Part II—Biomass Energy Considerations

Introduction

Although there are many options for disposing of biomass thinned from overcrowded forests, the vast amount of biomass that needs treatment limits consideration of many of these possibilities. The USDA's Forest Products Laboratory has worked to develop a broad array of options for traditional and non-traditional forest products throughout the U.S. Most of the non-traditional products require small amounts of material and therefore do not match the large amounts of biomass to be treated in the West. However, there appears to be an excellent match between the vast amounts of biomass resource in the form of forest residues and the large biomass market demands of the biomass power and emerging biomass ethanol industries.

This is not to say that other non-traditional products are unimportant. There can be, in some cases, a combination of traditional products (saw logs, pulp, fuel wood etc.) plus non-traditional products (small stakes, chips for organic mulch, compost, animal bedding etc.) that may make a forest thinning project economically feasible. The primary problem, however, remains that these combinations of products have not, in most cases, added up to the total amount of biomass that needs to be removed. Where that is the case, a biomass energy market may be the key to initiating many forest restoration projects.

The use of biomass for energy will always be the lowest-value use. Where alternative or non-traditional wood products can be produced, those biomass users will out-bid the energy industry for the biomass supply. The biomass energy market can, however, be a useful adjunct to those market opportunities, providing a way of disposing of otherwise problematic residual material in a least-cost, if not profitable, manner.

From a biomass energy standpoint, unhealthy forests are only one of many sources that could eventually support a robust biomass energy industry. The U.S. sends more than 200 million tons of organic waste to landfills each year and currently idles about 50 million acres of farmland, some of which is suited for growing dedicated energy crops. To put this in perspective, if fully used, these resources could produce enough ethanol to power most U.S. vehicles. While this level of market penetration is not realistic in the foreseeable future, aggressive policies to encourage the development and use of biomass could help biomass ethanol producers eventually reach something on the order of 50 billion gallons of ethanol per year, according to NREL estimates (Sheehan 2000).

Sources of biomass other than forests may be important in providing a full feedstock supply over the economic lifetime of a biomass energy plant. Short-term cleanup of surplus forest biomass may not, by itself, provide for an economical installation. In other words, it may be important for proponents of biomass industry development to focus attention on the total biomass opportunities in forest, agriculture and municipal sources in some areas. What seems logical is that the industry will not develop around one source of fuel alone. A larger industry that uses a mix of biomass fuel sources will provide opportunities that do not exist today.

The two leading technological options for converting large amounts of biomass in the U.S. to energy are conversion of biomass to ethanol and conversion of biomass to electricity. A number of technological conversion methods exist to produce ethanol from biomass, several of which are in various commercial planning stages today. There are essentially two technologies in operation today for conversion of biomass in power generation: the current combustion technology and long-term gasification technology.

Former President Clinton in August 1999 showed strong support for biomass products with his Executive Order seeking to accelerate the development and use of biomass fuels, products and chemicals in the U.S. Its goal is to triple the use of bioenergy and bio-products by 2010 and generate as much as $20 billion per year in new farm and rural community income. (Clinton 1999).

Biomass Conversion to Ethanol

Overview

The United States needs alternatives to foreign oil for transportation to wean the country from its dependency on imported oil. Using biomass as a feedstock for ethanol production could expand the domestic ethanol market, improve national security, create jobs, dispose of burdensome biomass waste and produce a clean transportation fuel.

Biomass is composed of three components: cellulose (6-carbon sugars), hemicellulose (mostly 5-carbon sugars in hardwoods and herbaceous crops and 6-carbon sugars in softwoods) and lignin (the "glue" holding polymers, or long chains, of these two sugars together). The production of ethanol involves the use of chemicals, or a combination of chemicals and enzymes, to break down the cellulose and hemicellulose into sugars, which are then fermented into ethanol. The lignin may be burned to provide the heat and energy needed to drive the process. Research is under way to develop new methods and technologies that can improve the efficiency of these processes (Hinman 1997).

The current corn ethanol industry converts the starch in the corn kernel to ethanol. Starch is another 6-carbon sugar polymer, but it is a much different molecule than cellulose and requires a different technology. The remainder of the grain is converted to high-value products such as animal feed and corn syrup. The U.S. Department of Agriculture (USDA) recently determined that today's corn ethanol plants have increased production efficiencies to reflect a net energy gain of 25 percent; the U.S. Department of Energy's (DOE) new technology for biomass conversion to ethanol could increase production efficiencies up to about 4:1. Cellulose-based conversion to ethanol differs from the current starch-based conversion in that it is a more cost-effective process that uses the entire resource (Argonne National Laboratory 1999).

Using biofuels such as ethanol provides measurable air quality benefits by reducing vehicle emissions and abating field burning of some agriculture residues. Increasing the use of biofuels will reduce air pollution and the greenhouse gases that are implicated in the problems of global climate change. An estimated 40 percent of today's smog, 33 percent of annual carbon dioxide emissions and 67 percent of carbon monoxide production comes from automobiles and other forms of transportation (Hinman 1997).

Production of biofuels can also contribute to cleaner air by providing a clean biomass disposal method that reduces the pollutants associated with open-field burning of agricultural crop residues such as rice straw or sugar cane bagasse. Located near forests that need surplus biomass removed as a means of lowering wildfire intensity, biomass energy facilities could also provide a disposal outlet that would result in lower emissions from wildfires.

Another benefit of bioethanol[22] is that the lignin component allows the biomass conversion process to be power independent in a stand-alone bioethanol plant. Also, by co-locating a bioethanol plant with an existing biomass power plant, it is possible to cogenerate electricity in the associated power plant that would burn the lignin component. Lignin has the same energy content as a mid- to high-grade coal, but it lacks coal's sulfur and nitrogen. Preliminary reports indicate that co-locating a bioethanol plant with a biomass power plant is quite cost-effective because of lignin use. Therefore, some of the first biomass ethanol plants in the U.S. (particularly in California) may be colocated with power plants to help cut down capital costs such as boilers and water treatment facilities (Yancey 2000).

