Pre-Feasibility Financial and Wood Supply Analysis for Biomass District Heating in Ely and Cook County, MN: University of Minnesota Report to Dovetail Partners, Inc.

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Table of Contents

List of Figures

List of Tables

Glossary

As received—wood waste and chips paid for on an “as received” basis without regard to moisture content.

Bioenergy—heat or electricity produced from biomass energy systems.

Biomass Cost of heat (Levelized Cost of Energy)—the cost per unit of energy that when held constant through the analysis period results in an NPV equal to zero.

Bole—the main trunk of the tree, above the stump and below the crown/top.

Btu—British thermal unit. Standard unit of energy equal to the heat required to increase the temperature of one pound of water one degree Fahrenheit.

Chips—a type of wood fuel. Clean chips are wood fiber processed by chipping, are free of contaminants like bark and needles, and generally include only the bolewood of a tree. Clean chips are suitable for residential and small industrial heating applications.

Co-firing—combustion of two types of materials, e.g., biomass with coal.

Co-generation—simultaneous production of heat and electricity from one or more fuels, also called combined heat and power (CHP).

Condensing power—power generated through a steam turbine where the steam is exhausted into a condenser, cooled to a liquid, and recycled back into a boiler.

Cord—stack of round or split wood consisting of 128 cubic ft of wood, bark, and air space (measures 4ft x 4ft x 8 ft).

Cordwood—equivalent to 4-ft lengths of roundwood cut and stacked into cords, or stacks of 4-ft x 4-ft x 8-ft. Cordwood is used for firewood in conventional fireplaces, wood-burning stoves, or boilers for home heating purposes.

DBH—diameter at breast height, used to measure trees.

Discount Rate—the rate used to determine the present value of future cash flows, which takes into account both the expected interest that could be earned on present money plus any uncertainty surrounding the future cash flows.

Forest biomass—the accumulated above- and belowground mass (bark, leaves, and wood) from living and dead woody shrubs and trees.

Forest residues—the aboveground material generated from logging during harvesting, e.g., leaves, bark, and tree tops (see also “Slash”)

Hog (hogged) fuel—a type of wood fuel generated by grinding wood and wood waste, including bark, leaves, branches, and tops of trees. Wildfire fuels reduction treatments and whole tree harvesting produce hog fuel, which is used for industrial, district heating and CHP applications.

Landing—the site where harvested trees are accumulated for loading onto trucks or further processing.

Maximum annual outlay - the largest amount of money that the project investor would have to come up with in any single year. Typically, this occurs in the first year of the project.

Net Present Value (NPV)—given a desired rate of return, the current worth of a future stream of cash flows (or savings) minus its current cost. Future cash flows (or savings) are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows.

Organic Rankine Cycle (ORC)—pressurizing, heating, vaporizing, condensing, and re-heating an organic fluid (e.g., propane, octamethyltrisiloxane (OMTS) in a closed cycle to generate electricity and 180°F hot water.

Oven-dry ton (odt)—ton of biomass or wood assuming zero percent moisture content by weight. Also referred to as dry ton and bone-dry ton.

Productive machine hour—time during scheduled operating hours when a machine performs its designated function; excluded downtime for maintenance, weather, and other delays.

Pulpwood—trees and wood suitable for manufacturing paper.

Rotation—number of years required to establish and grow trees to a specified size, product, or condition of maturity.

Roundwood—sawtimber, pulpwood, and other round sections cut from the tree.

Saw timber—log or tree meeting minimum diameter and stem quality requirements to be sawed into lumber.

Simple Payback Period—the number of years required to recover the cost of an investment with future cash flows discounted (see also NPV).

Skidding—moving trees from a felling site to a loading area or landing using specialized logging equipment.

Slagging—the formation of deposits on boiler tubes, usually due to the presence of chemical contaminants.

Slash—tree tops, branches, bark, or other residue left on the ground after forestry operations (see also "Forest Residues").

Stumpage—value or volume of uncut trees in the woods.

Thinning—partial harvesting of a stand of trees to accelerate the growth of the trees left standing.

Timberland—forested land capable of producing in excess of 20 cubic ft/acre per year of industrial wood crops under natural conditions.

Wildland-urban interface (WUI)—forest areas with increased human influence and land use conversion.

Wood Pellets—type of wood fuel made from compacted sawdust or pulverized wood chips. Premium pellets are made from sawdust and clean chips free of contaminants and are highly dense with low moisture content (below 10%) that are burned with greater combustion efficiency in residential and small industrial applications. Industrial grade pellets have higher ash content and are used in industrial applications with larger boilers and higher combustion temperatures than residential scale boilers.

Common Conversions

Energy Heating Values

Energy source	Factor	Unit	Moisture by weight
Coal	19,000,000	Btu/ton	--
Electric	3,413	Btu/kWh	--
Off-Peak Electric	3,413	Btu/kWh	--
#2 Heating Oil	140,000	Btu/gal	--
Kerosene	136,000	Btu/gal	--
Natural Gas	100,000	Btu/therm	--
Natural Gas	91,600	Btu/th. cu.ft.	--
Propane	91,600	Btu/gal	--
Cordwood	9,400,000	Btu/ton	35%
Clean Chips	9,600,000	Btu/ton	40%
Hog Fuel	8,800,000	Btu/ton	40%
Pellets	16,600,000	Btu/ton	10%

Common Forest Biomass Conversions[1]

Unit	Conversion
1 truckload of wood	23-26 green tons
1 green ton of wood (40% moisture content)	0.60 dry tons of wood
1 cord of roundwood	1.2 dry tons of wood (128 cu ft)
1 megawatt (MW) per year	5,300 – 7,000 dry tons of wood per year 85,000 – 110,000 million Btu per year powers approximately 750-900 homes per year

[1] One English (short) ton equals 2,000 lbs

1.0 INTRODUCTION

1.1 Report Purpose and Background

This report synthesizes findings of previous preliminary analyses conducted for biomass district energy systems in Ely, MN and Cook County, MN and presents financial scenarios upon which to compare options. Preliminary financial and wood supply impacts are presented for both locations to assist in making well-informed decisions about converting from fossil fuels to biomass energy. This phase of the study is funded by the Minnesota Environment and Natural Resources Trust Fund as recommended by the Legislative Citizen Commission on Minnesota Resources (LCCMR). It includes coordination and subsequent analyses of the following reports:

<u>Ely, Minnesota</u>

- **Ely District Energy Engineering Study** (LHB, Inc.; November 22, 2010) – preliminary analyses of capital costs and project structure establishing a biomass-fired 30 mmBtu/hr district heating system and 1 MW co-generation system in downtown and residential Ely. Project paid for by the U.S. Department of Energy and the Minnesota Department of Commerce through the American Recovery and Reinvestment Act of 2009 **(Appendix A)**.
- **Preliminary Feasibility Report: Ely Minnesota Biomass District Energy System** (Wilson Engineering Services, PC; July 6, 2012) – preliminary feasibility study evaluated a biomass-fueled district energy system consisting of thermal and thermally-led combined heat and power for a) Vermillion Community College, and b) the Ely-Bloomenson Community Hospital, Sibley Manor, and Independent School District 696. Project paid for by the Wood Education and Resource Center, U.S. Department of Agriculture, Northeastern Area State and Private Forestry **(Appendix B)**.

<u>Grand Marais, Minnesota</u>

- **Forest Biomass Heating and Electricity in Cook County, MN: Phase I Report** (Dovetail Partners and University of Minnesota; September 2011, updated February 2012) – results of preliminary scoping, technical feasibility, wood supply and air quality impacts of using locally generated forest biomass as an energy source for businesses and communities. Report commissioned by the Cook County Board of Commissioners **(Appendix C)**.
- **Review of Grand Marais Biomass District Heating System Feasibility Analysis** (FVB Energy, Inc.; August 3, 2012) – technical review of the above Phase I Report that presents recommendations to the City of Grand Marais on the technical and financial feasibility of a public facilities district heating system and a business district heating system. Technical review funded by the University of Minnesota, Swedish Bioenergy Association, and the BioBusiness Alliance of Minnesota **(Appendix D)**.

2.0 EXISTING ENERGY USE AND SYSTEM OPTIONS

2.1 Heat Load – ELY

LHB, Inc. first examined the feasibility of biomass energy systems in Ely in 2010, which included a district heating and combined heat-and-power (CHP) option for the residential and business core of the community. Five additional options for two smaller sites were analyzed by Wilson Engineering Services during the spring of 2012. Drawing from these two studies, this report considers seven total options for biomass energy systems in Ely.

Option 1, referenced as *Site 1: Biomass Heating (Hot Water)* in the Wilson Engineering report consists of a 3.3 mmBtu/hour biomass combustion unit and hot water boiler to generate domestic hot water and space heating at Vermillion Community College (VCC). The new boiler would connect directly to the existing VCC central heating plant and distribution system and offset approximately 85% of current heat consumption of 7,227 MMBtu/yr.

Option 2, referenced as *Site 2: Biomass Heating (Steam and Hot Water)* in the Wilson Engineering report consists of a 5 mmBtu/hour biomass combustion unit and steam boiler for the Ely-Bloomenson Community Hospital (EBCH), Sibley Manor, and Independent School District 696 (ISD 696) (Figure 1). The new boiler located south of Sibley Manor would generate low pressure steam (30 psig) to offset approximately 95% of current heat consumption of 16,235 MMBtu/yr. Low pressure steam would be directly distributed to EBCH and the Sibley Manor for heating and domestic hot water, and a shell and tube heat exchanger would use steam to heat a hot water thermal storage tank to distribute hot water for heating ISD 696. A radiator would be installed allowing the system to offset fossil fuel usage during low load summer conditions. Incidental connections to residents and businesses in proximity to the proposed pipeline were not assessed.

Option 3, referenced as *Site 2: Biomass Heating (Hot Water)* in the Wilson Engineering report consists of the same 5 mmBtu/hour biomass combustion unit described in the second option, but with a hot water boiler to generate hot water for space heating and domestic hot water at EBCH, Sibley Manor, and ISD 696. The system would require conversion of EBCH to hydronic heating from steam. A radiator would be installed allowing the system to offset fossil fuel usage during low load summer conditions. This system would offset an estimated 95% of current heat consumption of 16,235 MMBtu/yr. The system in this option and Option 2 is sized to accommodate additional heat load to serve nearby businesses if deemed feasible.

Option 4, referenced as *Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water)* in the Wilson Engineering report, consists of a 5 mmBtu/hour biomass fueled vented thermal oil heater with an unfired steam generator and 110 kW single-stage back-pressure steam turbine/generator at EBCH, Sibley Manor, and ISD 696. The system would offset approximately 95% of current heat consumption of 16,235 MMBtu/yr and generate 412,965 kWh of renewable electricity. Low pressure steam would be distributed to EBCH and Sibley Manor for heating and domestic hot water. A shell and tube heat exchanger would also utilize steam to heat a hot water thermal storage tank, which would be distributed to ISD 696. The system would be thermally-led and the turbine output would be dictated by the demand for heat. A radiator would be installed downstream of the turbine allowing the system to offset fossil fuel usage during low load summer conditions.

Option 5, referenced as *Site 2: Biomass ORC CHP (Thermal Oil and Hot Water)* in the Wilson Engineering report, consists of a 10 mmBtu/hour biomass combustion unit and vented thermal oil heater with a 600 kW Organic Rankine Cycle (ORC) CHP system at EBCH, Sibley Manor, and ISD 696. The system would offset approximately 95% of current heat consumption of 16,235 MMBtu/yr and generate 1,622,087 kWh of renewable electricity. The system would require conversion of the EBCH to hydronic heating from steam. The system would be thermally-led and electric generation would be dictated by the demand for heat. A radiator would be installed downstream of the ORC system allowing the system to offset fossil fuel usage during low load summer conditions.

Option 6, was generated from the 2010 LHB, Inc. report and consists of the LHB "*Base Project*" with a 25 mmBtu/hour biomass combustion unit and steam boiler. This consists of the district heat portion of a CHP system in the next option, Option 7. A stand-alone district heating system was not analyzed in the LHB report. The base project would serve VCC, ISD 696, Sibley Manor, EBCH, City Hall, and Zenith apartments. Build-out of the base project could eventually include 15 businesses and 365 residential customers located within the business and residential core of Ely. The new boiler would be located on South 17th Avenue East (south of Old Airport Road and adjacent to the City's main substation).

Option 7, was generated from the 2010 LHB, Inc. report and consists of the LHB "*Base Project*" with a 25 MMBtu/hour biomass combustion unit and thermal oil heater in conjunction with a 1 MW ORC combined heat and power system. The base project would serve VCC, ISD 696, Sibley Manor, EBCH, City Hall, and HRA apartments. Build-out of the base project would eventually include 15 businesses and 365 residential customers located within the business and residential core of Ely. The system would generate 1,043 kWh of renewable electricity.

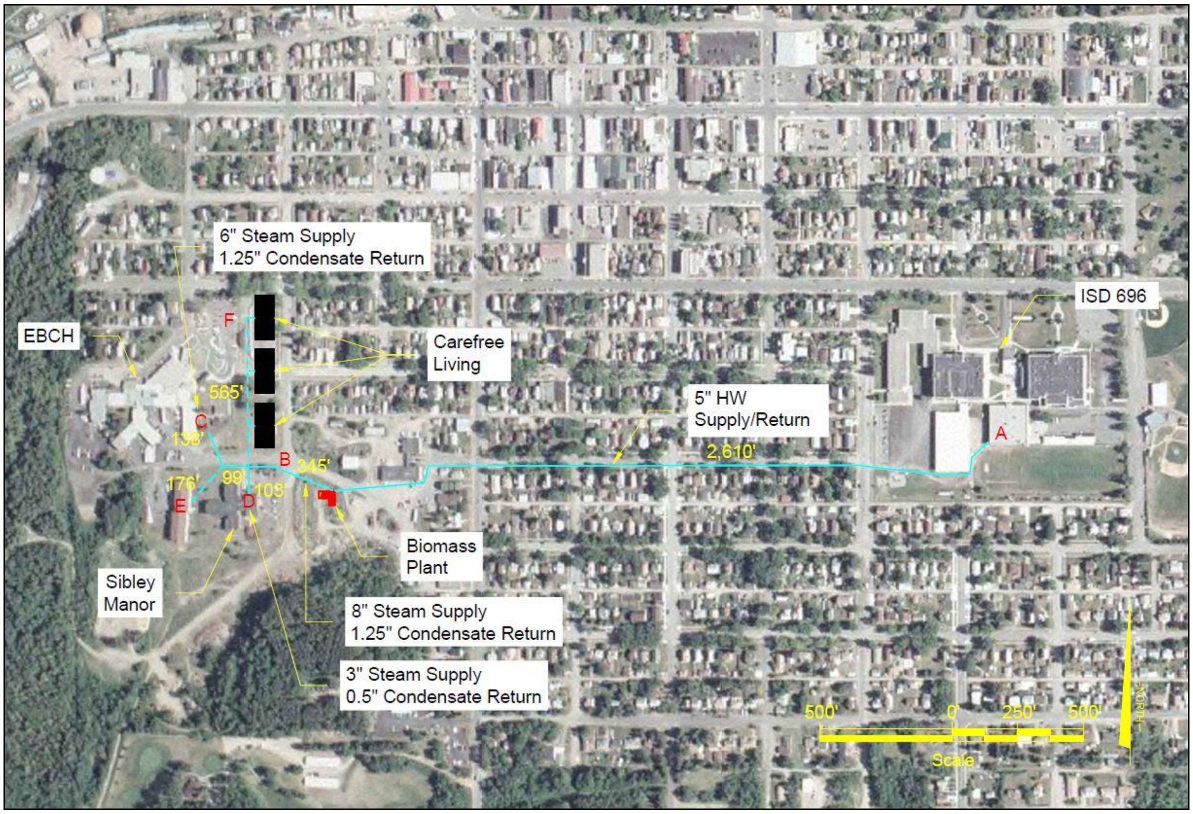

Figure 1. Coverage map of the Site 2 scenarios.

2.2 Biomass System Options – ELY

Table 1 provides site information on boiler, fuel type demand, piping, and buildings serviced in each scenario. Table 2 provides a preliminary cost estimate summary of capital, installation, operations and maintenance (O&M), buildings, piping, and related potential project development costs for each system modeled. Competitive quotes and industry knowledge of LHB, Inc. and Wilson Engineering Services were used to determine O&M estimates for each option.

Table 1. Modeled biomass systems and equipment specifications for Ely.

Configuration	Heat demand (non-peak) (MMBtu/yr)	Boiler capacity (max/hr)	Boiler efficiency	Piping (trench ft)	Building connections	Fuel type	Annual biomass demand dry tons (wet tons)
Option 1: VCC Hot Water	7,680	3.3 MMBtu/hr	65%	0	0	Chips/Hog	527 (878)
Option 2: Steam & Hot Water	23,424	5.0 MMBtu/hr	65%	3,200	3	Chips/Hog	1,754 (2,924)
Option 3: Hot Water	23,614	5.0 MMBtu/hr	65%	3,200	3	Chips/Hog	1,754 (2,924)
Option 4: Backpressure Steam CHP	35,772	5.0 MMBtu/hr	65%	3,200	3	Chips/Hog	1,904 (3,174)
Option 5: ORC CHP	41,272	10.0 MMBtu/hr	65%	3,200	3	Chips/Hog	2,838 (4,730)
Option 6: Ely District Heating (base)[1]	45,740	25.0 MMBtu/hr	73%	12,036	6	Hog fuel	5,974 (9,957)
Option 7: Ely ORC CHP (base)	79,490	25.0 MMBtu/hr	73%	12,036	6	Hog fuel	7,858 (13,096)

[1] Assumes 55-60% of heat load with peaking backup for coldest days.

[2] District heating portion of a CHP system; a stand-alone district heating system was not analyzed in the LHB report.

Table 2. Estimate of initial capital and annual operating costs for Ely scenarios.

Cost	Option 1: Hot Water	Option 2: Steam-HW	Option 3: Hot Water[1]	Option 4: Steam-CHP	Option 5: ORC-CHP	Option 6: District Heat	Option 7: ORC-CHP
Initial capital costs							
Plant	$1,904,318	$3,063,002	$3,045,866	$3,944,050	$6,494,786	$4,692,500	$12,622,003
Distribution	$0	$640,000	$640,000	$640,000	$640,000	$4,225,000	$4,373,493
Interconnection	$30,000	$80,000	$80,000	$80,000	$30,000[1]	*not assessed*	*not assessed*
Total capital costs	**$1,934,318**	**$3,783,002**	**$3,765,866**	**$4,664,050**	**$7,164,786**	**$8,917,500**	**$16,996,485**
Annual operating costs							
Biomass fuel ($/dry ton)	$37	$37	$37	$37	$37	$37	$37
Biomass fuel (total)	$26,331	$87,734	$87,734	$95,207	$141,912	$229,546	$299,223
Fuel oil/propane	$31,201	$21,673	$21,673	$21,673	$21,673	$40,000	$40,000
Electricity	$4,000	$6,000	$7,000	$6,000	$9,000	$60,152	$79,113
Maintenance	$5,600	$9,100	$7,100	$11,800	$17,100	$65,620	$105,000
Ash disposal	$1,000	$3,100	$3,100	$3,400	$5,000	*not assessed*	*not assessed*
Additional labor	$0	$0	$0	$0	$0	$53,223	$70,000
Total annual operating costs	**$68,132**	**$127,607**	**$126,607**	**$138,080**	**$194,685**	**$448,541**	**$593,336**

[1] Conversion of EBCH distribution from steam to hot water (Not Included in this study)

2.3 Heat Load – COOK COUNTY

Several sites were analyzed in the Phase I report and narrowed to a smaller subset considered in this analysis. The first option, reference as M1 in the Phase I Report, consists of the main building and guest cabins at Lutsen Resort on the south side of the Poplar River, approximately 20 miles south of Grand Marais on Hwy 61. Lutsen Resort serves as a proxy for similar sized, large resorts and small business clusters in the county. Total annual heat consumption of 5,200 MMBtu is assumed.

The second option, referenced as L3 in the Phase I Report, consists of a distributed hot water heating system for the public buildings north of 5th Street. The L3 scenario would serve 10 large customers, including the Cook County Hospital and Care Center, Sawtooth Mountain Clinic, Cook County Law Enforcement Center, and Cook County Schools. The L3 scenario analyzed herein would be extended from the hot water pipe configuration in the Phase I Report to include the County Courthouse and North Shore Laundry Mat. Total annual heat consumption of 11,796 MMBtu and a non-coincident peak demand of 6.2 MMBtu/hr are assumed.

The third option, referenced as L6 in the Phase I Report, consists of a distributed hot water heating system for the above described L3 option and the downtown business district. FVB Energy assumed a seasonal average fuel efficiency of 70% for annual heat consumption of MMBtu 30,562 MMBtu by the 75 potential customers included in the L6 scenario—61% of that is consumed by downtown businesses and 39% by public buildings and adjacent properties described in the L3 scenario. Eighteen customers are responsible for 80% of the load. An adjusted peak demand of 14.6 MMBtu/hr is used in the analysis.

The fourth option included in this report consists of a hybrid of the L3 and L6 options, referenced as Hybrid in the FVB Energy technical review. A total of 21 customers could be served in the Hybrid Scenario with a combined annual heating consumption of 24,186 and a non-coincident peak demand of 12.8 MMBtu/hr. The potential heat load would be nearly equal for the downtown (51%) and 5th St. area (49%). Figure 2 shows the preliminary routing of distribution piping, with the boiler facility assumed to be located east of the intersection of Gunflint Trail and 4th Ave. East. This location allows for the addition of future customers in conjunction with other scenarios analyzed.

Figure 2. Coverage map of the L3 (dotted line), Hybrid (dotted and solid lines), and L6 Scenarios (solid and starred lines)

2.4 Biomass System Options – COOK COUNTY

Table 3 provides site information on boiler, fuel type demand, piping, and buildings serviced in each scenario. Table 4 provides a preliminary cost estimate summary of capital, installation, operations and maintenance (O&M), buildings, piping, and related potential project development costs for each system modeled. Competitive quotes and industry knowledge of LHB, Inc. was used to determine O&M estimates for each option. Where available, capital cost and O&M estimates were updated using information from the FVB Energy technical review.

Table 3. Modeled biomass systems and equipment specifications for Cook County.

Configuration	Heat demand (non-peak) (MMBtu/yr)	Boiler capacity (max/hr)	Boiler efficiency	Piping (trench ft)	Building connections	Fuel type	Annual biomass demand dry tons (wet tons)
M1: Heat for main lodge and guest cabins at Lutsen Resort	5,200	4.4 MMBtu/hr	70%	1,100	12	Chips	390 (650)
L3: Public buildings north of 5th Street N and CC Courthouse	11,796	3.4 MMBtu/hr	70%	6,750	10	Chips/Hog	940 (1,567)
L6: District heat for downtown business district and L3	30,562	8.5 MMBtu/hr	70%	28,745	75	Chips/Hog	2,450 (4,083)
Hybrid: Combination of L3 and L6 scenarios for largest users	24,186	6.8 MMBtu/hr	70%	12,425	21	Clean chips Hog fuel	1,940 (3,233)

[1] Assumes 55-60% of heat load with peaking backup for coldest days.

Table 4. Estimate of initial capital and annual operating costs for Cook County scenarios.

Cost	M1	L3	L6	Hybrid
Initial capital costs				
Plant	$748,000	$2,150,000	$4,910,000	$3,960,000
Distribution	$242,000	$1,520,000	$5,640,000	$2,630,000
Interconnection	$5,000	$370,000	$1,250,000	$740,000
Total capital costs	**$995,000**	**$4,040,000**	**$11,800,000**	**$7,330,000**
Annual operating costs				
Biomass fuel ($/dry ton)	$36	$36	$37	$37
Biomass fuel (total)	$38,500	$76,672	$202,324	$157,203
Fuel oil/propane	$0	$45,136	$119,105	$92,543
Electricity	$0	$3,397	$11,736	$6,501
Maintenance	$15,300	$18,089	$53,377	$32,427
Ash disposal	*not assessed*	$656	$1,731	$1,345
Additional labor	$0	$35,000	$140,000	$70,000
Total annual operating costs	**$51,500**	**$178,950**	**$528,273**	**$360,019**

3.0 FINANCIAL PERFORMANCE

Table 5 shows the key financial assumptions used in the analysis. All prices are in real dollars for 2012 (not inflated), and are held constant for each scenario. The "usable life" of all equipment modeled was assumed to be 20 years. All costs and revenues are pre-tax.

Discount rates vary depending on the investor's view of the opportunity cost of money (if invested elsewhere) and the risk associated with the project. Higher discount rates make projects appear less attractive, meaning the investor believes an alternative project would be more profitable or that expected future cash flows from the current project are highly uncertain. One typically finds discount rates between 4%-8% for energy efficiency projects.[1] We adopt a discount rate of 4.5% for all scenarios.

Energy values for fossil fuels and for biomass fuels are shown in the Common Conversions table at the beginning of this report. While the energy contents for the fossil fuels are relatively constant, wood fuels fluctuate depending on the type of wood and moisture content.

Non-fuel factors such as labor, operating costs, and fuel costs change over time, directly affecting the delivered cost for biomass. Tables 6 and 7 show the average current fossil fuel prices for the study area and 20-year rates of change as projected by the Energy Information Administration (EIA) of the U.S. Department of Energy. The EIA "Reference Case" projects fossil fuel prices in northern Minnesota will track the rest of the northern Midwest over the next 20 years (2011-2030).[2] The starting price from which to escalate future prices uses averages of the most recent fuel receipts obtained from each site.

Table 5. Non-fuel investment and financing assumptions.

	Assumption
Useful life of plant (years)	20
Years of depreciation on investment	10
Discount rate	4.5%
Average income tax rate (federal & state)	35%
Amount financed (percent of capital)	100%
Financing term (years)	20
Loan interest rate	4.0%
Power Purchase Agreement (PPA) Price ($/kWh)	0.075
O&M cost rate (compared to inflation)	0.00%
Biomass cost rate (compared to inflation)	0.00%
Avg. current fuel price rate (compared to inflation)	1.36%

[1] Fuller, M. 2008. Enabling investments in energy efficiency: A study of energy efficiency programs that reduce first-cost barriers in the residential sector. Energy & Resources Group, UC Berkeley, Berkeley, CA. Website [http://www.eelriver.org/pdf/pge/Exhibit%2015%20CD-6%20(Fuller).pdf].

[2] US Energy Information Administration. 2010. Annual Energy Outlook 2010. DOE/EIA-0383. US Department of Energy, Washington, D.C. Available online at: http://www.eia.gov/oiaf/archive/aeo10/pdf/0383%282010%29.pdf.

Table 6. Average fossil fuel price, 20-year price escalation rate, and furnace efficiencies.

	Local price with delivery	Rate of price escalation	Furnace efficiency
Coal	$4.48/mmBtu	3.0%	80%
Electric	$0.13/kWh	-0.6%	80%
Off-peak electric	$0.06/kWh	-0.6%	80%
#2 heating oil	$3.10/gal	1.0%	70%
Kerosene	$3.06/gal	1.8%	80%
Natural gas	$0.83/therm	0.8%	90%
Propane	$2.18/gal	1.8%	70%

Source: US Energy Information Administration. 2010. Annual Energy Outlook 2010. DOE/EIA-0383. US Department of Energy, Washington, D.C. Available online at: http://www.eia.gov/oiaf/archive/aeo10/pdf/0383%282010%29.pdf.

There are several ways to measure the financial performance of an alternative energy project. Key metrics provided for each option are defined below:

- **Biomass cost of heat** – the cost per unit of energy that when held constant through the analysis period results in an NPV equal to zero. The "cost of heat" can also be described as the necessary average annual price paid to pay off all costs over the life of the project. Also known as the Levelized Cost of Energy (LCOE), this is calculated as the discounted lifetime capital and O&M costs divided by the total energy produced.
- **Net Present Value (NPV)** – given a desired rate of return, NPV is the current worth of a future stream of cash flows (or savings) minus its current cost. Future cash flows (or savings) are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows. NPV is also the value of the total lifetime savings (avoided expenditure on fossil fuels) from the project if offered to the investor today as one lump sum, minus the total cost of the project. If the value of the lump sum is greater than the cost of the project, then the NPV is positive.
- **Simple payback period** – the number of years required to recover the cost of an investment with future cash flows discounted (see also NPV). Simple payback period is the number of years it would take for the savings from a project to pay off the initial cost (not adjusted for the time value of money). This is the year in which cumulative net revenues become positive, and the project generates a positive financial return.
- **Maximum annual outlay** – the largest amount of money the project investor would have to come up with in any single year (usually the first year). Equal to the annual O&M and investment costs minus fuel cost savings from switching to biomass.

Tables 7 and 8 present cumulative and disaggregated cost data for each site in Ely and Grand Marais respectively, organized by capital construction costs and annual operating costs. Figures 3 and 4 show components of the biomass cost of heat for each option in Ely and Grand Marais. Tables 10 and 11 show how financial performance varies with a) a 50% increase in the price of delivered biomass ($37/dry ton base rate), b) 50% increase in interest rates (4.0% base rate), and c) 10% grant reflecting the third-party write-down of the cost of capital.

Table 7. Financial performance of proposed options for Ely.

	Option 1: Hot Water	Option 2: Steam-HW	Option 3: Hot Water	Option 4: Steam-CHP	Option 5: ORC-CHP	Option 6: District Heat	Option 6: ORC-CHP
Capital costs including hookup ($)	$1,934,318	$3,783,002	$3,765,866	$4,664,050	$7,164,786	$8,917,500	$16,996,485
Annual electricity sales ($)	$0	$0	$0	$7,106,000	$412,965	$0	$1,622,087
NPV project cost ($)	$2,601,514	$4,856,236	$4,832,649	$6,124,099	$8,822,533	$14,555,989	$24,402,762
NPV savings (including PPA) ($)	$2,666,281	$5,996,704	$6,051,390	$6,454,276	$7,633,890	$13,495,720	$20,427,970
Net Present Value ($)	$64,767	$1,140,469	$1,218,741	$330,177	$(1,188,643)	$(1,060,268)	$(3,974,792)
Simple payback period (years)	12	0	0	9	>20	>20	>20
Biomass cost of heat ($/mmBtu)	$32	$26	$26	$31	$39	$35	$42
Current fossil fuel price ($/mmBtu)	$30	$29	$29	$29	$29	$29	$29
Maximum annual outlay ($)	$10,861	$0	$0	$23,339	$140,100	$193,248	$417,305

[1]Including Power Purchase Agreement (PPA) for electricity sold.
[2]Cost of fossil fuel only; does not include the full cost of heating.

Table 8. Financial performance of proposed options for Cook County.

	M1	L3	Hybrid	L6
Capital costs including hookup ($)	$994,700	$4,040,000	$7,330,000	$13,050,000
Annual electricity sales ($)	$0	$0	$0	$0
NPV project cost ($)	$1,303,533	$5,639,484	$10,586,839	$17,922,468
NPV savings (including PPA) ($)[1]	$2,316,000	$5,848,000	$11,894,000	$15,094,000
Net Present Value ($)	$1,012,158	$208,098	$1,306,862	$(2,828,098)
Simple payback period (years)	0	12	0	>20
Biomass cost of heat ($/mmBtu)	$23	$36	$33	$44
Current fossil fuel price ($/mmBtu)[2]	$34	$33	$33	$33
Maximum annual outlay ($)	$0	$33,453	$0	$342,679

[1]Including Power Purchase Agreement (PPA) for electricity sold.
[2]Cost of fossil fuel only; does not include the full cost of heating.

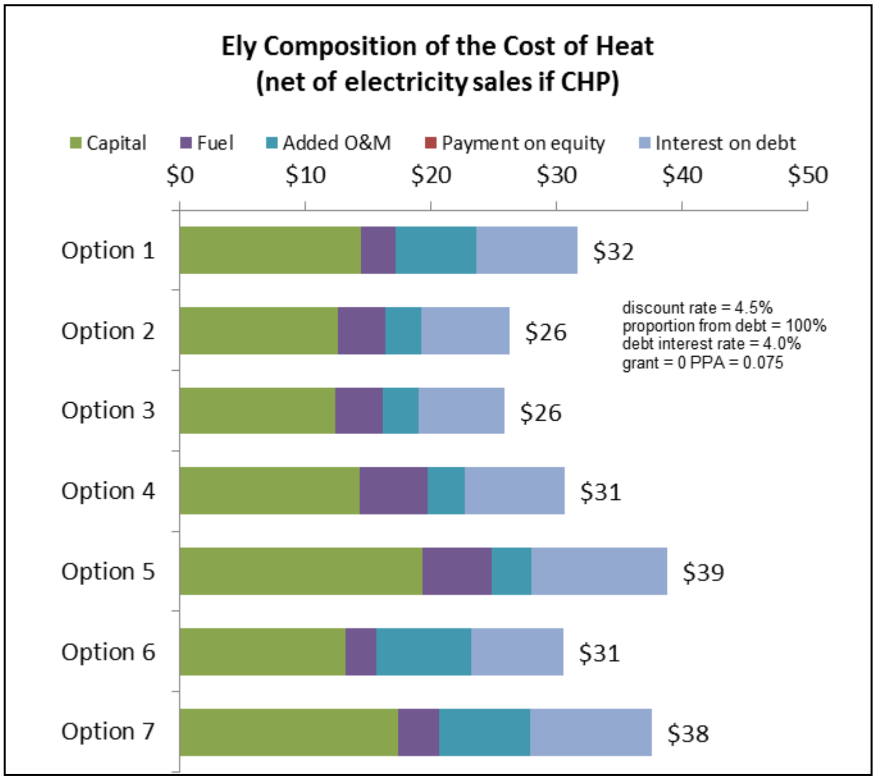

Figure 3. Ely Composition of Biomass Levelized Cost of Energy (LCOE) by site option.

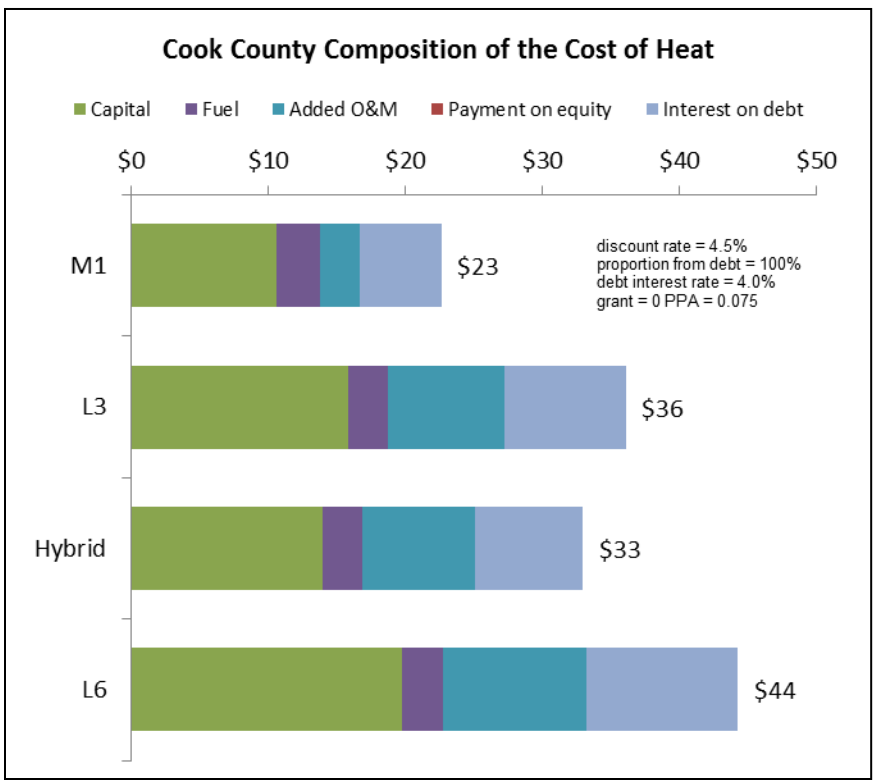

Figure 4. Cook County Composition of Biomass Levelized Cost of Energy (LCOE) by site option.

Table 9. Change in financial performance for options assessed in Ely.

	Base Case	50% increase in delivered biomass price (base: $37/odt)	50% increase in interest rate (base: 4.0%)	10% grant to write-down cost of capital
Site 1: VCC Hot Water				
Biomass cost of heat ($/MMBtu)	$32	$33	$36	$27
Net Present Value ($)	$64,767	$(46,339)	$(277,500)	$435,052
Simple payback period (years)	12	>20	>20	0
Maximum annual outlay ($)	$10,861	$19,403	$37,173	$0
Site 2: EBCH, Sibley Manor, and ISD 696 (Steam-Hot Water)				
Biomass cost of heat ($/MMBtu)	$26	$28	$30	$22
Net Present Value ($)	$1,140,469	$793,399	$471,088	$1,864,646
Simple payback period (years)	0	0	5	0
Maximum annual outlay ($)	$0	$0	$11,912	$0
Site 2: EBCH, Sibley Manor, and ISD 696 (Hot Water)				
Biomass cost of heat ($/MMBtu)	$26	$28	$29	$22
Net Present Value ($)	$1,218,741	$868,760	$552,392	$1,939,638
Simple payback period (years)	0	0	3	0
Maximum annual outlay ($)	$0	$0	$6,256	$0
Site 2: EBCH, Sibley Manor, and ISD 696 (Steam-CHP)				
Biomass cost of heat ($/MMBtu)	$31	$34	$35	$26
Net Present Value ($)	$330,177	$(209,667)	$(495,101)	$1,223,013
Simple payback period (years)	9	>20	>20	0
Maximum annual outlay ($)	$23,339	$64,840	$86,783	$0
Site 2: EBCH, Sibley Manor, and ISD 696 (ORC CHP)				
Biomass cost of heat ($/MMBtu)	$39	$42	$46	$31
Net Present Value ($)	$(1,188,643)	$(1,816,528)	$(2,456,412)	$182,908
Simple payback period (years)	>20	>20	>20	12
Maximum annual outlay ($)	$140,100	$188,370	$237,561	$34,661
Site 3: Ely District Heating (base project)				
Biomass cost of heat ($/MMBtu)	$35	$38	$39	$31
Net Present Value ($)	$(1,060,268)	$(2,536,747)	$(2,638,171)	$646,803
Simple payback period (years)	>20	>20	>20	10
Maximum annual outlay ($)	$193,248	$306,754	$314,551	$62,015
Site 3: Ely ORC CHP (base project)				
Biomass cost of heat ($/MMBtu)	$42	$47	$49	$34
Net Present Value ($)	$(3,974,792)	$(5,916,903)	$(6,982,226)	$(721,166)
Simple payback period (years)	>20	>20	>20	>20
Maximum annual outlay ($)	$417,305	$566,607	$648,505	$167,179

Table 10. Change in financial performance for options assessed in Cook County.

	Base Case	50% increase in delivered biomass price (base: $37/odt)	50% increase in interest rate (base: 4.0%)	10% grant to write-down cost of capital
M1: Lutsen Resort				
Biomass cost of heat ($/MMBtu)	$23	$24	$26	$19
Net Present Value ($)	$1,012,158	$920,986	$836,149	$1,202,575
Simple payback period (years)	0	0	0	0
Maximum annual outlay ($)	$0	$0	$0	$0
L3: Cook County Public Buildings				
Biomass cost of heat ($/MMBtu)	$36	$38	$41	$29
Net Present Value ($)	$208,098	$(12,994)	$(506,757)	$668,388
Simple payback period (years)	12	17	>20	0
Maximum annual outlay ($)	$33,453	$50,449	$88,408	$0
L6: Cook County Public Buildings and Downtown Business Core				
Biomass cost of heat ($/MMBtu)	$44	$46	$50	$31
Net Present Value ($)	$(2,828,098)	$(3,423,988)	$(5,137,223)	$981,473
Simple payback period (years)	>20	>20	>20	0
Maximum annual outlay ($)	$342,679	$388,488	$520,195	$0
Hybrid: Cook County Public Buildings and Largest Businesses				
Biomass cost of heat ($/MMBtu)	$33	$34	$37	$29
Net Present Value ($)	$1,306,862	$840,495	$9,860	$2,710,040
Simple payback period (years)	0	6	17	0
Maximum annual outlay ($)	$0	$31,748	$95,604	$0

4.0 FOREST BIOMASS AVAILABILITY AND PRICE

Although the Arrowhead Region of Minnesota has extensive forest resources, how much biomass is ultimately available for energy production is dictated by factors like forest conditions, timber harvest levels, ownership objectives, wood product markets, and wood processing capacity. The removal of vegetation from around homes and businesses to reduce hazardous fuels also produces wood waste that, in the past, was burned without energy capture but that could provide feedstock for heating and CHP systems.

In the following analysis, an estimation of annual biomass availability and price is based on annual tonnage from management activities and the cost of converting and transporting biomass as usable feedstocks to energy facilities. This assessment uses Forest Inventory and Analysis (FIA) data[3] provided by the USDA Forest Service, combined with a Forest Age Class Change Simulator (FACCS) model developed by researchers at the University of Minnesota,[4] to assess potentially available biomass from supply zones surrounding Ely and Grand Marais.

[3] USDA Forest Service. 2011. FIADB Version 4.1. Available online at: http://apps.fs.fed.us/fiadb-downloads/datamart.html.

[4] Domke, G.M. 2010. Resource assessment and analysis of aspen-dominated ecosystems in the Lake States. University of Minnesota, Ph.D. dissertation.

Target harvest rotation ages of 50 to 75 years are used, depending on species. 50% of available residual biomass is assumed left on site for soil nutrification, water management and wildlife habitat. The Minnesota Forest Resources Council (MFRC) guidelines on biomass harvesting recommend a 33% retention rate, that stumps and roots not be removed, and these materials are assumed to also be left on site and are excluded from the analysis.[5]

FIA data characterize forest resources in terms of forest type, species distribution, age, and general forest health. Bolewood and biomass yield curves were developed for the 3-county region (St. Louis, Lake, Cook) by forest type and age class. Combining FIA estimates of yield with the FACCS model analysis allows for the calculation of annual biomass yields based on forest type and age distribution within the area of interest. For the purposes of this analysis, available biomass is converted into four primary feedstocks:

- **Cordwood** is equivalent to 4-ft lengths of roundwood cut and stacked into cords, or stacks of 4-ft x 4-ft x 8-ft. Cordwood is used for firewood in conventional fireplaces, wood-burning stoves, or boilers for home heating purposes.
- **Chips** are a type of wood fuel. Clean chips are wood fiber processed by chipping and that is free of contaminants like bark and needles, and generally includes only the bolewood of a tree. Clean chips are suitable for residential and small industrial heating.
- **Hog (hogged) fuel** is a type of wood fuel generated by grinding wood and wood waste, including bark, leaves, branches, and tops of trees. Wildfire fuels reduction treatments and whole tree harvesting produce hog fuel, which is used for industrial, district heating, and CHP applications.
- **Wood pellets** are a type of wood fuel made from compacted sawdust or pulverized chips. Premium pellets are made from sawdust and clean chips free of contaminants and are highly dense with low moisture content allowing them to be burned with greater combustion efficiency in residential and small industrial applications. Industrial grade pellets have higher ash content and are used in industrial applications with larger boilers and higher combustion temperatures than residential scale boilers.

We examine bolewood (clean chips) and harvest residuals (e.g. tops and limbs) with an emphasis on residuals (hog fuel) at an annual timber harvest rate. A five-year average timber harvest rate was determined for the years 2006 – 2010 for each area. We also calculated an estimated threshold of sustainability based upon the *Final Generic Environmental Impact Statement on Timber Harvesting and Forest Management in Minnesota* (GEIS).[6] We use a conservative statewide rate of 4 million cords proportionally applied by species type to the supply regions assessed. A delivered biomass cost curve was developed for each region based

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[5] Minnesota Forest Resources Council (MFRC). 2007. *Biomass harvesting guidelines for forestlands, brushlands, and open lands.* St. Paul, MN: Minnesota Forest Resources Council. Available online at: http://www.frc.state.mn.us/initiatives_sitelevel_management.html.

[6] Jaakko Pöyry Consulting, Inc. 1994. Final generic environmental impact statement on timber harvesting and forest management in Minnesota. Prepared for the Minnesota Environmental Quality Board. Tarrytown, NY: Jaakko Pöyry Consulting, Inc.

upon an average transport distance and biomass availability within three mutually exclusive supply zones: 0-30 miles; 31-45 miles; and 46-60 miles.

The analysis then links yield estimates generated using the FACCS model with biomass supply zones calculated using ArcGIS Network Analyst and current roads data (Census 2010 Street Centerlines). Biomass supply zones were calculated using the Service Area Calculator in ArcGIS Network Analyst with distance as the accumulating impedance variable. Service area polygons were generalized and trimmed to include only locations within 1-mile of the existing road networks. The tables and figures below summarize this analysis for each region.

4.1. Physical Availability – Ely

Table 11 provides a breakdown of timberland acres in the 0-60 mile Ely biomass supply zone by age class and forest type for the most recent FIA reporting period (2006-2010). The Aspen-birch forest type occupies 646,730 acres (40% of timberland) and Spruce-fir occupies 560,647 acres (35% of timberland). Of those acres, 37% and 62% respectively, are greater than 60-years old and are either at or beyond their target harvest rotation age. Designated wilderness areas, old-growth reserves, wildlife management areas, state parks, and towns are not included in this analysis. Table 12 displays FIA estimates of the average oven-dry tons (dry tons) of biomass by type and ownership within the Ely 0-60 mile biomass supply zone.

Table 13 presents the estimated volume of hog fuel and clean chips by ownership within 60-miles of Ely based on the 2011 harvest rate for the region. The majority of 2011 bolewood was harvested from federal (153,747 cords) and private lands (145,391 cords). State and county lands provided another 137,681 cords. Total harvest residuals with 50% retention were approximately 59,856 dry tons, of which only a small portion was utilized.

Table 11. Timberland acres by age class and forest type in the Ely, MN 60-mile biomass supply zone (2006-20010 inventory cycle; non-stocked areas excluded).

Age class	White-red-jack pine	Spruce-fir	Oak-pine	Lowland hardwoods	Northern hardwoods	Aspen-birch
0-10	2,355	21,116	2,184	1,620	18,979	73,276
11-20	14,819	24,463	3,061	6,852	6,212	102,385
21-30	33,409	34,537	1,670	2,487	5,501	67,327
31-40	34,669	30,376	2,912	3,826	6,990	60,465
41-50	33,893	40,139	0	6,131	8,120	43,238
51-60	12,938	60,551	0	728	5,013	57,996
61-70	18,639	103,918	728	12,089	8,886	106,335
71-80	13,263	66,059	0	28,933	14,711	79,573
81-90	27,535	39,867	0	10,834	2,912	22,207
91-100	0	29,938	0	3,889	2,184	15,973
100+	28,343	109,683	3,061	3,982	10,117	17,955
Total	**219,863**	**560,647**	**13,616**	**81,371**	**89,625**	**646,730**

Table 12. Dry tons of living biomass by stand attribute and ownership within 60-miles of Ely.[1]

	Volume by Ownership (dry tons)				
Biomass Attribute	**Federal**	**State**	**County**	**Private[2]**	**Total**
Bolewood (≥5 in. dbh)	11,266,241	2,617,958	3,490,632	5,079,502	**22,454,332**
Tops and limbs	2,666,193	593,142	846,531	1,232,756	**5,338,620**
Saplings (1-4.9 in. dbh)	3,611,847	852,085	1,444,004	2,166,918	**8,074,854**
Stumps	690,230	166,942	210,350	322,079	**1,389,601**
Belowground roots	3,978,542	934,937	1,301,923	1,930,763	**8,146,167**

[1] No significant difference in site-level variation. Tree size is a function of diameter at breast height (dbh).
[2]Tribal lands are included in the Private lands category by FIA.

Table 13. FACCS estimate of biomass volume available by ownership within 60-miles of Ely. Biomass harvest estimate average for the first 30 years based upon 2011 harvest rate reported for different ownerships.

Ownership	**2011 harvest (cords)**	**2011 harvest (dry tons)**	**50% of tops & limbs (dry tons)**	**10% of bole harvest (dry tons)**	**Fuel treatment removals (dry tons)[9]**
Federal[1,2]	153,747	176,373	20,016	17,637	n/a
State[3]	53,032	60,625	6,764	6,063	n/a
County[4,5]	84,649	97,222	11,576	9,722	n/a
Private[6,7]	145,391	168,178	21,499	16,818	n/a
Total[8]	436,820	502,398	59,856	50,240	n/a

[1]Rate based on reported harvests from Superior National Forest West Zone for 2011 (Laurentian, LaCroix, and Kawishiwi Districts). 76,438 cords harvested from 338,000 acres in 2011.
[2]Rate based on reported harvests from Superior National Forest West Zone for 2001 - 2011 (Laurentian, LaCroix, and Kawishiwi Districts). Average of 86,003 cords harvested annually from 338,000 acres.
[3]Rate based on average harvests reported by Mike Magnuson (DNR Forestry Supervisor) for DNR lands in the Orr (241) and Tower (245) Areas outside of the Boundary Waters Canoe and Wilderness Area. Average of 81,000 cords per year harvested from 301,000 acres.
[4]Rate based on 2011 harvest information reported by Tom Zeisler (Resource Data Supervisor) for St Louis County. Average of 188,388 cords harvested from 572,215 acres of timberland.
[5]Rate based on 2001-2011 harvest information reported by Tom Zeisler (Resource Data Supervisor) for St. Louis County. Average of 176,631 cords harvested annually from 572,215 acres of timberland.
[6]Rate based on removal estimates provided by FIA for the 2006-2010 inventory cycle.
[7]Rate based on 7-year average removal estimates provided by FIA for 2004-2010 inventory period.
[8]Totals may differ slightly from those presented in other tables due to differences in harvests modeled by ownerships versus forest type or biomass supply zone.
[9]Fuel treatment removals include wildfire fuels reduction efforts on public lands as well as additional Firewise fuels reduction on non-public lands in 2010. Future removals assumed constant.

By combining biomass volumes with the haul distances from FIA sample plots to prospective energy facilities, we calculate an average haul distance and delivery cost for each supply zone in Table 14. Cost assessments for each supply zone around Ely are based on the Origin-Destination analysis. Total biomass costs for hog fuel and clean chips are presented. Total delivered cost includes stumpage, market premium, processed cost at the landing, and delivery. Delivery costs include round-trip transport cost with no backhaul ($4.25/mile), 25-green tons maximum per load, and 40% moisture content. Availability of hog fuel and clean chips are presented based on the proportion of the land area harvested at the GEIS 4 million cord statewide harvest rate, which is comparable to the 2011 harvest rate for this area.

Figure 5 presents a biomass cost curve based on the information presented in Table 14. The Ely cost curve was developed by extrapolating supply costs based upon the price and volume available at known distances from the proposed facility. Prices assume a static rate without consideration for competition or the premium paid for the quality of material delivered. These prices are used to model the biomass energy/heat production scenarios presented in Table 9. Figure 6 shows the geographic distribution of biomass resources calculated in Table 14 for the existing road network and distance from the proposed Ely facility.

Table 14. Average haul distance, cost, and annually available biomass volume for supply zones surrounding Ely. Based on average harvest estimate for the first 30 years of the project at GEIS 4 million cord statewide harvests.

Supply zone	Annual harvest (cords)[1]	Avg. haul distance (miles)[2]	Hog fuel[3] ---------(50% tops & limbs) --------- green tons ($/ton)[4,5]	dry tons ($/ton)[5]	Clean chips --------(10% of annual harvest) -------- green tons ($/ton)[4,5]	dry tons ($/ton)[5]
2006–2010 average harvest						
0 – 30 miles	63,815	18.2	16,148 ($22.00)	9,689 ($36.67)	12,422 ($29.02)	7,453 ($48.37)
31 – 45 miles	82,190	37.6	21,625 ($28.61)	12,975 ($47.68)	16,112 ($35.63)	9,667 ($59.38)
46 – 60 miles	145,293	53.2	36,692 ($33.91)	22,015 ($56.52)	28,648 ($40.93)	17,189 ($68.22)
Total	291,298	--	74,465	44,679	57,182	34,309
GEIS harvest[7]						
0 – 30 miles	102,523	18.2	22,601 ($22.00)	13,561 ($36.67)	19,665 ($29.02)	11,799 ($48.37)
31 – 45 miles	124,928	37.6	28,207 ($28.61)	16,924 ($47.68)	23,916 ($35.63)	14,350 ($59.38)
46 – 60 miles	209,363	53.2	46,640 ($33.91)	27,984 ($56.52)	40,102 ($40.93)	24,061 ($68.22)
Total	436,814	--	97,448	58,469	83,683	50,210

[1] Assumes an average of 1.2 dry tons per cord of wood. Actual conversions will vary by species.

[2] Average one-way haul distance to city center from FIA plots within the delineated zone. Actual haul distances will vary by harvest site location.

[3] Hog fuel is the tops, limbs, branches, small trees and needles as defined by the USDA Forest Service FIA biomass attributes. A conservative estimate of 50% is retained on site to meet the MFRC Biomass Harvest Guidelines.

[4] Assumes 40% moisture content at time of transport.

[5] Delivered cost of biomass reflects a hypothetical market price with assumed transportation cost of $4.25 per mile (25-green ton load at 40% moisture content with return trip) with in-woods processing costs of $11.47/dry ton (hog fuel) and $23.17/dry ton (clean chips).

[7] Biomass removal estimates based upon the proportion of a statewide timber harvest rate of 4.0 million cords as estimated in the 1990 Base Scenario analyzed in the Final Generic Environmental Impact Statement (GEIS) for Minnesota.

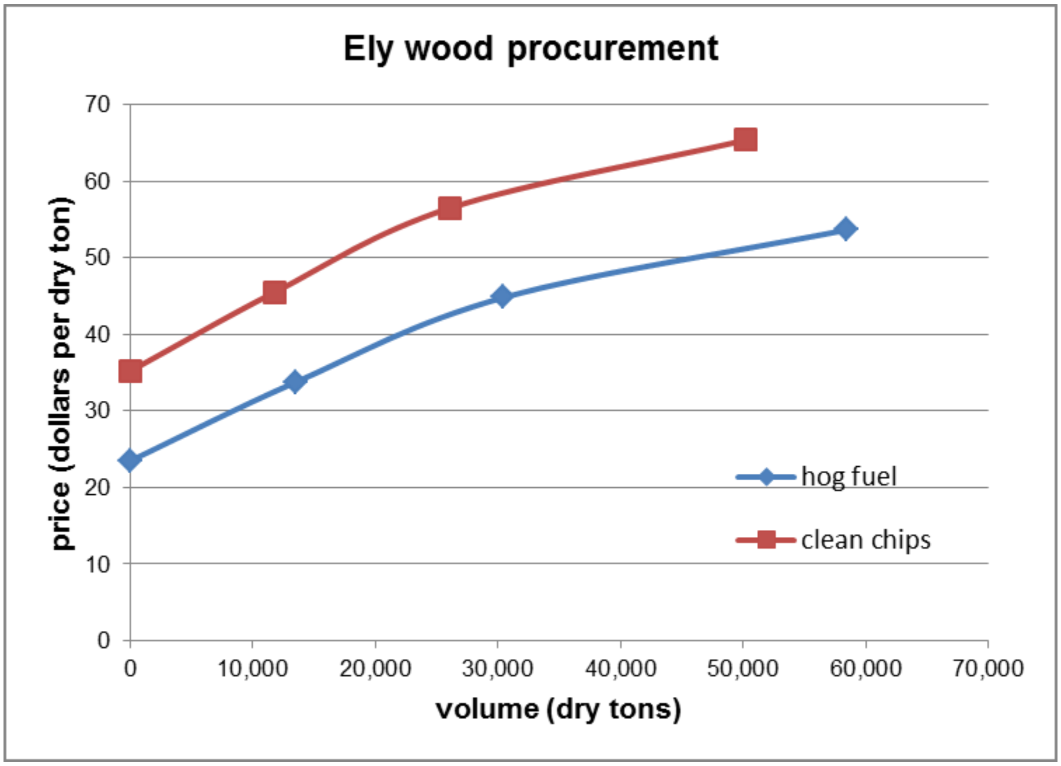

Figure 5. Biomass cost versus volume within the 60-mile supply zone around Ely. Prices do not account for potential competition for biomass.

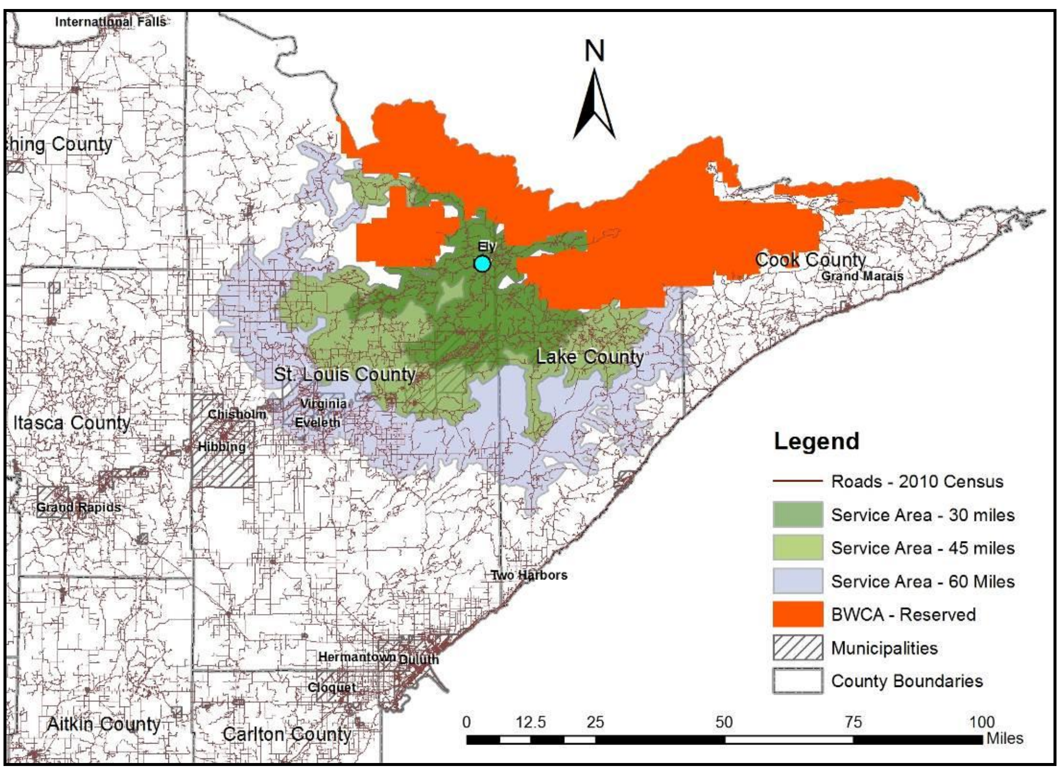

Figure 6. Biomass supply service areas around Ely.

4.2. Physical Availability – Cook County

Table 15 provides a breakdown of timberland acres in the 0-60 mile Grand Marais biomass supply zone by age class and forest type for the most recent FIA reporting period (2006-2010). The Aspen-birch forest type occupies 415,659 acres (51% of timberland) and Spruce-fir occupies 200,027 acres (25% of timberland). Of those acres, 53% and 42% respectively, are greater than 60-years and are either at or beyond their target harvest rotation age. Designated wilderness areas, old-growth reserves, wildlife management areas, state parks, and towns are not included in this analysis. Table 16 displays FIA estimates of the average oven-dry tons (dry tons) of biomass by type and ownership within the Grand Marais 0-60 mile biomass supply zone.

Table 17 presents the estimated volume of hog fuel and clean chips by ownership within 60-miles of Grand Marais based on the 2006-2010 harvest rate for the region. The majority of 2006-2010 bolewood was harvested from private (27,644 cords) and county lands (24,292 cords). Federal and state lands provided another 34,057 cords. Total harvest residuals with 50% retention were approximately 12,576 dry tons, of which only a small portion was utilized.

Table 15. Timberland acres by age class and forest type in the Grand Marais 60-mile biomass supply zone (2006-2010 inventory cycle; non-stocked areas excluded).

Age class	White-red-jack pine	Spruce-fir	Oak-pine	Lowland hardwoods	Northern hardwoods	Aspen-birch
0-10	8,680	2,625	6,449	2,495	4,531	47,766
11-20	11,606	17,706	0	0	3,240	34,578
21-30	12,597	25,040	5,095	0	5,440	29,803
31-40	4,940	19,860	0	0	3,450	15,894
41-50	5,202	21,754	6,136	0	2,912	18,437
51-60	6,971	29,900	0	0	3,641	48,540
61-70	5,461	15,291	0	3,383	22,091	93,417
71-80	0	9,957	2,682	5,093	23,848	68,548
81-90	0	7,200	0	9,559	11,218	35,570
91-100	728	17,763	2,912	0	0	8,875
100+	3,370	32,931	0	993	10,346	14,231
Total	**59,555**	**200,027**	**23,274**	**21,523**	**90,717**	**415,659**

Table 16. Dry tons of living biomass by attribute and ownership within 60-miles of Grand Marais.[1]

	Volume by Ownership (dry tons)				
Biomass Attribute	**Federal**	**State**	**County**	**Private[2]**	**Total**
Bolewood (≥5 in. dbh)	8,077,619	2,189,163	1,261,951	3,274,078	**14,802,811**
Tops and limbs	1,983,803	566,898	332,851	848,939	**3,732,492**
Saplings (1-4.9 in. dbh)	2,148,922	546,475	283,814	737,914	**3,717,125**
Stumps	474,564	132,514	72,834	186,600	**866,512**
Belowground roots	2,697,582	726,210	398,939	1,044,310	**4,867,042**

[1] No significant difference in site-level variation. Tree size is a function of diameter at breast height (dbh).
[2] Tribal lands are included in the Private lands category by FIA.

Table 17. FACCS estimate of biomass volume available by ownership within 60-miles of Grand Marais. Biomass harvest estimate average for the first 30 years based upon 2006-2010 FIA harvest rate reported for different ownerships.

Ownership	2006-2010 annual harvest (cords)	2006-2010 annual harvest (dry tons)	50% of tops & limbs (dry tons)	10% of bole harvest (dry tons)	Fuel treatment removals (dry tons)[2]
Federal	21,120	24,435	2,884	2,444	3,189
State	12,937	14,839	1,806	1,484	n/a
County[1]	24,292	28,355	3,812	2,836	n/a
Private	27,644	31,975	4,073	3,198	3,005
Total	85,992	99,603	12,576	9,960	6,194

[1]Majority of county land harvested within 60-miles from Lake County. FIA estimates that Cook County has 9,686 acres of County owned timberland while Lake County has 189,897 acres. Total county owned acres used to model harvests include 60,727 acres of timberland.

[2]Fuel treatment removals include wildfire fuels reduction efforts on public lands as well as additional Firewise fuels reduction on non-public lands in 2010. Future removals assumed constant.

By combining biomass volumes with the haul distances from FIA sample plots to prospective energy facilities, we calculate an average haul distance and delivery cost for each supply zone in Table 18. Cost assessments for each supply zone around Grand Marais are based on the Origin-Destination analysis. Total biomass costs for hog fuel and clean chips are presented. Total delivered cost includes stumpage, market premium, processed cost at the landing, and delivery. Delivery costs include round-trip transport cost with no backhaul ($4.25/mile), 25-green tons maximum per load, and 40% moisture content. Availability of hog fuel and clean chips are also presented based on the proportion of the land harvested at the GEIS 4 million cord statewide harvest rate, which is significantly greater than the 2006-2010 harvest rate for this area.

Figure 7 presents a biomass cost curve based on the information presented in Table 18. The Grand Marais cost curve was developed by extrapolating supply costs based upon the price and volume available at known distances from the proposed facility. Prices assume a static rate without consideration for competition or the premium paid for the quality of material delivered. These prices are used to model the biomass energy/heat production scenarios presented in Table 10. Figure 8 shows the geographic distribution of biomass resources calculated in Table 18 for the existing road network and distance from the proposed Grand Marais facility.

Table 18. Average haul distance, cost, and annually available biomass volume for supply zones surrounding Grand Marais. Based on average 2006-2010 harvest estimate for the first 30 years at GEIS 4 million cord harvest rates.

Supply zone	Annual harvest (cords)[1]	Avg. haul distance (miles)[2]	Hog fuel[3] ---------(50% tops & limbs) --------- green tons ($/ton)[4,5]	dry tons ($/ton)[5]	Clean chips --------(10% of annual harvest) -------- green tons ($/ton)[4,5]	dry tons ($/ton)[5]
2006–2010 average harvest						
0 – 30 miles	33,504	18.6	7,855 ($22.00)	4,713 ($36.67)	6,457 ($29.02)	3,874 ($48.37)
31 – 45 miles	27,055	36.4	6,620 ($28.05)	3,972 ($46.75)	5,271 ($35.07)	3,163 ($58.45)
46 – 60 miles	19,013	52.7	4,608 ($33.58)	2,765 ($55.97)	3,682 ($40.60)	2,209 ($67.67)
Total	79,572	--	19,083	11,450	15,410	9,246
GEIS harvest[7]						
0 – 30 miles	97,752	18.6	22,591 ($22.00)	13,555 ($36.67)	18,768 ($29.02)	11,261 ($48.37)
31 – 45 miles	70,675	36.4	17,135 ($28.05)	10,281 ($46.75)	13,714 ($35.07)	8,228 ($58.45)
46 – 60 miles	51,283	52.7	12,097 ($33.58)	7,258 ($55.97)	9,865 ($40.60)	5,919 ($67.67)
Total	219,710	--	51,823	31,094	42,347	25,408

[1] Assumes an average of 1.2 dry tons per cord of wood. Actual conversions will vary by species.

[2] Average one-way haul distance to city center from FIA plots within the delineated zone. Actual haul distances will vary by harvest site location.

[3] Hog fuel is the tops, limbs, branches, small trees and needles as defined by the USDA Forest Service FIA biomass attributes. A conservative estimate of 50% is retained on site to meet the MFRC Biomass Harvest Guidelines.

[4] Assumes 40% moisture content at time of transport.

[5] Delivered cost of biomass reflects a hypothetical market price with assumed transportation cost of $4.25 per mile (25-green ton load at 40% moisture content with return trip) with in-woods processing costs of $11.47/dry ton (hog fuel) and $23.17/dry ton (clean chips).

[7] Biomass removal estimates based upon the proportion of a statewide timber harvest rate of 4.0 million cords as estimated in the 1990 Base Scenario analyzed in the Final Generic Environmental Impact Statement (GEIS) for Minnesota.

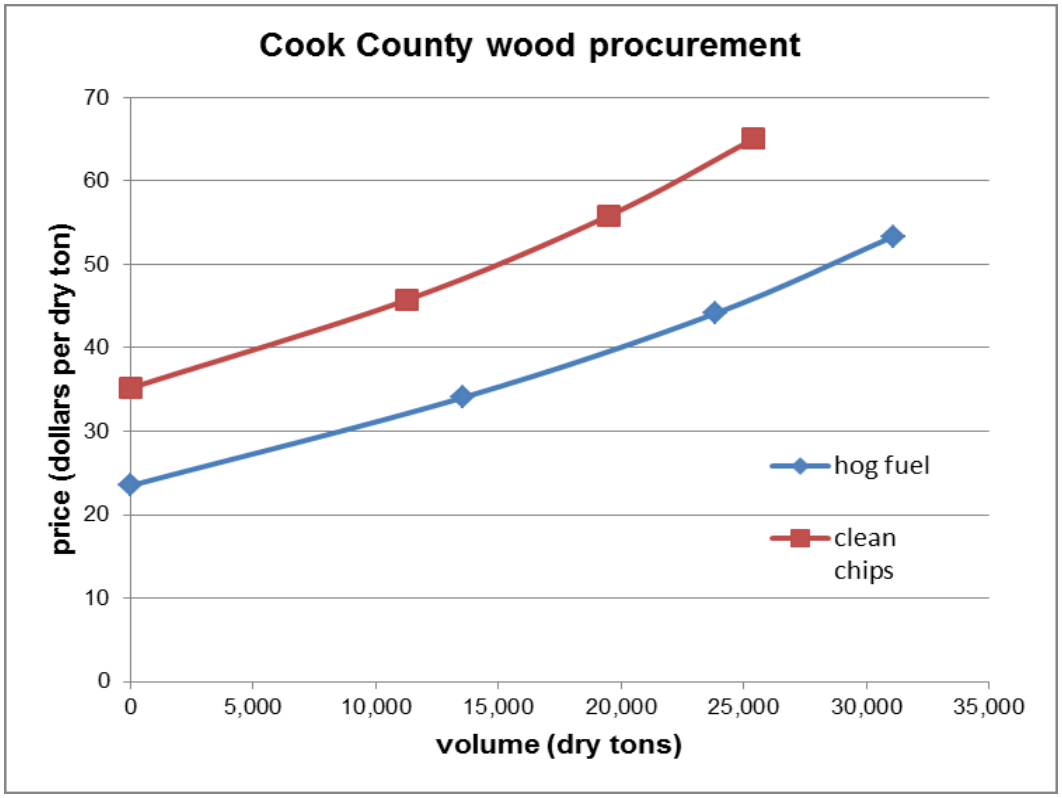

Figure 7. Biomass cost versus volume within the 60-mile supply zone around Grand Marais. Prices do not account for potential competition for biomass.

