DOE Project Final Report
White Earth Biomass/Biogas Feasibility Study

White Earth Nation
DOE Tribal Energy Program Grant EE0005635
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Executive Summary

The White Earth Nation seeks to potentially integrate biomass into the fuel mix for the tribal casino's hot water boilers, off-setting expensive fuel oil and propane and reducing environmental emissions from burning petroleum- based fuels. The feasibility study looked at the technical and economic feasibility of biogas production and biomass to electric energy conversion to supply the large tribal casino campus. Early research found that the biogas production opportunity was not viable for the site and in terms of feedstock volume and that biomass to electric power could not be competitive with the low electric utility rates afforded the casino facility. The study did find adequate biomass resources and that biomass could technically and economically replace 60-70 percent of the existing fuel oil and propane consumption used to fire the facility hot water boilers.

Project Overview

The White Earth Nation owns and operates a tribal casino, hotel, conference facility on the reservation in the Mahnomen community that employees a significant number of tribal members and other residents of the tribal reservation and adjacent communities. The initial casino/bingo facility was built in the early 1990's and then a few years later the event center and hotel were added. Two large fuel oil-fired hot water boilers provide hot water and heat the casino and ancillary spaces and two large propane fired hot water boilers provide hot water and heat the Event Center. These systems are very well maintained but are nearing 20 years in age. With the high annual cost of fuel oil and propane the tribal leadership desired to look at how biomass fuel could be integrated into the facility being more "green" and saving substantial money.

Objectives

1) Attain energy self-sufficiency through the use of indigenous biomass resources;

2) Fulfill the strong Tribal commitment to stewardship of the land by utilizing waste biomass material generated as a byproduct of forest, agricultural and waste disposal operations; and

3) Provide enhanced employment opportunities on the reservation.

Description of Activities Performed

A consultant was engaged to look at the opportunity for integrating biomass into the fuel mix for the casino facility, both in terms of the heating load and what the opportunities might be for biomass to energy in producing electric energy for consumption or resale at the casino or within the Mahnomen community.

Task 1: Pre-Work Conference. The purpose of the pre-work meeting is to initiate the feasibility study by meeting with key Tribal staff to review the project need and approach, scope of work tasks, project schedule, recent studies/assessments in the NW Minnesota region, review current power and thermal energy technologies, and share key contact information.

Pre-Work Conference was completed on June 11, 2012.

Task 2: Tribal Energy Load Assessment. Utilize utility, and propane/fuel oil invoices for previous five years to assess real time energy loads at the casino, hotel and other targeted Tribal buildings. Confirm daily peak power and fossil fuel usage.

Energy load assessment task was completed and the assessment document delivered on July 19, 2012.

Task 3: Feedstock Availability and Cost Assessment. Conduct an assessment of potential biomass feedstocks available from forest management, agricultural and waste management activities conducted in the region tributary to Mahnomen, MN. Historic forestry, agriculture and waste management trends and activities will be analyzed to confirm actual availability and costs to collect, process and transport feedstocks. Competition analysis will be conducted to confirm extending market demand for biomass feedstocks in the region. A feedstock availability and pricing forecast will be provided. Future feedstock supply and risks will be addressed.

Feedstock availability and cost assessment task completed and assessment document delivered on August 22, 2012.

Task 4: Conversion Technology Review and Selection. Findings from the Tribal energy load and feedstock assessments will be used to conduct a combined heat and power technology review to match feedstock availability/characteristics, local environmental permitting requirements, site attributes and power/thermal load forecast, with existing, commercially proven technologies. Both direct-fired and gasification technologies for the proposed biomass-fired cogeneration facility will be investigated. System suppliers will be contacted and asked to supply cost and performance information for their systems.

Conversion Technology review and selection task completed and document delivered on August 14, 2012.

Task 5: Preliminary System Design. The top two technologies to be considered will be presented to Tribal staff with recommendations. Staff will subsequently select one technology for the project. Once the preferred technology has been selected, the technology vendor will be contacted and specific cost estimates/details will be secured for the following: Equipment capital costs, equipment installation costs, annual operations and maintenance costs, training required for operations personnel, site requirements, Infrastructure requirements, and estimated raw material supply needs. Working closely with the technology vendor, a preliminary facility design will be generated.

Delivered technology vendor comparison matrix on draft on November 9, 2012.

Task 6: Capital Cost, Installation Cost, Operating & Maintenance Costs. Working closely with the technology vendor the detailed capital cost, installation cost and O&M costs will be calculated. Interviews with facility managers operating existing facilities will be conducted to confirm actual costs.

Completed second quarter of 2013.

Task 7: Environmental Permit Review. No environmental analyses addressing the impact of the proposed cogeneration Project have been conducted to date. All potential environmental impacts will be addressed in this task along with a permitting plan that defines tasks and a schedule to secure environmental permits.

Completed second quarter of 2013.

Task 8: Energy Sales and Marketing. The State of Minnesota initiated a Renewable Portfolio Standard in 2007 which requires regulated utilities operating within the state to include renewable generation as at least 25% of their generation portfolio. Contact will be made with Minnesota based utilities to market the base load power for potential long term power sales. Interconnection opportunities and costs with local distribution and transmission grid will be assessed.

Energy sales and marketing task completed and document delivered July 24, 2012.

Task 9: Economic Feasibility Analysis. An economic analysis will be performed to estimate the cost of electricity and heat from the cogeneration facility (or if the electricity is sold, the price that must be received to provide an adequate return on investment), and a comparison of that cost/price with what electricity and heat currently (or within the near future) cost the Tribe.

Completed second quarter of 2013.

Task 10: Environmental Benefit Analysis. Environmental Benefits (e.g., greenhouse gas reduction) from the project will be assessed and documented.

Completed second quarter of 2013.

Task 11: Tribal Benefit Analysis. The benefits to the Tribe and to the surrounding community from implementation of the proposed biomass-fired cogeneration facility will be assessed.

Completed second quarter of 2013.

Task 12: Training and Professional Development. A detailed training program for facility operators will be generated with significant assistance from the technology vendor. A well-defined operations and maintenance plan will be generated with significant assistance from the technology vendor.

Task 13: Annual DOE Project Review. The Project Manager will develop a presentation showing the progress of the Project and meet with DOE representatives to review Project progress.

Completed second quarter of 2013.

Task 14: Draft Report. A draft report will be developed through contributions of all participants in the Project.

Completed second quarter of 2013.

Task 15: Final Report. The draft report will be edited by the Project Management and his designated reviewers to produce the final Project report.

Draft final report was delivered in March 2013, and review and changes made in April 2013, and finalized in May, 2013.

Task 16: Project Management. Monthly progress reports will be issued that document monthly accomplishments, challenges and plans for the next thirty days. Regular conference calls (at least monthly) will be convened between the prime contractor and Tribal staff.

Task 16 is ongoing throughout the duration of the project

Task 17: Feedstock Procurement Plan. Consultant will 1) identify potential feedstock suppliers that have the equipment and staff to deliver fuel that meets the fuel specifications as provided by the equipment vendor, 2) will verify the ability of the suppliers to provide appropriate quality feedstock given specific delivery schedules, 3) will develop and negotiate long-term feedstock contracts with feedstock providers to ensure predictability in expenses, 4) will provide a feedstock procurement plan that includes: a) A list of fuel suppliers that are able to deliver fuel meeting fuel specifications as provided by the equipment vendor, b) Recommendations regarding key considerations in the development of a Tribal business venture that could provide fuel to the project, c) Fuel purchase agreement templates, d) Recommendations regarding fuel procurement options and strategies, e) Fuel delivery pricing and schedule for first year of operation.

Consultant completed this additional task in July 2013.

Task 18: Environmental Permitting. Consultant will work with the White Earth Nation permitting personnel and the U.S. Environmental Protection Agency (EPA), Region 5, to implement the permitting plan outlined in the WEN Biomass Feasibility Study report (Task 7). This will include technical assistance in permit applications or to receive permit waivers. Additionally the consultant will help facilitate and provide materials for communication with local regulatory agencies, where appropriate. The principal permit to be addressed will be the U.S. EPA Tribal New Source Review, as the planned biomass thermal unit criteria pollutant emissions appear to exceed the thresholds for this review. Components of the Tribal New Source Review that will require evaluation and determination include: a) Confirmation of calculated criteria air pollutant emissions concentrations of subject biomass thermal system.

☐b) Emissions control technology review for pollutants that exceed Tribal New Source

Review thresholds. Pollutants exceeding thresholds are subject to Lowest Achievable

Reduction Technology (LAER) analysis. c) ☐Possible air qualit
participation process for the Tribal New Source Review permit process.

Consultant completed this task in September 2013 and EPA Region 5 has issued air quality permit.

Conclusions and Recommendations

The findings of the feasibility study revealed that biomass to electrical energy would not be viable due to heavy completion from low existing and projected electrical rates from the utility serving the casino and the Mahnomen community. More importantly, the study did find that integrating a 5 million Btu per hour biomass hot water boiler into the facility would have the potential for saving over $500,000 per year in fuel oil and propane costs, lower the environmental impact from burning fuel oil, and provide an income stream to a tribal member owned business supplying $125,000 in wood chips annually to fuel the system, with a payback potential of 3-5 years. Initially, the cost of the equipment and facility improvements and related engineering were thought to be about $1.4 million, but with more detailed examination the cost is expected to be closer to $2.5 million, but still feasible from technical and financial perspectives.

Lessons Learned

In 2012 and 2013 there were some desire on the part of the Mahnomen community and some tribal leaders to bring natural gas 30-35 miles to the Mahnomen community. That seemed very difficult at the time, but in early 2014 the City of Mahnomen and the White Earth Nation were approached by a vendor who was successfully bringing natural gas service to areas of the state that had previously been unserved when natural gas was put throughout this part of the state well over 30 years ago. Their innovation was to put another community and several grain bin sites, a large turkey barn operator, and several elevators in Mahnomen and the casino into the mix to make the project viable. This mirrors the trend across the country in fuel oil and propane being displaced by natural gas as more and more lower-priced natural gas becomes available. One lesson learned then was that clean natural gas is stiff competition for renewable biomass venues.

The other lesson learned was that a greater effort needed to be made to do a better job of determining implementation costs. Particularly with the high differential in construction costs on tribal reservations. When subsequent more detailed construction cost projections were developed after the study was completed there were substantial cost differences from the feasibility study albeit that the project was still economically feasible with our without grant assistance.

While this feasibility study did not directly result in the proposed facility being built at this time reliable information was obtained that is useful for other potential project of similar nature in the area or should the decision be made in the future to pursue a biomass project for the casino facility based upon this research.

WHITE EARTH NATION BIOMASS TO ENERGY FEASIBILITY STUDY

May 6, 2013

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<u>White Earth Reservation Tribal Council</u>

- Erma J. Vizenor, Chair
- Robert J. Durant, Secretary-Treasurer
- District I – Irene Auginaush
- District II – Terrence Tibbetts
- District III – Kenneth Bevins

<u>Tribal and Shooting Star Casino Staff</u>

- Jerome Lhotka, WEN Economic Development Director
- Mike Triplett, WEN Economic Development Department, Planner, Project Manager
- Ed Hanson, Shooting Star Casino, General Manager
- Gerald "Mike" Smith, Shooting Star Casino, Facilities Manager
- Chuck Anderson, Shooting Star Casino, Facilities Department
- Dan Guenther, Shooting Star Casino, Facilities Department

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The TSS Consultants feasibility study team included:

- Tad Mason, Forester and CEO, Project Manager
- Frederick Tornatore, Chief Technical Officer
- Todd Hansen, Forester and GIS Specialist
- Matt Hart, Renewable Energy Specialist
- David Augustine, Senior Analyst

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INTRODUCTION

The White Earth Nation (WEN) has retained TSS Consultants (TSS) to provide technical assistance in evaluating the feasibility for development of a biogas- or biomass-feed thermal-only energy, combined heat and power (CHP), or anaerobic digestion (AD) project. The intent of the project would be generation of electricity and heat for a CHP facility or exclusively heat for a thermal-only energy facility. Such a facility would be co-located with other WEN-owned facilities, such as the Shooting Star Casino, Hotel, and Event Center (SSC).

The region surrounding the WEN tribal lands has a robust agricultural and forest-product manufacturing sector. The CHP or thermal-only energy facility could use biomass from a variety of sources, including byproduct from agricultural operations, recovered urban wood waste, forest-product manufacturing, and the residue of forest-harvesting operations. An AD facility could be feed primarily from food and animal waste.

In the agricultural sector, soybeans, corn, and spring wheat dominate the region's planting and harvest. To the west of Mahnomen, sugar beet production increases significantly. WEN owns and manages an estimated 58,000 acres of productive forestland and markets annual timber-harvest sales to tribal logging contractors. In addition, a significant number of acres within the reservation boundary are owned or managed by the Minnesota Department of Natural Resources, Division of Forestry (MNDNR), by Becker and Clearwater Counties, as well as non-industrial private landowners.

The demand side market for CHP, thermal-only energy, and AD system outputs in the region is based on the availability and price of electricity, heat, and transportation fuels. The predominant local sources of liquid fuels are gasoline, diesel, propane, and fuel oil. While natural gas is available in the state, there are not pipelines capable of delivering fuel to the SSC or the local vicinity. Electricity across the WEN lands is primarily provided by Otter Tail Power (OTP) and the Wild Rice Cooperative. OTP is bound by Minnesota's Renewable Energy Standard (RES), a policy mandating that, at a minimum, 25% of an electricity provider's power be generated from renewable energy.

After a review of the supply side (feedstock), demand side (energy marketing), and permitting constraints, a preliminary assessment of available technology determines a focused subset of biogas or biomass project developers with technologies appropriate for further review. This assessment ensured technology compatibility with proposed feedstock sources, environmental issues and concerns, and system efficiencies. By identifying the proper technology type, a specific technology vendor is selected through a competitive process and a financial feasibility model is constructed to evaluate the economic impacts of the biogas or biomass project.

In addition to an economic analysis, an environmental analysis and tribal benefits analysis are performed to understand the holistic impacts of a biomass project on tribal lands. A potential project that meets the expectations of the WEN staff and passes the economic, environmental, and tribal-benefits analysis may be appropriate for project implementation.

EXECUTIVE SUMMARY

Biomass Resource

The results of a review of potentially and practically available biomass feedstock supply within the six county feedstock sourcing area (FSA) surrounding Mahnomen are shown in Table 1. Practically available volume reflects operational and economic biomass recovery filtering as well as accounting for competing facilities procuring feedstock from within the FSA.

Table 1. Potentially and Practically Available Biomass Feedstock Summary

FEEDSTOCK TYPE	POTENTIALLY AVAILABLE FEEDSTOCK [GT]	PRACTICALLY AVAILABLE FEEDSTOCK [GT]
Corn Stover	229,792	63,193
Wheat Straw	264,900	72,848
Sugar Beet Tailings	23,000	46,000
Animal Waste	186,674	18,667
Food Waste	590	1,600
Forest Operations	66,625	34,640
Forest Product Manufacturing	14,000	14,000
Urban Wood Waste	21,329	2,000
TOTALS	**806,910**	**252,948**

The current range of prices for biomass feedstock delivered to a project sited at the SSC in Mahnomen is shown in Table 2.

Table 2. Range of Delivered Feedstock Price by Biomass Feedstock Type

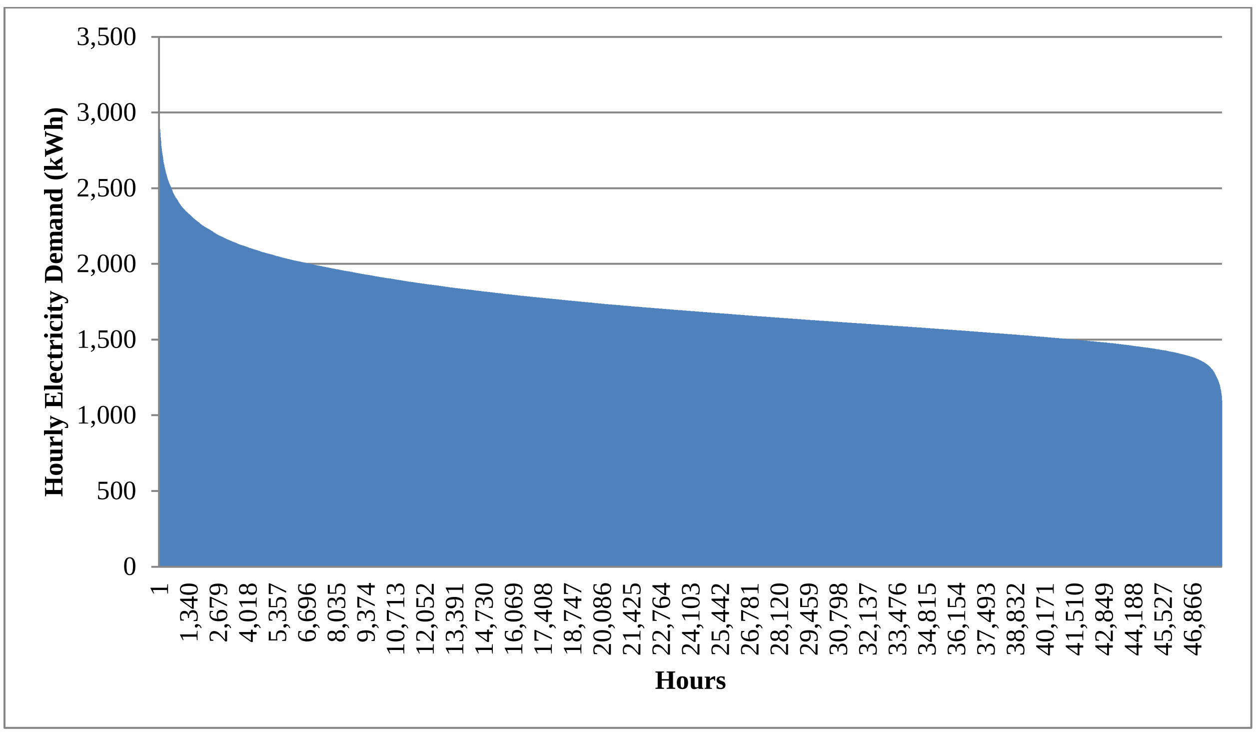
FEEDSTOCK TYPE	ESTIMATED PRICE RANGE [$/GT]	
	LOW RANGE	HIGH RANGE
Corn Stover	55.00	75.00
Wheat Straw	50.00	70.00
Sugar Beet Tailings	15.00	22.00
Animal Waste	14.00	24.00
Food Waste	14.00	85.00
Forest Operations	23.00	55.00
Forest Product Manufacturing	20.00	28.00
Urban Wood Waste	20.00	28.00

There is currently an abundance of available biomass feedstock within the FSA. There is significant activity in both the agriculture and forestry sector which generates potentially suitable feedstock. Excepting small volumes of woody biomass feedstock used for thermal energy at the local school district buildings and a greenhouse located south of Mahnomen, there is currently very little competition within the FSA.

Energy Load

The energy load analysis identified the SSC as the most promising site for a biomass CHP or thermal energy-only facility due to the scale and consistency of its energy demands. The SSC draws approximately 1.5 megawatts (MW) of baseload electricity with peak demand reaching 3.0 MW (see Figure 1). Data analysis from the past five years indicates that a 2.0 MW power plant is the upper threshold for a CHP facility used for net metering with OTP, the local utility. The high, consistent demand for electricity makes the SSC a strong candidate for a biomass-fired CHP facility.

Figure 1. Shooting Star Casino's Electric Load Profile



The SSC is currently heated by four fossil-fuel fired boilers. Two of the boilers utilizes fuel oil and the others utilizes propane. With the current and historic costs of fuel oil and propane, a biomass CHP or thermal energy-only facility may provide significant cost savings by displacing fossil-fuel consumption for space heating. Table 3 shows an estimate of cost per unit of heat produced by technology and fuel type.

Table 3. Price of Delivered Energy by Feedstock Type and Conversion Technology

HEAT SOURCE	DELIVERED PRICE OF FEEDSTOCK [$/MMBTU]		SYSTEM EFFICIENCY[1]	DELIVERED PRICE OF ENERGY [$/MMBTU]	
Fuel Oil	25.34		81%	31.28	
Electricity	12.55		98%	12.81	
Propane	13.62		80%	17.03	
BIOMASS FEEDSTOCK	**LOW RANGE $[\$/\text{MMBTU}_{IN}]$**	**HIGH RANGE $[\$/\text{MMBTU}_{IN}]$**	**SYSTEM EFFICIENCY[2]**	**LOW RANGE $[\$/\text{MMBTU}_{OUT}]$**	**HIGH RANGE $[\$/\text{MMBTU}_{OUT}]$**
Corn Stover	4.87	6.64	70%	6.96	9.49
Wheat Straw	4.06	5.69	70%	5.80	8.13
Forest Operations	2.44	5.83	70%	3.49	8.33
Forest Product Manufacturing	2.02	2.82	70%	2.89	4.03
Urban Wood Waste	1.58	2.21	75%	2.11	2.95
Sugar Beet Tailings	5.90	8.65	60%	9.83	14.42
Animal Waste	1.99	3.41	60%	3.32	5.68
Food Waste	2.33	14.17	60%	3.88	23.62

Even with the high-cost feedstock and with lower system efficiencies, all of the potential biomass feedstock types offer competitive marginal pricing when compared to fuel oil, and only the high-range costs of food waste are more expensive than propane's marginal cost. When displacing fuel oil and propane, biomass offers a promising opportunity for displacing fossil-fuel consumption.

Based on the historic fossil-fuel consumption data, a 3.0 to 5.0 MMBtu per hour boiler was recommended for the SSC facilities to adequately displace fossil-fuel consumption while maintaining a high system capacity factor. A biomass boiler at this scale of thermal output will require backup capacity during the winter season to meet high demand loads. That backup or peaking capacity could be delivered with the fossil-fuel boilers on an as-needed basis.

Technology Analysis

The technology analysis reviewed potential commercially-proven technologies and pre-commercial technologies providing direct-fired combustion, gasification, and AD systems.

[1] Using efficiencies for the existing fuel oil and propane installations where possible.
[2] Ibid.

Potential vendors were initially reviewed to determine system efficiencies and approximate marginal costs of energy production. Through the initial analysis and in conjunction with WEN staff, the preferred technology type for the site was direct-fired combustion for a thermal energy-only facility. This decision was largely based on the financial opportunity of the thermal energy-only facility compared with CHP or AD systems.

TSS reviewed potential direct-fired combustion technology vendors and presented WEN staff with the top two finalists. Through a request for proposals (RFP) process, the WEN staff selected a preferred technology vendor.

Economic Analysis

TSS worked closely with the selected technology vendor and conducted a thorough review of existing studies and literature to identify potential capital and operational costs for the project. Using these cost estimates as a reference case, a one-dimensional sensitivity analysis was performed with nine key project metrics. The results of this analysis yielded four major economic variables that dictate the project outlook: capacity factor, feedstock costs, fossil-fuel costs, and capital costs. To show the interaction between these variables, two-dimensional sensitivities were performed to measure the impact of changes of pairs of each of these four variables.

The baseline financial outlook indicated an attractive simple payback period of approximately 1.6 years and an internal rate of return over the lifetime of the project of 164%, assuming five years of debt financing. The two-dimensional sensitivities identified critical scenarios that should be monitored throughout project development. These critical scenarios would offer grounds to postpone or cancel the project. Each of the critical scenarios included a significant drop in fossil-fuel prices back to their respective five-year lows. Fossil-fuel pricing is the basis for avoided cost savings and fossil-fuel trends should be monitored closely for indications of long-term decreases in pricing.

SCOPE OF WORK

Detailed below are tasks that TSS performed in support of the feasibility study for an AD, thermal-only energy, or small-scale CHP facility to be co-located with the WEN-owned facilities. TSS made a concerted effort to utilize relevant data and information from existing assessments and studies conducted in the region.

Task 1. Pre-Work Conference

The purpose of the pre-work meeting is to initiate the feasibility study by meeting with key WEN staff to review the project's needs and approach, scope of work tasks, project schedule, recent studies/assessments in the NW Minnesota region, review current power and thermal energy technologies, and share key contact information.

Task 2. Tribal Energy Load Assessment

Utilize power, propane, and fuel oil invoices for previous five years to predict future energy loads at the casino, hotel, event center, and other targeted tribal buildings. Confirm daily peak power and fossil fuel usage.

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Conduct an assessment of potential biomass feedstocks available from forest, agricultural, and waste management activities conducted in the region tributary to Mahnomen, Minnesota. Historic forest, agriculture, and waste management trends and activities will be analyzed to confirm actual availability and costs to collect, process, and transport feedstocks. Competition analysis will be conducted to confirm existing market demand for biomass feedstocks in the region. A 10-year feedstock availability and pricing forecast will be provided. Future feedstock supply and risks will be addressed.

Task 4. Conversion Technology Review and Selection

Findings from the tribal energy load and feedstock assessments will be used to conduct a technology review to match feedstock availability and characteristics, local environmental permitting requirements, site attributes and power and thermal load forecast with existing, commercially-proven technologies. Direct-fired, gasification, and AD technologies for the proposed biomass-fired facility will be investigated. System suppliers will be contacted and asked to supply cost and performance information for their systems.

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The top two technologies to be considered will be presented to tribal staff with recommendations. Staff will subsequently select one technology for the project. Once the preferred technology has been selected, the technology vendor will be contacted and specific cost estimates/details will be secured for the following: equipment capital costs, equipment installation costs, annual operations and maintenance costs, training required for operations personnel, site requirements, infrastructure requirements, and estimated raw material supply needs. Working closely with the technology vendor, a preliminary facility design will be generated.

Task 6. Capital Cost, Installation Cost, Operating & Maintenance Costs

Working closely with the technology vendor, the detailed capital cost, installation cost, and operations and maintenance (O&M) costs will be calculated. Interviews with facility managers operating existing facilities will be conducted to confirm actual costs.

Task 7. Environmental Permit Review

No environmental analyses addressing the impact of the proposed cogeneration project have been conducted to date. All potential environmental impacts will be addressed in this task along with a permitting plan that defines tasks and a schedule to secure environmental permits.

Task 8. Energy Sales and Marketing

The state of Minnesota initiated a RES in 2007 which requires regulated utilities operating within the state to include renewable generation as at least 25% of their generation portfolio. Contact will be made with Minnesota-based utilities to market the baseload power for potential long-term power sales. Interconnection opportunities and costs with local distribution and transmission grid will be assessed.

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An economic analysis will be performed to estimate the cost of electricity and heat from the cogeneration facility (or if the electricity is sold, the price that must be received to provide an adequate return on investment) and to compare that cost/price with what electricity and heat currently (or within the near future) cost the SSC.

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Environmental benefits (e.g., greenhouse gas reduction) from the project will be assessed and documented.

Task 11. Tribal Benefit Analysis

The benefits to the WEN and to the surrounding community from implementation of the proposed biomass-fired facility will be assessed.

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A detailed training program for facility operators will be generated with significant assistance from the technology vendor. A well-defined O&M plan will be generated with significant assistance from the technology vendor.

Task 13. Annual Department of Energy Project Review

The project manager will develop a presentation showing the progress of the project and meet with Department of Energy representatives to review the project's progress.

Task 14. Draft Report

A draft report will be developed through contributions of all participants in the project.

Task 15. Final Report

The draft report will be edited by the project manager and his designated reviewers to produce the final project report.

Task 16. Project Management

Monthly progress reports will be issued that document monthly accomplishments, challenges and plans for the next thirty days. Regular conference calls (at least monthly) will be convened between the prime contractor and WEN staff.

TRIBAL ENERGY LOAD ASSESSMENT

Introduction

Energy load assessments provide detailed information about historic trends regarding a facility's energy consumption. The energy consumption and pricing data collected for this assessment spans a five-year period from November 2006 through March 2012. This range is used to minimize the impact of uncontrolled variables such as weather patterns and market spikes. Data output includes chronological usage patterns and temporal trends, annual maximum and minimum energy consumption and power demand, and energy price profiles. These data sets are used to determine the appropriate equipment size (electricity or heat generation capability), estimate the equipment's expected capacity factor, and model feedstock demand, revenues, and costs.

Historic Energy Consumption

Using a previous energy audit,[3] TSS identified the major energy sources and energy loads for the SSC and WEN administrative facilities. The major sources of energy are electricity, #2 fuel oil (fuel oil), and liquid petroleum gas (propane). Fuel oil and propane are primarily used for large thermal space heating applications as well as for hot water heating. For the SSC, fossil-fuel prices for March 2012 were $3.51 per gallon for fuel oil and $1.26 per gallon for propane.

Unlike thermal heat, electricity can be utilized by independent sites across the WEN-owned lands. The energy load assessment therefore evaluates electricity prices at multiple WEN facilities outside of the SSC ownership. Prices for electricity range from an average[4] of $0.06 per kilowatt-hour (kWh) to $0.13 per kWh.

<u>Neighboring Facilities</u>

The Mahnomen School (K-12) and the Mahnomen Health Center were assessed during the energy audit as the two largest facilities in the City of Mahnomen that are outside of the SSC. The facilities were analyzed as potential customers for heat sales. Electricity sales were not reviewed because the direct sale of electricity offsite would require the SSC or WEN to become a public utility, a generation and transmission cooperative, a municipal power agency, or a power district. There are significant challenges with the creation of any of these entities.

The Mahnomen School currently utilizes biomass for their facility's heating demand and operates with low-pressure steam. Since the Mahnomen School heats their facility with biomass, there is no potential for significant cost savings by utilizing heat produced by the SSC biomass project.

[3] Energy Use and Energy Audit: Shooting Star Casino / White Earth Nation, 2010.
[4] Average price per kWh includes all additional charges, such as taxes, demand charges, credits, and rate adjustments.

The Mahnomen Health Center uses fuel oil and operates with low-pressure steam. Since the SSC uses hot water as a medium for heat transport, providing the Mahnomen Health Center with thermal heat will be challenging, as it will require an additional boiler or a separate heat recovery system to provide low-pressure steam. Detailed engineering design would be necessary to determine the boiler or heat recovery system output pressure that would be required to provide the Mahnomen Health Center with the proper steam pressure to operate their systems.

Electricity Consumption

The analysis of the electricity demand includes Tribal facilities beyond the SSC site. Table 4 shows the five WEN-owned facilities with the largest electricity consumption and their respective average price of electricity.

Table 4. Facilities with the Greatest Annual Electricity Consumption

FACILITY NAME	LOCATION	ANNUAL CONSUMPTION [KWH]	PERCENTAGE OF TOTAL ELECTRICITY CONSUMPTION	AVERAGE PRICE OF ELECTRICITY [$/KWH]
Shooting Star Casino	Mahnomen	9,922,533	62.5%	0.060
Administration Building	White Earth	2,370,040	14.9%	0.060
Naytahwaush Sports Complex	Naytahwaush	687,133	4.3%	0.061
RTC Building	White Earth	472,783	3.0%	0.061
Circle of Life School	White Earth	444,517	2.8%	0.061

Table 5 displays the five facilities with the most expensive average electricity price and their respective electricity demand.

Table 5. Facilities with the Most Expensive Electricity

FACILITY NAME	LOCATION	ANNUAL CONSUMPTION [KWH]	PERCENTAGE OF TOTAL ELECTRICITY CONSUMPTION	AVERAGE PRICE OF ELECTRICITY [$/KWH]
EPA Office Branch	Ranch	6,000	0.04%	0.114
Garment Factory	Ranch	6,883	0.04%	0.104
New Pine Point School	Pine Point	8,450	0.05%	0.095
Roads Garages	Naytahwaush	16,733	0.10%	0.095
White Earth Builders	Callaway	10,683	0.07%	0.088

For any project using biomass as a feedstock, backup power is required for unplanned outages and periods of scheduled repair and maintenance. Traditionally, the electric grid serves as backup, but gas or diesel generators may be sufficient for short-term back up or for facilities without connection to an electric grid. As shown in Table 4 and Table 5, for the WEN, average electricity price varies inversely with annual demand. The five highest average prices cumulatively utilize approximately 48,749 kWh annually, which is only 0.5% of the total annual electricity consumption of the largest user, the SSC. Since the highest price users would require a baseload facility of 6.5 kW, TSS recommends that electricity displacement focus primarily on the facilities with the highest electricity demand despite their lower average electricity prices.

Electricity Service Contracts

Beginning on November 1, 2011, the rate structure for the SSC changed and is summarized in Table 6.

Table 6. Shooting Star Casino – Otter Tail Power Electricity Contract

GENERAL SERVICE - TIME OF USE				
Customer Charge per Month:	$19.00			
Monthly Minimum Bill:	Customer + Facilities + Demand Charges			
Facilities Charge per Month Per annual maximum kW (minimum 20kW per Month):	$0.60 /kW			
Energy Charge per kWh:	Summer		Winter	
Declared-Peak	20.332	¢/kWh	21.624	¢/kWh
Intermediate	5.162	¢/kWh	4.703	¢/kWh
Off-Peak	2.331	¢/kWh	3.505	¢/kWh
Demand Charge per kW (minimum of 20 kW):	Summer		Winter	
Declared-Peak	N/A	/kW	N/A	/kW
Intermediate	$2.64	/kW	$1.36	/kW
Off-Peak	$0.00	/kW	$0.00	/kW

The electricity service contract is based on time of use rates. Off-peak rates are from 10PM until 6AM, intermediate rates are from 6AM until 10PM, and the declared-peak rates are for any time that OTP notifies SSC that declared-peak rates will be active. Declared-peak notifications are issued one day in advance and are in response to three prevailing factors: 1) Midwest Independent System Operator (MISO) does not have enough capacity to serve the projected load, 2) it is more cost effective to reduce demand than increase supply, or 3) miscellaneous events, which may include instances such as outages for electricity generation plants and out-of-service transmission lines. OTP plans for fewer than 400 hours per year of declared-peak rates. The average winter rates, active from October 1 to May 31, are $0.04304 per kWh. The average summer rates, active from June 1 to September 30, are $0.04218 per kWh. For the year, the average rate is $0.04283 per kWh. This price is representative of a baseload electrical supply or demand.

Historic Use Data

SSC staff provided TSS with the OTP electricity bills for the five years preceding this feasibility study. Figure 2 shows historic energy demand from November 2006 through April 2012 based on OTP bills. Figure 3 shows the historic electricity use from November 2006 through April 2012 based on hourly energy demand data sourced directly from OTP. Figure 4 shows chronologic power demand (peak power usage) from November 2006 through April 2012. Power demand represents the most power required to meet the electricity demand at any given fifteen minute interval during the month.[5]

[5] Note that power is an instantaneous measure of available energy while energy is the use of power over time.

Figure 2. Historic Monthly Electricity Demand

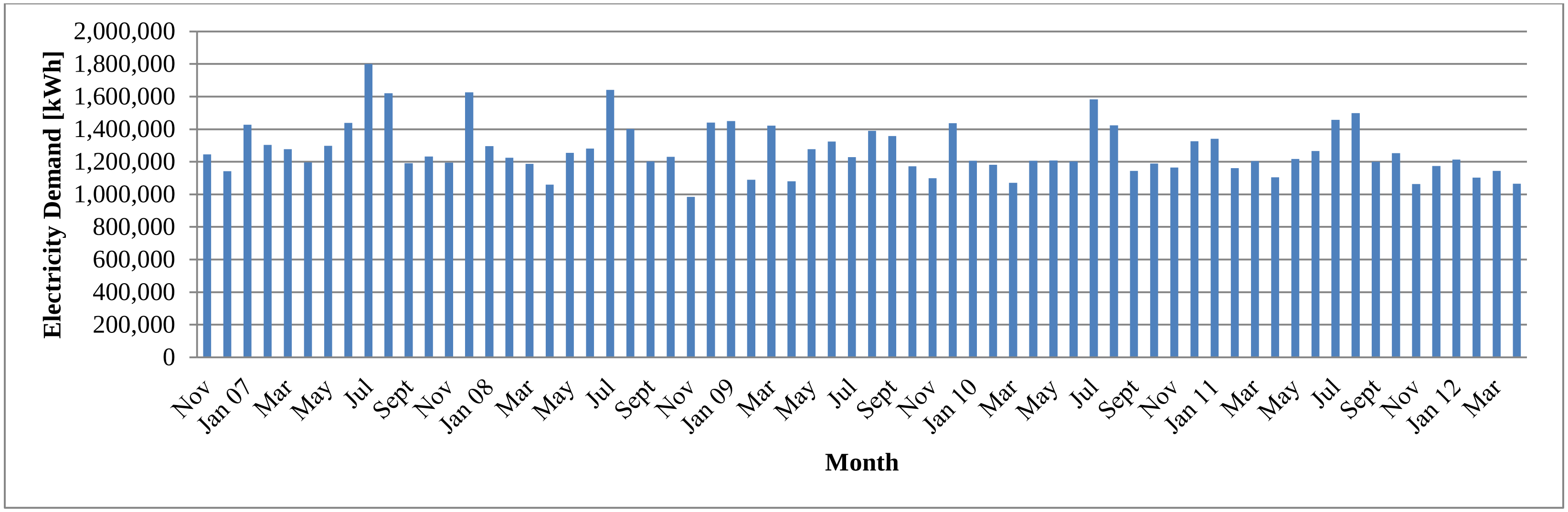


Figure 3. Historic Hourly Electricity Demand

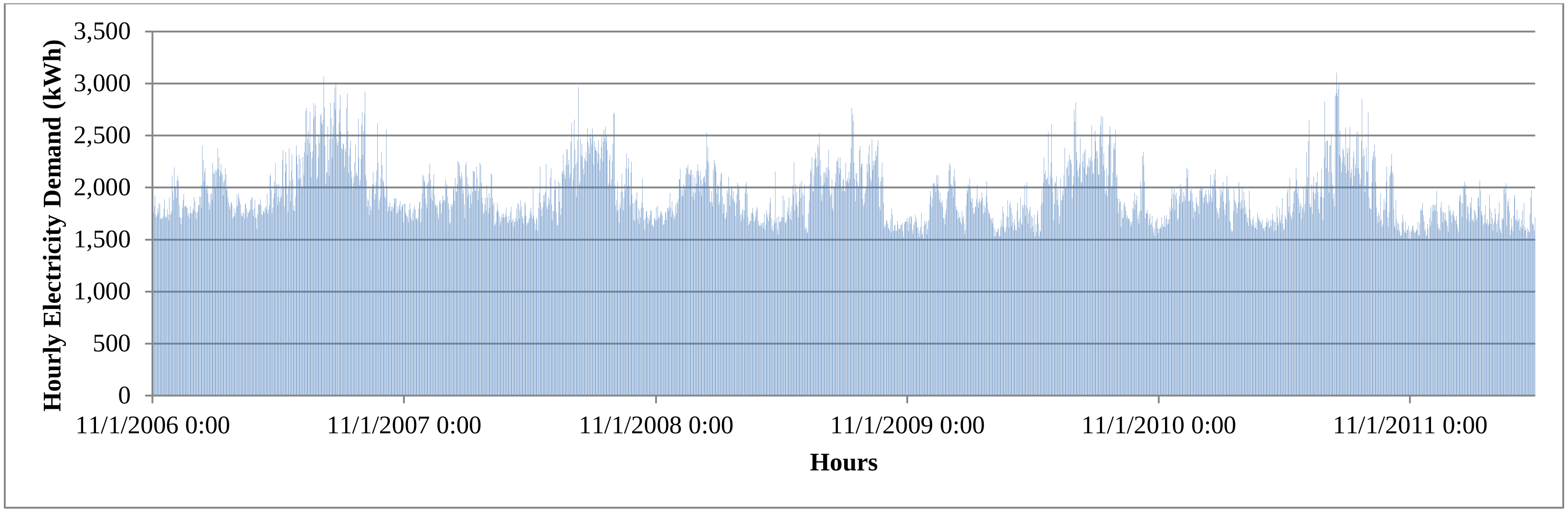


Figure 4. Historic Power Demand

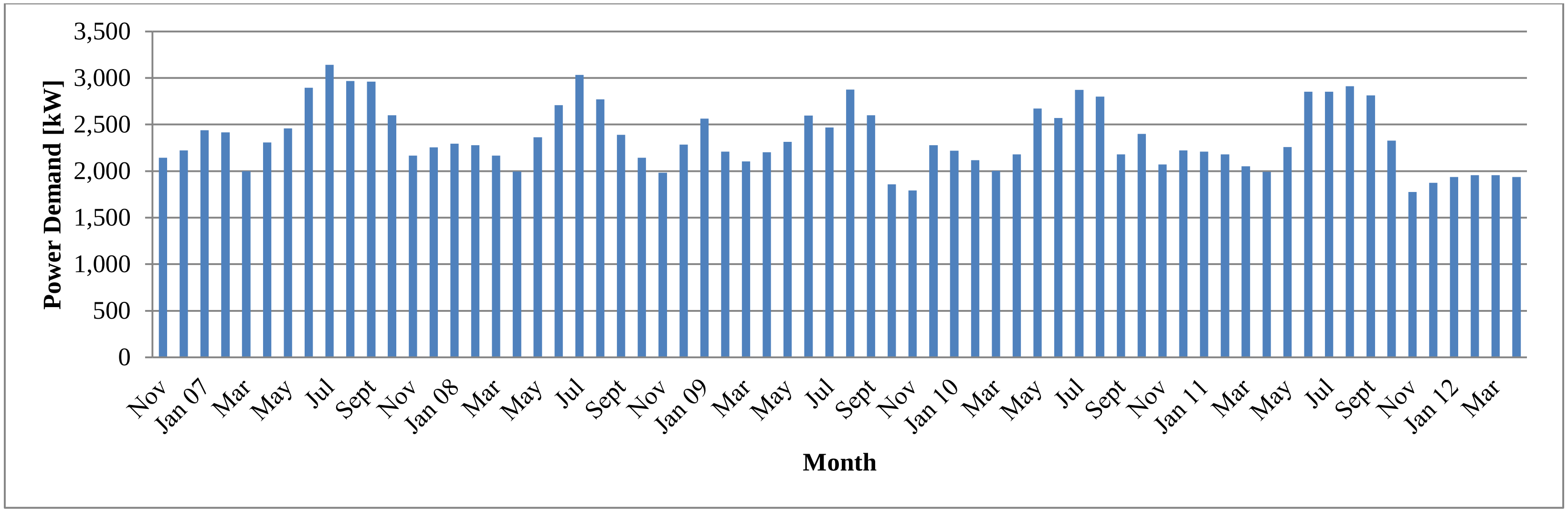
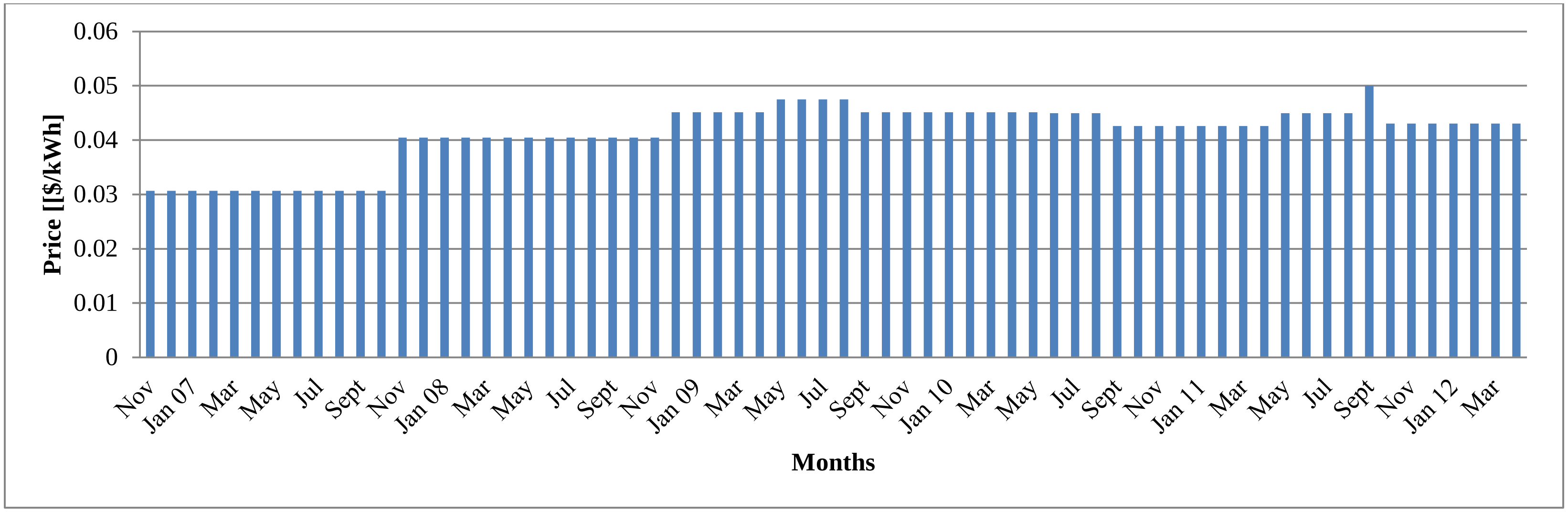


Figure 5. Shooting Star Casino Historic Marginal Price of Electricity



The historic electric energy use and power demand data show seasonal fluctuations that correspond primarily with air-conditioning loads. The annual trends are consistent annually with a slight trend towards lower energy consumption. In discussions with the master electrician[6] for the SSC, this pattern is consistent with energy-efficiency measures implemented throughout the SSC facilities.

Figure 5 displays the historic marginal price of electricity. The marginal price of electricity represents the cost associated with purchasing an additional kWh or conversely, the savings associated with reducing one kWh of electricity demand. Marginal pricing does not account for peak demand charges, connection fees, facility charges, or any other fees, as these expenses will not be reduced by the interconnection of a biomass-fired CHP facility. The historic data shown in Figure 5 do not support a prediction on electricity pricing trends, as the data do not incorporate any external variables that effect market pricing for electricity. The five-year low price is $0.03066 per kWh, the five-year high price is $0.0500 per kWh, and electricity pricing has remained relatively stable the last four years.

Fuel Oil Consumption

Fuel oil is used for the boilers and hot water heaters in the casino building in the SSC complex. These units were installed in 1992 when the building was initially constructed. Table 7 displays fuel oil consumption by equipment.

Table 7. Shooting Star Casino Fuel Oil Equipment

EQUIPMENT TYPE	LOCATION	SIZE	FUEL OIL CONSUMPTION
Superior Boiler	Casino Boiler Room	125 BHP 4.2 MMBtu/hr	37.35 gal/hr
Superior Boiler	Casino Boiler Room	125 BHP 4.2 MMBtu/hr	37.35 gal/hr
Water Heater PVI	Casino Boiler Room	400 gal 800,000 Btu	5.7 gal/hr
Water Heater PVI	Casino Boiler Room	250 gal 1,200,000 Btu	8.6 gal/hr
Water Heater PVI	Casino Boiler Room	250 gal 1,200,000 Btu	8.6 gal/hr
Water Heater PVI	Casino Boiler Room	400 gal 800,000 Btu	5.7 gal/hr
		Total:	**103.3 gal/hr**

[6] Chuck Anderson, Master Electrician, SSC.

The casino does not keep records of fuel use by each individual boiler and water heater. In lieu of detailed historic records, Figure 6 displays the fuel oil purchases and Figure 7 displays fuel oil purchase prices. Note, Figure 6 and Figure 7 are based on fuel oil purchase orders and do not directly reflect time-of-use data.

Figure 6. Shooting Star Casino Historic Fuel Oil Purchases

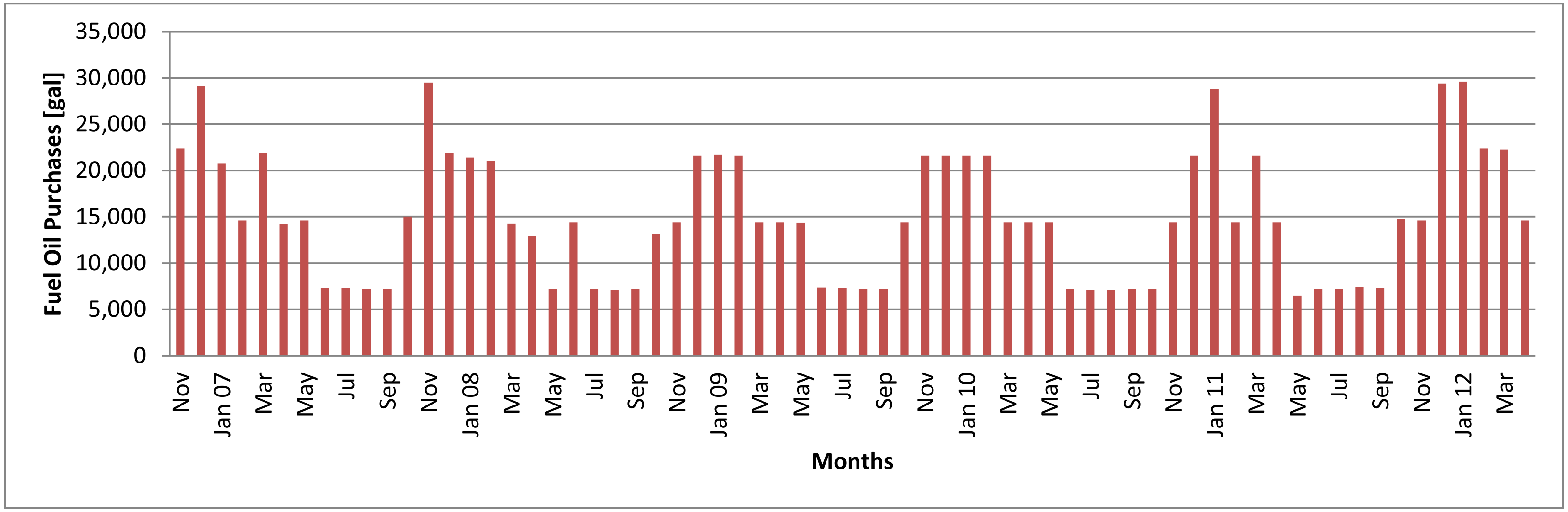
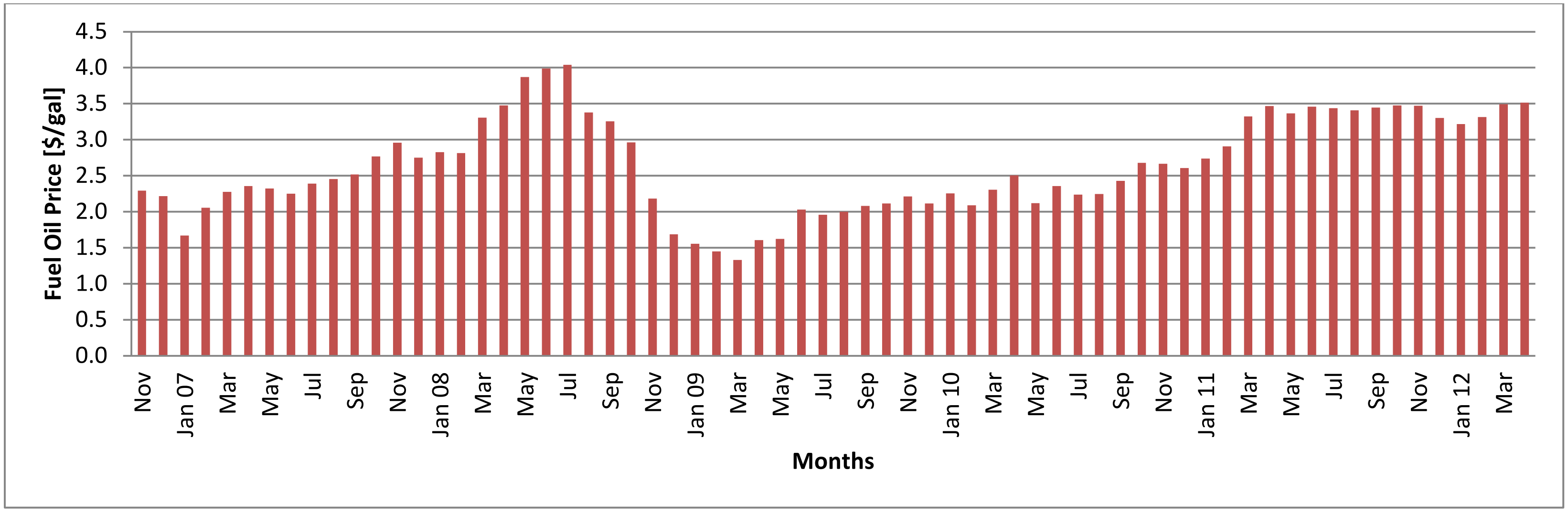


Figure 7. Shooting Star Casino Historic Fuel Oil Purchase Prices

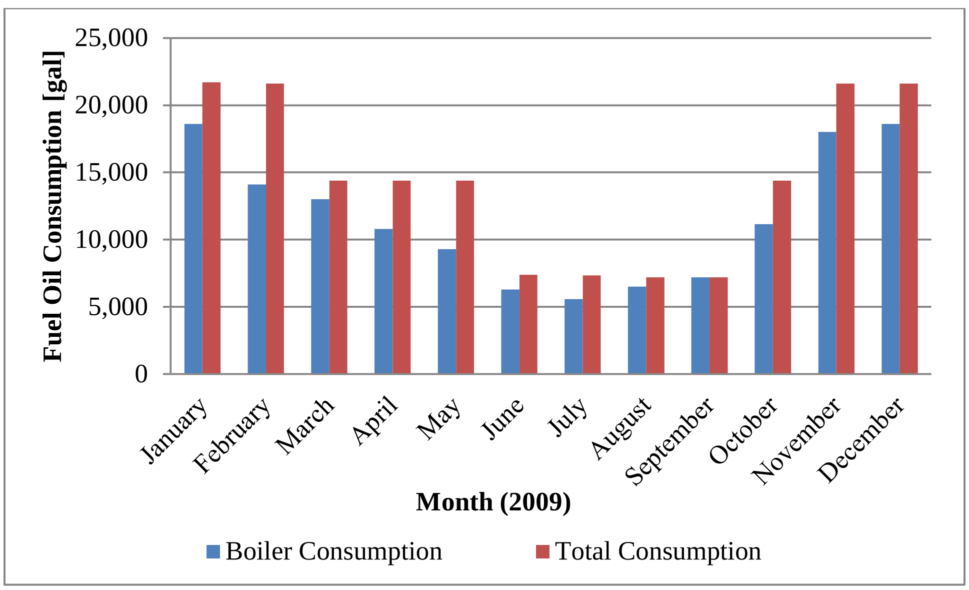


As displayed in Figure 6, fuel oil use is correlated with seasonal temperature swings and is relatively consistent on an annual basis. With no planned thermal retrofits to the casino building's thermal distribution system,[7] there are no expected deviations in future fuel oil consumption. Boiler efficiencies are approximately 81% and the current boilers are able to meet maximum demand while running in parallel at 100% capacity.

As indicated in Figure 7, fuel oil prices have fluctuated between $1.332 per gallon and $4.042 per gallon. After the 2008 summer spike in prices and subsequent fall in prices in 2009, fuel oil has shown consistent steady trends towards increasing prices. The historic data show that fuel oil prices have been increasing; however, there are insufficient data to forecast any long-term trends due to the volatility of the crude oil market and the wide variety of factors that contribute to crude oil pricing.

Time-of-use data are available for the casino room boilers for 2009 in the energy audit performed for the SSC and are shown in Figure 8 compared to the fuel oil purchases. Note that the fuel oil purchases for each month are greater than the boiler consumption. Fuel oil is used by the SSC for water heating along with space heating. Approximately 80.3% of the total fuel oil consumption is utilized for space heating.

Figure 8. 2009 Fuel Oil Consumption by Casino Room Boilers



Propane Consumption

Propane is used for the boilers and hot water heaters servicing the event center and the Stardust Hotel within the SSC complex. These buildings represent additions to the SSC facilities completed in 2001. The demand for propane is displayed in Table 8 by major equipment type.

[7] Discussion with Dan Guenther, Facility Operator/Supervisor, SSC.

Minor equipment includes kitchen appliances and is not listed in Table 8 because their propane demand is small relative to the major equipment types.

Table 8. Shooting Star Casino Propane Equipment

EQUIPMENT TYPE	LOCATION	SIZE	PROPANE CONSUMPTION
Burnham Industrial Boiler	Event Center	80 BHP 2.678 MMBtu/hr	36.2 gal/hr
Burnham Industrial Boiler	Event Center	80 BHP 2.678 MMBtu/hr	36.2 gal/hr
Water Heater PVI	Event Center	175 gal 600,000 Btu	6.5 gal/hr
Water Heater PVI	Event Center	175 gal 600,000 Btu	6.5 gal/hr
Water Heater PVI	Stardust	125 gal 600,000 Btu	6.5 gal/hr
Water Heater PVI	Stardust	125 gal 600,000 Btu	6.5 gal/hr
		Total:	**98.4 gal/hr**

As noted earlier, the SSC does not maintain records of fuel usage by boiler or water heater. In lieu of detailed historic records, Figure 9 displays the historic propane purchases and Figure 10 displays historic propane prices. Note, Figure 9 and Figure 10 are based on propane purchase orders and do not directly reflect time-of-use data.

