



Technical Manual for the SAM Biomass Power Generation Model

Jennie Jorgenson, Paul Gilman, and
Aron Dobos

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Executive Summary

This technical manual provides context for the implementation of the biomass electric power generation performance model in the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM). Additionally, the report details the engineering and scientific principles behind the underlying calculations in the model. The framework established in this manual is designed to give users a complete understanding of behind-the-scenes calculations and the results generated.

The addition of a biomass power model to SAM facilitates comparison of many renewable technologies regarded as “intermittent” to a “baseload” solid-fueled technology. The biomass power performance model is more detailed than the standard “generic” system model that is traditionally used for baseload-type generation and computes performance metrics such as the gross heat rate and capacity factor. The biomass power model generates this performance data based on specifications of the system's physical components, as well as information about various biomass feedstocks that can be automatically obtained for a particular location from an NREL Web service. The model's flexible design allows it to be used to model power systems that burn different types of solid fuels, including biomass and coal.

This technical manual describes the biomass power model's internal calculations and the engineering principles that guide them. It supplements the user documentation that comes with SAM, which describes the user inputs and how to operate the model.

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1 Introduction

This report provides detailed documentation regarding the engineering methodology associated with the System Advisor Model (SAM) biomass power generation model. Broadly, the model can be applied to any power generation technology utilizing a solid fuel that can be defined by its content and heating value. A solid-fueled combustion power plant can be broken into three discrete operations, each with its own mass and energy balances: the feed yard where the fuel is stored, the combustion system, and the turbine. This simplified approach makes it possible to model a range of feedstocks. For instance, the performance of a biomass-fired power plant can be modeled just as easily as a coal-fired power plant or co-fired plant.

1.1 SAM Overview

SAM is a system performance and economic model designed to facilitate decision making for project developers, financiers, and policymakers, as well as provide robust analysis capabilities for energy researchers. SAM models grid-connected power systems using biomass, solar, wind, and geothermal electric generation technologies, as well as small-scale solar water heating systems. For each technology, SAM pairs a performance model with a financial model to calculate the cost of energy over a multi-year analysis period. SAM makes economic calculations for residential and commercial projects that buy and sell power at retail rates and for larger-scale power plants that sell electricity through a power purchase agreement (PPA) to a utility.

The model calculates the cost of generating electricity (or the value of energy saved by a solar water heating system) based on user-specified inputs describing a system's physical configuration, its location, and the cost of installing and operating the system. SAM's financial model can represent various complex financing structures, taxes, and incentives.

SAM displays performance and financial model results in numerous tables and graphs, which range from a table of basic metrics, such as levelized cost of energy (LCOE) and total annual output, to tables of detailed hourly simulation results. A cash flow table shows project income, expenses, financing costs, incentive payments, and other details on a year-by-year basis over the full multi-year analysis period.

Advanced modeling options include parametric studies, sensitivity, and statistical analyses that can help investigate impacts of variations and uncertainty in performance, cost, and financial assumptions on model results. SAM's scripting language, SamUL, makes it possible to automate complex analysis tasks in batch mode.

1.2 Biomass Electric Power Generation

Many viable technologies convert biomass into electricity. As of 2009, biomass-power-generating capacity in the United States totaled about 12 GW, representing about 1.1% of the total capacity [1, 2]. Table 1 shows a sampling of current biomass power plants in the United States. Total biomass generation capacity in the world is approximately 50 GW [3]. Most of these power plants are well below 100 MW and are primarily located in the United States and Europe. However, biomass power capacity is expected to rise in future years [3].

Table 1. Select Biomass Power Plants in the United States

Plant Location	Capacity (MW)	Feedstock(s)	Year Online
Kettle Falls, WA	46.0	Primary Mill Residues	1983
New Meadows, ID	5.8	Wood Wastes	1983
Bethlehem, NH	15.0	Wood Wastes	1987
Tracy, CA	23.0	Wood Wastes	1990
Hurt, VA	79.5	Mill, Forest Residues	1994
Eagar, AZ	3.0	Forest Residues	2004
Snowflake, AZ	24.0	Wood Wastes, Mill Residues	2008

Currently, the primary approach for biomass conversion to electricity is also the most time-tested: combustion. Other biomass-to-power technologies are less straightforward and not yet as commercially demonstrable [3]. For example, biomass gasification converts biomass into a volatile “synthesis gas” (or syngas), which is combustible [3]. Another technology, anaerobic digestion of biomass, results in the formation of methane, which can be refined into various chemicals or similarly combusted [3]. The SAM biomass power model is limited to simple biomass combustion due to the known viability of the technology compared to more recent gasification and anaerobic digestion methods [4], as well as its direct applicability to generating electricity.

Biomass power plants are very similar in operation to coal-fired power plants, as illustrated in Figure 1. The biomass is delivered to the plant where storage piles or silos accommodate extra biomass that is not immediately fed to the plant. Biomass can undergo various preprocessing steps including size reduction, separation, and drying before being fed to the combustor. In the combustor, biomass oxidation occurs under excess air. The exothermic reaction heats the combustion gases, which generate steam via heat exchangers to power a typical Rankine-cycle turbine and electric generator.

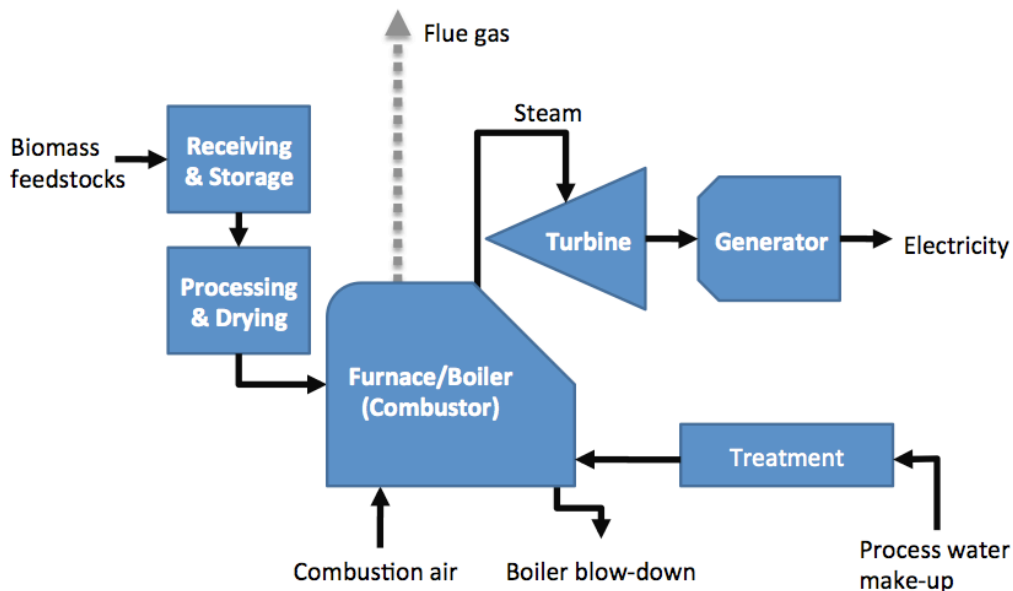


Figure 1. Biomass power process flow diagram

Biomass-fired power plants employ the same basic unit operations as a coal-fired power plant, making co-fired power plants that can run on either feedstock (or both in parallel) financially appealing. Since coal is more energy dense and the resource is more geospatially concentrated relative to biomass, coal transport can be economical over greater distances. Thus, most coal power plants are at least an order of magnitude larger than biomass power plants. Coal power plants can scale more easily, resulting in reduced expenses per megawatt (MW) capacity added. Additionally, larger plants can utilize higher pressures and temperature in steam cycles, leading to higher energy conversion efficiencies [5].

The SAM biomass power model can be applied to solid-fueled plants of any size and with any mix of biomass or coal fuels. Although the SAM model has no explicit limits on plant size, users should be aware of the feedstock input, component cost, and performance considerations and scale them appropriately to the system they are modeling.

1.3 Modeling Approach

The model consists of four primary modules, each represented by an input page in the user interface.

