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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:

Robert M. Pickett, Chairman
Stephen McAlpine
Rebecca L. Pauli
Norman Rokeberg
Janis W. Wilson

In the Matter of the Tariff Revision Designated as TA453-1 Filed by ALASKA ELECTRIC LIGHT AND POWER COMPANY

TA453-1

PREFILED DIRECT TESTIMONY OF CHRISTY M. YEAROUS

Q1. Please state your name, business address and occupation.

A1. My name is Christy M. Yearous. My business address is 5601 Tonsgard Court, Juneau, Alaska 99801. I am a Vice President and the Generation Engineer of Alaska Electric Light and Power Company ("AELP"). I have been in this position since November 2015. Prior to that, I was Assistant Generation Engineer, Electrical. I have been employed by AELP since January 2002.

Q2. What is your educational background and work experience?

A2. Please see my resume, which is attached to this testimony as Exhibit CMY-1.

Q3. What is the purpose of your testimony?

A3. As the head of the generation department at AELP, I am responsible for the operation, maintenance, construction, safety, and security of all power generation facilities, including the Snettisham Hydroelectric Project ("Snettisham"). I am providing testimony related to the addition of a 25 megawatt ("MW") backup diesel-fired generation plant ("New Backup Unit") to AELP's existing fleet of diesel-fired backup generation.

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Q4. Please provide a summary of AELP's electrical system.

A4. AELP is an isolated electric system that is fortunate to meet essentially 100% of its electric demand with hydroelectric power ("hydro"). However, due to (1) the fact that most of AELP's hydro resources are located at remote sites connected by transmission lines that are vulnerable to disruption, and (2) the unpredictable nature of precipitation to fuel the hydro projects, AELP long ago installed diesel-fired backup generation with sufficient capacity to provide electric service to its customers in the event of a lack of, or the inability to deliver, hydro power. Exhibit CMY-2 shows the location of AELP's hydro and backup generation resources.

Q5. Please describe AELP's reliability policy regarding standby (backup) generation.

A5. AELP's policy is to have sufficient backup diesel generation available for AELP to be able to serve all of its firm loads in the event that the Snettisham transmission line and AELP's largest diesel unit are out of service during the winter peak. This provides an "N-1" contingency in the event of a unit failure. Planning for an N-1 contingency is a standard for reliability in the provision of electric service.

Q6. Has AELP's standby generation policy proven to be necessary?

A6. Yes. The need for this contingency was proven during an avalanche in April 2008, when a 1.5 mile stretch of the Snettisham 138 kilovolt ("kV") transmission line was damaged. At that time, AELP's Lake Dorothy Hydroelectric Project ("Lake Dorothy") was not yet online, and Snettisham supplied approximately 85% of Juneau's energy. Without the ability to bring the Snettisham energy to town, AELP needed its existing standby generation equipment to meet the energy needs of the community. Repairs to the transmission line took approximately six weeks. During that time, the largest standby

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unit failed due to a cracked turbine blade and was out of service for approximately two weeks, one of AELP's electro-motive diesel engines suffered core damage and was out of service for approximately three weeks, and another of the diesel-fired turbines had a liquid fuel valve fail and was out of service for approximately two days for installation of a new valve and fuel control.

Another example of the need for the N-1 contingency is a series of events that occurred in 1989. It was this series of events that led AELP to modify its contingency plan to account for an N-1 contingency.

On January 25, 1989, a snowslide damaged a Snettisham transmission tower. Shortly thereafter, power to Juneau was restored with standby diesel generation. Later that same day, another outage occurred when Alaska Department of Transportation crews triggered a large avalanche after "shooting" the avalanche zone above Thane Road. That avalanche came down in three separate areas, destroying three structures and conductor on the upper 69 kV transmission line, and conductor on the lower (redundant) transmission line. The lower line structures held, due to breakaway links that had previously been installed on the conductor through the slide area. Power was again restored with diesel generation, but due to the damage from the Thane Road avalanche, energy from the Annex Creek Hydroelectric Project was no longer available to the majority of the Juneau customers. Energy available from two of the standby units was limited due to an earlier failure of a transformer. No energy was available from the Gold Creek Hydroelectric Project because it is a run-of-the-river project that typically does not have water in the winter.

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In the week following the two outages on January 25, 1989, temperatures in Juneau were below zero in some locations, with strong Taku winds gusting as high as 70 to 80 mph in exposed areas. Restoration of the transmission lines was difficult due to the adverse weather conditions.

On January 30, 1989, one of the standby units failed with damage to its stator coil windings. A standby unit that belonged to Glacier Highway Electric Association (which no longer exists) was used to supplement AELP's units, and generation available on that day was just slightly above the peak demand. The possibility of rolling blackouts, although never realized, was a major concern. Power from Snettisham was restored on February 1, 1989.

Another benefit of AELP's standby generation system is that it allows AELP to adequately test and maintain critical transmission facilities to avoid disruption of hydro energy delivery. For example, AELP periodically tests the original 138 kV submarine cables that cross the Taku Inlet to verify that they are serviceable spares in the event of a failure of more than one of the "new" submarine cables. AELP also rotates the spare "new" cable periodically to validate that all four cables are serviceable. This test requires a complete outage of the 138 kV line, during which the standby generation equipment is used to provide electric service to customers.

Q7. Why is AELP adding the New Backup Unit to its existing standby fleet?

A7. As is explained in greater detail in Exhibit CMY-3 (R.W. Beck's AELP Standby Generation Study) and Exhibit CMY-4 (AELP Standby Generator Impact Study), there are three primary reasons. First, AELP's peak firm load exceeds the capacity of AELP's

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existing standby generation system with its largest standby unit out of service. Thus, AELP's standby generation system no longer meets the N-1 contingency set forth in the AELP standby generation policy. The New Backup Unit will restore AELP's ability to meet the N-1 contingency.

Second, apart from hydroelectric supply or delivery disruptions, system disturbances in Juneau could preclude AELP's existing standby generation plants from being capable of serving local peak loads. That type of contingency is discussed in Scenario 2 of AELP's Standby Generator Impact Study (Exhibit CMY-4, Section 5.2). The New Backup Unit will ensure restoration of service to all customers in that type of contingency.

Third, the New Backup Unit will enhance the reliability, emissions compliance, and useful life of AELP's standby generation system. The backbone of AELP's existing standby generation system are Pratt & Whitney FT-4 type aero-derivative turbines. These three units were purchased by AELP as used units having original manufacture dates of 1966, 1968 and 1974. Over the last 10 years AELP has seen increasing numbers of age-related failures of components within these units. The New Backup Unit will reduce AELP's vulnerability to such age-related failures, better ensure that AELP's operation of its standby generation system complies with current and future emissions standards, and extend the life of AELP's standby generation system as a whole.

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Q8. Why doesn't AELP just build more hydro projects for backup instead of using diesel?

A8. As is explained in Section 3 of the AELP Standby Generator Impact Study (Exhibit CMY-4), the potential hydroelectric projects that have been identified would utilize the same transmission system and would be subject to the same outage risks.

Q9. There have been statements from the public that the New Backup Unit is being built to serve an industrial load. Is that the case?

A9. No. It appears that that statement is based on the fact that AELP has named the New Backup Unit the "Industrial Power Plant." However, that name merely reflects that the plant is located near Industrial Boulevard in Juneau and has been named for its location. The plant is being constructed as a backup source of power for AELP's firm customers.

AELP plans to run the New Backup Unit similarly to how it operates its existing standby generation units. For example, over the 10 year period of 2006 through 2015, AELP has generated on average 2.2% of annual energy with existing standby generation equipment. This average includes 2008 and 2009 when 13.8% and 4.6%, respectively, of AELP's energy was generated with the standby generation units due to the avalanches on the Snettisham line. Over the five-year period from 2011 through 2015, this average dropped to 0.3%.

Q10. Apart from the New Backup Unit, has AELP invested in other efforts to enhance the reliability of its hydro resources?

A10. Yes. After the 2008 and 2009 avalanches on the Snettisham transmission line, AELP installed avalanche diversion structures on the three most vulnerable transmission towers

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and removed one tower completely. AELP now engages in active avalanche control work, using state of the art equipment.

As mentioned earlier, AELP also periodically tests the original 138 kV submarine cables that cross the Taku Inlet and rotates the spare "new" cable periodically to validate that all of the submarine cables are serviceable.

AELP also has a redundant section of transmission line through the Thane avalanche area. AELP undergrounded the upper transmission line through this section, and installed additional breakaway links. AELP has installed a redundant transmission loop in the airport area. AELP maintains an inventory of spare towers, poles, conductors and parts.

Q11. Does this conclude your testimony?

A11. Yes.

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255 E. FIREWEED LANE, SUITE 200
ANCHORAGE, ALASKA 99503-2025
(907) 277-1604

Christina (Christy) Yearous
Alaska Electric Light & Power
5601 Tonsgard Court
Juneau, Alaska 99801

PROFESSIONAL CERTIFICATIONS:

Professional Engineer, Electrical, State of Alaska
Professional Engineer, Electrical, State of Oregon

EMPLOYMENT HISTORY:

Alaska Electric Light & Power
Juneau, AK
VP GENERATION, GENERATION ENGINEER — 2015 to Present
ASSISTANT POWER GENERATION ENGINEER — 2002 to 2015

Responsible for operation, maintenance and modifications to all AEL&P generation facilities, including five hydroelectric projects. Project lead for relicensing of the Salmon Creek and Annex Creek Hydroelectric Project, P-2307. Responsible for des procurement and testing of solutions for dam monitoring. Responsible for review of maintenance records and development of training programs for operators, maintenan crews and Duty Engineers. Part of AEL&P's Duty Engineer program. Participant i the Salmon Creek Dam Emergency Action Plan reviews as well as functional exerci

Emerson Process Management (ETI) — 1998 to 2002
Portland, OR
TECHNICAL SPECIALIST

Responsible for performing power systems studies and analysis, SEMI S2-93A and SEMI S2-0200 equipment evaluations, field evaluation inspections of unique equipment, acceptance and maintenance testing, troubleshooting and repairs on low high voltage equipment. Testing includes such equipment as ground fault systems, medium voltage cables, protective relays, low and medium voltage circuit breakers, transformers, infrared surveys.

Fluor Daniel — 1996 to 1998
Boulder, CO
SYSTEMS ENGINEER

Job responsibilities included systems engineering with primary responsibility for UPS/EPS, medium voltage and control systems at the IBM Boulder DataCenter. Project estimation, design, scheduling and management. Developing preventative maintenance programs, performing system assessments, including Y2K compliance.

Dowell Schlumberger — 1995 to 1996
Denver, CO
FIELD ENGINEER

Duties included job design, scheduling and execution, location QA/QC, equipment maintenance, hazardous materials training and field safety.

EDUCATION:

MSEE, University of Wyoming
Department of Energy and NASA Research Grants
Thesis Topic: Small Signal Stability of Power Systems
1995

BSEE, Power and Control Systems with Honors,
University of Alaska Fairbanks
1993

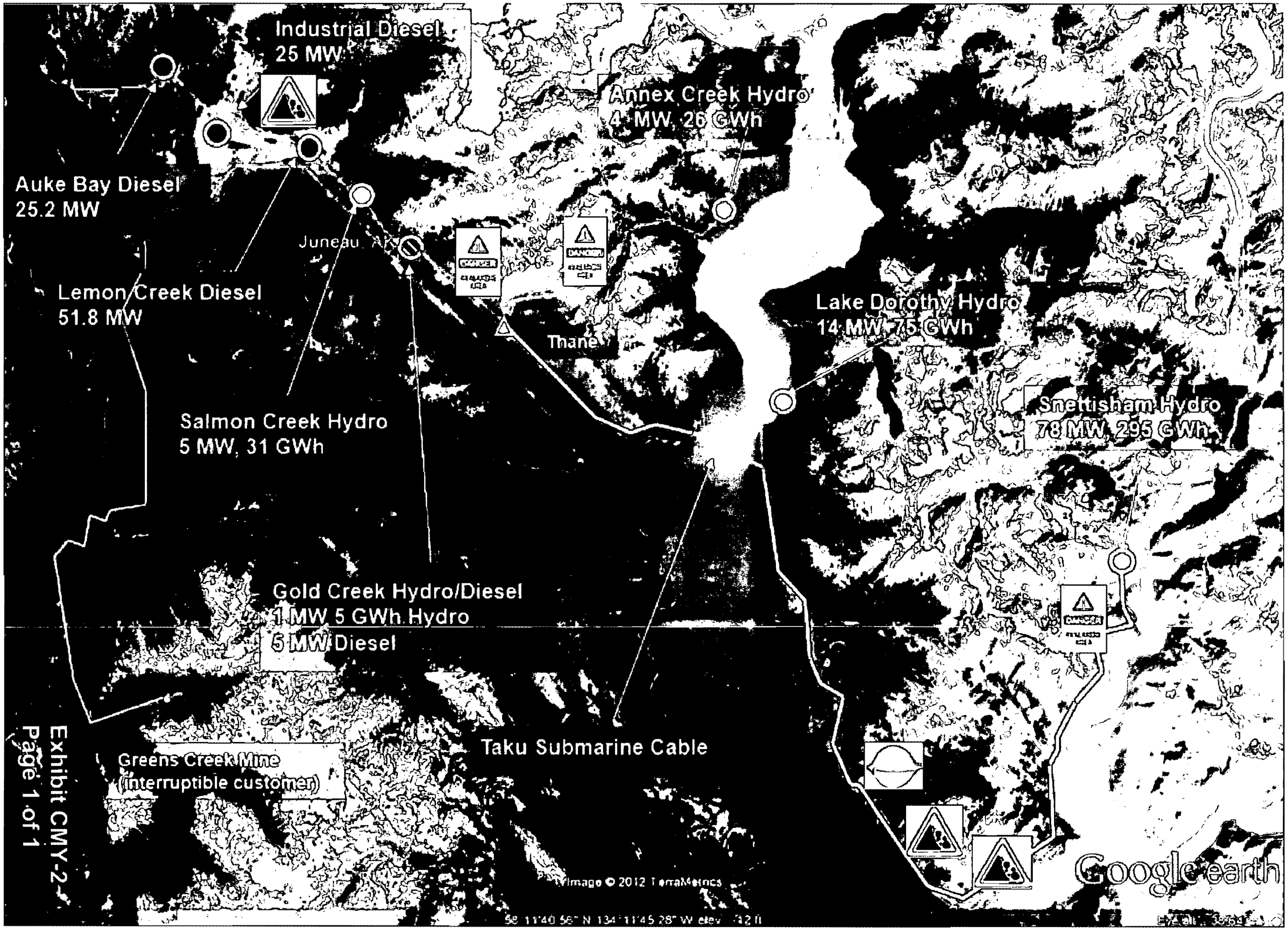

Exhibit CMY-2
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Standby Generation Study

Alaska Electric Light and Power Company
Juneau, Alaska

May 2009

May 2009

R·W·BECK

Standby Generation Study

Alaska Electric Light and Power Company
Juneau, Alaska

May 2009

May 2009

R·W·BECK

This report has been prepared for the use of the client for the specific purposes identified in the report. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. (R. W. Beck) constitute the opinions of R. W. Beck. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this report, R. W. Beck has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck makes no certification and gives no assurances except as explicitly set forth in this report.

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The Alaska Electric Light and Power Company (AEL&P) contracted with R. W. Beck, Inc., to perform a Standby Generation Study for the 2009–2018 time period. This report is a summary of the review, modeling and analysis activities R. W. Beck completed during the study and the results of these activities.

Background and Objective

AEL&P provides electric service to the greater City and Borough of Juneau, Alaska, the area in the southern part of the state. In 2007, its average load was approximately 41 megawatts (MW), and its peak load was approximately 66 MW. The total firm energy sales of AEL&P in 2007 were 345,741 MWh[1].

Currently, AEL&P satisfies its loads partly through a purchase of capacity and the associated energy from the state owned Snettisham Lake Hydroelectric Project, located about 28 miles south of Juneau. The remainder of AEL&P's requirements are supplied by hydroelectric and diesel-fired generation plants owned and operated by AEL&P. Power from the Snettisham Project is transmitted to AEL&P over a single circuit, 42-mile-long transmission line which includes a 3-mile-long submarine cable crossing of Taku Inlet. In the past, there have been failures of the Snettisham system. Harsh winter weather conditions and the remote location of the Snettisham transmission line have made repairs of the line difficult and occasionally of significant duration. In April 2008, an avalanche destroyed three transmission towers, forcing AEL&P to generate almost all of the Borough's electricity with diesel-powered generators. Another similar outage occurred in January of 2009.

