ALTERNATIVE GENERATION REVIEW

COPPER VALLEY ELECTRIC ASSOCIATION

November 2006

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I. INTRODUCTION

BACKGROUND

Copper Valley Electric Association ("CVEA") is a member-owned cooperative that provides electric service to users within the Copper River Basin and Valdez areas. Similar to many electric utilities throughout the State, CVEA is electrically isolated from other areas. However while most of these isolated utilities must rely nearly exclusively on diesel generation, hydroelectric power provides over half of CVEA's power requirements. At the same time, the electric isolation does limit the utility's options in meeting its remaining power requirements, and fossil fuels comprise the remaining portion of the overall resource mix.

Over the past decade or so, technological advances have been made in generation sources that do not rely on non-renewable resources for fuel. Even with these advances, resources such as wind turbines, solar, and others, were still relatively expensive to install, and the life-cycle costs were expected to be greater than that of continued reliance on generation using fossil fuels.

The increase in natural gas and oil prices over the past several years has changed that outlook. Now, while alternative sources of power may not provide immediate benefits, they are <u>at times</u> expected to be economic over the long term. Still, net benefits are typically found in large-scale applications where economies of scale can be taken advantage of.

Even though over half of CVEA's energy requirements are met with hydro power, the sharp increase in fuel prices has noticeably affected the utility's cost of power. Accordingly, CVEA commissioned the Financial Engineering Company to conduct a high-level investigation of resource options that might provide lower costs to the CVEA members. This report summarizes that analysis and findings.

METHODOLOGY

The analysis conducted herein is not a detailed power supply study that attempts to determine the type and optimum size of resource that should be constructed. Rather, this study evaluates potential generating resources using very preliminary and sometimes "generic" data to identify resources that <u>may</u> have potential in lowering the delivered cost of power to CVEA's members. This evaluation is accomplished by performing a "pre-screening analysis" where resources are compared using life-cycle costs. Since resource sizes vary significantly for the various resource options considered, the life-cycle costs are based on dollars/kilowatt-hour in lieu of strictly dollars.

For those options that may appear to have some merit, a more refined analysis is conducted that projects system costs as a whole. In this way, the effects that each potential resource has on other CVEA resources can be evaluated.

It is not within the scope of this study to project future power requirements. Since the focus of this analysis is to evaluate whether CVEA can replace its diesel generation with alternative sources of power, present loads and resource obligations are used. At the same time, potential for these alternative resources to produce more power than at current load levels is considered.

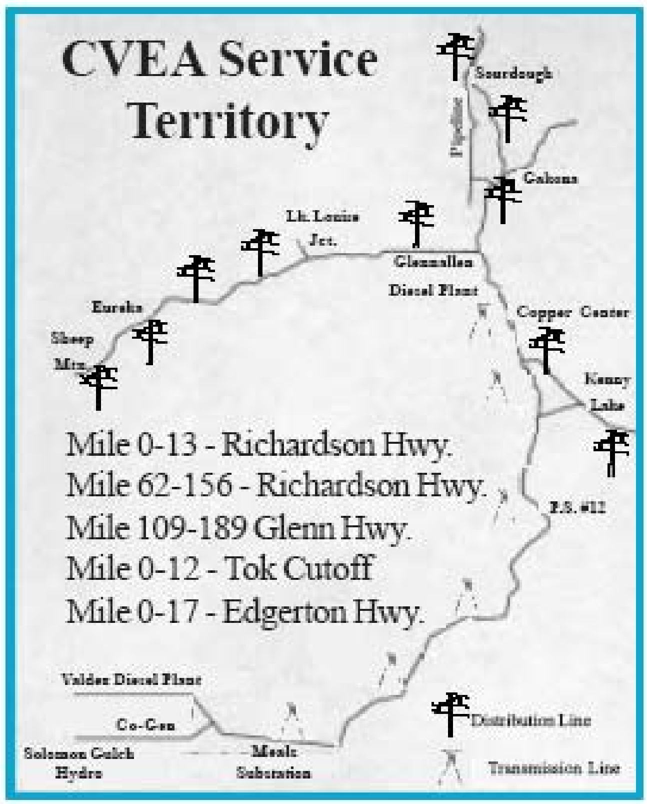
The analysis does not specifically assume natural gas being available in the CVEA area. None of the alternative resources considered, with the exception of fuel cells, use fossil fuels, and therefore, projected operating costs would not change. If gas became available, power requirements would undoubtedly change significantly, both in the short- and long-term. At that time, CVEA will evaluate the benefits of converting or replacing existing resources with natural gas.

II. CVEA SYSTEM

SERVICE AREA

CVEA's service area encompasses a large geographic area that runs from Gakona to Valdez. The service area can essentially be separated into two areas, the Copper River Basin area ("CRB") in the north and Valdez to the south. The two areas are interconnected with a 106-mile, 138-kV transmission line, which is subject to outages due to avalanches. Resource planning and reserve capacity are, therefore, accomplished on a system wide basis while ensuring that each area can maintain load in the event the transmission line is unavailable. A map of the service area is provided in Figure 1.

Figure 1
CVEA Service Area



CUSTOMERS AND LOADS

Over the past decade, CVEA's customer base has increased on average by slightly over 2 percent per year (Table 1). Energy sales have also increased, albeit at a lesser amount. One customer, the Petro Star Refinery in Valdez, accounts for over 15 percent of CVEA sales.

Table 1
Historical Load Data

	1995	2003	2004	2005	Annual Growth (1995 - 2005)
Customers					
Core Load					
Copper River Area	1,238	1,592	1,619	1,628	2.8%
Valdez Area	1,689	1,995	2,011	2,007	1.7%
Subtotal	2,927	3,587	3,630	3,635	2.2%
Petro Star	1	1	1	1	0.0%
Total	2,928	3,588	3,631	3,636	2.2%
Energy Sales (000 kWh)					
Core Load					
Copper River Area	20,315	25,604	26,101	25,800	2.4%
Valdez Area	38,117	39,256	39,173	39,126	0.3%
Subtotal	58,432	64,860	65,274	64,926	1.1%
Petro Star	13,403	10,821	11,704	12,435	-0.7%
Total	71,835	75,681	76,978	77,361	0.7%
System Peak (000 kW)					
Copper River Area	4.8	4.5	5.1	4.4	-0.9%
Valdez Area/Petro Star	9.3	9.1	9.1	8.7	-0.7%
Total[1]	13.2	13.1	13.2	12.7	-0.4%

1 Total is less than the sum of the individual areas due to diversity between the two areas.

FUTURE LOADS

In 2005, approximately 27 percent of CVEA's total energy sales were to six customers. This large usage by a small portion of the customer base lends to difficulties in projecting future loads with some degree of certainty. Indeed, the utility has experienced a number of large increases and decreases in energy sales in the past, and such swings can, and most likely will, occur in the future. Power supply planning for large resource additions must take into account both potential increases and decreases in load.

As described in the Introduction, it is not within the scope of work for this study to project future power requirements. Instead, present loads and resource obligations are used.

EXISTING RESOURCES

CVEA's primary source of power is from the Solomon Gulch Hydroelectric Project, a 12-megawatt hydroelectric facility owned and operated by the Four-Dam Pool Power Agency. Due to the seasonality of the power production from this resource, CVEA must rely on other resources during the winter months. Most important of these is a 5.2-megawatt cogeneration facility where exhaust heat is recovered and sold to and used by Petro Star for refining purposes. Diesel-fueled reciprocating gensets are also operated and maintained by CVEA for supplemental power requirements and for reserve purposes. A description of these resources follows, and a summary of their interrelationships is provided at the end of this section.

