Biomass Review for Possible Power Generation Capability for CVEA

In 2011, CVEA conducted an extensive review of biomass. This review had a three-pronged effort looking at the viability of biomass through an internal study, a literature search combined with expert testimony and an Independent Consultant's analysis. Here are the key results of this three pronged review:

1. Wood biomass is plentiful in Alaska and plentiful in the Copper Basin but it is not abundant as an "opportunity fuel" in the Copper Basin. An "opportunity fuel" is normally a byproduct of some manufacturing process such as a saw mill or lumber company. It normally means the fuel is free or very cheap and its source is located close to the biomass facility reducing or eliminating transportation costs. Most examples of successful biomass projects are located in the lower 48 utilizing "opportunity fuel" biomass. Most examples of successful biomass projects rely mainly on heat revenues and not power production revenues.

2. There are only a few examples of successful biomass projects in Alaska. These projects would not have been successful without state assistance. In some cases, biomass is an "opportunity fuel" such as recycling materials or biomass created by forest fire management in the Division of Forestry. At the date of this report, none of these projects are producing power with biomass.

3. Given the unavailability of "opportunity fuel," CVEA would need to purchase biomass, transport that biomass, store the biomass in a way to keep moisture down and then feed the biomass into a furnace. The more you handle this fuel, the more expensive it gets. Using realistic cost estimates, the Independent Consultant's analysis shows the cost of power for biomass at 2 to 3 times higher than the cost of power with diesel.

4. The reliability of power created from a biomass furnace would be a problem for CVEA. A biomass furnace has a slow reaction time to changes in load and it takes several hours for startup and shutdown. Biomass generators do not have the capability to be started remotely under a power outage condition unlike CVEA's diesel generators.

5. Future emission regulations are unknown. The Environmental Protection Agency has a temporary deferral on Biomass emission limits but this temporary deferral will end in two years.

The result of CVEA's Biomass study concludes that Biomass is not a viable option for producing power. It would bring reliability down while also bringing rates up.

Attached is the Independent Consultant's report to CVEA.

January 2012

BIOMASS REVIEW

COPPER VALLEY ELECTRIC ASSOCIATION

November 30, 2011

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January 2012

COPPER VALLEY ELECTRIC ASSOCIATION

BIOMASS REVIEW

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I. INTRODUCTION

BACKGROUND

Although Copper Valley Electric Association ("CVEA") has and continues to enjoy the relatively low and stable prices of its Solomon Gulch hydroelectric generation, not all of the utility's power requirements can be met with hydro. Like other remote utilities not interconnected with the Railbelt system, CVEA's options for supplemental power have historically been limited to diesel- or oil-fired generation. Such generation is relatively inexpensive to install, but fuel costs can be significant. Still, with the hydro providing for much of the total generation, the utility was partially shielded from the high or fluctuating fuel prices.

CVEA has long recognized that load growth and higher fuel prices would gradually erode the dominance of Solomon Gulch on the system, and alternatives for supplemental power have been actively sought. Alternatives that have been investigated in the past included an intertie to Anchorage and increasing the size of Solomon Gulch. But the utility's small size and even smaller supplemental power requirements have been the limiting factors in that the large capital costs of these projects would be spread over small amounts of energy. The resulting cost of power would simply far exceed the cost of power from diesel engines, even at high fuel prices. Smaller, less capital intensive alternatives were required for the economics to work.

New technologies did emerge in the mid- to late-80's as a result of earlier oil-price run-ups, but most were unproven on a commercial basis. The operational risks of these options were not commensurate with CVEA's small size and remoteness, and failure of an unproven technology would cause rates to increase to unmanageable levels. "Serial Number One" resources were not prudent options when considering the financial health and operational reliability of the system.

One option that CVEA was successful in implementing was the cogeneration project in Valdez where the exhaust heat from an oil-fired turbine is used by Petro Star for refining purposes. The dual use of the fuel oil partially shields the ratepayers from increases in oil prices. Still, the turbine uses oil and supplemental diesel generation is required during several months of the year.

With the recent renaissance of alternative generating technologies and utility loads at levels where hydro provides for only half the power requirements, CVEA initiated a reconnaissance-level study in late 2006 to investigate generation options that might reduce or stabilize the cost of power. The study used a pre-screening analysis where all technologies were evaluated for risk, unproven technology, or those that were clearly uneconomic. Options passing the pre-screening were then evaluated on an economic and financial basis against continued use of diesel for supplemental generation. The study was relatively high-level in nature since specific sites, resource configurations, and other parameters were not defined, and the study was meant to point the way to where more defined studies could prove beneficial.

In 2010, based in part on the results of the pre-screening analysis, CVEA conducted a pre-feasibility study of Silver Lake, a potential hydroelectric resource located on Prince William Sound. The study concluded that while technically feasible, the project has difficult land and environmental issues which create economic challenges. With a first year cost of power estimated at 41¢ per kwh the project was determined not to be economic compared to other available resources.

Also as a result of the pre-screening study, CVEA has moved forward with the Allison Creek hydro project, which is expected to be operational in 2016 or earlier. Once completed, hydroelectric generation is expected to provide for all requirements from June through mid-October.

One of the technologies that did not pass the pre-screening was biomass due to expected resource economics. Since then (and common to most, if not all, alternative generation technologies), expected costs have decreased, and interest has increased. Since there are biomass resources in the area, developers and CVEA members have approached the utility regarding the development of a biomass resource. This interest is directed toward a combined heat and power ("CHP") facility where heat would be used both for power generation and for space heating for nearby buildings.

In order to better understand the potential merits and risks of a biomass CHP resource, CVEA retained the services of the Financial Engineering Company to perform a high-level review and assess the merits of such a facility. The Financial Engineering Company, in turn, retained the services of Northern Economics for its knowledge of biomass resources local to the CVEA area. The following report summarizes the analysis and findings regarding the potential risks, merits, and economics of a CHP biomass resource if it were implemented by CVEA.

II. CVEA SYSTEM

INTRODUCTION

When a new resource is integrated into a utility system, it typically is not simply turned on and allowed to run at full output for every hour of the year. Hourly loads (commonly referred to as load profiles or load shapes), availability of other resources, operating costs of all resources, planned maintenance schedules, and numerous other factors all play a part in determining how each resource is used and dispatched into the system. This section provides an overview of the CVEA loads, resources, and dispatch of its resources to gain a better understanding of how a biomass resource might fit into the system.

POWER REQUIREMENTS

CVEA's energy sales, total requirements including station service and losses, and system peak, are summarized in the following table for the past several years. Sales decreased in 2009 due to a major fire at the Petro Star refinery. The fire occurred in December 2008, and the refinery did not resume operations until November 2009.

