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Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study

Final Report

February 2010

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- Steve Haagenson, AEA Executive Director
- Jim Strandberg, Project Manager
- Bryan Carey, Project Manager
- David Lockard, Geothermal and Ocean Energy Program Manager
- Doug Ott, Hydroelectric Program Manager
- James Jensen, Wind Program Manager
- Jim Hemsath, Deputy Director, Development
- Christopher Rutz, Procurement Manager
- Sherrie Siverson, Administrative Assistant

Railbelt Utilities (numerous management personnel from the following Railbelt utilities)

- Anchorage Municipal Light & Power
- Chugach Electric Association
- City of Seward Electric System
- Golden Valley Electric Association
- Homer Electric Association
- Matanuska Electric Association

Advisory Working Group Members

- Norman Rokeberg, Retired State of Alaska Representative, Chairman
- Chris Rose, Renewable Energy Alaska Project
- Brad Janorschke, Homer Electric Association
- Carri Lockhart, Marathon Oil Company
- Colleen Starring, Enstar Natural Gas Company
- Debra Schnebel, Scott Balice Strategies
- Jan Wilson, Regulatory Commission of Alaska
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- Pat Lavin, National Wildlife Federation - Alaska
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- Tony Izzo, TMI Consulting

Additional Individuals That Provided Substantive Input to Project

- Alan Dennis, Alaska Department of Natural Resources
- Bob Butera, HDR, Inc.
- Bob Swenson, Alaska Department of Natural Resources
- David Burlingame, Electric Power Systems, Inc. (EPS)
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- Mark Myers, Alaska Department of Natural Resources
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- Stephen Spain, HDR, Inc.

Purpose and Limitations of the RIRP

- The development of this RIRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor and State Legislature. With regard to energy policy making, however, the RIRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

  Having said this, the development of a State Energy Policy and or related policies could directly impact the specific alternative resource plan chosen for the Railbelt region's future. As such, the RIRP may need to be readdressed as future energy-related policies are enacted.

- This RIRP, consistent with all integrated resource plans, should be viewed as a "directional" plan. In this sense, the RIRP identifies alternative resource <u>paths</u> that the region can take to meet the future electric needs of Railbelt citizens and businesses; in other words, it identifies the <u>types</u> of resources that should be developed in the future. The granularity of the analysis underlying the RIRP is not sufficient to identify the optimal configuration (e.g., specific size, manufacturer, model, location, etc.) of <u>specific</u> resources that should be developed. The selection of specific resources requires additional and more detailed analysis.

- The alternative resource options considered in this study include a combination of <u>identified</u> projects (e.g., Susitna and Chakachamna hydroelectric projects, Mt. Spurr geothermal project, etc.), as well as <u>generic</u> resources (e.g., Generic Hydro – Kenai, Generic Wind – GVEA, generic conventional generation alternatives, etc.). <u>Identified</u> projects are included, and shown as such, because they are projects that are currently at various points in the project development lifecycle. Consequently, there is specific capital cost and operating assumptions available on these projects. <u>Generic</u> resources are included to enable the RIRP models to choose various resource <u>types</u>, based on capital cost and operating assumptions developed by Black & Veatch. This approach is common in the development of integrated resource plans.

  Consistent with the comment above regarding the RIRP being a "directional" plan, the actual resources developed in the future, while consistent with the resource <u>type</u> identified, may be: 1) the <u>identified</u> project shown in the resource plan (e.g., Chakachamna), 2) an alternative <u>identified</u> project of the same resource type (e.g., Susitna); or 3) an alternative <u>generic</u> project of the same resource <u>type</u>. One reason for this is the level of risks and uncertainties that exist regarding the ability to plan, permit, and develop each project. Consequently, when looking at the resource plans shown in this report, it is important to focus on the resource <u>type</u> of an <u>identified</u> resource, as opposed to the specific project.

- The capital costs and operating assumptions used in this study for alternative DSM/EE, generation and transmission resources do not consider the actual owner or developer of these resources. Ownership could be in the form of individual Railbelt utilities, a regional entity, or an independent power producer (IPP). Depending upon specific circumstances, ownership and development by IPPs may be the least-cost alternative.

- As with all integrated resource plans, this RIRP should be periodically updated (e.g., every three years) to identify changes that should be made to the preferred resource plan to reflect changing circumstances (e.g., resolution of uncertainties), improved cost and performance of emerging technologies (e.g., tidal), and other developments.

Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Table of Contents (Continued)

Tables (Continued)

Figures

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

Table of Contents (Continued)

Figures (Continued)

ACRONYM LIST

ACEEE	American Council for an Energy Efficiency Economy
ACESA	American Clean Energy and Security Act of 2009
AEA	Alaska Energy Authority
AHFC	Alaska Housing Finance Corporation
AIDEA	Alaska Industrial Development and Export Authority
APA	Alaska Power Authority
ARRA	American Recovery and Reinvestment Act of 2009
Bcf	Billion cubic feet
BESS	Battery energy storage system
CCS	Carbon capture and sequestration
CFL	Compact fluorescent light
C/I	Commercial and industrial
CO_2	Carbon dioxide
COLA	Construction and operation license application
CTG	Combustion turbine generator
CWIP	Construction-work-in-progress
DPP	Delta Power Plant
DR	Demand response
DSM/EE	Demand-side management/energy efficiency
EEI	Edison Electric Institute
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EPS	Electric Power Systems, Inc.
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
GE	General Electric
GHG	Greenhouse gas
GRETC	Greater Railbelt Energy & Transmission Company
G&T	Generation and transmission
GVEA	Golden Valley Electric Association
HAGO	High atmospheric gas oil
HCCP	Healy Clean Coal Project
HDR	HDR, Inc.
HEA	Homer Electric Association
HHV	Higher heating value
HPC	High-pressure compressor
HPT	High-pressure turbine
HSRG	Heat recovery steam generators
Hz	Hertz
IP	Intermediate-pressure
IPP	Independent power producers

ACRONYM LIST

IRS	Interconnection requirements studies
JV	Joint venture
kV	Kilovolt
KW	Kilowatt
kWh	Kilowatt-hour
LEEP	Lighting Energy Efficiency Pledge
LNG	Liquefied natural gas
LP	Low-pressure
LPT	Low-pressure turbine
MEA	Matanuska Electric Association
ML&P	Anchorage Municipal Light & Power
MMBtu	Million British thermal units
MMcf/d	Million cubic feet per day
MSW	Municipal solid waste
MW	Megawatt
NO_x	Nitrogen oxides
OEM	Original equipment manufacturer
O&M	Operations and maintenance
PC	Pulverized coal
PHEV	Plug-in hybrid vehicles
PPA	Power purchase agreement
PPM	Part per million
REC	Renewable energy credits
REGA	Railbelt Electrical Grid Authority
RIRP	Railbelt Integrated Resource Plan
ROW	Right-of-way
RPM	Revolutions per minute
RPS	Renewable portfolio standard
SBC	System benefit charge
SCR	Selective catalytic reduction
SES	City of Seward Electric System
SILOS	Shed in lieu of spin
SNW	Seattle-Northwest Securities Corporation
SO_x	Sodium oxides
SVC	Static var compensators
TOU	Time-of-use
ULSD	Ultra-low sulfur diesel
USDA-RUS	United States Department of Agriculture/Rural Utilities Service
WGA	Western Governor's Association

1.0 EXECUTIVE SUMMARY

In response to a directive from the Alaska Legislature, the Alaska Energy Authority (AEA) was the lead State agency for the development of a Regional Integrated Resource Plan (RIRP) for the Railbelt Region. This region is defined as the service areas of six regulated public utilities, including: Anchorage Municipal Light & Power (ML&P), Chugach Electric Association (Chugach), Golden Valley Electric Association (GVEA), Homer Electric Association (HEA), Matanuska Electric Association (MEA), and the City of Seward Electric System (SES). A seventh utility, Doyon, is interconnected to the Railbelt system serving the military bases of Fort Greely, Fort Wainwright, and Fort Richardson, but is not included in this RIRP.

The purpose of this document is to provide the results of the RIRP study. This section includes the following subsections:

- Current Situation Facing the Railbelt Utilities
- Project Overview
- Evaluation Scenarios
- Summary of Key Input Assumptions
- Susitna Analysis
- Transmission Analysis
- Summary of Results
- Implementation Risks and Issues
- Conclusions and Recommendations
- Near-Term Implementation Plan (2010-2012)

Some Definitions

- **REGA** means "Railbelt Electrical Grid Authority"
- **GRETC** means "Greater Railbelt Energy & Transmission Company"
- **RIRP** means "Railbelt Integrated Resource Plan"

Three Discrete Tasks

- **REGA study** determined the business structure for future Railbelt generation and transmission (G&T)
- **GRETC initiative** is the joint effort between Railbelt Utilities and AEA to unify Railbelt G&T
- **RIRP** is the economic plan for future capital investment in G&T and in fuel portfolios that GRETC would build, own and operate

1.1 Current Situation Facing the Railbelt Utilities

The Railbelt generation, transmission, and 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 (Chugach, GVEA, HEA, and MEA) and two municipal utilities (ML&P and 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 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 historical 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 environment, and changes in the mix of stakeholders, presents new dynamics for the way decisions must be made. This changing environment poses 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.

Current Situation

- Limited redundancy
- Limited economies of scale
- Dependence on fossil fuels
- Limited Cook Inlet gas deliverability and storage
- Aging G&T infrastructure
- Inefficient fuel use
- Difficult financing
- Duplicative G&T expertise

Categories of issues facing the Railbelt utilities include:

- Uniqueness of the Railbelt region
- Cost issues
- Natural gas issues
- Load uncertainties
- Infrastructure issues
- Future resource options
- Political issues
- Risk management issues

Table 1-1 provides a listing of the issues within each of these categories. A detailed discussion of these issues is provided in **Section 3**.

Table 1-1
Summary Listing of Issues Facing the Railbelt Region

Uniqueness of the Railbelt Region • Size and geographic expanse • Limited interconnections and redundancies	**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	**Infrastructure Issues** • Aging generation infrastructure • Baseload usage of inefficient generation facilities • Operating and spinning reserve requirements	**Risk Management Issues** • 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 – demand-side management/energy efficiency (DSM/EE) programs	

1.2 Project Overview

The goal of this project is to minimize future power supply costs, and maintain or improve on current levels of power supply reliability, through the development of a single comprehensive RIRP for the Railbelt region. The intent of the RIRP project, as stated in the AEA request-for-proposal, is to provide:

> **RIRP Objective Function**
>
> Minimize regional power supply costs, and maintain or improve current reliability, as opposed to minimizing power supply costs for any individual utility.

- An up-to-date model that the utilities and AEA can use as a common database and model for future planning studies and analysis.
- An assessment of loads and demands for the Railbelt electrical grid for a time horizon of 50 years including new potential industrial demands.
- Projections for Railbelt electrical capacity and energy growth, fuel prices, and resource options.
- An analysis of the range of potential generation resources available, including costs, construction schedule, and long-term operating costs.

- A schedule for existing generating unit retirement, new generation construction, and construction of backbone transmission lines that will allow the future Railbelt electrical grid to operate reliably under a transmission tariff which allows access by all potential power producers, and with a postage-stamp rate for electric energy and demand for the entire Railbelt as a whole.
- A long-term schedule for developing new fuel supplies that will provide for reliable, stable priced electrical energy for a 50-year planning horizon.
- A short-term schedule that coordinates immediate network needs (i.e., increasing penetration level of non-dispatchable generation, such as wind) within the first 10 years of the planning horizon, consistent with the long-term goals.
- A short-term plan addressing the transition from the present decentralized ownership and control to a unified G&T entity that identifies unified actions between utilities that must occur during this transition period.
- A diverse portfolio of power supply that includes, in appropriate portions, renewable and alternative energy projects and fossil fuel projects, some or all of which could be provided by independent power producers (IPPs).
- A comprehensive list of current and future generation and transmission power infrastructure projects.

Current Situation

- Limited redundancy
- Limited economies of scale
- Dependence on fossil fuels
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- Aging G&T infrastructure
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RIRP Study

- Plan that economically schedules what, when, and where to build, based on available fuel and energy supplies
- 50-year time horizon
- Competes generation, transmission, fuel supply and DSM/energy efficiency options
- Considers CO_2 regulation
- Includes renewable energy projects
- Arrives at a plan to build future infrastructure for minimum long-run cost to ratepayers
- Considers fuel supply options and risks

The alternative resource options considered in the RIRP analysis are shown in Table 1-2.

Black & Veatch conducted the REGA study for the AEA and the final report was released in September 2008. That study evaluated the feasibility of the Railbelt utilities forming an organization to provide coordinated unit commitment and economic dispatch of the region's generation resources, generation and transmission system planning, and project development. As a result of that study, legislation was proposed to create GRETC with a 10-year transition period to achieve these goals. This RIRP is based on the GRETC concept being implemented from the beginning of the study's time horizon.

Black & Veatch had primary responsibility for conducting this Railbelt RIRP. In addition to Black & Veatch, three other AEA contractors (HDR Inc., Electric Power Systems, Inc., and Seattle-Northwest Securities Corporation) played important roles in the development of the RIRP.

HDR updated work from the mid-1980s on the Susitna Hydroelectric Project and developed the capital and operating costs, as well as the generating characteristics, for several smaller-sized Susitna projects. HDR's work was used by Black & Veatch in the Strategist® and PROMOD® modeling discussed below. HDR's report summarizing the results of its work is provided in **Appendix A**.

Electric Power Systems, Inc. (EPS) assisted in the evaluation of the region's transmission system.

Table 1-2
Alternative Resource Options Considered

Demand-Side Management/Energy Efficiency (DSM/EE) Measure Categories	Conventional Generation Resources	Renewable Resources
Residential • Appliances • Water Heating • Lighting • Shell • Cooling/Heating **Commercial** • Water Heating • Office Loads • Motors • Lighting • Refrigeration • Cooling/Heating	**Simple Cycle Combustion Turbines** • LM6000 (48 MW) • LMS100 (96 MW) **Combined Cycle** • 1x1 6FA (154 MW) • 2X1 6FA (310 MW) **Coal Units** • Healy Clean Coal • Generic – 130 MW	**Hydroelectric Projects** • Susitna • Chakachamna • Glacier Fork • Generic Hydro – Kenai • Generic Hydro - MEA **Wind** • BQ Energy/Nikiski • Fire Island • Generic Wind – Kenai • Generic Wind - GVEA **Geothermal** • Mt. Spurr **Municipal Solid Waste** • Generic – Anchorage • Generic - GVEA
Other Resources Included in Sensitivity Cases • Modular Nuclear • Tidal		

Seattle-Northwest Securities Corporation (SNW) developed the financial model used to determine the overall financing costs for the portfolio of generation and transmission projects developed as part of this project, and evaluated the impact of some financial options that could be used to address financing issues and mitigating related rate impacts. The results of SNW's analysis are provided in **Appendix B**.

Additional information regarding Black & Veatch's approach to the completion of this study is provided in **Section 2**.

Purpose and Limitations of the RIRP

- The development of this RIRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor and State Legislature. With regard to energy policy making, however, the RIRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

  Having said this, the development of a State Energy Policy and or related policies could directly impact the specific alternative resource plan chosen for the Railbelt region's future. As such, the RIRP may need to be readdressed as future energy-related policies are enacted.

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1.3 Evaluation Scenarios

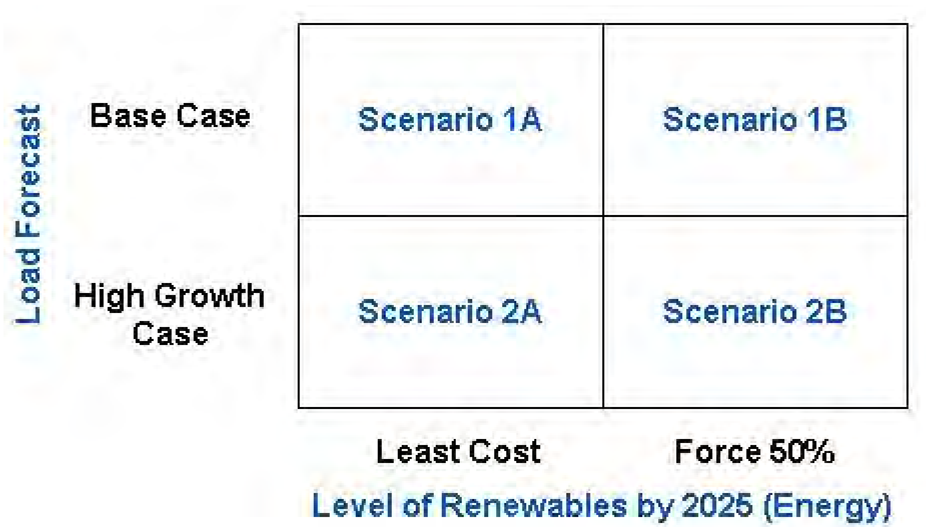
Black & Veatch, in collaboration with the Advisory Working Group that was assembled by the AEA for this project, developed four Evaluation Scenarios; Black & Veatch then developed a 50-year resource plan for each of these Evaluation Scenarios.

The primary objective of these Evaluation Scenarios was to evaluate two key drivers. The first driver was to look at what the impacts would be if the demand in the region was significantly greater than it is today; of primary interest was to see if higher demands would result in greater reliance on large generation resource options and allow for more aggressive expansion of the region's transmission network.

The second driver was to determine the impact associated with the pursuit of a significant amount of renewable resources over the 50-year time horizon.

As a result, Black & Veatch evaluated the four Evaluation Scenarios shown in Figure 1-1.

Figure 1-1
Evaluation Scenarios



The key assumptions underlying each Evaluation Scenario include:

- **Scenario 1 – Base Case Load Forecast**
  - Current regional loads with projected growth
  - All available resources – fossil fuel, renewables, and DSM/EE
  - Probabilistic estimate of gas supply availability and prices
  - Deterministic price forecasts for other fossil fuels
  - Emissions including CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 1A – Least Cost Plan**
  - **Scenario 1B – Force 50% Renewables**

- **Scenario 2 – Large Growth Load Forecast**
  - Significant growth in regional loads due to economic development efforts or large scale electrification (e.g., economic development loads, space and water heating fuel switching, and electric vehicles)
  - Base case resources, fuel availability/price forecasts and CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 2A – Least Cost Plan**
  - **Scenario 2B – Force 50% Renewables**

1.4 Summary of Key Input Assumptions

The completion of this RIRP required the development of a large number of assumptions in the following categories:

- **Section 4 – Description of Existing System**, including information on existing generation resources, committed generation resources, and the existing Railbelt transmission network.
- **Section 5 – Economic Parameters**, including inflation rates, financing rates, present worth discount rate, interest during construction rate, and fixed charge rates.
- **Section 6 – Forecast of Electrical Demand and Consumption**, including 50-year peak demand forecasts and net energy for load requirements.
- **Section 7 – Fuel and Emissions Allowance Price Projections**, including price forecasts for various fuels and emission allowance price projections.
- **Section 8 – Reliability Criteria**, including the region's planning and operating reserve margin requirements.
- **Section 9 – Capacity Requirements**, including the region's capacity requirements over the 50-year planning horizon.
- **Section 10 – Supply-Side Options**, including an overview of the supply-side resource option input assumptions used in this study, including both conventional technologies and renewable energy options.
- **Section 11 – DSM/EE Resources**, including a summary of the methodology and assumptions that Black & Veatch used to evaluate potential DSM/EE measures.
- **Section 12 – Transmission Projects**, including an overview of the transmission projects required to improve the overall reliability of the region's transmission network and connect the generation resources included in the alternative resource plans that were developed as part of this project.

1.5 Susitna Analysis

A hydroelectric project on the Susitna River has been studied for more than 50 years and is again being considered by the State of Alaska as a long term source of energy. In the 1980s, the project was studied extensively by the Alaska Power Authority (APA) and a license application was submitted to the Federal Energy Regulatory Commission (FERC). Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986.

In 2008, the Alaska State Legislature authorized the AEA to perform an update of the project. That authorization also included this RIRP project to evaluate the ability of this project and other sources of energy to meet the long term energy demand for the Railbelt region of Alaska. Of all the hydro projects in the Railbelt region, the Susitna projects are the most advanced and best understood.

HDR was contracted by AEA to update the cost estimate, energy estimates and the project development schedule for a Susitna River hydroelectric project. The initial alternatives reviewed were based upon the 1983 FERC license application and subsequent 1985 amendment which presented several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 MW.
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.
- **Devil Canyon.** This alternative consists of the construction of a 646-foot-high concrete dam at the Devil Canyon site with a four-unit powerhouse with a total installed capacity of 680 MW.
- **Watana/Devil Canyon.** This alternative consists of the full-height Watana development and the Devil Canyon development as presented in the 1983 FERC license application. The two dams and powerhouses would be constructed sequentially without delays. The combined Watana/Devil Canyon development would have a total installed capacity of 1,880 MW.
- **Staged Watana/Devil Canyon.** This alternative consists of the Watana development constructed in stages and the Devil Canyon development as presented in the 1985 FERC amendment. In stage one the Watana dam would be constructed to the lower height and the Watana powerhouse would only have four out of the six turbine generators installed, but would be constructed to the full sized powerhouse. In stage two the Devil Canyon dam and powerhouse would be constructed. In stage three the Watana dam would be raised to its full height, the existing turbines upgraded for the higher head, and the remaining two units installed. At completion, the project would have a total installed capacity of 1,880 MW.

As the RIRP process defined the future Railbelt power requirement it became evident that lower cost hydroelectric project alternatives, that were a closer fit to the energy needs of the Railbelt, should be sought. As such, the following single dam configurations were also evaluated:

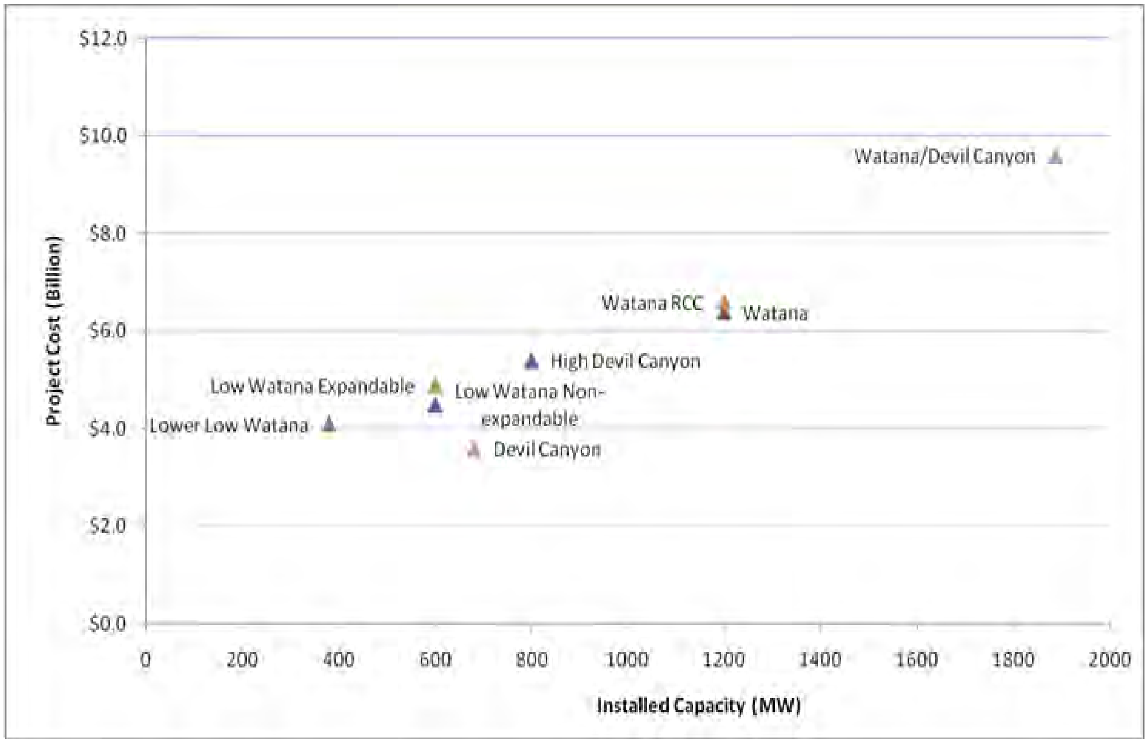
- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing four turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative consists of the Watana dam constructed to a height of 650 feet along with a powerhouse containing three turbines with a total installed capacity of 380 MW. This alternative has no provisions for future expansion.
- **High Devil Canyon.** This alternative consists of a roller-compacted concrete (RCC) dam constructed to a height of 810 feet, along with a powerhouse containing four turbines with a total installed capacity of 800 MW.
- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing six turbines with a total installed capacity of 1,200 MW.

The results of this study are summarized in Table 1-3 and a comparison of project size versus project cost is shown in Figure 1-2.

Table 1-3
Susitna Summary

Alternative	Dam Type	Dam Height (feet)	Ultimate Capacity (MW)	Firm Capacity, 98% (MW)	2008 Construction Cost ($ Billion)	Energy (GWh/yr)	Schedule (Years from Start of Licensing)
Lower Low Watana	Rockfill	650	380	170	$4.1	2,100	13-14
Low Watana Non-expandable	Rockfill	700	600	245	$4.5	2,600	14-15
Low Watana Expandable	Rockfill	700	600	245	$4.9	2,600	14-15
Watana	Rockfill	885	1,200	380	$6.4	3,600	15-16
Watana RCC	RCC	885	1,200	380	$6.6	3,600	15-16
Devil Canyon	Concrete Arch	646	680	75	$3.6	2,700	14-15
High Devil Canyon	RCC	810	800	345	$5.4	3,900	13-14
Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$9.6	7,200	15-20
Staged Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$10.0	7,200	15-24

Figure 1-2
Comparison of Project Cost Versus Installed Capacity



In all cases, the ability to store water increases the firm capacity over the winter. Projects developed with dams in series allow the water to be used twice. However, because of their locations on the Susitna River, not all projects can be combined. The Devil Canyon site precludes development of the High Devil Canyon site but works well with Watana. The High Devil Canyon site precludes development of Watana but could potentially be paired with other sites located further upstream.

The detailed results of the HDR Susitna study, except for the detailed appendices, are provided in **Appendix A**. One of the appendices contained within the HDR report (Appendix D), which is not included in Appendix A of this report, addresses the issue of the potential impact of climatic changes on Susitna's resource potential; this appendix can be viewed in the full HDR report which is available on the AEA web site.

1.6 Transmission Analysis

An important element of this RIRP was the analysis of transmission investments required to integrate the generation resources in each resource plan, ensure reliability and enable the region to take advantage of economy energy transfers between load areas within the region.

The fundamental objective underlying the transmission analysis was to upgrade the transmission system over a 10-year period to remove transmission constraints that currently prevent the coordinated operation of all the utilities as a single entity.

The study included all assets 69 kV and above. These assets, over a transition period, may flow into GRETC and form the basis for a phased upgrade of the system into a robust, reliable transmission system that can accommodate the economic operation of the interconnected system. The transmission analysis also assumed that all utilities would participate in GRETC with planning being conducted on a GRETC (i.e., regional) basis. The common goal would be the tight integration of the system operated by GRETC.

Potential transmission investments in each of the following four categories were considered:

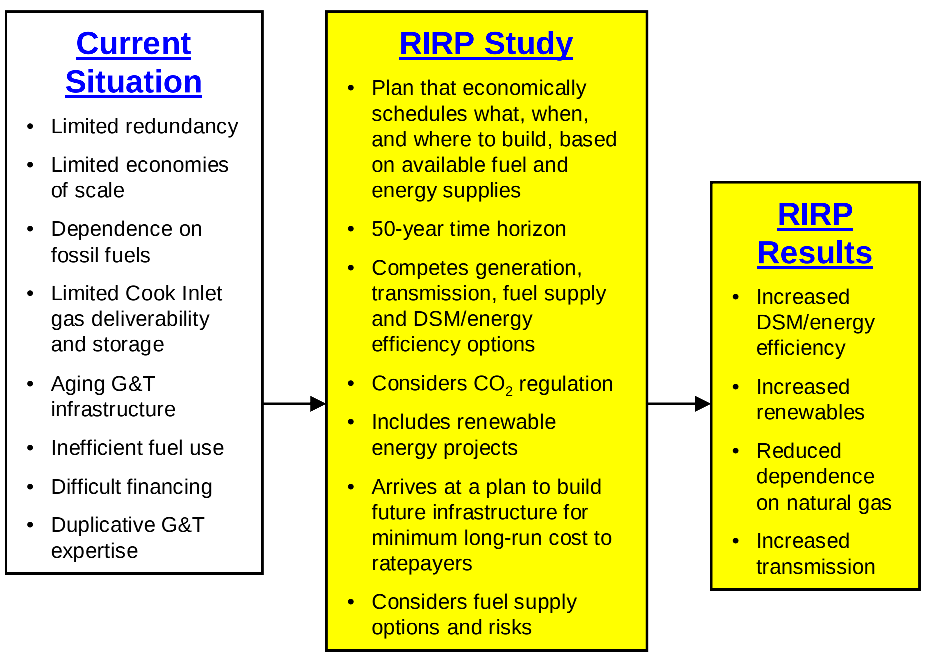
- Transmission systems that need to be replaced because of age and condition (Category 1)
- Transmission projects required to improve grid reliability, power transfer capability, and reserve sharing (Category 2)
- Transmission projects required to connect new generation projects to the grid (Category 3)
- Transmission projects to upgrade the grid required by a new generation project (Category 4)

In developing the transmission system, reliability remains a significant focus. Redundancy is one way to increase reliability, but may not be the only way to improve or maintain reliability.

The results of Black & Veatch’s transmission assessment are discussed later in this section.

1.7 Summary of Results

The purpose of this subsection is to summarize the results of the RIRP analysis. We begin by providing a summary of the base case results for each of the four Evaluation Scenarios. We then provide a comparative summary of the economic and emission results for all base cases and sensitivity cases. This is followed by a summary of the results of the transmission analysis that was completed and, finally, the results of the financial analysis. More detailed information regarding the results of the RIRP study is provided in **Section 13**.



1.7.1 Results of Reference Cases

In this subsection, we provide summaries of the reference case results for each of the following four Evaluation Scenarios:

- Scenario 1A – Base Case Load Forecast – Least Cost Plan
- Scenario 1B - Base Case Load Forecast – Force 50% Renewables
- Scenario 2A – Large Growth Load Forecast – Least Cost Plan
- Scenario 2B - Large Growth Load Forecast – Force 50% Renewables

Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built. Hereafter, we will refer to Scenarios 1A and 1B together.

We begin with a summary of the impact that DSM/EE measures have on the region's capacity and annual energy requirements. This is followed by summary graphics and information for each of the Evaluation Scenarios. Detailed model output for each of the reference cases are provided in **Appendices E-G**.

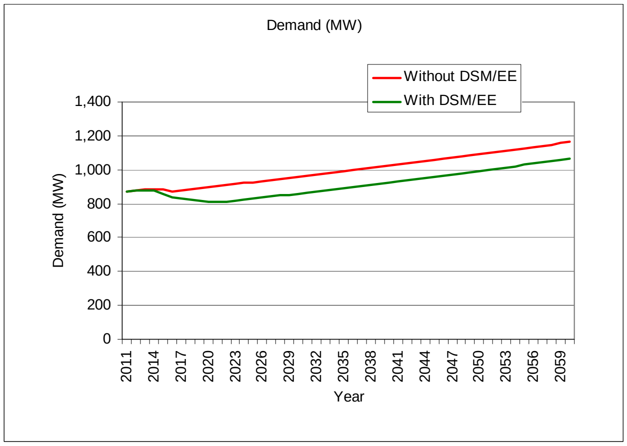
1.7.1.1 DSM/EE Resources

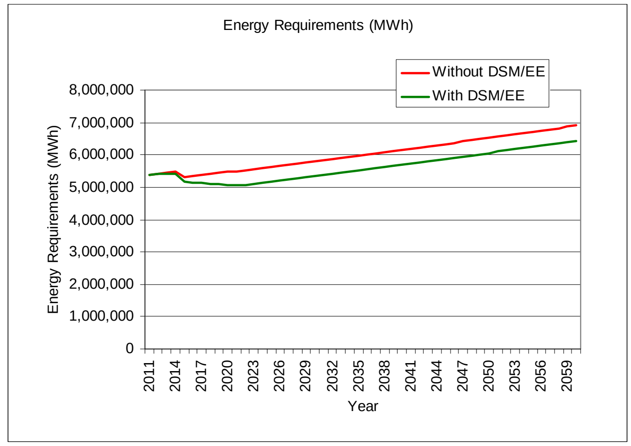
As discussed in **Section 11**, Black & Veatch screened a broad array of residential and commercial DSM/EE measures. Based on this screening, 21 residential and 51 commercial DSM/EE measures were selected for inclusion in the RIRP models, Strategist® and PROMOD®, as potential resources to be selected.

Based upon the relative economics and savings of these screened residential and commercial DSM/EE measures, from the utility perspective, all of the residential and commercial DSM/EE measures were selected in each of the four Evaluation Scenarios. As discussed in **Section 11**, the penetration of the measures was based on technology adoption curves for DSM/EE studies from the BASS model; additionally, DSM/EE measures are treated by Strategist® and PROMOD® as a reduction to the load forecast from which the alternative supply-side options are considered for adding generation resources.

As can be seen in Figure 1-3, DSM/EE measures result in a significant impact on the region's capacity and energy requirements. After the initial program start-up years, DSM/EE measures reduce the region's capacity requirements by approximately 8 percent. A similar level of impact is also shown for annual energy requirements.

Figure 1-3
Impact of DSM/EE Resources – Base Case Load Forecast





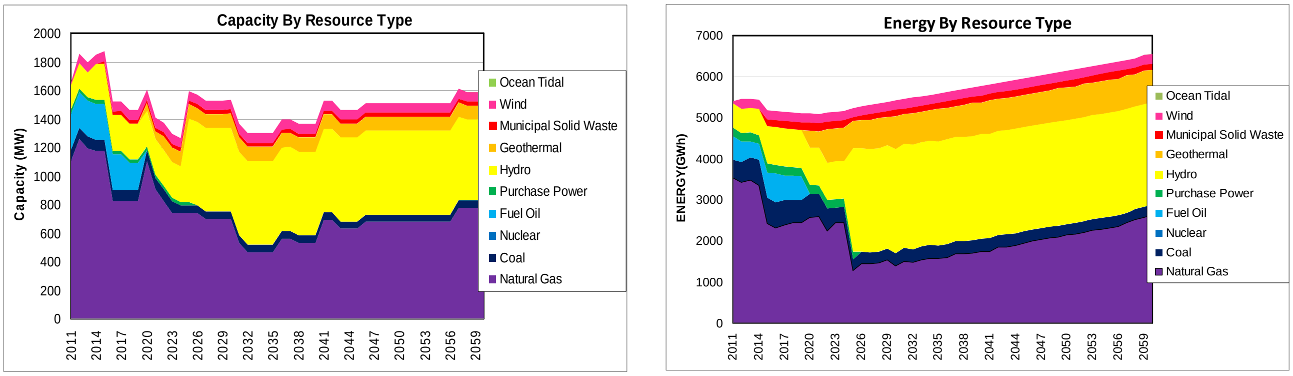
It should be noted that this study did not include an evaluation of innovative rate designs (e.g., real-time pricing and demand response rates), nor did it consider the potential benefits of a Smart Grid, and the associated widespread implementation of smart meters. These options could result in even greater reductions in peak demand and annual energy usage.

A Note Regarding DSM/EE Resources

- This RIRP demonstrates the economic potential of DSM/EE resources.
- Due to limited Alaska-specific DSM/EE-related data and experience, Black & Veatch limited the amount of DSM/EE resources included in the preferred resource plan.
- Additional analysis, both by Black & Veatch as part of this study and by others, along with the experience of other utilities throughout the US, suggest that additional levels of DSM/EE resources may be economic.
- However, given the lack of Alaska-specific data and experience, additional data gathering and analysis is required before the optimal level of DSM/EE resources can be determined.
- Furthermore, the isolated nature of the Railbelt coupled with severe weather conditions, dictates caution with regard to the ultimate reliance on DSM/EE resources.
- Additionally, the limited penetration of electric space heating in the Railbelt region affects the ultimate level of DSM/EE savings.
- To develop the full potential of DSM/EE resources, it will be necessary to collect baseline end-use saturation, customer and vendor information, as well as address the reduction in utility margins that result from the implementation of DSM/EE programs.
- Additionally, Black & Veatch believes that a regional approach to the development of DSM/EE programs (e.g., GRETC) will be more successful than if the six Railbelt utilities develop independent DSM/EE programs.

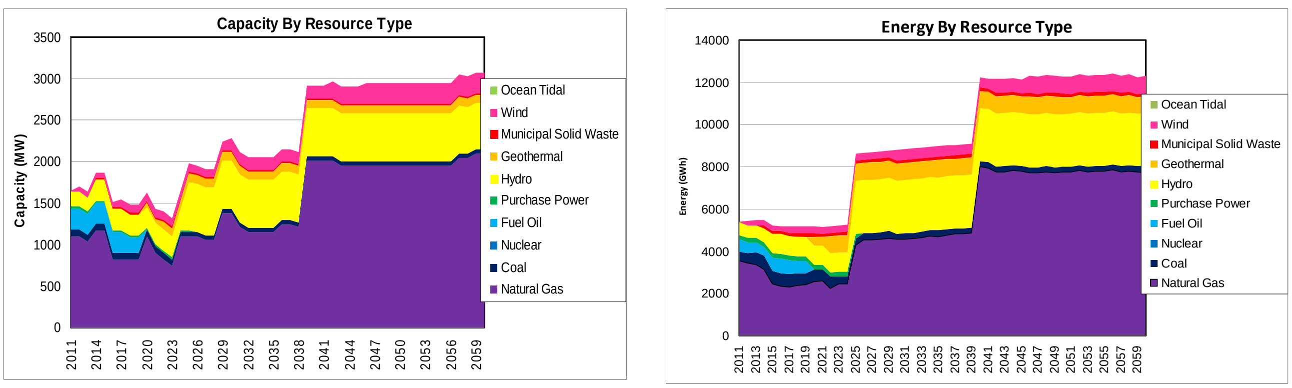
1.7.1.2 Results – Scenarios 1A/1B Reference Cases

Figure 1-4
Results – Scenarios 1A/1B Reference Cases



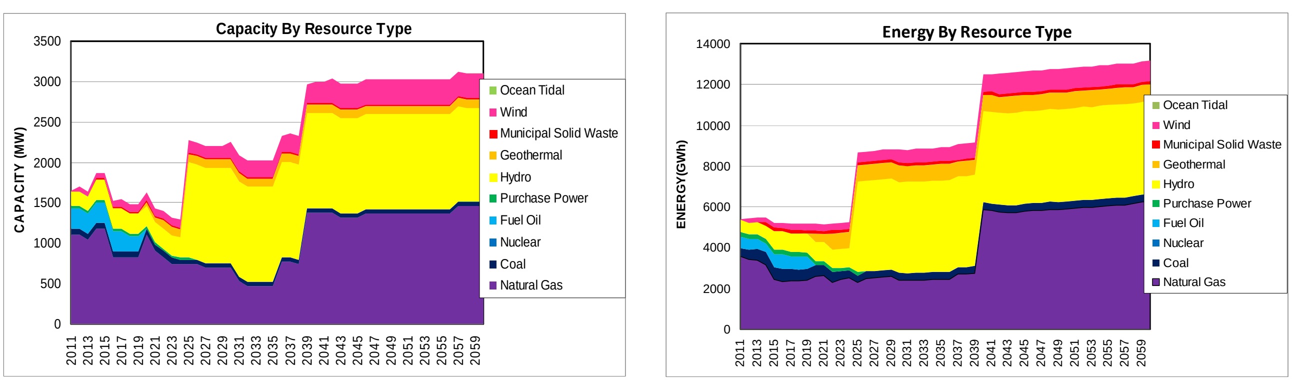
1.7.1.3 Results – Scenario 2A Reference Case

Figure 1-5
Results – Scenario 2A Reference Case



1.7.1.4 Results – Scenario 2B Reference Case

Figure 1-6
Results – Scenario 2B Reference Case



A Note Regarding Emerging Technologies

- In the economic analysis underlying this RIRP, Black & Veatch used current cost and performance assumptions for all generation technology options considered. This was done because of the inherent difficulty in predicting the future cost and performance of technologies, particularly emerging technologies (e.g., on-shore and off-shore wind and tidal).
- Recent improvements in wind-related costs and performance demonstrate the potential for emerging technologies. Conversely, the cost and performance of conventional resource technologies are stable at best and not likely to improve.
- Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to become economic within the planning horizon.
- These diverging cost and performance trends are one reason why this RIRP needs to be updated periodically; by so doing, emerging technologies can be added to the region's preferred resource plan as their costs and performance improve.

1.7.2 Sensitivity Cases Evaluated

The following sensitivity cases were evaluated:

- Scenarios 1A/1B Without DSM/EE Measures
- Scenarios 1A/1B With Double DSM/EE Measures
- Scenarios 1A/1B With Committed Units Included
- Scenarios 1A/1B Without CO_2 Costs
- Scenarios 1A/1B With Higher Gas Prices
- Scenarios 1A/1B Without Chakachamna
- Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%
- Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced
- Scenarios 1A/1B With Susitna (Watana Option) Forced
- Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced
- Scenarios 1A/1B With Modular Nuclear
- Scenarios 1A/1B With Tidal
- Scenarios 1A/1B With Lower Coal Capital and Fuel Costs
- Scenarios 1A/1B With Federal Tax Credits for Renewables

1.7.3 Summary of Results – Economics and Emissions

In this subsection, we provide a comparative summary of the economic and emissions results for all of the reference cases and sensitivity cases.

1.7.3.1 Summary of Results - Economics

Table 1-4 summarizes the economic results, including:

- Cumulative present value cost (from the utility perspective)
- Average wholesale power cost (from the utility perspective)
- Renewable energy in 2025
- Total capital investment

Table 1-4
Summary of Results – Economics

Case	Cumulative Present Value Cost ($000,000)	Average Wholesale Power Cost (¢ per kWh)	Renewable Energy in 2025 (%)	Total Capital Investment ($000,000)
Scenarios				
Scenario 1A	$13,625	17.26	62.32%	$9,087
Scenario 1B	$13,625	17.26	62.32%	$9,087
Scenario 2A	$20,162	19.75	42.64%	$14,111
Scenario 2B	$21,109	20.68	65.83%	$18,805
Sensitivities				
1A/1B Without DSM/EE Measures	$14,507	17.40	67.10%	$8,603
1A/1B With Double DSM	$12,546	15.89	65.15%	$8,861
1A/1B With Committed Units Included	$14,109	17.87	46.84%	$8,090
1A/1B Without CO2 Costs	$11,206	14.20	49.07%	$8,381
1A/1B With Higher Gas Prices	$14,064	17.82	61.95%	$9,248
1A/1B Without Chakachamna	$14,332	18.16	38.06%	$7,719
1A/1B With Chakachamna Capital Costs Increased by 75%	$14,332	18.16	38.06%	$7,719
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	$15,228	19.29	61.01%	$12,421
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	$15,040	19.05	63.01%	$15,057
1A/1B With Susitna (Low Watana Expandable Option) Forced	$15,346	19.44	63.01%	$15,588
1A/1B With Susitna (Low Watana Expansion Option) Forced	$14,854	18.82	66.90%	$14,069
1A/1B With Susitna (Watana Option) Forced	$15,683	19.87	70.97%	$13,211
1A/1B With Susitna (High Devil Canyon Option) Forced	$14,795	18.74	66.92%	$11,633
1A/1B With Modular Nuclear	$13,841	17.53	60.51%	$9,105
1A/1B With Tidal	$13,712	17.37	65.52%	$9,679
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	$13,625	17.26	62.32%	$9,087
1A/1B With Tax Credits for Renewables	$12,954	16.41	67.56%	$9,256

1.7.3.2 Summary of Results - Emissions

Table 1-5 summarizes the emissions-related results of all of the reference and sensitivity cases. The following information is provided for each case:

- CO_2 emissions
- NO_x emissions
- SO_x emissions

Table 1-5
Summary of Results – Emissions

Case	CO_2 ('000 tons)	NO_x ('000 tons)	SO_2 ('000 tons)
Scenarios			
Scenario 1A	80,259,047	124,215	21,768
Scenario 1B	80,259,047	124,215	21,768
Scenario 2A	152,318,066	133,642	24,476
Scenario 2B	125,498,202	140,897	26,348
Sensitivities			
1A/1B Without DSM/EE Measures	88,181,350	139,179	30,605
1A/1B With Double DSM	69,324,920	131,299	18,994
1A/1B With Committed Units Included	91,212,598	136,946	16,482
1A/1B Without CO2 Costs	100,753,030	134,031	23,960
1A/1B With Higher Gas Prices	78,323,066	121,700	25,232
1A/1B Without Chakachamna	105,643,650	133,577	25,700
1A/1B With Chakachamna Capital Costs Increased by 75%	105,643,650	133,577	25,700
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	82,328,762	127,921	22,124
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expansion Option) Forced	67,724,563	136,906	23,589
1A/1B With Susitna (Watana Option) Forced	70,966,059	111,307	19,171
1A/1B With Susitna (High Devil Canyon Option) Forced	71,853,368	121,538	19,909
1A/1B With Modular Nuclear	79,664,701	126,881	22,787
1A/1B With Tidal	75,598,948	121,306	21,067
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	80,259,047	124,215	21,768
1A/1B With Tax Credits for Renewables	74,046,352	129,384	18,832

1.7.4 Results of Transmission Analysis

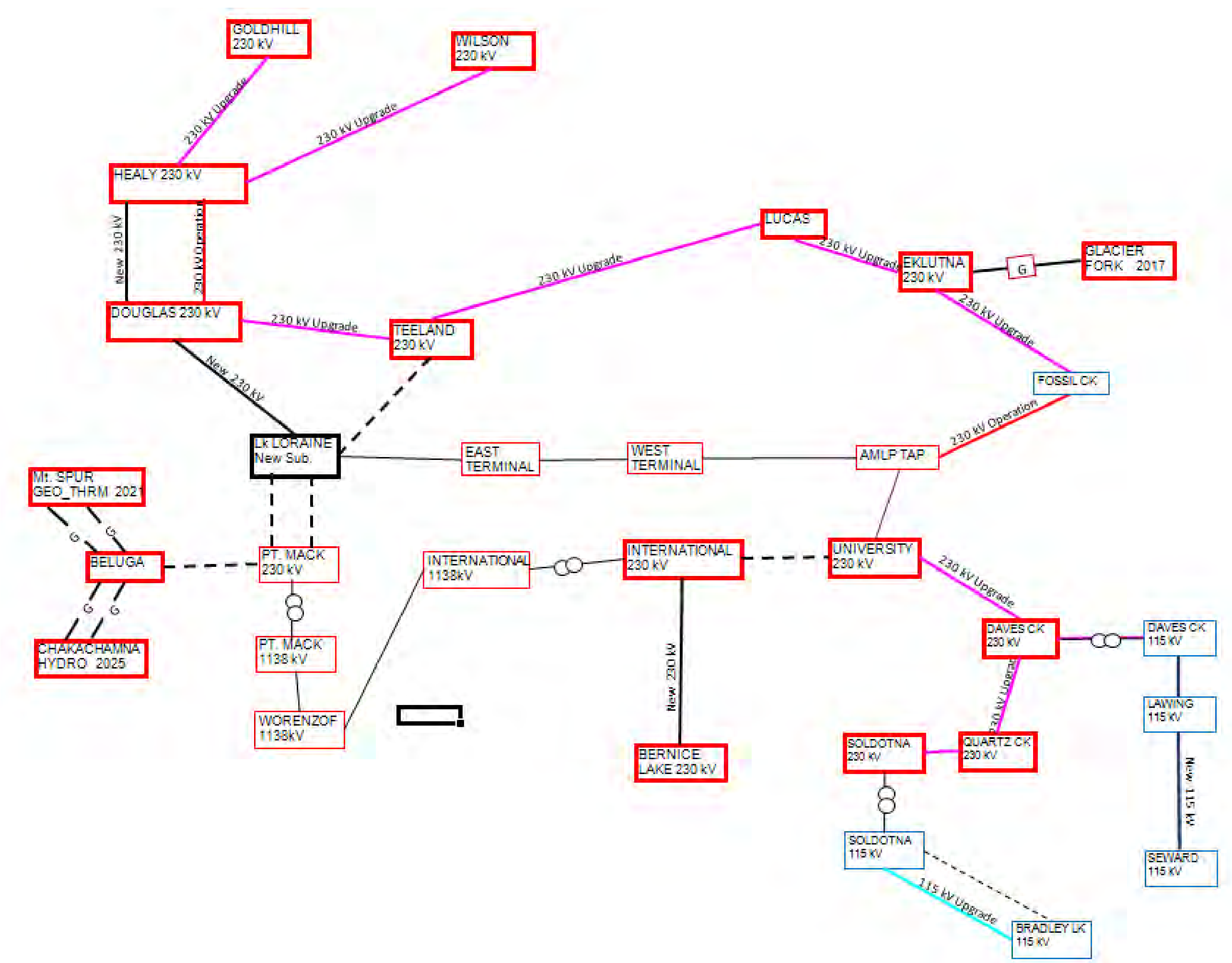
Table 1-6 lists the proposed transmission system expansions and enhancements that resulted from our transmission analysis. More detailed information on each of the identified transmission projects is provided in **Section 12**.

Table 1-6
Summary of Proposed Transmission Projects

Project No.	Transmission Projects	Type	Cost ($000)
A	Bernice Lake – International	New Build (230 kV)	227,500
B	Soldotna – Quartz Creek	R&R (230 kV)	126,500
C	Quartz Creek – University	R&R (230 kV)	165,000
D	Douglas – Teeland	R&R (230 kV)	62,500
E	Lake Lorraine – Douglas	New Build (230 kV)	80,000
F	Douglas – Healy	Upgrade (230 kV)	30,000
G	Douglas – Healy	New Build (230 kV)	252,000
H	Eklutna – Fossil Creek	Upgrade (230 kV)	65,000
I	Healy – Gold Hill	R&R (230 kV)	180,500
J	Healy – Wilson	Upgrade (230 kV)	32,000
K	Soldotna – Diamond Ridge	R&R (115 kV)	66,000
L	Lawing – Seward	Upgrade (115 kV)	15,450
M	Eklutna – Lucas	R&R(115 kV/230 kV)	12,300
N	Lucas – Teeland	R&R (230 kV)	51,100
O	Fossil Creek – Plant 2	Upgrade (230 kV)	13,650
P	Pt. Mackenzie – Plant 2	R&R (230 kV)	32,400
Q	Bernice Lake – Soldotna	Rebuild (115 kV)	24,000
R	Bernice Lake – Beaver Creek - Soldotna	Rebuild (115 kV)	24,000
S	Susitna Transmission Additions	New Build (230 kV)	57,000

A diagram that shows the location of the proposed transmission system enhancements is shown in Figure 1-7. This graphic shows the proposed transmission projects if the Susitna hydroelectric project is not developed. A similar graphic of proposed transmission projects if Susitna is built is provided in **Section 12**.

Figure 1-7
Location of Proposed Transmission Projects (Without Susitna)



The following issues result from our transmission analysis:

- We were unable to complete a stability analysis based upon our proposed transmission system configuration prior to the completion of this project. This analysis is required to ensure that the proposed transmission system expansions and enhancements result in the necessary stability to ensure reliable electric service over the planning horizon. This analysis should be completed as part of the future work to further define, prioritize, and design specific transmission projects.

- In addition to the transmission lines listed above, other projects were considered that could contribute to improving the reliability of the Railbelt system. These projects generally fall into one or more of the following categories:
    - Providing reactive power (static var compensators – SVCs)
    - Providing or assisting with the provision of other ancillary services (regulation and/or spinning reserves)
    - Assistance in control of line flows or substation voltages
    - Assistance in the transition and coordination of transmission project implementation (mobile transforms or substations)
    - Communications and control facilities

  Several of these projects have been identified and discussed while others will result from the transmission reliability assessment. Potential projects in this category include:
    - Substation capacitor banks
    - Series capacitors
    - SVCs
    - Battery energy storage systems (BESS)
    - Mobile substations that could provide construction flexibility during the implementation phase
- Projects that could facilitate or complement the implementation of other projects (e.g., wind), were of particular interest during project discussions. These projects, if implemented, could smooth the transition and adoption by the utilities of the GRETC concept. One such project was the BESS that could provide much needed frequency regulation and potentially some spinning reserves when non-dispatchable projects, such as wind, are considered. A BESS was specified that could provide frequency regulation required by the system when wind projects were selected by the RIRP. The BESS was sized in relation to the size of the non-dispatchable project to be 50 percent of the project nominal capacity for a 20-minute duration. Although the performance of the BESS has not yet been analyzed as part of the stability analysis, the costs for each such system were included in the analysis. Other options (e.g., fly wheel storage technologies and compressed air energy storage) that could provide the required frequency regulation should also be considered.
- It should be noted that if the need for frequency regulation is driven in part by an IPP-sponsored renewable project, policies will need to be adopted to allocate an appropriate portion of the regulation costs to those projects.
- The Fire Island Wind Project is a 54 MW maximum output wind project. Each wind turbine will be equipped with reactive power and voltage support capabilities that should facilitate interconnection into the transmission grid. Current plans are to interconnect the project to the grid via a 34.5 kV underground and submarine cable to the Chugach 34.5 kV Raspberry Substation. There has been some discussions regarding the most appropriate transmission interconnection for the Fire Island Project and detailed interconnection studies have not been completed. The timeframe for implementing this project in order to qualify for available grants under the American Recovery and Reinvestment Act of 2009 (ARRA) could preclude more detailed transmission studies and consideration of alternatives to the currently proposed 34.5 kV interconnection. An option to consider if Fire Island is constructed is to lay cables from Fire Island to Anchorage insulated for 230 kV and review a transmission routing for the new transmission connection to the Kenai peninsula that would begin at the International 230 kV Substation to Bernice Lake Substation along the Kenai cost line then via submarine cable across the Cook Inlet to Fire Island. The interconnection would then use the 230 kV submarine cable previously laid over to the Anchorage coast then into the International 230 kV Substation.

- The recommended transmission system expansions and enhancements can not be justified based solely on economics. However, in addition to their underlying economics, these transmission projects are required to ensure the reliable delivery of electricity throughout the region over the 50-year planning horizon and to provide the foundation for future economic development efforts.

The proposed projects identified in **Section 12** are not presented in any specific order or priority. It was felt that the information currently available, as well as the uncertainty which exists surrounding the selected generation plans, did not permit a more definitive prioritization of projects. This does not mean, however, that all the projects in the list have the same impact on the reliability of the Railbelt system, or that the projects are equally important to each utility. In several instances the projects were in extremely poor physical condition and were scheduled to be repaired or rebuilt to prevent the lines from literally falling to the ground. To facilitate the immediate repairs to these lines, the projects that should be addressed within the next five years because of their potential impact on the reliability of the system have been identified. Additionally, some of the projects will need to be evaluated and specified further and funds have been identified to facilitate the studies that are required to further identify and schedule the transmission improvements that will be required.

The following projects and studies have been identified for priority attention (i.e., to be completed within the next five years) because of their immediate impact on the reliability of the existing system. All of the projects will require detailed system feasibility studies prior to actual implementation.

1. Soldotna to Quartz Creek Transmission Line ($126.5 million – Project B)
2. Quartz Creek to University Transmission Line ($165.0 million – Project C)
3. Douglas to Teeland Transmission Line ($62.5 million – Project D)
4. Lake Lorraine to Douglas Transmission Line ($80.0 million – Project E)
5. SVCs ($25.0 million - Other Reliability Projects)
6. Funds to undertake the study of the Southern Intertie ($1.0 million)
7. Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50.0 million, including cost of BESS – Other Reliability Projects)

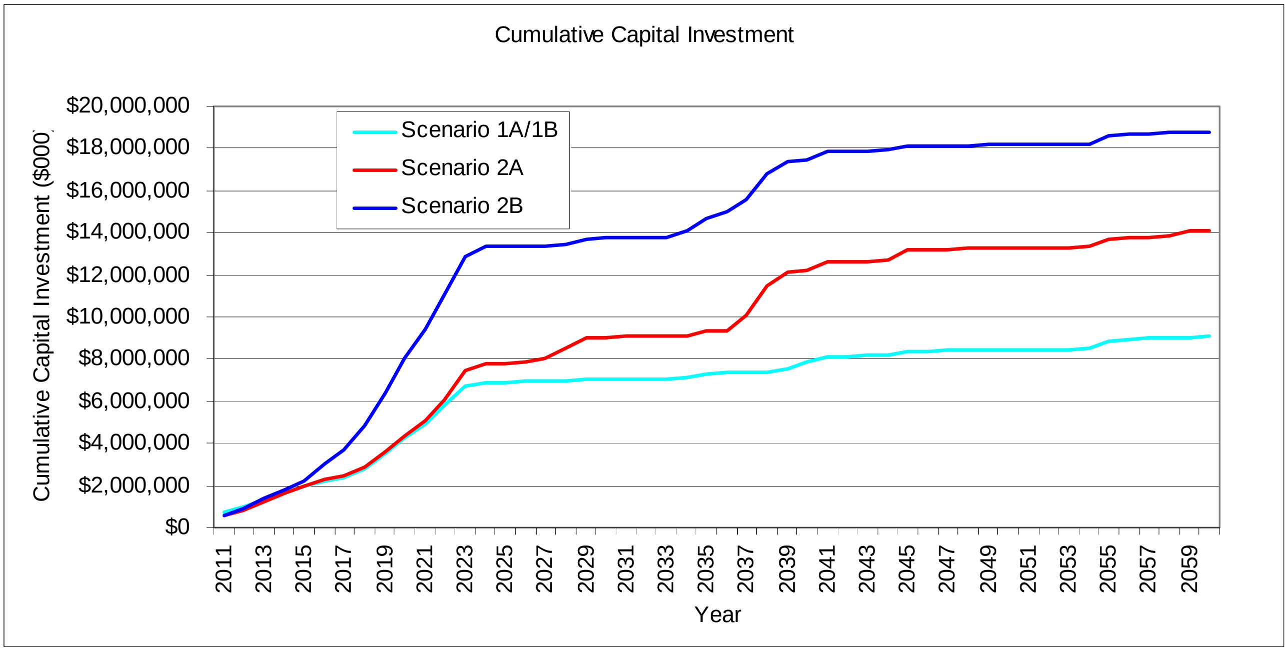
The total estimate costs necessary for transmission projects during the initial five years of the RIRP is $510 million in 2009 dollars.

1.7.5 Results of Financial Analysis

It will be difficult for the region to obtain the necessary financing for the DSM/EE, generation and transmission resources included in the alternative resource plans that were developed. The formation of a regional entity with some form of State assistance will help meet this challenge.

Figure 1-8 summarizes the cumulative capital investment required for each of the four base cases.

Figure 1-8
Required Cumulative Capital Investment for Each Base Case



To assist in the completion of the financial analysis, AEA contracted with SNW to:

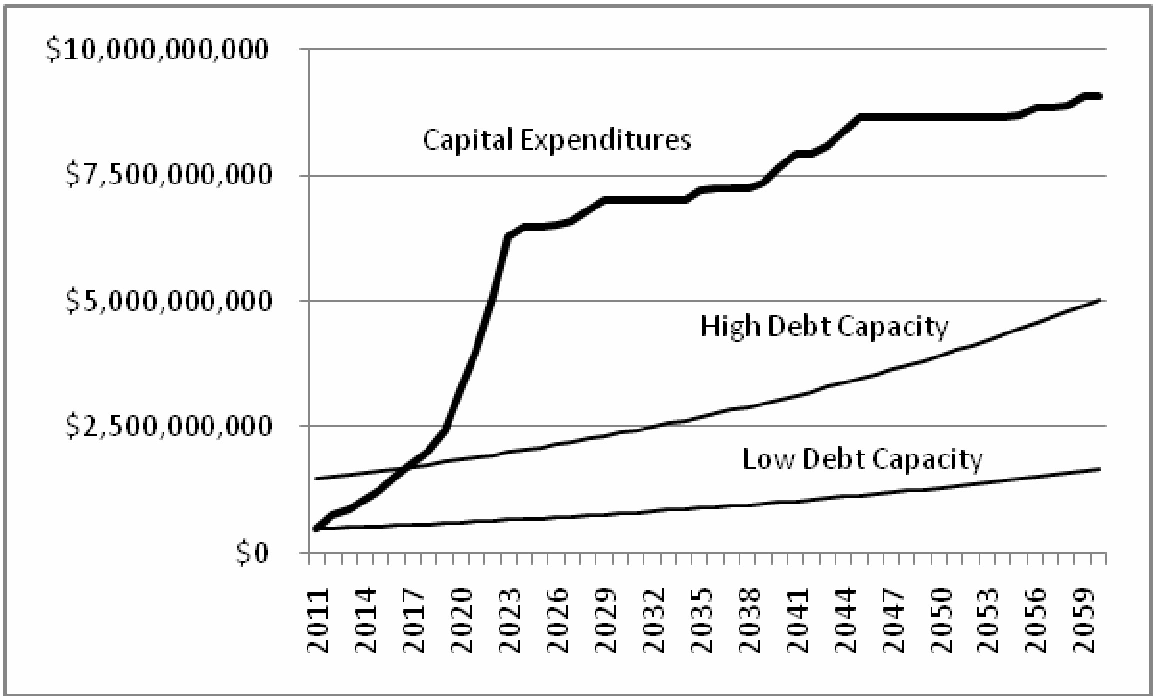
- Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities.
- Analyze strategies to capitalize selected RIRP assets by integrating State (which could include loans, State appropriations, Permanent Fund, State moral obligation bonds, etc.) and federal (e.g., USDA-RUS) financing resources with debt capital market resources.
- Develop a spreadsheet model that utilizes inputs from this RIRP analysis and overlays realistic debt capital funding to provide a total cost to ratepayers of the optimal resource plan.

The results of the financial analysis completed by SNW are provided in **Appendix B**.

Important conclusions from SNW's report include:

- The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or cooperative utility to independently secure debt financing without committing substantial amounts of equity of cash reserves.
- Figure 1-9 helps to put into context the scope of the required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent SNW's estimate of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

Figure 1-9
Required Cumulative Capital Investment (Scenarios 1A/1B) Relative to Railbelt Utility Debt Capacity



Source: SNW Report included in Appendix C.

- A regional entity, such as GRETC, with "all outputs" contracts migrating over time to "all requirements" contracts will have greater access to capital than the combined capital capacity of the individual utilities.
- There are several strategies that could be employed to lower the RIRP-related capital costs to customers, including:
  - **Ratepayer Benefits Charge** – A charge levied on all ratepayers within the Railbelt system that would be used to cash fund and thereby defer borrowing for infrastructure capital.
  - **"Pay-Go" Versus Borrowing for Capital** – A pay-go financing structure minimizes the total cost of projects through the reduction in interest costs. A "pay-go" capital financing program is one in which ongoing capital projects are paid for from remaining revenue after operations and maintenance (O&M) expenses and debt service are paid for. A balance of these two funding approaches appears to be the most effective in lowering the overall cost of the RIRP, as well as spreading out the costs over a longer period of time.
  - **Construction Work in Progress (CWIP)** – CWIP is a rate methodology that allows for the recovery of interest expense on project construction expenditures through the base rate during construction, rather than capitalizing the interest until the projects are on-line and generating power. It should be noted that this rate methodology is sometimes criticized for shifting risks for shareholders to ratepayers; however, in the case of a public cooperative or municipal utility, the "shareholders" are the ratepayers.

  - **State Financial Assistance** – State financial assistance could take a variety of forms as previously noted; for the purposes of this project, SNW focused on State assistance structured similarly to the Bradley Lake project. The benefits of State funding include: repayment flexibility, credit support/risk mitigation, and potential interest cost benefit.

    It should be noted that the economic comparison of resource options (using Strategist™ and PROMOD™) does not assume any of these financing strategies, including any State grants of Federal tax credits, with the exception of the Federal Tax Credits for Renewables Sensitivity Case.

- The overall objective of SNW's analysis was to identify ways to overcome the funding challenges inherent with large-scale projects, including the length of construction time before the project is online and access to capital markets, and to develop strategies that could be used to produce equitable rates over the useful life of the assets being financed. With these challenges in mind, SNW developed separate versions of its model to capture the cost of financing under a "base case" scenario and an "alternative" scenario. The base case financing model was structured such that the list of RIRP projects during the first 20 years would be financed through the capital markets in advance of construction and that the cost of the financing in the form of debt service on the bonds would immediately be passed through to the ratepayers; the projects being financed over the balance of the 50-year period would be financed through cash flow created through normal rates and charges ("pay-go"), once debt service coverage from previous years has grown to levels that create cash flow balance amounts sufficient to pay for the projects as their construction costs come due. The alternative model was developed with the goal of minimizing the rate shock that may otherwise occur with such a large capital plan, and levelizing the rate over time so that the economic burden derived from these projects can be spread more equitably over the useful life of the projects being contemplated.
- In both the base and alternative cases, SNW transferred the excess operating cash flow that is generated to create the debt service coverage level, and using that balance to both partially fund the capital projects in the early years and almost fully fund the projects in the later years. In the alternative case, SNW also included: 1) a Capital Benefits Surcharge ($0.01 per kWH) over the first 17 years, when approximately 75 percent of the capital projects will have been constructed, and 2) State assistance as an equity participant, structured in a manner similar to the Bradley Lake financing model (SNW assumed that the State would provide a $2.4 billion zero-interest loan to GRETC to provide the upfront funding for the Chakachamna project, only to be paid back by GRETC out of system revenues over an extended period of time, and following the repayment of the potentially more expensive capital market debt).
- Under the base case, the <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.13 per kWH, while the <u>average</u> fixed charge rate over the 50-year period is $0.07 per kWh.
- In the alternative case, the <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.08 per kWH, while the <u>average</u> fixed charge rate over the 50-year period is $0.06 per kWh, not including the $0.01 consumer benefit surcharge that is in place for the first 17 years.
- **While the <u>average</u> rates between the two cases are essentially the same, the <u>maximum</u> rate in the alternative case is much lower, showing the ability of innovative financing tools and ratemaking methodologies to overcome the funding challenges and provide equitable rates over the 50-year period.**

- The formation of a regional entity, such as GRETC, that would combine the existing resources and rate base of the Railbelt utilities, as well as provide an organized front in working to obtain private financing and the necessary levels of State assistance, would be, in SNW's opinion, a necessary next step towards achieving the goal of reliable energy for the Railbelt region now and in the future.

1.8 Implementation Risks and Issues

There are a number of general risks and issues that must be addressed regardless of the resource future that is chosen by stakeholders, including the utilities and State policy makers. Additionally, each alternative DSM/EE, generation and transmission resource type has its own specific risks and issues. **Section 14** includes a detailed discussion of these general and resource-specific implementation-related risks and issues.

A Note Regarding Risks

- Risk is an inherent element of any long-term integrated resource plan. This RIRP is not different.
- Risks associated with fuel supply, project development, operations, environmental, transmission, regulatory, and so forth, all affect the region's optimal future resource path. These risks are identified and discussed in this report.
- In many ways, this RIRP is the beginning of a journey; hard work is required to address these risks and make the difficult policy choices necessary to secure a reliable energy future.

1.8.1 General Risks and Issues

General issues and risks related to the implementation of the RIRP include the following:

- **Organizational**, including:
  - The lack of a regional entity with the responsibility for implementing the RIRP will lead to suboptimal solutions, resulting in higher costs, lower reliability and the inability to manage the successful integration of DSM/EE and renewable resources into the Railbelt system.
  - To date, the Railbelt utilities have not been able to take full advantage of economies of scale for several reasons. Absent taking a regional approach to future resource planning and development, this reality will continue.
  - Fuel supply risks, including the future deliverability and price of natural gas.
  - Risks resulting from the inadequacy of the current regional transmission network.
  - Market development risks and issues, including the need to implement a competitive power procurement process to encourage the development of generation projects by IPPs, and the potential for large load increases.
  - Financing and rate issues, related to the ability of the region to finance the capital investments identified in the RIRP and the need to mitigate the rate impact of those investments.
  - Legislative and regulatory issues, including the potential impact that a State Energy Plan and the passage of energy-related policies could have on the RIRP.

1.8.2 Resource Specific Risks and Issues

Table 1-7 provides Black & Veatch's assessment of the relative magnitude of various categories of risks and issues for each resource type, including:

- **Resource Potential Risks** – the risk associated with the total energy and capacity that could be economically developed for each resource option.
- **Project Development and Operational Risks** – the risks and issues associated with the development of specific projects, including regulatory and permitting issues, the potential for construction costs overruns, actual operational performance relative to planned performance, and so forth. This category also includes non-completion risks once a project gets started, the risk that adverse operating conditions will severely damage the facilities resulting in a shorter useful life than expected, and project delay risks.
- **Fuel Supply Risks** – the risks and issues associated with the adequacy and pricing of required fuel supplies.
- **Environmental Risks** – the risks of environmental-related operational concerns and the potential for future changes in environmental regulations.
- **Transmission Constraint Risks** – the risk that the ability to move power from a specific generation resource to where that power is needed will be inadequate, an issue that is particularly important for large generation projects and remote renewable projects.
- **Financing Risks** – the risk that a regional entity or individual utility will not be able to obtain the financing required for specific resource options under reasonable and affordable terms and conditions.
- **Regulatory/Legislative Risks** – the risk that regulatory and legislative issues could affect the economic feasibility of specific resource options.
- **Price Stability Risks** – the risk that wholesale power costs will increase significantly as a result of changes in fuel prices and other factors (e.g., CO_2 costs).

Fundamental RIRP-Related Risks and Uncertainties

General

- Regional implementation of RIRP elements
- Financial capability of Railbelt utilities

DSM/Energy Efficiency (DSM/EE)

- Lack of Alaska-specific information
- Total achievable resource potential
- Long-term reliability of savings
- Funding source

Generation Resources – Conventional

- Natural gas supplies, deliverability and prices
- Future emissions regulations (including CO_2)

Generation Resources – Renewables

- Total economic resource potential
- Optimization of potential sites
- Project completion risks associated with large hydro and tidal
- Integration of non-dispatchable resources
- Environmental and permitting issues

Transmission

- Adequacy of backbone grid to move power and ensure reliability
- Generation site-specific interconnections
- Siting and permitting issues

Table 1-7
Resource Specific Risks and Issues - Summary

Resource	Relative Magnitude of Risk/Issue							
	Resource Potential Risks	Project Development and Operational Risks	Fuel Supply Risks	Environmental Risks	Transmission Constraint Risks	Financing Risks	Regulatory/ Legislative Risks	Price Stability Risks
DSM/EE	Moderate	Limited	N/A	N/A	N/A	Limited - Moderate	Moderate	Limited
Generation Resources								
Natural Gas	Limited	Limited	Significant	Moderate	Limited	Moderate	Moderate	Significant
Coal	Limited	Moderate-Significant	Limited	Moderate - Significant	Limited - Significant	Moderate – Significant	Moderate	Moderate
Modular Nuclear	Limited	Significant	Moderate	Significant	Limited	Significant	Significant	Significant
Large Hydro	Limited	Significant	Limited	Significant	Significant	Significant	Significant	Limited
Small Hydro	Moderate	Moderate	Limited	Moderate	Moderate	Limited - Moderate	Limited	Limited
Wind	Moderate	Moderate	N/A	Limited	Moderate	Limited - Moderate	Limited	Limited - Moderate
Geothermal	Moderate	Limited - Moderate	N/A	Limited - Moderate	Moderate – Significant	Limited – Moderate	Limited	Limited
Solid Waste	Limited	Moderate-Significant	N/A	Significant	Moderate	Limited – Moderate	Limited-Moderate	Moderate
Tidal	Limited	Significant	N/A	Significant	Moderate - Significant	Moderate – Significant	Moderate - Significant	Limited - Moderate
Transmission	Limited	Significant	N/A	Moderate	N/A	Significant	Moderate - Significant	N/A

1.9 Conclusions and Recommendations

1.9.1 Conclusions

The primary conclusions from the RIRP study are discussed below.

1. The current situation facing the Railbelt utilities includes a number of challenging issues that place the region at a historical crossroad regarding the mix of DSM/EE, generation, and transmission resources that it will rely on to economically and reliably meet the future electric needs of the region's citizens and businesses. As a result of these issues, the Railbelt utilities are faced with the following challenges:
   - A transmission network that is isolated and has limited total transfer capabilities and redundancies.
   - The inability of the region to take full advantage of economies of scale due to its limited size.
   - A heavy dependence on natural gas from the Cook Inlet for electric generation.
   - Limited and declining Cook Inlet gas deliverability.
   - Lack of natural gas storage capability.
   - The region's aging generation and transmission infrastructure.
   - A heavy reliance on older, inefficient natural gas generation assets.
   - The region's limited financing capability, both individually and collectively among the Railbelt utilities.
   - Duplicative and diffused generation and transmission expertise among the Railbelt utilities.
2. The key factors that drive the results of Black & Veatch's analysis include the following:
   - The risks and uncertainties that exist for all alternative DSM/EE, generation, and transmission resource options.
   - The future availability and price of natural gas.
   - The public acceptability and ability to permit a large hydroelectric project which is a greater concern, based upon Black & Veatch's discussions with numerous stakeholders, than the acceptability and ability to permit other types of renewable projects, such as wind and geothermal.
   - Potential future CO_2 prices, which would impact all fossil fuels, that may or may not result from proposed Federal legislation.
   - The region's existing transmission network, which limits: 1) the ability to transfer power between areas within the region to minimize power costs, and 2) places a maximum limit on the amount of non-dispatchable resources that can be integrated into the region's transmission grid.
   - The ability of the region to raise the required financing, either by the utilities on their own or through a regional G&T entity.
   - Whether the Railbelt utilities develop a number of currently proposed projects that were selected outside of a regional planning process.

   Figures 1-10 and 1-11 graphically demonstrate how the results of the various reference and sensitivity cases are impacted by these important uncertainties. Figure 1-10 shows the cumulative present value cost for each year over the 50-year planning horizon; similarly, Figure 1-11 shows the annual wholesale power cost (cents/kWh) in 2010 dollars. In both cases, we have shown selected reference and sensitivity cases to highlight how dependent the results are to these key uncertainties.

Figure 1-10
Cumulative Present Value Cost – Selected Reference and Sensitivity Cases

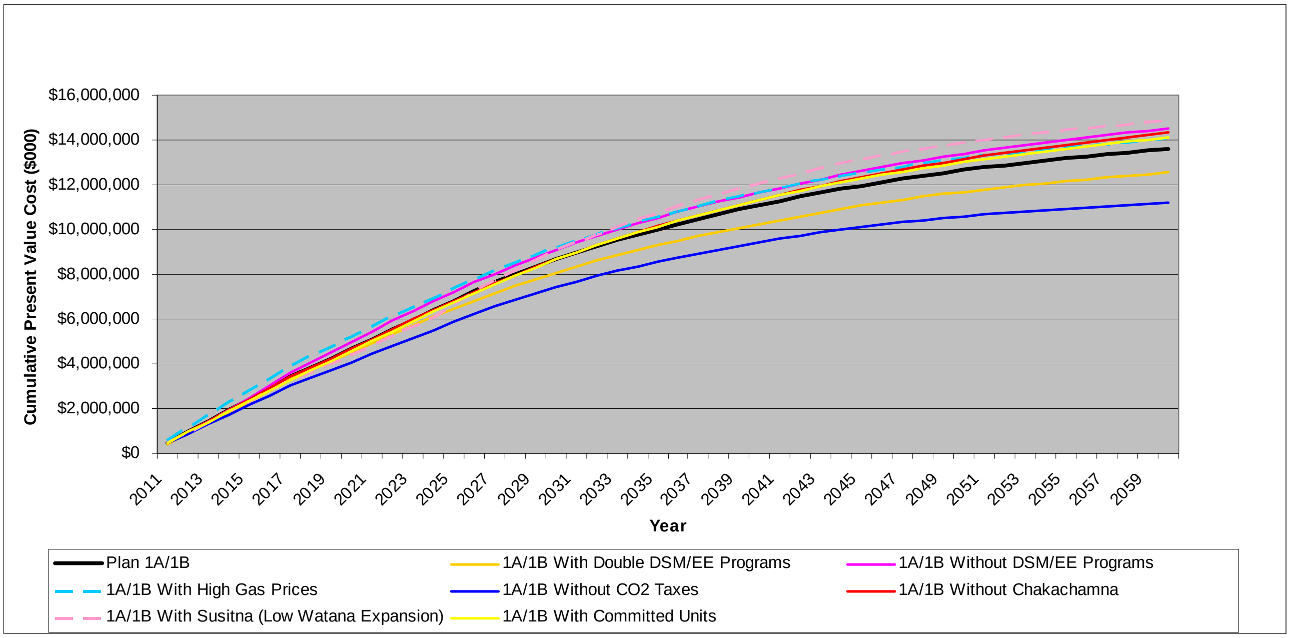
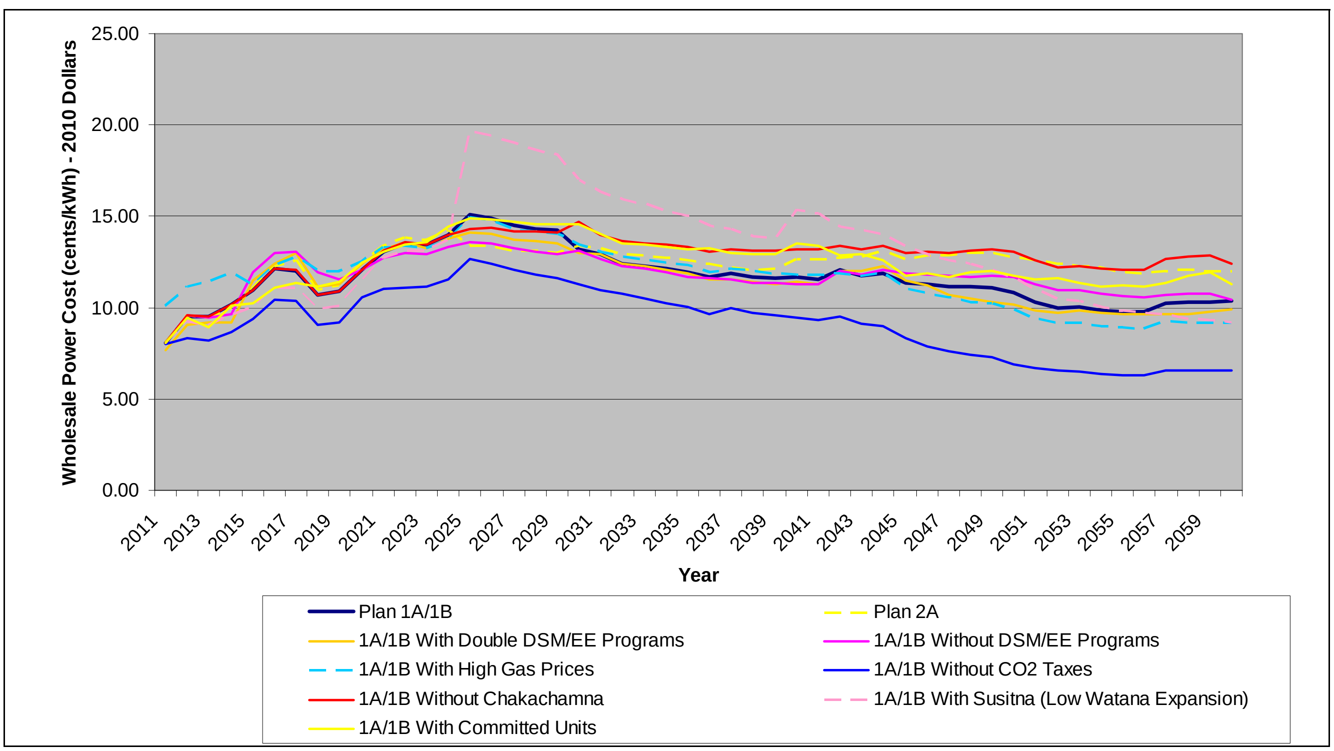


Figure 1-11
Annual Wholesale Power Cost – Selected Reference and Sensitivity Cases



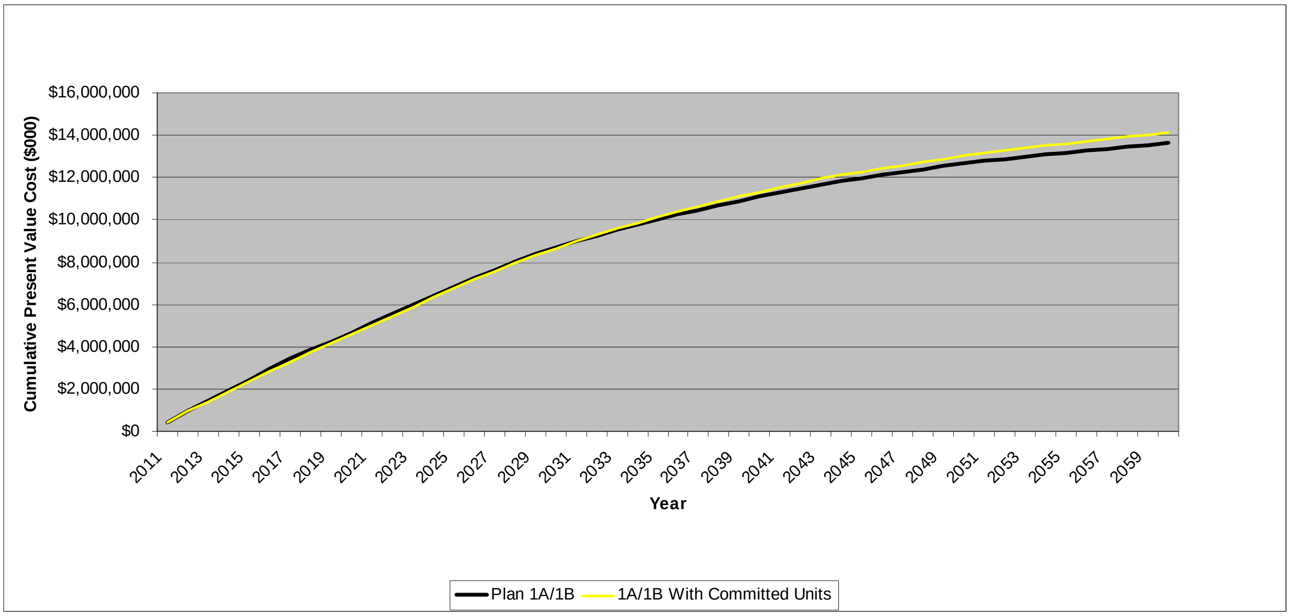
As can be seen in Figure 1-10, which shows cumulative net present value costs over the 50-year planning horizon, the 1A/1B With Susitna (Low Watana Expansion), 1A/1B With no DSM/EE Programs, 1A/1B Without Chakachamna, 1A/1BWith Committed Units, and 1A/1B With High Gas Prices Sensitivity Cases are all higher cost than Scenario 1A/1B, in descending order. The 1A/1B With Double DSM/EE Programs and 1A/1B With No CO_2 Taxes Sensitivity Cases are lower cost that Scenario 1A/1B.

Figure 1-11 shows how significant the uncertainty regarding CO_2 taxes is with regard to the results. It also shows the economic value of achieving higher DSM/EE savings that were assumed in the Scenario 1A/1B Reference Case if those savings can be achieved. Also, shown is the fact that the other sensitivity cases are higher cost than Scenario 1A/1B.

3. The resource plans that were developed as part of this study for each Evaluation Scenario include a diverse portfolio of resources. If implemented, the RIRP will lead to:
    - The development of a resource mix resulting from a regional planning process.
    - Greater reliance on DSM/EE and renewable resources and a lower dependence on natural gas.
    - A more robust transmission network.
    - More effective spreading of risks among all areas of the region.
    - A greater ability to respond to large load growth should these load increases occur. Stated another way, the implementation of the RIRP will provide a stronger foundation upon which to base future economic development efforts.
4. The cost of this greater reliance on DSM/EE and renewable resources is less than the continued heavy reliance on natural gas based upon the base case gas price forecast that was used in this analysis. This result is achievable if the region builds a large hydroelectric project. There are uncertainties, at this point in time, regarding the environmental and/or geotechnical conditions under which a large hydroelectric project could be built. If a large hydroelectric facility can not be developed, or if the cost of the large hydroelectric project significantly exceeds the current preliminary estimates, then the costs associated with a predominately renewable future would be greater than continuing to rely on natural gas.
5. Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built.
6. Scenarios 2A and 2B were evaluated to determine what the impact would be if the demand in the region was significantly greater than it is today. In fact, the per unit power costs were not less than Scenario 1A/1B due to the cost of Susitna which was the resource chosen to meet this additional load.
7. Additionally, the implementation of a regional plan will result in lower costs than if the individual Railbelt utilities continue to go forward on their own. While the scope of this study did not include the development of separate integrated resource plans for each of the six Railbelt utilities, we did complete a sensitivity analysis to show the cost impact if the utilities develop their currently proposed projects (referred to as committed units) that were selected outside of a regional planning process. The Railbelt utilities are moving forward with these projects due to the existing uncertainty regarding the formation of GRETC. While this sensitivity case does not fully capture the incremental cost of the utilities acting independently over the 50-year planning horizon, it does provide an indication of the relative cost differential. Figure 1-12 shows the resulting total annual costs of the two different resource plans. In the aggregate, the cost of the Committed Unit Sensitivity Case was approximately

5.6 percent, or $484 million on a cumulative net present value cost basis, higher than Scenario 1A/1B. The main conclusion to draw from this graphic is that there are significant cost savings associated with the Railbelt utilities implementing a plan that has been developed to minimize total regional costs, while ensuring reliable service, as opposed to the individual utilities working separately to meet the needs of their own customers.

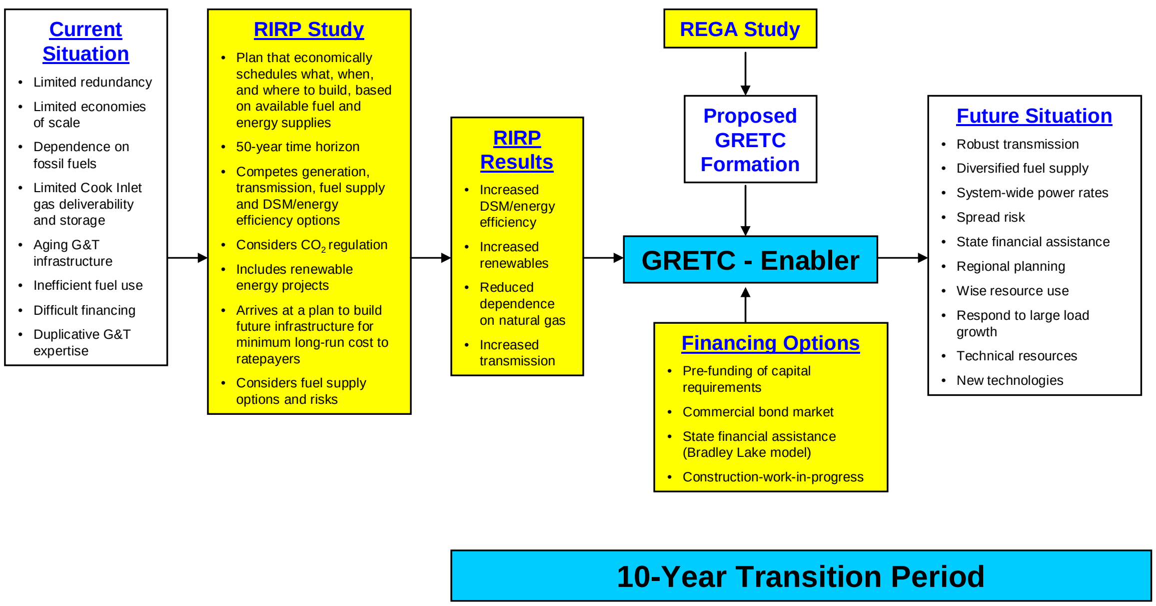
Figure 1-12
Comparison of Results - Scenario 1A/1B Versus Committed Units Sensitivity Case



8. There are a number of risks and uncertainties regardless of the resource options chosen. For example: 1) there is a lack of Alaska-specific data upon which to build an aggressive region-wide DSM/EE program, 2) the future availability and price of natural gas affects the viability of natural gas generation, and 3) the total economic potential of various renewable resources is unknown at this time. In some cases, these risks and uncertainties (e.g., the ability to permit a large hydroelectric facility) might completely eliminate a particular resource option. Due to these risks and uncertainties, it will be important for the region to maintain flexibility so that changes to the preferred resource plan can be made, as necessary, as these resource-specific risks and uncertainties become more clear or get resolved.
9. Significant investments in the region's transmission network need to be made within the next 10 years to ensure the reliable and economic transfer of power throughout the region. Without these investments, providing economic and reliable electric service will be a greater challenge.
10. The increased reliance on non-dispatchable renewable resources (e.g., wind) will require a higher level of frequency regulation within the region to handle swings in electric output from these resources. An increased level of regulation has been included in Black & Veatch's transmission plan. Even with this increased regulation, however, the challenges associated with the integration of non-dispatchable resources will ultimately place a maximum limit on the amount of these resources that can be developed.

11. The implementation of the RIRP does not require that a regional generation and transmission entity (e.g., GRETC) be formed. However, the absence of a regional entity with the responsibility for implementing the RIRP will increase the difficulty of the region's ability to implement a regional plan and, in fact, Black & Veatch believes that the lack of a regional entity will, as a practical matter, mean that the RIRP will not be fully implemented. As a consequence, the favorable outcomes of the RIRP discussed above would not be realized. The interplay between the formation of a regional entity and the RIRP is shown in Figure 1-13.

Figure 1-13
Interplay Between GRETC and Regional Integrated Resource Plan



1.9.2 Recommendations

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

- Recommendations – General
- Recommendations – Capital Projects
- Recommendations – Other

1.9.2.1 Recommendations - General

The following general actions should be taken to ensure the timely implementation of the RIRP:

1. The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity.

2. The State should establish certain energy-related policies, including:
   - The pursuit of large hydroelectric facilities
   - DSM/EE program targets
   - RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal (which will become commercially mature during the 50-year planning horizon) projects in addition to large hydroelectric projects; the passage of an RPS would be meaningful as a policy statement even though the preferred resource plan would achieve a 50 percent renewable level by 2025.
   - System benefit charge to fund DSM/EE programs and or renewable projects

3. The State should work closely with the Railbelt utilities and other stakeholders to establish the specific preferred resource plan. In establishing the preferred resource plan, the economic results of the various reference cases and sensitivity cases evaluated in this study should be considered, as well as the environmental impacts discussed in Section 13 and the project-specific risks discussed in Section 14.

4. Black & Veatch believes that the Scenario 1A/1B resource plan should be the starting point for the selection of the preferred resource plan as discussed below. Table 1-8 provides a summary of the specific resources that were selected, based upon economics, in the Scenario 1A/1B resource plan during the first 10 years.

   A project selected in Scenario 1A/1B after the first 10 years especially worthy of mention is the Chakachamna Hydroelectric Project in 2025.

   Another important consideration in the selection of a preferred resource plan is evaluation of the sensitivity cases evaluated, as presented in Section 13. Issues addressed through the sensitivity cases and considered in Black & Veatch's selection of a preferred resource plan include the following and are discussed in Table 1-9. Following that discussion,
   - What if CO_2 regulation doesn't occur?
   - What is the effect if the committed units are installed?
   - What if Chakachamna doesn't get developed?
   - What would be the impact of the alternative Susitna projects?

   There are several projects that are significantly under development and included in the preferred resource plan. These significantly developed projects include:
   - Healy Clean Coal Project (HCCP)
   - Southcentral Power Project
   - Fire Island Wind Project
   - Nikiski Wind Project

   These projects are discussed in Table 1-10.

   In addition to these resources, Black & Veatch believes that Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of the projects could actually be built.

Table 1-8
Resources Selected in Scenario 1A/1B Resource Plan

Project	Discussion
DSM/EE Resources	The full level of DSM/EE resources evaluated was selected based upon their relative economics. Sensitivity analysis indicates that even greater levels of DSM/EE may be cost-effective. The lack of Alaska-specific DSM/EE data causes the exact level of cost-effective DSM/EE to remain uncertain.
Nikiski Wind	The RIRP selected this project in the initial year. It is being developed as an IPP project and is well along in the development process. The ARRA potentially offers significant financial incentives if this project is completed by January 1, 2013. These incentives could further improve its competitiveness. As a wind unit, it has no impact on planning reserves, but contributes to renewable generation.
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. This project was selected in the initial year of the plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the $25 million grant from the State for interconnection. This project was selected in 2012.
Anchorage 1x1 6FA Combined Cycle	The RIRP selected this unit for commercial operation in 2013. This unit is very similar in size and performance to the Southcentral Power Project being developed as a joint ownership project by Chugach and ML&P for 2013 commercial operation. The project appears well under development with the combustion turbines already under contract. The project fits well with the RIRP and the joint ownership at least partially reflects the GRETC joint development concept.
Glacier Fork Hydroelectric Project	The RIRP selected this project for commercial operation in 2014, the first year that it was available for commercial operation in the models. Of the large hydroelectric projects, Glacier Fork is by far the least developed. Glacier Fork has very limited storage and thus does not offer the system operating flexibility of the other large hydroelectric units. There is also significant uncertainty with respect to its capital cost and ability to be licensed. Because it has such a minimal level of firm generation in the winter, it does not contribute significantly to planning reserves, but does contribute about 6 percent of the renewable energy to the Railbelt. Detailed feasibility studies and licensing are required to advance this option.
Anchorage and GVEA MSW Units	The RIRP selected these units in 2015 and 2017. Historically, mass burn MSW units such as those modeled, have faced significant opposition due to emissions of mercury, dioxin, and other pollutants. Other technologies which result in lower emissions, such as plasma arc, are not commercially demonstrated. The units included in the RIRP are relatively small (26 MW in total) and are not required to be installed to meet planning reserve requirements, but their base load nature contributes nearly 4 percent of the renewable energy. Detailed feasibility studies would be required to advance this alternative.
GVEA North Pole Retrofit	The retrofitting of GVEA's North Pole combined cycle unit with a second train using a LM6000 combustion turbine and heat recovery steam generator was selected in 2018 coincident with the assumption of the availability of natural gas to GVEA. The retrofit takes advantage of capital and operating cost savings resulting from the existing installation.

Table 1-8 (Continued)
Resources Selected in Scenario 1A/1B Resource Plan

Project	Discussion
Mt. Spurr Geothermal Project	The first unit at Mt. Spurr was selected in 2020. Mt. Spurr's developer, Ormat, currently has commercial operation scheduled for 2017. Significant development activity remains for the project including verifying the geothermal resource. Mt. Spurr will also require significant infrastructure development including access roads and transmission lines. This infrastructure may correspond to similar infrastructure development required for Chakachamna which is selected in 2025 in the RIRP. As the implementation of the RIRP unfolds, there will likely be the need to adjust the timing of the resource additions following the implementation of the initial projects.

Table 1-9
Impact of Selected Issues on the Preferred Resource Plan

Issue	Discussion
CO_2 Regulation	The sensitivity case for Scenario 1A without CO_2 regulation selects the Anchorage LMS 100 project instead of Fire Island and Mt. Spurr in the first 10 years.
Committed Units	Installation of the committed units significantly increases the cost of Scenario 1A/1B. In addition to the committed units, this plan selects five wind units from 2016 through 2024 in response to CO_2 regulation. The plan with the committed units eliminates Chakachamna and does not meet the 50 percent renewable target by 2025.
Chakachamna	Chakachamna could fail to develop because of licensing or technical issues. Also, if the cost of Chakachamna were to increase to be equivalent to the alternative Susitna projects on a GWh basis, it would not be selected. The sensitivity case without Chakachamna for the first 10 years is identical to Scenario 1A/1B. The case does not meet the 50 percent renewable target by 2025 and is 5.2 percent higher in cost than the preferred resource plan.
Susitna	None of the alternative Susitna projects are selected in the Scenario 1A/1B resource plan. The least cost Susitna option, which is Low Watana Expansion, is 15.3 percent more than the preferred resource plan and 9.0 percent more than the case without Chakachamna. The 50 percent renewable requirement can not be met without Susitna if Chakachamna is not available.

Table 1-10
Projects Significantly Under Development

Project	Discussion	Preferred Resource Plan Recommendation
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. The project is part of the least cost scenario. While CO_2 regulation has been assumed in the RIRP, those regulations are not in place and there is no absolute assurance that they will be in place or what the costs from the regulations will be. HCCP adds further fuel diversity to the Railbelt, especially to GVEA who doesn't currently have access to natural gas. As a steam unit, HCCP improves transmission system stability.	Black & Veatch recommends that HCCP be included in the preferred resource plan.
Southcentral Power Project	The Southcentral Power Project is well under development with the combustion turbines purchased. The timing and technology are generally consistent with the preferred resource plan. The project will improve the efficiency of natural gas generation in the Railbelt and permit the retirement of aging units.	Black & Veatch recommends the continued development of the Southcentral Power Project as part of the preferred resource plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the $25 million grant from the State for interconnection. This project is part of the least cost plan and provides renewable energy to the Railbelt system. Issues with interconnection and regulation will need to be resolved.	Subject to the successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.
Nikiski Wind Project	The Nikiski Wind Project is an IPP project like Fire Island and has the same potential to benefit from ARRA. It is also part of the least cost plan.	Like Fire Island, subject to successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.

In the case of the Mt. Spurr Geothermal Project, exploration should continue to determine the extent and characteristics of the geothermal resource at the site.

In the case of Susitna, the primary focus should be on completing engineering studies to optimize the size and minimize the costs of the project. In the case of Glacier Fork and Chakachamna, the additional work should look for "fatal flaws".

Additionally, further analysis needs to be completed relative to integrating wind and other non-dispatchable renewable resources into the transmission network.

5. The State and Railbelt utilities should develop a public outreach program to inform the general public regarding the preferred resource plan, including the costs and benefits.
6. The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan.
7. The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues. Specific actions that should be taken include:
   - Development of local gas storage capabilities with open access among all market participants as soon as possible.
   - Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured either in the Cook Inlet, from the North Slope or from long-term LNG supplies.
   - The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options. Once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources.
   - Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins. This action is required to provide the necessary long-term contractual certainty to result in additional exploration and development.

1.9.2.2 Recommendations – Capital Projects

Efforts should be undertaken to begin the development, including detailed engineering and permitting activities, of the following capital projects, which are included in Black & Veatch's recommended preferred resource plan.

1. Develop a comprehensive region-wide portfolio of DSM/EE programs.
2. Generation projects:
   - Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project)
   - Glacier Fork Hydroelectric Project
   - Generic Anchorage MSW Project
   - Generic GVEA MSW Project
   - GVEA North Pole Retrofit Project
   - Mt. Spurr Geothermal Project
   - Chakachamna Hydroelectric Project
   - Susitna Hydroelectric Project

3. Transmission and related substation projects, including the following projects which have been identified for priority attention because of their immediate impact on the reliability of the existing system. These projects are estimated to be required within the next five years.
   - Soldotna to Quartz Creek Transmission Line ($84 million – Project B)
   - Quartz Creek to University Transmission Line ($112.5 million – Project C)
   - Douglas to Teeland Transmission Line ($37.5 million – Project D)
   - Lake Lorraine to Douglas Transmission Line ($80 million – Project E)
   - SVCs ($25 million - Other Reliability Projects)
   - Funds to undertake the study of the Southern Intertie ($1 million)
   - Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50 million, including cost of BESS – Other Reliability Projects)

1.9.2.3 Recommendations - Other

Other actions, related to the implementation of the RIRP, that should be undertaken include:

1. The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts.
2. Develop a regional DSM/EE program measurement and evaluation protocol.
3. If GRETC is not formed, some type of a regional entity should be formed to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities.
4. Likewise, if GRETC is not formed, some type of a regional entity should be formed to develop the renewable resources included in the preferred resource plan.
5. Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs.
6. Aggressively pursue available Federal funding for DSM/EE programs and renewable projects.
7. Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to be economic within the planning horizon.
8. The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects, and conduct the necessary studies to address these issues and requirements.
9. Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable resources included in the preferred resource plan.
10. Develop streamlined siting and permitting processes for transmission projects.
11. Develop a regional frequency regulation strategy for non-dispatchable resources.
12. Develop a regional competitive power procurement process and a standard power purchase agreement to provide IPPs an equal opportunity to submit qualified proposals to develop specific projects.

13. Federal legislative and regulatory activities, including those related to emissions regulations, should be monitored closely and influenced to the degree possible.
14. Monitor the licensing progress of small modular nuclear units.

1.10 Near-Term Implementation Action Plan (2010-2012)

The purpose of this subsection section is to identify our overall recommendations regarding the near-term implementation plan, covering the period from 2010 to 2012. Our recommended actions are grouped into the following categories:

- General actions
- Capital projects
- Supporting studies and activities
- Other actions

In many ways, this near-term implementation plan shown in Tables 1-11 through 1-14 serves two objectives. First, it identifies that steps that should be taken during the next three years regardless of the alternative resource plan that is chosen as the preferred resource plan. Second, it is intended to maintain flexibility as the uncertainties and risks associated with each alternative resource plan become more clear and or resolved.

