Table 28. Technology Review Matrix

	Direct Combustion to Steam Turbine	Direct Combustion to ORC	Gasification to ICE	Gasification to ORC
Technological Maturity	B	C	C	C
Sensitivity to Ambient Conditions	A	C	B	C
Water Consumption	D	B	B	B
Feedstock Consumption/ Efficiency	D	C	A	C
Air Emissions Profile	C	C	B	B
Labor Costs	D	B	B	B

Technological Maturity:
- A: Commercial deployment of the integrated system at scale
- B: Commercial deployment of system components, but not the integrated system at scale
- C: Limited commercial deployment of the integrated system at scale
- D: No commercial deployment of the integrated system at scale

Sensitivity to Ambient Conditions (e.g., temperature, humidity):
- A: No variation in output with fluctuations in ambient conditions
- B: Output varies minimally with fluctuation in ambient conditions
- C: Output may vary significantly with fluctuations in ambient conditions
- D: Operation of the system is limited by ambient conditions

Water Consumption:
- A: No water is used for system operations
- B: Water use can be mitigated by the use of air-cooled radiators
- C: Some water use is required for normal operations
- D: Significant water use is required for normal operations

Feedstock Consumption/Efficiency:
- A: Total system efficiency is, on average, greater than 20 percent
- B: Total system efficiency is, on average, between 15 and 20 percent
- C: Total system efficiency is, on average, between 10 and 15 percent
- D: Total system efficiency is, on average, less than 10 percent

Air Emissions Profile:
- A: No emissions treatment necessary to meet local air standards
- B: Limited air emissions control devices are necessary to meet local air standards
- C: Air emissions control devices are necessary to meet local air standards
- D: Cannot meet local air standards with treatment

Labor Costs:
- A: The system can operate without staff present
- B: The system can operate with two employees per shift without any specific certifications
- C: The system requires more than two employees per shift (without any specific certifications)
- D: The system requires specialty certifications (e.g., high pressure steam boiler operator)

Considering the findings in Table 28, and given the interests communicated from the Task Force related to technology selection, a gasification-to-ICE approach would be preferred.

Gasification Technologies

Updraft, downdraft, and cross-draft gasifiers are the most common type of gasifier configurations. Each configuration is characterized by air flow through the gasification unit. The principle geometry of each gasifier is similar (Figure 11). The gasification schematic in Figure 11 is a downdraft gasifier defined by the direction of airflow moving down through the gasifier, first passing the loaded fuel, then the combustion zone, and finally through the reduction zone (biochar). Downdraft gasification is the most common gasification configuration due to a tendency to create cleaner gas, since the gas is filtered through the biochar in the reduction zone before collection.

Updraft gasification is comparable to the Figure 11 schematic but with opposite direction of airflow. Updraft gasifiers tend to have high-energy-value gas but often with more tar contaminants (which must be removed for use in an ICE). Thus far, updraft gasification has been used predominantly in larger distributed generation applications (greater than 3 MW) to achieve economies of scale for gas cleanup.

Cross-draft gasifiers have air flow that cross the gasifier (perpendicular to the flow of wood). Cross-draft gasifiers can achieve relatively high temperatures; however, gas flow may vary throughout the gasifier, yielding inconsistent tar cracking, and like the updraft gasifier, significant cleanup may be necessary.

Fluidized bed gasifiers follow updraft or downdraft configurations but have a solid additive (e.g., engineered sand) that provides for more consistent heating across the gasification vessel. Fluidized bed gasification is typically used for large reactors to more efficiently maintain consistent heat throughout the reaction vessel. Community-scale gasification typically utilizes relatively small gasifiers where, due to their size, uniform heat distribution is not as challenging; therefore, fluidized bed gasifiers are typically found in larger-scale applications (greater than 20 MW).

In addition to these three main gasifier configurations, many hybrid variations exist. For any technology considered for the Nevada County biomass project, operational data should be reviewed and evaluated as part of the selection criteria.

Technology Manufacturers

TSS reviewed technology companies manufacturing direct combustion, two-stage combustion, and gasification technologies. TSS filtered technology providers based on unit capacity to identify a subset of technology manufacturers that specialize in community-scale biomass-to-electricity applications. While many additional companies provide components in this process (e.g., engines, gasifiers, combustors), TSS focused on companies with experience integrating all of the system components.

In addition to evaluating the technology itself, TSS recommends that the Task Force evaluate the project developer, as the best technology alone will not itself result in a successful project. Identifying the right technology for the application and the right developer is paramount. TSS has identified a select list of technology providers and project developers with experience working on community-scale wood-to-energy projects (Table 29).

Table 29. Select Technology Manufacturers and Developers

Company Information	Technology Type	Unit Sizes
Biogen www.biogendr.com	Gasification	0.5–1.5 MW
Chiptec Wood Energy Systems www.chiptec.com	Two-Stage Combustion	1.0–5.0 MW
Emery Energy Company www.emeryenergy.com	Gasification	1.0–12 MW
Hurst Boiler www.hurstboiler.com	Direct Combustion	1.0–5.0 MW
PHG Energy www.phgenergy.com	Gasification	1.0–2.0 MW
Phoenix Energy www.phoenixenergy.net	Gasification	0.5–1.5 MW
Tucker RNG www.rngnow.com	Gasification	0.5–1.5 MW
West Biofuels www.westbiofuels.com	Gasification	0.25–1.0 MW
Zero Point Clean Tech www.zeropointcleantech.com	Gasification	0.5–2.0 MW
Zilkha Energy www.zilkha.com	Two-Stage Combustion	1.5–20 MW

Operations and Maintenance Labor Requirements

All of the gasification and combustion technologies listed in Table 29 are configured to operate as 24/7 power generation facilities. Skilled labor will be required to operate and maintain these facilities around the clock. A community-scale facility is expected to require a minimum of two employees onsite during all hours of operation. A total of nine to ten trained staff members would likely be required (including administrative personnel) to operate and maintain the facility.

ECONOMIC ANALYSIS

This section will assess job creation potential, labor force wages and availability in the area, product markets, specific cost centers (including regulatory requirements), development costs, capital investment costs, operational costs, and projected revenues.

Per the findings in the Bioenergy Technology Review section, gasification technology was selected as the preferred renewable energy technology. While each gasification system provider will have different requirements (e.g., feedstock specifications, labor, site footprint), the marketplace has demonstrated gasification technology to be cost competitive between technology providers. TSS utilized publicly available data[23] to identify anticipated costs for a 3 MW bioenergy project. During the technology selection process (after completion of this feasibility study), TSS urges the Task Force to select a specific developer using an open solicitation process. The cost assumption utilized in this section should be used as a framework by which to evaluate any economic data offered as part of a proposal response submitted by a technology vendor.

Job Creation and Employment

Community-scale gasification offers direct employment opportunities at the plant while supporting forest feedstock collection, processing, and transport infrastructure. A biomass gasification facility requires a minimum of two personnel per staffed operating shift.[24] A community-scale facility is expected to run three shifts per day, every day of the year (with the exception of scheduled maintenance). The time-of-day energy rate schedule ($/kWh), as set by the power off-take entity (e.g., PG&E), will be a driving factor to determine operations schedules. To staff each shift with two employees requires 2.9 full time equivalent (FTE) employees, yielding a total of 5.8 FTE employees for a two-shift operation and 8.7 for a three-shift operation. Staffing requirements vary substantially based on technology and site location (if labor sharing is an option).

Unlike direct combustion technology using a steam turbine as the primary driver, gasification does not require any specific certifications for its employees; however, basic electrical, mechanical, and plumbing skill sets are valued. Wages ranging from $12 per hour to $20 per hour are anticipated, dependent on skill set and time with the organization.

Employment statistics for Grass Valley and Nevada County are shown in Table 30. With a relatively high unemployment rate in Grass Valley and in Nevada County, labor force availability is not expected to be a challenge. The wage rates are expected to be competitive for the area.

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[23] "Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment." Black & Veatch. October 31, 2013.

[24] Per OSHA requirements.

Table 30. Employment Statistics for Grass Valley and Nevada County

	Grass Valley	Nevada County
Labor Force Size	5,430	47,864
Percentage in Related Industries[25]	14.4%	18.5%
Unemployment Rate	12.0%	10.4%
Median Household Income	$36,612	$57,382
Mean Household Income	$52,961	$74,619

In addition to direct job creation, support jobs are projected to be generated at a 2:1 ratio compared to plant employment.[26] This project is expected to support an additional 12 to 16 FTE jobs. Jobs supported by the development of a bioenergy facility in the Grass Valley area include chip truck drivers, private land managers, chipping operations, fuels treatment programs personnel, mechanics, diesel fuel supplies, and tire shops. As noted in the Biomass Feedstock Availability and Cost Analysis section of this report, TSS estimates that approximately 6 FTE operators and one field supervisor will be required to provide feedstock to a 3 MW bioenergy facility in Grass Valley.

Product Markets

Biomass-to-electricity projects generate electricity, heat, and solid residuals. For biomass gasification technology, the solid residual is biochar, while for biomass direct combustion technology, the solid residual is ash. Both of these residuals can have economic value.

<u>Electricity</u>

The primary product for a biomass gasification system is electricity. Electricity generated is typically sold to the local electric grid, which for this project is owned by PG&E. There are two feed-in tariff programs currently offered by PG&E for small-scale (less than 3 MW) distributed generation. Both programs are called the Renewable Market Adjusting Tariff (ReMAT), with SB 32 governing all renewables and SB 1122 governing bioenergy-specific projects.

The SB 32 ReMAT has been active since October 2013, with price offerings every two months. The ReMAT program is designed to have the price adjust up or down relative to market demand. Pricing for the SB 32 ReMAT program starts at $89.23 per MWh and has three generation categories: as-available peaking, as-available non-peaking, and baseload. Table 31 shows the status of the SB 32 ReMAT offerings as of October 2014 (the program has allowed for price fluctuations for approximately one year).

[25] Related industries include (1) Agriculture, Forestry, Fishing, and Mining, (2) Construction, and (3) Manufacturing.
[26] Morris, Gregory Paul. *The value of the benefits of US biomass power*. National Renewable Energy Laboratory, 1999.

Table 31. SB 32 ReMAT Current Offering Prices

	As-Available Peaking ($/MWh)	As-Available Non-Peaking ($/MWh)	Baseload ($/MWh)
PG&E	$57.23	$89.23	$89.23
SCE	$81.23	$89.23	$89.23
SDG&E	$89.23	$89.23	$89.23

Note: SCE = Southern California Edison; SDG&E = San Diego Gas & Electric

The SB 1122 ReMAT is designed for bioenergy projects exclusively (not including landfill gas projects). As with the SB 32 ReMAT, the SB 1122 ReMAT has three program categories, but they are based on feedstock type: urban feedstock, agricultural feedstock (including orchard by-products and dairy manure), and forest residue. The final program details for the SB 1122 ReMAT program are currently being finalized by the CPUC. The most recent Administrative Law Judge decision indicated the starting price to be $127.72 per MWh. Depending on market demand, after each offering (every two months) the base price can move up or down with sufficient program participation.[27] Table 32 shows the potential for the price to fluctuate up if there are no projects that accept a price offering (column 2) and the potential for the price to fluctuate down if there are sufficient projects that accept each price offering (column 3).

Table 32. SB 1122 ReMAT Price Fluctuation Potential

	Price Increase ($/MWh)	Price Decrease ($/MWh)
Program Period 1 (Base Price)	$127.72	$127.72
Program Period 2	$131.72 (+$4)	$123.72 (-$4)
Program Period 3	$139.72 (+$8)	$115.72 (-$8)
Program Period 4	$151.72 (+$12)	$103.72 (-$12)
Program Period 5	$163.72 (+$12)	$91.72 (-$12)

At this time, TSS estimates that the SB 1122 ReMAT process will begin in the second or third quarter of 2015. The project in the Grass Valley region would fall into Category 3, utilizing forestry residues. If the SB 1122 program begins at that time, TSS believes the price will have to increase in order to accommodate projects that will participate in Category 3. There is a risk that there will not be sufficient projects to justify a price increase under the proposed rules. A number of parties in the CPUC proceedings have advocated for a change in the rules to allow the price to fluctuate with a small number of unaffiliated projects (two rather than five) in the queue.

<u>Thermal Energy</u>

For a gasification-to-ICE system, a by-product of electricity production is heat. Heat is generated by the engine and the gas conditioning system. The primary source of waste heat is the ICE. The exhaust from the ICE provides high-temperature air (approximately 700°F to 900°F) and the jacket water (used to cool the engine body) captures low-temperature heat

[27] The most recent Administrative Law Judge decision requires a minimum of three unaffiliated projects per category to trigger the first series of price changes.

(approximately 120°F to 150°F). In many systems, the gas conditioning system cools the syngas with a combination of ambient passive cooling and active radiator cooling. Availability of heat from the conditioning system will vary greatly depending on ambient conditions. For gasification systems using forest-sourced biomass, much of the excess heat is used to dry the biomass (typically 40 percent to 55 percent) to an optimized moisture content for the gasification unit (10 percent to 25 percent moisture content).

Based on the Preliminary Site Analysis results, there are no sites that currently have a use for waste heat, although several sites have potential for additional development of businesses that could utilize waste heat. Revenue from the utilization of waste heat is typically based on alternative heat sources (e.g., propane, fuel oil, natural gas). As noted earlier, some of the available waste heat will be used onsite to dry feedstock.

Solid Residual By-products

Biochar is generated as part of the gasification process in a relatively lower-temperature, low-oxygen environment. Ash is generated as part of the direct combustion process in a relatively high-temperature, high-oxygen environment. Both ash and biochar are predominantly comprised of fixed carbon. Ash tends to have a relatively high concentration of alkali metal oxides (due to the high-temperature and high-oxygen environment), limiting the potential for ground application (as soil amendment) due to relatively high pH levels. Relatively low temperatures and low oxygen environments in biomass gasification technologies minimize the impacts of alkali metal oxides; however, the gasification environment will yield products of incomplete combustion, including polycyclic hydrocarbons and aldehydes (which will reduce the quality of biochar for agricultural and filtering applications). Air and gas flow through the gasification vessel determine the characteristics of biochar.

For a community-scale biomass-to-energy project, solid residual production quantities are relatively low: approximately 8 percent to 15 percent of dry feedstock input (weight basis) for biochar or 5 to 10 percent of dry feedstock input for ash. For a 3 MW project, biochar yields are expected to be between 1,920 and 3,600 tons per year (TPY), while ash yields (using direct combustion) are expected to be between 1,200 and 2,400 TPY.

Primary markets for both biochar and ash include soil amendment, concrete additive, and filtration agent. Table 33 outlines a comprehensive list of existing market applications for biochar and ash (both bottom ash and fly ash).

Table 33. Biochar and Ash Market Applications[28]

Application	Function	Sector
Binders alternative for standard cement	Component	Building Industry and Civil Engineering
C-fix	Filler	
Concrete (products) low-quality	Reactive Filler	
Road construction material	Binder/Raw Material	
Sand-lime bricks	Filler	
Infrastructure works (e.g., embankments, fillings)	Filling Material	
Soil stabilization	Binder	
Synthetic aggregates (including synthetic basalt)	Raw Material	
Fuel	Combustion	Energy Production
Back-filling mining	Filler	Mining
Polymers	Filler	Industry
Metals	Filler	
Phosphor production	Raw Material	
Zeolites	Raw Material	
Metals recovery	Raw Material	
Mineral fibers	Raw Material	
Soil improvement and fertilizer	Product/Raw Material	Agricultural
Neutralization of waste acids	Product	Environmental technology
Adsorption material	Raw Material	
Impermeable layer	Raw Material	

Market prices for biochar are heavily dependent on the chemical characterization of the material. With a relatively immature market, prices vary by producers; however, prices currently are reported from $100 to as high as $1,600 per ton wholesale and $0.50 to $2.00 per pound retail.

Fly ash and bottom ash prices range from $30 to $40 per ton depending on the ash characteristics and the proximity of preferred markets. Some fly ash and bottom ash generated at existing biomass power plants in California are currently hauled to landfills as a primary disposal option. There is also land application of biomass power plant ash in the Central Valley.

Carbon Credits

Biomass power is considered renewable energy that has the potential to generate carbon credits based primarily on the diversion of feedstock from open pile burning. Greenhouse gas offsets associated with the displacement of fossil fuel power are incorporated into the power purchase agreement of any Renewable Portfolio Standard (RPS) contracts. SB 1122 contracts fall under the RPS umbrella; therefore, these offsets will be sold and bundled with the electricity. Average 2014 price for carbon is $11.96 per metric tonne;[29] however, purchase contracts for carbon

[28] Pels, J. *Overview of options for utilization of (biomass) ashes*. Ash Utilization Conference – Stockholm, 25–27 January 2012. Accessed: http://www.varmeforsk.se/files/program/askor/ECN_Pels_final.pdf. 1 October 2014.
[29] California Carbon Dashboard. http://calcarbondash.org/.

credits are typically less than three years of duration, making them challenging to use as part of project financing. Additionally, biomass gasification projects currently lack a pathway with the California Air Resources Board (CARB) to quantify carbon offsets. Placer County is working on a pathway for biochar, but the pathway is still under development. Carbon credits are currently not a reliable source of additional revenue for biomass gasification projects.

Financial Analysis

As part of the CPUC's assessment of small-scale bioenergy, Black & Veatch was commissioned to assess the resource potential, costs, and feed-in tariff implementation.[30] As part of the assessment, Black & Veatch developed a financial analysis tool with representative costs for gasification technologies. While pricing will range by developer, TSS (through its extensive experience assessing community-scale biomass gasification technology) supports the technical assumptions used in the Black & Veatch model (Table 34). Careful consideration should be exercised if evaluating specific developer proposals with operations data outside of these ranges.

Table 34. Technical Assumptions from Black & Veatch

Technical Components	Low Range	Medium Range	High Range
Capital Cost ($/kW)	$5,000	$6,000	$7,500
O&M Costs ($/kW)	$347	$553	$590
O&M Escalation (%)	2%	2%	2%
Capacity Factor (%)	90%	85%	80%
Heat Rate (Btu/kWh)	15,000	16,500	18,000

In addition to these technical assumptions, TSS used the financial assumptions show in Table 35.

Table 35. Financial Assumptions Specific to Nevada County Project

Financial Components	Low Range	Medium Range	High Range
Feedstock Costs ($/BDT)	$50.30	$53.10[31]	$55.90
Feedstock Cost Escalation (%)	0.5%	1%	3%
Debt Percentage (%)	80%	70%	60%
Debt Rate (%)	4%	5.5%	7%
Debt Term (year)	15	12	10
Cost of Equity	10%	15%	18%

Additionally, several factors remain constant throughout the financial analysis:

- Project Size: 3 MW
- Discount Rate: 7%
- Economic Life of the Project: 20 years

[30] "Small-Scale Bioenergy: Resource Potential, Costs, and Feed-in Tariff Implementation Assessment." Black & Veatch. October 31, 2013.
[31] Consistent with 2017 base feedstock price forecast as noted in Table 20.

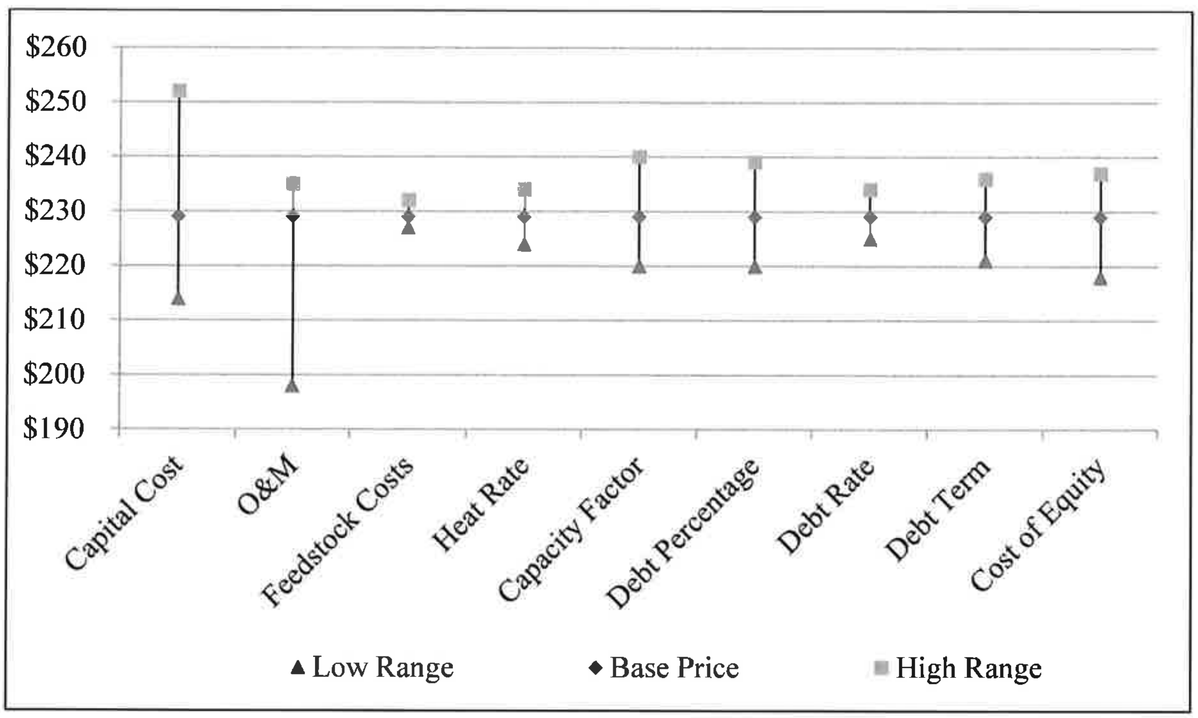
- Percent Depreciated: 100%
- Tax Rate: 40% (Federal and California tax)

Using the inputs in Table 33, Table 34, and Table 35, TSS developed a base case sensitivity analysis for the proposed project without any by-product sales or federal tax credits (e.g., Investment Tax Credit or Production Tax Credit). The base case will identify the cost of generating electricity without additional contracts for by-product sales. Table 36 and Figure 12 show the results of the preliminary sensitivity analysis.

Table 36. Base Case Sensitivity (No Incentives or By-product Sales)

Sensitivity Analysis	Low Cost ($/MWh)	Base Case ($/MWh)	High Cost ($/MWh)
Capital Cost	214	229	214
O&M Costs	198	229	198
Feedstock Costs	227	229	227
Heat Rate	224	229	224
Capacity Factor	220	229	220
Debt Percentage	220	229	239
Debt Rate	225	229	234
Debt Term	221	229	236
Cost of Equity	218	229	237

Figure 12. Base Case Sensitivity (No Incentives or By-product Sales)



As identified in Table 36, the base case price, without incentives or by-product sales, is $229 per MWh. With electricity sales alone, the economics of a biomass gasification project are challenging, particularly with relatively high feedstock costs. Figure 12 illustrates the sensitivity to system variables, particularly noting the importance of capital cost and O&M costs. These two variables offer the greatest potential to impact the overall project economics and should be a critical factor for technology selection; particularly the need for low O&M costs.

Effective project siting and technology selection can significantly adjust O&M costs. A stand-alone project must employ a minimum of two staff personnel per shift to meet Occupational Safety and Health Administration (OSHA) safety requirements. By collocating a project with an additional operation, shared labor can provide the safety necessary to meet OSHA requirements while optimizing the labor requirements to meet operational needs. Additionally, selecting a technology that does not require staffing during all operating hours can reduce labor costs by eliminating staff during one shift per day.

Capital costs can be mitigated by selecting a site that requires minimal infrastructure improvements. The locations identified as preferred sites in the siting analysis accounted for these cost considerations. The top site, the La Barr Meadows Road site collocated with Rare Earth Landscaping Materials, offers an opportunity to realize cost savings based on shared labor and with existing infrastructure and grading.

By-product Sales

Without any existing opportunities for heat sales at any of the preferred sites, biochar sale represents the most significant opportunity for additional revenue. Current market prices range from $100 to $1,600 per ton of biochar (freight-on-board truck at the bioenergy site); however, TSS estimates an average price of $325 per ton, as $1,600 per ton appears to be an outlier in reported data. As noted earlier, gasification equipment typically yields biochar at a rate between 8 percent and 15 percent of feedstock input (by weight). With approximately 24,000 BDT per year feedstock demand at the 3 MW scale, TSS estimates approximately 2,400 tons of biochar available per year. Using the base case identified in Table 36, Table 37 shows the potential impact of biochar on the levelized cost of electricity.

Table 37. Impacts of Biochar Sales on the Base Case

	Base Case	Low Price	Medium Price	High Price
Biochar Price ($/ton)	$0	$100	$325	$1,600
Impact on Base Case ($/MWh)	-	-$10	-$31	-$171
Levelized Cost of Electricity ($/MWh)	$229	$219	$194	$58

Biochar has the potential to have a serious and beneficial impact on the financial outlook of a project. With an immature market, developing a biochar offtake agreement will be critical for the financial community and for an accurate financial assessment of the project moving forward.

There is limited, but growing, demand for biochar in local landscaping markets in Grass Valley.[32]

Grants and Incentives

Forest biomass projects can be assisted by grant programs and federal tax incentive programs, particularly the Investment Tax Credit (ITC). Other federal tax credits such as the New Market Tax Credit (NMTC) are quite attractive, but the NMTC only applies to projects sited in areas of relatively high poverty. The Nevada County project is not eligible for the NMTC. On a federal level, the ITC is being renewed; however, biomass gasification may not apply, as current legislation imposes a minimum methane yield of 53 percent for qualifying biogas technologies. Gasification is not expected to be able to meet these standards (gasification technology produces a hydrogen-based gas, not a methane-based gas). If legislation is changed, TSS expects the ITC to be offered at a rate of 10 percent (previously the rate was 30 percent) of the total project cost. The ITC would decrease the base case power sales requirement from $229 per MWh to $211 per MWh.

State agencies such as the CEC, the National Forest Foundation, the Sierra Nevada Conservancy, and the U.S. Forest Service offer financial assistance in support of bioenergy project development. The CEC's EPIC program,[33] funded through utility ratepayers, offers the most significant investment in biomass-to-electricity projects, funding up to $5,000,000 in project capital costs. Each year, these state agencies revise and reassess their funding goals. They should be closely monitored for funding opportunities.

Table 38. Impacts from Grant Funding

	Base Case	Small Grant	Medium Grant	Large Grant
Grant Award ($)	$0	$1,000,000	$2,000,000	$5,000,000
Impact on Base Case ($/MWh)	-	-$5	-$10	-$25
Levelized Cost of Electricity ($/MWh)	$229	$224	$219	$204

At the 3 MW project scale, grant funding has limited potential to impact the overall project economics provided the size of existing grant opportunities. However, grant funding can significantly increase the interest of the private financial sector and allow for improved debt financing opportunities.

Sensitivity Analysis Findings

The sensitivity analysis identified capital cost, O&M costs, and biochar sales as the greatest potential impacts to the project price. In addition, the siting analysis indicates that the preferred project site has the potential to share labor and offers a site with some existing infrastructure.

32 Jim and Jami Hopper, owners of Rare Earth Landscaping Materials, Grass Valley
33 Electric Program Investment Charge website: http://www.energy.ca.gov/research/epic/

With the grant funding opportunities currently available and the significant demand for these funds, TSS anticipates that grant funding for bioenergy projects will continue for the next several years. Lastly, the preferred project site is collocated with a composting operation and proximate to a concrete batch plant, both of which offer potential for biochar sales.

Given these factors, TSS anticipates that a gasification project can be sited at the preferred location with the financial model factors as shown in Table 39.

Table 39. Financial Analysis for Nevada County Project

	Base Case	**Nevada County Project**
Capital Cost ($/kW)	$6,000	$5,500
O&M Costs ($/kW)	$553	$450
O&M Escalation (%)	2%	2%
Capacity Factor (%)	85%	85%
Heat Rate (Btu/kWh)	16,500	16,500
Feedstock Cost ($/BDT)	$53.10	$53.10
Feedstock Cost Escalation (%)	1%	1%
Debt Percentage (%)	70%	70%
Debt Rate (%)	5.5%	5%
Debt Term (years)	12	12
Investment Tax Credit (%)	0%	0%
Biochar Sales ($/ton)	0	$325
Cost of Equity (%)	15%	15%
Levelized Cost of Electricity ($/MWh)	**$229**	**$170**
Grant Funding ($)	0	$2,000,000
Levelized Cost of Electricity ($/MWh)	**$229**	**$160**
With Investment Tax Credit (%)	10%	10%
Levelized Cost of Electricity ($/MWh)	**$211**	**$145**

With SB 1122 proposed pricing mechanisms, a project requiring $145 to $160 per MWh would require four or five consecutive price increases to reach the desired price depending on grant funding or the availability of the ITC. Provided there are sufficient projects in the queue to trigger price movement, TSS anticipates that the price could rise to the required price offering of $160 per MWh. Using the assumptions in Table 39, Table 40 shows a detailed financial pro forma for the project if a $160 per MWh power purchase agreement were executed.

Table 40. Financial Pro Forma for Nevada County Project

Year	0	1	2	3	4	5	6	7	8	9	10
Annual Generation (MWh)		22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338
Cost of Generation ($/MWh)		$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02
Operating Revenues		**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**
Fixed O&M ($/yr)		$1,350,000	$1,377,000	$1,404,540	$1,432,631	$1,461,283	$1,490,509	$1,520,319	$1,550,726	$1,581,740	$1,613,375
Var. O&M ($/yr)		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost ($/yr)		$1,148,732	$1,160,219	$1,171,821	$1,183,539	$1,195,375	$1,207,329	$1,219,402	$1,231,596	$1,243,912	$1,256,351
Incentives ($/yr)		$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000
Operating Expenses		**$1,718,732**	**$1,757,219**	**$1,796,361**	**$1,836,170**	**$1,876,658**	**$1,917,838**	**$1,959,721**	**$2,002,321**	**$2,045,652**	**$2,089,726**
Interest Payment		$507,500	$475,616	$442,138	$406,986	$370,076	$331,321	$290,629	$247,901	$203,037	$155,930
Principal Payment		$637,678	$669,562	$703,040	$738,192	$775,101	$813,857	$854,549	$897,277	$942,141	$989,248
Debt Service		**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**	**$1,145,178**
Tax Depreciation		$2,072,050	$3,551,050	$2,536,050	$1,811,050	$1,294,850	$1,293,400	$1,294,850	$646,700	$0	$0
Taxable Income		($723,755)	($2,209,358)	($1,200,022)	($479,679)	$32,942	$31,968	$29,327	$677,604	$1,325,838	$1,328,871
PTC		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC		$0									
Taxes		**($289,502)**	**($883,743)**	**($480,009)**	**($191,872)**	**$13,177**	**$12,787**	**$11,731**	**$271,042**	**$530,335**	**$531,548**
Total	*(4,350,000)*	***1,000,119***	***1,555,873***	***1,112,997***	***785,051***	***539,514***	***498,724***	***457,897***	***155,986***	*(146,638)*	*(191,925)*

Table 40 is continued on the next page.