SOLOMON GULCH

Solomon Gulch is a 12-megawatt hydroelectric facility located near Valdez. The project was one of four hydroelectric facilities constructed by the State of Alaska in the 1980's and became part of what was then known as the Four Dam Pool. None of the four dams in the Four Dam Pool are interconnected with one another.

In January 2002, all four projects were turned over to the Four Dam Pool Power Agency ("FDPPA"). Under the terms of its power purchase agreement with FDPPA, CVEA is obligated to purchase all the power that can be produced from Solomon Gulch that is usable in CVEA's total loads over the course of a year. The cost of power includes two components: debt service and O&M. The debt service component is set at $0.04/kWh unless sales exceeded a certain amount, and operating and maintenance costs of the four projects are shared equally (on a per kilowatt-hour basis) by all participants in the Four Dam Pool. The power sales agreement terminates in 2030.

Like most hydroelectric resources, Solomon Gulch represents a long-term investment that will have significant financial benefits, especially when the debt service component terminates. For purposes of this analysis, Solomon Gulch is assumed to be part of the CVEA system for the long term.

On an annual basis, Solomon Gulch provides slightly over 60 percent of CVEA's energy requirements. During the course of a year, however, generation varies considerably. During June – August, the resource can provide for most, if not all, of CVEA's total power requirements and most of the requirements in September and October. During the winter, there is relatively little inflow into the reservoir, and the reservoir is gradually drawn down for generation such that it is empty by spring. (See Figure 3 on page 10.)

Important points to consider for Solomon Gulch include:

1. CVEA must purchase project output if it can be used prior to the use of other CVEA resources.
2. The term of the power purchase agreement expires in 2030. At that time, it is expected that the price will decrease significantly once the debt service

component of the rate is terminated. For purposes of this analysis, it is assumed that the resource will be a part of the CVEA resource mix for an indefinite period.

3. Generation is seasonal with nearly two thirds of the generation occurring during the June – October time period.
4. Generation can vary by year depending on the availability of water for generation.

COGENERATION PROJECT

In April 2000, CVEA completed construction of and began operation of a 5.2-megawatt combustion turbine located at the Petro Star refinery in Valdez. Electric power from the facility is used directly by CVEA, and the ensuing exhaust heat is recovered and sold to Petro Star for refining purposes. Fuel is Light Straight Run ("LSR"), an oil-based fuel produced by Petro Star at its refinery and sold to CVEA under the terms of a fuel sales agreement between the two parties.

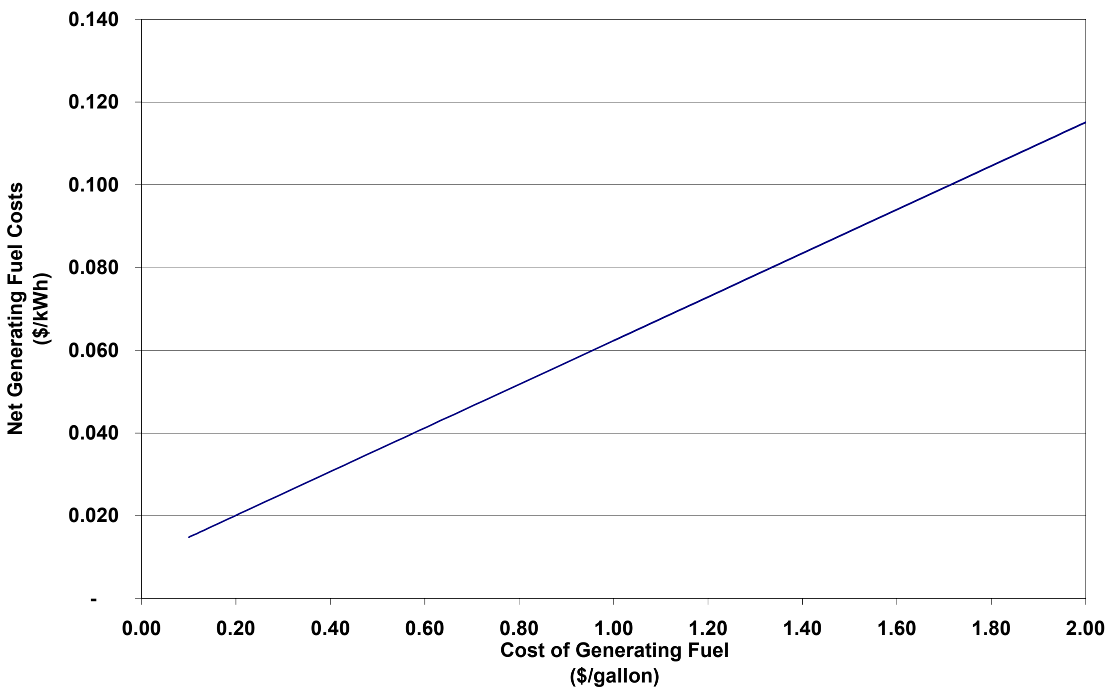
Heat is sold by CVEA to Petro Star pursuant to the terms and conditions of a 15-year heat sales agreement. The agreement obligates CVEA to operate the resource a minimum of 5,500 hours per year subject to availability of and required purchases from Solomon Gulch. Petro Star, in turn, agrees to purchase 30 million BTU's per hour of exhaust heat at a rate equal to the price of fuel (in $/BTU).

Since the revenues from heat sales are directly related to the cost of fuel, the net cost of generating fuel is partially shielded from changes in fuel price. For example, a $1.50/gallon fuel cost equates to $0.177/kkilowatt-hour at the expected generating efficiency and energy content of LSR. (See Table 2.) This amount is offset in part by the heat sales, and the resulting net cost of fuel is half that, or $0.089/kilowatt-hour. As fuel costs increase, revenues from heat sales also increase, thereby partially shielding the net generating costs from upward (or downward) movements in fuel prices. The net fuel costs provided in Figure 2 for a range of LSR prices show that for every 10 percent increase or decrease in the price of fuel (in dollars/gallon), the fuel component of generation (in dollars/kWh) changes by approximately 5.3 percent.

Table 2
Net Fuel Prices – Cogeneration Project

Fuel Cost ($/gallon)	$ 1.25	$ 1.50	$ 1.75
Adder	0.18	0.18	0.18
Total Fuel Cost	$ 1.43	$ 1.68	$ 1.93
Fuel Energy (BTU/gallon)	110,000	110,000	110,000
Assumed Generating Efficiency (kWh/gal)	9.50	9.50	9.50
Winter Rating (kW)	5,200	5,200	5,200
BTU Purchase (MMBTU/hr)	30	30	30
Fuel Cost ($/kWh)	0.15	0.18	0.20
Fuel Cost ($/MMBTU)	13.00	15.27	17.55
Cost of Fuel ($/kWh)			
Fuel	$ 0.151	$ 0.177	$ 0.203
Revenues	(0.075)	(0.088)	(0.101)
Net	$ 0.076	$ 0.089	$ 0.102

Figure 2
Net Fuel Cost – Cogeneration Project



Due to its obligations to operate a minimum number of hours per year (subject to the availability of Solomon Gulch), the cogeneration project is typically dispatched second after hydroelectric power. In the past three years, the cogeneration project provided, on average, approximately 25 percent of CVEA's total power requirements. (See Table 4 on page 10.)