In order to maintain full electric service to its customers, AEL&P's policy is to maintain standby generation sufficient to back up 100 percent of the needed power from the Snettisham Project without its largest single standby unit. During an extended outage of the Snettisham Project, AEL&P's generating facilities would be used on a continuous basis to supply its full power requirements. A failure of a large generating unit and hydroelectric station during peak load conditions could mean insufficient generating capacity to meet load. In addition, during the outage that

[1] Unless otherwise indicated, the following definitions are used in this report:
- **Energy Sales** – the total amount of kilowatt-hours sold in a given period of time, usually grouped by class of service, such as residential, commercial, industrial and other. Other sales include public street and highway lighting, other sales to public authorities, interdepartmental sales, etc.
- **Net System Requirements** – total energy sales plus distribution losses.
- **Total System Requirements** – total energy sales plus distribution and transmission losses, Company own use, and interruptible and dual fuel uses.
- **Load Factor** – the ratio of average load (total energy sales divided by total number of hours) to peak load during a specific period of time, expressed as a percent.
- **Peak Demand** – the maximum load during a specified period of time.

occurred in the spring of 2008, the costs of running AEL&P's standby diesel generation were significantly higher than usual due to high oil and diesel prices.

Due to the increasing power needs of its customers, the lengthy outages related to the Snettisham Project transmission line, the high volatility of oil and diesel prices, and other factors, AEL&P made a decision to follow through with a review of its need for additional standby generation. AEL&P asked R. W. Beck to perform the following standby generation study. Principal elements of the study include:

- Review power requirements and existing power supply resources
- Review basic reliability and generation reserve criteria
- Develop the need for additional generation capacity
- Review and assess standby generation options
- Review the addition of the Lake Dorothy Hydroelectric Project (Lake Dorothy) and its impact on standby requirements

Methodology, Data, and Assumptions

To complete the Standby Generation Study, R. W. Beck developed and utilized an Excel-based model of AEL&P's power supply function, which is based on an hourly commitment/dispatch model of the AEL&P system. The model is used to generate estimates of annual power supply costs (fuel and operations and maintenance expenses plus capital cost amortization) for a number of load and resource scenarios.

The model requires a significant amount of data, which R. W. Beck developed in conjunction with AEL&P staff:

- The base load forecast was provided by AEL&P. In order for R. W. Beck to review and, if necessary adjust, AEL&P's forecast, R. W. Beck used a hybrid econometric and end-use approach to perform load and energy requirement projections that reflect the recent economic and demographic trends in the Juneau area.
- AEL&P provided characteristics data for the existing diesel and hydro generating units, and R. W. Beck staff reviewed and verified these data.
- Based on previous research, R. W. Beck assumed that AEL&P would pay the lower-48 benchmark diesel fuel price, and utilized the Energy Information Agency's (EIA) most recent price forecast to generate the required diesel price forecast. In order to account for the volatility of fuel prices and to stress test the results of the analysis, a high fuel price scenario was also assumed.

Results

The study produced the following critical key results:

Load and Energy Requirements

To review AEL&P's current projections of load and energy requirements, R. W. Beck developed an independent projection of monthly and annual load and firm energy sales for AEL&P's service territory. This independent projection of power requirements and peak load presents an estimate of AEL&P's future electric energy requirements based on various assumptions concerning the expected levels of economic and demographic growth in AEL&P's service area. Also included are confidence intervals around the estimate that reflect the range of economic and demographic growth that could occur.

Historical data on AEL&P's energy sales, peak demand and customer accounts were compiled, along with historical, demographic, economic and weather data. The data for large customers and planned customer demand additions were individually analyzed to separately assess their future power requirements. Econometric equations were developed that explain the historical relationships between energy sales and peak demand with various explanatory variables such as electric rates, weather and employment levels. Assumptions were developed regarding the future values of these explanatory variables. A stochastic model using random estimates of these variables was then developed to estimate the expected value of energy sales and peak demand levels within specified confidence intervals. The analysis provided three load scenarios (base, low and high) that each represent a certain confidence level. The base case represents a more realistic view of the power requirements under the type of frequent emergency situations that AEL&P's system encounters. Therefore, we assumed a higher percentile growth for the base case than the usual median percentile. The economic scenario that underlies the base case forecast is one of moderate growth for Juneau over the next 10 years.

Energy sales for all customer classes are projected to increase moderately over the forecast period, with the most significant increases attributable to AEL&P's commercial class.

The projections of AEL&P's firm energy sales are presented in Figure ES-1. Under the base case, total energy sales are projected to increase at an average annual growth rate of 1.64 percent during the next 10 years, from 353,123 MWh in 2008 to 415,475 MWh in 2018. Sales to the Commercial class and Residential class are projected to increase at a 1.89 percent and 1.11 percent annual rate between 2009 and 2018, respectively. Sales to the Governmental class are projected to increase at a 0.66 percent annual rate between 2009 and 2018.

This growth in the next 10 years is primarily the result of general economic and demographic growth, the addition of a few large developments, and the resulting economic development.

Figures ES-1 and ES-2 show that AEL&P's projections and R. W. Beck's independent base case projections are within a reasonable range of each other.

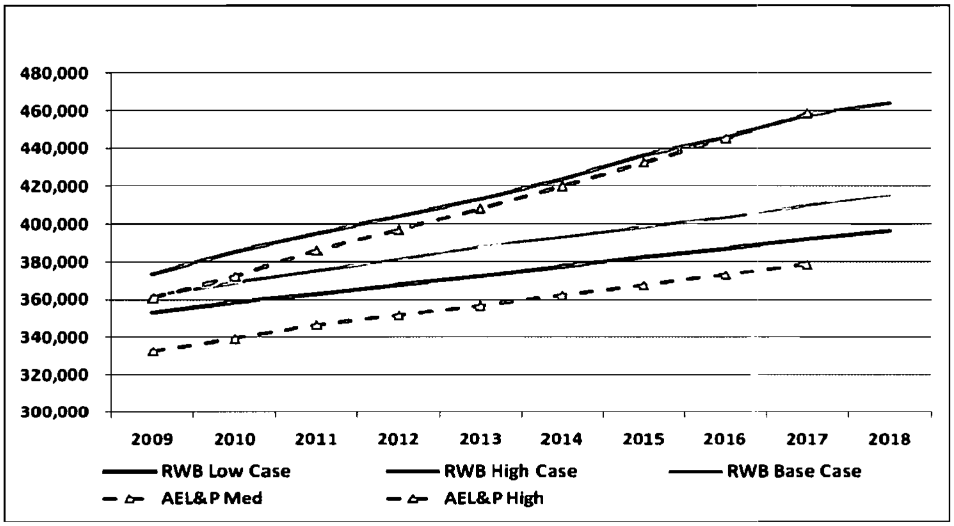


Figure ES-1: AEL&P 2009-2018 Firm Energy Sales (MWh)

The projections of AEL&P's peak demand are presented in Figure ES-2. AEL&P's peak demand under the base case forecast is projected to increase 12.4 MW over the next 10 years, from 68.1 MW in 2009 to 80.5 MW in 2018, with an annual average growth rate of 1.99 percent. This rate of future growth is higher than the average historical rate of growth, because we assumed a higher percentile than the usual median percentile for the base case.

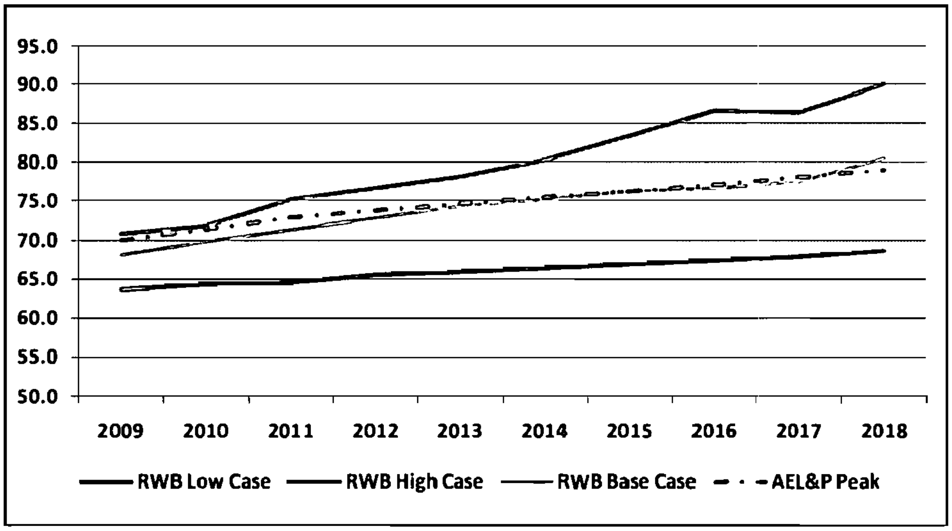


Figure ES-2: AELP 2009-2018 System Peak Demand

Table ES-1
Base Case Scenario
AEL&P Total Energy Sales (MWh) and Peak Demand (MW)

Year	Peak (MW)	Firm Sales (MWh)	Firm System Requirements* (MWh)	Residential Sales (MWh)	Commercial Sales (MWh)	Government Sales (MWh)
2008	66.1	353,123	376,222	143,267	125,283	76,710
2009	68.1	361,794	386,734	144,935	131,358	77,407
2010	69.8	368,454	393,967	146,186	135,451	77,744
2011	71.3	375,322	401,516	148,211	137,691	78,490
2012	72.9	380,919	407,655	149,821	140,380	78,857
2013	74.3	388,097	415,396	151,800	142,289	79,656
2014	75.2	392,956	420,843	153,401	143,704	80,007
2015	76.3	398,596	427,095	155,008	145,785	80,524
2016	76.7	403,508	432,646	156,378	148,386	80,869
2017	77.6	410,047	439,852	158,044	149,303	81,203
2018	80.5	415,475	445,279	159,910	151,026	81,924
Compounded Average Annual Growth						
	1.99%	1.64%	1.64%	1.11%	1.89%	0.66%

* Including Firm Sales, T&D Losses and Company use.

Load/Resource Balance

In order to satisfy the reserve margin requirement and to have enough resources to back up a full outage of the 138-kV line (losing both Snettisham and Lake Dorothy) and the outage of the largest diesel unit, AEL&P will need to add a net 25 MW of standby capacity over the period 2009–2018. However, if the outage of the 138-kV line would not affect Lake Dorothy operation, AEL&P will need only 10 MW of additional standby generation over the 2009–2018 period. As shown in Table ES-2 and Figure ES-3, the rationale for this assessment is as follows:

(1) Although the connection of Lake Dorothy to the Snettisham 138-kV line will increase AEL&P's generation capacity, it will add another level of complexity to the issue of standby generation balance. Two scenarios emerge from this interconnection: (a) If an outage of the 138-kV line leads to the loss of both Snettisham and Lake Dorothy, then the AEL&P system will need additional standby generation to back up both power plants; and (b) if an outage of the 138-kV line leads to the loss of Snettisham only, then Lake Dorothy will enhance the standby generation balance, reducing the AEL&P system's need for future additions of standby capacity.

(2) If the 138-kV line is out of service, leading to the loss of both the Snettisham and Lake Dorothy hydro power plants, AEL&P will have a deficit of 25 MW of standby generation, assuming that all the diesel standby generation is available, with the exception of the largest diesel generation unit (Auke Bay–TP&M FT4A-11 Gas Turbine). If Lake Dorothy is not affected and, therefore, AEL&P does not have to back it up, that deficit will be only 10 MW over the period 2009 – 2018.

(3) Due to the lengthy and severe impact of the 138-kV line outages, AEL&P should plan its standby generation policy based on the worst case scenario. The worst case scenario for AEL&P includes: (a) the outage of the 138-kV transmission line leading to the loss of both Snettisham and Lake Dorothy; (b) the outage of the 21-MW Auke Bay–TP&M FT4A-11 Gas Turbine; and (c) high load growth. Under this scenario, AEL&P will need to add 35 MW of standby generation over the period 2009–2018.

(4) There are several Diesel Reciprocating Engine and Combustion Turbine models available on the market in the 20-30 MW size range. Combustion Turbines have higher capital cost (per kW), higher heat rate (12,000–14,000 Btu/kWh), lower emission rate, and larger size (20 MW or higher per unit). On the other hand, Reciprocating Diesel Engines have a lower heat rate (~9,000 Btu/kWh), higher emission rate, and smaller size (2.5 MW per unit). In other words, there are cost, environmental, and reliability consequences related to the future additions of standby generation technology.

Table ES-2
Standby Load/Resource Balance
(MW)

	Standby Balance (MW) with Snettisham and Largest Unit Out									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2016
Peak Load - Base Case	68	70	71	73	74	75	76	77	78	81
Surplus (Deficit) - Lake Dorothy is a back up	(11)	1	(0)	(2)	(4)	(5)	(6)	(6)	(7)	(10)
Surplus (Deficit) - Lake Dorothy needs a back up	(11)	(13)	(15)	(16)	(18)	(19)	(20)	(21)	(22)	(25)
Peak Load - High Case	71	72	75	77	78	80	83	87	86	90
Surplus (Deficit) - Lake Dorothy is a back up	(14)	(1)	(5)	(6)	(8)	(10)	(14)	(17)	(17)	(21)
Surplus (Deficit) - Lake Dorothy needs a back up	(14)	(15)	(19)	(20)	(22)	(24)	(28)	(31)	(31)	(35)

* The addition of Lake Dorothy 14.3 MW is not accounted for in 2009.

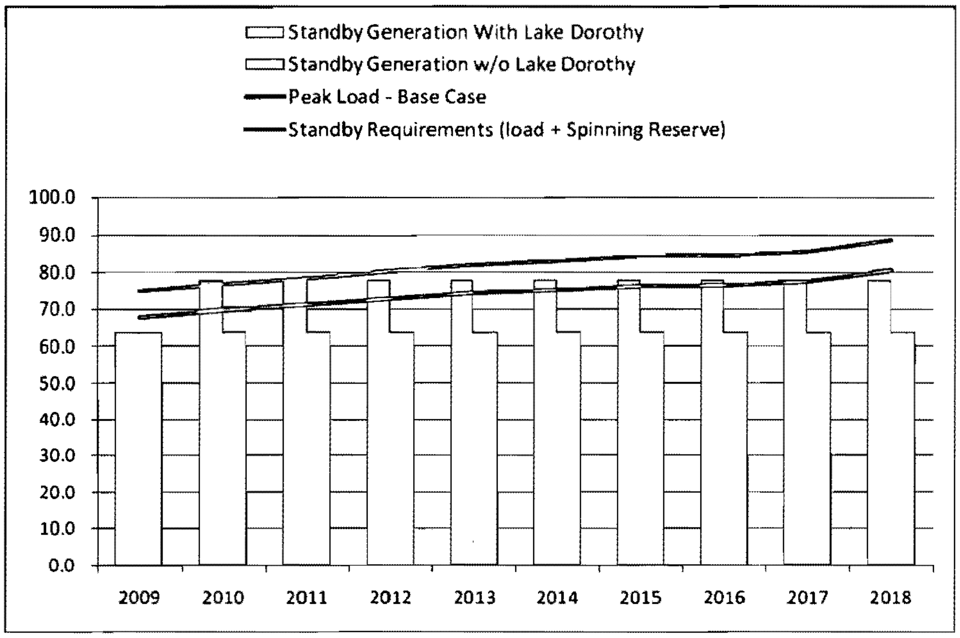


Figure ES-3: Standby Balance (MW) with Snettisham and Largest Unit Out

Standby Generation and Reliability Assessment

Because Snettisham supplies the bulk of the power for the AEL&P grid and since the overhead line is located in difficult, largely unpredictable terrain, this 138-kV single source link to AEL&P is the critical element in all considerations of reliability and standby generation needs. To estimate the impacts of different reliability scenarios related to Snettisham and/or the 138-kV line, we simulated the AEL&P system under the following five scenarios:

1. The base case, assuming normal (on-service) operation of the 138-kV transmission line connecting Snettisham and Lake Dorothy to AEL&P's load center.
2. Snettisham is out of service 50 percent of the time during January. January is the peak month and is the coldest month of the year. This case was simulated with and without Lake Dorothy.
3. Snettisham is out of service 100 percent of the time during January. This case was simulated with and without Lake Dorothy.
4. High load growth case and Snettisham is out of service 100 percent of the time during January.
5. High fuel price and load growth case and Snettisham is out of service 100 percent of the time during January. This case was simulated with and without Lake Dorothy.