Year	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Annual Generation (MWh)	22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338	22,338
Cost of Generation ($/MWh)	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02	$160.02
Operating Revenues	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**	**$3,574,527**
Fixed O&M ($/yr)	$1,645,642	$1,678,555	$1,712,126	$1,746,369	$1,781,296	$1,816,922	$1,853,261	$1,890,326	$1,928,132	$1,966,695
Var. O&M ($/yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel Cost ($/yr)	$1,268,914	$1,281,604	$1,294,420	$1,307,364	$1,320,437	$1,333,642	$1,346,978	$1,360,448	$1,374,052	$1,387,793
Incentives ($/yr)	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000	$780,000
Operating Expenses	**$2,134,557**	**$2,180,159**	**$2,226,546**	**$2,273,733**	**$2,321,734**	**$2,370,564**	**$2,420,239**	**$2,470,774**	**$2,522,185**	**$2,574,488**
Interest Payment	$106,468	$54,532	$0	$0	$0	$0	$0	$0	$0	$0
Principal Payment	$1,038,710	$1,090,646	$0	$0	$0	$0	$0	$0	$0	$0
Debt Service	**$1,145,178**	**$1,145,178**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Tax Depreciation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Taxable Income	$1,333,502	$1,339,836	$1,347,981	$1,300,794	$1,252,793	$1,203,963	$1,154,288	$1,103,753	$1,052,342	$1,000,039
PTC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ITC										
Taxes	**$533,401**	**$535,934**	**$539,192**	**$520,318**	**$501,117**	**$481,585**	**$461,715**	**$441,501**	**$420,937**	**$400,016**
Total	***(238,609)***	***(286,744)***	***808,789***	***780,477***	***751,676***	***722,378***	***692,573***	***662,252***	***631,405***	***600,023***

Findings

A biomass gasification project in western Nevada County is feasible with the correct combination of factors. Several sites offer land with relatively low development costs due to ease of road access, grading, and access to utilities. Additionally, the local landscaping yard (Rare Earth Landscaping) and cement plant (Hansen Brothers) offer the potential for local biochar offtake agreements. As identified in the Biomass Feedstock Availability and Cost Analysis, Highway 49 is one of the major access routes for feedstock transportation.

Despite these site advantages, biomass gasification in the forested setting presents a challenging financial model due primarily to the relatively high cost of feedstock (compared to agricultural or urban-sourced wood) and relatively low prices of electricity (compared to pricing outside the United States). As shown in Table 40, the project will work at $160 per MWh if each of the project components in this pro forma are met. Key aspects of project development include the following:

- ***Permitting***: When the site location has been finalized, obtaining a CUP for the gasification project is likely required. Obtaining the CUP will represent the completion of the CEQA review for the project. CEQA is a critical component of project development and should be a top priority to move the project forward.

- ***Technology Selection***: Selecting a project development partner is a critical next step in project development. The development partner should have experience with the construction and operation of biomass gasification facilities and have experience obtaining project financing through private equity markets, debt financing, and grants. The developer will assist with selecting an appropriate technology for the site and will work in close coordination with the project team to develop the site.

- ***Feedstock Procurement***: The financial markets require feedstock offtake agreements verifying the price and time frame for secured feedstock. Identifying a reputable organization to supply a long-term feedstock agreement for at least 70 percent of the necessary feedstock is critical.

- ***Biochar Offtake Agreements***: Biochar represents an important revenue stream for the project. Identifying long-term biochar purchasers and purchase price will be critical for leveraging funding from the financial markets.

- ***SB 1122 Eligibility***: SB 1122 will be the feed-in tariff that provides the primary revenue stream for the project. The system impact study (SIS) conducted by PG&E is the most significant undertaking to reach SB 1122 eligibility. After a technology has been selected with the project developer, conducting the SIS is a time-sensitive step that should be undertaken quickly to establish an early position in the SB 1122 queue.

RECOMMENDATIONS AND NEXT STEPS

The Task Force has made significant efforts to identify value-added opportunities to promote local economic development, improve public safety, utilize sustainable, regionally available resources, and improve air quality. The development of a biomass gasification facility is complex. This Feasibility Study evaluates the potential feedstock availability, reviews technology opportunities, identifies potential project sites, and evaluates the high-level risks and opportunities for community-scale gasification development. Financial viability is critical for project success, and the Task Force can make significant progress to move the project forward with pre-development work. TSS recommends the following next steps.

- Select a Target Site: While the Preliminary Site Analysis identified preferred sites, the interest of the site owners and managers is paramount. TSS suggests that the Task Force continue their outreach to owners of preferred sites to identify the most interested parties and select a target site based on site characteristics (as identified in the Preliminary Site Analysis) and ownership interest.

- Identify a Technology Developer: With a selected site, the Task Force should update the project description to reflect the attributes of the target site with particular attention to the opportunities for additional revenue (e.g., biochar and heat sales). Given the structure of the Task Force, TSS recommends that the Task Force focus on developer experience instead of technology type. A developer with a proven track record of successful projects will be able to work with the Task Force to drive the project forward in a more substantive manner than a technology vendor. The developer should have expertise in evaluating technologies that surpass those of the Task Force. The development process is likely to take time, and building a relationship with the project developer will be critical to project success and local acceptance.

- Land Use Permitting: The CEQA review process is an important part of project development. The development of a biomass gasification system is significant and will require CEQA review for a CUP (all sites reviewed in the Preliminary Site Analysis are in land use zones that may allow biomass power development with a CUP). TSS recommends that before applying for a CUP, the Task Force (with help from the selected developer and outside consultants, if necessary) develop detailed background documents to help inform the agency reviewers about the technical aspects of the project. This should help reduce the cost and time of the CEQA review and improve the chances of receiving a mitigated negative declaration or negative declaration and avoiding the time-intensive processes of a full environmental impact report.

- Public Outreach: Throughout the process, the Task Force should continue regular and transparent public outreach to keep local stakeholders informed about the project. This upfront effort builds local project support that can be critical for project success during pre-development, development, and operational stages.

- Identify Synergies with Local Enterprises: Successful project development relies on cooperation with local enterprises. Financing a biomass gasification project requires long-term feedstock supplies, by-product sales, and a local workforce. Identifying how the biomass gasification project can interact with the community increases local support and improves the project's economic viability.

- Grant Funding: Pre-development work takes time and costs money. Without significant investment partnerships, the Task Force must rely on state funding programs to provide bridge funding (before project financing is complete). Sources of pre-development and development funding that the Task Force should consider are outlined below.

    - *USFS Wood Innovation Program*: The USFS has released the Wood Innovation program, with proposals due January 23, 2015, for the upcoming grant cycle. The Wood Innovation program focuses on reducing hazardous fuels and improving forest health on national forest systems and other forest lands, reducing costs of forest management, and promoting the economic and environmental health of communities. The Wood Innovation program offers the opportunity to receive funding for "engineering designs, cost analyses, permitting, and other requirements for wood energy projects that are necessary in the later stages of project development to secure financing." Due to the short time frame, identifying project partners will be essential to accessing this funding source. Historically, the USFS has supported wood energy projects and is expected to continue funding project development costs over the near term. Past programs include the Woody Biomass Utilization Grant and the Wood to Energy program.

    - *Sierra Nevada Conservancy Grant Programs*: The Sierra Nevada Conservancy historically has funds available for pre-development advancement of forest biomass utilization programs. In 2014, the Conservancy's Proposition 84 grant program was completed. The Task Force should monitor the Conservancy as their next grant program is developed, likely in response to Proposition 1 funding. Proposition 1, the Water Bond, is focused on protecting and restoring California rivers, lakes, streams, and watersheds. Community-scale biomass gasification projects promote healthy and sustainable forest management which has many links into improved watershed health. The new grant program is expected to have opportunities for biomass gasification projects utilizing forest residue.

    - *CEC's EPIC Program*: The EPIC program, administered by the CEC, is funded through utility ratepayers. For each funding cycle, the specific EPIC program goals are revised and historically, there has been funding for research and development as well as demonstration of pre-commercial technologies. The EPIC program is designed for biomass gasification projects in the forested setting, as there are currently no commercial-scale projects and innovative solutions are required to address challenges related to the utilization of forest biomass. Participation in the EPIC program should be in partnership with the selected project developer and after CEQA review has been completed. The next EPIC funding cycle is expected to be released July 2015.

- *National Forest Foundation*: The National Forest Foundation has a variety of assistance programs designed to conservation work in America's national forests. In particular, the Forest Stewardship Fund is designed to support on-the-ground conservation work through a partnership with local businesses on or near national forests.

At this stage, TSS recommends that the Task Force focus on developing the framework and relationships necessary to achieve project financing. This feasibility study has identified that there is sufficient sustainably available biomass for a 3 MW facility, there are commercially available technologies that can utilize the local feedstock, and there are market mechanisms that could provide long-term contracts at an attractive rate. The next steps, as outlined above, if successfully achieved, will move the project closer to realization.

Appendix A. Site Scoring Criteria with Weight Factors

The siting criteria are listed and identified in two groups: critical and secondary. Critical criteria may likely cause the project to be infeasible due primarily to the potential high development costs and timeliness. In addition to the critical criteria, secondary constraints are used to compare sites. A zero score for any of the critical criteria will deem the project to be infeasible. Otherwise, no minimum threshold has been identified to filter for project viability.

Critical Criteria

1. Land Use Zoning (15%)
    - 3 Points: Industrial Zones or parcels already zoned for power production (existing Conditional Use Permit)
    - 2 Points: Zones with some flexibility but with limited industrial accepted uses (e.g., Public Purpose, Special Purpose, General Agriculture, Forest Resource/Timber Production Zone)
    - 1 Point: Zones already permitted for some machinery (e.g., Commercial)
    - 0 Points: Zones that explicitly exclude industrial uses or with specific intended uses (e.g., Residential, Hospital)

2. Space (10%)
    - 3 Points: Has over 3 acres of available space
    - 2 Points: Has 2 to 3 acres of available space
    - 1 Point: Has 1 to 2 acres of available space
    - 0 Points: Has less than 1 acre of available space

3. Proximity to Sensitive Receptors[34] (Noise, Air Quality, Public Health and Safety, Traffic, and Community and Regulatory Acceptance) (25%)
    - 3 Points: No receptors
    - 2 Points: No sensitive receptors, but have neighboring facilities
    - 1 Point: Sensitive receptors
    - 0 Points: Extra-sensitive receptors (e.g., schools, hospitals, etc.)

[34] Sensitive receptors are evaluated based on the potential opposition to a bioenergy project due to noise, air quality, and public health and safety concerns.

Secondary Criteria

1. Grid Infrastructure (10%)
    - 3 Points: Circuits with a net peak load greater than 20 MW (Peak Load – Existing Generation)
    - 2 Points: Circuits with a net peak load greater than 6 MW and less than 20 MW
    - 1 Point: Circuits with a net peak load less than 6 MW
    - 0 Points: No electric lines to site

2. Heat and Cooling Load Potential (5%)
    - 3 Points: Has a thermal load greater than 15 MMBtu/hr of installed capacity utilized on greater than 50% of the day (on average)
    - 2 Points: Has a thermal load greater than 15 MMBtu/hr of installed capacity utilized less than 50% of the day (on average)
    - 1 Point: Has a thermal load less than 15 MMBtu/hr of existing installed capacity
    - 0 Points: Has no potential thermal load

3. Road Infrastructure (Transportation and Traffic) (10%)
    - 3 Points: Existing tractor trailer access to the site
    - 2 Points: Former tractor trailer access to the site
    - 1 Point: Limited access via roads with existing tractor trailer use
    - 0 Points: No access via roads with existing tractor trailer use

4. Site Infrastructure & Environmental Clean Up Status (Economic Suitability) (10%)
    - 3 Points: Existing road access, fire hydrants, grading, and no relevant active clean up on the site
    - 2 Points: Missing 1 – Existing road access, fire hydrants, grading, and no relevant active clean up on the site
    - 1 Point: Missing 2 – Existing road access, fire hydrants, grading, and no relevant active clean up on the site
    - 0 Points: Missing 3 or more – Existing road access, fire hydrants, grading, and no relevant active clean up on the site

5. Water Supply and Discharge (5%)
    - 3 Points: Fire supply water and wastewater discharge system existing on site
    - 2 Points: Fire supply water already on site, no existing access to wastewater discharge system
    - 1 Point: Access for domestic water but no fire supply water or access to wastewater discharge system
    - 0 Points: No access to water

6. Biological Resources (5%)
   - 3 Points: Highly disturbed site with no known sensitive biological activity (e.g. wetlands, migration routes)
   - 2 Points: Disturbed site with known areas of sensitive biological activity
   - 1 Point: Regenerated or undisturbed site without known areas of sensitive biological activity
   - 0 Points: Regenerated or undisturbed site with known areas of sensitive biological activity

7. Cultural Resources (5%)
   - 3 Points: Developed parcel with no known cultural resources
   - 2 Points: Developed parcel with known cultural resources
   - 1 Point: Undeveloped site with no known cultural resources
   - 0 Points: Undeveloped site with known cultural resources

Appendix B. Site Ranking Matrix

Site Name	Weighting Factor	Airport	Auburn Rd. Site	Cement Hill	Centennial	East Bennett Rd. North Site
Site Location		39°13'12.53"N 121°00'18.02"W	39°09'13.61"N 121°04'51.37"W	39°16'04.27"N 121°01'44.53"W	39°13'18.3"N 121°02'03.4"W	39°13'05.61"N 121°02'21.00"W
Jurisdiction/Zoning Designation		Nevada County Light Industrial	Nevada County AG	Nevada City R1-SC-AN	Grass Valley M1	Nevada County Business Park
Site Information		Industrial Park	Rural area, woodlands	Wood storage lot and open space	Old Mine Ownership	Commercial site (older)
Land Use Zoning	15%	3	2	0	3	1
Space	10%	2	3		3	3
Proximity to Sensitive Receptors	25%	2	1		2	2
Interconnection Requirements	10%	1	1		1	2
Heating/Cooling Load	5%	0	0		0	0
Road Infrastructure	10%	3	0		3	3
Site Infrastructure & Environmental Cleanup Status	10%	2	2		2	2
Water Supply & Discharge	5%	2	1		1	1
Biological Resources	5%	3	1		3	3
Cultural Resource	5%	3	1		3	3
Total Score (of 3)		2.15	1.30	0.00	2.20	2.00
Total Score (of 100)		71.7%	43.3%	0.0%	73.3%	66.7%

Site Name	Weighting Factor	East Bennett Rd. South Site	Fairgrounds	Former Meeks Lumber	Former SPI Site	Grass Valley Hay and Feed
Site Location		39°12'58.59"N 121°02'32.07"W	39°12'27.76"N 121°04'57.73"W	39°14'33.05"N 121°02'07.90"W	39°12'28.73"N 121°00'52.66"W	39°13'25.49"N 121°02'20.18"W
Jurisdiction/Zoning Designation		Nevada County Light Industrial	Nevada County Public	Grass Valley C-2	Nevada County Light Industrial	Grass Valley M-1
Site Information		Vacant lot	Empty area of County Fairgrounds	Vacant retail lumber sales facility Former sawmill	Vacant - former sawmill site	Various current uses
Land Use Zoning	15%	3	2	0	3	3
Space	10%	3	2		3	2
Proximity to Sensitive Receptors	25%	2	1		1	2
Interconnection Requirements	10%	2	2		1	1
Heating/Cooling Load	5%	0	1		0	0
Road Infrastructure	10%	3	1		3	2
Site Infrastructure & Environmental Cleanup Status	10%	2	1		3	2
Water Supply & Discharge	5%	1	1		2	1
Biological Resources	5%	0	2		3	3
Cultural Resource	5%	1	3		3	3
Total Score (of 3)		2.05	1.50	0.00	2.10	2.00
Total Score (of 100)		68.3%	50.0%	0.0%	70.0%	66.7%

Site Name	Weighting Factor	Hansen Brothers	La Barr Meadows Rd. - Nevada County	La Barr Meadows Rd. - Rare Earth	McCourtney Transfer Station	Penn Valley Site
Site Location		39°11'32.15"N 121°03'04.09"W	39°11'04.31"N 121°02'52.22"W	39°10'19.34"N 121°06'34.87"W	39°10'19.34"N 121°06'34.87"W	39°12'15.61"N 121°10'35.89"W
Jurisdiction/Zoning Designation		Nevada County Light Industrial	Nevada County Public	Nevada County M2	Nevada County Public	Nevada County Light Industrial
Site Information		Unused space	County storage area	Former Sawmill Site	Solid waste transfer station	Vacant land
Land Use Zoning	15%	3	2	3	2	3
Space	10%	3	3	3	3	3
Proximity to Sensitive Receptors	25%	2	2	2	1	2
Interconnection Requirements	10%	2	2	2	1	2
Heating/Cooling Load	5%	0	0	0	0	0
Road Infrastructure	10%	3	3	3	3	3
Site Infrastructure & Environmental Cleanup Status	10%	2	2	2	3	2
Water Supply & Discharge	5%	1	1	1	2	2
Biological Resources	5%	1	3	3	3	1
Cultural Resource	5%	1	3	3	3	1
Total Score (of 3)		2.10	2.15	2.30	1.95	2.15
Total Score (of 100)		70.0%	71.7%	76.7%	65.0%	71.7%

Site Name	Weighting Factor	Pleasant Valley Site	Railroad Ave M-2 Site	Railroad Ave M-1 Site	South Auburn Street
Site Location		39°12'28.64"N 121°12'11.41"W	39°13'11.85"N 121°03'12.60"W	39°13'17.51"N 121°03'00.94"W	39°12'17.78"N 121°03'36.92"W
Jurisdiction/Zoning Designation		Nevada County Light Industrial	Grass Valley M-2	Grass Valley M-1	Grass Valley M-1
Site Information		Vacant land	Batch Plant	Storage and vacant land	Scattered business and vacant land
Land Use Zoning	15%	3	3	3	3
Space	10%	3	1	1	3
Proximity to Sensitive Receptors	25%	1	1	1	1
Interconnection Requirements	10%	2	2	2	1
Heating/Cooling Load	5%	0	0	0	0
Road Infrastructure	10%	2	3	3	2
Site Infrastructure & Environmental Cleanup Status	10%	2	2	1	1
Water Supply & Discharge	5%	2	2	2	1
Biological Resources	5%	1	3	3	1
Cultural Resource	5%	1	3	3	1
Total Score (of 3)		1.80	1.90	1.80	1.55
Total Score (of 100)		60.0%	63.3%	60.0%	51.7%

Appendix C. Senate Bill 1122 Text

Senate Bill No. 1122

CHAPTER 612

An act to amend Section 399.20 of the Public Utilities Code, relating to energy.

[Approved by Governor September 27, 2012. Filed with Secretary of State September 27, 2012.]

LEGISLATIVE COUNSEL'S DIGEST

SB 1122, Rubio. Energy: renewable bioenergy projects.

Under existing law, the Public Utilities Commission has regulatory authority over public utilities. Existing law requires every electrical corporation to file with the commission a standard tariff for electricity generated by an electric generation facility, as defined, that qualifies for the tariff, is owned and operated by a retail customer of the electrical corporation, and is located within the service territory of, and developed to sell electricity to, the electrical corporation. Existing law requires an electrical corporation to make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, as specified, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts, as specified.

This bill would require the commission, by June 1, 2013, to direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The bill would require the commission, for each electrical corporation, to allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. The bill would require the commission to allocate those 250 megawatts to electrical corporations from specified categories of bioenergy project types, with specified portions of that 250 megawatts to be allocated from each category. The bill would require the commission to encourage gas and electrical corporations to develop and offer programs and services to facilitate development of in-state biogas for a broad range of purposes. The bill would authorize the commission, in consultation with specified state agencies, if it finds that the allocations of those 250 megawatts are not appropriate, to reallocate those 250 megawatts among those categories.

The people of the State of California do enact as follows:

SECTION 1. Section 399.20 of the Public Utilities Code is amended to read:

399.20. (a) It is the policy of this state and the intent of the Legislature to encourage electrical generation from eligible renewable energy resources.

(b) As used in this section, "electric generation facility" means an electric generation facility located within the service territory of, and developed to sell electricity to, an electrical corporation that meets all of the following criteria:

(1) Has an effective capacity of not more than three megawatts.

(2) Is interconnected and operates in parallel with the electrical transmission and distribution grid.

(3) Is strategically located and interconnected to the electrical transmission and distribution grid in a manner that optimizes the deliverability of electricity generated at the facility to load centers.

(4) Is an eligible renewable energy resource.

(c) Every electrical corporation shall file with the commission a standard tariff for electricity purchased from an electric generation facility. The commission may modify or adjust the requirements of this section for any electrical corporation with less than 100,000 service connections, as individual circumstances merit.

(d) (1) The tariff shall provide for payment for every kilowatthour of electricity purchased from an electric generation facility for a period of 10, 15, or 20 years, as authorized by the commission. The payment shall be the market price determined by the commission pursuant to paragraph (2) and shall include all current and anticipated environmental compliance costs, including, but not limited to, mitigation of emissions of greenhouse gases and air pollution offsets associated with the operation of new generating facilities in the local air pollution control or air quality management district where the electric generation facility is located.

(2) The commission shall establish a methodology to determine the market price of electricity for terms corresponding to the length of contracts with an electric generation facility, in consideration of the following:

(A) The long-term market price of electricity for fixed price contracts, determined pursuant to an electrical corporation's general procurement activities as authorized by the commission.

(B) The long-term ownership, operating, and fixed-price fuel costs associated with fixed-price electricity from new generating facilities.

(C) The value of different electricity products including baseload, peaking, and as-available electricity.

(3) The commission may adjust the payment rate to reflect the value of every kilowatthour of electricity generated on a time-of-delivery basis.

(4) The commission shall ensure, with respect to rates and charges, that ratepayers that do not receive service pursuant to the tariff are indifferent to whether a ratepayer with an electric generation facility receives service pursuant to the tariff.

(e) An electrical corporation shall provide expedited interconnection procedures to an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit, if the electrical corporation determines that the electric generation facility will not adversely affect the distribution grid. The commission shall consider and may establish a value for an electric generation facility located on a distribution circuit that generates electricity at a time and in a manner so as to offset the peak demand on the distribution circuit.

(f) (1) An electrical corporation shall make the tariff available to the owner or operator of an electric generation facility within the service territory of the electrical corporation, upon request, on a first-come-first-served basis, until the electrical corporation meets its proportionate share of a statewide cap of 750 megawatts cumulative rated generation capacity served under this section and Section 387.6. The proportionate share shall be calculated based on the ratio of the electrical corporation's peak demand compared to the total statewide peak demand.

(2) By June 1, 2013, the commission shall, in addition to the 750 megawatts identified in paragraph (1), direct the electrical corporations to collectively procure at least 250 megawatts of cumulative rated generating capacity from developers of bioenergy projects that commence operation on or after June 1, 2013. The commission shall, for each electrical corporation, allocate shares of the additional 250 megawatts based on the ratio of each electrical corporation's peak demand compared to the total statewide peak demand. In implementing this paragraph, the commission shall do all of the following:

(A) Allocate the 250 megawatts identified in this paragraph among the electrical corporations based on the following categories:

(i) For biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, 110 megawatts.

(ii) For dairy and other agricultural bioenergy, 90 megawatts.

(iii) For bioenergy using byproducts of sustainable forest management, 50 megawatts. Allocations under this category shall be determined based on the proportion of bioenergy that sustainable forest management providers derive from sustainable forest management in fire threat treatment areas, as designated by the Department of Forestry and Fire Protection.

(B) Direct the electrical corporations to develop standard contract terms and conditions that reflect the operational characteristics of the projects, and to provide a streamlined contracting process.

(C) Coordinate, to the maximum extent feasible, any incentive or subsidy programs for bioenergy with the agencies listed in subparagraph (A) of paragraph (3) in order to provide maximum benefits to ratepayers and to ensure that incentives are used to reduce contract prices.

(D) The commission shall encourage gas and electrical corporations to develop and offer programs and services to facilitate development of in-state biogas for a broad range of purposes.

(3) (A) The commission, in consultation with the State Energy Resources Conservation and Development Commission, the State Air Resources Board, the Department of Forestry and Fire Protection, the Department of Food and Agriculture, and the Department of Resources Recycling and Recovery,

may review the allocations of the 250 additional megawatts identified in paragraph (2) to determine if those allocations are appropriate.

(B) If the commission finds that the allocations of the 250 additional megawatts identified in paragraph (2) are not appropriate, the commission may reallocate the 250 megawatts among the categories established in subparagraph (A) of paragraph (2).

(4) For the purposes of this subdivision, "bioenergy" means biogas and biomass.

(g) The electrical corporation may make the terms of the tariff available to owners and operators of an electric generation facility in the form of a standard contract subject to commission approval.

(h) Every kilowatthour of electricity purchased from an electric generation facility shall count toward meeting the electrical corporation's renewables portfolio standard annual procurement targets for purposes of paragraph (1) of subdivision (b) of Section 399.15.

(i) The physical generating capacity of an electric generation facility shall count toward the electrical corporation's resource adequacy requirement for purposes of Section 380.

(j) (1) The commission shall establish performance standards for any electric generation facility that has a capacity greater than one megawatt to ensure that those facilities are constructed, operated, and maintained to generate the expected annual net production of electricity and do not impact system reliability.

(2) The commission may reduce the three megawatt capacity limitation of paragraph (1) of subdivision (b) if the commission finds that a reduced capacity limitation is necessary to maintain system reliability within that electrical corporation's service territory.

(k) (1) Any owner or operator of an electric generation facility that received ratepayer-funded incentives in accordance with Section 379.6 of this code, or with Section 25782 of the Public Resources Code, and participated in a net metering program pursuant to Sections 2827, 2827.9, and 2827.10 of this code prior to January 1, 2010, shall be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section.

(2) In establishing the tariffs or standard contracts pursuant to this section, the commission shall consider ratepayer-funded incentive payments previously received by the generation facility pursuant to Section 379.6 of this code or Section 25782 of the Public Resources Code. The commission shall require reimbursement of any funds received from these incentive programs to an electric generation facility, in order for that facility to be eligible for a tariff or standard contract filed by an electrical corporation pursuant to this section, unless the commission determines ratepayers have received sufficient value from the incentives provided to the facility based on how long the project has been in operation and the amount of renewable electricity previously generated by the facility.

(3) A customer that receives service under a tariff or contract approved by the commission pursuant to this section is not eligible to participate in any net metering program.

(*l*) An owner or operator of an electric generation facility electing to receive service under a tariff or contract approved by the commission shall continue to receive service under the tariff or contract until either of the following occurs:

(1) The owner or operator of an electric generation facility no longer meets the eligibility requirements for receiving service pursuant to the tariff or contract.

(2) The period of service established by the commission pursuant to subdivision (d) is completed.

(m) Within 10 days of receipt of a request for a tariff pursuant to this section from an owner or operator of an electric generation facility, the electrical corporation that receives the request shall post a copy of the request on its Internet Web site. The information posted on the Internet Web site shall include the name of the city in which the facility is located, but information that is proprietary and confidential, including, but not limited to, address information beyond the name of the city in which the facility is located, shall be redacted.

(n) An electrical corporation may deny a tariff request pursuant to this section if the electrical corporation makes any of the following findings:

(1) The electric generation facility does not meet the requirements of this section.

(2) The transmission or distribution grid that would serve as the point of interconnection is inadequate.

(3) The electric generation facility does not meet all applicable state and local laws and building standards and utility interconnection requirements.

(4) The aggregate of all electric generating facilities on a distribution circuit would adversely impact utility operation and load restoration efforts of the distribution system.

(o) Upon receiving a notice of denial from an electrical corporation, the owner or operator of the electric generation facility denied a tariff pursuant to this section shall have the right to appeal that decision to the commission.

(p) In order to ensure the safety and reliability of electric generation facilities, the owner of an electric generation facility receiving a tariff pursuant to this section shall provide an inspection and maintenance report to the electrical corporation at least once every other year. The inspection and maintenance report shall be prepared at the owner's or operator's expense by a California-licensed contractor who is not the owner or operator of the electric generation facility. A California-licensed electrician shall perform the inspection of the electrical portion of the generation facility.

(q) The contract between the electric generation facility receiving the tariff and the electrical corporation shall contain provisions that ensure that construction of the electric generating facility complies with all applicable state and local laws and building standards, and utility interconnection requirements.

(r) (1) All construction and installation of facilities of the electrical corporation, including at the point of the output meter or at the transmission or distribution grid, shall be performed only by that electrical corporation.

(2) All interconnection facilities installed on the electrical corporation's side of the transfer point for electricity between the electrical corporation and the electrical conductors of the electric generation facility shall be owned, operated, and maintained only by the electrical corporation. The ownership, installation, operation, reading, and testing of revenue metering equipment for electric generating facilities shall only be performed by the electrical corporation.

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Appendix D. CAL FIRE Draft Guidelines for Sustainable Forest Biomass

Forest Derived Biomass Supply Eligibility under SECTION 1. Section 399.20 of the Public Utilities Code

Background

At the request of the Energy Division staff at the California Public Utilities Commission (CPUC), the Department of Forestry and Fire Protection (CAL FIRE), with the assistance and facilitation of Sierra Nevada Conservancy and a variety of other stakeholders, this whitepaper was prepared to assist in determining fuel sourcing bioenergy production eligibility criteria for "byproducts of sustainable forest management" consistent with the term as used in Public Utilities Code Section 399.20 (f)(2)(A)(iii). The intent of this whitepaper is to: 1) propose a definition of "sustainable forest management" and 2) provide recommendations for a process for certification, verification, and monitoring to be utilized by sellers and purchasers of eligible by-products to verify that biomass feedstocks utilized by a particular facility are supplied in a manner consistent with the statutory provision for sustainable forest management Section 399.20.