Table 1
Historical Load Data

	2005	2008	2009	2010
Energy (MWh)				
Sales	77,361	72,658	64,930	76,250
Station Service/Losses	6,763	10,048	9,386	10,412
Total Requirements	84,124	82,707	74,316	86,662
System Peak 000 (MW)	12.7	12.1	12.6	13.5

Note: Energy requirements are reduced slightly in 2008 and significantly in 2009 due to a fire at Petro Star refinery.

A detailed projection of power requirements is beyond the scope of work included in this study, and the analysis is based on sales achieved in 2010 with no load growth. However, the potential for both increases and decreases in power requirements will be factored in when evaluating risk.

EXISTING RESOURCES

CVEA's primary source of power is the Solomon Gulch Hydroelectric Project, a 12-megawatt hydroelectric facility located near Valdez. 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. Placed into operation in 1982, the resource was owned by three separate entities until 2009. At that time, CVEA acquired the resource, and the utility is now responsible for all costs and operations. All costs associated with Solomon Gulch are considered “fixed” in that they do not vary with generation.

Solomon Gulch has the capability to produce, during an average water year, approximately 45,600 megawatt-hours of energy. On an annual basis, Solomon Gulch now provides approximately one half 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.

ALLISON CREEK

As a result of the pre-screening analysis conducted in 2006, CVEA initiated a feasibility study regarding the hydroelectric potential in the Allison Lake basin. The study concluded that a run-of-river resource in Allison Creek was both technically feasible and economic, and a final license application for construction was submitted to the Federal Energy Regulatory Commission (“FERC”) on August 30, 2011. The project is expected to be commercially operable by mid 2016.

The Allison Creek hydro project will have a generating capability of 6.5 megawatts with 23.3 million kilowatt-hours of energy potential during May through November. The project will be a run-of-river resource in that water cannot be stored for generation at a later time. Once completed, Solomon Gulch and Allison Creek combined are expected to provide for all requirements from June through mid-October. As with Solomon Gulch, costs will be fixed and will not vary with generation.

COGENERATION PROJECT

In April 2000, CVEA completed construction of and began operation of a 5.2-megawatt combustion turbine cogeneration project 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. Pricing of LSR is tied to the price of Alaska North Slope Crude delivered to the West Coast (“ANS (WC)”).

Heat is sold by CVEA to Petro Star pursuant to the terms and conditions of several agreements that terminate in April 2015. In general terms, the agreements obligate CVEA to operate the resource a minimum of 5,500 hours per year subject to availability of turbine and Solomon Gulch operations and to operate it at the rated capacity when running the unit.

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). This equates to nearly one half of CVEA's fuel cost used for power generation from this resource. The actual offset is dependent upon how soon Petro Star takes heat following the cogen restart.

Due to its obligations to operate a minimum number of hours per year and at rated capacity, the cogeneration project is typically dispatched in the winter when it can be operated continuously at full output. At that time, hydro is used to follow load subject to availability and then diesel generation. The cogeneration project was not operated for a small part of 2008 and most of 2009 due to the fire at Petro Star. Thus, the historical amounts for those two years shown in Table 4 are not reflective of long-term amounts.

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 unit must be operated at rated capacity unless otherwise agreed to by the parties.
3. The agreements expire in April 2015.

DIESEL

Reciprocating gensets fueled with diesel make up the balance of CVEA's resource mix. These units, located in both Glennallen and Valdez, serve multiple purposes: baseload winter generation, supplemental generation, and reserves. Currently 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.

As inferred in the Introduction section of this report, diesel units make excellent reserve units. The cost of installation is relatively low as compared to other resources, and the high operating costs are offset by their expected low usage. Since the units are already in place and CVEA has adequate system reserves with the diesel units, a biomass resource would not be installed for reserve purposes.

Table 2
Summary of Installed Capacity
(kilowatts)

	Nameplate Rating	Summer Rating	Winter Rating
Solomon Gulch			
Unit 1	6,000	6,500	4,000
Unit 2	6,000	6,500	-
Allison Lake[1]	6,500	-	-
Cogeneration Plant	5,300	4,700	5,200
Diesel			
Glennallen			
GDP 3	560	-	-
GDP 4	597	-	-
GDP 5	597	-	-
GDP 6	2,624	2,000	2,000
GDP 7	2,624	2,000	2,000
GDP 8	1,200	1,100	1,100
GDP 9	2,800	2,800	2,500
Subtotal - Glennalle	11,002	7,900	7,600
Valdez			
VDP 2	597	-	-
VDP 4	1,926	1,800	1,800
VDP 5	2,620	2,000	2,000
VDP 6	965	900	900
VDP 7	2,800	-	-
Subtotal - Valdez	8,908	4,700	4,700
Total Diesel	19,910	12,600	12,300
Total	43,710	30,300	21,500

1 Expected to be completed in mid 2016. Allison Creek will be a run-of-river resource, and firm capacity, while not zero, may be reduced.

COSTS AND DISPATCH OF RESOURCES - ENERGY

Resources are typically dispatched based on a comparison of variable operating costs, although system stability and contractual obligations are also considered. In CVEA's case, the hydro resources can and will be able to respond to expected load swings on the system, and there is no need to run diesels at the same time for load following. Thus resources are dispatched based on variable costs subject to minimum run times, start-up costs, and other factors. Specific diesel units may also be dispatched over others for reliability purposes.

The most significant variable cost is fuel, but other costs can vary with output. Major maintenance activities are performed at specific operating hour intervals and are therefore considered variable. Lube oil and other miscellaneous supplies are also dependent on unit output. All of these non-fuel items are typically combined into a "Variable O&M" component that captures the amortized cost of maintenance as well as the variable day-to-day expenses.

Table 3 provides a summary of the fuel and other variable operating costs for CVEA's resources. Fuel costs, in $/kWh, will vary not only with the price of fuel but with output levels. As unit output decreases, total fuel consumption decreases at a lower rate, and fuel use in gallons per kilowatt-hour increases. The amounts shown in Table 4 for the diesel units are based on average fuel efficiencies over the past four years. Since hydro resources have no fuel costs and the variable O&M is so small, the variable O&M component is ignored.

