Quadrennial Technology Review 2015

Chapter 4: Advancing Clean Electric Power Technologies

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U.S. DEPARTMENT OF ENERGY

Biopower

Chapter 4: Technology Assessments

Introduction

Biopower, the generation of electricity and thermal energy from biomass, has the potential to serve as a significant source of energy and to help meet national goals for renewable energy. In addition, because stationary power sources can be designed to capture CO_2 emissions, biopower may also provide a future method of reducing atmospheric concentrations of CO_2. Fourteen biomass definitions have been included in legislation and the tax code since 2004; a recent comparison of the definitions in legislation is provided by the Congressional Research Service.[1] While there is no current agreed-upon definition of biomass in legislation, the concept of biopower already influences decisions about the types of crops and waste that are accessible and qualify for tax incentives.

For the purpose of this discussion, biopower includes the use of any biomass resource (e.g., wood waste, black liquor, agricultural residue) as fuel, either by itself or in conjunction with a fossil fuel, to generate utility-scale dispatchable power. While this technology assessment does not adopt any previous definition, the inclusion of municipal solid waste (MSW) and landfill gas in the total biopower capacity figures assumes that qualified biomass residuals have been segregated from the bulk waste source.

The U.S. Biopower Industry

Major growth of the U.S. biopower industry occurred in the 1980s after passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA), which guaranteed small generators that regulated utilities would purchase electricity at a price equal to the pertinent utility's avoided cost of electricity. In anticipation of increasing fuel prices and correspondingly high avoided costs, many utilities offered PURPA contracts, such as Standard Offer 4 contracts in California, which made biopower projects economically attractive. With deregulation of the electric industry in the early 1990s—in combination with increased natural gas supplies and reduced fuel costs—avoided costs decreased, making biopower projects less attractive. Over the past 15 years, some variation in total capacity and generation has occurred as older PURPA contracts expired, resulting in idling of plants, while only a few new plants have come into service.

As of 2014, the U.S. portfolio of biopower includes approximately 13.4 GW of installed capacity[2] burning agriculture and wood residues, other opportunity fuels such as assorted municipal waste, and digester or landfill gas. The net power generation for the year was 64.3 TWh as reported by the Energy Information Administration (EIA) and shown in Table 4.B.1 (or 1.5% of total U.S. utility power production). Additionally, co-firing and black liquor—spent cooking liquor from the Kraft chemical pulping process—produced an additional 62 TWh of electricity in the U.S., as indicated at the bottom of Table 4.B.1. The distribution and capacity of biopower are

Table 4.B.1 Biopower Generators and Capacity in the United States, 2014[3]

Biomass Category	Prime Mover	Number of Facilities (2012)	Name Plate Capacity (GW)	Annual Net Production (TWh)
EIA Tracked Feedstocks				
Wood and Wood-Derived Fuels	STG	186	8.3	43.1
Landfill Gas	ICE	275	2.1	11.0
Biogenic Municipal Solid Waste	STG	74	2.2	7.4
Other Waste Biomass	STG	37	0.8	2.9
Sub-Total from EIA Tracked Feedstocks		**572**	**13.4**	**64.3**
Other Biomass Feedstocks				
Black Liquor	STG	111	5.3	26.3
Co-Fired with Coal	STG	45	~ 5.0	35.0
Co-Fired with Fuel Oil	STG	13	< 0.1	0.2
Sub-Total from Other Biomass Feedstocks		**169**	**10.3**	**61.5**
Total		**741**	**23.7**	**125.8**

[a] Acronyms used in table: STG: steam turbine generator; ICE: internal combustion engine.

illustrated in Figure 4.B.1a and 4.B.1b and Figure 4.B.2. Wood and wood residuals are the dominant sources of biopower in the forest-producing regions of the Southeast, Northeast, and West Coast. MSW dominates the biopower landscape near large population centers where a significant and steady supply of refuse-derived fuel is possible. Landfill gas is naturally produced within composted MSW, but may taper off once gas that has accumulated for decades is produced and as more MSW is recycled or immediately converted to solid or liquid fuels. Digester biopower is most common near mega-dairy locations and in locations where sewage sludge management is economical or environmentally beneficial.

The capacity for the majority of biopower plants falls in the 10–100 MW range. This reflects the limited availability of locally sourced material and corresponding plant scales that provide a reasonable business case. Without the benefit of PURPA regulations, biopower plants may not be economically viable. In most cases, an independent power producer owns and operates these plants, and they are typically not easily connected to and synchronized with the grid.

Biopower Technologies

A variety of commercial stoker/grate and fluidized-bed combustion technologies are being used to burn the various forms of biomass. The heat produced in combustion is then converted to steam that is used to generate electrical power. Waste digester and landfill gas is typically burned in an internal combustion engine that is directly coupled to a generator set.

Expansion of biopower in the United States could occur by increasing the number of small distributed biopower plants or by establishing centralized, utility-scale plants that can attain higher thermodynamic efficiency: a

Figure 4.B.1a. Distribution of Agriculture Residuals (green) and Wood/Wood Residuals (yellow) Biopower Plants in the United States (none in Alaska)[4]