Under each case, the simulation model estimated, on an hourly, monthly, and annual basis, the level of generation and costs for every dispatched generation and contractual unit.

Table ES-3 depicts the summary results of the simulated scenarios. The results show the following observations:

(1) The cost associated with an annual outage of the 138-kV line and Snettisham for two weeks in January (~5 percent annual forced outage rate), is about $36 million in total present value over the 2009-2018 period with an average annual impact of about $4.4 million. If the outage also causes the loss of Lake Dorothy, the cost impact rises to $40 million. The cost impact is estimated as the difference between the present value of the total system cost under the base case (which assumes no outage during January) and the present value of the total system cost under the case in which the line is assumed to be out 50 percent of the time during January of each year. The total cost includes the variable and fixed costs of operating AEL&P own generations as well as the cost of Snettisham contract.

(2) If Snettisham or the 138-kV line are out of service during the entire month of January, the cost impact in total present value over the 2009-2018 period is about $44 million with an average annual impact of about $5.4 million. If the outage also causes the loss of Lake Dorothy, the cost impact rises to $52 million.

(3) Higher load growth increases the impact of Snettisham's full outage during January to $53 million in present value over the 2009-2018 period.

(4) Higher load growth and higher diesel fuel prices increase the impact of Snettisham's full outage during January to $64 million in present value over the 2009-2018 period.

(5) Depending on the outage level and duration, load growth and fuel prices, the Lake Dorothy addition will save a total of $5 to $9 million in production costs, in 2009 present value. The savings are due to the replacement of some of the standby generation costs. These savings do not account for the capital cost gains (losses) due to the impact of Lake Dorothy on the level of standby generation additions needed.

Table ES-3
Total Production Costs - Present Costs
($ million – 2009 Dollars)

	Production Costs - Present Value ($million $2009)		
Reliability / Resource Scenarios	**Total Costs with Lake Dorothy**	**Delta from Base Case**	**Total Costs w/o Lake Dorothy**
1. Base Case	$158.5	$0.0	$162.9
2. Snettisham out 50%	$194.2	$35.7	$198.3
3. Case III – Snettisham Out 100%	$202.6	$44.1	$210.6
4. Case III & High Load	$211.5	$53.0	

5. Case III & High Load and Fuel	$222.8	$64.3

Conclusions and Recommendations

Based on the results of investigation and analysis, R. W. Beck offers the following conclusions and recommendations:

1. AEL&P system demand and energy requirements are expected to continue to grow. The system peak load is expected to grow at 1.99 percent per year over the next 10 years. The growth projection used in this study is higher than the historical average growth rate; a higher percentile than the median was assumed in order to properly address the reliability of the system during frequent severe weather conditions.
2. AEL&P has traditionally maintained adequate generation resources to serve its peak demand in the event of failure of the 138-kV transmission line and its largest diesel generation unit. We strongly recommend that AEL&P continue that policy and keep, at a minimum, the same level of standby generation under any future supply scenario.
3. Despite the introduction of the Lake Dorothy hydro power plant, the current level of standby generation is inadequate to supply AEL&P's peak load if its largest generation unit fails during AEL&P's stand alone operation (i.e., when Snettisham and Lake Dorothy are out of service). AEL&P will need to add about 25 MW of new standby generation between now and 2018. If a more aggressive growth in demand materializes, as depicted in the high load growth case, AEL&P will need about 35 MW of new standby generation between now and 2018.
4. The Reciprocating Engine and Combustion Turbines Diesel models are the standard recommended models for standby generation in an isolated system. There are several models available of both technologies in the market that can serve AEL&P's needs. Combustion Turbines have a higher capital cost (per kW), higher heat rate (12,000–14,000 Btu/kWh), lower emission rate, and larger size (20 MW or higher per unit). On the other hand, Reciprocating Diesel Engines have a lower heat rate (~9,000 Btu/kWh), higher emission rate, and smaller size (2.5 MW per unit).
5. Standby generation units in AEL&P system are dispatched few hours per year, if any. Therefore, their operating efficiency in terms of heat rates and emission rates are not major factors in determining the technology of choice. Their capital costs and impact on reliability of the system should be the pivotal factors. The addition of a large size unit (e.g. a combustion turbine) may have the advantage of lower cost per unit of kW, but will have the disadvantage of increasing the risk of the size of MW outages and, therefore, increasing the need for more backup.

Purpose

Due to increasing power needs of its customers, lengthy outages of the Snettisham Project transmission line, and other energy related factors, the Alaska Electric Light and Power Company (AEL&P) is reviewing its need for additional standby generation in its service territory. AEL&P provides electric service to the greater City and Borough of Juneau, Alaska, the area in the southern part of the state. In the fall of 2008, AEL&P retained R. W. Beck, Inc., to perform a standby generation study. Principal elements of the study, which covers the 2009-2018 time period, are as follows:

- Review and update AEL&P's energy sales, total energy requirements and peak load projections
- Review existing power supply resources, basic reliability and generation reserve criteria
- Review and assess standby generation options, based on the following criteria:
  - Maintaining the highest level of reliable electricity service; and
  - Cost effectiveness
- Transmission reliability assessment

The purpose of this report is to summarize the background, analyses, and results of this 10-year study prepared for AEL&P.

The report presents an estimate of AEL&P's future electric energy requirements based on various assumptions concerning the expected levels of economic and demographic growth in AEL&P's service territory. In addition, the report presents an estimate of AEL&P's costs and reliability projections under different load, fuel price, and hydro outage scenarios. For comparison purposes a high case and a base case are provided based on confidence intervals around the estimates to reflect the range of economic growth that could occur. The historical AEL&P energy, demand and customer data presented in this report are the sum of data from AEL&P systems.

General Background

AEL&P has experienced slow power requirements growth during the last 10 years. However, this power requirements growth has not been consistent, with much slower growth in energy sales occurring during the 1998-2004 period and moderate growth occurring in the 2004-2007 period.

AEL&P anticipates the same moderate, but inconsistent, growth in both energy requirements and peak demand levels during the next 10 years due to economic and demographic development activities, employment and other factors. Economic growth in the AEL&P service area is also anticipated to increase the power requirements of the Commercial classes. AEL&P requested a review and update to its load forecast and a review and estimate of the likely future standby generation requirements in light of the recent significant exposure to power interruptions and volatile fuel costs.

Study Tasks

This study was developed using historical data on the greater City and Borough of Juneau area obtained from existing utility records. The data included historical economic, demographic and weather data, and various reviews and studies recently prepared for the area. The specific scope of services performed can be summarized as follows:

- Review and update AEL&P's energy sales, total energy requirements, and peak load projections.
  1. **Data Collection**: Reviewed and updated utility and non-utility data and conducted a preliminary analysis of customer growth patterns. Data was collected from a variety of sources, including city and state agencies. Historical data from AEL&P was reviewed to identify growth patterns and causal relationships.
  2. **Review of Existing Economic and Population Studies**: Updated the existing sources of data for changes in historical and projected economic and demographic factors in the AEL&P service area, including past studies prepared by various planning entities in the Juneau area. Reviewed the historical power usage of AEL&P's largest potential customers. An estimated range of the future power requirements was developed with an estimate of the expected value of power requirements for each of these customers.
  3. **Determine Appropriate Model Input Assumptions**: Reviewed and updated economic and demographic assumptions for the AEL&P service area based on limited projections prepared for the area and a review of historical relationships and trends. Assumptions regarding the expected value and projected standard deviation for population, employment, per capita income and other factors were developed and used in the study to represent alternative views of future Juneau economic activity.
  4. **Conduct Econometric Analysis and Develop a Stochastic Model**: Using a historical database of utility, economic, demographic, and weather information for the AEL&P service area covering the past 10 years, analyses were conducted for AEL&P's Residential, Commercial and Industrial customer classes. An econometric analysis was updated or performed using relevant available data, including: (i) customer growth patterns, (ii) average monthly rate per customer class, (iii) effects of economic and demographic service

territory growth, and (iv) weather normalization. A stochastic model was developed that incorporates the large customer analysis and econometric equations to produce an expected value of future energy requirements with a range around the expected value, and estimates of future peak demand.

- Review the characteristics and historical performance of existing hydro and fossil generating units.
  1. Review basic reliability and generation reserve criteria.
  2. Review AEL&P's need to maintain reliable service.
- Review and assess standby generation options.
- Review the addition of the Lake Dorothy Hydroelectric Project and its impact on standby requirements.
- Prepared a draft report for AEL&P's review, summarizing the assumptions, methodology and results of the study.

Considerations and Limitations

In this study we developed a series of power requirement projections for AEL&P that encompass a range of future economic growth assumptions. The uncertainty inherent in the input assumptions used in this forecasting effort (as in the development of any forecast) as well as the limitations of the specific assumptions that underlie the forecast should be recognized and considered when using the study results. The projections presented in this report do not account for the influence of any major external event having a significant impact on the Juneau economy.

For these and other reasons, the existing data do not provide a precise indication of the possible range of AEL&P's future load growth and standby generation needs. The results of this load forecast and supply generation assessment should be updated periodically to account for new information and any changes in planning expectations. Alternative percentile projections are provided in this study in an attempt to bracket the expected range of load growth projections. It should be cautioned, however, that even these alternative scenarios do not account for all possible outcomes.

Consideration should also be given to the nature of the forecasting procedure used. The primary purpose of this effort was to develop long-term projections of AEL&P's likely future power requirements. As such, the procedures used in this forecast included establishing long-term historical relationships and using these relationships to project future load requirements. Short-term results may not be as accurate as with alternative forecasting techniques more appropriate for near-term applications.

Founded in 1893, AEL&P was established to supply the City and Borough of Juneau citizens with electricity. More than 100 years later, AEL&P continues to be a unique entity and supplies electricity to about 15,550 customers, who consumed more than 345 million kilowatt-hours of electrical energy in 2007. AEL&P is currently the largest investor-owned or privately owned and financed electrical utility in Alaska, and the sixth largest utility in the state.

This section describes the demographic and economic background of the area that AEL&P serves.

Juneau

Juneau, the state capital of Alaska, is the third largest city in the state. Juneau is located in Southeast Alaska and its downtown is nestled at the base of Mount Juneau and across the channel from Douglas Island. The U.S. Census Bureau's 2007[2] population estimate for the City and Borough was 30,690 people. The population density was about 11.3/square mile and the average residential housing density was 4.5/sq mi. The median income for a household in the City and Borough was $62,034, and the median income for a family was $70,284. The per capita income for the City and Borough was $26,719.

The primary employer in Juneau, by a large margin, is the government. This includes the federal government, state government, municipal government (which includes the local airport, the local hospital, harbors, and the school district), and the University of Alaska Southeast. Another large contributor to the local economy, at least on a part-time basis, is the tourism industry. The cruise ship industry was estimated to bring nearly one million visitors to Juneau between the months of May and September.

The fishing industry used to be a major part of the Juneau economy. Until recently, Juneau was the 49th most lucrative U.S. fisheries port by volume and 45th by value, taking in 15 million pounds of fish and shellfish valued at $21.5 million in 2004, according to the National Marine Fisheries Service.

Real estate agencies, federally-funded highway construction, and mining are apparently still viable non-government local industries. Local mines include Greens Creek Mine and the proposed Kensington Gold Mine.

Before 2000, Juneau had faster growth in population, employment and the economy. Population grew close to 1.34 percent annually from 1990-2000 and per capita income

2 *2007 Population Estimates.* U.S. Census Bureau, Population Division. July 10, 2008. http://www.census.gov/popest/cities/tables/SUB-EST2007-04-02.csv. Retrieved on September 10 2008.

rose close to 2.0 percent annually from 1990-2000. Annual job growth was about 1.0 percent during the same period.

However, these trends have reversed over the past five years, as Juneau entered a slow population growth phase. Since 2000, Juneau's population grew at a slower rate. Job growth has also decreased to 0.7 percent, although per capita income grew at 3.5 percent which is twice as high as the growth rate during the 1990-2000 period. Economic activities are expected to moderately grow over the next few years, and Juneau expects the growth in commercial and tourism development to continue to provide most of the area's future growth.

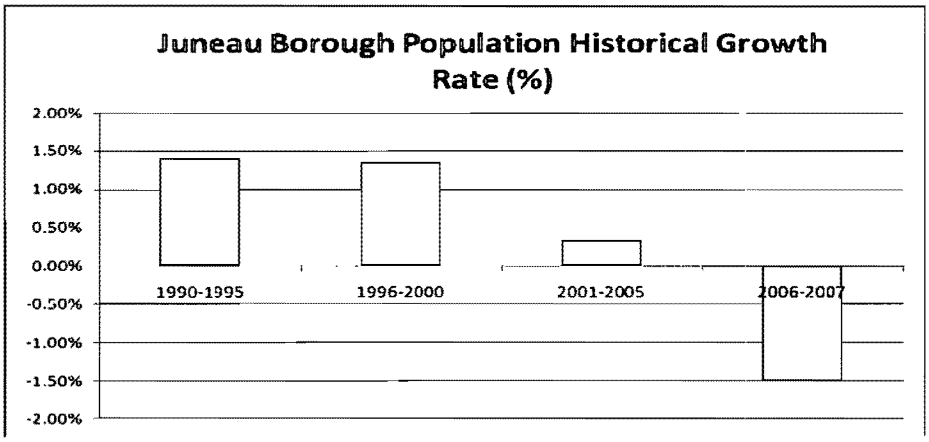


Figure 2-1: Annual Population Trends

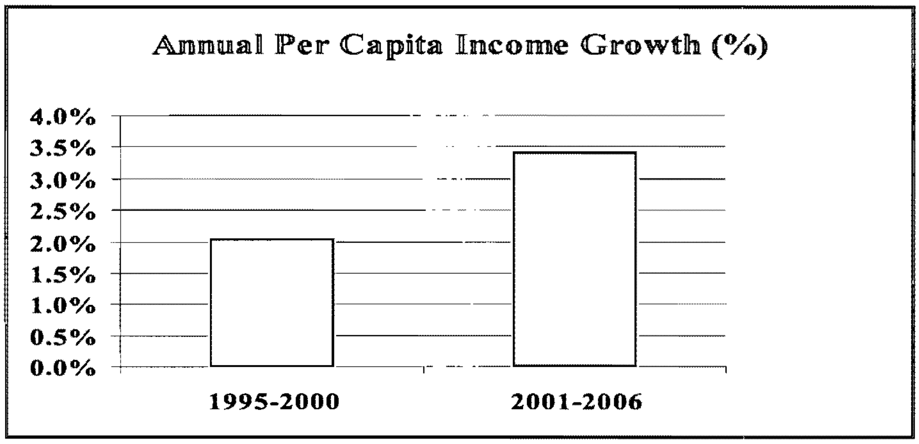


Figure 2-2: Annual Per Capita Income Trends

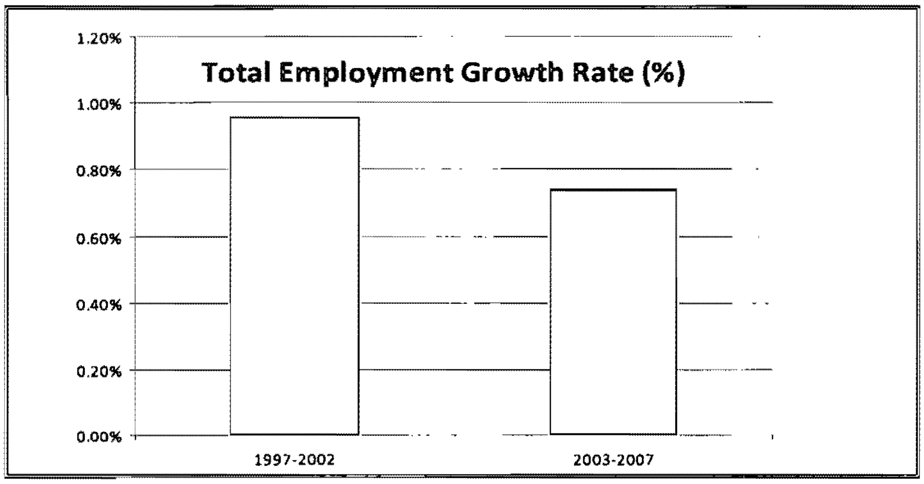


Figure 2-3: Annual Employment Trends

Overview

AEL&P's total energy sales in 2007 were 344,757 MWh, which represents a 16.7 percent increase over AEL&P's 1998 energy sales level (see Table 2-1). AEL&P provides retail power to three main customer groups identified as the Residential, Commercial, and Governmental classes.[3] Energy sales in 2007 to Residential customers were approximately 41.2 percent of total AEL&P energy sales. About 36.4 percent of total energy sales were to Commercial customers and 22.1 percent were to Governmental customers. The remaining 0.3 percent, or about 960 MWh of power, was sold to Public Street Lighting and others.