Table 3
Variable Cost of Production
($/kWh)

Hydro							
Fuel	-						
Variable O&M	Minimal						
Cogen Project	Petro Star Oil Price Including Quality Bank Adjustments ($/bbl)						
	80	90	100	110	120	130	140
Fuel							
Gross	0.219	0.245	0.270	0.295	0.320	0.345	0.370
Net of Heat Sales	0.110	0.123	0.135	0.148	0.160	0.173	0.186
Variable O&M	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Total (Net of Heat Sales)	0.118	0.131	0.143	0.156	0.168	0.181	0.194
	2009 Average $88.20/bbl						
	2010 Average $83.38/bbl						
Diesel Units	Diesel Price ($/gallon)						
	2.50	2.75	3.00	3.25	3.50	3.75	4.00
Fuel @ 14 kWh/gal	0.179	0.196	0.214	0.232	0.250	0.268	0.286
Variable O&M	0.015	0.015	0.015	0.015	0.015	0.015	0.015
Total	0.194	0.211	0.229	0.247	0.265	0.283	0.301
	2009 Average $2.08/gal						
	2010 Average $2.81/gal						

As shown in the previous table, the cogeneration project has a lower variable cost than the diesel units and would normally be dispatched prior to diesel as long as heat can be sold. Without heat sales, the diesel units would be dispatched prior to the turbine on an economic basis.

Table 4 summarizes the dispatch of resources over the past three years. However, it must be kept in mind that the Petro Star refinery fire skewed the results slightly for 2008 and significantly for 2009.

Table 4
Historical Production by Resource
(kilowatt-hours)

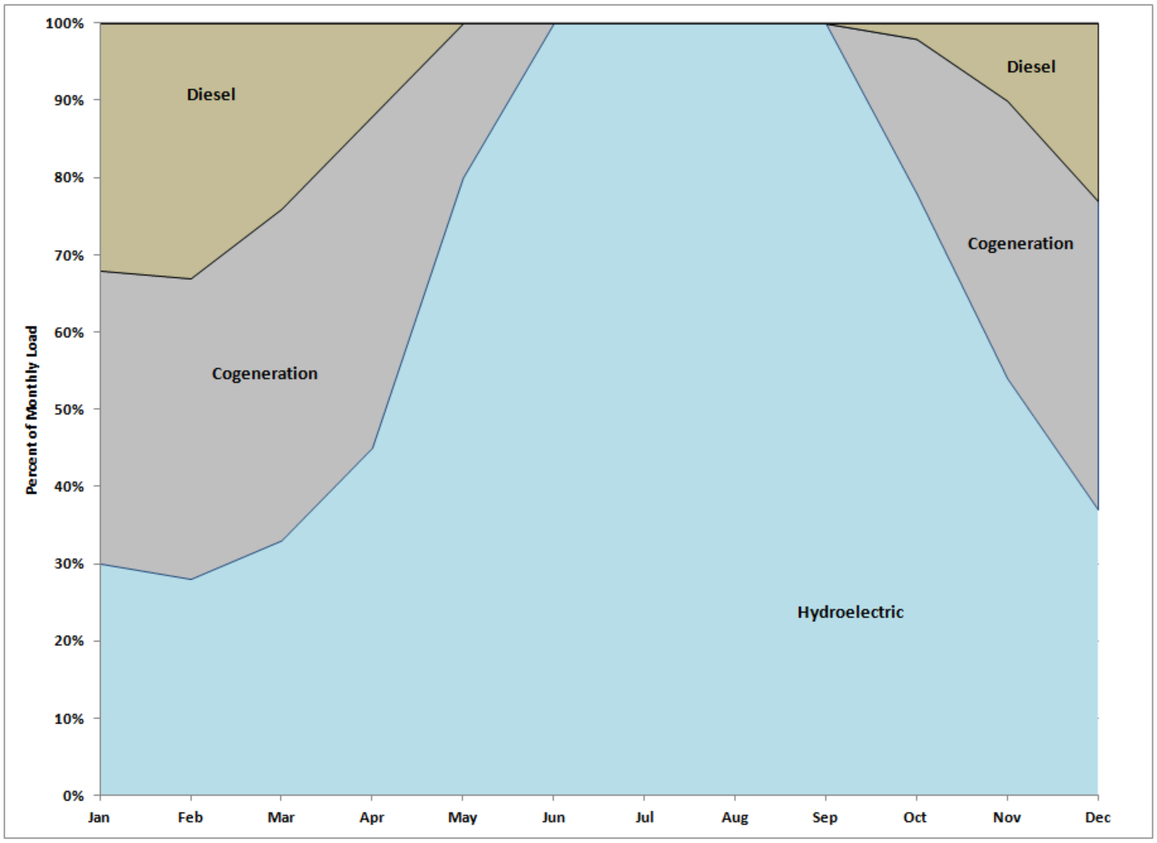
	2008	2009	2010
Generation (x 1,000 kWh)			
Solomon Gulch	47,989	45,472	45,200
Diesel Generation			
Glennallen Diesel	8,000	9,677	6,552
Valdez Diesel	2,333	12,039	4,591
Total Diesel	10,333	21,716	11,143
Cogeneration	24,385	7,127	30,319
Total Generation	82,707	74,316	86,662

Note: Both energy requirements and cogeneration production are reduced in 2008 and 2009 due to a fire at Petro Star refinery.

Once Allison Creek is completed, hydro will play an even more dominant role. Based on current loads, the average usable generations from Solomon Gulch and Allison Creek are estimated by CVEA to be 45,600 megawatt-hours and 16,000 megawatt-hours, respectively. Minimum contractual obligation for the cogen project is to run 5500 hours with the associated power generated from this obligation. But, the combined energy of these three resources exceeds current energy requirements, and not all will be usable. Furthermore, hydro generation will be limited during the winter, and diesel will be used for supplemental generation.

Figure 1 shows the expected dispatch of resources as a percent of monthly energy requirements. Hydro is anticipated to provide for all power requirements during the summer months whereas the cogen and diesel resources will fill in during the other months as necessary. Diesel generation, once Allison Creek is completed, is expected to provide for 10 million kilowatt-hours or less during a year.

