047)	(2,501,851)
47										
48	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
49	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
50										
51	**Subtotal - Economic Production Model**	**466,416**	**403,819**	**462,600**	**458,958**	**850,414**	**1,321,964**	**1,928,576**	**30,455,687**	**10,931,741**
52										
53	**Organizational Costs**									
54										
55	Start-up Costs									
56	Implementation Plan	67	267	267	-	-	-	-	1,335	1,077
57	Capital Investment	5	21	21	-	-	-	-	103	83
58	Other Non-labor Costs	17	67	67	-	-	-	-	332	268
59	Subtotal - Start-up Costs	89	354	354	-	-	-	-	1,770	1,428
60										
61	Operating Costs									
62	Direct Labor	450	1,854	1,910	2,149	2,491	3,349	4,242	84,282	33,368
63	Transferred Employee Salaries	225	927	955	1,075	1,246	1,674	2,121	42,142	16,684
64	Net Incremental Direct Labor	225	927	955	1,075	1,246	1,674	2,121	42,140	16,684
65										
66	Pension and Benefits	90	371	382	430	498	670	848	16,856	6,674
67										
68	Annual Licensing and Fees	19	19	20	22	24	31	38	815	337
69	Annual Maintenance / Hardware Replacement	34	34	35	80	90	116	141	2,866	1,116
70	Other Non-labor Costs	657	674	690	762	862	1,104	1,345	28,849	11,918
71	Subtotal - Operating Costs	1,024	2,025	2,082	2,368	2,721	3,594	4,493	91,527	36,728
72										
73	**Subtotal Organizational Costs**	**1,113**	**2,379**	**2,436**	**2,368**	**2,721**	**3,594**	**4,493**	**93,297**	**38,156**
74										
75	**Grand Total**	**467,529**	**406,198**	**465,035**	**461,326**	**853,135**	**1,325,558**	**1,933,069**	**30,548,984**	**10,969,897**
76										

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
77	*Path 3 - Independent Operation of the Railbelt Grid and Regional Economic Dispatch*									
78										
79	**Economic Production Model**									
80										
81	Fuel Cost	359,284	318,911	337,895	248,928	277,253	434,351	661,280	11,577,348	4,717,038
82										
83	Capital and Production Cost	166,746	202,248	174,300	331,925	661,582	1,035,524	1,651,869	23,432,037	7,917,337
84	Sales	(95,050)	(129,236)	(85,180)	(141,117)	(164,747)	(225,158)	(468,166)	(6,338,225)	(2,373,168)
85										
86	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
87	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
88										
89	**Subtotal - Economic Production Model**	**430,980**	**391,922**	**427,015**	**439,736**	**830,680**	**1,301,310**	**1,901,575**	**29,746,422**	**10,593,856**
90										
91	**Organizational Costs**									
92										
93	Start-up Costs									
94	Implementation Plan	139	557	557	-	-	-	-	2,787	2,248
95	Capital Investment	37	148	148	-	-	-	-	741	597
96	Other Non-labor Costs	22	87	87	-	-	-	-	436	352
97	Subtotal - Start-up Costs	198	793	793	-	-	-	-	3,963	3,197
98										
99	Operating Costs									
100	Direct Labor	626	2,578	2,655	2,989	3,465	4,657	5,899	117,206	46,402
101	Transferred Employee Salaries	250	1,031	1,062	1,195	1,386	1,863	2,360	46,882	18,561
102	Net Incremental Direct Labor	375	1,547	1,593	1,793	2,079	2,794	3,539	70,323	27,841
103										
104	Pension and Benefits	150	619	637	717	832	1,118	1,416	28,130	11,137
105										
106	Annual Licensing and Fees	505	521	536	604	702	951	1,217	24,265	9,784
107	Annual Maintenance / Hardware Replacement	39	40	41	100	113	145	177	3,589	1,394
108	Other Non-labor Costs	1,126	1,154	1,183	1,305	1,477	1,891	2,304	49,422	20,416
109	Subtotal - Operating Costs	2,196	3,880	3,990	4,520	5,202	6,899	8,653	175,729	70,572
110										
111	**Subtotal Organizational Costs**	**2,394**	**4,673**	**4,783**	**4,520**	**5,202**	**6,899**	**8,653**	**179,692**	**73,769**
112										
113	**Grand Total**	**433,374**	**396,595**	**431,798**	**444,256**	**835,883**	**1,308,208**	**1,910,228**	**29,926,114**	**10,667,625**
114										

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
115	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Tax-Exempt)*									
116										
117	**Economic Production Model**									
118										
119	Fuel Cost	368,643	318,950	346,714	328,087	283,354	420,247	672,455	11,980,262	4,930,220
120										
121	Capital and Production Cost	162,776	205,298	172,510	215,685	553,742	1,180,601	1,523,547	22,026,058	7,249,404
122	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(187,845)	(477,699)	(523,127)	(8,096,987)	(2,802,731)
123										
124	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
125	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
126										
127	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**460,338**	**705,844**	**1,179,742**	**1,729,468**	**26,984,594**	**9,709,543**
128										
129	**Organizational Costs**									
130										
131	Start-up Costs									
132	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
133	Capital Investment	45	180	180	-	-	-	-	899	725
134	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
135	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
136										
137	Operating Costs									
138	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
139	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
140	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
141										
142	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
143										
144	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
145	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
146	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
147	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
148										
149	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
150										
151	**Grand Total**	**431,480**	**388,711**	**434,026**	**472,603**	**719,982**	**1,198,542**	**1,753,091**	**27,468,674**	**9,905,904**
152										

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

Line	Description	1 2009	2 2010	3 2011	7 2015	12 2020	22 2030	30 2038	Total	NPV
153	*Path 4 - Independent Operation of the Railbelt Grid, Regional Economic Dispatch, Regional Resource Planning and Joint Project Development (Taxable)*									
154										
155	**Economic Production Model**									
156										
157	Fuel Cost	368,643	318,950	346,714	328,087	283,354	420,247	673,526	11,982,404	4,930,604
158										
159	Capital and Production Cost	162,776	205,298	172,510	217,848	591,418	1,241,113	1,359,060	22,590,565	7,473,889
160	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(187,845)	(477,699)	(390,566)	(7,831,865)	(2,755,185)
161										
162	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
163	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
164										
165	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**462,502**	**743,520**	**1,240,254**	**1,698,613**	**27,816,366**	**9,981,957**
166										
167	**Organizational Costs**									
168										
169	Start-up Costs									
170	Implementation Plan	247	986	986	-	-	-	-	4,932	3,979
171	Capital Investment	45	180	180	-	-	-	-	899	725
172	Other Non-labor Costs	52	207	207	-	-	-	-	1,035	835
173	Subtotal - Start-up Costs	343	1,373	1,373	-	-	-	-	6,867	5,539
174										
175	Operating Costs									
176	Direct Labor	1,954	8,050	8,291	9,332	10,818	14,539	18,418	365,957	144,886
177	Transferred Employee Salaries	645	2,656	2,736	3,080	3,570	4,798	6,078	120,766	47,812
178	Net Incremental Direct Labor	1,309	5,393	5,555	6,252	7,248	9,741	12,340	245,191	97,073
179										
180	Pension and Benefits	524	2,157	2,222	2,501	2,899	3,897	4,936	98,077	38,829
181										
182	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
183	Annual Maintenance / Hardware Replacement	54	55	57	182	206	263	321	6,498	2,508
184	Other Non-labor Costs	2,334	2,392	2,452	2,707	3,062	3,920	4,776	102,460	42,328
185	Subtotal - Operating Costs	4,742	10,535	10,839	12,264	14,139	18,800	23,624	477,214	190,822
186										
187	**Subtotal Organizational Costs**	**5,086**	**11,909**	**12,212**	**12,264**	**14,139**	**18,800**	**23,624**	**484,080**	**196,361**
188										
189	**Grand Total**	**431,480**	**388,711**	**434,026**	**474,766**	**757,659**	**1,259,054**	**1,722,236**	**28,300,446**	**10,178,319**
190										

Scenario D - Mixed Resource Portfolio Scenario

Summary of Results ($000)

		1	2	3	7	12	22	30		
Line	Description	2009	2010	2011	2015	2020	2030	2038	Total	NPV
191	*Path 5 - Power Pool*									
192										
193	**Economic Production Model**									
194										
195	Fuel Cost	368,643	318,950	346,714	328,087	283,354	420,247	672,455	11,980,262	4,930,220
196										
197	Capital and Production Cost	162,776	205,298	172,510	215,685	553,742	1,180,601	1,523,547	22,026,058	7,249,404
198	Sales	(105,025)	(147,445)	(97,410)	(83,433)	(187,845)	(477,699)	(523,127)	(8,096,987)	(2,802,731)
199										
200	Northern Intertie Upgrade Costs	-	-	-	-	41,464	41,464	41,464	787,816	243,723
201	Southern Intertie Upgrade Costs	-	-	-	-	15,129	15,129	15,129	287,446	88,926
202										
203	**Subtotal - Economic Production Model**	**426,394**	**376,803**	**421,814**	**460,338**	**705,844**	**1,179,742**	**1,729,468**	**26,984,594**	**9,709,543**
204										
205	**Organizational Costs**									
206										
207	Start-up Costs									
208	Implementation Plan	182	728	728	-	-	-	-	3,638	2,935
209	Capital Investment	42	168	168	-	-	-	-	842	679
210	Other Non-labor Costs	26	106	106	-	-	-	-	529	427
211	Subtotal - Start-up Costs	250	1,002	1,002	-	-	-	-	5,008	4,040
212										
213	Operating Costs									
214	Direct Labor	837	3,448	3,551	3,997	4,634	6,228	7,890	156,763	62,063
215	Transferred Employee Salaries	335	1,379	1,421	1,599	1,854	2,491	3,156	62,705	24,825
216	Net Incremental Direct Labor	502	2,069	2,131	2,398	2,780	3,737	4,734	94,058	37,238
217										
218	Pension and Benefits	201	828	852	959	1,112	1,495	1,894	37,623	14,895
219										
220	Annual Licensing and Fees	522	537	553	623	723	979	1,251	24,988	10,083
221	Annual Maintenance / Hardware Replacement	41	42	43	112	127	163	199	2,210	1,560
222	Other Non-labor Costs	1,441	1,477	1,514	1,671	1,890	2,420	2,949	13,621	26,131
223	Subtotal - Operating Costs	2,707	4,953	5,093	5,764	6,633	8,794	11,026	223,950	89,906
224										
225	**Subtotal Organizational Costs**	**2,957**	**5,954**	**6,095**	**5,764**	**6,633**	**8,794**	**11,026**	**228,959**	**93,946**
226										
227	**Grand Total**	**429,351**	**382,757**	**427,909**	**466,102**	**712,477**	**1,188,536**	**1,740,494**	**27,213,552**	**9,803,489**
228										

* Note: The total and NPV columns sum the entire 30-year cash flow.

