Feasibility Study of Biopower in East Helena, Montana

A Study Prepared in Partnership with the Environmental Protection Agency for the RE-Powering America's Land Initiative: Siting Renewable Energy on Potentially Contaminated Land and Mine Sites

Kristi Moriarty

Produced under direction of the U.S. Environmental Protection Agency (EPA) by the National Renewable Energy Laboratory (NREL) under Interagency Agreement IAG-09-1751 and Task No WFD4.1001.

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

Technical Report
NREL/TP-7A30-57610
February 2013
Contract No. DE-AC36-08GO28308

NATIONAL RENEWABLE ENERGY LABORATORY

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NOTICE

Cover Photos: (left to right) PIX 16416, PIX 17423, PIX 16560, PIX 17613, PIX 17436, PIX 17721

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Acknowledgments

The National Renewable Energy Laboratory (NREL) thanks the U.S. Environmental Protection Agency (EPA) for its interest in securing NREL's technical expertise.

Special thanks go to Shea Jones and Jessica Trice from EPA and Katie Brown, AAAS Science & Technology Policy Fellow, for providing assistance on the report, as well as Betsy Burns of EPA Region 8 for providing support. The author would also like to thank Brian Obert of Montana Business Assistance Connection for providing a wealth of information and previous studies critical to completing this report; Howard Skjervem and Frank Bennett of NorthWestern Energy for providing details on power generation, renewable portfolio standards, and rate data; and Ron Whitmoyer of East Helena School District and Jim Ford of Montana Environmental Trust Group for providing information and data during the site visit.

List of Acronyms

Asarco	American Smelting and Refining Company
Btu	British thermal units
CHP	combined heat and power
CO	carbon monoxide
CO_2	carbon dioxide
CREP	Community Renewable Energy Project
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FIDO	Forest Inventory Data Online
IBMG	International BioMass Group
IRR	internal rate of return
ITC	investment tax credit
MDEQ	Montana Department of Environmental Quality
METG	Montana Environmental Trust Group
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
NEW	Northwestern Energy
NPV	net present value
O&M	operations and maintenance
PM	particulate matter
PPA	power purchase agreement
PSC	public service commission
PTC	production tax credit
REAP	USDA Rural Energy for America Program
RFP	request for proposals
RPS	renewable portfolio standard
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
USFS	

Executive Summary

The U.S. Environmental Protection Agency (EPA) Office of Solid Waste and Emergency Response Center for Program Analysis developed the RE-Powering America's Land initiative to reuse contaminated sites for renewable energy generation when aligned with the community's vision for the site. The former American Smelting and Refining Company (Asarco) Smelter in East Helena, Montana, was selected for a feasibility study under the initiative. Biomass was chosen as the renewable energy resource based on the wood products industry in the area. Biopower was selected as the technology based on Montana's renewable portfolio standard (RPS) requiring utilities to purchase renewable power.

The Asarco Superfund site is located in East Helena, Montana. Subsequent to the Asarco bankruptcy in 2009, approximately 1,800 acres of former Asarco property was transferred to the Montana Environmental Trust Group, LLC as Trustee for the United States and State of Montana. Remediation of the land and removal of buildings and slag piles are ongoing. The acreage includes many areas along the highway and throughout town. There are several potential development sites for a biopower plant with infrastructure, including rail, water, electricity, and natural gas pipelines.

The forest products industry is significant in Montana, which could prove to be a substantial resource option for a future biopower plant. The United States Forest Service (USFS) collects data on forests, including acres, land ownership, number of trees, living and dead tree volume, and removals. There are nearly 2.5 million forest acres and 4.5 billion cubic feet of standing trees in the study area.

Table ES-1. Forestry Characteristics Within 50 Miles of the Site[1]

Land Owner	Acres	% of Total	Living Trees	Dead Trees	% of Total Trees
			(million cubic feet)		
National Forest	1,339,756	55%	2,876	484	73.7%
BLM	121,100	5%	193	15	4.6%
State	81,392	3%	79	20	2.2%
Private	914,983	37%	831	60	19.5%
Total	**2,457,231**		**3,979**	**579**	

Primary mill residues are generated at wood mills as trees are transformed into lumber. They include bark, slabs, edgings, trimmings, sawdust, veneer clippings and cores, and pulp screenings. Forest residues are leftover portions of trees from logging activities and other removals from thinning or land-clearing activities. Forestry residues require collection from the forest floor by a logging company. Mill residues are generally preferred over logging and forestry residues because they are clean wastes collected from area wood processors.

Area pricing for woody biomass is $34/green ton delivered ($56/dry ton based on 40% moisture content). Feedstock requirements for a 10-MW and 20-MW biopower plant are estimated at 79,000 and 154,000 bone dry tons (no moisture content) per year, respectively. Job creation is up to two

[1] Data from Forest Inventory Data Online (FIDO) within 50-mile radius of East Helena; survey year 2009. Accessed January 8, 2013: http://apps.fs.fed.us/fido/.

jobs per installed megawatt at a plant and up to two indirect jobs for the collection and delivery of feedstock.[2]

Table ES-2. Forestry Characteristics Within 50 Miles of the Site[3]

County	Primary Mill Residues	Forestry Residues
	Bone dry tons per year	
Broadwater	115,842	2,068
Cascade	303	3,530
Jefferson	none reported	12,051
Lewis and Clark	817	18,440
Meagher	none reported	4,957
Powell	120,349	45,222
Total	**237,311**	**86,268**

The Montana Renewable Power Production and Rural Economic Development Act established an RPS. The RPS requires utilities to purchase 15% renewable power by 2015. The RPS was met at the end of 2012 with the startup of a new wind plant. The RPS also contains a provision requiring each utility to purchase 75 MW of power from small community-owned power plants with generating capacities of 25 MW or less. This provision has not been met by the area utility. This indicates potential for a biopower plant at the East Helena site. The current Montana avoided cost rate that utilities pay to independent power producers varies between $54.44/MWh and $90.87/MWh, depending on power source type, generating capacity, and time of day/year.[4] There is some potential to achieve a higher rate through utility power purchase agreements to meet the small community-owned renewable energy power plant provision of the RPS.

Financial analysis was conducted using Natural Resources Canada's RETScreen tool. RETScreen is a Microsoft Excel-based tool that was developed to reduce the cost of feasibility studies and enable better decisions on renewable energy projects. NREL used inputs for capital and operating costs based on past experience. The capital costs for a 10-MW and 20-MW plant are estimated to be $42.63 million and $71.05 million, respectively. Net present value was set equal to zero in order to determine the minimum rate the project can accept for electricity. RETScreen generated electricity rates of $141.60–$123.12/MWh for the 10-MW and 20-MW plants. These rates exceed the current rates the local utility pays for other renewable electricity. This project may be profitable with lower feedstock or capital costs. The sensitivity analysis in Figure ES-1 shows economic performance as a function of electricity and feedstock prices with all other variables unchanged. The area above the red line and blue line shows the ranges or electricity and feedstock prices where a plant is estimated to be profitable.

[2] "Helping Biopower Help America." Biomass Power Association. Accessed January 10, 2013: http://www.usabiomass.org/docs/BPA%20PTC%20INFO%20SHEET.pdf.
[3] Data from NREL BioFuels Atlas USDA Forest Service Timber Output Database (2007). Accessed January 8, 2013: http://maps.nrel.gov/biomass.
[4] "NorthWestern Energy Electric Tariff Schedule No. QF-1 Qualifying Facility Power Purchase." Approved by PSC. November 30, 2011.

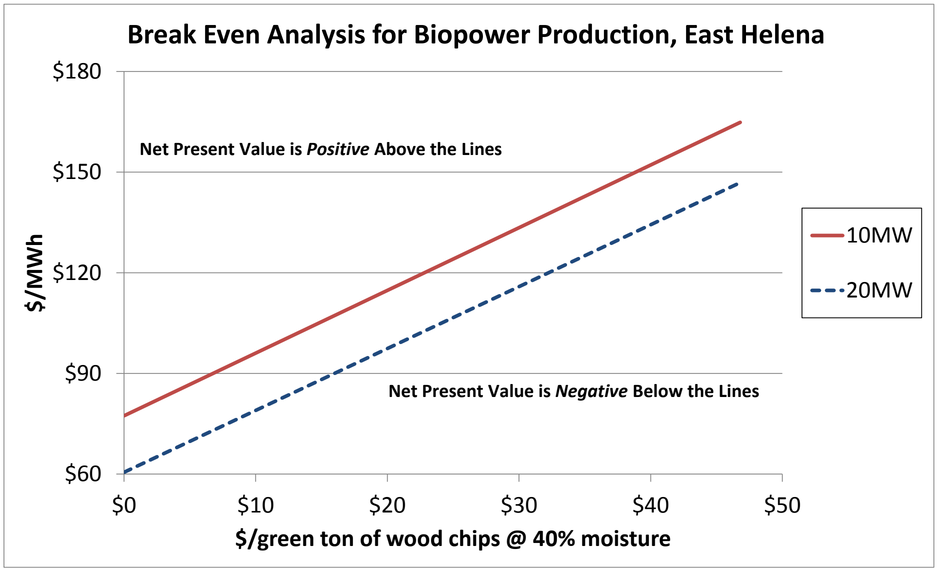

Figure ES-1. Sensitivity analysis

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1 Study and Site Background

1.1 Purpose of Study

The U.S. Environmental Protection Agency (EPA) Office of Solid Waste and Emergency Response Center for Program Analysis developed the RE-Powering America's Land initiative to reuse contaminated sites for renewable energy generation. EPA engaged the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL) to conduct feasibility studies to assess the viability of developing renewable energy generating facilities on contaminated sites. The former American Smelting and Refining Company (Asarco) Smelter in East Helena, Montana, was selected for a feasibility study under this initiative.

The area surrounding the site has ample woody biomass to support a bioenergy project (see Section 4). Biomass is the renewable energy feedstock and biopower is the technology selected for this study. The State of Montana has a renewable portfolio standard (RPS) that requires utilities to purchase renewable power with an additional stipulation to purchase power from smaller-scale community-based renewable energy plants. This provides an opportunity for a biopower plant at the Asarco site.

1.2 Scope of Work

The facility envisioned is a 10- or 20-MW power plant using woody biomass as feedstock. This feasibility study makes an evaluation of the following areas:

- Site assessment
- Overview of bioenergy technology
- Feedstock assessment
- Markets for heat and power
- Financial analysis.

1.3 Study Area and Site Description

The site is located in East Helena, Montana. The Superfund site encompasses parts of the town, nearby subdivisions, and agricultural lands due to contamination spreading from the plant into the surrounding community. The circle in Figure 1 represents an ideal collection radius for woody biomass.

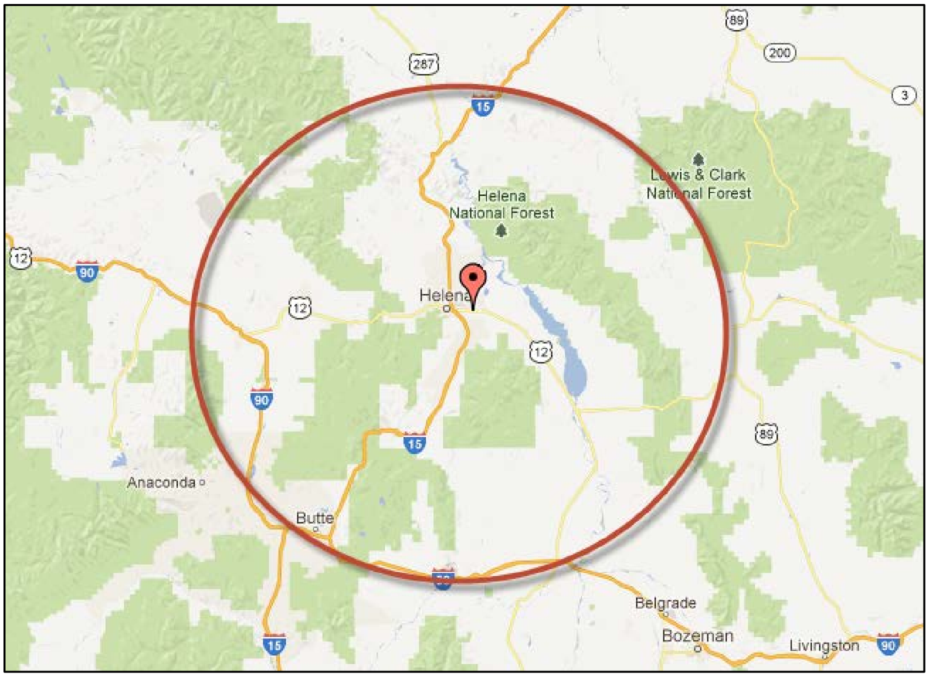

Figure 1. East Helena site. ***Illustration done in Google Maps***

The Superfund site was formerly Asarco, a lead and zinc smelter. The facility was in operation for over 100 years and ceased production in 2001. A bankruptcy settlement was completed in 2009 with transfer of real estate and remediation responsibility to the Montana Environmental Trust Group (METG), the custodial trustee (Figure 2). The METG manages approximately 1,800 acres, including the former smelter site and outlying formerly owned Asarco lands. The smelter area is undergoing corrective action remediation with scheduled demolition of existing building infrastructure beginning in the spring of 2013.

Approximately 5 million tons of unfumed slag is slated to be removed by rail to a facility in British Colombia. Unfortunately, none of the buildings can be repurposed.

Ideally, a bioenergy facility will be on Asarco lands in town where it is easy to tie into the grid and adjacent to potential users of resulting heat. The monitoring and remediation process has established the areas in East Helena best suited for industrial activities, such as a biomass energy plant. Soil will need to be evaluated to determine its suitability for construction of a biomass facility as lead contamination is an issue in the area. Any work below grade will require significant evaluation to determine the impact on contaminated lands or soils. Institutional controls, such as Lewis & Clark County Health Department and EPA's Region 8 office, will need to assess any plans that impact soils. Prevailing winds must be considered when selecting a specific site. METG's continued monitoring and remediation projects will likely inform opinions of best areas for development.

