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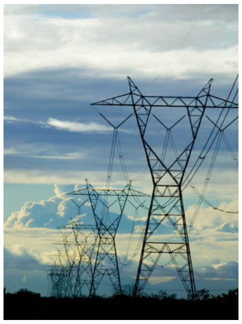


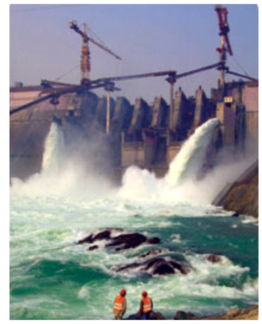


Alaska Railbelt Regional Integrated Resource Plan (RIRP) Study

Final Report

February 2010

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Alaska Energy Authority

- 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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- Nick Goodman, TDX Power, Inc.
- Pat Lavin, National Wildlife Federation - Alaska
- Steve Denton, Usibelli Coal Mine, Inc.
- 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)
- Dick Schober, Seattle-Northwest Securities Corporation
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- Jeb Spengler, Seattle-Northwest Securities Corporation
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- Kevin Banks, Alaska Department of Natural Resources
- Mark Myers, Alaska Department of Natural Resources
- Paul Berkshire, HDR, Inc.
- 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 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.

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

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
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- Duplicative G&T expertise

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	**Simple Cycle Combustion Turbines**	**Hydroelectric Projects**
• Appliances	• LM6000 (48 MW)	• Susitna
• Water Heating	• LMS100 (96 MW)	• Chakachamna
• Lighting	**Combined Cycle**	• Glacier Fork
• Shell	• 1x1 6FA (154 MW)	• Generic Hydro – Kenai
• Cooling/Heating	• 2X1 6FA (310 MW)	• Generic Hydro - MEA
Commercial	**Coal Units**	**Wind**
• Water Heating	• Healy Clean Coal	• BQ Energy/Nikiski
• Office Loads	• Generic – 130 MW	• Fire Island
• Motors		• Generic Wind – Kenai
• Lighting		• Generic Wind - GVEA
• Refrigeration		**Geothermal**
• Cooling/Heating		• 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**.

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  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

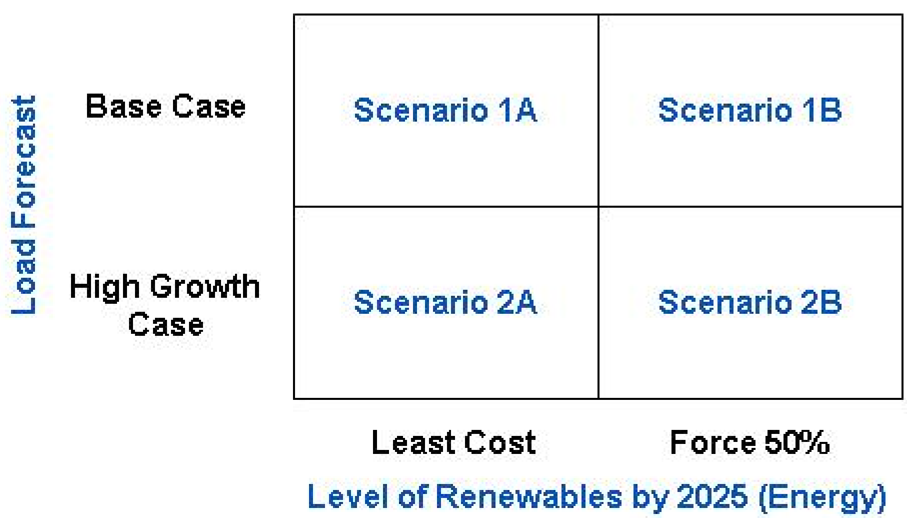
Black & Veatch, in collaboration with the Advisory Working Group that was assembled by the AEA for this project, developed four Evaluation Scenarios; Black & Veatch then developed a 50-year resource plan for each of these Evaluation Scenarios.

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:

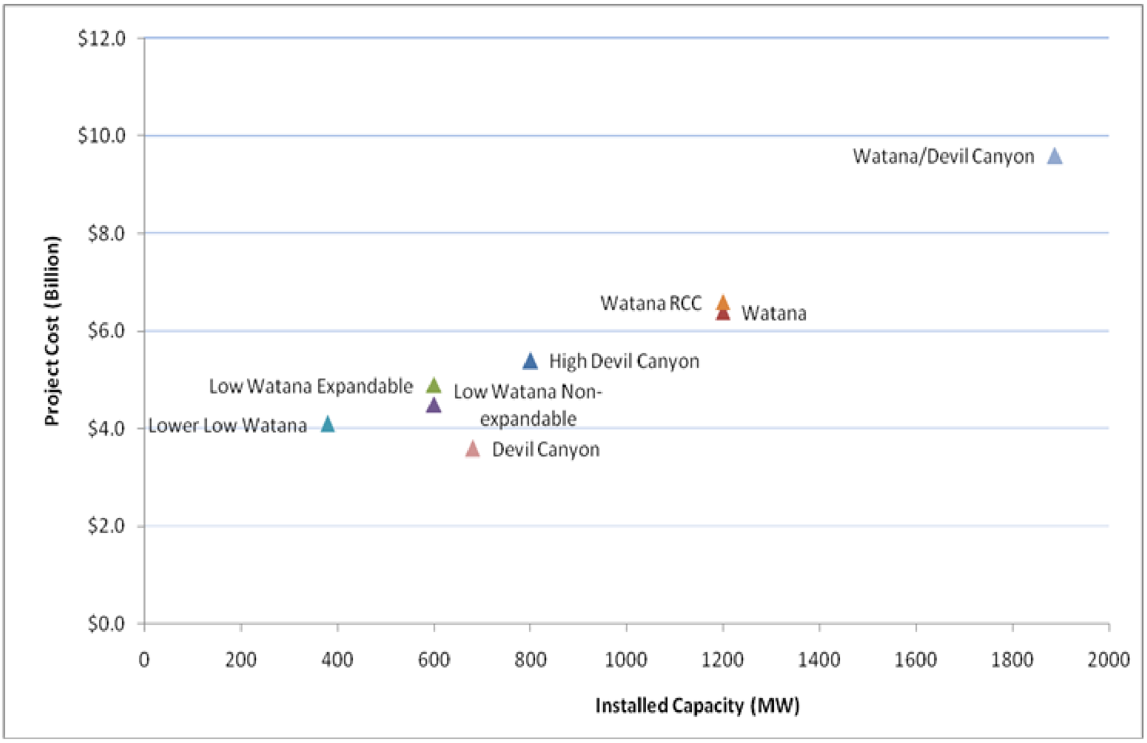
- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing four turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative 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:

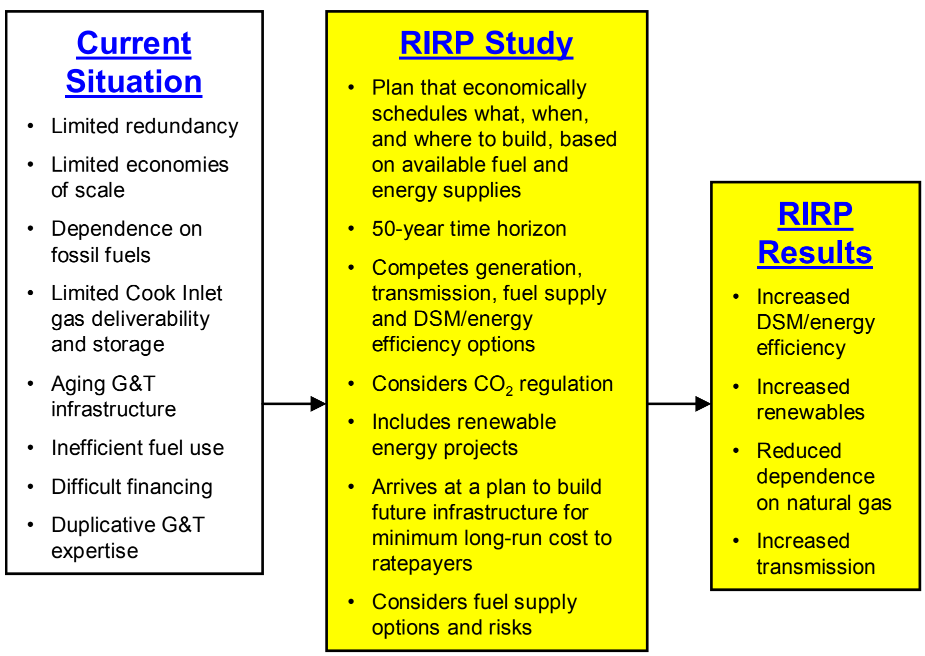
- Transmission systems that need to be replaced because of age and condition (Category 1)
- Transmission projects required to improve grid reliability, power transfer capability, and reserve sharing (Category 2)
- Transmission projects required to connect new generation projects to the grid (Category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