[22] In this discussion, the term "bioethanol" refers to ethanol produced from lignocellulosic biomass (or cellulose), in contrast to ethanol produced from grains, such as corn.

Ethanol as a Transportation Fuel

The Clean Air Act of 1970 signaled the beginning of a new era in which the United States federal government began relying on national standards to enforce environmental quality. First revised in 1977 and again in 1990, the Clean Air Act affects the health and economic welfare of millions of U.S. citizens. Air pollution levels have dropped significantly, including an 89 percent decline in emissions of lead between 1988 and 1993. In the same time period, a 20 percent decline of particulates is reported, along with a 26 percent decline in sulfur oxides and a 37 percent reduction in carbon monoxide, some of which is due to ethanol use (DOE 1995).

The 1990 Clean Air Act Amendments encouraged the development of alternative fuels as well as cleaner blended fuels. Alternative fuels are specifically defined as methanol, ethanol and other alcohols, reformulated gasoline and diesel, natural gas, liquefied petroleum or propane, hydrogen and electricity.

The final version of the Clean Air Act Amendments in 1990 stopped short of mandating the sale or use of alternative fuels, but the act does incorporate several programs requiring cleaner fuels, opening up the fuels market to non-petroleum gasoline additives. The two most important programs with respect to gasoline composition are the Oxygenated Fuels and Reformulated Gasoline programs.

Oxygenated Fuels Program

The Oxygenated Fuels program was designed to combat carbon monoxide, which is a product of the incomplete burning of carbon found in transportation fuel. In 1990, 42 urban areas with 22 million people exceeded the EPA's National Ambient Air Quality Standard for carbon monoxide. Since November 1992, gasoline sold in the winter in high-pollution areas is required to contain a minimum of 2.7 percent oxygen by weight, equating to about 10 percent ethanol in gasoline. This added oxygen causes more complete combustion of the fuels, resulting in lower carbon monoxide emissions.

Fuel additives such as ethanol and ethyl or methyl tertiary butyl ether (known as ETBE and MTBE, respectively) supply the extra oxygen for these oxygenated gasolines. The majority of MTBE used in the U.S. is imported; MTBE imports reached 1.5 billion gallons in 1997 alone (RFA 1998). Under the Oxygenated Fuels program, these additives, mostly in the form of MTBE, are used in about one-third of the nation's gasoline, displacing 100,000 to 200,000 barrels of oil per day. However, health concerns about MTBE, along with discoveries of underground gasoline tanks leaking MTBE into ground water, have caused state and federal legislation to be enacted that phases out MTBE use.

The Oxygenated Fuels program has been a success. A 95 percent reduction in the number of days exceeding the carbon monoxide health standard was reported within the first year of the program. The program is estimated to reduce vehicle carbon monoxide emissions by 15 percent to 25 percent.

Reformulated Gasoline Program

A second type of pollution problem, one addressed by the Clean Air Act's Reformulated Gasoline (RFG) program, is ozone formation. Ozone is the major component of smog and presents the U.S. with its most difficult urban air quality problem. Nearly 100 cities exceed the EPA's National Ambient Air Quality Standard for ozone, which is based on the highest ozone level a sensitive person can tolerate. There are nine urban areas inhabited by 57 million people affected by severe ozone pollution. These areas experience levels of 150 percent or more of the acceptable level of ozone.

Reformulated gasoline containing oxygenates substantially lowers tailpipe emissions that produce urban smog and toxic air pollutants, including carbon monoxide, carbon dioxide and sulfur oxides. To reduce evaporative emissions, reformulated gasoline standards mandate refiners to lower the vapor pressure of gasoline before blending in oxygenates (Clean Fuels Development Coalition 1997). Overall emission performance standards require RFG to achieve at least a 20 percent to 25 percent reduction in hydrocarbon and toxic compound emissions beginning in the year 2000 (DOE 1995). Requirements call for 22 percent of U.S. gasoline to be reformulated, displacing between 100,000 and 350,000 barrels of oil a day.

Reformulated gasoline eliminates more than 300,000 tons of air pollution annually, equivalent to taking 7.5 million vehicles off the road. A General Accounting Office report concluded that oxygenates in RFG will displace nearly 4 percent of U.S. gasoline consumption annually and, if fully implemented, could displace 10 percent (Durante 1996). Although it costs about 2 to 4 cents more per gallon than conventional gasoline, RFG reduces toxic emissions by nearly 20 percent more than the Clean Air Act actually requires (DOE 1995).

Adding oxygenates to RFG has two main benefits. Oxygen dilutes and replaces aromatics, such as the carcinogen benzene, and increases engine efficiency, causing gasoline to burn more completely. These two benefits make oxygenate addition one of the most feasible alternatives for refiners to achieve the required abatement in air toxics, while also reducing tailpipe sulfur, olefins and total volatile organic compound (VOC) emissions.

Environmental Issues and MTBE

MTBE, the fossil-based oxygenate that has been California's oxygenate of choice, has recently been found to have major environmental problems. In California, MTBE—a suspected carcinogen in animals and a highly persistent contaminant in water—has been leaking into groundwater from underground gasoline storage tanks and has been detected in drinking water. The governor of California has issued an executive order to phase out MTBE use in gasoline by 2002 (Davis 1999; Graf and Koehler 2000). The California governor's Environmental Policy Council concluded that ethanol is a safe and preferred oxygenate alternative; if it were to fully replace MTBE at its current level of use, the ethanol demand could potentially reach as much as 550 million gallons per year (Graf and Koehler 2000; Hickox 1999). This increased ethanol demand would create a greater market pull not only for ethanol but also for its required feedstocks such as wood residues.