Figure 1
Expected Monthly Generation with Allison Creek
(Percent of Monthly Energy Requirements)



CAPACITY ISSUES

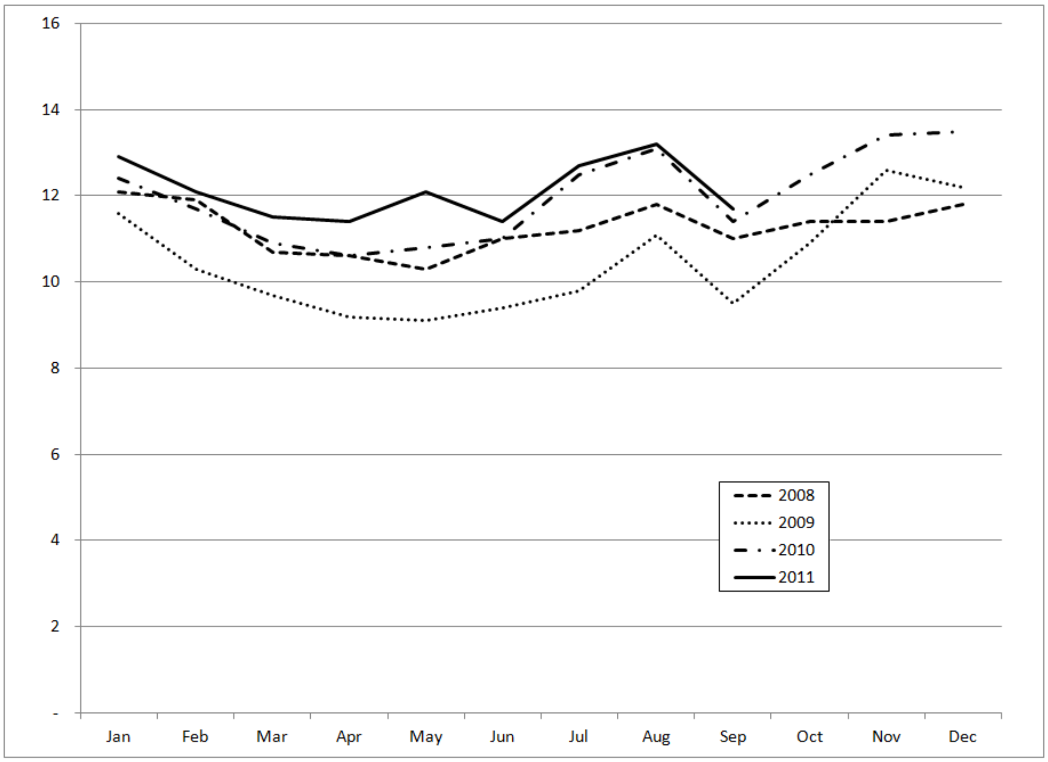
The preceding discussion provided an overview of cost thresholds and seasonal and contractual issues that a potential biomass resource will face in being dispatched. At current load levels, diesel generation that could be offset is expected to be approximately 10 million kilowatt-hours or less over the course of approximately six months. If a biomass resource was sized at 3,000 kilowatts, then it could produce 13.14 million kilowatt-hours of energy over a six-month period without considering maintenance and other outages.[1] But something else must be considered before saying a 3,000-kilowatt resource can provide for all residual diesel requirements. Unit size must also be considered.

Figure 2 on the following page shows the monthly system peak demand, or the maximum rate of energy flow for the month over a period of time (commonly measured over a 15-minute period). During the winter months when diesel units are dispatched, system peak is in the 12 – 13 megawatt range. During this time, Solomon Gulch may be providing 1.5 – 2 megawatts and the cogeneration project 5.2 megawatts. Thus, the diesel units are providing approximately 5 – 6 megawatts of capacity.

[1] 3,000 kW x 8,760 hours/year x 6/12= 13,140,000 kWh.

If a biomass resource was sized above this amount, then it could be expected to provide the entire net energy requirements from diesel. But if the resource is sized less than this amount, then it could not provide for all the residual diesel requirements. Any time the system peak exceeded the combined capability of hydro, cogeneration, and the biomass resources, a diesel unit would have to be turned on, and the energy from the diesel unit would not be associated with the biomass.

Figure 2
Historical Monthly System Peaks
(x 1,000 kilowatts)



Note: System peak is reduced in 2009 due to a fire at Petro Star refinery.

SUMMARY

CVEA has sufficient installed resources to meet both system peak as well as reserve requirements. Therefore, no capital costs associated with future resource additions would be displaced by the addition of a biomass resource. Economic benefits would be limited to displaced variable costs.

Displaced variable costs are limited since hydro will provide for much of CVEA's power requirements. Furthermore, the cogeneration project has relatively low variable costs since revenues received from heat sales reduce the effective variable cost of power. The use of a biomass resource would most likely be limited to displacing diesel units which is used for a small amount of CVEA's power requirements.

The following section summarizes the analysis and findings of the potential economics of a biomass resource based on the net power requirements described in this section. Since the agreement for the sale of heat from the cogeneration project terminates in April 2015, the economics are investigated both with and without a continuation of the agreement.

III. BIOMASS

A QUICK BACKGROUND

What exactly is biomass power? In very general terms, it is the use of organic fuels in producing electric and thermal power. Commercial applications have been in existence for quite some time, but these early projects were relatively limited to direct combustion applications where fuel was burned to heat water which, in turn, powered a steam turbine. But as the industry has evolved with the demand for renewable resources, new applications have appeared. Terms and concepts have morphed to the extent that there is a great deal of miscommunication and misplaced ideas. Biomass to one does not necessarily mean the same thing to another.

Biofuels, where organic (biomass) materials are fermented and refined into ethanol, bio-diesel, "liquors," and other fuels, have gained a great deal of attention and federal support through subsidies and tax credits over the past decade. While technically these are biomass power applications, the fermentation process is lengthy and is targeted more to the transportation industry rather than the production of electric power. One exception might be in the paper industry where the liquor byproduct is used at times for power production. In these applications, the liquor is usually co-fired with other fuels as the biofuel cannot meet all requirements. In any event, biofuels are not considered in this analysis but rather the direct combustion of raw biomass materials.

There are two primary technologies used in producing power from biomass: 1) direct combustion to heat water which, in turn, drives a *steam* turbine and 2) gasification where the biomass is heated to convert into a gas which is then used to power a separate engine/generator system. Commercial applications of the direct combustion technology have been in existence for a number of years, and examples can be found throughout the US and other countries. Most of these are, however, large in size in order to gain better economics. A good example of this might be the 50-megawatt (net) facility jointly owned by the City of Burlington, Vermont, and three other partners. In the early 1980's, the City and its partners constructed this generating facility that uses wood chips and sawdust for fuel. Fuel usage at maximum output is 76 tons of wood per hour, and natural gas can be used if required. The steam turbine configuration is similar to that of a coal plant where the unit is best operated in a baseload manner and output fluctuates little over time.

Direct combustion, however, has several disadvantages. Combustion is not all that "clean," and exhaust gases must be trapped and scrubbed. This, in turn, leads to higher operating and maintenance costs, thereby reducing resource economics. Another disadvantage is that steam turbines cannot react quickly to load changes, and system voltage and frequency can exceed or drop below allowable limits if other, faster-responding resources are not on-line. Finally, minimum output levels must be maintained for proper operations.

As a result of these factors, biomass gasifiers have emerged. The biomass is heated into a "syngas" which is then used to drive an internal combustion unit, with the exhausted heat used for heating purposes or even used to heat water to power a steam turbine.