Important points to consider for the cogeneration project are:

1. CVEA must operate the resource a minimum of 5,500 hours per year (subject to the availability and usability of Solomon Gulch).
2. The term of the heat sales agreement and fuel purchase agreement is 15 years and will expire in April 2015.
3. Generating costs are partially sheltered from price increases in fuel due to heat sales.
4. Operation as a cogeneration resource where heat is recovered increases the total efficiency to very high levels.

Diesel

CVEA's existing resource mix also includes a number of reciprocating gensets fueled with diesel. These units, located in both Glennallen and Valdez, serve two purposes. During times when peak and energy requirements cannot be met entirely from Solomon Gulch and the cogeneration plant, the diesel units are dispatched. Typically, the units in Glennallen are dispatched first since they are more fuel efficient and the use of the generators keeps the buildings warm.

The production costs summarized in Table 5 on page 11 show that the cogeneration project is less expensive than diesel only when heat is sold. Without heat sales, CVEA's diesel units are more economic to dispatch than the cogeneration project. Heat sales are contractually set until April 2015.

The second use of the diesel generators is that of reserves. Electric utilities must have a certain amount of reserve capacity (installed capacity less peak load) such that load can be provided for in the event one or more units are out of service during peak periods. In isolated areas such as CVEA, the <u>minimum</u> reserve requirement is "n-1" where the utility has sufficient capacity to meet peak load in the event the largest unit is unavailable. The transmission link between CRB and Valdez is, however, susceptible to avalanche failure, thereby electrically isolating the two areas from one another. Therefore, the utility maintains reserves based on "n-2" in each area such that each peak load can be met if both the intertie is out and the largest diesel unit in the area is out.

Recently, CVEA adopted a policy that excluded several of its smaller units from evaluations of reserve adequacy. While these units can be relied on for emergency purposes, the utility believes it prudent to not rely on them for long periods of time that might occur in the event the transmission line between Glennallen and Valdez is out of service. Therefore, the summary of resources in Table 3 on the next page shows a deficiency of reserves in the CRB area. The utility is now exploring various options for augmenting its reserve capacity in that area.

Table 3
Summary of Installed Capacity
(kilowatts)

	Summer			Winter		
	CRB	Valdez	System	CRB	Valdez	System
Solomon Gulch						
Unit 1	-	6,500	6,500	-	4,000	4,000
Unit 2	-	6,500	6,500	-		-
Cogeneration Plant		4,900	4,900		5,300	5,300
Diesel						
Unit 1	320		320	320		320
Unit 2	320	597	917	320	597	917
Unit 3	560		560	560		560
Unit 4	597	1,800	2,397	597	1,500	2,097
Unit 5	597	2,200	2,797	597	2,200	2,797
Unit 6	2,200	900	3,100	2,600	900	3,500
Unit 7	2,200	2,800	5,000	2,600	2,800	5,400
Unit 8	1,100		1,100	1,200		1,200
Total	7,894	26,197	34,091	8,794	17,297	26,091
Operational[1]	5,500	25,600	31,100	6,400	16,700	23,100
Largest Unit	2,200	6,500		2,600	5,300	
Firm Capacity	3,300	19,100		3,800	11,400	
2005 Peak	4,300	9,500		5,500	8,700	
Reserves	(1,000)	9,600		(1,700)	2,700	
Years to Insufficient Reserves at Specified Annual Load Growth:						
1%	0	>25		0	>25	
2%	0	23		0	24	
3%	0	16		0	16	

1 Operational capacity, used for evaluating reserves, does not include Units 1 – 5 in the CRB area and Unit 2 in the Valdez area.

Figure 3
Monthly Generation
(2002 – 2005 Average)

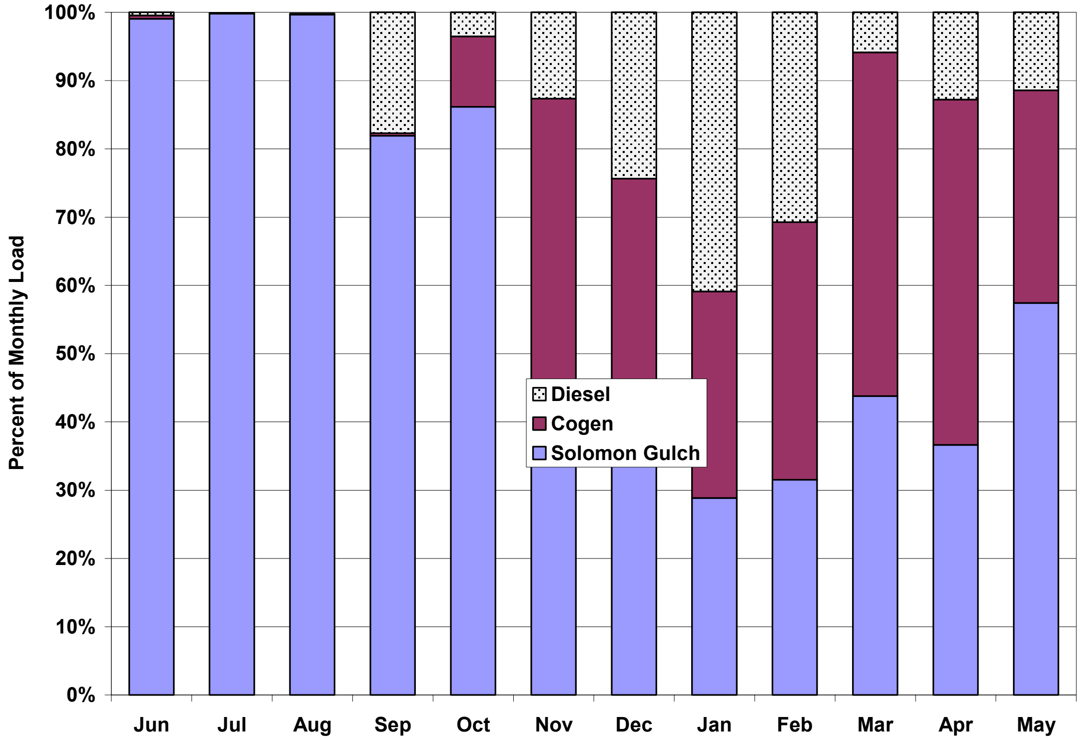


Table 4
Historical Production by Resource
(kilowatt-hours)

	2003	2004	2005	3-year Average
Solomon Gulch	51,812,830	51,352,790	49,427,430	61.1%
Cogen	21,483,872	21,429,181	20,518,956	25.4%
Diesel	8,450,132	10,972,370	14,177,947	13.5%
Total	81,746,834	83,754,341	84,124,333	100.0%

Table 5
Production Cost – Fuel Only

	2003	2004	2005
Solomon Gulch ($/kWh)			
Debt Service	0.040	0.040	0.040
O&M	0.028	0.028	0.028
Total	0.068	0.068	0.068
Cogeneration			
Fuel Cost ($/gallon)	0.939	1.129	1.616
Generating Costs ($/kWh)			
Gross Fuel	0.100	0.121	0.175
Heat Sales (Est)	(0.049)	(0.059)	(0.085)
Net Fuel	0.051	0.062	0.090
Diesel			
Fuel Cost ($/gallon)	1.048	1.311	1.748
Generating Costs ($/kWh)	0.073	0.093	0.123

III. PRE-SCREENING ANALYSIS

GENERAL

Besides construction and operating costs, resource economics are also highly dependent on energy usage. At times, not all energy that can be produced is usable due to both load and production patterns. CVEA's obligation to purchase hydro further complicates matters as do the economics of the cogeneration project and heat sales. If operations of the cogeneration project are significantly curtailed due to an alternative resource being less expensive, overall electric sales could drop if Petro Star discontinued or significantly curtailed capacity and energy purchases from CVEA.