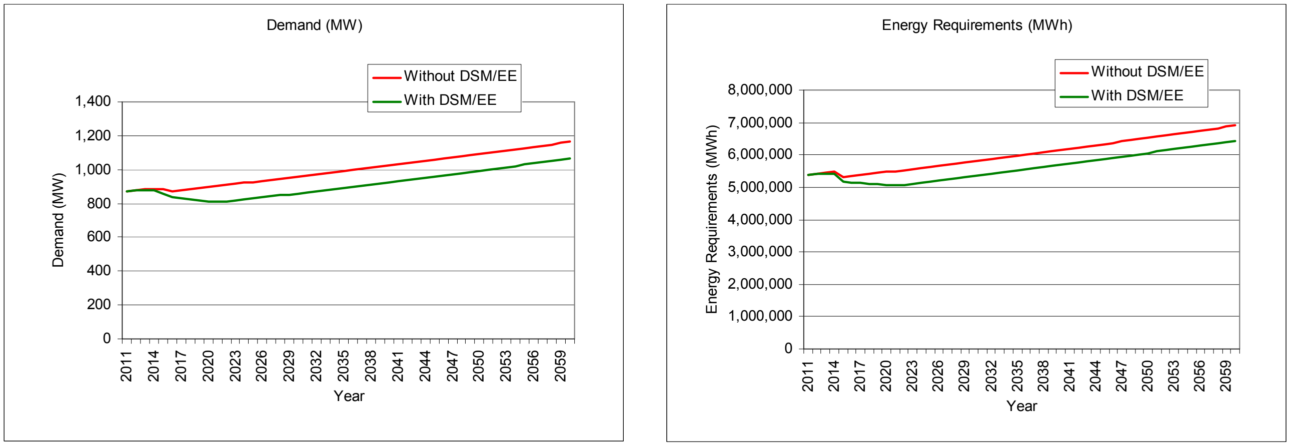
1.7.1.1 DSM/EE Resources

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



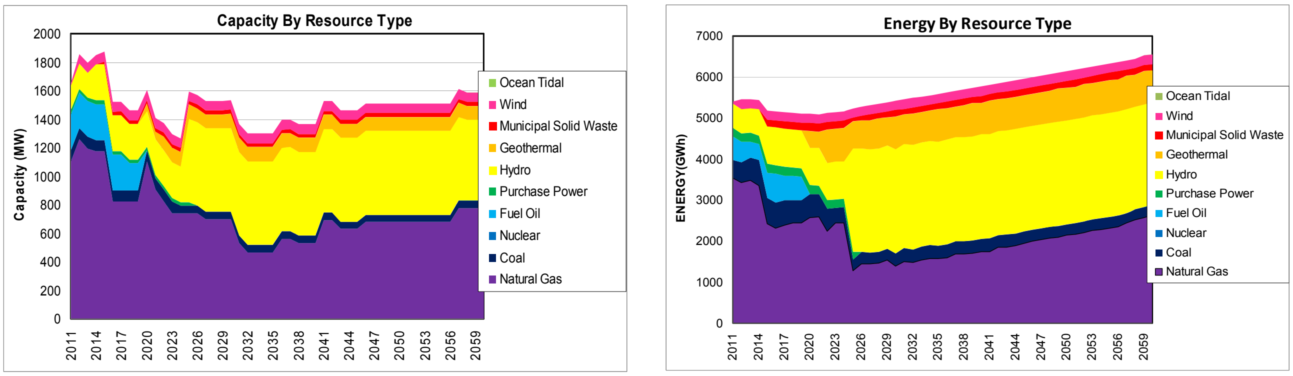
It should be noted that this study did not include an evaluation of innovative rate designs (e.g., real-time pricing and demand response rates), nor did it consider the potential benefits of a Smart Grid, and the associated widespread implementation of smart meters. These options could result in even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

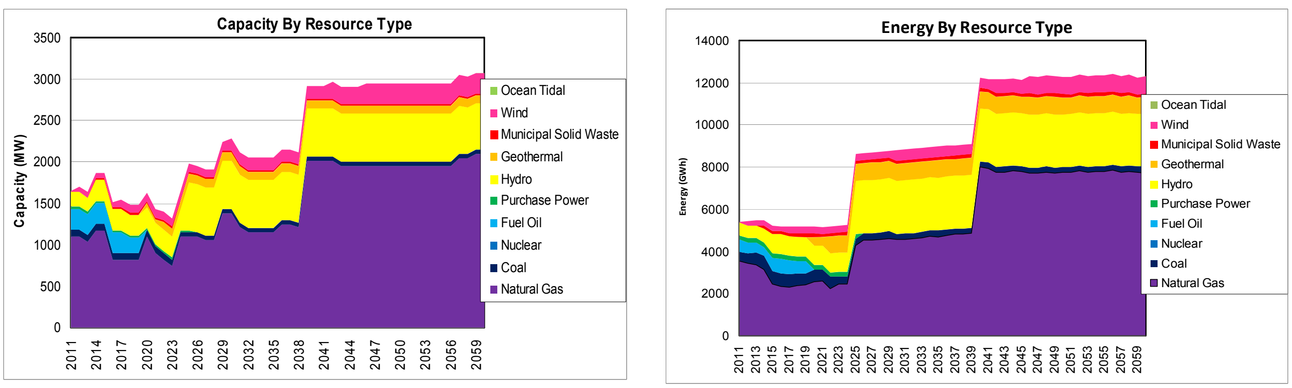
1.7.1.2 Results – Scenarios 1A/1B Reference Cases

