APPENDIX A

SUSITNA ANALYSIS

Susitna Hydroelectric Project

Conceptual Alternatives Design Report

Final Draft

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1 Executive Summary

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

In 2008, the Alaska State Legislature authorized the Alaska Energy Authority (AEA) to perform an update of the project. That authorization also included a Railbelt Integrated Resource Plan (RIRP) to evaluate the ability of this project and other sources of energy to meet the long term energy demand for the Railbelt region of Alaska. Renewable hydroelectric power is of particular interest to the railbelt because of its potential to provide stable power costs for the region. Of all the renewable resources in the railbelt region, the Susitna projects are the most advanced and best understood.

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

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 megawatts (MW).
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.
- **Devil Canyon.** This alternative consists of the construction of a 646-foot-high concrete dam at the Devil Canyon site with a four-unit powerhouse with a total installed capacity of 680 MW.
- **Watana/Devil Canyon.** This alternative consists of the full-height Watana development and the Devil Canyon development as presented in the 1983 FERC license application. The two dams and powerhouses would be constructed sequentially without delays. The combined Watana/Devil Canyon development would have a total installed capacity of 1,880 MW.
- **Staged Watana/Devil Canyon.** This alternative consists of the Watana development constructed in stages and the Devil Canyon development as presented in the 1985 FERC amendment. In stage one the Watana dam would be constructed to the lower height and the Watana powerhouse would only have 4 out of the 6 turbine generators installed, but would be constructed to the full sized powerhouse. In stage two the Devil Canyon dam and powerhouse would be constructed. In stage three the Watana dam would be raised to

its full height, the existing turbines upgraded for the higher head, and the remaining 2 units installed. At completion, the project would have a total installed capacity of 1,880 MW.

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

- **Low Watana Non-Expandable.** This alternative consists of the Watana dam constructed to a height of 700 feet, along with a powerhouse containing 4 turbines with a total installed capacity of 600 MW. This alternative has no provisions for future expansion.
- **Lower Low Watana.** This alternative consists of the Watana dam constructed to a height of 650 feet along with a powerhouse containing 3 turbines with a total installed capacity of 390 MW. This alternative has no provisions for future expansion.
- **High Devil Canyon.** This alternative consists of a roller-compacted concrete (RCC) dam constructed to a height of 810 feet, along with a powerhouse containing 4 turbines with a total installed capacity of 800 MW.
- **Watana RCC.** This alternative consists of a RCC Watana dam constructed to a height of 885 feet, along with a powerhouse containing 6 turbines with a total installed capacity of 1,200 megawatts (MW).

The results of this study are summarized in Table 1.

Table 1 - Susitna Summary

Alternative	Dam Type	Dam Height (feet)	Ultimate Capacity (MW)	Firm Capacity, 98% (MW)	Construction Cost ($ Billion)	Energy (GWh/yr)	Schedule (years from start of licensing)
Lower Low Watana	Rockfill	650	390	170	$4.1	2,100	13-14
Low Watana Non-expandable	Rockfill	700	600	245	$4.5	2,600	14-15
Low Watana Expandable	Rockfill	700	600	245	$4.9	2,600	14-15
Watana	Rockfill	885	1,200	380	$6.4	3,600	15-16
Watana RCC	RCC	885	1,200	380	$6.6	3,600	15-16
Devil Canyon	Concrete Arch	646	680	75	$3.6	2,700	14-15
High Devil Canyon	RCC	810	800	345	$5.4	3,900	13-14
Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$9.6	7,200	15-20
Staged Watana/Devil Canyon	Rockfill/Concrete Arch	885/646	1,880	710	$10.0	7,200	15-24

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

Development of any of the alternatives for the Susitna River will require careful consideration of many factors. Environmental issues, climate change and sedimentation are discussed in this report and the risk associated with these issues is considered manageable. An updated evaluation of seismicity has been done by others and this risk is also considered manageable.

Hydroelectric power has many economic and environmental benefits including long-term rate stabilization. Because the cost of the water (fuel) is essentially free and maintenance costs are minimal, the cost per kilowatt hour is driven largely by the project finance terms and is not subject to fluctuations in fuel cost.

2 Background

The Susitna River has its headwaters in the mountains of the Alaska Range about 90 miles south of Fairbanks. It flows generally southwards for 317 miles before discharging into Cook Inlet just west of Anchorage. Contained entirely within the south central Railbelt region, the Susitna River is situated between the two largest Alaska population centers of Anchorage and Fairbanks.

The Bureau of Reclamation first studied the Susitna River's hydroelectric potential in the early 1950s, with a subsequent review by Corps of Engineers in the 1970s. In 1980, the Alaska Power Authority (APA; now the Alaska Energy Authority) commissioned a comprehensive analysis to determine whether hydroelectric development on the Susitna River was viable. Based on those studies, the APA submitted a license application to the Federal Energy Regulatory Commission (FERC) in 1983 for the Watana/Devil Canyon project on the Susitna River. The license application was amended in 1985 for the construction of the Staged Watana/Devil Canyon project at an estimated cost of $5.4 billion (1985 dollars).

Developing a workable financing plan proved difficult for a project of this scale. When this existing difficulty was combined with the relatively low cost of gas-fired electricity in the Railbelt and the declining price of oil throughout the 1980s, and its resulting impacts upon the State budget, the APA terminated the project in March 1986.

At that point, the State of Alaska had appropriated approximately $227 million to the project from FY79-FY86, of which the project had expended $145 million to fund extensive field work, biological studies, and activities to support the FERC license application. Though the APA concluded that project impacts were manageable, the license application was withdrawn and the project data and reports were archived to be available for reconsideration sometime in the future.

In 2008, the Alaska State Legislature, in the FY 2009 capital budget, authorized the AEA to reevaluate the Susitna Hydro Project as it was conceived in 1985. The authorization also included funding a Railbelt Integrated Resource Plan (RIRP) to evaluate various sources of electrical power to satisfy the long term energy needs for the Railbelt portion of Alaska. A Susitna River hydroelectric project could play a significant role in meeting these needs.

2.1 Project Scope

The scope of this study was to collect and review pertinent information from the original studies and license application from the 1980's and re-estimate the project energy, costs and development schedule.

The initial 1982 FERC license application and subsequent 1985 amendment analyzed several project alternatives:

- **Watana.** This alternative consists of the construction of a large storage reservoir on the Susitna River at the Watana site with an 885-foot-high rock fill dam and a six-unit powerhouse with a total installed capacity of 1,200 megawatts (MW).
- **Low Watana Expandable.** This alternative consists of the Watana dam constructed to a lower height of 700 feet and a four-unit powerhouse with a total installed capacity of 600 MW. This alternative contains provisions that would allow for future raising of the dam and expansion of the powerhouse.

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

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Preliminary energy, cost, and schedule estimates for the analyzed alternatives are described in the following sections.

3 Preliminary Energy Estimate

3.1 Hydrologic Analysis

At the time the original study was issued in 1983 the hydrologic record contained data from 1950 to 1981. To develop an updated energy estimate for the Susitna hydroelectric project alternatives, a synthesized hydroelectric record for each site was created by a drainage area proration of daily flow data from United States Geological Survey (USGS) gage 1529000 at

Gold Creek. USGS gage 1529000 has a period of record from water year 1950-1996 and 2002-2008.

The hydrology of the upper Susitna Basin is dominated by melt water from snow and glaciers in the spring and summer, and substantial freezing during the winter months. As a result, a majority of the flow occurs between mid-April and mid-October. The following figure shows the average monthly flow at the Watana dam site for each year of record.

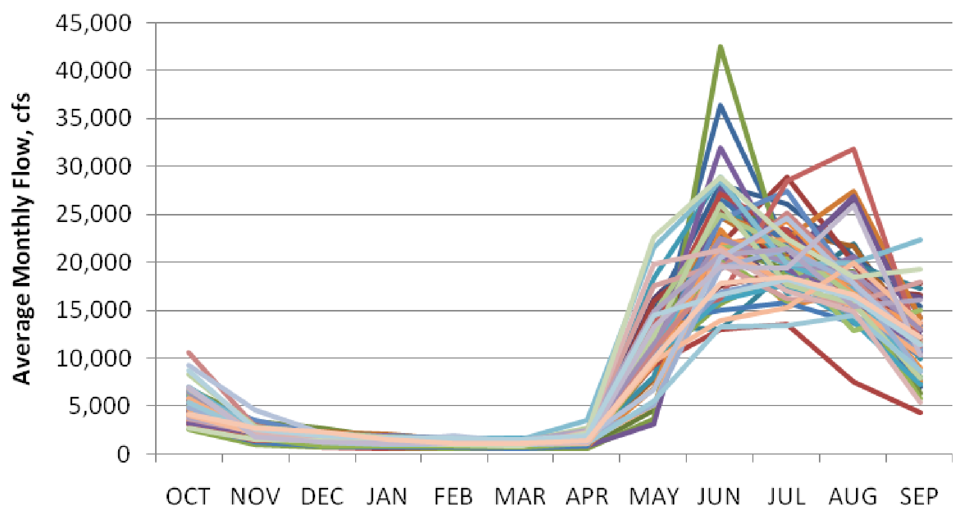

Figure 1 - Susitna River at Watana Hydrologic Variation

The manner in which precipitation and runoff might be affected by the impacts of either natural variability and/or potential climate change is discussed at the end of this report.

3.2 Evaluation of Firm Winter Capacities and Average Annual Energy

The amount of energy that can be produced from hydroelectric projects is a function of the amount of available water and in the case of storage projects, how the available water can be regulated (systematically released). For the RIRP evaluation process, in addition to the average annual energy, the firm capacity attainable during winter months is of particular importance. For hydroelectric projects, the firm capacity is almost always lower than the installed generation capacity for a project. For the purposes of this study work, firm capacity is defined as:

> "The amount of power the project can generate on a continuous basis from Nov. 1 through April 30 with 100% reliability".

The firm capacity is always driven by low periods in the hydrologic cycle. Since the hydrologic cycle varies, it is also desired to know at what level of reliability the project can generate at levels higher than the firm capacity. It should be noted that this is only one manner of regulation. The water can be regulated in a variety of different means in order to achieve other objectives, such as peaking, spinning reserve or backup capacity.

For this study, the average annual energy and winter plant capacities for the alternatives were estimated using a HDR proprietary energy modeling software tool customized for this particular purpose (Computer Hydro-Electric Operations and Planning Software or (CHEOPS)). Major assumptions used in the modeling efforts are presented below.

3.3 Model Assumptions and Data Sources

- Inflow hydrology was based upon USGS gage #1529000 located at Gold Creek on the Susitna River and scaled by a drainage area correction factor representing each of the dam sites.
- Reservoir capacity and area curves for the Watana and Devil Canyon alternatives were based on information presented in the 1985 FERC application. For the High Devil Canyon project this data was derived from USGS topographical data.
- Tailwater curves for the Watana and Devil Canyon projects were obtained from the 1985 FERC application and estimated for High Devil Canyon.
- Operating reservoir levels were obtained from the 1985 FERC application for the Watana, Low Watana and Devil Canyon projects, from the 1982 Acres feasibility study for the High Devil Canyon project, and estimated for the Lower Low Watana project.
- Environmental flow release constraints were as presented in the 1985 FERC application and scaled according to drainage areas for the various sites.
- Evaporation coefficients were obtained from the 1985 FERC application. Total reservoir evaporation was estimated in the 1985 FERC application to be between one (1) and three (3) inches per month in summer, with negligible evaporation during winter months.
- Equipment performance was based on vendor data obtained in 2008 specifically for the Watana and Devil Canyon projects and was assumed to be representative for the other projects.
- Headloss estimates were based on the water conveyance design from the 1985 FERC application for the Watana and Devil Canyon alternatives and the 1982 Acres feasibility study for the High Devil Canyon alternative.
- The reservoir was assumed to start full at the beginning of the simulation and was allowed to fluctuate over the remaining period of the simulation.
- Generation from Nov. 1 to April 30, “winter,” was at a constant capacity level (“block loaded”).
- Generation from May 1 to Oct. 31, “summer,” was to maximize energy with the objective of the reservoir being full on Nov. 1.
- Rule curves for summer target reservoir elevations were developed for each alternative using a mass balance approach. The ratio of the average monthly inflow volume to the average annual inflow volume during each of the reservoir filling months were used to set target elevations for the reservoir.
- Energy losses of 1.5 percent for un-scheduled outages and 2 percent for transformer losses were applied to the total generation.
- Active storage remained constant over the simulation period. Dead storage in the reservoirs was assumed to be sufficient to contain sedimentation loads.

- No ramping rate restrictions were imposed on either reservoir drawdown or downstream flow.

To determine the firm capacity for the combined Watana and Devil Canyon projects, the regulated flow from Watana was assumed to pass unregulated through Devil Canyon with the Devil Canyon pool at maximum operating level.

Key input parameters related to energy generation are shown in Table 2 below.

Table 2 - Summary of Susitna Project Alternatives

	Lower Low Watana	Low Watana (Both Alternatives)	Watana (Both Alternatives)	Devil Canyon	High Devil Canyon
Dam Type	Rockfill	Rockfill	Rockfill or RCC	Concrete Arch	RCC
Dam Height (ft)	650	700	885	646	810
Gross Head (ft)	495	557	734	605	729
Net Head (Max Flow) (ft)	481	543	729	598	707
Maximum Plant Flow (cfs)	10,700	14,500	22,300	14,000	14,800
Number of Units	3	4	6	4	4
Nameplate Capacity (MW)	390	600	1200	680	800
Maximum Pool Elevation (ft)	1951	2014	2193	1456	1751
Minimum Pool Elevation (ft)	1850	1850	2065	1405	1605
Tailwater Elevation (Max Flow) (ft)	1456	1457	1459	851	1022
Usable Storage (acre-ft)	1,536,200	2,704,800	3,888,50	310,000	2,254,700

3.4 Model Operation

For each alternative, 54 years of daily inflow data was used to determine each alternative's ability to meet a range of winter energy production targets and maximize summer generation. For each day from November through April the flow through the powerhouse was limited to the amount necessary to satisfy a prescribed capacity demand given the available head, environmental flow constraints, and reservoir operational restrictions. During the months of May through September energy production each day was maximized if the reservoir elevation was above the target rule curve. If the reservoir elevation was below the target rule curve then generation was limited to the amount that would allow the downstream environmental flow constraints to be met. The simulation was repeated at various increasing winter load demands until the maximum firm capacity was determined.

To better quantify the effect of storage and extreme low water years on the firm winter capacity, winter load levels in excess of the firm capacity were also evaluated. The results of this analysis are expressed as a capacity at a given percent exceedance level. For example, a project might have a firm capacity of 250 MW at a 100% exceedance level and a firm capacity of 300 MW at a 98% exceedance level. This would mean that the project could provide 250 MW 100% of the time in the winter over the simulation period or 300 MW 98% of the time over the winter. The large change in firm capacity between the 100% exceedance level and the 98% exceedance level for all alternatives is primarily due to a single low water year in 1970.

The resulting firm capacities and average annual energy production estimates are presented in Figure 2 and partially summarized in Table 3. Detailed input assumptions and results of these energy analyses are provided in Appendix A of this report. The average annual energy production was relatively constant over the range of winter power demand levels that were modeled.

Table 3 - Firm Capacity and Energy Estimates

Alternative	Firm Winter Capacity (MW)	98% Winter Capacity (MW)	Average Annual Energy Production (GWh)
Lower Low Watana	100	170	2,100
Low Watana (both alternatives) *	150	245	2,600
Watana (both alternatives) **	250	380	3,600
Watana/Devil Canyon ***	470	710	7,200
Devil Canyon	50	75	2,700
High Devil Canyon	250	345	3,900

* Low Watana Expandable and Low Watana Non-Expandable have the same energy characteristics.
** Watana Rockfill and Watana RCC have the same energy characteristics.
*** Watana/Devil Canyon and the Staged Watana/Devil Canyon have similar energy characteristics.

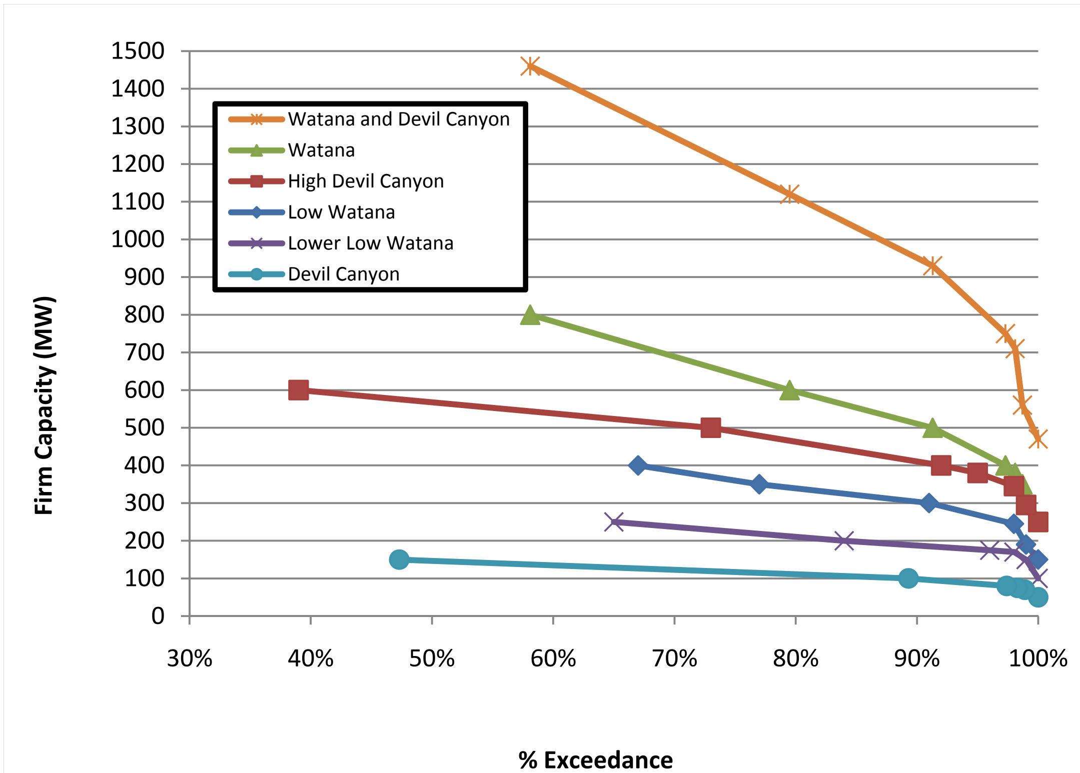

Figure 2 - Firm Capacity

4 Estimates of Probable Project Development Costs

4.1 Original Cost Estimate

In 1982 the cost for developing the complete full Watana/Devil Canyon project was estimated to be $5.0 billion (1982 dollars). In 1985 the cost for developing the staged Watana/Devil Canyon project was $5.4 billion (1985 dollars).

The Devil Canyon and High Devil Canyon alternatives were as envisioned in the 1980's. The four rockfill Watana Dam configurations considered in this evaluation are depicted in Figure 3 below.

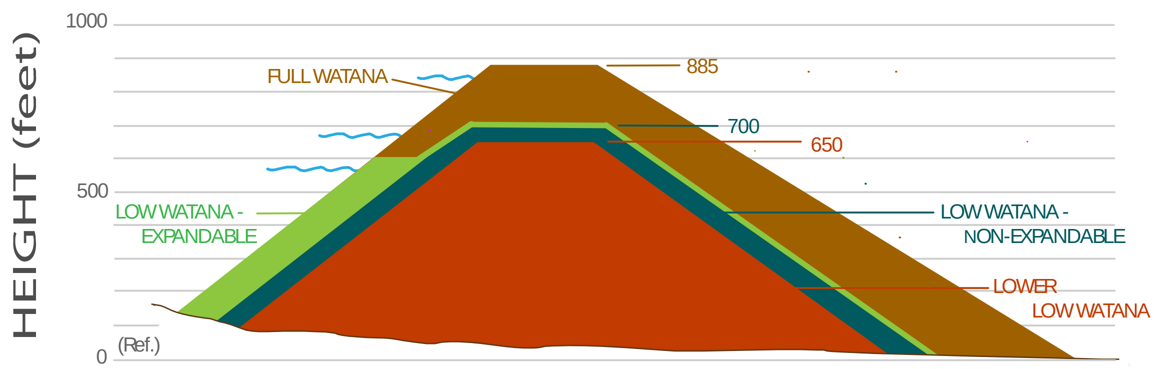

Figure 3 - Watana Dam Configurations

The estimates for the Watana, Low Watana-Expandable, Devil Canyon and Staged Watana-Devil Canyon alternatives were developed in depth in a March 2009 Interim report and were revised to reflect changes primarily in transmission, access and camp costs. Using this information as a base, new estimates were made for the development costs of the Low Watana Non-Expandable and of the Lower Low Watana alternatives. Cost estimates of $5.4 billion for the High Devil Canyon RCC and $6.6 billion for the Watana RCC alternatives were provided by a separate contractor using similar assumptions and are presented here for completeness of information. The following discussion details the basis for the cost estimates for the Watana embankment projects, the assumptions that were used in creating those estimates, and provides a summary of the projected construction costs.

4.2 Expandability

The Low Watana alternative, as proposed in previous studies, included provisions for eventual expansion of the dam from 700 feet to a height of approximately 885 feet and an increase in powerhouse capacity from 800 MW to 1200 MW. The most notable of these provisions are the design of the dam cross section and construction of the powerhouse and water conduits to their ultimate capacity. The two non-expandable alternatives contain no provisions for future expansion.

For the Low Watana Expandable alternative the dam cross-section is expanded on the upstream side to provide the opportunity to later raise the dam. This results in additional fill material due to the wider base. The powerhouse, powerhouse equipment, and water conveyance scheme would be built to house six units, but only four turbines would be initially installed.

For the Low Watana Non-expandable alternative the cross-section is narrower and does not accommodate expansion of the dam at a later time. Similarly the powerhouse and water conduit features are sized for only four turbine/generator units instead of six.

4.3 Quantities

Quantities for the construction cost estimates were based upon detailed estimates developed as part of the 1982 Acres feasibility study for the full sized Watana project and the Devil Canyon project. To estimate the quantities of the smaller Watana alternatives, the full sized Watana quantities were scaled based on the size of the development. As part of a separate report, quantities were developed for the High Devil Canyon alternative based upon a new conceptual design using RCC construction.

Table 4 summarizes the embankment fill volumes that were used for the cost estimates. The dam heights and fill volumes of the Watana and Low Watana Expandable configurations were adopted directly from the 1985 FERC application. The embankment volumes for the Lower Low Watana and Low Watana Non-Expandable alternatives were estimated assuming a 2:1 side slope on the downstream portion of the dam and a 2.4:1 side slope on the upstream portion of the dam as were assumed for the other alternatives. Volume changes were limited to the rock-fill and riprap portion of the dam only. The concrete volumes for the Devil Canyon, Watana RCC, and High Devil Canyon alternatives are shown for comparison.

Table 4 - Estimated Total Fill Volumes

Alternative	Type	Total Fill Volume(cy)
Watana	Rockfill	61,000,000
Low Watana Expandable	Rockfill	32,000,000
Low Watana Non-Expandable	Rockfill	22,000,000
Lower Low Watana	Rockfill	17,000,000
Devil Canyon	Concrete Arch	1,300,000
Watana*	RCC	15,000,000
High Devil Canyon*	RCC	11,600,000

* R&M, 2009.

The quantity estimates for the water conduit layouts and powerhouses for all alternatives were based on the 1985 layout as opposed to the 1983 layout. The 1983 arrangement used a separate penstock for each unit with a very long conveyance scheme. The 1985 arrangement employed a headrace for every two units bifurcating into dedicated penstocks. The total length of conveyance was less than half that of the 1983 design. To maintain consistency with the energy model, and to further refine the cost estimates, the 1985 configuration was used for this study.

Table 5 summarizes the design features that were assumed in each estimate. The powerhouse and water conveyance systems for Watana and the Low Watana Expandable alternatives were designed to service six units as contemplated in 1983. However, the water conduit layout reflects the 1985 arrangement with three headraces bifurcated into six penstocks and discharged into two tailraces. Low Watana Non-Expandable was assumed to be built to accommodate a four-unit powerhouse with two headraces, four penstocks and a single tailrace. Lower Low Watana was designed for a three-unit powerhouse with one headrace, three penstocks, and one tailrace. The diameters of the water conduits were sized to be consistent with the 1985 design. The powerhouse structures were also scaled accordingly.