Benefits of Bioethanol

Bioethanol can be manufactured from feedstocks that are troublesome to the environment and to communities nationwide. For example, many areas of the United States have become burdened with solid waste disposal, causing landfills to turn away waste and leaving few options. In California, even simple refuse such as yard trimmings is piling up and creating problems. California has legislation in place requiring a 50 percent reduction of municipalities' solid waste going to landfill sites. These wastes could be converted into ethanol. Ethanol-plant side-products—various acids and terpenics such as gallic acid—may be highly marketable products in the future (Greef 1999). It has been estimated that California alone has enough biomass to support an ethanol industry of 1 to 1.5 billion gallons per year. Most of that biomass is a burdensome waste disposal problem today (Forrest 1999). In contrast, the total ethanol production of the U.S. currently stands at 1.5 billion gallons a year (ABA 2000b).

As we have discussed above, the benefits of the use of bioethanol include the reduction of air pollutants from tailpipe emissions. In addition, the growth of new tree and plant sources of biomass recaptures carbon during photosynthesis. This process absorbs atmospheric carbon dioxide, which has been associated with global climate change.

Bioethanol Production and the Western Market

The estimated cost of bioethanol has dropped from \$3.60 a gallon in 1980 to between \$1.15 and \$1.43 a gallon in 2000. Advances in feedstock processing and biotechnology could reduce bioethanol costs to between \$.69 and \$.98 per gallon over the next two decades (DiPardo, in Graf and Koehler 2000).

Most of the cost reduction estimates are based on the introduction of superior enzymes and process designs, a result of research conducted for almost two decades at the U.S. Department of Energy's National Renewable Energy Laboratory (Mielenz et al. 1996). It should be noted that these cost projections do not include government tax incentives.

A rough estimate based on pilot plant results shows that 200 bone-dry tons (BDT) a day or 70,000 BDT a year of western softwood biomass are required for production of 3-to-6 million gallons of ethanol a year in a biomass ethanol plant, depending on the technology chosen. Estimates indicate that the 70,000 BDT a year would produce 3.6 million gallons with dilute nitric acid technology, 5.6 million gallons with an advanced enzymatic process and 6 million gallons with a concentrated sulfuric acid process. The conversion efficiency rate depends on the type of biomass feedstock used and its sugar content, (amount and types of 5- versus 6-carbon sugars in the biomass) as well as the technology used (acid versus enzymatic hydrolysis, etc.)(Yancey 2000; NREL 1997).

Ethanol demand in the Western states of California, Arizona, Nevada, Oregon and Washington rose from 154 million gallons in 1992 to 214 million gallons in 1996 but dropped to 124 million gallons in 1997 as California and Washington changed their policies (NREL 1997). However, this demand is still significantly more than the current ethanol production capacity on the West Coast, which is estimated at only 14 million gallons per year. If additional Western supplies could be developed from biomass, the advantage in reduced transportation costs for Western producers is estimated to be between 5 and 15 cents per gallon when compared to importing Midwest sources.(Yancey 2000)

Figure 2.1 Ethanol costs per gallon are projected to fall significantly by 2010 (Sheehan 2000).

Status of the Bioethanol Industry

The U.S. Department of Energy and the National Renewable Energy Laboratory (NREL) have been working closely with state agencies and a wide range of industrial partners to accelerate the advancement of new bioethanol technology.

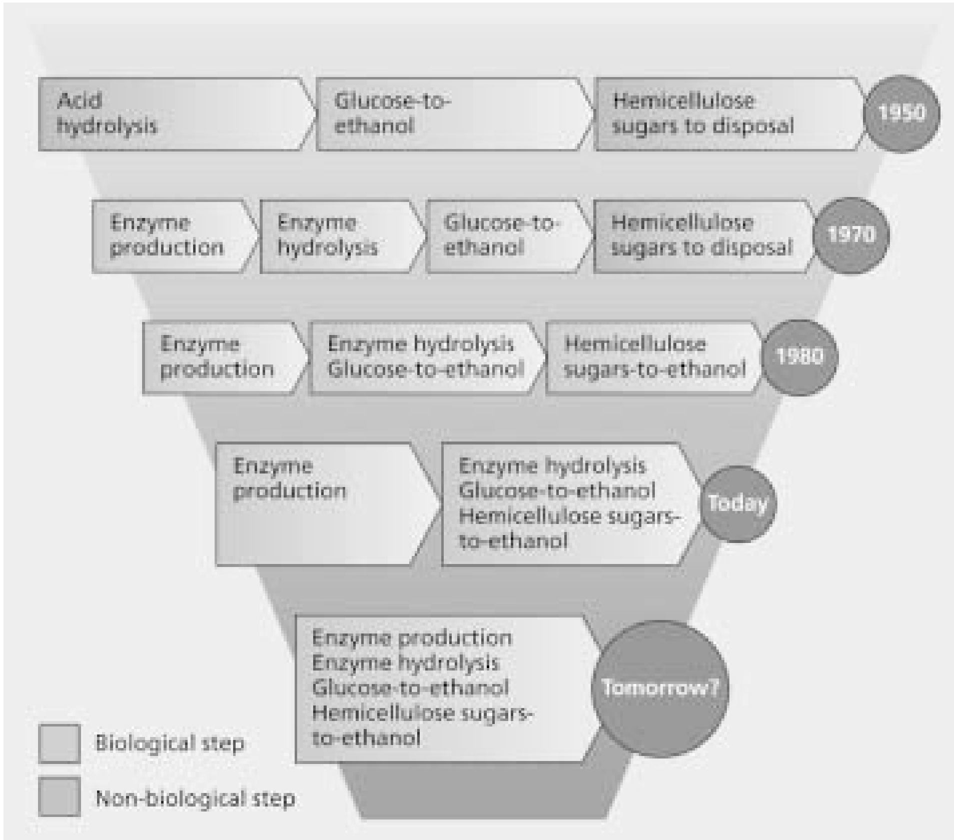

Figure 2.2 Progress of biomass-to-ethanol conversion technology (Sheehan 2000).