APPENDIX G - TAX-EXEMPT BOND FINANCING OPTIONS FOR CONSTRUCTION OF A NEW ELECTRIC GENERATION AND TRANSMISSION FACILITY TO SERVE THE RAILBELT

Tax-Exempt Bond Financing Options
for Construction of a New Electric Generation and
Transmission Facility to Serve the Railbelt

July 10, 2008

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Disclaimer: **This paper has been prepared at the request of the Alaska Energy Authority to assist the REGA Advisory Working Group in its process of deciding whether and how to finance the construction of an electric generation and transmission facility to benefit the Railbelt area of Alaska. This paper is not a bond opinion and may not be relied upon by anybody as such. This paper is prepared solely for the benefit of the Alaska Energy Authority and the REGA Advisory Working Group and for inclusion in a report to be prepared by Black & Veatch as consultants to the REGA Advisory Working Group. Except as set forth above, this paper may not be relied upon by any other person or used for any other purpose or published in any other manner without the express written consent of the author. The author disclaims any responsibility to update this paper.**

The purpose of this paper is to set forth some options that are available to provide tax-exempt bond financing for the construction of a new electric generation and transmission facility to service the Railbelt area of Alaska. This paper is being prepared in connection with, and to aid, the efforts of the "REGA Advisory Working Group" in its discussions relating to the improvement of electric power distribution in the Railbelt area. To understand the options that are available, it is helpful to understand some of the basic provisions of the Internal Revenue Code that will apply.

Internal Revenue Code Considerations

The Internal Revenue Code and the regulations adopted under it control with respect to most tax-exempt bond financing, and the Code and regulations contain many detailed provisions that a general synopsis, such as this, cannot incorporate or discuss. It is important to keep this in mind before reaching any conclusions regarding a specific financing.

Another fact about the Internal Revenue Code and the regulations adopted under it is this: most projects are either clearly eligible for financing with proceeds of tax-exempt bonds or are clearly not eligible, but there are some projects which are not so clear. Occasionally, there are differences of opinion among bond attorneys regarding the eligibility of a given project for tax-exempt bond financing. Those situations that are not so clear will generally require an answer by the Internal Revenue Service (in response to a ruling request) before a bond counsel opinion can be given.

Finally, it should be kept in mind that this paper sets forth general rules applicable to tax-exempt bond financing without addressing the exceptions that apply to almost every rule under the Internal Revenue Code and the regulations adopted under it. Where an exception to a general rule is applicable, I have addressed the exception as well as the general rule.

With the preceding caveats in mind, this discussion of tax-exempt bond financing begins with a description of the difference between government obligations that are not private activity bonds ("government obligations") and government obligations that are private activity bonds ("private activity bonds"). Tax-exempt bond financing can be done with government obligations and with private activity bonds. The differences between the two are described in the next two subsections of this paper.

Government Obligations

Most tax-exempt bonds must be issued by either a state or municipal government. If a state or municipal government issues a bond, the bond is a government obligation. If the issuer of the bond takes certain actions as described below under "Private Activity Bonds," the issuer can cause its government obligation to become a private activity bond. In most cases, this is a result that the issuer would prefer to avoid if possible.

The advantages of government obligations that are not private activity bonds are: (1) they are presumed to be tax-exempt unless the government issuer does something to cause them to be taxable, and (2) they are not subject to the alternative minimum tax. While both government obligations and private activity bonds can be tax-exempt, the applicability of the alternative minimum tax to most private activity bonds means that those private activity bonds are really only partially tax-exempt. As a result, there is a smaller market for private activity bonds, and the interest rate demanded by the bond-buying market will, generally speaking, be slightly higher than the interest rate that would be demanded for an alternative-minimum-tax-free government obligation of substantially equivalent terms and credit strength (although the interest rate demanded for the private activity bond would, generally speaking, still be lower than the interest rate demanded for a fully taxable bond of substantially equivalent terms and credit strength).

The most likely things that an issuer can do to cause a government obligation to become taxable are: (1) to allow the proceeds of the bonds to be used differently than as described and contemplated in the original bond issuance documents and (2) to violate arbitrage restrictions.

For example, if a state or local government issuer were to issue bonds for the purpose of building a new administration building to be owned and occupied entirely by the issuer for the issuer's governmental purposes, this would qualify for tax-exempt bond financing. If, after issuing the bonds, the issuer allowed a private company to rent the entire building, this would be a use that was not contemplated in the original bond issuance documents and would most likely cause the bonds to become taxable.

Violating arbitrage restrictions is another way that government obligations can become taxable. The Internal Revenue Code and regulations contain complex provisions relating to arbitrage. Generally, they aim to prevent issuers from taking advantage of the difference between tax-exempt and taxable interest rates. Issuers are not permitted to issue tax-exempt bonds for the purpose of investing the proceeds in taxable investments and making earnings from the difference between the tax-exempt rate on the bonds and the taxable rate on the investments. To enforce this concept, the Internal Revenue Service has adopted many pages of intricately detailed regulations and has issued many rulings. Most bond attorneys apply these regulations and rulings to the particular bond issuance through a tax or arbitrage certificate or agreement.

Assuming the issuer uses the proceeds of the bonds as contemplated by the bond documents and does not violate the arbitrage rules, then the bonds will likely remain tax-exempt as government obligations. This means that the purchaser of the bond will not have to declare the interest income as part of that purchaser's gross income for federal income tax purposes, and the interest will also not be counted toward the alternative minimum tax. The fact that the owner of the bond does not pay taxes on the interest income the owner receives means that the owner should be willing to accept a lower interest payment for a government obligation than the owner would receive for either a tax-exempt private activity bond or a taxable bond of similar credit strength and terms.

Private Activity Bonds

A government obligation becomes a private activity bond when it passes the private use and private security tests or when a substantial amount of the proceeds of the bond is used to make a loan to a private person. Since we are not talking about using tax-exempt bonds for private loans, I will ignore that test for purposes of this discussion.

To cause a government obligation to become a private activity bond, the bond must satisfy both the private use test and the private security or payment test. The private use test is met if more than more than 10% (5% in the case of electric generation, transmission, and distribution facilities) of the proceeds of the bonds will be used to provide a facility that is used in the trade or business of a person that is not a governmental entity.

If a state authority issues bonds and uses the proceeds of the bonds to build an electric generating facility, those bonds would pass the private use test if more than 5% of the proceeds of the bonds were used to build a facility that is used in the trade or business of a person that is not a governmental entity (such as a private utility). The Internal Revenue Service will measure use of the facility by taking into account all of the facts and circumstances of the relationship between the issuer and the private entity. They will consider a contract that provides for the sale of more than 5% of the electricity generated by the facility to a private user to equal use of more than 5% of the utility by that private user. To put it in more straightforward terms, if the issuer of the bonds enters into a power sale agreement for the sale of more than 5% of the electricity produced by the generating facility to a private business, then the bonds will pass the private use test. It bears noting that if the arrangement is only a "requirements" contract (i.e., the purchaser of the electricity only purchases as much as the purchaser requires and is not obligated to purchase any amount), such contract would not create a "use" by the purchaser for purposes of determining whether the 5% limit is reached.

Another, more subtle, way of passing the private business use test is through management contracts. If the issuer of the bonds, instead of entering into a power sale agreement with a private utility, enters into a management contract with a private utility under which the private utility agrees to operate or maintain the generating facility for the issuer, that agreement could create private business use unless the management contract complies with the Internal Revenue Service's regulations relating to management contracts. In general, those regulations require that the management contracts be limited to a certain term of years. In the case of output facility management contracts, the term can be as long as 20 years, but at the end of the term the issuer must have absolute discretion to end the contract or to enter into a contract with another contractor. It is worth noting here that a contract for an electric generation and transmission facility owner to use the distribution system of a utility would not be a management contract for purposes of determining use of the generation and transmission facility.

The private business use test is only half of the analysis regarding whether a government obligation is a private activity bond. The other half is the private security or payment test. This test is passed if more than 5% (for bonds issued to finance electric output facilities; 10% for most other kinds of bonds) of the money that will be used to pay the bonds is derived from a private business source. So, if the issuer of the bonds enters into a power sales agreement and then pledges the revenues it will receive from the power sales agreement to the payment of the bonds, the bonds will pass the private security or payment test assuming that the revenues from the power sales agreement are greater than 5% of the total payments on the bonds. In most cases where there is private business use there will also be private business security or payment.

What is the significance of turning a government obligation into a private activity bond? Most importantly, while a government obligation is tax-exempt unless the issuer does something that causes the bond to become taxable, a private activity bond is taxable unless there is a specific Internal Revenue Code provision the permits it to be tax-exempt. The Internal Revenue Code does permit private activity bonds that are used to finance electric output facilities to be tax-exempt but only if certain conditions are satisfied.

For a private activity bond that finances an electric output facility to be tax-exempt, the Internal Revenue Code requires (i) that the facility be used to provide electricity to no more than two contiguous counties (boroughs in Alaska) or one county and one contiguous city (the "two-county rule") and (ii) that the user of the facility must have provided electric service in the area that the facility will serve since at least January 1, 1997, or be a successor to such an entity (the "sunset rule"). This is another important distinction between government obligations and private activity bonds when the proceeds of the bonds will be used to finance an electric generating facility: private activity bonds will have to meet the two-county rule and the sunset rule, while government obligations do not.

Another distinction between government obligations and private activity bonds is the applicability of the alternative minimum tax. Generally speaking, it applies to private activity bonds and does not apply to government obligations. The effect of the alternative minimum tax is to make the tax-exemption of private activity bonds slightly less valuable. This is because the alternative minimum tax applies a tax to these bonds for certain investors even though the bonds are otherwise tax-exempt. In this regard, private activity bonds are not exactly taxable and not exactly tax-exempt. They are somewhere in the middle, and the interest rates that apply to private activity bonds reflect that status.

There are a number of other limitations that also apply to private activity bonds but not government obligations. Private activity bonds are subject to each state's private activity bond volume cap imposed by the Internal Revenue Code. In Alaska the limit for 2008 is $262,095,000. The volume cap for each state changes each year to adjust for changes in the consumer price index. Since the inception of the volume cap in 1986, Alaska has never used all of its volume cap in a single year. The annual volume cap amount can be carried forward for up to three years to the extent that it is not used entirely within a single year, and users of the volume cap in Alaska have routinely used the carry forward feature to preserve the availability of the volume cap for their projects or programs. In 2008, for example, there is approximately $360,000,000 of carried forward volume cap. However, volume cap that is carried forward must be carried forward for a specific use and cannot be re-directed to another use after the carry forward election is made. Each year, there is typically some competition for the available volume cap from bond issuers in Alaska. The determination of how to allocate available volume cap is in the hands of the State Bond Committee. By far the largest portion of the state's volume cap is used by the Alaska Housing Finance Corporation to help finance its home mortgage financing programs and by the Alaska Student Loan Corporation to help finance its student loan program.

The weighted average maturity of a private activity bond may not exceed 120% of the reasonably expected economic life of the project being financed. No more than 25% of the proceeds of private activity bonds may be used for the acquisition of land. Private activity bonds cannot be used to acquire existing property unless capital expenditures are made for the rehabilitation of the property. The rehabilitation expenditures must be made within two years after the issuance of the private activity bonds and must equal at least 15% of the amount of the private activity bonds used to pay for the acquisition of the property. The 15% figure applies if the existing property being purchased is a building; if the property is personal property or equipment, then the rehabilitation expenditures must equal 100% of the amount of the bonds used to acquire the property. No more than 2% of the proceeds of private activity bonds may be used to pay for the costs of issuance of the private activity bonds, and the issuance of tax-exempt private activity bonds must be given public approval by the chief elected officer of the issuing entity and also the chief elected officer of each jurisdiction in which the project is located. The approval must follow a public hearing, and the public hearing must be given at least 14 days public notice.