In 2007, AEL&P had system energy losses of approximately 5.7 percent of its total system requirements. AEL&P's peak demand in 2007 was 66.0 MW, which represents a 59.6 percent load factor on AEL&P's total energy sales. Historical energy sales, firm sales, revenues, and peak demand are summarized in Table 2-1.

Currently, AEL&P's energy requirements are met by a combination of generation facilities owned by AEL&P and purchases from the state-owned Snettisham hydro facility. AEL&P's own generation portfolio is comprised of base load hydro units and small diesel-fired units.[4]

3 The term "customer" is used in this study to refer to a consumer, individual customer account or meter served by AEL&P.

4 AEL&P data files.

Table 2-1
AEL&P's Energy Sales (MWh) and Peak Demand (MW)

Year	Total Number of Customers	Total Sales	Total Revenue	Employment	Peak Load
		MWh	Dollars		MW
1998	169,414	291,975	24,078,916	197,526	60.0
1999	171,295	298,983	24,651,253	199,920	59.5
2000	173,026	301,940	24,630,546	204,567	59.2
2001	175,067	307,740	25,606,679	207,453	58.8
2002	177,020	311,548	25,807,081	207,973	60.3
2003	178,698	304,587	25,699,929	209,565	57.4
2004	180,307	307,514	25,807,309	207,054	64.0
2005	182,028	313,721	26,586,007	211,722	62.8
2006	184,005	346,840	29,354,300	216,340	65.0
2007	185,776	344,757	29,999,398	215,768	66.0
Compounded Average Annual Growth	1.03%	1.86%	2.47%	0.99%	1.06%

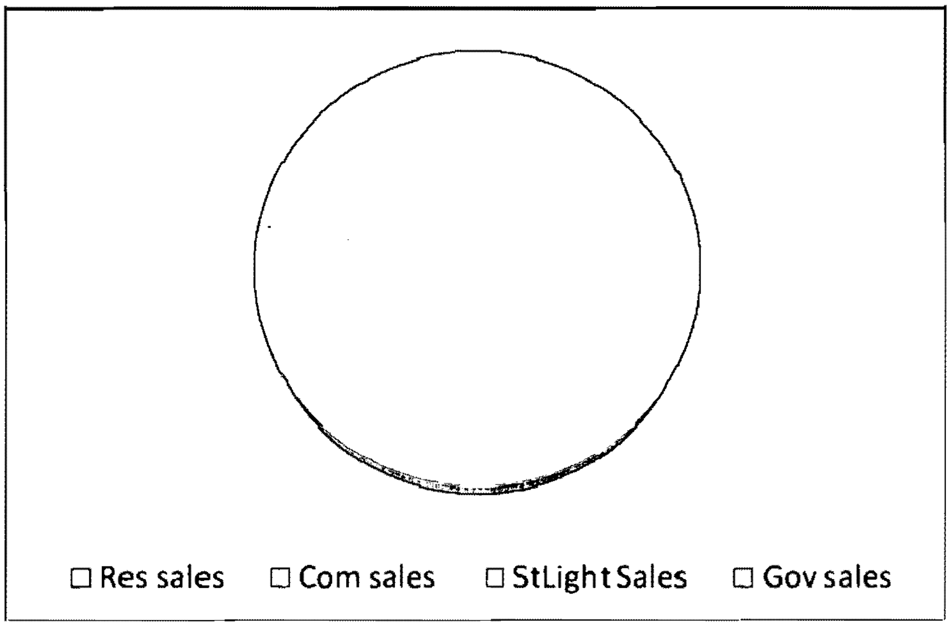


Figure 2-4: AEL&P's Customer Class Sales

Total Energy Sales

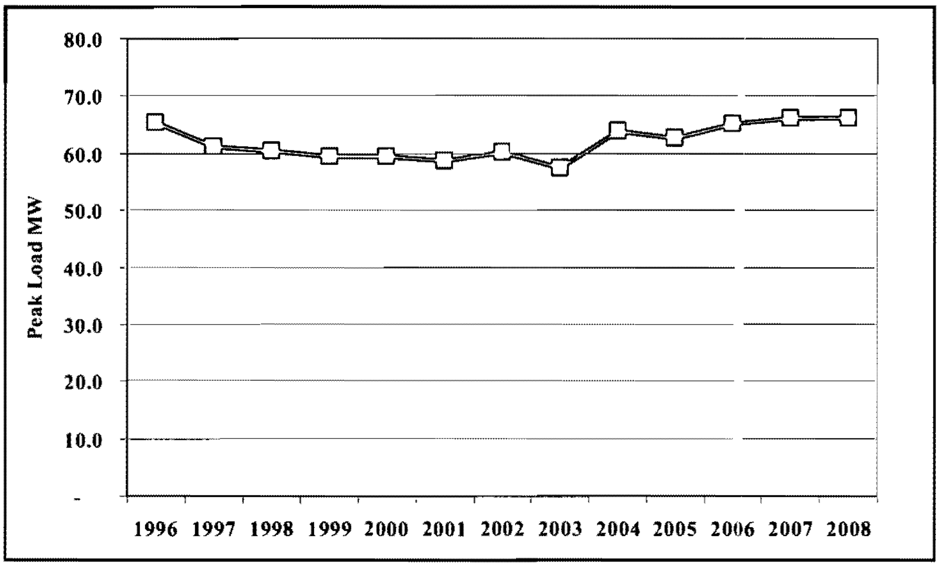
Overall, AEL&P experienced moderate but steady growth in its energy sales between 1998 and 2007. AEL&P's total energy sales increased at an average annual growth rate of 1.86 percent during this 10-year period (see Table 2-1). The Commercial and Residential classes have been responsible for the largest portion of this growth.

Total System Requirements

AEL&P's historical total system energy requirements comprise AEL&P's system energy sales (firm and interruptible) plus the utility's own power use and system transmission and distribution energy losses. According to AEL&P's staff estimate, AEL&P's own energy use represents approximately 1.0 percent of 2007 energy requirements (also a function of AEL&P's own generation operation). Based on historical analysis conducted by AEL&P's staff, retail losses are estimated at an annual average rate of 3.45 percent while the wholesale losses are estimated at 2.2 percent. AEL&P's estimated total losses are, therefore, assumed to be 5.7 percent.

System Peak Demand

AEL&P's net system peak demand has generally increased at a slower rate than AEL&P's total system energy requirements over the last 10 years. AEL&P's system peak demand increased at a 1.06 percent average annual growth rate from 1998 to 2007 (see Table 2-1 and Figure 2-5). AEL&P's peak demand reached an all-time high of 70 MW (including 5 MW of interruptible demand) in November 2006.. AEL&P's system load factor averaged 59.63 percent in 2007, and averaged close to 57.8 percent during the last 10 years.



(1) Data Source: AELP's files.

Figure 2-5: AELP Historical Peak Demand (1)

Future Power Requirements

This section summarizes the load forecast results for AEL&P. Table 2-2 provides a summary of AEL&P's projected annual energy sales, net and total system energy requirements and system peak demand for the base case scenario. Table 2-3 provides a summary for the low case results. Also provided is the high case representing the 90th percentile estimates of projected energy requirements as described in Section 1.

Load Forecast Results

As discussed earlier, the base case, the low case and the high case estimates of future power requirements are the result of stochastic analysis in which the future values of explanatory variables were estimated using 100 random draws based on assumed expected values and standard deviations. The base case represents the 75th percentile of the 100 estimates and therefore reflects the value that is most appropriate for structuring standby generation policy. The low case projection provides the level of peak load and energy requirements under average economic growth conditions. The 90th percentile case provides statistical boundaries for the base case forecast. The economic scenario that underlies these forecasts is the expected most likely range of growth in the Juneau area during the next 10 years.

In addition to the econometric projections, some of planned load additions were analyzed separately. The Commercial class historical monthly load profile was used to allocate these loads to the projected system load. The list of these loads is presented below.

Table 2-2
Commercial Class Load (kW) and Energy (MWh)

Planned Load Additions	Commercial Date Month/Year	Load KW	Energy MWh/yr	Load Factor %
NOAA fisheries lab	mid-2007	300	2000	76.1%
Breeze Inn	2008	200	1000	57.1%
New High School	9/2008	400	1200	34.2%
University of Alaska (UAF)	2009	120	700	66.6%
Capitol Annex	2009	200	800	45.7%
Swimming pool	2010	600	1500	28.5%

The projections of AEL&P's energy sales for the base, low and high cases are presented in Figure 2-6. AEL&P's annual energy sales were estimated econometrically, and also by adding large projects that are either under development or planned. Under the base case, total energy sales are projected to increase at an average annual growth rate of 1.64 percent during the next 10 years, from 353,123 MWh in 2008 to 415,475 MWh 2018. Sales to the Commercial class and Residential class are projected to increase at a 1.89 percent and 1.11 percent annual rate between 2009 and 2018, respectively. Sales to the Governmental class are projected to increase at a 0.66 percent annual rate between 2009 and 2018.

Under the low case projection, total energy sales are projected to increase at an average annual growth rate of 1.31 percent during the next 10 years, from 348,218 MWh in 2008 to 396,581 MWh in 2018. Sales to the Commercial class and Residential class are projected to increase at a 1.18 percent and 0.54 percent annual rate between 2009 and 2018, respectively. Sales to the governmental class are projected to increase at a 0.22 percent annual rate between 2009 and 2018.

This growth in the next 10 years is primarily the result of the general economic and demographic growth, the addition of a few large developments, and the resulting economic development.

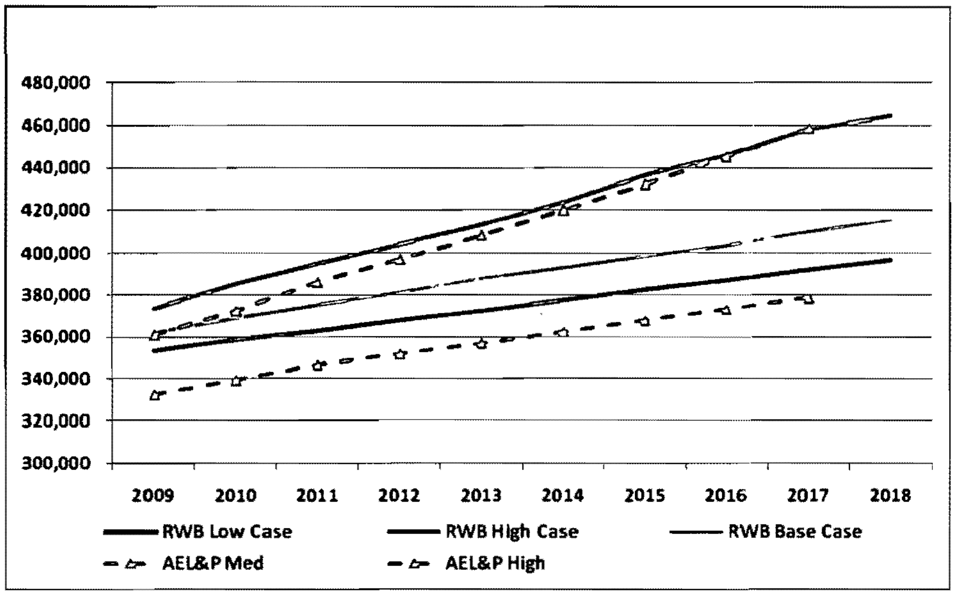


Figure 2-6: AEL&P Projected Firm Energy Sales (MWh), 2009–2018

Exhibit CMY-3
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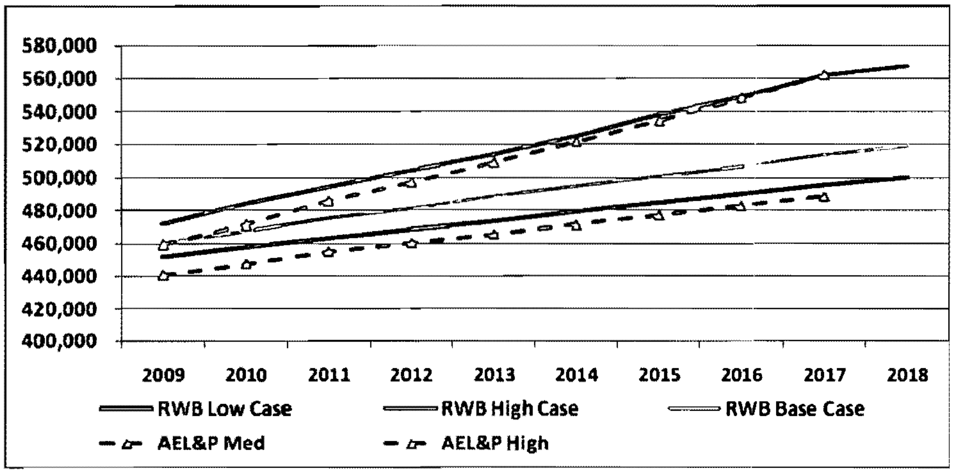

Figure 2-7: AEL&P Projected Total Energy Requirements (MWh), 2009–2018

The projections of AEL&P's peak demand are presented in Figure 2-8. AEL&P's peak demand under the base case forecast is projected to increase 14.4 MW over the next 10 years, from 66.1 MW in 2009 to 80.5 MW in 2018, at an annual average growth rate of 1.99 percent. AEL&P's peak demand under the low case forecast is projected to increase 5.4 MW over the next 10 years, from 63.3 MW in 2009 to 68.7 MW in 2018, at an annual average growth rate of 0.82 percent.

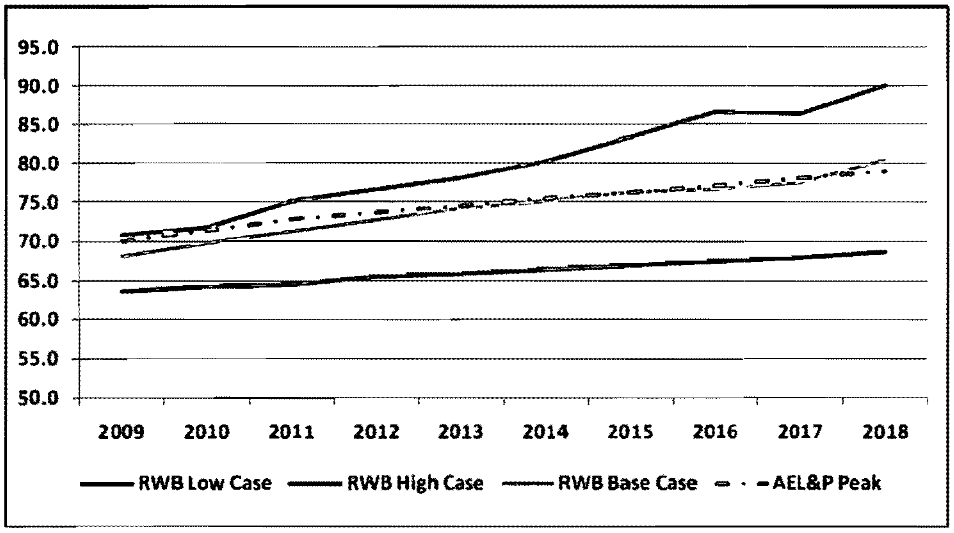

Figure 2-8: AELP Projected System Peak Demand, 2009–2018

AEL&P's total system energy requirements are summarized in Tables 2-3 and 2-4 and generally follow the growth of AEL&P's energy sales with adjustments for system (transmission and distribution) losses, interruptible and dual fuel requirements, and AEL&P's own use. Total system requirements are projected to increase at an average annual growth rate of 1.22 percent under the low case and 1.49 under the base case during the next 10 years.