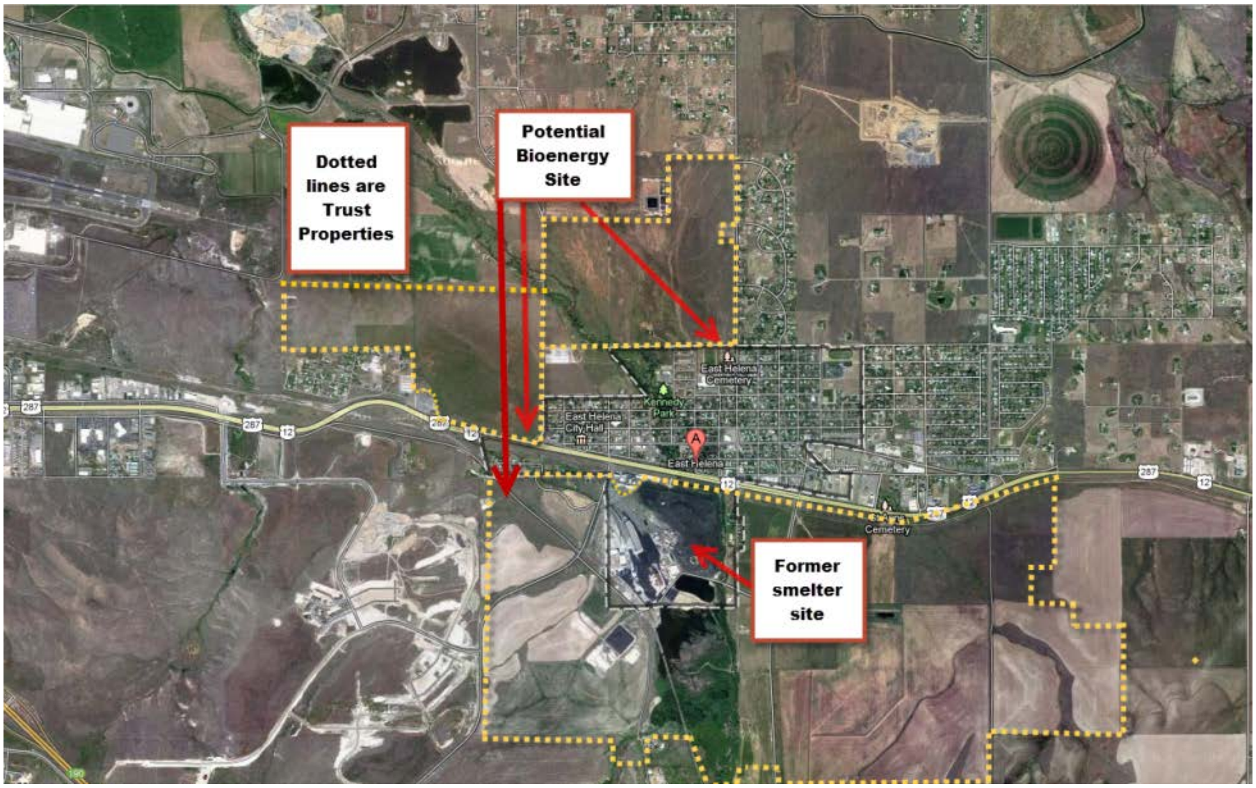

Figure 2. Former smelter site and trustee lands. ***Illustration done in Google Maps***

1.4 Site Considerations

The criteria for a successful bioenergy facility include feedstock proximity, road and rail access, state and federal codes, and proximity to required utilities. Another consideration is a market for selling energy from the plant.

The site is located in Lewis and Clark County approximately 5 miles east of Helena and Interstate 15. Trustee lands are located north and south of U.S. Highway 12/287. Burlington Northern Railroad runs a line between Helena and Great Falls. MRL rail connects East Helena on the south side of Highway 12/287 to Bozeman and Missoula. NorthWestern Energy (NWE) is the local utility servicing the area. There are natural gas pipelines and a substation with three transmission lines that supply the town. Transmission lines are near capacity and the utility is considering expanding transmission capacity in the area. Area groundwater is contaminated with arsenic and selenium and cannot be used. The City of East Helena provides water.

Proximity to communities is also an important factor because of increased traffic volume to deliver feedstock. Woody biomass will be delivered via truck to the site resulting in more traffic. The area has long been associated with heavy industry due to the smelter and other area manufacturing. A route for delivery of feedstock should be considered when selecting a site in this area.

1.5 Federal and State Regulations Impacting Biopower

The size and design of the plant, the method of steam and power generation, and local permitting requirements ultimately affect the actual permits required for a biopower plant. State agencies generally handle permitting. This section is not comprehensive but provides basic information on relevant regulations and permits.

The federal regulations and permits potentially required for a biopower project include:

- National Emission Standards for Hazardous Air Pollutants covers boilers[5]
- EPA's National Ambient Air Quality Standards says combustion devices must emit below stated levels[6]
- 2011 EPA Clean Air Act pollution standards requires biomass boilers over 10 million Btu/hr for 876 or more hours per year to meet numeric emission standards[7]
- 40 CFR Part 89 limits emissions on non-road internal combustion engines[8]
- 40 CFR Part 60 limits emissions on steam generating units over 10 million Btu/hr[5]
- 40 CFR Part 63 requires reciprocating internal combustion engines or generators over 300 hp to meet specific carbon monoxide standards[5]
- Resource Conservation and Recovery Act Subtitle D covers solid wastes and says the facility may be considered a waste processing facility[9]
- 40 CFR Part 257 sets disposal standards for owners of non-municipal non-hazardous wastes, which would include a facility accepting food wastes[6]
- National Pollutant Discharge Elimination System covers what happens to wastewater from the facility[10]
- Prevention of Significant Deterioration and construction permits requires any new major source of pollutants to conduct analysis and use best control technologies[11]
- Risk management plan requires new facilities to develop a plan if certain chemicals are stored.[12]

The required state permits generally include construction, air, water, and solid waste permits. Montana's Department of Environmental Quality (MDEQ) published a Bioenergy Guide Book

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[5] http://www.epa.gov/ttn/atw/eparules.html
[6] http://www.epa.gov/air/criteria.html
[7] "Final Air Toxics Standards for Industrial, Commercial, and Institutional Boilers at Area Source Facilities." EPA. 2011. Accessed January 8, 2013: http://www.epa.gov/airtoxics/boiler/area_final_fs.pdf.
[8] "Code of Federal Regulations. Title 40. Chapter 1 – Environmental Protection Agency. Subchapter C – Air Programs. Parts 50-99."U.S. Government Printing Office. Accessed January 8, 2013: http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR.
[9] "Code of Federal Regulations. Title 40. Chapter 1 – Environmental Protection Agency. Subchapter I – Solid Wastes. Parts 239-282."U.S. Government Printing Office. Accessed January 8, 2013: http://www.gpo.gov/fdsys/browse/collectionCfr.action?collectionCode=CFR.
[10] http://www.epa.gov/compliance/monitoring/programs/cwa/npdes.html
[11] http://www.epa.gov/NSR/psd.html
[12] http://www.epa.gov/oem/content/rmp/

that provides vast information on permits and licensing required for various bioenergy projects.[13] Some examples include:

- MDEQ
  - Air quality permits
  - Water quality permits; water appropriation permits
  - Certificate of compliance permit
  - Montana Groundwater Pollution Control System permit
  - Montana Pollutant Discharge Elimination System permit
  - General permit for storm water discharges associated with construction activity
  - Solid waste management system license
- Montana Department of Natural Resources and Conservation
  - Beneficial water use permit
  - Stream bed and land preservation permit
- Department of Fish, Wildlife, & Parks
  - Stream Protection Act permit
- Department of Labor and Industry
  - Weighing or measuring device license
- Montana Department of Transportation
  - Highway access permit
  - Possible easement rights
- State Department of Public Health & Human Service
- Local
  - Building, electrical, mechanical, and plumbing permits.

[13] Montana Bioenergy Guide Book. Department of Environmental Quality, 2010. Accessed January 23, 2013: deq.mt.gov/Energy/bioenergy/pdf/BioEnergyGuidebook2010.pdf.

2 Development of Biomass Energy on Superfund Sites

One very promising and innovative use of contaminated sites is to repurpose them for biomass power systems. Biopower systems work well on Superfund sites where there is an adequate biomass fuel supply and favorable power sales rates.

The cleanup and reuse of potentially contaminated properties provides many benefits, including:

- Preserving greenfields
- Reducing blight and improving the appearance of a community
- Raising property values and creating jobs
- Allowing for access to existing infrastructure, including electric transmission lines and roads
- Enabling a potentially contaminated property to return to a productive and sustainable use.

By taking advantage of these potential benefits, biopower can provide a viable, beneficial reuse—in many cases generating revenue on a site that would otherwise go unused.

The site in East Helena, Montana, is managed by METG, which is interested in a potential renewable energy project on trustee land. For many contaminated or formerly contaminated sites, the local community has significant interest in the redevelopment of the site and community engagement is critical to match future reuse options to the community's vision for the site.

The subject site has potential to be used for other functions beyond the biopower project proposed in this report. Any potential use should align with the community vision for the site and should work to enhance the overall utility of the property.

Most states rely heavily on fossil fuels to operate their power plants. There are many compelling reasons to consider moving toward renewable energy sources for power generation instead of fossil fuels, including:

- Using fossil fuels to produce power may not be sustainable
- Burning fossil fuels can have negative effects on human health and the environment
- Extracting and transporting fossil fuels can lead to accidental spills, which can be damaging to the environment and communities
- Fluctuating electric costs are associated with fossil-fuel-based power plants
- Burning fossil fuels emits greenhouse gases, possibly contributing to climate change.

3 Bioenergy Technology

Biopower, or biomass power, is the use of biomass to generate electricity. Biopower system technologies include direct-firing, co-firing, gasification, pyrolysis, and anaerobic digestion. Most biopower plants are direct-fired systems. This section will focus on direct-fired systems.

Co-firing refers to mixing biomass with fossil fuels in conventional power plants. Coal-fired power plants can use co-firing systems to significantly reduce emissions, especially sulfur dioxide. Pyrolysis is a thermal process that occurs without oxygen with outputs of syngas, liquids, and charcoal, which can be used to produce heat and power or reformed into liquid fuels and chemical products. Anaerobic digestion is a biological degradation of organic matter without oxygen to produce biogas, which can be used in heat or electricity application.

Gasification systems use elevated temperatures and an oxygen-starved environment to convert biomass into synthesis gas, a mixture of hydrogen and carbon monoxide. The synthesis gas, or syngas, can then be chemically converted into other fuels or products, burned in a conventional boiler, or used instead of natural gas in a gas turbine. Gas turbines are very much like jet engines, but they are used to turn electric generators instead of propel a jet. Gas turbines are very efficient, but the overall system efficiency can be further improved by operating them in a combined cycle arrangement. During combined cycle operation the exhaust gases are used to boil water for steam to provide additional power generation or heat.

The amount of energy that can be produced by a biopower system depends on several factors, including the type of biomass, technology employed, and numerous economic factors. Biopower systems can be sized to supply internal energy needs only or sized larger to feed energy to the grid for sale. Figure 3 shows a typical biopower direct-fired system.

Figure 3. Direct-fired biopower system. ***Photo by Wheelabrator Shasta Energy Co., NREL 07163***

These plants burn biomass feedstocks directly to produce steam. This steam drives a turbine, which turns a generator that converts the power into electricity. In some biomass plants, turbine extraction steam from the power plant is also used for manufacturing processes or to heat buildings. Such combined heat and power (CHP) systems increase overall energy efficiency. This makes sense when a large heat user is located nearby. These systems normally operate 24 hours per day and 7 days per week, with several weeks of down time per year for maintenance and repairs. Plants of this type are not normally cycled with many starts and stops. Frequent cooling and re-heating of the components leads to fatigue and failure, making it more cost-effective to operate around the clock even though power rates are lower during off-peak hours. While direct-fired units are most common, the NREL biomass assessment team uses several tools to assess the optimal facility fuel, technology, plant size, and configuration for each particular location under consideration.

3.1 Types of Bioenergy Systems

A biopower system should be sized based on both the availability of cost-effective biomass feedstock and the energy requirements of the end-user. The most common installation types are described below. In general, these systems can be divided into thermal energy only, power generation only, and CHP categories. The system choice is mostly dependent upon economics. The cost of fuel, the rate that power can be sold, and the rate available for the sale of thermal energy are a few of the key economic parameters.

3.1.1 Thermal Energy Only

Figure 4 illustrates a "thermal energy only" system. Biomass energy is converted to steam that is sent to a nearby business that utilizes the heat in the steam for heating, cooling, manufacturing, or any other number of industrial uses (boiler steam to load in Figure 4). The steam is condensed as the energy is extracted and the warm condensate is pumped back to the biomass facility where it is reintroduced to the boiler and converted once again to steam. This type of system can be economical as the inefficiencies associated with generating electrical power on a small scale are avoided and the capital costs for a steam turbine, condenser, cooling tower, circulating water pumps, and other items are not incurred. High pressure, superheated steam is not required making the boiler less expensive and easier to operate. This system is common and has been implemented for many decades in this country.

Finding a business that is close enough to accept steam without lengthy piping systems is often challenging. In many cases where a steam host is present, it makes sense to generate both steam and electricity.

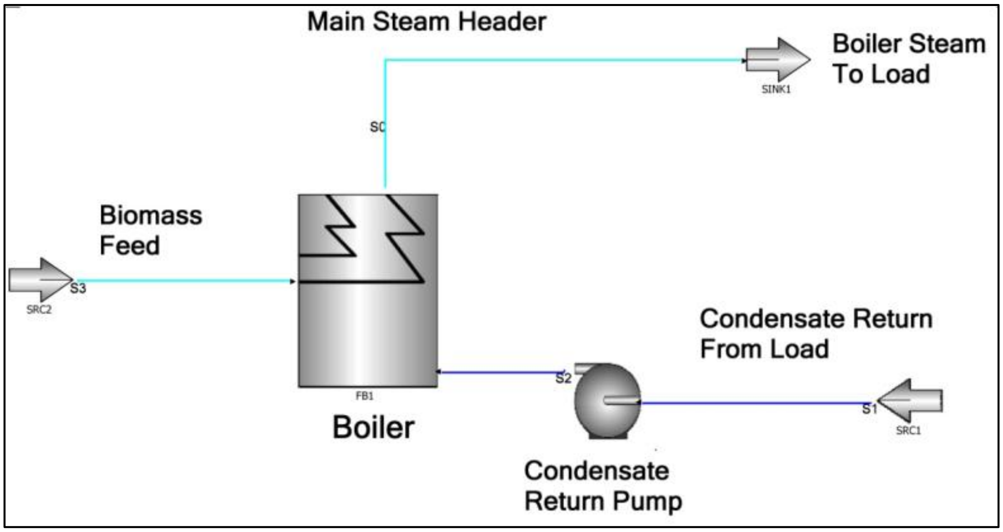

Figure 4. Thermal only biomass energy system. ***Illustration by Gregg Tomberlin, NREL***

3.1.2 Power Generation Only

Figure 5 illustrates a "power generation only" system. Biomass energy is converted into high pressure, superheated steam for introduction into a steam turbine. The turbine generates electricity at the most efficient rate practical depending on the size of the system. The steam is condensed at near vacuum to maximize efficiency. This is accomplished in a condenser, which uses cooling water that typically comes from an evaporative cooling tower. It is also possible to use a dry type of air-cooled condenser.

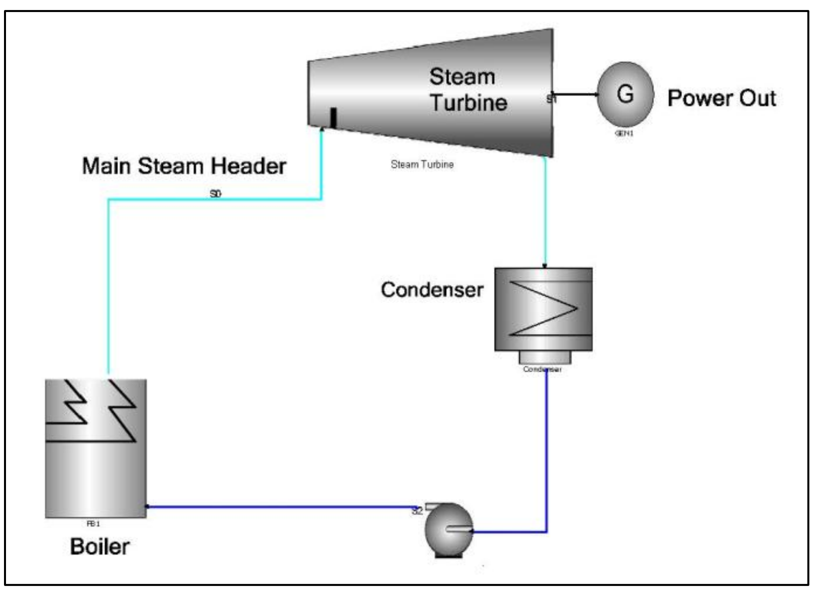

Figure 5. Power generation only biomass energy system (cooling tower not shown). ***Illustration by Gregg Tomberlin, NREL***

3.1.3 Combined Heat and Power

CHP is technically the concurrent generation of multiple forms of energy in a single system. CHP systems can include reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells. These systems are capable of utilizing a variety of fuels, including natural gas, coal, oil, and alternative fuels. While generating electric power, the thermal energy from the system can be used in direct applications or indirectly to produce steam, hot water, or chilled water for process cooling. Over 60% of biomass power systems use CHP.