Credit: National Renewable Energy Laboratory

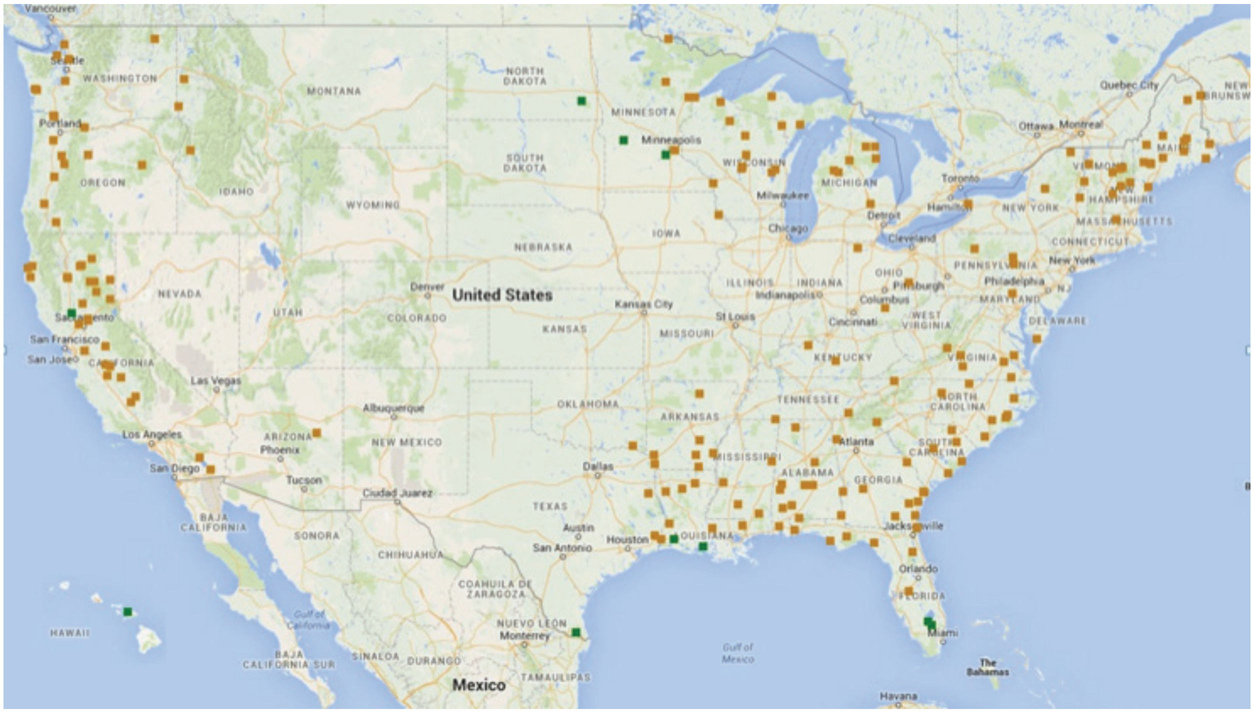


Figure 4.B.1b. Distribution of Municipal Solid Waste (red), Landfill Gas (purple), and Digester Gas (gray) Biopower Plants in the United States (none in Alaska or Hawaii)[4]

Credit: National Renewable Energy Laboratory

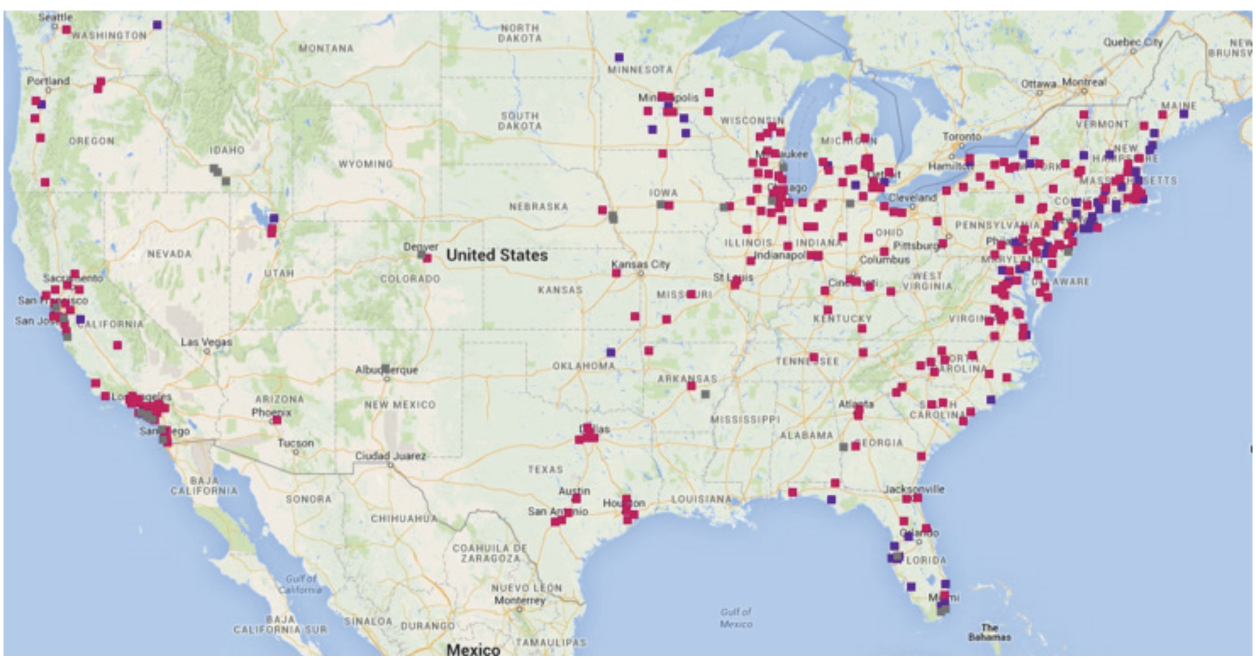
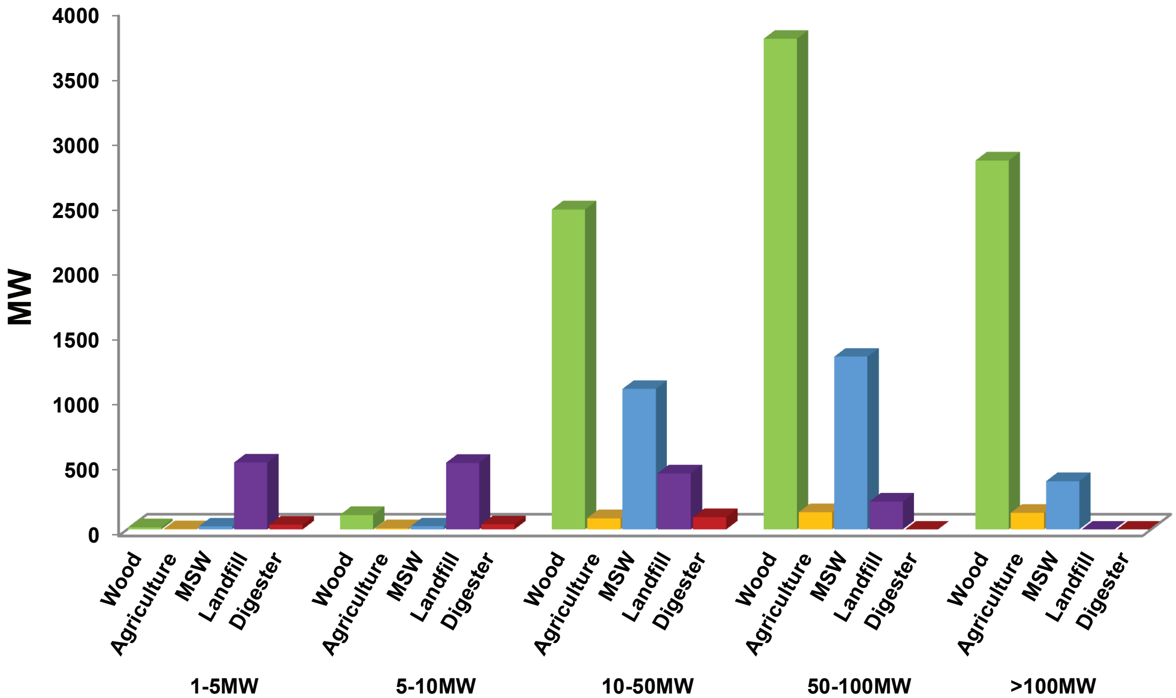


Figure 4.B.2. Scale of Biopower Plants in the United States[4]

Credit: National Renewable Energy Laboratory



typical small-scale wood boiler achieves only 20%–25% efficiency, while a utility scale plant operates at 30% efficiency or higher (utility scale is defined as any power plant >100 MWe that provides power to a utility market). Utility-scale co-firing in coal-fired power plants is becoming commercially feasible. The major barriers to increasing co-firing in large power plants include the cost to retrofit the plants to burn biomass plus the cost to obtain and treat a large supply of material.