In this section, alternative resources that could displace diesel generation are pre-screened on a high-level basis. Detailed assessments have not been performed, and construction and operating costs are based on preliminary and sometimes "generic" estimates. Even without detailed cost estimates for specific resource concepts, industry data supplemented by the experience of other utilities in the state will allow reasonable assessments to be made and proper courses of action taken.

Annual costs for each resource are based on level amortization of all capital costs at a 7.5 percent interest rate over the specified number of years. Life-cycle costs, projected on a dollars/kilowatt-hour basis, are based on the present value of the annual costs during the assumed life divided by the total energy over the same period. Load growth is not assumed for this pre-screening analysis.

A summary of all resources is provided at the end of this section and compared to continued reliance on existing resources (Table 12). For those resources that appear to have some merit, a more refined evaluation is provided in the next section.

GEOTHERMAL

Geothermal powered resources are very site specific and must be located at or very near an underground source of heat. Hot water or steam is extracted from the ground where it is used to drive a turbine. There are three separate technologies used in geothermal power. These include:

1. Dry Steam. Very hot (>450 degrees F) steam with little water is extracted and run directly to the turbine.
2. Flash Steam. Hot water (>360 degrees F) is extracted and run through a flash tank. With the sudden loss of pressure, the water vaporizes and is then run through the turbine.
3. Binary. Water that is more moderate in temperature (225 - 360 degrees F) is extracted and pumped through a heat exchanger. There, the heat in the water is used to flash a secondary fluid with a flash point lower than water. The steam is then run through the turbine, condensed back to water, and reused.

Geologic conditions must be just right for geothermal power. Not only is a large natural heat source required but large amounts of ground water must be near that heat source. Consequently, geothermal resources are found in relatively few locations throughout the world. When conditions are right, however, this technology has been quite successful in providing long-term economic power.

Development of geothermal resources requires extensive field development where test wells are dug and, if the fluid is deemed to be available in sufficient quantities, production and re-injection wells drilled. The overall cost structure is relatively capital intensive, and baseload operations are typically required for the resource to be economic.

Capital costs (in $/installed kW) can vary significantly. Some of the more important influencing factors include: the technology being used (dry steam, flash steam, binary), unit size, location, transmission requirements, land acquisition, and others. One industry source provides the following information regarding capital costs.

- Capital costs for small plants: $1,900 – 3,500/kW (current dollars)
- Drilling costs: $ 1 – 4 million per well
- Drilling costs: 30 - 50 percent of the total capital costs

Another source indicates a cost "as low as $2,800 per kilowatt," thus inferring near optimal conditions. The source goes on to say that a binary plant could be up to four times as much as a flash steam plant, and transmission costs can also add significantly to the overall cost structure.

Geothermal resource maps indicate a potential area east of Glennallen in the Wrangell-St. Elias National Park & Preserve. It is unknown at this time whether detailed data has been collected, and the availability and temperature of geothermal fluid is not known. Based on the assumption that there is a geothermal fluid available, a preliminary assessment of resource economics was conducted.

Based on the remoteness of the potential resource, lack of remote sensing, anticipated size, and current drilling climate, the following assumptions were made:

- Unit Size: 5,000 kW
- Wells required: 3
- Cost per well: $5 million
- Other facilities except transmission: 2 x that of drilling
- Transmission: 20 miles at $1,000,000 per mile

Usable energy is based on the geothermal resource being able to meet 90 percent of the requirements currently being met with the cogeneration and diesel plants subject to the maximum capability of 5,000 kilowatts. Thus the project assumes that the agreements with Petro Star are not renewed at the end of the current terms.

Table 6
Geothermal Costs

Assumed Capacity		5,000	kilowatts
Capital Costs:			
Drilling	$	15,000,000	
Project		30,000,000	
Transmission		12,000,000	
Capitalized Interest		2,100,000	
Total	$	44,100,000	
Annual Debt Service (30 years)	$	3,734,001	
Annual Operating Costs		1,000,000	
Total Annual Costs	$	4,734,001	
Expected Usable Energy		25,900,000	
Total Costs ($/kWh)			
Initial Year	$	0.183	
Life Cycle (30 years)			
0% Discount Rate	$	0.203	
7.5% Discount Rate	$	0.083	

The above costs are based on the assumption that a usable geothermal fluid is located relatively close to the CVEA system. Furthermore, preliminary exploration work, remote sensing, and drilling of a test well(s) can add significantly to the overall capital requirements shown in the table. Thus, the costs shown above should be considered very preliminary at this time and on the lower end of the anticipated range to be expected if a usable geothermal fluid is indeed available.

FUEL CELLS

Although this technology has been in existence and used for a number of years, commercial applications are very limited. Fuel cells use hydrogen-rich fuels and through a chemical process produce electric power. Although many types of fossil fuels can, in theory, be used, a great deal of research and testing is yet to be performed on the use of fuel oils. Currently commercial applications are limited to “clean” fuels such as natural gas, propane, other natural gas liquids, and hydrogen itself.

Fuel cells have a number of drawbacks at this time including it being a relatively new technology and continued reliance on fossil fuels. Capital costs, too, are quite high at this time, and research is now focused more on transportation and small applications with the use of pure hydrogen being used as the fuel.

Here in Alaska, two commercial applications have been evaluated. Several years ago, Chugach Electric Association installed a 1,000-kilowatt fuel cell to provide for power requirements at an adjacent postal facility. After several years of operations, the conclusion was that power was being produced for about twice the cost available from other resources. The project was dismantled in 2004.

In 2003, Fairbanks Natural Gas ("FNG"), in conjunction with the U.S. Department of Energy's National Energy Technology Laboratory, installed a 5-kilowatt fuel cell at FNG's facilities in Fairbanks. The unit ran from August 2003 until September 2004 when it was shut down.

Current capital cost estimates are now in the range of $3,500/kilowatt. A fuel supply must also be secured, with propane being the only reasonable alternative until natural gas is available in the CVEA area. The availability of natural gas is not expected to significantly change the overall economics of the resource.

Table 7
Fuel Cell Costs

Assumed Capacity		200	kilowatts
Capital Costs:			
Project	$	700,000	
Capitalized Interest		-	
Total	$	700,000	
Annual Debt Service (20 years)	$	68,665	
Annual Operating Costs			
Fuel		366,606	
Other		25,000	
Total Annual Costs	$	460,271	
Expected Usable Energy		1,401,600	
Total Costs ($/kWh)			
Initial Year	$	0.328	
Life Cycle (20 years)			
0% Discount Rate	$	0.415	
7.5% Discount Rate	$	0.215	
Propane Use @ 40% Efficiency		18.60	gal/hr
Propane Cost ($/gallon)		2.25	

The above costs do not include any benefits from the recovery of heat from the resource. The resource will produce some amount of hot water and other heat, but given the high cost of power production, the benefits from recovered heat would not significantly change the economics of the resource.