- The *Climate* page specifies the weather data that goes into hourly performance calculations. The ambient dry bulb temperature, atmospheric pressure, and relative humidity data from the weather file affect the performance of the plant.
- The *Feedstock* page specifies the biomass resource properties, availability, and maximum radius for collection. The user can also describe additional non-standard feedstock types by supplying the *elemental composition*, *moisture content*, and *heating value*.
- The *Plant Specification* page allows users to specify components of the system, such as the *drying method*, *percent excess air*, and *combustor system* type. It also estimates various efficiency losses that apply to the combustion system, which change in real-time to reflect user-made modifications. Users can see the direct effect of various inputs, such as *percent excess air*, on boiler efficiency. Actual efficiencies will be calculated during simulations. The user also specifies the *rated cycle conversion efficiency*, *minimum load*, and *max over design operation* of the Rankine cycle. Additionally, the user can enable a *time of dispatch schedule*, which allows the user to define an operation schedule for the plant over the course of a year.
- The *Emissions Comparison* page inputs do not affect the modeled performance of the plant but generate data about avoided emissions and ash production when compared to a displaced power generation source.

During simulations, SAM calculates performance metrics such as electricity produced, capacity factor, heat rate, and thermal efficiency. The specifics of these outputs and associated calculations are detailed in Section 7.

Broadly, SAM's biopower model requires inputs, such as location and system design parameters, and calculates the estimated capacity of a potential biomass power plant as well as its capacity factor, heat rate, and energy produced. This distinguishes SAM from other biopower models, which typically require that the plant's performance parameters be specified as inputs. For example, the Electric Power Research Institute (EPRI) BIOPOWER Model requires the capacity factor and heat rate as inputs and generates biomass usage and thermal efficiency outputs [5]. SAM, in a sense, operates in reverse and is useful in cases where plant metrics such as heat rate are not already known. This makes the SAM model particularly appropriate for scoping and screening various possible plant configurations, locations, and costs to help navigate towards a feasible and economic overall design. Advanced built-in analysis capabilities, such as parametric simulation coupled with detailed financing structures, allow users to explore a wide variety of options and assess the various tradeoffs involved.

The internal calculations in SAM's biopower model use a different timescale than the solar and wind models, which operate on hourly timescales (or smaller) to capture the variability of the solar and wind resources. However, biopower is typically a baseload power source that runs almost constantly on its fuel source, and biomass fuel properties generally remain constant over the hourly timescale. Therefore, the moisture content instead is calculated over a monthly timescale. Hourly ambient temperature influences both boiler and turbine efficiency, so the efficiencies are calculated hourly and monthly and averaged before incorporating the efficiency loss due to biomass moisture, which is presumed to remain constant over the course of an hour.

1.4 Abbreviations and Variable Names

Italicized phrases in this manual refer to terms found in the SAM user interface.

Table 2. Abbreviations Used in this Document

Abbreviation	Description
ABMA	American Boiler Manufacturer's Association
Btu	British thermal unit
EMC	equilibrium moisture content
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	fluidized bed combustor
HHV	higher heating value
LHV	lower heating value
MACT	Maximum Achievable Control Technology
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
psi	pounds per square inch (pressure)
SAM	System Advisor Model

Table 3. Variable Naming Conventions

Name	Description	Units	Units Abbrv.
a	Percent excess fed air (molar basis)	Percent	%
A	Ash weight percent (dry)	Percent	%
ash	Ash production	tons per year	ton/yr
\dot{b}	Biomass feed rate	Pounds per hour	lb/hr
C	Carbon weight percent (dry)	Percent	%
CF	Capacity factor	Percent	%
C_{gross}	Gross generating capacity	Megawatts	MW
C_{net}	Net generating capacity	Megawatts	MW
EMC	Equilibrium moisture content weight percent (dry)	Percent	%
e_x	Efficiency loss as a percent of total heat input due to x	Percent	%
H	Hydrogen weight percent (dry)	Percent	%
H_2	Diatomic hydrogen weight percent (dry)	Percent	%
HHV	Higher heating value	British thermal units per pound	Btu/lb
HR_{gross}	Net heat rate	Million Btu per megawatt-hr	MMBtu/MWh
HR_{net}	Gross heat rate	Million Btu per megawatt-hr	MMBtu/MWh
H_x	Enthalpy of species x	British thermal units per hour	Btu/hr
LHV	Lower heating value	British thermal units per pound	Btu/lb
M_{db}	Moisture content (dry basis)	Percent	%
M_{wb}	Moisture content (wet basis)	Percent	%
\dot{m}_x	Mass flow rate of species x	Pounds per hour	lb/hr
N	Nitrogen weight percent (dry)	Percent	%
\dot{n}	Mass flow rate of dry gas per fuel input	Pounds per Btu fuel	lb/Btu
O	Oxygen weight percent (dry)	Percent	%
O_{gross}	Gross annual output	Kilowatt-hours	kWh
O_{net}	Net annual output	Kilowatt-hours	kWh
P	Parasitic load, as percent of gross capacity	Percent	%
P_b	Barometric pressure from weather file	Pounds per square foot	psi
P_{vd}	Saturated pressure of water vapor at ambient temperature	Pounds per square foot	psi
\dot{Q}_x	Heat transfer rate	British thermal units per hour	Btu/hr
R	Relative humidity	Percent	%
r	Relative humidity	Fraction (%/100)	
T_A	Monthly average ambient temperature	Degrees Celsius	°C
T_C	Temperature	Degrees Celsius	°C
T_F	Temperature	Degrees Fahrenheit	°F

T_{FG}	Flue gas temperature	Degrees Celsius	°C
T_K	Temperature	Kelvin	K
T_n	Hourly weather file temperature (n^{th} hour)	Degrees Celsius	°C
η_x	Efficiency as a fraction of heat input for component x	Fraction (%/100)	

2 Feedstock

2.1 Feedstock Availability

Biomass feedstock availability is highly dependent on location, climate, and season. SAM biopower can use the NREL Biopower Atlas to estimate regional biomass resource availability. Primarily, biomass residues calculated by Biopower Atlas fall into two categories: crop and woody residues. Crop residues can be further broken down into field residues and process residues. Bagasse is a residue that is a product of sugarcane and sorghum processing. Barley straw, corn stover, rice straw, and wheat straw are all field residues that remain after harvest. Woody residues can come from a variety of sources. Forest residues usually refer to lumber that is unfit for sawmill processing, such as smaller-diameter branches or stumps, misshapen trees, and undergrowth that may fuel forest fires. Primary mill residues are wastes generated by mill processes. Urban wood waste includes prunings from residential areas, as well as woody construction materials and used pallets.

By entering a *weather file location* on the *Climate* page and specifying a *collection radius*, SAM can directly query the NREL's Biopower Atlas for feedstock data at a particular location. The Web service will return annual resource potential for the eight standard biomass resource types in tons per year, assuming that a certain amount of harvest residue must remain on the field to prevent soil erosion and maintain nutrients [6]. These data become visible to the user as *resource available* (in bone dry tons per year). However, it may not be realistic to gather all available residues due to supply and demand considerations. Thus, the *monthly obtainability* adjusts the available biomass feedstock (at 100% obtainability) to the realistically obtainable biomass feedstock. The default *resource obtainability* factor is 50%; however, the value is highly region and feedstock specific. The U.S. Energy Information Administration publishes biomass supply curves that may be helpful when estimating the amount of biomass that is economically obtainable [7].

2.2 Biomass Properties

2.2.1 Moisture Content

Biomass moisture content is highly variable and dependent on biomass type, season, and location. Additionally, moisture content is expressed on a dry or wet basis [8]. Dry basis moisture (M_{db}) content is a ratio of the weight of water to the dry biomass weight. Wet basis moisture (M_{wb}) content is the ratio of the weight of water to the wet biomass weight. The two moisture contents are related in the following manner [8]:

$$M_{wb} = \frac{M_{db}}{(1 + M_{db})}$$

$$M_{db} = \frac{M_{wb}}{(1 - M_{wb})}$$

The *moisture content* in the SAM user interface is based on the wet moisture content and represents the yearly average of the moisture content of biomass as collected. The

simulation engine adjusts the moisture content based on monthly average ambient temperature and humidity. In the SAM user interface, the wet moisture content is required since its definition is slightly more intuitive. However, many publications report the dry basis weight, so conversion may be necessary. Table 4 shows the default moisture content corresponding to biomass type. Note that these values are hardly universal and are only shown for basis of comparison.