For biomass direct-fired systems, the most common CHP configuration consists of steam from a biomass-fired boiler directed to a steam turbine. Steam is extracted at some point in this process to provide heat to meet internal requirements of the facility or to sell to a local steam host. The steam can be taken from the power process in three primary methods:

1. Main steam extraction
2. Extraction turbine
3. Back pressure turbine.

Main steam extraction extracts some of the boiler outlet steam prior to being introduced into the steam turbine. This high pressure, high temperature steam would typically have to be reduced in pressure and temperature prior to its final use. This is not the most efficient method for optimizing power output but avoids the cost of a more expensive extraction turbine (described below). The remaining steam runs through the entire length of the turbine and then discharges into a condenser at very low pressure (vacuum) to maximize the electric power generated. The condenser circulates large quantities of cooling water that is cooled by evaporation in a cooling tower or by an air-cooled condenser (Figure 6). Warm condensate is pumped back to the biomass facility where it is reintroduced to the boiler and converted once again to steam.

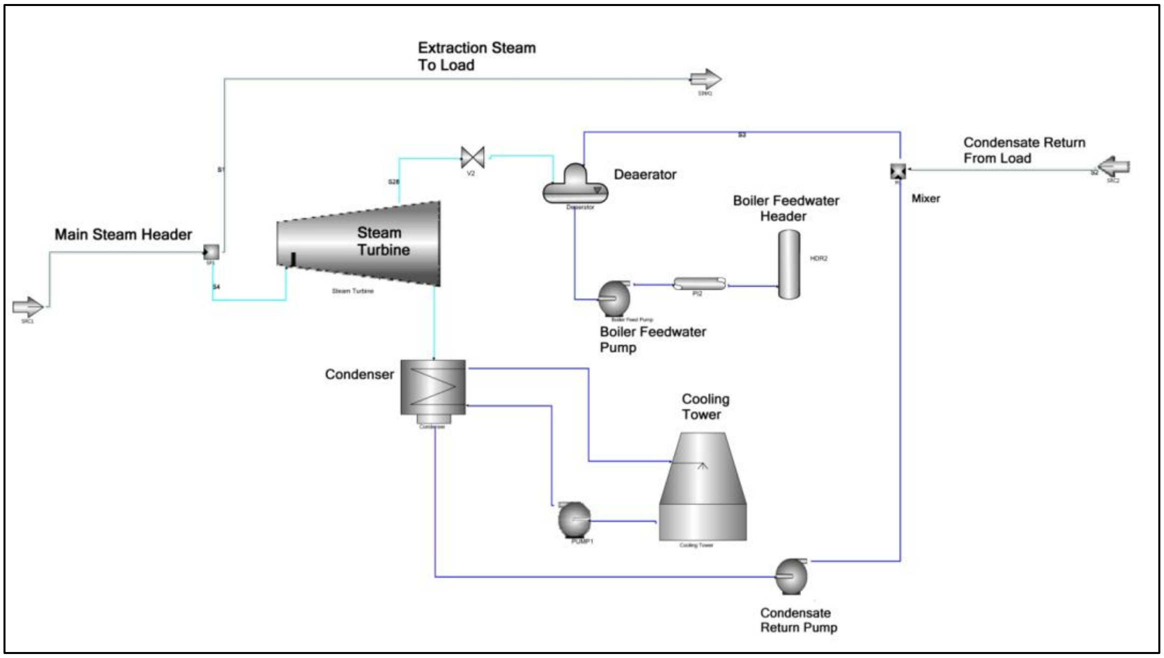

Figure 6. CHP main steam extraction. ***Illustration by Gregg Tomberlin, NREL***

An extraction turbine accepts all boiler steam at its inlet and extracts the required process steam at some intermediate point along the turbine steam path. This allows the process steam to produce electric power prior to its extraction, increasing the efficiency of the overall process. The cost for an extraction turbine is typically higher and is not normally utilized in smaller systems (less than 10 MW). The remaining steam continues through the lower pressure stages of the turbine and then discharges into a condenser (Figure 7).

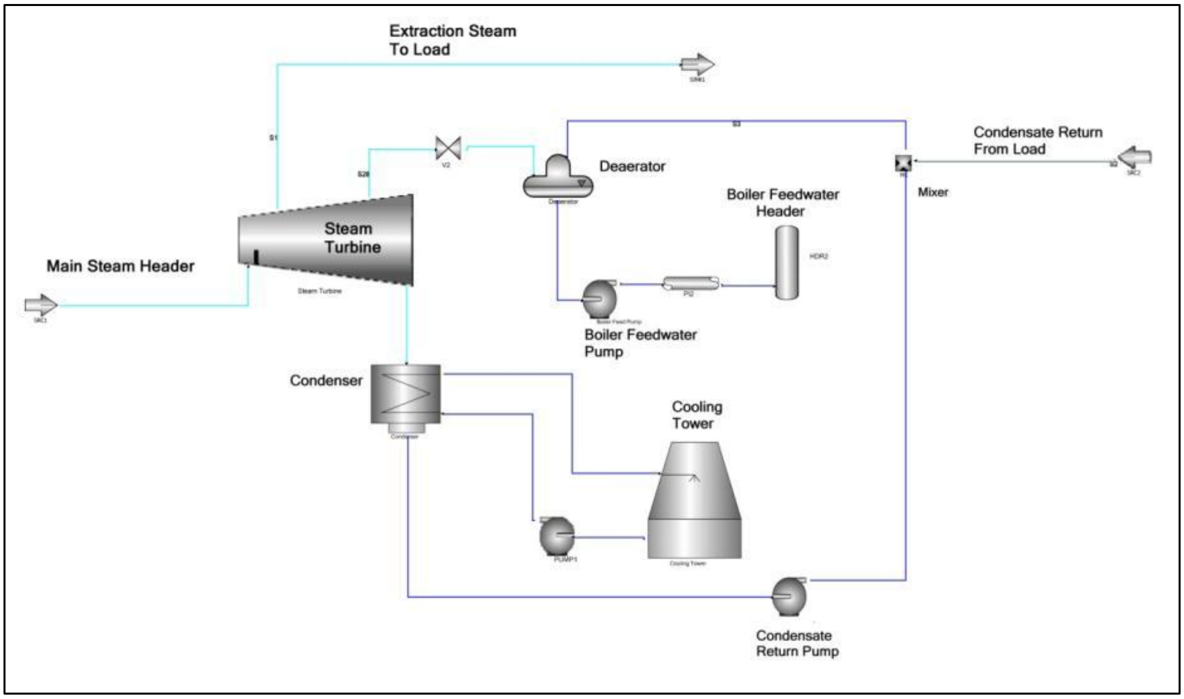

Figure 7. CHP extraction turbine. ***Illustration by Gregg Tomberlin, NREL***

A backpressure turbine accepts all boiler steam at the steam turbine inlet but discharges all of the steam at the higher pressure required by the end steam user (Figure 8). There are considerable cost savings with this approach. The steam turbine is much less expensive because the lower-pressure sections of a turbine are the largest and costliest. There is no need for a condenser, a cooling tower, or large circulating water pumps to push the cooling water through the condenser. The steam is typically condensed by the load and then returns to the plant as warm condensate to be reheated and reintroduced to the system.

There are two disadvantages to this arrangement. Firstly, the amount of electric power produced is greatly reduced due to the shortening of the turbine and the relatively high discharge pressure. Secondly, if the steam host reduces its steam requirements to a quantity less than the full steam turbine capacity, the steam turbine must be turned down or the excess steam must be condensed by way of an external steam condenser, which would also require a cooling water source.

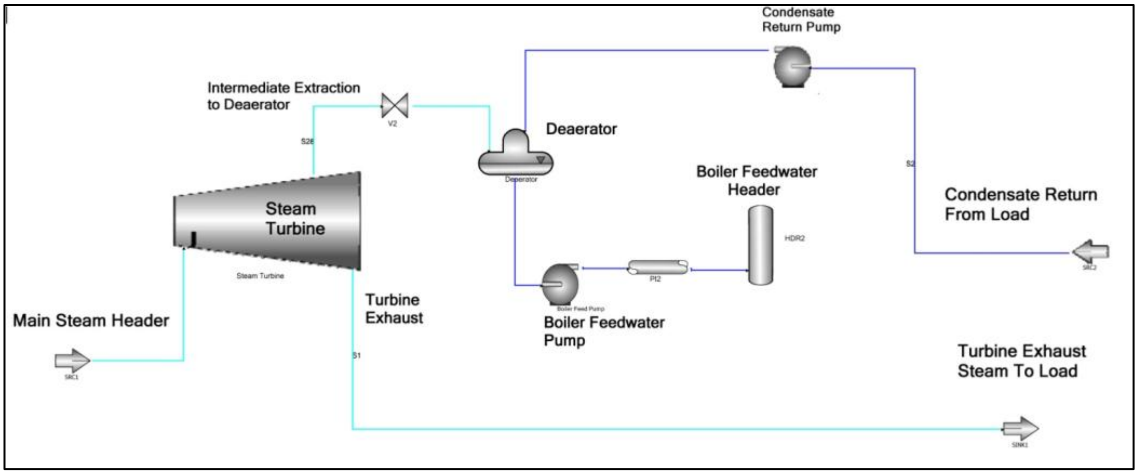

Figure 8. CHP backpressure turbine. ***Illustration by Gregg Tomberlin, NREL***

3.1.4 District Heating

District heating is defined as a central unit providing heat to nearby buildings and homes through a series of pipes carrying hot water or steam. The scheme generally includes a set of pipes—one pipe delivers hot water at a temperature between 180°F and 250°F. Heat enters a building's conventional heating system through a heat exchanger. After heat is extracted, another pipe returns water (104–158°F) to the central heating plant. Pipes are typically double walled and generally buried underground. District heating systems are most common in Scandinavia. In Denmark, district heating provides 60% of thermal energy with 17% derived from biomass.[14] Lower temperature district heating systems are under development, using hot water as low as 122°F.[15]

Capital costs are high for district heating systems due to the network of piping and heat exchangers and other equipment that must be installed for each customer. Economics work best for district heating when waste heat can be obtained from a nearby power plant at minimal cost, when replacing electric heating systems, and in densely populated areas with high-rise apartments. A 2009 report for United Kingdom's Department of Energy and Climate Change concluded that district heating will not be widely implemented regardless of heat source due to high initial investment and costs compared with other methods.[16]

Several cities and universities have district heating systems powered by traditional energy sources. Most were built many decades ago. There are district heating systems in the United States but only two that use biomass as an energy source. District Energy St. Paul operates a

[14] "Renewable Heat Initial Business Case." DEFRA and BURR. United Kingdom, September 2007. Accessed January 8, 2013: http://webarchive.nationalarchives.gov.uk/+/http://www.berr.gov.uk/files/file41432.pdf.
[15] Thorson, J.; Christiansen, C.; Marek, B. "Experience on Low-Temperature District Heating in Lystrup, Denmark." International Conference of District Energy. Portoroz, Slovenia, 2011.
[16] Davies, G.; Woods, P. "The Potential and Costs of District Heating Networks." United Kingdom Department of Energy and Climate Change, April 2009. Accessed January 8, 2013: http://www.decc.gov.uk/assets/decc/What%20we%20do/UK%20energy%20supply/Energy%20mix/Distributed%20Energy%20Heat/1467-potential-costs-district-heating-network.pdf.

biomass district heating system in St. Paul, Minnesota.[17] It is also the largest hot water district heating system in the United States. The system operates from a CHP system using waste wood as a fuel source as well as a recently installed solar thermal system. The University of New Hampshire meets all heat and electricity requirements from a district system using methane from a nearby landfill.[18] Many other universities have district heating systems powered by traditional energy sources.

The East Helena site is not a good candidate for district heating due to small loads and long distances between potential users of such a system.

3.2 Biopower System Components

A typical direct-fired biopower system has the following components:

- Major components
    - Fuel receiving, storage, and handling
    - Combustion system and steam generator
    - Steam turbine and electrical generator
    - Air pollution control
    - Condenser and cooling tower
- Other equipment and auxiliaries
    - Stack and monitoring equipment
    - Instrumentation and controls
    - Ash handling
    - Fans and blowers
    - Water treatment
    - Electrical equipment
    - Pumps and piping
    - Buildings.

3.2.1 Fuel Receiving, Storage, and Handling

Biomass can be received at the site by truck, rail, or barge. It can be delivered as chips or pellets, or logs and brush can be processed on site into chips. Wood chips are typically stored in a fuel yard (exposed or covered) or in storage silos (Figure 9). Wood pellets are stored in silos and are easily handled and fed with standard equipment. Fuel handling may be fully automated or semi-automated requiring some labor. A fully automated system will typically be installed below grade. Wood chips would be delivered by truck to the storage bin and conveyor belts

[17] District Energy St. Paul. Accessed January 9, 2013: http://www.districtenergy.com/technologies/district-heating/.
[18] "First University In Nation To Use Landfill Gas As Primary Energy Source." University of New Hampshire Media Relations, August 14, 2007. Accessed January 9, 2013: http://www.unh.edu/news/cj_nr/2007/aug/kb14landfill.cfm.

automatically feed the boiler. Automated systems are generally used to serve large facilities such as the 10-MW and 20-MW biopower plants evaluated in this study. Semi-automated systems are less expensive but require more labor. They typically include above-ground chip storage and a hopper with capacity to supply the boiler for a few days. An operator moves woody biomass from the storage area to the hopper as needed. Operator workload is estimated at 60–90 minutes per day.[19]

Figure 9. Biomass storage options: fuel yard (left) and fuel silo (right). ***Photos by Warren Gretz, NREL 04736 (left) and Gerry Harrow, NREL 15041 (right)***

3.2.2 Combustion System and Steam Generator

The most common system for converting solid biomass fuel into energy is a direct-fired combustion system. The fuel is burned typically on a grate or in a fluidized bed to create hot combustion gases that pass over a series of boiler tubes transferring heat into water inside the tubes creating steam. The combination of the burning apparatus and the heat transfer surface areas are typically referred to as the boiler.

Boilers are differentiated by their configuration, size, and the quality of the steam or hot water produced. Boiler size is most often measured by the fuel input in millions of British thermal units per hour (MMBtu/hr), but it may also be measured by output in pounds per hour of steam produced. The two most commonly used types of boilers for biomass firing are stoker boilers and fluidized bed boilers. Either of these combustion systems can be fueled entirely by biomass fuel or co-fired with a combination of biomass and coal or other solid fuel.[20]

The traveling grate stoker boiler introduces fuel at one end of the furnace. The grate slowly moves the fuel through the hot zone until combustion is complete and the ash falls off at the opposite end.[21] The fuel is either dropped onto the grate and travels away from the feeder or it is

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[19] "Woodchip Fuel Specifications in the Northeastern United States." Biomass Energy Resource Center. Accessed January 8, 2013: http://www.biomasscenter.org/resources/publications.html.