Provisions Applicable to All Tax-Exempt Bonds

In addition to the provisions noted above that apply only to private activity bonds, there are a number of provisions that the Internal Revenue Code imposes on all tax-exempt bonds, whether government obligations or private activity bonds.

No tax-exempt bond may be federally guaranteed.

Tax-exempt bonds can be used to reimburse expenditures that were incurred before the issuance of the bonds only if the expenditures to be reimbursed occurred not more than 60 days before the issuer adopts an "official intent." An "official intent" is the issuer's declaration that it intends to incur debt to pay for the costs of the project. The "official intent" can be made in any reasonable form, but usually the board of directors of the issuer adopts a resolution for this purpose. The "official intent" must include a description of the project and must state the maximum principal amount of the bonds to be issued. The use of the proceeds of the bonds to reimburse the original expenditures must occur no later than 18 months after the later of (i) the date of the original expenditure or (ii) the date the project is placed in service or abandoned, but, in any event, no more than 3 years after the original expenditure.

Finally, all tax-exempt bonds are subject to the arbitrage and arbitrage rebate provisions of the Internal Revenue Code and regulations. The arbitrage and arbitrage rebate provisions are far too complex to attempt to summarize here. As part of any tax-exempt bond issuance, bond counsel will prepare a document, generally referred to as an Arbitrage Certificate or as a Tax Certificate or some similar name, that will set forth in detail the issuer's (and sometimes the facility user's) statements demonstrating compliance with the arbitrage and arbitrage rebate provisions. For purposes of this narration, it is probably sufficient to simply say that the arbitrage and arbitrage rebate provisions prevent issuers from issuing bonds and making money by investing the bond proceeds in an amount greater than the amount that must be paid on the bonds.

<u>The Difference between Taxable and Tax-Exempt Bond Interest Rates</u>

As a bond attorney, knowledge of the market and the interest rates that may apply to bonds on any given day is not my focus. I include this section to pass along what information I have learned over 26 or so years of working with underwriters and financial advisors and to pass along information from recent discussions with underwriters regarding the REGA Advisory Working Group efforts; however, I defer to the greater knowledge and expertise of underwriters and financial advisors, for whom this kind of information is the focus of their professions.

In a perfect world, the interest rate applicable to a tax-exempt bond would at least approximate the rate applicable to a taxable bond with similar maturity and similar security, but the interest rate would be lower to reflect the value to the bondholder of not having to pay federal income tax on the interest earned on the tax-exempt bond. Of course, in the real world the difference between taxable and tax-exempt interest rates varies from day to day and from bond issue to bond issue. It is a matter that is affected by a wide variety of factors.

There is no generally applicable spread between taxable and tax-exempt rates. It is generally true that tax-exempt rates are lower than taxable rates (assuming all other factors, such as those discussed below, are identical), but there is no specific guideline that can be relied on at all times. Nevertheless, it seems fair to say that 1.5% (or 150 basis points) is a good general guideline. This is only a general guideline that reflects more or less average differences over a span of years. The difference from day to day will vary based upon many variables.

The most significant factor that pertains to the interest rate that would apply to a given tax-exempt financing on any given day, beyond the general difference between the taxable and tax-exempt bond markets, is the security for the particular bond issuance. This is where ratings are particularly important. The rating agencies (Standard & Poor's, Moody's, and Fitch) assess the financial strength of the issue and assign a rating that is meant to reflect that strength. The strongest rating is AAA (or Aaa, in the case of Moody's). Minimum investment grade ratings (i.e., minimum ratings that will qualify a bond for being purchased by managers of large investment funds) are no lower than the B category. So-called "junk bonds" carry the highest interest rates because of the perceived security risk involved and are generally rated (if rated at all) in the C category or below. On any given day of issuance, the higher the rating assigned to the bond, the lower the likely interest rate applicable to it. Conversely, a lower rating should result in a higher interest rate. If all other factors are equal, one would expect that two bonds with equal ratings would trade at identical interest rates on a given day. Again, the real world intercedes, and on any given day two bonds with identical ratings will not necessarily bear the same interest rate even if other factors (the type of bond, the terms of the bond, the particular issuer, and others) are substantially the same.

Issuers frequently "borrow" ratings for their issuances if they think it is worth the cost. Bond insurers (such as FSA, Ambac, MBIA, FGIC, and others) maintain their own ratings so that, if an issuer purchases bond insurance from the insurer, the issuer's bond will be rated at the rating level of the insurer. The bond insurance is a promise by the insurer that it will make timely principal and interest payments on the bond if the issuer defaults. Because of this promise, the rating agencies are willing to rate the bond at (or, in recent history, occasionally above) the rating of the bond insurer. An issuer would only purchase bond insurance if the cost of the insurance is less than the present value savings in interest costs that the issuer expects to receive as a result of the insurance. An issuer would expect an interest rate savings if the bond insurer's rating is higher than the rating the bonds would receive without the bond insurance.

Until recently, bond insurers were generally rated in the highest categories by all three rating agencies. Recent developments resulting from the sub-prime mortgage lending debacle have caused significant distress in the bond insurance industry, and, now, the only bond insurer that remains rated in the highest category by all three rating agencies is FSA. All the other bond insurers have been downgraded by at least one of the rating agencies, and some of the bond insurers are now unable to continue issuing bond insurance. This has significantly changed the strategies regarding use of bond insurance at least temporarily.

Another aspect of the security for the bonds is the financial strength of the issuer and the financial strength of the issuer's program. This is the reason that the official statement (or other offering document) for a series of bonds usually goes into some detail in discussing the issuer of the bonds, the project or program being financed with proceeds of the bonds, the source of money expected to be used to repay the bonds, and other matters relating to the financial backing for the bonds. This is also the reason that newly created bond issuing agencies sometimes have difficulty selling their bonds in the market, or at least selling their bonds at the lowest possible interest rates. The bond market simply is not familiar with the new issuer and is uncertain as to the strength of the issuer's management or program.

There are other factors that influence the interest rate applicable to an issuance of bonds. Underwriters attempt to match the structure of a bond issuance to the needs of their bond-buying customers. The success of a bond issue depends in part on the underwriter's ability to match the bond to the buyer. When a bond is structured to match the highest demand in the market, there is more competition to purchase the bond. More competition means lower interest rates. On the other hand, the most appealing structure to the bond purchasers may not be the structure that best matches the issuer's needs. Ongoing discussions with the underwriters and financial advisor are the best way to match the two interests.

The lowest rates available are generally short-term rates. Issuers usually have to pay more to borrow for a longer term, although there have been times when this has not been true. For most projects, borrowing on a short-term basis (with maturities of less than a year or two) would be extremely inefficient. Underwriters can try to obtain short-term rates for the issuer without requiring the issuer to borrow on a short-term basis by creating a "synthetic" short-term borrowing. This is accomplished with "put" options. Under this structure, the holder of the bond can tender the bond for purchase on short notice and, therefore, is willing to accept lower, short-term interest rates. The issuer will usually have to purchase a liquidity facility so that the bond purchasers have assurance that the issuer will be able to honor the puts when they occur. This adds to the cost of the issuance. As with bond insurance, the issuer will purchase the liquidity facility only if the issuer is satisfied that the cost of the liquidity facility factored into the variable interest rates to be borne by the bond is still less than the interest rate that would apply if the issuer issued fixed rate bonds instead of variable rate bonds. The risk factor associated with floating interest rates can then be mitigated through the use of a swap agreement, but this adds yet another cost element to the financing.

Because of the problems created by the sub-prime mortgage lending fiasco, the tax-exempt bond market has changed in recent months. Some of the options that may have been considered to achieve the lowest possible interest rate on bonds are no longer desirable or even available (the auction rate bond market, for example, has collapsed, and auction rate bonds are no longer an option). The economic advantages of tax-exempt bonds may not be so great now as they have been at times in the past because of the current upheaval in the bond market. The relative advantages of tax-exempt financing will change from time to time in the future as it has in the past. The best approach to determining the actual benefit that can be achieved with tax-exempt bonds is to discuss the matter thoroughly with your financial advisors and your underwriters.

<u>Tax-Exempt Bond Financing Options</u>

Financing with Government Obligations

Since the generation and transmission facility that has been discussed would exceed two counties and the owner and operator of the facility would not satisfy the sunset rule, private activity bonds are not available for tax-exempt financing of the facility (unless a special permission is obtained through passage of a federal law as discussed below). To obtain tax-exempt financing for the facility, the bonds would need to be government obligations that are not private activity bonds.

There are two ways to accomplish this result that we have discussed at the REGA Advisory Working Group meetings: one is the approach advanced by John Pirog of Hawkins, Delafield & Wood and Fred Boness, former Municipal Attorney for the Municipality of Anchorage and currently on contract with the Municipality; the other is the Alaska Railroad approach.

<u>Pirog/Boness Approach</u>. Under the Pirog/Boness approach, a public corporation of the State could be created (or the Alaska Energy Authority could be legislatively retrofitted) to issue bonds to finance the construction of the facility and which would own the facility. Theoretically, a city or borough government could own the facility, but it seems more feasible to have a state authority involved in this instance. The public corporation would sell electricity generated by the facility directly to retail consumers on a "requirements" basis. There would be no minimum purchase obligation and there would be no power sales agreement with any of the utilities. Since this results in no private business use of the facility, the bonds would not pass the private business use test and would remain government obligations and not private activity bonds.

I should note that two of the six utilities participating in the REGA Advisory Working Group are publicly owned municipal entities. As such, the state authority could sell electricity to these utilities for distribution by these utilities to their customers. The sale of electricity from one governmental entity to another does not create private business use. For the remainder of this paper, in discussing the sale of electricity directly to customers of a utility, this is meant to refer to private utilities, although the public utilities could certainly enter into the same agreements with the state authority.

The existing utilities would continue to serve their customers with electricity generated by their own facilities. The electricity generated by the public corporation's facility would supplement the existing utilities' electricity. The public corporation would enter into contracts with the existing utilities for the use of the existing utilities' distribution systems and for billing services.

The advantage of the Pirog/Boness approach is that it is available under present Internal Revenue Code provisions. It would not be necessary to seek a ruling from the Internal Revenue Service, nor would it be necessary to seek any change of existing law. On July 4 of this year the Internal Revenue Service released its Private Letter Ruling 200827023, which addressed a situation similar to that proposed by the Pirog/Boness approach. Private letter rulings cannot be used as precedence with the Internal Revenue Service, which means that the Service is free to come to a different conclusion in a different ruling. However, the Service does attempt to be consistent, and private letter rulings are a good indication of how the Service approaches tax questions. In Private Letter Ruling 200827023, the Service stated:

> The issue presented is whether Utility 1 and Utility 2, by transmitting and distributing the electricity purchased with the proceeds of the Certificates, will be private business users of the electricity.
>
> Neither Utility 1 nor Utility 2 is entering into any arrangement to purchase the financed electricity or that otherwise conveys special legal entitlement to actual or beneficial use of the electricity. Utility 1 and Utility 2 will use their facilities to provide transmission and distribution services to Authority and its customers....Authority will set and receive the electricity supply charges from its customers, and Utility 1 and Utility 2 will continue to assess and retain the delivery and other utility charges.

