13.0 SUMMARY OF RESULTS

The purpose of this section is to summarize the results of the RIRP analysis. We begin by providing a summary of the reference case results for each of the four Evaluation Scenarios, followed by a summary of the results for the various sensitivity cases that were evaluated. We then provide a comparative summary of the economic and emission results for all cases. This is followed by a summary of the results of the transmission analysis that was completed and, finally, the results of the financial analysis.

13.1 Results of Reference Cases

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

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

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

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

13.1.1 Results - DSM/EE Resources

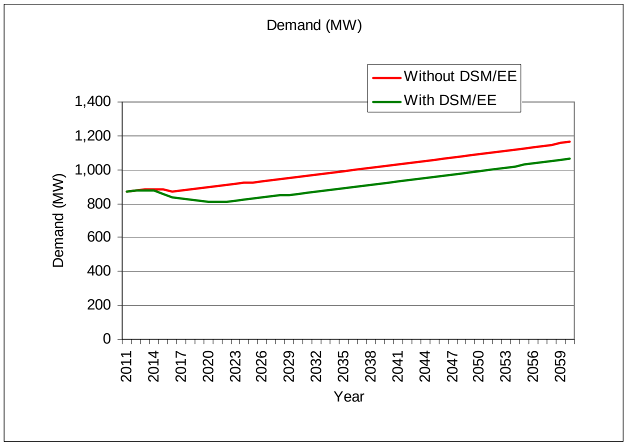
As discussed in Section 11, Black & Veatch screened a broad array of residential and commercial DSM/EE measures. Based on this screening, 21 residential and 51 commercial DSM/EE measures were selected for inclusion in the RIRP models, Strategist® and PROMOD®, as potential resources to be selected.

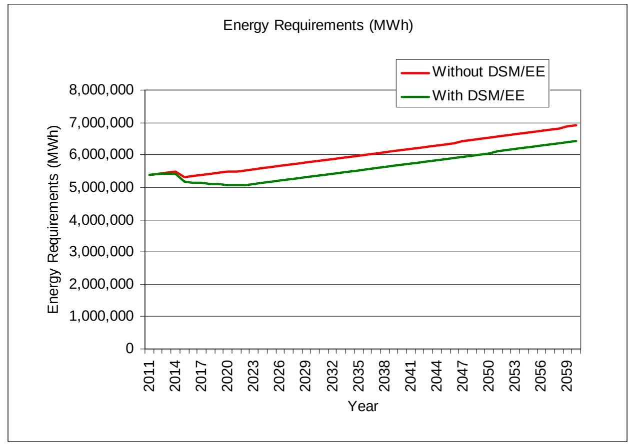
Based upon the relative economics and savings of these screened residential and commercial DSM/EE measures, from the utility perspective, all of the residential and commercial DSM/EE measures were selected in each of the four Evaluation Scenarios. As discussed in Section 11, the penetration of the measures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

Since the maximum allowed level of DSM/EE resources were selected in each of the four Evaluation Scenarios, we summarize the resulting impact on the Base Case Load Forecast for Scenario 1A in the following graphic.

As can be seen in Figure 13-1, DSM/EE measures result in a significant impact on the region's capacity and energy requirements. After the initial program start-up years, DSM/EE measures reduce the region's capacity requirements by approximately 8 percent. A similar level of impact is also shown for annual energy requirements.

Figure 13-1
Impact of DSM/EE Resources – Base Case Load Forecast

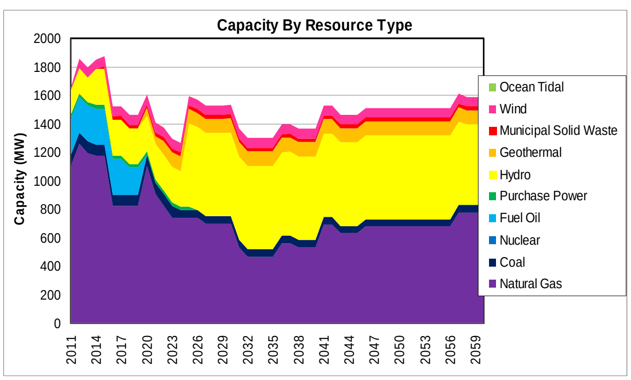


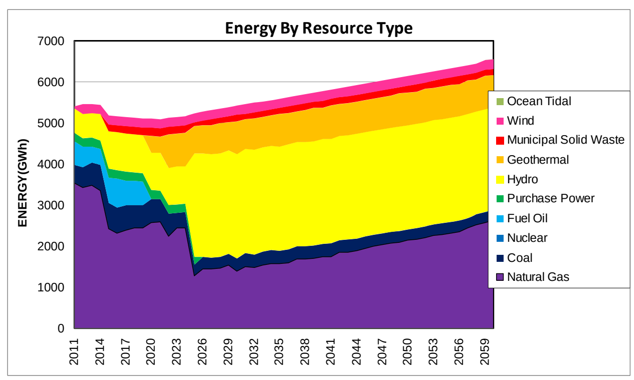


It should be noted that this study did not include an evaluation of innovative rate designs (e.g., real-time pricing and demand response rates), nor did it consider the potential benefits of a Smart Grid and the associated widespread implementation of smart meters. These options could result in even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

13.1.2 Results - Scenarios 1A/1B Reference Cases

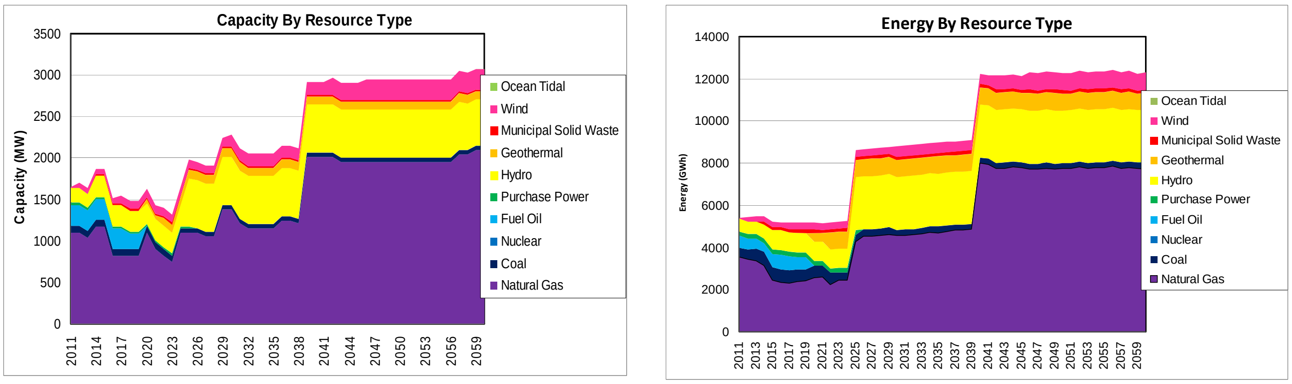
Figure 13-2
Results – Scenarios 1A/1B Reference Cases





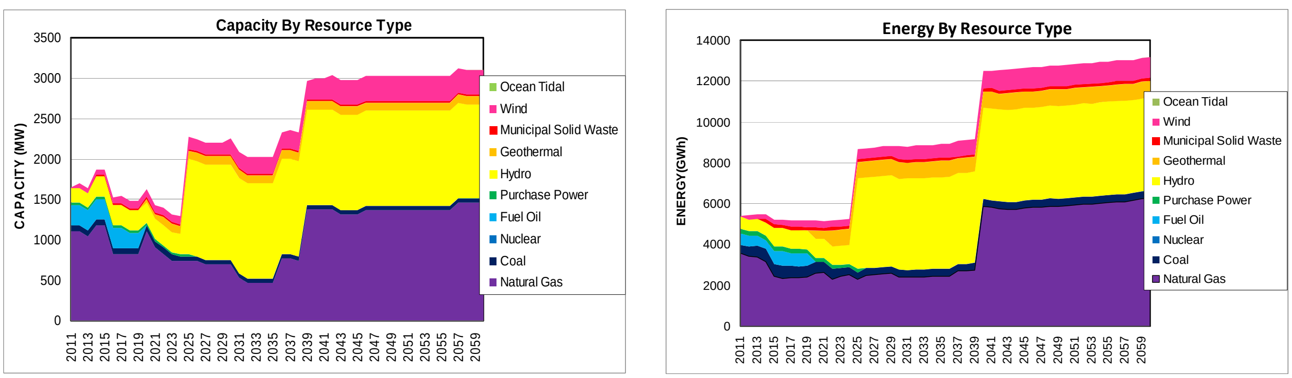
13.1.3 Results - Scenario 2A Reference Case Results

Figure 13-3
Results – Scenario 2A Reference Case



13.1.4 Results - Scenario 2B Reference Case Results

Figure 13-4
Results – Scenario 2B Reference Case



13.2 Results of Sensitivity Cases

In this subsection, we list the various sensitivity cases that were evaluated. We then provide graphics that summarize the results for each sensitivity case. Additional summary information on the results of each sensitivity case is provided at the end of this section.

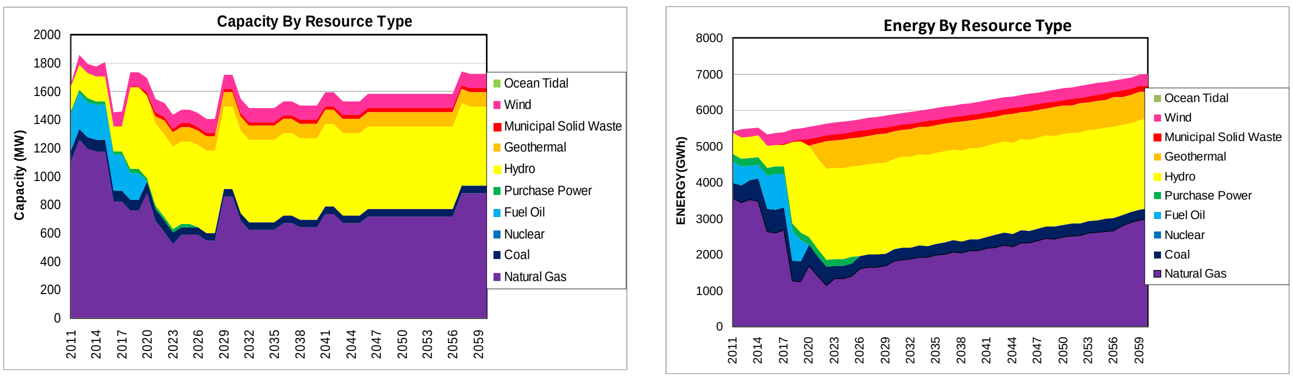
13.2.1 Sensitivity Cases Evaluated

- Scenarios 1A/1B Without DSM/EE Measures
- Scenarios 1A/1B With Double DSM/EE Measures
- Scenarios 1A/1B With Committed Units Included
- Scenarios 1A/1B Without CO_2 Costs
- Scenarios 1A/1B With Higher Gas Prices
- Scenarios 1A/1B Without Chakachamna
- Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%
- Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

- Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced
- Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced
- Scenarios 1A/1B With Susitna (Watana Option) Forced
- Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced
- Scenarios 1A/1B With Modular Nuclear
- Scenarios 1A/1B With Tidal
- Scenarios 1A/1B With Lower Coal Capital and Fuel Costs
- Scenarios 1A/1B With Federal Tax Credits for Renewables

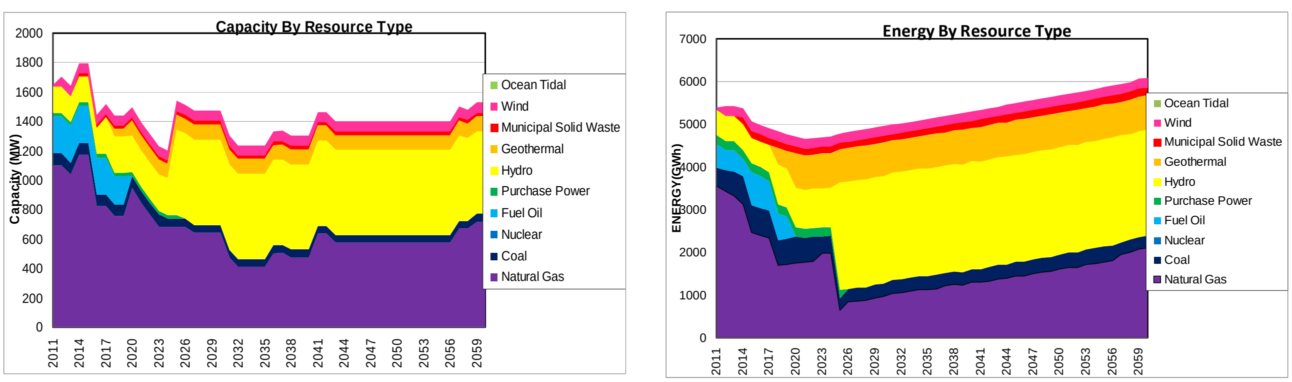
13.2.2 Sensitivity Results – Scenarios 1A/1B Without DSM/EE Measures

Figure 13-5
Sensitivity Results – Scenarios 1A/1B Without DSM/EE Measures



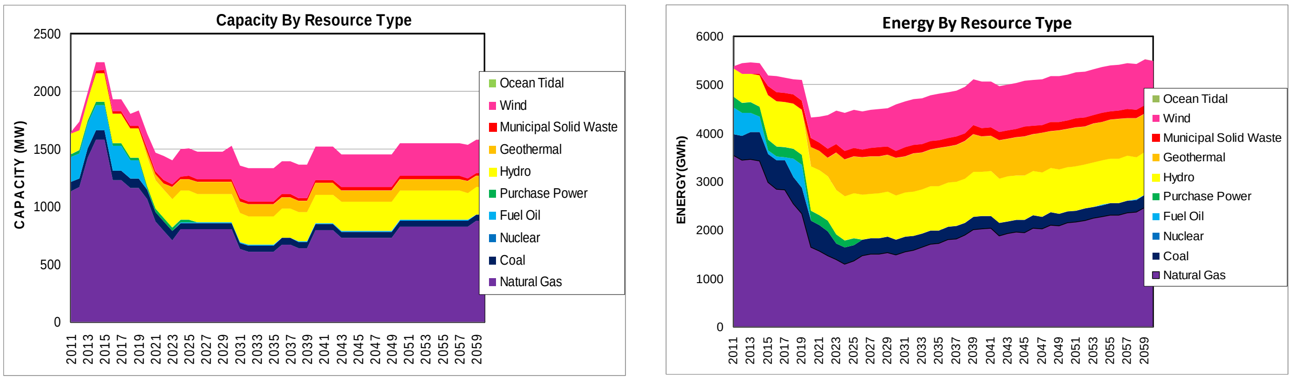
13.2.3 Sensitivity Results – Scenarios 1A/1B With Double DSM/EE Measures