Internal combustion reciprocating units have quick reaction times and can follow load swings found on utility systems. The gasification process is much cleaner than the direct combustion, leading to better environmental emissions and reduced maintenance costs. Fuel consumption is also typically better for these types of units, although various factors can play into this.

Gasifiers are relatively new in this type of application, and quality of gas has been an issue. If the fuel was completely homogeneous, this would not be an issue, but gas content and quality will vary as fuels do. Advances have been made, but gas quality and other factors still remain an issue for small (less than 1 megawatt) systems, with tars the dominant problem. Even with these advances, applications have been limited thus far to internal combustion units and not to *gas* turbines.[2] Current thinking is that gas turbine applications may come in another two years or so. It is important to remember, however, that biomass gasifiers and internal combustion generators are still relatively new with very limited commercial installations.

While local conditions can certainly override general trends, the following factors are usually required in order for biomass power applications to be economic.

1. *Combined Heat and Power Applications.* Without the dual use of thermal output (power generation and heating), capital and operating costs are too high to be competitive with other forms of power production.
2. *Proximity to the Fuel Source.* Fuel must be transported to the place of use, and if the fuel source is too far, transportation costs can prove to be too costly.
3. *Financing Incentives.* Grants, loan guarantees, and tax credits are often available and required to lower the capital costs to economic levels.
4. *Renewable Portfolio Standards.* Although not found in Alaska at this time, many states have implemented standards that impose monetary penalties on utilities that do not meet the standards. If the biomass CHP facility qualifies as a "renewable resource" as defined by the state, project output becomes more valuable.

The rest of this section focuses on conditions local to CVEA. In order to set some boundaries in the analysis, a unit size and type is first selected. From this and the expected generation, the amount of biomass fuel can be estimated. The biomass resource itself and its sustainability are then discussed followed by expected economics of a system. It is noted that the analysis summarized in this report is high level and is not meant to be used in making actual decisions on whether a biomass facility should be implemented. Rather, the report should be used for guidance on whether project economics could be reasonably expected and more detailed studies should be undertaken.

TYPE, UNIT SIZE, AND FUEL USE

Even though biomass gasifiers have very limited commercial history, that type of system appears to be better suited for CVEA than a direct combustion system. The resource will not be operated in a baseload manner that a direct combustion system is more suited to, and the system may be called on to follow load on a real-time basis. Furthermore, emissions are significantly reduced from that found with direct combustors.

[2] "Gas turbines" are also referred to as "combustion turbines."

The selection of unit size is always a series of tradeoffs. As size increases, capital costs do so as well. However, increased size brings greater efficiencies, and the installed cost in dollars/installed kilowatt decreases. Similarly, increased size normally brings greater fuel and operating efficiency. But countering all these incentives to increase size is the limit on the expected use of the resource. The previous section showed that a resource greater than 5 - 6,000 kilowatts would be oversized if the cogeneration agreement continues with Petro Star. Even then, the biomass facility would be used for only half the year. In some instances, a utility might be able to operate the biomass system year round and store reservoir water for generation in winter months. If that, in turn, reduced net system peaks on supplemental generation, then more energy might be produced from the biomass and less from diesel. However, that does not appear to work with CVEA since with Allison Creek, there is excess hydro generation in the summer that cannot be used. Thus any usage by the biomass in the summer months would simply result in more hydro spill.

For purposes of this analysis, two resources are considered: 1,000 and 2,000 kilowatts. Detailed dispatch analyses that fit these two sizes into CVEA's load profiles are beyond the scope of this analysis. However, a review of the expected diesel generating requirements indicates that approximately 3.5 million and 4.5 million kilowatt-hours of usable energy would be expected from these two resource sizes.

A review of product literature and conversation with a gasifier system points toward an electric efficiency of approximately 30 percent, or 11,377 Btu/kWh. Overall efficiency, when combined with heat sales, could increase to 80 percent or even higher, which would result in 5,689 Btu/kWh generated that could be used for heating purposes. It is noted that the gasifier system could be oversized if additional heat was required.

Estimates of how energy intensive the gasification of wood is ranges considerably, and vendors are reluctant to divulge specific data without non-disclosure agreements. One source provided an estimate of 68 – 73 percent depending on the moisture content of the biomass material (the higher the moisture content, the lower the efficiency). Energy content per cubic foot of biomass will vary depending on the moisture content which varies considerably throughout the region. Moisture content of spruce and aspen, the dominant species in the area, is expected to be just below 40 percent. For purposes of this analysis, a gasification efficiency of 70 percent is used. In other words, 30 percent of the energy available in the wood is used for conversion to gas. Table 5 provides a summary of the operating assumptions used in the analysis.

Table 5
Biomass Operating Assumptions

Type:	Gasifer with Internal Combustion		
Size:	1,000 kW and 2,000 kW		
Gasification Efficiency	70%		
Average Efficiency:			
Electric	30%	11,377	Btu/kWh
Overall	80%+		
Annual Energy			
1,000 kW Unit	3,500,000 kWh		
2,000 kW Unit	4,500,000 kWh		
Biomass:			
Btu/lb	5,100		
Lb/Cubic Foot	43.6		
Annual Biomass Volume (cubic feet/year)			
1,000 kW Unit	255,816		
2,000 kW Unit	328,907		

BIOMASS RESOURCES IN THE AREA

Biomass resources in the Glennallen area consist almost entirely of trees. Other sources, such as pallets, scrap lumber, and residential and commercial Municipal Solid Waste ("MSW") exist, but volumes are very minimal and not considered.

Large-tract land ownership in the Glennallen area includes federal, state, and private, and inventories have been conducted to different extents on all three ownerships. The first inventory, conducted by the US Forest Service ("USFS") in 1968, covered the largest area of the four inventories at just over 2.0 million acres. The second inventory was completed by foresters and technicians with the Tatitlek Chenega Corporations ("TCC") in 1989 – 1991 for three areas (Gakona, Gulkana, Mentasta).[3] This was then followed by a survey on Ahtna lands in 1995-96 by Darrel McRoberts, and finally by a State survey in 2010. This last survey was conducted by the State Department of Natural Resources ("DNR") on State lands in and around the Glennallen area.

Other, less-intensive inventories (known as area or sale cruises) were conducted for CITIFOR (a private firm) and an Alberta-based company, both of whom tried to develop export log operations at Glennallen and Valdez from timber harvest on Ahtna lands. These data are held confidential to the operators and are not available.

Each of the four inventories are summarized as follows.