Table 2-3
Base Case Scenario
AEL&P Total Energy Sales (MWh), Net and Total System Requirements (MWh) and Peak Demand (MW)

Year	Peak MW	Firm Sales MWh	Firm System Requirements* MWh	Residential Sales MWh	Commercial Sales MWh	Government Sales MWh	Total Energy Requirements** MWh
2008	66.1	353,123	376,222	143,267	125,283	76,710	447,722
2009	68.1	361,794	386,734	144,935	131,358	77,407	460,434
2010	69.8	368,454	393,967	146,186	135,451	77,744	467,667
2011	71.3	375,322	401,516	148,211	137,691	78,490	475,216
2012	72.9	380,919	407,655	149,821	140,380	78,857	481,355
2013	74.3	388,097	415,396	151,800	142,289	79,656	489,096
2014	75.2	392,956	420,843	153,401	143,704	80,007	494,543
2015	76.3	398,596	427,095	155,008	145,785	80,524	500,795
2016	76.7	403,508	432,646	156,378	148,386	80,869	506,346
2017	77.6	410,047	439,852	158,044	149,303	81,203	513,552
2018	80.5	415,475	445,279	159,910	151,026	81,924	518,979
Compounded Average Annual Growth							
	1.99%	1.64%	1.64%	1.11%	1.89%	0.66%	1.49%

* Include T&D losses, and company use.

** Includes firm sales, interruptible sales, company use, transmission and distribution losses (~5.7%).

Table 2-4
Low Case Scenario
AEL&P Total Energy Sales (MWh), Net and Total System Requirements (MWh) and Peak Demand (MW)

Year	Peak MW	Firm Sales MWh	Firm System Requirements* MWh	Residential Sales MWh	Commercial Sales MWh	Government Sales MWh	Total Energy Requirements** MWh
2008	63.3	348,218	371,317	141,278	120,934	75,853	442,817
2009	63.7	353,314	378,254	141,064	125,337	75,780	451,954
2010	64.3	358,716	384,229	141,287	127,958	75,825	457,929
2011	64.6	363,055	389,248	141,795	129,056	75,935	462,948
2012	65.6	367,909	394,645	142,633	130,127	76,143	468,345
2013	65.9	372,572	399,871	143,525	131,002	76,339	473,571
2014	66.4	377,583	405,470	144,628	132,020	76,600	479,170
2015	66.9	382,435	410,934	145,748	133,093	76,847	484,634
2016	67.4	387,191	416,329	146,863	134,040	77,081	490,029
2017	68.0	391,876	421,680	147,966	135,073	77,301	495,380
2018	68.7	396,581	426,386	149,076	136,025	77,521	500,086
Compounded Average Annual Growth							
	0.82%	1.31%	1.31%	0.54%	1.18%	0.22%	1.22%

* Include T&D losses, and company use.

** Includes firm sales, interruptible sales, company use, transmission and distribution losses (~5.7%).

Results of the High Case

The high case (90th percentile) results represent the upper bound above the base case projections. These results are consistent with a scenario of growing population, employment and per capita income growth over the 10-year forecast period in the Juneau area and relatively high load growth for large commercial customers.

Energy growth for AEL&P in the high case is summarized in Table 2-5. In this case, AEL&P's total energy sales are projected to increase at a 2.57 percent annual growth rate during the 10-year forecast period. Because of the higher growth in energy sales, AEL&P's peak demand is projected to increase at approximately 2.93 percent per year with an overall increase of 25.6 MW over the 10-year forecast period.

Table 2-5
High Case Scenario
AELP Energy Sales (MWh) and Peak Demand (MW)

Year	Peak MW	Firm Sales MWh	Firm System Requirements* MWh	Residential Sales MWh	Commercial Sales MWh	Government Sales MWh	Total Energy Requirements** MWh
2008	67.5	360,367	383,466	146,180	130,825	77,970	454,966
2009	70.7	373,303	398,243	150,191	140,565	79,592	471,943
2010	71.7	385,279	410,793	153,918	145,446	80,988	484,493
2011	75.2	394,796	420,990	158,463	151,032	82,446	494,690
2012	76.6	403,904	430,639	162,161	153,969	83,686	504,339
2013	78.1	413,130	440,429	165,357	158,166	84,802	514,129
2014	80.2	423,749	451,636	170,126	159,910	86,510	525,336
2015	83.3	436,452	464,952	175,997	163,936	88,336	538,652
2016	86.6	446,219	475,358	180,368	167,810	90,094	549,058
2017	86.4	458,281	488,085	186,363	171,587	91,879	561,785
2018	90.1	464,503	494,308	188,763	174,674	92,642	568,008
Compounded Average Annual Growth							
	2.93%	2.57%	2.57%	2.59%	2.93%	1.74%	2.24%

* Include T&D Losses, and Company Use.

** Includes firm sales, interruptible sales, company use, transmission and distribution losses (~5.7%)

The Snettisham Hydroelectric Project, located about 30 miles south of Juneau and owned by the Alaska Industrial Development and Export Authority (AIDEA), provides approximately 85 percent of AEL&P's power requirements. Currently, AEL&P has an agreement with AIDEA to operate and maintain the generation plant and transmission facilities. The Snettisham Project has approximately 75.8 MW of capacity (normal rating), and its energy production is transmitted to the Thane Substation via 44 miles of 138-kV transmission line. The addition of a third turbine (Crater Lake Expansion) to the Snettisham powerhouse was completed in late 1989. The project is presently capable of generating 273,000,000 kWh of firm annual energy.

In addition to its firm power purchases from AIDEA, AEL&P produces firm and standby power from its own hydroelectric, diesel, and gas turbine generators. The utility owns and operates six hydroelectric generating units, four combustion turbines and fifteen diesel powered generators located at five separate sites. AEL&P-owned hydro generation units are used for base load generation. AEL&P's total standby capacity (normal rating) is 77.0 MW. AEL&P's total standby capacity without its largest thermal unit is 56.0 MW, which is lower than the expected annual winter peak load. Due to locational, staffing, and emission limitations, Gold Creek Power Station is considered by AEL&P to have negligible use, even as an emergency resource of last resort, and therefore we did not list this as a resource in this study. AEL&P's thermal and hydro generating capacity ratings, installation dates, and historical performance are summarized in Tables 3-1, 3-2, and 3-3.

The new Lake Dorothy Hydroelectric Project will have a capacity of 14.3 MW and will generate 62,800,000 kWh of firm load, with an average of 74,500,000 kWh. The project is located approximately 14.5 miles south of Juneau and will connect to the Snettisham 138-kV line at the East Taku River cable crossing termination building. The location and interconnection point of the project is important, as it indicates that the hydro project should may sometimes impacted by the outages of the 138-kV line and, therefore, the standby generation policy should consider additional capacity to back up the plant potential outages.

Table 3-1
AEL&P Existing Oil-Fueled Generation Units

Plant / Unit	Manufacture Date	Installation Date	Normal Rating (kW)	Maximum Rating (kW)
LEMON CREEK				
EMD 20-645E4 Engine – 1	1969	1969	2,200	2,500
EMD 20-645E4 Engine – 2	1969	1969	2,200	2,500
EMD 20-645E4 Engine – 3	1974	1975	2,200	2,500
EMD 20-645E4 Engine – 7	1966	1983	2,200	2,500
EMD 20-645E4 Engine – 8	1967	1985	2,200	2,500
EMD 20-645E4 Engine – 9	1967	1985	2,200	2,500
EMD 20-645E4 Engine – 10	1967	1984	2,200	2,500
EMD 20-645E4 Engine – 11	1967	1984	2,200	2,500
EMD 20-645E4 Engine – 12	1967	1984	2,200	2,500
TP&M FT4A-8 Gas Turbine – 5	1966	1981	16,000	18,000
TP&M FT4A-8 Gas Turbine – 6	1968	1983	16,000	18,000
LEMON CREEK TOTAL			**51,800**	**58,500**
AUKE BAY				
EMD 20-645E4 Engine – 4	1975	1983	2,200	2,500
Solar Centaur Gas Turbine – 13	1975	1993	2,000	2,200
TP&M FT4A-11 Gas Turbine – 14	1971	1994	21,000	23,000
AUKE BAY TOTAL			**25,200**	**27,700**
Total Standby			**77,000**	**86,200**
Total Standby without Largest unit			**56,000**	**63,200**
Total Standby with governing			**73,000**	**82,000**

Table 3-2
AEL&P Existing Diesel-Fueled Generation Units – Historical Performance

	Plant Fuel Use (gallons diesel)		Plant Generation (MWh)		Heat Rate (Btu/kWh)		Fuel Price ($/gal.)
	Lemon Cr.	Auke Bay	Lemon Cr.	Auke Bay	Lemon Cr.	Auke Bay	
2000	393,982	229,277	3,960	2,168	13,831	14,702	1.02
2001	100,665	93,001	1,105	814	12,664	15,883	0.97
2002	671,698	290,228	7,252	2,576	12,876	15,662	0.95
2003	72,489	52,417	628	498	16,042	14,642	1.09
2004	128,174	61,114	1,013	539	17,589	15,766	1.41
2005	96,749	44,510	699	362	19,250	17,100	2.26
2006	75,680	88,957	931	790	11,300	15,652	2.33
2007	356,448	64,957	4,452	616	11,129	14,667	2.36

Table 3-3
AEL&P Owned and Contracted Hydro Generation Units

Plant / Unit	Manufacture Date	Installation Date	Normal Rating	Maximum Rating	Emergency 3-Hour Rating
SALMON CREEK					
Gilkes Turgo Turbine - Hydro 7	1984	1984	4,600	5,000	5,000
SALMON CREEK TOTAL	1984	1984	4,600	5,000	5,000
ANNEX CREEK					
Allis Chalmers - Hydro 5	1914	1915	1,600	1,800	1,800
Allis Chalmers - Hydro 6	1914	1915	1,600	1,800	1,800
ANNEX CREEK TOTAL			3,200	3,600	3,600
SNETTISHAM					
Long Lake Unit 1	1973	1973	23,580	27,117	27,117
- Thane Bus Bar Rating (-3%)			22,873	26,303	26,303
Long Lake Unit 2	1973	1973	23,580	27,117	27,117
- Thane Bus Bar Rating (-3%)			22,873	26,303	26,303
Crater Lake Unit 3	1989	1989	31,050	31,050	31,050
- Thane Bus Bar Rating (-3%)			30,119	30,119	30,119
SNETTISHAM TOTALS			78,210	85,284	85,284
SNETTISHAM THANE BUS BAR TOTALS (-3%)			75,864	82,725	82,725
TOTAL HYDRO RESOURCES (at Thane)			83,664	91,325	91,325

Load / Resource Balance

In order to satisfy the reserve margin requirement and to have enough resources to back up a full outage of the 138-kV line (losing both Snettisham and Lake Dorothy) and the outage of the largest diesel unit, AEL&P will need to add a net 25 MW of standby capacity over the period 2009-2018. However, if the outage of the 138-kV line would not affect Lake Dorothy operation, AEL&P will need only 10-MW additional standby generation over the 2009-2018 period.

As shown in Table 3-4 and Figures 3-1 and 3-2, the rationale for this assessment is as follows:

(1) Although the connection of Lake Dorothy to the Snettisham 138-kV line will increase AEL&P's generation capacity, it will add another level of complexity to the issue of standby generation balance. Two scenarios emerge from this interconnection: (a) If an outage of the 138-kV line leads to the loss of both Snettisham and Lake Dorothy, then the AEL&P system will need additional

standby generation to back up both power plants; and (b) if an outage of the 138-kV line leads to the loss of Snettisham only, then Lake Dorothy will enhance the standby generation balance, reducing the AEL&P system's need for future additions of standby capacity.

(2) If the 138-kV line is out of service, leading to the loss of both the Snettisham and Lake Dorothy hydro power plants, AEL&P will have a deficit of 25 MW of standby generation, assuming that all the diesel standby generation is available with the exception of the largest diesel generation unit (Auke Bay–TP&M FT4A-11 Gas Turbine). If Lake Dorothy is not affected and, therefore, AEL&P does not have to back it up, that deficit will only be 10 MW over the period 2009-2018.

(3) Due to the lengthy and severe impact of the possible 138-kV line outages, AEL&P should base its standby generation policy on a worst case scenario. The worst case scenario for AEL&P includes: (a) the outage of the 138-kV transmission line leading to the loss of both Snettisham and Lake Dorothy; (b) the outage of the 21-MW Auke Bay–TP&M FT4A-11 Gas Turbine; and (c) high load growth. Under this scenario, AEL&P will need to add 35 MW of standby generation over the period 2009-2018.

(4) There are several Diesel Reciprocating Engine and Combustion Turbine models available on the market within the 20-30 MW size range. Combustion turbines have higher capital cost (per kW), higher heat rate (12,000–14,000 Btu/kWh), lower emission rate, and larger size (20 MW or higher per unit). On the other hand, Reciprocating Diesel Engines have a lower heat rate (~9,000 Btu/kWh), higher emission rate, and are configured in smaller sizes (~2.5 MW per unit). In other words, there are cost, environmental, and reliability consequences related to the choice of standby generation technology additions.

Table 3-4
Standby Generation Load/Resource Balance
(MW)

	Standby Load / Resource Balance (MW)									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Load – Base Case	68	70	71	73	74	75	76	77	78	81
Lake Dorothy is a back up										
Spinning Reserve (10% of Peak Load)	7	7	7	7	7	8	8	8	8	8
Standby Requirements (load + Spinning Reserve)	75	77	78	80	82	83	84	84	85	89
Total Standby (Diesel + Own Hydro + Lake Dorothy - Largest Diesel Unit)	64	78	78	78	78	78	78	78	78	78
Surplus (deficit)	(11)	1	(0)	(2)	(4)	(5)	(6)	(6)	(7)	(10)
Lake Dorothy needs a back up										
Spinning Reserve (10% of Peak Load)	7	7	7	7	7	8	8	8	8	8
Standby Requirements (load + Spinning Reserve)	75	77	78	80	82	83	84	84	85	89
Total Standby (Diesel Own Hydro - Largest Diesel Unit)	64	64	64	64	64	64	64	64	64	64
Surplus (deficit)	(11)	(13)	(15)	(16)	(18)	(19)	(20)	(21)	(22)	(25)

	Standby Load / Resource Balance (MW)									
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Peak Load – High Case	71	72	75	77	78	80	83	87	86	90
Lake Dorothy is a back up										
Spinning Reserve (10% of Peak Load)	7	7	8	8	8	8	8	9	9	9
Standby Requirements (load + Spinning Reserve)	78	79	83	84	86	88	92	95	95	99
Total Standby (Diesel Own Hydro + Lake Dorothy - Largest Diesel Unit)	64	78	78	78	78	78	78	78	78	78
Surplus (deficit)	(14)	(1)	(5)	(6)	(8)	(10)	(14)	(17)	(17)	(21)
Lake Dorothy needs a back up										
Spinning Reserve (10% of Peak Load)	7	7	8	8	8	8	8	9	9	9
Standby Requirements (load + Spinning Reserve)	78	79	83	84	86	88	92	95	95	99
Total Standby (Diesel Own Hydro - Largest Diesel Unit)	64	64	64	64	64	64	64	64	64	64
Surplus (deficit)	(14)	(15)	(19)	(20)	(22)	(24)	(28)	(31)	(31)	(35)