Figure 13-6
Sensitivity Results – Scenarios 1A/1B With Double DSM/EE Measures



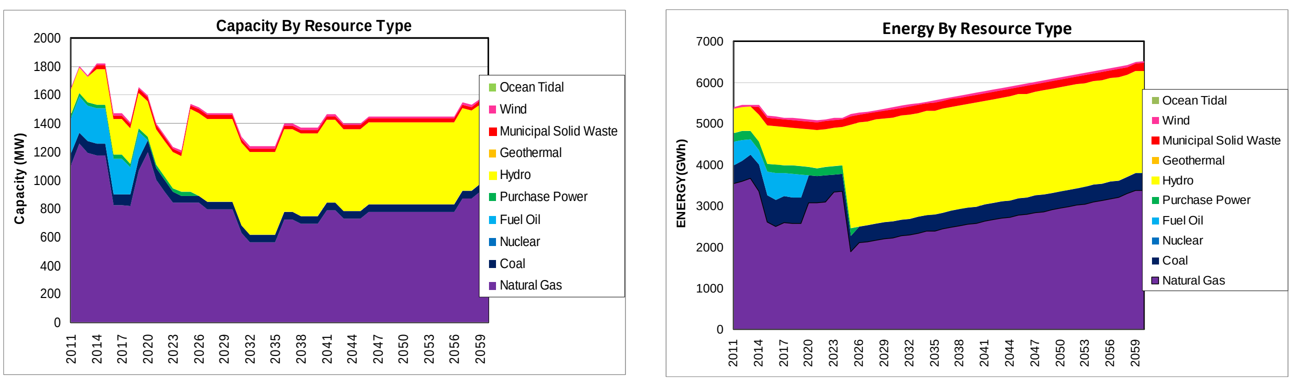
13.2.4 Sensitivity Results – Scenarios 1A/1B With Committed Units Included

Figure 13-7
Sensitivity Results – Scenarios 1A/1B With Committed Units Included



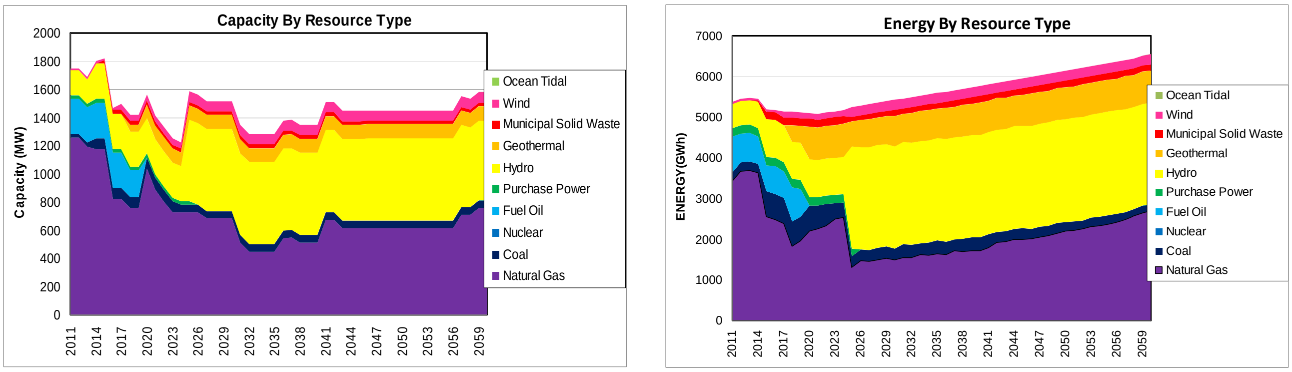
13.2.5 Sensitivity Results – Scenarios 1A/1B Without CO_2 Costs

Figure 13-8
Sensitivity Results – Scenarios 1A/1B Without CO_2 Costs



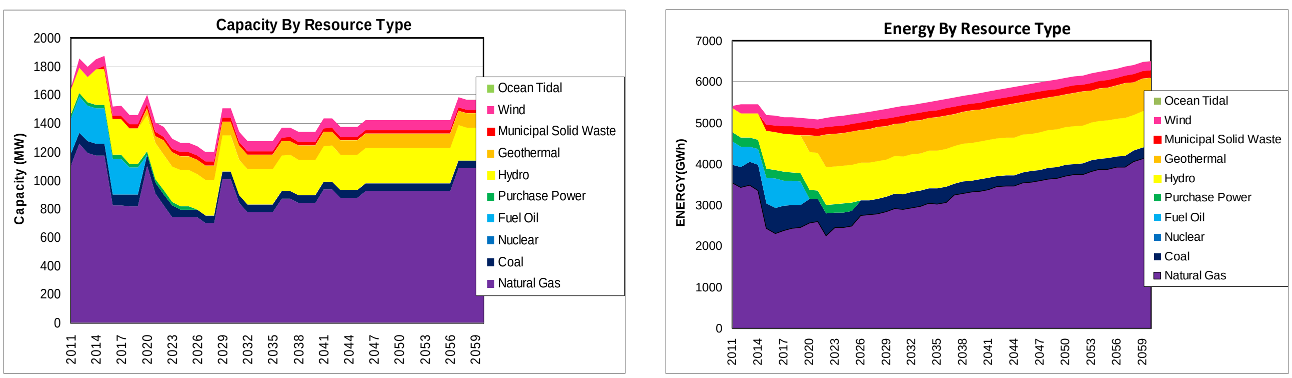
13.2.6 Sensitivity Results – Scenarios 1A/1B With Higher Gas Prices

Figure 13-9
Sensitivity Results – Scenarios 1A/1B With Higher Gas Prices



13.2.7 Sensitivity Results – Scenarios 1A/1B Without Chakachamna

Figure 13-10
Sensitivity Results – Scenarios 1A/1B Without Chakachamna

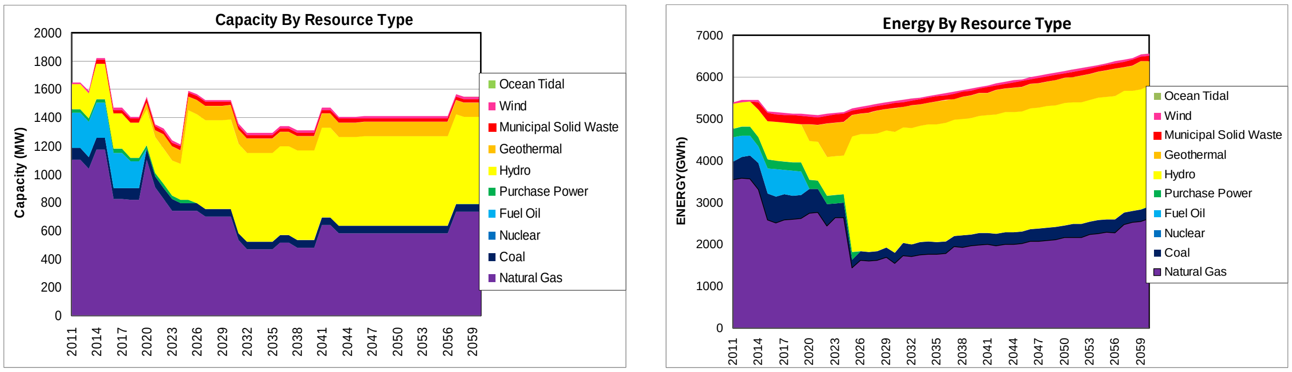


13.2.8 Sensitivity Results – Scenarios 1A/1B With Chakachamna Capital Costs Increased by 75%

When Chakachamna's capital costs are increased by 75 percent, it is no longer selected as a resource in the resource plan. As a result, the results of this sensitivity case are the same as the Scenario 1A Without Chakachmna Sensitivity Case above. Consequently, the resulting breakdown of capacity and energy generated by resource type is the same as the graphs shown in Figure 13-10.

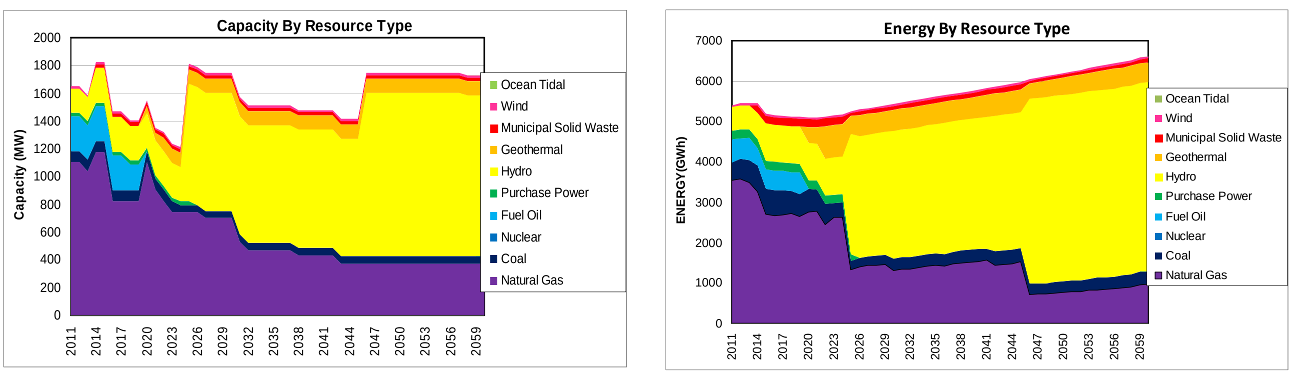
13.2.9 Sensitivity Results – Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced

Figure 13-11
Sensitivity Results – Scenarios 1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced



13.2.10 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

Figure 13-12
Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

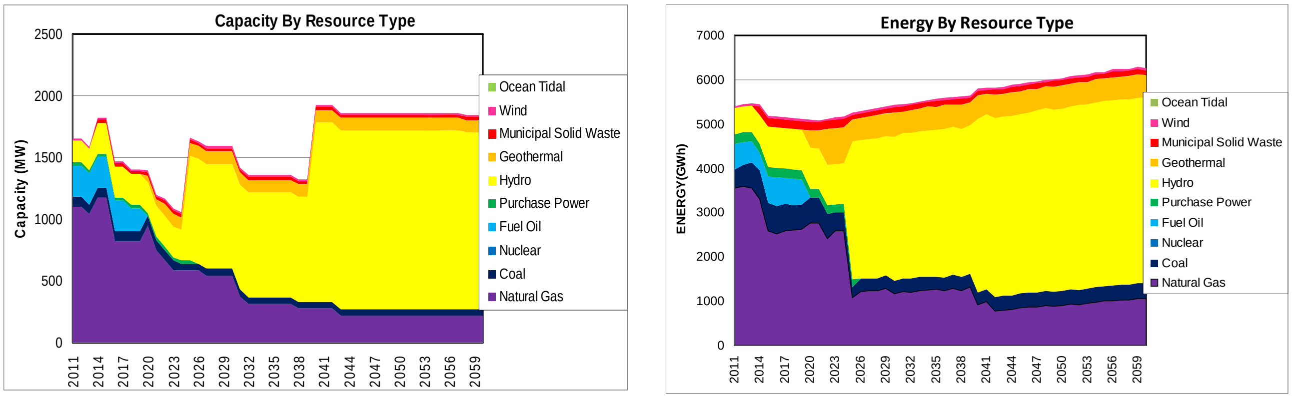


13.2.11 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expandable Option) Forced

In this sensitivity case, we forced the Susitna (Low Watana Expandable Option) to be selected, in a similar manner to the Susitna (Low Watana Non-Expandable Option) Sensitivity Case immediately above. Consequently, the resulting breakdown of capacity and energy generation by resource type is the same as the graphs shown in Figure 13-12. However, the total cumulative prevent value, average unit cost, and total capital requirements for this sensitivity case are higher; this results from the fact that the only difference between this and the Susitna (Low Watana Non-Expandable Option) Sensitivity Case is that capital costs associated with this option are $400 million higher to preserve the option of future expansion.