[20] "Biomass Combined Heat and Power Catalog of Technologies." EPA, September 2007. Accessed January 8, 2013: http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf.

[21] Johnson, N. "Fundamentals of Stoker Fired Boiler Design and Operation." CIBO Emission Controls Technology Conference. July 2012. Accessed January 10, 2013: http://www.cibo.org/emissions/2002/a1.pdf.

thrown to the opposite end and comes back towards the feeder. The latter is called a spreader stoker. A fluidized bed boiler introduces feedstock into the bed with a heat transfer medium (typically sand).[22] The bed material is fluidized using high pressure air from underneath the grate creating a good mixing zone.

3.2.2.1 Steam Turbine

The steam turbine is a key component and major cost element for the facility. In many cases, additional cost can result in increased turbine efficiency, which must be assessed with regards to overall plant economics. The higher the steam inlet pressure and the lower the steam exhaust pressure, the more energy can be extracted from the steam. These both come at a cost and have to be balanced with the system economics. Typically, smaller systems use lower pressure steam and larger systems can afford to operate at higher pressures yielding more power production to compensate for the increased capital costs.

3.2.3 Air Pollution Control

Biomass is a relatively clean fuel and contains lower quantities of the pollutants commonly found in coal and other solid fuels. The primary pollutants of concern in biomass combustion are carbon monoxide (CO), nitrogen oxides (NO_x), and particulate matter (PM).

CO emissions are largely a function of good combustion. Good air mixing will oxidize most CO molecules into carbon dioxide (CO_2), which is not a regulated pollutant. The control of NO_x is not always required, but NO_x can be controlled by either selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR). SNCR is accomplished by the introduction of nitrogenous reagents (urea or ammonia) at specific temperatures creating a reducing reaction. SCR is a similar process but also uses a catalyst to achieve higher removal efficiencies.

For PM the small ash particles are captured in the fabric of large bags, and the bags are pulsed occasionally to dislodge the dust into an ash hopper for removal. These systems are known as fabric filters or baghouses. Electrostatic precipitators are also commonly used for particulate removal.

EPA's "Final Air Toxics Standards for Industrial, Commercial, and Institutional Boilers at Area Source Facilities" was released in 2011 and applies to biomass boilers. The following provisions apply to new biomass boilers[23]:

- Boilers with capacity above 10 MMBtu/hr must meet PM limits
- Boilers with capacity below 10 MMBtu/hr must conduct a boiler tune-up every 2 years.

3.2.4 Condenser, Cooling Tower

As the steam exits the turbine, it is condensed for reuse in the cycle. The most common method is to use a steam surface condenser and a cooling tower. The surface condenser is a large vessel filled with tubes that circulate cool water from the cooling tower. The steam flows over the tubes

[22] Crawford, M. "Fluidized Bed Combustors for Biomass Boilers." ASME, September 2012. Accessed January 10, 2013: https://www.asme.org/kb/news---articles/articles/boilers/fluidized-bed-combustors-for-biomass-boilers.
[23] "Final Air Toxics Standards For Industrial, Commercial, and Institutional Boilers at Area Source Facilities." EPA, 2011. Accessed January 28, 2013: http://www.epa.gov/airtoxics/boiler/area_final_fs.pdf.

condensing into a hot well at the bottom of the condenser. The cooling water that leaves the condenser is pumped back to the cooling tower, which uses evaporative cooling to cool the water for reintroduction into the condenser.

A large amount of water is lost due to evaporation from the cooling tower, and that water needs to be replaced on a continuous basis. In areas where water is scarce and expensive, this introduces a large operating cost. In these cases, the water is commonly cooled by an air-cooled system. The capital costs for this equipment is higher and the electric power to operate the fans is higher, but no water is consumed with this method.

4 Feedstock Evaluation

4.1 Woody Biomass in Study Area

East Helena is surrounded by forests, and woody biomass is available in large quantities. The most common tree type is Douglas-fir followed by Lodgepole pine and lesser amounts of Ponderosa pine. A typical economic delivery radius for green biomass is 50 miles due to the negative effects of moisture content and bulky characteristics of woody biomass (represented by the blue shaded area in Figure 10). It might be possible to extend this range, especially when delivery by rail is economical.

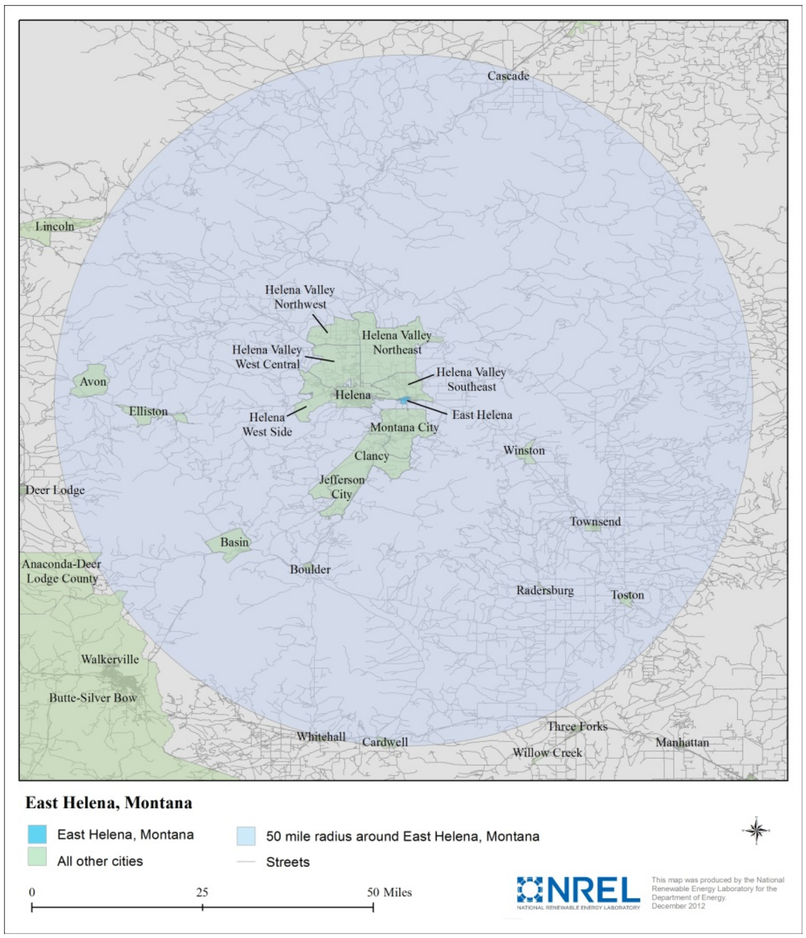

Figure 10. Study area

The United States Forest Service (USFS) collects data on forests, including acreage, land ownership, number of trees, living and dead tree volume, and removals. There are nearly 2.5 million forest acres and 4.5 billion cubic feet of standing trees in the study area (Table 1). The majority of forest land within 50 miles of the site is on public lands. The total volume of trees is significantly higher on federal lands compared to private lands. Of total standing trees in the study area, 87% are living and 13% are dead.[24] As with many western forests, beetle kill pine

[24] Forest Inventory Data Online (FIDO) within 50 mile radius of East Helena; survey year 2009. Accessed January 8, 2013: http://apps.fs.fed.us/fido/.

and fir trees are common and removing them mitigates fire risk. Many private forestland acres are owned by forest industry companies.

Table 1. Forestry Characteristics Within 50 Miles of Study Area[25]

Land Owner	Acres	% of Total	Living Trees	Dead Trees	% of Total Trees
			(billion cubic feet)		
National Forest	1,339,756	55%	2,876	484	74%
BLM	121,100	5%	193	15	5%
State	81,392	3%	79	20	2%
Private	914,983	37%	831	60	20%
Total	**2,457,231**		**3,979**	**579**	

4.1.1 Primary Mill Residues

USFS's Timber Product Output database reports volumes of forest residues and primary mill residues.[26] Primary mill residues are generated at wood mills as trees are transformed into lumber. They include bark, slabs, edgings, trimmings, sawdust, veneer clippings and cores, and pulp screenings. Table 2 shows total primary mill residue generation in the counties surrounding East Helena. Figure 11 highlights areas concentrated with primary mill residues.

The primary mill residues in the area are sufficient to support a biopower plant. Mill residues are preferred over logging and forestry residues because they are clean wastes collected from area wood processors. USFS does not collect secondary data on mill residues, which include wood scraps and sawdust from woodworking shops, such as furniture factories, wood container and pallet mills, and wholesale lumberyards. There are many secondary wood processing facilities in Montana that could provide an additional source for woody biomass. There are numerous wood processing facilities within and just beyond a 50-mile radius of East Helena (Figure 12).

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[25] Data from Forest Inventory Data Online (FIDO) within 50 mile radius of East Helena; survey year 2009. Accessed January 8, 2013: http://apps.fs.fed.us/fido/.
[26] USFS Timber Product Output Database. Accessed January 31, 2013: http://srsfia2.fs.fed.us/php/tpo_2009/tpo_rpa_int1.php.

Table 2. Primary Mill Residues in the Study Area[27]

County	Primary Mill Residues
	dry tons per year
Broadwater	115,842
Cascade	303
Jefferson	none reported
Lewis and Clark	817
Meagher	none reported
Powell	120,349
Total	**237,311**

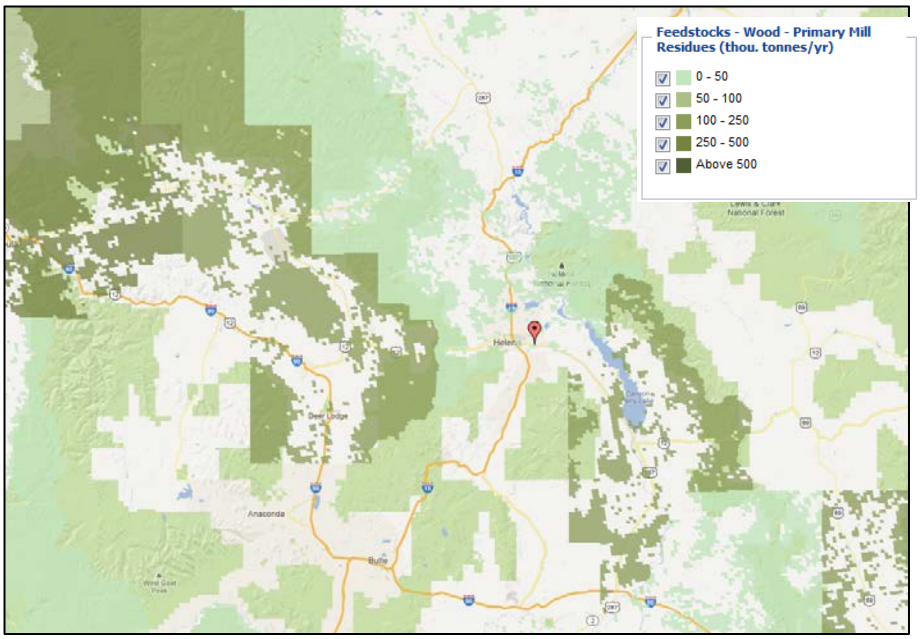

Figure 11. Primary mill residues. ***Illustration done in Google Maps***

[27] Data from NREL BioFuels Atlas USDA Forest Service Timber Output Database, 2007. Accessed January 8, 2013: http://maps.nrel.gov/biomass.

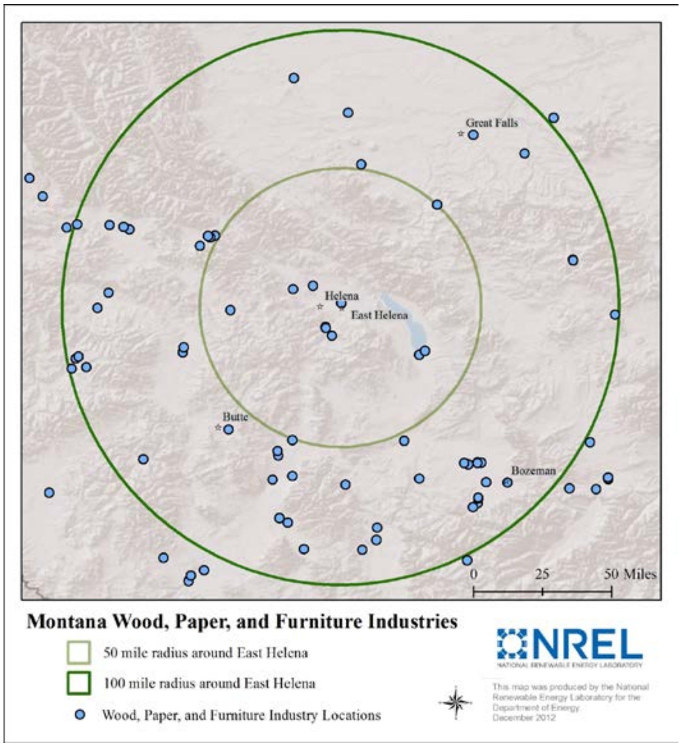

Figure 12. Area wood waste producers[28]

4.1.2 Forest Residues

Forest residues are leftover portions of trees from logging activities and other removals from thinning or land clearing activities. Forestry residues require collection from the forest floor by a logging company. Some portion of the reported forest residues is likely on federal lands. Table 3 shows total forest residue generation in the counties surrounding East Helena. Figure 13 shows areas of concentrated forestry residues.

Table 3. Forest Residues in the Study Area[29]

County	Forestry Residues
	Bone dry tons per year
Broadwater	2,068
Cascade	3,530
Jefferson	12,051
Lewis and Clark	18,440
Meagher	4,957
Powell	45,222
Total	**86,268**

[28] Data from University of Montana Manufacturers Information System. Accessed January 8, 2013: http://www.mmis.umt.edu/default.asp.
[29] Data from NREL BioFuels Atlas USDA Forest Service Timber Output Database, 2007. Accessed January 8, 2013: http://maps.nrel.gov/biomass.

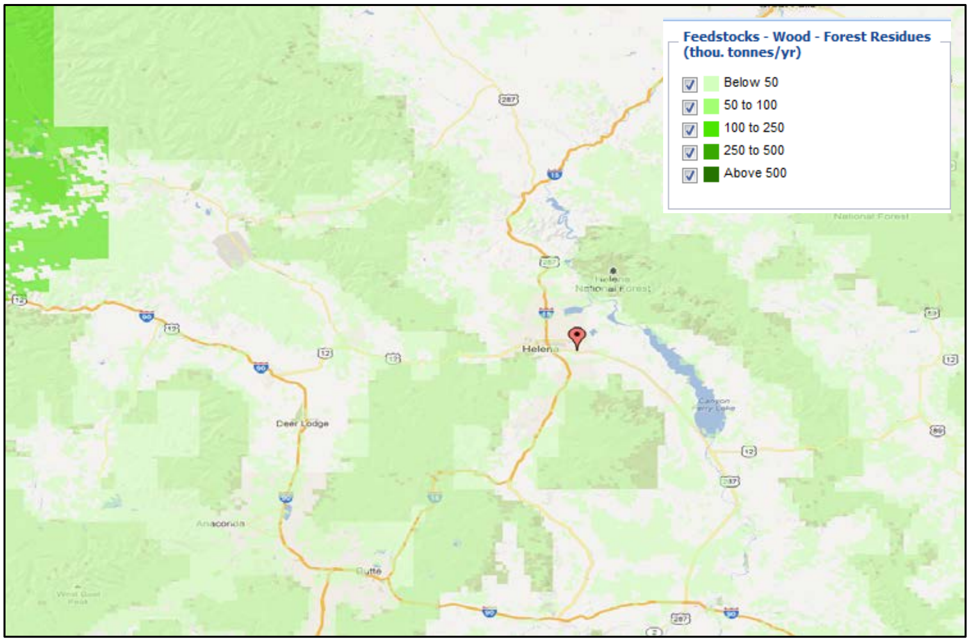

Figure 13. Forest residues.[30] ***Illustration done in Google Maps***

There are challenges in obtaining a steady supply of woody biomass (both trees and residues) from federal lands, as there has been a decline in management of federal forestlands. There were 600 million board feet of timber harvest in 1987 on federal lands—far more than the 60 million board feet harvested in 2008.[31] For comparison, private harvest was 700 million board feet in 1987 compared with 325 million board feet in 2008. The forest products industry remains important in Montana with ample residues to support bioenergy projects.