Table 4. Default Biomass Moisture Contents

	M_{wb}	M_{db}
Bagasse [9]	50%	100%
Barley Straw [10]	16%	19%
Corn Stover [8]	30%	42%
Rice Straw [11]	67%	200%
Wheat Straw [8]	12%	14%
Forest Residues [12]	44%	78%
Primary Mill Residues [12]	48%	91%
Urban Wood Residues [13]	12%	14%

2.2.2 Heating Value

The heating value of a fuel describes the amount of energy released upon combustion per unit mass of fuel. Heating values can either be described as higher (gross) heating value or lower (net) heating value. The *higher heating value* (HHV) takes into account the latent heat of vaporization of water, meaning that it assumes all water vapor generated during combustion condenses back into water. The condensation of water increases the theoretical amount of energy available for use. More practically, however, the latent heat will not be recovered and the water remains in vapor form. In this case, the *lower heating value* (LHV) is more appropriate. SAM displays both the HHV and LHV. When only the LHV is known, the following equation can give an approximation for the HHV, which is a required SAM input for additional fuels [14]:

$$HHV = LHV + 10.30 (H_2 \times 8.94)$$

where the heating values are in British thermal units per pound (Btu/lb) and H_2 represents the mass percent of diatomic hydrogen in the fuel.

Empirical relations exist between heating value and elemental composition. Thus, the heating value can be calculated if the elemental composition is known using the following formula [15]:

$$HHV = 3.55C^2 - 232C - 2,230H + 51.2C \times H + 131N + 20,600$$

where C , H , and N are the dry biomass weight percent of carbon, hydrogen, and nitrogen, respectively. Online databases have vast collections of biomass compositions [16, 17].

2.3 Transportation

Increasing the *collection radius* generally increases the amount of available biomass determined by the Biopower Atlas but may cause feedstock prices to be prohibitively high due to transportation costs. Transporting biomass differs from transporting fossil fuels in two ways. Biomass has a significantly lower energy density and generally higher moisture content compared with coal and other fossil fuels. Additionally, biomass resources are more spatially distributed than fossil fuels, which are largely collected from extraction points such as mines or wells. Since long-distance biomass transportation is currently unfeasible, most biomass is delivered nearby via diesel trucks. At larger distances, railway transport may become more cost effective. Mahmudi and Flynn offer a comparison of railway- and truck-hauling costs for fuels [18]. A similar analysis with 2008 diesel prices shows that rail transport becomes economical at a hauling distance of 60 miles [19].

2.4 Handling and Preparation

After delivery, biomass feedstock undergoes preparation for combustion. In general, the process involves four steps: receiving, processing, storage, and transport [20]. Each step requires capital and energy expenditures. Dryers, grinders, conveyors, separators, and storage bins may be necessary depending on feedstock. Additionally, biomass decay may become a consideration even if the biomass is stored in piles for a relatively short amount of time (1–2 months). Biomass decay may result in dry matter loss and thus reduced energy content. However, with proper storage techniques, the storage losses are minimal [21]. Good storage practices include covering biomass piles, rotating biomass on a “first in, first out” schedule, and maintaining a large particle size distribution within the pile [21]. When modeling a co-fired power plant with biomass and coal fuels, the user should note that the fuel preparation requirements are different (for instance, coal fuel requires pulverizing), which may result in additional capital and operating costs.

The SAM biopower model assumes that biomass is properly stored and thus dry matter weight and heating value do not change over time. This assumption is reasonable for 1–2-month storage periods. For longer storage times (6 months or more), losses become more significant and the heating value should be adjusted accordingly [22]. Studies indicate that 6 months of storage may reduce energy content by up to 20% [23, 24].

Biomass moisture content is highly seasonal and regional. Biomass feedstock can be handled in a few different ways. SAM provides three feedstock-handling options, which can be specified on the *Plant Specs* page:

- *Fed as received*: The biomass does not undergo any substantial drying before being fed to the combustor. This option avoids drying costs but penalizes the boiler efficiency since evaporation of biomass moisture requires energy input. The season in which biomass is harvested also affects moisture content. Biomass harvested in the summer months can be up to 10% drier based on operating experience. This applies even to biomass that does not undergo intentional drying. However, this option means that all biomass will be fed at the *moisture content* specified in the user interface without implementing a dryer.

- *Dry to equilibrium moisture content* (EMC) assumes that the biomass is exposed to the ambient atmospheric conditions for a sufficient amount of time to reach EMC. The EMC calculations are detailed in Section 2.4.1.
- *Drying to specified moisture content* involves including a dryer as an additional capital expenditure. Generally, adding a dryer will also increase the parasitic load of the plant and may add incremental operation and maintenance (O&M) costs. In theory, adding a dryer can increase the boiler efficiency by several percent, but this practice is not always used due to the other considerations [12].

2.4.1 Equilibrium Moisture Concentration (EMC)

Biomass is hygroscopic, meaning that water absorbs and desorbs freely into biomass as dictated by the surrounding conditions. The properties of a specific biomass and the surrounding temperature and humidity determine the moisture concentration of biomass in equilibrium with its surroundings (the EMC). SAM calculates the EMC when the *allow feedstock to air-dry* option is selected on the *Plant Specifications* page. For this option, the biomass undergoes ambient drying during storage. SAM assumes that the storage system is equipped with a proper biomass-mixing device so that all biomass is equally exposed to ambient airflow. During storage, however, moisture composition does not change instantly. Depending on the type of biomass, pile shape, presence of bark, and size of chip, reaching the EMC may require anywhere from hours to months [25]. Thus, the equilibrium moisture levels are calculated on a monthly basis. Due to differences in desorption characteristics, EMC calculations differ for each type of biomass. Since the relations are empirical, equations also have different temperature and humidity conventions, as shown in the equations below.

The weather data has monthly values for ambient temperature (in Celsius) and relative humidity. As mentioned, biomass properties change on a longer timescale. The following equation converts hourly temperatures to a monthly average temperature:

$$T_A = \frac{\sum_{n=0}^{N \times 24} T_n}{N \times 24}$$

where T_A is the monthly weather file ambient temperature (in degrees Celsius), T_n is the temperature of the n^{th} hour of the month, and N is number of days in the month. Calculations for a monthly averaged relative humidity utilize the same approach.

2.4.1.1 Bagasse Equilibrium Moisture Concentration Calculation

The following empirical equation determines the EMC of bagasse [26]:

$$EMC = \frac{1,800}{W} \left[\frac{KR}{(1 - KR)} + \frac{K_1KH + 2K_1K_2K^2R^2}{1 + K_1KH + K_1K_2K^2R^2} \right]$$

The constants W , K , K_1 , and K_2 are described by:

$$W = -57.70 - 0.1982T_k + 22.305T_k^{0.5}$$

$$K = -2,778.14 - 2,042.09T_K + 5,238.88T_K^{0.5}$$

$$K_1 = -70.42 - 13.68T_K + 180.22T_K^{0.5}$$

$$K_2 = 194.01 + 0.62T_K + 51.48T_K^{0.5}$$

where EMC is represented on a percent dry basis, T_K is the absolute temperature in Kelvin, and R is the relative humidity (%).

2.4.1.2 Barley Straw Equilibrium Moisture Concentration Calculation

Barley straw EMC calculations use the modified Chung-Pfost equation [27]:

$$EMC = \left(\frac{1}{-0.14843} \right) * \ln \left(\frac{T_C + 71.996}{-474.12} \times \ln(R) \right)$$

where EMC is represented on a percent dry basis, T_C is the absolute temperature in Celsius, and R is the relative humidity (%).

2.4.1.3 Corn Stover Equilibrium Moisture Concentration Calculation

Corn stover moisture calculations utilize the modified Oswin equation [28]. The values for the constants were described using the “stalk” component of corn stover, which includes both the stalk skin and stalk pith:

$$EMC = (10.9137 + (-0.0746 \times T_C)) \times \left[\frac{R}{(1 - R)} \right]^{2.4116}$$

where EMC is represented on a percent dry basis, T_C is the absolute temperature in Celsius, and R is the relative humidity (%).