Preconditioned biomass can be fed into the existing infrastructure of a coal-fired power plant, as depicted in Figure 4.B.3. The biomass generally must be pretreated to meet combustor particle size, grindability, heating value, and ash content specifications. Boiler feed rates of 5%–10% biomass have been successfully demonstrated in pulverized coal power plants for planning and test trials (Table 4.B.2).

Biopower Incentives and Impediments in the Marketplace

The technical feasibility and the cost/benefits of co-firing biomass, at up to 20% ratios, were recently evaluated in two independent studies.[5,6] The projected levelized cost of electricity (LCOE) was shown to increase by 18%[7] when wood was co-fired with coal in a typical power plant in Alabama, while it was 54%[8] higher for co-firing switchgrass in a power plant in Ohio. This is largely due to the relatively higher cost of biomass feedstock compared to coal. These costs do not include any form of financial credits for reducing greenhouse gas (GHG) emissions—the U.S. government has not directly monetized the value of CO_2 abatement.

Figure 4.B.3. State-of-the-Art Biopower Co-firing Application

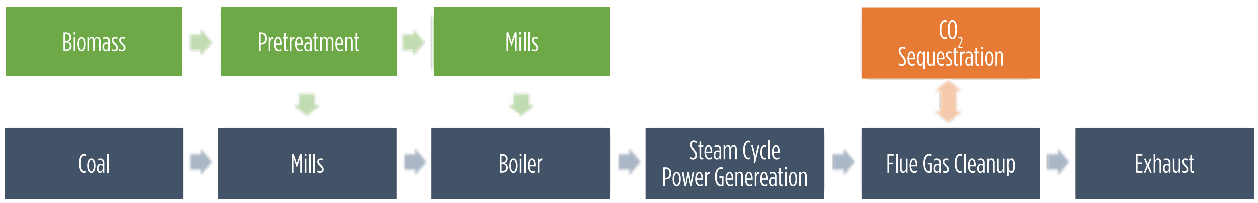


Table 4.B.2 Selected Co-firing Tests in the United States[5]

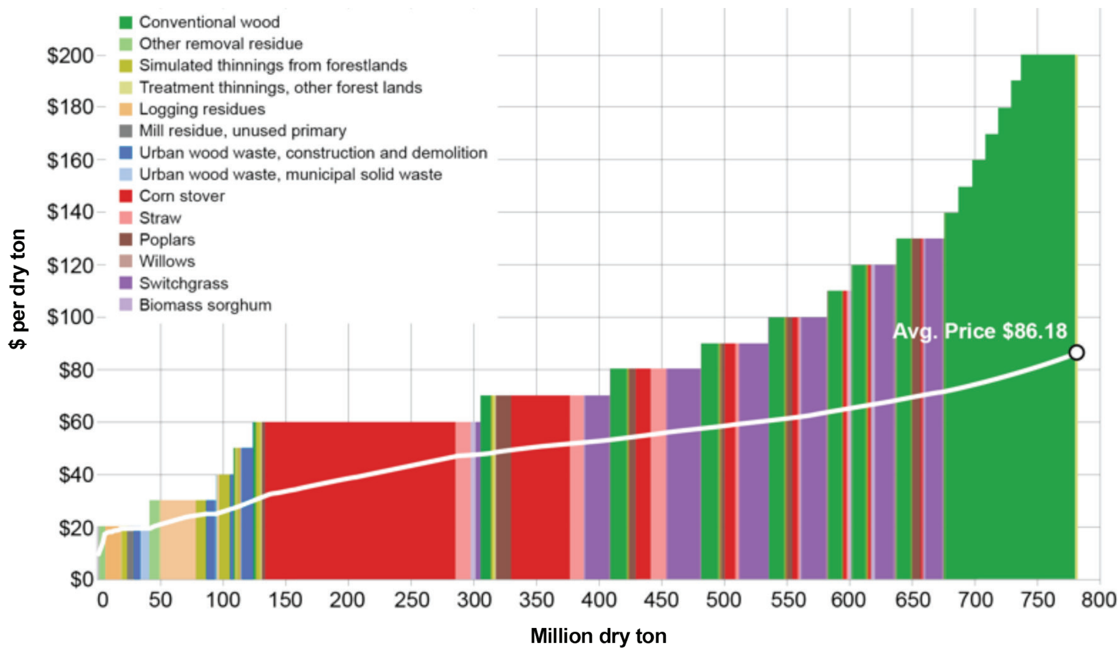
Utility and Plant	Boiler Capacity and Type	Biomass Heat Input (max)	Biomass Type	Average Moisture	Coal Type	Biofuel Feeding
TVA Allen	272 MW Cyclone	10%	Sawdust	44%	Illinois Basin, Utah bituminous	Blending biomass & coal
TVA Colbert	190 MW wall-fired	1.5%	Sawdust	44%	Eastern bituminous	Blending biomass & coal
NYSEG Greeenidge	108 MW tangential	10%	Wood waste	30%	Eastern bituminous	Separate injection
GPU Seward	32 MW wall-fired	10%	Sawdust	44%	Eastern bituminous	Separate injection
MG&E Blount St.	50 MW wall-fired	10%	Switchgrass	10%	Midwest bituminous	Separate injection
NIPSCO Mich. City	469 MW cyclone	6.5%	Urban wood waste	30%	Powder River Basin, Shoshone	Blending biomass & coal
NIPSCO Bailly	194 MW cyclone	5%–10%	Wood	14%	Illinois, Shoshone	Blending biomass & coal
Allegheny Willow Island	188 MW cyclone	5%–10%	Sawdust	Unknown	Eastern bituminous	Blending biomass & coal
Allegheny Allbright	150 MW tangential	5%–10%	Sawdust	Unknown	Eastern bituminous	Separate injection

In Europe, several utility-scale power plants have been retrofitted to burn 100% biomass in response to climate change legislation that restricts coal use. Europe's willingness to pay higher costs for low-GHG electricity has led to an increasing wood pellet supply export industry in the United States and Canada, with pellets currently selling for $140 to $175 per ton freight-on-board at southeastern ports of the United States.[9] At these biomass prices, the LCOE for biopower in the United States would be higher than indicated by the above-referenced co-firing studies.[10] Consequently, biopower in the United States will likely continue to be limited to smaller, community- or industry-owned power plants that burn local supplies of wood waste.

Biomass Supply

In order to better understand the costs of biopower, it is critical to understand the quantity, quality, and price of domestically available biomass feedstock supplies (for a more detailed discussion, see *Technology Assessment Chapter 7.B Biomass Feedstocks and Logistics* of the *2015 Quadrennial Technology Review*).[10] Figure 4.B.4 is a supply curve projection for terrestrial biomass in 2022. It shows a step-wise supply curve that indicates increased cellulosic feedstock supplies in the market with increasing farm-gate prices between $20 and $200 per dry ton. Competition for biomass feedstock among the food supply, the biofuel industry, the biopower industry, the pellet export market, and feed crops for livestock is not yet fully understood in the United States—smart use of biomass resources should balance these competing demands.