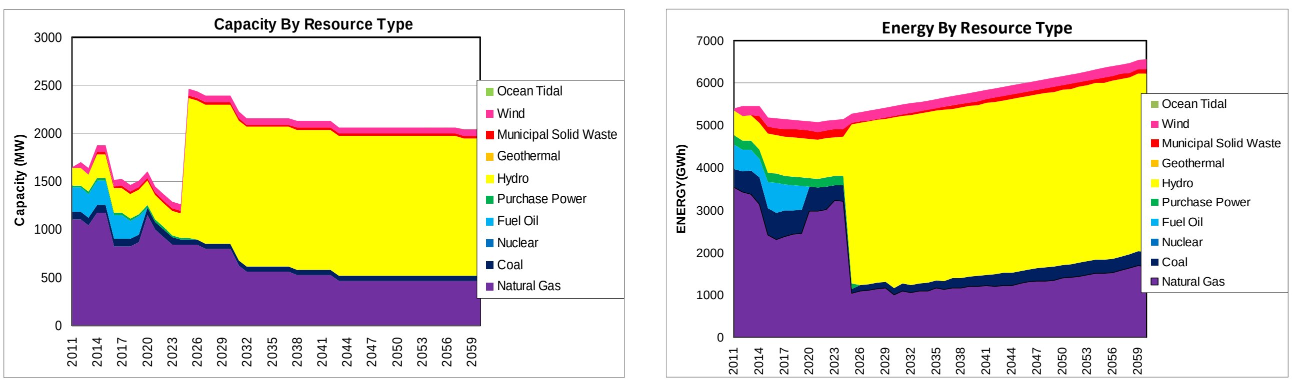
13.2.12 Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced

Figure 13-13
Sensitivity Results – Scenarios 1A/1B With Susitna (Low Watana Expansion Option) Forced



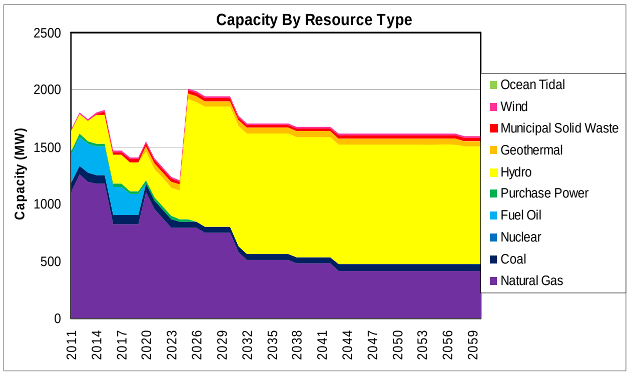
13.2.13 Sensitivity Results – Scenarios 1A/1B With Susitna (Watana Option) Forced

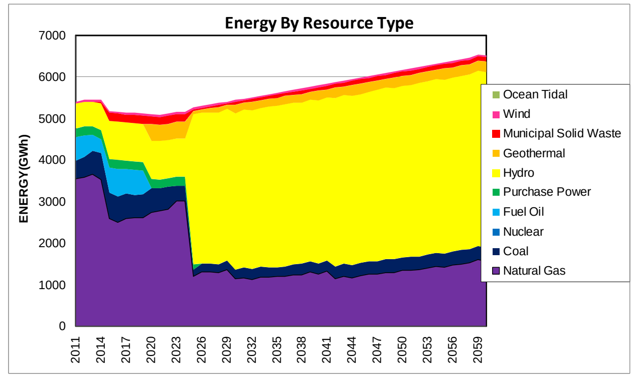
Figure 13-14
Sensitivity Results – Scenarios 1A/1B With Susitna (Watana Option) Forced



13.2.14 Sensitivity Results – Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced

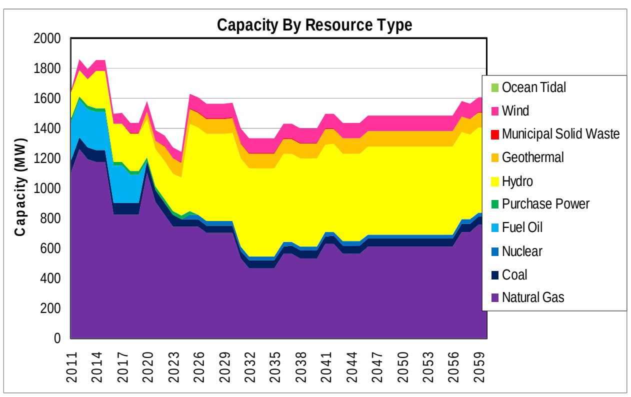
Figure 13-15
Sensitivity Results – Scenarios 1A/1B With Susitna (High Devil Canyon Option) Forced

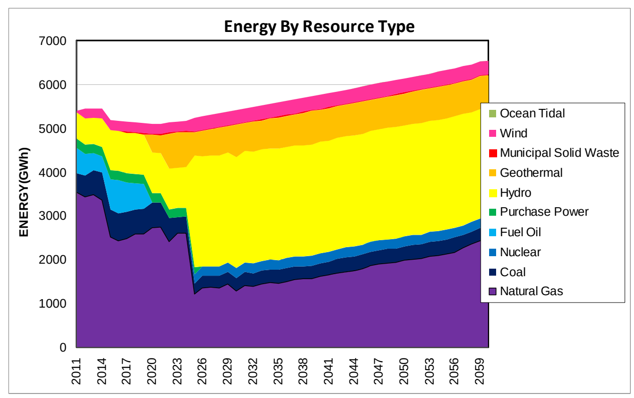




13.2.15 Sensitivity Results – Scenarios 1A/1B With Modular Nuclear

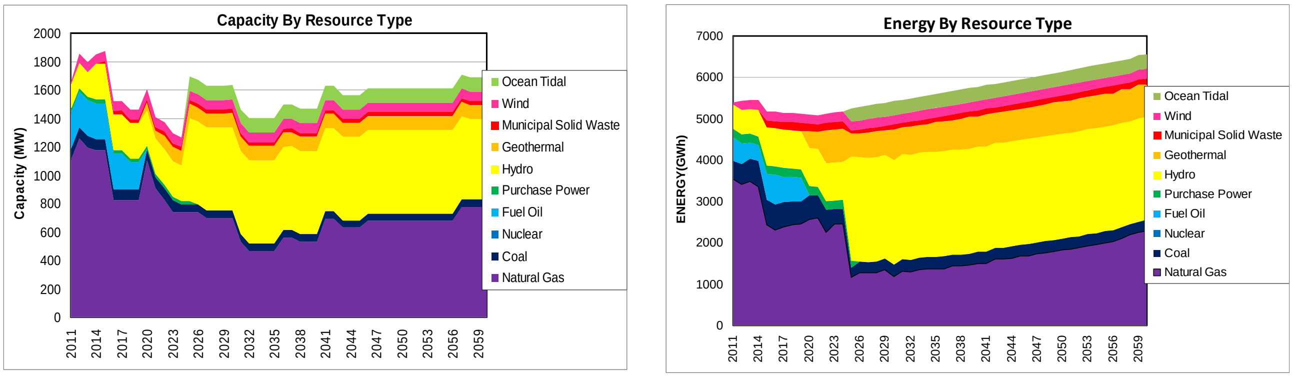
Figure 13-16
Sensitivity Results – Scenarios 1A/1B With Modular Nuclear





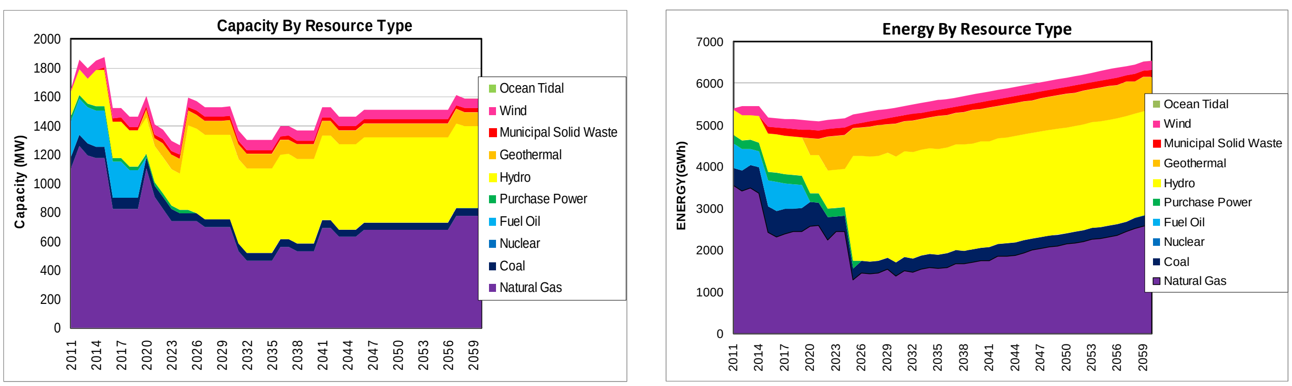
13.2.16 Sensitivity Results – Scenarios 1A/1B With Tidal

Figure 13-17
Sensitivity Results – Scenarios 1A/1B With Tidal



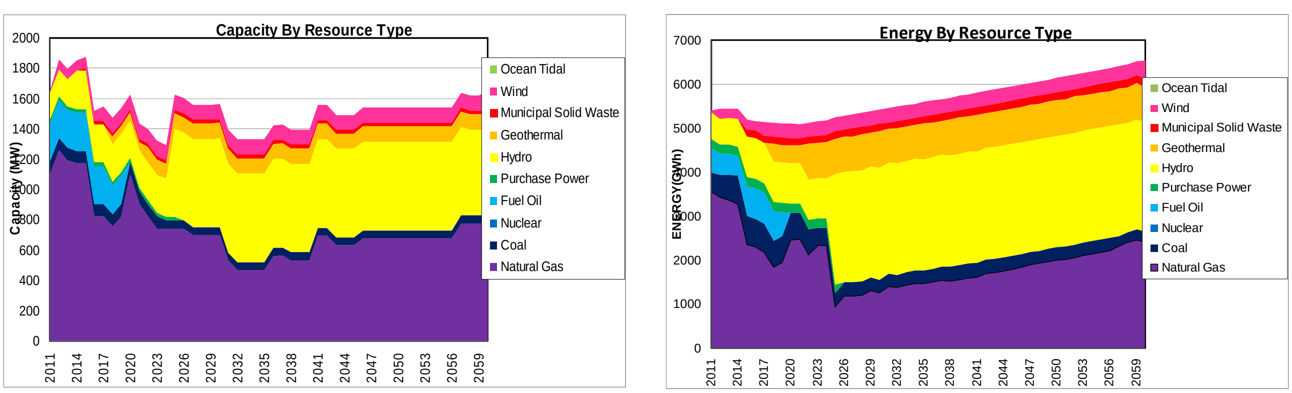
13.2.17 Sensitivity Results – Scenarios 1A/1B With Lower Coal Capital and Fuel Costs

Figure 13-18
Sensitivity Results – Scenarios 1A/1B With Lower Coal Capital and Fuel Costs



13.2.18 Sensitivity Results – Scenarios 1A/1B With Federal Tax Credits for Renewables

Figure 13-19
Sensitivity Results – Scenarios 1A/1B With Federal Tax Credits for Renewables



13.3 Summary of Results

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

13.3.1 Summary of Results - Economics

Table 13-1 summarizes the economic results, including:

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

13.3.2 Summary of Results - Emissions

Table 13-2 summarizes the emissions-related results of all of the reference and sensitivity cases. The following information is provided for each case:

- CO_2 emissions
- NO_x emissions
- SO_x emissions

13.4 Results of Transmission Analysis

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

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

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

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

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

Table 13-3 lists the recommended transmission system expansions and enhancements that resulted from our transmission analysis. Detailed information on each of the transmission projects listed in the following table is provided in Section 12.

Table 13-1
Summary of Results – Economics

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

Table 13-2
Summary of Results – Emissions

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

Table 13-3
Summary of Proposed Transmission Projects

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

The following issues result from our transmission analysis:

- We were unable to complete a stability analysis based upon our proposed transmission system configuration prior to the completion of this project. This analysis is required to ensure that the proposed transmission system expansions and enhancements result in the necessary stability to ensure reliable electric service over the planning horizon. This analysis should be completed as part of the future work to further define, prioritize, and design specific transmission projects.
- In addition to the transmission lines listed above, other projects were considered that could contribute to improving the reliability of the Railbelt system. These projects generally fall into one or more of the following categories:
    - Providing reactive power (static var compensators – SVCs)
    - Providing or assisting with the provision of other ancillary services (regulation and/or spinning reserves)
    - Assistance in control of line flows or substation voltages
    - Assistance in the transition and coordination of transmission project implementation (mobile transforms or substations)
    - Communications and control facilities

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

Island. The interconnection would then use the 230 kV submarine cable previously laid over to the Anchorage coast then into the International 230 kV Substation.

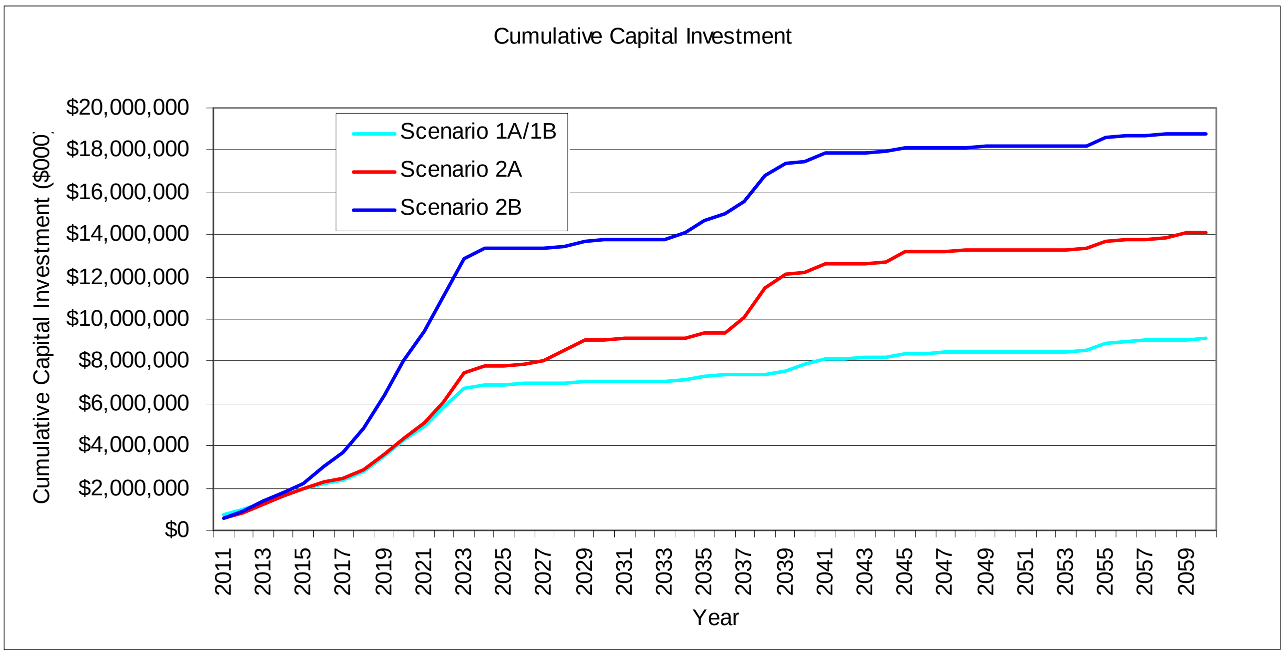
- The recommended transmission system expansions and enhancements can not be justified based solely on economics. However, in addition to their underlying economics, these transmission projects are required to ensure the reliable delivery of electricity throughout the region over the 50-year planning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

13.5 Results of Financial Analysis

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

Figure 13-20 summarizes the cumulative capital investment required for each of the reference cases.