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



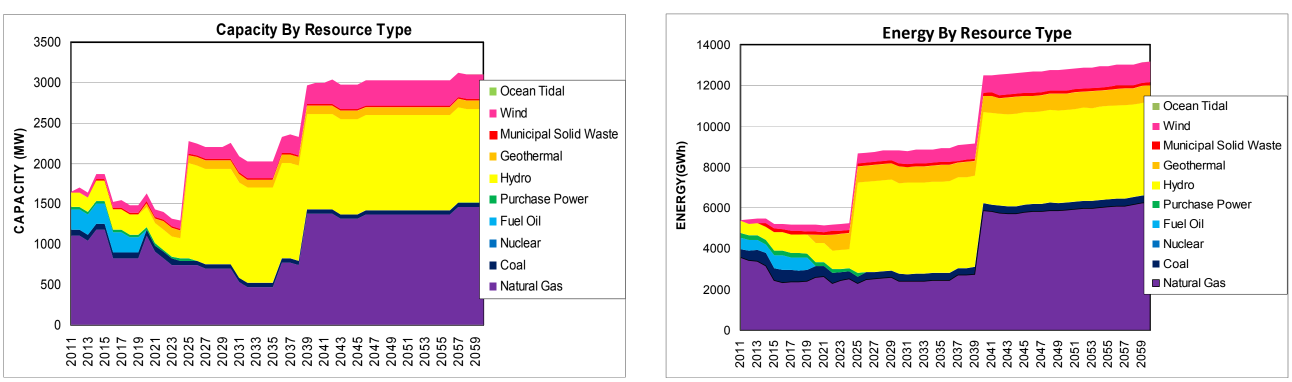
1.7.1.3 Results – Scenario 2A Reference Case

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

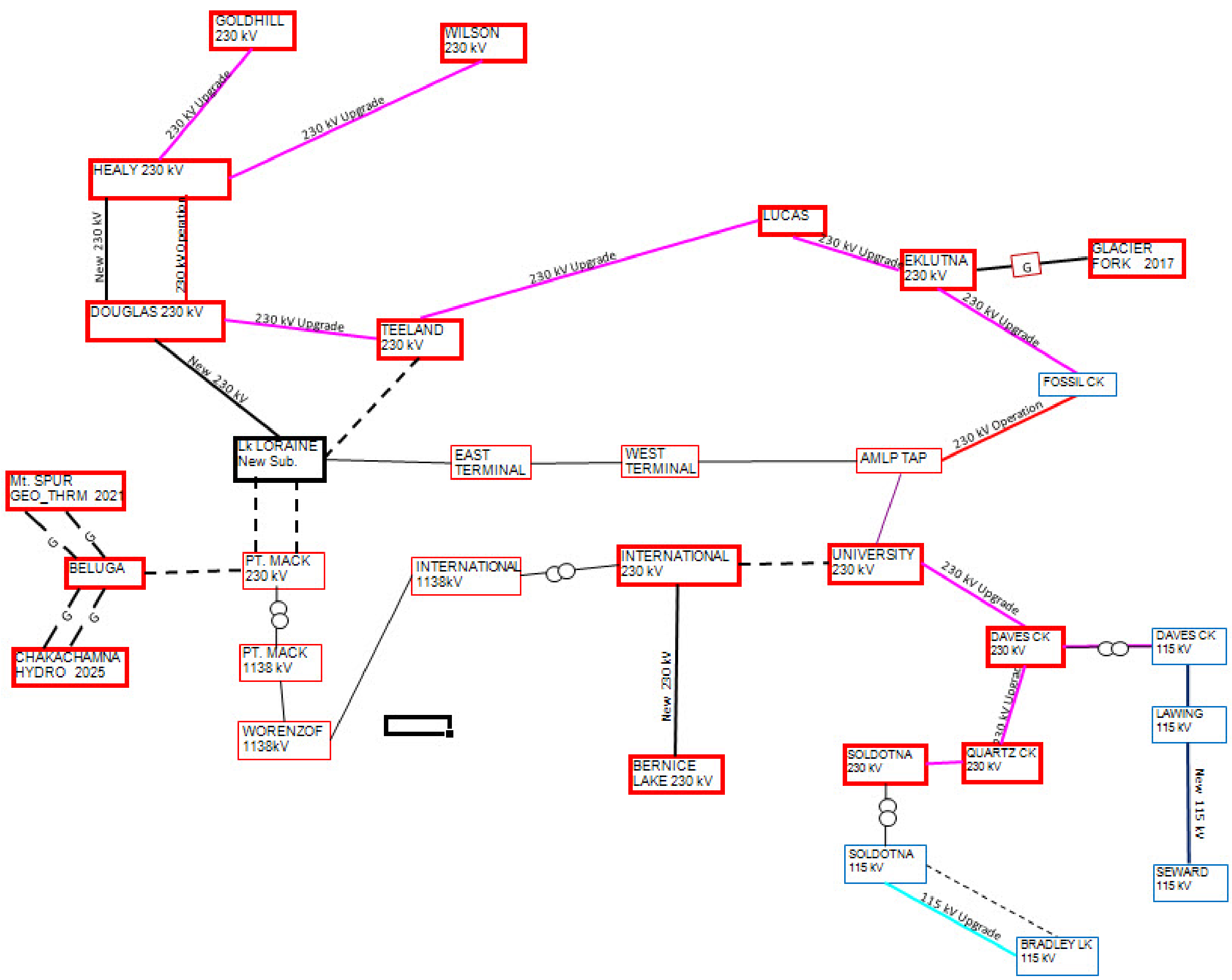
Table 1-6 lists the proposed transmission system expansions and enhancements that resulted from our transmission analysis. More detailed information on each of the identified transmission projects is provided in **Section 12**.