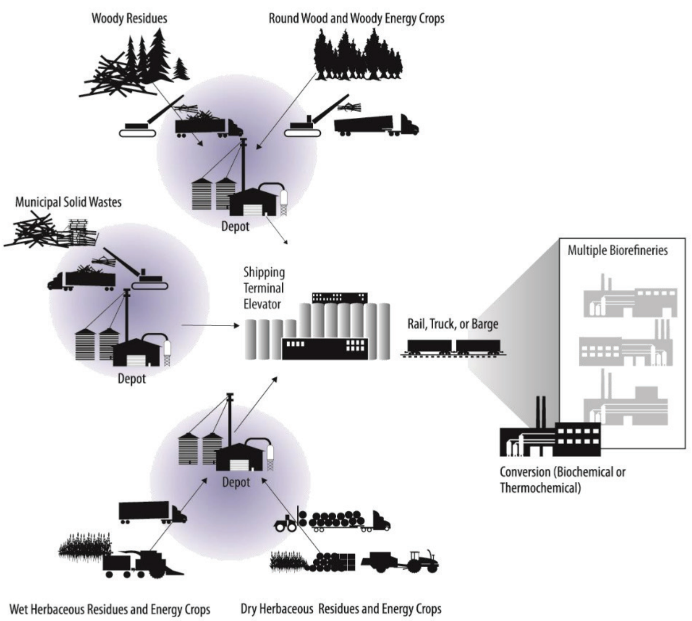
Figure 4.B.4 Biomass Supply Projections at Marginal Prices Between $20 and $200/Dry Ton in 2022.[11]



This figure shows both the marginal price and average price (white line). For the purpose of the referenced study, farm-gate price was defined as the price needed for biomass producers to supply biomass to the roadside. It includes, when appropriate, the planting, maintenance (e.g., fertilization, weed control, pest management), harvest, and transport of biomass in the form of bales or chips (or other appropriate forms—e.g., billets, bundles) to the farm-gate or forest landing. The term "marginal price" was used in biomass supply analysis to convey the price needed to supply an additional ton of biomass to the farm-gate, forest landing, biomass depot, or conversion facility. "Average price" was used to convey the price to acquire biomass from the first to the last ton over a specific period of time. The average price was less than the marginal price for a single feedstock.

The farm-gate price, however, is not the full cost associated with the biomass feedstock. It is important to include the cost of logistics to transport the material from the farm to the energy plant, as well as any off-site pretreatment steps. An advanced biomass collection system will need to aggregate and coordinate the collection and utilization of feedstocks for biomass-based energy and/or bioproduct plants to optimize access to low cost feedstocks and minimize the costs of logistics. Approaches that can densify the biomass in a form more suitable for transportation and subsequent usage, thus enabling larger cost-effective collection areas and increases in plant scale, are desirable—a potential example is depicted in Figure 4.B.5. The ultimate objective of a national supply system is to reduce the variability and cost of biomass supply.

Figure 4.B.5 Advanced Biomass Commodity Supply Network



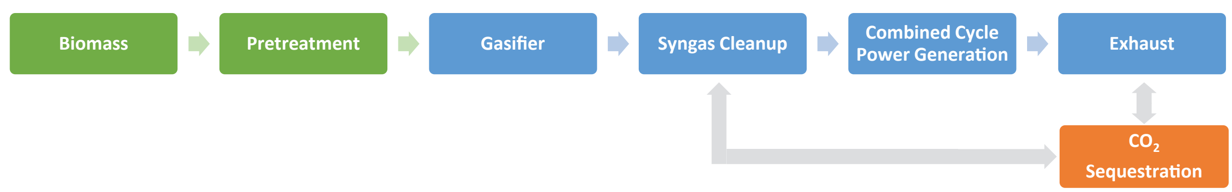
Under the right circumstances, biopower can accomplish three goals: (1) provide secure electricity by using domestically sourced biomass, (2) provide low-cost power when the cost of feedstock is competitive with alternative clean power generation sources, and (3) reduce atmospheric CO_2 concentrations when biomass is obtained from managed plantations. Expansion of domestic biopower capacity depends on the development of biomass production as a low-cost commodity on a regional or even a national basis to ensure a reliable feedstock source that is not disruptive to the commerce of food and feed and that is cost-competitive with other clean energy sources. Additionally, advances in combustion systems will help improve the efficiency of biomass combustion and gasification to achieve the highest efficiency possible while mitigating feed system, boiler maintenance, and flue gas cleanup issues that are different for biomass than traditional fossil fuels.

Research Strategy and Priority

Over the past decade, biopower research has mainly focused on four activities: (1) increasing the availability and quality of biomass to optimize the economic and environmental benefits of this resource as well as potentially commoditizing the supply; (2) developing and understanding biomass treatment requirements for storage, conveyance, and feed into various types of power plants; (3) developing biomass feed systems that are applicable to conventional power plants and high pressure combustors and gasifiers; and (4) developing combustion or gasification technology optimally suited to the unique properties of biomass. These activities are incorporated into programs pertaining to the development of bioenergy technologies and advanced coal conversion technologies. These technologies are each described separately in other sections of the *2015 Quadrennial Technology Review*;[12] only a general discussion of the merger of the bioenergy and clean coal programs technology development plans is necessary here. This technology review is oriented to biomass that is formatted specifically for conversion in future combustion or gasification systems that may either be adapted or optimally designed for biomass combustion or gasification.

The block flow process diagram illustrated in Figure 4.B.6 is representative of biopower that could be deployed in step with the development of technologies for biomass pretreatment, milling, and feed injection into pressurized conversion vessels. In this example, a gasifier produces combustible syngas that can be burned in a gas turbine. Using this concept, carbon monoxide (CO) contained in the syngas can be shifted with steam to produce hydrogen (H_2) and CO_2 (represented by the gray line connecting the syngas cleanup box with CO_2 sequestration in Figure 4.B.6) which can be subsequently captured for storage or sequestration. Following CO_2 separation, a stream of nearly pure H_2 is then available to burn in a gas turbine, resulting in a power system with near-zero emissions.

Figure 4.B.6 Schematic of Biomass Gasification with CO2 Capture and Combined Cycle Power Generation



Biopower will build upon elements of clean coal research, accelerating deployment efforts. Clean coal research is currently focusing on advancements in coal combustion technologies as well as new, emerging technologies that may improve cost and performance relative to currently available technologies. A general goal is to develop second-generation and transformational technologies that will reduce the cost of electricity while incorporating CO_2 capture and storage (CCS). Oxy-fired combustion is one approach being developed for new power plants and to retrofit existing power plants. Integrated coal gasification/combined-cycle power generation (IGCC) is viewed as another leading technology for achieving higher overall power production efficiencies. Technologies in both combustion and gasification pathways for coal with carbon capture are being readied for future time frames.