Figure 13-20
Required Cumulative Capital Investment for Each Reference Case



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

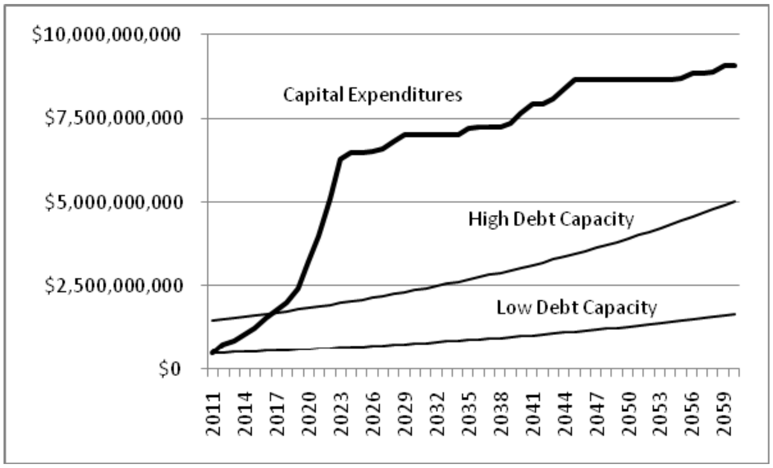
- Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities.
- Analyze strategies to capitalize selected RIRP assets by integrating State (which could include loans, State appropriations, Permanent Fund, State moral obligation bonds, etc.) and federal (e.g., USDA-RUS)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

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

Important conclusions from SNW's report include:

- The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or cooperative utility to independently secure debt financing without committing substantial amounts of equity of cash reserves.
- Figure 13-21 helps to put into context the scope of the required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent SNW's estimate of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

Figure 13-21
Required Cumulative Capital Investment (Scenarios 1A/1B) Relative to Railbelt Utility Debt Capacity



Source: SNW Report included in Appendix C.

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

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

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

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

Plan 1A/1B

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,624,595

Renewable Energy % In 2025
62.32%

Total Capital Investment ($000)
$9,086,710

Plan 2A

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Kenai Wind
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Anchorage 2x1 6FA Anchorage LM6000 Chakachamna
2026	
2027	
2028	
2029	
2030	GVEA 2x1 6FA GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	Anchorage 2x1 6FA GVEA 1x1 6FA GVEA 2x1 6FA
2041	
2042	GVEA Wind
2043	
2044	
2045	
2046	GVEA Wind
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	HEA LMS100
2058	
2059	
2060	HEA LM6000

Cumulative Present Worth Cost ($000)
$20,162,223

Renewable Energy % In 2025
42.64%

Total Capital Investment ($000)
$14,110,777

Plan 2B

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Kenai Wind
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna GVEA Wind Low Watana (Non-Expandable)
2026	
2027	
2028	
2029	
2030	GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage 2x1 6FA Kenai Wind
2038	
2039	
2040	Anchorage 2x1 6FA Kenai Wind GVEA 2x1 6FA
2041	
2042	GVEA Wind
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$21,108,823

Renewable Energy % In 2025
65.83%

Total Capital Investment ($000)
$18,804,578

1A/1B Without DSM/EE Measures

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	
2015	Kenai Wind
2016	
2017	GVEA MSW
2018	Chakachamna Glacier Fork
2019	
2020	Anchorage MSW
2021	Mount Spurr
2022	Mount Spurr
2023	
2024	
2025	GVEA 1X1 NPole Retrofit
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LM6000
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,506,801

Renewable Energy % In 2025
67.10%

Total Capital Investment ($000)
$9,791,215

1A/1B With Double DSM/EE Measures

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	Glacier Fork
2018	Mount Spurr
2019	
2020	Mount Spurr
2021	GVEA 1X1 NPole Retrofit
2022	Anchorage LMS100
2023	
2024	
2025	GVEA MSW Chakachamna
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	GVEA LMS100
2056	
2057	
2058	
2059	
2060	HEA LM6000

Cumulative Present Worth Cost ($000)
$12,545,859

Renewable Energy % In 2025
65.15%

Total Capital Investment ($000)
$8,860,649

1A/1B With Committed Units Included

Year	Unit Additions
2011	Nikiski Wind Seward 1 Healy Clean Coal
2012	Fire Island MLP LM2500 Nikiski Seward 2
2013	
2014	HEA Frame South Central PP MLP LM6000 CC GVEA MSW HEA Aero
2015	Eklutna Generation
2016	Kenai Wind
2017	
2018	
2019	Kenai Wind
2020	Mount Spurr T
2021	Kenai Wind
2022	GVEA Wind
2023	Mount Spurr
2024	Kenai Wind
2025	Anchorage LMS100
2026	
2027	
2028	
2029	
2030	GVEA Wind
2031	
2032	
2033	
2034	
2035	
2036	GVEA 1X1 NPole Retrofit
2037	
2038	
2039	
2040	Anchorage 1x1 6FA
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	Anchorage LMS100
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	GVEA LM6000
2060	

Cumulative Present Worth Cost ($000)
$14,108,513

Renewable Energy % In 2025
46.84%

Total Capital Investment ($000)
$9,086,710

1A/1B Without CO2 Costs

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	Anchorage 1x1 6FA
2014	GVEA MSW Glacier Fork Anchorage MSW
2015	
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Anchorage LMS100
2021	
2022	
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA 1x1 6FA
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	GVEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	GVEA LM6000

Cumulative Present Worth Cost ($000)
$11,205,673

Renewable Energy % In 2025
49.07%

Total Capital Investment ($000)
$8,381,277

1A/1B With Higher Gas Prices

Year	Unit Additions
2011	Nikiski Wind
2012	Anchorage 1x1 6FA
2013	
2014	Glacier Fork GVEA MSW
2015	Anchorage MSW
2016	
2017	Kenai Wind
2018	Mount Spurr
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Anchorage LM6000
2023	
2024	
2025	Chakachamna Kenai Wind
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Kenai Hydro
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	Anchorage LM6000

Cumulative Present Worth Cost ($000)
$14,064,201

Renewable Energy % In 2025
61.95%

Total Capital Investment ($000)
$9,248,373

1A/1B Without Chakachamna

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA LM6000
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	HEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,331,969

Renewable Energy % In 2025
38.06%

Total Capital Investment ($000)
$7,719,034

1A/1B With Chakachamna Capital Costs Increased by 75%

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA LM6000
2026	
2027	
2028	
2029	
2030	Anchorage 2x1 6FA
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	HEA LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,331,969

Renewable Energy % In 2025
38.06%

Total Capital Investment ($000)
$7,719,034

1A/1B With Susitna (Lower Low Watana Non-Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Lower Low Watana
2026	
2027	
2028	
2029	
2030	MEA Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	Anchorage LM6000
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Kenai Hydro
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage 1x1 6FA
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$15,228,141

Renewable Energy % In 2025
61.01%

Total Capital Investment ($000)
$12,420,673

1A/1B With Susitna (Low Watana Non-Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Non-Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	Chakachamna
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$15,039,926

Renewable Energy % In 2025
63.01%

Total Capital Investment ($000)
$15,056,672

1A/1B With Susitna (Low Watana Expandable Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	Chakachamna
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$15,345,647

Renewable Energy % In 2025
60.18%

Total Capital Investment ($000)
$15,588,186

1A/1B With Susitna (Low Watana Expansion Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	
2014	Glacier Fork Anchorage MSW GVEA MSW
2015	Anchorage 1x1 6FA
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Low Watana (Expandable)
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	Low Watana Expansion
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,854,377

Renewable Energy % In 2025
66.90%

Total Capital Investment ($000)
$14,068,673

1A/1B With Susitna (Watana Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	
2014	Glacier Fork Anchorage MSW
2015	Anchorage 1x1 6FA
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Anchorage LM6000
2021	Anchorage 1x1 6FA
2022	GVEA LM6000
2023	
2024	
2025	Watana
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$15,682,774

Renewable Energy % In 2025
70.97%

Total Capital Investment ($000)
$13,210,718

1A/1B With Susitna (High Devil Canyon Option) Forced

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	
2013	Anchorage 1x1 6FA
2014	Glacier Fork; GVEA MSW
2015	Anchorage MSW
2016	
2017	
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	GVEA LM6000
2023	
2024	
2025	High Devil Canyon
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$14,794,958

Renewable Energy % In 2025
66.92%

Total Capital Investment ($000)
$11,633,307

1A/1B With Modular Nuclear

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna Kenai Wind Anchorage Nuc
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	Anchorage LMS100
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	Anchorage LMS100
2058	
2059	
2060	Anchorage LM6000

Cumulative Present Worth Cost ($000)
$13,841,100

Renewable Energy % In 2025
60.51%

Total Capital Investment ($000)
$9,105,176

1A/1B With Tidal

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna Turnagain Tidal Arm
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,712,483

Renewable Energy % In 2025
65.52%

Total Capital Investment ($000)
$9,679,006

1A/1B With Lower Coal Capital and Fuel Costs

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	GVEA MSW
2018	GVEA 1X1 NPole Retrofit
2019	
2020	Mount Spurr
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	

Cumulative Present Worth Cost ($000)
$13,624,595

Renewable Energy % In 2025
62.32%

Total Capital Investment ($000)
$9,086,710

1A/1B With Federal Tax Credits for Renewables

Year	Unit Additions
2011	Nikiski Wind Healy Clean Coal
2012	Fire Island
2013	Anchorage 1x1 6FA
2014	Glacier Fork
2015	Anchorage MSW
2016	
2017	Kenai Wind
2018	Mount Spurr
2019	
2020	GVEA 1X1 NPole Retrofit
2021	Anchorage 1x1 6FA
2022	Mount Spurr
2023	
2024	
2025	GVEA MSW Chakachamna
2026	
2027	
2028	
2029	
2030	Kenai Hydro
2031	
2032	
2033	
2034	
2035	
2036	
2037	GVEA LMS100
2038	
2039	
2040	
2041	
2042	GVEA 1x1 6FA
2043	
2044	
2045	
2046	Anchorage LM6000
2047	
2048	
2049	
2050	
2051	
2052	
2053	
2054	
2055	
2056	
2057	GVEA LMS100
2058	
2059	
2060	Kenai Wind

Cumulative Present Worth Cost ($000)
$12,953,856

Renewable Energy % In 2025
67.56%

Total Capital Investment ($000)
$9,256,012

14.0 IMPLEMENTATION RISKS AND ISSUES

In this section, Black & Veatch identifies a number of general risks and issues that must be addressed regardless of the resource future that is chosen by stakeholders, including the utilities and State policy makers.

This is followed by a discussion of the risks and issues associated with each alternative generation resource type including transmission, and the actions that should be taken to address these resource-specific risks and issues.

14.1 General Risks and Issues

In this subsection, Black & Veatch identifies and discuss a number of general issues and risks that relate to the implementation of this RIRP. These general issues and risks are grouped into the following categories:

- Organizational
- Resource
- Fuel Supply
- Transmission
- Market Development
- Financing and Rate
- Legislative and Regulatory
- Value of Optionality

14.1.1 Organizational Risks and Issues

As previously discussed, the four resource plans that have been developed as part of this project focus on the Railbelt region as a whole. In other words, the four alternative resource plans were developed on a comprehensive regional basis to minimize costs, while maintaining adequate reliability, rather than for the individual utilities.

14.1.1.1 Regional Implementation

The possible formation of a new Railbelt regional generation and transmission entity (i.e., GRETC) is under consideration. The functional responsibilities of this new regional entity would include:

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

The existing Railbelt utilities would retain the responsibility for providing traditional distribution and customer services, such as moving power from transmission/distribution substations to individual customers, meter reading, turn-ons/offs, billing and responding to customer inquiries.

Taking a regional approach to economic dispatch and system operation, integrated resource planning, and project planning and development will most likely lead to better results than the current situation of six individual utilities working separately to meet the needs of their own residential and commercial customers without full regard to the benefits of coordination of activities among the utilities, provided that the regional entity has the appropriate governance structure, and financial and technical expertise. Additional benefits of a regional entity will likely include:

- A regional entity, with rational regional planning, would enable the region to identify and prioritize projects on a regional basis and it puts the State in a better position to evaluate, award and monitor funding.
- A regional entity improves the opportunities to obtain the benefits of economies of scale in generation, transmission, and DSM/EE projects and programs.
- The formation of a regional entity could lead to a reduction in the required levels of reserve margins over time.
- A regional entity is better able to integrate non-dispatchable resources, such as wind and solar, given the impact of these resources on system operation and reliability.
- With regard to project development, the concentration of staff within one organization will increase the ability to make timely and effective mid-course corrections, as required.
- A regional entity is in a better position to manage risks which is particularly important given the current circumstances in the Railbelt region.
- A regional entity could also result in other cost savings, including:
    - The region would need to develop only one regional Integrated Resource Plan, as opposed to three or more Integrated Resource Plans, every three to five years.
    - Legal and consulting expenses can be reduced as more issues are addressed on a regional basis versus on an individual utility basis.
    - Total staffing levels in certain areas on a regional basis can likely be reduced.
    - Better access to lower cost financing due to the overall financial strength of the regional entity relative to the six individual utilities.
- A regional entity would be responsible for development and implementation of a single region-wide DSM/EE program-related communications and outreach effort, thereby ensuring consistency of message and procedures for participation, along with the attendant cost efficiencies involved. This would help avoid confusion and facilitate use of mass marketing, while still enabling co-branding with individual Railbelt utilities.
- A single point of contact for DSM/EE activities for the region would make program administration and evaluation much easier. All data would be housed in a central DSM/EE tracking system for ease of tracking progress towards the achievement of goals, reporting on individual entities or total, and tracking performance of vendors.
- The formation of a regional entity can increase the flexibility of the region to respond to major events (e.g., a large load increase, such as a new or expanded mine).
- A regional entity would be in a better position to work with Enstar Natural Gas Company and the gas producers to address the region's energy issues in a more comprehensive manner.