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)

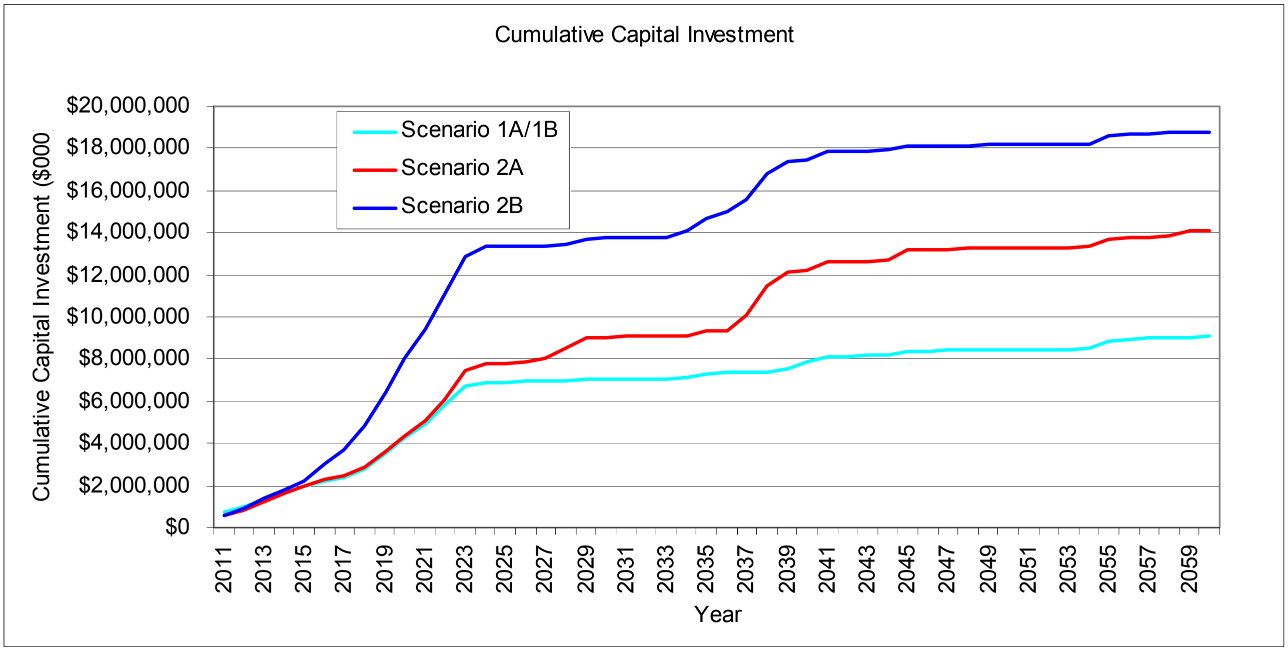
The total estimate costs necessary for transmission projects during the initial five years of the RIRP is $510 million in 2009 dollars.