SOLAR PHOTOVOLTAIC

Once used in very limited applications, solar photovoltaic panels have garnered a recent amount of public awareness. In the past year alone, installations here in the U.S. nearly doubled from that of the previous year. Still, costs remain considerably higher than alternative energy sources, and it is only though federal and state subsidies that installations can be expected to provide economic benefits in the long term.

Besides the obvious limitation of requiring sunlight, one of the disadvantages of solar panels is that current efficiencies in converting sunlight to energy are low. With current production processes, conversion efficiencies range in the 9 – 14 percent range, with a theoretical maximum of around 30 percent. New methods of production are now being developed that are expected to raise the practical limit to 30 percent or more. These low efficiencies create large space requirements for utility-scale applications. Therefore, installations have typically been in small-scale applications.

Capital costs have decreased significantly over the past decades, decreasing from $27/watt (DC) in 1982 to around $4/watt (DC) today. These costs are for just the panels, and other costs will be required including power converters, transformers, land, and others. A complete installation can be as much as $10,000/kilowatt (AC).

Based on historical data collected by the federal government, a 385-kilowatt system in Gakona would produce approximately 477,500 kWh per year, a capacity factor of 14 percent.

Table 8
Solar Costs

Assumed Capacity	385	kilowatts
Capital Costs:		
Project	$ 3,850,000	
Capitalized Interest	-	
Total	$ 3,850,000	
Annual Debt Service (20 years)	$ 377,655	
Annual Operating Costs	50,000	
Total Annual Costs	$ 427,655	
Expected Usable Energy (kWh)	477,500	
Total Costs ($/kWh)		
Initial Year	$ 0.896	
Life Cycle (20 years)		
0% Discount Rate	$ 0.928	
7.5% Discount Rate	$ 0.504	

WIND

Easily the most prevalent of "green" resources being considered, installation of new wind turbine capacity in the U.S. has been unparalleled in the past decade. Supported by technologic advances in the equipment, tax credits and other financial incentives, and high fuel prices, total installed capacity has increased from 2,000 megawatts in 1999 to 10,000 megawatts in 2006.

In the Lower-48, projects are dominated by large-scale installations with total installed capacities of up to 200 megawatts and numerous turbines. Even with these large installations, officials cite the continued need for tax credits and other financial incentives in order for the industry to grow. In Alaska, a number of small-scale turbines have been installed, but federal grant funds have financed most of these costs, and true economics are difficult to obtain.

Energy from wind turbines is proportionate to the cube of wind speed, and a site with an average wind speed of 16 mph will have 50 percent more production than a site with an average wind speed of 14 mph. Therefore, site selection is very important, and one or more years of wind monitoring is typically performed at potential sites prior to installing a turbine. From this data, energy from wind production can be modeled while taking into account detailed wind speed data and periods when units are shut down due to too much or too little wind. Such detailed monitoring has not been performed at potential sites in the CVEA system. Historical data at federal weather stations is available, but this data is usually at sites quite some distance from where the turbine is to be placed. Furthermore, the data is typically somewhat limited in detail and will not fully disclose how turbulent the wind might be.

In Alaska, Kotzebue Electric Association, Alaska Village Electric Cooperative ("AVEC"), and TDX Power have all installed wind turbines. Installed costs are as high as $6,000/kilowatt due to the small size of turbines being placed and high installation costs. In the Lower-48, the norm for installation costs in larger installations is approximately one third of the equipment costs; whereas here in Alaska, installation costs can be equal to or even exceed equipment costs.

The installations of these three utilities are all located in western Alaska on coasts or areas with very little vertical relief. Winds in these areas are typically steady and from a single, general direction – both factors that favor power production. Mountainous terrains, such as that found in much of the CVEA area, tend to produce gusty winds, and direction can change 180 degrees in very short periods of time – factors that significantly reduce power production. Although the average wind speed in these areas may appear to be favorable, it is not uncommon for wind gusts to reach speeds where turbines will go into a "brake" mode and shut down operations. Snow depths in the Thompson Pass and other potential areas can reach depths that require tower heights that quickly erode any remaining economics. Areas on ridges where wind direction and speed and snow depths may be more favorable are located quite some distance from CVEA's existing infrastructure, and the capital costs associated with the required transmission lines would also quickly erode resource economics. Finally, icing on turbine blades will be an important issue in many areas.

Two wind consultants recently visually inspected potential areas in the Thompson Pass area and felt that wind turbines would likely not be feasible due to the conditions just listed.

There may be other areas within the CVEA area other than Thompson Pass that are more favorable to wind turbines, but the distance from the site to CVEA's existing transmission infrastructure will be an important issue. Potential costs for a 1-megawatt installation are provided in the following table. Capital costs are based on preliminary quotes from vendors with installation costs assumed to be 60 percent of equipment costs. For purposes of this estimate, the site is assumed to be five miles from CVEA's existing transmission infrastructure.

As described earlier, energy production is very site specific. Without identifying a particular site, corresponding estimates of the expected annual energy cannot be made. A range of energy production is therefore provided based on the upper threshold of what might be found in the CVEA area.

Table 9
Wind Costs

Turbine Nameplate Rating		250	kilowatts	
Number of turbines		4		
Total Installed Capacity		1,000	kilowatts	
Capital Costs:				
Project	$	2,560,000		
Transmission		4,000,000		
Capitalized Interest		-		
Total	$	6,560,000		
Annual Debt Service (15 years)	$	743,164		
Annual Operating Costs		50,000		
Total Annual Costs	$	793,164		
Assumed Usable Energy				
Capacity Factor		40%		30%
Energy (kWh)		3,504,000		2,628,000
Total Costs ($/kWh)				
Initial Year	$	0.226	$	0.302
Life Cycle (20 years)				
0% Discount Rate	$	0.229	$	0.306
7.5% Discount Rate	$	0.145	$	0.193

COAL

Even with the amount of coal reserves that are located in the State, there are limited coal-fired resources. Part of this stems from the accessibility to the reserves, part from the capital costs of coal, and part from the relatively low cost of alternative sources of power.

Economics of coal-fired resources favor large-scale plants with operations at full output at all times. Small projects or low-use projects quickly become uneconomic.

In order to assess costs in a preliminary manner, the expected costs of a 25,000-kilowatt resource were reviewed, and these are summarized in Table 10. Two separate energy production numbers are used: 80 percent plant factor and 25 percent plant factor. Very little of the energy output of the resource could be used by CVEA, and therefore the costs were projected for the lower capacity factor. Still, the cogeneration project would have to be shut down for even this lower amount to be used.