Biomass plants operate for decades, and investors require a long-term reliable supply of feedstock. Federal agencies award stewardship contracts to maintain forests and reduce fire risk by designating areas of federal forestlands that require removal of trees and biomass. Unfortunately, these stewardship contracts are generally 2 years or less. There is only one example of the USFS approving a long-term stewardship contract. Future Forest, LLC obtains wood for their pellet plant from a 10-year stewardship contract with Apache-Sitgreaves National Forest.[32] This agreement has resulted in successful management of forest lands while providing the bioenergy facility with a steady supply of feedstock. This type of stewardship contract has not been replicated elsewhere.

There is an ample woody biomass resource on public lands surrounding East Helena. Any woody biomass project in the area should work with local USFS offices to establish long-term stewardship contracts that benefit both the forests and the bioenergy project.

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[30] Data from NREL BioFuels Atlas USDA Forest Service Timber Output Database, 2007. Accessed January 8, 2013: http://maps.nrel.gov/biomass.

[31] "Developing a Business Case for Sustainable Biomass Generation: A Regional Model for Western Montana." Northwestern Energy and Montana Community Development Corporation. June 2010.

[32] Data from Future Forest, LLC. Accessed January 31, 2013: http://www.futureforest.info/partners.html.

4.2 Previous Montana Woody Biomass Resource and Biopower Studies

The Montana Department of Natural Resources and Conservation commissioned a study to assess forest-based woody biomass supply and demand. The study reviewed live and standing dead trees, forest residues, and primary mill residues.[33] Using USFS data, the report determined that Montana consumes between 2.2 million and 2.7 million dry tons of woody biomass each year. Woody biomass is mostly utilized to power boilers at wood products companies to power their manufacturing processes. This report estimated that 99%–100% of mill residues are utilized; however, this was determined prior to the closure of facilities using mill residues. Both forest and mill residue volumes have decreased over time due to mill closures. Today, it is estimated that approximately 70% of potentially available woody biomass is on public forest lands.

A green ton refers to woody biomass delivered with moisture content. Moisture content varies but is typically between 40% and 50%. Beetle kill trees likely have a lower moisture content. A bone dry ton refers to woody biomass with no moisture content.

The International BioMass Group (IBMG) is planning a wood/plastic pellet manufacturing facility in Silver City, Montana, at a former sawmill 15 miles northwest of Helena.[34] The proposed plant plans to export all pellets in order to obtain the highest price. Capacity is planned at 132,000 tons of pellets annually requiring 125,000 dry tons woody biomass. IBMG holds contracts with private area timber lands to harvest beetle kill trees. Their feasibility analysis found a large supply of woody biomass within 30 miles of their site. IBMG's study estimates delivered costs at $31/green ton.[31] This cost was based on another forest product company delivering woody biomass via rail to Helena for $30/ton and their own analysis of beetle kill tree logging ($20/ton) and delivery costs (average $10/ton), totaling $30/ton. This study found that a paper mill in Bonner, Montana, is paying $30–$33/green ton. The IBMG study determined a positive internal rate of return (IRR) on the pellet mill. If this plant is built, there is potential to use these pellets as feedstock at a biopower plant, but they are unlikely to be the lowest cost feedstock.

NWE, East Helena's local utility, and Montana Community Development Corporation issued a report on sustainable biomass power generation.[35] This report specifically evaluated the feasibility of biomass-based CHP plants at existing sawmills to help NWE meet their quota of the RPS. Montana's RPS requires NWE to purchase a total of 75 MW of power from community renewable energy plants generating 25 MW or less. There is enough woody biomass in western Montana to develop 15- to 20-MW CHP plants at each of the seven evaluated sawmills. The study reviewed availability of mill residues, logging slash, and urban wood wastes within a 40- and 70-mile radius of each sawmill. Total biomass from these sources was 826,000 dry tons. Additionally, small diameter trees and dead timber in the study area was estimated at 253 million

[33] Morgan, T. "An Assessment of Forest-based Woody Biomass Supply and Use in Montana." Montana Department of Natural Resources and Conservation, April 29, 2009. Accessed January 8, 2013: http://dnrc.mt.gov/forestry/Assistance/Biomass/Documents/MT_WoodyBiomassAssessment.pdf.

[34] "International BioMass Group: RDF Plant Feasibility Study." The Beck Group. April 2012.

[35] "Developing a Business Case for Sustainable Biomass Generation: A Regional Model for Western Montana." NorthWestern Energy and Montana Community Development Corporation. June 2010.

tons. The study estimated the value of mill residues at $28/dry ton and delivered cost of logging slash at $44/dry ton.

NWE's analysis assumed an 18-MW plant using 121,000 bone dry tons annually (2/3 mill residues; 1/3 logging slash) at $29.05/dry ton with capital costs of $53.6 million. The economics of the CHP plants are dependent on the rate the utility pays, which is established by request for proposals (RFPs) from a utility and avoided cost rates determined by Montana's Public Service Commission (PSC). Avoided cost is the cost a utility avoids by purchasing power from an independent producer.

The permanent closure of the Smurfit Stone paper mill in Frenchtown, Montana, has resulted in greater availability of mill residues in the area surrounding East Helena. During the site visit, it was reported that Ry Timber is 28 miles southeast of East Helena and they have 30,000 tons of excess clean wood mill residues available with delivered costs estimated at $37/ton.[36] Mark-Miller Post and Pole is 7 miles away with 10,000 tons per year of excess mill residues.

These past studies indicate that there is sufficient woody biomass feedstock in the area to support multiple biomass energy projects.

4.3 Woody Biomass Requirements and Price

Past studies have provided some cost data for the area. The pellet mill study stated that delivery of woody biomass to Helena was $30/green ton.[37] A nearby wood mill is offering wood chips for $37/green ton. The average of these known price points is $34/green ton (or $56/dry ton assuming 40% moisture content). The financial model used in this study is RETscreen—a model developed by Natural Resources Canada for evaluating the viability and performance of renewable energy projects.[38] NREL loaded known assumptions for biopower plants into RETscreen, which estimated feedstock requirements based on average wood waste feedstock for a 10-MW and 20-MW plant at 78,840 and 153,686 dry tons, respectively. These requirements could vary based on quality of woody biomass used.

4.4 Woody Biomass Characteristics

The Biomass Energy Resource Center provides excellent information and case studies on woody biomass to energy projects. They produce a brochure "Woodchip Fuel Specifications in the Northeastern United States" that provides important information for any bioenergy project.[39] Performance of a bioenergy plant is impacted by the quality of the woody biomass feedstock. Wood chips that are uniform in size and clean ensure optimal performance. Clean wood wastes reduce ash and maintenance on equipment. There are several types of wood chips of varying quality with different characteristics (see Table 4 and Table 5). The most desirable wood chips are from sawmills where trees have already been de-barked. The average moisture content for all types is 42%, and the average energy content is 4,785 Btu/green pound. These numbers will vary throughout the United States based on tree types and local climate.

[36] Ry Timber and Mark Post and Pole volumes and prices provided by site contact during site visit on June 14, 2014.
[37] "International BioMass Group: RDF Plant Feasibility Study." The Beck Group. April 2012.
[38] RETScreen. Accessed October 1, 2012: http://www.retscreen.net/ang/home.php.
[39] "Woodchip Fuel Specifications in the Northeastern United States". Biomass Energy Resource Center. Accessed January 8, 2013: http://www.biomasscenter.org/resources/publications.html.

Table 4. Wood Chip Types[40]

Wood Chip Quality	Examples	Description
Grade A (high)	Paper-Grade	De-barked sawmill residues
Grade B (medium)	Bole	Un-merchantable logs—includes bark
Grade C (low)	Whole-Tree	Produced in forest when harvesting
Grade D (lowest)	Urban	Produced in grinder; higher probability of contamination

Table 5. Wood Chip Characteristics

Wood Chip Quality	Dimensions	Ash	% Wood Chips Meeting Specs[a]
Grade A	1.5" x 1.5" x 0.25"	1%	95%
Grade B	2.0"x 2.0" x 0.25"	1%	90%
Grade C	2.0"x 2.0" x 0.25"	2%	85%
Grade D	3.0” x 1.5” x 0.50”	3%	90%
[a] Percent retained by 1/2" mesh screen in pre-processing step			

4.5 Feedstock Summary

There is ample feedstock in the area surrounding East Helena to support a 10- or 20-MW biopower plant. If the price is economical, the first choice feedstock will be primary mill residues as they are clean wood wastes produced at area wood processing facilities. The proposed project should also work with loggers working on private forest land to obtain forest residues as they are also available nearby. If the proposed pellet plant is built, there may be economies of scale in contracting with loggers to deliver feedstock. The price of woody biomass feedstock is estimated to be $34/green ton ($56/bone dry ton assuming 40% moisture content), based on current area pricing.

[40] Woodchip Fuel Specifications in the Northeastern United States”. Biomass Energy Resource Center. Accessed January 8, 2013: http://www.biomasscenter.org/resources/publications.html.

5 Heat and Power Markets

In 2005, the Montana Renewable Power Production and Rural Economic Development Act established an RPS. The RPS requires utilities to supply increasing amounts of renewable power: 10% through 2014 and 15% in 2015 and beyond.[41] Montana has achieved 14% renewable energy generation through recent rapid installation of wind capacity. The RPS was met at the end of 2012 with startup of a new wind plant.[42]

The RPS has a Community Renewable Energy Project (CREP) provision that requires utilities to purchase at least 75 MW from renewable energy plants with capacity equal to or less than 25 MW where local owners have controlling interest. The provision does allow a utility to own a CREP. NWE stated that they have not met the criteria and issued an RFP for CREP in 2012.[43] NWE's contractor is currently reviewing the 30 bids received; all but a few submissions were wind projects.[44] They will select projects for power purchase agreements (PPA) based on commercial readiness and rate. NWE expects the selected projects will meet their CREPs portion of the RFS through 2017, after which they plan to issue another RFP. NWE will either enter into a PPA with a CREP or will purchase the power plant. This represents an opportunity for a biopower plant in East Helena.

Montana's PSC establishes rates utilities pay independent power producers under a PPA. These rates are based on avoided cost—defined as cost to the utility to generate the power itself or by obtaining power from another source. This applies to both traditional and renewable energy plants. These rates change over time and may go up. NWE provided PSC's current rate structure. These rates assume a PPA contract length between 19 months and 25 years.[44]

Table 6. PSC Avoided Cost Rates for Independent Power Producers[44]

Plant Type	PSC Rate
	$/kWh
Below 10 MW	
On-Peak Hours	0.09087
Off-Peak Hours	0.05444
Above 10 MW (all hours)	0.05444
Wind (all hours)	0.05787

NWE may pay higher rates than avoided costs for CREP based on projects selected under the 2012 RFP. The proposals include expected PPA rates.

The RPS is based on 15% of consumption. The number of customers and consumption in residential and commercial sectors continues to increase. Lewis & Clark County population is

[41] "Montana Renewable Portfolio Standard." DSIRE. North Carolina Solar Center. DOE. Accessed January 9, 2013: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=MT11R&re=0&ee=0.
[42] Skjervem, Howard. Personal communication. NorthWestern Energy, Montana,14 June 2012.
[43] NorthWestern Energy's RFP for Community Power. Accessed January 9, 2013: http://www.landsenergy.com/NorthWestern_Energy_RFP.html. Bids were due September 28, 2012.
[44] Bennett, Frank. Phone interview. NorthWestern Energy, Montana, 6 December 2012.

growing and future projections indicate a steady increase, necessitating the need for sufficient energy generation to meet future demand (Figure 14).

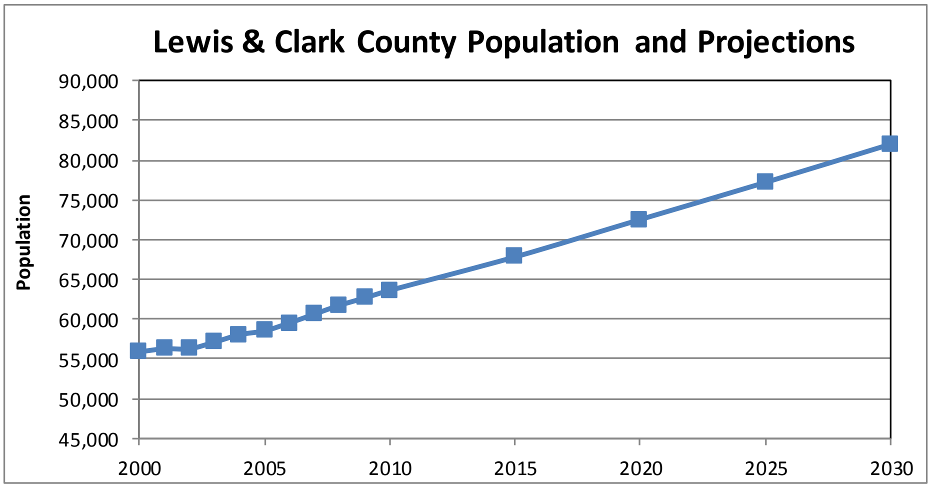

Figure 14. Lewis & Clark population[45]

5.1 Power Markets

Montana electricity generation is dominated by coal as an energy source followed by hydroelectric and wind (Table 7). NWE's power sources are approximately 40% coal and 30% hydro, with the balance supplied by natural gas and wind. NWE meets its demand through its own power plants (15%), and the balance is acquired through PPAs. Canyon Ferry hydroelectric plant in Lewis & Clark County has capacity of 50 MW. Nearby Cascade County has approximately 127 MW of installed capacity.

Table 7. Montana Electricity Generation by Source (2010)[46]

Energy Source	Generation (MWh)	% Total
Coal	18,600,634	62.4%
Hydroelectric Conventional	9,414,662	31.6%
Natural Gas	57,112	0.2%
Other	281,214	0.9%
Other Gases	1,899	0.0%
Petroleum	408,501	1.4%
Wind	930,233	3.1%
Wood and Wood Derived Fuels	96,924	0.3%
Total	29,791,181	

[45] "Montana Population Projections." NPA Data Services, Inc. Census and Economic Information Center, Montana Dept. of Commerce, 2008. Accessed January 9, 2013: http://ceic.mt.gov/Demog/project/proj_mt_pop_total_08.pdf.
[46] Data from DOE EIA. Net Generation by State by Type of Producer by Energy Source. Accessed January 8, 2013: http://www.eia.gov/electricity/data/state/.

Montana electricity rates are generally lower than the U.S. average in all sectors, with particularly low rates for industrial users (Table 8). NWE rates are somewhat higher for all sectors when compared with average Montana rates (Figure 15). NWE and statewide consumption are dominated by residential and commercial sectors (Figure 16). NWE has experienced growth in number of consumers in all sectors (Table 9).