The Service concluded that "neither Utility 1 nor Utility 2 will be considered to use the electricity financed with proceeds of the Certificates in a private business use within the meaning of sec. 1.141-3."

So, the advantage of this approach is that it is currently available for use. The disadvantage is that it requires that a new entity be given access to at least the private utilities' service areas to provide electricity directly to those private utilities' customers. Moreover, to maintain its status as a true public entity, which is essential to this approach, the board of directors of the public authority would have to be appointed by the Governor. This is understandably a matter of concern to the utilities.

63-20 Corporation. The concern over control of the entity owning the facility can be mitigated somewhat through the use of a "63-20 corporation." In Revenue Ruling 63-20, the Internal Revenue Service set forth conditions under which private corporations may issue tax-exempt bonds on behalf of state and municipal governments. These corporations have become known as "63-20 corporations." The conditions set forth in Revenue Ruling 63-20 are as follows:

- The corporation must be formed under the general nonprofit corporation law of a state for the purpose of stimulating industrial development within a political subdivision of the state.

- The corporation must engage in activities which are essentially public in nature.

- The corporation must be one which is not organized for profit.

- The corporate income must not inure to any private person.

- The state or political subdivision thereof must have a beneficial interest in the corporation while the indebtedness remains outstanding and it must obtain full legal title to the property of the corporation with respect to which the indebtedness was incurred upon retirement of such indebtedness.

- The corporation must have been approved by the state or a political subdivision thereof, either of which must also have approved the specific obligations issued by the corporation.

Following the issuance of Revenue Ruling 63-20, the Internal Revenue Service explained some of the rules of Revenue Ruling 63-20 through the issuance of its Revenue Procedure 82-26. The following bullets summarize the explanations contained in Revenue Procedure 82-26:

- The requirement that the nonprofit corporation must engage in activities that are essentially public in nature will be met if:

    - The activities and purposes of the corporation are those permitted under the general nonprofit corporation law of the state; and

    - The property to be provided by the corporation's obligations is located within the geographical boundaries of or has a substantial connection with the governmental unit on whose behalf the obligations are issued.

- The requirement that the corporation must not be organized for profit will be met if:

    - The corporation is organized under the general nonprofit corporation law of the state in which is located the governmental unit on whose behalf the corporation will issue its obligations; and

    - The articles of incorporation of the corporation provide that the corporation is one that is not organized for profit.

- The requirement that the corporate income not inure to any private person will be met if the articles of incorporation provide that the corporate income will not inure to any private person, and, in fact, the corporate income does not inure to any private person.

- The requirement that the governmental unit must have a beneficial interest in the corporation while the indebtedness remains outstanding will be met if:

  - o One of the following three requirements is satisfied:

    - The governmental unit has exclusive beneficial possession and use of a portion of the property financed by the obligations and additions to that property equivalent to 95% or more of its fair rental value for the life of the obligations; or

    - Both of the following are satisfied:

      - The nonprofit corporation has exclusive beneficial possession and use of a portion of the property financed by the obligations, and any additions to that property, equivalent to 95% or more of its fair rental value for the life of the obligations; and

      - The governmental unit on whose behalf the nonprofit corporation is issuing the obligations (A) appoints or approves the appointment of at least 80% of the members of the governing board of the corporation, and (B) has the power to remove, for cause, either directly or through judicial proceedings, any member of the governing board and appoint a successor; or

    - The governmental unit has the right at any time to obtain unencumbered fee title and exclusive possession of the property financed by the obligations, and any additions to that property, by (1) placing into escrow an amount that will be sufficient to defease the obligations, and (2) paying reasonable costs incident to the defeasance. However, the governmental unit, at any time before it defeases the obligations, may not agree or otherwise be obligated to convey any interest in the property to any person for any period extending beyond or beginning after the unit defeases the obligations. In addition, generally the unit may not agree or otherwise be obligated to convey a fee interest in the property to any person who was a user of the property, or a related person, before the defeasance within 90 days after the unit defeases the obligations; and

  - o In the event the nonprofit corporation defaults in its payments under the obligations, the governmental unit has an exclusive option to purchase the property financed by the obligations and additions to the property for the amount of the outstanding indebtedness and accrued interest to the date of default.

- The requirement that the governmental unit must obtain full legal title to the property of the corporation with respect to which the indebtedness was incurred upon retirement of the indebtedness will be met if:

- o The obligations of the nonprofit corporation are issued on behalf of no more than one governmental unit and unencumbered fee title to the property will vest solely in that governmental unit when the obligations are discharged.

- o All of the original proceeds and investment proceeds of the obligation s are used to provide tangible real or tangible personal property.

- o The governmental unit obtains upon discharge of the obligations unencumbered fee title and exclusive possession and use of the property financed by the obligations, including any additions to the property, without demand or further action on its part.

- o Before the obligations are issued, the governmental unit adopts a resolution stating that it will accept title to the property financed by the obligations, including any additions to that property, when the obligations are discharged.

- o The indenture or other documents under which the obligations are issued provide that any other obligations issued by the nonprofit corporation either to make improvements to the property or to refund a prior issue of the nonprofit corporation's obligations will be discharged no later than the latest maturity date of the original obligations, regardless of whether the original obligations are callable at an earlier date. In addition, the maturity date of the original obligations or any other obligations issued by the nonprofit corporation with respect to the property may not be extended beyond the latest maturity date of the original obligations, regardless of whether the original obligations are callable at an earlier date. If the governmental unit has the beneficial interest described above, the obligations need not meet the requirements of this bullet.

- o The proceeds of fire or other casualty insurance policies received in connection with damage to or destruction of the property financed by the obligations will, subject to the claims of the holders of the obligations, (a) be used to reconstruct the property, regardless of whether the insurance proceeds are sufficient to pay for the reconstruction, or (b) be remitted to the governmental unit.

- o A reasonable estimate of the fair market value of the property on the latest maturity date of the obligations, regardless of whether the obligations are callable at an earlier date, is equal to at least 20% of the original cost of the property financed by the obligations, and a reasonable estimate of the remaining useful life of the property on the latest maturity date of the obligations is the longer of one year or 20% of the originally estimated useful life of the property financed by the obligations.

- The requirement that the governmental unit must approve both the nonprofit corporation and the specific obligations to be issued by the corporation will be met if, within one year prior to the issuance of the obligations, the governmental unit adopts a resolution approving the purposes and activities of the corporation and the specific obligations to be issued by the corporation. If the corporation intends to issue obligations for a single project through a series of obligations to be issued over a period not to exceed five years, the governmental unit may meet the requirements of this bullet by adopting a single resolution, approving the purposes and activities of the corporation and all obligations to be issued in the series, within one year prior to the issuance of the first in the series.

Assuming that the requirements of Revenue Ruling 63-20, as amplified by Revenue Procedure 82-26, are met, the Pirog/Boness approach could be implemented through a nonprofit corporation with a board of directors controlled by the utilities involved. Instead of having bonds issued, and the facility owned, by a state authority, the 63-20 corporation could issue the bonds and own and operate the facility.

Alaska Railroad Corporation. A very special circumstance exists with the Alaska Railroad Corporation. The federal act that transferred ownership of the railroad from the federal government to the State of Alaska stipulated that bonds issued by the Alaska Railroad Corporation would be treated as government obligations and would never be treated as private activity bonds. With this special power, the Alaska Railroad Corporation could issue bonds to finance the construction of a generation and transmission facility, and the bonds would be tax-exempt government obligations and would not be private activity bonds. Theoretically, this would apply even if the facility financed with the bonds were owned by one or more of the utilities.

The state law that governs the Alaska Railroad Corporation requires the enactment of special legislation before the Alaska Railroad Corporation may issue any bonds. As a result of this state law limitation, the corporation could not issue bonds to build a generation and transmission facility until after enactment of state authorizing legislation. This imposes the time constraint of waiting for the process of passage of a state law to be completed.

In addition to requiring state legislation, involving the use of the railroad's special power will require seeking a ruling from the Internal Revenue Service to confirm that the power actually applies to this situation. In my reading of the railroad transfer act, I see no reason that the railroad's power cannot be used for this purpose, and I would expect a favorable ruling to result from the Internal Revenue Service. Bringing this question to the attention of the Internal Revenue Service, however, could very well result in an effort to close the railroad's special power. This, then, becomes a political question of what is the best use of the railroad's power assuming that there is at least a chance that it will only be able to be used once before the federal law is changed to eliminate the power.

Financing with the help of Special Federal Legislation

Other than using the Pirog/Boness approach (through a state authority or through a 63-20 corporation) or using the Alaska Railroad Corporation, the present federal tax laws and regulations provide no realistic avenue for tax-exempt financing of the proposed generation and transmission facility. Pursuit of tax-exempt financing without using one of these two approaches would require obtaining special federal legislative permission. This has been done at least twice in Alaska for electric generation facilities.

The Bradley Lake Hydroelectric Project received a special exemption from the two county rule in 1984. In 1995, the Snettisham Hydroelectric Project received a special exemption from the rule that requires rehabilitation expenditures to be made when tax-exempt private activity bond proceeds are used to acquire existing property. A special exemption from the two county rule and the sunset rule for a new generation and transmission facility would permit such a facility to be financed with tax-exempt private activity bonds.

The difficulty in obtaining a special federal exemption for bonds to finance the proposed generation and transmission facility is Congress' scoring rule. Before any tax reduction measure can be enacted, Congress now requires that a corresponding measure be enacted to balance the loss of revenue to the federal treasury. This scoring requirement did not exist when the Bradley Lake exemption was granted in 1984. The scoring requirement was in place in 1995 when Snettisham received its special exemption; however, the exemption for Snettisham was granted in connection with the sale of the Snettisham facility from the federal government to the Alaska Energy Authority.

Conclusions

The most readily available and viable tax-exempt bond financing option for a generation and transmission facility to serve the Railbelt area of Alaska is the Pirog/Boness approach. It has the advantage of being immediately available and involving the lowest interest rate kind of bonds without the need for involvement from either Congress or the Internal Revenue Service. On the other hand, it will require state legislation and it requires that customers of at least the private utilities be served directly (i.e., not through a utility) by the owner of the facility. If it is a state authority that issues the bonds, the control over the state authority will be in the hands of the state government.

The Pirog/Boness approach could be modified by using a 63-20 corporation, which could provide a greater level of control over the facility by the utilities. This would still require state legislation, but it could give the utilities some control over the facility while the initially issued bonds are still outstanding.

An alternative is to seek bond financing from the Alaska Railroad Corporation. This will also require state legislation. Further, it will require requesting a ruling from the Internal Revenue Service and, in so doing, will bring the Alaska Railroad Corporation's special bonding power to the attention of the Internal Revenue Service. This introduces the political question of finding the best use of the railroad's power considering the possibility that it could be the only use before the power is eliminated. The advantages of this approach are that (1) it can be used to finance a facility owned by the utilities, (2) it does not require any other entity to provide electric service directly to the utilities' customers, and (3) it also involves the use of the lowest interest rate kind of bonds.