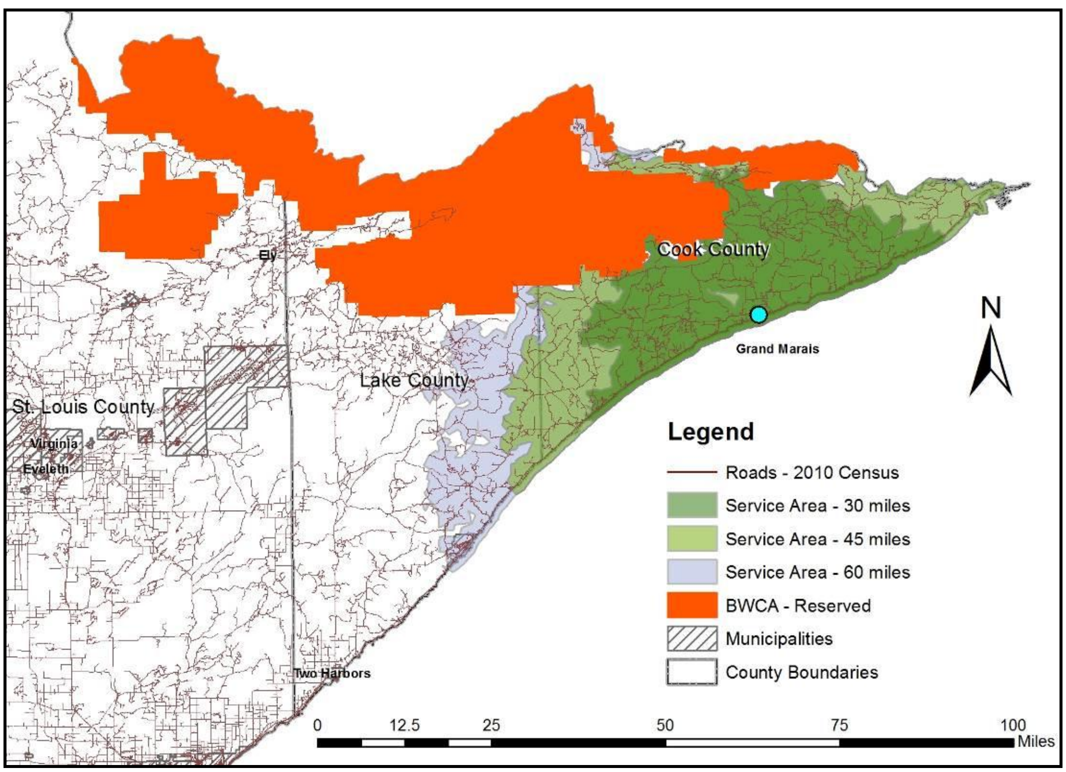

Figure 8. Biomass supply service areas around Grand Marais.

4.3 Competition

To provide an estimate of potential competition for biomass, this analysis examined the overlap of each 60-mile supply zone for Ely and Grand Marais and the existing wood yard for the Virginia-Hibbing Laurentian Energy Authority in Mountain Iron, MN (Figure 9). The volume of sustainably harvestable biomass within overlapping supply zones was is calculated in Table 19.

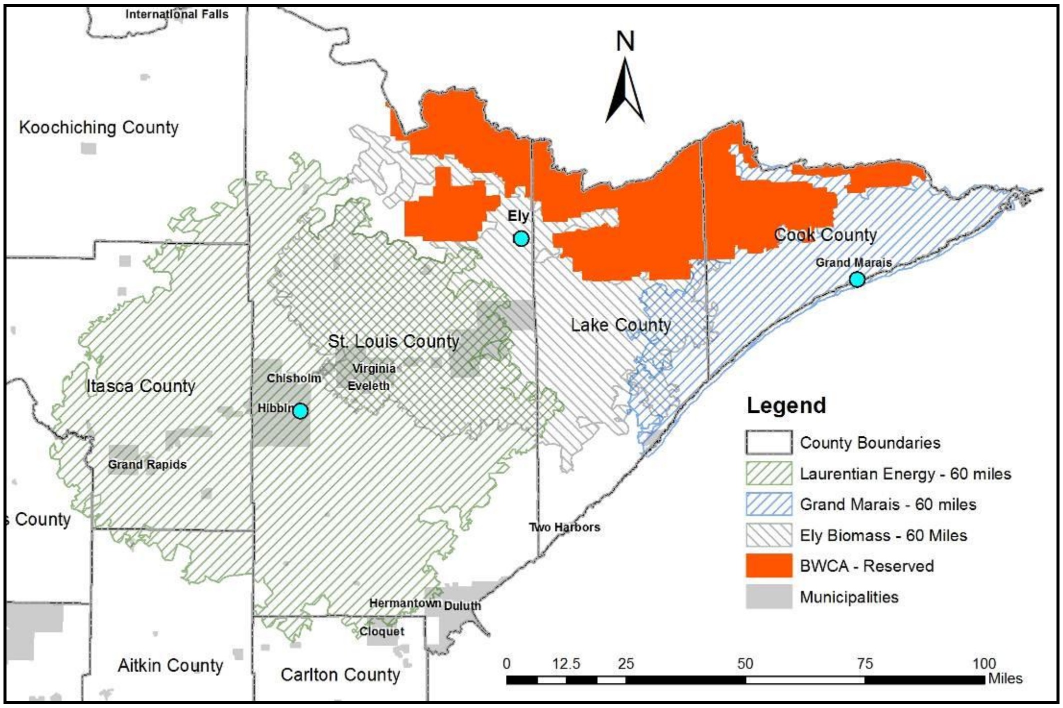

Figure 9. Overlap of 60-mile biomass supply zones for Laurentian Energy Authority (Mountain Iron wood yard), Ely, and Grand Marais.

Table 19. Biomass resources potentially subject to competition within overlapping 60-mile supply zones. Biomass harvest estimate average for the first 30 years based on GEIS 4 million cord annual harvests.

60-mile overlap	Annual bole harvest (dry tons)	50% of tops & limbs (dry tons)	Percent of overlapping supply	Bole + 50% of tops & limbs (dry tons)
Ely - Grand Marais	45,381	5,402	12%	50,783
Ely - Laurentian	230,225	27,861	12%	258,085
Grand Marais – Laurentian	0	0	0%	0

4.4 Biomass Harvesting and Transport Costs

The costs of harvesting, handling, and transporting biomass to a processing facility are critical factors in the total price paid. These costs also vary widely based on operator and equipment productivity, tree species harvested, distance to processing facility, and whether co-products exist (e.g., pulpwood). For the purposes of this analysis, we assume separate harvest costs for bolewood chips and hog fuel. Bolewood chips, or clean chips, require the removal of the tree for biomass production and subsequent costs are attributed to that market. For the hog fuel material, harvest and skidding costs associated with moving trees to a forest landing are a function of a primary pulpwood or sawlog market. Therefore, the price paid for residual hog fuel biomass collected and processed at the landing includes only the chipping/grinding operation. Wages, benefits, and employer costs for workers' compensation and unemployment insurance are held constant. Total fixed and variable costs are calculated at a rate of $183.72/PMH (productive machine hour), which are the total hours of use for scheduled purposes over the course of one year. Appendix E provides a breakdown of equipment costs used in the analysis.[7] We used processing/chipping costs of $11.47/odt for hog fuel and $23.17/odt for clean chips.

4.5 Forest Operations

For a logger to justify moving equipment to a site to process biomass there needs to be enough throughputs to offset hourly costs. Small parcel sizes, long mobilization distances between harvest sites, and long transport distances to a heating or CHP site are disincentives. Having the appropriate equipment to efficiently harvest and process biomass are also barriers. We conducted interviews with area loggers to determine their level of interest in participating in biomass markets, equipment capacity and needs, and the costs of production, including mobilization of equipment and biomass processing. Interest among those interviewed was high but tempered by the cost of equipment and lack of biomass harvesting volume to justify expenses. We foresee no new investment in biomass chipping equipment until sufficient volumes and consistent market prices warrant expansion.

[7] Brinker RW, Kinard J, Rummer B, Lanford B. 2002. Machine rates for selected forest harvesting machines. Circular 296. Auburn, AL: Alabama Agricultural Experiment Station.

APPENDIX A.

Ely District Energy Engineering Study (LHB, Inc.)

Ely District Energy Engineering Study

November 22, 2010

Prepared by:

LHB

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This project was made possible by a grant from the U.S. Department of Energy and the Minnesota Department of Commerce through the American Recovery and Reinvestment Act of 2009 (ARRA).

Ely District Energy Engineering Study

Table of Contents

Ely District Energy Engineering Study

Forward

LHB was contracted by Ely to complete a District Heat (DH) and Co-generation (together known as District Energy, DE), Engineering Study funded by an American Recovery and Reinvestment Act (ARRA) of 2009 and administered by the Minnesota Department of Commerce Office of Energy Security. The Study followed up on the November 2009 Summary Feasibility Study and subsequent May 2010 Addendum. The specific purpose of this Study was to gather equipment budget quotations and estimate construction costs for the DE plant, including:

1. A biomass fired Thermal Oil Heater (TOH)
2. Biomass (wood pellet) hot water peaking boiler(s)
3. Organic Rankine Cycle (ORC) co-generation
4. Fossil fuel (propane) back-up hot water boilers and
5. Hot water distribution piping system

Project structure, funding and billing recommendations are also included.

In addition to significant cost savings and renewable energy, the Ely DE facility offers 5 key benefits, including:

1. **Showcasing New Technology:** The plant will be the first District Heating facility in North America to use wood waste powered ORC CHP. Well proven in more than a hundred plants in Europe, wood waste DH reduces heating costs by about 50% when compared to propane and fuel oil. State of the art control systems for the TOH will minimize particulate matter (PM), oxides of nitrogen (NOx) and Carbon Monoxide (CO) emissions.

2. **9 New Jobs:** Approximately 6 new logging and trucking jobs, 2 private plumbing and 1 DH plant jobs will be created.

3. **More Dollars Stay Within Community:** Studies have shown that 75% or more of biomass energy dollars stay within the local community, as opposed to only 5% or less of fossil fuel energy dollars. <u>At full build-out, about $2,500,000 more dollars will stay in the Ely area.</u>

4. **Enhanced Forest Management Practices:** Permanent shutdown of three Orientated Strand Board (OSB) plants in Minnesota has reduced wood harvest to less than 50% of the State's sustainable growth. Mature trees are being left in the woods, creating wildfire hazards. This project will predominately use forest residue and underutilized species, and only about 23,000 tons per year from a very small radius, predominantly 15 miles or less.

Ely District Energy Engineering Study
Forward (continued)

5. **Reduced Imported Oil and Heating Related CO2 Emissions:** At system full load, about 375,000 gallons/year of fuel oil and 550,000 gallons/year of propane will be displaced. The release of about 15,000 tons per year of Carbon Dioxide, equivalent to taking about 4,000 cars off the road, will be avoided.

The report is organized as follows:

- Project Narrative (Word Document): Executive Summary, Background and Findings (Project Description, Sizing, Costs, Structure, etc.)
- Project Spreadsheet (Excel Worksheets): 30 Worksheets containing summaries, calculations, including user inputted variables for; Grants, Interest Rate, Term, $/€ Exchange Rate, Infrastructure Payment, Wood Waste, Pellet, Fuel Oil and Propane Costs, estimates as well as a "Renewables Comparison" which shows the relative value of the this project compared to Wind, Solar and Ground Source Heat Pumps
- Drawings: District Heating Piping Plans, District Energy Building/Layout/Flowsheet, Vendor supplied drawings
- Written Budget Quotes for all major pieces of equipment
- Equipment Brochures and Manuals for all major pieces of equipment
- District Energy/District Heating Reference Materials from the Turboden (ORC supplier), International District Energy Association (IDEA), Biomass Energy Resource Center (BERC), University of Minnesota Biomass Study (Digital Only)
- TREEA Reference Material: Thermal Renewable Energy Efficiency Act sponsored by Senator Al Franken and Representative Betty McCollum
- Excerpts from District Heating Handbook
- Profiles of primary author and LHB

LHB gratefully acknowledges the help of several Ely Alternative Energy Task Force (AETF) personnel who assisted in this effort, including City Operations Director Harold Langowski, Mayor Roger Skraba, Chairman Kurt Soderburg, Dave Olsen, Rebecca Spangler, Steve Piragis and the rest of the AETF as well as Bill Mittlefeldt of the NE Minnesota CERT and Jerry Pelofski and Bacon Reuille of the Duluth Steam Cooperative Association and the OES. We also gratefully appreciate the materials used by permission by Turboden, VAS, Biomass Energy Resource Center, International District Heating Association and others as well as funding by the DOE and Minnesota Office of Energy Security.

We sincerely appreciate the opportunity to be involved with Ely on this exciting project.

Ely District Energy Engineering Study

Glossary

Binary Power: Also known as Organic Rankine Cycle (ORC), the process of using 2 fluids to transfer heat and generate electricity. The second fluid is a low boiling point organic fluid that is pressurized, heated and vaporized, expanded in a turbine generator and condensed to a liquid to complete a closed cycle.

Co-generation: Sequential generation of thermal (usually steam) and electrical energy. Fuel Chargeable to Power (FCP) for co-generation electric power electric is between 4000 and 5000 Btu/kWh. Co-generation is also known as Combined Heat and Power (CHP).

Combustion: A heat generating (i.e., exothermic) reaction between a combustible and an oxidant (usually air).

Condensing Power: Electrical generation where the used steam is condensed, giving up a considerable amount of heat to an air or water cooled condenser. FCP for condensing power is usually about 12,000 for coal and as high as 17,000 Btu/kWh for biomass.

District Heating (DH): Supplying multiple building heating systems (and sometimes cooling) from a centralized plant. While very common in Northern Europe, District Heating is not as common in the US. Minnesota examples with co-generation include; Virginia, Hibbing and St. Paul. Duluth has District Heating without co-generation.

District Energy (DE): District Energy usually implies the combination of District Heating and some form of co-generation (steam, ORC, etc.).

Fuel Chargeable to Power (FCP): The incremental fuel for electric power generation. When only electrical power is produced, the FCP is equal to the Neat Heat Rate (NHR). US units are usually Btu/kWh. The co-generation owner would reimburse the heat source owner for FCP

Gasification: Converting carbon based material into carbon monoxide and hydrogen gases in an oxygen deficient (less than stoichiometric) environment.

H2/CO Ratio: The hydrogen to carbon monoxide ratio which determines the fuel content of synthetic gaseous fuels.

Heating Degree Day (HDD): Sometimes just referred to as “Degree Day”, HDD’s are historical average of an indices designed to reflect the heating requirement for a building. In sizing DH equipment, it can be useful in estimating the difference between winter peak and annual average loads.

Ely District Energy Engineering Study

Glossary (continued)

Higher Heating Value (HHV): The gross amount of heat released by a combusted fuel. HHV is commonly used in the U.S. and includes latent energy needed to evaporate water in the fuel.

Infrastructure Payment (IP): A fee paid by a co-generation owner to the host plant in consideration of the heat source infrastructure capital and operating expense.

Lower Heating Value (LHV): Is the net amount of heat energy released by a combusted fuel. LHV is commonly used in Europe and excludes latent energy needed to evaporate water in the fuel.

Net Heat Rate (NHR): The incremental fuel for electric power generation, usually in Btu/kWh.

Organic Rankine Cycle (ORC): Using an organic fluid such as iso-pentane, propane, butane, octamethyltrisiloxane (OMTS), etc in a binary power cycle to generate electricity.

Pelletizing: The process of mechanical densification of biomass into a uniform and dense form suitable for transportation and automatic feeding.

Pyrolysis: Chemical decomposition of organic material in the absence of oxygen. Biomass Pyrolysis can yield Pyrolysis oil, charcoal, and/or combustible gases.

Simple Cycle: Usually referring to a standalone Combustion Turbine Generator. Simple cycle electrical generation has a NHR of greater that 11,000 Btu/kWh.

Synthetic Gas: Sometimes referred to Synthetic Natural Gas (SNG), higher heating value than produced gas, approximately 300 Btu/cu ft. SNG can be produced from wood through the use of steam rather than oxygen.

Tri-generation: Sequential generation of thermal energy (steam or hot water), electrical energy and chilled water.

Wood Refuse: Bark, sawdust, brush, waste chips, dead or diseased wood, etc. In short, wood retrieved from the forest that is not used for lumber, Orientated Strand Board, paper, extractives, pellets, etc. Wood refuse is also known as hogged fuel, wood waste, logging residue, etc.

Ely District Energy Engineering Study

Professional Certification

I hereby certify that this report was prepared by me and that I am a duly Licensed Professional Engineer under the laws of the State of Minnesota.

Charles Eugene Hartley

November 22, 2010

License #43831

Ely District Energy Engineering Study

Executive Summary

The following report addresses the capital costs and project structure recommendations for the establishment of a biomass fired 30 mmBtu/hr District Heating (DH) and 1 Mega Watt (MW) Co-generation (aka Combined Heat and Power, CHP) system in Ely. Combined together, DH and Co-gen are District Energy (DE).

District Heating, i.e., a centralized heating plant serving multiple buildings, is not a new idea. Systems in major cities have been in operation decades, e.g. Philadelphia and New York City had systems since the early 1900's while Duluth's steam plant has been in operation since the early 1930's. These systems have proven cost effective and reliable, especially where there is vertical density (tall buildings).

What is new in the US and for Ely is the adoption of proven European technology to produce DH and CHP electricity with wood waste *on a community scale.* Using 180°F condenser water from an Organic Rankine Cycle (ORC) turbine generator, a system can efficiency and cost effectively heat businesses, institutions and homes within communities with only a few thousand inhabitants.

This project would be the first of its kind in the United States, showcasing how the use of biomass fired ORC for district heat and CHP can be done at overall efficiencies of near 75% and with very low criteria pollutant emissions.

Besides demonstrating new technology, the project will create 9 jobs, keep about $2,500,000 energy dollars within the local community, decrease fossil fuel imports and carbon dioxide emissions by about 15,000 tons per year and enhance forest management practices.

The cost of the base project, defined as the plant, a piping main from the plant on Highway 1 near Old Airport Road to major DH users; Vermillion Community College (VCC) , ISD 696 school complex, Ely-Bloomenson Community Hospital (EBCH), HRA apartments and City Hall, is estimated at $16,990,000.

Including indirect costs, the total cost is broken down by about $720,000 for site work and plant utilities, $7,300,000 for the District Heat (Thermal Oil Heater, 2 Pellet Peaking Boilers, 2 Propane Back-up Boilers and the Building), $3,140,000 for Co-generation, and $5,830,000 for about 27,000 feet of 10", 8" and 6" hot water transportation piping. At least one quote for every major piece of equipment was solicited and received.

"All-in" DH costs for the base project, with potential grants and including financing, fees and taxes are about $19/mmBtu, while full load costs are about $14/mmBtu. End of financing term costs would be about $12/mmBtu.

Subsequent phases of the project include adding about 13,000 feet of 6" lateral transportation piping, estimated at a cost of $1,780,000, and some 43,000 feet of 3" distribution piping, estimated at a cost of $4,840,000, for tying in 1" homeowner lines. Eventually, heating load will require one additional pellet peaking boiler.

Once permitted and funded, the base project could be completed in about 16 months.

Connected electrical load for the district heating plant is about 0.655 MW while running load is about 0.182 MW.

It appears that a City owned Co-operative is the most common project structure here in the US and we believe that this would be the best course for Ely. A Co-op Board with an odd number of Directors made up of customers representing each user class with representation by the PUC would make recommendations to the City Council regarding operating, capital and billing issues. We believe that the co-generation system is more valuable to a utility and recommend that a utility partner be pursued for ownership with Ely reimbursed for fuel chargeable to power, ownership and maintenance costs and an infrastructure credit.

Billing might take the most common form of a demand and commodity charges. Demand, i.e., the rate of use during a peak time frame such as January, would typically cover fixed costs, serving to level user costs and producer revenues throughout the year. Commodity, i.e. the amount of use for a given time, would typically reflect variable costs, such as fuel. City management fee and taxes would typically be included.

Including large user hook-up ($1,000,000), individual homeowner equipment and piping (about $2,400,000), and the third pellet peaking boiler, the eventual total biomass District Energy cost will approach $27,500,000. While this is a large amount, it still is much more cost effective (better simple return without incentives) than ground source heat pumps, solar PV or wind.

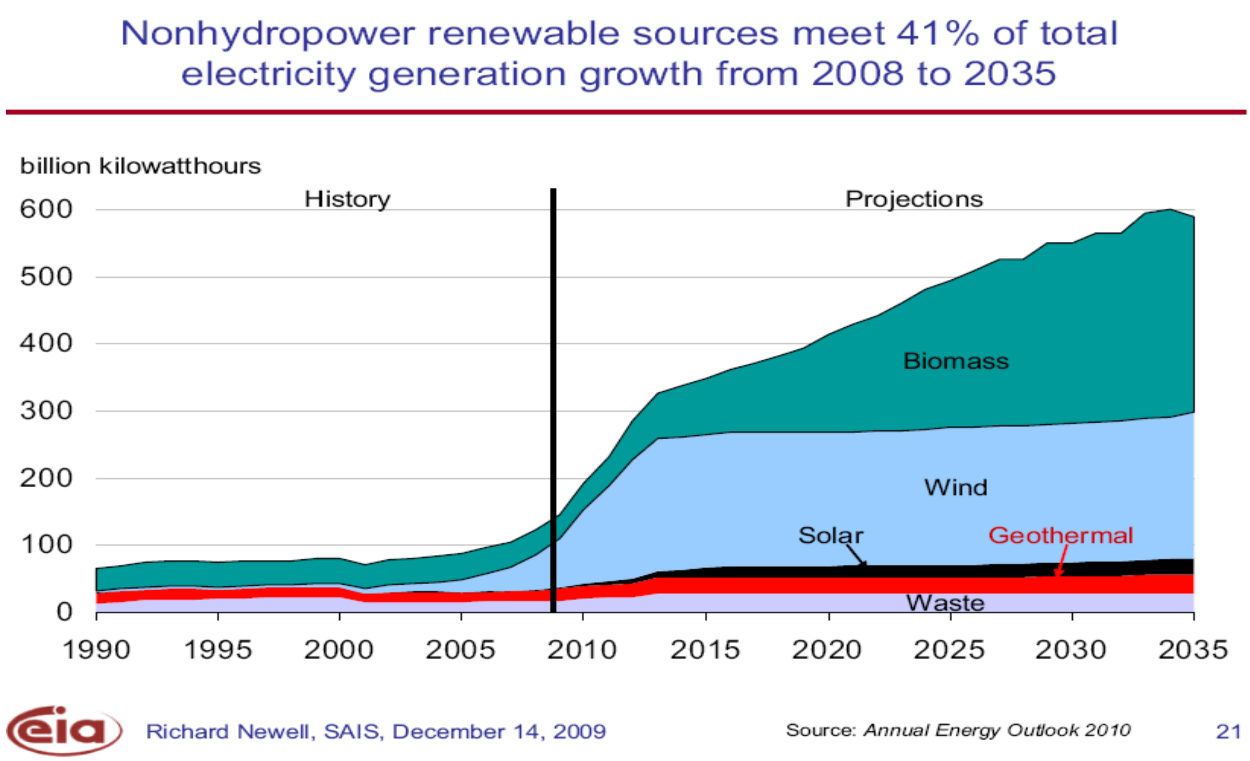
In contrast to Biomass DE, the other renewable alternatives do not keep energy dollars within the community or create local jobs and only Biomass DE and ground source heat pumps displace any imported oil.

Ely District Energy Engineering Study

Findings: Background

Biomass Use for Energy: As the US addresses the need to reduce Greenhouse Gas (GHG), imported oil and fossil fuel environmental ramifications concurrently with the need for jobs, biomass for energy would seem to be poised for growth.

The Department of Energy's Annual Energy Outlook projects that biomass for electrical generation will grow more than solar and even wind.



Wood based biomass is renewable, but not unlimited and, especially in Northern Minnesota, is slow growing and should be used in high efficiency applications. Net cycle efficiency of biomass, i.e., the amount of useable energy per unit of as received fuel (usually at about 50% moisture), can vary from the mid-teens for transportation ethanol and low 20%'s for electrical generation by utilities or mid 30% for gasification systems and Pyrolysis oil to over 70% for District Heat (centralized heating for multiple buildings) and Co-generation (simultaneous generation of electricity and heat) and pellets.

Premium wood pellet heating appliance efficiencies now exceed 75% with EPA Certified emissions lower than 1 gram/hr.

Ely District Energy Engineering Study

Findings: Background (continued)

When not used for paper and other value added forest products, good stewardship and basic economics would suggest that slow growing wood should be used for high efficiency energy conversion and, whenever possible, be used to displace high cost, non-renewable imported oil and propane. With this project, Ely is making a conscious effort to convert underutilized wood waste into energy in a high efficiency, low emission process. In doing so, Ely will enhance the local economy, forest, environment and national energy security.

There has been significant recent discussion regarding the carbon neutrality of energy from biomass. The author and a member of the AETF attended a recent forum where a representative of the Manomet Center for Conservation Sciences, authors of the controversial Massachusetts study on Biomass Energy, presented an overview.

The study looked at debt and dividend of woody biomass in Massachusetts, i.e., burning wood results in carbon emissions (debt) and as the replacement tree grows, absorbs CO2 (dividend). The study focused on electrical generation using low efficiency condensing power, but did acknowledge that the calculations are much more favorable when co-generation. In short, we believe that the Ely DE project's70%+ efficiency and state-of-the-art emission controls are significantly preferable to existing Ely energy systems.

Please see the worksheet labeled "Renew Comp" (Renewables Comparison, last page, page 56) in the attached spreadsheet, where we compared the simple return, without principle and interest payments and government incentives of the proposed Ground Source Heat Pump (geothermal) system for VCC, a recently installed Solar Photovoltaic system in NE Minnesota, the Taconite Ridge Wind Farm and the ELY DE project. Results are below:

Renewable Technology	Simple Return (yrs)	Benefits	Comments
VCC Geothermal	34	Displaces foreign oil	Does not include maintenance costs Minimal Carbon Reduction,
Solar PV	55	No emissions	Does not include maintenance costs
Taconite Ridge	13	No emissions	Does not include maintenance costs Does not include lease payments
Ely DE	18	Displaces foreign oil Keeps energy $'s local	Includes operations costs Includes maintenance costs

		Creates jobs	

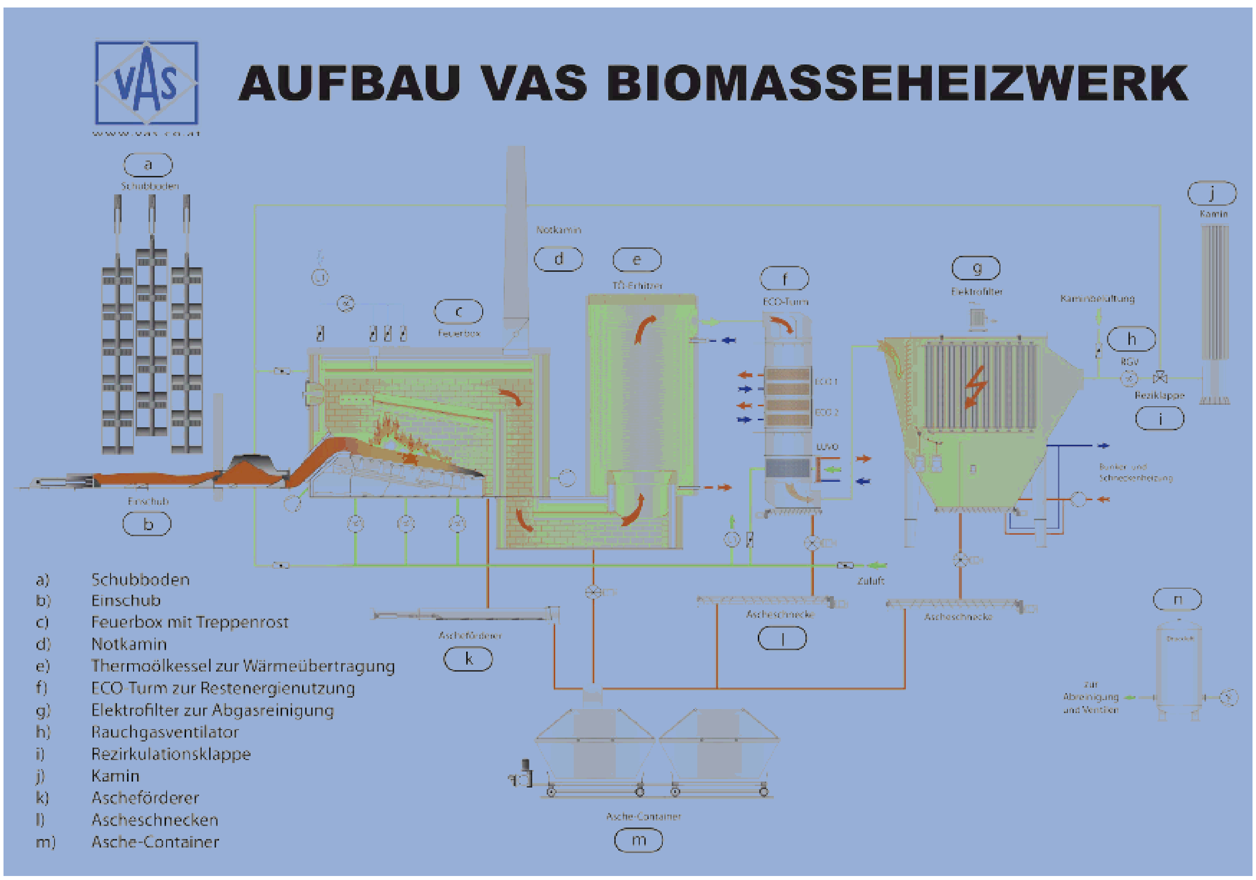
Findings: Process Flow

Please refer to the flow diagram and equipment brochures included in the appendix and the schematics included below:

Thermal Oil Heater Fuel Receiving: Hogged fuel (chipped in the woods tops, branches, bark and whole tree chips) will be delivered to the DH plant by an average of 3 or 4 trucks per weekday (about 23,000 tons per year). Unloaded hogged fuel will be moved by a front end loader to a storage pile.

A scale and truck dumper will weigh and unload the incoming trucks. Empty trucks will be scaled to determine delivered amounts for invoicing. The scale and dumper will be operated by the truckers. The truck scale is fully automatic with Key Cards for each driver.

Thermal Oil Heater: The production of co-generation electricity and district heating hot water begins in the Thermal Oil Heater (see below
schematic).



Courtesy of VAS-Energy Systems GmbH

Findings: Process Flow (continued)

The front end loader will feed a 3 day capacity storage bin (a), allowing for full weekend unattended operation. The bin will have a hydraulically driven walking floor or drag chain that continuously delivers fuel to the infeed conveyor (b), also hydraulically driven and driven by the centralized hydraulic system. Fuel is pushed up through a widening plenum and onto the grate of the refractory lined combustion chamber (c).

Pre-heated under-grate primary combustion air is provided by fans supplying different zones with flue gas recirculation and high pressure secondary air nozzles design for maximum turbulence, allowing for complete combustion and low NOx and CO emissions. Bottom ash is collected and discharged through conveyors (k) for collection and storage in a steel ash dumpster (m). An emergency bypass stack (d) is provided in case of a complete power loss.

1900°F combustion gases travel to the Thermal Oil (TO) heater (e). By not having radiation heat transfer and fluid temperatures lower than conventional Rankine (steam) boilers, tube corrosion and fouling is reduced, allowing for the use of air sootblowers and sonic horns to maintain the cleanliness of convection heat transfer surfaces. The thermal oil travels around the perimeter of the heater within concentric loops of tangent tubes, heated by the flue gas traveling on the outside of the tubes. Flow of the thermal oil and flue gas is counter-current to increase thermal efficiency, increasing thermal oil temperature to about 600°F.

Flue gas temperature is about 750°F as it exits the TO heater and enters the economizer sections (f) where the thermal oil is preheated in 2 stages for maximum efficiency. Fly ash from the economizer hopper is usually discharged into the bottom ash storage bin. Particulate emissions are controlled by both both a dust collector and an electrostatic precipitator (ESP, g) in series or an integral dust-collector/ESP with mechanical removal at turning vanes at the ESP inlet. ESP fly ash is discharged to a drag chain (i) and into another steel ash receptacle (m).

NOx, CO and Particulate Emissions are well below EPA standard factors (AP 42 Bark and Wet Wood Boiler, see Summary Feasibility Study for more detail).

Criteria Pollutant	EPA AP 42 Factor (lbs/mmBtu)	Vender Guarantees (lbs/mmBtu)
Carbon Monoxide (CO)	0.60	0.08
Oxides of Nitrogen (NOx)	0.22	0.20
Particulate Matter (PM)	0.35	0.04

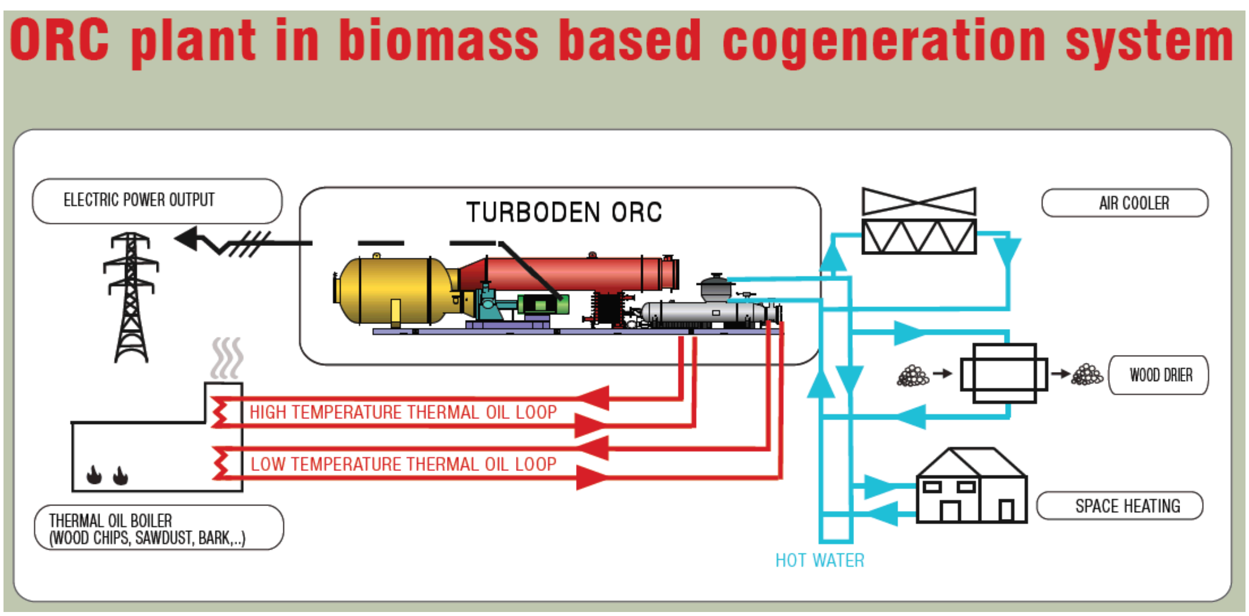
Findings: Process Flow (continued)

Co-generation: The 600°F heated thermal oil transfers its heat into the evaporator section of the ORC unit (see below). The organic fluid, Octamethyltrisiloxane (OTMS), is pre-heated and evaporated by the thermal oil and piped to turbine generator (green) where it turns the turbine which spins the generator (asynchronous motor). Electricity is generated, used within the DH Plant, with the excess fed onto the grid.

The OTMS gives up some of its heat as it spins the turbine and is further cooled in the regenerator (gold vessel) as it preheats condensed OMTS from the condenser (red horizontal tube and shell heat exchanger). The OMTS cools to the liquid phase in the condenser where it heats returning DH water.

ORC units are designed to operate unattended and fill a small scale (300 to 2500 kWe) niche in which other technologies cannot efficiently compete. The 175°F waste heat water is much more useable than conventional steam plant condenser water at 105°F and, as demonstrated by more than 140 plants in Europe, is suitable for district heating and or drying wood fiber (lumber, pellet feedstock, etc.).

When heating load is low, condenser water heat can be rejected to the air coolers to increase electrical generation, albeit at a lower overall thermal efficiency.



Courtesy of Turboden, a Pratt & Whitney Power Systems company

Ely District Heat & Co-gen Engineering Study

Findings: Process Flow (continued)

Pellet Peaking Boilers: Please see attached Wood Master Brochure.

For this study, we focused on the Wood Master (headquartered in Red Lake Falls, MN) BioMax series boiler to be manufactured in Superior, WI at Superior Steel under license from the Swedish Company ABioNova AB. The author has examined a 3.5 mmBtu/hr BioMax demonstration unit and judged it to be well built and quite suitable for this application.

The two base project (eventually three in total) peaking units are 3 pass fire-tube boilers. Pellet fuel is feed from individual 50 ton (2500 cubic feet) silos via a screw conveyor to the individual boiler feed bin.

Air locked screw conveyors feed pellets to the refractory lined hearth from the rear of the boiler. Individual primary and secondary air fans feed primary air to the hearth and secondary air through cast iron nozzles above the hearth.

Flue gas travels up the rear to the second pass tubes, then horizontally to the front of the boiler before turning 180° again to the 3rd pass tubes. The flue gas leaves the boiler out the back end to the dust collector via the negative pressure created by an induced draft fan. Cleaned flue gases are exhausted out individual stacks.

Heat transfer surfaces are kept clean by means of a high pressure air sootblower system. Turbulators (coiled springs) are installed in the fire tubes to spin the flue gas and maximize heat transfer, increasing efficiency. Ash is removed automatically and continuously by screw conveyors.

The full load analysis shows the pellet peaking boilers only operating December through February and during the Thermal Oil Heater annual shutdown. However, should demand warrant, they can be operated for a longer period.

We have included an allowance of $90,000 each for adding a propane burner to each peaking boiler for automatic start-up.

Ely District Heat & Co-gen Engineering Study

Findings: Process Flow (continued)

Propane Back-up Boilers: Please see attached Cleaver Brooks and Hurst quotes, brochures and manuals.

We solicited quotes from both Cleaver Brooks (CB) and Hurst for the fire-tube back-up boilers (flue gas flows horizontally through tubes immersed in a water pressure vessel). Both units are well proven and very common throughout the US and world.

The major difference between the CB and Hurst are the number of passes. CB offered a 4 pass unit while Hurst quoted a typically less efficient 3 pass unit, the difference being 1 extra pass (length of horizontal heat exchange tubes). Since the units would only operate in a rare back-up condition (one or more of the other units unavailable), the efficiency comparison is not critical. However, for the study we used the higher priced CB units for the capital estimate.

Although both back-up units are not really required until full build-out, we included both in the base project as the cost was not all that great ($150,000 each). Purchasing both at one time and installing together will most likely save the difference in working capital that delaying one of the units would provide.

District Heat Pumps: Please see attached Flowserve quote and pump data sheet.

Three pumps, each rated for 1000 gpm pumps and 250 ft of head (110 psig) with variable frequency drives were included in the study. The pumps are horizontally split with 125 hp motors.

The low or base project January flow is expected to be about 500 gpm.

Full load peak flow is expected to be less than 1800 gpm.

Ely District Heat & Co-gen Engineering Study

Findings: Equipment Sizing

Please see Degree Days, Heating Load and Heating Capacity & Fuel worksheets on pages 32 through 35.

The Ely District Energy plant was sized using the "European" model, i.e., keeping the ORC plant at least 55% loaded in co-generation mode for the year, unless operated in the condensing mode where low heating load waste heat is rejected to the air coolers. We found that the 1 MW size from last year's Feasibility Study is still appropriate for the project, resulting in a 58.9% ORC load factor at full build-out.

With the ORC unit size verified, we assigned monthly average heating load based on percentages from degree days and actual usages for a variety of installations, e.g., 17.7% for January, 14.4% for February, etc. Subtracting the ORC full load thermal energy (14.4 mmBtu/hr) from the monthly heat load yields the peaking boiler(s) average load.

Co-generation and the variety of loads, i.e., VCC, the School, Hospital and homes as well as domestic hot water heating adds diversity which results in flatter peaks than just Degree Days, but it's essential to have enough capacity for -35°F heating peaks common in Northern Minnesota.

Duluth's Steam Plant sees January peaks that exceed the January average by 50%. We sized the peaking boilers to provide for a 75% peak above the January average. Including the back-up boilers, the Ely installation will have twice as much (200%) capacity as the peak load.

Some European DH standards require 20% reserve capacity and, "in the event of the breakdown of the largest generating unit, 100% of maximum capacity must still be available". The Ely installation will exceed both of these recommendations.

When compared to Vipiteno in the Italian Alps (see table below, one of the installations visited by the Dave Olsen of the AETF and the author), the Ely installation has much more reserve capacity as well as reserve diversity (3 peaking boilers versus 1 and 2 back-up boilers versus 1).

Findings: Equipment Sizing (continued)

	Ely Low Load (mmBtu/hr)	Ely Full Load (mmBtu/hr)	Vipiteno (mmBtu/hr)	Comments
CHP Capacity	1 MW	1 MW	1.2 MW	Vipiteno, IT. 750 customers, pop. 8000
ORC Condenser	14.4	14.4	18.7	Some Condensing Power at Low Load
Peaking Unit(s)	13.6	20.4	29.2	2, 6.8 mmBtu/hr, add 3rd when load requires
Back-up Unit(s)	26.8	26.8	30.7	1, 13.4 mmBtu/hr, 2nd when load requires
Total	41.7	61.6	78.7	
January Average	9.5	19.9	47.7	
January Peak	14.3	29.8	74.8	150% of average for Ely, 157% for Vipiteno
Total Cap/ Peak	2.9	2.1	1.05	

With the excess capacity and trend to improved weatherization comes the potential for customer growth exceeding the projections, i.e., perhaps 600 homes or more over time.

Ely District Heat & Co-gen Engineering Study

Findings: Plant Location

Please see attached Ely Aerial drawing.

The recommended plant location is on South 17th Avenue East (aka Highway 1), south of Old Airport Road and adjacent to the City's main substation.

While a few other sites were briefly discussed (e.g., in the City's outside storage lot near the hospital, North 17th Avenue East near VCC, etc.), the recommended location offers the following major advantages:

1. Easy truck access from a Class 1 road,
2. City owned unused land,
3. Short cable run to substation,
4. "Industrial" area setting, and
5. Somewhat distant from existing homes, but the piping run to the main hot water transportation route is still relatively short at 1200 feet.

Ely District Heat & Co-gen Engineering Study

Findings: Piping

Please see attached Piping Routing Plans labeled S1.00, S1.01 and S1.02.

In this case, large bore piping; 6”, 8” and 10” is referred to as “Transportation” while 4” and below small bore piping is referred to as “Distribution”.

The lay out for the Transportation piping in Ely is derived from the recommended location of the DE plant and the location of the 3 major Base Project heating customers, VCC, the ISD 696 school complex and the Ely-Bloomenson Community Hospital.

We researched several references and other installations, but could not find any other layout philosophy (e.g., loops) that would give reason to deviate from an 8”piping transportation main running East/West along the length of Harvey Street.

As we developed plans for beyond the Base Project, i.e., 6”laterals for running North/South off the main and 3” distribution lines running East/West off of the laterals, this scheme seemed to make even more sense.

The Base Project consists of 27,000 ft (5.1 miles) of pipe while the 6” Transportation (T) laterals will consist of 13,000 ft (2.5 miles) and the 3” Distribution (D) lines could eventually include nearly 43,000 feet (8.2 miles). In total, the project will consist of over 80,000 feet or nearly 16 miles of T&D pipe at an average cost of $135 per foot, or $270 per foot of piped trench (supply and return in the same trench). This does not include the 1” homeowner supply lines. We assumed that each customer would be responsible for piping from the street connection to their building.

We conjecture that the project will most likely progress beyond the Base project in “spurts”, concurrently with road re-construction, sewer and other infrastructure projects and as further funding, incentives and customer commitments are available.

Ely District Heat & Co-gen Engineering Study

Findings: Cost Estimate

Please see the attached spreadsheet and worksheet labeled “Cap”, page 31.

The cost of the base project is estimated at $16,990,000. Of that, about $720,000 is for site preparation and finishing, about $7,300,000 for the District Heat, $3,140,000 for Co-generation and $5,830,000 for the piping.

In preparing this estimate, we used budget quotes by multiple venders for all major equipment and detailed construction estimates by experienced LHB engineers and construction managers. Where multiple quotes were received for individual pieces of equipment, we used either the perceived industry leader or the higher priced unit.

We did not include a specific line item for “contingency”. It has been our experience that some people view contingency money as a “nice to have” project money and is spent without proper authorization. We believe that there is some built-in contingency in that we used Budget quotes versus “Best and Final” which are typically 10% or more lower. We also included an extra $270,000 for optional propane burners on the pellet peaking boilers as well as the higher priced 4 pass back-up boilers ($112,000).

Beyond the base project, the full build-out project is estimated to cost about $27,300,000, including; $800,000 for major user system revisions and connections, $1,777,000 for future 6” Transportation piping, $4,838,000 for future 3” Distribution, $2,370,000 for homeowner piping and $525,000 for the future 3rd pellet boiler.

Ely District Heat & Co-gen Engineering Study

Findings: Project Schedule

Please see attached detail schedule in the appendix (page 54).

We would expect 2011 to be consumed with garnering public and political support, negotiations with utility partners and funding activities, final scoping and permitting

Once the air permit application is submitted to the MPCA, we would expect approval within 3 months. We allowed another month in the schedule for final approval by the City Council.

Upon funding and final Council authorization, "Best and Final" quotes for shortlisted major equipment would be solicited with priority given to the longest lead time items; the Organic Rankine Cycle unit (11 months), the Thermal Oil Heater (9 months) and the Pellet Peaking Boilers (7 months).

Site preparation could begin with permit approval and Council authorization.

Depending on the time of year for the groundbreaking, we would anticipate a 16 month construction schedule.

As discussed in the piping section, full build-out will happen over a period of years, hopefully 5 or less, as road and other utility projects mesh with concentrations of customer commitments.

Ely District Heat & Co-gen Engineering Study

Findings: District Energy Structure

Analyses of District Energy Structures suggest that it be divided into 3 parts, i.e., the District Heating (DH) Plant, Piping System and Co-generation (CHP).

For DH and the Piping System, Municipal Ownership seems to be the most common in the US. Although alternative structures are discussed and sometimes considered, such as Consumer Co-operatives and Community Energy Trusts, most US systems follow the Municipal Ownership model.

St. Paul District Energy is only significant alternative as it is an independent non-profit organized as a (501 (c) (3). Over the years, St. Paul DE has garnered a variable line of credit that has resulted in an interest of less than 3%. Fifty per-cent of St. Paul's DE's $30,000,000/year revenue is in debt service.

In Europe, Private Ownership in the form of Corporations and Co-operatives are prevalent. Europe also has Public/Private Partnership Models where facilities are privately owned with publically owned transmission/distribution piping.

Duluth has had such a Municipal Ownership/Co-operative structure since the City bought the plant in the early 1970's. Duluth's plant is governed by an 11 member board, with a rotating chair. Currently, there are only 10 members (one vacancy) and the chair is Tony Mancuso, the St. Louis County Property Management Director.

Duluth's Board members are customer representatives from a cross-section of the customer base. Each board member has only one vote, preventing large users from dictating policies that may not be fair to all customer classes. The City Council approves Co-op Board recommendations and has ultimate authority.

For the Co-generation part of the project, we still recommend Utility ownership, either Minnesota Power or Lake Country/Great River Energy, for the simple reason that, as the Utilities are required supply renewable electricity, the biomass co-generated output of the ORC unit is worth more to the Utility than it is to the City to displace lower cost coal based electricity.

Ely District Heat & Co-gen Engineering Study

Findings: District Energy Structure (continued)

The sub-structure for this type of arrangement is relatively straight forward. The Owning Electric Utility supplies the capital for the co-generation part of the project and reimburses the Municipal Ownership for Fuel Chargeable to Power, O&M and Infrastructure Credit, defined as:

Fuel Chargeable to Power (FCP): The incremental fuel for electric power generation. When only electrical power is produced, the FCP is equal to the Net Heat Rate. US units are usually Btu/kWh. The co-generation owner would reimburse the heat source owner for FCP based on the relative share of fuel cost. For example; if the FCP is 5000 Btu/kW and 700,000 kWh were produced in a particular month and the fuel cost was $3.06/mmBtu ($27/ton), the FCP would be:

5000 Btu/kW x 700,000 kW /1,000,000 Btu/mmBtu x $3.06/mmBtu = $10,710 or $0.0153/kWh

Operations & Maintenance (O&M): These costs can be pro-rated based on the heat share of the DE Plant. If the DH uses 75% of the energy in the Thermal Oil and the Co-gen uses 25%, then the ratio of the direct TOH system O&M costs would be 25% for the Co-generation. O&M costs for the Peaking and Back-up Boilers would not be included in the Co-gen cost share.

Infrastructure Payment (IP): The IP would be a fee paid by the Co-generation owner (electric utility) to the host plant in consideration of the heat source infrastructure capital and expense and building rent. A simple way to look at the IP is to consider the IP going towards a portion of the P&I payment for the DH plant, building & piping. Once the project loan or bonds are paid in full, the City and/or consumers could receive further revenues or savings. Numbers are calculated for these costs in the spreadsheet on the Ely Principle and Interest (P&I) worksheet.

Green Credits (e.g. Renewable Energy Credits, equal to 1 MWh) would be the property of the co-generation system, i.e., the utility partner. The REC's as an environmental attribute can separated from the commodity and sold on the open market or used to fulfill a Renewable Portfolio Standard (RPS, Minnesota's Next Generation Energy Act is 25% renewables by 2025).

The author has arranged the sale of over 250,000 REC's and would suggest that while they have some value, they are worth more to the Utility mandated to meet the RPS than they are to the City. The Co-gen Agreement, specifically the Infrastructure Payment language, can include "opener" language for gain sharing should the value of the REC's significantly exceed current expectations. For example, the percentage of P&I that might make up the IP could graduate versus the average selling price of REC's at the Chicago Exchange.

Ely District Heat & Co-gen Engineering Study

Findings: Billing

Please see the "Potential DH Billing Scenario" on the Summary page of the attached Excel spreadsheet (1st worksheet).

We interviewed Duluth Steam and found that most US District Heating Utilities use a two-part rate structure, i.e., a capacity charge to cover fixed costs (labor, maintenance, debt, etc.) and an energy charge to cover variable costs (fuel, chemicals, etc.).

The energy charge is based on the monthly meter reading of actual consumption. The capacity charge can be based either on the entire previous year's use (divided by 12) or a peak month or day. Duluth uses the total annual consumption divided by 12. Units for both are typically in mmBtu's (millions of British thermal units). This arrangement seems to be advantageous for the customer and the DH utility in that heating bills and thus revenues are somewhat flattened.

Some combination of the energy and capacity charge may be graduated based on load, i.e., larger users pay a lower unit cost and perhaps a lower capacity charge as well. This should be based on an actual analysis of comparable equipment and fossil fuel bulk delivery price differences for large versus residential customers.

The City of Duluth is paid an administration fee for billing services. If the utility is City owned, a Franchise Fee would not be appropriate. Sales taxes are paid as applicable.

The challenge for Ely during the load growth from the low load base plant to the full build-out is that initially the rates are only about 20% cheaper than fossil fuel, barring more than expected grant money.

Should the proposed Thermal Renewable Energy Efficiency Act (TREEA) be enacted, it could provide a Production Tax Credit of $6.15/mmBtu for closed loop biomass (energy crops, e.g. hybrid poplar) or about $3.20 for open loop biomass (logging residue). Using open loop biomass, TREEA could provide another $120,000/yr at Base Load and $260,000/yr at full build out. According to the International District Energy Association (IDEA), TREEA may be revised from a Production to an Investment Tax Credit.

Ely District Heat & Co-gen Engineering Study

Findings: Funding

Please see worksheets labeled “Sum”, “Base Fin”, “Fin”, and “P&I”.

Funding mechanisms for this type of major infrastructure project will probably include grants and bonds from a variety of sources as well as a strategic utility partner.

We envision that for the Ely DE project, a combination of all 3 might be used as follows:

Mechanism	Amount	Source/Comment
Site Work & Utilities Grant	$750,000	County and State Economic Development
Unsolicited DE/CHP Grant	$8,500,000	Department of Energy
Permitting and Detailed Engineering Grant	$770,000	Iron Range Resources, Blandin Foundation
Strategic Utility Partner	$2,600,000	MN Power or Lake Country Power/Great River Energy
Tax Exempt Bonds	$4,400,000	Piping systems qualify for tax exemption.

The “Sum” worksheet contains variables that, when altered, allow for immediate review of the results. Key variables include are:

1. Grants & Partnerships (%)
2. Interest Rate (%)
3. Term (years)
4. $/€ Exchange Rate
5. Co-gen Infrastructure Payment (% of P&I)
6. Wood Waste Cost/ton
7. Pellet Cost/ton
8. Fuel Oil Cost/gal
9. Propane Cost/gal

The Key Result is the detailed Demand and Energy unit cost for the Base project and at full load (P&I, O&M, fuel, etc.).

APPENDIX B.

Ely Minnesota Biomass District Energy System (Wilson Engineering Services)

U.S. Department of Agriculture
Northeastern Area
State and Private Forestry

WERC

Wood Education and Resource Center
310 Hardwood Lane
Princeton, WV 24740
304-487-1510
www.na.fs.fed.us/werc

Preliminary Feasibility Report

Ely Minnesota
Biomass District Energy System

Version: Final

Date: July 6, 2012

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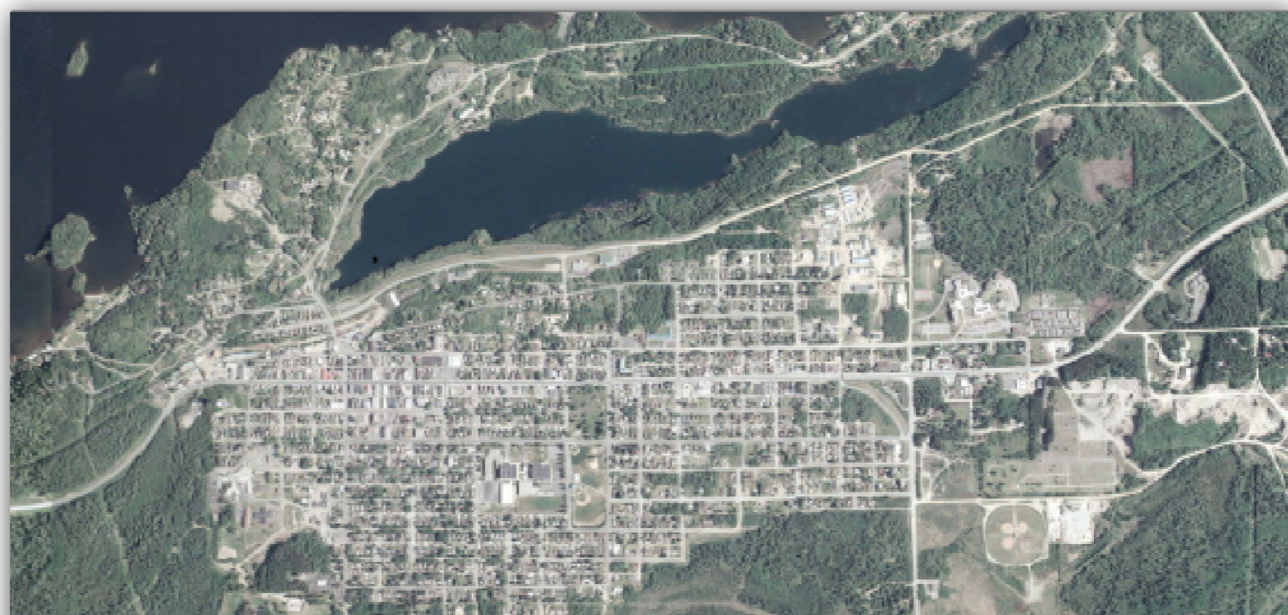


Image Source: datagateway.nrcs.usda.gov

The Wood Education and Resource Center is located in Princeton, W.Va., and administered by the Northeastern Area State and Private Forestry unit of the U.S. Department of Agriculture Forest Service. The Center's mission is to work with the forest products industry toward sustainable forest products production for the eastern hardwood forest region. It provides state-of-the-art training, technology transfer, networking opportunities, applied research, and information. Visit www.na.fs.fed.us/werc for more information about the Center.

WERC
WOOD EDUCATION
AND
RESOURCE CENTER

Table of Contents

1.0 EXECUTIVE SUMMARY

This preliminary feasibility study evaluates options for Ely, Minnesota to utilize renewable biomass to supply energy. The options evaluated focus on biomass utilization for the major heating loads within Ely. Should biomass utilization provide a viable option for the major heating loads, Ely may consider the addition of smaller heating users to a comprehensive district heating network. This report focuses evaluation on two potential sites for a biomass fueled district energy system consisting of thermal and thermally-led combined heat and power (CHP) options. The major user for Site 1 is Vermillion Community College (VCC). The major users for Site 2 are Ely-Bloomenson Community Hospital (EBCH), Sibley Manor, and Independent School District 696 (ISD 696).

Existing Energy Usage and Systems

The main sources of fuel for both sites are fuel oil and propane. Site 1 consisting of VCC, has a central heating system firing on #2 fuel oil for heating and propane for domestic hot water (DHW). A district heating system circulates hot water for heating the campus. A wood chip combustion unit and hot water boiler are currently installed in the heating plant, but have not been operational for over 10 years due to lack of fuel screening in the wood chip handling system.

EBCH, Sibley Manor, and ISD 696 have separate heating systems and Site 2 includes tie-in to each of these facilities. EBCH has a central steam boiler plant firing on #2 fuel oil. The EBCH boiler plant provides low pressure steam for heating a nursing home, clinic, and hospital. The nursing home utilizes a shell and tube heat exchanger to heat a radiant hot water heating loop with steam; the hospital uses a combination of shell and tube heat exchangers and steam coils for heating; the clinic uses steam coils for heating. Domestic hot water is heated indirectly by the central plant. Laundry services are performed off site. ISD 696 has a central propane-fired heating plant that provides hot water for heating. Domestic hot water usage is minimal and is heated indirectly by the central plant. A biomass gasification system was retrofitted to a propane fired boiler and is located in a decommissioned central boiler plant. The plant has not been operational for over 20 years. Sibley Manor has a central propane-fired boiler system that provides hot water for heating and domestic hot water. Table ES1 provides the current annual fuel usage targeted by the proposed biomass utilization options.

Biomass Availability and Price

Biomass boilers of the sizes to be installed for the Ely, MN project options would be capable of utilizing multiple biomass fuel types. The biomass boiler and fuel transfer system should provide fuel flexibility to be able to take advantage of low cost opportunity biomass fuels as they become available. Wood chips have been focused on as the fuel source for this feasibility study. Further investigation of other biomass supply should be performed if the biomass project is pursued. Based on initial investigation, ample, sustainable biomass supply exists in the region to provide for the proposed biomass options. Initial phone conversations with biomass suppliers indicate a price range of $25 to $35 per green ton. The price for biomass fuel used as the basis for this report is $30 per green ton.

Options Evaluated

Four options are evaluated in this study for district heating at major users in Ely, MN.

Option 1 – Site 1: Biomass Heating (Hot Water): A 3.3 mmBtu/hour advanced biomass combustion unit and hot water boiler will generate hot water for space heating and domestic hot water at Vermillion Community College. This system would offset an estimated 85% of the fossil fuel currently used by the central heating plant at the campus.

Option 2 – Site 2: Biomass Heating (Steam and Hot Water): A 5 mmBtu/hour advanced biomass combustion unit and steam boiler rated at 30 psig will generate low pressure steam to offset 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696. Low pressure steam would be directly distributed to EBCH and the Sibley Manor for heating and domestic hot water, and a shell and tube heat exchanger would use steam to heat a hot water thermal storage tank to distribute hot water for heating ISD 696. A radiator will be installed allowing the system to offset fossil fuel usage during low load summer conditions.

Option 3 – Site 2: Biomass Heating (Hot Water): A 5 mmBtu/hour advanced biomass combustion unit and hot water boiler will generate hot water for space heating and domestic hot water at EBCH, Sibley Manor, and ISD 696. The system would provide hot water for district heating, and would require conversion of EBCH to hydronic heating from steam. Buried pre-insulated hot water distribution piping will be installed connecting the biomass building to ISD 696, Sibley Manor, and EBCH. A radiator will be installed allowing the system to offset fossil fuel usage during low load summer conditions. This system would offset an estimated 95% of the fossil fuel currently used at all three facilities.

Option 4 – Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water): A 5 mmBtu/hour biomass fueled vented thermal oil heater in conjunction with an unfired steam generator and 110 kW single-stage backpressure steam turbine/generator would offset 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696 and generate 412,965 kWh of renewable electricity. Low pressure steam would be directly distributed to EBCH and Sibley Manor for heating and domestic hot water. A shell and tube heat exchanger would also utilize steam to heat a hot water thermal storage tank. Hot water from the thermal storage would be distributed to ISD 696. The system would be thermally-led and the turbine output would be dictated by the demand for heat. A radiator will be installed downstream of the turbine allowing the system to offset fossil fuel usage during low load summer conditions.

Option 5 – Site 2: Biomass ORC CHP (Thermal Oil and Hot Water): A 10 mmBtu/hour advanced biomass combustion unit and vented thermal oil heater in conjunction with a 600 kW Organic Rankine Cycle (ORC) combined heat and power system would replace 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696 with renewable biomass fuel. The system would provide hot water for district heating, and would require conversion of EBCH to hydronic heating from steam. The system would be thermally-led and electric generation would be dictated by the demand for heat. The system would generate 1,622,087 kWh of renewable electricity annually from biomass. A radiator will be installed downstream of the ORC system allowing the system to offset fossil fuel usage during low load summer conditions.

Biomass Project Cost and Benefits

The capital cost associated with Option 1 is $1.9 million which includes the biomass combustion unit and boiler, boiler housing, fuel storage, multi-cyclone for emission control, thermal storage tank, and interconnections with the existing VCC central boiler plant. Option 2 would cost $3.8 million which includes the biomass combustion unit and steam boiler, boiler housing, fuel storage, multi-cyclone for emission control, thermal storage tank, buried pre-insulated distribution piping, and interconnections with the existing boiler systems. Option 3 would have a net deduct of approximately $17,000 for utilizing a hot water boiler with a larger thermal storage tank for a total project cost of $3.8 million. Option 4 would have a net add of approximately $880,000 for utilizing a thermal oil heater, unfired steam generator, turbine/generator equipment, and electrical connections for a total project cost of $4.7 million The capital cost associated with Option 5 is $7.2 million which includes the biomass combustion unit and thermal oil heater, boiler housing, ORC generation system, fuel storage, dry electrostatic precipitator (ESP) for emission control, buried pre-insulated distribution piping, and interconnections with the existing boiler systems. The cost for Options 3 and 5 does not include the cost to convert steam heating sections of EBCH to hydronic heating.

A summary of the biomass system energy profile is provided in Table ES1 which shows existing fossil fuel usage, potential annual biomass and fossil fuel usage, and potential electric generation with a district biomass plant for each Option.

Table ES1 – Current & Proposed Biomass System Energy Profile Summary

Option	Current Annual		Potential Annual with Biomass			
	Fuel Oil Usage, Gallons	Propane Usage, Gallons	Biomass Usage, Tons	Electric Generated, kWh	Fuel Oil Usage, Gallons[1]	Propane Usage, Gallons[1]
1	62,357	3,332	878	-	9,680	0
2	81,246	99,729	2,924	-	5,486	2,804
3	81,246	99,729	2,924	-	5,486	2,804
4	81,246	99,729	3,174	412,965	5,486	2,804
5	81,246	99,729	4,730	1,622,087	5,486	2,804

Note: Section 3.2 describes the development of current annual fuel usage values. Coverage of peak loads and low loads will be accomplished with fuel oil for Option 1. This coverage will be provided by a combination of fuel oil and propane for Options 2-4. Since maintenance on the biomass system will likely be completed in the summer months, it is assumed for the purposes of this report that ~75% of the fossil fuel coverage will be from fuel oil and ~25% will be from propane for these options. Biomass usage is estimated using 10 mmBtu/ton and 40% moisture content (wet basis). The conversion from green tons to cords is 2.5 tons/cord for "lighter northern hardwoods"[1]

[1] http://www.extension.umn.edu/distribution/naturalresources/DD2723.html

Annual net operating savings were calculated for each option considering costs for fuel, electricity, and O&M costs. Table ES2 shows a summary of estimated first year annual operating savings based on most recent fossil fuel prices.

Table ES2 – Potential Annual Net Operating Savings

Option	Current Annual Fuel Cost	Annual Biomass Cost	Annual Electric Generation, kWh/Yr	Annual Electric Value	Fossil Fuel Cost with Biomass System	Biomass System O&M Costs	Potential Savings
1	$208,005	($26,331)	0	$0	($31,201)	($10,600)	$139,873
2	$433,461	($87,734)	0	$0	($21,673)	($18,200)	$305,854
3	$433,461	($87,734)	0	$0	($21,673)	($17,200)	$306,854
4	$433,461	($95,207)	412,965	$29,733	($21,673)	($21,200)	$325,115
5	$433,461	($141,912)	1,622,087	$116,790	($21,673)	($31,100)	$355,566

A cash flow analysis was completed for financing the project over a 20 year term at 4.5% interest. Under this scenario, 25-yr net present values (NPV) were calculated at $1.5 M for Option 1, $3.8 M for Option 2, $3.9 M for Option 3, $3.3 M for Option 4, and $1.2 M for Option 5. Table ES3 shows a summary of the results of this analysis.

Table ES3 – Biomass System First Year Cash Flow Analysis Summary

Option	Financed Amount	Annual Financing Payment	20 Year Financing, 1st Year Cash Flow	25 Year Net Present Value
1	$1,934,318	($148,703)	($8,830)	$1,484,642
2	$3,783,002	($290,823)	$15,031	$3,832,127
3	$3,765,866	($289,505)	$17,349	$3,877,825
4	$4,664,050	($358,554)	($33,439)	$3,303,992
5	$7,164,786	($550,801)	($195,235)	$1,204,394

Conclusions and Recommendations

Woody biomass utilization options present Ely, MN with an opportunity to reduce operating costs at major energy users within the city. Connection of additional residential and commercial properties may be accomplished by direct payment by the owner on an "opt-in" basis or encompassed in an expanded system with costs recovered through annual energy sales. The benefits and costs associated with interconnecting smaller users are not evaluated in detail in this study. However, the study shows that residences adjacent to district heating pipelines already justified by larger users should help to improve the overall economics of project options. The options evaluated in this report, with the assumption of 20-yr financing at 4.5% interest rate would provide benefits as summarized:

- Option 1 – Site 1: Biomass Heating (Hot Water) would offset 85% of current fossil fuel usage by producing hot water for heating the existing central heating plant located at Vermillion

Community College for a capital cost of $1.9 M and provide a first year net operating savings of $139,873 and 25 year Net Present Value (NPV) of $1.5 million.

- Option 2 – Site 2: Biomass Heating (Steam and Hot water) would offset 95% of current fossil fuel usage by generating steam for space heating and DHW at EBCH and the Sibley Manor, and heat a hot water thermal storage tank to provide heat and DHW to ISD 696. This option would produce a first year net operating savings of $305,854 and 25 year NPV of $3.8 million for a capital cost of $3.8 M.
- Option 3 – Site 2: Biomass Heating (Hot Water) would offset 95% of current fossil fuel usage by generating hot water to heat a hot water thermal storage tank to provide heat and DHW to EBCH, Sibley Manor, and ISD 696. This option would produce a first year net operating savings of $306,854 and 25 year NPV of $3.9 million for a capital cost of $3.8 M. The cost to convert EBCH to hot water from steam is not included in this cost estimate, and would need to be considered if this option is pursued.
- Option 4 – Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water) would offset 95% of fossil fuel usage and generate 412,965 kWh with a backpressure steam turbine/generator. Option 4 provides a first year net operating savings of $325,115 and 25 year NPV of $3.3 million for a capital cost of $4.7 M.
- Option 5 – Site 2: Biomass ORC CHP (Thermal Oil and Hot Water) would offset 95% of fossil fuel usage and generate 1,622,087 kWh with an ORC generator. Option 5 provides a first year net operating savings of $355,566 and 25 year NPV of $1.2 million for a capital cost of $7.2 M.

Additional benefits that would be provided by a woody biomass project include:

- Keeping dollars spent on energy within the local economy, between $30,000 and $140,000 annually, depending on option selected.
- Decreased dependence on imported oil by replacing fuel oil and propane use with renewable wood chip fuel;
- A hedge against the volatility of the fossil fuel market;
- A reduction in net CO_2 emissions of 553 metric tonnes for Site 1 and ranging from 1,321 – 2,740 metric tonnes for Site 2 depending on the option selected. Credits generated through this net reduction would be eligible for sale on the voluntary carbon market;
- Educational opportunities for local students and opportunities for eco-tourism.