1.10.1 General Actions

Table 1-11
Near-Term Implementation Action Plan – General Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
General Actions	• The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity	2010	$6.8 million
	• Establish State energy-related policies regarding: o The pursuit of large hydroelectric facilities o DSM/EE program targets o RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal projects o System benefit charge to fund DSM/EE programs and or renewable projects	2010-2011	$0.2 million
	• The State should work closely with the Railbelt utilities and other stakeholders to establish the preferred resource plan, using the Scenario 1A/1B resource plan as the starting point	2010	Not applicable
	• Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of these projects could actually be built	2010-2011	To be determined
	• Develop a public outreach program to inform the public regarding the preferred resource plan, including the costs and benefits	2010-2011	$0.1 million
	• The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan	2010-2011	Not applicable

Table 1-11 (Continued)
Near-Term Implementation Action Plan – General Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
	• The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues; specific actions that should be taken include: o Development of local gas storage capabilities as soon as possible o Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured o The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options; once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources o Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins	2010-2012	To be determined

1.10.2 Capital Projects

Table 1-12
Near-Term Implementation Action Plan – Capital Projects

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Capital Projects	• Develop a comprehensive region-wide portfolio of DSM/EE programs within first six years	2011-2016	$34 million
	• Begin detailed engineering and permitting activities associated with the generation projects identified in the initial years of the preferred resource plan, including: o Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project) o Glacier Fork Hydroelectric Project o Generic Anchorage MSW Project o Generic GVEA MSW Project o GVEA North Pole Retrofit Project o Mt. Spurr Geothermal Project o Chakachamna Hydroelectric Project o Susitna Hydroelectric Project	2011-2016	Varies by project
	• Begin detailed engineering and permitting activities associated with the transmission projects identified in the initial years of the preferred resource plan, including: o Soldotna to Quartz Creek Transmission Line o Quartz Creek to University Transmission Line o Douglas to Teeland Transmission Line o Lake Lorraine to Douglas Transmission Line o SVCs o Funds to undertake the study of the Southern Intertie o Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system	2011-2016	Varies by project

1.10.3 Supporting Studies and Activities

Table 1-13
Near-Term Implementation Action Plan – Supporting Studies and Activities

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Supporting Studies and Activities	• The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts	2010-2011	$1.0 million
	• Develop a regional DSM/EE program measurement and evaluation protocol	2012	$0.1 million
	• The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects	2010-2011	$0.2 million
	• Conduct necessary studies to address resource agencies' issues and data requirements related to large hydroelectric and tidal projects	2011-2012	To be determined
	• Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable projects included in the preferred resource plan	2010-2012	$1.5 million
	• Develop a regional frequency regulation strategy for non-dispatchable resources	2011	$0.5 million
	• Develop a regional standard power purchase agreement for IPP-developed projects	2011-2012	$0.2 million
	• Develop a regional competitive power procurement process to encourage IPP development of projects included in the preferred resource plan	2011-2012	$0.2 million

1.10.4 Other Actions

Table 1-14
Near-Term Implementation Action Plan – Other Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Other Actions	• Form a regional entity (if GRETC is not formed) to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities	2010-2011	Subject to decision regarding formation of GRETC
	• Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs	2010-2011	$0.2 million
	• Aggressively pursue available Federal funding for DSM/EE programs	2010-2011	$0.2 million
	• Form a regional entity (if GRETC is not formed) and encourage IPPs to identify and develop renewable projects that are included in the preferred resource plan	2011-2012	Subject to decision regarding formation of GRETC
	• Further encourage the development of tidal power	Ongoing	To be determined
	• Monitor, and influence to the degree possible, Federal legislative and regulatory activities, including those related to emissions regulations	Ongoing	Not applicable
	• Aggressively pursue available Federal funding for renewable projects	2010-2012	$0.2 million
	• Develop streamlined siting and permitting processes for transmission projects	2010-2011	$0.5 million
	• Monitor the licensing progress of small modular nuclear units	Ongoing	Not applicable

2.0 PROJECT OVERVIEW AND APPROACH

This section provides an overview of the RIRP and Black & Veatch's approach to the completion of this study.

2.1 Project Overview

In response to a directive from the Alaska Legislature, the AEA was the lead agency for the development of this RIRP for the Railbelt region. This region is defined as the service areas of six regulated public utilities that comprise the region, including: Anchorage ML&P, Chugach, GVEA, HEA, MEA, and SES.

The goal of this project is to minimize future power supply costs and maintain or improve on current levels of power supply reliability through the development of a single comprehensive RIRP for the Railbelt region. The intent of the RIRP project is to provide:

- An up-to-date model that the utilities and AEA can use as a common database and model for future planning studies and analysis.
- An assessment of loads and demands for the Railbelt electrical grid for a time horizon of 50 years including new potential industrial demands.
- Projections for Railbelt electrical capacity and energy growth, fuel prices, and resource options.
- An analysis of the range of potential generation resources available, including costs, construction schedule, and long-term operating costs.
- A schedule for existing generating unit retirement, new generation construction, and construction of backbone redundant transmission lines that will allow the future Railbelt electrical grid to operate reliably under a transmission tariff which allows access by all potential power producers, and with a postage-stamp rate for electric energy and demand for the entire Railbelt as a whole.
- A long-term schedule for developing new fuel supplies that will provide for reliable, stable priced electrical energy for a 50-year planning horizon.
- A short-term schedule that coordinates immediate network needs (i.e., increasing penetration level of non-dispatchable generation, such as wind) within the first 10 years of the planning horizon with the long-term goals.
- A short-term plan addressing the transition from the present decentralized ownership and control to a unified G&T entity that identifies unified actions between utilities that must occur during this transition period.
- A diverse portfolio of power supply that includes, in appropriate portions, renewable and alternative energy projects and fossil fuel projects, some or all of which could be provided by IPPs.
- A comprehensive list of current and future generation, transmission and electric power infrastructure projects.

Black & Veatch conducted the REGA study for the AEA, which evaluated the feasibility of the Railbelt utilities forming an organization to provide coordinated unit commitment and economic dispatch of the region's generation resources, generation and transmission system planning, and project development for the Railbelt. As a result of that study, legislation was proposed to create GRETC, with a 10-year transition period in to achieve these goals. This RIRP is based on the GRETC concept being implemented from the beginning of the study's time horizon.

Black & Veatch had primary responsibility for conducting this Railbelt RIRP. In addition to Black & Veatch, three other AEA contractors (HDR, EPS, and SNW) played important roles in the development of the RIRP.

HDR updated work from the mid-1980s on the Susitna Hydroelectric Project and developed the capital and operating costs, as well as the generating characteristics, for several smaller sized Susitna options. HDR's work was used by Black & Veatch in the Strategist® and PROMOD® modeling discussed below. HDR's report summarizing the results of its work is provided in Appendix A.

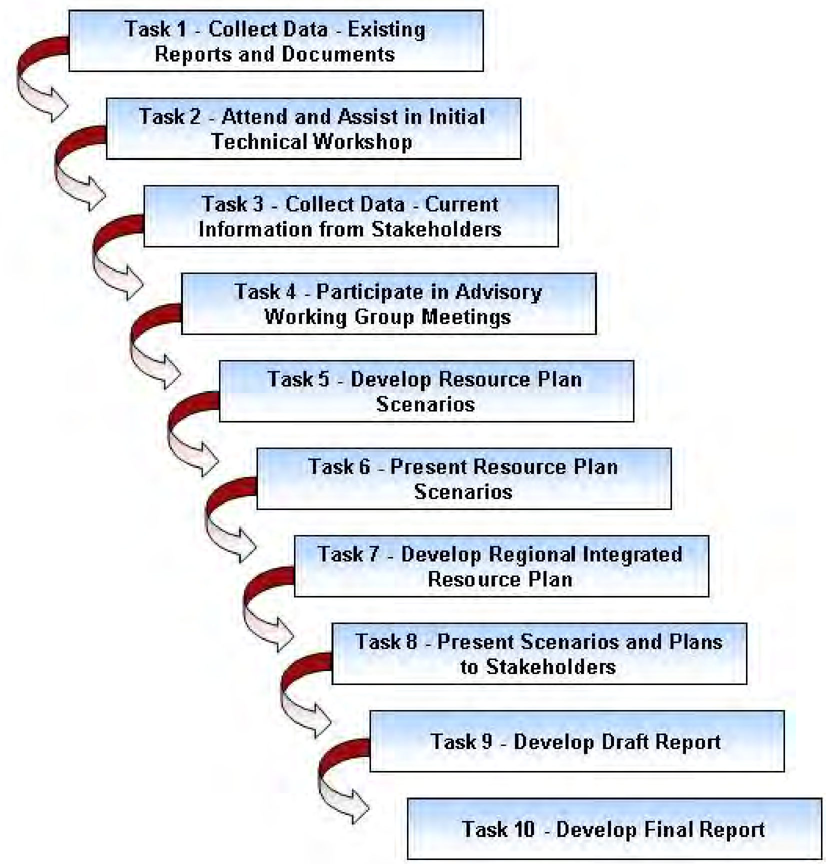
EPS assisted in the evaluation of the region's transmission system.

SNW developed the financial model used to determine the overall financing costs for the portfolios of generation and transmission projects developed as part of this project, and evaluated the impact of some financial options that could be used to address financing issues and mitigating related rate impacts. The results of SNW's analysis are provided in Appendix B.

2.2 Project Approach

The RIRP study process for the Railbelt system consisted of three key stages: data collection, optimal generation expansion along with integrated transmission expansion planning and production cost modeling, and report writing and documentation. Throughout this process, data related to alternative demand-side, supply-side, and transmission resource options were compiled, reviewed, screened for appropriateness, and modeled using Ventyx's Strategist® and PROMOD® optimal generation expansion and production cost models. Model inputs and assumptions take into consideration possible sensitivity cases and any considerations unique to the six utilities to derive the least-cost plan for the Railbelt region's electric system. To complete this study, the Black & Veatch project team, in collaboration with the other aforementioned AEA contractors, completed the tasks shown in Figure 2-1.

Figure 2-1
Project Approach Overview



Task 1 – Collect Data – Existing Reports and Documents

Black & Veatch issued data requests to the six Railbelt utilities to update and add to the data previously obtained in the REGA study. These data included existing generating resources and operating data, load and energy requirements, transmission characteristics, purchase power transactions, and DSM/EE programs.

Task 2 – Attend and Assist in Initial Technical Workshop

Black & Veatch worked with the AEA to sponsor a Technical Workshop near the beginning of the project to obtain information and input from the various regional stakeholders and to enable the development of scenarios for evaluation which provided the basis for the assessment of future fuel supply, generation, and transmission resource alternatives for the Railbelt.

Task 3 – Collect Data – Current Information From Stakeholders

Black & Veatch collected additional information from other regional stakeholders, including producers, ratepayer groups, and representatives from project developers, as well as the DSM/EE, environmental and renewables communities.

Task 4 – Participate in Advisory Working Group Meetings

Black & Veatch participated in five meetings with the Advisory Working Group that was formed for the project. The role of this Advisory Working Group is described later in this section.

Task 5 – Develop Resource Plan Scenarios

This task involved the following activities:

Subtask 5.1 – Development of Economic Parameters
Subtask 5.2 – Development of Regional Load Forecast
Subtask 5.3 – Development of Fuel Price Forecasts
Subtask 5.4 – Development of Reserve Criteria
Subtask 5.5 – Evaluation of Conventional Supply-Side Alternatives
Subtask 5.6 – Evaluation of Hydro Projects
Subtask 5.7 – Evaluation of Wind and Other Renewable Projects
Subtask 5.8 – Evaluation of Transmission System Expansions
Subtask 5.9 – Evaluation of Generation Unit Retirements
Subtask 5.10 – Evaluation of DSM/EE Measures
Subtask 5.11 – Scenario Mapping
Subtask 5.12 – Benchmarking Analysis

Task 6 – Present Resource Plan Scenarios

Black & Veatch made a presentation to the RIRP Advisory Working Group and AEA explaining the resource scenarios and describing the recommended Evaluation Scenarios.

Task 7 – Develop Regional Integrated Resource Plan

Black & Veatch then developed alternative resource plans for each of the four Evaluation Scenarios, based upon the results of Task 5.

Task 8 – Present Scenarios and Plans to Stakeholders

Black & Veatch presented its preliminary results, conclusions and recommendations to interested parties at a second Technical Conference that was held in December.

Task 9 – Develop Draft Report

Black & Veatch prepared a Draft Report that was provided to the AEA and made available to interested parties for review and comment.

Task 10 – Develop Final Report

Black & Veatch prepared a Final Report that incorporated comments received on the Draft Report.

2.3 Modeling Methodology

2.3.1 Study Period and Considerations

The evaluation timeframe consists of a 50-year study period from 2011 through 2060. Evaluations were conducted in nominal dollars with the annual costs discounted to 2011 dollars for comparison using the present worth discount rate discussed in Section 5. After evaluating the seasonal month definitions of the utilities, Black & Veatch defined the summer season as May 1 through October 31, and the winter season as November 1 through April 30.

The 50-year planning period presented challenges to reduce the running time for the Strategist® model to acceptable levels. Several techniques were used including bracketing years and pre-screening alternatives to reduce the number of alternatives included in the Strategist® runs to reduce run time to a target level of approximately 24 hours per run.

For comparison purposes, existing project capital costs are not carried forward. Only new generation, transmission, and DSM/EE costs, as well as system fuel, O&M and emission allowance costs, are considered when comparing the various expansion plan scenarios.

2.3.2 Strategist® and PROMOD® Overview

For the RIRP Study, Black & Veatch used Ventyx's Strategist® optimal generation expansion model to evaluate the various alternatives and scenarios. The Strategist® model is capable of evaluating a large number of plans with generating, transmission, and DSM/EE alternatives by using probabilistic dispatch, dynamic programming, and elimination of factors that typically are not taken into account when comparing thousands (or millions) of plans, such as ramp-up and ramp-down rates and start-up energy and start-up fuel costs.

The model utilizes a typical week methodology and evaluates the relative economics between all possible plans within a given set of criteria and minimizes utility costs through optimization. The model checks all feasible combinations in every year of the study period using dynamic programming. At the end of the study period, the model traces back through the matrix of feasible states to find the plans with the best financial or other operational criteria (cumulative present worth cost in this case) and ranks these plans according to this criteria. The plans that are shown to be most promising from an economic standpoint are then input into Ventyx's hourly chronological model, PROMOD®, for additional analysis with this more detailed production costing model.

PROMOD® performs unit commitment and economic dispatch under a wide array of operation constraints along with detailed transmission simulation. The model develops hourly generation, production costs, and fuel consumption for generating units utilizing detailed operating characteristic inputs. Hours on-line and start-up hours are also calculated. Transmission line information such as hourly flow and constraints are available for output along with unserved energy. Debt service (i.e., return on investment and depreciation) for capital additions are added externally to the operating costs developed by PROMOD®.

2.3.3 Benchmarking

With the uniqueness of the Railbelt electric system, it was important that Black & Veatch benchmark the models' production costing against an actual year in order to validate the models' abilities to appropriately model the characteristics of the Railbelt. The benchmarking exercise was based on 2008 actual data as that was the most recent year with complete generation, transmission, and purchases and sales data to benchmark against. Actual 2008 data was gathered from the utilities regarding generating unit performance, outages, and costs, as well as information on purchases and sales of economy energy and corresponding costs.

The goal of the benchmarking effort was to model system inputs and validate the outputs against actual values for 2008 for each utility. Outputs to be validated were generating unit capacity factors, hydroelectric generation amounts, generation costs, economy energy purchases and sales, and resulting costs. Wheeling rates, fuel costs, operations and maintenance (O&M) costs, and other costs were input on a per unit basis. Scheduled and forced outages were input directly to reflect actual unit availability.

Accurately benchmarking the Railbelt's hydroelectric generation was important to validate the models. Much of the Railbelt system in 2008 was powered by combined cycle and simple cycle turbines. With most of the scheduled maintenance on combined cycles occurring in the summer months due to high electric demand in the winter, less-efficient, more costly combustion turbines must be used for generation. When total system costs begin to rise, hydroelectric storage units can be used to generate a portion of the Railbelt's requirements. The fact that storage water for hydro is finite must also be taken into account. Water levels in hydroelectric reservoirs have minimums and maximums. The model was set up to limit the amount of generation available in each month to avoid exhausting all of the available water in one month and not having enough remaining in other months.

Overall, the benchmarking process verified that the models adequately reflect operation in the Railbelt for purposes of the RIRP. While the models have limitations in their modeling of the Railbelt system, they also have other benefits for their use in this study.

2.3.4 Hydroelectric Methodology

Strategist® treats hydroelectric generation as a load modifier, while PROMOD® offers the option of treating hydroelectric as a load modifier or dispatching it. In Strategist® hydroelectric generating units are dispatched one at a time. Each unit has a maximum and minimum capacity level at which it operates. Each unit can also be given a monthly total energy that is available. The utility's overall load is reduced by the minimum hydro generation available in each hour. The difference between the total hydroelectric energy in the month and the minimum hydro energy is the energy available for peak shaving. Capacity available for peak shaving is the difference between the maximum and minimum capacities of the unit. The resulting load shape is then met by unit dispatch of other available resources.

Black & Veatch provided the model with the monthly energy limits for hydroelectric units and allowed the model to perform the load modifications. These limits were calculated from the average monthly historical generation of the units provided by the utilities. Providing monthly energy limits for each hydroelectric unit prevents the model from taking an unrealistic amount of water from the reservoirs, but still allows for variance throughout the year. The amount of baseload energy to be met will be reduced, thereby allowing some units to be shut down, or run minimally. This methodology will also lower the amount of load to be met by less-efficient thermal units and lowers production costs. Peak load reduction will also work to reduce the amount of units that need to be started to handle peak times.

There are several factors that drive hydroelectric generation in the Railbelt system. Summer maintenance outages on other generating units can increase the amount of hydroelectric generation necessary to reduce system costs. Limitations on the deliverability of natural gas in the winter for thermal generating units can also drive the use of hydroelectric generation in the region. As the system ages, the correlation between higher system costs and generating unit maintenance will be reduced as less efficient units will be retired and replaced. With multiple factors influencing hydroelectric generation in the Railbelt region, Black & Veatch believes that the load modification technique is an appropriate method to model hydroelectric generation in the Railbelt. Modeling assumptions specific to each hydroelectric unit are presented in Section 4.

PROMOD® offers the additional modeling feature that, on a weekly basis, PROMOD® will dispatch available hydro energy at the times when avoided thermal unit costs are greatest. This feature was used in the PROMOD® modeling.

2.3.5 Evaluation Scenarios

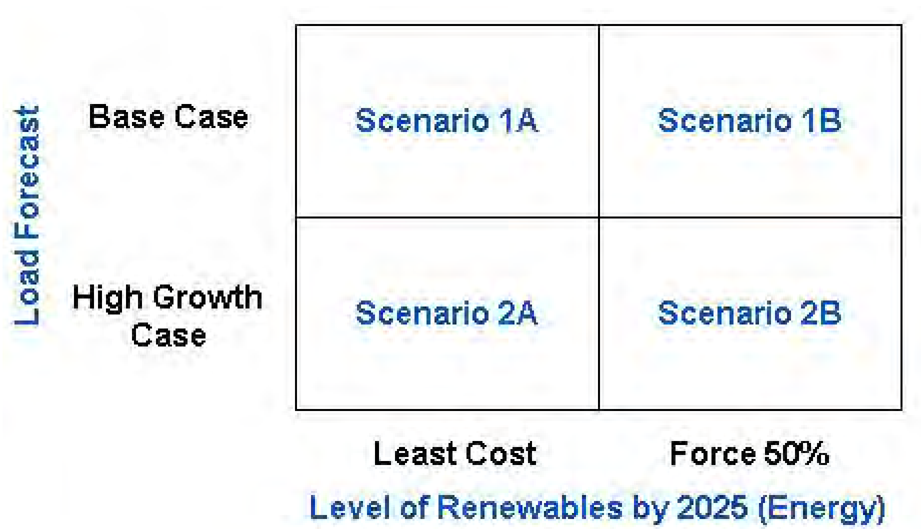
Black & Veatch, in collaboration with the Advisory Working Group, developed four Evaluation Scenarios for this project. Black & Veatch then developed a 50-year resource plan for each of these Evaluation Scenarios.

The primary objective of these Evaluation Scenarios was to evaluate two key drivers. The first driver was to look at what the impacts would be if the demand in the region was significantly greater than it is today; of primary interest was to see if higher demands would result in greater reliance on large generation resource options and allow for more aggressive expansions of the region's transmission network.

The second driver was to determine the impact associated with the pursuit of a significant amount of renewable resources over the 50-year time horizon.

As a result, Black & Veatch evaluated the four Evaluation Scenarios shown on Figure 2-2.

Figure 2-2
Evaluation Scenarios



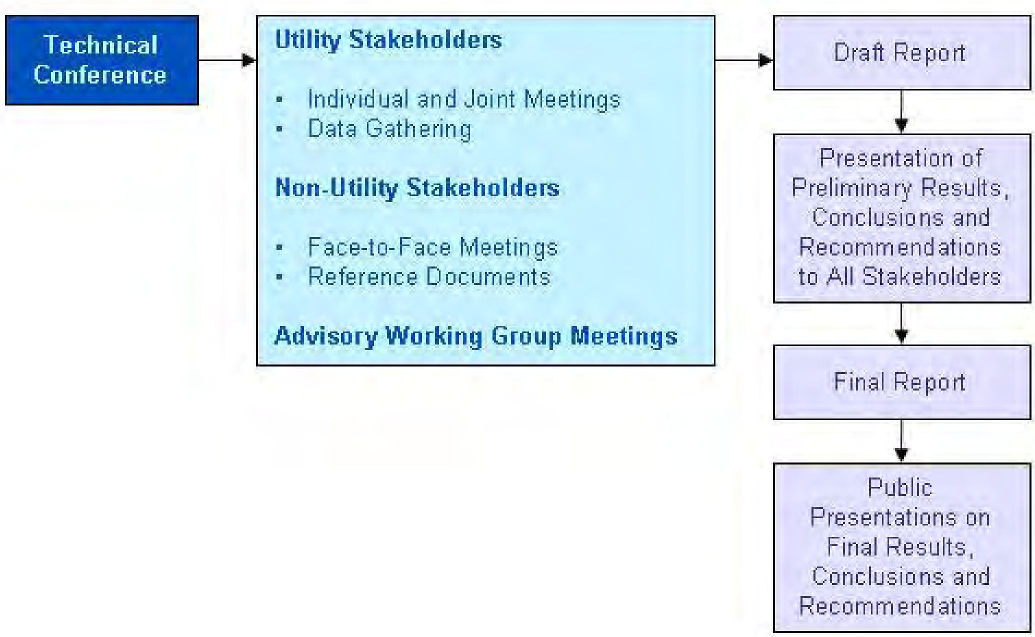
The key assumptions underlying each Evaluation Scenario include:

- **Scenario 1 – Base Case Load Forecast**
  - Current regional loads with projected growth
  - All available resources – fossil fuel, renewables, and DSM/EE
  - Probabilistic estimate of gas supply availability and prices
  - Deterministic price forecasts for other fossil fuels
  - Emissions including CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 1A – Least Cost Plan**
  - **Scenario 1B – Force 50% Renewables**
- **Scenario 2 – Large Growth Load Forecast**
  - Significant growth in regional loads due to economic development efforts or large scale electrification (e.g., economic development loads, space and water heating fuel switching, and electric vehicles)
  - Base case resources, fuel availability/price forecasts and CO_2 costs
  - Transmission system investments required to support selected resources
  - **Scenario 2A – Least Cost Plan**
  - **Scenario 2B – Force 50% Renewables**

2.4 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 a broad cross-section of the Railbelt region's stakeholders. Elements of the stakeholder involvement process are summarized in Figure 2-3.

Figure 2-3
Elements of Stakeholder Involvement Process



As the first element of this public participation process, the AEA held a two-day Technical Conference near 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 and to provide comments specific to the completion of this study. Approximately 100 individuals, including Black & Veatch project team members, participated in this conference.

Additionally, Black & Veatch met with a number of non-utility stakeholders to provide them with the opportunity to present their input directly to the Black & Veatch project team members. These meetings were in addition to the meetings that Black & Veatch held with Railbelt utility representatives.

Black & Veatch and the AEA also held several meetings with the Advisory Working Group that was assembled for this project. The role and membership of this Advisory Working Group is discussed in the next subsection.

Additionally, the AEA held a second Technical Conference during which the Black & Veatch project team presented our preliminary results, conclusions and recommendations. Subsequent to that presentation, all stakeholders were provided the opportunity to review and comment on our Draft Report.

2.5 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
- Chris Rose, Renewable Energy Alaska Project
- Brad Janorschke, Homer Electric Association
- Carri Lockhart, Marathon Oil Company
- Colleen Starring, Enstar Natural Gas Company
- Debra Schnebel, Scott Balice Strategies
- Jan Wilson, Regulatory Commission of Alaska
- Jim Sykes, Alaska Public Interest Group
- Lois Lester, AARP
- Marilyn Leland, Alaska Power Association
- Mark Foster, Mark A. Foster & Associates
- Nick Goodman, TDX Power, Inc.
- Pat Lavin, National Wildlife Federation - Alaska
- Steve Denton, Usibelli Coal Mine, Inc.
- Tony Izzo, TMI Consulting

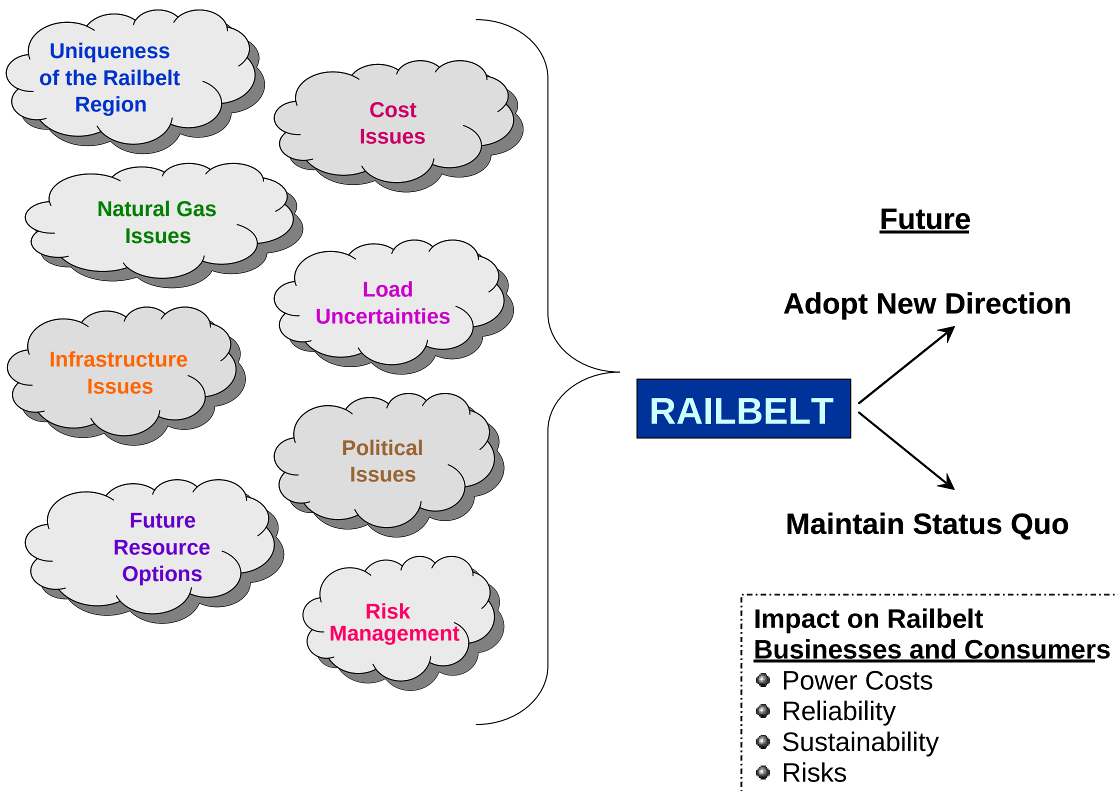
The Advisory Working Group provided input on a number of project-related issues, including the following:

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

3.0 SITUATIONAL ASSESSMENT

The purpose of this section is to discuss the myriad of issues facing the Railbelt electric utilities; the major categories of issues are shown on Figure 3-1. This discussion is largely drawn from the REGA study that was completed by Black & Veatch.

Figure 3-1
Summary of Issues Facing the Railbelt Region



Each of these issue categories is discussed below.

3.1 Uniqueness of the Railbelt Region

In comparison to the business and operating environment of the utility industry in the lower-48 states, 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 combined peak load of all six utilities is approximately 870 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 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.
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 consequence, 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.

3.2 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 3-1. Alaska's average retail rate was 13.3 cents per kWh; in comparison, Hawaii was the highest ranked state at 21.3 cents per kWh and Idaho was the lowest at 5.1 cents per kWh. The U.S. average was 9.1 cents per kWh.

Issue	Description
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 3-2 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	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 regional entity responsible for developing and delivering DSM and energy efficiency programs to residential and commercial customers throughout the Railbelt region.

Table 3-1
Relative Cost per kWh (Alaska Versus Other States) - 2007

Name	Average Retail Price (cents/kWh)	Name	Average Retail Price (cents/kWh)
Hawaii	21.29	North Carolina	7.83
Connecticut	16.45	Colorado	7.76
New York	15.22	Alabama	7.57
Massachusetts	15.16	Minnesota	7.44
Maine	14.59	New Mexico	7.44
New Hampshire	13.98	Oklahoma	7.29
Alaska	13.28	South Carolina	7.18
Rhode Island	13.12	Montana	7.13
New Jersey	13.01	Virginia	7.12
California	12.80	Tennessee	7.07
Vermont	12.04	Oregon	7.02
District of Columbia	11.79	Arkansas	6.96
Maryland	11.50	South Dakota	6.89
Delaware	11.35	Kansas	6.84
Florida	10.33	Iowa	6.83
Texas	10.11	Missouri	6.56
Nevada	9.99	Indiana	6.50
Pennsylvania	9.08	North Dakota	6.42
Arizona	8.54	Utah	6.41
Michigan	8.53	Washington	6.37
Wisconsin	8.48	Nebraska	6.28
Illinois	8.46	Kentucky	5.84
Louisiana	8.39	West Virginia	5.34
Mississippi	8.03	Wyoming	5.29
Ohio	7.91	Idaho	5.07
Georgia	7.86	**US Average**	**9.13**

Source: Energy Information Administration, “State Electricity Profiles,” DOE/EIA-0348, April 2009.

Table 3-2
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		
GVEA	0.05903	0.000274	0.11153	0.170834	15	750	$143.13		
Chugach	0.02478	0.000274	0.09282	0.117874	8.42	750	$96.83		
MEA	0.03084	0.000274	0.09447	0.125584	5.65	750	$99.84		
ML&P	-0.00655	0.000274	0.09476	0.088484	6.56	750	$72.92		
Homer (North of Kachemak Bay)	0.00078	0.000274	0.12718	0.128234	11	750	$107.18		
Homer (South of Kachemak Bay)	0.00078	0.000274	0.13056	0.131614	11	750	$109.71		
City of Seward	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**		
GVEA	0.05903	0.000274	0.10957	0.168874	20	10,000	$1,708.74		
Chugach	0.02478	0.000274	0.08001	0.105064	18.26	10,000	$1,068.90		
MEA	0.03084	0.000274	0.07677	0.107884	5.65	10,000	$1,084.49		
ML&P	-0.00655	0.000274	0.09182	0.085544	12.88	10,000	$868.32		
Homer (North of Kachemak Bay)	0.00078	0.000274	0.1181	0.119154	24	10,000	$1,215.54		
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	10,000	$1,198.44		
City of Seward	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**
GVEA	0.05903	0.000274	0.7835	0.137654	50	8.55	150,000	500	$24,973.10
Chugach	0.02478	0.000274	0.0462	0.071254	58.85	11.65	150,000	500	$16,571.95
MEA	0.03084	0.000274	0.06004	0.091154	13.37	4.85	150,000	500	$16,111.47
ML&P	-0.00655	0.000274	0.05351	0.047234	44.15	11.85	150,000	500	$13,054.25
Homer (South of Kachemak Bay)	0.00078	0.000274	0.11479	0.115844	40	6.73	150,000	500	$20,781.60
City of Seward	NA	NA	NA	NA	NA	NA	NA	NA	NA
Average									**$18,298.47**

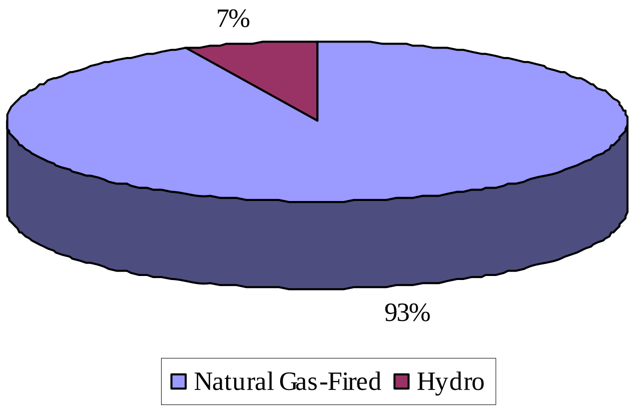
3.3 Natural Gas Issues

The Railbelt utilities use Cook Inlet 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 3-2 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, based on 2007 statistics. 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. Chugach is currently working with its natural gas suppliers to renegotiate these contracts. Although those negotiations are have not all 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 3-3. As can be seen in Figure 3-3, the population of the Anchorage, Mat-Su, and Kenai Peninsula areas has increased 170% from 1970 to 2005. 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. 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 a liquefied natural gas (LNG) import terminal is developed to supplement Cook Inlet supplies.

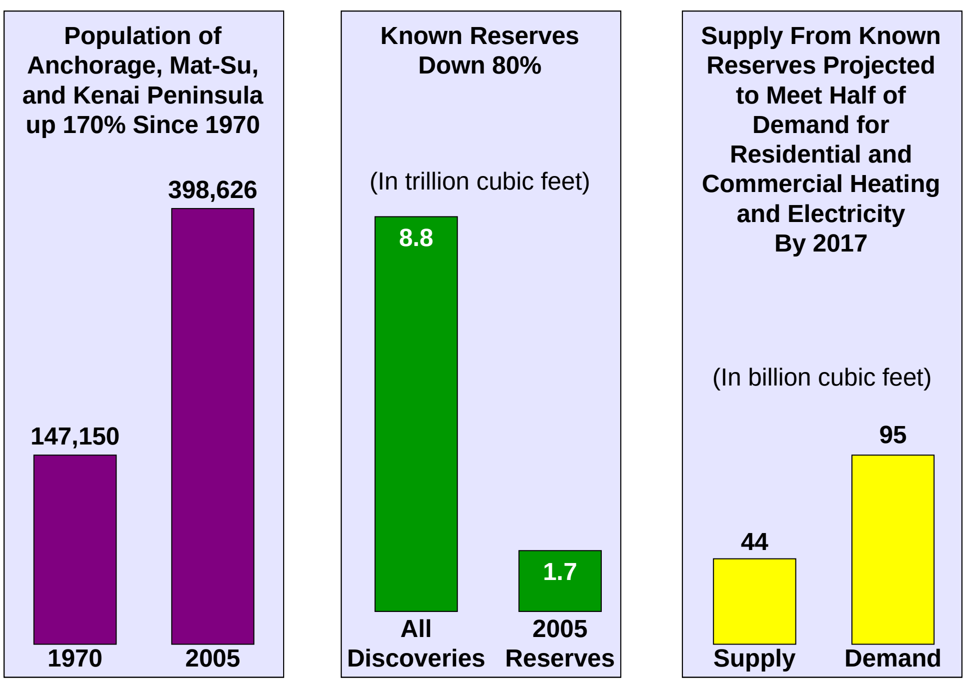
Issue	Description
Historical Increase in Gas Prices	Railbelt residential and commercial customers are directly feeling the rise in natural gas prices that have occurred in recent years. These price increases are shown in Figure 3-4, which shows historical gas prices paid by Chugach. Figure 3-5 shows 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 very recently. With natural gas prices expected to continue increasing, Railbelt consumers and businesses will experience even greater electric prices in the future.
Potential Gas Supplies and Prices	Regardless of the future source of additional natural gas supplies (whether new gas supplies from the Cook Inlet, gas from the North Slope, or imported LNG supplies), 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 and development. 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 Line 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 3-2
Chugach's Reliance on Natural Gas



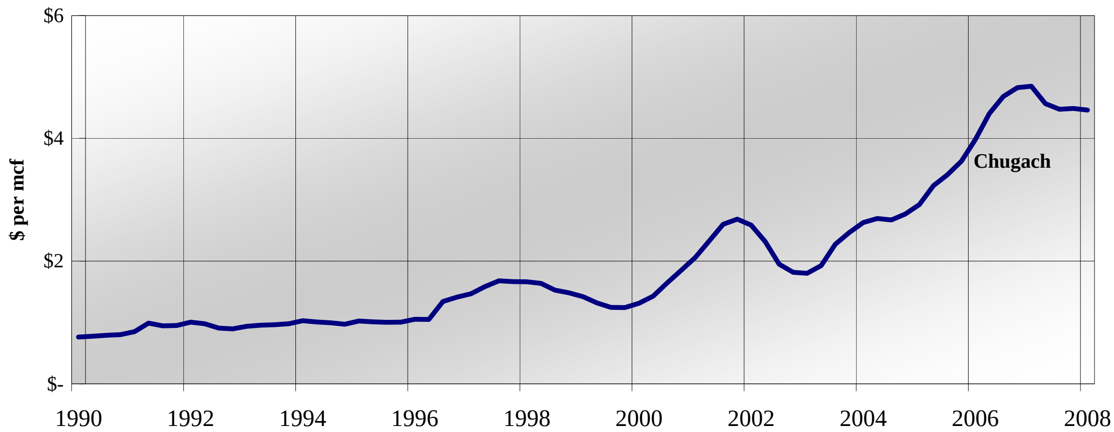
Total Power Produced in 2007: 2,628 gWh
Source: Chugach Electric Association.

Figure 3-3
Overview of Cook Inlet Gas Situation



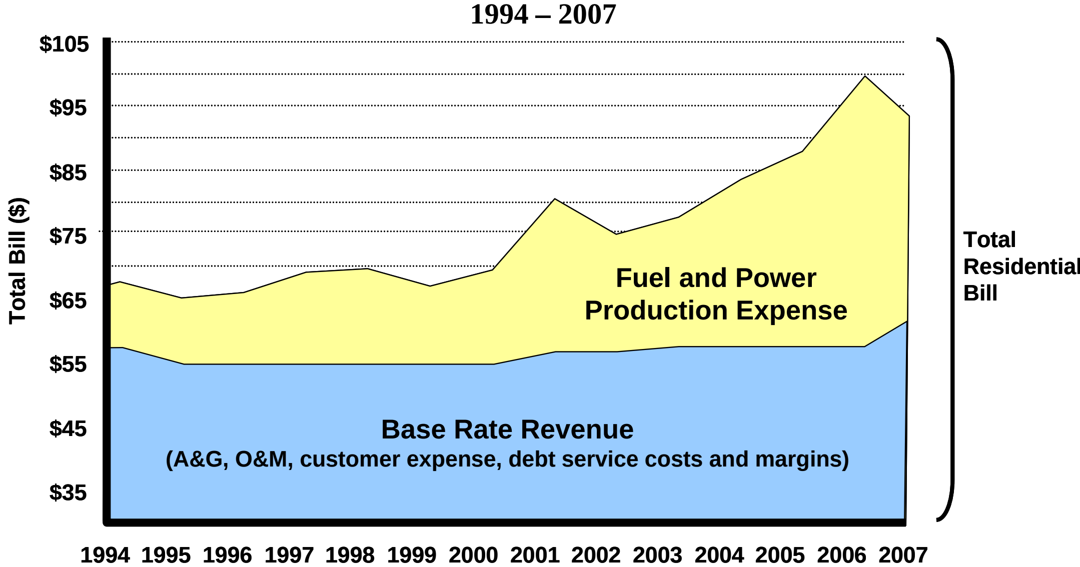
Source: Alaska Department of Labor, Alaska Division of Oil and Gas, and Science Applications International Corporation.

Figure 3-4
Historical Chugach Natural Gas Prices Paid



Source: Chugach Electric Association.

Figure 3-5
Chugach Residential Bills Based on 700 kWh Consumption
1994 – 2007



Source: Chugach Electric Association.

3.4 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 or the enactment of policies that would result in increased electric loads (e.g., gas to electric fuel switching, electric vehicles, etc.). Additionally, there will likely be a significant increase in Railbelt population if the proposed North Slope natural gas pipeline, and or the Spur Line 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.

3.5 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 67 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, which is offset by the lower cost of generation with better heat rates or when plants incorporate lower fuel cost resources.
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 costs and heat rate, the combination of rising energy costs and more production from high heat rate units causes large increases in the cost of energy. 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 the expected life.

Issue	Description
Operating and Spinning Reserve Requirements	Railbelt reliability criteria 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.

3.6 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. 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, bills are currently working their way through the Federal legislative process, and additional bills may be introduced in the future. 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 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, and one of the primary reasons why this RIRP project was commissioned. 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 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.

Issue	Description
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 reflects, to a certain degree, 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 will create additional opportunities for renewables as part of the portfolio of resources. The issue of integrating technologies having variable outputs (i.e., non-dispatchable resources), such as wind and solar, into a fossil-fueled grid presents substantial operational challenges including the determination of the optimal level of these resources. Additionally, an important issue related to the implementation of renewables 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/EE 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/EE 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/EE programs are limited from the perspective of the Railbelt electric utilities. Notwithstanding this, additional opportunities do exist in this area. An implementation issue that needs to be addressed is whether the development and deployment of DSM/EE 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/EE programs that would be beneficial to both. This would create economies of scope for the region and reduce the delivery costs of DSM/EE programs.

3.7 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.

3.8 Risk Management Issues

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 ensure safe, reliable and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility.
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.
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.
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.

4.0 DESCRIPTION OF EXISTING SYSTEM

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. Detailed information on each existing generating unit is presented in Appendix C.

4.1 Existing Generating Resources

4.1.1 Anchorage Municipal Light & Power

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 and 2 are not available for normal dispatch, but are available if needed in an emergency. Unit 4 is dispatched on a normal, but infrequent basis. For this study, Units 1, 2, and 4 were not modeled. ML&P's other units provide approximately 280 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 Table 4-1.

Table 4-1
ML&P Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Anchorage ML&P – Plant 1	1[(1)]	Natural Gas	16.2	N/A
Anchorage ML&P – Plant 1	2[(1)]	Natural Gas	16.2	N/A
Anchorage ML&P – Plant 1	3	Natural Gas	32	2037
Anchorage ML&P – Plant 1	4[(1)]	Natural Gas	34.1	N/A
Anchorage ML&P – Plant 2	5	Natural Gas	37.4	2020
Anchorage ML&P – Plant 2	5/6	Natural Gas	49.2	2020
Anchorage ML&P – Plant 2	7	Natural Gas	81.8	2030
Anchorage ML&P – Plant 2	7/6	Natural Gas	109.5	2020
Anchorage ML&P – Plant 2	8	Natural Gas	87.6	2030
Anchorage ML&P – Plant 2	6	N/A	N/A	2030

[(1)]Denotes units not included in modeling for this study.

4.1.2 Chugach Electric Association

Chugach 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. Chugach has approximately 500 MW of generating capability. Chugach's existing thermal units are shown in Table 4-2.

Table 4-2
Chugach Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Bernice	2	Natural Gas	19	2014
Bernice	3	Natural Gas	25.5	2014
Bernice	4	Natural Gas	25.5	2014
Beluga	1	Natural Gas	17.5	2011
Beluga	2	Natural Gas	17.5	2011
Beluga	3	Natural Gas	66.5	2014
Beluga	5	Natural Gas	65	2017
Beluga	6	Natural Gas	82	2020
Beluga	6/8	Natural Gas	108.5	2014
Beluga	7	Natural Gas	82	2021
Beluga	7/8	Natural Gas	108.5	2014
International	1	Natural Gas	14	2011
International	2	Natural Gas	14	2011
International	3	Natural Gas	19	2012

4.1.3 Golden Valley Electric Association

GVEA's generating capability of 278 MW is supplied by four generating facilities. The Healy Power Plant is a 27 MW coal-fired unit located adjacent to the Usibelli Coal Mine. GVEA's 187 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 39 MW. The Delta Power Plant (DPP), formerly the Chena 6 Power Plant, can produce 26 MW. GVEA's existing thermal units are shown in Table 4-3.

Table 4-3
GVEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Zehnder	GT1	HAGO	19.2	2030
Zehnder	GT2	HAGO	19.6	2030
North Pole	GT1	HAGO	62.6	2017
North Pole	GT2	HAGO	60.6	2018
North Pole	GT3	NAPHTHA	51.3	2042
North Pole	ST4	STEAM	12	2042
Healy	ST1	COAL	27	2022
DPP	1	HAGO	25.8	2030

4.1.4 Homer Electric Association

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 42 MW. This unit is shown in Table 4-4.

Table 4-4
HEA Existing Thermal Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Retirement Date
Nikiski	1	Natural Gas	42.0	2026

4.1.5 Matanuska Electric Association

MEA does not have any existing thermal units.

4.1.6 Seward Electric System

The City of Seward currently has three diesel generators in operation, each with capacities of 2.5 MW, and one diesel generator with a capacity of 2.9 MW. In this study, these small existing diesel generators are not included since the City of Seward is a full requirements customer of Chugach and the existing diesels are mainly used for back-up.

4.1.7 Hydroelectric Resources

Currently, each of the utilities in the Railbelt region has full or partial ownership in existing hydroelectric generation facilities. The hydroelectric generation plants include Bradley Lake (a 120 MW hydroelectric plant that under normal conditions dispatches up to 90 MW and provides an additional 27 MW of spinning reserves), Eklutna Lake hydroelectric facility (maximum capacity of 40 MW), and Cooper Lake hydroelectric facility (20 MW of capacity). Table 4-5 gives the percent ownership, average annual energy, and capacity for each utility for each of the existing hydroelectric plants. In the existing system, hydroelectric capacity and energy allocations are based on percent ownership, but in the RIRP modeling runs, all hydroelectric generation is placed geographically such that capacity and energy enter the Railbelt system from the areas in which the projects are physically located. The annual and monthly energy is based on the average historical energy generated at each plant for the previous 9-10 years (depending on historical plant data provided) and is presented in Table 4-6.

Table 4-5
Railbelt Hydroelectric Generation Plants

	Bradley Lake[(1)]				Eklutna Lake			Cooper Lake		
Utility	Percent Allocation	Annual Energy (MWh)	Capacity (MW)	Spinning Reserves (MW)	Percent Allocation	Annual Energy (MWh)	Capacity (MW)	Percent Allocation	Annual Energy (MWh)	Capacity (MW)
MEA	13.8	54,383	12.4	3.7	16.7	26,056	6.7	0	0	0
HEA	12	47,289	10.8	3.2	0	0	0	0	0	0
CEA	30.4	119,800	27.4	8.2	30	46,806	12	100	41,342	20
GVEA	16.9	66,599	15.2	4.6	0	0	0	0	0	0
ML&P	25.9	102,066	23.3	7	53.3	83,159	21.3	0	0	0
SES	1	3,941	0.9	0.3	0	0	0	0	0	0
Total	**100**	**394,078**	**90**	**27**	**100**	**156,021**	**40**	**100**	**41,342**	**20**

[(1)]The values for capacity and spinning reserves represent normal operation. The plant has a nameplate capacity of 126 MW with a nominal rating of 120 MW.

Table 4-6
Hydroelectric Monthly and Annual Energy (MWh)

Month	Bradley Lake	Eklutna Lake	Cooper Lake
January	28,688	11,153	3,696
February	29,448	10,653	3,421
March	31,737	12,374	3,967
April	28,829	12,039	3,687
May	28,643	10,094	3,854
June	31,586	13,425	4,072
July	35,372	14,547	4,361
August	37,881	17,954	3,328
September	37,728	17,494	3,388
October	37,654	14,102	2,421
November	34,152	11,452	2,198
December	32,360	10,734	2,951
Total	**394,078**	**156,021**	**41,342**

4.1.8 Railbelt System

Table 4-7 shows the resulting total capacity for each utility within the Railbelt region.

Table 4-7
Railbelt Installed Capacity

Utility	Thermal Existing Capacity	Bradley Lake Capacity(1)	Eklutna Lake Capacity	Cooper Lake Capacity	Total
MEA	0	16.1	6.7	0	22.8
HEA	42	14.0	0	0	56.0
CEA	500.5	35.6	12	20	568.1
GVEA	278.1	19.8	0	0	297.9
ML&P	278.3	30.3	21.3	0	329.9
SES	0	1.2	0	0	1.2
Total	**1,098.9**	**117**	**40**	**20**	**1,275.9**

(1)The nameplate rating for Bradley Lake is 126 MW with 90 MW dispatchable and 27 MW available for spinning reserves under normal conditions.

4.2 Committed Generating Resources

Committed generating resources are generating units planned by the individual Railbelt utilities and which are considered committed for installation by the individual Railbelt utilities. Table 4-8 summarizes the cost and performance estimates for the committed units. The cost and performance information was either provided by the individual Railbelt utilities or estimated by Black & Veatch. Cost information is presented in 2009 dollars. The following subsections briefly describe each of the committed units. The committed units are not included in the Reference Case Scenarios; this is discussed further in Section 13.

4.2.1 Southcentral Power Project

The Southcentral Power Project, previously known as the South Central Alaska Power Project, is a 3x1 natural gas fired, combined cycle project that utilizes GE LM6000 combustion turbines for a total capacity of approximately 180 MW. Currently, the project is to be jointly owned by Chugach and ML&P with 70 percent of the capacity owned by Chugach and the remaining 30 percent to be owned by ML&P. For modeling purposes, the entire 180 MW is included in the Anchorage area, which is comprised of both Chugach's and ML&P's service areas. The capital cost for the Southcentral Power Project is approximately $370 million with an estimated 2013 commercial operation date. A significant portion of the cost of this unit has already been spent.

4.2.2 ML&P Units

ML&P plans to add two units to its system by 2014. The addition of these units will allow ML&P to retire some of its older, less efficient units. In 2012, ML&P plans to install a GE LM2500 simple cycle combustion turbine with an estimated output of 30 MW. The capital cost associated with this unit is estimated to be $43 million in 2009 dollars. ML&P also plans to construct a GE LM6000 combined cycle plant for commercial operation by 2014. The output of this plant is estimated at 58 MW. The capital cost associated with this project is approximately $95 million in 2009 dollars.

Table 4-8
Railbelt Committed Generating Resources[1]

Plant Name	Area	Capital Cost ($000)	Maximum Winter Capacity (MW)	Full Load Heat Rate (Btu/kWh)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Commercia l Online Date
Southcentral Power Project	Anchorage	370,000	180	7,091	4.29	15.38	2013
ML&P 2500 Simple Cycle	Anchorage	43,200	30	9,960	2.32	28.72	2012
MLP LM6000 Combined Cycle	Anchorage	95,200	58	7,091	2.32	26.45	2014
Healy Clean Coal Project	GVEA	95,000	50	11,090	8.44	79.53	2011/2014
HEA Aeroderivative	HEA	[2]	34	8,800	3.85	64.42	2014
HEA Frame	HEA	[2]	42	11,500	3.08	79.07	2014
Nikiski Upgrade	HEA	[2]	77 (34 incremental)	10,000	2.91	4.83	2012
Eklutna Generation Station	MEA	356,000	187	8,500	4.29	15.38	2015
Seward Diesel #N1	City of Seward	7,200	2.9	9,200	11.41	31.93	2010
Seward Diesel #N2	City of Seward	1,100	2.5	9,200	11.41	31.93	2011

[1] 2009 dollars
[2]HEA has requested that their cost estimates remain confidential while they are obtaining their bids.

4.2.3 Healy Clean Coal Project

The Healy Clean Coal Project (HCCP) resulted from a nationwide competition held by the Department of Energy (DOE) to address the issues surrounding acid rain. The project is located adjacent to Golden Valley's current Healy 1 coal-fired power plant. HCCP utilizes a staged combustion process and other methods to minimize the formation of nitrogen and sulfur oxides. Construction and testing of the project was completed in December 1999, but issues were raised concerning the operations and maintenance cost, reliability, and safety of the project[1].

After several years of legal disputes, an agreement was reached for the sale of HCCP to GVEA. GVEA will pay $50 million for the plant "as is" and will have a line of credit up to $45 million to get the unit operating up to GVEA's standards and to integrate the plant into its system. For the RIRP, Black & Veatch has assumed the entire $95 million will be paid by GVEA. The project has an assumed commercial on-line date of 2011, but is expected to have poor reliability initially. GVEA will back up 100 percent of the plant's output with spinning reserve and its battery energy storage system (BESS) until plant reliability improves and settles by 2014. For modeling purposes, Black & Veatch has assumed a 50 percent forced outage rate for HCCP beginning in 2011 and decreasing linearly to the steady state forced outage rate of 3 percent in 2014. Because the HCCP is currently built, it is considered as an alternative in all the model runs except for the committed units case, where it is forced in along with the other committed units in this section.

4.2.4 HEA Units

Currently, HEA is an all requirements customer of Chugach in that they receive all of their electric needs from Chugach. The existing agreement expires in 2014 at which time HEA plans to supply its own load. In order to reliably serve its customers at that time, HEA must have generation built or supply contracts to support its service area. HEA has indicated plans to upgrade one of its existing units and build two new units before becoming independent. In 2012, HEA plans to complete an upgrade of its existing Nikiski unit from simple cycle to a combined cycle configuration. The upgrade would add 34 MW to the power plant and bring the plant's capacity from 43 MW to 77 MW. HEA is also planning to construct a new simple cycle aeroderivative unit in 2014 with approximately 34 MW of capacity. HEA may purchase reserves instead of installing the aeroderivative. Also in 2014, HEA plans to build a simple cycle frame unit with approximately 42 MW of capacity.

4.2.5 MEA Units

In a situation similar to that of HEA, MEA is currently an all requirements customer of Chugach and plans to be responsible for supplying their own load by 2015. In order to provide reliable service to MEA's customers, it must plan to build generation at that time. Currently, MEA's only source of power generation is the Eklutna hydroelectric power plant. MEA plans to build the Eklutna Generation Station in 2015 with an estimated 180 MW of natural gas fired capacity. Since the project is in the early stages of conceptualization, much of the unit's performance and cost information have been estimated by Black & Veatch and is similar to that of the Southcentral Power Project. The capital cost for this project was developed using the same $/kW amount as the Southcentral Power Project and is estimated at $370 million in 2009 dollars.

4.2.6 City of Seward Diesels

The City of Seward currently has four diesel generators in operation totaling approximately 10 MW. Although these four generators have not been included in the existing RIRP modeling, the City of Seward's future diesel generators are being included in the committed units sensitivity case. The existing diesels were not included because Seward is a full requirements customer of Chugach and the existing diesels are primarily used for back-up. Seward plans to install two more diesel generators in 2010 and 2011. Generator #N1 is

[1] http://www.aidea.org/PDF%20files/HCCP/HCCPFactSheet.pdf.

scheduled to be installed in the spring 2010 with an output of 2.9 MW. The capital cost for #N1 is estimated at $7.2 million in 2009 dollars. Generator #N2 is scheduled to be installed in the spring 2011 with an output of 2.5 MW. Generator #N2 currently exists, but is not connected to the City of Seward's electrical system. The estimated cost for bringing #N2 to operation and for interconnection is $1.0 million in 2009 dollars.

4.3 Existing Transmission Grid

For purposes of the RIRP study, the Railbelt transmission system is separated into four main load centers: GVEA or the interior, MEA, Anchorage comprised of Chugach's and ML&P's service areas, and the Kenai comprised of HEA and the City of Seward. Within each load center, energy is assumed to flow freely without transmission constraints. The existing transmission system of the Railbelt may be characterized as weak and in need of development. Power transfer between areas of the system is currently constrained by weak transmission links and stability constraints. Generating reserves cannot be readily shared between areas and project development activities are seriously affected.

GVEA's service area is connected with 138 kV lines that supply Delta Junction, Fairbanks, and Healy.

The interior and MEA 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 connecting the Douglas and Healy substations. The Healy-Fairbanks transmission line is a 230 kV, 90-mile transmission line, operated at 138 kV, and runs from the Healy to the Wilson substations which deliver 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 MEA load center. The current transfer capability of the Alaska Intertie and Healy-Fairbanks transmission lines is assumed to be 75 MW and 140 MW, respectively.

MEA serves customers down the southern half of the intertie and south of the intertie through the towns of Wasilla and Palmer.

The Anchorage load center consists of ML&P's, and Chugach's service territories. ML&P serves the load of the residents and businesses in the central core of Anchorage. Chugach also serves residents and businesses in Anchorage along with the area south of Anchorage, the City of Seward, and into the southern portion of the Kenai Peninsula. For modeling purposes, the City of Seward's load and generation have been placed in the Kenai peninsula to allow economic commitment and dispatch in accordance with GRETC.

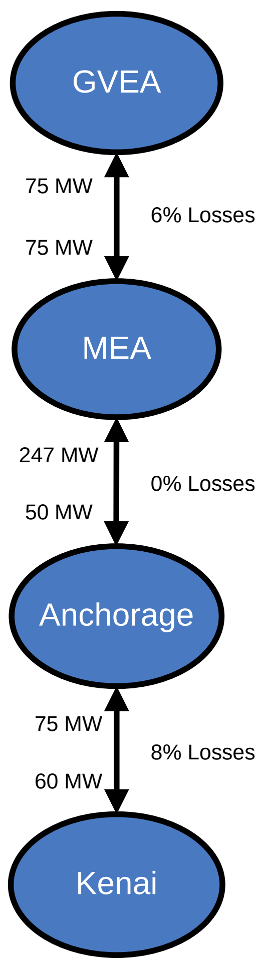
The MEA and Anchorage load centers are connected via two transmission lines. A 230 kV transmission line connects the Teeland substation to Chugach's Beluga plant in the western portion of the Anchorage load center. A 115 kV transmission line connects the Eklutna Hydro Project and runs through ML&P's area, continuing into Chugach's service territory. The current total transfer capability of these lines is assumed to be 250 MW when power is flowing north into MEA and 50 MW when power is flowing south into Anchorage.

The Anchorage and Kenai load centers are connected via a 135-mile, 115 kV transmission line, referred to as the "Southern Intertie," which connects the Chugach system to that of the Kenai Peninsula. The current transfer capability of the Southern Intertie is assumed to be 75 MW when power is flowing north to Anchorage, and 60 MW when the flow is south into the Kenai.

The Kenai load center consists of HEA's and the City of Seward's service territories. The HEA service area includes the cities of Homer and Soldotna.

Figure 4-1 shows the current Railbelt transmission transfer paths, four load centers, and existing transfer capability as modeled. Transfer capability varies depending on generating unit availability and performance as well as on direction of power flow between the areas. The transfer capabilities shown in Figure 4-1 represent the total MW transferable between the respective areas in the indicated direction with no transmission criteria violated. Major generating project additions requiring interconnection to the system are modeled as specific additional areas to appropriately account for transmission losses. Projects that require such areas are Susitna and Chakachamna hydroelectric, Mt. Spurr geothermal, and Turnagain Arm tidal. As transmission lines are added to the system throughout the planning period, transfer capabilities and transmission losses are modified.

Figure 4-1
Railbelt Existing Transmission System as Modeled



4.3.1 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 Seldovia in the south. 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, Chugach, GVEA, and AEG&T Cooperative, Inc., which is comprised of HEA and MEA. 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 Chugach. 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 as shown in Table 4-5. 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. In practice, however, the GVEA's power from Bradley Lake is displaced by power sold by Chugach to HEA and Seward.

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 the 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 spinning reserve to preserve the reliability of electrical supply throughout the network.

4.3.2 Southern Intertie

The Southern Intertie consists of approximately 130 miles of 115 kV transmission line constructed some 50 years ago that connects the Anchorage area operated by the Chugach, and the Kenai peninsula operated by HEA. The Southern Intertie connects the Soldotna substation and the University substation by way of Quartz Creek, Daves Creek and several other load serving taps between Daves Creek and the University substation. The section from Soldotna to Quartz Creek is owned and operated by HEA while the section from Daves Creek to the University substation is owned and operated by Chugach.

The HEA section of the Southern Intertie is in poor condition, routed through swampy terrain, and is consequently affected by frost jacking which pushes the poles out of the ground. The Chugach section of the intertie runs through areas susceptible to frequent avalanches. Several sections have been rebuilt; however, over 60 percent of the line's structures are in need of repairs. Although the thermal limit of the 115 kV line is considered to be approximately 145 MW, this intertie is limited to a transfer limit of approximately 75 MW by stability considerations. The intertie is currently used to transfer power from the jointly owned Bradley Lake Hydro Units to utilities in the Anchorage area. This line is considered essential to the development and operation of an integrated Railbelt transmission system.

4.3.3 Transmission Losses

Existing transmission losses have been modeled between the four major load centers. The percentage of losses varies with the load on the transmission lines. Losses for each of the connections between the four load centers that are included in the models are illustrated in Figure 4-1 and represent a percentage of the total flow along the lines. The losses shown represent the losses applied to power flowing both north and south.

4.4 Must Run Capacity

Must run capacity are units that are run to maintain the reliability of the Railbelt system regardless of whether they are the most economical generation available. Must run capacity can also result from purchase power contracts which require the utility to purchase the power at all times. Additionally, must run capacity can result from a generating unit not having the capability to be shutdown and started up in response to economic commitment and dispatch. Units are also required to run to maintain voltage and stability. The Railbelt Utilities have indicated the following three units are current must run capacity units and have been modeled as such.

- Nikiski through 2013
- Healy 1
- Aurora Purchase Power

5.0 ECONOMIC PARAMETERS

The economic parameters are those necessary for developing the expansion plans using Strategist® and determining the costs associated with those expansion plans. They include inflation, escalation, financing, present worth discount rate, interest during construction interest rate, and development of fixed charge rates.

5.1 Inflation and Escalation Rates

Escalation rates have been developed for capital and O&M costs and are consistent with the general inflation rate. The same general inflation rate and escalation rates were used for all Railbelt utilities. For evaluation purposes, 2.5 percent was used for annual general inflation and escalation.

5.2 Financing Rates

The cost of capital was assumed to be 7 percent.

5.3 Present Worth Discount Rate

The present worth discount rate was assumed to be equal to the cost of capital, of 7 percent.

5.4 Interest During Construction Interest Rate

The interest during construction interest rate was assumed to be 7 percent.

5.5 Fixed Charge Rates

Fixed charge rates were developed for new capital additions based on the cost of capital. The fixed charge rates were based on the assumption of using taxable financing, and further assumed 100 percent debt. In developing financing assumptions, Seattle Northwest Securities Corporation was consulted and a general consensus developed for purposes of estimating the cost of capital for evaluation purposes.

The fixed charge rates include the following components in addition to debt amortization:

- Issuance costs for debt - 2 percent
- Property insurance - 0.5 percent
- Property taxes - 0.5 percent
- Debt service reserve funds - 1 year
- Earnings on reserve funds - 7 percent

Levelized fixed charge rates were developed for the following financing terms as appropriate. Table 5-1 summarizes these terms as modeled for the GRETC system:

- Simple Cycle Combustion Turbines - 25 years
- Combined Cycle Units - 30 years
- Coal Units - 30 years
- Hydro Units - 100 years
- Wind - 20 years
- Municipal Solid Waste – 30 years
- Tidal - 20 years
- Geothermal - 25 years
- Generic Greenfield Nuclear - 30 years

Table 5-1
Cost of Capital and Fixed Charge Rates for the GRETC System

Cost of Capital (%)	Levelized Fixed Charge Rates (%) Financing Terms (Years)			
	20	25	30	100
7.0	10.543	9.536	8.925	8.163

The fixed charge rates were used for Strategist® to ensure that all alternatives for expansion plans were selected on a consistent basis. The 100-year term for hydro units, while longer than traditional financing, was selected based on the long life span of hydro units so that hydro units would be considered on this consistent basis by Strategist®.

6.0 FORECAST OF ELECTRICAL DEMAND AND CONSUMPTION

6.1 Load Forecasts

Load forecasts were provided by the utilities in response to a Black & Veatch data request. Since the RIRP Study has a 50-year planning horizon, load forecast data was extrapolated through 2060. The load forecast does not include incremental DSM/EE programs not inherently included in the utilities' forecasts.

6.2 Load Forecasting Methodology

Each of the utilities provided load forecasts spanning different lengths of time that required extrapolation to develop annual peak and energy requirements for the GRETC electrical system over the 50-year study period. Typically, simple extrapolation of load forecasts is based on exponential growth by using the average annual percentage growth rate for the last 5 or 10 years. This potentially can lead to over forecasting when these percentage growth rates are applied over long periods of time. To compensate for this potential over forecasting, Black & Veatch extrapolated the load forecasts in two different ways and took the average of the two extrapolated forecasts as the forecast used in the RIRP. The first method of extrapolation was the typical approach of extrapolating at the average annual percentage load growth over the last 10 years of the forecast. The second method extrapolated the average annual increase in load over the last 10 years of the forecast. In addition to peak load forecasts, annual minimum load, or valley, forecasts were also developed for the GRETC system. The peak and valley demand and net energy for load requirements forecasts are provided in the following subsection; it should be noted that demand and energy forecasts do not include transmission losses between utilities.

6.3 Peak Demand and Net Energy for Load Requirements

Tables 6-1 and 6-2 present the winter and summer peak demand forecasts for each utility as well as the coincident winter and summer peak demands for the GRETC system. The coincident peak demand forecasts were developed by combining all of the utilities' hourly load profiles for 2008 and calculating the 2008 coincident peak demands. The resulting coincident peak demands were compared to the 2008 non-coincident peak demands to develop coincident factors. These factors were applied seasonally to the noncoincident peak demand for both winter and summer months of the study period to develop the resulting coincident peak demand forecasts for the GRETC system.

Table 6-3 presents the annual valley demand forecasts for each utility and the coincident valley demands for the GRETC system. The valley demand forecasts for each utility were developed by taking the minimum load for each utility from the provided hourly load information for 2008. Valley demand forecasts for 2011 and beyond were calculated for each utility by applying the annual increase in peak demands to the valleys. A non-coincident value was calculated by summing up the minimum load for each utility and the result was compared to the coincident minimum load value for the GRETC system that was developed by taking the minimum load from the GRETC hourly profile to develop a valley coincident factor. The resulting valley coincident factor was applied to the annual non-coincident valley load for the GRETC system to develop a coincident valley demand forecast through 2060.

The net energy for load requirements for the GRETC system were developed by taking the sum of all the utilities' individual energy requirements. The resulting net energy for load forecast is provided in Table 6-4.

Table 6-1
GRETC's Winter Peak Load Forecast for Evaluation (MW)
2011 - 2060

Year	Winter Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	233.9	238.1	87.0	146.0	188.0	9.5	869.3
2015	234.5	217.5	89.0	157.0	192.0	10.4	867.8
2020	238.1	226.0	92.0	167.0	197.0	10.4	896.3
2025	242.2	234.3	96.0	178.0	202.0	10.4	927.5
2030	246.9	242.8	100.0	188.0	207.0	10.4	959.0
2035	251.6	251.5	104.0	199.0	212.1	10.4	991.2
2040	256.3	260.3	108.1	210.4	217.2	10.4	1,024.1
2045	261.1	269.2	112.3	222.1	222.5	10.4	1,057.7
2050	265.9	278.4	116.5	234.2	227.7	10.4	1,092.0
2055	270.7	287.7	120.9	246.8	233.1	10.4	1,127.1
2060	275.7	297.3	125.4	259.7	238.5	10.4	1,163.0

Table 6-2
GRETC's Summer Peak Load Forecast for Evaluation (MW)
2011 - 2060

Year	Summer Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	160.6	191.4	75.1	91.1	167.2	10.0	668.0
2015	161.3	174.8	76.8	95.5	170.8	11.0	666.8
2020	163.4	181.6	79.4	95.0	175.2	11.0	688.7
2025	166.3	188.3	82.8	99.9	179.7	11.0	712.7
2030	169.9	195.2	86.3	105.9	184.1	11.0	736.9
2035	173.1	202.1	89.7	112.5	188.7	11.0	761.6
2040	176.3	209.2	93.3	119.3	193.2	11.3	786.9
2045	179.6	216.4	96.9	126.4	197.9	11.6	812.7
2050	182.9	223.8	100.5	133.7	202.6	11.9	839.1
2055	186.3	231.3	104.3	141.3	207.3	12.2	866.0
2060	189.6	238.9	108.2	149.1	212.2	12.5	893.6

Table 6-3
GRETC's Annual Valley Load Forecast for Evaluation (MW)
2011 - 2060

Year	Annual Valley Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	95.4	88.6	44.4	53.2	91.0	4.4	413.5
2015	95.8	81.0	45.5	57.2	92.9	4.8	413.7
2020	97.1	84.1	47.0	60.9	95.3	4.8	426.9
2025	98.8	87.2	49.0	64.9	97.7	4.8	441.4
2030	100.9	90.4	51.1	68.5	100.2	4.8	456.1
2035	102.8	93.6	53.1	72.6	102.6	4.8	471.1
2040	104.8	96.9	55.2	76.7	105.1	4.8	486.4
2045	106.7	100.2	57.3	81.0	107.6	4.8	502.0
2050	108.7	103.6	59.5	85.4	110.2	4.8	517.9
2055	110.7	107.1	61.7	90.0	112.8	4.8	534.2
2060	112.7	110.7	64.0	94.7	115.4	4.8	550.9

Table 6-4
GRETC's Net Energy for Load Forecast for Evaluation (GWh)
2011 - 2060

Year	Utility Net Energy for Load Forecast (GWh)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	1,302.0	1,522.7	554.5	771.2	1,162.8	64.6	5,377.8
2015	1,311.4	1,333.5	568.1	831.9	1,184.9	65.6	5,295.3
2020	1,334.5	1,373.4	591.2	888.3	1,213.0	67.4	5,467.8
2025	1,359.2	1,403.8	615.5	946.4	1,241.7	69.3	5,636.0
2030	1,384.5	1,434.7	640.0	1,004.7	1,271.2	71.2	5,806.3
2035	1,409.9	1,465.7	665.1	1,065.4	1,300.9	73.1	5,980.1
2040	1,435.5	1,497.1	690.7	1,128.1	1,330.9	75.1	6,157.4
2045	1,461.4	1,528.9	716.8	1,192.9	1,361.3	77.1	6,338.4
2050	1,487.5	1,561.1	743.5	1,259.9	1,392.1	79.1	6,523.2
2055	1,513.9	1,593.6	770.8	1,329.4	1,423.2	81.1	6,712.0
2060	1,540.5	1,626.5	798.7	1,401.4	1,454.7	83.2	6,905.0

The GRETC peak demand is projected to increase at an average annual rate of 0.6 percent and average annual GRETC system energy is projected to increase at 0.5 percent.

Appendix D presents the annual forecasts for winter and summer peak demand, system valley, and net energy for load.

6.4 Significant Opportunities for Increased Loads

As discussed in Section 2, a scenario representing a significant increase in load was evaluated in addition to the base case load forecast. This section evaluates some potential increases in load that could lead to the large increase in load scenario; Black & Veatch is not predicting that these additional loads will occur (such prediction is outside of the scope of this project) but, rather, offers this discussion to illustrate some of the ways that the regional load could increase significantly.

6.4.1 Plug-In Hybrid Vehicles

Energy security and climate change issues are driving change in the transportation sector now more than ever. With the potential of carbon legislation and the possibility of high gasoline prices returning , there is an increased need to consider new advanced technology vehicles that hold the promise of considerably improving fleet energy efficiency and reducing fleet carbon footprint, such as plug-in hybrid vehicles (PHEV).

According to a recent study conducted by the Transportation Research Institute at University of Michigan (UMTRI)[1], fleet penetration of PHEVs is expected to reach 1 percent of the national market by 2015, 2 percent by 2020, and 16 percent by 2040 (Table 6-5). Since these vehicles cost a lot more than their conventional counterparts, especially in the near term, their market viability depends heavily on government subsidies and incentives. This study assumes that appropriate government policy initiatives were instituted to enable successful market penetration. Market penetration estimates from an ORNL study[2] predict that nationwide penetration will not surpass 25 percent (Table 6-5).

Table 6-5
Projected PHEV Penetration in the American Auto Market

Year	PHEV Penetration (%)
2015	1
2020	2
2040	16
2060	25

[1] “PHEV Marketplace Penetration: An Agent Based Simulation;” Sullivan, Salmeen, and Simon; July 2009.
[2] “Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation;” Hadley and Tsvetkova; January 2008.

Given that the Alaska Railbelt region had 53 percent of all vehicles in the state in 2008 (338,943)[3], that the average daily personal vehicle travel in the Alaska Railbelt area is 32 miles/day[4], and that the average PHEV33 (a vehicle capable of running 33 miles on a single charge) requires 0.35 kWh of energy per mile[5] (Table 6-6), it is assumed the Alaska Railbelt region could experience an increase in annual energy as shown in Table 6-7.

Table 6-6
Electric Consumption for a PHEV33 PNNL Kinter-Meyer

Vehicle Class	Specific Energy Requirements (kWh/mile)
Compact Sedan	0.26
Mid-size Sedan	0.30
Mid-size SUV	0.38
Full-size SUV	0.46
Average	**0.35**

Table 6-7
Additional Annual Energy Required in the Alaska Railbelt Region from PHEVs

Year	Additional Load from PHEVs (MWh/year)
2015	14,736
2020	31,242
2040	327,489
2060	679,391

PHEVs can be plugged in and recharged when they are not on the road, which according to Figure 6-1 occurs in the late evening or early morning.

Consistent with the previous observation, a study conducted by EPRI/NRDC assumed that 70 percent of the charging would occur “off-peak,” when electric demand is relatively low (Figure 6-2). Rate designs, such as night rates, and time-of-use rates, could provide electric customers with incentives to utilize “off-peak” charging.

[3] Registered vehicles in 2008, including only pickups and passenger vehicles. Division of Motor Vehicles from the Alaska Department of Administration.
[4] From interviews to local car insurance companies conducted by NORECON.
[5] Pacific Northwest National Laboratory (PNNL). Kinter-Meyer.

Figure 6-1
US Daily Driving Patterns

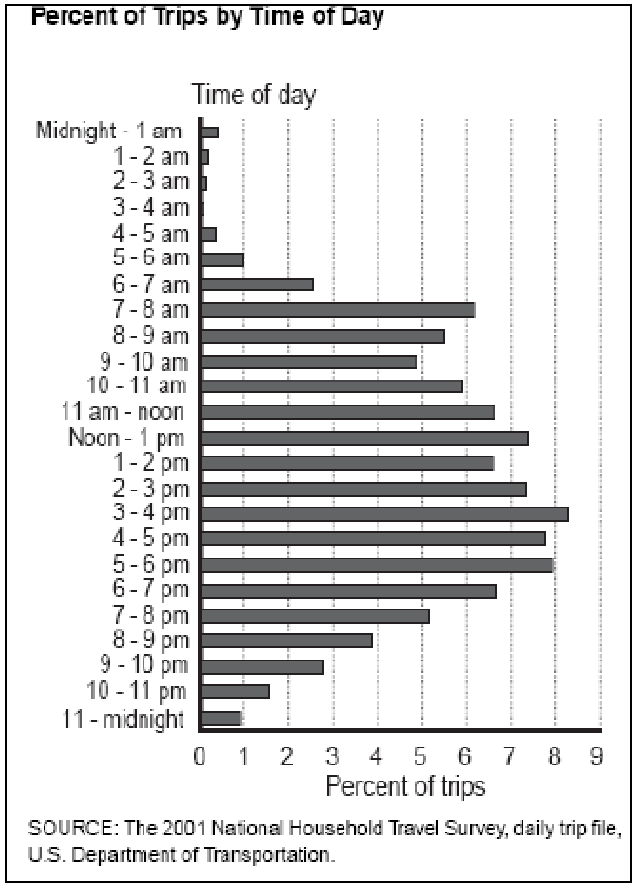


Figure 6-2
PHEV Daily Charging Availability Profile

Table 6-8 and Figure 6-3 show how the extra load from PHEVs would likely be distributed on a typical day.

This high penetration of PHEVs scenario has the potential to increase the energy requirement of the Alaska Railbelt system by as much as 9.8 percent in 2060. Figure 6-4 and Table 6-9 illustrate these impacts.

This high penetration of PHEVs scenario has the potential to increase the peak demand of the Alaska Railbelt system by as much as 5.5 percent in 2060. There would also be a shift in the peak hour from the 18th hour to the 22nd hour of the peak day by 2060. Figure 6-5 and Table 6-10 illustrate these impacts.

Table 6-8
Hourly Distribution of PHEV Load on a Typical Day – Alaska Railbelt Region

Hour of Day	Charging Fraction (%)	Typical Day Hourly Load (MW)				
		2010	2015	2020	2040	2060
1	10	0	4.0	8.6	89.7	186.1
2	10	0	4.0	8.6	89.7	186.1
3	9	0	3.6	7.7	80.8	167.5
4	6	0	2.4	5.1	53.8	111.7
5	4	0	1.6	3.4	35.9	74.5
6	2	0	0.8	1.7	17.9	37.2
7	1	0	0.4	0.9	9.0	18.6
8	0.5	0	0.2	0.4	4.5	9.3
9	0.5	0	0.2	0.4	4.5	9.3
10	1.5	0	0.6	1.3	13.5	27.9
11	2.5	0	1.0	2.1	22.4	46.5
12	2.5	0	1.0	2.1	22.4	46.5
13	2.5	0	1.0	2.1	22.4	46.5
14	2.5	0	1.0	2.1	22.4	46.5
15	2.5	0	1.0	2.1	22.4	46.5
16	1	0	0.4	0.9	9.0	18.6
17	0.5	0	0.2	0.4	4.5	9.3
18	0.5	0	0.2	0.4	4.5	9.3
19	2	0	0.8	1.7	17.9	37.2
20	4	0	1.6	3.4	35.9	74.5
21	6	0	2.4	5.1	53.8	111.7
22	9	0	3.6	7.7	80.8	167.5
23	10	0	4.0	8.6	89.7	186.1
24	10	0	4.0	8.6	89.7	186.1
Total	**100**	**0**	**40**	**86**	**897**	**1,861**

Figure 6-3
Hourly Distribution of PHEV Load on a Typical Day – Alaska Railbelt Region

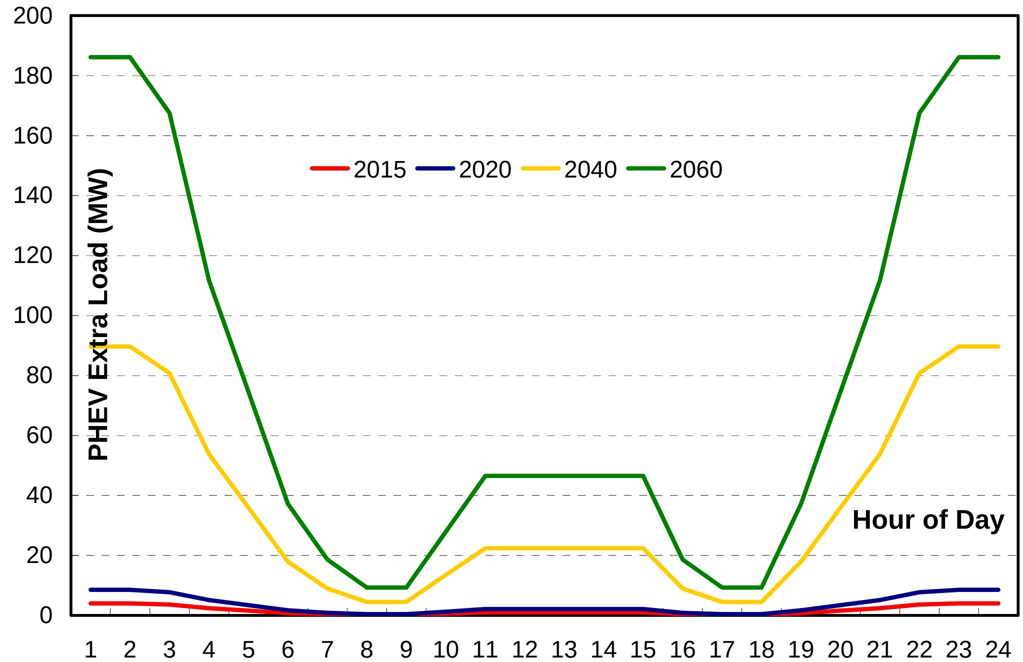


Figure 6-4
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Energy Requirement

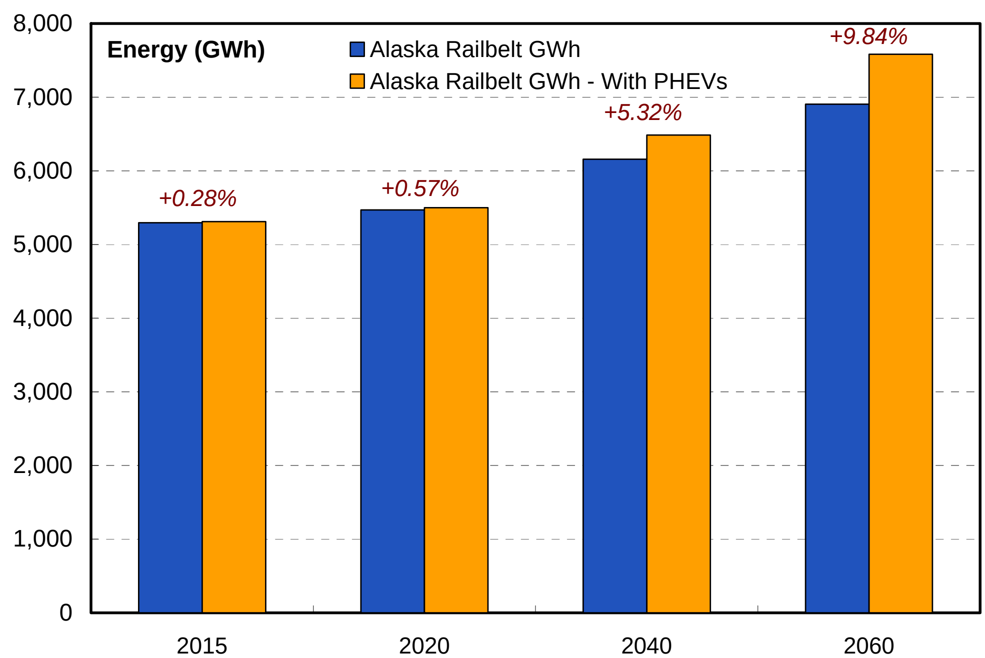


Table 6-9
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Energy Requirement

	2015	2020	2040	2060
Alaska Railbelt GWh	5,295	5,468	6,157	6,905
Alaska Railbelt GWh - With PHEVs	5,310	5,499	6,484	7,584
Percent Increase	0.28	0.57	5.32	9.84

Figure 6-5
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Peak Demand

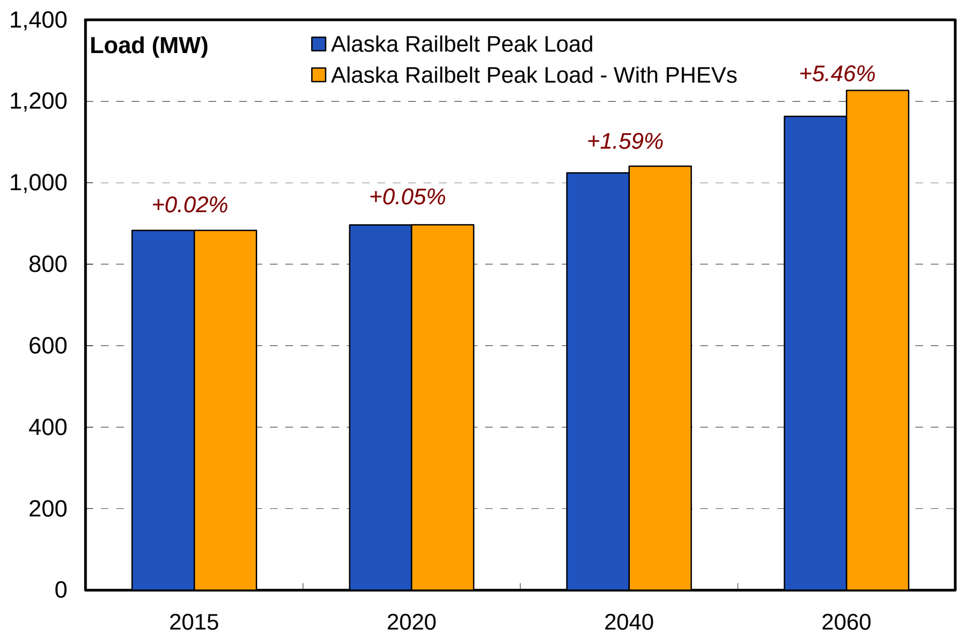


Table 6-10
Impact of a High PHEV Penetration Scenario Over the Alaska Railbelt System's Peak Demand

	2015	2020	2040	2060
Alaska Railbelt Peak Load	882.70	896.30	1,024.10	1,163.00
Alaska Railbelt Peak Load - With PHEVs	882.90	896.73	1,040.36	1,226.45
Percent Increase	0.02	0.05	1.59	5.46
Peak Hour	18	18	20	22

6.4.2 Electric Space and Water Heating Load

Another means of significantly increasing electric demand within the region would to encourage increased penetration of electric space and water heating. ENSTAR Natural Gas is the primary supplier of natural gas within the State of Alaska along with Barrow Utilities Electric Coop and Fairbanks Natural Gas. Natural gas consumption within the State is almost evenly distributed between residential, commercial and industrial customers. The Energy Information Administration (EIA) publishes statistics on natural gas on an annual basis. Table 6-11 provides a summary of 2007 data for the state of Alaska.

Table 6-11
2007 Natural Gas Consumption for the State of Alaska (Source: EIA)

	Residential Customers	Commercial Customers	Industrial Customers
Natural Gas Delivered (MMcf)	19,840	18,760	19,750

For purposes of this discussion, it is assumed that 100 percent of the gas consumption within the State of Alaska applies to the Railbelt region, given that an estimated 97 percent or more of natural gas is consumed within the region. According to the American Gas Association, space and water heating accounts for approximately 85 percent of the natural gas application in the New England region for residential customers. It is assumed that a similar proportion is applicable to commercial customers. The percentage of industrial consumption related to space and water heating is negligible compared to other applications and, therefore, is not included in this study. Table 6-12 contains the calculated energy and demand if all residential and commercial space and water heating requirements were met through electricity, based on a 2007 heating value of 1,005 Btu/cf, published by the EIA for the State of Alaska. The energy and demand calculations assume that natural gas space and water heating are 85 percent efficient. Peak demand is based on the residential natural gas load factor for the state of 39 percent.

Table 6-12
Calculated Railbelt System Energy and Demand by Customer Type for Electric Space and Water Heating

	Residential Customers	Commercial Customers
Calculated Space and Water Heating Energy, MWh	4,222,640	3,991,324
Calculated Space and Water Heating Demand, MW	1,243	1,174

6.4.3 Economic Development Loads

Another opportunity for increased loads in the Railbelt is from large new industrial loads. Black &Veatch obtained a list of potential economic development projects from the Alaska Industrial Development & Export Authority (AIDEA) presented in Table 6-13, as well as possible areas in which they might be located. For purposes of this study, Chugach’s and ML&P’s service areas have been combined as the Anchorage area. For purposes of load forecasting, Interior loads were assumed to be in GVEA’s service area. Loads in the Kenai area were assumed as occurring in HEA’s area.

Table 6-13
Potential Economic Development Projects

Potential Project	Area Location	Size (MW)
Ore Processing Facility	Anchorage	300
Internet Server Facility	Anchorage	300
Coal Mine	Anchorage	50
Subtotal – Anchorage Area		**650**
Gold Mine	Interior	150
Mine	Interior	200
Subtotal - Interior		**350**
Nitrogen/Urea Facility	Kenai	50
Total		**1,050**

In addition to the loads identified in Table 6-13, the Pebble Mine is another potential large load estimated to be approximately 300 MW. While it appears likely that if it is developed, it will develop on-site power, there has been some consideration that it could be supplied by the Railbelt through HEA’s system. Other potential large loads could be from electric compressors for the proposed natural gas pipelines from the North Slope. Many of these compressors, however, would likely be remotely located.

It appears conceivable that a 1,000 MW of new load could potentially be developed in the Railbelt within the time frame of this study. Such new load would likely require specific policies to be implemented whether if from fuel switching or large industrial loads. For the purposes of creating a load forecast for the large load scenarios, new loads of 500 MW will be added in both 2025 and 2040, with 350 MW of each addition of new load being assumed in the Anchorage area and 150 MW of the new load being assumed in the Interior. For load forecasting purposes, the new load was assumed to have a 75 percent load factor. Tables 6-14 and 6-15 present the winter peak demand and net energy for load forecasts for the large load scenarios. Annual forecasts for the large load scenario are presented in Appendix D.

Table 6-14
GRETC's Winter Peak Large Load Forecast for Evaluation (MW)
2011 - 2060

Year	Large Load Winter Peak Demand (MW)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	238.1	412.2	146.0	96.3	869.3
2015	217.5	417.1	157.0	99.2	867.8
2020	226.0	425.1	167.0	102.2	896.3
2025	384.3	734.0	178.0	156.2	1,398.3
2030	392.8	744.0	188.0	160.1	1,429.5
2035	401.5	753.5	199.0	164.1	1,461.4
2040	560.3	1063.2	210.4	218.5	1,975.7
2045	569.2	1072.9	222.1	222.9	2,009.3
2050	578.4	1082.8	234.2	227.4	2,043.6
2055	587.7	1092.8	246.8	232.1	2,078.8
2060	597.3	1102.9	259.7	236.8	2,114.7

Table 6-15
GRETC's Large Load Net Energy for Load Forecast for Evaluation (GWh)
2011 - 2060

Year	Utility Large Load Net Energy for Load Forecast (GWh)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	1522.7	2464.8	771.2	619.1	5,377.8
2015	1333.5	2496.2	831.9	633.7	5,295.3
2020	1373.4	2547.4	888.3	658.6	5,467.8
2025	2389.3	4572.0	946.4	1013.3	8,921.0
2030	2420.2	4626.7	1,004.7	1039.7	9,091.3
2035	2451.2	4681.8	1,065.4	1066.7	9,265.1
2040	3473.5	6719.2	1,128.1	1424.6	12,745.4
2045	3499.9	6764.7	1,192.9	1450.9	12,908.4
2050	3532.1	6821.6	1,259.9	1479.6	13,093.2
2055	3564.6	6879.1	1,329.4	1508.9	13,282.0
2060	3602.9	6948.0	1,401.4	1540.7	13,493.0

7.0 FUEL AND EMISSIONS ALLOWANCE PRICE PROJECTIONS

7.1 Fuel Price Forecasts

7.1.1 Natural Gas Availability and Price Forecasts

7.1.1.1 Description of Risk-Based Assessment Methodology

Risk-based forecasts differ from other types of forecasts by acknowledging the element of chance in the way that multiple factors can combine to produce a range of outcomes. For example, there might be a 60 percent chance that a gas field will produce 150 million cubic feet per day (MMcf/d) in a given year but only a 20 percent chance that it will produce 200 MMcf/d. Likewise, a new gas pipeline might be 25 percent likely to begin flowing gas at 200 MMcf/d in a given year but 55 percent likely to begin flowing at 250 MMcf/d two years later. In both cases, an analysis is required to convert the best estimates of chance into a mathematical formula that will support a risk-based forecast of what the total gas supply might be in a given year if the gas field and pipeline were considered together in the range of possible outcomes.

For development of the RIRP, Black & Veatch's risk-based natural gas supply forecasts employed a model that considered performance prospects of each of several prospective gas sources and their variations over the 50-year planning horizon. The model was constructed using Palisade DecisionTools Professional 5.0 software. A decision-tree architecture was employed where each gas supply node was supported by a mathematical probability distribution function that described the node's annualized performance over the 50-year period. Monte Carlo methods were used to run gas supply simulations using alternative sets of assumptions about performance of each supply node. The purpose of the model was to run "what if" types of scenarios that would provide information about the aggregate supplies of gas in a specified year. The main gas sources included production from the Cook Inlet basin, importation of LNG from outside Alaska, and delivery of gas from the Alaska North Slope to the Railbelt by means of an instate pipeline. Variations among the model runs featured different sets of assumptions about the future capacity of Cook Inlet production, including possible enhancements, as well as the timing and volume throughput of LNG imports and the instate pipeline, respectively.

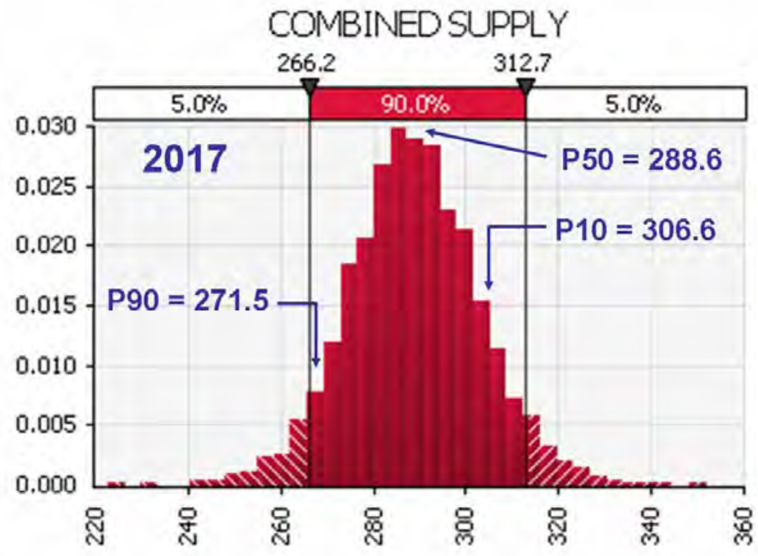
Model runs analyzed individual years for the decade of 2010-2019. For the years 2020-2060, model runs were made by five-year intervals (for example, 2020-2024, 2025-2029, etc.).

In evaluating results, attention was focused on probabilities for attainment of gas supplies at three benchmark levels:

- P90: Gas capacity achievable with 90% probability
- P50: Gas capacity achievable with 50% probability
- P10: Gas capacity achievable with 10% probability

Figure 7-1 illustrates the P90, P50 and P10 metrics from an actual gas supply model simulation. Clearly, as the gas capacity goes up, the probability for attaining that capacity goes down. Although conservatism might argue for using P90 values (the lowest of the three capacities) for all planning purposes, the P50 value is a reasonable choice for two primary reasons. First, P50 is easier to intuitively reference and visualize because it always falls near the middle of the range of possibilities. Second, P50 is the metric most comparable to "average expectation" forecasts that can be made with assumptions about average performance of gas sources where probabilities are ignored. Indeed, P50 supply was the metric chosen for the reference price forecast.

Figure 7-1
Results of a Risk-Based Gas Supply Model Simulation for the Year 2017



Results from the risk-based model forecasts comprised gas volumes, in annualized units of MMcf/d, that served as inputs into separate price forecasts. The price forecasts employed conventional methods from energy market analysis that used the interplay of supply and demand to predict a commodity value for gas that would be delivered at the Cook Inlet as if from the historical Cook Inlet gas production. Black & Veatch developed mathematical relationships for the commodity value using historical Alaska gas supply, gas demand and gas price data published by the U. S. Energy Information Administration as well as from additional research.

To that commodity value, estimated transportation costs were added for any volume of gas that was obtained from a non-local source; namely, LNG imports or the instate pipeline. Black & Veatch conducted research to estimate reasonable transportation costs. LNG costs were based on market knowledge of the Asia-Pacific Basin LNG markets. Pipeline costs were based on previously published studies of instate gas pipelines, both for stand-alone direct lines from the North Slope to the Anchorage area and for lateral lines from a large pipeline that might carry gas from the North Slope to Alberta, Canada.

The final price estimate, consisting of the commodity value and transportation adders, is equivalent to a "city gate" price that would be available to a high-volume buyer such as an electric utility or a gas distribution company. As used by the U. S. Energy Information Administration, a "city gate" price is the first point of sale for gas before it enters the wholesale markets. Ownership of gas beyond the "city gate" typically changes several times before it reaches residential consumers, with price increases at each change of ownership. Therefore, "city gate" prices are substantially lower that residential retail prices. Because the price forecasts used risk-based model gas supplies as input, separate prices were associated with P90, P50 and P10 supplies, respectively.

7.1.1.2 Gas Stakeholder Input Process

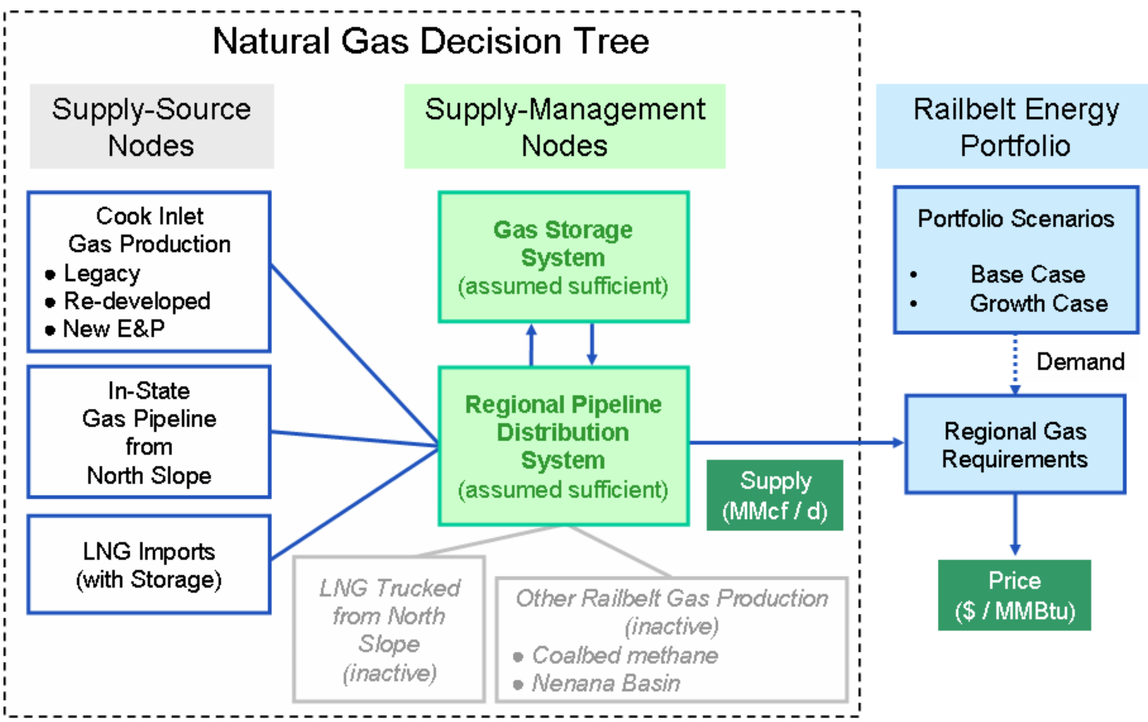
Black & Veatch conducted multiple rounds of reviews with numerous stakeholders to discuss the construction of the gas supply forecast model, as well as preliminary results for supply and price forecasts. These stakeholders included State of Alaska officials; technical specialists and executives from the Railbelt electric utilities; technical specialists and executives from Enstar; producers; and independent, Alaska-based energy consultants.

The gas stakeholder meetings were conducted over a three-month period and involved four different editions of the Black & Veatch gas supply forecast model. After each round of stakeholder meetings, Black & Veatch made changes to the gas supply forecast model in response to stakeholder feedback. The fourth version of the model was used to produce the results reported in this report.

7.1.1.3 Structure of the Natural Gas Decision Tree

The gas supply and price forecasts considered a variety of possibilities but utilized only those that could be supported quantitatively with the necessary degree of mathematical precision. Specifically, model attributes were separated into factors that were modeled and factors that were not modeled as summarized in Figure 7-2 and discussed below.

Figure 7-2
Schematic Summary of the Probabilistic Gas Supply Forecast Model



7.1.1.4 Decision Tree Input Assumptions

7.1.1.4.1 Gas Demand

Black & Veatch reviewed publicly-available data on historical consumption of natural gas in the Railbelt region and re-calculated those data into mathematical functions that were compatible with the risk-based, gas supply forecast model. Sources included the U.S. Energy Information Administration, State of Alaska and Enstar. As shown in Table 7-1, adjustments were made for the fact that traditional consumers of gas are changing as the decade of 2000-2009 gives way to the decades of 2010-2019 and forward. For example, the decade of 2000-2009 included major use of gas by the Agrium fertilizer plant and by the Nikiski LNG plant (as exports to Japan). But the Agrium fertilizer plant ceased operations in 2007 and the Nikiski LNG exports are expected to end by March 2011. So going forward, the main consumers of gas are expected to be electric-utilities, and gas pipeline users (including space heating) plus oilfield operations. Accordingly, the P90, P50 and P10 metrics for gas demand reflect a significant downturn in risk-based demand in 2010-2019 followed by slow growth in the expected use of gas for power, heating and field operations.

Table 7-1
Representative Risk-Based Metrics for Railbelt Natural Gas Demand
Based on Historical Data and Known Changes in Gas Consumption

Risk-Based Demand Metric	Annualized Gas Demand (MMcf /d)		
	2000-2009	2010-2019	2020-2029
P90 (90% likely that this demand will occur)	415	216	252
P50 (50% likely that this demand will occur)	524	245	257
P10 (10% likely that this demand will occur)	632	275	262

It should be noted that the 2006-2009 decade was one of rapid change, both in gas demand and gas production. The curve-fitting approach needed to render demand data into a probability curve, as required for the probabilistic supply forecasts, displayed large spreads in key percentages in the decadal curve as a consequence of large year-to-year changes in the historical data there were used as input.

7.1.1.4.2 Gas Supplies

7.1.1.4.2.1 Cook Inlet Gas Production

Prospects included a “legacy” component based on the expected future performance of historically known, producing gas reservoirs. A “re-developed” component represented additional performance that might be possible from “legacy” reservoirs through new or re-worked gas wells. Finally, a “New E&P” component represented geoscience-based estimates of discoverable, new gas reservoirs within the greater Cook Inlet region. After consulting subject matter experts among the Railbelt gas stakeholders, and reviewing previously published reports about gas resources and reserves, Black & Veatch concluded that enhanced Cook Inlet gas production could be made to meet P50 gas demand through 2016 with plausible assumptions about re-working and re-investment. Enhanced Cook Inlet production was retained as a source in the gas supply model through 2039 but with significant performance decline after 2017.

7.1.1.4.2.2 Instate Gas Pipeline

This supply node was predicated upon construction of a pipeline to deliver gas from the Alaska North Slope (Prudhoe Bay, Point Thomson) to the Anchorage area. Prospects included a stand-alone, direct line as well as a lateral from a larger pipeline that might carry gas into Canada and the USA Lower-48 states. After consulting subject matter experts among the Railbelt gas stakeholders, and reviewing previously published reports about possible instate pipeline projects, Black & Veatch concluded that an instate pipeline was plausible after 2018 and with a maximum capacity of 350 MMcf/d. Such an instate pipeline source was included in the gas supply model with ramp-up from 2018 through 2022 and maximum capacity thereafter. No attempt was made to analyze the economics of building smaller or larger pipelines. Although published descriptions of possible pipeline projects cover the range of about 50-500 MMcf/d capacities, the limit of 350 MMcf/d was chosen as the largest capacity likely to be built given the demand outlook (Table 7-1).

7.1.1.4.2.3 LNG Imports (With Storage)

This supply node was premised on bringing LNG to the Cook Inlet through ocean tankers supplied from sources within the Asia-Pacific basin. Prospects included re-engineering the Nikiski export plant to become a receiving and storage facility or building a new receiving facility with associated storage.