Figure 9. Shooting Star Casino Historic Propane Purchases

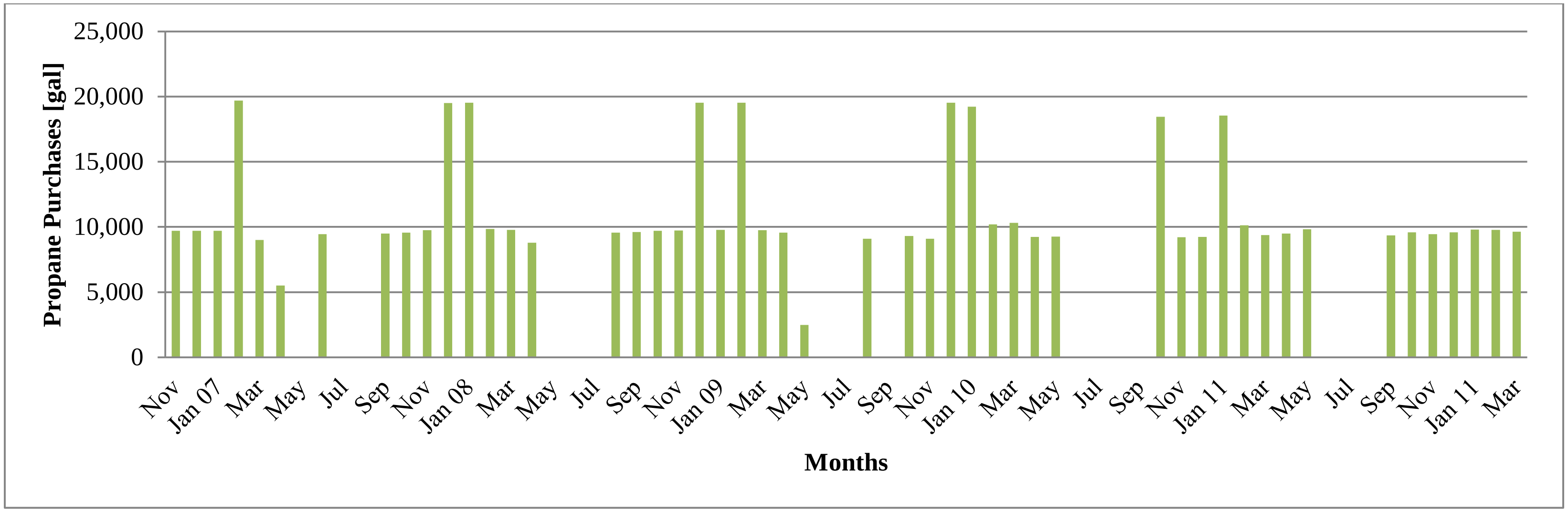
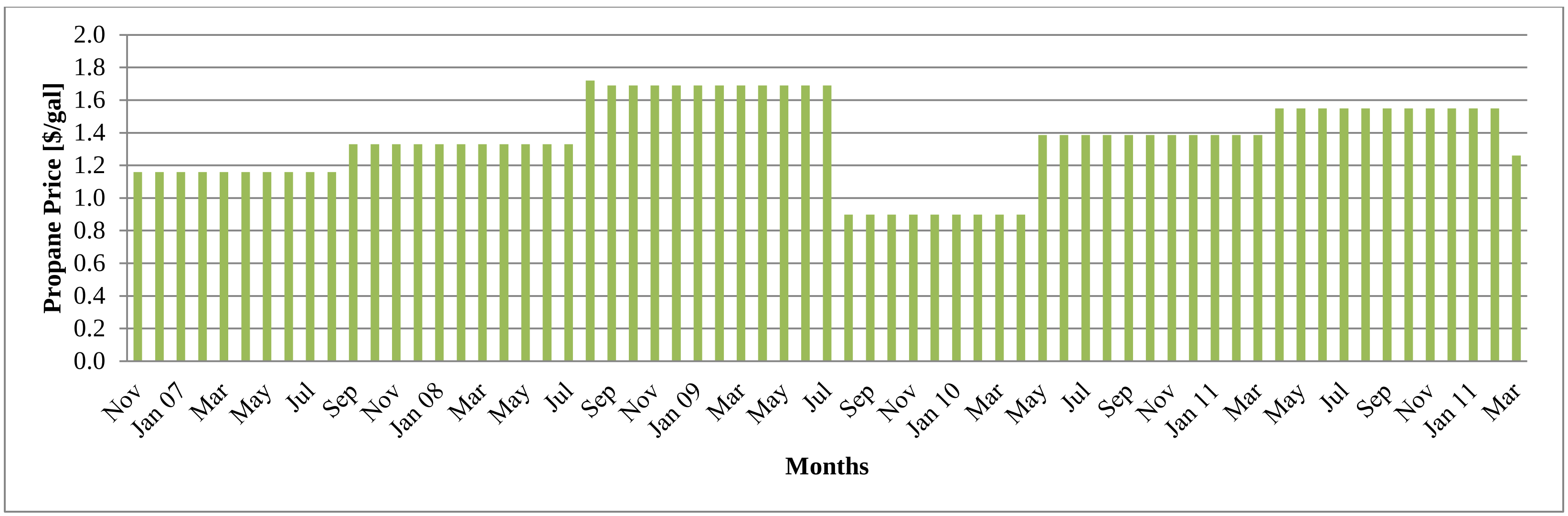


Figure 10. Shooting Star Casino Historic Propane Purchase Prices

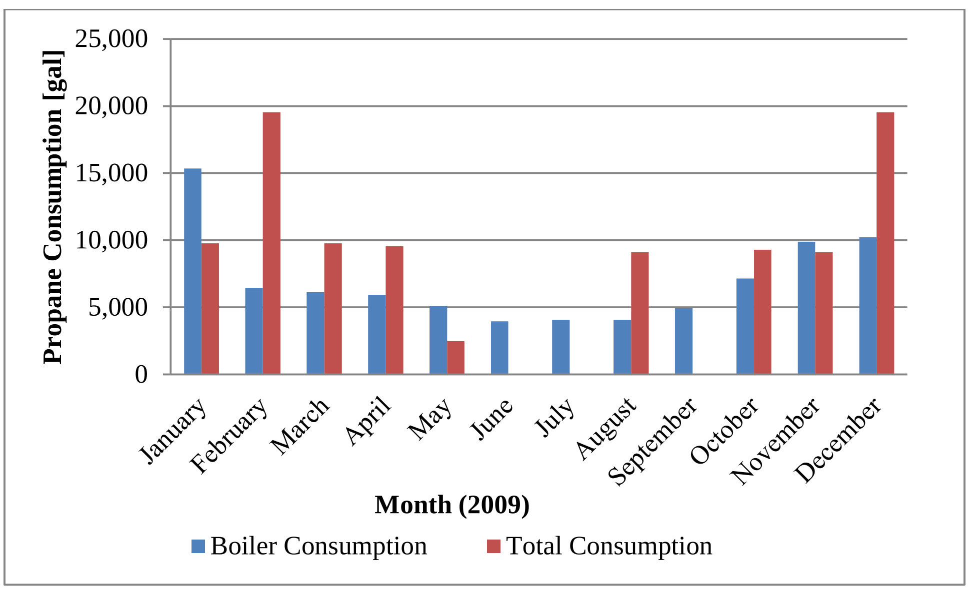


As with fuel oil and consistent with expected equipment performance, propane use is correlated with seasonal temperature swings and is relatively consistent on an annual basis. There are no expected deviations in future propane consumption since there are no planned thermal retrofits.[8] Boiler efficiencies are approximately 80% and the current boilers are able to meet maximum demand while running in parallel at 100% capacity.

As indicated in Figure 10, propane prices have fluctuated between $0.899 per gallon and $1.720 per gallon. While trends between November 2006 and July 2009 and between August 2009 and January 2012 indicate increasing prices, the current price is only 8% (10 cents) above the October 2006 price, indicating a relatively stable price for propane over the previous five years. However, there are insufficient data to forecast any long-term trends due to the volatility of the propane market and the wide variety of factors that contribute to crude oil pricing.

Time-of-use data are available for the event center boilers for 2009 in the Energy Audit performed for the SSC and are shown in Figure 11. The correlation between propane purchases and propane use is not consistent by month. This reflects the difference between propane use and order size. Propane is used for both space heating and for water heating. Approximately 85% of the purchased propane for 2009 was used for space heating.

Figure 11. 2009 Propane Consumption by Event Center Boilers



[8] Conversations with Dan Guenther, Facility Operator/Supervisor.

Energy Value

Using current prices, Table 9 summarizes the price of energy paid by the SSC in consistent units.

Table 9. Energy Value with March 2012 Commodity Prices

ENERGY SOURCE	CURRENT PRICE [$/UNIT]	CURRENT PRICE [$/MMBTU]	HISTORIC LOW [$/MMBTU]	HISTORIC HIGH [$/MMBTU]	5-YEAR AVERAGE [$/MMBTU]
Fuel Oil[9]	3.510/gal	25.07	9.04	28.87	18.94
Electricity[10]	0.04283/kWh	12.55	8.99	14.65	12.09
Propane[11]	1.260/gal	13.62	9.72	18.59	14.64

The data in Table 9 allow for comparison of equipment that utilizes different types of fuel. When using Table 9, system efficiencies must be accounted for when comparing the relative price of different equipment: the energy prices must be divided by the efficiency to compare price per MMBtu of output.

Summary

The total energy consumption is shown in Figure 12 across all energy types. Figure 12 shows the trend for electricity to peak in the summer months and for fossil-fuel consumption to peak in the winter months. The total energy profile shows the relative magnitude of each energy source. Electricity represents the primary energy utilized by the SSC followed by fuel oil and propane.

Figure 13 illustrates the historic price trends of the energy sources utilized by the SSC. Electricity is the cheapest energy source followed closely by propane. Fuel oil is the most expensive fuel source utilized by the SSC. By combining the data displayed in Figure 12 and Figure 13, the primary aim of energy savings should be directed towards fuel oil, as it represents the highest cost energy source and the second highest energy consumption.

[9] 140,000 Btu per gallon.
[10] Marginal Price per kWh, not inclusive of fixed costs.
[11] 92,500 Btu per gallon.

Figure 12. Overall Shooting Star Casino Energy Consumption

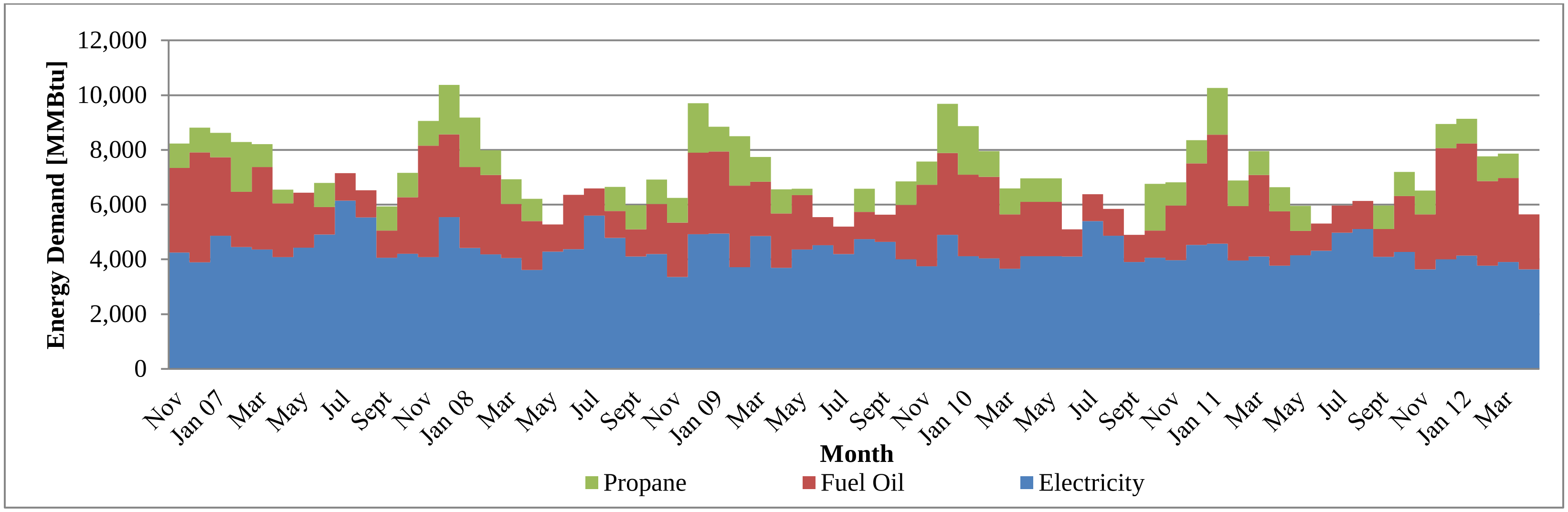
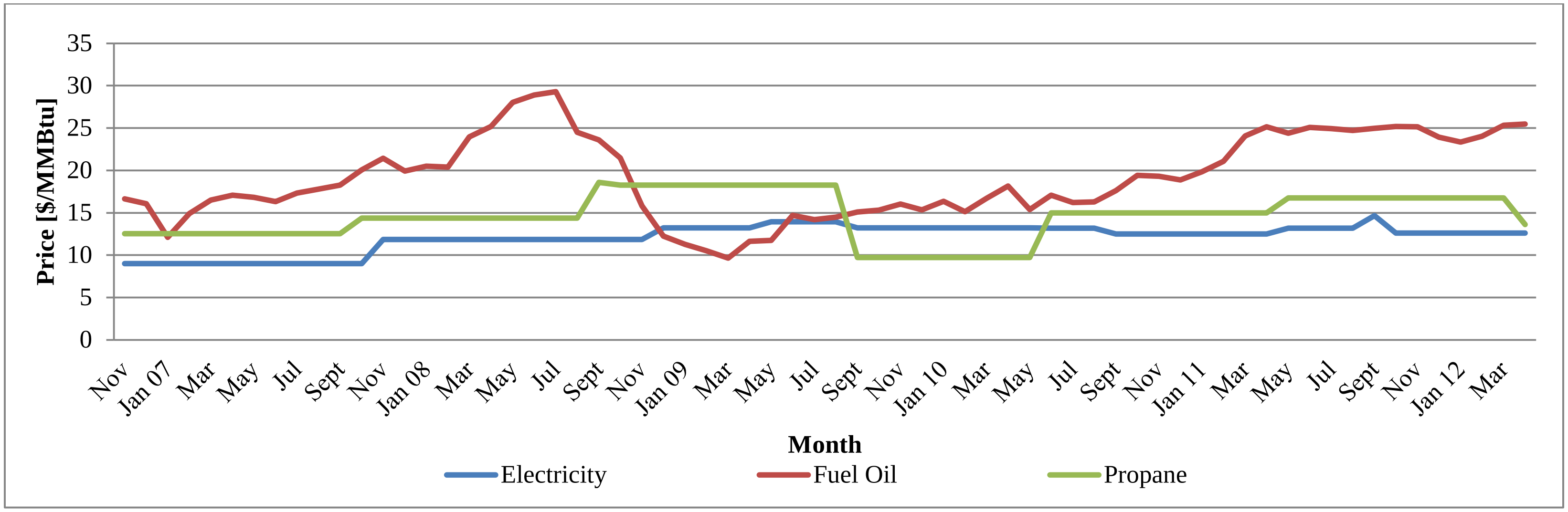


Figure 13. Historic Energy Prices for the Shooting Star Casino



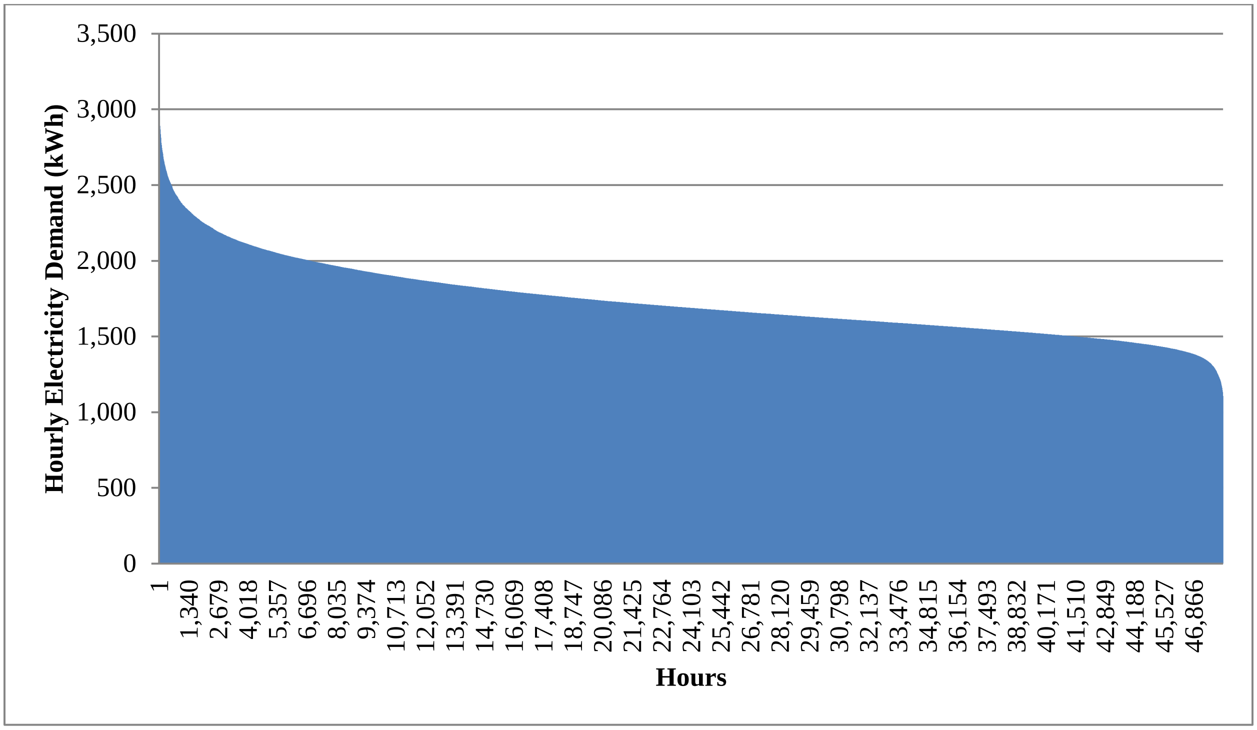
Energy Load Forecasting

Energy load forecasting utilizes historic energy data to project future consumption patterns. The SSC does not have near-term expansion plans and therefore the historic data should accurately represent the future energy demand. The forecasted energy loads are used to estimate the size of potential biomass CHP or thermal-only facilities.

<u>Electricity</u>

The SSC's electricity profile for the last five years is shown in Figure 14 by aggregating this data set from greatest demand to least demand.

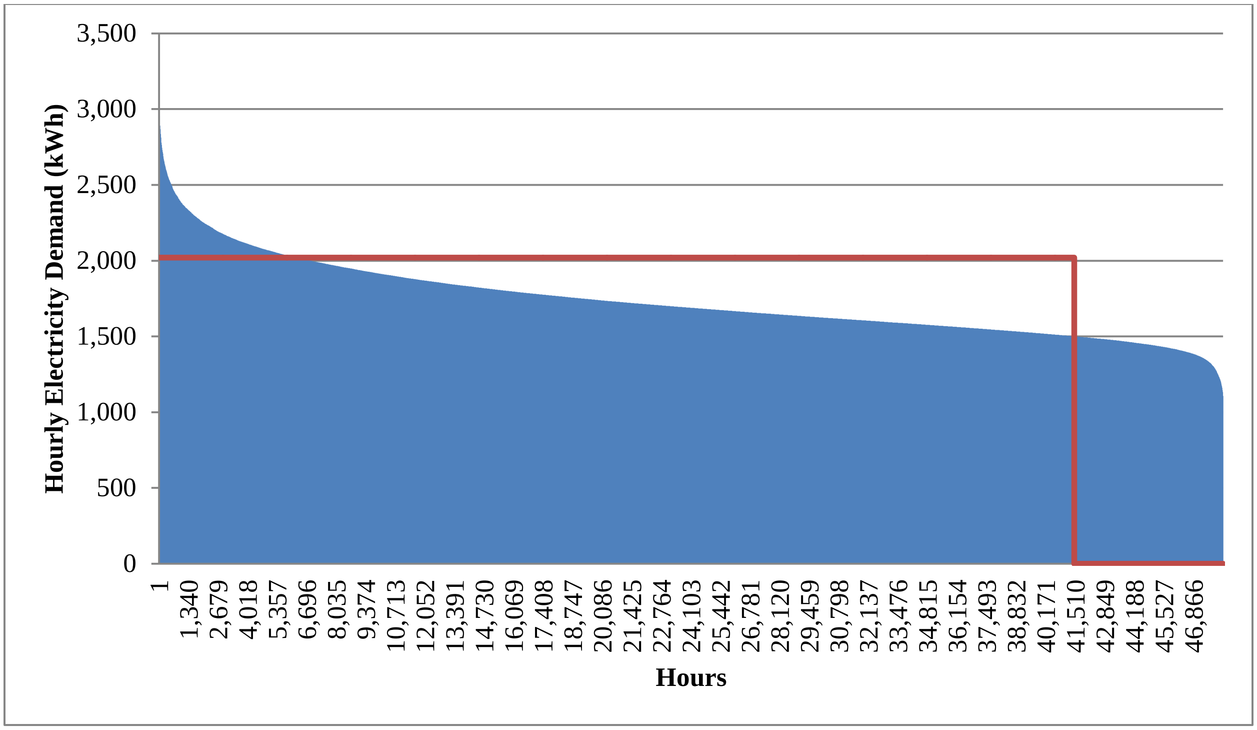
Figure 14. Shooting Star Casino's Electric Load Profile



A biomass facility that produces electricity runs most effectively as a baseload (e.g., 24 hours, seven days per week) electricity producer and would not operate to match the instantaneous needs for the facilities. Net metering, in its simplest form, allows the electricity customer (e.g., SSC) to subtract the total energy produced (e.g., by the biomass CHP facility) from the total electricity demanded by the SSC. The electricity provider (e.g., OTP) will charge the net-metering customer for the difference between the amount of electricity generated and demanded. Figure 14 is developed to analyze net metering opportunities. To provide sufficient energy to reach a net zero usage given the available data, the biomass CHP facility would be sized for 2.02

MW.[12] Figure 15 displays expected output from a 2.02 MW facility overlaid on the electricity profile.

Figure 15. Electricity Profile with Net Zero Generation Capacity

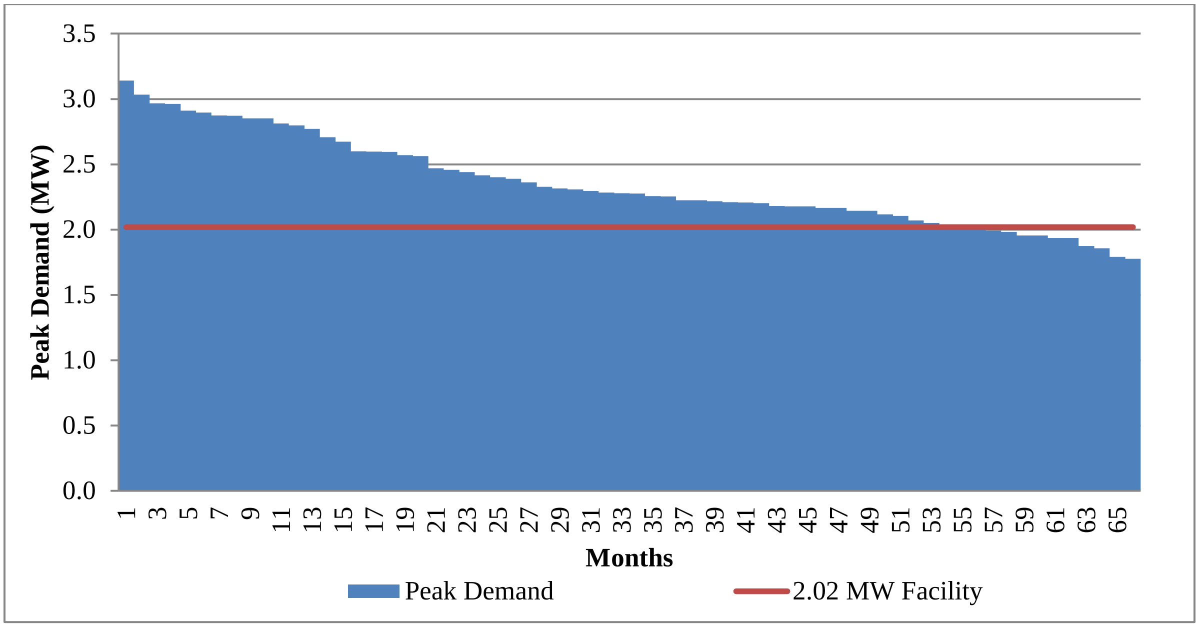


As displayed in Figure 15, the net-zero line does not meet electricity usage for 6,223 hours in this data set (approximately 12.9% of the total hours). Additionally, for 14% of the total hours, the biomass facility is not expected to produce any electricity. This is representative of a conservative 86% capacity factor for scheduled maintenance. During the times when demand exceeds supply, electricity would be purchased from OTP. For the remainder of the time, a surplus of electricity would be generated. This electricity would be placed back on the OTP electrical grid. Ultimately with a net-metering system, the amount of electricity placed on the grid will equal the amount of electricity pulled off the grid.

Based on the peak demand profile,[13] as highlighted in Figure 16, the peak demand would only be met 13 of 66 months. These findings indicate that the SSC would likely still pay for demand charges on an average month. This means that the avoided cost of a biomass CHP facility will be the marginal cost of the energy.

[12] Capacity factor of 0.86 has been assumed for these calculations
[13] Note that this data set is collected by month as peak demand charges are based on the highest 15 minute average power demand during the billing cycle.

Figure 16. Peak Demand Profile



The net-zero point is an important indicator for electricity generation. A larger facility will require a power purchase agreement (PPA) with OTP, or other local utility, to realize a revenue stream from the excess electricity generation (excess to SSC power needs). For a smaller facility, a net metering agreement will be sufficient because less power will be generated than consumed.

A community-scale electricity-generating unit should be sized to match the demands of the facilities it is meant to serve. Based on the energy load analysis, a 2.0 MW facility represents the scale appropriate for annual net zero electricity usage. Any smaller unit will be a behind the meter installation. A 3.0 MW facility represents a unit with sufficient power to cover almost all of the power demand and all of the electricity demand at any time throughout the year. These findings suggest that the selected technology should be sized to produce between 0.5 MW[14] and 3.0 MW of electricity.

Heat

Without specific use data for the fuel oil or propane boilers, a detailed energy profile for these thermal systems cannot be produced. From interviews with the SSC facilities manager and the master electrician, the two fuel oil boilers run in parallel and the two propane boilers run in parallel to service their respective loads. Because net metering is not available for thermal loads, the units must be sized for their peak demand or be supplemented by an additional system (such as the existing boilers).

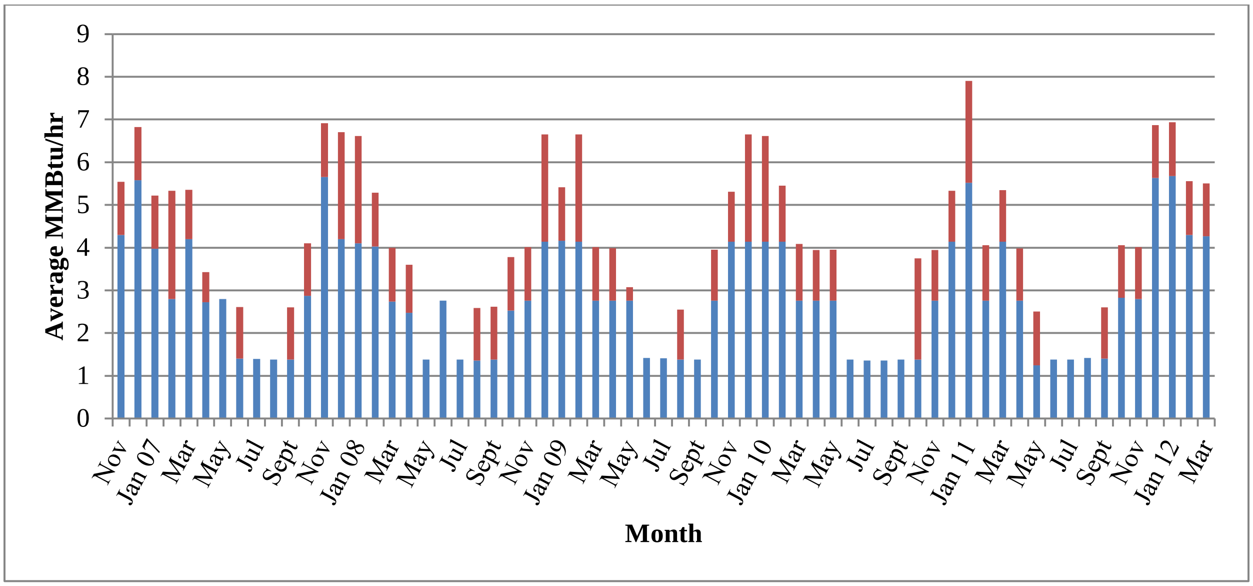
[14] 0.5 MW represents the lower limits of commercial-scale technology for biomass-fired electricity production.

As shown in the Tribal Energy Load Assessment, the two fuel oil boilers combine to provide peak output of 8.2 MMBtu per hour of heat. The two propane boilers combine for 5.3 MMBtu per hour of heat. Therefore, the peak output from all of the boilers is 13.5 MMBtu per hour of heat to service all of the facilities. It is recommended that at least one of each of the boilers remain as a backup to a new biomass-fired CHP or thermal-energy only facility.

An alternative to fully replacing the thermal units would be to size the biomass-fired facility to replace one of each of the pairs so that the remaining units are utilized for system back-up and augmentation during peak demand.

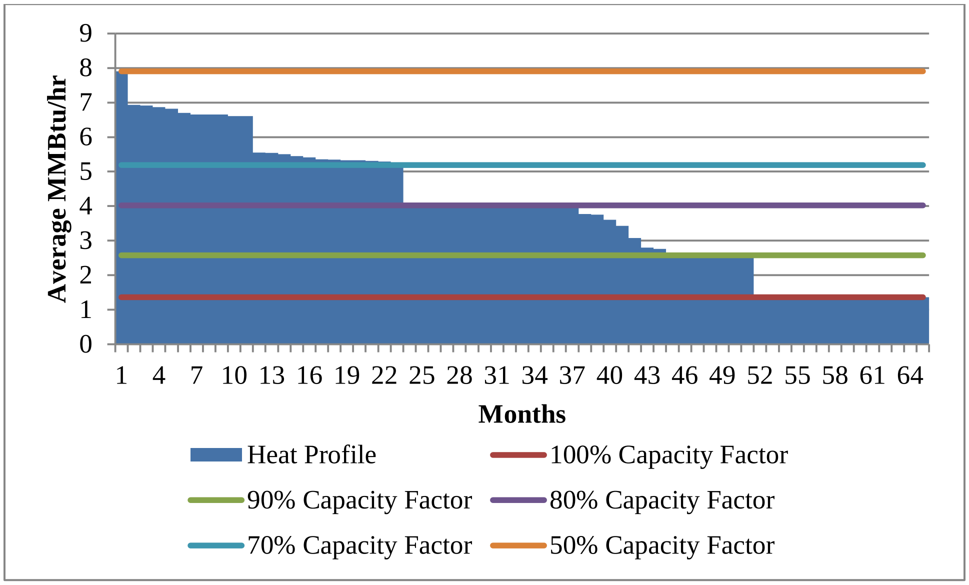
Based on fuel purchase records, the average aggregate monthly heat demand is displayed in Figure 17. These data points are calculated by converting the monthly fuel purchases from gallons of fuel to the equivalent energy content, summing the fuel oil and propane data, and averaging it over the number of hours in each month. Fuel oil purchases were reduced by 19.7% and propane purchases were reduced by 15% to match the ratio identified by the 2009 Energy Audit (Figure 8 and Figure 11).

Figure 17. Average Monthly Fuel Consumption from Fuel Purchase Orders



The average heat demand ranges from 1.1 MMBtu per hour to 6.6 MMBtu per hour. By sizing a biomass system to provide enough heat to cover the average demand, the existing boilers should only be used to cover peak heat demands. While Figure 17 shows average demands, short-term spikes must be accounted for. By maintaining the existing boilers for back up and peaking, the biomass unit may be sized for the average loads instead of the peak loads. The heat profile in Figure 18 allows for estimates of capacity factor based on demand averages.

Figure 18. Heat Profile for the Shooting Star Casino



The capacity factor is the ratio of actual operation versus potential operation. For the economics of a project it is important to balance maximizing the system's capacity factor with the unit's ability to meet demand. The decision to maintain the fossil-fuel boilers will impact the size for the biomass boiler. If all the boilers remain installed and maintained, the biomass boiler may be downsized to 5.0 MMBtu per hour with an expected operation of 60-70% capacity factor. For this configuration, the biomass unit would be able to operate without assistance for 54 of the previous 65 months while during the other 11 months, the fossil-fuel boilers would be utilized to provide the additional heat to match the load. This analysis includes piping the heat to both boiler rooms to displace both fuel oil and propane. The most economic decision depends on many factors, including the cost of fossil-fuels and maintenance costs for the fossil-fuel boilers.

Alternatively, the boiler rooms could be treated separately. Figure 19 and Figure 20 show the estimated heat profile for each individual boiler room.

Figure 19. Heat Profile for the Casino Boiler Room

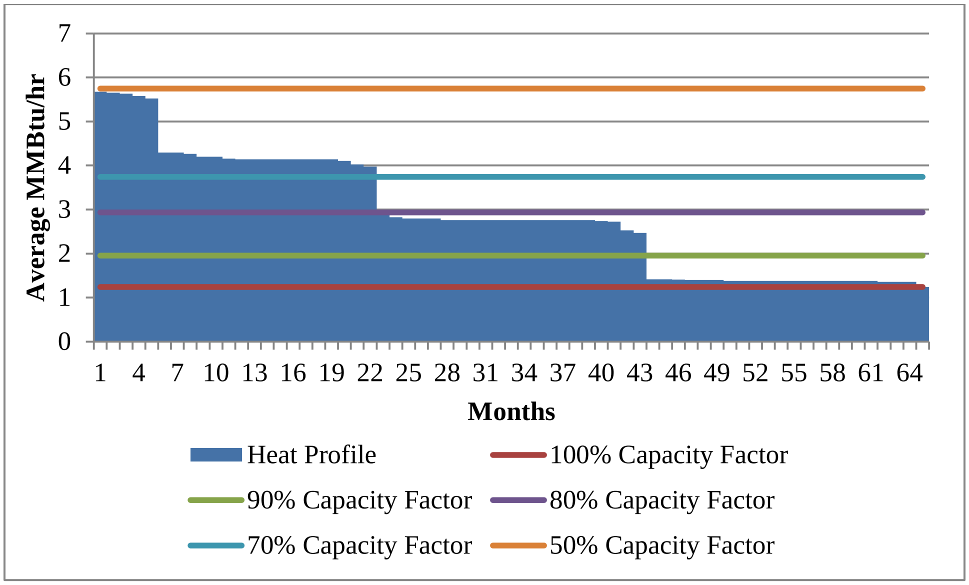
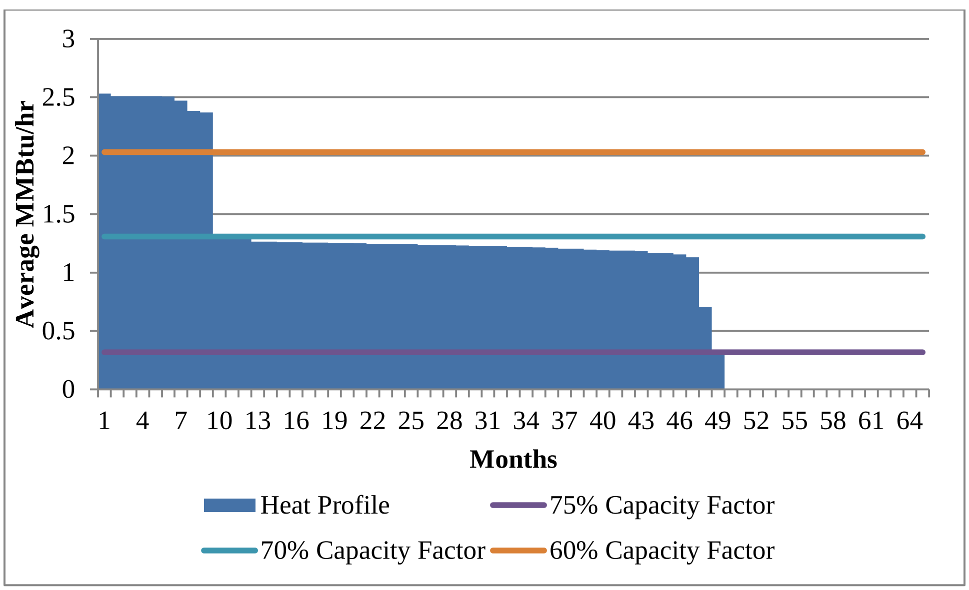


Figure 19 shows that a 3.0 MMBtu per hour to 3.8 MMBtu per hour boiler would be appropriate for the Casino Boiler Room only to reach 60 to 70% capacity factor. This boiler size is well within the range of standard biomass boilers.

Figure 20. Heat Profile for the Event Center Boiler Room



The heat profile in Figure 20 is disjointed due to the volume of propane purchases and the lower energy demand on the propane boilers. Detailed boiler consumption data, like the data shown in Figure 11, would enhance the accuracy of the heat profile. Based on the available data, a 0.5 MMBtu per hour to 1.2 MMBtu per hour would be appropriate for the Event Center Boiler

Room. This size biomass boiler may be more appropriate for pellets than wood chips because of the low feedstock flow rate.

Combined Heat and Power

Based on the previous assessments, a CHP unit would be sized for 0.5 to 3.0 MW and between 1.1 MMBtu per hour and 13.5 MMBtu per hour. CHP is preferred to strictly electrical generation because it is a more efficient use of the biomass feedstock. However, due to the energy losses associated with electricity production, CHP is less efficient than thermal-energy only units.

Findings

Fuel Consumption

The SSC utilizes electricity, fuel oil, and propane to meet energy demand. The electricity demand fluctuates seasonally in correlation to air conditioning loads while the fuel oil and propane usage fluctuate relative to space heating and water heating demand. Figure 12 displays the cumulative energy demand by the SSC. Overall, the energy demand peaks in the winter and decreases in the summer, consistent with expectations based on weather patterns in western Minnesota. The total energy load ranges from 4,895 MMBtu per month to 10,375 MMBtu per month, with peak demand of 3,140.2 kilowatts (kW) for electricity, 8.4 MMBtu per hour for fuel oil, and 5.3 MMBtu per hour for propane.

Energy Pricing

Figure 13 displays the historic price of energy in terms of dollars per MMBtu. In the past five years, prices have fluctuated significantly for fuel oil and propane while electricity pricing has been relatively stable with a gradual trend towards higher pricing. Figure 13 displays the historic pricing of each energy type. Understanding market drivers is critical to interpreting the price variability and must be incorporated into any future speculation on energy prices. Figure 13 provides a comparison of relative energy prices where the prevailing trend is that prices traditionally increase over time across all energy types: electricity, propane, and fuel oil.

FEEDSTOCK AVAILABILITY AND COST ASSESSMENT

Biomass feedstock is typically produced as a byproduct of other value-added processing (e.g., agricultural operations) or natural resource management (e.g., forest management) operations. Suitable feedstock availability is predicated upon agricultural and forestry operations conducted to market higher value products generating byproduct for potential use as feedstock in a thermal-energy only or CHP facility. Feedstock from urban wood waste is recovered from material typically destined for landfills, such as construction and demolition material, wooden pallets, and tree and shrub trimmings.

The FSA for this analysis was centered on Mahnomen, Minnesota, the site of WEN's SSC facility. Long-term sustainability of the resources considered is a key metric of availability. The types of potential biomass feedstocks reviewed include:

- Byproduct of agricultural operations;
- Food waste;
- Byproduct of forest operations, primarily timber harvesting;
- Byproduct of forest products manufacturing; and
- Urban wood waste (construction/demolition wood, pallets, tree trimmings).

The costs associated with collection, processing, and transport of these potential feedstocks were evaluated. Findings from this analysis were used to provide a forecast of biomass material that meet feedstock specifications and are available annually within the FSA for use in a thermal-energy only or CHP facility.

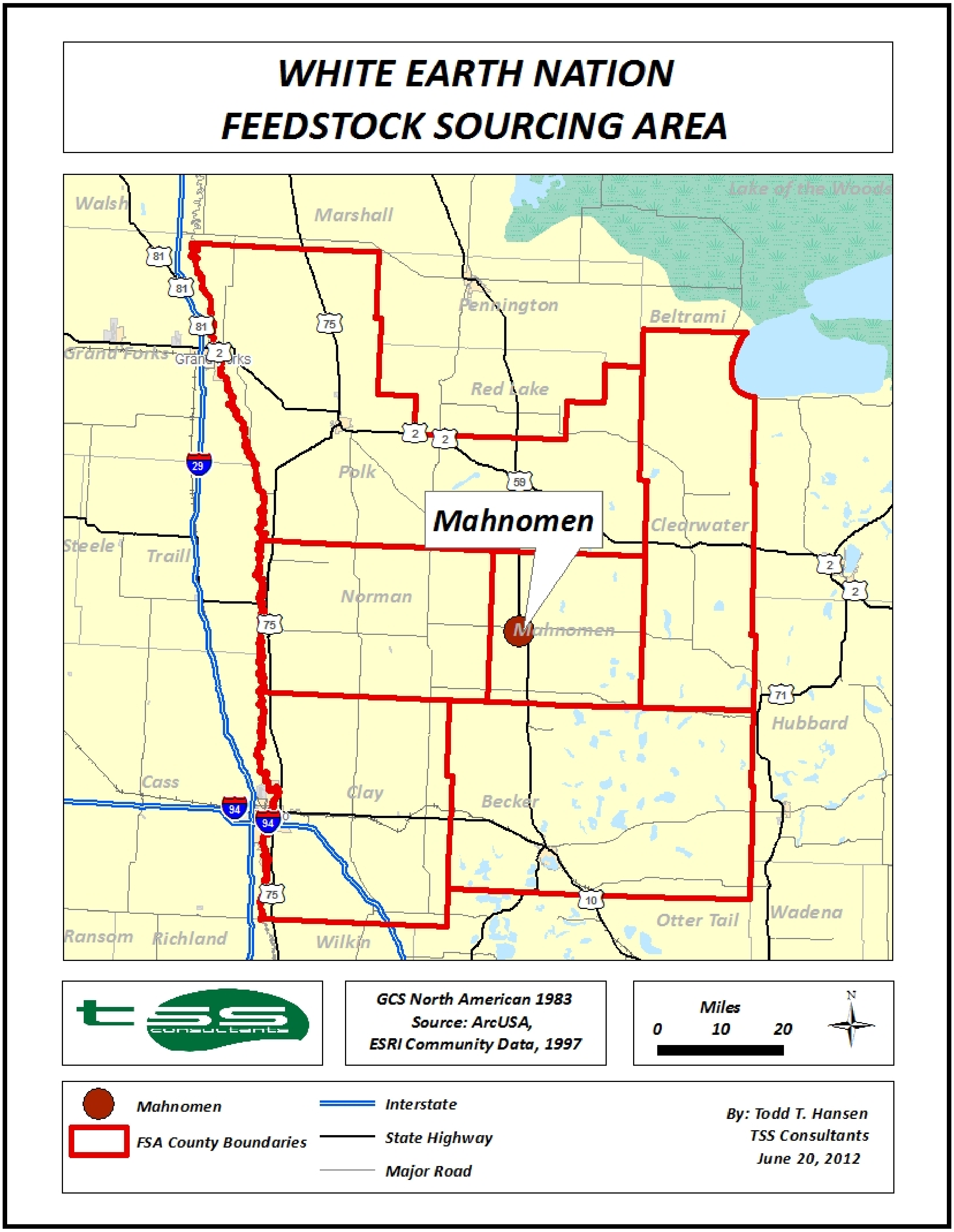
An ESRI ArcMap based Geographic Information System (GIS) was employed to provide updated graphic demonstration:

- General FSA and surrounding region;
- Land cover in the defined FSA (forest, agriculture, etc.); and
- Land ownership within the FSA of suitable waste material location and ownership.

Feedstock Sourcing Area

The FSA for this biomass resource feedstock assessment consists of a six county area centered on the community of Mahnomen, Minnesota. In particular, the SSC serves as the primary focus of the FSA. Figure 21 shows the FSA, which consists of nearly 4.5 million acres.

Figure 21. Feedstock Sourcing Area



The FSA, as shown in Figure 21, consists of nearly 4.5 million acres. Table 10 shows the total acres of each county within the FSA, as well as by percent of total for each county.

Table 10. FSA Acres by County

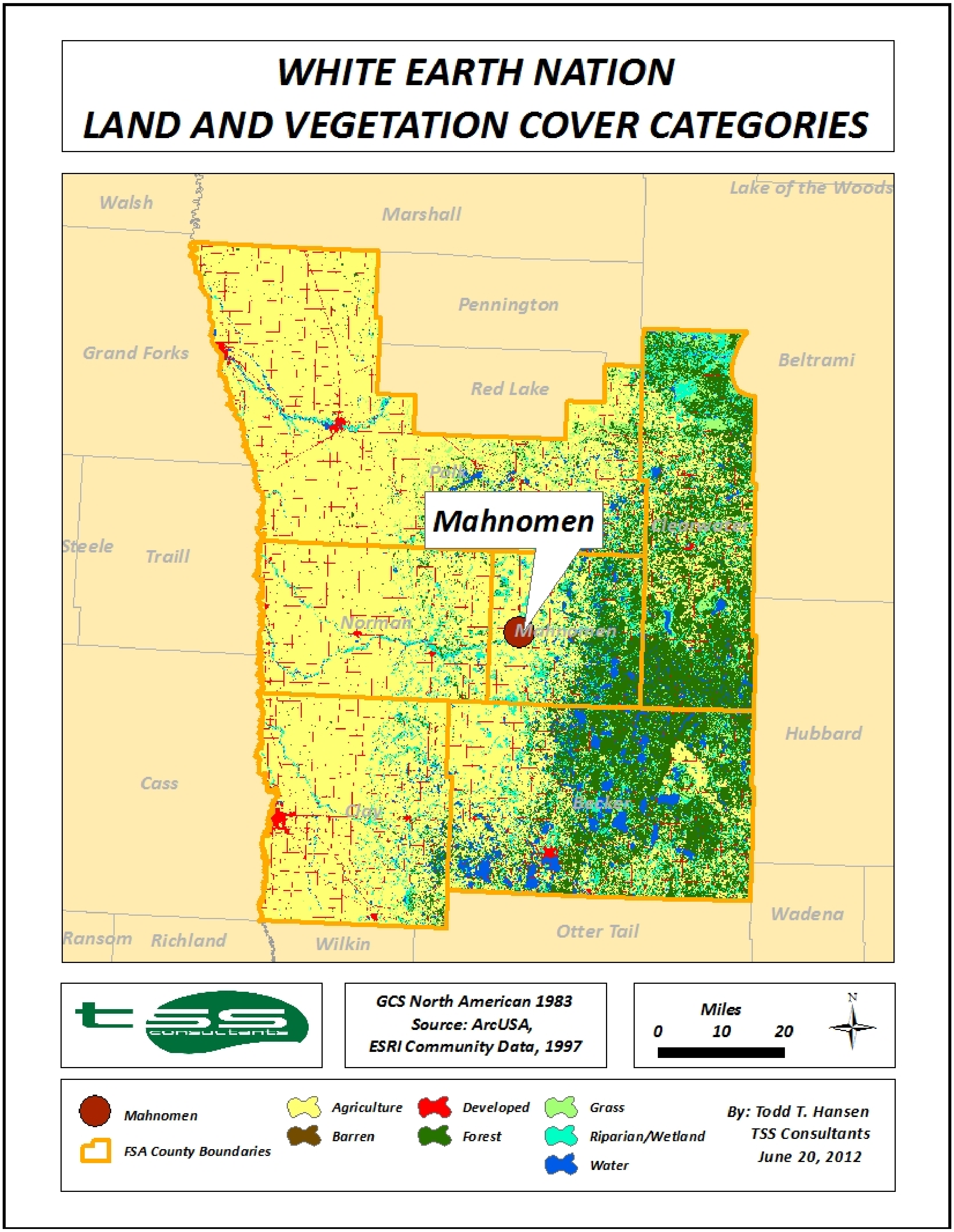
COUNTY	ACRES	PERCENT OF FSA
Polk	1,279,480	28.6%
Clearwater	659,017	14.7%
Norman	561,592	12.6%
Mahnomen	373,535	8.3%
Clay	674,378	15.1%
Becker	925,073	20.7%
TOTAL	**4,473,075**	**100.0%**

<u>Land and Vegetation Cover Categories</u>

Feedstock material available on a sustained basis, over time, and for a given area is directly dependent upon vegetation cover type. In order to confirm feedstock material availability, it is necessary to evaluate land and vegetation cover types within the FSA. The primary land and vegetative data source used in mapping and analysis for this assessment were LANDFIRE. LANDFIRE is a shared project between the U.S. Forest Service (USFS) and U.S. Department of the Interior (USDI). LANDFIRE data allow ready evaluation of land and vegetative cover composition and structure.[15] Figure 22 highlights the various vegetation and other cover categories within the FSA.

[15] LANDFIRE. [Homepage of the LANDFIRE Project, U.S. Department of Agriculture, Forest Service; U.S. Department of Interior]: http://www.landfire.gov/index.php [2010, October 28].

Figure 22. FSA Land and Vegetation Cover Categories



As Figure 22 clearly shows, the western portion of the FSA is dominated by agriculture (eastern side of the Red River Valley), and the eastern portion is dominated by forest cover. Table 11 shows the allocation of acres by land and vegetation cover categories from the LANDFIRE GIS analysis.

Table 11. FSA Acres by Cover Category

COVER CATEGORY	ACRES	PERCENT OF FSA
Agriculture	2,576,090	57.6%
Barren	1,340	0.1%
Developed Areas	202,779	4.5%
Forest	926,783	20.7%
Grassland	271,207	6.1%
Riparian/Wetland	305,139	6.8%
Water	189,737	4.2%
TOTAL	**4,473,075**	**100.0%**

Agriculture dominates the FSA at nearly 58%, with forest next at nearly 21%. Both of these vegetation cover categories offer opportunities to recover biomass as feedstock. Both are governed by the seasonal nature of operations; more so perhaps with agriculture, as opportunities for feedstock recovery occur only after crop harvest during specific periods of the year. Storage at the field site is a possibility if the feedstock is covered for protection from precipitation.

Figure 23 shows the allocation of cover categories by percent of total area within the FSA.

Figure 23. Cover Category by Percent of Total

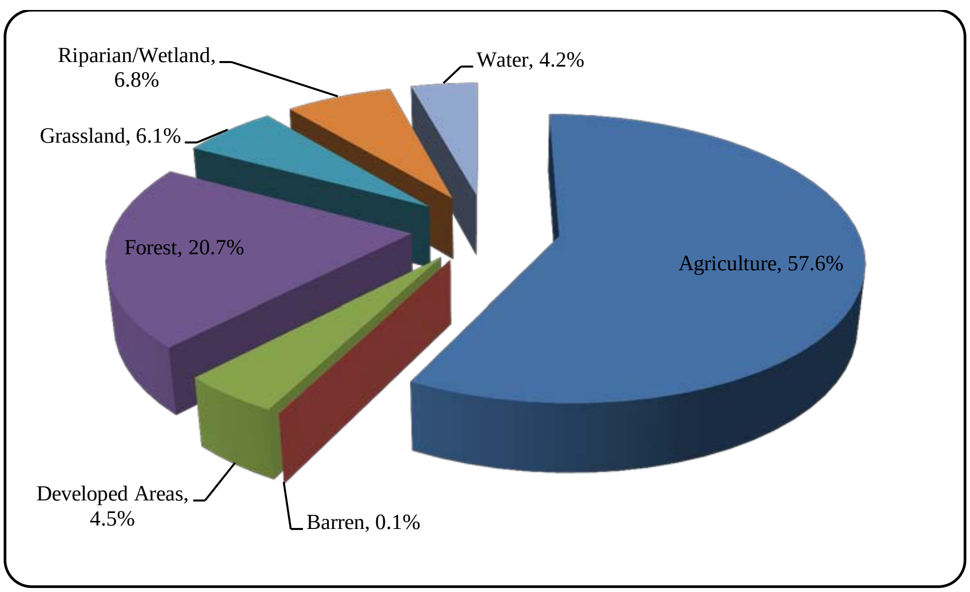


Table 12 and Table 13 show the allocation of acres by cover categories within each of the six counties as well as percent of each category. This demonstrates areas to target for specific feedstock type: agricultural byproduct or byproduct from forest operations.

Table 12. Acres by County by Cover Category

COVER CATEGORY	BECKER	CLAY	CLEARWATER	MAHNOMEN	NORMAN	POLK	TOTALS[16]
Agriculture	275,031 (29.73%)	547,588 (81.20%)	109,540 (16.62%)	163,172 (43.68%)	476,380 (84.83%)	1,004,378 (78.50%)	**2,576,090 (57.59%)**
Barren	352 (0.03%)	355 (0.05%)	176 (0.03%)	76 (0.02%)	32 (0.01%)	347 (0.03%)	**1,339 (0.03%)**
Developed Areas	34,846 (3.76%)	41,471 (6.15%)	17,566 (2.67%)	11,794 (3.16%)	27,036 (4.81%)	70,065 (5.48%)	**202,779 (4.53%)**
Forest	364,553 (39.4%)	21,886 (3.25%)	353,267 (53.60%)	111,803 (29.93%)	13,798 (2.46%)	61,477 (4.81%)	**926,783 (20.72%)**
Grassland	74,452 (8.04%)	12,965 (1.92%)	77,693 (11.79%)	18,069 (4.84%)	9,133 (1.63%)	78,896 (6.16%)	**271,208 (6.07%)**
Riparian/Wetland	83,860 (9.06%)	35,517 (5.27%)	76,763 (11.65%)	48,254 (12.92%)	28,718 (5.11%)	32,026 (2.50%)	**305,139 (6.82%)**
Water	91,977 (9.94%)	14,596 (2.16%)	24,012 (3.64%)	20,367 (5.45%)	6,494 (1.15%)	32,291 (2.52%)	**189,737 (4.24%)**
TOTALS	**925,071 (100%)**	**674,378 (100%)**	**659,017 (100%)**	**373,535 (100%)**	**561,592 (100%)**	**1,279,480 (100%)**	**4,473,075 (100%)**

Table 13. Percent of Cover Category by County

COVER CATEGORY	BECKER	CLAY	CLEARWATER	MAHNOMEN	NORMAN	POLK	TOTALS[17]
Agriculture	10.7%	21.3%	4.2%	6.3%	18.5%	39.0%	**100%**
Barren	26.3%	26.5%	13.2%	5.7%	2.4%	25.9%	**100%**
Developed Areas	17.2%	20.5%	8.7%	5.8%	13.3%	34.5%	**100%**
Forest	39.3%	2.4%	38.1%	12.1%	1.5%	6.6%	**100%**
Grassland	27.4%	4.8%	28.6%	6.7%	3.4%	29.1%	**100%**
Riparian/Wetland	27.5%	11.6%	25.2%	15.8%	9.4%	10.5%	**100%**
Water	48.5%	7.7%	12.7%	10.7%	3.4%	17.0%	**100%**

[16] Rounding will account for any discrepancies between the individual data points and the totaled values.
[17] Ibid.

Table 13 shows that Polk County contains a significant percentage of the total agriculture lands within the FSA. Becker and Clearwater counties contain a significant percentage of forestland within the FSA, comprising nearly 80% of the total. This data set provides guidance with regard to feedstock sourcing by feedstock type.

Land Ownership

Land ownership plays a significant role in potential woody biomass generation in forest landscapes. Regions or ownerships dominated by landowners or land managers with restrictive or constrained practices or policies relative to their operations will typically provide fewer opportunities for biomass (agriculture or forestry) recovery than ownerships with less restrictive operations. Private ownerships and large-scale, industrial tree farm owners with primary business in timber or log sales offer the most significant opportunities for biomass recovery. Figure 24 shows the various land ownership categories[18] within the FSA.

[18] Sourced from the Minnesota Department of Natural Resources GIS datasets; http://deli.dnr.state.mn.us/index.html

Figure 24. FSA Land Ownership

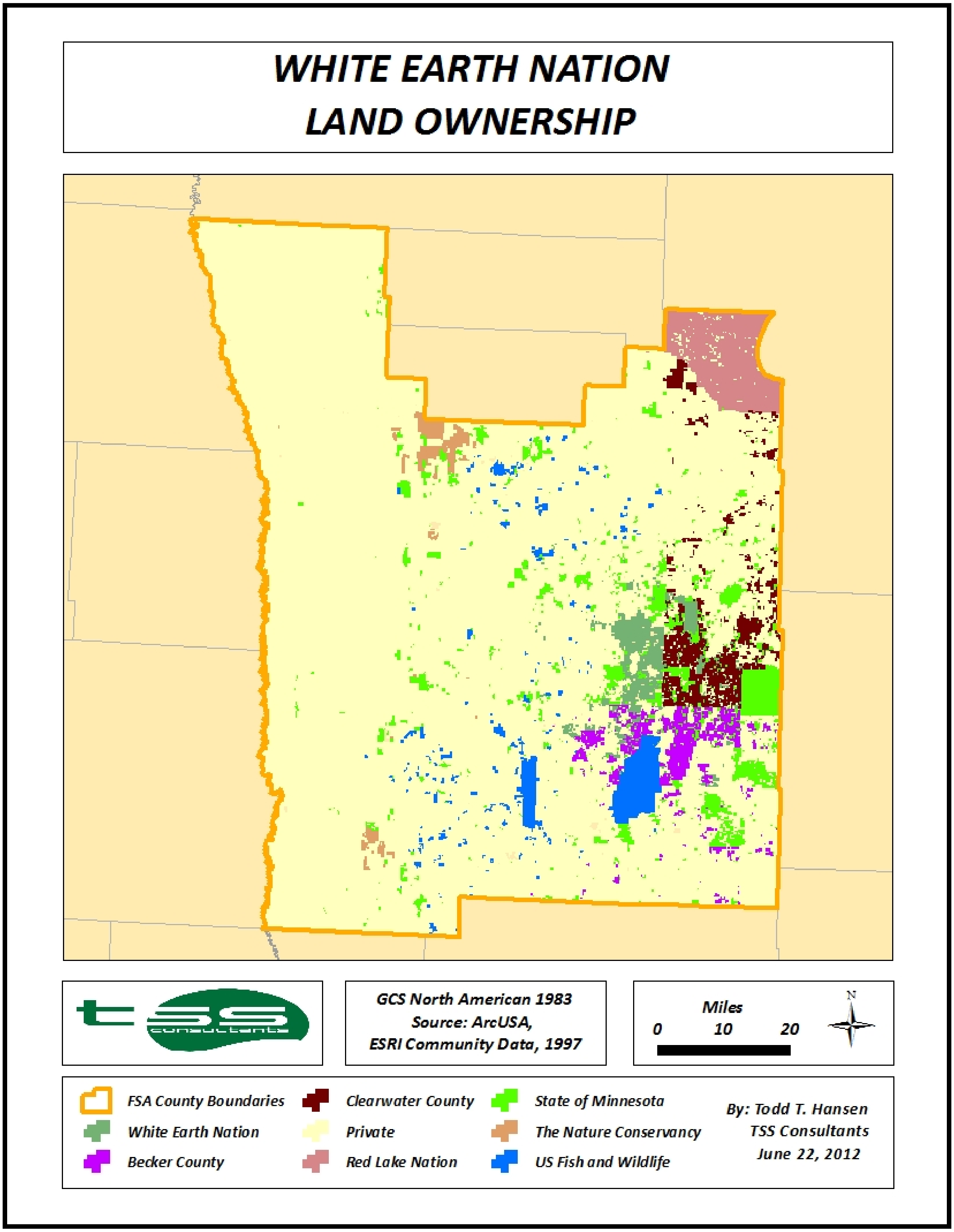


Figure 24 shows the diversity of ownership within the FSA. Table 14 summarizes the number of acres by significant landowner or land manager within the FSA.

Table 14. Ownership Acres and Percent of Total

OWNER/MANAGER	ACRES	PERCENT OF TOTAL
White Earth Nation	65,918	1.47%
Red Lake Nation	94,986	2.12%
City/County	3,970	0.09%
State of Minnesota	463,993	10.37%
Nature Conservancy	32,941	0.74%
Private	3,712,594	83.00%
U.S. Fish & Wildlife	96,831	2.16%
U.S. Other	1,842	0.04%
TOTAL	**4,473,075**	**100.00%**

The accuracy of this data set is subject to some scrutiny, as the data to develop Table 14 were derived from a variety of sources, all with conflicting information. TSS made every effort to contact each owner or managing agency to acquire data directly from the source whenever possible. However, there are still some unresolved issues and as such, the data represent the best publically available estimates.

The significant landowners or land managers identified in Table 14 comprise 99.6% of the entire FSA area. Private ownership dominates the FSA at 83% of the total area. The State of Minnesota is the second largest landowner/manager at 10.4%. The state's holdings are divided between various state agencies, with the majority of the holdings under management by the MNDNR. The MNDNR Division of Forestry manages an estimated 95,661 acres within the FSA.

Agriculture Operations

As Table 12 shows, almost 60% of the six county FSA (2,576,090 acres) is focused upon agriculture production. While there is substantial diversity in the crops produced within the FSA, in general three crops dominate the industry: corn, soybeans, and wheat. There are minor acreages of alfalfa and sugar beets in the western portion of the FSA. Table 15 shows the number of acres for each crop by county for the year 2011.[19]

[19] "*2011 Minnesota Agricultural Statistics*" Minnesota Department of Agriculture and the U.S. Department of Agriculture, National Agricultural Statistics Service.