2.4.1.4 Rice Straw, Wheat Straw, and Woody Biomass Equilibrium Moisture Concentration Calculation

Rice, wheat, and woody biomass (primary mill residue, forest residue, and urban wood residue) all use the same calculation. Rice straw desorbs marginally less moisture, however, making its EMC higher by about 10% [8]. Note that this equation is similar to the bagasse equation but with different constants [29]:

$$EMC = \frac{1,800}{W} \left[\frac{Kr}{(1 - Kr)} + \frac{K_1Kr + 2K_1K_2K^2r^2}{1 + K_1Kr + K_1K_2K^2r^2} \right]$$

The constants W , K , K_1 , and K_2 are described by:

$$W = 330 - 0.452T_K + 0.00415T_K^2$$

$$K = 0.791 + 0.000463T_K + 0.0000000844T_K^2$$

$$K_1 = 6.34 + 0.000775T_K - 0.0000935T_K^2$$

$$K_2 = 1.09 + 0.0284T_K - 0.0000904T_K^2$$

where EMC is represented on a percent dry basis, T_K is the absolute temperature in Kelvin, and r is the fraction relative humidity (%/100).

2.4.1.5 Equilibrium Moisture Concentration Calculation Example for Various U.S. Locations

The following case study illustrates the effect of ambient temperature and relative humidity on the EMC for woody biomass. Table 5 shows the relevant weather file data in Fargo, North Dakota; Boulder, Colorado; Olympia, Washington; and Phoenix, Arizona.

Table 5. Average Monthly Weather Characteristics of Various U.S. Locations

	Fargo, ND		Boulder, CO		Olympia, WA		Phoenix, AZ	
	Temp (°C)	Relative Humidity (%)	Temp (°C)	Relative Humidity (%)	Temp (°C)	Relative Humidity (%)	Temp (°C)	Relative Humidity (%)
January	-13.2	73.0	-1.0	57.0	3.7	88.9	12.1	48.1
February	-11.6	75.7	0.6	59.7	5.3	82.7	12.4	44.9
March	-1.4	75.6	3.6	52.8	6.3	76.0	18.5	37.8
April	6.8	65.4	9.2	49.0	8.1	77.7	21.8	26.8
May	13.6	61.6	13.6	51.9	12.1	75.1	25.9	22.7
June	18.6	64.6	18.3	49.4	15.8	71.7	32.3	20.8
July	21.4	67.1	23.1	48.9	18.0	68.6	33.3	35.3
August	20.1	67.6	21.2	50.5	18.0	68.2	32.4	34.2
September	15.5	72.6	16.9	43.3	14.5	75.3	29.6	36.1
October	8.1	70.8	10.8	49.2	9.7	86.9	22.7	36.6
November	-2.3	82.5	3.4	58.8	6.3	89.8	17.3	46.9
December	-10.9	74.6	-1.6	53.2	3.8	89.3	11.4	46.0

Figure 2 shows the corresponding EMCs for each month. Note that the EMC is calculated on a monthly basis, and thus, the lines between data points only indicate trends. The graph shows the dramatic effect that ambient conditions can have on biomass moisture content.

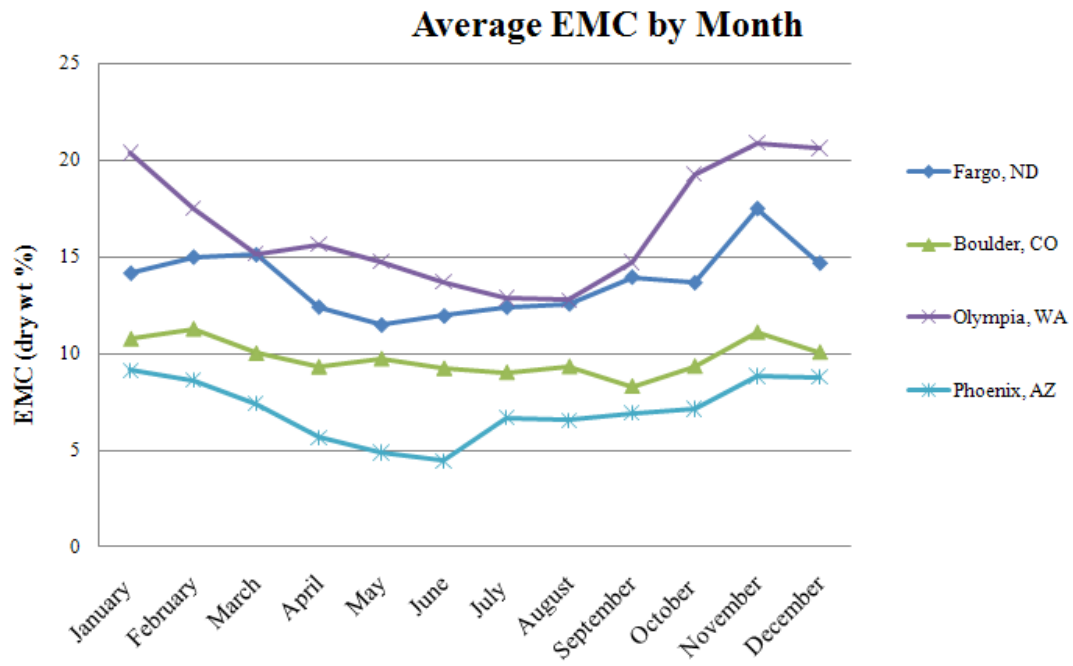


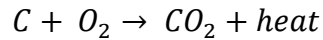
Figure 2. Average EMC for woody biomass in various U.S. locations

3 Combustion System

3.1 Introduction

3.1.1 Principles of Combustion

After processing, the fuel is fed to the combustion system. Here, the term *combustion system* encompasses the combustion chamber and boiler where steam generation occurs. Combustion occurs when fuel-bound carbon reacts with an oxidant (oxygen gas, in this case). Generally, the reaction takes the form:



Breaking chemical bonds is an endothermic process, meaning it requires energy input. Conversely, forming new chemical bonds releases energy and thus is an exothermic process. Since combustion releases energy in the form of heat, breaking chemical bonds in the fuel must require less energy than the energy generated in making new bonds. A *combustion system* or furnace is simply a process unit that combines all necessary aspects of combustion: a fuel source (biomass), an oxidant (here, oxygen supplied by combustion air), and a spark.

The model computes the efficiency of a combustion system as specified by the user. Here, the main inputs are *moisture content*, the *biomass feedstock handling* option, *combustion system* type, *percent excess fed air*, *flue gas temperature*, *number of boilers*, *steam grade*, and *boiler overdesign factor*. These inputs generate the system efficiency. The system efficiency and the heat content of the fuel determine the rate that steam is supplied to the turbine.

3.1.2 Types of Combustors

Many types of combustion systems are encountered in biomass power plants. Most commonly, a *grate stoker furnace* is designed to feed solid fuel onto a grate where burning occurs, with combustion air passing through the grate. Stokers are generally the least expensive of the three boiler types available in SAM and are best suited for large fuel feed rates (75,000–700,000 lb/hr) [14]. Since the moving grate continuously collects the unburned ash, maintenance costs are significantly lower than older combustors that simply burn a pile of fuel [5].

A *fluidized-bed combustor* (FBC) features a bed of fuel and sand or other inert substance that becomes suspended by the combustion air flowing upward. The combustion air functions both as an oxidant and suspension medium. This technology reduces the fluctuations in steam production associated with inconsistent feedstocks or switching fuels. Additionally, the combustion temperature is lower compared to both grate stoker and cyclone furnaces, which results in the reduced formation of pollutants [14]. However, capital costs and O&M costs generally increase [20].

Cyclone furnaces, like FBCs, allow for flexibility in fuel types and increase combustion efficiency over stoker boilers by feeding the fuel in a spiral manner. Cyclone furnaces are smaller and have less capital cost than FBCs and thus may be more suitable for smaller burn rates [14].