Table 5 - Watana Water Conduit and Powerhouse Size Parameters

Item	Lower Low Watana	Low Watana Non-Exandable	Low Watana Expandable	Watana
Number of Units	3	4	4	6
Unit Size (MW)	130	150	150	200
Plant Nameplate Capacity (MW)	390	600	600	1200
# of Headraces	1	2	3	3
Headrace Diameter (ft)	24	24	24	24
# of Penstocks	3	4	6	6
Concrete Lined Penstock Diameter (ft)	18	18	18	18
Steel Penstock Diameter (ft)	15	15	15	15
# of Tailrace Tunnels	1	1	2	2
Tailrace Diameter (ft)	34	34	34	34

4.4 Unit Costs

U.S. Cost, a company specializing in creating cost estimates for large capital infrastructure projects, developed unit prices for the materials detailed in the 1982 estimate in 2008 dollars. This cost data was used to develop the estimates presented in the Interim Report and the same pricing was used in this study. Lump sum items were inflated using a construction cost index.

For the water-to-wire turbine-generator equipment estimates, budget pricing for the Watana alternative was requested directly from manufacturers. The water-to-wire equipment includes turbines, generators, turbine shutoff valves, and other miscellaneous mechanical and electrical equipment, including installation costs. The equipment costs for other smaller alternatives were developed by scaling the Watana vendor quotes on a per kilowatt basis.

4.5 Indirect Costs

A contingency of 20 percent was added to the direct construction costs to reflect level of design and uncertainty in the project.

Project licensing, environmental studies and engineering design were estimated at 7 percent of direct construction costs. Construction management was estimated at 4 percent of the direct construction costs, and has been included as a separate line item.

4.6 Interest During Construction and Financing Costs

Costs associated with interest during construction and project financing are not included in the estimates.

4.7 Changes from 1983 Design

The camps, access roads and transmission, infrastructure assumptions used in the 1983 configuration have been modified as discussed below.

4.7.1 Camps

Reductions were made in the scale of the permanent and construction camps needed to accommodate the workers. These changes were made based on the fact that permanent town facilities were no longer necessary due to advances in remote project operation. It was also assumed that due to modern construction methods, the number of construction personnel could be reduced. It was assumed that 750 people would need to be housed for the Lower Low Watana arrangement, 825 people for Low Watana and 900 people for Watana. In 1983 it was originally assumed that housing would be provided for 3000 people plus families. Budget pricing for the construction camp was provided by vendors.

4.7.2 Access

For all the Watana alternatives, access is assumed to be via the Denali Highway from the north as shown in Figure 4. The route would include the upgrade of 21 miles of the Denali Highway to a construction grade road and the construction of approximately 40 miles of new road to the Watana site. The price per mile of new road has been assumed at $3M/mile which is the current budgetary estimate of the Alaska Department of Transportation and Public Facilities for the road to Bettles and Umiat from the Dalton Highway which is similar in nature to the road that would be required for a Susitna project. Upgrading of the Denali Highway has been assumed to be $1M/mile and local site roads have been estimated at $750k/mile.

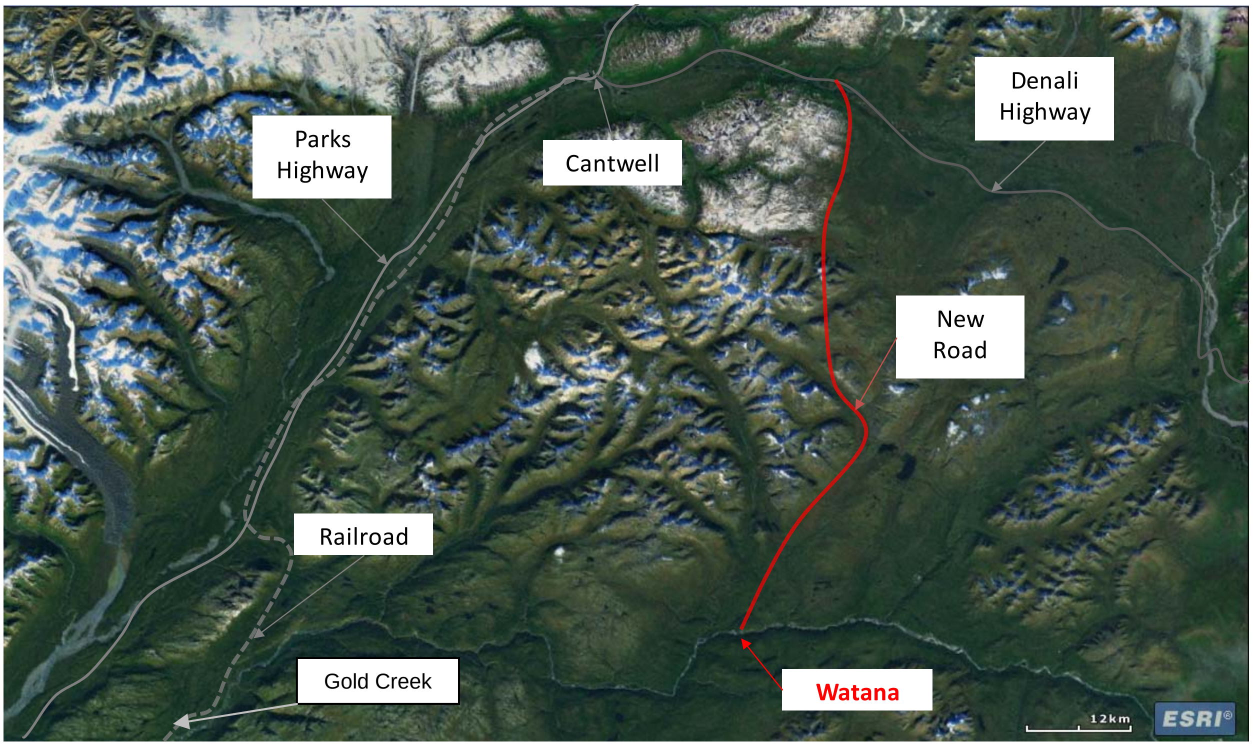

Figure 4 - Proposed Access Route

For the Devil Canyon and High Devil Canyon alternatives, rail access was assumed and will originate on the Parks Hwy near MP 156 and proceed upstream on the south side of the river.

4.7.3 Transmission

A separate study (EPS, 2009) has investigated the transmission lines and interconnection requirements for the entire Alaska railbelt region as part of the RIRP process and the results are incorporated here at the direction of the AEA. This study estimates that a transmission line from the project site to the substation at Gold Creek would cost approximately $4.5M/mile. Substation costs are estimated at $16M per location. No costs have been assumed to increase or modify the regional transmission grid beyond the Gold Creek substation.

4.8 Conclusions

The approach, methodology and assumptions previously described resulted in the estimated project costs detailed below in the summary table.

Table 6 - Alternate Project Configuration Cost Summary Table ($Millions)

FERC Line #	Line Item Name	Lower Low Watana	Low Watana Non-Expandable	Low Watana Expandable	Watana	Watana RCC*	Devil Canyon	High Devil Canyon*	Watana/ Devil Canyon	Staged Watana/ Devil Canyon
71A	Engineering, Env., and Regulatory (7%)	$ 213	$ 236	$ 259	$ 338	$342	$191	$281	$501	$528
330	Land and Land Rights	$ 121	$ 121	$ 121	$ 121	$121	$52	$121	$173	$173
331	Power Plant Structure Improvements	$ 93	$ 115	$ 159	$ 159	$159	$165	$159	$324	$325
332.1-.4	Reservoir, Dams and Tunnels	$ 1,415	$ 1,538	$ 1,718	$ 2,424	$2,307	$900	$1,803	$3,324	$3,485
332.5-.9	Waterways	$ 590	$ 590	$ 677	$ 677	$558	$415	$552	$1,093	$1,191
333	Waterwheels, Turbines and Generators	$ 213	$ 297	$ 297	$ 475	$487	$295	$487	$770	$834
334	Accessory Electrical Equipment	$ 29	$ 41	$ 41	$ 72	$57	$38	$57	$110	$119
335	Misc Power Plant Equipment	$ 17	$ 21	$ 32	$ 32	$32	$29	$32	$61	$61
336	Roads, Rails and Air Facilities	$ 232	$ 232	$ 232	$ 280	$584	$535	$490	$388	$394
350-390	Transmission Features	$ 177	$ 224	$ 224	$ 353	$322	$99	$119	$481	$481
399	Other Tangible Property	$ 12	$ 16	$ 16	$ 20	$12	$16	$12	$36	$42
63	Main Construction Camp	$ 150	$ 180	$ 180	$ 210	$244	$180	$189	$390	$440
71B	Construction Management, 4%	$ 122	$ 135	$ 148	$ 193	$195	$109	$161	$286	$302
Total Subtotal		$ 3,384	$ 3,746	$ 4,104	$ 5,354	$5,420	$3,024	$4,463	$7,937	$8,375
Total Contingency		$ 676	$ 749	$ 821	$ 1,071	$1,155	$605	$954	$1,587	$1,675
Total (Millions of Dollars, rounded)		$ 4,100	$ 4,500	$ 4,900	$6,400	$6,600	$3,600	$5,400	$9,600	$10,000

* R&M (2009)

5 Project Development Schedule

Updated schedules were developed for each of the project alternatives. These schedules extend from approval, through licensing, design, construction, and commissioning. The primary purpose of these schedules is to provide timelines for cash flow and estimated energy revenue to determine economic feasibility. These schedules assume that:

- Construction times are based on 1983 FERC license application.
- The licensing process from start to FERC order is estimated at 7 to 10 or more years. We have set a reasonable target of 8 years for the proposed project analysis, provided that the effort is begun immediately, ambitiously, fully funded, and conducted in parallel with environmental studies, engineering, and with active public outreach and cooperation by stakeholders.
- The FERC License Application will be based on the 1985 application, updated to reflect more than 20 years of regulatory changes and changes in engineering and construction methods.
- Any new environmental studies will be based on data acquired during the studies in the 1980's, updated to reflect present site conditions, public interests, wildlife, and recreational needs.
- Construction will begin immediately upon issuance of the license.
- Roads and staging will be state permitted outside the FERC project and will begin several years before FERC license, including pioneer and permanent roads, airports, bridges, construction camps and staging areas. Building facilities in advance of the project license is the most effective way to trim the projected timeline although there is some uncertainty whether permits could be obtained to construct these facilities before the project license is issued. The schedule for each of the project alternatives would be extended by one to two years if this assumption is not valid.
- Construction of diversion dams and tunnels will begin on issuance of the license, with upstream and downstream coffer dams and tunnels to divert the Susitna River during construction of main dams at Watana/Devil Canyon.
- Spillway construction will follow diversion dam and tunnel construction, and will include site preparation, approach channels, control structures, gates, stoplogs, chute, and flip buckets for main and emergency spillways.
- Dam construction at Watana will follow site preparation, grouting, and installation of a pressure relief system.
- The main dam construction at Devil Canyon will include a thin-arch concrete dam, preceded by site preparation, foundations, abutments, and thrust blocks. Rock-fill saddle dam construction will follow grouting and pressure relief system.
- The powerhouse and transmission will include power intake, tunnels/penstock, surge chamber, tailrace, powerhouse, turbine/generators, mechanical/electrical systems, switchyard, control buildings, and transmission lines.

- Reservoir filling will be based on the latest hydrologic data for inflow and turbine data for outflow.
- Devil Canyon construction will commence immediately upon completion of Watana for the Watana/Devil Canyon alternative.

Table 7 - Power Generation Time Estimates

Alternative	Generation of first power (years)*	Generation of full power (years)*
Lower Low Watana	13	14
Low Watana (both alternatives)	14	15
Watana (both alternatives)	15	16
Devil Canyon	14	15
High Devil Canyon	13	14
Watana/Devil Canyon	15	20
Staged Watana/Devil Canyon	15	24

*From start of licensing

6 Project Development Issues

Development of a hydroelectric project on the Susitna River would face a variety of issues over their design lifetime. The design lifetime for a modern dam is greater than 100 years. The following discussion is not intended to be all inclusive but rather highlight the likely major areas of concern.

6.1 Engineering

The projects being contemplated for the Susitna River would be on the larger end of the scale in the world in terms of size of the dams. Projects of this size have not been undertaken in the United States for many decades. As such, a major engineering effort will be required.

6.2 Siltation

Rivers, by nature, transport the products of erosion to the oceans. Dams interrupt this flow of material. Given time the effective amount of storage in the reservoir behind the dam can diminish. The alternatives investigated here have been designed with dead storage to accommodate bedload and it is not expected that siltation will have any detrimental affect on the energy projected energy production of any of the projects during their design lifetime.

6.3 Seismicity

Seismic (earthquake) events have the potential to effect hydroelectric projects. The main areas of concern are damage from ground shaking, opening of faults along the dam axis, landslides and settlement, and the creation of large waves in the reservoir. The previous studies on seismicity have concluded that these concerns can be designed for and therefore do not pose a significant threat. New analytic methods are now available to evaluate more complex seismic situations and these evaluations, along with the most stringent safety factors would be incorporated into a modern project design (R&M, 2009).

6.4 Climate Change

There has been much discussion about climate change and what the effects of climate change will be on river flows. Analyses of the potential affects of climate change on the Susitna River are included in Appendix D. The annual runoff from the Susitna River basin shows remarkable balance during very disparate climate regimes. The analyses support the consistent supply of water from the basin precipitation to support hydro-power generation regardless of the climate fluctuations. While global climate models suggests additional warming may impact the Arctic and Alaska, it seems very unlikely that these impacts will cause an unbalance in the runoff production of the basin.

Based on this, there is no conclusive evidence to suggest that runoff will be statistically different in the next 50 years from what it has been in the last 50 years.

6.5 Environmental Issues

After the Susitna project was discontinued in 1986 a database of 3,573 documents was created. In September 2008, the 87 most-relevant documents were scanned into HDR's files, of which 18 of the most relevant environmental documents were summarized. A synthesis of the 7 most-pertinent documents was completed. Because not all of the documents were summarized, some relevant information has likely been overlooked; however, most information was included in the synthesis.

These documents contain information on potential impacts of the proposed project and mitigation proposals for those impacts. Specifically, the documents deal with fisheries resources, botanical resources, wildlife resources, and cultural resources in the potential project area. The documents divide the Susitna River Basin into 4 geographic regions:

- Impoundment zones
- Middle Susitna River
- Lower Susitna River
- Access roads and transmission lines

The potential impacts and mitigation options are discussed for each category in each geographic region as much as possible. It is important to note that not all categories will be impacted in all geographic regions. Mitigation for the proposed impacts is divided into the following categories: avoidance, minimization, rectification, reduction, and compensation. Avoidance is always the preferred mitigation, though it is not usually feasible. Compensation is the only mitigation option for many of the impacts.

6.5.1 Fisheries Impacts

The fisheries resources have the highest potential to be impacted by the project. Most of the potential impacts will occur in the middle Susitna River. There will be impacts due to changes in water quality, thermal activity, the water's suspended sediment load, reservoir draw-down fluctuations, impoundment zone inundation, flow regime, and lost fish habitat. Not all impacts to fish populations will be negative. For example, the increase in winter water temperatures could lead to the creation of more overwintering habitat and thus greater fish survival; however, the cooler spring water temperatures will slow fish growth.

In the Watana impoundment zone, 51 river miles will be inundated and transformed into reservoir habitat. An additional 27 miles of tributary streams and 31 lakes will be inundated.

In the Devil Canyon impoundment zone 31 miles of the main river channel will be inundated and an additional 6 miles of tributary streams will be impacted.

Mitigation for these impacts was proposed by compensation through land acquisition, habitat modification, and reservoir stocking.

6.5.2 Botanical Impacts

The project area contains 295 vascular plant species, 11 lichen genera, and 7 moss taxa. Low Watana inundation will permanently remove 16,000 acres of vegetation. Devil Canyon inundation will permanently remove 6,000 acres of vegetation. Watana inundation will permanently remove an additional 16,000 acres of vegetation. There will be a total of 38,000 acres of vegetation permanently removed. Most of the vegetation inundated will be spruce forest. An additional 836 acres of vegetation will be permanently removed due to access road construction. In the transmission corridor affect on vegetation will be minimal due to intermittent placement of control stations, relay buildings, and towers.

There will be limited botanical impacts downstream from the reservoir(s). These involve changes to the vegetation due to a more stable environment. Due to flow regulation there will no longer be major flooding events, which destroy the riparian vegetation; instead; rather, there will be succession of the riparian vegetation and colonization of new floodplains. The increase in winter water temperatures will decrease the amount of ice scouring that occurs, which will result in effects similar to those caused by the decrease in flooding.

Botanical resource mitigation will consist largely of compensation for permanently removed vegetation.

6.5.3 Wildlife Impacts

Within the Susitna River Basin there are 135 bird species, 16 small-mammal species, and 18 large-mammal and furbearing species. There are currently no known listed endangered species in the project area. There will be 5 classes of potential impacts to terrestrial vertebrates:

Permanent habitat loss, including flooding of habitat and covering with gravel pads or roads.

Temporary habitat loss and habitat alteration resulting from reclaimed and revegetated areas such as borrow pits, temporary right of ways, transmission corridors, and from alteration of climate and hydrology.

Barriers, impediments, and hazards to movement.

Disturbances associated with project construction and operation.

Consequences of increased human access not directly related to project activities.

Mitigation for the proposed impacts involve mostly compensation since there will be permanent habitat loss for most species.

6.5.4 Cultural Resource Impacts

Within the proposed project area, 297 historic and prehistoric archaeological sites were located. An additional 22 sites were already on file. Sites located within 500 feet of the reservoir's maximum extent may be indirectly impacted due to slumping from shoreline erosion. Indirect impacts may also result from vandalism due to increase in access to the sites. The project has the potential to impact 140 sites. None of these sites will occur in the proposed road corridor or transmission lines. The majority of these sites are relatively small prehistoric sites.

Mitigation for the lost cultural resources will mostly occur through data recovery. Preservation would also be used for some sites. Options to consider include construction of protective barriers to minimize erosion, controlled burial, or fencing of the site to restrict access.

Currently, there are a variety of federal, state, and local land use plans that encompass the Susitna Basin.

6.5.5 Carbon Emissions

According to the United Nations working group on carbon emissions from freshwater reservoirs the worst case carbon emissions from a reservoir in a boreal climate is 6.7 grams per square meter per year (United Nations, 2009). For the Watana/Devil Canyon alternative this equates to

465,000 metric tons of carbon per year or 0.065 metric tons per MWhr. The US Department of Energy reports the average carbon emissions due to electric generation for the State of Alaska to be 0.626[1] metric tons per MWhr. Operation of the Susitna project has the potential to eliminate up to 4 million metric tons of carbon production per year.

[1] http://www.eia.doe.gov/cneaf/electricity/st_profiles/alaska.html

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Appendix A:
Energy Analysis Input and Results

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix B:
Detailed Cost Estimates

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix C:
Detailed Schedules

For the purposes of this submittal, the appendices have been attached as PDFs.

Appendix D:
Climate Change Analyses

For the purposes of this submittal, the appendices have been attached as PDFs.

APPENDIX B

FINANCIAL ANALYSIS

Regional Integrated Resource Plan

Financial Analysis Summary Report

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Introduction

The Regional Integrated Resource Plan (RIRP) is a 50-year, long-range plan tasked with identifying the optimal combination of generation and transmission capital improvement projects in the Railbelt region of Alaska. The objectives of the financial analysis portion of the plan are threefold:

1. Provide a high-level analysis of the capital funding capacity of each of the Railbelt utilities, given their current financial condition and assuming that each utility will borrow on its own, rather than utilizing a joint-powers structure or receiving assistance from the State of Alaska.
2. Analyze strategies to capitalize selected RIRP assets by integrating State and federal financing resources with debt capital market resources. Specifically, we look at ways to utilize State funding to:
    - mitigate construction risk,
    - lower capital cost prior to placing assets in service, and
    - extend the debt repayment term beyond terms available in the debt capital markets.
3. Develop a spreadsheet-based model that utilizes inputs from the RIRP model, including total capital requirements, demand-side management (DSM), fuel cost, CO_2 cost, and operation and maintenance cost (O&M), and overlays realistic debt capital funding to provide a total cost to ratepayers of the optimal resource plan.

Railbelt Utility Capital Capacity

The non-profit organizational structure of generation and transmission (G&T) and distribution cooperatives makes it difficult for these entities to produce operating margins and build equity to the levels needed to access the public debt markets. Rate setting is designed to recover operating cost with moderate margins, and any capital in excess of minimal reserves is returned to coop members. Nevertheless, some coops, including Chugach Electric, are able to maintain coverage margins sufficient to secure investment grade credit ratings and utilize the debt capital market to fund asset expansion. Likewise, municipal governments face a similar rate-setting challenge in the form of political pressure to keep rates at levels just sufficient to cover operations and maintain net plant and equipment. In the following sections, we take a look at several key financial measures of coop and municipally owned utilities and utilize these measures to estimate the remaining debt capacity of each of the Railbelt utilities.

To develop the framework for this analysis, we retrieved the publicly available financial reports from each utility's website and the annual filings from the Regulatory Commission of Alaska's website. Using these reports, we summarized each of the utilities' current outstanding debt obligations, company equity, total assets and total plant. We used these figures to derive several important financial ratios, discussed in detail below, that are used by the investment community as well as the nationally recognized rating agencies (Moody's, Standard & Poor's, and Fitch) to determine the ability of each organization to manage its current and/or future debt obligations. It's important to point out that, while no single financial ratio by itself is an accurate determinant of a utility's ability to incur additional debt for capital projects, an analysis of a sampling of several ratios in conjunction with other non-financial metrics (*e.g.*, demand growth, rate-setting authority, political climate, etc.) helps to create some guidelines for how much debt could reasonably be considered and issued in the capital markets.

Debt to Equity Ratio. The debt to equity ratio (or debt as a percentage of total capitalization) is derived by dividing a utility's total debt by its net capital. The rating agencies have developed median debt to equity ratios for each of the different types of utility organizational structures. For example, a G&T cooperative can expect to have a higher debt ratio percentage than a retail power distributer due to the need to finance large and relatively expensive generation and transmission assets. A summary of these utility medians for debt to equity is provided in the following table:

2008 Median Debt to Capitalization % By Utility System Type	
G&T Coop	82%
Municipal Wholesale	93%
Retail Self Generating	60%
Retail Power Purchaser (Distribution)	40%
Source: Fitch U.S. Public Power Peer Study, June 2009	

The table below calculates the remaining debt capacity for each of the Railbelt utilities under varying debt to equity ratios to derive a total debt capacity amount given existing equity capitalization. Debt to equity capitalization for this analysis ranges from 40% to 80%.

Railbelt Utility Additional Debt Capacity Based on Current Debt to Equity Ratios					
	Existing Debt as of 12/31/2008[1]	40%	60%	70%	80%
ML&P	$159,405,791	-	$175,744,945	$362,920,220	730,502,349
Chugach	354,383,506	-	-	9,355,443	260,137,205
MEA	89,128,488	-	48,090,737	129,409,217	277,237,086
HEA	148,257,837	-	-	-	99,152,015
GVEA	301,670,508	-	-	-	131,081,336
Seward	2	2	2	2	2
		-	$223,835,682	$501,684,880	$1,498,109,991

(1) 2008 Annual reports and 12/31/2008 Annual Reports to the Regulatory Commission of Alaska
(2) The City of Seward was not included in this analysis due to lack of information regarding their Electric Enterprise Fund

Our analysis found that the debt-to-capitalization ratio for each of the utilities is close to or higher than the median ratio for its organizational type. There does appear to be some additional bonding capacity available for each of the utilities under a G&T cooperative-type structure when compared to the Fitch median ratio of 82%. However, given the utilities' existing debt burdens and current conditions in the financial markets, which have made it more difficult for lower rated power utilities to access capital, it is not clear that the six utilities could support debt capitalization much above 70%. Fitch Ratings specifically mentions that higher debt capitalization percentages can result in negative ratings pressure going forward[1]. At approximately 70%

[1] Fitch Ratings, U.S. Public Power Peer Study, June 2009

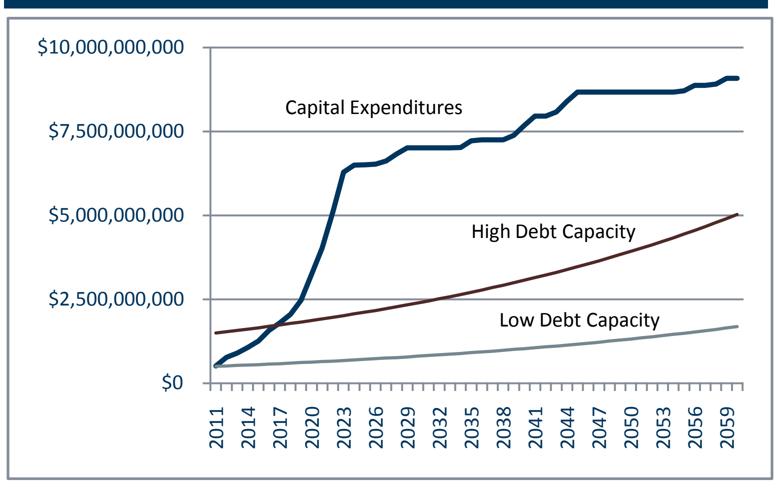
debt capitalization, the six utilities together could support between $500 and $700 million of additional debt. At 80%, available additional debt capacity for the six utilities combined increases to approximately $1.5 billion. This analysis does not include the City of Seward's capacity. Given its Electric Enterprise Fund asset base of $26 million (as of 2007), the overall borrowing capacity number would not change by a significant amount if the City of Seward were included.