The near-term focus for rapidly commercializing biopower is understanding the properties and/or feed systems that will accommodate biomass feed injection into the coal conversion reactors and its impact on the flame properties, heat transfer steam generation tubes, and gas cleanup unit operations. The longer-term strategy is development of combustion technology that is optimally suited for up to 100% biomass combustion or gasification. An important strategy for decision-makers to consider will be to look to develop advanced biomass gasification systems in the future when cost-competitive, uniform format, biomass feedstocks are available for utility-scale power production.

Biomass gasification/combined cycle (BGCC) power generation is projected to provide the optimum approach for biopower. BGCC uniquely offers the relative benefit of scalability and flexibility commensurate with a variety of biomass feedstock markets. When combined with CCS, BGCC can effectively reduce atmospheric concentrations of CO_2 when utilizing renewable biomass grown on a plantation and biomass residuals that might otherwise be left to decay in the environment or that may be combusted in small-scale combined heat and power (CHP) plants that are not equipped with CCS.[13]

A summary of the commercial readiness and development needs for biomass conversion technologies is listed in Table 4.B.3.

Table 4.B.3 Utility-scale Technology Commercial Readiness for Biopower in the United States

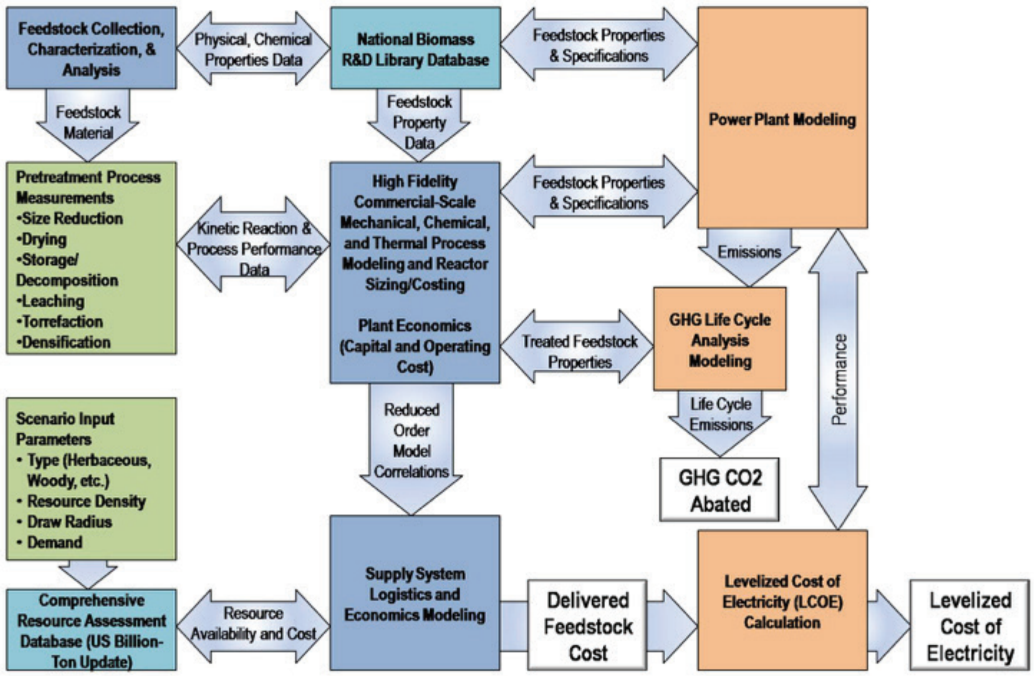
Technology	Commercial Readiness	Development Activities
Low- to medium-rate	Mature	None
Co-firing	Deployment in Europe; demonstration in United States	Feedstock diversification
Biomass repowering options	Early deployment in both Europe and United States	Pyrolysis oil upgrading
Pyrolysis oils (including biodiesel and biorefinery by-product lignin and residues)	At CHP plants supporting biorefinery operations	Supply chain compatibility
Atmospheric gasification	Commercial demonstration	Feed system(s) demonstration
High-rate co-firing	Development	■ Additional feedstock pretreatment, grinding, transport, and reactivity characterization R&D is needed. ■ Oxy-fired pulverized-coal-boiler development is in early stages for coal power plants. ■ CO_2 separation and compression for biomass-fired plant operations is similar for coal-fired and biomass-fired combustion and gasification operations.
Pressurized gasification (circulating fluidized-bed and entrained flow)	Early development in both Europe and United States	■ Feedstock pretreatment, grinding, transport, and reactivity characterization is being carried out by government and industry. ■ High-pressure dry feed systems (up to 1,000 psi) ■ Syngas cooling and clean-up optimized for biomass requires future attention. ■ CO_2 separation ■ Scaled-down combined cycle power train development for smaller biopower plants is needed to increase power cycle efficiency.

A credible techno-enviro-economic analysis (TEEA) approach is illustrated in Figure 4.B.7. The sensitivity of biomass feedstock price at the plant gate is determined as a function of collection distance and torrefaction/densification at either distributed collection depots or on the power plant site. Physical property data for the feedstocks of interest are extracted from publically accessible databases.[14] Feedstock processing and preparation costs are predicted by using the Biomass Logistics Model. The models for these costs were calibrated through laboratory and bench-scale equipment testing.

Computation of LCOE and GHG emissions is determined with process modeling. Predictions account for the effects of biomass combustion on the boiler heating rate and the production of syngas and syngas compositions in the case of gasification. Power plant models incorporate process details for the thermal conversion operations balance of plant unit operations, including pollution control and CO_2 capture and compression for storage. At the current price structure, justification for biopower depends on low-cost and abundant biomass feedstock supply and clean energy policy incentives, such as state Renewable Portfolio Standards, which mandate a percentage of power from clean energy sources.

Figure 4.B.7 Data Acquisition and Modeling Steps Leading to Scenario-specific Feedstock Costs, LCOE, and Life-cycle GHG Emissions

Credit: Pacific Northwest National Laboratory



Feedstock development generally follows a four-step process, laid out in Table 4.B.4. The four steps may be followed to develop a regional or nationwide biomass commodity or co-optimize with the end user in mind (e.g., a biorefinery or biopower).

Biopower Technology Development Approach for Advanced Biopower

Biopower development will leverage the ongoing development of a biomass supply chain and clean coal research activities. A merger of these programs is anticipated when the availability and cost of biomass is favorable relative to alternative uses of biomass and alternative clean power generation options. All major technology barriers for co-firing biomass in coal boilers have been raised to a technology-readiness level sufficient to elicit future commercial demonstration and deployment. BGCC-CCS, on the other hand, remains at a lower readiness level.

Efficient and cost-effective biomass pretreatment is essential for improving the physical and chemical properties of biomass and allowing higher percentages of biomass to be co-fired with coal.[15] Pretreatment helps to overcome the technical limitations of biomass as fuel and helps avoid derating of the plant due to the lower heating value of the biomass. Common methods that help to improve the physical properties, chemical composition, and energy properties of biomass are listed in Table 4.B.5.