Finally, special federal legislation can be sought through the Alaska congressional delegation. Such federal legislation could permit ownership of the facility by the utilities without a new entity providing service to the utilities' customers. Most likely, the special exemption would still leave the bonds as private activity bonds; so, this approach would probably not involve the lower interest rates generally available to government obligations that are not private activity bonds. Also, this approach would have to address the congressional scoring requirement.

APPENDIX H

APPENDIX H - BIBLIOGRAPHY

Appendix H
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APPENDIX I - PUBLIC COMMENTS RECEIVED ON DRAFT REPORT

Golden Valley Electric Association
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Your Touchstone Energy® Cooperative

August 20, 2008

Kevin Harper, Black & Veatch
Jim Strandberg, AIDEA

Dear Kevin & Jim,

Golden Valley Electric Association (GVEA) submits these comments in regards to the Alaska Railbelt Electrical Grid Authority (REGA) Study draft report dated July 23, 2008.

1) Overall, GVEA favors the formation of a generation and transmission entity that would align with Path 4 of the study. This includes an entity that would be responsible for independent operation of the grid, conduct regional dispatching, and coordinate regional resource planning and joint project development.

2) If "hope is not a strategy," then why has the study recommended that a State Power Authority entity be formed in hopes that the Governor and State Legislature would more inclined to provide financial assistance to a public entity? In addition, doesn't the study also place a great deal of hope in procuring tax exempt financing too.

3) Section 1, Executive Summary, Net Savings (page 15) – GVEA questions whether monthly savings ranging from $.60 to $3.20 for typical residential consumers are enough to support a public state authority rather than their locally owned and controlled cooperative. The issues, in our opinion, are local control versus state control and member-owned versus publically owned.

4) Section 1, Executive Summary, Conclusion and Recommendations (page 20) - GVEA does not believe that the Governor and State Legislature would be more willing to provide financial assistance to the Railbelt region if the new regional entity was formed as a State Power Authority rather than a private cooperative. Instead, history has shown that past administrations and State Legislatures have provided significant financial support for numerous cooperative capital projects including the northern Intertie, the Teeland transmission build around, Static Voltage Compensators (SVC) project, and many other distribution line projects.

5) Section 1, Executive Summary, Value of tax-Exempt Financing (page 19) and Conclusion and Recommendations (page 21) - GVEA does not believe an

assumed 1.75 percent (175 basis points) savings exist between taxable and tax-exempt interest rates. Instead, as the conclusions and recommendations point out (page 21) interest rates through the Rural Utility Service (RUS)/Federal Finance Bank (FFB) are relative to the rates that are available in the tax-exempt bond market.

6) Section 1, Executive Summary, Conclusion and Recommendations (page 21) - GVEA agrees that regardless of the entity formed, the Board of Directors and management team should be individuals with substantive knowledge and understanding of the electric business, specifically generation and transmission experience. Also, the Board of Directors should not be subject to political cycles (i.e. political appointed positions) and instead should be comprised of cooperative directors/CEOs and municipal commissioners/managers.

7) Section 6, Organizational Issues, Joint Project Development Issues, All-in or opt-out option (page 85) – how could cooperatives as private corporations be required to participate in future generation and transmission projects that result from a regional resource planning process if they have elected not to be a member of the regional entity?

8) Section 6, Organizational Issues, Tax and Legal Issues, Transfer of Ownership of Existing Assets (page 86) – GVEA bylaws also require that the sale, lease, or other disposition of more than 15 percent of its total assets to be approved by an affirmative vote of two-thirds of members voting unless the disposition of assets is to another cooperative or the State of Alaska, then the disposition must be approved by a majority of members voting in an election in which at least 10% of the members vote.

9) Section 6, Organizational Issues, Tax and Legal Issues, Governance (page 86) – GVEA takes exception to the notion that the new entity will need to be a public entity (state authority) to finance a large percentage of future infrastructure investments. Instead, GVEA believes that a G&T Cooperative structure can finance a large percentage of future infrastructure investments.

   A state authority is type of public benefit corporation that takes on a more bureaucratic role that often has broad powers to regulate or maintain public property. Typically state authorities borrow from both municipal corporations and private corporations, in that they resemble private nonprofit companies and take on roles that private corporations might otherwise perform. Authorities often perform a specific, narrow function for the public good. However, many feel that a state authority is "an economist's dream but a manager's nightmare," and that every time government gets involved in these types of things, taxpayers are taken to the cleaners.

   History has shown that power authorities have a financial advantage over investor-owned electric companies. Because they don't have to make a profit, they pay less in taxes and have access to tax-free financing. But, power authorities have little financial advantage over cooperative electric companies. Electric cooperatives are also not for profit companies that pay no taxes and too have access to both low-cost federal and private financing.

10) Section 1, Executive Summary, Setting a Course for the Future (page 4 paragraph 2) - states that project development will unquestionably lead to better results than the current situation. Currently only Chugach, AML&P and GVEA plan and build Generation and Transmission facilities for the most part. Larger projects have been developed with cooperation between the state and all affected utilities. GVEA questions that the decisions made by a separate G&T entity will be unquestionably better.

11) Section 1, Executive Summary, Organizational Paths and Scenarios Evaluated, Path 2, (page 5) - states that generation is not economically dispatched on a regional basis. It is in fact economically dispatched within the constraints of the interconnected grid and availability of economic energy. GVEA could import more gas fired energy from Anchorage; however, there are many times when more economic energy is unavailable.

12) Section 1, Executive Summary, non-Economic Benefits (page 17) -There are several points GVEA disagrees with:
    a. A regional entity provides more career options - in fact it would offer less options as it would result in a overall reduction in the workforce which is how it saves money overall. Less engineering staff, fewer managers and fewer dispatchers than currently exist.
    b. It increases the ability to monitor developments and project status - there would really be no change in this area as all other projects have had a project manager to provide direction. This statement would be true if project management had been performed by a committee.
    c. The concentration of staff would lead to more sophisticated planning - again I don't believe there would be an increase in this area. Currently Integrated Resource Plans and Load forecasts along with system modeling are used to make current decisions. The system models incorporate the entire Railbelt system and not just the individual utilities.

13) Section 3, Situational Assessment, Uniqueness of Railbelt Region, Size and Geographic Expanse (page 42) - the peak total load of the utilities is not 1,100 MW. It is closer to 850 MW. Table 23 shows that projected peak demand in 2037 adds up to 1,092 MW.

14) Section 5, Existing and Future Resource Options, Existing Transmission Grid (Page 70) - Map is incomplete - does not include GVEA's Carney to North Pole 138 kV or the Ground-base Missile Defense & Alyeska Pump 9 138 kV transmission lines.

15) Section 7, Summary of Assumptions, Table 26 (page 94) - GVEA's last IRP indicates no need for additional capacity until 2026. Incorporating the latest GVEA load forecast will push the need for additional capacity beyond 2030.

16) Section 9, Conclusion and Recommendations, Operational Issues, O&M Responsibility (page 130) - one major issue GVEA believes has not been discussed in this document would be what voltage level determines which lines are considered transmission. Most of the transmission lines in the Railbelt are

considered sub-transmission on interconnected grids in the lower 48. For example should the G&T only be responsible for 138 kV transmission lines and above or should there be tie points where the local utility takes over responsibility which are not voltage dependent. GVEA has many distribution substations tied into 69 kV transmission lines in which case local utility control may be desired.

17) General questions and comments:

a. If the proposed entity (State Authority) is not regulated by the Regulatory Commission of Alaska, in part due to the inappropriateness of one State entity regulating another, should the entity also be exempt from Alaska Department Environmental Conservation regulation?

b. If a driver for choosing a State Power Authority is its ability to undertake tax-exempt debt, what role will Independent Power Producer's play considering that the other organizational structures were rejected, in large part because of their inability to obtain tax-exempt debt?

c. The ability to issue tax-exempt debt is sometimes be subject to certain scoring rules. Therefore, the State should immediately look into getting credit for past and future Permanent Fund Dividends (PFD) payouts as well as the upcoming energy credit added to this year's PFD. These payments are clearly funds that other states would provide via services, but Alaska chooses to give directly to its residents thus causing a new tax stream that the Feds would not have otherwise had.

d. If a State Power Authority is formed, it is likely that the entity will need to negotiate fuel contracts. As the Oil companies, a couple of years back, wanted to tie tax issues to the building of a gas line, would the State be willing to use tax issues and risk in kind in their negotiations also?

e. The state has traditionally interpreted "highest price" as the meaning of best value when selling oil. Will this still be their interpretation when they sell electricity via a State Authority directly to end consumers (some of which will be petroleum-based generation)?

f. It is possible that the SCADA HW/SW costs in the executive summary are too low, at least for a new system. The cost maybe sufficient for retrofitting an existing system, but then there would not be the benefit of having expertise "down the hall."

g. Many of the non-economic benefits are not necessarily benefits for an existing utility entity. For example, the study opines that the new entity would be in a good position to compete for labor in the market place. This marketplace would likely be from existing utilities. In addition, the reduced legal expenses are touted as an advantage, yet the majority of legal challenges is this state have been over power supply issues.

h. The Municipality of Anchorage currently requires most new electrical services to be underground, which are reflected in higher AMLP rates. Should a State Authority be considered, what would stop the Fairbanks

North Star Borough (FNSB) or other borough or municipality from requiring (by ordinance) that all transmission lines be installed underground so that the costs are passed to all electrical consumers in the State?

i. Who will determine the level of electric reliability for each region or municipality? For example, currently downtown Anchorage businesses require (and pay for) a high standard of electric reliability, while outlying areas receive a reduced level of reliability. Can the level of generation and transmission reliability be segregated from distribution reliability when the level of service is provided by two separate utilities?

j. Should a State Authority entity sell electricity directly to end consumers, how will large industrial customers that are served at transmission voltage be handled? (i.e. such customers typically deal and talk directly with the dispatch center personnel rather than with distribution personnel.)

Thank you for the opportunity to share our concerns, comments, and questions. If you have questions or need further clarification, please feel free to contact me.

Brian Newton

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COPY

August 14, 2008

Robert M. Pickett, Chair
Regulatory Commission of Alaska
701 W. 8th Avenue, Suite 300
Anchorage, Alaska
99501-3469

Re: Railbelt Electric Grid Authority, Draft Report

Dear Chairman Pickett:

Matanuska Electric Association, Inc. (MEA) respectfully submits these comments for consideration as the Commission develops its comments on the Railbelt Electric Grid Authority (REGA) Draft Report. MEA has been reviewing the REGA Draft Report, and is seriously disappointed by the deficiencies in this $800,000 study. MEA is submitting these comments to the Alaska Energy Authority, but believes that there are certain issues related to this Report that the Commission should also address in its comments.

DEREGULATION OF RAILBELT G&T:

Foremost of these issues is the recommendation that the new Generation and Transmission (G&T) entity should be generally exempt from RCA regulation.[1] MEA strongly disagrees with this recommendation. Even if the Commission were to endorse the recommendation that the Railbelt G&T should be a State agency or authority, full economic regulation under AS 42.05 should be mandatory.