For all three types of combustors, hot flue gases produced in the furnace travel upward to the boiler. The boiler is a heat exchanger that transfers thermal energy contained in the hot flue gas to boiler-feed water to generate steam. The steam goes on to power the turbine in a Rankine cycle and after condensation is recycled back to the boiler.

For SAM calculations, the type of furnace selected solely impacts the percent-unburned carbon efficiency loss. In reality, the combustion system choice affects the capital costs and O&M costs, but SAM is not designed as a cost-predictive model. However, the furnace type also affects the *boiler overdesign factor*, *flue gas temperature*, *steam grade* selection, and *number of boilers* that may be installed. Thus, the user may want to consider the following guidelines when selecting a combustor type:

1. Stoker boilers have the greatest unburned carbon loss at 3.5% [20]. For FBCs, the unburned fuel loss is 0.25% [20]. Cyclone furnaces fall in between the two at 3% [30]. However, the capital cost for FBCs may be 30%–100% higher [20]. The user should adjust the capital costs accordingly.
2. The lower combustion temperatures in FBCs produce a less “severe” grade of steam. Typically, the steam temperature for FBCs is between 750–850°F and the pressure is around 600–850 psig [12]. Cyclone and grate stoker furnaces typically have higher temperatures of around 900°F and pressures of 1,200–1,500 psig [12]. The *steam grade* input should be adjusted accordingly.
3. Grate furnaces sometimes require higher than 50% excess air levels [31]. FBCs can often operate below 20% excess air [31].
4. FBCs are often the best choice for systems where there is a high degree of heterogeneity in the properties of the fuel.
5. Cyclone furnaces are not as commonly seen in biomass power plants but may be implemented if boiler size is a concern [14]. They are the smallest furnace and often have the lowest capital cost [14].

3.2 Energy Balance

The energy balance on the combustion system in SAM follows the “Btu Method” as presented by Babcock and Wilcox [14]. The overall heating value of the fuel is penalized by various efficiency losses. The most significant efficiency losses in the combustion system are listed in the SAM user interface as: *dry flue gas losses*, *moisture in fuel*, *latent heat*, *unburned fuel*, and *radiation and miscellaneous*. Each of these losses will be explained in detail in Sections 3.2.1–3.2.5. The SAM simulation engine also calculates the penalty associated with moisture in air, but the significance on the overall efficiency is generally small relative to the other derates and is not displayed in the user interface.

3.2.1 Dry Flue Gas Losses

Combustion air enters the furnace at ambient temperature, where it is immediately subject to preheating by waste process heat, such as the spent flue gas exiting the stack. Regardless of how the air is preheated, a significant loss of enthalpy occurs when the combustion gas exits the plant at a much higher temperature than the temperature at which it was fed. Additionally, heating the gas liberated during combustion (carbon

dioxide) requires energy. In general terms, the rate of enthalpy loss can be calculated as follows:

$$H_{dry\ gas\ loss} = (H_2 - H_1) \dot{m}$$

where $H_{dry\ gas\ loss}$ is the enthalpy lost (in units of energy per time, or Btu/hr), \dot{m} is the mass flow rate of dry gas in pounds per hour, and H_2 and H_1 are the enthalpy of the combustion gas before and after combustion.

The flow rate of dry flue gas is largely determined by the *percent excess fed air* input. By convention, the percent excess air is specified on a volumetric/molar basis. However, combustion air from the atmosphere is only 21% oxygen by volume (and the balance nitrogen). Thus, much of the enthalpy losses result from heating up the nitrogen that accompanies the combustion oxygen.

The efficiency loss, displayed as *dry flue gas losses*, is estimated by assuming an input combustion air temperature of 80°F and an output temperature as specified by the user input, *flue gas temperature*, which defaults to 390°F [14]. The combustion air specification of 80°F is chosen for a simple estimation calculation in the user interface before the simulation engine runs. The actual simulation, however, computes the monthly average ambient temperature (as detailed in Section 2.4.1) to accurately compute the efficiency, since the combustion air is assumed to be fed at the ambient temperature. The efficiency derate (as a percent of total heat input) is calculated as follows:

$$e_{dry\ gas\ loss} = 24 \times (T_{FG} - T_A) \dot{n}$$

and

$$\dot{n} = \left(\left((12.7C + 38.1H) \times \left(1 + \frac{a}{100} \right) \right) - 0.5O \right) \frac{1}{HHV}$$

where $e_{dry\ gas\ loss}$ is the efficiency loss as a percent of total heat input; \dot{n} is the mass flow rate of dry gas in pounds per Btu fuel; T_{FG} and T_A are the temperature of the combustion gas before and after combustion; C , H , and O are the respective mass fractions of carbon, hydrogen, and oxygen in the fuel; a is the *percent excess fed air*; and HHV is in Btu/lb. T_{FG} is also known as the “stack temperature” or “flue gas temperature,” which is the user input as *flue gas temperature*, meaning that all useable heat has been collected when the combustion gas is that temperature. At that point they exit the plant through the stack. T_A is the temperature at which air enters the system, which is the ambient temperature. The constants in front of the variables capture the specific heat capacity and unit conversions. This calculation follows the Btu Combustion Method detailed in Chapter 21 of Babcock & Wilcox’s *Steam* [14]. Dry flue gas losses are often responsible for the greatest efficiency loss in the furnace.

3.2.2 Moisture in Fuel

Moisture in fuel adversely affects the plant efficiency in two primary ways. First, water in biomass imposes extra mass that must be consequently hauled and processed with the

biomass itself. Since water supplies no heating value, the moisture is essentially “dead weight.” Additionally, the water absorbs heat from the combustion reaction that is unlikely to be recovered. The enthalpy lost in biomass moisture is calculated similarly to the dry flue gas calculation. When the fuel enters the boiler, the water in the fuel will be at the feed-fuel temperature. Upon leaving the combustion system, the water, now vaporized, will be at the same temperature as the flue gas. The sensible heat of the flue gas imposes another energy penalty on the system.

The enthalpy of the vaporized moisture leaving the stack as steam at atmospheric pressure is calculated in the following equation:

$$H_2 = (0.00003958T_{FG} + 0.4329)T_{FG} + 1,062.2$$

where H_2 is the enthalpy of the steam in Btu/lb and T_{FG} is the steam temperature in degrees Fahrenheit, which leaves the stack at the *flue gas temperature*. Likewise, the enthalpy of the water in the biomass at its pre-combustion (or ambient) temperature is calculated as below:

$$H_1 = T_A - 32$$

where H_1 is the enthalpy of the water in Btu/lb, and T_A is the temperature in degrees Fahrenheit of the biomass before combustion, which in this case is the ambient temperature.

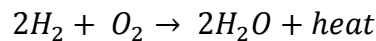
The efficiency loss ($e_{fuel\ moisture}$) is calculated as a percent of total heat input using the following relationship:

$$e_{fuel\ moisture} = M_{db} \frac{(H_2 - H_1)}{HHV}$$

where $e_{fuel\ moisture}$ is the efficiency loss as a percent of total heat input, HHV is in Btu/lb, M_{db} is the percent moisture content (dry basis), and H_2 and H_1 are the enthalpies of the steam leaving the stack at the *flue gas temperature* and the enthalpy of the water initially, as calculated in the equations immediately above.

3.2.3 Latent Heat

Solid fuels generally contain about 5% hydrogen by weight. During combustion, liberated hydrogen reacts with oxygen:



The reaction shows that the hydrogen in the fuel leaves the stack at the *flue gas temperature* as water vapor, thus requiring the latent heat of vaporization of water as well as the sensible heat of the vapor at the *flue gas temperature* [32].

As detailed in Babcock and Wilcox [30], the efficiency loss for the additional steam generated upon combustion is determined using the following equation:

$$e_{latent\ heat} = \frac{H \times 100 \times 8.94}{HHV} (H_2 - H_1)$$

where $e_{latent\ heat}$ is the efficiency loss as a percent of total heat input, H is the dry weight fraction hydrogen, HHV is in Btu/lb, and H_2 and H_1 are the enthalpies of the steam leaving the stack at the *flue gas temperature* and the enthalpy of the water initially, as calculated in Section 3.2.2.