Since submission of the whitepaper in late 2013, staff from CAL FIRE and Board of Forestry and Fire Protection (BOF) identified the need for some changes in the original document. Changes have been made to ensure that the objectives of SB 1122 are achieved, while recognizing the current adequacy of regulations governing commercial timber operations under the Z'berg-Nejedly Forest Practice Act and BOF forest practice regulations.

Issue 1-Recommendations for Defining of "Byproducts of Sustainable Forest Management"

SB 1122 directs 50Mw of bioenergy using byproducts of sustainable forest management allocated based on the proportion of bioenergy derived from Fire Threat Treatment Areas as designated by the Department of Forestry and Fire Protection. The current Fire Threat Treatment Area designation by the Department was completed in 2005 and reflects an index of expected fire frequency and fire behavior based upon fuel ranking and anticipated fire frequency (Sethi, et.al, 2005). Estimates of bioenergy which are to be used for allocation purposes from Fire Threat Treatment Areas were made based on datasets which reflected inventories and vegetation structure on forested lands and shrublands.

The categories of potential bioenergy sourcing were adapted from the Public Interest Energy Resources publication titled "An assessment of biomass resources in California" published in 2004. Categories included in the assessment for development of biomass and bioenergy estimates included 1) logging slash, 2) forest thinning, 3) mill wastes, and 4) shrub. These categorizations are sufficient to support an allocation of the 50Mw to the investor owned utilities (IOUs).

However, given the assumptions utilized to develop the overall estimates and the scale at which the bioenergy estimates were developed, the Department concurs with the Black and Veatch draft consultant report (April, 2013) that the resource potential and data assumptions for forest materials that would be considered sustainable at the project level needs to be refined for the purposes of determining whether a particular project which supplies by-products, meets the sustainable forest management criteria.

The process for determining sustainable forest management byproduct eligibility under the provisions of SB 1122 relies on the definition of sustainable forestry in part 2 of the Society of American Foresters definition (Appendix A) as well as the federal level defined in FS-979 (Appendix B) and a series of public workshops which were held to refine these broad definitions for the purposes of determining byproduct eligibility under SB 1122. To meet eligibility requirements all biomass feedstocks that are used within this program must be derived from projects that are conducted in conformance with local, state, and federal policy, statutes and regulation, including CEQA and the National Environmental Policy Act (NEPA). This whitepaper, however, does not support requiring CEQA or NEPA review on projects that would not have otherwise been required to be reviewed under those laws.

The workshop process was planned and facilitated to assist in refining and integrating the key elements of the two definitions of forest sustainability applicable to the determination of feedstock eligibility for purposes of compliance with PUC Section 399.20. This five month process included stakeholders from the environmental, community, governmental and private industry sectors. Numerous background materials were prepared and circulated, three workshops were held to facilitate input and build consensus and multiple drafts of this white paper were circulated for comment. This paper reflects a balance of viewpoints and attempts to ensure that the majority of biomass feedstock is derived from sustainable forest management practices while providing the biomass energy operators enough flexibility to be able to use diverse sources to ensure year-round reliability.

Environmental stakeholders expressed concerns focused on the potential for markets for biomass materials to lead to utilization of components of existing vegetation types which have not been traditionally utilized at a pace and scale that would not be sustainable over time. This concern also mirrors concerns raised in literature review including a comprehensive literature review done by Stewart et. al. (July, 2011).

Paraphrasing Stewart, et. al. the structural stand components most likely to be harvested or manipulated during woody biomass operations include:

1. Dead or downed wood (pre-existing) and harvest generated slash,
2. Understory shrub, herbaceous plants and non-merchantable trees,
3. Wildlife structural trees (decaying live trees, cavity trees, mast producing trees, etc.)

Stewart further notes:

> "The maintenance recruitment of structural elements such as large tree and snags, logs, and coarse woody debris that would otherwise not be replaced under an intensive biomass harvesting regime is an issue of critical concern for biodiversity and food webs related to these elements."

There was general concurrence from the workshop participants regarding these key areas and recognition that approaches to evaluating the potential impacts of a proposed forest management vary somewhat between federal, private, and state ownerships both in terms of environmental permitting requirements, review, approval, implementation, inspections, enforcement, etc. Furthermore, the literature reviewed as part of this process did not make specific recommendations on prescriptive retention standards.

There was also general concurrence that there be some certainty for supply of by-products and that the process for verifying that by-products were eligible be kept as simple and straightforward as possible.

Existing California Sustainable Forest Management Regulatory and Management Framework for Non-federal and Federal lands.

Forest management activities on federal, state and private ownerships in California, that could provide biomass to 3Mw or less electric generation facilities as defined in Section 399.20(b), are subject to numerous statutes and regulation.

Existing Regulatory Framework for Non-federal Lands - Forest management activities conducted on state and private forest ownerships, meeting the statutory definition of *timberland*, involving the barter or sale of biomass byproducts, is subject to regulation under the provisions of the Z-berg-Nejedly Forest Practice Act (Division 4, Chapter 8, Public Resources Code) and associated regulations under Title 14, California Code of Regulations, Chapter 4. The Public Resources Code and its associated regulations apply to activities that include a wide range of prescriptive standards designed to protect water quality, wildlife habitat, fisheries habitat, soils productivity, archaeological resources, aesthetics, and forest productivity. Landowners with more than 50,000 acres of forestland are required by regulation to demonstrate how their planned management activities will meet long-term sustained yield objectives.

Private forest land owners with less than 2,500 acres of timberland are eligible to submit a Non-industrial Timber Management Plan which outlines the long term management strategy for the property. Once approved through a multi-agency review, the landowner can conduct timber operations under a Notice of Timber Operations. Non-industrial Timber Management Plans have a core component that requires an assessment of long-term sustained yield based on an uneven-age silvicultural prescription. The practice of uneven aged management requires demonstration of natural regeneration and the maintenance of a balanced forest stand structure. State and private landowners may also conduct timber harvesting operations designed to address fuel management, including biomass harvesting, under a variety of exemptions and emergency notice provisions.

It is also anticipated that forest management activities that will generate biomass from private or state forest landownerships that do not meet the definition of timberland, under the Z'berg-Nejedley Forest Practice Act, will be eligible. These lands would typically not support a stand of commercial tree species, but may still support other non-commercial tree species or other woody vegetation. While these projects are not subject to regulation under the Forest Practice Act, they would generally fall under the provisions of the California Environmental Quality Act (CEQA). Therefore, the types of forest management activities that generate biomass feedstocks from most forest fuel hazard reduction activities will fall within the definition of sustainable forest management given their alignment with subpart (f) of the attached definition of sustainable forestry endorsed by the Society of American Foresters (Appendix A), as well as by meeting the intent of SB 1122. As such, these feedstocks will be classified as eligible.

Existing Regulatory Framework for Federal Lands - Federal policy for sustainability activities on National Forest Lands is described in the National Forest Management Act of 1976 (P.L.94-588). National Forests are required to prepare Forest and Resource Land Management Plans to guide how forests are managed and to guide design of project level activities consistent with 36 CFR 219. The first priority under 36 CFR 219.2 is to maintain or restore ecological sustainability of national forests to provide for a wide variety of uses, values, products and services and to conform to all applicable environmental laws and regulations. Additional federal policy on sustainability is outlined in the *National Report on Sustainable Forests—2010* (FS 979). Current guidance regarding management activities on federal lands in the

National Forest System in California emphasize application of restoration principles identified in General Technical Report (GTR)-220 (North, et.al., 2009) with management guidance provided in GTR-237, titled *Managing Sierra Nevada Forests* (North, 2012).

Biomass Utilization and Sustainable Forest Management

A number of authors have recognized the clear benefits of reducing density of vegetation, particularly on dry forest types to achieve numerous goals including reducing impacts associated with fire, improving forest health, improving resilience of forests in light of anticipated climate change, and maintaining sustainable carbon stocks and sequestration capacity of forested landscapes (Naeem, et. al. 1999, Aber, et. al., 2000, Franklin and Johnson, 2013, Forest Guild 2013, Franklin and Johnson, 2012). In addition, reducing density of vegetation while maintaining important forest structure elements like snags, down woody debris and native oaks often increase forest structural diversity and enhance wildlife habitats (Spies and Franklin, 1991, Hayes et al., 1997), and increase overall wildlife and native plant biodiversity at both the project and landscape scale (Hayes et al., 2003, Rupp et al. 2012, Verschuyl et al. 2011, Zwolak, 2009).

Markets for biomass feedstocks generated from forested landscapes in California have generally been confined to those areas in close proximity to existing biomass facilities. It is anticipated that build out of 50 new Mw of capacity under the provisions of Public Utilities Section 399.20 will expand existing markets for biomass feedstocks.

Sustainable Forest Management Definition Recommendations for Purposes of Determining Byproduct Eligibility

While the Department recognizes that timber operations on private timberlands must address sustained yield, sustainable forest management practices within the context of PUC Section 399.20 encompasses a broader set of criteria and includes acreage in federal ownership. Given the emphasis of SB 1122 on fire threat treatment linked to sustainable forest management activities and the input from workshop participants, the Department recommends that CPUC staff focus on utilization of the definition developed by the Society of American Foresters as a basis for determining sustainable forest management. Further, the Department recommends that eligible project types for the purposes of determining byproduct eligibility focus on 1) projects that incorporates the specific element in the SAF definition associated with maintenance of long term socioeconomic benefits associated with public safety, jobs, air quality, and economic benefits fuel treatment will provide if markets are found for by-products of fuel treatments, [Paraphrase of SAF definition subpart 2(f)] as well as, 2) projects that maintains biodiversity, productivity, regeneration capacity, vitality and potential to fulfill relevant ecological, economic, and social functions[Paraphrase of SAF definition subpart 2].

Specifically, the Department recommends that CPUC staff consider the following definition of **sustainable forest management** for purposes of determining eligibility of by-products—

> *Qualifying byproducts from sustainable forest management include materials derived from projects that are conducted to reduce fuels which pose a threat to public and the environment in an around communities as well as projects which can be demonstrated to contribute to restoration of forests, enhance the resilience of forests through reduction in fire threat, contribute to restoration of unique forest habitats or maintains or restores forest biodiversity, productivity and regeneration capacity.*

Issue 2-Verification, Certification, and Monitoring of Feedstock Eligibility

Consistent with the above definition, to meet the sustainable forest management eligibility fuel sourcing criteria the owner or operator must ensure that biomass feedstock from any project is sourced from one or more of the following project types and that, where appropriate, a third-party verification process addresses the key elements and gaps related to sustainable forest management risk associated with biomass operations identified by Stewart and others. The key elements to be evaluated are listed in appendix C-2:

<u>Eligible Byproduct Sources:</u>

I. ***Fire Threat Reduction*** *- biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate state, local or federal agency. On federal lands this includes fuel reduction activities approved under 36 CFR 220.6(e)(6)ii and (12) thru (14).*

II. ***Fire Safe Clearance Activities*** *- biomass feedstock originating from fuel reduction activities conducted to comply with PRC Sections 4290 and 4291. This would include biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) (150' Fuel Reduction Exemption) as well as projects that fall under 14 CCR 1052.4 (Emergency for Fuel Hazard Reduction), 14 CCR 1051.3-1051.7 (Modified THP for Fuel Hazard Reduction), and 14 CCR 1038(i) (Forest Fire Prevention Exemption), and categorical exclusions on federal lands approved under 36 CFR 220.6(e)(6)ii and (12)-(14).*

III. ***Infrastructure Clearance Projects*** *- biomass feedstock derived from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CCR 1104.1(b),(c),(d),(e),(f) &(g).*

IV. ***Other Sustainable Forest Management*** *– biomass feedstock derived from sustainable forest management activities that accomplish one or more of the following: 1) forest management applications that maintain biodiversity, productivity, and regeneration capacity of forests in support of ecological, economic and social needs, 2) contributes to forest restoration and ecosystem sustainability, 3) reduces fire threat through removal of surface and ladder fuels to reduce the likelihood of active crown fire and/or surface fire intensity that would result in excessive levels of mortality and loss of forest cover or, 4) contributes to restoration of unique habitats within forested landscapes.*

It is recommended by the Department that by-products which do not meet the criteria listed above would not be eligible by-products of sustainable forest management. Based on input from the workshop participants, it was recognized that some flexibility be provided to producers relative to mix of fuel sources and that some provision be provided to allow a producer to utilize material sourced from projects that would not meet the eligibility criteria listed above. To accommodate this need for some supply flexibility the Department recommends that CPUC staff consider allowances for up to 20% of the by-products be sourced from "other" sources as described below.

Other Eligible Supply Sources: Eligible byproducts from this category include the following:

I. *biomass feedstocks derived from other forest management activities that fail to meet 12 out of 15 of the eligibility criteria in the checklist found in Appendix C-1 and C-2.*

ii. *biomass feedstocks that will be used at the facilities from "other" waste streams identified in SB 1122*

Establishing the Basis for and Use of Eligibility Criteria

It is recommended that by-products from projects which fall into the Fuel Reduction, Fire Safe Clearance, and Infrastructure Categories as defined above (i, ii and iii) be presumed to be eligible and would not be required to fill out the eligibility criteria form in Appendix C-1 and C-2. These projects will, however, need to submit a certification form (Appendix D) and be compliant with other applicable federal, state and local laws.

With some exceptions, as noted below, forest management activities not associated with the above referenced categories are required to fill out the eligibility form in Appendix C-1 and C-2 to determine if the biomass to be generated by the project is eligible and meets the criteria of Sustainable Forest Management Practices for the purposes of SB 1122.

Evaluations, completed by a Registered Professional Forester or appropriate federal officer, with exceptions noted herein, must be done on a project-by-project basis upon an assessment of the applicable management practices.

Evaluation of biomass supply eligibility from by-products of sustainable forest management for federal projects - Federal projects which generate biomass on National Forest System Lands or other federally owned or managed lands which incorporate management principles identified in GTR-220 and GTR-237 will generally be eligible as being sourced from Sustainable Forest Management. To document the consistency of a specific project with the restoration principles in the GTR guidance document, the appropriate Forest Officer or agency official will utilize the eligibility form to determine whether biomass feedstock meets sustainability criteria and can be certified as a by-product of sustainable forest management consistent with Section 399.20. The Forest Biomass Sustainability Byproduct Eligibility Form is used to help evaluate the project to determine and document if byproducts from a forest management project are eligible as a sustainable forest management source.

Evaluation of biomass supply eligibility from by-products of sustainable forest management from projects subject to regulation under the Z'Berg-Nejedley Forest Practice Act - For timber harvesting conducted on state and private timberlands, removal of biomass material for sale constitutes a commercial activity and is subject to regulation under the Forest Practice Act. Current forest practice rules generally do not have c prescriptive regulatory requirements specifically addressing biomass harvesting because the low volume harvesting of small woody material (tree tops, branches, slash from logging operations, and small sapling/pole sized conifers and hardwoods) has not been viewed as an activity likely to result in significant adverse or cumulative impacts. CAL FIRE would expect that biomass harvesting, incidental to the more common types of commercial timber operations, not to rise to the level of potential significant adverse impacts, and therefore the requirements of CEQA (disclosure, evaluation and mitigation) would not be triggered. However, in cases where a fair argument for significant adverse impacts is raised, CAL FIRE would expect the registered professional forester preparing the timber harvesting plan (THP) to address those impacts in sufficient detail to mitigate the impacts.

Since the Board of Forestry and Fire Protection's forest practice rules are not tied to the proposed definition of 'sustainable forest management' as described in Appendix A of this document, it is recommended that CPUC should recognize the need for a separate governance process for biomass harvesting operations that would be subject to Section 399.20 of the Public Utilities Code. CAL FIRE does not view the two processes in conflict (enforcement of the Forest Practice Act by the department and enforcement of Section 399.20 by PUC). THPs are intended to address significant adverse impacts, and not necessarily intended to address the broader definition of sustainable forest management as described in this whitepaper. While the Forest Practice Regulations (FPRs) governing THPs generally address "the stewardship and use of forests and forest lands in a way, and at a rate, that maintains their biodiversity, productivity, regeneration capacity, vitality, and potential to fulfill, now and in the future, relevant ecological, economic, and social functions at local, national, and global levels", the FPRs were not intended for the type of specificity required in determining byproduct eligibility under SB 1122. The FPRs do not explicitly mention stewarding lands to fulfill economic and social functions at a local or national level. Nonetheless, the department and many participants in the aforementioned workshops deemed this to be an important consideration.

A checklist approach for certification has been provided in Appendix C-2; however, this should be viewed as a recommendation, where the specific content could be modified or edited by PUC as improvements, clarifications, or new issues are identified.

For each of the elements to be addressed in Appendix C-2 it is recommended that the seller of biomass describe the planned operations and potential positive and/or negative impacts to each resource issue to be addressed in Appendix C. Review of concepts from GTR 220, GTR 237, CEC-500-2011-036, (Stewart, et.al), and GTR 292 (Jain et. al., 2012) are recommended as important references to assist in assessing and addressing the sustainability of proposed operations where biomass removals are proposed to achieve forest management, forest restoration, and/or fire threat reduction objectives.

Utilization of this approach will facilitate environmental review by third party verifiers, as well as completion of Appendix C-2 (Forest Biomass Sustainability Byproduct Eligibility Form) for determination of whether the biomass generated by the project meets eligible byproducts under PUC Section 399.20.

For ownerships with approved Sustained-Yield Plans or Programmatic Timber Environmental Impact Reports, harvest documents may rely on the assessment of sustainability contained in the programmatic documents to the extent that those elements are addressed and summarize the operational elements applicable to any project under the appropriate area in Appendix C-2.

Exceptions to the requirement to apply Appendix C-1 and C-2 for Biomass Produced During Restoration Projects and Small Projects: The following project types are assumed to meet the sustainable forest management criteria or small project size and are recommended to be exempted from completing the Forest Biomass Sustainability Byproduct Eligibility Form (Appendix C-2).

1) Sustainable forest management projects implemented on state, federal, and private ownership which involve meadow restoration, restoration of wetlands, restoration of aspen and other similar activities which are undertaken for restoration purposes and are subject to environmental review under CEQA or NEPA.

2) Operations conducted pursuant to an approved Non-Industrial Timber Management Plan where the plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant adverse impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
3) Operations conducted pursuant to an approved Timber Harvesting Plan or Modified Timber Harvesting Plans on non-industrial timberland ownerships where the landowner is not primarily engaged in the manufacture of wood products and where the approved plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant adverse impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
4) Operations with a total estimated volume of 250 bone dry tons or less.

These projects will need to submit a certification form (Appendix D) and be compliant with other applicable federal, state and local laws.

Certification, Verification and Monitoring to Determine Biomass/Byproduct Eligibility Requirements

Certification: For projects on private timberlands, completion of the "Forest Biomass Sustainability Byproduct Form (Appendix C-2)" by a Registered Professional Forester as defined in Title 14 of the California Code of Regulations, Chapter 10 is recommended. Representations of the Registered Professional Forester in completion of the form and certification will be subject to the disciplinary guidelines as described in Public Resources Code Sections 774-779 and the provisions of the California Code of Regulations, Chapter 10, Sections 1612-1614.

For federal projects certification will be completed by the appropriate federal officer with authority to approve project decisions pursuant to Forest Service Manual 2400 and all subtitles. Representatives with responsibility for accuracy of the certification are subject to personnel procedures outlined in Code of Federal Regulations Title 5, Subpart 430, Performance Management.

Certification by the Registered Professional Forester or appropriate federal representative should be completed utilizing the certification form included in Appendix D. It is expected that each project will have an identifier, map, certification relative to fuel source and an estimated volume by fuel source category or categories.

Verification: The owner/operator of the bioenergy facility will be responsible for verifying that the fuel has been appropriately certified. Trip tickets and loads origin will demonstrate a chain-of-custody to the project source. Information shall be available at the bioenergy facility for audit.

Monitoring for Compliance with Eligibility Criteria: It is recommended that a random audit procedure be established to ensure compliance with program requirements. The consequences for failure to comply should be discussed and developed collaboratively between the CPUC, appropriate federal agencies and CAL FIRE.

Recommended Audit Period and Remediation: It is also recommended that for purposes of verifying that an individual biomass facility is securing supplies from eligible biomass feedstock sources in a proportion consistent with the targets, the compliance with biomass feedstock supply mix criteria shall be determined based on a 5-year rolling average. It is also recommended that CPUC staff develop a process or processes that bring the biomass feedstock supply mix into conformance with the eligibility requirements, if it is determined that a given facility is out of compliance. A process for facilities to alter the eligible biomass feedstock mix should also be developed.

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APPENDIX A

Society of American Foresters: The Dictionary of Forestry

(sustainable forestry) (SFM) *this evolving concept has several definitions* **1.** the practice of meeting the forest resource needs and values of the present without compromising the similar capability of future generations —*note* sustainable forest management involves practicing a land stewardship ethic that integrates the reforestation, managing, growing, nurturing, and harvesting of trees for useful products with the conservation of soil, air and water quality, wildlife and fish habitat, and aesthetics (UN Conference on Environment and Development, Rio De Janeiro, 1992) **2.** the stewardship and use of forests and forest lands in a way, and at a rate, that maintains their biodiversity, productivity, regeneration capacity, vitality, and potential to fulfill, now and in the future, relevant ecological, economic, and social functions at local, national, and global levels, and that does not cause damage to other ecosystems (the Ministerial Conference on the Protection of Forests in Europe, Helsinki, 1993) —*note* criteria for sustainable forestry include (a) conservation of biological diversity, (b) maintenance of productive capacity of forest ecosystems, (c) maintenance of forest ecosystem health and vitality, (d) conservation and maintenance of soil and water resources, (e) maintenance of forest contributions to global carbon cycles, (f) maintenance and enhancement of long-term multiple socioeconomic benefits to meet the needs of societies, and (g) a legal, institutional, and economic framework for forest conservation and sustainable management (Montréal Process, 1993) —*see* biological legacy, certify, chain of custody, criteria and indicators, criterion, ecosystem management.

This definition last updated 10/23/2008.

APPENDIX B

United States Department of Agriculture: Forest Service: *"National Report on Sustainable Forests", June 2011 (* FS-979).

Sustainable forest management definition:
The stewardship and use of forests and forest lands in such a way, and at a rate, that maintains their biodiversity, productivity, regeneration capacity, and vitality, and forest's potential to fulfill, now and in the future, relevant ecological, economic, and social functions at local, national, and global levels, and not cause damage to other ecosystems.
The criteria and indicators are intended to provide a common understanding of what is meant by sustainable forest management. They provide a framework for describing, assessing, and evaluating a country's progress toward sustainability at the national level and include measures of:

1. Conservation of biological diversity.
2. Maintenance of productive capacity.
3. Maintenance of forest ecosystem health.
4. Conservation and maintenance of soil and water resources.
5. Maintenance of forest contribution to global carbon cycles.
6. Maintenance and enhancement of long-term multiple socioeconomic benefits to meet the needs of society.
7. Legal, institutional, and economic frameworks for forest conservation.

APPENDIX C - 1

SB1122 Forest Biomass

Forest Biomass Sustainability Byproduct Eligibility Form:

Instructions and Worksheet

Instructions

Projects which fall into the Fuel Reduction, Fire Safe Clearance, and Infrastructure categories as defined under sustainable forest management are presumed to be eligible and are not required to fill out Appendix C-2. Projects which meet the sustainable forest management criteria, but are exempt from submitting Appendix C-2 must still meet the minimum sustainability criteria outlined in Appendix C-2. Projects conducted under "I", 'ii", "iii" or "iv" (including exempt projects) must submit a certification form (Appendix D).

With the exception of projects types noted below, forest management activities not associated with forest biomass categories "i", "ii", and "iii", referenced below, will require use of the Forest Biomass Sustainability Byproduct Eligibility Form (Appendix C-2) to determine if the biomass generated by the project is eligible, and meets the criteria of Sustainable Forest Management Practices under PUC 399.20.

Ranking criteria have been developed to reflect and support the broad criteria described within the above referenced definition of Sustainable Forest Management. Evaluations, completed by a Registered Professional Forester or appropriate federal officer with exceptions noted herein, must be on a project-by-project basis upon an assessment of the applicable management practices.

Eligible Forest Biomass Categories

*i. **Fire Threat Reduction** - biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate, state, local or federal agency. On federal lands this includes fuel reduction activities approved under36 CFR 220.6(e)(6)ii and (12) thru (14).*

*ii. **Fire Safe Clearance Activities** - biomass feedstock originating from fuel reduction activities conducted to comply with PRC Sections 4290 and 4291. This would include biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) 150' Fuel Reduction Exemption,* as well as projects that fall under 14 CCR 1052.4 (Emergency for Fuel Hazard Reduction), 14 CCR 1051.3-1051.7 (Modified THP for Fuel Hazard Reduction), and 14 CCR 1038(i) Forest fire Prevention Exemption, Categorical exclusions on federal lands approved under 36 CFR 220.6.(e).(6)ii.,

*iii. **Infrastructure Clearance Projects** - biomass feedstock derived from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CC1104. 1(b),(c),(d),(e),(f) &(g).*

*iv. **Other Sustainable Forest Management** – biomass feedstock derived from sustainable forest management activities that accomplish one or more of the following: 1) forest management applications that maintain biodiversity, productivity, and regeneration capacity of forests in support of ecological, economic and social needs, 2) contributes to forest restoration and ecosystem sustainability,* *3) reduces fire threat through removal of surface and ladder fuels to reduce the likelihood of active crown fire and/or surface fire intensity that would result in excessive levels of mortality and loss of forest cover or, 4) contributes to restoration of unique habitats within forested landscapes.*

The following project types meet the sustainable forest management criteria and are <u>exempted</u> from submitting the Forest Biomass Sustainability Form (Appendix C-2)

1) Sustainable Forest Management projects implemented on state, federal, and private ownership which involve meadow restoration, restoration of wetlands, restoration of aspen and other similar activities which are undertaken for restoration purposes and are subject to environmental review under CEQA or NEPA.
2) Operations conducted pursuant to an approved Non-Industrial Timber Management Plan where the plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant adverse impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
3) Operations conducted pursuant to an approved Timber Harvesting Plan or Modified Timber Harvesting Plans on non-industrial timberland ownerships where the landowner is not primarily engaged in the manufacture of wood products and where the approved plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
4) Operations with a total estimated volume of less than 250 bone dry tons.

<u>Section I</u>

Ownership Category: identify if the parcel on which the project is conducted is owned by a private entity, the state or the Federal Government
Number of Acres: Identify how many acres are being treated / harvested by the project
Type of Harvest Document (if applicable): Identify the type of harvest document, State Permit, Federal Permit or exemption that apply to this project
Harvest Document Designator: Identify the State or Federal entity that issued the harvest permit, exemption or other document that applies to this project
Facility Identifier: Provide the identifier for the SB1122 (or other) forest biomass facility which will receive and utilize the forest waste (biomass) to generate energy.

<u>Section II</u>

To qualify under forest biomass category **"iv"**, treatment activities must provide co-benefits for at least 12 of the 16 items identified in Appendix C-2, Section II, Items A – E. In addition, at least one item must come from each of Section II A – D. A Registered Professional Forester should determine if planned activities meet the sustainability criteria under section "iv".

APPENDIX C - 2

Forest Biomass Sustainability Byproduct Eligibility Form

SECTION I

Ownership Category: ☐ Private ☐ State ☐ Federal Number of Acres: ________

Type of Harvest/NEPA Document: ______________ Harvest/NEPA Document Designator: ____________

Facility Identifier: ______________

SECTION II

Note: Please keep responses brief (under 250 words) and focused on the basis for the determination that the project will support sustainability of the specific objective. In lieu of providing a written response or in addition to the written response, where appropriate provide source references to the approved harvest/NEPA document where discussion of potential significant adverse impacts, evaluation and mitigation measures are provided.

A. Habitat, Temporal and Spatial Diversity Objectives (Pick all that apply)

☐ Openings for shade intolerant species were created to promote regeneration and habitat diversity.
Please describe percent and distribution of areas in small openings less than 2.5 acres in size and planned regeneration methods:

☐ Multi-age, multi-species tree habitats were created at the project level.
Please describe how the project immediately post harvest will support maintenance, enhancement and/or restoration of canopy cover and maintain or increase the QMD of an overstory of multi-age, multi-species tree habitats.

☐ Understory vegetation was retained and distributed across the project site consistent with fire threat reduction and habitat objectives and contributes to spatial heterogeneity by varying treatments to retain untreated patches, openings and widely spaced single trees and clumps.
Please describe objectives for retention of understory shrubs and trees and estimate post-harvest areas of untreated patches and openings.

563 B. Habitat Elements: (Pick all that apply)

☐ Snags are retained consistent with safety, FPRs, and fire threat reduction goals.
Please describe post harvest snag retention objectives and estimate the percentage of existing snags to be removed as part of the planned forest management activities.

☐ Down logs with benefit to habitat diversity are retained consistent with fire threat reduction goals.
Please describe project treatment objectives for retention of existing or project related down woody material.

☐ Large hardwoods and Legacy trees are retained as post treatment stand components and habitat.
Please describe post harvest retention objectives for hardwoods and legacy trees.

☐ Management practices and harvesting associated with the project impacts are consistent with objectives of retaining or recruiting large trees at the project and landscape level.
Please describe post harvest old growth tree retention objectives:

564 C. Forest Health and Fire Management Objectives: (Pick all that apply)

☐ Fire threat is reduced through treatment of ladder fuels and surface fuels to achieve reduction in incidence of crown torching in overstory trees and to avoid active crown fires under most conditions.
Please describe post harvest spatial arrangement objectives for retention of understory shrubs and trees in relation to overstory trees.

☐ Outcomes support reintroduction of prescribed fire.
Please describe, if applicable post harvest surface and ladder fuel conditions and proposed use of prescribed fire.

☐ Improvement of overall forest health through reduction in overstocking in small tree sizes and reduction of competition for soil moisture with overstory trees.
Please describe:

565 D. Air and Water Quality Protection: (Pick all that apply)

☐ Avoided emissions by eliminating need for open burning of slash piles and/or decomposition.
Please describe the relative reduction in emissions attributable to removal of material from the project site for use as fuel for energy generation in comparison to piling and burning or piling and decomposition.):

☐ Measures have been incorporated to address moist microsites, and near stream habitats.
Please describe what measures will be employed to protect moist microsites and near-stream habitats.

☐ Soil protection measures used to minimize compaction and loss of A-horizons and soil carbon. Please describe.