Gasifiers are typically referred to as direct (pyrolysis, gasification, and partial combustion take place in one vessel) or indirect (pyrolysis and gasification occur in one vessel; combustion occurs in a separate vessel). In direct gasification, air and sometimes steam are directly introduced to the single gasifier vessel. In indirect gasification, an inert heat transfer medium, such as sand, carries heat generated in the combustor to the gasifier to drive the pyrolysis and char gasification reactions. Current indirect gasification systems operate near atmospheric pressure. Direct gasification systems have been demonstrated at both elevated and atmospheric pressures. While it is similar with coal gasification, biomass gasification has differences in terms of chemistry,

Table 4.B.4 Feedstock Supply Logistics and Reactivity Research

Activity or Step	Approach	Current Status
Analysis of market use	Technical-economic-environmental assessment for real options	TEEA completed for utility-scale co-firing Comparison of benefits versus biofuels production is situational dependent.
Feedstock supply system development	Optimize supply system based on cost and feedstock specification requirements. Determine resource availability and variation in market (i.e., seasonal availability, annual average, and variance).	Assessment tools: ■ Knowledge Discovery Framework for supply and demand trade-off studies ■ Biomass Logistics Model for feedstock pretreatment conversion processes benefits and cost estimation ■ Combustion and gasification simulation models to predict conversion to power efficiency and associated pollutant emissions ■ Life-cycle GHG assessment models ■ Plant capital and operating cost estimation and cost-of-electricity economic tools for combustion and gasification
Feedstock characterization	Matrix of analysis of physical and chemical properties relevant to ■ chemical composition and heating value ■ particle size ■ densification and durability ■ storage and transport performance ■ grindability and particle conveyance	■ Library of samples available for most major categories and types of woody and agriculture biomass ■ National User-Facility-Process Deployment Unit available to produce pilot-plant test quantities of on-specification samples
Particle reactivity	Project- or plant-specific scaled testing for pyrolysis, gasification, or combustion	Technology and project-specific testing

Table 4.B.5 Benefit of Common Biomass Pretreatment Steps

Pretreatment Step	Benefit	Technology Improvement Needs
Washing and leaching	Reduces ash and mineral deposition on boiler tubes, slag formation and gasifier refractory, and gas cleanup unit operations. Reduces corrosion and wastewater cleanup.	Advancements in washing and leaching processes using water, dilute acids, solvents, supercritical fluids, etc.
Steam explosion	Biomass is defibrated and chemically altered. Moisture content is reduced. Lignin is broken down, and its reactivity is enhanced. May help densification properties and improves grindability behavior for pulverized feed injection systems.	Commercially developed and proven process
Torrefaction	Mild heat treatment reduces moisture content and removes light volatiles. Reduces the hydrophilic nature of biomass and upgrades the heating value for higher heating rates in combustors and gasifiers. Improves grindability behavior for pulverized feed injection. Torrefaction of MSW eliminates hazardous emissions.	Commercially developed and proven process
Pelletizing	Compacts biomass and renders it more conveyable in coal transport systems.	Commercially proven and widely applied; opportunity in low-cost additives to drive down overall pellet cost

process, and syngas quality because of biomass being a highly variable mixture of compounds, such as cellulose, hemicellulose, lignin, extractives, and minerals. Additionally, the typically high ash content of biomass can cause sintering, slagging, deposition, and corrosion in gasifiers. Biomass gasification on a utility scale will likely leverage ongoing research and development (R&D) of two leading coal gasifier options as follows:

- Conversion of biomass occurring in a fluidized bed in an atmosphere of steam or sub-stoichiometric air/oxygen to a medium- or low-heating value gas to produce a syngas, rich in carbon monoxide and hydrogen, plus relatively high amounts of methane and carbon dioxide.
- Higher temperature gasification that involves oxygen/steam conversion of biomass (or biomass and coal blends) will produce a syngas mixture that is rich in carbon monoxide and hydrogen, with only a small amount of methane and relatively low amounts of carbon dioxide in the gas. These gasifiers typically operate at higher pressure, which may have cost benefits for downstream syngas processing.

Circulating fluidized bed (CFB) gasifiers demonstrate several advantages despite their more complex design and operation, including the following:[16]

- Greater fuel flexibility—wider range of acceptable feedstock particle sizes, density, moisture, ash content, and mixtures of different fuels
- Lower operating temperature—avoids the problem of ash sintering and agglomeration
- Greater throughput and/or smaller reactor volume
- Improved heat and mass transfer from fuel
- High conversion rates and higher heating value of produced syngas

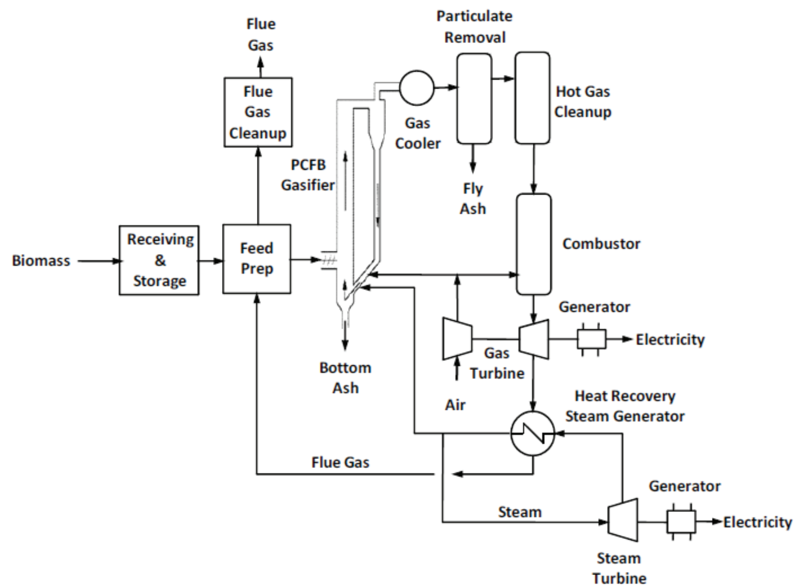
These features make fluidized bed gasifiers particularly good for biomass fuels, such as agriculture residues, woody biomass, and MSW. CFBs have less restriction on the size and shape of fuel and can process a wider range of feedstock particles, especially lightweight and fine material, without the penalty of entrainment loss. In addition, due to the high velocities within the reactor and cyclone, a CFB unit can achieve a much greater throughput than a bubbling fluidized bed for a given bed area. When operating at elevated pressures, pressurized CFB (PCFB) gasification is commonly oxygen-blown. However, PCFBs require a more complicated pressurized feed system and a high pressure syngas cleanup train.