Table 10
Coal Costs

Nameplate Rating	25,000 kilowatts	
Capital Costs:		
Project	$ 200,000,000	
Capitalized Interest	30,000,000	
Total	$ 230,000,000	
Fixed Operating Costs n($/year)	$ 3,750,000	
Variable O&M ($/kWh)	$ 0.00675	
Fuel ($/kWh)	$ 0.0263	
Annual Debt Service (20 years)	$ 22,561,204	
Fixed O&M	3,750,000	
Total Annual Costs - Fixed Only	$ 26,311,204	
Assumed Usable Energy		
Capacity Factor	80%	25%
Energy (kWh)	175,200,000	54,750,000
Total Costs - Initial Year ($/kWh)		
Fixed	$ 0.150	$ 0.481
Variable O&M	0.007	0.007
Fuel	0.026	0.026
Total	$ 0.183	$ 0.514

HYDROELECTRIC

Several potential hydroelectric resources have been investigated in the CVEA area. Typically, hydro resources are relatively capital intensive with low operating costs. Thus, a potential resource may be expected to be economic over the life of the project, but costs in the early years are prohibitively expensive. The relative remoteness of the CVEA system and sites being considered would add even more to capital costs, further exacerbating the high costs during the early years. Another factor that must be considered is that most hydroelectric generation in the area would come during the summer months, a time when Solomon Gulch is meeting most, if not all, of CVEA requirements. Therefore, a new hydro resource must have significant amounts of generation during the winter months for it to have any affect on displacing meaningful amounts of oil-fired generation.

ALLISON LAKE

Foremost of the hydro resources that have been investigated is the Allison Lake project. The project would divert water from Allison Lake into the Solomon Gulch reservoir through a tunnel of approximately 12,000 feet in length. Prior to entering the Solomon Gulch reservoir, water would pass through a powerhouse for power generation. Water would then be released as needed from the reservoir and generate power from the existing Solomon Gulch powerhouse. Most of the diversions would occur during the winter months when the existing reservoir is depleted and therefore would displace oil-fired generation. Average annual energy production was estimate to be approximately 27,396,000 kilowatt-hours.

A 1991 study estimated the costs to be $30.9 million excluding financing costs. An alternative design that used a pipeline instead of tunnel was also considered that lowered the estimated costs to $15.4 million. However due to the limiting size of the pipeline, annual energy production was reduced to 15,434,000 kilowatt-hours.

The analysis was conducted at a time prior to the construction of the cogeneration project. Therefore, the usable energy just mentioned may be dependent on reduced operations of the cogeneration project.

Approximately one half of the generation would be from the new powerhouse located just prior to where water would enter Solomon Gulch reservoir, and the other half would be from additional generation at the existing Solomon Gulch powerhouse. Since power from Solomon Gulch is considered a purchase from the FDPPA, that agency may take the position that the excess energy production due to Allison Lake should also be priced at the purchased power rate (currently $0.068/kilowatt-hour). Therefore, the projected costs from this potential resource are provided in Table 11 on page 22 both with and without the payment to FDPPA for the Allison Lake energy produced from the Solomon Gulch powerhouse.

SILVER LAKE

The 1991 review of Allison Lake also included an update of the potential Silver Lake Hydro Project. Silver Lake is approximately 15 miles southwest of Valdez and flows into the Duck River. The lake would act as a storage reservoir and allow for scheduling of power production.

Two alternatives were evaluated, both with sufficient capacity to act as a backup to Solomon Gulch. Estimates of annual energy production were based on regulating flow to maximize production at times during the winter months when Solomon Gulch was not providing for all of CVEA's power requirements. The estimates were as follows:

Alternative A:

- Winter: 43,575 MWh
- Summer 1,175 MWh
- Total 44,750 MWh

Alternative B:

- Winter: 46,375 MWh
- Summer 2,375 MWh
- Total 48,750 MWh

The maximum amount of energy that can be used by CVEA during the initial years is approximately 35 million kilowatt-hours per year, the residual load after Solomon Gulch (Table 4). If the cogeneration project was continued, usable energy would be limited to less than 15 million kilowatt-hours per year.

OTHER

Other hydro resources that have been investigated in a preliminary manner include three small resources in the CRB area. These include one near Copper Center, one near Gakona, and one at Kenny Lake, ten miles northwest of Chitina. All of these are relatively small facilities and could probably displace diesel with continued operations at the cogeneration project. It is also noted that these studies were conducted in the very early 1980's and were more of a reconnaissance level type of investigation.

Table 11
Hydroelectric Summary

	Allison Lake				Silver Lake				
	Tunnel Option		Pipeline Option				Copper Center	Gakona	Kenny Lake
	No FDPPA Payment	With FDPPA Payment	No FDPPA Payment	With FDPPA Payment	Option A	Option B			
Installed Capacity (kW)	3,145	3,145	1,800	1,800	15,000	14,000	2,780	1,075	394
Energy (000 kWh)	27,396	27,396	15,354	15,354	34,000	34,000	11,698	4,520	1,657
Construction Cost (000)									
Initial Estimate	$ 30,937	$ 30,937	$ 15,434	$ 15,434	$ 51,200	$ 58,250	$ 28,000	$ 13,000	$ 5,000
Base Year	1992	1992	1992	1992	1992	1992	1981	1981	1981
Revised to 2010[1]	$ 49,400	$ 49,400	$ 24,600	$ 24,600	$ 81,690	$ 92,939	$ 57,700	$ 26,800	$ 10,300
Interest During Construction	3,705	3,705	1,845	1,845	12,254	13,941	4,328	2,010	773
Total	$ 53,105	$ 53,105	$ 26,445	$ 26,445	$ 93,944	$ 106,879	$ 62,028	$ 28,810	$ 11,073
Annual Costs (000)									
Debt Service (30 years)	$ 4,496	$ 4,496	$ 2,239	$ 2,239	$ 7,954	$ 9,050	$ 5,252	$ 2,439	$ 938
O&M	450	1,392	450	981	575	575	75	50	20
Total	$ 4,946	$ 5,888	$ 2,689	$ 3,220	$ 8,529	$ 9,625	$ 5,327	$ 2,489	$ 958
Total Costs ($/kWh)									
Initial Year	$ 0.181	$ 0.215	$ 0.175	$ 0.209	$ 0.251	$ 0.283	$ 0.455	$ 0.551	$ 0.578
Life Cycle: (50 years)									
0% Discount Rate	$ 0.134	$ 0.171	$ 0.150	$ 0.187	$ 0.177	$ 0.196	$ 0.265	$ 0.325	$ 0.342
7.5 % Discount Rate	$ 0.048	$ 0.059	$ 0.049	$ 0.059	$ 0.066	$ 0.075	$ 0.109	$ 0.132	$ 0.139

1 Based on the Handy-Whitman Index – Total Hydraulic Production Plant through January 2006 and 2.75 percent per year thereafter

OTHER

Other technologies exist that could theoretically be used to offset diesel generation. Such resources include tidal and refuse fueled. Tidal power is not considered as it is still in its infancy and very much in the research and development stage. Such resources carry a high degree of risk and should not be undertaken by a small utility such as CVEA. Refuse-fueled resources are not considered due to the lack of a sustained fuel source.

Another potential resource is biomass where electric power is produced using bio-fuels. These fuels are classified into five major categories: wood wastes, mill residues, forest residues, agricultural residues, and dedicated energy crops. Other than the fuel, the resource is similar to that of a combustion turbine where steam is used to turn a turbine. Although biomass resources are a proven technology, they are dependent on a sustainable fuel source. Furthermore, costs are quite high with expected costs of $0.12/kilowatt-hour or higher for a 25,000-kilowatt resource. These costs are based on baseload (fulltime) operations. Due to the size of resource that could be used in the CVEA system, the availability of fuel, and the seasonal nature of required generation, biomass resources would be prohibitively expensive.