☐ Operational plans provide for the retention of fine woody debris to minimize potential threats to soil productivity and meet fire threat reduction objectives. Please describe.

566 E. Societal and Economic Benefits: (Pick all that apply)

☐ Project contributes to societal benefits of local communities by way of fire safety, improved environmental health and overall quality of life. Please describe.

☐ Project contributes to local economies by way of providing additional local employment opportunities and investment.
Please describe .

APPENDIX D

SB1122 Forest Biomass

Project Eligibility Certification

Ownership Category: ☐ Private ☐ State ☐ Federal Number of Acres: __________
Type of Harvest/NEPA Document: ___________ Harvest/NEPA Document Designator: _____________
Facility Identifier: __________________ RPF License Number (if Applicable): _____________

Eligible Fuel Source: (Pick one)

To meet the eligible fuel sourcing criteria the owner or operator must ensure that biomass feedstock from any project is sourced from one or more of the following project types:

☐ ***Fire Threat Reduction*** *- biomass feedstock which originates from fuel reduction activities identified in a fire plan approved by CAL FIRE or other appropriate, state, local or federal agency, Categorical exclusions on federal lands approved under 36 CFR 220.6.(e).(6)ii.*

☐ ***Fire Safe Clearance Activities****- biomass feedstock originating from fuel reduction activities conducted to comply with PRC Sections 4290 and 4291. This would include biomass feedstocks from timber operations conducted in conformance with 14 CCR 1038(c) 150' Fuel Reduction Exemption, or Categorical exclusions on federal lands approved under36 CFR 220.6(e)(6)ii and (12) thru (14).*

☐ ***Infrastructure clearance projects****- biomass feedstock derived from fuel reduction activities undertaken by or on behalf of a utility or local, state or federal agency for the purposes of protecting infrastructure including but not limited to: power lines, poles, towers, substations, switch yards, material storage areas, construction camps, roads, railways, etc. This includes timber operations conducted pursuant to 14 CC1104.1(b),(c),(d),(e),(f) &(g).*

☐ ***Other Sustainable Forest Management**** *– biomass feedstock derived from sustainable forest management activities that accomplish one or more of the following: 1) forest management applications that maintain biodiversity, productivity, and regeneration capacity of forests in support of ecological, economic and social needs, 2) contributes to forest restoration and ecosystem sustainability, 3) reduces fire threat through removal of surface and ladder fuels to reduce the likelihood of active crown fire and/or surface fire intensity that would result in excessive levels of mortality and loss of forest cover or, 4) contributes to restoration of unique habitats within forested landscapes.*

Other Fuel Sources:

Eligible fuel from this category includes the following:

☐ *biomass feedstocks derived from other forest management activities that fail to meet the requirements of the checklist found in Appendix "C".*

☐ *biomass feedstocks that will be used at the facilities from " other " waste streams covered by SB 1122*

I hereby certify that the information contained in this certification is complete and accurate to the best of my knowledge and conforms to State and Federal Laws,

Print Name:______________________________ Signature:_______________________________

As appropriate attach Forest Biomass Sustainability Byproduct Eligibility Form.

*** The following project types are assumed to meet the sustainable forest management criteria and are exempted from completing the Forest Biomass Sustainability Form (Appendix C-2)**

1) Sustainable Forest Management projects implemented on state, federal, and private ownership which involve meadow restoration, restoration of wetlands, restoration of aspen and other similar activities which are undertaken for restoration purposes and are subject to environmental review under CEQA or NEPA.
2) Operations conducted pursuant to an approved Non-Industrial Timber Management Plan where the plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant adverse impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
3) Operations conducted pursuant to an approved Timber Harvesting Plan or Modified Timber Harvesting Plans on non-industrial timberland ownerships where the landowner is not primarily engaged in the manufacture of wood products and where the approved plan or amendment to the plan evaluates and provides for a discussion of intended biomass operations and byproducts that may have potential significant adverse impacts, evaluates potential significant impacts, and mitigates potential significant impacts.
4) Operations with a total estimated volume of less than 250 bone dry tons.

City of Willows
CALIFORNIA

Appendix C – 9

IRENA WORKING PAPER

IRENA
International Renewable Energy Agency

RENEWABLE ENERGY TECHNOLOGIES: COST ANALYSIS SERIES

Volume 1: Power Sector

Issue 1/5

Biomass for Power Generation

June 2012

About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation dedicated to renewable energy.

In accordance with its Statute, IRENA's objective is to "promote the widespread and increased adoption and the sustainable use of all forms of renewable energy". This concerns all forms of energy produced from renewable sources in a sustainable manner and includes bioenergy, geothermal energy, hydropower, ocean, solar and wind energy.

As of May 2012, the membership of IRENA comprised 158 States and the European Union (EU), out of which 94 States and the EU have ratified the Statute.

Acknowledgement

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For further information or to provide feedback, please contact Michael Taylor, IRENA Innovation and Technology Centre, Robert-Schuman-Platz 3, 53175 Bonn, Germany; MTaylor@irena.org.

This working paper is available for download from www.irena.org/Publications

Disclaimer

Preface

Renewable power generation can help countries meet their sustainable development goals through provision of access to clean, secure, reliable and affordable energy.

Renewable energy has gone mainstream, accounting for the majority of capacity additions in power generation today. Tens of gigawatts of wind, hydropower and solar photovoltaic capacity are installed worldwide every year in a renewable energy market that is worth more than a hundred billion USD annually. Other renewable power technology markets are also emerging. Recent years have seen dramatic reductions in renewable energy technologies' costs as a result of R&D and accelerated deployment. Yet policy-makers are often not aware of the latest cost data.

International Renewable Energy Agency (IRENA) Member Countries have asked for better, objective cost data for renewable energy technologies. This working paper aims to serve that need and is part of a set of five reports on biomass, wind, hydropower, concentrating solar power and solar pholtovoltaics that address the current costs of these key renewable power technology options. The reports provide valuable insights into the current state of deployment, types of technologies available and their costs and performance. The analysis is based on a range of data sources with the objective of developing a uniform dataset that supports comparison across technologies of different cost indicators – equipment, project and levelised cost of electricity – and allows for technology and cost trends, as well as their variability to be assessed.

The papers are not a detailed financial analysis of project economics. However, they do provide simple, clear metrics based on up-to-date and reliable information which can be used to evaluate the costs and performance of different renewable power generation technologies. These reports help to inform the current debate about renewable power generation and assist governments and key decision makers to make informed decisions on policy and investment.

The dataset used in these papers will be augmented over time with new project cost data collected from IRENA Member Countries. The combined data will be the basis for forthcoming IRENA publications and toolkits to assist countries with renewable energy policy development and planning. Therefore, we welcome your feedback on the data and analysis presented in these papers, and we hope that they help you in your policy, planning and investment decisions.

Dolf Gielen
Director, Innovation and Technology

Contents

Key findings

1. The total installed costs of biomass power generation technologies varies significantly by technology and country. The total installed costs of stoker boilers was between USD 1 880 and USD 4 260/kW in 2010, while those of circulating fluidised bed boilers were between USD 2 170 and USD 4 500/kW. Anaerobic digester power systems had capital costs between USD 2 570 and USD 6 100/kW. Gasification technologies, including fixed bed and fluidised bed solutions, had total installed capital costs of between USD 2 140 and USD 5 700/kW. Co-firing biomass at low-levels in existing thermal plants typically requires additional investments of USD 400 to USD 600/kW. Using landfill gas for power generation has capital costs of between USD 1920 and USD 2 440/kW. The cost of CHP plants is significantly higher than for the electricity-only configuration.

TABLE 1: TYPICAL CAPITAL COSTS AND THE LEVELISED COST OF ELECTRICITY OF BIOMASS POWER TECHNOLOGIES

	Investment costs USD/kW	LCOE range USD/kWh
Stoker boiler	1 880 – 4 260	0.06 – 0.21
Bubbling and circulating fluidised boilers	2 170 – 4 500	0.07 – 0.21
Fixed and fluidised bed gasifiers	2 140 – 5 700	0.07 – 0 24
Stoker CHP	3 550 – 6 820	0.07 – 0.29
Gasifier CHP	5 570 – 6 545	0.11 – 0.28
Landfill gas	1 917 – 2 436	0.09 – 0.12
Digesters	2 574 – 6 104	0.06 – 0.15
Co-firing	140 – 850	0.04 – 0.13

2. Operations and maintenance (O&M) costs can make a significant contribution to the levelised cost of electricity (LCOE) and typically account for between 9% and 20% of the LCOE for biomass power plants. It can be lower than this in the case co-firing and greater for plants with extensive fuel preparation, handling and conversion needs. Fixed O&M costs range from 2% of installed costs per year to 7% for most biomass technologies, with variable O&M costs of around USD 0.005/kWh. Landfill gas systems have much higher fixed O&M costs, which can be between 10% and 20% of initial capital costs per year.

3. Secure, long-term supplies of low-cost, sustainably sourced feedstocks are critical to the economics of biomass power plants. Feedstock costs can be zero for wastes which would otherwise have disposal costs or that are produced onsite at an industrial installation (e.g. black liquor at pulp and paper mills or bagasse at sugar mills). Feedstock costs may be modest where agricultural residues can be collected and transported over short distances. However, feedstock costs can be high where significant transport distances are involved due to the low energy density of biomass (e.g. the trade in wood chips and pellets). The analysis in this report examines feedstock costs of between USD 10/tonne for low cost residues to USD 160/tonne for internationally traded pellets.

4. The LCOE of biomass-fired power plants ranges from USD 0.06 to USD 0.29/kWh depending on capital costs and feedstock costs. Where low-cost feedstocks are available and capital costs are modest, biomass can be a very competitive power generation option. Where low-cost agricultural or forestry residues and wastes are available, biomass can often compete with conventional power sources. Even where feedstocks are more expensive, the LCOE range for biomass is still more competitive than for diesel-fired generation, making biomass an ideal solution for off-grid or mini-grid electricity supply.

5. Many biomass power generation options are mature, commercially available technologies (e.g. direct combustion in stoker boilers, low-percentage co-firing, anaerobic digestion, municipal solid waste incineration, landfill gas and combined heat and power). While others are less mature and only at the beginning of their deployment (e.g. atmospheric biomass gasification and pyrolysis), still others are only at the demonstration or R&D phases (e.g. integrated gasification combined cycle, bio-refineries, bio-hydrogen). The potential for cost reductions is therefore very heterogeneous. Only marginal cost reductions are anticipated in the short-term, but the long-term potential for cost reductions from the technologies that are not yet widely deployed is good.

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1. Introduction

Renewable energy technologies can help countries meet their policy goals for secure, reliable and affordable energy to expand electricity access and promote development. This paper is part of a series on the cost and performance of renewable energy technologies produced by IRENA. The goal of these papers is to assist government decision-making and ensure that governments have access to up-to-date and reliable information on the costs and performance of renewable energy technologies.

Without access to reliable information on the relative costs and benefits of renewable energy technologies, it is difficult, if not impossible, for governments to arrive at an accurate assessment of which renewable energy technologies are the most appropriate for their particular circumstances. These papers fill a significant gap in information availability because there is a lack of accurate, comparable, reliable and up-to-date data on the costs and performance of renewable energy technologies. There is also a significant amount of perceived knowledge about the cost and performance of renewable power generation that is not accurate, or, indeed, is even misleading. Conventions on how to calculate cost can influence the outcome significantly, and it is imperative that these are well-documented.

The absence of accurate and reliable data on the cost and performance of renewable power generation technologies is therefore a significant barrier to the uptake of these technologies. Providing this information will help governments, policy-makers, investors and utilities make informed decisions about the role renewables can play in their power generation mix. This paper examines the fixed and variable cost components of biomass power, by country and by region, and provides the levelised cost of electricity from biomass power given a number of key assumptions. This up-to-date analysis of the costs of generating electricity from biomass will allow a fair comparison of biomass with other power generating technologies.[1]

1.1 DIFFERENT MEASURES OF COST AND DATA LIMITATIONS

Cost can be measured in a number of different ways, and each way of accounting for the cost of power generation brings its own insights. The costs that can be examined include equipment costs (e.g. wind turbines, PV modules, solar reflectors), financing costs, total installed cost, fixed and variable operating and maintenance costs (O&M), fuel costs and the levelised cost of energy (LCOE), if any.

The analysis of costs can be very detailed, but for comparison purposes and transparency, the approach used here is a simplified one. This allows greater scrutiny of the underlying data and assumptions, improved transparency and confidence in the analysis, as well as facilitating the comparison of costs by country or region for the same technologies in order to identify what are the key drivers in any differences.

The three indicators that have been selected are:

- Equipment cost (factory gate FOB and delivered at site CIF);
- Total installed project cost, including fixed financing costs[2]; and
- The levelised cost of electricity LCOE.

The analysis in this paper focuses on estimating the cost of biomass power from the perspective of an investor, whether it is a state-owned electricity generation utility, an independent power producer or

1 IRENA, through its other work programmes, is also looking at the costs and benefits, as well as the macro-economic impacts, of renewable power generation technologies. See WWW.IRENA.ORG for further details.

2 Banks or other financial institutions will often charge a fee, usually a percentage of the total funds sought, to arrange the debt financing of a project. These costs are often reported separately under project development costs.

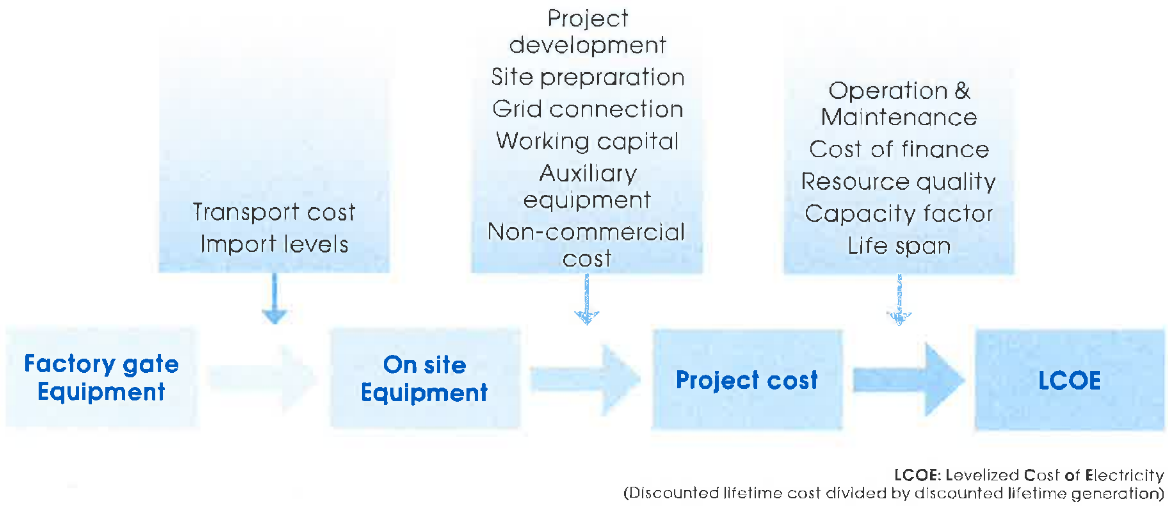


FIGURE 1.1: RENEWABLE POWER GENERATION COSTS INDICATORS AND BOUNDARIES

an individual or community looking to invest in small-scale renewables (Figure 1.1). The analysis excludes the impact of government incentives or subsidies, system balancing costs associated with variable renewables and any system-wide cost-savings from the merit order effect. Further, the analysis does not take into account any CO2 pricing, nor the benefits of renewables in reducing other externalities (e.g. reduced local air pollution and contamination of the natural environment). Similarly, the benefits of renewables being insulated from volatile fossil fuel prices have not been quantified. These issues are important but are covered by other programmes of work at IRENA.

It is important to include clear definitions of the technology categories, where this is relevant, to ensure that cost comparisons are robust and provide useful insights (e.g. biomass combustion vs. biomass gasification technologies). Similarly, it is important to differentiate between the functionality and/or qualities of the renewable power generation technologies being investigated (e.g. ability to scale-up, feedstock requirements). It is important to ensure that system boundaries for costs are clearly set and that the available data are directly comparable. Other issues can also be important, such as cost allocation rules for combined heat and power plants and grid connection costs.

The data used for the comparisons in this paper come from a variety of sources, such as business journals, industry associations, consultancies, governments, auctions and tenders. Every effort has been made to ensure that these data are directly comparable and are for the same system boundaries. Where this is not the case, the data have been corrected to a common basis using the best available data or assumptions. It is planned that these data will be complemented by detailed surveys of real world project data in forthcoming work by the agency.

An important point is that although this paper tries to examine costs, strictly speaking, the data available are actually prices, and not even true market average prices, but price indicators. The difference between costs and prices is determined by the amount above, or below, the normal profit that would be seen in a competitive market. The rapid growth of renewables markets from a small base means that the market for renewable power generation technologies is rarely well-balanced. As a result, prices, particularly for biomass feedstocks, can rise significantly above costs in the short-term if supply is not expanding as fast as demand, while in times of excess supply losses can occur and prices may be below production costs. This makes analysing the cost of renewable power generation technologies challenging and every effort is made to indicate whether costs are above or below their long-term trend.

The cost of equipment at the factory gate is often available from market surveys or from other sources. A key difficulty is often reconciling different sources of data to identify why data for the same period differ. The balance of capital costs in total project costs tends to vary even more widely than power generation equipment costs, as it is often based on significant local content, which depends on the cost structure of where the project is being developed. Total installed costs can therefore vary significantly by project, country and region, depending on a wide range of factors.

1.2 LEVELISED COST OF ELECTRICITY GENERATION

The LCOE of renewable energy technologies varies by technology, country and project, based on the renewable energy resource, capital and operating costs and the efficiency/performance of the technology. The approach used in the analysis presented here is based on a discounted cash flow (DCF) analysis. This method of calculating the cost of renewable energy technologies is based on discounting financial flows (annual, quarterly or monthly) to a common basis, taking into consideration the time value of money. The weighted average cost of capital (WACC), often also referred to as the discount rate, is an important part of the information required to evaluate biomass power generation projects and has an important impact on the LCOE.

There are many potential trade-offs to be considered when developing an LCOE modelling approach. The approach taken here is relatively simplistic, given the fact that the model needs to be applied to a wide range of technologies in different countries and regions. However, this has the additional advantage that the analysis is transparent and easy to understand. In addition, more detailed LCOE analysis results in a significantly higher overhead in terms of the granularity of assumptions required. This often gives the impression of greater accuracy, but when it is not possible to robustly populate the model with assumptions, or to differentiate assumptions based on real world data, then the "accuracy" of the approach can be misleading.

The formula used for calculating the LCOE of renewable energy technologies is[3]:

$$\textbf{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE = the average lifetime levelised cost of electricity generation;

I_t = investment expenditures in the year t;

M_t = operations and maintenance expenditures in the year t;

F_t = fuel expenditures in the year t;

E_t = electricity generation in the year t;

r = discount rate; and

n = life of the system.

All costs presented in this paper are real 2010 USD, unless otherwise stated,[3] that is to say after inflation has been taken into account.[4] The LCOE is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate. An electricity price above this would yield a greater return on capital while a price below it would yield a lower return on capital or even a loss.

As already mentioned, although different cost measures are useful in different situations, the LCOE of renewable energy technologies is a widely used measure by which renewable energy technologies can be evaluated for modelling or policy development purposes. Similarly, more detailed DCF approaches, taking into account taxation, subsidies and other incentives, are used by renewable energy project developers to assess the profitability of real world

3 Note that for biomass CHP, a credit is allocated for the steam produced. The methodology used for allocating costs between electricity and heat production can have an important impact on the estimated LCOE (Coelho, 1997).

4 The 2010 USD/Euro exchange rate was 1.327 and the USD/GBP exchange rate was 1.546. All data for exchange rates and GDP deflators were sourced from the International Monetary Fund's databases or from the World Bank's "World Economic Outlook".

5 An analysis based on nominal values with specific inflation assumptions for each of the cost components is beyond the scope of this analysis. Project developers will develop their own specific cash-flow models to identify the profitability of a project from their perspective.

2. Biomass power generation technologies

This paper examines biomass power generation technologies but also touches on the technical and economic characterisation of biomass resources, preparation and storage. There can be many advantages to using biomass instead of fossil fuels for power generation, including lower greenhouse gas (GHG) emissions, energy cost savings, improved security of supply, waste management/reduction opportunities and local economic development opportunities. However, whether these benefits are realised, and to what extent, depends critically on the source and nature of the biomass feedstock.

In order to analyse the use of biomass for power generation, it is important to consider three critical components of the process:

- Biomass feedstocks: These come in a variety of forms and have different properties that impact their use for power generation.
- Biomass conversion: This is the process by which biomass feedstocks are transformed into the energy form that will be used to generate heat and/or electricity.
- Power generation technologies: There is a wide range of commercially proven power generation technologies available that can use biomass as a fuel input.

The source and sustainability of the biomass feedstock is critical to a biomass power generation project's economics and success. There are a wide range of biomass feedstocks and these can be split into whether they are urban or rural (Table 2.1).

A critical issue for the biomass feedstock is its energy, ash and moisture content, and homogeneity. These will have an impact on the cost of biomass feedstock per unit of energy, transportation, pre-treatment and storage costs, as well as the appropriateness of different conversion technologies.

Bioenergy can be converted into power through thermal-chemical processes (i.e. combustion, gasification and pyrolysis) or bio-chemical processes like anaerobic digestion. (Table 2.2).

TABLE 2.1: BIOMASS FEEDSTOCKS

Rural	Urban
Forest residues and wood waste	Urban wood waste (packing crates, pallets, etc.)
Agricultural residues (corn stovers, wheat stalks, etc.)	Wastewater and sewage biogas
Energy crops (grasses or trees)	Landfill gas
Biogas from livestock effluent	Municipal solid waste Food processing residues

TABLE 2.2: THERMO-CHEMICAL AND BIO-CHEMICAL CONVERSION PROCESSES FOR BIOMASS FEEDSTOCKS

Thermo-Chemical Process	
Combustion	The cycle used is the conventional rankine cycle with biomass being burned (oxidised) in a high pressure boiler to generate steam. The net power cycle efficiencies that can be achieved are about 23% to 25%. The exhaust of the steam turbine can either be fully condensed to produce power or used partly or fully for another useful heating activity. In addition to the exclusive use of biomass combustion to power a steam turbine, biomass can be co-fired with coal in a coal-fired power plant. Direct co-firing is the process of adding a percentage of biomass to the fuel mix in a coal-fired power plant. It can be co-fired up to 5-10% of biomass (in energy terms) and 50-80%[6] with extensive pre-treatment of the feedstock (i.e. torrefaction) with only minor changes in the handling equipment. For percentages above 10% or if biomass and coal are burning separately in different boilers, known as parallel co-firing, then changes in mills, burners and dryers are needed.
Gasification	Gasification is achieved by the partial combustion of the biomass in a low oxygen environment, leading to the release of a gaseous product (producer gas or syngas). So-called "allothermal" or indirect gasification is also possible. The gasifier can either be of a "fixed bed", "fluidised bed" or "entrained flow" configuration. The resulting gas is a mixture of carbon monoxide, water, CO_2, char, tar and hydrogen, and it can be used in combustion engines, micro-turbines, fuel cells or gas turbines. When used in turbines and fuel cells, higher electrical efficiencies can be achieved than those achieved in a steam turbine. It is possible to co-fire a power plant either directly (i.e. biomass and coal are gasified together) or indirectly (i.e. gasifying coal and biomass separately for use in gas turbines).
Pyrolsis	Pyrolsis is a subset of gasification systems. In pyrolysis, the partial combustion is stopped at a lower temperature (450°C to 600°C), resulting in the creation of a liquid bio-oil, as well as gaseous and solid products. The pyrolysis oil can then be used as a fuel to generate electricity.
Bio-Chemical Process	
Anaerobic Digestion	Anaerobic digestion is a process which takes place in almost any biological material that is decomposing and is favored by warm, wet and airless conditions. The resulting gas consists mainly of methane and carbon dioxide and is referred to as biogas. The biogas can be used, after clean-up, in internal combustion engines, micro-turbines, gas turbines, fuel cells and stirling engines or it can be upgraded to biomethane for distribution.

SOURCE: BASED ON EPRI, 2012

Power generation from biomass can be achieved with a wide range of feedstocks and power generation technologies that may or may not include an intermediate conversion process (e.g. gasification). In each case, the technologies available range from commercially proven solutions with a wide range of technology suppliers (e.g. solid fuel combustion) through to those that are only just being deployed at commercial scale (e.g. gasification). There are other technologies that are at an earlier stage of development and are not considered in this analysis (Figure 2.1). In addition, different feedstocks and technologies are limited or more suited to different scales of application, further complicating the picture. The following sections discuss each of the major technology groups and their technical parameters.

6 *See for example, http://www.topellenergy.com/product/torrefied-biomass/*

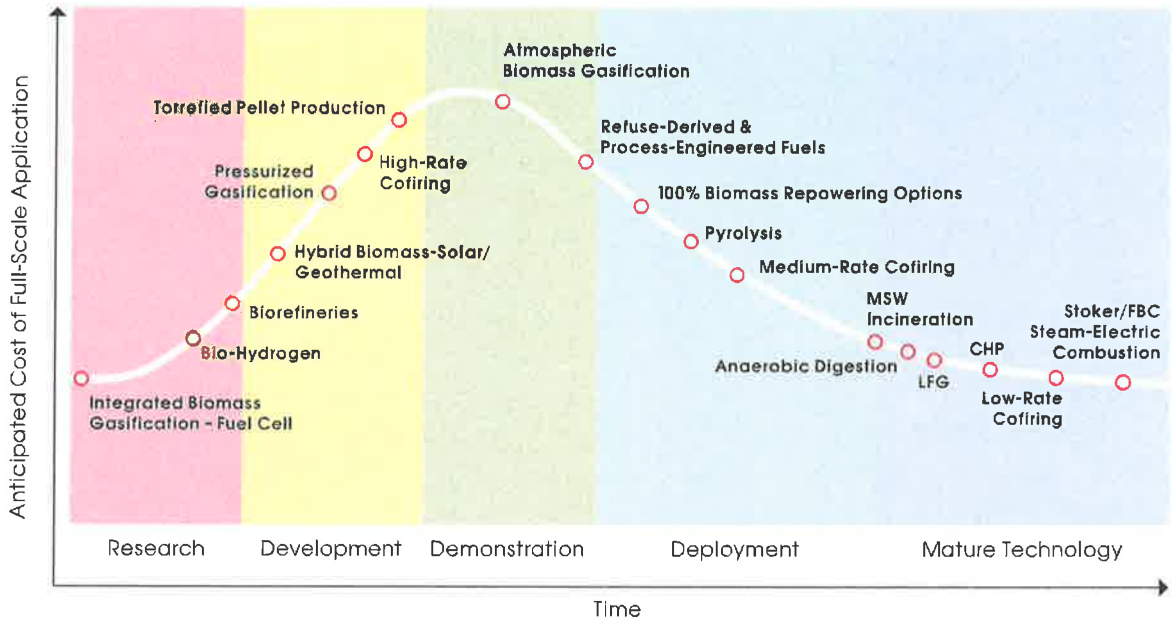


FIGURE 2.1: BIOMASS POWER GENERATION TECHNOLOGY MATURITY STATUS

SOURCE: EPRI, 2011

2.1 BIOMASS COMBUSTION TECHNOLOGIES

Direct combustion of biomass for power generation is a mature, commercially available technology that can be applied on a wide range of scales from a few MW to 100 MW or more and is the most common form of biomass power generation. Around the globe, over 90% of the biomass that is used for energy purposes goes through the combustion route. Feedstock availability and costs have a strong influence on project size and economics, since with increasing scale the increased transport costs for the biomass feedstock may outweigh economies of scale from larger plants. However, this is very project-specific and pre-treatment (e.g. torrefaction) to achieve higher energy densities can help to reduce this impact and allow larger-scale plant.

There are two main components of a combustion-based biomass plant: 1) the biomass-fired boiler that produces steam; and 2) the steam turbine, which is then used to generate electricity.

The two most common forms of boilers are stoker and fluidised bed (see Box 1). These can be fuelled entirely by biomass or can be co-fired with a combination of biomass and coal or other solid fuels (EPA, 2008).

Box 1

BOILER TYPES

Stoker boilers burn fuel on a grate, producing hot flue gases that are then used to produce steam. The ash from the combusted fuel is removed continuously by the fixed or moving grate. There are two general types of stokers. Underfeed boilers supply both the fuel and the air from under the grate. Overfeed boilers supply the fuel from above the grate and the air from below.

Fluidised bed boilers suspend fuels on upward blowing jets of air during the combustion process. They are categorised as either atmospheric or pressurised units. Atmospheric fluidised bed boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between bubbling-bed and circulating-bed boilers is the fluidisation velocity (higher for circulating). Circulating fluidised bed boilers (CFB) separate and capture fuel solids entrained in the high-velocity exhaust gas and return them to the bed for complete combustion. Pressurised CFB are available, although atmospheric-bubbling fluidised bed boilers are more commonly used when the fuel is biomass. They can also be a more effective way to generate electricity from biomass with a higher moisture content than typical in a stoker boiler (UNIDO, 2009).

The steam produced in the boilers is injected into steam turbines. These convert the heat contained in the steam into mechanical power, which drives the generation of electricity. There are three major types of turbines with each one having its own specific characteristics (Table 2.3).

TABLE 2.3: STEAM TURBINE TYPES AND CHARACTERISTICS

Condensing Steam Turbine	Extraction Steam Turbine	Backpressure Steam Turbine
These are designed to obtain the maximum amount of shaft work out of a given steam input in order to maximise electrical efficiency. This is the default choice for a standalone steam electric generating plant.	This is a variation of a straight condensing turbine. It is designed to allow steam to be extracted from the turbine at intermediate pressures in the middle part of the turbine. This is desirable for combined heat and power systems, as the heat and power generation levels can be adjusted to the different requirements. This type of turbine offers a high flexibility of operation but at the expense of electrical efficiency.	This design is mostly used when a constant supply of heat is required to provide steam to an industrial or commercial process. Backpressure turbines discharge steam at high temperatures and pressures. Due to the higher pressure discharge, a backpressure turbine will produce lower amounts of shaft power and have a lower electrical efficiency. Commonly used in Brazil in the sugar cane industry, they are cheaper but less flexible than condensing and extraction steam turbines.

SOURCE: McHALE, 2010.