This study was undertaken largely on the premise that such a regional entity would be formed to implement the chosen RIRP. While it is not an absolute requirement that a regional entity be formed to implement the RIRP, such implementation would be considerably more difficult if it is left up to the six individual Railbelt utilities, as they are required under their own governance policies to focus on identifying and implementing the best solutions for their own members and customers, as opposed to focusing on the most optimal regional solution.

It is Black & Veatch's belief that the formation of a regional entity is critical to implementing many of the recommendations of this report, whether the regional entity is the proposed GRETC or a different, but similar, regional entity. Black & Veatch also believes that the formation of this entity should occur as quickly as possible; delay will only make the challenges greater and, if the regional entity is not formed now, decisions will need to be made by individual utilities and these decisions will not result in optimal results from a regional perspective. Suboptimal solutions result in higher costs, lower reliability and the inability to manage the successful integration of DSM/EE resources and renewable resources into the Railbelt system.

14.1.1.2 Achieving Economies of Scale

The Railbelt utilities, to date, have not been able to take full advantage of economies of scale for several reasons. First, as previously noted, the combined peak load of the six Railbelt utilities is still relatively small. Second, the Railbelt transmission grid's lack of redundancies and interconnections with other regions has placed reliability-driven limits on the size of generation facilities that could be integrated into the Railbelt region.

Third, the fact that each utility has developed their own long-term resource plans has led to less optimal results (from a regional perspective) relative to what could be accomplished through a rational, fully coordinated regional planning process. Finally, the existence of six separate utilities, and their small size on an individual utility basis, has restricted their ability to take advantage of economies of scale with regards to staffing and their skill sets. For example, the development of six separate programs to develop and deliver DSM/EE programs is a considerably more difficult challenge than would be the case if there was one regional entity, with the responsibility for developing and delivering DSM/EE programs to residential and commercial customers throughout the Railbelt region.

In addition to the benefits of scale related to generation and transmission resources, there are benefits associated with staffing, including:

- The concentration of staff would likely lead to more sophisticated generation and transmission planning, resulting in better regional resource planning decisions.
- Better coordination is possible if all regional employees with generation and transmission responsibilities are part of one organization.
- Depth of bench – it is easier to take advantage of the depth of everyone's skills and expertise when everyone works for one organization, and greater specialization can occur.
- The concentration of staff increases the ability of the regional entity to keep abreast of new technologies (e.g., renewables) and industry trends.
- The concentration of staff also increases the ability of the Railbelt region to develop and support the delivery of cost-effective renewables and DSM/EE programs.

14.1.2 Resource Risks and Issues

There are a myriad of risks and issues associated with the implementation of specific resource options, whether DSM/EE, generation, or transmission. General areas of risk are discussed below and resource specific issues and risks are discussed in the next subsection.

14.1.3 Fuel Supply Risks and Issues

Natural gas has been the predominant source of fuel for electric generation used for the customers of Chugach, ML&P, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years.

There are a number of inherent risks whenever a utility or region is so dependent upon one fuel source including risks related to prices, availability and deliverability. An additional risk faced by Chugach is the fact that its current gas supply contracts are expected to expire in the 2010-2012 timeframe. An additional problem faced by the Railbelt utilities, due to their dependence on natural gas, is the fact that existing developed reserves in the Cook Inlet are declining as well as the current deliverability of that gas.

Consequently, the Railbelt region will not be able to continue its heavy dependence upon natural gas in the future unless enhanced gas supplies become available. Those enhanced supplies could include additional reserves discovered in the Cook Inlet, new reserves discovered in basins within or near the Railbelt region, North Slope gas delivered by an interstate pipeline, or a LNG import terminal with access to LNG suppliers outside Alaska.

Historically low prices for natural gas in the Cook Inlet region have been rationalized in some cases as a consequence of “stranded gas” in supply that exceeds the available market outlets. But in fact the export of LNG to Japan, where premium prices are assured, has provided the most significant market outlet and has made the “stranded gas” argument unconvincing. Indeed, the LNG export outlet has served as much of the financial incentive for producers to continue gas production from Cook Inlet.

Whether new gas supplies from the Cook Inlet become available or gas from the North Slope is brought to the Railbelt region, one reality can not be escaped: future gas supply prices will be higher than in past experience. For additional gas supplies in the Cook Inlet to become available, prices will need to increase to encourage exploration and production, and to help offset losses if LNG exports come to an end. This results from the fact that oil and gas producers make investment decisions based upon expected returns relative to investment opportunities available elsewhere in the world.

In the case of North Slope gas supplies, the cost, probability and timing of potential gas flows to the Railbelt region are unknown at this time. Nevertheless, given the construction lead times for a potential gas pipeline to provide gas from the North Slope, gas from that region is unlikely to be available for a number of years. Furthermore, if gas from the North Slope becomes available in the Railbelt region through either the Bullet Line or Spur Line, prices will likely be tied to market prices since potential natural gas flows to the Railbelt region will likely be just one of the competing demands for the available gas. Additionally, the pipeline transmission rates that will be paid to move gas to the Railbelt region will be significantly higher than the relatively low transportation rates that are imbedded in the delivered cost of gas from Cook Inlet suppliers under existing contracts.

14.1.4 Transmission Risks and Issues

As previously noted, the Railbelt electric transmission grid has been described as a long straw, as opposed to the integrated, interconnected, and redundant grid that is in place throughout the lower-48 states. This characterization reflects the fact that the Railbelt electric transmission grid is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies.

As a result of the lack of redundancies and interconnections with other regions, each Railbelt utility is required to maintain higher generation reserve margins (reserve margins reflect the amount of extra capacity beyond the peak load requirement that a utility needs to assure reliable system operation in the event that a generating units fails) and higher spinning reserve requirements (spinning reserve represents the amount of capacity that is available to serve load instantaneously if an operating generator disconnects from the grid) than elsewhere in order to ensure reliability in the case of a generation or transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region, such as:

- The requirement for larger regulating reserves (regulating reserves are extra capacity that are required to be synchronized and on-line and are able to adjust output both up and down in real-time as load fluctuates). This maintains stable frequency performance.
- The requirement for enough units on-line that can influence the rate of change of frequency when the balance between real-time load and real-time generation is out of balance. The lack of other interconnected units result in a lower system inertia and, consequently, a much more rapid fluctuation rate for frequency. This issue assumes greater importance when high penetration of non-dispatchable generation (e.g., wind) is being considered in the system.
- The lack of interconnection coupled with the relatively small size of the Railbelt system also results in smaller unit sizes than would otherwise be considered. This means that the full benefit of economies of scale will not be available and possibly more limited potential for jointly developed larger projects.
- Benefits of more economic system operation based on the potential for diversity of operation and wider power marketing transactions, as well as higher operation load factors for generators.
- Environmental benefits of system interconnection could result in reductions, through inter-regional commitment and dispatch, of greenhouse gas (GHG) emissions from electricity production in thermal plants. The value of the avoided emissions may be expressed as the total reduction in GHG times the cost of the emissions.

14.1.5 Market Development Risks and Issues

14.1.5.1 Competitive Power Procurement

An important market development-related issue relates to the ability of IPPs, or non-utility generators of electricity, to enter the market. To date, the level of IPP penetration is the Railbelt region has been minor. The most significant activity is the current efforts by Cook Inlet Regional, Inc./enXco to develop the Fire Island wind farm. Additionally, other activities include those by Ormat to develop the Mt. Spurr geothermal project. Other IPP development activities are either for smaller projects or are not as far along in the development process. However, none of these current activities are guaranteed to succeed. There are a number of reasons for lower IPP activity in the Railbelt region than has occurred in other regions of the country. Not the least of these reasons is the fact that IPPs must work with individual utilities to gain acceptance on their projects, including the negotiation of power purchase agreements under varying terms and conditions and dealing with various generation interconnection requirements. The region would likely benefit from the adoption of policies that attract IPP development of project alternatives under the resource addition parameters established by the RIRP. One such policy would be the development of a competitive power procurement policy that would establish a "level playing field" for IPP-proposed projects. Under competitive procurement, IPP developers would be able to bid projects that offer economic benefits to the grid against other economic options. This assures that the combination of resources selected would be the most economic options for customers.

14.1.5.2 Load Growth

With regard to native load growth (e.g., normal load growth resulting from residential and commercial customers), Railbelt utilities have experienced limited, stable growth in recent years. This stable native load growth is expected to continue in the years ahead, absent significant economic development gains in the region.

There are, however, a number of potential significant, discrete load additions that could result from economic development efforts. These potential load additions could result from the development of new, or expansion of existing, mines (e.g., Pebble and Donlin Creek), continued military base realignment, other economic development efforts and or State policy decisions. Additionally, there will likely be a significant increase in Railbelt population if the North Slope natural gas pipeline, and or the Spur Line or Bullet Line, is built. Where large discreet load additions occur, there will be associated changes in both generation and transmission infrastructure to maintain system reliability. Under a consolidated integrated resource plan the discreet additions would be coordinated with other regional reliability projects to minimize costs and to optimize system considerations such as the size, timing and location of new resources.

14.1.6 Financing and Rate Risks and Issues

14.1.6.1 Financing

As noted above, the Railbelt utilities face a very significant challenge in terms of their ability to finance the future. Traditional means of financing by the Railbelt utilities going forward independently simply are inadequate given the capital investment requirements over the next 50 years that result from each of the four alternative resource plans. Essentially, the existing net cash flow for the individual utilities would not provide sufficient debt coverage ratios to support investment grade debt financing for large, multi-year construction projects. Even for a regional entity, the available net cash flow to support such projects would be difficult without State assistance.

14.1.6.2 Rate Design

In addition to the challenge associated with securing the required financing, that capital investment will need to be recovered through rates, thereby resulting in higher monthly bills for residential and commercial customers. While the need to recover capital investments is a reality, innovative rate design options (e.g., Construction-Work-in-Progress - CWIP) are available to smooth out these rate increases over time so that they are more affordable to residential and commercial customers. CWIP also helps to address the cash flow issues associated with financing new projects.

14.1.7 Legislative and Regulatory Risks and Issues

14.1.7.1 State Energy Policy

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

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

14.1.7.2 Regulatory Commission of Alaska

While it is not within the scope of this RIRP to address the level and quality of regulation for either the individual utilities or GRETC, the level and quality of regulation impacts current and future investment decisions by both the electric and natural gas industries.

14.1.8 Value of Optionality

Optionality represents the ability to make other choices once an initial choice has been made. Given the large fixed cost commitments associated with generation and transmission projects, any optionality in a resource plan adds value. As previously discussed, the recent increases in natural gas prices highlight the dangers inherent from an over-reliance on one fuel source or generation technology. That is, given the sunk cost of generation from gas fired resources, there is little option for reducing costs as gas prices rise. Just as investors rely on a portfolio of assets to manage risk, it is important for utilities to develop a portfolio of assets to ensure safe, reliable and cost-effective service to customers. It also demonstrates the importance of maintaining flexibility.

In this context, maintaining flexibility has two dimensions. The first dimension of flexibility relates to future generation resources and fuel supplies. Any future resource path should be chosen only if it is likely to enhance the region's ability to maintain and improve the region's resource asset portfolio flexibility.

The second dimension of flexibility relates to the ability to adjust to changing State and Federal policies, whether they are related to a State Energy Plan, carbon emissions regulations, support of the North Slope gas pipeline and or the Bullet or Spur Lines, and so forth. Resource decisions being made by utility managers are increasingly driven or influenced by energy policy makers.

Fuel supply diversity inherently has value in terms of risk management. Simply stated, the greater a region's dependence upon one fuel source, the less flexibility the region will have to react to future price and availability problems.

The level of uncertainty facing the Railbelt region continues to grow, as do the risks attendant to utility operations. One important approach to risk management is to spread the risk to a greater base of investors and consumers so that the impact of those risks on individuals is reduced. Simply stated, the ability of the region to absorb the risks facing it is greater on a regional basis than it is on an individual utility basis.

Additionally, maintaining flexibility is important. In that regard, even after a particular resource plan has been adopted, it is important to pursue activities that maintain the viability of other resource options; therefore, the region can modify it resource plan, as required, as the issues and risks associated with the selected resource plan become better known

14.2 Resource Specific Risks and Issues

14.2.1 Introduction

The purpose of this section is to identify the primary issues and risks associated with the development of the following resource options:

- DSM/EE
- Generation resources, including natural gas, coal and modular nuclear, as well as renewable resources including large and small hydro, wind, geothermal, solid waste and tidal
- Transmission resources

14.2.2 Resource Specific Risks and Issues – Summary

The following table provides Black & Veatch's assessment of the relative magnitude of various categories of risks and issues for each resource type, including:

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

Table 14-1
Resource Specific Risks and Issues - Summary

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

The following provides some commentary related to the basis for these qualitative assessment of resource specific risks and issues:

- **Resource Potential Risks**

  Resource potential risks are deemed to be moderate for some of the renewables resource options primarily due to the fact that enough resource potential studies have not been completed to provide a high degree confidence in the amount of energy capacity and energy that could be provided by these different resource options. For other renewable resource options, initial studies indicate significant resources are available, but more detailed studies have not been conducted to ensure that these large potential resources can actually be converted into renewable generation. Based upon the studies that have been completed, there is a solid foundation for believing that each of these different forms of renewable resources offers the potential for relatively significant capacity and energy within the Railbelt region. However, additional studies must be completed to identify the most attractive locations and to firm up the resource potential estimates for each type of renewable resource technology.