The Alaska Intertie, owned by the Alaska Energy Authority (AEA), provides a good example of why economic regulation is necessary. As was freely admitted under oath by Henri Dale of Golden Valley Electric Association, Inc. in his October 28, 2004, oral testimony in Docket No. U-03-100[2], the wheeling rates for MEA use of the Alaska Intertie are not fair. Under the Alaska Intertie Agreement, a change in rates requires unanimous consent of all Participants.[3]

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[1] *See*, REGA Draft Report, Executive Summary, page 23, Table 11, *and*, Section 9, page 132.

[2] At Transcript, Volume II, Page 80, Lines 2-18.

[3] Alaska Intertie Agreement, at page 39, Article 26 (posted on the Alaska Energy Authority website at: http://www.akenergyauthority.org/IntertieFiles/AKIntertieAgmt19852.pdf)

As rates on the Alaska Intertie are not regulated by this Commission,[4] there was no prospect of MEA receiving service on this State facility at rates which are just and reasonable for MEA's customers unless MEA was able to bring pressure to bear on the other Participants such that they were willing to forego the Intertie subsidy being paid by MEA. AEA was never able to resolve this situation, or a number of other issued related to the Alaska Intertie, and has now given notice of termination of the Alaska Intertie Agreement. The State has made little progress developing a replacement agreement, let alone one that includes rates based upon the cost causer/cost payer principle.

Clearly, wheeling rates on the Alaska Intertie need to be regulated by a consumer protection entity such as this Commission, rather than an entity such as AEA which is necessarily more concerned with Intertie ownership and operation issues. Consistent application of traditional rate making procedures should encourage greater cooperation among the Participants, because they would no longer be constantly competing for a disproportionate share of the limited pool of available benefits.

Further, regulation of the Alaska Intertie and other Railbelt G&T assets ensures that these facilities are available for utilization by smaller producers.[5] MEA believes that the risk of harm to consumers from elimination of Commission regulatory oversight of the Railbelt G&T system would be proportionately greater than the harm to consumers that has resulted from exempting the Alaska Intertie from Commission regulation.

INACCURATE ASSUMPTIONS:

A second major issue with the REGA Draft Report that should be addressed by this Commission is the inaccurate assumptions upon which the recommendations are based. Two glaring examples of this are the assumption that tax exempt financing will necessarily result in significant cost savings, and the assumption that a state authority G&T is more likely to receive grants from the Legislature than a cooperative G&T.

The most significant assumption upon which the REGA Draft Report bases its recommendation that the Railbelt G&T be a State authority is that such an authority can finance G&T construction with tax exempt municipal bond financing at rates that are 175 basis points lower than the taxable financing available to a cooperative G&T not borrowing from Rural Utility Services (RUS)/Federal Financing Bank (FFB).[6] The REGA Draft Report states that a

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[4] *See*, AS 44.83.090(b).

[5] For example, MEA recently received an inquiry from the Native Village of Cantwell about purchasing part of the output of a hydroelectric project the Village is currently investigating. Currently, power from the Village could only reach MEA's system through the Alaska Intertie. Under the existing Alaska Intertie Agreement, it is not clear that this power could be wheeled over the Alaska Intertie, despite the fact that southbound capacity on the Intertie has been virtually unused for the life of this transmission line. If the Alaska Intertie were subject to Commission regulation, AS 42.05.311(a) would ensure that the Village could have access to this capacity on just and reasonable terms.

[6] *See*, REGA Draft Report, *at* Executive Summary, pages 19-20; Section 7, page 91 & Table 22; *and* Section 9, at pages 126-127

cooperative G&T can borrow at similarly advantageous rates through the RUS/FFB, but then discounts this possible source of financing for several reasons.[7] These assumptions are based upon consultation with "financial advisors."[8]

The problem with these assumptions is that they do not match the reality of Railbelt utility experience. ML&P is financed through tax-exempt municipal bonds and MEA is financed through the National Rural Utilities Cooperative Finance Corporation (CFC). Comparison of the information on ML&P's 2007 Annual Report with the information on MEA's 2007 Annual Report shows that ML&P's average cost of debt is more than 100 basis points higher than MEA's cost of debt, not 175 basis points lower as assumed in the REGA Draft Report. GVEA is primarily financed through RUS/FFB, and a comparison of the information in its 2007 Annual Report with that in MEA's shows a virtually identical average cost of debt.

It appears that the financial advisors consulted for the REGA Draft Report overstated the value of tax-exempt bond financing versus the value of financing through CFC or RUS/FFB. Based upon the actual results experienced in the Railbelt, financing available to a cooperative G&T through either RUS/FFB or CFC have proven to be more than 100 basis points less expensive than financing through tax-exempt municipal bonds. Future results, of course, will vary with such factors as timing and prevailing rates.

A second major assumption upon which the REGA Draft Report conclusions are based is that:

> It seems reasonable to conclude that the Governor and State Legislature would be more willing to provide some level of financial assistance to the Railbelt region if the new regional entity was formed as a State Power Authority, as opposed to a private business such as a G&T Cooperative.[9]

No objective support is given for this assumption anywhere in this Report, and this assumption was directly refuted by former legislator Norm Rokeberg, chair of the REGA Study Advisory Work Group and author of the $800,000 REGA appropriation, at a meeting of the REGA study advisory group.

The record shows that since 1993,[10] the Legislature and Governor have approved: a grant of $42.2 million plus interest of over $20 million to Golden Valley Electric Association (GVEA) for the Northern Intertie (Section 1, Chapter 19, Session Laws of Alaska (SLA) 1993); a grant of $46.8 million plus over $27 million in interest to Chugach Electric Association (CEA) for the

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[7] *Id.*, at Executive Summary, page 21.

[8] *Id.*, at Section 7, page 91.

[9] REGA Draft Report, Executive Summary, page 20.

[10] MEA is only going back to 1993 because the Alaska Legislature's website only goes back that far.

Southern Intertie (Section 2, Chapter 19, Session Laws of Alaska (SLA) 1993); an interest free loan of $35 million to MEA and Copper Valley Electric Association (CVEA) for the Sutton to Glennallen Intertie; $12 million to Cordova Electric Cooperative for the Power Creek hydroelectric project (Section 6, Chapter 115, SLA 2002); $10 million to CVEA for the Valdez cogeneration facility (Section 6, Chapter 115, SLA 2002); and $6 million to Kodiak Electric Association for the Nyman cogeneration facility (Section 6, Chapter 115, SLA 2002). In addition to these G&T grants to cooperatives, the Legislature and Governor have approved financial assistance for G&T development worth hundreds of millions of dollars to the Four Dam Pool Power Agency, a Joint Action Agency (JAA) formed by two cooperative and three municipal electric utilities, plus made several other G&T grants to municipal utilities. The Legislature and Governor approved a conditional $5 million grant to Agrium, Inc., a Canadian for-profit corporation, to study development of a coal gasification generation facility in 2006.[11] The PCE subsidy goes to cooperative, municipal, and for-profit private utilities.

Since 1993, hundreds of millions of dollars were invested in the still dormant Healy Clean Coal Plant and otherwise the only financial aid approved by the Legislature and Governor for state owned G&T facilities of which MEA is aware is the $20.3 million grant for Alaska Intertie upgrades.[12] Based upon this history, it is clear that the Legislature and Governor are at least as likely to give grants to a cooperative G&T as it is to give grants to a state G&T entity. In fact, as this Commission found out in its efforts to get capital funding for its new computer system, it may be easier for private entities to get financial aid in Alaska than it is for state entities to do so. The REGA Draft Report assumption quoted above is clearly overreaching without factual or historical support.

CONCLUSION:

There are a number of additional problems with the REGA Draft Report, particularly issues related to the proposed treatment, or lack thereof, of existing G&T facilities, wholesale power contracts, fuel contracts, and debt management. These implementation issues will assure continued dysfunctional dealings between the utilities if left unaddressed. However, the implementation issues are overshadowed by the pivotal and incorrect premises upon which this Report is based.

There is no public policy reason for the State of Alaska to directly become the retail power supplier for hundreds of thousands of consumers.[13] MEA also questions whether the State will develop the customer service infrastructure required to address such public concerns as will be forthcoming during such events as brown-outs and actual power outages. Clearly, if the distribution utilities have no control over the G&T system,[14] our customer service personnel can

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[11] *See*, Section 1, Chapter 82, SLA 2006.

[12] *See*, Section 78(c), Chapter 1, SSSLA 2002, as modified by Section 69, Chapter 29, SLA 2008.

[13] *See*, REGA Draft Report, Section 9, page 135 (recommendation to establish direct privity with retail customers).

[14] *See*, REGA Draft Report, Section 9, page 134 (recommendation that majority of G&T entity Directors be independent of existing utilities).

only redirect concerned consumers to the State for redress of those concerns. The REGA Draft Report does not address this issue at all.

The REGA study is intended to assist the Legislature and Governor in developing the statutory and financial framework within which electric utility service can be provided to Railbelt consumers at an affordable price. Given the serious flaws in this Draft Report, it appears doubtful that AEA is going to come up with an appropriate basis for development of this framework.

It must be noted that the REGA Draft Report was funded and managed by a State authority that funds most of its activities through grants and tax exempt bonds. It comes as no surprise that this Report recommends that the ownership, operation and planning of future Railbelt G&T infrastructure be controlled by a State authority funding most of its activities through grants and tax exempt bonds. The appearance of bias in favor of a state agency G&T and against a cooperative G&T is undeniable.

MEA respectfully requests that this Commission immediately bring its expertise to bear on this issue, so that the Governor and Legislature will get an unbiased factual basis from which to develop this essential framework. Specifically, MEA requests that the REGA Draft Report be imported into Docket No. R-07-001, and that this Commission actively investigate development of a cooperative Railbelt G&T organized in a manner consistent with the national model.

If you have any questions, please do not hesitate to call me at (907) 761-9275.

Sincerely,

James L. Walker
Senior Counsel

cc: Commissioner Kate Giard, RCA
Commissioner Mark K. Johnson, RCA
Commissioner Anthony A. Price, RCA
Commissioner Janis W. Wilson, RCA
REGA Project Manager James Strandberg, AEA

CHUGACH
POWERING ALASKA'S FUTURE

August 27, 2008

Jim Strandberg, Project Manager
Alaska Energy Authority
813 W. Northern Lights Boulevard
Anchorage, AK 99503

Kevin M. Harper, Director
Enterprise Management Solutions Division
Black & Veatch
24513 SE 37th Street
Issaquah, WA 98029

RE: Comments, Draft Report July 23, 2008, Alaska Railbelt Electric Grid Authority (REGA) Study

Chugach supports the REGA process to unite the Railbelt's generation and transmission (G&T) functions. This effort will require a commitment from the governor and the legislature and require utilities to work cooperatively for the best interest of their rate payers. This transition comes with many challenges.

The primary challenges with the Black & Veatch recommendations include:

1. Governance and corporate structure of the G&T organization
2. Transfer/lease of utility assets
3. Transformation of the numerous bi-lateral agreements
4. Cost allocation and hold harmless implementation
5. Tax-exempt financing viability
6. Regulatory oversight

<u>The utilities do recognize the benefits of joint efforts:</u>
As you are aware, Chugach and Anchorage Municipal Light & Power (ML&P) have been working for a year now to restructure in some form. In November of 2007, Navigant Consulting released a report on cost savings from alternative combinations of both utilities that identified considerable savings.