For a re-developed (i.e., brownfield) Nikiski facility, storage capacity would be limited to the liquid equivalent of about 2,300 MMcf of gas. Although re-developed Nikiski could provide peak deliverability of 100 MMcf/d for short durations, total storage volume translated to annualized deliverability would be only about 6 MMcf/d. Black & Veatch research found that a plausible design for a new (i.e., greenfield) LNG facility with tank storage might increase the total available storage to a liquid equivalent of 5,700 MMcf which would have an annualized deliverability equivalent of about 15 MMcf/d. But the latter facility likely would require a capital investment at least several times that of the re-developed Nikiski facility.

A new receiving facility built with associated underground geologic storage (depleted oil or gas reservoir), in principle, could be made more scalable than for tank storage based on phased expansion of storage capacity through successive re-commissioning of depleted reservoirs. Because geologic-based storage typically scales in multiples of one billion cubic feet (1 Bcf = 1,000 MMcf), the two limiting factors for the Cook Inlet would be how fast depleted reservoirs could be re-developed into storage (Bcf per unit time) and what practical limits would apply to ocean tanker-based deliveries (tanker deliveries per unit time). After consulting subject matter experts among the Railbelt stakeholders, researching performance characteristics of LNG ocean tankers, and reviewing previously published reports about possible gas storage projects, Black & Veatch arrived at a plausible order of magnitude for LNG imports with associated geologic-based storage. A reasonable lower-end estimate would be five (5) deliveries per year, by a tanker with 138,000 cubic meter (liquid) capacity, and as supported by an available (working gas) storage capacity of at least 15-20 Bcf to produce the equivalent of an annualized gas supply of 42 MMcf/d. A reasonable upper-end limit would be 12 deliveries per year, by a tanker with 150,900 cubic meter (liquid) capacity, and as supported by an available (working gas) storage capacity of at least 40-45 Bcf to produce the equivalent of an annualized gas supply of 106 MMcf/d. For the gas supply model, Black & Veatch used the 41 MMcf/d capacity limit, beginning imports and ramp-up in 2013, for the base case. But alternative simulations also were made using the 106 MMcf/d capacity limit.

7.1.1.4.3 Other Considerations

Regional pipeline distribution systems, and gas storage not affiliated with LNG imports, were considered not to be performance bottlenecks so they were treated as non-issues in the gas supply model (Figure 7-2). Black & Veatch interviews with stakeholders led to the conclusion that the gas pipeline distribution system, at least in the Cook Inlet region, has sufficient capacity to handle new gas supplies without requiring significant capital investments. Also, published reports on geologic gas-storage prospects identified suitable volumes of reservoirs that could, in principle, be re-commissioned before the instate pipeline appeared in 2018 and ramped-up to maximum capacity in 2022. Gas storage required for earlier imports of LNG was treated as storage implicit in the import project and scaled as discussed above.

Stakeholders suggested other possible sources of gas that Black & Veatch did not include in the gas supply model for lack of the necessary quantitative supporting information. Although such sources might become viable in the future, the performance data required to model their probabilities for performance were not available either through published or unpublished sources.

First, overland trucking of LNG from the North Slope to Fairbanks was proposed. Although such a supply could be significant for residential space heating, the plausible scale of such deliveries is virtually immaterial to gas-fired power plants. Specifically, a 10,000-gallon LNG tanker truck delivered five (5) times per week for every week of the year provides a gas equivalent of less than 1 MMcf/d whereas a continuously-run, 100 MW gas-fired power plant would need about 20-30 MMcf/d. So given the emphasis of the current report on power generation, overland LNG trucking was not selected as a gas source in the supply simulations.

Second, gas production from Railbelt geologic sources other than Cook Inlet has not been confirmed in publicly-available reports. The Nenana Basin was mentioned specifically by several stakeholders but Black & Veatch was not able to confirm whether gas had been proven or resources estimated through ongoing exploratory drilling activities.

Third, gas production from coalbed methane was mentioned by a few stakeholders who did not provide supporting data. Black & Veatch researched available reports but could not confirm plausible projects that would deliver significant amounts of gas within the same timeframe as LNG imports or an instate gas pipeline.

7.1.1.5 Natural Gas Price Forecasts

Black & Veatch approached the price forecast as:

Price = Commodity Value (supply, demand) + Delivery Cost

using the following main premises:

- Metric is a single, pooled Railbelt price as if for a single, unified consumer
- Focus on “city gate” price that would be a proxy for fuel procurement plans by electric utilities – not retail consumer prices
- Commodity value estimated from historical-empirical data regressions
- A premium adder included for Cook Inlet enhanced production
- All-in delivery and storage costs for imported LNG
- Tariffs for instate pipeline, North Slope to Anchorage

For the commodity value, Black & Veatch analyzed historical supply, demand and price data for Alaska to develop five empirical relationships, each with an individual strength of correlation. Those five model relationships were combined using weighting factors proportional to the strengths of the respective correlation coefficients.

For the delivery cost, Black & Veatch reviewed publicly-available information on LNG ocean-tanker transportation and alternative proposals for Alaska instate pipeline projects. Although LNG transportation costs are well-established, Alaska pipeline projects remain incompletely defined and, therefore, carry larger associated uncertainties. Both for LNG and instate pipeline, anticipated costs fell within the range of $1.50-$2.00/MMBtu. In addition, Black & Veatch estimated that investments to realize the postulated enhancement to Cook Inlet production would require additional costs in the range of $0.25-$1.00/MMBtu.

To develop the price forecast for a given year, Black & Veatch applied the P50 supply output from the risk-based gas supply forecast to the commodity value model. Then delivery adders were applied for all of the supply sources that were presumed to be operational in that year. The result effectively was a weighted-average cost of gas involving the various gas sources.

7.1.1.6 Summary of Results

Black & Veatch selected two sets of gas supply simulations to illustrate the challenges that exist in providing suitable volumes of natural gas to Railbelt users, as follows:

Base Case (used for Scenario 1A in the RIRP model)

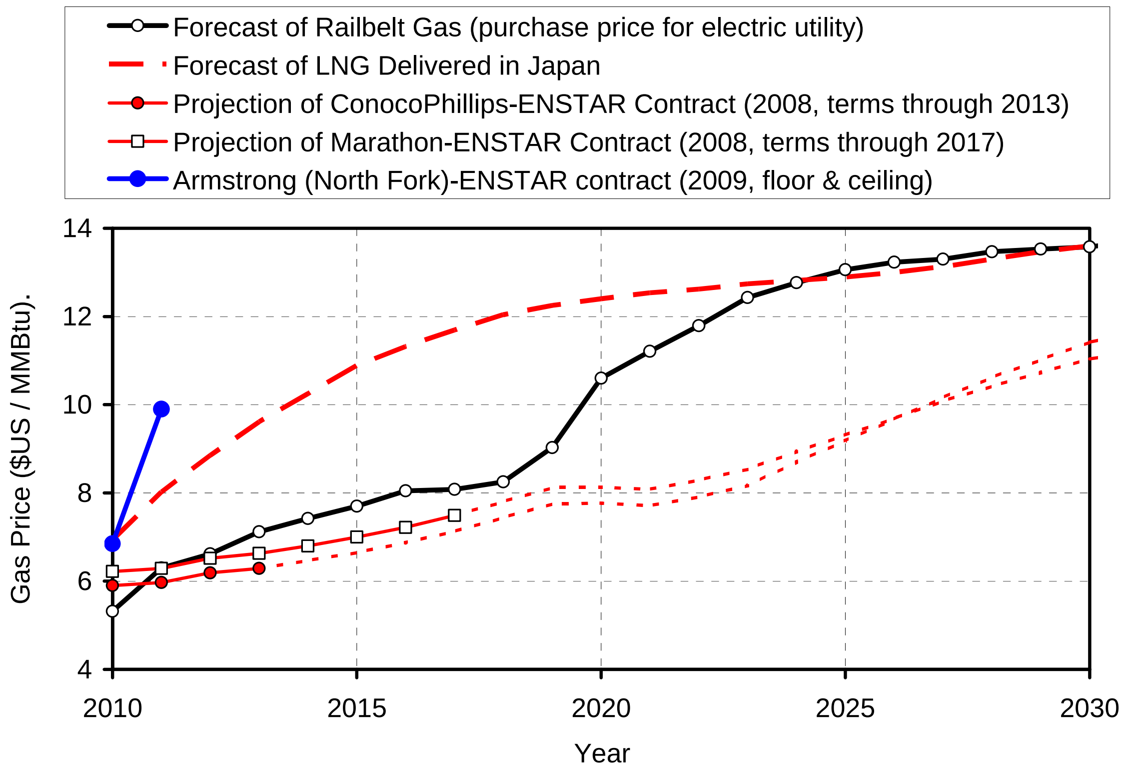
- Expanded Cook Inlet production, beginning in 2012, matched P50 demand but with decline toward a supply-demand deficit beginning in 2017 and with end of production as of 2039
- LNG imports began in 2013, and ramped-up to annualized equivalent of 41 MMcf/d, before ending in 2018 (when the instate pipeline appeared)
- Instate pipeline began in 2018, with ramp-up to maximum capacity of 350 MMcf/d by 2022, and continued operation thereafter
- Met anticipated P50 demand (with P90 to P50 supplies) through 2060
- Performance sensitivities during 2018-2024 related to uncertainties in appearance and ramp-up of the instate pipeline

Sensitivity Case (for comparison and contrast with Base Case)

- Expanded Cook Inlet production as in Base Case
- LNG imports began in 2013, with ramp-up to annualized equivalent of 106 MMcf/d, and continuous operation thereafter
- No instate pipeline was available
- Failed to meet anticipated P50 gas demand after 2018
- Performance sensitivities during 2017-2024 related to uncertainties in ramp-up of LNG imports

Railbelt gas price forecasts derived from the P50 supply simulated in the Base Case are shown in Figure 7-3 along with alternative forecasts for comparison. Before 2018, the Railbelt forecast resembles projections of bi-lateral contracts executed in the Cook Inlet in 2008. But the Railbelt forecasts are higher than the subject contracts because of additional costs associated with importation of non-Alaska LNG as well as enhanced Cook Inlet production. After 2018, the Railbelt forecasts trend much higher under heavy influence of the transportation costs assumed for the instate gas pipeline. It should be noted that the bi-lateral contracts referenced have terms only through 2013 and 2017, respectively, and are predicated on Cook Inlet production as the sole source of gas. Also, the prices projected from those contract terms pertain to the "base tier" or "base load" price that is the lowest price available; both contracts provide for multipliers up to 130 percent of the base price for gas sold under peak-demand conditions. Finally, the price for "LNG Delivered in Japan" is considered an upper limit for the Railbelt price, including the supply-starved Sensitivity Case.

Figure 7-3
Comparison of Natural Gas Price Forecasts Relevant to Railbelt Resource Plans



Gas pricing in the bi-lateral sales contracts referenced in Figure 7-3 utilize formulas that reference an assortment of non-Alaska price points with various provisions for floor and ceiling pricing. For the two contracts collectively, the reference price points include Alberta, Canada; the border of British Columbia, Canada with Washington state; the Oregon-California border; northern California; southern California; and Chicago, Illinois. Therefore, the Black & Veatch projections of those contract prices are based on forecasts of annualized prices at each of those reference price points.

Black & Veatch used conventional market analysis methods to correlate historical prices at reference price points with historical prices at the Henry Hub, LA price point. Based on those correlations, individual forecast models were developed for each reference price point in order to accomplish the individualized price forecast for each reference point, based on Black & Veatch selection of a forecast for Henry Hub.

From the price curves depicted in Figure 7-3, representative prices are summarized in Table 7-2. For reasons discussed above, the Railbelt forecast prices fall between the Cook Inlet bi-lateral contracts from 2008 and the anticipated forward price in Japan.

The “Forecast of Railbelt Gas” curve is the price corresponding to the P50 supply output from the Base Case described above. Projections for the ConocoPhillips and Marathon contracts were made by Black & Veatch using the price terms in the 2008 contracts which end in 2013 and 2017, respectively.

Table 7-2
Representative Forecasts of Railbelt Natural Gas Price
According to Different Benchmarks

Price Reference	Natural Gas "City Gate" Price ($US / MMBtu) as Delivered at Cook Inlet AK (unless noted otherwise)						
	2011	2013	2015	2017	2019	2021	2023
LNG Delivered in Japan	8.02	9.61	10.89	11.69	12.25	12.54	12.74
Forecast for Railbelt	6.30	7.12	7.70	8.08	9.03	11.21	12.43
Projection of ConocoPhillips-Enstar Contract (Base Tier)	5.97	6.29	N/A	N/A	N/A	N/A	N/A
Projection of Marathon-Enstar Contract (Base Load)	6.29	6.63	7.00	7.49	N/A	N/A	N/A

The main conclusions from these gas supply analyses are as follows:

- There are plausible scenarios for long-term supplies of natural gas in the Alaska Railbelt but they will require new capital investments that include enhanced production from the Cook Inlet, as well as importation of LNG from non-Alaska sources and or North Slope gas through an instate pipeline.
- LNG imports are a useful supplement to Cook Inlet production but are not likely to supplant the higher capacity provided by an instate pipeline.
- Both LNG imports and instate gas pipeline supplies will be more costly than historical production from the Cook Inlet and will necessitate significantly higher gas prices than in historical experience.

7.1.2 Methodology for Other Fuel Price Forecasts

7.1.2.1 Coal

The price forecast for the RIRP study represents the EIA AEO2009[1] delivered industrial price (dollars per short ton) but with an energy conversion factor of 20.169 MMBtu/ton and with the low end of possible transportation costs. The energy conversion factor was chosen to resemble available assays of Alaska coal.

In addition to the delivered price of coal, a minemouth coal price estimate was developed for the Healy plant and for a coal sensitivity analysis. The minemouth price is based on the delivered price less an estimate for delivery costs.

7.1.2.2 HAGO

High Atmospheric Gas Oil (HAGO) was treated as materially equivalent to a sub-grade of Fuel Oil No. 4. The price forecast adopted here represents a 75 percent multiplier applied to the EIA AEO2009[2] forecast for distillate fuel oil delivered for electric power and using an energy conversion factor of 0.139 MMBtu/gallon.

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[1] EIA AEO2009. U. S. Energy Information Administration, Annual Energy Outlook 2009, March 2009. Available online at http://www.eia.doe.gov/oiaf/aeo/index.html.

[2] EIA AEO2009 (previously referenced).

7.1.2.3 Naphtha
Naphtha was treated as materially equivalent to a sub-grade of jet fuel. The price forecast adopted here represents a 75 percent multiplier applied to the EIA AEO2009[3] forecast for jet fuel delivered for aviation and using an energy conversion factor of 0.139 MMBtu/gallon.

7.1.2.4 Propane
Propane is not currently used as a fuel for electric power generation in the Railbelt region. However, in response to a stakeholder request, propane was added for comparison as an alternative fuel. The price forecast reported here utilized an historical-empirical relationship developed for propane and natural gas in the Lower-48 states as applied to the natural gas price predicted for the Railbelt.

7.1.3 Resulting Fuel Price Forecasts
Table 7-3 summarizes the resulting annualized prices predicted for hydrocarbon fuels from 2011 to 2060. Although seasonal variation of price can be expected to occur in response to demand swings, the prices represented here reflect a single average price for a given year.

7.2 Emission Allowance Price Projections

7.2.1 Existing Legislation
Currently, there is no existing legislation in place that subjects electric generating units in Alaska to an emission allowance trading program for NO_x, SO_2, CO_2, or Hg emissions. As a result, no emission allowance costs are included in the economic evaluations other than for CO_2 as discussed in the next subsection. Capital and operating costs are included for generating units in order for the units to meet expected emission limitations under the Environmental Protection Agency's Prevention of Significant Deterioration Program.

7.2.2 Proposed Legislation
Currently, there is no proposed federal or state legislation that would subject electric generating units in Alaska to an emission allowance trading program for NO_x, SO_2, or Hg. There have been a number of bills introduced in the U.S. Congress that would create an emission allowance trading program and corresponding emission reductions for CO_2. The only bill that has passed either House of Congress is H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA), which was passed in the House of Representatives in 2009. While it is unknown if H.R. 2454 will ultimately be passed into law, after vetting the issue with numerous stakeholders in the RIRP process, it was decided that CO_2 allowance costs would be included in the economic evaluations for the RIRP. The development of those allowance costs is presented in the following subsection.

7.2.3 Development of CO_2 Emission Price Projection
The CO_2 emission price projection used in this analysis is based upon price projections developed by the Energy Information Administration (EIA) and by the Environmental Protection Agency (EPA). The base price projection is presented in EIA report number SR-OIAF/2009-05, entitled *Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (ACESA)*, dated August 4, 2009. The EIA report considered the energy-related provisions in ACESA that could be analyzed using EIA's National Energy Modeling System. The ACESA basic case was used for the CO_2 emission price projection for the years 2012 through 2030.

[3] EIA AEO2009 (previously referenced).

Table 7-3
Nominal Fuel Price Forecasts ($/MMBtu)

Year	Natural Gas	Delivered Coal	Minemouth Coal	HAGO	Naphtha	Propane
2011	6.30	2.94	2.18	12.98	13.77	9.05
2012	6.62	2.99	2.21	14.52	15.24	9.45
2013	7.12	3.02	2.24	15.26	16.16	10.08
2014	7.42	3.08	2.28	16.31	17.24	10.46
2015	7.70	3.19	2.36	17.23	18.11	10.81
2016	8.05	3.23	2.39	17.79	18.71	11.25
2017	8.08	3.29	2.44	18.23	19.25	11.29
2018	8.25	3.36	2.49	18.71	19.79	11.50
2019	9.03	3.43	2.54	19.29	20.45	12.49
2020	10.60	3.50	2.59	19.77	20.85	14.46
2021	11.21	3.55	2.63	20.26	21.33	15.23
2022	11.79	3.61	2.67	20.78	21.86	15.96
2023	12.43	3.67	2.72	20.98	22.09	16.76
2024	12.77	3.73	2.76	21.50	22.56	17.19
2025	13.06	3.80	2.81	21.98	23.09	17.56
2026	13.23	3.86	2.86	22.43	23.57	17.77
2027	13.30	3.93	2.91	22.98	24.03	17.86
2028	13.47	4.00	2.96	23.76	24.83	18.07
2029	13.53	4.07	3.01	24.38	25.50	18.15
2030	13.58	4.11	3.04	25.07	26.01	18.21
2031	13.72	4.24	3.14	25.82	26.79	18.39
2032	13.92	4.36	3.23	26.60	27.59	18.64
2033	14.00	4.49	3.33	27.40	28.42	18.74
2034	14.08	4.63	3.43	28.22	29.27	18.84
2035	14.21	4.77	3.53	29.07	30.15	19.00
2036	14.11	4.91	3.64	29.94	31.06	18.88
2037	13.93	5.06	3.75	30.84	31.99	18.65
2038	13.84	5.21	3.86	31.76	32.95	18.54
2039	13.59	5.37	3.98	32.72	33.93	18.22
2040	13.91	5.53	4.10	33.70	34.95	18.63
2041	13.96	5.69	4.21	34.71	36.00	18.69

Table 7-3 (Continued)
Nominal Fuel Price Forecasts ($/MMBtu)

Year	Natural Gas	Delivered Coal	Minemouth Coal	HAGO	Naphtha	Propane
2042	14.17	5.86	4.34	35.75	37.08	18.95
2043	14.30	6.04	4.47	36.82	38.19	19.12
2044	14.59	6.22	4.61	37.93	39.34	19.48
2045	14.73	6.41	4.75	39.06	40.52	19.66
2046	14.94	6.60	4.89	40.24	41.73	19.92
2047	15.07	6.80	5.04	41.45	42.98	20.08
2048	15.37	7.00	5.19	42.68	44.27	20.46
2049	15.50	7.21	5.34	43.97	45.60	20.63
2050	15.64	7.43	5.50	45.29	46.97	20.80
2051	15.77	7.65	5.67	46.64	48.38	20.97
2052	16.08	7.88	5.84	48.05	49.83	21.36
2053	16.21	8.12	6.01	49.49	51.33	21.52
2054	16.34	8.36	6.19	50.97	52.87	21.68
2055	16.57	8.61	6.38	52.50	54.45	21.97
2056	16.80	8.87	6.57	54.08	56.09	22.26
2057	16.93	9.14	6.77	55.70	57.77	22.43
2058	17.17	9.41	6.97	57.37	59.51	22.73
2059	17.30	9.69	7.18	59.09	61.29	22.89
2060	17.75	9.98	7.39	60.86	63.13	23.46

The EPA has also made an analysis of ACESA. EPA's CO_2 emission price projection is presented in a presentation, entitled *EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the 111th Congress*, dated June 23, 2009. The EPA report provides CO_2 emission prices for the years 2015, 2030, and 2050. The EPA analysis was used to develop CO_2 emission price projections for 2030 through 2050. Emission price projections from 2050 through 2060 were escalated at the general inflation rate of 2.5 percent annually. The CO_2 emission allowance price projections are presented in Table 7-4.

Both the EIA and EPA analyses of H.R 2454 consider the development and deployment of carbon capture and sequestration (CCS).

Table 7-4
CO_2 Allowance Price Projections

Year	$/ton
2012	18.41
2020	39.70
2030	103.78
2040	213.91
2050	440.89
2060	564.38

8.0 RELIABILITY CRITERIA

The purpose of this section is to discuss the reliability criteria that were used in this study.

8.1 Planning Reserve Margin Requirements

Currently, the Railbelt utilities maintain a 30 percent reserve margin. For planning purposes, GRETC is assumed to be required to maintain a 30 percent reserve margin. As the GRETC transmission projects are implemented and experience is gained in the Railbelt with a more robust transmission system, it may be possible to reduce the 30 percent planning reserve margin which would further increase benefits under GRETC. This potential additional savings, however, is not modeled in this study.

8.2 Operating Reserve Margin Requirements

8.2.1 Spinning Reserves

Spinning reserve requirements for the Railbelt system are based on the largest unit on-line. Currently, Chugach, GVEA, HEA, and ML&P share that spinning reserve requirement in relation to their largest units on-line. Table 8-1 presents the largest unit for each of the Railbelt utilities and shows their share of the largest unit.

Table 8-1
Railbelt Spinning Reserve Requirements

Utility	Largest Unit	Capacity (MW)	Percentage of Largest Unit	Spinning Reserve Requirement (MW)
CEA	Beluga 7/8	108.6	33.6	36.9
GVEA	North Pole 2	62.6	19.4	21.2
HEA	Nikiski	42.0	13.0	14.3
ML&P	Plant 2 Units 7/6	109.6	34.0	37.2
Total		319.5	100.0	109.6

Spinning reserve requirements vary continuously based on the largest unit operating. Throughout the study period, the spinning reserve requirements increase when new units become the largest unit on the system.

Generally, any unit operating below its maximum load can contribute to the spinning reserve requirement. In addition, Bradley Lake can provide up to 27 MW of spinning reserves as shown in Table 4-5.

GVEA also has a Battery Energy Storage System (BESS) which provides 27 MW of equivalent spinning reserves. GVEA currently employs Shed in Lieu of Spin (SILOS) for a portion of GVEA's spinning reserve responsibility. In this RIRP, SILOS is not considered for spinning reserve.

8.2.2 Non-Spinning Operating Reserves

The Railbelt currently requires total operating reserves to be 150 percent of the spinning requirement. This results in an amount of non-spinning reserves up to 50 percent of spinning reserve capacity that may be provided by quick-start capacity in order to meet the operating reserve requirement. This non-spinning operating reserve is proportioned between the Railbelt utilities in the same proportions as spinning reserves. The units that qualify as quick-start units for meeting operating reserves are presented in Table 8-2.

8.3 Renewable Considerations

Wind, solar, and tidal renewable technologies are not dispatchable; consequently, they are not counted toward planning or operating reserves.

8.4 Regulation

Resources that are not dispatchable and subject to varying output due to factors that cannot be controlled such as weather (e.g., variations in wind speed that result in variable wind power output), require additional regulating capacity in order to maintain system reliability when the wind does not blow or the sun does not shine. For evaluation purposes, it is assumed that 50 percent of the nameplate capacity of wind and solar resources will be required to be maintained as additional regulating capacity. Tidal resources, while not dispatchable, are more predictable, and for evaluation purposes, additional regulating capacity is not included.

Table 8-2
Quick-Start Units

Name	Unit	Winter Rating (MW)
Anchorage ML&P – Plant 1	3	32
Anchorage ML&P – Plant 1	4	34.1
Anchorage ML&P – Plant 2	5	37.4
Anchorage ML&P – Plant 2	7	81.8
Anchorage ML&P – Plant 2	8	87.6
Beluga	1	17.5
Beluga	2	17.5
Beluga	3	66.5
Beluga	5	65
Beluga	6	82
Beluga	7	82
Bernice	2	19
Bernice	3	25.5
Bernice	4	25.5
DPP	1	25.8
International	1	14
International	2	14
International	3	19
Nikiski	1	42
North Pole	GT1	62.6
North Pole	GT2	60.6
Zehnder	GT1	19.2
Zehnder	GT2	19.6

9.0 CAPACITY REQUIREMENTS

When the 30 percent planning reserve criteria described in Section 8 is applied to the load forecasts presented in Section 6, the capacity requirements for the Railbelt are established. Comparing those capacity requirements to the existing generating units and their expected retirement dates results in the capacity addition requirements for the Railbelt. Figures 9-1 through 9-6 present the capacity requirements for the following cases.

- Figure 9-1 - Scenario 1A Capacity Requirements Without DSM/EE
- Figure 9-2 - Scenario 1A Capacity Requirements With DSM/EE
- Figure 9-3 - Scenario 2A Capacity Requirements Without DSM/EE
- Figure 9-4 - Scenario 2A Capacity Requirements With DSM/EE
- Figure 9-5 - Scenario 1A Capacity Requirements Including Committed Units Without DSM/EE
- Figure 9-6 - Scenario 1A Capacity Requirements Including Committed Units With DSM/EE

Figure 9-1
Scenario 1A Capacity Requirements Without DSM/EE

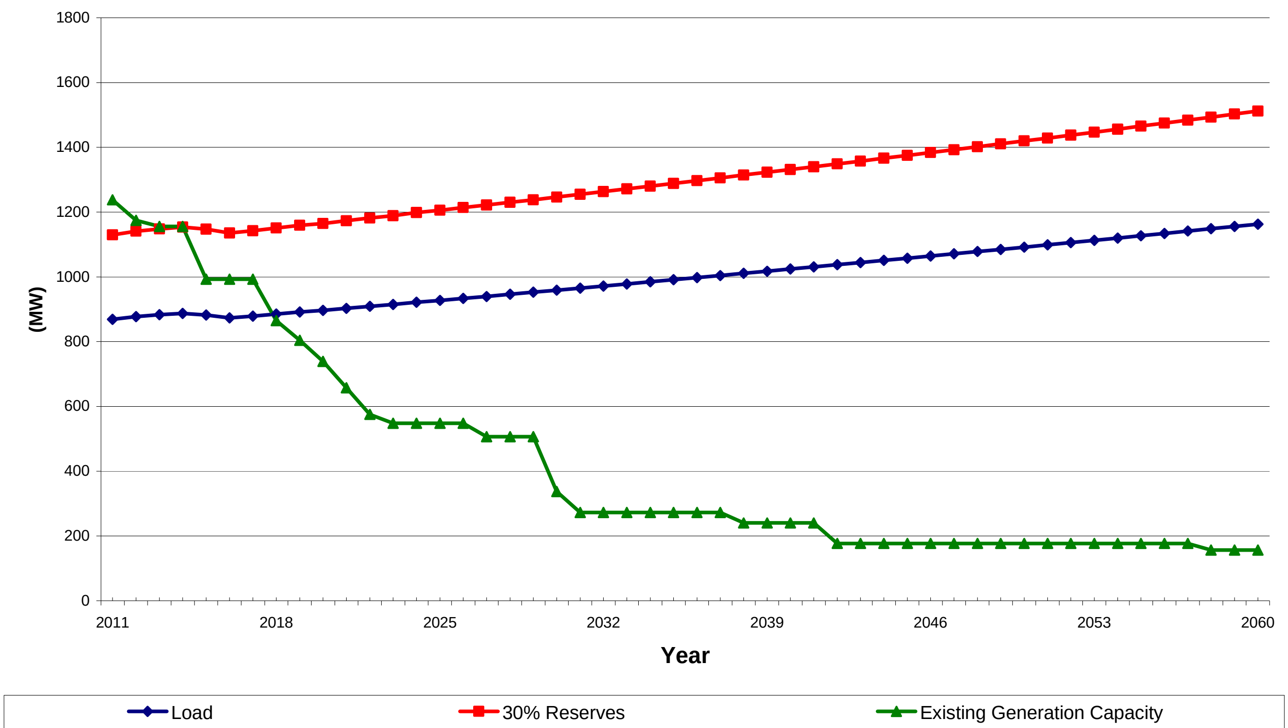


Figure 9-2
Scenario 1A Capacity Requirements With DSM/EE

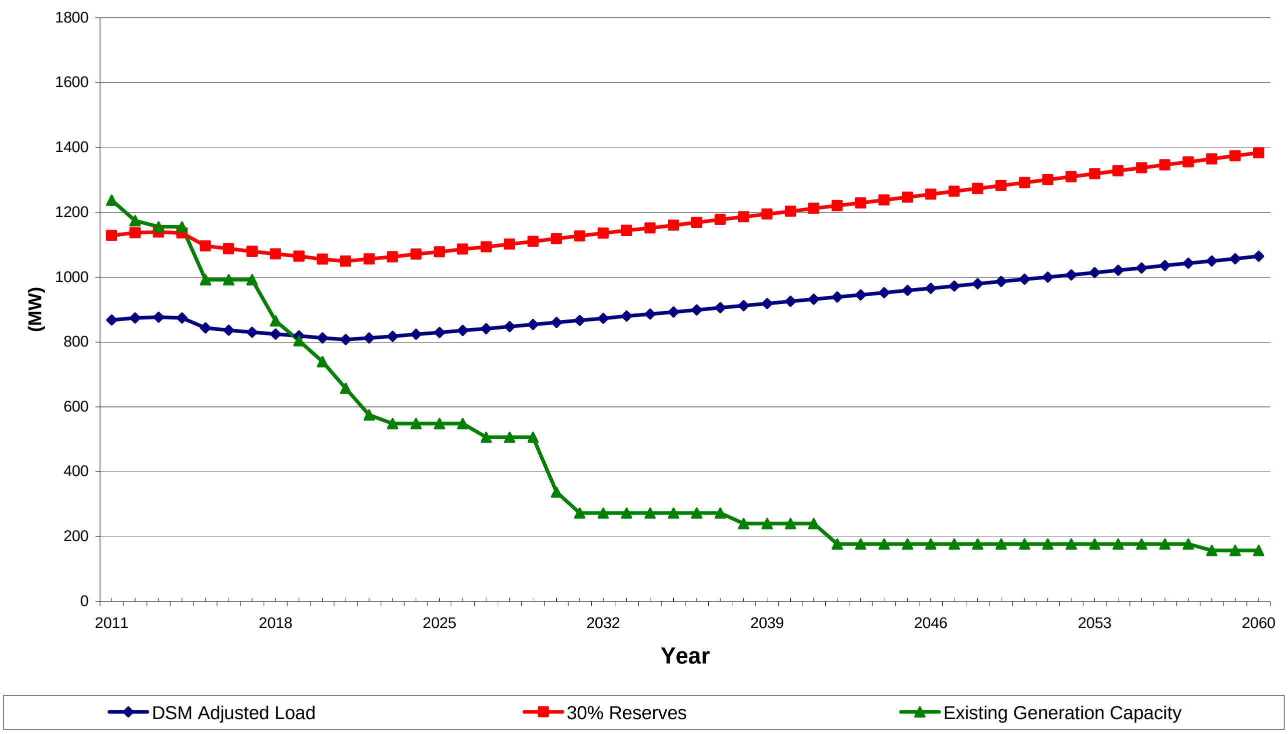


Figure 9-3
Scenario 2A Capacity Requirements Without DSM/EE

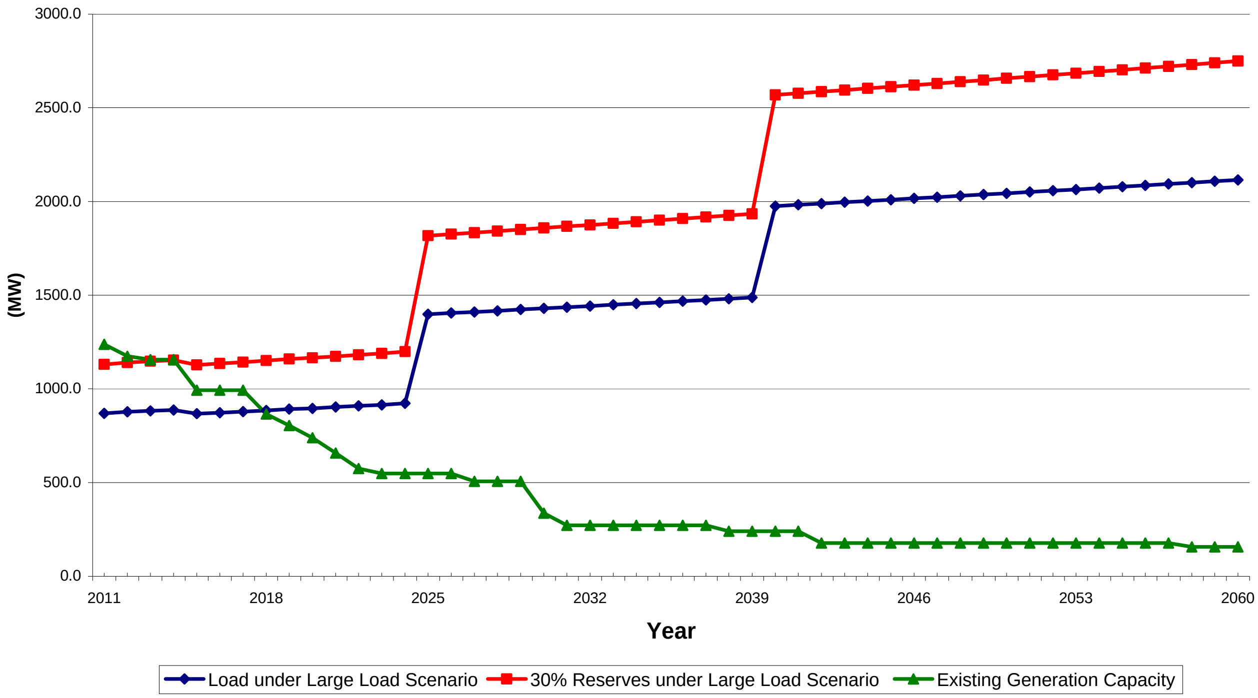


Figure 9-4
Scenario 2A Capacity Requirements With DSM/EE

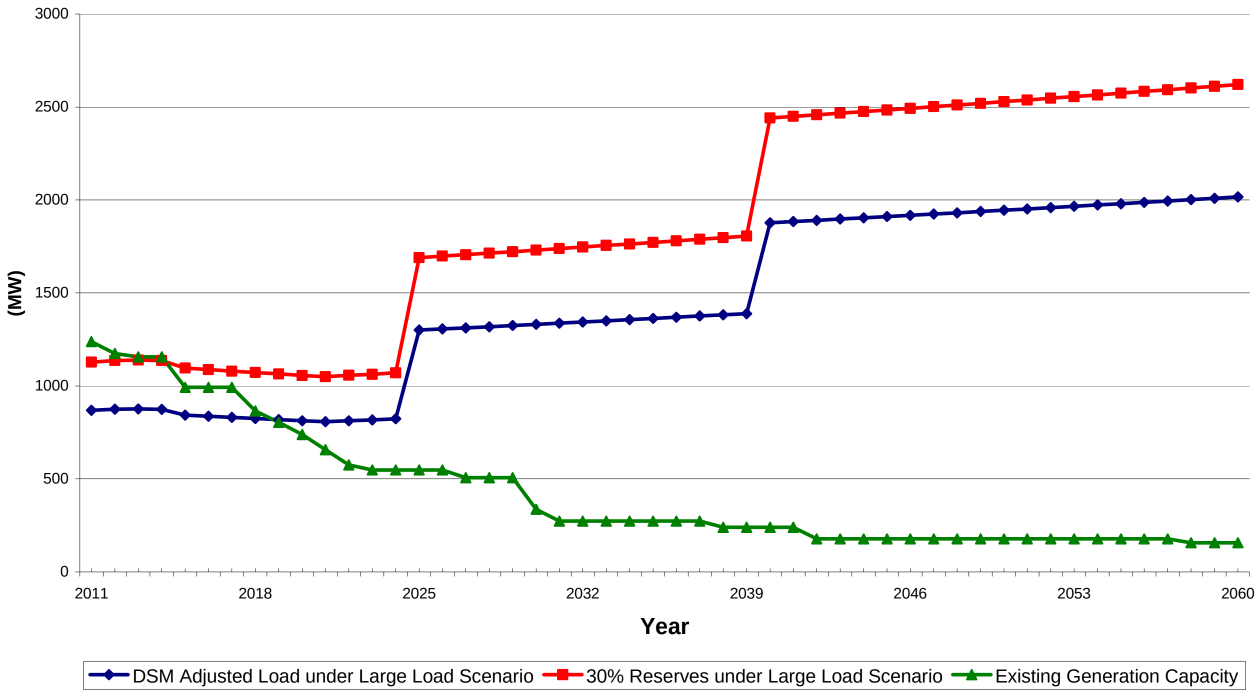


Figure 9-5
Scenario 1A Capacity Requirements Including Committed Units Without DSM/EE

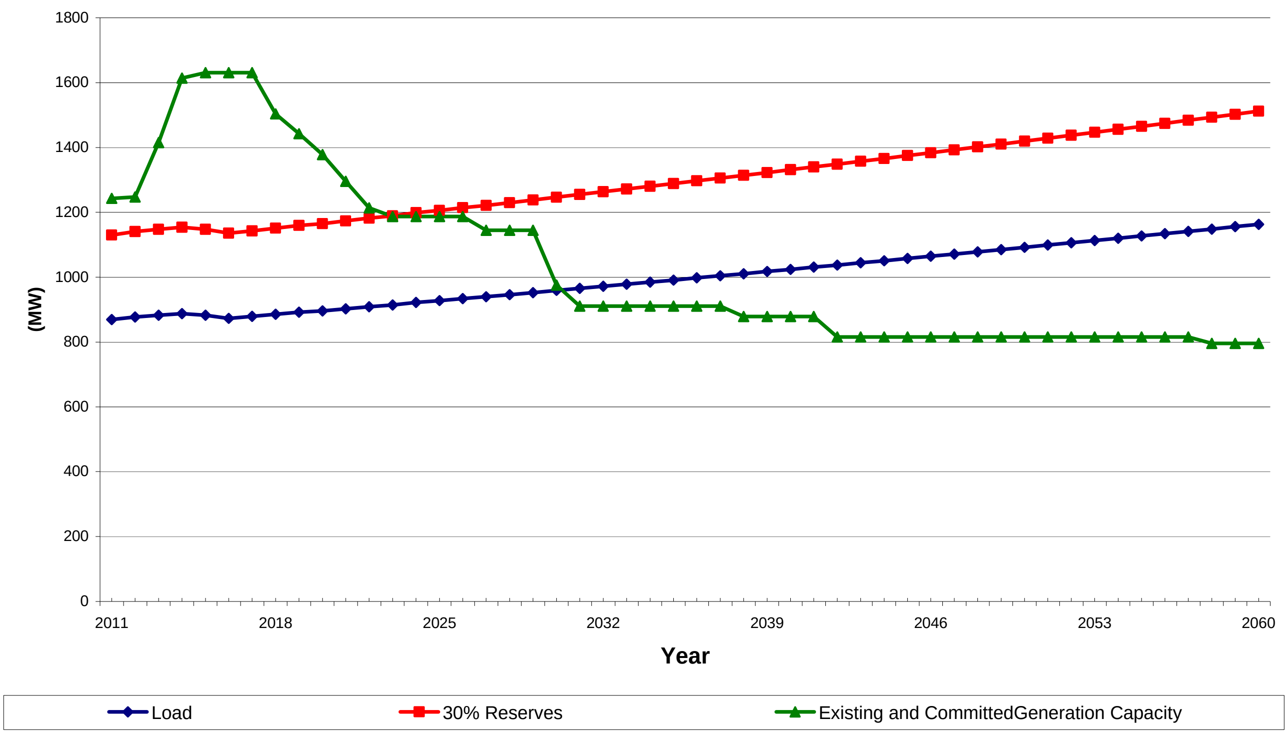
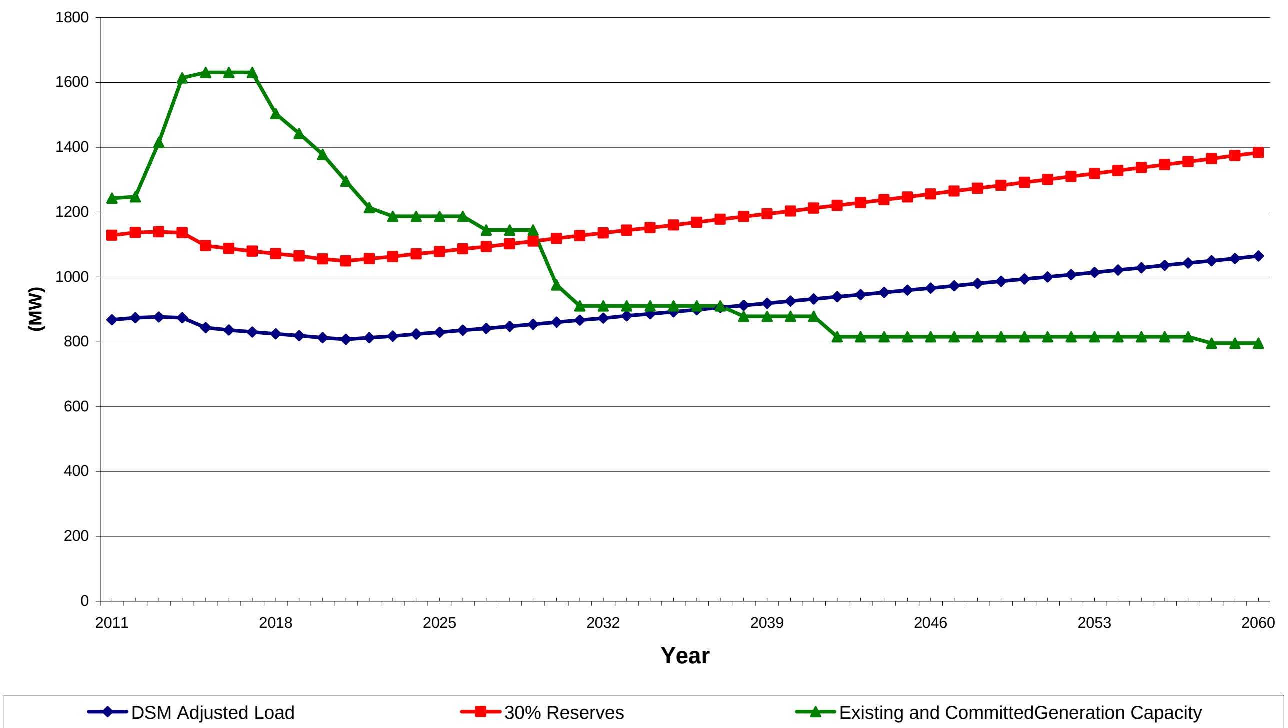


Figure 9-6
Scenario 1A Capacity Requirements Including Committed Units With DSM/EE



10.0 SUPPLY-SIDE OPTIONS

The purpose of this section is to summarize the input assumptions that Black & Veatch used related to the various supply-side resource options considered in the RIRP study. Information is provided for both conventional technologies and renewable resources.

10.1 Conventional Technologies

10.1.1 Introduction

This subsection describes and characterizes various conventional supply-side technologies including General Electric (GE) LM6000 and LMS100 simple cycle units, GE 6FA combined cycle units and a 130 MW pulverized coal (PC) facility. In addition to greenfield developments, the option of repowering Beluga Unit 8 has been considered.

10.1.2 Capital, and Operating and Maintenance (O&M) Cost Assumptions

The capital cost estimates developed in this report include both direct and indirect costs. An allowance for general owner's cost items (exclusive of escalation, financing fees, and interest during construction), as summarized in Table 10-1, has been accounted for in the cost estimates or provided as a percentage of total costs. The capital cost estimates were developed on an engineer, procure, and construct (EPC) basis.

The O&M cost estimates were derived from proprietary Black & Veatch O&M estimating tools and representative estimates for similar projects. Costs are based on vendor estimates and recommendations, and estimated performance information. The cost estimates are divided into fixed and variable O&M. Fixed O&M costs, expressed as dollars per unit of capacity per year ($/kW-yr), do not vary directly with plant power generation and consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance and other fees. Variable O&M costs, expressed as dollars per unit of generation ($/MWh) tend to vary in near direct proportion to the output of the unit. Variable O&M include costs associated with equipment outage maintenance, utilities, chemicals, and other consumables. Fuel costs are determined separately and are not included in either fixed or variable O&M costs.

10.1.3 Generating Alternatives Assumptions

10.1.3.1 General Capital Cost Assumptions

Unless otherwise discussed, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- The plant will not be located on wetlands nor require any other mitigation.
- Service and fire water will be supplied via on-site groundwater wells.
- Potable water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Costs for transmission lines and switching stations are included as part of the owner's cost.

Table 10-1
Possible Owner's Costs

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (e.g., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Start-up/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate, but not in direct capital cost)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

10.1.3.2 Combustion Turbine Capital Cost Assumptions

- Combustion turbines will be fueled with natural gas as the primary fuel with an option provided for dual fuel with No. 2 ultra-low sulfur diesel (ULSD) fuel oil as the backup fuel. The cost of fuel unloading and delivery to the site(s) is included.
- The LM6000 and the LMS100 will utilize water injection for primary NO_x control when operating on fuel oil. The 6FA configurations will utilize dry low NO_x burners when operating on natural gas and water injection when operating on fuel oil.
- All of the combustion turbine configurations will include selective catalytic reduction (SCR) and a CO catalyst.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the LM6000 and the combined cycle alternatives. Gas compressors will be included for the LMS100 combustion turbine. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be provided via portable demineralizers for simple cycle alternatives and will be supplied by a demineralized water treatment system for the combined cycle options.
- Both of the combustion turbine combined cycle configurations will utilize air cooled condensers for heat rejection.
- None of the combustion turbine configurations will utilize inlet cooling.
- Field erected storage tanks include the following:
  - Service/fire water storage tank.
  - Fuel oil storage tank (3 days storage capacity).
  - Demineralized water storage tank (3 days storage capacity).

10.1.3.3 Coal Facility Capital Cost Assumptions

- The PC plant will be equipped with an SCR for NO_x control, an activated carbon injection system for mercury reduction, a dry flue gas desulfurization unit for sulfur reduction and a fabric filter system for managing particulate emissions.
- The subcritical PC plant will utilize an air cooled condenser for heat rejection.

10.1.3.4 Direct Cost Assumptions

- Total direct capital costs are expressed in 2009 dollars.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for start-up are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

10.1.3.5 Indirect Cost Assumptions

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.

- Technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Start-up and commissioning spare parts.
- Allowance for funds used during construction and financing fees will be accounted for separately as part of the economic evaluations and, therefore, are not included in the capital cost or owner's cost estimates.

10.1.3.6 Combustion Turbine O&M Cost Assumptions

- O&M cost estimates are provided based on an assumed capacity factor of 75 percent.
- Simple cycle units are assumed to start 200 times per year.
- Combined cycle units are assumed to start 50 times per year.
- Location was considered to be a greenfield site.
- Plant staff wage rates are based on an operator rate of $93,200 per year.
- Burden rate is 56 percent.
- Staff supplies and materials are estimated to be 5 percent of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs are estimated through at least one major overhaul.
- Combustion turbine combustion inspections, hot gas path inspections, and major overhauls are based on Original Equipment Manufacturer (OEM) pricing and recommendations.
- Steam turbine, generator, heat recovery steam generator and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data and recommendations.
- SCR was included for NO_x control for the simple cycle and combined cycle equipment.
- SCR uses 19 percent aqueous ammonia. Aqueous ammonia cost was estimated at $250/wet ton.
- Costs associated with a CO catalyst are included.
- Raw water costs are $0.77 per 1,000 gallons.
- Water treatment costs are included for water make-up and demineralized water where needed.
- Demineralized water treatment costs are $3.00 per 1,000 gallons.
- Station net capacity output is based on fired operation (duct burners) at annual average ambient conditions.
- The O&M analysis was completed in 2009 dollars.

10.1.3.7 Coal Facility O&M Cost Assumptions

- Fuel is pulverized coal.
- Net plant heat rate is 9,698 Btu/kWh.
- O&M cost estimates are based on an assumed gross capacity factor of 75 percent.
- O&M cost estimates assume the unit will start 50 times per year.
- Location was considered to be a greenfield site.
- Plant staff wage rates are based on an operator rate of $93,200 per year.

- Burden rate was 56 percent.
- Staff supplies and material are estimated to be 5 percent of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs are estimated through at least one major overhaul.
- Steam turbine, generator, boiler and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data and recommendations.
- SCR is included for NO_x control.
- SCR uses anhydrous ammonia with an estimated cost of $800/wet ton.
- Powdered activated carbon is included for mercury control.
- Activated carbon costs are estimated to be $1,600/ton.
- Dry Flue Gas Desulfurization (FGD) is used for SO_2 control.
- Dry FGD uses lime with an estimated cost of $75/ton.
- A fabric filter system is included for particulate control.
- Raw water costs are $0.77 per 1,000 gallons.
- Water treatment costs are included for cycle make-up and service water where needed.
- Cycle make-up water treatment costs are $5.00 per 1,000 gallons.
- The O&M analysis was completed in 2009 dollars.

10.1.4 Conventional Technology Options

The conventional technology supply-side options are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital costs, O&M costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

The conventional technologies considered include simple cycle combustion turbines, combined cycle configurations and a PC coal generating plant.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to these models. Rather, such assumptions were made to provide indicative output and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the performance data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Power plant output and heat rate performance will degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The average degradation over the unit's operating life that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed by Black & Veatch to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so technology-specific nonrecoverable output and heat rate factors have been developed and are presented in Table 10-2. The degradation percentages are applied one time to the new and clean performance data, and reflect average lifetime aggregate nonrecoverable degradation.

Table 10-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 1x1 6FA Combined Cycle	2.7	1.50
GE 2x1 6FA Combined Cycle	2.7	1.50

10.1.4.1 Simple Cycle Combustion Turbine Alternatives

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 2,000ºF 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. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot (typically 900ºF to 1,100ºF) gases exiting the turbine exhaust. 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.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease due to the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit’s full load capacity while maintaining emission levels within required limits.

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 capacity. 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. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

GE LM6000PC Combustion Turbine

The GE LM6000PC was selected as a potential simple cycle alternative due to its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC), a 14-stage variable geometry high-pressure compressor (HPC), an annular combustor, a two-stage air-cooled high-pressure turbine (HPT), a five-stage low-pressure turbine (LPT), and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct-coupling to 3,600 revolutions per minute (rpm) generators for 60 hertz (Hz) power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold," end of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes
- Cycling or peaking operation
- Synchronous condenser capability
- Compact, modular design
- More than 5 million operating hours
- More than 450 turbines sold
- Dual fuel capability

The capital cost estimate was based on utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 10-3 presents the operating characteristics of the LM6000 combustion turbine. Water injection and high temperature SCR would be used to control NO_x to 3 ppmvd while operating on natural gas and on ULSD. Table 10-4 presents estimated emissions for the LM6000.

GE LMS100 Combustion Turbine

The LMS100 is a newer GE unit and has the disadvantage of not having as much commercial experience. As the LMS100 gains commercial acceptance, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an approximate efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated through additional LMS100 experience.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

Table 10-3
GE LM6000 PC Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Winter (-10º F and 100% RH) (Full Load)	46.6	9,636
Winter (15º F and 68% RH) (Full Load)	47.5	9,662
Winter (15º F and 68% RH) (75% Load)	35.5	10,313
Winter (15º F and 68% RH) (50% Load)	23.5	11,791
Average (30º F and 68% RH) (Full Load)	47.6	9,741
Average (30º F and 68% RH) (75% Load)	35.6	10,365
Average (30º F and 68% RH) (50% Load)	23.6	11,828
Summer (59º F and 68% RH) (Full Load)	39.9	10,058

RH = Relative humidity.

(1)Net capacity and net plant heat rate include degradation factors.
(2)Net capacity and heat rate assume operation on natural gas.

Table 10-4
GE LM6000 PC Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0108
SO_2, lb/MBtu	0.0022
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

(1)Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR, water injection and CO catalyst.

There are two main differences between the LM6000 and the LMS100. The LMS100 cools the compressor air after the first stage of compression with an external heat exchanger and unlike the LM6000, which has an HPT and a power turbine, the LMS100 has an additional IPT to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800º F, which allows the use of a standard SCR system for NO_x control.

Table 10-5 presents the operating characteristics of the LMS100 combustion turbine. Standard SCR will be used to control NO_x to 3 ppmvd while operating on natural gas. Water injection and SCR will be used to control NO_x while operating on ULSD. Table 10-6 presents estimated emissions for the LMS100.

10.1.4.2 Combined Cycle Alternatives

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

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 due to added plant complexity.

1x1 GE 6FA Combined Cycle Alternative

The 1x1 combined cycle generating unit would include one GE 6FA CTG, one HRSG, one steam turbine generator, and an air cooled condenser. The combined cycle unit will be dual-fueled, with natural gas as the primary fuel and ULSD as the backup fuel.

The GE 6FA heavy-duty gas turbine is an aerodynamic scale of the GE 7FA. In the development of the turbine GE scaled a proven advanced-technology design and combined it with advanced aircraft engine cooling and sealing technology. The 6FA fleet has over two million operating hours logged with more than 100 units installed or on order. The 6FA gas turbine configuration includes an 18-stage compressor, six combustion chambers and a three-stage turbine. The shaft is supported on two bearings. The combustion system standard offering includes dry low NO_x burners capable of multi-fuel applications.

The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the steam turbine generator. The HRSG is expected to be a natural circulation, three pressure, reheat unit. The combined cycle alternative will be designed for supplemental duct firing (on natural gas only). Supplemental firing necessitates a larger steam turbine and changes to other plant components, leading to an increase in total capital cost and a decrease in plant efficiency in order to realize the additional output. SCR and dry low-NO_x burners will be included to control NO_x to 3 ppmvd while burning natural gas, and a CO catalyst will be included to reduce emissions. Water injection will be used for NO_x control when burning ULSD.

Table 10-5
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (-10º F and 100% RH) (Full Load)	95.3	8,894
Winter (15º F and 68% RH) (Full Load)	95.5	8,925
Winter (15º F and 68% RH) (75% Load)	71.4	9,445
Winter (15º F and 68% RH) (50% Load)	47.3	10,489
Winter (15º F and 68% RH) (Min Load)	35.7	11,444
Average (30º F and 68% RH) (Full Load)	96.0	8,963
Average (30º F and 68% RH) (75% Load)	71.8	9,456
Average (30º F and 68% RH) (50% Load)	47.6	10,501
Average (30º F and 68% RH) (Min Load)	36.3	11,415
Summer (59º F and 68% RH) (Full Load)	97.4	9,041

RH = Relative humidity.

(1)Net capacity and net plant heat rate include degradation factors.
(2)Net capacity and heat rate assume operation on natural gas.

Table 10-6
GE LMS100 Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0108
SO_2, lb/MBtu	0.0022
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

(1)Emissions are at full load at 30º F, and include the effects of SCR, water injection and CO catalyst.

The steam turbine is based on a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one intermediate-pressure (IP) section, and a two-flow low-pressure (LP) section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine.

Table 10-7 presents the operating characteristics of the 1x1 GE 6FA combined cycle generating unit. Table 10-8 presents estimated emissions for the 1x1 GE 6FA combined cycle generating unit.

2x1 GE 6FA Combined Cycle Alternative

The 2x1 combined cycle generating unit would include two GE 6FA CTG, two HRSGs, one steam turbine generator, and an air cooled condenser. The combined cycle unit will be dual-fueled, with natural gas as the primary fuel and ULSD as the backup fuel.

The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the steam turbine generator. The HRSG is expected to be a natural circulation, three pressure, reheat unit. The combined cycle alternative will be designed for supplemental duct firing (on natural gas only). SCR and dry low- NO_x burners will be included to control NO_x to 3 ppmvd while burning natural gas, and a CO catalyst will be included to reduce emissions. Water injection will be used for NO_x control when burning ULSD.

The steam turbine is based on a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment, lubricating oil system, hydraulic oil system, and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine.

Table 10-9 presents the operating characteristics of the 2x1 GE 6FA combined cycle generating unit. Table 10-10 presents estimated emissions for the 2x1 GE 6FA combined cycle generating unit.

10.1.4.3 Coal Technologies

The coal technology presented in this technology assessment includes a subcritical PC generating facility. Other coal technologies such as integrated gasification combined cycle (IGCC) or carbon capture and sequestration (CCS) could also be considered, but those technologies have not developed to a point where they have significantly penetrated the coal generation market. In addition, generating costs from these technologies generally exceed those of PC's. Therefore, this technology assessment provides estimates of the performance and cost for the PC alternative.

Subcritical Pulverized Coal (PC) (130 MW)

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate a single unit size of up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

Table 10-7
GE 1x1 6FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)(1, 2)		Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)	
	Fired	Unfired	Fired	Unfired
Winter (-10º F and 100% RH) (Full Load)	161.3	120.8	7,814	7,581
Winter (15º F and 68% RH) (Full Load)	153.7	118.1	7,770	7,307
Winter (15º F and 68% RH) (75% Load) (3)		115.1		7,290
Winter (15º F and 68% RH) (50% Load) (3)		76.6		8,288
Winter (15º F and 68% RH) (Min Load) (3)		50.6		9,187
Average (30º F and 68% RH) (Full Load) (3)	150.4	113.8	7,751	7,418
Average (30º F and 68% RH) (75% Load) (3)		112.7		7,426
Average (30º F and 68% RH) (50% Load) (3)		75.4		8,047
Average (30º F and 68% RH) (Min Load) (3)		48.5		9,531
Summer (59º F and 68% RH) (Full Load)	143.0	110.6	7,768	7,282

RH = Relative humidity.
(1)Net capacity and net plant heat rate include degradation factors
(2)Net capacity and heat rate assume operation on natural gas.
(3)Part load performance percent load is based on gas turbine load point.

Table 10-8
GE 1x1 6FA Combined Cycle Estimated Emissions(1)

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0109
SO_2, lb/MBtu	0.0020
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

(1)Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

Table 10-9
GE 2x1 6FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1, 2]		Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]	
	Fired	Unfired	Fired	Unfired
Winter (-10º F and 100% RH) (Full Load)	325.0	248.4	7,755	7,374
Winter (15º F and 68% RH) (Full Load)	310.2	237.6	7,698	7,264
Winter (15º F and 68% RH) (75% Load) [3]		229.8		7,366
Winter (15º F and 68% RH) (50% Load) [3]		154.9		8,089
Winter (15º F and 68% RH) (Min Load) [3]		99.4		9,335
Average (30º F and 68% RH) (Full Load) [3]	303.9	231.9	7,684	7,281
Average (30º F and 68% RH) (75% Load) [3]		227.6		7,283
Average (30º F and 68% RH) (50% Load) [3]		151.7		7,996
Average (30º F and 68% RH) (Min Load) [3]		99.6		9,277
Summer (59º F and 68% RH) (Full Load)	289.2	222.9	7,698	7,224

RH = Relative humidity.
[1]Net capacity and net plant heat rate include degradation factors
[2]Net capacity and heat rate assume operation on natural gas.
[3]Part load performance percent load is based on gas turbine load point.

Table 10-10
GE 2x1 6FA Combined Cycle Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	3
NO_x, lb/MBtu	0.0109
SO_2, lb/MBtu	0.0020
CO_2, lb/MBtu	115.1
CO, ppmvd at 15% O_2	3

[1]Emissions are at full load at 30º F, reflect operation on natural gas, and include the effects of SCR and CO catalyst.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psig, compared to the steam pressure of 2,400 psig for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psig) to supercritical (3,500 psig) generally improves the net plant heat rate by about 200 Btu/kWh (higher heating value [HHV]), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

The subcritical PC generating unit characterized here includes a single steam turbine generator and subcritical PC boiler fueled by low-grade sub-bituminous coal. Air quality control systems include low- NO_x burners, SCR for NO_x control, dry FGD for SO_2 control, activated carbon injection for mercury control, and fabric filters for particulate control. Heat rejection is accomplished by an air cooled condenser.

Table 10-11 presents the operating characteristics of the subcritical PC generating unit and Table 10-12 presents the estimated.

10.1.4.4 Conventional Technology Alternatives Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The estimated capital costs, O&M costs, schedules, forced outage, and maintenance assumptions for the conventional alternatives are summarized in Table 10-13. All costs are provided in 2009 dollars. The EPC cost is inclusive of engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. Owner’s costs were developed using the previously described assumptions, with site-specific cost additions or reductions as discussed previously. The assumed owner’s cost allowance is representative of typical owner’s costs, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses. Owner’s costs are specific to individual projects and may change from those presented in Table 10-13.

Fixed and variable O&M costs are also provided in 2009 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Variable costs include outage maintenance, consumables, and replacements dependent upon unit operation. Construction schedules are indicative of typical construction durations for the alternative technologies and plant sizes and represent estimated schedules from receipt of notice-to-proceed to commercial operation. Actual construction schedules will depend upon equipment delivery schedules, which are highly market driven, and therefore may be longer than those presented in Table 10-13. Actual costs may also vary from the estimates provided in Table 10-13.

The annual average scheduled and forced outage assumptions for the generating alternatives are also presented in Table 10-13. The scheduled forced outages represent the average outage through a complete maintenance cycle.

Table 10-11
Subcritical PC Thermal Performance Estimates

Ambient Condition	Net Capacity (MW)(1, 2)	Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Winter (-10º F and 100% RH) (Full Load)	128.1	9,830
Winter (15º F and 68% RH) (Full Load)	128.1	9,834
Winter (15º F and 68% RH) (75% Load)	96.0	10,143
Winter (15º F and 68% RH) (50% Load)	64.0	12,030
Winter (15º F and 68% RH) (Min Load)	51.2	12,246
Average (30º F and 68% RH) (Full Load)	128.1	9,843
Average (30º F and 68% RH) (75% Load)	96.0	10,109
Average (30º F and 68% RH) (50% Load)	64.0	11,734
Average (30º F and 68% RH) (Min Load)	51.2	12,547
Summer (59º F and 68% RH) (Full Load)	128.1	10,004

RH = Relative humidity.

(1)Net capacity and net plant heat rate include an applied 1.5% degradation factor.
(2)Net capacity and heat rate assume operation on a bituminous coal and petcoke blend.

Table 10-12
Subcritical PC Estimated Air Emissions(1)

NO_x, lb/MBtu	0.05
SO_2, lb/MBtu	0.06
CO_2, lb/MBtu	212
CO, lb/MBtu	0.10
PM_{10}, lb/MBtu	0.018

(1)Emissions are at full load at 30º F, reflect operation on sub-bituminous coal. All estimates are presented on the basis of HHV.

Table 10-13
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives (All Costs in 2009 Dollars)

Supply Alternative	EPC Cost ($Millions)(1)	Owner's Cost ($Millions)(2)	Total Cost ($Millions)	Full Load Net Capacity at 70° F (MW)	Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr) at 70° F	Variable O&M ($/MWh)	Construction Schedule (Months)(3)	Scheduled Maintenance (days)	Forced Outage (percent)
GE LM6000 SC	49.71	12.43	62.14	49.2	1,263	64.41	3.85	21	10	2
GE LMS100 SC	100.54	25.14	125.68	99.2	1,267	32.5	3.08	24	10	2
1x1 GE 6FA CC w/ Supplemental Firing	259.11	64.78	323.89	154.6	2,095	24.61	2.71	30	14	3
2x1 GE 6FA CC w/ Supplemental Firing	409.20	102.30	511.50	312.3	1,638	16.12	2.61	30	14	3
130 MW sub-critical PC	688.30	206.49	894.79	130.1	6,878	100.89	2.59	62	16	5

(1)EPC costs include SCR, CO catalyst, and dual fuel capability as applicable to each alternative.
(2)Owner's costs are specific to individual projects and may change from those presented.
(3)Construction schedules will depend upon equipment delivery schedules, which are highly market driven, and therefore may be longer than those presented.

10.2 Beluga Unit 8 Repowering

Currently, Chugach Electric plans to retire its Beluga Generation Unit Number 8, which is the steam turbine unit at the Beluga 2x1 combined cycle facility, at the end of 2014. As an alternative to building new gas fired generation, Chugach identified an option that would include rebuilding Unit 8 and continuing to operate the Beluga Generation plant in combined cycle mode through the end of 2034. The rebuild would occur over a three year period from 2014 through 2016 with a total cost of $50 million.

10.3 GVEA North Pole 1x1 Retrofit

GVEA identified an opportunity for a combined cycle retrofit at the existing North Pole combined cycle facility. The 1x1 North Pole combined cycle facility was built to accommodate another 1x1 train and the steam turbine is already sized for a 2x1. The retrofit involves adding an LM6000 and a heat recovery steam generator to the existing facility. The new 1x1 combined cycle train has a maximum capacity of 64 MW and a full load heat rate of 8,270 Btu/kWh. The capital cost for the retrofit has a total cost of $83 million in 2009 dollars. The variable O&M for the unit is modeled at $2.19/MWh. Since the fixed O&M costs are already modeled in the existing North Pole combined cycle unit, they are set at $0/kW-yr for the retrofitted unit.

10.4 Renewable Energy Options

10.4.1 Hydroelectric Project Options

Hydroelectric power is currently the Railbelt's largest source of renewable energy, responsible for approximately 9 percent of the Railbelt's electrical energy. Many of the State's developed hydro resources are located near communities in Southcentral, 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. The locations for the projects shown below represent either the service area in which the project is located or the transmission area shown in Figure 4-1 in which the project is interconnected to the Railbelt grid.

- Susitna - 380 – 1,880 MW, MEA
- Glacier Fork – 75 MW, MEA
- Chakachamna – 330 MW, Chugach (Anchorage)
- South Fork/Eagle River – 1 MW, MEA
- Fishhook – 2 MW, MEA
- Grant Lake/Falls Creek – 5 MW, Kenai
- 7 Other Small Hydro Projects in AEA's database

In addition, the developers of several proposed hydro projects (each with $5 million or above estimated project cost) on the Railbelt have applied for grant requests from the AEA Renewable Energy Fund Grant Program, which was established by Alaska Legislature in 2008. Table 10-14 shows each proposed hydro project's name, applicant, estimated project cost, grant requested, funding decision and amount recommended by AEA after two rounds of ranking and funding allocations conducted by AEA.

Based on review of the above information and discussion with stakeholders including the Railbelt Utilities, Black & Veatch assumed that the proposed Susitna, Chakachamna, and Glacier Fork projects will be considered as potential supply-side alternatives in this RIRP study along with a 5 MW generic hydro unit in the Kenai and a 2 MW generic hydro unit in MEA's service area. The following subsections discuss further details of these proposed projects.

Table 10-14
AEA Recommended Funding Decisions - Hydro

Project Name	Applicant	Project Cost ($000)	Grant Requested ($000)	Recommended Funding Decision	Recommended Funding Amount ($000)
Grant Lake/Falls Creek Hydro Feasibility Study	Kenai Hydro, LLC	$26,924	$816	Full funding	$816
Fourth of July Creek Hydro Reconnaissance	Independence Power, LLC	$15,675	$7,838	Partial funding	$20
Victor Creek Hydro(1)	Kenai Hydro, LLC	$19,860	$88	Full funding	$88
Glacier Fork Hydro	Glacier Fork Hydro, LLC	$330,000	$5,000	Partial funding	$500
Archangel Creek Hydro	Archangel Green Power, LLC	$6,420	$100	Not recommended(2)	None
Nenana Healy Hydro Phase II	GVEA	$24,000	$2,200	Application Withdrawn	None

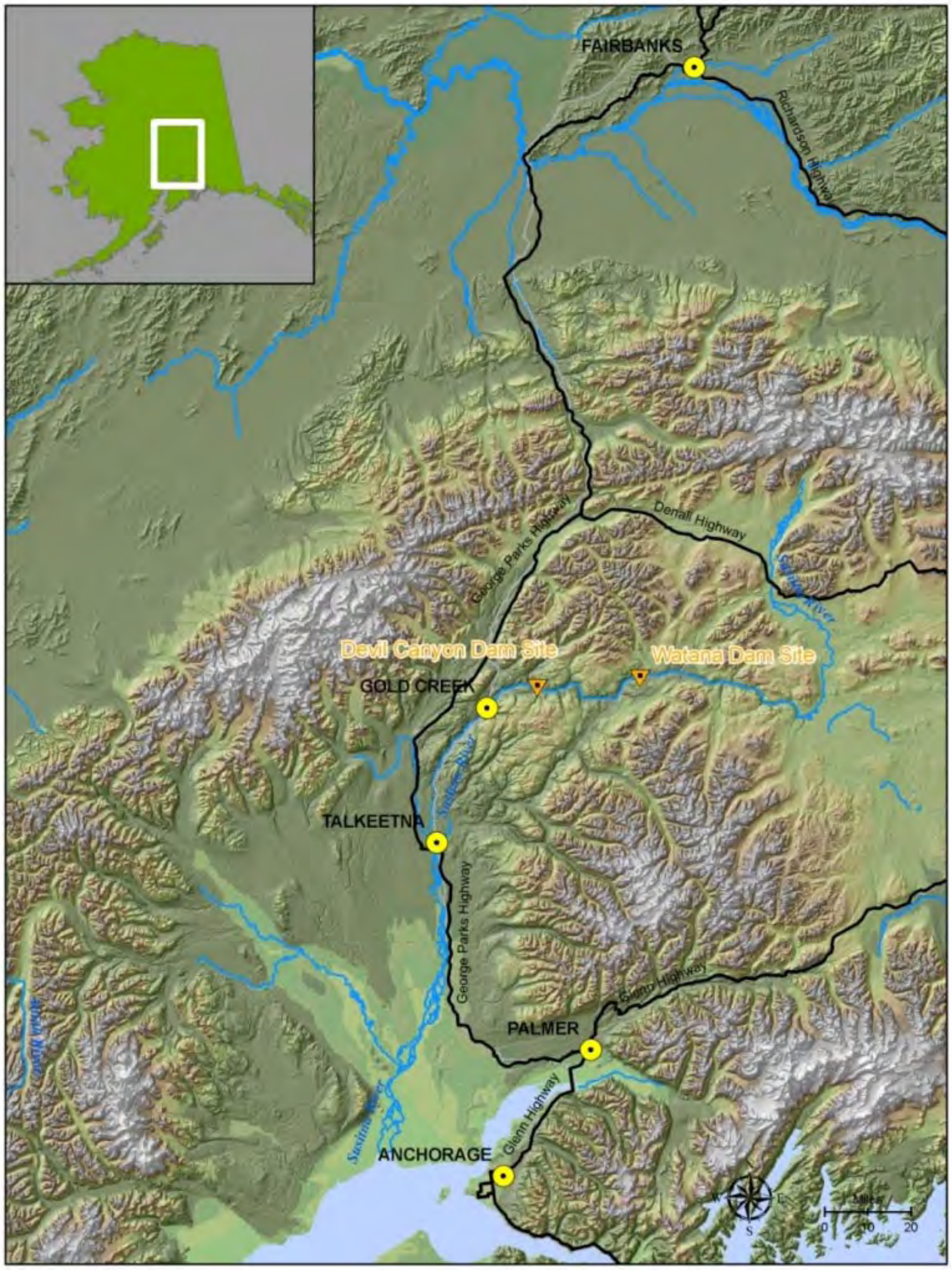
Note:
1. Project failed to get funding after the appropriation for Round 2 was limited to $25 million.
2. The project did not pass Stage 2 review or was excluded in Stage 3 review for geographical spreading.

10.4.1.1 Susitna Project

Description of Project
A hydroelectric project on the Susitna River has been studied for more than 50 years and is again being considered by the State of Alaska as a long term source of energy. In the 1980s, the project was studied extensively by the Alaska Power Authority (APA) and a license application was submitted to the Federal Energy Regulatory Commission (FERC). Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986. The project's location is shown in Figure 10-1.

In 2008, the Alaska State Legislature authorized the AEA to perform an update of the project. That authorization also included this RIRP project to evaluate the ability of this project and other sources of energy to meet the long term energy demand for the Railbelt region of Alaska. Of all the hydro projects in the Railbelt region, the Susitna projects are the most advanced and best understood.

Figure 10-1
Proposed Susitna Hydro Project Location
(Source: HDR)



HDR was contracted by AEA to update the cost estimate, energy estimates and the project development schedule for a Susitna River hydroelectric project. The results of that study, except for the detailed appendices, are included in Appendix A (note: one of the detailed appendices in the HDR Report [Appendix D], which is not included in Appendix A of this report, addresses the issue of the potential impact of climate changes on Susitna's resource potential; this appendix can be viewed in the full HDR report which is available on the AEA web site).

The initial alternatives reviewed were based upon the 1983 FERC license application and subsequent 1985 amendment which presented several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 MW.
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.
- **Devil Canyon.** This alternative consists of the construction of a 646-foot-high concrete dam at the Devil Canyon site with a four-unit powerhouse with a total installed capacity of 680 MW.
- **Watana/Devil Canyon.** This alternative consists of the full-height Watana development and the Devil Canyon development as presented in the 1983 FERC license application. The two dams and powerhouses would be constructed sequentially without delays. The combined Watana/Devil Canyon development would have a total installed capacity of 1,880 MW.
- **Staged Watana/Devil Canyon.** This alternative consists of the Watana development constructed in stages and the Devil Canyon development as presented in the 1985 FERC amendment. In stage one the Watana dam would be constructed to the lower height and the Watana powerhouse would only have four out of the six turbine generators installed, but would be constructed to the full sized powerhouse. In stage two the Devil Canyon dam and powerhouse would be constructed. In stage three the Watana dam would be raised to its full height, the existing turbines upgraded for the higher head, and the remaining two units installed. At completion, the project would have a total installed capacity of 1,880 MW.

As the RIRP process defined the future Railbelt power requirement it became evident that lower cost hydroelectric project alternatives, that were a closer fit to the energy needs of the Railbelt, should be sought. As such, the following single dam configurations were also evaluated:

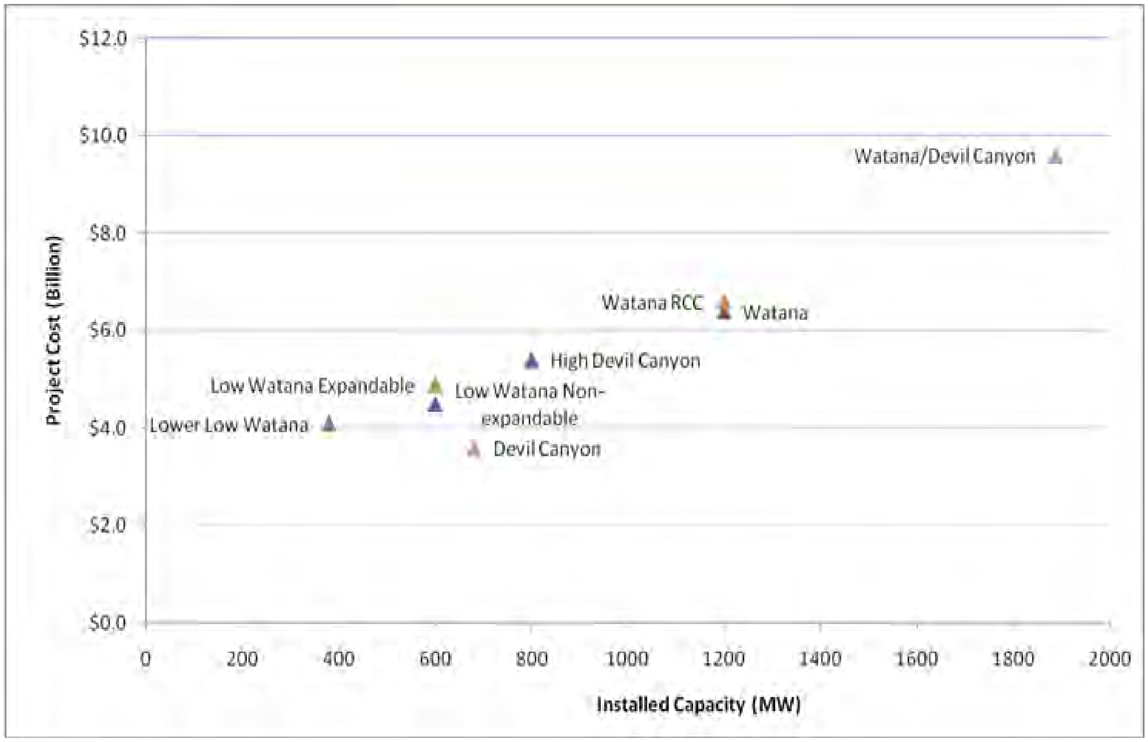
- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing four turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative consists of the Watana dam constructed to a height of 650 feet along with a powerhouse containing three turbines with a total installed capacity of 380 MW. This alternative has no provisions for future expansion.
- **High Devil Canyon.** This alternative consists of a roller-compacted concrete (RCC) dam constructed to a height of 810 feet, along with a powerhouse containing four turbines with a total installed capacity of 800 MW.
- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing six turbines with a total installed capacity of 1,200 MW.

The results of this study are summarized in Table 10-15 and a comparison of project size versus project cost is shown in Figure 10-2.

Table 10-15
Susitna Summary

Alternative	Dam Type	Dam Height (feet)	Ultimate Capacity (MW)	Firm Capacity, 98% (MW)	2008 Construction Cost ($ Billion)	Energy (GWh/yr)	Schedule (Years from Start of Licensing)
Lower Low Watana	Rockfill	650	380	170	$4.1	2,100	13-14
Low Watana Non-expandable	Rockfill	700	600	245	$4.5	2,600	14-15
Low Watana Expandable	Rockfill	700	600	245	$4.9	2,600	14-15
Watana	Rockfill	885	1,200	380	$6.4	3,600	15-16
Watana RCC	RCC	885	1,200	380	$6.6	3,600	15-16
Devil Canyon	Concrete Arch	646	680	75	$3.6	2,700	14-15
High Devil Canyon	RCC	810	800	345	$5.4	3,900	13-14
Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$9.6	7,200	15-20
Staged Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$10.0	7,200	15-24

Figure 10-2
Comparison of Project Cost Versus Installed Capacity



In all cases, the ability to store water increases the firm capacity over the winter. Projects developed with dams in series allow the water to be used twice. However, because of their locations on the Susitna River, not all projects can be combined. The Devil Canyon site precludes development of the High Devil Canyon site but works well with Watana. The High Devil Canyon site precludes development of Watana but could potentially be paired with other sites located further upstream.

Mode of Operation

All of the alternatives identified have significant storage capability which enhances their benefits to the Railbelt Utilities. Table 10-16 presents the average annual and average monthly generation from each of the alternatives.

Capital Costs

The estimated capital costs for the alternative Susitna projects are presented in Table 10-15. For evaluation purposes, the capital cost for the Low Watana expansion to Watana is estimated as the difference in costs between Watana and Low Watana (Expansion) since it was not part of HDR's scope and they did not explicitly develop the cost for expansion.

Table 10-16
Average Annual Monthly Generation from Susitna Projects (MWh)

Alternative	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Lower Low Watana (non-expandable)	2,006,000	127,000	116,000	127,000	117,000	101,000	208,000	270,000	28,000	256,000	153,000	123,000	128,000
Low Watana (non-expandable)	2,617,000	182,000	166,000	183,000	176,000	119,000	241,000	334,000	378,000	315,000	157,000	180,000	186,000
Low Watana (expandable)	2,617,000	182,000	166,000	183,000	176,000	119,000	241,000	334,000	378,000	315,000	157,000	180,000	186,000
Watana	3,676,000	280,000	254,000	279,000	261,000	498,000	443,000	370,000	326,000	237,000	169,000	275,000	284,000
High Devil Canyon	3,891,000	262,000	235,000	257,000	247,000	287,000	382,000	468,000	522,000	467,000	251,000	252,000	261,000
Low Watana (Expansion)	1,059,000	73,648	67,174	74,053	71,220	48,155	97,524	135,157	152,962	127,468	63,532	72,839	75,267

O&M Costs
O&M costs include fixed and variable costs. Fixed O&M costs for the Susitna hydro projects vary based on the number of turbines, transformers, and dams in each specific project. A schedule and cost estimate of major maintenance items were provided by HDR through time.

Schedule
HDR provided development schedules for the original Susitna alternatives as shown in Table 10-15.

10.4.1.2 Chakachamna Project

Description of Project
TDX Power, Incorporated (TDX) is developing a hydro project on the Chakachamna River system. The proposed project will divert stream flow via a lake tap from the Chakachamna River to a powerhouse on the McArthur River via a 25 foot diameter power tunnel that will be approximately 10 miles long. The project will be located approximately 42 miles from Chugach's Beluga power generating facility. Figure 10-3 illustrates the proposed project's location. According to TDX, the proposed project will have an installed capacity of 330 MW, and will be able to generate approximately 1,600 GWh of electricity annually. Table 10-17 shows the average monthly and annual energy that will be generated by the project.

Figure 10-3
Proposed Chakachamna Hydro Project Location
(Source: TDX)

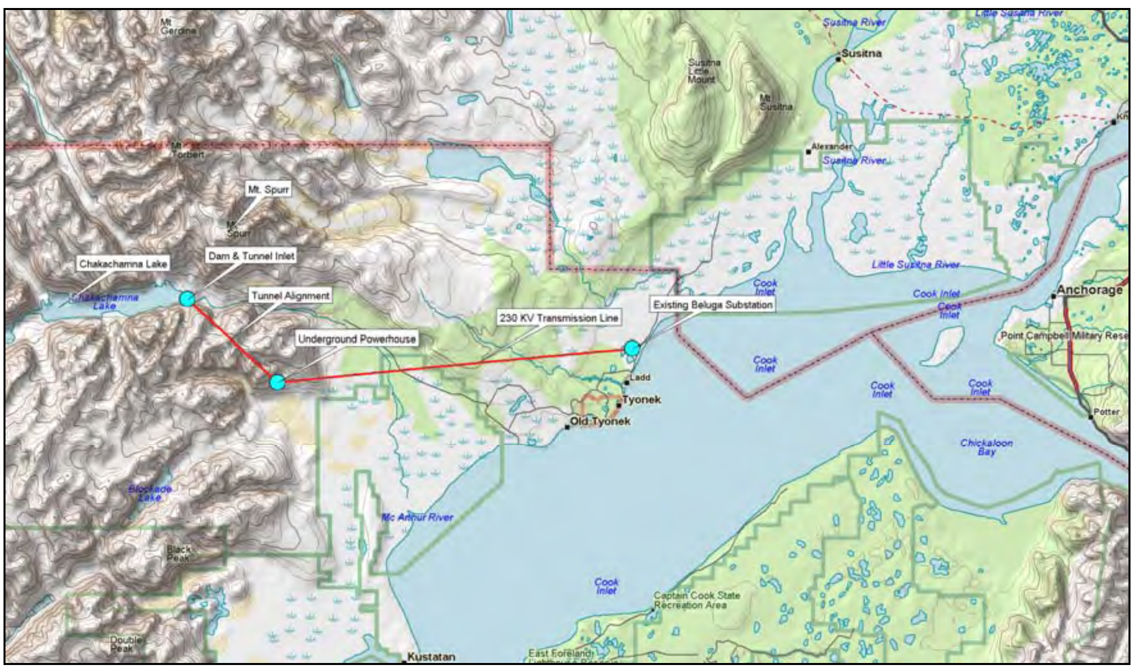


Table 10-17
Monthly Average and Annual Generation

Month	Generation (GWh)
January	163
February	140
March	138
April	120
May	113
June	106
July	108
August	113
September	120
October	142
November	158
December	177
Total	**1,598**

The project will not require the construction of a dam on the Chakachamna Lake, but fish gates will be installed at the outlet of the lake. The reservoir has approximately 16,700 acres of water surface at an elevation of 1,142 feet. Other facilities that will be constructed include fish passage facilities for adult migration and juvenile outmigration, a 42-mile transmission line from the project site to Chugach's Beluga substation, and site access.

Mode of Operation
It is expected that this project will be designed and permitted as a diverted flow type hydroelectric generating facility.

Capital Costs
According to TDX, the total capital cost of the proposed project will be approximately $1.6 billion in 2008 dollars or $5,100/kW in 2009 dollars. Transmission costs of $58 million are included in capital costs.

O&M Costs
O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation.

According to TDX, the total O&M cost for the proposed project will be approximately $10 million per year in 2008 dollars or $30/kW-Yr in 2009 dollars.

For the purpose of this study, Black & Veatch assumes that the variable O&M costs will be zero, and the fixed O&M costs will be $30/kW-Yr in 2009 dollars.

Schedule
Base on the schedule provided by TDX in their April 2009 presentation, TDX expects that the proposed hydro generating project could be available for commercial operations starting in 2017.

10.4.1.3 Glacier Fork

Description of Project
The proposed Glacier Fork project is a 75 MW hydroelectric project being developed by Glacier Fork Hydropower LLC on the Knik River, approximately 25 miles southeast of Palmer in the Matanuska-Susitna Borough.

According to information provided by Glacier Fork Hydropower LLC, the project would consist of: 1) a proposed 800-foot-long, 430-foot-high dam; 2) a proposed reservoir having a surface area of 390 acres and a storage capacity of 75,000 acre-feet and normal water surface elevation of 980 feet above mean low sea level (msl); 3) a proposed 8,300-foot-long, 12-foot diameter steel penstock; 4) a proposed powerhouse containing three generating units having an installed capacity of 75 MW; 5) a proposed tailrace; 6) a proposed 25-mile-long, 115-kilovolt transmission line; and 7) appurtenant facilities.

The proposed Glacier Fork Hydroelectric Project would have an average annual generation of 330 GWh. The estimated average monthly generation is presented in Table 10-18.

Table 10-18
Glacier Fork Hydroelectric Project
Average Monthly Energy Generation

Month	Average Monthly Energy (MWh)
Installed Capacity (MW)	75
January	6,755
February	5,314
March	4,882
April	6,727
May	28,794
June	53,612
July	55,400
August	55,400
September	53,305
October	35,964
November	13,767
December	7,617
Annual Total (MWh)	327,538

Note: Data based on USGS Gauge on Knik River.

Mode of Operation
As indicated in Table 10-18, the Glacier Fork project is primarily a run-of-river project with the ability to provide firm capacity significantly reduced from its nameplate ratings during winter and spring. This reduced output during these periods was included in the Strategist® and PROMOD® modeling.

Capital Costs
The total capital cost of the proposed project will be approximately $4,400/kW, or $330 million, in 2009 dollars. Transmission costs are assumed to be $22.5 million (25 miles, 115 kV @ $900K/mile) and are included in capital cost.

Operation and Maintenance Cost
O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation.

The total O&M cost for the proposed project will be approximately $68/kW-Yr in 2009 dollars. For the purpose of this study, Black & Veatch assumed that the variable O&M costs will be zero, and the fixed O&M costs will be $68/kW-Yr in 2009 dollars.

Schedule
Based on information provided by Glacier Fork Hydropower LLC, the proposed hydro generating project could be available for commercial operations starting Fall 2014 at the earliest.

10.4.1.4 Generic Hydroelectric Projects
Black & Veatch developed two small, generic hydroelectric project alternatives to represent several hydroelectric opportunities that have been identified in the Railbelt. The first hydroelectric project is a 5 MW project located in the Kenai area. The project is assumed to have 20 GWh of average annual energy with a capital cost of $35 million in 2009 dollars. The other generic project is a 2 MW project located in MEA's area. The MEA project is assumed to have an average annual energy of 7.5 GWh and a capital cost of $16 million in 2009 dollars.

10.4.2 Ocean (Tidal Wave) Project Option
Alaska has a wide coastal area that allows for the consideration of renewable tidal resources. The Cook Inlet in particular offers a great potential for tidal projects since it has the fourth highest tide in the world with 25 feet (7.6m) between low tide and high tide. Also, it is located between Anchorage, Alaska's largest city, and Kenai, where a number of industries are located.

Some institutions are already interested in taking advantage of this resource in this particular location and have started studies and licensing for tidal projects including the Turnagain Arm Tidal Electric Generation Project.

There are several different technologies available for tidal projects. Based on Black & Veatch's review of available information, we assumed that the proposed Turnagain Arm tidal project would be representative of the technologies available, although it is Black & Veatch's opinion that tidal energy is not to the level of commercialization equivalent to other conventional and renewable alternatives considered in the RIRP. The ultimate selection of the optimal technology for Railbelt conditions will need to be based on additional analysis. As a result, tidal energy will be considered as a sensitivity case in the evaluations. The following subsections discuss further details of the proposed project.

10.4.2.1 Turnagain Arm

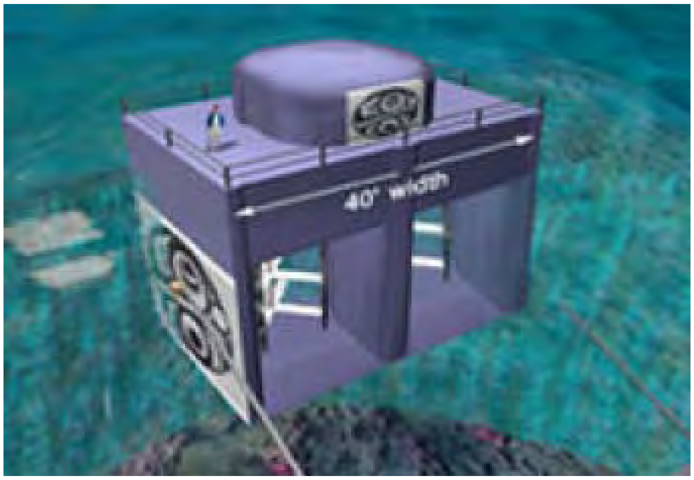
Description of Project
Little Susitna Construction Co. and Blue Energy Canada filed an application for a preliminary FERC permit for the Turnagain Arm Tidal Project, to be developed in Cook Inlet.

According to the preliminary permit application, the project calls for the use of Blue Energy's Tidal Bridge which will use the Davis Turbine to generate electricity with the movement of the tides. The Davis Turbine is a mechanical device that employs a hydrodynamic lift principle, causing vertically oriented foils to turn a shaft and a generator. Figure 10-4 shows an array of vertical-axis tidal turbines stacked and joined in series across a marine passage.

Figure 10-4
Blue Energy's Tidal Bridge With Davis Turbine
(Source: Blue Energy)

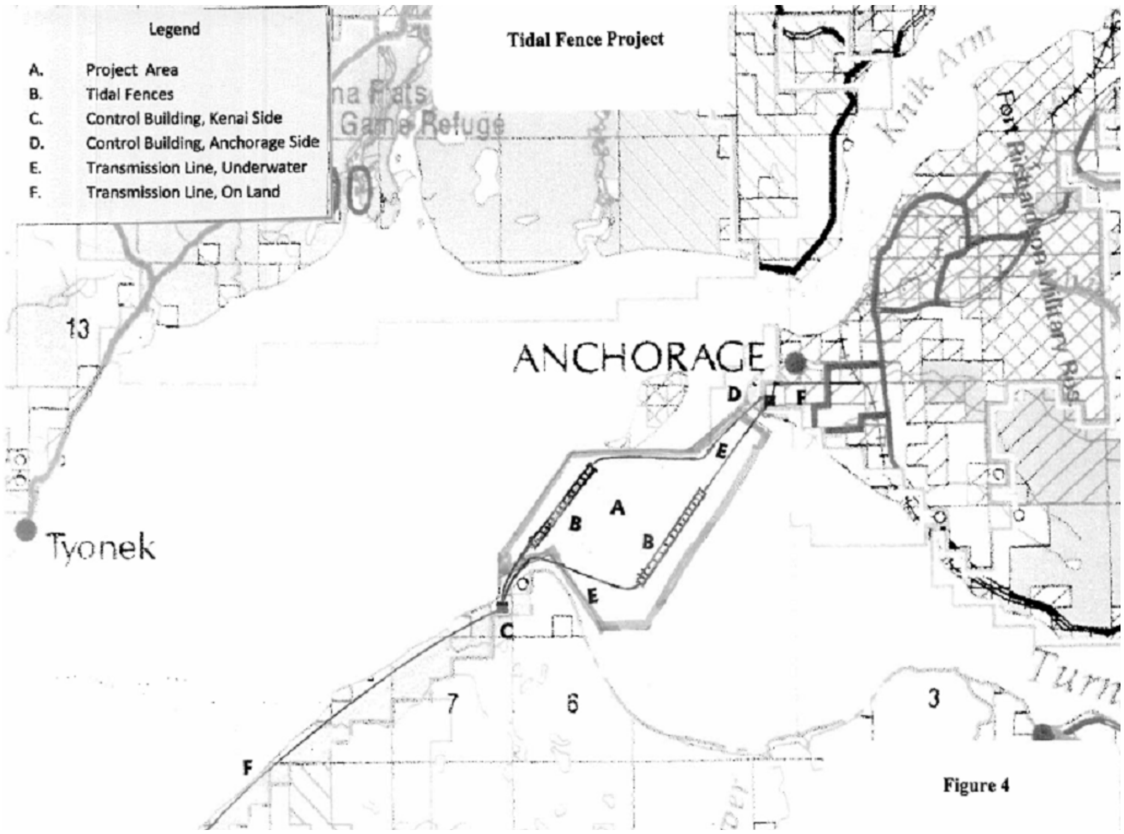
This turbine is comprised of vertical hydrofoils attached to a central shaft transmitting torque to a generator. The kinetic energy from tidal flows can thus be harnessed and converted to electrical energy. Contrary to the traditional drag driven paddle wheel design, the Davis turbine rotor is designed to be lift driven, much like the modern wind turbines, thus allowing the blades to operate at a significantly higher efficiency. In order to further increase the efficiency of the turbine, the entire rotor assembly is housed in a thin-shell marine concrete caisson structure that channels the water flow and acts as a housing for the generator and electrical components. The shape of the caisson inner walls accelerate the velocity of the water flow through the turbine rotor by acting as a venturi and controls flow direction to provide more uniform turbine performance. In addition, the Davis turbine is designed to work through the entire tidal range with a typical cut-in speed of 1m/s. Figure 10-5 shows the configuration of a Davis tidal turbine.

Figure 10-5
Cutaway Graphic of a Mid-Range-Scale Vertical Axis Tidal Turbine
(Source: Blue Energy)



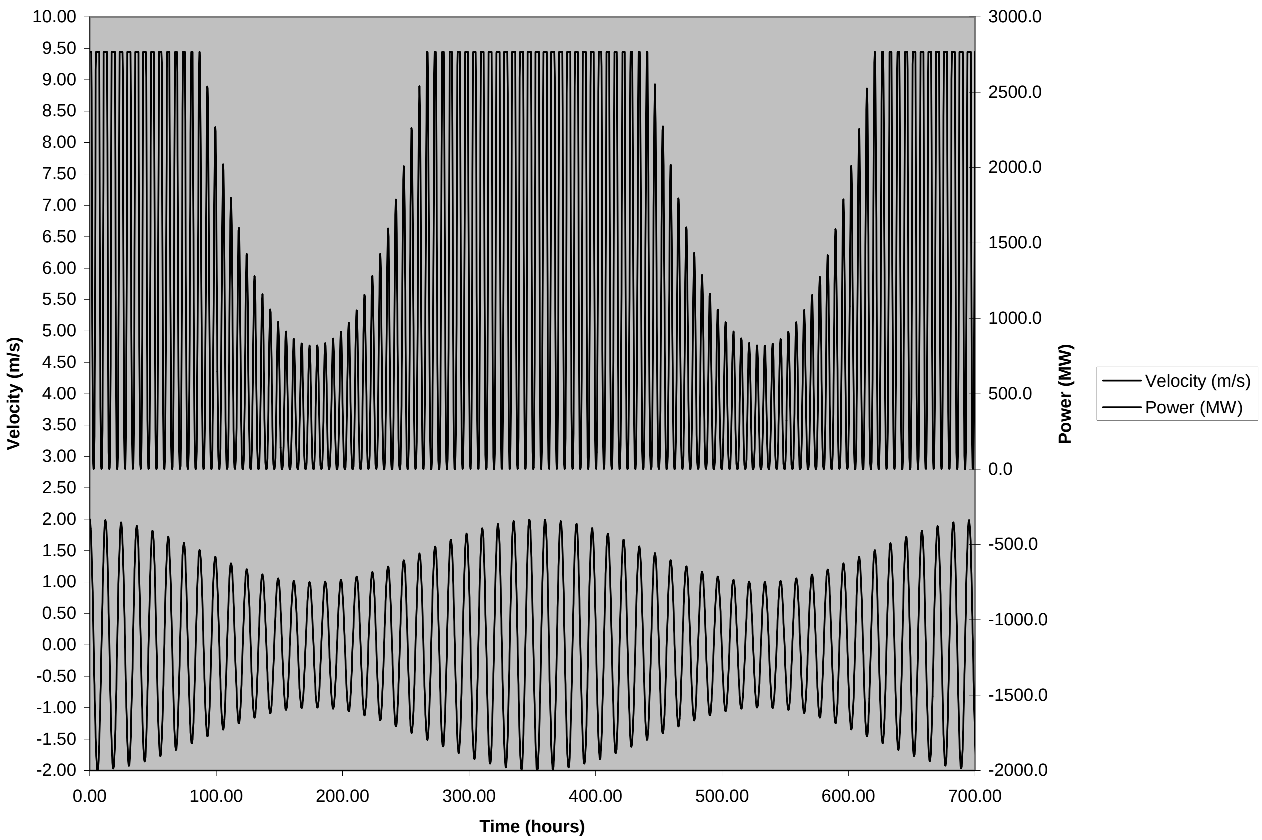
The Turnagain Arm tidal project would be comprised of two tidal fences each eight miles long extending from Kenai to Anchorage, with minimum separation of five miles to allow the tidal force to recover its strength after going through the first fence. The tidal fence will have a service road across the top and connected to the land. Two control buildings would be required, one located near Possession Point in Kenai Borough and the other along Raspberry Road in Anchorage. They will be connected by a pair of transmission lines across the tidal fence and connect to the HEA grid on the Kenai side and to the Chugach grid on the Anchorage side. From there, the power can be moved throughout the Railbelt grid. Figure 10-6 depicts the proposed layout of the tidal plant.

Figure 10-6
Proposed Layout of the Turnagain Arm Tidal Project
(Source: Little Susitna Construction Co. and Blue Energy of Canada)



Mode of Operation
Tidal energy while fairly predictable is very variable. Black & Veatch conducted a high level analysis of the monthly generation from the Turnagain Arm tidal project. That analysis is presented in Figure 10-7.

Figure 10-7
Turnagain Arm Tidal Project Monthly Generation



As discussed for the large Susitna options, the capacity of the Turnagain Arm tidal project significantly exceeds the Railbelt loads. For evaluation purposes, Black & Veatch modeled a 100 MW project with following $/kW cost.

Capital Costs
Capital costs of $2.5 billion in 2009 dollars for the 1,200 MW Turnagain Arm tidal project or approximately $2,100/kW are expected, including supporting infrastructure. Black & Veatch's experience with the development of similar projects indicates that the Turnagain Arm tidal project costs are significantly lower than other projects that Black & Veatch has worked with. For evaluation purposes, Black & Veatch has used a capital cost of $4,200/kW.

O&M Costs
O&M costs include fixed and variable costs.

Fixed O&M Costs
Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. For the purpose of this study, the fixed O&M costs associated with the project are estimated to be $42 /kW-year in 2009 dollars.

Variable O&M
Variable O&M costs include consumables, chemicals, lubricants, major inspections, and overhauls of the turbine generators and associated equipment. Variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch has assumed no Variable O&M costs for this project.

Schedule
Black & Veatch expects that the proposed tidal generating project will be available for commercial operations starting in 2020 at the earliest.

10.4.3 Geothermal Project Option

Description of Project
Ormat Technologies, Inc (Ormat) has approached the AEA for the potential development of a geothermal power plant project at Mount Spurr, which is located approximately 33 miles from Tyonek, Alaska. According to Ormat, there is the potential geothermal resource to develop a geothermal power plant project with an estimated maximum output of 50–100 MW at Mount Spurr.

Depending on the specific resource conditions available at Mount Spurr, the proposed geothermal project option will likely be based on either a binary geothermal power plant configuration or a geothermal combined cycle power plant configuration.

Figure 10-8 illustrates a simplified binary geothermal power plant process diagram. A geothermal fluid (brine, or steam, or a mixture of brine and steam) from an underground reservoir can be used to drive a binary plant. The geothermal fluid flows from the wellhead to heat exchangers through pipelines. The fluid is used to heat and vaporize a secondary working fluid in the heat exchangers. The secondary working fluid is typically an organic fluid with a low boiling temperature point. The generated vapors are used to drive an organic vapor turbine, which powers the generator, and then are condensed in a dry cooled or wet cooled condenser. The condensed secondary fluid is then recycled back into the heat exchangers by a pump while the geothermal fluid is re-injected into the reservoir.

Figure 10-9 illustrates a simplified geothermal combined cycle power plant process diagram. A geothermal combined cycle is most effective when the available geothermal resource is mostly steam. The high-pressure steam from a separator drives a back pressure turbine. The low-pressure steam exits this turbine at a positive pressure and flows into the vaporizer. The heat of condensation of the low-pressure steam is used to vaporize a secondary working fluid and the expansion of these secondary fluid vapors drives the secondary turbine. The secondary fluid vapors are then condensed, and pumped back into the pre-heater and the geothermal fluid is re-injected into the reservoir.

For the purpose of this study, Black & Veatch assumed that the proposed geothermal project can be developed in two 50 MW blocks.