Debt to Funds Available for Debt Service. An important measure of operating leverage is the Debt to Funds Available for Debt Service ratio (Debt/FADS). This ratio measures a utility's ability to handle its current fixed debt burden based on annual operating cash flow. A lower Debt/FADS ratio indicates either a low overall debt burden or a high operating cash flow, with the opposite being true for a higher Debt/FADS ratio. In the "A" rating category and higher, all but one G&T wholesale system rated by Fitch Ratings had a Debt/FADS ratio higher than 8.8 in 2008. For comparison purposes, the average (and median) Debt/FADS ratio for the Railbelt utilities in 2008 was approximately 8.4, with the highest being 13.66. The operating leverage of the six utilities would increase dramatically as capital spending and debt burden increase. An increase in the operating leverage ratio would cause ratings pressure for utilities maintaining a public credit rating and increased scrutiny by creditors including commercial banks and cooperative banks such as CFC or CoBank.

***RIRP Capital Requirements Relative to Railbelt Utility Debt Capacity*.** The preceding debt to equity and Debt/FADS discussions do not take into consideration several additional factors that are relevant to the collective debt capacity of the Railbelt utilities. These factors can impact debt capacity both positively and negatively and include amortization of existing utility debt, the level of new debt required to maintain distribution infrastructure, and potential rate increases.

While these factors are influential, they do not have sufficient positive impact to alter our opinion that the utilities individually do not have the capital capacity to fund the projects recommended by the RIRP. The scope of the RIRP projects is too great, and for certain individual projects, it is reasonable to conclude that there is no ability for a municipality or coop to independently secure debt financing without committing substantial amounts of equity or cash reserves. Specifically, these individual projects would include any that require large capital investment and have any of the following characteristics: exceptionally long construction period, significant construction risk, or significant technological risk. These types of risk are associated with equity rates of return and are rarely, if ever, borne by fixed income investors.

Black & Veatch Plan 1A Capital Expenditures (Cumulative Total)



The graphic to the right helps to put into context the scope of required RIRP capital investments relative to the estimated combined debt capacity of the Railbelt utilities. The lines toward the bottom of the graph represent our view of the bracketed range of additional debt capacity collectively for the Railbelt utilities, adjusted for inflation and customer growth over time.

***Railbelt Utility Debt Capacity Conclusions*.** The REGA study completed in 2008 concluded that the most cost effective approach to funding necessary Railbelt generation and transmission assets was to form a regional G&T. While SNW was not asked to validate this conclusion, we are of the opinion that a regional entity such as GRETC, with "all outputs" contracts migrating over time to "all requirements" contracts, will have greater access to capital than the combined capital capacity of the individual utilities. To be clear, our conclusion should not be interpreted to mean that a regional G&T agency would be able to execute the RIRP capital plan independent of any State or federal assistance; however, a regional G&T agency will have lower-cost access to debt capital than the utilities would have on their own. This is primarily due to two factors: (1) a regional G&T entity will eliminate the rate pressure/competition that naturally exists under the current Railbelt construct of each of the 6 utilities independently providing generation and transmission services to their customers, and (2) a regional G&T entity executing a utility-approved comprehensive RIRP plan with strong power purchase agreements will be better positioned with the rating agencies and private investors.

Strategies to Lower Capital Cost of RIRP to Ratepayers

As previously noted, the scope of the RIRP is significant. The complexity of the overall capital plan and the size and construction duration of various projects within the plan will necessitate some amount of "equity" capital from ratepayers and/or the State of Alaska. Furthermore, equity capital, in the form of a ratepayer benefits charge or State financial assistance through either loans or grants, is the most efficient source of funding available to GRETC for the RIRP. Capital accruing from the State in the form of grants or from existing ratepayers in any form needs to be balanced with long-term debt capital so that future rate payers who will benefit from the RIRP assets share the cost of funding these assets. The following sections discuss various sources of equity capital funding and methods for involving the State in the execution of the RIRP.

Ratepayer Benefits Charge. A ratepayer benefits charge is a charge levied on all ratepayers within the Railbelt system that will be used to cash fund and thereby defer borrowing for infrastructure capital. A rate surcharge that is implemented prior to construction allows for partial "pay-go" funding of capital projects and reduces the overall cost of the projects by reducing the amount of interest paid for funding in the capital markets. For example, the potential interest cost savings that could be realized if GRETC were to fund some portion of a $2 billion project through rates rather than entirely upfront through bond proceeds are shown in the table below:

$2 billion project		
Rate Surcharge Through Construction	Funded With Bonds	Interest Cost Reduction (1)
$500 million	$1.5 billion	$1.2 billion
$1.0 billion	$1.0 billion	$2.4 billion
(1) Assumes 30-year debt to fund construction at 7.00% interest.		

"Pay-Go" vs. Borrowing for Capital. A "pay-go" capital financing program is one in which ongoing capital projects are paid for from remaining revenue after maintenance and operations (M&O) expenses, and debt service are paid for. As will be discussed in further detail later, we have assumed that any bonds sold in the capital markets will require generation of a 1.25 times debt service coverage ratio. Covenanted coverage would likely be lower than 1.25 times. The cash generated in excess of M&O expense and debt service expense ("coverage") will be used to fund reasonable reserves with the balance going towards ongoing capital projects. For example, in years where debt service on outstanding bond issues is the highest, the 1.25 times debt service coverage ratio creates additional reserves in the amount of nearly $130 million above what is required to pay operating expense and debt service.

There is a tradeoff between the benefits derived from a pay-go financing structure versus one for which all projects are bonded. The benefit to ratepayers and GRETC in the pay-go structure is that it minimizes the total cost of the projects through the reduction of interest costs. On the other hand, the benefit of borrowing for a portion of capital needs is that expenses are spread out over time, and the cost of the debt can be structured to more closely match the useful life of the assets being financed. This is particularly important for some of the larger hydro-electric projects, where the useful life would likely exceed 50 years; these projects have large upfront costs that would be cost-prohibitive if funded entirely through rates. A balance of these two funding approaches appears to be most effective in lowering the overall cost of the project as well as spreading out the costs over a longer period of time.

Construction Work In Progress. Construction Work In Progress (CWIP) is a rate methodology that allows for the recovery of interest expense on project construction expenditures through the rate base during construction, rather than capitalizing the interest until the projects are completed and operating. This concept is important: the overall cost of the projects is significantly reduced through the immediate payment of interest on construction borrowing, versus the alternative of borrowing an additional sum just to pay for the interest while the project is still under construction. The benefit to ratepayers of the CWIP concept is that it significantly lowers both the overall cost of the project as well as the future revenue requirements needed to pay debt service. The use of CWIP in Alaska will most likely need to be vetted and approved by the Regulatory Commission of Alaska.

Both CWIP and pay-as-you-go funding rely on ratepayers to advance dollars for capital projects and thereby convey some project risk to ratepayers. If for example, a generation project were not completed for any reason ratepayers would have paid for a portion of the project even though the asset never produced power. SNW believes that ratepayers in a typical municipal utility structure generally incur this risk regardless of rate setting policies or methodologies. The ability to shift project risk to creditors is both limited and expensive and may not be appropriate for the "System" envisioned by GRETC. Under an Investor Owned Utility (IOU) structure, shareholders are responsible for bearing some of this risk, however shifting risk to shareholders requires higher equity rates of return to those investors. GRETC is not presently contemplated to be structured as an IOU.

State Financial Assistance. State financial assistance could take a variety of forms, but for the purpose of this report, we will focus on State assistance structured similarly to the Bradley Lake project. State financial assistance offers GRETC a number of advantages not available through traditional utility enterprise bond funding or project finance. Similar to a ratepayer benefits charge, State funding, whether in the form of a grant or loan, can be utilized to defer higher cost conventional revenue bond funding. Obviously a grant from the State provides the cheapest form of capital to GRETC, but even when structured as a loan, State assistance can dramatically lower GRETC's overall cost of capital. State funding in the form of a loan has three significant advantages when compared to revenue bonds or a loan from a commercial lender. The advantages of State funding include:

1. *Repayment flexibility.* State funding can be utilized to extend debt repayment beyond the term maturities available in the public or commercial debt capital markets. Additionally, a State loan can easily be restructured or deferred to achieve system rate objectives.
2. *Credit support/risk mitigation.* State funding can be used to mitigate project construction risk. This is particularly relevant for projects with extended construction timelines, such as large hydro-electric projects. Risk mitigation is also relevant in situations where permitting is an issue or a new technology is being used. Generally, fixed income investors will not accept significant construction and permitting risks inherent with the large-scale projects included in the RIRP without some form of support from the State.
3. *Potential interest cost benefit.* State funding can provide a lower cost source of capital. The State's high investment grade credit rating allows it to borrow for less than even the most secure utility enterprise. Assumptions as to the form of State assistance in the financial model are discussed in greater detail below; however, the terms of any loan, agreement, or grant between the State and GRETC will need to be further researched and developed in the next stage of the GRETC formation process.

RIRP Financial Model Summary Results

The development of the RIRP financial model took into account several different goals and objectives. The first goal was to identify ways to overcome the funding challenges inherent with large scale projects, including the length of construction time before the project is online and access to the capital markets. A second goal was to develop strategies that could be used to meet an objective of the RIRP of producing equitable rates over the useful life of the assets being financed. Structures commonly used in the current capital markets would not meet this goal, as certain of the assets required to be financed have longer useful lives than the longest term capital markets transaction could bear. With these challenges in mind, we developed separate versions of the model that would capture the cost of financing under a "*base case*" scenario and an "*alternative*" scenario, both of which are described in greater detail below.

***Major Assumptions (Black &Veatch Inputs)*.** The input assumptions for the RIRP financial model were developed around outputs from the Black & Veatch PROMOD/Strategist modeling analysis. The results created a detailed list of the capital costs for the projects chosen over the 50-year RIRP time horizon. The results show both generation unit costs as well as required transmission development costs associated with the selected projects. Other assumptions used from the Black & Veatch PROMOD analysis include associated fuel costs, fixed and variable O&M, CO_2 charges, and forecasted energy load requirements by year, including DSM energy use reductions.

Major Assumptions (Financing Model Inputs). The assumptions used for capital markets transactions within the financing model are all market-accepted structures for an investment grade utility, cooperative, or joint action agency. Below is a summary of the major structuring assumptions used for both financing scenarios:

- 30-year debt repayment on all bond issues sold in the capital markets
- 7.00% interest rate on all bond issues sold in the capital markets
- Rate generated debt service coverage of 1.25X
- All energy generation developed is used or sold
- Debt Service Reserve Fund (DSRF) for each bond issue funded at 10% of bond issue par amount. The DSRF balance is maintained throughout the 50-year RIRP and earns 3.00% interest, which is used to pay debt service on an annual basis.

Base Case Model: Specific Assumptions. The *base case* financing model was structured such that the list of generation and transmission projects would be financed through the capital markets in advance of construction and that the cost of the financing in the form of debt service on the bonds would immediately be passed through to rate payers (see "Construction Work in Progress" herein). Bond issues are assumed to be sold prior to the required project funding dates, and staggered in approximately three-year intervals over the first 20-years, when the majority of the large capital projects and transmission projects are scheduled. The projects being financed over the balance of the 50-year RIRP period are financed through cash flow created through normal rates and charges ("pay-go"). The pay-go approach works once debt service coverage from previous years has grown to levels that create cash reserve balance amounts sufficient to pay for the projects as their construction costs come due.

The sources of funds for the projects included in the RIRP under the base case model are as follows:

RIRP Plan 1A : Base Case Sources of Funds (dollars in millions)	
Bonds	$5,889
State Funds	$0
Infrastructure Tax	$0
Pay-Go	$3,196

The *base case* model assumes that approximately $5.9 billion of bonds are sold over the RIRP time horizon through five different bond sales ranging in size from $656 million to $2.5 billion. The <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.13 per kWh, while the <u>average</u> fixed charge rate over the 50-years is $0.07 per kWh.

Alternative Model: Specific Assumptions. The *alternative* model was developed with the goal of minimizing the rate shock that may otherwise occur with such a large capital plan, and levelizing the rate over time so that the economic burden derived from these projects can be spread more equitably over the useful life of the projects being contemplated. Similar to the *base case* scenario, the first method used was to transfer the excess operating cash flow that is generated to create the debt service coverage level, and use that balance to both partially fund the capital projects in the early years and almost fully fund the projects in the later years. The second method used was the implementation of a Capital Benefits Surcharge that is applied to rate payers starting the day GRETC is formed. For this analysis, it was assumed that a $0.01 rate surcharge would be in place for the first 17 years, during which time approximately 75% of the capital projects in the plan will have been constructed. The third method used to spread out the costs over a longer time period was the use of the State as an equity participant in the execution of the RIRP capital funding plan. In a financing structure that is similar to the Bradley Lake financing model, the State would provide the upfront funding for any large hydroelectric projects, to be paid back by GRETC out of system revenues over an extended period of time, and following the repayment of the potentially more expensive capital markets debt. This analysis assumes that a $2.4 billion hydroelectric project is financed through a zero interest loan to GRETC that is then paid back through a 30-year capital markets take-out bond issue in 2047.

The sources of funds for the projects included in the RIRP under the alternative case model are as follows:

RIRP Plan 1A : Alternative Case Sources of Funds (dollars in millions)	
Bonds	$3,657
State Funds	$2,409
Benefit Surcharge	$883
Pay-Go	$2,135

The *alternative* model assumes that $5.9 billion of bonds are sold over the RIRP time horizon through nine different bond sales ranging in size from $32 million to $2.4 billion, which includes the $2.4 billion take-out financing to repay the State for front-funding of hydroelectric assets. The capital costs not bonded for come from the rate surcharge that is applied from day one and cash flow generated from rates and charges after operations and debt service (pay-go capital). The <u>maximum</u> fixed charge rate on the capital portion alone is estimated to cost $0.08 per kWh, while the <u>average</u> fixed charge rate over the initial 50-year period is $0.06 per kWh, not including the $0.01 consumer benefit surcharge that is in place for the first 17 years. While the average fixed cost is not significantly different between the *base case* and *alternative* scenarios, the difference between the two maximum rates are significant. The lower maximum rate in the alternative scenario benefits the rate payers by smoothing out the rates over a period of time that more closely matches the useful life of the RIRP assets.

Summary, Next Steps, Conclusion. The RIRP presents a number of funding challenges, given the size and scope of the projects being contemplated. It has become evident through the financial modeling and the individual debt capacity analyses of this process that the utilities on their own would not be able to accomplish such an ambitious capital plan. The formation of a regional entity, such as GRETC, that would combine the existing resources and rate-base of the Railbelt utilities, as well provide an organized front in working to obtain private financing and the necessary levels of State assistance would be, in our opinion, a necessary next step towards achieving the goal of reliable energy for the Railbelt now and in the future.

Alaska Regional Integrated Resource Plan
Scenario Cash Flow Summary
dollars in millions

RIRP PLAN 1A	
Base Case	
100% Fixed Rate	
Sources of Funds	
BONDS	5,889
STATE (through construction)	0
Infrastructure Tax through 2027	0
Other (use of coverage reserves)	3,196
Total Source of Funds	9,085
Use of Funds	
Project/Construction	9,085
Payment of interest accrued	0
Reserve Funds	0
Issuance Costs	0
Capitalized Interest (through construction)	0
Total Uses of Funds	9,085
Maximum Annual Debt Service Requirements	
BONDS	539
STATE	0
Ave. Annual Energy Requirement (GWhr)	5,625
Target Debt Service Coverage (DSC)	1.25X
All-in Borrowing Cost	7.00%
Escalation Factor (Inflation)	2.50%
Average Cost of Energy ($/per kWh)	0.07

Assumptions
- Issuance Cost = 2% of Par Amount
- Par coupons
- Debt service reserve funded at 10% of Bond Par Amount
- Bonds all assumed to be 30 years from date of issue

	Year	Hydro Capital Requirements	Other Unit Cost Capital Requirements	Transmission Requirements	Total Capital Requirements	STATE Funding	Use of coverage balance for capital projects	Capital Markets - BONDS
1	12/1/2011	1	506,496,362	-	506,496,363	-		$ 886,736,593
2	12/1/2012	-	256,773,239	-	256,773,239	-	-	-
3	12/1/2013	-	119,476,707	3,990,284	123,466,991	-	-	-
4	12/1/2014	-	122,463,625	52,942,550	175,406,175	-	(25,000,000)	$ 656,306,880
5	12/1/2015	-	2,435,356	191,310,564	193,745,920	-	-	-
6	12/1/2016	33,699,203	22,466,161	255,989,420	312,154,784	-	-	-
7	12/1/2017	26,865,753	74,229,623	117,965,769	219,061,145	-	(105,000,000)	$ 795,887,676
8	12/1/2018	43,273,053	174,256,113	41,630,847	259,160,013	-	-	-
9	12/1/2019	79,301,147	174,171,476	169,193,895	422,666,518	-	-	-
10	12/1/2020	238,340,271	208,891,416	321,882,411	769,114,097	-	(190,000,000)	$ 2,454,911,924
11	12/1/2021	481,536,897	21,500,060	282,636,456	785,673,412	-	-	-
12	12/1/2022	652,793,164	-	437,331,250	1,090,124,414	-	-	-
13	12/1/2023	712,137,997	-	464,423,300	1,176,561,297	-	(320,000,000)	$ 1,095,198,536
14	12/1/2024	141,426,155	-	59,937,820	201,363,975	-	-	-
15	12/1/2025	-	-	18,210,430	18,210,430	-	-	-
16	12/1/2026	-	-	19,062,834	19,062,834	-	-	-
17	12/1/2027	-	88,657,273	-	88,657,273	-	(485,500,231)	$ -
18	12/1/2028	-	208,125,424	-	208,125,424	-	-	-
19	12/1/2029	-	188,717,535	-	188,717,535	-	-	-
20	12/1/2030	-	-		-	-	-	-
21	12/1/2031	-	-		-	-	-	-
22	12/1/2032	-	-		-	-	-	-
23	12/1/2033	-	-		-	-	-	-
24	12/1/2034	-	2,260,136		2,260,136	-	(239,531,757)	$ -
25	12/1/2035	-	206,133,124		206,133,124	-	-	-
26	12/1/2036	-	31,138,497		31,138,497	-	-	-
27	12/1/2037	-	-		-	-	-	-
28	12/1/2038	-	-		-	-	-	-
29	12/1/2039	-	127,791,596		127,791,596	-	(699,805,525)	$ -
30	12/1/2040	-	299,994,339		299,994,339	-	-	-
31	12/1/2041	-	272,019,589		272,019,589	-	-	-
32	12/1/2042	-	-		-	-	-	-
33	12/1/2043	-	131,612,221		131,612,221	-	(720,727,822)	$ -
34	12/1/2044	-	308,963,361		308,963,361	-	-	-
35	12/1/2045	-	280,152,241		280,152,241	-	-	-
36	12/1/2046	-	-		-	-	-	-
37	12/1/2047	-	-		-	-	-	-
38	12/1/2048	-	-		-	-	-	-
39	12/1/2049	-	-		-	-	-	-
40	12/1/2050	-	-		-	-	-	-
41	12/1/2051	-	-		-	-	-	-
42	12/1/2052	-	-		-	-	-	-
43	12/1/2053	-	-		-	-	-	-
44	12/1/2054	-	-		-	-	(410,069,419)	$ -
45	12/1/2055	-	35,525,625		35,525,625	-	-	-
46	12/1/2056	-	161,918,291		161,918,291	-	-	-
47	12/1/2057	-	-		-	-	-	-
48	12/1/2058	-	38,257,213		38,257,213	-	-	-
49	12/1/2059	-	174,368,290		174,368,290	-	-	-
50	12/1/2060	-	-			-		-

	Year	Repayment of State funds	GRETC Direct Debt Service - paid to bondholders	DSRF Interest Earnings	Total Requirements	Energy per Year (GWhr)	Surcharge for seed capital	Fixed Rate Charge for Capital	DSM	Fuel Rate	O&M Rate (Fixed + Variable)	CO^2	Incremental Cost (¢ per kWh)
1	12/1/2011	$ -	$ 35,268,100	$ -	$ 35,268,100	5,372	-	0.01	0.000	0.048	0.013	0.000	**0.07**
2	12/1/2012		81,206,200	2,660,210	78,545,990	5,412	-	0.02	0.000	0.051	0.013	0.010	**0.09**
3	12/1/2013		81,204,300	2,660,210	78,544,090	5,424	-	0.02	0.001	0.048	0.014	0.011	**0.09**
4	12/1/2014		107,308,425	2,660,210	104,648,215	5,421	-	0.02	0.001	0.053	0.014	0.012	**0.10**
5	12/1/2015		141,306,550	4,629,130	136,677,420	5,167	-	0.03	0.002	0.067	0.013	0.012	**0.13**
6	12/1/2016		141,309,000	4,629,130	136,679,870	5,147	-	0.03	0.002	0.070	0.014	0.013	**0.13**
7	12/1/2017		172,958,250	4,629,130	168,329,120	5,129	-	0.04	0.002	0.066	0.014	0.014	**0.14**
8	12/1/2018		214,187,950	7,016,793	207,171,157	5,105	-	0.05	0.002	0.042	0.013	0.015	**0.12**
9	12/1/2019		214,190,100	7,016,793	207,173,307	5,085	-	0.05	0.002	0.045	0.013	0.016	**0.13**
10	12/1/2020		311,827,975	7,016,793	304,811,182	5,068	-	0.08	0.002	0.044	0.012	0.017	**0.15**
11	12/1/2021		439,001,050	14,381,529	424,619,521	5,052	-	0.11	0.002	0.046	0.013	0.018	**0.18**
12	12/1/2022		439,000,300	14,381,529	424,618,771	5,081	-	0.10	0.003	0.050	0.013	0.021	**0.19**
13	12/1/2023		482,557,325	14,381,529	468,175,796	5,111	-	0.11	0.001	0.053	0.012	0.021	**0.20**
14	12/1/2024		539,293,200	17,667,125	521,626,075	5,140	-	0.13	0.001	0.055	0.013	0.023	**0.22**
15	12/1/2025		539,294,650	17,667,125	521,627,525	5,174	-	0.13	0.001	0.037	0.016	0.017	**0.20**
16	12/1/2026	-	539,289,900	17,667,125	521,622,775	5,207		0.13	0.001	0.042	0.014	0.020	**0.20**
17	12/1/2027	-	539,284,300	17,667,125	521,617,175	5,241		0.12	0.002	0.044	0.014	0.022	**0.21**
18	12/1/2028	-	539,290,400	17,667,125	521,623,275	5,275		0.12	0.002	0.046	0.014	0.024	**0.21**
19	12/1/2029	-	539,297,250	17,667,125	521,630,125	5,309		0.12	0.003	0.049	0.015	0.027	**0.22**
20	12/1/2030	-	539,296,800	17,667,125	521,629,675	5,344		0.12	0.003	0.042	0.019	0.025	**0.21**
21	12/1/2031	-	539,293,550	17,667,125	521,626,425	5,378		0.12	0.003	0.042	0.019	0.026	**0.21**
22	12/1/2032	-	539,293,500	17,667,125	521,626,375	5,413		0.12	0.003	0.044	0.019	0.028	**0.21**
23	12/1/2033	-	539,288,800	17,667,125	521,621,675	5,447		0.12	0.003	0.046	0.019	0.031	**0.22**
24	12/1/2034	-	539,293,450	17,667,125	521,626,325	5,482		0.12	0.003	0.048	0.020	0.034	**0.22**
25	12/1/2035	-	539,286,550	17,667,125	521,619,425	5,517		0.12	0.003	0.052	0.020	0.037	**0.23**
26	12/1/2036	-	539,289,400	17,667,125	521,622,275	5,553		0.12	0.001	0.054	0.021	0.041	**0.23**
27	12/1/2037	-	539,287,350	17,667,125	521,620,225	5,588		0.12	0.001	0.062	0.022	0.048	**0.25**
28	12/1/2038	-	539,291,900	17,667,125	521,624,775	5,623		0.12	0.001	0.066	0.022	0.052	**0.26**
29	12/1/2039	-	539,293,600	17,667,125	521,626,475	5,659		0.12	0.002	0.069	0.023	0.057	**0.27**
30	12/1/2040	-	539,288,100	17,667,125	521,620,975	5,695		0.11	0.002	0.072	0.023	0.062	**0.27**
31	12/1/2041	-	539,290,450	17,667,125	521,623,325	5,731		0.11	0.004	0.075	0.024	0.067	**0.28**
32	12/1/2042	-	458,083,350	17,667,125	440,416,225	5,767		0.10	0.004	0.073	0.022	0.069	**0.26**
33	12/1/2043	-	458,087,900	17,667,125	440,420,775	5,803		0.09	0.004	0.077	0.022	0.075	**0.27**
34	12/1/2044	-	458,086,400	17,667,125	440,419,275	5,839		0.09	0.004	0.080	0.033	0.082	**0.29**
35	12/1/2045	-	397,988,550	17,667,125	380,321,425	5,876		0.08	0.004	0.084	0.023	0.089	**0.28**
36	12/1/2046	-	397,984,050	17,667,125	380,316,925	5,912		0.08	0.004	0.078	0.031	0.087	**0.28**
37	12/1/2047	-	397,982,000	17,667,125	380,314,875	5,949		0.08	0.005	0.079	0.032	0.091	**0.29**
38	12/1/2048	-	325,101,750	17,667,125	307,434,625	5,986		0.06	0.005	0.083	0.032	0.100	**0.28**
39	12/1/2049	-	325,102,950	17,667,125	307,435,825	6,023		0.06	0.001	0.086	0.033	0.109	**0.29**
40	12/1/2050	-	325,107,400	17,667,125	307,440,275	6,060		0.06	0.002	0.089	0.034	0.117	**0.31**
41	12/1/2051	-	100,294,000	17,667,125	82,626,875	6,098		0.02	0.002	0.094	0.035	0.122	**0.27**
42	12/1/2052	-	100,293,100	17,667,125	82,625,975	6,135		0.02	0.002	0.097	0.035	0.126	**0.28**
43	12/1/2053	-	100,291,100	17,667,125	82,623,975	6,173		0.02	0.003	0.102	0.036	0.131	**0.29**
44	12/1/2054	-		-	-	6,211		-	0.004	0.105	0.037	0.135	**0.28**
45	12/1/2055	-		-	-	6,249		-	0.005	0.108	0.038	0.140	**0.29**
46	12/1/2056	-		-	-	6,287		-	0.006	0.113	0.039	0.144	**0.30**
47	12/1/2057	-		-	-	6,326		-	0.006	0.121	0.041	0.153	**0.32**
48	12/1/2058	-		-	-	6,364		-	0.006	0.127	0.041	0.161	**0.33**
49	12/1/2059	-		-	-	6,403		-	0.006	0.133	0.042	0.168	**0.35**
50	12/1/2060	-			-	6,442		-	0.006	0.137	0.043	0.172	**0.36**