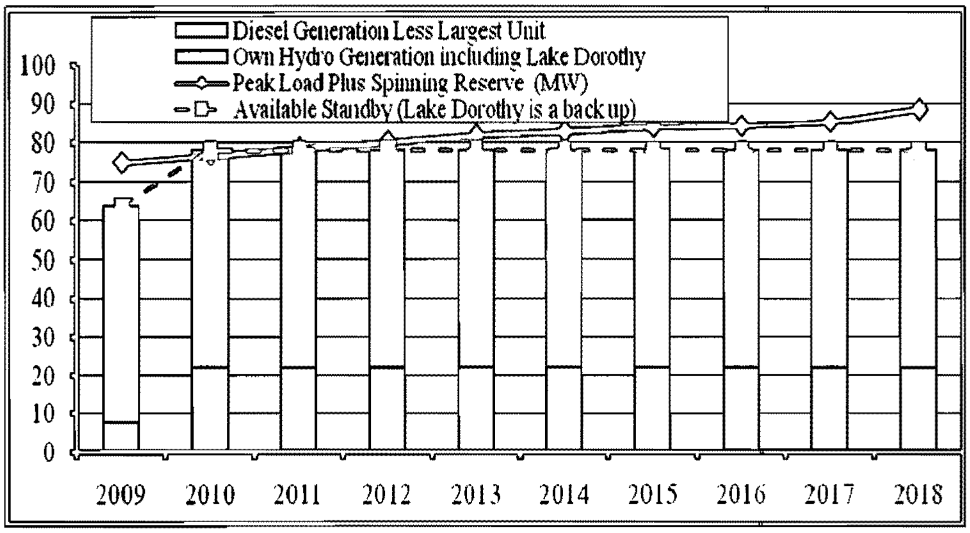

Figure 3-1: Load/Resource Balance (MW) Assuming Stand Alone status, Largest Unit is out, and Lake Dorothy is a back up

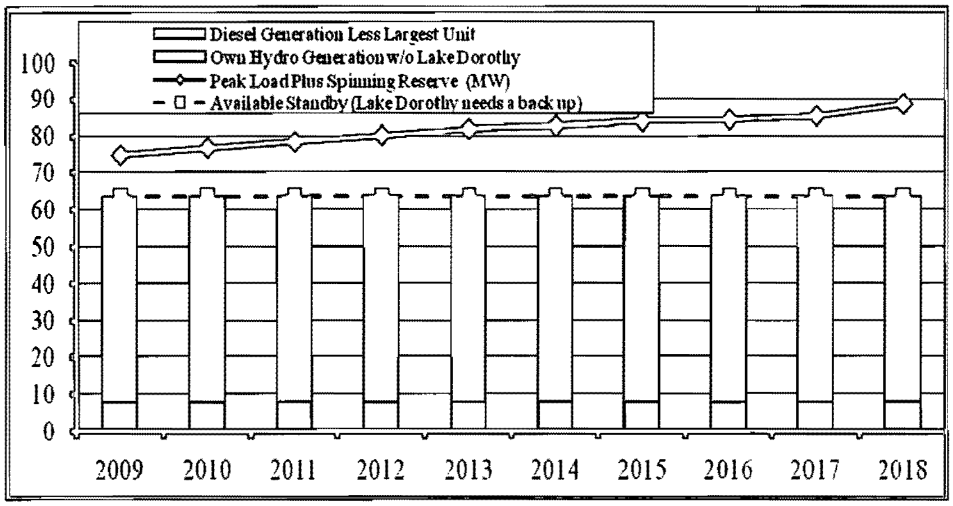

Figure 3-2: Load/Resource Balance (MW) Assuming Stand Alone status, Largest Unit is out, and Lake Dorothy needs a backup

The load/resource balance as expressed above does not tell the whole story. The following figure (Figure 3-3) depicts the annual expected firm energy loads against the total expected hydro generation from the Snettisham contract and AEL&P's own hydro resources. The graph shows the hydro generation under three different hydro scenarios (average, dry, and wet conditions). Under the normal (average) hydro scenario and after the introduction of the Lake Dorothy hydro project, AEL&P will need extra generation from its own system by 2015.

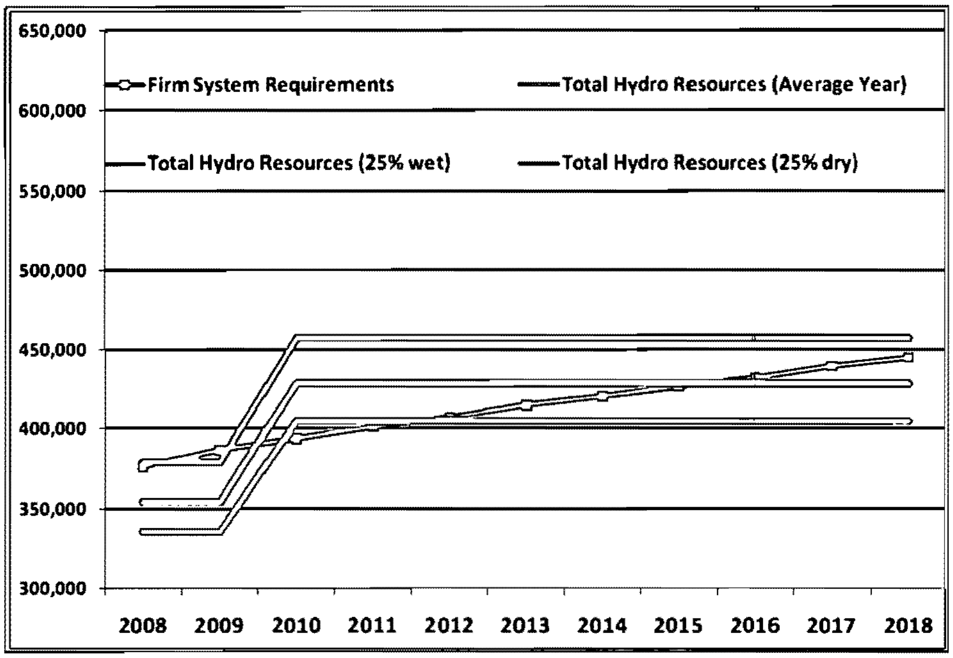

Figure 3-3: Firm System Requirements (Base Case) and Hydro Contract (Snettisham) Balance (MWh)

Standby Generation and Reliability Analysis

Because Snettisham supplies the bulk of power for the AEL&P grid and since the overhead line is located in difficult, largely unpredictable terrain, this 138-kV single source link to AEL&P is the critical element in all considerations of reliability and standby generation needs. To estimate the impacts of different reliability scenarios related to Snettisham and the 138-kV line, we simulated the AEL&P system under the following five scenarios:

1. The base case, assuming normal (on-service) operation of the 138-kV transmission line connecting Snettisham and Lake Dorothy to AEL&P's load center.
2. Snettisham is out of service 50 percent of the time during January. January is the peak month and is the coldest month of the year. This case was simulated with and without Lake Dorothy.
3. Snettisham is out of service 100 percent of the time during January. This case was simulated with and without Lake Dorothy.
4. High load growth case and Snettisham is out of service 100 percent of the time during January.

5. High fuel price and load growth case and Snettisham is out of service 100 percent of the time during January. This case was simulated with and without Lake Dorothy.

In order to assess the implications of each case on AEL&P's costs, we simulated the system using an Excel-based dispatching/planning model. For that purpose, we projected AEL&P's expected peak load, firm energy requirements and fuel prices. The projected prices are shown in Table 3-5. The projected load and energy requirements are discussed earlier in Section 2. For fuel price projections, the U.S. Energy Information Agency's (EIA) latest fuel (diesel) price projections were assumed as our base case scenario. The medium and high cases were estimated based on the calculation of historical volatility of diesel prices.

Table 3-5
Fuel Price Forecast
($/MMBtu)

	Nominal Annual Prices			Real Annual Prices		
Year	Base	Med	High	Base	Med	High
2009	14.5	15.6	16.3	13.5	14.5	15.2
2010	14.2	15.4	16.0	12.9	13.9	14.5
2011	13.8	14.8	15.6	12.2	13.1	13.8
2012	13.4	14.4	15.0	11.5	12.4	13.0
2013	12.9	13.9	14.5	10.9	11.7	12.2
2014	13.0	13.9	14.7	10.6	11.4	12.1
2015	12.6	13.6	14.3	10.1	10.9	11.4
2016	12.4	13.4	14.0	9.7	10.5	11.0
2017	12.7	13.8	14.3	9.7	10.5	10.9
2018	13.2	14.3	14.9	9.8	10.6	11.1
2019	13.8	14.8	15.5	10.0	10.8	11.2
2020	14.3	15.3	16.1	10.1	10.9	11.4
2021	14.8	15.9	16.7	10.2	11.0	11.5
2022	15.3	16.5	17.3	10.3	11.1	11.7
2023	16.0	17.3	18.1	10.5	11.3	11.9
2024	16.8	18.1	19.0	10.8	11.6	12.2
2025	17.5	18.7	19.7	11.0	11.7	12.3
2026	18.4	19.9	20.7	11.2	12.1	12.7
2027	19.1	20.5	21.7	11.4	12.2	12.9
2028	19.9	21.5	22.4	11.6	12.5	13.0
2029	20.9	22.6	23.5	11.8	12.8	13.3
2030	21.7	23.4	24.6	12.0	12.9	13.6

Under each of the scenarios, the simulation model estimated on an hourly, monthly and annual basis, the level of generation and the fuel, variable, fixed, and emission costs for every dispatched generation and contractual unit.

The following table (Table 3-6) and graph (Figure 3-4) depict the summary results of the simulated scenarios. The results show the following observations:

(6) The cost associated with an annual outage of the 138-kV line and Snettisham for two weeks in January (~5 percent forced outage rate), is about $36 million in total present value over the 2009-2018 period with an average annual impact of about $4.4 million. If the outage also causes the loss of Lake Dorothy, the cost impact rises to $40 million. The cost impact is estimated as the difference between the present value of the total system cost under the base case (which assumes no outage during January) and the present value of the total system cost under the case in which the line is assumed to be out 50 percent of the time during January of each year.

(7) If Snettisham or the 138-kV line are out of service during the entire month of January, the cost impact in total present value over the 2009-2018 period is about $44 million with an average annual impact of about $5.4 million. If the outage also causes the loss of Lake Dorothy, the cost impact rises to $52 million.

(8) Higher load growth increases the impact of Snettisham's full outage during January to $53 million in present value over the 2009-2018 period.

(9) Higher load growth and higher diesel fuel prices increase the impact of Snettisham's full outage during January to $64 million in present value over the 2009-2018 period.

(10) Depending on the outage level and duration, load growth and fuel prices, the Lake Dorothy addition will save a total of $5 to $9 million in production costs, in 2009 present value. The savings are due to the replacement of some of the standby generation costs. These savings do not account for the capital cost gains (losses) due to the impact of Lake Dorothy on the level of standby generation additions needed.

Table 3-6
Total Production Costs - Present Costs
($ million – 2009 Dollars)

	Production Costs - Present Value ($million $2009)		
Reliability / Resource Scenarios	**Total Costs with Lake Dorothy**	**Delta from Base Case**	**Total Costs w/o Lake Dorothy**
6. Base Case	$158.5	$0.0	$162.9
7. Snettisham out 50%	$194.2	$35.7	$198.3
8. Case III – Snettisham Out 100%	$202.6	$44.1	$210.6
9. Case III & High Load	$211.5	$53.0	
10. Case III & High Load and Fuel	$222.8	$64.3	

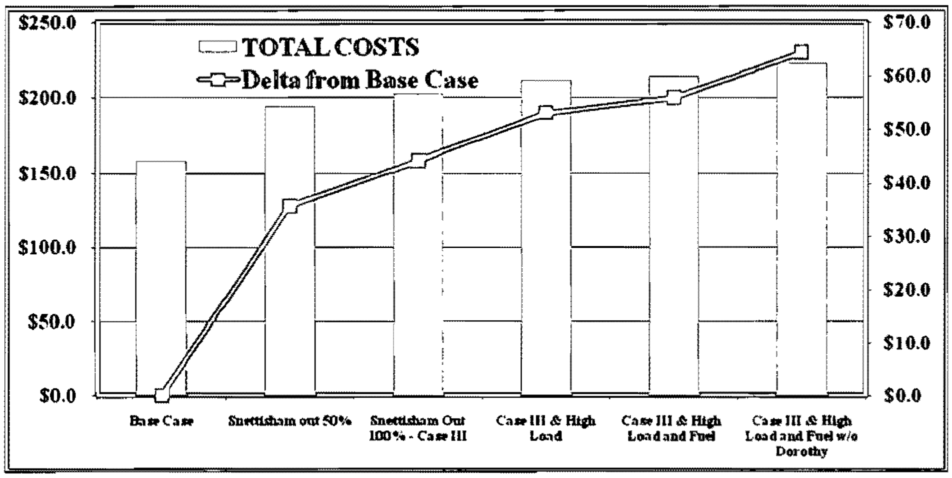

Figure 3-4: Impacts on Total System Costs Under Different Reliability Scenarios

Conclusions and Recommendations

Based on the results of investigation and analysis, R. W. Beck offers the following conclusions and recommendations:

1. AEL&P system demand and energy requirements are expected to continue to grow. The system peak load is expected to grow at 1.99 percent per year over the next 10 years. The growth projection used in this study is higher than the historical average growth rate; a higher percentile than the median was assumed in order to properly address the reliability of the system during frequent severe weather conditions.

2. AEL&P has traditionally maintained adequate generation resources to serve its peak demand in the event of failure of the 138-kV transmission line and its largest diesel generation unit. We strongly recommend that AEL&P continue that policy and keep, at a minimum, the same level of standby generation under any future supply scenario.

3. Despite the introduction of the Lake Dorothy hydro power plant, potentially by October 2009, the current level of standby generation is inadequate to supply AEL&P's peak load if its largest generation unit fails during AEL&P's stand alone operation (i.e., when Snettisham and Lake Dorothy are out of service). AEL&P will need to add about 25 MW of new standby generation between now and 2018. If a more aggressive growth in demand materializes, as depicted in the high load growth case, AEL&P will need about 35 MW of new standby generation between now and 2018.

4. The Reciprocating Engine and Combustion Turbine Diesel models are the standard recommended models for standby generation in an isolated system. There are several models available of both technologies in the market that can serve AEL&P's needs. Combustion Turbines have a higher capital cost (per kW),

higher heat rate (12,000–14,000 Btu/kWh), lower emission rate, and larger size (20 MW or higher per unit). On the other hand, Reciprocating Diesel Engines have a lower heat rate (~9,000 Btu/kWh), higher emission rate, and smaller size (2.5 MW per unit). In other words, there are cost, environmental, and reliability consequences related to the choice of standby generation technology additions.

5. Standby generation units in AEL&P system are dispatched few hours per year, if any. Therefore, their operating efficiency in terms of heat rates and emission rates are not major factors in determining the technology of choice. Their capital costs and impact on reliability of the system should be the pivotal factors. The addition of a large size unit (e.g. a combustion turbine) may have the advantage of lower cost per unit of kW, but will have the disadvantage of increasing the risk of the size of MW outages and, therefore, increasing the need for more backup.

AELP Standby Generator Impact Study

To Address RCA U16-067 Order 1:

Item 2 - Integration of Industrial Boulevard Power Plant into AELP Generation Fleet

Item 3 - Anticipated Load Flows Over AELP Transmission System

Alaska Electric Light and Power Company

Juneau, Alaska

August 2016

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Table of Contents

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1. INTRODUCTION

Alaska Electric Light and Power Company (AELP) generates, transmits and distributes power to customers in the City and Borough of Juneau. AELP operates 10 hydroelectric units split between 5 powerplants. Due to (1) the fact that the AELP electrical system operates as an island without any interconnections to other electric grids and (2) the remote location of the hydroelectric plants, AELP also maintains and operates a fleet of diesel-fired generation that is available for use when hydroelectric power is unavailable. AELP has a long range plan to help determine the appropriate amount of standby (backup) generation. The plan was written in 1993 and updated in 2009 by R.W. Beck.

Since 2004, the AELP peak firm demand has grown to exceed the standby generation capacity. In order to provide sufficient standby generation to cover this demand, AELP is currently in the process of installing a new standby generating unit.

AELP was required by the Regulatory Commission of Alaska (RCA) through Order No. U-16-067(1) to provide "a study showing the anticipated impacts of integrating this new generator into the AELP generation fleet" and "a study showing anticipated load flows over the AELP transmission system when the new generator is in operation and equivalent load flows when the new generator is not in operation."