Figure 10-8
Simplified Binary Geothermal Power Plant Process
(Source: Ormat)

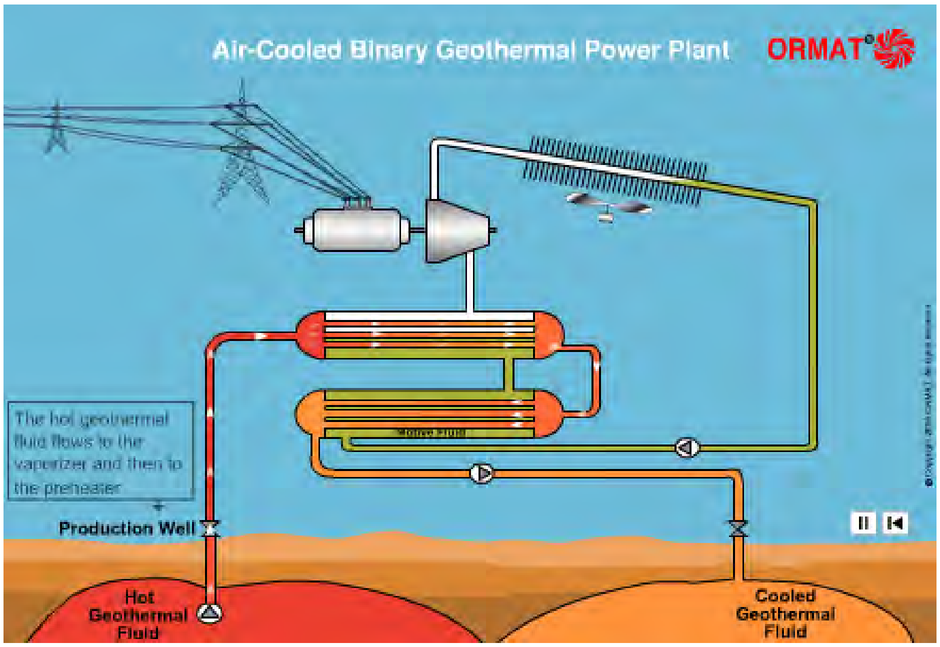
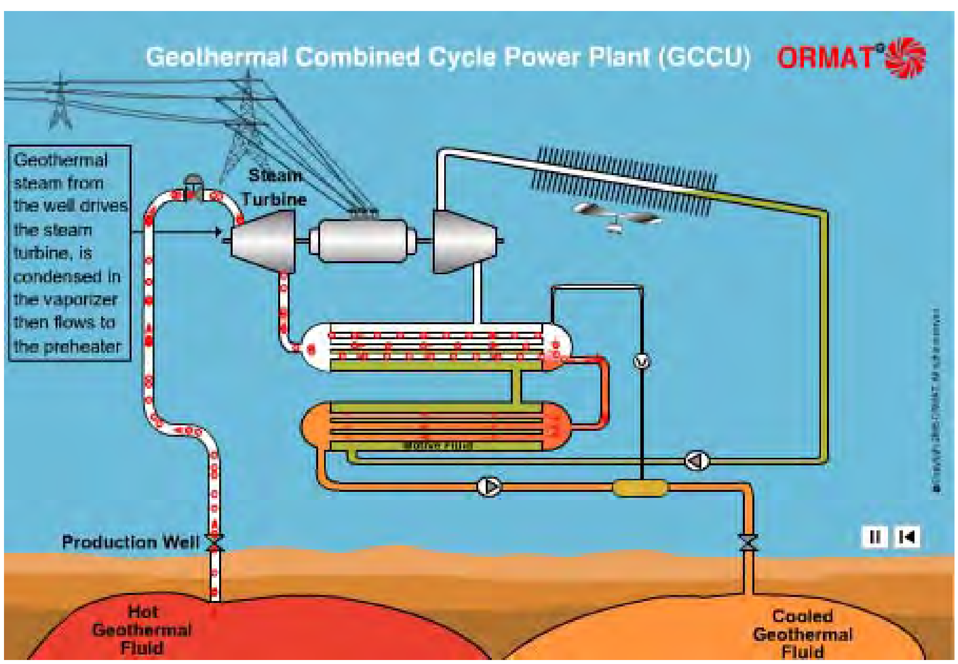


Figure 10-9
Simplified Geothermal Combined Cycle Power Plant Process
(Source: Ormat)



Mode of Operation

It is expected that the geothermal power plant project will be designed and permitted for baseload operations. Black & Veatch assumed that the proposed geothermal plant will be able to achieve 95 percent availability factor during its first commercial operation year and will experience approximately 0.5 percent output degradation annually for the following nine years until new wells are drilled to replace old wells. Black & Veatch also assumed that the estimated cost for drilling a new well to replace an old well will be approximately $2 million per well in 2009 dollars.

Based on the above assumptions and for the purpose of this study, Black & Veatch assumed that the proposed geothermal plant will operate at an average capacity factor of approximately 90 percent for 30 years, with an estimated levelized well drilling and replacement cost of $20/kW-year.

Capital Costs

Ormat did not provide estimated capital cost data for review by Black & Veatch. For the purpose of this study, Black & Veatch assumed that the construction cost for the first block of the proposed geothermal project will be approximately $4,000/kW in 2009 dollars. Black & Veatch assumed that this cost includes engineering, procurement, and construction costs for equipment, materials, construction contracts, and other indirect costs. Black & Veatch assumed that owner’s cost items such as land, contingency, etc., will be approximately $1,000/kW in 2009 dollars, or 25.0 percent of the project construction cost. Therefore, it is anticipated that the total capital cost for the proposed project will be approximately $5,000/kW in 2009 dollars. The capital cost for the second block is assumed to be 10 percent less than the first block.

O&M Costs

O&M costs include fixed and variable costs.

Fixed O&M Costs

Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. Therefore, for the purpose of this study the fixed O&M costs associated with the project are estimated to be $300/kW-year in 2009 dollars.

Variable O&M Costs

Variable O&M costs include consumables, chemicals, lubricants, water, major inspections, and overhauls of the steam turbine generator and associated equipment. Variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $2.00/MWh in 2009 dollars.

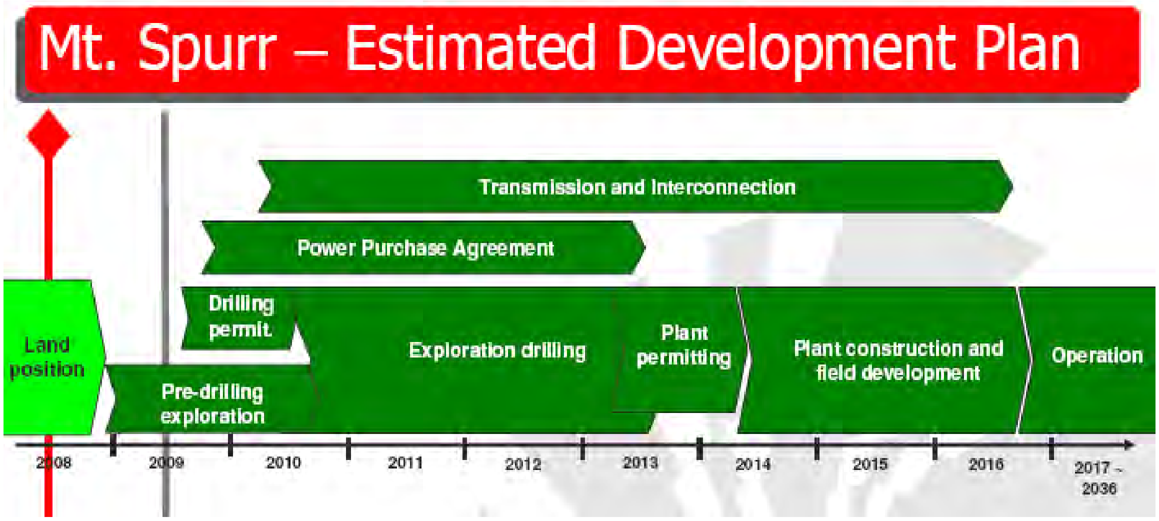
Availability Factor

Availability factor is a measure of the availability of a generating unit to produce power considering operational limitations such as unexpected equipment failures, repairs, routine maintenance, and scheduled maintenance activities. For the purpose of this study, Black & Veatch assumed that the initial availability factor of this proposed geothermal plant will be 95 percent.

Schedule

Figure 10-10 illustrates the estimated project development plan that Ormat presented to AEA on June 16, 2009. The plan indicates that the proposed geothermal project can be available for commercial operation by the end of 2016. For the purpose of this study, Black & Veatch assumed that the first proposed 50 MW geothermal generating units will be available for commercial operations starting in 2016.

Figure 10-10
Estimated Mount Spurr Project Development Plan
(Source: Ormat)



10.4.4 Wind Project Options

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. 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. Alaska appears to also have significant potential for off-shore wind projects. Since off-shore wind projects are generally more expensive than on-shore projects, off-shore projects are not explicitly considered in this study.

In the Railbelt, several of the utilities are examining wind power projects, including:

- BQ Energy/Nikiski – 15 MW, HEA
- Fire Island – 54 MW, Chugach
- Eva Creek – 24 MW, GVEA
- Delta Junction – 50 MW, GVEA
- Arctic Valley – 25 MW, Chugach
- Bird Point – 10 MW, Chugach
- Alaska Environmental Power – 15 MW, GVEA
- 63 Other Projects in AEA's Data Base

In addition, the developers of several proposed wind projects in the Railbelt have applied for grant requests from the AEA Renewable Energy Fund Grant Program, which was established by Alaska Legislature in 2008. Table 10-19 shows each proposed wind project's name, applicant, estimated project cost, grant requested, and funding decision and amount recommended by AEA after two rounds of ranking and funding allocations conducted by AEA.

Table 10-19
AEA Recommended Funding Decisions - Wind

Project Name	Applicant	Project Cost ($000)	Grant Requested ($000)	Recommended Funding Decision	Recommended Funding Amount ($000)
Nikiski Wind Farm	Kenai Winds, LLC	$46,800	$11,700	Partial funding	$80
Kenai Winds	Kenai Winds, LLC	$21,000	$5,850	Partial funding	$2,000
AVTEC Wind	Alaska Vocational Technical Center	$709	$635	Not recommended[1]	None
Delta Wind	Alaska Wind Power, LLC	$135,300	$13,000	Not recommended[1]	None

Note:
1. The project did not pass Stage 2 review or was excluded in Stage 3 review for geographical spreading.

Black & Veatch studied the details of each proposed wind project and applied the following screening criteria to determine which developments could be considered as a potential supply-side alternative in this RIRP study:

- Project size: Larger than 5 MW
- Permitting: In place or in progress
- Power Purchase Agreements (PPA): In place or in progress
- Readiness: Prepared for construction by end of 2010

Based on the review of the above information, Black & Veatch assumed that the proposed Fire Island project and the proposed BQ Energy/Nikiski project be considered as potential supply-side alternatives in this RIRP study. The following subsections discuss further details of these proposed projects.

10.4.4.1 Fire Island

Description of Project
A joint venture (JV) of CIRI, an Alaska Native Corporation, and enXco Development Corporation (enXco) has approached AEA for the potential development of a wind generation project on Fire Island, which is located in Cook Inlet approximately three miles off Point Campbell in Anchorage, Alaska. On May 14, 2009, the JV made a presentation to AEA to provide AEA staff with the latest status update of the proposed Fire Island Project. According to the JV, there is the potential to develop a wind generation plant with an estimated maximum output of 54 MW on Fire Island. Figure 10-11 illustrates a visual simulation of the proposed Fire Island wind generation project.

Figure 10-11
Visual Simulation of Fire Island Wind Generation Project
(Source: CIRI/enXco Joint Venture)

Figure 10-12 illustrates a preliminary site arrangement and interconnection route of the proposed wind project. The project will be based on installation of up to 36 GE 1.5 MW wind turbines. Each wind turbine will be equipped with reactive power and voltage support capabilities. The project is planned to be interconnected via 34.5 kV underground and submarine cables from an on-site 34.5 kV collector substation to Chugach's Raspberry substation. In addition, it is expected that the project will require the construction of a 5,000 square foot maintenance facility, approximately nine miles of gravel roads, and on-island housing facility for five maintenance staff.

For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be developed as a 54 MW nameplate-rated project.

Mode of Operation
It is expected that the wind generation project will be designed and permitted for intermittent operations subject to wind resource availability at the project site.

Capital Costs
EnXco provided estimated installed capital cost of $3,100/kW including interconnection costs. Since providing the cost estimate, enXco has closed their Anchorage office and Black & Veatch has been unable to confirm if the $3,100/kW capital cost included benefits of the American Recovery and Reinvestment Act of 2009. In 2008 the Alaska Legislature appropriated $25 million for the construction of the proposed underground and submarine cable project to interconnect the proposed wind generation project to the Railbelt grid.

Figure 10-12
Preliminary Site Arrangement and Interconnection Route
(Source: CIRI/enXco Joint Venture)

O&M Costs
O&M costs include fixed and variable costs.

Fixed O&M Costs
Fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. Black & Veatch assumed $122/kW-yr in $2009 for fixed O&M costs.

Variable O&M
Variable O&M costs include consumables, lubricants, and major inspections of the wind turbine generators and associated equipment. Variable O&M costs vary as a function of plant generation. AEA provided and estimate of $9.75/MWh in 2008 dollars for variable O&M costs for Fire Island. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $10.00/MWh in 2009 dollars.

Capacity Factor
According the JV's May 14, 2009 presentation, the proposed wind generation plant will be able to achieve approximately 33 percent average capacity factor during its operating years.

Schedule
It is Black & Veatch understanding the proposed wind generation project has completed the following activities:

- Reached consensus to interconnect the project with Chugach at 34.5 kV level in the June 2008 meeting with Chugach, ML&P, HEA, and GVEA.
- Received proposals and met with potential construction contractors.
- Submitted draft power purchase agreements (PPAs) to Chugach, ML&P, HEA, and GVEA.

- Initiated integration studies.
- Received the U.S. Army Corps of Engineers permit approval for the proposed wind generation and related electricity transmission infrastructure project.

According the JV's May 14, 2009 presentation, the JV expects to begin site preparation work in 2009, complete the project design and site preparation in 2010, and begin erection of wind turbines in 2011. For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be available for commercial operations starting in 2012.

10.4.4.2 BQ Energy/Nikiski

Description of Project
The project, being developed by Kenai Winds LLC, is a 15 MW wind energy generation facility to be located in the Nikiski Industrial Area, in Nikiski, on the Kenai Peninsula, close to the Tesoro Refinery (Figure 10-13).

There is very little supporting infrastructure required. Kenai Winds does not require new power lines (other than local collection system) and does not require new roads, ports, nor aircraft access facilities.

There are several possible points of delivery in the area of the wind farm. The optimum location among those choices has not been selected, but HEA has agreed to purchase the full output of the Kenai Winds project.

The developer applied for a grant from the AEA Renewable Energy Fund Grant Program and was approved, during Round 1, funding for $80,000 to complete development activities.

On March 6, 2009 the developer submitted Supplemental Information to its previous Request for Grant Application to provide AEA staff with the latest status update of the proposed BQ Energy/Nikiski project. Details of the information contained in this document will be presented in the following subsections.

Figure 10-13
Kenai Peninsula, Nikiski
(Source: Kenai Winds LLC)

Mode of Operation
It is expected that the wind generation project will be designed and permitted for intermittent operations subject to wind resource availability at the project site.

Capital Costs
Capital costs are estimated to be $1,933/kW in 2009$ with limited supporting infrastructure required.

O&M Costs
O&M costs include fixed and variable costs. O&M costs of $0.023/kWh in 2009 dollars based on AEA's analysis of non-rural projects.

Capacity Factor
According to the March 6, 2009 document presented by Kenai Winds to AEA, preliminary review of the meteorological data available yields that the net capacity factor from the project is expected to be 28 percent.

Schedule
It is Black & Veatch understanding the proposed wind generation project has completed the following activities:

- Received the US Federal Aviation Administration permit approval for the proposed wind generation.
- Reached consensus to interconnect the project with HEA.
- Submitted draft power sales term sheet to HEA and discussions around those terms are underway.
- Initiated Interconnection Requirements Studies (IRS).

According to the Kenai Wind's document dated March 6, 2009, the developer is expecting to complete the project design and start site preparation by August 2009, and begin erection of wind turbines in November 2009. For the purpose of this study, Black & Veatch assumed that the proposed wind generation project will be available for commercial operations starting in 2010.

10.4.5 Modular Nuclear Project Option

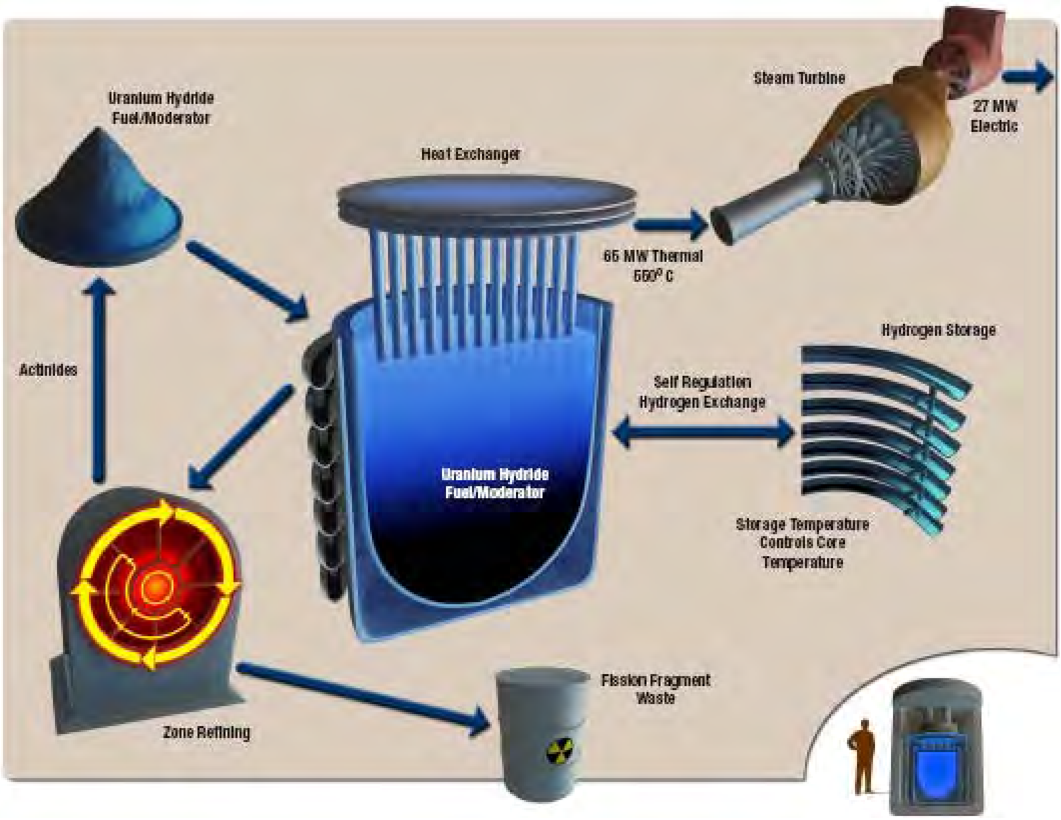
Description of Project
Alutiiq has been marketing a new small, modular nuclear power plant. This alternative would be available for use at most sites. Alutiiq has approached Chugach for a specific application of repowering at the Beluga power plant site.

The proposed nuclear project option is based on an advanced reactor design from Hyperion Power Generation (Hyperion) and Los Alamos National Laboratory. The project will consist of the following major components:

- A single unit, self-regulating, reactor module with heat exchanger.
- A uranium hydride fuel/moderator system.
- A steam turbine generator.
- Balance of plant mechanical, electrical, chemical, water, and interconnection systems.

Figure 10-14 illustrates a simplified power cycle process of the proposed nuclear project. The reactor will be designed to operate at an optimum temperature of 550°C and produce approximately 68 MW of thermal output. The thermal output from the reactor will be converted to approximately 27 MW of electrical output through a steam turbine generator.

Figure 10-14
Simplified Hyperion Power Cycle Diagram
(Source: Hyperion Power Generation)



Mode of Operation

It is expected that the project will be designed and permitted for both load following and base load operations.

Fuel Supply

Although it is anticipated that the reactor design for this project can accommodate a variety of fuel compositions, the initial reactor design and calculations were based on the use of uranium hydride. Depending on its use and mode of operations, each reactor is expected to last 7 to 10 years. The design proposed for this project does not allow for in-field refueling of the reactor. Each reactor will be sealed at the factory and transported to the project site for initial installation. When refueling is required after the anticipated 7- to 10-year period, a new reactor will need to be installed and the used reactor will need to be removed and transported back to the Hyperion factory for refurbishing and refueling.

For the purpose of economic evaluation for this study, Black & Veatch assumed that the project will incur zero variable fuel cost. However, Black & Veatch assumed that the project's reactor will be replaced every seven years. It is assumed that the reactor replacement cost will be approximately $25.0 million in 2008 dollars.

Capital Costs

Generic Greenfield Capital Costs
According to Hyperion's June 2008 "Brief for Public" presentation, General Atomics estimated that the construction cost for a 27 MW electrical output generic greenfield project will be approximately $37.0 million in 2008 dollars. Black & Veatch assumes that this cost includes engineering, procurement, and construction costs for equipment, materials, construction contracts, and other indirect costs. Black & Veatch assumes that owner's cost items such as land, contingency, etc., will be approximately $8.0 million in 2008 dollars, or 22 percent of the project construction cost. Therefore, it is anticipated that the total capital cost for the generic greenfield project will be approximately $45.0 million in 2008 dollars or approximately $1,667/kW.

Additional costs estimates provided by Chugach for small nuclear units include a 10 MW facility for $200 million or $20,000/kW and a 50 MW facility for $300 million or $6,000/kW. For evaluation purposes, Hyperion's cost estimates will be used in this study, but based on the other estimates, they appear to have the potential to be low.

Specific Chugach Repowering Capital Costs
Alutiiq provided a confidential rough cost for a Hyperion unit for repowering Beluga. Black & Veatch estimated the cost to connect the Hyperion unit to the Beluga steam turbine as well as an estimate of owner's cost. The total estimate cost of repowering the Beluga steam turbine is $39.6 million in 2009 dollars.

Non-fuel O&M Cost
Non-fuel O&M costs include fixed and variable costs.

Non-fuel Fixed O&M Costs
Non-fuel fixed O&M costs include labor, payroll burden, fixed routine maintenance, and administration costs. It is assumed that the project will have a full-time plant staff of 15 personnel consisting of a plant manager, an administrative staff, a nuclear safety officer, and 12 O&M personnel. Therefore, for the purpose of this study the non-fuel fixed O&M costs associated with the project are estimated to be $2.6 million per year in 2009 dollars.

Non-fuel Variable O&M Costs
Non-fuel variable O&M costs include consumables, chemicals, lubricants, water, major inspections, and overhauls of the steam turbine generator and associated equipment. Non-fuel variable O&M costs vary as a function of plant generation. For the purpose of this study, Black & Veatch assumed that the non-fuel variable O&M costs will be $2.56/MWh in 2009 dollars.

Availability Factor
Availability factor is a measure of the availability of a generating unit to produce power considering operational limitations such as unexpected equipment failures, repairs, routine maintenance, and scheduled maintenance activities. For the purpose of this study, Black & Veatch assumed that the average availability factor of this proposed nuclear plant will be 90 percent.

Schedule
According to the February 20, 2008 "Periodic Briefings on New Reactors" transcript and presentation Black & Veatch obtained from the Nuclear Regulatory Commission (NRC) website, Hyperion had submitted a letter of intent to NRC and met with the NRC in May 2007 to discuss the NRC licensing process. At the May 2007 meeting, Hyperion stated to NRC that Hyperion intended to submit a design certification application to the NRC in early 2012 as part of Hyperion's plan to obtain a manufacturing license from NRC. A schedule (See Figure 10-15) illustrating the requested application timelines based on NRC receipt of letters of intent from all potential advanced reactor license applicants was presented by NRC during the February 20, 2008 briefing. The schedule shows that the Hyperion manufacturing license review process will be completed by the end of 2015 based on the assumption that the NRC will have appropriate staffing level and capability to review licensing applications submitted by all applicants.

Figure 10-15
Requested Potential Advanced Reactor Licensing Application Timelines
(Source: NRC February 20, 2008 Briefing Presentation Slide)

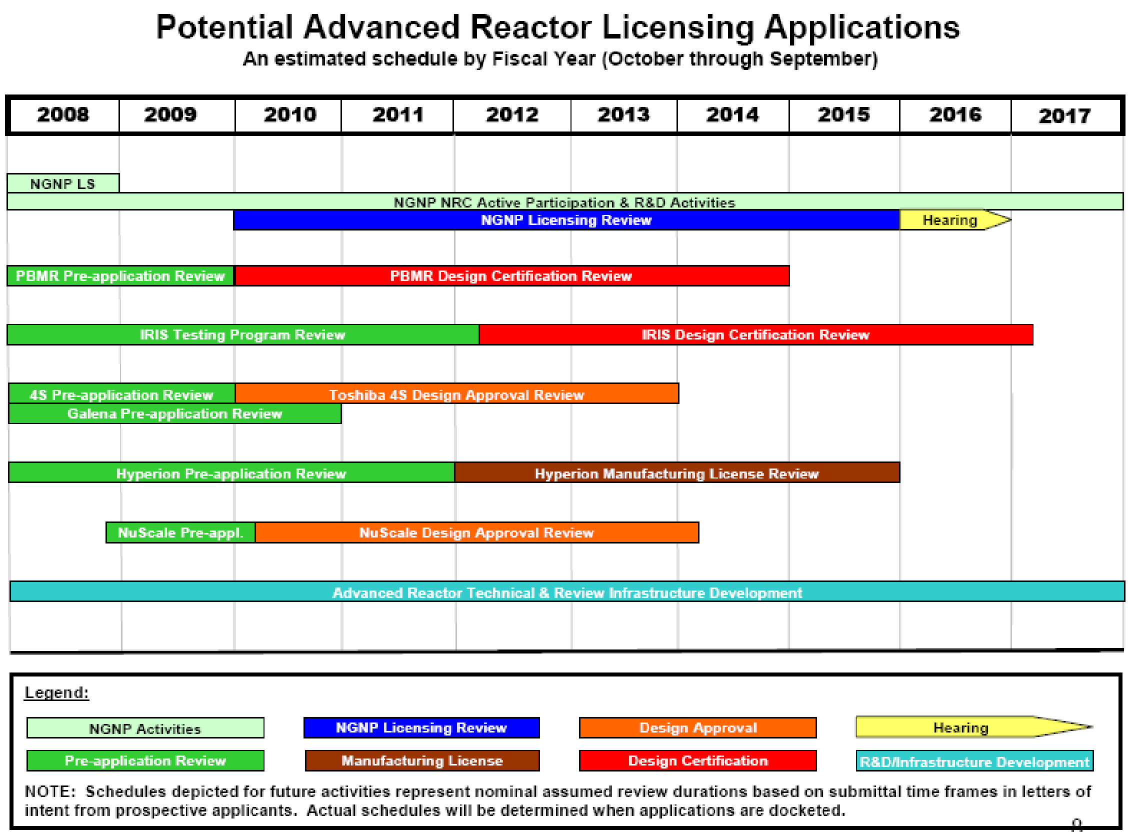
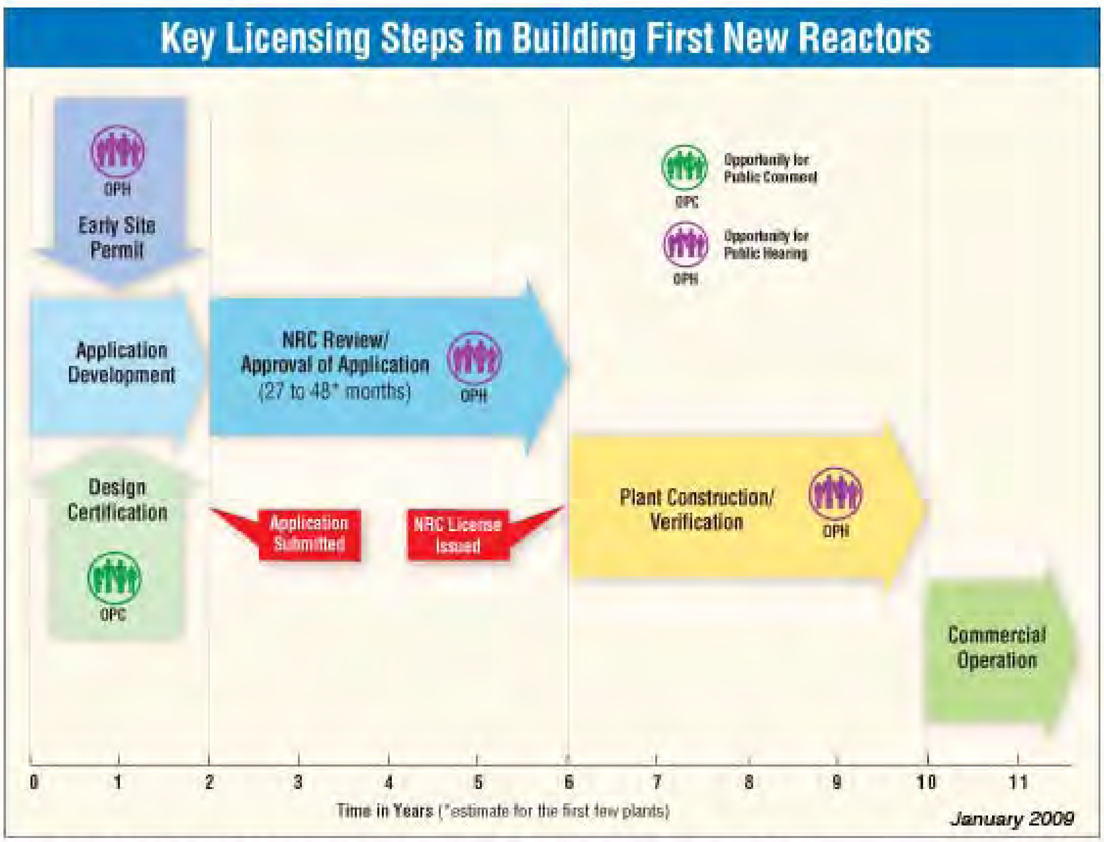


Figure 10-16 illustrates the Nuclear Energy Institute (NEI) latest understanding of the NRC's new licensing process. Figure 10-16 indicates that the expected time frame to process a Combined Construction and Operation License Application (COLA) is 27 to 48 months. Assuming that Hyperion proceeds in parallel, the license should be issued coincident with the Manufacturing License. Based on information provided by Hyperion, engineering, prototype, and testing will take four years. Further, it was assumed that it will take three years to manufacture and install the unit from issuance of the license to manufacture. Thus, the first of the units will be available for commercial operation in 2020.

Figure 10-16
NRC New Licensing Process and Construction Timelines for New Reactors
(Source: NEI website)



The NRC's new licensing process offers multiple opportunities for public input.

10.4.6 Municipal Solid Waste Project Options

Generic municipal solid waste projects were considered for the Anchorage and Interior areas. Black & Veatch sized the projects based on an estimated amount of trash produced in each area on a tons per day basis. This estimate was developed by multiplying the number of residents in each area by an estimated average of 4.5 pounds of trash per day, per person. The resulting tons per day number was compared with a list of municipal solid waste projects proposed and operating in the US to identify project sizes with similar tons per day consumption. As a result, 22 MW and 4 MW project capacities were developed for Anchorage and the Interior, respectively.

Black & Veatch assumed that the municipal solid waste projects would charge fees for taking the trash at a similar tipping fee rate currently charged by local landfills. Black & Veatch estimated capital costs of both projects to be $5,750/kW in 2009 dollars.

It should be noted that previous studies have been conducted regarding the feasibility of municipal solid waste projects in the Railbelt region. Furthermore, while Black & Veatch did not specifically evaluate landfill gas to energy technologies, they warrant further consideration.

10.4.7 Central Heat and Power

Central heat and power projects have not been explicitly modeled in this study. These projects are often developed by IPPs. If these projects meet the efficiency requirements to be certified as a Qualifying Facility (QF), then the existing utilities can be required to purchase the power from a central heat and power project at avoided costs. Since the qualification is very site specific, the development of specific projects to evaluate is beyond the scope of this study. It should be noted that under the GRETC concept, standard purchase power agreements will be available. The use of standard purchase power agreements will eliminate the specific need to be a FERC Qualifying Facility.

11.0 DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY RESOURCES

11.1 Introduction

The purpose of this section is to summarize Black & Veatch's approach to the assessment of DSM/EE measures as part of the overall RIRP project. A very important element of any comprehensive integrated resource plan is the development of a portfolio of proposed energy efficiency and demand reduction programs that can contribute energy savings and winter peak load reductions, and then evaluate these potential programs relative to alternative supply-side electric generation options on a cost per kWh and per kW basis. Those demand-side resources that prove to be more cost-effective than supply alternatives are then typically included in integrated resource planning model or models (in this case, Strategist® and PROMOD®) as a reduction to the load forecast. The resulting lower forecast then serves as the basis from which the alternative supply-side options are considered for adding generation resources when and as needed.

Black & Veatch has conducted a review of the Railbelt utilities' existing DSM/EE programs and developed a portfolio of potential DSM/EE measures for evaluation against supply-side alternatives. The costs and benefits associated with the DSM/EE measures are taken from existing data sources as described later in this section. Data on non-weather sensitive measures (e.g., lighting, appliances) are directly transferred from existing nationally-known sources, and data on weather-sensitive measures are transferred from existing sources using a regression model that considers both heating and cooling degree days as an adjustment factor. This approach has been used successfully in various other jurisdictions and has received general regulatory acceptance.

The design of DSM/EE programs involves three basic elements: 1) identification of target customer segments and end uses with the capacity to reduce energy use, 2) identification of technologies and behaviors that will result in the desired changes in consumption and load shape, and 3) identification of marketing approaches or program concepts to achieve the desired behavioral changes.

The short time frame, budget and limited data availability for this study precluded a rigorous analysis of electric DSM/EE potential (i.e., technical potential and maximum achievable potential) in the Railbelt region. However, Black & Veatch has made maximum use of existing data, augmented by interviews with a number of individuals, and employed industry-accepted data sources and analytical tools to produce a preliminary estimate of the cost-effective DSM/EE resources that exist within the Railbelt region.

In the next subsection, we present some background information on the Railbelt utilities' current DSM/EE programs and the literature sources that we reviewed. We then present a summary and characterization of the customer base for energy efficiency and demand reduction by company and sector. An estimate of DSM/EE potential is presented in the next subsection, followed by a discussion of the DSM/EE technologies or measures considered, screened, and included in the RIRP modeling. We conclude with some comments regarding the delivery of DSM/EE programs.

11.2 Background and Overview

11.2.1 Current Railbelt Utility DSM/EE Programs

Black & Veatch conducted two investigations to assess the current level of energy efficiency program activity at the Railbelt utilities. First, inquiries were made to the six Railbelt utilities and, second, websites of the utilities were researched.

Based upon the information gathered, Table 11-1 summarizes the current DSM/EE programs and related information offered by the Railbelt utilities.

Table 11-1
Current Railbelt Electric Utility DSM/EE-Related Activities

Utility	DSM/EE Programs and Other Assistance/Information Offered
Chugach	**Residential** • Provides compact fluorescent light (CFL) bulb coupons. **Other Assistance/Information** • Refers to a 2008 Board of Directors policy to establish an energy efficiency and conservation program. • Provides a calendar of events, workshops (sponsored by AHFC) and other activities (e.g. tours, fairs, contests, etc.) with links to the specific events. • Provides tips for buying and using appliances, CO_2 detectors, heating and cooling, holiday lighting, insulation, lighting, water heating, and windows. • Provides a tool to analyze accounts, which includes a table of costs for typical appliance usage and a link to the Energy Star® webpage's home energy yardstick which is a tool to analyze energy usage. • Provides a variety of documents related to energy efficiency.
GVEA	**Residential** • **Home$ense**: $40 energy audit that includes energy saving tips and installation of energy efficient products at no additional cost. **Commercial** • **Builder$ense**: rebate program for home builders who install electrical energy efficiency measures during construction. • **Business$ense**: rebate program of up to $20,000 for commercial members who reduce their lighting loads through energy efficient lighting retrofit projects. **Other Assistance/Information** • Link to AHFC and University of Alaska Fairbanks-Alaska Cooperative Extension Service, energy and housing. • Department of Energy document with tips and ideas on how to increase home energy efficiency and how to buy energy efficient products. • Calculator to determine savings by replacing standard incandescent light bulbs with compact fluorescents.

Table 11-1 (Continued)
Current Railbelt Electric Utility DSM/EE-Related Activities

Utility	DSM/EE Programs and Other Assistance/Information Offered
HEA	**Residential** • Information on WiseWatts program and incentives. • Offers a Black & Decker Power Monitor for $50. • Line of credit for HEA customers from $200 to $5,000 for the purchase of approved energy-efficient electrical appliances and other approved merchandise. The repayment period can be from 6 to 36 months upon approved credit. There is an application fee of $35 at the time the loan closes. **Other Assistance/Information** • Touchstone Energy Savers: contains links to Touchstone Energy® tools, tips and resources designed to create greater home comfort and promote energy efficiency. Included on this page are an on-line home energy saver audit, information about stimulus package energy efficiency and weatherization programs, and a link to Alaska Building Science Network. • Offers advice on how to select new energy efficient appliances and products for homes and businesses. Also provides appliance usage tips to reduce energy consumption. • Information on CFL and old refrigerator disposal in the area.
MEA	**Other Assistance/Information** • Provides information on the benefits of Energy Star® appliances, including a link to the EnergyGuide label. • Provides information on how to save energy by managing monitor and PC power. • Provides energy saving tips, including heating and cooling, home electronics, lighting, and new energy efficient homes. • Provides a link to Energy Star® Home Energy Yardstick, a tool to analyze your energy usage. • Provides links to the AHFC and Cold Climate Housing Research Center.
ML&P	**Commercial** • Sponsor of Green Star's Lighting Energy Efficiency Pledge (LEEP) which encourages businesses to upgrade and retrofit their lighting. Participating businesses receive technical support and resources to help them achieve energy savings and Green Star promotes participating businesses. **Other Assistance/Information** • Provides a link to Home Energy Saver, which is the Department of Energy's free home energy audit tool as part of the Energy Star® program. • Provides tips to reduce utility bills and provides links to the Municipality of Anchorage's low-income weatherization program and the AHFC Research Information Center.

11.2.2 Literature Review

As previously stated, the Railbelt utilities have limited experience in the implementation of DSM/EE programs; likewise, there is limited Alaska-specific information available typically required to complete an evaluation of the resource potential and cost-effectiveness of DSM/EE resources. To supplement the information available from the utilities, Black & Veatch relied on other Alaskan sources of information as shown in Table 11-2.

Table 11-2
DSM/EE-Related Literature Sources

Printed Materials Reviewed	Websites Reviewed
Alaska Energy Authority; *Alternative Energy and Energy Efficiency Assistance Plan July 1, 2007 to June 30, 2009*; 2009.	ACEP – Alaska Center for Energy and Power (University of Alaska); http://www.uaf.edu/acep/publications/detail/index.xml.
Alaska Energy Authority; *Alternative Energy & Energy Efficiency Update*; 2007.	Alaska Housing Corporation; http://www.ahfc.state.ak.us/home/index.cfm.
Alaska Energy Authority, et al.; *Village End-Use, Energy Efficiency Projects Phase II Results -2007-2008*; 2009.	Alaska Energy Authority; http://www.akenergyauthority.org/.
Chugach Electric Association; *End Use Model Results*; 1991. (provides residential and commercial end-use projections for Chugach, HEA, and MEA)	Cold Climate Housing Research Center (CCHRC); http://www.cchrc.org/default.aspx.
Information Insights, Inc.; *Alaska Energy Efficiency Program and Policy Recommendations*; 2008.	Denali Commission; http://www.denali.gov/index.php.
Information Insights, Inc.; *Alaska Energy Efficiency Program and Policy Recommendations – Appendices*; 2008.	Municipality of Anchorage, Alaska; http://www.muni.org/OECD/energyEfficiency.cfm.
	Renewable Energy Alaska Project (REAP); http://alaskarenewableenergy.org/tag/energy-efficiency/.

11.2.3 Characterization of the Customer Base

Table 11-3 provides a summary of the customer base for each of the six Railbelt utilities, including the total number of customers for each utility, as well as information on the numbers of customers in the largest population centers. This table also shows a breakdown of customers into residential, commercial and industrial sectors.

This information was used in the analysis of potential penetration rates for various DSM/EE measures as discussed later.

Table 11-3
Railbelt Electric Utility Customer Base

Alaska Railbelt Utilities		Total Cust.	Number of Population Centers	Major Population Center(s)	Pop.	Res. Cust.	Comm. Cust.	Ind. Cust.	Number of Schools in all Pop. Centers	Govt & Schools in city	Low Income Res in city
Golden Valley Electric Association	GVEA	42,866	29	Fairbanks	34,540	36,395	6,008	463	61	37	4,076
				North Pole	2,183					8	227
				Delta Junction	942					9	98
				Nenana	352					2	37
				Anderson	274					1	28
Matanuska Electric Association	MEA	53,503	20	Wasilla	9,780	49,939	3,564	0	49	27	1,017
				Palmer	7,804					13	812
				Houston	2,017					0	210
Chugach Electric Association & Anchorage Municipal Light and Power	CEA and ML&P	108,472	10	Anchorage	279,671	93,493	14,973	6	125	104	18,458
Homer Electric Association	HEA	27,401	22	Homer	5,691	23,811	3,563	27	29	10	592
				Soldotna	4,289					10	446
				Kenai	7,686						
				Kachemak City	443					0	46
				Seldovia	306					1	32
City of Seward Electric System	CES	2,567	1	Seward	3,061	1,973	476	118	4	4	318
TOTAL:		234,809	82		359,039	205,611	28,584	614	268	226	26,397

Organization	state	cities
Golden Valley Electric Association	5.6%	7.8%
Anchorage Municipal Light & Power	40.9%	57.2%
Matanuska Electric Association	2.9%	4.0%
Chugach Electric Association	0.0%	0.0%
Homer Electric Association	2.7%	3.8%
City of Seward Electric System	0.4%	0.6%
Total Pop in Railbelt	52.53%	73.42%

Sources:

Customer information	Energy Velocity by Ventix
Population data	http://www.census.gov/
Economic data:	http://www.census.gov/
Schools data:	http://www.eed.state.ak.us/Alaskan_Schools/Public/

11.3 DSM/EE Potential

The purpose of this subsection is to provide an overview of Black & Veatch's estimate of the potential for DSM/EE measures in the Railbelt region.

11.3.1 Methodology for Determining Technical Potential

The general approach for developing an estimate of the DSM/EE technical potential consisted primarily of the following three steps:

1. Black & Veatch reviewed the universe of measures that are available in the marketplace to increase energy efficiency. This review included not only the limited DSM/EE program experience in Alaska but also a review of the DSM/EE program experience of other utilities throughout the U.S.

2. Black & Veatch eliminated non-electric energy savings measures since this study is focused on meeting the demand and energy requirements of the electric utilities within the Railbelt region.

3. Black & Veatch conducted an intuitive, or qualitative, screening of potential DSM/EE measures based on certain criteria, which are discussed below.

11.3.2 Intuitive Screening

A universe of DSM/EE measures exists that provide energy savings over standard products that serve the same end uses. The majority of these measures are well proven in terms of their impact on electric demand and energy requirements based upon the experience of utilities in other regions of the country. To cull this list, Black & Veatch used a process to screen measures to identify those that are most appropriate for the Railbelt region. The primary objective of this effort was to select the most appropriate measures for further analysis.

There is a considerable range of new products and technology options that are available for energy efficiency and demand reduction applications. Many of these are available today to consumers in the Railbelt region, while others are less prevalent or readily available. Black & Veatch examined a broad array of the most relevant technologies and measures for residential and commercial (non-residential) applications, and considered the extent to which each technology and measure makes sense for the Railbelt region.

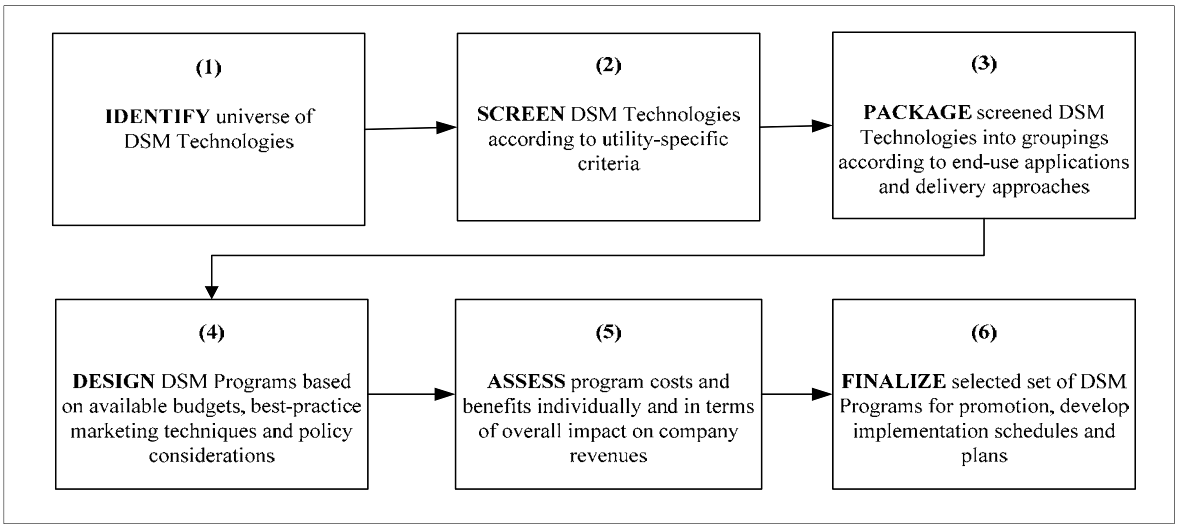
To ascertain which electric end-use measures would best provide energy efficiency opportunities for Railbelt electric customers, as well as help the Railbelt utilities meet their long-term energy and capacity planning goals, Black & Veatch felt that the initial step to aid in sifting through the number of measures would be to use an intuitive or qualitative technology screen. This process, first developed through the Electric Power Research Institute (EPRI) Customer Preference and Behavior Research Project in the 1980s, has been used by utilities across the nation as a first pass at the screening and ranking of DSM technologies.

Numerous measures were considered for the residential and commercial sectors. Certain criteria were developed to gauge the relative value of each measure for the Railbelt region, including: 1) the impact that each measure would have on the winter system load, 2) a preference for conservation measures (rather than peak impacting), and 3) whether the measure is currently offered in the marketplace. The Black & Veatch team felt that a review of each measure within these descriptive criteria would aid in indicating which measures "rise to the top" as "best" candidates and, as such, should be investigated for possible program inclusion.

11.3.3 Program Design Process

Once this initial screening was completed, Black & Veatch then grouped similar, or related, DSM/EE measures into potential DSM/EE programs that were further evaluated within the RIRP models. This approach is consistent with the approach typically used by utilities to develop DSM/EE programs, as shown on Figure 11-1.

Figure 11-1
Common DSM/EE Program Development Process



Typically, utilities develop detailed DSM/EE program plans for each program selected for implementation. These DSM/EE program plans commonly include the following elements:

- **Detailed description of the program--**Derived from best practices from various sources.
- **Reasons why the program would be successful in utility's service territory--**Derived from a comprehensive market assessment and background research.
- **Number of customers within the customer class/segment that are likely to adopt/use the proposed program--**Derived from market assessments and surveys, with a percent or modeled participation estimate based on experience from other utilities with similar programs; informed by actual results from other utilities offering similar programs.
- **Achievable energy savings--**From a variety of sources, consistent with a technology assessment and published reports.
- **Cost-effectiveness ratios/rating per individual program--**Calculated using standard tests, such as the Total Resource Cost (TRC), Participant, Administrators (or Utility) Cost, or Ratepayer Impact Measure (RIM) Tests, applying appropriate avoided cost figures.
- **Marketing plans which should include incentives, rebates and preferred distribution channels and how each reduces existing barriers to proposed program adoption/acceptance--**Based on best practices from a variety of sources; incentive amounts based on examples from other companies.
- **Detailed budget plans complete with explanations of anticipated increases/decreases in financial and human resources during the expected life of the program--**Based on best practices from a variety of sources, over a designated time period for the program life.

- **Recommended methodology or tracking tools for recording actual performance to budget--** Based on current standard practice using simple commercially available software.
- **Proposed program evaluations and reports--**Based on current standard practice using a logic model approach.

11.3.4 Achievable DSM Potential from Other Studies

There are several organizations that have estimated the potential for energy savings on a regional and statewide basis in recent years; most notably EPRI and the Edison Electric Institute (EPRI/EEI), and the American Council for an Energy Efficient Economy (ACEEE). None of these studies, however, specifically and exclusively examined Alaska. However, one study by the Energy Efficiency Task Force of the Western Governor's Association (WGA) was conducted under the Clean and Diversified Energy Initiative and published in January 2006. The states included in the study were Alaska, Arizona, California, Colorado, Hawaii, Idaho, Kansas, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming. The study estimates achievable potential for three years (2010, 2015, and 2020) at 7, 14, and 20 percent, respectively.

Taking Ohio as an example of a state with relatively little prior DSM/EE program offerings, the ACEEE estimates a total achievable energy savings potential of 33 percent by 2025. Other higher end percentages are seen in Illinois (ACEEE 1998) with 43 percent achievable energy efficiency potential, and a regional study for the Southwest that rendered 33 percent energy savings potential. [1]

The EPRI/EEI Assessment looked at the amount of energy savings deemed to be achievable in each of three time periods by sector and end use. The top 10 end uses did not vary considerably by region, and are shown on Figure 11-2 for the Western Census Region, which includes Alaska.

The EPRI/EEI report also indicates a demand response potential of 88 MW based on a 2006 assessment for Alaska and Hawaii combined (note: there is no indication of whether this is from the summer or winter peak).

These studies all provide comparative "top down" estimates from which to gauge the reasonableness of the estimates that Black & Veatch has derived from a "bottom up" assessment of DSM/EE potential in the Railbelt region.

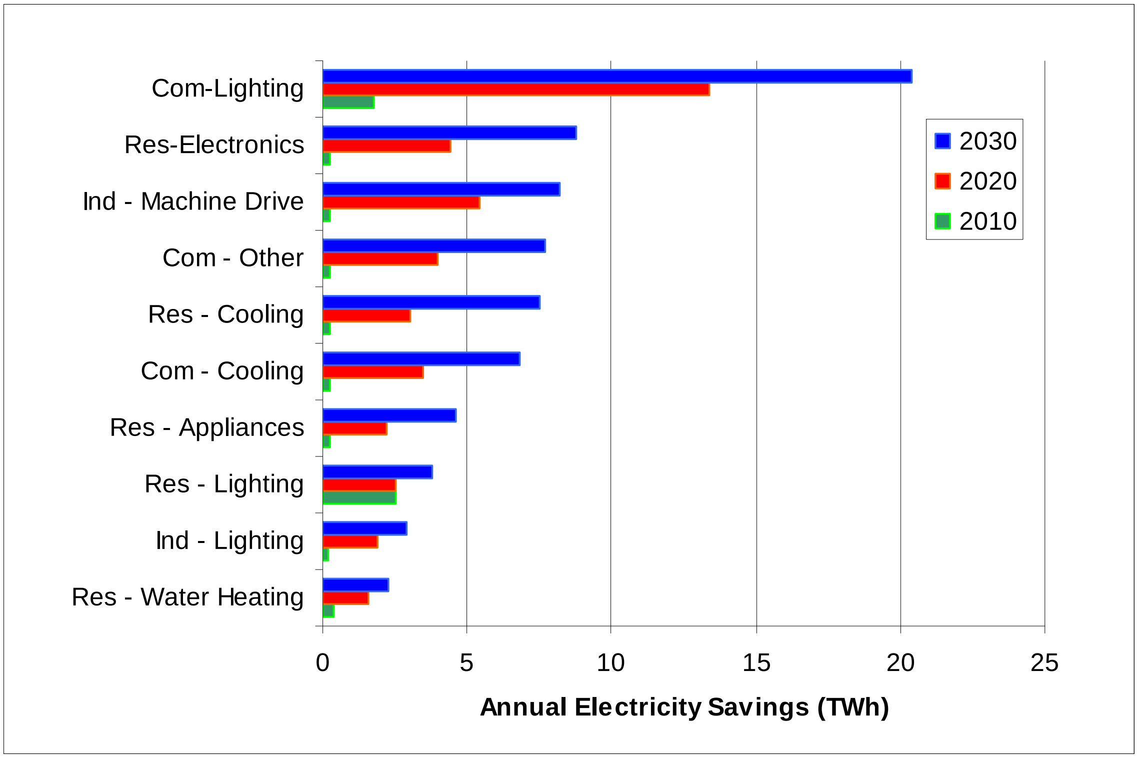
11.4 DSM/EE Measures

This section discusses the DSM/EE measures that are commonly considered in market potential studies of recent vintage. The standard approach to designing programs is to consider a wide range of measures, and then screen them by applying a set of criteria appropriate to the individual utility or region. The measures are then ranked and the most appropriate ones retained for modeling purposes.

Since there are numerous combinations of technology replacement situations (e.g., standard light bulbs with a 75 watt rating can be replaced with a compact fluorescent light bulb, CFL, using 15 watts; a standard 60 watt light bulb can be replaced with a 15 CFL, etc.), the modeling of measures only requires consideration of a representative group of measures in order to assess the potential benefits of promoting such measures in the region and service territory.

[1] US Department of Energy; *National Action Plan for Energy Efficiency*; Table A6-4 - Achievable Energy Efficiency Potential from Recent Studies; pages 6-16; July 2006.

Figure 11-2
EPRI/EEI Assessment: West Census Region Results



Black & Veatch began this phase of the work by considering a large number of residential and commercial/ industrial (C/I) measures. As previously discussed, two initial screens (i.e., removal on non-electric measures and intuitive screening) were applied to these lists.

This shorter list of electric-only measures was then reduced based on a set of four additional screening criteria as follows:

1. Relevance to the regional weather patterns
2. Commercial availability
3. Incremental cost per kWh over standard options
4. Contribution to winter peak load reduction

This review and ranking of the measures resulted in an abbreviated list of 21 residential and 51 C/I measures for further analysis. Table 11-4 summarizes this abbreviated list of residential and C/I measures that was selected for further analysis. It also provides the following information for each DSM/EE measure:

- Measure life
- Estimated kWh savings per customer
- Estimated kW savings per customer
- Incremental cost per installation

Table 11-4
Residential and Commercial DSM/EE Technologies Evaluated

Measure	Sector	Technology	Measure life	Estimated kWh percust	Estimated kW percust	Cost per installation ($2009)
Freezers Energy Star-Chest Freezer	Resid-NonWeather	Appliance	12	46.0	0.0	$ 50.88
Clothes Dryers	Resid-NonWeather	Appliance	14	144.0	0.0	$ 82.50
Refrigerators-Freezers Energy Star - Top Freezer	Resid-NonWeather	Appliance	12	79.0	0.0	$ 50.88
Refrigerators-Freezers Energy Star - Side by Side	Resid-NonWeather	Appliance	12	109.0	0.0	$ 50.88
Pump and Motor Single Speed	Resid-NonWeather	Appliance	10	694.0	0.4	$ 23.38
Smart Strip plug outlet	Resid-NonWeather	Appliance	5	184.0	0.0	$ 11.00
Freezer recycling	Resid-NonWeather	Appliance	6	1,551.0	0.2	$ 75.00
Refrigerator recycling	Resid-NonWeather	Appliance	6	1,672.0	0.2	$ 130.00
Heat Pump Water Heaters	Resid-NonWeather	Water Heater	15	2,885.0	0.3	$ 242.50
Low Flow Showerheads	Resid-NonWeather	Water Heater	12	518.0	0.1	$ 36.76
Pipe Wrap	Resid-NonWeather	Water Heater	6	257.0	0.0	$ 2.09
Holiday Lights	Resid-NonWeather	Lighting	10	10.6	0.0	$ 14.20
CFL fixtures	Resid-NonWeather	Lighting	12	78.0	0.0	$ 24.75
Torchiere Floor Lamps	Resid-NonWeather	Lighting	12	164.0	0.0	$ 10.00
LED Night Light	Resid-NonWeather	Lighting	12	22.0	0.0	$ 6.50
CFL bulbs regular - Outside	Resid-NonWeather	Lighting	9	191.6	0.0	$ 0.83
CFL bulbs regular	Resid-NonWeather	Lighting	9	44.1	0.0	$ 2.83
Ceiling Fans	Resid-Weather	Shell	15	47.8	0.0	$ 151.25
Duct sealing 20 leakage base	Resid-Weather	Shell	18	41.7	0.0	$ 143.70
Roof Insulation	Resid-Weather	Shell	20	41.7	0.0	$ 441.32
Setback thermostat - moderate setback	Resid-Weather	Cooling/Heating	9	152.1	0.0	$ 45.31
ENERGY STAR Steam Cookers 3 Pan	Comm-NonWeather	Water Heater	12	11,188.0	2.6	$ 1,141.25
Plug Load Occupancy Sensors Document Stations	Comm-NonWeather	Office Load	5	803.0	0.1	$ 50.88
HP Water Heater 10 to 50 MBH	Comm-NonWeather	Water Heater	15	21,156.0	4.2	$ 1,100.00

Measure	Sector	Technology	Measure life	Estimated kWh percust	Estimated kW percust	Cost per installation ($2009)
Motors 1 to 5 HP	Comm-NonWeather	Motor	15	113.3	0.024	$ 97.60
Motors 25 to 100 HP	Comm-NonWeather	Motor	15	1,056.0	0.224	$ 331.90
Motors 7.5 to 20 HP	Comm-NonWeather	Motor	15	408.4	0.087	$ 149.85
LED Exit Signs Electronic Fixtures (Retrofit Only)	Comm-NonWeather	Lighting	15	201.0	0.023	$ 33.00
LED Auto Traffic Signals	Comm-NonWeather	Lighting	6	275.0	0.085	$ 49.50
LED Pedestrian Signals	Comm-NonWeather	Lighting	8	150.0	0.044	$ 77.00
VFD HP 1.5 Process Pumping	Comm-NonWeather	Motor	15	1,623.4	0.343	$ 1,192.13
VFD HP 10 Process Pumping	Comm-NonWeather	Motor	15	10,713.4	2.286	$ 811.50
VFD HP 20 Process Pumping	Comm-NonWeather	Motor	15	21,643.1	4.571	$ 1,266.63
Vending Equipment Controller	Comm-NonWeather	Refrigeration	5	800.0	0.210	$ 78.76
Efficient Refrigeration Condenser	Comm-NonWeather	Refrigeration	15	120.0	0.118	$ 9.63
ENERGY STAR Commercial Solid Door Freezers less than 20ft3	Comm-NonWeather	Refrigeration	12	520.0	0.059	$ 41.25
ENERGY STAR Commercial Solid Door Freezers 20 to 48 ft3	Comm-NonWeather	Refrigeration	12	507.0	0.058	$ 330.00
ENERGY STAR Commercial Solid Door Refrigerators less than 20ft3	Comm-NonWeather	Refrigeration	12	905.0	0.103	$ 68.75
ENERGY STAR Commercial Solid Door Refrigerators 20 to 48 ft3	Comm-NonWeather	Refrigeration	12	1,069.0	0.122	$ 275.00
ENERGY STAR Ice Machines less than 500 lbs	Comm-NonWeather	Refrigeration	12	1,652.0	0.189	$ 330.00
ENERGY STAR Ice Machines 500 to 1000 lbs	Comm-NonWeather	Refrigeration	12	2,695.0	0.308	$ 825.00
ENERGY STAR Ice Machines more than 1000 lbs	Comm-NonWeather	Refrigeration	12	6,048.0	0.690	$ 550.00
Pumps HP 1.5	Comm-NonWeather	Motor	15	302.0	0.064	$ 313.75
Pumps HP 10	Comm-NonWeather	Motor	15	2,014.0	0.427	$ 116.30
Pre Rinse Sprayers	Comm-NonWeather	Water Heater	5	1,396.0	0.116	$ 9.63
Exterior HID replacement above 250W to 400W HID retrofit	Comm-NonWeather	Lighting	12	706.0	0.000	$ 585.20
High Bay 3L T5HO Replacing 250W HID	Comm-NonWeather	Lighting	12	449.0	0.103	$ 222.91
High Bay 4LT5HO Replacing 400W HID	Comm-NonWeather	Lighting	12	882.0	0.200	$ 159.28

Measure	Sector	Technology	Measure life	Estimated kWh percust	Estimated kW percust	Cost per installation ($2009)
High Bay 6L T5HO replacing 400W HID	Comm-NonWeather	Lighting	12	374.0	0.1	$ 369.27
High Bay Fluorescent 6LF32T8 Replacing 400W HID	Comm-NonWeather	Lighting	12	961.0	0.2	$ 70.84
High Bay Fluorescent 8LF32T8 Double fixture replace 1000W HID	Comm-NonWeather	Lighting	12	2,005.0	0.5	$ 136.84
CFL Fixture	Comm-NonWeather	Lighting	12	342.0	0.1	$ 21.70
CFL Screw in	Comm-NonWeather	Lighting	2	202.0	0.0	$ 8.29
Daylight Sensor controls	Comm-NonWeather	Lighting	12	14,800.0	3.8	$ 1,100.00
Central Lighting Control	Comm-NonWeather	Lighting	12	11,500.0	2.8	$ 2,035.00
Occupancy Sensors under 500 W	Comm-NonWeather	Lighting	10	397.0	0.1	$ 79.20
Low Watt T8 lamps	Comm-NonWeather	Lighting	12	15.0	0.0	$ 3.43
3 Lamp T5 replacing T12	Comm-NonWeather	Lighting	12	99.4	0.0	$ 110.09
4 Lamp T5HO replacing T12	Comm-NonWeather	Lighting	12	191.0	0.0	$ 168.33
HPT8 4ft 3 lamp, T12 to HPT8	Comm-NonWeather	Lighting	12	145.2	0.0	$ 75.99
HPT8 4ft 4 lamp, T12 to HPT8	Comm-NonWeather	Lighting	12	169.7	0.0	$ 80.88
T12HO 8ft 1 lamp retrofit to HPT8 T8 4ft 2 lamp	Comm-NonWeather	Lighting	12	174.0	0.0	$ 62.34
T12HO 8ft 2 lamp retrofit to HPT8 T8 4ft 4 lamp	Comm-NonWeather	Lighting	12	293.0	0.1	$ 80.88
T8 4ft 3 lamp	Comm-NonWeather	Lighting	12	128.8	0.0	$ 107.38
T8 4ft 4 lamp	Comm-NonWeather	Lighting	12	139.8	0.0	$ 113.90
T8 HO 8 ft 2 Lamp	Comm-NonWeather	Lighting	12	184.0	0.0	$ 124.92
Window Film	Comm-Weather	Cooling/Heating	10	256.0	0.1	$ 84.60
Refrigerant charging correction	Comm-Weather	Cooling/Heating	10	712.4	1.0	$ 21.10
VFD Fan	Comm-Weather	Cooling/Heating	10	1,185.6	0.0	$ 42.89
VFD Pump	Comm-Weather	Cooling/Heating	10	3,959.2	0.3	$ 41.01
Refrigeration Commissioning	Comm-NonWeather	Refrigeration	3	375.0	0.0	$ 37.29
Strip curtains for walk-ins - freezer	Comm-NonWeather	Refrigeration	4	613.0	0.1	$ 77.00

Tables 11-5 and 11-6 provide additional information regarding the input assumptions used in the evaluation of the residential and commercial DSM/EE measures, respectively. This information includes:

- Incremental equipment cost
- Rebate as a percentage of incremental equipment cost
- Rebate amount
- Administrative costs
- Vendor or other costs
- Total per unit costs

It should be noted that Black & Veatch did not complete a comprehensive cost-effectiveness evaluation of these measures using the traditional DSM cost-effectiveness tests (i.e., TRC, Participant, Utility and RIM tests). Regional avoided costs are required to evaluate DSM/EE measure using these tests, and these avoided costs were not available when this evaluation was completed as part of this project. Rather, Black & Veatch achieved the cost-effectiveness assessment of these measures by including them directly in the RIRP models, which allowed for a direct comparison of the economics of DSM/EE measures relative to alternative supply-side alternatives.

Furthermore, once the most appropriate technologies were screened, Black & Veatch estimated how many customers would adopt each technology each year in order to arrive at potential energy savings to be used in the RIRP modeling. Even though technologies are grouped into one or more program(s) for going to market, the application of a participation rate is done at the measure level. The number of customers available to adopt the technology was based upon the customer counts and appliance saturations discussed earlier. From this starting point, a set of technology adoption curves were applied that characterize the pattern of acceptance (or purchase) typical of products at different levels of marketing. For example, a high rebate amount for a product might be expected to achieve a high penetration in the early years, translating into a “steep” curve. On the other hand, a program that merely provides consumers with information about changing their behavior, but offers no monetary incentive, may result in an increase in related participation over time, but at a lower level and slower pace. To estimate maximum penetration rates for purposed of RIRP modeling, Black & Veatch used a series of technology adoption curves for DSM/EE studies from the BASS model. These curves are built from the original “S” shaped curve of product adoption and are a generally-accepted tool for characterizing consumer adoption patterns. Since Alaska is fairly new territory for DSM/EE programs, Black & Veatch assumed that the level of incentives required to move the market to adopt DSM/EE measures would average approximately 45 percent of incremental equipment costs.

Table 11-5
Input Assumptions - Residential DSM/EE Measures

Residential Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
Freezers Energy Star-Chest Freezer	$92.50	50%	$46.25	$4.63	--	$50.88
Clothes Dryers	$150.00	50%	$75.00	$7.50	--	$82.50
Refrigerators-Freezers Energy Star-Top Freezer	$92.50	50%	$46.25	$4.63	--	$50.88
Refrigerators-Freezers Energy Star-Side by Side	$92.50	50%	$46.25	$4.63	--	$50.88
Pump and Motor Single Speed	$85.00	25%	$21.25	$2.13	--	$23.38
Smart Strip Plug Outlet	$40.00	25%	$10.00	$1.00	--	$11.00
Freezer Recycling	$93.00	0%	--	--	$75.00	$75.00
Heat Pump Water Heaters	$700.00	25%	$175.00	$17.50	$50.00	$242.50
Refrigerator Recycling	$93.00	0%	--	--	$130.00	$130.00
Low Flow Showerheads	$31.60	100%	$31.60	$3.16	$2.00	$36.76
Pipe Wrap	$7.60	25%	$1.90	$0.19	--	$2.09
Holiday Lights	$12.00	100%	$12.00	$1.20	$1.00	$14.20
CFL Fixtures	$45.00	50%	$22.50	$2.25	--	$24.75
Torchiere Floor Lamps	$50.00	0%	--	--	$10.00	$10.00
LED Night Light	$5.00	100%	$5.00	$0.50	$1.00	$6.50
CFL Bulbs Regular-Outside	$3.00	25%	$0.75	$0.08	--	$0.83
CFL Bulbs Regular	$3.00	25%	$0.75	$0.08	$2.00	$2.83
Ceiling Fans	$275.00	50%	$137.50	$13.75	--	$151.25
Duct Sealing 20 Leakage Base	$215.82	50%	$107.91	$10.79	$25.00	$143.70
Roof Insulation	$756.95	50%	$378.48	$37.85	$25.00	$441.32
Setback Thermostat-Moderate Setback	$18.46	100%	$18.46	$1.85	$25.00	$45.31

Table 11-6
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
ENERGY STAR Steam Cookers 3 Pan	$4,150.00	25%	$1,037.50	$103.75	--	$1,141.25
Plug Load Occupancy Sensors Document Stations	$185.00	25%	$46.25	$4.63	--	$50.88
HP Water Heater 10 to 50 MBH	$4,000.00	25%	$1,000.00	$100.00	--	$1,100.00
Motors 1 to 5 HP	$88.00	75%	$66.00	$6.60	$25.00	$97.60
Motors 25 to 100 HP	$558.00	50%	$279.00	$27.90	$25.00	$331.90
Motors 7.5 to 20 HP	$227.00	50%	$113.50	$11.35	$25.00	$149.85
LED Exit Signs Electronic Fixtures (Retrofit Only)	$60.00	50%	$30.00	$3.00	--	$33.00
LED Auto Traffic Signals	$90.00	50%	$45.00	$4.50	--	$49.50
LED Pedestrian Signals	$140.00	50%	$70.00	$7.00	--	$77.00
VFD HP 1.5 Process Pumping	$1,445.00	75%	$1,083.75	$108.38	--	$1,192.13
VFD HP 10 Process Pumping	$2,860.00	25%	$715.00	$71.50	$25.00	$811.50
VFD HP 20 Process Pumping	$4,515.00	25%	$1,128.75	$112.88	$25.00	$,266.63
Vending Equipment Controller	$195.50	25%	$48.88	$4.89	$25.00	$78.76
Efficient Refrigeration Condenser	$35.00	25%	$8.75	$0.88	--	$9.63
ENERGY STAR Commercial Solid Door Freezers -Less Than 20ft3	$150.00	25%	$37.50	$3.75	--	$41.25
ENERGY STAR Commercial Solid Door Freezers-20 to 48 ft3	$400.00	75%	$300.00	$30.00	--	$330.00
ENERGY STAR Commercial Solid Door Refrigerators-Less Than 20ft3	$250.00	25%	$62.50	$6.25	--	$68.75
ENERGY STAR Commercial Solid Door Refrigerators-20 to 48 ft3	$500.00	50%	$250.00	$25.00	--	$275.00

Table 11-6 (Continued)
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
ENERGY STAR Ice Machines-Less Than 500 lbs	$600.00	50%	$300.00	$30.00	--	$330.00
ENERGY STAR Ice Machines-500 to 1,000 lbs	$1,500.00	50%	$750.00	$75.00	--	$825.00
ENERGY STAR Ice Machines-More Than 1,000 lbs	$2,000.00	25%	$500.00	$50.00	--	$550.00
Pumps HP 1.5	$350.00	75%	$262.50	$26.25	$25.00	$313.75
Pumps HP 10	$332.00	25%	$83.00	$8.30	$25.00	$116.30
Pre Rinse Sprayers	$35.00	25%	$8.75	$0.88	--	$9.63
Exterior HID Replacement Above 250W to 400W HID Retrofit	$1,064.00	50%	$532.00	$53.20	--	$585.20
High Bay 3L T5HO Replacing 250W HID	$277.60	73%	$202.65	$20.26	--	$222.91
High Bay 4LT5HO Replacing 400W HID	$289.60	50%	$144.80	$14.48	--	$159.28
High Bay 6L T5HO Replacing 400W HID	$447.60	75%	$335.70	$33.57	--	$369.27
High Bay Fluorescent 6LF32T8 Replacing 400W HID	$257.60	25%	$64.40	$6.44	--	$70.84
High Bay Fluorescent 8LF32T8 Double Fixture Replace 1,000W HID	$497.60	25%	$124.40	$12.44	--	$136.84
CFL Fixture	$78.92	25%	$19.73	$1.97	--	$21.70
CFL Screw-in	$30.14	25%	$7.53	$0.75	--	$8.29
Daylight Sensor Controls	$4,000.00	25%	$1,000.00	$100.00	--	$1,100.00
Central Lighting Control	$3,700.00	50%	$1,850.00	$185.00	--	$2,035.00
Occupancy Sensors-Under 500 W	$144.00	50%	$72.00	$7.20	--	$79.20
Low Watt T8 Lamps	$6.24	50%	$3.12	$0.31	--	$3.43
3 Lamp T5 Replacing T12	$200.16	50%	$100.08	$10.01	--	$110.09
4 Lamp T5HO Replacing T12	$306.06	50%	$153.03	$15.30	--	$168.33

Table 11-6 (Continued)
Input Assumptions - Commercial DSM/EE Measures

Commercial Measures	Incremental Equipment Cost ($)	Rebate as % of Incremental Equipment Cost	Rebate Amount ($)	Administrative Costs (10%)	Vendor or Other Costs	Total per Unit Program Costs
HPT8 4ft 3 Lamp, T12 to HPT8	$138.16	50%	$69.08	$6.91	--	$75.99
HPT8 4ft 4 Lamp, T12 to HPT8	$147.06	50%	$73.53	$7.35	--	$80.88
T12HO 8ft 1 Lamp Retrofit to HPT8 T8 4ft 2 Lamp	$113.35	50%	$56.68	$5.67	--	$62.34
T12HO 8ft 2 Lamp Retrofit to HPT8 T8 4ft 4 Lamp	$147.06	50%	$73.53	$7.35	--	$80.88
T8 4ft 3 Lamp	$130.16	75%	$97.62	$9.76	--	$107.38
T8 4ft 4 Lamp	$138.06	75%	$103.55	$10.35	--	$113.90
T8 HO 8 ft 2 Lamp	$151.42	75%	$113.57	$11.36	--	$124.92
Window Film	$153.81	50%	$76.91	$7.69	--	$84.60
Refrigerant Charging Correction	$38.36	50%	$19.18	$1.92	--	$21.10
VFD Fan	$155.96	25%	$38.99	$3.90	--	$42.89
VFD Pump	$149.14	25%	$37.28	$3.73	--	$41.01
Refrigeration Commissioning	$113.00	30%	$33.90	$3.39	--	$37.29
Strip Curtains for Walk-ins-Freezer	$200.00	35%	$70.00	$7.00	--	$77.00

11.5 DSM/EE Program Delivery

As will be discussed in Section 13, the RIRP models selected all DSM/EE measures for inclusion in each of the four alternative resource plans, based upon the costs incurred and savings achieved from the utility persepctive. The successful implementation of these resources, however, is dependent on several factors.

First, it is important that a comprehensive technical and achievable potential study be completed, including the comprehensive cost-effectiveness evaluation of the available DSM/EE measures and using Railbelt-specific information.

Second, it is Black & Veatch's belief that a regional entity should be formed to develop and deliver DSM/EE programs on a regional basis, in close coordination with the six Railbelt utilities. This entity could be the proposed GRETC organization or another entity focused exclusively on DSM/EE programs.

This was addressed in the REGA Study Final Report, which included the following observations regarding the potential deployment of DSM programs by the Alaska Railbelt utilities:

> *" …, 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.*
>
> *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." (pps. 49-50)*

Third, the Railbelt electric utilities should work closely with Enstar and the AHFC with regard to the implementation of DSM/EE programs.

These points are discussed further in Section 16.

12.0 TRANSMISSION PROJECTS

The Railbelt transmission system included in this study consists of six independent utilities loosely interconnected by a transmission system that is constrained and inadequate to support interconnected operation envisioned by the GRETC concept of robust reliable service for all Railbelt utilities. One of the primary objectives of the current RIRP is to develop a transmission system that can support the economic development and operation of an integrated Railbelt system.

12.1 Existing Railbelt System

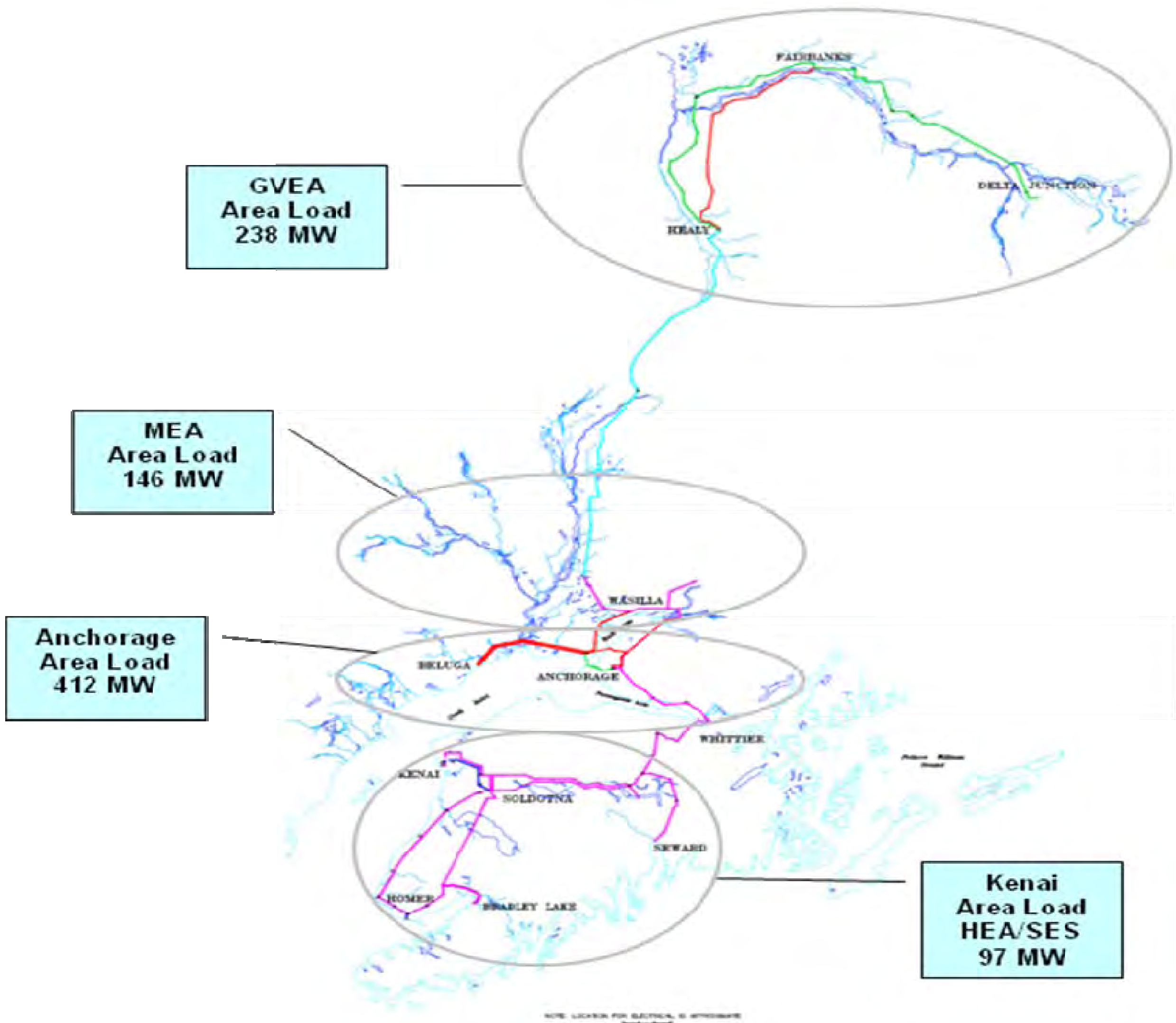
The Alaskan transmission infrastructure is relatively new compared with other transmission and distribution facilities in the lower-48 states. In the 1940s, the Chugach, GVEA, HEA, MEA, ML&P, and SES systems were formed to provide electric service to consumers within their respective service areas. The Doyon service area which is not explicitly included in this study was established in 2007 to serve the loads of the US Army bases at Fort Greely, Fort Wainwright in Fairbanks and Fort Richardson in Anchorage.

These utilities developed and operated independently of each other and were successful in providing reasonable service to businesses and residences. In 1984, the State of Alaska constructed the Anchorage-Fairbanks Intertie, and Chugach and ML&P strengthened their interconnection allowing improved operation and reliability among the utilities. In that same year, the State of Alaska and the Railbelt utilities established the Alaska Intertie Agreement. This agreement has served as the operating contract between all utilities for the past 25 years, but will expire within the next two years. Also, the expiration of the thirty-year power sales agreements between Chugach, MEA and HEA will terminate in 2014. Presumably, following the expiration of the current power sales contracts, each of the Railbelt utilities will assume the responsibility of planning the transmission system to serve its own requirements. However, the planning, repair, and construction of transmission facilities required to continue to provide economic and reliability benefits to all utilities does not fall under the responsibility of any of the specific Railbelt utilities. The expiration of the Chugach power supply contracts and the Intertie Operating Agreement leaves a void in the planning and operation of critical transmission assets required for inter-utility power transfers and reliability improvements. Changing generation plans may decrease the importance of transmission to a single utility, but the transmission will remain critical to the interconnected system. However, with the changing power supply conditions which include heightened environmental awareness, fuel cost volatility and availability, and the aging generation plants of the Railbelt, it became evident that investigation of a more coordinated approach of the Railbelt utilities to planning and operating together could provide significant benefits for the people of Alaska. The first obstacle to the goal of coordinated planning and operation is the lack of an entity that has the responsibility and authority for the planning and operation of the transmission system utilized to interconnect the systems of individual utilities. The second obstacle to coordinated generation planning and operations is the lack of an adequate transmission infrastructure to support joint economic and reliable operations. This section focuses on the transmission projects that may be necessary for the Railbelt utilities to construct a reliable transmission system that is capable of providing transfers of firm and economy energy transactions and also allow for the economic planning of firm generation capacity and reserves.

The existing Railbelt utilities cover the Fairbanks area, the Anchorage area, and the Kenai Peninsula and are interconnected between Fairbanks and Anchorage via a single transmission line known as the Anchorage-Fairbanks Intertie, while Anchorage and the Kenai are connected by a single transmission line known as the Anchorage-Kenai Intertie. These existing facilities are discussed in Section 4.

The existing Railbelt transmission system, as well as the loads supplied in each area, is presented in Figure 12-1. A significant issue affecting the existing Railbelt system results from the constrained transmission infrastructure interconnecting the utilities. This existing transmission infrastructure results in the system operation being severely constrained by stability and power transfer limits. As a result of being stability constrained, individual transmission projects constructed to increase transmission capacity cannot be fully loaded to their thermal limits and the economic sharing of reserves between utilities is also inhibited. This void cannot be filled by the existing planning and development strategy of independent utilities but should be tackled by an integrated development of the transmission system by an independent entity responsible for the planning, construction and operation of the interconnected system.

Figure 12-1
Railbelt Transmission System Overview



12.2 The GRETC Transmission Concept

One of the goals of the current study is to facilitate the development of generation and transmission systems in the most economic and reliable manner possible. By coordinating the needs of all utilities, common problems such as aging generation, unequal reliability and more levelized power supply rate structures can be developed for the Railbelt region. By assessing the problems of the system as a whole, projects that may be more economic and offer a more stable rate structure for the entire Railbelt may be developed, bringing rate stability and a dependable power cost to the entire Railbelt region.

In order to provide an organization capable of undertaking the needs of the Railbelt utilities, the Legislature is considering the formation of GRETC which would become the entity charged with planning, constructing, and operating the integrated energy and transmission system to serve the Railbelt utilities.

The corporate identity of GRETC has yet to be determined. Several organizational structures have been evaluated and will require further study. The purpose of this study is not to identify the structure of GRETC as an organization, but to identify its role in the Railbelt electrical system. GRETC's role in the Railbelt system is envisioned as follows:

Planning

GRETC will serve as the entity responsible for performing system studies, analysis, and evaluation of transmission projects, and will be required to:

- Develop plans to repair and replace (R&R) the existing transmission system as required to maintain the service and reliability of the existing system such that the future system will be at least no worse than the reliability and transfer capacity that exist today.
- Develop plans to repair, replace and maintain the communication and control system required to ensure system reliability and economic operation.
- Develop long-range transmission plans (LRTP) to identify transmission projects required over the next 50 years to provide the same or comparable reliability and service to all Railbelt utilities.
- Develop generation and transmission plans such that at the completion of each plan, no single contingency within the GRETC system results in the loss of firm load.
- Develop mid-range transmission plans (10-Year Plan, or TYP) to prioritize the transmission projects identified in the LRTP and R&R plans into a single plan that is consistent with the requirements of the Railbelt utilities and within the financing capability of GRETC.
- Develop and maintain rolling Five-Year Plans (FYP) that identify the projects to be constructed within the next five years as outlined in the TYP. Develop project schedules, including permitting and right-of-way (ROW) schedules for long-term projects.
- Develop design criteria for each project identified in the plan, develop the design, construction management, construction, and close-out schedules and budgets.
- Administer design, construction management, and construction contracts associated with the projects.

Operation

- GRETC should be responsible for operation of the transmission and generation system required to deliver power between GRETC generation or GRETC delivery points to Railbelt utilities to ensure that each utility, over the long-term planning horizon receives comparable service in terms of transmission reliability, access to reserves, and transmission costs.

- GRETC should be responsible for the economic operation of the Railbelt generation system, ensuring that power throughout the Railbelt is produced in the most economical manner possible.
- GRETC should be responsible for allocation of reserves to ensure system reliability is maintained at no worse than existing levels.

In developing projects for the integrated operation of the Railbelt transmission system the following criteria were adopted:

- The transmission system will be upgraded over time to remove transmission constraints that currently prevent the coordinated operation of all the utilities as a single entity. The transmission planning period is 50 years. The ability of GRETC to construct the transmission improvements identified in this study within any certain time period is unknown. The prioritization of the transmission projects and their subsequent schedule for construction cannot be completed in the scope of this study. As such, this study attempts to identify required transmission improvements for evaluation in future studies.
- The study includes all the utilities' assets, 69 kV and above, that are used to transmit power from a GRETC generator to the Railbelt system or between significant load areas. These assets, over a transition period, may flow into GRETC and form the basis for a phased upgrade of the system into a robust, reliable transmission system that can accommodate the economic operation of the interconnected system. Utility assets, 69 kV and above, that are not used to transmit power between GRETC generation or between GRETC transmission delivery points may or may not be transferred to GRETC.
- Generation assets not utilized by GRETC for power delivery, reserves or other uses may be retained by the individual utilities for their own uses such as emergency generation, load-side generation, load serving etc.
- The study assumes that all utilities participate in GRETC with transmission and generation planning being conducted on a GRETC (i.e., regional) basis. The common goal would be the tight integration of GRETC with the utilities for planning and operations as previously described.

12.3 Project Categories

The projects selected for consideration were based on the overall GRETC concept of developing a robust, reliable transmission system that can accommodate the economic operation of the Railbelt integrated system. Discussions were held with the utilities and a list of potential projects was developed for further consideration. The projects were classified in the following categories:

- Transmission systems that need to be replaced because of age and condition (Category 1)
- Transmission projects required to improve grid reliability, power transfer capability, and reserve sharing (Category 2)
- Transmission projects required to connect new generation projects to the grid (Category 3)
- Transmission projects to upgrade the grid required by a new generation project (Category 4)

In developing the system, reliability remains a significant focus. Redundancy is one way to increase reliability, but may not be the only way to improve or maintain reliability as indicated in the analysis below.

12.4 Summary of Transmission Analysis Conducted

A transmission analysis consisting of power system load flows and N-1 analysis was conducted to determine the deficiencies of the existing system. In the existing transmission system, constraints preclude the economic development of large projects that are common to the entire Railbelt. Lack of transfer capacity and single contingency interties prevent projects being developed in any one area to serve firm power to the entire region. Improvements to the power system required to alleviate overloads, transfer limitations and address

N-1 contingencies under the existing generation and the generation configurations developed as part of this plan were identified as projects and evaluated in power flow studies to determine if the resulting system satisfied the main objectives and criteria set for the RIRP. Identified projects were evaluated to determine if the system could supply the projected load under economic generation dispatch without violating the transmission criteria of no loss of load or voltage violations under the N-1 criteria as well as to establish a redundant system with a 230 kV backbone through the Railbelt. Similar to the generation alternatives, this plan has identified possible projects that are required to meet the goals and objectives of GRETC. Prioritization and detailed development of the projects should be completed concurrent with the subsequent generation plan to provide a comprehensive and coordinated approach to serving the Railbelt utilities.

12.4.1 Cases Reviewed

The base case for 2060 was evaluated with all the projects included, along with the load forecast for 2060 as developed for the RIRP. The generating resources selected by the RIRP for the different scenarios were also modeled for the respective cases. With each case developed, the generating resources were dispatched economically and several contingencies evaluated to determine if there were any constraints on the Railbelt transmission system. A review of the recent projects designed and constructed for the Railbelt utilities, has revealed that many projects have been designed at a higher voltage than the existing voltage of the line. In many cases, the circuits have been rebuilt to a higher voltage but placed back in operation at the same voltage awaiting an opportunity to increase the capacity of these circuits when appropriate. These lines, in many instances, have been insulated to operate at 230 kV from the existing 115 kV or 138 kV levels. To capture the benefits of increased transmission capacity, as well as to capture the benefits of standardizing transmission voltages at a specific level thus controlling operation and maintenance costs going forward, standardization of the Railbelt transmission grid at 230 kV was determined by Black & Veatch, EPS, and the Railbelt utilities to be appropriate. This key concept of developing a reliable transmission backbone for the Railbelt occasionally results in projects that are designed and constructed at a higher voltage but operated at a lower voltage until the transition to the higher voltage can be facilitated or justified This is particularly applicable in the repair and replacement of existing transmission facilities. Portions of the existing Railbelt transmission system are not recommended to be included in the 230 kV upgrade due to difficulties in obtaining ROW and other considerations. As a result, portions of the existing 115 kV system on the Kenai, ML&P and MEA areas would remain at 115 kV and portions of the Chugach and GVEA systems would remain at 138 kV throughout the life of this plan.

In accordance with the ideals of GRETC, some of the existing transmission systems would not be incorporated into the GRETC system, but would remain with the local utility to own, operate and maintain for its own use.

Since the repair and replacement of the existing transmission facilities is scheduled over many years, it is likely that that the initial portions of a transmission line replacement project will be operated at its existing voltage for many years until the entire transmission line is replaced and a justification to convert any required substations and operate the transmission line at its ultimate construction voltage is warranted.

The above analysis was based on load flow evaluations with consideration given to possible stability issues. The development of the final transmission plan will require more detailed studies, analysis and integration with the selected generation plan. The projects that are interrelated with generation scenarios will require evaluation concurrent with more detailed generation scenarios. Projects that are independent of generation scenarios can undergo detailed studies, including stability analysis and detailed evaluation prior to selection of the preferred generation scenario. The results of these future studies may result in some changes to the projects identified.

12.4.2 Results of 2060 Analysis

The transmission analysis included normal and N-1 contingency analysis of all transmission branches in the Railbelt, with all the generating resources dispatched economically. The power flow analysis was evaluated to determine if any overloads or voltage violations of any of the transmission lines within the Railbelt system occur during both normal and N-1 conditions.

Limited stability studies were completed to evaluate the ability of the Railbelt system to operate for select cases. As future studies refine transmission and generation projects, additional power flow and stability studies will be required to evaluate the requirements of the transmission system.

12.5 Proposed Projects

Project A – Bernice Lake Power Plant to International 230 kV Transmission Line (Southern Intertie) (New Build - Category 2)

The Bernice Lake Power Plant to International Substation 230 kV project is a new 230 kV line between the Anchorage area and the Kenai. The project commences at the ITSS substation, crosses Turnagain Arm via submarine cable and an overhead crossing of Fire Island and proceeds overhead along the coastline to the Bernice Lake Substation. The project is comprised of a total of 15 miles of submarine cable and 47 miles of overhead transmission line. The project is intended to follow the recommended route included in the Environmental Impact Statement managed by Chugach.

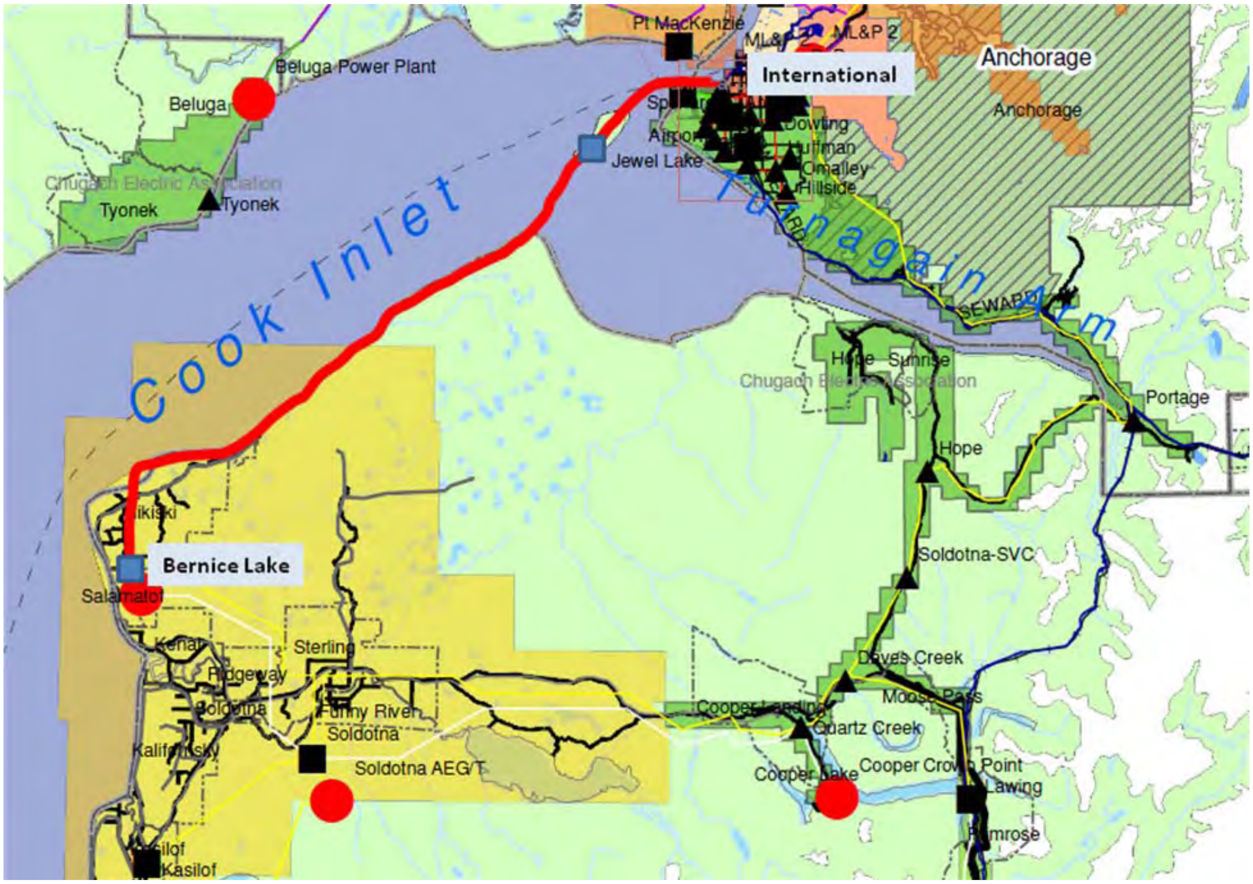
The single transmission line between Anchorage and Kenai prevents the economic construction of generation in the Railbelt, and places constraints on both the amount of power that can be exported from the Kenai area and the amount of power that can be imported into the Kenai area.

In addition to the export and import of energy to the Kenai, the ability to utilize reserves across this single transmission line is a severe restriction to the economic operation of the system as a whole. For instance, if the Bradley reserves are increased to 50 MW, the ability of the northern utilities to utilize these additional reserves is questionable since the transfer of these reserves requires transmission across the single tie-line that is already transferring real power to the northern utilities and the transfer of these reserves is beyond the stability limit of the transmission system.

In order to meet the planning criteria that no N-1 contingency results in the loss of load from the GRETC system, without a second tie-line, the generation on the Kenai has to be severely constrained to limit power transfers into the Kenai area. This constraint increases both capital and operating costs for the Railbelt, forcing the location of new generation on the Kenai as well as new generation in the northern parts of the system to supply reserves that are not transferable across the existing transmission line.

This project is the second intertie between the areas and is required to increase the transfer limit between the two areas. The current transfer limit between the areas is limited due to stability considerations to 75 MW. The steady-state limit is constrained to 105 MW (winter) due to voltage collapse while the thermal limit for the existing 115 kV transmission line is approximately185 MW (winter) and 95 MW (summer). This project is a Category 2 project required for reliability and increased transfer capability. Figure 12-2 presents the proposed project. More investigation is required to determine detailed transmission characteristics and routing.

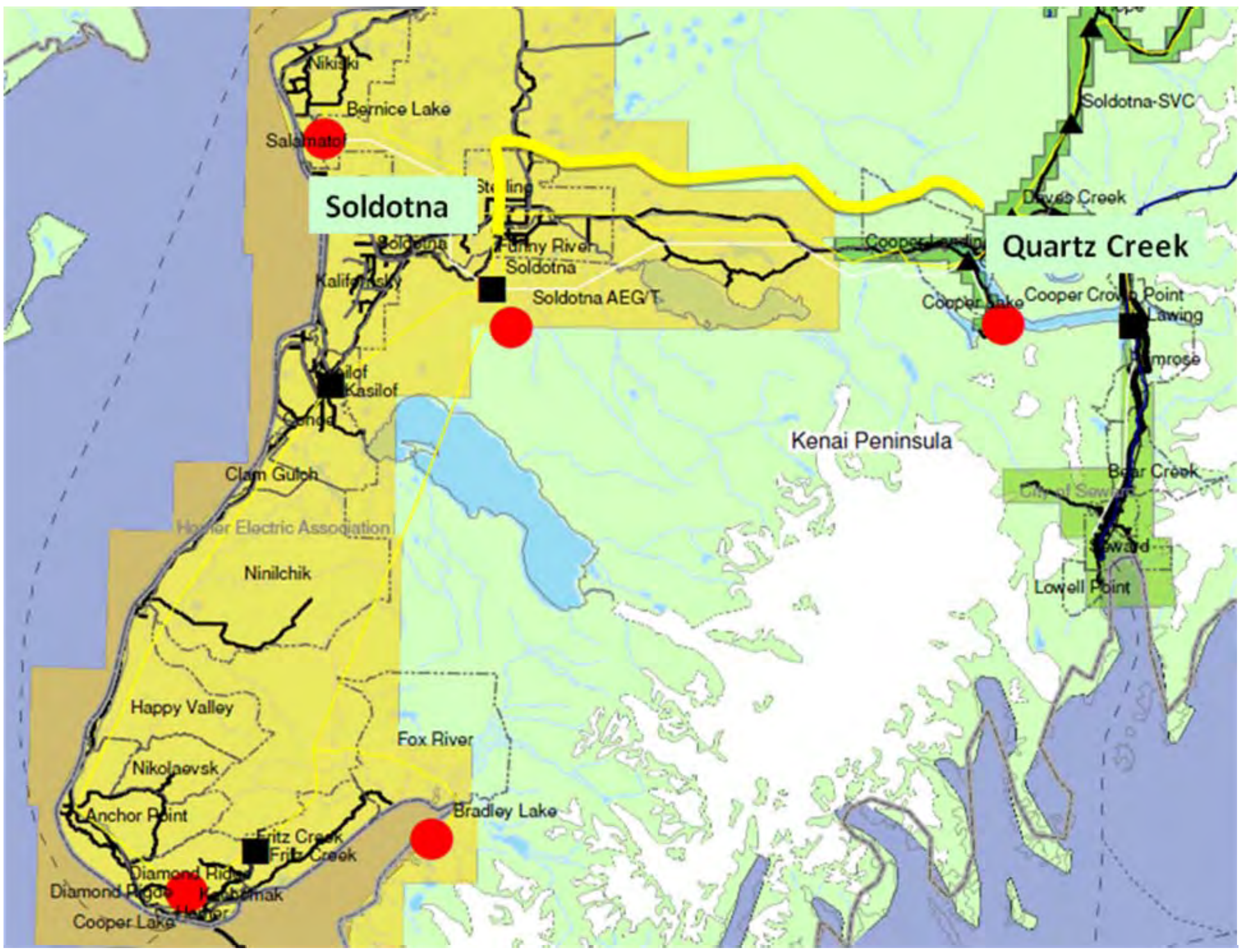
Figure 12-2
Bernice Lake Power Plant to International 230 kV Transmission Line (New Build)



Project B – Soldotna to Quartz Creek 230 kV Transmission Line (Repair and Replacement - Category 1)

This project is the upgrade of the existing 54-mile long, 115 kV transmission line between Soldotna and Quartz Creek substations. This line was constructed in 1959 and is in very poor condition, suffering from frost jacking and age deterioration. The transmission line is a continuation of the Anchorage – Daves Creek line and results in the same stability and reliability constraints as the Project 1-line described above. Because of the importance of this intertie to the integrated operation of the Railbelt system, this line is proposed to be rebuilt for operation at 230 kV. The line would continue to operate at 115 kV until conversion to 230 kV operation is warranted. Figure 12-3 presents the proposed upgrade.

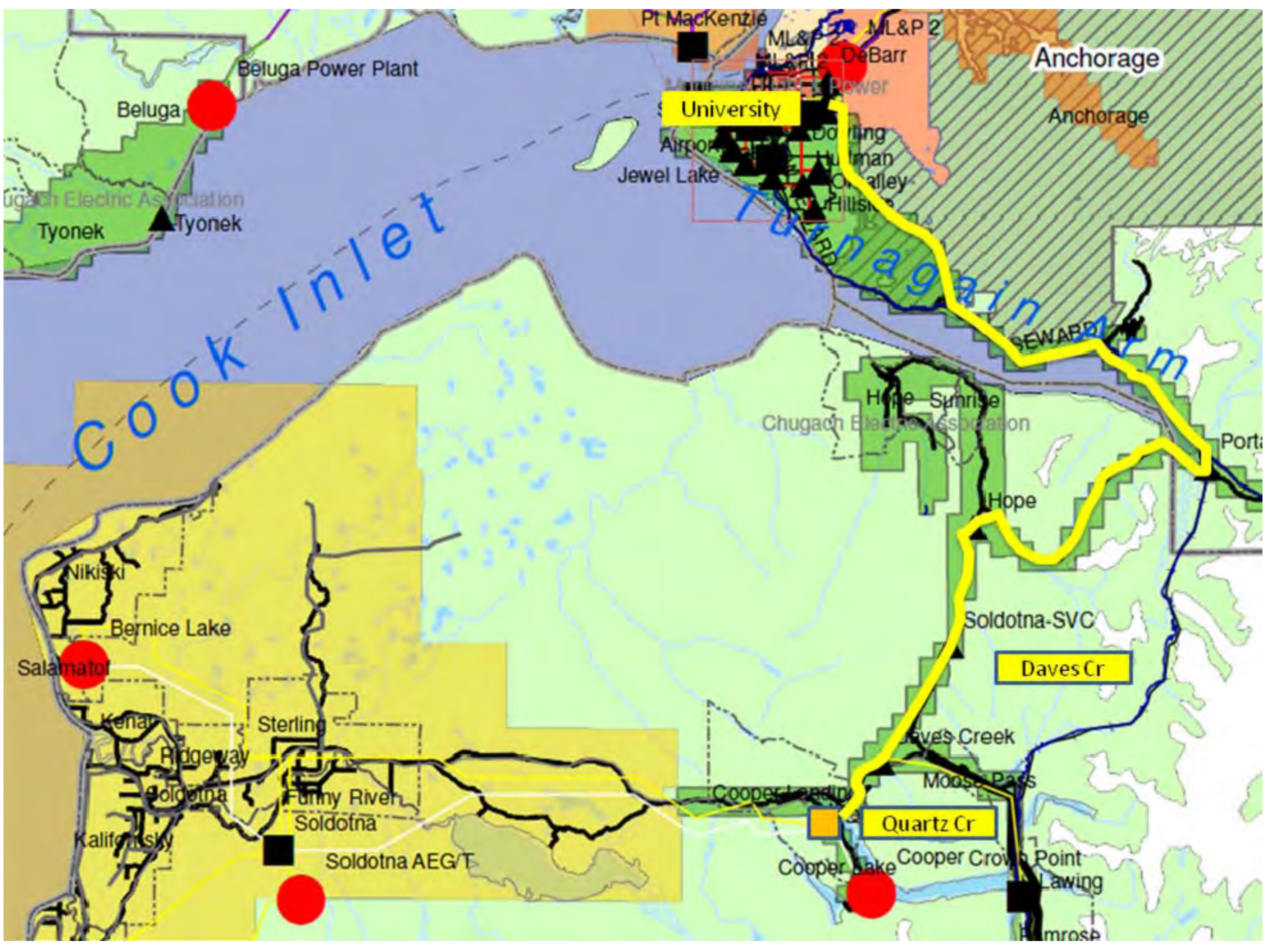
Figure 12-3
Soldotna to Quartz Creek 230kV Transmission Line (Repair and Replacement)



Project C – Quartz Creek to University 230 kV Transmission Line (Repair and Replacement - Category 1)

This is the section of the existing 115 kV Kenai Intertie owned by Chugach and was constructed in 1959 and consists of two sections. The first section is from Quartz Creek to Daves Creek and is approximately 7.7 miles long. The second section is from Daves Creek to University and is approximately 68.2 miles long. Portions of this line have been upgraded over time however approximately 65 percent of this wood pole line is over 50 years old and is subject to avalanches and severe weather conditions. It will require significant rebuilding to keep it in service over the life of this plan. The line is considered a critical component of the transfer capability between the Anchorage and Kenai areas and is also required for reliability and reserve sharing. The current transfer limit between the areas is limited due to stability considerations to 75 MW. The steady-state limit is constrained to 105 MW due to voltage collapse while the thermal limit for the existing 115 kV transmission line is approximately185 MW in the winter and 95 MW in the summer. The line is recommended to be upgraded to 230 kV over the life of this plan to increase the stability limit transfer capability and reserve sharing between the areas. Figure 12-4 presents the proposed upgrade.