  Resource potential risks and issues are relatively lower for natural gas, coal and modular nuclear, as well as for additional transmission resources.

  Resource potential risks associated with DSM/EE programs are more commonly related to the reliability, or lack thereof, of the resource in that it is less under the control of the utility and relies more on mass market decision-making and/or behavior.

- **Project Development and Operational Risks**

  Project development and operational risks and issues are significant for modular nuclear, large hydro, tidal, and transmission. They are also fairly significant for coal and solid waste. In the case of large hydro, these risks are significant due to the stringent environmental and permitting issues that would need to be addressed. Additionally, the potential for significant construction cost overruns is significant for large hydro.

  Tidal power represents an option with significant potential in the Railbelt. However, this technology has not been widely commercialized and there are significant environmental and permitting risks and issues associated with this technology.

  In the case of transmission, project development risks are deemed significant due to NIMBY concerns and the rough terrain and difficult construction conditions that exist.

  Coal, solid waste, and modular nuclear face NIMBY concerns as well as permitting and licensing concerns.

  The project development-related risks are believed to be lower, or moderate, for the other types of renewable resources, including small hydro, wind, and geothermal; they are even lower, or minimal, for DSM/EE resources, and generation resources that are fueled by natural gas and other fossil fuels.

- **Fuel Supply Risks**

  Fuel supply-related risks are very significant for natural gas generation resources. They are generally limited for generation options that rely on other fossil fuels, and they do not apply to DSM/EE and the various renewable resources.

- **Environmental Risks**

  Environmental-related risks are believed moderate for natural gas generation, and moderate to significant for other fossil fueled generation options. Future carbon restrictions represent an important risk for all generation resources that rely on fossil fuels and are very significant in the case of coal.

  Environmental-related risks are shown as significant for modular nuclear, large hydro options, solid waste, and tidal power due to their potential environmental impact.

  They are believed to be moderate for small hydro and geothermal, and limited for wind based, in large part, on experience with these technologies in other regions of the country and elsewhere in the world.

- **Transmission Constraint Risks**

  Existing transmission constraints are significant for large hydro because the current transmission network is insufficient to move large amounts of capacity and energy throughout the region which would be required for any large hydro project to be economic.

  Transmission constraints also represent a moderate to significant issue for geothermal and tidal, depending upon the ultimate amount of these resources developed within the region.

  They are believed to be moderate with regard to small hydro, wind, and solid waste due to the typical size of these projects and the fact that they can generally be developed throughout the Railbelt region, thereby reducing the need to have transmission to move the related capacity and energy from one area of the Railbelt region to another.

  Transmission constraints are deemed limited for natural gas-fuel generation, again due to the typical size of these projects and the fact that they can be located throughout the Railbelt region, and they do not exist with regard to DSM/EE resources due to the distributed nature of these resources.

- **Financing Risks**

  Financing risks and issues are significant for any large scale resource option including coal, modular nuclear, large hydro, and transmission resources. They are moderate for natural gas generation.

  Financing risks are limited to moderate for most of the renewable resources (e.g., including small hydro, wind, geothermal, solid waste and tidal) depending upon the actual size of the projects developed; likewise they are limited to moderate for DSM/EE resources.

- **Regulatory/Legislative Risks**

  Regulatory and legislative risks and issues are limited for smaller-scale renewable resources, including small hydro, wind, geothermal, and solid waste.

  They are moderate for DSM/EE resources, primarily due to the fact that regulatory (and potentially legislative) changes would be required to eliminate the disincentive that exists under the current regulatory framework for utilities to encourage customers to use less electricity. They are also believed to be moderate for natural gas and other fossil fueled generation resources.

  Regulatory and legislative risks and issues are believed to be significant for modular nuclear and large hydro, and moderate to significant for tidal and transmission resources.

- **Price Stability Risks**

  Price stability risks and issues are limited for DSM/EE programs, small and large hydro, and geothermal; limited to moderate for wind and tidal. They are moderate for coal and solid waste, and significant for natural gas and modular nuclear.

More detailed information related to the risks and issues associated with each type of resource options is provided in the following subsection.

14.2.3 Resource Specific Risks and Issues – Detailed Discussion

This section provides more detailed information related to the risks and issues associated with each of the following types of resource options:

- DSM/EE
- Generation
  - Natural gas
  - Coal
  - Modular nuclear
  - Large hydro
  - Small hydro
  - Wind
  - Geothermal
  - Solid waste
  - Tidal
- Transmission

This section consists of a series of tables that identifies the most significant risks and issues for each type of resource options, broken down by the major risk/issue categories discussed in the previous section. These tables also identify the primary actions that should be taken to address these risks and issues.

14.2.3.1 DSM/EE

Table 14-2
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • General lack of Alaska-specific data to determine economic resource potential, including end-use saturations, measure persistence, weather sensitive impacts, and cost-effectiveness • Reliability is a key concern with DSM since utilities have less control over its acquisition and management	• Establish Alaska-specific baseline information through the completion of region-wide residential and commercial end-use saturation surveys and customer attitudinal surveys • Complete comprehensive economically achievable potential study that includes a detailed cost-effectiveness evaluation of all feasible DSM/EE measures • Complete vendor surveys to determine availability and relative costs of DSM/EE measures in the Railbelt region • Develop regional DSM/EE program measurement and evaluation protocols • Focus programs on hard-wired technology replacements rather than behavioral based savings • If demand reduction is a goal, focus DSM programs on peak load reduction program strategies that can be dispatched or under greater control by the utility
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing their own DSM/EE programs • Ineffectiveness and inefficiencies associated with lack of coordination between the electric utilities, Enstar, and AHFC • Lack of customer awareness regarding DSM/EE options and economics	• Establish a regional entity (e.g., GRETC or independent third party) to develop and deliver, in coordination with the six Railbelt utilities, DSM/EE efficiency programs to all customers in the Railbelt region • Develop and implement regional DSM/EE programs in close coordination with Enstar and AHFC • Develop public outreach program to increase awareness of DSM/EE options • Develop and learn from near-term DSM/EE pilot programs throughout the Railbelt region

Table 14-2 (Continued)
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Not applicable	• Not applicable
Transmission Constraints	• Not applicable	• Not applicable
Financing	• Lack of funding source for initial activities (e.g., collect baseline information and consumer education) required to build a viable and successful DSM/EE program • Lack of stable source of long-term financing for DSM/EE program	• Legislature should appropriate funds for the initial development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) customer attitudinal survey, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts • Increase State funding of low income weatherization and residential and energy audit (both residential and commercial) program • Aggressively pursue available Federal funding for DSM/EE programs • Consider implementation of a System Benefit Charge, or SBC, (i.e., a surcharge on customer bills that would be dedicated to the funding of DSM/EE programs) to provide for the long-term funding of DSM/EE programs
Regulatory/Legislative	• The implementation of DSM/EE reduces energy sales and, therefore, reduces the ability of utilities to recover costs under current rate design principles • Lack of innovative rate structures in the Railbelt region, such as time-of-use (TOU) and demand response (DR) rates • Lack of strict building codes and enforcement of those codes • Lack of State leadership related to DSM/EE	• Implement a decoupling mechanism so that a regional entity and or the individual Railbelt utilities can still recover their costs even with lower sales • Allow utilities to develop pilot programs to test the effectiveness of TOU and DR rates • Establish more stringent residential and commercial building codes that lead to lower energy use in new homes and buildings and increase the enforcement of those building codes

Table 14-2 (Continued)
Resource Specific Risks and Issues – DSM/EE

Resource: DSM/EE		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Regulatory/Legislative (Continued)		• Establish State targets for DSM/EE savings based on the economics of the programs • Establish State goals for reducing energy usage at State facilities • Develop and implement programs to increase energy efficiency in State buildings and schools

14.2.3.2 Generation Resources

14.2.3.2.1 Generation Resources – Natural Gas

Table 14-3
Resource Specific Risks and Issues – Generation – Natural Gas

Resource: Generation – Natural Gas		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• See Fuel Supply	• See Fuel Supply
Project Development	• Development risks are well known and understood	• Not applicable
Fuel Supply	• Near-term adequacy and deliverability of natural gas supplies appear inadequate • Several long-term gas supply options exist but the relative risks and economics of those options have not been fully assessed	• Electric utilities need to work closely with the State, gas producers and Enstar to ensure the adequacy of near-term gas supplies • Current LNG export agreement should not be extended and the related gas should be used for the needs of Railbelt gas and electric customers, although the loss of the LNG export outlet might require the Cook Inlet gas price to be re-set • Short-term imported LNG gas supplies should be secured to serve as transitional gas supply option • Local gas storage capabilities should be developed as soon as possible • The State should complete a detailed risk and cost evaluation of available long-term gas supply options to determine the best option • Once the most attractive long-term supplies of natural gas have been determined, detailed engineering studies and permitting activities should be undertaken • Appropriate commercial terms and pricing structures should be established to provide producers the incentive to increase exploration for additional Cook Inlet gas supplies • State should consider providing incentives to encourage additional exploration for Cook Inlet gas supplies

Table 14-3 (Continued)
Resource Specific Risks and Issues – Generation – Natural Gas

Resource: Generation – Natural Gas		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Environmental	• Risk of accident	• Continue efforts to enforce safety and operational regulations
Transmission Constraints	• Proper location of gas-fired generation resources mitigates transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• For larger projects, financing can be difficult given the financial strength of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider State assistance for new gas-fired generation projects that replace old, inefficient natural gas plants
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions	• Monitor Federal legislative and regulatory activities related to emission regulations • Monitor technological developments regarding carbon capturing technologies (e.g., carbon sequestration)

14.2.3.2.2 Generation Resources – Coal

Table 14-4
Resource Specific Risks and Issues – Generation – Coal

Resource: Generation – Coal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Not applicable	• Not applicable
Project Development	• Development risks are generally known and understood	• Not applicable
Fuel Supply	• Not applicable	• Not applicable
Environmental	• See Regulatory/Legislative	• Not applicable
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• For larger projects, financing can be difficult given the financial strength of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities
Regulatory/Legislative	• Potential future environmental regulations related to emissions, including carbon and other emissions, and coal mining • Potential regulations of regarding ash disposal	• Monitor Federal legislative and regulatory activities related to emission regulations and coal mining • Monitor technological developments regarding carbon capturing technologies (e.g., carbon sequestration) • Implement appropriate design to mitigate environmental impacts

14.2.3.2.3 Generation Resources – Modular Nuclear

Table 14-5
Resource Specific Risks and Issues – Generation – Modular Nuclear

Resource: Generation – Modular Nuclear		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Resource potential would be very large, but technology not demonstrated	• Monitor development and licensing of technology
Project Development	• Significant permitting challenges exist for modular nuclear • Public acceptability of modular nuclear is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of modular nuclear • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of modular nuclear may not be significant, but public perception about environmental impacts may be very significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• The small size of the modular nuclear projects should not pose transmission constraints	• Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• The lack of technology demonstration at this small size may create concerns in the financing community • Costs per kW may be significant	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance reduce resistance to finance • Aggressively pursue available Federal funding
Regulatory/Legislative	• NRC licensing is uncertain	• Monitor NRC licensing process

14.2.3.2.4 Generation Resources – Large Hydro

Table 14-6
Resource Specific Risks and Issues – Generation – Large Hydro

Resource: Generation – Large Hydro		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Both Susitna and Chakachamna sites are adequate to play a major role in meeting the region's future electric capacity and energy requirements	• Not applicable
Project Development	• Significant permitting challenges exist for large hydro projects • Public acceptability of large hydro is unknown • Potential for construction cost overruns is significant • Infrastructure needs to support project construction are significant	• Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of large hydro • Implement best practices related to management of construction costs
Fuel Supply	• Potential impact of climate change	• Monitor water flows
Environmental	• Environmental impacts of large hydro projects are potentially significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of large hydro facility into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Complete required studies to ensure the ability to integrate large hydro projects into the transmission grid
Financing	• Financing requirements of a large hydro project are greater than the combined financial capabilities of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for large hydro projects
Regulatory/Legislative	• Potential future environmental regulations related to large hydro projects • Regional commitment to large hydro is uncertain	• Monitor Federal activities related to large hydro projects • Determine State policy regarding the desirability of large hydro projects • Establish State Renewable Portfolio Standard (RPS) targets • Develop State policies regarding Renewable Energy Credits (RECs) and Green Pricing

14.2.3.2.5 Generation Resources – Small Hydro

Table 14-7
Resource Specific Risks and Issues – Generation – Small Hydro

Resource: Generation – Small Hydro		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing small hydro projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction may be significant	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop small hydro projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Potential impact of climate change	• Monitor water flows
Environmental	• Site specific environmental issues including impact on fish	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.2.6 Generation Resources – Wind

Table 14-8
Resource Specific Risks and Issues – Generation – Wind

Resource: Generation – Wind		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing wind projects • Lack of standard power purchase agreements for projects developed by IPPs	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop wind projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.2.7 Generation Resources – Geothermal

Table 14-9
Resource Specific Risks and Issues – Generation – Geothermal

Resource: Generation – Geothermal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing geothermal projects • Lack of standard power purchase agreements for projects developed by IPPs • Infrastructure needs to support construction are likely significant	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop geothermal projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Explore if synergies can be achieved for infrastructure with hydro projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW can be significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain • Potential future environmental regulations related to emissions, including carbon and other emissions	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing • Monitor Federal legislative and regulatory activities related to emission regulations

14.2.3.2.8 Generation Resources – Solid Waste

Table 14-10
Resource Specific Risks and Issues – Generation – Solid Waste

Resource: Generation – Solid Waste		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown	• Complete regional economic potential assessment, including the identification of the most attractive sites
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing solid waste projects • Lack of standard power purchase agreements for projects developed by IPPs	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop solid waste projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects
Fuel Supply	• See Resource Potential	• Not applicable
Environmental	• Site specific environmental issues	• Comprehensive evaluation of site specific environmental impacts at attractive sites
Transmission Constraints	• Location of new facilities can add to transmission constraints	• Expand Railbelt transmission network • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process
Financing	• Cost per kW is very significant	• Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain • Potential future environmental regulations related to emissions, including carbon and other emissions	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing • Monitor Federal legislative and regulatory activities related to emission regulations