The purpose of this study is to identify the benefits and costs of woody biomass system options serving the major thermal energy users within Ely. WERC recommends detailed investigation of the smaller residential and commercial loads within Ely, if it is determined the benefits warrant pursuit of a woody biomass project. WERC also recommends that personnel from the major users in Ely, MN visit existing biomass boiler installations to develop a detailed understanding of the equipment and its capabilities. WERC is available to assist in arranging tours of existing facilities. As Ely, MN continues to pursue biomass renewable energy options, WERC recommends that the next level of evaluation includes detailed consideration of the following items:

- System ownership and business model for ownership;
- Collection of energy use and energy system data for additional residential and commercial owners along the main district heating pipeline routes and potential adjustment to pipe and boiler sizing based on findings;
- Inclusion of additional heat users based on parameters set by acceptable economic returns for business models identified;
- Utilization of existing employees at major users to maintain equipment and comply with local boiler licensing requirements;
- Discussion of biomass plant siting with potential stakeholders within the city;
- Monitoring actual heating demand at major users to verify optimal biomass system sizing;
- Performance of site investigations (utility, geotechnical, topographic) for site selected based on stakeholder discussions, and further develop biomass project plant layout and capital costs based on investigation results;
- Identification of alternative funding sources (low interest loans, grants, and incentives).

2.0 INTRODUCTION

2.1 WERC PROGRAM

The USDA Forest Service Wood Education and Resource Center (WERC), is providing professional services to promote and support projects utilizing wood energy in a sustainable manner. This is being done through the Wood Energy Utilization Support Program. The goal of the program is to promote the Forest Service's Northeast Area Strategic Plan objective on the sustainable use of forest resources to provide efficient use of renewable energy resources and accomplish greenhouse gas reduction. The services are available to public and private entities (clients) interested in and committed to efficient use of local wood for energy. This report is the result of a prefeasibility-level study and is developed under the WERC program by Wilson Engineering Services, PC.

2.2 ELY OPPORTUNITY

Ely, Minnesota is located in the eastern part of the state and has substantial renewable biomass resources. Currently fuel oil and propane are available for domestic hot water and space heating within the city. Ely, Minnesota has the opportunity to leverage local renewable biomass resources to provide heat, hot water, and electricity while reducing its carbon footprint through the use of district heating or combined heat and power (CHP). Utilization of local biomass would lower annual costs for each site evaluated and keep dollars spent on energy in the local economy.

3.0 EXISTING ENERGY USE, COST, AND SYSTEMS

3.1 EXISTING HEATING EQUIPMENT

Two sites are considered in this analysis. Site 1, consisting of Vermillion Community College, has a central heating system firing on #2 fuel oil for heating and propane for DHW. The main heating plant contains a 5 mmBtu/hour Hurst fuel oil boiler installed in 1998 and a 3.912 mmBtu/hour Federal Boiler Company biomass boiler installed in 1985. The fuel oil boiler handles 100% of the load under normal operation. The biomass boiler has not been functional in over 10 years. A second hot water fuel oil boiler installed in 1971 is located in a building 100' away. The Iron Fireman boiler is rated at 4 mmBtu/hour output and is used for emergency backup. The smaller backup boiler cannot meet peak heating demands on the coldest days of the year.

The distribution piping arrangement is a primary-secondary system. The boilers are connected to the primary hot water loop which is manually maintained at 185-202°F. The primary loop heats a secondary heating loop with heat exchangers. The temperature of the secondary loop is adjusted based on outside air temperature. The secondary loop circulates water for heating the 160,216 ft^2 campus.

Site 2 consists of EBCH, ISD 696, and Sibley Manor, each of which has a separate heating system. EBCH has a central steam boiler plant firing on #2 fuel oil. The boiler plant consists of two 4.8 mmBtu/hour Kewanee steam boilers installed in 1957 and a 4.2 mmBtu/hour Kewanee steam boiler installed in 2002. All three boilers fire on #2 fuel oil. The central plant provides low pressure steam for space heating and domestic hot water for a nursing home, clinic, and hospital. Steam is used directly in air handler steam coils and shell and tube heat exchangers to heat hydronic systems used for radiant heat, VAV reheat, and hot water heating coils in air handlers. Higher pressure steam for autoclave sterilizers is produced by stand-alone electric steam generators. Humidification is produced using ultrasonic humidifiers located in the air stream of air handlers. Laundry services for the hospital are performed off site.

ISD 696 utilizes a central boiler plant for heating 211,618 ft^2 in three buildings on campus. Three 2.7 mmBtu/hour output Hydrotherm propane fired condensing boilers installed in 2011 heat a glycol and water mixture. The glycol mix is circulated to the Memorial, Washington, and Industrial buildings for space and domestic hot water heating. The distribution loop temperature is adjusted based on outside air temperature. The boilers are shut down for the summer months. A decommissioned central boiler plant that used to serve the school contains three 11.76 mmBtu/hr output propane-fired low pressure steam boilers, one of which was converted to burn gas created from pyrolizing wood chips. The biomass system consists of a two bay below grade biomass storage pit with a hydraulic rake system. The chips are transferred by auger and bucket elevator into a dryer, then transferred by auger to a gasification chamber. Gas created by pyrolizing wood chips is burned in the retrofitted propane boiler, and the ash is transferred by auger out of the gasification chamber. The propane boilers were decommissioned when the new boiler plant was installed in 2011. The biomass system has not been operational for over 20 years.

The Sibley Manor utilizes two 522,000 btu/hour Crown Freeport propane fired hot water boilers which feed a hydronic radiant heating system. The building is heated using baseboard radiators that are separated into 5 zones. Domestic hot water is heated by a 500,000 Btu/hr Jarco hot water heater and stored in two 80 gallon DHW tanks.

3.2 EXISTING ENERGY USAGE

Annual fuel deliveries from 2009, 2010, and 2011 are listed in Table 1 for the major heat users in Ely. Propane at VCC is mostly used by stand-alone units for DHW heating. This study evaluates the ability to offset 30% of the propane usage at VCC with biomass since a portion of the DHW load was recently interconnected to the central fuel oil heating system. Three year average propane usage for ISD 696 would overestimate current heating demand since new high efficiency condensing boilers were installed in the summer of 2011. Calendar Year (CY) 2011 usage was 38.6% lower than CY 2010 consumption with the new boilers operating half of the year. Because of this, 50% of ISD 696's CY 2010 fuel delivery data is used as the basis for financial analysis and modeling instead of the 3 year average.

Table 1 – Fuel Deliveries for Major Users and Values Used for Analysis of Biomass Options

Year	Site 1		Site 2		
	VCC Fuel Oil Usage (Gallons/Yr)	**VCC Propane Usage (Gallons/Yr)**	**EBCH Fuel Oil Usage (Gallons/Yr)**	**ISD 696 Propane Usage (Gallons/Yr)**	**Sibley Propane Usage (Gallons/Yr)**
2009	72,492	-	80,087	152,887	24,788
2010	58,654	-	82,254	153,771	22,924
2011	55,926	11,106	81,397	94,408	20,818
Average	62,357	11,106	81,246	133,688	22,843
Value Used for Biomass Options Analysis	**62,357**	**3,332***	**81,246**	**76,886****	**22,843**

*Notes: *This is equivalent to 30% of reported 2011 propane usage. This value is included due to recent tie-in of dorm DHW to the central plant heating loop.*
*** This value is equivalent to 50% of the 2010 usage. This is used due to heating system upgrades implemented in 2011.*

Using the values presented in the bottom row of Table 1, a daily heat demand model was developed individually for Site 1 and Site 2 to allow for estimating daily average heat demand that could be offset by a central biomass plant. Energy demand was distributed daily based on heating degree days (HDD) calculated using average temperature data from the Weather Underground Station KELO in Ely, MN and the following assumptions:

- HDD were based on 55 °F
- The fuel oil and propane boilers operate at a thermal efficiency of 80%
- The heat content of the available fuels are 91,300 Btu/gallon for propane and 140,000 Btu/gallon for #2 fuel oil
- The base load for Site 1 is assumed to be 1 mmBtu/day when the college is in session. The central boiler plant is assumed to be shut down from June through September.
- The base load for the facilities that makeup Site 2 is assumed to be 14.8 mmBtu/day. This is equivalent to the hospital's base load in the summer, which is carried through for the remainder of the year.

Figure 1 shows the resulting combined daily average heat demand for VCC in Site 1 during CY 2010.

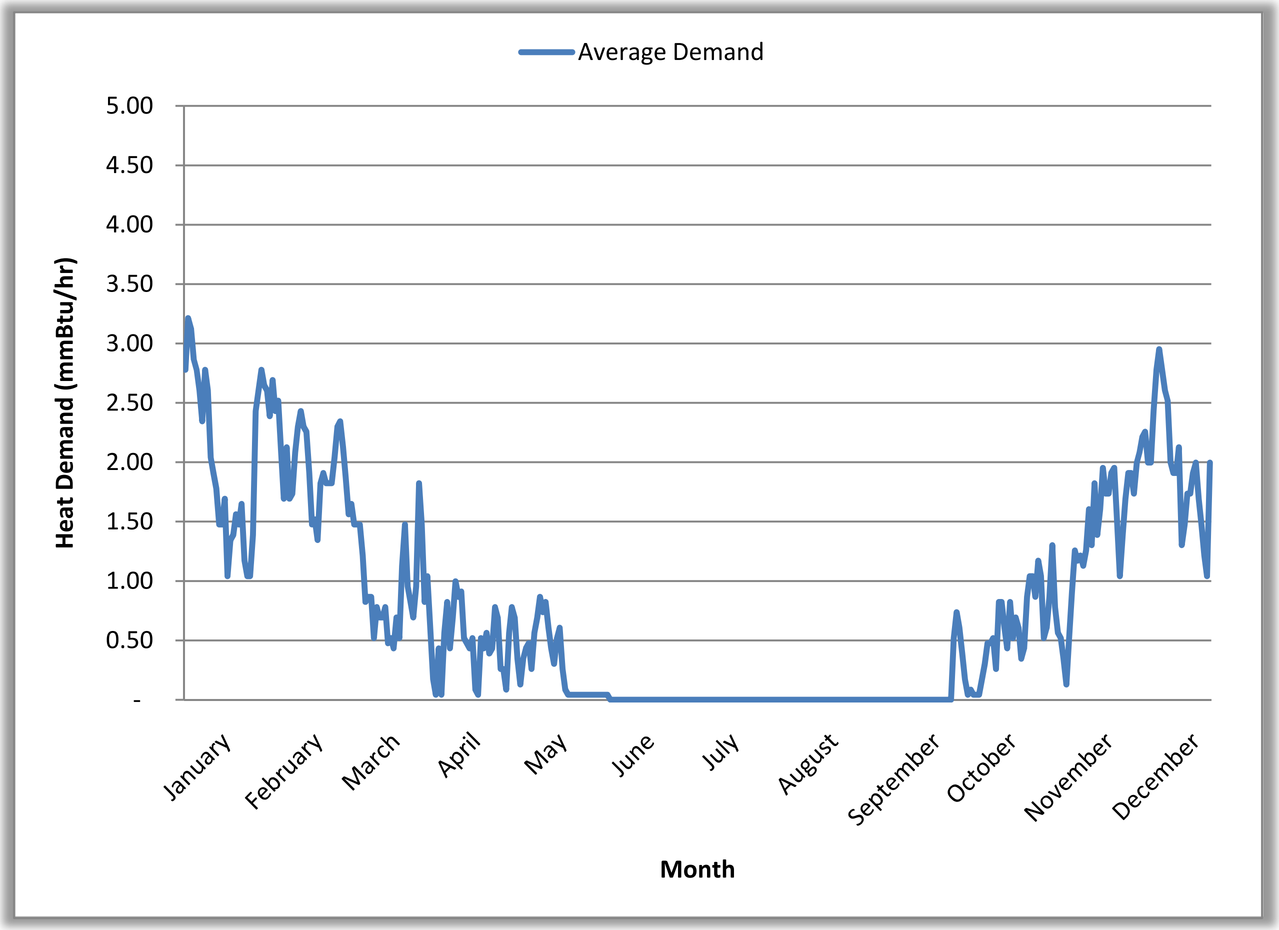


Figure 1 – Site 1 Daily Average Heat Demand (CY 2010)

Note: The average output/demand model is based on local weather data and fuel delivery records provided by Vermillion Community College in Ely, MN. The central plant is shut down during the summer months. A base load of 1 mmBtu per day is used during the period when school is in session, outside of the summer months.

Figure 2 shows the load duration curve corresponding to data presented in Figure 1. It is important to note that the actual hourly demand will vary over the course of a 24-hr period. For the purposes of this report, the daily peak load is estimated to be 50% higher than the daily average load and is represented by the red curve. Peak loads would be reached for a very limited duration during a typical day.

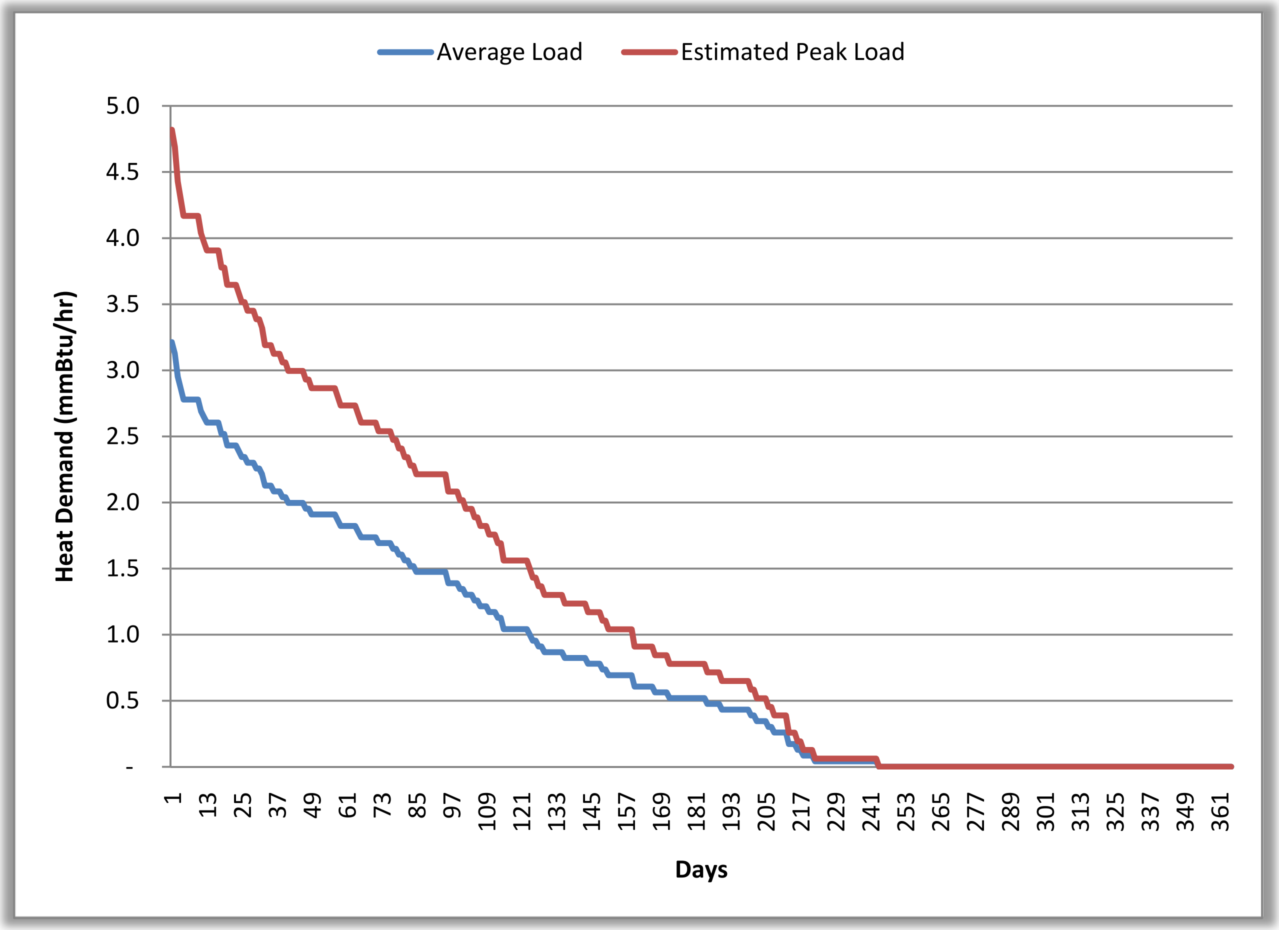


Figure 2 – Site 1 Load Duration Curve (CY 2010)

Note: The figure shows a load duration curve for an average output/demand model (Figure 1) based on local weather data and fuel delivery records provided by Vermillion Community College in Ely, MN. The central plant is shut down during the summer months. A base load of 1 mmBtu per day is used during the period when school is in session, outside of the summer months.

Figure 3 shows the modeled daily average heat demand for EBCH, ISD 696, and Sibley Manor combined in Site 2 during CY 2010.

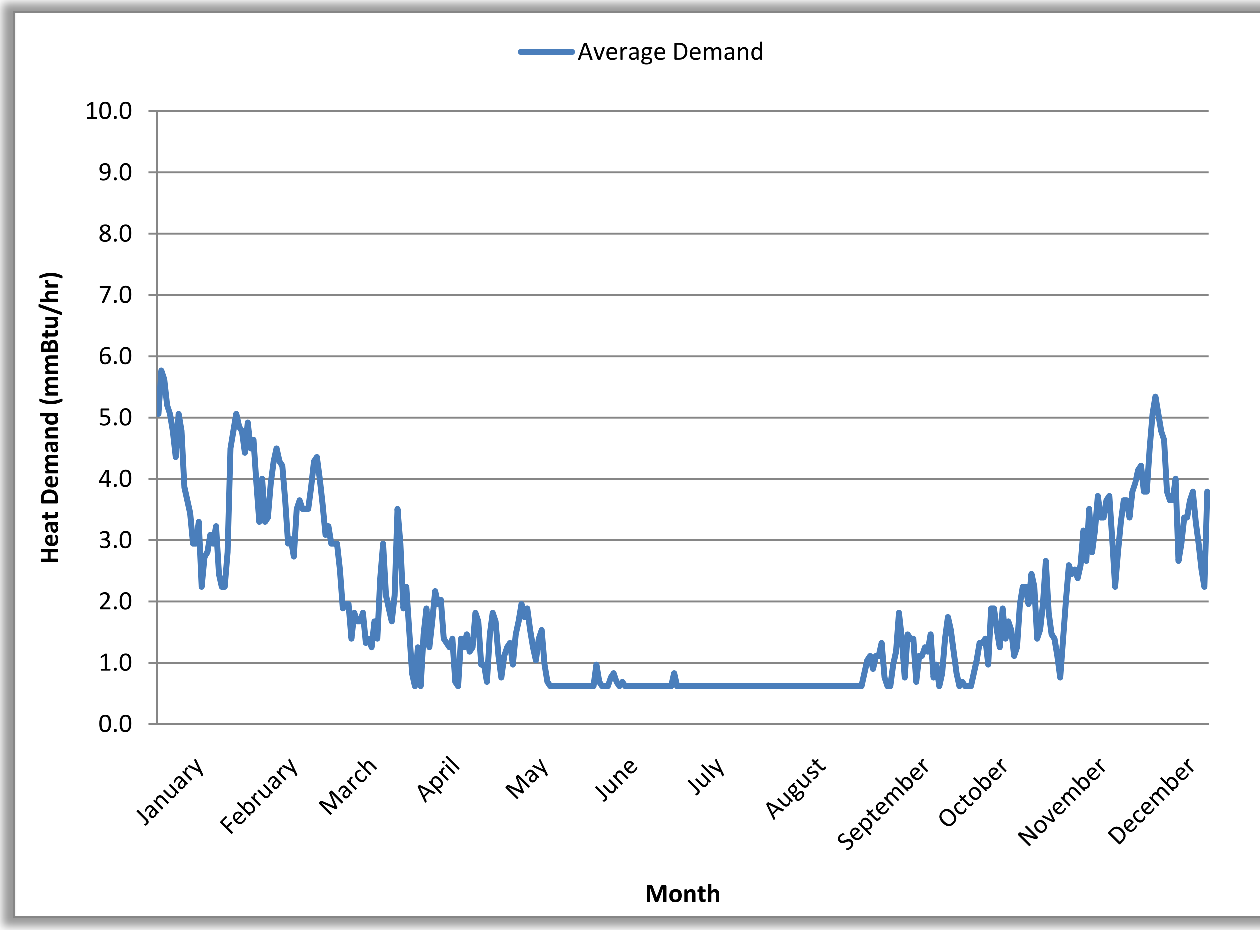


Figure 3 – Site 2 Daily Average Heat Demand (CY 2010)

Note: The average output/demand model is based on local weather data and fuel delivery records provided by the three major users. A base load of 14.8 mmBtu per day is developed based on summer deliveries as reported by EBCH. This base load is carried through the entire year. Base loads for Sibley and ISD 696 are considered to be negligible for the purposes of developing the model.

Figure 4 shows the load duration curve corresponding to the CY 2010 average daily heat demand for the data presented in Figure 3 for Site 2. It is important to note that the actual hourly demand will vary over the course of a 24-hr period. For the purposes of this report, the daily peak load is estimated to be 50% higher than the daily average load and is represented by the red curve. Peak loads would be reached for a very limited duration during a typical day.

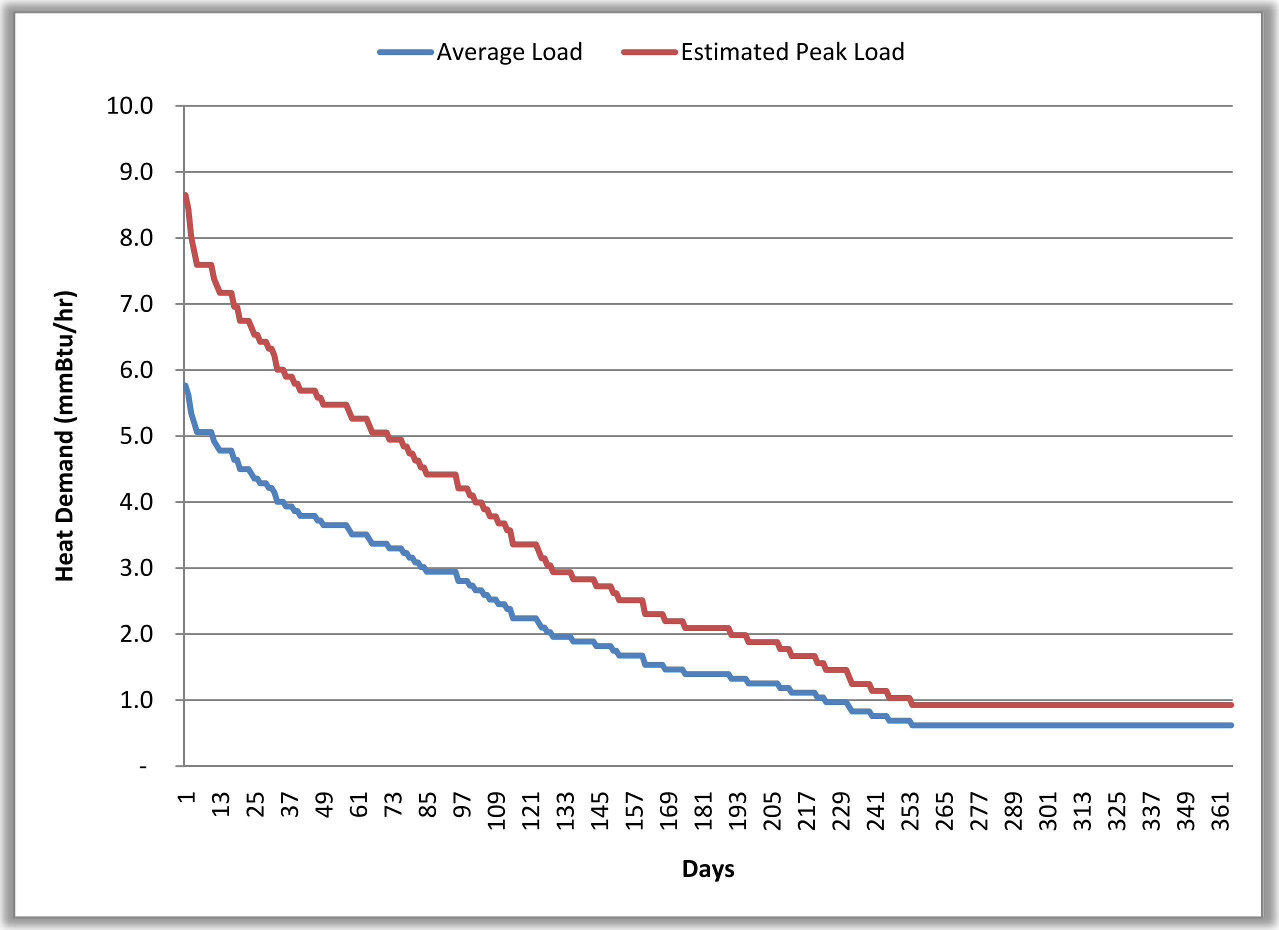


Figure 4 – Site 2 Load Duration Curve (CY 2010)

Note: The figure shows a load duration curve for an average output/demand model (Figure 3) based on local weather data and fuel delivery records provided by the three major users. A base load of 14.8 mmBtu per day is developed based on summer deliveries as reported by EBCH. This base load is carried through the entire year. Base loads for Sibley and ISD 696 are considered to be negligible for the purposes of developing the model.

4.0 BIOMASS AVAILABILITY AND PRICE

Biomass boilers of the sizes to be installed for the Ely, MN project would be capable of utilizing multiple biomass fuel types including hog fuel, whole tree chips, mill chips, and potentially other sources of biomass depending on air permitting restrictions and material handling systems installed. It is recommended that a biomass boiler system have fuel flexibility to be able to take advantage of low cost opportunity fuels as they become available. Wood chips have been focused on as the fuel source for this feasibility study. Further investigation of other biomass supply should be performed if the biomass project is pursued. Based on initial investigation, ample, sustainable biomass supply exists in the region to provide for the proposed biomass options. Initial phone conversations by the University of Minnesota Department Of Forest Resources with biomass suppliers indicate a price range of \$25 to \$35 per green ton. The price for biomass fuel used as the basis for this report is \$30 per green ton.

The approximate costs of heating with fuel oil, propane, and wood chips are listed in Table 2 based on thermal efficiencies of 70% for biomass boilers, 65% system efficiency for biomass boilers with a large piping distribution network including heat loss from piping, and 80% for fossil fuel boilers.

Table 2 – Comparison of Delivered Heating Costs

Fuel	Unit Cost	Heating Value (Btu) per Unit Input	Delivery Efficiency	Cost per mmBtu Output
Biomass, Ton	$30.00	10,000,000	70%	$ 4.29
Biomass, Ton	$30.00	10,000,000	65%	$ 4.62
Fuel Oil, Gallon	$ 3.24	140,000	80%	$28.93
Fuel Oil, Gallon	$ 3.20	140,000	80%	$28.57
Propane, Gallon	$ 1.80	91,300	80%	$24.64
Propane, Gallon	$ 1.79	91,300	80%	$24.51
Propane, Gallon	$ 1.72	91,300	80%	$23.55

5.0 BIOMASS SYSTEM OPTIONS

5.1 OPTIONS EVALUATED

Five options are evaluated in this study for district heating at major users in Ely, MN. An overview of each option is listed below and detailed analysis provided in Sections 5.2 – 5.6. All options will require installing distribution pumps in the biomass plant and piping to the interconnected buildings. The main distribution pumps should operate with a variable speed drive to maintain loop pressure or temperature differential between supply and return lines as desired.

Option 1 – Site 1: Biomass Heating (Hot Water): A 3.3 mmBtu/hour advanced biomass combustion unit and hot water boiler will generate hot water for space heating and domestic hot water at Vermillion Community College. This system would offset an estimated 85% of the fossil fuel currently used by the central heating plant at the campus.

Option 2 – Site 2: Biomass Heating (Steam and Hot Water): A 5 mmBtu/hour advanced biomass combustion unit and steam boiler rated at 30 psig will generate low pressure steam to offset 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696. Low pressure steam would be directly distributed to EBCH and the Sibley Manor for heating and domestic hot water, and a shell and tube heat exchanger would use steam to heat a hot water thermal storage tank to distribute hot water for heating ISD 696. A radiator will be installed allowing the system to offset fossil fuel usage during low load summer conditions.

Option 3 – Site 2: Biomass Heating (Hot Water): A 5 mmBtu/hour advanced biomass combustion unit and hot water boiler will generate hot water for space heating and domestic hot water at EBCH, Sibley Manor, and ISD 696. The system would provide hot water for district heating, and would require conversion of EBCH to hydronic heating from steam. Buried pre-insulated hot water distribution piping will be installed connecting the biomass building to ISD 696, Sibley Manor, and EBCH. A radiator will be installed allowing the system to offset fossil fuel usage during low load summer conditions. This system would offset an estimated 95% of the fossil fuel currently used at all three facilities.

Option 4 – Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water): A 5 mmBtu/hour biomass fueled vented thermal oil heater in conjunction with an unfired steam generator and 110 kW single-stage backpressure steam turbine/generator would offset 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696 and generate 412,965 kWh of renewable electricity. Low pressure steam would be directly distributed to EBCH and the Sibley Manor for heating and domestic hot water. A shell and tube heat exchanger would also utilize steam to heat a hot water thermal storage tank. Hot water from the thermal storage would be distributed to ISD 696. The system would be thermally-led and the turbine output would be dictated by the demand for heat. A radiator will be installed downstream of the turbine allowing the system to offset fossil fuel usage during low load summer conditions.

Option 5 – Site 2: Biomass ORC CHP (Thermal Oil and Hot Water): A 10 mmBtu/hour advanced biomass combustion unit and vented thermal oil heater in conjunction with a 600 kW Organic Rankine Cycle (ORC) combined heat and power system would replace 95% of the fossil fuel usage at EBCH, Sibley Manor, and ISD 696 with renewable biomass fuel. The system would provide hot water for district heating, and would require conversion of EBCH to hydronic heating from steam. The system would be thermally-led and electric generation would be dictated by the demand for heat. The system would generate 1,622,087 kWh of renewable electricity annually from biomass. A radiator will be installed downstream of the ORC system allowing the system to offset fossil fuel usage during low load summer conditions.

Each biomass option includes construction of a new boiler plant. Appendix A shows a conceptual boiler plant location and layout for Site 1 and 2. A geotechnical analysis has not been completed at this level of study. The conceptual plant layout includes a storage building providing 2-3 days of below-grade chip storage at peak boiler output. Additional space in the biomass building has been allocated for an additional biomass combustion unit and boiler should loads increase through future expansion. The building type for this analysis is assumed to be a pre-engineered steel building. Should Ely, MN require a building with a brick façade or other aesthetic features, the cost of the building would be increased from what is presented in the cost estimates shown in Appendix B.

An alternate location for the Site 2 biomass plant has been located to the south of Sibley Manor as shown in Appendix A.5. This location would add 834 linear feet of district heating piping, and additional costs for connection of utility services including electric, phone, internet, sewer, and water would be expected. District heating piping would add approximately $165,000 to the project at an estimated cost of $200/linear foot, and costs for bringing in utilities would likely add to project cost increases depending on the nearest access points. For the purposes of this analysis, the economics are run on the location nearer the major loads.

Central fossil fuel backup is not included in this study. It is assumed that existing fossil fuel boilers located at the major users would remain in place to provide backup should the biomass system go offline due to maintenance or emergency situations. The fossil fuel boilers would also boost distribution water temperature during the coldest days of the year when demand on the district heating system exceeds the output of the biomass boiler.

The options proposed in this report consist of biomass boilers rated at 3.3, 5, and 10 mmBtu/hr output. Federal rules impose emission limits on PM for wood boilers rated at 10 mmBtu per hour (input) and larger. The 3.3 and 5 mmBtu/hr boilers in Options 1, 2, 3, and 4 would have maximum fuel inputs that are less than 10 mmBtu/hr. A multi-cyclone is the standard emission control technology for use with advanced biomass combustion units in the size range of those in Options 1, 2, 3, and 4. The advanced systems operating in their efficient firing range with a multi-cyclone will have PM emission rates in the 0.1-0.25 lbs/mmBtu range. The 10 mmBtu/hr output boiler in Option 5 would be required by federal rules to meet PM limits of 0.07 lbs/mmBtu input. An electrostatic precipitator (ESP) is selected as the appropriate emission control technology for use with Option 5. The estimated capital costs associated with emission controls have been included for all options in this report. Local air quality permitting and regulations vary by location and may dictate use of specific emission controls or operating procedures. An ESP could be added to Options 1 – 4, and would add approximately $250,000 - $300,000 to the cost of each project. The added cost of an ESP is not included in this study for Options 1 – 4 for the purposes of developing system economics. Table 3 shows the comparison of estimated emissions for the existing fossil fuel boilers, biomass system with a multi cyclone, and biomass system with an ESP. Option 5 only includes an ESP since this is what would be required to meet federal emission limits.

Table 3 – Estimated Emissions of Existing Fossil Fuel Boilers and Potential Biomass System

Option	Estimated Annual Emissions, Tons/yr			
	PM	NOx	SOx	Total
Existing Site 1	0.06	0.65	0.59	1.30
Existing Site 2	0.12	1.46	0.77	2.35
Option 1	0.89	0.89	0.10	1.88
Option 2	2.93	2.70	0.08	5.72
Option 2 - ESP	0.45	2.70	0.08	3.23
Option 3	2.93	2.70	0.08	5.72
Option 3 - ESP	0.45	2.70	0.08	3.23
Option 4	3.18	2.93	0.08	6.19
Option 4 - ESP	0.48	2.93	0.08	3.50
Option 5 - ESP	0.72	4.33	0.10	5.15

Note: Oil emission factors are taken from AP42 for <100 mmBtu/hr, using values of 0.132% sulfur content and high heating value of 0.14 Btu/gallon; Propane emission factors are taken from AP42 with sulfur content of 0.2 g/100ft3; Wood chip emission factors are obtained from combustion test results.

Site plans showing loads, preliminary biomass plant placement, and potential distribution piping routes and sizes are provided in Appendix A. Potential routes to buildings not included in the analysis are shown with dashed lines. Hot water pipes are sized based on a 30°F ΔT and estimated peak demand. The hot water supply and return lines to ISD 696 have been upsized to 5” to provide capacity for future expansion or connection to intermediate loads. The dashed pipe route from the Site 1 biomass plant to the Zenith and Pioneer Manor has been upsized to 4” to provide additional capacity should Ely, MN decide to include this pipe run into the project. Steam piping has been sized based on estimated peak loads and steam velocities between 4,000 and 6,000 feet per minute.

A biomass plant at Site 1 would directly connect into VCC’s existing central heating plant and distribution system. Heat losses through pipes would already be accounted for in the fuel usage supplied by VCC. Piping losses were considered for the distribution piping interconnecting Site 2 users to a biomass plant. There would be an estimated 3,116 linear feet of distribution piping connecting major users based on the preliminary piping runs and biomass plant siting as shown in Appendix A. It was assumed that the thermal storage tank and hot water distribution lines to ISD 696 would be shut down during summer months and piping losses are only included when the hot water system would be operational. Year round piping losses were included for the steam (or hot water for Options 3 and 5) lines to EBCH and Sibley Manor. Table 4 shows the total annual heating and domestic hot water load that would be covered by the biomass system at the district heating plant and existing fossil fuel boilers located at each building, the portion of the annual load covered by the biomass system, heat losses in the piping connecting the biomass system to the buildings in each site, and the percentage of the piping heat losses compared to the biomass coverage of the annual load.

Table 4 – Estimated Distribution Piping Losses for Connection of Major Loads

Option	Total Annual Heating Load (mmBtu)	Biomass Coverage of Annual Load (mmBtu)	Annual Pipe Heat Loss (mmBtu)	Percentage of Biomass Coverage Lost
1	7,227	6,143	0	0.0%
2	16,235	15,424	857	5.6%
3	16,235	15,424	787	5.1%
4	16,235	15,424	857	5.6%
5	16,235	15,424	787	5.1%

The heat loss from distribution piping in Options 3 and 5 are lower since hot water distribution piping to EBCH and Sibley Manor would have lower heat losses than steam piping based on the temperatures of distributing steam at 10 psig. This study uses a biomass system efficiency of 65% for Site 2 in Options 2, 3, 4, and 5 to account for these distribution piping losses.

5.2 Option 1 – Site 1: Biomass Heating (Hot Water)

A 3.3 mmBtu/hour advanced biomass combustion unit and hot water boiler will be used to heat a 3,500 gallon thermal storage tank located in the biomass building. Thermal storage tanks are typically maintained above 195°F. This high temperature water in the tank will be blended with return water from the existing central heating plant to maintain the desired supply water temperature set point. A schematic describing this system is provided in Appendix A.

Wood chip fueled biomass boilers operate most efficiently between 25% and 100% of their rated heating output (0.825 to 3.3 mmBtu/hour), which will enable this system to replace 85% of the fossil fuel used at VCC by the central plant with renewable biomass fuel. The existing fossil fuel boilers in the VCC boiler room will operate during periods of high and low heating demand to supplement the biomass system. The shaded area in Figure 5 illustrates the estimated biomass system coverage of the daily average heat demand.

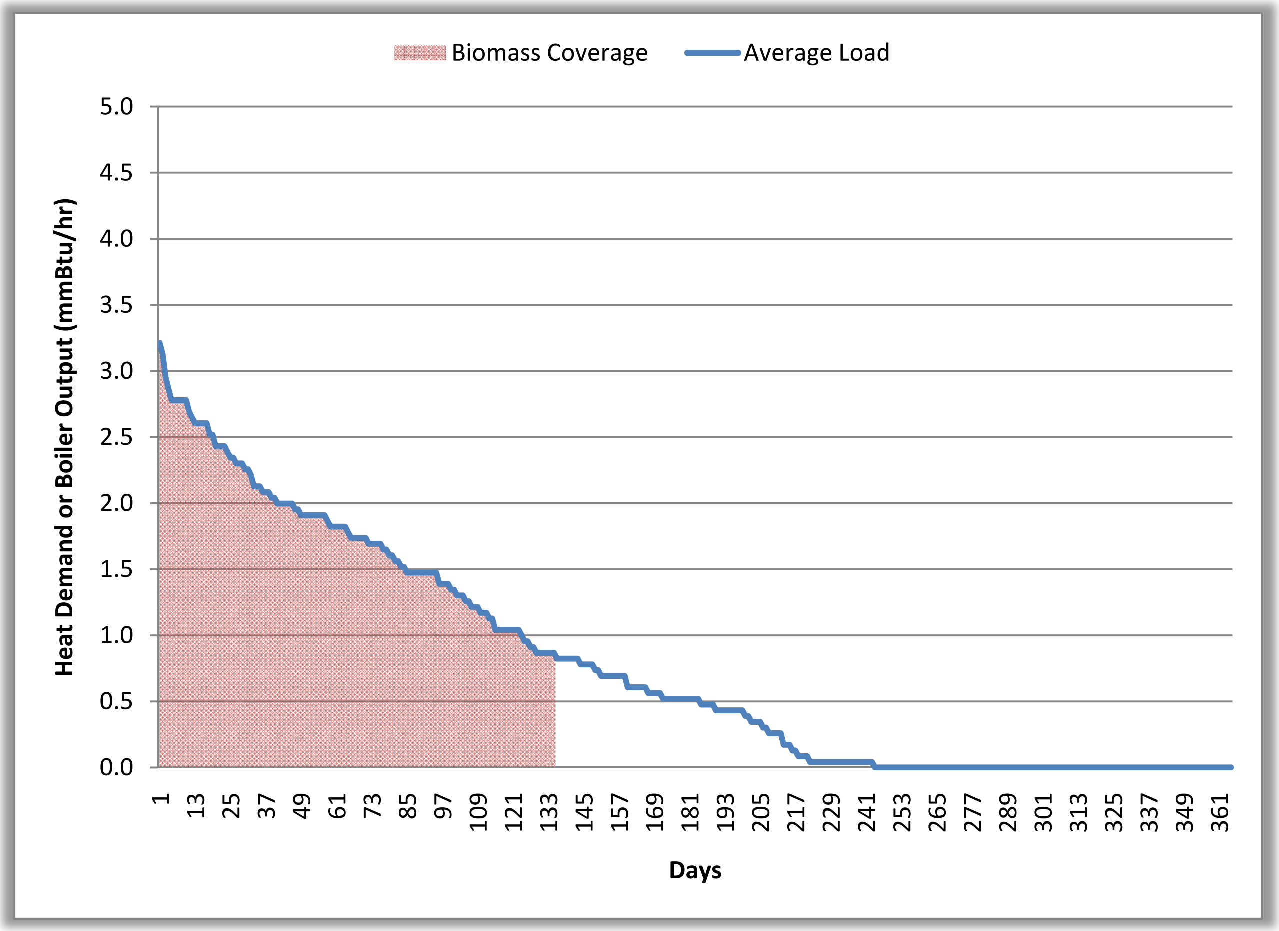


Figure 5 – Option 1 Biomass Coverage of CY 2010 Load Duration Curve for Site 1

Note: The average output model is based on local weather data and fuel delivery records provided by Vermillion Community College in Ely, MN. The biomass system is shown as being shut down during the summer months. Management of loads and the use of thermal storage may allow biomass coverage during times of low heating demand.

It is assumed for Option 1 that the boiler will be shut down during the summer months due to extended periods of low heating and domestic hot water demand. Management of loads and the use of thermal storage may allow use of the biomass system during the low load periods of the shoulder seasons with the equipment identified. This possibility is ignored for the purposes of developing the economics in this report. Figure 5 shows 85% biomass coverage of the daily average demand. Actual coverage will vary depending on weather conditions, peak demands, and periods when the boiler is shut down for maintenance. This report assumes 85% coverage for Option 1 for the purpose of estimating fossil fuel offset.

5.3 OPTION 2 – SITE 2: BIOMASS HEATING (STEAM AND HOT WATER)

Option 2 will utilize a 5 mmBtu/hour advanced biomass combustion unit and steam boiler rated at 30 psig and trimmed to generate steam at 10 psig. Steam from the boiler will be directly distributed to EBCH and tie into the steam header located in the existing mechanical room. A shell and tube heat exchanger will be installed at the Sibley Manor that will heat the existing hot water distribution system. Steam will also be utilized to heat a 4,000 gallon thermal storage tank with a shell and tube heat exchanger located in the biomass building. Buried pre-insulated hot water distribution piping will be installed connecting the biomass building to the boiler plant in ISD 696. Hot water from the thermal storage tank will blend with return water from ISD 696 to maintain the desired supply water temperature for heating the school. Distribution pumps will supply the hot water from the biomass plant to interconnect directly into the existing central heating plant located at ISD 696. The existing boilers in ISD 696 and EBCH will operate during periods of high heating demand to supplement the biomass system.

A radiator will be installed allowing the biomass system to dump heat to maintain minimum efficient fire during low load conditions. The savings are greater from offsetting the fuel oil and propane usage at EBCH and the Sibley Manor with biomass fuel during periods of low heating demand than the cost of using additional biomass fuel and dumping heat to maintain minimum efficient fire throughout the summer.

The shaded area in Figure 6 illustrates the estimated biomass system coverage of the daily average heat demand without a radiator at 83% and Figure 7 shows the biomass system coverage with a radiator at 99%. Coverage is shown with the biomass district heating system operating between 4.6 mmBtu/hour and 1.2 mmBtu/hour which includes the heat loss through the distribution pipes. Actual coverage will vary depending on weather conditions, peak demands, and periods when the boiler is shut down for maintenance. This report assumes usage of a radiator and 95% coverage for Option 2 for the purpose of estimating fossil fuel offset.

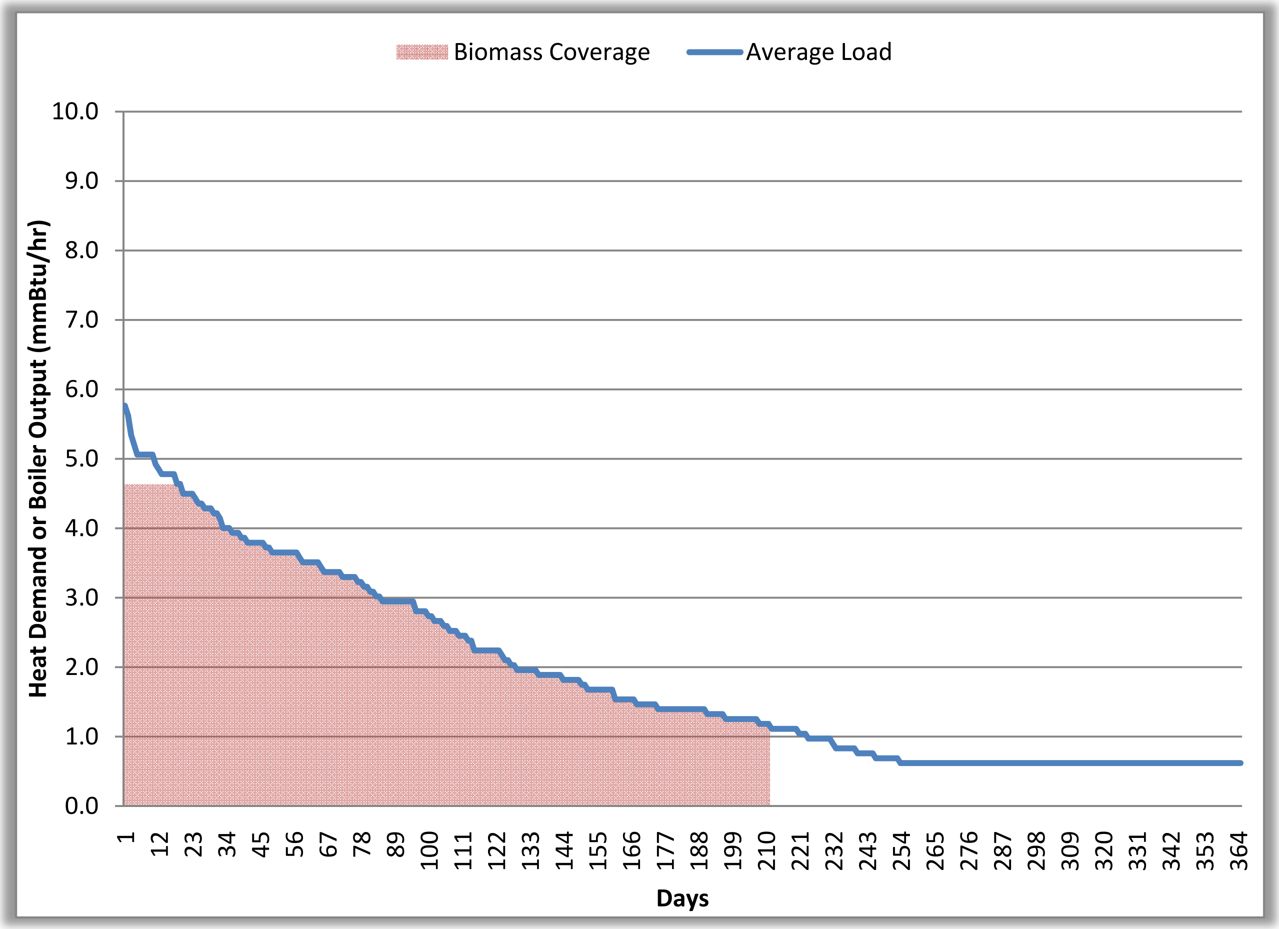


Figure 6 – Option 2 Biomass Coverage of CY 2010 Load Duration Curve for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass district system is shown as delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping and is not operational during low load conditions.

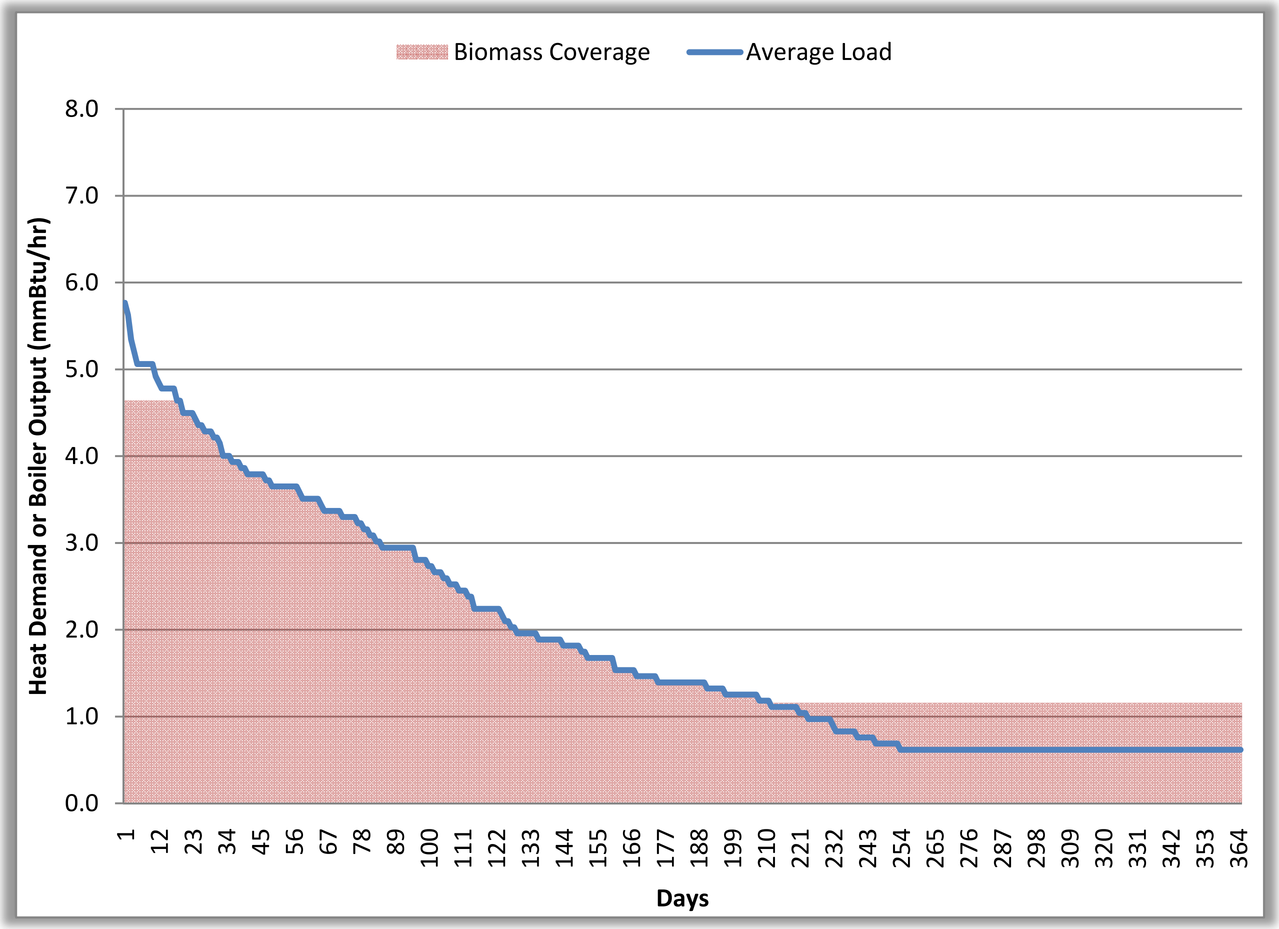


Figure 7 – Option 2 Biomass Coverage of CY 2010 Load Duration Curve with Radiator for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as being operational during the summer months and delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping. Management of loads and the use of a radiator to reject heat will allow biomass coverage during times of low heating demand. The biomass boiler output is shown to be above the load during low load periods as a result of the minimum heating demand placed on the system by the radiator.

5.4 OPTION 3 – SITE 2: BIOMASS HEATING (HOT WATER)

Option 3 will utilize a 5 mmBtu/hour advanced biomass combustion unit and hot water boiler. Hot water generated by the boiler at 210°F will be pumped into a 5,000 gallon thermal storage tank located in the biomass building. Buried pre-insulated hot water distribution piping will be installed connecting the biomass building to ISD 696, Sibley Manor, and EBCH. Option 3 assumes that EBCH has converted their steam distribution system to hot water (costs and requirements for conversion are not included in this study). Hot water from the thermal storage tank will blend with return water from the three buildings to maintain the desired supply water temperature for heating. Distribution pumps will circulate the hot water from the biomass plant to interconnect directly into the existing central heating plants located at ISD 696, Sibley Manor, and EBCH. The existing boilers at ISD 696, Sibley Manor, and EBCH will remain in place for emergency backup and to supplement the biomass system during periods that exceed the biomass boiler output. A radiator will be installed allowing the biomass system to reject heat to maintain minimum efficient fire during low load conditions. The savings are greater from offsetting the fuel oil and propane usage at EBCH and the Sibley Manor with biomass fuel during periods of low heating demand than the cost of using additional biomass fuel and dumping heat to maintain minimum fire throughout the summer.

The shaded area in Figure 8 illustrates the estimated biomass system coverage of the daily average heat demand without a radiator at 83% and Figure 9 shows the biomass system coverage with a radiator at 99%. Coverage is shown with the biomass district heating system operating between 4.6 mmBtu/hour and 1.2 mmBtu/hour which includes the heat loss through the distribution pipes. Actual coverage will vary depending on weather conditions, peak demands, and periods when the boiler is shut down for maintenance. This report assumes usage of a radiator and 95% coverage for Option 3 for the purpose of estimating fossil fuel offset.

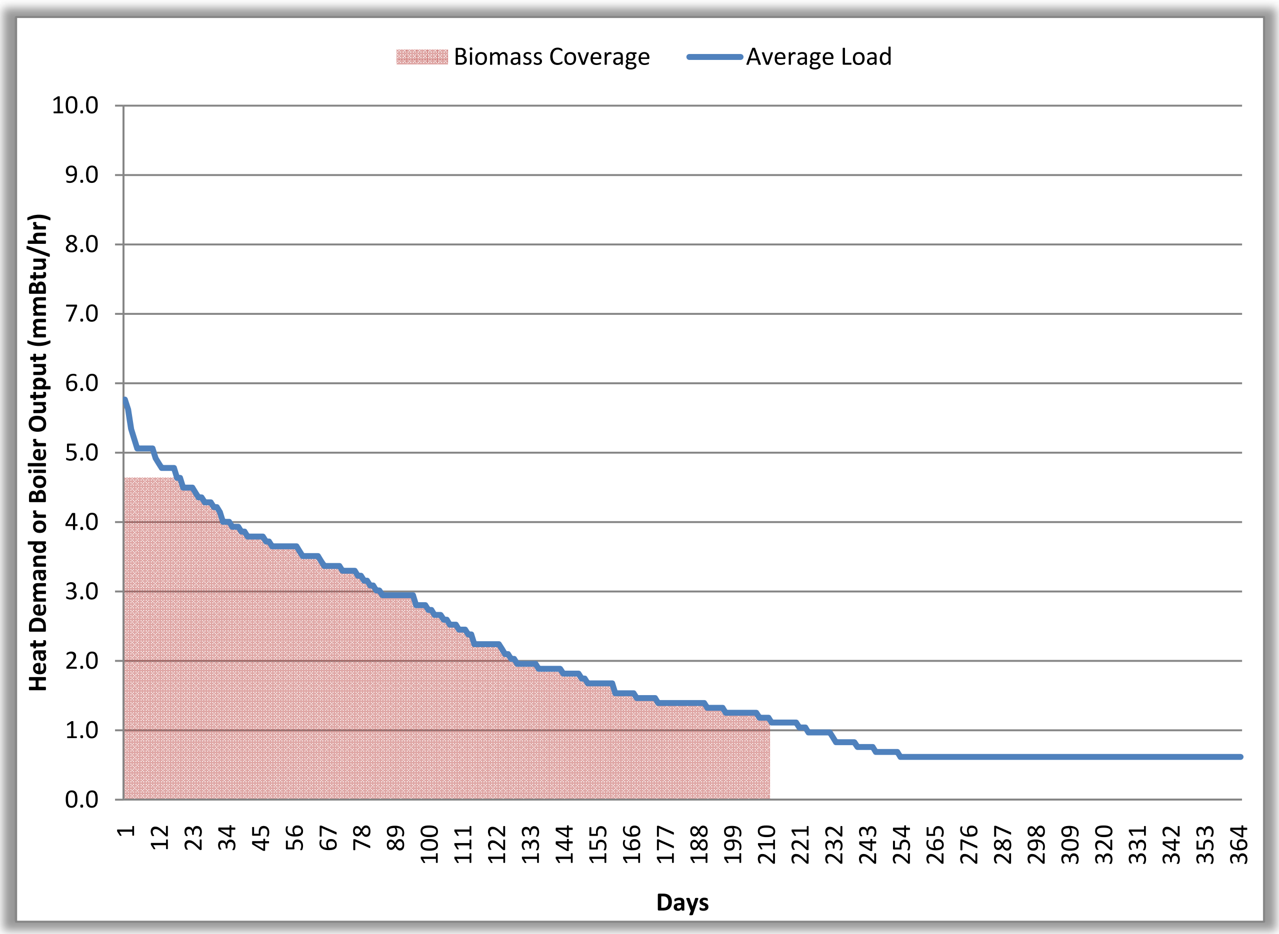


Figure 8– Option 3 Biomass Coverage of CY 2010 Load Duration Curve for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass district system is shown as delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping and is not operational during low load conditions.

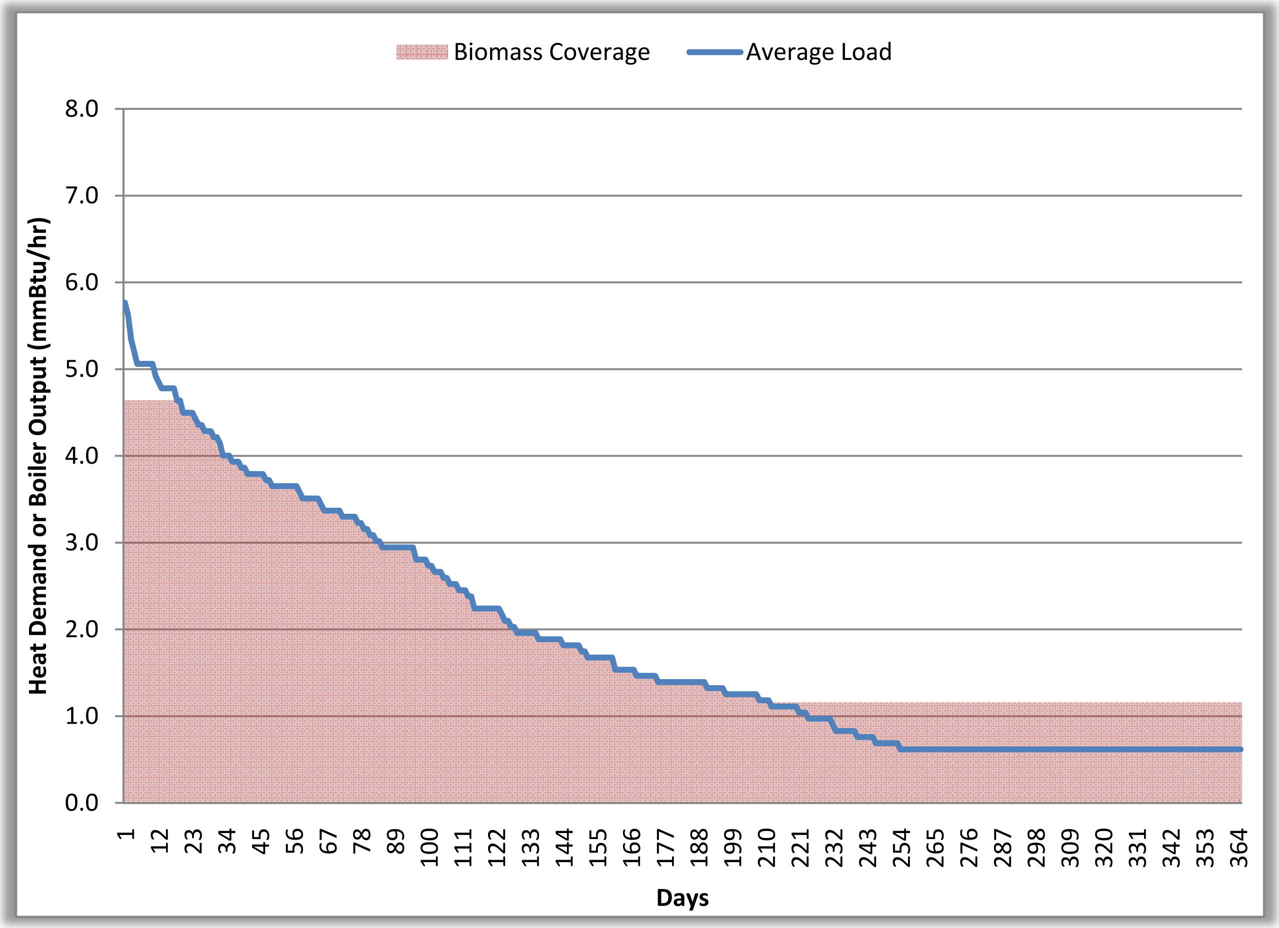


Figure 9 – Option 3 Biomass Coverage of CY 2010 Load Duration Curve with Radiator for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as being operational during the summer months and delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping. Management of loads and the use of a radiator to reject heat will allow biomass coverage during times of low heating demand. The biomass boiler output is shown to be above the load during low load periods as a result of the minimum heating demand placed on the system by the radiator.

5.5 OPTION 4 – SITE 2: BIOMASS BACKPRESSURE STEAM CHP (THERMAL OIL, STEAM, HOT WATER)

Option 4 will utilize a 5 mmBtu/hour advanced biomass combustion unit and vented thermal oil heater to heat oil to a minimum of 575°F. Hot oil will be pumped into a heat exchanger to indirectly generate steam at 250 psig. Steam at 250 psig will flow into a single-stage 110 kW backpressure steam turbine/generator that will generate electricity while reducing steam pressure to 10 psig. A slight upsizing of the 5 mmBtu/hr size may be required depending on losses in the vented and backpressure steam system, and this should be investigated in detail if this option moves forward. This change in size would be minor and would not impact system economics, and thus is not investigated in this report. A pressure reducing valve (PRV) would be piped in parallel to the turbine to reduce the pressure of the steam when a shutdown of the turbine is required. Low pressure steam exiting the turbine would be able to flow to three different locations. Steam would be piped directly to EBCH to tie into the steam header in the hospital mechanical room and to a shell and tube heat exchanger installed at the Sibley Manor utilizing steam to heat the existing hot water distribution system. A shell and tube heat exchanger located in the biomass building would also utilize steam to heat a 4,000 gallon hot water thermal storage tank.

Hot water from the thermal storage tank will be blended with return water from ISD 696. The existing boilers in ISD 696, EBCH, and Sibley Manor will operate during periods of high heating demand to supplement the biomass system. As described in Option 2, a radiator should be installed to reject heat for summer operation. The radiator should be located on the downstream side of the backpressure steam turbine/generator to take advantage of generating electricity during times of heat rejection.

The shaded area in Figure 10 illustrates the estimated biomass system coverage of the daily average heat demand without a radiator at 83% and Figure 11 shows the biomass system coverage with a radiator at 99%. Actual coverage will vary depending on weather conditions, peak demands, and periods when the boiler is shut down for maintenance. This report assumes usage of a radiator and 95% coverage for Option 4 for the purpose of estimating fossil fuel offset.

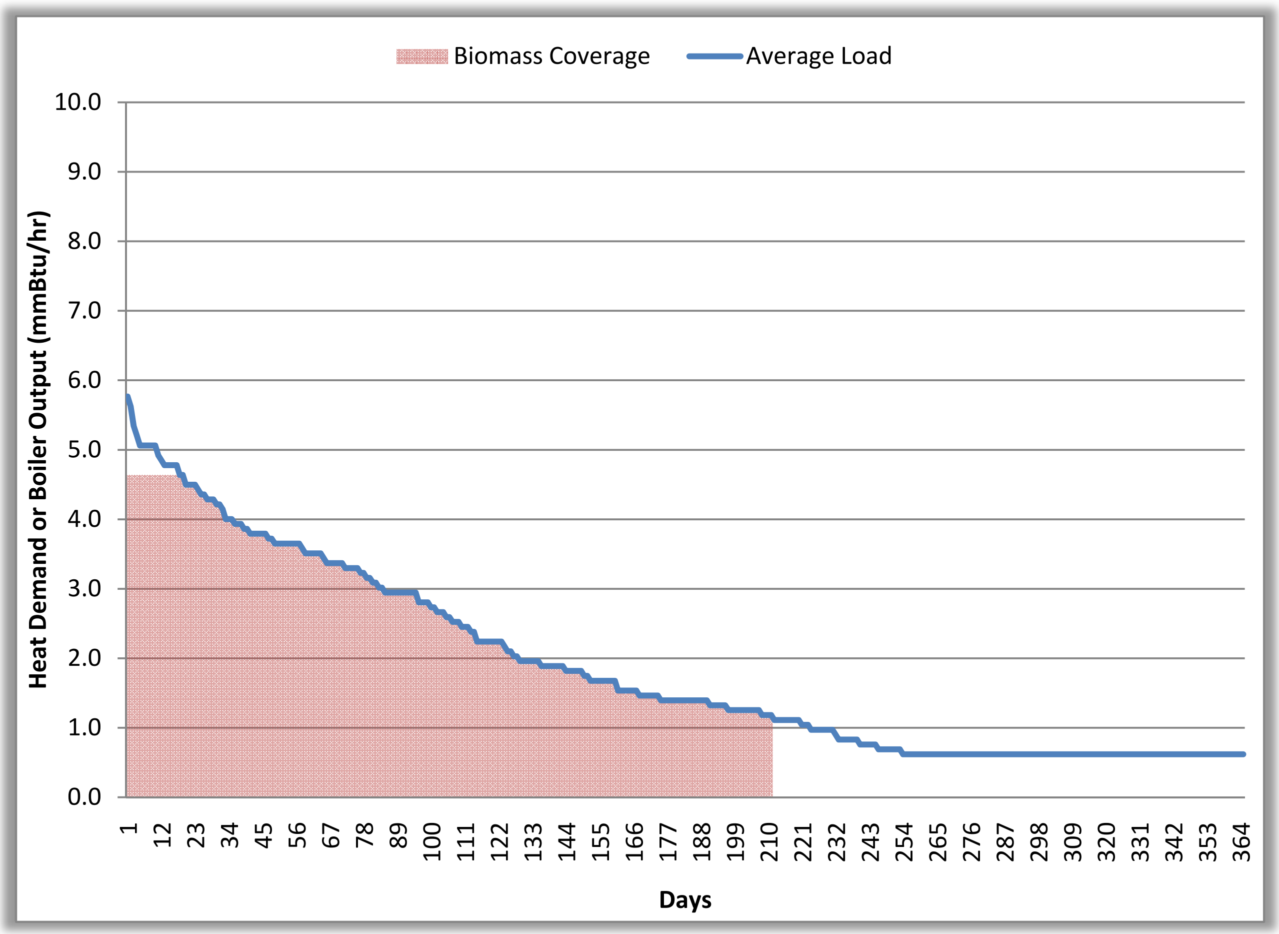


Figure 10 – Option 4 Biomass Coverage of CY 2010 Load Duration Curve for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as not being operational during low load conditions and delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping.