In the press lately, you have seen that Chugach and ML&P have moved forward to jointly build a highly efficient combined cycle gas turbine plant in Anchorage. Homer Electric Association (HEA) was an initial participant in that project but ultimately decided to build a plant on the Kenai. Matanuska Electric Association (MEA) is currently evaluating participation in the joint project.

There are also existing projects that involve joint partners.

- Chugach, ML&P and MEA operate the Eklutna Hydroelectric project as joint owners.
- All Railbelt utilities participate in the Bradley Lake Hydroelectric project.
- The Alaska Intertie Agreement

The bottom line is utilities do support unification when it is in there best interest to do so.

<u>The Railbelt as a whole has needs that if undertaken jointly will reduce costs in the long run for Railbelt customers:</u>

The governor and legislature have provided immediate energy assistance to all Alaskans - the $1,200 single payment will help with fuel bills this year but we need a sustainable plan for the long-term.

The Railbelt has immediate needs that must be addressed and studies that must be undertaken to address the Railbelt's rising cost of energy. The top priorities are listed below:

1. Energy policy/strategy for Cook Inlet gas production to meet local demands
2. R&D/pilot project development for fuel diversity
3. Study/project development of renewable resource projects that substantially reduce dependence on fossil fuels
4. Conservation and energy efficiency program development
5. Support of regionally developed generation facilities that improve fuel efficiency and reduce demand on Cook Inlet natural gas supplies

Given the challenges and needs to immediately address these priorities we recommend the following:

- Establish management/technical teams to address key issues of governance, asset consolidation, transition and regulation. The following are concepts Chugach would endorse.
    - Governance should include a professional board (knowledgeable in electric utility matters) that cannot be swayed by political forces. Members should recognize fiduciary responsibility to the Railbelt as whole rather than individual utilities.
    - Many of the needs simply need human resources to undertake. We recommend an entity be established that manages the efforts and uses consultants and utility technical expertise to provide guidance
    - The State should encourage and support regional project development. Bradley Lake is a good model of public/private partnership. The project is owned by the State, operated and maintained by private utilities and financed through state grants and utility guarantees. Susitna or Chakachamna could follow this same concept.
    - We agree that asset transfer is problematic and that pledging assets for the benefit of all would be a preferable approach. We think transmission should be the first area to unite.
    - Generation will be a much more difficult task. We recommend a regional approach for projects less than 300MW with continued bi-lateral agreements. An example would be the proposed South Central Alaska Power Project (SCAPP) with multiple participants.
    - Economic dispatch is currently done by Chugach, ML&P and GVEA. There is really no benefit in reinventing the wheel. A combined Chugach/ML&P will economically dispatch 80% of the power in the Railbelt. We recommend leveraging the existing dispatch system infrastructure and having future generation providers seek services through bi-lateral agreements.
    - Tax exempt debt should not drive the corporate structure. We should concentrate on leveraging the State's financial strength through grants and/or low interest loans for joint projects.

    - We recommend that RCA regulation be adopted for a five-year period with a sunset review to evaluate its effectiveness. We see this as being necessary to gain acceptance of the overall concept. Chugach has stated that if the State creates a unified system operator, it would transfer its operation to the state if acceptable with our consumers.
- The State should provide incentives (grants and/or low-interest loans) to utilities that join together to build regional generation plants that improve fuel efficiency by at least 15%. To be eligible, the utility must agree to be signatory to the Railbelt system interconnection agreement. Further, generation plants must meet Railbelt planning criteria in accordance with a system-wide resource plan
- Create legislation that forms a Railbelt-wide system operator – individual utilities would pledge the use of their transmission assets for the benefit of Railbelt users on a non-discriminatory basis. The system operator would be responsible for the following activities:
    - Asset Management of G&T assets (Planning, engineering, procurement, construction, administration and O&M) – default responsibility but use competitive process (outsourcing) with utilities or other entities
    - Define, administrate and uphold Railbelt interconnection regulations (NERC to be used as guideline)
    - Create postage stamp transmission tariff (FERC to be used as guideline)
    - R&D efforts for new fuels and technology
    - Development of renewable resource projects
    - Development of energy conservation measures
    - Evaluate gas storage and bullet/spur line project development
    - Evaluate fuel consolidation services for generating entities
    - Finance capability of mega-projects (projects whose capital costs exceed the capability of individual utilities or regional utilities - TBD)

We believe many of the benefits of a unified system operator can be achieved within a reasonable time frame if the above concepts are endorsed. Chugach stands ready to debate the issues and move forward with a public/private partnership that benefits all Railbelt energy consumers.

We appreciate the opportunity to comment on this draft study.

Sincerely,

Bradley Evans

Bradley W. Evans
Chief Executive Officer

MUNICIPAL
LIGHT & POWER

September 8, 2008

Mr. Kevin M. Harper
Director, Enterprise Management
Solutions Division
Black & Veatch
24513 SE 37th Street
Issaquah, WA 98029

Mr. Jim Strandberg
Project Manager
Alaska Energy Authority
813 West Northern Lights Boulevard
Anchorage, Alaska 99503

RE: ML&P Comments on REGA Project Draft Report

Dear Kevin & Jim:

Anchorage's Municipal Light and Power (ML&P) appreciates the extended opportunity to submit written comments on the Railbelt Electrical Grid Authority (REGA) July 23, 2008 Draft Report.

First, Black & Veatch as project consultant and AEA as project manager are to be commended for the integrity and scope of your work effort. AEA provided an excellent outreach forum to interact with Black & Veatch throughout the study period, and the consultant has in essence developed a marvelous matrix identifying the many choice points facing the Railbelt energy community that will impact our electrical infrastructure for the coming decades. The consultant has also offered suggestions on broad issues of whether a regional electrical entity for the Railbelt should be created, its most desirable organizational mode and its most desirable business structure (together with suggestions on subsidiary matters such as economic regulation, regional IRP responsibility, regional economic dispatch, etc.).

A transition team will now have to decide on the broad and subsidiary recommendations as well as the necessary "implementation" matters, also meticulously identified and in critical areas left expressly unresolved (such as the vital governance dimension for a Railbelt REGA). ML&P at this time will offer its position as to only the broadest of the Draft Report's recommendations, and address remaining matters in the next stages.

In our opinion, the Railbelt has arrived at (or is being driven by external events to) a point that some regional electrical entity is presently desirable to facilitate the best future responsiveness and evolution of our energy infrastructure. We therefore agree with the

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Draft Report to the extent that a regional entity coordinating at least the Railbelt transmission grid is desirable, with the precise elements of that coordination still to be worked out and with the addition of further activities to its mandate also possible in the future (such as perhaps developing advisory regional IRPs on a periodic basis).

The REGA project has also revealed substantial appreciation and value of a forum for the Railbelt's impacted stakeholders to consider a wide range of energy matters, and we recommend that an effort be made to weave a continuing stakeholder forum into the REGA's activities.

But ML&P has difficulty participating in the Draft Report's recommendation that the REGA should be constituted as a "Path 4" organization, which would develop the regional IRP and provide transmission and generation services for all of the Railbelt utilities (with a transitional "save harmless" period for ML&P). Certainly we can understand why at least some of the Railbelt electric cooperatives might find such an organizational mode appropriate for their situations of restricted access to low cost financing and difficult load characteristics, among other matters. However, as a municipal electric utility, ML&P is fortunate to enjoy access to low cost financing coupled with a very favorable load profile and resource situation. Under these circumstances (and even with a transitional grace period), mandatory participation in a Path 4 REGA would not enable ML&P to sustain continuing delivery to its ratepayers of their legitimate entitlements. Consequently, in the best interest of ML&P rate payers, we must retain the ability to determine and provide for our own future generation needs.

However, our reluctance to participate in a Path 4 REGA should not be mistaken as a reluctance to engage in joint Railbelt projects. ML&P has participated in joint projects in the past and otherwise repeatedly demonstrated enthusiastic support for joint projects among the Railbelt utilities. Even more importantly ML&P anticipates a future of increasing joint Railbelt projects with one or more other utilities and/or the REGA entity itself that will advance the mutual interests of ML&P and the other participant(s).

Again, thank you for the opportunity to submit these comments and even more importantly for your contributions. Please feel free to contact me if you have questions.

Sincerely,

James M. Posey
ML&P General Manager

STATE OF ALASKA
DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT

Sarah Palin, Governor
Emil Notti, Commissioner
Robert M. Pickett, Chairman

Regulatory Commission of Alaska

August 20, 2008

James S. Strandberg
Project Manager
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Kevin M. Harper
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Black & Veatch Corporation
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Issaquah, WA 98029

RE: Comments on the Alaska Railbelt Electrical Grid Authority Draft Study

Dear Messieurs Strandberg and Harper:

We appreciate the opportunity to comment on the Alaska Railbelt Electrical Grid Authority (REGA) Draft Study (REGA Study).

We strongly support the efforts of the Railbelt Utilities and the State of Alaska working together to create a comprehensive plan for the future of energy generation and transmission. The REGA Study identified potential economies of scale in joint ownership of generation and transmission facilities and has demonstrated that substantial benefit could accrete to Railbelt electric consumers from Homer to Fairbanks over the next 50 years. For that, we commend your efforts.

It is well known that the relationship between all Railbelt electric utilities over the past 30 years has been contentious and frequently the subject of costly litigation before this commission and Alaska's state courts. It is encouraging to see a future through the eyes of the REGA Study where all parties work together in the best interest of electric utilities and their customers.

However, this future has the best chance to become Alaska's reality only if it results in far less litigation than in the past and lower costs of power for Alaska's consumers. It is with this goal in mind that we considered the REGA Study.

In brief, we found the recommended regulatory construct a very confusing and potentially volatile framework that could undermine the benefits of joint generation and transmission and result in extensive litigation. It does not appear that a complete analysis of the mechanics of the proposed regulatory construct has been performed. Potential overlap of jurisdiction and unclear lines of authority among the state authority, the RCA, and the regulated electric utilities will surely result unless more work is done before the final report is issued.

We are also concerned that Daniel Patrick O'Tierney, Chief Assistant Attorney General, Regulatory Affairs and Public Advocacy section (RAPA),[1] charged to represent utility ratepayer interests through the Office of the Attorney General, had no role in REGA study groups and apparently has not even been consulted during the entire public process.

Alaska's electric utility ratepayers have the greatest stake in any entity that may come out of the REGA Study. We believe it is critical that the RAPA be thoroughly briefed and provided sufficient time to reflect on the recommendations contained in the REGA Study and its impact on Alaska's ratepayers. We do not view any ancillary public interest group to be a satisfactory substitute for the knowledge and experience of RAPA and its commitment to the public interest of Alaska's ratepayers.

If addressed early before a final recommendation is made, the deficiencies in the draft report can be mitigated. To that end, if you believe it would be beneficial, we invite you to participate in a workshop with RCA commissioners and other interested members of the public.

[1]The responsibility of public advocacy for regulatory affairs was established in July 2003 within the Department of Law to advocate on behalf of the public interest in utility matters that come before the Regulatory Commission of Alaska. AS 44.23.020(e). The Attorney General, as the Public Advocate, determines and advocates for the general public interest with particular attention to the interests of consumers who would not otherwise have an effective voice regarding the rates and services of regulated utilities or pipeline carriers operating in the state. http://www.law.state.ak.us/department/civil/rapa/rapa.html

We have attached, for your consideration, a brief list of the areas we believe need further development before release of the final report. We appreciate the opportunity to comment and look forward to working together in the coming weeks.