PRE-SCREENING SUMMARY

Table 12 provides a summary of the resources considered and a comparison to continued use of fossil fuels. The comparison includes debt service on capital costs for the new resources but not for the existing resources since those costs are for past expenditures and cannot be eliminated. Many of the resources included in Table 12 would not provide firm capacity, and additional reserve capacity would be required in the same timeframe as if the unit had not been built.

Of the resources considered, only Allison Lake may provide economic benefits when compared to the continued use of fossil fuels. Although wind turbines fail the pre-screening analysis at this time, potential sites should be sought. If a site with the potential for good wind production can be located close to existing transmission facilities, economics can be re-evaluated at that time.

Units that pass the pre-screening are further analyzed in the next section.

Table 12
Pre-Screening Summary

Resource	Firm Capacity?	2010 Costs ($/kWh)	Life Cycle Costs ($/kWh) 0% Discount	Life Cycle Costs ($/kWh) 7.5% Discount	Pre-Screening Pass	Reason for Fail
Cogen[1]	Yes	$ 0.110	$ 0.170	$ 0.062		
Diesel[2]	Yes	0.148	0.226	0.083		
Geothermal	Yes	0.183	0.203	0.083	No	Risk, No proven resource
Fuel Cells	Yes	0.328	0.415	0.215	No	Risk, Cost
Solar	No	0.896	0.920	0.504	No	Cost
Wind	No	> 0.20	> 0.20	> 0.14	No	Cost
Coal	Yes	> 0.18			No	Risk, Cost
Allison Lake (Tunnel)	Yes	0.181	0.134	0.048	Yes	
Allison Lake (Tunnel) w/ FDPPA Payment	Yes	0.215	0.171	0.059	Yes	
Allison Lake (Pipeline)	Yes	0.175	0.150	0.049	Yes	
Allison Lake (Pipeline) w/ FDPPA Payment	Yes	0.209	0.187	0.059	Yes	
Silver Lake Opt. A	Yes	0.251	0.177	0.066	No	Cost as compared to Allison
Silver Lake Opt. B	Yes	0.283	0.196	0.075	No	Cost as compared to Allison
Copper Center	Yes	0.455	0.265	0.109	No	Cost
Gakona	Yes	0.551	0.325	0.132	No	Cost
Kenny Lake	Yes	0.578	0.342	0.139	No	Cost

1 Assumes a 2005 net cost of fuel of $0.09/kWh and $0.01/kWh for variable O&M. Both components are escalated at inflation.
2 Assumes a 2005 cost of fuel of $0.123/kWh and $0.01/kWh for variable O&M. Both components are escalated at inflation.

IV. REFINEMENT ANALYSIS

The pre-screening analysis conducted in the previous section indicates that only two hydro options may have benefits to the CVEA consumer. However, the hydro options were initially evaluated prior to the installation of the cogeneration project. Therefore, usable energy estimates may require a partial or total reduction in operations of that project. In order to estimate the impact to the rate payer if operations at the cogeneration project had to be curtailed, the CVEA power supply costs are projected over a multi-year period.

In making these projections, certain assumptions were made regarding CVEA's existing resources. These include the following.

1. General inflation averages 2.75 percent per year.
2. Generating requirements and resource production without Allison Lake are equal to that incurred during 2005. No load growth is included.
3. Solomon Lake costs are equal to \$0.04/kilowatt-hour for debt service and \$0.028/kilowatt-hour for O&M. Only the O&M component is escalated at general inflation.
4. Cogeneration costs are equal to \$0.09/kilowatt-hour for fuel in 2005 (net of heat sales) and \$0.01/kilowatt-hour for O&M. Fuel is escalated at one half of inflation and O&M at full inflation.
5. The cost of diesel production is \$0.123/kilowatt-hour for fuel and \$0.01/kilowatt-hour for O&M in 2005 dollars. Both are escalated at general inflation.

Three separate cases were run for the Allison Lake – Tunnel Option and the same three for Allison Lake – Pipeline Option. These cases are:

1. Base Case. Without Allison Lake
2. No Heat Sales. In this case, heat sales to Petro Star are terminated. Since the cogeneration project would then have higher operating costs than diesel, energy requirements net of Solomon Gulch and Allison Lake are met with diesel. This case assumes that all production from Allison Lake is usable.
3. Continued Use of Heat Sales. In this case, the cogeneration project is continued as in the Base Case. Allison Lake provides for the net requirements after Solomon Gulch and the cogeneration project. For the tunnel option of Allison Lake, this could reasonably be expected since the potential energy from Allison Lake is significantly more than existing diesel production. However for the pipeline option, the potential hydro energy and existing diesel production are quite close, and not all hydro energy may be usable. Therefore, for the Allison Lake – Pipeline Option, it was assumed that 80 percent of the diesel generation is displaced.

The results of the cases run for each option are shown in Figures 4 and 5. Projections that include the scenario where payments are made to the FDPPA are provided for the "No

Reduction of Cogen" case only. From this, costs for the "No Cogen" case can be inferred. Although Allison Lake may provide long-term economic benefits, the figures show that it could be 20 or more years before annual benefits begin to accrue.