3.2.4 Unburned Fuel

Unburned fuel losses simply result from incomplete combustion in the boiler. In practice, the unburned fuel percentage depends on the type of boiler and excess fed air. This efficiency loss is one of the hardest to predict. For well-maintained boilers at proper levels of excess air, the degree of incomplete combustion should be similar among various technologies, as detailed in Section 3.1 and reiterated below [20].

$$\eta_{unburned\ carbon} = \begin{cases} 3.5\% \text{ for stoker boilers} \\ 0.25\% \text{ for FBC} \\ 3.0\% \text{ for cyclone combustors} \end{cases}$$

3.2.5 Radiation and Miscellaneous

The surface of a furnace is at a much higher temperature than its surroundings; therefore, furnaces lose heat to the surroundings by radiation and convection. Since smaller furnaces have a larger surface area relative to their heat output, radiation losses are more significant for smaller boilers [32]. Modern boilers tend to maintain a near-constant external temperature despite the fraction of capacity at which they operate [32]. Thus, boilers operating at full capacity experience less severe radiation losses relative to their heat input [32]. The American Boiler Manufacturer's Association (ABMA) has released a table that estimates radiation losses as a function of full capacity and operating capacity [32]. In the SAM simulation engine, the ABMA radiation table is used to calculate the radiation efficiency loss, e_{rad} .

The “miscellaneous” category also encompasses various losses that are difficult to quantify or predict, such as moisture in air, sensible heat in ash, radiation in ash pit, and sensible heat in flue dust. The moisture in air loss depends on location and is calculated by the SAM simulation engine. The other derates, however, are lumped together under a “manufacturer's margin” (or e_{manu}) derate, which here is taken to be 2.03% [20].

In the SAM simulation engine, the efficiency loss due to moisture in the air is determined using the following equation:

$$e_{moisture\ in\ air} = 45 \times \dot{n} \left(0.622 \times \left(\frac{(0.01 \times R \times P_{vd})}{P_b - (0.01 \times R \times P_{vd})} \right) \right) (T_{FG} - T_A)$$

where $e_{moisture\ in\ air}$ is the efficiency loss as a percent of total heat input, \dot{n} is the mass flow rate of dry combustion gas in pounds per Btu fuel (calculated as in Section 3.2.1), T_{FG} and T_A are the temperature of the combustion gas after (*flue gas temperature*) and the ambient temperature before combustion, R is the percent relative humidity, P_b is the barometric pressure (in psi, as given in the weather file), and P_{vd} is the absolute saturated pressure of water vapor at the ambient temperature in psi. Again, the constant in the front of the equation represents the heat capacity as well as necessary unit adjustments. P_{vd} varies with ambient temperature as follows [33]:

$$p_{vd} = 0.0886e^{\left(\frac{17.2694T_C}{T_C+238.3}\right)}$$

where T_C is the ambient temperature (in degrees Celsius) and P_{vd} is expressed in psi absolute.

3.3 Mass Balance

The mass balance on the combustion system is simple to resolve with two material balances: one on the biomass stream and one on the boiler steam stream. After the vaporization of the biomass stream through combustion, it becomes flue gas that exits the plant through the stack. During combustion, the biomass transfers all of its useful heat to the boiler feedwater stream. The amount of useful heat is calculated using the following manner:

$$\begin{aligned} \dot{Q} = \dot{b} \times HHV \times (100 - (e_{moisture\ in\ air} + e_{manu} + e_{rad} \\ + e_{unburned\ carbon} + e_{latent\ heat} + e_{fuel\ moisture} \\ + e_{dry\ gas\ loss}))/100) \end{aligned}$$

where \dot{Q} is the heat transferred to the boiler feedwater in Btu/hr, HHV is in Btu/lb, \dot{b} is the dry biomass feed rate in lb/hr, and e describes each of the various efficiency losses expressed as a percent of total heat input.

The spent gas that exits the plant has closed the biomass material balance, but the flue gas composition and flow rate remains necessary information for determining environmental implications.

Now we are concerned with the steam that has just been created in the boiler. The amount of steam created can be described using the following equation:

$$\dot{m}_{steam} = \frac{\dot{Q}}{H_{steam}}$$

where \dot{Q} is the heat transferred to the steam as calculated above in Btu/hr, H_{steam} is the enthalpy (or grade) of the steam, and \dot{m}_{steam} is the required flow rate of steam in pounds per hour, and by extension, the required flow rate of the feedwater to the boiler. The *steam grade* can be specified by the user, and the enthalpy available directly determines the amount of boiler feedwater fed to the combustion system. The created steam then powers the turbine, as detailed next in Section 4.

4 Steam Rankine Cycle

The steam Rankine cycle, sometimes referred to as a power cycle, includes the equipment necessary to convert the heat contained in boiler steam into electrical energy. For the purposes of the biopower model, this entails a conventional steam Rankine cycle and an electric generator. Many existing biomass power plants use a combined heat and power approach, meaning that some of the boiler steam is directly used in industrial processes rather than generating electricity [12]. Since steam cycle conversions are only around 30%–40% efficient, using heat directly dramatically increases the efficiency of a power plant [20]. However, the SAM biopower model focuses only on electricity generation, and combined heat and power generation is beyond the scope of the current model. The SAM Physical Parabolic Trough Plant Model documentation has a detailed account of modeling typical power cycles [34].

4.1 Efficiency Fluctuations

The *rated efficiency* of the turbine, or “power block,” is the baseline efficiency of the conversion. However, the efficiency fluctuates based on the ambient air temperature, as well as on the part load (or fraction of capacity) at which the turbine operates. The effect of temperature and part load on efficiency can be described as a fourth-order polynomial with the coefficients $F_0 - F_4$, as shown in the equations below. These coefficients define a polynomial equation to describe η , a fractional value that adjusts the amount of heat supplied to the power block based on deviations from full load and design temperature. The user inputs all defining coefficients.

$$\eta_q = F_0 + F_1 Q_{norm} + F_2 Q_{norm}^2 + F_3 Q_{norm}^3 + F_4 Q_{norm}^4$$

$$\eta_T = F_0 + F_1 T_{norm} + F_2 T_{norm}^2 + F_3 T_{norm}^3 + F_4 T_{norm}^4$$

when

$$Q_{norm} = Q_{actual}/Q_{design}$$

$$T_{norm} = T_{actual} - T_{design}$$

where η_q and η_T are fractional efficiencies that adjust the heat supplied to the power block, $F_0 - F_4$ are user-defined inputs that can be specified separately (the *part load efficiency adjustment* and *temperature efficiency adjustment* coefficients, respectively), Q_{actual} is the actual unadjusted heat supplied to the power block, Q_{design} is the designed heat load (determined by the *Nameplate capacity, gross* input), T_{actual} is ambient air temperature entering the power block, and T_{design} is the specified *power cycle design temperature*.

4.2 Minimum Load and Maximum Overdesign Operation

Turbines generally do not operate below a certain fraction of full load since turbine performance is difficult to predict and the economics may become unfavorable [14]. The fractional value for *minimum load* represents the threshold below which the turbine will

not operate. Likewise, the *max overdesign operation* specification will prevent the turbine from operating above a certain fraction of the design load where operation also becomes unpredictable and may introduce unwanted physical stress on the device. Since biomass is a baseload power source, generation should be relatively constant. In SAM biopower, the biomass is assumed to be fed constantly, and only fluctuations in biomass moisture and ambient conditions will affect generation, unless the user specifies a generation profile as detailed in Section 6.

If the *use estimated max for nameplate capacity* option is selected, the turbine size will be calculated to utilize nearly all of the thermal capacity of the furnace system. The user may choose to *specify nameplate capacity*. In that case, the plant may utilize the biomass feedstock sub-optimally. If the *specified capacity* is greater than the *estimated max gross nameplate capacity*, the plant will constantly be operating at a fraction of the designed capacity. Alternatively, if the *specified capacity* is less than the *estimated max gross nameplate capacity*, the plant will constantly be producing at maximum in an attempt to use all of the biomass feedstock. In that case, the surplus biomass will be wasted. Thus, if a user desires a capacity significantly smaller or larger than the *estimated max gross nameplate capacity*, the obtainable feedstock should be adjusted accordingly for a more appropriately sized plant.