DOE and NREL, along with California's Energy Commission, Air Resources Board, and Food and Agriculture Agency, are exploring the possibility of California producing its own domestic bioethanol to curb toxic transportation emissions and simultaneously stimulate its economy. One of DOE's objectives is to have the first new-technology bioethanol plant operational in 2002. Several biomass ethanol plants are being considered for construction in California, with operations projected to begin by 2003. The projects, using an array of technologies, include:

■ *City of Gridley*: In California, BC International Corporation (BCI) will use its technology on waste rice straw, alleviating open-field burning. This plant may also use forest residues and will most likely be co-located with an existing biomass power facility.

■ *Collins Pine*: BCI, in cooperation with Collins Companies, a large private timber firm, is planning a plant fed by forest residues. The plant will be sited in Chester, California, near an existing sawmill operation and will also use sawmill residues as feedstock.

■ *Arkenol, Inc.*: In a plant project near Sacramento, California, Arkenol will use a patented new technology to convert rice straw to ethanol and other feedstocks such as lactic and citric acids. This project will use a proprietary hydrolysis process, a technology different from the one to be employed at the BCI/Gridley project. The same process can work with forest biomass if a steady, long-term supply can be guaranteed (Greef 1999). While this plant is on hold, Arkenol is also considering a plant in Southern California using the paper component of municipal solid waste (ABA 2000a).

Several other plants that could be coupled to existing biomass power plants may be feasible in California. Many biomass power plants went out of business in recent years because of the ending of California's Standard Offer contracts stemming from Public Utility Reform Policy Act (PURPA) legislation. California has lost about 300 megawatts of its 880-megawatt capacity supplied by these plants (California EPA 1997). A bioethanol plant would be able to derive enough kilowatt-hours of electricity from the lignin component of biomass to operate the bioethanol plant and still have excess electricity left over for sale to the power market. In some cases, it would be beneficial to co-locate a biomass ethanol plant with existing power plants, which might improve the economics enough to keep some of these power plants operational (NREL 1997a; Yancey 2000).

Front Range Forest Health Partnership Feasibility Study

The Front Range Forest Health Partnership consists of public, private and citizen groups organized to investigate possible options for using wood residues generated through forest thinning and through commercial activities in urban communities along Colorado's Front Range. The partnership's 1998 feasibility study, prepared with the help of the Forest Service and the National Renewable Energy Laboratory, contains an inventory of woody biomass resources and a siting analysis for potential forest biomass-to-ethanol facilities.

The study concludes that:

- More than 520,000 bone-dry tons per year of material are available within a 50-to-100 mile radius of the Denver Metropolitan area.
- Coors Brewing Company of Golden, Colorado, is the most viable site for an ethanol plant. Coors already produces some ethanol from waste beer at its Golden facility.
- A biomass ethanol plant is feasible but questions of secure supply and transportation cost must be resolved.

Quincy Library Group Feasibility Study

The Quincy Library Group, a forest health advocacy group located in Quincy, California, used assistance from the California Resources Agency to perform a feasibility study of building and operating a biomass ethanol plant in Northern California. NREL provided technical support and publication. The proposed plant was based on the group's plan for strategic thinning of the region's federal forests as a way of reducing fire danger, improving forest health and restoring forest ecosystems.

The forest thinning plan was enacted into law in October 1998 as the Herger/Feinstein Quincy Library Group Forest Recovery Act of 1998.[23] Under this law, the Quincy Library Group has received full funding of about $30 million in 2001 for a five-year program of thinning 40,000 to 60,000 acres per year. However, the plan continues to face significant opposition from environmental organizations.

The Quincy Library Group is trying to address the forest health situation that is common in many areas of the West as we have discussed in Part I of this report. The challenge is to find an economically feasible and environmentally suitable way to dispose of large quantities of non-marketable small trees and other biomass. The feasibility study concluded (NREL 1997)[24]:

■ There is adequate biomass in the region for one or more plants. In studies of forests within a 25-mile radius of four proposed plant sites, sustainable supplies ranged from 187,000 to 336,000 bone-dry tons per year.

■ Feasible sites for production facilities exist; sites near existing or former sawmill sites, with access to existing biomass power plants, showed the most promise.

■ Several operating technologies were evaluated for feasibility, with plant sizes limited to the estimated sustainable biomass supply within a 25-mile radius. The resulting plants would range from 11.8 million gallons per year to 28.2 million gallons per year, well within the market demand of the Western states.

■ Not all of the plants were equally attractive economically. One plant located far from an existing biomass power plant showed a negative internal rate of return for technology based on the dilute sulfuric acid process. The others all showed a positive internal rate of return.

■ Sensitivity analysis indicated that the economics of these plants was most sensitive to feedstock cost and the ability of prospective owners to find financing.

■ Environmental impacts, while needing adequate attention, are manageable within the current policy authorities.

■ A 15 million-gallon per year bioethanol plant, co-located with an existing biomass electricity generating plant, would produce about 28 plant jobs and 60-to-128 jobs in the woods for gathering feedstock. These would be aug-

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[23] The Herger/Feinstein QLG Forest Recovery Act of 1998 was part of the Omnibus Appropriations Bill for FY 1999, P.L. 105-277.