Box 2

COMBINED HEAT AND POWER

Combined heat and power (CHP), also known as a co-generation, is the simultaneous production of electricity and heat from one source of energy. CHP systems can achieve higher overall efficiencies than the separate production of electricity and heat when the heat produced is used by industry and/or district heating systems (Figure 2.2). Biomass-fired CHP systems can provide heat or steam for use in industry (e.g. the pulp and paper, steel, or processing industries) or for use for space and water heating in buildings, directly or through a district heating network.

The viability of biomass CHP plants is usually governed by the price of electricity and the availability and cost of the biomass feedstock. Although many sources of biomass are available for co-generation, the greatest potential lies in the sugar cane and wood processing industries, as the feedstock is readily available at low cost and the process heat needs are onsite (UNIDO, 2008).

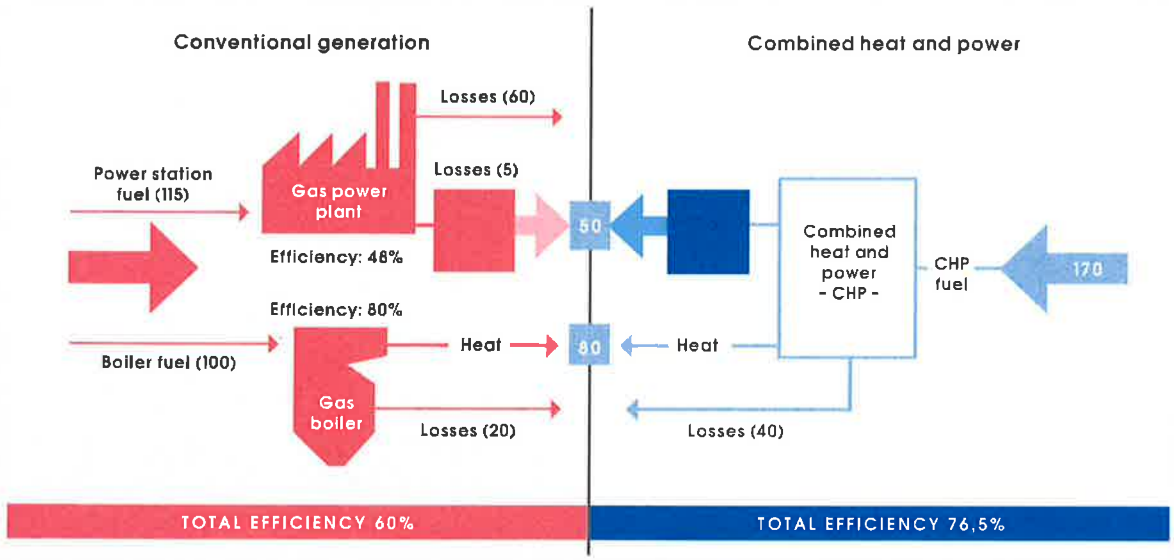


FIGURE 2.2: AN EXAMPLE OF EFFICIENCY GAINS FROM CHP

SOURCE: BASED ON IEA, 2008.

The co-firing of biomass with coal in large coal-fired power plants is becoming increasingly common. Around 55 GW of coal-fired capacity is now co-fired with biomass in North America and Europe (IEA Bioenergy, 2012). In Europe, approximately 45 GW of thermal power generation capacity is co-fired with biomass with from as little as 3% to as much as 95% biomass fuel content. The advantage of biomass co-firing is that, on average, electric efficiency in co-firing plants is higher than in dedicated biomass combustion plants. The incremental investment costs are relatively low although they can increase the cost of a coal-fired power plant by as much as a third.

There are three possible technology set-ups for co-firing (Figure 2.3):

» Direct co-firing, whereby biomass and coal are fed into a boiler with shared or separate burners;

» Indirect co-firing, whereby solid biomass is converted into a fuel gas that is burned together with the coal; and

» Parallel co-firing, whereby biomass is burned in a separate boiler and steam is supplied to the coal-fired power plant.

Technically it is possible to co-fire up to about 20% of capacity without any technological modifications; however, most existing co-firing plants use up to about 10% biomass. The co-firing mix also depends on the type of boiler available. In general, fluidised bed boilers can substitute higher levels of biomass than pulverised coal-fired or grate-fired boilers. Dedicated biomass co-firing plants can run up to 100% biomass at times, especially in those co-firing plants that are seasonally supplied with large quantities of biomass (IRENA, 2012).

However, co-firing more than 20% will usually require more sophisticated boiler process control and boiler design, as well as different combustion considerations, fuel blend control and fuel handling systems due to the demanding requirements of biomass-firing and the need to have greater control over the combustion of mixed-feedstocks.
Biomass is also co-fired with natural gas, but in this case the natural gas is often used to stabilise combustion when biomass with high-moisture content (e.g. municipal solid waste) is used and the percentage of natural gas consumed is generally low (US EPA, 2007).

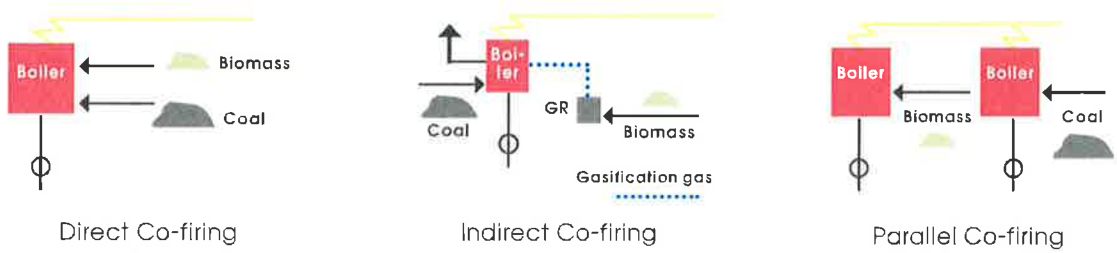


FIGURE 2.3: DIFFERENT BIOMASS CO-FIRING CONFIGURATIONS

SOURCE: EUBIONET, 2003.

An important source of electricity generation from bioenergy today is found in the pulp and paper industry in the form of black liquor. Black liquor is a by-product of the paper-making process and consists of the remaining components after cellulose fibres have been "cooked" out of the wood feedstock. Although initially weak (15% solids), this solution is concentrated by evaporation until it has a solid content of around 75% to 80%. It can then be combusted in an energy recovery boiler or, less commonly, gasified. The black liquor then provides electricity and heat for the process needs of the plant and possibly for export. Combustion in boilers is a mature technology, but commercial gasification technologies are only just being deployed.

2.2 ANAEROBIC DIGESTION

Anaerobic digestion (AD) converts biomass feedstocks with a relatively high moisture content into a biogas. Anaerobic digestion is a naturally occurring process and can be harnessed to provide a very effective means to treat organic materials, including energy crops (although this is often at the R&D stage, depending on the crop), residues and wastes from many industrial and agricultural processes and municipal waste streams (Table 2.4). AD is most commonly operated as a continuous process and thus needs a steady supply of feedstock. The feedstock needs to be strictly checked and usually needs some form of pre-treatment to maximise methane production and minimise the possibility of killing the natural digestion process. Co-digestion of multiple feedstocks is most commonly practised to achieve the best balance of biogas yield and process stability. The two main products of AD are biogas and a residue digestate, which, after appropriate treatment, can be used as a bio-fertiliser. Biogas is primarily a mixture of methane (CH_4) and carbon dioxide (CO_2), as well as some other minor constituents including nitrogen, ammonia (NH_3), sulfur dioxide (SO_2), hydrogen sulfide (H_2S) and hydrogen.

TABLE 2.4: APPROPRIATE ANAEROBIC DIGESTERS BY WASTE OR CROP STREAM

Type of Waste	Liquid Waste	Slurry Waste	Semi-solid Waste
Appropriate digester	Covered lagoon digester/ Upflow anaerobic sludge blanket/Fixed Film	Complete mix digester	Plug flow digester
Description	Covered lagoon or sludge blanket-type digesters are used with wastes discharged into water. The decomposition of waste in water creates a naturally anaerobic environment.	Complete mix digesters work best with slurry manure or wastes that are semi-liquid (generally, when the waste's solids composition is less than 10%). These wastes are deposited in a heated tank and periodically mixed. Biogas that is produced remains in the tank until use or flaring	Plug flow digesters are used for solid manure or waste (generally when the waste's solids composition is 11% or greater). Wastes are deposited in a long, heated tank that is typically situated below ground. Biogas remains in the tank until use or flaring.

SOURCE: CENTRE FOR CLIMATE AND ENERGY SOLUTIONS, 2012.

Biogas is readily used as a fuel in power or combined heat and power units and has the potential to be used as a substitute for natural gas after appropriate cleaning and upgrading (IEA Bioenergy, 2011). Large-scale plants using municipal solid waste (MSW), agricultural waste and industrial organic wastes require between 8 000 and 9 000 tonnes of MSW/MW/year. Landfill gas and digesters are proven technologies, but they can be limited in scale by feedstock availability. Table 2.5 provides an indication of the quantities of three different crop feeds that would be required to power a 500 kW electrical prime mover and its electrical and thermal output.

TABLE 2.5: OPERATIONAL PARAMETERS OF A REPRESENTATIVE ANAEROBIC DIGESTER USING ENERGY CROPS

	per year
Input of maize silage (tonnes)	5 940
Input of grass silage (tonnes)	2 181
Input of clover silage (tonnes)	1 374
Total feedstock (tonnes)	9 495
Biogas production (million m^3)	1.88
Electricity produced (MWh)	4 153
Thermal energy produced (MWh)	4 220
Own electricity consumption (MWh)	161
Own thermal energy consumption (MWh)	701
Electricity available for sale (MWh)	3 992
Thermal energy available for sale (MWh)	1 697

SOURCE: MURPHY ET AL., 2010.

In Europe in mid-2011, Germany, with 7 090 digesters, was the leading country for both the number and installed capacity of AD's (Linke, 2011). The total installed electrical capacity of these plants is 2 394 MW. Virtually all of this capacity is located in the agricultural sector where maize sillage, other crops and animal slurry are used. This important contribution is driven by a feed-in tariff in Germany that supports electricity generation from biogas from AD.

2.3 BIOMASS GASIFICATION TECHNOLOGIES

Gasifier technologies offer the possibility of converting biomass into a producer gas, which can be burned in simple or combined-cycle gas turbines at higher efficiencies than the combustion of biomass to drive a steam turbine. Although gasification technologies are commercially available, more needs to be done in terms of R&D and demonstration to promote their widespread commercial use, as only around 373 MW_{th} of installed large-scale capacity was in use in 2010, with just two additional projects totaling 29 MW_{th} planned for the period to 2016 (US DOE, 2010). The key technical challenges that require further R&D include improving fuel flexibility, removing particulates, alkali-metals and chlorine; and the removal of tars and ammonia (Kurkela, 2010). From an economic perspective, reducing complexity and costs, and improving performance and efficiency are required.

There are three main types of gasification technology[7]:

- Fixed bed gasifiers;
- Fluidised (circulating or bubbling) bed gasifiers; and
- Entrained flow gasifiers.[8]

However, there are a wide range of possible configurations, and gasifiers can be classified according to four separate characteristics:

- Oxidation agent: This can be air, oxygen, steam or a mixture of these gases.
- Heat for the process: This can be either direct (i.e. within the reactor vessel by the combustion process) or indirect (i.e. provided from an external source to the reactor).

7 One additional option is the use of air as the reactive agent, but this yields a very low energy content gas, albeit suitable for use in boilers or internal combustion engines.

8 Entrained flow gasifiers are not discussed in detail in this paper, as their main advantage is the possibility to work at large scales (from 100 MW to over 1 000 MW), which aren't common for biomass-fired power generation projects.

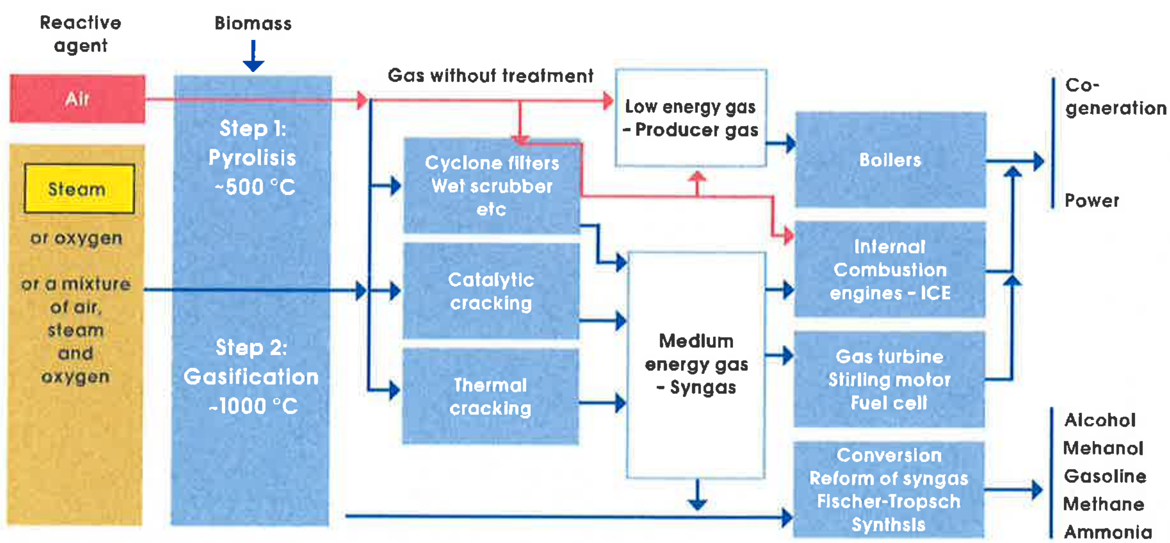
- The pressure level: Gasification can occur at atmospheric pressure or at higher pressures.

- Reactor type: As already discussed, these can be fixed bed, fluidised bed or entrained flow.

Gasification comprises a two-step process. The first step, pyrolysis, is the decomposition of the biomass feedstock by heat. This yields 75% to 90% volatile materials in the form of liquids and gases, with the remaining non-volatile products being referred to as char. The second step is the gasification process, where the volatile hydrocarbons and the char are gasified at higher temperatures in the presence of the reactive agent (air, oxygen, steam or a mixture of these gases) to produce CO and H_2, with some CO_2, methane, other higher hydrocarbons and compounds including tar and ash. These two steps are typically achieved in different zones of the reactor vessel and do not require separate equipment. A third step is sometimes included: gas clean-up to remove contaminants, such as tars or particulates.

Air-based gasifiers are relatively cheap and typically produce a hydrogen/carbon monoxide "producer gas" with a high nitrogen content (from the air) and a low energy content (5–6 MJ/m^3 on a dry-basis). Gasifiers using oxygen or steam as the reactive agent tend to produce a syngas with relatively high concentrations of CO and H_2 with a much higher energy content (9–19 MJ/m^3), albeit at greater cost than an air-blown gasifier

The gasification process is a predominantly endothermic process that requires significant amounts of heat. The producer gas, once produced, will contain a number of contaminants, some of which are undesirable, depending on the power generation technology used. Tars, for example, can clog engine valves and accumulate on turbine blades, leading to increased maintenance costs and decreased performance. Some producer gas clean-up will therefore usually be required. After cleaning, the producer gas can be used as a replacement for natural gas and injected in gas turbines or it can produce liquid biofuels, such as synthetic diesel, ethanol, gasoline or other liquid hydrocarbons via Fischer-Tropsch synthesis.



*Note: Commercial is defined as the equipment available for sale with emission and performance guarantees and currently in commercial operation with an availability equivalent to commercial generation equipment by a party other than the manufacturer or developer of the technology.

FIGURE 2.4: SCHEMATIC OF THE GASIFICATION PROCESS

SOURCE: BASED ON SADAKA, 2010; BELGIORNO, 2003; AND MCHALE, 2010.

One of the key characteristics of gasifiers, in addition to the producer gas they produce, is the size range to which they are suited. Fixed bed downdraft gasifiers do not scale well above around 1 MW_{th} in size due to the difficulty in maintaining uniform reaction conditions (Lettner, 2007). Fixed bed updraft gasifiers have fewer restrictions on their scale while atmospheric and pressurised fluidised bed and circulating bed, and entrained flow gasifiers can provide large-scale gasification solutions.[9]

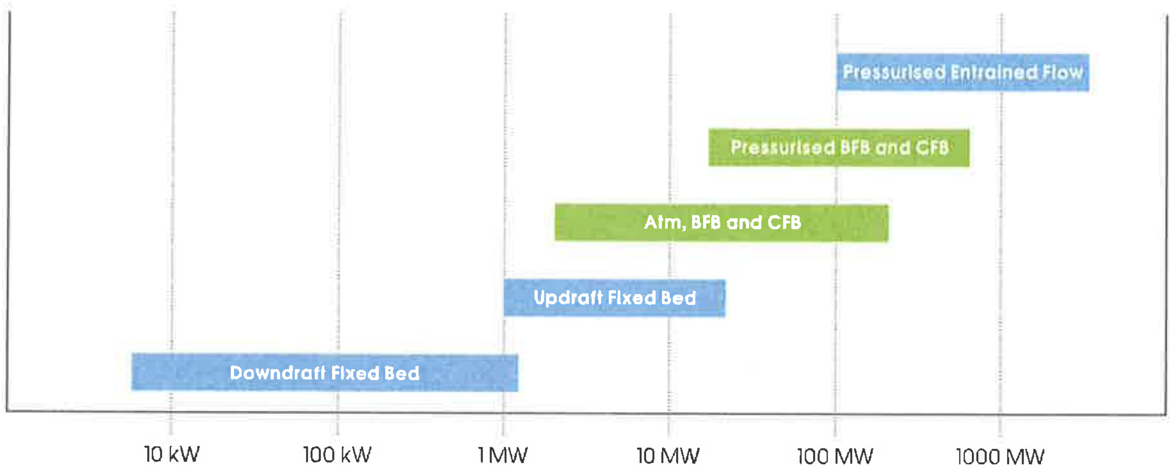


FIGURE 2.5: GASIFIER SIZE BY TYPE

SOURCE: RENSFELT, 2005.

Fixed bed gasifiers

Fixed bed gasifiers typically have a grate to support the gasifying biomass and maintain a stationary reaction bed. They are relatively easy to design and operate and generally experience minimum erosion of the reactor body.

There are three types of fixed bed designs:

- » In an *updraft fixed bed gasifier*, biomass enters at the top of the reactor and the reactive agent (i.e. air, steam and/or oxygen) below the grate. The producer gas, together with tars and volatiles, exits from the top while chars and ashes fall through the grate (at the bottom). These gasifiers are often used for direct heating, but gas clean-up can remove the relatively high levels of tar and other impurities to allow electricity generation or CHP, albeit with increased capital costs.[10] Slagging problems can also arise if high-ash biomass is used.

- » In a *downdraft fixed bed gasifier*, the biomass and the reactive agent are introduced at the top of the reactor and the tars pass through the oxidation and charcoal reduction zones, meaning levels of tar in the gas are much lower than in updraft gasifiers. They tend to require a homogenous feedstock to achieve the best results.

- » *Cross-draft fixed bed gasifiers* are similar to downdraft gasifiers and are often used to

9 *The entrained flow gasifier is based on even higher velocities in the reactor where the material is picked up and carried off in the airflow. They aren't considered here, as there principle benefits of larger scale-up make feedstock sourcing problematic. Other options provide the scale required for biomass power generation*

10 *See for instance http://www.volund.dk/solutions_references/gasification_solutions*

gasify charcoal, but the reactive agent enters at the side, low down in the reactor vessel and parallel to the biomass movement. They respond rapidly to load changes, are relatively simple to construct and the gas produced is suitable for a number of applications. However, they are more complicated to operate and if a fuel high in volatiles and tars is used, very high amounts of tar and hydrocarbons will be present in the producer gas.

Fixed bed gasifiers are the preferred solution for small- to medium-scale applications with thermal requirements up to 1 MW_{th} (Klein, 2002). Updraft gasifiers can scale up to as much as 40 MW_{th}. However, down-draft gasifiers do not scale well beyond 1 MW_{th}.

Biomass gasification is successfully applied in India, and rice-husk gasification is a widely deployed technology. To produce electricity, piles of rice husks are fed into small biomass gasifiers, and the gas produced is used to fuel internal combustion engines. The operation's by-product is rice-husk ash, which can be sold for use in concrete. Several equipment suppliers are active and one, Husk Power Systems (HPS), has installed 60 mini-power plants that power around 25 000 households in more than 250 communities. Investment costs are low (USD 1 000 to USD 1 500/kW) and overall efficiencies are between 7% and 14%, but they are labour-intensive in O&M as there is significant fouling. One of the keys to their success has been the recruitment of reliable staff with a vested interest in the ongoing operation of the plant to ensure this regular maintenance.

Although they do not meet OECD air pollution standards and some developing country standards as well, they can be an important part of off-grid electricity access in rural areas. These systems are being promoted by The International Finance Corporation (IFC) and HPS in Kenya and Nigeria. In Benin, GIZ (Germany) is promoting biomass gasification for combined heat and power (CHP) generation in decentralised settings as an economic alternative to grid extension in remote areas of the country.

The critical factors for these gasification systems are the reliability of the gasifier and the cost of the biomass supply. While feedstock may be free when the first plant begins operating, prices can quickly rise if the technology takes off and competition for feedstock arises. This often places a limit on the potential of waste-based power generation.

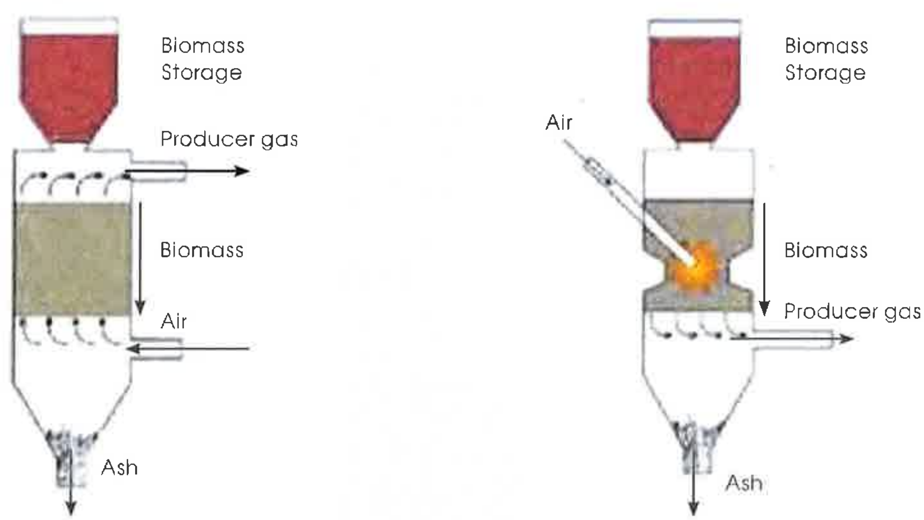


FIGURE 2.6: SMALL-SCALE UPDRAFT AND DOWNDRAFT FIXED BED GASIFIERS

SOURCE: BRANDIN, ET AL. 2011.

Fluidised bed gasifiers

There are two main types of fluidised bed gasifiers: bubbling fluidised bed (BFB) and circulating fluidised bed (CFB), which can be either atmospheric or pressurised.[11] In fluidised bed gasification, the gasification process occurs in a bed of hot inert materials (usually sand or alumina) suspended by an upward motion of oxygen-deprived gas. As the flow increases, the bed of these materials will rise and become "fluidised".

The use of inert materials in the bed increases the rate of reaction of the biomass with the fluidised bed compared to fixed bed reactors, thereby improving performance. In addition to improved performance over fixed bed systems, they can accept a wider range of feedstocks, achieve larger scales and potentially yield a production gas with a higher energy content. However, fluidised bed systems cost more and are significantly more complex. The main advantages and disadvantages of fluidised bed gasifiers are presented in Table 2.6.

Gas clean-up

The gasification process yields a producer gas that contains a range of contaminants, depending on the feedstock and the gasification process. These contaminants are not usually a major problem when the gas is combusted in a boiler or an internal combustion engine.[12] However, when used in turbines to achieve higher electric efficiencies, some form of gas clean-up will be required to ensure the gas reduces contaminant concentrations to harmless levels (Table 2.7). However, the economics of this approach need to be carefully examined for each project, as the removal of these impurities and contaminants increases the capital (the gas clean-up equipment) and operating costs.

Different technologies have different tolerances to contaminants, so the correct design and selection of feedstocks, gasifier and the generating technology can help minimise gas clean-up requirements.

A range of technologies are available to clean up producer gas streams. Cyclones can remove up to 90% of larger particles at reasonable cost, but removing smaller particles will require high-temperature ceramic or sintered metal filters, or the use of electrostatic precipitators.

TABLE 2.6: ADVANTAGES AND DISADVANTAGES OF FLUIDISED BED GASIFIERS

Advantages	Disadvantages	
Fluidised bed gasifiers	**BFB**	**CFB**
Creates a homogenous, good quality producer gas	Complicated control needs	
Can accept a range of feedstocks and particle sizes	Slow response to load changes	
Excellent heat transfer performance through contact with bed materials	Increased cost and complexity	
Large heat storage capacity		Less efficient heat exchange than BFB
Good temperature control		Temperature gradients in the reactor vessel
		Fuel particle size can be an issue
		High velocities can accelerate erosion

11 In BFB gasifiers, the reactive gases pass through the reactor bed at the minimum velocity required to achieve a bubbling effect where the "bubbles" flow upwards through the bed material. At the top of the inert material, the bubbles burst and the bed material falls back into the bed. In CFB gasifiers, the gas velocities are higher than the minimum fluidisation point, resulting in the circulation of the inert bed materials in the gas stream. The bed particles thus exit the top of the reactor with the producer gas and must then be separated in a cyclone to be re-circulated to the reactor.

12 This is not always the case, and some gas clean-up may be required even in these circumstances.

TABLE 2.7: EXAMPLES OF PRODUCER GAS CONTAMINANTS

Contaminants	Examples	Potential problem
Particles	Ash, char, fluid bed material	Erosion in gasifier and prime mover
Alkali metals	Sodium and Potassium compounds	Hot corrosion
Nitrogen compounds	NH_3 and HCN	Local pollutant emissions
Tars	Refractive aromatics	Clogging of filters and other fouling
Sulphur, chlorine	H_2S and HC1	Corrosion, emissions

SOURCE: WIANT, ET AL. 1998.

Tars[13] are a major problem, as they can build up on turbine blades and/or foul turbine systems. One solution to this problem is to "crack" the tars. Cracking can be either thermal or catalytic. Another option is wet scrubbing of the gas to remove up to half the tar and, when used in conjunction with a venturi scrubber, can remove up to 97% of the tar. The disadvantage of simple scrubbing systems is that they cool off the biogas and create a waste stream that has to be disposed of. However, the OLGA tar removal process is based on multiple scrubbers and effectively recycles almost all of the tar to the gasifier to be eliminated.[14]

Biomass integrated combined cycle gasification

Biomass integrated combined cycle gasification (BIGCC), or biomass integrated gas turbine technology (BIG-GT), as it is sometimes referred to, has the potential to achieve much higher efficiencies than conventional biomass-powered generation using steam cycles by creating a high quality gas in a pressurised gasifier that can be used in a combined cycle gas turbine. Significant R&D was conducted and pilot-scale plants were built in the late 1990s and the early 2000s. Several demonstration plants were also built. However, performance has not been as good as hoped for, and the higher feedstock costs for large-scale BIGCC and the higher capital costs due to fuel handling and biomass gasification has resulted in a cooling of interest.

Pyrolysis

Pyrolysis is a subset of the gasification system. Essentially, pyrolysis uses the same process as gasification, but the process is limited to between 300°C and 600°C. Conventional pyrolysis involves heating the original material in a reactor vessel in the absence of air, typically at between 300°C and 500°C, until the volatile matter has been released from the biomass. At this point, a liquid bio-oil is produced, as well as gaseous products and a solid residue. The residue is char – more commonly known as charcoal – a fuel which has about twice the energy density of the original biomass feedstock and which burns at a much higher temperature. With more sophisticated pyrolysis techniques, the volatiles can be collected, and careful choice of the temperature at which the process takes place allows control of their composition. The liquid bio-oil produced has similar properties to crude oil but is contaminated with acids and must be treated before being used as fuel. Both the charcoal and the oil produced by this technology could be used to produce electricity (although this is not yet commercially viable) and/or heat.

13 Tars are the name given to the mostly poly-nuclear hydrocarbons, such as pyrene and anthracene, that form as part of the gasification process.

14 For a description of the process see http://www.renewableenergy.nl/index.php?pageID=3220&n=545&itemID=351069

3. Feedstock

Biomass is the organic material of recently living plants from trees, grasses and agricultural crops. Biomass feedstocks are very heterogenous and the chemical composition is highly dependent on the plant species. This highly hetrogenous nature of biomass can be a problem since, although some combustion technologies can accept a wide range of biomass feedstocks, others require much more homogenous feedstocks in order to operate.

TABLE 3.1: HEAT CONTENT OF VARIOUS BIOMASS FUELS (DRY BASIS)

	Higher heating value MJ/kg	Lower heating value MJ/kg
Agricultural Residues		
Corn stalks/stover	17.6 – 20.5	16.8 – 18.1
Sugarcane bagasse	15.6 – 19.4	15 – 17.9
Wheat straw	16.1 – 18.9	15.1 – 17.7
Hulls, shells, prunings	15.8 – 20.5	
Fruit pits		
Herbaceous Crops		
Miscanthus	18.1 – 19.6	17.8 – 18.1
Switchgrass	18.0 – 19.1	16.8 – 18.6
Other grasses	18.2 – 18.6	16.9 – 17.3
Bamboo	19.0 – 19.8	
Woody Crops		
Black locust	19.5 – 19.9	18.5
Eucalyptus	19.0 – 19.6	18.0
Hybrid poplar	19.0 – 19.7	17.7
Douglas fir	19.5 – 21.4	
Poplar	18.8 – 22.4	
Maple wood	18.5 – 19.9	
Pine	19.2 – 22.4	
Willow	18.6 – 20.2	16.7 – 18.4
Forest Residues		
Hardwood wood	18.6 – 20.7	
Softwood wood	18.6 – 21.1	17.5 – 20.8
Urban Residues		
MSW	13.1 – 19.9	12.0 – 18.6
RDF	15.5 – 19.9	14.3 – 18.6
Newspaper	19.7 – 22.2	18.4 – 20.7
Corrugated paper	17.3 – 18.5	17.2
Waxed cartons	27.3	25.6

SOURCES: US DOE, 2012; JENKINS, 1993; JENKINS, ET AL., 1998; TILMAN, 1978; BUSHNELL, 1989; ECN, 2011; AND CIOLKOSZ, 2010.