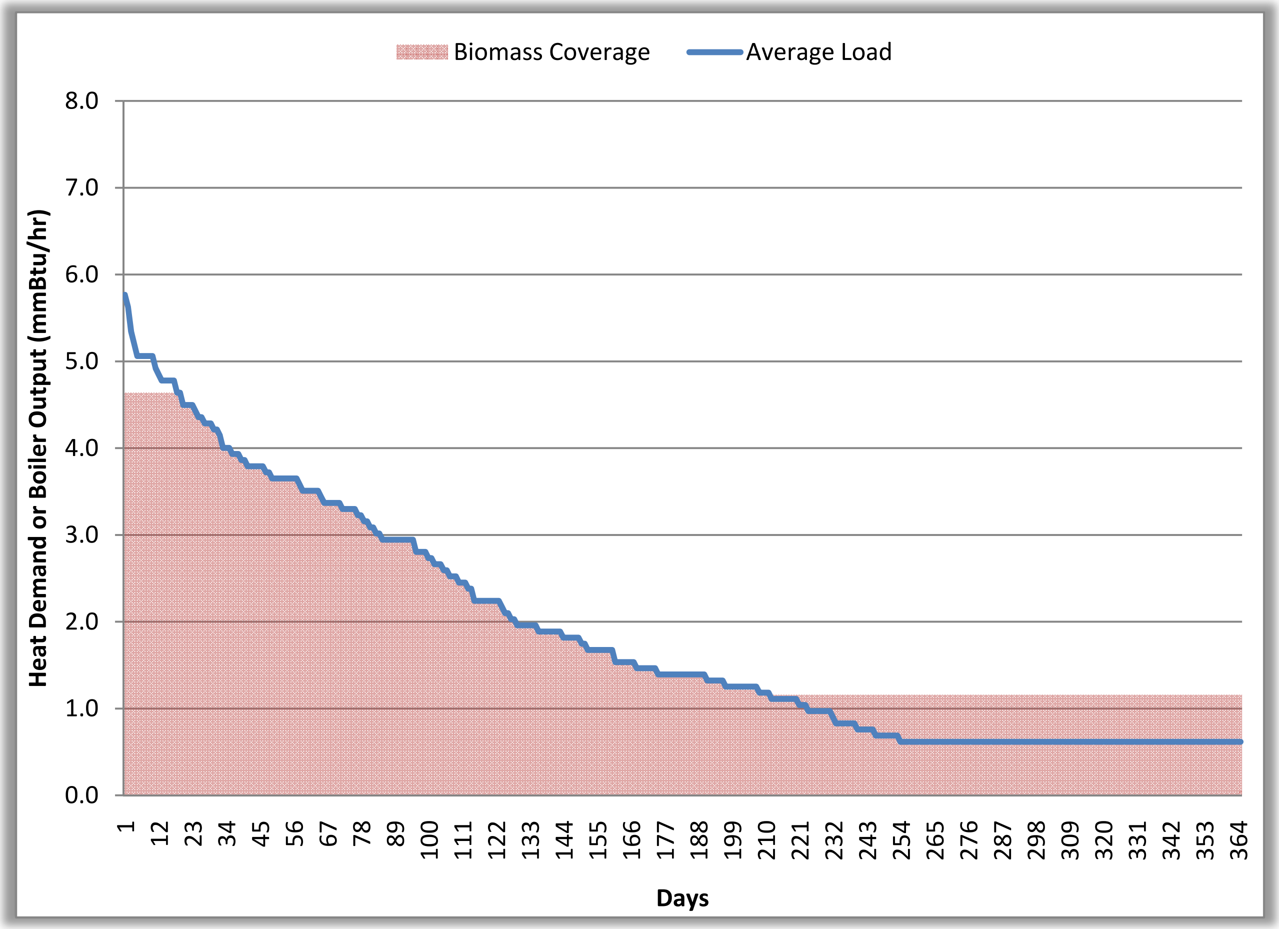


Figure 11–Option 4 Biomass Coverage of CY 2010 Load Duration Curve with Radiator for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as being operational during the summer months and delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping. Management of loads and the use of a radiator to reject heat will allow biomass coverage during times of low heating demand. The biomass boiler output is shown to be above the load during low load periods as a result of the heating demand placed on the system by the radiator.

Minnesota boiler law requires a boiler of the size recommended in Option 4 that generates steam at pressures higher than 15 psig to be inspected every two hours. This would require hiring approximately 5 additional boiler operators at an annual cost of approximately $400,000. Utilizing a vented thermal oil heater that indirectly generates steam through an unfired steam generator would be required to be checked on daily. It is assumed that existing staff from the city or major users would conduct daily inspections.

5.6 Option 5 – Site 2: Biomass ORC CHP (Thermal Oil and Hot Water)

Option 5 will utilize a 10 mmBtu/hour advanced biomass combustion unit and vented thermal oil heater that is connected to a 600 kW Organic Rankine Cycle (ORC) combined heat and power system. The biomass combustion unit will burn biomass fuel to heat oil that is selected to withstand high temperatures to 590°F. The hot oil will be pumped into the ORC system at 590°F to generate electricity and heat a hot water distribution system for ISD 696, Sibley

Manor, and EBCH. The ORC unit will be thermally-led, which means that the ORC electric generation would be dictated by the heating demand of Site 2. A schematic is provided in Appendix A showing the major components of Option 5.

Approximately 78% of the energy input to the ORC system will be usable for heating the district heating system, 18.5% will be generated as electricity, and ~3.5% will be lost due to inefficiencies in the ORC system. ORC electric generation increases as supply water temperatures decrease for the district heating loop. For example, an ORC system would be more efficient in generating electricity while supplying 180°F instead of 190°F for the distribution system. To optimize the electric generation of the ORC system, thermal storage would not be installed, allowing 180°F water to be generated and directly distributed to the major loads at Site 2 for heating. Option 5 will require the conversion of steam heating in EBCH to hot water. The cost for this conversion is not included in the cost estimate for Option 5 in this report.

The existing boilers in ISD 696, EBCH, and Sibley Manor will operate during periods of high heating demand to supplement the biomass system. A radiator will be installed in the district heating system downstream of the ORC system. This will create a load on the biomass ORC system during times of low heating demand. The radiator should be located on the downstream side of the ORC system to take advantage of generating electricity during periods of heat rejection. The additional savings from fuel oil and propane offset and electricity generated during times of low heating demand are greater than the cost of the additional biomass fuel required for heat dissipation through the radiator.

The shaded area in Figure 12 illustrates the estimated biomass ORC system coverage of the daily average heat demand without a radiator at 71% and Figure 13 shows the biomass system coverage with a radiator at 100%. Actual coverage will vary depending on weather conditions, peak demands, and periods when the boiler is shut down for maintenance. This report assumes usage of a radiator and 95% coverage for Option 5 for the purpose of estimating fossil fuel offset.

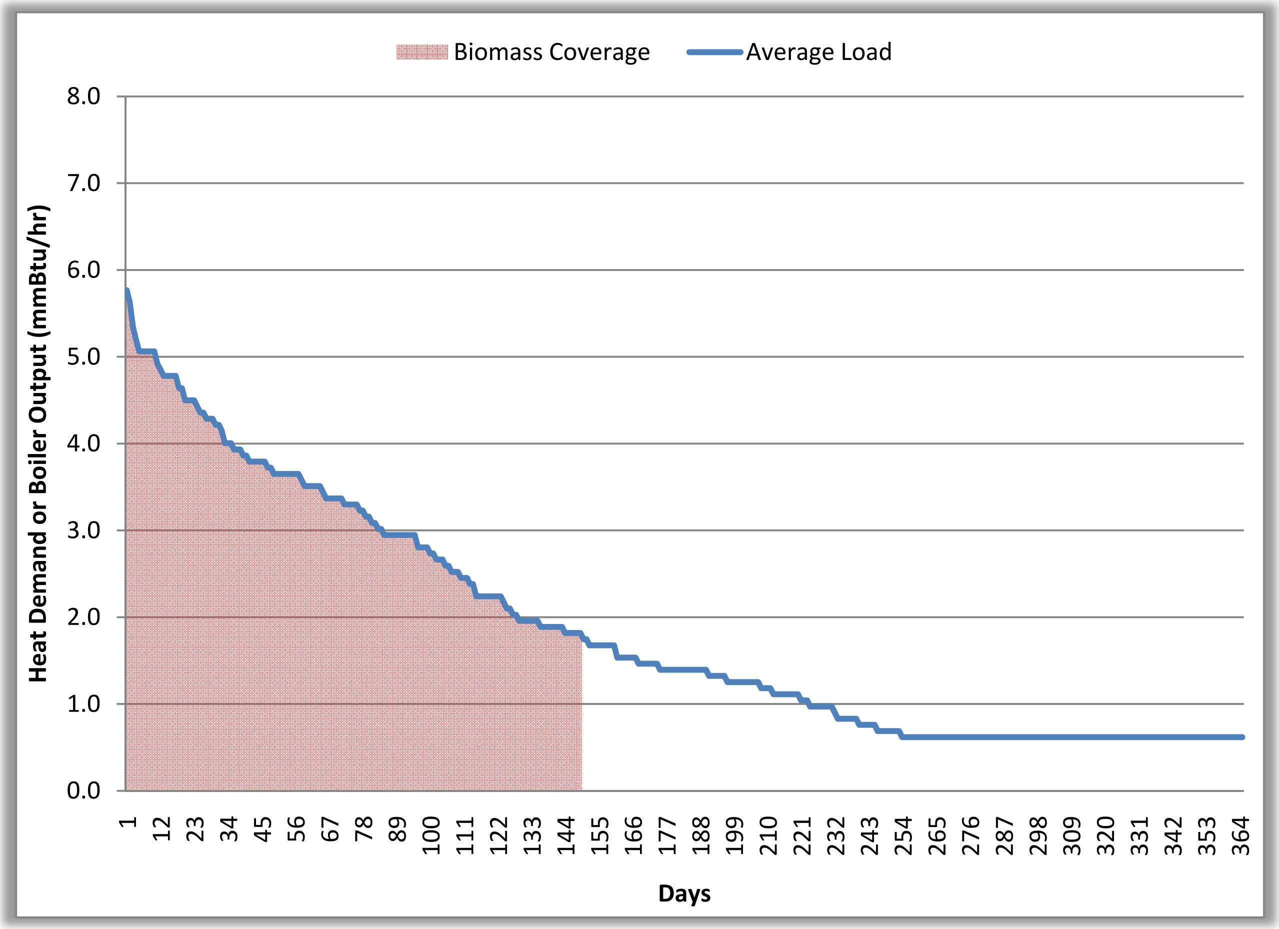


Figure 12 – Option 5 Biomass Coverage of CY 2010 Load Duration Curve for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as not shut down during the summer months with the ability to deliver 7.2 to 1.8 mmBtu/hour due to heat losses in distribution piping. ORC generations systems can modulate down to 10% output, but biomass combustion unit efficiency drops off significantly below 25% of rated boiler output.

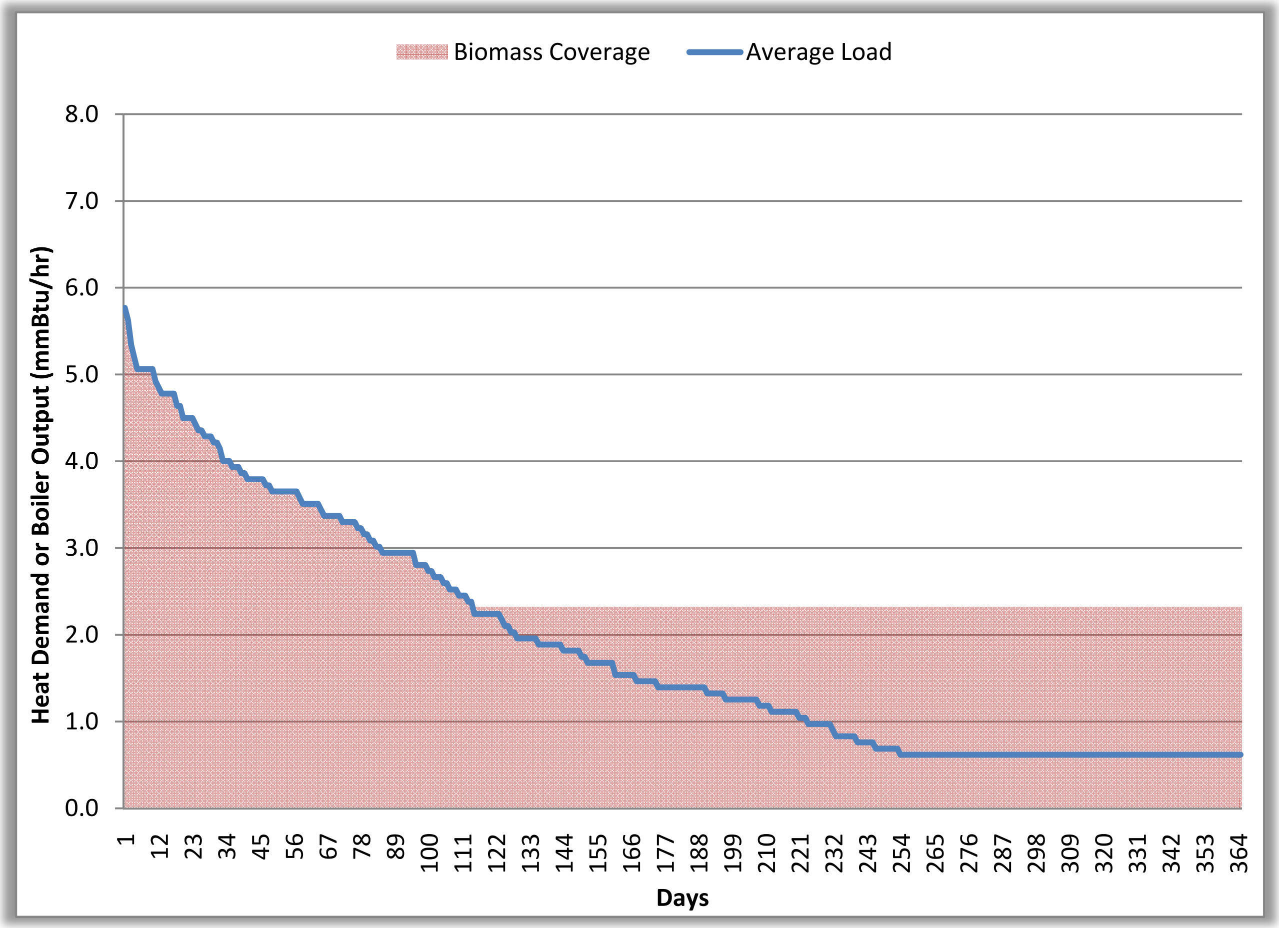


Figure 13–Option 5 Biomass Coverage of CY 2010 Load Duration Curve with Radiator for Site 2

Note: The average output model is based on local weather data and fuel delivery records provided by EBCH, Sibley Manor, and ISD 696 in Ely, MN. The biomass system is shown as being operational during the summer months with the ability to deliver 7.2 to 1.8 mmBtu/hour due to heat losses in distribution piping. Management of loads and the use of a radiator to reject heat will allow biomass coverage during times of low heating demand. The biomass boiler output is shown to be above the load during low load periods as a result of the heating demand placed on the system by the radiator.

5.7 Additional Large Buildings and Pipe Runs

Additional capacity has been built into the piping system and increased system loads can be absorbed by the biomass boilers specified in this report without the need for the addition of added boilers. It is estimated that an increase in annual heating demand of up to 50% could be absorbed by the systems without the need for increase in biomass boiler capacity. This allows efficient sizing of one unit now with flexibility in when additional boiler capacity would be required. As an example, Figure 14 demonstrates what an increase of 50% in annual load would do to the system for Site 2 and Options 2-4. The blue curve shows the new demand curve with a 50% increase in annual thermal load. The red shading shows the biomass system coverage for this new curve. The figure shows that the potential percentage covered would drop from approximately 99% to 89% when using the radiator to ensure the summer load is captured. Even though coverage percentage decreases, quantity of annual fossil fuel offset would increase from 15,564 mmBtu to approximately 21,627 mmBtu. This would be an increase in the quantity of fossil fuel offset by 39% without increasing the boiler size. This additional load would dramatically improve the economics for the project. If it is deemed that the economics warrant, space has been left in the boiler plant to add another boiler to bump the potential coverage back up to 99%. The piping system will allow coverage of these loads. As further investigation of the system continues, initial pipe sizes could be increased if more potential load is identified.

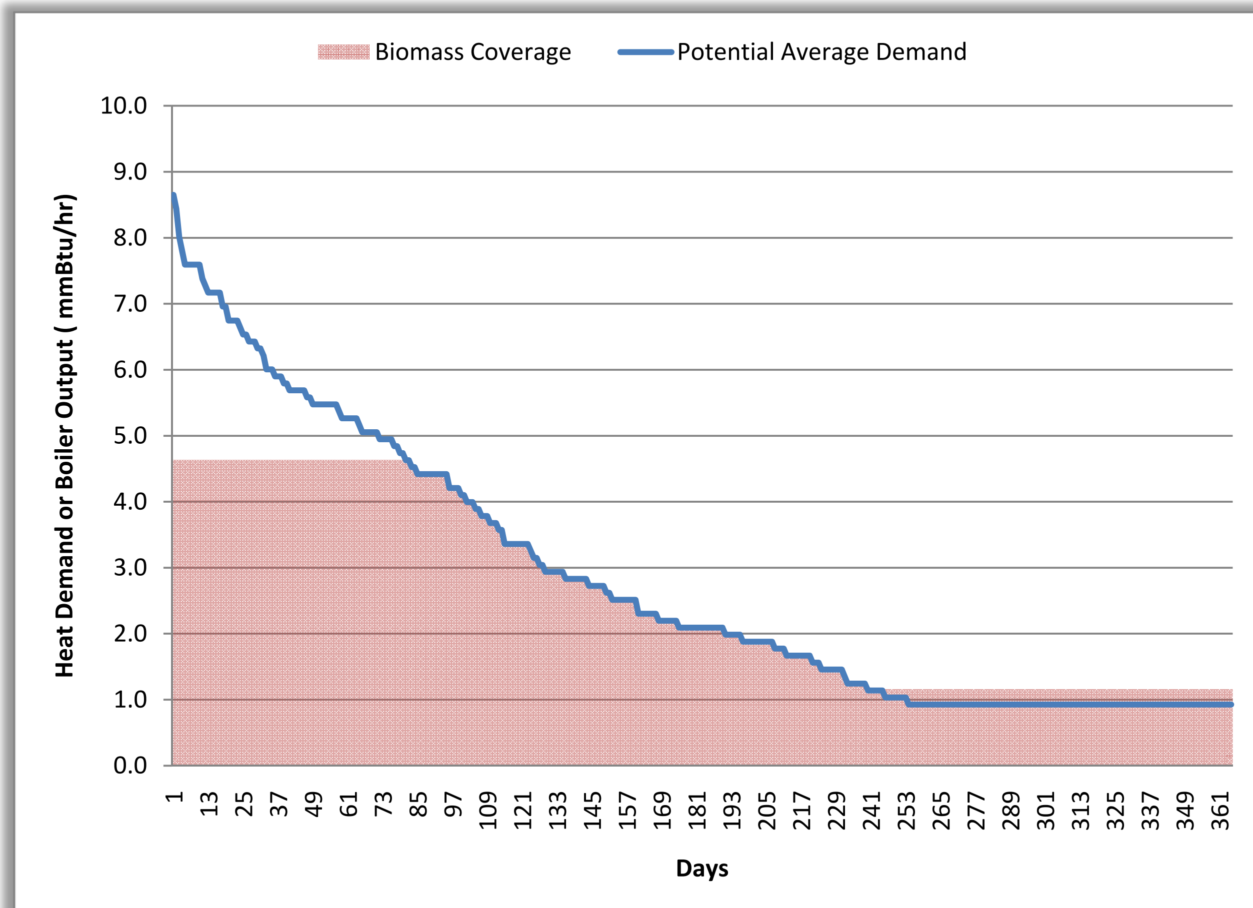


Figure 14 – Potential Biomass Coverage of 50% Increase in Average Heat Demand

Note: Curve and coverage is generated by increasing average heat demand for Site 2 by 50% over the course of the year. The biomass system is shown as being operational during the summer months delivering 4.6 to 1.2 mmBtu/hour due to heat losses in distribution piping. Management of loads and the use of a radiator to reject heat will allow biomass coverage during times of low heating demand. The biomass boiler output is shown to be above the load during low load periods as a result of the heating demand placed on the system by the radiator.

Connecting additional loads would also reduce the amount of heat dumped by the radiator during low load conditions. Additional space in the biomass building has been provided in Options 1 through 4 for a second biomass boiler to be installed in the future should expansion of the district heating system require it. Additional space was not included in Option 5 to optimize building capital costs since the biomass system output is much higher than Options 1-4.

Fuel usage was provided for additional locations in the vicinity of Site 1 and Site 2. Initial investigation shows that it may be cost prohibitive to include additional buildings to the district heating system due to the distances and piping costs for interconnection. Table 5 provides the building analyzed, pipe run label corresponding to the site plans in Appendix A, estimated piping lengths and installation costs at $200 per linear foot, current fuel costs using the most recent cost for the fuel provided, and the estimated maximum annual savings by interconnecting to the district heating system.

Table 5 – Analysis of Connecting Additional Buildings

Building	Site	Pipe Run	Estimated Pipe Length	Estimated Piping Cost	Current Fuel Cost	Maximum Annual Savings
Zenith and Pioneer	Site 1	H	4,239	$ 847,800	$ 73,450	$ 60,888
Joint Garage	Site 1	I	2,060	$ 412,000	$ 14,620	$ 11,246
Kawishiwi Ranger Station (KRS)	Site 1	J	1,955	$ 391,000	$ 24,417	$ 20,251
International Wolf Center (IWC)	Site 1	K	835	$ 167,000	$ 17,655	$ 14,643
KRS and IWC Combined	Site 1	J+K	2,790	$ 558,000	$ 42,072	$ 34,894
Grahek Apartments	Site 2	E	176	$ 35,200	Not Available	Not Available
Carefree Assisted Living	Site 2	F	655	$ 131,000	Not Available	Not Available

Note: Values presented are meant to provide a general idea of connection potential. Maximum annual savings are equivalent to offsetting 100% of fossil fuel usage for each building, and does not account for operating costs. This is an overestimate of actual potential savings. Estimated piping costs do not include the costs associated with tie-in of hydronic or steam district heating system.

Table 5 assumes that 100% of the fossil fuel load would be offset with biomass to show the maximum possible savings for each building. Parasitic losses from pumps, O&M costs, and potential savings from CHP are not considered for this level of investigation. Actual savings could vary depending on the portion of the load that could be offset for each building, fossil fuel costs, and biomass costs. The piping costs do not include tie-in costs. These costs are not estimated for the purposes of this report. The buildings and savings listed in Table 5 are not included in the financial analysis of the Options in this study.

5.8 ADDITION OF RESIDENTIAL LOADS

The addition of residential loads is evaluated on an independent basis for the purposes of this report. Residential load and heating system data was provided for one residence along the hot water distribution pipe route between the Site 2 biomass facility and the ISD 696 load. The 1,200 square foot residence used 557 gallons of fuel oil in 2010 at a cost of $1,623 ($2.91/gallon). The house was weatherized in 2007 and has a central hydronic system. The usage for the home is equivalent to 65,000 Btu/sf/yr of fuel oil input and an energy demand of 52,000 Btu/sf/yr assuming a boiler/water heater efficiency of 80%.

The cost for this home to be connected to the district heating loop would be on the order of $10,000-$13,000. This includes the cost of laying pipe, installation of the necessary heat exchangers, valves, and metering equipment to tie into the existing hydronic space heating system, and tie-in to the existing domestic hot water system. Actual costs for interconnection will vary with distance from the district heating pipe route and ease of interconnection with the existing heating system.

The business model for energy sales to residential or commercial units has not been evaluated in this report. However, strictly on an energy cost basis, the district heating system could provide the same amount of energy as the existing fuel oil system for approximately $290/yr of wood input costs. This is a reduction in fuel cost of $1,330 per year, which could provide a simple payback of 7.5 - 9.8 years to the home owner. In addition, homeowners and small business owners would avoid replacement costs of their existing heating equipment since backup will be maintained by boilers at the major users. Some of the fuel cost savings would need to be apportioned to ownership and operation costs for the district heating system, and thus, this payback calculated here is slightly aggressive. However, this payback compares favorably to the simple payback for Option 2 (12.8 years). If the residence used as an example were added to Option 2, it would improve the overall economics of the project. Connection of residences with central heating systems that use over 500 gallons of fuel oil or 750 gallons of propane in close proximity to the district heating pipe route should improve overall project economics. As additional piping is required to reach added residences further away from the main distribution line, the economic viability of adding residences would decrease.

Should Ely move forward with a district heating system, WERC recommends obtaining detailed fuel usage and heating system information from residences and businesses adjacent to pipe line routes that are justified by the key loads. WERC also recommends that Ely identify options for ownership models and required economic returns for the system owner. The required economic returns for the owner will be a major factor in determining the extent to which a district system can be expanded beyond the major heating loads.

5.9 Absorption Cooling

Absorption cooling can provide operating savings for a biomass project as well as increase boiler plant efficiency during low heating load periods. The magnitude of savings is dependent on the annual cooling load, cost of electricity, cost of biomass fuel, and the efficiency of the existing chillers being replaced. Table 6 lists the costs per ton-hour of cooling with single and double effect absorption chillers at a biomass cost of $30 per ton and two examples of water cooled electric chillers at an electric cost of $0.085 per kWh.

Table 6 - Cost of Cooling Comparison for Electric and Absorption Chillers

Chiller Compressor Technology	Estimated COP	Cost / Ton-Hour ($30/ton chips & $0.085/kWh electric)
Single Effect Absorption Chiller	0.6	$0.086
Double Effect Absorption Chiller	1.2	$0.043
Reciprocating Electric Chiller	4.5	$0.066
Centrifugal Electric Chiller	6.5	$0.046

Note: Table assumes a cost of $0.085 per kWh for electric chillers, $30/ton and 10 mmBtu/ton wood chips, a biomass boiler efficiency of 70%, and the cost / ton-hour only considers the Coefficient of Performance (COP) of the compressors. Parasitic loads for cooling towers, pumps, and ancillary equipment are not included in the cost/ton-hour.

Other considerations to be analyzed between the chiller technologies are requirements for additional cooling towers, pumps, controls, piping, and system interconnection. Capital cost requirements for installing and integrating absorption chillers can be substantial and can range from $1,000 to $2,000+ per ton of installed capacity depending on the size and scope of implementation. Siting and placement of an absorption chiller plant can have a considerable impact on a project's initial and operating costs. It would be difficult to justify the additional capital costs associated with absorption cooling based on the available energy savings using current average electric costs, biomass costs, and cooling loads for Ely, MN. Absorption cooling is not analyzed further in this study due to limited potential savings given current economics.

6.0 ANALYSIS OF BIOMASS OPTIONS

6.1 CAPITAL COST ESTIMATE AND OPERATIONAL COSTS

Capital costs for each option are shown in Table 7. Estimates were established using recent bid results from similar biomass projects and quotes from manufacturers. The capital cost estimate for each option is based on the biomass building layout in Appendix A. The building is assumed to be a pre-engineered steel building. Appendix B provides a breakdown of the capital cost estimates for each option.

Table 7 – Pre-Feasibility Level Cost Estimates

Option	Description	Estimated Capital Cost
1	Site 1: Biomass Heating (Hot Water)	$1,934,318
2	Site 2: Biomass Heating (Steam and Hot Water)	$3,783,002
3	Site 2: Biomass Heating (Hot Water)	$3,765,866
4	Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water)	$4,664,050
5	Site 2: Biomass ORC CHP (Thermal Oil and Hot Water)	$7,164,786

Additional costs associated with a steam boiler system for Option 2 includes steam specialties such as a deaerator tank, condensate return piping and pumps, automatic blow down, steam traps, etc... Additional costs for CHP using backpressure steam in Option 4 include the installed costs for an advanced biomass combustion unit and thermal oil heater, installed costs for an unfired steam generator, thermal oil pumps, deaerator tank, condensate return piping and pumps, blow downs, steam traps, pressure reducing valves to bypass the turbine/generator for maintenance or emergencies, and additional electrical equipment and requirements.

Capital costs for the ORC CHP system in Option 5 include installed costs for an advanced biomass combustion unit and thermal oil heater, ORC generation system, thermal oil pumps, and controls. The capital costs to convert the steam distribution system at EBCH to hot water are not included in the capital cost listed for Options 3 and 5.

Table 8 lists an estimate of annual operation and maintenance costs associated with the biomass boiler options. The electricity line item covers added costs to run biomass equipment and distribution pumps. The ash removal line item assumes that the city pays for removal of the ash at a cost of $70/ton. The ash is actually a valuable product that may be used as a soil amendment on city grounds, and much of this cost could likely be avoided. It is assumed for all five options that a First Class Engineer Grade C would perform between 1 and 5 hours per week of maintenance on the proposed boiler plant to coordinate deliveries, empty ash bins, and check on the system once per day. It is assumed in this study that existing facility or City staff would fulfill this requirement.

Table 8 – Estimated Annual O&M Costs

Items	Option 1	Option 2	Option 3	Option 4	Option 5
Electricity	$4,000	$6,000	$7,000	$6,000	$9,000
Maintenance / Wear Parts	$5,600	$8,100	$7,100	$10,600	$17,100
Ash Removal	$1,000	$3,100	$3,100	$3,400	$5,000
Makeup Water Treatment (Steam System Only)	$0	$1,000	$0	$1,200	$0
Boiler Operator	$0	$0	$0	$0	$0
Total	**$10,600**	**$18,200**	**$17,200**	**$21,200**	**$31,100**

Note: Table 8 assumes that existing staff from one of the major users or the City will check on the biomass plant daily to meet Minnesota regulations. It is assumed that hiring of additional boiler operators will not be required.

Minnesota boiler regulations license boilers based on heating surface area instead of Btu output. The Minnesota Chief Boiler Inspector suggested that a 5 mmBtu/hour boiler would be licensed as a 75 hp boiler and a 10 mmBtu/hour boiler as a 150 hp boiler. To eliminate confusion, boilers and oil heaters are sized in this study based on rated Btu output instead of boiler horsepower.

Boilers that are vented to atmosphere are not regulated under Minnesota boiler pressure vessel regulations. Full time boiler operators would be required for Option 3 if a high pressure steam boiler was utilized instead of thermal oil boiler indirectly generating steam through a heat exchanger and Option 4 if a non-vented thermal oil system was utilized. Major users in Ely, MN should investigate boiler licensing requirements and utilizing existing staff should they proceed with further investigation of any of the four biomass options presented in this report.

6.2 Financial Analysis

The first year net operating savings were calculated for all five biomass system options. Option 1 would offset an estimated 85% of the current fossil fuel usage used by the existing central heating plant at Vermillion Community College with renewable biomass fuel. Options 2, 3, 4, and 5 would offset an estimated 95% of the current fossil fuel usage for heating and domestic hot water with biomass fuel at Ely-Bloomenson Community Hospital, Independent School District 696, and Sibley Manor. The resulting energy profiles for each option are shown in Table 9.

Table 9 – Current & Proposed Biomass System Energy Profile Summary

Option	Current Annual		Potential Annual with Biomass			
	Fuel Oil Usage, Gallons	Propane Usage, Gallons	Biomass Usage, Tons	Electric Generated, kWh	Fuel Oil Usage, Gallons	Propane Usage, Gallons
1	62,357	3,332	878	-	9,680	0
2	81,246	99,729	2,924	-	5,486	2,804
3	81,246	99,729	2,924	-	5,486	2,804
4	81,246	99,729	3,174	412,965	5,486	2,804
5	81,246	99,729	4,730	1,622,087	5,486	2,804

Note: Section 3.2 describes the development of current annual fuel usage values. Coverage of peak loads and low loads will be accomplished with fuel oil for Option 1. This coverage will be provided by a combination of fuel oil and propane for Options 2-5. Since maintenance on the biomass system will likely be completed in the summer months, it is assumed for the purposes of this report that ~75% of the fossil fuel coverage will be from fuel oil and ~25% will be from propane for these options. Biomass usage is estimated using 10 mmBtu/ton and 40% moisture content (wet basis). The conversion from green tons to cords is 2.5 tons/cord for "lighter northern hardwoods"[2].

Table 10 contains the estimated net operating savings for each option. All savings values are based on the most recent fuel prices supplied to WERC and $30 per ton for biomass as supplied by the University of Minnesota Department Of Forest Resources. Annual savings for electricity generation through CHP have been estimated using an electric offset value of $0.072 per kWh. This was the average three year cost of electricity for ECBH after subtracting demand charge.

[2] http://www.extension.umn.edu/distribution/naturalresources/DD2723.html

Table 10 – Potential Annual Net Operating Savings

Option	Current Annual Fuel Cost	Annual Biomass Cost	Annual Electric Generation, kWh/yr	Annual Electric Value	Fossil Fuel Cost with Biomass System	Biomass System O&M Costs	Potential Savings
1	$208,005	($26,331)	0	$0	($31,201)	($10,600)	$139,873
2	$433,461	($87,734)	0	$0	($21,673)	($18,200)	$305,854
3	$433,461	($87,734)	0	$0	($21,673)	($17,200)	$306,854
4	$433,461	($95,207)	412,965	$29,733	($21,673)	($21,200)	$325,115
5	$433,461	($141,912)	1,622,087	$116,790	($21,673)	($31,100)	$355,566

Note: *Annual fuel costs were calculated with the quantities and prices listed in Table 11. Electricity offset values are calculated using $0.072 per kWh. Potential savings do not include financing costs or annual payment of debt service. Values in parenthesis are negative.*

Table 11 shows the effect on 1st year net operating savings from doubling the current prices of biomass and fossil fuel costs.

Table 11 – Sensitivity Analysis of Fossil Fuel and Biomass Prices

Option	Potential Savings at Current Biomass and Fossil Fuel Prices	Potential Savings with Biomass Price Doubled (Fossil Fixed)	Potential Savings with Fossil Fuel Price Doubled (Biomass Fixed)
Option 1	$139,873	$113,542	$316,677
Option 2	$305,854	$218,120	$717,642
Option 3	$306,854	$219,120	$718,642
Option 4	$325,115	$229,908	$736,903
Option 5	$355,566	$213,654	$767,354

Note: *Current fossil fuel costs are used to develop potential savings with biomass price doubled. Current biomass prices ($30/ton) are used to develop potential savings with fossil fuel price doubled.*

The results of the sensitivity analysis show that project savings are more sensitive to fossil fuel prices than biomass prices. For example, the savings for Option 1 would be reduced 19% if biomass costs doubled versus a 126% increase in savings if fossil fuel prices doubled. Therefore the project feasibility is more dependent on fossil fuel costs than biomass costs. A detailed sensitivity analysis for each option is provided in Appendix C showing the potential 1st year net operating savings based on price changes of fossil fuel on a percentage basis to account for the use of both fuel oil and propane compared to biomass prices. The highlighted cell in each table identifies the 1st year cash flow based on the prices assumed in this report.

A cash flow analysis was also completed for financing the project assuming a 20 year financing term at a 4.5% interest rate. 25 Year Net Present Values for the biomass project are $1.5 million for Option 1, $3.8 million for Option 2, $3.9 million for Option 3, $3.3 million for Option 4, and $1.2 Million for Option 5. When comparing projects, a project with a higher Net Present Value typically means the project is better than a similar project with a lower Net Present Value. Table 12 shows a summary of the results of this analysis and Table 13 provides the assumptions used in the financial analysis. The detailed analyses are provided in Appendix C.

Table 12 – Biomass System First Year Cash Flow Analysis Summary

Option	Financed Amount	Annual Financing Payment	20 Year Financing, 1st Yr Cash Flow	25 Year Net Present Value
1	$1,934,318	($148,703)	($8,830)	$1,484,642
2	$3,783,002	($290,823)	$15,031	$3,832,127
3	$3,765,866	($289,505)	$17,349	$3,877,825
4	$4,664,050	($358,554)	($33,439)	$3,303,992
5	$7,164,786	($550,801)	($195,235)	$1,204,394

Table 13 – Assumptions

Item	Value	Unit
Site 1: Vermillion Community College (VCC) 3 Year Average Fuel Oil Usage	62,357	Gallons
Site 1: VCC Most Recent Fuel Oil Price	$3.24	Per Gallon
Site 1: VCC 2011 Total Propane Usage	11,106	Gallons
Site 1: VCC 2011 Propane Usage offset by Central Plant (30% of total propane usage)	3,332	Gallons
Site 1: VCC Most Recent Propane Price	$1.79	Per Gallon
Site 2: Ely-Bloomenson Community Hospital (EBCH) 3 Year Average Fuel Oil Usage	81,246	Gallons
Site 2: EBCH Most Recent Fuel Oil Price	$3.20	Per Gallon
Site 2: Independent School District (ISD) 696 Propane Usage (50% of CY 2010)	76,886	Gallons
Site 2: ISD 696 Most Recent Propane Price	$1.72	Per Gallon
Site 2: Sibley Manor 3 Year Propane Usage	22,843	Gallons
Site 2: Sibley Manor Most Recent Propane Price	$1.80	Per Gallon
Percent of Load Replaced with Biomass for Option 1	85%	Percent
Percent of Load Replaced with Biomass for Option 2	95%	Percent
Percent of Load Replaced with Biomass for Option 3	95%	Percent
Percent of Load Replaced with Biomass for Option 4	95%	Percent
Percent of Load Replaced with Biomass for Option 5	95%	Percent
Biomass Fuel Unit Cost	$30	Per Ton
Electricity Generation Offset Value	$0.072	Per kWh
Biomass Boiler Efficiency	70%	Percent
Site 2 Biomass District Heating System Efficiency (Includes distribution pipe heating losses)	65%	Percent
Fossil Fuel System Efficiency	80%	Percent
#2 Fuel Oil High Heating Value	0.1400	mmBtu/Gallon
Propane High Heating Value	0.0913	mmBtu/Gallon
Biomass Fuel High Heating Value (40% moisture content green wood chips)	10	mmBtu/Ton

6.3 Additional Benefits of Biomass System

Additional benefits that would be provided by a woody biomass project include:

- Keeping dollars spent on energy within the local economy, between $30,000 and $140,000 annually, depending on option selected.
- Decreased dependence on imported oil by replacing fuel oil and propane use with renewable wood chip fuel;
- A hedge against the volatility of the fossil fuel market;
- A reduction in net CO_2 emissions of 553 metric tonnes for Site 1 and ranging from 1,321 – 2,740 metric tonnes for Site 2 depending on the option selected. Credits generated through this net reduction would be eligible for sale on the voluntary carbon market;
- Educational opportunities for local students and opportunities for eco-tourism.

7.0 CONCLUSIONS AND RECOMMENDATIONS

Woody biomass utilization options present Ely, MN with an opportunity to reduce operating costs at major energy users within the city. Connection of additional residential and commercial properties may be accomplished by direct payment by the owner on an “opt-in” basis or encompassed in an expanded system with costs recovered through annual energy sales. The benefits and costs associated with interconnecting smaller users are not evaluated in detail in this study. However, the study shows that residences adjacent to district heating pipelines already justified by larger users should help to improve the overall economics of project options. The options evaluated in this report, with the assumption of 20-yr financing at 4.5% interest rate would provide benefits as summarized:

- Option 1 – Site 1: Biomass Heating (Hot Water) would offset 85% of current fossil fuel usage by producing hot water for heating the existing central heating plant located at Vermillion Community College for a capital cost of $1.9 M and provide a first year net operating savings of $139,873 and 25 year Net Present Value (NPV) of $1.5 million.

- Option 2 – Site 2: Biomass Heating (Steam and Hot water) would offset 95% of current fossil fuel usage by generating steam for space heating and DHW at EBCH and the Sibley Manor, and heat a hot water thermal storage tank to provide heat and DHW to ISD 696. This option would produce a first year net operating savings of $305,854 and 25 year NPV of $3.8 million for a capital cost of $3.8 M.

- Option 3 – Site 2: Biomass Heating (Hot Water) would offset 95% of current fossil fuel usage by generating hot water to heat a hot water thermal storage tank to provide heat and DHW to EBCH, Sibley Manor, and ISD 696. This option would produce a first year net operating savings of $306,854 and 25 year NPV of $3.9 million for a capital cost of $3.8 M. The cost to convert EBCH to hot water from steam is not included in this cost estimate, and would need to be considered if this option is pursued.

- Option 4 – Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water) would offset 95% of fossil fuel usage and generate 412,965 kWh with a backpressure steam turbine/generator. Option 4 provides a first year net operating savings of $325,115 and 25 year NPV of $3.3 million for a capital cost of $4.7 M.

- Option 5 – Site 2: Biomass ORC CHP (Thermal Oil and Hot Water) would offset 95% of fossil fuel usage and generate 1,622,087 kWh with an ORC generator. Option 5 provides a first year net operating savings of $355,566 and 25 year NPV of $1.2 million for a capital cost of $7.2 M.

Additional benefits that would be provided by a woody biomass project include:

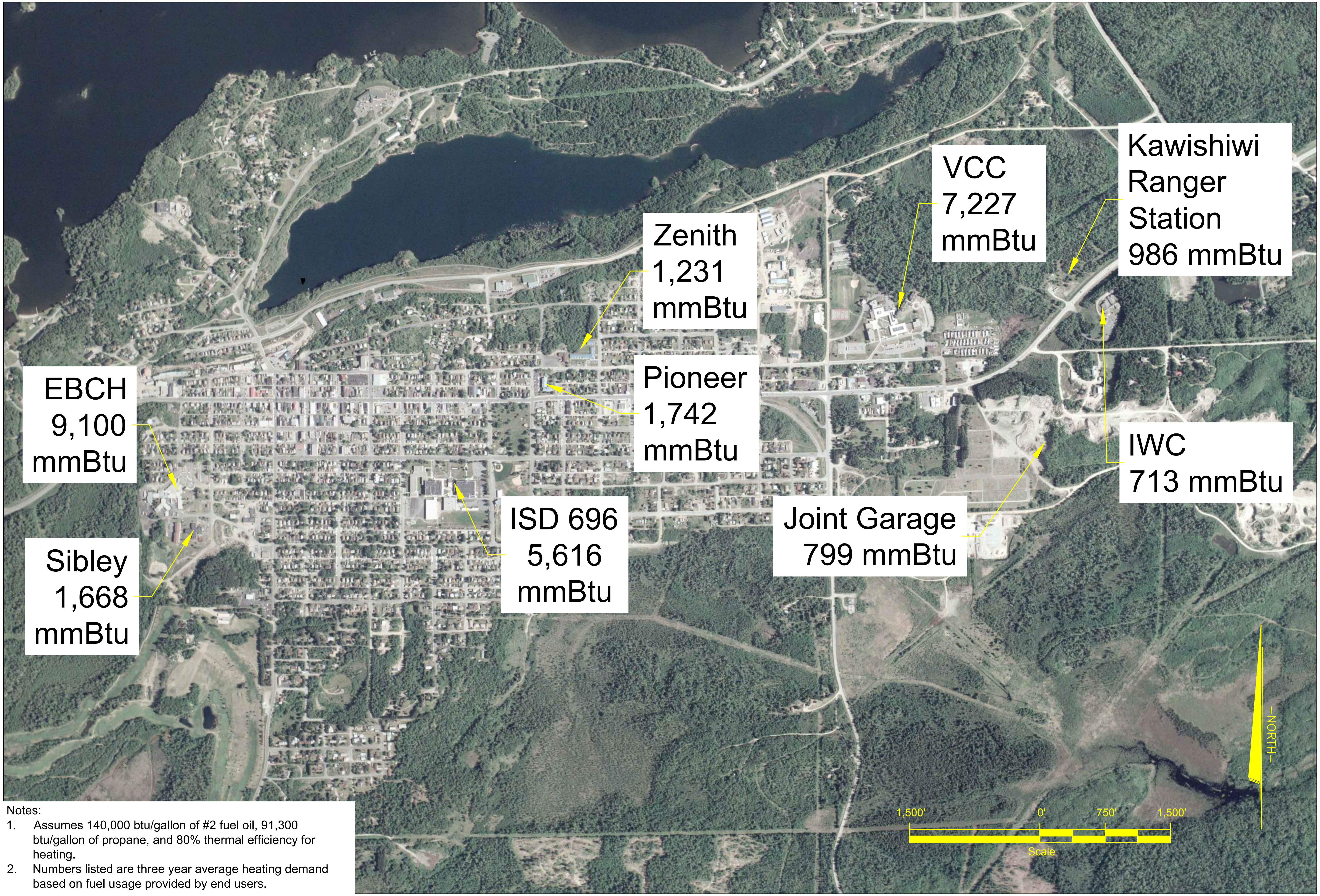
- Keeping dollars spent on energy within the local economy, between $30,000 and $140,000 annually, depending on option selected.
- Decreased dependence on imported oil by replacing fuel oil and propane use with renewable wood chip fuel;
- A hedge against the volatility of the fossil fuel market;
- A reduction in net CO_2 emissions of 553 metric tonnes for Site 1 and ranging from 1,321 – 2,740 metric tonnes for Site 2 depending on the option selected. Credits generated through this net reduction would be eligible for sale on the voluntary carbon market;
- Educational opportunities for local students and opportunities for eco-tourism.

The purpose of this study is to identify the benefits and costs of woody biomass system options serving the major thermal energy users within Ely. WERC recommends detailed investigation of the smaller residential and commercial loads within Ely, if it is determined the benefits warrant pursuit of a woody biomass project. WERC also recommends that personnel from the major users in Ely, MN visit existing biomass boiler installations to develop a detailed understanding of the equipment and its capabilities. WERC is available to assist in arranging tours of existing facilities. As Ely, MN continues to pursue biomass renewable energy options, WERC recommends that the next level of evaluation includes detailed consideration of the following items:

- System ownership and business model for ownership;
- Collection of energy use and energy system data for additional residential and commercial owners along the main district heating pipeline routes and potential adjustment to pipe and boiler sizing based on findings;
- Inclusion of additional heat users based on parameters set by acceptable economic returns for business models identified;
- Utilization of existing employees at major users to maintain equipment and comply with local boiler licensing requirements;
- Discussion of biomass plant siting with potential stakeholders within the city;
- Monitoring actual heating demand at major users to verify optimal biomass system sizing;
- Performance of site investigations (utility, geotechnical, topographic) for site selected based on stakeholder discussions, and further develop biomass project plant layout and capital costs based on investigation results;
- Identification of alternative funding sources (low interest loans, grants, and incentives).

Appendix A

Drawings



Notes:

1. Assumes 140,000 btu/gallon of #2 fuel oil, 91,300 btu/gallon of propane, and 80% thermal efficiency for heating.
2. Numbers listed are three year average heating demand based on fuel usage provided by end users.

Designed GJF 4-3-12
Drawn GJF 4-3-12
Checked DAW 4-4-12
Date
Job Class
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Title

Ely District Energy System

Ely, Minnesota

Heating Load Site Plan

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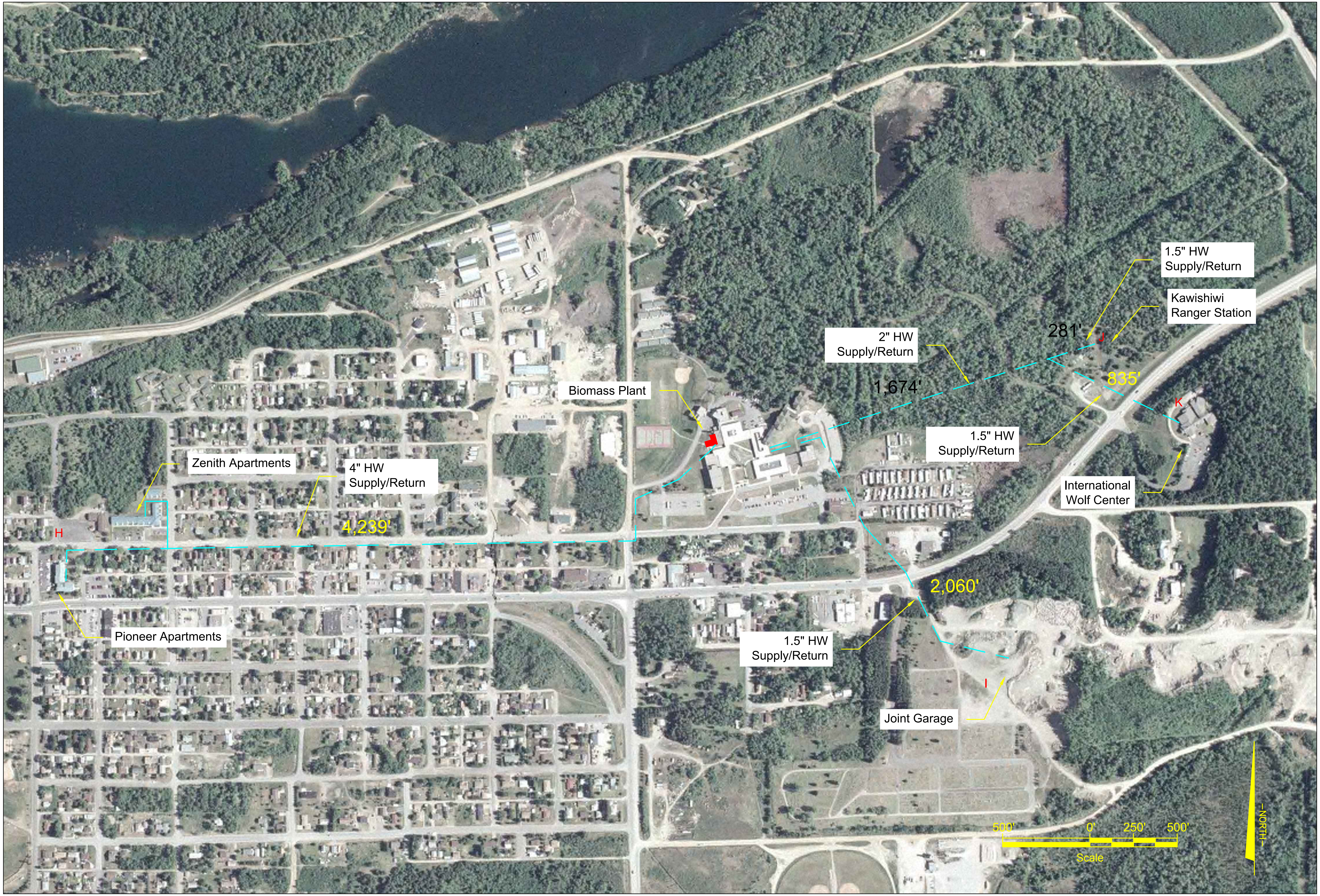
Appendix A.1



Ely District Energy System

Ely, Minnesota

Site 1: Site Plan

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Designed	GJF	4-3-12
Drawn	GJF	4-3-12
Checked	DAW	4-4-12

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Title ______ Job Class ______

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Appendix A.2

Designed GJF 4-3-12
Drawn GJF 4-3-12
Checked DAW 4-4-12
Approved
Date
Title
Job Class

Ely District Energy System
Ely, Minnesota

Site 2 : Site Plan
Option 2 and 4 Pipe Sizes

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Appendix A.3

Designed GJF 4-3-12
Drawn GJF 4-3-12
Checked DAW 4-4-12

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Ely District Energy System

Ely, Minnesota

Site 2 : Site Plan
Option 3 and 5 Pipe Sizes

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Designed GJF 4-3-12
Drawn GJF 4-3-12
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Title
Job Class

Ely District Energy System

Ely, Minnesota

Site 2 : Site Plan
Alternate Biomass Plant Location

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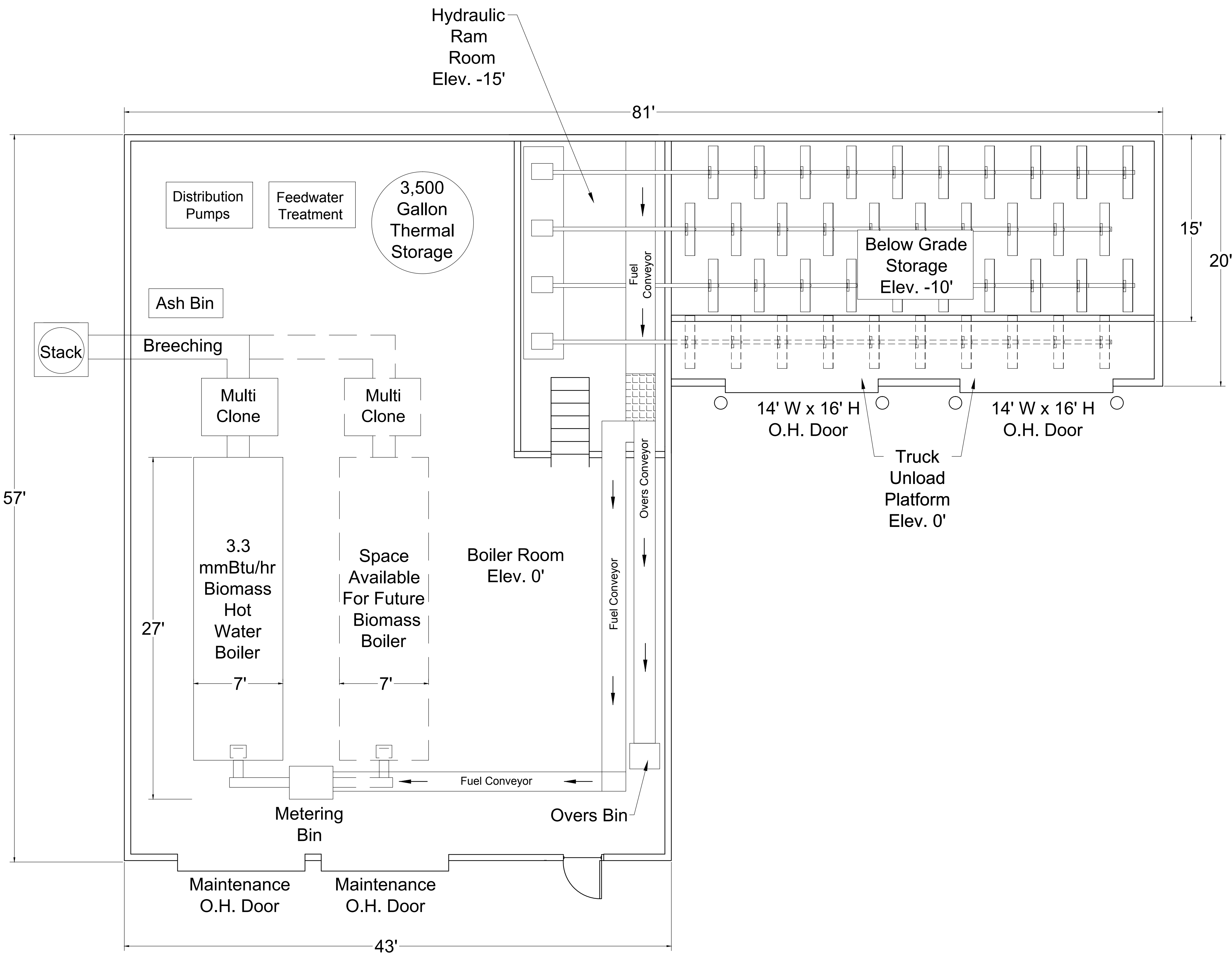
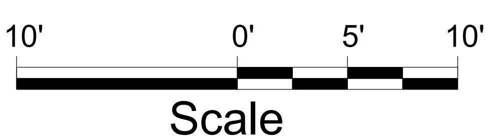
Appendix A.5





Note:
This drawing is a conceptual layout for the purposes of developing surveying and geo-technIcal investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.

Designed	GJF	5-1-12
Drawn	GJF	5-1-12
Checked	DAW	5-17-12

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Date
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Ely District Energy System
Ely, Minnesota

Option 1 Biomass Building Layout

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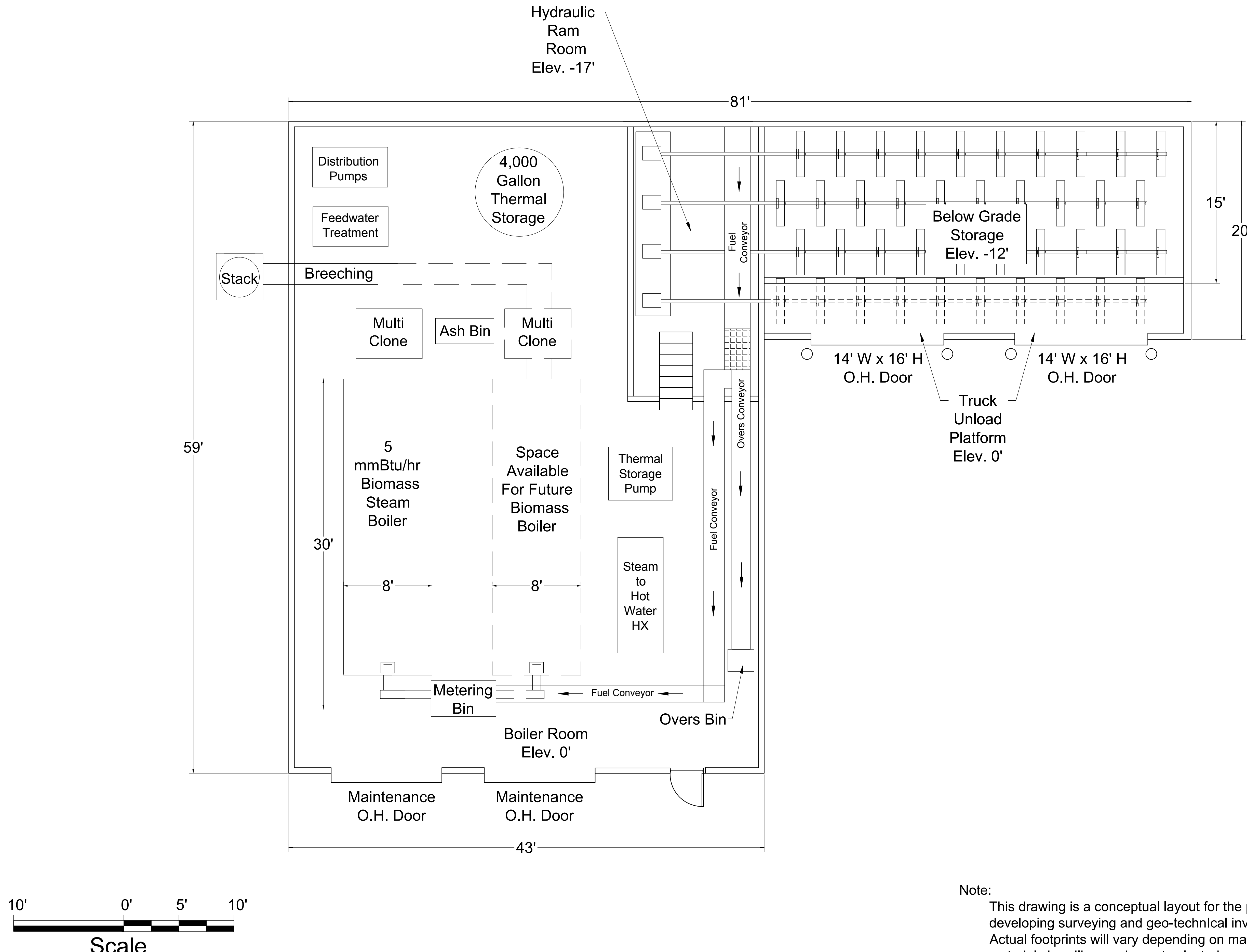

Note:
This drawing is a conceptual layout for the purposes of developing surveying and geo-technIcal investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.

Designed GJF 5-1-12
Drawn GJF 5-1-12
Checked DAW 5-17-12
Approved ______ Date ______
Title ______ Job Class ______

Ely District Energy System
Ely, Minnesota

Option 2 Biomass Building Layout

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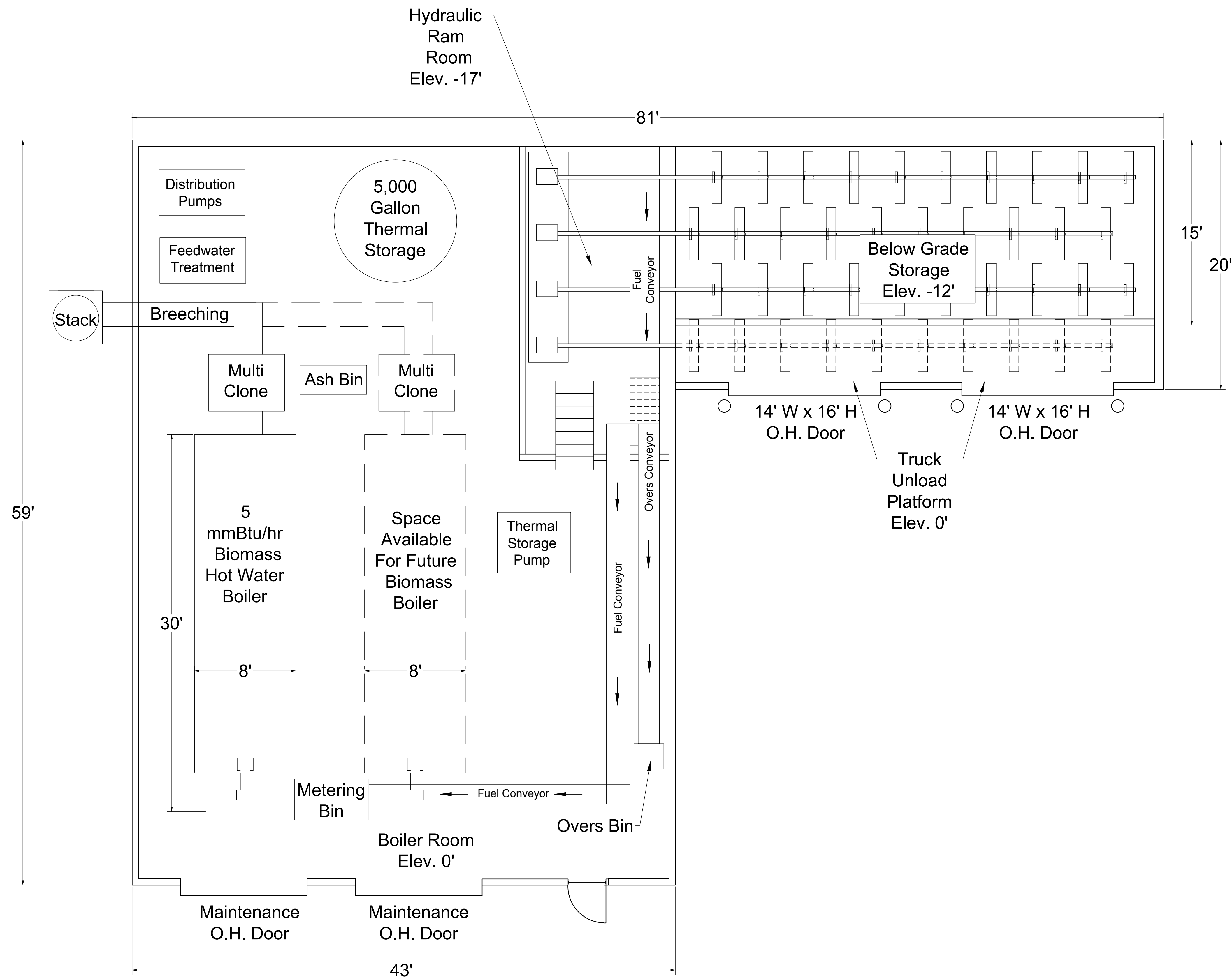

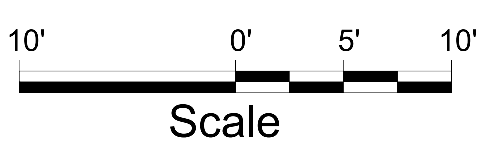

Note:

This drawing is a conceptual layout for the purposes of developing surveying and geo-technical investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.

Designed	GJF	5-1-12
Drawn	GJF	5-1-12
Checked	DAW	5-17-12

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Ely District Energy System

Ely, Minnesota

Option 3 Biomass Building Layout

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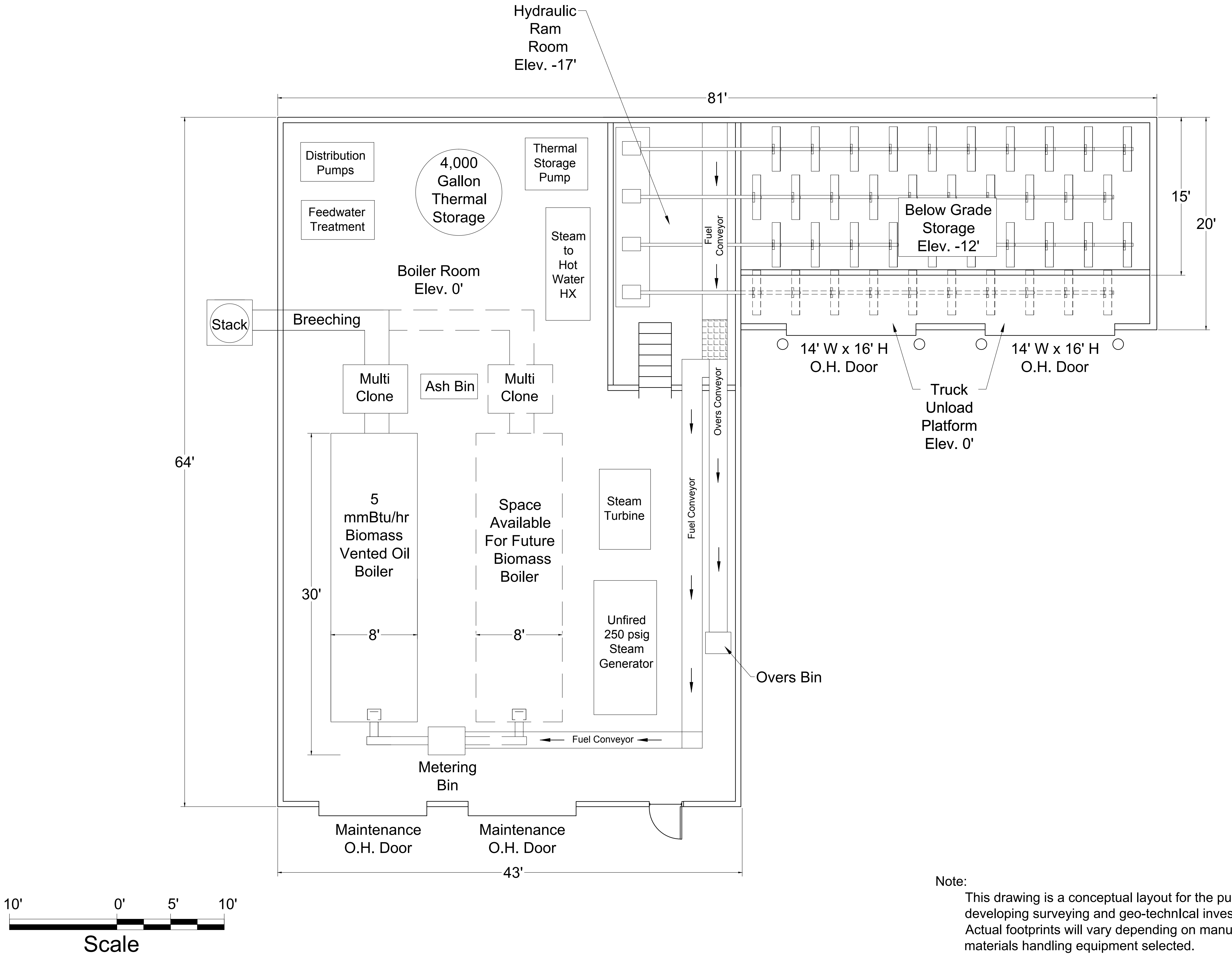

Note:

This drawing is a conceptual layout for the purposes of developing surveying and geo-technIcal investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.

Designed GJF 5-1-12
Drawn GJF 5-1-12
Checked DAW 5-17-12
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Title
Date
Job Class

Ely District Energy System
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Option 4 Biomass Building Layout

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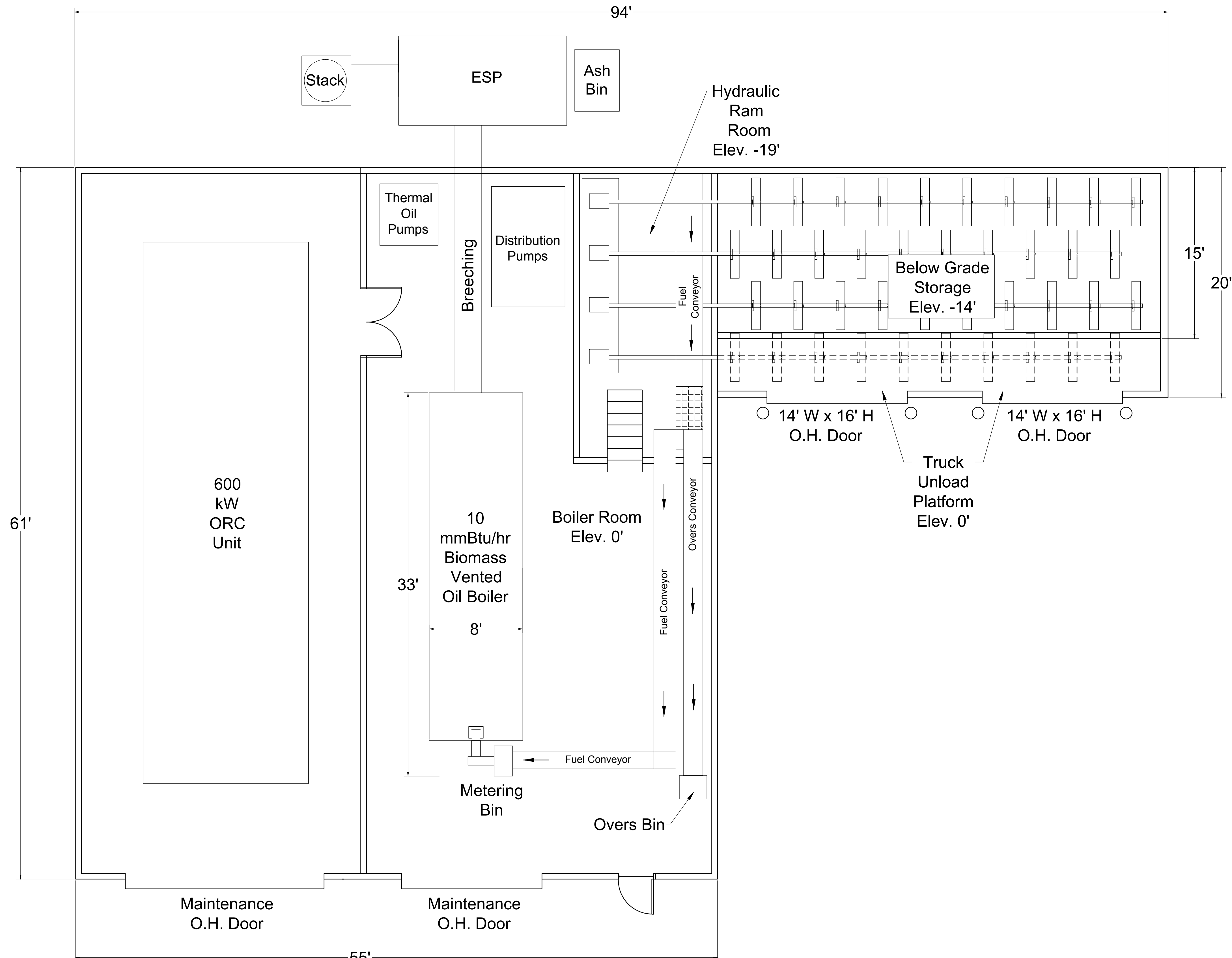

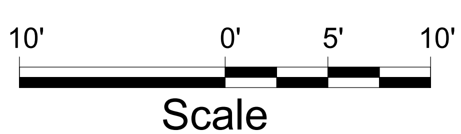

Note:

This drawing is a conceptual layout for the purposes of developing surveying and geo-technIcal investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.