The SAM biopower model attempts to approach a true “baseload” plant that constantly operates near capacity. In practice, however, fuel shortages, equipment failure, planned and unplanned shutdowns, and many other factors may cause a plant to operate at reduced load. Increased electric loads, fuel surpluses, or economically advantageous spot prices for electricity may induce a plant to operate above the designed capacity.

4.3 Temperature Correction Mode

The two options for the temperature correction mode, dry- or wet-bulb, refer to the type of cooling employed after steam is spent in the turbine. Dry-bulb temperature refers to the temperature of the air that can be found with a standard thermometer. The wet-bulb temperature also captures the moisture content of the air and is always less than the dry-bulb temperature (except at 100% relative humidity when the two are equal). Evaporative cooling uses the evaporation of water to cool the process condensate to near the wet-bulb temperature, whereas dry-cooling uses ambient air and thus the minimum heat rejection is the dry-bulb temperature. In general, air-cooled systems require more capital, are less thermodynamically efficient, and use more energy. However, evaporative cooling demands significantly more water and might not be possible in some regions.

The choice of *temperature correction mode* simply affects what temperature is used as the reference temperature—the dry- or wet-bulb temperature. Both temperatures are usually specified in the weather files. Choosing the *wet-bulb* option will yield a higher energy output since the cooling is more efficient, but the equipment will generally cost more. Note that the SAM biomass power model does not explicitly model a full cooling system with condensers, associated pressure drops, and other related considerations.

The simulation will use the specified *rated cycle conversion efficiency* to calculate the output on an hourly basis, which is summed to calculate the annual energy produced:

$$O_{net} = \frac{(\sum_0^{8760} \dot{Q} \times \eta \times \eta_q \times \eta_t \times t)}{3,412.14}$$

where \dot{Q} is the heat supplied to the turbine in the form of steam as calculated in Section 3.3, η is the user-specified *rated cycle conversion efficiency*, η_q and η_t are the fractional efficiencies calculated in Section 4.1, t represents the time step of one hour, O_{net} is the net annual output in kilowatt-hours (kWh), and 3,412.14 is the conversion factor from Btu to kWh.

5 Parasitic Losses

Parasitic loss is the load that a power plant requires to operate itself. Fans, conveyors, and pumps all impose a load. The SAM biopower model handles the parasitic load as a percent of the (gross) nameplate capacity:

$$C_{net} = C_{gross} \times \left(1 - \frac{P}{100}\right)$$

where C_{net} is the net generating capacity in MW, C_{gross} is the gross generating capacity in MW, and P is the specified parasitic load as a percent of the capacity.

Additionally,

$$O_{net} = O_{gross} \times \left(1 - \frac{P}{100}\right)$$

where O_{net} is the net energy output in kWh, O_{gross} is the gross energy output in kWh, and P is the specified parasitic load as a percent of the capacity.

Adding extraneous units that require power will increase the parasitic load. The user should be aware that installing a dryer (choosing the option *dry to specified moisture content*) will increase the parasitic load of the plant in practice. SAM will not automatically compensate for additional parasitic loads—this is up to the user. Additionally, air-cooled systems (see Section 4.3) require more energy than evaporative cooling.

6 Dispatch Schedule

Although biomass has been differentiated from other renewable technologies by its “baseload” generation characteristics, some users may wish to model the effects of a dispatch schedule. The dispatch schedule will adjust the power output of the plant to some fraction of the capacity according to a month-by-hour specification. Biomass power plants are “dispatchable” to a certain degree, meaning that their power output can be adjusted a certain amount in response to demand. For example, Ridge Generating Station in Auburndale, Florida, operates at capacity from 11 a.m. until 10 p.m. and reduces its load overnight [12]. Many other plants have similar schedules [12]. However, cycling power equipment does have implications on the O&M costs due to thermal strain on the materials [35], among other factors. Additionally, equipment performance is generally limited by maximum “ramp rates” that determine how quickly power output can be increased. A “cold start-up,” or a start-up from zero output, may take up to 12 hours for an average-sized biomass plant [12]. A “hot start-up,” or a start-up from a fractional output, may take anywhere from 1–5 hours [12].

If the user selects the *enable time of dispatch schedule* option, up to nine periods of fractional generation can be specified on a month-by-hour schedule. The periods are defined by a *fractional generation (of nameplate)*, representing the fraction of the nameplate capacity at which the plant will operate during a particular period. The fractional value can be as low as zero, which may occur, for example, during scheduled seasonal outages but can also be above one. For instance, if the plant experiences greater demand during the summer months, it can operate above capacity. However, the generation is limited by the design of the plant—namely the *max over design operation fraction* and *boiler overdesign factor*. Simulation warnings will be issued if the user specifies an impossibly high fraction for operation and modeled power output will be clipped. Using the dispatch schedule, the user can compensate for maintenance outages or biomass shortages and surpluses.

The user has three options for specifying the ramp rate at which the plant operation can be augmented. First, the user can select *do not specify ramp rate*, which will take each hourly fraction and not adjust when generation changes. In this case, it will be up to the user to either: (1) assume that the capacity can be adjusted in much less than an hour or (2) to increment the generation gradually. Secondly, the user can select *specify ramp rate in kW per hour*. In this case, when the fractional generation varies, the simulation engine will compensate for the required ramping time when computing power output. *Specify ramp rate in percent of capacity per hour* will affect the simulation in the same way but gives the user a different manner to specify the ramp rate.

When deciding to cycle a baseline power plant, the user should take care to adjust O&M costs to reflect the increased strain on the plant. With good design, however, the entire process can be less affected by changes in the output.

7 Model Outputs

After the system is fully specified, SAM provides the user with performance metrics, such as the annual energy output (kWh), capacity factor (%), thermal efficiency (%), and heat rate (MMBtu/MWh). SAM generates graphs to visualize the monthly energy output and the percent change in byproducts and emissions as compared to displaced fossil fuel power. The net annual energy output (\dot{O}) calculation is detailed in Sections 4.3 and 5. The heat rate, an important indication of plant performance, is then calculated as below:

$$HR_{gross} = \frac{\dot{b} \times HHV}{\dot{O} \times 1000}$$

$$HR_{net} = \frac{\dot{b} \times LHV}{\dot{O} \times 1000}$$

where HR_{gross} is the gross heat rate in MMBtu/MWh, HR_{net} is the net heat rate in MMBtu/MWh, HHV is in Btu/dry lb, LHV is in Btu/dry lb, \dot{b} is the dry biomass feed rate in pounds per year, and \dot{O} is annual output in kWh. Thermal efficiency is a conversion of the heat rate:

$$\eta_{therm,HHV} = \frac{341.23}{HR_{gross}}$$

$$\eta_{therm,LHV} = \frac{341.23}{HR_{net}}$$

where HR_{gross} is the gross heat rate in MMBtu/MWh, HR_{net} is the net heat rate in MMBtu/MWh, $\eta_{therm,HHV}$ is the percent thermal efficiency on an HHV basis, and $\eta_{therm,LHV}$ is the percent thermal efficiency on an LHV basis. Finally, the capacity factor is calculated as:

$$CF = \frac{\dot{O}}{C_{design} \times 8760}$$

where CF is the capacity factor percentage, \dot{O} is the annual energy output in kWh, and C_{design} is the nameplate capacity of the plant in kW. Table 6 shows the performance metrics output table for the default case of a theoretical 60 MW biomass power plant in Fargo, North Dakota. Note that economic metrics are not included in the table but are available in SAM when the biomass model is used in conjunction with a financial model. Figure 3 shows the monthly energy generation for the same case.