A biomass-based power plant process flow diagram based on an IGCC system is shown in Figure 4.B.8. The system consists of the following components:

- Feed handling and preparation system (comparable to the system in the co-firing discussion)
- Biomass dryer (typically a rotary dryer)
- Biomass gasifier (in this case a partial oxidation gasifier)
- Gas cooler (to reduce gas temperature to the maximum allowable temperature of a hot gas filter and to preheat water for a heat recovery steam generator)
- Hot gas filter (either a ceramic or sintered metal filter)
- Gas cleanup for contaminants, such as sulfur or chlorine
- Brayton cycle combustion turbine (gas turbine) with air extraction for gasifier use (also called a topping cycle)
- Heat recovery steam generator that uses turbine exhaust gas to produce steam
- Rankine cycle extracting/condensing steam turbine (steam extracted for gasifier use), also called a bottoming cycle
- Ancillary utilities, such as cooling water systems and exhaust CO_2 separation and compression

Figure 4.B.8 Process Flow Diagram for a Pressurized Circulating Fluidized-Bed Biomass Gasifier and a Combined-Cycle Power System[17]

Credit: National Renewable Energy Laboratory



Entrained-flow (EF) gasifiers are capable of operating at higher temperatures and pressures relative to either a CFB or PCFB, respectively. High-rank coals benefit from higher temperatures to attain more effective gasification rates. The higher temperatures will also result in less tar formation. EF gasifiers may achieve higher quality syngas than CFBs or PCFBs in terms of methane, hydrocarbons, and tars. Commercially proven EF gasifiers in Europe have successfully been used to co-gasify a variety of biomass residues with coal.

Considering the unique physical and chemical properties of biomass, such as ash composition and generally higher reactivity than coal (viz., depolymerization, devolatilization, and char gasification or oxidation), future biomass gasification research will likely include reducing the technical risk and cost of the following three key technology areas: upstream processes (e.g., feedstock preprocessing and feed systems), gasifier design and optimization, and downstream processes (e.g., syngas processing systems). Future industrial R&D highlights for each of these areas, at minimum, are projected to include the following (see also Table 4.B.6):

- Upstream processes achieve optimal particle size distribution and moisture content of biomass feedstocks. For biomass co-gasification with coal, modification of the feed systems may be necessary, considering the fibrous nature of biomass. Current R&D efforts of the clean coal program may be leveraged in the future when biomass gasification is considered an imperative.
- Gasifier design and optimization relative to coal gasification development R&D projects will likely lead to more durable refractory materials and may mitigate the clogging and fouling of syngas coolers and may be especially important to future biomass gasification. However, this will require verification and possible additional R&D relative to biomass feedstocks in the future. Gasifier concepts that are currently under development for multiple combinations and blends of coal and biomass feedstocks will be useful for progression to 100% biomass gasification in the future. Further, the unique reactivity of biomass compared to coal suggests that re-optimization of CFB, PCFB, or EF gasifiers may be beneficial for 100% biomass gasification.
- Downstream processes require further R&D of improved syngas heat recovery, particulate removal, pollutant and impurity separation, and CO_2 capture technologies. Biomass gasification will introduce additional or new organic pollutants or trace contaminates that may impact syngas scrubbing, adsorption, or catalytic reactors that are developed for coal gasification syngas cleanup and conditioning. Therefore, future validation of the systems being developed prior to any market push for biomass gasification will likely require testing to verify application to 100% biomass-fed gasification. Modifications to the systems or to the feedstock properties may be required to reduce the probability of fouling or deactivating the syngas cleanup unit operations.

Table 4.B.6 Focus of Potential Future Biomass Gasification Systems Technology Development

Technology Focus	Technology Challenge	Research Focus
Upstream processes	■ Fibrous nature of biomass ■ High ash content of herbaceous biomass ■ High moisture content ■ Low bulk density	■ Develop efficient pretreatment systems to increase energy density and to reduce ash content ■ Develop size reduction system to meet specification ■ Develop reliable feed system to deliver high volume of biomass feedstock for existing plants and to reduce possible tangle problems owing to the fibrous characteristics of biomass
Gasifier design and optimization	■ Slagging, corrosion ■ Temperature profile	■ Slagging mechanisms relative to biomass feedstock ■ Fate of alkali metals ■ Reactor design optimization relative to biomass particle reactivity
Downstream processes	■ Presence of tars and volatile alkali compounds and associated impact on syngas cleanup, conditioning, and CO_2 separation unit operations	■ Gasifier screening and related design optimization for candidate biomass feedstocks ■ Alkali removal

Goals and Benefits

The technology development goals for the commercialization of biopower are either consistent with or will leverage the current biomass and clean coal research efforts. These goals may include the following:

- Leveraging biomass feedstock pretreatment and supply development by industry and government in order to optimize feedstock supply quantity, quality, and cost
- Leveraging fuel systems optimization development, including for PCFB and EF gasification units
- Demonstrating 1,000–2,500 tons/hour feed rate circulating fluidized-bed and entrained gasifier(s) for major sources of biomass
- Demonstrating slag recovery and particulate control for volatile alkaline ash component associated with biomass feedstocks
- Leveraging advanced syngas cooling and heat recovery for volatile alkaline ash components associated with biomass feedstocks
- Leveraging carbon capture and storage demonstration, advanced syngas conversion, and novel H_2 enrichment membranes
- Leveraging advancement in O_2–H_2 turbine integration with biomass gasifier
- Achieving a relative reduction in LCOE, possibly accounting for life-cycle GHG advantages

A nominal 200 MWe biomass gasifier equipped with CCS could be a reasonable goal for utility-scale BGCC power plant. This size of a gasifier generally matches the quantity of biomass that can be collected within a 50-mile radius (100-mile circle) of the plant. This scale of gasifier could provide the electrical power demand for a community of 100,000-200,000 persons. This scale would also be sufficiently large to justify CO_2 capture for commercial uses or sequestration. Community power production of 200 MWe is consistent with one gasifier project now being undertaken in Europe. Several gasifiers at this scale, distributed throughout regions of high biomass availability, could demonstrate net atmospheric drawdown of atmospheric CO_2 levels.

Based on the assumed scale of BGCC, the associated technology and feedstock targets and goals would be the following:

- Technology focus—200 MWe, oxy-fired gasifier: The biopower target would be to adapt and apply commercial gasifiers developed for coal and/or biomass to produce 200 MWe. This choice is based on the following assumptions:
  - Combustion turbine sizes and frames are currently offered by commercial vendors.
  - Each gasifier would use about 2 million tons-dry per year, approximately the amount required for 20% co-firing in a 2,000 MWe PC power plant.
  - Projected price for this quantity of feedstock would be approximately $80/ton-dry, as suggested in the trend shown Figure 4.B.9.
- Market penetration—5 GWe biopower additions by 2025; 20 GWe by 2035: These projections require the following biomass resource commitments beyond the current biopower market:
  - Utility co-firing of 100 million tons per year.
  - 200 million tons per year with BGCC by 2035.
- Cost of electricity goal—a 20% reduction in LCOE from current study projected average costs of approximately $100/MW): A 20% LCOE cost projection would be feasible when the following techno-economic goals are attained:
  - $80/ton for either woody or herbaceous feedstock costs with pioneer feedstock collection, treatment, and delivery systems in a uniform format compatible with BGCC milling and feed injection system.
  - BGCC heating rate improved from 10,000 Btu/kWh to 8,000 Btu/kWh by 2035, based on advancement of the syngas cleanup systems.
  - Overall thermodynamic efficiency increased from 0.40 to 0.42 by 2035, based on tailoring the combined cycle.
  - CO_2 capture penalty reduced to 0.02 efficiency points by 2035, based on R&D of CO_2 capture, compression, transport, and management systems.
  - Plant capital costs less than $4,000/kW installed without CCS and less than $5,500/kW with CCS for a 200 MWe plant.
  - 30 year capital payback with an internal rate of return of 12%.
- GHG reduction—100 million metric ton reduction by 2025; >400 million metric tons by 2035: This goal invokes the following assumptions:
  - CCS applied on power plants beginning by 2025.
  - 5 GWe biopower employed by 2025, as any variety of clean coal plants.
  - 20 GWe biopower employed by 2035 as BGCC.
  - Interagency Panel on Climate Change (IPCC) GHG emissions for coal, on average, 400 g-CO_2eq/MJ (Table 4.B.7).[18]
  - CCS resulting in net life-cycle sequestration of 300 g CO_2 eq/MJ.