	Year	DSM (000s)	Fuel Cost (000s)	Fixed O&M Cost (000s)	Variable O&M Cost (000s)	CO^2 Cost (000s)	Seed Capital	Seed Capital Fund Balance	Fixed Rate Charge for Revenues	Revenue available after debt service	GRETC Direct Debt Service Coverage	Use of Coverage	Coverage Balance
1	12/1/2011	651	259,482	39,359	30,852	-	-	-	44,085,125	8,817,025	1.25		8,817,025
2	12/1/2012	1,491	271,611	38,557	32,902	54,963	-	-	98,182,488	19,636,498	1.25		28,453,523
3	12/1/2013	3,063	258,329	42,181	31,820	56,995	-	-	98,180,113	19,636,023	1.25		48,089,545
4	12/1/2014	5,878	282,641	42,195	32,212	63,421	-	-	130,810,269	26,162,054	1.25	25,000,000	49,251,599
5	12/1/2015	10,455	361,674	35,055	35,819	65,306	-	-	170,846,774	34,169,355	1.25		83,420,954
6	12/1/2016	12,759	373,704	37,978	35,083	68,216	-	-	170,849,837	34,169,967	1.25		117,590,921
7	12/1/2017	11,891	352,673	38,010	36,043	73,346	-	-	210,411,399	42,082,280	1.25	105,000,000	54,673,201
8	12/1/2018	12,241	224,380	36,088	34,170	81,543	-	-	258,963,946	51,792,789	1.25	-	106,465,990
9	12/1/2019	12,657	244,337	34,987	35,596	86,958	-	-	258,966,633	51,793,327	1.25		158,259,317
10	12/1/2020	13,124	235,418	37,177	29,384	90,354	-	-	381,013,977	76,202,795	1.25	190,000,000	44,462,112
11	12/1/2021	13,346	247,202	39,360	30,390	97,474	-	-	530,774,401	106,154,880	1.25		150,616,992
12	12/1/2022	14,024	267,038	41,731	29,426	110,165	-	-	530,773,463	106,154,693	1.25		256,771,685
13	12/1/2023	4,166	284,104	35,897	30,380	114,805	-	-	585,219,745	117,043,949	1.25	320,000,000	53,815,634
14	12/1/2024	3,313	297,843	36,104	33,631	125,785	-	-	652,032,594	130,406,519	1.25		184,222,153
15	12/1/2025	4,222	201,105	57,389	29,739	90,619	-	-	652,034,406	130,406,881	1.25		314,629,034
16	12/1/2026	5,342	227,331	57,967	16,925	107,681	-	-	652,028,469	130,405,694	1.25		445,034,728
17	12/1/2027	8,551	238,262	58,593	17,362	118,039	-	-	652,021,469	130,404,294	1.25	485,500,231	89,938,791
18	12/1/2028	13,323	247,810	59,207	18,257	130,862	-	-	652,029,094	130,405,819	1.25	-	220,344,610
19	12/1/2029	16,151	261,837	59,916	18,745	146,548	-	-	652,037,656	130,407,531	1.25		350,752,141
20	12/1/2030	17,064	226,648	84,248	17,865	135,367		-	652,037,094	130,407,419	1.25		481,159,560
21	12/1/2031	14,951	224,691	84,983	15,652	140,642		-	652,033,031	130,406,606	1.25		611,566,166
22	12/1/2032	15,081	234,947	86,456	16,121	152,129		-	652,032,969	130,406,594	1.25		741,972,760
23	12/1/2033	15,919	249,713	87,902	16,762	166,550		-	652,027,094	130,405,419	1.25		872,378,179
24	12/1/2034	16,747	260,041	89,276	17,408	180,198		-	652,032,906	130,406,581	1.25	239,531,757	763,253,003
25	12/1/2035	18,111	279,793	90,794	18,296	200,974		-	652,024,281	130,404,856	1.25		893,657,859
26	12/1/2036	5,493	292,296	92,408	18,814	218,387		-	652,027,844	130,405,569	1.25		1,024,063,428
27	12/1/2037	7,019	335,171	97,112	19,787	257,520		-	652,025,281	130,405,056	1.25		1,154,468,484
28	12/1/2038	6,453	352,597	98,638	20,542	281,586		-	652,030,969	130,406,194	1.25		1,284,874,678
29	12/1/2039	8,848	368,539	100,317	21,287	306,519		-	652,033,094	130,406,619	1.25	699,805,525	715,475,772
30	12/1/2040	12,284	385,523	101,920	22,049	332,326		-	652,026,219	130,405,244	1.25		845,881,016
31	12/1/2041	18,825	403,233	103,660	22,861	361,453		-	652,029,156	130,405,831	1.25		976,286,847
32	12/1/2042	21,552	394,321	95,445	21,546	371,427		-	550,520,281	110,104,056	1.25		1,086,390,903
33	12/1/2043	22,199	412,100	97,223	22,392	404,276		-	550,525,969	110,105,194	1.25	720,727,822	475,768,275
34	12/1/2044	23,458	428,330	152,761	23,116	439,168		-	550,524,094	110,104,819	1.25		585,873,094
35	12/1/2045	22,134	449,075	101,037	23,977	476,267		-	475,401,781	95,080,356	1.25		680,953,450
36	12/1/2046	22,961	421,293	140,010	26,073	466,403		-	475,396,156	95,079,231	1.25		776,032,681
37	12/1/2047	24,452	424,059	142,963	26,511	490,408		-	475,393,594	95,078,719	1.25		871,111,400
38	12/1/2048	25,398	444,961	146,057	27,392	537,229		-	384,293,281	76,858,656	1.25		947,970,056
39	12/1/2049	6,909	461,902	149,291	28,395	584,308		-	384,294,781	76,858,956	1.25		1,024,829,013
40	12/1/2050	8,724	477,627	152,489	29,313	630,743		-	384,300,344	76,860,069	1.25		1,101,689,082
41	12/1/2051	11,174	503,605	155,601	30,361	656,308		-	103,283,594	20,656,719	1.25		1,122,345,800
42	12/1/2052	9,139	520,728	158,955	31,315	676,369		-	103,282,469	20,656,494	1.25		1,143,002,294
43	12/1/2053	14,889	546,462	162,470	32,477	705,371		-	103,279,969	20,655,994	1.25		1,163,658,288
44	12/1/2054	22,880	562,487	165,955	33,535	723,997		-	-	-	0.00	410,069,419	753,588,869
45	12/1/2055	27,949	579,273	169,720	34,785	749,388		-	-	-	0.00		753,588,869
46	12/1/2056	30,133	605,200	173,255	35,877	774,023		-	-	-	0.00		753,588,869
47	12/1/2057	33,288	647,750	180,086	37,668	822,050		-	-	-	0.00		753,588,869
48	12/1/2058	33,226	682,788	182,230	38,924	862,251		-	-	-	0.00		753,588,869
49	12/1/2059	31,309	716,551	186,278	40,624	900,505		-	-	-	0.00		753,588,869
50	12/1/2060	32,092	734,465	190,935	41,639	923,018		-	-	-	0.00		753,588,869

Alaska Regional Integrated Resource Plan

Scenario Cash Flow Summary

dollars in millions

RIRP PLAN 1A	
Alternative Scenario	
100% Fixed Rate	
Sources of Funds	
BONDS	3,657
STATE (through construction)	2,409
Infrastructure Tax through 2027	883
Other (Use of Coverage Reserves)	2,135
Total Source of Funds	9,085
Use of Funds	
Project/Construction	9,085
Payment of interest accrued	0
Reserve Funds	0
Issuance Costs	0
Capitalized Interest (through construction)	0
Total Uses of Funds	9,085
Maximum Annual Debt Service Requirements	
BONDS	314
STATE	322
Ave.Annual Energy Requirement (GWhr)	5,625
Target Debt Service Coverage (DSC)	1.25X
All-in Borrowing Cost	7.00%
Escalation Factor (Inflation)	2.50%
Average Cost of Energy ($/per kWh)	0.06

Assumptions

- Issuance Cost = 2% of Par Amount
- Par coupons
- Debt service reserve funded at 10% of Bond Par Amount
- Bonds all assumed to be 30 years from date of issue

	Year	Hydro Capital Requirements	Other Unit Cost Capital Requirements	Transmission Requirements	Total Capital Requirements (less large hydro)	STATE Funding - loan and payback	Use of coverage balance for capital projects	Capital Markets - BONDS
1	12/1/2011	**1**	**506,496,362**	**-**	**506,496,362**	-		$ 833,019,182
2	12/1/2012	**-**	**256,773,239**	**-**	**256,773,239**	-	-	-
3	12/1/2013	**-**	**119,476,707**	**3,990,284**	**123,466,991**	-	-	-
4	12/1/2014	**-**	**122,463,625**	**52,942,550**	**175,406,175**	-	(15,000,000)	$ 470,031,769
5	12/1/2015	**-**	**2,435,356**	**191,310,564**	**193,745,920**	-	-	-
6	12/1/2016	**33,699,203**	**22,466,161**	**255,989,420**	**278,455,581**	2,409,373,640	-	-
7	12/1/2017	**26,865,753**	**74,229,623**	**117,965,769**	**192,195,392**	-	(75,000,000)	$ 522,012,548
8	12/1/2018	**43,273,053**	**174,256,113**	**41,630,847**	**215,886,960**	-	-	-
9	12/1/2019	**79,301,147**	**174,171,476**	**169,193,895**	**343,365,370**	-	-	-
10	12/1/2020	**238,340,271**	**208,891,416**	**321,882,411**	**530,773,827**	-	(120,000,000)	$ 999,656,778
11	12/1/2021	**481,536,897**	**21,500,060**	**282,636,456**	**304,136,516**	-	-	-
12	12/1/2022	**652,793,164**	**-**	**437,331,250**	**437,331,250**	-	-	-
13	12/1/2023	**712,137,997**	**-**	**464,423,300**	**464,423,300**	-	(180,000,000)	$ 229,188,962
14	12/1/2024	**141,426,155**	**-**	**59,937,820**	**59,937,820**	-	-	-
15	12/1/2025	**-**	**-**	**18,210,430**	**18,210,430**	-	-	-
16	12/1/2026	**-**	**-**	**19,062,834**	**19,062,834**	-	-	-
17	12/1/2027	**-**	**88,657,273**	**-**	**88,657,273**	-	(245,000,000)	$ 32,875,895
18	12/1/2028	**-**	**208,125,424**	**-**	**208,125,424**	-	-	-
19	12/1/2029	**-**	**188,717,535**	**-**	**188,717,535**	-	-	-
20	12/1/2030	**-**	**-**		**-**	-	-	-
21	12/1/2031	**-**	**-**		**-**	-	-	-
22	12/1/2032	**-**	**-**		**-**	-	-	-
23	12/1/2033	**-**	**-**		**-**	-	-	-
24	12/1/2034	**-**	**2,260,136**		**2,260,136**	-	(239,531,757)	$ 0
25	12/1/2035	**-**	**206,133,124**		**206,133,124**	-	-	-
26	12/1/2036	**-**	**31,138,497**		**31,138,497**	-	-	-
27	12/1/2037	**-**	**-**		**-**	-	-	-
28	12/1/2038	**-**	**-**		**-**	-	-	-
29	12/1/2039	**-**	**127,791,596**		**127,791,596**	-	(600,000,000)	$ 99,805,525
30	12/1/2040	**-**	**299,994,339**		**299,994,339**	-	-	-
31	12/1/2041	**-**	**272,019,589**		**272,019,589**	-	-	-
32	12/1/2042	**-**	**-**		**-**	-	-	-
33	12/1/2043	**-**	**131,612,221**		**131,612,221**	-	(250,000,000)	$ 470,727,822
34	12/1/2044	**-**	**308,963,361**		**308,963,361**	-	-	-
35	12/1/2045	**-**	**280,152,241**		**280,152,241**	-	-	-
36	12/1/2046	**-**	**-**		**-**	-	-	-
37	12/1/2047	**-**	**-**		**-**	2,409,373,640	-	-
38	12/1/2048	**-**	**-**		**-**	-	-	-
39	12/1/2049	**-**	**-**		**-**	-	-	-
40	12/1/2050	**-**	**-**		**-**	-	-	-
41	12/1/2051	**-**	**-**		**-**	-	-	-
42	12/1/2052	**-**	**-**		**-**	-	-	-
43	12/1/2053	**-**	**-**		**-**	-	-	-
44	12/1/2054	**-**	**-**		**-**	-	(410,069,419)	$ (0)
45	12/1/2055	**-**	**35,525,625**		**35,525,625**	-	-	-
46	12/1/2056	**-**	**161,918,291**		**161,918,291**	-	-	-
47	12/1/2057	**-**	**-**		**-**	-	-	-
48	12/1/2058	**-**	**38,257,213**		**38,257,213**	-	-	-
49	12/1/2059	**-**	**174,368,290**		**174,368,290**	-	-	-
50	12/1/2060	**-**	**-**			-		-

	Year	Repayment of State funds	GRETC Direct Debt Service - paid to bondholders	DSRF Interest Earnings	Total Requirements	Energy per Year (GWhr)	Surcharge for seed capital	Fixed Rate Charge for Capital	DSM	Fuel Rate	O&M Rate (Fixed + Variable)	CO^2	Incremental Cost (¢ per kWh)
1	12/1/2011	$ -	$ 33,131,525	$ -	$ 33,131,525	5,372	0.010	0.01	0.000	0.048	0.013	0.000	**0.08**
2	12/1/2012		76,283,050	2,499,058	73,783,992	5,412	0.010	0.02	0.000	0.051	0.013	0.010	**0.10**
3	12/1/2013		76,281,650	2,499,058	73,782,592	5,424	0.010	0.02	0.001	0.048	0.014	0.011	**0.10**
4	12/1/2014		94,980,800	2,499,058	92,481,742	5,421	0.010	0.02	0.001	0.053	0.014	0.012	**0.11**
5	12/1/2015		119,327,100	3,909,153	115,417,947	5,167	0.010	0.03	0.002	0.067	0.013	0.012	**0.13**
6	12/1/2016	-	119,327,000	3,909,153	115,417,847	5,147	0.010	0.03	0.002	0.070	0.014	0.013	**0.14**
7	12/1/2017	-	140,091,050	3,909,153	136,181,897	5,129	0.010	0.03	0.002	0.066	0.014	0.014	**0.14**
8	12/1/2018	-	167,135,950	5,475,190	161,660,760	5,105	0.010	0.04	0.002	0.042	0.013	0.015	**0.12**
9	12/1/2019	-	167,133,450	5,475,190	161,658,260	5,085	0.010	0.04	0.002	0.045	0.013	0.016	**0.13**
10	12/1/2020	-	206,891,825	5,475,190	201,416,635	5,068	0.010	0.05	0.002	0.044	0.012	0.017	**0.14**
11	12/1/2021	-	258,677,150	8,474,161	250,202,989	5,052	0.010	0.06	0.002	0.046	0.013	0.018	**0.15**
12	12/1/2022	-	258,678,050	8,474,161	250,203,889	5,081	0.010	0.06	0.003	0.050	0.013	0.021	**0.16**
13	12/1/2023	-	267,790,975	8,474,161	259,316,814	5,111	0.010	0.06	0.001	0.053	0.012	0.021	**0.16**
14	12/1/2024	-	279,659,600	9,161,728	270,497,872	5,140	0.010	0.07	0.001	0.055	0.013	0.023	**0.17**
15	12/1/2025	-	279,668,350	9,161,728	270,506,622	5,174	0.010	0.07	0.001	0.037	0.016	0.017	**0.15**
16	12/1/2026	-	279,658,100	9,161,728	270,496,372	5,207	0.010	0.06	0.001	0.042	0.014	0.020	**0.15**
17	12/1/2027	-	292,456,550	9,161,728	283,294,822	5,241	0.010	0.07	0.002	0.044	0.014	0.022	**0.16**
18	12/1/2028	-	305,241,850	9,260,355	295,981,495	5,275		0.07	0.002	0.046	0.014	0.024	**0.16**
19	12/1/2029	-	305,240,900	9,260,355	295,980,545	5,309		0.07	0.003	0.049	0.015	0.027	**0.16**
20	12/1/2030	-	305,242,800	9,260,355	295,982,445	5,344		0.07	0.003	0.042	0.019	0.025	**0.16**
21	12/1/2031	-	305,244,200	9,260,355	295,983,845	5,378		0.07	0.003	0.042	0.019	0.026	**0.16**
22	12/1/2032	-	305,245,000	9,260,355	295,984,645	5,413		0.07	0.003	0.044	0.019	0.028	**0.16**
23	12/1/2033	-	305,243,000	9,260,355	295,982,645	5,447		0.07	0.003	0.046	0.019	0.031	**0.17**
24	12/1/2034	-	305,243,900	9,260,355	295,983,545	5,482		0.07	0.003	0.048	0.020	0.034	**0.17**
25	12/1/2035	-	305,240,600	9,260,355	295,980,245	5,517		0.07	0.003	0.052	0.020	0.037	**0.18**
26	12/1/2036	-	305,243,900	9,260,355	295,983,545	5,553		0.07	0.001	0.054	0.021	0.041	**0.18**
27	12/1/2037	-	305,236,100	9,260,355	295,975,745	5,588		0.07	0.001	0.062	0.022	0.048	**0.20**
28	12/1/2038	-	305,237,750	9,260,355	295,977,395	5,623		0.07	0.001	0.066	0.022	0.052	**0.21**
29	12/1/2039	-	309,204,550	9,260,355	299,944,195	5,659		0.07	0.002	0.069	0.023	0.057	**0.22**
30	12/1/2040	-	314,375,350	9,559,772	304,815,578	5,695		0.07	0.002	0.072	0.023	0.062	**0.23**
31	12/1/2041	-	314,385,800	9,559,772	304,826,028	5,731		0.07	0.004	0.075	0.024	0.067	**0.24**
32	12/1/2042	-	238,098,800	9,559,772	228,539,028	5,767		0.05	0.004	0.073	0.022	0.069	**0.22**
33	12/1/2043	-	256,818,500	9,559,772	247,258,728	5,803		0.05	0.004	0.077	0.022	0.075	**0.23**
34	12/1/2044	-	281,213,300	10,971,955	270,241,345	5,839		0.06	0.004	0.080	0.033	0.082	**0.26**
35	12/1/2045	-	238,156,850	10,971,955	227,184,895	5,876		0.05	0.004	0.084	0.023	0.089	**0.25**
36	12/1/2046	-	238,159,400	10,971,955	227,187,445	5,912		0.05	0.004	0.078	0.031	0.087	**0.25**
37	12/1/2047	95,827,375	238,157,150	10,971,955	323,012,570	5,949		0.07	0.005	0.079	0.032	0.091	**0.27**
38	12/1/2048	191,654,750	190,355,650	10,971,955	371,038,445	5,986		0.08	0.005	0.083	0.032	0.100	**0.30**
39	12/1/2049	191,654,750	190,357,950	10,971,955	371,040,745	6,023		0.08	0.001	0.086	0.033	0.109	**0.31**
40	12/1/2050	191,654,750	190,355,750	10,971,955	371,038,545	6,060		0.08	0.002	0.089	0.034	0.117	**0.32**
41	12/1/2051	191,654,750	98,815,900	10,971,955	279,498,695	6,098		0.06	0.002	0.094	0.035	0.122	**0.31**
42	12/1/2052	191,654,750	98,809,900	10,971,955	279,492,695	6,135		0.06	0.002	0.097	0.035	0.126	**0.32**
43	12/1/2053	191,654,750	98,809,900	10,971,955	279,492,695	6,173		0.06	0.003	0.102	0.036	0.131	**0.33**
44	12/1/2054	191,654,750	77,824,800	10,971,955	258,507,595	6,211		0.05	0.004	0.105	0.037	0.135	**0.33**
45	12/1/2055	196,264,750	77,826,750	10,971,955	263,119,545	6,249		0.05	0.005	0.108	0.038	0.140	**0.34**
46	12/1/2056	201,172,050	77,826,500	10,971,955	268,026,595	6,287		0.05	0.006	0.113	0.039	0.144	**0.35**
47	12/1/2057	206,198,250	52,247,150	10,971,955	247,473,445	6,326		0.05	0.006	0.121	0.041	0.153	**0.37**
48	12/1/2058	211,354,400	52,246,350	10,971,955	252,628,795	6,364		0.05	0.006	0.127	0.041	0.161	**0.38**
49	12/1/2059	216,638,400	52,250,150	10,971,955	257,916,595	6,403		0.05	0.006	0.133	0.042	0.168	**0.40**
50	12/1/2060	222,055,700	52,242,250	10,971,955	263,325,995	6,442		0.05	0.006	0.137	0.043	0.172	**0.41**