Table 8. Current Electricity Rates Comparison[47]

Sector	Montana Rank	Montana	U.S. Average
		$/ kWh	
Residential	15th lowest	0.1053	0.1217
Commercial	21st lowest	0.0917	0.1043
Industrial	4th lowest	0.0529	0.0711

Table 9. Number of Electricity Consumers[48]

Customer Type	2004	2011
NWE Electricity Customers		
Residential	248,584	271,938
Commercial	58,053	64,844
Industrial	1,325	1,436
Montana Electricity Consumers		
Residential	430,282	469,963
Commercial	93,109	101,129
Industrial	4,547	5,877

[47] Data from DOE EIA. Average Retail Price of Electricity to Ultimate Consumers, Table 5.6.A, July 2012. Accessed September 10, 2012: http://www.eia.gov/electricity/data.cfm#sales.
[48] Data from DOE EIA Average Retail Price of Electricity to Ultimate Consumers by End-Use by State. Tables 4, 6, 7, 8, and 10. Accessed January 9, 2013: http://www.eia.gov/electricity/sales_revenue_price/index.cfm.

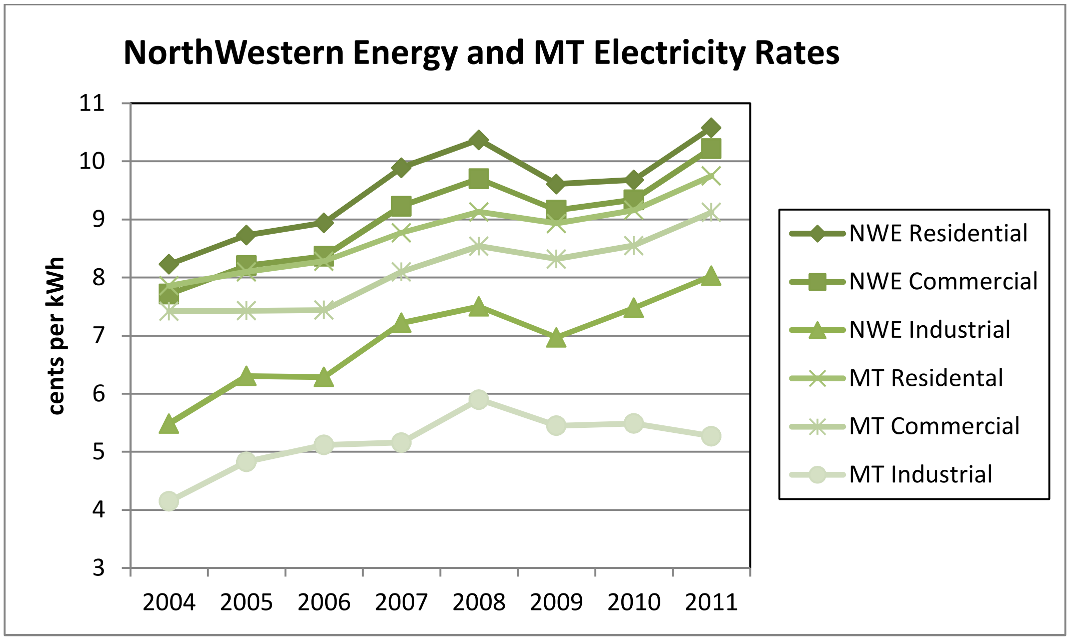

Figure 15. Electricity prices[49]

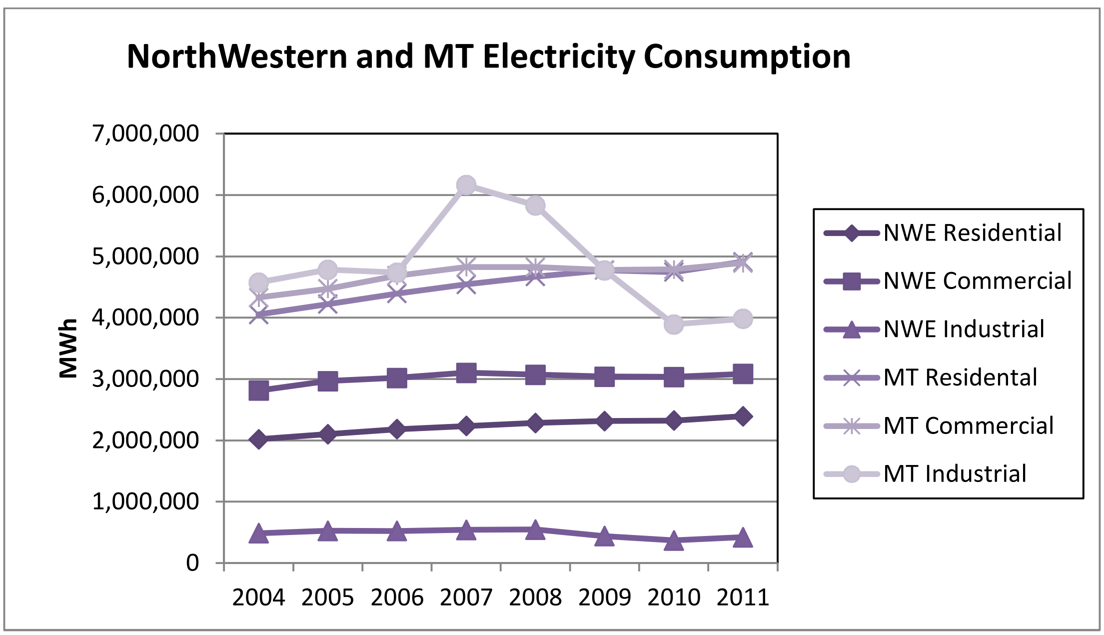

Figure 16. Electricity consumption[49]

[49] Data from DOE EIA. Consumption and Average Retail Price of Electricity to Ultimate Consumers by End-Use by State. Tables 4, 6, 7, 8, and 10. Accessed January 9, 2013: http://www.eia.gov/electricity/sales_revenue_price/index.cfm.

5.2 Thermal Energy Markets

Montana household and commercial use of natural gas has grown over the past decade (Table 10). Industrial demand dominated consumption in the mid-2000s, but it fell to 19 billion cubic feet in 2011. Currently, demand for both residential and commercial sectors is approximately 22,000 million cubic feet annually (Figure 17).

Montana natural gas pricing is similar for residential and commercial use (Figure 18). This varies from U.S. averages and most states where rates are lower for commercial use. The average U.S. industrial rate over the past year was $4.32/thousand cubic feet while the Montana rate was significantly higher at $8.34/thousand cubic feet over the same time period (Table 11). Natural gas is not a significant source of electricity generation in Montana.

Table 10. Number of Montana Natural Gas Consumers[50]

Customer Type	2001	2005	2010
Residential	226,171	240,554	257,322
Commercial	29,429	31,817	34,002
Industrial	73	716	384

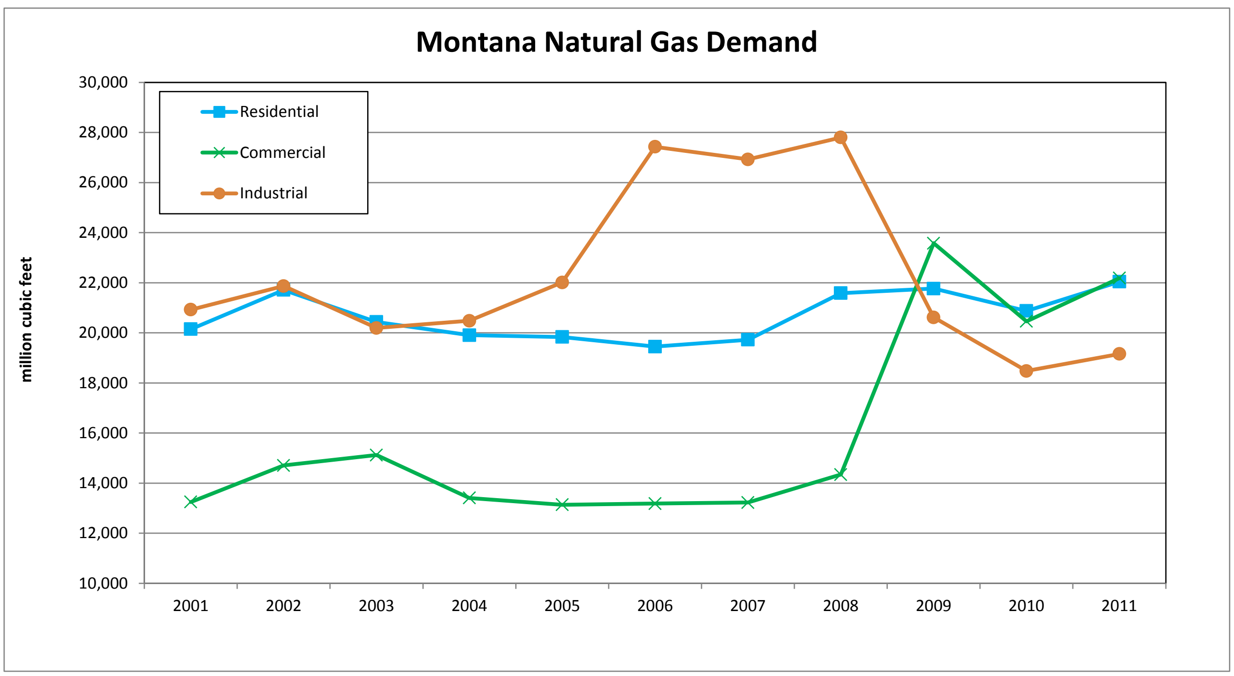

Figure 17. Natural gas consumption in Montana[51]

[50] Data from DOE EIA. Number of Natural Gas Consumers. Accessed January 9, 2013: http://www.eia.gov/dnav/ng/ng_cons_num_a_EPG0_VN3_Count_a.htm.

[51] Data from DOE EIA. Natural Gas Consumption by End Use. Accessed January 9, 2013: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm.

Table 11. Montana and U.S. Average Natural Gas Prices[52]

Sector	MT	U.S
Residential	$ 9.06	$ 12.13
Commercial	$ 8.54	$ 8.43
Industrial	$ 8.34	$ 4.33

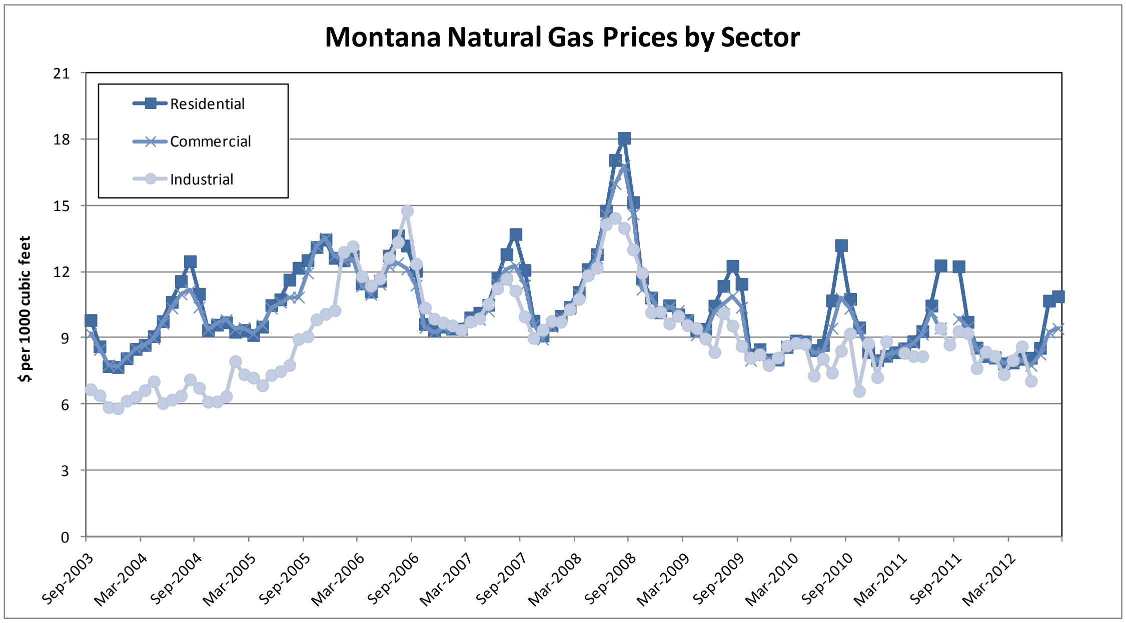

Figure 18. Natural gas prices in Montana[53]

5.3 Market Summary

There is a market for renewable power in Montana. While the 15% renewable power provision of the RPS was met by the end of 2012, the requirement for community-based renewable power plants with capacity of 25 MW or less has not been satisfied. The avoided cost rates NWE pays to independent power plants is not sufficient to cover costs associated with creating power from a biomass project. There is potential to receive a higher rate through PSC rate determination or through NWE's RFP process. The financial chapter of this report establishes the minimum electric rate for an economically viable biopower plant. It may be possible to sell excess heat to a nearby user such as the airport or any other large area buildings.

[52] Data from DOE EIA. Natural Gas Prices by Sector. Average price for residential and commercial based on 9/2011-8/2012. Average price for industrial based on 6/2011-5/2012. Accessed September 10, 2012: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

[53] Data from DOE EIA. Natural Gas Prices by Sector. Accessed January 8, 2013: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

6 Financial Analysis

Natural Resources Canada's RETScreen was used to evaluate this project.[54] RETScreen was developed to reduce the cost of feasibility studies and to enable better decisions on renewable energy projects. RETScreen is a Microsoft Excel-based renewable energy project financial evaluation tool. NREL loaded assumptions into RETScreen based on past biopower projects and studies.

6.1 Financial Forecast Assumptions

The major variables for the financial analysis are feedstock costs, capital and operating costs, and price received for electricity. A 10-MW biopower plant and 20-MW biopower plant using woody biomass are evaluated in this study based on resource potential from the surrounding area. Detailed inputs for RETScreen are available in Appendix A and B.

6.1.1 Capital Costs

Up-front costs for biopower are higher per unit of capacity than fossil fuel energy plants, such as coal or natural gas. NREL estimates capital costs based on past experience on biopower assessments and internal NREL data. They include all equipment for receiving woody biomass and producing biopower ready for export to the grid. The estimated capital costs for a 10-MW plant are estimated at $42.63 million. Estimated costs for a 20-MW plant are $71.05 million.

6.1.2 Operating and Maintenance Costs

This covers the costs for all operation and maintenance (O&M) activities, including processing feedstock, maintenance, employment, and removing ash. These are calculated in RETScreen and are typically around 5% of capital costs but are higher for smaller plants. O&M costs for 10-MW and 20-MW plants are $2.67 million and $3.72 million per year, respectively. Job creation is up to two jobs per installed megawatt at a plant and up to two indirect jobs for the collection and delivery of feedstock.[55]

6.1.3 Feedstock Requirements

Feedstock requirements are calculated by RETScreen based on operational efficiencies and megawatt generation. Dry ton requirements per year are 78,389 (10 MW) and 151,380 (20 MW).

6.1.4 Feedstock Price

The feedstock price is set at $34/green ton ($56.00/dry ton based on 40% moisture content) based on average area pricing for woody biomass (see Section 4). Feedstock prices are expected to increase at an annual rate of 1.69% based on Census data.[56]

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[54] RETScreen. Accessed January 8, 2013: http://www.retscreen.net/ang/home.php.

[55] "Helping Biopower Help America." Biomass Power Association. Accessed January 10, 2013. http://www.usabiomass.org/docs/BPA%20PTC%20INFO%20SHEET.pdf.