1968 USFS Study

Two designations were used in the study: Commercial Forest Land ("CFL") with the ability to *grow* 20 net cubic feet of biomass per acre per year and Non-Commercial Forest Land

[3] Source: Joe Bovee, lands specialist at Ahtna, Inc.,

("NCFL") that did not meet the growth requirement but had a minimum of 800 cubic feet per acre of *standing* timber.

Findings of the survey are as follows.

Table 6
Summary of 1968 USFS Survey

Designation	Cubic Feet/ Acre	Acres (x 1,000)	Percent
NCFL	0 - 299	76.5	17.4%
NCFL	300 - 799	90.7	20.6%
CFL	800 - 1,499	177.4	40.3%
CFL	1,500 - 2,199	62.1	14.1%
CFL	> 2,200	33.9	7.7%
		440.6	100.0%

Since this survey was conducted over 40 years ago, it is of very limited use regarding NCFL lands, as the standing timber that was there at the time may or may not be there now. However, the CFL designation is still of use since it designated the amount of land that could produce at least 20 cubic feet per year. At the minimum threshold, one would expect that approximately 5.5 million cubic feet per year could be produced – a level that could easily sustain either of the unit sizes being considered.

Several events took place in the 42 years separating the first and last study in the area. First and foremost was the passage of the Alaska Native Claims Settlement Act ("ANCSA") and State of Alaska land selections that reduced the acreage of public lands. High altitude and GIS mapping and inventory systems evolved allowing better inventory of large area. Finally, spruce bark beetles reached epidemic proportions, and several fires burned large volumes of biomass in the area.

2010 DNR Study

The second study performed on public lands was the most recent, the 2010 DNR study. Approximately 435,600 acres of State lands were inventoried, with 119,227 acres classified as non-forest and 96,880 acres of dwarf (black spruce) forest. The inventory found approximately half of the State's lands (219,550 acres) to have at least 10 percent tree cover. Specific findings are summarized in the following table.

Table 7
Summary of 2010 DNR Survey

Stratum		Acres	Percent	cf/ acre	million cf
1	WS Saw	6,756	3.1%	1,661	11.2
2	WS Pole Closed	20,637	9.5%	1,243	25.7
3	WS Pole Open	30,210	13.9%	955	28.9
4	Sp Reprod Closed	10,220	4.7%	330	3.4
5	Sp Reprod Open	91,794	42.4%	98	9.0
6	Aspen Pole Closed	11,738	5.4%	1,236	14.5
7	WS-Aspen Pole	33,855	15.6%	1,020	34.5
8	WS - Cottonwood	11,372	5.3%	957	10.9
		216,582	100.0%	637	138.0
	Total without Reprod	114,568		1,097	125.6

Note
WS: White Spruce
Sp: Spruce
Saw: Sawlogs - larger than Pole logs
Reprod: Reproduction (small trees)
Pole: Pole logs

Excluding Strata 4 and 5 due to size, there are approximately 114,500 total acres with 125.6 million cubic feet of material potentially available for CVEA biomass in-feed stock. Without any renewed growth, this could easily sustain the units being considered for years.

<u>*TCC Inventory*</u>

The TCC inventory on three areas, from 1989 to 1991, found the following on an estimated 60,000 acres of forested lands.

Table 8
Summary of 1990 TCC Survey

	Area			
	Gakona	Gulkana	Mentasta	Total
Forested Acres	17,600	17,325	25,132	60,057
Acres with Spruce	12,708	15,810	11,886	40,404
Sawtimber				
MBF	54,458	21,407	125,879	201,744
Approx Million cf	20	8	46	73
MBF/Acre	3.1	1.2	5.0	3.4

Note:
MBF: 1,000 Board Feet
cf: Cubic Foot

Again, sufficient inventory exists to last well past the expected life of the units being considered.

<u>Ahtna Inventory</u>

The1995-1996 inventory on Ahtna lands generated the following results.

Table 9
Summary of Ahtna Survey

Twnshp	Total Acres	Volume (cubic feet)					
		White Spruce	Aspen	Poplar	Black Spruce	Birch	Cotton-wood
T1S, R2W	1,565	1,112,273	134,627	12,544	15,962		
T1N, R2W	2,278	2,136,366	315,511	41,040	18,490		
T2N, R1W	6,271	5,690,691	1,233,452	88,197	44,489		
T1N, R1W	249	292,317	39,062	13,216	-		
T2N, R1W	1,710	1,269,094	453,614	29,596	1,618	17,658	
T1N, R2W	1,000	1,084,982	71,275	26,221	15,277		
T1S, R2W	1,023	908,697	321,956	20,886	-	2,555	
T1N, R1E	4,082	3,078,715	1,405,902	278,457	4,486		
T2N, R1E	9,455	8,765,737	5,304,946	1,170,313	44,656		
T1N, R2E	4,791	9,461,252	1,590,161	487,269	437		
T1S, R2E	3,851	2,823,895	1,384,890	344,708	929		
T1S, R3E	7,676	10,114,888	2,011,892	575,173	5,490		52,572
	43,951	46,738,907	14,267,288	3,087,620	151,834	20,213	52,572
cf/acre		1,063	325	70	3	0	1

Similar to other surveys, White Spruce and Aspen dominate the area. And, with the small volumes required to fuel the potential biomass unit, there is sufficient volume to last many years.

<u>Summary</u>

As may be inferred from the summary tables just shown, there is no single GIS database that covers all-ownership forested lands with the same timber mapping criteria. But, given the limited volume required for a biomass resource as compared to the amount available, this inconsistency should not be an insurmountable problem.

The surveys have indicated that not only is there sufficient volumes for a biomass resource, but a resource of the size being contemplated could be sustained on a renewable basis. The forest resource is well-suited for biomass production, given the mixture of lower-quality spruce logs, open-grown form (more limbs), and the hardwood component (aspen, generally) of most timber stands.

Comparing general results from State, Ahtna, and BLM inventories suggests private lands like Ahtna's grow more volume and have larger trees. The DNR lands are less well-stocked and have lower volumes than reported inventory data for Ahtna. According to an Ahtna publication (2008) downloaded from the Alaska Energy Authority ftp site, Ahtna and the seven (of eight) villages that merged with the ANCSA regional corporation own approximately 1.77 million acres with 80 percent considered forested (about 1.4 million acres). Not all land selections have been conveyed.

Of note, however, is the lack of infrastructure in place to harvest trees. Lack of access roads and equipment as well as haul distances, and other factors will all work against the economics of a project.

DELIVERED COST OF BIOMASS

Costs of the delivered biomass material to the CHP facility will be comprised of three major components: 1) harvesting, 2) transportation, and 3) processing (chipping). In addition, the land owner will want royalties of some kind. While there is ample data (at least on an anecdotal basis) of delivered firewood, the volumes required for the CHP facility and processing limit the usefulness of the firewood data.