	Year	DSM (000s)	Fuel Cost (000s)	Fixed O&M Cost (000s)	Variable O&M Cost (000s)	CO^2 Cost (000s)	Seed Capital	Fixed Rate Charge for Revenues	Revenue available after debt service	GRETC Direct Debt Service Coverage	Use of Coverage	Coverage Balance
1	12/1/2011	651	259,482	39,359	30,852	-	53,717,410.47	41,414,406	8,282,881	1.25		8,282,881
2	12/1/2012	1,491	271,611	38,557	32,902	54,963	54,120,733.86	92,229,991	18,445,998	1.25		26,728,879
3	12/1/2013	3,063	258,329	42,181	31,820	56,995	54,241,323.99	92,228,241	18,445,648	1.25		45,174,527
4	12/1/2014	5,878	282,641	42,195	32,212	63,421	54,213,850.02	115,602,178	23,120,436	1.25	15,000,000	53,294,963
5	12/1/2015	10,455	361,674	35,055	35,819	65,306	51,673,819.94	144,272,434	28,854,487	1.25		82,149,450
6	12/1/2016	12,759	373,704	37,978	35,083	68,216	51,473,835.41	144,272,309	28,854,462	1.25		111,003,912
7	12/1/2017	11,891	352,673	38,010	36,043	73,346	51,287,518.63	170,227,371	34,045,474	1.25	75,000,000	70,049,386
8	12/1/2018	12,241	224,380	36,088	34,170	81,543	51,052,273.99	202,075,949	40,415,190	1.25	-	110,464,576
9	12/1/2019	12,657	244,337	34,987	35,596	86,958	50,849,002.21	202,072,824	40,414,565	1.25		150,879,141
10	12/1/2020	13,124	235,418	37,177	29,384	90,354	50,683,538.05	251,770,793	50,354,159	1.25	120,000,000	81,233,299
11	12/1/2021	13,346	247,202	39,360	30,390	97,474	50,524,635.70	312,753,736	62,550,747	1.25		143,784,047
12	12/1/2022	14,024	267,038	41,731	29,426	110,165	50,814,618.33	312,754,861	62,550,972	1.25		206,335,019
13	12/1/2023	4,166	284,104	35,897	30,380	114,805	51,106,167.59	324,146,018	64,829,204	1.25	180,000,000	91,164,222
14	12/1/2024	3,313	297,843	36,104	33,631	125,785	51,401,295.01	338,122,340	67,624,468	1.25		158,788,691
15	12/1/2025	4,222	201,105	57,389	29,739	90,619	51,736,787.37	338,133,278	67,626,656	1.25		226,415,346
16	12/1/2026	5,342	227,331	57,967	16,925	107,681	52,073,821.68	338,120,465	67,624,093	1.25		294,039,439
17	12/1/2027	8,551	238,262	58,593	17,362	118,039	52,412,432.40	354,118,528	70,823,706	1.25	245,000,000	119,863,145
18	12/1/2028	13,323	247,810	59,207	18,257	130,862	-	369,976,868	73,995,374	1.25		193,858,518
19	12/1/2029	16,151	261,837	59,916	18,745	146,548	-	369,975,681	73,995,136	1.25		267,853,655
20	12/1/2030	17,064	226,648	84,248	17,865	135,367	-	369,978,056	73,995,611	1.25		341,849,266
21	12/1/2031	14,951	224,691	84,983	15,652	140,642	-	369,979,806	73,995,961	1.25		415,845,227
22	12/1/2032	15,081	234,947	86,456	16,121	152,129	-	369,980,806	73,996,161	1.25		489,841,388
23	12/1/2033	15,919	249,713	87,902	16,762	166,550	-	369,978,306	73,995,661	1.25		563,837,049
24	12/1/2034	16,747	260,041	89,276	17,408	180,198	-	369,979,431	73,995,886	1.25	239,531,757	398,301,178
25	12/1/2035	18,111	279,793	90,794	18,296	200,974	-	369,975,306	73,995,061	1.25	-	472,296,239
26	12/1/2036	5,493	292,296	92,408	18,814	218,387	-	369,979,431	73,995,886	1.25		546,292,126
27	12/1/2037	7,019	335,171	97,112	19,787	257,520	-	369,969,681	73,993,936	1.25		620,286,062
28	12/1/2038	6,453	352,597	98,638	20,542	281,586	-	369,971,743	73,994,349	1.25		694,280,410
29	12/1/2039	8,848	368,539	100,317	21,287	306,519	-	374,930,243	74,986,049	1.25	600,000,000	169,266,459
30	12/1/2040	12,284	385,523	101,920	22,049	332,326	-	381,019,473	76,203,895	1.25		245,470,354
31	12/1/2041	18,825	403,233	103,660	22,861	361,453	-	381,032,535	76,206,507	1.25		321,676,861
32	12/1/2042	21,552	394,321	95,445	21,546	371,427	-	285,673,785	57,134,757	1.25		378,811,618
33	12/1/2043	22,199	412,100	97,223	22,392	404,276	-	309,073,410	61,814,682	1.25	250,000,000	190,626,300
34	12/1/2044	23,458	428,330	152,761	23,116	439,168	-	337,801,681	67,560,336	1.25	-	258,186,636
35	12/1/2045	22,134	449,075	101,037	23,977	476,267	-	283,981,118	56,796,224	1.25		314,982,859
36	12/1/2046	22,961	421,293	140,010	26,073	466,403	-	283,984,306	56,796,861	1.25		371,779,720
37	12/1/2047	24,452	424,059	142,963	26,511	490,408	-	403,765,712	80,753,142	1.25		452,532,863
38	12/1/2048	25,398	444,961	146,057	27,392	537,229	-	463,798,056	92,759,611	1.25		545,292,474
39	12/1/2049	6,909	461,902	149,291	28,395	584,308	-	463,800,931	92,760,186	1.25		638,052,660
40	12/1/2050	8,724	477,627	152,489	29,313	630,743	-	463,798,181	92,759,636	1.25		730,812,296
41	12/1/2051	11,174	503,605	155,601	30,361	656,308	-	349,373,368	69,874,674	1.25		800,686,970
42	12/1/2052	9,139	520,728	158,955	31,315	676,369	-	349,365,868	69,873,174	1.25		870,560,144
43	12/1/2053	14,889	546,462	162,470	32,477	705,371	-	349,365,868	69,873,174	1.25		940,433,317
44	12/1/2054	22,880	562,487	165,955	33,535	723,997	-	323,134,493	64,626,899	1.25	410,069,419	594,990,797
45	12/1/2055	27,949	579,273	169,720	34,785	749,388	-	328,899,431	65,779,886	1.25		660,770,683
46	12/1/2056	30,133	605,200	173,255	35,877	774,023	-	335,033,243	67,006,649	1.25		727,777,332
47	12/1/2057	33,288	647,750	180,086	37,668	822,050	-	309,341,806	61,868,361	1.25		789,645,693
48	12/1/2058	33,226	682,788	182,230	38,924	862,251	-	315,785,993	63,157,199	1.25		852,802,891
49	12/1/2059	31,309	716,551	186,278	40,624	900,505	-	322,395,743	64,479,149	1.25		917,282,040
50	12/1/2060	32,092	734,465	190,935	41,639	923,018		329,157,493	65,831,499	1.25		983,113,539

APPENDIX C

EXISTING GENERATION UNITS

Detailed Existing Unit Tables

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Anchorage ML&P – Plant 1	3	Natural Gas	Natural Gas	32	29.3	1	3.72	10.87	9,780	6.0	N	114.8	0.44	0.000045	2037
Anchorage ML&P – Plant 2	5	Natural Gas	Natural Gas	37.4	33.8	5	3.72	11.62	14	1.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	5/6	Natural Gas	Natural Gas	49.2	44.5	10	3.72	11.62	11	1.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	7	Natural Gas	Natural Gas	81.8	74.4	10	3.72	7.79	1,193	0.1	N	114.8	0.625	0.000045	2030
Anchorage ML&P – Plant 2	7/6	Natural Gas	Natural Gas	109.5	99.5	10	3.72	7.79	9,030	0.1	N	114.8	0.625	0.000045	2020
Anchorage ML&P – Plant 2	8	Natural Gas	Natural Gas	87.6	77.3	20	3.72	7.47	11,930	1.7	N	114.8	0.08	0.000045	2030

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Bernice	2	Natural Gas	Natural Gas	19	19	3	1.23	6.15	14,673	2.0	N	115	0.32	0.000045	2014
Bernice	3	Natural Gas	Natural Gas	25.5	25.5	13	1.23	19.48	13,409	2.0	N	115	0.13	0.000045	2014
Bernice	4	Natural Gas	Natural Gas	25.5	25.5	13	1.23	19.48	13,741	2.0	N	115	0.13	0.000045	2014
Beluga	1	Natural Gas	Natural Gas	17.5	16	3	1.23	14.35	15,198	2.0	N	115	0.32	0.0002	2011
Beluga	2	Natural Gas	Natural Gas	17.5	16	3	1.23	14.35	14,851	2.0	N	115	0.32	0.0002	2011
Beluga	3	Natural Gas	Natural Gas	66.5	56	3	1.44	12.30	12,236	2.0	N	115	0.32	0.0002	2014
Beluga	5	Natural Gas	Natural Gas	65	54	3	1.44	12.30	12,537	2.0	N	115	0.32	0.0002	2017
Beluga	6	Natural Gas	Natural Gas	82	64	3	1.64	13.33	11,528	1.0	N	115	0.2	0.001	2020
Beluga	6/8	Natural Gas	Natural Gas	108.5	83	48	2.56	29.73	9,329	4.0	N	115	0.2	0.001	2014
Beluga	7	Natural Gas	Natural Gas	82	66	3	1.64	13.33	12,184	1.0	N	115	0.34	0.006	2021
Beluga	7/8	Natural Gas	Natural Gas	108.5	85	48	2.56	29.73	9,086	4.0	N	115	0.34	0.006	2014
International	1	Natural Gas	Natural Gas	14	13	3	1.23	14.35	16,379	2.0	N	115	0.32	0.002	2011
International	2	Natural Gas	Natural Gas	14	12.5	3	1.23	14.35	17,425	2.0	N	115	0.32	0.002	2011
International	3	Natural Gas	Natural Gas	19	16	3	1.23	14.35	15,116	2.0	N	115	0.32	0.002	2012

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Zehnder	GT1	HAGO	Distillate Fuel Oil	19.2	15.8	4	8.23	10.98	14,030	0.1	N	128	0.7	0.8	2030
Zehnder	GT2	HAGO	Distillate Fuel Oil	19.6	15	4	8.23	10.98	14,190	0.2	N	128	0.7	0.8	2030
North Pole	GT1	HAGO	Distillate Fuel Oil	62.6	50	10	3.91	21.41	10,010	0.6	N	128	0.7	0.7	2017
North Pole	GT2	HAGO	Distillate Fuel Oil	60.6	48	10	3.91	21.41	9,720	0.5	N	128	0.7	0.7	2018
North Pole	CC	NAPHTHA	Distillate Fuel Oil	65	54	38	3.20	224.56	6,620	0.4	N	114.8	0.76	0.0022	2042
Healy	ST1	COAL	Distillate Fuel Oil	27	26.5	20	3.30	208.60	13,870	0.7	Y	211	0.25	0.3	2022
DPP	1	HAGO	Distillate Fuel Oil	25.8	23.1	4	8.23	10.98	13,210	0.3	N	128	0.7	0.12	2030

Name	Unit	Primary Fuel	Startup Fuel	Winter Rating (MW)	Summer Rating (MW)	Minimum Capacity (MW)	Variable O&M (2009 $/MWh)	Fixed O&M (2009 $/kW-yr)	Full Load Net Plant Heat Rate (Btu/kWh - HHV)	Forcd Outage Rate (%)	Must Run (Y/N)	CO2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	SO2 Emission Rate (lb/mmBtu)	Retirement Date
Nikiski	1	Natural Gas	Natural Gas	42	38	3	6.63	4.82	12,170	1.0	Y	114.8	0.13	0.000045	2026

APPENDIX D

REGIONAL LOAD FORECASTS

Table D-1
GRETC's Winter Peak Load Forecast for Evaluation
2011 - 2060

Year	Winter Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2010/2011	233.9	238.1	87.0	146.0	188.0	9.5	869.3
2011/2012	233.9	239.6	88.0	151.0	189.0	9.5	877.5
2012/2013	233.9	241.3	88.0	153.0	190.0	10.4	883.0
2013/2014	233.9	242.9	88.0	155.0	191.0	10.4	887.4
2014/2015	234.5	217.5	89.0	157.0	192.0	10.4	867.8
2015/2016	234.9	219.2	90.0	159.0	193.0	10.4	873.3
2016/2017	235.5	221.1	90.0	161.0	194.0	10.4	879.0
2017/2018	236.5	222.7	91.0	163.0	195.0	10.4	885.4
2018/2019	237.6	224.3	92.0	165.0	196.0	10.4	891.8
2019/2020	238.1	226.0	92.0	167.0	197.0	10.4	896.3
2020/2021	238.6	227.6	93.0	169.0	198.0	10.4	902.7
2021/2022	239.7	229.2	94.0	171.0	199.0	10.4	909.1
2022/2023	240.7	230.9	94.0	173.0	200.0	10.4	914.6
2023/2024	241.7	232.6	95.0	176.0	201.0	10.4	922.1
2024/2025	242.2	234.3	96.0	178.0	202.0	10.4	927.5
2025/2026	242.8	236.0	97.0	180.0	203.0	10.4	934.0
2026/2027	243.8	237.7	97.0	182.0	204.0	10.4	939.6
2027/2028	244.8	239.4	98.0	184.0	205.0	10.4	946.1
2028/2029	245.9	241.1	99.0	186.0	206.0	10.4	952.5
2029/2030	246.9	242.8	100.0	188.0	207.0	10.4	959.0
2030/2031	247.9	244.5	100.8	190.2	208.0	10.4	965.4
2031/2032	248.8	246.2	101.6	192.4	209.0	10.4	971.8
2032/2033	249.7	248.0	102.4	194.6	210.0	10.4	978.3
2033/2034	250.7	249.7	103.2	196.8	211.1	10.4	984.7
2034/2035	251.6	251.5	104.0	199.0	212.1	10.4	991.2
2035/2036	252.5	253.2	104.8	201.3	213.1	10.4	997.7
2036/2037	253.5	255.0	105.6	203.5	214.1	10.4	1004.3
2037/2038	254.4	256.7	106.4	205.8	215.2	10.4	1010.9
2038/2039	255.4	258.5	107.3	208.1	216.2	10.4	1017.4
2039/2040	256.3	260.3	108.1	210.4	217.2	10.4	1024.1
2040/2041	257.3	262.0	108.9	212.7	218.3	10.4	1030.7
2041/2042	258.2	263.8	109.7	215.0	219.3	10.4	1037.4
2042/2043	259.2	265.6	110.6	217.4	220.4	10.4	1044.1
2043/2044	260.1	267.4	111.4	219.7	221.4	10.4	1050.9
2044/2045	261.1	269.2	112.3	222.1	222.5	10.4	1057.7
2045/2046	262.0	271.1	113.1	224.5	223.5	10.4	1064.5
2046/2047	263.0	272.9	114.0	226.9	224.6	10.4	1071.3
2047/2048	264.0	274.7	114.8	229.3	225.6	10.4	1078.2
2048/2049	264.9	276.5	115.7	231.8	226.7	10.4	1085.0
2049/2050	265.9	278.4	116.5	234.2	227.7	10.4	1092.0
2050/2051	266.9	280.2	117.4	236.7	228.8	10.4	1098.9
2051/2052	267.8	282.1	118.3	239.2	229.9	10.4	1105.9
2052/2053	268.8	284.0	119.1	241.7	231.0	10.4	1112.9
2053/2054	269.8	285.8	120.0	244.2	232.0	10.4	1120.0
2054/2055	270.7	287.7	120.9	246.8	233.1	10.4	1127.1
2055/2056	271.7	289.6	121.8	249.3	234.2	10.4	1134.2
2056/2057	272.7	291.5	122.7	251.9	235.3	10.4	1141.4
2057/2058	273.7	293.4	123.6	254.5	236.4	10.4	1148.5
2058/2059	274.7	295.3	124.4	257.1	237.4	10.4	1155.8
2059/2060	275.7	297.3	125.4	259.7	238.5	10.4	1163.0

Table D-2
GRETC's Summer Peak Load Forecast for Evaluation
2011 - 2060

Year	Summer Peak Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	160.6	191.4	75.1	91.1	167.2	10.0	668.0
2012	160.6	192.6	75.9	94.1	168.1	10.0	674.3
2013	160.6	193.9	75.9	95.0	169.0	11.0	678.5
2014	160.6	195.2	75.9	95.5	169.9	11.0	681.9
2015	161.3	174.8	76.8	95.5	170.8	11.0	666.8
2016	161.3	176.2	77.7	95.4	171.7	11.0	671.0
2017	162.0	177.7	77.7	95.3	172.6	11.0	675.4
2018	162.7	179.0	78.5	95.1	173.5	11.0	680.3
2019	163.4	180.3	79.4	95.0	174.3	11.0	685.3
2020	163.4	181.6	79.4	95.0	175.2	11.0	688.7
2021	164.2	182.9	80.2	94.9	176.1	11.0	693.6
2022	164.9	184.3	81.1	96.0	177.0	11.0	698.6
2023	165.6	185.6	81.1	97.1	177.9	11.0	702.8
2024	166.3	187.0	82.0	98.7	178.8	11.0	708.5
2025	166.3	188.3	82.8	99.9	179.7	11.0	712.7
2026	167.0	189.7	83.7	101.1	180.6	11.0	717.7
2027	167.7	191.1	83.7	102.3	181.5	11.0	722.0
2028	168.4	192.4	84.6	103.5	182.3	11.0	726.9
2029	169.2	193.8	85.4	104.7	183.2	11.0	731.9
2030	169.9	195.2	86.3	105.9	184.1	11.0	736.9
2031	170.5	196.5	87.0	107.2	185.0	11.0	741.8
2032	171.2	197.9	87.7	108.5	185.9	11.0	746.8
2033	171.8	199.3	88.3	109.8	186.8	11.0	751.7
2034	172.4	200.7	89.0	111.1	187.7	11.0	756.7
2035	173.1	202.1	89.7	112.5	188.7	11.0	761.6
2036	173.7	203.5	90.4	113.8	189.6	11.1	766.7
2037	174.4	204.9	91.1	115.2	190.5	11.1	771.7
2038	175.0	206.3	91.8	116.6	191.4	11.2	776.7
2039	175.7	207.8	92.6	117.9	192.3	11.2	781.8
2040	176.3	209.2	93.3	119.3	193.2	11.3	786.9
2041	177.0	210.6	94.0	120.7	194.2	11.4	792.0
2042	177.6	212.1	94.7	122.1	195.1	11.4	797.1
2043	178.3	213.5	95.4	123.5	196.0	11.5	802.3
2044	179.0	214.9	96.1	124.9	196.9	11.5	807.5
2045	179.6	216.4	96.9	126.4	197.9	11.6	812.7
2046	180.3	217.9	97.6	127.8	198.8	11.7	817.9
2047	180.9	219.3	98.3	129.3	199.8	11.7	823.2
2048	181.6	220.8	99.1	130.7	200.7	11.8	828.4
2049	182.3	222.3	99.8	132.2	201.6	11.8	833.7
2050	182.9	223.8	100.5	133.7	202.6	11.9	839.1
2051	183.6	225.3	101.3	135.2	203.5	12.0	844.4
2052	184.3	226.7	102.0	136.7	204.5	12.0	849.8
2053	184.9	228.2	102.8	138.2	205.4	12.1	855.2
2054	185.6	229.8	103.6	139.7	206.4	12.1	860.6
2055	186.3	231.3	104.3	141.3	207.3	12.2	866.0
2056	186.9	232.8	105.1	142.8	208.3	12.3	871.5
2057	187.6	234.3	105.8	144.4	209.3	12.3	877.0
2058	188.3	235.8	106.6	145.9	210.2	12.4	882.5
2059	189.0	237.4	107.4	147.5	211.2	12.4	888.1
2060	189.6	238.9	108.2	149.1	212.2	12.5	893.6

Table D-3
GRETC's Annual Valley Load Forecast for Evaluation
2011 - 2060

Year	Annual Valley Demand (MW)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	95.4	88.6	44.4	53.2	91.0	4.4	413.5
2012	95.4	89.2	44.9	55.0	91.5	4.4	417.2
2013	95.4	89.8	44.9	55.8	91.9	4.8	419.7
2014	95.4	90.4	44.9	56.5	92.4	4.8	421.7
2015	95.8	81.0	45.5	57.2	92.9	4.8	413.7
2016	95.8	81.6	46.0	58.0	93.4	4.8	416.3
2017	96.3	82.3	46.0	58.7	93.9	4.8	418.9
2018	96.7	82.9	46.5	59.4	94.4	4.8	421.9
2019	97.1	83.5	47.0	60.2	94.8	4.8	424.9
2020	97.1	84.1	47.0	60.9	95.3	4.8	426.9
2021	97.5	84.7	47.5	61.6	95.8	4.8	429.9
2022	98.0	85.3	48.0	62.3	96.3	4.8	433.0
2023	98.4	86.0	48.0	63.1	96.8	4.8	435.4
2024	98.8	86.6	48.5	64.2	97.3	4.8	438.9
2025	98.8	87.2	49.0	64.9	97.7	4.8	441.4
2026	99.2	87.8	49.5	65.6	98.2	4.8	444.5
2027	99.7	88.5	49.5	66.4	98.7	4.8	447.0
2028	100.1	89.1	50.1	67.1	99.2	4.8	450.0
2029	100.5	89.7	50.6	67.8	99.7	4.8	453.1
2030	100.9	90.4	51.1	68.5	100.2	4.8	456.1
2031	101.3	91.0	51.5	69.3	100.7	4.8	459.1
2032	101.7	91.7	51.9	70.1	101.1	4.8	462.1
2033	102.1	92.3	52.3	70.9	101.6	4.8	465.1
2034	102.5	93.0	52.7	71.7	102.1	4.8	468.1
2035	102.8	93.6	53.1	72.6	102.6	4.8	471.1
2036	103.2	94.3	53.5	73.4	103.1	4.8	474.1
2037	103.6	94.9	54.0	74.2	103.6	4.8	477.2
2038	104.0	95.6	54.4	75.0	104.1	4.8	480.2
2039	104.4	96.2	54.8	75.9	104.6	4.8	483.3
2040	104.8	96.9	55.2	76.7	105.1	4.8	486.4
2041	105.2	97.5	55.6	77.5	105.6	4.8	489.5
2042	105.5	98.2	56.1	78.4	106.1	4.8	492.6
2043	105.9	98.9	56.5	79.2	106.6	4.8	495.7
2044	106.3	99.5	56.9	80.1	107.1	4.8	498.8
2045	106.7	100.2	57.3	81.0	107.6	4.8	502.0
2046	107.1	100.9	57.8	81.8	108.2	4.8	505.2
2047	107.5	101.6	58.2	82.7	108.7	4.8	508.3
2048	107.9	102.3	58.6	83.6	109.2	4.8	511.5
2049	108.3	102.9	59.1	84.5	109.7	4.8	514.7
2050	108.7	103.6	59.5	85.4	110.2	4.8	517.9
2051	109.1	104.3	60.0	86.3	110.7	4.8	521.2
2052	109.5	105.0	60.4	87.2	111.2	4.8	524.4
2053	109.9	105.7	60.9	88.1	111.8	4.8	527.7
2054	110.3	106.4	61.3	89.0	112.3	4.8	530.9
2055	110.7	107.1	61.7	90.0	112.8	4.8	534.2
2056	111.1	107.8	62.2	90.9	113.3	4.8	537.5
2057	111.5	108.5	62.7	91.8	113.8	4.8	540.8
2058	111.9	109.2	63.1	92.8	114.4	4.8	544.2
2059	112.3	109.9	63.6	93.7	114.9	4.8	547.5
2060	112.7	110.7	64.0	94.7	115.4	4.8	550.9

Table D-4
GRETC's Net Energy for Load Forecast for Evaluation
2011 - 2060

Year	Utility Net Energy for Load Forecast (GWh)						
	CEA	GVEA	HEA	MEA	ML&P	SES	GRETC
2011	1,302.0	1,522.7	554.5	771.2	1,162.8	64.6	5,377.8
2012	1,303.2	1,532.1	557.1	801.9	1,168.3	64.8	5,427.4
2013	1,305.0	1,543.0	560.2	811.1	1,173.8	65.0	5,458.1
2014	1,307.5	1,553.2	564.0	820.9	1,179.3	65.3	5,490.3
2015	1,311.4	1,333.5	568.1	831.9	1,184.9	65.6	5,295.3
2016	1,315.6	1,344.4	572.4	842.8	1,190.4	65.9	5,331.5
2017	1,320.1	1,355.5	577.0	854.0	1,196.0	66.3	5,369.0
2018	1,324.8	1,361.5	581.7	865.4	1,201.6	66.6	5,401.6
2019	1,329.6	1,367.4	586.5	876.8	1,207.3	67.0	5,434.7
2020	1,334.5	1,373.4	591.2	888.3	1,213.0	67.4	5,467.8
2021	1,339.4	1,379.5	596.1	900.1	1,218.7	67.8	5,501.6
2022	1,344.3	1,385.5	601.0	911.7	1,224.4	68.1	5,535.0
2023	1,349.2	1,391.6	605.9	923.2	1,230.1	68.5	5,568.6
2024	1,354.3	1,397.7	610.7	934.8	1,235.9	68.9	5,602.3
2025	1,359.2	1,403.8	615.5	946.4	1,241.7	69.3	5,636.0
2026	1,364.2	1,410.0	620.4	958.0	1,247.6	69.7	5,669.9
2027	1,369.3	1,416.2	625.3	969.7	1,253.4	70.0	5,703.9
2028	1,374.4	1,422.3	630.2	981.3	1,259.3	70.4	5,738.0
2029	1,379.5	1,428.5	635.1	992.9	1,265.3	70.8	5,772.0
2030	1,384.5	1,434.7	640.0	1,004.7	1,271.2	71.2	5,806.3
2031	1,389.6	1,440.8	645.0	1,016.7	1,277.1	71.6	5,840.8
2032	1,394.7	1,447.0	650.0	1,028.7	1,283.0	72.0	5,875.4
2033	1,399.7	1,453.3	655.0	1,040.9	1,289.0	72.4	5,910.2
2034	1,404.8	1,459.5	660.0	1,053.1	1,294.9	72.7	5,945.1
2035	1,409.9	1,465.7	665.1	1,065.4	1,300.9	73.1	5,980.1
2036	1,415.0	1,472.0	670.2	1,077.8	1,306.8	73.5	6,015.3
2037	1,420.1	1,478.2	675.3	1,090.2	1,312.8	73.9	6,050.6
2038	1,425.3	1,484.5	680.4	1,102.8	1,318.8	74.3	6,086.1
2039	1,430.4	1,490.8	685.5	1,115.4	1,324.9	74.7	6,121.7
2040	1,435.5	1,497.1	690.7	1,128.1	1,330.9	75.1	6,157.4
2041	1,440.7	1,503.5	695.9	1,140.9	1,336.9	75.5	6,193.3
2042	1,445.8	1,509.8	701.1	1,153.7	1,343.0	75.9	6,229.3
2043	1,451.0	1,516.2	706.3	1,166.7	1,349.1	76.3	6,265.5
2044	1,456.2	1,522.5	711.5	1,179.7	1,355.2	76.7	6,301.9
2045	1,461.4	1,528.9	716.8	1,192.9	1,361.3	77.1	6,338.4
2046	1,466.6	1,535.3	722.1	1,206.1	1,367.4	77.5	6,375.0
2047	1,471.8	1,541.7	727.4	1,219.4	1,373.5	77.9	6,411.8
2048	1,477.0	1,548.2	732.8	1,232.8	1,379.7	78.3	6,448.8
2049	1,482.3	1,554.6	738.1	1,246.3	1,385.9	78.7	6,485.9
2050	1,487.5	1,561.1	743.5	1,259.9	1,392.1	79.1	6,523.2
2051	1,492.8	1,567.5	748.9	1,273.6	1,398.3	79.5	6,560.6
2052	1,498.0	1,574.0	754.4	1,287.4	1,404.5	79.9	6,598.2
2053	1,503.3	1,580.5	759.8	1,301.3	1,410.7	80.3	6,635.9
2054	1,508.6	1,587.1	765.3	1,315.3	1,416.9	80.7	6,673.9
2055	1,513.9	1,593.6	770.8	1,329.4	1,423.2	81.1	6,712.0
2056	1,519.2	1,600.1	776.3	1,343.6	1,429.5	81.5	6,750.2
2057	1,524.5	1,606.7	781.9	1,357.9	1,435.8	81.9	6,788.7
2058	1,529.8	1,613.3	787.5	1,372.3	1,442.1	82.3	6,827.3
2059	1,535.1	1,619.9	793.1	1,386.8	1,448.4	82.8	6,866.0
2060	1,540.5	1,626.5	798.7	1,401.4	1,454.7	83.2	6,905.0