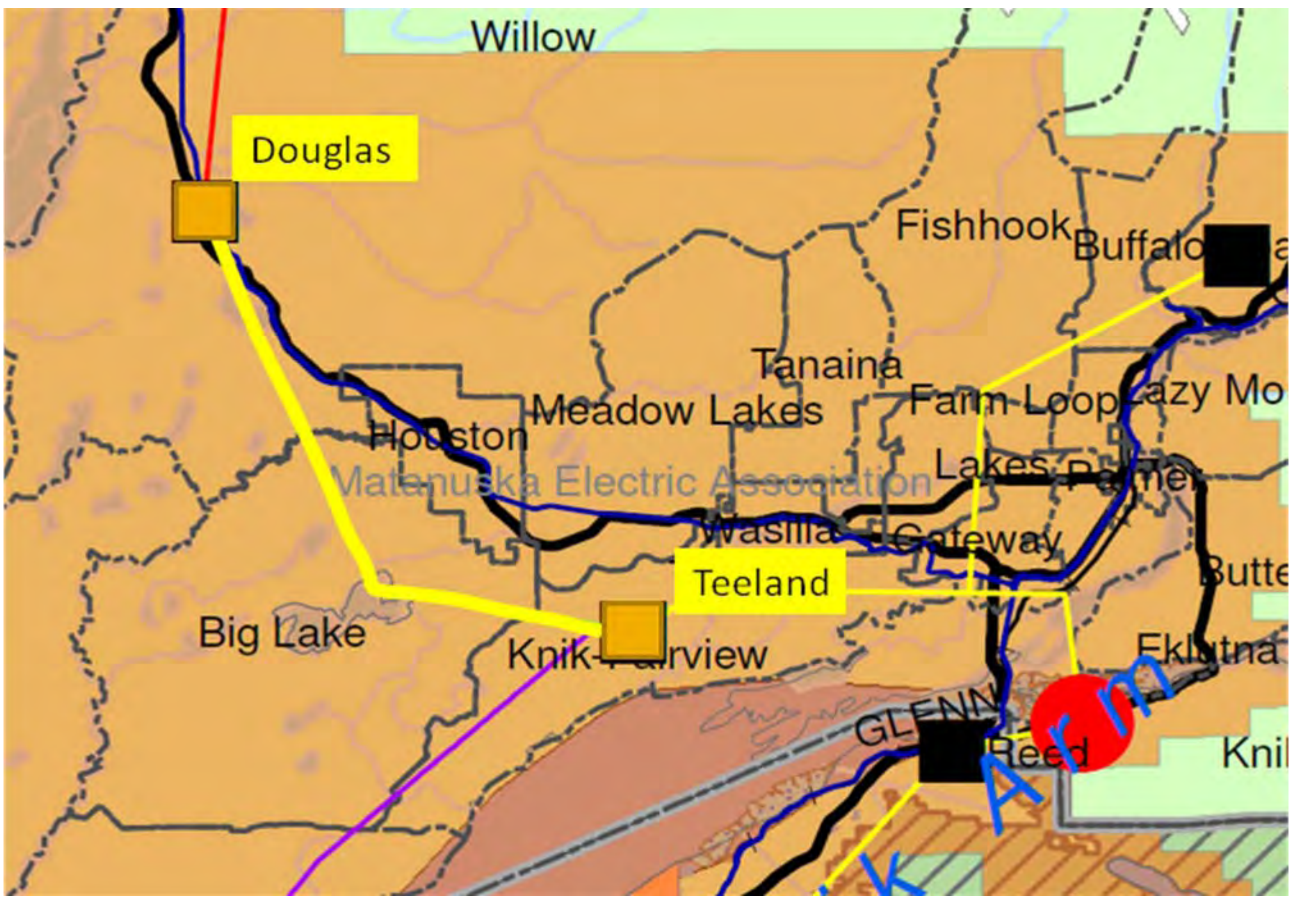
Figure 12-4
Quartz Creek to University 230kV Transmission Line (Repair and Replacement)



Project D – Douglas to Teeland 230 kV Transmission Line (Repair and Replacement - Category 2)
The Douglas to Teeland line was originally constructed for operation at 115 kV and currently operates at 138 kV and serves as the final line section of the Anchorage-Fairbanks Intertie.

The construction of the Lorraine-Douglas line described below and the upgrade of the Anchorage-Fairbanks Intertie to 230 kV requires the upgrade of this line section to 230 kV to form a transmission loop between Lorraine-Teeland and Douglas stations. The proposed loop will eliminate single contingency outages to the southern portion of the Intertie and permits higher transfer limits between load and generation areas. The line should be constructed following the completion of the Lorraine – Douglas line section to mitigate the impact of the line's construction on energy transfers between the Anchorage and Fairbanks areas. Figure 12-5 presents the proposed upgrade.

Figure 12-5
Douglas to Teeland 230 kV Transmission Line (Repair and Replacement)



Project E – Lake Lorraine to Douglas 230 kV Transmission Line (New Build - Category 2)
Pt. MacKenzie substation is a key component in the Railbelt transmission grid, serving as the hub of electrical power generated at Beluga and providing interconnections to all other utilities. Teeland substation currently serves as the sole terminus of the Anchorage-Fairbanks Intertie and also as the primary source of power for MEA's consumers in the Palmer-Wasilla area.

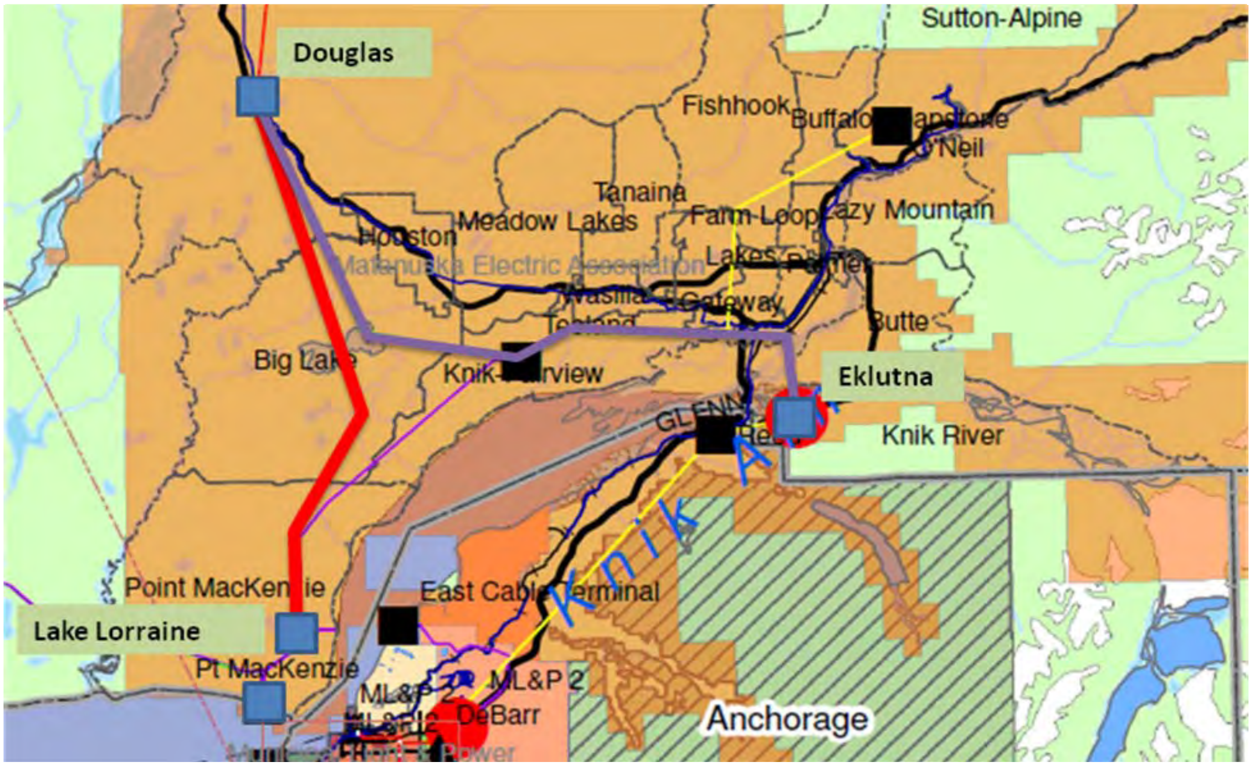
The Pt. MacKenzie–Teeland transmission line is the heaviest loaded line in the Railbelt, often carrying over 200 MW during peak months. By comparison, the Anchorage-Kenai Intertie is constrained to no more than 75 MW during its peak loading and the Anchorage-Fairbanks Intertie is restricted to less than 85 MW. Under both summer and winter loading conditions, the loss of the Pt. MacKenzie-Teeland transmission line results in unstable conditions in the Anchorage-Kenai transmission system during certain generation conditions. This instability is in addition to the blackout of approximately 25 percent of the Railbelt consumers caused by the line outage. The unstable conditions could result in widespread blackouts from Fairbanks to Homer. In the worst case, the system will suffer a complete blackout, with a risk of damage to Railbelt generators.

The construction of a new substation at Lake Lorraine, with a new transmission line to Douglas Substation provides a transmission loop between Pt. MacKenzie, Lake Lorraine, Teeland and Douglas substations will eliminate the largest single contingency in the Railbelt system. Following the completion of the Lorraine-Douglas line, the loss of any single transmission line in this loop will not result in widespread outages in the Fairbanks and Mat-Su areas.

The construction of the Lake Lorraine-Douglas transmission line has a dramatic impact on the reliability of service to the Railbelt consumers. The elimination of a single point of failure for the entire electrical system in the summer conditions is achieved. In both winter and summer conditions, outages to all consumers in the Palmer – Wasilla areas and a significant number of consumers in the Fairbanks area by the failure of a single transmission line are eliminated. The stability margin for the winter conditions is improved, but unlike the summer conditions, the risk of system instability is not eliminated.

This project will also require the upgrade of the existing SVCs at Teeland, Healy and Gold Hill. These SVCs were installed in 1984 as part of the original Intertie construction. The SVC components are no longer manufactured or available from third party vendors. Spare parts have been exhausted and replacement components cannot be obtained. Loss of the SVCs is critical to the operation of the Intertie and the economic transfer of both energy and capacity between Anchorage and Fairbanks. Figure 12-6 presents this proposed project.

Figure 12-6
Lake Lorraine to Douglas 230 kV Transmission Line (New Build)



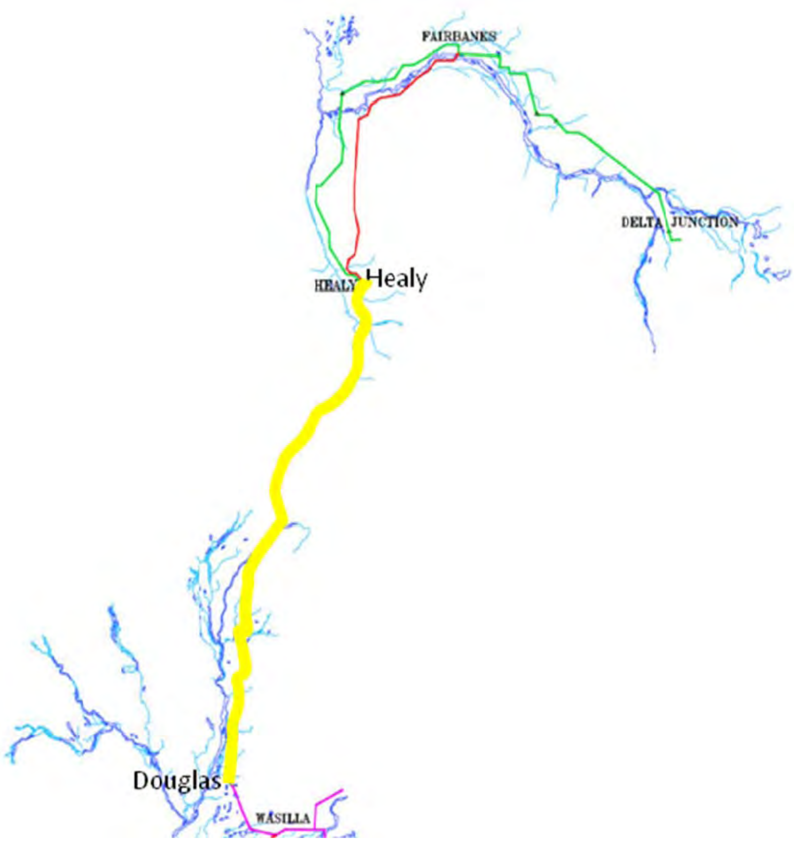
Project F – Douglas to Healy 230 kV Transmission Line (Upgrade - Category 2)
The Alaska Intertie includes a 170-mile, 345 kV transmission line between Willow and Healy and voltage control devices at Teeland, Healy and Gold Hill Substations. The line built with State grant funds, went into operation in 1985, and is operated at 138 kV.

The line is the state-owned portion of the 300 mile Anchorage to Fairbanks transmission system. The Intertie allows GVEA to purchase lower cost energy from Anchorage and the Kenai generated from natural gas and the Bradley Lake hydroelectric project. Chugach and ML&P generate revenue from the sale of economy energy to GVEA. The line also allows reserves, both operating and non-operating to be shared between the northern and southern areas of the system.

The ability to import power into the Fairbanks area is limited to the current stability limit of approximately 85 MW. Although stability aids could increase this power transfer capability, the amount of power transferred over the intertie would still be limited to approximately 85 MW as this is considered the maximum allowable import limit into the Fairbanks area to survive the N-1 contingency of the loss of the intertie.

The proposed transmission line upgrade will allow power transfers to increase from the existing limit of approximately 85 MW and will eliminate the loss of load associated with an N-1 contingency and bring the Fairbanks GRETC area into compliance with the planning criteria following the completion of the second transmission line. Figure 12-7 presents the proposed transmission line.

Figure 12-7
Douglas to Healy 230 kV Transmission Line (Upgrade)



Project G – Douglas to Healy 230 kV Transmission Line (New Build - Category 2)
An additional line between the Douglas and Healy substation is required to meet the reliability criteria for no loss of load for any N-1 condition and to increase the transfer capability between the northern and central portions of the Railbelt. The ability to import power into the Fairbanks area is limited to the current stability limit of approximately 85 MW over the single transmission line. Although stability aids could increase this power transfer capability, the amount of power transferred over a single intertie would still be limited to approximately 85 MW as this is considered the maximum allowable import limit into the Fairbanks area to ensure survival following the N-1 contingency loss of the intertie.

The proposed transmission line will allow power transfers to increase from the existing limit of approximately 85 MW and will eliminate the loss of load associated with an N-1 contingency and bring the Fairbanks GRETC area into compliance with the planning criteria following the completion of the second transmission line. The proposed route would parallel the existing intertie. A significant portion, but not all of the right-of-way, of the existing intertie will accommodate an additional line. The exact routing and characteristics of the transmission line, along with any associated changes in compensation at the terminals of the line will be determined in future studies. Figure 12-8 presents the proposed new line. If the preferred generation plan includes a Susitna option, this line configuration will change depending on the selected Susitna alternative.

Figure 12-8
Douglas to Healy 230 kV Transmission Line (New Build)

Project H – Eklutna to Fossil Creek 230 kV Transmission Line (Upgrade - Category 2)
The Eklutna and Briggs substations are interconnected by a 230 kV double circuit line with one circuit used to supply multiple MEA distribution substations at 115 kV. The other circuit is not connected to local distribution substations and can function as a direct connection from Eklutna to Fossil Creek. From Fossil Creek the 230 kV line currently connects to the ML&P Plant 2 230 kV substation while the 115 kV line connects to the 115 kV substation at ML&P's Plant 2 generation plant. The construction of a 230 kV/115 kV substation at Fossil Creek would allow this line section to serve an express 115 kV line to Eklutna station while the tapped line would be used to serve local load. As part of the long range goals, the express feeder would be converted to 230 kV with a corresponding 230 kV/115 kV substation at Eklutna. This project, along with upgrade of the MEA 115 kV system (Projects M and N), will be part of a redundant 230 kV path from Beluga to Anchorage. This project includes the construction of a 230 kV/ 115 kV substation at Fossil Creek and Eklutna to serve the MEA 115 kV system. Figure 12-9 presents the proposed line from Eklutna to the Fossil Creek substation.

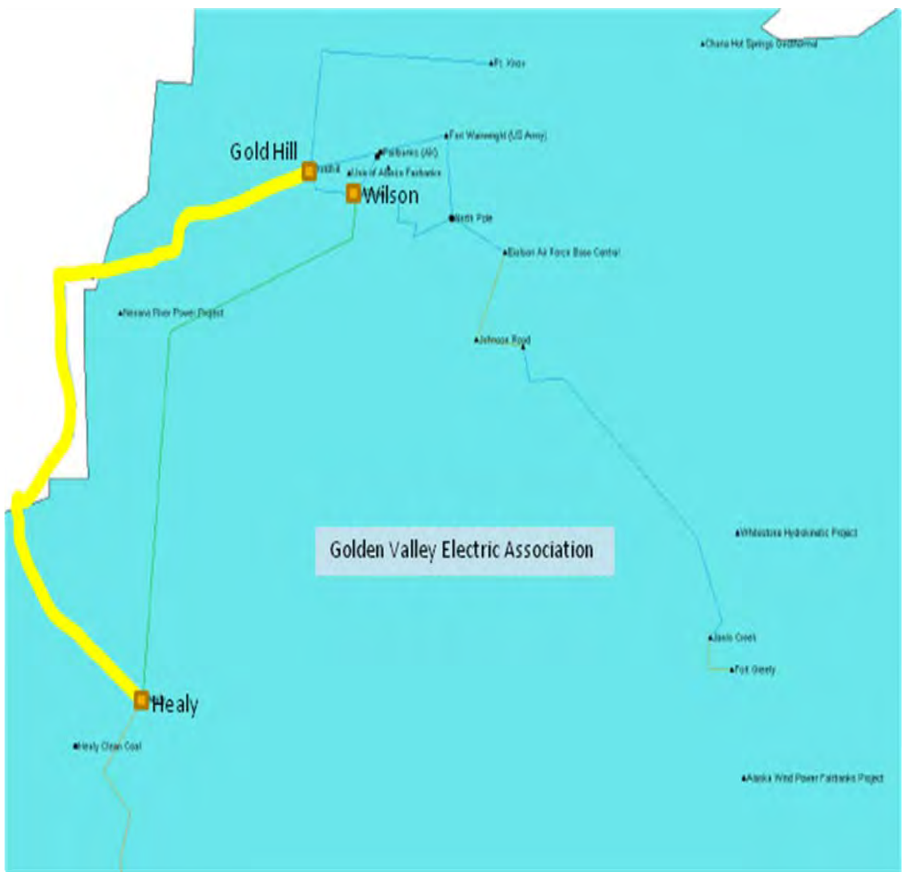
This project will also require the construction of a 230 kV line section from ML&P Plant 2 to University station for N-1 contingencies at Plant 2 and to support the ML&P and Chugach 138 kV and 115 kV systems as described in other project summaries.

The project may consist of a staged approach resulting in the 115 kV systems in the MEA area continuing to operate at 115 kV for many years while the infrastructure continues to develop.

Figure 12-9
Eklutna to Fossil Creek 230 kV Transmission Line (Upgrade)

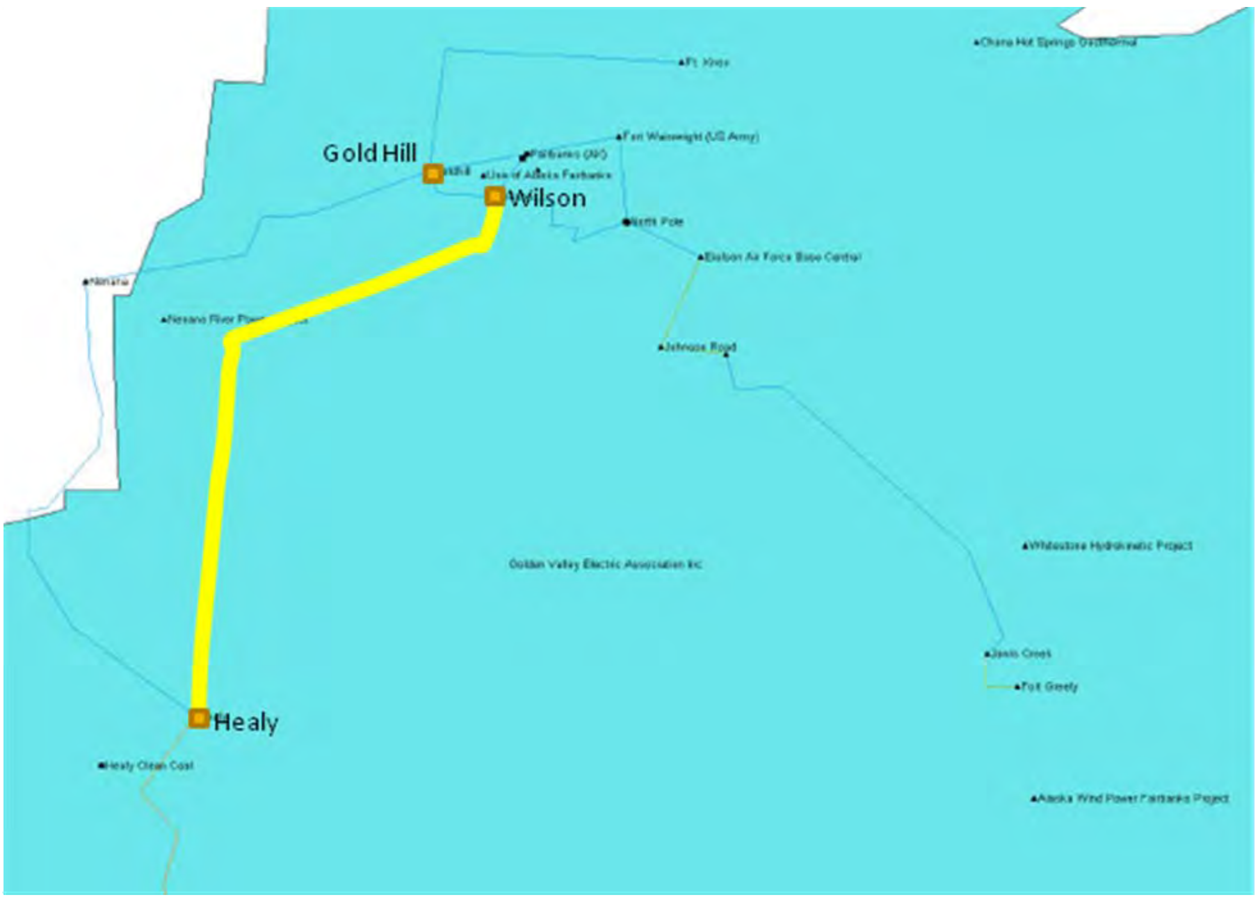
Project I – Healy to Gold Hill 230 kV Transmission Line (Repair and Replacement - Category 1)
The existing Healy to Gold Hill 138 kV line was constructed and placed in service in 1968. This line serves as one of two paths between Healy and Fairbanks and delivers firm and economy power to Fairbanks from the Healy, Anchorage, and Kenai areas. In 2007, the GVEA Long Range Planning Study recommended that this line be rebuilt in stages between 2017 and 2021. The study further recommended that this line should be upgraded to 230 kV although it would initially be operated at 138 kV. When the transmission plan is completed, the existing 138 kV line becomes the weak link in the transmission system and limits the ability to import power into Fairbanks following the N-1 loss of the Northern Intertie. This project is required to meet the GRETC concept of providing a reliable transmission system backbone throughout the Railbelt.
Figure 12-10 presents the proposed upgrade.

Figure 12-10
Healy to Gold Hill 230 kV Transmission Line (Repair and Replacement)



Project J – Healy to Wilson 230 kV Transmission Line (Upgrade - Category 2)
The existing Healy to Wilson line was constructed in 2005 at 230 kV and presently operated at 138 kV. To increase the power transfer capability of the transmission system above its current limits, the line is required to be operated at 230 kV. Operation of this line along with the Healy to Gold Hill line at 230 kV is a part of the phased development of a reliable 230 kV backbone of transmission facilities. Figure 12-11 presents the proposed upgrade.

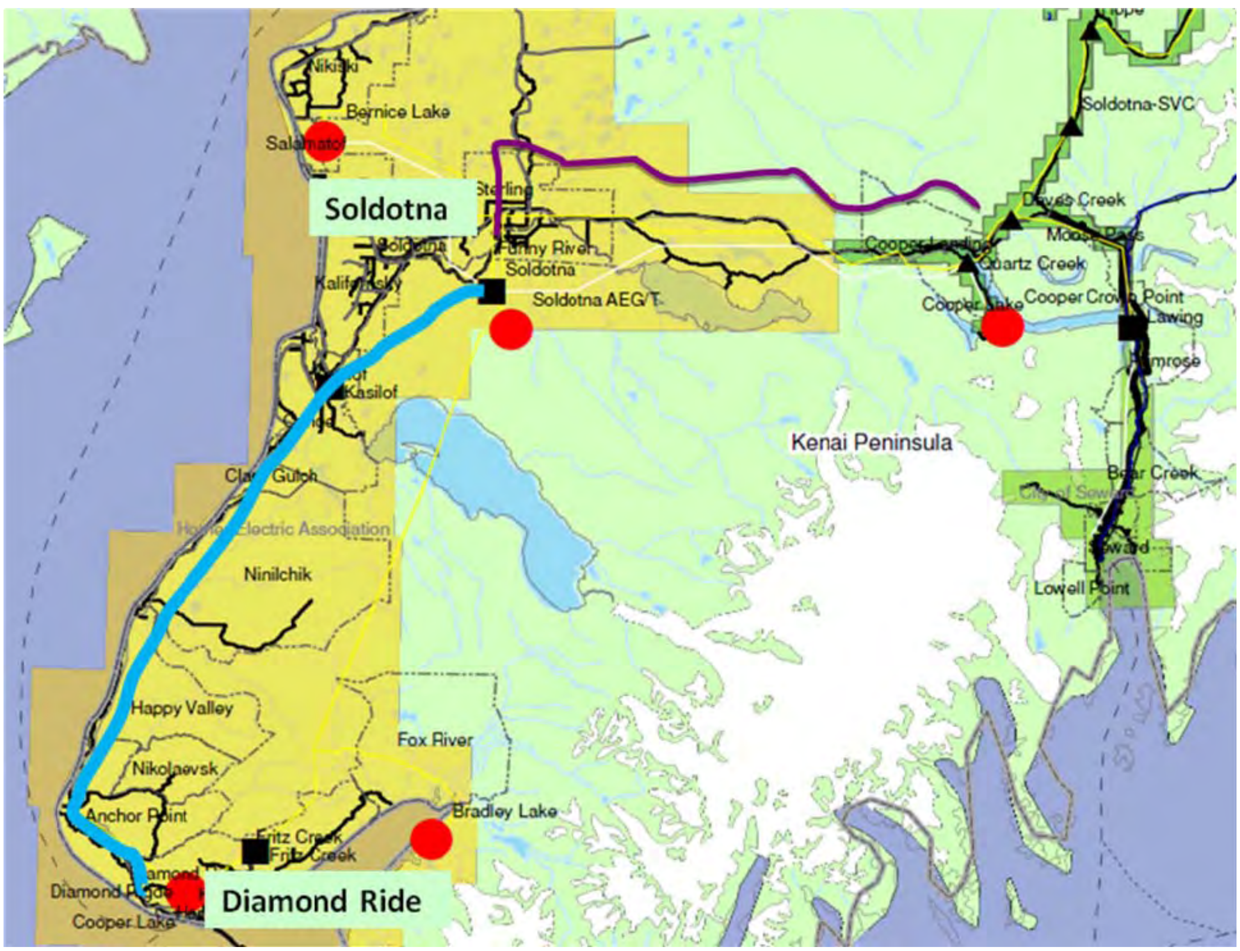
Figure 12-11
Healy to Wilson 230 kV Transmission Line (Upgrade)



Project K – Soldotna to Diamond Ridge 115 kV Transmission Line (Repair and Replacement - Category 1)

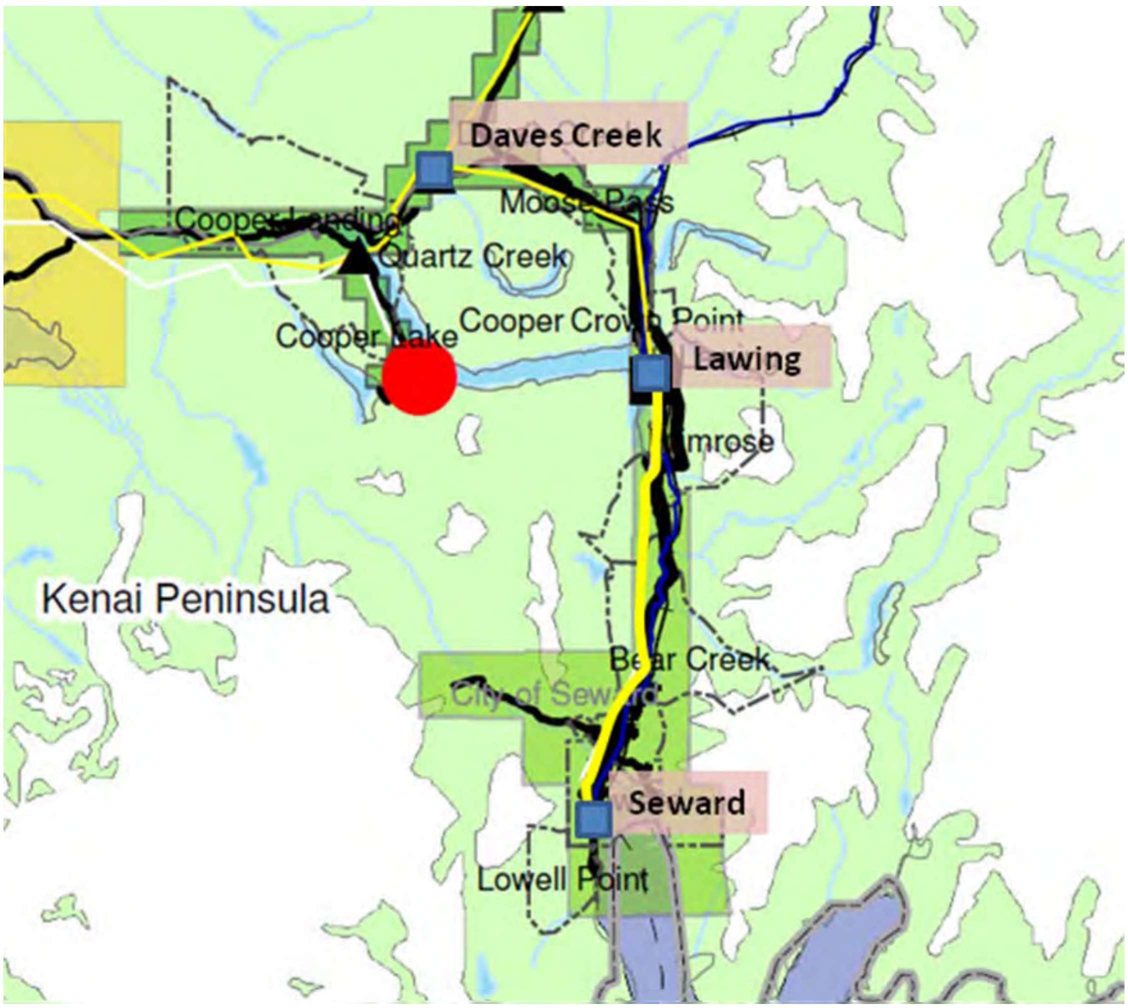
The Soldotna to Diamond Ridge 115 kV line serves several distribution substations on the Kenai from Ski Hill, Kasilof, Anchor Point, Diamond Ridge, and Fritz Creek and as part of a transmission loop from Soldotna Substation to Bradley Lake generation facility. The older of the two lines comprising the transmission loop is in poor condition and has a very small conductor size. The small conductor size on this line segment results in high impedance, high losses and limited capacity transfer over the line. Outage of the express Soldotna to Bradley Lake 115 kV line results in low voltages and line overloads in the southern Kenai and restricts the Bradley Lake project to an output of less than 60 MW in summer months. This proposed project will rebuild the line with larger conductor at the existing transmission line voltage. Figure 12-12 presents the proposed upgrade.

Figure 12-12
Soldotna to Diamond Ridge 115 kV Transmission Line (Repair and Replacement)



Project L – Lawing to Seward 115 kV Transmission Line (Upgrade - Category 1)
The City of Seward is served by a 115 kV line from Daves Creek on the Kenai to the Lawing substation. The voltage is then stepped down to 69 kV and the line continues into the City of Seward. Most of the 69 kV line section was replaced and upgraded to 115 kV insulation, but left to operate at 69 kV. Some distribution stations and the short line to Spring Creek will need to be converted from 69 kV to 115 kV. The transmission line runs primarily through the Department of Forestry lands with sections along the Alaska Railroad. The City of Seward is a full-requirements customer of Chugach and has a winter peak load of approximately 10 MW. Figure 12-13 presents the proposed upgrade.

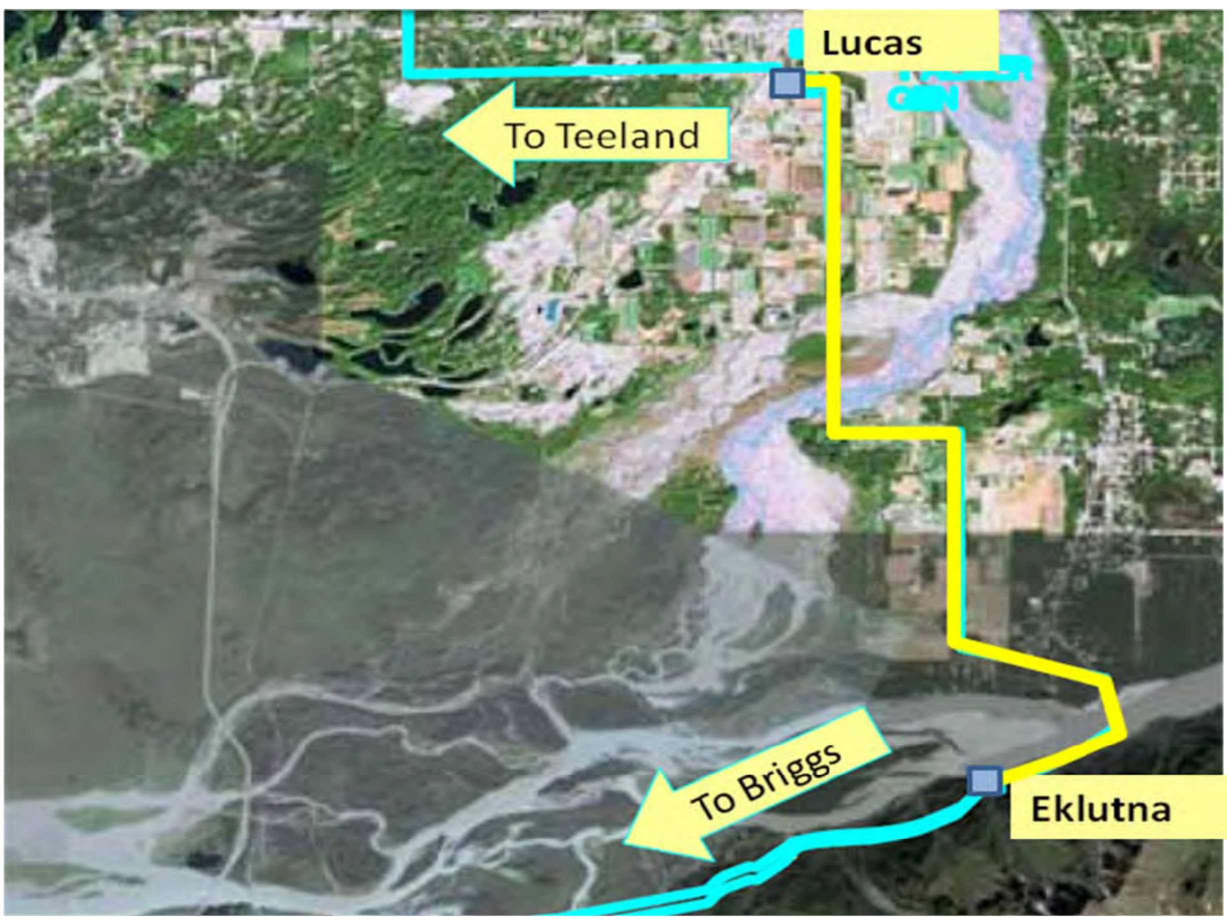
Figure 12-13
Lawing to Seward 115 kV Transmission Line (Upgrade)



Project M – Eklutna to Lucas (Hospital Substation) 115 kV/ 230 kV Transmission Line (Repair and Replacement - Category 1)

The existing Eklutna to Lucas line was originally built as part of the Eklutna Project in 1955 and needs to be rebuilt due to the age and condition of the line. The line requires upgrading or an additional line to meet the requirements of the system over the life of this plan. The optimal construction of this project should be determined in conjunction with the preferred generation plan. The deficiencies of the system can be addressed in a number of different manners. An express 115 kV line similar to the Briggs–Eklutna line eliminates low voltage conditions and provides reliability improvements to meet the GRETC requirements. The express feeder should be insulated to 230 kV to serve as a possible tie to the Teeland station. Alternatively, the existing line could be rebuilt at 230 kV converting all of the MEA substations to 230 kV, or finally the express feeder could be built and operated at 230 kV with a corresponding 230 kV/115 kV substation in the Lucas or Hospital Sub area. The final configuration of the project should be determined in future studies following determination of the preferred generation plan. Figure 12-14 presents the proposed project.

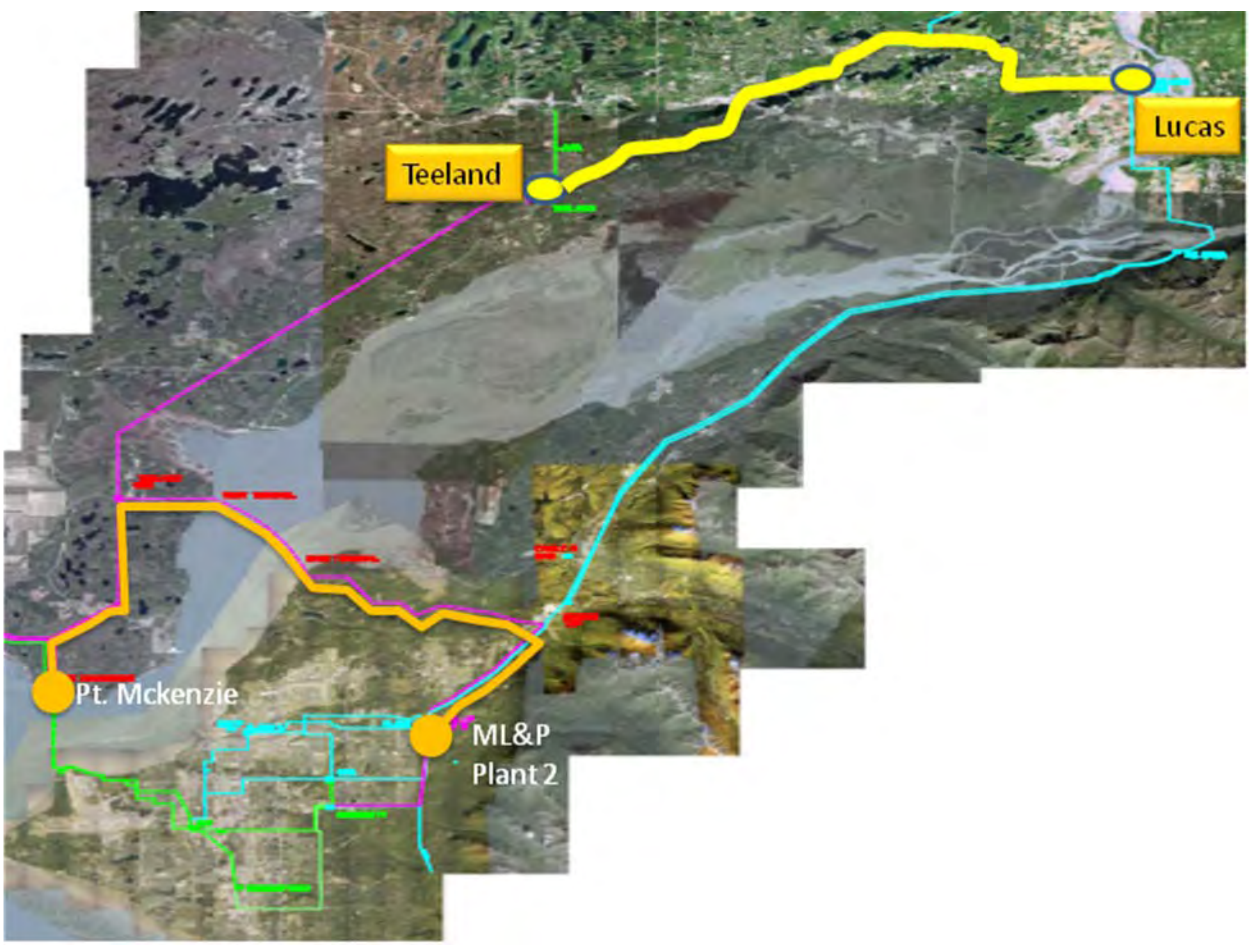
Figure 12-14
Eklutna to Lucas 230 kV Transmission Line (Repair and Replacement)



Project N – Lucas to Teeland 230 kV (115 kV) Transmission Line (Repair and Replacement - Category 2)

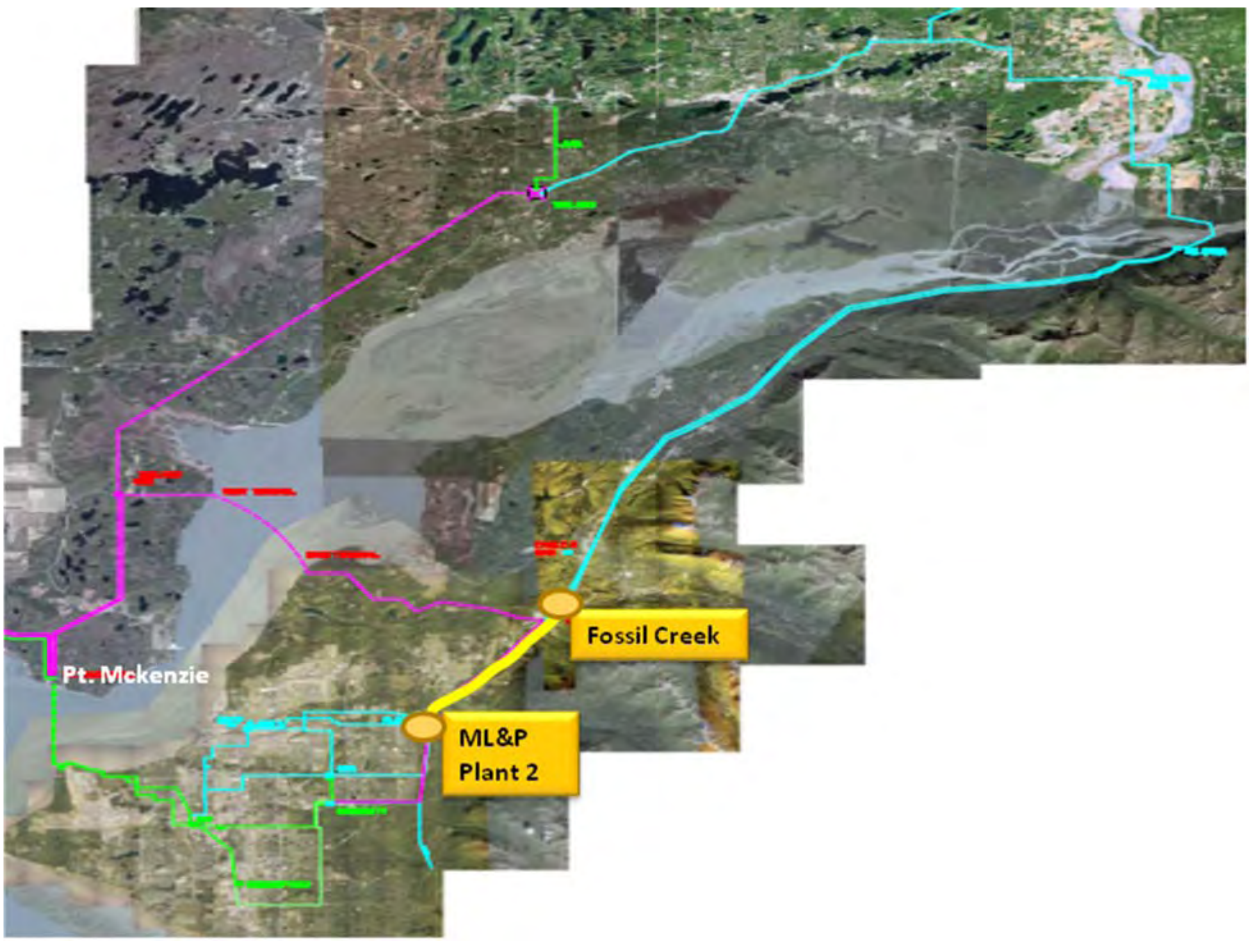
The existing 115 kV Teeland to Lucas line serves several substations in the MEA area. This section of line is subject to low voltages and load loss with the single contingency outage of the Teeland 230 kV/ 115 kV transformer or the Teeland – Pt. MacKenzie 230 kV transmission line. The transmission contingency is alleviated by the construction of Project E (Lake Loraine to Douglas 230 kV line), but the construction of this line does not mitigate the loss of load and low voltage conditions experienced following the loss of the Teeland Transformer. There is currently a 138 kV/115 kV transformer that serves as a emergency replacement for the 230 kV/115 kV transformer, however, this transformer will be retired when the Intertie is converted to 230 kV. In order to alleviate low voltage conditions and loss of load in the MEA area for contingency operations, a new transmission line is required into the Lucas/Hospital Sub area of the MEA territory. The optimum selection of the line and its construction and operating voltage requires more detailed study than is possible in this analysis and will require coordination with other transmission projects and generation alternatives. This project should be evaluated as part of future transmission planning studies. Figure 12-15 presents the proposed replacement.

Figure 12-15
Lucas to Teeland 230 kV Transmission Line (Repair and Replacement)



Project O – Fossil Creek to Plant 2 230 kV Transmission Line (Upgrade - Category 2)
This section of line consists of a double circuit 230 kV constructed line , with one circuit operated at 230 kV and one circuit currently being operated at 115 kV. This project is required to enhance the reliability of the Anchorage and MEA areas. Operation of both circuits at 230 kV will require the construction of a 230 kV/115 kV substation at Fossil Creek and construction of a 230 kV line section from ML&P Plant 2 to University station. Alternatively, it may be possible to install a second transformer at ML&P Plant 2 and increase the transfer capacity of the AML&P 115 kV system. The exact configuration should be determined in future studies. Figure 12-16 presents the proposed upgrade.

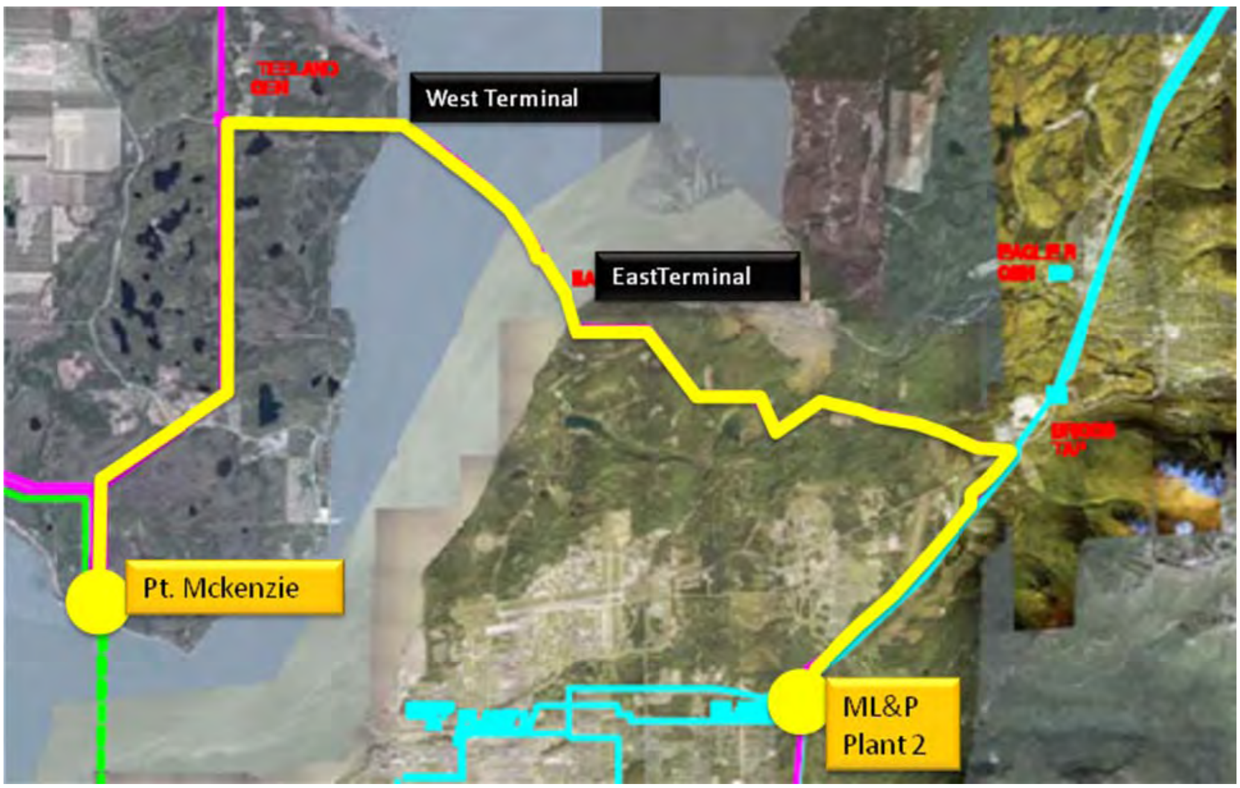
Figure 12-16
Fossil Creek to Plant 2 230 kV Transmission Line (Upgrade)



Project P – Pt. Mackenzie (Lorraine) to Plant 2 230 kV Transmission Line (Repair and Replacement - Category 2)

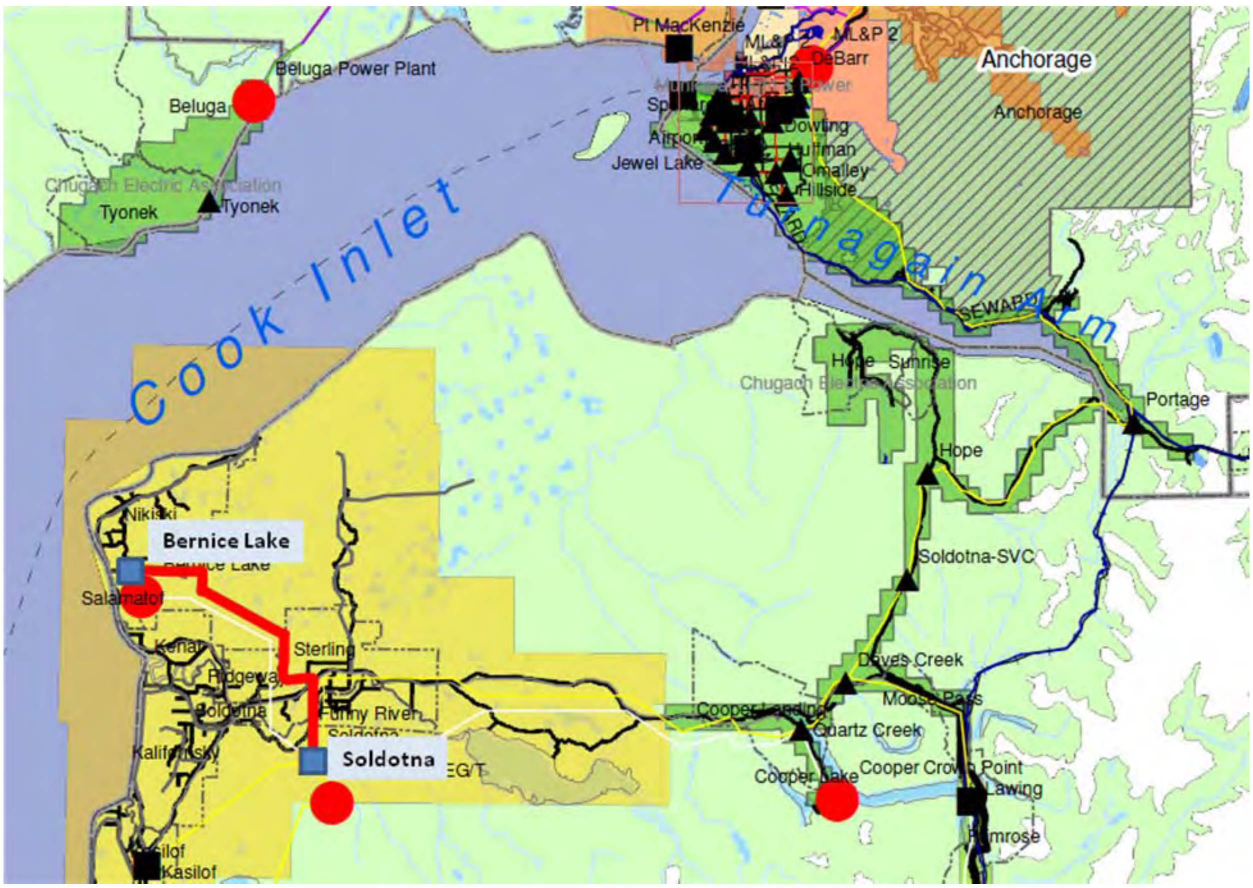
The existing Pt. Mackenzie to Plant 2 transmission line consists of two sections of 230 kV overhead transmission line and a section of underwater cable between the East Terminal and West Terminal stations. The overhead line is in reasonably good condition but the submarine cable is expected to be in need of replacement and repairs by 2025. At that time, the terminus of the transmission line will be Lorraine and AML&P Plant 2 stations. This circuit is critical to the reliability of the Railbelt system and is, therefore, scheduled as a GRETC replacement project. The project is presented in Figure 12-17.

Figure 12-17
Pt. Mackenzie to Plant 2 230 kV Transmission Line (Repair and Replacement)



Project Q – Bernice Lake – Soldotna 115 kV Transmission Line (Rebuild - Category 2)
The 115 kV transmission line from Bernice Lake Power Plant to Soldotna Substation serves as the critical link between the proposed Southern Intertie, the existing Kenai intertie and the Bradley Lake power plant. The transmission line was constructed in 1971 and is expected to require significant reconstruction over the life of this plan. Further study should be undertaken before this line is upgraded to determine if 230 kV operation is required or is possible over the life of this plan. 230 kV operation will require significant permitting and environmental effort and may not be warranted. The project is presented in Figure 12-18.

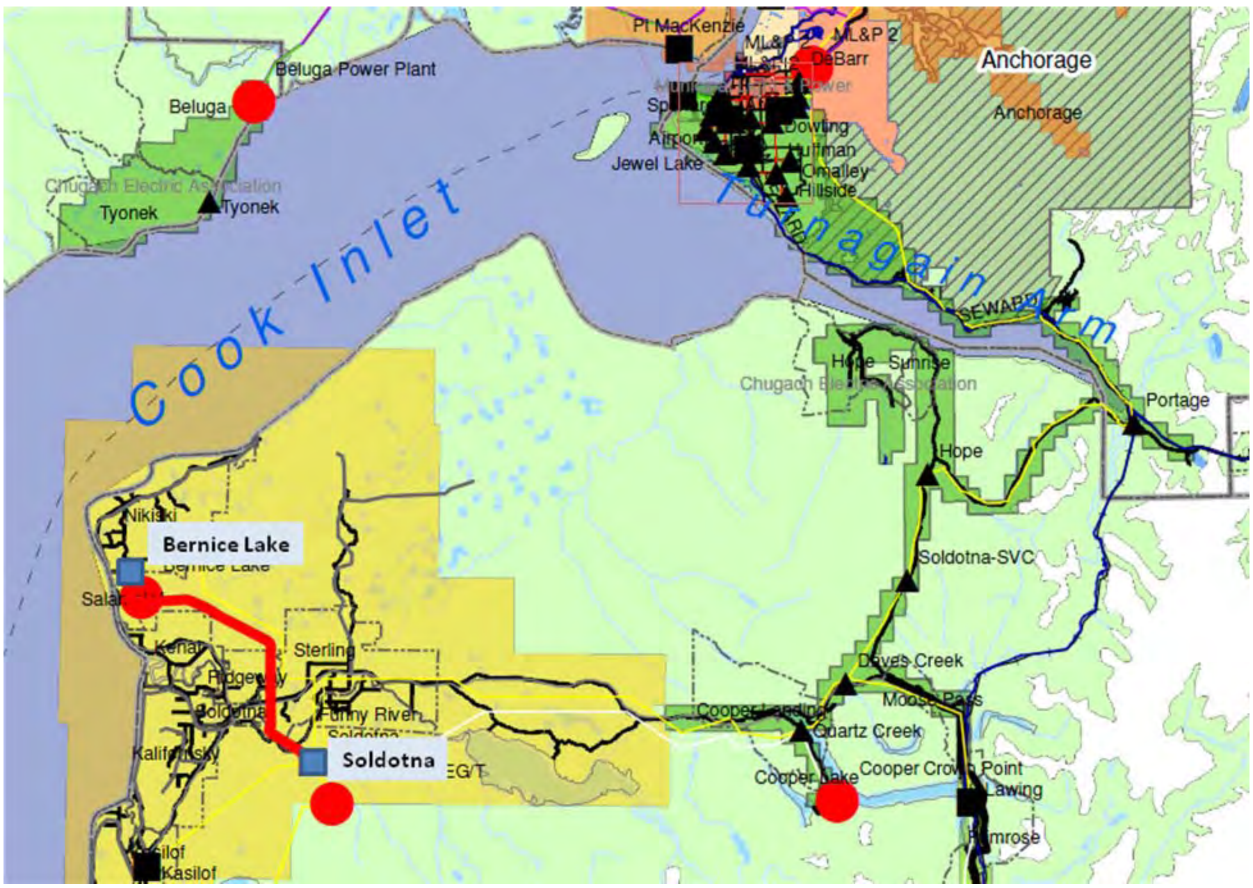
Figure 12-18
Bernice Lake to Soldotna 115 kV Transmission Line (Rebuild)



Project R – Bernice Lake–Beaver Creek - Soldotna 115 kV Transmission Line (Rebuild - Category 2)
The existing 69 kV transmission line between Bernice Lake, Beaver Creek and Soldotna stations cannot be operated in parallel with the 115 kV transmission line between Bernice Lake and Soldotna due to the limited transfer capacity of the line and transient stability limitations. The 69 kV line is required to be upgraded to 115 kV to eliminate the single contingency loss of the existing 115 kV transmission line between Soldotna and Bernice Lake. HEA has rebuilt portions of the 69 kV line to 115 kV construction and Marathon Station is constructed to 115 kV construction.

The project consists of upgrading the remaining portions of the 69 kV line to 115 kV and modifications to the stations at Bernice Lake, Beaver Creek and Soldotna. This line should not be considered for 230 kV operation. The project is presented in Figure 12-19.

Figure 12-19
Bernice Lake to Beaver Creek to Soldotna 115 kV Transmission Line (Rebuild)



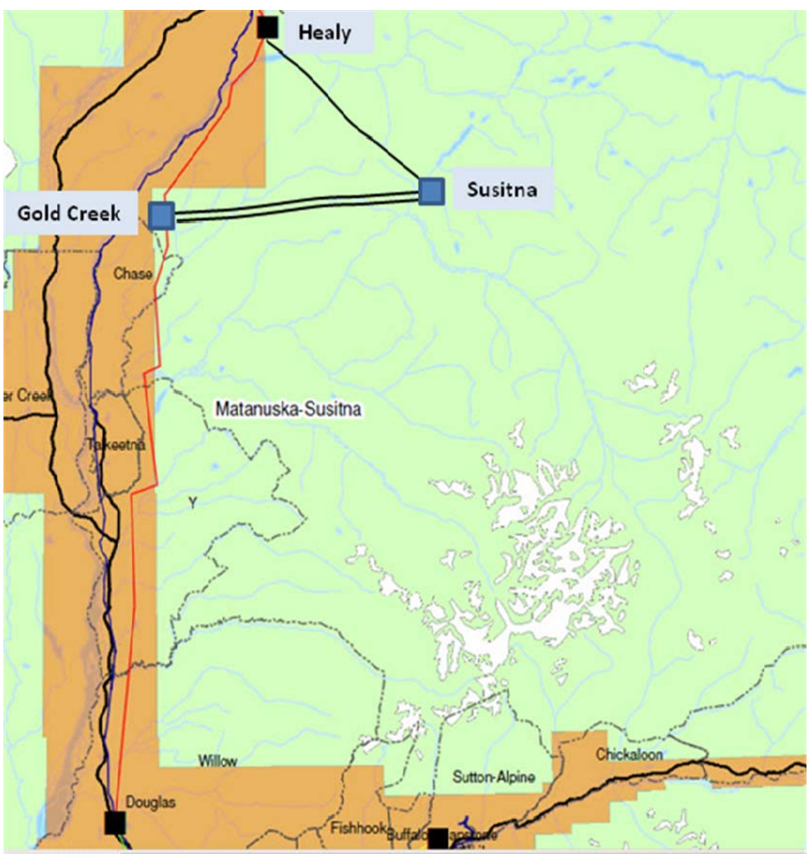
12.6 Susitna

Project S – Susitna Transmission Additions (New Project - Category 3)

The Susitna transmission interconnection configuration will depend on the selected generation site at Susitna. The Watana option consists of two 230 kV transmission lines connecting the Susitna substation to the new 230 kV Gold Creek substation, one transmission line from Sustina to Healy Substation, one additional 230 kV transmission line from the Gold Creek substation south to the Douglas 230 kV substation, and one line 230 kV transmission line from Douglas to Pt. MacKenzie Substation. The Gold Creek substation is approximately 33 miles from the Susitna substation and is the terminating point for the two 230 kV lines from Susitna as well as a switching station for the Douglas to Healy tie lines and the connecting point for the Gold Creek to Douglas 230 kV line that will transport power from the Susitna plant into the southern regions of the Railbelt. The capital cost for the Susitna substation, the two 230 kV transmission lines from Susitna to Gold Creek, and the Gold Creek substation are included in the capital cost for the Susitna projects. The capital cost for the Douglas to Lake Lorraine 230 kV transmission line is included as the incremental cost making the Douglas to Lake Lorraine 230 kV transmission line described in Project E a double circuit line. The Susitna to Gold Creek lines and the Gold Creek to Douglas line are presented in Figure 12-20. The Douglas to Lake Lorraine 230 kV transmission line is shown in Figure 12-6. Project S is not required if the Susitna project is not constructed.

If the Devils Canyon site is selected, three lines between Susitna and Gold Creek are required; however, the second Intertie between Gold Creek and Healy would replace the Susitna-Healy line.

Figure 12-20
Susitna to Gold Creek 230 kV Transmission Line



12.7 Summary of Transmission Projects

The list of transmission projects is presented in Table 12-1, and their locations are shown in Figures 12-21 and 12-22. Table 12-1 also includes preliminary cost estimates for each of the listed projects. Note that this list does not include a description of the associated distribution substations that would need to be upgraded to accommodate the new voltage levels of the transmission projects. The cost of these projects are however included in the total cost for each scenario and is also shown in the table below. While the details of GRETC are not yet developed to a point that determines whether these distribution substations would be a part of the GRETC system or part of the individual utilities distribution systems, they are a necessary cost resulting from the development of the GRETC system and have been included in the economic evaluations. All the transmission projects presented in this section were evaluated by a transmission load flow analysis to determine how the Railbelt system performed with these projects along with the economic dispatch of the selected generating resources in the RIRP.

Table 12-1
Summary of Proposed Transmission Projects

Project No.	Transmission Projects	Type	Cost ($000)
A	Bernice Lake – International	New Build (230 kV)	227,500
B	Soldotna – Quartz Creek	R&R (230 kV)	126,500
C	Quartz Creek – University	R&R (230 kV)	165,000
D	Douglas – Teeland	R&R (230 kV)	62,500
E	Lake Lorraine – Douglas	New Build (230 kV)	80,000
F	Douglas – Healy	Upgrade (230 kV)	30,000
G	Douglas – Healy	New Build (230 kV)	252,000
H	Eklutna – Fossil Creek	Upgrade (230 kV)	65,000
I	Healy – Gold Hill	R&R (230 kV)	180,500
J	Healy – Wilson	Upgrade (230 kV)	32,000
K	Soldotna – Diamond Ridge	R&R (115 kV)	66,000
L	Lawing – Seward	Upgrade (115 kV)	15,450
M	Eklutna – Lucas	R&R(115 kV/230 kV)	12,300
N	Lucas – Teeland	R&R (230 kV)	51,100
O	Fossil Creek – Plant 2	Upgrade (230 kV)	13,650
P	Pt. Mackenzie – Plant 2	R&R (230 kV)	32,400
Q	Bernice Lake – Soldotna	Rebuild (115 kV)	24,000
R	Bernice Lake – Beaver Creek - Soldotna	Rebuild (115 kV)	24,000
S	Susitna Transmission Additions	New Build (230 kV)	57,000

Figure 12-21
Location of Proposed Transmission Projects (Without Susitna)

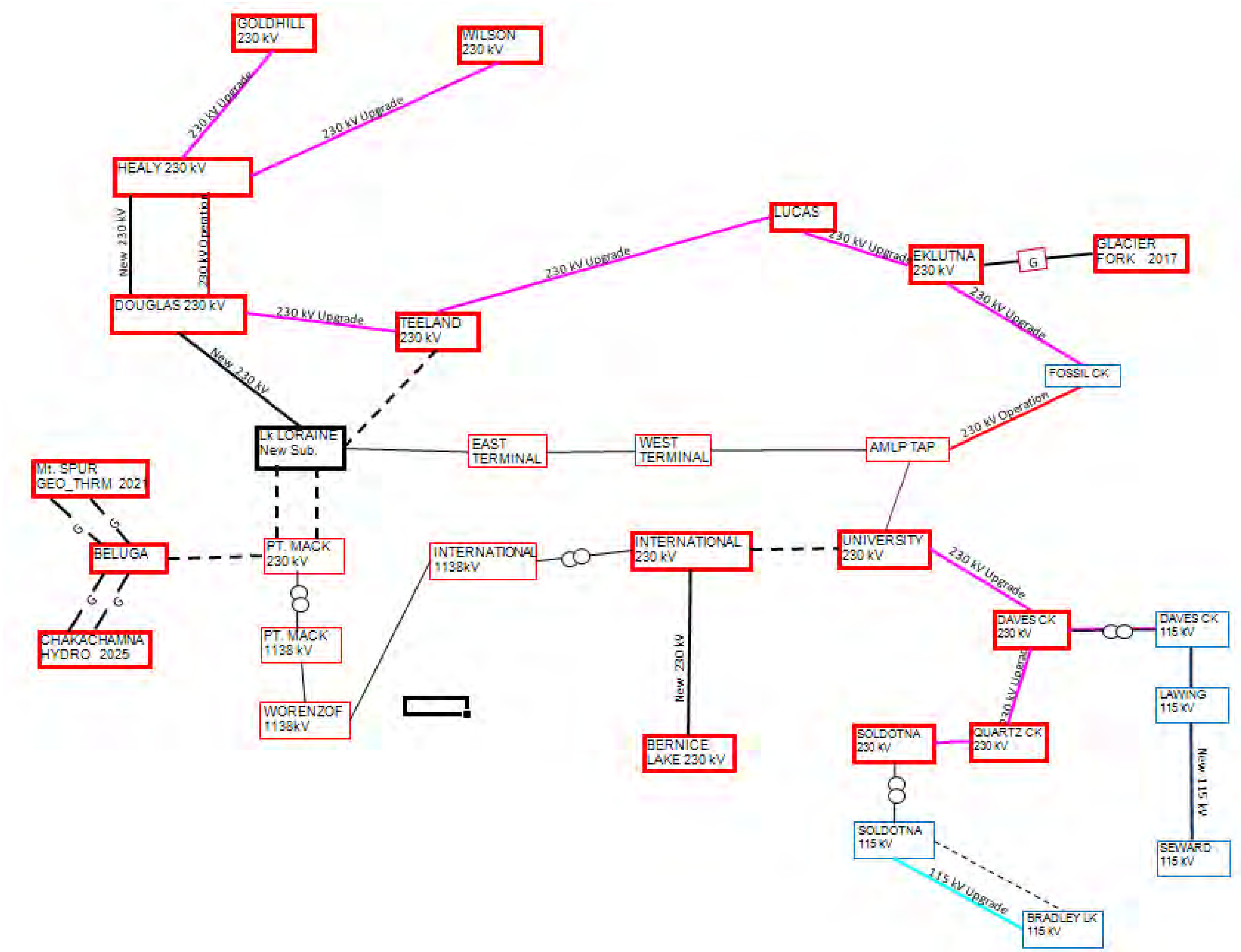
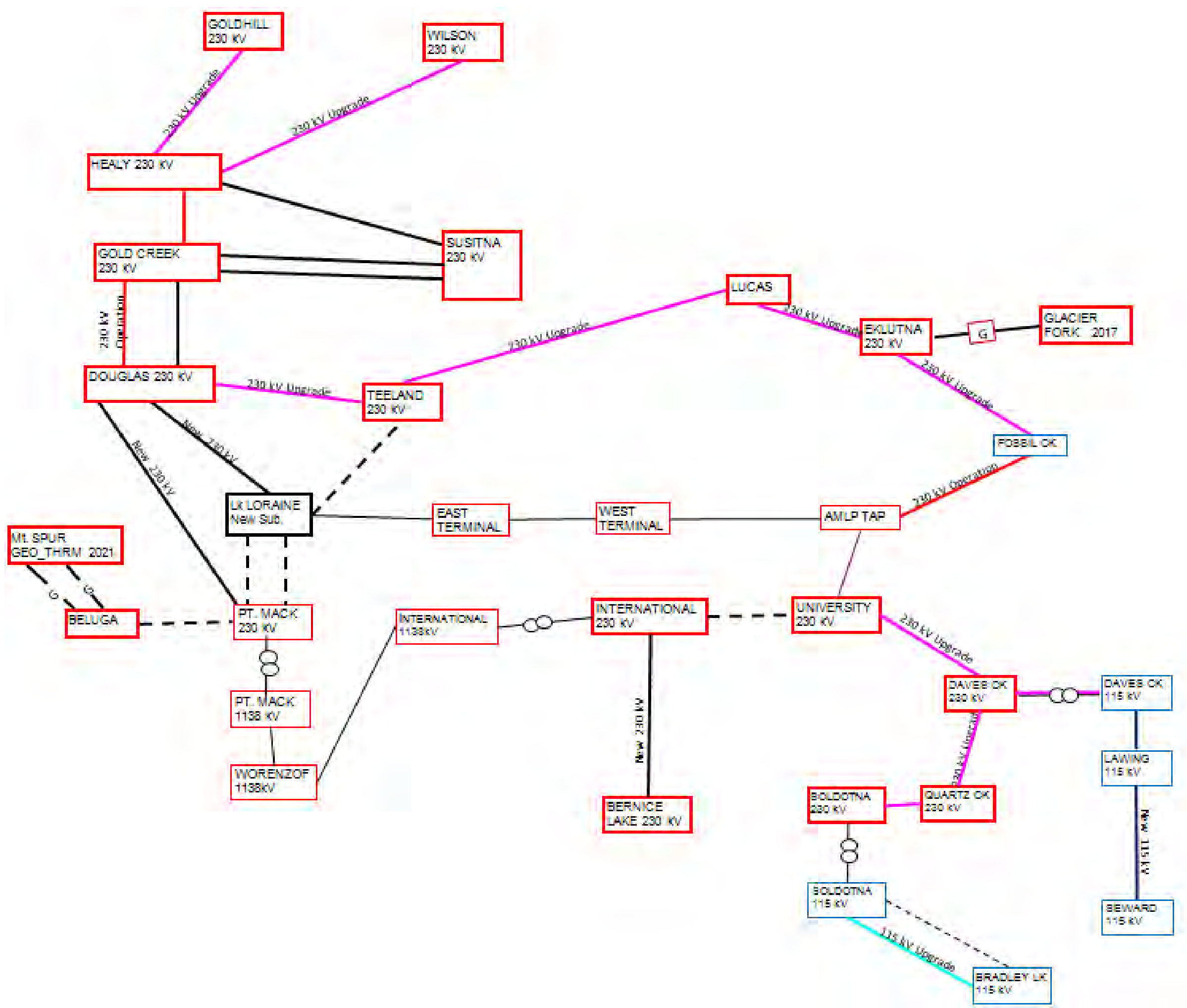


Figure 12-22
Location of Proposed Transmission Projects (With Susitna)



12.8 Other Reliability Projects

In addition to the transmission lines presented in this section, other projects were considered that could contribute to improving the reliability of the Railbelt system. These projects generally fall into one or more of the following categories:

- Providing reactive power (static var compensators – SVCs)
- Providing or assisting with the provision of other ancillary services (regulation and/or spinning reserves)
- Assistance in control of line flows or substation voltages
- Assistance in the transition and coordination of transmission project implementation (mobile transformers or substations)
- Communications and control facilities

Several of these projects have been identified and discussed while others will result from the transmission reliability assessment. Potential projects in this category include:

- Substation capacitor banks
- Series capacitors
- SVCs
- BESS
- Mobile substations that could provide construction flexibility during the implementation phase

Many of the projects listed will be proposed and reviewed during the reliability evaluation phase, while others may be identified only when more detailed design and specification of the transmission projects are undertaken. Where preliminary information indicates that these projects will be required as part of the projects identified above, their estimated costs have been included in the project cost in Table 12-1. The cost for any additional projects will be developed during the reliability analysis conducted as part of the implementation.

The Railbelt system currently has several SVCs deployed across the system to assist in the operation of the system and to assist in the stable transfer of power between areas. These were installed several years ago and are considered critical to the stable operation of the system. Further analysis of the projects outlined in Section 12.5 is expected to result in potential changes to these projects, as well as a requirement for several more SVCs at locations to be identified by the stability analysis. Additionally, the currently deployed SVCs are in need of repairs if they are to continue in service and provide the reliability functions they were designed to provide. It is estimated that the repair or replacement of these existing SVCs would cost a total of approximately $25 million.

Projects that could facilitate or complement the implementation of other projects (e.g., wind) were of particular interest during project discussions. These projects, if implemented, could smooth the transition and adoption by the utilities of the GRETC concept. One such project was the BESS that could provide much needed frequency regulation and potentially some spinning reserves when non dispatchable projects, such as wind, are considered. Specific stability and regulation studies will be required to determine the best methods of integrating the wind generation.

A BESS was specified that could provide frequency regulation required by the system when wind projects were selected by the RIRP. The BESS was sized in relation to the size of the non-dispatchable project to be 50 percent of the project nominal capacity for a 20-minute duration. For evaluation purposes, a 27 MW BESS which would provide 50 percent of 54 MW Fire Island project is estimated to cost approximately $50 million. Although the performance of the BESS has not yet been analyzed as part of the stability analysis, the cost for the system was included in the analysis in Section 13. Other options (e.g., fly wheel storage technologies and compressed air energy storage) that could provide the required frequency regulation should also be considered.

It should be noted that if the need for frequency regulation is driven in part by an IPP-sponsored renewable project, policies will need to be adopted to allocate an appropriate portion of the regulation costs to those projects.

The GRETC system will require upgrades to the communication and control systems of the existing facilities in order to operate as a unified grid. Communication for pilot relaying between Anchorage and Fairbanks as well as communication upgrades to the Anchorage – Kenai system will be required for protective relaying and control. The individual utilities have their own communication and control systems. The alternatives and costs for implementing the necessary communication and control systems for GRETC operation were discussed in the REGA study. Those costs which are considered necessary administrative costs for implementing GRETC are not included in the costs in Table 12-1.

12.9 Projects Priorities

The proposed projects presented in Section 12.5 are not presented in any specific order or priority. It was felt that the information currently available, as well as the uncertainty which exists surrounding the selected generation plans, did not permit a more definitive prioritization of projects. This does not mean, however, that all the projects in the list have the same impact on the reliability of the Railbelt system, or that the projects are equally important to each utility. In several instances the projects were in extremely poor physical condition and were scheduled to be repaired or rebuilt to prevent the lines from literally falling to the ground. To facilitate the immediate repairs to these lines, the projects that should be addressed within the next five years because of their potential impact on the reliability of the system have been identified. Additionally, some of the projects will need to be evaluated and specified further and funds have been identified to facilitate the studies that are required to further identify and schedule the transmission improvements that will be required.

The following projects and studies have been identified for priority attention because of their immediate impact on the reliability of the existing system. All of the projects will require detailed system feasibility studies prior to actual implementation. Estimated costs for these studies are included as part of the project costs estimates in Table 12-1. The following projects are estimated to be required within the next five years.

1. Soldotna to Quartz Creek Transmission Line ($126.5 million – Project B)
2. Quartz Creek to University Transmission Line ($165.0 million – Project C)
3. Douglas to Teeland Transmission Line ($62.5 million – Project D)
4. Lake Lorraine to Douglas Transmission Line ($80.0 million – Project E)
5. SVCs ($25.0 million - Other Reliability Projects)
6. Funds to undertake the study of the Southern Intertie ($1.0 million)
7. Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50.0 million, including cost of BESS – Other Reliability Projects)

The total estimate costs necessary for transmission projects during the initial five years of the RIRP is $510 million in 2009 dollars.

13.0 SUMMARY OF RESULTS

The purpose of this section is to summarize the results of the RIRP analysis. We begin by providing a summary of the reference case results for each of the four Evaluation Scenarios, followed by a summary of the results for the various sensitivity cases that were evaluated. We then provide a comparative summary of the economic and emission results for all cases. This is followed by a summary of the results of the transmission analysis that was completed and, finally, the results of the financial analysis.

13.1 Results of Reference Cases

In this subsection, we provide summaries of the reference case results for each of the following four Evaluation Scenarios:

- Scenario 1A – Base Case Load Forecast – Least Cost Plan
- Scenario 1B - Base Case Load Forecast – Force 50% Renewables
- Scenario 2A – Large Growth Load Forecast – Least Cost Plan
- Scenario 2B - Large Growth Load Forecast – Force 50% Renewables

Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built. Hereafter, we will refer to Scenarios 1A and 1B together.

We begin with a summary of the impact that DSM/EE measures have on the region's capacity and annual energy requirements. This is followed by summary graphics and information for each of the Evaluation Scenarios. Additional summary information on the results of each reference case is provided at the end of this section. Detailed model output for each of the reference cases are provided in Appendices E-G.

13.1.1 Results - DSM/EE Resources

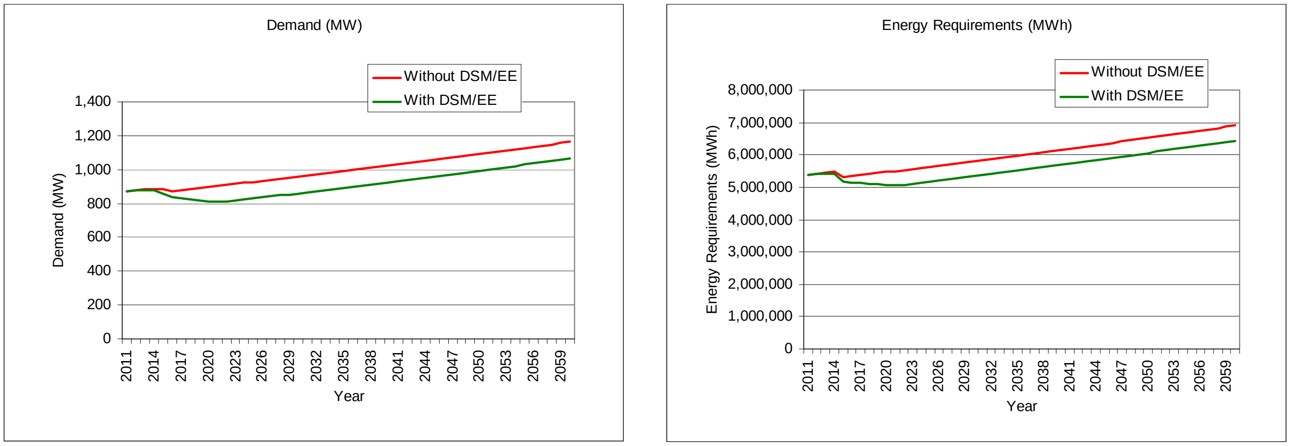
As discussed in Section 11, Black & Veatch screened a broad array of residential and commercial DSM/EE measures. Based on this screening, 21 residential and 51 commercial DSM/EE measures were selected for inclusion in the RIRP models, Strategist® and PROMOD®, as potential resources to be selected.

Based upon the relative economics and savings of these screened residential and commercial DSM/EE measures, from the utility perspective, all of the residential and commercial DSM/EE measures were selected in each of the four Evaluation Scenarios. As discussed in Section 11, the penetration of the measures was based on technology adoption curves for DSM/EE studies from the BASS model; additionally, as discussed, DSM/EE measures are treated by Strategist® and PROMOD® as a reduction to the load forecast from which the alternative supply-side options are considered for adding generation resources.

Since the maximum allowed level of DSM/EE resources were selected in each of the four Evaluation Scenarios, we summarize the resulting impact on the Base Case Load Forecast for Scenario 1A in the following graphic.

As can be seen in Figure 13-1, DSM/EE measures result in a significant impact on the region's capacity and energy requirements. After the initial program start-up years, DSM/EE measures reduce the region's capacity requirements by approximately 8 percent. A similar level of impact is also shown for annual energy requirements.

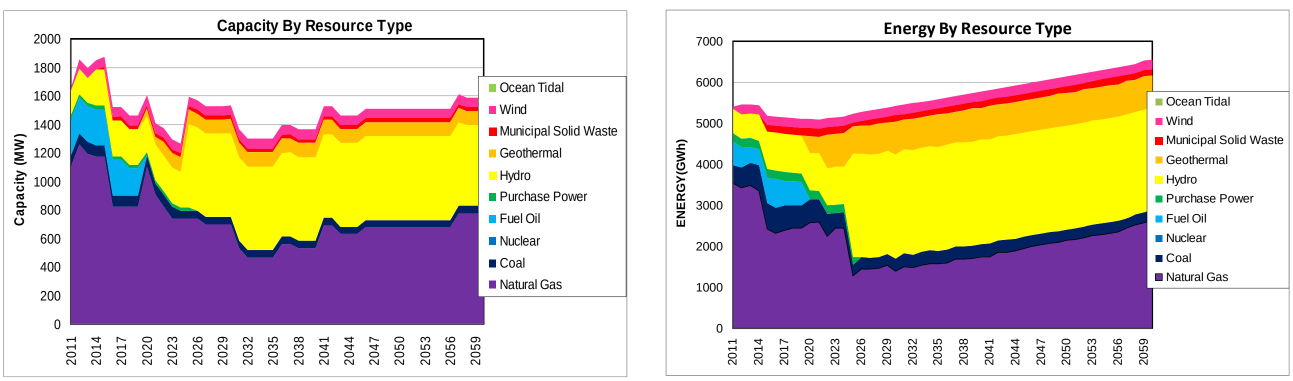
Figure 13-1
Impact of DSM/EE Resources – Base Case Load Forecast



It should be noted that this study did not include an evaluation of innovative rate designs (e.g., real-time pricing and demand response rates), nor did it consider the potential benefits of a Smart Grid and the associated widespread implementation of smart meters. These options could result in even greater reductions in peak demand and annual energy usage.

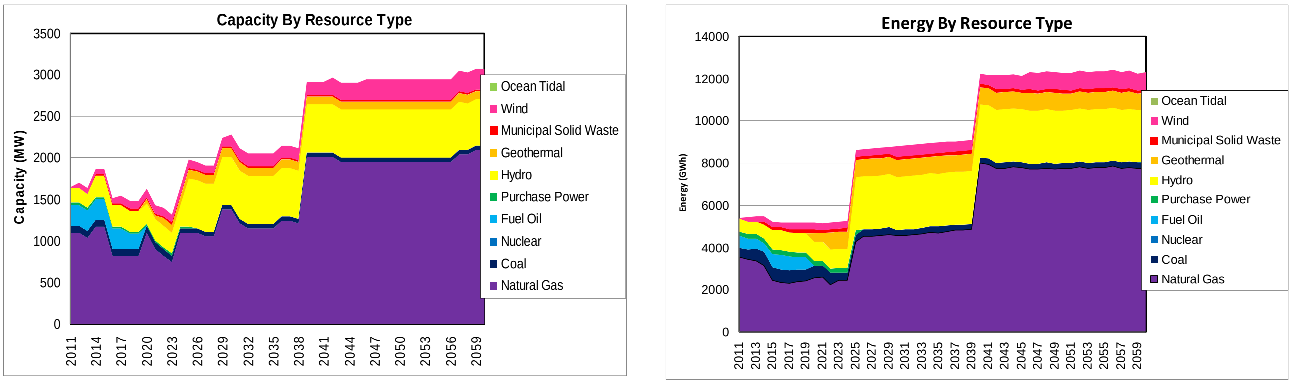
13.1.2 Results - Scenarios 1A/1B Reference Cases

Figure 13-2
Results – Scenarios 1A/1B Reference Cases



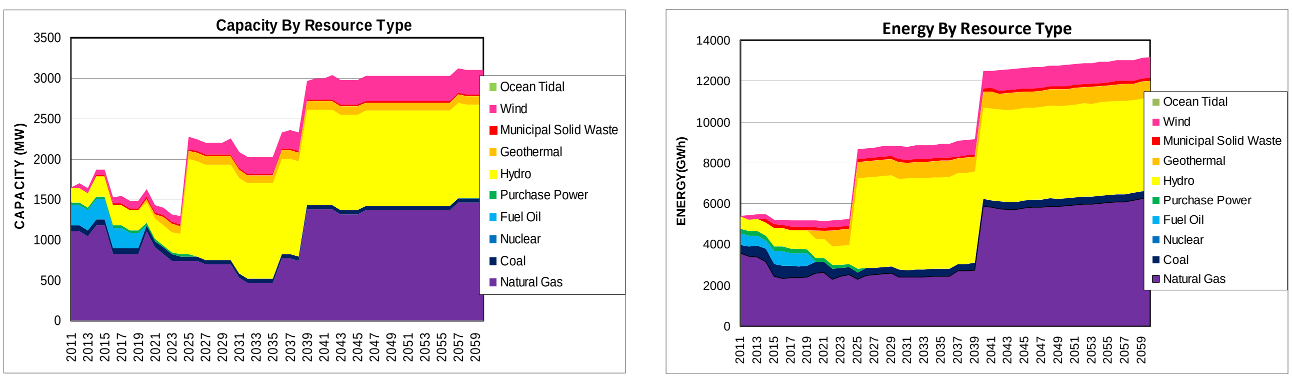
13.1.3 Results - Scenario 2A Reference Case Results

Figure 13-3
Results – Scenario 2A Reference Case



13.1.4 Results - Scenario 2B Reference Case Results

Figure 13-4
Results – Scenario 2B Reference Case



13.2 Results of Sensitivity Cases

In this subsection, we list the various sensitivity cases that were evaluated. We then provide graphics that summarize the results for each sensitivity case. Additional summary information on the results of each sensitivity case is provided at the end of this section.

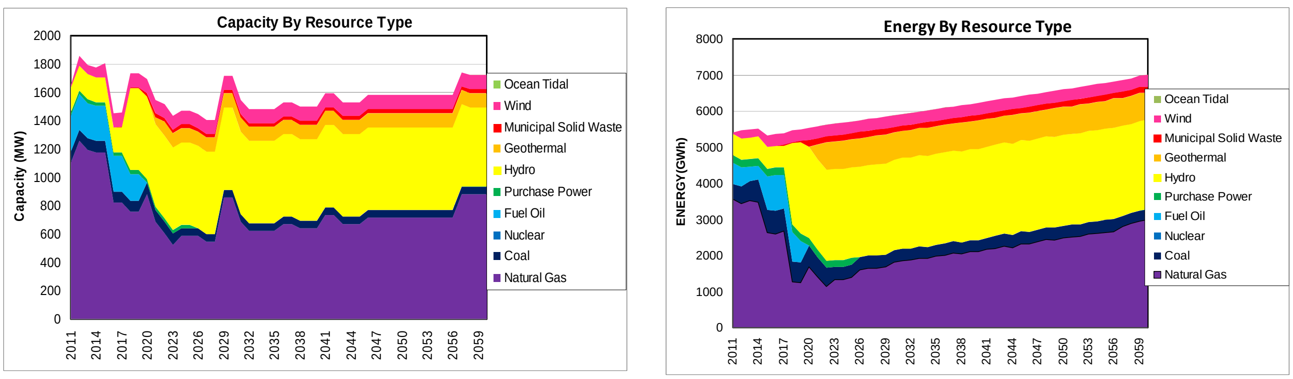
13.2.1 Sensitivity Cases Evaluated

- Scenarios 1A/1B Without DSM/EE Measures
- Scenarios 1A/1B With Double DSM/EE Measures
- Scenarios 1A/1B With Committed Units Included
- Scenarios 1A/1B Without CO_2 Costs
- Scenarios 1A/1B With Higher Gas Prices
- Scenarios 1A/1B Without Chakachamna
- Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%
- Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

- Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced
- Scenarios 1A/1B With Susitna (Watana Option) Forced
- Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced
- Scenarios 1A/1B With Modular Nuclear
- Scenarios 1A/1B With Tidal
- Scenarios 1A/1B With Lower Coal Capital and Fuel Costs
- Scenarios 1A/1B With Federal Tax Credits for Renewables

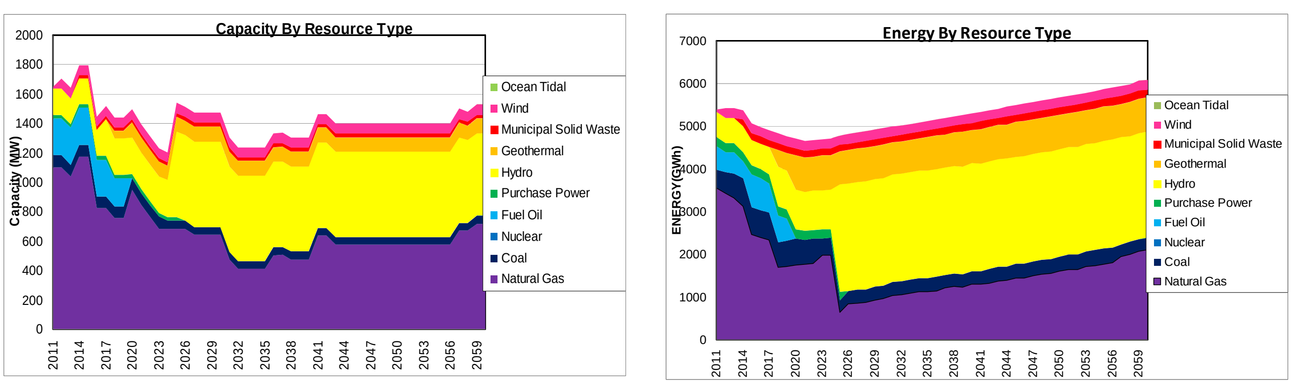
13.2.2 Sensitivity Results – Scenarios 1A/1B Without DSM/EE Measures

Figure 13-5
Sensitivity Results – Scenarios 1A/1B Without DSM/EE Measures



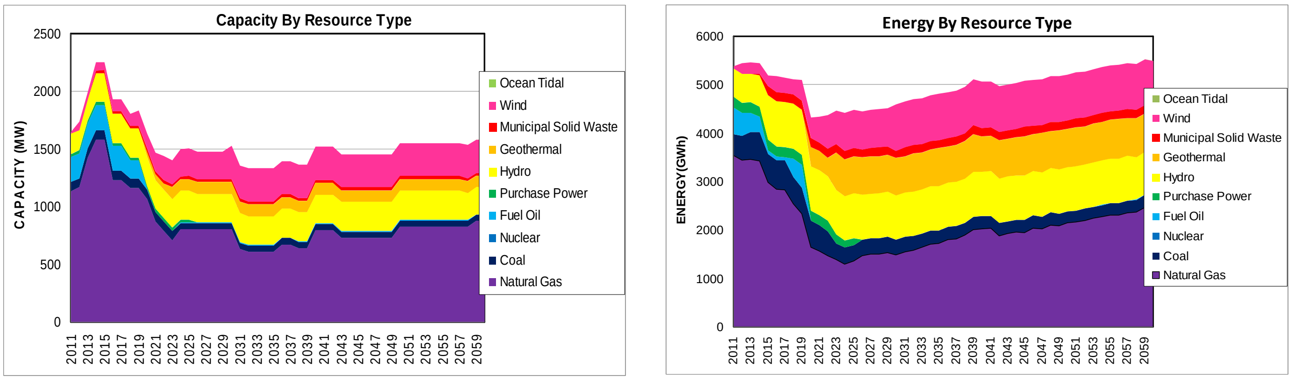
13.2.3 Sensitivity Results – Scenarios 1A/1B With Double DSM/EE Measures

Figure 13-6
Sensitivity Results – Scenarios 1A/1B With Double DSM/EE Measures



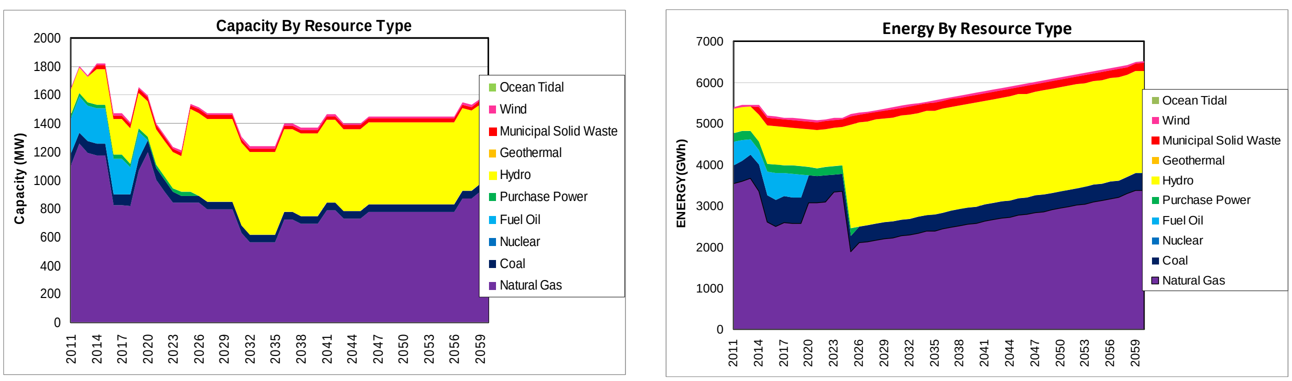
13.2.4 Sensitivity Results – Scenarios 1A/1B With Committed Units Included

Figure 13-7
Sensitivity Results – Scenarios 1A/1B With Committed Units Included



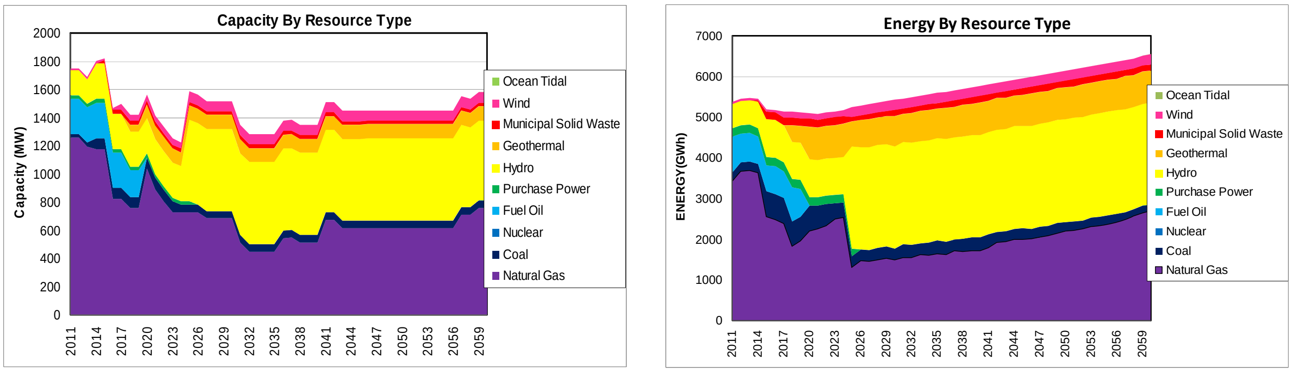
13.2.5 Sensitivity Results – Scenarios 1A/1B Without CO_2 Costs

Figure 13-8
Sensitivity Results – Scenarios 1A/1B Without CO_2 Costs



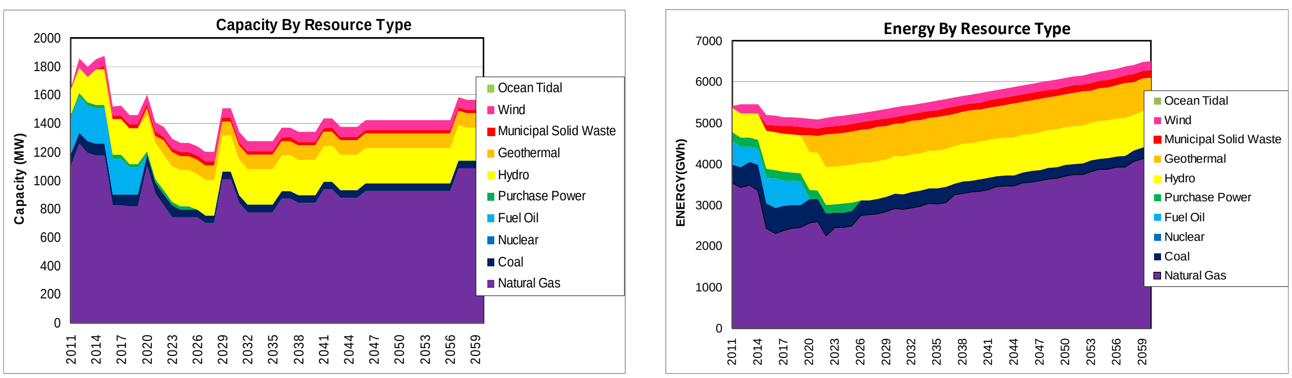
13.2.6 Sensitivity Results – Scenarios 1A/1B With Higher Gas Prices

Figure 13-9
Sensitivity Results – Scenarios 1A/1B With Higher Gas Prices



13.2.7 Sensitivity Results – Scenarios 1A/1B Without Chakachamna

Figure 13-10
Sensitivity Results – Scenarios 1A/1B Without Chakachamna

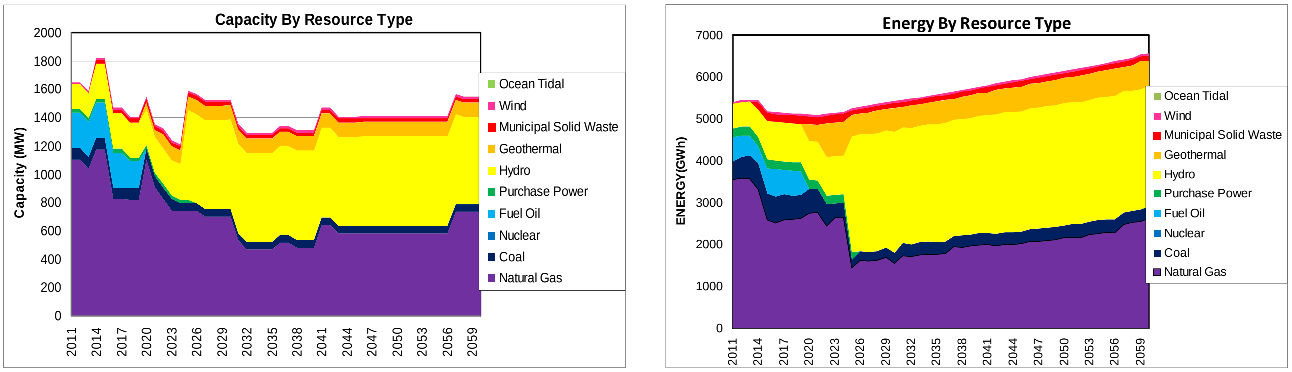


13.2.8 Sensitivity Results – Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%

When Chakachamna's capital costs are increased by 75 percent, it is no longer selected as a resource in the resource plan. As a result, the results of this sensitivity case are the same as the Scenario 1A Without Chakachmna Sensitivity Case above. Consequently, the resulting breakdown of capacity and energy generated by resource type is the same as the graphs shown in Figure 13-10.