One data source in the public domain is the Alaska Energy Authority's Renewable Energy Fund grant program that included an application from Ahtna for a facility similar to Superior Wood Pellets at North Pole. Superior has four hammer mills, with the first able to pulverize up to 12-inch diameter logs. The Ahtna grant request (circa 2009) suggested (section 4.4.2) "timber extraction, chipping and hauling" would cost $92 per ton. Based on this information, two costs are used: $75/ton and $100/ton. Based on an expected average weight of 44 pounds/cubic foot, this equates to $1.65 - $2.20/cubic foot.

It is important to note that these costs are based, in part, on 2009 data. Fuel prices have increased from that time, and delivered prices may now be higher than the range suggested.

IV. ECONOMICS

ASSUMPTIONS

With any “generic” resource being considered, capital and operating costs are difficult to estimate with any precision. This is especially true for the resource being considered here given its lack of history. A conversation with a vendor’s representative provided a capital cost estimate of $7,000 per kilowatt, and this was substantiated from published data for a gasifier/internal combustion installation located at a public facility. It is believed that these costs do not include detailed studies, land acquisition, support equipment (loaders, etc.), interconnection with the utility’s system, and other up-front costs.

Variable operating costs are assumed to be slightly higher than industry standards for internal combustion units to account for the maintenance that will be required on the gasifier. Fuel costs are assumed as described in the preceding section. Fixed operating costs include provisions for a six-person crew, one half of the year, plus an additional amount for insurance, administrative, permitting and other costs.

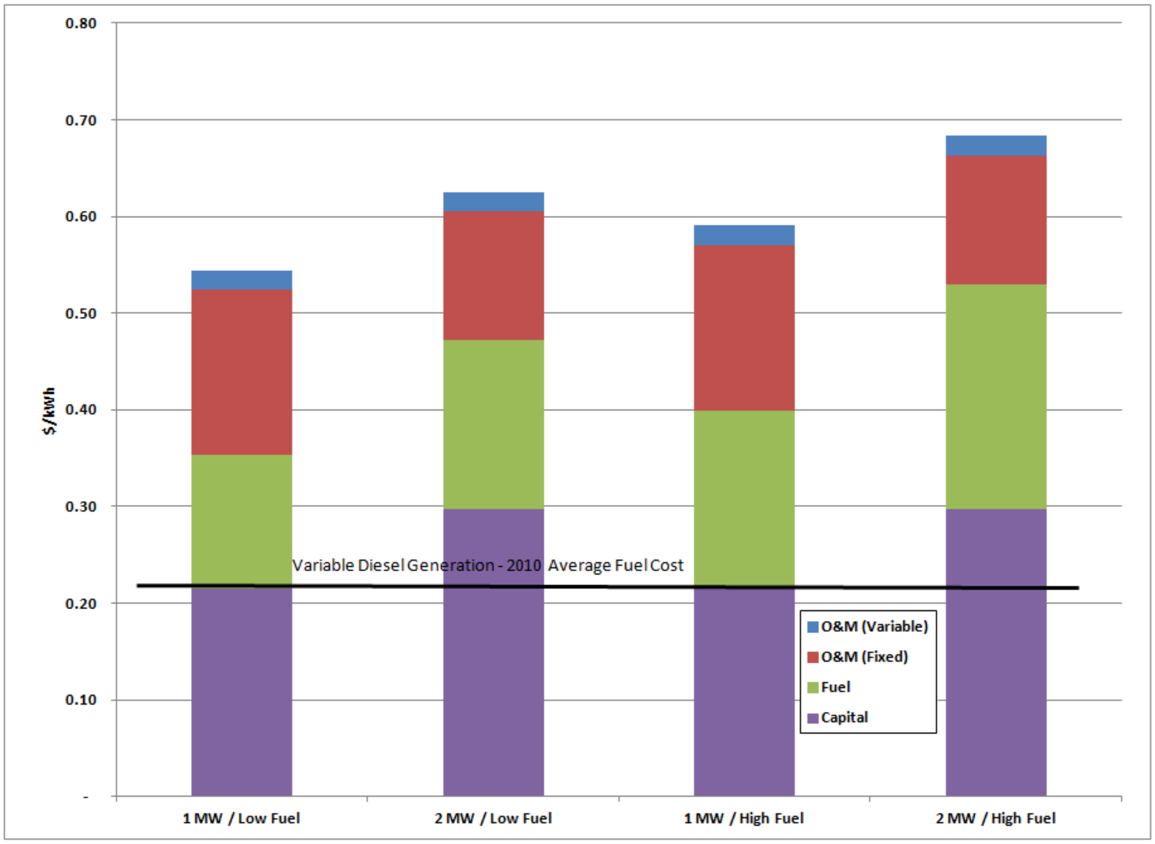
Table 10
Biomass Cost Assumptions

Resource Size (kW)		1,000		2,000
Energy (kWh/year)		3,500,000		4,500,000
Fuel (cf/yr)		292,362		475,088
Capital Cost				
Plant	$	7,000,000	$	14,000,000
Other		2,000,000		2,000,000
Total	$	9,000,000	$	16,000,000
Operating Costs ($/kWh)				
Variable ($/kWh)		0.020		0.020
Fixed ($/yr)	$	600,000	$	600,000
Fuel				
$1.65/cf				
$/year	$	482,397	$	783,895
$/kWh	$	0.138	$	0.174
$2.20/cf				
$/year	$	643,196	$	1,045,194
$/kWh	$	0.184	$	0.232

ANALYSIS

Figure 3 on the following page provides a summary of the annual costs in dollars/kilowatt-hour for both units and both fuel assumptions. For comparison, the variable costs of generation from the diesel units are also provided using the 2010 average diesel cost of $2.81/gallon. Capital costs are based on the full costs shown in the preceding table with no grants. Capital is amortized at 5.5 percent over 20 years. No provisions for debt service coverage ("DSC") or Times Interest Earnings Ratios ("TIER") are included which could increase the capital component from that shown.