Biomass' chemical composition is comprised of a generally high (but variable) moisture content, a fibrous structure, which is comprised of lignin, carbohydrates or sugars and ash. Ligno-cellulose is the botanical term used to describe biomass from woody or fibrous plant materials. It is a combination of lignin, cellulose and hemicellulose polymers interlinked in a heterogenous matrix. The chemical composition of the biomass feedstock influences its energy density. Table 3.1 presents the energy density on a dry basis of different feedstocks. Hardwoods tend to have higher energy densities but tend to grow more slowly.

The main characteristics that affect the quality of biomass feedstock are moisture content, ash content and particle size, and density.

Moisture content

The moisture of biomass can vary from 10% to 60%, or even more in the case of some organic wastes. Stoker and CFB boilers can accept higher moisture content fuel than gasifiers. In anaerobic digestion, several options are available, including high solids-dry, high solids-wet or low solids-wet. In the case of a low solids-wet configuration, such as with manure slurry, the solids content can be 15% or less.[15] The key problem with a high moisture content, even when it is destined for anaerobic digestion, is that it reduces the energy value of the feedstock. This increases transportation costs and the fuel cost on an energy basis, as more wet material is required to be transported and provide the equivalent net energy content for combustion.[16] Figure 3.1 presents the impact of moisture content on the price per unit of energy (net) of a wood feedstock for a range of prices of the wet feedstock per tonne.

Improving the energy density of the feedstock helps to reduce transportation costs and can improve combustion efficiency. The principal means of achieving this is through drying by natural or accelerated means. Other options include torrefaction, pelletising or briquetting, and conversion to charcoal. The trade-off is that these processes increase feedstock prices, and the energy balance decreases significantly due to the energy consumption used for the pre-treatment of the biomass. However, although this increases the costs per tonne of feedstock, it can sometimes reduce the price of the feedstock per unit of energy.

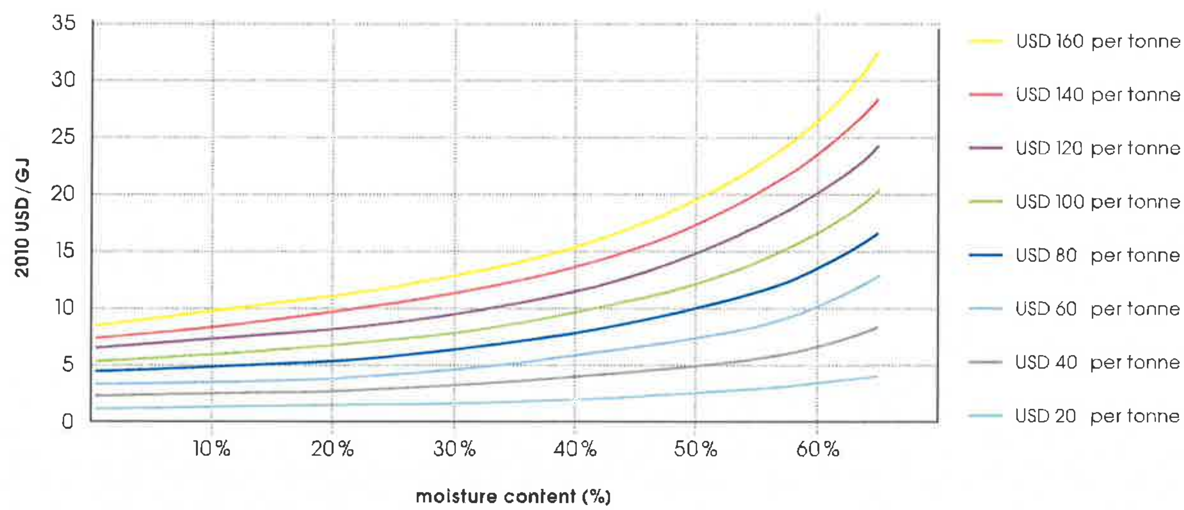


FIGURE 3.1: IMPACT OF MOISTURE CONTENT ON THE PRICE OF FEEDSTOCK COST ON A NET ENERGY BASIS

15 Although virtually any organic material can be used as a feedstock for anaerobic digestion, the more putrescible (digestible) the feedstock the higher the potential gas yield.

16 That is to say the remaining energy of the fuel after the energy required to evaporate the water contained in the feedstock.

Ash content and slagging

An important consideration for feedstocks is the ash content, as ash can form deposits inside the combustion chamber and gasifier, called "slagging" and "fouling", which can impair performance and increase maintenance costs. Grasses, bark and field crop residues typically have higher amounts of ash than wood.

Slagging occurs in the boiler sections that are directly exposed to flame irradiation. Slagging deposits consist of an inner powdery layer followed by deposits of silicate and alkali compounds. Fouling deposits form in the convective parts of the boiler, mainly due to condensation of volatile compounds that have been vaporised in previous boiler sections and are loosely bonded (Masiá, 2005).

Slagging and fouling can be minimised by keeping the combustion temperature low enough to prevent the ash from fusing. Alternately, high-temperature combustion could be designed to encourage the formation of clinkers (hardened ash), which could then be more easily disposed of.

Some types of biomass have problems with the ash generated. This is the case for rice husks that need special combustion systems due to the silica content of the husks.[17]

Feedstock size

The size and density of the biomass is also important because they affect the rate of heating and drying during the process (Ciolkosz, 2010). Large particles heat up more slowly than smaller ones, resulting in larger particles producing more char and less tar (Sadaka, 2010). In fixed bed gasifiers, fine-grained and/or fluffy feedstock may cause flow problems in the bunker section, resulting in an unacceptable pressure drop in the reduction zone and a high proportion of dust particles in the gas. In downdraft gasifiers, the large pressure drop can also reduce the gas load, resulting in low temperatures and higher tar production.

The type of handling equipment is also determined by the size, shape, density, moisture content and composition of the fuel. The wrong design will have an impact on the efficiency of the combustion/ gasification process and may cause damage to the handling system.

Biogas from anaerobic digestion and landfill gas

In anaerobic digestion and landfill gas, the presence of non-fuel substances reduces the amount of gas produced. The biogas is primarily methane and CO_2, and more methane means more energy content of the biogas. The methane formation is influenced by parameters like moisture content, percentage of organic matter, pH and temperature. Hence, control of these characteristics is a crucial prerequisite to having a good quality gas for electricity generation.

Overview of biomass power generation technologies and biomass feedstock characteristics

Table 3.2 gives an overview of biomass technology, feedstock and the requirements on particle size and moisture content. Co-firing in coal-fired power plants has the most stringent requirements for moisture content and feedstock size if efficiency is not to be degraded.

17 For experience in Brazil, see Hoffman et al.(undated) http://www.ufsm.br/cenergia/arte_final.pdf

TABLE 3.2: BIOMASS POWER GENERATION TECHNOLOGIES AND FEEDSTOCK REQUIREMENTS

Biomass conversion technology	Commonly used fuel types	Particle size requirements	Moisture content requirements (wet basis)	Average capacity range
Stoker grate boilers	Sawdust, non-stringy bark, shavings, end cuts, chips, hog fuel, bagasse, rice husks and other agricultural residues	6 - 50 mm	10 - 50%	4 to 300 MW many in 20 to 50 MW range
Fluidised bed combustor (BFB or CFB)	Bagasse, low alkali content fuels, mostly wood residues with high moisture content, other. No flour or stringy materials	< 50 mm	< 60%	Up to 300 MW (Many at 20 to 25 MW)
Co-firing: pulverised coal boiler	Sawdust, non-stringy bark, shavings, flour, sander dust	< 6 mm	< 25%	Up to 1500 MW
Co-firing: stokers, fluidised bed	Sawdust, non-stringy bark, shavings, flour, hog fuel, bagasse	< 72 mm	10 - 50%	Up to 300 MW
Fixed bed (updraft) gasifier	Chipped wood or hog fuel, rice hulls, dried sewage sludge	6 - 100 mm	< 20%	5 to 90 MW_{th}, + up to 12 MW_e
Downdraft, moving bed gasifier	Wood chips, pellets, wood scrapes, nut shells	< 50 mm	< 15%	~ 25 - 100 kW
Circulating fluidised bed, dual vessel, gasifier	Most wood and chipped agricultural residues but no flour or stringy materials	6 - 50 mm	15 - 50%	~ 5 - 10 MW
Anerobic digesters.	Animal manures & bedding, food processing residues, MSW, other industry organic residues	NA	65% to 99.9% liquid depending on type (i.e. from 0.1 to 35% solids)	

SOURCE: US EPA, 2007.

4. Global Biomass Power Market Trends

4.1 CURRENT INSTALLED CAPACITY AND GENERATION

In 2010 the global installed capacity of biomass power generation plants was between 54 GW and 62 GW (REN21, 2011 and Platts, 2011). The range suggests that power generation from biomass represents 1.2% of total global power generation capacity and provides around 1.4% to 1.5% of global electricity production (Platts, 2011 and IEA, 2011).

Europe, North America and South America account for around 85% of total installed capacity globally. In Europe, 61% of total European installed capacity using solid biomass (excluding wood chips) is in England, Scotland and Sweden. Wood-fired biomass power capacity is concentrated in Finland, Sweden, England and Germany. Together these four countries account for 67.5% of European wood-fired biomass power generation capacity. Landfill gas capacity is concentrated in England with 45% of the European total, while biogas capacity is concentrated in Germany with 37% of total European capacity. In North America wood accounts for 65% of total installed capacity and landfill gas 16% (Platts, 2011). In South America, Brazil is the largest producer of biomass electricity as a result of the extensive use of bagasse for co-generation in the sugar and ethanol industry.

Despite the large biomass resources in developing and emerging economies, the relative contribution of biomass is small, with the majority of biomass capacity located in Europe and North America. The

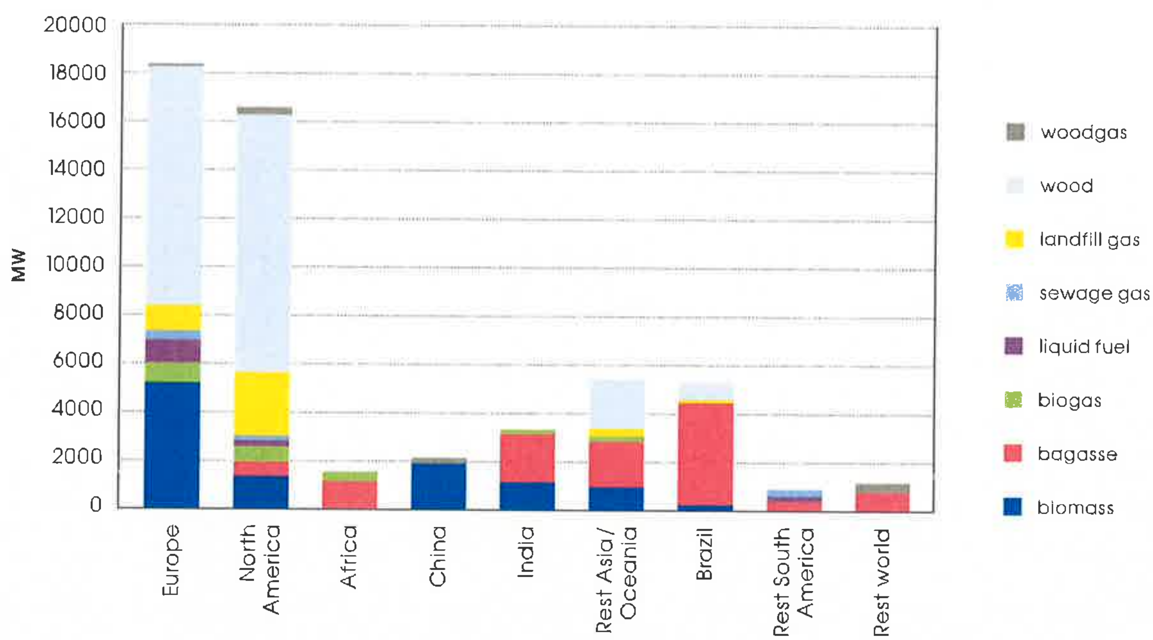


FIGURE 4.1: GLOBAL GRID-CONNECTED BIOMASS CAPACITY IN 2010 BY FEEDSTOCK AND COUNTRY/REGION (MW)

SOURCE: PLATTS, 2011.

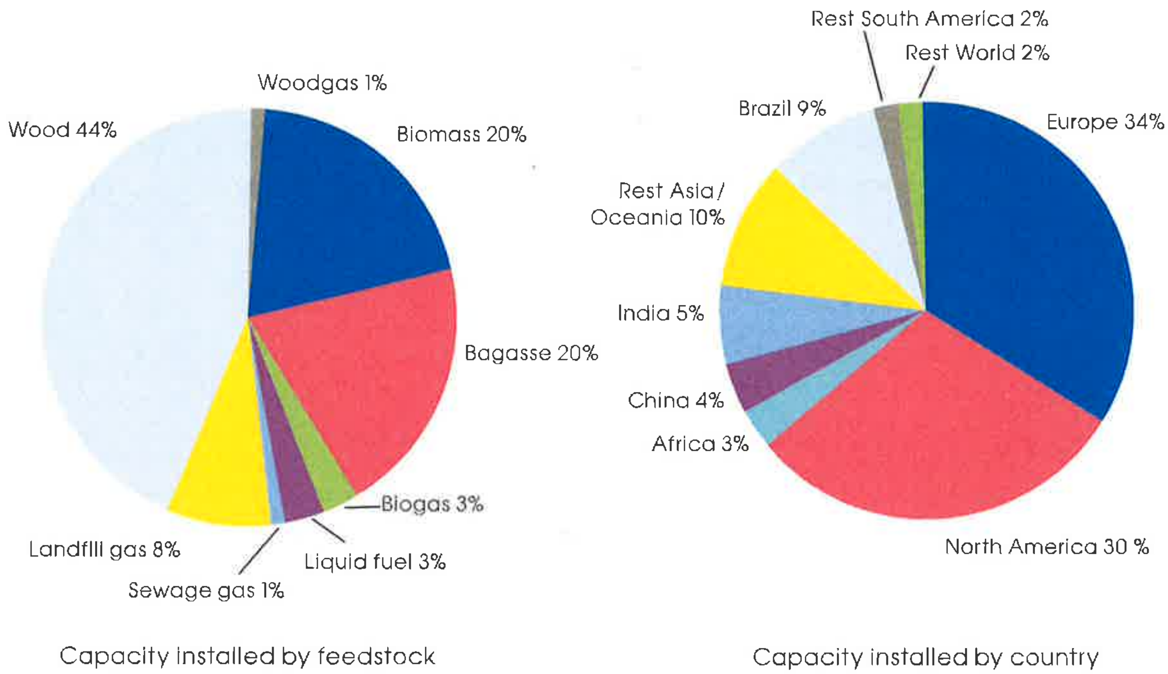


FIGURE 4.2: SHARE OF GLOBAL INSTALLED BIOMASS CAPACITY IN 2010 BY FEEDSTOCK AND COUNTRY/REGION

SOURCE: PLATTS, 2011.

combustion of bagasse is the dominant source of electricity from bioenergy in non-OECD countries. In Brazil, the combustion of bagasse from the large sugar cane industry accounted for around 4.4 GW of grid-connected capacity in 2010 (Figure 4.1)

Around 84% of total installed biomass power generation today is based on combustion with steam turbines for power generation, with around half of this capacity also producing heat (combined heat and power) for industry or the residential and service sectors.

The co-firing of thermal plants with biomass is becoming increasingly common. By the end of 2011, around 45 GW of thermal capacity was being co-fired with biomass to some extent in Europe. In North America, around 10 GW of capacity is co-firing with biomass (IEA Bioenergy, 2012 and Platts, 2011).[18]

Table 4.1 presents examples of the co-firing of biomass in coal-fired power plants in the Netherlands. The level of co-firing ranges from 5% to 35% and there is a range of technologies and feedstocks being used.

4.2 FUTURE PROJECTIONS OF BIOMASS POWER GENERATION GROWTH

Biomass currently accounts for a significant, but declining share of total renewable power generation capacity installed worldwide, but significant growth is expected in the next few years due to support policies for renewable energy in Europe and North America. In addition to the environmental and energy security benefits all renewables share, biomass has the additional advantage that is a schedulable renewable power generation source and can complement the growth in other variable renewables. Biomass for CHP can also greatly improve the economics of

18 The Platts data identifies power plants with the capacity to co-fire, unfortunately no statistics are available on the amount of biomass used in co-firing. Another source of data is the co-firing database, created by IEA Bioenergy, which can be found at http://www.ieabcc.nl/database/cofiring.php.

TABLE 4.1: DETAILS OF FOSSIL-FUEL FIRED POWER PLANTS CO-FIRING WITH BIOMASS IN THE NETHERLANDS

Power plant	Type of combustion	MW	Co-firing
Gelderland 13	Direct co-combustion with separate milling, injection of pulverised wood in the pf-lines and simultaneous combustion	635	5%
Amer 8	Direct co-combustion: separate dedicated milling and combustion in dedicated biomass burners	645	20%
Amer 9	Direct co-firing: biomass is milled separately in dedicated mills and combusted in separate burners	600	35%
Amer 9	Indirect co-firing : gasification in an atmospheric circulating bed gasifier and co-firing of the fuel gas in the coal-fired boiler	33	n/a
Borssele 12	Practice 1: direct co-firing by separate milling and combustion Practice 2: direct co-firing by mixing with the raw coal before the mills	403	16%
Maasvlakte 1&2	Practice 1: direct co-firing of biomass, pulverised in a separate hammer mill, injection into the pf-lines and simultaneous combustion. Practice 2: liquid organics fired in separate oil burners	1040	12%
Willem Alexandre	Direct co-gasification	253	30%
Maasbracht	Direct co-firing of palm-oil in dedicated burners	640	15%

SOURCE: EUBIA, 2011.

biomass power generation, particularly when there are low cost sources (e.g. residues from industry or agriculture) located next to industrial heat process heat needs. Another important synergy for biomass power generation is with the biofuels industry, as the residues from biofuels feedstock (e.g. bagasse, corn stover and straw) and biofuels process residues can be used as raw material for co-generation systems.

The total capacity of proposed biomass power generation projects that are either under construction or have secured financing and will be completed by 2013 is 10 GW. The vast majority of these projects (87%) are for combustion technologies, but plans for new biogas capacity in Germany (due to its feed-in tariff schemes for biogas) and the United States are also in the pipeline (BNEF, 2011). However, when co-firing plans are also considered, projects based on biomass combustion account for 94% of the projects that will be built by 2013.

In the longer term, biomass and waste[19] power generation could grow from 62 GW in 2010 to 270 GW in 2030 (BNEF, 2011). The expected annual investment to meet this growth would be between USD 21 billion and USD 35 billion (Figure 4.4). This would represent around 10% of new renewables' capacity and investment until 2030. China and Brazil appear to have the largest potential: growth in Brazil will be based on the continuing development of the biofuel industry and the possibilities for using the resulting bagasse for electricity generation, while in China better utilisation of the large quantities of agricultural residues and waste produced is possible. In Europe, Germany and the United Kingdom are likely to be the largest markets for biomass technologies, especially co-firing. The United States and Canada will be important sources of biomass feedstock, particularly wood chips and pellets (BNEF, 2011).

19 Considering biogas combustion from agriculture animal waste and landfill gas; energy from waste in solid municipal waste facilities, including incineration and gasification; combustion of biomass pellets, either in dedicated facilities or co-firing in coal plants; and combustion of bagasse in sugar-cane producing plants

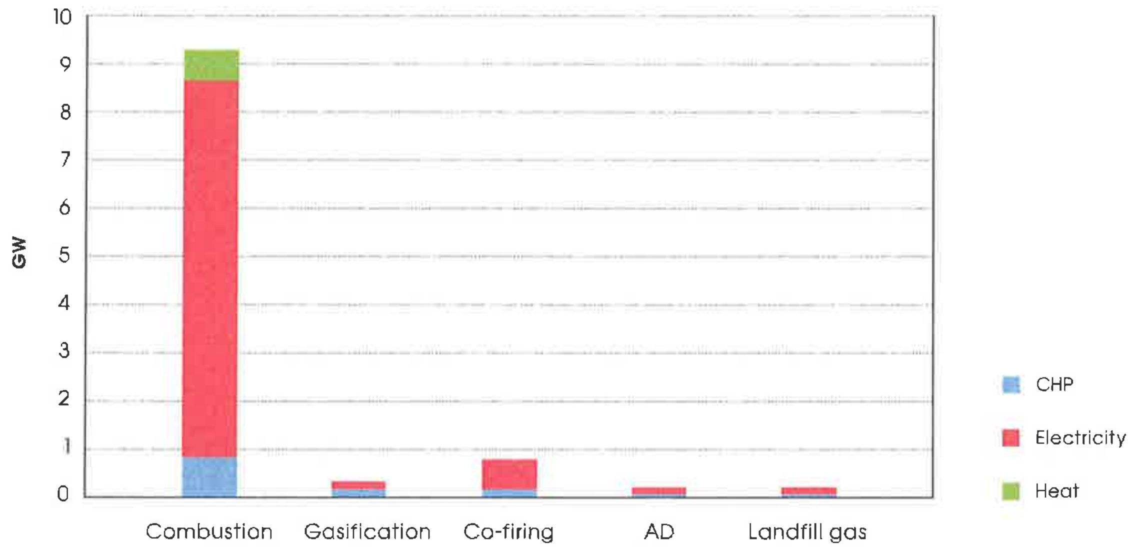


FIGURE 4.3: BIOMASS POWER GENERATION PROJECTS WITH SECURED FINANCING/UNDER CONSTRUCTION (GW)

SOURCE: BASED ON BNEF, 2011

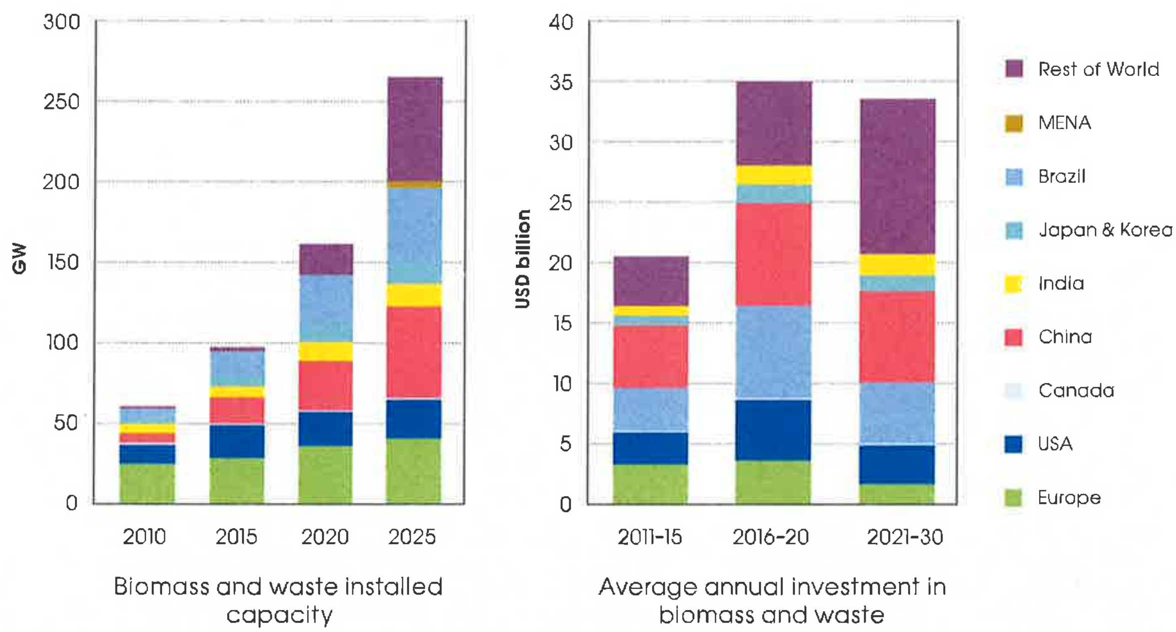


FIGURE 4.4: PROJECTED BIOMASS AND WASTE INSTALLED CAPACITY FOR POWER GENERATION AND ANNUAL INVESTMENT, 2010 TO 2030

SOURCE: BASED ON BNEF, 2011.

The main assumptions driving the scenario to 2030 are:

- The abundance of forest residues and their proven exploitation in Scandinavian countries;
- The supportive policy environment for biomass-fired power generation, for instance from the EU directives on the promotion of renewable energy;
- The targets adopted by the China's Government to incentivise waste-to-energy capacity due to a need to dispose of agricultural residues and waste; and
- The future increase of co-firing, especially in Europe and North America.

4.3 FEEDSTOCK MARKET

With some notable exceptions, there are few formal price markets for biomass. The biomass market is primarily focused on the trade of wood chips and pellets. However, the vast majority of biomass feedstock is not traded, as it is used for domestic cooking, heating and lighting. In addition, the low energy content of biomass, its bulky nature and the costs of handling and transporting biomass feedstocks also tends to mean that local markets often are not integrated.

The majority of the biomass used for power generation therefore comes from non-traded sources, such as wastes and residues from agricultural and industrial processes, forestry arisings, etc. that are consumed locally. In certain regions, this may not be the case, and significant commercial markets for biomass feedstocks may exist. However, in general, the local nature of feedstock sources means that biomass power generation plants tend to be small in scale (up to 50 MW is typical), as securing enough low-cost feedstock for large-scale plants once transportation is taken into account is challenging.

However, a small but growing trade is emerging in pellets and wood chips. The support policies for renewable power generation in many regions will support further growth in these markets. First used for district and household heating, wood chips and pellets are increasingly being used to co-fire fossil fuel power plants or to displace them entirely. In the first nine months of 2010, the EU 27 imported 1.7 million tonnes of wood pellets, which does not include intra-EU trade (Forest Energy Monitor). Currently, the Netherlands is the largest EU importer of wood pellets with 0.77 million tonnes (Mt) imported in 2010 (Forest Energy Monitor, 2011).

The trade in wood chips is much larger than that of pellets for the moment and tends to be more regional and international. Japan is the main market for wood chips and accounted for 77% of the 19.4 million oven dry tonnes (ODT) shipped in 2008 (Junginger, 2011). Although data exist for the wood chip and pellets trade, limited data on the amount that is being burned in co-fired coal power plants are available.

China appears as an important forest biomass importer from North America. In 2010 it imported 29 Mt, twice that of in the previous year (14 Mt), but the primarily use of this biomass is for heating and charcoal production as co-firing and direct burning of biomass is still in the commencement stage.

An analysis of the world market estimates that 8 Mt of pellets was traded internationally in 2008, as well as 1.8 Mt in the United States and 1.4 Mt in Canada for a total of 11.2 Mt. Canada, the United States and Western Russia are the major exporters to Europe. The largest consumers are Sweden, Denmark, the Netherlands, Belgium, Germany and Italy. Scenarios for development of supply and demand for power production until 2015 suggest that pellet demand for the electricity market will be approximately 8 Mt in 2015 although this is highly dependent on support policies, logistics and the possible introduction of sustainability criteria. The British and Dutch markets will experience the strongest expected growth between 2011–2015, growing to 1.5 Mt per year in the Netherlands and 4.5 Mt per year in the UK (Junginger, 2011).

For non-traded biomass, the only costs for the raw material are often the transport, handling and storage required to deliver the biomass wastes or residues to the power plant. Some local markets do exist, but these are based on bilateral contracts and data are often not available on prices paid. For instance, prices in Brazil for bagasse can range from USD 7.7 to USD 26.5/tonne. The problem with low-cost feedstocks that are associated with agricultural production is that, in the case of an independent power producer, the amount of bagasse available depends on the ethanol and sugar markets. This makes it difficult to negotiate long-term contracts that are designed to reduce price risk and guarantee security of feedstock supply that will be required to allow access to financing. The same issues can often occur with other waste and residue streams, such as sawdust, bark, chips, black liquor, etc. This is one of the reasons why many biomass power projects, particularly for CHP, are promoted by the industry which controls the process that produces the wastes and residues.

5. Current Costs of Biomass Power

5.1 FEEDSTOCK PRICES

Unlike wind, solar and hydro biomass electricity generation requires a feedstock that must be produced, collected, transported and stored. The economics of biomass power generation are critically dependent upon the availability of a secure, long term supply of an appropriate biomass feedstock at a competitive cost.

Feedstock costs can represent 40% to 50% of the total cost of electricity produced. The lowest cost feedstock is typically agricultural residues like straw and bagasse from sugar cane, as these can be collected at harvest (ECF, 2010). For forest arising, the cost is dominated by the collection and transportation costs. The density of the forestry arisings has a direct impact on the radius of transport required to deliver a given energy requirement for a plant. The low energy density of biomass feedstocks tends to limit the transport distance from a biomass power plant that it is economical to transport the feedstock. This can place a limit on the scale of the biomass power plant, meaning that biomass struggles to take advantage of economies of scale in the generating plant because large quantities of low-cost feedstock are not available.

The prices of pellets and woodchips are quoted regularly in Europe by ENDEX and PIX (Table 5.1). The prices are for delivery to Rotterdam or North/Baltic Sea ports and do not include inland transport to other areas.

Prices for biomass sourced and consumed locally are difficult to obtain and no time series data on a comparable basis are available. Prices paid will depend on the energy content of the fuel, its moisture content and other properties that will impact the costs of handling or processing at the power plant and their impact on the efficiency of generation. Table 5.2 presents price estimates for biomass feedstocks in the United States.

The 2011 "U.S. Billion-ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry" provides very detailed estimates of the amount of biomass feedstocks available at different prices in the United States. Figure 5.1 presents the results of this analysis for forest and wood wastes, agricultural biomass and wastes, and dedicated energy crops, respectively.

TABLE 5.1: BIOMASS AND PELLET MARKET PRICES, JANUARY 2011

Europe	USD/tonne	USD/GJ
Industrial wood pellets (1)	166	9.8
Industrial wood pellets (2)		11.1
North America	**USD/tonne**	**USD/GJ**
Energy Chips/residuals-North East U.S. (3)		3.7

Notes: (1) ENDEX - CIF Rotterdam; (2) PIX - CIF Baltic Sea or North Sea port; (3) Mixed grades, delivered.