14.2.3.2.9 Generation Resources – Tidal

Table 14-11
Resource Specific Risks and Issues – Generation – Tidal

Resource: Generation – Tidal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• Total economic resource potential is unknown • Resource potential may be constrained by Railbelt regional system regulation requirements	• Complete regional economic potential assessment, including the identification of the most attractive sites • Develop regional regulation strategy for non-dispatchable resources
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing tidal projects • Lack of standard power purchase agreements for projects developed by IPPs • Significant permitting challenges exist for large hydro projects • Public acceptability of tidal is unknown • Potential for construction cost overruns is significant • Technology not fully developed	• Establish a regional entity (e.g., GRETC) or rely on IPPs to identify and develop tidal projects • Develop regional standard power purchase agreements • Develop regional competitive power procurement process to encourage IPP development of projects • Work closely with resource agencies to identify permitting requirements • Develop public outreach program to better determine public acceptability of tidal • Implement best practices related to management of construction costs • Support research and development of technology and pilot projects
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Environmental impacts of tidal projects are potentially significant	• Work closely with resource agencies to identify environmental issues • Conduct necessary studies to address resource agencies' issues and data requirements
Transmission Constraints	• Location of new facilities can add to transmission constraints • Integration of large tidal facility into Railbelt transmission grid poses challenges • Integration of non-dispatchable resources into Railbelt transmission grid poses challenges	• Expand Railbelt transmission network • Complete required studies to ensure the ability to integrate large tidal projects into the transmission grid • Require that all proposed plant locations also include transmission infrastructure analyses and costs as part of any approval process • Develop regional strategy for the integration of non-dispatchable resources

Table 14-11 (Continued)
Resource Specific Risks and Issues – Generation – Tidal

Resource: Generation – Tidal		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Financing	• Financing requirements of a large tidal project are greater than the combined financial capabilities of the Railbelt utilities	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for large tidal projects • Aggressively pursue available Federal funding for renewable projects
Regulatory/Legislative	• Regional commitment to renewable resources is uncertain	• Establish State RPS targets • Develop State policies regarding RECs and Green Pricing

14.2.3.3 Transmission

Table 14-12
Resource Specific Risks and Issues – Transmission

Resource: Transmission		
Risk/Issue Category	**Description**	**Primary Actions to Address Risk/Issue**
Resource Potential	• "Resource potential" is not limited; issue is determining the most appropriate projects, voltage, and siting	• Implement transmission plan included in this RIRP
Project Development	• Ineffectiveness and inefficiencies associated with six individual utilities developing transmission projects • Potential for construction cost overruns is significant	• Establish a regional entity (e.g., GRETC) to identify and develop transmission projects • Implement best practices related to management of construction costs • Centralize all siting and permitting at the State level
Fuel Supply	• Not applicable	• Not applicable
Environmental	• Potential for local environmental issues	• Pursue statewide permitting by GRETC
Transmission Constraints	• Not applicable	• Not applicable
Financing	• Financing requirements of transmission projects are significant	• Formation of a regional G&T entity (e.g., GRETC) would provide greater financial capabilities • Consider alternative forms of State assistance for transmission projects
Regulatory/Legislative	• Siting and permitting issues are potentially significant	• Develop streamlined siting and permitting processes for transmission projects

15.0 CONCLUSIONS AND RECOMMENDATIONS

This section provides an overview of the conclusions and recommendations resulting from the RIRP study.

Purpose and Limitations of the RIRP

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

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

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

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

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

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

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

15.1 Conclusions

The primary conclusions from the RIRP study are discussed below.

1. The current situation facing the Railbelt utilities includes a number of challenging issues that place the region at a historical crossroad regarding the mix of DSM/EE, generation, and transmission resources that it will rely on to economically and reliably meet the future electric needs of the region's citizens and businesses. As a result of these issues, the Railbelt utilities are faced with the following challenges:
   - A transmission network that is isolated and has limited total transfer capabilities and redundancies.
   - The inability of the region to take full advantage of economies of scale due to its limited size.
   - A heavy dependence on natural gas from the Cook Inlet for electric generation.
   - Limited and declining Cook Inlet gas deliverability.
   - Lack of natural gas storage capability.
   - The region's aging generation and transmission infrastructure.
   - A heavy reliance on older, inefficient natural gas generation assets.
   - The region's limited financing capability, both individually and collectively among the Railbelt utilities.
   - Duplicative and diffused generation and transmission expertise among the Railbelt utilities.

2. The key factors that drive the results of Black & Veatch's analysis include the following:
   - The risks and uncertainties that exist for all alternative DSM/EE, generation, and transmission resource options.
   - The future availability and price of natural gas.
   - The public acceptability and ability to permit a large hydroelectric project which is a greater concern, based upon Black & Veatch's discussions with numerous stakeholders, than the acceptability and ability to permit other types of renewable projects, such as wind and geothermal.
   - Potential future CO_2 prices, which would impact all fossil fuels, that may or may not result from proposed Federal legislation.
   - The region's existing transmission network, which limits: 1) the ability to transfer power between areas within the region to minimize power costs, and 2) places a maximum limit on the amount of non-dispatchable resources that can be integrated into the region's transmission grid.
   - The ability of the region to raise the required financing, either by the utilities on their own or through a regional G&T entity.
   - Whether the Railbelt utilities develop a number of currently proposed projects that were selected outside of a regional planning process.

   Figures 15-1 and 15-2 graphically demonstrate how the results of the various reference and sensitivity cases are impacted by these important uncertainties. Figure 15-1 shows the cumulative present value cost for each year over the 50-year planning horizon; similarly, Figure 15-2 shows the annual wholesale power cost (cents/kWh) in 2010 dollars. In both cases, we have shown selected reference and sensitivity cases to highlight how dependent the results are to these key uncertainties.

Figure 15-1
Cumulative Present Value Cost – Selected Reference and Sensitivity Cases

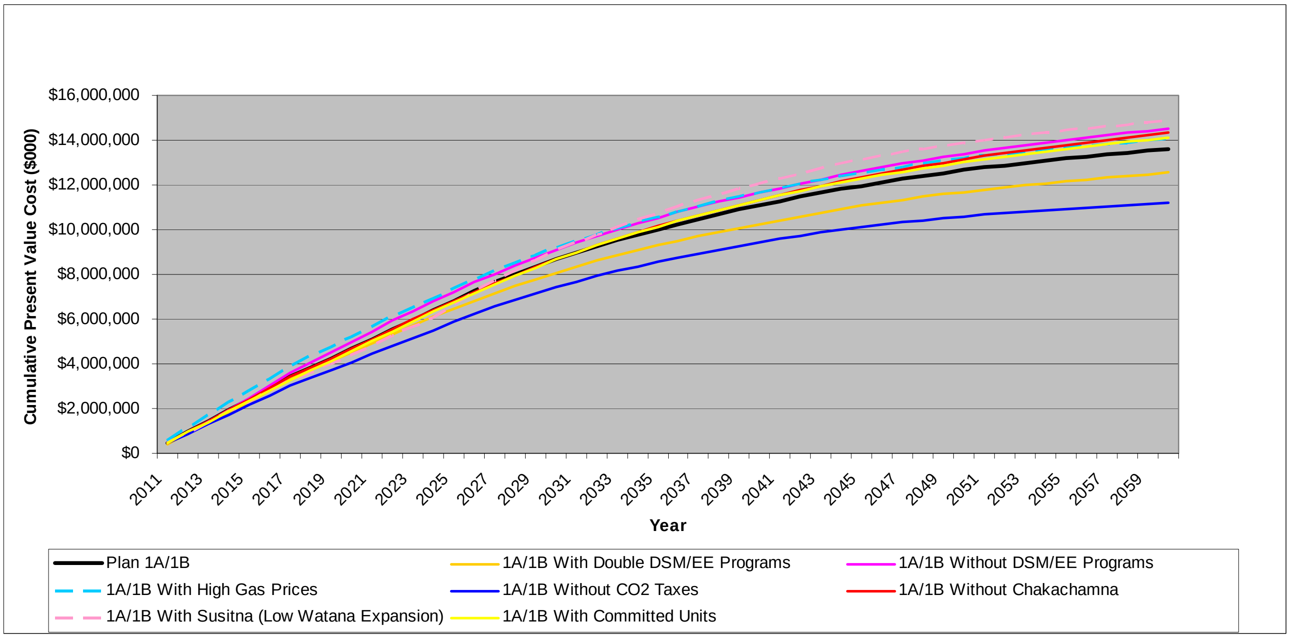
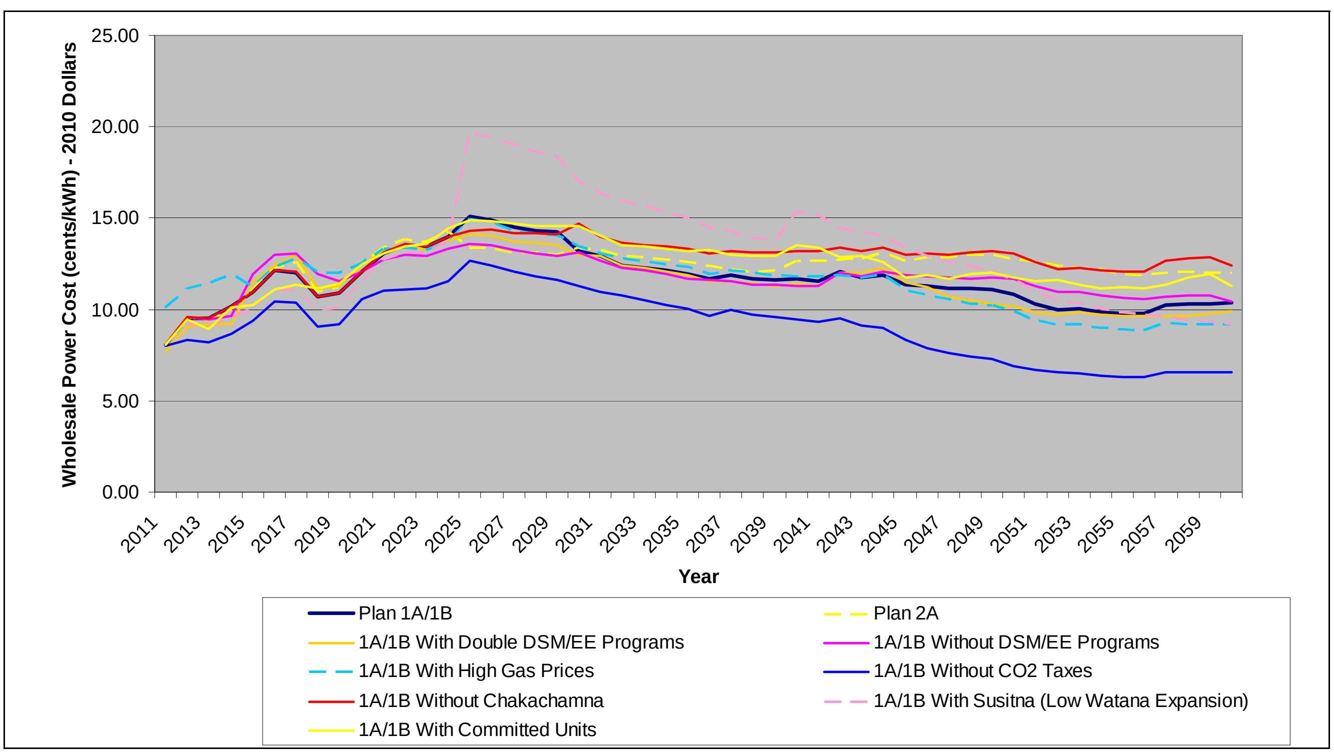


Figure 15-2
Annual Wholesale Power Cost – Selected Reference and Sensitivity Cases



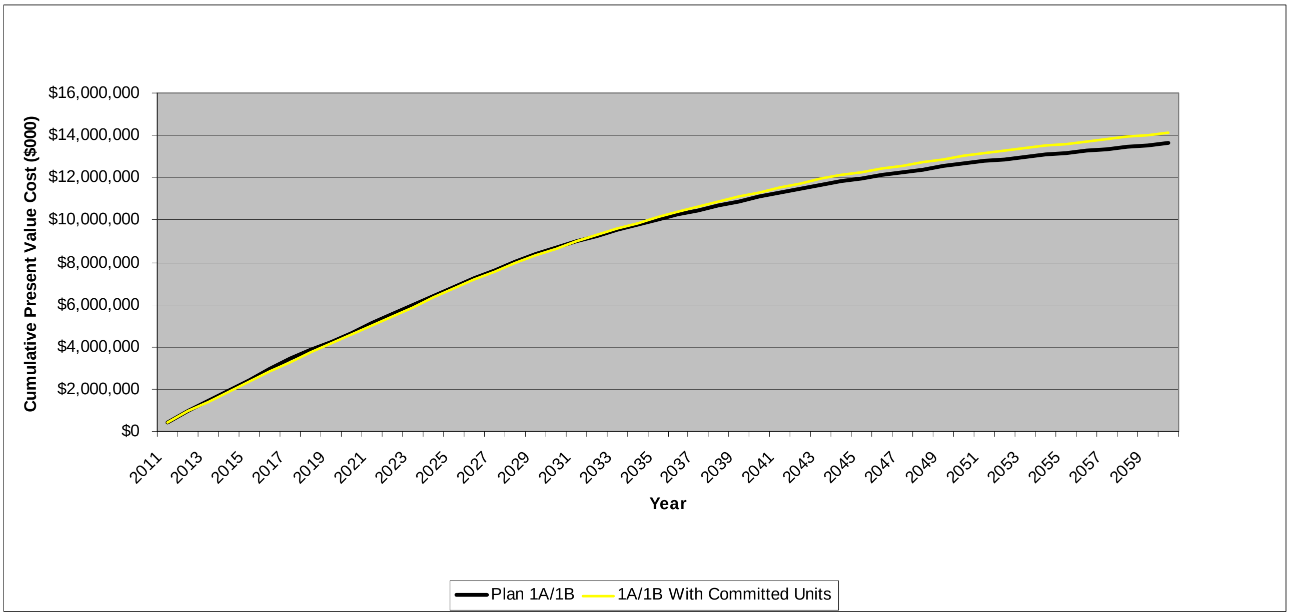
As can be seen in Figures 15-1, which shows cumulative net present value costs over the 50-year planning horizon, the 1A/1B With Susitna (Low Watana Expansion), 1A/1B With no DSM/EE Programs, 1A/1B Without Chakachamna, 1A/1BWith Committed Units, and 1A/1B With High Gas Prices Sensitivity Cases are all higher cost than Scenario 1A/1B, in descending order. The 1A/1B With Double DSM/EE Programs and 1A/1B With No CO_2 Taxes Sensitivity Cases are lower cost that Scenario 1A/1B.