[24] All of the conclusions in this section come from the Northeastern California Ethanol Manufacturing Feasibility Study (NREL 1997). This study, composed of several intensive studies of various aspects of the project, is available through the Quincy Library Group on the Internet http://www.qlg.org.

mented by an additional 93-to-122 indirect or multiplier jobs. In total, the plant could generate between 184 and 250 jobs in its local area, for an annual estimated payroll of nearly $5 million.

■ Because the most sensitive factors in the analysis are feedstock supply and cost, a method of assuring long-term supplies and prices seems critical to the success of such a venture, particularly in the case of the initial efforts.

Legislation Affecting Ethanol

The recent detection of the oxygenate MTBE in California groundwater has put oxygenates in general, including ethanol, under close public scrutiny. Many federal and state bills under consideration would affect the California and national ethanol market. Several pieces of proposed federal legislation, if passed, would free oil companies from a mandate for the use of oxygenates in California by allowing them a waiver from the Clean Air Act's oxygenate standard. While the aim of legislation such as H.R. 11 is to decrease or eliminate the use of MTBE due to groundwater concerns, its passage could also take away future opportunities for ethanol in the state (H.R. 11, 106th Cong., 1st sess. [1999]).

The California EPA and California Energy Commission estimate that about 300-to-580 million gallons of ethanol will be used annually without an oxygenate waiver, but only 150-to-300 million gallons per year will be used if the waiver passes (California Energy Commission 1999; Hickox 1999). The latter estimate, particularly on the lower end, is not a very significant market for biofuels considering the potential for producing 1-to-1.5 billion gallons per year of ethanol in California from indigenous biomass. However, the biofuels market is still worth pursuing by local bioethanol producers who could exploit their transportation advantage to compete for the market.

Biomass Conversion to Power

Overview

Forest and other biomass is currently being used for conversion to electric power through conventional combustion technology. The biomass power industry is composed of about 350 plants with combined capacity of about 7,800 megawatts, according to a DOE database. Of those plants, 45 are idle, equating to 655 megawatts of unrealized capacity. The plants are spread out over most of the U.S., with plants in every state except West Virginia, Colorado, Delaware, Indiana, Kansas, Nebraska, New Mexico, New Jersey, North Dakota, Rhode Island and South Dakota. In addition, another 650 industrial plants generate electricity with biomass for their own use. The biomass power industry employs more than 66,000 people in the U.S. and has an investment base of about $15 billion (NREL 1999). It is estimated that 50,000 megawatts of biopower could be generated by 2010 using advanced technologies and improved feedstock supplies. Biopower plants require a guaranteed, long-term biomass fuel supply to ensure operation (DOE 1995a).

Of the industrial combustion facilities, 148 plants use existing boilers at pulp and paper mills. The technology used in the pulp and paper industry was designed for waste disposal initially, but new technology focusing on energy production will improve efficiencies (SERBEP 1995). In California, the plants were originally built under Standard Offer contracts stemming from the qualifying facility mandate under the Public Utility Reform Policy Act (PURPA); several are cogeneration facilities. PURPA fueled the rapid development of the biopower industry until the mid-1980s, when the industry began to level off. The early contracts were based on the belief that fossil fuel prices would continue to increase. When that did not happen, utility companies purchased many of the remaining above-market contracts and retired the non-competitive facilities. Expiration of contracts and competition for biomass resources have put pressure on the biopower industry to close or revitalize the less efficient plants. Plants in California and the Northeast are feeling pressure on their revenues as avoided cost rates (cost of building new capacity) paid for electricity have declined (DOE 1996). By December 1996, California had lost about 30 percent of its existing biopower capacity, with 30 biomass power plants operating and 15 more that could be returned to service if conditions warrant (California EPA 1997).

Stand-alone biopower producers often play an integral role in the management of residue and waste flows in a region, accepting waste materials that would otherwise be landfilled or open-burned. To the benefit of the biopower plant, the fuel cost is often only that of transporting these materials. The feedstock issue is at the core of sustainability for biopower. While the use of dedicated biomass crops for energy production is recognized as neutral in terms of the net emission of carbon dioxide, the current use of biomass waste and residues for power production also decreases greenhouse gas emissions by capturing and using material for conversion to energy that might otherwise be composted, creating greenhouse gases such as methane (California EPA 1997).

Although biopower is generated currently through the combustion, or burning, of biomass, recent advancements in biomass power generation include gas turbines (such as BIOTEN GP's modular suspension combustion system or Power Generating's direct-fired turbine) and gasification. U.S. DOE is working with the existing biopower industry to improve the efficiency of its equipment (DOE 1993). Advanced biomass steam-turbine systems have efficiencies as high as 40 percent; in comparison, combined-cycle gas turbines using natural gas have efficiencies as high as 55 percent (DOE 1995a).

Policy Considerations of Biopower

The 1992 National Energy Policy Act (EPACT) established two highly attractive incentives for biopower:

- A 1.5 cent/kWh tax credit for closed-loop biopower systems
- A 1.5 cent/kWh payment that will be available to nonprofit utilities—that is, municipal and rural co-op utilities—for biopower produced. The payment will be administered by U.S. DOE (EPS 1992).

The closed-loop tax credit is not being used because of the definition of the term "closed-loop," which limits the qualifying feedstock to biomass that has been grown for the sole purpose of energy production. Efforts are now underway to expand this definition to include agricultural and forest residues. This change in the law would benefit existing biomass power plants and perhaps save some of these plants from shutting down.