Table D-5
GRETC's Winter Peak Large Load Forecast for Evaluation
2011 - 2060

Year	Large Load Winter Peak Demand (MW)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2010/2011	238.1	412.2	146.0	96.3	869.3
2011/2012	239.6	413.2	151.0	97.2	877.5
2012/2013	241.3	414.2	153.0	98.2	883.0
2013/2014	242.9	415.1	155.0	98.2	887.4
2014/2015	217.5	417.1	157.0	99.2	867.8
2015/2016	219.2	418.1	159.0	100.2	873.3
2016/2017	221.1	420.1	161.0	100.2	879.0
2017/2018	222.7	422.1	163.0	101.2	885.4
2018/2019	224.3	424.1	165.0	102.2	891.8
2019/2020	226.0	425.1	167.0	102.2	896.3
2020/2021	227.6	427.1	169.0	103.2	902.7
2021/2022	229.2	429.0	171.0	104.2	909.1
2022/2023	230.9	431.0	173.0	104.2	914.6
2023/2024	232.6	433.0	176.0	105.2	922.1
2024/2025	384.3	734.0	178.0	156.2	1398.3
2025/2026	386.0	736.0	180.0	157.2	1404.7
2026/2027	387.7	738.0	182.0	157.2	1410.2
2027/2028	389.4	740.0	184.0	158.2	1416.6
2028/2029	391.1	742.0	186.0	159.2	1423.1
2029/2030	392.8	744.0	188.0	160.1	1429.5
2030/2031	394.5	745.9	190.2	160.9	1435.8
2031/2032	396.2	747.8	192.4	161.7	1442.2
2032/2033	398.0	749.7	194.6	162.5	1448.6
2033/2034	399.7	751.6	196.8	163.3	1455.0
2034/2035	401.5	753.5	199.0	164.1	1461.4
2035/2036	403.2	755.4	201.3	165.0	1468.0
2036/2037	405.0	757.4	203.5	165.8	1474.5
2037/2038	406.7	759.3	205.8	166.7	1481.1
2038/2039	408.5	761.2	208.1	167.6	1487.7
2039/2040	560.3	1063.2	210.4	218.5	1975.7
2040/2041	562.0	1065.1	212.7	219.3	1982.3
2041/2042	563.8	1067.1	215.0	220.2	1989.0
2042/2043	565.6	1069.0	217.4	221.1	1995.7
2043/2044	567.4	1071.0	219.7	222.0	2002.5
2044/2045	569.2	1072.9	222.1	222.9	2009.3
2045/2046	571.1	1074.9	224.5	223.8	2016.1
2046/2047	572.9	1076.9	226.9	224.7	2022.9
2047/2048	574.7	1078.9	229.3	225.6	2029.8
2048/2049	576.5	1080.8	231.8	226.5	2036.7
2049/2050	578.4	1082.8	234.2	227.4	2043.6
2050/2051	580.2	1084.8	236.7	228.4	2050.6
2051/2052	582.1	1086.8	239.2	229.3	2057.6
2052/2053	584.0	1088.8	241.7	230.2	2064.6
2053/2054	585.8	1090.8	244.2	231.1	2071.7
2054/2055	587.7	1092.8	246.8	232.1	2078.8
2055/2056	589.6	1094.8	249.3	233.0	2085.9
2056/2057	591.5	1096.8	251.9	234.0	2093.0
2057/2058	593.4	1098.9	254.5	234.9	2100.2
2058/2059	595.3	1100.9	257.1	235.8	2107.5
2059/2060	597.3	1102.9	259.7	236.8	2114.7

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

Year	Large Load Net Energy for Load Forecast (GWh)				
	GVEA	Anchorage	MEA	Kenai	GRETC
2011	1,522.7	2,464.8	771.2	619.1	5,377.8
2012	1,532.1	2,471.5	801.9	621.9	5,427.4
2013	1,543.0	2,478.8	811.1	625.2	5,458.1
2014	1,553.2	2,486.9	820.9	629.3	5,490.3
2015	1,333.5	2,496.2	831.9	633.7	5,295.3
2016	1,344.4	2,506.0	842.8	638.3	5,331.5
2017	1,355.5	2,516.2	854.0	643.3	5,369.0
2018	1,361.5	2,526.4	865.4	648.3	5,401.6
2019	1,367.4	2,536.9	876.8	653.5	5,434.7
2020	1,373.4	2,547.4	888.3	658.6	5,467.8
2021	1,379.5	2,558.1	900.1	663.9	5,501.6
2022	1,385.5	2,568.7	911.7	669.1	5,535.0
2023	1,391.6	2,579.4	923.2	674.4	5,568.6
2024	1,397.7	2,590.2	934.8	679.6	5,602.3
2025	2,389.3	4,572.0	946.4	1,013.3	8,921.0
2026	2,395.5	4,582.8	958.0	1,018.6	8,954.9
2027	2,401.7	4,593.7	969.7	1,023.8	8,988.9
2028	2,410.5	4,610.1	981.3	1,030.0	9,032.0
2029	2,414.0	4,615.7	992.9	1,034.4	9,057.0
2030	2,420.2	4,626.7	1,004.7	1,039.7	9,091.3
2031	2,426.3	4,637.7	1,016.7	1,045.1	9,125.8
2032	2,435.2	4,654.1	1,028.7	1,051.3	9,169.4
2033	2,438.8	4,659.7	1,040.9	1,055.8	9,195.2
2034	2,445.0	4,670.7	1,053.1	1,061.3	9,230.1
2035	2,451.2	4,681.8	1,065.4	1,066.7	9,265.1
2036	2,460.2	4,698.3	1,077.8	1,073.1	9,309.3
2037	2,463.7	4,704.0	1,090.2	1,077.7	9,335.6
2038	2,470.0	4,715.1	1,102.8	1,083.2	9,371.1
2039	2,476.3	4,726.2	1,115.4	1,088.7	9,406.7
2040	3,473.5	6,719.2	1,128.1	1,424.6	12,745.4
2041	3,474.5	6,719.6	1,140.9	1,428.3	12,763.3
2042	3,480.8	6,730.9	1,153.7	1,433.9	12,799.3
2043	3,487.2	6,742.1	1,166.7	1,439.6	12,835.5
2044	3,498.9	6,764.2	1,179.7	1,447.0	12,889.9
2045	3,499.9	6,764.7	1,192.9	1,450.9	12,908.4
2046	3,506.3	6,776.0	1,206.1	1,456.6	12,945.0
2047	3,512.7	6,787.4	1,219.4	1,462.3	12,981.8
2048	3,524.6	6,809.5	1,232.8	1,469.8	13,036.8
2049	3,525.6	6,810.1	1,246.3	1,473.8	13,055.9
2050	3,532.1	6,821.6	1,259.9	1,479.6	13,093.2
2051	3,538.5	6,833.0	1,273.6	1,485.4	13,130.6
2052	3,550.4	6,855.3	1,287.4	1,493.0	13,186.2
2053	3,551.5	6,856.0	1,301.3	1,497.1	13,205.9
2054	3,558.1	6,867.5	1,315.3	1,503.0	13,243.9
2055	3,564.6	6,879.1	1,329.4	1,508.9	13,282.0
2056	3,576.5	6,901.5	1,343.6	1,516.6	13,338.2
2057	3,577.7	6,902.3	1,357.9	1,520.8	13,358.7
2058	3,584.3	6,913.9	1,372.3	1,526.8	13,397.3
2059	3,590.9	6,925.6	1,386.8	1,532.8	13,436.0
2060	3,602.9	6,948.0	1,401.4	1,540.7	13,493.0

APPENDIX E

DETAILED RESULTS – SCENARIOS 1A / 1B

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)	Fuel Costs ($000)	Total O&M Costs ($000)	CO2 Costs ($000)	DSM Costs ($000)	Annual Capital Fixed Charges ($000)	Total Annual Costs ($000)	Present Value of Annual Costs ($000)	Cumulative Present Value ($000)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1; International - 2	55.82%	11.92%	$351,806	$78,494	$1,102	$651	$12,326	$444,378	$444,378	$444,378
2012	Fire Island	International - 3	47.47%	15.18%	$359,297	$86,269	$54,767	$1,491	$40,350	$542,175	506,706	951,084
2013	Anchorage 1x1 6FA		62.51%	14.98%	$330,019	$88,259	$57,514	$3,063	$75,558	$554,413	484,245	1,435,329
2014	Glacier Fork	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	71.52%	15.94%	$339,919	$90,226	$63,386	$5,878	$108,169	$607,578	495,965	1,931,294
2015	Anchorage MSW		55.23%	24.72%	$348,659	$87,384	$62,082	$10,455	$131,358	$639,938	488,205	2,419,500
2016			59.21%	24.60%	$382,711	$89,392	$68,949	$12,759	$170,907	$724,717	516,713	2,936,213
2017	GVEA MSW	Beluga - 5; NP1	60.91%	24.85%	$357,899	$89,413	$74,393	$11,891	$199,985	$733,582	488,817	3,425,030
2018	GVEA 1X1 NPole Retrofit	NP2	54.30%	24.83%	$276,253	$83,051	$80,365	$12,241	$211,778	$663,688	413,311	3,838,341
2019			47.96%	24.62%	$295,815	$82,983	$87,105	$12,657	$211,778	$690,338	401,783	4,240,124
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	46.22%	31.89%	$302,861	$102,110	$88,427	$13,124	$273,431	$779,954	424,243	4,664,367
2021	Anchorage 1x1 6FA	Beluga - 7	55.99%	31.60%	$310,824	$106,747	$93,910	$13,346	$342,861	$867,688	441,089	5,105,456
2022	Mount Spurr	Healy - 1	51.00%	38.52%	$297,025	$126,402	$96,170	$14,024	$391,772	$925,393	439,648	5,545,103
2023			46.86%	38.33%	$325,599	$123,469	$97,048	$4,166	$395,365	$945,647	419,879	5,964,982
2024			45.69%	38.18%	$340,682	$126,429	$109,073	$3,313	$433,745	$1,013,242	420,460	6,385,441
2025	Chakachamna:Chakachamna	GVEA Aurora Purchase - Tier I	84.55%	62.32%	$220,174	$138,656	$75,946	$4,222	$693,340	$1,132,337	439,140	6,824,581
2026		Nikiski	75.13%	62.52%	$234,402	$129,355	$88,159	$5,342	$693,340	$1,150,598	417,030	7,241,611
2027			73.98%	63.00%	$227,330	$132,294	$94,512	$8,551	$695,689	$1,158,376	392,382	7,633,993
2028			72.66%	63.06%	$230,300	$135,279	$103,224	$13,323	$695,689	$1,177,815	372,866	8,006,859
2029			71.37%	61.83%	$242,192	$138,036	$118,165	$16,151	$695,689	$1,210,233	358,064	8,364,923
2030	Kenai Hydro	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	50.97%	63.97%	$185,036	$139,321	$110,881	$17,064	$700,698	$1,153,000	318,814	8,683,737
2031			42.40%	62.03%	$192,346	$139,762	$120,883	$14,951	$697,301	$1,165,243	301,121	8,984,858
2032			41.36%	62.78%	$191,723	$142,989	$129,151	$15,081	$677,251	$1,156,195	279,236	9,264,095
2033			40.32%	61.88%	$199,354	$146,152	$141,847	$15,919	$677,251	$1,180,522	266,459	9,530,554
2034			39.30%	61.50%	$203,127	$149,310	$154,233	$16,747	$677,251	$1,200,668	253,277	9,783,831
2035			38.29%	61.86%	$205,017	$152,770	$165,394	$18,111	$677,251	$1,218,543	240,232	10,024,063
2036			37.29%	61.55%	$207,662	$156,125	$183,109	$5,493	$677,251	$1,229,640	226,560	10,250,623
2037	GVEA LMS100	MLP 3	43.27%	60.64%	$217,063	$162,624	$200,100	$7,019	$703,248	$1,290,053	222,141	10,472,764
2038			42.23%	60.94%	$218,402	$166,071	$217,232	$6,453	$703,248	$1,311,404	211,045	10,683,809
2039			41.22%	60.75%	$230,127	$170,053	$235,833	$8,848	$703,248	$1,348,108	202,758	10,886,568
2040			40.20%	60.25%	$243,640	$173,619	$259,739	$12,284	$703,248	$1,392,529	195,738	11,082,305
2041			39.21%	60.34%	$253,301	$177,608	$279,986	$18,825	$694,319	$1,424,038	187,072	11,269,377
2042	GVEA 1x1 6FA	NPCC	48.65%	59.27%	$276,556	$169,650	$309,508	$21,552	$758,395	$1,535,661	188,538	11,457,915
2043			47.60%	59.37%	$288,608	$173,713	$335,805	$22,199	$723,187	$1,543,512	177,104	11,635,019
2044			46.55%	59.21%	$300,081	$231,589	$363,392	$23,458	$690,575	$1,609,095	172,551	11,807,570
2045			45.51%	58.76%	$317,604	$181,983	$395,339	$22,134	$667,387	$1,584,446	158,792	11,966,362
2046	Anchorage LM6000		49.40%	58.33%	$337,808	$189,592	$429,301	$22,961	$643,804	$1,623,465	152,059	12,118,421
2047			48.36%	57.93%	$353,295	$194,064	$464,681	$24,452	$614,726	$1,651,218	144,540	12,262,961
2048			47.31%	57.73%	$370,037	$198,719	$505,529	$25,398	$602,933	$1,702,617	139,289	12,402,250
2049			46.30%	57.57%	$386,486	$203,794	$546,949	$6,909	$602,933	$1,747,070	133,575	12,535,825
2050			45.26%	57.17%	$405,470	$208,369	$595,985	$8,724	$541,280	$1,759,830	125,749	12,661,574
2051			44.26%	57.05%	$420,223	$213,071	$616,838	$11,174	$471,850	$1,733,156	115,741	12,777,315
2052			43.26%	56.77%	$438,398	$218,532	$632,661	$9,139	$422,939	$1,721,668	107,452	12,884,767
2053			42.27%	56.11%	$463,378	$223,819	$667,701	$14,889	$419,346	$1,789,132	104,358	12,989,124
2054			41.28%	55.98%	$481,702	$229,337	$692,040	$22,880	$380,966	$1,806,925	98,500	13,087,625
2055			40.31%	55.65%	$503,136	$235,076	$717,142	$27,949	$376,280	$1,859,584	94,739	13,182,364
2056			39.35%	55.43%	$521,505	$240,450	$745,668	$30,133	$376,280	$1,914,035	91,134	13,273,498
2057	GVEA LMS100	Cooper Lake	47.51%	54.83%	$585,511	$250,156	$787,838	$33,288	$416,531	$2,073,323	92,260	13,365,758
2058			44.71%	53.85%	$615,490	$254,038	$829,889	$33,226	$416,531	$2,149,172	89,379	13,455,136
2059			43.71%	53.88%	$647,398	$261,068	$862,589	$31,309	$416,531	$2,218,894	86,241	13,541,378
2060			42.73%	53.09%	$677,429	$267,339	$902,580	$32,092	$411,521	$2,290,960	83,217	13,624,595
			Present Value of Costs		**4,547,973**	**1,750,430**	**1,921,235**	**149,474**	**5,255,484**		**Grand Total**	**13,624,595**

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)					
Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,720	0	0	4,304	38,024
2012	31,553	0	0	5,310	36,863
2013	31,457	0	0	3,877	35,334
2014	30,904	0	0	3,241	34,145
2015	22,249	0	0	2,555	24,803
2016	21,201	0	0	2,757	23,957
2017	21,919	0	0	2,645	24,563
2018	18,693	9,034	0	2,741	30,468
2019	18,656	8,262	0	2,780	29,697
2020	14,852	8,087	0	2,803	25,742
2021	15,866	7,311	0	2,215	25,391
2022	14,094	6,846	0	2,041	22,980
2023	14,741	7,727	0	2,070	24,538
2024	15,267	7,366	0	2,197	24,830
2025	10,081	4,435	0	1,328	15,844
2026	10,393	5,170	0	956	16,519
2027	10,646	5,243	0	0	15,889
2028	10,638	5,289	0	0	15,927
2029	10,865	5,792	0	0	16,657
2030	5,914	6,410	0	0	12,324
2031	7,382	5,563	0	0	12,945
2032	7,325	5,366	0	0	12,690
2033	7,524	5,595	0	0	13,118
2034	7,679	5,589	0	0	13,268
2035	7,709	5,543	0	0	13,253
2036	8,464	4,990	0	0	13,454
2037	6,734	7,581	0	0	14,315
2038	6,460	7,995	0	0	14,455
2039	6,583	8,118	0	0	14,701
2040	6,626	8,411	0	0	15,037
2041	6,725	8,363	0	0	15,088
2042	6,098	9,918	0	0	16,015
2043	6,074	10,083	0	0	16,157
2044	6,226	10,003	0	0	16,229
2045	6,293	10,376	0	0	16,670
2046	7,987	9,250	0	0	17,237
2047	8,290	9,166	0	0	17,456
2048	8,296	9,419	0	0	17,715
2049	8,431	9,493	0	0	17,924
2050	8,533	9,714	0	0	18,247
2051	8,649	9,696	0	0	18,345
2052	8,864	9,698	0	0	18,563
2053	8,917	10,106	0	0	19,023
2054	9,061	10,114	0	0	19,175
2055	9,078	10,367	0	0	19,445
2056	9,378	10,196	0	0	19,573
2057	7,933	13,595	0	0	21,528
2058	8,355	13,629	0	0	21,984
2059	8,374	14,102	0	0	22,476
2060	8,529	14,320	0	0	22,849

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Anchorage 1x1 6FA	Glacier Fork	Anchorage MSW	GVEA MSW	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Chakachamna:Chakachamna	Kenai Hydro	GVEA LMS100	GVEA 1x1 6FA	Anchorage LM6000	GVEA LMS100	Generating Unit Capital Cost Cash Flow ($000)
2011	30,468	99,809	175,454	210,604	127,935	0	0	0	0	0	0	0		0	0	0	0	644,270
2012				132,925	116,563	40,740												290,228
2013					119,477	95,638												215,114
2014						86,719	9,000											95,719
2015							21,127	18,083										39,210
2016							19,157	42,450				33,699						95,306
2017								38,492	72,765			26,866						138,123
2018									170,818	76,085		43,273						290,177
2019									154,889	178,613	68,804	79,301						481,607
2020										161,957	161,519	238,340						561,816
2021											146,457	481,537						627,994
2022												652,793						652,793
2023												712,138	247					712,385
2024												141,426	253					141,680
2025													260					260
2026													266					266
2027													18,560					18,560
2028													17,905					17,905
2029													18,353					18,353
2030																		
2031																		
2032																		
2033																		
2034														2,260				2,260
2035														206,133				206,133
2036														31,138				31,138
2037																		
2038																		
2039															127,792			127,792
2040															299,994			299,994
2041															272,020			272,020
2042																		
2043																		
2044																27,076		27,076
2045																123,405		123,405
2046																		
2047																		
2048																		
2049																		
2050																		
2051																		
2052																		
2053																		
2054																	3,703	3,703
2055																	337,773	337,773
2056																	51,024	51,024
2057																		
2058																		
2059																		
2060																		
Total																		6,524,085

Scenario 1A/1B Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Capital Cost Cash Flow ($000)	Total Transmission Project Capital Cost Cash Flow ($000)	Total Capital Cost Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	644,270	79,848	724,118	651	351,806	43,795	34,699	1,102	5,372
2012	290,228	3,365	293,593	1,491	359,297	48,337	37,933	54,767	5,412
2013	215,114	51,272	266,387	3,063	330,019	52,191	36,068	57,514	5,424
2014	95,719	228,409	324,128	5,878	339,919	53,317	36,909	63,386	5,421
2015	39,210	314,097	353,307	10,455	348,659	48,327	39,057	62,082	5,167
2016	95,306	129,804	225,111	12,759	382,711	48,775	40,617	68,949	5,147
2017	138,123	8,812	146,935	11,891	357,899	49,059	40,354	74,393	5,129
2018	290,177	97,549	387,726	12,241	276,253	47,413	35,638	80,365	5,105
2019	481,607	214,570	696,177	12,657	295,815	46,596	36,386	87,105	5,085
2020	561,816	166,433	728,249	13,124	302,861	64,626	37,485	88,427	5,068
2021	627,994	73,715	701,709	13,346	310,824	68,386	38,361	93,910	5,052
2022	652,793	195,732	848,525	14,024	297,025	86,668	39,734	96,170	5,081
2023	712,385	205,995	918,380	4,166	325,599	82,114	41,355	97,048	5,111
2024	141,680	23,643	165,323	3,313	340,682	83,658	42,770	109,073	5,140
2025	260	10,784	11,044	4,222	220,174	106,273	32,383	75,946	5,174
2026	266	11,289	11,555	5,342	234,402	108,234	21,121	88,159	5,207
2027	18,560		18,560	8,551	227,330	110,277	22,017	94,512	5,241
2028	17,905		17,905	13,323	230,300	112,362	22,917	103,224	5,275
2029	18,353		18,353	16,151	242,192	114,541	23,495	118,165	5,309
2030			0	17,064	185,036	116,065	23,256	110,881	5,344
2031			0	14,951	192,346	117,757	22,005	120,883	5,378
2032			0	15,081	191,723	120,236	22,754	129,151	5,413
2033			0	15,919	199,354	122,661	23,490	141,847	5,447
2034	2,260		2,260	16,747	203,127	125,061	24,250	154,233	5,482
2035	206,133		206,133	18,111	205,017	127,634	25,135	165,394	5,517
2036	31,138		31,138	5,493	207,662	130,359	25,766	183,109	5,553
2037			0	7,019	217,063	136,144	26,480	200,100	5,588
2038			0	6,453	218,402	138,807	27,264	217,232	5,623
2039	127,792		127,792	8,848	230,127	141,651	28,402	235,833	5,659
2040	299,994		299,994	12,284	243,640	144,475	29,143	259,739	5,695
2041	272,020		272,020	18,825	253,301	147,408	30,200	279,986	5,731
2042			0	21,552	276,556	140,448	29,202	309,508	5,767
2043			0	22,199	288,608	143,513	30,200	335,805	5,803
2044	27,076		27,076	23,458	300,081	200,404	31,185	363,392	5,839
2045	123,405		123,405	22,134	317,604	149,991	31,991	395,339	5,876
2046			0	22,961	337,808	156,421	33,170	429,301	5,912
2047			0	24,452	353,295	159,869	34,195	464,681	5,949
2048			0	25,398	370,037	163,510	35,210	505,529	5,986
2049			0	6,909	386,486	167,227	36,567	546,949	6,023
2050			0	8,724	405,470	170,958	37,411	595,985	6,060
2051			0	11,174	420,223	174,609	38,462	616,838	6,098
2052			0	9,139	438,398	178,567	39,965	632,661	6,135
2053			0	14,889	463,378	182,614	41,204	667,701	6,173
2054	3,703		3,703	22,880	481,702	186,688	42,648	692,040	6,211
2055	337,773		337,773	27,949	503,136	191,057	44,020	717,142	6,249
2056	51,024		51,024	30,133	521,505	195,250	45,200	745,668	6,287
2057			0	33,288	585,511	202,909	47,247	787,838	6,326
2058			0	33,226	615,490	205,703	48,334	829,889	6,364
2059			0	31,309	647,398	210,417	50,651	862,589	6,403
2060			0	32,092	677,429	215,317	52,022	902,580	6,442
Total	6,524,085	1,815,317	Total of Cash Flows &	9,086,710					