Figure 3
Cost Summary – No Heat Sales



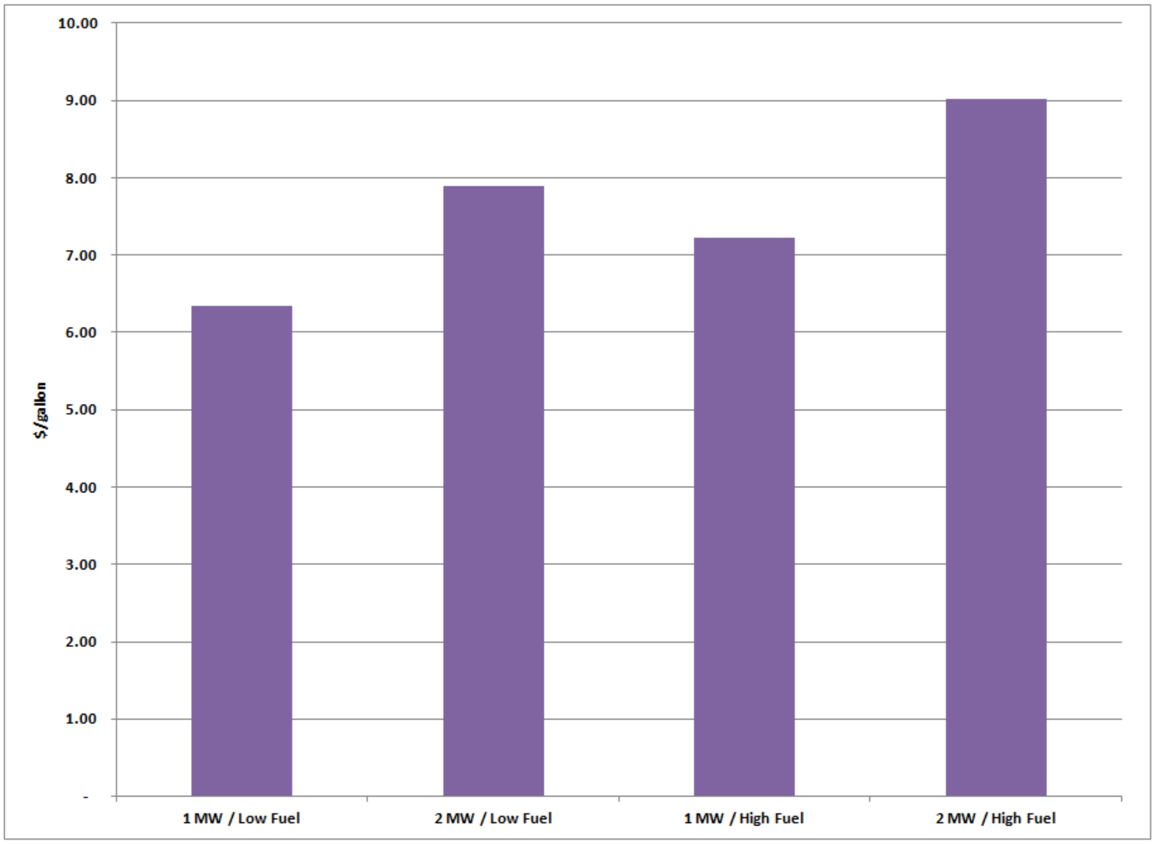
The figure above shows that a biomass facility used strictly for power generation would not provide economic power to CVEA. Even in the most favorable scenario assumed, delivered cost of power would be more than twice that of the power displaced.

As biomass facilities have evolved over the past several years, use of the exhausted heat has become a requirement for any potential resource to provide favorable economics. Heat can be used to drive a steam turbine for additional power generation or be used for space heating or other types of heating requirements. In this case, additional power generation would not be beneficial since the power is used for limited times during the year.

If the facility was located near several large buildings, the exhausted heat could be used for space heating purposes to offset the use of heating oil in the buildings. The identification of potential users or sites is not part of this study, and such identifications are required to develop reasonable estimates of the required capital costs for integration. Furthermore, permitting issues become an increasing concern when generation facilities are located near areas with large heating loads.

Even without capital cost estimates, certain observations and conclusions can be made regarding the use of heat. The following figure provides the cost, in $/gallon, that the displaced heating fuel must be in order for a CHP facility to provide economic value to both electric power production and space heating. It is important to remember that the costs shown in the figure do not include capital costs required for integration or permitting costs. For every $500,000 in capital costs, the breakeven cost of heating fuel would increase by $0.23/gallon for the 1,000-kilowatt facility and $0.18/gallon for the 2,000-kilowatt facility.[4]

Figure 4
Breakeven Cost of Heating Fuel
(Does Not Include Capital and Other Costs of Integration to System)



The preceding figure shows that for the 1,000-kilowatt/low fuel case, heating oil must be approximately $6.25/gallon for a CHP facility to provide benefits to both CVEA and to a heat user. As just noted, when interconnection and additional permitting costs are included, the breakeven price would be approximately $6.50/gallon. It is important to remember that the preceding table is based on 2010 cost levels. While fuel prices have increased since that time, the delivered cost of biomass and development costs would also increase.

[4] Based on a levelized amortization at 5.5 percent over 20 years.

V. SUMMARY

The analysis conducted and summarized herein investigated the potential merits of a biomass resource operated in a combined heat and power configuration. The analysis was high-level and not based on specific sites or detailed estimates of capital and operating costs. Nevertheless, based on the analysis and the associated assumptions, certain conclusions can be made.

1. CVEA's existing and planned hydro resources will limit the use of a biomass resource to seven or eight months per year. For part of this time, production would be limited due to the availability of hydro and the dispatch of cogen resource.

2. While diesel generation is estimated to provide approximately 10 million kilowatt-hours of generation, a potential biomass facility would not displace all of this. During the winter months, system demand net of the hydro and cogen resources, would exceed the capacity of a biomass facility.

3. A larger biomass resource could be built than that assumed herein to displace increased diesel production. However, the analysis showed that resource economics are eroded since the increased capital costs would be spread over an increasingly smaller amount of energy.

4. There are biomass resources in the area sufficient to sustain the long-term operation of a resource sized commensurate with the CVEA system.

5. Existing biomass facilities typically include steam boilers that are operated in baseload manners and not meant to fluctuate with loads. The limited use of a facility in the CVEA system, both on a seasonal and hourly basis, leads itself to a resource that is better operated on an intermediate basis that responds to load changes and can be shut down for periods of time.

6. The gasified systems that are expected to be better suited for such operations have very limited operating history. While certain facilities have been developed, they are geared mainly towards demonstration projects at this time.

7. Operated strictly for power production, the cost of power would be 2 – 3 times the displaced cost of power.

8. If all the residual heat could be used for space heating requirements, the cost of displaced heating oil must be $6 – 9/gallon for the facility to provide benefits for both power production and heating uses.

9. A facility with little track record poses a significant amount of financial and operational risk on the CVEA system and its members. The expected capital cost of nearly $10 million for a small, 1,000-kilowatt facility represents 80 percent of the utility's patronage capital, and failure of the resource would be felt for many years to come.