SOURCE: FOREST ENERGY MONITOR, 2011.

TABLE 5.2: BIOMASS FEEDSTOCK PRICES AND CHARACTERISTICS IN THE UNITED STATES

	Tyical Moisture content	Heat value MJ/kg (LHV)	Price (USD/GJ)	Price (USD/tonne)	Cost structure
Forest residues	30% - 40%	11.5	1.30 - 2.61	15 - 30	Collecting, harvesting, chipping, loading, transportation and unloading. Stumpage fee and return for profit and risk.
Wood waste (a)	5% - 15%	19.9	0.50 - 2.51	10 - 50	Cost can vary from zero, where there would otherwise be disposal costs, to quite high, where there is an established market for their use in the region.
Aricultural residues (b)	20% - 35%	11.35 - 11.55	1.73 - 4.33	20 - 50	Collecting, premium paid to farmers, transportation.
Energy crops (c)	10% - 30%	14.25 - 18.25	4.51 - 6.94	39 - 60	Not disclosed.
Landfill gas		18.6 - 29.8 (d)	0.94 - 2.84[1]	0.017 - 0.051 (d)	Gas collection and flare.

Notes:

(a) Sawmills, pulp and paper companies (bark, chip, sander dust, sawdust). Moisture content is often low because they have already been through a manufacturing process. In cases where disposal is required, prices can be zero as the avoided costs of disposal can make it worthwhile to find a productive use for the feedstock.

(b) Corn stover and straw.

(c) Poplar, willow and switchgrass. Disadvantages of energy crops are higher overall cost than many fossil fuels, higher-value alternative land uses that further drive up costs.

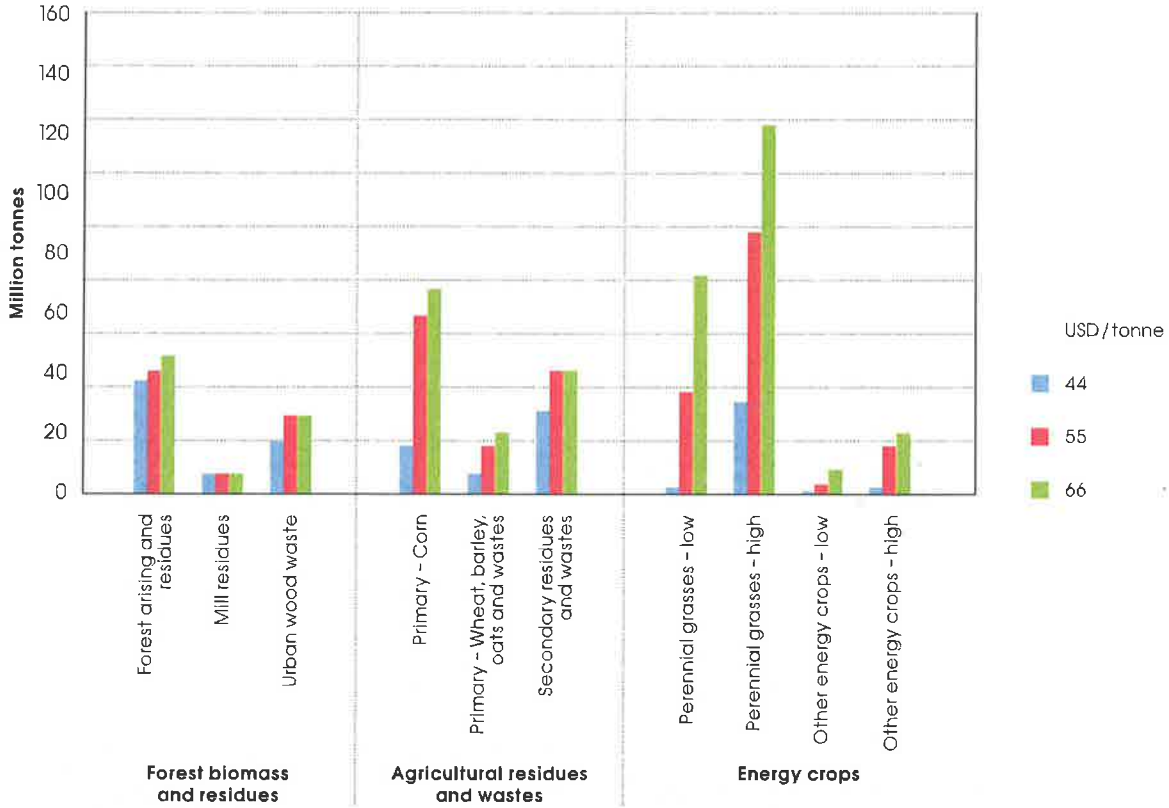
(d) For landfill gas the heat value and price is in MJ/m³ USD/m³.

SOURCE: BASED ON US EPA, 2007.

This analysis for the United States is based on detailed geographic simulations and includes supply curves for the different biomass feedstocks by region. Detailed analysis of this nature helps to give policy-makers confidence in resource availability and costs when developing support policies for biomass. Significant quantities of bioenergy feedstocks are available from forestry arisings and other residues while significant residues and wastes from corn production are available at USD 55/tonne and above. Dedicated energy crop availability is strongly related to cost, representing the important impact that the best crop, land and climate conditions can have on feedstock costs.

Other important cost considerations for biomass feedstocks include the preparation the biomass requires before it can be used to fuel the power plant. Analysis suggests that there are significant economies of scale in biomass feedstock preparation and handling (Figure 5.2).[20] The capital costs fall from around USD 29 100/tonnes/day for systems with 90

20 The fuel preparation systems analysed (receiving, processing, storage and fuel metering conveyors, meters and pneumatic transport) were based on three separate systems: 100 tons/day, manual handling. 50% moisture content; 450 tons/day and 680 tons/day, automatic handling, 30% moisture content; which allowed drawing a trend line of the handling costs system based on the quantity of fuel being prepared per day (ton/day).



Note: "Secondary residues and wastes" include rice field and husk residues, cotton field residues and gin trash, sugarcane residue, orchard and vineyard prunings, wheat dust and animal manure. "Other energy crops" include woody crops and annual energy crops. Energy crop data are for 2017, all other data for 2012.

FIGURE 5.1: BREAKDOWN OF BIOMASS AND WASTE AVAILABILITY BY COST IN THE UNITED STATES, 2012/2017

SOURCE: US DOE, 2011.

tonnes/day throughput to USD 8 700/tonnes/day for systems with 800 tonnes/day. The capital costs for preparation and handling can represent around 6% to 20% of total investment costs of the power plant for systems above 550 tonnes/day. Assuming a heat value of forest residue with 35% moisture content to be 11 500 kJ/kg, the handling capital costs could therefore range from a low of USD 772/GJ/day to as high as USD 2 522/GJ/day.

In Europe, recent analysis of four biomass sources and supply chains identified feedstock costs of between USD 5.2 and USD 8.2/GJ for European sourced woodchips (European Climate Foundation et al., 2010). Local agricultural residues were estimated to cost USD 4.8 to USD 6.0/GJ. Imported pellets from North America are competitive with European wood chips if they must be transported from Scandinavia to continental Europe.[21] These are representative examples, and there will be significant variation in actual feedstock costs, depending on the actual project details.[22]

21 According to the report, at present forest residues and agricultural residues are only utilised to a significant extent in Scandinavia and Denmark respectively and there are only two pellet mills in the world with a production capacity of 500 000 tons per year or more.
22 For pellets the heat value considered was 16 900 kJ/kg and moisture content of 10%.

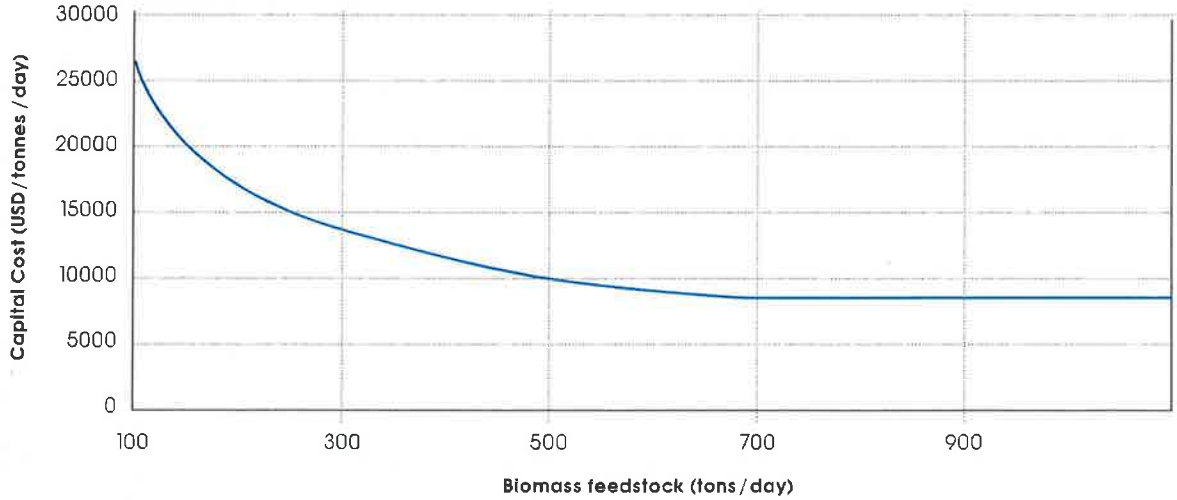


FIGURE 5.2: BIOMASS FEEDSTOCK PREPARATION AND HANDLING CAPITAL COSTS AS A FUNCTION OF THROUGHPUT

SOURCE: US EPA, 2007.

TABLE 5.3: BIOMASS FEEDSTOCK COSTS INCLUDING TRANSPORT FOR USE IN EUROPE

		Feedstock		Transport		Total costs	
		USD / GJ	USD / tonne	USD / GJ	USD / tonne	USD / GJ	USD / tonne
Woodchips from local energy crops		5.2 - 8.2	60 - 94	-	-	5.2 - 8.2	60 - 94
Woodchips from Scandinavian forest residues to continental Europe		5.6 - 6.7	64 - 77	3.0 - 3.4	34 - 38	8.6 - 10.1	98 - 115
Local agricultural residues		4.8 - 6.0	55 - 68	-	-	4.8 - 6.0	55 - 68
Imported pellets (from U.S. to continental Europe)	Feedstock	3.0 - 3.7	50 - 63	-	-	3 - 3.7	50-63
	Pelletising	3 - 3.4	50 - 56	-	-	3.0 - 3.4	50-56
	Total	6.0 - 7.1	100 - 119	3.4 - 3.7	56 - 63	9.3 - 10.8	157-182

SOURCE: EUROPEAN CLIMATE FOUNDATION ET AL., 2010.

Prices for feedstocks in developing countries are available but relatively limited. In the case of Brazil, the price of bagasse[23] varies significantly, depending on the harvest period. It can range from zero to USD 27/tonne[24] with the average price being around USD 11/tonne, where a market exists. These low bagasse prices make the economics of bioenergy power plants with other feedstocks extremely challenging, except where a captive feedstock exists (i.e. in the pulp and paper industry). As a result, most of the other bioenergy power generation projects in Brazil rely on black liquor and woodwaste for co-generation in industry with the surplus electricity sold to the market.[25]

23 Which is a residue from process and has no transportation costs if used in the same alcohol/sugar plant for electricity generation
24 1 USD = 1.80 R$

TABLE 5.4: FEEDSTOCK COSTS FOR AGRICULTURAL RESIDUES IN BRAZIL AND INDIA

USD / GJ	Typical moisture content	Heat value (kJ/kg)	USD / GJ	USD / tonne
Bagasse	40% - 55%	5 600 - 8 900	1.3 - 2.3 1.4 - 2.5	11 - 13 (Brazil) 12 - 14 (India)
Woodchip		7 745	9.30	71 (Brazil)
Charcoal mill		18 840	5.31	95 (Brazil)
Rice husk	11%	12 960	...	22 - 30 (India)

SOURCE: RODRIGUES, 2009; AND UNFCCC, 2011.

In India, the price for bagasse is around USD 12 to USD 14/tonne, and the price of rice husks is around USD 22/tonne (UNFCCC, 2011). The biomass resources are multiple as rice straw, rice husks, bagasse, wood waste, wood, wild bushes and paper mill waste[26]. In India, small-scale gasifier systems for off-grid, mini-grid and grid-connected applications are relatively successful and as much as 28 MW were installed by mid-2008 in industry and up to 80 MW in rural systems (Winrock International, 2008).

Anaerobic digestion biogas systems typically take advantage of existing waste streams, such as sewage and animal effluent, but it is possible to supplement this with energy crops. They are therefore well-suited to rural electrification programmes. In developed countries, costs tend to be higher and significant economies of scale are required compared to developing countries to make biogas systems economic.[27] In the United States, AD systems to produce biogas were identified as interesting options for dairy farms with 500 cows or more, pig farms with at least 2 000 pigs and where the manure management system collects and stores manure in liquid, slurry or semi-solid form.

For landfill gas, the cost of the feedstock is simply the amortised cost of the investment in the gas collection system. However, the economics of these projects can be greatly enhanced if credits for the avoided methane emissions are available. The United States Environmental Protection Agency (EPA) Landfill Methane Outreach Program undertook an economic assessment for 3 MW landfill gas electricity project using an internal combustion engine (ICE). The costs related to gas collection and flare are around USD 0.9 to USD 2.8/GJ. Biogas has relatively low energy content (from 18–29 MJ/m³) and hence significant volumes are required to produce a useful biogas output. The efficiency can be improved by finding customers for the heat produced; in Germany, Denmark and Austria, it is becoming popular to use digesters for heat and power (Mott MacDonald, 2011).

5.2 BIOMASS POWER GENERATION TECHNOLOGY COSTS

The cost and efficiency of biomass power generation equipment varies significantly by technology. Equipment costs for an individual technology type can also vary, depending on the region but also depending on the nature of the feedstock and how much feedstock preparation and handling is done on-site.

25 A study that looked at the economic feasibility of a small CHP plant identified woodchip and charcoal mill prices of USD 9/GJ and USD 5.3/GJ if these were to be bought from the forestry and charcoal industries (Rodrigues, 2009)

26 According to Shukala, Nearly 55 MW of grid connected biomass power capacity is commissioned and another 90 MW capacity is under construction. There are estimates of 350 million tons of agricultural and agro-industrial residues produced annually in India.

27 An additional complication is that systems in hot climates will have faster reaction rates, improving the "efficiency" of the process.

TABLE 5.5: ESTIMATED EQUIPMENT COSTS FOR BIOMASS POWER GENERATION TECHNOLOGIES BY STUDY

	O'Connor, 2011	Mott MacDonald, 2011	EPA, 2007 and EIA, 2010	Obernberger, 2008
		(2010 USD/kW)		
Stoker boiler	2 600 – 3 000	1 980 – 2 590	1 390 – 1 600	2 080
Stoker CHP	2 500 – 4 000		3 320 – 5 080*	3 019
CFB	2 600 – 3 000	1 440	1 750 – 1 960	
CFB CHP			4 260 – 15 500	
BFB		2 540	3 860	
Co-firing	100 – 600			
100% biomass repowering	900 – 1 500			
MSW	5 000 – 6 000			
Fixed bed gasifier ICE		4 150	1 730	4 321 – 5 074
Fixed bed gasifier GT	3 000 -3 500			
Fluidised gasifier GT			2 470-4 610	
BIGCC	3 500 – 4 300		2 200-7 894	
Digester ICE	1 650 – 1 850	2 840 – 3 665		
Digester GT	1 850 – 2 300			
Landfill gas ICE	1 350 – 1 500		1 804	

Note:

* = CHP back pressure steam turbine. ICE = internal combustion engine.
GT = gas turbine. MSW = municipal solid waste.

Table 5.5 presents the equipment costs for representative technologies by size. The United States EPA analysis highlights that there are significant economies of scale for some technologies. CFB boilers are a good example as the price of a CHP system comprising a CFB boiler and steam turbine with a generating capacity of 0.5 MWe is USD 14 790/kW, but this drops to just over USD 4 000/kW for a 8.8 MW system. Other technologies are less influenced by scale, and the same analysis suggests that prices for small-scale stoker-based CHP systems range between USD 3 150 and USD 4 800/kW for roughly the same MW range. The technology choice is thus influenced by the type, availability and cost of the biomass feedstock, as well as by the local markets for electricity and heat. These will determine the potential size of the project and also the type of system that will best suit the feedstock. However, the costs and efficiency of the various technology choices will then determine what trade-offs lead to the most economic solution.

Stokers are a mature technology, and there is significant experience with them in many countries to the point where well-researched and designed projects are generally bankable.

As with many renewable technologies that are in their growth phase, it is also important to note that there can be a significant difference between equipment prices and the underlying cost of manufacture and marketing for a number of technologies. In some cases, a market "congestion premium" plays a significant role in increasing prices (Mott MacDonald, 2011).

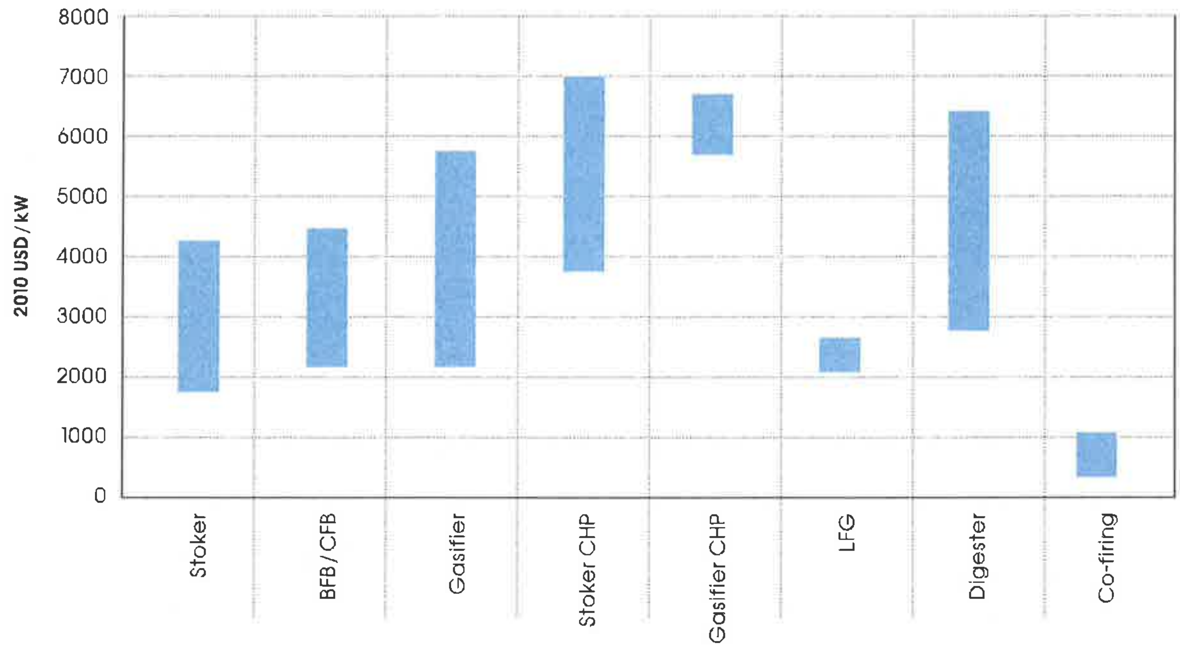


FIGURE 5.3: INSTALLED CAPITAL COST RANGES BY BIOMASS POWER GENERATION TECHNOLOGY

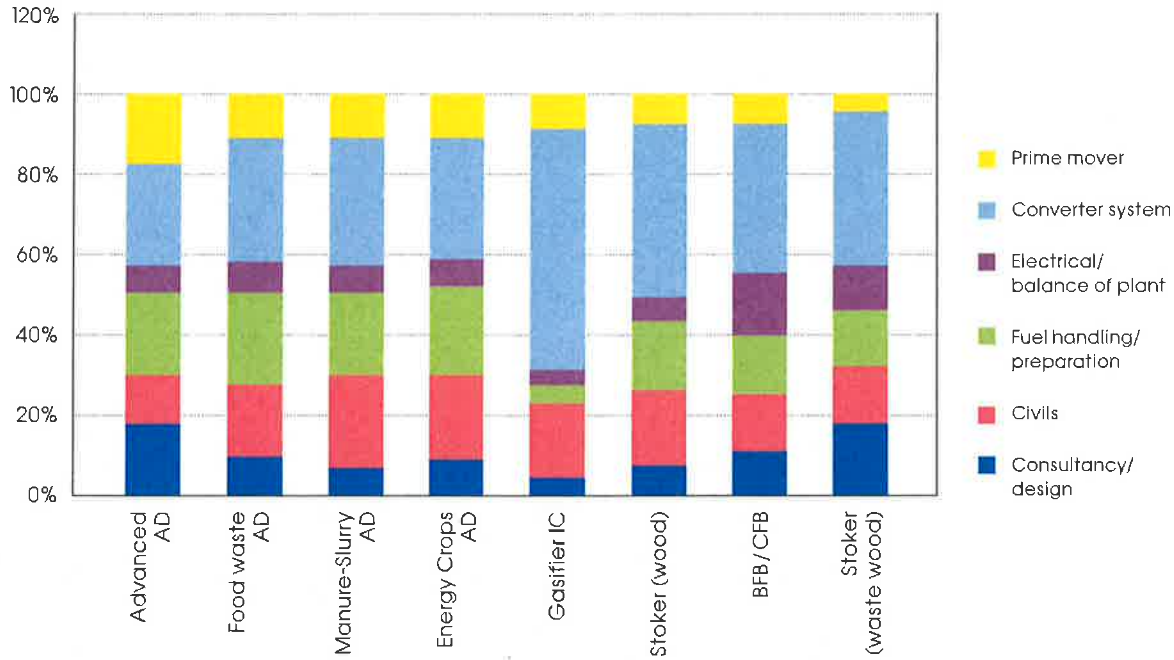
The total investment cost – capital expenditure (CAPEX) – consists of the equipment (prime mover and fuel conversion system), fuel handling and preparation machinery, engineering and construction costs, and planning (Figure 5.3). It can also include grid connection, roads and any kind of new infrastructure or improvements to existing infrastructure required for the project. Different projects will have different requirements for each of these components with infrastructure requirements/ improvements in particular being very project-sensitive.

Figure 5.4 presents a breakdown of the typical cost structure of different biomass power generation technologies[28]. The feedstock conversion system comprises boilers (stoker, CFB, BFB, etc.), gasifiers and anaerobic digesters with a gas collection system, as well as the gas cleaning systems for gasifiers and gas treatment systems for AD systems. The prime mover is the power generation technology and includes any in-line elements, such as particulate matter, filters etc. As can be seen, the prime mover, feedstock conversion technology and feedstock preparation and handling machinery account for between 62% and 77% of the capital costs for the biomass power generation technologies presented.

The total installed cost range, including all balance of plant equipment (e.g. electrical, fuel handling, civil works), as well as owners costs including consultancy, design and working capital is presented in Figure 5.3.

The contribution of the prime mover to the total costs is very low and ranges from 5% to 15% (Mott MacDonald, 2011). The converter system (e.g. stoker boiler, gasifier) usually accounts for the largest share of capital costs, although fuel handling and preparation is also an important contributor to total costs (Figure 5.4).

28 Transmission lines, road and any kind of infrastructure are not being considered in the costs breakdown as they are site/location specific



Note: "Electrical/balance of the plant" includes grid connection and control and monitoring systems, but not any cost for extending transmission lines. AD = anaerobic digester and IC = internal combustion.

FIGURE 5.4: CAPITAL COST BREAKDOWN FOR BIOMASS POWER GENERATION TECHNOLOGIES

SOURCE: MOTT MACDONALD, 2011.

For co-combustion, the costs quoted are incremental costs only. These will raise the installed cost of a new coal-fired power plant from around USD 2 000 to USD 2 500/kW to USD 2 100 to USD 3 100/kW, depending on the configuration. Another consideration is that high co-combustion rates will also start to significantly reduce the capacity of the coal-fired plant with a consequent impact on the LCOE.

In developing countries, some small-scale manure and wastewater systems associated with electricity generation have been installed under Clean Development Mechanism projects – 42 manure and 82 wastewater projects – most of them with capacities between 1 MW and3 MW and investments between USD 500 and USD 5 000/kW.

5.3 OPERATION AND MAINTENANCE EXPENDITURE (OPEX)

Operation and maintenance (O&M) refers to the fixed and variable costs associated with the operation of biomass-fired power generation plants. Fixed O&M costs can be expressed as a percentage of capital costs. For biomass power plants, they typically range from 1% to 6% of the initial CAPEX per year (Table 5.6). Fixed O&M costs consist of labour, scheduled maintenance, routine component/equipment replacement (for boilers, gasifiers, feedstock handling equipment, etc.), insurance, etc. The larger the plant, the lower the specific (per kW) fixed O&M costs, because of the impact of economies of scale, particularly for the labour required. Variable O&M costs depend on the output of the system and are usually expressed as a value per unit of output (USD/kWh). They include non-biomass fuels costs, ash disposal, unplanned maintenance, equipment replacement and incremental servicing costs. The

TABLE 5.6: FIXED AND VARIABLE OPERATIONS AND MAINTENANCE COSTS FOR BIOMASS POWER

Technology	Fixed O&M (% of installed cost)	Variable O&M (USD/MWh)
Stokers / BFB / CFC boilers	3.2 – 4.2 3 – 6	3.8 – 4.7
Gasifier	3 6	3.7
AD systems	2.1 – 3.2 2.3 – 7	4.2
LFG	11 – 20	n.a.

SOURCES: US DOA, 2007; US EPA, 2009; AND MOTT MACDONALD, 2011.

data available will often combine fixed and variable O&M costs into one number so a breakdown between fixed and variable O&M costs is often not available.

Care should be taken in comparing the O&M costs of gasifiers with other bioenergy power generation technologies since gasifiers have less commercial experience and are not as mature as the other solutions.

5.4 COST REDUCTION POTENTIALS FOR BIOMASS-FIRED ELECTRICITY GENERATION

Analysing the potential for cost reductions in biomass power generation equipment is complicated by the range of technologies available, from the mature to those still at the pilot or R&D stage, and by the often significant variations in local technology solutions. However, some analysis has examined potential cost reductions in the future.

There is currently little discussion about learning curves for biomass power generation. This is in part due to the range of technologies available and to their different states of commercialisation but also due to a lack of authoritative time series cost data.

Combustion technologies are well-established and are generally bankable if the project economics are solid. Gasification with low gas energy content and internal combustion engines are an established niche technology in India, but shifting from these simple gasifiers to ones with greater efficiency, using oxygen as a reactive agent, gas clean-up and gas turbines to scale-up this technology to larger power plants still requires more demonstration, especially because it requires expensive gas clean-up, which is currently the main focus of gasification technology improvements. In anaerobic systems (AD), the main technological development needed is linked to the digesters (as better control of the process: enzymes, pH, temperature) and the clean-up of the biogas before combustion.

The main question regarding the viability of biomass power plants lies in the development of a reliable feedstock supply chain, especially because long-term feedstock agreements are essential for financing any biomass project. Predicting biomass cost reduction potentials is challenging because many factors are involved, such as the local supply chain, resource potential, land availability, competitive industrial uses (e.g. biochemical), risks of deforestation, sustainability criteria, etc.

Research into cost saving processes is currently underway. For example, it has been shown that denser fuel pellets can offer LCOE savings, but the drawback is that often the pelletisation process results in significant feedstock loss and increased cost. At the same time, the storage and transportation costs of denser pellets are significantly lower than other densification options, such as baling. Efforts to integrate biomass with traditional agriculture, for example through the use of crop rotation and agricultural intensification, may lead to yield increases and price reductions. Sustainable harvesting techniques, such as one-pass harvesting, can reduce harvest site fuel consumption significantly. Further,

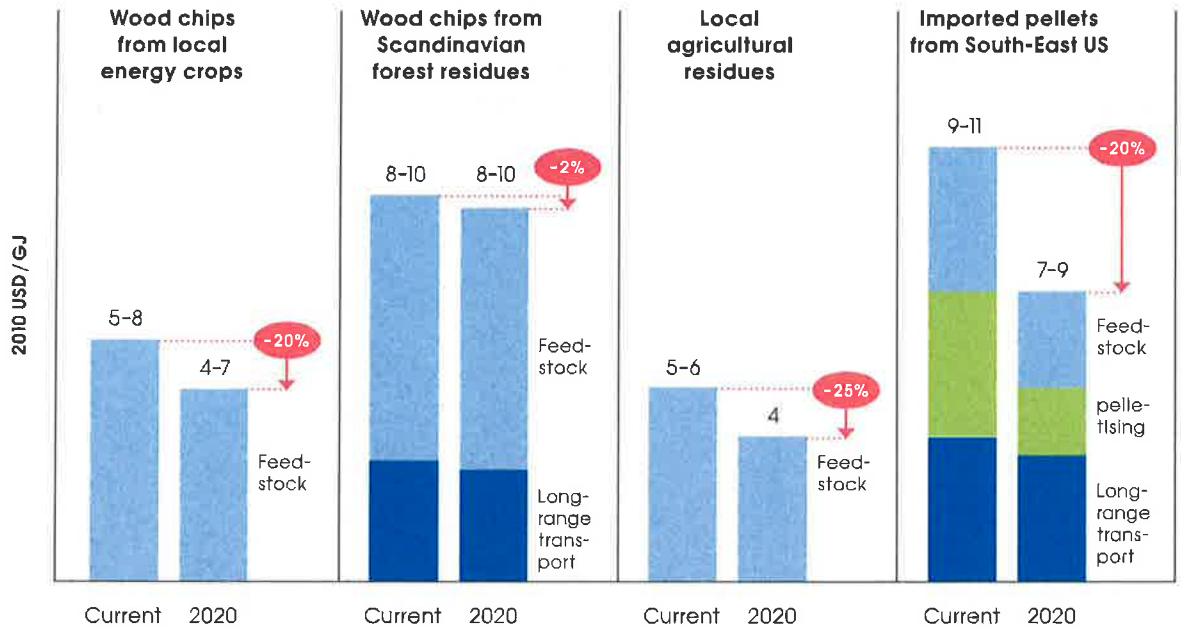


FIGURE 5.5: BIOMASS FEEDSTOCK COST REDUCTION POTENTIAL TO 2020 IN EUROPE

SOURCE: EUROPEAN CLIMATE FOUNDATION ET AL., 2010

TABLE 5.7: LONG-RUN COST REDUCTION POTENTIAL OPPORTUNITIES FOR BIOENERGY POWER GENERATION TECHNOLOGIES

	Cost reduction potential
Consultancy/design	limited
Civils	small
Fuel handling and preparation	significant especially for CFB and BFB
Electrical and balance of the plant	small
Converter system	medium
Prime mover	small

developing synergies between harvest and transport, for example by using self-compacting wagons for both harvesting and transportation, may also provide cost savings (Bechen, 2011).[29]

Analysis of the potential for biomass feedstock cost reductions for the European market to 2020 suggests that cost reductions of 2% to 25% could be achieved (Figure 5.5). Average cost reductions for energy crops by 2015 are difficult to estimate. It is assumed that dedicated energy crops will be 5-10% cheaper as the result of harvesting and logistic improvements by 2015. Trends for forestry and agricultural residue prices and costs are uncertain as the balance of positive (e.g. supply/logistic chain cost reductions) and negative effects (e.g. increased competition for residues) is difficult to estimate.