Table 6. Example Performance Metrics for a Theoretical 60 MW Biomass Power Plant in Fargo, North Dakota

Metric	Base
Annual Energy (kWh)	451,843,928
Annual biomass usage (dry tons/yr)	388,686
Annual Capacity Factor (%)	86.5
Gross Heat Rate (MMBtu/MWh)	13.03
Net Heat Rate (MMBtu/MWh)	12.19
Thermal efficiency, HHV (%)	26.2
Thermal efficiency, LHV (%)	28.0

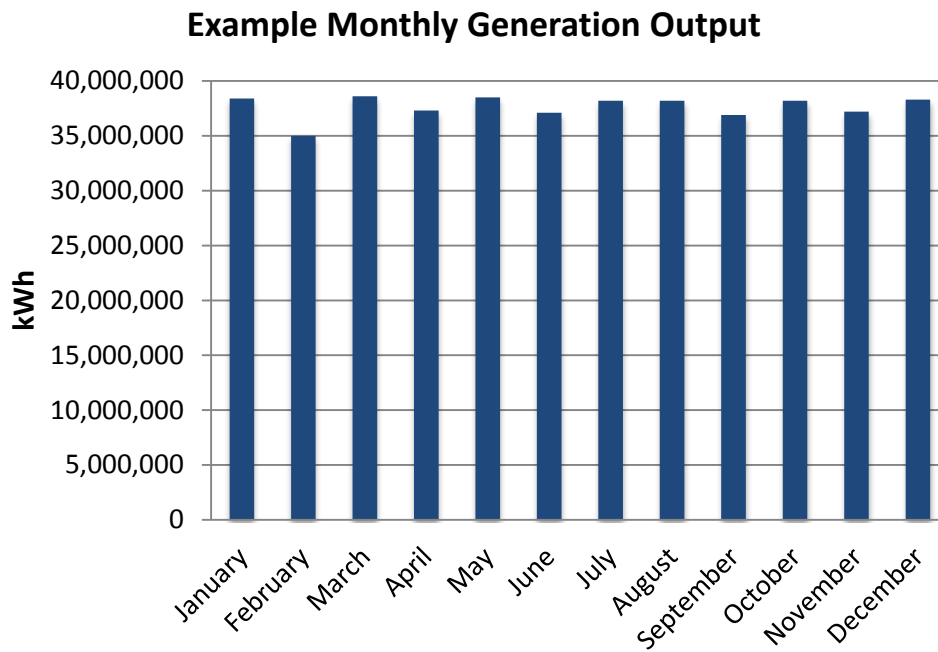


Figure 3. Example monthly energy output for a theoretical 60 MW biomass power plant in Fargo, North Dakota

8 Emissions Comparison

The input parameters on the *emissions comparison* input page inform the implications of displacing fossil fuels with biomass power. The default values reflect the current national distribution of the listed fuel sources [1]. These emissions inputs result in a graph comparing direct emissions of the plant, which include polluting nitrogen compounds (chemically known as NO_x), sulfur dioxide (SO₂), and carbon dioxide (CO₂). Additionally, the graph compares the amount of ash generated in biomass plants versus other conventional power plants. Changing emissions-related inputs do not affect the calculated performance of the power plant. These outputs will vary significantly based on local conditions, and it is incumbent upon the user to update the generation mix inputs for their particular location to get reasonable results. Figure 4 shows a sample analysis for a theoretical 60 MW plant in Fargo, North Dakota, displacing coal power.

In addition to being environmentally unfavorable, NO_x and SO₂ emissions are also regulated by the U.S. Environmental Protection Agency (EPA). Recently adopted Maximum Achievable Control Technology (MACT) standards may cause coal-burning plants to install additional emissions removal equipment or, alternatively, co-fire with biomass to avoid the extensive capital cost associated with the new installations. The user should also note that this calculation does not capture additional harmful emissions, such as mercury, which is not generally associated with biomass combustion [36].

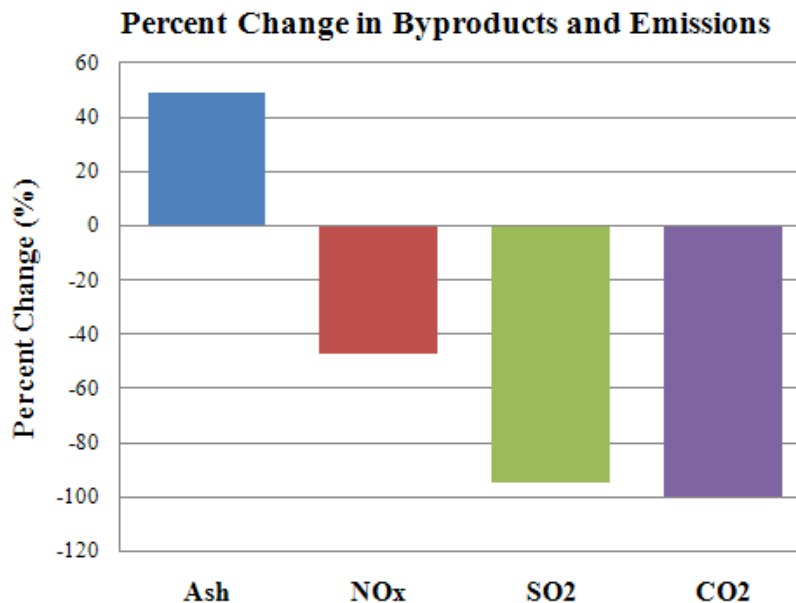


Figure 4. Example change in byproducts and emissions by displacing an equivalent coal fuel plant by a theoretical 60 MW biomass power plant in Fargo, North Dakota

8.1 Stack Emissions Calculations

The stack emissions data compares current fossil-fueled power plants to current average biopower plants. Solid fuels contain elemental sulfur and nitrogen that react during combustion to make pollutants such as nitrogen oxides (NO_x) and sulfur dioxide (SO₂). Plants install “scrubbers” to remove pollutants before flue gas exits into the atmosphere. However, pollutants still escape from the stack. Table 7 shows the emissions data for current plants using each technology [36].

Table 7. Average Emissions Rates for Power-Producing Technologies

Power Plant Fuel	NO_x (lb/MWh)	SO₂ (lb/MWh)
Agricultural Residues	2.6	0.1
Wood Residues	2.5	0.3
Bituminous/Subbituminous Coal	4.8	5.9
Lignite Coal	3.8	10.3
Natural Gas	2.4	0.1
Oil	20.7	2.1

Carbon calculations assume that 100% of the carbon dioxide emitted from biomass fuels is reabsorbed into growing biomass, meaning zero net pounds of carbon dioxide. Note that the calculation does not take into account the carbon released in biomass harvesting and transportation. However, it also does not consider the avoided emissions associated with un-harvested biomass decomposition because the model is only concerned with the bounds of the plant. Although this oversimplifies the carbon cycle, it provides useful insight into the environmental impacts of biomass power generation.¹

8.2 Ash Production Calculations

Some types of biomass have higher ash contents than coal; however, the ash may contain less potentially hazardous compounds. Most coal ash is currently used as an additive in cement and tar production [39]. Some biomass ash is used as a fertilizer to restore nutrients to the soil from which it was produced [40].

The fossil fuel ash contents are determined using the following equation:

$$ash = A \times \frac{HR_{gross}}{HHV} \times \frac{\dot{O}}{2,000}$$

where *ash* is calculated in tons per year, *A* is the dry ash weight percent, *HR* is the heat rate of the plant in Btu/kWh as calculated in Section 6, *HHV* is in Btu/lb, and \dot{O} is the annual output in kWh/year. Table 8 shows the various heat rates [41]. Note that heat rate is the industry standard for measuring plant efficiency per unit of heat input into the plant [1].

¹ For more information regarding a more complete life-cycle approach to biomass power, see Spath & Mann [37, 38].

Table 8. Average Industry Heat Rates for Fossil Fuel Plants (2009)

Power Plant Fuel	Heat Rate (Btu/kWh)
Coal	10,404
Fuel Oil	10,921
Natural Gas	8,160

9 Summary

This manual presented the aim, development, and technical underpinnings of a biomass electric power generation model implemented in SAM. The tool allows various stakeholders, including energy analysts, policymakers, project developers, and financiers, to better understand the various tradeoffs involved with biomass power generation by giving access to detailed system performance parameters and the associated economics. The SAM biomass power implementation leverages an established solar, wind, and geothermal modeling platform to produce credible analyses in a straightforward manner.

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