Scenario 1A/1B Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type																				
	Natural Gas		Coal		Nuclear		Fuel Oil		Purchase Power		Hydro		Geothermal		Municipal Solid Waste		Wind		Ocean Tidal	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,542	80	435			251	580	25	210	176	591					15	49		
2012	1,258	3,425	80	493			251	501	25	215	176	593					69	231		
2013	1,195	3,490	80	556			251	384	25	213	176	591					69	226		
2014	1,176	3,354	80	630			251	380	25	213	251	649					69	227		
2015	1,176	2,432	80	618			251	619	25	212	251	919			22	163	69	227		
2016	822	2,316	80	625			251	703	25	213	251	921			22	163	69	228		
2017	822	2,388	80	611			251	602	25	212	251	919			26	188	69	227		
2018	821	2,441	80	554			189	591	25	212	251	919			26	195	69	227		
2019	821	2,443	80	563			189	563	25	212	251	919			26	193	69	226		
2020	1,103	2,567	80	587					25	211	251	921	50	403	26	192	69	228		
2021	907	2,595	80	550					25	208	251	919	50	402	26	190	69	227		
2022	825	2,250	80	543					25	204	251	919	100	800	26	186	69	227		
2023	743	2,450	80	364					25	205	251	919	100	802	26	187	69	227		
2024	743	2,452	53	374					25	206	251	921	100	803	26	188	69	227		
2025	743	1,285	53	278					25	174	581	2,528	100	651	26	107	69	226		
2026	743	1,448	53	292							581	2,519	100	680	26	119	69	227		
2027	701	1,441	53	285							581	2,518	100	708	26	140	69	227		
2028	701	1,456	53	282							581	2,525	100	734	26	132	69	227		
2029	701	1,537	53	282							581	2,517	100	688	26	136	69	227		
2030	701	1,387	53	323							586	2,537	100	797	26	154	69	226		
2031	531	1,507	53	325							586	2,538	100	719	26	139	69	226		
2032	467	1,476	53	327							586	2,544	100	765	26	152	69	228		
2033	467	1,540	53	327							586	2,537	100	746	26	147	69	227		
2034	467	1,572	53	330							586	2,538	100	739	26	153	69	227		
2035	467	1,568	53	328							586	2,538	100	783	26	151	69	227		
2036	562	1,588	53	340							586	2,544	100	768	26	163	69	227		
2037	564	1,676	53	317							586	2,537	100	752	26	153	69	227		
2038	532	1,676	53	317							586	2,537	100	783	26	162	69	227		
2039	532	1,700	53	320							586	2,537	100	808	26	147	69	227		
2040	532	1,740	53	323							586	2,544	100	771	26	164	69	231		
2041	693	1,749	53	324							586	2,537	100	813	26	161	69	226		
2042	693	1,851	53	303							586	2,537	100	764	26	165	69	227		
2043	630	1,859	53	305							586	2,537	100	787	26	169	69	227		
2044	630	1,880	53	308							586	2,544	100	792	26	168	69	228		
2045	630	1,935	53	297							586	2,537	100	789	26	171	69	227		
2046	678	1,996	53	279							586	2,537	100	780	26	174	69	227		
2047	678	2,039	53	277							586	2,537	100	785	26	166	69	226		
2048	678	2,069	53	275							586	2,544	100	781	26	170	69	228		
2049	678	2,100	53	272							586	2,537	100	812	26	158	69	227		
2050	678	2,149	53	264							586	2,537	100	793	26	172	69	227		
2051	678	2,172	53	265							586	2,537	100	792	26	187	69	227		
2052	678	2,209	53	264							586	2,544	100	813	26	162	69	227		
2053	678	2,259	53	273							586	2,537	100	786	26	175	69	227		
2054	678	2,281	53	276							586	2,537	100	796	26	176	69	227		
2055	678	2,319	53	278							586	2,537	100	796	26	175	69	227		
2056	678	2,344	53	283							586	2,544	100	774	26	197	69	228		
2057	775	2,441	53	248							586	2,537	100	813	26	146	69	227		
2058	775	2,522	53	251							567	2,496	100	783	26	172	69	226		
2059	775	2,577	53	252							567	2,496	100	823	26	154	69	227		
2060	775	2,623	53	260							567	2,502	100	775	26	160	69	228		

APPENDIX F

DETAILED RESULTS – SCENARIO 2A

Scenario 2A Plan - P50 Natural Gas Forecast												
Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)	Fuel Costs ($000)	Total O&M Costs ($000)	CO2 Costs ($000)	DSM Costs ($000)	Annual Capital Fixed Charges ($000)	Total Annual Costs ($000)	Present Value of Annual Costs ($000)	Cumulative Present Value ($000)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1; International - 2	55.82%	11.92%	$351,604	$78,521	$1,106	$651	$12,326	$444,208	$444,208	$444,208
2012	Fire Island	International - 3	47.47%	15.18%	$360,422	$86,221	$54,846	$1,491	$40,350	$543,330	507,785	951,993
2013			44.98%	14.98%	$363,525	$85,731	$60,377	$3,063	$40,350	$553,045	483,051	1,435,044
2014	Glacier Fork; Anchorage MSW	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	56.46%	18.90%	$349,083	$86,281	$66,100	$5,878	$88,695	$596,037	486,543	1,921,587
2015	Anchorage 1x1 6FA		55.23%	24.72%	$354,267	$87,454	$62,615	$10,455	$132,747	$647,538	494,004	2,415,591
2016			59.21%	24.60%	$389,510	$89,445	$69,555	$12,759	$172,296	$733,565	523,022	2,938,612
2017	Kenai Wind	Beluga - 5; NP1	60.42%	26.14%	$372,476	$92,929	$74,394	$11,891	$216,010	$767,700	511,551	3,450,163
2018	GVEA 1X1 NPole Retrofit	NP2	53.81%	26.11%	$275,355	$86,095	$80,031	$12,241	$227,803	$681,525	424,419	3,874,583
2019			47.47%	25.89%	$296,482	$86,310	$87,228	$12,657	$227,803	$710,481	413,506	4,288,089
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	45.73%	33.16%	$304,731	$105,371	$88,752	$13,124	$289,455	$801,433	435,927	4,724,016
2021	Anchorage 1x1 6FA	Beluga - 7	55.49%	32.84%	$312,537	$109,985	$94,579	$13,346	$358,886	$889,333	452,092	5,176,107
2022	Mount Spurr	Healy - 1	50.51%	39.74%	$297,344	$129,708	$96,528	$14,024	$407,797	$945,400	449,153	5,625,260
2023			46.37%	39.54%	$327,794	$126,766	$97,214	$4,166	$411,390	$967,329	429,506	6,054,766
2024			45.20%	39.58%	$343,341	$130,139	$109,253	$3,313	$449,770	$1,035,816	429,827	6,484,593
2025	Anchorage 2x1 6FA; Anchorage LM6000; Chakachamna:Chakachamna	GVEA Aurora Purchase - Tier I	41.74%	42.64%	$493,814	$190,671	$158,554	$4,222	$793,649	$1,640,909	636,373	7,120,965
2026		Nikiski	36.05%	42.27%	$529,070	$179,677	$183,279	$5,342	$793,649	$1,691,017	612,902	7,733,868
2027			35.49%	42.50%	$520,677	$182,769	$197,038	$8,551	$795,997	$1,705,032	577,553	8,311,421
2028			34.84%	42.34%	$533,295	$187,338	$219,018	$13,323	$795,997	$1,748,972	553,680	8,865,101
2029			34.21%	41.95%	$539,569	$190,662	$241,299	$16,151	$795,997	$1,783,679	527,726	9,392,827
2030	GVEA 2x1 6FA; GVEA Wind	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	45.01%	43.53%	$509,936	$198,465	$245,385	$17,064	$918,989	$1,889,839	522,556	9,915,383
2031			39.60%	43.40%	$523,101	$201,504	$270,945	$14,951	$915,592	$1,926,094	497,739	10,413,123
2032			38.95%	43.61%	$531,763	$205,894	$291,795	$15,081	$895,542	$1,940,075	468,554	10,881,676
2033			38.30%	43.19%	$541,607	$210,376	$316,985	$15,919	$895,542	$1,980,429	447,009	11,328,685
2034			37.66%	42.72%	$551,169	$214,842	$343,023	$16,747	$895,542	$2,021,323	426,392	11,755,077
2035			37.01%	43.03%	$555,584	$219,480	$368,689	$18,111	$895,542	$2,057,407	405,611	12,160,688
2036			36.38%	42.85%	$560,666	$224,269	$402,574	$5,493	$895,542	$2,088,545	384,813	12,545,500
2037	GVEA LMS100	MLP 3	40.23%	42.52%	$548,121	$231,752	$422,523	$7,019	$904,831	$2,114,246	364,064	12,909,564
2038			39.58%	42.47%	$547,828	$236,660	$454,017	$6,453	$904,831	$2,149,789	345,966	13,255,530
2039			38.94%	42.26%	$570,844	$241,766	$490,794	$8,848	$904,831	$2,217,083	333,454	13,588,984
2040	Anchorage 2x1 6FA; GVEA 1x1 6FA; GVEA 2x1 6FA		43.74%	31.31%	$955,710	$278,383	$819,820	$12,284	$1,190,010	$3,256,208	457,702	14,046,686
2041			43.25%	31.09%	$986,042	$283,245	$876,847	$18,825	$1,181,081	$3,346,041	439,560	14,486,246
2042	GVEA Wind	NPCC	39.49%	32.33%	$995,004	$281,841	$929,314	$21,552	$1,222,216	$3,449,927	423,558	14,909,804
2043			39.01%	32.23%	$1,034,873	$288,300	$1,005,832	$22,199	$1,222,216	$3,573,421	410,018	15,319,822
2044			38.53%	32.09%	$1,075,355	$401,879	$1,082,555	$23,458	$1,173,871	$3,757,118	402,893	15,722,716
2045			38.05%	31.69%	$1,109,371	$300,374	$1,161,219	$22,134	$1,129,819	$3,722,917	373,108	16,095,824
2046	GVEA Wind		37.57%	33.53%	$1,151,293	$316,843	$1,258,017	$22,961	$1,144,476	$3,893,591	364,685	16,460,509
2047			37.09%	33.00%	$1,190,168	$323,306	$1,347,332	$24,452	$1,117,471	$4,002,728	350,381	16,810,890
2048			36.62%	33.07%	$1,239,185	$331,193	$1,461,949	$25,398	$1,105,678	$4,163,403	340,603	17,151,493
2049			36.15%	33.23%	$1,269,655	$338,080	$1,559,594	$6,909	$1,105,678	$4,279,915	327,229	17,478,722
2050			35.67%	32.85%	$1,313,929	$345,174	$1,673,485	$8,724	$996,132	$4,337,444	309,932	17,788,654
2051			35.20%	32.51%	$1,360,215	$352,585	$1,720,933	$11,174	$926,701	$4,371,608	291,938	18,080,591
2052			34.73%	32.77%	$1,411,933	$361,346	$1,775,167	$9,139	$877,791	$4,435,375	276,819	18,357,410
2053			34.26%	32.61%	$1,448,204	$368,777	$1,813,619	$14,889	$874,198	$4,519,685	263,627	18,621,037
2054			33.79%	32.49%	$1,498,727	$377,675	$1,868,803	$22,880	$835,817	$4,603,903	250,971	18,872,008
2055			33.32%	32.40%	$1,544,239	$386,271	$1,919,022	$27,949	$756,353	$4,633,834	236,077	19,108,085
2056			32.86%	32.38%	$1,597,860	$395,323	$1,971,742	$30,133	$756,353	$4,751,411	226,231	19,334,317
2057	HEA LMS100	Cooper Lake	37.07%	32.13%	$1,654,506	$407,185	$2,040,275	$33,288	$796,604	$4,931,857	219,461	19,553,777
2058			35.67%	32.04%	$1,721,950	$415,039	$2,114,255	$33,226	$796,604	$5,081,073	211,309	19,765,086
2059			35.19%	31.25%	$1,775,748	$423,369	$2,170,886	$31,309	$796,604	$5,197,916	202,026	19,967,113
2060	HEA LM6000		37.02%	31.66%	$1,876,300	$437,564	$2,290,856	$32,092	$734,560	$5,371,371	195,110	20,162,223
		Present Value of Costs			7,215,425	2,198,167	3,949,357	149,474	6,649,800		Grand Total	20,162,223

Scenario 2A Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)					
Year	**Anchorage**	**Interior**	**Matanuska**	**Kenai**	**Total Railbelt**
2011	33,725	0	0	4,347	38,073
2012	31,564	0	0	5,343	36,907
2013	31,009	0	0	5,402	36,412
2014	29,719	0	0	4,652	34,370
2015	22,335	0	0	2,653	24,988
2016	21,242	0	0	2,901	24,143
2017	22,336	0	0	1,634	23,970
2018	19,206	9,353	0	1,741	30,299
2019	19,347	8,532	0	1,746	29,625
2020	15,697	8,368	0	1,731	25,797
2021	16,406	7,538	0	1,513	25,457
2022	14,499	7,039	0	1,433	22,971
2023	15,391	7,732	0	1,464	24,586
2024	15,768	7,496	0	1,513	24,777
2025	27,374	7,039	0	1,342	35,755
2026	28,989	7,671	0	907	37,566
2027	29,128	7,695	0	0	36,823
2028	29,273	7,720	0	0	36,992
2029	29,637	7,844	0	0	37,481
2030	21,656	14,225	0	0	35,881
2031	25,908	10,532	0	0	36,439
2032	25,811	10,699	0	0	36,510
2033	26,214	10,719	0	0	36,934
2034	26,659	10,685	0	0	37,344
2035	26,479	10,796	0	0	37,275
2036	26,896	10,928	0	0	37,824
2037	22,325	15,185	0	0	37,510
2038	22,251	15,409	0	0	37,660
2039	22,546	15,324	0	0	37,870
2040	35,623	24,998	0	0	60,621
2041	35,747	24,267	0	0	60,014
2042	35,457	24,128	0	0	59,585
2043	35,422	24,438	0	0	59,860
2044	35,569	24,571	0	0	60,140
2045	35,140	24,891	0	0	60,031
2046	36,415	23,834	0	0	60,249
2047	36,121	24,167	0	0	60,288
2048	36,458	24,321	0	0	60,779
2049	36,055	24,284	0	0	60,339
2050	36,134	24,399	0	0	60,533
2051	36,276	24,487	0	0	60,764
2052	36,850	24,320	0	0	61,170
2053	36,228	24,613	0	0	60,841
2054	36,437	24,627	0	0	61,064
2055	36,257	24,797	0	0	61,053
2056	36,722	24,654	0	0	61,376
2057	35,530	24,335	0	1,797	61,661
2058	35,362	24,558	0	2,422	62,342
2059	34,939	25,059	0	2,440	62,438
2060	33,668	24,847	0	5,605	64,120

Scenario 2A Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Glacier Fork	Anchorage MSW	Anchorage 1x1 6FA	Kenai Wind T Lines	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Anchorage 2x1 6FA	Anchorage LM6000	Chakachamna:Chakachamna	GVEA 2x1 6FA	GVEA Wind T Lines	GVEA LMS100	Anchorage 2x1 6FA	GVEA 1x1 6FA	GVEA 2x1 6FA	GVEA Wind	GVEA Wind	HEA LMS100	HEA LM6000	Generating Unit Cash Flow ($000)
2011	30,468	99,809	175,454	127,935	39,746	0		0	0	0	0	0	0	0	0		0	0	0	0			0	0	473,413
2012				116,563	93,305	65,608																			275,476
2013				119,477	84,604	154,017																			358,098
2014						139,655																			139,655
2015							13,577	18,083																	31,660
2016							125,247	42,450						33,699											201,396
2017								38,492	72,765					26,866											138,123
2018									170,818	76,085				43,273											290,177
2019									154,889	178,613	68,804			79,301											481,607
2020										161,957	161,519			238,340											561,816
2021											146,457			481,537											627,994
2022												197,360		652,793											850,153
2023												393,458	16,120	712,138											1,121,716
2024												130,159	73,474	141,426											345,059
2025																									
2026																									
2027															223,295										223,295
2028															445,161	32,772									477,933
2029															147,263	302,325									449,588
2030																									
2031																									
2032																									
2033																									
2034																	2,260								2,260
2035																	206,133								206,133
2036																	31,138								31,138
2037																		285,836	121,634	285,836					693,306
2038																		569,844	285,539	569,844					1,425,227
2039																		188,510	258,912	188,510					635,931
2040																					41,925				41,925
2041																					386,759				386,759
2042																									
2043																									
2044																						46,278			46,278
2045																						426,910			426,910
2046																									
2047																									
2048																									
2049																									
2050																									
2051																									
2052																									
2053																									
2054																							3,703		3,703
2055																							337,773		337,773
2056																							51,024		51,024
2057																									
2058																								38,257	38,257
2059																								174,368	174,368
2060																									
Total																									11,548,152

Scenario 2A Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Cash Flow ($000)	Total Transmission Project Cash Flow ($000)	Total Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	473,413	79,848	553,260	651	351,604	43,795	34,726	1,106	5,372
2012	275,476	3,365	278,841	1,491	360,422	48,337	37,885	54,846	5,412
2013	358,098	51,272	409,370	3,063	363,525	48,328	37,403	60,377	5,424
2014	139,655	228,409	368,063	5,878	349,083	49,454	36,828	66,100	5,421
2015	31,660	314,097	345,757	10,455	354,267	48,327	39,127	62,615	5,167
2016	201,396	129,804	331,201	12,759	389,510	48,775	40,670	69,555	5,147
2017	138,123	8,812	146,935	11,891	372,476	49,059	43,870	74,394	5,129
2018	290,177	97,549	387,726	12,241	275,355	47,413	38,682	80,031	5,105
2019	481,607	214,570	696,177	12,657	296,482	46,596	39,714	87,228	5,085
2020	561,816	166,433	728,249	13,124	304,731	64,626	40,745	88,752	5,068
2021	627,994	73,715	701,709	13,346	312,537	68,386	41,599	94,579	5,052
2022	850,153	195,732	1,045,885	14,024	297,344	86,668	43,040	96,528	5,081
2023	1,121,716	205,995	1,327,711	4,166	327,794	82,114	44,651	97,214	5,111
2024	345,059	23,643	368,702	3,313	343,341	83,658	46,481	109,253	5,140
2025		10,784	10,784	4,222	493,814	135,630	55,041	158,554	8,459
2026		11,289	11,289	5,342	529,070	138,121	41,556	183,279	8,492
2027	223,295		223,295	8,551	520,677	140,707	42,062	197,038	8,526
2028	477,933		477,933	13,323	533,295	143,349	43,988	219,018	8,569
2029	449,588		449,588	16,151	539,569	146,097	44,566	241,299	8,594
2030			0	17,064	509,936	152,823	45,642	245,385	8,629
2031			0	14,951	523,101	155,099	46,405	270,945	8,663
2032			0	15,081	531,763	158,176	47,718	291,795	8,707
2033			0	15,919	541,607	161,218	49,158	316,985	8,732
2034	2,260		2,260	16,747	551,169	164,248	50,595	343,023	8,767
2035	206,133		206,133	18,111	555,584	167,467	52,013	368,689	8,802
2036	31,138		31,138	5,493	560,666	170,851	53,418	402,574	8,847
2037	693,306		693,306	7,019	548,121	177,317	54,436	422,523	8,873
2038	1,425,227		1,425,227	6,453	547,828	180,675	55,985	454,017	8,908
2039	635,931		635,931	8,848	570,844	184,232	57,534	490,794	8,944
2040	41,925		41,925	12,284	955,710	202,018	76,366	819,820	12,283
2041	386,759		386,759	18,825	986,042	205,701	77,544	876,847	12,301
2042			0	21,552	995,004	195,580	86,261	929,314	12,337
2043			0	22,199	1,034,873	199,431	88,869	1,005,832	12,373
2044	46,278		46,278	23,458	1,075,355	310,643	91,236	1,082,555	12,427
2045	426,910		426,910	22,134	1,109,371	207,543	92,831	1,161,219	12,446
2046			0	22,961	1,151,293	211,768	105,075	1,258,017	12,482
2047			0	24,452	1,190,168	216,084	107,221	1,347,332	12,519
2048			0	25,398	1,239,185	220,612	110,581	1,461,949	12,574
2049			0	6,909	1,269,655	225,244	112,836	1,559,594	12,593
2050			0	8,724	1,313,929	229,911	115,263	1,673,485	12,630
2051			0	11,174	1,360,215	234,521	118,065	1,720,933	12,668
2052			0	9,139	1,411,933	239,458	121,888	1,775,167	12,723
2053			0	14,889	1,448,204	244,515	124,261	1,813,619	12,743
2054	3,703		3,703	22,880	1,498,727	249,622	128,054	1,868,803	12,781
2055	337,773		337,773	27,949	1,544,239	255,048	131,223	1,919,022	12,819
2056	51,024		51,024	30,133	1,597,860	260,323	135,000	1,971,742	12,875
2057			0	33,288	1,654,506	269,102	138,083	2,040,275	12,896
2058	38,257		38,257	33,226	1,721,950	273,035	142,003	2,114,255	12,934
2059	174,368		174,368	31,309	1,775,748	278,917	144,451	2,170,886	12,973
2060			0	32,092	1,876,300	288,064	149,500	2,290,856	13,030
Total	11,548,152	1,815,317	Total of Cash F	14,110,777					

Scenario 2A Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type																				
	Natural Gas		Coal		Nuclear		Fuel Oil		Purchase Power		Hydro		Geothermal		Municipal Solid Waste		Wind		Ocean Tidal	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,548	80	435			251	576	25	210	176	591					15	49		
2012	1,104	3,427	80	493			251	502	25	215	176	593					69	231		
2013	1,041	3,376	80	568			251	494	25	214	176	591					69	226		
2014	1,176	3,145	80	643			251	426	25	214	251	649			22	163	69	227		
2015	1,176	2,439	80	619			251	633	25	212	251	919			22	163	69	227		
2016	822	2,329	80	625			251	720	25	214	251	921			22	163	69	228		
2017	822	2,299	80	616			251	656	25	212	251	919			22	159	99	326		
2018	821	2,381	80	562			189	618	25	213	251	919			22	166	99	326		
2019	821	2,401	80	576			189	578	25	213	251	919			22	163	99	325		
2020	1,103	2,558	80	597					25	210	251	921	50	403	22	163	99	327		
2021	907	2,583	80	568					25	209	251	919	50	401	22	161	99	326		
2022	825	2,241	80	559					25	205	251	919	100	798	22	156	99	326		
2023	743	2,450	80	372					25	206	251	919	100	799	22	158	99	326		
2024	1,100	2,442	53	382					25	207	251	921	100	812	22	159	99	326		
2025	1,101	4,261	53	353					25	212	581	2,517	100	802	22	160	99	325		
2026	1,101	4,516	53	360							581	2,517	100	790	22	152	99	326		
2027	1,059	4,533	53	344							581	2,517	100	816	22	161	99	326		
2028	1,059	4,562	53	349							581	2,524	100	806	22	169	99	326		
2029	1,384	4,624	53	340							581	2,517	100	803	22	154	99	326		
2030	1,384	4,571	53	266							581	2,517	100	794	22	157	149	489		
2031	1,214	4,577	53	295							581	2,517	100	794	22	161	149	489		
2032	1,150	4,589	53	291							581	2,524	100	812	22	172	149	491		
2033	1,150	4,640	53	295							581	2,517	100	802	22	161	149	491		
2034	1,150	4,704	53	296							581	2,517	100	785	22	150	149	490		
2035	1,150	4,697	53	294							581	2,517	100	818	22	162	149	490		
2036	1,245	4,735	53	298							581	2,524	100	813	22	162	149	490		
2037	1,247	4,812	53	258							581	2,517	100	787	22	175	149	491		
2038	1,215	4,839	53	255							581	2,517	100	813	22	160	149	491		
2039	2,011	4,870	53	256							581	2,517	100	807	22	160	149	491		
2040	2,011	8,001	53	272							581	2,524	100	805	22	163	149	499		
2041	2,011	7,943	53	278							581	2,517	100	800	22	162	149	489		
2042	2,011	7,741	53	276							581	2,517	100	805	22	163	199	653		
2043	1,948	7,764	53	283							581	2,517	100	803	22	163	199	655		
2044	1,948	7,809	53	276							581	2,524	100	804	22	152	199	656		
2045	1,948	7,778	53	277							581	2,517	100	761	22	158	199	655		
2046	1,948	7,698	53	282							581	2,517	100	827	22	177	249	820		
2047	1,948	7,706	53	276							581	2,517	100	802	22	147	249	817		
2048	1,948	7,761	53	274							581	2,524	100	804	22	163	249	822		
2049	1,948	7,724	53	259							581	2,517	100	828	22	174	249	820		
2050	1,948	7,744	53	247							581	2,517	100	802	22	162	249	820		
2051	1,948	7,757	53	251							581	2,517	100	781	22	151	249	820		
2052	1,948	7,822	53	245							581	2,524	100	814	22	163	249	821		
2053	1,948	7,765	53	250							581	2,517	100	804	22	168	249	817		
2054	1,948	7,790	53	261							581	2,517	100	804	22	162	249	820		
2055	1,948	7,789	53	264							581	2,517	100	798	22	169	249	820		
2056	1,948	7,841	53	260							581	2,524	100	812	22	162	249	821		
2057	2,046	7,748	53	280							581	2,517	100	794	22	162	249	820		
2058	2,046	7,802	53	283							562	2,476	100	834	22	167	249	817		
2059	2,093	7,761	53	290							562	2,476	100	758	22	148	249	817		
2060	2,093	7,725	53	304							562	2,482	100	806	22	163	249	821		