Table 15. Acres by Primary Crop by County

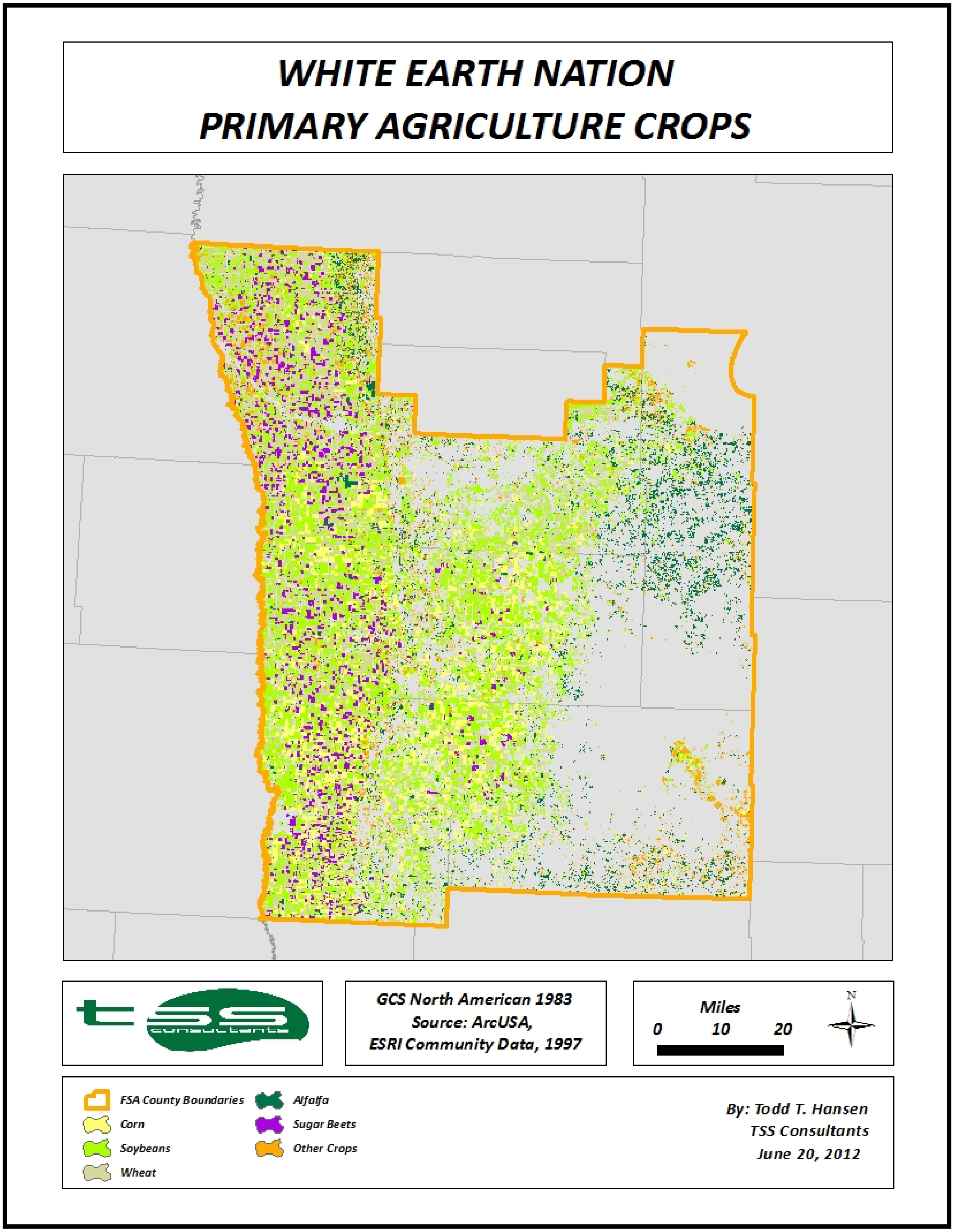
COUNTY	CORN	SOYBEANS	WHEAT	SUGAR BEETS	ALFALFA
Becker	40,250	85,400	43,700	7,400	24,100
Clay	95,100	191,300	91,900	42,900	16,100
Clearwater	3,400	12,500	6,900	0	34,200
Mahnomen	33,700	66,200	21,400	2,400	6,900
Norman	70,600	183,000	98,900	37,900	7,100
Polk	44,190	269,000	267,000	90,600	24,500
TOTAL	**287,240**	**807,400**	**529,800**	**181,200**	**112,900**

The acreage estimates from these crops alone represent nearly 42.9% of the entire FSA. While many byproducts of agricultural operations have been evaluated for use as feedstock for biomass thermal-energy only or CHP facilities, the most appropriate for a WEN thermal-energy only or CHP facility would include corn stover and wheat straw. Soybean production dominates the industry within the FSA; however, the residuals resulting from harvesting provide minimal yields (tons per acre) and are typically necessary for nutrient augmentation for the next planting.[20] Sugar beet tailings could provide supplemental feedstock for an AD facility in conjunction with food and perhaps animal waste.

Figure 25 shows the distribution of the primary crops within the FSA.[21]

[20] Discussion with Alan Doering, Senior Associate Scientist, University of Minnesota Agricultural Utilization Research Institute.
[21] The data were generated from Cropscape, a GIS interactive crop layer produced by the U.S. Department of Agriculture, National Agricultural Statistics Service.

Figure 25. Primary Agricultural Crops



A potential crop rotation could include corn or spring wheat planted in spring and harvested in August, followed by soybeans to be harvested in September. Less corn and more wheat is planted in the northern portion of the FSA, and the opposite is true in areas in the southern portion of the FSA. As farmers elect which crop to rotate with soybeans (wheat or corn), the market prices and their decision will impact the annual acres of each crop within the FSA.

In fact, discussion with a local grain farmer indicated that acreage planted to corn and soybeans is increasing while acreage planted to wheat is in significant decline.[22] Table 15, based on data from the Minnesota Department of Agriculture, indicates that wheat accounts for nearly 28% of the total while corn is estimated at only 15%. Figure 25, based on data from the U.S. Department of Agriculture, indicates wheat acreage at 16.8% of the total and corn at 22.3%. The accuracy of the data from these sources may not reflect recent changes in the agriculture markets, including recent price increases for corn and soybeans favoring these crops over wheat by a significant margin.

Forest Operations

The byproducts of timber harvest, stand improvement, forest health, and ecosystem restoration projects can provide significant volumes of woody biomass feedstock material. Typically available as limbs, tops, and unmerchantable logs, these residuals are byproducts of conventional forest management operations. As such, these residuals can be a relatively economic raw material feedstock supply. Once collected and processed using portable grinders or chippers, this material can be an excellent biomass feedstock source with regard to quality (ash content) and heating value (Btu per dry pound).

Woody biomass feedstock availability assessments traditionally rely on historic data regarding timber harvest or other forest operation activity and associated volumes. This information can provide insight in determining trends, benchmarks, and activities regarding timber harvest or other forest operations over time that can generate significant volumes of byproducts. The term "timber harvest volume" is used to reflect measurable volume recovered from all forest operations. Sawlogs and pulp logs manufactured during forest operations are typically measured for markets in board feet[23] (BF) and cords,[24] respectively.

There are a number of sources of prospective feedstock from forest operations within the FSA, including forestland owned by: WEN; MNDNR, Division of Forestry; Clearwater County; Becker County; industrial forest landowners; and non-industrial private forest landowners. The majority of forest operations conducted within the FSA is timber harvests, including clear cutting and commercial thinning. The majority of the volume harvested is marketed to composite panel

[22] Perry Skaurud, Skaurud Grain Farms.
[23] One board foot is a solid wood board measured 12 inches square by 1 inch thick. MBF represents 1,000 board foot measure.
[24] A cord represents 128 cubic feet of solid wood measure. A cord may also be defined as a stack of wood 4 feet wide by 4 feet tall by 8 feet in length.

manufacturers or the pulp and paper industry. Only minor volumes of harvested material are of suitable quality for use as sawlogs for lumber recovery.

The primary markets for harvested wood within the FSA include:

- Norbord in Bemidji, utilizing aspen and pine;
- Potlatch in Bemidji, utilizing pine logs for stud manufacturing;
- Hillside Lumber Company in Bagley, utilizing sawlogs;
- Verso Paper Corp. in Sartell, utilizing balsam fir and aspen pulp logs or chips;
- UPM in Grand Rapids, utilizing spruce pulp logs or chips; and
- Boise Cascade in International Falls, utilizing jack pine pulp logs or chips.

The Verso Paper Corp. facility in Sartell experienced an explosion and subsequent fire in May 2012, inflicting sufficient damage to infrastructure and existing inventory. In August 2012, Verso Paper management announced that the Sartell facility will not re-open.

A small commercial sawmill, Hillside Lumber, is currently operating in Bagley. Hillside Lumber utilizes a wide variety of species to produce pallet stock and custom timbers and dimension lumber for pole barn construction.

White Earth Nation

WEN owns and manages an estimated 58,000 acres in three counties. The WEN annual target harvest volume is set at an estimated 5,000 thousand board feet (MBF) or 10,000 cords. Table 16 shows the actual timber harvest volumes by year during the period 2007 through 2011.

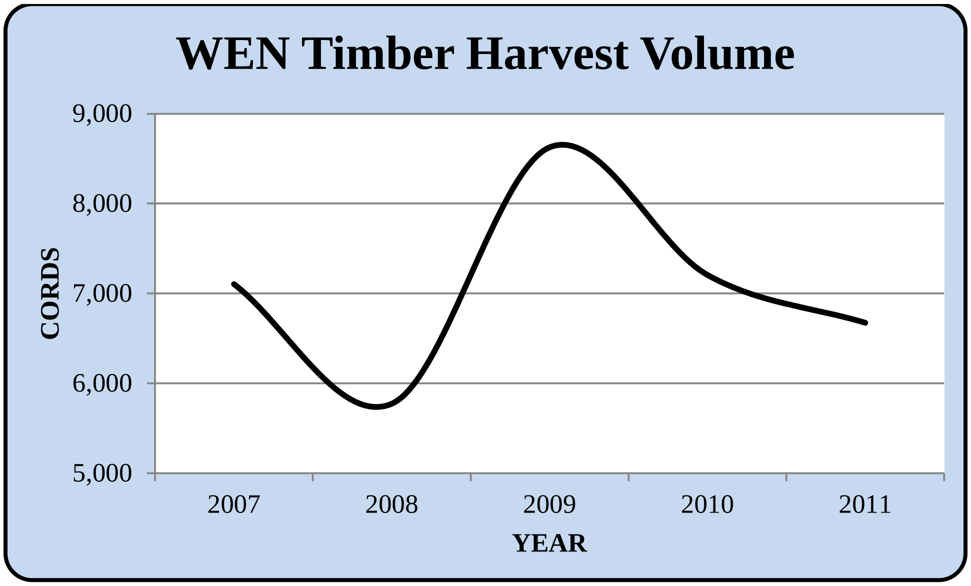
Table 16. WEN Timber Harvest Annual Volume 2007-2011

VOLUME MEASURE	2007	2008	2009	2010	2011	5-YEAR ANNUAL AVERAGE
MBF	3,552	2,887	4,313	3,603	3,337	**3,538**
Cords	7,104	5,774	8,626	7,206	6,674	**7,077**

Timber harvest volume measured in MBF is converted to cords through a conversion of 500 BF per cord.[25] The average for the five-year period is 3,538 MBF or 7,077 cords, though there is some variability from year to year. Figure 26 graphically represents the change in timber harvest from WEN ownership within the FSA as depicted in Table 16.

[25] The conversion factor employed by the MNDNR, per discussion with Jon Drimel, Forester, MNDNR Division of Forestry.

Figure 26. WEN Timber Harvest Volume [Cords] 2007-2011



Timber harvest volume has varied significantly from WEN ownership during the period 2007 through 2011. The harvest volume in 2009 was 50% greater than the volume from the previous year. The annual harvest volume was below the Annual Allowable Cut of 10,000 cords for each year during the 2007 through 2011 period.

The majority of the harvest volume from WEN lands consists of aspen, and the primary market for material from the timber harvest activity is Norbord, a composite panel manufacturer (oriented strand board) located near Bemidji. Aspen comprised over 80% of the total harvest volume during the five-year period shown in Figure 26. Timber harvesting is conducted on WEN forestland during the winter on frozen ground. The typical operating season occurs from December through mid-March. The abundance of wetland and associated riparian forested areas restricts access and operability during the summer months. The average harvest unit size is an estimated 20 acres.

Woody biomass feedstock recovery as a byproduct from forest operations has not been part of the standard operating procedure on timber harvest units on WEN lands. Current harvesting operation includes whole tree yarding; however, the skidder operator typically removes the limbs from the trees in the unit prior to yarding into the landing area. This would reduce available woody biomass feedstock at the landing, recovering only unmerchantable tree tops but leaving the limbs in the unit. WEN's Forestry Manager[26] indicated that operations could be modified in the event opportunities to recover and market woody biomass feedstock became a viable alternative.

[26]Michael C. Smith, Forestry Manager, WEN Natural Resources Department, Tribal Forestry.

Since woody biomass feedstock recovery has not occurred on WEN lands, no prospective stumpage fee has been determined. Woody biomass feedstock recovery operations would occur in conjunction with or very soon after timber harvest activity during the typical winter operating season only. Recovery during the summer months is not currently an option.

The State of Minnesota

The FSA encompasses an area serviced by MNDNR, Division of Forestry offices in Bemidji and Park Rapids, primarily in the counties of Becker, Clearwater and Mahnomen. The MNDNR Division of Forestry manages an estimated 95,661 acres within the FSA.[27]

The FSA encompasses a total of six ecological subsections (ES). The ecological subsections with acres and percent of total within the FSA are shown in Table 17.

Table 17. Ecological Subsections within the FSA

ECOLOGICAL SUBSECTION	ACRES	PERCENT OF TOTAL
Pine Moraines & Outwash Plains	593,371	13.3%
Hardwood Hills	858,587	19.2%
Chippewa Plains	298,124	6.7%
Aspen Parklands	381,810	8.5%
Red River Prairie	2,221,290	49.6%
Agassiz Lowlands	119,858	2.7%
TOTAL	**4,473,040**[28]	**100.0%**

The Red River Prairie ES is primarily agricultural lands. The primary forested ES include Pines Moraines & Outwash Plains, Hardwood Hills, Chippewa Plains, Aspen Parklands, and Agassiz Lowlands.

The Aspen Parklands consist of low-quality aspen, of lower site and growth potential than the other forested ESs. Most harvesting operations occur during the winter months on frozen ground in this ES. As with WEN ownership, the Aspen Parklands is characterized by significant areas of wetland and associated riparian forested environment. The primary management in Aspen Parklands is driven by wildlife habitat improvement, which includes shortened timber harvest rotations of existing species.

The Hardwood Hills ES represents a transitive area from mixed hardwood stands toward the higher-quality forested ESs of Pine Moraines & Outwash Plains, Chippewa Plains, and Agassiz

[27] Data and information regarding MNDNR operation within the FSA were sourced from Steve Vongroven, Utilization and Marketing Forester, Jon Drimel, Bemidji office and Mike Lichter, Park Rapids office.
[28] Due to rounding, this figure does not add up to the total FSA acreage of 4,473,075.

Lowlands. Hardwood Hills consists of oak, maple, basswood on rolling hills and ridges, offering opportunities for timber harvest operations in summer months.

The Pine Moraines & Outwash Plains, Chippewa Plains, and Agassiz Lowlands are the primary timber producing ESs within the FSA. The terrain consists of sandy, gravelly soils, again with rolling hills and ridges, affording opportunities for summer harvest operations. The primary species within this ES includes aspen and pine.

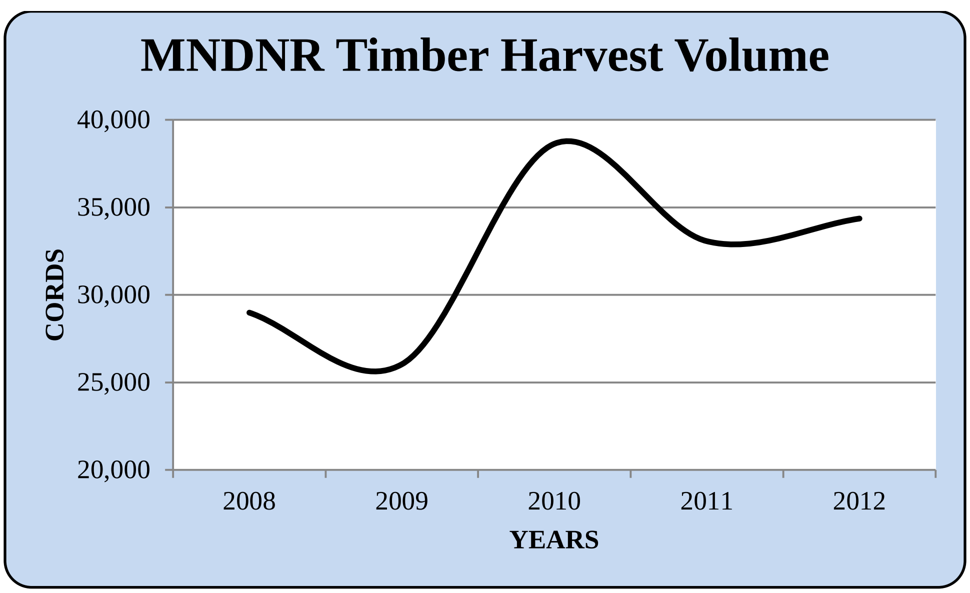
The MNDNR timber harvest volume by county during the period 2008 through 2012 is shown in Table 18.

Table 18. MNDNR Timber Harvest Annual Volume [Cords] 2008-2012

COUNTY	2008	2009	2010	2011	2012	5-YEAR ANNUAL AVERAGE
Becker	20,809	17,319	31,405	26,442	25,659	**24,327**
Clearwater	2,937	2,699	5,673	6,165	6,852	**4,865**
Mahnomen	5,240	6,020	1,555	460	1,850	**3,025**
TOTAL	**28,986**	**26,038**	**38,633**	**33,067**	**34,361**	**32,217**

The harvest volumes have increased significantly in the past three years from 2010 through 2012. Figure 27 shows the changes in annual harvest volume during the five-year period. The change in harvest volume from 2009 to 2010 represents a 48% increase.

Figure 27. MNDNR Timber Harvest Volume [Cords] 2008-2012



The majority of the timber harvest volume from MNDNR managed lands occurs in Becker County, accounting for over 75% of the total annual harvest volume. Aspen is the predominant harvest species at 46% of the total. However, in Clearwater and Mahnomen counties, aspen harvest volume is at 60% and 65% respectively. In Becker County, annual harvest volume from MNDNR managed lands also includes paper birch, Norway pine, white spruce, tamarack, Jack pine and other pine species.

An estimated 68% of the forested cover in the FSA consists of the area identified by MNDNR as summer operating potential, which affords nearly year-round operations excepting spring breakup when frozen ground begins to thaw and equipment operation can damage soils and roads. Whole tree yarding occurs on an estimated 75% of the harvest units. If processing occurs on the landing rather than within the unit, the potential for accumulating sufficient volume of woody biomass feedstock on the landings greatly increases, improving opportunities for recovery and marketing.

A cut-to-length harvest system is utilized for much of the commercial thinning in pine stands. This system allows the contractor to perform log processing (limbing and bucking) at the point where the tree is severed from the stump, distributing the woody biomass feedstock throughout the harvest unit rather than in a pile on the landing. If biomass is recovered from units employing such harvest systems, the unit must be re-entered with equipment suitable for gathering and transporting woody biomass feedstock back to the landing. This operation is not preferred due to increased impact to soils through re-entry and increasing costs through additional handling.

While there is access to landing locations with chip vans throughout nearly all of MNDNR's harvest operations within the FSA, the small harvest unit size of from 20 to 25 acres can result in low accumulated volume, impacting economic viability of biomass recovery. MNDNR biomass harvesting guidelines indicate the need to retain at least 20% of residual woody biomass feedstock generated from forest operations on site. The MNDNR requires a stumpage fee of $1 per green ton (GT) for woody biomass feedstock processed and transported to markets. Biomass recovery is optional for MNDNR administered timber harvest units. When biomass recovery is not an option for the logging contractor, the MNDNR encourages log processing in the unit or yarding limbs and tops back into the unit to minimize slash accumulation on landings.

Becker County

Becker County owns and manages an estimated 60,000 acres of commercial forestland.[29] Over 50% of the acreage consists of aspen, with significant acreage in mixed hardwood. The estimated sustainable harvest is 900 acres per year, with harvest volumes ranging from 12 to 38 GT per acre. Past harvest activity consisted of small unit size (10 to 15 acres) and less volume than is considered sustainable by the current forest management staff. The estimated annual harvest volume for the next five to ten year period is 20,000 cords.

[29] Becker County forestry data and information were provided by Martin Wiley, Becker County Natural Resources Management, and Recreation Director.

The current harvest operation requires the logging contractor to either perform log processing within the unit or yard limbs and tops back into the unit to prevent pile accumulation on the landing. Forest management staff indicated a willingness to modify operations to accommodate biomass recovery through encouraging whole tree yarding and processing logs at the landing. The ownership consists of an estimated 50% of the area suitable for summer or year-round operations and 50% restricted to winter operations only. As with other ownerships with winter operations, biomass recovery must occur soon after the completion of timber harvesting activity to ensure operations occur on frozen ground. Forest management staff indicated a proposed stumpage fee of $1 per GT for recovered and marketed woody biomass feedstock.

Clearwater County

Clearwater County owns and manages an estimated 90,000 acres of commercial forestland.[30] Annual timber harvest volumes have remained fairly constant at an estimated 30,000 cords per year. Nearly 60% of the annual harvest volume consists of aspen. When combined with other mixed hardwoods, the percent of the total harvest is between 85% and 90%.

Nearly all of the harvest units are conducted utilizing whole tree yarding with log processing occurring on the landing. Since few contractors are opting to recover woody biomass feedstock in conjunction with or subsequent to harvest operations, the forest management staff is requiring contractors to yard material back into the unit to prevent pile accumulation. The operating season for harvest activity is restricted only during spring break-up when frozen ground is thawing. Forest management staff indicated that on some units, no stumpage fee has been charged for woody biomass feedstock recovery, and no more than $0.50 per GT has been considered.

Private Landowners

There is currently no reliable source of data regarding timber harvest volume by county from private ownerships within Minnesota. The most valid source for timber harvest volumes by county for this region is from the USFS Forest Inventory and Analysis (FIA) program. The Timber Products Output report[31] enables users to generate timber harvest volumes by counties within states for public and private ownerships. The report generated harvest volume in cubic feet for all roundwood products for year 2006 (2006 is the most current data) for both Becker and Clearwater counties.

The data for public harvests for these counties for year 2006 were compared to the five-year average annual harvest volumes for the MNDNR within each county combined with the harvest data provided by each county's forest management staff. The cubic foot volume was converted

[30] Clearwater County forestry data and information were provided by Bruce Cox, Clearwater County Land Commissioner, Land & Forestry Department.
[31] USFS FIA data site: http://fia.fs.fed.us/tools-data/other/default.asp

to cords using a conversion factor of 91 cubic feet per cord.[32] The results indicate that the volume from the FIA Timber Products Output report is significantly higher than volumes reported by MNDNR and the counties. The actual five-year average harvest volume was 64.2% of the total results from the FIA data.

Some of this difference could be attributed to a decrease in harvest volume as a result of the economic downturn and associated reductions in lumber consumption. In 2006, housing starts were over double the annual average for the period 2008 through 2011. However, application of 64.2% to private harvest levels from FIA data may also reflect the impact of the economic downturn and provide a relatively conservative estimate of harvest volumes from private lands within the FSA.

The FIA Timber Products Output report yielded nearly 48,000 cords per year harvested from private ownerships. Applying the adjustment for public ownerships of 64.2% would yield a total of nearly 31,000 cords per year. Table 19 shows the FIA harvest data and adjusted harvest data by county.

Table 19. FIA and Adjusted Harvest Volumes for Private Ownerships

COUNTY	FIA HARVEST [CORDS]	ADJUSTED HARVEST [CORDS]
Becker	27,692	17,778
Clearwater	18,022	11,570
Mahnomen	2,077	1,333
TOTAL	**47,791**	**30,681**

Forest Operations Summary

The average annual timber harvest volume by ownership from within the FSA is shown in Table 20.

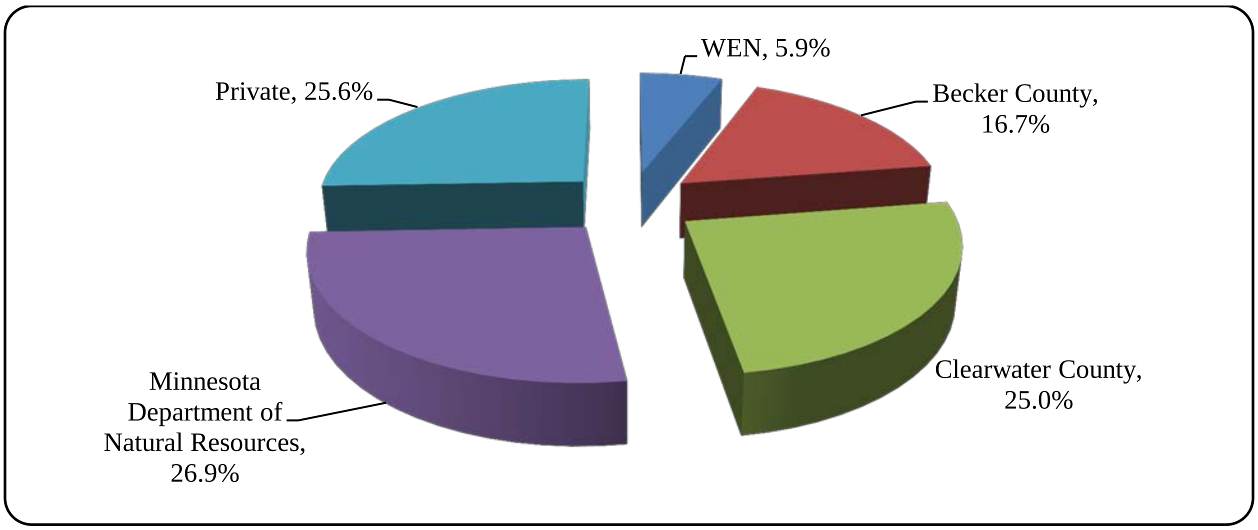
[32] *"Minnesota Logged Area Residue Analysis,"* MNDNR, Division of Forestry, Utilization and Marketing Program, August 2006.

Table 20. Annual Average Timber Harvest Volume by Owner/Manager

OWNER/MANAGER	ANNUAL HARVEST VOLUME [CORDS]
White Earth Nation	7,077
Becker County	20,000
Clearwater County	30,000
Minnesota Department of Natural Resources	32,217
Private	30,682
TOTAL	**119,976**

Figure 28 shows the allocation of annual timber harvest by owner/manager.

Figure 28. Timber Harvest Allocation by Owner/Manager



In addition to the forest operations discussed previously, some lands in the Conservation Reserve Program[33] (CRP) are planted with hybrid poplar plantations that could yield forest biomass material suitable as feedstock. Not all are enrolled in the CRP program, as many landowners were encouraged to plant hybrid poplar by regional consumers and in some areas, Verso Paper Corp. acquired lands to reforest or afforest with hybrid poplar as a potential raw material supply for the facility in Sartell. However, this practice has been discontinued, and the financial success

[33] The Conservation Reserve Program is a program for agricultural landowners to establish long-term cover on farmland as a resource conservation measure administered through the USDA Farm Service Agency. The landowner receives economic assistance for crop establishment and annual rent payments.

of these plantations is questionable, especially now that the Verso Paper operation at Sartell is closed. Though these plantations may provide spot market opportunities as biomass feedstock, TSS believes these prospective supplies are not sustainable due to a variety of factors, including the long-term economic viability of hybrid poplar plantations in the region.

Forest Product Manufacturing

The byproduct from forest product manufacturing can provide a stable, high-quality supply of prospective feedstock. The proposed WEN biomass project is located quite some distance from primary forest product manufacturing facilities, which would increase transport costs considerably as compared to other established outlets for such material. Several of these facilities operate their owner boilers, generating heat, steam, and in some cases power. These facilities rely upon their byproduct as an inexpensive form of readily available feedstock. Most consume all byproduct they generate internally and, on occasion, source feedstock from outside suppliers. Rarely will these facilities utilize byproduct from forest operations, as this material is typically more expensive than some alternatives, and feedstock quality can be an issue for some boilers.

Biomass Feedstock Availability

Sugar Beet Tailings

Sugar beet tailings could be utilized as a supplemental feedstock for generating biogas from an AD facility. Sugar beet tailings are a byproduct generated during the process of converting the beets into processed sugar. Beet tailings consist of small beets, broken or damaged beets, soil and other foreign material not suitable for sugar production, and the pulp of the beets once the sugars are extracted. Tailings are high in moisture (approximately 80 percent water) and as such, transportation is a major expense for beet tailings used as a feedstock.

American Crystal Sugar Company operates two plants tributary to the FSA, generating an estimated 200 GT per day when processing operations are underway. Processing at the plant occurs for an estimated 230 days per year.[34] This operation could yield 46,000 GT of sugar beet tailings from their processing operation. Sugar beet tailings are also sold as livestock feed. TSS assumes that 50% of the sugar beet tailings, or 23,000 GT, would be practically available on an annual basis as potential feedstock.

The American Crystal Sugar Company time their processing operations with the harvest of the sugar beets. Therefore, their utilization as potential feedstock would be seasonal and as such, would not be a consistent feedstock source for year-round operation.

[34] David Malmskog, Director of Economic Analysis, American Crystal Sugar Company.

Corn Stover

Corn stover consists of the residual material remaining in the field subsequent to harvesting. This material includes the stalk, leaves, and may include the husk and cob if the grain is harvested in the field. In some instances, this material is further reduced in size and incorporated into the soil. On occasion, planting occurs over the top of this material after it has overwintered.

This material is a potentially suitable feedstock for a WEN thermal-energy only or CHP facility. Although the local grain farmer indicated that there were significantly more acres in corn production than the data show in Table 15 (based on information from the Minnesota Department of Agriculture), TSS elected to use this data set for the analysis because it contains the best data available for the FSA and could represent a conservative approach to feedstock volume determination.

Many of the studies related to determining estimates of corn stover generated relate corn stover volume to grain yields. A staff member of the University of Minnesota's Agricultural Utilization Research Institute indicated that corn stover yields for areas of northwest Minnesota would be 3.2 GT for every 150 bushels of grain harvested,[35] with average grain yields in the region of 150 bushels per acre. At 20% moisture, this would yield 2.6 bone dry tons[36] (BDT) per acre. This figure is well within range of the conclusions from other studies, including one at Purdue University indicating expected yields of from 3.0 to 4.5 BDT per acre.

In order to account for resource conservation and corn stover retention, removal rates are recommended to be 50% of the total corn stover yields, removed only every two years. A presentation by researchers at the University of Nebraska, Lincoln, indicated that current technology is capable of recovering only 75% as a maximum, depending upon equipment employed.[37]

For this analysis, TSS assumes that 50% of the total number of acres in corn (287,240 acres in 2011) would be available, with recovery at 1.6 GT per acre (50% of 3.2 GT per acre). Though the moisture content can vary considerably, TSS assumes 20% as the average for delivered feedstock. The gross biomass feedstock volume from corn stover from within the FSA would be 229,792 GT per year. Obviously not all corn stover from within the FSA would be available, accessible and appropriately priced for use at the WEN facility in Mahnomen. TSS estimates that 55% of the FSA currently growing corn could serve as an operational and economic potential supply area and that only 50% of this supply would be available as annual biomass feedstock. This analysis yields 63,193 GT per year of corn stover as practically available on an annual basis within the FSA.

[35] Discussion with Alan Doering, Senior Associate Scientist, University of Minnesota Agricultural Utilization Research Institute.
[36] One bone dry ton is 2,000 pounds of fiber with zero percent moisture content.
[37] Dan Walters and Haishun Yang, University of Nebraska, Lincoln, Department of Agronomy and Horticulture.

Wheat Straw

Although discussions with a local grain farmer cast some doubt about the accuracy of the number of acres of wheat straw within the FSA, TSS assumes the data from the Minnesota Department of Agriculture to be the best available. The data may provide a conservative evaluation of corn stover; as well, it could overestimate wheat straw volumes. Since wheat and corn are the primary crops rotated with soybeans, the end result could simply be more corn stover production than the analysis concluded.

Wheat straw is the plant residue remaining in the field subsequent to grain (and chaff) harvest. This material is either burned, cut and removed, left on site, or incorporated into the soil. The alternatives are driven by weather conditions, airshed quality concerns, soil nutrient and erosion issues, and landowner preferences. This material is also a potentially suitable feedstock for thermal-energy only or CHP facilities.

Table 15 indicates that there was an estimated 529,800 acres of wheat grown within the FSA in 2011. The University of Minnesota Agricultural Extension agent for Polk and Clearwater counties provided yield estimates of 50 bushels of grain per acre and 2.5 GT per acre of wheat straw. [38] A study on wheat straw conducted by the Sun Grant Initiative of the University of Tennessee[39] indicated wheat straw based upon grain yields, employing a relationship of 1.3 to 12.0 of wheat straw to grain, with a bushel of grain weighing 60 pounds. Utilizing the wheat grain yields of 50 bushels per acre and the wheat straw to grain ration would yield 1.95 GT per acre.

Assuming a yield of 2.0 GT per acre with 529,800 acres would yield 1,059,600 GT per year within the FSA. Assuming retention requirements similar to those recommended for corn stover reduces the gross volume of wheat straw production to 264,900 GT per year from within the FSA. As with corn stover, not all wheat straw from within the FSA would be available, accessible and appropriately priced for use at the WEN facility in Mahnomen. TSS estimates that 55% of the FSA currently growing corn could serve as an operational and economic potential supply area and that only 50% of this supply would be available as annual biomass feedstock. This analysis yields 72,848 GT per year of wheat straw as practically available on an annual basis within the FSA.

Animal Waste

As noted earlier, a significant portion of the FSA consists of agricultural production, including crops, poultry and livestock. The production of poultry, sheep, horses, and cattle can generate substantive quantities of animal waste, which is a suitable organic feedstock for AD. Data from the U.S. Department of Agriculture[40] were utilized to determine animal population estimates.

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[38] Jim Stordahl, Polk and Clearwater Extension Service.
[39] http://bioweb.sungrant.org/Technical/Biomass+Resources/Agricultural+Resources/Crop+Residues/Wheat+Straw/Default.htm
[40] U.S. Department of Agriculture, National Agricultural Statistics Service.

Prospective animal waste production data were derived from a study conducted by Washington State University.[41]

Operational and economic recovery of manure only occurs where significant quantities are readily available, as when animals are kept in a confined area, such as a dairy or feedlot operation. For this reason, TSS focused the assessment of animal waste on beef cows and dairy cow populations within the FSA. Application of population for the entire FSA to manure production volumes yields 746,695 tons per year (TPY). Assuming that only 25% of the entire population of cows (dairy and beef) exists in confined areas suitable for operational, economic removal of manure yields 186,674 GT per year as potentially available.

As petroleum products and fertilizer prices in particular rise, manure has increasingly become a replacement for chemical nutrient augmentation for agricultural production. This has increased the value of manure and resulted in decreased availability in some regions. For determining practically available volumes, TSS applied a 10% recovery factor to the volume potentially available, yielding 18,667 GT of animal waste per year.

Food Waste

TSS surveyed local facilities capable of generating substantive quantities of food waste in Mahnomen to determine the quantity of food waste generated on a daily basis. The SSC facilities, the Mahnomen School, and the Health Center were surveyed because they are the largest local facilities. Currently, none of the three facilities sort their organic waste from the remaining trash and none have specific composition data about their waste streams. In lieu of direct testing, waste removal data and state published waste stream composition information were utilized to estimate a range of available food waste. Table 21 shows the available data.

[41] "Animal Manure Data Sheet," Ronald E. Hermanson, PE. and Prasanta K. Kalita, Washington State University Extension, May 1994.

Table 21. Local Organic Food Waste Feedstock Available

METHOD GENERATED	CASINO		SCHOOL		HEALTH CENTER		TOTAL	
	LOW	HIGH	LOW	HIGH	LOW	HIGH	LOW	HIGH
Dumpster Size (cubic yards)	20	20	4	4	4	4	**28**	**28**
Removal Rate (per week)	2	3	1	1.5	0.5	1	**3.5**	**5.5**
Available Volume (cubic yards per week)	40	60	4	6	2	4	**46**	**70**
Maximum Potential Mass (TPD)[42]	1.59	3.57	0.16	0.36	0.08	0.24	**1.83**	**4.17**
Average Mass (TPD)[43]	0.79	1.79	0.08	0.18	0.04	0.12	**0.91**	**2.09**
Recoverable Mass (TPD)	0.64	1.43	0.06	0.14	0.03	0.1	**0.73**	**1.67**
Operating Days per Year	358	365	189	230	261	365	**808**	**960**
Total Recoverable Mass (GT per year)	**229.12**	**521.95**	**11.34**	**32.2**	**7.83**	**36.5**	**589.84**	**1,603.2**

TSS assumed an 80% recovery rate for converting average mass to recoverable mass in GT per day. Applying the estimated days per year of operation for the various facilities yields a range of from 590 to 1,600 GT per year annually.

Organic waste recovery and collection from local facilities poses several challenges including collection, sorting, and transportation. For the small volumes available at the local facilities, an off-site sorting and processing facility is not economically feasible. For organic feedstock to be viable, separation and sorting must occur on-site where there may be challenges with adequate participation in composting programs and storage facilities.

Forest Operations

An evaluation of historic timber harvest volumes and other forest operations conducted within the FSA can provide insight into prospective forest operations capable of generating woody biomass feedstock for the WEN thermal-energy only or CHP facility. There are various metrics employed to estimate the volume of woody biomass feedstock throughout different regions of the U.S. with robust forest industry operations. Many are predicated upon the number of acres

[42] "Standard Volume-to-Weight Conversion Factors: Appendix B," U.S. Environmental Protection Agency; "Waste Materials – Density Data," Environmental Protection Agency, Victoria (Australia).

[43] "Summary of MN Wastewise Wastestream Analysis Report," February 2010. Macalester College; "Digging Deep Through School Trash: A waste composition analysis of trash, recycling, and organic material discarded at public schools in Minnesota," September 2010. Minnesota Pollution Control Agency; "Municipal Solid Waste Generation, Recycling, and Disposal in the United States: Tables and Figures for 2010," December 2011. U.S. Environmental Protection Agency: Office of Resource Conservation and Recovery.

within a given treatment area. TSS prefers to utilize an estimate of woody biomass feedstock volume from harvest operations that is tied directly to species and harvest volume.

The *"Minnesota Logging Area Residue Analysis,"* conducted by the MNDNR Division of Forestry (2006, corrected in 2007) indicated a range of from 9.5 to 19.2 GT per acre remaining within the unit as both pre-existing woody biomass feedstock and material generated as a result of the timber harvest operations, by cover type (species). A weighted average predicated upon the previous year's harvest for WEN, MNDNR, and Becker and Clearwater counties yielded 13.9 GT per acre.

The study also indicated a range of from 9.8 to 12.9 GT per acre based upon harvest silviculture employed on the harvest unit, from clear cutting to partial cutting (thinning). The range of woody biomass feedstock based upon harvest operation alternatives from whole tree to cut-to-length to leaving tops in the units yielded results from 4.6 to 12.8 GT per acre. Aspen dominates the harvest volume and clear cutting aspen utilizing whole tree harvesting yields 12.8 to 12.9 GT per acre.

Assuming harvest yields of 25 cords per acre (accounting for pine thinnings to provide a conservative estimate) using five-year annual average harvest data, an estimated 5,000 acres are harvested each year within the FSA, which would generate an estimated 64,250 GT per year based upon biomass yields of 12.85 GT per acre.

These results are for biomass material scattered throughout the harvest unit during the course of the harvest activity. Not all of this material would be operationally recoverable. In addition, MNDNR recommends retaining a minimum of 20% of biomass generated from these operations within the unit.

The MNDNR utilizes a biomass calculator for generating estimates of biomass material produced during the timber harvest operations. These estimates are predicated by species and size class, distinguishing harvests based upon an average diameter at breast height (dbh) of five inches to nine inches and greater than 9 inches. Discussions with MNDNR forestry staff indicated that for the vast majority of the FSA where harvest activity occurs, 60% of aspen volume and 65% of pine volume are in harvest units greater than 9 inches dbh. Employing the MNDNR biomass calculator to the five-year average harvest data by owner/manager and applying the size class data for aspen to other mixed hardwoods, and the pine data to other conifers yields an estimated 33,670 GT.

Though reliable data sets are limited, TSS acquired some data regarding biomass volumes in GT recovered from units with corresponding timber harvest sawlog or pulp log volumes in cords or GT. Data were provided by the MNDNR and biomass processing contractors operating in northwest Minnesota. The biomass recovery factor based upon this analysis is 0.83 GT per cord of harvest. Based upon the five-year average annual volume for the FSA of 119,976 cords from Table 20, this would yield an estimated biomass volume of 99,580 GT per year, substantially higher than the biomass volume predicted using the MNDNR calculator. Part of the higher volume is a result of some contractors chipping pulp log quality material in the woods, rather than transporting raw logs to a pulp and paper facility. The manufacture of chips in the woods generates additional bark material that would have otherwise been recovered at the pulp and paper operation.

Employing the midpoint between the two methods yields 66,625 GT per year from sustainable timber harvest operations within the FSA as potentially available. Assuming that 70% of this volume occurs in units of substantive size and with suitable access to warrant operational and economic recovery yields 20,000 BDT per year as practically available from forest operations within the FSA.

Forest Product Manufacturing

The only local forest products manufacturing facility is Hillside Lumber, located in Bagley. This facility utilizes a diverse array of species producing pallet stock and timbers for pole barn kits. The owner indicated the facility would be interested in providing suitable woody biomass feedstock material.

Urban Wood

Woody biomass generated as a result of tree trimming, land clearing, construction, demolition, and from commercial (non-forest products manufacturing) operations in the form of pallets and miscellaneous wood scraps can be a viable biomass feedstock resource. Known as urban wood, this material is typically low in moisture content (around 20%), has a relatively high heating value (7,600+ Btu[44] per dry pound), and is potentially available as a relatively low-cost feedstock. Communities consider the recovery and utilization of this wood stream important for a variety of reasons, including:

- Extending the functional life of landfills through diversion of wood waste material to alternative uses. Tip fees at the landfills can be discounted to provide an incentive for increased recycling/alternative utilization efforts.
- Residential and commercial development may require land clearing. This creates wood waste in the form of vegetative material (brush, small trees, etc.).
- Air quality concerns have placed increased restrictions on open burning of wood waste or vegetative material. Diverting wood waste that is typically open burned to a controlled combustion or gasification system reduces air emissions significantly.
- Reduction of greenhouse gas emissions associated with biomass disposal by shifting the form of the emissions from methane (CH_4) (if woody biomass feedstock is deposited in landfills or left to decompose) to carbon dioxide (CH_4 is almost 25 times more potent as a greenhouse gas than carbon dioxide).[45]

The volume of urban wood generated by a community or region is directly proportional to the size of the population. The higher the population within a given area, the more urban wood is

[44] Btu is a measure of relative heat value. One Btu represents the quantity of heat required to raise the temperature of one pound of water from 60° F to 61° F at a constant pressure of one atmosphere.
[45] Western Governors Association, Biomass Task Force Report, January 2006.

produced. The population for the FSA was determined using census data for each county. The FSA population is estimated at 145,000[46] residents.

TSS's experience analyzing urban wood generation indicates that approximately 10.5% of solid waste is comprised of urban wood.[47] Daily per capita solid waste generation is estimated to be 11.5 pounds. TSS estimates that approximately 65% of this wood is actually recoverable as biomass feedstock. Based upon previous TSS assessments in the region and the firm's experience with urban wood waste recovery, TSS has converted the volumes of wood to a bone dry ton basis using average moisture content of urban wood waste of 20%. Employing these factors produces an estimated 16,616 BDT of urban wood as potentially available annually within the FSA.

Previous studies performed by TSS[48] indicated that approximately 100 dry pounds of tree trimmings suitable for feedstock are generated annually per capita. Based on a population estimate of 145,000 residents, approximately 7,250 BDT of tree trimmings are generated annually. TSS estimates that approximately 65% of this wood is actually recoverable as biomass feedstock. Therefore, approximately 4,713 BDT of tree trimmings are potentially available each year from the FSA.

The volume of material from these sources can vary significantly from year to year and is down substantially from pre-recession years. The rural counties in northwestern Minnesota typically experience less residential and commercial development than more populated regions and therefore generate substantially less volume of material recovered from construction, demolition, and pallets. The small volumes, lack of infrastructure, and little demand for the material impact potential recovery. Minor volumes of green waste are converted into compost material. With the exception of Becker County, the majority of the material identified as urban wood or tree trimmings is deposited in landfills. Becker County transfer stations will separate out suitable woody material for processing and marketing into Fibrominn's power facility at Benson. TSS estimates that 2,000 BDT of urban wood waste would be practically available from sources throughout the six county FSA. However, processing and transport costs will restrict utilization due to the scattered nature of the sources. Table 22 shows the estimated volume of urban wood waste from the FSA.

[46] U.S. Census Bureau.
[47] Per municipal waste characterization studies conducted by TSS in 1991.
[48] Per urban tree waste characterization studies conducted by TSS in 1996.

Table 22. Biomass from Urban Wood and Tree Trimmings

POTENTIALLY AVAILABLE BIOMASS [BDT]	PRACTICALLY AVAILABLE BIOMASS [BDT]
21,329	2,000

Biomass Feedstock Availability Summary

Potentially and practically available biomass sourced from agricultural operations, food waste, forest operations, wood product manufacturing, and recovered urban wood is summarized and shown in Table 23. The practically available volume reflects operational and economic biomass recovery filtering as well as accounting for competing facilities procuring feedstock from within the FSA.

Table 23. Potentially and Practically Available Biomass Feedstock Summary

FEEDSTOCK TYPE	POTENTIALLY AVAILABLE FEEDSTOCK [GT]	PRACTICALLY AVAILABLE FEEDSTOCK [GT]
Corn Stover	229,792	63,193
Wheat Straw	264,900	72,848
Sugar Beet Tailings	23,000	46,000
Animal Waste	186,674	18,667
Food Waste	590	1,600
Forest Operations	66,625	34,640
Forest Product Manufacturing	14,000	14,000
Urban Wood	21,329	2,000
TOTALS	**806,910**	**252,948**

Feedstock Characteristics

The characteristics that define certain aspects of feedstock suitability for AD, CHP, or thermal energy are shown in Table 24 and Table 25.

Table 24. Characteristics for Anaerobic Digester Feedstocks

FEEDSTOCK TYPE	AS RECEIVED MOISTURE CONTENT [%]	WET BASIS HIGH HEATING VALUE [BTU/LB]	DRY BASIS HIGH HEATING VALUE [BTU/LB]
Sugar Beet Tailings[49]	83	1,271	5,778
Animal Waste[50]	37	3,516	5,495
Food Waste[51]	70	3,000	10,000

Table 25. Characteristics for Combined Heat and Power or Thermal Energy Feedstocks

FEEDSTOCK TYPE	AS RECEIVED MOISTURE CONTENT [%]	AS RECEIVED ASH [%]	DRY BASIS HIGH HEATING VALUE [BTU/LB]
Corn Stover	20	6.8	7060
Wheat Straw	10	10.4	6840
Forest Operations	45	0.97	8580
Forest Products Manufacturing	40	0.5	8270
Urban Wood	20	7.0	7920

The prevailing technology for boilers will allow utilization of agricultural byproduct such as corn stover and wheat straw as well as wood, but not as a combined feedstock supply. Most boilers are configured for one or the other but are not suitable for both feedstock types.

Biomass Feedstock Competition

There are a number of facilities using woody biomass material as feedstock for thermal-energy only or CHP in northern and western Minnesota. These facilities and their location and distance from Mahnomen are shown in Table 26.

[49] The heating values were predicated upon methane output;*"Single-stage, batch, leach-bed, thermophilic anaerobic digestion of spent sugar beet pulp,"* Abhay Koppar, Pratap Pullammanappallil, Bioresource Technology 99 (2008) 2831-2839.
[50] Energy, Utility, and Environment Conference, 2008 - Volume 2 - Paper #01, Dawn A. Santoianni, Matthew F. Bingham, Dawn M. Woodard, Jason C. Kinnell.
[51] *"Biofuels From Municipal Waste-Background Discussion Paper,"* Robert B. Williams, Department of Biological and Agricultural Engineering, University of California at Davis and the California Biomass Collaborative, March 28, 2007. Waste Age article,*"Profiles in Garbage: Food Waste,"* Chaz Miller, September 1, 2000.

Table 26. Facilities Currently Competing for Feedstock

FACILITY	LOCATION	DISTANCE FROM MAHNOMEN [MILES]
Boise Paper	International Falls	178
Resolute Forest Products	Fort Frances, Ontario	179
Minnesota Power	Grand Rapids	140
Fibrominn	Benson	165
Potlatch	Bemidji	69
Pine Products	Bemidji	69
Bergen's Greenhouse	Detroit Lakes	36
Mahnomen High School	Mahnomen	0

The first four facilities identified in Table 26 are located a considerable distance from Mahnomen. Minnesota Power's facility in Grand Rapids occasionally acquires minor volumes of woody biomass feedstock from forest operations in eastern Clearwater County and areas adjacent to the FSA. However, the transport distance and cost for material from within the FSA exceeds the market prices for these facilities. Resolute Forest Products has initiated operation of their 45 MW cogeneration expansion; however, they have been using natural gas as their primary fuel source. They have also had problems with woody biomass handling at the facility and feedstock costs, quality, and delivery scheduling from local Canadian suppliers.

Fibrominn sources small volumes of both urban wood and feedstock from forest operations from within Becker County. The procurement manager was not able to provide volume data but indicated the volumes were minor.[52] Potlatch's mill in Bemidji consumes only woody biomass feedstock produced as a byproduct of their operations. Pine Products acquires some woody biomass feedstock from forest operations to supplement their animal bedding and composting operation. Both Bergen's Greenhouse and the Mahnomen School District consume an estimated one to two loads per week of chipped birch material for their thermal energy needs. In summary, woody biomass feedstock currently consumed within the FSA by competing facilities is estimated at from 6,000 to 12,000 GT per year.

In any region of the U.S. with commercial agriculture or forestry operations, proposed or potential renewable energy projects are always in development. The region of northwest Minnesota is also an area with preferred attributes for such projects, and several could be considered as potentially viable. Table 27 identifies facilities that could compete for feedstock from within the FSA depending upon economic circumstances and development progress.

[52] Discussion with Jeff Schommer, Fuel Buyer for Fibrominn.

Table 27. Potential Facilities Competing for Feedstock

PROJECT NAME	LOCATION	DISTANCE FROM MAHNOMEN [MILES]
Norbord	Bemidji	69
Former Ainsworth Facility	Bemidji	69

Norbord has shifted production to different species with thinner bark and has been consuming more woody biomass feedstock at the plant in Bemidji. Processing species with thinner bark has resulted in a decrease in volume of wood byproduct from manufacturing. According to Norbord's log procurement manager,[53] the facility is currently using almost all wood byproduct produced at the plant, with no surplus inventory. Though sourcing feedstock from external sources is not currently being conducted, Norbord is anticipating the potential need for some material from other wood products manufacturing facilities and forest operations.

The Ainsworth Lumber Company's oriented strand board plant ceased operations in 2009. The Idea Circle, a local workforce development company, purchased the site the same year. Subsequent to the purchase, the company indicated the objective for the site would be a bio-energy industrial park for emerging green businesses. The management at The Idea Circle has not publicly issued any information about future development plans since that time, and the site currently remains undeveloped. TSS does not anticipate any competition for feedstock from within the FSA from this facility in the near term.

Biomass Feedstock Cost Assessment

TSS has analyzed the full expense of collection, processing, and transport to develop estimated cost of biomass feedstock delivered to the prospective facility. Interviews were conducted with local and regional farming operations, farm equipment operators, farm equipment marketing companies, fiber procurement managers, forest landowners and managers, forest operations contractors, wood products manufacturing owners/managers, solid waste agencies, and biomass feedstock suppliers.

Low and high-cost ranges are presented due to different variables that can impact costs of operation. The most significant variables for collection, processing and transport of biomass material for use as biomass feedstock within the FSA include:

- Haul distance to facility;
- Timber harvest residual pile distribution;
- Cost of diesel;
- Cost of labor;

[53] Jerry Richards, Norbord log buyer.

- Access/road condition;
- Road improvement and maintenance costs;
- Time of year delivery; and
- Competing uses for the biomass material.

Table 28 shows the estimated range of collection, processing, and transportation costs associated with each biomass feedstock type. The range of prices for wood product manufacturing byproduct and urban wood waste is influenced by local and regional market demand.

Table 28. Range of Delivered Feedstock Price by Biomass Feedstock Type

FEEDSTOCK TYPE	ESTIMATED PRICE RANGE [$/GT]	
	LOW RANGE	HIGH RANGE
Corn Stover	55	75
Wheat Straw	50	70
Sugar Beet Tailings	15	22
Animal Waste	14	24
Food Waste	14	850
Forest Operations	23	55
Forest Products Manufacturing	20	28
Urban Wood Waste	20	28

Existing research and literature was also reviewed for prospective pricing for corn stover, wheat straw, and animal waste. The variation in pricing for corn stover and wheat straw is due to inclusion or exclusion of fertilizer replacement values, farmer compensation, and pre-processing used in some price calculations and studies. Though wheat straw would not require the additional cost of cutting as compared to corn stover, the cost savings is offset by the reduced yields per acre. Therefore, the costs for both feedstocks are very similar. Wheat production has declined in recent years due to escalating prices for corn and as such, wheat straw values have increased. TSS learned that in some areas of the Midwest, wheat straw is selling for $100 per ton.

Animal waste delivered prices include transport costs for liquid and solid manure and includes compensation of nutrient value produced by animal.[54] Nutrient value per animal is the most common metric used to calculate the value of manure. A bulk commodity price would be the preferred metric to determine potential compensation; however, much of the manure sold in this manner is composted for retail outlets and not applicable to this analysis.

Food waste feedstock prices were predicated upon the volume and weight of the material in the dumpsters from Table 28 and the conversions used in the data calculations for this table. Truck

[54] "What is the Value of Cattle Manure? Putting a price on your black gold." By Richard Halopka, University of Wisconsin Extension, Clark County, 2009, Countryside Publications Ltd.

hauling rates of $95 per hour were applied to time estimates for dumpster pickup and delivery from the various sites of food waste sourcing. The large variation between the low and high range represents the difference in capacity between the dumpster at the casino and the small dumpsters used at the school and the health center and amortizing the cost among the tons within each dumpster.

Pricing Forecast

For the purposes of biomass feedstock price forecasting, TSS assumed an optimized fuel blend of 75% forest products manufacturing byproducts at a delivered price of $27 per GT and 25% forest operations biomass material at a delivered price of $54.50 per GT. The optimized blended base case delivered price of $33.90 per GT is shown in Table 29.

Table 29 represent a feedstock pricing forecast that demonstrates how an optimized feedstock blend at the facility at Mahnomen would track over the next ten-year period.

Table 29. Ten-Year Feedstock Pricing Forecast [$/GT] 2013-2022

FEEDSTOCK PRICE SCENARIO	2013	2014	2015	2016	2017
Base Case	33.90	33.90	33.90	34.58	35.27
Worst Case	37.90	39.23	40.60	42.02	40.06

FEEDSTOCK PRICE SCENARIO	2018	2019	2020	2021	2022
Base Case	35.97	37.40	36.20	36.92	37.66
Worst Case	41.46	43.80	45.33	46.92	48.56

The feedstock price forecast presented in Table 29 is based on the following assumptions.

Base Case Feedstock Price Forecast Assumptions:

- Feedstock supply chain is fully developed with feedstock available from local and regional sources;
- Diesel fuel prices remain near $4.10 per gallon through 2015, then escalate at 2% per year;
- Labor rates remain stable through 2015, then climb at 2% per year;
- Housing and construction sectors slowly increase; and
- Biomass feedstock prices remain flat through 2015, then escalate at 2% annual rate due to increased diesel fuel and labor costs from 2015 through 2022, with minor volatility occurring in isolated years during this period.

Worst Case Feedstock Price Forecast Assumptions:

- Feedstock supply chain development is not fully developed;
- Diesel fuel prices are $4.10 per gallon in 2014, escalating at 4% per year in 2015 through 2023;
- Labor rates remain stable through 2013, then climb at 3.5% per year;
- Housing and construction remain flat through 2016, then slowly improve; and
- Biomass feedstock prices escalate at a minimum 3.5% annual rate due to increased diesel fuel, labor costs, and pressure from competition from 2014 through 2022, with minor volatility occurring in isolated years during this period.

Biomass Feedstock Supply Risks and Future Sources

The primary mitigation measure to minimize the impact of potential or current biomass supply competition is to concentrate procurement efforts in the development of suppliers located close in and tributary to the facility location. A project will have significant transport cost advantages when sourcing biomass feedstock as near as possible to its location. An additional mitigation measure to minimize the impact of competing biomass purchasers is to secure stable and price competitive feedstock sources utilizing long-term supply agreements with key, reliable and financially stable feedstock suppliers.

Transport Cost

The cost of transporting biomass feedstock represents the single most significant expense when procuring biomass. Variables such as diesel fuel cost (currently at $4.10 per gallon[55]), workers compensation expense, and maintaining a workforce (locating and keeping qualified drivers) are all factors that significantly impact the cost to transport commodities such as biomass feedstock. Interviews with commercial transport companies indicate the current cost to transport a bulk commodity such as biomass feedstock is $2.00 to $2.20 per running mile, or $80 to $100 per hour.

At this time, diesel fuel costs are the most significant variable impacting transport costs. Diesel fuel price escalation has had a major impact on biomass feedstock prices throughout the U.S. in recent years. Based on TSS's experience, the average forest-sourced biomass feedstock requires approximately 1.75 to 2 gallons of diesel to produce and transport a GT of forest-sourced feedstock with an average roundtrip haul distance of 60 to 90 miles. Therefore, a $1.00 per gallon increase in diesel fuel equates to a $1.75 to $2.00 per GT increase in the cost to produce and transport forest-sourced biomass feedstock. Any significant increase in the price of diesel fuel presents a risk to the overall economics of producing forest-sourced biomass. Diesel fuel pricing volatility is primarily driven by the cost of crude oil. Figure 29 shows the volatility of diesel prices during the period July 2002 through July 2012.[56]

[55] Minnesota Gas Prices; http://www.minnesotagasprices.com
[56] Energy Information Administration, http://www.eia.gov/petroleum/data.cfm#prices

Figure 29. U.S. Midwest Diesel Prices 2002-2012

Figure 29 clearly shows a ten-year trend of increasing prices with short-term volatility. The fluctuations in diesel prices are the single largest potential impact to feedstock prices.

Seasonal Availability

Various regions within the forested ecosystems of the FSA have different operating seasons. Some areas and ownerships conduct operations only during winter months when the ground is frozen and equipment operates upon snow to minimize impact to soils. Other areas and ownerships indicated that operations are conducted year-round. Both operating scenarios experience closures or restricted operations during fall as the ground freezes and during spring break-up, as soils and roadbeds dry sufficiently to avoid negative impacts from continued use. Though there could be some periods of the year when access to woody biomass feedstock from forest operations is limited, the local biomass processing contractors have sufficient room at their company locations to stockpile material. In addition, woody biomass feedstock from wood products manufacturing will typically be available all year long.

Housing and Construction

As economic conditions improve and the housing and construction sectors rebound, wood product manufacturing and timber harvest activity will increase as well. An increase in wood product manufacturing will result in increasing volumes of byproduct, a traditional source of cost effective woody biomass feedstock for many biomass cogeneration facilities. An increase in timber harvest activity and volumes would generate additional volumes of woody biomass feedstock. This could result in a decrease in prices with excess local and regional capacity, and a reduction in transport costs as volume increases closer to the facility at Mahnomen.

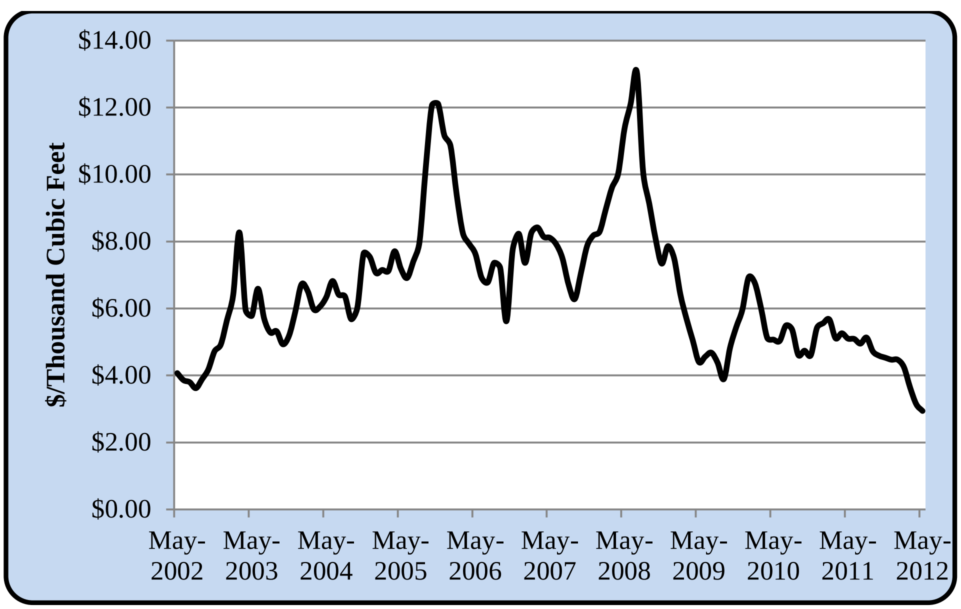
Improvements in housing and construction will result in an increase in volumes of urban wood from construction and demolition projects. Though little separation and utilization of this feedstock currently occurs within the FSA (except Becker County), this represents a real opportunity to work with local and regional landfills and transfer stations to develop inexpensive woody biomass feedstock volumes and diversify feedstock supply sources.