[56] Rushing, A.; Kneifel, J.; Lippicett, B. "Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2011." Annual Supplement to NIST Handbook 135 and NBS Special Publication 709. NISTIR 85-3273-26, September 2011. Accessed January 9, 2013: http://www1.eere.energy.gov/femp/pdfs/ashb11.pdf.

6.1.5 Feedstock Heating Value

RETScreen allows users to select from a defined list of feedstocks. Average wood waste was selected as it best represents a range of qualities of woody biomass a project may receive. RETScreen provides a heating value of 8,581.2 Btu/dry pound.

6.1.6 System Availability and Steam Turbine Performance

RETScreen assumes that the biomass system would have an availability factor of 90%, meaning it would operate 7,884 hrs/yr. The rate of steam production is 89,545 lbs/hr (10 MW) or 167,277 lbs/hr (20 MW). Details of steam turbine performance are available in Appendix A and Appendix B.

6.1.7 Electricity Sales

RETScreen calculates the minimum price that the project can sell electricity to achieve a net present value (NPV) of zero. An NPV of zero is the breakeven point. Electricity rates are expected to increase at an annual rate of 0.56%.[57]

6.1.8 Heat/Steam Sales

Thermal energy sales are not included in this analysis. For modeling purposes, there must be a nearby user with a known load. Piping is approximately $250/ft installed—the high price is for insulated, corrosion-resistant pipes. The waste heat from a biopower plant can be collected and sold if a user is nearby. This can be explored further if the project proceeds and a specific site is selected. Technical data on heat extraction from RETScreen is available in Appendix A.

6.1.9 Financing

Discount and interest rates of 8% and 6% were used. These rates vary with type of ownership and other factors. The debt-to-equity ratio is 80/20. The project life is 30 years. Inflation, feedstock escalation, and electricity rate escalation are based on regional rates published by the Census Bureau and National Institute of Standards and Technology. [57]

[57] Rushing, A.; Kneifel, J.; Lippicett, B. "Energy Price Indices and Discount Factors for Life-Cycle Cost Analysis – 2011." Annual Supplement to NIST Handbook 135 and NBS Special Publication 709. NISTIR 85-3273-26, September 2011. Accessed January 9, 2013: http://www1.eere.energy.gov/femp/pdfs/ashb11.pdf.

Table 12. Financial Model Inputs

Financial Model Inputs		
Parameters	**10 MW**	**20 MW**
Capital Costs	$42,630,000	$71,050,000
O&M Costs	$2,760,000	$3,718,365
Feedstock Requirement (tons)	78,389	151,380
Feedstock Cost	$4,445,804	$8,506,869
Discount Rate	8%	8%
Interest Rate	6%	6%
Inflation Rate	0.9%	0.9%
Electricity Escalation Rate	0.56%	0.56%
Feedstock Cost Escalation Rate	1.69%	1.69%
Debt Payment	20 years	20 years

6.2 RETScreen Modeling Results

The NPV is an assessment of the cash inflows and outflows over time for an enterprise discounted to their present value. The NPV is a key indicator of a project's financial potential. NREL used RETScreen and set NPV equal to zero (the breakeven point) to calculate the minimum electricity price for a biopower plant in East Helena. The calculated values are $141.48/MWh (10 MW) and $123.12/MWh (20 MW). This is more than avoided cost rates provided by the utility to independent power producers. Table 13 summarizes financial outputs from the RETScreen model for 10- and 20-MW biopower plants.

Table 13. Income Statement

Project Costs and Income Summary		With Net Present Value = 0	
Initial costs	**Unit**	**10 MW**	**20 MW**
Power system	$	$42,000,000	$70,000,000
Heating system	$	$0	$0
Cooling system	$	$0	$0
Balance of system & misc.	$	$630,000	$1,050,000
Total initial costs	$	$42,630,000	$71,050,000
Annual costs and debt payments			
O&M	$	$2,760,000	$3,718,365
Fuel cost - proposed case	$	$4,445,804	$8,506,869
Debt payments - 20 yrs	$	$2,973,342	$4,955,570
Total annual costs	$	$10,179,147	$17,180,804
Annual savings and income			
Electricity export income	$	$11,164,105	$18,922,051
Financial viability			
Pre-tax IRR - equity	%	9.39%	9.37%
Pre-tax IRR - assets	%	-0.82%	-1.03%
After-tax IRR - equity	%	8.00%	8.00%
After-tax IRR - assets	%	-2.43%	-2.64%
Simple payback	yr	10.8	10.6
Equity payback	yr	11.9	11.3
Benefit-cost (B-C) ratio		1	1
Debt service coverage ratio		1.28	1.29
Energy production cost	$/MWh	141.60	123.12

The project is most sensitive to feedstock, electricity sales, and capital costs. Figure 19 shows the combination of electricity prices and feedstock prices that yield a positive economic return. The area above the red line and blue line show the combinations of electricity and feedstock prices where a plant is estimated to be profitable.

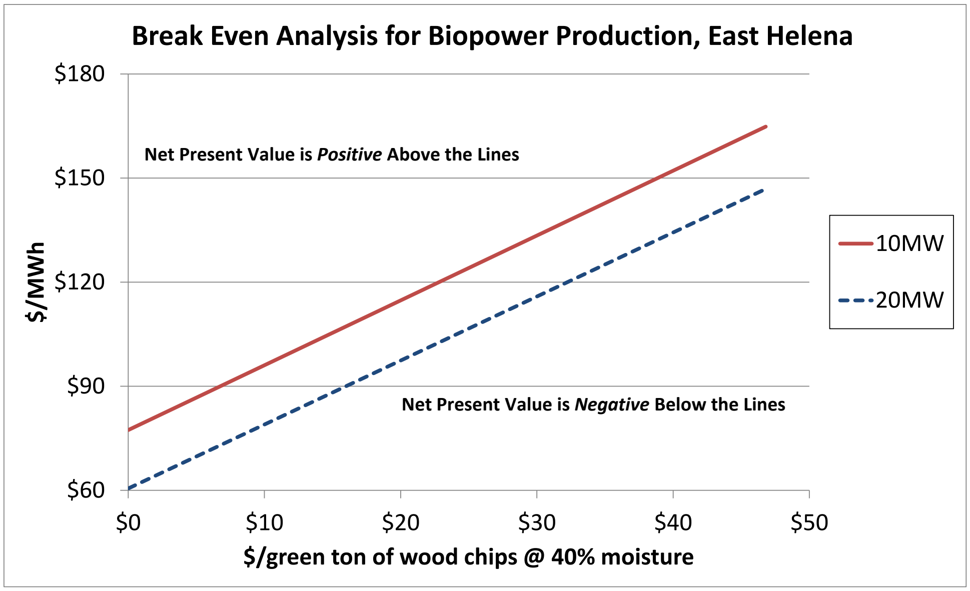

Figure 19. Electricity and feedstock sensitivity analysis[58]

Figure 20 and Figure 21 provide more detail on the sensitivity of the project by estimating the impact on economic performance as two variables increase and decrease with all other variables remaining constant. These figures display NPV as a function of feedstock costs increasing or decreasing in increments of 10% compared with the impact of other costs increasing or decreasing by 10% (capital/initial costs, electricity rate, and O&M). All other variables remain unchanged.

[58] Data from RETScreen outputs.

Perform analysis on	Net Present Value (NPV)	
Sensitivity range	20%	
Threshold	0	$

Initial costs		Fuel cost - proposed case				$
		3,556,644	4,001,224	4,445,804	4,890,385	5,334,965
$		-20%	-10%	0%	10%	20%
34,104,000	-20%	15,071,585	10,745,379	6,290,593	1,659,296	-3,248,841
38,367,000	-10%	12,253,101	7,804,257	3,206,940	-1,598,404	-6,755,825
42,630,000	0%	9,315,213	4,741,440	**0**	-4,966,210	-10,527,696
46,893,000	10%	6,269,743	1,573,533	-3,301,518	-8,427,547	-14,299,567
51,156,000	20%	3,130,510	-1,682,355	-6,683,578	-12,083,874	-18,071,438

Electricity export rate		Fuel cost - proposed case				$
		3,556,644	4,001,224	4,445,804	4,890,385	5,334,965
$/MWh		-20%	-10%	0%	10%	20%
113.28	-20%	-13,210,430	-19,197,994	-25,185,559	-31,173,123	-37,160,687
127.44	-10%	-1,200,404	-6,221,158	-11,869,063	-17,856,627	-23,844,192
141.60	0%	9,315,213	4,741,440	**0**	-4,966,210	-10,527,696
155.77	10%	19,143,412	14,821,761	10,411,110	5,880,354	1,188,911
169.93	20%	28,588,061	24,409,673	20,175,873	15,877,554	11,497,472

O&M		Fuel cost - proposed case				$
		3,556,644	4,001,224	4,445,804	4,890,385	5,334,965
$		-20%	-10%	0%	10%	20%
2,208,000	-20%	14,403,471	9,974,490	5,427,358	715,643	-4,216,510
2,484,000	-10%	11,876,938	7,383,060	2,744,701	-2,082,957	-7,189,103
2,760,000	0%	9,315,213	4,741,440	**0**	-4,966,210	-10,527,696
3,036,000	10%	6,708,218	2,045,105	-2,816,622	-7,967,681	-13,940,013
3,312,000	20%	4,051,401	-717,492	-5,721,077	-11,364,765	-17,352,330

Figure 20. NPV sensitivity to inputs for 10-MW plant

Perform analysis on	Net Present Value (NPV)	
Sensitivity range	20%	
Threshold	0	$

Initial costs		Fuel cost - proposed case				$
		6,805,495	7,656,182	8,506,869	9,357,556	10,208,243
$		-20%	-10%	0%	10%	20%
56,840,000	-20%	27,203,074	18,967,130	10,479,472	1,587,002	-8,045,668
63,945,000	-10%	22,558,749	14,108,302	5,344,145	-3,891,613	-14,332,120
71,050,000	0%	17,727,223	9,045,398	**0**	-9,562,392	-20,618,572
78,155,000	10%	12,718,642	3,801,878	-5,505,421	-15,448,059	-26,905,024
85,260,000	20%	7,545,046	-1,595,589	-11,151,041	-21,734,511	-33,191,476

Electricity export rate		Fuel cost - proposed case				$
		6,805,495	7,656,182	8,506,869	9,357,556	10,208,243
$/MWh		-20%	-10%	0%	10%	20%
98.50	-20%	-19,930,994	-31,387,959	-42,844,924	-54,301,889	-65,758,854
110.81	-10%	91,269	-9,435,014	-20,274,783	-31,731,748	-43,188,713
123.12	0%	17,727,223	9,045,398	**0**	-9,562,392	-20,618,572
135.43	10%	34,267,522	26,036,756	17,627,630	8,954,259	-91,269
147.74	20%	50,187,743	42,208,801	34,134,934	25,923,142	17,528,036

O&M		Fuel cost - proposed case				$
		6,805,495	7,656,182	8,506,869	9,357,556	10,208,243
$		-20%	-10%	0%	10%	20%
2,974,692	-20%	24,544,059	16,080,360	7,341,357	-1,786,308	-11,504,873
3,346,529	-10%	21,153,570	12,588,557	3,708,134	-5,619,114	-16,021,384
3,718,365	0%	17,727,223	9,045,398	**0**	-9,562,392	-20,618,572
4,090,202	10%	14,256,545	5,441,651	-3,787,120	-13,758,795	-25,215,760
4,462,038	20%	10,734,932	1,767,714	-7,668,532	-18,355,983	-29,812,948

Figure 21. NPV sensitivity to inputs for 20-MW plant[59]

[59] Data from RETScreen outputs.

6.3 Project Financing and Incentives

This type of project would likely require a loan guarantee to attract investors. Long-term feedstock supply contracts will be necessary for project funding. The project should use proven technology from companies with successful deployment of biomass boilers. The financial health of the project may be influenced by grant and other financial opportunities resulting in the ability to sell electricity for competitive rates.

6.3.1 Federal Incentives

There are several federal incentive programs to assist bioenergy projects.

6.3.1.1 Business Energy Investment Tax Credit

Under The American Recovery and Reinvestment Act of 2009, a CHP bioenergy plant taxpayer is eligible for a federal energy investment tax credit (ITC). Utilities can use the credit or the taxpayer can apply the credit against alternative minimum tax. For bioenergy plants, the allowable credit is 10% of expenditures.

6.3.1.2 Renewable Energy Production Tax Credit

The production tax credit (PTC) applies a $0.11/kWh corporate tax credit for biomass facilities. Unused credits may be carried forward up to 20 years. The credit will be applied for 5 years after a plant is in operation. To qualify, plants must be operational by December 31, 2013.

6.3.1.3 USDA Rural Energy for America Program Grants

The USDA Rural Energy for America Program (REAP) occasionally provides grants for up to 25% of project costs up to $500,000. There is also a loan guarantee program for up to 75% of eligible project costs not to exceed $25 million. Rural areas are defined as those with populations of 50,000 or less. The East Helena area should meet this criterion.

6.3.2 Montana Incentives

The State of Montana maintains a website that provides detailed information on state tax and financial incentives for renewable energy.[60] Incentives available to a 10- or 20-MW biopower plant include property tax (assessed at 50% of actual value for 15 years) and ITCs (up to 35% against individual or corporate tax). The state also provides grants for renewable energy research and development, as well as local government revenue bonds. There is also a loan program.

[60] Montana Incentives for Renewable Energy. Accessed January 24, 2013: http://deq.mt.gov/energy/renewable/taxincentrenew.mcpx#15-6-157.

7 Conclusion

There is adequate biomass in the area surrounding East Helena to support a 10-MW or 20-MW plant. Montana has an RPS requiring renewable electricity use of 15% statewide. There is a provision in the standard requiring purchase of power from community-owned renewable energy projects with generating capacity of 25 MW or less. These plants can be owned by a utility. However, the local utility's method to meet this provision is to issue RFPs for independent power generation. This provides a market for renewable power generated in East Helena.

Financial analysis based on expected capital costs and feedstock prices estimated breakeven electricity rates of \$141.60–\$123.12/MWh for the 10-MW and 20-MW plants. These rates exceed what the utilities are currently paying for wind power and power from independent producers. The project may be viable by obtaining lower feedstock prices, lowering capital costs, or receiving grants.