Designed	GJF	5-1-12
Drawn	GJF	5-1-12
Checked	DAW	5-17-12

Approved ____ Date ____

Title ____ Job Class ____

Ely District Energy System

Ely, Minnesota

Option 5 Biomass Building Layout

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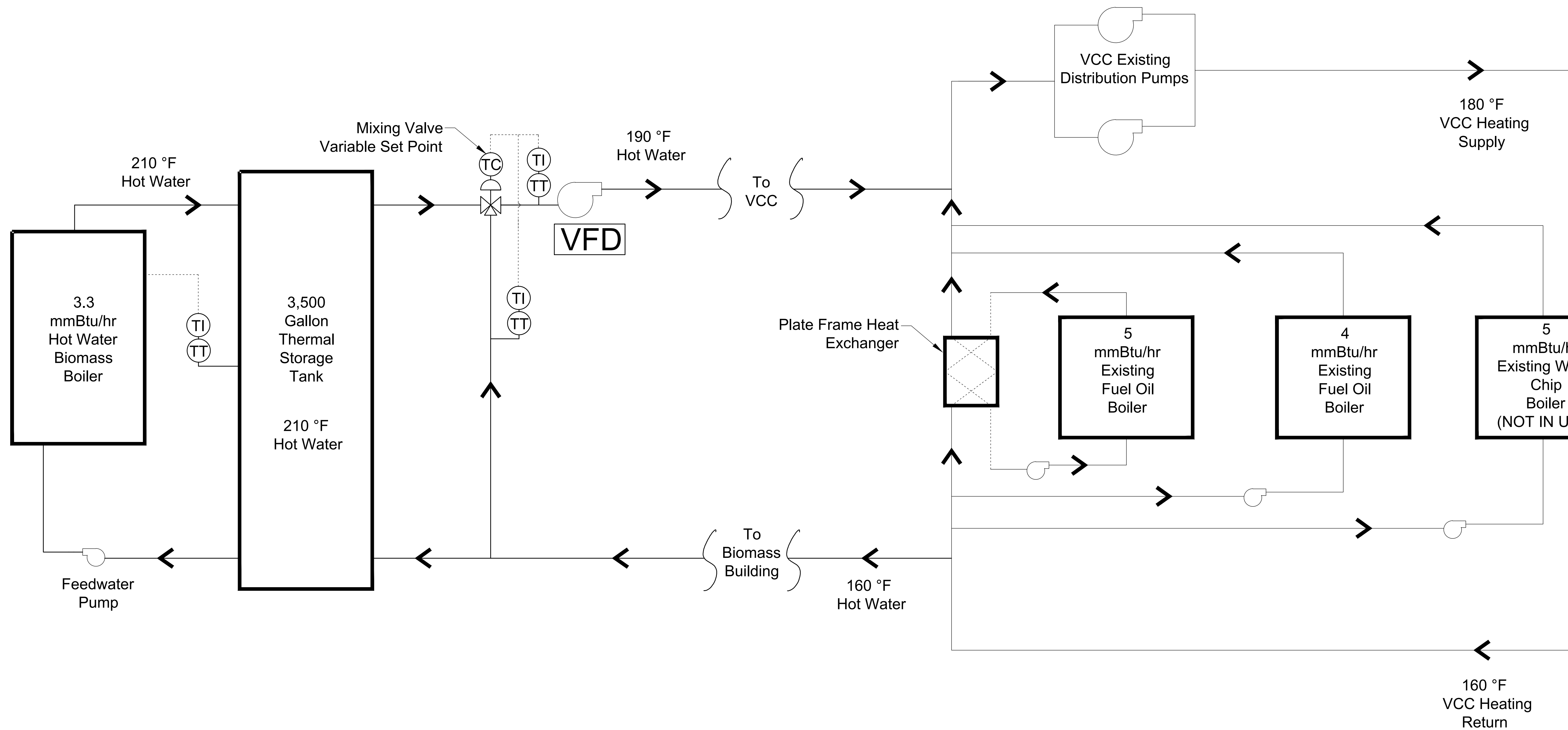
Appendix A.10



Legend:

	Three-way Control Valve
TT	Temperature transmitter
TI	Temperature indicator
TC	Temperature control
VFD	Variable Frequency Drive

Notes:

1. This is a conceptual drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Mixing valve blends return water with high temperature water from thermal storage to meet variable set point. Variable set point allows optimization thermal storage capacity and fuel offset.
3. Existing boilers remain to provide full backup and peaking.

Designed GJF 5-1-12
Drawn GJF 5-1-12
Checked DAW 5-17-12

Approved ____ Date ____
Title ____ Job Class ____

Ely District Energy System

Ely, Minnesota

Option 1 Biomass System Schematic

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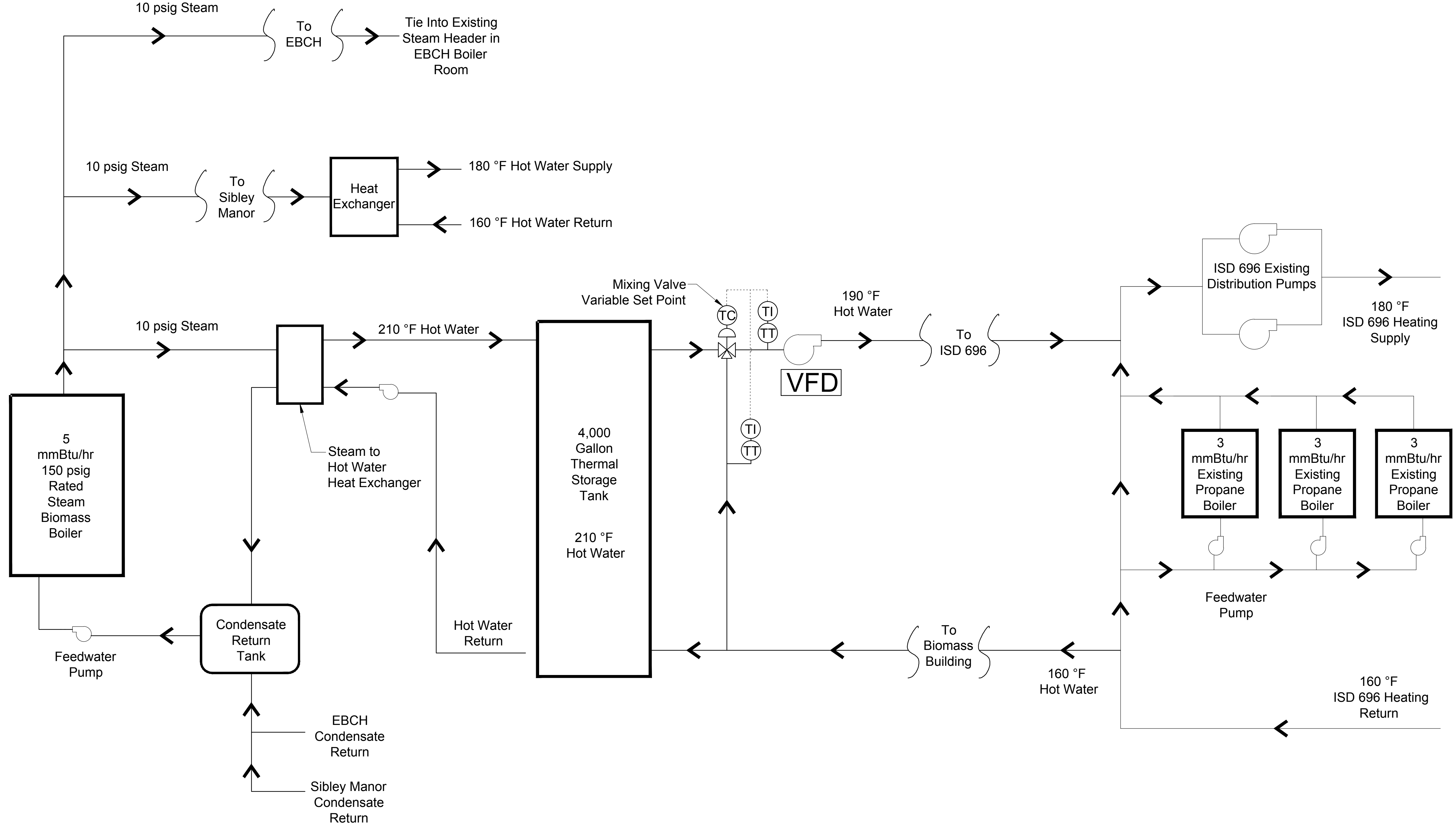

Legend:

Three-way Control Valve
TT Temperature transmitter
TI Temperature indicator
TC Temperature control
VFD Variable Frequency Drive

Notes:
1. This is a conceptual drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Mixing valve blends return water with high temperature water from thermal storage to meet variable set point. Variable set point allows optimization thermal storage capacity and fuel offset.
3. Existing boilers remain to provide full backup and peaking.

Designed GJF 5-1-12
Drawn GJF 5-1-12
Checked DAW 5-17-12
Approved
Date
Title
Job Class

Ely District Energy System
Ely, Minnesota

Option 2 Biomass System Schematic

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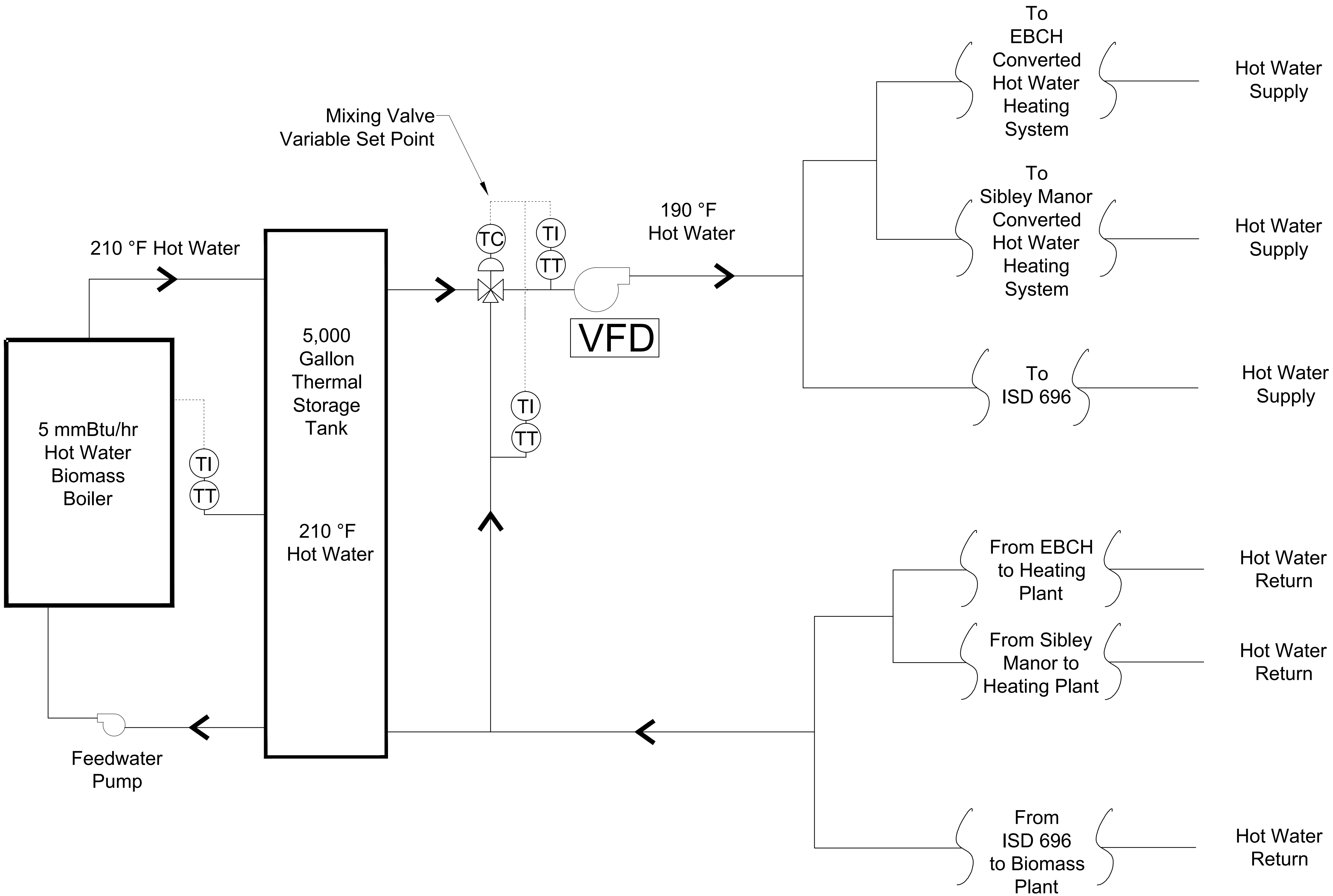

Legend:

	Three-way Control Valve
TT	Temperature transmitter
TI	Temperature indicator
TC	Temperature control

Notes:

1. This is a conceptual drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Existing boilers remain to provide full backup and peaking.

Designed GJF 5–1–12
Drawn GJF 5–1–12
Checked DAW 5–17–12

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Title ______ Job Class ______

Ely District Energy System
Ely, Minnesota

Option 3 Biomass System Schematic

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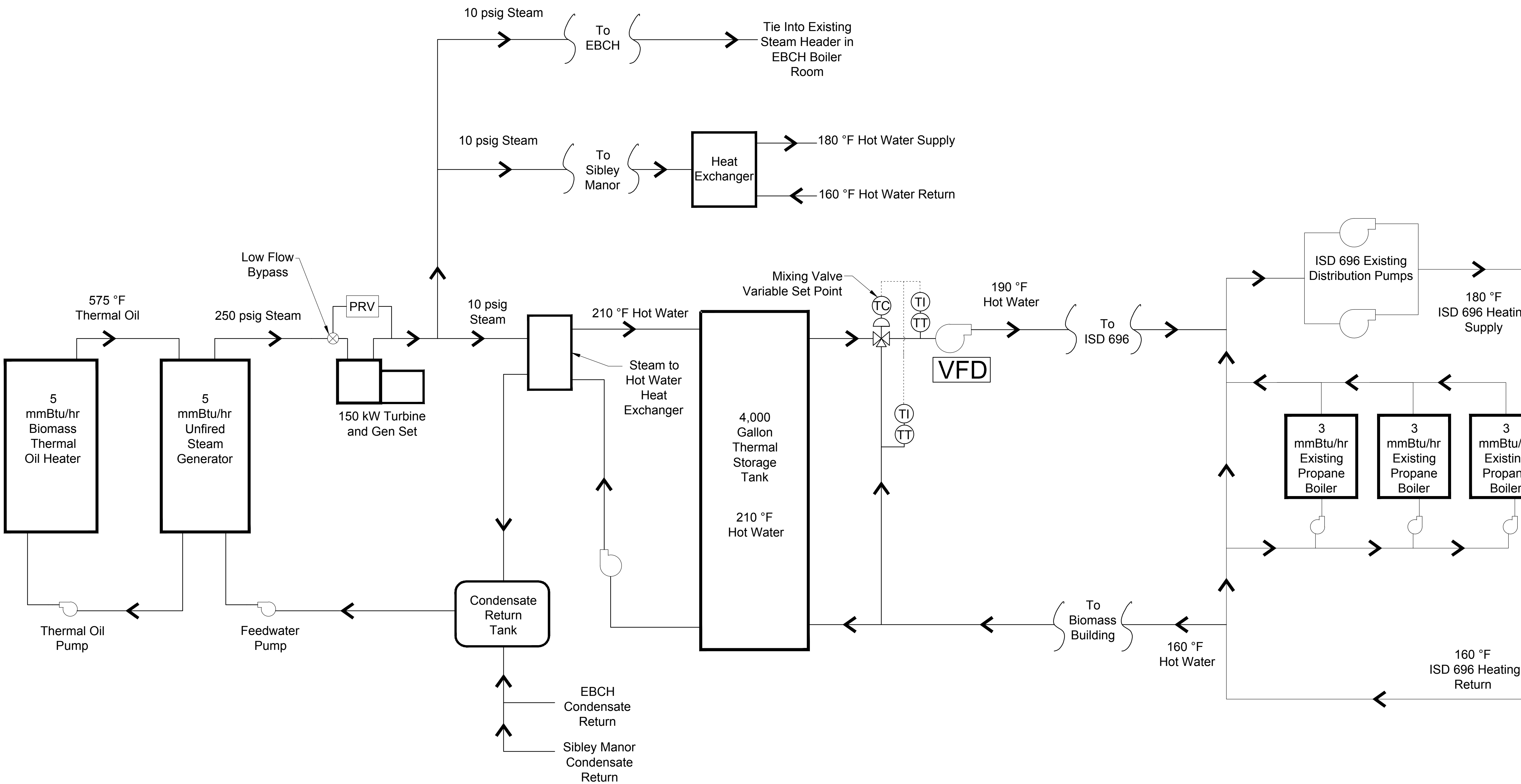
Date	Description	Approved

Appendix A.13



Legend:

Three-way Control Valve

TT Temperature transmitter

TI Temperature indicator

TC Temperature control

VFD Variable Frequency Drive

PRV Pressure Reducing Valve

Notes:

1. This is a conceptual drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Mixing valve blends return water with high temperature water from thermal storage to meet variable set point. Variable set point allows optimization thermal storage capacity and fuel offset.
3. Existing boilers remain to provide full backup and peaking.

Designed	GJF	5-1-12
Drawn	GJF	5-1-12
Checked	DAW	5-17-12

Date ____ Job Class ____

Approved ____ Title ____

Ely District Energy System

Ely, Minnesota

Option 4 Biomass System Schematic

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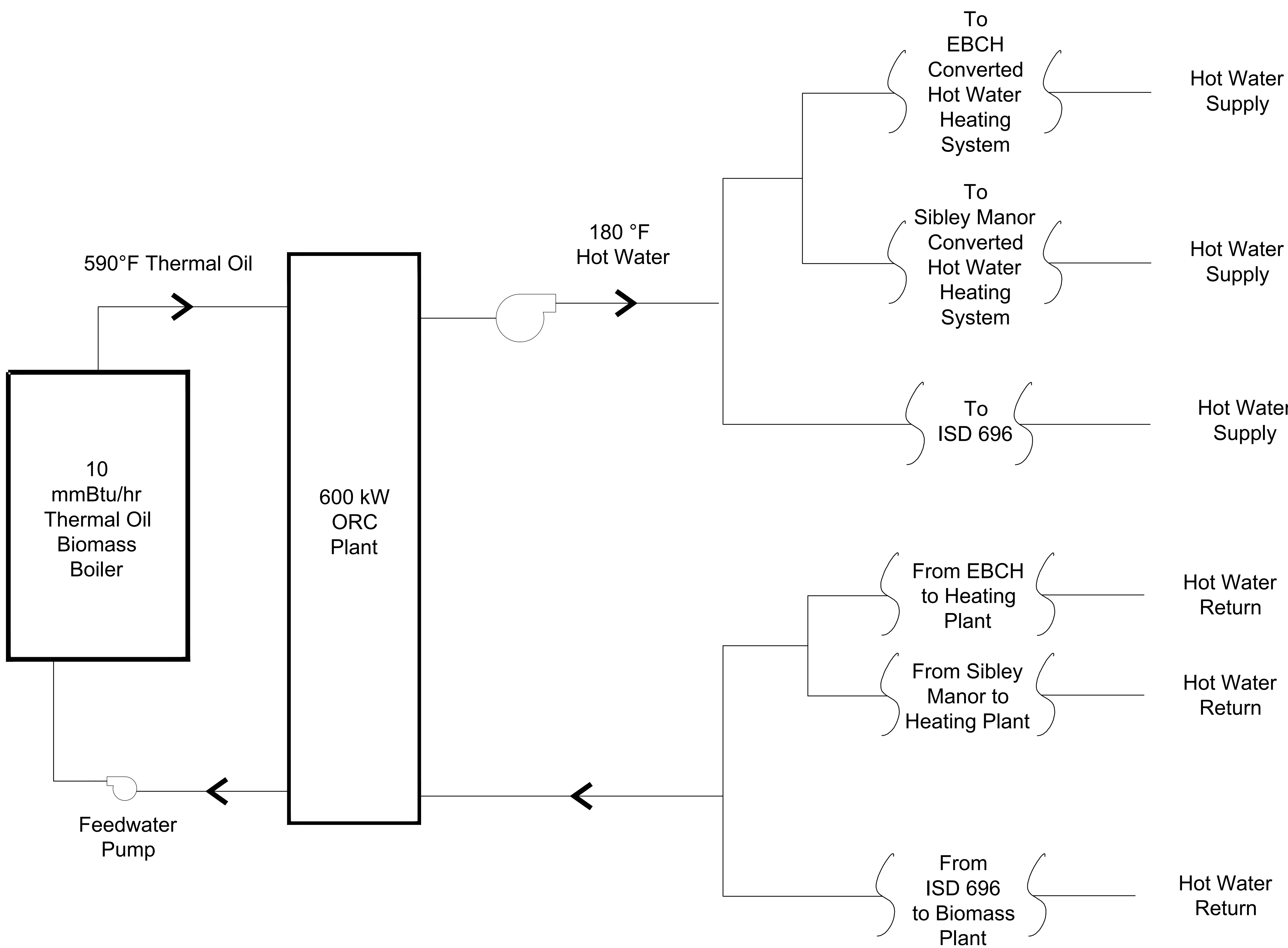

Legend:

- Three-way Control Valve
- TT Temperature transmitter
- TI Temperature indicator
- TC Temperature control

Notes:
1. This is a conceptual drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Existing boilers remain to provide full backup and peaking.

Designed	GJF	5-1-12
Drawn	GJF	5-1-12
Checked	DAW	5-17-12

Approved ______ Date ______

Title ______ Job Class ______

Ely District Energy System

Ely, Minnesota

Option 5 Biomass System Schematic

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Appendix B

Capital Cost Estimates

- B.1 : Option 1 – Site 1: Biomass Heating Project Cost Estimate
- B.2 : Option 2 – Site 2: Biomass Heating (Steam and Hot Water) Project Cost Estimate
- B.3 : Option 3 – Site 2: Biomass Heating (Hot Water) Project Cost Estimate
- B.4 : Option 4 – Site 2: Biomass Backpressure Steam CHP Project Cost Estimate
- B.5 : Option 5 – Site 2: Biomass ORC CHP Project Cost Estimate

Option 1 - Site 1: Biomass Heating (Hot Water)

Pre-Feasibility Level Capital Cost Estimate

Biomass Boiler Manufacturer Contract

Line Item		Cost[6,8]
3.3 mmBtu/hr, biomass combustion unit, hot water boiler, boiler room controls, installed		$ 300,000
Fuel bunker receiving, storage, material transfer, installed		$ 150,000
3,500 gallon thermal storage tank		$ 35,000
Biomass boiler room equipment and specialties, installed		$ 75,000
Boiler platform, stairs, and ladders installed		$ 15,000
Sub-total		$ 575,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 11,500
Total Boiler Manufacturer Contract		**$ 586,500**

General Contract

Line Item		Cost[8]
[1,5]Biomass boiler building and chip storage pit (2,500 sf @ $150 per sf)		$ 375,000
Site work		$ 100,000
[2]Interconnection with VCC boiler plant		$ 30,000
Electrical		$ 150,000
Mechanical		$ 200,000
Sub-Total		$ 855,000
Contractor profit overhead and insurance	*16%*	$ 136,800
Sub-Total		$ 991,800
Contingency	*15%*	*$ 148,770*
Total General Contract Building and Site		**$ 1,140,570**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 1,727,070
Professional Services [3]	*12%*	*$ 207,248*
Total Project Cost[4,6,7,8]		**$ 1,934,318**

Notes:

1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.

2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.

3 - Professional Services includes engineering, permitting, legal, and project management.

4 - Assumes that biomass boiler and general contract are bid seperately.

5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.

6 - Estimate is based on competitive bidding.

7 - Integration of the biomass system into the existing BMS controls is not required and not included in the project cost.

8 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Option 2 - Site 2: Biomass Heating (Steam and Hot Water)

Pre-Feasibility Level Capital Cost Estimate

Biomass Boiler Manufacturer Contract

Line Item		Cost[1,2,3]
5 mmBtu/hr, biomass combustion unit, 30 psig steam boiler, boiler controls, installed		$ 375,000
Fuel bunker receiving, storage, material transfer, installed		$ 175,000
4,000 gallon thermal storage tank serving ISD 696 system		$ 40,000
Biomass boiler room equipment and specialties, installed		$ 125,000
Boiler platform, stairs, and ladders installed		$ 20,000
Sub-total		$ 735,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 14,700
Total Boiler Manufacturer Contract		**$ 749,700**

General Contract

Line Item		Cost
[4]Biomass boiler building and chip storage pit (3,000 sf @ $150 per sf)		$ 450,000
Site work		$ 130,000
[5]Buried pre-insulated distribution piping, installed (3,200 ft @ $200 per ft)		$ 640,000
Interconnection with EBCH steam system		$ 30,000
Interconnection with ISD 696 hot water distribution system		$ 50,000
Electrical		$ 350,000
Mechanical		$ 300,000
Radiator for heat rejection, installed		$ 20,000
Sub-Total		$ 1,970,000
Contractor profit overhead and insurance	*16%*	$ 315,200
Sub-Total		$ 2,285,200
Contingency	*15%*	*$ 342,780*
Total General Contract Building and Site		**$ 2,627,980**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 3,377,680
Professional Services [6]	*12%*	*$ 405,322*
Total Project Cost[6,7,8]		**$ 3,783,002**

Notes:

1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.

2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.

3 - Professional Services includes engineering, permitting, legal, and project management.

4 - Assumes that biomass boiler and general contract are bid seperately.

5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.

6 - Estimate is based on competitive bidding.

7 - Integration of the biomass system into the existing BMS controls is not required and not included in the project cost.

8 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Option 3 - Site 2: Biomass Heating (Hot Water)

Pre-Feasibility Level Capital Cost Estimate

Biomass Boiler Manufacturer Contract

Line Item		Cost[1,2,3]
5 mmBtu/hr, biomass combustion unit, hot water boiler, boiler room controls, installed		$ 350,000
Fuel bunker receiving, storage, material transfer, installed		$ 175,000
5,000 gallon thermal storage tank serving ISD 696 system		$ 50,000
Biomass boiler room equipment and specialties, installed		$ 125,000
Boiler platform, stairs, and ladders installed		$ 20,000
Sub-total		$ 720,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 14,400
Total Boiler Manufacturer Contract		**$ 734,400**

General Contract

Line Item		Cost
[4]Biomass boiler building and chip storage pit (3,000 sf @ $150 per sf)		$ 450,000
Site work		$ 130,000
[5]Buried pre-insulated distribution piping, installed (3,200 ft @ $200 per ft)		$ 640,000
Interconnection with EBCH steam system		$ 30,000
Interconnection with ISD 696 hot water distribution system		$ 50,000
Electrical		$ 350,000
Mechanical		$ 300,000
Radiator for heat rejection, installed		$ 20,000
Sub-Total		$ 1,970,000
Contractor profit overhead and insurance	*16%*	$ 315,200
Sub-Total		$ 2,285,200
Contingency	*15%*	*$ 342,780*
Total General Contract Building and Site		**$ 2,627,980**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 3,362,380
Professional Services [6]	*12%*	*$ 403,486*
Total Project Cost[6,7,8]		**$ 3,765,866**

Notes:

1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.

2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.

3 - Professional Services includes engineering, permitting, legal, and project management.

4 - Assumes that biomass boiler and general contract are bid seperately.

5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.

6 - Estimate is based on competitive bidding.

7 - Integration of the biomass system into the existing BMS controls is not required and not included in the project cost.

8 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Option 4 - Site 2: Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water)
Pre-Feasibility Level Capital Cost Estimate

Biomass Boiler Manufacturer Contract

Line Item		Cost[1,2,3]
5 mmBtu/hr, biomass combustion unit, thermal oil boiler, boiler controls, installed		$ 475,000
Fuel bunker receiving, storage, material transfer, installed		$ 175,000
4,000 gallon thermal storage tank serving ISD 696 system		$ 40,000
Biomass boiler room equipment and specialties, installed		$ 175,000
Boiler platform, stairs, and ladders installed		$ 20,000
Sub-total		$ 885,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 17,700
Total Boiler Manufacturer Contract		**$ 902,700**

General Contract

Line Item		Cost
[4]Biomass boiler building and chip storage pit (3,000 sf @ $150 per sf)		$ 450,000
Site work		$ 130,000
[5]Buried pre-insulated distribution piping, installed (3,200 ft @ $200 per ft)		$ 640,000
Interconnection with EBCH steam system		$ 30,000
Interconnection with ISD 696 hot water distribution system		$ 50,000
5 mmBtu/hr unfired steam generator		$ 175,000
150 kW backpressure steam turbine and switchgear, installed		$ 250,000
Electrical		$ 400,000
Mechanical		$ 300,000
Radiator for heat rejection, installed		$ 20,000
Sub-Total		$ 2,445,000
Contractor profit overhead and insurance	*16%*	$ 391,200
Sub-Total		$ 2,836,200
Contingency	*15%*	*$ 425,430*
Total General Contract Building and Site		**$ 3,261,630**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 4,164,330
Professional Services [6]	*12%*	*$ 499,720*
Total Project Cost[6,7,8]		**$ 4,664,050**

Notes:

1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.

2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.

3 - Professional Services includes engineering, permitting, legal, and project management.

4 - Assumes that biomass boiler and general contract are bid seperately.

5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.

6 - Estimate is based on competitive bidding.

7 - Integration of the biomass system into the existing BMS controls is not required and not included in the project cost.

8 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Option 5 - Site 2: Biomass ORC CHP (Thermal Oil and Hot Water)

Pre-Feasibility Level Capital Cost Estimate

Biomass Boiler Manufacturer Contract

Line Item		Cost[1,2,3]
10 mmBtu/hr, biomass combustion unit, thermal oil boiler, boiler controls, installed		$ 750,000
Fuel bunker receiving, storage, material transfer, installed		$ 175,000
8,000 gallon thermal storage tank serving ISD 696 and EBCH systems		$ 70,000
Biomass boiler room equipment and specialties, installed		$ 200,000
Dry ESP, Installed		$ 350,000
Boiler platform, stairs, and ladders installed		$ 25,000
Sub-total		$ 1,570,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 31,400
Total Boiler Manufacturer Contract		**$ 1,601,400**

General Contract

Line Item		Cost
[4]Biomass boiler building and chip storage pit (3,500 sf @ $150 per sf)		$ 525,000
Site work		$ 130,000
[5]Buried pre-insulated distribution piping, installed		$ 640,000
Conversion of EBCH distribution from steam to hot water (Not Included in this study)		$ -
Interconnection with ISD 696 hot water distribution system		$ 30,000
600 kW ORC Turbine and generator, installed		$ 1,400,000
Electrical		$ 500,000
Mechanical		$ 350,000
Radiator for heat rejection, installed		$ 20,000
Sub-Total		$ 3,595,000
Contractor profit overhead and insurance	*16%*	$ 575,200
Sub-Total		$ 4,170,200
Contingency	*15%*	*$ 625,530*
Total General Contract Building and Site		**$ 4,795,730**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 6,397,130
Professional Services [6]	*12%*	*$ 767,656*
Total Project Cost[6,7,8]		**$ 7,164,786**

Notes:

1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.

2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.

3 - Professional Services includes engineering, permitting, legal, and project management.

4 - Assumes that biomass boiler and general contract are bid seperately.

5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.

6 - Estimate is based on competitive bidding.

7 - Integration of the biomass system into the existing BMS controls is not required and not included in the project cost.

8 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Appendix C

Detailed Financial Analysis

- C.1 : 20 yr. 4.5% Financing-Option 1
- C.2 : Sensitivity Analysis-Option 1
- C.3 : 20 yr. 4.5% Financing -Option 2
- C.4 : Sensitivity Analysis-Option 2
- C.5 : 20 yr. 4.5% Financing -Option 3
- C.6 : Sensitivity Analysis-Option 3
- C.7 : 20 yr. 4.5% Financing -Option 4
- C.8 : Sensitivity Analysis-Option 4
- C.9 : 20 yr. 4.5% Financing -Option 5
- C.10 : Sensitivity Analysis-Option 5

Option 1 - Site 1 : Biomass Heating (Hot Water)
20-year, 4.5% Financing Analysis

Input Variables	Value	Units
Project Costs Financed	1,934,318	$
Financing Term	20	# years
Financing Rate (apr)	4.5%	Percent
3 Year Avg Fuel Oil Usage	62,357	Gallons
2010 Propane Usage	3,331	Gallons
Current Fuel Oil Price	3.24	$/gallon
Current Propane Price	1.79	$/gallon
Wood Chip Usage	878	tons/yr
Year 1 Wood Chip Purchase Price	$ 30.00	$/ton
Annual Fossil Fuel Usage w/ Wood System	15%	Percent
Fossil Fuel Inflation Rate (apr)	3.3%	Percent
Wood Chip Inflation Rate (apr)	2.7%	Percent
General Inflation Rate (apr)	2.7%	Percent
Added Annual O&M Costs for Biomass Plant	$ 10,600	$/year

Year	Total Fossil Fuel Cost, Current System	Wood Chip Cost	Fossil Fuel Cost w/ Wood System	Added O&M Cost	Net Operating Savings	Annual Financing Payment	Net Cash Flow	Present Value of Net Cash Flow
1	$ 208,005	$ (26,331)	$ (31,201)	$ (10,600)	$ 139,873	$ (148,703)	$ (8,830)	$ (8,830)
2	$ 214,869	$ (27,042)	$ (32,230)	$ (10,886)	$ 144,710	$ (148,703)	$ (3,993)	$ (3,889)
3	$ 221,960	$ (27,773)	$ (33,294)	$ (11,180)	$ 149,713	$ (148,703)	$ 1,011	$ 957
4	$ 229,285	$ (28,522)	$ (34,393)	$ (11,482)	$ 154,888	$ (148,703)	$ 6,185	$ 5,709
5	$ 236,851	$ (29,292)	$ (35,528)	$ (11,792)	$ 160,239	$ (148,703)	$ 11,536	$ 10,369
6	$ 244,667	$ (30,083)	$ (36,700)	$ (12,110)	$ 165,773	$ (148,703)	$ 17,070	$ 14,940
7	$ 252,741	$ (30,896)	$ (37,911)	$ (12,437)	$ 171,497	$ (148,703)	$ 22,794	$ 19,426
8	$ 261,082	$ (31,730)	$ (39,162)	$ (12,773)	$ 177,417	$ (148,703)	$ 28,714	$ 23,827
9	$ 269,697	$ (32,587)	$ (40,455)	$ (13,118)	$ 183,538	$ (148,703)	$ 34,835	$ 28,148
10	$ 278,597	$ (33,466)	$ (41,790)	$ (13,472)	$ 189,869	$ (148,703)	$ 41,166	$ 32,389
11	$ 287,791	$ (34,370)	$ (43,169)	$ (13,836)	$ 196,417	$ (148,703)	$ 47,714	$ 36,553
12	$ 297,288	$ (35,298)	$ (44,593)	$ (14,210)	$ 203,188	$ (148,703)	$ 54,485	$ 40,643
13	$ 307,099	$ (36,251)	$ (46,065)	$ (14,593)	$ 210,190	$ (148,703)	$ 61,487	$ 44,661
14	$ 317,233	$ (37,230)	$ (47,585)	$ (14,987)	$ 217,431	$ (148,703)	$ 68,728	$ 48,608
15	$ 327,702	$ (38,235)	$ (49,155)	$ (15,392)	$ 224,920	$ (148,703)	$ 76,217	$ 52,487
16	$ 338,516	$ (39,267)	$ (50,777)	$ (15,807)	$ 232,664	$ (148,703)	$ 83,961	$ 56,301
17	$ 349,687	$ (40,328)	$ (52,453)	$ (16,234)	$ 240,672	$ (148,703)	$ 91,969	$ 60,049
18	$ 361,227	$ (41,416)	$ (54,184)	$ (16,673)	$ 248,954	$ (148,703)	$ 100,251	$ 63,736
19	$ 373,147	$ (42,535)	$ (55,972)	$ (17,123)	$ 257,518	$ (148,703)	$ 108,815	$ 67,362
20	$ 385,461	$ (43,683)	$ (57,819)	$ (17,585)	$ 266,374	$ (148,703)	$ 117,671	$ 70,929
21	$ 398,181	$ (44,862)	$ (59,727)	$ (18,060)	$ 275,532		$ 275,532	$ 161,719
22	$ 411,321	$ (46,074)	$ (61,698)	$ (18,547)	$ 285,002		$ 285,002	$ 162,879
23	$ 424,895	$ (47,318)	$ (63,734)	$ (19,048)	$ 294,795		$ 294,795	$ 164,047
24	$ 438,916	$ (48,595)	$ (65,837)	$ (19,563)	$ 304,921		$ 304,921	$ 165,221
25	$ 453,401	$ (49,907)	$ (68,010)	$ (20,091)	$ 315,392		$ 315,392	$ 166,402
							Net Present Value	**$ 1,484,642**

Option 1 - Site 1 : Biomass Heating (Hot Water)
Sensitivity Analysis

Table Shows Sensitivity of Annual Operating Savings to Changes in Fossil Fuel and Wood Chip Prices

Fossil Fuel Price Change

Price of Wood Chips - per Ton	-15%	-10%	-5%	0%	5%	10%	15%
$5	$135,295	$144,135	$152,976	$161,816	$170,656	$179,496	$188,337
$10	$130,907	$139,747	$148,587	$157,427	$166,268	$175,108	$183,948
$15	$126,518	$135,358	$144,199	$153,039	$161,879	$170,719	$179,559
$20	$122,130	$130,970	$139,810	$148,650	$157,490	$166,331	$175,171
$25	$117,741	$126,581	$135,421	$144,262	$153,102	$161,942	$170,782
$30	$113,352	$122,193	$131,033	$139,873	$148,713	$157,553	$166,394
$35	$108,964	$117,804	$126,644	$135,484	$144,325	$153,165	$162,005
$40	$104,575	$113,415	$122,256	$131,096	$139,936	$148,776	$157,617
$45	$100,187	$109,027	$117,867	$126,707	$135,548	$144,388	$153,228
$50	$95,798	$104,638	$113,479	$122,319	$131,159	$139,999	$148,839
$55	$91,410	$100,250	$109,090	$117,930	$126,770	$135,611	$144,451
$60	$87,021	$95,861	$104,701	$113,542	$122,382	$131,222	$140,062
$65	$82,632	$91,473	$100,313	$109,153	$117,993	$126,833	$135,674
$70	$78,244	$87,084	$95,924	$104,764	$113,605	$122,445	$131,285

**Notes: All other costs fixed. Excludes financing costs.*

Option 2 - Site 2 : Biomass Heating (Steam and Hot Water)
20-year, 4.5% Financing Analysis

Input Variables	Value	Units
Project Costs Financed	3,783,002	$
Financing Term	20	# years
Financing Rate (apr)	4.5%	Percent
EBCH 3 Year Avg Fuel Oil Usage	81,246	Gallons
ISD696 3 Year Avg Propane Usage	76,886	Gallons
Sibley 2011 Propane Usage	22,843	Gallons
EBCH Current Fuel Oil Price	3.20	$/gallon
ISD 696 Current Propane Price	1.72	$/gallon
Sibley Current Propane Price	1.80	$/gallon
Wood Chip Usage	2,924	tons/yr
Year 1 Wood Chip Purchase Price	$ 30.00	$/ton
Annual Fossil Fuel Usage w/ Wood System	5%	Percent
Fossil Fuel Inflation Rate (apr)	3.3%	Percent
Wood Chip Inflation Rate (apr)	2.7%	Percent
General Inflation Rate (apr)	2.7%	Percent
Added Annual O&M Costs for Biomass Plant	$ 18,200	$/year

Year	Total Fossil Fuel Cost, Current System	Wood Chip Cost	Fossil Cost w/ Wood System	Added O&M Cost	Net Operating Savings	Annual Financing Payment	Net Cash Flow	Present Value of Net Cash Flow
1	$ 433,461	$ (87,734)	$ (21,673)	$ (18,200)	$ 305,854	$ (290,823)	$ 15,031	$ 15,031
2	$ 447,765	$ (90,103)	$ (22,388)	$ (18,691)	$ 316,583	$ (290,823)	$ 25,760	$ 25,082
3	$ 462,541	$ (92,535)	$ (23,127)	$ (19,196)	$ 327,683	$ (290,823)	$ 36,860	$ 34,947
4	$ 477,805	$ (95,034)	$ (23,890)	$ (19,714)	$ 339,167	$ (290,823)	$ 48,344	$ 44,630
5	$ 493,573	$ (97,600)	$ (24,679)	$ (20,247)	$ 351,048	$ (290,823)	$ 60,225	$ 54,136
6	$ 509,861	$ (100,235)	$ (25,493)	$ (20,793)	$ 363,339	$ (290,823)	$ 72,517	$ 63,472
7	$ 526,686	$ (102,941)	$ (26,334)	$ (21,355)	$ 376,056	$ (290,823)	$ 85,233	$ 72,641
8	$ 544,067	$ (105,721)	$ (27,203)	$ (21,931)	$ 389,211	$ (290,823)	$ 98,389	$ 81,648
9	$ 562,021	$ (108,575)	$ (28,101)	$ (22,523)	$ 402,821	$ (290,823)	$ 111,999	$ 90,499
10	$ 580,568	$ (111,507)	$ (29,028)	$ (23,132)	$ 416,901	$ (290,823)	$ 126,078	$ 99,198
11	$ 599,726	$ (114,517)	$ (29,986)	$ (23,756)	$ 431,466	$ (290,823)	$ 140,644	$ 107,749
12	$ 619,517	$ (117,609)	$ (30,976)	$ (24,398)	$ 446,534	$ (290,823)	$ 155,712	$ 116,156
13	$ 639,961	$ (120,785)	$ (31,998)	$ (25,056)	$ 462,122	$ (290,823)	$ 171,300	$ 124,425
14	$ 661,080	$ (124,046)	$ (33,054)	$ (25,733)	$ 478,247	$ (290,823)	$ 187,425	$ 132,559
15	$ 682,896	$ (127,395)	$ (34,145)	$ (26,428)	$ 494,928	$ (290,823)	$ 204,105	$ 140,561
16	$ 705,431	$ (130,835)	$ (35,272)	$ (27,141)	$ 512,184	$ (290,823)	$ 221,361	$ 148,437
17	$ 728,710	$ (134,368)	$ (36,436)	$ (27,874)	$ 530,034	$ (290,823)	$ 239,211	$ 156,189
18	$ 752,758	$ (137,995)	$ (37,638)	$ (28,627)	$ 548,498	$ (290,823)	$ 257,675	$ 163,822
19	$ 777,599	$ (141,721)	$ (38,880)	$ (29,399)	$ 567,598	$ (290,823)	$ 276,776	$ 171,339
20	$ 803,260	$ (145,548)	$ (40,163)	$ (30,193)	$ 587,356	$ (290,823)	$ 296,533	$ 178,744
21	$ 829,767	$ (149,478)	$ (41,488)	$ (31,008)	$ 607,793		$ 607,793	$ 356,735
22	$ 857,150	$ (153,513)	$ (42,857)	$ (31,846)	$ 628,933		$ 628,933	$ 359,438
23	$ 885,436	$ (157,658)	$ (44,272)	$ (32,706)	$ 650,800		$ 650,800	$ 362,157
24	$ 914,655	$ (161,915)	$ (45,733)	$ (33,589)	$ 673,418		$ 673,418	$ 364,891
25	$ 944,839	$ (166,287)	$ (47,242)	$ (34,495)	$ 696,814		$ 696,814	$ 367,642
							Net Present Value	**$ 3,832,127**

Option 2 - Site 2 : Biomass Heating (Steam and Hot Water)
Sensitivity Analysis

Table Shows Sensitivity of Annual Operating Savings to Changes in Fossil Fuel and Wood Chip Prices

Price of Wood Chips - per Ton	Fossil Fuel Price Change						
	-15%	**-10%**	**-5%**	**0%**	**5%**	**10%**	**15%**
$5	$317,197	$337,787	$358,376	$378,965	$399,555	$420,144	$440,734
$10	$302,575	$323,164	$343,754	$364,343	$384,933	$405,522	$426,111
$15	$287,953	$308,542	$329,131	$349,721	$370,310	$390,900	$411,489
$20	$273,330	$293,920	$314,509	$335,099	$355,688	$376,277	$396,867
$25	$258,708	$279,297	$299,887	$320,476	$341,066	$361,655	$382,244
$30	$244,086	$264,675	$285,265	$305,854	$326,443	$347,033	$367,622
$35	$229,463	$250,053	$270,642	$291,232	$311,821	$332,410	$353,000
$40	$214,841	$235,431	$256,020	$276,609	$297,199	$317,788	$338,378
$45	$200,219	$220,808	$241,398	$261,987	$282,576	$303,166	$323,755
$50	$185,597	$206,186	$226,775	$247,365	$267,954	$288,544	$309,133
$55	$170,974	$191,564	$212,153	$232,742	$253,332	$273,921	$294,511
$60	$156,352	$176,941	$197,531	$218,120	$238,710	$259,299	$279,888
$65	$141,730	$162,319	$182,908	$203,498	$224,087	$244,677	$265,266
$70	$127,107	$147,697	$168,286	$188,875	$209,465	$230,054	$250,644

**Notes: All other costs fixed. Excludes financing costs.*

Option 3 - Site 2 : Biomass Heating (Hot Water)
20-year, 4.5% Financing Analysis

Input Variables	Value	Units
Project Costs Financed	3,765,866	$
Financing Term	20	# years
Financing Rate (apr)	4.5%	Percent
EBCH 3 Year Avg Fuel Oil Usage	81,246	Gallons
ISD696 3 Year Avg Propane Usage	76,886	Gallons
Sibley 2011 Propane Usage	22,843	Gallons
EBCH Current Fuel Oil Price	3.20	$/gallon
ISD 696 Current Propane Price	1.72	$/gallon
Sibley Current Propane Price	1.80	$/gallon
Wood Chip Usage	2,924	tons/yr
Year 1 Wood Chip Purchase Price	$ 30.00	$/ton
Annual Fossil Fuel Usage w/ Wood System	5%	Percent
Fossil Fuel Inflation Rate (apr)	3.3%	Percent
Wood Chip Inflation Rate (apr)	2.7%	Percent
General Inflation Rate (apr)	2.7%	Percent
Added Annual O&M Costs for Biomass Plant	$ 17,200	$/year

Year	Total Fossil Fuel Cost, Current System	Wood Chip Cost	Fossil Cost w/ Wood System	Added O&M Cost	Net Operating Savings	Annual Financing Payment	Net Cash Flow	Present Value of Net Cash Flow
1	$ 433,461	$ (87,734)	$ (21,673)	$ (17,200)	$ 306,854	$ (289,505)	$ 17,349	$ 17,349
2	$ 447,765	$ (90,103)	$ (22,388)	$ (17,664)	$ 317,610	$ (289,505)	$ 28,105	$ 27,365
3	$ 462,541	$ (92,535)	$ (23,127)	$ (18,141)	$ 328,737	$ (289,505)	$ 39,232	$ 37,196
4	$ 477,805	$ (95,034)	$ (23,890)	$ (18,631)	$ 340,250	$ (289,505)	$ 50,745	$ 46,846
5	$ 493,573	$ (97,600)	$ (24,679)	$ (19,134)	$ 352,160	$ (289,505)	$ 62,655	$ 56,320
6	$ 509,861	$ (100,235)	$ (25,493)	$ (19,651)	$ 364,482	$ (289,505)	$ 74,977	$ 65,625
7	$ 526,686	$ (102,941)	$ (26,334)	$ (20,181)	$ 377,229	$ (289,505)	$ 87,724	$ 74,763
8	$ 544,067	$ (105,721)	$ (27,203)	$ (20,726)	$ 390,416	$ (289,505)	$ 100,911	$ 83,741
9	$ 562,021	$ (108,575)	$ (28,101)	$ (21,286)	$ 404,059	$ (289,505)	$ 114,553	$ 92,564
10	$ 580,568	$ (111,507)	$ (29,028)	$ (21,861)	$ 418,172	$ (289,505)	$ 128,667	$ 101,234
11	$ 599,726	$ (114,517)	$ (29,986)	$ (22,451)	$ 432,772	$ (289,505)	$ 143,266	$ 109,758
12	$ 619,517	$ (117,609)	$ (30,976)	$ (23,057)	$ 447,875	$ (289,505)	$ 158,370	$ 118,139
13	$ 639,961	$ (120,785)	$ (31,998)	$ (23,680)	$ 463,499	$ (289,505)	$ 173,994	$ 126,382
14	$ 661,080	$ (124,046)	$ (33,054)	$ (24,319)	$ 479,661	$ (289,505)	$ 190,156	$ 134,490
15	$ 682,896	$ (127,395)	$ (34,145)	$ (24,976)	$ 496,380	$ (289,505)	$ 206,875	$ 142,468
16	$ 705,431	$ (130,835)	$ (35,272)	$ (25,650)	$ 513,675	$ (289,505)	$ 224,170	$ 150,320
17	$ 728,710	$ (134,368)	$ (36,436)	$ (26,342)	$ 531,565	$ (289,505)	$ 242,060	$ 158,049
18	$ 752,758	$ (137,995)	$ (37,638)	$ (27,054)	$ 550,071	$ (289,505)	$ 260,566	$ 165,660
19	$ 777,599	$ (141,721)	$ (38,880)	$ (27,784)	$ 569,214	$ (289,505)	$ 279,708	$ 173,155
20	$ 803,260	$ (145,548)	$ (40,163)	$ (28,534)	$ 589,015	$ (289,505)	$ 299,509	$ 180,538
21	$ 829,767	$ (149,478)	$ (41,488)	$ (29,305)	$ 609,497		$ 609,497	$ 357,735
22	$ 857,150	$ (153,513)	$ (42,857)	$ (30,096)	$ 630,683		$ 630,683	$ 360,438
23	$ 885,436	$ (157,658)	$ (44,272)	$ (30,909)	$ 652,597		$ 652,597	$ 363,157
24	$ 914,655	$ (161,915)	$ (45,733)	$ (31,743)	$ 675,264		$ 675,264	$ 365,891
25	$ 944,839	$ (166,287)	$ (47,242)	$ (32,600)	$ 698,710		$ 698,710	$ 368,642
							Net Present Value	**$ 3,877,825**

Option 3 - Site 2 : Biomass Heating (Hot Water)
Sensitivity Analysis

Table Shows Sensitivity of Annual Operating Savings to Changes in Fossil Fuel and Wood Chip Prices

Price of Wood Chips - per Ton	Fossil Fuel Price Change: -15%	-10%	-5%	0%	5%	10%	15%
$5	$318,197	$338,787	$359,376	$379,965	$400,555	$421,144	$441,734
$10	$303,575	$324,164	$344,754	$365,343	$385,933	$406,522	$427,111
$15	$288,953	$309,542	$330,131	$350,721	$371,310	$391,900	$412,489
$20	$274,330	$294,920	$315,509	$336,099	$356,688	$377,277	$397,867
$25	$259,708	$280,297	$300,887	$321,476	$342,066	$362,655	$383,244
$30	$245,086	$265,675	$286,265	$306,854	$327,443	$348,033	$368,622
$35	$230,463	$251,053	$271,642	$292,232	$312,821	$333,410	$354,000
$40	$215,841	$236,431	$257,020	$277,609	$298,199	$318,788	$339,378
$45	$201,219	$221,808	$242,398	$262,987	$283,576	$304,166	$324,755
$50	$186,597	$207,186	$227,775	$248,365	$268,954	$289,544	$310,133
$55	$171,974	$192,564	$213,153	$233,742	$254,332	$274,921	$295,511
$60	$157,352	$177,941	$198,531	$219,120	$239,710	$260,299	$280,888
$65	$142,730	$163,319	$183,908	$204,498	$225,087	$245,677	$266,266
$70	$128,107	$148,697	$169,286	$189,875	$210,465	$231,054	$251,644

**Notes: All other costs fixed. Excludes financing costs.*

Appendix C Option 4 - Site 2 : Biomass Backpressure Steam CHP (Thermal Oil, Steam, Hot Water)

20-year, 4.5% Financing Analysis

Input Variables	Value	Units
Project Costs Financed	4,664,050	$
Financing Term	20	# years
Financing Rate (apr)	4.5%	Percent
EBCH 3 Year Avg Fuel Oil Usage	81,246	Gallons
ISD696 3 Year Avg Propane Usage	76,886	Gallons
Sibley 2011 Propane Usage	22,843	Gallons
EBCH Current Fuel Oil Price	3.20	$/gallon
ISD 696 Current Propane Price	1.72	$/gallon
Sibley Current Propane Price	1.80	$/gallon
Biomass Usage	3,174	tons/yr
Year 1 Wood Chip Purchase Price	$ 30.00	$/ton
Annual Fossil Fuel Usage w/ Wood System	5%	Percent
Electric Generation	412,965	kWh
Year 1 Electricity Value	0.072	$/kWh
Fossil Fuel Inflation Rate (apr)	3.3%	Percent
Electricity Inflation Rate (apr)	3.3%	Percent
Wood Chip Inflation Rate (apr)	2.7%	Percent
General Inflation Rate (apr)	2.7%	Percent
Added Annual O&M Costs for Biomass Plan	$ 21,200	$/year

Year	Total Fossil Fuel Cost, Current System	Wood Chip Cost	Fossil Fuel Cost, w/ Wood System	Value of Electricity Generation	Added O&M Cost	Net Operating Savings	Annual Financing Payment	Net Cash Flow	Present Value of Net Cash Flow
1	$ 433,461	$ (95,207)	$ (21,673)	$ 29,733	$ (21,200)	$ 325,115	$ (358,554)	$ (33,439)	$ (33,439)
2	$ 447,765	$ (97,777)	$ (22,388)	$ 30,715	$ (21,772)	$ 336,542	$ (358,554)	$ (22,012)	$ (21,434)
3	$ 462,541	$ (100,417)	$ (23,127)	$ 31,728	$ (22,360)	$ 348,365	$ (358,554)	$ (10,189)	$ (9,661)
4	$ 477,805	$ (103,128)	$ (23,890)	$ 32,775	$ (22,964)	$ 360,598	$ (358,554)	$ 2,044	$ 1,886
5	$ 493,573	$ (105,913)	$ (24,679)	$ 33,857	$ (23,584)	$ 373,254	$ (358,554)	$ 14,700	$ 13,213
6	$ 509,861	$ (108,772)	$ (25,493)	$ 34,974	$ (24,221)	$ 386,349	$ (358,554)	$ 27,794	$ 24,327
7	$ 526,686	$ (111,709)	$ (26,334)	$ 36,128	$ (24,875)	$ 399,896	$ (358,554)	$ 41,342	$ 35,233
8	$ 544,067	$ (114,725)	$ (27,203)	$ 37,321	$ (25,546)	$ 413,912	$ (358,554)	$ 55,358	$ 45,939
9	$ 562,021	$ (117,823)	$ (28,101)	$ 38,552	$ (26,236)	$ 428,413	$ (358,554)	$ 69,859	$ 56,448
10	$ 580,568	$ (121,004)	$ (29,028)	$ 39,824	$ (26,944)	$ 443,415	$ (358,554)	$ 84,861	$ 66,768
11	$ 599,726	$ (124,271)	$ (29,986)	$ 41,139	$ (27,672)	$ 458,935	$ (358,554)	$ 100,381	$ 76,903
12	$ 619,517	$ (127,627)	$ (30,976)	$ 42,496	$ (28,419)	$ 474,992	$ (358,554)	$ 116,437	$ 86,859
13	$ 639,961	$ (131,073)	$ (31,998)	$ 43,898	$ (29,186)	$ 491,603	$ (358,554)	$ 133,048	$ 96,641
14	$ 661,080	$ (134,612)	$ (33,054)	$ 45,347	$ (29,974)	$ 508,787	$ (358,554)	$ 150,233	$ 106,254
15	$ 682,896	$ (138,246)	$ (34,145)	$ 46,844	$ (30,784)	$ 526,565	$ (358,554)	$ 168,010	$ 115,703
16	$ 705,431	$ (141,979)	$ (35,272)	$ 48,389	$ (31,615)	$ 544,955	$ (358,554)	$ 186,401	$ 124,994
17	$ 728,710	$ (145,812)	$ (36,436)	$ 49,986	$ (32,469)	$ 563,980	$ (358,554)	$ 205,426	$ 134,130
18	$ 752,758	$ (149,749)	$ (37,638)	$ 51,636	$ (33,345)	$ 583,662	$ (358,554)	$ 225,107	$ 143,116
19	$ 777,599	$ (153,792)	$ (38,880)	$ 53,340	$ (34,246)	$ 604,021	$ (358,554)	$ 245,467	$ 151,957
20	$ 803,260	$ (157,945)	$ (40,163)	$ 55,100	$ (35,170)	$ 625,082	$ (358,554)	$ 266,528	$ 160,658
21	$ 829,767	$ (162,209)	$ (41,488)	$ 56,918	$ (36,120)	$ 646,868		$ 646,868	$ 379,670
22	$ 857,150	$ (166,589)	$ (42,857)	$ 58,797	$ (37,095)	$ 669,405		$ 669,405	$ 382,568
23	$ 885,436	$ (171,087)	$ (44,272)	$ 60,737	$ (38,097)	$ 692,717		$ 692,717	$ 385,483
24	$ 914,655	$ (175,706)	$ (45,733)	$ 62,741	$ (39,125)	$ 716,832		$ 716,832	$ 388,415
25	$ 944,839	$ (180,450)	$ (47,242)	$ 64,812	$ (40,182)	$ 741,777		$ 741,777	$ 391,364
								Net Present Value	**$ 3,303,992**

Sensitivity Analysis

Table Shows Sensitivity of Annual Operating Savings to Changes in Fossil Fuel and Wood Chip Prices

Price of Wood Chips - per Ton	Fossil Fuel Price Change: -15%	-10%	-5%	0%	5%	10%	15%
$5	$342,685	$363,275	$383,864	$404,454	$425,043	$445,632	$466,222
$10	$326,818	$347,407	$367,996	$388,586	$409,175	$429,765	$450,354
$15	$310,950	$331,539	$352,129	$372,718	$393,307	$413,897	$434,486
$20	$295,082	$315,671	$336,261	$356,850	$377,440	$398,029	$418,618
$25	$279,214	$299,804	$320,393	$340,982	$361,572	$382,161	$402,751
$30	$263,347	$283,936	$304,525	$325,115	$345,704	$366,294	$386,883
$35	$247,479	$268,068	$288,658	$309,247	$329,836	$350,426	$371,015
$40	$231,611	$252,200	$272,790	$293,379	$313,969	$334,558	$355,147
$45	$215,743	$236,333	$256,922	$277,511	$298,101	$318,690	$339,280
$50	$199,876	$220,465	$241,054	$261,644	$282,233	$302,822	$323,412
$55	$184,008	$204,597	$225,187	$245,776	$266,365	$286,955	$307,544
$60	$168,140	$188,729	$209,319	$229,908	$250,498	$271,087	$291,676
$65	$152,272	$172,862	$193,451	$214,040	$234,630	$255,219	$275,809
$70	$136,405	$156,994	$177,583	$198,173	$218,762	$239,351	$259,941

**Notes: All other costs fixed. Excludes financing costs.*

Option 5 - Site 2 : Biomass ORC CHP (Thermal Oil and Hot Water)
20-year, 4.5% Financing Analysis

Input Variables	Value	Units
Project Costs Financed	7,164,786	$
Financing Term	20	# years
Financing Rate (apr)	4.5%	Percent
EBCH 3 Year Avg Fuel Oil Usage	81,246	Gallons
ISD696 3 Year Avg Propane Usage	76,886	Gallons
Sibley 2011 Propane Usage	22,843	Gallons
EBCH Current Fuel Oil Price	3.20	$/gallon
ISD 696 Current Propane Price	1.72	$/gallon
Sibley Current Propane Price	1.80	$/gallon
Biomass Usage	4,730	tons/yr
Year 1 Wood Chip Purchase Price	$ 30.00	$/ton
Annual Fossil Fuel Usage w/ Wood System	5%	Percent
Electric Generation	1,622,087	kWh
Year 1 Electricity Value	0.072	$/kWh
Fossil Fuel Inflation Rate (apr)	3.3%	Percent
Electricity Inflation Rate (apr)	3.3%	Percent
Wood Chip Inflation Rate (apr)	2.7%	Percent
General Inflation Rate (apr)	2.7%	Percent
Added Annual O&M Costs for Biomass Plan	$ 31,100	$/year

Year	Total Fossil Fuel Cost, Current System	Wood Chip Cost	Fossil Fuel Cost, w/ Wood System	Value of Electricity Generation	Added O&M Cost	Net Operating Savings	Annual Financing Payment	Net Cash Flow	Present Value of Net Cash Flow
1	$ 433,461	$ (141,912)	$ (21,673)	$ 116,790	$ (31,100)	$ 355,566	$ (550,801)	$ (195,235)	$ (195,235)
2	$ 447,765	$ (145,743)	$ (22,388)	$ 120,644	$ (31,940)	$ 368,338	$ (550,801)	$ (182,463)	$ (177,667)
3	$ 462,541	$ (149,679)	$ (23,127)	$ 124,626	$ (32,802)	$ 381,559	$ (550,801)	$ (169,242)	$ (160,461)
4	$ 477,805	$ (153,720)	$ (23,890)	$ 128,738	$ (33,688)	$ 395,246	$ (550,801)	$ (155,555)	$ (143,607)
5	$ 493,573	$ (157,870)	$ (24,679)	$ 132,987	$ (34,597)	$ 409,413	$ (550,801)	$ (141,388)	$ (127,097)
6	$ 509,861	$ (162,133)	$ (25,493)	$ 137,375	$ (35,531)	$ 424,079	$ (550,801)	$ (126,723)	$ (110,919)
7	$ 526,686	$ (166,510)	$ (26,334)	$ 141,909	$ (36,491)	$ 439,259	$ (550,801)	$ (111,542)	$ (95,065)
8	$ 544,067	$ (171,006)	$ (27,203)	$ 146,592	$ (37,476)	$ 454,973	$ (550,801)	$ (95,828)	$ (79,526)
9	$ 562,021	$ (175,623)	$ (28,101)	$ 151,429	$ (38,488)	$ 471,238	$ (550,801)	$ (79,563)	$ (64,292)
10	$ 580,568	$ (180,365)	$ (29,028)	$ 156,426	$ (39,527)	$ 488,073	$ (550,801)	$ (62,728)	$ (49,355)
11	$ 599,726	$ (185,235)	$ (29,986)	$ 161,588	$ (40,594)	$ 505,499	$ (550,801)	$ (45,302)	$ (34,708)
12	$ 619,517	$ (190,236)	$ (30,976)	$ 166,921	$ (41,690)	$ 523,535	$ (550,801)	$ (27,266)	$ (20,341)
13	$ 639,961	$ (195,373)	$ (31,998)	$ 172,429	$ (42,816)	$ 542,204	$ (550,801)	$ (8,597)	$ (6,246)
14	$ 661,080	$ (200,648)	$ (33,054)	$ 178,119	$ (43,972)	$ 561,526	$ (550,801)	$ 10,724	$ 7,584
15	$ 682,896	$ (206,065)	$ (34,145)	$ 183,997	$ (45,159)	$ 581,524	$ (550,801)	$ 30,722	$ 21,157
16	$ 705,431	$ (211,629)	$ (35,272)	$ 190,069	$ (46,379)	$ 602,221	$ (550,801)	$ 51,420	$ 34,480
17	$ 728,710	$ (217,343)	$ (36,436)	$ 196,341	$ (47,631)	$ 623,643	$ (550,801)	$ 72,841	$ 47,560
18	$ 752,758	$ (223,211)	$ (37,638)	$ 202,821	$ (48,917)	$ 645,813	$ (550,801)	$ 95,012	$ 60,405
19	$ 777,599	$ (229,238)	$ (38,880)	$ 209,514	$ (50,238)	$ 668,757	$ (550,801)	$ 117,956	$ 73,021
20	$ 803,260	$ (235,427)	$ (40,163)	$ 216,428	$ (51,594)	$ 692,503	$ (550,801)	$ 141,702	$ 85,415
21	$ 829,767	$ (241,784)	$ (41,488)	$ 223,570	$ (52,987)	$ 717,078		$ 717,078	$ 420,878
22	$ 857,150	$ (248,312)	$ (42,857)	$ 230,948	$ (54,418)	$ 742,510		$ 742,510	$ 424,348
23	$ 885,436	$ (255,017)	$ (44,272)	$ 238,569	$ (55,887)	$ 768,829		$ 768,829	$ 427,838
24	$ 914,655	$ (261,902)	$ (45,733)	$ 246,442	$ (57,396)	$ 796,066		$ 796,066	$ 431,348
25	$ 944,839	$ (268,973)	$ (47,242)	$ 254,574	$ (58,946)	$ 824,252		$ 824,252	$ 434,879
								Net Present Value	**$ 1,204,394**

Option 5 - Site 2 : Biomass ORC CHP (Thermal Oil and Hot Water)
Sensitivity Analysis

Table Shows Sensitivity of Annual Operating Savings to Changes in Fossil Fuel and Wood Chip Prices

Price of Wood Chips - per Ton	Fossil Fuel Price Change: -15%	-10%	-5%	0%	5%	10%	15%
$5	$412,058	$432,647	$453,237	$473,826	$494,415	$515,005	$535,594
$10	$388,406	$408,995	$429,585	$450,174	$470,764	$491,353	$511,942
$15	$364,754	$385,343	$405,933	$426,522	$447,112	$467,701	$488,290
$20	$341,102	$361,691	$382,281	$402,870	$423,460	$444,049	$464,638
$25	$317,450	$338,039	$358,629	$379,218	$399,808	$420,397	$440,986
$30	$293,798	$314,387	$334,977	$355,566	$376,156	$396,745	$417,334
$35	$270,146	$290,735	$311,325	$331,914	$352,504	$373,093	$393,682
$40	$246,494	$267,084	$287,673	$308,262	$328,852	$349,441	$370,030
$45	$222,842	$243,432	$264,021	$284,610	$305,200	$325,789	$346,379
$50	$199,190	$219,780	$240,369	$260,958	$281,548	$302,137	$322,727
$55	$175,538	$196,128	$216,717	$237,306	$257,896	$278,485	$299,075
$60	$151,886	$172,476	$193,065	$213,654	$234,244	$254,833	$275,423
$65	$128,234	$148,824	$169,413	$190,002	$210,592	$231,181	$251,771
$70	$104,582	$125,172	$145,761	$166,350	$186,940	$207,529	$228,119

**Notes: All other costs fixed. Excludes financing costs.*

APPENDIX C.