Securing long-term supply contracts with reliable vendors or sources will mitigate many of the potential changes in the market in the FSA. Anchoring the feedstock supply with local wood product manufacturing and biomass processing contractors would provide a solid foundation. This material is being produced at relatively low production levels when compared to pre-recession years and will only increase in volume and availability as the economy rebounds. Also, sourcing from local wood product manufacturers with a solid history of production and on secure financial footing is a sound strategy to reduce risk associated with feedstock procurement. The balance could be sourced from forest operations located closest to Mahnomen to minimize transport costs.

<u>Natural Gas</u>

The decline in natural gas prices has impacted the consumption of woody biomass feedstock material significantly. Many CHP facilities utilize natural gas as a supplemental fuel, back fuel source, or potential replacement and when natural gas prices were elevated, as during the period 2006 through 2008, many facilities using natural gas were seeking alternative fuels, such as woody biomass. As prices for natural gas declined, those facilities faced with higher feedstock prices from woody biomass material, opted to burn increasing volumes of cheaper natural gas. The volatility of natural gas prices will impact pricing and availability of woody biomass feedstock long term. Figure 30 shows the changes in natural gas prices from 2002 through 2012.

Figure 30. U.S. Natural Gas Prices 2002-2012



Recent changes in technology in the natural gas industry have improved the recovery of natural gas in dense shale formations utilizing hydrofracking, increasing availability, and lowering prices. Some are predicting low natural gas prices for as long as the next thirty years based upon this technology and known natural gas deposits in shale formations throughout the U.S. However, recently there have been some legal challenges to the environmental safety and consequences of hydrofracking to ground water. While future natural gas prices are difficult to predict, it is likely that natural gas prices have reached their low point.

Findings

Feedstock quantity, quality, and price were evaluated for feedstock within each of three distinct categories: agricultural residues, forest-sourced residues, and anaerobic digestion. Available agricultural residues within the FSA included wheat straw and corn stover. Forest-sourced residues included forest operations, forest product manufacturing, and urban wood. AD feedstock included sugar beet tailings, animal manure, and food waste. Table 30 indicates the price per MMBtu for each feedstock.

Table 30. Price per MMBtu by Available Feedstock

FEEDSTOCK TYPE	ENERGY PRICE LOW RANGE [$/MMBTU]	ENERGY PRICE HIGH RANGE [$/MMBTU]
Corn Stover	4.87	6.64
Wheat Straw	4.06	5.69
Sugar Beet Tailings	5.90	8.65
Animal Waste	1.99	3.41
Food Waste	2.33	14.17
Forest Operations	2.44	5.83
Forest Product Manufacturing	2.02	2.82
Urban Wood Waste	1.58	2.21

Based on the findings in Table 30, the feedstocks with the lowest cost are urban wood waste, forest product manufacturing, and animal waste. The conversion efficiency of each technology option will further refine the findings in Table 30 to determine the most appropriate technology for the SSC.

ENERGY SALES AND MARKETING

Introduction

Energy sales and avoided cost potential are primary drivers for the investment and development of any energy system. Biomass energy can be utilized to create electricity and thermal heat in the form of hot water and low or high-pressure steam. Biomass thermal energy can be utilized to displace the use of heat generated by electricity or fossil fuels. Electricity production may be used to net meter with large electricity users or be sold to the local utility grid. This section identifies the financial opportunities available for a biomass energy project in Mahnomen.

Renewable Energy Standard

Minnesota enacted legislation (Chapter 3 S.F.4) in February 2007 that created a RES targeting electric utilities operating within the state. In 2011, Minnesota Statute 216B.1691 amended the RES. The amendment to the 2007 RES statute changed some of the definitions found in subsection 1 to expand the definition of electric utility and place additional restrictions on small-scale hydropower. The RES sets production targets for electricity generation from qualifying renewable energy sources for a public utility, a generation and transmission cooperative, a municipal power agency, or a power district. Based on the definition of an electric utility found in subsection 1, the Minnesota Public Utilities Commission determined that the following entities are subject to the RES statue:

- Basin Electric Power Cooperative;
- Central Minnesota Municipal Power Agency;
- Dairyland Power Cooperative;
- East River Electric Cooperative;
- Great River Energy;
- Heartland Consumer Power District;
- Interstate Power and Light;
- L&O Power Cooperative;
- Minnkota Power Cooperative;
- Minnesota Municipal Power Agency;
- Minnesota Power;
- Missouri River Energy Services;
- Northwestern Wisconsin Electric Company;
- Otter Tail Power Company;
- Southern Minnesota Municipal Power Agency; and
- Xcel Energy.

There are two renewable objectives, one for electric utilities without nuclear power and one for electric utilities with nuclear power. Table 31 shows the two objectives.

Table 31. Minnesota Renewable Energy Standard Objectives

DATE	ELECTRIC UTILITY WITHOUT A NUCLEAR GENERATING FACILITY	ELECTRIC UTILITY WITH A NUCLEAR GENERATING FACILITY
December 31, 2010	-	15%
December 31, 2012	12%	18%
December 31, 2016	17%	25%
December 31, 2020	20%	30%
December 31, 2025	25%	-

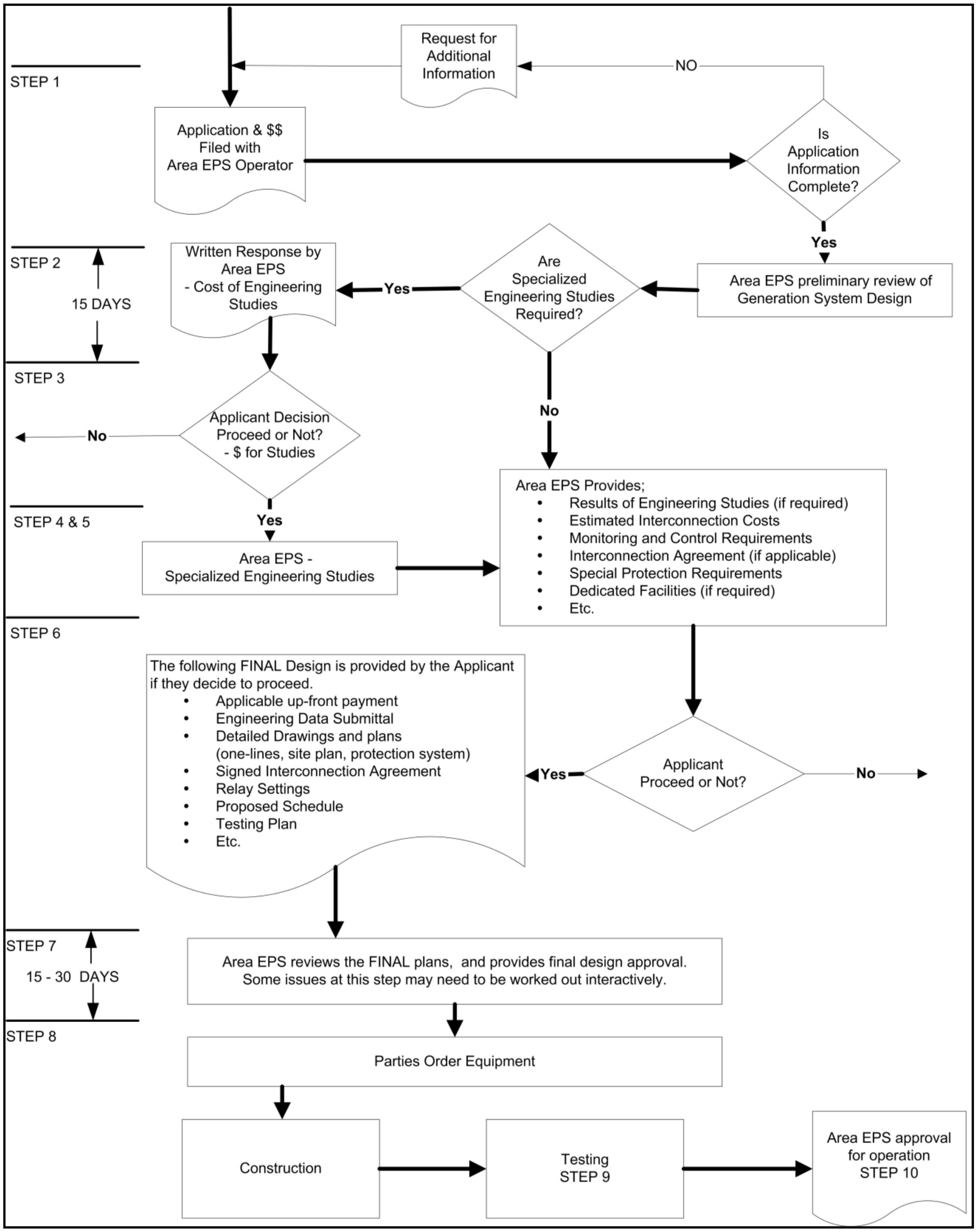
Xcel Energy (Xcel) is the only electric utility in Minnesota with nuclear generation facilities. It owns and operates the Monticello Nuclear Generating Plant and Prairie Island Nuclear Generating Plant. The RES requirements for Xcel further specify that of the 30% renewable energy, at least 25% must be generated by solar or wind energy conversion systems.

As of March 2012, all of the qualifying electric utilities are in compliance with the RES and are on track to meet their 2016 goals. The majority of the renewable energy utilized for compliance has been with large-scale wind projects in North Dakota, South Dakota, and Minnesota.

Interconnection Process

The interconnection process is an interaction between the utility provider (the owner of the existing power transmission and distribution infrastructure) and the power generating facility. Since the SSC is in the service territory of OTP, any CHP facility will interconnect with OTP and therefore is subject to the OTP interconnection requirements. Figure 31 shows a flow chart representing OTP's interconnection process.

Figure 31. Otter Tail Power Interconnection Flow Diagram[57]



[57] "Proposed Interconnection Process for Distributed Generation Systems," Otter Tail Power and the State of Minnesota.

The interconnection process can be a costly and time intensive process depending on the current infrastructure and the connecting technology. The ten steps outlined in Figure 31 show all major components of the process from the application to the approval for use. Each step has a specific time for response, and the process should be expected to take six to twelve months. Some of the steps specify their costs, but the largest contributors to the overall costs are the variable expenses from the engineering studies as shown in Step 2 and the interconnection costs defined in Step 4 and 5. While the known application cost would be $1,500 for a unit sized between 0.5 MW and 3.0 MW, the engineering study and the cost estimate for needed upgrades can vary widely, from several thousand dollars to over a million dollars.

Detailed information on OTP's interconnection process can be found in Appendix 4.

Renewable Energy Sales

A power generating facility sized under 10 MW is subject to the Public Utility Regulatory Policy Act (PURPA). PURPA, originally passed in 1978 and amended in 2005 and 2007, requires utilities to purchase power from electricity producers at their avoided cost rates. Each electric utility calculates its own avoided cost rates based on their blend of power generation assets. TSS reviewed potential power sales to OTP, Wild Rice Cooperative, Xcel, and Minnesota Power (MP). These four utilities were selected because of their geographic proximity to the SSC site. Additionally, Xcel has a unique RES requirement.

Otter Tail Power

OTP is the current electrical service provider for the SSC. The rates offered by OTP are shown in Table 32.

Table 32. Otter Tail Power Time of Day Purchase Rates[58]

DESCRIPTION	CAPACITY PAYMENT (ON-PEAK ONLY)	ENERGY CREDIT ON-PEAK	ENERGY CREDIT OFF-PEAK
Summer (Firm Power and Non-Firm Power)	0.275¢ per kWh	3.699¢ per kWh	2.536¢ per kWh
Winter (Firm Power and Non-Firm Power)	0.275¢ per kWh	4.311¢ per kWh	2.433¢ per kWh

This rate schedule is offered to qualifying facilities with generation of more than 100 kW if firm power is provided. Firm power is energy delivered by the qualifying facility to the utility with at least a 65% on-peak capacity factor in the month. For facilities that do not meet the 65%

[58] "Small Power Producer Rider Time of Day Purchase Rates" Section 12.03, Minnesota Public Utilities Commission.

on-peak capacity requirement in any month, the compensation will be the energy portion only (no capacity payment).

Summer on-peak rates extend from June 1 through September 30, including the hours from 8:00AM to 10:00PM Monday through Friday, excluding holidays. Winter on-peak rates extend from October 1 through May 31 including those hours from 7:00AM to 10:00PM Monday through Friday, excluding holidays. Observed holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Given these time-of-day definitions, the average purchase rate over a one-year period is 3.090¢ per kWh. As the electricity provider to the SSC, the potential for avoided cost rates is based on the price paid to the utility. The marginal price of electricity, as shown in Figure 5, is $0.04283 per kWh. This is the avoided cost potential for the SSC.

<u>Wild Rice Cooperative</u>

The Wild Rice Cooperative is a part of the Minnkota Power Cooperative (Minnkota). The nearest Minnkota lines are approximately eight miles from the SSC. To sell to Minnkota, a CHP system would interconnect to OTP infrastructure and the electricity would be wheeled to the Minnkota lines. Wheeling fees are negotiated on a case-by-case basis with OTP.

The process to set up a PPA with Minnkota is determined on a case-by-case basis. The qualifying facility owner sends Minnkota a proposal outlining the facility type, the expected output, and the expected costs. Since all contracts must be reviewed by the Minnesota Public Utilities Commission (MPUC), Minnkota must demonstrate that the proposed project meets two basic requirements: price and need. Price is based on competitive analysis of other resource options. Need must be demonstrated and can be in the form of meeting RES requirements, capacity, or energy profile. If the proposal meets these criteria, a PPA is developed.

As of March 2012, Minnkota is not actively seeking additional capacity, and its renewable generation portfolio includes large-scale wind to meet the RES. Minnkota does not have a published avoided cost rate schedule; however, with large-scale wind and coal, the expected avoided cost rates should be less than 2.5¢ per kWh.[59]

<u>Minnesota Power</u>

Minnesota Power's service territory ends approximately 20 miles to the east of Mahnomen. To sell power to MP, the power would have to be wheeled over OTP lines to MP. As previously noted, wheeling fees are negotiated on a case-by-case basis with OTP.

Since the SSC is outside of the service territory of MP, power sales would not be eligible for a feed in tariff rate.[60]

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[59] Interviews with Minnkota staff.

[60] Feed in Tariff is a policy mechanism design to promote investments in renewable energy by providing long term contracts to renewable energy producers based on the cost of generating electricity for each renewable energy technology.

For a standard PPA for renewable energy, MP does not publicly disclose rates, but bases its contracts on the energy futures market. Contracts are negotiated individually for five-year durations. Like with Minnkota, all contracts with MP must be reviewed by the MPUC and must meet two basic requirements: price and need. Price is based on competitive analysis of other resource options. Need must be demonstrated and can be in the form of meeting RES requirements, capacity, or energy profile.

As of March 2012, MP has planned to meet all of its renewable energy requirements with wind from operations located in North Dakota. Recent filings with the MPUC show expected purchase rates for 2.2¢ per kWh.[61] This power is expected to be available at a 45% capacity factor, which is substantially less than a biomass plant, leaving some room for price negotiation. At the scale of the SSC project (0.5 to 3 MW), the electricity production is too small to have an effect on system capacity or an energy load profile.

Xcel Energy

Xcel's service territory begins approximately 15 miles to the west of Mahnomen. To sell power to Xcel, the power would have to be wheeled over OTP lines to Xcel Energy. As noted earlier, wheeling fees are negotiated on a case-by-case basis with OTP. The published rates for Xcel Energy are shown in Table 33.

Table 33. Xcel Energy – Energy and Capacity Purchase Payments

DESCRIPTION	CAPACITY PAYMENT [¢ PER KWH]*	ENERGY CREDIT ON-PEAK [¢ PER KWH]	ENERGY CREDIT OFF-PEAK [¢ PER KWH]
Summer (Primary System Delivery)	0.0605	4.873	1.593
Winter (Primary System Delivery)	0.0605	2.914	1.593

*Based on 2001 payments, the most recent indicated in Xcel Energy's published material.

On-peak rates are effective from 9:00AM until 9:00PM Monday through Friday except for holidays. Observed holidays are New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Summer months are July and August. Given these time-of-day definitions, the average purchase rate over a one-year period is 2.298¢ per kWh.

Capacity payments are updated annually and are initially set at the rates in Table 33. The capacity payments are fixed to a 2.5% escalation rate. With capacity payments averaging $4.42 per kW-month (0.605¢ per kWh) and energy payment at 2.298¢ per kWh, the total rate (energy and capacity) amount to 2.903¢ per kWh.

[61] "Public Comments of the Minnesota Department of Commerce, Division of Energy Resources" Docket No. E015/M-11-234.

Electricity: Avoided Cost

Electricity generation for net metering is based on the current rates paid to OTP by the SSC. The current power rate is $0.04283 as indicated in the Tribal Energy Load Assessment.

Heat: Avoided Cost

Heat may be sold or used internally to displace alternative power use. In either situation, biomass energy must be compared to alternative energy sources. Table 34 combines the findings in Table 9 and Table 30 to compare energy prices. Although there is not natural gas available in Mahnomen, natural gas has been included into Table 34, as it may be an option in the future.

Table 34. Price per MMBtu by Energy Source

FOSSIL FUEL SOURCE	CURRENT PRICE [$/UNIT]		CURRENT PRICE [$/MMBTU]	
Fuel Oil	3.510/gal		25.34	
Electricity	0.04283/kWh		12.55	
Propane	1.260/gal		13.62	
Natural Gas[62]	0.775361/therm		7.75	
BIOMASS FEEDSTOCK SOURCE	**LOW RANGE [$/GT]**	**HIGH RANGE [$/GT]**	**LOW RANGE [$/MMBTU]**	**HIGH RANGE [$/MMBTU]**
Corn Stover	55.00	75.00	4.87	6.64
Wheat Straw	50.00	70.00	4.06	5.69
Sugar Beet Tailings	15.00	22.00	5.90	8.65
Animal Waste	14.00	24.00	1.99	3.41
Food Waste	14.00	85.00	2.33	14.17
Forest Operations	23.00	55.00	2.44	5.83
Forest Product Manufacturing	20.00	28.00	2.02	2.82
Urban Wood Waste	20.00	28.00	1.58	2.21

Given the available sources of energy (as listed in Table 34), all of the biomass feedstock alternatives offer significant potential for cost savings. It is important to note that conversion system efficiencies are important factors to determine the financial viability of a biomass conversion system. System efficiencies will be reviewed in the Conversion Technology Review and Selection section.

[62] Using Xcel Energy's natural gas winter rates: http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/Mg_Section_5.pdf

Heat: Energy Sales

The transportation of thermal heat is dependent on the type of heat (hot water or steam) and the insulation of the piping. With enough insulation, heat can be piped to customers located significant distances from the heat source. The cost of piping determines the economics of transport to customers.

The three largest heat users within a mile radius of the SSC property are the Mahnomen School, the Health Center, and the casino itself. The School and the Health Center operate with high pressure steam (7.5 psi and 8.5 psi respectively) and with biomass and fuel oil systems, respectively. To supply these facilities, a higher pressure steam would have to be produced on site due to pressure loss during transportation. The SSC operates with hot water. To feed the casino, hot water must be produced. Hot water systems are typically not compatible with steam systems.

TSS recommends that the SSC not pursue outside heat sales. The school operates a biomass unit and it is unlikely that the school will realize significant savings by switching to heat provided by the casino. While the hospital could realize significant savings by displacing fuel oil consumption, the hospital has tried in the past to partner with the school to utilize the school biomass boiler and was unsuccessful, as there were challenges with heat losses and steam pressure.

Findings

Markets for electricity and heat sales were reviewed to identify any potential partnerships the SSC may consider for a biomass project. The four electric utilities with service territories in or around Mahnomen were considered along with local facilities with high heat demands. The review found the renewable energy market in Minnesota is dominated by low-cost renewable energy from wind farms in North Dakota. Based on TSS's experience, without a price premium for renewable energy, community-scale CHP cannot compete with large-scale wind, natural gas, and coal. If the WEN is interested in pursuing CHP for energy independence, this endeavor will increase the expenses, as electricity from biomass will cost more than from the local utilities service the WEN facilities (OTP and Wild Rice Cooperative) are currently experiencing.

Additionally, there are no current heat producers in Mahnomen, as the health center and the school both utilize low pressure steam which is not compatible with the hot water system at the casino. However, there are significant opportunities to decrease expenditures on fuel oil and propane currently used to heat the SSC's facilities.

CONVERSION TECHNOLOGY REVIEW AND SELECTION

Introduction

The purpose of this section is to utilize the findings in the previous three sections where data were collected regarding the SSC's energy utilization, the available biomass feedstock, and the potential economic and market opportunities. This section will identify appropriate technologies to utilize the available biomass sized in accordance with the energy data findings, and compared to the economic and market opportunities.

Technology Overview

Biomass, such as woody waste from forest residues and sawmills, agricultural byproducts such as corn stover, wheat straw and beet tailings, or organic matter such as food waste and animal manure can be utilized as feedstock to produce renewable electricity, heat, or liquid fuels. Three conventional technology systems, direct-fired combustion, gasification, and AD are reviewed in this section for their technical and economical compatibility with the specific attributes of the SSC site. Each system can produce thermal energy (heat) and electricity. Gasification and anaerobic digestion have the potential to produce liquid or gaseous fuels.

Direct-Fired Combustion

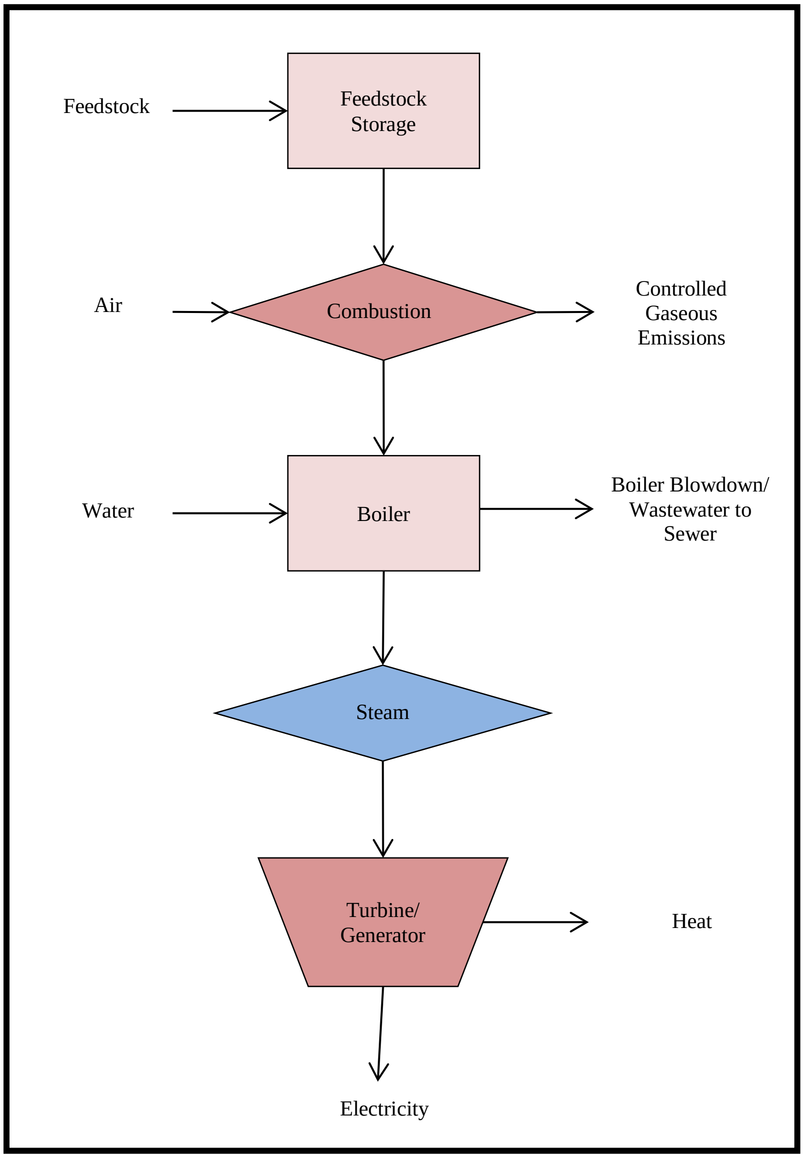
Direct-fired combustion in its most basic form is a fire. Modern direct-fired combustion technology carefully controls all aspects of combustion including temperature, feedstock loading, and oxygen levels to achieve a complete and efficient combustion process that maximizes the conversion of the feedstock's energy content to sensible heat.

Historically, industrial applications have utilized direct-fired combustion technology since the 1600's and electricity generation with steam cycle turbines has been available since the 1800's. Direct-combustion technology configured for coal feedstocks is commonly used in large-scale operations to provide a significant portion of the world's electricity demands. With increasing costs associated with emissions clean-up for coal, biomass demand has increased as a sustainable and cleaner alternative feedstock. In many parts of North America and Europe, biomass is becoming a substitute feedstock of choice for coal and fuel oil. A primary driver in the decision to utilize biomass is policies that target reduction of fossil fuel use in order to mitigate greenhouse gas emissions.

Across the United States, buildings and campuses have successfully deployed small-scale direct-fired combustion units for thermal heating. However, with the additional costs associated with operating a steam cycle turbine, small-scale electricity production has proven economically challenging as this technology greatly benefits from economies of scale.

For all direct-fired combustion systems, the biomass feedstock is directly burned (combusted) in a combustion chamber with access to sufficient oxygen to allow for the total decomposition of the molecular structure of the feedstock during the oxidation process. The heat from the combustion is transferred to a working fluid for distribution as heat (in the form of steam or hot water) or for use in a steam-cycle turbine to produce electricity. Common boilers used for biomass direct-combustion systems include traditional stoker boilers[63] and fluidized bed boilers.[64] A schematic for a direct-fired combustion unit is depicted in Figure 32. Notice that Figure 32 is a schematic for an electricity producing unit. For a thermal-energy only unit, the end product (hot water or steam) is represented in the blue diamond labeled "steam".

Figure 32. Schematic of a Typical Direct-Fired Combustion to Electricity System



[63]In stoker boilers, feedstock burns on a grate, with combustion air supplied both from under the grate and above the burning bed.
[64]In fluidized bed boilers, feedstock burns in suspension with inert materials (such as sand) forced through upward air jets.

Each combustion technology has individualized feedstock specifications that optimize system performance. It is important to consider feedstock requirements, as system efficiency may decrease and maintenance costs may increase with deviations from these specifications.

In addition to the direct-fired combustion system depicted in Figure 32, hybrid systems exist where the feedstock is gasified (see the Gasification section) and the producer gas rises from the gasification vessel into a combustion chamber where it is combusted for heat. Some technology vendors label these systems as gasifiers since there is a gasification component in the process. The convention utilized for this feasibility study requires that a gasification system has the ability to capture producer gas in a controlled manner such that it can be conditioned (impurities removed) for separate use. The hybrid systems previously described do not capture producer gas in a controlled manner and are therefore considered direct-combustion units in this analysis.

For thermal-energy only facilities, direct-fired combustion facilities follow the process flow diagram in Figure 32 until the process block labeled "steam". At this point, low or high pressure steam or hot water are produced and utilized in the system.

Based on TSS's experience, the efficiency of electricity generation using direction combustion and steam turbines is approximately 16% to 24% efficient. Direct-fired combustion units for thermal-energy only facilities are approximately 65% to 85% efficient dependent on the moisture content of the feedstock.

Gasification

Gasification in its most basic form is a fire starved of oxygen. Modern gasification technology carefully controls all aspects of this partial burn including feedstock flow rates, feedstock residence times, and most importantly, oxygen levels. The gasification chamber is controlled to create as much producer gas as possible while minimizing complete combustion.

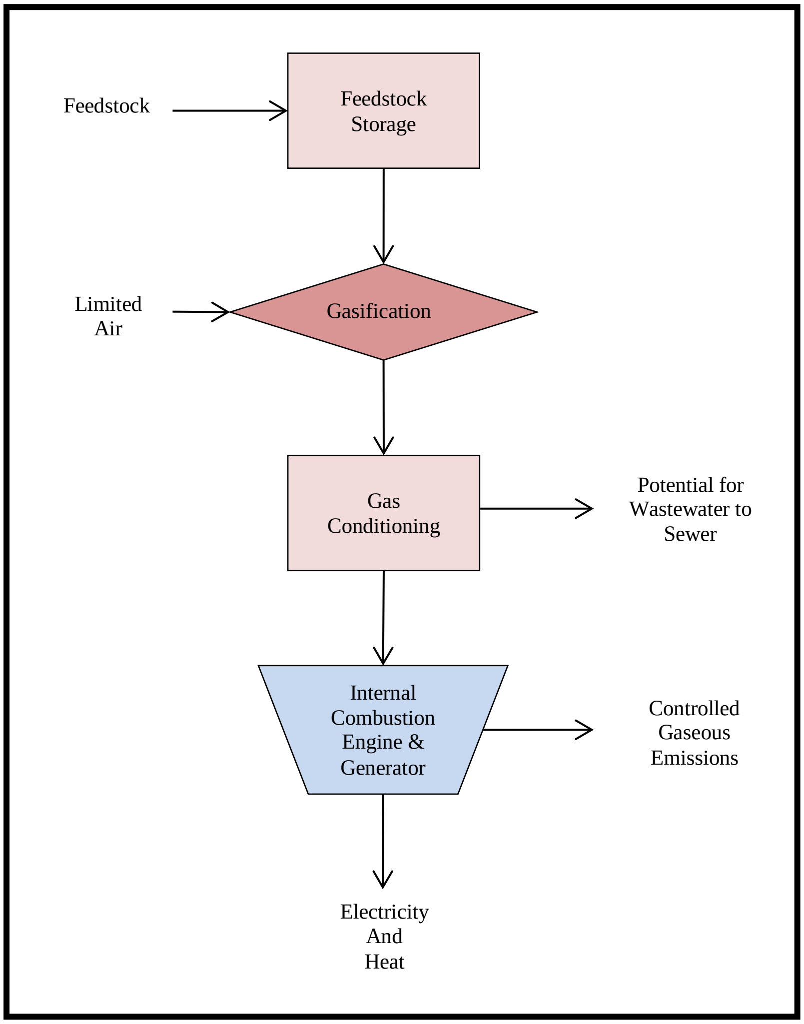
Historically, gasification has been utilized for energy since the late 1800's. Gasification has been deployed on a large-scale with integrated gasification combined cycle plants using coal as the feedstock. Small-scale gasification grew during World War II in countries (e.g., Germany) where petroleum supplies were scarce or vulnerable. For more than 50 years, synthetic gas (syngas), made during the gasification process, has been in commercial use as a replacement for natural gas. Within the last decade, small-scale distributed generation technologies utilizing gasification have grown in Europe and the United States due to an emphasis on clean and renewable distributed power generation.

While there are many variations on gasification systems, downdraft and updraft gasifiers are the two most prevalent small-scale systems. Both systems operate following the schematic shown in Figure 33.

The difference between an updraft and downdraft gasifier lies in the second stage – the red diamond labeled gasification. For both systems, the feedstock is delivered into the top of the gasification vessel, a small area of combustion resides in the middle of the gasification vessel, and the biochar is recovered at the bottom. For an updraft gasifier, air moves from the bottom to the top of the vessel while in a downdraft gasifier, the air movement is from the top to the bottom. For all gasifiers, the feedstock is heated which causes volatile gasses to be released, called producer gasses. A small area of complete combustion is required to maintain the heat necessary for gasification. This combustion area is tightly controlled by monitoring the oxygen levels in the gasifier. The producer gas is collected and conditioned to become syngas. Syngas is comprised primarily of carbon monoxide (CO), hydrogen (H_2), water (H_2O), CH_4, and tars. Most of the tars are removed during the conditioning step.

The configuration of the airflow significantly impacts the end product, the syngas. In a downdraft gasifier, the syngas energy content is lower but the producer gas is cleaner because the tars in the gas are heated and broken down as they pass through the combustion stage. In an updraft gasifier, the producer gas does not pass the combustion stage and retains its tars, which increases the energy content, but also increases the conditioning required to make syngas. For applications that require syngas conversion, distribution, or serve as inputs into an internal combustion engine generator (ICE), a downdraft gasifier is preferred because of the benefits of a cleaner producer gas. For applications where the syngas is combusted on site for the purposes of heat, an updraft gasifier is preferred for the higher heat content of the producer gas. The syngas end use determines the necessary conditioning for the producer gas.

Figure 33. Schematic of a Typical Gasification to Electricity System



For thermal-energy only gasification systems, the facilities follow the process flow diagram in Figure 33 through the first two stages. Instead of step three, “syngas conditioning,” the gas is directly burned in a burn box to run a boiler to create hot water or low or high pressure steam.

Based on TSS’s experience, the efficiency of electricity generation using gasification and internal combustion engines is approximately 18% to 26% efficient. Direct combustion units for thermal only facilities are approximately 75% to 85% efficient. The increased efficiency is due to the pre-drying of the feedstock.

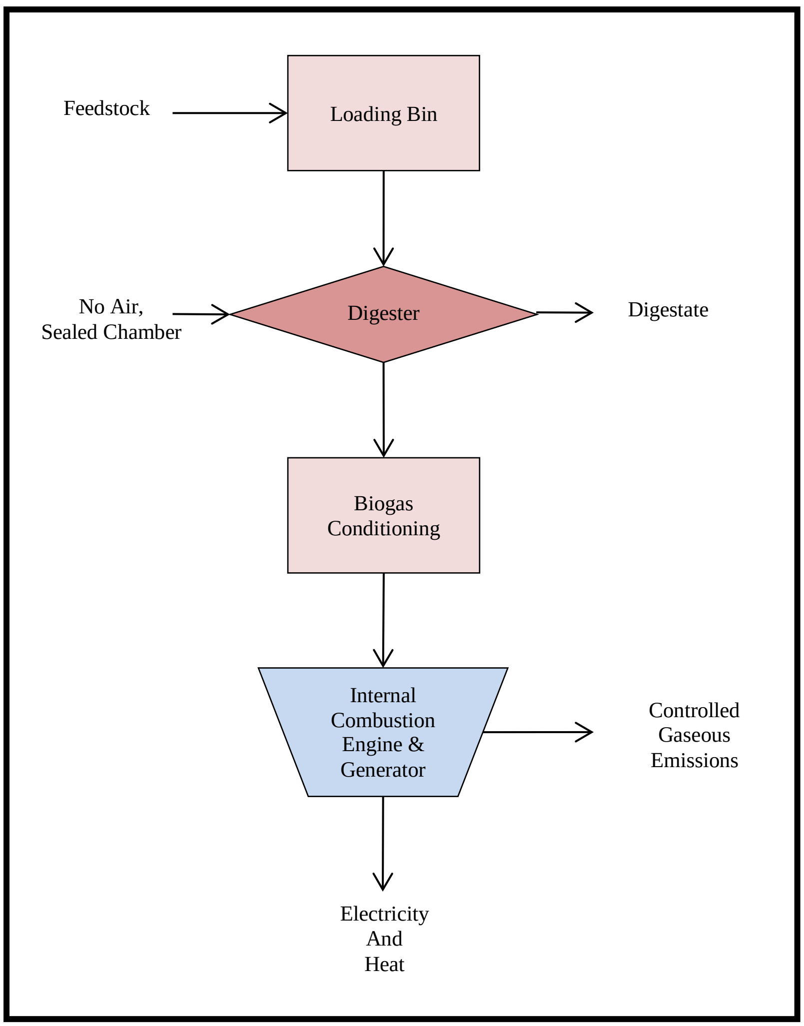
Anaerobic Digestion

AD in its most basic form is decomposition of organic matter. Modern anaerobic digestion technology carefully controls all aspects of the decomposition process including the microorganism composition, the oxygen levels, and the residence time of the feedstock. The AD chamber is controlled to maximize the creation and capture of the CH_4 in an oxygen-free environment.

Historically, AD has been utilized since the early 1930's to produce a usable gas for a variety of municipal applications including street lighting, electricity production, and natural gas substitution. Globally, the most common feedstock for anaerobic digestion is animal waste (manure) and on a limited scale, food and human waste. AD gained momentum from the demand for renewable energy because it utilizes waste streams for feedstock.

While there are many variations on AD systems, Figure 34 displays the schematic of a traditional AD to electricity system. Variations in digester types include the conveyance of feedstock, operating temperature, solid composition, and the number of stages.

Figure 34. Schematic of a Typical Anaerobic Digestion to Electricity System



AD utilizes organic waste that is processed in the digester by microorganisms that ultimately create CH_4 as a waste product. Typically there are four steps within the digestion process by the microorganisms that work in series to reach the desired product: hydrolysis, acidogenesis, acetogenesis, and methanogensis. Throughout these four stages, the organic matter is broken down and converted into largely CH_4, carbon dioxide (CO_2), H_2, and H_2O. Biogas (gaseous) and digestate (solids) are the two products from the digester. Biogas is conditioned and can be used for a variety of applications including natural gas substitution and electricity production. Digestate (solid waste generated as a byproduct) can be used as nutrient-rich compost. Approximately 95% to 99% (by mass) of the incoming feedstock is removed as digestate.

As with gasification, an anaerobic digester utilized for thermal-energy only applications is consistent with Figure 34 through the first two stages. The biogas is not conditioned, but is directly burned to run a boiler to produce hot water or low or high pressure steam.

Vendor Opportunities and Technology Sizing

There are many different technology suppliers for community-scale biomass facilities. Vendor selection requires an understanding of the on-site opportunities to best match the project objectives to the available technology. Thermal-energy only, CHP, and AD technologies have been reviewed for this section.

<u>Biomass Thermal</u>

There are many biomass thermal technologies available in the marketplace. Heat can be supplied from both gasifiers and direct combustion units. For thermal-energy only units, direct-fired combustion technologies are advantageous because they can use a wider range of feedstock types. Gasifiers typically require feedstocks with low moisture content. Direct-fired combustion technologies require less space because a feedstock dryer is not required.

The gasification technologies reviewed included Ankur, Emery Energy, and PHG Energy. These vendors were selected because of their operational experience and because they sell and install gasification units with syngas conditioning equipment. For thermal-energy only applications, syngas conditioning is not required, as the producer gas is completely combusted in a burn box which does not have the same gas conditioning requirements as an ICE. A challenge with these units comes from the fact that they are sold individually and the components required to create hot water have not been fully integrated.

The direct combustion units reviewed include Advanced Recycling Equipment, AFS Energy Systems, Chiptec, Ebner-Vyncke, Hurst, Messersmith, SolaGen, and Uniconfort. These vendors were selected because of their track record and their operational experience utilizing woody biomass feedstock.

The candidate technology vendors were asked to provide basic information for available units sized between 3.0 MMBtu per hour and 5.0 MMBtu per hour. Important considerations to differentiate these technologies include system efficiency, air emissions, water consumption and discharge, price, operational requirements, footprint, the ability to handle ground biomass feedstock, and successful projects were reviewed to select a candidate technology.

Thermal-energy only facilities are expected to utilize between 0.34 and 0.76 GT per hour or 8.16 and 18.24 GT per day for the size range appropriate for the facility. Based on TSS's experience, the price of direct-fired combustion equipment ranges from $150,000 to $500,000 and the price of gasification equipment ranges from $200,000 to $650,000.

Combined Heat and Power

For the 0.5 MW to 3.0 MW scale, there are three options for electric power generation: 1) steam turbine or steam engine, 2) ICE combined with a generator, and 3) organic rankine cycle (ORC) engine. A steam turbine or steam engine and an ORC can be used with either gasification or direct combustion. The ICE configuration is used exclusively with gasification units and requires syngas conditioning before injection into the ICE.

While steam turbines and steam engines can be utilized on a system of this scale, the economics are typically challenging because of the staffing requirements of the unit. These turbines or engines require high pressure steam to operate and therefore require a high pressure steam boiler operator on site at all times while in operation. This additional labor cost is difficult to justify due to the economies of scale unless a high pressure boiler operator is already on staff. Steam turbine or steam engine configurations are not recommended for this application since SSC does not have a high pressure boiler operator.

ICE systems use syngas from gasifiers. For these configurations, an ICE is linked to a generator and the ICE and generator set can achieve efficiencies of 35% to 40%. The primary form of available heat is recovered from the engine jacket (typically in the form of hot water between 175°F and 220°F).[65] The secondary source of process heat is the engine exhaust (hot air). Depending on the ICE selected, the heat may not be sufficient for use by the casino facilities without additional heating from the existing boilers.

ORC systems utilize a working fluid to run a refrigerant loop to run a turbine and are 15% to 20% efficient. ORC units are utilized for applications with a high thermal heat demand since an ORC's inefficient conversion process provides a significant hot water resource.

CHP systems reviewed include Emery Energy, Novo Energy, Phoenix Energy, PHG Energy, and Reliable Renewables. These vendors were selected for their experience in North America with syngas conditioning and integrating their gasifier with electrical generation systems.

The candidate technology vendors were asked to provide basic information for available units sized between 0.5 MW and 3.0 MW. Important criteria are the system efficiency, ability to utilize ground biomass feedstock, system footprint, air emissions, water consumption and discharge, capital cost, operational requirements, and anticipated cost of electricity.

CHP facilities for this size range are expected to consume between 0.61 and 4.93 GT per hour or between 14.64 and 118.32 GT per day. Based on TSS experience, for this range of CHP facility

[65] Based on engine data from Cummins, Guascor, and General Electric.

fully installed is approximately $2,000,000 to $18,000,000 with average costs of approximately $4,000 per kW to $5,000 per kW total costs.

TSS does not recommend CHP for this application due to the low price of electricity.

Anaerobic Digestion

AD systems reviewed included Clean World Partners, Zero Waste Energy, and Harvest Power. These vendors were selected because of their experience in North America with large-scale AD facilities. Each of the organizations implements a build, own, operate business model. Despite promising feedstock availability, the estimated capital costs of these facilities were between two and five times higher than for direct combustion.

To meet the heat demand indicated in the energy load forecasting section, an AD system would have to be scaled to utilize between 72 tons per day (TPD) and 150 TPD of feedstock for CHP applications. Based on TSS experience, the efficiency of electricity generation using anaerobic digestion and internal combustion engines is approximately 10% to 20% efficient. Direct-fired combustion units for thermal only facilities are approximately 50% to 70% efficient.

For thermal-energy only applications, anaerobic digestion systems are anticipated to use 0.71 to 3.28 GT per hour or 17.04 to 78.72 GT per day. For CHP applications, AD systems are estimated to utilize 1.62 to 26.85 GT per hour or 38.88 to 644.4 GT per day. Note that these feedstock consumption rates are based on the delivered moisture content of the feedstock as indicated in Table 24. To properly utilize these feedstock types, water will have to be added to increase the moisture content for animal waste and potentially for food waste.

Based on TSS experience, AD systems for CHP cost approximately $7,000 per kW to $9,000 per kW. The higher cost for AD systems is a reflection of the additional infrastructure necessary to process the high moisture content feedstock and the digestate byproduct.

Feedstock Viability

Direct-fired combustion and gasification facilities can utilize forest waste products and agricultural waste products. Direct-fired combustion systems can utilize feedstock with moisture contents up to 55%. Gasification facilities prefer feedstock with moisture content between 10% and 20%. When required, dryers may be installed as a part of feedstock handling and conveyance to reduce the moisture content of the incoming feedstock.

There are two types of AD systems, dry and wet. Dry systems utilize feedstock with moisture contents of approximately 60%. Wet systems utilize feedstock with moisture contents of approximately 80%. Food waste, animal waste, and sugar beet tailings are optimal for AD systems because of their high moisture content.

Direct-fired Combustion and Gasification

The initial findings for annual feedstock appropriate for direct-fired combustion and gasification are shown in Table 35. These feedstock types are suitable for a CHP facility as well as a thermal-energy only facility. Table 35 builds on Table 34 by including conversion efficiencies which yield the delivered cost of electricity.

Table 35. Delivered Electricity Values by Feedstock for Direct Combustion and Gasification

ENERGY SOURCE			DELIVERED PRICE OF ELECTRICITY [$/KWH]		
Electricity			0.04283		
BIOMASS TO ELECTRICITY SOURCE[66]	LOW RANGE [$/KWH$_{IN}$]	HIGH RANGE [$/KWH$_{IN}$]	SYSTEM EFFICIENCY[67]	LOW RANGE [$/KWH$_{OUT}$]	HIGH RANGE [$/KWH$_{OUT}$]
Corn Stover	0.0166	0.0227	22%	0.0755	0.1030
Wheat Straw	0.0139	0.0194	22%	0.0630	0.0882
Forest Operations	0.0083	0.0199	22%	0.0378	0.0904
Forest Product Manufacturing	0.0069	0.0096	22%	0.0313	0.0437
Urban Wood Waste	0.0054	0.0075	22%	0.0245	0.0343

Based on the findings in Table 35, the low range of the corn stover and wheat straw delivered electricity price immediately precludes these biomass sources from being competitive with avoided cost electricity rates without any other operational costs. Additionally, the woody biomass, while coming in under the avoided cost and some of the power purchase rates, is not likely to offer viable economic potential for electricity generation because the feedstock represents 57% to 88% of potential revenue stream without accounting for capital investment, operations, personnel, or maintenance. As of 2012, there are two community-scale biomass-to-electricity facilities operating with market price referents of $0.129 per kWh. Based on these findings, TSS recommends that electricity is not considered for this project with agricultural or woody biomass at this time.

Table 36 displays the delivered price of heat for direct combustion and gasification units compared to fossil-fuel and electric boilers.

[66] Conversion factor is 3412 Btu per kWh or 0.003412 MMBtu per kWh.
[67] Using the average system efficiency as identified previously in this section. Electricity numbers are from gasification efficiency estimation.

Table 36. Delivered Heat Values by Feedstock for Direct Combustion and Gasification

HEAT SOURCE	DELIVERED PRICE OF FEEDSTOCK [$/MMBTU]		SYSTEM EFFICIENCY[68]	DELIVERED PRICE OF ENERGY [$/MMBTU]	
Fuel Oil	25.34		81%	31.28	
Electricity	12.55		98%	12.81	
Propane	13.62		80%	17.03	
BIOMASS FEEDSTOCK	**LOW RANGE [$/MMBTU$_{IN}$]**	**HIGH RANGE [$/MMBTU$_{IN}$]**	**SYSTEM EFFICIENCY[69]**	**LOW RANGE [$/MMBTU$_{OUT}$]**	**HIGH RANGE [$/MMBTU$_{OUT}$]**
Corn Stover	4.87	6.64	70%	6.96	9.49
Wheat Straw	4.06	5.69	70%	5.80	8.13
Forest Operations	2.44	5.83	70%	3.49	8.33
Forest Product Manufacturing	2.02	2.82	70%	2.89	4.03
Urban Wood Waste	1.58	2.21	75%	2.11	2.95

Each feedstock type has the opportunity to provide cost savings when compared to electric or fossil-fuel boilers. While there are still savings potentials with corn stover and wheat straw, TSS recommends that the SSC focus on woody biomass because woody biomass offers the best opportunity for cost savings.

Feedstock for Anaerobic Digester

The initial findings for annual feedstock appropriate for anaerobic digestion are shown in Table 35. These feedstock types are suitable for a combined heat and power facility as well as a thermal energy facility. Table 35 builds on Table 34 by including conversion efficiencies which yield the delivered cost of heat.

As seen in Table 37, anaerobic digestion to electricity is not cost effective even before identifying the capital costs, operational costs, and maintenance costs. TSS does not recommend further study of anaerobic digestion for CHP facilities at this time.

68 Using efficiencies for the existing fuel oil and propane installations where possible.
69 Ibid.

Table 37. Delivered Electricity Values by Feedstock for Anaerobic Digestion

ENERGY SOURCE			DELIVERED PRICE OF ELECTRICITY [$/KWH]		
Electricity			0.04283		
BIOMASS TO ELECTRICITY SOURCE[70]	**LOW RANGE [$/KWH$_{IN}$]**	**HIGH RANGE [$/KWH$_{IN}$]**	**SYSTEM EFFICIENCY**[71]	**LOW RANGE [$/KWH$_{OUT}$]**	**HIGH RANGE [$/KWH$_{OUT}$]**
Sugar Beet Tailings	0.0201	0.0295	15%	0.1342	0.1968
Animal Waste	0.0068	0.0116	15%	0.0453	0.0776
Food Waste	0.0079	0.0483	15%	0.0530	0.3223

As shown in Table 38, food waste has the potential to provide energy savings by displacing electricity, propane, or fuel oil; however, it is important to recognize there are insufficient quantities of food waste available annually for year-round operations of an AD system, therefore precluding food waste as a viable feedstock source. Animal waste is the low cost leader and the only feedstock with sufficient year-round supply to feed an AD system.

Table 38. Delivered Heat Value by Feedstock for Anaerobic Digestion

HEAT SOURCE	DELIVERED PRICE OF FEEDSTOCK [$/MMBTU]		SYSTEM EFFICIENCY[72]	DELIVERED PRICE OF HEAT [$/MMBTU]	
Fuel Oil	25.34		81%	31.28	
Electricity	12.55		98%	12.81	
Propane	13.62		80%	17.03	
BIOMASS FEEDSTOCK	**LOW RANGE [$/MMBTU$_{IN}$]**	**HIGH RANGE [$/MMBTU$_{IN}$]**	**SYSTEM EFFICIENCY**[73]	**LOW RANGE [$/MMBtu$_{OUT}$]**	**HIGH RANGE [$/MMBtu$_{OUT}$]**
Sugar Beet Tailings	5.90	8.65	60%	9.83	14.42
Animal Waste	1.99	3.41	60%	3.32	5.68
Food Waste	2.33	14.17	60%	3.88	23.62

[70] Conversion factor is 3412 Btu per kWh or 0.003412 MMBtu per kWh.
[71] Using the average system efficiency as identified previously in this section. Electricity numbers are from gasification efficiency estimation.
[72] Using efficiencies for the existing fuel oil and propane installations where possible.
[73] Ibid.

Preliminary Environmental Permitting Requirements

The principal environmental permits for the proposed project are most likely to be for air quality and land use considerations. The actual environmental permitting requirements will vary depending on the site. If the project site is located on WEN-owned properties, land use and project use are governed by the WEN Zoning Code (Section 600.00 of the White Earth Environmental Code). If the proposed use is not considered suitable for the zoning designation of the property, a special condition permit may also be obtained. If the proposed project is located off tribal property, but is considered a tribal operation, it also would be under tribal jurisdiction, as no state or local government agency has jurisdiction over tribal matters.[74] As a matter of courtesy, WEN would seek comments and/or concerns from the City of Mahnomen regarding a specific project.[75]

Regarding air quality permitting, air pollution emitting projects such as biomass energy systems located on tribal land, or under tribal jurisdiction, may require air permits from the U.S. Environmental Protection Agency (EPA), as WEN does not have air quality permitting authority granted to them by the EPA. A proposed bioenergy project to be on WEN tribal property or owned/operated by a WEN tribal entity would be subject to EPA's Tribal New Source Review (TNSR) process. Given the potential small size of the proposed bioenergy project, the project would likely not be a major source of air emissions as defined by EPA (e.g., a Title V permit facility), but would be a minor source, still probably requiring a non-Title V permit from EPA. Permitting activities with EPA would be coordinated through the WEN Department of Natural Resources.

Other permits, such as building and waste water or storm water discharge that are necessary for the proposed project, would be under the jurisdiction of the WEN Zoning Office and the ordinances that office enforces.

Based on this initial assessment, priority is given to facility siting on White Earth Nation property, but is not required. Detailed environmental permitting requirements are discussed in the Environmental Permitting Plan section.

Findings

The price of feedstock relative to the existing energy alternatives suggests that the development of a CHP facility is not economically viable at this time. While the lowest cost feedstock has energy values less than the cost of SSC's average baseload power purchase rate, the feedstock alone is greater than 50% of electricity cost, leaving little room for infrastructure costs, capital costs, and O&M costs. TSS suggests that the SSC does not pursue a small-scale electrical facility at this time, as these facilities have higher capital and operations and maintenance costs relative to their electrical generation capacity than large-scale biomass facilities. The potential to

[74] Personal communication between Katherine Warren of the WEN Zoning Office and Mike Triplett, WEN Planner.
[75] Ibid.

subsidize the price of produced electricity by selling sufficient heat may be a viable solution with the high price of fuel oil and propane.

CHP facilities traditionally produce waste energy in the form of hot air and hot water. The ability to utilize the waste heat product depends on the proximity of the facility to the heat load and the demand for heat. The SSC's primary heat demand is in the form of hot water used by the boilers. While hot water can be efficiently transported over long distances, the cost of insulated and buried piping can be significant and based on TSS experience, is estimated at $50 per linear foot for insulation, Pittwrap, trenching, and backfill. Given feedstock prices and electricity cost, TSS suggests that the SSC focus on thermal-only facilities, as the additional expense for electrical generation does not offer promising returns.

For thermal-energy only applications, there is potential for several of the feedstock varieties to provide cost savings by displacing fuel oil or propane. With sufficient feedstock available for woody biomass or AD applications, TSS suggests that the SSC focus on woody biomass feedstock because of the lower capital investment than in an AD system.

Vendor Selection Process

Eight direct combustion vendors and three gasifier vendors were contacted as candidates for the thermal energy project at the SSC. Several technology vendors referred TSS to local distributors to better serve the region needs in Minnesota. The technology vendors were:

Direct Combustion

- Advanced Recycling Equipment
- AFS Energy Systems
- Chiptec
- Ebner-Vyncke
- Hurst
- Messersmith
- SolaGen
- Uniconfort

Gasification

- Ankur
- Emery Energy
- PHG Energy

Each vendor responded with basic information for their spectrum of products including system efficiency, air emissions, water consumption and discharge, indicative price, operational requirements, footprint, the ability to handle processed (ground or chipped) biomass feedstock, and successful projects.

TSS narrowed the candidates by utilizing coarse filters such as experience in the field, ability to handle processed woody biomass, footprint, and through discussions with individuals familiar with completed projects.

Finalist Selection

The top two finalists were sent a formal RFP which outlined the project requirements and requested detailed response regarding the proposed system configuration and operations, resource demands including footprint, water consumption, and electrical demands, anticipated environmental impacts, qualifications of the manufacturer, capital and operational cost estimates, and personnel requirements. The RFP can be found in Appendix 5.

Proposals were received from both technology vendors and were evaluated by TSS, the WEN staff, and the SSC Management. Proposals were both submitted on time and were shared with the White Earth Nation staff.

To organize and streamline the selection process, the WEN developed a list of selection criteria and prioritized them based on the goals and mission of the WEN and SSC. TSS worked with WEN staff to recommend the stronger candidate for each criterion based on the proposal. Based on the outcome of the proposal analysis, the final technology vendor was selected. A memorandum of understanding was developed between WEN and the selected technology vendor for continued development of the project.

PRELIMINARY SYSTEM DESIGN

Preliminary system design provides the client with the information necessary to begin the design and engineering phase with a qualified local engineering firm. The technology vendor should be expected to deliver and commission the biomass unit, provide detailed installation drawings for local contractors, and train facility staff to operate the equipment. In addition to the vendor's responsibilities, a new biomass thermal unit must be located on proper structural footings, integrated into the old system, and may require alterations to existing buildings or infrastructure. Each of these tasks is site specific and requires design from a qualified local engineering firm familiar with the site and the area. The preliminary system design provides a qualified engineering firm with appropriate descriptions of the project and the biomass system.

Site Identification

TSS worked with the WEN Development Planner, SSC Facilities Manager, and SSC Master Electrician to survey potential locations for siting a biomass-fired facility. Potential sites were selected based on initial environmental review, available locations, the SSC Master Plan, and findings from the previous sections. Potential sites were located close to the SSC facilities. Figure 35 displays an aerial view of the SSC and indicates the five sites for review. While a CHP facility is not recommended currently for the SSC, each of the identified sites has been reviewed for both thermal-energy only or CHP facilities.

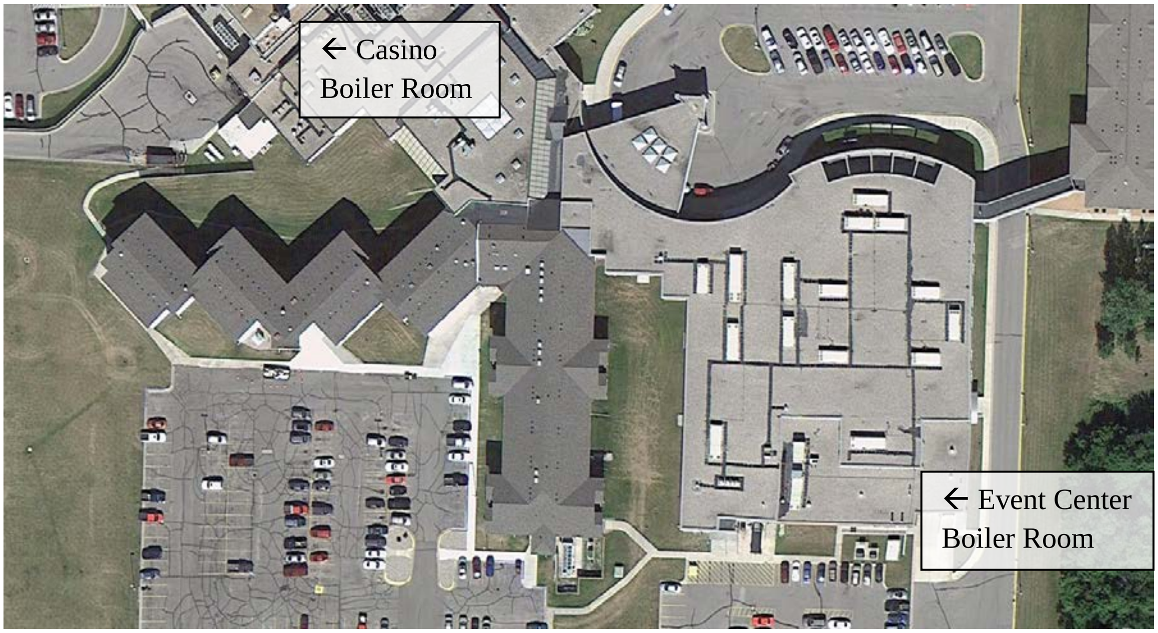
Figure 35. Aerial View of Shooting Star Casino Facilities

Source: Google Maps

Existing Boiler Rooms

The boiler room sites are located at the south end of the event center and the southwest end of the casino. The existing boilers rooms are indicated by number one (1) on Figure 35 and shown in detail in Figure 36.

Figure 36. Map of Existing Boiler Rooms



Source: Google Maps

The Casino Boiler Room houses two Superior Boilers and four PVI hot water heaters that use #2 fuel oil and service the casino facility and adjoining hotel. The Event Center Boiler Room houses two Burnham Industrial Boilers and two PVI water heaters that use propane and service the event center and the hotel.

Site Advantages

By utilizing an existing boiler room, the installation of a biomass unit would have access to the existing infrastructure used to heat the buildings. The location of the boiler rooms allows for feedstock delivery along existing truck routes around the casino facilities. This location provides savings for the project by reducing the necessary infrastructure costs, minimizing energy loss from transmission, and increasing system performance and reliability because of the proximity of staff.

The Casino Boiler Room was built as a part of the original casino complex. Since the SSC opened, additions have been made that block direct access from the boiler room to the outside. The room currently blocking the outside access is the surveillance room for the casino floor, which can be relocated. If the Casino Boiler Room is found to be the selected site, the surveillance room and the current boiler room would have to be combined.