Appendix A: 10-MW RETScreen Inputs and Outputs

Proposed case power system				
Technology		Steam turbine		
Availability	%		90.0%	7,884 h
Fuel selection method		Single fuel		
Fuel type		Wood waste (average)		
Fuel rate	$/t	56.000		
Steam turbine				
Steam flow	lb/h	89,545		
Operating pressure	psig	850		
Saturation temperature	°F	527		
Superheated temperature	°F	850		
Enthalpy	Btu/lb	1,431		
Entropy	Btu/lb/°R	1.62		
Extraction port		Yes		
Maximum extraction	%	13%		
Extraction	lb/h	11,641		
Extraction pressure	psig	50		
Temperature	°F	298		
Mixture quality		0.98		
Enthalpy	Btu/lb	1,162		
Theoretical steam rate (TSR)	lb/kWh	12.66		
Back pressure	psia	2.0		
Temperature	°F	125		
Mixture quality		0.82		
Enthalpy	Btu/lb	937		
Theoretical steam rate (TSR)	lb/kWh	6.89		
Steam turbine (ST) efficiency	%	77.0%		
Actual steam rate (ASR)	lb/kWh	9.93		
Summary				
Power capacity - with extraction	kW	9,020		
Power capacity - without extraction	kW	10,000		
Minimum capacity	%	40.0%		
Manufacturer				
Model and capacity				
Electricity exported to grid	MWh	78,840		
Seasonal efficiency	%	63.8%		
Return temperature	°F	125		
Fuel required	million Btu/h	187.9		
Heating capacity - without extraction	million Btu/h	0.0		
Heating capacity - with extraction	million Btu/h	12.5		
Electricity export rate	$/MWh	141.60		

Figure A-1. 10-MW proposed business case inputs

Base case electricity system (Baseline)

Country - region	Fuel type	GHG emission factor (excl. T&D) tCO2/MWh	T&D losses %	GHG emission factor tCO2/MWh
United States of America	Natural gas	0.439	6.0%	0.467

☐ Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	78,840	0.467	36,820.0
Total	100.0%	78,840	0.467	36,820.0

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %		T&D losses	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Wood waste (average)	100.0%			434,229	0.007	2,906.7
Total	100.0%			434,229	0.007	2,906.7
Electricity exported to grid	MWh	78,840	6.0%	4,730	0.467	2,209.2
					Total	5,115.9

GHG emission reduction summary

	Base case GHG emission tCO2	Proposed case GHG emission tCO2	Gross annual GHG emission reduction tCO2	GHG credits transaction fee %	Net annual GHG emission reduction tCO2
Power project	36,820.0	5,115.9	31,704.1	2%	31,070.0

Net annual GHG emission reduction 31,070 tCO2 is equivalent to 72,256 Barrels of crude oil not consumed

Figure A-2. 10-MW base case and greenhouse gas emission reductions

RETScreen Financial Analysis - Power project

Financial parameters

General		
Fuel cost escalation rate	%	1.7%
Inflation rate	%	0.9%
Discount rate	%	8.0%
Project life	yr	30
Finance		
Incentives and grants	$	0
Debt ratio	%	80.0%
Debt	$	34,104,000
Equity	$	8,526,000
Debt interest rate	%	6.00%
Debt term	yr	20
Debt payments	$/yr	2,973,342
Income tax analysis	☑	
Effective income tax rate	%	35.0%
Loss carryforward?		Yes
Depreciation method		Straight-line
Depreciation tax basis	%	90.0%
Depreciation period	yr	7
Tax holiday available?	yes/no	No

Annual income

Electricity export income		
Electricity exported to grid	MWh	78,840
Electricity export rate	$/MWh	141.60
Electricity export income	$	11,164,105
Electricity export escalation rate	%	0.6%
GHG reduction income	☐	
Net GHG reduction	tCO2/yr	31,070
Net GHG reduction - 30 yrs	tCO2	932,100
Customer premium income (rebate)	☐	
Other income (cost)	☐	
Clean Energy (CE) production income	☐	

Project costs and savings/income summary

Initial costs			
Power system	98.5%	$	42,000,000
Balance of system & misc.	1.5%	$	630,000
Total initial costs	**100.0%**	**$**	**42,630,000**
Annual costs and debt payments			
O&M		$	2,760,000
Fuel cost - proposed case		$	4,445,804
Debt payments - 20 yrs		$	2,973,342
Total annual costs		**$**	**10,179,147**
Periodic costs (credits)			
Annual savings and income			
Fuel cost - base case		$	0
Electricity export income		$	11,164,105
Total annual savings and income		**$**	**11,164,105**

Financial viability

Pre-tax IRR - equity	%	9.4%
Pre-tax IRR - assets	%	-0.8%
After-tax IRR - equity	%	8.0%
After-tax IRR - assets	%	-2.4%
Simple payback	yr	10.8
Equity payback	yr	11.9
Net Present Value (NPV)	$	0
Annual life cycle savings	$/yr	0
Benefit-Cost (B-C) ratio		1.00
Debt service coverage		1.28
Energy production cost	$/MWh	141.60
GHG reduction cost	$/tCO2	-

Yearly cash flows

Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-8,526,000	-8,526,000	-8,526,000
1	947,503	947,503	-7,578,497
2	908,905	908,905	-6,669,593
3	869,141	869,141	-5,800,451
4	828,192	828,192	-4,972,259
5	786,033	786,033	-4,186,226
6	742,643	742,643	-3,443,583
7	697,999	697,999	-2,745,584
8	652,076	652,076	-2,093,508
9	604,852	604,852	-1,488,656
10	556,301	556,301	-932,355
11	506,400	506,400	-425,954
12	455,124	455,124	29,170
13	402,446	402,446	431,615
14	348,341	348,341	779,956
15	292,782	292,782	1,072,738
16	235,743	235,743	1,308,481
17	177,196	177,196	1,485,677
18	117,114	117,114	1,602,791
19	55,468	55,468	1,658,259
20	-7,770	-585,441	1,072,818
21	2,900,712	1,885,463	2,958,280
22	2,834,201	1,842,230	4,800,511
23	2,766,008	1,797,905	6,598,416
24	2,696,103	1,752,467	8,350,882
25	2,624,454	1,705,895	10,056,777
26	2,551,030	1,658,170	11,714,947
27	2,475,798	1,609,269	13,324,216
28	2,398,726	1,559,172	14,883,388
29	2,319,780	1,507,857	16,391,245
30	2,238,926	1,455,302	17,846,547

Cumulative cash flows graph

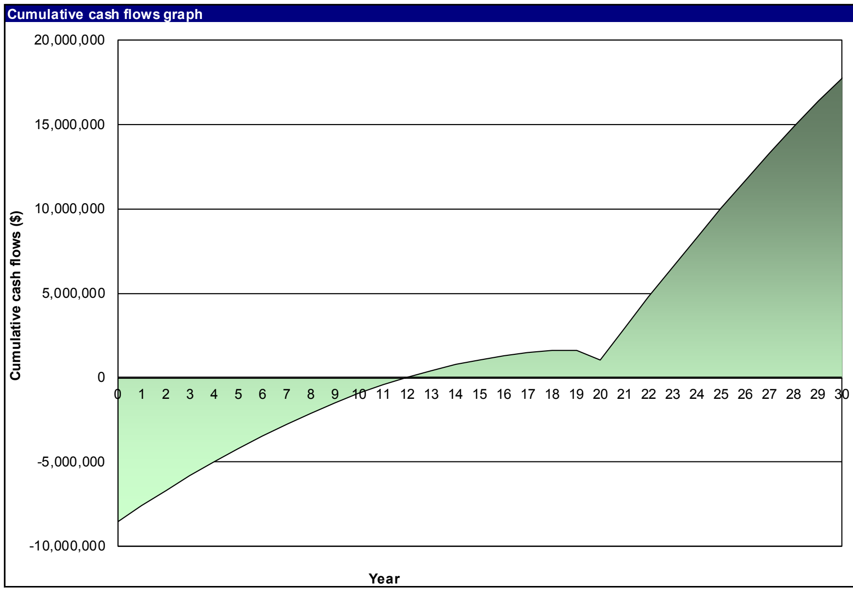

Figure A-3. 10-MW financial analysis

Appendix B: 20-MW RETScreen Inputs and Outputs

Proposed case power system				
Technology		Steam turbine		
Availability	%		90.0%	7,884 h
Fuel selection method		Single fuel		
Fuel type		Wood waste (average)		
Fuel rate	$/t	56.000		
Steam turbine				
Steam flow	lb/h	167,277		
Operating pressure	psig	900		
Saturation temperature	°F	534		
Superheated temperature	°F	905		
Enthalpy	Btu/lb	1,464		
Entropy	Btu/lb/°R	1.63		
Extraction port		Yes		
Maximum extraction	%	13%		
Extraction	lb/h	21,746		
Extraction pressure	psig	50		
Temperature	°F	298		
Mixture quality		1.00		
Enthalpy	Btu/lb	1,176		
Theoretical steam rate (TSR)	lb/kWh	11.85		
Back pressure	psia	2.0		
Temperature	°F	125		
Mixture quality		0.84		
Enthalpy	Btu/lb	947		
Theoretical steam rate (TSR)	lb/kWh	6.61		
Steam turbine (ST) efficiency	%	77.0%		
Actual steam rate (ASR)	lb/kWh	9.47		
Summary				
Power capacity - with extraction	kW	17,671		
Power capacity - without extraction	kW	19,494		
Minimum capacity	%	40.0%		
Manufacturer				
Model and capacity				
Electricity exported to grid	MWh	153,688		
Seasonal efficiency	%	63.8%		
Return temperature	°F	125		
Fuel required	million Btu/h	359.6		
Heating capacity - without extraction	million Btu/h	0.0		
Heating capacity - with extraction	million Btu/h	23.6		
Electricity export rate	$/MWh	123.12		

Figure B-1. 20-MW proposed business case inputs

Base case electricity system (Baseline)

Country - region	Fuel type	GHG emission factor (excl. T&D) tCO2/MWh	T&D losses %	GHG emission factor tCO2/MWh
United States of America	Natural gas	0.439	6.0%	0.467

☐ Baseline changes during project life

Base case system GHG summary (Baseline)

Fuel type	Fuel mix %	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Electricity	100.0%	153,688	0.467	71,775.6
Total	100.0%	153,688	0.467	71,775.6

Proposed case system GHG summary (Power project)

Fuel type	Fuel mix %		T&D losses	Fuel consumption MWh	GHG emission factor tCO2/MWh	GHG emission tCO2
Wood waste (average)	100.0%			830,879	0.007	5,561.8
Total	100.0%			830,879	0.007	5,561.8
Electricity exported to grid	MWh	153,688	6.0%	9,221	0.467	4,306.5
					Total	9,868.3

GHG emission reduction summary

	Base case GHG emission tCO2	Proposed case GHG emission tCO2	Gross annual GHG emission reduction tCO2	GHG credits transaction fee %	Net annual GHG emission reduction tCO2
Power project	71,775.6	9,868.3	61,907.3	2%	60,669.1

Net annual GHG emission reduction	60,669	tCO2	is equivalent to	141,091	Barrels of crude oil not consumed

Figure B-2. 20-MW base case and greenhouse gas emission reductions

Financial parameters

General		
Fuel cost escalation rate	%	1.7%
Inflation rate	%	0.9%
Discount rate	%	8.0%
Project life	yr	30
Finance		
Incentives and grants	$	0
Debt ratio	%	80.0%
Debt	$	56,840,000
Equity	$	14,210,000
Debt interest rate	%	6.00%
Debt term	yr	20
Debt payments	$/yr	4,955,570
Income tax analysis ☑		
Effective income tax rate	%	35.0%
Loss carryforward?		Yes
Depreciation method		Straight-line
Depreciation tax basis	%	90.0%
Depreciation period	yr	7
Tax holiday available?	yes/no	No

Annual income

Electricity export income		
Electricity exported to grid	MWh	153,688
Electricity export rate	$/MWh	123.12
Electricity export income	$	18,922,051
Electricity export escalation rate	%	0.6%
GHG reduction income ☐		
Net GHG reduction	tCO2/yr	60,669
Net GHG reduction - 30 yrs	tCO2	1,820,074
Customer premium income (rebate) ☐		
Other income (cost) ☐		
Clean Energy (CE) production income ☐		

Project costs and savings/income summary

Initial costs			
Power system	98.5%	$	70,000,000
Balance of system & misc.	1.5%	$	1,050,000
Total initial costs	**100.0%**	**$**	**71,050,000**
Annual costs and debt payments			
O&M		$	3,718,365
Fuel cost - proposed case		$	8,506,869
Debt payments - 20 yrs		$	4,955,570
Total annual costs		**$**	**17,180,804**
Periodic costs (credits)			
Annual savings and income			
Fuel cost - base case		$	0
Electricity export income		$	18,922,051
Total annual savings and income		**$**	**18,922,051**

Financial viability

Pre-tax IRR - equity	%	9.4%
Pre-tax IRR - assets	%	-1.0%
After-tax IRR - equity	%	8.0%
After-tax IRR - assets	%	-2.6%
Simple payback	yr	10.6
Equity payback	yr	11.3
Net Present Value (NPV)	$	0
Annual life cycle savings	$/yr	0
Benefit-Cost (B-C) ratio		1.00
Debt service coverage		1.29
Energy production cost	$/MWh	123.12
GHG reduction cost	$/tCO2	-

Yearly cash flows

Year	Pre-tax	After-tax	Cumulative
#	$	$	$
0	-14,210,000	-14,210,000	-14,210,000
1	1,669,979	1,669,979	-12,540,021
2	1,596,574	1,596,574	-10,943,447
3	1,520,991	1,520,991	-9,422,456
4	1,443,188	1,443,188	-7,979,268
5	1,363,125	1,363,125	-6,616,143
6	1,280,759	1,280,759	-5,335,384
7	1,196,045	1,196,045	-4,139,339
8	1,108,941	1,108,941	-3,030,398
9	1,019,401	1,019,401	-2,010,997
10	927,380	927,380	-1,083,617
11	832,831	832,831	-250,787
12	735,707	735,707	484,920
13	635,960	635,960	1,120,880
14	533,542	533,542	1,654,422
15	428,402	428,402	2,082,824
16	320,490	320,490	2,403,314
17	209,755	209,755	2,613,069
18	96,144	96,144	2,709,214
19	-20,395	-20,395	2,688,819
20	-139,917	-1,032,033	1,656,786
21	4,693,093	3,050,510	4,707,296
22	4,567,439	2,968,835	7,676,131
23	4,438,634	2,885,112	10,561,243
24	4,306,620	2,799,303	13,360,546
25	4,171,339	2,711,370	16,071,917
26	4,032,730	2,621,274	18,693,191
27	3,890,733	2,528,976	21,222,167
28	3,745,285	2,434,435	23,656,602
29	3,596,323	2,337,610	25,994,212
30	3,443,784	2,238,460	28,232,672

Cumulative cash flows graph

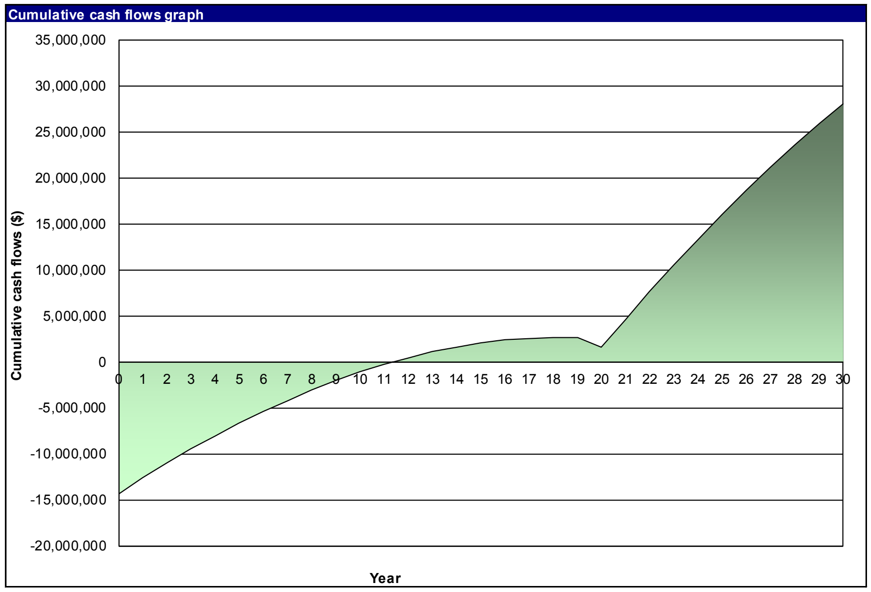

Figure B-3. 20-MW financial analysis