In the past, electrical utility restructuring was putting significant pressure on existing biopower plants in the form of lower power prices, which challenge both utilities and independent power producers. Recent increased demand for power and a shortage of new generation produced price spikes in Western electricity markets in late 2000 and the early months of 2001. The changed market conditions, if these prices remain high, favor new biopower development. At the time of this publication, it is unknown whether the change in market conditions will be temporary or long-lasting.

In the U.S., utilities are converting into multiple companies competing for smaller pieces of the power business—that is, generation, power brokering, transmission, distribution and on-site energy services. The fossil fuel supply infrastructure provides a competitive challenge to biopower development, with the Energy Information Administration projecting a favorable fuel supply environment for coal and natural gas until 2010. Natural gas represents the majority of expected new capacity, with 30 such plants in the planning stages for California alone (ABA 2000c).

Co-firing Biomass with Coal

Co-firing biomass with coal is an opportunity for some parts of the biomass supply industry located near coal-fired power plants that rely on high-sulfur coal.[25] Co-firing can assist with market development, aiding in uncertain fuel supply and delivery issues in some states. Co-firing offers a relatively inexpensive way to significantly reduce SOx, NOx, and CO emissions.

A 1993 study of the status and potential for co-firing of biomass with coal in the Great Lakes Region concludes that no significant technical barrier exists to the increased use of co-firing (Irland and Fisher 1993). Co-firing waste-wood biomass with high-sulfur coal is potentially attractive to some utilities in the U.S. because it avoids the addition of costly flue gas scrubbers, or simply permits the use of cheaper, higher sulfur coal even under tight constraints by EPA (DOE 1997).

Studies by the Electric Power Research Institute have indicated that co-firing with biomass at levels up to 15 percent can be economical when the difference in cost between coal and wood is in the range of \$0.25 to \$0.40 per million BTU. However, when coal costs \$1.00 to \$1.50 per million BTU, it is difficult for biomass to compete (SERBEP 1995).

Several fuel characteristics need to be considered that will influence the efficiency of co-firing opportunities (Junge 1989). Physical and chemical analysis of the materials can determine moisture content, heating value, fuel density, energy density and fuel combustion rates. Table 2.1 indicates some of these values for a few types of biomass and fossil fuels (Irland and Fisher 1993).

Gasification

To achieve higher efficiencies, biomass can be converted into a gaseous form called producer gas through a procedure called gasification. The U.S. DOE has helped develop

[25] The Boardman Coal Plant in Oregon burns mostly low-sulfur coal and therefore may not be a good candidate for biomass co-firing. California has no coal plants, which rules out the co-firing option for that state.

Table 2.1. Fuel Parameters for Selected Biomass and Fossil Fuels

Fuel Parameters	*Dry Wood Pellets*	*Typical Hogged Fuel*	*Municipal Solid Waste*	*Pennsylvania Coal*	*Wyoming Coal*	*No. 2 Fuel Oil*
Moisture content (% wet basis)	10.0	40.0	30.0	1.3	2.5	0.0
As-fired heating value (Btu/wet pound)	8,127.0	5,418.0	4,500.0	13,800.0	9,345.0	19,430.0
Fuel bulk density (pounds per cubic foot)	35.0	22.0	12.0	50.0	45.0	53.9
As-fired energy density (Btu per cubic foot)	284,400.0	119,200.0	54,000.0	690,000.0	420,500.0	1,047,000.0
Fuel feed rates (cubic foot per million Btu)	3.5	8.4	18.5	1.4	2.4	1.0

gasification pilot projects using producer gas around the nation, hoping to achieve efficiencies upwards of 50 percent in the future.

Biomass gasification and hot-gas clean-up systems technologies, such as contained in the SilvaGas™ process (FERCO 2000), are being developed that will meet the fuel requirement of combustion turbines. This allows the use of biomass in high-efficiency systems such as steam-injected gas turbines and combined-cycle systems and may help some biopower plants be more cost-effective through co-firing with natural gas (DOE 1993). Gasification of biomass has the potential to add much new capacity to the existing biomass power industry. While research on gasification is not complete, these facilities should offer improvement in efficiency, emissions and the range of feedstock types they can use.

Fuel cells are being developed to convert gaseous fuel directly to power using a process analogous to that of a battery. Using gasified biomass as a fuel source, power cycle efficiencies approaching 60 percent may be possible. Much work still needs to be done using hot-gas clean up in addressing gas quality for fuel cells (DOE 1993).

Status of Today's Biomass Gasification Pilot Projects

A small number of biomass gasification plants now at different phases of construction will serve as test facilities and pilot plants for the future industry. The major pilot plants include:

■ *Burlington, VT, Gasifier Project*: Burlington Electric Department's McNeil Generating Plant has been producing wood-fired biomass power at its 50 megawatt per year plant, but it recently integrated a new gasification technology to add more capacity. DOE, along with the technology licensee Future Energy Resource Corporation (FERCO), has added a 15 megawatt per year gasifier as a pilot plant. The plant successfully attained full operation in August 2000 producing electric power from biomass in a conventional gas turbine (ENS 2000). The initial full-capacity burn converted more than 285 tons of wood chips derived mainly from low-quality trees and harvest residues into more than 140 megawatt-hours of electric power (FERCO 2000). This project does not require a hot-gas cleanup system and produces a higher Btu gas stream than other gasification systems. Industry partners include: FERCO of Georgia (which is cost-sharing 50 percent of the total project with DOE), McNeil, Battelle and Zurn Nepco of Maine (ABA 1998; DOE 1997a, 1997b).