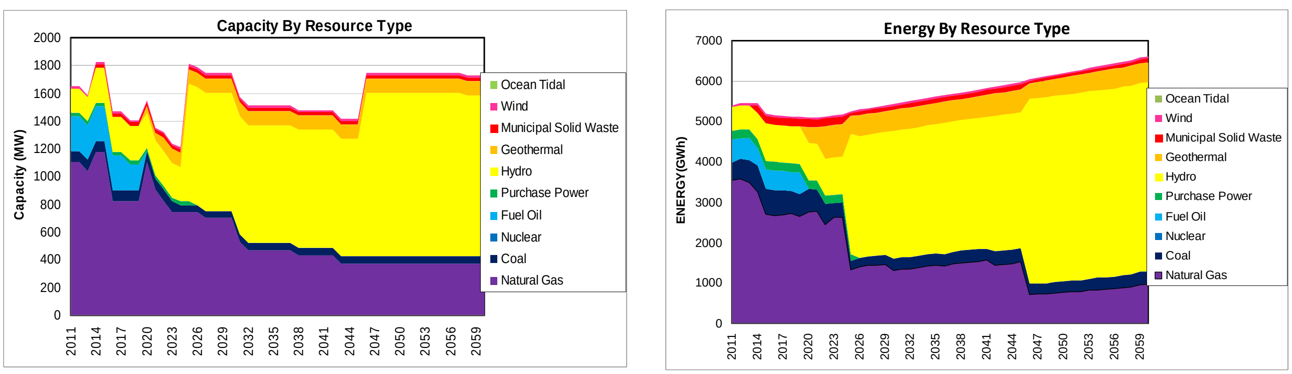
13.2.9 Sensitivity Results – Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced

Figure 13-11
Sensitivity Results – Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced



13.2.10 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

Figure 13-12
Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

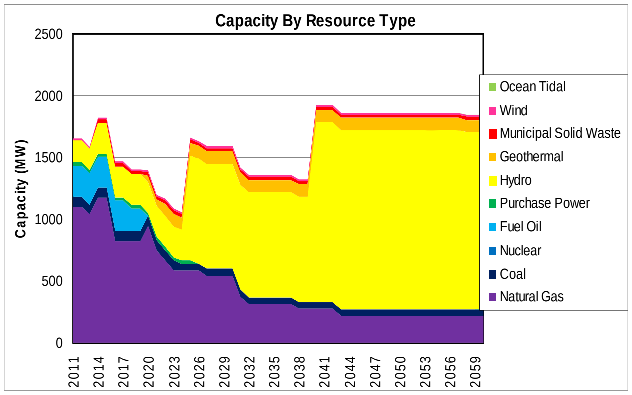


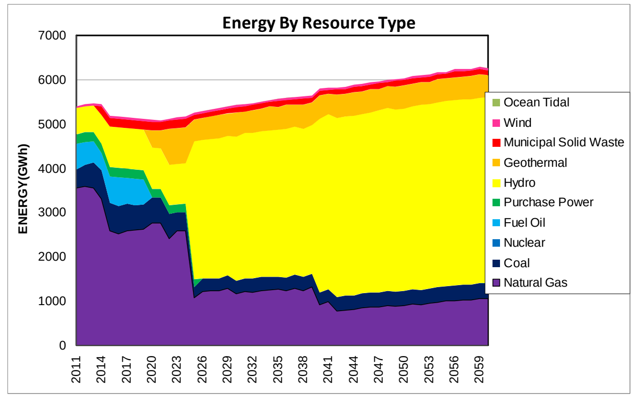
13.2.11 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced

In this sensitivity case, we forced the Susitna (Low Watana Expandable Option) to be selected, in a similar manner to the Susitna (Low Watana Non-Expandable Option) Sensitivity Case immediately above. Consequently, the resulting breakdown of capacity and energy generation by resource type is the same as the graphs shown in Figure 13-12. However, the total cumulative prevent value, average unit cost, and total capital requirements for this sensitivity case are higher; this results from the fact that the only difference between this and the Susitna (Low Watana Non-Expandable Option) Sensitivity Case is that capital costs associated with this option are $400 million higher to preserve the option of future expansion.

13.2.12 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced

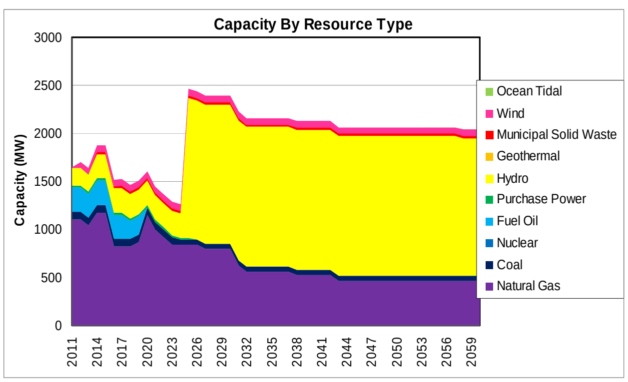
Figure 13-13
Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced

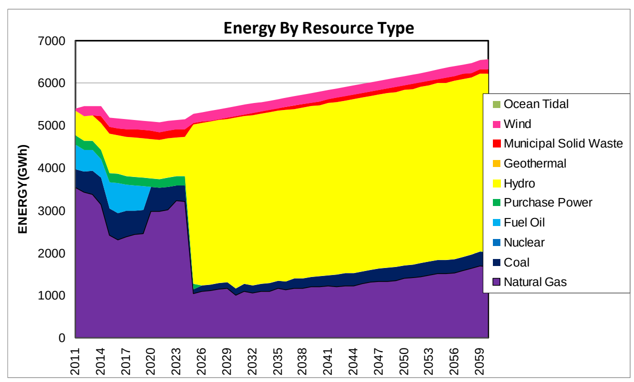




13.2.13 Sensitivity Results – Scenarios 1A/1B With Susitna (Watana Option) Forced

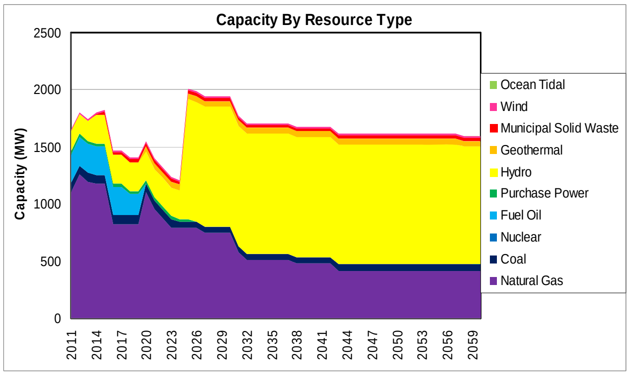
Figure 13-14
Sensitivity Results – Scenarios 1A/1B With Susitna (Watana Option) Forced

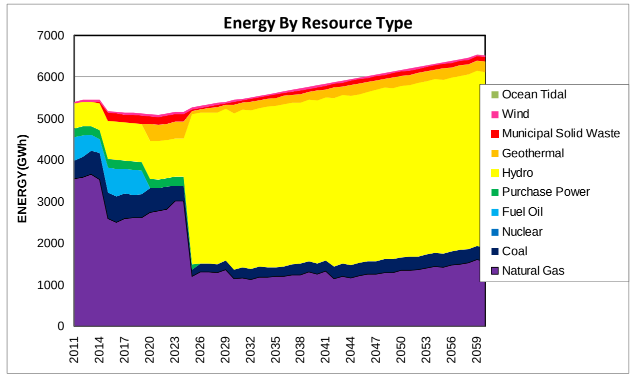




13.2.14 Sensitivity Results – Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced

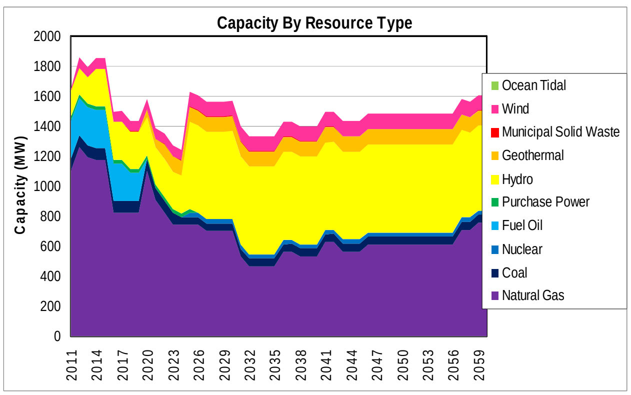
Figure 13-15
Sensitivity Results – Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced

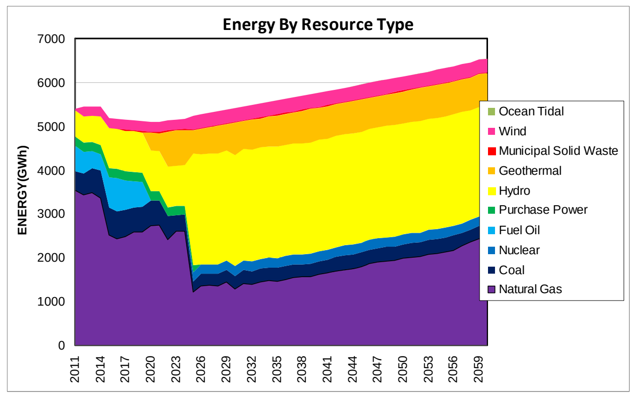




13.2.15 Sensitivity Results – Scenarios 1A/1B With Modular Nuclear

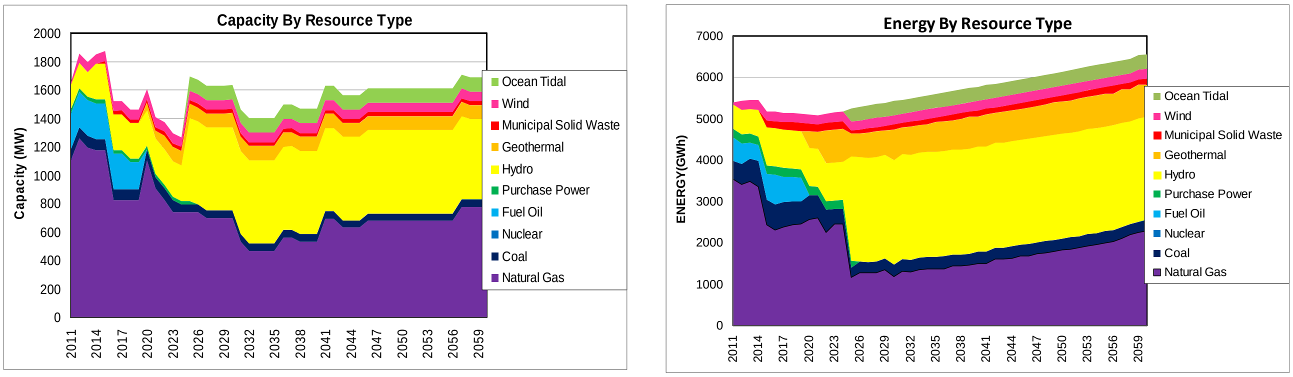
Figure 13-16
Sensitivity Results – Scenarios 1A/1B With Modular Nuclear





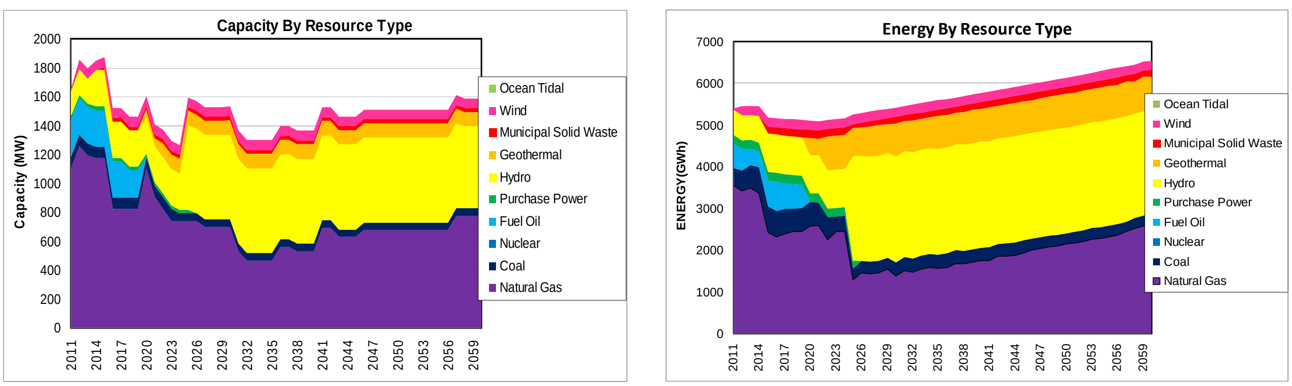
13.2.16 Sensitivity Results – Scenarios 1A/1B With Tidal

Figure 13-17
Sensitivity Results – Scenarios 1A/1B With Tidal



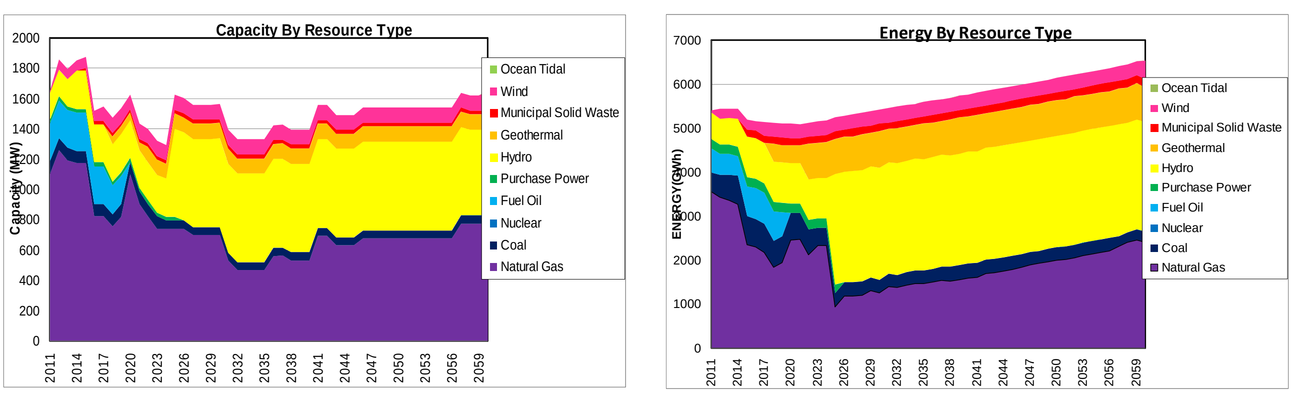
13.2.17 Sensitivity Results – Scenarios 1A/1B With Lower Coal Capital and Fuel Costs

Figure 13-18
Sensitivity Results – Scenarios 1A/1B With Lower Coal Capital and Fuel Costs



13.2.18 Sensitivity Results – Scenarios 1A/1B With Federal Tax Credits for Renewables

Figure 13-19
Sensitivity Results – Scenarios 1A/1B With Federal Tax Credits for Renewables



13.3 Summary of Results

In this subsection, we provide a comparative summary of the economic and emissions results for all of the reference and sensitivity cases.

13.3.1 Summary of Results - Economics

Table 13-1 summarizes the economic results, including:

- Cumulative present value cost (from the utility perspective)
- Average wholesale power cost (from the utility perspective)
- Renewable energy in 2025
- Total capital investment

13.3.2 Summary of Results - Emissions

Table 13-2 summarizes the emissions-related results of all of the reference and sensitivity cases. The following information is provided for each case:

- CO_2 emissions
- NO_x emissions
- SO_x emissions

13.4 Results of Transmission Analysis

An important element of this RIRP was the analysis of transmission investments required to integrate the generation resources in each resource plan, ensure reliability and enable the region to take advantage of economy energy transfers between load areas within the region.

The fundamental objective underlying the transmission analysis was to upgrade the transmission system over a 10-year period to remove transmission constraints that currently prevent the coordinated operation of all the utilities as a single entity.

The study included all the utilities' assets 69 kV and above. These assets, over a transition period, may flow into GRETC and form the basis for a phased upgrade of the system into a robust, reliable transmission system that can accommodate the economic operation of the interconnected system. The transmission analysis also assumed that all utilities would participate in GRETC with planning being conducted on a GRETC (i.e., regional) basis. The common goal would be the tight integration of the system operated by GRETC.

Potential transmission investments in each of the following four categories were considered:

- Transmission systems that need to be replaced because of age and condition (Category 1)
- Transmission projects required to improve grid reliability, power transfer capability, and reserve sharing (Category 2)
- Transmission projects required to connect new generation projects to the grid (Category 3)
- Transmission projects to upgrade the grid required by a new generation project (Category 4)

Table 13-3 lists the recommended transmission system expansions and enhancements that resulted from our transmission analysis. Detailed information on each of the transmission projects listed in the following table is provided in Section 12.

Table 13-1
Summary of Results – Economics

Case	Cumulative Present Value Cost ($000,000)	Average Wholesale Power Cost (¢ per kWh)	Renewable Energy in 2025 (%)	Total Capital Investment ($000,000)
Scenarios				
Scenario 1A	$13,625	17.26	62.32%	$9,087
Scenario 1B	$13,625	17.26	62.32%	$9,087
Scenario 2A	$20,162	19.75	42.64%	$14,111
Scenario 2B	$21,109	20.68	65.83%	$18,805
Sensitivities				
1A/1B Without DSM/EE Measures	$14,507	17.40	67.10%	$8,603
1A/1B With Double DSM	$12,546	15.89	65.15%	$8,861
1A/1B With Committed Units Included	$14,109	17.87	46.84%	$8,090
1A/1B Without CO2 Costs	$11,206	14.20	49.07%	$8,381
1A/1B With Higher Gas Prices	$14,064	17.82	61.95%	$9,248
1A/1B Without Chakachamna	$14,332	18.16	38.06%	$7,719
1A/1B With Chakachamna Capital Costs Increased by 75%	$14,332	18.16	38.06%	$7,719
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	$15,228	19.29	61.01%	$12,421
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	$15,040	19.05	63.01%	$15,057
1A/1B With Susitna (Low Watana Expandable Option) Forced	$15,346	19.44	63.01%	$15,588
1A/1B With Susitna (Low Watana Expansion Option) Forced	$14,854	18.82	66.90%	$14,069
1A/1B With Susitna (Watana Option) Forced	$15,683	19.87	70.97%	$13,211
1A/1B With Susitna (High Devil Canyon Option) Forced	$14,795	18.74	66.92%	$11,633
1A/1B With Modular Nuclear	$13,841	17.53	60.51%	$9,105
1A/1B With Tidal	$13,712	17.37	65.52%	$9,679
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	$13,625	17.26	62.32%	$9,087
1A/1B With Tax Credits for Renewables	$12,954	16.41	67.56%	$9,256

Table 13-2
Summary of Results – Emissions

Case	CO_2 ('000 tons)	NO_x ('000 tons)	SO_2 ('000 tons)
Scenarios			
Scenario 1A	80,259,047	124,215	21,768
Scenario 1B	80,259,047	124,215	21,768
Scenario 2A	152,318,066	133,642	24,476
Scenario 2B	125,498,202	140,897	26,348
Sensitivities			
1A/1B Without DSM/EE Measures	88,181,350	139,179	30,605
1A/1B With Double DSM	69,324,920	131,299	18,994
1A/1B With Committed Units Included	91,212,598	136,946	16,482
1A/1B Without CO2 Costs	100,753,030	134,031	23,960
1A/1B With Higher Gas Prices	78,323,066	121,700	25,232
1A/1B Without Chakachamna	105,643,650	133,577	25,700
1A/1B With Chakachamna Capital Costs Increased by 75%	105,643,650	133,577	25,700
1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced	82,328,762	127,921	22,124
1A/1B With Susitna (Low Watana Non-Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expandable Option) Forced	69,133,553	124,640	19,620
1A/1B With Susitna (Low Watana Expansion Option) Forced	67,724,563	136,906	23,589
1A/1B With Susitna (Watana Option) Forced	70,966,059	111,307	19,171
1A/1B With Susitna (High Devil Canyon Option) Forced	71,853,368	121,538	19,909
1A/1B With Modular Nuclear	79,664,701	126,881	22,787
1A/1B With Tidal	75,598,948	121,306	21,067
1A/1B With Lower Coal Fuel and Lower Coal Capital Costs	80,259,047	124,215	21,768
1A/1B With Tax Credits for Renewables	74,046,352	129,384	18,832

Table 13-3
Summary of Proposed Transmission Projects

Project No.	Transmission Projects	Type	Cost ($000)
A	Bernice Lake – International	New Build (230 kV)	227,500
B	Soldotna – Quartz Creek	R&R (230 kV)	126,500
C	Quartz Creek – University	R&R (230 kV)	165,000
D	Douglas – Teeland	R&R (230 kV)	62,500
E	Lake Lorraine – Douglas	New Build (230 kV)	80,000
F	Douglas – Healy	Upgrade (230 kV)	30,000
G	Douglas – Healy	New Build (230 kV)	252,000
H	Eklutna – Fossil Creek	Upgrade (230 kV)	65,000
I	Healy – Gold Hill	R&R (230 kV)	180,500
J	Healy – Wilson	Upgrade (230 kV)	32,000
K	Soldotna – Diamond Ridge	R&R (115 kV)	66,000
L	Lawing – Seward	Upgrade (115 kV)	15,450
M	Eklutna – Lucas	R&R(115 kV/230 kV)	12,300
N	Lucas – Teeland	R&R (230 kV)	51,100
O	Fossil Creek – Plant 2	Upgrade (230 kV)	13,650
P	Pt. Mackenzie – Plant 2	R&R (230 kV)	32,400
Q	Bernice Lake – Soldotna	Rebuild (115 kV)	24,000
R	Bernice Lake – Beaver Creek - Soldotna	Rebuild (115 kV)	24,000
S	Susitna Transmission Additions	New Build (230 kV)	57,000

The following issues result from our transmission analysis:

- We were unable to complete a stability analysis based upon our proposed transmission system configuration prior to the completion of this project. This analysis is required to ensure that the proposed transmission system expansions and enhancements result in the necessary stability to ensure reliable electric service over the planning horizon. This analysis should be completed as part of the future work to further define, prioritize, and design specific transmission projects.
- In addition to the transmission lines listed above, other projects were considered that could contribute to improving the reliability of the Railbelt system. These projects generally fall into one or more of the following categories:
    - Providing reactive power (static var compensators – SVCs)
    - Providing or assisting with the provision of other ancillary services (regulation and/or spinning reserves)
    - Assistance in control of line flows or substation voltages
    - Assistance in the transition and coordination of transmission project implementation (mobile transforms or substations)
    - Communications and control facilities

  Several of these projects have been identified and discussed while others will result from the transmission reliability assessment. Potential projects in this category include:
    - Substation capacitor banks
    - Series capacitors
    - SVCs
    - BESS
    - Mobile substations that could provide construction flexibility during the implementation phase
- Projects that could facilitate or complement the implementation of other projects (e.g., wind), were of particular interest during project discussions. These projects, if implemented, could smooth the transition and adoption by the utilities of the GRETC concept. One such project was the BESS that could provide much needed frequency regulation and potentially some spinning reserves when non-dispatchable projects, such as wind, are considered. A BESS was specified that could provide frequency regulation required by the system when wind projects were selected by the RIRP. The BESS was sized in relation to the size of the non-dispatchable project to be 50 percent of the project nominal capacity for a 20-minute duration. Although the performance of the BESS has not yet been analyzed as part of the stability analysis, the costs for each such system were included in the analysis. Other options (e.g., fly wheel storage technologies and compressed air energy storage) that could provide the required frequency regulation should also be considered.
- The Fire Island Wind Project is a 54 MW maximum output wind project. Each wind turbine will be equipped with reactive power and voltage support capabilities that should facilitate interconnection into the transmission grid. Current plans are to interconnect the project to the grid via a 34.5 kV underground and submarine cable to the Chugach 34.5 kV Raspberry Substation. There has been some discussions regarding the most appropriate transmission interconnection for the Fire Island Project and detailed interconnection studies have not been completed. The timeframe for implementing this project in order to qualify for available grants under the ARRA could preclude more detailed transmission studies and consideration of alternatives to the currently proposed 34.5 kV interconnection. An option to consider if Fire Island is constructed is to lay cables from Fire Island to Anchorage insulated for 230 kV and review a transmission routing for the new transmission connection to the Kenai peninsula that would begin at the International 230 kV Substation to Bernice Lake Substation along the Kenai cost line then via submarine cable across the Cook Inlet to Fire

Island. The interconnection would then use the 230 kV submarine cable previously laid over to the Anchorage coast then into the International 230 kV Substation.

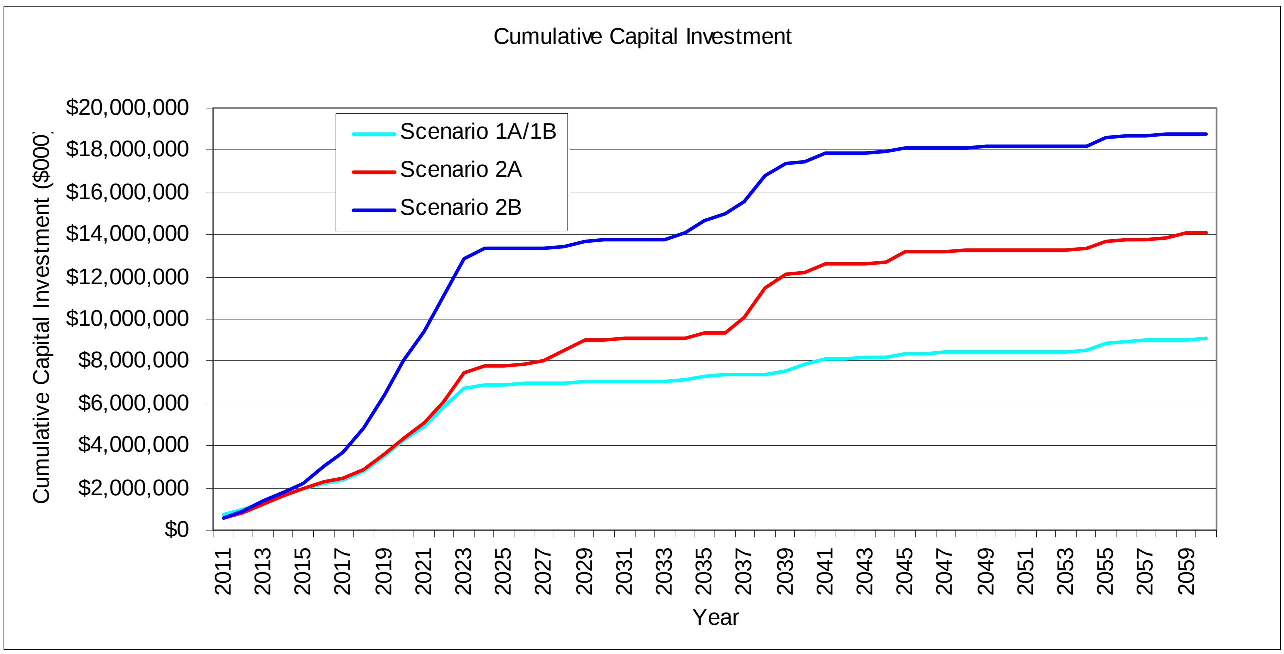
- The recommended transmission system expansions and enhancements can not be justified based solely on economics. However, in addition to their underlying economics, these transmission projects are required to ensure the reliable delivery of electricity throughout the region over the 50-year planning horizon and to provide the foundation for future economic development efforts.

13.5 Results of Financial Analysis

It will be difficult for the region to obtain the necessary financing for the DSM/EE, generation and transmission resources included in the alternative resource plans that were developed. The formation of a regional entity with some form of State assistance will help meet this challenge.

Figure 13-20 summarizes the cumulative capital investment required for each of the reference cases.

Figure 13-20
Required Cumulative Capital Investment for Each Reference Case



To assist in the completion of the financial analysis, the AEA contracted with SNW to:

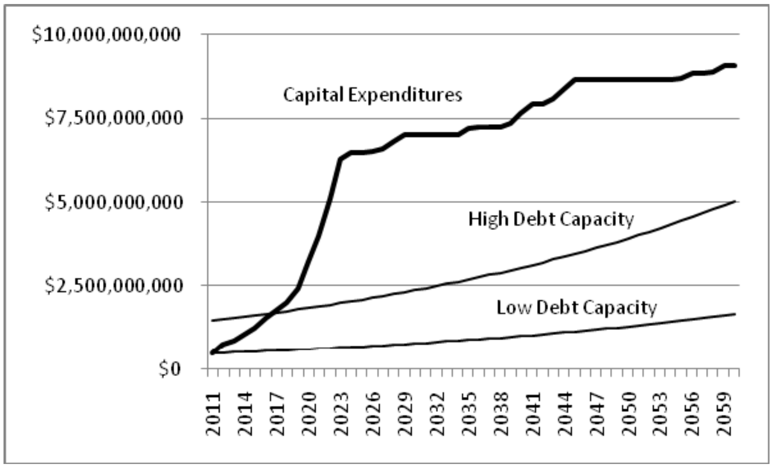
- Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities.
- Analyze strategies to capitalize selected RIRP assets by integrating State (which could include loans, State appropriations, Permanent Fund, State moral obligation bonds, etc.) and federal (e.g., USDA-RUS) financing resources with debt capital market resources.
- Develop a spreadsheet model that utilizes inputs from this RIRP analysis and overlays realistic debt capital funding to provide a total cost to ratepayers of the optimal resource plan.

The results of the financial analysis completed by SNW are provided in Appendix B.

Important conclusions from SNW's report include:

- The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or cooperative utility to independently secure debt financing without committing substantial amounts of equity of cash reserves.
- Figure 13-21 helps to put into context the scope of the required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent SNW's estimate of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

Figure 13-21
Required Cumulative Capital Investment (Scenarios 1A/1B) Relative to Railbelt Utility Debt Capacity



Source: SNW Report included in Appendix C.

- A regional entity, such as GRETC, with "all outputs" contracts migrating over time to "all requirements" contracts will have greater access to capital than the combined capital capacity of the individual utilities.
- There are several strategies that could be employed to lower the RIRP-related capital costs to customers, including:
  - **Ratepayer Benefits Charge** – A charge levied on all ratepayers within the Railbelt system that would be used to cash fund and thereby defer borrowing for infrastructure capital.
  - **"Pay-Go" Versus Borrowing for Capital** – A pay-go financing structure minimizes the total cost of projects through the reduction in interest costs. A "pay-go" capital financing program is one in which ongoing capital projects are paid for from remaining revenue after O&M expenses and debt service are paid for. A balance of these two funding approaches appears to be the most effective in lowering the overall cost of the RIRP, as well as spreading out the costs over a longer period of time.
  - **Construction Work in Progress (CWIP)** – CWIP is a rate methodology that allows for the recovery of interest expense on project construction expenditures through the base rate during construction, rather than capitalizing the interest until the projects are on-line and generating power. It should be noted that this rate methodology is sometimes criticized for shifting risks from shareholders to ratepayers; however, in the case of a public cooperative or municipal utility, the "shareholders" are the ratepayers.

- **State Financial Assistance** – State financial assistance could take a variety of forms as previously noted; for the purposes of this project, SNW focused on State assistance structured similarly to the Bradley Lake project. The benefits of State funding include: repayment flexibility, credit support/risk mitigation, and potential interest cost benefit.

  It should be noted that the economic comparison of resource options (using Strategist™ and PROMOD™) does not assume any of these financing strategies, including any State grants or loans, or federal tax credits, with the exception of the Federal Tax Credit for Renewables Sensitivity Case.

- The overall objective of SNW's analysis was to identify ways to overcome the funding challenges inherent with large-scale projects, including the length of construction time before the project is online and access to the capital markets, and to develop strategies that could be used to produce equitable rates over the useful life of the assets being financed. With these challenges in mind, SNW developed separate versions of its model to capture the cost of financing under a "base case" scenario and an "alternative" scenario. The base case financing model was structured such that the list of RIRP projects during the first 20 years would be financed through the capital markets in advance of construction and that the cost of the financing in the form of debt service on the bonds, would immediately be passed through to the ratepayers; the projects being financed over the balance of the 50-year period would be financed through cash flow created through normal rates and charges ("pay-go") capital once debt service coverage from previous years has grown to levels that create cash flow balance amounts sufficient to pay for the projects as their construction costs come due. The alternative model was developed with the goal of minimizing the rate shock that may otherwise occur with such a large capital plan, and levelizing the rate over time so that the economic burden derived from these projects can be spread more equitably over the useful life of the projects being contemplated.
- In both the base and alternative cases, SNW transferred the excess operating cash flow that is generated to create the debt service coverage level, and used that balance to both partially fund the capital projects in the early years and almost fully fund the projects in the later years. In the alternative case, SNW also included: 1) a Capital Benefits Surcharge ($0.01 per kWH) over the first 17 years, when approximately 75 percent of the capital projects will have been constructed, and 2) State assistance as an equity participant, structured in a manner similar to the Bradley Lake financing model (SNW assumed that the State would provide a $2.4 billion zero-interest loan to GRETC to provide the upfront funding for the Chakachamna project, only to be paid back by GRETC out of system revenues over an extended period of time, and following the repayment of the potentially more expensive capital markets debt).
- Under the base case, the <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.13 per kWH, while the <u>average</u> fixed charge rate over the 50-year period is $0.07 per kWh.
- In the alternative case, the <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.08 per kWH, while the <u>average</u> fixed charge rate over the 50-year period is $0.06 per kWh, not including the $0.01 consumer benefit surcharge that is in place for the first 17 years.
- While the <u>average</u> rates between the two cases are essentially the same, the <u>maximum</u> rate in the alternative case is much lower, showing the ability of innovative financing tools and ratemaking methodologies to overcome the funding challenges and produce equitable rates over the 50-year period.
- The formation of a regional entity, such as GRETC, that would combine the existing resources and rate base of the Railbelt utilities, as well as provide an organized front in working to obtain private financing and the necessary levels of State assistance, would be, in SNW's opinion, a necessary next step towards achieving the goal of reliable energy for the Railbelt region now and in the future.

Plan 1A/1B

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,624,595

Renewable Energy % In 2025
62.32%

Total Capital Investment ($000)
$9,086,710

Plan 2A

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Kenai Wind
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Anchorage 2x1 6FA Anchorage LM6000 Chakachamna
2026	
2027	
2028	
2029	
2030	GVEA 2x1 6FA GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	Anchorage 2x1 6FA GVEA 1x1 6FA GVEA 2x1 6FA
2041	
2042	GVEA Wind
2043	
2044	
2045	
2046	GVEA Wind
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	HEA LMS100
2058	
2059	
2060	HEA LM6000

Cumulative Present Worth Cost ($000)
$20,162,223

Renewable Energy % In 2025
42.64%

Total Capital Investment ($000)
$14,110,777

Plan 2B

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Kenai Wind
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna GVEA Wind Low Watana (Non-Expandable)
2026	
2027	
2028	
2029	
2030	GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage 2x1 6FA Kenai Wind
2038	
2039	
2040	Anchorage 2x1 6FA Kenai Wind GVEA 2x1 6FA
2041	
2042	GVEA Wind
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$21,108,823

Renewable Energy % In 2025
65.83%

Total Capital Investment ($000)
$18,804,578

1A/1B Without DSM/EE Measures

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	
2015	Kenai Wind
2016	
2017	GVEA MSW
2018	Chakachamna Glacier Fork
2019	
2020	Anchorage MSW
2021	Mount Spurr
2022	Mount Spurr
2023	
2024	
2025	GVEA 1X1 NPole Retrofit
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LM6000
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,506,801

Renewable Energy % In 2025
67.10%

Total Capital Investment ($000)
$9,791,215

1A/1B With Double DSM/EE Measures

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Glacier Fork
2018	Mount Spurr
2019	
2020	Mount Spurr
2021	GVEA 1X1 NPole Retrofit
2022	Anchorage LMS100
2023	
2024	
2025	GVEA MSW Chakachamna
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	GVEA LMS100
2056	
2057	
2058	
2059	
2060	HEA LM6000

Cumulative Present Worth Cost ($000)
$12,545,859

Renewable Energy % In 2025
65.15%

Total Capital Investment ($000)
$8,860,649

1A/1B With Committed Units Included

Year	Unit Additions
2011	Nikiski Wind Seward 1 Healy Clean Coal
2012	Fire Island MLP LM2500 Nikiski Seward 2
2013	
2014	HEA Frame South Central PP MLP LM6000 CC GVEA MSW HEA Aero
2015	Eklutna Generation
2016	Kenai Wind
2017	
2018	
2019	Kenai Wind
2020	Mount Spurr T
2021	Kenai Wind
2022	GVEA Wind
2023	Mount Spurr
2024	Kenai Wind
2025	Anchorage LMS100
2026	
2027	
2028	
2029	
2030	GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	GVEA 1X1 NPole Retrofit
2037	
2038	
2039	
2040	Anchorage 1x1 6FA
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	Anchorage LMS100
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	GVEA LM6000
2060	

Cumulative Present Worth Cost ($000)
$14,108,513

Renewable Energy % In 2025
46.84%

Total Capital Investment ($000)
$9,086,710

1A/1B Without CO2 Costs

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	Anchorage 1x1 6FA
2014	GVEA MSW Glacier Fork Anchorage MSW
2015	
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Anchorage LMS100
2021	
2022	
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA 1x1 6FA
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	GVEA LM6000

Cumulative Present Worth Cost ($000)
$11,205,673

Renewable Energy % In 2025
49.07%

Total Capital Investment ($000)
$8,381,277

1A/1B With Higher Gas Prices

Year	Unit Additions
2011	Nikiski Wind
2012	Anchorage 1x1 6FA
2013	
2014	Glacier Fork GVEA MSW
2015	Anchorage MSW
2016	
2017	Kenai Wind
2018	Mount Spurr
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Anchorage LM6000
2023	
2024	
2025	Chakachamna Kenai Wind
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Kenai Hydro
2047	
2048	
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2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	Anchorage LM6000

Cumulative Present Worth Cost ($000)
$14,064,201

Renewable Energy % In 2025
61.95%

Total Capital Investment ($000)
$9,248,373

1A/1B Without Chakachamna

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA LM6000
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	HEA LM6000
2047	
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2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,331,969

Renewable Energy % In 2025
38.06%

Total Capital Investment ($000)
$7,719,034

1A/1B With Chakachamna Capital Costs Increased by 75%

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA LM6000
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	HEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,331,969

Renewable Energy % In 2025
38.06%

Total Capital Investment ($000)
$7,719,034

1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Lower Low Watana
2026	
2027	
2028	
2029	
2030	MEA Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LM6000
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Kenai Hydro
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$15,228,141

Renewable Energy % In 2025
61.01%

Total Capital Investment ($000)
$12,420,673

1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Non-Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
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2035	
2036	
2037	
2038	
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2040	
2041	
2042	
2043	
2044	
2045	
2046	Chakachamna
2047	
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Cumulative Present Worth Cost ($000)
$15,039,926

Renewable Energy % In 2025
63.01%

Total Capital Investment ($000)
$15,056,672

1A/1B With Susitna (Low Watana Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	Chakachamna
2047	
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Cumulative Present Worth Cost ($000)
$15,345,647

Renewable Energy % In 2025
60.18%

Total Capital Investment ($000)
$15,588,186

1A/1B With Susitna (Low Watana Expansion Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	Low Watana Expansion
2041	
2042	
2043	
2044	
2045	
2046	
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2060	

Cumulative Present Worth Cost ($000)
$14,854,377

Renewable Energy % In 2025
66.90%

Total Capital Investment ($000)
$14,068,673

1A/1B With Susitna (Watana Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Anchorage LM6000
2021	Anchorage 1x1 6FA
2022	GVEA LM6000
2023	
2024	
2025	Watana
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
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2037	
2038	
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2060	

Cumulative Present Worth Cost ($000)
$15,682,774

Renewable Energy % In 2025
70.97%

Total Capital Investment ($000)
$13,210,718

1A/1B With Susitna (High Devil Canyon Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	Anchorage 1x1 6FA
2014	Glacier Fork; GVEA MSW
2015	Anchorage MSW
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	GVEA LM6000
2023	
2024	
2025	High Devil Canyon
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
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2060	

Cumulative Present Worth Cost ($000)
$14,794,958

Renewable Energy % In 2025
66.92%

Total Capital Investment ($000)
$11,633,307

1A/1B With Modular Nuclear

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna Kenai Wind Anchorage Nuc
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	Anchorage LM6000

Cumulative Present Worth Cost ($000)
$13,841,100

Renewable Energy % In 2025
60.51%

Total Capital Investment ($000)
$9,105,176

1A/1B With Tidal

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna Turnagain Tidal Arm
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,712,483

Renewable Energy % In 2025
65.52%

Total Capital Investment ($000)
$9,679,006

1A/1B With Lower Coal Capital and Fuel Costs

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,624,595

Renewable Energy % In 2025
62.32%

Total Capital Investment ($000)
$9,086,710

1A/1B With Federal Tax Credits for Renewables

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	Kenai Wind
2018	Mount Spurr
2019	
2020	GVEA 1X1 NPole Retrofit
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA MSW Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	Kenai Wind

Cumulative Present Worth Cost ($000)
$12,953,856

Renewable Energy % In 2025
67.56%

Total Capital Investment ($000)
$9,256,012

14.0 IMPLEMENTATION RISKS AND ISSUES

In this section, Black & Veatch identifies a number of general risks and issues that must be addressed regardless of the resource future that is chosen by stakeholders, including the utilities and State policy makers.

This is followed by a discussion of the risks and issues associated with each alternative generation resource type including transmission, and the actions that should be taken to address these resource-specific risks and issues.

14.1 General Risks and Issues

In this subsection, Black & Veatch identifies and discuss a number of general issues and risks that relate to the implementation of this RIRP. These general issues and risks are grouped into the following categories:

- Organizational
- Resource
- Fuel Supply
- Transmission
- Market Development
- Financing and Rate
- Legislative and Regulatory
- Value of Optionality

14.1.1 Organizational Risks and Issues

As previously discussed, the four resource plans that have been developed as part of this project focus on the Railbelt region as a whole. In other words, the four alternative resource plans were developed on a comprehensive regional basis to minimize costs, while maintaining adequate reliability, rather than for the individual utilities.

14.1.1.1 Regional Implementation

The possible formation of a new Railbelt regional generation and transmission entity (i.e., GRETC) is under consideration. The functional responsibilities of this new regional entity would include:

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

The existing Railbelt utilities would retain the responsibility for providing traditional distribution and customer services, such as moving power from transmission/distribution substations to individual customers, meter reading, turn-ons/offs, billing and responding to customer inquiries.

Taking a regional approach to economic dispatch and system operation, integrated resource planning, and project planning and development will most likely lead to better results than the current situation of six individual utilities working separately to meet the needs of their own residential and commercial customers without full regard to the benefits of coordination of activities among the utilities, provided that the regional entity has the appropriate governance structure, and financial and technical expertise. Additional benefits of a regional entity will likely include:

- A regional entity, with rational regional planning, would enable 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.
- A regional entity improves the opportunities to obtain the benefits of economies of scale in generation, transmission, and DSM/EE projects and programs.
- 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, given the impact of these resources on system operation and reliability.
- With regard to project development, the concentration of staff within one organization will increase 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 could also result in other cost savings, 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.
- A regional entity would be responsible for development and implementation of a single region-wide DSM/EE program-related communications and outreach effort, thereby ensuring consistency of message and procedures for participation, along with the attendant cost efficiencies involved. This would help avoid confusion and facilitate use of mass marketing, while still enabling co-branding with individual Railbelt utilities.
- A single point of contact for DSM/EE activities for the region would make program administration and evaluation much easier. All data would be housed in a central DSM/EE tracking system for ease of tracking progress towards the achievement of goals, reporting on individual entities or total, and tracking performance of vendors.
- 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.

This study was undertaken largely on the premise that such a regional entity would be formed to implement the chosen RIRP. While it is not an absolute requirement that a regional entity be formed to implement the RIRP, such implementation would be considerably more difficult if it is left up to the six individual Railbelt utilities, as they are required under their own governance policies to focus on identifying and implementing the best solutions for their own members and customers, as opposed to focusing on the most optimal regional solution.

It is Black & Veatch's belief that the formation of a regional entity is critical to implementing many of the recommendations of this report, whether the regional entity is the proposed GRETC or a different, but similar, regional entity. Black & Veatch also believes that the formation of this entity should occur as quickly as possible; 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. Suboptimal solutions result in higher costs, lower reliability and the inability to manage the successful integration of DSM/EE resources and renewable resources into the Railbelt system.

14.1.1.2 Achieving Economies of Scale

The Railbelt utilities, to date, have not been able to take full advantage of economies of scale for several reasons. 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/EE programs is a considerably more difficult challenge than would be the case if there was one regional entity, with the responsibility for developing and delivering DSM/EE programs to residential and commercial customers throughout the Railbelt region.

In addition to the benefits of scale related to generation and transmission resources, there are benefits associated with staffing, including:

- The concentration of staff would likely lead to more sophisticated generation and transmission planning, resulting in better regional resource planning decisions.
- 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/EE programs.

14.1.2 Resource Risks and Issues

There are a myriad of risks and issues associated with the implementation of specific resource options, whether DSM/EE, generation, or transmission. General areas of risk are discussed below and resource specific issues and risks are discussed in the next subsection.

14.1.3 Fuel Supply Risks and Issues

Natural gas has been the predominant source of fuel for electric generation used for the customers of Chugach, ML&P, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years.

There are a number of inherent risks whenever a utility or region is so dependent upon one fuel source including risks related 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. 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.

Consequently, the Railbelt region will not be able to continue its heavy dependence upon natural gas in the future unless enhanced gas supplies become available. Those enhanced supplies could include additional reserves discovered in the Cook Inlet, new reserves discovered in basins within or near the Railbelt region, North Slope gas delivered by an interstate pipeline, or a LNG import terminal with access to LNG suppliers outside Alaska.

Historically low prices for natural gas in the Cook Inlet region have been rationalized in some cases as a consequence of “stranded gas” in supply that exceeds the available market outlets. But in fact the export of LNG to Japan, where premium prices are assured, has provided the most significant market outlet and has made the “stranded gas” argument unconvincing. Indeed, the LNG export outlet has served as much of the financial incentive for producers to continue gas production from Cook Inlet.

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 than in past experience. For additional gas supplies in the Cook Inlet to become available, prices will need to increase to encourage exploration and production, and to help offset losses if LNG exports come to an end. 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 Line or Spur Line, prices will likely be tied to market prices since potential natural gas flows to the Railbelt region will likely 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 relatively low transportation rates that are imbedded in the delivered cost of gas from Cook Inlet suppliers under existing contracts.

14.1.4 Transmission Risks and Issues

As previously noted, 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 higher generation reserve margins (reserve margins reflect the amount of extra capacity beyond the peak load requirement that a utility needs to assure reliable system operation in the event that a generating units fails) and higher spinning reserve requirements (spinning reserve represents the amount of capacity that is available to serve load instantaneously if an operating generator disconnects from the grid) than elsewhere in order to ensure reliability in the case of a generation or transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region, such as:

- The requirement for larger regulating reserves (regulating reserves are extra capacity that are required to be synchronized and on-line and are able to adjust output both up and down in real-time as load fluctuates). This maintains stable frequency performance.
- The requirement for enough units on-line that can influence the rate of change of frequency when the balance between real-time load and real-time generation is out of balance. The lack of other interconnected units result in a lower system inertia and, consequently, a much more rapid fluctuation rate for frequency. This issue assumes greater importance when high penetration of non-dispatchable generation (e.g., wind) is being considered in the system.
- The lack of interconnection coupled with the relatively small size of the Railbelt system also results in smaller unit sizes than would otherwise be considered. This means that the full benefit of economies of scale will not be available and possibly more limited potential for jointly developed larger projects.
- Benefits of more economic system operation based on the potential for diversity of operation and wider power marketing transactions, as well as higher operation load factors for generators.
- Environmental benefits of system interconnection could result in reductions, through inter-regional commitment and dispatch, of greenhouse gas (GHG) emissions from electricity production in thermal plants. The value of the avoided emissions may be expressed as the total reduction in GHG times the cost of the emissions.

14.1.5 Market Development Risks and Issues

14.1.5.1 Competitive Power Procurement

An important market development-related issue relates to the ability of IPPs, or non-utility generators of electricity, to enter the market. To date, the level of IPP penetration is the Railbelt region has been minor. The most significant activity is the current efforts by Cook Inlet Regional, Inc./enXco to develop the Fire Island wind farm. Additionally, other activities include those by Ormat to develop the Mt. Spurr geothermal project. Other IPP development activities are either for smaller projects or are not as far along in the development process. However, none of these current activities are guaranteed to succeed. There are a number of reasons for lower IPP activity in the Railbelt region than has occurred in other regions of the country. Not the least of these reasons is the fact that IPPs must work with individual utilities to gain acceptance on their projects, including the negotiation of power purchase agreements under varying terms and conditions and dealing with various generation interconnection requirements. The region would likely benefit from the adoption of policies that attract IPP development of project alternatives under the resource addition parameters established by the RIRP. One such policy would be the development of a competitive power procurement policy that would establish a "level playing field" for IPP-proposed projects. Under competitive procurement, IPP developers would be able to bid projects that offer economic benefits to the grid against other economic options. This assures that the combination of resources selected would be the most economic options for customers.

14.1.5.2 Load Growth

With regard to native load growth (e.g., normal load growth resulting from residential and commercial customers), Railbelt utilities have experienced limited, 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.

There are, however, a number of potential significant, discrete 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, other economic development efforts and or State policy decisions. Additionally, there will likely be a significant increase in Railbelt population if the North Slope natural gas pipeline, and or the Spur Line or Bullet Line, is built. Where large discreet load additions occur, there will be associated changes in both generation and transmission infrastructure to maintain system reliability. Under a consolidated integrated resource plan the discreet additions would be coordinated with other regional reliability projects to minimize costs and to optimize system considerations such as the size, timing and location of new resources.

14.1.6 Financing and Rate Risks and Issues

14.1.6.1 Financing

As noted above, the Railbelt utilities face a very significant challenge in terms of their ability to finance the future. Traditional means of financing by the Railbelt utilities going forward independently simply are inadequate given the capital investment requirements over the next 50 years that result from each of the four alternative resource plans. Essentially, the existing net cash flow for the individual utilities would not provide sufficient debt coverage ratios to support investment grade debt financing for large, multi-year construction projects. Even for a regional entity, the available net cash flow to support such projects would be difficult without State assistance.

14.1.6.2 Rate Design

In addition to the challenge associated with securing the required financing, that capital investment will need to be recovered through rates, thereby resulting in higher monthly bills for residential and commercial customers. While the need to recover capital investments is a reality, innovative rate design options (e.g., Construction-Work-in-Progress - CWIP) are available to smooth out these rate increases over time so that they are more affordable to residential and commercial customers. CWIP also helps to address the cash flow issues associated with financing new projects.

14.1.7 Legislative and Regulatory Risks and Issues

14.1.7.1 State Energy Policy

The development of a RIRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor's office and State Legislature. With regard to energy policy making, however, the RIRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

Having said this, the development of a State Energy Policy and or related policies could directly impact the specific alternative resource plan chosen for the Railbelt region's future. As such, the RIRP may need to be readdressed as future energy-related policies are enacted.

14.1.7.2 Regulatory Commission of Alaska

While it is not within the scope of this RIRP to address the level and quality of regulation for either the individual utilities or GRETC, the level and quality of regulation impacts current and future investment decisions by both the electric and natural gas industries.

14.1.8 Value of Optionality

Optionality represents the ability to make other choices once an initial choice has been made. Given the large fixed cost commitments associated with generation and transmission projects, any optionality in a resource plan adds value. As previously discussed, the recent increases in natural gas prices highlight the dangers inherent from an over-reliance on one fuel source or generation technology. That is, given the sunk cost of generation from gas fired resources, there is little option for reducing costs as gas prices rise. Just as investors rely on a portfolio of assets to manage risk, it is important for utilities to develop a portfolio of assets to ensure safe, reliable and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility.

In this context, maintaining flexibility has two dimensions. The first dimension of flexibility relates to future generation resources and fuel supplies. Any future resource path should be chosen only if it is likely to enhance the region's ability to maintain and improve the region's resource asset portfolio flexibility.

The second 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 regulations, support of the North Slope gas pipeline and or the Bullet or Spur Lines, and so forth. Resource decisions being made by utility managers are increasingly driven or influenced by energy policy makers.

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 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.

Additionally, maintaining flexibility is important. In that regard, even after a particular resource plan has been adopted, it is important to pursue activities that maintain the viability of other resource options; therefore, the region can modify it resource plan, as required, as the issues and risks associated with the selected resource plan become better known

14.2 Resource Specific Risks and Issues

14.2.1 Introduction

The purpose of this section is to identify the primary issues and risks associated with the development of the following resource options:

- DSM/EE
- Generation resources, including natural gas, coal and modular nuclear, as well as renewable resources including large and small hydro, wind, geothermal, solid waste and tidal
- Transmission resources

14.2.2 Resource Specific Risks and Issues – Summary

The following table provides Black & Veatch's assessment of the relative magnitude of various categories of risks and issues for each resource type, including:

- **Resource Potential Risks** – the risk associated with the total energy and capacity that could be economically developed for each resource option.
- **Project Development and Operational Risks** – the risks and issues associated with the development of specific projects, including regulatory and permitting issues, the potential for construction costs overruns, actual operational performance relative to planned performance, and so forth. This category also includes non-completion risks once a project gets started, the risk that adverse operating conditions will severely damage the facilities resulting in a shorter useful life than expected, and project delay risks.
- **Fuel Supply Risks** – the risks and issues associated with the adequacy and pricing of required fuel supplies.
- **Environmental Risks** – the risks of environmental-related operational concerns and the potential for future changes in environmental regulations.
- **Transmission Constraint Risks** – the risk that the ability to move power from a specific generation resources to where that power is needed, an issue that is particularly important for large generation projects and remote renewable projects.
- **Financing Risks** – the risk that a regional entity or individual utility will not be able to obtain the financing required for specific resource options under reasonable and affordable terms and conditions.
- **Regulatory/Legislative Risks** – the risk that regulatory and legislative issues could affect the economic feasibility of specific resource options.
- **Price Stability Risks** – the risk that wholesale power costs will increase significantly as a result of changes in fuel prices and other factors (e.g., CO_2 costs).

Table 14-1
Resource Specific Risks and Issues - Summary

Resource	Relative Magnitude of Risk/Issue							
	Resource Potential Risks	Project Development and Operational Risks	Fuel Supply Risks	Environmental Risks	Transmission Constraint Risks	Financing Risks	Regulatory/ Legislative Risks	Price Stability Risks
DSM/EE	Moderate	Limited	N/A	N/A	N/A	Limited - Moderate	Moderate	Limited
Generation Resources								
Natural Gas	Limited	Limited	Significant	Moderate	Limited	Moderate	Moderate	Significant
Coal	Limited	Moderate-Significant	Limited	Moderate - Significant	Limited - Significant	Moderate – Significant	Moderate	Moderate
Modular Nuclear	Limited	Significant	Moderate	Significant	Limited	Significant	Significant	Significant
Large Hydro	Limited	Significant	Limited	Significant	Significant	Significant	Significant	Limited
Small Hydro	Moderate	Moderate	Limited	Moderate	Moderate	Limited - Moderate	Limited	Limited
Wind	Moderate	Moderate	N/A	Limited	Moderate	Limited - Moderate	Limited	Limited - Moderate
Geothermal	Moderate	Limited - Moderate	N/A	Limited - Moderate	Moderate – Significant	Limited – Moderate	Limited	Limited
Solid Waste	Limited	Moderate-Significant	N/A	Significant	Moderate	Limited – Moderate	Limited-Moderate	Moderate
Tidal	Limited	Significant	N/A	Significant	Moderate - Significant	Moderate – Significant	Moderate - Significant	Limited - Moderate
Transmission	Limited	Significant	N/A	Moderate	N/A	Significant	Moderate - Significant	N/A

The following provides some commentary related to the basis for these qualitative assessment of resource specific risks and issues:

- **Resource Potential Risks**

  Resource potential risks are deemed to be moderate for some of the renewables resource options primarily due to the fact that enough resource potential studies have not been completed to provide a high degree confidence in the amount of energy capacity and energy that could be provided by these different resource options. For other renewable resource options, initial studies indicate significant resources are available, but more detailed studies have not been conducted to ensure that these large potential resources can actually be converted into renewable generation. Based upon the studies that have been completed, there is a solid foundation for believing that each of these different forms of renewable resources offers the potential for relatively significant capacity and energy within the Railbelt region. However, additional studies must be completed to identify the most attractive locations and to firm up the resource potential estimates for each type of renewable resource technology.

  Resource potential risks and issues are relatively lower for natural gas, coal and modular nuclear, as well as for additional transmission resources.

  Resource potential risks associated with DSM/EE programs are more commonly related to the reliability, or lack thereof, of the resource in that it is less under the control of the utility and relies more on mass market decision-making and/or behavior.

- **Project Development and Operational Risks**

  Project development and operational risks and issues are significant for modular nuclear, large hydro, tidal, and transmission. They are also fairly significant for coal and solid waste. In the case of large hydro, these risks are significant due to the stringent environmental and permitting issues that would need to be addressed. Additionally, the potential for significant construction cost overruns is significant for large hydro.

  Tidal power represents an option with significant potential in the Railbelt. However, this technology has not been widely commercialized and there are significant environmental and permitting risks and issues associated with this technology.

  In the case of transmission, project development risks are deemed significant due to NIMBY concerns and the rough terrain and difficult construction conditions that exist.

  Coal, solid waste, and modular nuclear face NIMBY concerns as well as permitting and licensing concerns.

  The project development-related risks are believed to be lower, or moderate, for the other types of renewable resources, including small hydro, wind, and geothermal; they are even lower, or minimal, for DSM/EE resources, and generation resources that are fueled by natural gas and other fossil fuels.

- **Fuel Supply Risks**

  Fuel supply-related risks are very significant for natural gas generation resources. They are generally limited for generation options that rely on other fossil fuels, and they do not apply to DSM/EE and the various renewable resources.

- **Environmental Risks**

  Environmental-related risks are believed moderate for natural gas generation, and moderate to significant for other fossil fueled generation options. Future carbon restrictions represent an important risk for all generation resources that rely on fossil fuels and are very significant in the case of coal.

  Environmental-related risks are shown as significant for modular nuclear, large hydro options, solid waste, and tidal power due to their potential environmental impact.

  They are believed to be moderate for small hydro and geothermal, and limited for wind based, in large part, on experience with these technologies in other regions of the country and elsewhere in the world.

- **Transmission Constraint Risks**

  Existing transmission constraints are significant for large hydro because the current transmission network is insufficient to move large amounts of capacity and energy throughout the region which would be required for any large hydro project to be economic.

  Transmission constraints also represent a moderate to significant issue for geothermal and tidal, depending upon the ultimate amount of these resources developed within the region.

  They are believed to be moderate with regard to small hydro, wind, and solid waste due to the typical size of these projects and the fact that they can generally be developed throughout the Railbelt region, thereby reducing the need to have transmission to move the related capacity and energy from one area of the Railbelt region to another.

  Transmission constraints are deemed limited for natural gas-fuel generation, again due to the typical size of these projects and the fact that they can be located throughout the Railbelt region, and they do not exist with regard to DSM/EE resources due to the distributed nature of these resources.

- **Financing Risks**

  Financing risks and issues are significant for any large scale resource option including coal, modular nuclear, large hydro, and transmission resources. They are moderate for natural gas generation.

  Financing risks are limited to moderate for most of the renewable resources (e.g., including small hydro, wind, geothermal, solid waste and tidal) depending upon the actual size of the projects developed; likewise they are limited to moderate for DSM/EE resources.

- **Regulatory/Legislative Risks**

  Regulatory and legislative risks and issues are limited for smaller-scale renewable resources, including small hydro, wind, geothermal, and solid waste.

  They are moderate for DSM/EE resources, primarily due to the fact that regulatory (and potentially legislative) changes would be required to eliminate the disincentive that exists under the current regulatory framework for utilities to encourage customers to use less electricity. They are also believed to be moderate for natural gas and other fossil fueled generation resources.

  Regulatory and legislative risks and issues are believed to be significant for modular nuclear and large hydro, and moderate to significant for tidal and transmission resources.

- **Price Stability Risks**

  Price stability risks and issues are limited for DSM/EE programs, small and large hydro, and geothermal; limited to moderate for wind and tidal. They are moderate for coal and solid waste, and significant for natural gas and modular nuclear.

More detailed information related to the risks and issues associated with each type of resource options is provided in the following subsection.

14.2.3 Resource Specific Risks and Issues – Detailed Discussion

This section provides more detailed information related to the risks and issues associated with each of the following types of resource options:

- DSM/EE
- Generation
  - Natural gas
  - Coal
  - Modular nuclear
  - Large hydro
  - Small hydro
  - Wind
  - Geothermal
  - Solid waste
  - Tidal
- Transmission

This section consists of a series of tables that identifies the most significant risks and issues for each type of resource options, broken down by the major risk/issue categories discussed in the previous section. These tables also identify the primary actions that should be taken to address these risks and issues.

14.2.3.1 DSM/EE

Table 14-2
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • General lack of Alaska-specific data to determine economic resource potential, including end-use saturations, measure persistence, weather sensitive impacts, and cost-effectiveness • Reliability is a key concern with DSM since utilities have less control over its acquisition and management	• Establish Alaska-specific baseline information through the completion of region-wide residential and commercial end-use saturation surveys and customer attitudinal surveys • Complete comprehensive economically achievable potential study that includes a detailed cost-effectiveness evaluation of all feasible DSM/EE measures • Complete vendor surveys to determine availability and relative costs of DSM/EE measures in the Railbelt region • Develop regional DSM/EE program measurement and evaluation protocols • Focus programs on hard-wired technology replacements rather than behavioral based savings • If demand reduction is a goal, focus DSM programs on peak load reduction program strategies that can be dispatched or under greater control by the utility
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing their own DSM/EE programs • Ineffectiveness and inefficiencies associated with lack of coordination between the electric utilities, Enstar, and AHFC • Lack of customer awareness regarding DSM/EE options and economics	• Establish a regional entity (e.g., GRETC or independent third party) to develop and deliver, in coordination with the six Railbelt utilities, DSM/EE efficiency programs to all customers in the Railbelt region • Develop and implement regional DSM/EE programs in close coordination with Enstar and AHFC • Develop public outreach program to increase awareness of DSM/EE options • Develop and learn from near-term DSM/EE pilot programs throughout the Railbelt region

Table 14-2 (Continued)
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Not applicable	• Not applicable
Transmission Constraints	• Not applicable	• Not applicable
Financing	• Lack of funding source for initial activities (e.g., collect baseline information and consumer education) required to build a viable and successful DSM/EE program • Lack of stable source of long-term financing for DSM/EE program	• Legislature should appropriate funds for the initial development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) customer attitudinal survey, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts • Increase State funding of low income weatherization and residential and energy audit (both residential and commercial) program • Aggressively pursue available Federal funding for DSM/EE programs • Consider implementation of a System Benefit Charge, or SBC, (i.e., a surcharge on customer bills that would be dedicated to the funding of DSM/EE programs) to provide for the long-term funding of DSM/EE programs
Regulatory/Legislative	• The implementation of DSM/EE reduces energy sales and, therefore, reduces the ability of utilities to recover costs under current rate design principles • Lack of innovative rate structures in the Railbelt region, such as time-of-use (TOU) and demand response (DR) rates • Lack of strict building codes and enforcement of those codes • Lack of State leadership related to DSM/EE	• Implement a decoupling mechanism so that a regional entity and or the individual Railbelt utilities can still recover their costs even with lower sales • Allow utilities to develop pilot programs to test the effectiveness of TOU and DR rates • Establish more stringent residential and commercial building codes that lead to lower energy use in new homes and buildings and increase the enforcement of those building codes

Table 14-2 (Continued)
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Regulatory/Legislative (Continued)		• Establish State targets for DSM/EE savings based on the economics of the programs • Establish State goals for reducing energy usage at State facilities • Develop and implement programs to increase energy efficiency in State buildings and schools

14.2.3.2 Generation Resources

14.2.3.2.1 Generation Resources – Natural Gas

Table 14-3
Resource Specific Risks and Issues – Generation – Natural Gas

Resource: Generation – Natural Gas		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• See Fuel Supply	• See Fuel Supply
Project Development	• Development risks are well known and understood	• Not applicable
Fuel Supply	• Near-term adequacy and deliverability of natural gas supplies appear inadequate • Several long-term gas supply options exist but the relative risks and economics of those options have not been fully assessed	• Electric utilities need to work closely with the State, gas producers and Enstar to ensure the adequacy of near-term gas supplies • Current LNG export agreement should not be extended and the related gas should be used for the needs of Railbelt gas and electric customers, although the loss of the LNG export outlet might require the Cook Inlet gas price to be re-set • Short-term imported LNG gas supplies should be secured to serve as transitional gas supply option • Local gas storage capabilities should be developed as soon as possible • The State should complete a detailed risk and cost evaluation of available long-term gas supply options to determine the best option • Once the most attractive long-term supplies of natural gas have been determined, detailed engineering studies and permitting activities should be undertaken • Appropriate commercial terms and pricing structures should be established to provide producers the incentive to increase exploration for additional Cook Inlet gas supplies • State should consider providing incentives to encourage additional exploration for Cook Inlet gas supplies

Table 14-3 (Continued)
Resource Specific Risks and Issues – Generation – Natural Gas

Resource: Generation – Natural Gas		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Environmental	• Risk of accident	• Continue efforts to enforce safety and operational regulations
Transmission Constraints	• Proper location of gas-fired generation resources mitigates transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• For larger projects, financing can be difficult given the financial strength of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider State assistance for new gas-fired generation projects that replace old, inefficient natural gas plants
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions	• Monitor Federal legislative and regulatory activities related to emission regulations • Monitor technological developments regarding carbon capturing technologies (e.g., carbon sequestration)

14.2.3.2.2 Generation Resources – Coal

Table 14-4
Resource Specific Risks and Issues – Generation – Coal

Resource: Generation – Coal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Not applicable	• Not applicable
Project Development	• Development risks are generally known and understood	• Not applicable
Fuel Supply	• Not applicable	• Not applicable
Environmental	• See Regulatory/Legislative	• Not applicable
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• For larger projects, financing can be difficult given the financial strength of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions, and coal mining • Potential regulations of regarding ash disposal	• Monitor Federal legislative and regulatory activities related to emission regulations and coal mining • Monitor technological developments regarding carbon capturing technologies (e.g., carbon sequestration) • Implement appropriate design to mitigate environmental impacts

14.2.3.2.3 Generation Resources – Modular Nuclear

Table 14-5
Resource Specific Risks and Issues – Generation – Modular Nuclear

Resource: Generation – Modular Nuclear		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Resource potential would be very large, but technology not demonstrated	• Monitor development and licensing of technology
Project Development	• Significant permitting challenges exist for modular nuclear • Public acceptability of modular nuclear is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of modular nuclear • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of modular nuclear may not be significant, but public perception about environmental impacts may be very significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• The small size of the modular nuclear projects should not pose transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• The lack of technology demonstration at this small size may create concerns in the financing community • Costs per kW may be significant	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance reduce resistance to finance • Aggressively pursue available Federal funding
Regulatory/Legislative	• NRC licensing is uncertain	• Monitor NRC licensing process

14.2.3.2.4 Generation Resources – Large Hydro

Table 14-6
Resource Specific Risks and Issues – Generation – Large Hydro

Resource: Generation – Large Hydro		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Both Susitna and Chakachamna sites are adequate to play a major role in meeting the region's future electric capacity and energy requirements	• Not applicable
Project Development	• Significant permitting challenges exist for large hydro projects • Public acceptability of large hydro is unknown • Potential for construction cost overruns is significant • Infrastructure needs to support project construction are significant	• Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of large hydro • Implement best practices related to management of construction costs
Fuel Supply	• Potential impact of climate change	• Monitor water flows
Environmental	• Environmental impacts of large hydro projects are potentially significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of large hydro facility into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Complete required studies to ensure the ability to integrate large hydro projects into the transmission grid
Financing	• Financing requirements of a large hydro project are greater than the combined financial capabilities of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for large hydro projects
Regulatory/Legislative	• Potential future environmental regulations related to large hydro projects • Regional commitment to large hydro is uncertain	• Monitor Federal activities related to large hydro projects • Determine State policy regarding the desirability of large hydro projects • Establish State Renewable Portfolio Standard (RPS) targets • Develop State policies regarding Renewable Energy Credits (RECs) and Green Pricing

14.2.3.2.5 Generation Resources – Small Hydro

Table 14-7
Resource Specific Risks and Issues – Generation – Small Hydro

Resource: Generation – Small Hydro		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing small hydro projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction may be significant	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop small hydro projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Potential impact of climate change	• Monitor water flows
Environmental	• Site specific environmental issues including impact on fish	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.2.6 Generation Resources – Wind

Table 14-8
Resource Specific Risks and Issues – Generation – Wind

Resource: Generation – Wind		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing wind projects • Lack of standard power purchase agreements for projects developed by IPPs	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop wind projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.2.7 Generation Resources – Geothermal

Table 14-9
Resource Specific Risks and Issues – Generation – Geothermal

Resource: Generation – Geothermal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing geothermal projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction are likely significant	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop geothermal projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Explore if synergies can be achieved for infrastructure with hydro projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain • Potential future environmental regulations related to emissions, including carbon and other emissions	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing • Monitor Federal legislative and regulatory activities related to emission regulations

14.2.3.2.8 Generation Resources – Solid Waste

Table 14-10
Resource Specific Risks and Issues – Generation – Solid Waste

Resource: Generation – Solid Waste		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing solid waste projects • Lack of standard power purchase agreements for projects developed by IPPs	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop solid waste projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• See Resource Potential	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW is very significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain • Potential future environmental regulations related to emissions, including carbon and other emissions	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing • Monitor Federal legislative and regulatory activities related to emission regulations

14.2.3.2.9 Generation Resources – Tidal

Table 14-11
Resource Specific Risks and Issues – Generation – Tidal

Resource: Generation – Tidal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing tidal projects • Lack of standard power purchase agreements for projects developed by IPPs • Significant permitting challenges exist for large hydro projects • Public acceptability of tidal is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop tidal projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of tidal • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of tidal projects are potentially significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of large tidal facility into Railbelt transmission grid poses challenges • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Complete required studies to ensure the ability to integrate large tidal projects into the transmission grid • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources

Table 14-11 (Continued)
Resource Specific Risks and Issues – Generation – Tidal

Resource: Generation – Tidal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Financing	• Financing requirements of a large tidal project are greater than the combined financial capabilities of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for large tidal projects • Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.3 Transmission

Table 14-12
Resource Specific Risks and Issues – Transmission

Resource: Transmission		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• "Resource potential" is not limited; issue is determining the most appropriate projects, voltage, and siting	• Implement transmission plan included in this RIRP
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing transmission projects • Potential for construction cost overruns is significant	• Establish a regional entity (e.g., GRETC) to identify and develop transmission projects • Implement best practices related to management of construction costs • Centralize all siting and permitting at the State level
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Potential for local environmental issues	• Pursue statewide permitting by GRETC
Transmission Constraints	• Not applicable	• Not applicable
Financing	• Financing requirements of transmission projects are significant	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for transmission projects
Regulatory/Legislative	• Siting and permitting issues are potentially significant	• Develop streamlined siting and permitting processes for transmission projects

15.0 CONCLUSIONS AND RECOMMENDATIONS

This section provides an overview of the conclusions and recommendations resulting from the RIRP study.

Purpose and Limitations of the RIRP

- The development of this RIRP is not the same as the development of a State Energy Plan; nor does it set State policy. Setting energy-related policies is the role of the Governor and State Legislature. With regard to energy policy making, however, the RIRP does provide a foundation of information and analysis that can be used by policy makers to develop important policies.

  Having said this, the development of a State Energy Policy and or related policies could directly impact the specific alternative resource plan chosen for the Railbelt region's future. As such, the RIRP may need to be readdressed as future energy-related policies are enacted.

- This RIRP, consistent with all integrated resource plans, should be viewed as a "directional" plan. In this sense, the RIRP identifies alternative resource paths that the region can take to meet the future electric needs of Railbelt citizens and businesses; in other words, it identifies the types of resources that should be developed in the future. The granularity of the analysis underlying the RIRP is not sufficient to identify the optimal configuration (e.g., specific size, manufacturer, model, location, etc.) of specific resources that should be developed. The selection of specific resources requires additional and more detailed analysis.

- The alternative resource options considered in this study include a combination of identified projects (e.g., Susitna and Chakachamna hydroelectric projects, Mt. Spurr geothermal project, etc.), as well as generic resources (e.g., Generic Hydro – Kenai, Generic Wind – GVEA, generic conventional generation alternatives, etc.). Identified projects are included, and shown as such, because they are projects that are currently at various points in the project development lifecycle. Consequently, there is specific capital cost and operating assumptions available on these projects. Generic resources are included to enable the RIRP models to choose various resource types, based on capital cost and operating assumptions developed by Black & Veatch. This approach is common in the development of integrated resource plans.

  Consistent with the comment above regarding the RIRP being a "directional" plan, the actual resources developed in the future, while consistent with the resource type identified, may be: 1) the identified project shown in the resource plan (e.g., Chakachamna), 2) an alternative identified project of the same resource type (e.g., Susitna); or 3) an alternative generic project of the same resource type. One reason for this is the level of risks and uncertainties that exist regarding the ability to plan, permit, and develop each project. Consequently, when looking at the resource plans shown in this report, it is important to focus on the resource type of an identified resource, as opposed to the specific project.

- The capital costs and operating assumptions used in this study for alternative DSM/EE, generation and transmission resources do not consider the actual owner or developer of these resources. Ownership could be in the form of individual Railbelt utilities, a regional entity, or an independent power producer (IPP). Depending upon specific circumstances, ownership and development by IPPs may be the least-cost alternative.

- As with all integrated resource plans, this RIRP should be periodically updated (e.g., every three years) to identify changes that should be made to the preferred resource plan to reflect changing circumstances (e.g., resolution of uncertainties), improved cost and performance of emerging technologies (e.g., tidal), and other developments.

15.1 Conclusions

The primary conclusions from the RIRP study are discussed below.

1. The current situation facing the Railbelt utilities includes a number of challenging issues that place the region at a historical crossroad regarding the mix of DSM/EE, generation, and transmission resources that it will rely on to economically and reliably meet the future electric needs of the region's citizens and businesses. As a result of these issues, the Railbelt utilities are faced with the following challenges:
   - A transmission network that is isolated and has limited total transfer capabilities and redundancies.
   - The inability of the region to take full advantage of economies of scale due to its limited size.
   - A heavy dependence on natural gas from the Cook Inlet for electric generation.
   - Limited and declining Cook Inlet gas deliverability.
   - Lack of natural gas storage capability.
   - The region's aging generation and transmission infrastructure.
   - A heavy reliance on older, inefficient natural gas generation assets.
   - The region's limited financing capability, both individually and collectively among the Railbelt utilities.
   - Duplicative and diffused generation and transmission expertise among the Railbelt utilities.
2. The key factors that drive the results of Black & Veatch's analysis include the following:
   - The risks and uncertainties that exist for all alternative DSM/EE, generation, and transmission resource options.
   - The future availability and price of natural gas.
   - The public acceptability and ability to permit a large hydroelectric project which is a greater concern, based upon Black & Veatch's discussions with numerous stakeholders, than the acceptability and ability to permit other types of renewable projects, such as wind and geothermal.
   - Potential future CO_2 prices, which would impact all fossil fuels, that may or may not result from proposed Federal legislation.
   - The region's existing transmission network, which limits: 1) the ability to transfer power between areas within the region to minimize power costs, and 2) places a maximum limit on the amount of non-dispatchable resources that can be integrated into the region's transmission grid.
   - The ability of the region to raise the required financing, either by the utilities on their own or through a regional G&T entity.
   - Whether the Railbelt utilities develop a number of currently proposed projects that were selected outside of a regional planning process.

   Figures 15-1 and 15-2 graphically demonstrate how the results of the various reference and sensitivity cases are impacted by these important uncertainties. Figure 15-1 shows the cumulative present value cost for each year over the 50-year planning horizon; similarly, Figure 15-2 shows the annual wholesale power cost (cents/kWh) in 2010 dollars. In both cases, we have shown selected reference and sensitivity cases to highlight how dependent the results are to these key uncertainties.

Figure 15-1
Cumulative Present Value Cost – Selected Reference and Sensitivity Cases

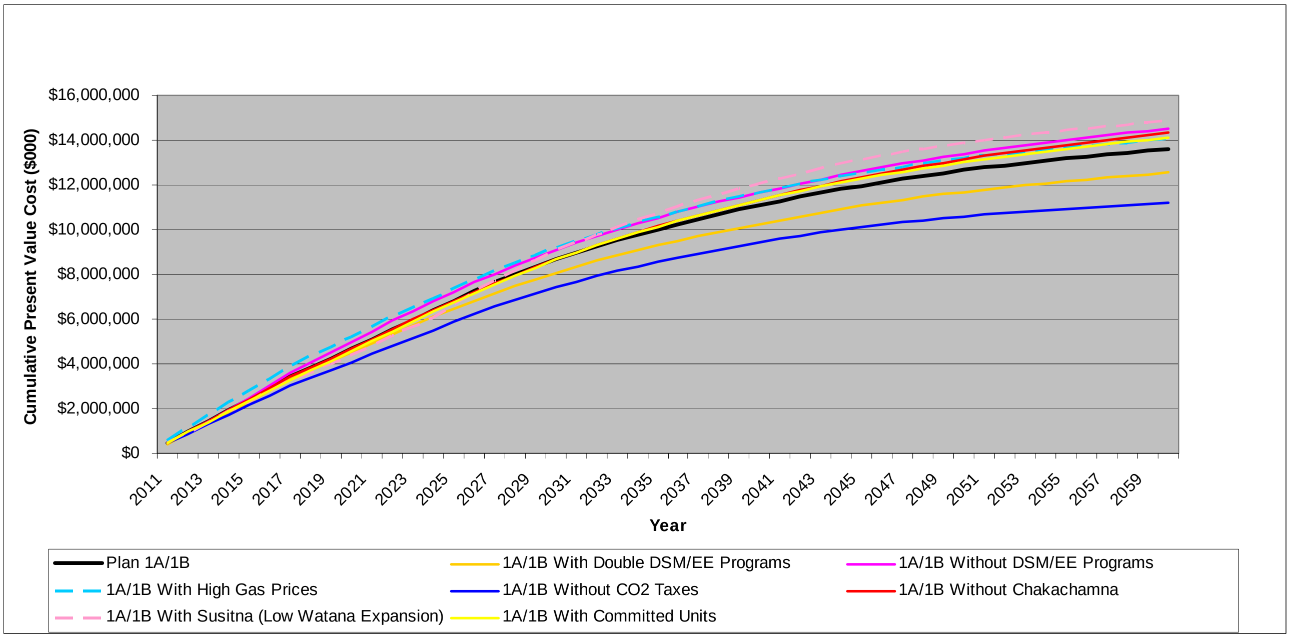
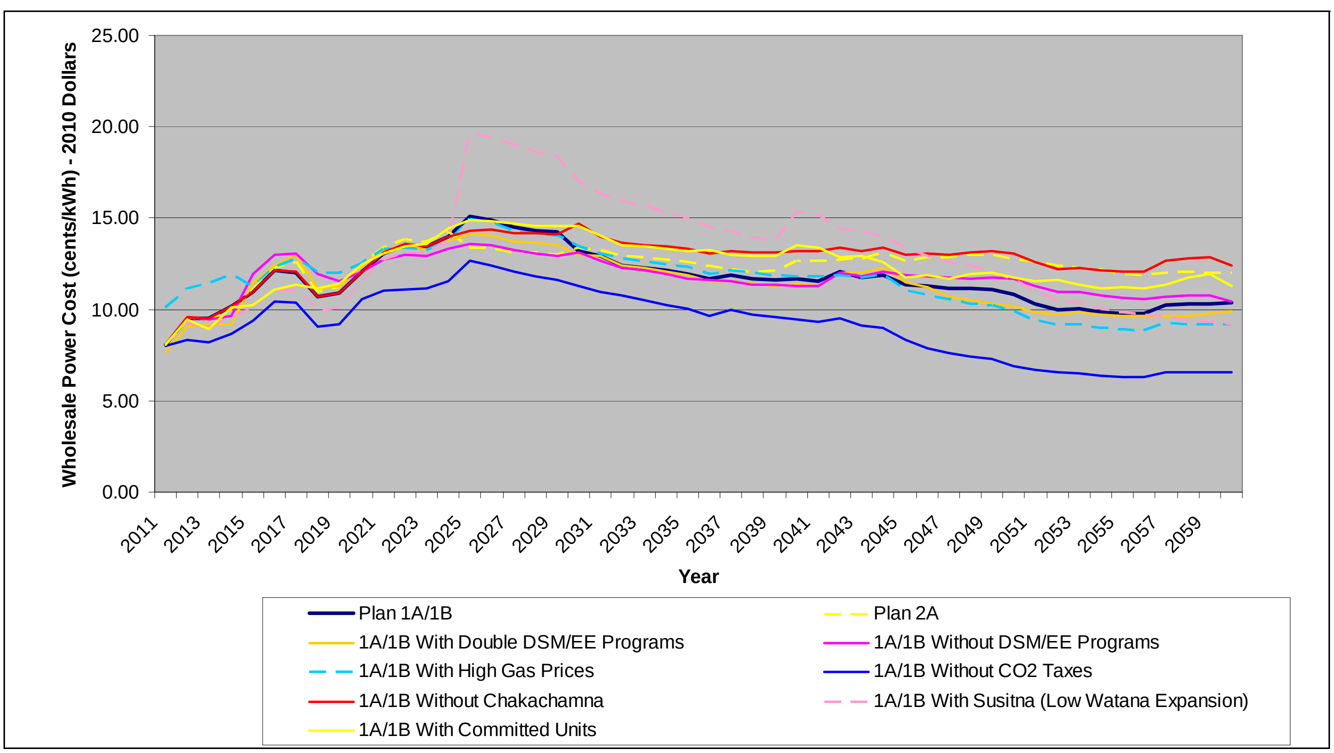


Figure 15-2
Annual Wholesale Power Cost – Selected Reference and Sensitivity Cases



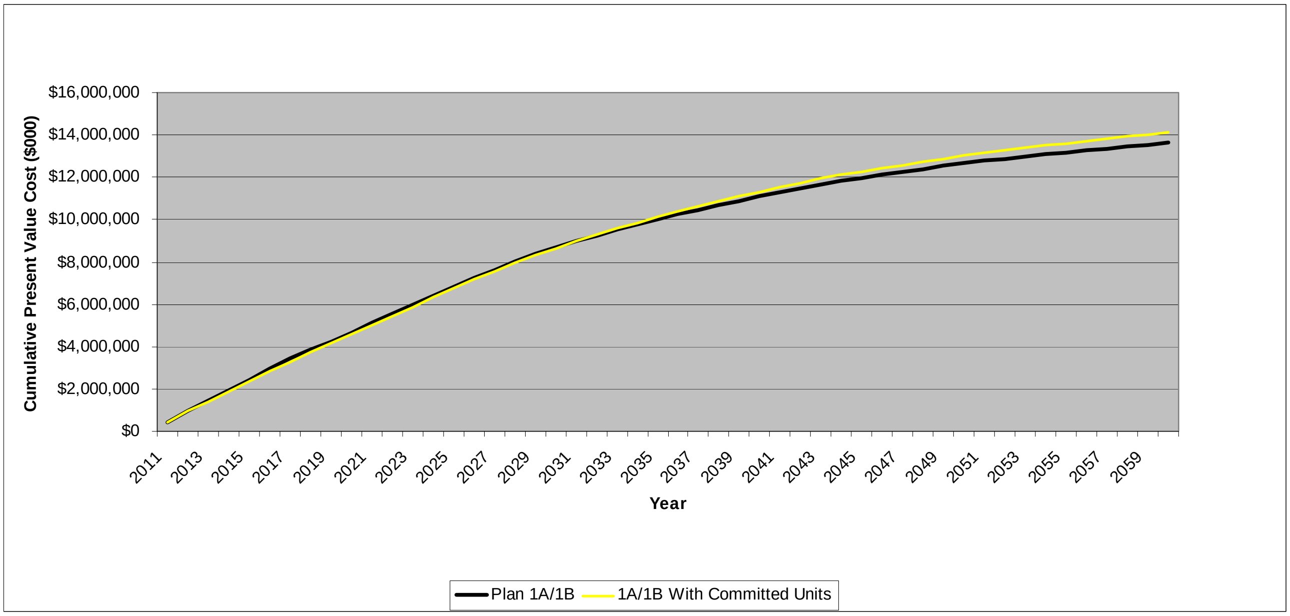
As can be seen in Figures 15-1, which shows cumulative net present value costs over the 50-year planning horizon, the 1A/1B With Susitna (Low Watana Expansion), 1A/1B With no DSM/EE Programs, 1A/1B Without Chakachamna, 1A/1BWith Committed Units, and 1A/1B With High Gas Prices Sensitivity Cases are all higher cost than Scenario 1A/1B, in descending order. The 1A/1B With Double DSM/EE Programs and 1A/1B With No CO_2 Taxes Sensitivity Cases are lower cost that Scenario 1A/1B.

Figure 15-2 shows how significant the uncertainty regarding CO_2 taxes is with regard to the results. It also shows the economic value of achieving higher DSM/EE savings that were assumed in the Scenario 1A/1B Reference Case if those savings can be achieved. Also, shown is the fact that the other sensitivity cases are higher cost than Scenario 1A/1B.

3. The resource plans that were developed as part of this study for each Evaluation Scenario include a diverse portfolio of resources. If implemented, the RIRP will lead to:
   - The development of a resource mix resulting from a regional planning process.
   - Greater reliance on DSM/EE and renewable resources and a lower dependence on natural gas.
   - A more robust transmission network.
   - More effective spreading of risks among all areas of the region.
   - A greater ability to respond to large load growth should these load increases occur. Stated another way, the implementation of the RIRP will provide a stronger foundation upon which to base future economic development efforts.
4. The cost of this greater reliance on DSM/EE and renewable resources is less than the continued heavy reliance on natural gas based upon the base case gas price forecast that was used in this analysis. This result is achievable if the region builds a large hydroelectric project. There are uncertainties, at this point in time, regarding the environmental and/or geotechnical conditions under which a large hydroelectric project could be built. If a large hydroelectric facility can not be developed, or if the cost of the large hydroelectric project significantly exceeds the current preliminary estimates, then the costs associated with a predominately renewable future would be greater than continuing to rely on natural gas.
5. Our analysis shows that Scenarios 1A and 1B result in the same resources and, consequently, the same costs and emissions. In other words, the cost of achieving a renewable energy target of 50 percent by 2025 (Scenario 1B) is no greater than the cost of the unconstrained solution (Scenario 1A). This result applies only if a large hydroelectric project is built.
6. Scenarios 2A and 2B were evaluated to determine what the impact would be if the demand in the region was significantly greater than it is today. In fact, the per unit power costs were not less than Scenario 1A/1B due to the cost of Susitna which was the resource chosen to meet this additional load..
7. Additionally, the implementation of a regional plan will result in lower costs than if the individual Railbelt utilities continue to go forward on their own. While the scope of this study did not include the development of separate integrated resource plans for each of the six Railbelt utilities, we did complete a sensitivity analysis to show the cost impact if the utilities develop their currently proposed projects (referred to as committed units) that were selected outside of a regional planning process. The Railbelt utilities are moving forward with these projects due to the existing uncertainty regarding the formation of GRETC. While this sensitivity case does not fully capture the incremental cost of the utilities acting independently over the 50-year planning horizon, it does provide an indication of

the relative cost differential. Figure 15-3 shows the resulting total annual costs of the two different resource plans. In the aggregate, the cost of the Committed Unit Sensitivity Case was approximately 5.6 percent, or $484 million on a cumulative net present value cost basis, higher than Scenario 1A/1B. The main conclusion to draw from this graphic is that there are significant cost savings associated with the Railbelt utilities implementing a plan that has been developed to minimize total regional costs, while ensuring reliable service, as opposed to the individual utilities working separately to meet the needs of their own customers.

Figure 15-3
Comparison of Results - Scenario 1A/1B Versus Committed Units Sensitivity Case



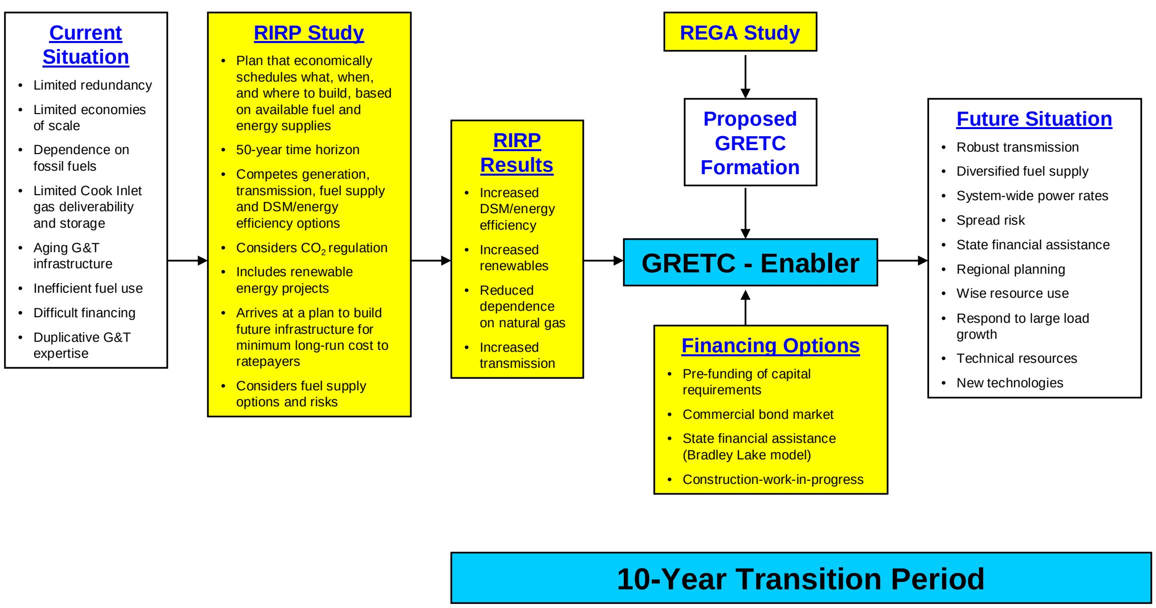
8. There are a number of risks and uncertainties regardless of the resource options chosen. For example: 1) there is a lack of Alaska-specific data upon which to build an aggressive region-wide DSM/EE program, 2) the future availability and price of natural gas affects the viability of natural gas generation, and 3) the total economic potential of various renewable resources is unknown at this time. In some cases, these risks and uncertainties (e.g., the ability to permit a large hydroelectric facility) might completely eliminate a particular resource option. Due to these risks and uncertainties, it will be important for the region to maintain flexibility so that changes to the preferred resource plan can be made, as necessary, as these resource-specific risks and uncertainties become more clear or get resolved.

9. Significant investments in the region’s transmission network need to be made within the next 10 years to ensure the reliable and economic transfer of power throughout the region. Without these investments, providing economic and reliable electric service will be a greater challenge.

10. The increased reliance on non-dispatchable renewable resources (e.g., wind) will require a higher level of frequency regulation within the region to handle swings in electric output from these resources. An increased level of regulation has been included in Black & Veatch's transmission plan. Even with this increased regulation, however, the challenges associated with the integration of non-dispatchable resources will ultimately place a maximum limit on the amount of these resources that can be developed.

11. The implementation of the RIRP does not require that a regional generation and transmission entity (e.g., GRETC) be formed. However, the absence of a regional entity with the responsibility for implementing the RIRP will increase the difficulty of the region's ability to implement a regional plan and, in fact, Black & Veatch believes that the lack of a regional entity will, as a practical matter, mean that the RIRP will not be fully implemented. As a consequence, the favorable outcomes of the RIRP discussed above would not be realized. The interplay between the formation of a regional entity and the RIRP is shown in Figure 15-4.

Figure 15-4
Interplay Between GRETC and Regional Integrated Resource Plan



15.2 Recommendations

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

- Recommendations – General
- Recommendations – Capital Projects
- Recommendations – Other

15.2.1 Recommendations - General

The following general actions should be taken to ensure the timely implementation of the RIRP:

1. The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity.
2. The State should establish certain energy-related policies, including:
    - The pursuit of large hydroelectric facilities
    - DSM/EE program targets
    - RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal (which will become commercially mature during the 50-year planning horizon) projects in addition to large hydroelectric projects; the passage of an RPS would be meaningful as a policy statement even though the preferred resource plan would achieve a 50 percent renewable level by 2025.
    - System benefit charge to fund DSM/EE programs and or renewable projects
3. The State should work closely with the Railbelt utilities and other stakeholders to establish the specific preferred resource plan. In establishing the preferred resource plan, the economic results of the various reference cases and sensitivity cases evaluated in this study should be considered, as well as the environmental impacts discussed in Section 13 and the project-specific risks discussed in Section 14.
4. Black & Veatch believes that the Scenario 1A/1B resource plan should be the starting point for the selection of the preferred resource plan as discussed below. Table 15-1 provides a summary of the specific resources that were selected, based upon economics, in the Scenario 1A/1B resource plan during the first 10 years.

    A project selected in Scenario 1A/1B after the first 10 years especially worthy of mention is the Chakachamna Hydroelectric Project in 2025.

    Another important consideration in the selection of a preferred resource plan is evaluation of the sensitivity cases evaluated, as presented in Section 13. Issues addressed through the sensitivity cases and considered in Black & Veatch's selection of a preferred resource plan include the following and are discussed in Table 15-2. Following that discussion, Table 15-3 provides a discussion regarding specific projects currently under development and their impact on the preferred resource plan.
    - What if CO_2 regulation doesn't occur?
    - What is the effect if the committed units are installed?
    - What if Chakachamna doesn't get developed?
    - What would be the impact of the alternative Susitna projects?

    There are several projects that are significantly under development and included in the preferred resource plan. These significantly developed projects include:
    - Healy Clean Coal Project (HCCP)
    - Southcentral Power Project
    - Fire Island Wind Project
    - Nikiski Wind Project

    These projects are discussed in Table 15-3.

Table 15-1
Resources Selected in Scenario 1A/1B Resource Plan

Project	Discussion
DSM/EE Resources	The full level of DSM/EE resources evaluated was selected based upon their relative economics. Sensitivity analysis indicates that even greater levels of DSM/EE may be cost-effective. The lack of Alaska-specific DSM/EE data causes the exact level of cost-effective DSM/EE to remain uncertain.
Nikiski Wind	The RIRP selected this project in the initial year. It is being developed as an IPP project and is well along in the development process. The ARRA potentially offers significant financial incentives if this project is completed by January 1, 2013. These incentives could further improve its competitiveness. As a wind unit, it has no impact on planning reserves, but contributes to renewable generation.
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. This project was selected in the initial year of the plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the $25 million grant from the State for interconnection. This project was selected in 2012.
Anchorage 1x1 6FA Combined Cycle	The RIRP selected this unit for commercial operation in 2013. This unit is very similar in size and performance to the Southcentral Power Project being developed as a joint ownership project by Chugach and ML&P for 2013 commercial operation. The project appears well under development with the combustion turbines already under contract. The project fits well with the RIRP and the joint ownership at least partially reflects the GRETC joint development concept.
Glacier Fork Hydroelectric Project	The RIRP selected this project for commercial operation in 2014, the first year that it was available for commercial operation in the models. Of the large hydroelectric projects, Glacier Fork is by far the least developed. Glacier Fork has very limited storage and thus does not offer the system operating flexibility of the other large hydroelectric units. There is also significant uncertainty with respect to its capital cost and ability to be licensed. Because it has such a minimal level of firm generation in the winter, it does not contribute significantly to planning reserves, but does contribute about 6 percent of the renewable energy to the Railbelt. Detailed feasibility studies and licensing are required to advance this option.
Anchorage and GVEA MSW Units	The RIRP selected these units in 2015 and 2017. Historically, mass burn MSW units such as those modeled, have faced significant opposition due to emissions of mercury, dioxin, and other pollutants. Other technologies which result in lower emissions, such as plasma arc, are not commercially demonstrated. The units included in the RIRP are relatively small (26 MW in total) and are not required to be installed to meet planning reserve requirements, but their base load nature contributes nearly 4 percent of the renewable energy. Detailed feasibility studies would be required to advance this alternative.
GVEA North Pole Retrofit	The retrofitting of GVEA's North Pole combined cycle unit with a second train using a LM6000 combustion turbine and heat recovery steam generator was selected in 2018 coincident with the assumption of the availability of natural gas to GVEA. The retrofit takes advantage of capital and operating cost savings resulting from the existing installation.

Table 15-1 (Continued)
Resources Selected in Scenario 1A/1B Resource Plan

Project	Discussion
Mt. Spurr Geothermal Project	The first unit at Mt. Spurr was selected in 2020. Mt. Spurr's developer, Ormat, currently has commercial operation scheduled for 2017. Significant development activity remains for the project including verifying the geothermal resource. Mt. Spurr will also require significant infrastructure development including access roads and transmission lines. This infrastructure may correspond to similar infrastructure development required for Chakachamna which is selected in 2025 in the RIRP. As the implementation of the RIRP unfolds, there will likely be the need to adjust the timing of the resource additions following the implementation of the initial projects.

Table 15-2
Impact of Selected Issues on the Preferred Resource Plan

Issue	Discussion
CO_2 Regulation	The sensitivity case for Scenario 1A without CO_2 regulation selects the Anchorage LMS 100 project instead of Fire Island and Mt. Spurr in the first 10 years.
Committed Units	Installation of the committed units significantly increases the cost of Scenario 1A/1B. In addition to the committed units, this plan selects five wind units from 2016 through 2024 in response to CO_2 regulation. The plan with the committed units eliminates Chakachamna and does not meet the 50 percent renewable target by 2025.
Chakachamna	Chakachamna could fail to develop because of licensing or technical issues. Also, if the cost of Chakachamna were to increase to be equivalent to the alternative Susitna projects on a GWh basis, it would not be selected. The sensitivity case without Chakachamna for the first 10 years is identical to Scenario 1A/1B. The case does not meet the 50 percent renewable target by 2025 and is 5.2 percent higher in cost than the preferred resource plan.
Susitna	None of the alternative Susitna projects are selected in the Scenario 1A/1B resource plan. The least cost Susitna option, which is Low Watana Expansion, is 15.3 percent more than the preferred resource plan and 9.0 percent more than the case without Chakachamna. The 50 percent renewable requirement can not be met without Susitna if Chakachamna is not available.

Table 15-3
Projects Significantly Under Development

Project	Discussion	Preferred Resource Plan Recommendation
HCCP	HCCP is completed and GVEA has negotiated with AIDEA for its purchase. The project is part of the least cost scenario. While CO_2 regulation has been assumed in the RIRP, those regulations are not in place and there is no absolute assurance that they will be in place or what the costs from the regulations will be. HCCP adds further fuel diversity to the Railbelt, especially to GVEA who doesn't currently have access to natural gas. As a steam unit, HCCP improves transmission system stability.	Black & Veatch recommends that HCCP be included in the preferred resource plan.
Southcentral Power Project	The Southcentral Power Project is well under development with the combustion turbines purchased. The timing and technology are generally consistent with the preferred resource plan. The project will improve the efficiency of natural gas generation in the Railbelt and permit the retirement of aging units.	Black & Veatch recommends the continued development of the Southcentral Power Project as part of the preferred resource plan.
Fire Island Wind Project	The Fire Island Wind Project is being developed as an IPP project with proposed power purchase agreements provided to the Railbelt utilities. The project may be able to benefit significantly from ARRA and the $25 million grant from the State for interconnection. This project is part of the least cost plan and provides renewable energy to the Railbelt system. Issues with interconnection and regulation will need to be resolved.	Subject to the successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.
Nikiski Wind Project	The Nikiski Wind Project is an IPP project like Fire Island and has the same potential to benefit from ARRA. It is also part of the least cost plan.	Like Fire Island, subject to successful negotiation of a purchase power agreement and successful negotiation of the interconnection and regulation issues, Black & Veatch recommends that it be part of the preferred resource plan in a time frame that allows for the ARRA benefits to be captured.

In addition to these resources, Black & Veatch believes that Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of the projects could actually be built.

In the case of the Mt. Spurr Geothermal Project, exploration should continue to determine the extent and characteristics of the geothermal resource at the site.

In the case of Susitna, the primary focus should be on completing engineering studies to optimize the size and minimize the costs of the project. In the case of Glacier Fork and Chakachamna, the additional work should look for "fatal flaws".

Additionally, further analysis needs to be completed relative to integrating wind and other non-dispatchable renewable resources into the transmission network.

5. The State and Railbelt utilities should develop a public outreach program to inform the general public regarding the preferred resource plan, including the costs and benefits.
6. The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan.
7. The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues. Specific actions that should be taken include:
    - Development of local gas storage capabilities with open access among all market participants as soon as possible.
    - Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured either in the Cook Inlet, from the North Slope or from long-term LNG supplies.
    - The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options. Once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources.
    - Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins. This action is required to provide the necessary long-term contractual certainty to result in additional exploration and development.

15.2.2 Recommendations – Capital Projects

Efforts should be undertaken to begin the development, including detailed engineering and permitting activities, of the following capital projects, which are included in Black & Veatch's recommended preferred resource plan.