Figure 4
Allison Lake – Tunnel Option

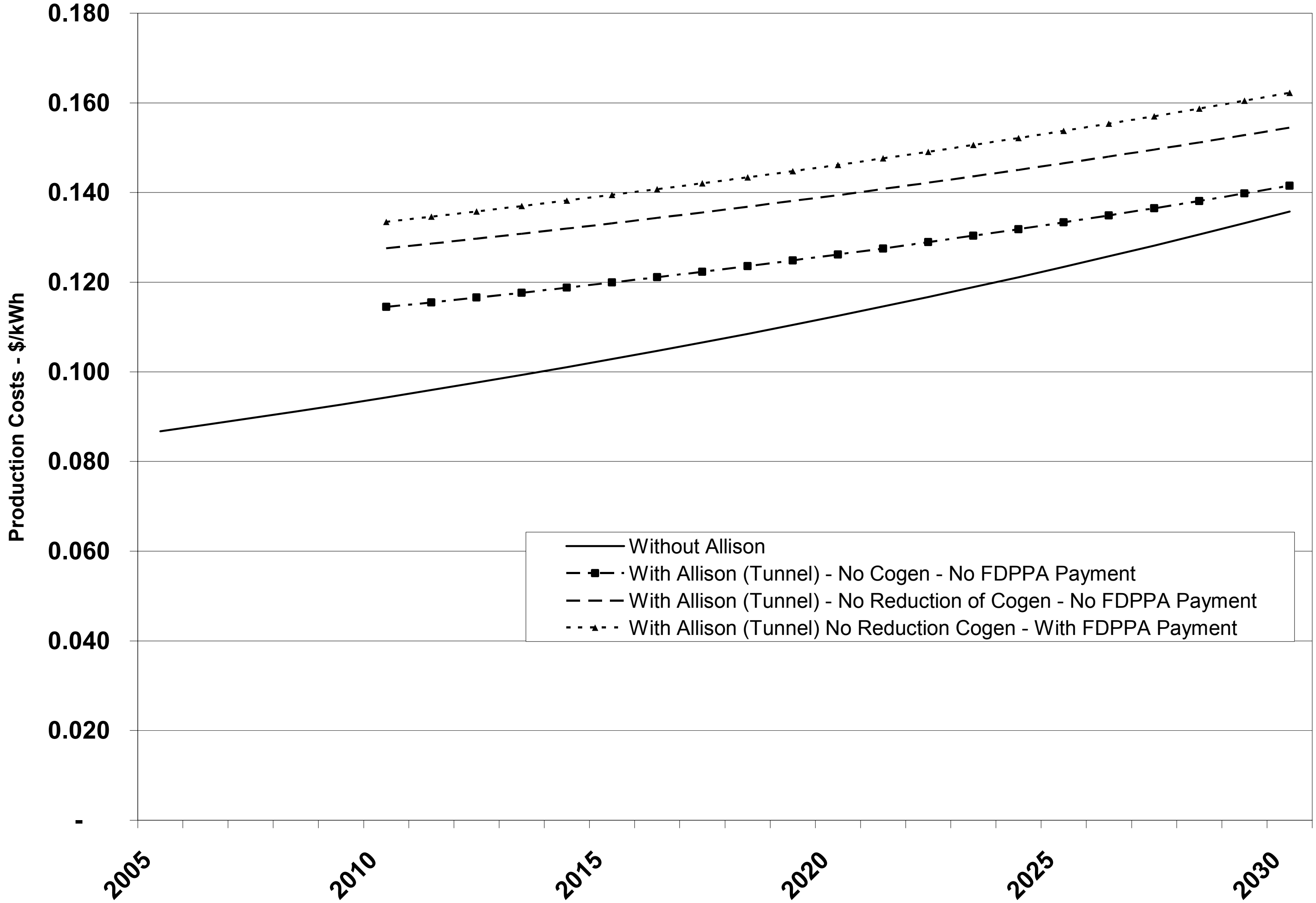
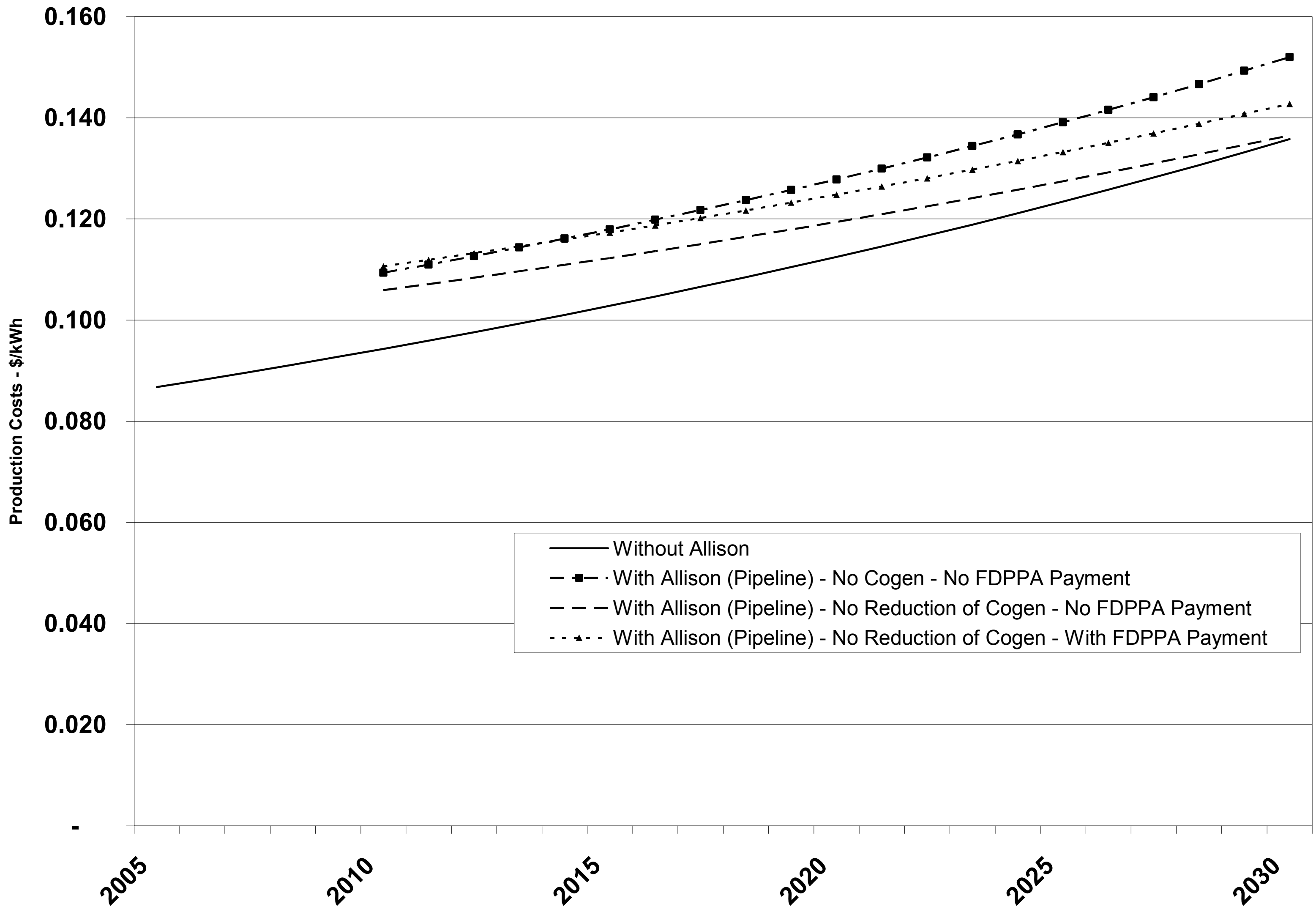


Figure 5
Allison Lake – Pipeline Option



V. SUMMARY

Nearly 60 percent of CVEA's resources come from Solomon Gulch, a hydroelectric project that CVEA is contractually obligated to purchase the output from for quite some time. Of the remaining 40 percent, approximately two thirds (or 25 percent of the total energy requirements) come from a cogeneration project that CVEA is obligated to operate until April 2015. Only 15 percent or less of the total generation is from diesel that can be displaced in the near term.

Similar to many utilities throughout the state, there are relatively few options that CVEA can pursue to displace the diesel-fired generation. One option the Allison Lake hydro project, may provide long-term benefits. However it, like all hydroelectric projects, is capital intensive with low operating costs. Thus even though annual costs are relatively fixed in nature (annual debt service), it would be a number of years before economic benefits begin to accrue to the ratepayer. The length of time until benefits begin accruing would be reduced if CVEA were successful in obtaining capital grants for the project. It is also noted that Allison Lake does not displace the need for CVEA to add reserve capacity in Glennallen.

All other resource options appear at this time to be prohibitively expensive.

Although there are limited options to pursue at this time, CVEA should continue to monitor these emerging technologies over the coming years. In the Lower-48, large utilities are implementing a number of these on a very limited basis - not in anticipation of economic benefits but more for research and development. Many of these are funded with government grants. With time, capital costs may decrease to levels where these new, emerging technologies become cost-competitive with existing resources.

Heat sales to Petro Star create a number of opportunities for CVEA, many of which have been explored by CVEA staff. Such opportunities include returning the revenues to CVEA members on an annual basis, offsetting fuel costs, offsetting a portion of the revenue requirements included in the base rates, and others. Due to the volatility of the revenues (heat sales revenues are tied to the cost of fuel), it may be difficult to include accurate estimates of the revenues in CVEA's financial planning horizon. Whatever option is implemented, the financial health of the system must be maintained