Without renovations, the Event Center Boiler Room is not sufficiently sized for a biomass unit. However, since the room has an exterior wall, the modification of the room necessary for a biomass unit would not be cost prohibitive.

Site Challenges

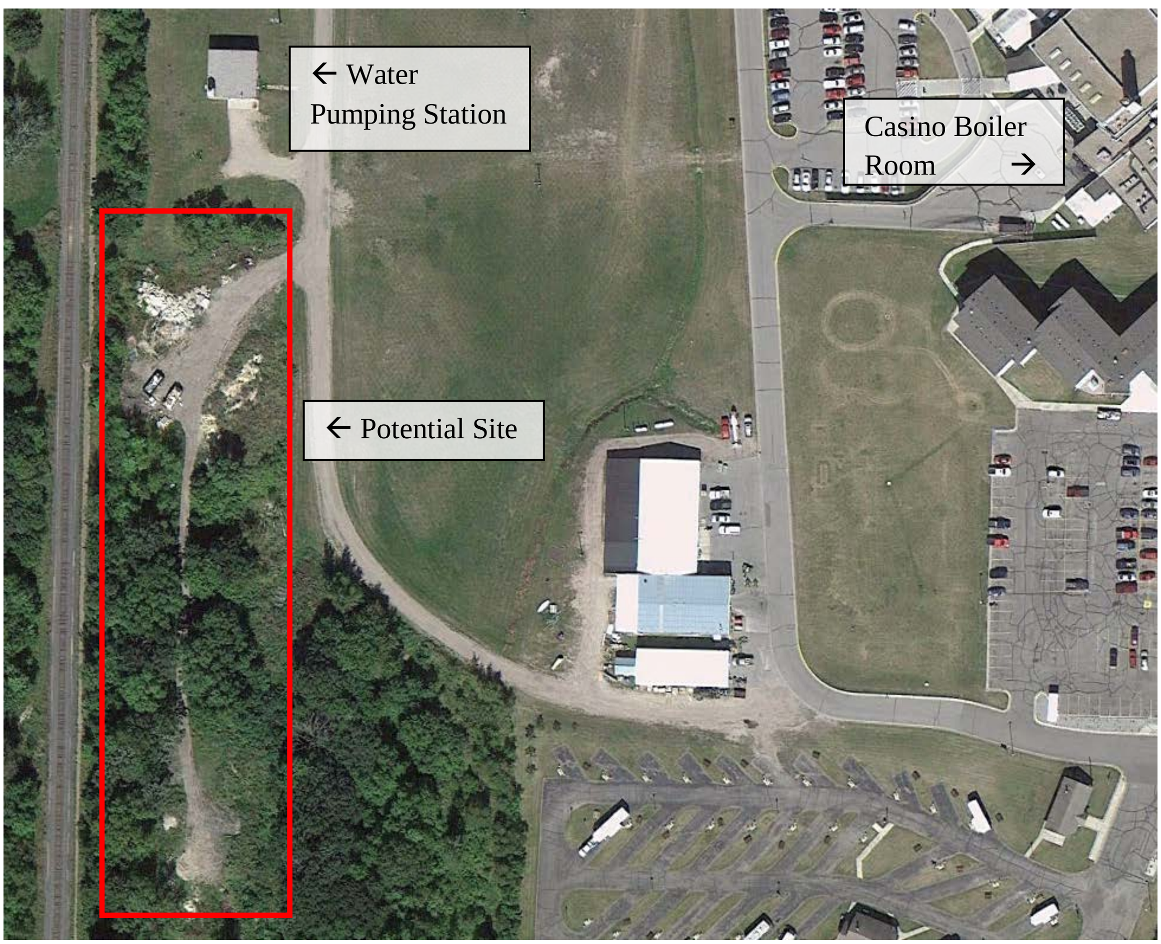
The most significant challenge for this site would be storage and space. Since the boiler rooms are located inside the existing complex, there are constraints on feedstock storage. Feedstock would have to be stored in a site away from the casino and event center and delivered on a just-in-time basis.

While some modifications can be made to the size of the rooms, the boiler room sites are limited and may not be suitable for the larger biomass systems under consideration.

South of the Water Pumping Station

The Water Pumping Station site is located on the western edge of the casino property south of the City of Mahnomen Water Pumping Station. The site is indicated as number two (2) on Figure 35 and is shown in detail in Figure 37.

Figure 37. Water Pumping Station Site



Source: Google Maps

The site is currently utilized for some outdoor storage with limited landscape management. Originally the site was a residence, and the SSC has since purchased the vacant property from the previous owners.

Site Advantages

The Water Pumping Station site is approximately 2 acres in size, enough space for the larger footprints and feedstock storage spaces considered for this project. The site is concealed from the main facilities and with the prevailing winds from the northwest, air emissions will not affect the casino facilities. The site is elevated above the flood plain and owned by the WEN.

To access the site, truck traffic would turn onto an access road (the dirt road in Figure 37 to the east of the site) and be able to loop around and return to South Casino Road. This traffic pattern would be consistent with the other deliveries currently accessing the casino.

Site Challenges

The most important challenge for this site is interconnection to energy loads. The site is located approximately 1,000 feet from the Casino Boiler Room and the Event Center Boiler Room. The infrastructure to transport heat underground will increase the capital cost of the facility. Electricity distribution will not be a challenge, as an overhead distribution line reaches the Water Pumping Station and the main transformer for the casino is only 1,500 feet to the north.

<u>South of the Aggregate Industries Batch Plant</u>

The Aggregate Industries batch plant site is located to the southeast of the batch plant on the east side of Highway 59. The site is shown on Figure 35 as number three (3) and in detail in Figure 38.

Figure 38. Aggregate Industries Batch Plant Site

Source: Google Maps

The site is leased by the SSC and is used as a lot for vehicles in need of repair, storage of snow removal equipment, and in the winter is used for snow removal storage.

Site Advantages

While the site borders the Wild Rice River, it is elevated and is above the flood plain. The site is approximately 2.5 acres in size and has enough space for the larger footprints and feedstock storage spaces considered for this project. The site is located so that the prevailing winds direct air emissions away from the casino. Lastly, the site's location off Highway 59 allows for easy truck access to the site.

Site Challenges

Challenges for this site are ownership, soils, and interconnection to the current hot water system. Since the site is not owned by the WEN, this increases the risk and cost of the project. The WEN performed soil samples for this site and found metal contaminates in the subsurface area which may pose geotechnical problems for foundations. These conditions may require significant site remediation before project construction may begin.

This site is located approximately 1,500 feet from the Event Center Boiler Room and 1,750 feet from the Casino Boiler Room. In addition to the challenges from the piping distance, underground piping must go under Highway 59, which will increase the costs for distribution infrastructure.

North of the Jefferson Avenue Overflow Lot

The Jefferson Avenue site is on the north side of the Jefferson Avenue across from the SSC's overflow parking lot. The site is indicated by number four (4) in Figure 35 and is shown in detail in Figure 39.

Figure 39. Jefferson Avenue Site

Source: Google Maps

The site is currently an unoccupied residence for sale. The lot is within the city limits and is zoned industrial.

Site Advantages

The site is above the flood plain and located on Jefferson Avenue within close proximity to Highway 59. While the current use of the property is residential, the site is zoned industrial and is surrounded by commercial property. The site is across the street from the transformer that feeds the Shooting Star facilities and is where the OTP meter is located.

Jefferson Avenue is a major road off of Highway 59 that is utilized by truck traffic for the casino. Additional truck traffic for a biomass facility would be consistent with the road's current traffic pattern.

Site Challenges

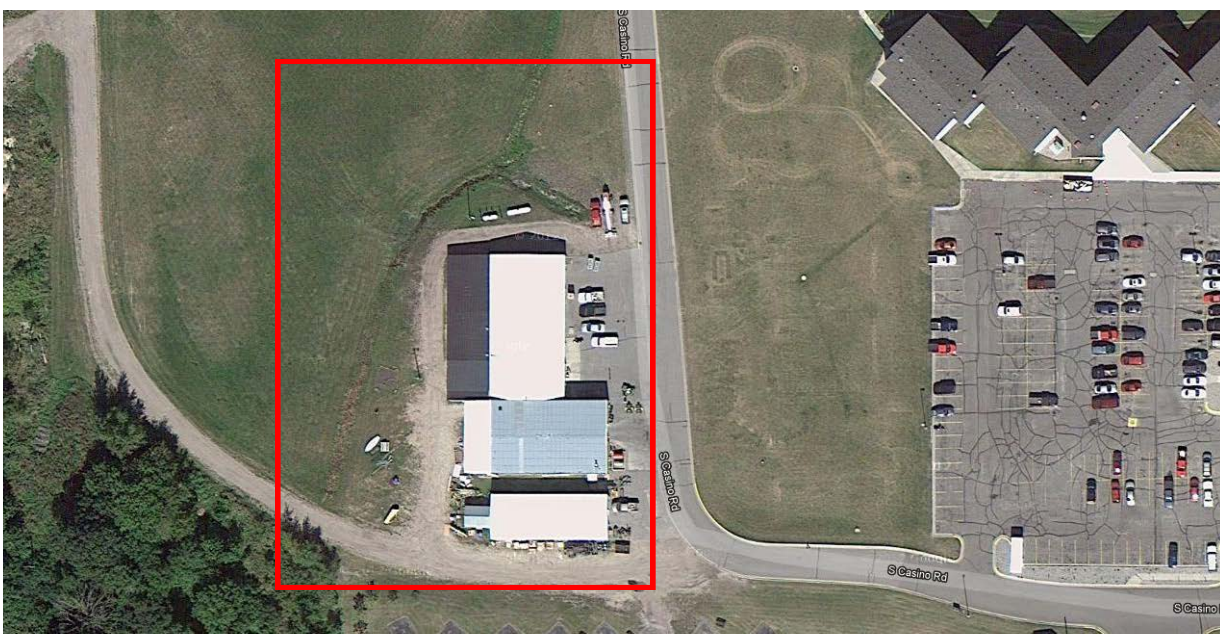
The Jefferson Avenue site is relatively small at approximately 1 acre. This area will limit the size of the project because of the requirements for feedstock storage. This site represents the most visible location and is closest to residential neighborhoods. The proximity could provide pushback from the community. However, the school has not had any negative press from their biomass thermal unit. At this site, the prevailing winds will blow towards the casino. Proper engineering of the air emissions should avoid contamination of the air from the odors of the facility's air emissions (smell of a grill) or feedstock storage (smell of mulch). This parcel is not large enough for an AD system.

The site is approximately 1,500 feet from the Casino Boiler Room and 2,000 feet from the Event Center Boiler Room. With the current infrastructure between the site and the boiler rooms, the piping for heat will be a significant additional cost.

<u>Mechanical and Maintenance Building Site</u>

The Mechanical and Maintenance Building site allows for two potential layouts, to the north or to the west of the current mechanical and maintenance buildings. The site is along the southwest portion of South Casino Road and is indicated by number five (5) in Figure 35; it is shown in detail in Figure 40.

Figure 40. Mechanical and Maintenance Building Site



Source: Google Maps

The buildings neighboring the site are actively used for maintenance and storage of equipment. The land surrounding the buildings is currently unused but is part of several potential development plans.

Site Advantages

The site is located along South Casino Road, which is currently used for deliveries to the casino. Only minor road improvements would be required for feedstock delivery. The site is adjacent to the mechanical and maintenance buildings facilitating access operations and maintenance of a biomass unit from qualified staff. The electricity distribution loop surrounding the casino passes this proposed site, and the substation is approximately 1,500 feet to the north. The prevailing winds direct any emissions away from the RV park and the hotel and casino.

Site Challenges

The site is located approximately 500 feet from the Casino Boiler Room and the Event Center Boiler Room. Significant buried piping runs would be required to move thermal energy from the biomass facility to the casino, hotel, and event center. Depending on the size of the biomass facility, the site may conflict with proposed development plans.

Site Selection

Site 1 was selected by the WEN and the SSC as the preferred location for the biomass thermal-energy only unit. The preferred location is in the existing room neighboring, and southwest of, the Casino Boiler Room. The SSC currently has their surveillance equipment and staff housed in this room. This site was selected because of its proximity to the Casino Boiler Room and Event Center Boiler Room, the existing road infrastructure, and the minimal impacts on development plans.

Prior to final selection, site assumptions were reviewed with E.A.P.C., the engineers of the existing casino and event center. Assumptions specifically addressed were:

- What are the major challenges of raising the roof of the proposed room 3 to 4 feet (if necessary)?
- Are there any physical constraints associated with relocating or elevating the air conditioning units currently located on grade outside of the existing boiler room?
- What are the major challenges associated with piping hot water from the Casino Boiler Room to the Event Center Boiler Room?
- Are there other potentially more feasible opportunities to pipe hot water from the casino room to the boiler room?
- What are the potential options for removing the existing fossil fuel boilers?
- Are there potential obstacles with siting a below grade wood chip storage area outside of the Casino Boiler Room due to the orientation of the fuel oil tank?

Representatives from E.A.P.C. were Derrick Lunski, Senior Mechanical Engineer, and Wayne Dietrich, Architect. Responses to the inquiry indicate that there were no structural fatal flaws for the preferred site since the proposed equipment does not exceed the existing roof height.

Project Layout

The selection of site 1 requires a custom project layout to accommodate the biomass equipment in an existing building. Comprehensive site layout includes civil, mechanical, electrical, and architectural work. To maximize the efficiency of design, TSS recommends that the selected vendor take the lead role in the mechanical design and site layout followed by an experienced local engineering firm for the architectural, civil, electrical, and integration work. This work structure allows the selected vendor the opportunity to optimize the equipment configuration with the constraints of the project site. The selected vendor can utilize their familiarity with their product and biomass feedstock conveyance to efficiently design the custom layout. With the completion of the layout, a local engineering firm can be utilized to upgrade the existing facility, integrate the system, and manage the project construction. A local engineering firm can utilize their expertise of design and construction work in the area and potentially past experience working with the SSC.

Potential Layout

The selected vendor in coordination with TSS developed a process flow diagram and potential site layout for site 1, as identified in the site selection section. The process flow diagram is shown in Figure 41

Figure 41. Process Flow Diagram for a Biomass Boiler

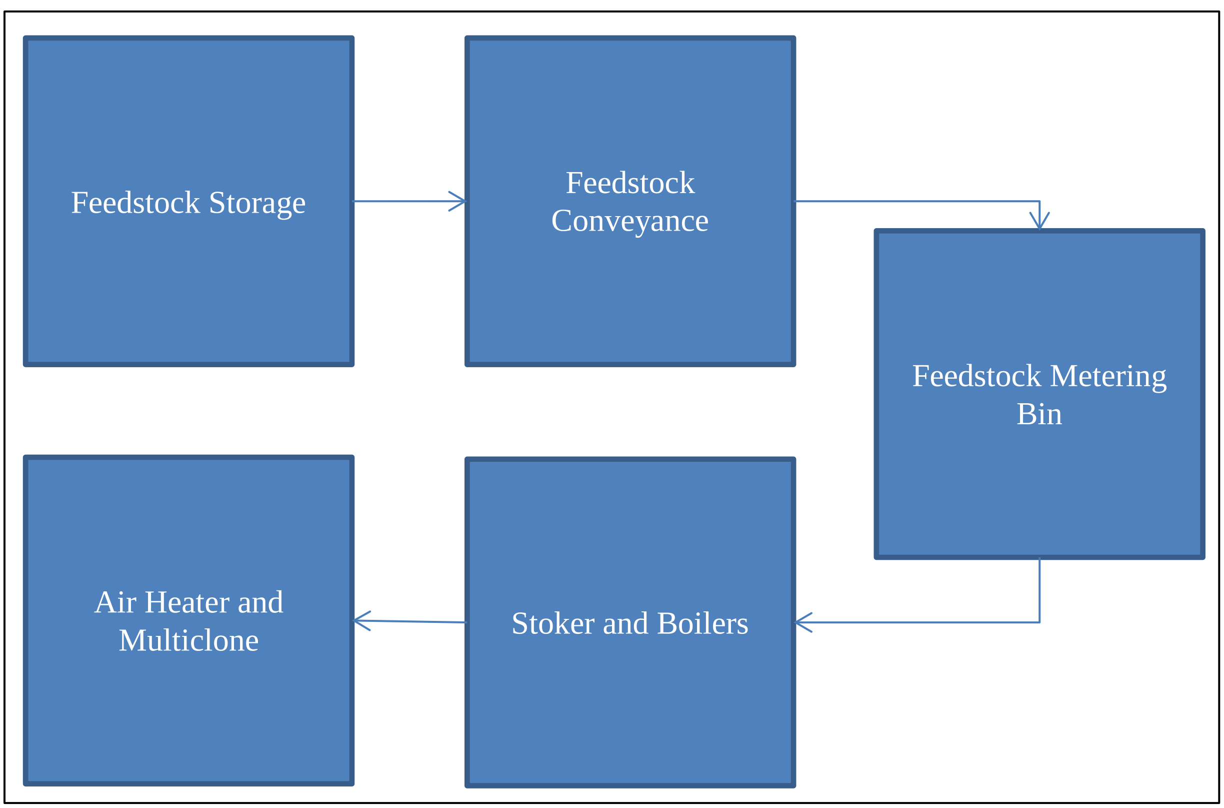


Figure 41 shows the steps as feedstock moves from storage through to emissions controls. The steps in the process are detailed below.

1. Feedstock Storage: The first step in the process is to collect the feedstock from the storage area. A screw augur or walking floor collects the biomass from where the delivery trucks dump the feedstock. The screw augur or walking floor deposits the feedstock in Step 2.
2. Feedstock Conveyance: The screw augur or walking floor conveyance system moves the feedstock form the storage facility to the fuel metering bin, located inside the boiler room. During this transportation process, “overs” may be sorted and discarded. Overs are wood chips that are larger than the acceptable feedstock size. The length of these belts is dependent on the location of the boiler and the feedstock delivery.
3. Feedstock Metering Bin: The fuel metering bin is a location used to hold wood chips before they are introduced into the combustion chamber. The feedstock metering bin provides a buffer so that the boiler may continue to run if the feedstock delivery system is temporarily jammed. The feedstock metering bin allows for more precise responsiveness to feedstock intake demands.
4. Stoker and Boiler: The stoker and boiler is the location where the feedstock is combusted to heat water in the boiler. The stoker is under the boiler allowing heat to rise and heat the water in the boiler. This is the step that produces the desired heat for the casino and hotel. A byproduct of this step is ash which is removed from the system with the ash rake, the ash collection conveyor, the incline ash screw, the ash drum, and lastly a human operator.
5. Air Heater and Multiclone: The air heater and multiclone are used to reduce the emissions from the stoker and boiler unit. Air is moved through these systems with fans and is ultimately expelled to the atmosphere through a connection to the existing system.

Based on the size and dimensions of site 1, the selected technology vendor produced a preliminary sketch to show a potential layout of the unit. This sketch was done based on CAD files of the original casino construction (which does not include the planned location for the biomass boiler), aerial photography, and photography from inside the buildings. The preliminary sketch is not included in this report due to the proprietary nature of the drawing.

Findings

A preferred site was selected for the biomass boiler. This site, represented in Figure 35 as site 1, was selected for its proximity to the existing heat demand, the existence of road infrastructure for feedstock delivery, and the existing building’s structural components. Based on initial measurements of the existing room, the selected technology vendor has confirmed the ability to install their unit in a room of that size.

As the project moves forward, the detailed CAD files for the proposed site should be located or rendered for the final site layout. With this information, the selected technology vendor can finalize their layout and work with an appropriate engineering firm to finalize the construction plans.

CAPITAL COSTS, ANNUAL COSTS, OPERATIONS AND MAINTENANCE COSTS

Introduction

A complete project budget includes anticipated costs associated with every aspect of the project. The largest components of the budget are the equipment capital costs, installation costs, operations cost, and maintenance costs. The proposals received by the WEN from the selected technology vendors represent a portion of the overall costs associated with a project. Additional cost considerations include architectural, civil, electrical, and mechanic design and engineering of the proposed site, construction and installation, permitting, project management, and operations and maintenance. TSS Consultants worked with the selected finalist technology vendors and references (provided by the technology vendors) during and after the selection process to estimate the costs for the entire project.

Interviews with Facility Managers

Interviews with vendor-supplied references were conducted to discuss their operational experience with the vendor's equipment. The interview process was conducted before the final selection of the preferred technology vendor and the responses were utilized to develop a selection criteria matrix (in the section). The questions for the references were tailored to illuminate portions of the vendor proposals. The interview questions were broken into six distinct categories: background; company track record; equipment track record; feedstock flexibility; O&M; and other. The questions were reviewed by WEN staff and are listed below.

<u>Questions for References</u>

Background

1. *What size and model are you operating?*
2. *How often is the unit operated?*
3. *Is the unit integrated into an existing system or is it stand alone? If integrated, any challenges with the integration?*

Company Track Record

4. *Can you describe the experience working with [vendor] as a product vendor and installer?*
5. *Were they responsive and flexible during the design, construction, and commissioning phases?*
6. *Were there any surprises during the installation process?*
7. *Did your project stay on budget? And if not, what were the challenges?*
8. *Can you help put into perspective the relative costs associated with the work outside of [vendor's] proposal? Architectural, Civil, Structural, Construction work, etc.?*
9. *Has [vendor] stood behind their warranties (if applicable)?*
10. *How has your relationship been with [vendor]?*

Equipment Track Record

11. *Are you satisfied with the performance of the [vendor] Boiler? Why or why not?*
12. *Were there any surprises or challenges with unit during commissioning?*
13. *What major maintenance, if any, have you experienced? Was it planned major maintenance?*
14. *Has the unit run as efficiently as expected?*

Feedstock Flexibility

15. *What feedstock are you utilizing?*
16. *Have there been any challenges conveying or burning the feedstock?*
17. *Lessons learned through any trials with alternative feedstocks?*

O&M and Ease of Maintenance

18. *Can you describe typical daily operations and maintenance?*
19. *Can you advise us on the time that should be budgeted for O&M?*
20. *What is a ballpark annual budget for O&M?*

Other

21. *What would be your top recommendations to a first-time woody biomass boiler operator?*

Reference Interview Findings

Two distinct themes were consistent across the interviews conducted with both vendor references: operator training and conveyance systems/fuel specifications. All interviewees stressed the importance of thorough operator training. The consensus was that woody biomass thermal boilers are not inherently challenging to operate, but they are substantially different than fossil fuel boilers and therefore require training to instruct operators to anticipate their specific operational procedures. The most common challenge utilizing biomass feedstock was with the feedstock conveyance system. Once the biomass was in the combustion chamber, the programmable logic controls (PLC) can control the combustion without operator input.

Feedstock conveyance was noted as the single most significant potential operational issue facing biomass boiler operators. There were two important factors noted on conveyance: experience is important for custom designs and adherence to feedstock specifications is critical. Each conveyance system and boiler is customized to operate for a specific type of feedstock. Fuel flexibility is an option when designing systems but must be expressly clear during the initial designs and will likely increase the cost of the facility, as larger components and additional mechanical screens may be necessary for varied feedstocks. When supplied with the specified feedstock, there have been few reported problems with the conveyance systems, but this requires diligence by the operator when receiving feedstock and preemptive measures when feedstock quality (typically sizing issues) does not meet standards.

Upfront Costs

Upfront costs include all of the costs associated with the development of the project that are not recurring operations and maintenance calls. This includes capital cost of equipment, design and engineering, infrastructure upgrades, installation and integration, permitting, and commissioning and training. For this analysis, costs are broken into capital costs which include the equipment, equipment design and engineering, commissioning, and training. These are the costs outlined in the RFP that was distributed to the vendors. The other category is non-capital costs. These costs include the infrastructure upgrades, the site design and engineering, the equipment installation and integration, and permitting.

Capital Cost

Based on discussions with the selected technology vendor, the estimated capital cost for the equipment necessary for a 5 MMBtu per hour direct combustion unit with storage and conveyance equipment is $512,161. This includes the design and engineering work to design the storage and conveyance system.

In addition to the capital cost, findings in Task 7 suggest that the use of a high efficiency multiclone may be the preferred technology to reduce the level of particulate matter emissions. TSS suggests a budget line estimate of $60,610 for multiclone equipment and installation. The addition of a high efficiency multiclone brings the total to $572,771.

Non-Capital Cost

Based on reference interviews, the biomass boiler and its components represent approximately 40% to 50% of the total, all-in project costs. Based on published data[76] from the Fuels for Schools and Beyond program, the biomass boiler and its components represent approximately 27% to 65% of the total, all-in project costs for systems of comparable size. Note that comparably sized projects in the Fuels for Schools and Beyond study did not have high efficiency multiclone equipment; therefore, to use the data for overall project costs, TSS will use the budget line for capital cost less the additional cost of a multiclone. Given the wide range of costs associated with complete product installation, the average of 46% will be used, which is consistent with the interviews with the vendors.[77] Using this estimation, total costs less the equipment costs are expected to be $601,232 with the historical data and interview data ranging from between $275,779 and $1,384,732. The cumulative total costs are expected to be $1,174,003 with a range between $848,550 and $1,957,503.

[76] http://www.fuelsforschools.info/pdf/Final_Report_Biomass_Boiler_Market_Assessment.pdf
[77] Note the vendors operating significantly larger or smaller systems were not included in this estimate as their installation was not of comparable magnitude.

Biomass Feedstock Cost

The biomass combustor and boiler is expected to operate with 68.4% efficiency based on the selected technology vendor's simulations utilizing biomass feedstock with 40% moisture content. Efficiency will increase with dryer feedstock as dictated by its incoming moisture content or with the addition of a preheater along the feedstock conveyance system for feedstock pre-drying. However, pre-drying feedstock is a significant additional cost. Traditionally, pre-drying is not economical when the sole production benefit is increased efficiency. Depending on the local emissions regulations, a pre-dryer could be the most cost effective emissions control device, as the increased efficiency decreases some of the critical air emissions pollutants.

At full capacity, the biomass unit is expected to utilize 860.5 dry pounds of feedstock per hour. This equates to 1,721 wet pounds of feedstock per hour at 50% moisture content and 1,076 wet pounds per hour for feedstock with 19.07% moisture content (the range of moisture content is based on the Hazen laboratory results of potential biomass feedstock sources). Feedstock pricing may range from $20 per GT to $55 per GT. The average blend of moisture content and pricing is 37.15% moisture content and $33.90 per GT (see Table 29). With an anticipated capacity factor of 0.7 as indicated in Figure 18 (Energy Load Forecasting section), the estimated annual cost of feedstock is $142,304 with a high and low range of $290,211 per year and $65,199 per year respectively.

Annual Costs

Personnel

Based on interviews and discussions with the selected technology vendor, daily operational tasks should be anticipated to take approximately one hour each day. This includes daily inspections and tasks and annual inspections as indicated below:

Daily Inspections and Tasks

- Clean boiler room
- Inspect fuel inventory and water chemicals
- Brief walkthrough boiler room
- Attentive to odd sounds, smells, vibrations
- Ash disposal
- Manual cleaning of grates or retort
- Blow down steam boilers and compressors

Annual Inspections and Tasks

- Thorough inspection
- Clean internals of complete system including brushing of heat exchanger surfaces
- Align and tension belt drives
- Check gearbox lubrication levels
- Lubricate bearings
- Inspect seals

- Inspect refractory
- Inspect wearing surfaces such as conveyor internals

Depending on the feedstock delivery schedule and the feedstock size uniformity, the expected personnel time could decrease to approximately 0.5 hours per day on average. With high variability in feedstock and storage in a location that is not directly adjacent to the boiler room, personnel time requirements could increase to as much as 2.5 hours per day. Annual personnel costs are calculated based on pay rates of $20 per hour with 30% increase for benefits, totaling $26 per hour. Annual expected costs are based on the assumption that maintenance staff is required to perform additional work for a biomass boiler when compared to O&M of the existing fossil-fuel boilers. The estimated labor costs are $9,490 per year ($28 per day at 365 days) with a high and low range of $23,725 per year and $4,745 per year respectively.

Maintenance

Maintenance costs include both annual maintenance and amortized major maintenance that is periodic and not expected each year. Based on interviews and discussions with the selected technology vendor, the anticipated maintenance costs are $4,500 per year (including periodic maintenance costs). This includes replacement valves, oil, and replacement motors. The high and low range for maintenance costs are $10,000 per year and $3,000 per year respectively.

Costs Summary

Upfront costs including capital cost of equipment, design and engineering, infrastructure upgrades, installation and integration, permitting, commissioning, and training are summarized in Table 39.

Table 39. Upfront Cost Summary

	UPFRONT COSTS		
	LOW RANG	ANTICIPATED COSTS	HIGH RANGE
Capital Costs	N/A	$572.771	N/A
Non-Capital Costs	$275,779	$601,232	$1,384,732
Total	**$848,550**	**$1,174,003**	**$1,957,503**

Annual costs such as feedstock costs and O&M costs are summarized in Table 40.

Table 40. Annual Cost Summary

	ANNUAL COSTS		
	LOW RANG	ANTICIPATED COSTS	HIGH RANGE
Feedstock Costs	$65,199	$89,547	$239,884
Operations Costs	$4,745	$9,490	$23,725
Maintenance Costs	$3,000	$4,500	$10,000
Total	**$72,944**	**$103,537**	**$273,609**

Findings

While there is significant variability in operations and annual costs, these expenses can be managed by comprehensive project development plans. The largest unknown for upfront costs comes from the civil, mechanical, and electrical work required to prepare the site for the biomass unit. Working with the technology vendor and providing sufficient background documentation will allow the technology vendor to develop a site layout in conjunction with a local engineering firm to minimize the costs of project development.

Additionally, for feedstock purchase, finding a supplier that can provide cost effective, low moisture content feedstock will be critical for reducing operations costs. Low moisture content feedstock can significantly reduce the annual fuel usage and expenditures. Based on the findings in Task 3, there are sufficient forest product manufacturing residues in the area to sufficiently provide the biomass boiler with low moisture content, relatively low price feedstock. It is important to negotiate long term feedstock contracts to decrease cost variability. With higher quality feedstock, there will also be lower maintenance and labor costs.

To optimize the expenses, upfront time detailing the systems layout and design, and negotiating long-term feedstock contracts is important to keep costs and expenses manageable throughout the lifetime of the project.

ENVIRONMENTAL PERMIT REVIEW

Introduction

This task is designed to examine the potential environmental impacts of installing and operating the proposed woody biomass thermal unit. The unit tentatively selected is a 5.0 MMBtu per hour system. The biomass thermal-energy only system is proposed to supplant the current distillate fuel oil and propane fired hot water systems used by the SSC and its appurtenant facilities and buildings.

A location within the SSC property has been identified (see the Preliminary System Design section). Out of several sites within the casino property, a site directly adjacent to the existing fuel oil fired boiler room was selected by the WEN and the SSC as the preferred location. The location was originally built for a planned expansion of the boiler system to add electric boilers and is located directly adjacent to, and southwest of, the Casino Boiler Room. The SSC currently has security surveillance equipment and staff housed in this room and does not have plans to install the electric boilers. This site was primarily selected because of its proximity to the casino's existing fuel oil boilers. In addition, a woody biomass feedstock storage area could be located directly outside of this room, affording relatively easy access to wood feedstock delivery vehicles.

Environmental Impact Analysis and Permitting Needs

In reviewing the potential environmental impacts of installing the biomass thermal unit in the preferred site location, the following environmental issue areas are considered:

- Land Use;
- Air Quality;
- Transportation;
- Noise;
- Odor;
- Hazardous Materials;
- Public Health and Safety;
- Solid Waste;
- Water Supply/Wastewater Discharge;
- Cultural Resources; and
- Aesthetics (Visual Quality).

The following is a summary of the potential environmental impacts, or lack of impacts. If a potential impact is deemed significant, mitigation measures that would eliminate or reduce the impact will be discussed. It should be noted that the proposed biomass thermal unit is of a size that is routinely installed in schools, hospitals, and other public facilities.

Land Use

Land use regulation on WEN lands such as those that include the SSC is administered by the WEN Zoning Office, which utilizes its Zoning Regulation Manual. Specifically, Title 6: Land Use and Zoning of the Manual dictates the intent and implementation of the tribal land use controls. Section 2 of Title 6 lays out the intent of the land use and zoning regulations as the following:

(a) To discourage land development in areas that pose a potential threat to the Reservation's resources, areas of cultural significance and to public health;

(b) To reduce the potential for conflict between new residential development and the resource-based economy of the White Earth Reservation; to provide for the orderly use of the Reservation's lands;

(c) To lessen congestion in public right-of-ways, secure safety from fire, panic and other dangers;

(d) To provide adequate light and air, facilitating the adequate provisions of water, sewerage and other public requirements;

(e) To conserve the value of natural resources and encourage the most appropriate use of land;

(f) To preserve and enhance the economic values and use of agricultural land;

(g) To preserve and enhance the quality of surface waters;

(h) To conserve the economic and natural environmental values of shorelands;

(i) To provide for the wise use of water and related land resources of the Reservation; and

(j) To accommodate the communication needs of residents and businesses while protecting the public health, safety, and general welfare.

The biomass thermal project to be installed and operated within the confines of the casino does not appear to violate or impact any of the stated land use and zoning intentions.

The WEN Zoning Office has indicated that the SSC property is zoned Mixed Use Floating (M).[78] The Mixed Use Floating zoning classification, according to Section 9 of Title 6, Chapter V is to provide for "maximum freedom in the development of commercial, industrial and public facilities, when such use does not adversely affect the natural and/or built environment." However, the Mixed Use Floating zoning district does have a caveat for energy production

[78] Personal communication with Katherine Warren, Manager, White Earth Nation Zoning Office, July 24, 2012.

facilities and/or equipment. Such a facility may require the need to apply to the WEN Planning Commission for a Special Condition Permit (a.k.a. Conditional Use Permit).

Regarding the need for a Special Condition Permit for the proposed biomass thermal unit, discussion was held between TSS and the WEN Zoning Office manager. It was determined that the proposed biomass thermal unit did not really meet the definition of an energy production facility. An energy production facility is generally considered by the Zoning Office to be a facility generating electricity for offsite transmission. The Zoning Office representative further opined that a Special Condition Permit was not required for the proposed biomass thermal unit.[79]

As the proposed biomass thermal unit meets the current zoning of the site and there is no need for a Special Condition Permit, no land use impacts occur due to the project.

Air Quality

As the proposed biomass thermal system involves the combustion of biomass under controlled conditions, there is nonetheless emissions of criteria air pollutants such as carbon monoxide (CO), nitrogen oxides (NO_x), sulfur oxides (SO_x), particulate matter (PM, PM_{10} and $PM_{2.5}$)[80], volatile organic compounds (VOC) and lead (Pb), which may impact air quality. These emissions may exceed certain threshold levels of significance and require an air quality permit, which may have operating conditions and emission control devices that lower the potential emissions to below the significant level.

Air quality for the WEN is overseen by the Environmental Affairs Office of the WEN Natural Resources Department. However, air quality permitting in Indian Country is conducted by the EPA unless the tribal entity has secured delegated air permitting authority from the EPA. The WEN has not secured air permitting authority from the EPA, and TSS was directed to communicate with the EPA Region 5 air permitting office in regards to estimated emissions from the proposed biomass thermal unit and potential permitting.[81]

The EPA has within the last two years established additional regulatory procedures for air emission sources in Indian Country. On July 1, 2011, the EPA promulgated a final Federal Implementation Plan (FIP) that implements New Source Review (NSR) preconstruction air pollution control requirements within Indian Country. The FIP, which is titled, "Review of New Sources and Modifications in Indian Country," includes two NSR rules for the protection of air quality in Indian Country (a.k.a. Tribal NSR or TNSR). One of those rules, known as the Minor TNSR Rule, applies to new air emission sources or modifications of existing air emission sources with the potential to emit equal to or more than the minor NSR thresholds but less than the major NSR thresholds, generally 100 to 250 TPY. As it was easily determined that the proposed biomass thermal would not meet the major NSR thresholds, this task did examine the

[79] Personal communication with Katherine Warren, Manager, White Earth Nation Zoning Office, September 6, 2012
[80] PM_{10} and $PM_{2.5}$ refer to particulate matter smaller than 10 microns and 2.5 microns respectively. At these sizes particulate matter can become lodged in the lungs and cause short-term and long-term human health effects
[81] Personal communication with Monica Hedstrom, Environmental Manager, White Earth Nation Environmental Affairs Office, September 6, 2012

potential for the proposed unit to possibly exceed the minor TNSR thresholds and thus require permitting by EPA Region 5.

Minor TNSR thresholds for the pertinent air pollutants are listed in Table 41.

Table 41. Tribal NSR Thresholds

CRITERIA POLLUTANTS	CO	NO_x	SO_x	PM	PM_{10}	$PM_{2.5}$	VOC	Pb
TNSR Thresholds [TPY]	10	10	10	10	5	3	5	0.1

Using air pollutant emission factors supplied by the selected technology vendor and emission factors from EPA's "Emissions Factors & AP-42, *Compilation of Air Pollutant Emissions Factors*," (AP-42) various scenarios using different size thermal equipment and operational capacity were conducted to understand the effect on the potential need for EPA permitting. The scenarios and calculations follow.

Scenario 1:

Biomass Thermal Unit Size: 5.0 MMBtu per hour
System Efficiency: 70%
Capacity Factor: 100%

Table 42 uses these inputs to determine which TNSR thresholds are exceeded.

Table 42. Scenario 1 Emission Estimates

	CO	NO_x	SO_x	PM	PM_{10}	$PM_{2.5}$	VOC	Pb
Emissions Factors [lbs/MMBtu]	0.6	0.059	0.047	0.257	0.168	0.147	0.017	0.000048
Projected Annual Emissions [TPY]	18.77	1.85	1.47	8.04	5.26	4.6	.53	.0015
Exceed TNSR Threshold?	Yes	No	No	No	Yes	Yes	No	No

Scenario 2:

Biomass Thermal Unit Size: 5 MMBtu per hour
System Efficiency: 70%
Capacity Factor: 70%

Table 43 uses these inputs to determine which TNSR thresholds are exceeded.

Table 43. Scenario 2 Emission Estimates

	CO	NO_x	SO_x	PM	PM_{10}	$PM_{2.5}$	VOC	Pb
Emissions Factors [lbs/MMBtu]	0.6	0.059	0.047	0.257	0.168	0.147	0.017	0.000048
Projected Annual Emissions [TPY]	13.14	1.29	1.03	5.63	3.68	3.22	0.37	.0011
Exceed TNSR Threshold?	Yes	No	No	No	No	Yes	No	No

Scenario 3:

Biomass Thermal Unit Size: 3.65 MMBtu per hour
System Efficiency: 70%
Capacity Factor: 70%

Table 44 uses these inputs to determine which TNSR thresholds are exceeded.

Table 44. Scenario 3 Emission Estimates

	CO	NO_x	SO_x	PM	PM_{10}	$PM_{2.5}$	VOC	Pb
Emissions Factors [lbs/MMBtu]	0.6	0.059	0.047	0.257	0.168	0.147	0.017	0.000048
Projected Annual Emissions [TPY]	9.59	0.94	0.75	4.11	2.69	2.35	0.27	.0008
Exceed TNSR Threshold?	No	No	No	No	No	No	No	No

These three scenarios were discussed with air permitting staff at EPA Region 5 to determine what the permitting process might be for each scenario.[82]

In Scenario 1, CO, PM_{10}, and $PM_{2.5}$ exceed the TNSR threshold and would thus be subject to the EPA permitting process. One of the facets of the TNSR is that air pollutants that exceed the TNSR threshold must undergo Best Available Control Technology (BACT) analysis. TSS's experience with BACT analysis on other biomass combustion projects, and general and specific knowledge of various control technologies, would indicate that a high efficiency multi-clone or fabric baghouse would be BACT for the $PM_{2.5}$. A 2010 study regarding emission controls for

[82] Various personal communications with Michael Langman, US EPA Region 5, December 2012

small biomass boilers,[83] cost estimates range from an average of $63,000 for high-efficiency multiclones to $110,000 for cyclone/baghouse combinations. Either control system should easily reduce the PM_{10} and $PM_{2.5}$ to below the TNSR thresholds and greatly reduce the PM, PM_{10} and $PM_{2.5}$ in general. BACT for CO can be as simple as good combustion practices during the operation of the thermal unit, specifically, maintaining the proper air to fuel ratio.

Scenario 1 sets the capacity factor at 100%, (8,760 hours per year of operation). In many air permitting processes, the permitting agency generally requires that an emission unit's production of air pollutant be calculated at a 100% capacity. Discussion with EPA Region 5 indicated that does not have to be the case, so Scenario 2 has a capacity (run time) of 70%, which is likely the high end of the range that the thermal unit will be operating over a one-year period. In Scenario 2, CO is exceeded as well as $PM_{2.5}$, so the same BACT analysis discussion in Scenario 1 applies to Scenario 2.

Scenario 3 is the attempt to determine at what thermal unit scale is a TNSR permit not even needed from the EPA. Calculations indicate that a thermal unit sized at 3.65 MMBtu per hour would not exceed any of the TNSR permitting thresholds. Discussions with EPA regarding Scenario 3 confirmed that if the thresholds are not met using reasonable emission factors, then a TNSR permit is not needed.

As noted in the two scenarios, PM_{10} and $PM_{2.5}$ are over, or still relatively near, the permitting threshold. More importantly, there is general concern by health experts that local emissions of PM_{10} and $PM_{2.5}$ should be controlled when possible. PM_{10} pose a health concern because they can be inhaled into and accumulate in the respiratory system. $PM_{2.5}$ are referred to as "fine" particles and are believed to pose the greatest health risks. Because of their small size (approximately 1/30th the average width of a human hair), fine particles can lodge deeply into the lungs. Given that there are periods of atmospheric inversion at the Casino site where any plume from the biomass combustion system might allow near ground concentration of particulate matter, add-on PM emissions controls are considered prudent.

Both PM_{10} and $PM_{2.5}$ can be greatly reduced from their already very low concentration with the addition of high-efficiency multiclone. A high-efficiency multiclone is recommended over a fabric filter baghouse or an electrostatic precipitator (ESP). Given the higher moisture content of the biomass fuel proposed for use at the Casino, there is a risk of fire hazard for the baghouse that significantly lowers the desirability of use. The higher moisture fuel will also cause maintenance issues with a baghouse. An ESP, while a highly efficient device, is prohibitively expensive for this relatively small-scale application. High-efficiency multiclones do not have these drawbacks and in addition to being an efficient control device, it is also a cost effective one which does not significantly impact the cost savings the Casino will realize in the switch to biomass (see Task 9 for financial analysis). A high-efficiency multiclone device will reduce the PM_{10} by 99% and the $PM_{2.5}$ by 86%. It will efficiently remove any PM_{10} by 99%+ as well.

[83] Tables 12 & 13 from "Emission Controls for Small Wood-Fired Boilers", May 2010, U.S. Forest Service, Western Forestry Leadership Coalition

Table 45 displays the actual reductions (pre-controlled PM emissions figures are taken from Table 43).

Table 45. Particulate Matter Emissions Control

	PM	**PM_{10}**	**$PM_{2.5}$**
Pre-Controlled Annual Emissions [TPY]	5.63	3.68	3.22
Emission Control Efficiency[84]	99%	99%	86%
Projected Controlled Annual Emissions [TPY]	0.4749	0.4554	0.45

Federal Air Rules for Reservations (FARR) registration will be necessary for the biomass boiler regarding any of the scenarios. Annual FARR registration is required to any air emission source that exceeds 2 TPY of criteria pollutants such as those listed in Table 41. The proposed biomass boiler exceeds this 2 TPY. FARR registration requires an estimate of annual emissions (which could be calculated using hours of run time).

It should be noted that the existing fossil fuel-fired boiler system at the Casino may likely exceed the threshold for FARR registration. Current FARR implementation rules require that the Casino must submit FARR registration beginning March 31, 2013. The Casino has been sent a letter from EPA (dated November 29, 2012) that provides additional information regarding the FARR registration process.

<u>Transportation</u>

The proposed biomass thermal unit will require delivery of wood chips by large chip vans. A 5 MMBtu per hour biomass thermal unit will require approximately 12.5 TPD of wood chips. This calculates to approximately one-half of a chip van truck per day on an annual average, or one truck every two days.

The Minnesota Department of Transportation (MNDOT) has vehicular traffic counts for State Highway 59, which passes in front of the SSC and will provide the main access road to the facility. In 2010, the Annual Average Daily Traffic (AADT) count was 4,400 vehicles per day along Highway 59 in the vicinity of the casino. This AADT takes into account all vehicles. The MNDOT further refined this vehicular count to parse out heavy commercial vehicles (such as chip van trucks). The heavy commercial AADT for the same stretch of Highway 59 amounts to 315 heavy-commercial vehicles per day on an annual average.

If an average of 315 heavy-duty vehicles pass by the casino daily, and one truck every other day is a chip van truck delivering wood feedstock to the proposed thermal unit is added to the total,

[84] PM control efficiencies from Tables 12 and 13, “Emission Controls for Small Wood-Fired Boilers”, May 2010, U.S. Forest Service, Western Forestry Leadership Coalition.

these deliveries would increase the heavy duty traffic by 0.16%. This represents a relatively minor increase which would not significantly impact the traffic in the area.

Odor

The storage of wood chips on site may release some odors generally associated with cut wood or lumber, as most of the feedstock will come from sawmill residuals. There may also be a faint odor of wood burning in the room where the biomass thermal unit will be located. However, this should not be dissimilar to odors that may emanate from the existing oil-fired boilers. Air exhaust fans could be placed in the ceiling of the room housing the biomass thermal-energy only unit to dissipate any odors associated with the unit.

Noise

Noise from the biomass thermal-energy only unit will be very similar in sound and volume as currently associated with the fuel oil boilers.

Hazardous Materials

The proposed biomass system will use small amounts of lube and gear oil similar to the existing lube and gear oil that are held for maintenance of the Casino's vehicle equipment. These petroleum-based materials will be handled and stored in a similar manner as well.

The existing oil-fired boilers currently depend on a 30,000-gallon underground fuel oil storage tank located in the truck delivery area outside of the boiler room. Although the existing oil-fired boilers will be kept in place for the foreseeable future as emergency backup and potential heat assist on extremely cold days, the use of fuel oil at the site will be greatly diminished. That means considerably less fuel oil will be brought to the site and left in underground storage. This, in turn, greatly diminishes the possibility of a fuel oil spill during transfer of fuel oil from a delivery truck to the underground storage tank. This also reduces commercial truck traffic in the vicinity of the casino.

Public Health and Safety

The proposed biomass thermal unit comes equipped with a water-based internal fire control system in the unlikely event of an uncontrolled fire within the system.

Solid Waste

The only potential solid waste to be generated by the biomass thermal unit will be the ash from the combusted wood. Forest-sourced or lumber mill-sourced biomass feedstock generally has a low ash content that is typically less than 3% and as low as 1% (by weight). As the proposed biomass thermal unit will use up to 880 bone dry pounds per hour, or 2,700 BDT per year, this equates to between 27 and 81 TPY of ash. Although this could be stockpiled and disposed of in a nearby landfill, the casino could have it utilized in the same manner that ash from the biomass boiler system at the Mahnomen School, which is to give it away as a soil amendment for local farms.

Water Supply/Wastewater Discharge

The proposed biomass thermal unit, which will use a closed loop water heat exchange system, requires very little makeup water and emits no wastewater.

Cultural Resources

The proposed biomass thermal unit is located in an existing building with no excavation to occur under the existing floor. Cultural resources will not be impacted.

Aesthetics (Visual Quality)

The proposed thermal energy facility would be incorporated into part of an already existing section of the casino structure. The feedstock storage would be located behind the proposed biomass boiler room and would have limited visible presence to some hotel rooms, but there is other non-storage equipment in that area already visible. Visual quality should be minimally impacted.

Permitting Schedule

As determined previously, the only environmental permit that may be required is an EPA Tribal Minor New Source Review permit. EPA Region 5 indicated that process time for a TNSR would require four to six months from the date that an application is submitted. A TNSR permit application could be filed with EPA within 30 days of TSS receiving permission to proceed.

ECONOMIC FEASIBILITY ANALYSIS

Introduction

This economic analysis provides predicted financial outcomes for the biomass thermal-energy project. This financial analysis is based on the specifications of the technology proposed by the selected technology vendor, interviews with equipment operators and project developers, and TSS's knowledge and experience in the biomass thermal-energy sector. The economic analysis serves the purpose of assessing a proposed project's financial viability by forecasting cash flows to develop internal rates of returns and simple payback period indicators and to identify important system criteria based on the project's sensitivity to deviations from the assumed values.

Key Project Variables and Assumptions

A financial pro forma was developed to project annual cash flows throughout the life of the project. Table 46 lists the variables used for the baseline calculation of the project's economic indicators. The values in Table 46 are derived from previous Tasks.

Table 46. Pro Forma Assumptions and Key Variables

KEY VARIABLES		BASELINE VALUES	SOURCE*
UPFRONT COSTS	Equipment	$475,771	See Task 5
	Engineering and Construction	$526,232	See Task 6
	Feedstock Storage and Conveyance	$97,000	See Task 5
	Permits	$10,000	See Task 7
	Project Management	$65,000	TSS
	Subtotal	***$1,174,003***	
FEEDSTOCK CHARACTERISTICS	Feedstock Cost	$33.90/GT	See Task 3
	Ash Production	1%	See Task 3
	Moisture Content	37.15%	See Task 3
	High Heating Value	8,500 Btu/ dry lb.	See Task 3
SYSTEM VARIABLES	Capacity Factor	70%	See Task 4
	System Efficiency	68.36%	See Task 5
	Unit Size	5 MMBtu/hr	See Task 2
O&M COSTS	Time Requirement	1 hr/day	See Task 6
	Wage (Inclusive of all Benefits)	$26/hr	See Task 6
	Subtotal	***$9,490/yr***	
	Annual Maintenance	$4,500/yr	See Task 6
AVOIDED COSTS	Fuel Oil Price	$3.515/gal	See Task 2
	Propane Price	$1.260/gal	See Task 2
	Ratio of Fuel Oil to Propane	2.57:1 (72% Fuel Oil, 28% Propane)	See Task 2
ESCALATION	Feedstock Escalation	2%	TSS
	Fuel Oil Escalation	1%	TSS
	Propane Escalation	1%	TSS
FINANCING	Debt to Equity Ratio	75%	TSS
	Debt Term	5 years	TSS
	Interest Rate	5%	TSS

The financial analysis is based on a five-year loan period. This financial strategy was suggested by the WEN staff as it balances the Casino's annual cash flow with low-interest payments.

One-Dimensional Sensitivities

One-dimensional sensitivities were used to illustrate how changes in one variable may affect the financial outlook for a project. For this analysis, eight metrics have been identified as having the potential to alter the economic viability of the project. Using data identified in previous sections of this report, a low and high range for each metric has been identified and is shown in Table 47 through Table 54 along with the results of the sensitivity analysis. The metrics reviewed are as follows:

- Upfront Costs
- Feedstock Price
- Feedstock Price Escalation
- Capacity Factor
- Fossil Fuel Price
- Fossil Fuel Price Escalation
- Labor Costs
- Maintenance Costs

The financial analysis results are shown as the internal rate of return (IRR) and the simple payback period (SPP). IRR focuses on cash flow over the project's lifetime and SPP provides a basic comparison of the annual revenue compared to the upfront costs. The source data for the low and high ranges in Table 47 through Table 54 can be found with the baseline information identified in Table 46.

Table 47. Upfront Costs

	LOW RANGE	BASELINE	HIGH RANGE
UPFRONT COSTS [$]	848,550	1,174,003	1,957,503
IRR [%]	253.0	164.5	75.6
SPP [YEARS]	1.25	1.72	2.87

Table 48. Feedstock Price

	LOW RANGE	BASELINE	HIGH RANGE
FEEDSTOCK PRICES [$/GT]	20.00	33.90	55.00
MOISTURE CONTENT [%]	19.07	37.15	50.0
ANNUAL COST [$/YEAR]	65,199	142,304	290,211
IRR [%]	190.7	164.5	114.7
SPP [YEARS]	1.55	1.72	2.20

Table 49. Feedstock Price Escalation

	LOW RANGE	BASELINE	HIGH RANGE
FEEDSTOCK PRICE ESCALATION [%/YEAR]	0.5	2	3.5
IRR [%]	165.0	164.5	164.1
SPP [YEARS]	1.72	1.72	1.72

Table 50. Capacity Factor

	LOW RANGE	BASELINE	HIGH RANGE
CAPACITY FACTOR [%]	50	70	80
IRR [%]	98.7	164.5	198.1
SPP [YEARS]	2.43	1.72	1.50

Table 51. Fossil Fuel Price

	LOW RANGE	BASELINE	HIGH RANGE
FUEL OIL PRICE [$/GAL]	1.332	3.515	4.042
PROPANE PRICE [$/GAL]	0.899	1.260	1.720
IRR [%]	25.4	164.5	217.9
SPP [YEARS]	5.59	1.72	1.40

Table 52. Fossil Fuel Price Escalation

	LOW RANGE	BASELINE	HIGH RANGE
FUEL OIL PRICE ESCALATION [%/YEAR]	-1	1	3
PROPANE PRICE ESCALATION [%/YEAR]	-1	1	3
IRR [%]	161.0	164.5	167.9
SPP [YEARS]	1.72	1.72	1.72

Table 53. Labor Costs

	LOW RANGE	BASELINE	HIGH RANGE
LABOR COSTS [$/YEAR]	4,745	9,490	23,725
IRR [%]	166.1	164.5	159.7
SPP [YEARS]	1.71	1.72	1.76

Table 54. Maintenance Costs

	LOW RANGE	BASELINE	HIGH RANGE
MAINTENANCE COSTS [$/YEAR]	3,000	4,500	10,000
IRR [%]	165.0	164.5	162.7
SPP [YEARS]	1.72	1.72	1.74

Findings

Table 47 through Table 54 show the results of the financial analysis and the project's sensitivity to changing parameters. The impact of each metric on the overall economic feasibility of the project can be seen by the range of IRR and SPP. Note that for the metrics of inflation, SPP does not change; this is because the SPP only compares the total cost of the project to the cash flow of year one excluding debt payment and depreciation. For each metric, the IRR and SPP results are displayed in Figure 42 and Figure 43 respectively.

The four most sensitive metrics are upfront costs, fossil fuel pricing, capacity factor and feedstock pricing. Changes in these variables from low to high range costs significantly affect the projected IRR and SPP for the project. The remaining factors, feedstock price escalation, fossil fuel price escalation, labor costs, and maintenance costs, did not have a significant effect on the end result.

Moving forward, the paired combinations of each of the four most significant metrics are analyzed in the two-dimensional analysis.

Figure 42. One-Dimensional Financial Analysis Results: Internal Rate of Return

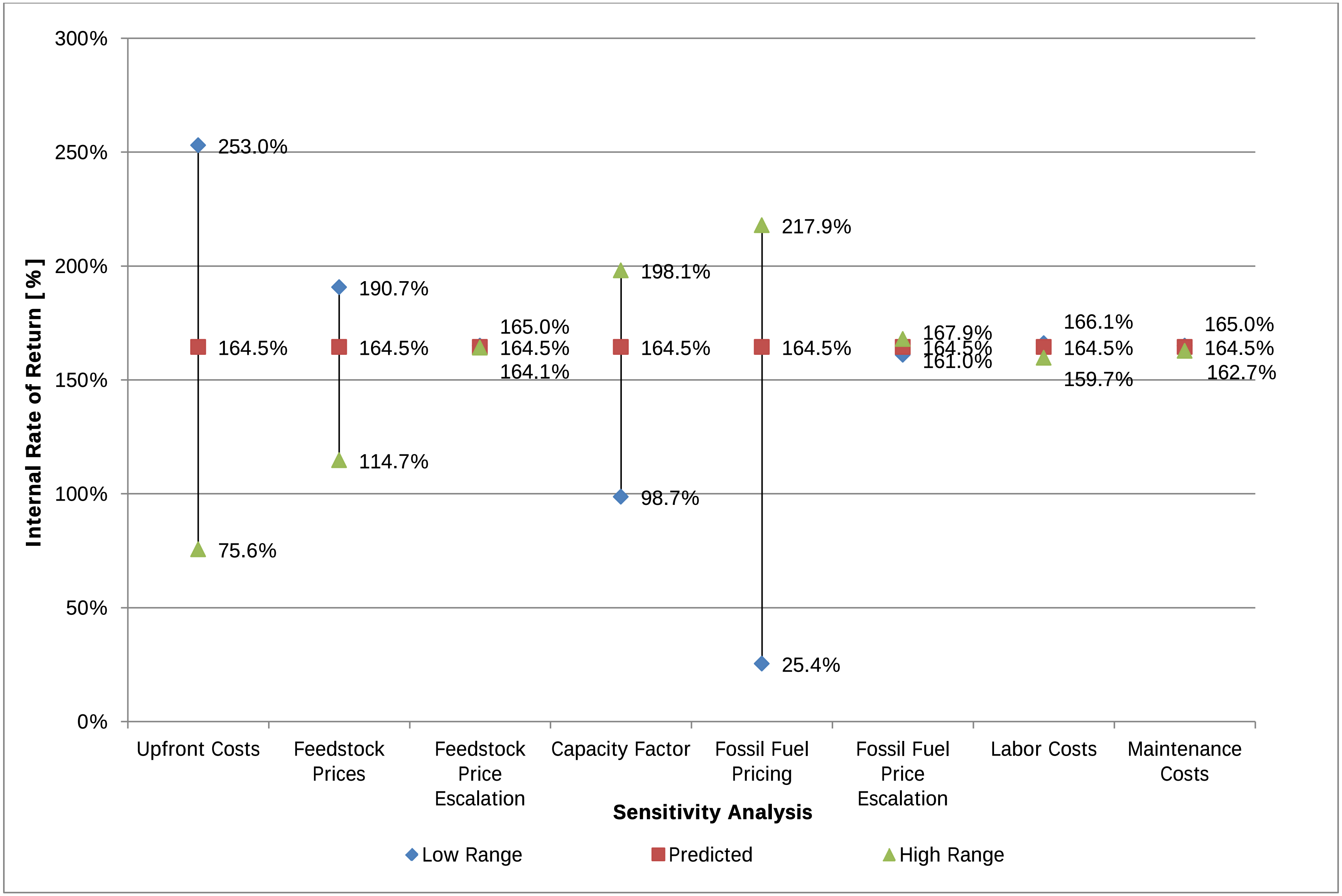
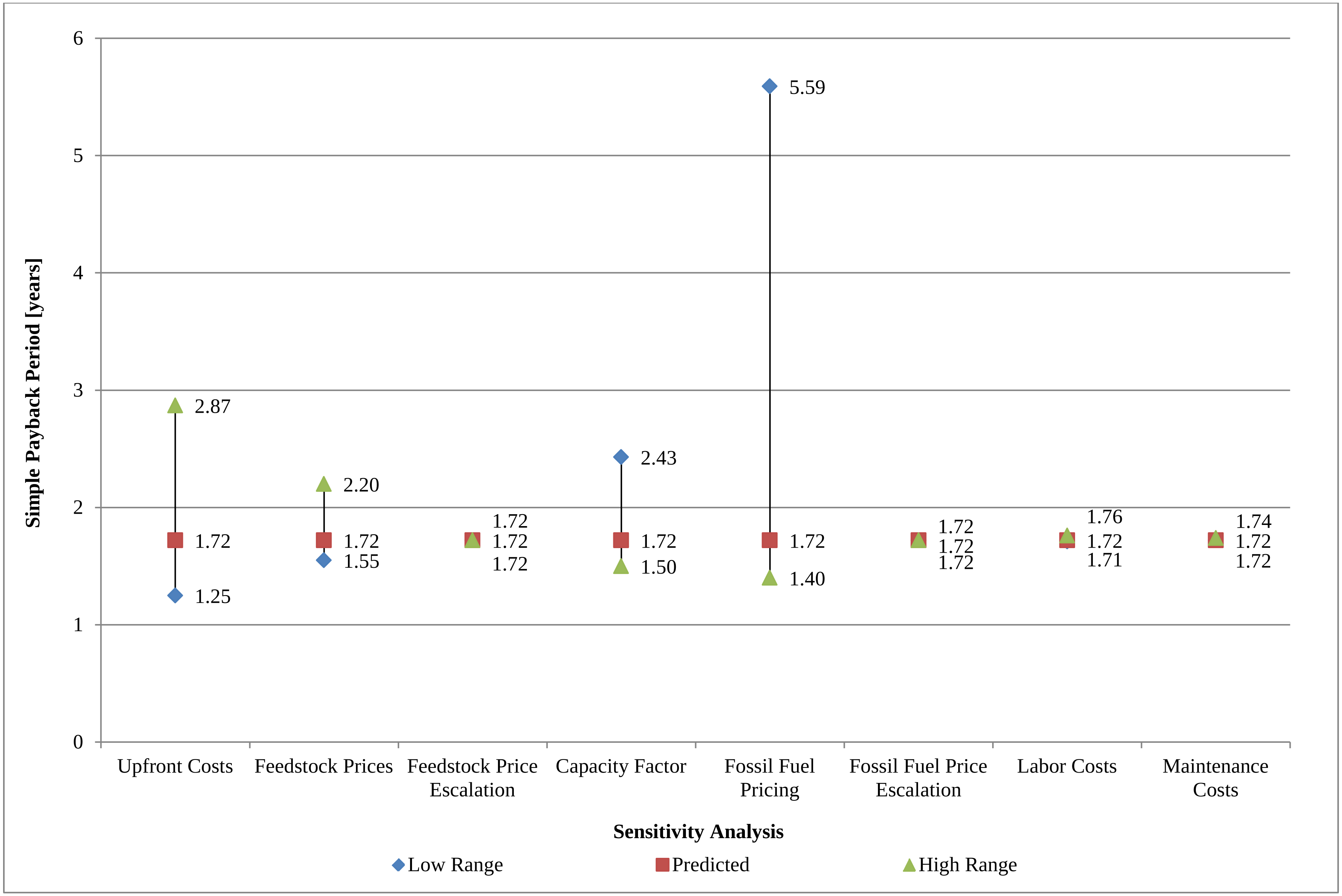


Figure 43. One-Dimensional Financial Analysis Results: Simple Payback Period



Two-Dimensional Sensitivities

Two-dimensional sensitivities will be used to illustrate how changes in two variables at the same time may affect an outcome. For this economic analysis, two-dimensional sensitivity runs will be performed on each combination of the four most significant factors as identified after the one-dimensional analysis. These scenarios are:

- Upfront Cost and Fossil Fuel Price
- Upfront Cost and Feedstock Price
- Upfront Cost and Capacity Factor
- Feedstock Price and Fossil Fuel Price
- Feedstock Price and Capacity Factor
- Capacity Factor and Fossil Fuel Price

Table 55 through Table 60 show the results of the two-dimensional analysis. Each metric is organized so that the best case scenario appears in the top left corner of the table and the worst case scenario appears in the bottom right corner of the table. The outcomes are shaded based on the following:

Red: < 20% IRR or > 5 years SPP
Yellow: IRR between 20% and 40% or SPP between 2 and 5 years
Green: > 40% IRR and < 2 years SPP

The cells are shaded based on the most conservative category in which the results fall. Note that the IRR terms are percentages equivalent to the time value of money appropriate to yield a zero net present value of the cash flow. SPP is in units of years that would be required to recuperate the capital investment with the revenue stream from year one.