2. STANDBY GENERATION PURPOSE

Because we cannot always prevent events from happening, AELP plans and operates the Juneau electric system so that when events occur their effects are manageable and the consequences are acceptable. One way of minimizing the risk to firm customers of having a prolonged outage is to provide standby (backup) generation in close proximity to customer loads. AELP policy requires sufficient standby diesel generation to meet the system peak firm load minus the largest diesel unit; this provides N-1 contingency in the event of a unit failure. The need for this contingency was proven during the avalanche in 2008. After the avalanche occurred, power was restored to Juneau using existing standby generation equipment. After several days of operation, the largest unit in the system failed due to a cracked turbine blade. Alternate units were used to provide power to Juneau until repairs could be made. Based on the age of the installed equipment and availability of alternate power sources, N-1 contingency planning is appropriate.

The existing diesel-fired generation available for use is shown in Table 1. The capacities shown in Table 1 are the maximum possible output for each unit as well as the normal output, which is the typical operating capacity of the units. These numbers differ from the generator nameplate capacity. The nameplate capacity is the rating of the generator without taking into consideration the rating of the turbine or engine which is used to rotate the generator. In the case of AELP's system, the limiting equipment is the prime mover, which is why the maximum possible output listed in Table 1 is less than the nameplate capacity.

The average age of the standby generation units at Lemon Creek is 49 years. All but three of the units were purchased as used units and installed in the 1980s; the others were installed in the late 1960s and early 1970s. At Auke Bay, the average age of the standby generation units is 42 years, with those units being installed in the 1980s and 1990s. The last standby generation unit was added to the system in 1994, which was a used 1971 Pratt & Whitney turbine. AELP maintains these units in good working condition. However, as these units near 50 years old, fatigue and degradation of internal components is an issue and running them at maximum capacity for prolonged periods of time is not practical due to the high likelihood of unit failure.

Location	Total Capacity (Maximum/Normal)	Number of Units	Comments
Auke Bay	27.7/25.2	3	Largest Unit 23/21MW
Lemon Creek	58.5/51.8	11	Largest Unit 18/16MW
Total	86.2/77MW	**Total Minus Largest Unit**	**63.2/56MW**

Table 1. Standby Capacity

System operations require spinning reserve, which is generation capacity available by increasing the power output of the generators already connected to the system. Spinning reserve is necessary to respond immediately to system load changes. For example, if a customer turns on their lights, one or more generators in the system must be able to increase power output to meet the increased demand. Typically, it is desired to have around 10% spinning reserve. (RW Beck, 2009)

The Juneau area firm peak generation is defined as the total generation on line at the time of the system peak (highest demand on the system), after subtracting the load for the Greens Creek mine. Since AELP is a winter peaking system, the cruise ships are not being served at the time of the peak. Table 2 below shows the Firm Generation Peaks since 2000. The table shows that since 2004, the firm generation peak has exceeded the N-1 capacity of 63.2MW.

Year	Generation Firm Peak (MW)	Date	Juneau Airport Temperature (F)
2000	61.3	1/17/2000	6
2001	61.2	12/16/2001	7
2002	62.8	1/27/2002	-1
2003	59.4	1/23/2003	17
2004	66.1	1/26/2004	3
2005	64.8	1/12/2005	-5
2006	69.1	11/27/2006	-5
2007	66.2(1)	12/3/2007	0
2008	66.1	2/8/2008	-8
2009	66.3	1/7/2009	-9
2010	64.9	12/20/2010	3
2011	65.7	2/28/2011	9
2012	70.5	1/16/2012	3
2013	67.8	1/28/2013	5
2014	69.2	2/11/2014	3
2015	65.3	2/7/2015	6

Note 1. This number is firm feeder load, not firm generation peak which would be approximately 5% higher due to losses.

Table 2. Firm Generation Peak

AELP's original long range plan was to install future diesel generation at the Auke Bay powerplant. However, changes in air quality regulations since the addition of the previous unit in 1994 meant that adding a new unit at the plant would require that all existing units at that location would need to be upgraded to meet the new air quality standards. This was not an economic option. Adding a new unit at the Lemon Creek plant was investigated, but resulted in similar findings. When it became evident that adding additional generation at the existing powerplants was not feasible, alternate sites were evaluated. Sites near Lena Cove and North Douglas were evaluated, but not selected. Ultimately, a site in the Mendenhall Valley was selected based on air flow patterns, proximity to transmission, access for fuel deliveries, and property availability.

3. Need For Standby Generation

Standby generation plant is needed if hydroelectric generation is not available to meet firm customer demand. The lack of hydroelectric generation can be due to a transmission fault in a variety of locations. The figure below shows the Juneau Area power system, with the location of generation facilities identified. Also shown on the map are areas where the transmission system has been damaged in the past. In recent years, there has been a lot of focus on the avalanche zone located approximately 3 miles from Snettisham, but historically the line has also been subjected to damage due to landslides and marker ball failures. In addition to the Snettisham line, the 69kV transmission system located on the Juneau road system has known areas where damage has resulted from landslides, avalanches and other storm damage. Of course, future faults can also occur in areas that have not previously experienced problems.

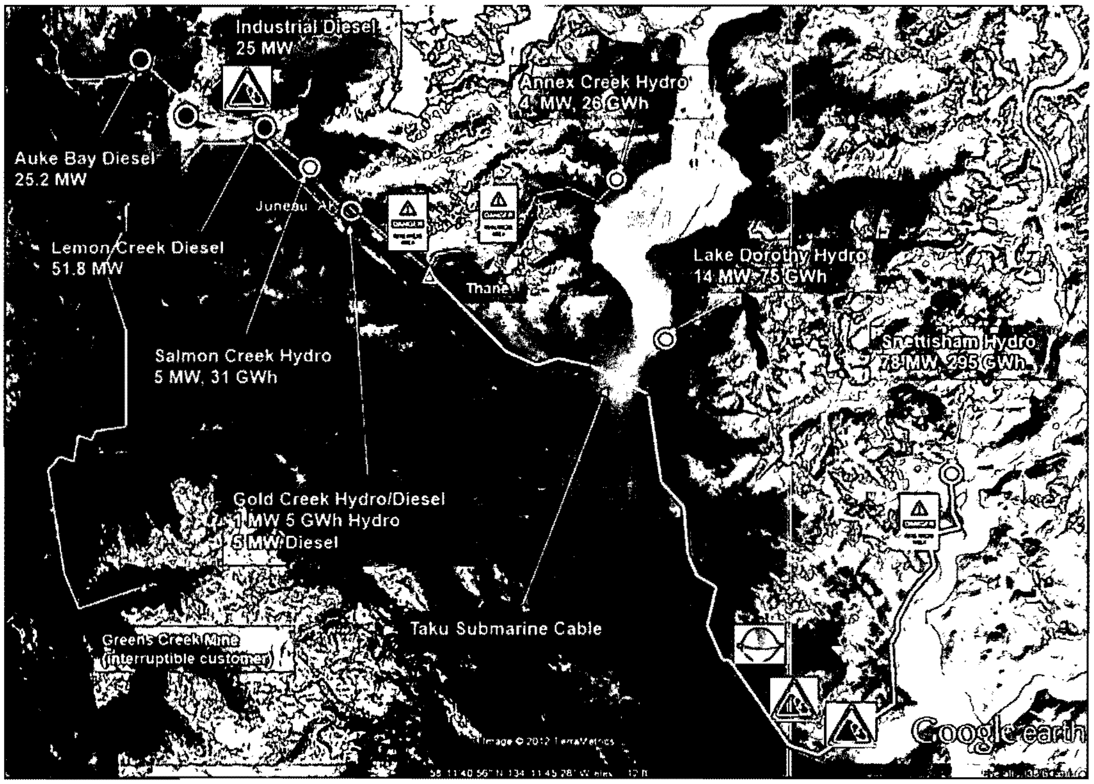

Figure 1. Fault Map

After an outage occurs, AELP engineers evaluate the cause of the outage, and when appropriate, design and install mitigation measures to reduce the risk of the same outage happening in the future. An example of this is burying 1000 feet of the uphill 69kV transmission line through the most common Thane Road avalanche chute. This allows AELP to transfer all customers to the undergrounded cable and isolate the remaining overhead transmission line prior to Alaska DOT shooting the avalanche paths on Thane Road, thereby minimizing risk to customers of an outage. Other examples of mitigation are moving pole/tower locations, moving guy wires, and installing avalanche diversion structures in the main avalanche area along the Snettisham line.

Potential new hydroelectric generation sources are available, but they are located south of Juneau and in most cases will be subject to the same outages that occur on the Snettisham line. To maintain or improve reliability, the hydroelectric generation would have to be geographically and electrically diverse from the existing hydroelectric generation. Therefore the addition of new hydroelectric projects does not offset the need for standby diesel generation.

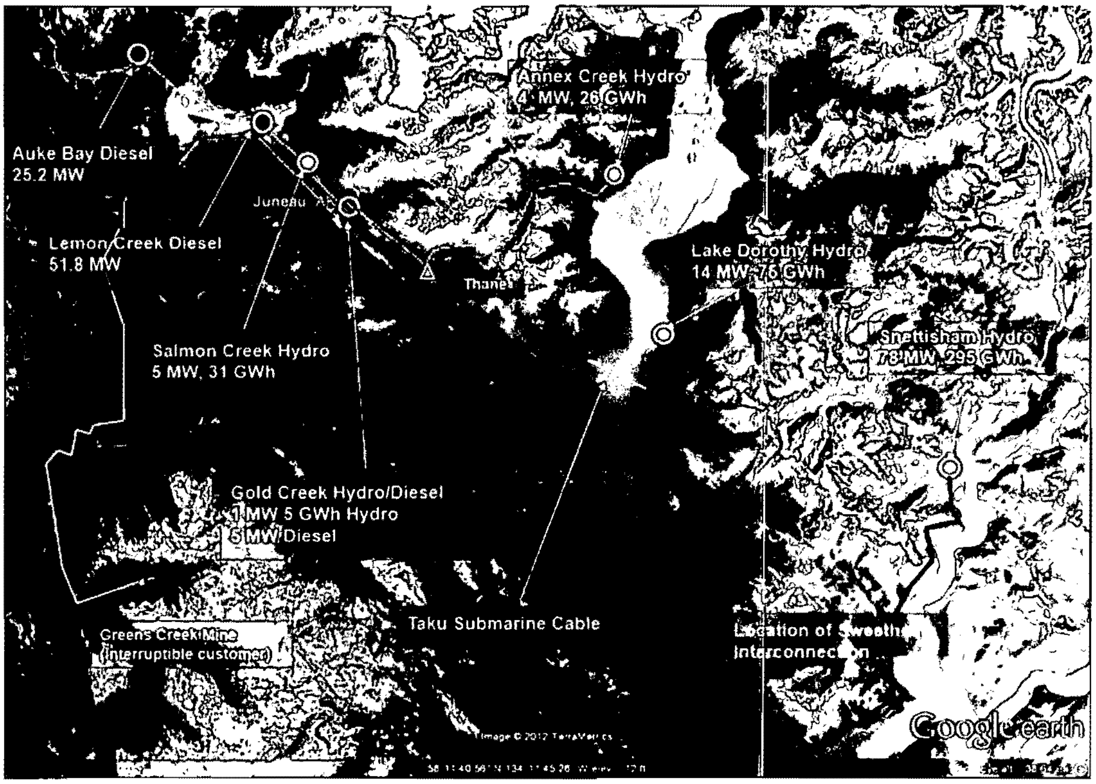

Figure 2. Point of JHI Interconnection

For example, Figure 2 shows the approximate location of the interconnection proposed by Juneau Hydropower Inc. (JHI) to the Sweetheart Project. The JHI project would utilize approximately 30 miles of the Snettisham line including the submarine cable as well as the 69kV transmission system in order to serve customers. In the event of a fault in the Thane Road avalanche zone, energy delivery from Snettisham, Lake Dorothy and Sweetheart would be severed. There have been many cases where car accidents, mudslides and storms have affected the 69kV transmission system, and even though sufficient hydroelectric energy was available, it could not be delivered to customers. The only way to reliably have power available to customers is to have generation distributed near the load centers so that customers can be served in the event of a transmission line failure. It is impossible to plan for all scenarios, but AELP has devoted significant resources to identifying contingencies and developing plans to minimize the risk to customers of having a prolonged power outage.

4. Generation Dispatch Incorporating Industrial Blvd

The AELP standby generation units are a combination of differently sized units, each with various air quality restrictions and unit efficiencies. During an emergency situation, units are selected based on availability and ease of access. However, if an outage is expected to last longer than a couple of hours, AELP Generation Engineering evaluates the situation and reviews the load profile for the previous week to determine which combination of units should be run to provide the best efficiency while not compromising unit operation due to air quality restrictions. At least one of the larger diesel-fired turbines is always selected to provide stable frequency for the system and spinning reserve. Depending on the time of year and/or time of day, the remainder of the load will be met with additional turbines, reciprocating engines, or a combination of both.

The Industrial Blvd powerplant has emissions control equipment that will make it the cleanest of all of AELP's standby units, as well as the most efficient. Therefore, it is reasonable to assume that this unit will be the primary turbine placed into service when standby diesel generation is required. However, it should be noted that the emissions controls require that the unit always be loaded above 30%. Therefore, this unit would not be selected for use if the need was less than 7.5MW.

5. Load Flow Study

Christy Yearous, P.E. of AELP has prepared this load flow study using ASPEN DistriView. A copy of the raw load flow results from DistriView are located in Appendix A. The following sections describe the methodology used for the study and summarize the results. For the purposes of this study, the 2015 peak firm load was used, meaning the highest hourly feeder loads as shown in Table 3. Note from Table 2 that 2015 was a relatively warm year with a peak load only 92% of the maximum peak load that was recorded in 2012. So, these results do not represent a complete worst case scenario.

Interruptible Customers such as Greens Creek and the Federal Building Heat are not included since they would not receive energy under these scenarios. For this study, all generation units were loaded at their Normal Rating for the reasons described in Section 2.

Lena	Loop	Auke Bay	Airport	Salmon Creek	Capital	Second Street	Lemon Creek	West Juneau
2.3MW	12.6MW	5.9MW	9.0MW	3.4MW	4.8MW	6.0MW	7.8MW	9.6MW

Table 3. 2015 Peak Firm Feeder Load

All standby generation units are run periodically for routine testing and planned outages. These scenarios have not been modeled, as they are typically limited to a few hours and are necessary for equipment and system maintenance.

In the figures below, the MW loading of the transmission lines and standby generation facilities are shown. The color green indicates that the transmission lines and/or generators are operating within their capabilities. The color red indicates that the transmission lines and/or generators are outside of their capabilities.

5.1. Scenario 1 – 138kV Outage

The scenario modeled for a complete system outage is the worst case scenario where a fault occurs between the East Terminal Building (where the 138kV submarine cable comes out of the water on the east side of the Taku Inlet) and Thane Substation. In this scenario, both Lake Dorothy and Snettisham (as well as any future hydroelectric generation facilities south of the Taku Inlet) would not be able to serve Juneau area loads.

5.1.1. Existing Generation

The load flow results show that at the 2015 feeder peak load, all of the existing standby generation units would be required. The largest unit, Auke Bay GT#14, would be loaded at 5MW and provide an additional 6MW of spinning reserve. No contingency would be available in the event of a failure of the largest unit. A summary of the load flow results are shown in Figure 3.

5.1.2. Industrial Blvd Plant in Service

The same scenario was modeled with the new standby diesel plant in service in addition to existing standby generation units. In this scenario the generation system as a whole is now in compliance with the AELP policy to have enough standby generation minus the largest diesel unit. GT#14 at Auke Bay is now out of service and in operational reserve status while Industrial Blvd. provides the spinning reserve and serves customer load as shown in Figure 4.