Figure 4.B.9 Illustrative Cost of Biomass for a 200 MWe BGCC Plant[19]

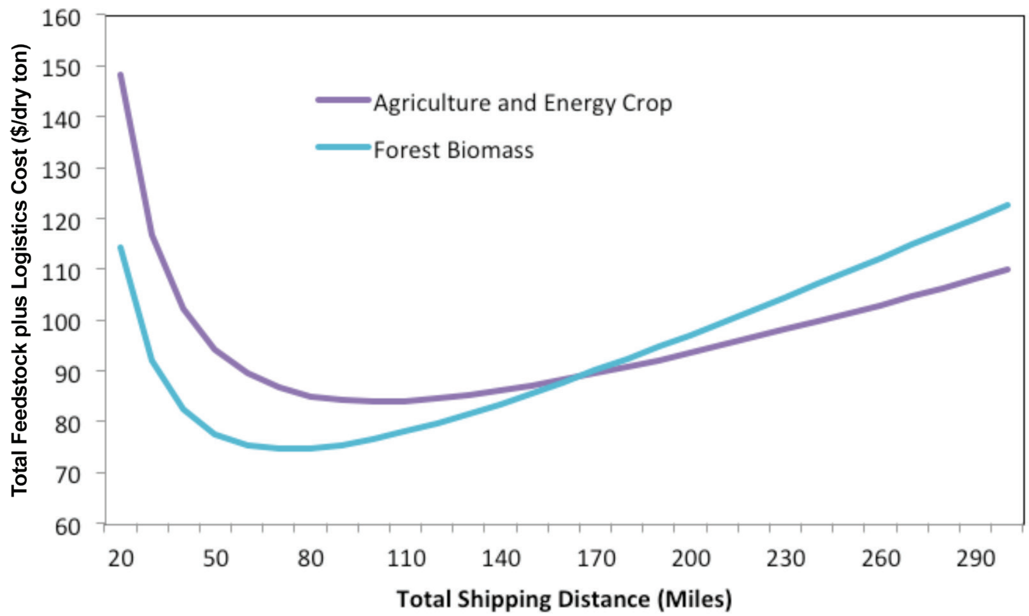


Table 4.B.7 Focus of Potential Future Biomass Gasification Systems Technology Development[18]

	Electricity (g CO_2 eq/MJ)[a]				Transportation (g CO_2 eq/MJ)[a]			
	Oil	Coal	Fossil Gas	Biomass	Natural Gas	Petroleum Gasoline	Ethanol	Corn & Wheat Ethanol
Min.	200	300	100	12	68	90	-1	17
Mean	250	400	150	17	73	98	16	42
Max.	300	500	200	22	78	106	33	67

[a] Land use-related net changes in carbon stocks and land management impacts are excluded.

Schedule

Currently, no biopower production goals are driven by regulations. Therefore, the biopower technology development roadmap leverages market-based R&D goals for clean coal technology development[20,21] and feedstock supply and logistics[22] as follows:

- CCS is demonstrated and becomes commercially ready by 2025 in strategic co-firing locations corresponding to high concentrations of biomass production in the midwest states, Ohio Valley and eastern coastal states, and the southeast coastal states.
- CO_2 capture is applied on participating co-fired, coal-fired power plants by 2025.
- By 2025, IGCC is commercially viable for coal gasification.

In the event biopower is incentivized by policy, the following objectives could be considered to meet the illustrative examples of this summary:

- By 2025, one million tons of renewable feedstocks are developed for U.S. biopower by commercial pellet plants in a format that is compatible with existing coal-plant milling and pneumatic injection systems.
- By 2030, BGCC is commercially proven.
- By 2035, two million tons of renewable feedstocks are developed for U.S. biopower by commercial pellet plants in a format that is compatible with existing coal-plant milling and pneumatic injection systems.

Closing Note

The following, comes from the National Renewable Energy Laboratory:

> "The most important issue for large-scale deployment of biopower is feedstock competition with lignocellulosic biofuels and other uses for wood. Although biomass can serve a dual role in helping to meet both U.S. electricity generation needs and transportation energy needs, RE Futures resource estimates were not adjusted for potential use in biofuels production. Both biopower and biofuels will play important roles in the future. To the extent that electricity serves a transportation role through plug-in hybrids and battery electric vehicles, biopower will serve a transportation role. In many conceptual biofuels processes, electricity is produced as a by-product, much like it is in the existing pulp and paper industry. The existing biopower industry uses primarily residues and waste materials with widely varying properties and with limited control of feed properties and therefore uses feeds that are unsuitable for those biofuels processes that currently require very uniform feedstock. The issue of future feedstock competition between the power and fuel sectors is unresolved."[23]

Endnotes

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- Capacity from EIA Electric Power Annual Report 2013 tables 4.2a and 4.2b (as per QTR Table 4.1)
- For Black Liquor: RISI Mill Intelligence Database. http://www.risiinfo.com/ Accessed through May – August 2015
- For Co-firing: National Renewable Energy Laboratory. NREL Biopower Atlas, 2014. http://maps.nrel.gov/biopower

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12 U.S. Department of Energy 2015. "2015 Quadrennial Technology Review." http://energy.gov/quadrennial-technology-review-2015. See Chapter 7 of the main QTR report as well as Technology Assessments 7.A and 7.B

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- See also: http://energy.gov/eere/bioenergy/downloads/biomass-feedstock-bioenergy-and-bioproducts-industry-technical-feasibility

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Acronyms

BGCC	Biomass gasification/combined cycle (power generation)
CCS	Carbon capture and storage
CFB	Circulating fluidized bed
CHP	Combined heat and power
CO_2	Carbon dioxide
DT	Dry tons
EF	Entrained-flow (gasifier)
GHG	Greenhouse gas
GW	Gigawatts
ICE	Internal combustion engine
IGCC	Integrated coal gasification/combined-cycle (power generation)
IPCC	Interagency panel on climate change
LCOE	Levelized cost of energy
MJ	Megajoules
MSW	Municipal solid waste
MW	Megawatts
PCFB	Pressurized circulating fluidized bed
PURPA	Public utilities regulatory policies act of 1978
R&D	Research and development
STG	Steam turbine generator
TEEA	Techno-enviro-economic analysis