Table 55. Upfront Cost vs. Fossil Fuel Price

			UPFRONT COSTS [$]		
			LOW RANGE	**BASELINE**	**HIGH RANGE**
			848,550	1,174,003	1,957,503
FOSSIL FUEL PRICE [$/GAL]	**HIGH RANGE**	Fuel Oil: 4.042 Propane: 1.720	IRR: 327.3% SPP: 1.01	IRR: 217.9% SPP: 1.40	IRR: 105.4% SPP: 2.33
	BASELINE	Fuel Oil: 3.515 Propane: 1.260	IRR: 2.53% SPP: 1.25	IRR: 164.5% SPP: 1.72	IRR: 75.6% SPP: 2.87
	LOW RANGE	Fuel Oil: 1.332 Propane: 0.899	IRR: 42.4% SPP: 4.04	IRR: 25.4% SPP: 5.59	IRR: 12.1% SPP: 9.32

Table 56. Upfront Cost vs. Feedstock Price

			UPFRONT COSTS [$]		
			LOW RANGE	BASELINE	HIGH RANGE
			848,550	1,174,003	1,957,503
FEEDSTOCK PRICE [$/GT]	HIGH RANGE	Price: 20.00 MC: 19.07%	IRR: 289.5% SPP: 1.12	IRR: 190.7% SPP: 1.55	IRR: 90.1% SPP: 2.58
	BASELINE	Price: 33.90 MC: 37.15%	IRR: 2.53% SPP: 1.25	IRR: 164.5% SPP: 1.72	IRR: 75.6% SPP: 2.87
	LOW RANGE	Price: 55.00 MC: 50.0%	IRR: 183.2% SPP: 1.59	IRR: 114.7% SPP: 2.20	IRR: 49.9% SPP: 3.67

Table 57. Upfront Cost vs. Capacity Factor

			UPFRONT COSTS [$]		
			LOW RANGE	BASELINE	HIGH RANGE
			848,550	1,174,003	1,957,503
CAPACITY FACTOR [%]	HIGH RANGE	80	IRR: 299.8% SPP: 1.09	IRR: 198.1% SPP: 1.50	IRR: 94.1% SPP: 2.51
	BASELINE	70	IRR: 2.53% SPP: 1.25	IRR: 164.5% SPP: 1.72	IRR: 75.6% SPP: 2.87
	LOW RANGE	50	IRR: 160.0% SPP: 1.76	IRR: 98.7% SPP: 2.96	IRR: 42.8% SPP: 4.06

Table 58. Feedstock Price vs. Fossil Fuel Price

			FEEDSTOCK PRICE [$/GT]		
			LOW RANGE	BASELINE	HIGH RANGE
			Price: 20.00 MC: 19.07%	Price: 33.90 MC: 37.15%	Price: 55.00 MC: 50.0%
FOSSIL FUEL PRICE [$/GAL]	HIGH RANGE	Fuel Oil: 4.042 Propane: 1.720	IRR: 244.2% SPP: 1.28	IRR: 217.9% SPP: 1.40	IRR: 167.5% SPP: 1.70
	BASELINE	Fuel Oil: 3.515 Propane: 1.260	IRR: 190.7% SPP: 1.55	IRR: 164.5% SPP: 1.72	IRR: 114.7% SPP: 2.20
	LOW RANGE	Fuel Oil: 1.332 Propane: 0.899	IRR: 42.3% SPP: 4.09	IRR: 25.4% SPP: 5.59	IRR: N/A SPP: 18.87

Table 59. Feedstock Price vs. Capacity Factor

			FEEDSTOCK PRICE [$/GT]		
			LOW RANGE	**BASELINE**	**HIGH RANGE**
			Price: 20.00 MC: 19.07%	Price: 33.90 MC: 37.15%	Price: 55.00 MC: 50.0%
CAPACITY FACTOR [%]	**HIGH RANGE**	80	IRR: 228.1% SPP: 1.35	IRR: 198.1% SPP: 1.50	IRR: 140.6% SPP: 1.92
	BASELINE	70	IRR: 190.7% SPP: 1.55	IRR: 164.5% SPP: 1.72	IRR: 114.7% SPP: 2.20
	LOW RANGE	50	IRR: 116.8% SPP: 2.18	IRR: 98.7% SPP: 2.96	IRR: 65.6% SPP: 3.11

Table 60. Capacity Factor vs. Fossil Fuel Price

			CAPACITY FACTOR [%]		
			LOW RANGE	**BASELINE**	**HIGH RANGE**
			80	70	50
FOSSIL FUEL PRICE [$/GAL]	**HIGH RANGE**	Fuel Oil: 4.042 Propane: 1.720	IRR: 259.3% SPP: 1.22	IRR: 217.9% SPP: 1.40	IRR: 135.8% SPP: 1.97
	BASELINE	Fuel Oil: 3.515 Propane: 1.260	IRR: 198.1% SPP: 1.50	IRR: 164.5% SPP: 1.72	IRR: 98.7% SPP: 2.96
	LOW RANGE	Fuel Oil: 1.332 Propane: 0.899	IRR: 31.6% SPP: 4.85	IRR: 25.4% SPP: 5.59	IRR: 15.0% SPP: 8.04

The strongest interaction between two variables is between feedstock prices and fossil fuel prices (Table 58) followed by upfront cost and fossil fuel prices (Table 55). Note that the scenario of high feedstock costs and low fossil fuel does not yield a calculable IRR, indicating that the project is not financially viable with these parameters. Overall, the two-dimensional sensitivity shows the importance of fossil fuel prices to the project's financial viability. The return to low fossil-fuel prices would make the project challenging. However, with stable prices or increased fossil-fuel costs, the project routinely has SPPs of less than 2 years and in all cases, less than 3 years. The results are graphically displayed in Figure 44 and Figure 45.

Findings

The two-dimensional analysis shows the volatility of the project's economics. As the project progresses and costs are finalized, these analyses can be used to check that the project is remaining on track and with acceptable financial outcomes.

Fossil fuel price has the strongest link to the financial outcome of the project, followed by upfront costs. Even with a return to the lowest fossil fuel prices over the last five years, the project is projected to have a positive IRR and SPP unless biomass prices reach the potential high range.

The key outcome of this economic analysis is to recognize the effects of changes to the four crucial metrics of upfront costs, feedstock price, fossil fuel price, and capacity factor. While fossil fuel prices cannot be controlled, feedstock price and capacity factor can be controlled through upfront engineering and contract negotiation.

Figure 44. Two Dimensional Financial Analysis Results: Internal Rate of Return

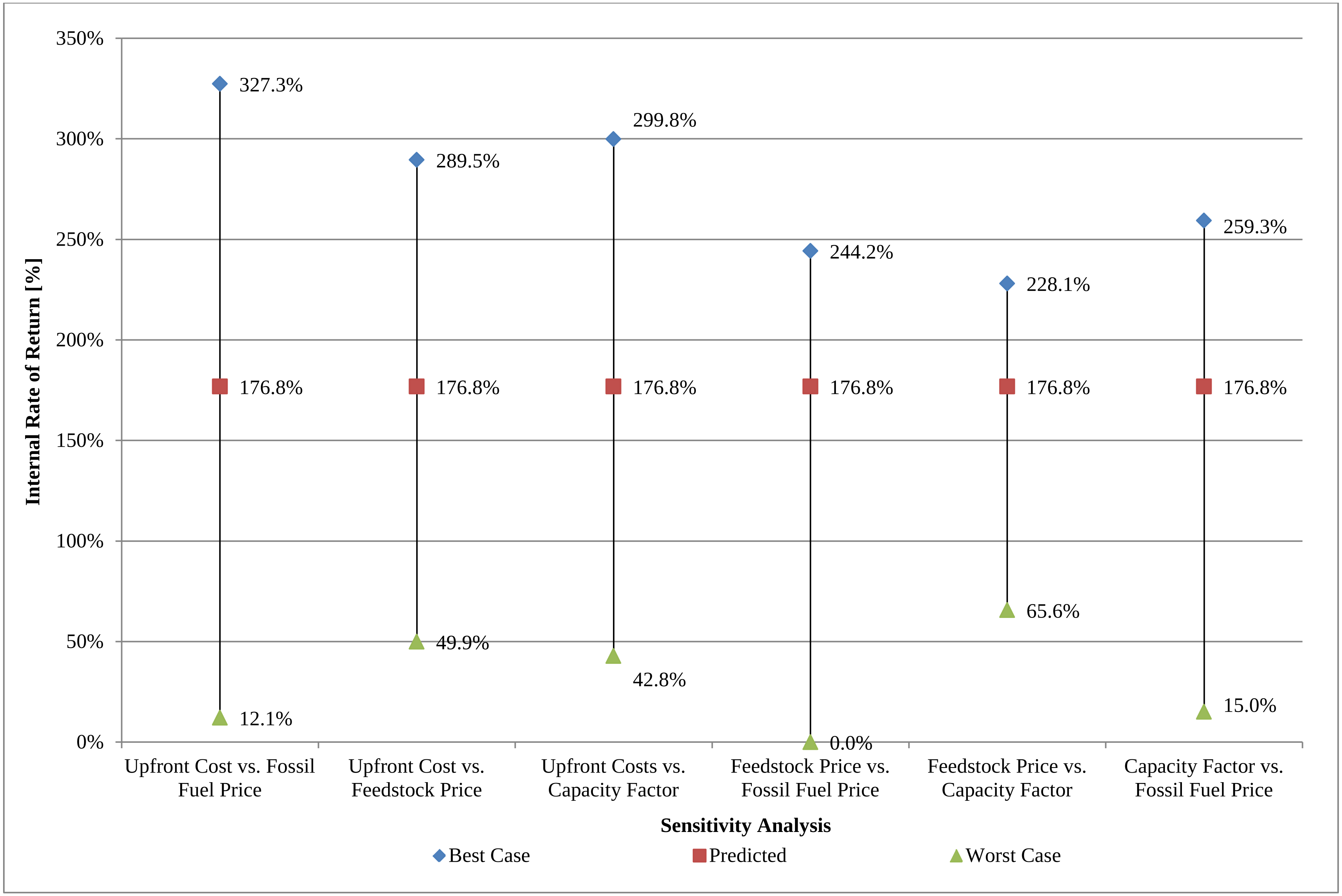
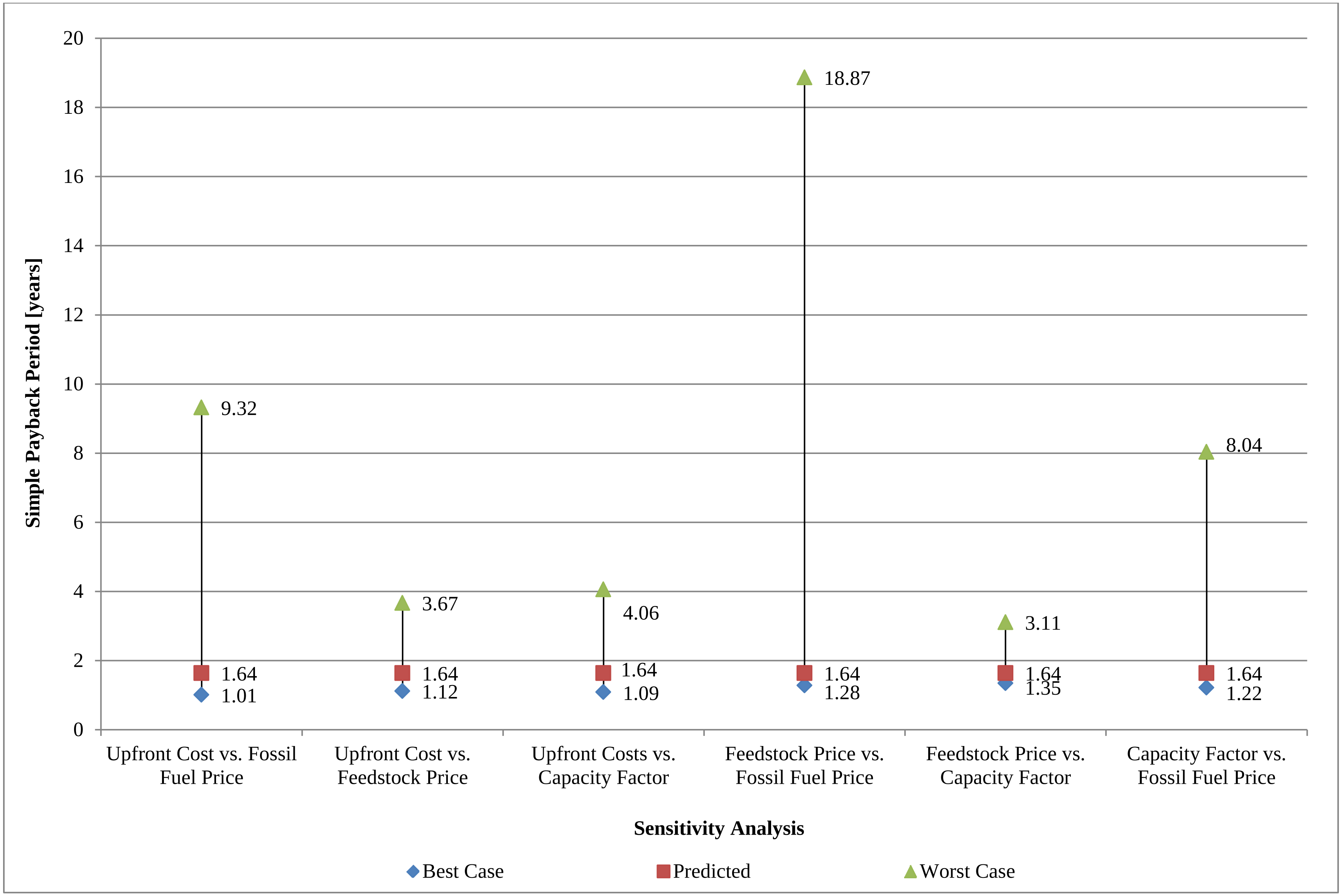


Figure 45. Two Dimensional Financial Analysis Results: Simple Payback Period



ENVIRONMENTAL BENEFIT ANALYSIS

Introduction

The environmental benefits analysis quantifies the potential impact of a biomass boiler installation and operation compared to business-as-usual practices (e.g., continuing to run the fossil fuel-fired boilers). At the SSC, the biomass boiler is projected to reduce the tribe's dependence on fossil fuel consumption and will utilize local woody biomass waste streams. For a thermal energy-only application, the primary environmental impact of a system is air quality, as neither the original fossil fuel systems or the biomass system are projected to use any water outside of the requirements for the boiler, nor is there any discharge of wastewater from the system. The boiler water requirements (primarily for makeup water) are identical for both systems. Published emissions factors are utilized to quantify emissions when source tests (air emissions testing results) are not available.

Business-As-Usual

The SSC uses fuel oil and propane to provide space heat to the hotel, event center, and gaming operation. These fossil fuels are used to fire boilers with 81% and 80% efficiencies respectively. These units are not source tested and air emissions factors for these facilities will be taken from the AP-42[85].

The biomass that is intended for use as primary feedstock for the proposed project is either sawmill byproduct or forest residue. Currently, sawmill residue is used as compost, mulch, soil amendment, absorptive material, animal bedding, or it is not used and decomposes in a pile. Each of these end products results in the open decomposition of the sawmill byproduct. The forest residue is not currently used and is piled and burned in the forest as a means of disposal. During logging operations or forest management operations, some of the residue can and must be left on site for proper nutrient recovery; however, leaving 100% of the residue would stifle the regrowth of the next generation and is therefore collected and disposed of typically by open pile burning activities managed by the landowner or the logging company.

Boiler Emissions

Air emissions factors from EPA AP-42 are shown in Table 61 for fuel oil consumption and propane consumption in small-scale boilers. The air emissions of concern are PM, SO_x, NO_x, CO_2, CO, VOC, and CH_4. Of these air pollutants, CO_2 and CH_4 are considered direct greenhouse gases, meaning that they are believed to directly contribute to climate change. The other pollutants are evaluated because of their potential to contribute short-term and long-term human illness or to contribute to the formation of acid rain.

[85] EPA AP-42 is the primary compilation of EPA's emission factor information. It is used by both industry and air quality regulatory agencies for setting emission factors for a given air pollutant emitting system or equipment.

Table 61. Fuel Oil and Propane AP-42 Emissions Factors

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Fuel Oil[86] [lb/1000 gal]	2	144S	20	22,300	5	0.34	0.216
Propane[87] [lb/1000 gal]	0.7	0.10S	13	12,500	7.5	0.8	0.2

The values in Table 61 are indicated as pounds per thousand gallons of fuel consumed. In AP-42, the SO_x emissions factors have the term "S" which is equal to the percentage of sulfur in fuel oil or the sulfur content expressed in grams per hundred cubic feet for propane. By mass, fuel oil in the U.S. is, on average, 0.5% sulfur and propane is 343.6 grams of sulfur per hundred cubic foot.[88]

Table 62 incorporates the average sulfur content and converts each emission factor to units of pounds per MMBtu. This unit of measure standardizes the emissions rates and will be used to compare energy sources.

Table 62. Converted Fuel Oil and Propane Emissions Factors

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Fuel Oil [$lb/MMBtu_{input}$]	0.01429	0.514	0.143	159.3	0.0357	0.00243	0.00154
Propane [$lb/MMBtu_{input}$]	0.00765	0.376	0.142	136.6	0.0820	0.00874	0.00219

Wood Feedstock Emissions

Based on the biomass feasibility assessment, the lowest cost wood waste is sawmill byproduct. This wood waste is currently used as compost, mulch, soil amendment, absorptive material, or animal bedding. For each of these scenarios, the wood is left to decompose exposed to the atmosphere. Emissions rates for spreading and decomposition are based on "The Value of the Benefits of U.S. Biomass Power," a study performed by NREL in November, 1999 (Appendix 6) and is shown in Table 63.

Forest biomass residues represent the remaining wood waste from forest management or timber harvest operations. This does not include biomass left in the forest for ecosystem health. The business-as-usual practice for disposing of forest biomass residues is to pile and burn. This practice is used to reduce wildfire hazards due to buildup of excess biomass on forested

[86] http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf Table 1.3-1, Table 1.3-3, Table 1.3-12
[87] http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s05.pdf Table 1.5-1
[88] http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/ea_app1.pdf and conversions factors of density = 2.01 g/cm^3 and energy content = 0.04644 GJ/kg, ATM for Sulfur of 32.065 and for Oxygen of 15.9994

landscapes and to decrease CH_4 emissions. The emissions from pile and burn practices are also shown in Table 63.

Table 63. Alternative Woody Biomass Emissions Factors[89]

	Total PM	SO_x	NO_x	CO_2[90]	CO	VOC	CH_4
Spreading [lb/1000 BDT]	-	-	-	3,200,000	-	-	130,000
Pile and Burn [lb/1000 BDT]	15,000	150	7,000	3,380,000	150,000	24,000	8,000

Using a conversion factor of 8,000 Btu per pound,[91] Table 64 shows the standardized emissions factors.

Table 64. Standardized Woody Biomass Emissions Factors[92]

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Spreading [lb/$MMBtu_{input}$]	-	-	-	200.0	-	-	8.13
Pile and Burn [lb/$MMBtu_{input}$]	0.938	0.0094	0.438	211.3	9.375	1.50	0.50

<u>Total Emissions</u>

The total air emissions for the business-as-usual scenario are the emissions from the fossil fuel boilers plus the emissions from open burning of the biomass that would have been utilized for a biomass unit. The quantity of wood is based on the conversion efficiencies of each unit. Table 65 displays the conversion efficiencies for each of the types of boilers based on the findings of Task 2 and Task 5.

Table 65. Conversion Efficiency for Heat Production

Technology Type	Conversion Efficiency
Fuel Oil Boiler	81%
Propane Boiler	80%
Biomass Boiler	68%

89 http://www.nrel.gov/docs/fy00osti/27541.pdf
90 Note, CO_2 emissions may be larger (by weight) than the original amount of wood combusted. Wood during combustion contributes carbon to the formation of CO_2 while oxygen (O_2) is contributed from the air that is consumed. Carbon represents 27.3% of the total weight of a CO_2 molecule (carbon's molecular weight is approximately 12 atomic mass units (amu) and O_2's molecular weight is approximately 32 amu). For example, if 12 pounds of carbon are released from the combustion of wood, the carbon molecules will combine with 32 pounds of O_2 to yield a total of 44 pounds of CO_2.
91 http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf
92 http://www.nrel.gov/docs/fy00osti/27541.pdf

To compare the scenarios, the total emissions will be displayed per unit of useable energy. This is energy available for heating after the combustion of the feedstock or fuel. Table 66 indicates the total emissions for fuel oil, propane, and the blend of fuel oil and propane used by the SSC as identified in the Tribal Energy Load Assessment.

Table 66. Total Emissions Factors for Business-as-Usual Practices

Fossil Fuel Practices	Biomass Practices	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Fuel Oil Consumption	Spreading [lb/MMBtu$_{output}$]	0.018	0.635	0.176	489.22	0.04	0.003	11.89
	Open Burn [lb/MMBtu$_{output}$]	1.389	0.649	0.816	505.67	13.76	2.197	0.73
Propane Consumption	Spreading [lb/MMBtu$_{output}$]	0.010	0.470	0.178	463.33	0.10	0.011	11.89
	Open Burn [lb/MMBtu$_{output}$]	1.381	0.484	0.818	479.79	13.82	2.205	0.73
Blended Consumption	Spreading [lb/MMBtu$_{output}$]	0.015	0.589	0.177	481.97	0.06	0.005	11.89
	Open Burn [lb/MMBtu$_{output}$]	1.387	0.602	0.817	498.43	13.77	2.199	0.73

Of the pollutants listed in Table 66, CO_2 and CH_4 are greenhouse gasses. SO_x, NO_x, CO, PM, and VOC all may indirectly contribute to the formation of additional greenhouse gases, but for this analysis they will not be used to calculate the global warming potential,l as they are not direct greenhouse gases. Table 67 displays the hundred year global warming potential (GWP_{100}) for each scenario using the Intergovernmental Panel on Climate Change (IPCC) data for CH_4 of 25 CO_2 equivalency (CO_2eq). Note that the units for GWP_{100} are units of CO_2eq per unit of the identified pollutant. For CH_4, this means that for every one pound of CH_4 released to the atmosphere, the effects are the same as if 25 pounds of CO_2 were released.

Table 67. Global Warming Potential of Business-as-Usual Practices

Fossil Fuel Practices	Biomass Practices	GWP_{100}
Fuel Oil Consumption	Spreading [lb$_{CO2eq}$/MMBtu$_{output}$]	786.4
	Open Burn [lb$_{CO2eq}$/MMBtu$_{output}$]	524.0
Propane Consumption	Spreading [lb$_{CO2eq}$/MMBtu$_{output}$]	760.5
	Open Burn [lb$_{CO2eq}$/MMBtu$_{output}$]	498.1
Blended Consumption	Spreading [lb$_{CO2eq}$/MMBtu$_{output}$]	779.2
	Open Burn [lb$_{CO2eq}$/MMBtu$_{output}$]	516.8

Utilizing Biomass for Renewable Energy

There are two important emissions sources when utilizing biomass energy. The first is the combustion of the biomass and the second is from the processing and transportation of the biomass from its source to the energy facility (in this case a thermal energy facility).

Biomass Boiler Emissions

Using air pollutant emission factors supplied by the selected technology vendor and emission factors from AP-42, emission factors for the biomass boiler are found in Table 68. As with the business-as-usual analysis, the data in AP-42 are relative to the energy input, not the energy output. Wet wood is used for this calculation, as EPA defines wet wood as having moisture content greater than 20%. As indicated in the Task 3 findings, all of the potential feedstock tested higher than 19% moisture content, indicating that there is a high likelihood for wet wood feedstock.

Table 68. EPA AP-42 Emissions Factors for Wet Wood Biomass[93]

	Total PM	SO_x	NO_x	CO_2	CO	VOC[94]	CH_4
Wet Wood, No PM Controls [lb/$MMBtu_{input}$]	0.33	0.047	0.059	195	0.60	0.017	0.021
Wet Wood, With PM Controls[95] [lb/$MMBtu_{input}$]	0.0358	0.047	0.059	195	0.60	0.00184	0.021

Biomass Processing and Transportation

Biomass processing and transportation includes chipping the wood, loading it into a chip van, and the roundtrip haul distance for the chip van. Emissions factors are cited from "Emissions Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning" published in the Journal of the Air & Waste Management Association (January 2011) and authored by the Placer County (California) Air Pollution Control District, TSS Consultants, and Placer County Planning Department (see Appendix 7). Emissions Factors are shown in Table 69.

[93] http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf Table 1.6-1, Table 1.6-2, Table 1.6-3
[94] AP-42 emissions factors do not account for PM controls. Since most VOCs are attached to PM, the VOC emissions factor has been reduced proportional to the reduction in PM due to controls.
[95] AP-42 does not offer emissions factors for high efficiency multiclones, data from Table 12 and Table 13 of "Emissions Controls for Small Wood-Fired Boilers" was used for this table. http://www.wflccenter.org/news_pdf/361_pdf.pdf

Table 69. Processing and Transportation Emissions Factors for Woody Biomass

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Grinder/Chipper [lb/BDT]	0.191	-	0.267	33.20	0.361	0.011	0.0252
Chip Van [lb/mi]	0.00089	-	0.0377	4.91	0.0889	0.0011	0.00213

The values in Table 69 have been calculated based on a bioenergy research project that utilized 6,096 bone dry metric tons of forest-sourced material to produce 7,710 megawatt-hours (MWh) of electricity. The emissions factors from this paper do not have SO_x emissions due to negligible amounts of sulfur in forest-sourced woody biomass feedstock. The SO_x emissions for the processing and transportation of the feedstock are proportional to the percentage of sulfur in the diesel fuel. Traditionally, ultra-low sulfur diesel (less than 15 ppm) will be utilized, yielding negligible SO_x emissions.

EPA AP-42 defines dry woody biomass to have an energy density of 8,000 Btu per dry pound. Using a 90-mile round trip haul time as indicated in the Feedstock Availability and Cost Assessment and a 25 green ton chip van, Table 70 standardizes these emissions factors into MMBtu of feedstock to be used as input into a boiler. This does not include the efficiency of the unit. For forest-based operations, the moisture content is considered to be 45% and for sawmill byproduct, the moisture content is considered to be 40% as indicated in Task 3.

Table 70. Standardized Processing and Transportation Emissions Factors for Biomass

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
Grinder/Chipper [$lb/MMBtu_{input}$]	0.01195	-	0.017	2.08	0.023	0.00068	0.00158
Chip Van, Forest Residue [$lb/MMBtu_{input}$]	0.00036	-	0.015	2.01	0.036	0.00045	0.00087
Chip Van, Sawmill Residue [$lb/MMBtu_{input}$]	0.00033	-	0.014	1.84	0.033	0.00041	0.00080

Notice that the values in Table 70 are significantly lower than the emissions factors in Table 68. While there are air emissions generated from processing and transportation, these emissions do not greatly contribute to the overall emissions profile of operating a biomass boiler.

Combining the emissions numbers from Table 68 and Table 70 along with the efficiency of the unit as indicated in Table 65 yields the total emissions factors for the energy output of the biomass unit. Table 71 shows the emissions factors for each potential scenario regarding emissions control devices for particulate matter and sawmill byproduct or forest residue.

Table 71. Total Emissions Factors for the Utilization of a Biomass Boiler

Boiler Controls	Biomass Sources	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4
No PM Control	Forest Sourced [lb/MMBtu$_{output}$]	0.501	0.069	0.133	291.2	0.933	0.027	0.034
	Sawmill Byproduct [lb/MMBtu$_{output}$]	0.501	0.069	0.131	291.0	0.929	0.026	0.034
PM Control	Forest Sourced [lb/MMBtu$_{output}$]	0.070	0.069	0.133	291.2	0.933	0.004	0.034
	Sawmill Byproduct [lb/MMBtu$_{output}$]	0.070	0.069	0.131	291.0	0.929	0.004	0.034

Of the pollutants listed in Table 71, CO_2 and CH_4 are greenhouse gases. SO_x, NO_x, CO, PM, and VOC all may contribute to the formation of additional greenhouse gases, but for this analysis they will not be used to calculate the GWP as they are not direct greenhouse gases. Table 72 displays the GWP for each scenario using IPCC data for CH_4 of 25 CO_2eq.

Table 72. Global Warming Potential of Biomass Boiler Utilization

Fossil Fuel Practices	Biomass Practices	GWP_{100}
No PM Control	Forest Sourced [lb/MMBtu$_{output}$]	292.1
	Sawmill Byproduct [lb/MMBtu$_{output}$]	291.8
PM Control	Forest Sourced [lb/MMBtu$_{output}$]	292.1
	Sawmill Byproduct [lb/MMBtu$_{output}$]	291.8

Comparison

By standardizing the air emission factors to pounds per MMBtu of heat output, the different scenarios may be compared. Table 73 compares the environmental impacts of switching from fossil fuels to sawmill byproduct.

Table 73. Emissions Profile from Sawmill Byproduct Utilization

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4	GWP_{100}
Blended Fossil Fuel Consumption [lb/$MMBtu_{output}$]	0.015	0.589	0.177	481.97	0.060	0.005	11.888	779.2
Biomass with PM Controls [lb/$MMBtu_{output}$]	0.070	0.069	0.131	290.98	0.929	0.004	0.034	291.8
Difference	0.055	-0.520	-0.045	190.99	0.868	-0.001	-11.854	-487.3
Percentage Change	357.5%	-88.3%	-25.6%	-39.6%	1,436.8%	-17.8%	-99.7%	-62.5%

Ambient emissions between the business-as-usual scenario and the biomass boiler when utilizing sawmill byproduct vary between air pollutant sources. Air emissions from PM and CO increase while all other emissions factors decrease. These emissions increases are due to the challenges of burning solid fuel compared to liquid fuel. Additionally, the alternative use for sawmill byproduct does not involve combustion, so the air emissions are predominantly CH_4 for the sawmill byproduct. However, decreases in CO_2 and CH_4 emissions yield an overall 62.5% reduction in total greenhouse gasses.

Table 74 compares the environmental impacts of switching from fossil fuels to forest residues.

Table 74. Emissions Profile from Forest Residue Utilization

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4	GWP_{100}
Blended Fossil Fuel Consumption [lb/$MMBtu_{output}$]	1.387	0.602	0.817	490.20	13.775	2.199	0.734	516.8
Biomass with PM Controls [lb/$MMBtu_{output}$]	0.070	0.069	0.133	291.11	0.933	0.004	0.034	292.1
Difference	-1.317	-0.534	-0.683	199.09	-12.841	-2.195	-0.699	-224.7
Percentage Change	-94.9%	-88.6%	-83.7%	-40.6%	-93.2%	-99.8%	-95.3%	-43.5%

When utilizing forest biomass, all air pollutant emissions levels are reduced. The reduction is primarily from the avoided emissions from pile and burn practices. The feedstock blend identified in the Feedstock Availability and Cost Assessment is 50% sawmill byproduct and 50% forest residue. The project air emissions for this scenario are presented in Table 75.

Table 75. Emissions Profile from Blended Feedstock Utilization

	Total PM	SO_x	NO_x	CO_2	CO	VOC	CH_4	GWP_{100}
Blended Fossil Fuel Consumption [lb/$MMBtu_{output}$]	0.701	0.596	0.497	490.19	6.918	1.102	6.311	647.965
Biomass with PM Controls [lb/$MMBtu_{output}$]	0.070	0.069	0.132	291.10	0.931	0.004	0.034	291.963
Difference	-0.631	-0.527	-0.364	-199.09	-5.987	-1.098	-6.276	-356.002
Percentage Change	-90.0%	-88.5%	-73.4%	-40.6%	-86.5%	-99.6%	-99.5%	-54.9%

Findings

The environmental benefits of a biomass energy project are heavily dependent on the type of biomass feedstock and its alternative use. Traditionally, biomass boilers have higher emissions factors than fossil fuel boilers because of the challenges of combustion with a solid feedstock with relatively high moisture content. The controlled environment of a fossil fuel boiler can yield advantages when compared to biomass combustion. However, using a holistic approach by valuing the use of the biomass feedstock as a waste stream and accounting for its business-as-usual fate confirms the environmental benefits of utilizing a biomass boiler. Figure 46 and Figure 47 show that the utilization of biomass feedstock results in a net reduction of air emissions. The analysis in this section does not include carbon sequestration from new tree growth, yet there are reductions in global warming potential from the system's emissions.

Figure 46. Project Annual Emissions Comparison: Non-Greenhouse Gas Pollutants

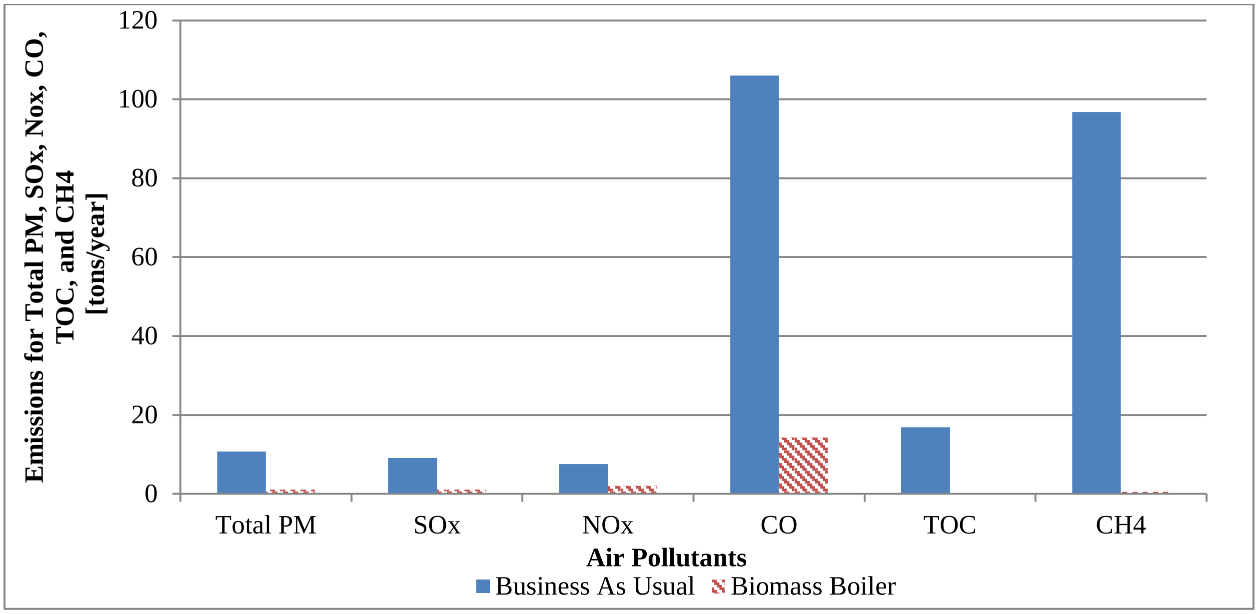
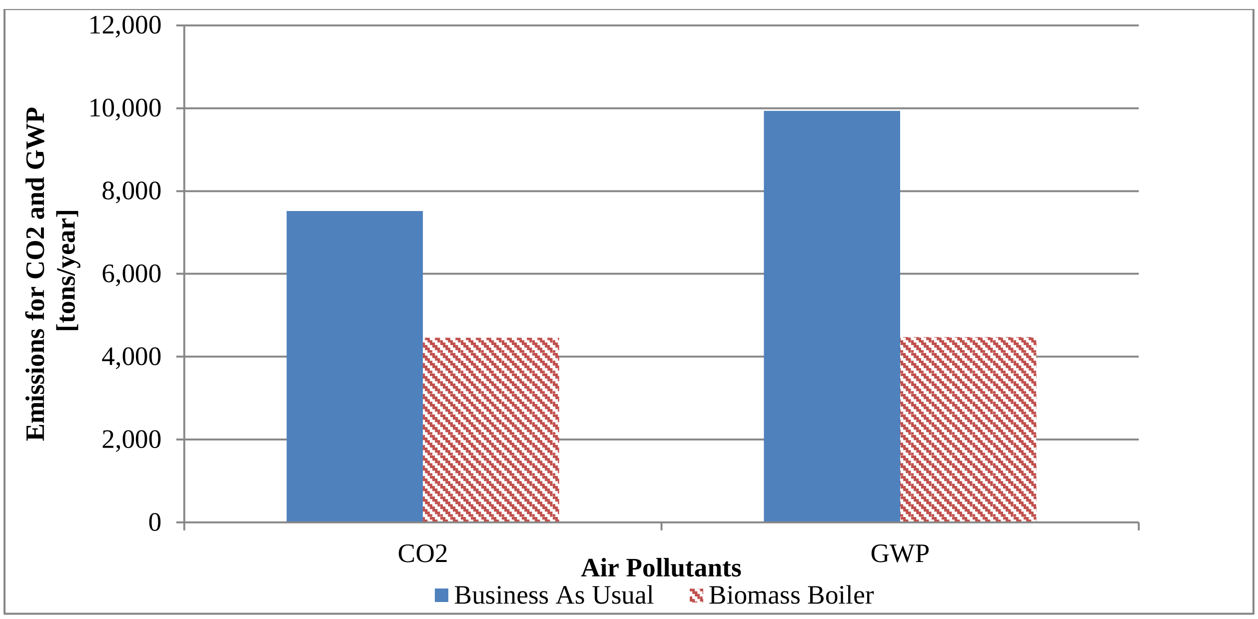


Figure 47. Project Annual Emissions Comparison: Greenhouse Gas Pollutants



TRIBAL BENEFIT ANALYSIS

Introduction

The tribal benefits analysis focuses on the potential benefits for the WEN Tribe and the surrounding communities that could result from shifting from petroleum-based fuels to woody biomass feedstocks in a 5.0 MMBtu per hour biomass boiler at the SSC. Benefits assessed include job training and employment, support of local business, air quality, cultural resources, and economic factors.

<u>Job Training and Employment</u>

A biomass thermal-energy only facility located at the SSC would utilize a blend of locally available forest biomass and sawmill byproducts. In order to utilize forest-sourced biomass (generated as a waste byproduct of timber harvest activities) it must be collected, processed, and transported to the thermal-energy facility. These three cost centers – collection, processing, and transport – all require skilled labor and specialized equipment.

A thermal-energy only facility will require 4,400 GT per year if sized at 5.0 MMBtu per hour. This volume of material would amount to one truckload of feedstock approximately every other day, totaling approximately 15 truckloads per month (based on an annualized average). As indicated in the Feedstock Availability and Cost Assessment, the anticipated feedstock blend will be 50% forest-sourced biomass and 50% sawmill byproduct requiring approximately 2,200 GT per year of feedstock from the local forested landscape over the six to nine months (depending on land ownership) that the forest is open for management.

There may be an opportunity to create a WEN enterprise dedicated to the recovery of forest biomass for utilization as feedstock in a thermal-energy only facility. In order to establish a forest biomass recovery enterprise on and off the reservation, there will be some defined steps to consider including:

- Capital expense for equipment
- Job training program
- Safety and illness prevention program
- Marketing of processed forest biomass
- Financial analysis to confirm viability of business model

A WEN enterprise dedicated to the collection, processing, and transport of timber harvest residuals could employ between four and six employees depending on the scale of the operation. Scale of the operation (loads produced per week) would be dependent upon local demand for the biomass feedstock produced. The feedstock demand at the SSC is relatively small (three to four truckloads per week) and by itself would not be enough demand to warrant the creation of a dedicated Tribal enterprise. As noted in the Feedstock Availability and Cost Assessment, there are facilities currently utilizing woody biomass feedstocks in the area (e.g., Mahnomen High School, Bergen's Greenhouse) that may serve as ready customers of a Tribal enterprise focused on the production of biomass feedstock.

Job training for SSC staff will be provided by the selected technology vendor and is detailed in the Training and Professional Development section. It is not anticipated that the SSC will need to hire any additional staff for the operation of the biomass unit; nevertheless, the existing staff will learn value-added skills associated with boiler operations and woody biomass feedstock management.

Support of Local Business

As indicated in Feedstock Availability and Cost Assessment, biomass feedstock sourcing from local sawmills is expected to provide 50% of the total biomass feedstock, or 2,200 BDT annually. By purchasing biomass feedstock from the existing mill waste products, the SSC will support local businesses by providing them with an additional source of predictable and consistent revenue.

The recent downturn in the forest products manufacturing sector within northern Minnesota has significantly reduced commercial manufacturing infrastructure. In the last five years, a number of industrial-scale facilities have ceased operation in northern Minnesota including:

- Ainsworth – Bemidji,
- Ainsworth – Grand Rapids,
- Ainsworth – Cook,
- Georgia Pacific – Duluth, and
- Verso Paper – Sartel.

As the forest products manufacturing sector has constricted, so too has the number of family wage jobs associated with manufacturing and logging as well as the numerous indirect jobs that support this sector. Utilization of sawmill residuals from local sawmill enterprises will provide them with additional markets for residuals, thus helping to support a key business sector in the region.

In addition to direct employment (collection, processing, and transport of woody biomass feedstocks), there will be indirect benefits for enterprises engaged in providing support services including (but not limited to) tire shops, petroleum product distributors, and restaurants.

Communities in the region will benefit through additional taxes collected (e.g., sales tax, employment taxes, commercial enterprise taxes) to support local public infrastructure.

Air Quality

A detailed analysis of the air quality effects of a biomass boiler installation are shown in the Environmental Benefit Analysis. Important findings from the Environmental Benefit Analysis include the source of the biomass feedstock, as the avoided business-as-usual fate of the biomass feedstock source is critical to the holistic analysis of the system's air emissions. Utilizing biomass that is considered a waste product by another industry is an essential part of responsible and sustainable biomass utilization. With a blend of biomass feedstock with 50% derived from the forest and 50% derived from sawmill byproduct, the Environmental Benefit Analysis illustrates that there is an opportunity to lower all criteria air pollutants, many by as much as 80%. Improved air quality (reduced air emissions, reduced regional haze) for the region can have direct impacts on community health, specifically with respect to asthma through reduction of PM. Reduction in SO_x and NO_x can help reduce the formation of acid rain and therefore yield positive indirect benefits to local agricultural activities. The decrease in greenhouse gases allows the WEN to positively contribute to reducing the effects of climate change.

Cultural Resources

The proposed biomass boiler location will be in an existing building within the SSC. The only additional structure to be built would be the feedstock receiving area. This new construction has been proposed on a site that is currently paved over and has, in the immediate vicinity, a fuel-oil underground storage tank. Since the thermal-energy only facility is planned on highly disturbed land, TSS does not anticipate that the construction of the new facility will negatively impact any cultural resources.

Economic Factors

In the short term, the conversion from fossil fuels to biomass is projected to have significant cost savings for the SSC. As detailed in the Economic Feasibility Analysis, many of the reviewed scenarios yield a high IRR and a SPP of less than three years. While the financial analysis confirms that investment in a biomass thermal-energy only facility is an attractive investment, it is important to note the dependence of many of the analyses on the market price of fuel oil and propane. Task 9 illustrates a strong correlation between the price of fossil fuels and the economic viability of the project. Without near-term accessibility to natural gas at the Casino, current trends suggest that fuel oil and propane prices for the Casino will remain stable or increase over the next ten years. As with every investment, there are risks involved; however, the conversion to a biomass boiler is a promising investment based on the projected prices for fossil fuels and biomass.

In the long term, the conversion from fossil fuels to biomass increases the financial certainty of the SSC's operations. Biomass feedstock availability is significant (as confirmed in the Feedstock Availability and Cost Assessment) and recent discussions with local forest products enterprises confirm an interest in providing sawmill residuals as feedstock. Long-term feedstock procurement agreements could be arranged to provide surety of pricing and supply. Fuel oil and propane contracts are currently reevaluated every year through a competitive bid process but still fluctuate based on the global market price which is affected by numerous unpredictable variables.

TRAINING AND PROFESSIONAL DEVELOPMENT

Introduction

As identified in the Capital Costs, Annual Costs, Operations and Maintenance Costs section, operator training is one of the most crucial elements of implementing a successful biomass thermal energy project. Traditionally, facilities developing biomass boilers are switching from a liquid fossil-fuel boiler to a biomass boiler for both economic, environmental, and/or sustainability reasons. While there are many advantages to utilizing a biomass boiler, ease of operations can be challenging when compared to liquid-fuel boilers. Liquid fuels are simple to deploy because they are easy to transport and convey. For the fuel-oil and propane boilers used by the SSC, the fuel is delivered to the site and stored in tanks. The pressure differential developed by the boiler, when in operation, pulls the fuel through the in-feed system. Liquid-fuel is efficiently combusted by specialized delivery systems optimized to ensure the proper air to fuel ratio to maximize energy production and minimize emissions.

A biomass boiler utilizes solid feedstock as fuel. Solid feedstocks are more challenging than liquid fuels because of their inability to conform to containers and the inability to easily alter the geometry of an individual shape. Just as with liquid fuels, biomass boilers are more efficient with a uniform feedstock size because the in-feed system can be optimized for that particular geometry (e.g., chip size). An operator must know how to monitor the system to react to changes in feedstock sizing and quality (e.g., wood species, moisture content). Since liquid-fueled boilers are always able to generate uniform in-feed characteristics, changing feedstock quality is not a challenge that boiler operators are accustomed to addressing. Additionally, the conveyance of solid feedstocks are mechanized and are therefore prone to more challenges than the passive in-feed system of a liquid fuel boiler that is driven by the unit's operational vacuum.

For each of these challenges, the common thread is feedstock size and quality. A detailed review of feedstock providers and their ability to consistently meet feedstock specifications is important to minimize the downtime from feedstock conveyance and maximize the combustion efficiency. However, the feedstock quality is not always within the control of the operator, and typical fuel contracts allow for tolerances with feedstock sizes and moisture content. It is therefore the operator's role to be able to manage and identify potential obstacles and proactively respond to minimize the impact of feedstock quality on the functioning of the system.

For a new biomass boiler operator, the challenges facing the operations and maintenance staff are not particularly difficult, but it is important that operators are educated about the challenges before commencing operation of the unit. A proper training regime allows one-on-one time for each potential operator or maintenance staff member to ensure that they understand the system and the common challenges. The training regimen outlined in this section provides goals for each stage of the program. While a biomass boiler is not difficult to operate, it is important to understand the mechanics of the system to be able to properly react to any situation.

Note that the traditional terminology of a boiler refers to two distinct components, the combustion chamber where the fuel or feedstock is combusted to generate heat and the water or steam side of the boiler to where the heat is transferred.

Personnel Requirements

A biomass boiler requires more staff oversight than a liquid-fuel boiler because of the feedstock conveyance system. It is recommended that the principal operator of the biomass boiler have experience managing and operating liquid-fuel boilers. The water or steam side of a biomass boiler is no different than that of a liquid-fueled boiler. Properly managing the water or steam temperature and pressure, the chemical cleaning and softening agents, and top off water are all necessary for both a biomass boiler and a liquid-fueled boiler. An experienced boiler operator will be able to identify these operations and maintenance issues and can focus on learning the particulars that distinguish a biomass boiler from a traditional boiler. A biomass boiler operator does not need prior experience working with wood chips. However, experience and familiarity with mechanical systems like motors or heating, ventilation, and air conditioning (HVAC) systems is recommended.

In addition to the primary operator(s), personnel are recommended to help monitor the conveyance system and the feedstock delivery. It is recommended that these positions be filled by personnel who have experience with mechanical systems. Experience handling wood products or experience operating a boiler is not required.

Staffing for the boiler operator should not be any different than the current staffing schedule utilized by the SSC. Since the challenges in the biomass boiler system stem from the feedstock conveyance system, the boiler itself is predictable and stable. Just like the fuel oil and propane boilers, when fed the proper fuels, the boiler will function properly. It is important that there is one trained staff person available during any time of operations to be able to quickly respond to any conveyance system impediments. Staff schedules will determine the number of personnel required to cover the typical operating hours for the unit.

Lastly, a protocol should be developed and staff personnel should be assigned the role of accepting and inspecting feedstock delivery to ensure feedstock quality. There are no prerequisites for this position.

Training Program

The training program should be tailored to each individual and their prior experience and background. Training will focus on three primary categories: a comprehensive overview of the system and a description of how the components operate and interact with each other; a detailed description of the control system; and a detailed description and demonstration of startup, shut down, and daily maintenance.

<u>System and Components</u>

The boiler operator and maintenance personnel will benefit from a comprehensive understanding of how the unit components are integrated. It is recommended that select staff is available for and partake in the installation of the biomass boiler system. Training will review the function of and the traditional challenges with each component. After training, staff should be able to identify the characteristics of the feedstock that could cause downtime with each component. This training will take place over one or two days, depending on the experiences of the staff. The training time will be tailored to ensure that each staff member is adequately informed and appropriately understands the new tasks specific to the boiler operations. The selected technology vendor will lead the hands-on training of the boiler operators and maintenance personnel.

Control System

This portion of the training will be limited to the boiler operators. This training will review the PLC and how to navigate the control system. An understanding of the PLC will allow the operator to control the combustion settings through the integrated controls.

A critical part of this part of training will be to develop an understanding of how biomass feedstock characteristics affect the boiler's performance. This will allow the boiler operator to better adjust and tune the system. The selected technology vendor will lead the hands-on training of the boiler operators and will provide an operations manual that details the key functions of the PLC.

Start Up, Shut Down, and Maintenance

The selected technology vendor will work with the boiler operators to walk through each step of system start up and system shut down. Biomass boilers have unique start up and shut down systems because of their large combustion chambers. Correctly starting and shutting down the system will minimize the impact of thermal expansion on the boiler's components. This portion of the training will be exclusively for the boiler operators.

A maintenance checklist will be developed and reviewed with all of the staff associated with the biomass boiler. The maintenance checklist will include daily and annual maintenance and tasks as outlined below.

Daily Inspections and Tasks
- Clean boiler room
- Inspect feedstock inventory and water chemicals
- Brief walkthrough boiler room
- Attentive to odd sounds, smells, vibrations
- Ash disposal
- Manual cleaning of grates or retort
- Blow down steam boilers and compressors

Annual Inspections and Tasks
- Thorough inspection
- Clean internals of complete system including brushing of heat exchanger surfaces
- Align and tension belt drives
- Check gearbox lubrication levels
- Lubricate bearings

- Inspect seals
- Inspect refractory
- Inspect wearing surfaces such as conveyor internals
- Calibrate PLC

Timing and Scheduling

The identification of staff personnel is the first step for training. Select personnel should be available during the construction of the biomass boiler to gain a better understanding of the biomass system and specifically the feedstock conveyance system.

A majority of the training will occur during the unit commissioning. The SSC will be able to utilize the availability of the selected technology vendor's staff during this time and can coordinate to make the most effective and efficient use of their time while on site. Training will take place over one or two days, depending on the number of SSC staff in attendance and their prior experience.

Appendix 1. List of Figures

Appendix 2. List of Tables

Appendix 3. Abbreviations and Acronyms

The abbreviations and acronyms utilized in this report include:

Organizations

EPA	Environmental Protection Agency
IPCC	Intergovernmental Panel on Climate Change
MISO	Midwest Independent System Operator
Minnkota	Minnkota Power Cooperative
MNDNR	Minnesota Department of Natural Resources
MNDOT	Minnesota Department of Transportation
MPUC	Minnesota Public Utilities Commission
OTP	Otter Tail Power
SSC	Shooting Star Casino, Hotel, and Event Center
TSS	TSS Consultants
WEN	White Earth Nation
USFS	United States Forest Service
USDI	United States Department of the Interior
Xcel	XCEL Energy

Other Terms

AADT	Annual Average Daily Traffic
AD	Anaerobic Digestion
a.k.a.	Also Known As
amu	Atomic Mass Unit
AP-42	Environmental Protection Agency AP-42
BACT	Best Available Control Technology
BDT	Bone Dry Ton(s)
BF	Board Feet
BHP	Boiler Horsepower
Btu	British Thermal Unit
CAD	Computer Aided Design
CH_4	Methane
CHP	Combined Heat and Power
cm	Centimeter
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2eq}	Carbon Dioxide Equivalency
CRP	Conservation Reserve Program
dbh	Diameter at Breast Height
ES	Ecological Subsection
ESP	Electrostatic Precipitator
FARR	Federal Air Rules for Reservations
FIA	United States Forest Service Forest Inventory Program

FIP	Federal Implementation Plan
FSA	Feedstock Sourcing Area
g	Grams
gal	Gallon
GIS	Geographic Information System
GJ	Gigajoules
GT	Green Tons
GWP_{100}	One Hundred Year Global Warming Potential
H_2	Hydrogen
H_2O	Water
Hr	Hour
HVAC	Heating Ventilation & Air Conditioning
ICE	Internal Combustion Engine
IRR	Internal Rate of Return
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
lb	Pound
MBF	Thousand Board Feet
MMBtu	Million British Thermal Units
MN	Minnesota
MW	Megawatt
MWh	Megawatt-hour
NO_x	Nitrogen Oxides
NSR	New Source Review
O&M	Operations and Maintenance
O_2	Oxygen
ORC	Organic Rankine Cycle
Pb	Lead
PLC	Programmable Logic Controls
PPA	Power Purchase Agreement
PURPA	Public Utility Regulatory Policy Act
RES	Renewable Energy Standard
RFP	Request for Proposals
sf	Square Feet
SO_x	Sulfur Oxides
SPP	Simple Payback Period
TNSR	Tribal New Source Review
TPD	Tons per Day
TPY	Tons per Year
U.S.	United States

Appendix 4. Proposed Interconnection Process for Distributed Generation Systems

State of Minnesota

Proposed Interconnection Process for Distributed Generation Systems

Introduction

This document has been prepared to explain the process established in the State of Minnesota, to interconnect a Generation System with Otter Tail Power, the Area Electrical Power System (Area EPS). This document covers the interconnection process for all types of Generation Systems which are rated 10MW's or less of total generation Nameplate Capacity; are planned for interconnection with the Otter Tail Power's Distribution System; are not intended for wholesale transactions and aren't anticipated to affect the transmission system. This document does not discuss the interconnection Technical Requirements, which are covered in the **"State of Minnesota Distributed Generation Interconnection Requirements"** document. This other interconnection requirements document also provides definitions and explanations of the terms utilized within this document. To interconnect a Generation System with the Otter Tail Power, there are several steps that must be followed. This document outlines those steps and the Parties' responsibilities. At any point in the process, if there are questions, please contact the Generation Interconnection Coordinator at Otter Tail Power. Since this document has been developed to provide an interconnection process which covers a very diverse range of Generation Systems, the process appears to be very involved and cumbersome. For many Generation Systems the process is streamlined and provides an easy path for interconnection.

The promulgation of interconnection standards for Generation Systems by the Minnesota Public Utilities Commission (MPUC) must be done in the context of a reasonable interpretation of the boundary between state and federal jurisdiction. The Federal Energy Regulatory Commission (FERC) has asserted authority in the area, at least as far as interconnection at the transmission level is concerned. This, however, leaves open the question of jurisdiction over interconnection at the distribution level. The Midwest Independent System Operator's (MISO) FERC Electric Tariff, (first revised volume 1, August 23,2001) Attachment R (Generator Interconnection Procedures and Agreement) states in section 2.1 that "Any existing or new generator connecting at transmission voltages, sub-transmission voltages, or distribution voltages, planning to engage in the sale for resale of wholesale energy, capacity, or ancillary services requiring transmission service under the Midwest ISO OATT must apply to the Midwest ISO for interconnection service". Further in section 2.4 it states that "A Generator not intending to engage in the sale of wholesale energy, capacity, or ancillary services under the Midwest ISO OATT, that proposes to interconnect a new generating facility to the distribution system of a Transmission Owner or local distribution utility interconnected with the Transmission System shall apply to the Transmission Owner or local distribution utility for interconnection". It goes on further to state "Where facilities under the control of the Midwest ISO are affected by such interconnection, such interconnections may be subject to the planning and operating protocols of the Midwest ISO…."

Through discussions with MISO personnel and as a practical matter, if the Generation System Nameplate Capacity is not greater in size than the minimum expected load on the distribution substation, that is feeding the proposed Generation System, and Generation System's energy is not being sold on the wholesale market, then that installation may be considered as not "affecting" the transmission system and the interconnection may be considered as governed by this process. If the Generation System will be selling energy on the wholesale market or the Generation System's total Nameplate Capacity is greater than the expected distribution substation minimum load, then the Applicant shall contact MISO (Midwest Independent System Operator) and follow their procedures.

Application process

GENERAL INFORMATION

A) Definitions

1) “Applicant” is defined as the person or entity who is requesting the interconnection of the Generation System with the Otter Tail Power and is responsible for ensuring that the Generation System is designed, operated and maintained in compliance with the Technical Requirements.

2) “Area EPS” is defined as an electric power system (EPS) that serves Local EPS’s. Note. Typically, an Area EPS has primary access to public rights-of-way, priority crossing of property boundaries, etc. Otter Tail Power’s distribution system is an AREA EPS.

3) “Area EPS Operator” is the entity who operates the Area EPS, here Otter Tail Power.