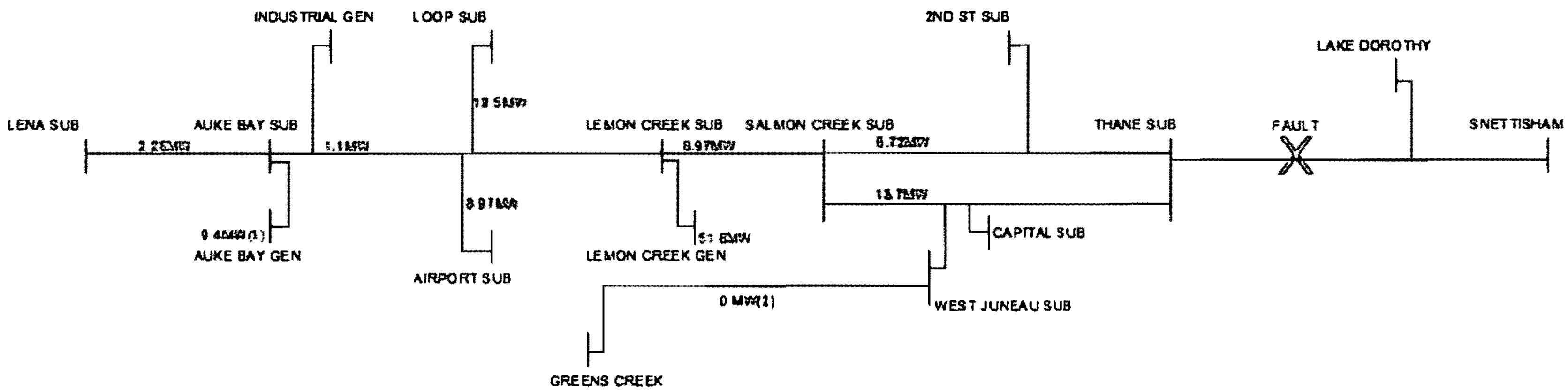

Figure 3. System Outage – Existing Generation

Note 1. All generation facilities are required to supply load, the system does not meet the AELP standby policy of having sufficient capacity with the largest unit unavailable. Auke Bay powerplant would also be providing an additional 6MW of capacity for spinning reserve.

Note 2. Interruptible customers such as Greens Creek have been removed from service and will not be taking load. In the event of a complete system outage, the line to Admiralty Island which serves Greens Creek will automatically open (i.e. disconnect the mine from AELP's electric system) and remain in that configuration until the AELP system operator switches it back into service.

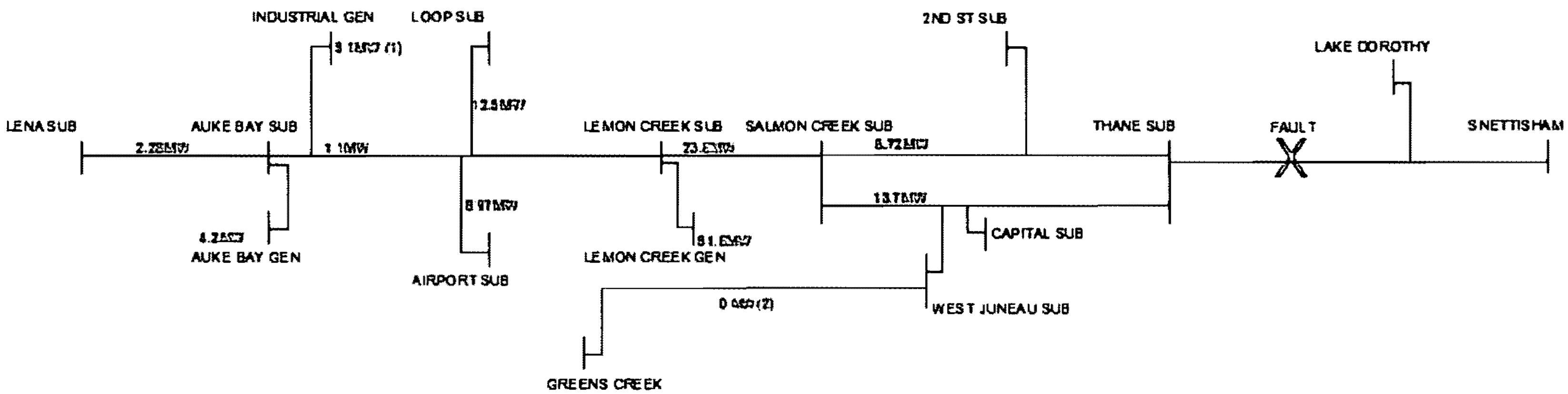

Figure 4. System Outage – Additional Plant

Note 1. Industrial Blvd. Powerplant is providing 5.1MW of generation as well as an additional capacity of 6MW for spinning reserve.

Note 2. Interruptible customers such as Greens Creek have been removed from service and will not be taking load. In the event of a complete system outage, the line to Admiralty Island which serves Greens Creek will automatically open (i.e. disconnect the mine from AELP's electric system) and remain in that configuration until the AELP system operator switches it back into service.

Exhibit CMY-4
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5.2. Scenario 2 – Mendenhall Valley Outage

In Scenario 2, a transmission fault between Lemon Creek and the Mendenhall Valley was modeled. This splits the system in half, with downtown Juneau and Douglas remaining on hydroelectric generation while the Mendenhall Valley and Auke Bay areas are without power. The scenario was chosen because of the vulnerability of the radial transmission system that extends from Lemon Creek towards the Mendenhall Valley. A fault in this area has a high impact due to the amount of customer load located in the valley and that neither Lemon Creek diesel generation nor any hydroelectric generation would be available to serve the load.

5.2.1. Existing Generation

In this scenario, the existing generation plant at Auke Bay would be used to restore power. In 2015, the peak firm load for this area was 29.2MW. The Maximum rating of the Auke Bay plant is 27.7MW. It is evident that this plant cannot cover the peak load, nor does it allow an excess capacity to cover spinning reserve.

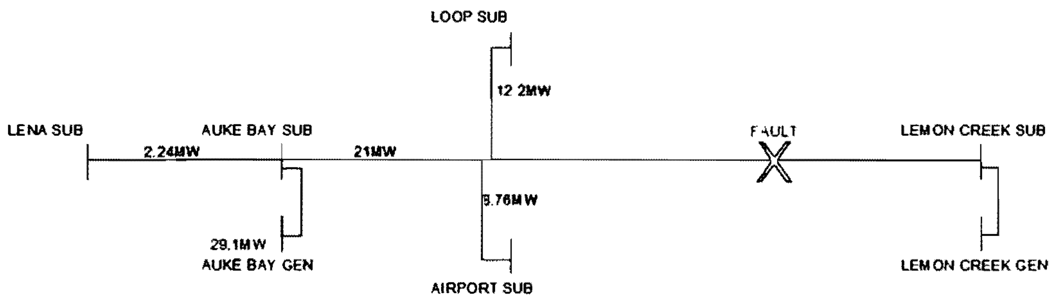

Figure 5. Valley Outage – Existing Generation

Figure 5 shows the load flow summary for this scenario. The transmission lines are all operating within ratings; however, Auke Bay generation is not adequate to supply the load. This would result in a partial blackout or rolling blackouts. Rolling blackouts mean that one or more areas would be left without power and that area would change periodically, so a customer might not have power for one hour out of every three. This is a common practice if generation resources cannot meet customer demand and was utilized in Sitka in 2010 when damage from a storm severed the transmission line connecting their hydroelectric generation to town and available standby generation was not sufficient to meet customer demand. Since that outage, Sitka has installed an addition 15MW of standby generation.

5.2.2. Industrial Blvd Plant in Service

With Industrial Blvd Powerplant in addition to Auke Bay, the two turbines can be used in conjunction to restore power to all customers and still provide spinning reserve as shown in the Figure below.

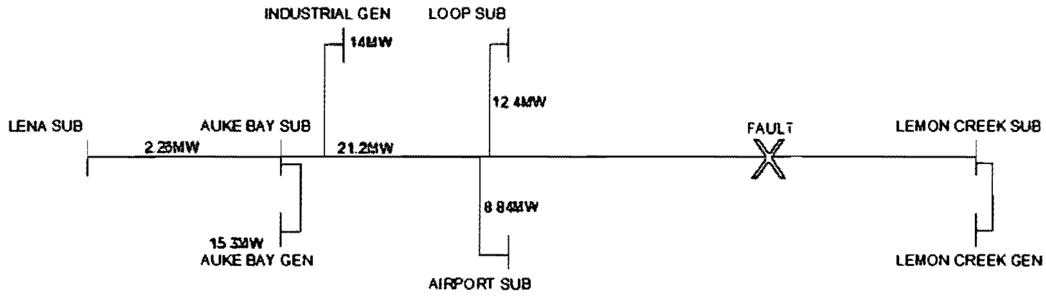

Figure 6. Valley Outage – Additional Generation

The transmission lines and generation plants are all operating within their ratings and able to provide enough power to cover the full peak load of all customers located within the affected area.

6. SUMMARY

The additional generation provided by the Industrial Blvd Powerplant is necessary to meet peak firm load in both system-wide and partial-outage scenarios. This unit is a 25MW water injected diesel-fired turbine that was selected to be the most efficient and cleanest of all AELP standby generation units. Its location in the Mendenhall Valley provides generation local to the area of dense load, which minimizes the risk that sufficient standby generation would be unavailable to serve customers in this area in the event that hydroelectric generation is unavailable.

Appendix A - ASPEN DistriView Output

Scenario 1A - 138kV Transmission Outage Existing Generation									
Bus1	Bus2	kV	I1	I2	I3	kW1	kVAR1	Loss KW	Loss KVAR
AB-LN	LENA SUB	69	19.7	19.8	19.8	2282.4	158.5	0.2	-22.4
Airport Sub.	FD Meyer	69	0	0	0	0	0	0	0
Airport Sub.	Airport Tap	69	77.7	77.7	77.7	8965.4	829.1	0.9	3.6
Airport Tap	Loop Tap	69	68.8	68.5	68	-7877.6	-886.3	0.8	3.5
Auke Bay	AB-LN	69	19.6	19.8	19.7	2284.4	78.7	1.9	-79.8
Auke Bay	T-812	69	9	9.5	9.8	1087.9	-67.5	0.1	-0.2
Capital Ave.	Capital Tap	69	41.2	41.2	41.2	4713.5	756.4	40.8	80.2
Capital Ave.	Second St.	69	0	0	0	0	0	0	0
Capital Tap	SFD Tap	69	8.9	8.9	8.9	-1030	-78.4	0	-0.1
FD Meyer	Loop Tap	69	175.7	176.9	177.6	-20391	-1922	20.6	88.3
Lemon Creek	Salm CK	69	205.2	205.3	205.2	23801	1945.2	48	222.4
Lemon Creek	FD Meyer	69	175.7	176.9	177.6	-20411.6	-2010.2	38.3	163.9
Loop Sub.	Loop Tap	69	106.9	108.5	109.7	12512.5	1032.2	13.1	55.7
Lower Salmon	Salm CK	69	28.4	28.4	28.4	3296.2	140.6	0	11.5
Salm CK	L. S. Tap	69	176.8	176.9	176.8	20456.8	1582.1	4.5	6
Second St.	Second St. T	69	49.6	49.6	49.5	5688.2	790.3	0	0
Second St. T	Tram Test	69	0	0	0	0	0	0	0
SFD	SFD Tap	69	0	0	0	0	4.2	0	-0.6
SFD Tap	Thane	69	8.9	8.9	8.9	-1030	-82.5	0.2	-0.2
T712	L. S. Tap	69	58.2	58.2	58.2	6723.9	591.7	4.1	-47.2
T712	Second St. T	69	58.2	58.3	58.2	6719.7	638.9	1.1	4.7
T808	L. S. Tap	69	118.6	118.7	118.6	13728.5	984.5	15.1	64.2
T808	Capital Tap	69	32.3	32.3	32.3	3683.6	678.6	0.2	0.7
T-812	Industrial	69	0.1	0.1	0.1	0	-10.1	0	-11.9
T-812	Airport Tap	69	9	9.5	9.8	1087.8	-57.3	0	-0.1
Thane	Tram Test	69	9	9	9	1030.4	-156.1	0.2	-281.4
Tram Test	Second St. T	69	9	9	9	1030.4	-156	0	0
West Juneau	North Doug	69	2.5	2.5	2.5	0	-295	0	-295
West Juneau	T808	69	86.6	86.6	86.6	10029.7	241.6	1.7	-3.9

Scenario 1B - System Wide Outage with Industrial Blvd. in Service									
Bus1	Bus2	kV	I1	I2	I3	kW1	kVAR1	Loss KW	Loss KVAR
AB-LN	LENA SUB	69	19.7	19.8	19.8	2280.5	158.4	0.2	-22.3
Airport Sub.	FD Meyer	69	0	0	0	0	0	0	0
Airport Sub.	Airport Tap	69	77.7	77.7	77.7	8962.7	828.9	0.9	3.6
Airport Tap	Loop Tap	69	69	68.6	68	-7891.1	-859.7	0.9	3.6
Auke Bay	AB-LN	69	19.6	19.8	19.7	2282.4	78.7	1.9	-79.7
Auke Bay	T-812	69	34.5	34.7	34.5	4001.6	102.3	1.2	4.7
Capital Ave.	Capital Tap	69	41.2	41.2	41.2	4712	756.2	40.7	80.2
Capital Ave.	Second St.	69	0	0	0	0	0	0	0
Capital Tap	SFD Tap	69	8.9	8.9	8.9	-1029.7	-78.4	0	-0.1
FD Meyer	Loop Tap	69	175.9	177	177.7	-20400.6	-1895.2	20.7	88.4
Lemon Creek	Salm CK	69	205.2	205.3	205.2	23793.9	1944.8	48	222.4
Lemon Creek	FD Meyer	69	175.9	177	177.7	-20421.3	-1983.6	38.4	164.1
Loop Sub.	Loop Tap	69	106.9	108.4	109.7	12508.7	1031.9	13.1	55.7
Lower Salmon	Salm CK	69	28.4	28.4	28.4	3295.6	140.6	0	11.5
Salm CK	L. S. Tap	69	176.8	176.9	176.8	20450.2	1581.8	4.5	6
Second St.	Second St. T	69	49.5	49.6	49.5	5686.4	790.1	0	0
Second St. T	Tram Test	69	0	0	0	0	0	0	0
SFD	SFD Tap	69	0	0	0	0	4.2	0	-0.6
SFD Tap	Thane	69	8.9	8.9	8.9	-1029.7	-82.4	0.2	-0.2
T712	L. S. Tap	69	58.2	58.2	58.2	6721.7	591.6	4.1	-47.2
T712	Second St. T	69	58.2	58.3	58.2	6717.6	638.8	1.1	4.7
T808	L. S. Tap	69	118.6	118.7	118.6	13724.1	984.3	15.1	64.2
T808	Capital Tap	69	32.3	32.3	32.3	3682.6	678.5	0.2	0.7
T-812	Industrial	69	43.3	43.9	44.2	5073.9	61	0.6	-10.4
T-812	Airport Tap	69	8.8	9.3	9.7	1071.6	-30.9	0	-0.1
Thane	Tram Test	69	9	9	9	1030	-156	0.2	-281.2
Tram Test	Second St. T	69	9	9	9	1030.1	-155.9	0	0
West Juneau	North Doug	69	2.5	2.5	2.5	0	-294.8	0	-294.8
West Juneau	T808	69	86.6	86.6	86.6	10026.4	241.6	1.7	-3.9

Scenario 2A - Mendenhall Valley Outage Existing Generation

Load flow did not calculate. Load exceeded generation capacity.

Scenario 2B - Mendenhall Valley Outage New Standby Generation

Bus1	Bus2	kV	I1	I2	I3	kW1	kVAR1	Loss KW	Loss KVAR
AB-LN	LENA SUB	69	19.7	19.7	19.7	2248.9	156.2	0.2	-21.9
Airport Sub.	FD Meyer	69	0	0	0	0	0	0	0
Airport Sub.	Airport Tap	69	77.4	77.4	77.3	8831.9	818.9	0.8	3.6
Airport Tap	Loop Tap	69	106.4	108	109.2	12321.6	1029.9	2.1	9
Auke Bay	AB-LN	69	19.5	19.8	19.7	2250.8	78.2	1.9	-78.1
Auke Bay	T-812	69	71.4	72.5	72.4	-7269.7	3949.7	5.3	22.1
FD Meyer	Loop Tap	69	0	0	0	0	-0.3	0	-0.3
Loop Sub.	Loop Tap	69	106.4	108	109.2	12319.5	1021.2	13	55.3
T-812	Industrial	69	130.7	131.3	132.3	13904.3	5864.1	5.8	1.8
T-812	Airport Tap	69	183.8	185.4	186.5	21168.3	1912.6	14.7	63.8