Many biomass generation technologies are mature and are not likely to undergo significant technological change, while cost reductions through scale-up will be modest. However, for the less mature technologies, significant cost reductions are likely to occur as commercial experience is gained. Gasififcation technologies using wood or waste wood as feedstock may achieve capital cost reductions of 22% by 2020, while those for stoker/BFB/CFB direct combustion technologies will be more modest at between 12% and 16%. By 2015 cost reductions for BFB and CFB gasification technologies could be in the order of 5% to 11%, while for direct combustion cost reductions they may be 0% to 5%. AD technologies could benefit from greater commercialisation, and cost reductions of 17% to 19% might be possible by 2020, with cost reductions of 5% to 8% by 2015.

29 See http://biomassmagazine.com/articles/5195/addressing-obstacles-in-the-biomass-feedstock-supply-chain

6. Levelised Cost of Electricity from Biomass

The boundary of analysis and the key assumptions are presented in Figure 6.1. The critical assumptions required to derive the LCOE from biomass-fired power generation systems are:

- equipment costs and other initial capital costs;
- discount rate;
- economic life;
- feedstock costs;
- O&M costs; and
- efficiency.

For the analysis of biomass-fired power generation, certain exceptions have been made to what might be considered a standard approach. They are that:

- The CAPEX costs do not include grid connection, distribution systems and transmission line costs if required. These costs are very project-specific and cannot be easily generalised.
- O&M does not include insurance or grid charges.

Key assumptions

The discount rate used to represent the average cost of capital for bioenergy power generation is assumed to be 10%. The LCOE of a bioenergy plant is generally sensitive to the discount rate used; however, it is generally less sensitive to the discount rate than wind, hydropower and solar due to the impact of the bioenergy fuel costs.

The economic life of biomass plants is assumed to be 20 to 25 years. Minor equipment refurbishment and replacement is included in O&M costs.

The range of feedstock costs is assumed to be from USD 10/tonne for local waste feedstocks (around USD 1/GJ) to USD 160/tonne (around USD 9/GJ) for pellets (with transportation included in the case of pellets). A typical moisture content on a lower heating value basis was assumed for each feedstock type in order to calculate feedstock consumption.
Ash disposal costs are assumed to be USD 132/tonne, for an average 1% of feedstock throughput by weight (Obernberger).[30]

Biomass-fired power plants are assumed to operate at an 85% capacity factor although the generation of a specific power plant will depend on its design and feedstock availability, quality and cost over the year. Power plants designed to take advantage of low-cost agricultural residues may experience periods where insufficient feedstock is available or periods where the necessary transportation costs to get similar or equivalent feedstocks from other markets are too expensive.

The assumed net electrical efficiency, after accounting for feedstock handling) of the prime mover is assumed to average 35% and varies between 31% for wood gasifiers and a high of 36% for stoker/CFC/BFB and AD systems (Mott MacDonald, 2011). BIGCC systems should achieve higher efficiencies than this but will require higher capital costs.

30 This was a simplifying assumption, as ash levels vary significantly depending on the feedstock type and conversion process used. Ash disposal costs also vary significantly by region, depending on the qualities of the ash and whether there is a local market for ash or not.

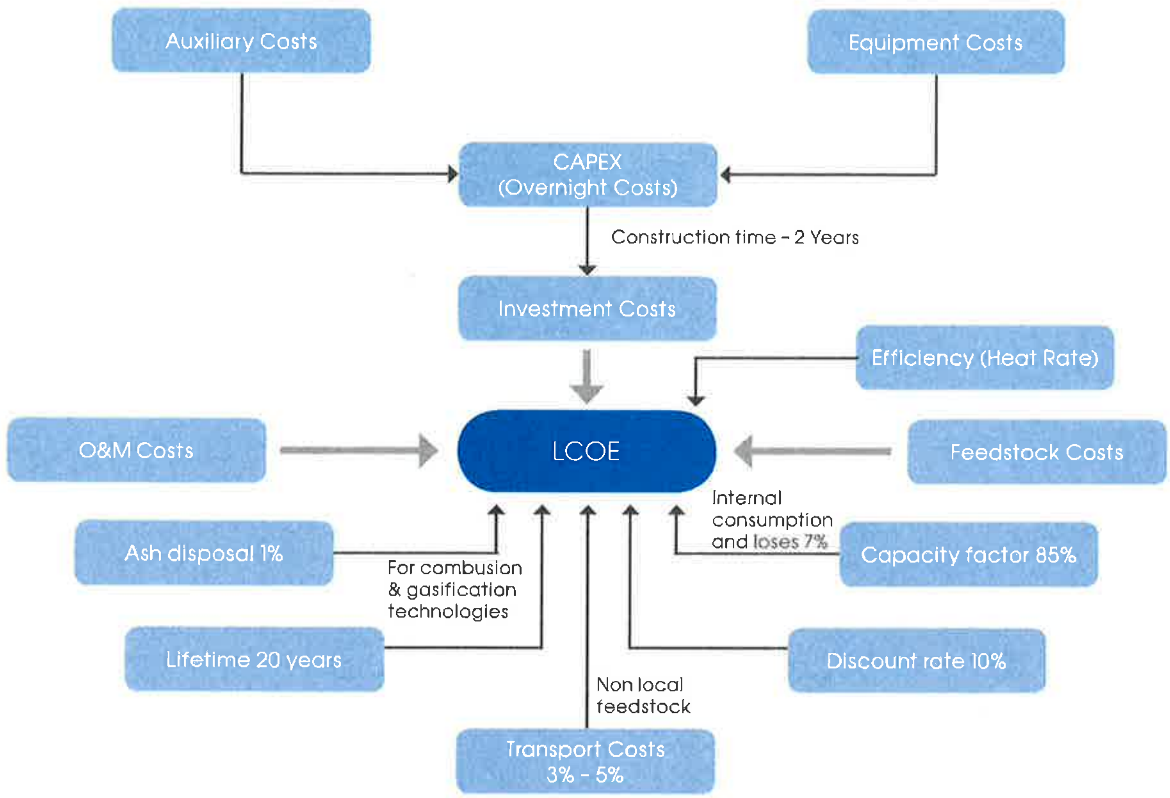


FIGURE 6.1: THE LCOE FRAMEWORK FOR BIOMASS POWER GENERATION

To account for the value of the heat from biomass-fired CHP, the IEA's methodology was used.[31] This assumes a credit for heat based on IPCCC assumptions and ranges from between USD 10 and 45/MWh_{th}.[32]

The capital cost assumptions for different biomass-fired power generation technologies are summarised in Figure 5.3. They range from as little as USD 1 325/kW for stoker boiler systems to almost USD 7 000/kW for stoker CHP.

6.1 THE LCOE OF BIOMASS-FIRED POWER GENERATION

The range of biomass-fired power generation technologies and feedstock costs result in a large range for the LCOE of biomass-fired power generation. Even for individual technologies, the range can be wide as different configurations, feedstocks, fuel handling and, in the case of gasification, gas clean-up requirements can lead to very different installed costs and efficiencies for a "single" technology.

31 See IEA, 2010 for further details.

32 Although not discussed in detail here, CHP plants with their high capital costs represent a niche power generation application. This is due to the fact they require high load factors and a nearby heat demand to make them economic. Industrial process needs are the perfect match, as they are large and generally stable loads. However, for district heating, sizing CHP to meet more than the year round base load demand (typically water heating) can be a challenging economic proposition as low load factors significantly increase annual energy costs compared to simply using boilers to meet space heating demands.

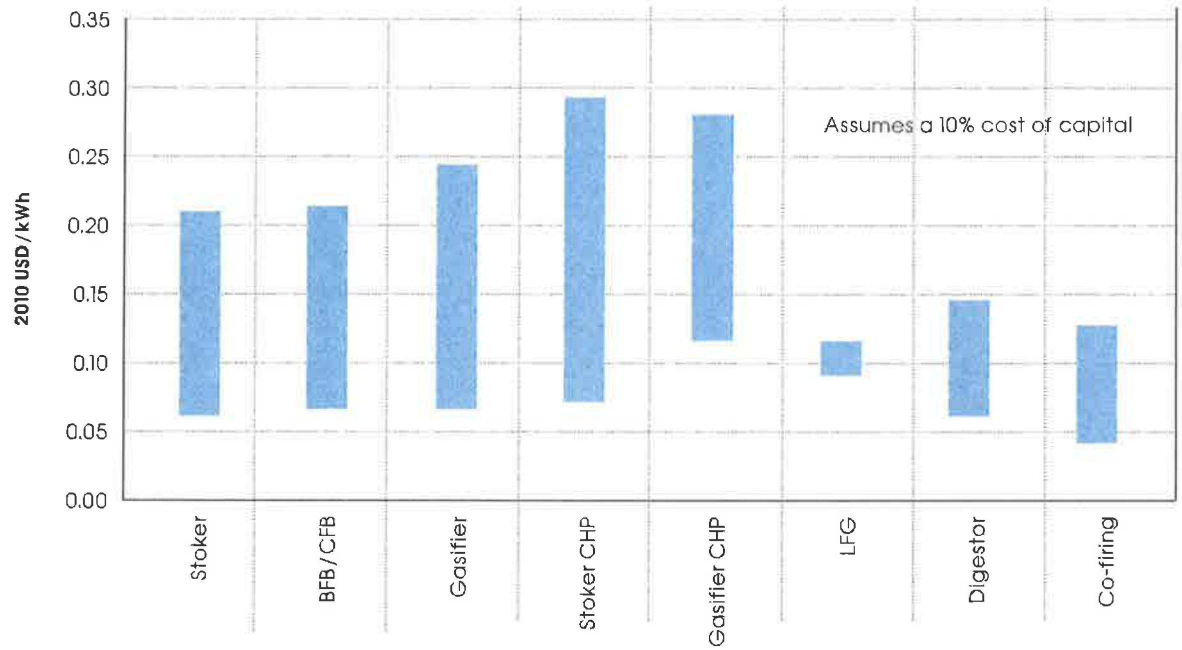


FIGURE 6.2: LCOE RANGES FOR BIOMASS-FIRED POWER GENERATION TECHNOLOGIES

Figure 6.2 summarises the range of costs that is possible for the core biomass power generation technologies when the low and high estimates of investment costs (Table 5.8) and feedstock costs are examined.[33] Assuming a cost of capital of 10%, the LCOE of biomass-fired electricity generation ranges from a low of USD 0.06/kWh to a high of USD 0.29/kWh.

Where capital costs are low and low-cost feedstocks are available, bioenergy can provide competitively priced, dispatchable electricity generation with an LCOE as low as around USD 0.06/kWh. However, with higher capital costs and more expensive fuel costs, power generation from bioenergy is not likely to be able to compete with incumbent technologies without support policies in place. Many of the low-cost opportunities to develop bioenergy-fired power plants will therefore be in taking advantage of forestry or agricultural residues and wastes (e.g.from the pulp and paper, forestry, food and agricultural industries) where low-cost feedstocks and sometimes handling facilities are available to keep feedstock and capital costs low. The development of competitive supply chains for feedstocks is therefore very important in making bioenergy-fired power generation competitive.

When low-cost stoker boilers are available and fuel costs are low (e.g. agricultural, forestry, pulp and paper residues), stoker boilers producing steam to power a steam turbine offer competitive electricity at as low as USD 0.062/kWh. However, where capital costs are high and only imported pellets are available to fire the boiler, the LCOE can be as high as USD 0.21/kWh. Combustion in BFB and CFB boilers has a slightly higher LCOE range than stoker boilers due to their higher capital costs.

The LCOE range for gasifiers is very wide, in part due to the range of feedstock costs, but also due to the fact that fixed bed gasifiers are a more proven technology that is cheaper than CFB or BFB gasifiers. The LCOE for gasifiers ranges from USD 0.065/kWh

33 For CHP technologies, the value of the heat produced is fixed at USD 15/MWh$_{th}$

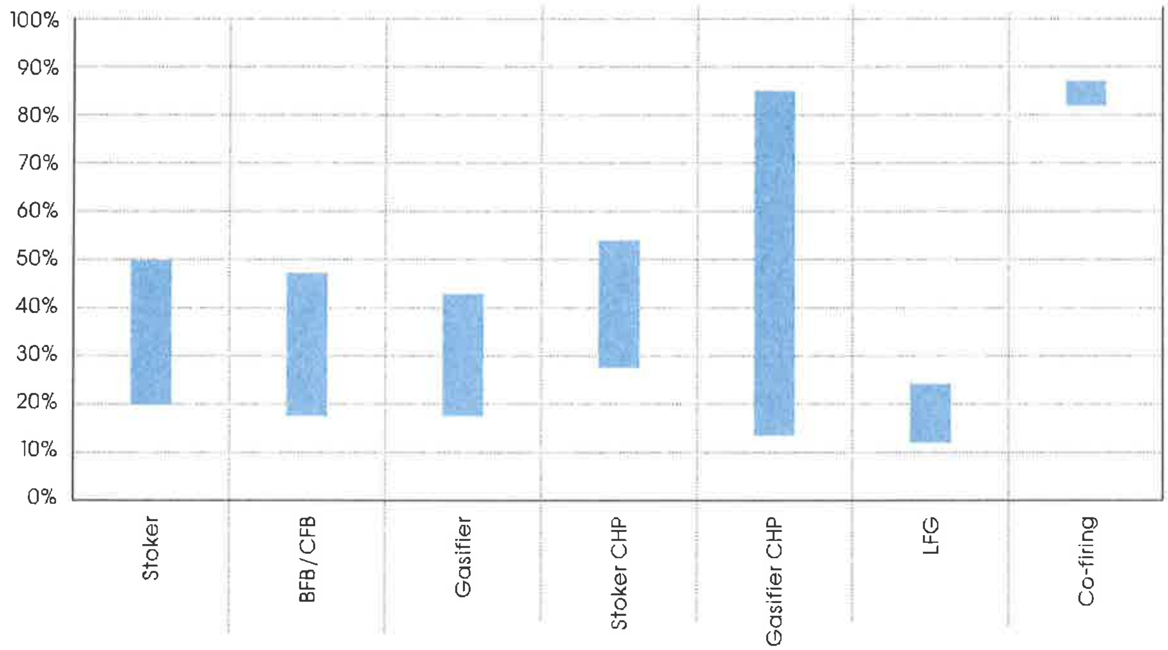


FIGURE 6.3: SHARE OF FUEL COSTS IN THE LCOE OF BIOENERGY POWER GENERATION FOR HIGH AND LOW FEEDSTOCK PRICES

for a fixed bed gasifier with low-cost bioenergy fuel to USD 0.24/kWh for a small-scale gasifier with an internal combustion engine as the prime mover (600 kW) that would be suitable for off-grid applications or mini-grids. However, although this is expensive compared to grid-scale options, it is more competitive than a diesel-fired solution.

CHP systems are substantially more expensive than an equivalent electricity-only generating system. However, they have higher overall efficiencies, and the sale or opportunity value of heat produced can make CHP very attractive, particularly in the agricultural, forestry and pulp and paper industries; where low-cost feedstocks and process heat needs are located together. The LCOE of stoker CHP systems ranges from USD 0.072 to USD 0.29/kWh, including the impact of the credit for heat production. Gasifier CHP systems have a higher but narrower range from USD 0.12 to USD 0.28/kWh due to the higher capital costs.

Landfill gas, anaerobic digesters and co-firing have narrower cost ranges. For landfill gas, this is because of the narrow capital cost range and the fact that this also determines the fuel cost. For anaerobic digestion, the capital cost range is relatively narrow, but the feedstock can vary from free for manure or sewage up to USD 40/tonne for energy crops for digestion. For co-firing, the incremental LCOE cost is as low USD 0.044 and USD 0.13/kWh.[34]

The share of fuel costs in the LCOE of biomass-fired power

Figure 6.3 presents the impact of the high and low ranges for the feedstock costs on their share of the LCOE. Excluding co-firing, which is a special case, feedstock costs typically account for between 20% and 50% of the LCOE of power generation only options. The range is significantly wider for gasifier-based CHP projects, where the feedstock cost can account for as little as 14% of the LCOE but up to 85% in the case of using imported wood chips.

34 Analysis of the average LCOE of the power plant with and without biomass co-firing is another way of comparing the overall value of co-firing.

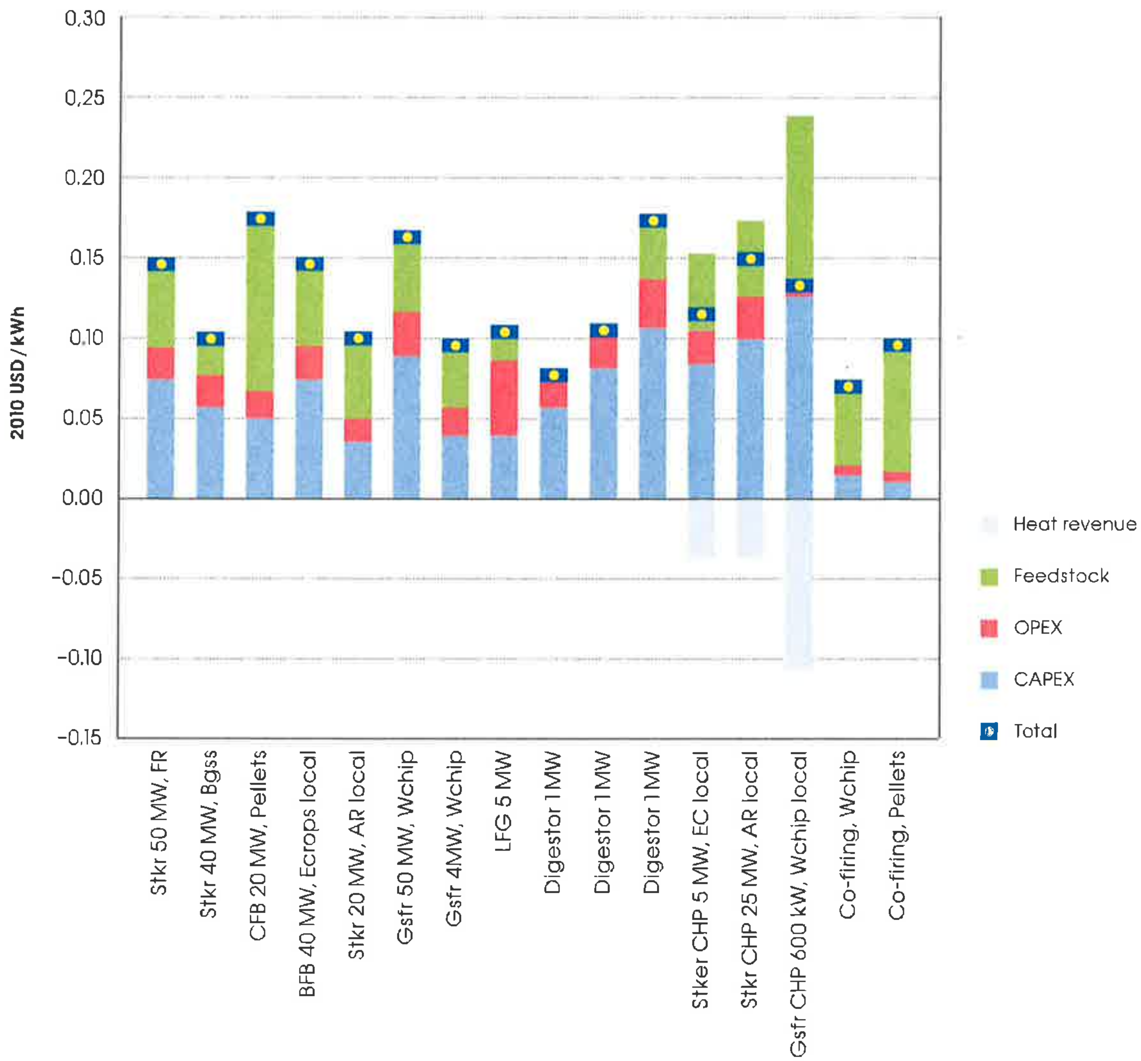


FIGURE 6.4: BREAKDOWN OF THE LCOE OF SELECTED BIOENERGY-FIRED POWER GENERATION TECHNOLOGIES

Breakdown of the LCOE of biomass-fired power generation

Figure 6.4 illustrates the impact of the different cost components on the LCOE of a range of specific bioenergy power generation technologies and feedstock cost assumptions.[35] These have been selected as examples and are not necessarily indicative of typical or average costs for each technology. Table 6.1 presents the assumptions for equipment, feedstock and installed capital costs for each of the chosen examples presented in Figure 6.4.

Assuming a 10% discount rate, results in the LCOE of stoker boilers varying from a low of USD 0.062/kWh to a high of USD 0.21/kWh. A stoker boiler using forest residues has an LCOE of USD 0.14/kWh with

35 These are indicative examples and are not meant to be average or median values for the ranges presented in Figure 6.2. They are designed to give an indication of the relative importance of the various components that make up the LCOE of a biomass power plant.

TABLE 6.1: ASSUMPTIONS FOR THE LCOE ANALYSIS OF BIOMASS-FIRED POWER GENERATION TECHNOLOGIES IN FIGURE 6.4

	Equipement type	Feedstock type and cost (2010 USD/tonne)	Total investment costs (2010 USD/kW)
Case 1	Stoker, 50 MW	Forest residues @ 25/tonne	4 264
Case 2	Stoker boiler, 40 MW	Bagasse @ 11/tonne	3 280
Case 3	CFB boiler, 20 MW	Pellets @ 110/tonne	3 118
Case 4	BFB boiler, 40 MW	Energy crop @ 50/tonne	4 400
Case 5	Stoker boiler, 20 MW	Agricultural residue local @ 50/tonne	2 296
Case 6	Gasifier GT, 50 MW	Woodchip local @ 80/tonne	5 255
Case 7	Gasifier ICE, 4MW	Woodchip EC local @ 60/tonne	2 470
Case 8	LFG ICE, 5MW	Biogas @ 0.030/tonne	2 460
Case 9	Digester, CT 1MW	Biogas @ zero	3 580
Case 10	Digester ICE, 1 MW	Manure slurry @ zero	5 053
Case 11	Digester ICE, 1 MW	Energy crops @ 40/tonne	6 603
Case 12	Stoker CHP, 5 MW	Energy crop @ 40/tonne	4 920
Case 13	Stoker CHP, 25 MW	Agricultural residue local @ 40/tonne	5 904
Case 14	Gasifier CHP 600 kW	Woodchip local @ 70/tonne	7 560
Case 15	Co-firing, separated feed	Woodchip local @ 60/tonne	984
Case 16	Co-firing, mixed injection	Pellets @ 110/tonne	820

around half of this accounted for by the investment cost and 35% by the fuel costs. A stoker boiler fired by bagasse with lower capital and fuel costs has an LCOE of USD 0.098/kWh. In this case, the capital expenditure accounts for a slightly higher proportion (57%) of the LCOE and fuel costs for just 27%. A low-cost stoker boiler using agricultural residues that cost USD 50/tonne delivered has an LCOE of USD 0.10/kWh, with 39% of the total cost attributable to the capital expenditure and around half coming from the fuel cost.

CFB and BFB boilers driving steam turbines have an LCOE of USD 0.17 and USD 0.15/kWh when using pellets and local energy crops, respectively. The capital costs account for 31% and 51% of the LCOE of the CFB and BFB systems, respectively, with the use of pellets doubling the absolute cost of fuel from USD 0.05/kWh to around USD 0.10/kWh and increasing the share of fuel costs in LCOE from 36% to 61%.

The chosen gasifier examples achieve an LCOE of between USD 0.09 and USD 0.16/kWh. In a simple, fixed bed gasifier with an internal combustion engine and relatively low capital costs, the share of capital costs in total LCOE is 45% and that of fuel costs 40%. In a more sophisticated BFB/CFB gasifier with gas clean-up for use in a gas turbine, capital costs are significantly higher and account for 55% of the LCOE with fuel costs accounting for 30%.

There is a range of possible digester solutions with significant differences in capital costs and feedstock costs, but capital costs dominate. Capital costs account for between 66% and 81% of the three examples analysed.

The LCOE of the large-scale CHP systems (stoker and gasifier) is between USD 0.12 and USD 0.15/kWh. Capital costs account for around half of the total LCOE with the feedstock accounting for around one-third of the total costs.

The cost of the feedstock plays an important role in determining the overall generation cost.

The feedstock accounts for a low of 27% in a stoker boiler and steam turbine combination when low-cost bagasse is available. In contrast, the LCOE of co-firing with biomass, with its low capital costs, is dominated by feedstock costs.

Operations and maintenance costs make a significant contribution to the LCOE of biomass plants and typically account for between 9% and 20% of the LCOE for biomass power plants. However, in the case of landfill gas power generation systems, the share is much higher and can reach 40% of the total LCOE. Efforts to improve fuel handling and conversion systems to help reduce O&M costs will help to improve the competitiveness of biomass power generation.

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Acronyms

AD – Anaerobic digestion

BFB – Bubbling fluidised bed (gasifier)

BIGCC – Biomass integrated combined cycle gasification

BIG-GT – Biomass integrated gas turbine technology

CAPEX – Capital expenditure

CDM – Clean Development Mechanism

CFB – Circulating fluidised bed (gasifier)

CHP – Combined heat and power

CIF – Cost, insurance and freight

DCF – Discounted cash flow

EPA – Environmental Protection Agency (U.S.)

FOB – Free-on-board

GHG – Greenhouse gas

ICE – Internal combustion engine

IFC – International Finance Corporation

IGCC – Integrated gasification combined cycle

IPCC – Inter-govermental Panel on Climate Change

LCOE – Levelised cost of energy

LFG – Landfill gas

LHV – Lower heating value

MC – Moisture content

MSW – Municipal solid waste

NREL – National Renewable Energy Laboratory

O&M – Operating and maintenance

ODT – Oven dry tonnes

OPEX – Operation and maintenance expenditure

R&D – Research and Development

SNG – Substitute for natural gas

WACC – Weighted average cost of capital

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Appendix C – 10

ATTACHMENT 2

FINANCIAL ANALYSIS – COSTS AND BENEFITS
Two Unit Biomass Gasification System
(RECOMMENDED OPTION)

RESULTS OF THE FINANCIAL ANALYSIS

Scenario	Capital Cost	Borrowed	1-14 Year NPV Cash Flow	15-20 Year NPV Cash Flow	Total NPV
No Project	$0	$0	-$13,990,557	-$5,284,892	-$19,274,892
Dual Unit	$12,636,000	$12,636,000	$1,143,601	$3,960,487	$5,104,089

Period	Average Cash Flow
Years 1 – 14	$98,420
Years 15-20	$1,158,134
Average Cash Flow Lifetime	$433,067

TWO UNITS – ASSUMPTIONS USED IN THE FINANCIAL ANALYSIS

- The total capital cost, including interconnect, is $12,636,000.
- Cost Estimates for the "No Project" Scenario are reflective of a) Electricity purchases the facility will have to make, and b) expenses the facility will incur from the disposal of wood waste. The elimination of these costs, is counted as a revenue stream in the project scenario. Electricity costs on site are assumed to be $304.30, with a cost increase of 2.5% per year. Disposal costs are assumed to be $40 per ton with a price escalator of 2% per year.
- Cost estimates for the 20 year period are mid-range, these estimates are neither worst-case nor best-case scenario, but error on the side of a conservative estimate (higher cost).
- Cash flow for the project will fluctuate, ranging from an estimated low of -$76,125 in year 2032. In 2033 with the loan payment complete, cash flow rises to $1,261,671. This cash flow is expected to be $1,047,545 at the end of the equipment's expected life in 2038.
- A discount rate of 3.5% is used to determine the net present value.
- The Capital Loan Interest Rate used is 5%.

- The City's 3% cost pass through is included in the cost analysis.
- The increase in relative profitability from the single unit system to the two unit system is largely due to a substantial increase in revenue, with only marginal increases in labor costs. The one unit system will require 9-10 full time employees, whereas the two unit system requires only 12 full time employees.
- Biochar production is modelled as approximately 9% of the feedstock weight of incoming material at 10% moisture content.
- Each unit transforms 7,648 tpy of wood waste into 688 tpy of biochar that sells for $1,000/ton ($0.50/lb.), with a 2% annual escalator in price.
- Savings from disposal are modelled at $40/ton with a 2% annual price escalator.
- Electricity revenue is modelled as Total Generation – On Site Use = Electricity Sold to Grid. This revenue stream is assumed to receive $127.72 per MWh with no escalator in price.
- The average cash flow throughout the project lifetime is $433,067 per year.

ENVIRONMENTAL BENEFITS ANALYSIS

- An estimated 15,295 tons of wood waste will be managed appropriately, without reliance on landfills, open burning, or conventional incineration.
- Using the protocol established by the California Air Pollution Control Officer's Association, "Biochar Production Project Reporting Protocol," 2,657 $MTCO_2e$ will be sequestered in the biochar resulting from the project.
- The project is expected to offset 15,217 MWh of electricity each year. Assuming California grid averages, and the Climate Registry's 2017 emissions factors, this is equivalent to 3,938 $MTCO_2e$.
- Transportation distances travelled annually are reduced by the project, as 927 truck trips to the existing biomass facility are reduced. This wood may now be processed on site.
- The combined benefits of carbon sequestration in biochar, and the offset electricity emissions are equivalent to removing 600 passenger cars from the road each year.