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:

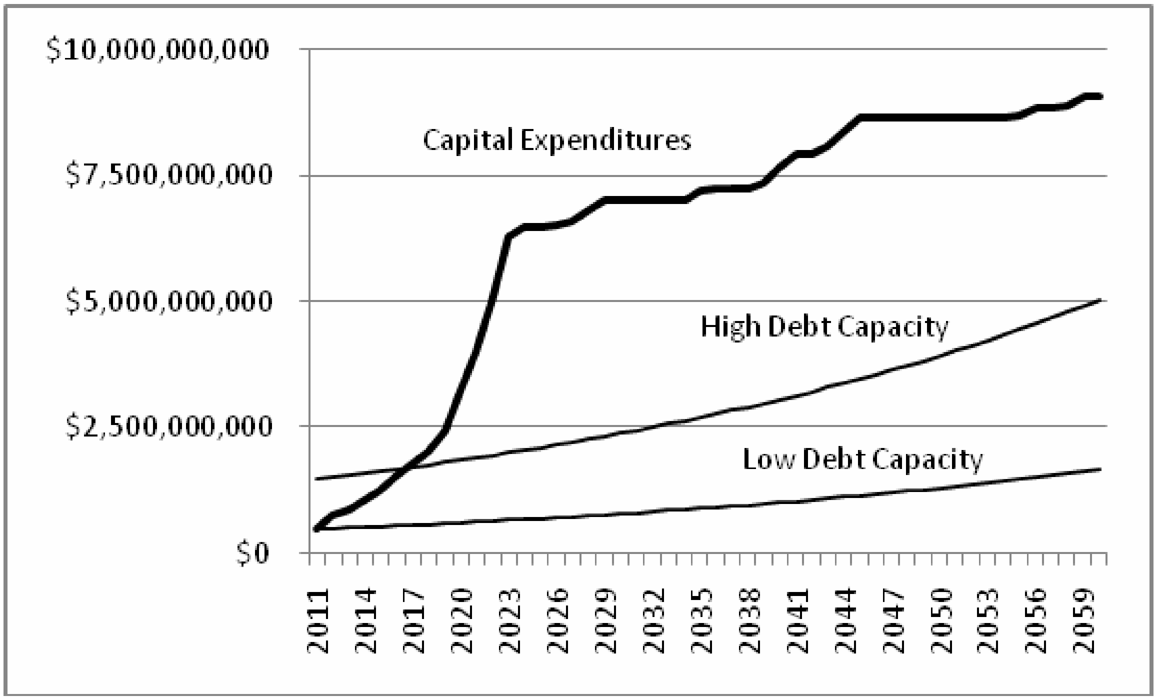
- Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities.
- Analyze strategies to capitalize selected RIRP assets by integrating State (which could include loans, State appropriations, Permanent Fund, State moral obligation bonds, etc.) and federal (e.g., USDA-RUS) 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