1. Develop a comprehensive region-wide portfolio of DSM/EE programs.
2. Generation projects:
    - Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project)

- Glacier Fork Hydroelectric Project
- Generic Anchorage MSW Project
- Generic GVEA MSW Project
- GVEA North Pole Retrofit Project
- Mt. Spurr Geothermal Project
- Chakachamna Hydroelectric Project
- Susitna Hydroelectric Project

3. Transmission and related substation projects, including the following projects which have been identified for priority attention because of their immediate impact on the reliability of the existing system. These projects are estimated to be required within the next five years.
   - Soldotna to Quartz Creek Transmission Line ($84 million – Project B)
   - Quartz Creek to University Transmission Line ($112.5 million – Project C)
   - Douglas to Teeland Transmission Line ($37.5 million – Project D)
   - Lake Lorraine to Douglas Transmission Line ($80 million – Project E)
   - SVCs ($25 million - Other Reliability Projects)
   - Funds to undertake the study of the Southern Intertie ($1 million)
   - Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50 million, including cost of BESS – Other Reliability Projects)

15.2.3 Recommendations - Other

Other actions, related to the implementation of the RIRP, that should be undertaken include:

1. The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts.
2. Develop a regional DSM/EE program measurement and evaluation protocol.
3. If GRETC is not formed, some type of a regional entity should be formed to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities.
4. Likewise, if GRETC is not formed, some type of a regional entity should be formed to develop the renewable resources included in the preferred resource plan.
5. Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs.
6. Aggressively pursue available Federal funding for DSM/EE programs and renewable projects.
7. Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to be economic within the planning horizon.
8. The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects, and conduct the necessary studies to address these issues and requirements.
9. Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable resources included in the preferred resource plan.

10. Develop streamlined siting and permitting processes for transmission projects.
11. Develop a regional frequency regulation strategy for non-dispatchable resources.
12. Develop a regional competitive power procurement process and a standard power purchase agreement to provide IPPs an equal opportunity to submit qualified proposals to develop specific projects.
13. Federal legislative and regulatory activities, including those related to emissions regulations, should be monitored closely and influenced to the degree possible.
14. Monitor the licensing progress of small modular nuclear units.

16.0 NEAR-TERM IMPLEMENTATION ACTION PLAN (2010-2012)

The purpose of this section is to provide Black & Veatch's recommended near-term implementation plan, covering the period from 2010 to 2012. Our recommended actions are grouped into the following categories:

- General actions
- Capital projects
- Supporting studies and activities
- Other actions

In many ways, the near-term implementation plan shown in the following tables serves two objectives. First, it identifies the steps that should be taken during the next three years regardless of the alternative resource plan that is chosen as the preferred resource plan. Second, it is intended to maintain flexibility as the uncertainties and risks associated with each alternative resource become more clear and or resolved.

16.1 General Actions

Table 16-1
Near-Term Implementation Action Plan – General Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
General Actions	• The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity	2010	$6.8 million
	• Establish State energy-related policies regarding: o The pursuit of large hydroelectric facilities o DSM/EE program targets o RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal projects o System benefit charge to fund DSM/EE programs and or renewable projects	2010-2011	$0.2 million
	• The State should work closely with the Railbelt utilities and other stakeholders to establish the preferred resource plan, using the Scenario 1A/1B resource plan as the starting point	2010	Not applicable
	• Mt. Spurr, Glacier Fork, Chakachamna and Susitna should be pursued further to the point that the uncertainties regarding the environmental, geotechnical and capital cost issues become adequately resolved to determine if any of these projects could actually be built	2010-2011	To be determined

Table 16-1 (Continued)
Near-Term Implementation Action Plan – General Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
	• Develop a public outreach program to inform the public regarding the preferred resource plan, including the costs and benefits	2010-2011	$0.1 million
	• The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan	2010-2011	Not applicable
	• The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues; specific actions that should be taken include: o Development of local gas storage capabilities as soon as possible o Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured o The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options; once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources o Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins	2010-2012	To be determined

16.2 Capital Projects

Table 16-2
Near-Term Implementation Action Plan – Capital Projects

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Capital Projects	• Develop a comprehensive region-wide portfolio of DSM/EE programs within first six years	2011-2016	$34 million
	• Begin detailed engineering and permitting activities associated with the generation projects identified in the initial years of the preferred resource plan, including: o Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project) o Glacier Fork Hydroelectric Project o Generic Anchorage MSW Project o Generic GVEA MSW Project o GVEA North Pole Retrofit Project o Mt. Spurr Geothermal Project o Chakachamna Hydroelectric Project o Susitna Hydroelectric Project	2011-2016	Varies by project
	• Begin detailed engineering and permitting activities associated with the transmission projects identified in the initial years of the preferred resource plan, including: o Soldotna to Quartz Creek Transmission Line ($84 million – Project B) o Quartz Creek to University Transmission Line ($112.5 million – Project C) o Douglas to Teeland Transmission Line ($37.5 million – Project D) o Lake Lorraine to Douglas Transmission Line ($80 million – Project E) o SVCs ($25 million - Other Reliability Projects) o Funds to undertake the study of the Southern Intertie ($1 million) o Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50 million, including cost of BESS – Other Reliability Projects)	2011-2016	Varies by project

16.3 Supporting Studies and Activities

Table 16-3
Near-Term Implementation Action Plan – Supporting Studies and Activities

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Supporting Studies and Activities	• The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts	2010-2011	$1.0 million
	• Develop a regional DSM/EE program measurement and evaluation protocol	2012	$0.1 million
	• The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects	2010-2011	$0.2 million
	• Conduct necessary studies to address resource agencies' issues and data requirements related to large hydroelectric and tidal projects	2011-2012	To be determined
	• Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable projects included in the preferred resource plan	2010-2012	$1.5 million
	• Develop a regional frequency regulation strategy for non-dispatchable resources	2011	$0.5 million
	• Develop a regional standard power purchase agreement for IPP-developed projects	2011-2012	$0.2 million
	• Develop a regional competitive power procurement process to encourage IPP development of projects included in the preferred resource plan	2011-2012	$0.2 million

16.4 Other Actions

Table 16-4
Near-Term Implementation Action Plan – Other Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Other Actions	• Form a regional entity (if GRETC is not formed) to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities	2010-2011	Subject to decision regarding formation of GRETC
	• Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs	2010-2011	$0.2 million
	• Aggressively pursue available Federal funding for DSM/EE programs	2010-2011	$0.2 million
	• Form a regional entity (if GRETC is not formed) and encourage IPPs to identify and develop renewable projects that are included in the preferred resource plan	2011-2012	Subject to decision regarding formation of GRETC
	• Further encourage the development of tidal power	Ongoing	To be determined
	• Monitor, and influence to the degree possible, Federal legislative and regulatory activities, including those related to emissions regulations	Ongoing	Not applicable
	• Aggressively pursue available Federal funding for renewable projects	2010-2012	$0.2 million
	• Develop streamlined siting and permitting processes for transmission projects	2010-2011	$0.5 million
	• Monitor the licensing progress of small modular nuclear units	Ongoing	Not applicable

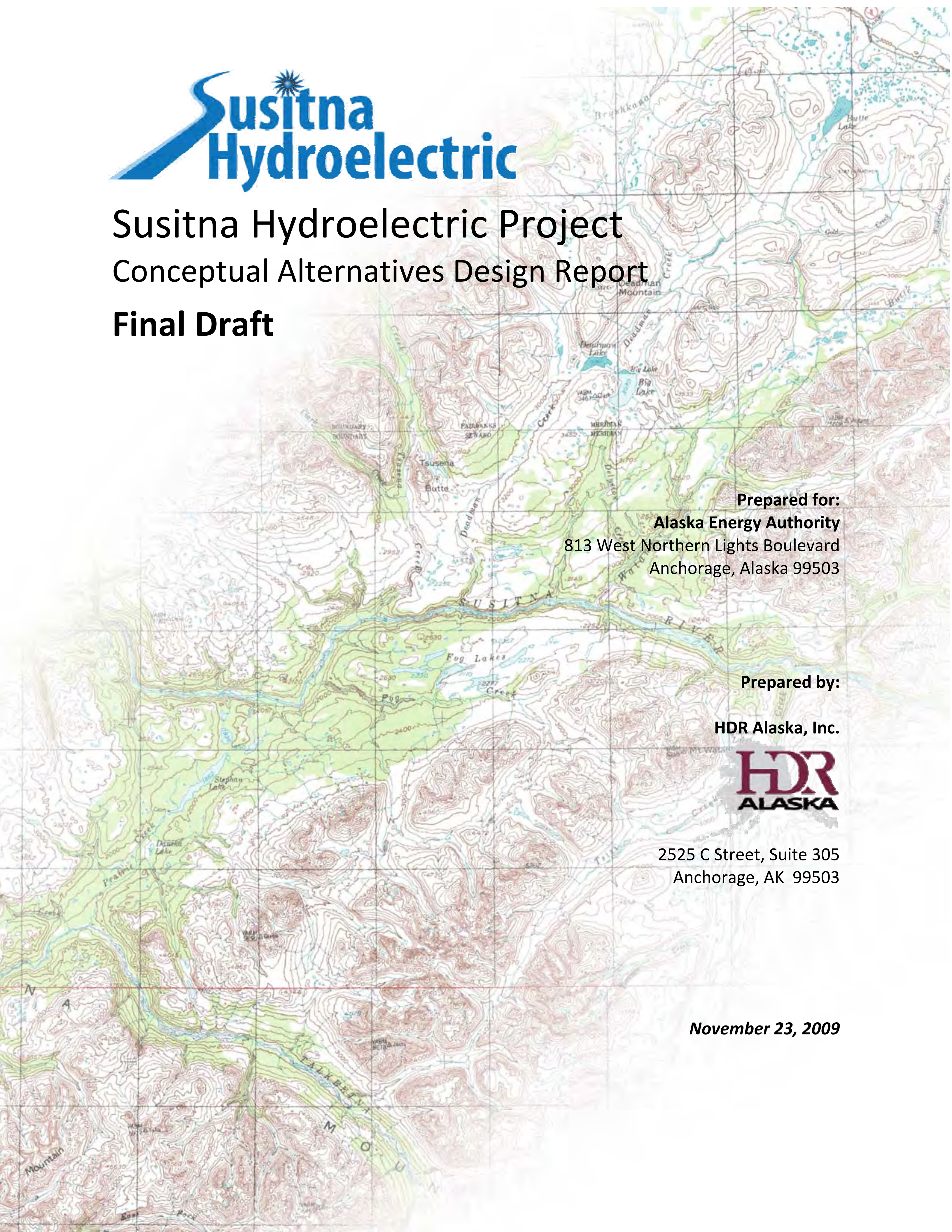
APPENDIX A

SUSITNA ANALYSIS

Susitna Hydroelectric Project

Conceptual Alternatives Design Report

Final Draft



Prepared for:
Alaska Energy Authority
813 West Northern Lights Boulevard
Anchorage, Alaska 99503

Prepared by:

HDR Alaska, Inc.

2525 C Street, Suite 305
Anchorage, AK 99503

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Contents

Tables

Figures

Appendices

1 Executive Summary

A hydroelectric project on the Susitna River has been studied for more than 50 years and is again being considered by the State of Alaska as a long term source of energy. In the 1980s, the project was studied extensively by the Alaska Power Authority (APA) and a license application was submitted to the Federal Energy Regulatory Commission (FERC). Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986.

In 2008, the Alaska State Legislature authorized the Alaska Energy Authority (AEA) to perform an update of the project. That authorization also included a Railbelt Integrated Resource Plan (RIRP) to evaluate the ability of this project and other sources of energy to meet the long term energy demand for the Railbelt region of Alaska. Renewable hydroelectric power is of particular interest to the railbelt because of its potential to provide stable power costs for the region. Of all the renewable resources in the railbelt region, the Susitna projects are the most advanced and best understood.

HDR was contracted by AEA to update the cost estimate, energy estimates and the project development schedule for a Susitna River hydroelectric project. This report summarizes the results of that study. The initial alternatives reviewed were based upon the 1983 FERC license application and subsequent 1985 amendment which presented several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 megawatts (MW).
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.
- **Devil Canyon.** This alternative consists of the construction of a 646-foot-high concrete dam at the Devil Canyon site with a four-unit powerhouse with a total installed capacity of 680 MW.
- **Watana/Devil Canyon.** This alternative consists of the full-height Watana development and the Devil Canyon development as presented in the 1983 FERC license application. The two dams and powerhouses would be constructed sequentially without delays. The combined Watana/Devil Canyon development would have a total installed capacity of 1,880 MW.
- **Staged Watana/Devil Canyon.** This alternative consists of the Watana development constructed in stages and the Devil Canyon development as presented in the 1985 FERC amendment. In stage one the Watana dam would be constructed to the lower height and the Watana powerhouse would only have 4 out of the 6 turbine generators installed, but would be constructed to the full sized powerhouse. In stage two the Devil Canyon dam and powerhouse would be constructed. In stage three the Watana dam would be raised to

its full height, the existing turbines upgraded for the higher head, and the remaining 2 units installed. At completion, the project would have a total installed capacity of 1,880 MW.

As the RIRP process defined the future railbelt power requirement it became evident that lower cost hydroelectric project alternatives, that were a closer fit to the energy needs of the railbelt, should be sought. As such, the following single dam configurations were also evaluated:

- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing 4 turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative consists of the Watana dam constructed to a height of 650 feet along with a powerhouse containing 3 turbines with a total installed capacity of 390 MW. This alternative has no provisions for future expansion.
- **High Devil Canyon.** This alternative consists of a roller-compacted concrete (RCC) dam constructed to a height of 810 feet, along with a powerhouse containing 4 turbines with a total installed capacity of 800 MW.
- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing 6 turbines with a total installed capacity of 1,200 megawatts (MW).

The results of this study are summarized in Table 1.

Table 1 - Susitna Summary

Alternative	Dam Type	Dam Height (feet)	Ultimate Capacity (MW)	Firm Capacity, 98% (MW)	Construction Cost ($ Billion)	Energy (GWh/yr)	Schedule (years from start of licensing)
Lower Low Watana	Rockfill	650	390	170	$4.1	2,100	13-14
Low Watana Non-expandable	Rockfill	700	600	245	$4.5	2,600	14-15
Low Watana Expandable	Rockfill	700	600	245	$4.9	2,600	14-15
Watana	Rockfill	885	1,200	380	$6.4	3,600	15-16
Watana RCC	RCC	885	1,200	380	$6.6	3,600	15-16
Devil Canyon	Concrete Arch	646	680	75	$3.6	2,700	14-15
High Devil Canyon	RCC	810	800	345	$5.4	3,900	13-14
Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$9.6	7,200	15-20
Staged Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$10.0	7,200	15-24

In all cases, the ability to store water increases the firm capacity over the winter. Projects developed with dams in series allow the water to be used twice. However, because of their locations on the Susitna River, not all projects can be combined. The Devil Canyon site precludes development of the High Devil Canyon site but works well with Watana. The High Devil Canyon site precludes development of Watana but could potentially be paired with other sites located further upstream.

Development of any of the alternatives for the Susitna River will require careful consideration of many factors. Environmental issues, climate change and sedimentation are discussed in this report and the risk associated with these issues is considered manageable. An updated evaluation of seismicity has been done by others and this risk is also considered manageable.

Hydroelectric power has many economic and environmental benefits including long-term rate stabilization. Because the cost of the water (fuel) is essentially free and maintenance costs are minimal, the cost per kilowatt hour is driven largely by the project finance terms and is not subject to fluctuations in fuel cost.

2 Background

The Susitna River has its headwaters in the mountains of the Alaska Range about 90 miles south of Fairbanks. It flows generally southwards for 317 miles before discharging into Cook Inlet just west of Anchorage. Contained entirely within the south central Railbelt region, the Susitna River is situated between the two largest Alaska population centers of Anchorage and Fairbanks.

The Bureau of Reclamation first studied the Susitna River's hydroelectric potential in the early 1950s, with a subsequent review by Corps of Engineers in the 1970s. In 1980, the Alaska Power Authority (APA; now the Alaska Energy Authority) commissioned a comprehensive analysis to determine whether hydroelectric development on the Susitna River was viable. Based on those studies, the APA submitted a license application to the Federal Energy Regulatory Commission (FERC) in 1983 for the Watana/Devil Canyon project on the Susitna River. The license application was amended in 1985 for the construction of the Staged Watana/Devil Canyon project at an estimated cost of $5.4 billion (1985 dollars).

Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986.

At that point, the State of Alaska had appropriated approximately $227 million to the project from FY79-FY86, of which the project had expended $145 million to fund extensive field work, biological studies, and activities to support the FERC license application. Though the APA concluded that project impacts were manageable, the license application was withdrawn and the project data and reports were archived to be available for reconsideration sometime in the future.

In 2008, the Alaska State Legislature, in the FY 2009 capital budget, authorized the AEA to reevaluate the Susitna Hydro Project as it was conceived in 1985. The authorization also included funding a Railbelt Integrated Resource Plan (RIRP) to evaluate various sources of electrical power to satisfy the long term energy needs for the Railbelt portion of Alaska. A Susitna River hydroelectric project could play a significant role in meeting these needs.

2.1 Project Scope

The scope of this study was to collect and review pertinent information from the original studies and license application from the 1980's and re-estimate the project energy, costs and development schedule.

The initial 1982 FERC license application and subsequent 1985 amendment analyzed several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 megawatts (MW).
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.

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As the RIRP process defined the future railbelt power requirement it became evident that lower cost hydroelectric project alternatives, that were a closer fit to the energy needs of the railbelt, should be sought. As such, the following single dam configurations were also evaluated:

- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing 4 turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
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- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing 6 turbines with a total installed capacity of 1,200 megawatts (MW).

Preliminary energy, cost, and schedule estimates for the analyzed alternatives are described in the following sections.

3 Preliminary Energy Estimate

3.1 Hydrologic Analysis

At the time the original study was issued in 1983 the hydrologic record contained data from 1950 to 1981. To develop an updated energy estimate for the Susitna hydroelectric project alternatives, a synthesized hydroelectric record for each site was created by a drainage area proration of daily flow data from United States Geological Survey (USGS) gage 1529000 at

Gold Creek. USGS gage 1529000 has a period of record from water year 1950-1996 and 2002-2008.

The hydrology of the upper Susitna Basin is dominated by melt water from snow and glaciers in the spring and summer, and substantial freezing during the winter months. As a result, a majority of the flow occurs between mid-April and mid-October. The following figure shows the average monthly flow at the Watana dam site for each year of record.

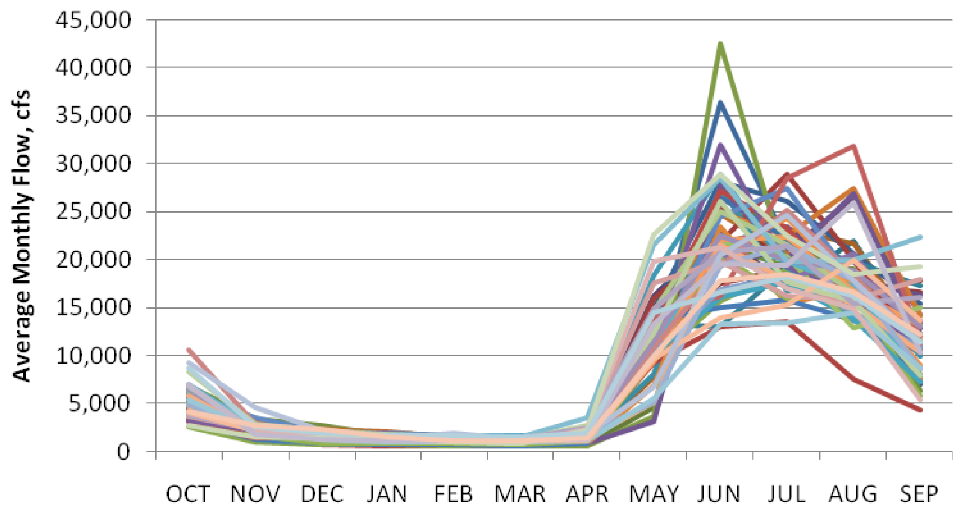

Figure 1 - Susitna River at Watana Hydrologic Variation

The manner in which precipitation and runoff might be affected by the impacts of either natural variability and/or potential climate change is discussed at the end of this report.

3.2 Evaluation of Firm Winter Capacities and Average Annual Energy

The amount of energy that can be produced from hydroelectric projects is a function of the amount of available water and in the case of storage projects, how the available water can be regulated (systematically released). For the RIRP evaluation process, in addition to the average annual energy, the firm capacity attainable during winter months is of particular importance. For hydroelectric projects, the firm capacity is almost always lower than the installed generation capacity for a project. For the purposes of this study work, firm capacity is defined as:

> "The amount of power the project can generate on a continuous basis from Nov. 1 through April 30 with 100% reliability".

The firm capacity is always driven by low periods in the hydrologic cycle. Since the hydrologic cycle varies, it is also desired to know at what level of reliability the project can generate at levels higher than the firm capacity. It should be noted that this is only one manner of regulation. The water can be regulated in a variety of different means in order to achieve other objectives, such as peaking, spinning reserve or backup capacity.

For this study, the average annual energy and winter plant capacities for the alternatives were estimated using a HDR proprietary energy modeling software tool customized for this particular purpose (Computer Hydro-Electric Operations and Planning Software or (CHEOPS)). Major assumptions used in the modeling efforts are presented below.

3.3 Model Assumptions and Data Sources

- Inflow hydrology was based upon USGS gage #1529000 located at Gold Creek on the Susitna River and scaled by a drainage area correction factor representing each of the dam sites.
- Reservoir capacity and area curves for the Watana and Devil Canyon alternatives were based on information presented in the 1985 FERC application. For the High Devil Canyon project this data was derived from USGS topographical data.
- Tailwater curves for the Watana and Devil Canyon projects were obtained from the 1985 FERC application and estimated for High Devil Canyon.
- Operating reservoir levels were obtained from the 1985 FERC application for the Watana, Low Watana and Devil Canyon projects, from the 1982 Acres feasibility study for the High Devil Canyon project, and estimated for the Lower Low Watana project.
- Environmental flow release constraints were as presented in the 1985 FERC application and scaled according to drainage areas for the various sites.
- Evaporation coefficients were obtained from the 1985 FERC application. Total reservoir evaporation was estimated in the 1985 FERC application to be between one (1) and three (3) inches per month in summer, with negligible evaporation during winter months.
- Equipment performance was based on vendor data obtained in 2008 specifically for the Watana and Devil Canyon projects and was assumed to be representative for the other projects.
- Headloss estimates were based on the water conveyance design from the 1985 FERC application for the Watana and Devil Canyon alternatives and the 1982 Acres feasibility study for the High Devil Canyon alternative.
- The reservoir was assumed to start full at the beginning of the simulation and was allowed to fluctuate over the remaining period of the simulation.
- Generation from Nov. 1 to April 30, “winter,” was at a constant capacity level (“block loaded”).
- Generation from May 1 to Oct. 31, “summer,” was to maximize energy with the objective of the reservoir being full on Nov. 1.
- Rule curves for summer target reservoir elevations were developed for each alternative using a mass balance approach. The ratio of the average monthly inflow volume to the average annual inflow volume during each of the reservoir filling months were used to set target elevations for the reservoir.
- Energy losses of 1.5 percent for un-scheduled outages and 2 percent for transformer losses were applied to the total generation.
- Active storage remained constant over the simulation period. Dead storage in the reservoirs was assumed to be sufficient to contain sedimentation loads.

- No ramping rate restrictions were imposed on either reservoir drawdown or downstream flow.

To determine the firm capacity for the combined Watana and Devil Canyon projects, the regulated flow from Watana was assumed to pass unregulated through Devil Canyon with the Devil Canyon pool at maximum operating level.

Key input parameters related to energy generation are shown in Table 2 below.

Table 2 - Summary of Susitna Project Alternatives

	Lower Low Watana	**Low Watana (Both Alternatives)**	**Watana (Both Alternatives)**	**Devil Canyon**	**High Devil Canyon**
Dam Type	Rockfill	Rockfill	Rockfill or RCC	Concrete Arch	RCC
Dam Height (ft)	650	700	885	646	810
Gross Head (ft)	495	557	734	605	729
Net Head (Max Flow) (ft)	481	543	729	598	707
Maximum Plant Flow (cfs)	10,700	14,500	22,300	14,000	14,800
Number of Units	3	4	6	4	4
Nameplate Capacity (MW)	390	600	1200	680	800
Maximum Pool Elevation (ft)	1951	2014	2193	1456	1751
Minimum Pool Elevation (ft)	1850	1850	2065	1405	1605
Tailwater Elevation (Max Flow) (ft)	1456	1457	1459	851	1022
Usable Storage (acre-ft)	1,536,200	2,704,800	3,888,50	310,000	2,254,700

3.4 Model Operation

For each alternative, 54 years of daily inflow data was used to determine each alternative's ability to meet a range of winter energy production targets and maximize summer generation. For each day from November through April the flow through the powerhouse was limited to the amount necessary to satisfy a prescribed capacity demand given the available head, environmental flow constraints, and reservoir operational restrictions. During the months of May through September energy production each day was maximized if the reservoir elevation was above the target rule curve. If the reservoir elevation was below the target rule curve then generation was limited to the amount that would allow the downstream environmental flow constraints to be met. The simulation was repeated at various increasing winter load demands until the maximum firm capacity was determined.

To better quantify the effect of storage and extreme low water years on the firm winter capacity, winter load levels in excess of the firm capacity were also evaluated. The results of this analysis are expressed as a capacity at a given percent exceedance level. For example, a project might have a firm capacity of 250 MW at a 100% exceedance level and a firm capacity of 300 MW at a 98% exceedance level. This would mean that the project could provide 250 MW 100% of the time in the winter over the simulation period or 300 MW 98% of the time over the winter. The large change in firm capacity between the 100% exceedance level and the 98% exceedance level for all alternatives is primarily due to a single low water year in 1970.

The resulting firm capacities and average annual energy production estimates are presented in Figure 2 and partially summarized in Table 3. Detailed input assumptions and results of these energy analyses are provided in Appendix A of this report. The average annual energy production was relatively constant over the range of winter power demand levels that were modeled.

Table 3 - Firm Capacity and Energy Estimates

Alternative	Firm Winter Capacity (MW)	98% Winter Capacity (MW)	Average Annual Energy Production (GWh)
Lower Low Watana	100	170	2,100
Low Watana (both alternatives) *	150	245	2,600
Watana (both alternatives) **	250	380	3,600
Watana/Devil Canyon ***	470	710	7,200
Devil Canyon	50	75	2,700
High Devil Canyon	250	345	3,900

* Low Watana Expandable and Low Watana Non-Expandable have the same energy characteristics.
** Watana Rockfill and Watana RCC have the same energy characteristics.
*** Watana/Devil Canyon and the Staged Watana/Devil Canyon have similar energy characteristics.

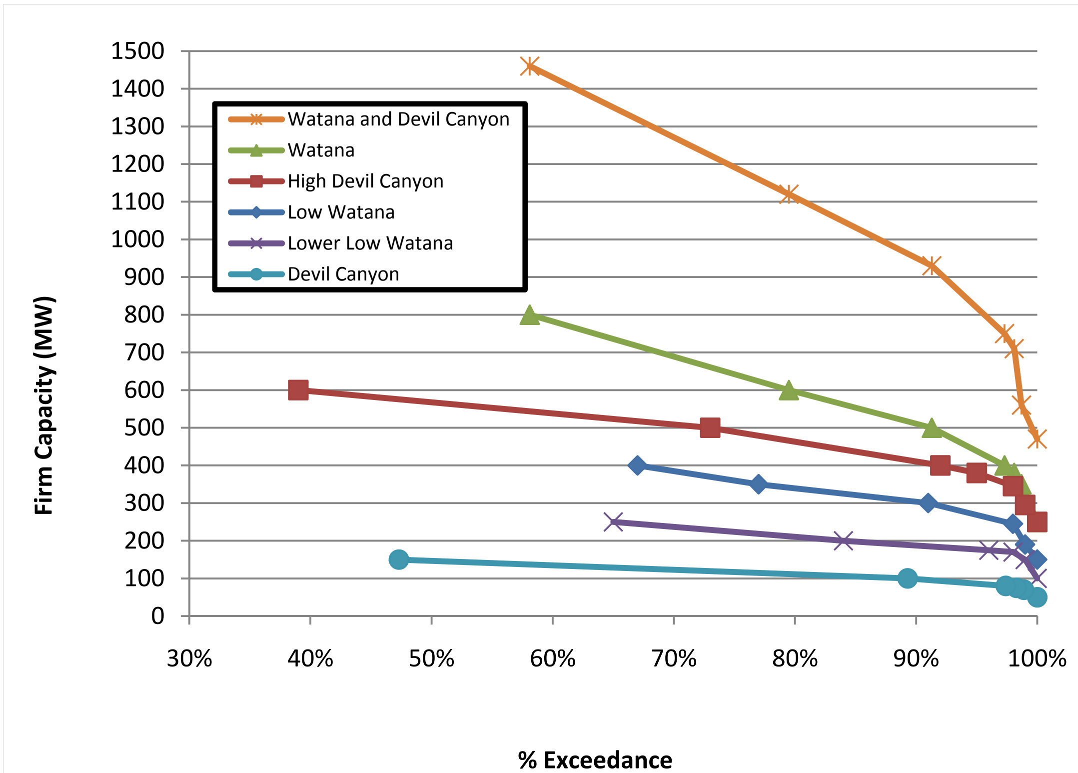

Figure 2 - Firm Capacity

4 Estimates of Probable Project Development Costs

4.1 Original Cost Estimate

In 1982 the cost for developing the complete full Watana/Devil Canyon project was estimated to be $5.0 billion (1982 dollars). In 1985 the cost for developing the staged Watana/Devil Canyon project was $5.4 billion (1985 dollars).

The Devil Canyon and High Devil Canyon alternatives were as envisioned in the 1980's. The four rockfill Watana Dam configurations considered in this evaluation are depicted in Figure 3 below.

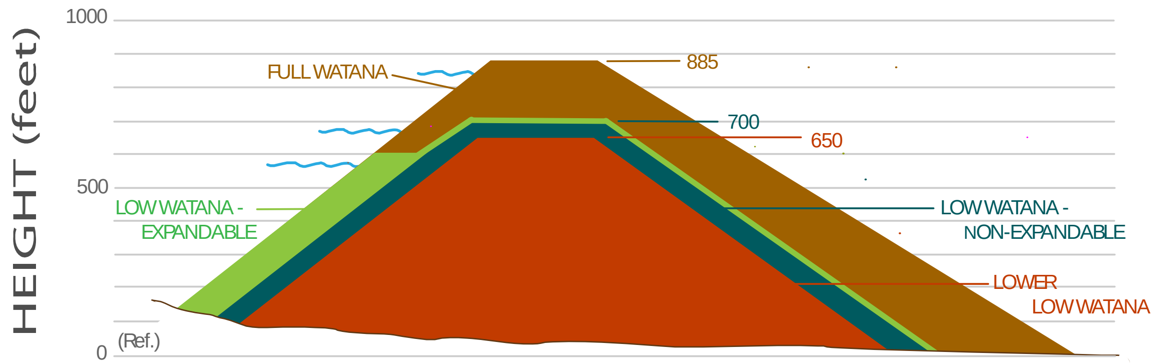

Figure 3 - Watana Dam Configurations

The estimates for the Watana, Low Watana-Expandable, Devil Canyon and Staged Watana-Devil Canyon alternatives were developed in depth in a March 2009 Interim report and were revised to reflect changes primarily in transmission, access and camp costs. Using this information as a base, new estimates were made for the development costs of the Low Watana Non-Expandable and of the Lower Low Watana alternatives. Cost estimates of $5.4 billion for the High Devil Canyon RCC and $6.6 billion for the Watana RCC alternatives were provided by a separate contractor using similar assumptions and are presented here for completeness of information. The following discussion details the basis for the cost estimates for the Watana embankment projects, the assumptions that were used in creating those estimates, and provides a summary of the projected construction costs.

4.2 Expandability

The Low Watana alternative, as proposed in previous studies, included provisions for eventual expansion of the dam from 700 feet to a height of approximately 885 feet and an increase in powerhouse capacity from 800 MW to 1200 MW. The most notable of these provisions are the design of the dam cross section and construction of the powerhouse and water conduits to their ultimate capacity. The two non-expandable alternatives contain no provisions for future expansion.

For the Low Watana Expandable alternative the dam cross-section is expanded on the upstream side to provide the opportunity to later raise the dam. This results in additional fill material due to the wider base. The powerhouse, powerhouse equipment, and water conveyance scheme would be built to house six units, but only four turbines would be initially installed.

For the Low Watana Non-expandable alternative the cross-section is narrower and does not accommodate expansion of the dam at a later time. Similarly the powerhouse and water conduit features are sized for only four turbine/generator units instead of six.

4.3 Quantities

Quantities for the construction cost estimates were based upon detailed estimates developed as part of the 1982 Acres feasibility study for the full sized Watana project and the Devil Canyon project. To estimate the quantities of the smaller Watana alternatives, the full sized Watana quantities were scaled based on the size of the development. As part of a separate report, quantities were developed for the High Devil Canyon alternative based upon a new conceptual design using RCC construction.

Table 4 summarizes the embankment fill volumes that were used for the cost estimates. The dam heights and fill volumes of the Watana and Low Watana Expandable configurations were adopted directly from the 1985 FERC application. The embankment volumes for the Lower Low Watana and Low Watana Non-Expandable alternatives were estimated assuming a 2:1 side slope on the downstream portion of the dam and a 2.4:1 side slope on the upstream portion of the dam as were assumed for the other alternatives. Volume changes were limited to the rock-fill and riprap portion of the dam only. The concrete volumes for the Devil Canyon, Watana RCC, and High Devil Canyon alternatives are shown for comparison.

Table 4 - Estimated Total Fill Volumes

Alternative	Type	Total Fill Volume(cy)
Watana	Rockfill	61,000,000
Low Watana Expandable	Rockfill	32,000,000
Low Watana Non-Expandable	Rockfill	22,000,000
Lower Low Watana	Rockfill	17,000,000
Devil Canyon	Concrete Arch	1,300,000
Watana*	RCC	15,000,000
High Devil Canyon*	RCC	11,600,000

* R&M, 2009.

The quantity estimates for the water conduit layouts and powerhouses for all alternatives were based on the 1985 layout as opposed to the 1983 layout. The 1983 arrangement used a separate penstock for each unit with a very long conveyance scheme. The 1985 arrangement employed a headrace for every two units bifurcating into dedicated penstocks. The total length of conveyance was less than half that of the 1983 design. To maintain consistency with the energy model, and to further refine the cost estimates, the 1985 configuration was used for this study.

Table 5 summarizes the design features that were assumed in each estimate. The powerhouse and water conveyance systems for Watana and the Low Watana Expandable alternatives were designed to service six units as contemplated in 1983. However, the water conduit layout reflects the 1985 arrangement with three headraces bifurcated into six penstocks and discharged into two tailraces. Low Watana Non-Expandable was assumed to be built to accommodate a four-unit powerhouse with two headraces, four penstocks and a single tailrace. Lower Low Watana was designed for a three-unit powerhouse with one headrace, three penstocks, and one tailrace. The diameters of the water conduits were sized to be consistent with the 1985 design. The powerhouse structures were also scaled accordingly.

Table 5 - Watana Water Conduit and Powerhouse Size Parameters

Item	Lower Low Watana	Low Watana Non-Exandable	Low Watana Expandable	Watana
Number of Units	3	4	4	6
Unit Size (MW)	130	150	150	200
Plant Nameplate Capacity (MW)	390	600	600	1200
# of Headraces	1	2	3	3
Headrace Diameter (ft)	24	24	24	24
# of Penstocks	3	4	6	6
Concrete Lined Penstock Diameter (ft)	18	18	18	18
Steel Penstock Diameter (ft)	15	15	15	15
# of Tailrace Tunnels	1	1	2	2
Tailrace Diameter (ft)	34	34	34	34

4.4 Unit Costs

U.S. Cost, a company specializing in creating cost estimates for large capital infrastructure projects, developed unit prices for the materials detailed in the 1982 estimate in 2008 dollars. This cost data was used to develop the estimates presented in the Interim Report and the same pricing was used in this study. Lump sum items were inflated using a construction cost index.

For the water-to-wire turbine-generator equipment estimates, budget pricing for the Watana alternative was requested directly from manufacturers. The water-to-wire equipment includes turbines, generators, turbine shutoff valves, and other miscellaneous mechanical and electrical equipment, including installation costs. The equipment costs for other smaller alternatives were developed by scaling the Watana vendor quotes on a per kilowatt basis.

4.5 Indirect Costs

A contingency of 20 percent was added to the direct construction costs to reflect level of design and uncertainty in the project.

Project licensing, environmental studies and engineering design were estimated at 7 percent of direct construction costs. Construction management was estimated at 4 percent of the direct construction costs, and has been included as a separate line item.

4.6 Interest During Construction and Financing Costs

Costs associated with interest during construction and project financing are not included in the estimates.

4.7 Changes from 1983 Design

The camps, access roads and transmission, infrastructure assumptions used in the 1983 configuration have been modified as discussed below.

4.7.1 Camps

Reductions were made in the scale of the permanent and construction camps needed to accommodate the workers. These changes were made based on the fact that permanent town facilities were no longer necessary due to advances in remote project operation. It was also assumed that due to modern construction methods, the number of construction personnel could be reduced. It was assumed that 750 people would need to be housed for the Lower Low Watana arrangement, 825 people for Low Watana and 900 people for Watana. In 1983 it was originally assumed that housing would be provided for 3000 people plus families. Budget pricing for the construction camp was provided by vendors.

4.7.2 Access

For all the Watana alternatives, access is assumed to be via the Denali Highway from the north as shown in Figure 4. The route would include the upgrade of 21 miles of the Denali Highway to a construction grade road and the construction of approximately 40 miles of new road to the Watana site. The price per mile of new road has been assumed at $3M/mile which is the current budgetary estimate of the Alaska Department of Transportation and Public Facilities for the road to Bettles and Umiat from the Dalton Highway which is similar in nature to the road that would be required for a Susitna project. Upgrading of the Denali Highway has been assumed to be $1M/mile and local site roads have been estimated at $750k/mile.

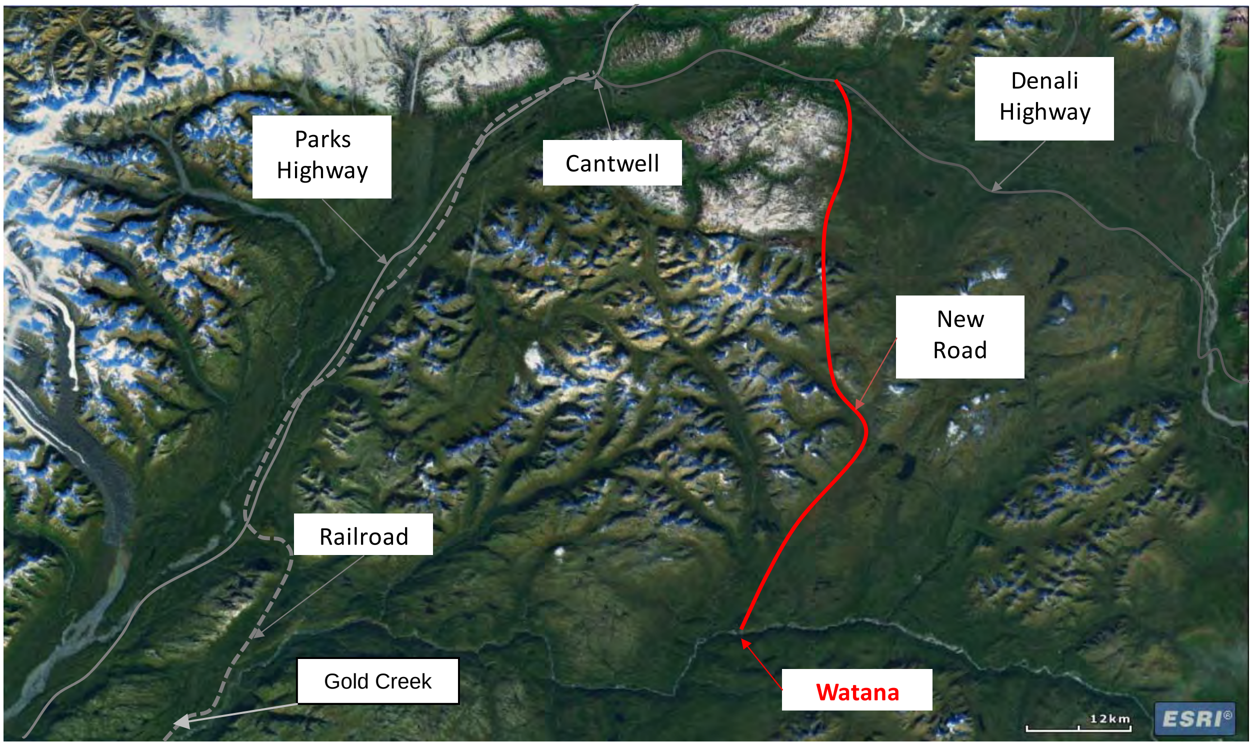

Figure 4 - Proposed Access Route

For the Devil Canyon and High Devil Canyon alternatives, rail access was assumed and will originate on the Parks Hwy near MP 156 and proceed upstream on the south side of the river.

4.7.3 Transmission

A separate study (EPS, 2009) has investigated the transmission lines and interconnection requirements for the entire Alaska railbelt region as part of the RIRP process and the results are incorporated here at the direction of the AEA. This study estimates that a transmission line from the project site to the substation at Gold Creek would cost approximately $4.5M/mile. Substation costs are estimated at $16M per location. No costs have been assumed to increase or modify the regional transmission grid beyond the Gold Creek substation.

4.8 Conclusions

The approach, methodology and assumptions previously described resulted in the estimated project costs detailed below in the summary table.

Table 6 - Alternate Project Configuration Cost Summary Table ($Millions)

FERC Line #	Line Item Name	Lower Low Watana	Low Watana Non-Expandable	Low Watana Expandable	Watana	Watana RCC*	Devil Canyon	High Devil Canyon*	Watana/ Devil Canyon	Staged Watana/ Devil Canyon
71A	Engineering, Env., and Regulatory (7%)	$ 213	$ 236	$ 259	$ 338	$342	$191	$281	$501	$528
330	Land and Land Rights	$ 121	$ 121	$ 121	$ 121	$121	$52	$121	$173	$173
331	Power Plant Structure Improvements	$ 93	$ 115	$ 159	$ 159	$159	$165	$159	$324	$325
332.1-.4	Reservoir, Dams and Tunnels	$ 1,415	$ 1,538	$ 1,718	$ 2,424	$2,307	$900	$1,803	$3,324	$3,485
332.5-.9	Waterways	$ 590	$ 590	$ 677	$ 677	$558	$415	$552	$1,093	$1,191
333	Waterwheels, Turbines and Generators	$ 213	$ 297	$ 297	$ 475	$487	$295	$487	$770	$834
334	Accessory Electrical Equipment	$ 29	$ 41	$ 41	$ 72	$57	$38	$57	$110	$119
335	Misc Power Plant Equipment	$ 17	$ 21	$ 32	$ 32	$32	$29	$32	$61	$61
336	Roads, Rails and Air Facilities	$ 232	$ 232	$ 232	$ 280	$584	$535	$490	$388	$394
350-390	Transmission Features	$ 177	$ 224	$ 224	$ 353	$322	$99	$119	$481	$481
399	Other Tangible Property	$ 12	$ 16	$ 16	$ 20	$12	$16	$12	$36	$42
63	Main Construction Camp	$ 150	$ 180	$ 180	$ 210	$244	$180	$189	$390	$440
71B	Construction Management, 4%	$ 122	$ 135	$ 148	$ 193	$195	$109	$161	$286	$302
Total Subtotal		$ 3,384	$ 3,746	$ 4,104	$ 5,354	$5,420	$3,024	$4,463	$7,937	$8,375
Total Contingency		$ 676	$ 749	$ 821	$ 1,071	$1,155	$605	$954	$1,587	$1,675
Total (Millions of Dollars, rounded)		$ 4,100	$ 4,500	$ 4,900	$6,400	$6,600	$3,600	$5,400	$9,600	$10,000

* R&M (2009)

5 Project Development Schedule

Updated schedules were developed for each of the project alternatives. These schedules extend from approval, through licensing, design, construction, and commissioning. The primary purpose of these schedules is to provide timelines for cash flow and estimated energy revenue to determine economic feasibility. These schedules assume that:

- Construction times are based on 1983 FERC license application.
- The licensing process from start to FERC order is estimated at 7 to 10 or more years. We have set a reasonable target of 8 years for the proposed project analysis, provided that the effort is begun immediately, ambitiously, fully funded, and conducted in parallel with environmental studies, engineering, and with active public outreach and cooperation by stakeholders.
- The FERC License Application will be based on the 1985 application, updated to reflect more than 20 years of regulatory changes and changes in engineering and construction methods.
- Any new environmental studies will be based on data acquired during the studies in the 1980's, updated to reflect present site conditions, public interests, wildlife, and recreational needs.
- Construction will begin immediately upon issuance of the license.
- Roads and staging will be state permitted outside the FERC project and will begin several years before FERC license, including pioneer and permanent roads, airports, bridges, construction camps and staging areas. Building facilities in advance of the project license is the most effective way to trim the projected timeline although there is some uncertainty whether permits could be obtained to construct these facilities before the project license is issued. The schedule for each of the project alternatives would be extended by one to two years if this assumption is not valid.
- Construction of diversion dams and tunnels will begin on issuance of the license, with upstream and downstream coffer dams and tunnels to divert the Susitna River during construction of main dams at Watana/Devil Canyon.
- Spillway construction will follow diversion dam and tunnel construction, and will include site preparation, approach channels, control structures, gates, stoplogs, chute, and flip buckets for main and emergency spillways.
- Dam construction at Watana will follow site preparation, grouting, and installation of a pressure relief system.
- The main dam construction at Devil Canyon will include a thin-arch concrete dam, preceded by site preparation, foundations, abutments, and thrust blocks. Rock-fill saddle dam construction will follow grouting and pressure relief system.
- The powerhouse and transmission will include power intake, tunnels/penstock, surge chamber, tailrace, powerhouse, turbine/generators, mechanical/electrical systems, switchyard, control buildings, and transmission lines.

- Reservoir filling will be based on the latest hydrologic data for inflow and turbine data for outflow.
- Devil Canyon construction will commence immediately upon completion of Watana for the Watana/Devil Canyon alternative.

Table 7 - Power Generation Time Estimates

Alternative	Generation of first power (years)*	Generation of full power (years)*
Lower Low Watana	13	14
Low Watana (both alternatives)	14	15
Watana (both alternatives)	15	16
Devil Canyon	14	15
High Devil Canyon	13	14
Watana/Devil Canyon	15	20
Staged Watana/Devil Canyon	15	24

*From start of licensing

6 Project Development Issues

Development of a hydroelectric project on the Susitna River would face a variety of issues over their design lifetime. The design lifetime for a modern dam is greater than 100 years. The following discussion is not intended to be all inclusive but rather highlight the likely major areas of concern.

6.1 Engineering

The projects being contemplated for the Susitna River would be on the larger end of the scale in the world in terms of size of the dams. Projects of this size have not been undertaken in the United States for many decades. As such, a major engineering effort will be required.

6.2 Siltation

Rivers, by nature, transport the products of erosion to the oceans. Dams interrupt this flow of material. Given time the effective amount of storage in the reservoir behind the dam can diminish. The alternatives investigated here have been designed with dead storage to accommodate bedload and it is not expected that siltation will have any detrimental affect on the energy projected energy production of any of the projects during their design lifetime.

6.3 Seismicity

Seismic (earthquake) events have the potential to effect hydroelectric projects. The main areas of concern are damage from ground shaking, opening of faults along the dam axis, landslides and settlement, and the creation of large waves in the reservoir. The previous studies on seismicity have concluded that these concerns can be designed for and therefore do not pose a significant threat. New analytic methods are now available to evaluate more complex seismic situations and these evaluations, along with the most stringent safety factors would be incorporated into a modern project design (R&M, 2009).

6.4 Climate Change

There has been much discussion about climate change and what the effects of climate change will be on river flows. Analyses of the potential affects of climate change on the Susitna River are included in Appendix D. The annual runoff from the Susitna River basin shows remarkable balance during very disparate climate regimes. The analyses support the consistent supply of water from the basin precipitation to support hydro-power generation regardless of the climate fluctuations. While global climate models suggests additional warming may impact the Arctic and Alaska, it seems very unlikely that these impacts will cause an unbalance in the runoff production of the basin.

Based on this, there is no conclusive evidence to suggest that runoff will be statistically different in the next 50 years from what it has been in the last 50 years.

6.5 Environmental Issues

After the Susitna project was discontinued in 1986 a database of 3,573 documents was created. In September 2008, the 87 most-relevant documents were scanned into HDR’s files, of which 18 of the most relevant environmental documents were summarized. A synthesis of the 7 most-pertinent documents was completed. Because not all of the documents were summarized, some relevant information has likely been overlooked; however, most information was included in the synthesis.

These documents contain information on potential impacts of the proposed project and mitigation proposals for those impacts. Specifically, the documents deal with fisheries resources, botanical resources, wildlife resources, and cultural resources in the potential project area. The documents divide the Susitna River Basin into 4 geographic regions:

- Impoundment zones
- Middle Susitna River
- Lower Susitna River
- Access roads and transmission lines

The potential impacts and mitigation options are discussed for each category in each geographic region as much as possible. It is important to note that not all categories will be impacted in all geographic regions. Mitigation for the proposed impacts is divided into the following categories: avoidance, minimization, rectification, reduction, and compensation. Avoidance is always the preferred mitigation, though it is not usually feasible. Compensation is the only mitigation option for many of the impacts.

6.5.1 Fisheries Impacts

The fisheries resources have the highest potential to be impacted by the project. Most of the potential impacts will occur in the middle Susitna River. There will be impacts due to changes in water quality, thermal activity, the water's suspended sediment load, reservoir draw-down fluctuations, impoundment zone inundation, flow regime, and lost fish habitat. Not all impacts to fish populations will be negative. For example, the increase in winter water temperatures could lead to the creation of more overwintering habitat and thus greater fish survival; however, the cooler spring water temperatures will slow fish growth.

In the Watana impoundment zone, 51 river miles will be inundated and transformed into reservoir habitat. An additional 27 miles of tributary streams and 31 lakes will be inundated.

In the Devil Canyon impoundment zone 31 miles of the main river channel will be inundated and an additional 6 miles of tributary streams will be impacted.

Mitigation for these impacts was proposed by compensation through land acquisition, habitat modification, and reservoir stocking.

6.5.2 Botanical Impacts

The project area contains 295 vascular plant species, 11 lichen genera, and 7 moss taxa. Low Watana inundation will permanently remove 16,000 acres of vegetation. Devil Canyon inundation will permanently remove 6,000 acres of vegetation. Watana inundation will permanently remove an additional 16,000 acres of vegetation. There will be a total of 38,000 acres of vegetation permanently removed. Most of the vegetation inundated will be spruce forest. An additional 836 acres of vegetation will be permanently removed due to access road construction. In the transmission corridor affect on vegetation will be minimal due to intermittent placement of control stations, relay buildings, and towers.

There will be limited botanical impacts downstream from the reservoir(s). These involve changes to the vegetation due to a more stable environment. Due to flow regulation there will no longer be major flooding events, which destroy the riparian vegetation; instead; rather, there will be succession of the riparian vegetation and colonization of new floodplains. The increase in winter water temperatures will decrease the amount of ice scouring that occurs, which will result in effects similar to those caused by the decrease in flooding.

Botanical resource mitigation will consist largely of compensation for permanently removed vegetation.

6.5.3 Wildlife Impacts

Within the Susitna River Basin there are 135 bird species, 16 small-mammal species, and 18 large-mammal and furbearing species. There are currently no known listed endangered species in the project area. There will be 5 classes of potential impacts to terrestrial vertebrates:

Permanent habitat loss, including flooding of habitat and covering with gravel pads or roads.

Temporary habitat loss and habitat alteration resulting from reclaimed and revegetated areas such as borrow pits, temporary right of ways, transmission corridors, and from alteration of climate and hydrology.

Barriers, impediments, and hazards to movement.

Disturbances associated with project construction and operation.

Consequences of increased human access not directly related to project activities.

Mitigation for the proposed impacts involve mostly compensation since there will be permanent habitat loss for most species.

6.5.4 Cultural Resource Impacts

Within the proposed project area, 297 historic and prehistoric archaeological sites were located. An additional 22 sites were already on file. Sites located within 500 feet of the reservoir’s maximum extent may be indirectly impacted due to slumping from shoreline erosion. Indirect impacts may also result from vandalism due to increase in access to the sites. The project has the potential to impact 140 sites. None of these sites will occur in the proposed road corridor or transmission lines. The majority of these sites are relatively small prehistoric sites.

Mitigation for the lost cultural resources will mostly occur through data recovery. Preservation would also be used for some sites. Options to consider include construction of protective barriers to minimize erosion, controlled burial, or fencing of the site to restrict access.

Currently, there are a variety of federal, state, and local land use plans that encompass the Susitna Basin.

6.5.5 Carbon Emissions

According to the United Nations working group on carbon emissions from freshwater reservoirs the worst case carbon emissions from a reservoir in a boreal climate is 6.7 grams per square meter per year (United Nations, 2009). For the Watana/Devil Canyon alternative this equates to

465,000 metric tons of carbon per year or 0.065 metric tons per MWhr. The US Department of Energy reports the average carbon emissions due to electric generation for the State of Alaska to be 0.626[1] metric tons per MWhr. Operation of the Susitna project has the potential to eliminate up to 4 million metric tons of carbon production per year.

[1] http://www.eia.doe.gov/cneaf/electricity/st_profiles/alaska.html

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Appendix A:
Energy Analysis Input and Results

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix B:
Detailed Cost Estimates

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix C:
Detailed Schedules

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix D:
Climate Change Analyses

For the purposes of this submittal, the appendices have been attached as PDFs.

APPENDIX B

FINANCIAL ANALYSIS

Regional Integrated Resource Plan

Financial Analysis Summary Report

SNW

1420 Fifth Avenue, Suite 4300
Seattle, Washington
98101

Phone: (206) 628-2882

Fax: (206) 343-2103

2/3/2010

Introduction

The Regional Integrated Resource Plan (RIRP) is a 50-year, long-range plan tasked with identifying the optimal combination of generation and transmission capital improvement projects in the Railbelt region of Alaska. The objectives of the financial analysis portion of the plan are threefold:

1. Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities, given their current financial condition and assuming that each utility will borrow on its own, rather than utilizing a joint-powers structure or receiving assistance from the State of Alaska.
2. Analyze strategies to capitalize selected RIRP assets by integrating State and federal financing resources with debt capital market resources. Specifically, we look at ways to utilize State funding to:
   - mitigate construction risk,
   - lower capital cost prior to placing assets in service, and
   - extend the debt repayment term beyond terms available in the debt capital markets.
3. Develop a spreadsheet-based model that utilizes inputs from the RIRP model, including total capital requirements, demand-side management (DSM), fuel cost, CO_2 cost, and operation and maintenance cost (O&M), and overlays realistic debt capital funding to provide a total cost to ratepayers of the optimal resource plan.

Railbelt Utility Capital Capacity

The non-profit organizational structure of generation and transmission (G&T) and distribution cooperatives makes it difficult for these entities to produce operating margins and build equity to the levels needed to access the public debt markets. Rate setting is designed to recover operating cost with moderate margins, and any capital in excess of minimal reserves is returned to coop members. Nevertheless, some coops, including Chugach Electric, are able to maintain coverage margins sufficient to secure investment grade credit ratings and utilize the debt capital market to fund asset expansion. Likewise, municipal governments face a similar rate-setting challenge in the form of political pressure to keep rates at levels just sufficient to cover operations and maintain net plant and equipment. In the following sections, we take a look at several key financial measures of coop and municipally owned utilities and utilize these measures to estimate the remaining debt capacity of each of the Railbelt utilities.

To develop the framework for this analysis, we retrieved the publicly available financial reports from each utility's website and the annual filings from the Regulatory Commission of Alaska's website. Using these reports, we summarized each of the utilities' current outstanding debt obligations, company equity, total assets and total plant. We used these figures to derive several important financial ratios, discussed in detail below, that are used by the investment community as well as the nationally recognized rating agencies (Moody's, Standard & Poor's, and Fitch) to determine the ability of each organization to manage its current and/or future debt obligations. It's important to point out that, while no single financial ratio by itself is an accurate determinant of a utility's ability to incur additional debt for capital projects, an analysis of a sampling of several ratios in conjunction with other non-financial metrics (*e.g.*, demand growth, rate-setting authority, political climate, etc.) helps to create some guidelines for how much debt could reasonably be considered and issued in the capital markets.

Debt to Equity Ratio. The debt to equity ratio (or debt as a percentage of total capitalization) is derived by dividing a utility's total debt by its net capital. The rating agencies have developed median debt to equity ratios for each of the different types of utility organizational structures. For example, a G&T cooperative can expect to have a higher debt ratio percentage than a retail power distributer due to the need to finance large and relatively expensive generation and transmission assets. A summary of these utility medians for debt to equity is provided in the following table:

2008 Median Debt to Capitalization % By Utility System Type	
G&T Coop	82%
Municipal Wholesale	93%
Retail Self Generating	60%
Retail Power Purchaser (Distribution)	40%
Source: Fitch U.S. Public Power Peer Study, June 2009	

The table below calculates the remaining debt capacity for each of the Railbelt utilities under varying debt to equity ratios to derive a total debt capacity amount given existing equity capitalization. Debt to equity capitalization for this analysis ranges from 40% to 80%.

Railbelt Utility Additional Debt Capacity Based on Current Debt to Equity Ratios					
	Existing Debt as of 12/31/2008[1]	40%	60%	70%	80%
ML&P	$159,405,791	-	$175,744,945	$362,920,220	730,502,349
Chugach	354,383,506	-	-	9,355,443	260,137,205
MEA	89,128,488	-	48,090,737	129,409,217	277,237,086
HEA	148,257,837	-	-	-	99,152,015
GVEA	301,670,508	-	-	-	131,081,336
Seward	2	2	2	2	2
		-	$223,835,682	$501,684,880	$1,498,109,991

(1) 2008 Annual reports and 12/31/2008 Annual Reports to the Regulatory Commission of Alaska
(2) The City of Seward was not included in this analysis due to lack of information regarding their Electric Enterprise Fund

Our analysis found that the debt-to-capitalization ratio for each of the utilities is close to or higher than the median ratio for its organizational type. There does appear to be some additional bonding capacity available for each of the utilities under a G&T cooperative-type structure when compared to the Fitch median ratio of 82%. However, given the utilities' existing debt burdens and current conditions in the financial markets, which have made it more difficult for lower rated power utilities to access capital, it is not clear that the six utilities could support debt capitalization much above 70%. Fitch Ratings specifically mentions that higher debt capitalization percentages can result in negative ratings pressure going forward[1]. At approximately 70%

[1] Fitch Ratings, U.S. Public Power Peer Study, June 2009

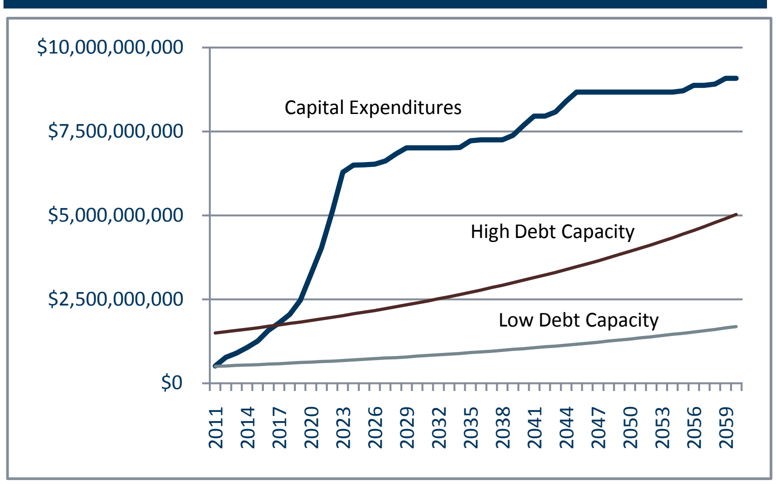
debt capitalization, the six utilities together could support between $500 and $700 million of additional debt. At 80%, available additional debt capacity for the six utilities combined increases to approximately $1.5 billion. This analysis does not include the City of Seward's capacity. Given its Electric Enterprise Fund asset base of $26 million (as of 2007), the overall borrowing capacity number would not change by a significant amount if the City of Seward were included.

Debt to Funds Available for Debt Service. An important measure of operating leverage is the Debt to Funds Available for Debt Service ratio (Debt/FADS). This ratio measures a utility's ability to handle its current fixed debt burden based on annual operating cash flow. A lower Debt/FADS ratio indicates either a low overall debt burden or a high operating cash flow, with the opposite being true for a higher Debt/FADS ratio. In the "A" rating category and higher, all but one G&T wholesale system rated by Fitch Ratings had a Debt/FADS ratio higher than 8.8 in 2008. For comparison purposes, the average (and median) Debt/FADS ratio for the Railbelt utilities in 2008 was approximately 8.4, with the highest being 13.66. The operating leverage of the six utilities would increase dramatically as capital spending and debt burden increase. An increase in the operating leverage ratio would cause ratings pressure for utilities maintaining a public credit rating and increased scrutiny by creditors including commercial banks and cooperative banks such as CFC or CoBank.

RIRP Capital Requirements Relative to Railbelt Utility Debt Capacity**.** The preceding debt to equity and Debt/FADS discussions do not take into consideration several additional factors that are relevant to the collective debt capacity of the Railbelt utilities. These factors can impact debt capacity both positively and negatively and include amortization of existing utility debt, the level of new debt required to maintain distribution infrastructure, and potential rate increases.

While these factors are influential, they do not have sufficient positive impact to alter our opinion that the utilities individually do not have the capital capacity to fund the projects recommended by the RIRP. The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or coop to independently secure debt financing without committing substantial amounts of equity or cash reserves. Specifically, these individual projects would include any that require large capital investment and have any of the following characteristics: exceptionally long construction period, significant construction risk, or significant technological risk. These types of risk are associated with equity rates of return and are rarely, if ever, borne by fixed income investors.

Black & Veatch Plan 1A Capital Expenditures (Cumulative Total)



The graphic to the right helps to put into context the scope of required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent our view of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

***Railbelt Utility Debt Capacity Conclusions*.** The REGA study completed in 2008 concluded that the most cost effective approach to funding necessary Railbelt generation and transmission assets was to form a regional G&T. While SNW was not asked to validate this conclusion, we are of the opinion that a regional entity such as GRETC, with "all outputs" contracts migrating over time to "all requirements" contracts, will have greater access to capital than the combined capital capacity of the individual utilities. To be clear, our conclusion should not be interpreted to mean that a regional G&T agency would be able to execute the RIRP capital plan independent of any State or federal assistance; however, a regional G&T agency will have lower-cost access to debt capital than the utilities would have on their own. This is primarily due to two factors: (1) a regional G&T entity will eliminate the rate pressure/competition that naturally exists under the current Railbelt construct of each of the 6 utilities independently providing generation and transmission services to their customers, and (2) a regional G&T entity executing a utility-approved comprehensive RIRP plan with strong power purchase agreements will be better positioned with the rating agencies and private investors.

Strategies to Lower Capital Cost of RIRP to Ratepayers

As previously noted, the scope of the RIRP is significant. The complexity of the overall capital plan and the size and construction duration of various projects within the plan will necessitate some amount of "equity" capital from ratepayers and/or the State of Alaska. Furthermore, equity capital, in the form of a ratepayer benefits charge or State financial assistance through either loans or grants, is the most efficient source of funding available to GRETC for the RIRP. Capital accruing from the State in the form of grants or from existing ratepayers in any form needs to be balanced with long-term debt capital so that future rate payers who will benefit from the RIRP assets share the cost of funding these assets. The following sections discuss various sources of equity capital funding and methods for involving the State in the execution of the RIRP.

Ratepayer Benefits Charge. A ratepayer benefits charge is a charge levied on all ratepayers within the Railbelt system that will be used to cash fund and thereby defer borrowing for infrastructure capital. A rate surcharge that is implemented prior to construction allows for partial "pay-go" funding of capital projects and reduces the overall cost of the projects by reducing the amount of interest paid for funding in the capital markets. For example, the potential interest cost savings that could be realized if GRETC were to fund some portion of a $2 billion project through rates rather than entirely upfront through bond proceeds are shown in the table below:

$2 billion project		
Rate Surcharge Through Construction	Funded With Bonds	Interest Cost Reduction (1)
$500 million	$1.5 billion	$1.2 billion
$1.0 billion	$1.0 billion	$2.4 billion

(1) Assumes 30-year debt to fund construction at 7.00% interest.

"Pay-Go" vs. Borrowing for Capital. A "pay-go" capital financing program is one in which ongoing capital projects are paid for from remaining revenue after maintenance and operations (M&O) expenses, and debt service are paid for. As will be discussed in further detail later, we have assumed that any bonds sold in the capital markets will require generation of a 1.25 times debt service coverage ratio. Covenanted coverage would likely be lower than 1.25 times. The cash generated in excess of M&O expense and debt service expense ("coverage") will be used to fund reasonable reserves with the balance going towards ongoing capital projects. For example, in years where debt service on outstanding bond issues is the highest, the 1.25 times debt service coverage ratio creates additional reserves in the amount of nearly $130 million above what is required to pay operating expense and debt service.

There is a tradeoff between the benefits derived from a pay-go financing structure versus one for which all projects are bonded. The benefit to ratepayers and GRETC in the pay-go structure is that it minimizes the total cost of the projects through the reduction of interest costs. On the other hand, the benefit of borrowing for a portion of capital needs is that expenses are spread out over time, and the cost of the debt can be structured to more closely match the useful life of the assets being financed. This is particularly important for some of the larger hydro-electric projects, where the useful life would likely exceed 50 years; these projects have large upfront costs that would be cost-prohibitive if funded entirely through rates. A balance of these two funding approaches appears to be most effective in lowering the overall cost of the project as well as spreading out the costs over a longer period of time.

Construction Work In Progress. Construction Work In Progress (CWIP) is a rate methodology that allows for the recovery of interest expense on project construction expenditures through the rate base during construction, rather than capitalizing the interest until the projects are completed and operating. This concept is important: the overall cost of the projects is significantly reduced through the immediate payment of interest on construction borrowing, versus the alternative of borrowing an additional sum just to pay for the interest while the project is still under construction. The benefit to ratepayers of the CWIP concept is that it significantly lowers both the overall cost of the project as well as the future revenue requirements needed to pay debt service. The use of CWIP in Alaska will most likely need to be vetted and approved by the Regulatory Commission of Alaska.

Both CWIP and pay-as-you-go funding rely on ratepayers to advance dollars for capital projects and thereby convey some project risk to ratepayers. If for example, a generation project were not completed for any reason ratepayers would have paid for a portion of the project even though the asset never produced power. SNW believes that ratepayers in a typical municipal utility structure generally incur this risk regardless of rate setting policies or methodologies. The ability to shift project risk to creditors is both limited and expensive and may not be appropriate for the "System" envisioned by GRETC. Under an Investor Owned Utility (IOU) structure, shareholders are responsible for bearing some of this risk, however shifting risk to shareholders requires higher equity rates of return to those investors. GRETC is not presently contemplated to be structured as an IOU.

State Financial Assistance. State financial assistance could take a variety of forms, but for the purpose of this report, we will focus on State assistance structured similarly to the Bradley Lake project. State financial assistance offers GRETC a number of advantages not available through traditional utility enterprise bond funding or project finance. Similar to a ratepayer benefits charge, State funding, whether in the form of a grant or loan, can be utilized to defer higher cost conventional revenue bond funding. Obviously a grant from the State provides the cheapest form of capital to GRETC, but even when structured as a loan, State assistance can dramatically lower GRETC's overall cost of capital. State funding in the form of a loan has three significant advantages when compared to revenue bonds or a loan from a commercial lender. The advantages of State funding include:

1. *Repayment flexibility.* State funding can be utilized to extend debt repayment beyond the term maturities available in the public or commercial debt capital markets. Additionally, a State loan can easily be restructured or deferred to achieve system rate objectives.
2. *Credit support/risk mitigation.* State funding can be used to mitigate project construction risk. This is particularly relevant for projects with extended construction timelines, such as large hydro-electric projects. Risk mitigation is also relevant in situations where permitting is an issue or a new technology is being used. Generally, fixed income investors will not accept significant construction and permitting risks inherent with the large-scale projects included in the RIRP without some form of support from the State.
3. *Potential interest cost benefit.* State funding can provide a lower cost source of capital. The State's high investment grade credit rating allows it to borrow for less than even the most secure utility enterprise. Assumptions as to the form of State assistance in the financial model are discussed in greater detail below; however, the terms of any loan, agreement, or grant between the State and GRETC will need to be further researched and developed in the next stage of the GRETC formation process.

RIRP Financial Model Summary Results

The development of the RIRP financial model took into account several different goals and objectives. The first goal was to identify ways to overcome the funding challenges inherent with large scale projects, including the length of construction time before the project is online and access to the capital markets. A second goal was to develop strategies that could be used to meet an objective of the RIRP of producing equitable rates over the useful life of the assets being financed. Structures commonly used in the current capital markets would not meet this goal, as certain of the assets required to be financed have longer useful lives than the longest term capital markets transaction could bear. With these challenges in mind, we developed separate versions of the model that would capture the cost of financing under a "*base case*" scenario and an "*alternative*" scenario, both of which are described in greater detail below.

Major Assumptions (Black &Veatch Inputs)**.** The input assumptions for the RIRP financial model were developed around outputs from the Black & Veatch PROMOD/Strategist modeling analysis. The results created a detailed list of the capital costs for the projects chosen over the 50-year RIRP time horizon. The results show both generation unit costs as well as required transmission development costs associated with the selected projects. Other assumptions used from the Black & Veatch PROMOD analysis include associated fuel costs, fixed and variable O&M, CO_2 charges, and forecasted energy load requirements by year, including DSM energy use reductions.

Major Assumptions (Financing Model Inputs). The assumptions used for capital markets transactions within the financing model are all market-accepted structures for an investment grade utility, cooperative, or joint action agency. Below is a summary of the major structuring assumptions used for both financing scenarios:

- 30-year debt repayment on all bond issues sold in the capital markets
- 7.00% interest rate on all bond issues sold in the capital markets
- Rate generated debt service coverage of 1.25X
- All energy generation developed is used or sold
- Debt Service Reserve Fund (DSRF) for each bond issue funded at 10% of bond issue par amount. The DSRF balance is maintained throughout the 50-year RIRP and earns 3.00% interest, which is used to pay debt service on an annual basis.

Base Case Model: Specific Assumptions. The *base case* financing model was structured such that the list of generation and transmission projects would be financed through the capital markets in advance of construction and that the cost of the financing in the form of debt service on the bonds would immediately be passed through to rate payers (see "Construction Work in Progress" herein). Bond issues are assumed to be sold prior to the required project funding dates, and staggered in approximately three-year intervals over the first 20-years, when the majority of the large capital projects and transmission projects are scheduled. The projects being financed over the balance of the 50-year RIRP period are financed through cash flow created through normal rates and charges ("pay-go"). The pay-go approach works once debt service coverage from previous years has grown to levels that create cash reserve balance amounts sufficient to pay for the projects as their construction costs come due.

The sources of funds for the projects included in the RIRP under the base case model are as follows:

RIRP Plan 1A : Base Case Sources of Funds (dollars in millions)	
Bonds	$5,889
State Funds	$0
Infrastructure Tax	$0
Pay-Go	$3,196

The *base case* model assumes that approximately $5.9 billion of bonds are sold over the RIRP time horizon through five different bond sales ranging in size from $656 million to $2.5 billion. The <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.13 per kWh, while the <u>average</u> fixed charge rate over the 50-years is $0.07 per kWh.

Alternative Model: Specific Assumptions. The *alternative* model was developed with the goal of minimizing the rate shock that may otherwise occur with such a large capital plan, and levelizing the rate over time so that the economic burden derived from these projects can be spread more equitably over the useful life of the projects being contemplated. Similar to the *base case* scenario, the first method used was to transfer the excess operating cash flow that is generated to create the debt service coverage level, and use that balance to both partially fund the capital projects in the early years and almost fully fund the projects in the later years. The second method used was the implementation of a Capital Benefits Surcharge that is applied to rate payers starting the day GRETC is formed. For this analysis, it was assumed that a $0.01 rate surcharge would be in place for the first 17 years, during which time approximately 75% of the capital projects in the plan will have been constructed. The third method used to spread out the costs over a longer time period was the use of the State as an equity participant in the execution of the RIRP capital funding plan. In a financing structure that is similar to the Bradley Lake financing model, the State would provide the upfront funding for any large hydroelectric projects, to be paid back by GRETC out of system revenues over an extended period of time, and following the repayment of the potentially more expensive capital markets debt. This analysis assumes that a $2.4 billion hydroelectric project is financed through a zero interest loan to GRETC that is then paid back through a 30-year capital markets take-out bond issue in 2047.

The sources of funds for the projects included in the RIRP under the alternative case model are as follows:

RIRP Plan 1A : Alternative Case Sources of Funds (dollars in millions)	
Bonds	$3,657
State Funds	$2,409
Benefit Surcharge	$883
Pay-Go	$2,135

The *alternative* model assumes that $5.9 billion of bonds are sold over the RIRP time horizon through nine different bond sales ranging in size from $32 million to $2.4 billion, which includes the $2.4 billion take-out financing to repay the State for front-funding of hydroelectric assets. The capital costs not bonded for come from the rate surcharge that is applied from day one and cash flow generated from rates and charges after operations and debt service (pay-go capital). The <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.08 per kWh, while the <u>average</u> fixed charge rate over the initial 50-year period is $0.06 per kWh, not including the $0.01 consumer benefit surcharge that is in place for the first 17 years. While the average fixed cost is not significantly different between the *base case* and *alternative* scenarios, the difference between the two maximum rates are significant. The lower maximum rate in the alternative scenario benefits the rate payers by smoothing out the rates over a period of time that more closely matches the useful life of the RIRP assets.

Summary, Next Steps, Conclusion. The RIRP presents a number of funding challenges, given the size and scope of the projects being contemplated. It has become evident through the financial modeling and the individual debt capacity analyses of this process that the utilities on their own would not be able to accomplish such an ambitious capital plan. The formation of a regional entity, such as GRETC, that would combine the existing resources and rate-base of the Railbelt utilities, as well provide an organized front in working to obtain private financing and the necessary levels of State assistance would be, in our opinion, a necessary next step towards achieving the goal of reliable energy for the Railbelt now and in the future.

Alaska Regional Integrated Resource Plan
Scenario Cash Flow Summary
dollars in millions

RIRP PLAN 1A	
Base Case	
100% Fixed Rate	
Sources of Funds	
BONDS	5,889
STATE (through construction)	0
Infrastructure Tax through 2027	0
Other (use of coverage reserves)	3,196
Total Source of Funds	9,085
Use of Funds	
Project/Construction	9,085
Payment of interest accrued	0
Reserve Funds	0
Issuance Costs	0
Capitalized Interest (through construction)	0
Total Uses of Funds	9,085
Maximum Annual Debt Service Requirements	
BONDS	539
STATE	0
Ave. Annual Energy Requirement (GWhr)	5,625
Target Debt Service Coverage (DSC)	1.25X
All-in Borrowing Cost	7.00%
Escalation Factor (Inflation)	2.50%
Average Cost of Energy ($/per kWh)	0.07

Assumptions

Issuance Cost = 2% of Par Amount
Par coupons
Debt service reserve funded at 10% of Bond Par Amount
Bonds all assumed to be 30 years from date of issue

	Year	Hydro Capital Requirements	Other Unit Cost Capital Requirements	Transmission Requirements	Total Capital Requirements	STATE Funding	Use of coverage balance for capital projects	Capital Markets - BONDS
1	12/1/2011	1	506,496,362	-	506,496,363	-		$ 886,736,593
2	12/1/2012	-	256,773,239	-	256,773,239	-	-	-
3	12/1/2013	-	119,476,707	3,990,284	123,466,991	-	-	-
4	12/1/2014	-	122,463,625	52,942,550	175,406,175	-	(25,000,000)	$ 656,306,880
5	12/1/2015	-	2,435,356	191,310,564	193,745,920	-	-	-
6	12/1/2016	33,699,203	22,466,161	255,989,420	312,154,784	-	-	-
7	12/1/2017	26,865,753	74,229,623	117,965,769	219,061,145	-	(105,000,000)	$ 795,887,676
8	12/1/2018	43,273,053	174,256,113	41,630,847	259,160,013	-	-	-
9	12/1/2019	79,301,147	174,171,476	169,193,895	422,666,518	-	-	-
10	12/1/2020	238,340,271	208,891,416	321,882,411	769,114,097	-	(190,000,000)	$ 2,454,911,924
11	12/1/2021	481,536,897	21,500,060	282,636,456	785,673,412	-	-	-
12	12/1/2022	652,793,164	-	437,331,250	1,090,124,414	-	-	-
13	12/1/2023	712,137,997	-	464,423,300	1,176,561,297	-	(320,000,000)	$ 1,095,198,536
14	12/1/2024	141,426,155	-	59,937,820	201,363,975	-	-	-
15	12/1/2025	-	-	18,210,430	18,210,430	-	-	-
16	12/1/2026	-	-	19,062,834	19,062,834	-	-	-
17	12/1/2027	-	88,657,273	-	88,657,273	-	(485,500,231)	$ -
18	12/1/2028	-	208,125,424	-	208,125,424	-	-	-
19	12/1/2029	-	188,717,535	-	188,717,535	-	-	-
20	12/1/2030	-	-		-	-	-	-
21	12/1/2031	-	-		-	-	-	-
22	12/1/2032	-	-		-	-	-	-
23	12/1/2033	-	-		-	-	-	-
24	12/1/2034	-	2,260,136		2,260,136	-	(239,531,757)	$ -
25	12/1/2035	-	206,133,124		206,133,124	-	-	-
26	12/1/2036	-	31,138,497		31,138,497	-	-	-
27	12/1/2037	-	-		-	-	-	-
28	12/1/2038	-	-		-	-	-	-
29	12/1/2039	-	127,791,596		127,791,596	-	(699,805,525)	$ -
30	12/1/2040	-	299,994,339		299,994,339	-	-	-
31	12/1/2041	-	272,019,589		272,019,589	-	-	-
32	12/1/2042	-	-		-	-	-	-
33	12/1/2043	-	131,612,221		131,612,221	-	(720,727,822)	$ -
34	12/1/2044	-	308,963,361		308,963,361	-	-	-
35	12/1/2045	-	280,152,241		280,152,241	-	-	-
36	12/1/2046	-	-		-	-	-	-
37	12/1/2047	-	-		-	-	-	-
38	12/1/2048	-	-		-	-	-	-
39	12/1/2049	-	-		-	-	-	-
40	12/1/2050	-	-		-	-	-	-
41	12/1/2051	-	-		-	-	-	-
42	12/1/2052	-	-		-	-	-	-
43	12/1/2053	-	-		-	-	-	-
44	12/1/2054	-	-		-	-	(410,069,419)	$ -
45	12/1/2055	-	35,525,625		35,525,625	-	-	-
46	12/1/2056	-	161,918,291		161,918,291	-	-	-
47	12/1/2057	-	-		-	-	-	-
48	12/1/2058	-	38,257,213		38,257,213	-	-	-
49	12/1/2059	-	174,368,290		174,368,290	-	-	-
50	12/1/2060	-	-			-		-

	Year	Repayment of State funds	GRETC Direct Debt Service - paid to bondholders	DSRF Interest Earnings	Total Requirements	Energy per Year (GWhr)	Surcharge for seed capital	Fixed Rate Charge for Capital	DSM	Fuel Rate	O&M Rate (Fixed + Variable)	CO^2	Incremental Cost (¢ per kWh)
1	12/1/2011	$ -	$ 35,268,100	$ -	$ 35,268,100	5,372	-	0.01	0.000	0.048	0.013	0.000	**0.07**
2	12/1/2012		81,206,200	2,660,210	78,545,990	5,412	-	0.02	0.000	0.051	0.013	0.010	**0.09**
3	12/1/2013		81,204,300	2,660,210	78,544,090	5,424	-	0.02	0.001	0.048	0.014	0.011	**0.09**
4	12/1/2014		107,308,425	2,660,210	104,648,215	5,421	-	0.02	0.001	0.053	0.014	0.012	**0.10**
5	12/1/2015		141,306,550	4,629,130	136,677,420	5,167	-	0.03	0.002	0.067	0.013	0.012	**0.13**
6	12/1/2016		141,309,000	4,629,130	136,679,870	5,147	-	0.03	0.002	0.070	0.014	0.013	**0.13**
7	12/1/2017		172,958,250	4,629,130	168,329,120	5,129	-	0.04	0.002	0.066	0.014	0.014	**0.14**
8	12/1/2018		214,187,950	7,016,793	207,171,157	5,105	-	0.05	0.002	0.042	0.013	0.015	**0.12**
9	12/1/2019		214,190,100	7,016,793	207,173,307	5,085	-	0.05	0.002	0.045	0.013	0.016	**0.13**
10	12/1/2020		311,827,975	7,016,793	304,811,182	5,068	-	0.08	0.002	0.044	0.012	0.017	**0.15**
11	12/1/2021		439,001,050	14,381,529	424,619,521	5,052	-	0.11	0.002	0.046	0.013	0.018	**0.18**
12	12/1/2022		439,000,300	14,381,529	424,618,771	5,081	-	0.10	0.003	0.050	0.013	0.021	**0.19**
13	12/1/2023		482,557,325	14,381,529	468,175,796	5,111	-	0.11	0.001	0.053	0.012	0.021	**0.20**
14	12/1/2024		539,293,200	17,667,125	521,626,075	5,140	-	0.13	0.001	0.055	0.013	0.023	**0.22**
15	12/1/2025		539,294,650	17,667,125	521,627,525	5,174	-	0.13	0.001	0.037	0.016	0.017	**0.20**
16	12/1/2026	-	539,289,900	17,667,125	521,622,775	5,207		0.13	0.001	0.042	0.014	0.020	**0.20**
17	12/1/2027	-	539,284,300	17,667,125	521,617,175	5,241		0.12	0.002	0.044	0.014	0.022	**0.21**
18	12/1/2028	-	539,290,400	17,667,125	521,623,275	5,275		0.12	0.002	0.046	0.014	0.024	**0.21**
19	12/1/2029	-	539,297,250	17,667,125	521,630,125	5,309		0.12	0.003	0.049	0.015	0.027	**0.22**
20	12/1/2030	-	539,296,800	17,667,125	521,629,675	5,344		0.12	0.003	0.042	0.019	0.025	**0.21**
21	12/1/2031	-	539,293,550	17,667,125	521,626,425	5,378		0.12	0.003	0.042	0.019	0.026	**0.21**
22	12/1/2032	-	539,293,500	17,667,125	521,626,375	5,413		0.12	0.003	0.044	0.019	0.028	**0.21**
23	12/1/2033	-	539,288,800	17,667,125	521,621,675	5,447		0.12	0.003	0.046	0.019	0.031	**0.22**
24	12/1/2034	-	539,293,450	17,667,125	521,626,325	5,482		0.12	0.003	0.048	0.020	0.034	**0.22**
25	12/1/2035	-	539,286,550	17,667,125	521,619,425	5,517		0.12	0.003	0.052	0.020	0.037	**0.23**
26	12/1/2036	-	539,289,400	17,667,125	521,622,275	5,553		0.12	0.001	0.054	0.021	0.041	**0.23**
27	12/1/2037	-	539,287,350	17,667,125	521,620,225	5,588		0.12	0.001	0.062	0.022	0.048	**0.25**
28	12/1/2038	-	539,291,900	17,667,125	521,624,775	5,623		0.12	0.001	0.066	0.022	0.052	**0.26**
29	12/1/2039	-	539,293,600	17,667,125	521,626,475	5,659		0.12	0.002	0.069	0.023	0.057	**0.27**
30	12/1/2040	-	539,288,100	17,667,125	521,620,975	5,695		0.11	0.002	0.072	0.023	0.062	**0.27**
31	12/1/2041	-	539,290,450	17,667,125	521,623,325	5,731		0.11	0.004	0.075	0.024	0.067	**0.28**
32	12/1/2042	-	458,083,350	17,667,125	440,416,225	5,767		0.10	0.004	0.073	0.022	0.069	**0.26**
33	12/1/2043	-	458,087,900	17,667,125	440,420,775	5,803		0.09	0.004	0.077	0.022	0.075	**0.27**
34	12/1/2044	-	458,086,400	17,667,125	440,419,275	5,839		0.09	0.004	0.080	0.033	0.082	**0.29**
35	12/1/2045	-	397,988,550	17,667,125	380,321,425	5,876		0.08	0.004	0.084	0.023	0.089	**0.28**
36	12/1/2046	-	397,984,050	17,667,125	380,316,925	5,912		0.08	0.004	0.078	0.031	0.087	**0.28**
37	12/1/2047	-	397,982,000	17,667,125	380,314,875	5,949		0.08	0.005	0.079	0.032	0.091	**0.29**
38	12/1/2048	-	325,101,750	17,667,125	307,434,625	5,986		0.06	0.005	0.083	0.032	0.100	**0.28**
39	12/1/2049	-	325,102,950	17,667,125	307,435,825	6,023		0.06	0.001	0.086	0.033	0.109	**0.29**
40	12/1/2050	-	325,107,400	17,667,125	307,440,275	6,060		0.06	0.002	0.089	0.034	0.117	**0.31**
41	12/1/2051	-	100,294,000	17,667,125	82,626,875	6,098		0.02	0.002	0.094	0.035	0.122	**0.27**
42	12/1/2052	-	100,293,100	17,667,125	82,625,975	6,135		0.02	0.002	0.097	0.035	0.126	**0.28**
43	12/1/2053	-	100,291,100	17,667,125	82,623,975	6,173		0.02	0.003	0.102	0.036	0.131	**0.29**
44	12/1/2054	-		-	-	6,211		-	0.004	0.105	0.037	0.135	**0.28**
45	12/1/2055	-		-	-	6,249		-	0.005	0.108	0.038	0.140	**0.29**
46	12/1/2056	-		-	-	6,287		-	0.006	0.113	0.039	0.144	**0.30**
47	12/1/2057	-		-	-	6,326		-	0.006	0.121	0.041	0.153	**0.32**
48	12/1/2058	-		-	-	6,364		-	0.006	0.127	0.041	0.161	**0.33**
49	12/1/2059	-		-	-	6,403		-	0.006	0.133	0.042	0.168	**0.35**
50	12/1/2060	-			-	6,442		-	0.006	0.137	0.043	0.172	**0.36**

	Year	DSM (000s)	Fuel Cost (000s)	Fixed O&M Cost (000s)	Variable O&M Cost (000s)	CO^2 Cost (000s)	Seed Capital	Seed Capital Fund Balance	Fixed Rate Charge for Revenues	Revenue available after debt service	GRETC Direct Debt Service Coverage	Use of Coverage	Coverage Balance
1	12/1/2011	651	259,482	39,359	30,852	-	-	-	44,085,125	8,817,025	1.25		8,817,025
2	12/1/2012	1,491	271,611	38,557	32,902	54,963	-	-	98,182,488	19,636,498	1.25		28,453,523
3	12/1/2013	3,063	258,329	42,181	31,820	56,995	-	-	98,180,113	19,636,023	1.25		48,089,545
4	12/1/2014	5,878	282,641	42,195	32,212	63,421	-	-	130,810,269	26,162,054	1.25	25,000,000	49,251,599
5	12/1/2015	10,455	361,674	35,055	35,819	65,306	-	-	170,846,774	34,169,355	1.25		83,420,954
6	12/1/2016	12,759	373,704	37,978	35,083	68,216	-	-	170,849,837	34,169,967	1.25		117,590,921
7	12/1/2017	11,891	352,673	38,010	36,043	73,346	-	-	210,411,399	42,082,280	1.25	105,000,000	54,673,201
8	12/1/2018	12,241	224,380	36,088	34,170	81,543	-	-	258,963,946	51,792,789	1.25	-	106,465,990
9	12/1/2019	12,657	244,337	34,987	35,596	86,958	-	-	258,966,633	51,793,327	1.25		158,259,317
10	12/1/2020	13,124	235,418	37,177	29,384	90,354	-	-	381,013,977	76,202,795	1.25	190,000,000	44,462,112
11	12/1/2021	13,346	247,202	39,360	30,390	97,474	-	-	530,774,401	106,154,880	1.25		150,616,992
12	12/1/2022	14,024	267,038	41,731	29,426	110,165	-	-	530,773,463	106,154,693	1.25		256,771,685
13	12/1/2023	4,166	284,104	35,897	30,380	114,805	-	-	585,219,745	117,043,949	1.25	320,000,000	53,815,634
14	12/1/2024	3,313	297,843	36,104	33,631	125,785	-	-	652,032,594	130,406,519	1.25		184,222,153
15	12/1/2025	4,222	201,105	57,389	29,739	90,619	-	-	652,034,406	130,406,881	1.25		314,629,034
16	12/1/2026	5,342	227,331	57,967	16,925	107,681	-	-	652,028,469	130,405,694	1.25		445,034,728
17	12/1/2027	8,551	238,262	58,593	17,362	118,039	-	-	652,021,469	130,404,294	1.25	485,500,231	89,938,791
18	12/1/2028	13,323	247,810	59,207	18,257	130,862	-	-	652,029,094	130,405,819	1.25	-	220,344,610
19	12/1/2029	16,151	261,837	59,916	18,745	146,548	-	-	652,037,656	130,407,531	1.25		350,752,141
20	12/1/2030	17,064	226,648	84,248	17,865	135,367		-	652,037,094	130,407,419	1.25		481,159,560
21	12/1/2031	14,951	224,691	84,983	15,652	140,642		-	652,033,031	130,406,606	1.25		611,566,166
22	12/1/2032	15,081	234,947	86,456	16,121	152,129		-	652,032,969	130,406,594	1.25		741,972,760
23	12/1/2033	15,919	249,713	87,902	16,762	166,550		-	652,027,094	130,405,419	1.25		872,378,179
24	12/1/2034	16,747	260,041	89,276	17,408	180,198		-	652,032,906	130,406,581	1.25	239,531,757	763,253,003
25	12/1/2035	18,111	279,793	90,794	18,296	200,974		-	652,024,281	130,404,856	1.25		893,657,859
26	12/1/2036	5,493	292,296	92,408	18,814	218,387		-	652,027,844	130,405,569	1.25		1,024,063,428
27	12/1/2037	7,019	335,171	97,112	19,787	257,520		-	652,025,281	130,405,056	1.25		1,154,468,484
28	12/1/2038	6,453	352,597	98,638	20,542	281,586		-	652,030,969	130,406,194	1.25		1,284,874,678
29	12/1/2039	8,848	368,539	100,317	21,287	306,519		-	652,033,094	130,406,619	1.25	699,805,525	715,475,772
30	12/1/2040	12,284	385,523	101,920	22,049	332,326		-	652,026,219	130,405,244	1.25		845,881,016
31	12/1/2041	18,825	403,233	103,660	22,861	361,453		-	652,029,156	130,405,831	1.25		976,286,847
32	12/1/2042	21,552	394,321	95,445	21,546	371,427		-	550,520,281	110,104,056	1.25		1,086,390,903
33	12/1/2043	22,199	412,100	97,223	22,392	404,276		-	550,525,969	110,105,194	1.25	720,727,822	475,768,275
34	12/1/2044	23,458	428,330	152,761	23,116	439,168		-	550,524,094	110,104,819	1.25		585,873,094
35	12/1/2045	22,134	449,075	101,037	23,977	476,267		-	475,401,781	95,080,356	1.25		680,953,450
36	12/1/2046	22,961	421,293	140,010	26,073	466,403		-	475,396,156	95,079,231	1.25		776,032,681
37	12/1/2047	24,452	424,059	142,963	26,511	490,408		-	475,393,594	95,078,719	1.25		871,111,400
38	12/1/2048	25,398	444,961	146,057	27,392	537,229		-	384,293,281	76,858,656	1.25		947,970,056
39	12/1/2049	6,909	461,902	149,291	28,395	584,308		-	384,294,781	76,858,956	1.25		1,024,829,013
40	12/1/2050	8,724	477,627	152,489	29,313	630,743		-	384,300,344	76,860,069	1.25		1,101,689,082
41	12/1/2051	11,174	503,605	155,601	30,361	656,308		-	103,283,594	20,656,719	1.25		1,122,345,800
42	12/1/2052	9,139	520,728	158,955	31,315	676,369		-	103,282,469	20,656,494	1.25		1,143,002,294
43	12/1/2053	14,889	546,462	162,470	32,477	705,371		-	103,279,969	20,655,994	1.25		1,163,658,288
44	12/1/2054	22,880	562,487	165,955	33,535	723,997		-	-	-	0.00	410,069,419	753,588,869
45	12/1/2055	27,949	579,273	169,720	34,785	749,388		-	-	-	0.00		753,588,869
46	12/1/2056	30,133	605,200	173,255	35,877	774,023		-	-	-	0.00		753,588,869
47	12/1/2057	33,288	647,750	180,086	37,668	822,050		-	-	-	0.00		753,588,869
48	12/1/2058	33,226	682,788	182,230	38,924	862,251		-	-	-	0.00		753,588,869
49	12/1/2059	31,309	716,551	186,278	40,624	900,505		-	-	-	0.00		753,588,869
50	12/1/2060	32,092	734,465	190,935	41,639	923,018		-	-	-	0.00		753,588,869

Alaska Regional Integrated Resource Plan
Scenario Cash Flow Summary
dollars in millions

RIRP PLAN 1A	
Alternative Scenario	
100% Fixed Rate	
Sources of Funds	
BONDS	3,657
STATE (through construction)	2,409
Infrastructure Tax through 2027	883
Other (Use of Coverage Reserves)	2,135
Total Source of Funds	9,085
Use of Funds	
Project/Construction	9,085
Payment of interest accrued	0
Reserve Funds	0
Issuance Costs	0
Capitalized Interest (through construction)	0
Total Uses of Funds	9,085
Maximum Annual Debt Service Requirements	
BONDS	314
STATE	322
Ave.Annual Energy Requirement (GWhr)	5,625
Target Debt Service Coverage (DSC)	1.25X
All-in Borrowing Cost	7.00%
Escalation Factor (Inflation)	2.50%
Average Cost of Energy ($/per kWh)	0.06

Assumptions
- Issuance Cost = 2% of Par Amount
- Par coupons
- Debt service reserve funded at 10% of Bond Par Amount
- Bonds all assumed to be 30 years from date of issue

	Year	Hydro Capital Requirements	Other Unit Cost Capital Requirements	Transmission Requirements	Total Capital Requirements (less large hydro)	STATE Funding - loan and payback	Use of coverage balance for capital projects	Capital Markets - BONDS
1	12/1/2011	**1**	**506,496,362**	**-**	**506,496,362**	-		$ 833,019,182
2	12/1/2012	**-**	**256,773,239**	**-**	**256,773,239**	-	-	-
3	12/1/2013	**-**	**119,476,707**	**3,990,284**	**123,466,991**	-	-	-
4	12/1/2014	**-**	**122,463,625**	**52,942,550**	**175,406,175**	-	(15,000,000)	$ 470,031,769
5	12/1/2015	**-**	**2,435,356**	**191,310,564**	**193,745,920**	-	-	-
6	12/1/2016	**33,699,203**	**22,466,161**	**255,989,420**	**278,455,581**	2,409,373,640	-	-
7	12/1/2017	**26,865,753**	**74,229,623**	**117,965,769**	**192,195,392**	-	(75,000,000)	$ 522,012,548
8	12/1/2018	**43,273,053**	**174,256,113**	**41,630,847**	**215,886,960**	-	-	-
9	12/1/2019	**79,301,147**	**174,171,476**	**169,193,895**	**343,365,370**	-	-	-
10	12/1/2020	**238,340,271**	**208,891,416**	**321,882,411**	**530,773,827**	-	(120,000,000)	$ 999,656,778
11	12/1/2021	**481,536,897**	**21,500,060**	**282,636,456**	**304,136,516**	-	-	-
12	12/1/2022	**652,793,164**	**-**	**437,331,250**	**437,331,250**	-	-	-
13	12/1/2023	**712,137,997**	**-**	**464,423,300**	**464,423,300**	-	(180,000,000)	$ 229,188,962
14	12/1/2024	**141,426,155**	**-**	**59,937,820**	**59,937,820**	-	-	-
15	12/1/2025	**-**	**-**	**18,210,430**	**18,210,430**	-	-	-
16	12/1/2026	**-**	**-**	**19,062,834**	**19,062,834**	-	-	-
17	12/1/2027	**-**	**88,657,273**	**-**	**88,657,273**	-	(245,000,000)	$ 32,875,895
18	12/1/2028	**-**	**208,125,424**	**-**	**208,125,424**	-	-	-
19	12/1/2029	**-**	**188,717,535**	**-**	**188,717,535**	-	-	-
20	12/1/2030	**-**	**-**		**-**	-	-	-
21	12/1/2031	**-**	**-**		**-**	-	-	-
22	12/1/2032	**-**	**-**		**-**	-	-	-
23	12/1/2033	**-**	**-**		**-**	-	-	-
24	12/1/2034	**-**	**2,260,136**		**2,260,136**	-	(239,531,757)	$ 0
25	12/1/2035	**-**	**206,133,124**		**206,133,124**	-	-	-
26	12/1/2036	**-**	**31,138,497**		**31,138,497**	-	-	-
27	12/1/2037	**-**	**-**		**-**	-	-	-
28	12/1/2038	**-**	**-**		**-**	-	-	-
29	12/1/2039	**-**	**127,791,596**		**127,791,596**	-	(600,000,000)	$ 99,805,525
30	12/1/2040	**-**	**299,994,339**		**299,994,339**	-	-	-
31	12/1/2041	**-**	**272,019,589**		**272,019,589**	-	-	-
32	12/1/2042	**-**	**-**		**-**	-	-	-
33	12/1/2043	**-**	**131,612,221**		**131,612,221**	-	(250,000,000)	$ 470,727,822
34	12/1/2044	**-**	**308,963,361**		**308,963,361**	-	-	-
35	12/1/2045	**-**	**280,152,241**		**280,152,241**	-	-	-
36	12/1/2046	**-**	**-**		**-**	-	-	-
37	12/1/2047	**-**	**-**		**-**	2,409,373,640	-	-
38	12/1/2048	**-**	**-**		**-**	-	-	-
39	12/1/2049	**-**	**-**		**-**	-	-	-
40	12/1/2050	**-**	**-**		**-**	-	-	-
41	12/1/2051	**-**	**-**		**-**	-	-	-
42	12/1/2052	**-**	**-**		**-**	-	-	-
43	12/1/2053	**-**	**-**		**-**	-	-	-
44	12/1/2054	**-**	**-**		**-**	-	(410,069,419)	$ (0)
45	12/1/2055	**-**	**35,525,625**		**35,525,625**	-	-	-
46	12/1/2056	**-**	**161,918,291**		**161,918,291**	-	-	-
47	12/1/2057	**-**	**-**		**-**	-	-	-
48	12/1/2058	**-**	**38,257,213**		**38,257,213**	-	-	-
49	12/1/2059	**-**	**174,368,290**		**174,368,290**	-	-	-
50	12/1/2060	**-**	**-**			-		-