APPENDIX G

DETAILED RESULTS – SCENARIO 2B

Scenario 2B Plan - P50 Natural Gas Forecast

Year	Additions	Retirements	Reserve Margin (%)	Renewable Generation (%)	Fuel Costs ($000)	Total O&M Costs ($000)	CO2 Costs ($000)	DSM Costs ($000)	Annual Capital Fixed Charges ($000)	Total Annual Costs ($000)	Present Value of Annual Costs ($000)	Cumulative Present Value ($000)
2011	Nikiski Wind; HCCP	Beluga - 1; Beluga - 2; International - 1 International - 2	55.82%	11.92%	$351,493	$78,517	$0	$651	$12,326	$442,987	$442,987	$442,987
2012	Fire Island	International - 3	47.47%	15.18%	$360,816	$86,324	$54,859	$1,491	$40,350	$543,841	508,262	951,249
2013			44.98%	14.98%	$373,571	$86,176	$60,950	$3,063	$40,350	$564,109	492,714	1,443,963
2014	Glacier Fork; Anchorage MSW	Beluga - 3; Beluga - 6/8; Beluga - 7/8; Bernice - 2; Bernice - 3	56.46%	18.90%	$355,455	$86,614	$66,555	$5,878	$88,695	$603,197	492,389	1,936,352
2015	Anchorage 1x1 6FA		55.23%	24.72%	$355,881	$87,506	$62,699	$10,455	$132,747	$649,288	495,339	2,431,691
2016			59.21%	24.60%	$391,713	$89,457	$69,675	$12,759	$172,296	$735,900	524,686	2,956,377
2017	Kenai Wind	Beluga - 5; NP1	60.42%	26.14%	$357,236	$92,343	$73,636	$11,891	$216,010	$751,117	500,501	3,456,878
2018	GVEA 1X1 NPole Retrofit	NP2	53.81%	26.11%	$275,319	$86,055	$80,008	$12,241	$227,803	$681,426	424,358	3,881,236
2019			47.47%	25.89%	$296,301	$86,307	$87,426	$12,657	$227,803	$710,494	413,514	4,294,750
2020	Mount Spurr	Beluga - 6; MLP 5; MLP 5/6; MLP 7/6	45.73%	33.15%	$313,065	$104,598	$88,585	$13,124	$289,455	$808,827	439,949	4,734,699
2021	Anchorage 1x1 6FA	Beluga - 7	55.49%	32.84%	$319,829	$107,286	$95,077	$13,346	$358,886	$894,423	454,679	5,189,378
2022	Mount Spurr	Healy - 1	50.51%	39.73%	$303,446	$126,760	$96,696	$14,024	$407,797	$948,722	450,731	5,640,109
2023			46.37%	39.57%	$338,009	$123,561	$101,020	$4,166	$411,390	$978,146	434,308	6,074,418
2024			45.20%	39.43%	$354,550	$125,350	$111,759	$3,313	$449,770	$1,044,742	433,531	6,507,949
2025	Chakachamna:Chakachamna; GVEA Wind; Low Watana (Non-Expandable)	GVEA Aurora Purchase - Tier I	59.97%	65.83%	$327,284	$177,358	$109,666	$4,222	$1,387,377	$2,005,906	777,925	7,285,874
2026		Nikiski	54.19%	65.70%	$355,930	$168,282	$129,694	$5,342	$1,387,377	$2,046,625	741,791	8,027,664
2027			53.56%	65.52%	$354,583	$171,861	$141,138	$8,551	$1,389,726	$2,065,860	699,778	8,727,443
2028			52.82%	65.41%	$362,315	$175,663	$156,239	$13,323	$1,389,726	$2,097,266	663,941	9,391,383
2029			52.11%	65.12%	$370,599	$179,717	$173,790	$16,151	$1,389,726	$2,129,983	630,185	10,021,568
2030	GVEA Wind	DPP - 6; MLP 7; MLP 8; Zen1; Zen2	38.93%	66.50%	$324,824	$188,512	$170,425	$17,064	$1,426,241	$2,127,066	588,151	10,609,720
2031			33.55%	66.21%	$287,389	$185,763	$167,924	$14,951	$1,422,844	$2,078,872	537,220	11,146,940
2032			32.93%	66.42%	$291,077	$190,378	$181,400	$15,081	$1,402,794	$2,080,731	502,524	11,649,463
2033			32.30%	66.03%	$294,120	$194,462	$195,275	$15,919	$1,402,794	$2,102,569	474,578	12,124,041
2034			31.69%	65.66%	$300,588	$198,861	$213,080	$16,747	$1,402,794	$2,132,070	449,754	12,573,794
2035			31.08%	65.94%	$303,932	$203,534	$228,670	$18,111	$1,402,794	$2,157,041	425,253	12,999,048
2036			30.47%	65.48%	$304,372	$207,945	$248,912	$5,493	$1,402,794	$2,169,516	399,732	13,398,779
2037	Anchorage 2x1 6FA; Kenai Wind	MLP 3	49.65%	64.70%	$337,305	$221,770	$284,317	$7,019	$1,512,696	$2,363,107	406,916	13,805,696
2038			48.95%	64.92%	$335,376	$226,742	$306,870	$6,453	$1,512,696	$2,388,138	384,324	14,190,020
2039			48.26%	64.44%	$355,211	$231,941	$335,719	$8,848	$1,512,696	$2,444,416	367,646	14,557,665
2040	Anchorage 2x1 6FA; Kenai Wind; GVEA 2x1 6FA		42.24%	49.31%	$726,114	$261,828	$658,141	$12,284	$1,757,343	$3,415,710	480,122	15,037,787
2041			41.75%	49.68%	$749,303	$266,953	$705,228	$18,825	$1,748,414	$3,488,723	458,303	15,496,090
2042	GVEA Wind	NPCC	38.00%	50.31%	$764,582	$266,145	$750,700	$21,552	$1,789,549	$3,592,529	441,066	15,937,156
2043			37.52%	50.68%	$785,633	$272,478	$804,064	$22,199	$1,789,549	$3,673,924	421,550	16,358,706
2044			37.04%	50.66%	$815,768	$279,122	$870,100	$23,458	$1,741,204	$3,729,652	399,948	16,758,654
2045			36.57%	50.24%	$852,178	$285,535	$937,781	$22,134	$1,663,223	$3,760,851	376,910	17,135,564
2046	GVEA LM6000		38.46%	50.01%	$890,057	$295,214	$1,020,949	$22,961	$1,639,640	$3,868,823	362,365	17,497,930
2047			37.99%	50.14%	$918,798	$302,026	$1,096,440	$24,452	$1,612,635	$3,954,351	346,146	17,844,075
2048			37.51%	49.97%	$957,221	$309,807	$1,185,769	$25,398	$1,600,842	$4,079,038	333,701	18,177,777
2049			37.04%	50.05%	$989,273	$316,912	$1,280,071	$6,909	$1,600,842	$4,194,007	320,661	18,498,437
2050			36.55%	49.77%	$1,024,435	$324,240	$1,376,949	$8,724	$1,502,675	$4,237,023	302,756	18,801,194
2051			36.08%	49.82%	$1,061,115	$331,990	$1,416,126	$11,174	$1,433,244	$4,253,649	284,060	19,085,254
2052			35.61%	49.47%	$1,106,193	$339,840	$1,464,813	$9,139	$1,384,333	$4,304,318	268,639	19,353,893
2053			35.14%	49.47%	$1,134,383	$347,466	$1,496,925	$14,889	$1,380,740	$4,374,402	255,153	19,609,046
2054			34.66%	49.38%	$1,177,971	$356,121	$1,545,993	$22,880	$1,342,360	$4,445,327	242,327	19,851,373
2055			34.19%	49.25%	$1,223,021	$364,747	$1,593,720	$27,949	$1,329,430	$4,538,867	231,239	20,082,612
2056			33.72%	49.23%	$1,262,068	$373,263	$1,640,623	$30,133	$1,329,430	$4,635,516	220,713	20,303,325
2057	Anchorage LMS100	Cooper Lake	37.93%	49.04%	$1,322,441	$385,797	$1,701,489	$33,288	$1,343,638	$4,786,652	212,999	20,516,324
2058			36.53%	48.61%	$1,372,591	$445,852	$1,765,190	$33,226	$1,343,638	$4,960,497	206,295	20,722,619
2059			36.04%	48.57%	$1,430,714	$518,902	$1,826,864	$31,309	$1,343,638	$5,151,426	200,219	20,922,838
2060			35.57%	48.39%	$1,480,273	$412,965	$1,879,232	$32,092	$1,315,593	$5,120,155	185,985	21,108,823
			Present Value of Costs		**6,024,495**	**2,107,805**	**3,188,181**	**149,474**	**9,638,868**		**Grand Total**	**21,108,823**

Scenario 2B Plan - P50 Natural Gas Forecast

Annual Natural Gas Usage (mmBtu)					
Year	Anchorage	Interior	Matanuska	Kenai	Total Railbelt
2011	33,729	0	0	4,344	38,073
2012	31,544	0	0	5,351	36,895
2013	30,782	0	0	5,745	36,527
2014	29,533	0	0	4,978	34,510
2015	22,300	0	0	2,660	24,960
2016	21,206	0	0	2,931	24,137
2017	21,504	0	0	2,718	24,222
2018	18,121	9,333	0	2,846	30,300
2019	18,265	8,505	0	2,876	29,646
2020	15,363	7,447	0	3,213	26,023
2021	18,274	5,312	0	2,521	26,108
2022	16,131	5,075	0	2,341	23,547
2023	17,306	5,444	0	2,485	25,235
2024	18,090	4,863	0	2,709	25,663
2025	15,198	6,048	0	2,135	23,381
2026	16,286	6,683	0	1,623	24,592
2027	17,378	6,898	0	0	24,276
2028	17,654	6,802	0	0	24,456
2029	17,734	7,075	0	0	24,809
2030	13,735	6,592	0	0	20,327
2031	13,861	5,722	0	0	19,583
2032	14,037	5,482	0	0	19,518
2033	13,932	5,653	0	0	19,585
2034	14,126	5,736	0	0	19,862
2035	14,240	5,650	0	0	19,890
2036	14,623	5,370	0	0	19,993
2037	17,352	5,224	0	0	22,576
2038	17,154	5,353	0	0	22,507
2039	17,527	5,499	0	0	23,026
2040	31,944	14,295	0	0	46,239
2041	31,757	14,198	0	0	45,956
2042	32,415	12,885	0	0	45,300
2043	32,242	12,717	0	0	44,960
2044	32,303	12,810	0	0	45,113
2045	32,857	12,772	0	0	45,629
2046	32,801	13,321	0	0	46,121
2047	32,648	13,422	0	0	46,070
2048	33,107	13,360	0	0	46,467
2049	32,822	13,701	0	0	46,523
2050	32,986	13,694	0	0	46,679
2051	33,318	13,588	0	0	46,906
2052	33,518	13,900	0	0	47,418
2053	33,414	13,736	0	0	47,150
2054	33,741	13,762	0	0	47,503
2055	33,901	13,984	0	0	47,885
2056	34,108	13,890	0	0	47,998
2057	34,725	14,124	0	0	48,849
2058	35,127	14,122	0	0	49,249
2059	35,493	14,393	0	0	49,885
2060	35,785	14,392	0	0	50,177

Scenario 2B Plan - P50 Natural Gas Forecast

Cash Flow per Generating Unit Addition

Year	Nikiski Wind	HCCP	Fire Island	Glacier Fork	Anchorage MSW	Anchorage 1x1 6FA	Kenai Wind T Lines	GVEA 1X1 NPole Retrofit	Mount Spurr T	Anchorage 1x1 6FA	Mount Spurr	Chakachamna:Chakachamna	GVEA Wind T Lines	Low Watana (Non-Expandable)	GVEA Wind	Anchorage 2x1 6FA	Kenai Wind	Anchorage 2x1 6FA	Kenai Wind	GVEA 2x1 6FA	GVEA Wind	GVEA LM6000	Anchorage LMS100	Generating Unit Cash Flow ($000)
2011	30,468	99,809	175,454	127,935	39,746	0		0	0	0	0	0		48,624		0		0		0		0	0	522,036
2012				116,563	93,305	65,608								32,371										307,847
2013				119,477	84,604	154,017								30,231										388,329
2014						139,655								41,025										180,680
2015							13,577	18,083						43,102										74,761
2016							125,247	42,450				33,699		503,963										705,359
2017								38,492	72,765			26,866		529,476										667,599
2018									170,818	76,085		43,273		711,878										1,002,055
2019									154,889	178,613	68,804	79,301		840,242										1,321,849
2020										161,957	161,519	238,340		882,779										1,444,596
2021											146,457	481,537		721,781										1,349,775
2022												652,793		758,321										1,411,114
2023												712,138	28,966	796,711										1,537,815
2024												141,426	267,211	39,033										447,670
2025																								
2026																								
2027																								
2028															31,174									31,174
2029															287,577									287,577
2030																								
2031																								
2032																								
2033																								
2034																265,427								265,427
2035																529,157	22,233							551,390
2036																175,050	205,103							380,153
2037																		285,836		285,836				571,672
2038																		569,844	23,943	569,844				1,163,631
2039																		188,510	220,874	188,510				597,893
2040																					41,925			41,925
2041																					386,759			386,759
2042																								
2043																								
2044																						27,076		27,076
2045																						123,405		123,405
2046																								
2047																								
2048																								
2049																								
2050																								
2051																								
2052																								
2053																								
2054																							3,703	3,703
2055																							337,773	337,773
2056																							51,024	51,024
2057																								
2058																								
2059																								
2060																								
Total																								16,182,068

Scenario 2B Plan - P50 Natural Gas Forecast

Summary of Cash Flows and Production Costs

Year	Total Generating Unit Cash Flow ($000)	Total Transmission Project Cash Flow ($000)	Total Cash Flow ($000)	DSM Costs ($000)	Fuel Cost ($000)	Fixed O&M ($000)	Variable O&M ($000)	CO2 Costs ($000)	Energy Requirements After DSM (GWh)
2011	522,036	79,848	601,884	651	351,493	43,795	34,722		5,372
2012	307,847	3,365	311,212	1,491	360,816	48,337	37,987	54,859	5,412
2013	388,329	51,272	439,601	3,063	373,571	48,328	37,848	60,950	5,424
2014	180,680	228,409	409,088	5,878	355,455	49,454	37,160	66,555	5,421
2015	74,761	314,097	388,859	10,455	355,881	48,327	39,179	62,699	5,167
2016	705,359	129,804	835,164	12,759	391,713	48,775	40,682	69,675	5,147
2017	667,599	8,812	676,411	11,891	357,236	49,059	43,284	73,636	5,129
2018	1,002,055	97,549	1,099,604	12,241	275,319	47,413	38,642	80,008	5,105
2019	1,321,849	214,570	1,536,419	12,657	296,301	46,596	39,711	87,426	5,085
2020	1,444,596	166,433	1,611,028	13,124	313,065	64,626	39,972	88,585	5,068
2021	1,349,775	73,715	1,423,490	13,346	319,829	68,386	38,900	95,077	5,052
2022	1,411,114	198,726	1,609,841	14,024	303,446	86,668	40,092	96,696	5,081
2023	1,537,815	234,141	1,771,956	4,166	338,009	82,114	41,446	101,020	5,111
2024	447,670	52,388	500,059	3,313	354,550	83,658	41,692	111,759	5,140
2025		10,784	10,784	4,222	327,284	127,467	49,890	109,666	8,459
2026		11,289	11,289	5,342	355,930	129,959	38,323	129,694	8,492
2027		0	0	8,551	354,583	132,545	39,316	141,138	8,526
2028	31,174	0	31,174	13,323	362,315	135,187	40,476	156,239	8,569
2029	287,577	0	287,577	16,151	370,599	137,934	41,783	173,790	8,594
2030		0	0	17,064	324,824	139,466	49,046	170,425	8,629
2031		0	0	14,951	287,389	141,743	44,020	167,924	8,663
2032		0	0	15,081	291,077	144,820	45,559	181,400	8,707
2033		0	0	15,919	294,120	147,862	46,600	195,275	8,732
2034	265,427	0	265,427	16,747	300,588	150,891	47,970	213,080	8,767
2035	551,390	0	551,390	18,111	303,932	154,111	49,423	228,670	8,802
2036	380,153	0	380,153	5,493	304,372	157,495	50,450	248,912	8,847
2037	571,672	0	571,672	7,019	337,305	165,776	55,994	284,317	8,873
2038	1,163,631	0	1,163,631	6,453	335,376	169,134	57,608	306,870	8,908
2039	597,893	0	597,893	8,848	355,211	172,691	59,250	335,719	8,944
2040	41,925	0	41,925	12,284	726,114	177,577	84,251	658,141	12,283
2041	386,759	0	386,759	18,825	749,303	181,035	85,917	705,228	12,301
2042		0	0	21,552	764,582	170,684	95,461	750,700	12,337
2043		0	0	22,199	785,633	174,300	98,178	804,064	12,373
2044	27,076	0	27,076	23,458	815,768	178,239	100,883	870,100	12,427
2045	123,405	0	123,405	22,134	852,178	181,923	103,612	937,781	12,446
2046		0	0	22,961	890,057	188,926	106,288	1,020,949	12,482
2047		0	0	24,452	918,798	192,983	109,044	1,096,440	12,519
2048		0	0	25,398	957,221	197,244	112,564	1,185,769	12,574
2049		0	0	6,909	989,273	201,602	115,310	1,280,071	12,593
2050		0	0	8,724	1,024,435	205,989	118,251	1,376,949	12,630
2051		0	0	11,174	1,061,115	210,312	121,678	1,416,126	12,668
2052		0	0	9,139	1,106,193	214,955	124,885	1,464,813	12,723
2053		0	0	14,889	1,134,383	219,711	127,755	1,496,925	12,743
2054	3,703	0	3,703	22,880	1,177,971	224,508	131,614	1,545,993	12,781
2055	337,773	0	337,773	27,949	1,223,021	229,617	135,130	1,593,720	12,819
2056	51,024	0	51,024	30,133	1,262,068	234,567	138,695	1,640,623	12,875
2057		0	0	33,288	1,322,441	243,013	142,783	1,701,489	12,896
2058		0	0	33,226	1,372,591	300,121	145,731	1,765,190	12,934
2059		0	0	31,309	1,430,714	368,398	150,504	1,826,864	12,973
2060		0	0	32,092	1,480,273	257,872	155,093	1,879,232	13,030
Total	16,182,068	1,875,203	Total of Cash Flows & D	18,804,578					

Scenario 2B Plan - P50 Natural Gas Forecast: Cumulative Capacity and Energy by Resource Type																				
	Natural Gas		**Coal**		**Nuclear**		**Fuel Oil**		**Purchase Power**		**Hydro**		**Geothermal**		**Municipal Solid Waste**		**Wind**		**Ocean Tidal**	
Year	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)
2011	1,104	3,547	80	435			251	576	25	210	176	591					15	49		
2012	1,104	3,424	80	494			251	505	25	215	176	593					69	231		
2013	1,041	3,360	80	567			251	512	25	214	176	591					69	226		
2014	1,176	3,140	80	643			251	434	25	214	251	649			22	163	69	227		
2015	1,176	2,434	80	620			251	638	25	212	251	919			22	163	69	227		
2016	822	2,323	80	625			251	726	25	214	251	921			22	163	69	228		
2017	822	2,355	80	615			251	602	25	212	251	919			22	159	99	326		
2018	821	2,383	80	562			189	618	25	213	251	919			22	166	99	326		
2019	821	2,399	80	581			189	576	25	213	251	919			22	163	99	325		
2020	1,103	2,594	80	574					25	190	251	921	50	403	22	162	99	327		
2021	907	2,611	80	552					25	178	251	919	50	401	22	161	99	326		
2022	825	2,274	80	542					25	175	251	919	100	797	22	157	99	326		
2023	743	2,456	80	398					25	167	251	919	100	800	22	159	99	326		
2024	743	2,505	53	381					25	155	251	921	100	811	22	151	99	326		
2025	743	2,303	53	322					25	188	1,181	4,435	100	790	22	158	149	489		
2026	743	2,485	53	352							1,181	4,450	100	788	22	155	149	491		
2027	701	2,519	53	348							1,181	4,448	100	798	22	153	149	491		
2028	701	2,546	53	349							1,181	4,466	100	796	22	155	149	491		
2029	701	2,583	53	344							1,181	4,451	100	802	22	154	149	490		
2030	701	2,416	53	355							1,181	4,453	100	795	22	146	199	653		
2031	531	2,402	53	354							1,181	4,478	100	772	22	139	199	653		
2032	467	2,401	53	360							1,181	4,484	100	802	22	148	199	656		
2033	467	2,408	53	359							1,181	4,480	100	792	22	144	199	655		
2034	467	2,446	53	367							1,181	4,476	100	785	22	144	199	655		
2035	467	2,450	53	361							1,181	4,488	100	819	22	147	199	655		
2036	777	2,455	53	370							1,181	4,487	100	801	22	153	199	654		
2037	777	2,687	53	340							1,181	4,497	100	687	22	103	229	754		
2038	745	2,689	53	344							1,181	4,479	100	737	22	114	229	754		
2039	1,380	2,753	53	346							1,181	4,482	100	715	22	110	229	754		
2040	1,380	5,850	53	363							1,181	4,495	100	768	22	155	259	867		
2041	1,380	5,805	53	363							1,181	4,496	100	834	22	161	259	850		
2042	1,380	5,732	53	375							1,181	4,510	100	771	22	144	309	1,014		
2043	1,317	5,687	53	377							1,181	4,513	100	816	22	158	309	1,018		
2044	1,317	5,719	53	379							1,181	4,527	100	809	22	174	309	1,019		
2045	1,317	5,785	53	376							1,181	4,517	100	807	22	144	309	1,017		
2046	1,364	5,822	53	374							1,181	4,518	100	768	22	170	309	1,017		
2047	1,364	5,813	53	375							1,181	4,531	100	801	22	164	309	1,014		
2048	1,364	5,874	53	377							1,181	4,547	100	802	22	146	309	1,019		
2049	1,364	5,868	53	374							1,181	4,535	100	809	22	172	309	1,018		
2050	1,364	5,890	53	375							1,181	4,537	100	801	22	160	309	1,018		
2051	1,364	5,916	53	376							1,181	4,541	100	827	22	157	309	1,017		
2052	1,364	5,984	53	375							1,181	4,565	100	786	22	154	309	1,019		
2053	1,364	5,962	53	377							1,181	4,556	100	801	22	161	309	1,014		
2054	1,364	6,012	53	380							1,181	4,559	100	802	22	161	309	1,018		
2055	1,364	6,045	53	376							1,181	4,561	100	801	22	161	309	1,018		
2056	1,364	6,069	53	378							1,181	4,577	100	794	22	176	309	1,019		
2057	1,462	6,087	53	379							1,181	4,569	100	818	22	146	309	1,017		
2058	1,462	6,145	53	381							1,162	4,544	100	779	22	176	309	1,014		
2059	1,462	6,231	53	382							1,162	4,547	100	803	22	161	309	1,014		
2060	1,462	6,267	53	384							1,162	4,558	100	805	22	147	309	1,019		