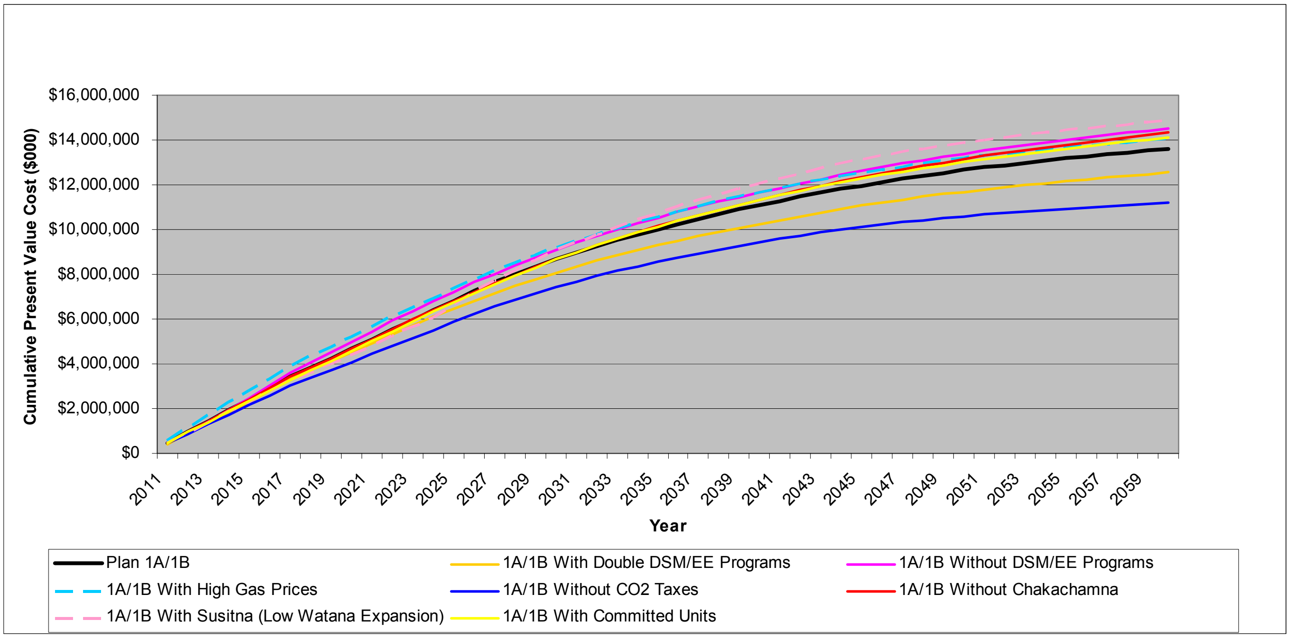
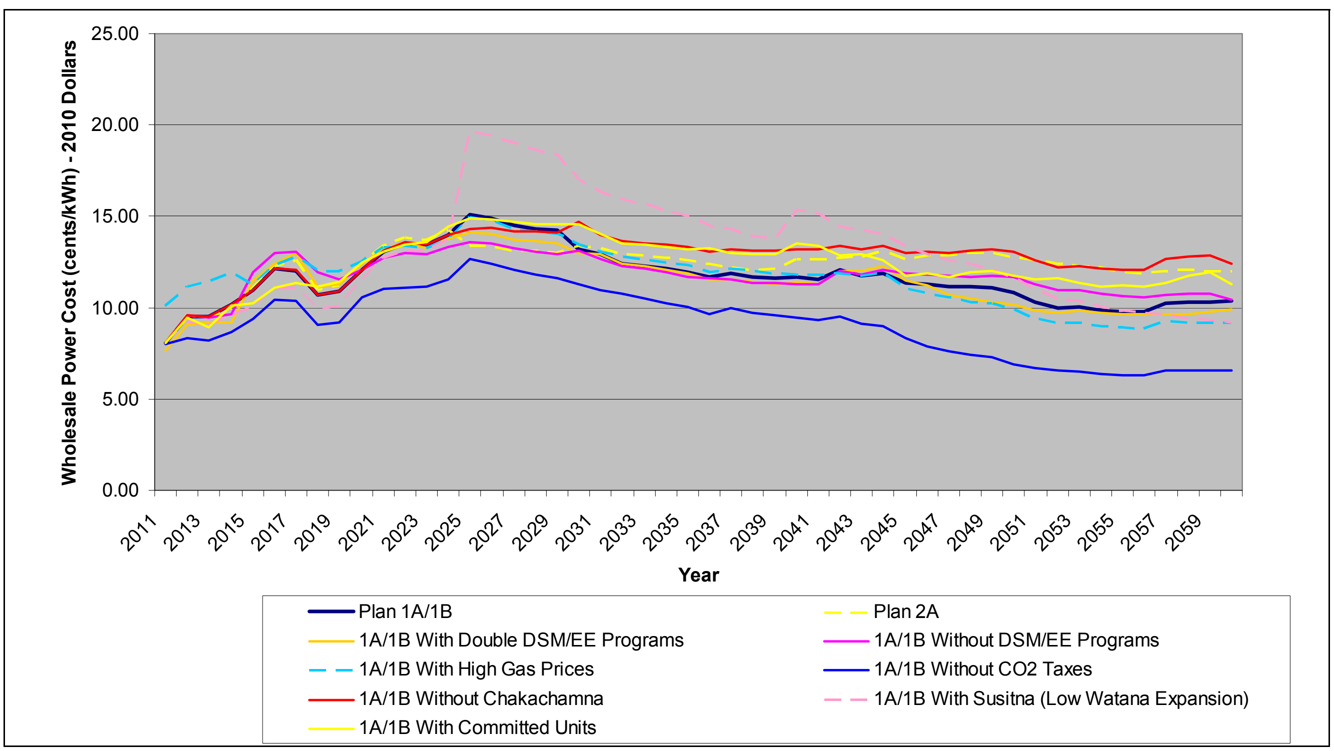


Figure 1-11
Annual Wholesale Power Cost – Selected Reference and Sensitivity Cases