Figure 15-2 shows how significant the uncertainty regarding CO_2 taxes is with regard to the results. It also shows the economic value of achieving higher DSM/EE savings that were assumed in the Scenario 1A/1B Reference Case if those savings can be achieved. Also, shown is the fact that the other sensitivity cases are higher cost than Scenario 1A/1B.

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

the relative cost differential. Figure 15-3 shows the resulting total annual costs of the two different resource plans. In the aggregate, the cost of the Committed Unit Sensitivity Case was approximately 5.6 percent, or $484 million on a cumulative net present value cost basis, higher than Scenario 1A/1B. The main conclusion to draw from this graphic is that there are significant cost savings associated with the Railbelt utilities implementing a plan that has been developed to minimize total regional costs, while ensuring reliable service, as opposed to the individual utilities working separately to meet the needs of their own customers.

Figure 15-3
Comparison of Results - Scenario 1A/1B Versus Committed Units Sensitivity Case



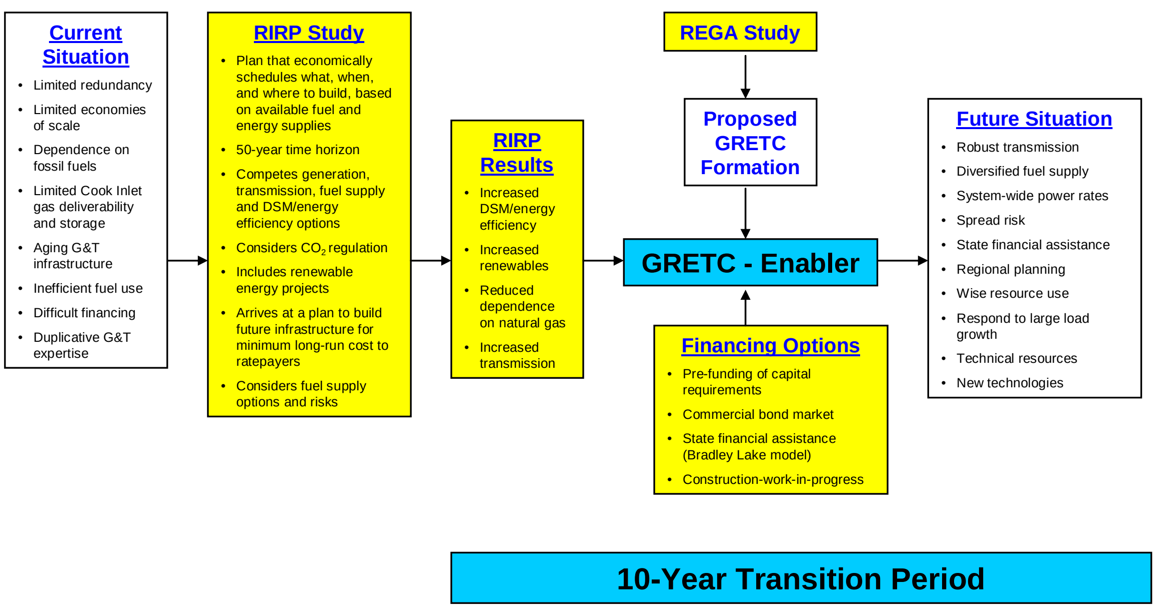
8. There are a number of risks and uncertainties regardless of the resource options chosen. For example: 1) there is a lack of Alaska-specific data upon which to build an aggressive region-wide DSM/EE program, 2) the future availability and price of natural gas affects the viability of natural gas generation, and 3) the total economic potential of various renewable resources is unknown at this time. In some cases, these risks and uncertainties (e.g., the ability to permit a large hydroelectric facility) might completely eliminate a particular resource option. Due to these risks and uncertainties, it will be important for the region to maintain flexibility so that changes to the preferred resource plan can be made, as necessary, as these resource-specific risks and uncertainties become more clear or get resolved.

9. Significant investments in the region's transmission network need to be made within the next 10 years to ensure the reliable and economic transfer of power throughout the region. Without these investments, providing economic and reliable electric service will be a greater challenge.

10. The increased reliance on non-dispatchable renewable resources (e.g., wind) will require a higher level of frequency regulation within the region to handle swings in electric output from these resources. An increased level of regulation has been included in Black & Veatch's transmission plan. Even with this increased regulation, however, the challenges associated with the integration of non-dispatchable resources will ultimately place a maximum limit on the amount of these resources that can be developed.

11. The implementation of the RIRP does not require that a regional generation and transmission entity (e.g., GRETC) be formed. However, the absence of a regional entity with the responsibility for implementing the RIRP will increase the difficulty of the region's ability to implement a regional plan and, in fact, Black & Veatch believes that the lack of a regional entity will, as a practical matter, mean that the RIRP will not be fully implemented. As a consequence, the favorable outcomes of the RIRP discussed above would not be realized. The interplay between the formation of a regional entity and the RIRP is shown in Figure 15-4.

Figure 15-4
Interplay Between GRETC and Regional Integrated Resource Plan



15.2 Recommendations

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

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

15.2.1 Recommendations - General

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

1. The State should work closely with the utilities and other stakeholders to make a decision regarding the formation of GRETC and to develop the required governance plan, financial and capital improvement plan, capital management plan and transmission access plan, and address other matters related to the formation of the proposed regional entity.
2. The State should establish certain energy-related policies, including:
   - The pursuit of large hydroelectric facilities
   - DSM/EE program targets
   - RPS (i.e., target for renewable resources), and the pursuit of wind, geothermal, and tidal (which will become commercially mature during the 50-year planning horizon) projects in addition to large hydroelectric projects; the passage of an RPS would be meaningful as a policy statement even though the preferred resource plan would achieve a 50 percent renewable level by 2025.
   - System benefit charge to fund DSM/EE programs and or renewable projects
3. The State should work closely with the Railbelt utilities and other stakeholders to establish the specific preferred resource plan. In establishing the preferred resource plan, the economic results of the various reference cases and sensitivity cases evaluated in this study should be considered, as well as the environmental impacts discussed in Section 13 and the project-specific risks discussed in Section 14.
4. Black & Veatch believes that the Scenario 1A/1B resource plan should be the starting point for the selection of the preferred resource plan as discussed below. Table 15-1 provides a summary of the specific resources that were selected, based upon economics, in the Scenario 1A/1B resource plan during the first 10 years.

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

   Another important consideration in the selection of a preferred resource plan is evaluation of the sensitivity cases evaluated, as presented in Section 13. Issues addressed through the sensitivity cases and considered in Black & Veatch's selection of a preferred resource plan include the following and are discussed in Table 15-2. Following that discussion, Table 15-3 provides a discussion regarding specific projects currently under development and their impact on the preferred resource plan.
   - What if CO_2 regulation doesn't occur?
   - What is the effect if the committed units are installed?
   - What if Chakachamna doesn't get developed?
   - What would be the impact of the alternative Susitna projects?

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

   These projects are discussed in Table 15-3.

Table 15-1
Resources Selected in Scenario 1A/1B Resource Plan

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

Table 15-1 (Continued)
Resources Selected in Scenario 1A/1B Resource Plan

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

Table 15-2
Impact of Selected Issues on the Preferred Resource Plan

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

Table 15-3
Projects Significantly Under Development

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

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

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

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

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

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

15.2.2 Recommendations – Capital Projects

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

1. Develop a comprehensive region-wide portfolio of DSM/EE programs.
2. Generation projects:
    - Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project)

- Glacier Fork Hydroelectric Project
- Generic Anchorage MSW Project
- Generic GVEA MSW Project
- GVEA North Pole Retrofit Project
- Mt. Spurr Geothermal Project
- Chakachamna Hydroelectric Project
- Susitna Hydroelectric Project

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

15.2.3 Recommendations - Other

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

1. The State Legislature should appropriate funds for the initial stages of the development of a regional DSM/EE program, including 1) region-wide residential and commercial end-use saturation surveys, 2) residential and commercial customer attitudinal surveys, 3) vendor surveys, 4) comprehensive evaluation of economically achievable potential, and 5) detailed DSM/EE program design efforts.

2. Develop a regional DSM/EE program measurement and evaluation protocol.

3. If GRETC is not formed, some type of a regional entity should be formed to develop and deliver DSM/EE programs to residential and commercial customers throughout the Railbelt region, in close coordination with the Railbelt utilities.

4. Likewise, if GRETC is not formed, some type of a regional entity should be formed to develop the renewable resources included in the preferred resource plan.

5. Establish close coordination between the Railbelt electric utilities, Enstar and AHFC regarding the development and delivery of DSM/EE programs.

6. Aggressively pursue available Federal funding for DSM/EE programs and renewable projects.

7. Further development of tidal power should be encouraged due to its resource potential in the Railbelt region. Although this technology is not commercially available, in Black & Veatch's opinion, at this point in time, it has the potential to be economic within the planning horizon.

8. The State and Railbelt utilities should work closely with resource agencies to identify environmental issues and permitting requirements related to large hydroelectric and tidal projects, and conduct the necessary studies to address these issues and requirements.

9. Complete a regional economic potential assessment, including the identification of the most attractive sites, for all renewable resources included in the preferred resource plan.

10. Develop streamlined siting and permitting processes for transmission projects.
11. Develop a regional frequency regulation strategy for non-dispatchable resources.
12. Develop a regional competitive power procurement process and a standard power purchase agreement to provide IPPs an equal opportunity to submit qualified proposals to develop specific projects.
13. Federal legislative and regulatory activities, including those related to emissions regulations, should be monitored closely and influenced to the degree possible.
14. Monitor the licensing progress of small modular nuclear units.

16.0 NEAR-TERM IMPLEMENTATION ACTION PLAN (2010-2012)

The purpose of this section is to provide Black & Veatch's recommended near-term implementation plan, covering the period from 2010 to 2012. Our recommended actions are grouped into the following categories:

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

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

16.1 General Actions

Table 16-1
Near-Term Implementation Action Plan – General Actions

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

Table 16-1 (Continued)
Near-Term Implementation Action Plan – General Actions

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
	• Develop a public outreach program to inform the public regarding the preferred resource plan, including the costs and benefits	2010-2011	$0.1 million
	• The State Legislature should make decisions regarding the level and form of State financial assistance that will be provided to assist the Railbelt utilities and AEA, under a unified regional G&T entity (i.e., GRETC), develop the generation resources and transmission projects identified in the preferred resource plan	2010-2011	Not applicable
	• The electric utilities, various State agencies, Enstar and Cook Inlet producers need to work more closely together to address short-term and long-term gas supply issues; specific actions that should be taken include: o Development of local gas storage capabilities as soon as possible o Undertake efforts to secure near-term LNG supplies to ensure adequate gas over the 10-year transition period until additional gas supplies can be secured o The State should complete a detailed cost and risk evaluation of available long-term gas supply options to determine the best options; once the most attractive long-term supplies of natural gas have been identified, detailed engineering studies and permitting activities should be undertaken to secure these resources o Appropriate commercial terms and pricing structures should be established through State and regulatory actions to provide producers with the incentive to increase exploration for additional gas supplies in the Cook Inlet or nearby basins	2010-2012	To be determined

16.2 Capital Projects

Table 16-2
Near-Term Implementation Action Plan – Capital Projects

Actions			
Category	**Description**	**Timeline**	**Est. Cost**
Capital Projects	• Develop a comprehensive region-wide portfolio of DSM/EE programs within first six years	2011-2016	$34 million
	• Begin detailed engineering and permitting activities associated with the generation projects identified in the initial years of the preferred resource plan, including: o Projects under development (HCCP, Southcentral Power Project, Fire Island Wind Project, and Nikiski Wind Project) o Glacier Fork Hydroelectric Project o Generic Anchorage MSW Project o Generic GVEA MSW Project o GVEA North Pole Retrofit Project o Mt. Spurr Geothermal Project o Chakachamna Hydroelectric Project o Susitna Hydroelectric Project	2011-2016	Varies by project
	• Begin detailed engineering and permitting activities associated with the transmission projects identified in the initial years of the preferred resource plan, including: o Soldotna to Quartz Creek Transmission Line ($84 million – Project B) o Quartz Creek to University Transmission Line ($112.5 million – Project C) o Douglas to Teeland Transmission Line ($37.5 million – Project D) o Lake Lorraine to Douglas Transmission Line ($80 million – Project E) o SVCs ($25 million - Other Reliability Projects) o Funds to undertake the study of the Southern Intertie ($1 million) o Funds to investigate the provision of regulation that will facilitate the integration of renewable energy projects into the Railbelt system ($50 million, including cost of BESS – Other Reliability Projects)	2011-2016	Varies by project

16.3 Supporting Studies and Activities

Table 16-3
Near-Term Implementation Action Plan – Supporting Studies and Activities

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

16.4 Other Actions

Table 16-4
Near-Term Implementation Action Plan – Other Actions

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