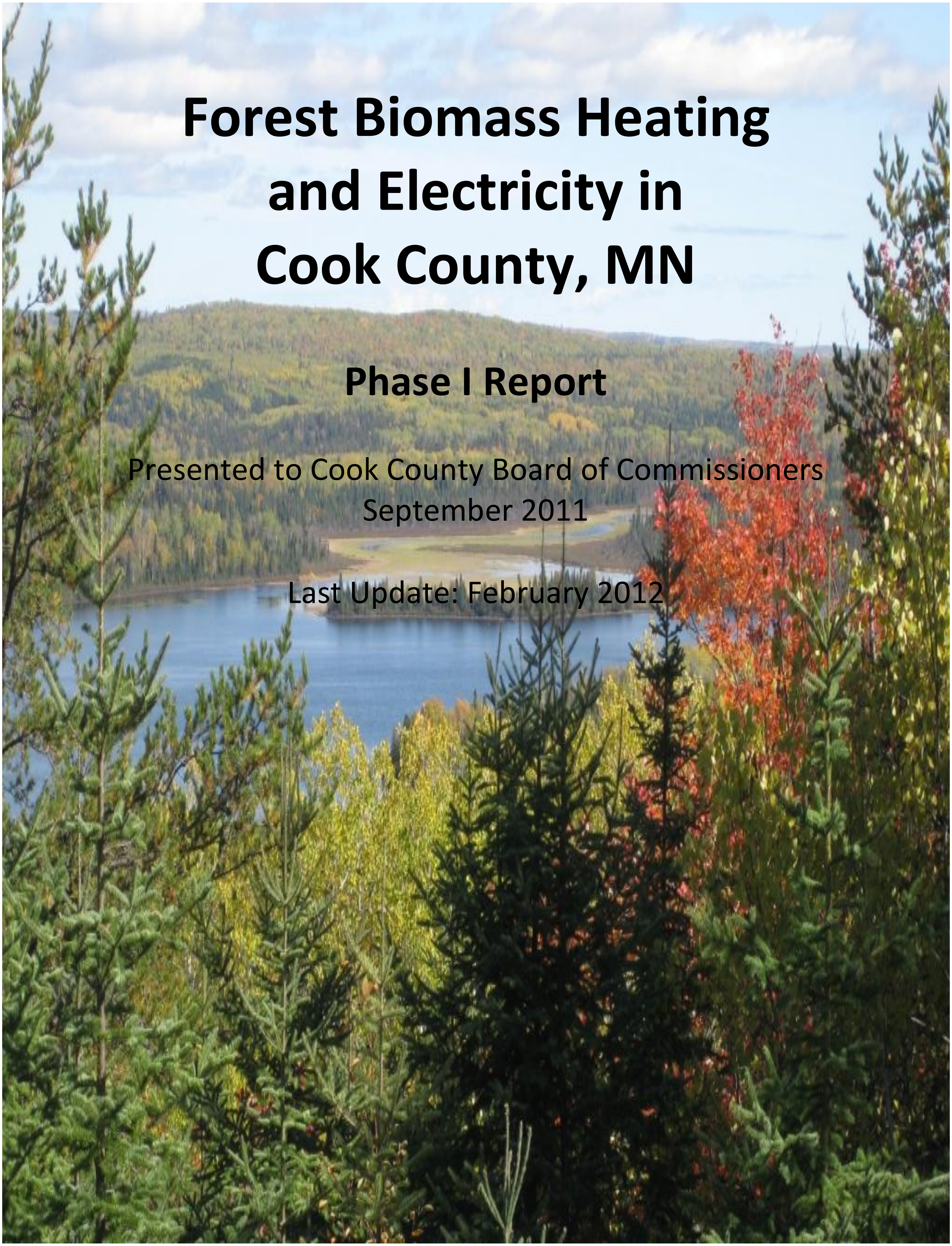
Forest Biomass Heating and Electricity in Cook County: Phase I Report (Dovetail & University of Minnesota)

Forest Biomass Heating and Electricity in Cook County, MN

Phase I Report

Presented to Cook County Board of Commissioners
September 2011

Last Update: February 2012



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Cover photo: Courtesy of Gunflint District - U.S. Forest Service

Forest Biomass Heating and Electricity in Cook County, MN
Phase I Report

Table of Contents

List of Figures

List of Tables

Executive Summary

This report covers the first phase of a two-part study of the technical and financial aspects of using forest biomass as an energy source in Cook County. The two-part study provides county residents with information about the impacts of biomass energy on local energy security and costs, utilization of wood waste and reduction of fire risk, and stewardship of regional forests, water and air quality, greenhouse gas emissions, and local economies. Phase I, which includes the following components, was funded by Cook County:

- Availability of forest biomass for energy production in Cook County;
- Options for biomass combustion technology for small, medium, and large systems; and
- Financial implications of converting to biomass energy in various Cook County settings.

The Phase II report, funded by the Legislative Citizen Commission of Minnesota Resources (LCCMR), will provide additional information on biomass supply issues and impacts. It will describe life cycle impacts of biomass energy systems, including environmental impacts, and assess stakeholder and community attitudes about expanded conversion to these systems. The Phase II report will also present conclusions about the long-term viability of biomass energy in the county and recommendations for next steps.

I. Biomass Availability for Energy Production

Biomass used as heating fuel comes in four forms: 1) cordwood, 2) clean chips, 3) hog (hogged) fuel, and 4) wood pellets. The suitability of using one of these fuels in a particular facility depends on the physical properties and cleanliness of the biomass, its availability, size and efficiency of the heating system, handling and storage limitations, labor requirements, and community considerations. Cordwood is only evaluated for the smallest systems because of storage limitations and the labor requirements of larger systems. Alternatively, hog fuel generated from logging residue (bark, treetops, and branches) and mixed wood material generated by fire mitigation treatments is an option for large district energy systems, where mechanical feeding systems and high temperatures support increased efficiency and reduced emissions. Clean chips can be substituted for hog fuel to provide lower emissions, but are more expensive. Premium wood pellets are produced from roundwood (bole of the tree) and, because of convenient handling characteristics and consistent moisture content, offer lower initial equipment and operation costs, but are more expensive. The table below (Table A) summarizes the volume of biomass available annually for energy production and estimated demand for a range of heating options (Table B).

Table A. Current and potential biomass availability by ownership and management scenario

	Current availability			Potential availability			
Ownership	**2010 bolewood harvest (odt)[1]**	**2010 residual biomass (odt)[2]**	**2010 Firewise removals (odt)[3]**	**10% of 2010 bolewood (odt)**	**20% of 2010 bolewood (odt)**	**Future Firewise removals (odt)[3]**	**Residuals from GEIS harvest (odt)[4]**
Federal forests	16,021	1,851	3,189	1,602	3,204	3,189	14,014
State, county, and local	19,009	2,344	--	1,901	3,802	--	3,790
Private[5]	8,889	1,034	--	889	1,778	--	5,505
Total	**43,919**	**5,229**	**3,189**	**4,392**	**8,784**	**3,189**	**23,309**

[1] A cord is equivalent to 1.2 dry tons. The total 2010 bolewood harvest is equivalent to 38,911 cords.
[2] Residual biomass is the tops, limbs, branches and needles as defined by the USDA Forest Service FIA biomass attributes, and is in addition to the reported 2010 roundwood harvest rate for Cook County. Residual biomass availability assumes 50% retention on-site.
[3] Firewise removals are estimated for Superior National Forest removals only of slash from fuels reductions efforts based on an estimated 12,599 cu. yards of slash generated in 2010. Future removals assumed equal to 2010 and not constrained by future budget allocations.
[4] The highest level of sustainable biomass removal based upon the proportion of a statewide timber harvest level of 4.0 million cords as estimated in the Final Generic Environmental Impact Statement (GEIS) for Minnesota. This amount is residual biomass only assuming 50% retention on-site, and does not include bolewood potential.
[5] Includes corporate, non-governmental conservation/natural resources organizations, unincorporated local partnerships/associations/clubs, and tribal timberlands; also includes non-industrial private woodlands.

II. Technical Analysis

Thermal (heat) energy is the primary focus of this study. In the biomass systems analyzed, feedstocks are burned to heat water, which is then conveyed through insulated piping to heat one or more buildings. Cooled water is then returned to the heating plant where it is re-heated and re-circulated. All options, except individual buildings, assume the construction of a separate building to house the central heating boiler and a hot water delivery and return piping network. Pipes are 4 to 6-inches in diameter depending on heat load, and are typically buried 24-inches below ground level with 6-inches of sand beneath. Additional piping delivers the district heating fluid to each business or home, where it goes through a heat exchanger for use as hot water and/or space heating. Some conversion of the building's heating system for a hot water heat supply may also be necessary.

Thirteen technological options, or configurations, covering the diversity of sizes, locations, and heating needs in Cook County were analyzed in the study, ranging from single-family houses, medium-sized to large resorts or business clusters, and larger systems capable of heating part or all of Grand Marais. Three representative sites were assessed: Bearskin Lodge (small option, S1 - 4), Lutsen Resort (medium, M1) and Grand Marais public buildings, business district, and residential area (large, L1 - 8). One option assesses combined heat and electrical power (CHP) for Grand Marais. For each site, current heat use, multiple technical configurations, and different fuels were analyzed. The detailed assessment at each site provides data that can be extrapolated to the majority of sites in the county.

III. **Financial Evaluation and Performance**

A financial evaluation of capital, operating, and maintenance costs of each configuration was conducted and compared to the cost of existing fossil fuel-based systems (Table B). Comparisons are based upon assumptions developed by the U.S. Energy Information Administration about fossil fuel prices in the next 20 years. The "reference case" assumes fossil fuel prices to be $100-123/barrel by 2030; while the "high oil price" scenario assumes $196/barrel by that time. Four different measures of financial performance are employed to estimate (1) energy cost per mmBtu (million British thermal units of heat energy); (2) simple payback period; (3) return on investment (ROI); and (4) outstanding capital needed in addition to the fuel cost savings.

General considerations drawn from this analysis include: (1) piping is costly ($138 - 220/foot), so configurations with more closely spaced buildings and simplified installation are most cost effective; (2) configurations with higher heat demand have lower costs per unit of energy; and (3) construction and operating costs (including fuel costs) sometimes run counter to one another. As noted above, pellet-based systems are less expensive to build, but are considerably higher than clean chips and hog fuel to operate because of the delivered cost of pellets.

These comparisons do not capture non-financial benefits, (e.g., wildfire risk reduction) and drawbacks of conversion to biomass energy. The manner and cost of financing is also not included because of the variability involved and the method of financing is a separate decision from whether or not to invest.

Table B. Financial evaluation and performance of modeled configurations.

Configuration	Annual heat load	Fuel type	Biomass demand (dry ton/yr)	Capital construction costs	Annual O&M costs	Simple payback (yrs) Reference scenario	Simple payback (yrs) High oil price scenario
S1: Supplemental heat stove for single-family residence	35 mmBtu	Cordwood Pellets	3.6 2.3	$4,000 $3,500	$800 $600	9 6	8 5
S2: Biomass furnace for single-family residence	70 mmBtu	Cordwood Pellets	7.2 4.7	$15,000 $15,000	$1,500 $1,100	16 11	12 9
S3: Heat for main lodge only	500 mmBtu	Cordwood	44	$162,000	$10,600	20+	20+
S4: Heat for multiple cabins and main lodge	1,100 mmBtu	Clean chips Pellets	107 72	$649,000 $575,000	$17,000 $20,600	20+	20+
M1: Heat for multiple buildings	5,200 mmBtu	Clean chips Pellets	510 342	$995,000 $909,000	$53,800 $87,100	9 12	8 10
L1: Heat for Cook County Courthouse	1,400 mmBtu	Clean chips Pellets	132 88	$336,000 $269,000	$13,200 $22,900	10 11	9 9
L2: Heat for public buildings north of 5th Street N (no hospital)	5,800 mmBtu	Clean chips Pellets	561 376	$1,443,000 $1,354,000	$46,000 $90,000	10 13	8 10
L3: Heat for public buildings north of 5th Street N (hospital)	12,100 mmBtu	Clean chips Pellets	1,178 790	$2,137,000 $1,964,000	$96,000 $188,500	7 10	7 8
L4: District heat for Grand Marais business district	19,700 mmBtu	Hog fuel Pellets	1,950 1,300	$7,058,000 $6,679,000	$210,000 $388,000	16 20+	13 18
L5: District heat for business district (L4) and public buildings (L2) (no hospital)	25,500 mmBtu	Hog fuel Pellets	2,500 1,700	$8,405,000 $7,992,000	$253,000 $494,000	14 20+	12 17
L6: District heat for business district (L4) and public buildings (L3) (hospital)	34,200 mmBtu	Hog fuel Pellets	3,400 1,520	$8,855,000 $8,457,000	$304,000 $645,000	11 18	10 15
L7: District heat for homes & businesses between 5th Ave W. and 6th Ave E.	45,000 mmBtu	Hog fuel Pellets	4,600 3,100	$13,226,000 $12,641,000	$437,000 $867,000	13 20+	11 17
L8: Combined heat and power (CHP) system for configuration L7	45,000 mmBtu	Hog fuel Pellets	8,750 6,850	$15,483,000 $17,751,000	$563,000 $1,758,000	15 20+	13 20+

Phase I Findings

1. At current timber harvest and Firewise treatment levels in Cook County, approximately 8,500 dry tons of biomass is annually available, which is sufficient to supply various district heating configurations in Cook County and/or Grand Marais. Chipping bolewood for clean chips or pellet production could significantly increase feedstock availability but that could divert material from existing pulpwood markets and increase prices. Barring construction of a pellet production plant in Cook County, any option utilizing wood pellets would require purchase from an outside supplier.
2. All the slash generated from hazardous fuels reduction treatments within 50-miles of Grand Marais could be fully utilized by district heating and/or combined heat and power (CHP) for the Grand Marais business district and public buildings north of 5th Street North.
3. Future biomass availability is expected to continue to be dependent upon the level of production of higher valued co-products harvested from roundwood for pulp or sawlogs, which typically subsidize the removal of residuals to roadside or landing for processing. Future harvest rates are highly dependent upon market fluctuations and are thus difficult to predict. Supply contracts or other agreements may be needed.
4. Current harvest levels in Cook County are about 75% below the estimated Generic Environmental Impact Statement (GEIS) threshold for sustainable forest management in the state. Increasing timber harvesting to a sustainable threshold of 163,546 cords/year increases the availability of residual biomass to 23,309 dry tons annually, assuming 50% are retained on site for ecological purposes.
5. In all the configurations modeled, annual biomass fuel purchases and O&M (operating and maintenance) costs are lower than for a conventional fossil fuel heating system. However, all of the sites assessed already possess heating systems that could continue in operation, whereas new investment would be needed in order to burn biomass. At some point, new investment will be necessary to replace old fossil fuel boilers as well.
6. Financial performance of all options depends on assumptions about future fossil fuel prices and/or taxes. Under the reference or business-as-usual scenario, seven of the configurations would take more than 20 years to pay back, or the assumed life of the equipment. Under the high oil price scenario, payback time for 21 options is less than the 20-year threshold.
7. Small-scale biomass furnaces (70 – 1,200mmBtus annual heat demand) range from $15,000 for single-family homes and buildings, $120,000 for small lodges; and $340,000 - $415,000 for small central heating systems for a lodge and several cabins (plus building and piping). For single-family homes or other relatively small buildings, free standing wood or pellet stoves producing 35 mmBtu/year costs about $4,000. Single building furnaces (without piping) are cost efficient, with payback periods between 5 – 9 years and high returns on investment. Low population densities can limit the size of energy systems due to high piping costs and the amount of heat loss resulting from moving hot water over long distances.

8. Medium-sized biomass heating systems for resorts, roughly the size of Lutsen Resort, or business clusters having annual heat demands approximating 6,000 mmBtu/year are \$670,000 – \$770,000, not including building and piping. A system heating multiple, closely spaced buildings with clean chips provides a potentially return on investment of 134-234% over the 20-year life, which will vary depending on future fossil fuel costs and financing.

9. Large heating systems range from a single public building (County Courthouse) to systems heating the majority of public buildings, businesses, and residences in Grand Marais. Annual heat demand for district heating configurations is 20,000 – 45,000 mmBtu. Options providing heat to public buildings north of 5th Street are projected to pay for themselves in fuel savings alone in less than 10 years. Options that would expand to the business district are more feasible under the high oil price scenario. However, high piping costs because of low building density and an estimated \$6,500 hook-up costs make district heating for all of Grand Marais less cost efficient.

10. CHP for the majority of buildings in Grand Marais has capital costs considerably more than other options. This technology produces approximately one unit of electricity for every four units of heat.

11. The Minnesota Pollution Control Agency requires the calculation of emissions associated with each of the district heating/CHP configurations, the largest of which would require an "Option D" registration air permit and emissions tracking. An "Option D" permit is issued when facilities have allowable emissions below federal thresholds, which is the case for each of the configurations assessed.

12. Although in-depth assessment of local manufacturing of pellets was not a formal part of this study, available information suggests that there is insufficient local demand to make such an enterprise profitable (see appendix D).

13. Phase I analysis did not include a local economic impact assessment of biomass conversion. However, findings from studies in other parts of the country indicate a range of economic impacts possible. Multipliers for bioenergy applications in different parts of the country indicate that for every dollar spent locally on bioenergy fuel, an additional \$0.26 – \$0.83 is re-spent locally through indirect and induced spending. Actual impacts will depend on the type of system(s) employed and mix of local industries present.

14. The financial analysis does <u>not</u> include non-financial factors important for making decisions, including tradeoffs associated with the utilization of hazardous fuels, reduced emissions, wealth retention and job creation, fuel security, and others.

15. Phase II analyses will include more information on the various environmental and economic impacts of biomass energy systems assessed. It will also provide a formal process for considering the financial and non-financial factors important to making decisions at the household, community, and county levels, and the tradeoffs involved.

Glossary

As received—wood waste and chips paid for on an “as received” basis without regard to moisture content.

Bioenergy—heat and/or electricity produced from biomass energy systems.

Bole—the main trunk of the tree, above the stump and below the crown/top.

Btu—British thermal unit. Standard unit of energy equal to the heat required to increase the temperature of one pound of water one degree Fahrenheit.

Clean chips—wood fiber processed into a wood chip that is free of contaminants like bark and needles, and generally includes only the bolewood of a tree.

Co-firing—combustion of two types of materials, e.g., biomass with coal.

Co-generation—simultaneous production of heat and electricity from one or more fuels, also called combined heat and power (CHP).

Condensing power—power generated through a steam turbine where the steam is exhausted into a condenser, cooled to a liquid, and recycled back into a boiler.

Cord—stack of round or split wood consisting of 128 cubic ft of wood, bark, and air space (measures 4ft x 4ft x 8 ft).

DBH—diameter at breast height, used to measure trees.

Discount Rate—the rate used to determine the present value of future cash flows, which takes into account both the expected interest that could be earned on present money plus any uncertainty surrounding the future cash flows.

Discounted Payback Period—the number of years required to recover the cost of an investment with future cash flows discounted (see also NPV).

Forest biomass—the accumulated above- and belowground mass (bark, leaves, and wood) from living and dead woody shrubs and trees.

Forest residues—the aboveground material generated from logging during harvesting, e.g., leaves, bark, and tree tops.

Hog (hogged) fuel—biomass generated by grinding wood and wood waste and used for energy production.

Internal Rate of Return (IRR)—the discount rate that makes the net present value of all cash flows (or net savings) from a project equal to zero. More desirable projects generally have higher IRR’s.

Landing—the site where harvested trees are accumulated for loading onto trucks or processed for chips or hog fuel.

Levelized Cost of Energy (LCOE)—the cost per unit of energy that, if held constant through the analysis period, would result in an NPV equal to zero.

Net Present Value (NPV)—given a desired rate of return, the current worth of a future stream of cash flows (or savings) minus its current cost. Future cash flows (or savings) are discounted at the discount rate, and the higher the discount rate, the lower the present value of the future cash flows.

Organic Rankine Cycle (ORC)—pressurizing, heating, vaporizing, condensing, and re-heating an organic fluid (e.g., propane, octamethyltrisiloxane (OMTS) in a closed cycle to generate electricity and 180°F district hot water.

Oven-dry ton (odt)—ton of biomass or wood assuming zero percent moisture content by weight. Also referred to as dry ton and bone-dry ton.

Pellets—type of wood fuel. Premium pellets are made from compacted sawdust that is a byproduct of sawmilling.

Productive machine hour—time during scheduled operating hours when a machine performs its designated function; excluded downtime for maintenance, weather, and other delays.

Pulpwood—trees and wood suitable for manufacturing paper.

Rotation—number of years required to establish and grow trees to a specified size, product, or condition of maturity.

Roundwood—logs, bolts, and other round sections cut from the tree.

Sawtimber—log or tree meeting minimum diameter and stem quality requirements to be sawed into lumber.

Skidding—moving trees from a felling site to a loading area or landing using specialized logging equipment.

Slagging—the formation of deposits on boiler tubes, usually due to the presence of chemical contaminants.

Slash—tree tops, branches, bark, or other residue left on the ground after forestry operations.

Stumpage—value or volume of uncut trees in the woods.

Thinning—partial harvesting of a stand of trees to accelerate the growth of the trees left standing.

Timberland—forested land capable of producing in excess of 20 cubic ft/acre per year of industrial wood crops under natural conditions.

Wildland-urban interface (WUI)—areas of increased human influence and land use conversion in forests.

Common Conversions

Energy Heating Values

Heat source	Heat Value		Moisture percentage by wet weight (delivered average)
Electric/off-peak electric	3,413	Btu/kWh	--
#2 Heating Oil	135,000	Btu/gal	--
Propane	91,600	Btu/gal	--
Cordwood	9,400,000	Btu/ton	35%
Wood pellets	16,800,000	Btu/ton	10%
Clean wood chips	8,800,000	Btu/ton	40%
Hog fuel	8,800,000	Btu/ton	40%

Common Forest Biomass Conversions[1]

Unit	Conversion
1 truckload of wood	23-26 green tons
1 green ton of wood	0.70 dry tons of wood (30% moisture content)
1 cord of roundwood	1.2 dry tons of wood (128 cu ft)
1 oven dry ton (odt)	7,600-9,600 Btu/lb (18-22 GJ/t)
1 megawatt (MW) per year	5,300 – 7,000 dry tons of wood per year 85,000 – 110,000 million Btu per year powers approximately 750-900 homes per year

[1] One ton equals 2,000 lbs

1.0 Introduction and Background

This report covers Phase I of a two-part study of short and long-term economic, social, and the environmental impacts of woody biomass energy systems in northeastern Minnesota. Phase I was commissioned by the Minnesota Cook County Board of Commissioners to provide preliminary information on the technical and financial feasibility of using locally generated forest biomass as an energy source for businesses and communities. Phase II, sponsored by the Legislative Citizen Commission on Minnesota Resources (LCCMR), considers life cycle, environmental, greenhouse gas emissions, and other impacts of locally sourced forest bioenergy. The goal of these studies is to assist the public in making well-informed decisions about converting from fossil fuels to biomass energy.

Phase I analysis is organized into three steps. The first step characterizes forest biomass supplies in Cook County including the physical availability, cost, and logistics of producing and delivering biomass feedstocks. The second step examines biomass energy technology options for small, medium, and large energy systems. Stand-alone heating furnaces are considered for single buildings and small resorts, district heating for multiple buildings at larger resorts or business clusters, and community-scale heating or combined heat-and-power options focusing on Grand Marais. The third step evaluates the financial performance of alternative biomass energy systems and contrasts these to existing conventional fossil fuel systems. Air quality impacts and permitting, economic impacts, and renewable energy incentives are also discussed.

The Phase II report will provide expanded analysis and community input, followed by a set of conclusions about the viability of biomass energy conversion in the county, and pathways for moving forward.

2.0 Cook County Profile and Community Concerns

Cook County covers approximately 3,340 square miles of which 950,207 acres (44%) is land cover and the rest water. 91,272 acres (9.6%) are privately owned with an additional 45,013 acres owned by the Grand Portage Tribe. The remaining acres are administered by the USDA Forest Service (Superior National Forest—400,777 ac; Boundary Waters Canoe Area—261,809 ac), State of Minnesota—Department of Natural Resources (144,828 ac), and local and county government (6,508 ac) (Figure 2.1).[1]

Cook County has 5,176 residents living in 2,707 owner and renter-occupied households (Table 2.1) and population density of 6.4 people per mile.[2] Grand Marais is the county seat with 1,238 residents in 657 households. Other communities are Grand Portage (598 residents; 292 households), Lutsen (363 residents; 165 households), Hovland (272 residents; 122 households), Tofte (263 residents; 108 households), and Schroeder (220 residents; 105 households).[3]

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[1] Cook County Minnesota Assessor's Office. 2011. Personal communication.
[2] US Census Bureau. 2011. 2005-2009 American Community Survey. US Census Bureau, Washington, DC.
[3] Ibid

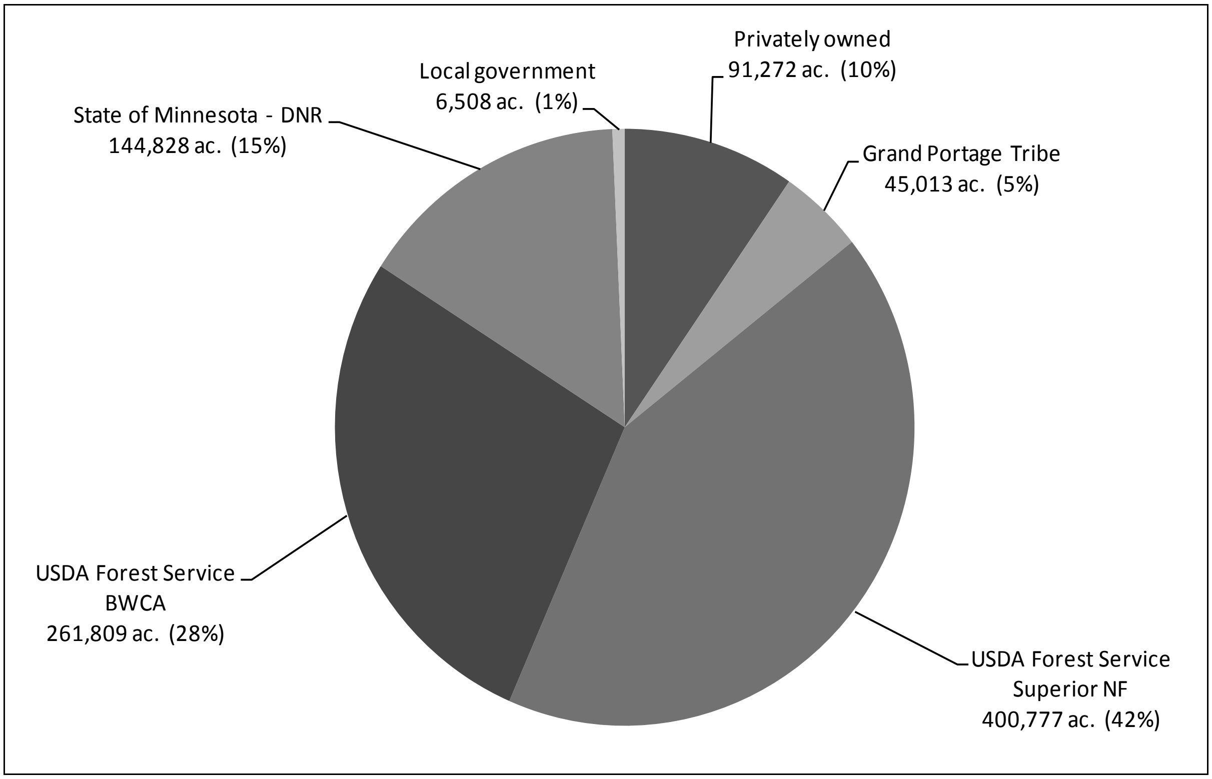

Figure 1.1. Cook County land ownership by type and amount.

US Census data show tourism and related services as the largest economic sectors in the county in terms of employment (23% of jobs). Retail (14%), education and health-social services (13%), and construction (11%) are the next largest. The US Bureau of Labor Statistics reports 3,282 individuals in the workforce in 2010 with a seasonally adjusted local area unemployment rate of 6.8%.[4] The median household income in that year was $47,933.

Population projections for Cook County were last made in 2007 by the Minnesota State Demographic Center based on 2000 US Census Bureau data.[5] The projected 2010 population for the county using that data was 5,570, which was about 8% higher than measured. Adjusting future projections downward by 8%, Cook County is projected to grow to 6,320 individuals by 2030 (22% increase over 2010 population). Similar projections for Grand Marais estimated a 2010 population of 1,570 individuals, which was 21% higher than the actual population. Adjusting future projections downward by this factor, Grand Marais is projected to grow to 1,566 by 2030 (26% increase over 2010 population). Information on the impact of population growth on biomass demand can be found in Appendix B. However, it is not factored into the analysis on heat demand because of the uncertainty of the rate of change, and because heat demand would need to grow substantially to change the configurations as assessed. Projected growth is not such that significant new heating demand is expected.

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[4] US Department of Labor. 2011. Local Area Unemployment Statistics, 2010. US Dept of Labor, Washington, D.C.

[5] Minnesota State Demographic Center. 2011. Projected population to 2030 for cities and townships outside the Twin Cities area. Available online at: http://www.demography.state.mn.us/projections.html.

According to US Census data, the most common form of owner-occupied home heating is propane followed by electricity and equal amounts of heating oil and wood. Propane was the most common heating source in rentals followed by electricity and small amounts of heating oil and wood. Table 2.1 shows the average delivered, in-home price of these fuel sources for 2010.

Table 2.1. Fuel use in Cook County, MN baseline information.[6]

	Housing			2010 fuel price
	Owner-occupied	**Renter-occupied**	**Total**	**(avg $/mmBtu)**
Residents	--	--	**5,176**	--
Housing units	2,023	684	**2,707**	--
Home heating (%)				
Propane	40.9	49.4	**36.4**	$22.40/mmBtu
Electricity (peak)	21.3	31.4	**24.5**	$28.10/mmBtu
#2 heating oil	18.2	11.3	**15.1**	$22.90/mmBtu
Wood (cord)	18.1	2.1	**18.5**	$14.63/mmBtu
Other	1.5	5.8	**5.5**	--

Community Outreach Findings

Surveys of public opinion in Cook County reveal a variety of concerns driving interest in alternatives to existing home heating options, and prompting this study:

- Volatile and rising prices for propane and heating oil, which are a significant portion of monthly household expenditures;
- Utilization of waste wood and slash generated by wildfire hazardous fuels reduction projects around structures and communities. Developing markets for under-utilized biomass could pay for increased forest management and forest restoration activities;
- Reducing greenhouse gases generated from burning of fossil fuels. Locally produced biomass for community-scale energy systems could contribute to meeting Minnesota's target of 25% renewable energy consumption by 2025;
- Local economic development and job opportunities in forest management, harvesting, processing, and energy operations;
- Retention of money spent on energy within the county.

Public surveys also identified concerns about potential negative impacts of conversion to bioenergy that need careful analysis:

- Negative impacts from rising demand for and over-harvest of forest biomass, including increased forest harvest to meet demands, extension of forest roads to access biomass, and the environmental impacts of biomass removal;
- Impacts on air quality from biomass combustion, including changes in emissions of particulate matter (PM), NOx, sulfur dioxide (SO2), carbon (CO), and volatile organic compounds (VOC).

[6] US Census Bureau. 2011. 2005-2009 American Community Survey. US Census Bureau, Washington, DC.

processing capacity. The removal of vegetation from around homes and communities to reduce hazardous fuels also produces wood waste that, in the past, was burned but that could provide feedstock for heating and CHP systems.

In the following analysis, a preliminary estimation of annual biomass availability is based on annual tonnage from different management activities and the cost of converting and transporting it as usable feedstocks to energy facilities. The tables below summarize the steps in this process.

3.1. Physical Availability

For the purposes of this analysis, available biomass can be converted into four types of feedstocks used in the combustion technologies in this report:

- **Cordwood** is equivalent to 4-ft lengths of roundwood cut and stacked into cords, or stacks of 4-ft x 4-ft x 8-ft. Cordwood is used for firewood in conventional fireplaces, wood-burning stoves, or boilers for home heating purposes.
- **Clean chips** are wood fiber, generally the bolewood of the tree, processed into chips free of contaminants like bark and needles. Clean chips are suitable for residential and small industrial heating applications.
- **Hog (hogged) fuel** is wood fiber generated by grinding or chipping wood and wood waste including bark, leaves, branches, and tops of trees. Wildfire fuels reduction treatments and whole tree harvesting produces hog fuel, which is used for industrial and district heating and CHP applications.
- **Wood pellets** are made from compacted sawdust or pulverized wood chips. Premium pellets are made from sawdust and clean chips free of contaminants and are highly dense with low moisture content (below 10%) allowing them to be burned with greater combustion efficiency in residential and small industrial applications. Industrial grade pellets have higher ash content and are used in industrial applications with larger boilers and higher combustion temperatures than residential scale boilers.

Table 3.1 provides a breakdown of timberland acres in Cook County by age class and forest type for the most recent Forest Inventory and Analysis (FIA) reporting period (2004-2008).[7] This information was derived using the Forest Age Class Change Simulator (FACCS), which estimates total biomass by ownership type and tree species.[8] The Aspen-birch forest type occupies 324,783 acres (53% of timberland) and Spruce-fir occupies 161,671 acres (26% of timberland). Of those acres, 48% and 41% respectively, are greater than 60 years old and are either at or

[7] USDA Forest Service. 2011. FIADB Version 4.0. Available online at: http://199.128.173.17/fiadb4-downloads/datamart.html.

[8] Domke, G.M. 2010. Resource assessment and analysis of aspen-dominated ecosystems in the Lake States. University of Minnesota, Ph.D. dissertation.

beyond their target harvest rotation age. Designated wilderness areas, old-growth reserves, wildlife management areas, state parks, and towns are not included in this analysis.

Table 3.1. Timberland acres by age class and forest type in Cook County, MN (2004-2008 inventory period; non-stocked areas excluded).

Age Class	White-red-jack pine	Spruce-fir[1]	Oak-pine	Oak-hickory	Elm-ash-cottonwood	Maple-beech-birch[2]	Aspen-birch
0-10	2,902	8,767	7,311	-	2,486	4,973	41,034
11-20	13,462	13,082	-	-	-	-	31,288
21-30	8,284	14,512	-	-	-	5,455	21,003
31-40	4,820	14,491	-	-	-	2,902	12,039
41-50	726	18,667	-	-	597	5,590	20,958
51-60	3,500	26,201	-	-	3,585	11,667	42,640
61-70	-	14,249	-	-	1,693	14,288	87,763
71-80	5,511	7,741	-	-	2,902	10,061	43,490
81-90	-	4,801	-	-	3,241	12,603	14,498
91-100	726	14,559	-	-	-	-	7,680
100+	-	24,601	-	-	1,840	726	2,390
TOTAL	**39,931**	**161,671**	**7,311**	**0**	**16,344**	**68,265**	**324,783**

[1] Other softwoods combined with the Spruce-fir forest type.
[2] Other hardwoods combined with the Maple-beech-birch forest type.

Table 3.2 displays the average oven-dry tons (odt) per acre by type and ownership. Forest biomass is classified into bolewood (main stem roundwood), limbs and tops, saplings, stumps, and roots. The Minnesota Forest Resources Council (MFRC) guidelines on biomass harvesting recommend that stumps and roots, comprising 21% of total biomass, not be removed and are thus excluded from the analysis.[9]

Table 3.2. Dry tons of living biomass by stand attribute and ownership in Cook County, MN.[1,2]

	Government					
Biomass attribute	**Federal**	**State**	**Local**	**Private industrial**	**Private non-industrial**	**Total**
Bolewood (≥5 in. dbh)	4,127,594	840,203	75,967	887,021	344,490	6,275,275
Tops and limbs	1,138,389	230,814	24,542	258,656	103,253	1,755,654
Saplings (1-4.9 in. dbh)	1,971,652	494,522	58,354	382,320	201,886	3,108,735
Stumps	262,857	53,908	4,840	54,752	22,006	398,362
Belowground roots	1,656,088	365,096	37,814	345,168	150,159	2,554,326

[9] Minnesota Forest Resources Council (MFRC). 2007. *Biomass harvesting guidelines for forestlands, brushlands, and open lands.* St. Paul, MN: Minnesota Forest Resources Council. Available online at: http://www.frc.state.mn.us/initiatives_sitelevel_management.html.

[1] Site-level variation does not differ significantly within forest types.
[2] Size of trees measured in inches as a function of diameter at breast height (dbh).

Table 3.3 presents FIA and Minnesota Department of Natural Resources (DNR) data showing the average annual timber harvest rate in Cook County between the years 2005 and 2009 was approximately 28,178 cords (32,290 odt).[10,11] The 2010 harvest rate, which was used in Phase I analysis was 38,911 cords. The majority of the harvest was in the Aspen-birch and Spruce-fir forest type groups with more than 40% of the total harvest from the Pat Bayle and Grand Portage State Forests. Timber harvesting on public lands is expected to remain stable in the near future. Harvest by the Grand Portage Tribe could increase with expanding bioenergy applications. Future timber harvesting on private lands is unknown.

Table 3.3. Average annual timber harvest by forest type in Cook County, MN 2005 – 2009.

Forest Type	Avg harvest (cords)[1]	Oven-dry tons (odt)/cord	Avg harvest (odt)	Target rotation (yrs)[2]
White-red-jack pine	4,997	1.1417	5,705	100
Spruce-fir	4,214	1.0500	4,425	75
Oak-pine	633	1.3750	870	75
Oak-hickory	0	1.3750	0	75
Elm-ash-cottonwood	121	1.2917	156	75
Maple-beech-birch	414	1.2500	518	75
Aspen-birch	17,799	1.1583	20,617	50
TOTAL	**28,178**	**--**	**32,290**	**--**

[1] Harvest data obtained from FIA and Minnesota DNR.[12,13]
[2] Target harvest rotation age based upon a statewide assessment of silvicultural practices[14] and the state *Forest Development Manual* guidelines.[15]

[10] USDA Forest Service. 2011. FIADB Version 4.0. Available online at: http://199.128.173.17/fiadb4-downloads/datamart.html.
[11] Don Deckard, Minnesota DNR Forest Economist. Personal communication. June 24, 2011.
[12] USDA Forest Service. 2011. FIADB Version 4.0. Available online at: http://199.128.173.17/fiadb4-downloads/datamart.html.
[13] Don Deckard, Minnesota DNR Forest Economist. Personal communication. June 24, 2011.
[14] D'Amato AW, Bolton NW, Blinn, CR, Ek AR. Current status and long-term trends of silvicultural practices in Minnesota: A 2008 Assessment. Staff Paper 205. University of Minnesota, Department of Forest Resources.
[15] Minnesota Department of Natural Resources. 1997. *Forest Development Manual*. St. Paul, MN: Department of Natural Resources, Division of Forestry.

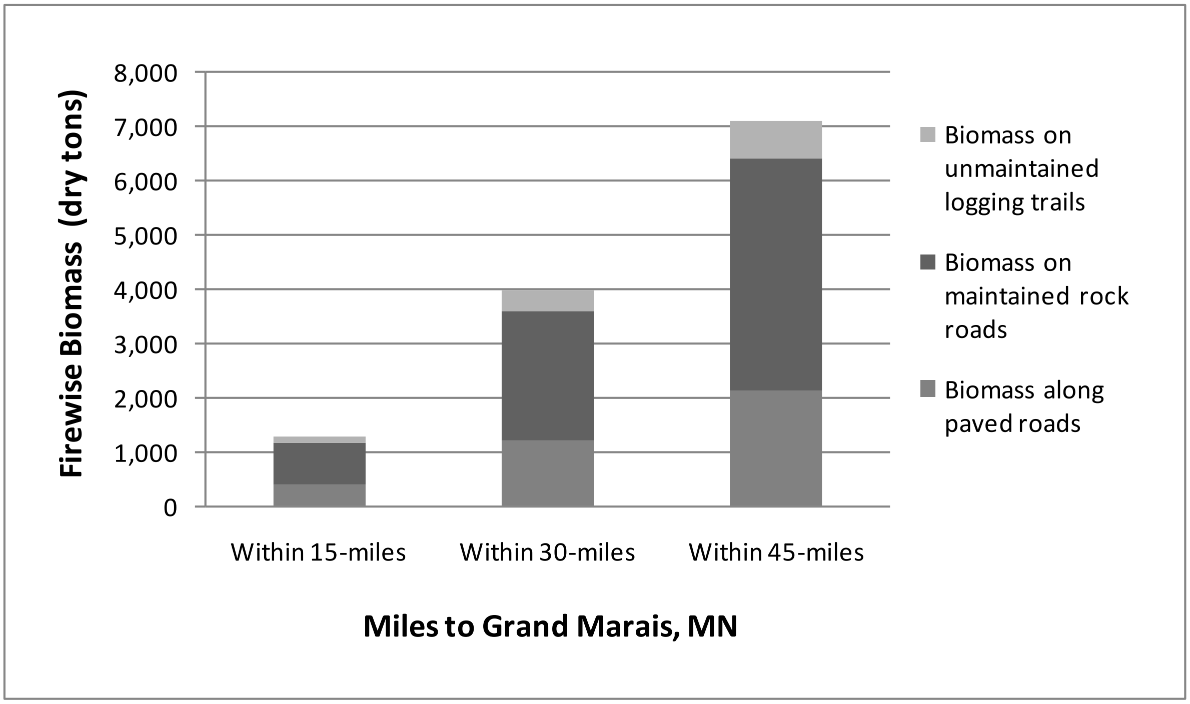

Figure 3.1. Dry tons of hog fuel from Superior National Forest timber sales and fuels reduction treatments within 45-miles of Grand Marais, MN.

Table 3.4 shows total annual biomass generated from timber harvests reported in Table 3.3. Target harvest rotation ages of 50 to 100 years are used. A 50% retention rate of available residual biomass is assumed left on site (tops and limbs) for soil nutrification, water management and wildlife habitat, which is more than the 33% retention rate recommended in the MFRC biomass harvest guidelines. The analysis indicates 5,229 odt residual biomass from timber harvesting is available annually within the county at the 38,911-cord harvest level. Table 3.4 also presents annual biomass availability for different management scenarios. For instance, as timber harvesting for primary forest products (e.g., pulpwood) increases, the corresponding amount of residual biomass increases. Assuming a statewide harvest rate of 4.0 million cords, as calculated in the *Final GEIS on Timber Harvesting and Forest Management in Minnesota*,[16] the annual sustainable harvest rate in Cook County increases to 163,546 cords/yr, nearly a 76% increase over the current year. Corresponding residual biomass increases to 23,309 odt/yr, assuming 50% retention on-site. These estimates assume no other constraints on harvest levels and are suggestive of possible removal rates only. They do not constitute a harvest plan and do not include estimates of available biomass outside the county.

[16] Jaakko Pöyry Consulting, Inc. 1994. Final generic environmental impact statement on timber harvesting and forest management in Minnesota. Prepared for the Minnesota Environmental Quality Board. Tarrytown, NY: Jaakko Pöyry Consulting, Inc.

Other management scenarios analyzed included chipping bolewood for clean chips, and wildfire fuels reduction treatments for hog fuel, referred to as Firewise removals.[17] Early stand treatments (e.g., pre-commercial thinning) and use of under-utilized species were not analyzed because of the skewed distribution of forest age classes in the county, and in particular the abundance of standing aspen-birch and spruce-fir in older age-classes (Table 3.1). Table 3.4 shows scenarios in which 10% and 20% of available bolewood at the 2010 harvest rate is chipped for bioenergy (clean chips). Bolewood chipping increases availability by an additional 4,392 odt/yr and 8,784 odt/yr, respectively. Under the GEIS scenario of 163,546-odt harvest rate, 10% bolewood generates an 18,931 odt annually.

Table 3.4 shows 3,189 odt (12,599 cu. yards) of biomass generated from Firewise removals on the Superior National Forest within Cook County. This material, which is classified as hog fuel because it includes bark, branches and needles, was generated from 1,425 acres of treatments in 2010 with an average removal rate of 3.72 odt/acre. Figure 3.1 shows the amount of this hog fuel available from the Superior National Forest within 15, 30, and 45-miles of Grand Marais by road type. Although higher removal rates are sustainable, future Firewise removals on Superior National Forest land are assumed equal to 2010 removal rates and are not constrained by budget allocations.

[17] http://www.firewise.org/

Table 3.4. Current and potential biomass availability by ownership and management scenario in Cook County, MN.

	Current availability				Potential availability			
Ownership	**2010 bolewood harvest (odt)[1]**	**2010 residual biomass (odt)[2]**	**2010 Firewise removals (odt)[3]**	**2010 total hog fuel (odt)**	**10% of 2010 bolewood (clean chips) (odt)**	**20% of 2010 bolewood (clean chips) (odt)**	**Future Firewise removals (odt)[3]**	**Residuals from GEIS harvest rate (odt)[4]**
Federal forests	16,021	1,851	3,189	5,040	1,602	3,204	3,189	14,014
State, county, and local	19,009	2,344	--	2,344	1,901	3,802	--	3,790
Private[5]	8,889	1,034	--	1,034	889	1,778	--	5,505
Total	**43,919**	**5,229**	**3,189**	**8,418**	**4,392**	**8,784**	**3,189**	**23,309**

[1] A cord is equivalent to 1.2 dry tons. The total 2010 bolewood harvest is equivalent to 38,911 cords.

[2] Residual biomass is the tops, limbs, branches and needles as defined by the USDA Forest Service FIA biomass attributes, and is in addition to the reported 2010 roundwood harvest rate for Cook County. Residual biomass availability assumes 50% retention on-site.

[3] Firewise removals are estimated for Superior National Forest removals only of slash from fuels reductions efforts based on an estimated 12,599 cu. yards of slash generated in 2010. Future removals assumed equal to 2010 and not constrained by future budget allocations.

[4] The highest level of sustainable biomass removal based upon the proportion of a statewide timber harvest level of 4.0 million cords as estimated in the Final Generic Environmental Impact Statement (GEIS) for Minnesota.[18] This amount is residual biomass only assuming 50% retention on-site, and does not include bolewood potential.

[5] Includes corporate, non-governmental conservation/natural resources organizations, unincorporated local partnerships/associations/clubs, and tribal timberlands; also includes non-industrial private woodlands.

[18] Jaakko Pöyry Consulting, Inc. 1994. Final generic environmental impact statement on timber harvesting and forest management in Minnesota. Prepared for the Minnesota Environmental Quality Board. Tarrytown, NY: Jaakko Pöyry Consulting, Inc.

3.2 Biomass Harvesting and Transport Costs

The costs of harvesting, handling, and transporting biomass to a processing facility are critical factors in the total price paid. These costs also vary widely based on operator and equipment productivity, tree species harvested, distance to processing facility, and whether co-products exist (e.g., pulpwood). For the purposes of this analysis, we assume all harvest and skidding costs associated with moving trees to a forest landing are a function of a primary pulpwood or sawlog market. Therefore, the price paid for residual biomass (tops and limbs) does not include harvest and skidding costs because they would not be incurred if it were not for those markets. Rather, the price paid at the landing includes only the chipping/grinding operation. Wages, benefits, and employer costs for workers' compensation and unemployment insurance are held constant. Total fixed and variable costs are calculated at a rate of $183.72/PMH (productive machine hour), which are the total hours of use for scheduled purposes over the course of one year (assumes $2.80/gal off-highway diesel fuel price). Assuming a productivity rate of 24 odt/PMH (approximately 2 truckloads/hr), chipping cost are $7.66/odt ($183.72/PMH ÷ 24 odt/PMH) at the landing. Appendix A provides a breakdown of equipment costs.[19]

Transportation costs are the costs of transporting biomass from the forest landing to the heating or CHP facility. Transportation costs are calculated as a function of distance traveled and highway diesel fuel cost of $3.32/gal (12-month Midwest average).[20] Using a methodology developed by the Idaho National Laboratory,[21] the average transport cost for a loaded semi-truck and trailer (25 tons) is $21.36/odt on improved roads. Within 50 miles, we therefore use a rate of $0.43/odt/mile to calculate the variable costs of transportation from the woods to the thermal heating or CHP sites analyzed in the next section.

The delivered cost of biomass is the aggregate of the harvesting, processing/handling, and transportation costs to the assessed sites. It also includes the stumpage rate for biomass, which the Superior National Forest and Minnesota DNR set at approximately $0.80/odt. The average delivered cost of biomass up to 50 miles is $29.82/odt ($0.80/odt + $7.66/odt + $21.36/odt). A summary of these costs are included in Section 5, Financial Performance.

3.3 Forest Operations

For a logger to justify moving equipment to a site to process biomass there needs to be enough throughputs to offset hourly costs. Small parcel sizes, long mobilization distances between harvest sites, and long transport distances to a heating or CHP site are disincentives. Having the appropriate equipment to efficiently harvest and process biomass are also barriers. We

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19 Brinker RW, Kinard J, Rummer B, Lanford B. 2002. Machine rates for selected forest harvesting machines. Circular 296. Auburn, AL: Alabama Agricultural Experiment Station.

20 US Energy Information Administration. 2011. Petroleum and other liquids: Annual retail gasoline and diesel prices. US Department of Energy, Washington, D.C. Available online at: http://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_nus_a.htm.

21 Blackwelder, D.B., and E. Wilkerson. 2008. Supply system costs of slash, forest thinnings, and commercial energy wood crops. TM2008-008-0 (INL/MIS-09-15228). Idaho National Laboratory.

conducted interviews with area loggers during the spring of 2011 to determine their level of interest in participating in biomass markets, equipment capacity and needs, and the costs of production, including mobilization of equipment and biomass processing. Interest among those interviewed was high but tempered by the cost of equipment and lack of biomass harvesting volume to justify expenses. None of the interviewed loggers was removing biomass generated from commercial timber harvests in Cook County at the time of interviews, but most were willing to do so if adequate markets developed for the material. One operator was conducting whole-tree chipping (bolewood/roundwood) of low value trees used for generating heat at the Grand Portage Casino in Grand Portage, MN. That same operator, who uses a stationary chipper, was the only one in the region with the equipment for processing biomass. In-woods chippers would best accommodate the types of biomass systems considered in this analysis, but biomass markets would need to expand substantially to justify additional investment.

4.0 Site Selection and Engineering

This study examines two principal methods for converting woody biomass to energy and then distributing that energy to individual buildings and businesses:

- **Thermal heating** is generated by burning biomass in a stove/furnace/boiler to produce hot water or radiant convection heat, which is circulated through a single or multiple buildings via piping and then distributed as heat through a network of radiant units or through a heat exchanger using forced air (Figure 4.1).

- **Combined heat and power (CHP, or cogeneration)** is a technology that employs a vaporized, low boiling point, high molecular weight organic fluid to spin a turbine and generate electricity. The waste heat generated is sufficient to produce 175°F water, which is circulated to homes and businesses (Figure 4.2).

In both cases, insulated piping is required to convey the hot water to the building(s) and return the cooled water to the heating plant where it is re-heated and re-circulated. The piping will vary in diameter from 1” to 10”, depending on the heat load, and is typically buried on a 6” sand base with at least 24” of cover. Additional piping is also needed to connect each business or home to the main supply line. The district heating fluid goes through a heat exchanger at the home or business to be used for hot water or heat. Some conversion of the building’s heating system to a hot water heat supply may also be necessary.

A number of businesses in Cook County are seasonal and located in remote areas. This presents both opportunities and challenges. In areas such as Tofte and Lutsen, low population density limits the size of energy systems due to high piping costs and the amount of heat loss resulting from moving hot water over long distances. Even in Grand Marais the population density is low for the application of district heat. However, there is a potential for biomass to be used on a relatively small scale to provide energy to communities, or scaled to individual homes or resorts, using small district heating or individual biomass-powered furnaces.

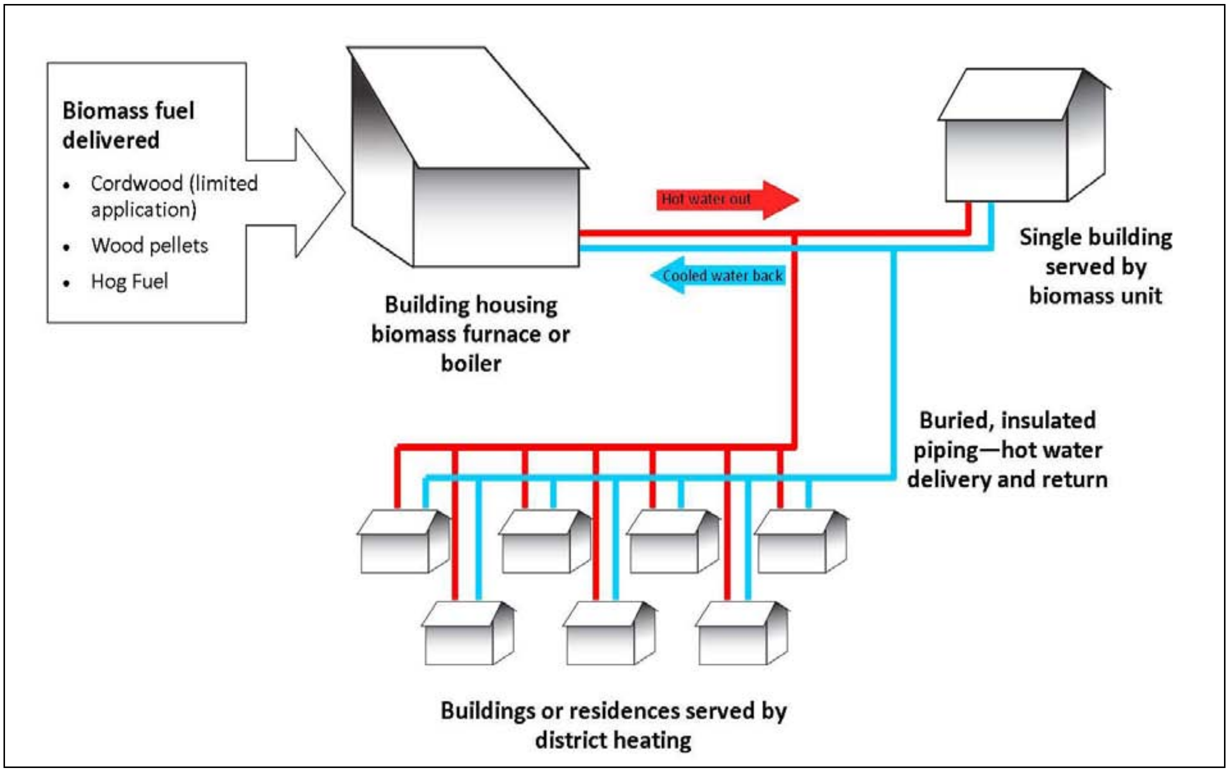

Figure 4.1. Generic woody biomass thermal heating system.

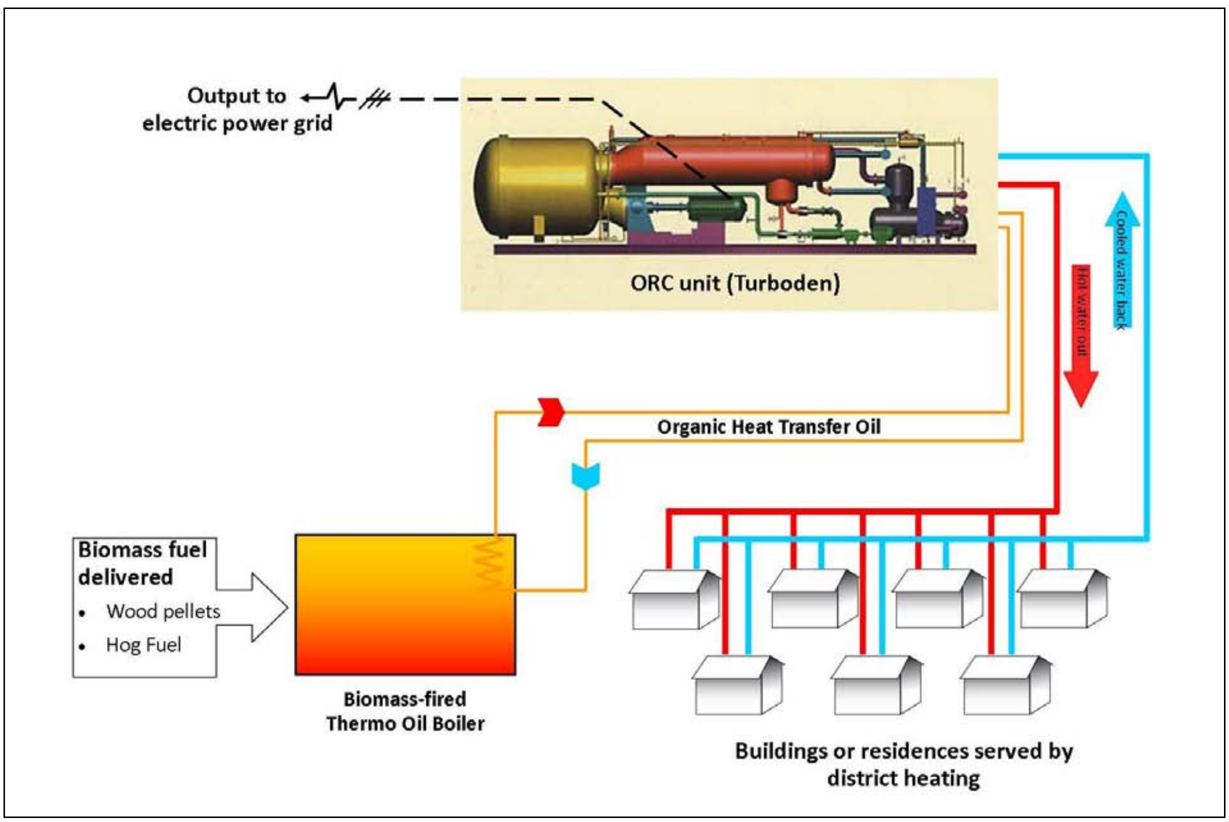

Figure 4.2. Organic Rankin Cycle (ORC) combined heat and power (CHP) system.

The approach used in Phase I analysis was to develop proxy information that could be applied to different sites reflecting the diversity of size, location, and types of heating systems in Cook County. An initial selection of thirteen sites was made across three categories of relative scale—small, medium and large. The team concluded that a detailed assessment of one site at each scale was sufficient to provide data that could be extrapolated to the majority of sites in the county. Within each site multiple configurations were modeled to approximate conditions in non-assessed sites. The final study sites selected were Individual homes & Bearskin Lodge (small), Lutsen Resort (medium), Grand Marais (large).

Multiple combinations of scale and technology were modeled for each site to assess technical and financial performance. The mix of technologies were selected and sized to optimize financial and technical performance using cordwood, clean chips, hog fuel, or wood pellets. While these configurations are specific to actual facilities or clusters of buildings, the analysis can be applied to a variety of locations by altering site-specific variables like distance of hot water piping and mmBtu required. The following sections provide a breakdown of specific equipment and site factors modeled for the small, medium, and large configurations. See Table 4.1 for equipment specifications.

- **Small-scale configurations (S)** modeled two types of buildings, a single-family residence and Bearskin Lodge. The single residence configuration (S1) was modeled for a free-standing stove using cordwood or wood pellets. A larger flex-fuel boiler that provides space heating and hot water using cordwood or wood pellets as the primary heat source was modeled as S2. Bearskin Lodge, which is 25 miles north of Grand Marais on the Gun Flint Trail (County Road 12), has 17 total buildings on site. A mix of propane fueled hot water and forced air heating are the primary heat sources. Two configurations were modeled for this scale, the first (S3) modeled a cordwood-boiler for the main lodge. The second configuration (S4) modeled a distributed heating system for the main lodge and guest cabins using clean chips and wood pellets as the primary heat source. Other buildings were omitted due to the distance of piping needed and small heating demand.

- **Medium-scale configuration (M)** modeled Lutsen Resort on Lake Superior, approximately 20 miles south of Grand Marais on Hwy 61, can serve as a proxy for larger resorts and business clusters in the county. Lutsen Resort has 30 buildings and approximately 133,000 sq ft of required heating space. Propane fueled hot water is the primary heat source. Only one configuration was modeled for this site (M1), which was a distributed heating system for the main building and guest cabins on the south side of the Poplar River using clean chips and wood pellets as the primary heat source. Included is the hot water load to heat the indoor pool in the main building. The Poplar River Condos on the north side of the river were excluded because of the distance of piping required, and the interruptible electricity rate in place for those buildings making it unlikely wood energy would compete financially. The S2 configuration would be similar to the Poplar River Condos in terms of heat load.

- **Large-scale configurations (L)** modeled various options in Grand Marais, with the potential to reach up to 45 commercial properties, hundreds of residences, three condominiums, three apartment complexes, hospital, county courthouse, existing community center, and law enforcement center.[22] Hot water demand was included in the total demand load for each configuration. In total, eight configurations were modeled, the first (L1) being a thermal heating system for the Cook County Courthouse fueled by clean chips or wood pellets, which is similar to Bearskin Lodge but would require less underground piping. The second (L2), a distributed heating system for the public buildings north of 5th Street North excluding the hospital and clinic because of the need for 175-degree water for sterilization, and recent heating system upgrades to the clinic. Clean chips and pellets were modeled as the primary fuel source. The third configuration (L3) encompasses the same buildings as L2 plus adding the hospital and clinic. The fourth configuration (L4) modeled district heating for the downtown commercial district south of Hwy 61 bounded by 4th Ave East with total heating load of 19,500 mmBtu/yr (Figure 4.3). The fifth configuration (L5) includes the downtown commercial district plus the public buildings north of 5th Street North, excluding the hospital and clinic. Piping would run along Hwy 61, north on 6th Ave East and west on 5th St North bounded by 5th Ave West (Figure 4.4). The sixth configuration (L6) encompasses the same buildings and piping as L5 plus adding the hospital and clinic. The seventh (L7) modeled district heating for residential and commercial businesses in Grand Marais bounded by 5th Ave West and 6th Ave East with total heat usage of 45,000 mmBtu/year (Figure 4.5). The eighth configuration (L8) modeled the same area as in L7 but using an Organic Rankine Cycle (ORC) system to produce heat and electricity. Hog fuel and wood pellets were modeled as the primary fuel sources for L4-L8.

Fuel usage data for small and medium configurations were obtained from the owners of the assessed facilities, most of which are heated with propane and off-peak electricity. Household fuel use data were obtained from the Census Bureau's Profile of Housing Characteristics.[23] Large users in Grand Marais, most of which use propane or heating oil, were surveyed to determine current use volumes by season. Fuel usage was in line with current statewide fossil fuel price averages and rates were confirmed with fuel suppliers in the Grand Marais area. Historic trends of the statewide average prices are shown in Figure 5.1.

Table 4.2 provides a cost summary of capital, installation, operations and maintenance (O&M), buildings, piping, and related project development aspects for each system, scale, and configuration modeled. Competitive quotes were obtained for larger equipment. Industry knowledge of LHB, Inc. was used to determine O&M estimates for smaller configurations.

[22] Proposed facilities were excluded from the analysis; any new facility could significantly alter results depending on size, location, and scheduled heat demand.

[23] Factfinder.Census.gov. Fact Sheet Grand Marais city, 2000 Housing Characteristics. (2010 census data not yet available)

Figure 4.3. Coverage map of configuration L4.

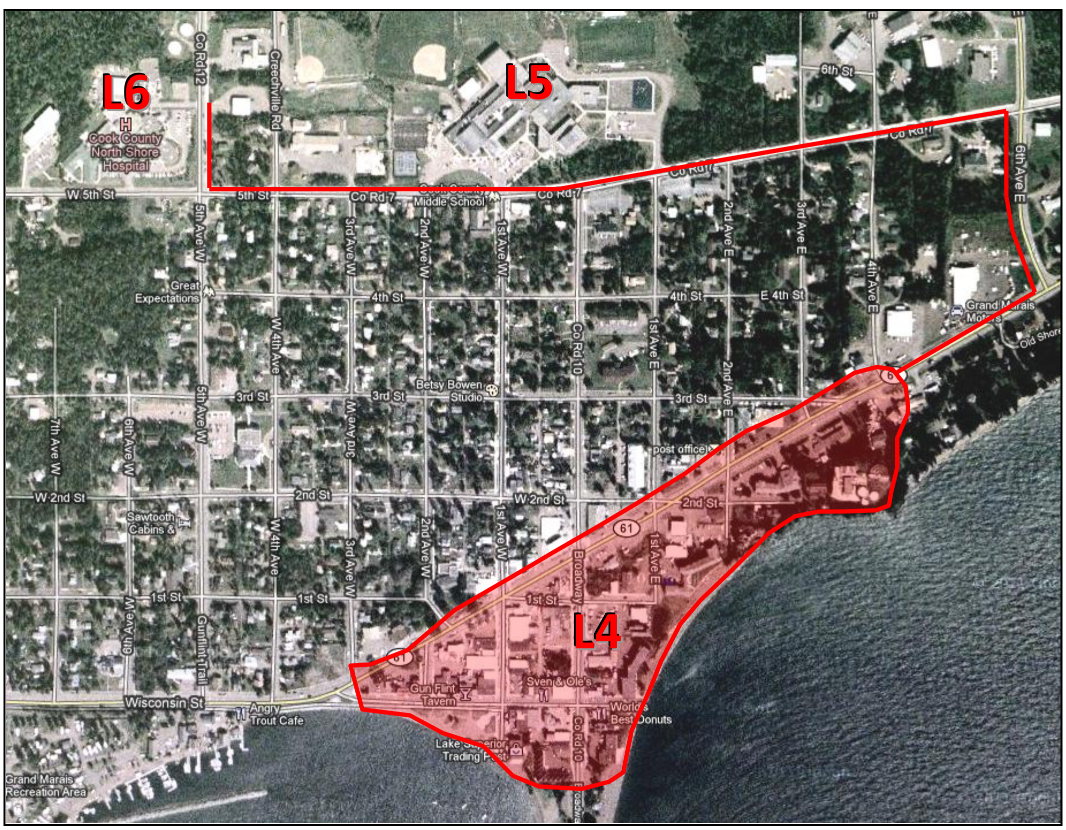

Figure 4.4. Coverage map of configuration L5 (without hospital) and L6 (with hospital).

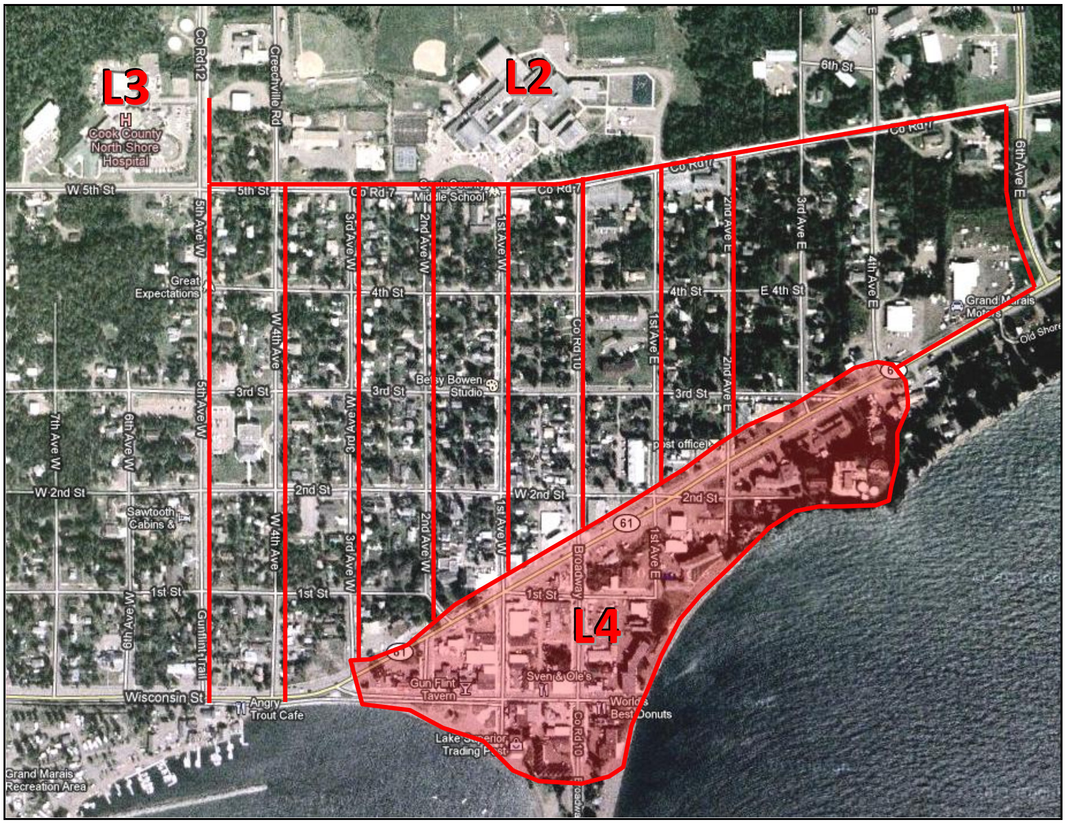

Figure 4.5. Coverage map of configuration L7 (district heat) and L8 (CHP).

Table 4.1. Modeled system configurations and equipment specifications.