4) “Dedicated Facilities” is the equipment that is installed due to the interconnection of the Generation System and not required to serve other Otter Tail Power customers.

5) “Distribution System” is the Otter Tail Power facilities which are not part of the Otter Tail Power Transmission System or any Generation System.

6) “Extended Parallel” means the Generation System is designed to remain connected with the Otter Tail Power for an extended period of time.

7) “Generation” is defined as any device producing electrical energy, i.e., rotating generators driven by wind, steam turbines, internal combustion engines, hydraulic turbines, solar, fuel cells, etc.; or any other electric producing device, including energy storage technologies.

8) “Generation Interconnection Coordinator” is the person or persons designated by Otter Tail Power to provide a single point of coordination with the Applicant for the generation interconnection process.

9) “Generation System” is the interconnected generator(s), controls, relays, switches, breakers, transformers, inverters and associated wiring and cables, up to the Point of Common Coupling.

10) “Interconnection Customer” is the party or parties who will own/operate the Generation System and are responsible for meeting the requirements of the agreements and Technical Requirements. This could be the Generation System applicant, installer, owner, designer, or operator.

11) “Local EPS” is an electric power system (EPS) contained entirely within a single premises or group of premises

12) “Nameplate Capacity” is the total nameplate capacity rating of all the Generation included in the Generation System. For this definition the “standby” and/or maximum rated kW capacity on the nameplate shall be used.

13) "Open Transfer" is a method of transferring the local loads from Otter Tail Power to the generator such that the generator and Otter Tail Power are never connected together.

14) "Point of Common Coupling" is the point where the Local EPS is connected to Otter Tail Power

15) "Quick Closed" is a method of generation transfer which does not parallel or parallels for less then 100msec with Otter Tail Power and has utility grade timers which limit the parallel duration to less then 100 msec (milliseconds) with Otter Tail Power.

16) "Technical Requirements" "is the State of Minnesota Distributed Generation Interconnection Requirements".

17) "Transmission System" means those facilities as defined by using the guidelines established by the Minnesota State Public Utilities Commission; "In the Matter of Developing Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions" Docket No. E-015/M-99-1002.

B) Dispute Resolution

The following is the dispute resolution process to be followed for problems that occur with the implementation of this process.

1) Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

2) In the event a dispute arises under this process, and if it cannot be resolved by the Parties within thirty (30) days after written notice of the dispute to the other Party, the Parties shall submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in the State of Minnesota. The Parties agree to participate in good faith in the mediation for a period of 90 days. If the parties are not successful in resolving their disputes through mediation, then the Parties may refer the dispute for resolution to the Minnesota Public Utilities Commission, which shall maintain continuing jurisdiction over this process

C) Otter Tail Power's Generation Interconnection Coordinator.

Otter Tail Power shall designate a Generation Interconnection Coordinator(s) and this person or persons shall provide a single point of contact for an Applicant's questions on this Generation Interconnection process. Otter Tail Power may have several Generation Interconnection Coordinators assigned, due to the geographical size of their electrical service territory or the amount of interconnection applications. This Generation Interconnection Coordinator will typically not be able to directly answer or resolve all of the issues involved in the review and implementation of the interconnection process and standards, but shall be available to provide coordination assistance with the Applicant

D) Engineering Studies

During the process of design of a Generation System interconnection between a Generation System and Otter Tail Power, there are several studies which many need to be undertaken. On the Local EPS (Customers side of the interconnection) the addition of a Generation System may increase the fault current levels, even if the generation is never interconnected with Otter Tail Power's system. The Interconnection Customer may need to conduct a fault current analysis of the Local EPS in conjunction with adding the Generation System. The addition of the Generation System may also affect Otter Tail Power and special engineering studies may need to be undertaken looking at Otter Tail Power's distribution system with the Generation System included. Appendix D, lists some of the issues that may need to receive further analysis for the Generation System interconnection.

While, it is not a straightforward process to identify which engineering studies are required, we can at least develop screening criteria to identify which Generation Systems may require further analysis. The following is the basic screening criteria to be used for this interconnection process.

1) Generation System total Nameplate Capacity does not exceed 5% of the radial circuit expected peak load. The peak load is the total expected load on the radial circuit when the other generators on that same radial circuit are not in operation.

2) The aggregate generation's total Nameplate Capacity, including all existing and proposed generation, does not exceed 25% of the radial circuit peak load and that total is also less then the radial circuit minimum load.

3) Generation System does not exceed 15% of the Annual Peak Load for the Line Section, which it will interconnect with. A Line Section is defined as that section of the distribution system between two sectionalizing devices in Otter Tail Power's distribution system.

4) Generation System does not contribute more than 10% to the distribution circuit's maximum fault current at the point at the nearest interconnection with Otter Tail Power's primary distribution voltage.

5) The proposed Generation System total Nameplate Capacity, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment to exceed 85 percent of the short circuit interrupting capability.

6) If the proposed Generation System is to be interconnected on a single-phase shared secondary, the aggregate generation Nameplate Capacity on the shared secondary, including the proposed generation, does not exceed 20kW.

7) Generation System will not be interconnected with a "networked" system

Application process

E) **Scoping Meeting**

During Step 2 of this process, the Applicant or Otter Tail Power has the option to request a scoping meeting. The purpose of the scoping meeting shall be to discuss the Applicant's interconnection request and review the application filed. This scoping meeting is to be held so that each Party can gain a better understanding of the issues involved with the requested interconnection. Otter Tail Power and Applicant shall bring to the meeting personnel, including system engineers, and other resources as may be reasonably required, to accomplish the purpose of the meeting. The Applicant shall not expect Otter Tail Power to complete the preliminary review of the proposed Generation System at the scoping meeting. If a scoping meeting is requested, Otter Tail Power shall schedule the scoping meeting within the 15 business day review period allowed for in Step 2. Otter Tail Power shall then have an additional 5 days, after the completion of the scoping meeting, to complete the formal response required in Step 2. The Application fee shall cover Otter Tail Power's costs for this scoping meeting. There shall be no additional charges imposed by Otter Tail Power for this initial scoping meeting

F) **Insurance**

1) At a minimum, in connection with the Interconnection Customer's performance of its duties and obligations under this Agreement, the Interconnection Customer shall maintain, during the term of the Agreement, general liability insurance, from a qualified insurance agency with a B+ or better rating by "Best" and with a combined single limit of not less then:

   a) Two million dollars ($2,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is greater then 250kW.

   b) One million dollars ($1,000,000) for each occurrence if the Gross Nameplate Rating of the Generation System is between 40kW and 250kW.

   c) Three hundred thousand ($300,000) for each occurrence if the Gross Nameplate Rating of the Generation System is less then 40kW.

   d) Such general liability insurance shall include coverage against claims for damages resulting from (i) bodily injury, including wrongful death; and (ii) property damage arising out of the Interconnection Customer's ownership and/or operating of the Generation System under this agreement.

2) The general liability insurance required shall, by endorsement to the policy or policies, (a) include Otter Tail Power as an additional insured; (b) contain a sever ability of interest clause or cross-liability clause; (c) provide that Otter Tail Power shall not by reason of its inclusion as an additional insured incur liability to the insurance carrier for the payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to Otter Tail Power prior to cancellation, termination, alteration, or material change of such insurance.

3) If the Generation System is connected to an account receiving residential service from Otter Tail Power and it total generating capacity is smaller then 40kW, then the endorsements required in Section F.2 shall not apply.

4) The Interconnection Customer shall furnish the required insurance certificates and endorsements to Otter Tail Power prior to the initial operation of the Generation System. Thereafter, Otter Tail Power shall have the right to periodically inspect or obtain a copy of the original policy or policies of insurance

5) Evidence of the insurance required in Section F.1. shall state that coverage provided is primary and is not excess to or contributing with any insurance or self-insurance maintained by Otter Tail Power.

6) If the Interconnection Customer is self-insured with an established record of self-insurance, the Interconnection Customer may comply with the following in lieu of Section F.1 – 5:

7) Interconnection Customer shall provide to Otter Tail Power, at least thirty (30) days prior to the date of initial operation, evidence of an acceptable plan to self-insure to a level of coverage equivalent to that required under section F.1

8) If Interconnection Customer ceases to self-insure to the level required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of it's ability to self-insure, the Interconnection Customer agrees to immediately obtain the coverage required under section F.1.

9) Failure of the Interconnection Customer or Otter Tail Power to enforce the minimum levels of insurance does not relieve the Interconnection Customer from maintaining such levels of insurance or relieve the Interconnection Customer of any liability.

G) Pre-Certification

The most important part of the process to interconnect generation with Local EPS and Otter Tail Power is safety. One of the key components of ensuring the safety of the public and employees is to ensure that the design and implementation of the elements connected to the electrical power system operate as required. To meet this goal, all of the electrical wiring in a business or residence, is required by the State of Minnesota to be listed by a recognized testing and certification laboratory, for its intended purpose. Typically we see this as "UL" listed. Since Generation Systems have tended to be uniquely designed for each installation they have been designed and approved by Professional Engineers. This process has been set up to be able to deal with these uniquely designed systems. As the number of Generation Systems installed increase, vendors are working towards creating equipment packages which can be tested in the factory and then will only require limited field testing. This will allow us to move towards "plug and play" installations. For this reason, this interconnection process recognizes the efficiently of "pre-certification" of Generation System equipment packages that will help streamline the design and installation process.

An equipment package shall be considered certified for interconnected operation if it has been submitted by a manufacture, tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous utility interactive operation in compliance with the applicable codes and standards. Presently generation paralleling equipment that is listed by a nationally recognized testing laboratory as having met the applicable type-testing requirements of UL 1741 and IEEE 929 shall be acceptable for interconnection without additional protection system requirements. An “equipment package” shall include all interface components including switchgear, inverters, or other interface devices and may include an integrated generator or electric source. If the equipment package has been tested and listed as an integrated package which includes a generator or other electric source, it shall not required further design review, testing or additional equipment to meet the certification requirements for interconnection. If the equipment package includes only the interface components (switchgear, inverters, or other interface devices), then the Interconnection Customer shall show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and consistent with the testing and listing specified for the package. Provided the generator or electric source combined with the equipment package is consistent with the testing ad listing performed by the nationally recognized testing and certification laboratory, no further design review, testing or additional equipment shall be required to meet the certification requirements of this interconnection procedure. A certified equipment package does not include equipment provided by Otter Tail Power.

The use of Pre-Certified equipment does not automatically qualify the Interconnection Customer to be interconnected to Otter Tail Power. An application will still need to be submitted and an interconnection review may still need to be performed, to determine the compatibility of the Generation System with Otter Tail Power.

H) Confidential Information

Except as otherwise agreed, each Party shall hold in confidence and shall not disclose confidential information, to any person (except employees, officers, representatives and agents, who agree to be bound by this section). Confidential information shall be clearly marked as such on each page or otherwise affirmatively identified. If a court, government agency or entity with the right, power, and authority to do so, requests or requires either Party, by subpoena, oral disposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirements(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this Agreement. In the absence of a protective order or waiver the Party shall disclose such confidential information which, in the opinion of its counsel, the party is legally compelled to disclose. Each Party will use reasonable efforts to obtain reliable assurance that confidential treatment will be accorded any confidential information so furnished.

I) Non-Warranty.

Neither by inspection, if any, or non-rejection, nor in any other way, does Otter Tail Power give any warranty, expressed or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Applicant or leased by the Applicant from third parties, including without limitation the Generation System and any structures, equipment, wires, appliances or devices pertinent thereto.

Application process

J) Required Documents

The chart below lists the documents required for each type and size of Generation System proposed for interconnection.

Find your type of Generation System interconnection, across the top, then follow the chart straight down, to determine what documents are required as part of the interconnection process.

<table>
<tr><th colspan="6">GENERATION INTERCONNECTION DOCUMENT SUMMARY</th></tr>
<tr><th rowspan="2">Open Transfer</th><th rowspan="2">Quick Closed Transfer</th><th rowspan="2">Soft Loading Transfer</th><th colspan="3">Extended Parallel Operation</th></tr>
<tr><th>QF facility <40kW</th><th>Without Sales</th><th>With Sales</th></tr>
<tr><td colspan="6">Interconnection Process (This document)</td></tr>
<tr><td colspan="6">State of Minnesota Distributed Generation Interconnection Requirements</td></tr>
<tr><td colspan="6">Generation Interconnection Application (Appendix B)</td></tr>
<tr><td></td><td></td><td colspan="4">Engineering Data Submittal (Appendix C)</td></tr>
<tr><td></td><td></td><td></td><td colspan="3">Interconnection Agreement (Appendix E)</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="2">MISO / FERC</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>PPA</td></tr>
</table>

Interconnection Process = “State of Minnesota Interconnection Process for Distributed Generation Systems.” (This document)

State of Minnesota Distributed Generation Interconnection Requirements = “State of Minnesota Distributed Generation Interconnection Requirements”

Generation Interconnection Application = The application form in Appendix B of this document.

Engineering Data Submittal = The Engineering Data Form/Agreement, which is attached as Appendix C of this document.

Interconnection Agreement = “Minnesota State Interconnection Agreement for the Interconnection of Extended Parallel Distributed Generation Systems with Electric Utilities”, which is attached as Appendix E to this document.

MISO. = Midwest Independent System Operator, www.midwestiso.org

FERC = Federal Energy Regulatory Commission, www.ferc.gov

PPA = Power Purchase Agreement.

Application process

Process for Interconnection

Step 1   Application (By Applicant)

Once a decision has been made by the Applicant, that they would like to interconnect a Generation System with Otter Tail Power, the Applicant shall supply Otter Tail Power with the following information:

1) Completed Generation Interconnection Application (Appendix C), including;
   a) One-line diagram showing;
      i) Protective relaying.
      ii) Point of Common Coupling.
   b) Site plan of the proposed installation.
   c) Proposed schedule of the installation.
2) Payment of the application fee, according to the following sliding scale.

Generation Interconnection Application Fees

Interconnection Type	≤ 20kW	>20kW & ≤250kW	>250kW & ≤500kW	> 500 kW & ≤1000kW	>1000 kW
Open Transfer	$0	$0	$0	$100	$100
Quick Closed	$0	$100	$100	$250	$500
Soft Loading	$100	$250	$500	$500	$1000
Extended Parallel (Pre Certified System)	$0	$250	$1000	$1000	$1500
Other Extended Parallel Systems	$100	$500	$1500	$1500	$1500

This application fee is to contribute to Otter Tail Power's labor costs for administration, review of the design concept and preliminary engineering screening for the proposed Generation System interconnection.

For the Application Fees chart, above;
The size (kW) of the Generation System is the total maximum Nameplate Capacity of the Generation System.

Step 2   Preliminary Review (By Otter Tail Power)

Within 15 business days of receipt of all the information listed in Step 1, Otter Tail Power's Generation Interconnection Coordinator shall respond to the Applicant with the information listed below. (If the information required in Step 1 is not complete, the Applicant will be notified, within 10 business days of what is missing and no further review will be completed until the missing information is submitted. The 15-day clock will restart with the new submittal)

As part of Step 2 the proposed Generation System will be screened to see if additional Engineering Studies are required. The base screening criteria is listed in the general information section of this document.

Application process

1) A single point of contact with Otter Tail Power for this project. (Generation Interconnection Coordinator)

2) Approval or rejection of the generation interconnection request.
   a) Rejection – Otter Tail Power shall supply the technical reasons, with supporting information, for rejection of the interconnection Application.
   b) Approval - An approved Application is valid for 6 months from the date of the approval. Otter Tail Power's Generation Interconnection Coordinator may extend this time if requested by the Applicant

3) If additional specialized engineering studies are required for the proposed interconnection, the following information will be provided to the Applicant. Typical Engineering Studies are outlined in Appendix D. The costs to the Applicant, for these studies shall be not exceed the values shown in the following table for pre-certified equipment.

Generation System Size	**Engineering Study Maximum Costs**
<20kW	$0
20kW – 100kW	$500
100kW – 250kW	$1000
>250kW or not pre-certified equipment	Actual costs

   a) General scope of the engineering studies required.
   b) Estimated cost of the engineering studies.
   c) Estimated duration of the engineering studies.
   d) Additional information required to allow the completion of the engineering studies.
   e) Study authorization agreement.

4) Comments on the schedule provided.

5) If the rules of MISO (Midwest Independent System Operator) require that this interconnection request be processed through the MISO process, the Generation Interconnection Coordinator will notify the Applicant that the generation system is not eligible for review through the State of Minnesota process.

Step 3 Go-No Go Decision for Engineering Studies (By Applicant)

In this step, the Applicant will decide whether or not to proceed with the required engineering studies for the proposed generation interconnection. If no specialized engineering studies are required by Otter Tail Power, Otter Tail Power and the Applicant will automatically skip this step.

If the Applicant decides NOT to proceed with the engineering studies, the Applicant shall notify the Otter Tail Power's Generation Interconnection Coordinator, so other generation interconnection requests in the queue are not adversely impacted. Should the Applicant decide to proceed, the Applicant shall provide the following to the Otter Tail Power's Generation Interconnection Coordinator:

1) Payment required by Otter Tail Power for the specialized engineering studies.

2) Additional information requested by Otter Tail Power to allow completion of the engineering studies.

Application process

Step 4 Engineering Studies (By Otter Tail Power)

In this step, Otter Tail Power will be completing the specialized engineering studies for the proposed generation interconnection, as outlined in Step 2. These studies should be completed in the time frame provided in step 2, by Otter Tail Power. It is expected that Otter Tail Power shall make all reasonable efforts to complete the Engineering Studies within the time frames shown below. If additional time is required to complete the engineering studies the Generation Interconnection Coordinator shall notify the Applicant and provide the reasons for the time extension. Upon receipt of written notice to proceed, payment of applicable fee, and receipt of all engineering study information requested by Otter Tail Power in step 2, Otter Tail Power shall initiate the engineering studies.

Generation System Size	Engineering Study Completion
<20kW	20 working days
20kW – 250kW	30 working days
250kW – 1MW	40 working days
> 1MW	90 working days

Once it is known by Otter Tail Power that the actual costs for the engineering studies will exceed the estimated amount by more the 25%, then the Applicant shall be notified. Otter Tail Power shall then provide the reason(s) for the studies needing to exceed the original estimated amount and provide an updated estimate of the total cost for the engineering studies. The Applicant shall be given the option of either withdrawing the application, or paying the additional estimated amount to continue with the engineering studies.

Step 5 Study Results and Construction Estimates (By Otter Tail Power)

Upon completion of the specialized engineering studies, or if none was necessary, the following information will be provided to the Applicant.

1) Results of the engineering studies, if needed.
2) Monitoring & control requirements for the proposed generation.
3) Special protection requirements for the Generation System interconnection.
4) Comments on the schedule proposed by the Applicant.
5) Distributed Generation distribution constrained credits available
6) Interconnection Agreement (if applicable).
7) Cost estimate and payment schedule for required Otter Tail Power work, including, but not limited to;
   a) Labor costs related to the final design review.
   b) Labor & expense costs for attending meetings
   c) Required Dedicated Facilities and other Otter Tail Power modification(s).
   d) Final acceptance testing costs.

Step 6 Final Go-No Go Decision (By Applicant)

Application process

In this step, the Applicant shall again have the opportunity to indicate whether or not they want to proceed with the proposed generation interconnection. If the decision is NOT to proceed, the Applicant will notify Otter Tail Power's Generation Interconnection Coordinator, so that other generation interconnections in the queue are not adversely impacted. Should the Applicant decide to proceed, a more detailed design, if not already completed by the Applicant, must be done, and the following information is to be supplied to Otter Tail Power's Generation Interconnection Coordinator:

1) Applicable up-front payment required by Otter Tail Power, per Payment Schedule, provided in Step 5. (if applicable)

2) Signed Interconnection Agreement (if applicable).

3) Final proposed schedule, incorporating Otter Tail Power comments. The schedule of the project should include such milestones as foundations poured, equipment delivery dates, all conduit installed, cutover (energizing of the new switchgear/transfer switch), Otter Tail Power work, relays set and tested, preliminary vendor testing, final Otter Tail Power acceptance testing, and any other major milestones.

4) Detailed one-line diagram of the Generation System, including the generator, transfer switch/switchgear, service entrance, lockable and visible disconnect, metering, protection and metering CT's / VT's, protective relaying and generator control system.

5) Detailed information on the proposed equipment, including wiring diagrams, models and types.

6) Proposed relay settings for all interconnection required relays.

7) Detailed site plan of the Generation System.

8) Drawing(s) showing the monitoring system (as required per table 5A and section 5 of the "State of Minnesota Distributed Generation Interconnection Requirements". Including a drawing which shows the interface terminal block with Otter Tail Power 's monitoring system.

9) Proposed testing schedule and initial procedure, including;
   a) Time of day (after-hours testing required?).
   b) Days required.
   c) Testing steps proposed.

Step 7   Final Design Review (By Otter Tail Power)

Within 15 business days of receipt of the information required in Step 6, Otter Tail Power 's Generation Interconnection Coordinator will provide the Applicant with an estimated time table for final review. If the information required in Step 6 is not complete, the Applicant will be notified, within 10 business days of what information is missing. No further review may be completed until the missing information is submitted. The 15-business day clock will restart with the new submittal. This final design review shall not take longer then 15 additional business days to complete, for a total of 30 business days.

During this step, Otter Tail Power shall complete the review of the final Generation System design. If the final design has significant changes from the Generation System proposed on the original Application which invalidate the engineering studies or the preliminary engineering screening, the Generation System Interconnection Application request may be rejected by Otter Tail Power and the Applicant may be requested to reapply with the revised design.

Upon completion of this step the Generation Interconnection Coordinator shall supply the following information to the Applicant.

1) Requested modifications or corrections of the detailed drawings provided by the Applicant.

2) Approval of and agreement with the Project Schedule. (This may need to be interactively discussed between the Parties, during this Step)

3) Final review of Distributed Generation Credit amount(s) (where applicable).

4) Initial testing procedure review comments. (Additional work on the testing process will occur during Step 8, once the actual equipment is identified)

Step 8 Order Equipment and Construction (By Both Parties)

The following activities shall be completed during this step. For larger installations this step will involve much interaction between the Parties. It is typical for approval drawings to be supplied by the Applicant to Otter Tail Power for review and comments. It is also typical for Otter Tail Power to require review and approval of the drawings that cover the interconnection equipment and interconnection protection system. If Otter Tail Power also requires remote control and/or monitoring, those drawings are also exchanged for review and comment.

By the Applicant's personnel:
1) Ordering of Generation System equipment.
2) Installing Generation System.
3) Submit approval drawings for interconnection equipment and protection systems, as required by Otter Tail Power.
4) Provide final relay settings provided to Otter Tail Power.
5) Submit Completed and signed Engineering Data Submittal form.
6) Submit proof of insurance, as required by the Otter Tail Power tariff(s) or interconnection agreements.
7) Submit required State of Minnesota electrical inspection forms ("blue Copy) filed with Otter Tail Power.
8) Inspecting and functional testing Generation System components.
9) Work with Otter Tail Power personnel and equipment vendor(s) to finalize the installation testing procedure.

By Otter Tail Power personnel:
1) Ordering any necessary Otter Tail Power equipment.
2) Installing and testing any required equipment.
   a) Monitoring facilities.
   b) Dedicated Equipment.
3) Assisting Applicant's personnel with interconnection installation coordination issues
4) Providing review and input for testing procedures.

Step 9 Final Tests (By Otter Tail Power / Applicant)

(Due to equipment lead times and construction, a significant amount of time may take place between the execution of Step 8 and Step 9.) During this time the final test steps are developed and the construction of the facilities are completed.

Application process

Final acceptance testing will commence when all equipment has been installed, all contractor preliminary testing has been accomplished and all Otter Tail Power preliminary testing of the monitoring and dedicated equipment is completed. One to three weeks prior to the start of the acceptance testing of the generation interconnection the Applicant shall provide, a report stating;

- that the Generation System meets all interconnection requirements.
- all contractor preliminary testing has been completed.
- the protective systems are functionally tested and ready.
- and provides a proposed date that the Generation System will be is ready to be energized and acceptance tested.

For non-type certified systems a Professional Electrical Engineer registered in the State of Minnesota is required to provide this formal report.

For smaller systems scheduling of this testing may be more flexible, as less testing time is required than for larger systems.

In many cases, this testing is done after hours to ensure no typical business-hour load is disturbed. If acceptance testing occurs after hours, Otter Tail Power's labor will be billed at overtime wages. During this testing, Otter Tail Power will typically run three different tests. These tests can differ depending on which type of communication / monitoring system(s) Otter Tail Power decides to install at the site.

For, problems created by Otter Tail Power or any Otter Tail Power equipment that arise during testing, Otter Tail Power will fix the problem as soon as reasonably possible. If problems arise during testing which are caused by the Applicant or Applicant's vendor or any vendor supplied or installed equipment, Otter Tail Power will leave the project until the problem is resolved. Having the testing resume will then be subject to Otter Tail Power personnel time and availability.

Step 10 (By Otter Tail Power)

After all Otter Tail Power acceptance testing has been accomplished and all requirements are met, Otter Tail Power shall provide written approval for normal operation of the Generation System interconnection, within 3 business days of successful completion of the acceptance tests..

Step 11 (By Applicant)

Within two (2) months of interconnection, the Applicant shall provide Otter Tail Power with updated drawings and prints showing the Generation System as it were when approved for normal operation by Otter Tail Power. The drawings shall include all changes which were made during construction and the testing process.

Attachments:

Attached are several documents which may be required for the interconnection process. They are as follows;

Appendix A:
Flow chart showing summary of the interconnection process.

Appendix B:
Generation Interconnection Application Form.

Application process

Appendix C:

Engineering Data Submittal Form.

Appendix D:

Engineering Studies: Brief description of the types of possible Engineering Studies that may be required for the review of the Generation System interconnection.

Appendix E:

State of Minnesota Interconnection Agreement for the Interconnection of Extended Paralleled Distributed Generation Systems with Electric Utilities.

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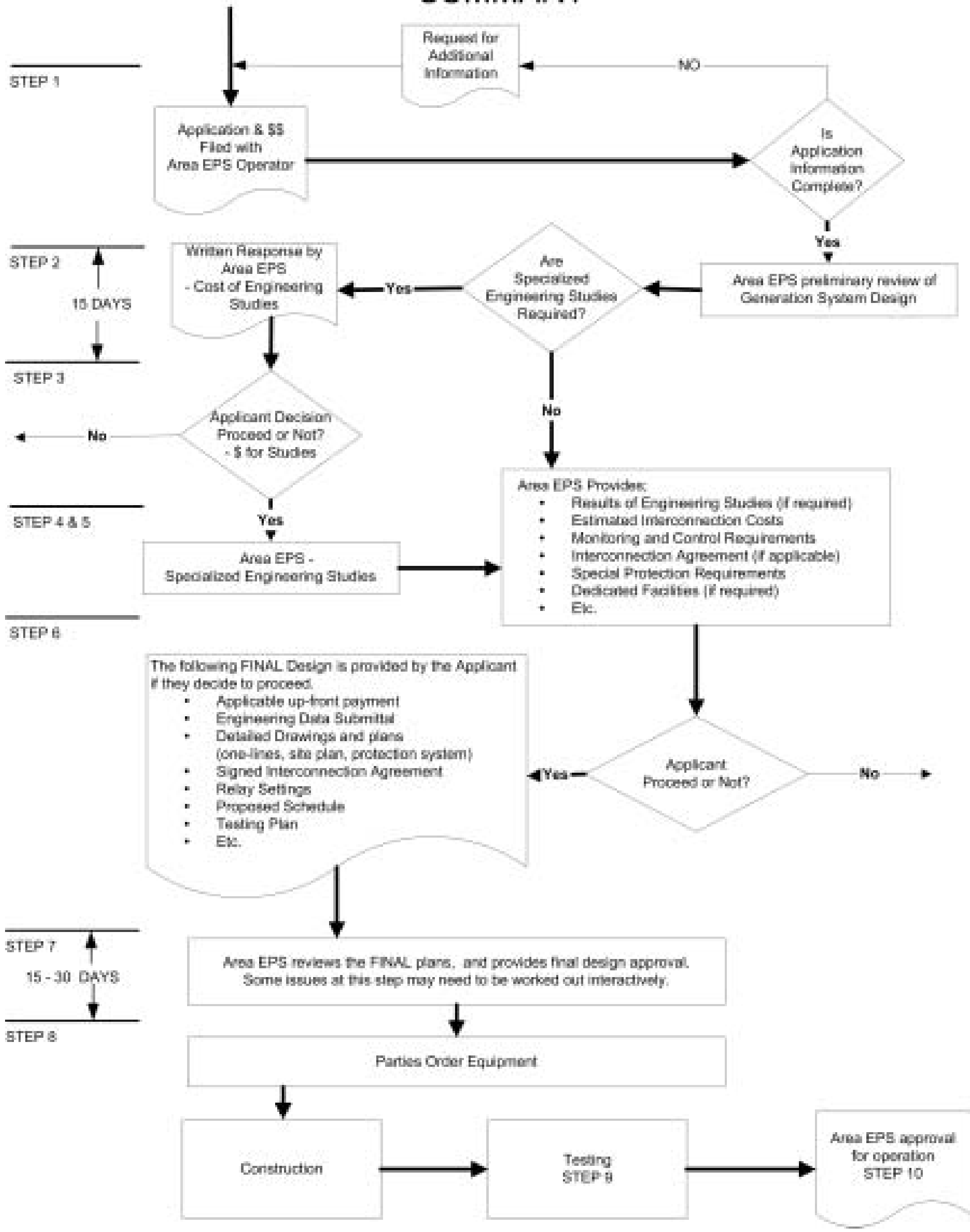
Application process

APPENDIX A

DISTRIBUTED GENERATION INTERCONNECTION PROCESS SUMMARY



APPENDIX B

INSERT

INTERCONNECTION

APPLICATION

FORM

APPENDIX C

INSERT

ENGINEERING DATA

SUBMITTAL

FORM

APPENDIX D

Engineering Studies

For the engineering studies there are two main parts of the study: 1. Does the distributed generator cause a problem? and 2. What would it cost to make a change to handle the problem.? The first question is relatively straightforward to determine as the Otter Tail Power Engineer reviews the proposed installation. The second question typically has multiple alternatives and can turn into an iterative process. This iterative process can become quite large for more complex generation installations. For the Engineer there is no "cook book" solution which can be applied.

For some of the large generation installations and/or the more complex interconnections Otter Tail Power may suggest dividing up the engineering studies into the two parts; identify the scope of the problems and attempt to identify solutions to resolve the problems. By splitting the engineering studies into two steps, it will allow for the Applicant to see the problems identified and to provide the Applicant the ability to remove the request for interconnection if the problems are too large and expensive to resolve. This would then save the additional costs to the Applicant for the more expensive engineering studies; to identity ways to resolve the problem(s).

This appendix provides an overview of some of the main issues that are looked at during the engineering study process. Every interconnection has its unique issues, such as relative strength of the distribution system, ratio of the generation size to the existing area loads, etc. Thus many of the generation interconnections will require further review of one or several of the issues listed.

- Short circuit analysis – the system is studied to make sure that the addition of the generation will not over stress any of the Otter Tail Power equipment and that equipment will still be able to clear during a fault. It is expected that the Applicant will complete their own short circuit analysis on their equipment to ensure that the addition of the generation system does not overstress the Applicant's electrical equipment.

- Power Flow and Voltage Drop
  - Reviews potential islanding of the generation
  - Will Otter Tail Power Equipment be overloaded
    - Under normal operation?
    - Under contingent operation? With backfeeds?

- Flicker Analysis –
  - Will the operation of the generation cause voltage swings?
    - When it loads up? When it off loads?
  - How will the generation interact with Otter Tail Power's voltage regulation?
  - Will Otter Tail Power's capacitor switching affect the generation while on-line?

- Protection Coordination
  - Reclosing issues – this is where the reclosing for the distribution system and transmission system are looked at to see if the Generation System protection can be set up to ensure that it will clear from the distribution system before the feeder is reenergized.
    - Is voltage supervision of reclosing needed?
  - Is transfer-trip required?
  - Do we need to modify the existing protection systems? Existing settings?
  - At which points do we need "out of sync" protection?
  - Is the proposed interconnection protection system sufficient to sense a problem on Otter Tail Power's distribution system?
  - Are there protection problems created by the step-up transformer?

Application process

- Grounding Reviews
  - Does the proposed grounding system for the Generation System meet the requirements of the NESC? "National Electrical Safety Code" published by the Institute of Electrical and Electronics Engineers (IEEE)

- System Operation Impact.
  - Are special operating procedures needed with the addition of the generation?
  - Reclosing and out of sync operation of facilities.
  - What limitations need to be placed on the operation of the generation?
  - Operational Var requirements?.

APPENDIX E

INSERT

STATE OF MINNESOTA
INTERCONNECTION AGREEMENT

FOR THE

INTERCONNECTION OF EXTENDED PARALLELED
DISTRIBUTION GENERATION SYSTEMS

WITH

ELECTRIC UTILITIES

Appendix 5. Request for Proposals

WOODY BIOMASS-FIRED THERMAL HEAT PROJECT IN MAHNOMEN, MN

Request for Proposal

Based on an economic and technical feasibility evaluation performed by TSS Consultants, the White Earth Nation has determined that a woody biomass-fired heating system is appropriate for the Shooting Star Casino in Mahnomen, MN. The project is a strategic step to reduce costs, mitigate risk, and adhere to the tribe's mission of sustainability and stewardship of the land. [Company] has been selected as one of two preferred candidates to receive this Request for Proposals (RFP).

Community Objectives: In developing a biomass fired thermal energy facility at the Shooting Star Casino, the White Earth Nation hopes to meet the following objectives:

- Support local subsidiary businesses such as biomass harvesting, chipping and transport.
- Beneficially utilize woody biomass being removed from surrounding public, private, and tribal land for purposes of fire safety and/or ecological restoration.
- Have minimal noise and odor impacts to guests, nearby residents, and businesses.
- Cost savings by reducing the use of #2 fuel oil and propane.

Project Timeline: RFP responses are due October 15, 2012. After a review period of up to 60 days, the top ranked technology and project development team will enter into negotiations to determine the path forward for the completion of the project.

Technology Requirement: The proposed technology should be capable of generating up to 5 MMBtu/hr of hot water at 180°F EWT, 200°F LWT. The system shall be capable of, 600 GPM, 50% Ethylene Glycol mixture, with a maximum of 6 PSI WPD through the Biomass Boiler System. The proposed system must be able to convey and utilize the feedstock as specified by the feedstock parameters (posted below) and meet any regulations outlined in this RFP.

Feedstock Parameters: Biomass will be locally sourced from sawmills and forest operations. The proposed system must be sufficiently robust to utilize ground and chipped woody biomass as the primary feedstock. Woody biomass material will range from ¼" to 4" in particle size. Feedstock may be delivered with moisture contents ranging from 30% - 50% (wet basis). Heat content of the fuel is expected to be 8,000 – 8,500 Btu/lb (dry basis). Feedstock samples may be sent upon request via standard USPS shipping. Appendix A displays fuel sample testing results and photographs of anticipated feedstock sources.

Air Emissions: As the proposed system will be located on White Earth Nation tribal-owned land, air quality permitting will be subject to the U.S. Environmental Protection Agency regulations. It is desired that the projected emissions remain below the Minor Tribal NSR Rule Thresholds:

- CO: 10 TPY (tons per year)
- NO_x: 10 TPY
- SO_2: 10 TPY
- PM: 10 TPY
- PM-10: 5 TPY
- PM-2.5: 3 TPY

- Lead: 0.1 TPY
- VOC: 5 TPY

Emissions source tests or successful permit applications for comparably sized units would be appreciated where possible.

Selection Criteria: Responses will be evaluated based on the following criteria: (1) Ability to produce hot water with the specified biomass feedstock; (2) Ability to meet air emissions requirements; (3) Facility size (footprint) without fuel storage; (4) Fuel consumption rates per unit of output (net heat rate); and (5) Estimated capital, training, installation, freight, and operating and maintenance costs for entire system.

Contents of Response Submittal: All responses should include the following information. Responses should be organized in the following format:

1) A technical description of the entire proposed system including feedstock handling, ash removal, and emissions controls.
2) Identify required resources including footprint, system efficiency, and electrical requirements.
3) Environmental impact summary including noise impacts, expected air emissions, ash disposal rates, etc.
4) Statement of qualifications of manufacturer, including experience with woody biomass fuels, contact information for proposed or currently operating systems, available operating histories and references (operators of systems utilizing ground woody feedstock are preferred).
5) Cost estimates including equipment capital costs, freight, training, installation (not including interconnection to the existing system), commissioning, expected maintenance costs and timeframe, and service contract options.
6) Operating requirements of on-site personnel and maintenance schedule.
7) Supplementary information (at the discretion of the candidate).

Deadline for Responses: Electronic replies are due by close of business October 15, 2012. Reponses are to be submitted to mhart@tssconsultants.com unless other arrangements are requested in advance. Please limit your responses to no more than 30 pages. Candidate's responses should be delivered in digital format (no need to send hardcopies).

Contact: All communications should be directed to Matt Hart, TSS Consultants. Email: mhart@tssconsultants.com, Tel: 650.796.6288.

Appendix 6. The Value of the Benefits of U.S. Biomass Power

Subcontractor Report

November 1999 • NREL/SR-570-27541

The Value of the Benefits of U.S. Biomass Power

G. Morris
Green Power Institute
Berkeley, California

National Renewable Energy Laboratory

1617 Cole Boulevard
Golden, Colorado 80401-3393

NREL is a U.S. Department of Energy Laboratory
Operated by Midwest Research Institute • Battelle • Bechtel

Contract No. DE-AC36-99-GO10337

November 1999 • NREL/SR-570-27541

The Value of the Benefits of U.S. Biomass Power

G. Morris
Green Power Institute
Berkeley, California

NREL Technical Monitor: R. Bain

Prepared under Subcontract No. AXE-9-18132

National Renewable Energy Laboratory

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Executive Summary

The U.S. biomass industry is at a crossroad. The contribution of biomass power generation is second only to that of hydropower among the renewables to the national energy supply. Biomass has always been used to generate power in the forest products industry, but its widespread use for supplying power to the U.S. grid is a relatively recent phenomenon, a response to the energy crises of the 1970s. Today independent biomass power generators supply 11 billion kWh/yr to the national electricity grid and, in the process, provide an environmentally superior disposal service for 22 million tons/yr of solid waste.

The problem is that, in the current environment of cheap fossil fuel supplies and deregulation of the electric utility industry, biomass power generation may be unable to compete. The inherent cost of power generation from biomass is high for two principal reasons: (1) Biomass is a low-density fuel, so fuel production, handling, and transportation are more expensive than for fossil fuels; and (2) because of the dispersed nature of the resource, biomass power generating facilities tend to be small, so they cannot capture the economies of scale typical of fossil fuel-fired generating facilities. These characteristics leave biomass generation at a distinct disadvantage in a market that is increasingly driven by cost.

The great dilemma for public policy is that, although biomass power generation is expensive, it also provides very valuable waste disposal services that would be lost if the industry were to fail. Shrinkage of the industry in several regions during the past few years means that residues previously used for energy production are now being open burned or buried in landfills. Jurisdictions that have trouble meeting environmental mandates are finding their efforts at compliance completely trumped when they experience a drop in demand for biomass fuels.

This report describes an attempt to estimate the value of the ancillary services provided by biomass power generation, in order to provide policy makers with a yardstick against which to judge the cost of policy interventions that might preserve the viability of the biomass power industry. The following categories of impacts are considered:

- Criteria air pollutants
- Greenhouse gas emissions
- Landfill capacity use
- Forest and watershed improvement
- Rural employment and economic development
- Energy diversity and security

This report uses an analytical approach to compare the impacts of biomass energy production with that of alternative disposal of the residues, as well as of the alternative provision of the energy product. The principal alternative fates for biomass residues in the absence of energy production are open burning, landfill burial, and accumulation in forests. Approximately half the biomass fuels used by the independent biomass power industry in the United States today would be buried in landfills. Another third would be open burned. The remainder would be spread, composted, or remain as overstocked material in the forests.

Open burning of biomass residues produces massive emissions of smoke that contains particulates and other pollutants. Landfill burial of biomass residues accelerates the depletion of landfill capacity and leads to much higher emissions of greenhouse gases compared to controlled combustion of the material in power plants. Failure to thin and remove excess biomass from overgrown forests depresses forest health and productivity, increases risks of catastrophic wildfires, and degrades functioning of watersheds.

The environmental services provided by biomass power production are clearly valuable to society. Just *how valuable*, however, is not a simple question. The marketplace for environmental services provides some insights. The best market values available in the literature for criteria pollutants, greenhouse gases, landfill use, and mechanical thinning of forests are applied to the savings in these quantities associated with biomass energy production, allowing the calculation of a value for the environmental services provided, at least within the context of the categories included in the analysis. Based on a base-case, conservative analysis, the value of the environmental services associated with biomass energy production in the United States is 11.4 ¢/kWh. Moreover, this value includes none of the desirable benefits of rural employment, rural economic development, and energy diversity and security provided by biomass energy production.

A major contributor of value in the overall benefits calculation consists of greenhouse gas emissions. Greenhouse gas emissions are currently not regulated in the United States, and enacting programs to limit them is controversial. Counting greenhouse gas emissions at zero value leaves a residual value for the environmental benefits of biomass energy production for all other impact categories of 4.0 ¢/kWh. Taking minimum estimates for the values of all impact categories included in the analysis, the computed value of the nonelectric benefits of biomass energy is 4.7 ¢/kWh. Using a long-term perspective for the delayed emissions from landfills yields a calculated benefit value of 14.1 ¢/kWh.

Current experience in California with support payments in the amount of 1.5 ¢/kWh shows that this level of support apparently provides the incentive needed for the continued operation of biomass energy facilities. However, the rest of the country has no such program, and the support program in California will be scaled back at the end of 1999, and eliminated two years later. The future of the industry may depend on the enactment of policies that provide tangible, ongoing compensation to biomass generators for the ancillary services they currently provide free of charge. The amount of compensation needed is only a small fraction of the value of the benefits preserved. Demonstrating that there will be a substantial net benefit to society from policies that preserve the viability of the biomass energy industry in the United States is easy.

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1.0 Introduction: Description of the U.S. Biomass Energy Industry

The biomass energy industry in the United States is one of the greatest, but least known, successes of the late 1970s. It enhances energy security and improves the environment. Biomass power plants today provide 2,410 MW of power to the national power grid, and an additional 5,035 MW of power directly to industrial energy users, particularly in the wood products industry. Biomass power generation consumes more than 100 million tons/yr of fuel, virtually all of which is waste or residue material that requires some form of treatment and disposal.

This report focuses on the segment of the biomass power industry that, because of changing conditions in the electric utility industry, is most vulnerable to extinction: the facilities outside the pulp and paper industry, and that generate power for distribution and sale through the interconnected electric utility grid. This segment consists of more than 100 operating biomass generation facilities in 23 states. These facilities provide 1,860 MW of power generating capacity to the U.S. grid, and provide for the disposal of 22 million tons/yr[1] of waste and residue material. This segment would become eligible for the IRS Section 45 tax credit, should legislation currently under consideration by Congress be enacted into law.

This report presents the results of a study of the environmental and social benefits associated with biomass power production in the United States today. The approach involved conducting a literature search to identify the types and magnitudes of benefits provided by biomass power production, and the economic or dollar value of the benefits categories of interest. Readily available data were plugged into a model that computes the values of the identified and quantified benefits of biomass power production. The model traces the benefits from their sources, such as the avoided landfill disposal and avoided open burning of biomass residue materials. Avoided emissions, landfill use, and forestry improvements are quantified, and economic values are applied to the measures. Finally, the value of the alternative disposal activities is compared to the value of the energy option, allowing the value of the net cost or benefit of the energy pathway to be computed.

[1] Biomass fuels are sometimes reported in terms of green tons, and other times as bone dry ton (bdt) equivalents, which is a measure of the fiber content of the material. Green tons are used in the text of this report, except as indicated otherwise. Twenty-two million green tons/yr are equivalent to 11.9 million bdt/yr.

2.0 Sources of Benefits: Alternatives for Biomass Residue Disposal

The biomass energy industry in the United States has always performed two separate and important functions: energy production and waste disposal. Each has important environmental implications. Energy production from biomass entails emissions during a variety of energy conversion processes, while avoiding the emissions associated with the production of a like amount of energy from fossil fuels. At the same time, disposal in biomass energy facilities avoids the environmental impacts associated with alternative disposal fates for the residues used as fuel, such as landfill burial or open burning. The latter effects constitute the most important source of environmental benefits associated with the production of energy from biomass resources.

2.1 Biomass Fuel Use and Alternative Disposal Options

The U.S. independent biomass energy industry[2] today provides for the disposal of approximately 22 million tons/yr of solid biomass waste. Figure 1, for example, shows the history of biomass fuel use in California during the past 20 years, illustrating the rapid growth of biomass fuel use during the 1980s, followed by a decline during the mid-1990s. The pattern of biomass fuel use shown is typical of occurrences across the country.

The biomass residues used as power plant fuels come from a variety of sources, and would be subject to a variety of alternative fates if the biomass industry were not an available disposal option. The major categories of biomass fuels used in the United States today include:

- Wood processing residues
- In-forest residues
- Agricultural residues
- Urban wood residues

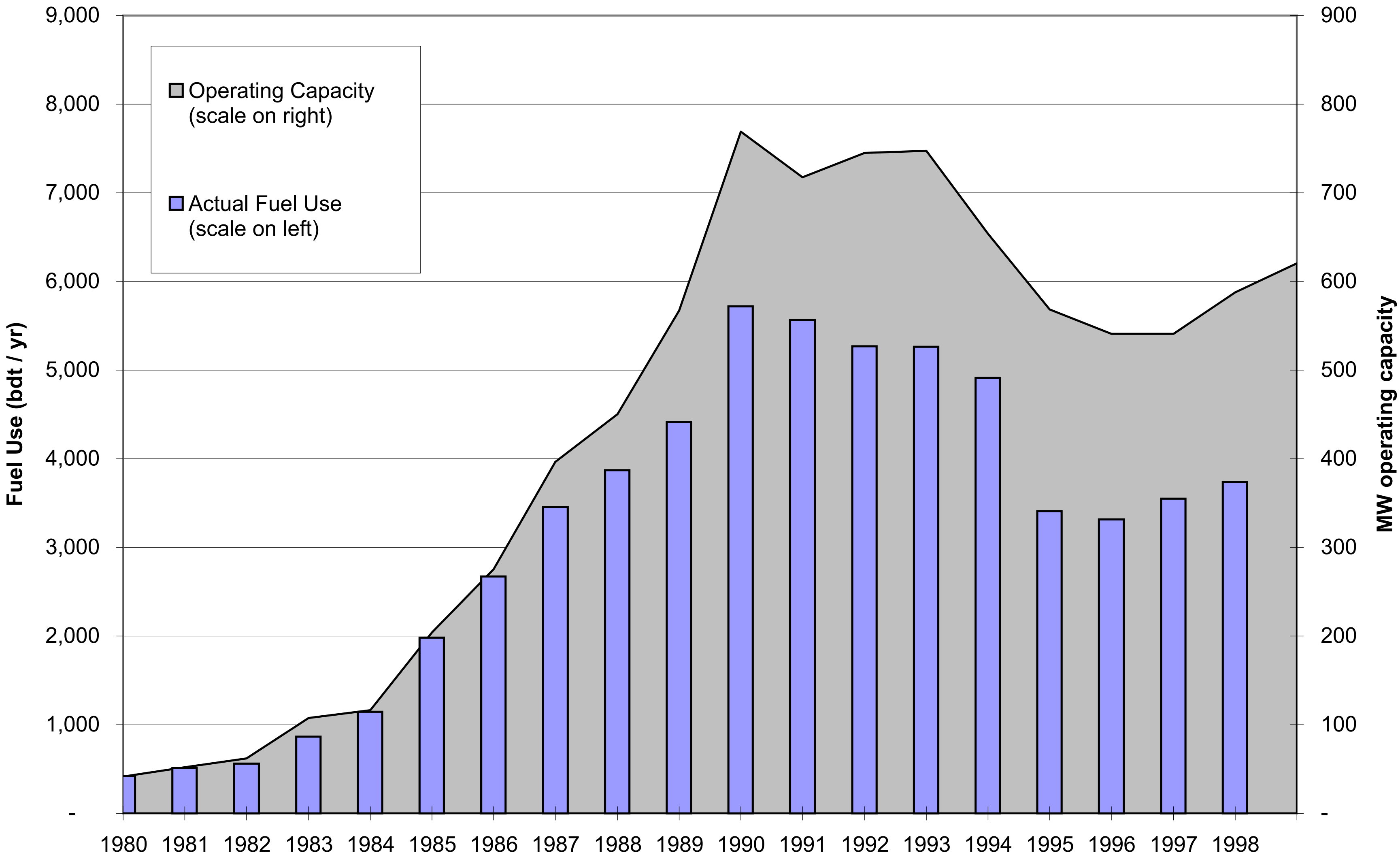
To account for the nonmarket societal costs and benefits of using biomass residues to produce energy, the impacts associated with energy production have to be compared with the consequences of the alternative fates the residues would experience in the absence of energy production. Thus, these fates must be characterized for the various residues and their associated impacts, as well as for the impacts of energy production, to determine the net environmental implications of biomass energy use.

In many regions of the United States the biomass energy industry has become an integral part of the solid waste disposal infrastructure. If the biomass industry were to fail, finding new disposal outlets for all the biomass residue material currently being used for fuel would be difficult. Identifying the probable alternative fates for these residues is also difficult. The major categories of alternative (nonenergy) disposal options for biomass residues include:

- Open burning of agricultural and forestry residues
- Landfill disposal of waste wood
- Composting and land application of waste wood
- Land spreading of wood chips and bark as mulch and cover
- In-forest accumulation of residues as downed and over-growth material

[2] This paper defines the independent biomass energy industry as that segment of the industry that is outside the pulp and paper industry, and that sells electricity into the grid-connected market.

Figure 1: California Biomass Power Capacity



Open burning of biomass residues leads to heavy emissions of smoke and air pollutants. Landfill disposal of recyclable biomass accelerates landfill capacity depletion, and increases emissions of greenhouse gases. Composting and spreading also lead to higher greenhouse gas emissions than does energy production, and although growing rapidly, the markets for these materials are limited. In-forest accumulation of excess biomass residues degrades forest health, retards forest growth, diminishes watershed productivity, and increases the risk of destructive wildfires.

2.1.1 Wood Processing Residues

Wood processing residues constitute the most important biomass fuel source used in the United States, consistently accounting for more than 50% of the country's total biomass fuel supply. Almost half the biomass content of a typical sawlog becomes residue at a primary sawmill. A variety of secondary forest products applications have been developed to use a portion of this material. Active markets for wood processing residues in many regions include pulp chips, wood fiber for fiberboard and composites, animal bedding, and garden products such as decorative bark. Sawmills are used to segregating their residues into the highest-value markets available, but a substantial amount of the residues, typically 15%–20% of the biomass content of the sawlogs brought to a sawmill, have no useful application and must somehow be disposed. Biomass power plants have become the disposal option of choice for much of this material.

Wood processing residues come in a variety of forms, including:

- Bark
- Round-offs
- End cuts
- Trimmings
- Sawdust
- Shavings
- Reject lumber

The traditional method used to dispose of wood processing residues at sawmills was incineration in "teepee burners," a technology that produces copious amounts of smoke and other air pollutants. Beginning in the early 1970s, air pollution control efforts applied increasing pressure on sawmills to close down their teepee burners, leading them to search for new disposal alternatives. This was an important factor that led to the development of the biomass power industry during the 1980s. In regions as diverse as California, Maine, and North Carolina, virtually all the readily available wood processing residues that have no higher-valued applications are used as power-plant fuel. Wood processing residues are the cheapest form of biomass fuel to produce and deliver. They would probably be the last type of biomass fuel to exit the system if the demand for biomass fuels were to decline.

Because of their severe air pollution problems, teepee burners have been largely eliminated as a disposal option for wood processing residues. The only readily available option for disposing of these materials, if fuel use were not a possibility, is landfilling. However, landfilling of waste wood is an undesirable option for a variety of reasons. Waste wood has a slower decay rate than other biomass forms, and is thus slow to stabilize in the landfill environment. It takes up 15%–20% percent of the space in a typical county landfill, and its decay leads to emissions of methane (CH_4), a more potent greenhouse gas than carbon dioxide (CO_2).

If the biomass energy industry were to collapse, a strong effort would probably be made to develop alternatives to landfilling. Nevertheless, for purposes of analysis, the probable alternative fate for most wood processing residues currently used for power production is landfill disposal. Some of the residues would probably be composted or land spread. Table 1 shows a breakdown of the probable alternative fates for wood processing residues in the absence of energy production, as well as other categories of biomass residues used for energy production in the United States.

Table 1: Alternative Fates for Biomass Fuels

	Mill	Forest	Ag	Urban	Total
US Biomass Fuel Use (th.bdt/yr)	6,400	1,800	2,300	1,400	11,900
Alternative Fate (% of category)	Mill	Forest	Ag	Urban	
open burning	5%	50%	100%		
landfill	70%			90%	
composting	10%			10%	
spreading	15%				
forest accum.		50%			
Alternative Fate (th.bdt/yr)	Mill	Forest	Ag	Urban	Total
open burning	320	900	2,300	-	3,520
landfill	4,480	-	-	1,260	5,740
composting	640	-	-	140	780
spreading	960	-	-	-	960
forest accum.	-	900	-	-	900

th.bdt = thousands of bone-dry ton equivalents, which is a measure of the dry weight of biomass fuels

2.1.2 In-Forest Residues

In-forest residues constitute a major source of biomass fuels in the United States. Timber harvesting operations produce forest residues in the forms of slash (tops, limbs, bark, broken pieces) and cull trees. If left in place these residues are unsightly, impede forest regeneration, and increase the risk of forest fire. Increasingly, harvesting plans on public and private lands require some form of residue management, which usually means either piling and burning, or removal and use as fuel. Logging slash is an important source of biomass fuel in several regions.

In addition to logging residues, forest treatment residues (thinnings) comprise an important source of fuel for the biomass energy industry. Because of past forestry practices and aggressive fire-fighting efforts during the past 80–100 years, vast areas of American forests are overstocked with biomass material, which represents an increased risk of destructive wildfires and a generally degraded functioning of the forest ecosystems. These forests benefit greatly from mechanical thinning operations. The amount of in-forest biomass residues that could be converted to energy is far greater than the total amount of biomass fuel demand in most regions of the country. However, this fuel source is generally more expensive to produce than other biomass fuels, so the quantity used is less.

As the market for biomass fuels has retracted in the United States, the amount of logging residues converted to fuel use has remained relatively constant, because of its link to the lumber market. The major adjustment has been in the quantities of thinnings being collected and converted to fuel. Most logging residues used for energy production would be pile burned, if energy applications were not available. On the other hand, forests would simply not be thinned, so material of this origin would accumulate as excess biomass. As shown in Table 1, this analysis assumes that 50% of the in-forest residues used for fuel would otherwise be pile-burned, and the other 50% would accumulate in the forest.

2.1.3 Agricultural Residues

Agricultural operations produce large quantities of residues, which come in a wide variety of forms and consistencies. Agricultural residues suitable for use as power plant fuels include:

- Food processing residues such as pits, shells, and hulls
- Orchard and vineyard removals
- Orchard and vineyard prunings
- Field straws and stalks

Most of these residues require some form of treatment as a part of normal agricultural practice. In most cases the lowest-cost treatment option is open burning, a major source of smoke and air pollution. Avoiding agricultural burning is a principal reason biomass energy facilities have been developed.

In California, for example, approximately one-third of the biomass power plants were built in agricultural regions, and most are permitted on the basis of the state's agricultural offsets protocol, which provides air emissions offsets for pollutants that are avoided when biomass residues that would otherwise be open burned are used as fuel. During the 1990s agricultural fuels have consistently supplied about 20% of California's biomass fuel supply. More than 1 million tons/yr of agricultural residues are used as biomass fuel.

Most of the agricultural residues used as fuels in California are woody residues derived from the state's extensive orchard crops. Whole-tree chips produced from orchard removals constitute a particularly successful source of biomass fuel. Fuels are also produced from orchard prunings, vineyard removals and prunings, and other types of residues such as straws and food processing residues. Even with the present level of agricultural biomass fuel use in California, an enormous amount of agricultural residues suitable for use as power plant fuels continues to be open-burned. The alternative fate for the agricultural residues used for fuel is open burning (see Table 1), although a small percentage of these materials could be landfilled or plowed under.

2.1.4 Urban Wood Residues

As much as 15%–20% of the solid waste traditionally disposed of in U.S. landfills is clean wood waste that can be segregated and converted into power plant fuel. This material comes from a variety of sources, including:

- Construction and demolition wood waste
- Wood and brush from land clearing
- Wood and brush from public and private tree trimmers and landscapers
- Wood waste from the manufacturing of cabinets, furniture, and other wood products
- Discarded pallets and drayage

The traditional disposal option for urban wood waste is burial in landfills. However, the alternatives that might be used for this material in the future, should the fuels market disappear, are more complicated to project. For example, California's solid waste diversion law mandates that by the year 2000 all counties must achieve a diversion rate of 50% of their total solid waste, compared to their performance during the designated base year of 1990. An intermediate target of 25% diversion by 1995 was met statewide, but compliance with the year 2000 standards will be more difficult to achieve.

During the 1990s, landfill-diverted waste wood has supplied approximately 1.5 million tons of fuel annually to the California biomass power industry, hitting a peak of 1.9 million tons in 1993. As the overall biomass fuels market has declined, the percentage of landfill-diverted fuels in the state's biomass fuel mix has increased, from approximately 20% at the beginning of the decade, to 30% today.

Solid waste managers are under pressure to develop diversion applications of all kinds, and at least some of the material currently used as fuel would presumably be diverted into some other outlet, were it not used as fuel. For purposes of analysis, most of the waste wood currently diverted from landfills and converted into biomass fuel would otherwise be buried in the landfills. As shown on Table 1, 90% of the urban biomass fuels would otherwise presumably be landfilled; the other 10% would be composted.

2.2 Environmental Impacts of Disposal Alternatives

All alternatives for the disposal of biomass wastes and residues, including leaving forest residues in place, entail environmental impacts. Energy production from biomass residues produces air pollutants and solid waste (ash), and consumes water resources. These impacts must be balanced against those impacts that would occur if the energy alternative were not available, including the impacts of alternate disposal of the material used as fuel, and the impacts of alternative production of the electricity that must be supplied to the market.

2.2.1 Environmental Impacts of Open Burning

Open burning of forestry and agricultural biomass residues is a major source of air pollution in many regions. Open burning produces massive amounts of visible smoke and particulates, and significant quantities of emissions of nitrogen oxides (NO_x), carbon monoxide (CO), and hydrocarbons that contribute to the formation of atmospheric ozone. Quantifying the emissions resulting from open burning is difficult because residues, burning practices, and environmental conditions are extremely variable. Nevertheless, use of these residues as power plant fuel vastly reduces the smoke and particulate emissions associated with their disposal, and significantly reduces the amounts of CO, NO_x, and hydrocarbons released to the atmosphere.

Open residue burning is a particularly big problem in California's agricultural valleys, many of which are classified as nonattainment with respect to federal air quality standards for criteria pollutants. Decreasing the amount of open burning of agricultural residues in California has long been an objective of air quality regulators, but the imperative for farmers to dispose of their residues cost effectively has prevented the banning of agricultural burning. The development of the biomass power industry during the 1980s helped mitigate the problem, but a great deal of residue continues to be open burned. At the peak of biomass fuel use in California from 1990 to 1993, more than 1.5 million tons/yr of agricultural residues were used as fuel. The decrease in biomass fuel use since 1993 has led to a decrease in the use of agricultural residue fuel. As a result, 0.5 million tons/yr of agricultural residues used as fuel as recently as 1993 are once again being disposed by open burning.

The state's air quality regulatory agencies recognized early that the biomass power industry could help eliminate open burning of agricultural residues. To give the biomass power producers credit for the air quality benefits they provide, regulators developed a set of agricultural offset protocols, through which facilities that burn agricultural residues that would otherwise be open burned earn an offset for their emissions of pollutants at the power plant. Because emission offsets are required only for pollutants for which the receiving basin is nonattainment, most agricultural offsets have been for emissions of NO_x and particulates. For most facilities that were permitted on the basis of the agricultural offset protocols, the permits require that one-half to two-thirds of their fuel be obtained from agricultural residue sources.