Sincerely,

REGULATORY COMMISSION OF ALASKA

Robert Pickett
Chairman

Attachment

The REGA Study recommends a State Power Authority (SPA) be formed which would be responsible for independent operation of the grid, regional economic dispatch, regional resource planning, and joint project development. According to the analysis, utility customers would realize the greatest economic benefit under that scenario. As part of the report, Black and Veatch recommends exemption from regulation except upon complaint. While the listing below does not constitute all concerns, the RCA believes it provides a good foundation for future discussion.

- Does RAPA concur with the regulatory construct of the draft report?
- Are there sufficient protections for ratepayers from unjust or unreasonable rates?
- Does the RCA's authority over special contracts extend to fuel contracts negotiated between the SPA and the regulated utilities?
- Can the RCA disallow costs flowing from the SPA to Alaska's ratepayers if those costs are found to be unjust or unreasonable?
- If the RCA does disallow costs, what effect does the RCA's rejection of costs have on the SPA's bond ratings and its ability to repay debt?
- What happens to cost overruns on facility construction or in the circumstance when the facilities do not perform as intended, such as was the case with the Healy Clean Coal Plant? Are ratepayers expected to absorb these costs as part of their electric rates or will the SPA absorb any losses?
- What remedies exist for consumer complaints or complaints from regulated public utilities?
- Will RAPA be able to investigate concerns on behalf of Alaska's ratepayers? Will RAPA be allowed an evidentiary hearing before an independent panel separate from the board of directors? Will RAPA be allowed discovery and due process in conducting its investigation?
- Will rates be established based on generally accepted regulatory practices, under a just and reasonable standard? Will facilities be required to be used and useful before ratepayers are required to pay for the costs of those facilities?
- What are the areas of cross-jurisdiction between the planned SPA and the RCA and what modifications are needed to AS 42.05 to clarify those jurisdictional roles?
- How could the SPA benefit from economic regulation by the RCA? What are the specific disadvantages of RCA regulation for the SPA?

On behalf of the MEA Ratepayers Alliance, Inc., we would like to extend our deep appreciation and commendations to Mr. James Strandberg, Project Manager of the Alaska Railbelt Electrical Grid (REGA) Study; to Mr. Kevin Harper and Mr. Doland Cheung of Black and Veatch,REGA Study Consultants; to the staff and personnel of the Alaska Energy Authority; to the members of the REGA Advisory Working Group; and to all the Railbelt utilities, professionals, REGA stakeholders, and members of the community who gave of their time, energy, expertise, and experience to the REGA Study. We would also like to thank the Alaska State Legislature for its vision and foresight to provide the funding necessary for this tremendous and valuable undertaking and to the Governor of Alaska for directly stating her office's commitment and plans for addressing the energy needs of the state.

In our view, the REGA Study has provided the kind of breadth, depth, and thoroughness of information, analysis, and presentation of the interconnection and complexity of factors that is needed if we are to move ahead intelligently in creating viable and long term solutions to the energy needs that we are and will be facing in Alaska. We think the Study has provided the much needed direction, formulation, and implementation for an organizational structure that will be responsive to the various dynamics, functions, and technologies that will come into play as decisions are made regarding safe, clean, reliable, and affordable energy efficiency, fuel sources, generation, transmission, and distribution. In addition, through the Technical Conference and the formation and regular and consistent involvement of the REGA Study Advisory Working Group, opportunities were provided for direct interaction of a broad range of concerns, players, and perspectives which we found to be invaluable.

As ratepayers and citizens, we have been most impressed with the insistence, perseverance, and integrity of the REGA Study Project Manager and REGA Study consultants to have a formal and responsive process that continues to maximize active participation and input from the diverse professional, technological, and public sectors. This process was open and made available and accessible the pertinent schedules, progress, and information pertaining to the REGA Study on the Alaska Energy Authority's web site. This kind of accessibility of information as well as that of the REGA Project Manager and the REGA Study consultants made it possible for those who have a deep interest and concern about the issues to have the opportunity to be informed and offer their perspectives when they could not directly participate in any of the conferences or meetings because of their job schedules and/or places of residence. We see that his kind of formal, open, and participatory process will be critical and necessary for the work that lies ahead for creating any organizational structure, integrated resource planning, and a State Energy plan that is comprehensive, coordinated, responsive, and economically, environmentally, socially, and culturally responsible to the citizens and energy future of Alaska.

In reviewing the draft and the recommendations for an organizational structure for the Railbelt we find that many of our concerns and ideas for what we saw as specific needs and possible solutions to the situation here were clearly addressed. It is evident to us that the recommendation for the formation of a regional entity with the responsibility for generation and transmission along with the specific functional responsibilities as presented in in the overall organizational structure recommendations, is what is needed and that the entity indeed should be formed as a State Power Authority.

Given the history and the present and future needs of the Railbelt as well as those of Alaska, we see that it is imperative that the recommendations of the Study be implemented and that the recommended steps for implementation be initiated as soon as possible. The convergence of many factors at this particular time, we think , make it possible for the recommendations of the REGA Study to be implemented. We have a governor who has made it clear that the cooperation and participation of all the utilities, the State, and the public are needed for solutions to be identified and put into action. The energy needs and issues of climate change of the state, the nation, and the world are pushing us to examine our lives and to face the critical need for comprehensive, long-term planning and solutions at and from all levels. The REGA Study itself has brought together through an open, educational, and participatory process critical aspects as well as executive, legislative, and regulatory leadership, interest, and involvement and those of stakeholders from the utilities and community at large. An arena has been established for interaction and direct communication among various players at different levers and within specific fields that we feel that business, politics, and paradigms as usual cannot continue if we are to go into the future together with the knowledge and dynamics that have been established as a result of this study.

If we can do what will ensure intelligent leadership, a Board and organization that is independent, knowledgeable, and committed to the those principles and recommendations that will benefit the region and state as a whole and representative of the aspects of the whole, and formalize a process of oversight and input from the financial, governmental, regulatory, environmental, consumer, and other stakeholder sectors of the community, we can move ahead with confidence to create the kind of organizational structure that work in alignment with comprehensive and intelligent planning responsive to the energy needs of the Railbelt as well as those of the state as a whole.

Thank you for the opportunity for comment and for the all the work that has and is being done. We look forward to the next REGA Advisory Working Group meeting to see what other comments have been submitted and what will be the next steps to be considered and taken.

Respectfully submitted,

Tim Leach
Christine Vecchio
MEA Ratepayers Alliance, Inc.

Comment from Les Webber, Marathon Oil

REGA STUDY

JULY 23, 2008 DRAFT REPORT

COMMENTS

EXECUTIVE SUMMARY	
o Page 1	I would prefer to see a very short summary of the conclusions and recommendations right up front on page 1 rather than waiting to find them on page 20.
o Page 3, fourth line from bottom	"stakeholders", not "stakeholders"
o Page 4, last paragraph	I do not know how to best convey the immediate need for integrated resource planning across the Railbelt. I see the proposed Chugach Electric/ML&P project delaying that process, with the possible result that key decisions that should be taken in the near term (such as hydroelectric generation) are delayed. Also, such a project may not allow for the optimal reduction in reserve margins over time.
o Page 11	I am trying to find where you refer to Section 8 in terms of "Summary of Results"
o Page 12	In terms of "Organizational Cost Results", should it be specifically pointed out that these results do not include the cost savings that will inevitably occur in the existing cooperatives and utilities?
o Page 15, Table 7	I question the introduction of "% Savings" in this table, since the "total power costs under each Organizational Path 4" [Scenario] are not shown. It begs the question: "Where is the data?".
o Page 19, Tables 9 and 10	The annual savings should be expressed in the same units (i.e. millions of $) in both tables. The values in Table 9 seem very low to me. Where in the report are the results in Tables 9 and 10 supported?
o Page 21	The second bullet point on this page is absolutely key. Is

	there any way to emphasize it? The Regulatory Commission of Alaska today lacks such expertise.
o Page 24	About half way down the page, the "Retail Requirements Approach" concept is introduced. I did not see that it was previously defined or explained.
o Page 25	The "Start-up Implementation Plan" appears to be a daunting task. The time and effort to do this could be discussed, i.e. it is "doable" over a period of x months.
o Page 27	The description of AEA seems a little out of place.
o Page 41	In the first full paragraph, in the third line, "raising natural gas prices" should be "rising …" and "outside on the" should be "outside of the". In the fifth line of the same paragraph, "themselves" is spelled incorrectly.
o Page 45, Table 13	In the "Large Commercial" section, there is no "Homer (North of Kachemak Bay: category shown.
o Page 48, Figure 13	The top line could be labeled as "Gas Demand".
o Page 48, Figure 14	Re "Known Reserves", the 2005 figure is "Remaining Reserves".
o Page 49, Figure 15	The line represents "Supply", the colored sections "Demand".
o Page 50, Figure 17	Y-axis represents "Total Monthly Bill ($)".
o Page 51	In the section, "Potential Major New Loads", has the subject of the Railbelt's ability to handle such loads in the absence of a regional G&T been adequately addressed, especially if the Anchorage area forms a municipal G&T? It is likely that a major new load will be outside the Municipality of Anchorage. In addition, has the Study focused at all on the situation that will be faced by the smaller cooperatives, HEA and MEA, as they try to proceed on their own, once their contracts with CEA expire? They may be exposed to significant risk and high costs if they are unable to proceed with their own generation. The regional G&T would assure them of equitable treatment. Plus, there is the issue of operating and spinning reserve requirements (page 52).
o Page 56. "Future Fuel Diversity"	No comma needed in line 4, after "reserves".
o Page 57, "Proposed ML&P/Chugach Merger"	This merger could also be viewed as an impediment to the formation of a regional entity.
o Page 65 and thereafter	It would be interesting to include, in all the existing units, the capability to consume an alternative fuel (as a backstop) as well as their ability to "black start" with the alternative fuel. Are the "Retirement Dates" shown firm or estimated?

o Page 74	Is the term “HRSG” in line 5 of the “Combined Cycle Combustion Turbines” description defined?
o Page 92	Three lines above Table 24, HAGO is “heavy atmospheric gas oil”.
o Page 93	Regarding the first full paragraph, “BRU” means the Beluga River Unit (not defined). While the ML&P price/value/cost of its share of BRU gas is confidential, the Alaska Department of Natural Resources does publish a production forecast for all fields, including the Beluga River field, on a periodic (annual) basis.
o Page 96	Second last paragraph, fourth line – should be “fixed O&M costs”
o Page 106, Table 34	Total power costs are not shown (re % savings).
o Page 113, Table 38	Annual savings appear very low.
o Page 117, Figure 31	I do not know where the data in this table comes from. How derived? Moreover, there has to be a better way to arrange the bars to demonstrate the points made. In addition, the legend colors are not distinctive enough.

Comments Received Within E-Mail Transmittals

Elizabeth Brown, Alaska State Legislature

I have reviewed your REGA Study Draft. I like the Pirog/Boness Approach. One matter was not addressed though, and that was the future "Road to Nome" project being currently considered. Would the newly created board format the energy abilities of many native villages there? Just wondering.

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