Configuration	Annual heat load[1]	Boiler as priced (max/hr)[2]	Fuel type	Equipment efficiency	Biomass demand odt/yr (wet tons)	Peak boiler (gal/yr)
S1: Free-standing stove for single-family residence	35 mmBtu	Free standing stove	Cordwood Pellets	70% 83%	3.6 (5.5) 2.3 (2.6)	--
S2: Biomass furnace for single-family residence	70 mmBtu	Woodmaster Flex Fuel Furnace	Cordwood Pellets	70% 83%	7.2 (11.0) 4.7 (5.2)	--
S3: Heat for main lodge only	500 mmBtu	GARN 3200(0.42 mmBtu/hr)	Cordwood	72%	44 (68)	--
S4: Heat for multiple cabins and main lodge	1,100 mmBtu	Woodmaster Biomax(1.02 mmBtu/hr)	Clean chips Pellets	70% 82%	107 (179) 72 (80)	--
M1: Heat for multiple buildings	5,200 mmBtu	Woodmaster Biomax(4.4 mmBtu/hr)	Clean chips Pellets	70% 80%	510 (850) 342 (380)	--
L1: Heat for Cook County Courthouse	1,400 mmBtu	Woodmaster Biomax(1.02 mmBtu/hr)	Clean chips Pellets	70% 82%	132 (219) 88 (98)	--
L2: Heat for public buildings north of 5th Street N (no hospital)	5,800 mmBtu	Woodmaster Biomax(3.2 mmBtu/hr)	Clean chips Pellets	70% 80%	561 (935) 376 (418)	--
L3: Heat for public buildings north of 5th Street N (hospital)	12,100 mmBtu	Woodmaster Biomax(6.8 mmBtu/hr)	Clean chips Pellets	70% 82%	1,178 (1,963) 790 (878)	--
L4: District heat for Grand Marais business district	19,700 mmBtu	Hurst Woodmaster Biomax(13.3 mmBtu/hr)	Hog fuel Pellets	70% 80%	1,950 (3,250) 1,300 (1,450)	--
L5: District heat for business district (L4) and public buildings (L2) (no hospital)	25,500 mmBtu	Hurst Woodmaster Biomax(14.2 mmBtu/hr)	Hog fuel Pellets	70% 80%	2,500 (4,200) 1,700 (1,850)	--
L6: District heat for business district (L4) and public buildings (L3) (hospital)	34,200 mmBtu	Hurst Woodmaster Biomax(15.0 mmBtu/hr)	Hog fuel Pellets	70% 80%	3,400 (5,700) 1,520 (2,500)	--
L7: District heat for homes & businesses between 5th Ave W. and 6th Ave E.	45,000 mmBtu	Hurst Woodmaster Biomax(16.7 mmBtu/hr)	Hog fuel Pellets	70% 80%	4,600 (7,600) 3,100 (3,400)	8,800 (propane)
L8: Combined heat and power (CHP) system for configuration L7	45,000 mmBtu	VAS Thermal (heat) Turboden (CHP) 0.7 MW ORC; 1.1 mmBtu/hr peak boiler	Hog fuel Pellets	82% 82%	8,750 (14,600) 6,850 (7,600)	20,800 (propane)

[1] Assumes 55-60% of heat load with peaking backup for coldest days.

[2] Heat demand calculated for Grand Marais assumes 100-mmBtus annual demand per residence heating with propane (39%) or fuel oil (42%).

Table 4.2. Generalized costs for small, medium, and large-scale configurations in Cook County, MN.

Configuration	Fuel type	Boiler capital & installation[1]	Annual O&M[2]	Building Only[3]	Piping[4]	Customer Hookup[5]	Tax, insur., freight	Engineering; const. mgt.
S1: Free-standing stove for single-family residence	Cordwood Pellets	$4,000 $3,500	$0 $0	n/a n/a	$0	--	0%	0%; 0%
S2: Biomass furnace for single-family residence	Cordwood Pellets	$15,000 $15,000	$0 $0	n/a n/a	$0	--	0%	0%; 0%
S3: Heat for main lodge only	Cordwood	$84,350	$1,000	$36,400 (364 sq ft)	250 ft @ $165/ft	--	10%	6%; 10%
S4: Heat for multiple cabins and main lodge	Clean chips Pellets	$385,550 $310,664	$8,000 $3,000	$36,400 (364 sq ft)	1,200 ft @ $190/ft	--	10%	6%; 10%
M1: Heat for multiple buildings	Clean chips Pellets	$691,113 $610,620	$13,000 $5,000	$61,600 $56,000	1,100 ft @ $220/ft	--	10%	6%; 10%
L1: Heat for Cook County Courthouse	Clean chips Pellets	$286,492 $218,906	$2,000 $1,000	$36,400 (364 sq ft)	60 ft @ $220/ft	--	10%	6%; 10%
L2: Heat for public buildings north of 5th Street N (no hospital)	Clean chips Pellets	$735,148 $652,145	$4,000 $2,000	$61,600 $56,000	3,400 ft @ $190/ft	--	10%	6%; 10%
L3: Heat for public buildings north of 5th Street N (hospital)	Clean chips Pellets	$1,272,507 $1,109,126	$7,000 $3,500	$104,720 $95,200	4,000 ft @ $190/ft	--	10%	6%; 10%
L4: District heat for Grand Marais business district	Hog fuel Pellets	$3,150,623 $2,835,560	$150,000 $75,000	$700,000	17,765 ft @ $138/ft	$750,000	3.2%	7%; 1.4%
L5: District heat for business district (L4) and public buildings (L2)(no hospital)	Hog fuel Pellets	$3,436,224 $3,092,600	$175,000 $87,500	$730,000	25,128 ft @ $138/ft	$800,000	3.2%	7%; 1.4%
L6: District heat for business district (L4) and public buildings (L3)(hospital)	Hog fuel Pellets	$3,617,078 $3,255,370	$200,000 $100,000	$730,000	26,450 ft @ $138/ft	$950,000	3.2%	7%; 1.4%
L7: District heat for homes, businesses between 5th Ave W. and 6th Ave E.	Hog fuel Pellets	$4,400,289 $3,960,260	$300,000 $150,000	$780,000	45,400 ft @ $138/ft	$1,767,500	3.2%	7%; 1.4%
L8: Combined heat and power (CHP) system for configuration L7	Hog fuel Pellets	$9,150,299 $8,235,269	$300,000 $150,000	$1,140,000	45,400 ft @ $138/ft	$1,767,500	3.2%	6.5%; 1.4%

[1] All systems assume a 20-year usable life. Purchase price based on actual equipment supplier quotes.

[2] Excludes fuel costs and incremental electrical.

[3] Building costs assume $100/sq ft construction. Costs do not include site acquisition.

[4] Average piping costs inclusive of materials (6-in pipe with insulation), trenching (2-ft cover with 6-in sand beneath), and labor.

[5] Individual hookup costs assume $6,500 cost/homeowner, $10,000 cost/business; L7/L8 assume 70% of potential customers connect.

5.0 Financial Performance

5.1 Financial Assumptions

Table 5.1 shows the assumptions used in the financial analysis. All prices are in real dollars for 2010 meaning prices change only if there are technological changes or if shifts occur in supply or demand. Prices are held constant for each configuration. See Appendix B for financial performance metrics and definitions.

The "usable life" of all equipment modeled was assumed to be 20 years, which is common for energy-saving capital investments. Beyond 20 years, technological changes and costs for overhauls and repairs mean that most of the value of capital has depreciated. Also, the lower "discounted" value of future savings means that cash flows more than 20 years into the future are unlikely to influence present decisions.

Discount rates vary depending on the investor's view of the opportunity cost of money (if invested elsewhere) and the risk associated with the project. Higher discount rates make projects appear less attractive, meaning the investor believes an alternative project would be profitable or that expected future cash flows from the current project are highly uncertain. One typically finds discount rates between 5%-8% for energy efficiency projects.[24] We adopt a discount rate of 6.5% for all scenarios.

Non-fuel factors such as labor, operating, and maintenance costs are assumed constant because it is not conceivable that the configurations assessed would have a noticeable impact on the labor supply in Cook County or on the market for heating equipment. However, fuel costs change over time directly affecting delivered costs for cordwood, clean chips, hog fuel, and wood pellets. About 20% of harvest, handling and processing costs are fuel-related so we inflate prices at 20% of the inflation rate of diesel fuel (See Appendix A cost breakdown).

Energy values used are consistent with engineering assumptions and held constant across sites. While the energy contents for the fossil fuels are relatively constant, wood fuels fluctuate depending on the type of wood and moisture content. The energy value used for delivered cordwood is consistent with seasoned firewood, 9.4 mmBtu/ton. The energy value used for delivered clean chips and hog fuel is 8.8 mmBtu/ton, based on an average moisture content throughout the year. Wood pellets have a more consistent energy value of 16.8 mmBtu/ton.

Table 5.2 shows the average current fossil fuel prices and 20-year projections. The Energy Information Administration (EIA) of the U.S. Department of Energy publishes annual forecasts of fossil fuel costs using supply, demand, and price projections on a per mmBtu basis for the West-North-Central region of the US. We use the EIA "Reference Case" of projected annual

[24] Fuller, M. 2008. Enabling investments in energy efficiency: A study of energy efficiency programs that reduce first-cost barriers in the residential sector. Energy & Resources Group, UC Berkeley, Berkeley, CA. Website [http://www.eelriver.org/pdf/pge/Exhibit%2015%20CD-6%20(Fuller).pdf].

price change over the next 20 years (2011-2030), which assumes that fossil fuel prices in northern Minnesota will track the rest of the northern Midwest. [25] The starting price from which to escalate future prices uses averages of the most recent fuel receipts obtained from each site. Projected costs are in real 2010 dollars. Prices for the Reference Case are shown in Figure 5.1 with Minnesota and Midwest heating fuel prices over the past 10 years.

We tested the sensitivity of results to future energy prices by modeling each configuration under the "High Oil Price" scenario from the *2011 Annual Energy Outlook*.[26] Oil prices themselves are not included but are related to the prices of other fossil fuels. For comparison, in the Reference Case benchmark oil prices start at $100/barrel and increase to $123/barrel in 2030. In the High Oil Price scenario they increase to $196/barrel by 2030.

Table 5.3 shows the average current biomass fuel prices and 20-year projections. Price quotes were obtained from local suppliers of cordwood, wood pellets, and clean chips. Because there is no local market for hog fuel, we developed a delivered price of $29.82/odt (Section 3.2), which equates to $17.89/ton at 40% moisture content by weight.[27] The delivered price of cordwood was $165/cord (35% moisture content by weight) ($211/odt or $137.50/wet ton).[28]

The estimated delivered price of wood pellets was $210/ton (10% moisture by weight), which was derived from quarterly regional price reports compiled by the Pellet Fuels Institute over the past five years.[29] Those data show the average price for bagged pellets is $149.50/ton and we add an average delivery charge of $60/ton, for a total delivered pellet price of $209.50/ton. As comparison, Birch Grove School in Tofte currently pays $133/ton for standard pellets plus $79/ton bulk delivery for a delivered price of $212/ton.

To calculate future pellet prices, we used information on the fuel costs of producing pellets as a price escalator. Electricity comprises about 6.5% of the cost of pellet production, and drying fuel using pellet dust or hog fuel comprises 16%. To be consistent with other assumptions, we link the electricity portion of pellet production costs to the change in electricity prices and link the drying fuel portion to the change in hog fuel prices. As a result, the price of production increases by 0.1% per year in the Reference Case scenario and 0.4% per year in the High Oil Price scenario. We link the delivery portion of pellet prices to the EIA Reference Case for diesel fuel, which has an annual price increase of 1.4%. In the High Oil Price scenario, diesel fuel increases 3.3% annually.

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[25] US Energy Information Administration. 2010. Annual Energy Outlook 2010. DOE/EIA-0383. US Department of Energy, Washington, D.C. Available online at: http://www.eia.gov/oiaf/archive/aeo10/pdf/0383%282010%29.pdf.

[26] Ibid

[27] Formula for translating dry weight and wet weight: wet weight * (1 - % moisture content by weight) = dry weight. 1 dry ton equals 1.67 tons at 40% moisture; $29.82/dry ton ÷ (1.67 wet tons/dry ton) = $17.89/wet ton.

[28] 1 wet cord * (1 - .35 Moisture by weight) = .65 dry cords. With 1.2 dry tons per cord, this equals (.65 * 1.2) = .78 dry tons/wet cord. $165 ÷ .78 = $211/dry ton. $211/dry ton ÷ (1.54 wet tons/dry ton) = $137.50/wet ton.

[29] Pellet Fuels Institute. 2010. PFI quarterly newsletters. Arlington, VA. Available online at: http://pelletheat.org/about-us/pfi-newsletter/.

Finally, we estimated the delivered price of clean chips to be $45/ton (40% moisture by weight) with an average delivery distance of 50 miles. While there are limited markets for clean chips in the county, chip prices have been consistent over the past few years with most price changes occurring from the increased cost of delivery.

Table 5.1. Non-fuel investment and financing assumptions.

Financial metric	Assumption
Capital useful life	20 years
Discount rate	6.5%
Annual inflation rate (non-fuel)	0%
Years tax depreciation (if applicable)	10 years
Income tax rate (if applicable)	35%
Financed amount	0%
Financing term (if applicable)	10 years
Interest rate on loan (if applicable)	6.7%

Table 5.2. Average current fossil fuel prices and 20-year annual rates of change.

Fuel type	Statewide average price[1]	Cook County price used[2]	Annual change, reference case	Annual change, high oil price
Electric (¢/kWh)	10.4¢	10.4¢ to 12.5¢	-0.65%	-0.57%
Off-peak electric (¢/kWh)[3]	n/a	6.0¢	-0.65%	-0.57%
#2 heating oil ($/gal)	$3.09	$3.09	0.95%	2.89%
Propane ($/gal)	$2.18	$2.05 to $2.30	1.84%	4.26%
Diesel fuel ($/gal)	$3.32	$3.32	1.44%	3.34%

[1] Based on Minnesota data from the Energy Information Administration

[2] Prices approximate 2010/2011 averages, from current Cook County users.

[3] Price from current Cook County, MN users; escalation rate same as regular electric.

Table 5.3. Average current biomass delivered fuel prices in Cook County, MN

Biomass type	Cook County price $/dry ton (+delivery)	Cook County price $/wet ton (+delivery)	Annual % change, reference scenario (delivery)	Annual % change, high oil scenario (delivery)
Cordwood[1]	$154 ($58)	$100 ($38)	0.3 (1.4)	0.7 (3.3)
Pellets[2]	$167 ($67)	$150 ($60)	0.1 (1.4)	0.4 (3.3)
Clean chips[3]	$58 ($17)	$35 ($10)	0.3 (1.4)	0.7 (3.3)
Hog fuel[4]	$8.50 ($21)	$5 ($13)	0.3 (1.4)	0.7 (3.3)

[1] Price based on conversations with local suppliers

[2] Price based on Pellet Fuels Institute data and conversations with local bulk pellet buyers

[3] Price based on conversations with local buyers

[4] Calculated via Section 3.2, Biomass Harvesting and Transport Costs.

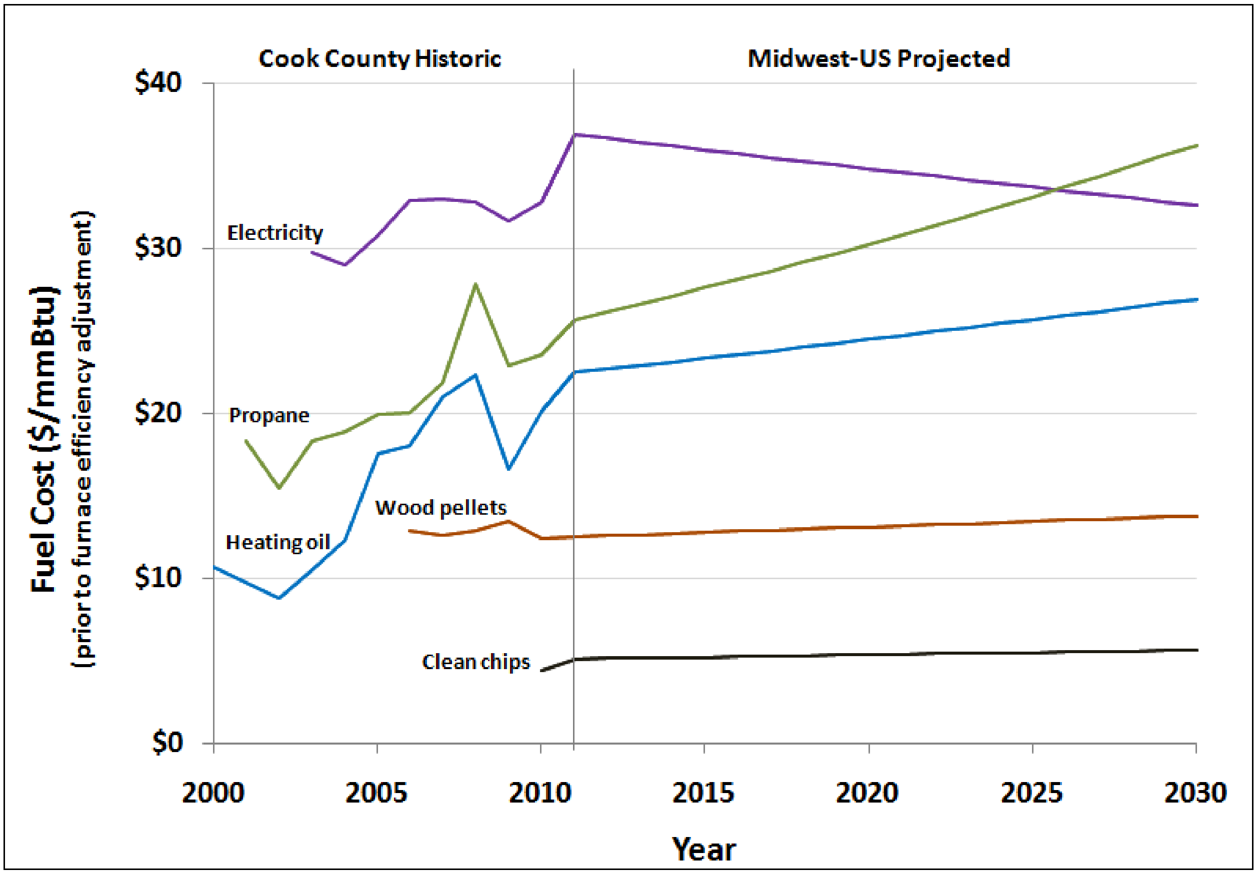

Figure 5.1. Cook County historic and Midwest-US projected prices by fuel type (2010 dollars).

5.2 Financial Performance Summary

Table 5.4 presents cumulative and disaggregated cost data for each configuration organized by capital construction costs and annual operating costs for the reference and high oil price scenarios for future projections. Shown at the bottom of the table, the performance metrics provided for each configuration are:

- **Cost of heat**, also known as the Levelized Cost of Energy (LCOE), is the lifetime capital and O&M costs divided by the total energy united produced (see Appendix C);
- **Simple payback period** is the number of years it would take for the savings from a project to pay off the initial cost (not adjusted for the time value of money);
- **Return on investment** is the (undiscounted) financial return minus the cost of investment, divided by the cost of investment *over the life of the project*. The time value of money (discount rate) is not considered, but the simple undiscounted return on investment can be used to compare between projects of equal life.
- **Outstanding capital needed** is the total amortized capital and annual operating cost of a new biomass system minus the savings on fuel over 20-years. The lower this figure is, the more attractive the biomass project.

Table 5.4. Financial performance of small (S), medium (M), and large (L) configurations.

	S1 Free standing stove for single-family residence		S2 Biomass furnace for single-family residence		S3 Heat for main lodge	S4 Heat for multiple cabins and lodge		M1 Heat for multiple buildings	
Thermal demand	35 mmBtu/yr		70 mmBtu/yr		500 mmBtu/yr	1,100 mmBtu/yr		5,200 mmBtu/yr	
20-yr effective fossil fuel price[2]	$29.50/mmBtu		$29.50/mmBtu		$22.50/mmBtu	$24.00/mmBtu		$31.50/mmBtu	
Fuel type	Cordwood	Pellets	Cordwood	Pellets	Cordwood	Clean chips	Pellets	Clean chips	Pellets
Capital construction costs									
Site prep and& building	$1,500	$1,000	$5,000	$5,000	$41,000	$97,000	$83,000	$149,000	$128,000
Boiler and fuel receiving	$2,500	$2,500	$10,000	$10,000	$45,000	$185,000	$140,000	$397,000	$349,000
Back-up boilers	--	--	--	--	--	--	--	--	--
Piping & pumping	--	--	--	--	$43,000	$233,000	$233,000	$247,000	$247,000
Other misc[1]	$0	$0	$0	$0	$33,000	$134,000	$119,000	$202,000	$185,000
Homeowner hookup	--	--	--	--	--	--	--	--	--
TOTAL	**$4,000**	**$3,500**	**$15,000**	**$15,000**	**$162,000**	**$649,000**	**$575,000**	**$995,000**	**$909,000**
Annual operating costs (20 yrs)									
Delivered wood costs									
Reference scenario	$800	$600	$1,500	$1,100	$9,400	$8,100	$16,900	$38,500	$80,300
High oil price scenario	$800	$600	$1,500	$1,100	$9,500	$8,100	$17,000	$38,700	$80,800
O&M, utilities & electric	$0	$0	$0	$0	$1,200	$8,900	$3,700	$15,300	$6,800
TOTAL Reference	**$800**	**$600**	**$1,500**	**$1,100**	**$10,600**	**$17,000**	**$20,600**	**$53,800**	**$87,100**
TOTAL High Oil Price	**$800**	**$600**	**$1,500**	**$1,100**	**$10,700**	**$17,000**	**$20,700**	**$54,000**	**$87,600**
Reference scenario									
Cost of heat ($/mmBtu)[2]	$32.00	$24.70	$40.80	$34.80	$55.90	$69.30	$66.70	$27.80	$32.90
Simple payback period	9 years	6 years	16 years	11 years	>20 years	>20 years	>20 years	9 years	12 yrs
Return on investment[3]	147%	310%	32%	91%	-109%	-71%	-81%	134%	78%
Outstanding capital needed[4]	$0	$0	$4,900	$100	$170,200	$548,900	$517,700	$0	$76,100
High oil price scenario									
Cost of heat ($/mmBtu)[2]	$33.60	$25.70	$42.40	$35.80	$57.40	$69.80	$67.60	$28.30	$33.90
Simple payback period	8 years	5 years	12 years	9 years	>20 years	>20 years	>20 years	8 years	10 years
Return on investment[3]	312%	514%	120%	186%	-105%	-61%	-72%	234%	181%
Outstanding capital needed[4]	$0	$0	$0	$0	$166,800	$519,300	$494,500	$0	$0

[1] Other miscellaneous costs include taxes, insurance, freight, engineering services, and construction management.

[2] The annual levelized cost of providing heat over the next 20 years, which is the capital and operating costs divided by the total units of energy produced (mmBtu) over that time period adjusted for furnace efficiency. Cost of heat does not include the replacement cost of existing boiler(s). For L8 configurations, this figure does not include credit for electricity sales; these are shown instead in Figure 5.2.

[3] Total revenue divided by total expenses over 20-years (non-discounted rate, before taxes).

[4] Amount of investment needed in addition to the fuel cost savings achieved over 20 years; includes all capital and operating costs amortized over 20 years.

Table 5.4 (continued). Financial performance of small (S), medium (M), and large (L) configurations.

	L1 **Heat for Cook County Courthouse**		**L2** **Heat for public buildings north of 5th St N (no hospital)**		**L3** **Heat for public buildings north of 5th St N (hospital)**		**L4** **District heat for Grand Marais business district**	
Thermal demand	1,400 mmBtu/yr		5,800 mmBtu/yr		12,100 mmBtu/yr		19,700 mmBtu/yr	
20-yr effective fossil fuel price[2]	$35.90/mmBtu		$34.90/mmBtu		$32.60/mmBtu		$33.30/mmBtu	
Fuel type	Clean chips	Pellets	Clean Chips	Pellets	Clean Chips	Pellets	Hog fuel	Pellets
Capital construction costs								
Site prep and& building	$67,000	$58,000	$149,000	$128,000	$208,000	$180,000	$1,235,000	$1,112,000
Boiler and fuel receiving	$185,000	$140,000	$350,000	$300,000	$520,000	$460,000	$1,360,000	$1,224,000
Back-up boilers	--	--	--	--	$200,000	$150,000	$330,000	$297,000
Piping & pumping	$15,000	$15,000	$651,000	$651,000	$775,000	$775,000	$2,522,000	$2,522,000
Other misc[1]	$69,000	$55,000	$293,000	$275,000	$434,000	$399,000	$861,000	$775,000
Homeowner hookup	--	--	--	--	--	--	$750,000	$750,000
TOTAL	**$336,000**	**$269,000**	**$1,443,000**	**$1,354,000**	**$2,137,000**	**$1,964,000**	**$7,058,000**	**$6,679,000**
Annual operating costs (20 yrs)								
Delivered wood costs								
Reference scenario	$10,000	$21,000	$42,000	$88,000	$89,000	$185,000	$60,000	$313,000
High oil price scenario	$10,000	$21,000	$42,000	$89,000	$89,000	$186,000	$61,000	$320,000
O&M, utilities & electric	$3,200	$1,900	$4,000	$2,000	$7,000	$3,500	$150,000	$75,000
TOTAL Reference	**$13,200**	**$22,900**	**$46,000**	**$90,000**	**$96,000**	**$188,500**	**$210,000**	**$388,000**
TOTAL High Oil Price	**$13,200**	**$22,900**	**$46,000**	**$91,000**	**$96,000**	**$189,500**	**$211,000**	**$395,000**
Reference scenario								
Cost of heat ($/mmBtu)[2]	$32.80	$35.50	$31.00	$37.60	$24.20	$31.00	$43.50	$51.20
Simple payback period	10 yrs	11 yrs	10 yrs	13 yrs	7 yrs	10 yrs	16 yrs	>20 yrs
Return on investment[3]	117%	98%	122%	68%	186%	111%	30%	-19%
Outstanding capital needed[4]	$0	$0	$0	$170,000	$0	$0	$2,217,000	$3,879,000
High oil price scenario								
Cost of heat ($/mmBtu)[2]	$33.20	$36.50	$31.40	$38.30	$24.60	$31.70	$44.00	$54.50
Simple payback period	9 yrs	9 yrs	8 yrs	10 yrs	7 yrs	8 yrs	13 yrs	18 yrs
Return on investment[3]	205%	201%	205%	153%	283%	211%	80%	13%
Outstanding capital needed[4]	$0	$0	$0	$0	$0	$0	$701,000	$2,981,000

[1] Other miscellaneous costs include taxes, insurance, freight, engineering services, and construction management.

[2] The annual levelized cost of providing heat over the next 20 years, which is the capital and operating costs divided by the total units of energy produced (mmBtu) over that time period adjusted for furnace efficiency. Cost of heat does not include the replacement cost of existing boiler(s). For L8 configurations, this figure does not include credit for electricity sales; these are shown instead in Figure 5.2.

[3] Total revenue divided by total expenses over 20-years (non-discounted rate, before taxes).

[4] Amount of investment needed in addition to the fuel cost savings achieved over 20 years; includes all capital and operating costs amortized over 20 years.

Table 5.4 (continued). Financial performance of small (S), medium (M), and large (L) configurations.

	L5 Business district plus public buildings (no hospital)		**L6** Business district plus public buildings (with hospital)		**L7** Grand Marais homes and businesses		**L8** Combined heat and power system for Grand Marais	
Thermal demand	25,500 mmBtu/yr		34,200 mmBtu/yr		45,000 mmBtu/yr		45,000 mmBtu/yr	
20-yr eff. fossil fuel price[2]	$33.60/mmBtu		$32.60/mmBtu		$33.20/mmBtu		$33.20/mmBtu	
Fuel type	Hog fuel	Pellets	Hog fuel	Pellets	Hog fuel	Pellets	Hog fuel	Pellets
Capital construction costs								
Site prep and& building	$1,264,000	$1,137,000	$1,330,000	$1,197,000	$1,485,000	$1,337,000	$1,945,000	$1,797,000
Boiler and fuel receiving	$1,482,000	$1,334,000	$1,560,000	$1,404,000	$1,810,000	$1,629,000	$4,010,000	$5,819,000
Back-up boilers	$333,000	$299,000	$350,000	$315,000	$374,000	$337,000	$374,000	$337,000
Piping & pumping	$3,542,000	$3,542,000	$3,658,000	$3,658,000	$6,278,000	$6,278,000	$6,279,000	$6,278,000
Other misc[1]	$985,000	$887,000	$1,037,000	$933,000	$1,511,000	$1,292,000	$1,107,000	$1,752,000
Homeowner hookup	$800,000	$800,000	$950,000	$950,000	$1,768,000	$1,768,000	$1,768,000	$1,768,000
TOTAL	**$8,405,000**	**$7,992,000**	**$8,855,000**	**$8,457,000**	**$13,226,000**	**$12,641,000**	**$15,483,000**	**$17,751,000**
Annual op. costs (20 yrs)								
Delivered wood costs								
Reference scenario	$78,000	$406,000	$104,000	$545,000	$137,000	$717,000	$263,000	$1,608,000
High oil price scenario	$79,000	$414,000	$106,000	$556,000	$139,000	$731,000	$267,000	$1,641,000
O&M, utilities & electric	$175,000	$88,000	$200,000	$100,000	$300,000	$150,000	$300,000	$150,000
TOTAL Reference	**$253,000**	**$494,000**	**$304,000**	**$645,000**	**$437,000**	**$867,000**	**$563,000**	**$1,758,000**
TOTAL High Oil Price	**$254,000**	**$502,000**	**$306,000**	**$656,000**	**$439,000**	**$881,000**	**$567,000**	**$1,791,000**
Reference scenario								
Cost of heat ($/mmBtu)[2]	$40.20	$48.50	$32.90	$42.10	$37.20	$46.10	$51.30	$77.70
Simple payback period	14 yrs	>20 yrs	11 yrs	18 yrs	13 yrs	>20 yrs	15 yrs	>20 yrs
Return on investment[3]	48%	-7%	86%	12%	59%	-5%	30%	-106%
Outst.cap. needed[4]	$1,837,000	$4,171,000	$113,000	$3,561,000	$1,996,000	$6,381,000	$8,972,000	$22,056,000
High oil price scenario								
Cost of heat ($/mmBtu)[2]	$40.60	$51.80	$33.40	$45.40	$37.80	$49.50	$52.50	$85.50
Simple payback period	12 yrs	17 yrs	10 yrs	15 yrs	11 yrs	17 yrs	13 yrs	>20 yrs
Return on investment[3]	104%	29%	151%	51%	112%	24%	65%	-113%
Outst. cap. needed[4]	$0	$2,956,000	$0	$2,142,000	$0	$4,809,000	$6,283,000	$22,618,000

[1] Other miscellaneous costs include taxes, insurance, freight, engineering services, and construction management.

[2] The annual levelized cost of providing heat over the next 20 years, which is the capital and operating costs divided by the total units of energy produced (mmBtu) over that time period adjusted for furnace efficiency. Cost of heat does not include the replacement cost of existing boiler(s). For L8 configurations, this figure does not include credit for electricity sales; these are shown instead in Figure 5.2.

[3] Total revenue divided by total expenses over 20-years (non-discounted rate, before taxes).

[4] Amount of investment needed in addition to the fuel cost savings achieved over 20 years; includes all capital and operating costs amortized over 20 years.

Figure 5.2 shows the cost of heat, or LCOE, for each configuration and the portion comprised by each cost component. Worth noting is the portion of the LCOE represented by piping costs, which can have a significant impact on profitability of small systems. In the CHP configurations (L8), the LCOE includes sales of electricity at $0.075/kWh. 4.2 million kWh would be produced annually, resulting in annual revenues of $315,000.

Figure 5.3 shows the LCOE for each configuration assuming the EIA Reference Case. For comparison, the white stripe marks the average 20-year fossil fuel price (adjusted for furnace efficiency). Where the LCOE is lower than the fossil fuel price, the biomass system would "pay for itself" in fuel savings in 20-years or less. Figure 5.4 shows the same information, but under the assumption of high oil prices. The LCOE for the biomass configurations are relatively similar. However, there is a noticeable difference in the higher level of fossil fuel prices, which improves the savings from the biomass systems allowing them to "pay for themselves" more quickly.

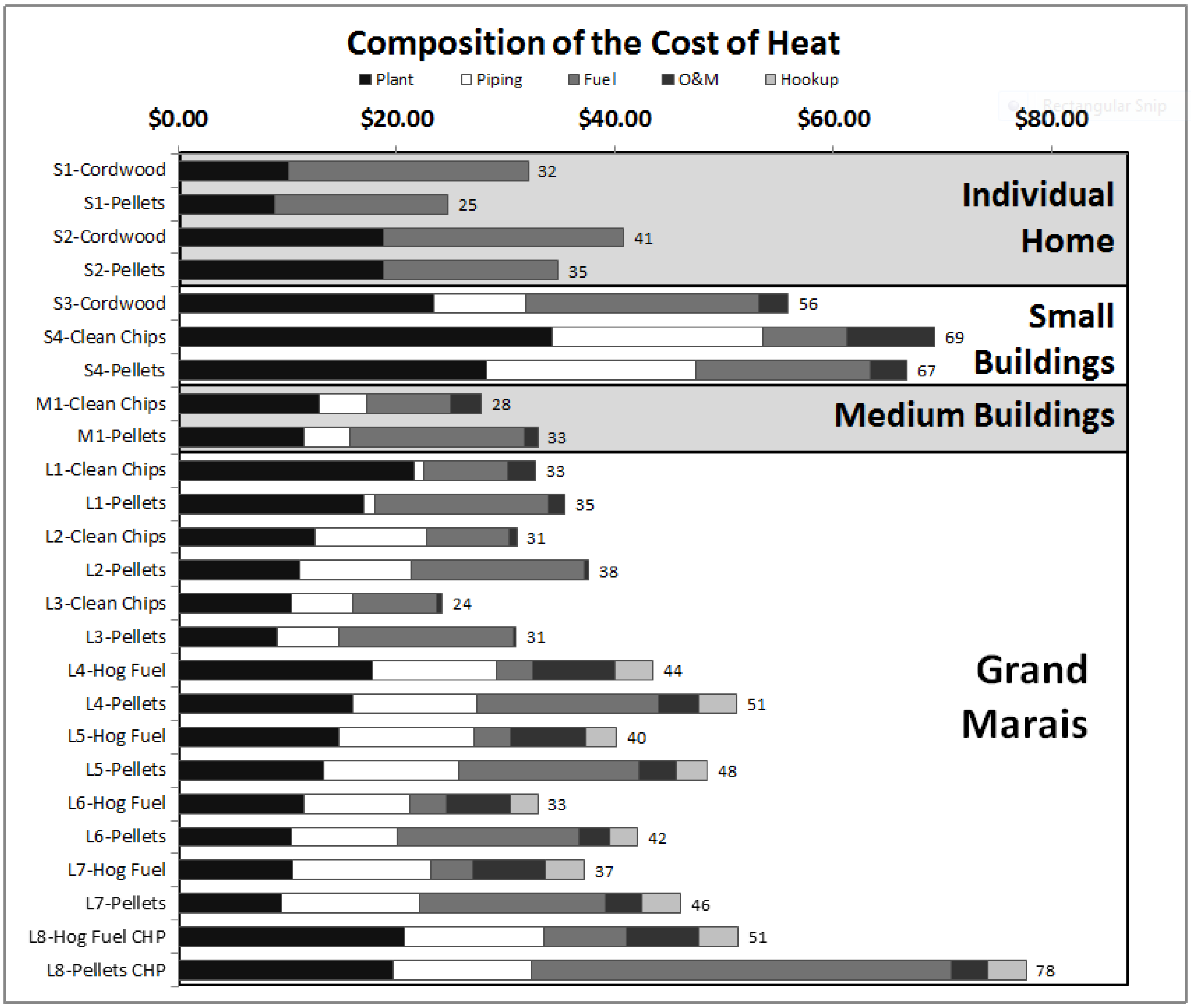

Figure 5.2. Composition of the Levelized Cost of Energy (LCOE) by site configuration.

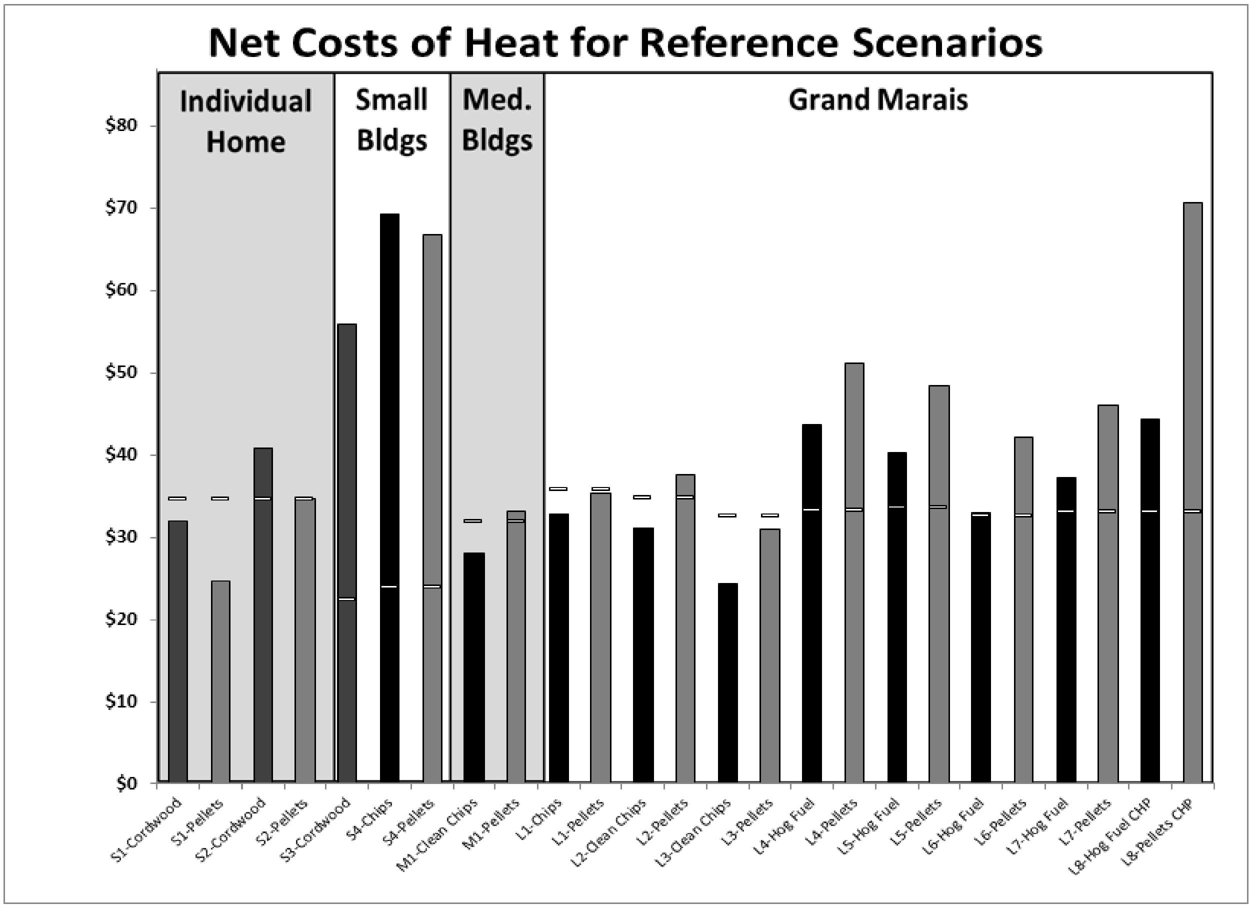

Figure 5.3. 20-year Levelized Cost of Energy by site configuration using the EIA Reference Scenario.

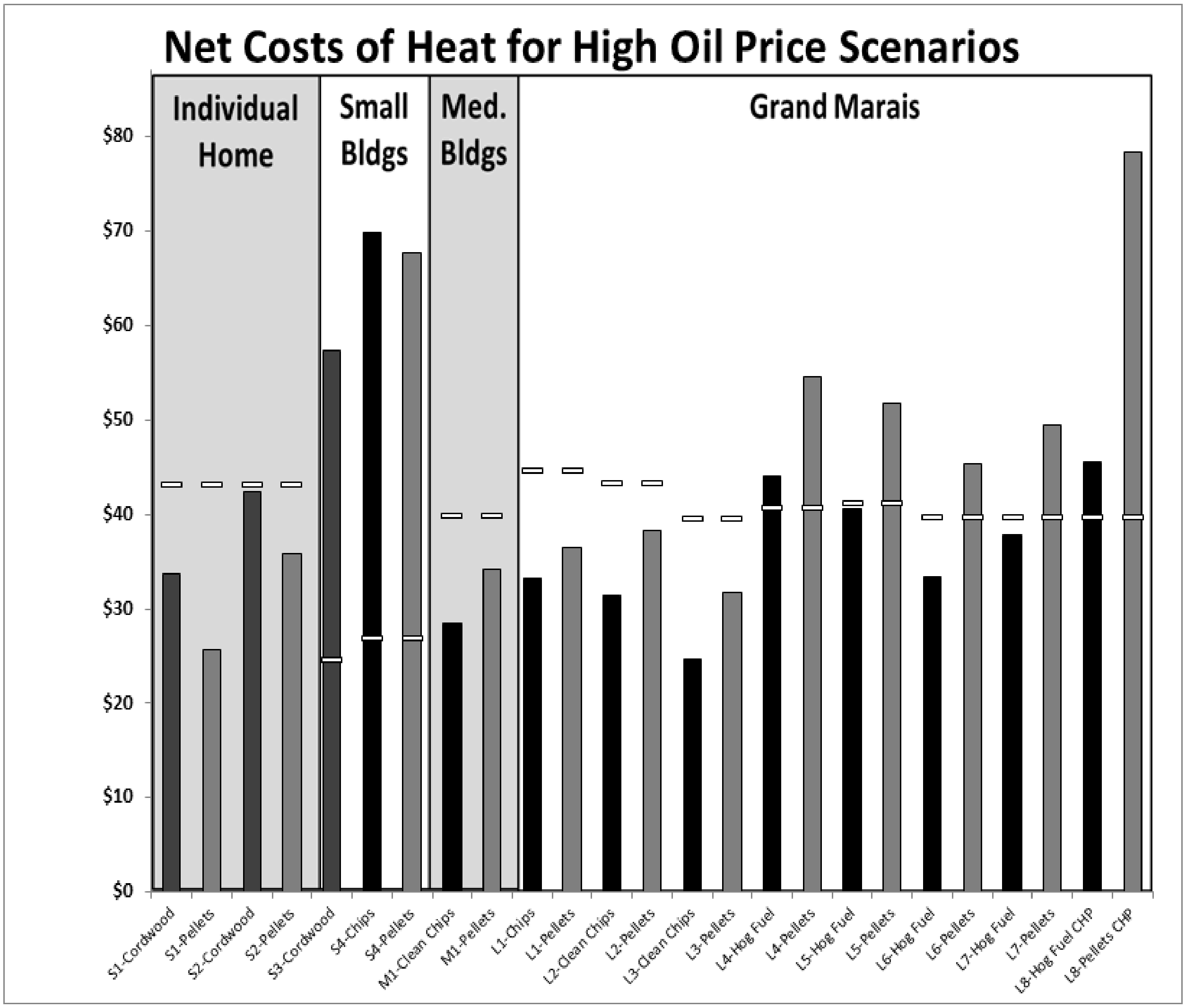

Figure 5.4. 20-year levelized cost of heat by site configuration assuming high oil prices.

6.0 Other Considerations

6.1 Measuring Regional Economic Impacts

It is not within the scope of this study to conduct an economic impact analysis of biomass utilization in Cook County. However, we reference findings from studies in other parts of the country to identify a range of economic impacts possible (Table 6.1). We emphasize that the impacts reported may not be applicable to Cook County because of differences in the mix of local industries and the flow of goods and services into and out of the region. The results of these studies are also highly variable and depend upon the size of the region and diversity of goods and services available.

An accurate analysis for Cook County would require a substantial investment to determine the proportion of fossil fuel expenditures "leaking" out of the local economy relative to the "direct, indirect, and induced" spending that would occur by switching to biomass energy. The greater the diversity of industrial sectors existing locally in which to absorb new spending, the greater the indirect and induced effects, which are referred to as multipliers. Multipliers are a calculation of the proportion of new spending re-circulating before eventually leaking out the economy and spent elsewhere. If bioenergy is locally produced, Cook County residences and businesses could use the money that would otherwise flow out of region in the form of fossil fuel payments for any variety of local goods and services, including bioenergy.[30]

The ***direct effect*** of converting to locally produced bioenergy is to increase local economic spending by the price of the replacement biomass fuel.[31] Capital equipment purchased from outside the region would have zero direct effect on the local economy, so most studies cited only consider the labor portion of capital costs in their calculation of the direct effect. There are also additional ***indirect*** and ***induced effects***, which result from the recirculation of bioenergy payments and the forgone fossil fuel payments, increasing local economic activity with each transaction where the dollars are retained locally.[32] The ***total effect*** is the sum of the direct, indirect and induced effects, which can be measured in jobs, income, or spending. The ***output multiplier*** is the total effect divided by the direct effect. The total impact on the local economy of switching to bioenergy is calculated by multiplying biomass purchases by the output multiplier. Generally, this multiplier will be higher where the region's economy is larger or more diverse.

Table 6.1 presents the range of multipliers for bioenergy applications in different parts of the country, each with a different mix of business sectors and subsequent economic impacts. Multipliers ranged from 1.26 to 1.83, meaning that for every dollar spent locally on bioenergy fuel an additional \$0.26 – \$0.83 was re-spent locally through indirect and induced spending.

[30] It is important to note that not *all* the price paid for fossil fuels flows out of the community. A 2005 study prepared for the city of Santa Fe, New Mexico, for instance, estimated that 14.49% of expenditures on natural gas remained in the local economy.

[31] This is the ***gross*** *direct effect*, and does not take into account the portion of foregone fossil fuel payments that would have remained in the local economy.

[32] The *indirect and induced* effects vary widely depending on the structure, diversity and purchasing habits of residents and businesses within the local economy. For example, saved money that is spent at a local business results in indirect and induced effects for the local economy. Saved money used to purchase a sweater through a mail-order catalogue results in near zero indirect and induced effects within the local economy.

Table 6.1. Local economic impact multipliers for biomass energy systems.

Biomass system measured	Study area	Year	Author	Direct purchases	Indirect & induced purchases	Total effect	Output multiplier
District heating	Santa Fe, NM	2005	Shuman[33]	$1.00	$0.26	$1.26	1.26
Heating	Massachusetts	2004	Timmons, et al. [34]	$66.5	$46.5	$113.0	1.70
Heating	Northeast US	1992	Timmons, et al.[35]	$70.6 million	$4.2mm	74.8mm	1.06
Heating	Voralberg, Austria	2006	Madlener & Koller[36]	€714,335	€309,909	€1,024,244	1.43
Electricity	Southeast US	2004	English, et al. [37]	$5,453	$1,896	$7,349	1.35
Electricity (100 MW)	Mississippi	2008	Perez-Verdin et al. [38]	$64.47	38.95	103.42	1.60
Electricity (3,200 MW)	Florida	2010	Hodges, et al. [39]	$1.2 billion	$1.0 Billion	$2.2 Billion	1.83

[33] Shuman, Michael H. "Economics of Proposed Biomass-fired District Heating System for Santa Fe, New Mexico." Nov. 2005. <http://small-mart.org/files/Santa-Fe-Biomass-Paper.pdf>.

[34] Timmons, David, David Damery and Geoff Allen. "Energy from Forest Biomass: Potential Economic Impacts in Massachusetts." Dec. 2007. <http://bct.eco.umass.edu/wp-content/uploads/2009/04/bio-eco-impact-biomass.pdf>.

[35] Ibid

[36] Madlener, Reinhard and Martin Koller. "Economic and CO2 mitigation impacts of promoting biomass heating systems: an input-output study for Vorarlberg, Austria." Sept. 2006. Centre for Energy Policy and Economics. <http://www.cepe.ethz.ch/publications/workingPapers/CEPE_WP50.pdf>.

[37] English, Burton C., et al. "Economic Impacts Resulting from Co-firing Biomass Feedstocks in Southeastern United States Coal-Fired Plants." July 2004. <http://ageconsearch.umn.edu/bitstream/20200/1/sp04en01.pdf>.

[38] Perez-Verdin, Gustavo, et al. "Economic impacts of woody biomass utilization for bioenergy in Mississippi." 2008. Forest Products Journal. <http://www.fwrc.msstate.edu/pubs/10487.pdf>.

[39] Hodges, Alan W., Thomas J. Stevens and Mohammad Rahmani. "Economic Impacts of Expanded Woody Biomass Utilization on the Bioenergy and Forest Products Industries in Florida." 23 Feb. 2010. University of Florida, Institute of Food and Agricultural Sciences. <http://www.fl-dof.com/forest_management/fm_pdfs/Final%20Report%20on%20Economic%20Impacts%20of%20Woody%20Biomass%20Utilization.pdf>.

6.2 Environmental Permitting and Regulations

At the highest possible scale of district heat implementation, with and without CHP technologies, the Minnesota Pollution Control Agency (MPCA) requires the biomass utilizing body to calculate their Maximum Potential to Emit (MPTE), acquire an "Option D" Registration air permit, and track emissions. Minnesota Registration permits are more "streamlined" than Federal permits and do not require a 45 day EPA review and do not expire.

A State of Minnesota Registration Option D permits is issued when facilities have allowable emissions below federal thresholds. MPTE emissions are calculated using EPA AP42 (default) emission rates and vendor guaranteed rates (lbs/mmBtu). The EPA's AP42 emission rates for "bark and wet wood with a mechanical collector" were used to determine the Biomass Hot Water Boiler MPTE and guarantees from VAS, an Austrian thermal oil heater, were used for the co-gen option. VAS uses a mechanical collector and electrostatic precipitator (ESP) for particulate matter control, flue gas recirculation for NOX, and over-fire air for CO control.

Table 6.2 shows emissions rates for criteria pollutants for the configurations assessed. All emissions are below the Option D threshold and, with the exception of CO for the biomass hot water boiler, below the Reduced Recordkeeping Threshold allowing for annual versus monthly emission calculations. Depending on the hot water boiler size and manufacturer, it may be possible achieve a CO MPTE below the 25 tons/yr threshold. Emission records must be kept on site for five years. Dust collector pressure drop and ESP voltage and current readings are recorded daily. Emission fees ($30 per ton pollutant) are payable annually with submission of the emission inventory. Figure 6.1 shows relative emission rates of fine particles for woody biomass and fossil fuel burning.

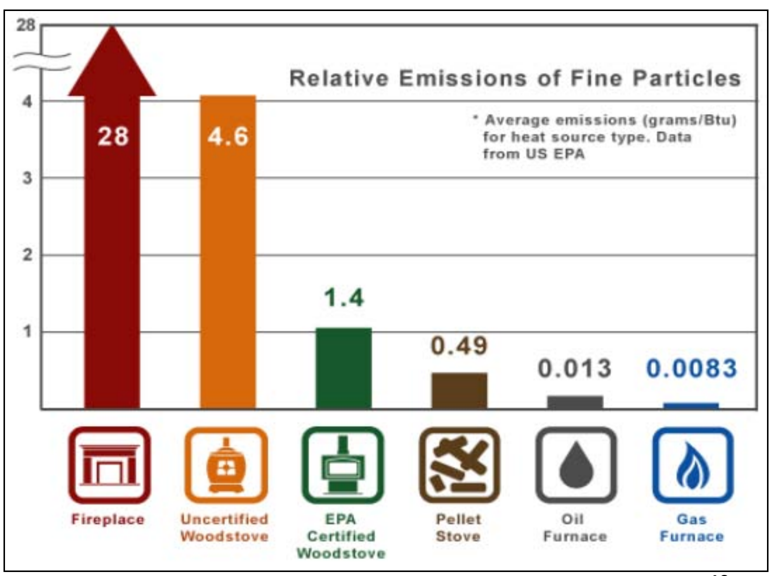

Figure 6.1. Relative emissions of fine particles (PM2.5)[40]

[40] US EPA. 2005. Clean burning wood stoves and fireplaces. http://www.epa.gov/burnwise/energyefficiency.html (Accessed August 31, 2011)

Table 6.2. Maximum potential to emit (MPTE) for criteria pollutants from biomass burning and comparison technologies (tons/yr).

	PM	PM10	NO_x	SO_2	CO	VOC	Total emissions	Single HAP	Total HAP
Option D permit thresholds									
Standard threshold	50	50[1]	50	50	50	50	250	5	12.5
Reduced record keeping	25	25	25	25	25	25	125	2.5	6.25
Configurations									
S1: Supplemental heat stove for single-family residence	0.01	0.01	--	0.01	0.04	0.01	0.06	0.01	0.01
S2: Biomass furnace for single-family residence	0.01	0.01	0.02	0.01	0.03	0.01	0.05	0.01	0.01
S3: Heat main lodge only	0.03	0.02	--	0.01	0.13	0.01	0.16	0.01	0.01
S4: Heat multiple cabins and main lodge	0.04	0.04	0.07	0.01	0.30	0.01	0.42	0.01	0.02
M1: Heat multiple buildings	0.37	0.34	0.62	0.03	2.73	0.064	3.82	0.07	0.22
L1: Heat for Cook County Courthouse	0.10	0.09	0.16	0.01	0.71	0.02	0.99	0.02	0.06
L2: Heat public buildings north of 5th Street N (no hospital)	0.41	0.37	0.68	0.034	3.00	0.07	4.20	0.08	0.24
L3: Heat public buildings north of 5th Street N (hospital)	3.11	2.80	1.96	0.22	5.33	0.15	10.77	0.17	0.52
L4: District heat for Grand Marais business district	6.90	6.21	4.34	0.49	11.83	0.34	23.89	0.34	1.15
L5: District heat for business district (L4) and public buildings (L2)(no hospital)	6.51	5.86	4.09	0.47	11.16	0.32	22.55	0.36	1.09
L6: District heat for business district (L4) and public buildings (L3)(hospital)	8.14	7.33	5.12	0.58	13.95	0.40	28.19	0.44	1.36
L7: District heat for homes, businesses between 5th Ave W. and 6th Ave E.	11.57	10.42	7.27	0.83	19.84	0.56	40.08	0.63	1.93
L8: Combined heat and power (CHP) system for configuration L7	2.80	2.52	14.02	1.75	5.61	1.19	25.37	1.34	4.10
Non-biomass burning references									
Oil boiler	0.0031	0.0028	0.0313	0.1095	0.0077	--	--	--	--
Propane boiler	0.0009	0.0008	0.0337	0.0035	0.0046	--	--	--	--
Taconite Harbor facility (2008)	unknown	744	2351	4720	230	28	7328	--	--

[1] 25 non-attainment area

Appendix A. Reference Biomass Harvest Costs

Table A.1. Harvest costs for a conventional biomass harvesting system.

Machine costs	**200-hp feller/buncher**	**169-hp skidder**	**225-hp chain flail delimber**	**174-hp tracked loader**	**860-hp chipper (self-loading)**	**120 cu-yd van**
Fixed cost inputs						
Purchase price	$217,000	$227,000	$354,900	$181,030	$580,000	$125,000
Scheduled hours/yr (SMH)	2,000	2,000	2,000	2,000	2,000	2,000
Production hours/yr (PMH)	1,300	1,200	1,300	1,300	1,300	1,300
Machine life (yrs)	4	5	5	5	5	8
Salvage value (% of new)	0.2	0.25	0.2	0.2	0.2	0.2
Interest rate (%)	0.1	0.1	0.1	0.1	0.1	0.1
Insurance (annual premiums)	$7,600	$10,200	$7,100	$3,600	$12,000	$6,000
Taxes/tags (% of new)	0	0	0	0	0	0
Operating cost inputs						
Tire cost (total)	--	--	--	--	--	$3,500
Local fuel cost ($/gal)	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99
Horsepower	200	169	225	174	860	450
Fuel consumption (g/hp-hr)	0.026	0.028	0.028	0.022	0.028	6
Oil and lube use (% of fuel)	0.37	0.037	0.37	0.37	0.13	0.1
Repair/maintenance (% of dep)	1	0.9	0.9	0.9	0.75	0.6
Misc consumables ($/op hr)	--	--	--	--	$9.28	--
Labor cost inputs						
Basic labor rate	$18	$18	$18	$18	$18	$18
Benefits (% of base)	0.33	0.33	0.33	0.33	0.33	0.33
Total costs breakdown						
Fixed cost ($/PMH)	$42.10	$41.40	$66.84	$35.02	$55.01	$13.62
Variable costs ($/PMH)	$48.45	$42.80	$77.40	$32.70	$104.77	$17.15
Labor costs ($/PMH)	$23.94	$23.94	$23.94	$23.94	$23.94	$23.94
Total $/PMH	**$114.49**	**$108.14**	**$168.18**	**$91.66**	**$183.72**	**$54.71**

Appendix B. Hypothetical Biomass Demand

Biomass demand was calculated for a hypothetical scenario in which it is assumed that all businesses and residences in Grand Marais and a portion of Cook County switch to one of the assessed biomass heating options: cordwood, clean chips, pellets, hog fuel. Of the 2,707 occupied housing units in the county, an estimated 500 already heating with wood and about half of those are in Grand Marais.[41] We assume the remaining 2,207 housing units would require, on average, 100 mmBtu/year of usable heat. We also assume each of the 84 businesses in Grand Marais would require 579 mmBtu/year of usable heat, and an additional 40 businesses outside of Grand Marais would require 600 mmBtu/year. Table B.1 summarizes the amount of biomass that would be required if all 2,331 units transitioned to wood-based heating in 2011. The table also summarizes heating demand in 2030 assuming a 22% increase in population (Section 2.0).

Table B.1. Additional biomass demand if Cook County switched to wood heat, 2011 and 2030.

			Biomass demand (dry tons/yr)[1]			
	Number of units	**Heat demand (mmBtu/yr)**	**Cordwood**	**Clean chips**	**Pellets**	**Hog fuel**
Housing units						
Grand Marais	250	25,000	1,060	1,331	1,488	1,331
Outside Grand Marais	1,957	195,700	8,299	10,420	11,649	--[3]
Businesses						
Grand Marais	84	48,652	2,063	2,590	2,896	2,590
Outside Grand Marais	40	24,000	1,018	1,278	1,429	1,278
Total in 2011	2,331	**293,352**	**12,440**	**15,620**	**17,462**	**5,200**
Total in 2030[2]	2,844	**357,890**	**15,176**	**19,056**	**21,302**	**6,344**

[1] Demand is *not* cumulative; assumes all users switch to one biomass type only.
[2] Assumes a 22% increase in Cook County population.
[3] Not feasible to heat individual homes with hog fuel because of technology limitations.

[41] US Census Bureau. 2011. 2005-2009 American Community Survey. US Census Bureau, Washington, DC.

Appendix C. Financial Performance Metrics

There are several ways to measure the financial performance of an alternative energy project, and no single metric is best. One measurement is the cost of heat, or the **Levelized Cost of Energy (LCOE)**. The LCOE represents the lifetime capital and operating costs of the equipment divided by the total units of energy produced over the equipment's lifetime (future costs and production are discounted to account for the time value of money). The LCOE is a useful way of comparing technology alternatives prior to installation, but is less useful when comparing *existing* systems to planned installations. This is because the state of the existing system (and operating expenses associated with it) is not a factor in calculating the cost of energy for a new system.

In all the configurations modeled, the annual biomass fuel and O&M (operating and maintenance) costs are lower than for a conventional fossil fuel heating system. However, all of the sites assessed already possess heating systems that could continue in operation, whereas entirely new capital would need to be purchased in order to burn biomass. The question, then, is whether the annual savings from the biomass heating system are sufficient to justify the initial purchase and installation of the new biomass heating capital. A simply understood measurement of these savings is the **Discounted Payback Period (DPP)**. This is the number of years it would take for the savings from the alternative energy project to pay for the project's initial cost (adjusted for the time value of money). Another measurement is the **Net Present Value (NPV)**. The NPV is the value of the total lifetime savings from the project if they were offered to the investor today as one lump sum, minus the cost of the project. If the value of the lump sum is greater than the cost of the project then the NPV is positive. A weakness of the NPV is that it implicitly assumes a fixed discount rate, which may not be comparable between individual investors with different goals and risk tolerances. To avoid the drawbacks of using a discount rate, the **Internal Rate of Return (IRR)** is used, which assumes the NPV equals zero. If the IRR is greater than the desired return that the investor could achieve elsewhere, then they should undertake the project. Finally, for homeowners and businesses not planning to continue operating their current heating systems, the more appropriate metric is the **Outstanding Capital Needed**. If a home or business owner must decide whether to replace their current heating system with a similar fossil fuel-burning one or upgrade to a biomass heating system, they would choose the fossil fuel heating system only if its capital cost is lower than this initial capital threshold. One important assumption is that the efficiency of the replacement fossil fuel-burning system is similar to the efficiency of the current fossil fuel-burning system (assumed 82%). The metric takes into account the capital costs and fuel costs of both systems, as well as the additional (incremental) O&M costs of the biomass system.

Appendix D. Pellet Production

According to the USDA, the North American Pellet Market grew from 1.1 million metric tons in 2003 to 4.2 million metric tons in 2008.[42] European demand is predicted to reach 11 million metric tons in 2011 and 25 million metric tons by 2020.[43]

US pellet appliance sales, which are tracked by the Hearth, Patio and Barbecue Association (HPBA), have shown substantial volatility with oil and housing starts but overall the US pellet market is trending upward at about 5% per year.[44] It is generally accepted that new pellet heating appliances are more reliable, efficient (75% or higher) and convenient while emitting very low emissions; often less than 1 gram per hour of particulate for an average home pellet stove.

At present, pellets cost about half as much as propane or fuel oil on a Btu basis, often allowing the homeowner to recover equipment costs in about five years. While we believe that certified premium wood pellets (less than 1% ash and no bark) will be the growth heating fuel for all of Northern Minnesota, there are currently no significant pellet manufacturers in Minnesota. The closest US suppliers to Cook County are Great Lakes Renewable Energy in Hayward, WI (35,000-tpy capacity) and Indeck in Ladysmith, WI (90,000-tpy capacity).

The City of Silver Bay and the Fond du Lac Band of Lake Superior Chippewa are both considering 100,000 tons per year premium pellet manufacturing facilities. The trend is for larger pellet plants that use de-barked roundwood, not dependent on local sawmills, that have an economy of scale that allows for year round operation. Greenfield scale (100,000 tpy) plants have capital costs approaching $20,000,000[45] and create about 20 plant jobs, and 50 or more logging and trucking jobs.

It has been suggested that Cook County build a pellet manufacturing facility. While the County has more than enough wood for even a large plant (100,000 tpy, requiring about 100,000 cords), the northern portion of Highway 61 product transportation logistics may preclude a scale plant, while a smaller plant (25,000 tpy) would cost over $9,000,000, nearly half as much as a 100,000 tpy plant. At about 6 tons (100 mmBtu) per year per home, even if all homes and businesses in Cook County switched to pellets, demand would only approach about 17,000 tpy.[46] Table D.1 provides estimated cost breakdown for a 25,000-tpy pellet plant.

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[42] Spelter, H. and D. Toth. 2009. North America's wood pellet sector. Research Paper FPL-RP-656. USDA Forest Service, Forest Products Laboratory, Madison, WI. Available at: http://www.fpl.fs.fed.us/documnts/fplrp/fpl_rp656.pdf.

[43] Sikkema, R., Steiner, M., Junginger, M., Hiegl, W.,Hansen, M.T., Faaij, A. 2011. The European wood pellet markets: current status and prospects for 2020. Biofuels, Bioproducts and Biorefining, In press.

[44] Valentas, K. J., V. Gauto, P. Gillitzer, M. von Keitz, C. Lehman, S. J. Taff, and D. Wyse. Chisago-Isanti-Pine Biofuels Feasibility Study. University of Minnesota. March 2009.

[45] Chuck Hartley, LHB Inc., personal communication, July 19, 2011.

[46] Ibid

Table D.1. Cost components of a 25,000-ton/year pellet plant.

Component	**Equipment**	**Materials & Labor**	**Total**
Site Work	$0	$75,000	**$75,000**
Utilities	$0	$300,000	**$300,000**
Product building (6,400 sq ft)	$1,152,000	$25,000	**$1,177,000**
Mechanical (not incl in materials & labor)	$25,000	$25,000	**$50,000**
Electric & instruments (not incl in materials & labor)	$25,000	$25,000	**$50,000**
Civil (not incl in materials & labor)	$25,000	$25,000	**$50,000**
Receiving & rolling stock	$815,000	$390,000	**$1,205,000**
Debarking & chipping	$1,000,000	$250,000	**$1,250,000**
Raw material in-feed & screen	$85,000	$50,000	**$135,000**
Wet sizing	$100,000	$100,000	**$200,000**
Drum dryer, combustor, cyclones	$750,000	$250,000	**$1,000,000**
Dry raw material storage	$40,000	$40,000	**$80,000**
Dry sizing	$75,000	$75,000	**$150,000**
Sizing bag houses	$35,000	$35,000	**$70,000**
Pelletizer	$250,000	$50,000	**$300,000**
Cooler	$20,000	$20,000	**$40,000**
Screen	$16,000	$6,000	**$22,000**
Conveyors	$325,000	$50,000	**$375,000**
Cyclone/air system	$20,000	$8,000	**$28,000**
Bag filter	$40,000	$60,000	**$100,000**
Bagging & palletizing	$500,000	$38,000	**$538,000**
Bulk handling (not incl in other)	$50,000	$10,000	**$60,000**
Pellet bin	$45,000	$50,000	**$95,000**
Truck bin	$50,000	$50,000	**$100,000**
Blacktop (40,000 @ $2.10)	$84,000	$0	**$84,000**
Air comp, tools, office	$200,000	$85,000	**$285,000**
Construction gen conditions	$125,000	$125,000	**$250,000**
Ownership cost (tax, freight, ins) (4.5%)	$564,830	$0	**$564,830**
Engineering (7.0%)	$564,830	$0	**$564,830**
Construction management (1.0%)	$80,690	$0	**$80,690**
TOTAL	**$7,062,350**	**$2,217,000**	**$9,279,350**

Appendix E. Renewable Energy Incentive Programs and Financing

Outline for State of Minnesota and federal policies which have the potential to offset initial investment costs or entice businesses and individuals to participate in a bioenergy market.

Table E.1. Incentives for producing heat and electricity from biomass.

Program/incentive	Description	Qualifying
FEDERAL		
Residential Energy Efficiency Tax Credit	Biomass stoves (including pellets) receive a tax credit up to $300 in the year of purchase	Homeowner – heating
Modified Accelerated Cost-Recovery System (MACRS)	Allows 7-year Modified Accelerated Cost-Recovery System on assets used to create hot water, gas, steam or electricity from biomass, and on equipment & structures to receive, handle, collect and process.	Industry – heating
Business Energy Investment Tax Credit (ITC)	For Commercial, Industrial, Utility, and Agricultural entities	Industry – electricity
Renewable Electricity Production Tax Credit	For Commercial and Industrial entities	Industry – electricity
Rural Energy for America Program (REAP)	Funds up to 25% of the project costs or loan guarantees up to 75% of project	General – heating
Tribal Energy Program Grant		Tribal – heating
Qualified Energy Conservation Bonds (QECBs)		Government – heating
STATE of MINNESOTA		
Home Energy Loan Program	Low-interest loan for energy improvements; up to 49% of residence can be used for business; homes built prior to 1989.	Homeowner – heating
MHFA Fix-up Fund	Low-interest loan of up to $35,000 for energy efficiency and renewable energy technologies (income less than $96,000)	Homeowner – heating
Various Utilities - Residential Energy Efficiency Rebate Program	Most utilities offer a variety of heating system rebates to residential customers to make homes more energy efficient	Homeowner – heating
MHFA Rental Rehabilitation Loan Program	Similar to the MHFA Fix-up Fund, but for landlords who rent out their properties	Homeowner – heating
Rental Energy Loan Fund	Similar to the MHFA Rental Rehabilitation Loan Program	Homeowner – heating
Agricultural Improvement Loan Program	Borrowers with net worth of <$409,000 may apply for a loan with an interest rate of 4.5% for up to 45% of the project cost or $300,000 (whichever is less)	Landowner – heating
Value-Added Stock Loan Participation Program	Like the Ag Improvement Loan Program but focused on purchasing stock in a renewable energy cooperative	Landowner – heating

Table 6.2 (continued). Incentives for producing heat and electricity from biomass.

Program/incentive	Description	Qualifying
STATE of MINNESOTA		
Sustainable Agriculture Loan Program	Low-interest loans to landowners for capital expenditures that enhance the environmental and economic viability	Landowner – heating
Power Grant Program	Grants up to $50,000 to Minnesota Power commercial, industrial, and ag customers for renewable energy products, new electro-technologies that lower energy costs per unit of production in a manufacturing process, innovative technologies that are new/underutilized, and the inclusion of energy-efficient options in the design phase of a project	General – electricity
Net Metering & Interconnection Standards	Utilities must allow net metering for electricity facilities of less than 40 kW, essentially compensating producers at the utility's retail rate	Utilities – electricity
Community-Based Energy Development (C-BED) Tariff	20-year power purchase agreement (PPA) for community-owned renewable energy projects; tariff rate must be higher in the first 10 years of the agreement than the last ten years	COOPs – electricity

Forest Biomass Heating and Electricity in Cook County, MN
Phase I Report
September 2011

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APPENDIX D.

Review of Grand Marais Biomass District Heating System (FVB Energy, Inc.)

Review of Grand Marais Biomass District Heating System Feasibility Analysis

Funded by

Swedish Bioenergy Association and BioBusiness Alliance of Minnesota

Submitted by

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Aug. 3, 2012

Contents

Tables

Figures

Executive Summary

This review was undertaken by FVB Energy with funding provided by the partnership of the Swedish Bioenergy Association (Svebio) and the BioBusiness Alliance of Minnesota (BBAM). The Cook County Local Energy Project (CCLEP) is now interested in pursuing the development of a detailed design and business plan, with particular interest in the “L3” and “L6” scenarios as presented in the “Forest Biomass District Heating and Electricity in Cook County, MN, Phase I Report”. The L3 scenario would serve public buildings north of 5th Street and the hospital. The L6 scenario would serve the downtown Grand Marais business district as well as the L3 loads.