One of the largest efforts to measure the emissions of open burning of biomass was undertaken by researchers at the University of California, Riverside (Darley 1979). The emission factors reported from this study were used as the basis for developing agricultural offset protocols, and remain the best, albeit limited, source of data on emissions from the open burning of biomass. AP-42, the U.S. Environmental Protection Agency's (EPA) compilation of air pollution emissions from a variety of industrial activities, uses the Darley data and other sources to characterize the emissions typical of open burning of a variety of biomass residues, under various conditions. Table 2 shows emissions estimates for open burning of biomass residues under various conditions, as well as emissions factors for other activities described in the following sections.

2.2.2 Environmental Impacts of Burial

Recoverable wood waste represents approximately 15% by weight, and as much as 20% by volume, of the material that typically enters sanitary landfills. All these materials enter the landfill gate separate from mixed household garbage.

Separable wood residues enter the landfill in debris boxes, roll-off bins, vans, and pickup trucks. In the absence of a fuel-use option, they are buried along with other wastes entering the landfill gate. Some landfills segregate and shred inbound waste wood to use as daily landfill cover or for other applications, but this represents a small fraction of the total recoverable resource, and these applications would be unlikely to expand significantly if the fuel market collapsed. Indeed, there is reason to believe that nonfuel applications would actually decline if the fuel market collapsed, because the production of these products in most cases depends on the coproduction of fuel, and loss of the fuel market would render production of the other products less viable.

Landfill burial of the wood residues that can be recovered and converted into power plant fuel entails the same kinds of environmental impacts associated with the disposal of all kinds of organic wastes in landfills. Compared to other types of organic wastes, woody materials are slow to degrade, which means that landfill stabilization is delayed. Like all organic material in the landfill, waste wood can be a source of water-polluting leachates, and as the material degrades, it produces emissions of CH_4 and CO_2 in roughly equal quantities. Methane and CO_2 are both greenhouse gases, but CH_4 is much more reactive, by a factor of some 25 times per unit of carbon (IPCC 1996), so emissions of the residue-bound carbon in the form of a 50:50 mix of CH_4 and CO_2, rather than as pure CO_2, are far more damaging from the perspective of greenhouse gas buildup in the atmosphere (Morris 1992).

Large landfills are now required by EPA regulations to control their fugitive emissions by collecting a portion of the landfill gas and flaring it. For example, approximately 60% of the landfills in California, which receive 80%–95% of the state's solid waste, are covered by this regulation. In general, gas collection systems capture about 80% of the CH_4 released by the landfill, which means that final emissions of the waste carbon to the atmosphere are approximately 90% CO_2 and 10% CH_4 (compared with approximately 50:50 for an uncontrolled landfill). Emitting the carbon in the 90:10 mixture of CO_2 and CH_4 results in an effective greenhouse gas emission 3.4 times more potent than emissions of the same amount of carbon in the form of 100% CO_2. For uncontrolled landfills, the 50:50 mixture of the gases emitted leads to an effective greenhouse gas emission 13 times more potent than emissions of the same amount of carbon in the form of 100% CO_2. The only effective means of eliminating CH_4 emissions from the disposal of wood residues that would otherwise be buried in a landfill is to use the material as fuel. Table 2 shows emissions factors for burial of waste wood in landfills.

Use of waste wood as a fuel results in immediate emissions of CO_2; burial of the material in a landfill results in delayed emissions of CO_2 and CH_4. Wood waste decays slowly in the landfill environment, so emissions of most ultimate landfill gases are significantly delayed. This should be taken into account in

Table 2: Emissions Factors for Biomass Disposal Activities and Alternative Energy Production

	SO_x (lb/th.bdt)	NO_x (lb/th.bdt)	particulate (lb/th.bdt)	CO (lb/th.bdt)	CH_4 (lb/th.bdt)	nmHCs (lb/th.bdt)	CO_2 (ton/th.bdt)	landfill (m^3/th.bdt)	thinned (acres/th.bdt)
biomass energy *	150	2,500	450	7,500	250	25	1,780	24.2	
open burning	150	7,000	15,000	150,000	8,000	24,000	1,690		
landfill					430,000		1,200	2,400	
composting--immediate					33,000		850		
composting--delayed					65,000		800		
spreading					130,000		1,600		
forest accum.	150	7,000	21,000	280,000	7,000	23,000	1,690		40
coal (unit/mmkWh)	3,500	3,100	140	960	15	290	1,100	43.9	
gas/st (unit/mmkWh)	6	270	80	910	25	60	600		
gas/cc (unit/mmkWh)	5	85	330	860	130	60	450		

* Note that for biomass energy production, unit/th.bdt is approximately the same as unit/mil.kWh)

an analysis that compares the two options. The immediate result of diverting landfill-bound waste wood to a power plant is that virtually all the carbon content is added to the atmospheric stock of CO_2, rather than being stored underground as buried waste. This means that the atmospheric greenhouse gas burden associated with the biomass residue used as fuel is greater in the immediate aftermath of its combustion than if the material were landfilled. Over time, however, the landfill out-gases a mixture of CH_4 and CO_2, and the much greater radiative effectiveness of CH_4 rapidly leads to a greater greenhouse gas burden, which eventually becomes a major liability for the landfill option, even with the use of gas-control systems on landfills.

2.2.3 Environmental Impacts of Spreading and Composting

An alternative disposal option to landfilling biomass wastes is surface spreading, which can be done with or without prior composting of the material. Bark and wood chips can be used directly for mulch, which usually consists of open spreading of the untreated material. Biomass can also be composted before spreading, although woody material is not ideal for composting, because it breaks down more slowly than other types of biomass residues, such as residential green waste.

Composting of biomass residues accelerates the natural decomposition process. Decomposition occurs through aerobic and anaerobic pathways, producing a mixture of CO_2 and CH_4 emissions. In a well-managed compost operation the emissions are primarily CO_2, because of frequent aeration of the material. The compost product, which contains approximately 50% of the original biomass carbon, is then spread, where it continues to decompose, although no longer at an accelerated pace. Table 2 shows estimates of the greenhouse gas emissions associated with composting and/or spreading of biomass residues.

2.2.4 Environmental Impacts of In-Forest Accumulation

All forests are prone to periodic fires. However, the natural fire cycle has been altered in many regions of the United States by past forestry practices, by vigorous fire suppression efforts, and by increasing populations in wooded areas. These phenomena have increased the amount of fuel loading and degraded forest health and productivity (see, for example, Cal. Dept. of Forestry 1996).

The fuel building up in the nation's forests includes standing dead and diseased wood, downed woody material of all varieties, and an overall increase in the density of the forest growing stock. The accumulation of dead and diseased wood, both standing and downed, is particularly problematic from a forest fire risk perspective because it usually has a lower moisture content than growing stock, making it easier to ignite, hotter burning, and more prone to spreading of fire. As the fuel loading continues to increase, fires that burn out of control tend to be much more severe and destructive than the naturally occurring periodic fires that were a component of the pre-industrial ecosystem. They burn much hotter than the traditional fires, and consume much larger areas with more extensive destruction. Table 2 shows estimates of the emissions associated with forest fires in overstocked forest conditions.

Fuel overloading also contributes to the degradation of the health and ecosystem functioning of forests and watersheds. For example, healthy, relatively undisturbed forest ecosystems in California have approximately a 40% level of canopy closure, whereas other forests have an approximately 60%–65% or more canopy closure level. This elevated level means that the amount of available rainfall that enters the evapotranspiration cycle is higher than in the native ecosystem, and less of the rainfall moves through the watershed as runoff and groundwater. Reduced flows of runoff and groundwater mean that less water is transferred to the meadows and lowlands, where water is stored during the rainy season and released gradually during the dry season.

The net result of this chain of events is that useful water production from many watersheds is lower than if the forests were in a more natural condition. This includes water for human consumption, and environmental water available for river and delta ecosystems. An effective, sustained thinning program in key watersheds could increase useful water supplies without further development of water supply infrastructures. Several experimental programs are underway to prove this connection, and to provide data on the amounts of water production that will result from thinning and other watershed improvement operations (Cal. Dept. of Water Resources 1994). A great deal of work remains to be done to understand the relationship between watershed improvement activities and the rate of water production from the treated watershed.

2.2.5 Environmental Impacts of Energy Production, Including Fossil Fuel Alternatives

Combustion of biomass fuels in modern power plants leads to many of the same kinds of emissions as the combustion of fossil fuels, including criteria air pollutants, greenhouse gases, and solid wastes (ash). Fuel processing, which in most cases involves some type of grinding operation, produces emissions of dust and particulates. Air emissions and water consumption are usually the principal sources of environmental concern related to biomass facilities.

Biomass power plants are required to achieve stringent emissions control levels for the criteria, or regulated, pollutants. These include particulates, NO_x, oxides of sulfur (SO_x), hydrocarbons, and CO. NO_x, hydrocarbons, and CO are usually controlled by using advanced combustion technologies, often including fluidized-bed combustors, staged-combustion, and flue-gas recirculation. Some of the newest biomass power facilities are required to use ammonia injection to further control NO_x emissions. SO_x emissions generally are not a concern with biomass combustion because biomass, especially woody forms of biomass, has a very low sulfur content. Some facilities that have fluidized-bed combustors inject limestone to capture sulfur, but no biomass facilities are required to have flue-gas scrubbers to control SO_x emissions.

Particulates are controlled using a variety of technologies. Virtually all biomass power plants use cyclones to remove most large particulates from the flue gas. Most biomass facilities are equipped with electrostatic precipitators for final particulate removal; some facilities use baghouses. Most modern biomass power plants are required to achieve zero visible emissions to meet environmental permit conditions. Their emissions of total and sub-micron particulates are also regulated and controlled to stringent levels, comparable to or better than the emissions levels achieved by the large fossil fuel power plants operated by the electric utility companies.

Table 3 shows average emissions levels of the criteria pollutants for biomass power generation. The data are based on information supplied by 34 California biomass facilities, and include permitted emissions levels and actual source test data. The data are further differentiated by combustor type. Eleven of the 34 facilities have fluidized-bed combustors; the other 23 have grate-burners of various designs. The fluidized-bed combustors achieve lower emissions levels of all criteria pollutants of concern for biomass power plants, compared to the grate burners. The most dramatic difference is in CO emissions, for which the fluidized-bed combustors are more than an order of magnitude better than the grate-burners. The fluidized-bed combustors achieve emissions factors of half or less than the grate-burners for all pollutants for which data are available.

Table 3: Emissions from Biomass Power Plants

(lb/bdt)

	Permit Levels			Measured Emissions		
	All	Grates	FBs	All	Grates	FBs
NO_x	2.6	3.1	1.5	2.0	2.5	1.0
SO_x	1.2	0.9	1.7	0.1	NA	0.1
CO	11.5	16.3	2.0	10.3	14.7	0.2
HCs	1.7	1.8	1.6	0.5	0.7	0.1
Particulates	0.8	1.0	0.6	0.5	0.6	0.3

Data averaged for 34 California biomass facilities, 23 Grates, 11 fluidized-bed burners.

The production of electricity in biomass power plants helps reduce air pollution by displacing the production of power using conventional sources. There is considerable geographic variability, but the marginal generating source displaced by biomass generation in most cases in the United States is either natural gas-fired power generation or coal-fired power generation. The full net emissions reductions associated with biomass power generation can be calculated as the difference between the net emissions associated with the biomass power cycle alone, and those that would be produced by fossil fuel-based generation, which would be used if the biomass-generated power were not available. Table 2 shows emissions factors for fossil fuel-fired electricity production, based on AP-42 and other sources. These data include only the emissions at the power plant, not those associated with producing and processing the fuels.

2.3 Social Costs and Benefits of Disposal Alternatives

In addition to the environmental benefits of energy production from biomass fuels, biomass energy production provides important social and economic benefits to rural areas. These include high-quality jobs, the generation of local and regional tax revenues, and energy diversity and supply security for regional and national energy systems.

2.3.1 Rural Employment and Taxes

The specific nature of a biomass power plant's fuel supply is the primary determinant of both its design and location. Because most facilities use significant components of agricultural or forestry residuals, most are located in rural areas dominated by resource-based economies. These communities are often characterized by slow economic growth rates and high unemployment. Biomass power facilities mean jobs with good comparative wages. Power plant employees receive attractive benefits packages, and in many cases support workers engaged in fuel-production operations do as well. Support jobs are generated at a ratio of almost 2:1 compared to plant employment, with total employment equal to 4.9 full-time jobs per each megawatt of net plant generating capacity. The long-term nature of this employment provides durable improvement and added stability to the local and regional economies surrounding the plants.

Biomass power plants also make important contributions to the tax base of many rural communities. In many cases biomass power plants are the largest single property tax payers in their respective jurisdictions. The facilities also generate income taxes and sales taxes from their employees and from the workers that support them.

2.3.2 The Benefits of Energy Diversity and Domestic Supply

Although more than two decades have passed since the oil embargoes of the 1970s, the United States remains energy-deficit, importing nearly 60% of its petroleum. In the event of a major supply disruption, electricity generation could be severely affected. Additionally, the present concentration of large power plants at grid centers in urban areas makes power supply vulnerable to both natural and human-caused destruction. The scale and dispersion of biomass energy facilities, and their renewable fuel supply in primarily rural areas, provide a low probability of grid-related or human-caused failure. Indeed, during the heat-related brownouts of 1996 in California, all biomass plants remained online while many large utility plants reduced load or went offline completely.

The biomass power industry also contributes to the potential of biomass energy use in general, in all its possible manifestations. The federal government has invested a significant amount of money and effort to develop new technologies and applications for biomass energy, including advanced electricity generating technologies and liquid fuel technologies. Many projections of energy supplies for the United States envision an increasing role for biomass. The future of biomass energy production, whatever direction it might take, will inevitably be built on the foundation of the industry that has already been created.

3.0 Value of Benefits: Estimates of the Dollar Value of Ancillary Services

Conversion of biomass wastes and residues to energy provides great environmental benefits by reducing the amount of air pollution, greenhouse gas emissions, and landfill use associated with their disposal, by promoting healthier forests, contributing to rural economies, and displacing the use of fossil fuels. Placing monetary values on these environmental and social benefits is more difficult. This study uses literature values for the dollar value of various environmental impact categories, and applies them to the impacts of biomass energy production, and the activities it avoids. The net value of biomass energy production is calculated as the difference between the costs of the impacts of energy production, and the costs of the alternative disposal options and alternative power provision.

3.1 Values of Environment Costs and Benefits

This analysis focuses on the environmental benefits of the current biomass power industry, and their quantification. Because of uncertainties in assigning dollar values to the various impact categories, ranges of values that encompass current economic thinking on the subject, observed and forecast market values, and the effects of current regulations and economic conditions, are presented in Table 4. Most are transaction values based on “cap and trade” systems. They represent societal values for marginal reductions in emissions, assuming that society has correctly determined an optimal “cap” for the emissions. Evidence suggests that there is still substantial damage, mortality, and morbidity at the current capped levels. In such a case, these market values represent a “floor” value of the benefits of marginally reducing emissions. The real societal values may well be higher.

Many of the air pollutants shown in Table 4 have multiple values because there are different prices for these emissions in different markets. Prices are generally higher in more densely populated areas, and often vary from one region to another. The appropriate prices must be used when quantifying the value of current biomass generation. There may be one value for substitute generation located near load centers in urban areas, and another for disposal of the biomass that would have been consumed in generally rural facilities. For analytical purposes, the same values are used throughout for each given impact category. This represents conservatism in the analysis.

3.1.1 Value of Criteria Pollutants

SO_x: There is a wide and active trading market for sulfur dioxide (SO_2) emissions because of the EPA Acid Rain Program. Prices tend to be stable and uniform, signs of a maturing market. The values in Table 4 are indicative of current prices for trades. They are almost double the prices of a year ago, and reflect Phase II of the Acid Rain Program. They represent good long-term societal values for analytical purposes.

NO_x: NO_x values vary more than other criteria pollutants. Prices vary by location and season. These differences should be considered when determining the benefit/cost of reducing or increasing NO_x emissions. This means that the cost of increases in NO_x emissions associated with substitute generation near populated load centers may be greater per unit than the cost of increases in NO_x emissions for disposal of wood waste as power plant fuel in a rural environment. NO_x values cannot be varied, Cantor Fitzgerald Environmental Brokerage Services average national price index for NO_x can be used.

Table 4. Biomass Benefits

Category	Value (1999$, 1st quarter)	Source	Comments
SO_2	\$206–\$212/ton	Market prices for the first half of 1999 reported by brokerage firms and the Fieldston Publications market survey as reported by the EPA Acid Rain Program.	These prices are indicative of current prices for trades. They are almost double the price a year ago and reflect Phase II of the Acid Rain Program. They are better long-term prices than those of a year ago.
NO_X	Cantor Fitzgerald Market Price: 2000–\$2,100/ton 2000-02–\$2,018/ton New England: Ozone Season – \$1000– 1,050/tpy Non-Ozone – \$650–700/tpy Mid Atlantic (NY, PA) Severe – \$5,000/tpy Moderate – \$2,000/tpy California (ERCs): San Joaquin Valley – \$9,733/tpy Bay Area – \$6,500/tpy	Cantor Fitzgerald Environmental Brokerage Services	NO_X prices vary quite a bit regionally, and by time of year. Values are generally higher in the California, urban areas and during the summer. The C-F Market Price is a good compromise for a single value, but regional values should be used, with lower values for rural areas (unless rural area is a non-attainment area, i.e., California).
CO_2	Current Transactions: \$0.45–\$1.81/ton CO_2 SGM (Administration) \$7.74–\$41.47/ton CO_2 EIA/NEMS (2010 Price): \$18.94–\$83.10/ton CO_2 Markel-Macro Model (2010 Price): \$25.01–\$41.74/ton CO_2	Cantor Fitzgerald Environmental Brokerage Services *Unfinished Business: The Economics of the Kyoto Protocol*, Battelle PNL, 7/98 (draft) *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, EIA, 10/98 *Climate Change Economic Analysis: Technical Annex,* Interagency Analytic Team, 7/97	Current transaction price represents current trades being undertaken for risk management purposes in the absence of U.S. ratification of the Kyoto Protocol. The model runs are for the prices in 2010. The low values assume unlimited international trading, the high values assume no international trading.
Methane	Current Transactions: \$31–\$124/ton CH_4 Model Forecasts (2010 Price): \$532–\$5,700/ton CH_4		Methane values are CO_2 values multiplied by 25, the instantaneous global warming potential for methane.

VOC	California ERCs: San Joaquin Valley – $3,600/tpy Bay Area – $5,500/tpy Maryland ERCs: $2,500/tpy New York/Pennsylvania ERCs: Severe – $2,000/tpy Moderate – $1,850/tpy Massachusetts ERCs: $3,000/tpy	Cantor Fitzgerald Environmental Brokerage Services	The values for non-methane hydrocarbons (volatile organic compounds [VOCs]) vary significantly from region to region. In rural areas the values tend to be lower. Values also tend to be lower in the East than in the West, and lower in the Mid-Atlantic than in New England.
Particulate	Rural: $1,050/1,000 lbs. Urban: $1,506/1,000 lbs.	*Environmental Costs of Electricity*, Pace University Center for Environmental Legal Studies, 1990	The values are based on PM-10. Rural values are for visibility and the Urban values include visibility and mortality/morbidity.
CO	Current Transactions: $0.71-2.84/ton CO Model Forecasts (2010 Price): $12.16-130.59/ton CO		The values are based on the equivalent greenhouse gas value on a per-carbon basis to CO_2.
Landfill	$15.06/ton - $29.94/ton	*Full Cost Accounting in Action: Case Studies of Six Solid Waste Management Agencies*, USEPA, 12/98	Landfill costs vary by site, an average of $22.00/ton. Seems to be reasonable. The values here are fully allocated costs, including capital, financing and O&M.
Forest Productivity	$125 – $650/acre	Recent studies by Jolley & Carlson, and Morris (see references)	

Particulates: Most recent literature on particulates focuses on smaller particles of 10 microns or smaller (the most recent literature focuses on particles smaller than 2.5 microns). Open burning of biomass waste creates many particles larger than 10 microns; controlled burning tends to release small particles.

The values in the table are based on PM-10. Rural values are for visibility degradation and the urban values include visibility degradation and increases in mortality/morbidity.

CO: A review of the literature indicates that CO pollution reduction is primarily of value in a limited number of urban "hot spots," and that reductions in rural releases of CO, through a reduction in open burning, had little or no value to the environment. There has been a significant reduction in the ambient levels of CO during the past two decades, primarily through improvements in the environmental performance of automobiles. This improvement has diminished the value of further reductions in CO emissions from stationary sources.

Carbon monoxide in the atmosphere has a greenhouse gas warming potential roughly equal to that of CO_2 (see *Value of Greenhouse Gas Emissions*), and in fact the ultimate fate of atmospheric CO is oxidation to CO_2. Thus, at a minimum, the value of CO emissions is equivalent, on a per-carbon basis, to the value assumed for CO_2 emissions.

Non-methane hydrocarbons: The values for non-methane hydrocarbons (volatile organic compounds [VOCs]) vary significantly from region to region. In rural areas the values tend to be lower. Values also tend to be lower in the East than in the West, and lower in the Mid-Atlantic than in New England.

3.1.2 Value of Greenhouse Gas Emissions

CO_2: The market for CO_2 emissions trading is in its infancy. Trades executed so far have been voluntary, not pushed by regulatory compliance requirements. These transactions have been conducted at very low prices, \$0.45–\$1.81/ton of CO_2, (\$1.83–\$7.33/metric ton of carbon equivalent). The current transaction price represents trades being undertaken for risk management purposes in the absence of U.S. ratification of the Kyoto Protocol. If the Kyoto Protocol is ratified, prices are expected to increase dramatically. Price forecasts vary substantially, based mostly on the amount of trading assumed in the forecast. Prices vary from a low of approximately \$7.74/ton CO_2 in the Clinton Administration's analysis (assuming widespread and unlimited international trading), to \$83.10/ton CO_2 in the analysis done by the Energy Information Administration, U.S. Department of Energy, at the request of Congress (assuming very little trading). An average of the two, \$45.42/ton CO_2 is close to the upper end of the Interagency Analytic Team's (IAT) forecast. For analytical purposes, a value of \$33/ton CO_2 is used for the base-case data set, which is the average of the IAT forecasts.

CH_4: Methane has an instantaneous global warming potential 25 times greater than CO_2 on a per-carbon basis (IPCC 1996). However, the residence time of CH_4 in the atmosphere is much shorter than that of CO_2, so in the long term the difference in warming potential between the two gases decreases. The IPCC recommends using a value of 20.4 for a 20-year time perspective, and 7.6 for a 100-year time perspective. The model developed for this study calculates a value of 15.8 for a 20-year time perspective, and 6.8 for a 100-year time perspective, which is slightly more conservative than the IPCC recommendations.

3.1.3 Value of Landfill Accumulation

The values for reductions in the amount of landfill used resulting from diversion of waste wood to energy production is based on the fully allocated costs of current landfills. It does not represent the cost to open a new landfill (the long-term marginal cost of waste disposal in a landfill), and so is a lower bound on the value of benefits of reduced landfill use caused by current biomass capacity. However, the cost includes the cost of EPA regulations to capture and dispose of landfill CH_4.

3.1.4 Value of Forest Treatments

The literature on the value of forest treatment activities is sparse, but a recent paper (Jolley and Carlson 1999) provides a useful measure, which can be defined as the saving in ultimate cost, on a net-present value basis, of using mechanical thinning for forest treatment versus a regime of prescribed burns that must be carried out over a number of years to achieve the same degree of forest improvement.

The mechanical thinning regime, followed 5 years later by a prescribed burn, has a cost (npv) of \$432/acre. The alternative of three prescribed fire treatments during a 20-year period has a cost (npv) of \$560/acre, for a net saving of \$128/acre using the mechanical thinning and fuel-production alternative. This sets a lower limit on the marginal value of the mechanical thinning alternative. It does not credit the thinning alternative for its reduction in ultimate air emissions during the various burns, for its reduction in residual stand damage, and for the fact that the benefits of fuels reduction are achieved immediately with the mechanical thinning/fuel production option, while the benefits are achieved over a 20-year period with the prescribed burning alternative.

Another recent study (Morris 1998), which takes into account factors such as long-term timber stand values and reductions in fire-fighting costs, calculates a net benefit of mechanical thinning operations in the range of \$200–\$650 per acre treated. A mid-point value of \$400/acre is used in the model as the base-case value.

3.2 Value of the Social Benefits of Biomass Power Production

The social benefits of biomass power production, such as the generation of rural employment and economic development, and energy diversity and security, are even more difficult than the environmental benefits to quantify and value. Thus, no values are included in the model for social benefits, although they are significant and valuable. The following discussion illustrates the magnitude of the tax benefits that are provided by biomass power plants.

Based on an average annual income of \$35,500 (not including benefits or employer-paid taxes), and 4.9 workers per MW of installed capacity, biomass power plant employees and support workers generate \$26,200 in federal income tax, and \$8,700 in state income tax, for each megawatt of operating biomass electric generating capacity. Local and personal sales taxes are not included.

Property tax, based on a rate of 1% of assessed valuation, equates to \$8,900/MW power plants plus \$1,400/MW for fuel supply infrastructure and related equipment. In addition, based on average taxable purchases of supplies, parts, and equipment of \$28,000/MW, sales tax at 7% yields an additional \$2,000/MW annually. The total tax revenue generated from biomass energy production is approximately \$47,200/MW power produced per year. This translates into a total tax contribution of \$88 million in the United States annually that is attributable to the independent biomass energy industry.

3.3 Calculated Value of the Ancillary Services of Biomass Power Production

A model has been constructed to compute the value of the identified ancillary services provided by biomass power production. The model begins with an accounting of the types and quantities of fuels used by the independent biomass power industry in the United States today. This inventory is based on an updated database of operating U.S. biomass power facilities maintained by the principal author of this report. The industry provides for the disposal of 22 million tons of biomass residues annually. More than half the total fuel supply is composed of sawmill residues; the remainder is distributed among the categories of in-forest residues, agricultural residues, and urban waste wood. The first page of the model's printout, shown on Table 5, shows the amounts of biomass residues used as power-plant fuels. (Fuel use values in the model are presented in bdt, not green tons.)

Assumptions about the alternatives fates of the various residues, if they were not used as fuels (Table 1), are applied to the fuel use data to determine the avoided disposal pathways for which the biomass energy industry provides. Almost half the residues would be landfilled in the absence of energy production, about one-third would be open burned, and the remainder would be composted or spread, or represent an accumulation of overstocked material in the nation's forests.

Emissions factors and other environmental measures (Table 2) are applied to the alternative disposal activities to compute the magnitude of the emissions and other measures for biomass energy production, and for all the activities it avoids. This computation is shown on the second page of the model's printout (Table 6). The magnitudes of the values are then summed across the categories, and the two alternatives, biomass energy production versus biomass residue disposal and fossil-fuel energy production, are compared.

For analytical purposes, a conservative base-case data set was selected. Some base-case data, such as fuel use data, assumptions about alternative fates for the biomass, impacts, and impact values, were discussed earlier. Several additional assumptions, shown in the lower half of Table 5, are worthy of discussion. In the base case 40% of the power displaced, at the margin, by the current level of biomass power generation is assumed to be coal, and the remainder is natural gas. This is a conservative assumption, as more than 50% of power in the United States is generated from coal, and biomass often competes with base-load generating sources, of which coal is an example.

The base case also uses a 20-year timeframe for the analysis, and counts only the delayed emissions of landfill disposal and other alternatives during the first 20 years after use. For landfills, for example, in which waste wood is conservatively assumed to have a half-life of 30 years, only 37% of the ultimate emissions are counted. The base-case half-lives for landfilled waste wood and residues accumulating in forests are both conservatively chosen to be long.

As shown in Tables 5 and 6, using conservative base-case values for all the identified impact categories, the value for the ancillary environmental benefits of biomass energy production is calculated as $1.2 billion/yr, or 11.4¢/kWh of electricity produced from biomass. This represents an average for all the biomass fuel used by the independent biomass power industry in the United States. This calculated value covers only the categories of impacts included in the analysis, and excludes the economic and social benefits of biomass energy production discussed previously.

Using the base-case data set, the computed value of using each of the four types of biomass residues varies within the range of 7.8 (in-forest residues) to 14.0 ¢/kWh (urban waste wood). Residues that would otherwise be open burned provide a benefit of 8.9 ¢/kWh if used for energy production. Residues diverted from landfill disposal provide a benefit of 14.9 ¢/kWh when used for energy production. Residues left as overstocking in the forest provide a benefit of 6.7 ¢/kWh if used for energy production.

The dollar value for each impact category is reported in the literature as a range of values (Table 4). Values for many of the categories have rather broad ranges of uncertainty. Running the model with minimum values for all categories produces a benefit value of 4.7 ¢/kWh for biomass energy production. Using maximum values for all the categories, the benefit value is 24.7 ¢/kWh.

A significant contributor to the computed value of these biomass energy benefits is the value of avoided greenhouse gas emissions. Greenhouse gases are not regulated in current practice; hence, there is no established market value for them. The international Kyoto protocols, (in the process of ratification by countries around the world) require reductions in greenhouse gas emissions, which would establish a market and value for these materials. Assuming a zero value for greenhouse gases leaves a residual value for the other computed benefits of biomass energy production with the base-case data set of 4.0 ¢/kWh. Estimating the value of avoided greenhouse gas emissions is complicated by the timeframe used to judge the delayed emissions of CH_4 and CO_2 from landfills, the disposal alternative for 48% of the biomass fuels used in the United States today. The base case includes all emissions released over a 20-year period following the use or burial of the biomass fuels. A long-term time perspective, for example using a 75-year timeframe, increases the calculated benefits with otherwise base-case assumptions to 14.1 ¢/kWh.

Table 5. Value of the Environmental Benefits of the U.S. Biomass Energy Industry

	Mill	Forest	Ag	Urban		
Fuel Use (th.bdt/yr)	6,400	1,800	2,300	1,400		
Alternative Fate (%)						
open burning	5%	50%	100%			
landfill	70%			90%		
composting	10%			10%		
spreading	15%					
forest accumulation		50%				
Alternative Fate (th.bdt/yr)					Total	
open burning	320	900	2,300	-	3,520	30%
landfill	4,480	-	-	1,260	5,740	48%
composting	640	-	-	140	780	7%
spreading	960	-	-	-	960	8%
forest accumulation	-	900	-	-	900	8%

Total Fuel Use	11,900	th.bdt/yr
Electric Generation Effic.	1.10	bdt/MWh
Electricity Produced	10,818	mmkWh/yr

% of displaced electricity that would have been supplied by

Coal	40%
Natural Gas / Steam Turbine	30%
Natural Gas / Combined Cycle	30%

<u>Delayed Emissions Factors</u>

Years of Delayed Emissions	20	years

	½ Life in Storage	% Ultimate	Multiplier
landfill	30	37%	
composting	2.5	100%	
spreading	2.5	100%	
forest accumulation	35	32%	2.00

(data in boxes are inputs to the model)

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Table 6. Value of the Environmental Benefits of the US Biomass Energy Industry

Ultimate Impacts (unit/th.bdt)	SOx	NOx	particulate	CO	CH_4	nmHCs	CO_2	landfill	thinned
unit	lb	lb	lb	lb	lb	lb	ton	m3	acres
biomass energy	150	2,500	450	7,500	250	25	1,780	24.2	
VS.									
open burning	150	7,000	15,000	150,000	8,000	24,000	1,690		
landfill					430,000		1,200	2,400	
composting--immediate					33,000		850		
composting--delayed					65,000		800		
spreading					130,000		1,600		
forest accum.	150	7,000	21,000	280,000	7,000	23,000	1,690		40
coal (unit/mmkWh)	3,500	3,100	140	960	15	290	1,100	43.9	
gas/st (unit/mmkWh)	6	270	80	910	25	60	600		
gas/cc (unit/mmkWh)	5	85	330	860	130	60	450		

Impacts	th.lb/yr	th.lb/yr	th.lb/yr	th.lb/yr	th.lb/yr	th.lb/yr	th.ton/yr	th.m3/yr	th.acres/yr
open burning	528	24,640	52,800	528,000	28,160	84,480	5,949	-	-
landfill	-	-	-	-	903,451	-	2,521	13,776	-
composting	-	-	-	-	76,349	-	1,286	-	-
spreading	-	-	-	-	124,575	-	1,533	-	-
forest accum.	87	4,069	12,207	162,766	4,069	13,370	982	-	36
coal	15,145	13,415	606	4,154	65	1,255	4,760	190	-
gas/st	19	876	260	2,953	81	195	1,947	-	-
gas/cc	16	276	1,071	2,791	422	195	1,460	-	-
Total, no energy	15,796	43,276	66,944	700,664	1,137,172	99,494	20,439	13,966	36
VS.									
biomass energy	1,785	29,750	5,355	89,250	2,975	298	21,182	288	-

	SOx	NOx	particulate	CO	CH4	nmHCs	CO2	landfill	thinned
	\$/th.lb	\$/th.lb	\$/th.lb	\$/th.lb	\$/th.lb	\$/th.lb	\$/th.ton	\$/th.m3	\$/th.acres
Value of Impacts	(105)	(1,050)	(1,250)	(26)	(717)	(1,200)	(33,000)	(15,000)	(400,000)
(approx. mid points)									
Value (th.\$/yr)									
biomass energy	(187)	(31,238)	(6,694)	(2,314)	(2,134)	(357)	(699,006)	(4,320)	-
no biomass energy	(1,659)	(45,440)	(83,680)	(18,167)	(815,528)	(119,393)	(674,497)	(209,490)	(14,400)
Net Biomass Benefit (th.\$/yr)	1,471	14,202	76,986	15,853	813,394	119,036	(24,509)	205,170	14,400
Benefit in ¢ / kWh	0.01	0.13	0.71	0.15	7.52	1.10	(0.23)	1.90	0.13

Total Value	**(th.\$/yr)**
biomass energy:	(746,249)
no biomass energy:	(1,982,253)

Net Benefit: **11.4 ¢/kWh**

(data in boxes are inputs to the model)

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3.4 Loss of Benefits: Consequences of a Shrinking Biomass Power Industry

The independent biomass power industry in the United States reached its peak level of production around 1990, and has since declined by more than 25%. This decline has a variety of causes, many of which are regional, but the underlying reality is that biomass energy is expensive to produce, compared to the lowest-cost alternatives available on the grid. The high cost of biomass power production, an inevitable result of the small size of the facilities and the high cost of collecting and transporting low-density residue materials, is a considerable liability in a market that is deregulating and increasingly emphasizing cost. The future viability of the enterprise is in doubt.

Any further decline in biomass energy production in the United States, whether caused by facility closures or to cutbacks in operations by the operating facilities, leads directly to a loss in the amount of environmental and social benefits provided by the industry. As demonstrated earlier, based on a conservative base-case set of assumptions, the value for the quantifiable benefits is 11.4 ¢/kWh of electricity produced from biomass. The identified social benefits not included in the computation are also significant, and add to the total societal value. These are very impressive numbers, much higher than the current market value of the energy, which is in the range of 2–3¢/kWh in most regions. Even using minimal values for all quantified impacts, and ignoring the nonquantifiable ones, the benefits of biomass power production (4.7 ¢/kWh) are much higher than the level of support necessary to preserve the enterprise. The expected societal return on support for biomass power production is a multiplicative factor of 7.6. And this value includes only selected environmental impacts for which data are available.

Disappearance of the biomass energy industry in the United States would present serious social and environmental consequences for the regions that would be most affected. More than 5 million tons/yr of residues currently used as fuel would be added to the burden of material entering sanitary landfills, further burdening the capacity problem, making compliance with landfill diversion statutes in many regions virtually impossible, and loading the country with future greenhouse gas emissions that will not be avoidable when greenhouse gas emissions reduction mandates must be achieved.

Disappearance of the industry would mean that 4.6 million tons of residues currently being used as fuels will return to open burning piles, where they will add measurably to air pollution problems in affected agricultural and forested regions, many of which are already out of compliance with air quality standards. An additional 1.6 million tons/yr of residues will be allowed to accumulate in overstocked or otherwise unhealthy forests and watersheds. These residues will exacerbate the risks of destructive wildfires and ecosystem degradation.

The loss of the biomass energy industry would represent a loss of almost 12,000 rural employment positions, with serious impacts in affected regions. Many rural communities would also lose their largest source of property taxes, and would suffer other multiplier effects. Energy diversity and security values would be lost.

The loss of the U.S. biomass energy industry would exacerbate a number of important environmental problems, and leave affected rural regions with virtually irreplaceable losses of quality employment opportunities and tax base. In fact, increasing the capacity use of the current infrastructure, and encouraging the development of new biomass installations using ever-advancing technology, should be important goals of national and regional energy policy. The ancillary benefits of biomass power production are worth far more than its above-market costs. A modest level of compensation for these benefits will achieve a several-fold return in social and environmental benefits. The California experience with the payment of biomass production credits in the amount of 1.5 ¢/kWh demonstrates that this level of support can achieve stabilization and increased facilities to use. A higher level of support probably would be needed to encourage the development of new biomass energy production capacity.

Biomass energy production provides two valuable services to society: it is the second most important source of renewable energy currently being produced in the United States, and it is an important component of the nation's solid-waste disposal infrastructure. In the old world of high energy prices, sales of electricity alone were sufficient to pay for the entire enterprise. In the current world of low energy prices and increasing competition, electricity revenues cannot support the continuing operation of biomass energy facilities. Unless a mechanism is developed to compensate biomass generators for the ancillary services they provide, these services will be lost. This report demonstrates that the easily quantifiable environmental benefits of biomass energy production, using conservative assumptions, are worth 7.6 times more than the amount of support needed to sustain it. When social benefits and more difficult to quantify environmental benefits are added to the equation, the societal return on support for biomass energy production is even greater.

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Appendix 7. Emissions Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning

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Emission Reductions from Woody Biomass Waste for Energy as an Alternative to Open Burning

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ABSTRACT

Woody biomass waste is generated throughout California from forest management, hazardous fuel reduction, and agricultural operations. Open pile burning in the vicinity of generation is frequently the only economic disposal option. A framework is developed to quantify air emissions reductions for projects that alternatively utilize biomass waste as fuel for energy production. A demonstration project was conducted involving the grinding and 97-km one-way transport of 6096 bone-dry metric tons (BDT) of mixed conifer forest slash in the Sierra Nevada foothills for use as fuel in a biomass power cogeneration facility. Compared with the traditional open pile burning method of disposal for the forest harvest slash, utilization of the slash for fuel reduced particulate matter (PM) emissions by 98% (6 kg PM/BDT biomass), nitrogen oxides (NO_x) by 54% (1.6 kg NO_x/BDT), nonmethane volatile organics (NMOCs) by 99% (4.7 kg NMOCs/BDT), carbon monoxide (CO) by 97% (58 kg CO/BDT), and carbon dioxide equivalents (CO_2e) by 17% (0.38 t CO_2e/BDT). Emission contributions from biomass processing and transport operations are negligible. CO_2e benefits are dependent on the emission characteristics of the displaced marginal electricity supply. Monetization of emissions reductions will assist with fuel sourcing activities and the conduct of biomass energy projects.

INTRODUCTION

Woody biomass waste material is generated as a byproduct throughout Placer County portions of the Sacramento Valley, foothills, and Sierra Nevada mountains from forest management projects, defensible space clearing, tree trimming, construction/demolition activities, and agricultural operations.

Forest management projects that produce woody biomass byproducts (tree stems, tops, limbs and branches, and brush) include fuel hazard reduction, forest health and productivity improvement, and traditional commercial harvest. These projects take place on private land and lands managed by various public agencies including the U.S. Forest Service (USFS), Bureau of Land Management, and state/federal parks. Forest fuel hazard reduction activities involving selective, targeted thinning treatments are implemented to lessen wildfire severity and improve forest-fire resiliency through reducing hazardous fuel accumulations resulting from a century of successful wildfire suppression efforts. Commercial timber harvests include thinning to improve health and productivity, and intensive management to optimize the yield of merchantable material for lumber production.

Defensible space clearings and fuel breaks in an expanding wildland urban interface area, including residential and commercial structures, produce woody biomass that typically includes deciduous and coniferous trees and brush.

Agricultural operations such as fruit and nut orchards and grape vineyards are a source of biomass wastes from annual pruning and periodic removal and replacement with more productive varieties or growing stock.

Open burning (in piles or broadcast burning) near the site of generation is the usual method of disposal for a significant quantity of the excess woody waste biomass throughout much of the western United States. A forest slash pile burn in the Lake Tahoe Basin is shown in Figure 1. The cost to collect, process, and transport biomass waste is often higher than its value for fuel or wood products because of the distance of the forest treatment activity location from the end user (e.g., mill, biomass energy facility), lack of infrastructure, and/or economics of biomass energy compared with fossil fuel generation. This limits the feasibility of using biomass waste for energy production although such use has significant environmental benefits.

IMPLICATIONS

Economic considerations frequently dictate the disposal of woody biomass wastes by open burning. The alternative use for energy provides significant reduction in criteria air pollutant and greenhouse emissions. Valuing these reductions will improve the economic viability and increase the use of biomass for energy as well as assist with forest and agricultural management objectives.

Figure 1. Open pile burn of forest fuel treatment woody biomass in Lake Tahoe Basin.

The Placer County Air Pollution Control District (PCAPCD), with responsibility for managing air quality in Placer County, shares regulatory authority over open burning with local fire agencies. Open burning is problematic because of the limited time of year it can be conducted, subsequent monitoring of smoldering piles for days after they are lit, and the production of significant quantities of air pollutant emissions and esthetically unpleasing residuals (blackened logs and woody debris). The PCAPCD expends significant resources reviewing smoke management plans, issuing burn permits, inspecting burn piles, and responding to complaints from smoke.

PCAPCD[1,2] and others[3,4] report that the utilization of woody biomass waste for energy as an alternative to open burning can provide significant air emissions mitigation for criteria pollutants, air toxics, and greenhouse gases, along with energy benefits through production of renewable energy in a well-controlled conversion process. To quantitatively value these benefits, PCAPCD is developing an emission reduction accounting framework and has sponsored several biomass waste-for-energy field operations to evaluate alternatives to minimize open burning.

EMISSION REDUCTION ACCOUNTING FRAMEWORK

The emission reduction framework is intended to provide a basis for financial support for the utilization of biomass wastes for energy in which the biomass waste under "baseline, business as usual" conditions would have been open-burned. This requires an evaluation of the economics of the biomass management alternatives and institutional and regional practices to demonstrate that the biomass waste would be open-burned without the additional financial contributions from a biomass project proponent. Biomass must also be shown to be a byproduct of forest or agricultural harvest projects that meet local, state, and federal environmental regulations, including the National Environmental Policy Act, the California Environmental Quality Act, and/or Best Management Practices. The biomass must also be demonstrated to be excessive to ecosystem needs.

Net emission reductions are considered to be the difference between the biomass energy project and the open burning baseline. As shown in Figure 2, the biomass project boundary includes processing (loading and chipping), transport, and the energy conversion plant. The baseline considers biomass open burning and the marginal generation of energy that was displaced by the biomass project. Table 1 details the project activities and data requirements for emissions reduction determinations that are real, permanent, quantifiable, verifiable, and enforceable.

Emissions from the forest management projects and agricultural operations that generate the excess biomass waste (e.g., chain saws and yarders) are not considered in the accounting framework because biomass removal is required for management purposes and will occur regardless of which biomass disposal option is pursued. Biomass waste that falls under the framework must have economic value that is less than the cost to process and transport (it must be a disposal burden). The biomass removal operations must be required for reasons (e.g., fire hazard reduction, forest management, timber production, or food production) that are unrelated to any potential biomass value. Furthermore, emission contributions from the biomass removal operations are minor compared with processing, transport, or open burning.[3,4]

Emissions from operations to process and transport fossil fuels, which are used in the baseline to provide equivalent energy and in the biomass project to facilitate wood chip transport and biomass processing/loading equipment, are not considered because of the difficulty of accurately defining their energy usage and emission characteristics.

It is anticipated that reductions resulting from biomass utilization projects may be banked or sold for air emissions and/or greenhouse gas mitigation obligations.

DEMONSTRATION PROJECT

PCAPCD and the County of Placer Biomass Program teamed with USFS, Sierra Pacific Industries (SPI), and the Sierra Nevada Conservancy to sponsor an on-the-ground biomass waste-for-energy demonstration project. The project targeted woody biomass waste piles that were originally generated from two USFS fuel reduction stewardship contracts implemented in 2007 on the Tahoe National Forest, American River Ranger District, which is located above Foresthill, CA. The stewardship contracts involved the thinning treatment of over 1215 ha of mixed conifer and ponderosa pine stands with 500-1000 trees/ha (preharvest). The thinning prescription had a target of

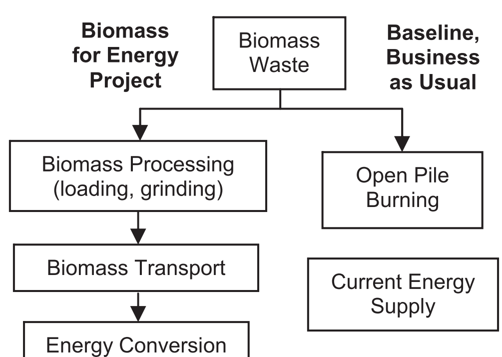

Figure 2. Biomass-for-energy project emission reduction procedure.

Table 1. Project data and monitoring.

Parameter	Method, Frequency
Biomass weight delivered to energy conversion facility	Transport vehicle weight scale, each separate delivery
Biomass moisture	Representative sample, when biomass source changes
Biomass heating value	Representative sample, when biomass source changes
Transport vehicle miles traveled and gas mileage	Vehicle odometer, fuel dispensing
Processing equipment diesel engine operating hours and fuel usage	Engine hour meter, fuel dispensing
Energy production efficiency of energy conversion facility	Fuel input and useful energy output
Emission factors for open pile burning	Literature review
Emission factors for fossil fuel combustion engines	Engine manufacturer, literature
Emission factor for grinding	Literature review
Emission factor for transport over unpaved roads	Literature review
Emission factors for biomass energy conversion facility	Source testing, annual
Emission factors for displaced energy	Marginal energy supply analysis, source testing

180–250 trees/ha at 7.6-m spacing through selected removal of trees 10–51 cm in diameter at breast height (DBH). Removed biomass that was greater than 15 cm DBH and greater than 3.1 m long was transported to a sawmill for processing into lumber products. The stewardship contracts called for unmerchantable slash to be piled at the site for later open burning, the traditional method of disposal.

For the demonstration project, a forest products contractor, Brushbusters, Inc., was retained to process and transport the woody biomass waste piles for use as fuel in a cogeneration facility located at a SPI lumber mill in Lincoln, CA. At each landing slash pile location, excavators were used to transfer the piles into a horizontal grinder. Wood chips from the grinder were conveyed directly into chip vans and transported to the SPI Lincoln mill, a 97-km one-way trip. Equipment and engines used for the chipping and transport operations are described in Table 2.

The SPI Lincoln sawmill facility includes a wood-fired boiler that produces steam for use in lumber drying kilns and a steam turbine that produces up to 18 MW of electricity. The boiler is a McBurney stoker grate design with a firing rate capacity of 88 MW that produces 63,560 kg of steam at 90 bar and 510 °C. It is fueled by biomass wastes including lumber mill wood wastes generated on-site (primarily sawdust), agricultural wastes including nut shells and orchard removals and prunings, wood waste from timber operations, and urban wood waste (tree trimmings and construction debris). The boiler utilizes selective noncatalytic reduction for control of nitrogen oxides (NO_x), multiclones, and a three-field electrostatic precipitator for particulate matter (PM) control. The net boiler heat rate is 16.8 MJ of heat input per kWh electric net, a net efficiency of 22%.

Table 2. Equipment and engines for biomass processing and transport.

Equipment	Vendor, Model, Year	Engine, Model, Horsepower
Horizontal grinder	Bandit Beast, model 3680, 2008	Caterpillar C18, Tier III, 522 kW
Excavator	Linkbelt, model 290, 2003	Isuzu CC-6BG1TC, 132 kW
Excavator	Linkbelt, model 135, 2003	Isuzu BB-4BG1T, 66 kW
Chip van	Kenworth, 1997	Cummins N14, 324 kW
Chip van	Kenworth, 2006	Caterpillar C13, 298 kW

During the period of April 14, 2008 through December 12, 2008, on 86 separate work days, 6096 bone-dry metric tons (BDT) (9537 green tons [GT]) of forest slash were collected, processed, and transported. A total of 444 separate chip vanloads were delivered to the SPI boiler, with each delivery averaging 13.7 BDT (21.5 GT).

The biomass processing machines (a grinder and two excavators) each worked a total of 265 hr and produced biomass fuel at the rate of 36.3 GT per hour of equipment operation. Diesel engine fuel consumption for the grinder and two excavators averaged 2.92 and 0.79 L/GT, respectively. This is comparable with the grinder fuel usage of 2.1 and 3.1 L/GT reported in other studies.[3,4] Chip transport truck/trailer diesel fuel usage averaged 1.9 km/L over the 193-km round trip (4.6 L/GT), also comparable to other studies.[3,4]

Biomass fuel delivered to the boiler had an average heating value of 20.9 MJ/kg, a moisture content of 36.1%, and an ash content of 2% dry weight. The boiler produced 7710 MWh of electricity utilizing biomass fuel from this project.

The biomass project significantly reduced the utilization of fossil fuels. The project required 511 MJ of diesel/BDT, but it displaced the need for 9806 MJ of natural gas/BDT for electricity generated by the biomass-fired cogeneration facility. Energy benefits would be greater if the fossil fuel energy required to collect, refine, and deliver fossil fuel to market (with added fossil fuel energy penalty on the order of 20%) was considered.[3]

Table 3 shows the emission factors used to calculate project and baseline operations, including NO_x, PM, carbon monoxide (CO), nonmethane volatile organics (NMOCs), methane (CH_4), and carbon dioxide (CO_2). Open pile burning factors considering numerous laboratory-, pilot-, and full-scale studies on conifer biomass are compiled in Table 4.[5–21] The burn pile emission factor was used with a burn pile consumption efficiency rate of 95%. Diesel engine combustion, chipping, and unpaved road travel emission factors are from the California Air Resources Board and the U.S. Environmental Protection Agency (EPA).[24–28] Biomass boiler factors are from annual

Table 3. Emission factors for project and baseline operations.

Process/Reference	Units	NO_x	PM	NMOC	CO	CO_2	CH_4
Open pile burning[5–20]	g/dry kg wood	3	6.5	5	63	1833	3
Chip van engine[24]	g/km traveled	10.6	0.25	0.31	25	1381	0.6
Chip van[25]	g/km unpaved road	–	300	–	–	–	–
Grinder engine[26]	g/kWh	3.1	0.18	0.16	4.0	530[b]	0.32
Excavator engine[26]	g/kWh	5.6	0.17	0.25	5.4	350[b]	0.51
Excavator engine[26]	g/kWh	6.4	0.26	0.31	6.7	370[b]	0.62
Grinder[27]	g/green kg wood	–	0.05	–	–	–	–
Biomass boiler[22]	g/GJ	52	7.7	1.7	73	88,000	4
Natural gas combined cycle[23]	Kg/MWh	0.016	0.011	0.002	0.005	384	–
California in-state electricity production[a28]	Kg/MWh	0.08	0.025	0.01	0.13	250	–

Notes: [a]Shown for comparison purposes; [b]Determined from engine diesel fuel usage, operating hours, and rated power output.

manual method stack sampling test programs and continuous emission monitors that are required by PCAPCD to demonstrate compliance with permit limits.[22] Electricity production factors are from the displacement of marginal power from a local utility natural gas combined cycle 120-MW plant that uses selective catalytic reduction and oxidation catalysts for NO_x and CO control.[23] For comparison, overall California state electricity generation emissions factors are also shown.[28]

Table 5 compares biomass project emissions with baseline (open pile burning) emissions. The project reduced PM emissions by 98% (6 kg PM/BDT biomass), NO_x emissions by 54% (1.6 kg NO_x/BDT), NMOC emissions by 99% (4.7 kg NMOCs/BDT), CO emissions by 97% (58 kg CO/BDT), and CO_2 equivalent (CO_2e; determined as $CO_2 + 21 \times CH_4$) emissions by 17% (0.38 t CO_2e/BDT).

The cost to process and transport the piles to the SPI cogeneration facility averaged \$64.40/BDT, including \$33/BDT to process and \$31/BDT to transport the piles. The competitive market value at the time of the project for biomass sourced from timber harvest residual in the central Sierra Nevada region was approximately \$33/BDT. The cost to dispose of the biomass wastes at the site of generation with open pile burning is relatively small. Thus, the demonstration program operated with a cost deficit of \$31.30/BDT biomass processed.

For the demonstration project to be economically viable, the cost to process and deliver the biomass must be reduced, the price paid at the cogeneration facility must be increased, and/or emission reduction credits must be sold. To break even, emission reduction credits would need to be valued for CO_2e at \$83/t CO_2e, NO_x at

Table 4. Emission factors for open pile burning of woody biomass.

Source, Reference, Test Conditions, Material Type	Material Type	Emission Factor (g/kg dry biomass burned)				
		PM	CO	CH_4	NMOC	NO_x
EPA AP-42,[18] conifer logging slash, piled	Flaming	4	28	1.0	–	–
	Smoldering	7	116	8.5	–	–
	Fire	4	37	1.8	–	–
EPA AP-42,[17] pile burn	Unspecified	14	116	4.7	15	–
	Fir, cedar, hemlock	3.4	75	1	3.4	–
	Ponderosa pine	10	164	2.9	9	–
Ward et al.,[19] Hardy,[10] consume model, 90% consumption efficiency	Dozer piled	6	77	6	4	–
	Crane piled	13	93	11	8	–
	Consume 90% consumption efficiency	9	80	3.8	3.1	–
Jenkins et al.,[12] wind tunnel simulator	Almond	5	53	1.3	10	4
	Douglas fir	7	56	1.5	6	2
	Ponderosa pine	6	43	0.9	4.4	3
	Walnut tree	5	71	2.0	7	5
Lutes and Kariher,[14] pilot, land clearing piles		7–22	19–29	–	4–16[a]	0.2–2
Andreae and Merlet,[5] literature compilation		5–17	81–100	–	–	–
Janhall et al.,[11] literature compilation, forest residues		8	–	–	–	–
Chen et al.,[7] laboratory	Ponderosa pine wood	4	17	–	0.5[a]	0.8
	Ponderosa pine needles	3.3	32	–	3.5[a]	4.1
Freeborn et al.,[8] laboratory, pine, fir, aspen		7	50	–	–	4
McMeeking et al.,[16] laboratory, pine, fir		–	90	3.7	5	2.2
Yokelson et al.,[20] pilot	Broadcast	8	–	–	2[a]	3
	Slash	4	–	–	2[a]	2
	Crowns	–	–	–	4[a]	3

Notes: [a]Total hydrocarbons.

Table 5. Emissions comparison: open pile burning vs. biomass energy.

Operation	Air Emissions (t)						
	NO_x	PM	NMOC	CO	CO_2	CH_4	CO_2e[a]
Baseline, open pile burning							
Open pile burning	17.37	37.65	28.96	362	10,618	17.37	10,983
Displaced power from grid	0.47	0.28	0.06	1	2,733		2,733
Total	17.84	37.93	29.02	363	13,352	17.37	13,717
Biomass project							
Boiler	6.58	0.98	0.22	9	11,178	0.55	11,189
Process and transport							
Grinding	0.43	0.52	0.02	1	73	0.04	74
Loading	0.31	0.01	0.01	0	19	0.03	19
Chip van transport	0.91	0.02	0.03	2	118	0.05	119
Total	8.23	1.53	0.28	12	11,388	0.70	11,402
Emissions reductions	9.62	36.39	28.74	350	1,965	16.7	2,315
Percent reduction	54%	96%	99%	97%	15%	96%	17%

Notes: [a]CO_2e determined as $CO_2 + 21 \times CH_4$.

\$19,570/t NO_x, or at a lower price if a combination of pollutant credits is sold. Biomass market fuel prices are trending upward partly because of an increased demand for renewable energy (resulting from the California Renewable Portfolio Standard).

Opportunities were identified to significantly reduce future biomass waste processing costs through maximizing equipment productive work time (minimizing equipment downtime and mobilization) by careful formation of piles, creation of larger piles, and efficient scheduling and coordination of truck transport and grinding equipment. In particular, the grinder (the most expensive cost center) was frequently idle while waiting for the arrival of chip truck transport. Cost reductions can be achieved through operating the grinder closer to full time by using additional chip trucks or grinding into piles that are subsequently loaded into chip trucks at a later time with less expensive equipment such as front-end loaders.

The largest source of uncertainty in the emissions determinations is from the biomass open pile burning emissions factor. Open pile burn emission factors vary depending on woody biomass chemical composition (moisture, ash), physical characteristics (pile packing size and arrangement, biomass particle size), and atmospheric conditions (temperature, humidity, wind speed). Variability in the biomass open pile burn emissions factor will impact the magnitude of the emission reductions, but it will not alter the conclusion that emissions from the biomass energy project are lower compared with open pile burning. Variability for emissions from the diesel engines, biomass boiler, and displaced electricity grid operations are not significant to the project results because emissions factors from the processes are well established, process operating rates are accurately measured and monitored, the processes are inherently steady, and contributions from these sources are generally much smaller than those from open pile burning.

The demonstration project results are readily applicable to a very broad range of potential forest sourced biomass projects throughout the West and the entire United States. The biomass energy recovery boiler design, operation, and performance used for the demonstration project are representative of existing plants that are in commercial service throughout the United States. Emission contributions from biomass processing and transport are very small in comparison with traditional open pile burning. Thus variations in grinding efficiency, transportation distance, and engine emission characteristics will have very little impact on emission reductions. Transportation distance has a significant impact on the economic viability of biomass energy projects, adding approximately \$0.13/BDT per additional kilometer traveled, but it has very little impact on emission benefits.

CO_2 benefits are strongly dependent on the CO_2 emissions profile from the displaced marginal electricity source. Reductions will be much greater than achieved in the demonstration project for biomass projects in areas where coal firing is prevalent, whereas benefits will be minimal in areas where production is from lower CO_2-emitting sources such as hydroelectric and/or nuclear sources.

NO_x benefits are somewhat dependent on biomass boiler performance. NO_x reductions will be significantly greater than in the demonstration program for low NO_x-emitting systems including emerging energy conversion technologies such as gasification, pyrolysis, and fuel cells and recently constructed or modified biomass boilers that use selective catalytic reduction.

CONCLUSIONS

A framework is developed to quantify air emission reductions for projects that utilize woody biomass waste as fuel for energy production as an alternative to open burning. A demonstration project was conducted involving the grinding and 97-km transport of forest slash in the Sierra Nevada foothills for use in a biomass-fired cogeneration boiler. Significant air emission benefits were obtained: PM emissions were reduced by 98% (6 kg PM/BDT), NO_x emissions by 54% (1.6 kg NO_x/BDT), NMOC emissions by 99% (4.7 kg NMOC/BDT), CO emissions by 97% (58 kg CO/BDT), and CO_2e emissions by 17% (0.38 t CO_2e/BDT).

PM, NO_x, CO, and volatile organic emission reductions result from the utilization of biomass wastes in an energy conversion process that provides efficient combustion and uses add-on control methods for PM and NO_x emissions compared with the inefficient and uncontrolled disposal of biomass wastes using traditional open burning techniques. CO_2e benefits result from the production of renewable energy that displaces marginal supply and elimination of CH_4 emissions from open burning.

Biomass processing (grinding) and transport operations have a significant cost burden on the biomass energy project but a negligible contribution to air emissions. CO_2e benefits are strongly dependent on the CO_2e emission characteristics of the displaced marginal energy generation; benefits will be much greater for projects in regions where coal firing is predominant. Recognition of the value of emission benefits through sale of emission reduction credits will improve the financial performance of biomass power generation facilities and allow them to access more forest- and agricultural-sourced biomass waste fuel.

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