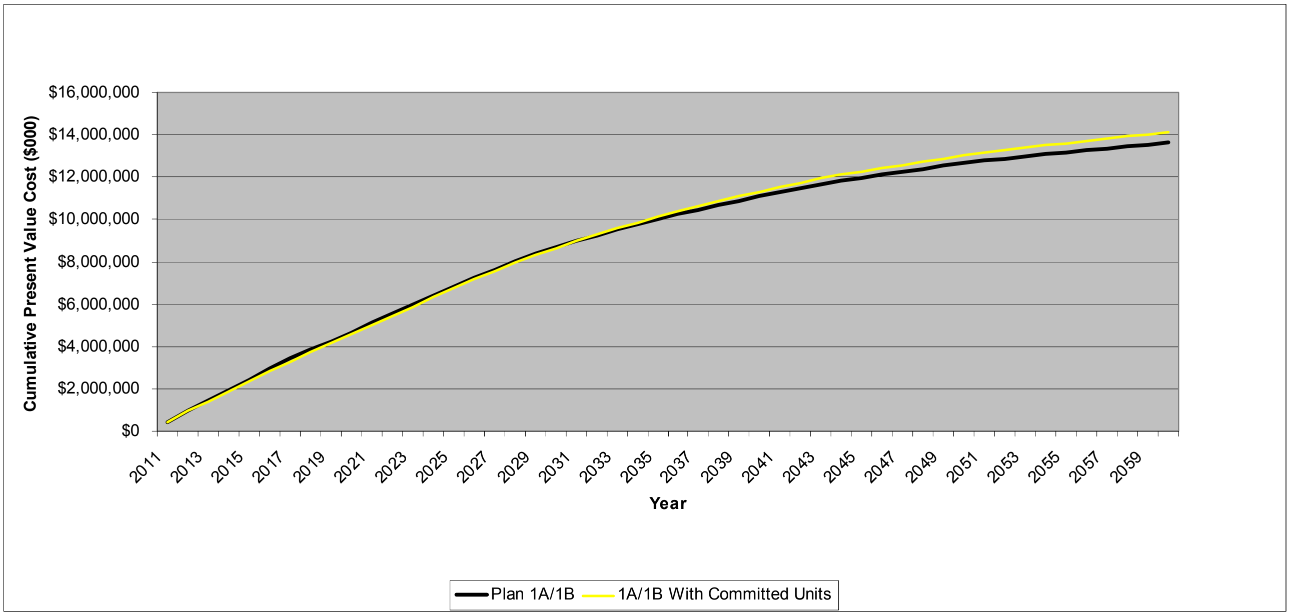
As can be seen in Figure 1-10, which shows cumulative net present value costs over the 50-year planning horizon, the 1A/1B With Susitna (Low Watana Expansion), 1A/1B With no DSM/EE Programs, 1A/1B Without Chakachamna, 1A/1BWith Committed Units, and 1A/1B With High Gas Prices Sensitivity Cases are all 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.

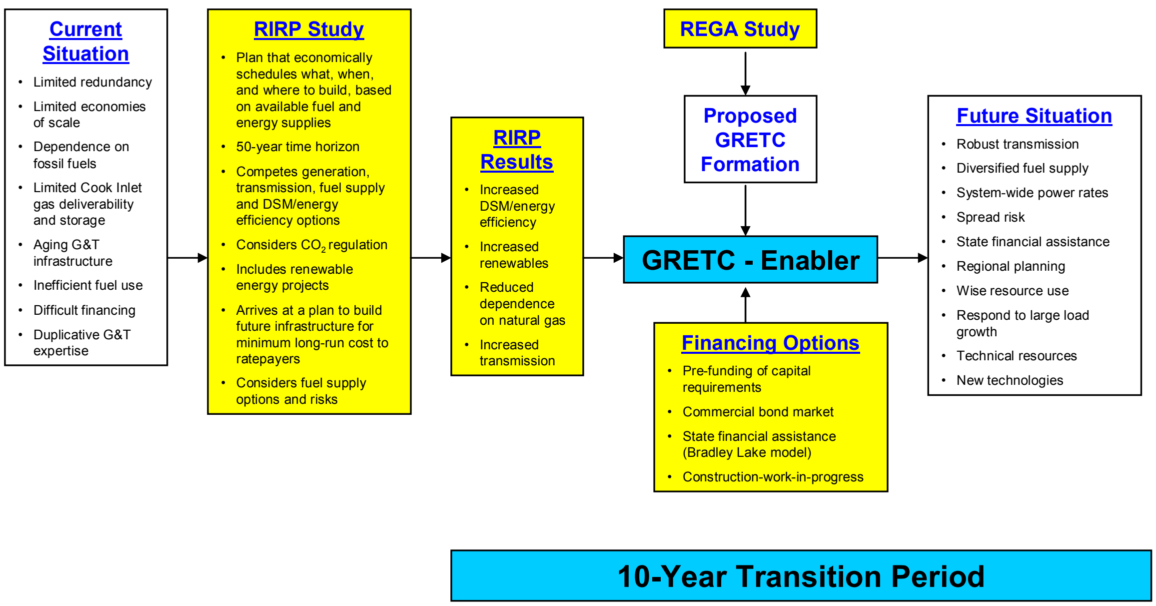
Figure 1-12
Comparison of Results - Scenario 1A/1B Versus Committed Units Sensitivity Case



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: ○ 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 projects ○ 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: ○ Development of local gas storage capabilities 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 ○ 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	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: ○ 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	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: ○ Soldotna to Quartz Creek Transmission Line ○ Quartz Creek to University Transmission Line ○ Douglas to Teeland Transmission Line ○ Lake Lorraine to Douglas Transmission Line ○ SVCs ○ Funds to undertake the study of the Southern Intertie ○ 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