Based on our review, we believe that service to all L6 customers is not viable at this time. Consequently, we examined the financial viability of the L3 scenario and a new Hybrid Scenario that combines the N. 5th St. loads with selected downtown loads. The figure below shows the preliminary routing of distribution piping mains for the Hybrid scenario, with the plant assumed to be located east of the intersection of Gunflint Trail and 4th Ave. East (green box). Service lines to individual customers are not shown. From this distribution system, 21 customers could be served, with a combined annual heating consumption of app. 24,000 MMBtu and a non-coincident peak demand of 12.8 MMBtu/hr.

Twenty year financial projections were made for the three scenarios (L3, L6 and Hybrid). Costs were escalated based on U.S. Energy Information Administration projections in Annual Energy Outlook 2011. The sales price of heat was assumed to be 95% of the customer self-generation costs, with the heat price escalated two ways:

A. Based on the weighted average EIA escalation projections for fuel oil and propane, weighted according the Hybrid Scenario customer fuel split (54% fuel oil, 46% propane); or
B. Based on EIA general inflation rates.

In the simplified financial analysis, debt service costs are based on 100% debt financing over 20 years at a rate of 3.8%, a rate that is slightly higher than the currently anticipated State of Minnesota bond interest rate. A number of financial criteria are addressed:

- The annual profit or loss is shown. None of the scenarios shows positive cash flow the first year. However, for example, the Hybrid Scenario achieves positive cumulative cash flow in year 5 (Heat Price Escalation Scenario A). Projected early-year negative cash flow is typically handled by capitalizing a cash flow reserve fund.
- A key financial performance criterion is Net Present Value (NPV), which discounts cash flows based on an assumed discount rate. In this analysis we assume a 3.8% discount rate. An NPV above zero is a potentially viable scenario. The NPV results are summarized in the table below.
- Another financial test is Internal Rate of Return (IRR), which is the discount rate that exactly balanced the negative cash flow of the initial capital investment with the operating cash flows. An IRR above an organization's discount rate is considered a potential viable scenario.

	L3	**L6**	**Hybrid**
Net Present Value			
Heat rate escalation A	$ 195,351	$(1,802,962)	$ 1,427,461
Heat rate escalation B	$ (738,714)	$(4,222,968)	$ (487,674)
Internal rate of return			
Heat rate escalation A	4.3%	2.2%	5.7%
Heat rate escalation B	1.7%	-0.7%	3.1%

There are many variables that affect the ultimate financial viability of a biomass district heating system, and many uncertainties remain regarding key technical and economic parameters for this system. This report reflects a quick assessment based on available information and FVB's experience. With that context, we offer our conclusions:

1. The capital costs for implementing the L3 or L6 Scenarios are likely to be significantly higher than indicated in the Phase I study.
2. The L3 Scenario is potentially viable if the escalation rate for the price of heat rate is pegged to projected changes in the price of fuel oil and propane.
3. A Hybrid Scenario which combines the N. 5th St. loads and larger loads in the southeastern part of downtown is more cost-effective than the L3 scenario and is significantly more cost-effective than the L6 scenario.
4. The L3 Scenario includes 10 customers and the Hybrid Scenario as evaluated includes 21 customers.
5. There is likely a modified Hybrid Scenario that is viable with fewer than 21 customers.

Ultimately, Grand Marais must determine its willingness to make a substantial capital investment in community infrastructure in order to:

- Stabilize and reduce long-term energy costs;
- Reduce dependence on imported fossil fuel resources;
- Reduce fire risks and the costs associated with managing this risk; and
- Keep more energy dollars the local economy.

We recommend a step-wise process to study, refine, design and develop a plan for biomass district heating in Grand Marais. The first step should be the development of a complete Phase I feasibility study concurrent with informed and serious marketing efforts. It is critically important to develop a realistic Phase I assessment which results in a workable system technical concept (including distribution piping and building conversion and interconnection for viable customers) and accurate estimates of capital and operating costs. This can then provide the foundation for a business plan which establishes clear and realistic assumptions regarding financing the systems and which evaluates financial performance with accepted methodologies and calculations.

Once the Phase I feasibility analysis has been completed in this manner, the County can then make an informed decision about spending additional funds for a Phase II study including development of a complete Schematic Design and full Business Plan, as proposed below. The Phase II study would include detailed recommendations for implementation, including:

- Business organization, financing approach and rate structure; and
- Procurement alternatives and recommended procurement path for each major element in the system (plant, distribution and building conversion/interconnection).

The end result would be the technical, financial and business basis for financing the detailed design, procurement and construction of the system.

Introduction

The BioBusiness Alliance of Minnesota (BBAM) and the Swedish Bioenergy Association (Svebio) have worked in partnership over the past year with the overall objective to expand and accelerate biomass-to-energy opportunities in Minnesota. As peer not for-profit organizations, the establishment of the BBAM – Svebio Bioenergy Partnership works to assist project owners and developers located in Minnesota to help ensure successful bioenergy project development. The partnership seeks to de-risk biomass-to-energy project development throughout the state by leveraging world-leading Swedish technology and know-how that includes decades of proven experience and a successful track-record. The partnership provides time, resources, and specific insights relevant to each unique project and opportunity through highly-customized project management and by offering access to its joint network of industry, government, academic, and other non-governmental organizational resources.

The Grand Marais Biomass District Heating Project is viewed by the partnership as an exceptional opportunity to develop a community-scale biomass-to-energy installation to serve as a state-wide model, as well as, a nationally-recognized biomass district heating system. For this reason, the partnership has funded this "flyover" review of the feasibility analysis performed to date.

The Cook County Local Energy Project (CCLEP) is now interested in pursuing the development of a detailed design and business plan, with particular interest in the "L3" and "L6" scenarios as presented in the "Forest Biomass District Heating and Electricity in Cook County, MN, Phase I Report". The L3 scenario would serve public buildings north of 5th Street and the hospital. The L6 scenario would serve the downtown Grand Marais business district as well as the L3 loads.

Heat Load

Appendix 1 shows data and estimates of fuel consumption by the 75 potential customers included in the L6 scenario, sorted by volume of fuel consumption in million Btu (MMBtu). Of the total fuel consumption, 61% is in the downtown and 39% is in the N. 5th St. area (Figure 1).

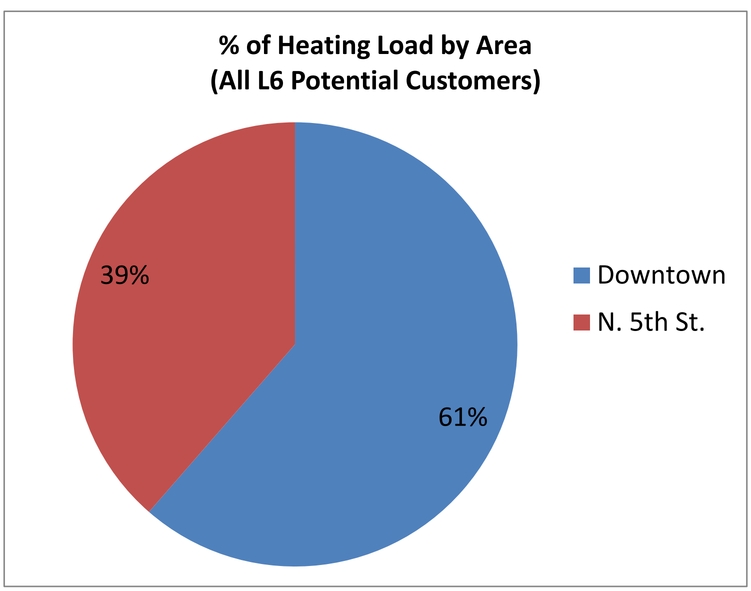

Figure 1. Split of Total L6 Fuel Consumption by Area

The total annual fuel consumption is 43,660 MMBtu. At an assumed seasonal average fuel efficiency of 70%, the total annual heat consumption is 30,562 MMBtu. We estimate that the total of the individual building peak demands (the "non-coincident peak demand) is 16.2 MMBtu/hr. Accounting for the fact that not all building peak at the same time, we estimate that the peak demand on the district energy system (the "coincident peak demand") is 14.6 MMBtu/hr.

Of the total L6 potential load, only 18 customers are responsible for 80% of the load, with the remaining 57 customers having 20% of the load. Of these top 18 customers, 54% are in downtown and 46% in the N. 5^{th} St. area (Figure 2).

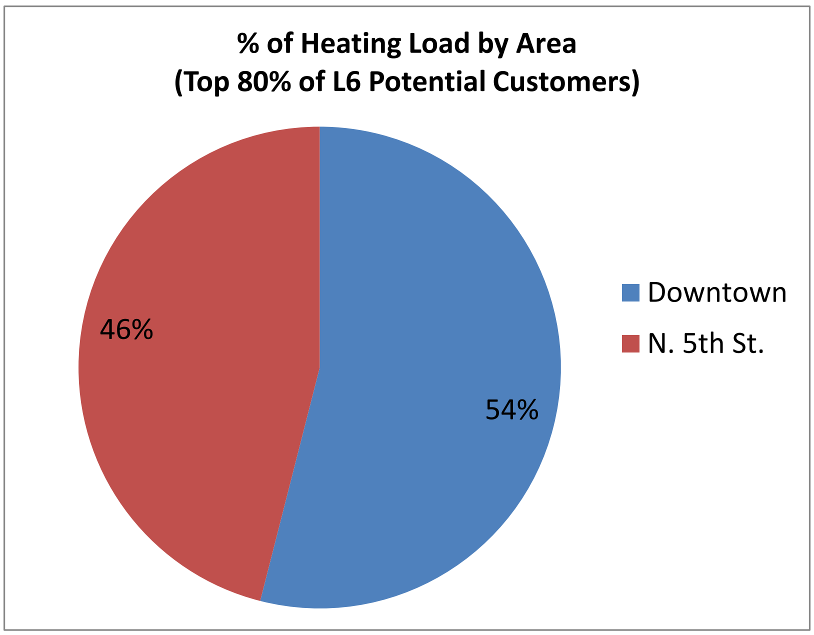

Figure 2. Split of Top 80% of L6 Fuel Consumption by Area

Based on the quick financial review presented below, we believe that service to all L6 customers is not viable at this time. Consequently, we examined the financial viability of the L3 scenario and a new Hybrid scenario that combines the N. 5^{th} St. loads with selected downtown loads.

The L3 scenario would serve 10 customers with a total annual heat consumption of 11,796 MMBtu and a non-coincident peak demand of 6.2 MMBtu/hr. Data on the L3 Scenario potential customers is provided in Appendix 2. County Services account for 97% of the heating load in the L3 scenario.

Figure 3 shows the preliminary routing of distribution piping mains for the Hybrid scenario, with the plant assumed to be located east of the intersection of Gunflint Trail and 4^{th} Ave. East (green box). Service lines to individual customers are not shown. From this distribution system, 21 customers could be served, with a combined annual heating consumption of 24,186 MMBtu and a non-coincident peak demand of 12.8 MMBtu/hr. Data on the Hybrid Scenario potential customers is provided in Appendix 3.

51% of the Hybrid Scenario potential heat load is in downtown and 49% is in the N. 5^{th} St. area. The breakdown by customer type is shown in Figure 4. It is notable that nearly half of the load is County Services.

Figure 3. Preliminary Routing of Hybrid Scenario Distribution System

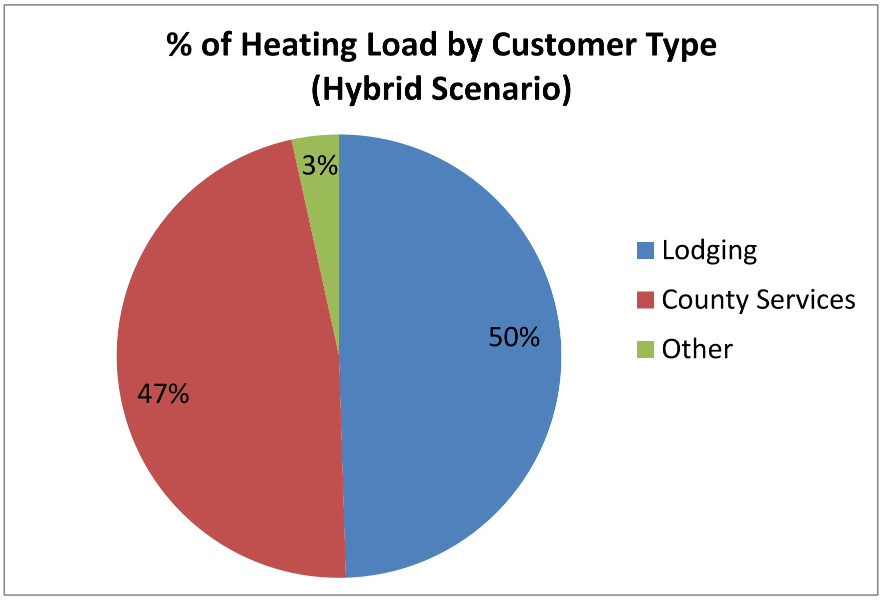

Figure 4. Hybrid Scenario Potential Customers by Type

Capital Costs

FVB's initial capital cost estimates for the L3, L6 and Hybrid scenarios are shown in Table 1. The L3 and L6 estimates differ significantly from the Phase 1 report estimates, as indicated. Key parameters upon which the FVB estimates were based are summarized in Table 2. The Phase I study plant capital cost estimates were based on biomass boiler capacities of 6.8 and 15.0 MMBtu/hr for Scenarios L3 and L6, respectively. The Phase I study indicates 4,000 and 26,450 trench feet of piping for the L3 and L6 scenarios, respectively. This appears to not have included service lines from the pipe mains to the buildings. The basis for the interconnection cost estimates is not clear.

FVB Estimates	L3	L6	Hybrid
Plant	$ 2.15	$ 4.91	$ 3.96
Distribution	$ 1.52	$ 5.64	$ 2.63
Building interconnections	$ 0.37	$ 1.25	$ 0.74
Total	$ 4.04	$ 11.80	$ 7.33

Phase 1 Study Estimates	L3	L6
Plant	$ 1.36	$ 4.25
Distribution	$ 0.78	$ 3.66
Building interconnections	$ -	$ 0.95
Total	$ 2.14	$ 8.86

Table 1. FVB Initial Estimates of Capital Costs (million $)

	L3	L6	Hybrid
Biomass boiler capacity (MMBtu/hr)	3.4	8.5	6.8
Distribution and service lines (trench feet)	6,750	28,745	12,425
Building interconnections (#)	10	75	21

Table 2. Key Parameters in FVB Initial Estimates

Operating Costs

Operating costs include biomass fuel, peaking/backup fuel, electricity, maintenance, ash disposal and labor. Figure 5, Figure 6, and Figure 7 show the heating production duration curves for the L3, L6 and Hybrid scenarios, respectively. With the biomass capacity as assumed, biomass provides about 88% of the total annual heat production, with the remainder provided with back-up/peaking fuel oil boilers. Biomass fuel was assumed to cost $45 per delivered wet ton at 45% moisture. Fuel oil was assumed to cost $3.10 per gallon. Biomass and fuel oil boiler efficiencies were assumed to be 70% and 75%, respectively.

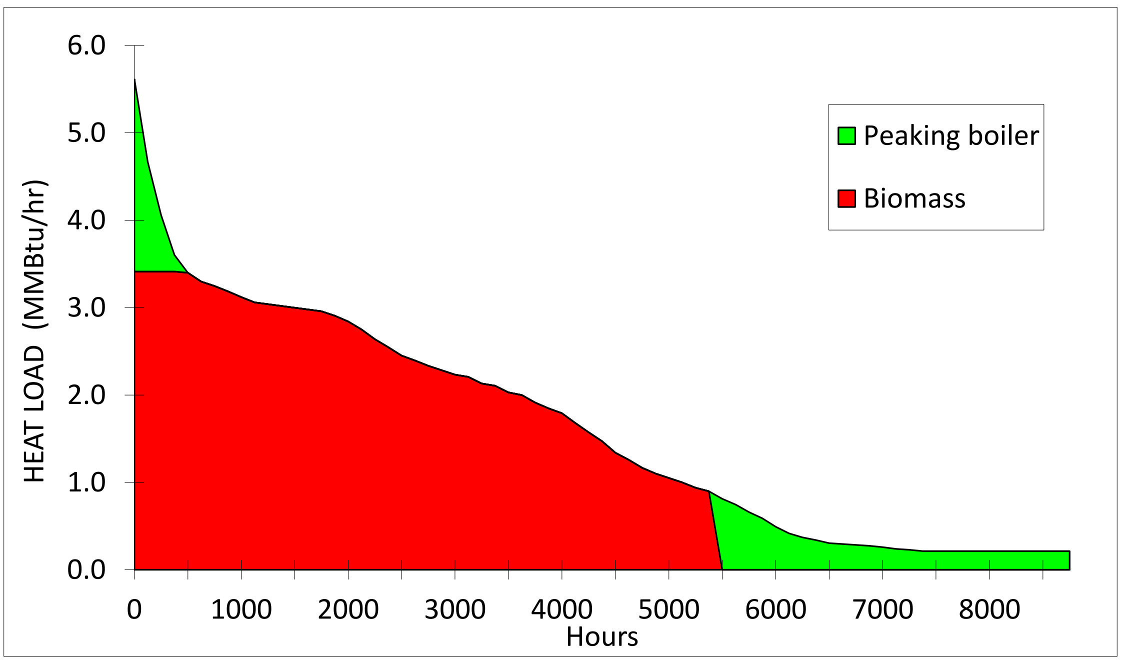

Figure 5. L3 Scenario Heat Production Duration Curve

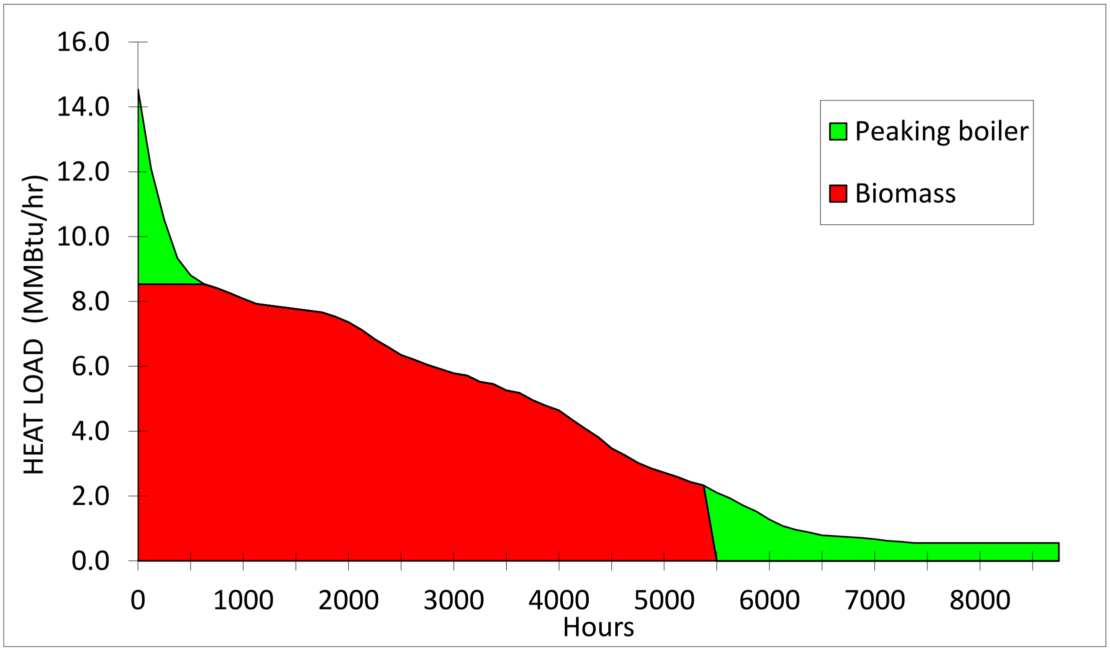

Figure 6. L6 Scenario Heat Production Duration Curve

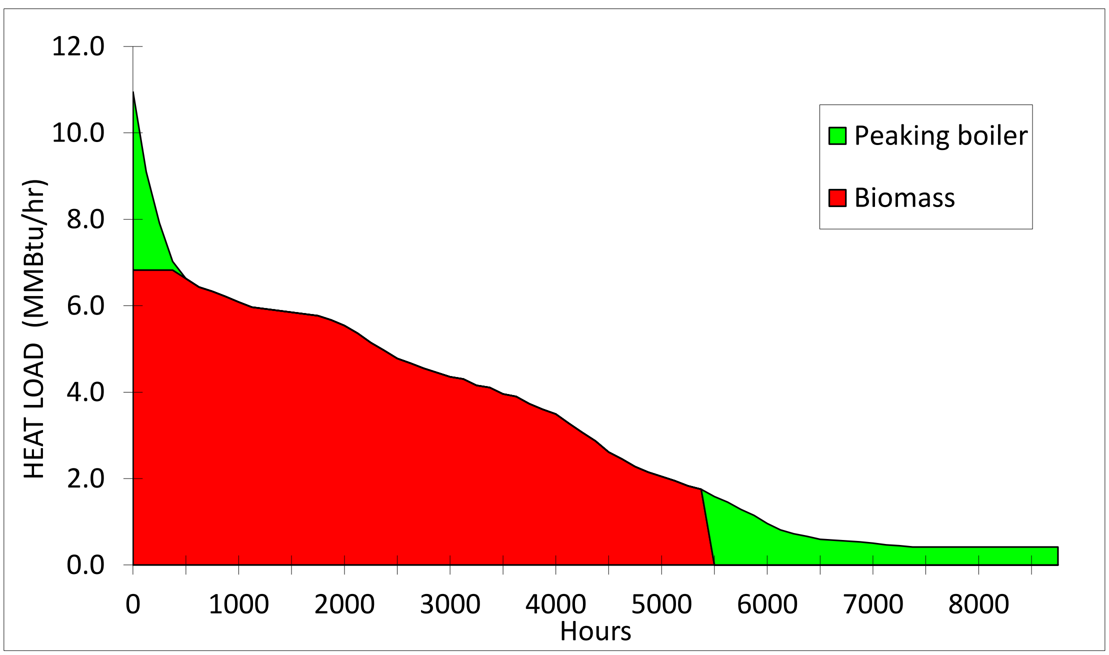

Figure 7. Hybrid Scenario Heat Production Duration Curve

	L3	L6	Hybrid
Biomass fuel	$ 76,672	$ 202,324	$ 157,203
Fuel oil	$ 45,136	$ 119,105	$ 92,543
Electricity	$ 3,397	$ 11,736	$ 6,501
Maintenance	$ 18,089	$ 53,377	$ 32,427
Ash disposal	$ 656	$ 1,731	$ 1,345
Labor	$ 35,000	$ 140,000	$ 70,000
Total	$ 178,950	$ 528,273	$ 360,019

Table 3. Operating Cost Estimates

Self-Generation Costs

The costs for supplying heat from individual building systems will vary depending on many factors, including heating system type, fuel, age of facilities and maintenance practices. Current fuel oil and propane costs are $3.10 and 2.18 per gallon, respectively. This equates to $22.38 and 23.57 per MMBtu of fuel content. At a realistic annual fuel efficiency of 70%, the cost of production of heat with fuel oil or propane are $31.98 or $33.67 per MMBtu of heat. Given that the fuel split is about 50/50 (see Table 4), we will assume that the offset fuel cost for customers is about $33.00 per MMBtu of heat. Maintenance of boiler facilities will add another $1.40 per MMBtu of heat, for a total customer cost savings of $33.40 per MMBtu of delivered heat.

	L3	L6	Hybrid
Fuel Oil	47%	50%	54%
Propane	53%	50%	46%

Table 4. Split of Fuels Used by Potential Customers in Each Scenario

The fuel cost of delivered biomass district heat (assuming $45 per delivered wet ton and including boiler efficiency and distribution losses) is dramatically lower than the current fuel costs of fuel oil and propane heat, as illustrated in Figure 8.

During the last 10 years, the price of distillate fuel oil has increased 253%, as illustrated in Figure 9. In the same period, the price of propane has increased 155%, as illustrated in Figure 10.

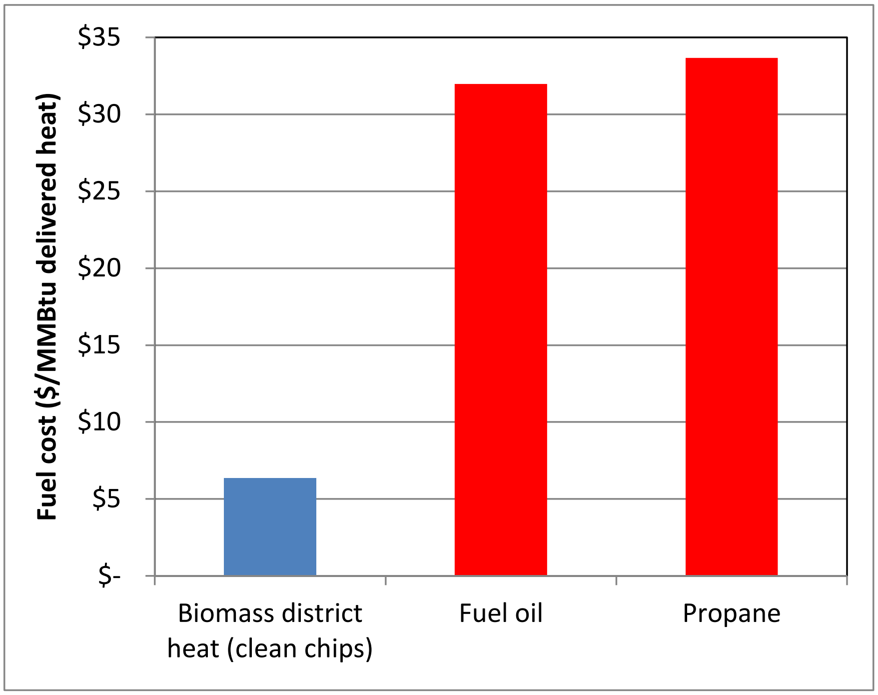

Figure 8. Fuel Cost of Delivered Heat

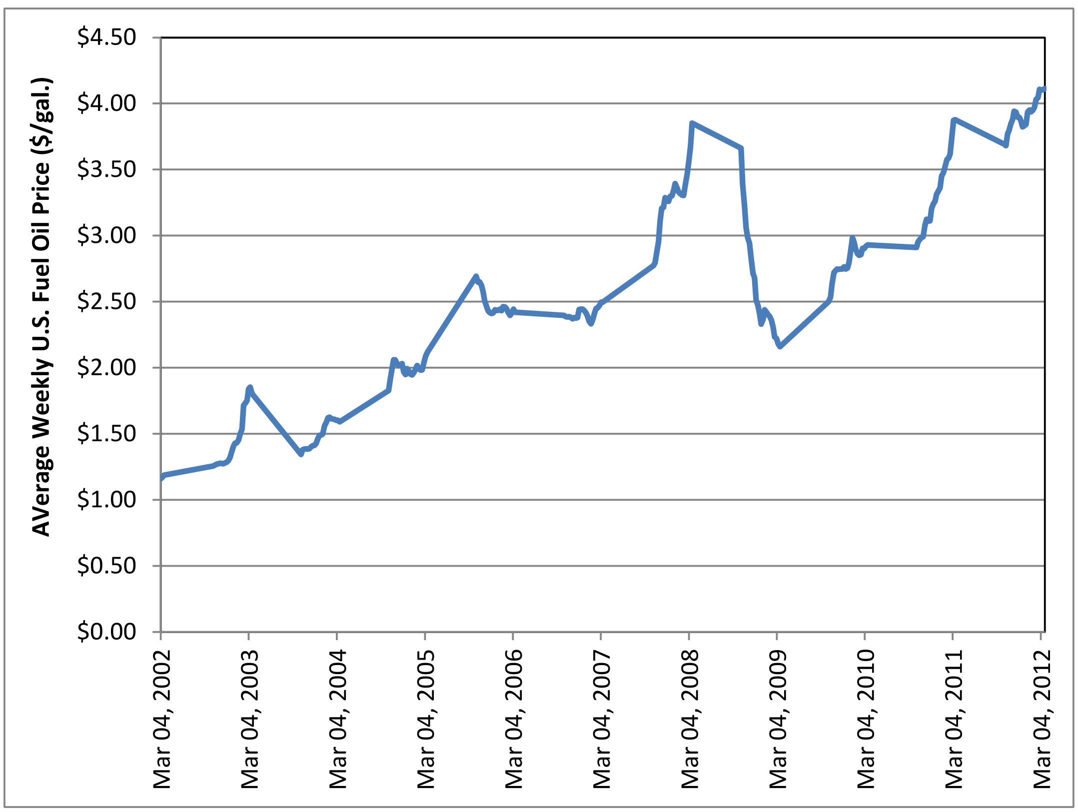

Figure 9. Distillate Fuel Oil Price History 2002-2012

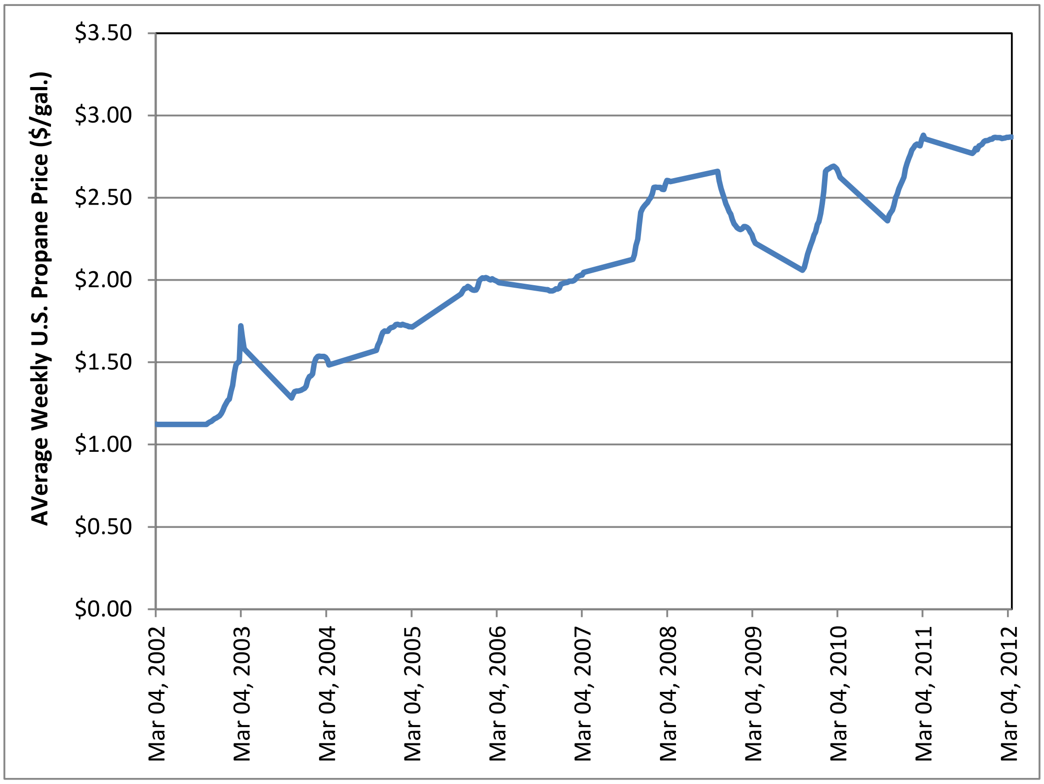

Figure 10. Propane Price History 2002-2012

Financial Analysis

Twenty year financial projections were made for the three scenarios, as presented in Appendix 4. Costs were escalated based on U.S. Energy Information Administration projections in Annual Energy Outlook 2011. For simplicity, it was assumed that the system would be constructed in 2013 and all customer connections made in 2013, with year 1 starting in late 2013. The sales price of heat was assumed to be 95% of the self-generation costs presented above, with the heat price escalated two ways:

A. Based on the weighted average EIA escalation projections for fuel oil and propane, weighted according the Hybrid Scenario customer fuel split (54% fuel oil, 46% propane); or
B. Based on EIA general inflation rates.

In the simplified financial analysis, debt service costs are based on 100% debt financing over 20 years at a rate of 3.8%, a rate that is slightly higher than the currently anticipated State of Minnesota bond interest rate. A number of financial criteria are addressed.

Profit (Loss)

The annual profit or loss is shown. None of the scenarios shows positive cash flow the first year. However, for example, the Hybrid Scenario achieves positive cumulative cash flow in year 4 for Heat Price Escalation Scenario A. Projected early-year negative cash flow is typically handled by capitalizing a cash flow reserve fund.

Net Present Value

A key financial performance criterion is Net Present Value (NPV), which discounts cash flows based on an assumed discount rate. In this analysis we assume a 3.8% discount rate. An NPV above zero is a potentially viable scenario. The NPV results are summarized in Table 5.

Internal Rate of Return

Another financial test is Internal Rate of Return (IRR), which is the discount rate that exactly balanced the negative cash flow of the initial capital investment with the operating cash flows. An IRR above an organization's discount rate is considered a potential viable scenario.

	L3	L6	Hybrid
Net Present Value			
Heat rate escalation A	$ 195,351	$(1,802,962)	$ 1,427,461
Heat rate escalation B	$ (738,714)	$(4,222,968)	$ (487,674)
Internal rate of return			
Heat rate escalation A	4.3%	2.2%	5.7%
Heat rate escalation B	1.7%	-0.7%	3.1%

Table 5. Summary of Net Present Value and Internal Rate of Return Analysis

Conclusions

There are many variables that affect the ultimate financial viability of a biomass district heating system, and many uncertainties remain regarding key technical and economic parameters for this system. This report reflects a quick assessment based on available information and FVB's long experience. With that context, we can offer our conclusions:

1. The capital costs for implementing the L3 or L6 Scenarios are estimated to be higher than indicated in the Phase I study.
2. The L3 Scenario is potentially viable if the escalation rate for the price of heat rate is pegged to projected changes in the price of fuel oil and propane.
3. A Hybrid Scenario which combines the N. 5th St. loads and larger loads in the southeastern part of downtown is more cost-effective than the L3 scenario and is significantly more cost-effective than the L6 scenario.
4. The L3 Scenario includes 10 customers and the Hybrid Scenario as evaluated includes 21 customers.
5. There is likely a modified Hybrid Scenario that is viable with fewer than 21 customers.

Ultimately, Grand Marais must determine its willingness to make a substantial capital investment in community infrastructure in order to:

- Stabilize and reduce long-term energy costs;
- Reduce dependence on imported fossil fuel resources;
- Reduce fire risks and the costs associated with managing this risk; and
- Keep more energy dollars the local economy.

Recommendations

We recommend a step-wise process to study, refine, design and develop a plan for biomass district heating in Grand Marais. The first step should be the development of a complete Phase I feasibility study concurrent with informed and serious marketing efforts. The existing Phase I study is focused primarily on the plant facilities, whereas the (sometimes fatal) challenges in development of a district energy system (DES) to serve existing buildings lie in assessing the heating load and marketable price for district heat, and thus the systems revenues, and in determining the costs of converting and interconnecting numerous customer buildings.

It is critically important to develop a realistic Phase I assessment which results in a workable system technical concept (including distribution piping and building conversion and interconnection for viable customers) and accurate estimates of capital and operating costs. This can then provide the foundation for a business plan which establishes clear and realistic assumptions regarding financing the systems and which evaluates financial performance with accepted methodologies and calculations.

Once the Phase I feasibility analysis has been completed in this manner, the County can then make an informed decision about spending additional funds for a Phase II study including development of a complete Schematic Design and full Business Plan, as proposed below. The Phase II study would include detailed recommendations for implementation, including:

- Business organization, financing approach and rate structure; and
- Procurement alternatives and recommended procurement path for each major element in the system (plant, distribution and building conversion/interconnection).

The recommended work plan for these efforts is as follows:

Full Phase I Feasibility Analysis, Marketing and Draft Business Plan

1. **Market Assessment**
    1.1. Load analysis
    1.2. Load mapping
    1.3. Building conversion/connection assessment
    1.4. Self-generation cost comparison
    1.5. Identify viable scenarios

2. **Marketing and Customer Letters of Intent**
    2.1. Initial meetings with prospective customers
    2.2. Data gathering and analysis
    2.3. Preparation and presentation of draft Term Sheet
    2.4. Obtain Letters of Intent

3. **Revised Technical Concept**
    3.1. Plant site identification and assessment
    3.2. Distribution system layout and pipe sizing
    3.3. Fuel supply assessment
    3.4. Plant design concept
    3.5. Distribution and interconnection design concept

4. **Draft Business Plan**

- 4.1. Capital and operating costs
- 4.2. Business model assessment
- 4.3. Economic proforma model
- 4.4. Alternative financing strategies
- 4.5. Conclusions and recommendations

Phase II Study including Schematic Design and Full Business Plan

1. **Schematic Design**
   - 1.1. Plant design
   - 1.2. Hot Water Distribution Piping System
   - 1.3. Building Conversions and Interconnections

2. **Business Plan**
   - 2.1. Confirm capital and operating cost parameters
   - 2.2. Economic proforma model
   - 2.3. Analyze costs and benefits
   - 2.4. Detailed business plan

The end result would be the technical, financial and business basis for financing the detailed design, procurement and construction of the system.

Appendix 1 – L6 Potential Customers

L6 Potential Customers

								Fuel Consumption			Heat Consumption (6)		Estimated Peak Demand (MMBtu/hr) (7)	
Count	No.	Business Name	Fuel Type	Annual Usage (gal.)	Type of Business		Location Code 1 = Downtown 2 = N. 5th St (Cty 7) 3 = outside both 4 = potential "2"	Annual mmBTUs	Cumul. Annual mmBTUs	% of total	Annual mmBTUs	Cumul. Annual mmBTUs	Customer	Cumul.
1	80	Cook County Hospital & Care Center	Fuel Oil	51,613	County Services		2	6,968	6,968	16%	4,877	4,877	2.58	2.58
2	56	Shoreline Motel	Fuel Oil	50,000	Lodging		1	6,750	13,718	31%	4,725	9,602	2.50	5.08
3	57	Aspen Lodge	Fuel Oil	29,000	Lodging		1	3,915	17,633	40%	2,741	12,343	1.45	6.53
4	1	Superior Best Western	Propane	29,500	Lodging		1	2,702	20,335	47%	1,892	14,234	1.00	7.53
5	41	Cook County Schools	Propane	25,000	County Services		2	2,290	22,625	52%	1,603	15,837	0.85	8.38
6	42	CC Law Enforcement Center	Propane	20,000	County Services		2	1,832	24,457	56%	1,282	17,120	0.68	9.06
7	43	Cook County Courthouse	Propane	18,000	County Services		2	1,649	26,106	60%	1,154	18,274	0.61	9.67
8	2	East Bay Condominuims	Propane	15,000	Lodging		1	1,374	27,480	63%	962	19,236	0.51	10.18
9	44	Community Center	Propane	12,500	County Services		2	1,145	28,625	66%	802	20,037	0.42	10.60
10	3	Cobblestone Cove	Propane	12,000	Lodging		1	1,099	29,724	68%	769	20,807	0.41	11.01
11	81	County Garage 2	Fuel Oil	6,500	County Service		2	878	30,601	70%	614	21,421	0.33	11.33
12	4	Tourist Info, City Hall & Mun. Liquor	Propane	9,500	City Services		1	870	31,472	72%	609	22,030	0.32	11.66
13	55	Sawtooth Mountain Clinic	Propane	7,725	County Services		2	708	32,179	74%	495	22,525	0.26	11.92
14	5	NAPA Auto	Propane	6,000	Retail		1	550	32,729	75%	385	22,910	0.20	12.12
15	48	North Shore Dairy/Laundramat	Propane	6,000	Service		2	550	33,278	76%	385	23,295	0.20	12.33
16	58	Johnson Foods	Fuel Oil	4,000	Groceries	*	1	540	33,818	77%	378	23,673	0.20	12.53
17	6	Joynes	Propane	5,700	Retail		1	522	34,341	79%	365	24,038	0.19	12.72
18	7	Lake Superior Trading Post	Propane	5,000	Retail	*	1	458	34,799	80%	321	24,359	0.17	12.89
19	45	County Garage 1	Propane	5,000	County Services		2	458	35,257	81%	321	24,680	0.17	13.06
20	46	Recycling Center	Propane	4,100	County Services		2	376	35,632	82%	263	24,943	0.14	13.20
21	8	Hiway 61 Laundromat	Propane	4,000	Service	*	1	366	35,999	82%	256	25,199	0.14	13.33
22	49	Grand Marais Wastewater Treatment	Propane	3,700	Utilities		1	339	36,337	83%	237	25,436	0.13	13.46
23	59	Harbor Inn	Fuel Oil	2,500	Lodging		1	338	36,675	84%	236	25,672	0.13	13.58
24	9	Bluewater Café	Propane	3,500	Food Service		1	321	36,996	85%	224	25,897	0.12	13.70
25	10	Grand Marais Auto	Propane	3,000	Automotive Services		1	275	37,270	85%	192	26,089	0.10	13.80
26	11	Crooked Spoon	Propane	3,000	Food Service		1	275	37,545	86%	192	26,282	0.10	13.91
27	12	Sister's	Propane	3,000	Food Service	*	1	275	37,820	87%	192	26,474	0.10	14.01
28	60	American Legion	Fuel Oil	2,000	Food Service		1	270	38,090	87%	189	26,663	0.10	14.11
29	13	SOB	Propane	2,275	Food Service		1	208	38,298	88%	146	26,809	0.08	14.18
30	14	Grand Marais State Bank	Propane	2,200	Financial		1	202	38,500	88%	141	26,950	0.07	14.26
31	15	Subway	Propane	2,100	Food Service	*	1	192	38,692	89%	135	27,085	0.07	14.33
32	61	Eight Broadway	Fuel Oil	1,400	Retail	*	1	189	38,881	89%	132	27,217	0.07	14.40
33	16	Svens	Propane	2,000	Food Service		1	183	39,064	89%	128	27,345	0.07	14.47
34	17	Gun Flint Tavern	Propane	2,000	Food Service	*	1	183	39,248	90%	128	27,473	0.07	14.54
35	18	Cook County Whole Foods Co-op	Propane	2,000	Groceries	*	1	183	39,431	90%	128	27,602	0.07	14.60
36	19	Cook County Historical Museum	Propane	1,800	County Services		1	165	39,596	91%	115	27,717	0.06	14.67

37	20	Almost Home Appliances	Propane	1,800	Retail	*	1	165	39,761	91%	115	27,832	0.06	14.73
38	21	Buck's Hardware Hank	Propane	1,800	Retail/Fuel	*	1	165	39,925	91%	115	27,948	0.06	14.79
39	62	Security State Bank	Fuel Oil	1,150	Financial		1	155	40,081	92%	109	28,057	0.06	14.84
40	22	Senior Center	Propane	1,650	County Services		1	151	40,232	92%	106	28,162	0.06	14.90
41	63	Sivertson Gallery	Fuel Oil	1,100	Retail	*	1	149	40,380	92%	104	28,266	0.06	14.96
42	64	The Market	Fuel Oil	1,100	Retail	*	1	149	40,529	93%	104	28,370	0.06	15.01
43	23	Tire & Auto Lodge	Propane	1,500	Automotive Services	*	1	137	40,666	93%	96	28,466	0.05	15.06
44	24	Post Office	Propane	1,500	Federal		1	137	40,804	93%	96	28,563	0.05	15.11
45	25	NSFCU	Propane	1,500	Financial		1	137	40,941	94%	96	28,659	0.05	15.16
46	26	Johnson Heritage Post Art Gallery	Propane	1,500	Gallery	*	1	137	41,078	94%	96	28,755	0.05	15.21
47	27	Mangy Moose Motel	Propane	1,500	Lodging	*	1	137	41,216	94%	96	28,851	0.05	15.27
48	65	Birchbark Books & Gifts	Fuel Oil	1,000	Retail	*	1	135	41,351	95%	95	28,946	0.05	15.32
49	66	Cook County News-Herald	Fuel Oil	900	Professional Services	*	1	122	41,472	95%	85	29,031	0.05	15.36
50	67	White Pine North	Fuel Oil	900	Retail		1	122	41,594	95%	85	29,116	0.05	15.41
51	68	Superior Designs Jewelry	Fuel Oil	900	Retail	*	1	122	41,715	96%	85	29,201	0.05	15.45
52	28	Coldwell Banker Professional Bldg	Propane	1,300	Professional Services	*	1	119	41,834	96%	83	29,284	0.04	15.49
53	29	The Attic	Propane	1,300	Retail		1	119	41,954	96%	83	29,367	0.04	15.54
54	30	Como Oil & Propane	Propane	1,200	Utilities	*	1	110	42,063	96%	77	29,444	0.04	15.58
55	69	Mike's Holiday Station	Fuel Oil	800	Convenience	*	1	108	42,171	97%	76	29,520	0.04	15.62
56	70	Pump House Fitness Center Bldg	Fuel Oil	800	Personal Services	*	1	108	42,279	97%	76	29,596	0.04	15.66
57	71	Beth's Fudge & Gifts	Fuel Oil	800	Retail		1	108	42,387	97%	76	29,671	0.04	15.70
58	72	Grand Marais Dental	Fuel Oil	700	Professional Services	*	1	95	42,482	97%	66	29,737	0.04	15.73
59	31	Hughie's	Propane	1,000	Food Service	*	1	92	42,574	98%	64	29,801	0.03	15.77
60	32	Java Moose	Propane	1,000	Food Service	*	1	92	42,665	98%	64	29,866	0.03	15.80
61	33	Jill Terrill Clothing	Propane	1,000	Retail	*	1	92	42,757	98%	64	29,930	0.03	15.84
62	34	Superior North Outdoors/Superior Photo	Propane	1,000	Retail	*	1	92	42,848	98%	64	29,994	0.03	15.87
63	35	Grand Marais Public Library **	Propane	1,000	City Services	*	1	92	42,940	98%	64	30,058	0.03	15.90
64	73	Gunflint Realty	Fuel Oil	670	Professional Services	*	1	90	43,030	99%	63	30,121	0.03	15.94
65	36	Arrowhead Pharmacy/Viking Hus Gifts	Propane	900	Professional Services	*	1	82	43,113	99%	58	30,179	0.03	15.97
66	74	Former Leng's Bldg	Fuel Oil	600	Retail	*	1	81	43,194	99%	57	30,236	0.03	16.00
67	75	1st & 2nd Resale	Fuel Oil	600	Retail	*	1	81	43,275	99%	57	30,292	0.03	16.03
68	37	Drury Lane Books	Propane	750	Retail	*	1	69	43,344	99%	48	30,340	0.03	16.05
69	76	Gunflint Merchantile	Fuel Oil	500	Retail	*	1	68	43,411	99%	47	30,388	0.03	16.08
70	77	Beaver House	Fuel Oil	500	Retail	*	1	68	43,479	100%	47	30,435	0.03	16.10
71	78	Country Insurance & Financial	Fuel Oil	400	Professional Services	*	1	54	43,533	100%	38	30,473	0.02	16.12
72	38	Sven & Ollie Annex	Propane	400	Food Service	*	1	37	43,569	100%	26	30,498	0.01	16.14
73	39	World's Best Donuts	Propane	400	Food Service	*	1	37	43,606	100%	26	30,524	0.01	16.15
74	40	Super America	Propane	300	Convenience		1	27	43,633	100%	19	30,543	0.01	16.16
75	79	Chuck's Barber Shop	Fuel Oil	200	Personal Services	*	1	27	43,660	100%	19	30,562	0.01	16.17
					Total			**43,660**			**30,562**		**16.17**	

NOTES:

1) The core area is defined by Lake Superior to the south, the new Gunflint Trail on the north, 4th Ave. E and 5th Ave. W.

2) Number of businesses within the core area is derived from an actual count.

3) Number of residences is based on a large-scale aerial photo of the core area.

It may include small cabins or outbuildings which are not separate residences. The number may vary from the actual +/- 5%.

4) Fuel usage for the entries marked with (*) were estimated based on similar businesses (type and hours of operation) in similarly sized buildings.

5) The left-hand column "No." connects the property to its location on "Commercial Core DH Map."

6) Assumes annual fuel efficiency of 70%

7) Assumes individual building EFLH of 1,890

** Grand Marais Public Library was electric baseboard heat when data was collected. It has since been converted to propane.

Appendix 2 – L3 Potential Customers

L3 Scenario Potential Customers

								Fuel Consumption			Heat Consumption (6)		Estimated Peak Demand (MMBtu/hr) (7)	
Count	No.	Business Name	Fuel Type	Annual Usage (gal.)	Type of Business		Location Code 1 = Downtown 2 = N. 5th St (Cty 7)	Annual mmBTUs	Cumul. Annual mmBTUs	% of total	Annual mmBTUs	Cumul. Annual mmBTUs	Customer	Cumul.
1	80	Cook County Hospital & Care Center	Fuel Oil	51,613	County Services		2	6,968	6,968	41%	4,877	4,877	2.58	2.58
2	41	Cook County Schools	Propane	25,000	County Services		2	2,290	9,258	55%	1,603	6,480	0.85	3.43
3	42	CC Law Enforcement Center	Propane	20,000	County Services		2	1,832	11,090	66%	1,282	7,763	0.68	4.11
4	43	Cook County Courthouse	Propane	18,000	County Services		2	1,649	12,739	76%	1,154	8,917	0.61	4.72
5	44	Community Center	Propane	12,500	County Services		2	1,145	13,884	82%	802	9,718	0.42	5.14
6	81	County Garage 2	Fuel Oil	6,500	County Service		2	878	14,761	88%	614	10,333	0.33	5.47
7	55	Sawtooth Mountain Clinic	Propane	7,725	County Services		2	708	15,469	92%	495	10,828	0.26	5.73
8	48	North Shore Dairy/Laundramat	Propane	6,000	Service		2	550	16,018	95%	385	11,213	0.20	5.93
9	45	County Garage 1	Propane	5,000	County Services		2	458	16,476	98%	321	11,533	0.17	6.10
10	46	Recycling Center	Propane	4,100	County Services		2	376	16,852	100%	263	11,796	0.14	6.24
					Total			**16,852**			**11,796**		**6.24**	

NOTES:

1) The core area is defined by Lake Superior to the south, the new Gunflint Trail on the north, 4th Ave. E and 5th Ave. W.

2) Number of businesses within the core area is derived from an actual count.

3) Number of residences is based on a large-scale aerial photo of the core area.

It may include small cabins or outbuildings which are not separate residences. The number may vary from the actual +/- 5%.

4) Fuel usage for the entries marked with (*) were estimated based on similar businesses (type and hours of operation) in similarly sized buildings.

5) The left-hand column "No." connects the property to its location on "Commercial Core DH Map."

6) Assumes annual fuel efficiency of 70%

7) Assumes individual building EFLH of 1,890

** Grand Marais Public Library was electric baseboard heat when data was collected. It has since been converted to propane.

Appendix 3 – Hybrid Scenario Potential Customers

Hybrid Scenario Potential Customers

								Fuel Consumption			Heat Consumption (6)		Estimated Peak Demand (MMBtu/hr) (7)	
Count	No.	Business Name	Fuel Type	Annual Usage (gal.)	Type of Business		Location Code 1 = Downtown 2 = N. 5th St (Cty 7)	Annual mmBTUs	Cumul. Annual mmBTUs	% of total	Annual mmBTUs	Cumul. Annual mmBTUs	Customer	Cumul.
1	80	Cook County Hospital & Care Center	Fuel Oil	51,613	County Services		2	6,968	6,968	20%	4,877	4,877	2.58	2.58
2	56	Shoreline Motel	Fuel Oil	50,000	Lodging		1	6,750	13,718	40%	4,725	9,602	2.50	5.08
3	57	Aspen Lodge	Fuel Oil	29,000	Lodging		1	3,915	17,633	51%	2,741	12,343	1.45	6.53
4	1	Superior Best Western	Propane	29,500	Lodging		1	2,702	20,335	59%	1,892	14,234	1.00	7.53
5	41	Cook County Schools	Propane	25,000	County Services		2	2,290	22,625	65%	1,603	15,837	0.85	8.38
6	42	CC Law Enforcement Center	Propane	20,000	County Services		2	1,832	24,457	71%	1,282	17,120	0.68	9.06
7	43	Cook County Courthouse	Propane	18,000	County Services		2	1,649	26,106	76%	1,154	18,274	0.61	9.67
8	2	East Bay Condominuims	Propane	15,000	Lodging		1	1,374	27,480	80%	962	19,236	0.51	10.18
9	44	Community Center	Propane	12,500	County Services		2	1,145	28,625	83%	802	20,037	0.42	10.60
10	3	Cobblestone Cove	Propane	12,000	Lodging		1	1,099	29,724	86%	769	20,807	0.41	11.01
11	81	County Garage 2	Fuel Oil	6,500	County Service		2	878	30,601	89%	614	21,421	0.33	11.33
12	55	Sawtooth Mountain Clinic	Propane	7,725	County Services		2	708	31,309	91%	495	21,916	0.26	11.60
13	48	North Shore Dairy/Laundramat	Propane	6,000	Service		2	550	31,859	92%	385	22,301	0.20	11.80
14	5	NAPA Auto	Propane	6,000	Retail		1	550	32,408	94%	385	22,686	0.20	12.00
15	45	County Garage 1	Propane	5,000	County Services		2	458	32,866	95%	321	23,006	0.17	12.17
16	46	Recycling Center	Propane	4,100	County Services		2	376	33,242	96%	263	23,269	0.14	12.31
17	8	Hiway 61 Laundromat	Propane	4,000	Service	*	1	366	33,608	97%	256	23,526	0.14	12.45
18	49	Grand Marais Wastewater Treatment	Propane	3,700	Utilities		1	339	33,947	98%	237	23,763	0.13	12.57
19	10	Grand Marais Auto	Propane	3,000	Automotive Services		1	275	34,222	99%	192	23,955	0.10	12.67
20	15	Subway	Propane	2,100	Food Service	*	1	192	34,414	100%	135	24,090	0.07	12.75
21	23	Tire & Auto Lodge	Propane	1,500	Automotive Services	*	1	137	34,552	100%	96	24,186	0.05	12.80
					Total			34,552			24,186		12.80	

FVB ENERGY INC

NOTES:

1) The core area is defined by Lake Superior to the south, the new Gunflint Trail on the north, 4th Ave. E and 5th Ave. W.

2) Number of businesses within the core area is derived from an actual count.

3) Number of residences is based on a large-scale aerial photo of the core area.

It may include small cabins or outbuildings which are not separate residences. The number may vary from the actual +/- 5%.

4) Fuel usage for the entries marked with (*) were estimated based on similar businesses (type and hours of operation) in similarly sized buildings.

5) The left-hand column "No." connects the property to its location on "Commercial Core DH Map."

6) Assumes annual fuel efficiency of 70%

7) Assumes individual building EFLH of 1,890

** Grand Marais Public Library was electric baseboard heat when data was collected. It has since been converted to propane.

Appendix 4 – Financial Analysis

Financial Analysis **Scenario L3**

Year ---->	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
LOADS AND PRODUCTION																					
Heat consumption (MMBtu)		11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796	11,796
Heat production (MMBtu)																					
Biomass		11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211	11,211
Fuel oil		1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529	1,529
Total		12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740
Fuel consumption (MMBtu)																					
Biomass		16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016	16,016
Fuel oil		2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038
Total		18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054	18,054
OPERATING COSTS																					
Biomass fuel		76,672	78,246	79,833	81,541	83,297	85,018	86,793	88,486	90,120	91,729	93,433	95,098	96,847	98,676	100,547	102,480	104,323	106,270	108,327	110,898
Fuel oil		45,136	46,804	49,087	51,403	53,694	55,930	57,878	59,710	61,670	63,354	65,474	67,203	69,009	70,952	72,779	74,774	76,204	77,852	79,529	81,533
Maintenance		18,089	18,460	18,835	19,238	19,652	20,058	20,477	20,876	21,262	21,641	22,043	22,436	22,849	23,280	23,722	24,178	24,612	25,072	25,557	26,164
Labor		35,000	35,718	36,443	37,223	38,024	38,810	39,620	40,393	41,139	41,873	42,651	43,411	44,210	45,045	45,899	46,781	47,622	48,511	49,450	50,624
Ash disposal		656	669	683	698	713	727	743	757	771	785	799	814	829	844	860	877	893	909	927	949
Electricity		3,397	3,419	3,462	3,555	3,621	3,660	3,711	3,748	3,831	3,914	3,997	4,091	4,174	4,229	4,290	4,360	4,434	4,534	4,639	4,760
Total		178,950	183,317	188,343	193,658	199,002	204,203	209,221	213,970	218,794	223,295	228,398	233,053	237,917	243,026	248,097	253,450	258,088	263,148	268,429	274,927
REVENUE PER MMBTU SOLD		32.68	33.89	35.54	37.22	38.88	40.49	41.91	43.23	44.65	45.87	47.41	48.66	49.96	51.37	52.69	54.14	55.17	56.37	57.58	59.03
OPERATING REVENUE		385,502	399,749	419,246	439,032	458,600	477,690	494,334	509,981	526,721	541,098	559,210	573,977	589,400	605,995	621,603	638,642	650,853	664,926	679,248	696,364
NET OPERATING REVENUE		206,552	216,432	230,903	245,374	259,598	273,487	285,113	296,011	307,927	317,803	330,812	340,923	351,482	362,969	373,506	385,192	392,765	401,778	410,819	421,437
DEBT SERVICE COSTS		291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870	291,870
PROFIT (LOSS)		(85,318)	(75,438)	(60,967)	(46,496)	(32,272)	(18,383)	(6,757)	4,141	16,057	25,933	38,942	49,053	59,612	71,099	81,636	93,322	100,895	109,908	118,949	129,567
Cumulative Profit (Loss)		(85,318)	(160,756)	(221,723)	(268,219)	(300,491)	(318,875)	(325,632)	(321,491)	(305,434)	(279,500)	(240,559)	(191,505)	(131,893)	(60,794)	20,842	114,164	215,059	324,967	443,916	573,483
INTERNAL RATE OF RETURN CALCULATION																					
Cash flow	(4,037,793)	206,552	216,432	230,903	245,374	259,598	273,487	285,113	296,011	307,927	317,803	330,812	340,923	351,482	362,969	373,506	385,192	392,765	401,778	410,819	421,437
Internal Rate of Return	4.3%																				
NET PRESENT VALUE CALCULATION																					
Discount rate	3.80%																				
Cash flow	(4,037,793)	206,552	216,432	230,903	245,374	259,598	273,487	285,113	296,011	307,927	317,803	330,812	340,923	351,482	362,969	373,506	385,192	392,765	401,778	410,819	421,437
NPV	195,351																				
PV of savings	4,233,144																				

Financial Analysis Scenario L6

Year ---->	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
LOADS AND PRODUCTION																					
Heat consumption (MMBtu)		30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562	30,562
Heat production (MMBtu)																					
Biomass		29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584	29,584
Fuel oil		4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034	4,034
Total		33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618	33,618
Fuel consumption (MMBtu)																					
Biomass		42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263
Fuel oil		5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379	5,379
Total		47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642	47,642
OPERATING COSTS																					
Biomass fuel		202,324	206,476	210,665	215,172	219,806	224,347	229,030	233,497	237,811	242,055	246,552	250,946	255,561	260,388	265,325	270,427	275,288	280,427	285,855	292,640
Fuel oil		119,105	123,507	129,531	135,644	141,690	147,588	152,730	157,564	162,736	167,178	172,774	177,337	182,102	187,229	192,051	197,316	201,088	205,436	209,861	215,149
Maintenance		53,377	54,472	55,577	56,766	57,989	59,187	60,422	61,601	62,739	63,858	65,045	66,204	67,422	68,695	69,998	71,344	72,626	73,982	75,414	77,204
Labor		140,000	142,873	145,772	148,890	152,097	155,239	158,480	161,571	164,556	167,492	170,604	173,645	176,838	180,178	183,594	187,125	190,489	194,044	197,800	202,495
Ash disposal		1,731	1,767	1,802	1,841	1,881	1,919	1,959	1,998	2,035	2,071	2,109	2,147	2,186	2,228	2,270	2,314	2,355	2,399	2,446	2,504
Electricity		11,736	11,812	11,959	12,281	12,509	12,645	12,820	12,949	13,235	13,520	13,808	14,131	14,420	14,609	14,819	15,060	15,318	15,664	16,026	16,443
Total		528,273	540,908	555,307	570,594	585,972	600,925	615,441	629,179	643,111	656,174	670,893	684,410	698,529	713,327	728,057	743,584	757,165	771,952	787,402	806,435
REVENUE PER MMBTU SOLD		32.68	33.89	35.54	37.22	38.88	40.49	41.91	43.23	44.65	45.87	47.41	48.66	49.96	51.37	52.69	54.14	55.17	56.37	57.58	59.03
OPERATING REVENUE		998,773	1,035,684	1,086,197	1,137,458	1,188,157	1,237,616	1,280,739	1,321,276	1,364,646	1,401,896	1,448,820	1,487,078	1,527,037	1,570,033	1,610,470	1,654,616	1,686,252	1,722,714	1,759,821	1,804,164
NET OPERATING REVENUE		470,500	494,776	530,891	566,864	602,185	636,691	665,297	692,097	721,535	745,722	777,927	802,668	828,508	856,707	882,412	911,032	929,088	950,762	972,419	997,729
DEBT SERVICE COSTS		852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621	852,621
PROFIT (LOSS)		(382,120)	(357,844)	(321,730)	(285,757)	(250,436)	(215,930)	(187,323)	(160,523)	(131,085)	(106,899)	(74,694)	(49,953)	(24,113)	4,086	29,792	58,412	76,467	98,141	119,798	145,108
Cumulative Profit (Loss)		(382,120)	(739,964)	(1,061,695)	(1,347,451)	(1,597,887)	(1,813,817)	(2,001,140)	(2,161,664)	(2,292,749)	(2,399,648)	(2,474,341)	(2,524,294)	(2,548,407)	(2,544,321)	(2,514,529)	(2,456,117)	(2,379,650)	(2,281,509)	(2,161,711)	(2,016,603)
INTERNAL RATE OF RETURN CALCULATION																					
Cash flow	(11,795,338)	470,500	494,776	530,891	566,864	602,185	636,691	665,297	692,097	721,535	745,722	777,927	802,668	828,508	856,707	882,412	911,032	929,088	950,762	972,419	997,729
Internal Rate of Return	2.2%																				
NET PRESENT VALUE CALCULATION																					
Discount rate	3.80%																				
Cash flow	(11,795,338)	470,500	494,776	530,891	566,864	602,185	636,691	665,297	692,097	721,535	745,722	777,927	802,668	828,508	856,707	882,412	911,032	929,088	950,762	972,419	997,729
NPV	(1,802,962)																				
PV of savings	9,992,377																				

Financial Analysis Scenario Hybrid

Year ---->	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
LOADS AND PRODUCTION																					
Heat consumption (MMBtu)		24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186	24,186
Heat production (MMBtu)																					
Biomass		22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987	22,987
Fuel oil		3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135
Total		26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121	26,121
Fuel consumption (MMBtu)																					
Biomass		32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838	32,838
Fuel oil		4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179	4,179
Total		37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017	37,017
OPERATING COSTS																					
Biomass fuel		157,203	160,429	163,684	167,186	170,787	174,315	177,953	181,424	184,776	188,073	191,568	194,982	198,568	202,318	206,154	210,118	213,896	217,888	222,106	227,377
Fuel oil		92,543	95,963	100,644	105,393	110,091	114,674	118,669	122,425	126,444	129,895	134,243	137,788	141,491	145,475	149,221	153,312	156,243	159,621	163,060	167,168
Maintenance		32,427	33,093	33,764	34,486	35,229	35,957	36,707	37,423	38,115	38,795	39,516	40,220	40,960	41,733	42,524	43,342	44,121	44,945	45,815	46,902
Labor		70,000	71,437	72,886	74,445	76,049	77,620	79,240	80,785	82,278	83,746	85,302	86,823	88,419	90,089	91,797	93,562	95,244	97,022	98,900	101,248
Ash disposal		1,345	1,373	1,400	1,430	1,461	1,491	1,522	1,552	1,581	1,609	1,639	1,668	1,699	1,731	1,764	1,798	1,830	1,864	1,900	1,945
Electricity		6,501	6,544	6,625	6,803	6,930	7,005	7,102	7,173	7,332	7,490	7,649	7,828	7,988	8,093	8,209	8,343	8,485	8,677	8,878	9,109
Total		360,019	368,838	379,003	389,744	400,546	411,061	421,194	430,783	440,525	449,608	459,917	469,309	479,124	489,439	499,670	510,475	519,820	530,018	540,658	553,750
REVENUE PER MMBTU SOLD		32.68	33.89	35.54	37.22	38.88	40.49	41.91	43.23	44.65	45.87	47.41	48.66	49.96	51.37	52.69	54.14	55.17	56.37	57.58	59.03
OPERATING REVENUE		790,405	819,616	859,590	900,157	940,279	979,419	1,013,546	1,045,626	1,079,948	1,109,427	1,146,561	1,176,838	1,208,460	1,242,487	1,274,487	1,309,424	1,334,459	1,363,314	1,392,680	1,427,772
NET OPERATING REVENUE		430,385	450,777	480,587	510,413	539,732	568,358	592,352	614,843	639,423	659,819	686,644	707,529	729,336	753,048	774,817	798,949	814,640	833,297	852,021	874,022
DEBT SERVICE COSTS		529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514	529,514
PROFIT (LOSS)		(99,128)	(78,736)	(48,926)	(19,101)	10,219	38,845	62,838	85,329	109,910	130,305	157,130	178,015	199,823	223,534	245,303	269,435	285,126	303,783	322,508	344,508
Cumulative Profit (Loss)		(99,128)	(177,865)	(226,791)	(245,892)	(235,673)	(196,828)	(133,990)	(48,661)	61,249	191,554	348,684	526,700	726,522	950,057	1,195,360	1,464,795	1,749,921	2,053,704	2,376,212	2,720,720
INTERNAL RATE OF RETURN CALCULATION																					
Cash flow	(7,325,406)	430,385	450,777	480,587	510,413	539,732	568,358	592,352	614,843	639,423	659,819	686,644	707,529	729,336	753,048	774,817	798,949	814,640	833,297	852,021	874,022
Internal Rate of Return	5.7%																				
NET PRESENT VALUE CALCULATION																					
Discount rate	3.80%																				
Cash flow	(7,325,406)	430,385	450,777	480,587	510,413	539,732	568,358	592,352	614,843	639,423	659,819	686,644	707,529	729,336	753,048	774,817	798,949	814,640	833,297	852,021	874,022
NPV	1,427,461																				
PV of savings	8,752,867																				

FVB ENERGY INC

Appendix E. Reference Biomass Harvest Costs

Table E.1. Harvest costs for a conventional biomass harvesting system.

Machine costs	**200-hp feller/buncher**	**169-hp skidder**	**225-hp chain flail delimber**	**174-hp tracked loader**	**860-hp chipper (self-loading)**	**120 cu-yd van**
Fixed cost inputs						
Purchase price	$217,000	$227,000	$354,900	$181,030	$580,000	$125,000
Scheduled hours/yr (SMH)	2,000	2,000	2,000	2,000	2,000	2,000
Production hours/yr (PMH)	1,300	1,200	1,300	1,300	1,300	1,300
Machine life (yrs)	4	5	5	5	5	8
Salvage value (% of new)	0.2	0.25	0.2	0.2	0.2	0.2
Interest rate (%)	0.1	0.1	0.1	0.1	0.1	0.1
Insurance (annual premiums)	$7,600	$10,200	$7,100	$3,600	$12,000	$6,000
Taxes/tags (% of new)	0	0	0	0	0	0
Operating cost inputs						
Tire cost (total)	--	--	--	--	--	$3,500
Local fuel cost ($/gal)	$2.99	$2.99	$2.99	$2.99	$2.99	$2.99
Horsepower	200	169	225	174	860	450
Fuel consumption (g/hp-hr)	0.026	0.028	0.028	0.022	0.028	6
Oil and lube use (% of fuel)	0.37	0.037	0.37	0.37	0.13	0.1
Repair/maintenance (% of dep)	1	0.9	0.9	0.9	0.75	0.6
Misc consumables ($/op hr)	--	--	--	--	$9.28	--
Labor cost inputs						
Basic labor rate	$18	$18	$18	$18	$18	$18
Benefits (% of base)	0.33	0.33	0.33	0.33	0.33	0.33
Total costs breakdown						
Fixed cost ($/PMH)	$42.10	$41.40	$66.84	$35.02	$55.01	$13.62
Variable costs ($/PMH)	$48.45	$42.80	$77.40	$32.70	$104.77	$17.15
Labor costs ($/PMH)	$23.94	$23.94	$23.94	$23.94	$23.94	$23.94
Total $/PMH	**$114.49**	**$108.14**	**$168.18**	**$91.66**	**$183.72**	**$54.71**