■ *Chariton Valley Resource Conservation and Development (RC&D) Project*: This Iowa project is a public/private partnership between U.S. DOE, U.S. Department of Agriculture and the Chariton Valley RC&D Area, under DOE/USDA's Biomass Power for Rural Development Initiative. About 500 local farmers and landowners are aligned with the combined research and investment power of 14 organizations. The project will be growing switchgrass on 30,000-to-40,000 acres of underutilized, marginal cropland. The partnership received authorization from USDA Farm Services Agency for a 4,000-acre demonstration project supporting the development of energy crops on existing Conservation Reserve Program (CRP) land, as the CRP is phased-out (DOE 1996a). As of 1998, 75 percent of the acres in the Chariton test plots had been planted in switchgrass (West Bioenergy 1998). A test firing of 1,500 to 2,000 tons of switchgrass at Alliant Power's Ottumwa Generating Station is planned prior to Spring 2001. The test firing will determine the feasibility of using a dedicated supply of southern Iowa biomass as a fuel source.

Table 2.2. Typical soil erosion rates and chemical use of selected food and energy crops (National Biofuels Roundtable 1994).

Crop	*Soil Erosion ($Mgha^{-1}yr^{-1}$)*	*Nitrogen ($Kgha^{-1}yr^{-1}$)*	*Phosphorous ($Kgha^{-1}yr^{-1}$)*	*Potassium ($Kgha^{-1}yr^{-1}$)*	*Herbicide ($Kgha^{-1}yr^{-1}$)*
Corn	21.8	135	60	80	3.06
Soybeans	7.1	10	35	70	1.83
Herbaceous energy crops	0.2	30	50	90	0.25
Short-rotation woody crops	2.0	60	30	80	0.39
Pasture	2.0	20	30	30	0.15

■ *Niagara Mohawk Power Corporation Project*: This co-firing project in upstate New York and the surrounding region is also part of the DOE/USDA Biomass Power for Rural Development Initiative, with the cost estimated at about $14 million over six years, including a 45 percent federal cost-share. The feedstock for the plant is a hybridized fast-growing willow tree, developed by the State University of New York at Syracuse Biomass Program and dedicated for energy crop purposes. Niagara Mohawk represents The Salix Consortium, a partnership of more than 25 research institutions, farmer groups, governments, environmental groups and five power-generating companies. The willow energy crop will be grown on 2,600 acres of land. At least 26 local farmers have committed to invest their resources in the facility, which is expected to produce between 37 and 47 megawatts of electric capacity through co-firing with coal (DOE 1996b). More than 370 acres of commercial biomass crops had been established as of 1999; 18 smaller 1-to-2 acre trial sites had also been established in seven eastern states and Canada (Abrahamson 1999). This project would be the first true closed-loop biopower plant in the U.S.

Environmental Impacts of Biopower

Biopower plants produce virtually no sulfur emissions, helping mitigate acid rain and air pollution. Combustion of biomass results in less ash than coal combustion, reducing ash disposal costs and landfill requirements. Global warming impacts are reduced because of the recapture of carbon through photosynthesis. The CO_2 emissions from the nation's current fuel mix is more than 600 metric tons of CO_2 per gigawatt-hour, and additional biopower could help bring the net emission level down.

Several of the biomass power projects cited above produce benefits such as soil and water conservation, reduced fertilizer and herbicide use, water quality protection, and a broadened rural economic base during growth of alfalfa, switchgrass or dedicated energy plantation crops (see Table 2.2). Of course, dedicated energy crops also can be used as feedstock for ethanol and chemical production

Biomass power benefits include the following (CBEA 1988):

- Reductions of particulate matter (PM_{10}), NOx, SOx, CO, and volatile organic compounds (VOCs), with the greatest reduction in CO. The monetary value of these reductions to the environment is about $14 million per year.
- Avoidance of open burning of 1.1 million tons per year of wood residues, saving taxpayers an estimated $25 million per year.
- Diverting waste from landfills (1.7 million tons per year from 1994 figures), saving taxpayers $55 million per year.
- For 50,000 acres treated by thinning, more than 10 percent of acreage will have a reduction in burning with a value of $17-to-$54 million per year (water/watershed loss varies from $169-to-639/acre).
- Employment benefit of $165 million per year, with an estimated employment of 6,600 people at biomass power plants and in collection, processing and transport operations.
- Tax revenues of $67 million per year, including estimates for power plants, fuel processing facilities and license fees on fuel trucks.
- Displacement of fossil fuel-derived electricity, providing diversity and reliability through distributed generation (from 1991 to 1995, calculated values varied from $90-to-$156 million per year).
- Increased water yield from areas of biomass fuel collection estimated at 1.1-to-2.1 million acre-feet per year with a value of $55-to-$148 million per year.

Supplemental Opportunities for Biomass Utilization

The primary barrier to increased biomass use appears to be economic. Given the competitive position of fossil-based energy options compared to biomass, additional opportunities to improve biomass economics through production of co-products are being sought by both the bioethanol and biopower industries.

A larger and more profitable opportunity than biomass power and fuels may lie in the ability to extract valuable chemical compounds from biomass prior to or during its conversion to biofuels or combustion for energy. Research on a variety of products from woody biomass has produced several options that may help significantly improve biomass energy economics. Most of the companies now working to build biomass ethanol plants are strongly considering conversion of at least some of the biomass to chemicals, such as different types of acids or lignin-based chemicals. Such a diversion of biomass will undoubtedly help in the economics of energy from biomass, as output options for products can vary depending on markets for the different products. The larger corn ethanol plants now rely on market pull to sway their production among different commodities such as ethanol, animal feed or corn syrup. In the future, once these specialty biomass chemicals are proven cost-effective, more biomass-based chemicals will be co-produced along with ethanol and power in a "bio-refinery" operation (ABA 2000b).

The Lake Tahoe Biopower Program

The Lake Tahoe Biopower Program, a proposed project in California and Nevada, has as its goal the improvement of forest health by thinning excess woody biomass and using it as a renewable energy source. The Lake Tahoe program study is exceptionally relevant for Oregon's biomass efforts because its issues and problems are similar. The results of resource assessments, green power market research and marketing strategy development provide a template that Oregon may find useful in developing its biomass programs.