	Year	Repayment of State funds	GRETC Direct Debt Service - paid to bondholders	DSRF Interest Earnings	Total Requirements	Energy per Year (GWhr)	Surcharge for seed capital	Fixed Rate Charge for Capital	DSM	Fuel Rate	O&M Rate (Fixed + Variable)	CO^2	Incremental Cost (¢ per kWh)
1	12/1/2011	$ -	$ 33,131,525	$ -	$ 33,131,525	5,372	0.010	0.01	0.000	0.048	0.013	0.000	**0.08**
2	12/1/2012		76,283,050	2,499,058	73,783,992	5,412	0.010	0.02	0.000	0.051	0.013	0.010	**0.10**
3	12/1/2013		76,281,650	2,499,058	73,782,592	5,424	0.010	0.02	0.001	0.048	0.014	0.011	**0.10**
4	12/1/2014		94,980,800	2,499,058	92,481,742	5,421	0.010	0.02	0.001	0.053	0.014	0.012	**0.11**
5	12/1/2015		119,327,100	3,909,153	115,417,947	5,167	0.010	0.03	0.002	0.067	0.013	0.012	**0.13**
6	12/1/2016	-	119,327,000	3,909,153	115,417,847	5,147	0.010	0.03	0.002	0.070	0.014	0.013	**0.14**
7	12/1/2017	-	140,091,050	3,909,153	136,181,897	5,129	0.010	0.03	0.002	0.066	0.014	0.014	**0.14**
8	12/1/2018	-	167,135,950	5,475,190	161,660,760	5,105	0.010	0.04	0.002	0.042	0.013	0.015	**0.12**
9	12/1/2019	-	167,133,450	5,475,190	161,658,260	5,085	0.010	0.04	0.002	0.045	0.013	0.016	**0.13**
10	12/1/2020	-	206,891,825	5,475,190	201,416,635	5,068	0.010	0.05	0.002	0.044	0.012	0.017	**0.14**
11	12/1/2021	-	258,677,150	8,474,161	250,202,989	5,052	0.010	0.06	0.002	0.046	0.013	0.018	**0.15**
12	12/1/2022	-	258,678,050	8,474,161	250,203,889	5,081	0.010	0.06	0.003	0.050	0.013	0.021	**0.16**
13	12/1/2023	-	267,790,975	8,474,161	259,316,814	5,111	0.010	0.06	0.001	0.053	0.012	0.021	**0.16**
14	12/1/2024	-	279,659,600	9,161,728	270,497,872	5,140	0.010	0.07	0.001	0.055	0.013	0.023	**0.17**
15	12/1/2025	-	279,668,350	9,161,728	270,506,622	5,174	0.010	0.07	0.001	0.037	0.016	0.017	**0.15**
16	12/1/2026	-	279,658,100	9,161,728	270,496,372	5,207	0.010	0.06	0.001	0.042	0.014	0.020	**0.15**
17	12/1/2027	-	292,456,550	9,161,728	283,294,822	5,241	0.010	0.07	0.002	0.044	0.014	0.022	**0.16**
18	12/1/2028	-	305,241,850	9,260,355	295,981,495	5,275		0.07	0.002	0.046	0.014	0.024	**0.16**
19	12/1/2029	-	305,240,900	9,260,355	295,980,545	5,309		0.07	0.003	0.049	0.015	0.027	**0.16**
20	12/1/2030	-	305,242,800	9,260,355	295,982,445	5,344		0.07	0.003	0.042	0.019	0.025	**0.16**
21	12/1/2031	-	305,244,200	9,260,355	295,983,845	5,378		0.07	0.003	0.042	0.019	0.026	**0.16**
22	12/1/2032	-	305,245,000	9,260,355	295,984,645	5,413		0.07	0.003	0.044	0.019	0.028	**0.16**
23	12/1/2033	-	305,243,000	9,260,355	295,982,645	5,447		0.07	0.003	0.046	0.019	0.031	**0.17**
24	12/1/2034	-	305,243,900	9,260,355	295,983,545	5,482		0.07	0.003	0.048	0.020	0.034	**0.17**
25	12/1/2035	-	305,240,600	9,260,355	295,980,245	5,517		0.07	0.003	0.052	0.020	0.037	**0.18**
26	12/1/2036	-	305,243,900	9,260,355	295,983,545	5,553		0.07	0.001	0.054	0.021	0.041	**0.18**
27	12/1/2037	-	305,236,100	9,260,355	295,975,745	5,588		0.07	0.001	0.062	0.022	0.048	**0.20**
28	12/1/2038	-	305,237,750	9,260,355	295,977,395	5,623		0.07	0.001	0.066	0.022	0.052	**0.21**
29	12/1/2039	-	309,204,550	9,260,355	299,944,195	5,659		0.07	0.002	0.069	0.023	0.057	**0.22**
30	12/1/2040	-	314,375,350	9,559,772	304,815,578	5,695		0.07	0.002	0.072	0.023	0.062	**0.23**
31	12/1/2041	-	314,385,800	9,559,772	304,826,028	5,731		0.07	0.004	0.075	0.024	0.067	**0.24**
32	12/1/2042	-	238,098,800	9,559,772	228,539,028	5,767		0.05	0.004	0.073	0.022	0.069	**0.22**
33	12/1/2043	-	256,818,500	9,559,772	247,258,728	5,803		0.05	0.004	0.077	0.022	0.075	**0.23**
34	12/1/2044	-	281,213,300	10,971,955	270,241,345	5,839		0.06	0.004	0.080	0.033	0.082	**0.26**
35	12/1/2045	-	238,156,850	10,971,955	227,184,895	5,876		0.05	0.004	0.084	0.023	0.089	**0.25**
36	12/1/2046	-	238,159,400	10,971,955	227,187,445	5,912		0.05	0.004	0.078	0.031	0.087	**0.25**
37	12/1/2047	95,827,375	238,157,150	10,971,955	323,012,570	5,949		0.07	0.005	0.079	0.032	0.091	**0.27**
38	12/1/2048	191,654,750	190,355,650	10,971,955	371,038,445	5,986		0.08	0.005	0.083	0.032	0.100	**0.30**
39	12/1/2049	191,654,750	190,357,950	10,971,955	371,040,745	6,023		0.08	0.001	0.086	0.033	0.109	**0.31**
40	12/1/2050	191,654,750	190,355,750	10,971,955	371,038,545	6,060		0.08	0.002	0.089	0.034	0.117	**0.32**
41	12/1/2051	191,654,750	98,815,900	10,971,955	279,498,695	6,098		0.06	0.002	0.094	0.035	0.122	**0.31**
42	12/1/2052	191,654,750	98,809,900	10,971,955	279,492,695	6,135		0.06	0.002	0.097	0.035	0.126	**0.32**
43	12/1/2053	191,654,750	98,809,900	10,971,955	279,492,695	6,173		0.06	0.003	0.102	0.036	0.131	**0.33**
44	12/1/2054	191,654,750	77,824,800	10,971,955	258,507,595	6,211		0.05	0.004	0.105	0.037	0.135	**0.33**
45	12/1/2055	196,264,750	77,826,750	10,971,955	263,119,545	6,249		0.05	0.005	0.108	0.038	0.140	**0.34**
46	12/1/2056	201,172,050	77,826,500	10,971,955	268,026,595	6,287		0.05	0.006	0.113	0.039	0.144	**0.35**
47	12/1/2057	206,198,250	52,247,150	10,971,955	247,473,445	6,326		0.05	0.006	0.121	0.041	0.153	**0.37**
48	12/1/2058	211,354,400	52,246,350	10,971,955	252,628,795	6,364		0.05	0.006	0.127	0.041	0.161	**0.38**
49	12/1/2059	216,638,400	52,250,150	10,971,955	257,916,595	6,403		0.05	0.006	0.133	0.042	0.168	**0.40**
50	12/1/2060	222,055,700	52,242,250	10,971,955	263,325,995	6,442		0.05	0.006	0.137	0.043	0.172	**0.41**

	Year	DSM (000s)	Fuel Cost (000s)	Fixed O&M Cost (000s)	Variable O&M Cost (000s)	CO^2 Cost (000s)	Seed Capital	Fixed Rate Charge for Revenues	Revenue available after debt service	GRETC Direct Debt Service Coverage	Use of Coverage	Coverage Balance
1	12/1/2011	651	259,482	39,359	30,852	-	53,717,410.47	41,414,406	8,282,881	1.25		8,282,881
2	12/1/2012	1,491	271,611	38,557	32,902	54,963	54,120,733.86	92,229,991	18,445,998	1.25		26,728,879
3	12/1/2013	3,063	258,329	42,181	31,820	56,995	54,241,323.99	92,228,241	18,445,648	1.25		45,174,527
4	12/1/2014	5,878	282,641	42,195	32,212	63,421	54,213,850.02	115,602,178	23,120,436	1.25	15,000,000	53,294,963
5	12/1/2015	10,455	361,674	35,055	35,819	65,306	51,673,819.94	144,272,434	28,854,487	1.25		82,149,450
6	12/1/2016	12,759	373,704	37,978	35,083	68,216	51,473,835.41	144,272,309	28,854,462	1.25		111,003,912
7	12/1/2017	11,891	352,673	38,010	36,043	73,346	51,287,518.63	170,227,371	34,045,474	1.25	75,000,000	70,049,386
8	12/1/2018	12,241	224,380	36,088	34,170	81,543	51,052,273.99	202,075,949	40,415,190	1.25	-	110,464,576
9	12/1/2019	12,657	244,337	34,987	35,596	86,958	50,849,002.21	202,072,824	40,414,565	1.25		150,879,141
10	12/1/2020	13,124	235,418	37,177	29,384	90,354	50,683,538.05	251,770,793	50,354,159	1.25	120,000,000	81,233,299
11	12/1/2021	13,346	247,202	39,360	30,390	97,474	50,524,635.70	312,753,736	62,550,747	1.25		143,784,047
12	12/1/2022	14,024	267,038	41,731	29,426	110,165	50,814,618.33	312,754,861	62,550,972	1.25		206,335,019
13	12/1/2023	4,166	284,104	35,897	30,380	114,805	51,106,167.59	324,146,018	64,829,204	1.25	180,000,000	91,164,222
14	12/1/2024	3,313	297,843	36,104	33,631	125,785	51,401,295.01	338,122,340	67,624,468	1.25		158,788,691
15	12/1/2025	4,222	201,105	57,389	29,739	90,619	51,736,787.37	338,133,278	67,626,656	1.25		226,415,346
16	12/1/2026	5,342	227,331	57,967	16,925	107,681	52,073,821.68	338,120,465	67,624,093	1.25		294,039,439
17	12/1/2027	8,551	238,262	58,593	17,362	118,039	52,412,432.40	354,118,528	70,823,706	1.25	245,000,000	119,863,145
18	12/1/2028	13,323	247,810	59,207	18,257	130,862	-	369,976,868	73,995,374	1.25		193,858,518
19	12/1/2029	16,151	261,837	59,916	18,745	146,548	-	369,975,681	73,995,136	1.25		267,853,655
20	12/1/2030	17,064	226,648	84,248	17,865	135,367	-	369,978,056	73,995,611	1.25		341,849,266
21	12/1/2031	14,951	224,691	84,983	15,652	140,642	-	369,979,806	73,995,961	1.25		415,845,227
22	12/1/2032	15,081	234,947	86,456	16,121	152,129	-	369,980,806	73,996,161	1.25		489,841,388
23	12/1/2033	15,919	249,713	87,902	16,762	166,550	-	369,978,306	73,995,661	1.25		563,837,049
24	12/1/2034	16,747	260,041	89,276	17,408	180,198	-	369,979,431	73,995,886	1.25	239,531,757	398,301,178
25	12/1/2035	18,111	279,793	90,794	18,296	200,974	-	369,975,306	73,995,061	1.25	-	472,296,239
26	12/1/2036	5,493	292,296	92,408	18,814	218,387	-	369,979,431	73,995,886	1.25		546,292,126
27	12/1/2037	7,019	335,171	97,112	19,787	257,520	-	369,969,681	73,993,936	1.25		620,286,062
28	12/1/2038	6,453	352,597	98,638	20,542	281,586	-	369,971,743	73,994,349	1.25		694,280,410
29	12/1/2039	8,848	368,539	100,317	21,287	306,519	-	374,930,243	74,986,049	1.25	600,000,000	169,266,459
30	12/1/2040	12,284	385,523	101,920	22,049	332,326	-	381,019,473	76,203,895	1.25		245,470,354
31	12/1/2041	18,825	403,233	103,660	22,861	361,453	-	381,032,535	76,206,507	1.25		321,676,861
32	12/1/2042	21,552	394,321	95,445	21,546	371,427	-	285,673,785	57,134,757	1.25		378,811,618
33	12/1/2043	22,199	412,100	97,223	22,392	404,276	-	309,073,410	61,814,682	1.25	250,000,000	190,626,300
34	12/1/2044	23,458	428,330	152,761	23,116	439,168	-	337,801,681	67,560,336	1.25	-	258,186,636
35	12/1/2045	22,134	449,075	101,037	23,977	476,267	-	283,981,118	56,796,224	1.25		314,982,859
36	12/1/2046	22,961	421,293	140,010	26,073	466,403	-	283,984,306	56,796,861	1.25		371,779,720
37	12/1/2047	24,452	424,059	142,963	26,511	490,408	-	403,765,712	80,753,142	1.25		452,532,863
38	12/1/2048	25,398	444,961	146,057	27,392	537,229	-	463,798,056	92,759,611	1.25		545,292,474
39	12/1/2049	6,909	461,902	149,291	28,395	584,308	-	463,800,931	92,760,186	1.25		638,052,660
40	12/1/2050	8,724	477,627	152,489	29,313	630,743	-	463,798,181	92,759,636	1.25		730,812,296
41	12/1/2051	11,174	503,605	155,601	30,361	656,308	-	349,373,368	69,874,674	1.25		800,686,970
42	12/1/2052	9,139	520,728	158,955	31,315	676,369	-	349,365,868	69,873,174	1.25		870,560,144
43	12/1/2053	14,889	546,462	162,470	32,477	705,371	-	349,365,868	69,873,174	1.25		940,433,317
44	12/1/2054	22,880	562,487	165,955	33,535	723,997	-	323,134,493	64,626,899	1.25	410,069,419	594,990,797
45	12/1/2055	27,949	579,273	169,720	34,785	749,388	-	328,899,431	65,779,886	1.25		660,770,683
46	12/1/2056	30,133	605,200	173,255	35,877	774,023	-	335,033,243	67,006,649	1.25		727,777,332
47	12/1/2057	33,288	647,750	180,086	37,668	822,050	-	309,341,806	61,868,361	1.25		789,645,693
48	12/1/2058	33,226	682,788	182,230	38,924	862,251	-	315,785,993	63,157,199	1.25		852,802,891
49	12/1/2059	31,309	716,551	186,278	40,624	900,505	-	322,395,743	64,479,149	1.25		917,282,040
50	12/1/2060	32,092	734,465	190,935	41,639	923,018		329,157,493	65,831,499	1.25		983,113,539

APPENDIX C

EXISTING GENERATION UNITS

Detailed Existing Unit Tables

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Anchorage ML&P – Plant 1	3	Natural Gas	Natural Gas	32	29.3	1	3.72	10.87	9,780	6.0	N	114.8	0.44	0.000045	2037
Anchorage ML&P – Plant 2	5	Natural Gas	Natural Gas	37.4	33.8	5	3.72	11.62	14	1.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	5/6	Natural Gas	Natural Gas	49.2	44.5	10	3.72	11.62	11	1.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	7	Natural Gas	Natural Gas	81.8	74.4	10	3.72	7.79	1,193	0.1	N	114.8	0.625	0.000045	2030
Anchorage ML&P – Plant 2	7/6	Natural Gas	Natural Gas	109.5	99.5	10	3.72	7.79	9,030	0.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	8	Natural Gas	Natural Gas	87.6	77.3	20	3.72	7.47	11,930	1.7	N	114.8	0.08	0.000045	2030

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Bernice	2	Natural Gas	Natural Gas	19	19	3	1.23	6.15	14,673	2.0	N	115	0.32	0.000045	2014
Bernice	3	Natural Gas	Natural Gas	25.5	25.5	13	1.23	19.48	13,409	2.0	N	115	0.13	0.000045	2014
Bernice	4	Natural Gas	Natural Gas	25.5	25.5	13	1.23	19.48	13,741	2.0	N	115	0.13	0.000045	2014
Beluga	1	Natural Gas	Natural Gas	17.5	16	3	1.23	14.35	15,198	2.0	N	115	0.32	0.0002	2011
Beluga	2	Natural Gas	Natural Gas	17.5	16	3	1.23	14.35	14,851	2.0	N	115	0.32	0.0002	2011
Beluga	3	Natural Gas	Natural Gas	66.5	56	3	1.44	12.30	12,236	2.0	N	115	0.32	0.0002	2014
Beluga	5	Natural Gas	Natural Gas	65	54	3	1.44	12.30	12,537	2.0	N	115	0.32	0.0002	2017
Beluga	6	Natural Gas	Natural Gas	82	64	3	1.64	13.33	11,528	1.0	N	115	0.2	0.001	2020
Beluga	6/8	Natural Gas	Natural Gas	108.5	83	48	2.56	29.73	9,329	4.0	N	115	0.2	0.001	2014
Beluga	7	Natural Gas	Natural Gas	82	66	3	1.64	13.33	12,184	1.0	N	115	0.34	0.006	2021
Beluga	7/8	Natural Gas	Natural Gas	108.5	85	48	2.56	29.73	9,086	4.0	N	115	0.34	0.006	2014
International	1	Natural Gas	Natural Gas	14	13	3	1.23	14.35	16,379	2.0	N	115	0.32	0.002	2011
International	2	Natural Gas	Natural Gas	14	12.5	3	1.23	14.35	17,425	2.0	N	115	0.32	0.002	2011
International	3	Natural Gas	Natural Gas	19	16	3	1.23	14.35	15,116	2.0	N	115	0.32	0.002	2012

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Zehnder	GT1	HAGO	Distillate Fuel Oil	19.2	15.8	4	8.23	10.98	14,030	0.1	N	128	0.7	0.8	2030
Zehnder	GT2	HAGO	Distillate Fuel Oil	19.6	15	4	8.23	10.98	14,190	0.2	N	128	0.7	0.8	2030
North Pole	GT1	HAGO	Distillate Fuel Oil	62.6	50	10	3.91	21.41	10,010	0.6	N	128	0.7	0.7	2017
North Pole	GT2	HAGO	Distillate Fuel Oil	60.6	48	10	3.91	21.41	9,720	0.5	N	128	0.7	0.7	2018
North Pole	CC	NAPHTHA	Distillate Fuel Oil	65	54	38	3.20	224.56	6,620	0.4	N	114.8	0.76	0.0022	2042
Healy	ST1	COAL	Distillate Fuel Oil	27	26.5	20	3.30	208.60	13,870	0.7	Y	211	0.25	0.3	2022
DPP	1	HAGO	Distillate Fuel Oil	25.8	23.1	4	8.23	10.98	13,210	0.3	N	128	0.7	0.12	2030

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Nikiski	1	Natural Gas	Natural Gas	42	38	3	6.63	4.82	12,170	1.0	Y	114.8	0.13	0.000045	2026

APPENDIX D

REGIONAL LOAD FORECASTS

Table D-1
GRETC's Winter Peak Load Forecast for Evaluation
2011 - 2060

Year	Winter Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2010/2011	233.9	238.1	87.0	146.0	188.0	9.5	869.3
2011/2012	233.9	239.6	88.0	151.0	189.0	9.5	877.5
2012/2013	233.9	241.3	88.0	153.0	190.0	10.4	883.0
2013/2014	233.9	242.9	88.0	155.0	191.0	10.4	887.4
2014/2015	234.5	217.5	89.0	157.0	192.0	10.4	867.8
2015/2016	234.9	219.2	90.0	159.0	193.0	10.4	873.3
2016/2017	235.5	221.1	90.0	161.0	194.0	10.4	879.0
2017/2018	236.5	222.7	91.0	163.0	195.0	10.4	885.4
2018/2019	237.6	224.3	92.0	165.0	196.0	10.4	891.8
2019/2020	238.1	226.0	92.0	167.0	197.0	10.4	896.3
2020/2021	238.6	227.6	93.0	169.0	198.0	10.4	902.7
2021/2022	239.7	229.2	94.0	171.0	199.0	10.4	909.1
2022/2023	240.7	230.9	94.0	173.0	200.0	10.4	914.6
2023/2024	241.7	232.6	95.0	176.0	201.0	10.4	922.1
2024/2025	242.2	234.3	96.0	178.0	202.0	10.4	927.5
2025/2026	242.8	236.0	97.0	180.0	203.0	10.4	934.0
2026/2027	243.8	237.7	97.0	182.0	204.0	10.4	939.6
2027/2028	244.8	239.4	98.0	184.0	205.0	10.4	946.1
2028/2029	245.9	241.1	99.0	186.0	206.0	10.4	952.5
2029/2030	246.9	242.8	100.0	188.0	207.0	10.4	959.0
2030/2031	247.9	244.5	100.8	190.2	208.0	10.4	965.4
2031/2032	248.8	246.2	101.6	192.4	209.0	10.4	971.8
2032/2033	249.7	248.0	102.4	194.6	210.0	10.4	978.3
2033/2034	250.7	249.7	103.2	196.8	211.1	10.4	984.7
2034/2035	251.6	251.5	104.0	199.0	212.1	10.4	991.2
2035/2036	252.5	253.2	104.8	201.3	213.1	10.4	997.7
2036/2037	253.5	255.0	105.6	203.5	214.1	10.4	1004.3
2037/2038	254.4	256.7	106.4	205.8	215.2	10.4	1010.9
2038/2039	255.4	258.5	107.3	208.1	216.2	10.4	1017.4
2039/2040	256.3	260.3	108.1	210.4	217.2	10.4	1024.1
2040/2041	257.3	262.0	108.9	212.7	218.3	10.4	1030.7
2041/2042	258.2	263.8	109.7	215.0	219.3	10.4	1037.4
2042/2043	259.2	265.6	110.6	217.4	220.4	10.4	1044.1
2043/2044	260.1	267.4	111.4	219.7	221.4	10.4	1050.9
2044/2045	261.1	269.2	112.3	222.1	222.5	10.4	1057.7
2045/2046	262.0	271.1	113.1	224.5	223.5	10.4	1064.5
2046/2047	263.0	272.9	114.0	226.9	224.6	10.4	1071.3
2047/2048	264.0	274.7	114.8	229.3	225.6	10.4	1078.2
2048/2049	264.9	276.5	115.7	231.8	226.7	10.4	1085.0
2049/2050	265.9	278.4	116.5	234.2	227.7	10.4	1092.0
2050/2051	266.9	280.2	117.4	236.7	228.8	10.4	1098.9
2051/2052	267.8	282.1	118.3	239.2	229.9	10.4	1105.9
2052/2053	268.8	284.0	119.1	241.7	231.0	10.4	1112.9
2053/2054	269.8	285.8	120.0	244.2	232.0	10.4	1120.0
2054/2055	270.7	287.7	120.9	246.8	233.1	10.4	1127.1
2055/2056	271.7	289.6	121.8	249.3	234.2	10.4	1134.2
2056/2057	272.7	291.5	122.7	251.9	235.3	10.4	1141.4
2057/2058	273.7	293.4	123.6	254.5	236.4	10.4	1148.5
2058/2059	274.7	295.3	124.4	257.1	237.4	10.4	1155.8
2059/2060	275.7	297.3	125.4	259.7	238.5	10.4	1163.0

Table D-2
GRETC's Summer Peak Load Forecast for Evaluation
2011 - 2060

Year	Summer Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	160.6	191.4	75.1	91.1	167.2	10.0	668.0
2012	160.6	192.6	75.9	94.1	168.1	10.0	674.3
2013	160.6	193.9	75.9	95.0	169.0	11.0	678.5
2014	160.6	195.2	75.9	95.5	169.9	11.0	681.9
2015	161.3	174.8	76.8	95.5	170.8	11.0	666.8
2016	161.3	176.2	77.7	95.4	171.7	11.0	671.0
2017	162.0	177.7	77.7	95.3	172.6	11.0	675.4
2018	162.7	179.0	78.5	95.1	173.5	11.0	680.3
2019	163.4	180.3	79.4	95.0	174.3	11.0	685.3
2020	163.4	181.6	79.4	95.0	175.2	11.0	688.7
2021	164.2	182.9	80.2	94.9	176.1	11.0	693.6
2022	164.9	184.3	81.1	96.0	177.0	11.0	698.6
2023	165.6	185.6	81.1	97.1	177.9	11.0	702.8
2024	166.3	187.0	82.0	98.7	178.8	11.0	708.5
2025	166.3	188.3	82.8	99.9	179.7	11.0	712.7
2026	167.0	189.7	83.7	101.1	180.6	11.0	717.7
2027	167.7	191.1	83.7	102.3	181.5	11.0	722.0
2028	168.4	192.4	84.6	103.5	182.3	11.0	726.9
2029	169.2	193.8	85.4	104.7	183.2	11.0	731.9
2030	169.9	195.2	86.3	105.9	184.1	11.0	736.9
2031	170.5	196.5	87.0	107.2	185.0	11.0	741.8
2032	171.2	197.9	87.7	108.5	185.9	11.0	746.8
2033	171.8	199.3	88.3	109.8	186.8	11.0	751.7
2034	172.4	200.7	89.0	111.1	187.7	11.0	756.7
2035	173.1	202.1	89.7	112.5	188.7	11.0	761.6
2036	173.7	203.5	90.4	113.8	189.6	11.1	766.7
2037	174.4	204.9	91.1	115.2	190.5	11.1	771.7
2038	175.0	206.3	91.8	116.6	191.4	11.2	776.7
2039	175.7	207.8	92.6	117.9	192.3	11.2	781.8
2040	176.3	209.2	93.3	119.3	193.2	11.3	786.9
2041	177.0	210.6	94.0	120.7	194.2	11.4	792.0
2042	177.6	212.1	94.7	122.1	195.1	11.4	797.1
2043	178.3	213.5	95.4	123.5	196.0	11.5	802.3
2044	179.0	214.9	96.1	124.9	196.9	11.5	807.5
2045	179.6	216.4	96.9	126.4	197.9	11.6	812.7
2046	180.3	217.9	97.6	127.8	198.8	11.7	817.9
2047	180.9	219.3	98.3	129.3	199.8	11.7	823.2
2048	181.6	220.8	99.1	130.7	200.7	11.8	828.4
2049	182.3	222.3	99.8	132.2	201.6	11.8	833.7
2050	182.9	223.8	100.5	133.7	202.6	11.9	839.1
2051	183.6	225.3	101.3	135.2	203.5	12.0	844.4
2052	184.3	226.7	102.0	136.7	204.5	12.0	849.8
2053	184.9	228.2	102.8	138.2	205.4	12.1	855.2
2054	185.6	229.8	103.6	139.7	206.4	12.1	860.6
2055	186.3	231.3	104.3	141.3	207.3	12.2	866.0
2056	186.9	232.8	105.1	142.8	208.3	12.3	871.5
2057	187.6	234.3	105.8	144.4	209.3	12.3	877.0
2058	188.3	235.8	106.6	145.9	210.2	12.4	882.5
2059	189.0	237.4	107.4	147.5	211.2	12.4	888.1
2060	189.6	238.9	108.2	149.1	212.2	12.5	893.6

Table D-3
GRETC's Annual Valley Load Forecast for Evaluation
2011 - 2060

Year	Annual Valley Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	95.4	88.6	44.4	53.2	91.0	4.4	413.5
2012	95.4	89.2	44.9	55.0	91.5	4.4	417.2
2013	95.4	89.8	44.9	55.8	91.9	4.8	419.7
2014	95.4	90.4	44.9	56.5	92.4	4.8	421.7
2015	95.8	81.0	45.5	57.2	92.9	4.8	413.7
2016	95.8	81.6	46.0	58.0	93.4	4.8	416.3
2017	96.3	82.3	46.0	58.7	93.9	4.8	418.9
2018	96.7	82.9	46.5	59.4	94.4	4.8	421.9
2019	97.1	83.5	47.0	60.2	94.8	4.8	424.9
2020	97.1	84.1	47.0	60.9	95.3	4.8	426.9
2021	97.5	84.7	47.5	61.6	95.8	4.8	429.9
2022	98.0	85.3	48.0	62.3	96.3	4.8	433.0
2023	98.4	86.0	48.0	63.1	96.8	4.8	435.4
2024	98.8	86.6	48.5	64.2	97.3	4.8	438.9
2025	98.8	87.2	49.0	64.9	97.7	4.8	441.4
2026	99.2	87.8	49.5	65.6	98.2	4.8	444.5
2027	99.7	88.5	49.5	66.4	98.7	4.8	447.0
2028	100.1	89.1	50.1	67.1	99.2	4.8	450.0
2029	100.5	89.7	50.6	67.8	99.7	4.8	453.1
2030	100.9	90.4	51.1	68.5	100.2	4.8	456.1
2031	101.3	91.0	51.5	69.3	100.7	4.8	459.1
2032	101.7	91.7	51.9	70.1	101.1	4.8	462.1
2033	102.1	92.3	52.3	70.9	101.6	4.8	465.1
2034	102.5	93.0	52.7	71.7	102.1	4.8	468.1
2035	102.8	93.6	53.1	72.6	102.6	4.8	471.1
2036	103.2	94.3	53.5	73.4	103.1	4.8	474.1
2037	103.6	94.9	54.0	74.2	103.6	4.8	477.2
2038	104.0	95.6	54.4	75.0	104.1	4.8	480.2
2039	104.4	96.2	54.8	75.9	104.6	4.8	483.3
2040	104.8	96.9	55.2	76.7	105.1	4.8	486.4
2041	105.2	97.5	55.6	77.5	105.6	4.8	489.5
2042	105.5	98.2	56.1	78.4	106.1	4.8	492.6
2043	105.9	98.9	56.5	79.2	106.6	4.8	495.7
2044	106.3	99.5	56.9	80.1	107.1	4.8	498.8
2045	106.7	100.2	57.3	81.0	107.6	4.8	502.0
2046	107.1	100.9	57.8	81.8	108.2	4.8	505.2
2047	107.5	101.6	58.2	82.7	108.7	4.8	508.3
2048	107.9	102.3	58.6	83.6	109.2	4.8	511.5
2049	108.3	102.9	59.1	84.5	109.7	4.8	514.7
2050	108.7	103.6	59.5	85.4	110.2	4.8	517.9
2051	109.1	104.3	60.0	86.3	110.7	4.8	521.2
2052	109.5	105.0	60.4	87.2	111.2	4.8	524.4
2053	109.9	105.7	60.9	88.1	111.8	4.8	527.7
2054	110.3	106.4	61.3	89.0	112.3	4.8	530.9
2055	110.7	107.1	61.7	90.0	112.8	4.8	534.2
2056	111.1	107.8	62.2	90.9	113.3	4.8	537.5
2057	111.5	108.5	62.7	91.8	113.8	4.8	540.8
2058	111.9	109.2	63.1	92.8	114.4	4.8	544.2
2059	112.3	109.9	63.6	93.7	114.9	4.8	547.5
2060	112.7	110.7	64.0	94.7	115.4	4.8	550.9

Table D-4
GRETC's Net Energy for Load Forecast for Evaluation
2011 - 2060

Year	Utility Net Energy for Load Forecast (GWh)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	1,302.0	1,522.7	554.5	771.2	1,162.8	64.6	5,377.8
2012	1,303.2	1,532.1	557.1	801.9	1,168.3	64.8	5,427.4
2013	1,305.0	1,543.0	560.2	811.1	1,173.8	65.0	5,458.1
2014	1,307.5	1,553.2	564.0	820.9	1,179.3	65.3	5,490.3
2015	1,311.4	1,333.5	568.1	831.9	1,184.9	65.6	5,295.3
2016	1,315.6	1,344.4	572.4	842.8	1,190.4	65.9	5,331.5
2017	1,320.1	1,355.5	577.0	854.0	1,196.0	66.3	5,369.0
2018	1,324.8	1,361.5	581.7	865.4	1,201.6	66.6	5,401.6
2019	1,329.6	1,367.4	586.5	876.8	1,207.3	67.0	5,434.7
2020	1,334.5	1,373.4	591.2	888.3	1,213.0	67.4	5,467.8
2021	1,339.4	1,379.5	596.1	900.1	1,218.7	67.8	5,501.6
2022	1,344.3	1,385.5	601.0	911.7	1,224.4	68.1	5,535.0
2023	1,349.2	1,391.6	605.9	923.2	1,230.1	68.5	5,568.6
2024	1,354.3	1,397.7	610.7	934.8	1,235.9	68.9	5,602.3
2025	1,359.2	1,403.8	615.5	946.4	1,241.7	69.3	5,636.0
2026	1,364.2	1,410.0	620.4	958.0	1,247.6	69.7	5,669.9
2027	1,369.3	1,416.2	625.3	969.7	1,253.4	70.0	5,703.9
2028	1,374.4	1,422.3	630.2	981.3	1,259.3	70.4	5,738.0
2029	1,379.5	1,428.5	635.1	992.9	1,265.3	70.8	5,772.0
2030	1,384.5	1,434.7	640.0	1,004.7	1,271.2	71.2	5,806.3
2031	1,389.6	1,440.8	645.0	1,016.7	1,277.1	71.6	5,840.8
2032	1,394.7	1,447.0	650.0	1,028.7	1,283.0	72.0	5,875.4
2033	1,399.7	1,453.3	655.0	1,040.9	1,289.0	72.4	5,910.2
2034	1,404.8	1,459.5	660.0	1,053.1	1,294.9	72.7	5,945.1
2035	1,409.9	1,465.7	665.1	1,065.4	1,300.9	73.1	5,980.1
2036	1,415.0	1,472.0	670.2	1,077.8	1,306.8	73.5	6,015.3
2037	1,420.1	1,478.2	675.3	1,090.2	1,312.8	73.9	6,050.6
2038	1,425.3	1,484.5	680.4	1,102.8	1,318.8	74.3	6,086.1
2039	1,430.4	1,490.8	685.5	1,115.4	1,324.9	74.7	6,121.7
2040	1,435.5	1,497.1	690.7	1,128.1	1,330.9	75.1	6,157.4
2041	1,440.7	1,503.5	695.9	1,140.9	1,336.9	75.5	6,193.3
2042	1,445.8	1,509.8	701.1	1,153.7	1,343.0	75.9	6,229.3
2043	1,451.0	1,516.2	706.3	1,166.7	1,349.1	76.3	6,265.5
2044	1,456.2	1,522.5	711.5	1,179.7	1,355.2	76.7	6,301.9
2045	1,461.4	1,528.9	716.8	1,192.9	1,361.3	77.1	6,338.4
2046	1,466.6	1,535.3	722.1	1,206.1	1,367.4	77.5	6,375.0
2047	1,471.8	1,541.7	727.4	1,219.4	1,373.5	77.9	6,411.8
2048	1,477.0	1,548.2	732.8	1,232.8	1,379.7	78.3	6,448.8
2049	1,482.3	1,554.6	738.1	1,246.3	1,385.9	78.7	6,485.9
2050	1,487.5	1,561.1	743.5	1,259.9	1,392.1	79.1	6,523.2
2051	1,492.8	1,567.5	748.9	1,273.6	1,398.3	79.5	6,560.6
2052	1,498.0	1,574.0	754.4	1,287.4	1,404.5	79.9	6,598.2
2053	1,503.3	1,580.5	759.8	1,301.3	1,410.7	80.3	6,635.9
2054	1,508.6	1,587.1	765.3	1,315.3	1,416.9	80.7	6,673.9
2055	1,513.9	1,593.6	770.8	1,329.4	1,423.2	81.1	6,712.0
2056	1,519.2	1,600.1	776.3	1,343.6	1,429.5	81.5	6,750.2
2057	1,524.5	1,606.7	781.9	1,357.9	1,435.8	81.9	6,788.7
2058	1,529.8	1,613.3	787.5	1,372.3	1,442.1	82.3	6,827.3
2059	1,535.1	1,619.9	793.1	1,386.8	1,448.4	82.8	6,866.0
2060	1,540.5	1,626.5	798.7	1,401.4	1,454.7	83.2	6,905.0

Table D-5
GRETC's Winter Peak Large Load Forecast for Evaluation
2011 - 2060

Year	Large Load Winter Peak Demand (MW)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2010/2011	238.1	412.2	146.0	96.3	869.3
2011/2012	239.6	413.2	151.0	97.2	877.5
2012/2013	241.3	414.2	153.0	98.2	883.0
2013/2014	242.9	415.1	155.0	98.2	887.4
2014/2015	217.5	417.1	157.0	99.2	867.8
2015/2016	219.2	418.1	159.0	100.2	873.3
2016/2017	221.1	420.1	161.0	100.2	879.0
2017/2018	222.7	422.1	163.0	101.2	885.4
2018/2019	224.3	424.1	165.0	102.2	891.8
2019/2020	226.0	425.1	167.0	102.2	896.3
2020/2021	227.6	427.1	169.0	103.2	902.7
2021/2022	229.2	429.0	171.0	104.2	909.1
2022/2023	230.9	431.0	173.0	104.2	914.6
2023/2024	232.6	433.0	176.0	105.2	922.1
2024/2025	384.3	734.0	178.0	156.2	1398.3
2025/2026	386.0	736.0	180.0	157.2	1404.7
2026/2027	387.7	738.0	182.0	157.2	1410.2
2027/2028	389.4	740.0	184.0	158.2	1416.6
2028/2029	391.1	742.0	186.0	159.2	1423.1
2029/2030	392.8	744.0	188.0	160.1	1429.5
2030/2031	394.5	745.9	190.2	160.9	1435.8
2031/2032	396.2	747.8	192.4	161.7	1442.2
2032/2033	398.0	749.7	194.6	162.5	1448.6
2033/2034	399.7	751.6	196.8	163.3	1455.0
2034/2035	401.5	753.5	199.0	164.1	1461.4
2035/2036	403.2	755.4	201.3	165.0	1468.0
2036/2037	405.0	757.4	203.5	165.8	1474.5
2037/2038	406.7	759.3	205.8	166.7	1481.1
2038/2039	408.5	761.2	208.1	167.6	1487.7
2039/2040	560.3	1063.2	210.4	218.5	1975.7
2040/2041	562.0	1065.1	212.7	219.3	1982.3
2041/2042	563.8	1067.1	215.0	220.2	1989.0
2042/2043	565.6	1069.0	217.4	221.1	1995.7
2043/2044	567.4	1071.0	219.7	222.0	2002.5
2044/2045	569.2	1072.9	222.1	222.9	2009.3
2045/2046	571.1	1074.9	224.5	223.8	2016.1
2046/2047	572.9	1076.9	226.9	224.7	2022.9
2047/2048	574.7	1078.9	229.3	225.6	2029.8
2048/2049	576.5	1080.8	231.8	226.5	2036.7
2049/2050	578.4	1082.8	234.2	227.4	2043.6
2050/2051	580.2	1084.8	236.7	228.4	2050.6
2051/2052	582.1	1086.8	239.2	229.3	2057.6
2052/2053	584.0	1088.8	241.7	230.2	2064.6
2053/2054	585.8	1090.8	244.2	231.1	2071.7
2054/2055	587.7	1092.8	246.8	232.1	2078.8
2055/2056	589.6	1094.8	249.3	233.0	2085.9
2056/2057	591.5	1096.8	251.9	234.0	2093.0
2057/2058	593.4	1098.9	254.5	234.9	2100.2
2058/2059	595.3	1100.9	257.1	235.8	2107.5
2059/2060	597.3	1102.9	259.7	236.8	2114.7

Table D-6
GRETC's Large Load Net Energy for Load Forecast for Evaluation (GWh)
2011 - 2060

Year	Large Load Net Energy for Load Forecast (GWh)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	1,522.7	2,464.8	771.2	619.1	5,377.8
2012	1,532.1	2,471.5	801.9	621.9	5,427.4
2013	1,543.0	2,478.8	811.1	625.2	5,458.1
2014	1,553.2	2,486.9	820.9	629.3	5,490.3
2015	1,333.5	2,496.2	831.9	633.7	5,295.3
2016	1,344.4	2,506.0	842.8	638.3	5,331.5
2017	1,355.5	2,516.2	854.0	643.3	5,369.0
2018	1,361.5	2,526.4	865.4	648.3	5,401.6
2019	1,367.4	2,536.9	876.8	653.5	5,434.7
2020	1,373.4	2,547.4	888.3	658.6	5,467.8
2021	1,379.5	2,558.1	900.1	663.9	5,501.6
2022	1,385.5	2,568.7	911.7	669.1	5,535.0
2023	1,391.6	2,579.4	923.2	674.4	5,568.6
2024	1,397.7	2,590.2	934.8	679.6	5,602.3
2025	2,389.3	4,572.0	946.4	1,013.3	8,921.0
2026	2,395.5	4,582.8	958.0	1,018.6	8,954.9
2027	2,401.7	4,593.7	969.7	1,023.8	8,988.9
2028	2,410.5	4,610.1	981.3	1,030.0	9,032.0
2029	2,414.0	4,615.7	992.9	1,034.4	9,057.0
2030	2,420.2	4,626.7	1,004.7	1,039.7	9,091.3
2031	2,426.3	4,637.7	1,016.7	1,045.1	9,125.8
2032	2,435.2	4,654.1	1,028.7	1,051.3	9,169.4
2033	2,438.8	4,659.7	1,040.9	1,055.8	9,195.2
2034	2,445.0	4,670.7	1,053.1	1,061.3	9,230.1
2035	2,451.2	4,681.8	1,065.4	1,066.7	9,265.1
2036	2,460.2	4,698.3	1,077.8	1,073.1	9,309.3
2037	2,463.7	4,704.0	1,090.2	1,077.7	9,335.6
2038	2,470.0	4,715.1	1,102.8	1,083.2	9,371.1
2039	2,476.3	4,726.2	1,115.4	1,088.7	9,406.7
2040	3,473.5	6,719.2	1,128.1	1,424.6	12,745.4
2041	3,474.5	6,719.6	1,140.9	1,428.3	12,763.3
2042	3,480.8	6,730.9	1,153.7	1,433.9	12,799.3
2043	3,487.2	6,742.1	1,166.7	1,439.6	12,835.5
2044	3,498.9	6,764.2	1,179.7	1,447.0	12,889.9
2045	3,499.9	6,764.7	1,192.9	1,450.9	12,908.4
2046	3,506.3	6,776.0	1,206.1	1,456.6	12,945.0
2047	3,512.7	6,787.4	1,219.4	1,462.3	12,981.8
2048	3,524.6	6,809.5	1,232.8	1,469.8	13,036.8
2049	3,525.6	6,810.1	1,246.3	1,473.8	13,055.9
2050	3,532.1	6,821.6	1,259.9	1,479.6	13,093.2
2051	3,538.5	6,833.0	1,273.6	1,485.4	13,130.6
2052	3,550.4	6,855.3	1,287.4	1,493.0	13,186.2
2053	3,551.5	6,856.0	1,301.3	1,497.1	13,205.9
2054	3,558.1	6,867.5	1,315.3	1,503.0	13,243.9
2055	3,564.6	6,879.1	1,329.4	1,508.9	13,282.0
2056	3,576.5	6,901.5	1,343.6	1,516.6	13,338.2
2057	3,577.7	6,902.3	1,357.9	1,520.8	13,358.7
2058	3,584.3	6,913.9	1,372.3	1,526.8	13,397.3
2059	3,590.9	6,925.6	1,386.8	1,532.8	13,436.0
2060	3,602.9	6,948.0	1,401.4	1,540.7	13,493.0

APPENDIX E

DETAILED RESULTS – SCENARIOS 1A / 1B

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)	Fuel Costs ($000)	Total O&M Costs ($000)	CO2 Costs ($000)	DSM Costs ($000)	Annual Capital Fixed Charges ($000)	Total Annual Costs ($000)	Present Value of Annual Costs ($000)	Cumulative Present Value ($000)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1; International - 2	55.82%	11.92%	$351,806	$78,494	$1,102	$651	$12,326	$444,378	$444,378	$444,378
2012	Fire Island	International - 3	47.47%	15.18%	$359,297	$86,269	$54,767	$1,491	$40,350	$542,175	506,706	951,084
2013	Anchorage 1x1 6FA		62.51%	14.98%	$330,019	$88,259	$57,514	$3,063	$75,558	$554,413	484,245	1,435,329
2014	Glacier Fork	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	71.52%	15.94%	$339,919	$90,226	$63,386	$5,878	$108,169	$607,578	495,965	1,931,294
2015	Anchorage MSW		55.23%	24.72%	$348,659	$87,384	$62,082	$10,455	$131,358	$639,938	488,205	2,419,500
2016			59.21%	24.60%	$382,711	$89,392	$68,949	$12,759	$170,907	$724,717	516,713	2,936,213
2017	GVEA MSW	Beluga - 5; NP1	60.91%	24.85%	$357,899	$89,413	$74,393	$11,891	$199,985	$733,582	488,817	3,425,030
2018	GVEA 1X1 NPole Retrofit	NP2	54.30%	24.83%	$276,253	$83,051	$80,365	$12,241	$211,778	$663,688	413,311	3,838,341
2019			47.96%	24.62%	$295,815	$82,983	$87,105	$12,657	$211,778	$690,338	401,783	4,240,124
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	46.22%	31.89%	$302,861	$102,110	$88,427	$13,124	$273,431	$779,954	424,243	4,664,367
2021	Anchorage 1x1 6FA	Beluga - 7	55.99%	31.60%	$310,824	$106,747	$93,910	$13,346	$342,861	$867,688	441,089	5,105,456
2022	Mount Spurr	Healy - 1	51.00%	38.52%	$297,025	$126,402	$96,170	$14,024	$391,772	$925,393	439,648	5,545,103
2023			46.86%	38.33%	$325,599	$123,469	$97,048	$4,166	$395,365	$945,647	419,879	5,964,982
2024			45.69%	38.18%	$340,682	$126,429	$109,073	$3,313	$433,745	$1,013,242	420,460	6,385,441
2025	Chakachamna:Chakachamna	GVEA Aurora Purchase - Tier I	84.55%	62.32%	$220,174	$138,656	$75,946	$4,222	$693,340	$1,132,337	439,140	6,824,581
2026		Nikiski	75.13%	62.52%	$234,402	$129,355	$88,159	$5,342	$693,340	$1,150,598	417,030	7,241,611
2027			73.98%	63.00%	$227,330	$132,294	$94,512	$8,551	$695,689	$1,158,376	392,382	7,633,993
2028			72.66%	63.06%	$230,300	$135,279	$103,224	$13,323	$695,689	$1,177,815	372,866	8,006,859
2029			71.37%	61.83%	$242,192	$138,036	$118,165	$16,151	$695,689	$1,210,233	358,064	8,364,923
2030	Kenai Hydro	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	50.97%	63.97%	$185,036	$139,321	$110,881	$17,064	$700,698	$1,153,000	318,814	8,683,737
2031			42.40%	62.03%	$192,346	$139,762	$120,883	$14,951	$697,301	$1,165,243	301,121	8,984,858
2032			41.36%	62.78%	$191,723	$142,989	$129,151	$15,081	$677,251	$1,156,195	279,236	9,264,095
2033			40.32%	61.88%	$199,354	$146,152	$141,847	$15,919	$677,251	$1,180,522	266,459	9,530,554
2034			39.30%	61.50%	$203,127	$149,310	$154,233	$16,747	$677,251	$1,200,668	253,277	9,783,831
2035			38.29%	61.86%	$205,017	$152,770	$165,394	$18,111	$677,251	$1,218,543	240,232	10,024,063
2036			37.29%	61.55%	$207,662	$156,125	$183,109	$5,493	$677,251	$1,229,640	226,560	10,250,623
2037	GVEA LMS100	MLP 3	43.27%	60.64%	$217,063	$162,624	$200,100	$7,019	$703,248	$1,290,053	222,141	10,472,764
2038			42.23%	60.94%	$218,402	$166,071	$217,232	$6,453	$703,248	$1,311,404	211,045	10,683,809
2039			41.22%	60.75%	$230,127	$170,053	$235,833	$8,848	$703,248	$1,348,108	202,758	10,886,568
2040			40.20%	60.25%	$243,640	$173,619	$259,739	$12,284	$703,248	$1,392,529	195,738	11,082,305
2041			39.21%	60.34%	$253,301	$177,608	$279,986	$18,825	$694,319	$1,424,038	187,072	11,269,377
2042	GVEA 1x1 6FA	NPCC	48.65%	59.27%	$276,556	$169,650	$309,508	$21,552	$758,395	$1,535,661	188,538	11,457,915
2043			47.60%	59.37%	$288,608	$173,713	$335,805	$22,199	$723,187	$1,543,512	177,104	11,635,019
2044			46.55%	59.21%	$300,081	$231,589	$363,392	$23,458	$690,575	$1,609,095	172,551	11,807,570
2045			45.51%	58.76%	$317,604	$181,983	$395,339	$22,134	$667,387	$1,584,446	158,792	11,966,362
2046	Anchorage LM6000		49.40%	58.33%	$337,808	$189,592	$429,301	$22,961	$643,804	$1,623,465	152,059	12,118,421
2047			48.36%	57.93%	$353,295	$194,064	$464,681	$24,452	$614,726	$1,651,218	144,540	12,262,961
2048			47.31%	57.73%	$370,037	$198,719	$505,529	$25,398	$602,933	$1,702,617	139,289	12,402,250
2049			46.30%	57.57%	$386,486	$203,794	$546,949	$6,909	$602,933	$1,747,070	133,575	12,535,825
2050			45.26%	57.17%	$405,470	$208,369	$595,985	$8,724	$541,280	$1,759,830	125,749	12,661,574
2051			44.26%	57.05%	$420,223	$213,071	$616,838	$11,174	$471,850	$1,733,156	115,741	12,777,315
2052			43.26%	56.77%	$438,398	$218,532	$632,661	$9,139	$422,939	$1,721,668	107,452	12,884,767
2053			42.27%	56.11%	$463,378	$223,819	$667,701	$14,889	$419,346	$1,789,132	104,358	12,989,124
2054			41.28%	55.98%	$481,702	$229,337	$692,040	$22,880	$380,966	$1,806,925	98,500	13,087,625
2055			40.31%	55.65%	$503,136	$235,076	$717,142	$27,949	$376,280	$1,859,584	94,739	13,182,364
2056			39.35%	55.43%	$521,505	$240,450	$745,668	$30,133	$376,280	$1,914,035	91,134	13,273,498
2057	GVEA LMS100	Cooper Lake	47.51%	54.83%	$585,511	$250,156	$787,838	$33,288	$416,531	$2,073,323	92,260	13,365,758
2058			44.71%	53.85%	$615,490	$254,038	$829,889	$33,226	$416,531	$2,149,172	89,379	13,455,136
2059			43.71%	53.88%	$647,398	$261,068	$862,589	$31,309	$416,531	$2,218,894	86,241	13,541,378
2060			42.73%	53.09%	$677,429	$267,339	$902,580	$32,092	$411,521	$2,290,960	83,217	13,624,595
			Present Value of Costs		**4,547,973**	**1,750,430**	**1,921,235**	**149,474**	**5,255,484**		**Grand Total**	**13,624,595**

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)

Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,720	0	0	4,304	38,024
2012	31,553	0	0	5,310	36,863
2013	31,457	0	0	3,877	35,334
2014	30,904	0	0	3,241	34,145
2015	22,249	0	0	2,555	24,803
2016	21,201	0	0	2,757	23,957
2017	21,919	0	0	2,645	24,563
2018	18,693	9,034	0	2,741	30,468
2019	18,656	8,262	0	2,780	29,697
2020	14,852	8,087	0	2,803	25,742
2021	15,866	7,311	0	2,215	25,391
2022	14,094	6,846	0	2,041	22,980
2023	14,741	7,727	0	2,070	24,538
2024	15,267	7,366	0	2,197	24,830
2025	10,081	4,435	0	1,328	15,844
2026	10,393	5,170	0	956	16,519
2027	10,646	5,243	0	0	15,889
2028	10,638	5,289	0	0	15,927
2029	10,865	5,792	0	0	16,657
2030	5,914	6,410	0	0	12,324
2031	7,382	5,563	0	0	12,945
2032	7,325	5,366	0	0	12,690
2033	7,524	5,595	0	0	13,118
2034	7,679	5,589	0	0	13,268
2035	7,709	5,543	0	0	13,253
2036	8,464	4,990	0	0	13,454
2037	6,734	7,581	0	0	14,315
2038	6,460	7,995	0	0	14,455
2039	6,583	8,118	0	0	14,701
2040	6,626	8,411	0	0	15,037
2041	6,725	8,363	0	0	15,088
2042	6,098	9,918	0	0	16,015
2043	6,074	10,083	0	0	16,157
2044	6,226	10,003	0	0	16,229
2045	6,293	10,376	0	0	16,670
2046	7,987	9,250	0	0	17,237
2047	8,290	9,166	0	0	17,456
2048	8,296	9,419	0	0	17,715
2049	8,431	9,493	0	0	17,924
2050	8,533	9,714	0	0	18,247
2051	8,649	9,696	0	0	18,345
2052	8,864	9,698	0	0	18,563
2053	8,917	10,106	0	0	19,023
2054	9,061	10,114	0	0	19,175
2055	9,078	10,367	0	0	19,445
2056	9,378	10,196	0	0	19,573
2057	7,933	13,595	0	0	21,528
2058	8,355	13,629	0	0	21,984
2059	8,374	14,102	0	0	22,476
2060	8,529	14,320	0	0	22,849

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Anchorage 1x1 6FA	Glacier Fork	Anchorage MSW	GVEA MSW	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Chakachamna:Chakachamna	Kenai Hydro	GVEA LMS100	GVEA 1x1 6FA	Anchorage LM6000	GVEA LMS100	Generating Unit Capital Cost Cash Flow ($000)
2011	30,468	99,809	175,454	210,604	127,935	0	0	0	0	0	0	0		0	0	0	0	644,270
2012				132,925	116,563	40,740												290,228
2013					119,477	95,638												215,114
2014						86,719	9,000											95,719
2015							21,127	18,083										39,210
2016							19,157	42,450				33,699						95,306
2017								38,492	72,765			26,866						138,123
2018									170,818	76,085		43,273						290,177
2019									154,889	178,613	68,804	79,301						481,607
2020										161,957	161,519	238,340						561,816
2021											146,457	481,537						627,994
2022												652,793						652,793
2023												712,138	247					712,385
2024												141,426	253					141,680
2025													260					260
2026													266					266
2027													18,560					18,560
2028													17,905					17,905
2029													18,353					18,353
2030																		
2031																		
2032																		
2033																		
2034														2,260				2,260
2035														206,133				206,133
2036														31,138				31,138
2037																		
2038																		
2039															127,792			127,792
2040															299,994			299,994
2041															272,020			272,020
2042																		
2043																		
2044																27,076		27,076
2045																123,405		123,405
2046																		
2047																		
2048																		
2049																		
2050																		
2051																		
2052																		
2053																		
2054																	3,703	3,703
2055																	337,773	337,773
2056																	51,024	51,024
2057																		
2058																		
2059																		
2060																		
Total																		6,524,085

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Capital Cost Cash Flow ($000)	Total Transmission Project Capital Cost Cash Flow ($000)	Total Capital Cost Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	644,270	79,848	724,118	651	351,806	43,795	34,699	1,102	5,372
2012	290,228	3,365	293,593	1,491	359,297	48,337	37,933	54,767	5,412
2013	215,114	51,272	266,387	3,063	330,019	52,191	36,068	57,514	5,424
2014	95,719	228,409	324,128	5,878	339,919	53,317	36,909	63,386	5,421
2015	39,210	314,097	353,307	10,455	348,659	48,327	39,057	62,082	5,167
2016	95,306	129,804	225,111	12,759	382,711	48,775	40,617	68,949	5,147
2017	138,123	8,812	146,935	11,891	357,899	49,059	40,354	74,393	5,129
2018	290,177	97,549	387,726	12,241	276,253	47,413	35,638	80,365	5,105
2019	481,607	214,570	696,177	12,657	295,815	46,596	36,386	87,105	5,085
2020	561,816	166,433	728,249	13,124	302,861	64,626	37,485	88,427	5,068
2021	627,994	73,715	701,709	13,346	310,824	68,386	38,361	93,910	5,052
2022	652,793	195,732	848,525	14,024	297,025	86,668	39,734	96,170	5,081
2023	712,385	205,995	918,380	4,166	325,599	82,114	41,355	97,048	5,111
2024	141,680	23,643	165,323	3,313	340,682	83,658	42,770	109,073	5,140
2025	260	10,784	11,044	4,222	220,174	106,273	32,383	75,946	5,174
2026	266	11,289	11,555	5,342	234,402	108,234	21,121	88,159	5,207
2027	18,560		18,560	8,551	227,330	110,277	22,017	94,512	5,241
2028	17,905		17,905	13,323	230,300	112,362	22,917	103,224	5,275
2029	18,353		18,353	16,151	242,192	114,541	23,495	118,165	5,309
2030			0	17,064	185,036	116,065	23,256	110,881	5,344
2031			0	14,951	192,346	117,757	22,005	120,883	5,378
2032			0	15,081	191,723	120,236	22,754	129,151	5,413
2033			0	15,919	199,354	122,661	23,490	141,847	5,447
2034	2,260		2,260	16,747	203,127	125,061	24,250	154,233	5,482
2035	206,133		206,133	18,111	205,017	127,634	25,135	165,394	5,517
2036	31,138		31,138	5,493	207,662	130,359	25,766	183,109	5,553
2037			0	7,019	217,063	136,144	26,480	200,100	5,588
2038			0	6,453	218,402	138,807	27,264	217,232	5,623
2039	127,792		127,792	8,848	230,127	141,651	28,402	235,833	5,659
2040	299,994		299,994	12,284	243,640	144,475	29,143	259,739	5,695
2041	272,020		272,020	18,825	253,301	147,408	30,200	279,986	5,731
2042			0	21,552	276,556	140,448	29,202	309,508	5,767
2043			0	22,199	288,608	143,513	30,200	335,805	5,803
2044	27,076		27,076	23,458	300,081	200,404	31,185	363,392	5,839
2045	123,405		123,405	22,134	317,604	149,991	31,991	395,339	5,876
2046			0	22,961	337,808	156,421	33,170	429,301	5,912
2047			0	24,452	353,295	159,869	34,195	464,681	5,949
2048			0	25,398	370,037	163,510	35,210	505,529	5,986
2049			0	6,909	386,486	167,227	36,567	546,949	6,023
2050			0	8,724	405,470	170,958	37,411	595,985	6,060
2051			0	11,174	420,223	174,609	38,462	616,838	6,098
2052			0	9,139	438,398	178,567	39,965	632,661	6,135
2053			0	14,889	463,378	182,614	41,204	667,701	6,173
2054	3,703		3,703	22,880	481,702	186,688	42,648	692,040	6,211
2055	337,773		337,773	27,949	503,136	191,057	44,020	717,142	6,249
2056	51,024		51,024	30,133	521,505	195,250	45,200	745,668	6,287
2057			0	33,288	585,511	202,909	47,247	787,838	6,326
2058			0	33,226	615,490	205,703	48,334	829,889	6,364
2059			0	31,309	647,398	210,417	50,651	862,589	6,403
2060			0	32,092	677,429	215,317	52,022	902,580	6,442
Total	6,524,085	1,815,317	Total of Cash Flows &	9,086,710					

Scenario 1A/1B Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type																				
	Natural Gas		Coal		Nuclear		Fuel Oil		Purchase Power		Hydro		Geothermal		Municipal Solid Waste		Wind		Ocean Tidal	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,542	80	435			251	580	25	210	176	591					15	49		
2012	1,258	3,425	80	493			251	501	25	215	176	593					69	231		
2013	1,195	3,490	80	556			251	384	25	213	176	591					69	226		
2014	1,176	3,354	80	630			251	380	25	213	251	649					69	227		
2015	1,176	2,432	80	618			251	619	25	212	251	919			22	163	69	227		
2016	822	2,316	80	625			251	703	25	213	251	921			22	163	69	228		
2017	822	2,388	80	611			251	602	25	212	251	919			26	188	69	227		
2018	821	2,441	80	554			189	591	25	212	251	919			26	195	69	227		
2019	821	2,443	80	563			189	563	25	212	251	919			26	193	69	226		
2020	1,103	2,567	80	587					25	211	251	921	50	403	26	192	69	228		
2021	907	2,595	80	550					25	208	251	919	50	402	26	190	69	227		
2022	825	2,250	80	543					25	204	251	919	100	800	26	186	69	227		
2023	743	2,450	80	364					25	205	251	919	100	802	26	187	69	227		
2024	743	2,452	53	374					25	206	251	921	100	803	26	188	69	227		
2025	743	1,285	53	278					25	174	581	2,528	100	651	26	107	69	226		
2026	743	1,448	53	292							581	2,519	100	680	26	119	69	227		
2027	701	1,441	53	285							581	2,518	100	708	26	140	69	227		
2028	701	1,456	53	282							581	2,525	100	734	26	132	69	227		
2029	701	1,537	53	282							581	2,517	100	688	26	136	69	227		
2030	701	1,387	53	323							586	2,537	100	797	26	154	69	226		
2031	531	1,507	53	325							586	2,538	100	719	26	139	69	226		
2032	467	1,476	53	327							586	2,544	100	765	26	152	69	228		
2033	467	1,540	53	327							586	2,537	100	746	26	147	69	227		
2034	467	1,572	53	330							586	2,538	100	739	26	153	69	227		
2035	467	1,568	53	328							586	2,538	100	783	26	151	69	227		
2036	562	1,588	53	340							586	2,544	100	768	26	163	69	227		
2037	564	1,676	53	317							586	2,537	100	752	26	153	69	227		
2038	532	1,676	53	317							586	2,537	100	783	26	162	69	227		
2039	532	1,700	53	320							586	2,537	100	808	26	147	69	227		
2040	532	1,740	53	323							586	2,544	100	771	26	164	69	231		
2041	693	1,749	53	324							586	2,537	100	813	26	161	69	226		
2042	693	1,851	53	303							586	2,537	100	764	26	165	69	227		
2043	630	1,859	53	305							586	2,537	100	787	26	169	69	227		
2044	630	1,880	53	308							586	2,544	100	792	26	168	69	228		
2045	630	1,935	53	297							586	2,537	100	789	26	171	69	227		
2046	678	1,996	53	279							586	2,537	100	780	26	174	69	227		
2047	678	2,039	53	277							586	2,537	100	785	26	166	69	226		
2048	678	2,069	53	275							586	2,544	100	781	26	170	69	228		
2049	678	2,100	53	272							586	2,537	100	812	26	158	69	227		
2050	678	2,149	53	264							586	2,537	100	793	26	172	69	227		
2051	678	2,172	53	265							586	2,537	100	792	26	187	69	227		
2052	678	2,209	53	264							586	2,544	100	813	26	162	69	227		
2053	678	2,259	53	273							586	2,537	100	786	26	175	69	227		
2054	678	2,281	53	276							586	2,537	100	796	26	176	69	227		
2055	678	2,319	53	278							586	2,537	100	796	26	175	69	227		
2056	678	2,344	53	283							586	2,544	100	774	26	197	69	228		
2057	775	2,441	53	248							586	2,537	100	813	26	146	69	227		
2058	775	2,522	53	251							567	2,496	100	783	26	172	69	226		
2059	775	2,577	53	252							567	2,496	100	823	26	154	69	227		
2060	775	2,623	53	260							567	2,502	100	775	26	160	69	228		

APPENDIX F

DETAILED RESULTS – SCENARIO 2A

Scenario 2A Plan - P50 Natural Gas Forecast												
Year	**Additions**	**Retirements**	**Reserve Margin (%)**	**Renewable Generation (%)**	**Fuel Costs ($000)**	**Total O&M Costs ($000)**	**CO2 Costs ($000)**	**DSM Costs ($000)**	**Annual Capital Fixed Charges ($000)**	**Total Annual Costs ($000)**	**Present Value of Annual Costs ($000)**	**Cumulative Present Value ($000)**
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1; International - 2	55.82%	11.92%	$351,604	$78,521	$1,106	$651	$12,326	$444,208	$444,208	$444,208
2012	Fire Island	International - 3	47.47%	15.18%	$360,422	$86,221	$54,846	$1,491	$40,350	$543,330	507,785	951,993
2013			44.98%	14.98%	$363,525	$85,731	$60,377	$3,063	$40,350	$553,045	483,051	1,435,044
2014	Glacier Fork; Anchorage MSW	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	56.46%	18.90%	$349,083	$86,281	$66,100	$5,878	$88,695	$596,037	486,543	1,921,587
2015	Anchorage 1x1 6FA		55.23%	24.72%	$354,267	$87,454	$62,615	$10,455	$132,747	$647,538	494,004	2,415,591
2016			59.21%	24.60%	$389,510	$89,445	$69,555	$12,759	$172,296	$733,565	523,022	2,938,612
2017	Kenai Wind	Beluga - 5; NP1	60.42%	26.14%	$372,476	$92,929	$74,394	$11,891	$216,010	$767,700	511,551	3,450,163
2018	GVEA 1X1 NPole Retrofit	NP2	53.81%	26.11%	$275,355	$86,095	$80,031	$12,241	$227,803	$681,525	424,419	3,874,583
2019			47.47%	25.89%	$296,482	$86,310	$87,228	$12,657	$227,803	$710,481	413,506	4,288,089
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	45.73%	33.16%	$304,731	$105,371	$88,752	$13,124	$289,455	$801,433	435,927	4,724,016
2021	Anchorage 1x1 6FA	Beluga - 7	55.49%	32.84%	$312,537	$109,985	$94,579	$13,346	$358,886	$889,333	452,092	5,176,107
2022	Mount Spurr	Healy - 1	50.51%	39.74%	$297,344	$129,708	$96,528	$14,024	$407,797	$945,400	449,153	5,625,260
2023			46.37%	39.54%	$327,794	$126,766	$97,214	$4,166	$411,390	$967,329	429,506	6,054,766
2024			45.20%	39.58%	$343,341	$130,139	$109,253	$3,313	$449,770	$1,035,816	429,827	6,484,593
2025	Anchorage 2x1 6FA; Anchorage LM6000; Chakachamna:Chakachamna	GVEA Aurora Purchase - Tier I	41.74%	42.64%	$493,814	$190,671	$158,554	$4,222	$793,649	$1,640,909	636,373	7,120,965
2026		Nikiski	36.05%	42.27%	$529,070	$179,677	$183,279	$5,342	$793,649	$1,691,017	612,902	7,733,868
2027			35.49%	42.50%	$520,677	$182,769	$197,038	$8,551	$795,997	$1,705,032	577,553	8,311,421
2028			34.84%	42.34%	$533,295	$187,338	$219,018	$13,323	$795,997	$1,748,972	553,680	8,865,101
2029			34.21%	41.95%	$539,569	$190,662	$241,299	$16,151	$795,997	$1,783,679	527,726	9,392,827
2030	GVEA 2x1 6FA; GVEA Wind	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	45.01%	43.53%	$509,936	$198,465	$245,385	$17,064	$918,989	$1,889,839	522,556	9,915,383
2031			39.60%	43.40%	$523,101	$201,504	$270,945	$14,951	$915,592	$1,926,094	497,739	10,413,123
2032			38.95%	43.61%	$531,763	$205,894	$291,795	$15,081	$895,542	$1,940,075	468,554	10,881,676
2033			38.30%	43.19%	$541,607	$210,376	$316,985	$15,919	$895,542	$1,980,429	447,009	11,328,685
2034			37.66%	42.72%	$551,169	$214,842	$343,023	$16,747	$895,542	$2,021,323	426,392	11,755,077
2035			37.01%	43.03%	$555,584	$219,480	$368,689	$18,111	$895,542	$2,057,407	405,611	12,160,688
2036			36.38%	42.85%	$560,666	$224,269	$402,574	$5,493	$895,542	$2,088,545	384,813	12,545,500
2037	GVEA LMS100	MLP 3	40.23%	42.52%	$548,121	$231,752	$422,523	$7,019	$904,831	$2,114,246	364,064	12,909,564
2038			39.58%	42.47%	$547,828	$236,660	$454,017	$6,453	$904,831	$2,149,789	345,966	13,255,530
2039			38.94%	42.26%	$570,844	$241,766	$490,794	$8,848	$904,831	$2,217,083	333,454	13,588,984
2040	Anchorage 2x1 6FA; GVEA 1x1 6FA; GVEA 2x1 6FA		43.74%	31.31%	$955,710	$278,383	$819,820	$12,284	$1,190,010	$3,256,208	457,702	14,046,686
2041			43.25%	31.09%	$986,042	$283,245	$876,847	$18,825	$1,181,081	$3,346,041	439,560	14,486,246
2042	GVEA Wind	NPCC	39.49%	32.33%	$995,004	$281,841	$929,314	$21,552	$1,222,216	$3,449,927	423,558	14,909,804
2043			39.01%	32.23%	$1,034,873	$288,300	$1,005,832	$22,199	$1,222,216	$3,573,421	410,018	15,319,822
2044			38.53%	32.09%	$1,075,355	$401,879	$1,082,555	$23,458	$1,173,871	$3,757,118	402,893	15,722,716
2045			38.05%	31.69%	$1,109,371	$300,374	$1,161,219	$22,134	$1,129,819	$3,722,917	373,108	16,095,824
2046	GVEA Wind		37.57%	33.53%	$1,151,293	$316,843	$1,258,017	$22,961	$1,144,476	$3,893,591	364,685	16,460,509
2047			37.09%	33.00%	$1,190,168	$323,306	$1,347,332	$24,452	$1,117,471	$4,002,728	350,381	16,810,890
2048			36.62%	33.07%	$1,239,185	$331,193	$1,461,949	$25,398	$1,105,678	$4,163,403	340,603	17,151,493
2049			36.15%	33.23%	$1,269,655	$338,080	$1,559,594	$6,909	$1,105,678	$4,279,915	327,229	17,478,722
2050			35.67%	32.85%	$1,313,929	$345,174	$1,673,485	$8,724	$996,132	$4,337,444	309,932	17,788,654
2051			35.20%	32.51%	$1,360,215	$352,585	$1,720,933	$11,174	$926,701	$4,371,608	291,938	18,080,591
2052			34.73%	32.77%	$1,411,933	$361,346	$1,775,167	$9,139	$877,791	$4,435,375	276,819	18,357,410
2053			34.26%	32.61%	$1,448,204	$368,777	$1,813,619	$14,889	$874,198	$4,519,685	263,627	18,621,037
2054			33.79%	32.49%	$1,498,727	$377,675	$1,868,803	$22,880	$835,817	$4,603,903	250,971	18,872,008
2055			33.32%	32.40%	$1,544,239	$386,271	$1,919,022	$27,949	$756,353	$4,633,834	236,077	19,108,085
2056			32.86%	32.38%	$1,597,860	$395,323	$1,971,742	$30,133	$756,353	$4,751,411	226,231	19,334,317
2057	HEA LMS100	Cooper Lake	37.07%	32.13%	$1,654,506	$407,185	$2,040,275	$33,288	$796,604	$4,931,857	219,461	19,553,777
2058			35.67%	32.04%	$1,721,950	$415,039	$2,114,255	$33,226	$796,604	$5,081,073	211,309	19,765,086
2059			35.19%	31.25%	$1,775,748	$423,369	$2,170,886	$31,309	$796,604	$5,197,916	202,026	19,967,113
2060	HEA LM6000		37.02%	31.66%	$1,876,300	$437,564	$2,290,856	$32,092	$734,560	$5,371,371	195,110	20,162,223
			Present Value of Costs		**7,215,425**	**2,198,167**	**3,949,357**	**149,474**	**6,649,800**		**Grand Total**	**20,162,223**

Scenario 2A Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)					
Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,725	0	0	4,347	38,073
2012	31,564	0	0	5,343	36,907
2013	31,009	0	0	5,402	36,412
2014	29,719	0	0	4,652	34,370
2015	22,335	0	0	2,653	24,988
2016	21,242	0	0	2,901	24,143
2017	22,336	0	0	1,634	23,970
2018	19,206	9,353	0	1,741	30,299
2019	19,347	8,532	0	1,746	29,625
2020	15,697	8,368	0	1,731	25,797
2021	16,406	7,538	0	1,513	25,457
2022	14,499	7,039	0	1,433	22,971
2023	15,391	7,732	0	1,464	24,586
2024	15,768	7,496	0	1,513	24,777
2025	27,374	7,039	0	1,342	35,755
2026	28,989	7,671	0	907	37,566
2027	29,128	7,695	0	0	36,823
2028	29,273	7,720	0	0	36,992
2029	29,637	7,844	0	0	37,481
2030	21,656	14,225	0	0	35,881
2031	25,908	10,532	0	0	36,439
2032	25,811	10,699	0	0	36,510
2033	26,214	10,719	0	0	36,934
2034	26,659	10,685	0	0	37,344
2035	26,479	10,796	0	0	37,275
2036	26,896	10,928	0	0	37,824
2037	22,325	15,185	0	0	37,510
2038	22,251	15,409	0	0	37,660
2039	22,546	15,324	0	0	37,870
2040	35,623	24,998	0	0	60,621
2041	35,747	24,267	0	0	60,014
2042	35,457	24,128	0	0	59,585
2043	35,422	24,438	0	0	59,860
2044	35,569	24,571	0	0	60,140
2045	35,140	24,891	0	0	60,031
2046	36,415	23,834	0	0	60,249
2047	36,121	24,167	0	0	60,288
2048	36,458	24,321	0	0	60,779
2049	36,055	24,284	0	0	60,339
2050	36,134	24,399	0	0	60,533
2051	36,276	24,487	0	0	60,764
2052	36,850	24,320	0	0	61,170
2053	36,228	24,613	0	0	60,841
2054	36,437	24,627	0	0	61,064
2055	36,257	24,797	0	0	61,053
2056	36,722	24,654	0	0	61,376
2057	35,530	24,335	0	1,797	61,661
2058	35,362	24,558	0	2,422	62,342
2059	34,939	25,059	0	2,440	62,438
2060	33,668	24,847	0	5,605	64,120

Scenario 2A Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Glacier Fork	Anchorage MSW	Anchorage 1x1 6FA	Kenai Wind T Lines	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Anchorage 2x1 6FA	Anchorage LM6000	Chakachamna:Chakachamna	GVEA 2x1 6FA	GVEA Wind T Lines	GVEA LMS100	Anchorage 2x1 6FA	GVEA 1x1 6FA	GVEA 2x1 6FA	GVEA Wind	GVEA Wind	HEA LMS100	HEA LM6000	Generating Unit Cash Flow ($000)
2011	30,468	99,809	175,454	127,935	39,746	0		0	0	0	0	0	0	0	0		0	0	0	0			0	0	473,413
2012				116,563	93,305	65,608																			275,476
2013				119,477	84,604	154,017																			358,098
2014						139,655																			139,655
2015							13,577	18,083																	31,660
2016							125,247	42,450						33,699											201,396
2017								38,492	72,765					26,866											138,123
2018									170,818	76,085				43,273											290,177
2019									154,889	178,613	68,804			79,301											481,607
2020										161,957	161,519			238,340											561,816
2021											146,457			481,537											627,994
2022												197,360		652,793											850,153
2023												393,458	16,120	712,138											1,121,716
2024												130,159	73,474	141,426											345,059
2025																									
2026																									
2027															223,295										223,295
2028															445,161	32,772									477,933
2029															147,263	302,325									449,588
2030																									
2031																									
2032																									
2033																									
2034																	2,260								2,260
2035																	206,133								206,133
2036																	31,138								31,138
2037																		285,836	121,634	285,836					693,306
2038																		569,844	285,539	569,844					1,425,227
2039																		188,510	258,912	188,510					635,931
2040																					41,925				41,925
2041																					386,759				386,759
2042																									
2043																									
2044																						46,278			46,278
2045																						426,910			426,910
2046																									
2047																									
2048																									
2049																									
2050																									
2051																									
2052																									
2053																									
2054																							3,703		3,703
2055																							337,773		337,773
2056																							51,024		51,024
2057																									
2058																								38,257	38,257
2059																								174,368	174,368
2060																									
Total																									11,548,152

Scenario 2A Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Cash Flow ($000)	Total Transmission Project Cash Flow ($000)	Total Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	473,413	79,848	553,260	651	351,604	43,795	34,726	1,106	5,372
2012	275,476	3,365	278,841	1,491	360,422	48,337	37,885	54,846	5,412
2013	358,098	51,272	409,370	3,063	363,525	48,328	37,403	60,377	5,424
2014	139,655	228,409	368,063	5,878	349,083	49,454	36,828	66,100	5,421
2015	31,660	314,097	345,757	10,455	354,267	48,327	39,127	62,615	5,167
2016	201,396	129,804	331,201	12,759	389,510	48,775	40,670	69,555	5,147
2017	138,123	8,812	146,935	11,891	372,476	49,059	43,870	74,394	5,129
2018	290,177	97,549	387,726	12,241	275,355	47,413	38,682	80,031	5,105
2019	481,607	214,570	696,177	12,657	296,482	46,596	39,714	87,228	5,085
2020	561,816	166,433	728,249	13,124	304,731	64,626	40,745	88,752	5,068
2021	627,994	73,715	701,709	13,346	312,537	68,386	41,599	94,579	5,052
2022	850,153	195,732	1,045,885	14,024	297,344	86,668	43,040	96,528	5,081
2023	1,121,716	205,995	1,327,711	4,166	327,794	82,114	44,651	97,214	5,111
2024	345,059	23,643	368,702	3,313	343,341	83,658	46,481	109,253	5,140
2025		10,784	10,784	4,222	493,814	135,630	55,041	158,554	8,459
2026		11,289	11,289	5,342	529,070	138,121	41,556	183,279	8,492
2027	223,295		223,295	8,551	520,677	140,707	42,062	197,038	8,526
2028	477,933		477,933	13,323	533,295	143,349	43,988	219,018	8,569
2029	449,588		449,588	16,151	539,569	146,097	44,566	241,299	8,594
2030			0	17,064	509,936	152,823	45,642	245,385	8,629
2031			0	14,951	523,101	155,099	46,405	270,945	8,663
2032			0	15,081	531,763	158,176	47,718	291,795	8,707
2033			0	15,919	541,607	161,218	49,158	316,985	8,732
2034	2,260		2,260	16,747	551,169	164,248	50,595	343,023	8,767
2035	206,133		206,133	18,111	555,584	167,467	52,013	368,689	8,802
2036	31,138		31,138	5,493	560,666	170,851	53,418	402,574	8,847
2037	693,306		693,306	7,019	548,121	177,317	54,436	422,523	8,873
2038	1,425,227		1,425,227	6,453	547,828	180,675	55,985	454,017	8,908
2039	635,931		635,931	8,848	570,844	184,232	57,534	490,794	8,944
2040	41,925		41,925	12,284	955,710	202,018	76,366	819,820	12,283
2041	386,759		386,759	18,825	986,042	205,701	77,544	876,847	12,301
2042			0	21,552	995,004	195,580	86,261	929,314	12,337
2043			0	22,199	1,034,873	199,431	88,869	1,005,832	12,373
2044	46,278		46,278	23,458	1,075,355	310,643	91,236	1,082,555	12,427
2045	426,910		426,910	22,134	1,109,371	207,543	92,831	1,161,219	12,446
2046			0	22,961	1,151,293	211,768	105,075	1,258,017	12,482
2047			0	24,452	1,190,168	216,084	107,221	1,347,332	12,519
2048			0	25,398	1,239,185	220,612	110,581	1,461,949	12,574
2049			0	6,909	1,269,655	225,244	112,836	1,559,594	12,593
2050			0	8,724	1,313,929	229,911	115,263	1,673,485	12,630
2051			0	11,174	1,360,215	234,521	118,065	1,720,933	12,668
2052			0	9,139	1,411,933	239,458	121,888	1,775,167	12,723
2053			0	14,889	1,448,204	244,515	124,261	1,813,619	12,743
2054	3,703		3,703	22,880	1,498,727	249,622	128,054	1,868,803	12,781
2055	337,773		337,773	27,949	1,544,239	255,048	131,223	1,919,022	12,819
2056	51,024		51,024	30,133	1,597,860	260,323	135,000	1,971,742	12,875
2057			0	33,288	1,654,506	269,102	138,083	2,040,275	12,896
2058	38,257		38,257	33,226	1,721,950	273,035	142,003	2,114,255	12,934
2059	174,368		174,368	31,309	1,775,748	278,917	144,451	2,170,886	12,973
2060			0	32,092	1,876,300	288,064	149,500	2,290,856	13,030
Total	11,548,152	1,815,317	Total of Cash F	14,110,777					

Scenario 2A Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type

	Natural Gas		Coal		Nuclear		Fuel Oil		Purchase Power		Hydro		Geothermal		Municipal Solid Waste		Wind		Ocean Tidal	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,548	80	435			251	576	25	210	176	591					15	49		
2012	1,104	3,427	80	493			251	502	25	215	176	593					69	231		
2013	1,041	3,376	80	568			251	494	25	214	176	591					69	226		
2014	1,176	3,145	80	643			251	426	25	214	251	649			22	163	69	227		
2015	1,176	2,439	80	619			251	633	25	212	251	919			22	163	69	227		
2016	822	2,329	80	625			251	720	25	214	251	921			22	163	69	228		
2017	822	2,299	80	616			251	656	25	212	251	919			22	159	99	326		
2018	821	2,381	80	562			189	618	25	213	251	919			22	166	99	326		
2019	821	2,401	80	576			189	578	25	213	251	919			22	163	99	325		
2020	1,103	2,558	80	597					25	210	251	921	50	403	22	163	99	327		
2021	907	2,583	80	568					25	209	251	919	50	401	22	161	99	326		
2022	825	2,241	80	559					25	205	251	919	100	798	22	156	99	326		
2023	743	2,450	80	372					25	206	251	919	100	799	22	158	99	326		
2024	1,100	2,442	53	382					25	207	251	921	100	812	22	159	99	326		
2025	1,101	4,261	53	353					25	212	581	2,517	100	802	22	160	99	325		
2026	1,101	4,516	53	360							581	2,517	100	790	22	152	99	326		
2027	1,059	4,533	53	344							581	2,517	100	816	22	161	99	326		
2028	1,059	4,562	53	349							581	2,524	100	806	22	169	99	326		
2029	1,384	4,624	53	340							581	2,517	100	803	22	154	99	326		
2030	1,384	4,571	53	266							581	2,517	100	794	22	157	149	489		
2031	1,214	4,577	53	295							581	2,517	100	794	22	161	149	489		
2032	1,150	4,589	53	291							581	2,524	100	812	22	172	149	491		
2033	1,150	4,640	53	295							581	2,517	100	802	22	161	149	491		
2034	1,150	4,704	53	296							581	2,517	100	785	22	150	149	490		
2035	1,150	4,697	53	294							581	2,517	100	818	22	162	149	490		
2036	1,245	4,735	53	298							581	2,524	100	813	22	162	149	490		
2037	1,247	4,812	53	258							581	2,517	100	787	22	175	149	491		
2038	1,215	4,839	53	255							581	2,517	100	813	22	160	149	491		
2039	2,011	4,870	53	256							581	2,517	100	807	22	160	149	491		
2040	2,011	8,001	53	272							581	2,524	100	805	22	163	149	499		
2041	2,011	7,943	53	278							581	2,517	100	800	22	162	149	489		
2042	2,011	7,741	53	276							581	2,517	100	805	22	163	199	653		
2043	1,948	7,764	53	283							581	2,517	100	803	22	163	199	655		
2044	1,948	7,809	53	276							581	2,524	100	804	22	152	199	656		
2045	1,948	7,778	53	277							581	2,517	100	761	22	158	199	655		
2046	1,948	7,698	53	282							581	2,517	100	827	22	177	249	820		
2047	1,948	7,706	53	276							581	2,517	100	802	22	147	249	817		
2048	1,948	7,761	53	274							581	2,524	100	804	22	163	249	822		
2049	1,948	7,724	53	259							581	2,517	100	828	22	174	249	820		
2050	1,948	7,744	53	247							581	2,517	100	802	22	162	249	820		
2051	1,948	7,757	53	251							581	2,517	100	781	22	151	249	820		
2052	1,948	7,822	53	245							581	2,524	100	814	22	163	249	821		
2053	1,948	7,765	53	250							581	2,517	100	804	22	168	249	817		
2054	1,948	7,790	53	261							581	2,517	100	804	22	162	249	820		
2055	1,948	7,789	53	264							581	2,517	100	798	22	169	249	820		
2056	1,948	7,841	53	260							581	2,524	100	812	22	162	249	821		
2057	2,046	7,748	53	280							581	2,517	100	794	22	162	249	820		
2058	2,046	7,802	53	283							562	2,476	100	834	22	167	249	817		
2059	2,093	7,761	53	290							562	2,476	100	758	22	148	249	817		
2060	2,093	7,725	53	304							562	2,482	100	806	22	163	249	821		

APPENDIX G

DETAILED RESULTS – SCENARIO 2B

Scenario 2B Plan - P50 Natural Gas Forecast													
Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)	Fuel Costs ($000)	Total O&M Costs ($000)	CO2 Costs ($000)	DSM Costs ($000)	Annual Capital Fixed Charges ($000)	Total Annual Costs ($000)	Present Value of Annual Costs ($000)	Cumulative Present Value ($000)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1 International - 2	55.82%	11.92%	$351,493	$78,517	$0	$651	$12,326	$442,987	$442,987	$442,987
2012	Fire Island	International - 3	47.47%	15.18%	$360,816	$86,324	$54,859	$1,491	$40,350	$543,841	508,262	951,249
2013			44.98%	14.98%	$373,571	$86,176	$60,950	$3,063	$40,350	$564,109	492,714	1,443,963
2014	Glacier Fork; Anchorage MSW	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	56.46%	18.90%	$355,455	$86,614	$66,555	$5,878	$88,695	$603,197	492,389	1,936,352
2015	Anchorage 1x1 6FA		55.23%	24.72%	$355,881	$87,506	$62,699	$10,455	$132,747	$649,288	495,339	2,431,691
2016			59.21%	24.60%	$391,713	$89,457	$69,675	$12,759	$172,296	$735,900	524,686	2,956,377
2017	Kenai Wind	Beluga - 5; NP1	60.42%	26.14%	$357,236	$92,343	$73,636	$11,891	$216,010	$751,117	500,501	3,456,878
2018	GVEA 1X1 NPole Retrofit	NP2	53.81%	26.11%	$275,319	$86,055	$80,008	$12,241	$227,803	$681,426	424,358	3,881,236
2019			47.47%	25.89%	$296,301	$86,307	$87,426	$12,657	$227,803	$710,494	413,514	4,294,750
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	45.73%	33.15%	$313,065	$104,598	$88,585	$13,124	$289,455	$808,827	439,949	4,734,699
2021	Anchorage 1x1 6FA	Beluga - 7	55.49%	32.84%	$319,829	$107,286	$95,077	$13,346	$358,886	$894,423	454,679	5,189,378
2022	Mount Spurr	Healy - 1	50.51%	39.73%	$303,446	$126,760	$96,696	$14,024	$407,797	$948,722	450,731	5,640,109
2023			46.37%	39.57%	$338,009	$123,561	$101,020	$4,166	$411,390	$978,146	434,308	6,074,418
2024			45.20%	39.43%	$354,550	$125,350	$111,759	$3,313	$449,770	$1,044,742	433,531	6,507,949
2025	Chakachamna:Chakachamna; GVEA Wind; Low Watana (Non-Expandable)	GVEA Aurora Purchase - Tier I	59.97%	65.83%	$327,284	$177,358	$109,666	$4,222	$1,387,377	$2,005,906	777,925	7,285,874
2026		Nikiski	54.19%	65.70%	$355,930	$168,282	$129,694	$5,342	$1,387,377	$2,046,625	741,791	8,027,664
2027			53.56%	65.52%	$354,583	$171,861	$141,138	$8,551	$1,389,726	$2,065,860	699,778	8,727,443
2028			52.82%	65.41%	$362,315	$175,663	$156,239	$13,323	$1,389,726	$2,097,266	663,941	9,391,383
2029			52.11%	65.12%	$370,599	$179,717	$173,790	$16,151	$1,389,726	$2,129,983	630,185	10,021,568
2030	GVEA Wind	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	38.93%	66.50%	$324,824	$188,512	$170,425	$17,064	$1,426,241	$2,127,066	588,151	10,609,720
2031			33.55%	66.21%	$287,389	$185,763	$167,924	$14,951	$1,422,844	$2,078,872	537,220	11,146,940
2032			32.93%	66.42%	$291,077	$190,378	$181,400	$15,081	$1,402,794	$2,080,731	502,524	11,649,463
2033			32.30%	66.03%	$294,120	$194,462	$195,275	$15,919	$1,402,794	$2,102,569	474,578	12,124,041
2034			31.69%	65.66%	$300,588	$198,861	$213,080	$16,747	$1,402,794	$2,132,070	449,754	12,573,794
2035			31.08%	65.94%	$303,932	$203,534	$228,670	$18,111	$1,402,794	$2,157,041	425,253	12,999,048
2036			30.47%	65.48%	$304,372	$207,945	$248,912	$5,493	$1,402,794	$2,169,516	399,732	13,398,779
2037	Anchorage 2x1 6FA; Kenai Wind	MLP 3	49.65%	64.70%	$337,305	$221,770	$284,317	$7,019	$1,512,696	$2,363,107	406,916	13,805,696
2038			48.95%	64.92%	$335,376	$226,742	$306,870	$6,453	$1,512,696	$2,388,138	384,324	14,190,020
2039			48.26%	64.44%	$355,211	$231,941	$335,719	$8,848	$1,512,696	$2,444,416	367,646	14,557,665
2040	Anchorage 2x1 6FA; Kenai Wind; GVEA 2x1 6FA		42.24%	49.31%	$726,114	$261,828	$658,141	$12,284	$1,757,343	$3,415,710	480,122	15,037,787
2041			41.75%	49.68%	$749,303	$266,953	$705,228	$18,825	$1,748,414	$3,488,723	458,303	15,496,090
2042	GVEA Wind	NPCC	38.00%	50.31%	$764,582	$266,145	$750,700	$21,552	$1,789,549	$3,592,529	441,066	15,937,156
2043			37.52%	50.68%	$785,633	$272,478	$804,064	$22,199	$1,789,549	$3,673,924	421,550	16,358,706
2044			37.04%	50.66%	$815,768	$279,122	$870,100	$23,458	$1,741,204	$3,729,652	399,948	16,758,654
2045			36.57%	50.24%	$852,178	$285,535	$937,781	$22,134	$1,663,223	$3,760,851	376,910	17,135,564
2046	GVEA LM6000		38.46%	50.01%	$890,057	$295,214	$1,020,949	$22,961	$1,639,640	$3,868,823	362,365	17,497,930
2047			37.99%	50.14%	$918,798	$302,026	$1,096,440	$24,452	$1,612,635	$3,954,351	346,146	17,844,075
2048			37.51%	49.97%	$957,221	$309,807	$1,185,769	$25,398	$1,600,842	$4,079,038	333,701	18,177,777
2049			37.04%	50.05%	$989,273	$316,912	$1,280,071	$6,909	$1,600,842	$4,194,007	320,661	18,498,437
2050			36.55%	49.77%	$1,024,435	$324,240	$1,376,949	$8,724	$1,502,675	$4,237,023	302,756	18,801,194
2051			36.08%	49.82%	$1,061,115	$331,990	$1,416,126	$11,174	$1,433,244	$4,253,649	284,060	19,085,254
2052			35.61%	49.47%	$1,106,193	$339,840	$1,464,813	$9,139	$1,384,333	$4,304,318	268,639	19,353,893
2053			35.14%	49.47%	$1,134,383	$347,466	$1,496,925	$14,889	$1,380,740	$4,374,402	255,153	19,609,046
2054			34.66%	49.38%	$1,177,971	$356,121	$1,545,993	$22,880	$1,342,360	$4,445,327	242,327	19,851,373
2055			34.19%	49.25%	$1,223,021	$364,747	$1,593,720	$27,949	$1,329,430	$4,538,867	231,239	20,082,612
2056			33.72%	49.23%	$1,262,068	$373,263	$1,640,623	$30,133	$1,329,430	$4,635,516	220,713	20,303,325
2057	Anchorage LMS100	Cooper Lake	37.93%	49.04%	$1,322,441	$385,797	$1,701,489	$33,288	$1,343,638	$4,786,652	212,999	20,516,324
2058			36.53%	48.61%	$1,372,591	$445,852	$1,765,190	$33,226	$1,343,638	$4,960,497	206,295	20,722,619
2059			36.04%	48.57%	$1,430,714	$518,902	$1,826,864	$31,309	$1,343,638	$5,151,426	200,219	20,922,838
2060			35.57%	48.39%	$1,480,273	$412,965	$1,879,232	$32,092	$1,315,593	$5,120,155	185,985	21,108,823
			Present Value of Costs		**6,024,495**	**2,107,805**	**3,188,181**	**149,474**	**9,638,868**		**Grand Total**	**21,108,823**

Scenario 2B Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)

Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,729	0	0	4,344	38,073
2012	31,544	0	0	5,351	36,895
2013	30,782	0	0	5,745	36,527
2014	29,533	0	0	4,978	34,510
2015	22,300	0	0	2,660	24,960
2016	21,206	0	0	2,931	24,137
2017	21,504	0	0	2,718	24,222
2018	18,121	9,333	0	2,846	30,300
2019	18,265	8,505	0	2,876	29,646
2020	15,363	7,447	0	3,213	26,023
2021	18,274	5,312	0	2,521	26,108
2022	16,131	5,075	0	2,341	23,547
2023	17,306	5,444	0	2,485	25,235
2024	18,090	4,863	0	2,709	25,663
2025	15,198	6,048	0	2,135	23,381
2026	16,286	6,683	0	1,623	24,592
2027	17,378	6,898	0	0	24,276
2028	17,654	6,802	0	0	24,456
2029	17,734	7,075	0	0	24,809
2030	13,735	6,592	0	0	20,327
2031	13,861	5,722	0	0	19,583
2032	14,037	5,482	0	0	19,518
2033	13,932	5,653	0	0	19,585
2034	14,126	5,736	0	0	19,862
2035	14,240	5,650	0	0	19,890
2036	14,623	5,370	0	0	19,993
2037	17,352	5,224	0	0	22,576
2038	17,154	5,353	0	0	22,507
2039	17,527	5,499	0	0	23,026
2040	31,944	14,295	0	0	46,239
2041	31,757	14,198	0	0	45,956
2042	32,415	12,885	0	0	45,300
2043	32,242	12,717	0	0	44,960
2044	32,303	12,810	0	0	45,113
2045	32,857	12,772	0	0	45,629
2046	32,801	13,321	0	0	46,121
2047	32,648	13,422	0	0	46,070
2048	33,107	13,360	0	0	46,467
2049	32,822	13,701	0	0	46,523
2050	32,986	13,694	0	0	46,679
2051	33,318	13,588	0	0	46,906
2052	33,518	13,900	0	0	47,418
2053	33,414	13,736	0	0	47,150
2054	33,741	13,762	0	0	47,503
2055	33,901	13,984	0	0	47,885
2056	34,108	13,890	0	0	47,998
2057	34,725	14,124	0	0	48,849
2058	35,127	14,122	0	0	49,249
2059	35,493	14,393	0	0	49,885
2060	35,785	14,392	0	0	50,177

Scenario 2B Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Glacier Fork	Anchorage MSW	Anchorage 1x1 6FA	Kenai Wind T Lines	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Chakachamna:Chakachamna	GVEA Wind T Lines	Low Watana (Non-Expandable)	GVEA Wind	Anchorage 2x1 6FA	Kenai Wind	Anchorage 2x1 6FA	Kenai Wind	GVEA 2x1 6FA	GVEA Wind	GVEA LM6000	Anchorage LMS100	Generating Unit Cash Flow ($000)
2011	30,468	99,809	175,454	127,935	39,746	0		0	0	0	0	0		48,624		0		0		0		0	0	522,036
2012				116,563	93,305	65,608								32,371										307,847
2013				119,477	84,604	154,017								30,231										388,329
2014						139,655								41,025										180,680
2015							13,577	18,083						43,102										74,761
2016							125,247	42,450				33,699		503,963										705,359
2017								38,492	72,765			26,866		529,476										667,599
2018									170,818	76,085		43,273		711,878										1,002,055
2019									154,889	178,613	68,804	79,301		840,242										1,321,849
2020										161,957	161,519	238,340		882,779										1,444,596
2021											146,457	481,537		721,781										1,349,775
2022												652,793		758,321										1,411,114
2023												712,138	28,966	796,711										1,537,815
2024												141,426	267,211	39,033										447,670
2025																								
2026																								
2027																								
2028															31,174									31,174
2029															287,577									287,577
2030																								
2031																								
2032																								
2033																								
2034																265,427								265,427
2035																529,157	22,233							551,390
2036																175,050	205,103							380,153
2037																		285,836		285,836				571,672
2038																		569,844	23,943	569,844				1,163,631
2039																		188,510	220,874	188,510				597,893
2040																					41,925			41,925
2041																					386,759			386,759
2042																								
2043																								
2044																						27,076		27,076
2045																						123,405		123,405
2046																								
2047																								
2048																								
2049																								
2050																								
2051																								
2052																								
2053																								
2054																							3,703	3,703
2055																							337,773	337,773
2056																							51,024	51,024
2057																								
2058																								
2059																								
2060																								
Total																								16,182,068

Scenario 2B Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Cash Flow ($000)	Total Transmission Project Cash Flow ($000)	Total Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	522,036	79,848	601,884	651	351,493	43,795	34,722		5,372
2012	307,847	3,365	311,212	1,491	360,816	48,337	37,987	54,859	5,412
2013	388,329	51,272	439,601	3,063	373,571	48,328	37,848	60,950	5,424
2014	180,680	228,409	409,088	5,878	355,455	49,454	37,160	66,555	5,421
2015	74,761	314,097	388,859	10,455	355,881	48,327	39,179	62,699	5,167
2016	705,359	129,804	835,164	12,759	391,713	48,775	40,682	69,675	5,147
2017	667,599	8,812	676,411	11,891	357,236	49,059	43,284	73,636	5,129
2018	1,002,055	97,549	1,099,604	12,241	275,319	47,413	38,642	80,008	5,105
2019	1,321,849	214,570	1,536,419	12,657	296,301	46,596	39,711	87,426	5,085
2020	1,444,596	166,433	1,611,028	13,124	313,065	64,626	39,972	88,585	5,068
2021	1,349,775	73,715	1,423,490	13,346	319,829	68,386	38,900	95,077	5,052
2022	1,411,114	198,726	1,609,841	14,024	303,446	86,668	40,092	96,696	5,081
2023	1,537,815	234,141	1,771,956	4,166	338,009	82,114	41,446	101,020	5,111
2024	447,670	52,388	500,059	3,313	354,550	83,658	41,692	111,759	5,140
2025		10,784	10,784	4,222	327,284	127,467	49,890	109,666	8,459
2026		11,289	11,289	5,342	355,930	129,959	38,323	129,694	8,492
2027		0	0	8,551	354,583	132,545	39,316	141,138	8,526
2028	31,174	0	31,174	13,323	362,315	135,187	40,476	156,239	8,569
2029	287,577	0	287,577	16,151	370,599	137,934	41,783	173,790	8,594
2030		0	0	17,064	324,824	139,466	49,046	170,425	8,629
2031		0	0	14,951	287,389	141,743	44,020	167,924	8,663
2032		0	0	15,081	291,077	144,820	45,559	181,400	8,707
2033		0	0	15,919	294,120	147,862	46,600	195,275	8,732
2034	265,427	0	265,427	16,747	300,588	150,891	47,970	213,080	8,767
2035	551,390	0	551,390	18,111	303,932	154,111	49,423	228,670	8,802
2036	380,153	0	380,153	5,493	304,372	157,495	50,450	248,912	8,847
2037	571,672	0	571,672	7,019	337,305	165,776	55,994	284,317	8,873
2038	1,163,631	0	1,163,631	6,453	335,376	169,134	57,608	306,870	8,908
2039	597,893	0	597,893	8,848	355,211	172,691	59,250	335,719	8,944
2040	41,925	0	41,925	12,284	726,114	177,577	84,251	658,141	12,283
2041	386,759	0	386,759	18,825	749,303	181,035	85,917	705,228	12,301
2042		0	0	21,552	764,582	170,684	95,461	750,700	12,337
2043		0	0	22,199	785,633	174,300	98,178	804,064	12,373
2044	27,076	0	27,076	23,458	815,768	178,239	100,883	870,100	12,427
2045	123,405	0	123,405	22,134	852,178	181,923	103,612	937,781	12,446
2046		0	0	22,961	890,057	188,926	106,288	1,020,949	12,482
2047		0	0	24,452	918,798	192,983	109,044	1,096,440	12,519
2048		0	0	25,398	957,221	197,244	112,564	1,185,769	12,574
2049		0	0	6,909	989,273	201,602	115,310	1,280,071	12,593
2050		0	0	8,724	1,024,435	205,989	118,251	1,376,949	12,630
2051		0	0	11,174	1,061,115	210,312	121,678	1,416,126	12,668
2052		0	0	9,139	1,106,193	214,955	124,885	1,464,813	12,723
2053		0	0	14,889	1,134,383	219,711	127,755	1,496,925	12,743
2054	3,703	0	3,703	22,880	1,177,971	224,508	131,614	1,545,993	12,781
2055	337,773	0	337,773	27,949	1,223,021	229,617	135,130	1,593,720	12,819
2056	51,024	0	51,024	30,133	1,262,068	234,567	138,695	1,640,623	12,875
2057		0	0	33,288	1,322,441	243,013	142,783	1,701,489	12,896
2058		0	0	33,226	1,372,591	300,121	145,731	1,765,190	12,934
2059		0	0	31,309	1,430,714	368,398	150,504	1,826,864	12,973
2060		0	0	32,092	1,480,273	257,872	155,093	1,879,232	13,030
Total	16,182,068	1,875,203	Total of Cash Flows & D	18,804,578					

Scenario 2B Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type

	Natural Gas		Coal		Nuclear		Fuel Oil		Purchase Power		Hydro		Geothermal		Municipal Solid Waste		Wind		Ocean Tidal	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,547	80	435			251	576	25	210	176	591					15	49		
2012	1,104	3,424	80	494			251	505	25	215	176	593					69	231		
2013	1,041	3,360	80	567			251	512	25	214	176	591					69	226		
2014	1,176	3,140	80	643			251	434	25	214	251	649			22	163	69	227		
2015	1,176	2,434	80	620			251	638	25	212	251	919			22	163	69	227		
2016	822	2,323	80	625			251	726	25	214	251	921			22	163	69	228		
2017	822	2,355	80	615			251	602	25	212	251	919			22	159	99	326		
2018	821	2,383	80	562			189	618	25	213	251	919			22	166	99	326		
2019	821	2,399	80	581			189	576	25	213	251	919			22	163	99	325		
2020	1,103	2,594	80	574					25	190	251	921	50	403	22	162	99	327		
2021	907	2,611	80	552					25	178	251	919	50	401	22	161	99	326		
2022	825	2,274	80	542					25	175	251	919	100	797	22	157	99	326		
2023	743	2,456	80	398					25	167	251	919	100	800	22	159	99	326		
2024	743	2,505	53	381					25	155	251	921	100	811	22	151	99	326		
2025	743	2,303	53	322					25	188	1,181	4,435	100	790	22	158	149	489		
2026	743	2,485	53	352							1,181	4,450	100	788	22	155	149	491		
2027	701	2,519	53	348							1,181	4,448	100	798	22	153	149	491		
2028	701	2,546	53	349							1,181	4,466	100	796	22	155	149	491		
2029	701	2,583	53	344							1,181	4,451	100	802	22	154	149	490		
2030	701	2,416	53	355							1,181	4,453	100	795	22	146	199	653		
2031	531	2,402	53	354							1,181	4,478	100	772	22	139	199	653		
2032	467	2,401	53	360							1,181	4,484	100	802	22	148	199	656		
2033	467	2,408	53	359							1,181	4,480	100	792	22	144	199	655		
2034	467	2,446	53	367							1,181	4,476	100	785	22	144	199	655		
2035	467	2,450	53	361							1,181	4,488	100	819	22	147	199	655		
2036	777	2,455	53	370							1,181	4,487	100	801	22	153	199	654		
2037	777	2,687	53	340							1,181	4,497	100	687	22	103	229	754		
2038	745	2,689	53	344							1,181	4,479	100	737	22	114	229	754		
2039	1,380	2,753	53	346							1,181	4,482	100	715	22	110	229	754		
2040	1,380	5,850	53	363							1,181	4,495	100	768	22	155	259	867		
2041	1,380	5,805	53	363							1,181	4,496	100	834	22	161	259	850		
2042	1,380	5,732	53	375							1,181	4,510	100	771	22	144	309	1,014		
2043	1,317	5,687	53	377							1,181	4,513	100	816	22	158	309	1,018		
2044	1,317	5,719	53	379							1,181	4,527	100	809	22	174	309	1,019		
2045	1,317	5,785	53	376							1,181	4,517	100	807	22	144	309	1,017		
2046	1,364	5,822	53	374							1,181	4,518	100	768	22	170	309	1,017		
2047	1,364	5,813	53	375							1,181	4,531	100	801	22	164	309	1,014		
2048	1,364	5,874	53	377							1,181	4,547	100	802	22	146	309	1,019		
2049	1,364	5,868	53	374							1,181	4,535	100	809	22	172	309	1,018		
2050	1,364	5,890	53	375							1,181	4,537	100	801	22	160	309	1,018		
2051	1,364	5,916	53	376							1,181	4,541	100	827	22	157	309	1,017		
2052	1,364	5,984	53	375							1,181	4,565	100	786	22	154	309	1,019		
2053	1,364	5,962	53	377							1,181	4,556	100	801	22	161	309	1,014		
2054	1,364	6,012	53	380							1,181	4,559	100	802	22	161	309	1,018		
2055	1,364	6,045	53	376							1,181	4,561	100	801	22	161	309	1,018		
2056	1,364	6,069	53	378							1,181	4,577	100	794	22	176	309	1,019		
2057	1,462	6,087	53	379							1,181	4,569	100	818	22	146	309	1,017		
2058	1,462	6,145	53	381							1,162	4,544	100	779	22	176	309	1,014		
2059	1,462	6,231	53	382							1,162	4,547	100	803	22	161	309	1,014		
2060	1,462	6,267	53	384							1,162	4,558	100	805	22	147	309	1,019		