The Lake Tahoe Biopower Program aims to develop cost-effective market outlets for woody biomass as a way to improve forest health in the Lake Tahoe Basin, a 519-square-mile area on the California/Nevada border. The program study was funded for the Nevada Tahoe Conservation District by the US DOE's Western Regional Biomass Energy Program (WRBEP) and prepared by McNeil Technologies (2000). Participants include government agencies, private industry, community organizations and environmental groups.

The Lake Tahoe Basin ecosystem has been dramatically altered since the mid-nineteenth century. It was logged extensively during the early years of settlement, and old-growth pines were replaced by regrowth of fire-susceptible firs. As a result of the exclusion of natural fires, lack of thinning and above-average rainfall earlier in this century, Tahoe Basin forests are now characterized by over-crowded, even-aged trees and dense undergrowth. A catastrophic fire could threaten the basin's soil, water and wildlife habitat, as well as its human residents and their property.

A previous WRBEP report (see McNeil 2000) concluded that the basin produces substantial amounts of excess woody biomass and that removing it could improve forest health, reduce fire risk and provide a renewable energy source. A presidential forum on forest health objectives estimated that a potential sbiomass yield of 45,500 bone-dry tons (BDT) per year was available, based on a per-acre yield of 13 BDT per year on 3,500 acres of USDA Forest Service and private timberlands. Using all the 26,000 bone-dry tons of biomass generated from mechanical thinning of just National Forest land could provide up to 27 gigawatt-hours of electricity per year.

The Lake Tahoe Basin program, if implemented, would capitalize on existing infrastructure. Biomass would be harvested, chipped and transported to the Sierra Pacific Industries (SPI) biomass cogeneration plant in Loyalton, California (or to some other biomass power generator). The cogeneration plant would burn the wood chips and produce biopower for sale to utility customers. The cost range for biomass prepared and delivered to the Loyalton plant is \$52.41 per bone-dry ton (low estimate) and \$112.50 per bone-dry ton (high estimate).[26] A preliminary study by the Sierra Pacific Power Company (SPPCo) concluded that SPPCo has sufficient transmission capacity to handle 3-to-4 MW of additional power from the Loyalton plant.

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[26] All costs and quantities reported were converted from green to bone-dry tons using a biomass moisture content of 52%, based on biomass testing performed by South Tahoe Refuse Company (STR). Biomass production costs for the Lake Tahoe study are based on data collected by the USFS and time and motion studies at forest restoration sites in Colorado and elsewhere in the Western US. These costs include stumpage, capital costs, labor costs, fuel costs and equipment maintenance costs. Chipping costs are taken from a prior chipping cost study by NEOS Corporation and a cost-shared study in support of the current project by STR. Transport costs are based on published biomass trucking costs and actual STR costs between a Tahoe area USFS site and the SPI Loyalton plant, a distance of 75 miles. See McNeil 2000.

Total estimated biopower costs—including collection, chipping, transport, generation and marketing—were estimated at $.075 per kilowatt-hour (kWh) as a low estimate and $0.129 per kWh as a high estimate. The difference between high- and low-end costs depends on the costs of delivered biomass fuel. Using a low-end scenario, a household with a monthly demand of 200 kWh would pay an additional $4 per month to meet all its electricity needs with biopower.

The costs mentioned above exclude California Energy Commission (CEC) credits, which are currently available at a rate of $0.015 per kWh for both California producers and consumers of renewable energy (including solar, wind, biomass and other green technologies). Factoring in the CEC credits, the biopower premium over conventionally produced electricity is $.02 per kWh as a low estimate and $.074 as a high estimate. However, as the date of this publication, the CEC supplier credit was targeted to be phased out by 2002, further increasing the price premium of biopower over conventional power in the future.

To be successful, the Lake Tahoe program will need a viable customer base for its power output, and that base will have to include customers from both residential and commercial sectors. An essential factor for success is recruitment of large commercial customers who are willing to commit to buying a significant quantity of biomass-based energy. Businesses that depend on the natural beauty of Lake Tahoe's forests can benefit from both improved forest health and public recognition of their role in supporting sound forest management. Federal agencies are also a good target due to a recent Executive Order (White House 1999) instructing agencies to increase their use of renewable energy. State, regional and local governments are potential customers and program supporters as are environmental groups and "green" product retail establishments.

Product differentiation is a challenge for renewable energy. The renewable power provider must be able to link biomass-derived power directly to the benefits it can have for local areas. Likewise, a tangible description of the benefits of forest management needs to be established and delivered to target consumer markets. People will be more likely to support biopower use, even at a price premium, if they associate it with sustainable forests, water quality improvement and reduced fire risk.

Results of a 1997 study[27] evaluating customer attitudes toward, and willingness to pay for, electricity generated from alternative sources indicated that both California and Nevada utility customers view the benefits of renewable energy options as outweighing perceived problems or barriers. Available information on willingness-to-pay suggests that utility customers in the Lake Tahoe Basin will pay more for biomass energy. The low end of the price premium, $.02 per kWh, is comparable to that for wind power from the Windsource Program in Colorado, and that program has more than 10,000 subscribers. A caveat: There is often a discrepancy between what people say they are willing to pay, as recorded through surveys, and what they actually do, in terms of actual sign-ups for green power programs. Using more conservative sign-up rates would better forecast actual subscriptions.

[27] In late 1997, a joint effort between SPPCo, the Nevada State Energy Office, and NREL resulted in an evaluation of customer attitudes towards and willingness to pay for electricity generated from alternative energy sources. See McNeil 2000.